Final Report

MUNICIPAL ELECTRICAL ENERGY MASTER PLAN

(ME2MP)

as part of the South African - German Energy Programme (SAGEN)

1 March 2022

Garden Route District Municipality

Prepared for : PASSMORE DONGI

PMU, Garden Route District Municipality

54 York Street, George

Western Cape

Tel: +27 (0)44 803 1335 | 067 272 9908

e-mail: Passmore@gardenroute.gov.za

Submitted by : WARRICK PIERCE

Principal Engineer

Energy Centre, Smart Places, CSIR

P O Box 395

Pretoria, 0001

e-mail: wpierce@csir.co.za

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APPROVED BY:

Responsibility	**Name**	**Signature**
Project Leader	Warrick Pierce	
Research Group Leader (RGL)	Dr Brian North	

PRIMARY DISTRIBUTION:

Company	**Contact Person**	**Copy Number**
CSIR: Energy Centre - Head	Dr Clinton Carter-Brown	1 of 3
CSIR: Energy Centre – Energy Systems RGL	Dr Brian North	2 of 3
Garden Route District Municipality	Mr Passmore Dongi	3 of 3

Executive Summary

South Africa is experiencing an electricity crisis – supply is not able to meet demand. Loadshedding has become part of everyday life in South Africa, and this may continue for the foreseeable future. Furthermore, the Electricity Supply Industry (ESI) is evolving but the end-state is unknown.

Solar PV is modulable and thus can work on small-scale. Internationally, the emergence of embedded generation, which can also be referred to as customer resource, is changing the flow of energy (and cash) from the traditional, solely top-down and centralized to incorporate some bottom-up and decentralized. Customers, including municipalities, are no longer captive. In light of these dynamics, municipalities are compelled to re-define their role in the electricity value chain and adapt their funding and operating models.

CSIR provided support to the Garden Route District Municipality. The region consists of seven individual municipalities, namely Bitou, George, Hessequa, Kannaland, Knysna, Mossel Bay and Oudtshoorn. The primary objective of the study is to provide insight on possible electricity futures for the region. Two focus areas were considered, first the potential of rooftop PV was identified. Secondly, technoeconomic optimisation of utility scale generation technologies to provide an optimal energy mix for the region, similar to the national IRP.

The region has a peak demand of around 250 MVA and annual consumption is about 1.3 TWh (less than 1% of the national demand). Eskom is the only supplier of electricity to the municipalities. Most of the 150,000 customers are residential but their share of electricity sales is about half.

Rooftop Solar PV

The geospatial work identified rooftop area for the individual municipalities per customer class. Residential customers 'house' 75% of the identified space. Installable PV capacity equates to approximately 1,750 MW - 7 times the regions MD (maximum demand).

Only 36% of the installable PV capacity is required to meet all customers' annual energy consumption, in terms of magnitude (not timing). Residential customers have ample roofspace to cover their own annual electricity consumption needs.

The business case analysis shows that rooftop solar PV currently makes sense in many instances. Due to increasing municipal tariffs and declining solar PV costs the business case improves with time. By 2040 solar PV makes financial sense for all customer classes and scenarios.

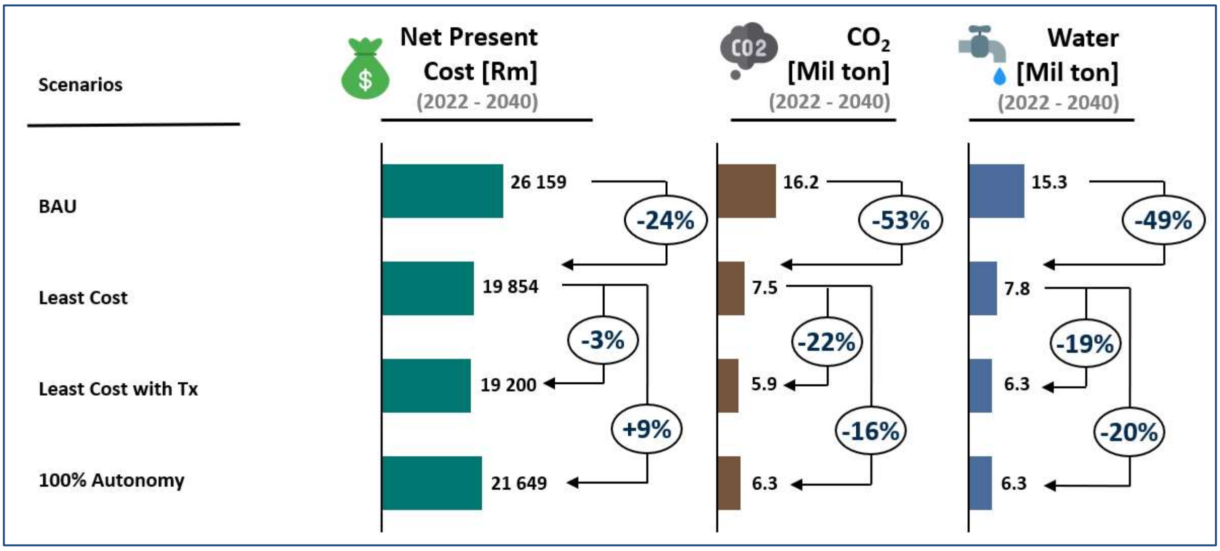
The GRDM is most likely in the initial-Early Adopters stage with an estimated market share of rooftop solar PV of roughly 3.5%. A 25% market share is estimated for 2040. By fitting a Bass diffusion model the market share in 2030 was shown to be around 10%.

The analysis showed that rooftop solar PV can play a significant role in the electricity future of the region. Decision makers should be mindful of this customer resource and promote the responsible and sustainable utilisation thereof.

Utility Scale Generation

The findings of this study showed that if the Eskom electricity tariff is escalated as per our assumptions and no interventions are taken (business as usual approach) that the net present value of total system cost for the entire GRDM will be 24% more expensive than adopting a Least cost plan. The Least cost plan has cost benefits as well as societal benefits derived from reducing CO_2 emissions and consuming less water. The figure below shows the cost savings, cumulative CO_2 emissions and water consumption for the combined GRDM. The cost of not taking action is high.

If a regional optimisation approach is applied (Least Cost with Transmission), then a further 3% cost savings could be achieved. Lastly a 100% Autonomy scenario was investigated to quantity what would be required if the individual municipalities are forced, or choose, to disconnect from the Eskom network. The cost premium for 100% Autonomy relative to Least Cost is only 9% and still lower than BAU. It was clearly shown that for the period 2022 to 2040, it is <u>not</u> economically optimal for the GRDM to disconnect from Eskom.



The findings per technology for utility scale generation are presented:

- ✓ New solar PV: The results conclusively showed that solar PV is already competitive with the current Eskom tariff, that most of the capacity build is concentrated in the early years and ramps up in the later years as more battery capacity is added in the mix. If the grid is constrained and it is not possible to wheel between municipalities in the region, then the GRDM should consider investing a minimum of 230MW solar PV as soon as possible in the medium-term horizon. If the grid is not constrained, then the investment in solar PV can be ramped to 285 MW.
- ✓ New Wind: It is also competitive with the current Eskom tariff; new capacity is required as early as 2027 though not to the same extent as solar PV. If the grid is constrained and it is not possible to wheel between municipalities in the region, then the GRDM should consider investing in a minimum of 150 MW wind as soon as possible placed as per the Least Cost plan. In the unconstrained scenario similar quantities of wind are required.
- ✓ New Battery: The results show that a large amount of new battery capacity is built in the later years where costs are expected to reduce, we recommend tracking battery costs and consider revising the IRP before making a significant investment in the later years. The GRDM should track battery cost for alignment with our assumption before investing in a minimum of 40MW (160 MWh) by 2025, the next phase of investment post-2025 should be informed by an updated IRP which tracks cost and performance characteristics of all technology options.
- ✓ New OCGT: the Least cost plan requires some amount of peaking capacity to maintain system flexibility and also to mitigate against periods with higher Eskom tariffs. The GRDM should track how Eskom electricity tariffs increase, the investment in OCGT is required post-2025 and should

be informed by an updated IRP. It is worth noting that the OCGT plants are modelled as diesel fired. Affordable gas (for instance LNG) and/or green hydrogen may provide more options/capacities for OCGT.

It is not recommended that municipalities make all the new capacity investment at once, but rather make firm investment decisions in the medium term and then revise the IRP once every three years to determine the next phase of investment.

Wheeling between Municipalities

As mentioned, if a regional optimisation approach is applied (Least Cost with Transmission), then a further 3% cost savings could be achieved. The table below provides a high-level comparison of the results of regional (which includes wheeling between the municipalities) vs nodal (no wheeling) optimization. The regional optimization is able to shift generation capacity to better solar and wind resource areas as shown below. The results are dependent on the cost of wheeling. Not surprisingly when wheeling is possible, more solar PV is built in Oudtshoorn and the power is evacuated to George, the largest demand center in the region.

	Solar PV	**Wind**	**Battery**	**OCGT**	**Eskom**	**Overall Energy**
Bitou	more	more	similar	similar (later)	less	exporter (to Knysna)
George	less	more	less	more	less	importer (from Mossel Bay and Oudtshoorn)
Hessequa	more	more	more	more	less	similar
Kannaland	similar	more	similar	less	less	similar
Knysna	less	less (none)	less	more	less	Importer (from Bitou)
Mossel Bay	more	less	more	more	less	exporter (to George)
Oudtshoorn	more	less	more	similar	less	exporter (to George)
Region*	more (21%)	less (-8%)	similar (-3%)	more (double)	less (-44%)	similar

* percentages are based on installed capacity (cumulative build) at 2040

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List of Abbreviations

AEP	Annual Energy Production
ATB	Annual Technology Baseline
BAU	Business As Usual
CO_2	Carbon Dioxide
COUE	Cost of Unserved Energy
DM	District Municipality
EIA	Environmental Impact Assessment
FOM	Fixed Operations and Maintenance
GRDM	Garden Route District Municipality
GW	Gigawatt (1 000 000 000 W)
GWh	Gigawatt hour (1 000 000 000 Wh)
km	Kilometer
LCOE	Levelized Cost of Electricity
LNG	Liquified Natural Gas
MSW	Municipal Solid Waste
MTS	Main Transmission Station
MYPD	Multi-Year Price Determination

NERSA	National Energy Regulator of South Africa
NPV	Net Present Value
p.u.	Per-unit
PV	Photovoltaic
REDZ	Renewable Energy Development Zones
REIPPPP	Renewable Energy Independent Power Producer Procurement Programme
SEZ	Special Economic Zone
SoDa	Solar Radiation Data Set
SSEG	Small Scale Embedded Generation
TOU	Time of Use
VOM	Variable Operations and Maintenance
WASA	Wind Atlas of South Africa

1. Background

1.1. Context

South Africa is experiencing an electricity crisis – supply is not able to meet demand. Loadshedding has become part of everyday life in South Africa, and this may continue for the foreseeable future. Furthermore, the Electricity Supply Industry (ESI) is evolving but the end-state is unknown.

On a utility scale, solar PV and onshore Wind are cost competitive, with reduced GHG emissions benefits. These Variable Renewable Energy (VRE) generation technologies and are being added to the national energy 'mix'. VRE is not just providing diversity from a technology/resource perspective but also from a geographical one – distributed generation.

Solar PV is modulable and thus can work on small-scale. Internationally, the emergence of embedded generation, which can also be referred to as customer resource, is changing the flow of energy (and cash) from the traditional, solely top-down and centralized (Figure 2) to incorporate some bottom-up and decentralized (Figure 3). Customers, including municipalities, are no longer captive. In light of these dynamics, municipalities are compelled to re-define their role in the electricity value chain and adapt their funding and operating models.

The South African - German Energy Programme (SAGEN) in cooperation with the Department of Mineral Resources and Energy (DMRE) and the South African Local Government Association (SALGA) as summarized in Figure 1 is intended to provide improved framework conditions for renewable energy (RE) and energy efficiency (EE) in South Africa. As part of Component B, technical support to the 278 municipalities across South Africa (8 metropolitan, 44 districts and 226 local) on aspects of this transition is provided across a number of work packages.

The Council for Scientific and Industrial Research (CSIR) is an implementing partner on the SAGEN programme and is focusing on the safe integration of Small-Scale Embedded Generators (SSEG) into municipal infrastructure as well as the development of sustainable business models for municipal utilities. The work packages (WPs) CSIR is responsible for implementing are shown is shown in Figure 4. In this regard, invitations for municipalities to be considered for support in the various areas highlighted were issued via the South African Local Government Association (SALGA).

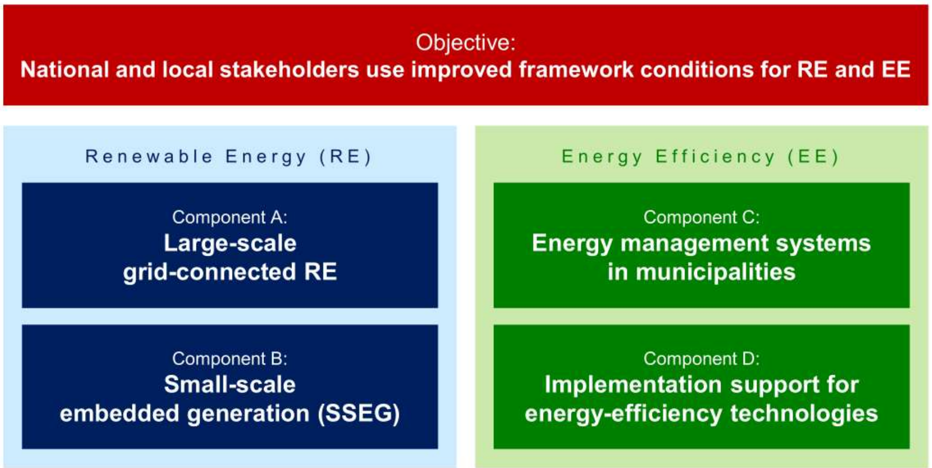

Figure 1: Structure of SAGEN-3 programme (GIZ)

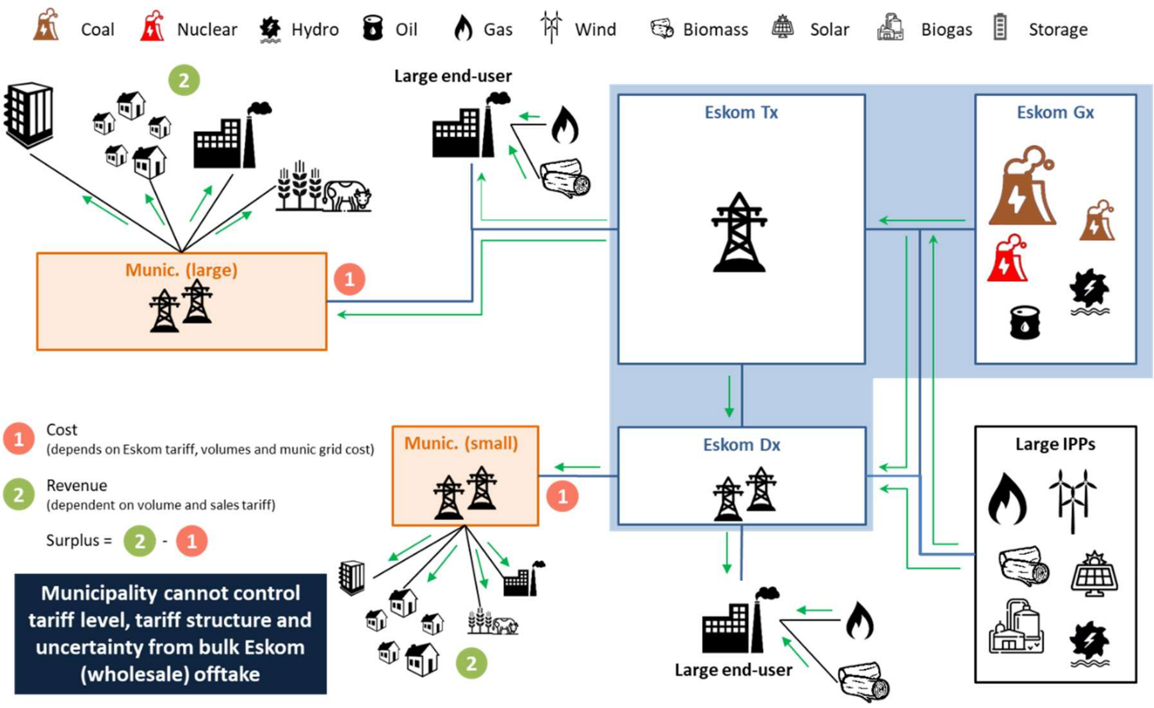

Figure 2: Centralised utility scale power generation supplying electricity needs of municipalities (status-quo)

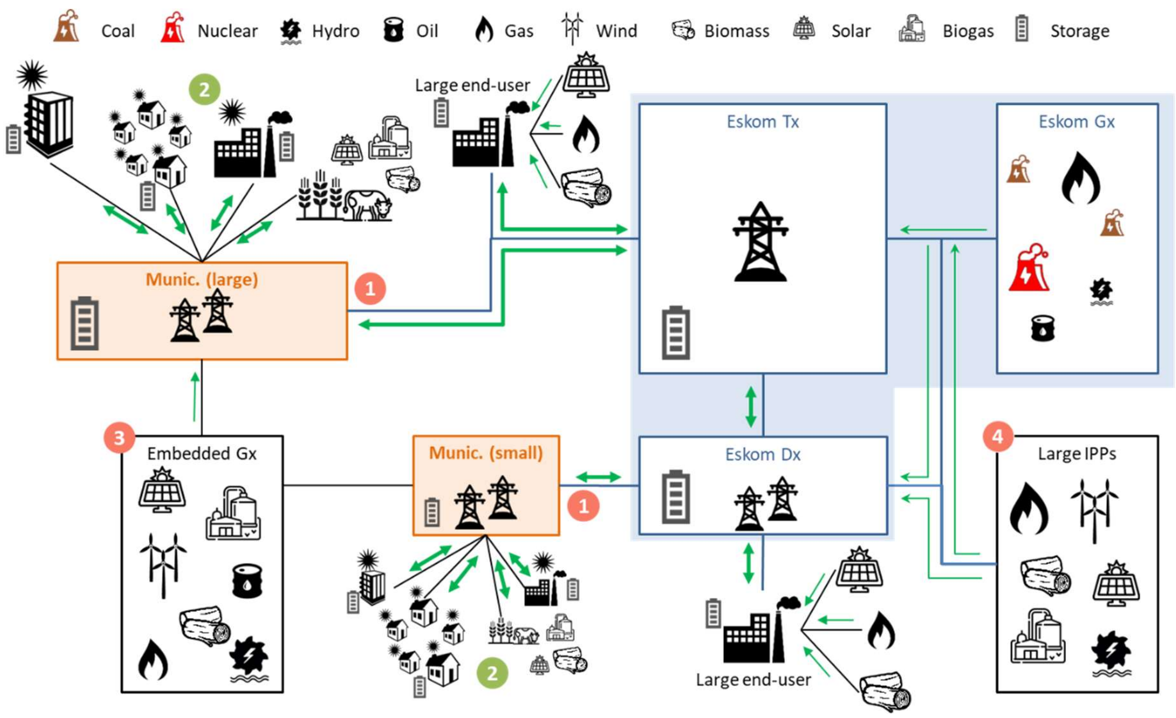

Figure 3: Increasing levels of distributed resources would impact the energy landscape where more distributed resources become embedded in municipal networks

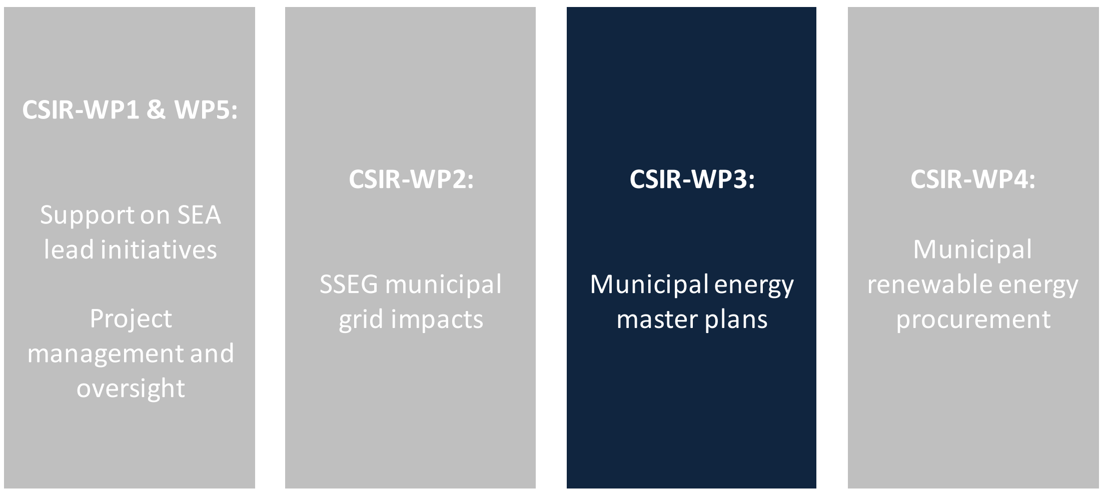

Figure 4: CSIR Work Packages (WPs) as part of implementation of SAGEN-3 programme highlighting WP on municipal electrical energy master plans (ME2MPs)

One of the areas of support is the development of Municipal Electrical Energy Master Plans (ME2MPs). Similar to the national level integrated resource plan (IRP) undertaken by the DMRE, the creation of MEMPs is intended to complement the national level IRP and is a critical foundation to empower municipalities to determine what type, when and the boundary conditions to procure/enable energy solutions in the respective jurisdictions. Such MEMPs form the business case for the municipal role in the sustainable energy transition, leveraging municipal competencies and integrating spatially dependent local resources and opportunities.

As part of a transparent and open selection process, the Garden Route District Municipality (GRDM) responded to an invitation for MEMPs development support and was selected as a preferred district municipality by partners. Within the GRDM are seven (7) local municipalities (in alphabetical order):

1. Bitou local municipality
2. George local municipality
3. Hessequa local municipality
4. Kannaland local municipality
5. Knysna local municipality
6. Mossel Bay local municipality
7. Oudtshoorn local municipality

Figure 5: Local municipalities withing the Garden Route District Municipality in the Western Cape Province of South Africa.

1.2. Project Objectives

The primary objective of the study is to provide guidance on possible electricity futures for the region. The report does not stipulate how to get there but provides possible scenarios.

The GRDM has clearly indicated its drive to become one of the greenest energy regions in the country. Local generation capacity may also lower and stabilise wholesale electricity prices. Further benefits may include local job and green branding. Economic development is not considered in this study.

A Municipal Electrical Energy Master Plan (ME2MP) based on the least-cost techno-economic optimisation of the municipal electrical energy system is developed. Factors that were considered include:

- Demand projections
- Tariff projections
- Local resources (solar and wind)
- Rooftop PV (customer resource) potential and penetration
- Technical performance and costs
- High-level considerations of power network constraints

1.3. Applied Methodology

The overall process is a least-cost, techno-economic optimisation of supply options to meet demand in the region. The outlook is from the year 2022 to 2040, the reference year is 2021. The study deviates from the national IRP on two aspects

- Customer resource – the option of embedded generation, namely rooftop PV is explored. This is executed before the generation expansion planning which (only) considers utility-scale generation options.
- Regional – the national IRP is non-spatial; the country is treated as single node (this is also true for town or city IRPs). For the GRDM we treat each municipality as a node which is inter-connected by a simplified electrical network. IRPs answer which technology to install (or retire) and when to do so. The where is not typically dealt with. Our approach considers the local resource and determine optimal placement of generation. For instance, is it better to build a solar PV plant near to Oudtshoorn (with a higher solar resource) and transmit over the

escarpment/mountain to George (the largest load centre in the region) or only build at George?

Due to the above extensions to a 'standard' IRP in South Africa we believe this work is innovative. The approach provides insights for the local decision/policy makers, lessons learnt can also be applied on a national level.

The work is grouped into four workstreams and four phases:

Table 1: Structure of the study

<table>
<tr><th></th><th>1. Status Quo (Input Data)</th><th>2. Forecast and Analysis</th><th>3. Capacity Expansion Modelling</th><th>4. Impact Assessment (Results)</th></tr>
<tr><td>Customer</td><td>Get to know your customer</td><td>Demand projections, rooftop PV analysis</td><td rowspan="4">Techno-economic optimisation (PLEXOS modelling)</td><td rowspan="4">Determine GHG reductions and impact on the cost of electricity for the GRDM (relative to BAU)</td></tr>
<tr><td>Technology</td><td>Technical performance and costs</td><td>Learning rates</td></tr>
<tr><td>Local Resource</td><td>VRE resource potential, GIS layers, Eskom electrical network</td><td>VRE generations, Simplified electrical network</td></tr>
<tr><td>Utility</td><td>Municipality and Eskom tariffs</td><td>Projected tariffs</td></tr>
</table>

The Customer is purposely placed at the top, the Utility at the bottom and Technology and Local Resources separating the two. As energy systems become more dynamic and customer-centric so too should energy systems planning.

1.4. Limitations of the Study

Energy planning is forward-looking, both the inputs to the analysis and the modelling outputs. The future is uncertain, so one should interpret the findings as possible scenarios, not one truth. The aim is not to predict the future (you cannot) but rather to plan/prepare for the uncertainty thereof.

Customer usage data is based on information sourced from the municipalities. The response to the request for input data was poor. This and subsequent time constraints prompted an alternative to detailed customer sales data, namely D-Forms. These forms need to be submitted by the municipality to NERSA so were readily available and did not require additional effort. It is acknowledged that there may be a variation of actual customer sales and reported but this is believed to be acceptable.

Details of the interconnecting electrical network, owned and operated by Eskom, were not available. High level assumptions and approximations were made to derive the network constraints. Therefore, instead of network constraints being an input to PLEXOS modelling, which would allow for co-optimisation, network constraints were considered post-processing

1.5. Document Structure

This document is structured as follows:

- Section 2: Input Data (Status quo)
- Section 3: Analysis and Forecast
- Section 4: Rooftop PV Analysis
- Section 5: Capacity Expansion Planning
- Section 6: Summary and Conclusions
- Section 7: Recommendation for Further Work

Section 2 and 3 use the four workstreams (Customer, Technology, Local Resource, Utility) as sub-headings.

2. Status Quo

2.1. Customer

2.1.1. Overview

Customer refers to the municipalities' customers – the end-user. Data was sourced via the municipalities. Initially, the data requirements requested by the study team from the municipalities was extensive. Unfortunately, not all municipalities responded in within the required timeframe. As mentioned in Section 1.4, an alternative to detailed customer sales data was employed. The D-Forms need to be submitted by the municipality to NERSA so were readily available and did not require additional effort. It is acknowledged that there may be a variation of actual customer sales and reported but this is believed to be acceptable.

The other data requirement was their monthly Eskom invoices, or a summary thereof. Other than Eskom, there are no electricity suppliers to the municipalities in the region. Both the inflow (Eskom invoices) and outflow (D-Forms) of electricity services and revenues, from the municipalities' perspective, were captured.

2.1.2. Electrical Demand

Total demand per Municipality is provided in Section 2.6.2. This section describes usage per customer class. Three customer classes are used, namely Residential (also known as Domestic), Commercial and Industrial. In some instances, for instance with land cover GIS analysis, Agriculture is also provided. The GRDM has significant agricultural activity, especially in terms of land cover.

The D-Forms for the most recent completed Financial Year (FY), namely 2020/21 (July 2020 to Jun 2021), were not available. Thus, the previous FY was used. Fortunately, the most recent FY Eskom invoices were available. D-Forms provide the total purchases which was solely Eskom purchases. The D-Form data is scaled accordingly with total purchases to present customer sales data for FY 2020/21.

The number of customers and relative split per municipality and customer class are presented, respectively, in Table 2 and **Figure 6.** Residential is by far the most prevalent. For the GRDM the overall split is 94% Residential, 5% Commercial and only 1% Industrial. The ratios for energy sales are very different.

Table 2: Number of Customers

	Bitou	George	Hessequa	Kannaland	Knysna	Mossel Bay	Oudtshoorn
Residential	11 699	44 788	13 243	3 596	22 299	36 830	10 533
Commercial	641	860	1 117	275	1 493	2 214	893
Industrial	275	384	64	23	-	162	115
Total	12 615	46 032	14 424	3 894	23 792	39 205	11 541

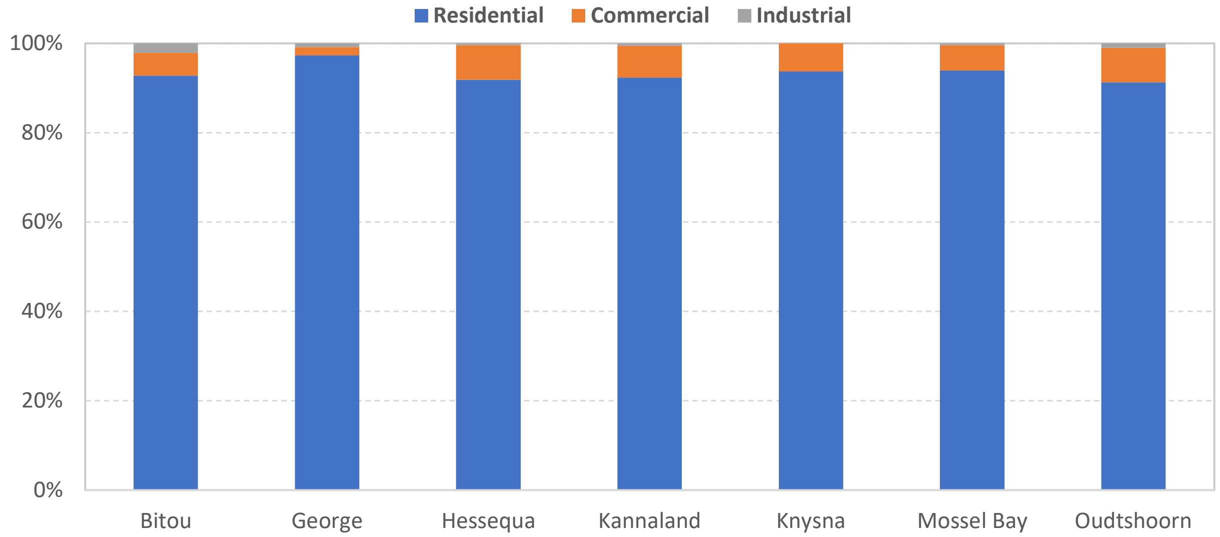

Figure 6: Customer split: number of customers

The annual energy sales and relative split per municipality and customer class are presented, respectively, in Table 3 and Figure 7. For the GRDM the total is 1,182 GWh with an overall split of 48% Residential, 18% Commercial and 34% Industrial. Kannaland is an outlier with almost 70% of annual sales coming from Industrial Customers that only make up 1% of their customer base. Table 4 presents the average monthly energy sales per Customer. The Residential average use is similar across the district, besides Kannaland which is (again) an outlier. This is likely due to Kannaland's very high indigent population.

Table 3: Annual electricity sales [GWh]

	Bitou	George	Hessequa	Kannaland	Knysna	Mossel Bay	Oudtshoorn
Residential	43.8	189.5	46.6	5.9	86.7	131.4	60.0
Commercial	16.8	39.8	23.4	3.9	65.8	47.5	21.1
Industrial	38.7	174.4	18.1	22.6	-	99.9	46.4
Total	99.4	404	88.2	32.4	153	279	128
% Residential	44%	47%	53%	18%	57%	47%	47%

Table 4: Average monthly electricity sales per customer [kWh/Customer]

	Bitou	George	Hessequa	Kannaland	Knysna	Mossel Bay	Oudtshoorn
Residential	353	294	137	324	297	475	353
Commercial	3 859	1 745	1 183	3 673	1 786	1 971	3 859
Industrial	37 868	23 566	81 331		51 529	33 615	37 868
Overall	99.4	404	88.2	32.4	153	279	128

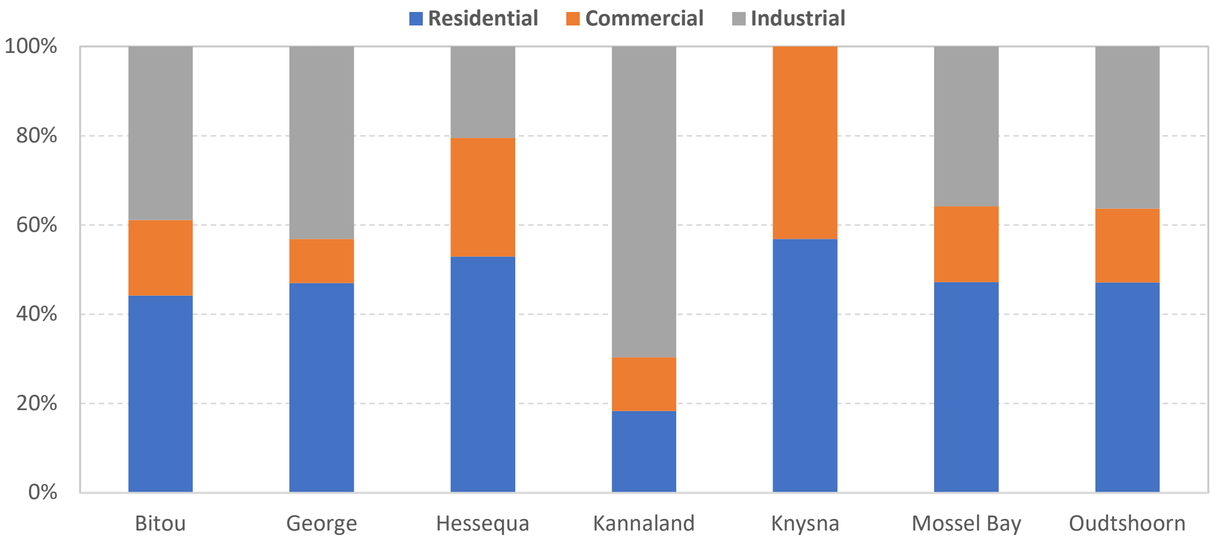

Figure 7: Customer split: annual energy sales

2.2. Local Resources

2.2.1. Overview

Two local resources are considered per municipality, namely solar and onshore wind. From these, the potential energy production for a solar PV and Onshore wind plant are modelled. Thus, the said resources are unique per municipality. The resource assessment produced hourly datasets for a year. A brief discussion is provided on the Eskom electrical interconnection network in Section 2.5.

For solar PV, the coordinates of the 'main' town per municipality were used. Due to changes in the terrain, the wind resource can vary significantly within a short distance. Thus, a more involved process was used for wind site selection. The sites are summarised in the following table.

Table 5: GPS coordinates of locations selected for solar and wind resource assessments

		Solar Assessment Site		Wind Assessment Site	
Municipality	Town	Latitude	Longitude	Latitude	Longitude
Bitou	Plettenberg Bay	-34.055	23.373	-34.098	23.359
George	George	-33.961	22.454	-33.729	23.180
Hessequa	Riversdale	-34.092	21.259	-34.334	21.684
Kannaland	Ladismith	-33.495	21.265	-33.563	20.934
Knysna	Knysna	-34.038	23.050	-34.041	22.956
Mossel Bay	Mossel Bay	-34.182	22.139	-33.910	21.704
Oudtshoorn	Oudtshoorn	-33.594	22.214	-33.424	22.113

The remainder of this section presents geospatial maps to describe the local area. The GRDM is an environmentally diverse area – forests of Knysna to arid, Karoo-type terrain of Oudtshoorn. Figure 8 displays the water features, including strategic water source areas. Most of the region is classified as high risk in terms of water quantity, quality and regulation, Figure 9. Most of the populated areas have highly stressed groundwater catchments.

When siting a project, environmentally sensitive areas need to be avoided as far as possible. The GRDM biodiversity and conservation planning areas are portrayed in Figure 10. The Western Cape Biodiversity Spatial Plan [1] provide for priority biodiversity areas and aims to guide land use, development planning, environmental assessment, and natural resources management. For example, in Critical Biodiversity Areas, only low-impact, biodiversity-sensitive land uses are recommended.

A high-level environmental constraints map provides an overview of potential areas that need to be avoided or may be constrained for new energy development, based on available spatial data, Figure 11. In reality and / or at a finer scale, other opportunities and constraints may be revealed. Areas that have been classified as “Avoid” may be considered as unavailable, potential fatal flaws or critical conflicts for utility-scale renewable energy development. Constrained areas present procedural or land use constraints. For example, in the case of rivers and wetlands, new development within 32 m of would require non-consumptive water use authorisation (i.e. procedural constraint). In the case of landcover / uses, these areas may be potential opportunities for new utility-scale solar PV development sites, but would require a transition to new / multi-purpose land use.

The development of facilities for the generation of electricity from a renewable resource require Environmental Authorisation in terms of the National Environmental Management Act (107 of 1998). An output of more than 10 MW requires a Basic Assessment procedure, whilst an output more than 20 MW requires a Full Scoping and Environmental Impact Assessment.

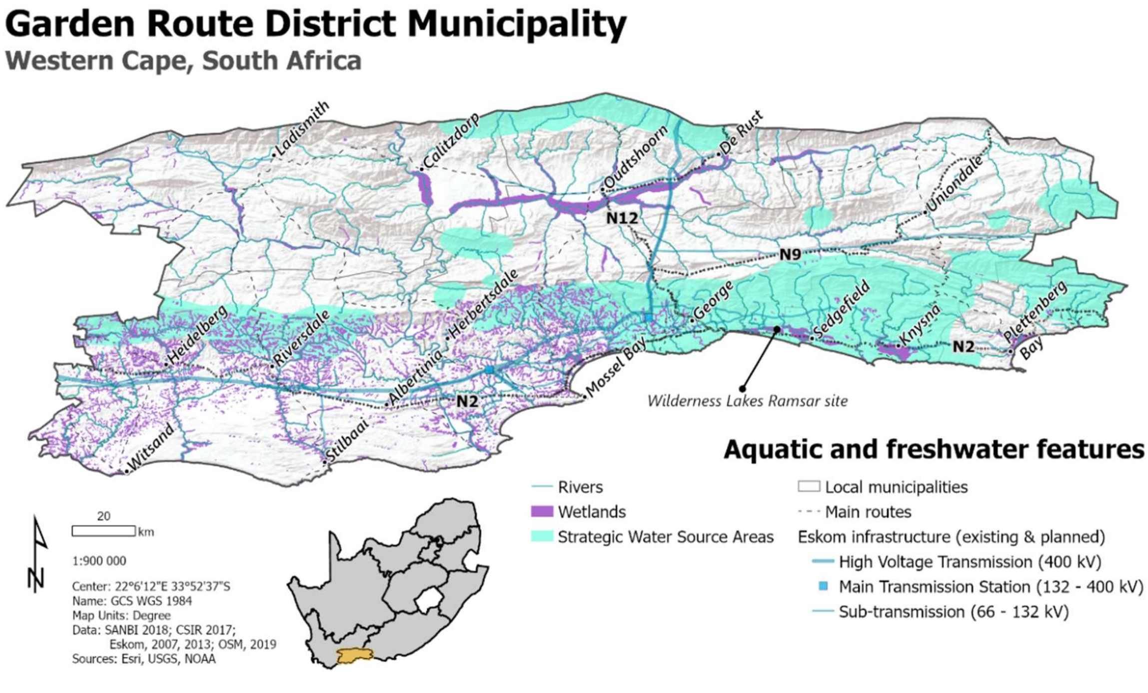

Figure **8**: Aquatic and freshwater features

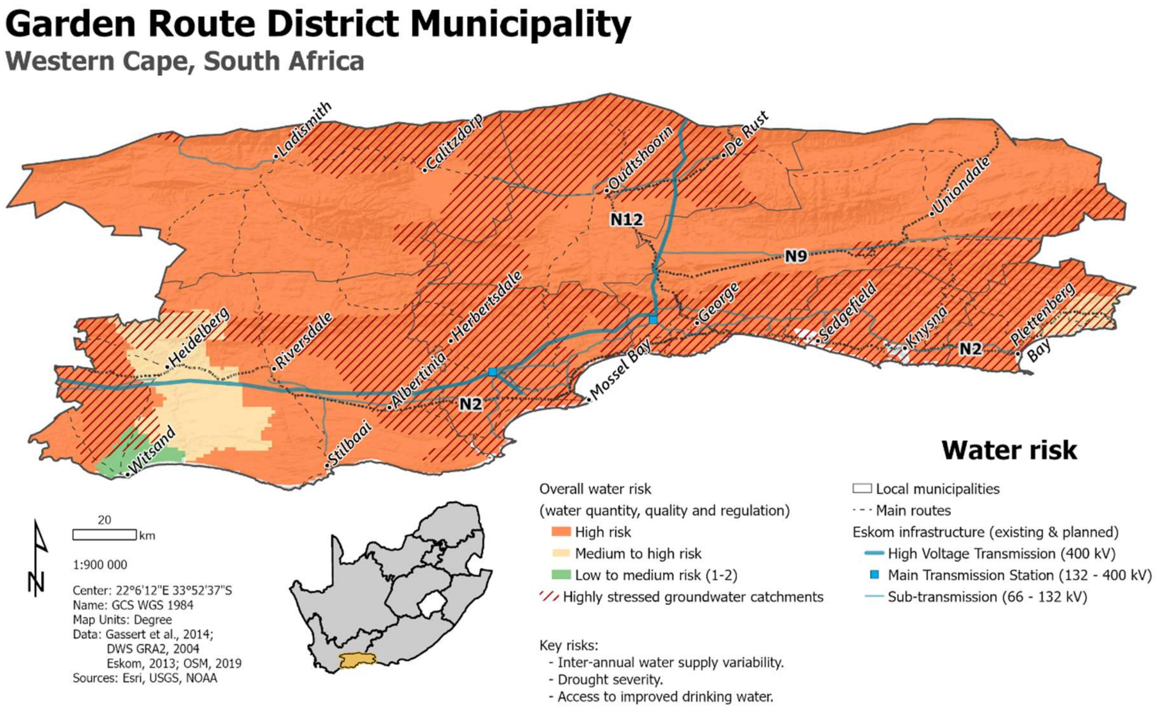

Figure **9**: Water risk

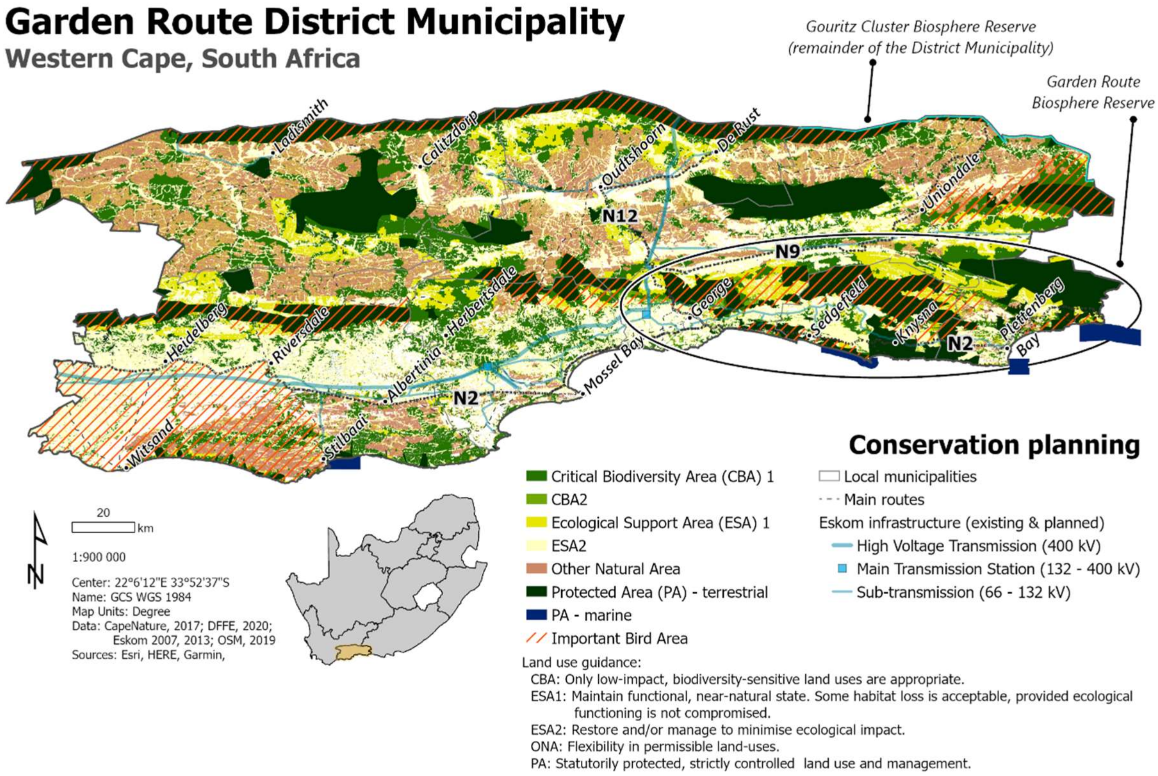

Figure **10**: Biodiversity and conservation planning

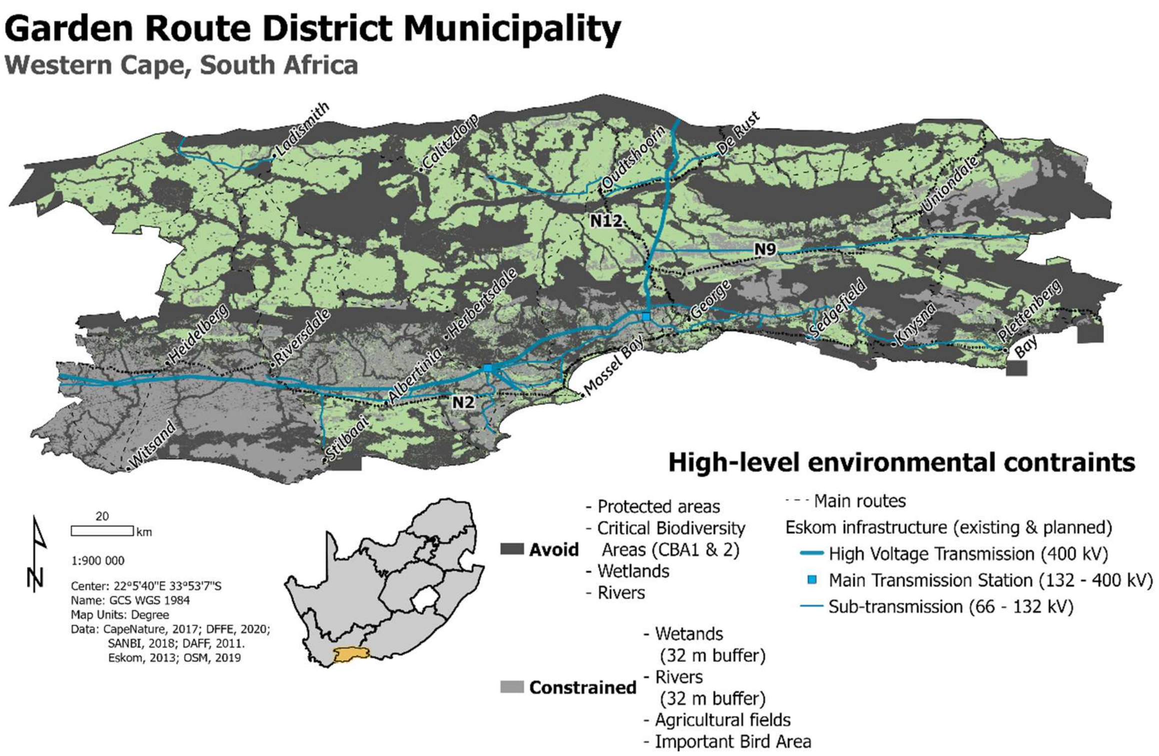

Figure 11: High-level environmental constraints.

The population of the region is concentred on the approximately 130 km of coastline between Mossel Bay and Plettenberg Bay (Bitou). Figure 12 provides the area typology (densely vs sparsely populated areas) and building concentration. In terms of residential customers, the top three municipalities (George, Mossel Bay and Knysna) contribute almost ¾ of the total (refer to Table 2).

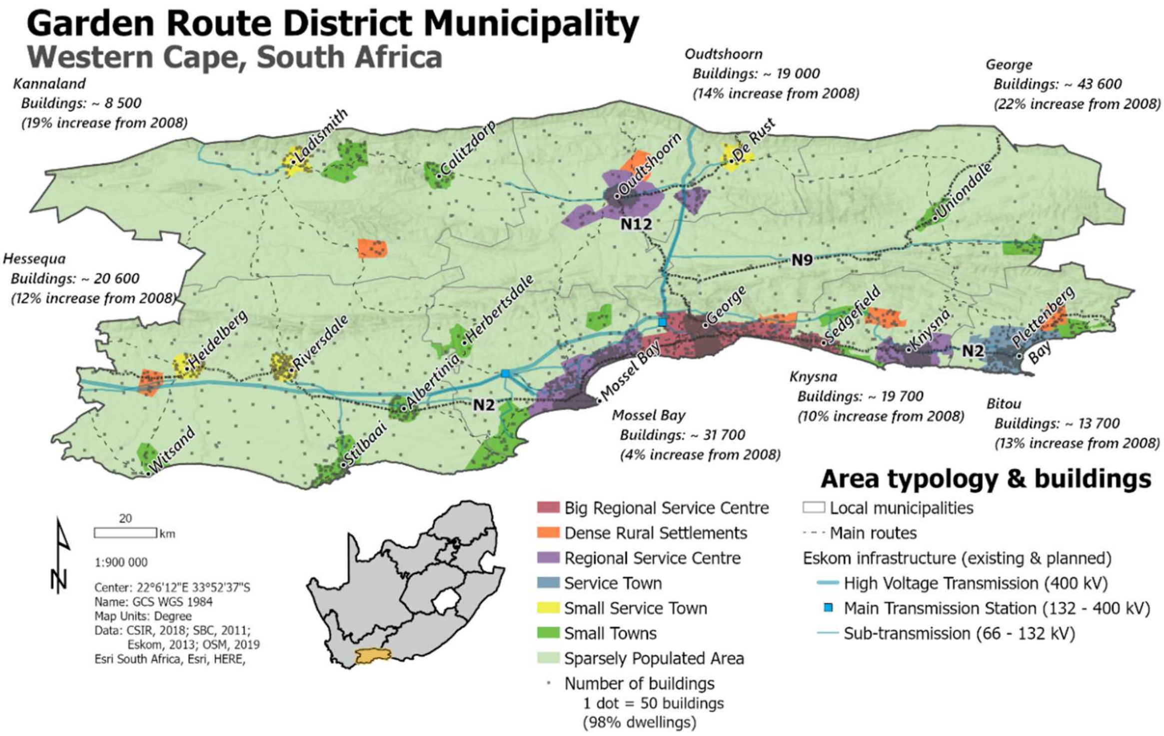

Figure **12**: Area typology and building density (dots)

2.3. Solar Resource Assessment

The details of the assessment are presented in Annexure A.

Generally speaking, although not the best in the country the solar resource is quite good with ≈1715 kWh/m^2/year in the Knysna area and up to ≈1957 kWh/m^2/year in the Oudtshoorn area, in terms of GHI. Figure 13 provides a summary of the local solar resource, specifically resulting capacity factor of a 1 MW$_{AC}$ solar PV facility.

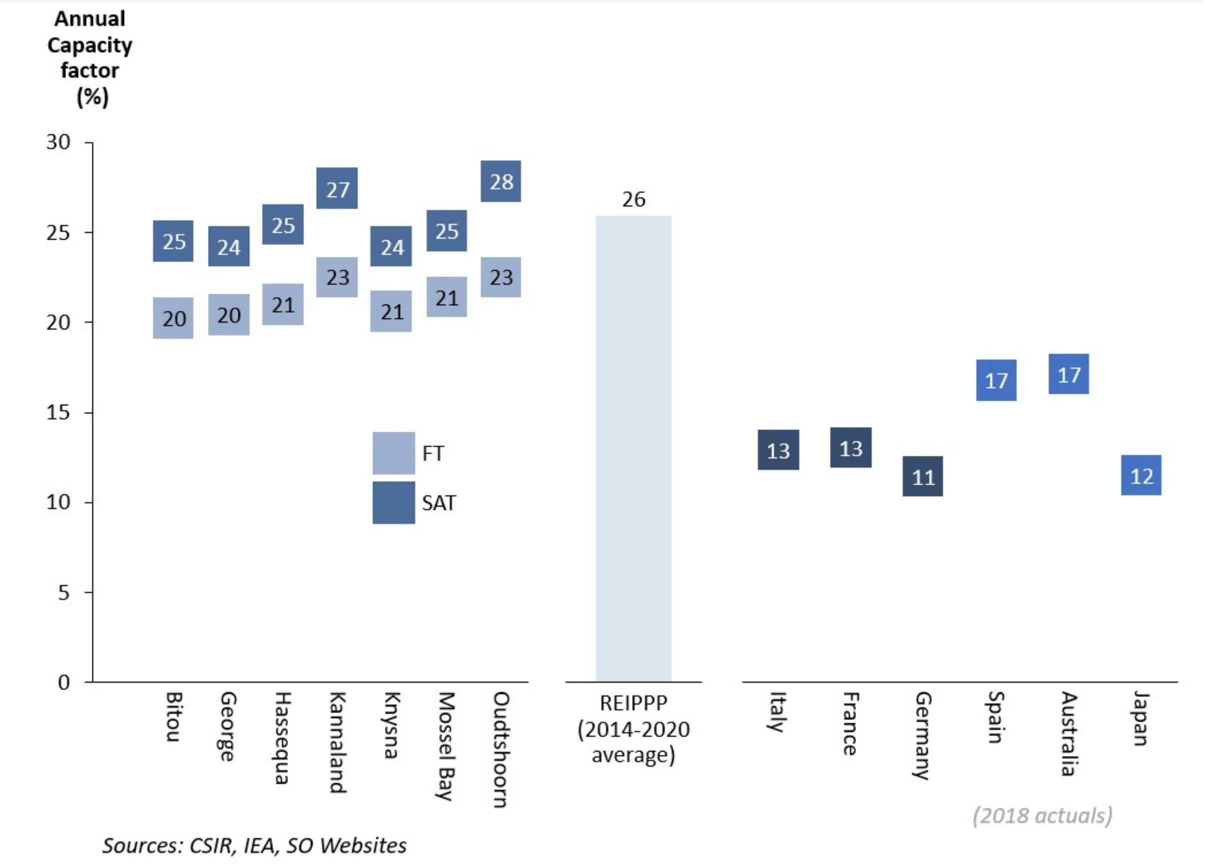

Figure 13: Summary of expected solar PV capacity factors and selected other jurisdictions (local and international)

2.4. Onshore Wind Resource Assessment

The details of the assessment are presented in Annexure B.

All the areas evaluated have a good wind environment and have significant development potential as seen from Figure 14.

Because this analysis was performed at the measured site and height, it does not exactly represent the yield that a potential farm may produce. A computer flow model must be conducted before an exact development yield can be obtained, allowing one to precisely estimate the wind climate across the terrain and at various heights. Software such as WAsP and WindPro can be used to model computational flow. This will provide a precise wind farm design as well as the estimated production of each Wind Turbine Generator based on its location.

Furthermore, while the evaluation can be carried out using modelled data, it is recommended that a measurement campaign be carried out using one of the traditional approaches. These include a wind met mast or a Lidar, both of which have grown in popularity as a result of their capacity to be deployed at a moment's notice.

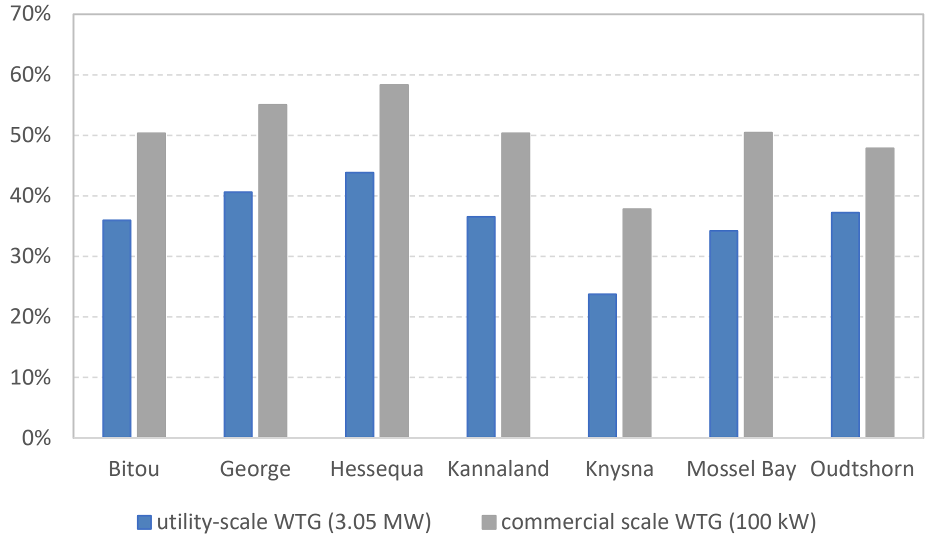

Figure 14: Onshore wind annual capacity factors

2.5. Interconnection Network

An overview of Garden Route DM's electrical infrastructure if show in Figure 15 indicating the grid supplying the seven local municipalities. And it clear that there is a 400 kV transmission going through the centre of the DM, and the key transmission substation in the DM is Proteus substation 400/132 kV (2x 500 MVA) (the large grey dot) located at about 30km northwest of Mossel Bay. The DM's total notified maximum demand is 322 MVA (refer to Table 7) which is 64% of the N-1 capacity of Proteus substation.

The loads are predominately distributed at 11-33 kV voltage level with the distribution voltage at sub-transmission voltages of 66 and 132 kV.

The supply to six of the seven local municipalities is from the central 400 kV line with Kannaland's demand also supplied by a 132 kV line that comes from the north-east. The new Narina transmission substation (400/132 kV, 2x500 MVA) in the George area, as shown in Figure 16, is planned is planned to be commissioned in 2030. The key driver for the establishment of the substation will be driven by residential, tourism and agricultural sectors. However, the presence of a second transmission substation opens up capacity that can be integrated to export power to the national grid. Such transmission strengthening will further increase the grid capacity for the integration of local generation in the DM.

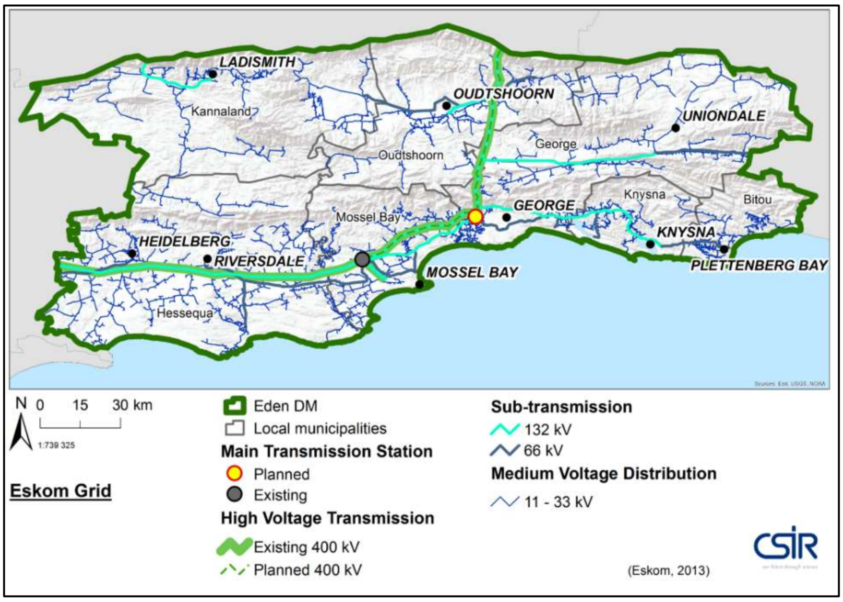

Figure 15: GRDM transmission and distribution network

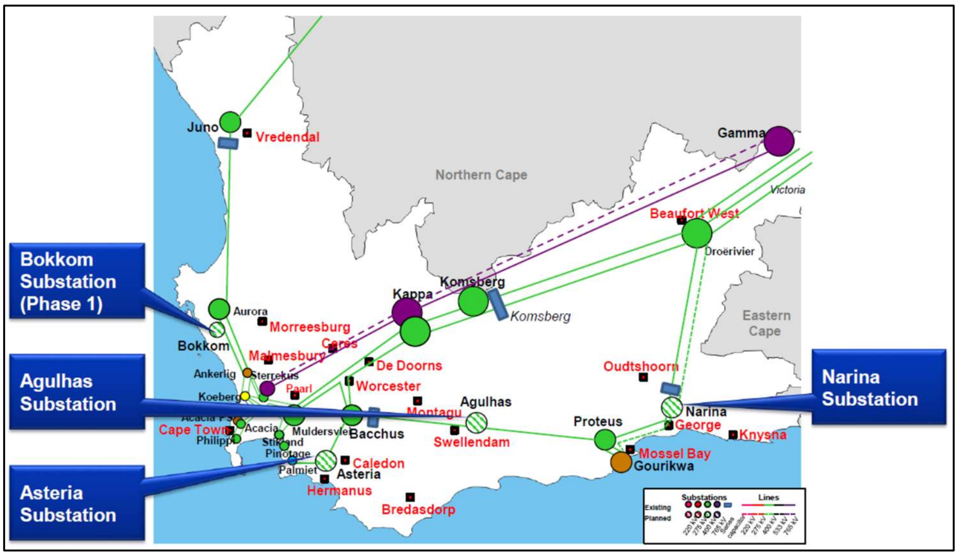

Figure 16: The planned Narina transmission substation in GRDM DM (source: Eskom TDP 2021)

2.6. Utility

2.6.1. Overview

The sole supplier of electricity to the municipalities in the region is Eskom. As in the rest of the country, there are also customers that are directly supplied by Eskom. The demand of Eskom direct customers is not considered in this study. Only municipal demand is discussed further.

This section presents the electricity supply by Eskom to the individual municipalities. A total of 39 Eskom Points of Delivery (PODs) exist across the region. Eskom has numerous tariff structures, four of which are found in the GRDM, Table 6. More than a 1/3 are of the Nightsave Rural type but these only constitutes 3% of annual electricity. Less than a half of the PODs are on a Megaflex tariff but these constitutes 94% of the annual electricity consumption. In general, the bulk PODs are Megaflex.

Table 6: Eskom tariff structures

	Number of PODs	Total annual electricity share
Megaflex	18	94%
Nightsave Rural	14	3.0%
Miniflex	4	2.8%
Ruralflex	3	0.7%
	39	100%

2.6.2. Electrical Demand

Electrical demand here refers to both energy (kWh) and peak capacity (kVA). Table 7 provides a summary of the Eskom electricity purchases per municipality. The top of the table shows energy related metrics and the bottom, capacity.

The annual Eskom sales for the GRDM is 1,298 GWh, which is less than 1% of the national demand (around 250 TWh). The top three purchasers (George (33%), Mossel Bay (24%) and Knysna (13%)) constitutes more than 70% of the sales. Low Demand (LD) and High Demand (HD) seasons are also considered to determine if the region follows the national trend of increased usage during the HD season (hence the use of 'high'). The seasons are normalised by number of days. Interestingly, three (Bitou, Hessequa and Kannaland) out of the seven municipalities actually have relatively lower usage in the HD season. The rest have moderate increases, maximum of 1.04 for Oudtshoorn.

Table 7: Summary of electricity purchases (Eskom) for FY 2020/21

	Bitou	George	Hessequa	Kannaland	Knysna	Mossel Bay	Oudtshoorn
LD GWh	79.6	324	70.8	27.7	129	233	105
HD GWh	26.6	111	23.2	8.4	43.3	80.2	36.6
Annual GWh	**106**	**435**	**94.0**	**36.1**	**172**	**313**	**141**
HD:LD ratio (normalised)	0.99	1.02	0.97	0.90	1.00	1.02	1.04
Total energy losses	6.4%	7.1%	6.2%	10.3%	11.3%	11.1%	9.8%
MD (MVA)	23.7	79.6	21.6	6.94	33.8	60.0	28.2
NMD (MVA)	33.5	85.0	25.9	11.8	47.1	82.0	36.6
Load Factor (average)	0.58	0.67	0.55	0.65	0.65	0.65	0.63
MD:NMD (average)	0.62	0.87	0.76	0.53	0.64	0.67	0.70
LF x MD:NMD	0.36	0.58	0.41	0.35	0.42	0.44	0.44

*LD (Low Demand), HD (High Demand), MD (Maximum Demand), NMD (Notified Maximum Demand), average means weighted average

The peak demand of the region is 254 MVA. This excludes diversity and is simply the sum of the parts. George has the 'best' weighted average load factor of 67%. Having a larger customer base provides for, *ceteris paribus*, greater diversity which would likely translate to a better load factor. The load factor is mostly dependent on the customer mix but Demand Response (DR) measures, such as ripple control, can be employed to improve the load factor. More recently, battery storage solutions have proven a viable option for, amongst other services, DR.

A metric that the municipality has more control over is the Maximum Demand (MD) to Notified Maximum Demand ratio. As with the Load Factor, the ideal is 1 but this would lead to excessive penalties when MD is above NMD. Again, George has the best ratio of 87%. Kannaland should explore the possibility of reducing their NMD.[1]

Figure 17 illustrates the time of use (TOU) split. The weighted average for the GRDM is 41% OffPeak, 42% Standard and 17% Peak. The municipalities are highly uniform in this regard, besides Kannaland with 44% OffPeak, 39% Standard and 16% Peak.

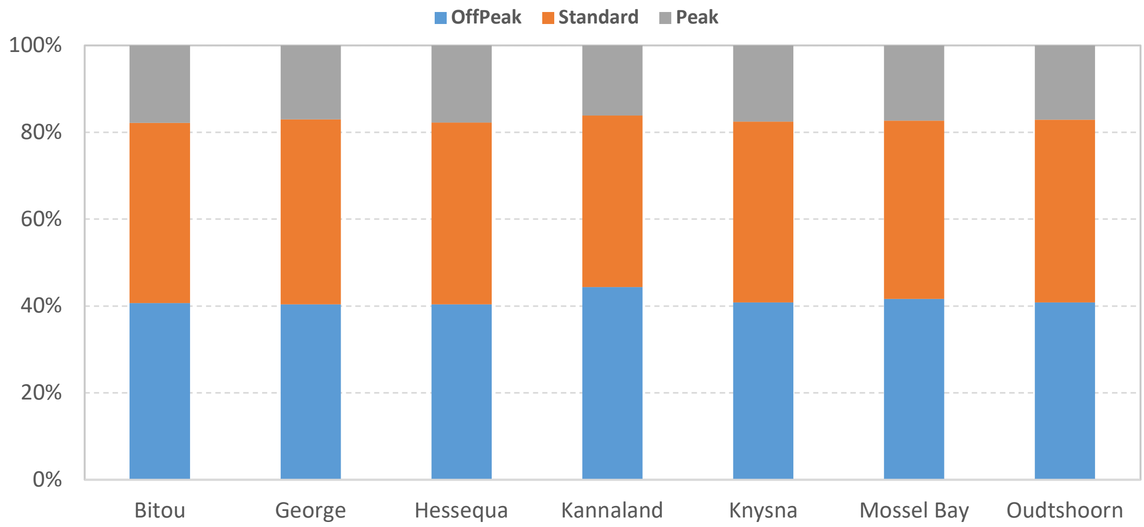

Figure 17: Eskom energy sales - TOU energy split

The total cost of electricity purchased from Eskom for the FY2020/21 was R 1.47 billion. The majority of which is energy related at 88%, 11% for demand charges and only 1% for fixed costs.

[1] Outside the scope of this study but the cost savings of a municipality reducing their NMD is significantly more than reducing their MD, and may simple be a 'paper exercise'

3. Analysis and Forecast

3.1. Customer Demand Profiles

Section 2.1.2 provided the current electrical demand of the municipalities' customers. This section utilises that data to extract representative hourly demand profiles.

Aligned to Eskom tariff structures, the profiles are provided per demand season (low and high). To account for weekly variation three profiles per week are considered, namely Weekday(Wk), Saturday(Sat) and Sunday(Sun). Therefore, a total of six daily profiles. The daily profiles have an hourly temporal resolution. The annual demand profiles (8760 hours) are made up of the said profiles 'stitched' together.

The Distribution Profile Mixer (DPM) software was developed for Eskom. The generic demand profiles from this software were used for residential (PC1), commercial (PC4) and industrial(PC6) customers, respectively, Figure 18, Figure 19 and Figure 20. The time presented on the x-axis is the end of the hour, for instance 19:00 is the average demand (kW) from 18:00 to 19:00. For Kannaland, the Profile Class 8 (PC8) was a better representation. PC8 is more uniform across season and day of week – compare Figure 21 to Figure 20.

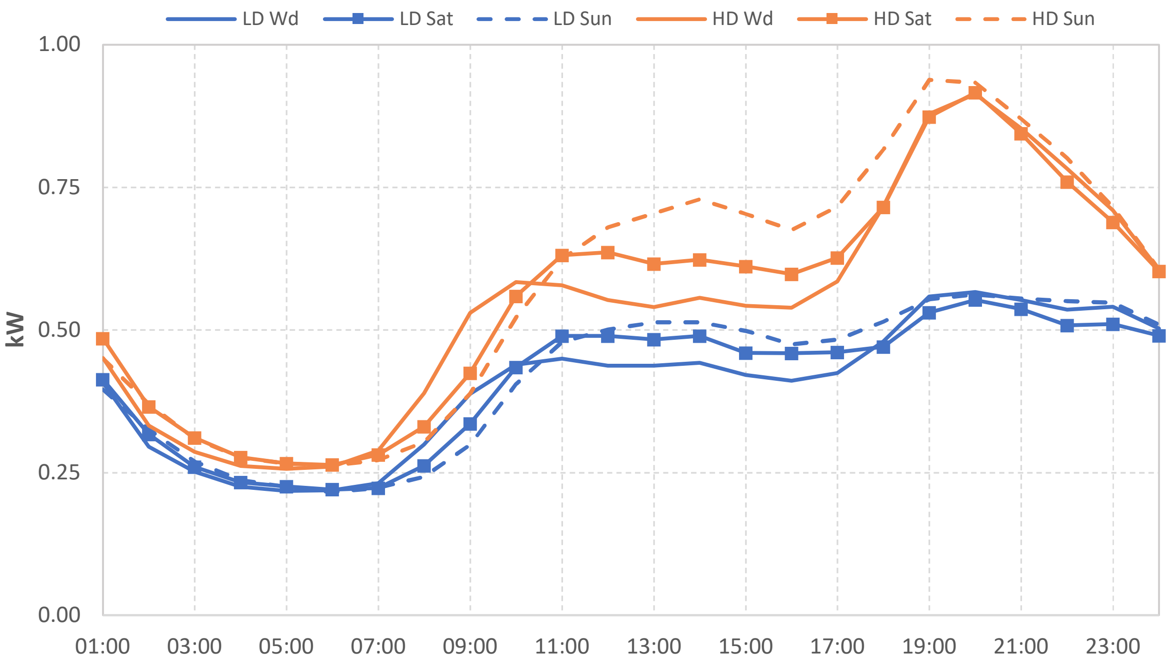

Figure 18: DPM residential demand profile

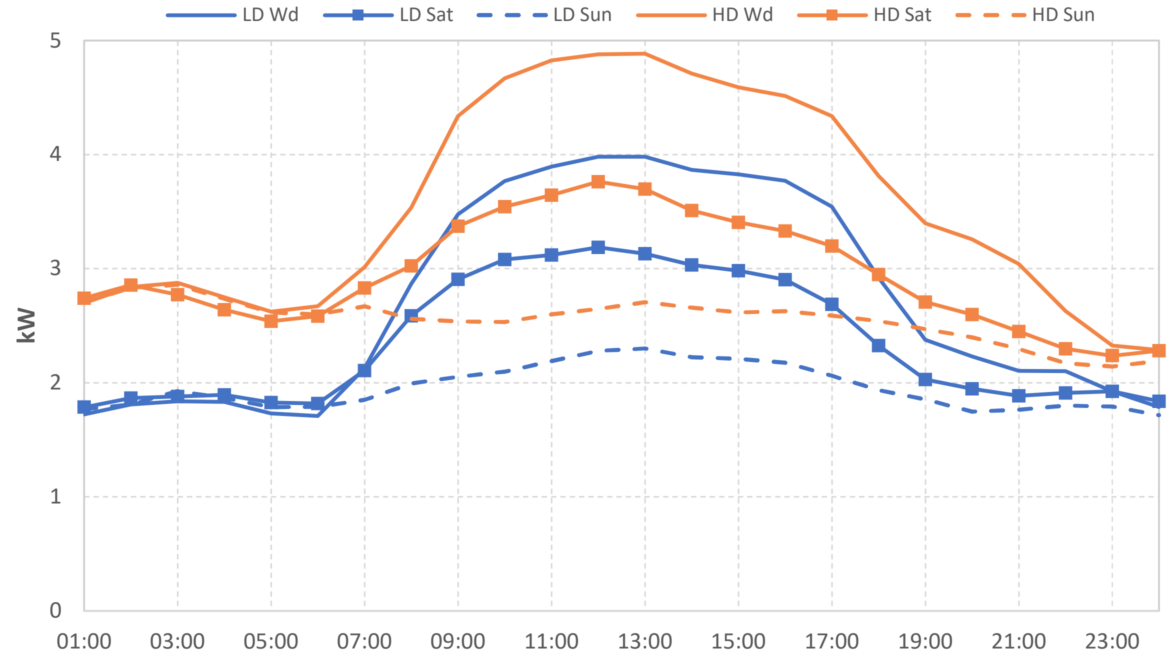

Figure 19: DPM commercial demand profile

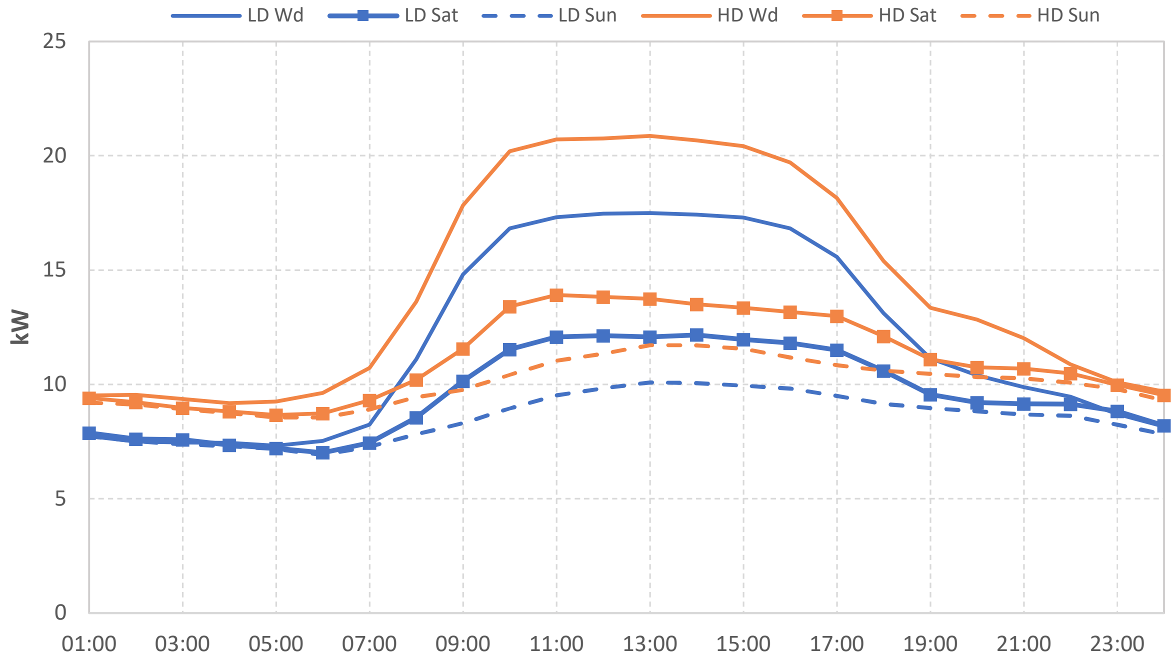

Figure 20: DPM industrial (PC6) demand profile

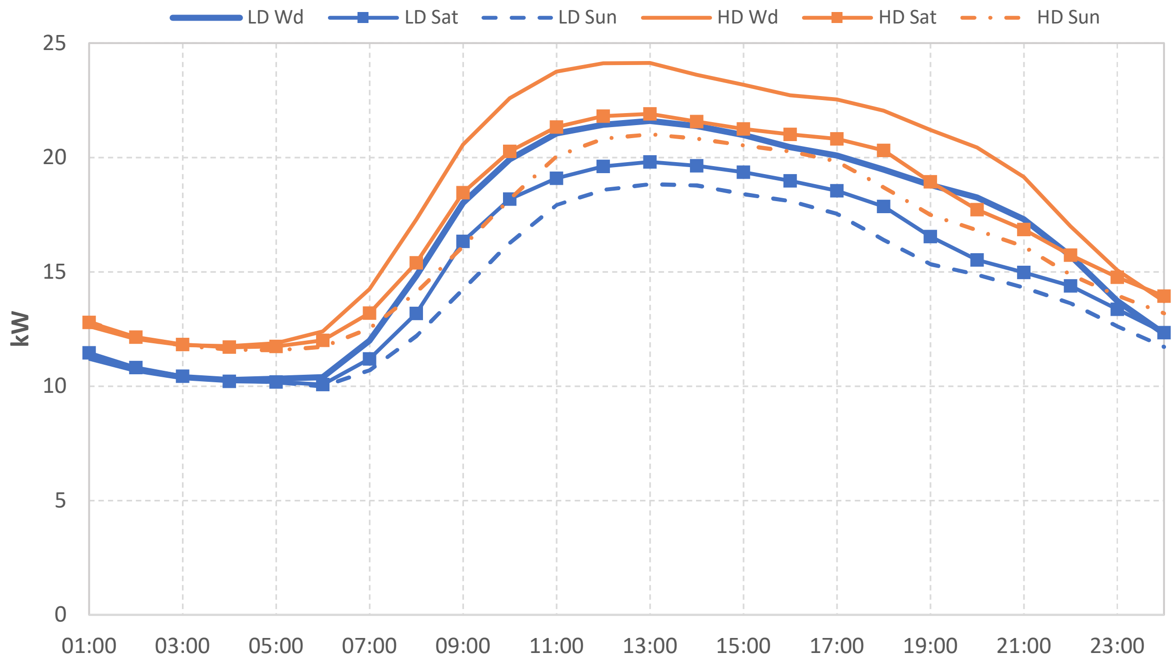

Figure 21: DPM industrial (PC8) demand profile

The process to fit these profiles to the actual customer data is as follows:

1. Low and High Demand ratios of Eskom purchases (per municipality) are noted
2. Annual sales (per customer class and municipality) are noted
3. Apply multipliers to DPM low and high profiles to get the correct seasonal ratio (item 1) and annual sales (item 2)

The fitted profiles plus total losses are summated to derive the municipal demand profile which is equivalent to the Eskom purchases. Loss factors in Eskom tariff book are used, namely 11.1% for residential and 6.1% for C&I (commercial and industrial). The loss factors are scaled to achieve the actual total losses as provided in Table 7.

The derived municipal demand profiles are checked against the Eskom purchases in terms of TOU. The absolute differences are provided in the following Table 8. The overall alignment is good with an absolute difference of 3.5% for the region. There is better TOU alignment in the low demand season. Kannaland is (again) an outlier with around 10% absolute difference, even after fitting a more uniform demand profile as described earlier in this section.

Table 8: Weighted absolute differences between replicated and actual Eskom purchases TOU

	Bitou	George	Hessequa	Kannaland	Knysna	Mossel Bay	Oudtshoorn
Low Demand	4.8%	1.8%	2.6%	9.8%	2.4%	5.2%	3.0%
High Demand	4.8%	2.6%	5.0%	10.0%	3.7%	5.9%	4.4%
Annual	**4.8%**	**2.0%**	**3.2%**	**9.8%**	**2.8%**	**5.4%**	**3.3%**

As noted, the annual energy consumption and seasonal variation of replicated profiles are an exact fit to Eskom purchases. The previous table only considers the absolute differences in terms of TOU. Overall, the replicated hourly demand profiles are a good approximation of the actual customer and municipal demands. These profiles are, respectively, inputs to the rooftop PV analysis (Section 0) and capacity expansion planning (Section 5) work.

3.2. Technology Costing and Learning Rates

Capacity expansion planning is sensitive to, amongst others, technical performance and technology costs. The former is provided in Section 5.5.2. Technology costs are dealt with in this section. For this study two technology scales are considered, namely embedded/distributed and utility scale. For embedded generation, only solar PV rooftop is considered (analysis discussed in Section 0).

3.2.1. Solar PV

Figure 22 and Figure 23 present the utility scale solar PV capital costs in 2021 ZAR / kW value and learning rates, respectively. The fixed tilt price hovered around R 13 000 to 17 000 in 2019 (IRENA, IEA), R 16 000 in 2020 (IRENA, CSIRO) and R12 000 to 15 000 which are low and high costs published for 2021 (Lazard). The single axis tracker price published by NREL is R 21 000 for 2019. The simple reverse engineering calculation based on the published tariffs for REIPPP bid window 4 estimate R 12 000 per kW. Based on the international literature and local experience review, R 12 000 per kW is reasonable to be considered as a baseline cost for applications in this study. The CSIR estimates or assumes a drop of 28%, 40% and 46% by 2030, 2040 and 2050 respectively based on the learning rate published by NREL, CSIRO and BNEF.

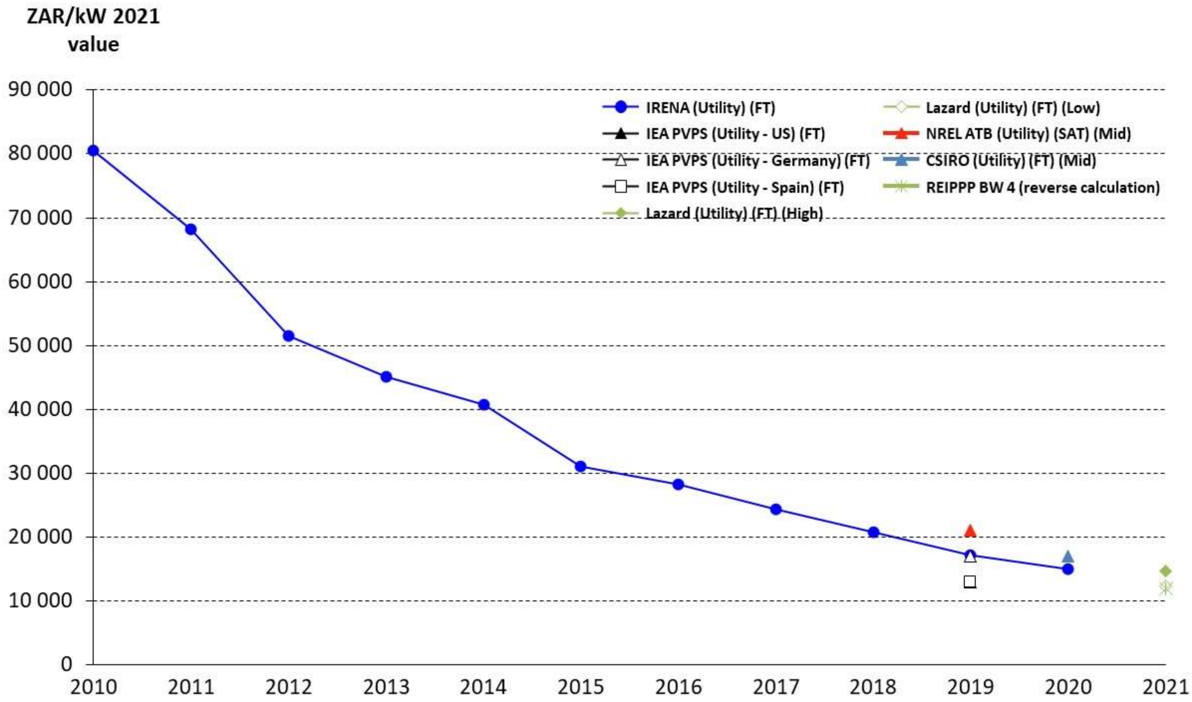

Figure 22: Solar PV system capital costs – utility-scale

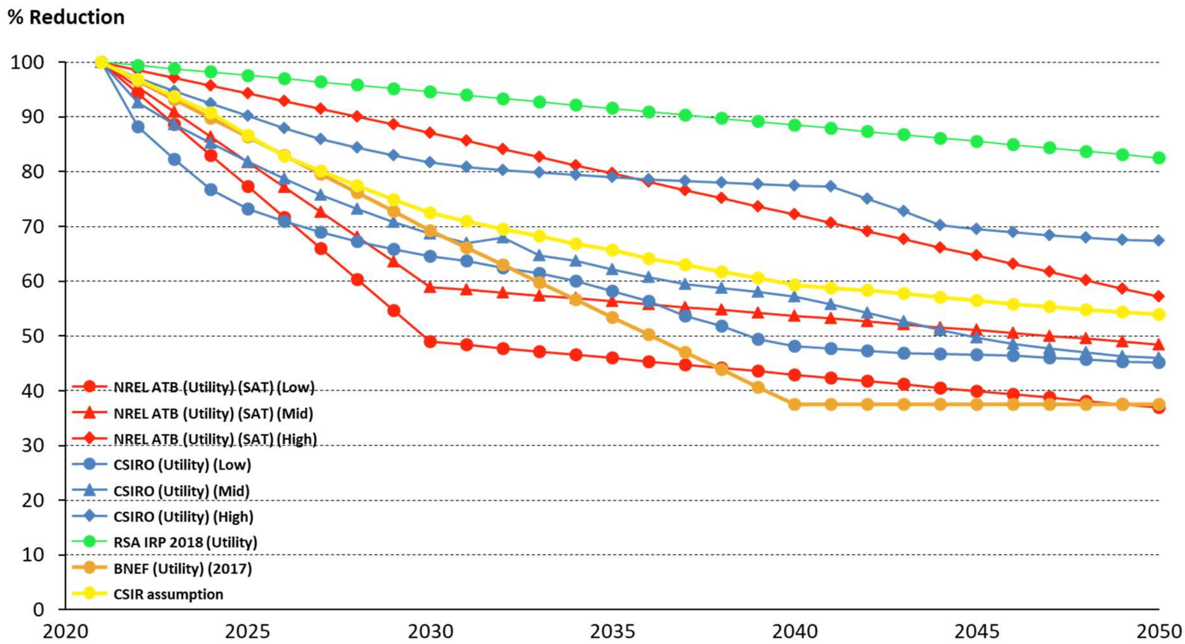

Figure 23: Solar PV learning rates - utility-scale

Figure 24 and Figure 25 presents the commercial scale solar PV capital costs in 2021 ZAR / kW value and learning rates, respectively. The price per kW hover around R 20 000 in 2019 based on IRENA & CSIR own experience realizing rooftop commercial scale solar PV plants at its campus as part of Smart Utility Program. IRENA publish about R14 000 per kW for the year 2020. The price for US region published by NREL and IEA is R 21 000 to R 27 000 during 2019 and Lazard publishes R 22 000 to R 44 000 for the year 2021. Based on the international literature review and local experience mainly IRENA predictions matching with CSIR own experience in Year 2019, R 15 000 per kW is reasonable to be considered as a baseline cost for applications in this study. The CSIR assumes a drop of 15%, 32% and 47% by 2030, 2040 and 2050 respectively based on the conservative learning rate published by NREL.

Figure 26 and Figure 27 presents the residential scale solar PV capital costs in 2021 ZAR / kW value and learning rate respectively. The price hover around R 30 000 to 43 000 in 2019 (IRENA, IEA, NREL), R 17 000 and 27 000 in 2020 (IRENA, CSIRO) and R 38 000 to 44 000 in 2021 by Lazard. The price for residential scale solar PV in US seems to be on very higher side compared to the experience in other parts of the world. Based on the international literature review, R 25 000 per kW, a price that lies between IRENA and CSIRO is reasonable to be considered as a baseline cost for applications in this study. The IRENA costs for commercial scale matches RSA local experience in 2019 thus providing confidence to use the IRENA published values for residential scale soar PV. The CSIR estimates or assumes a drop of 46%, 54% and 61% by 2030, 2040 and 2050 respectively based on the learning rate published by NREL and CSIRO.

3.2.2. Onshore Wind

Figure 28 and Figure 29 presents the residential scale solar PV capital costs in 2021 ZAR / kW value and learning rate respectively. The price hover around R 16 000 R 23 000 in 2020 as published by IRENA, US DoE, CSIRO, and R 16 000 to R 21 000 which are low and high costs published for 2021 by Lazard. The simple bottom up (reverse) calculation based on the published LCOE for REIPPP bid window 4 estimate R 16 000 per kW. Based on the international literature and local experience review, R 16 000 per kW is reasonable to be considered as a baseline cost for applications in this study. The CSIR estimates a drop of 18%, 30% and 33% by 2030, 2040 and 2050 respectively based on the learning rate published by NREL, CSIRO and BNEF.

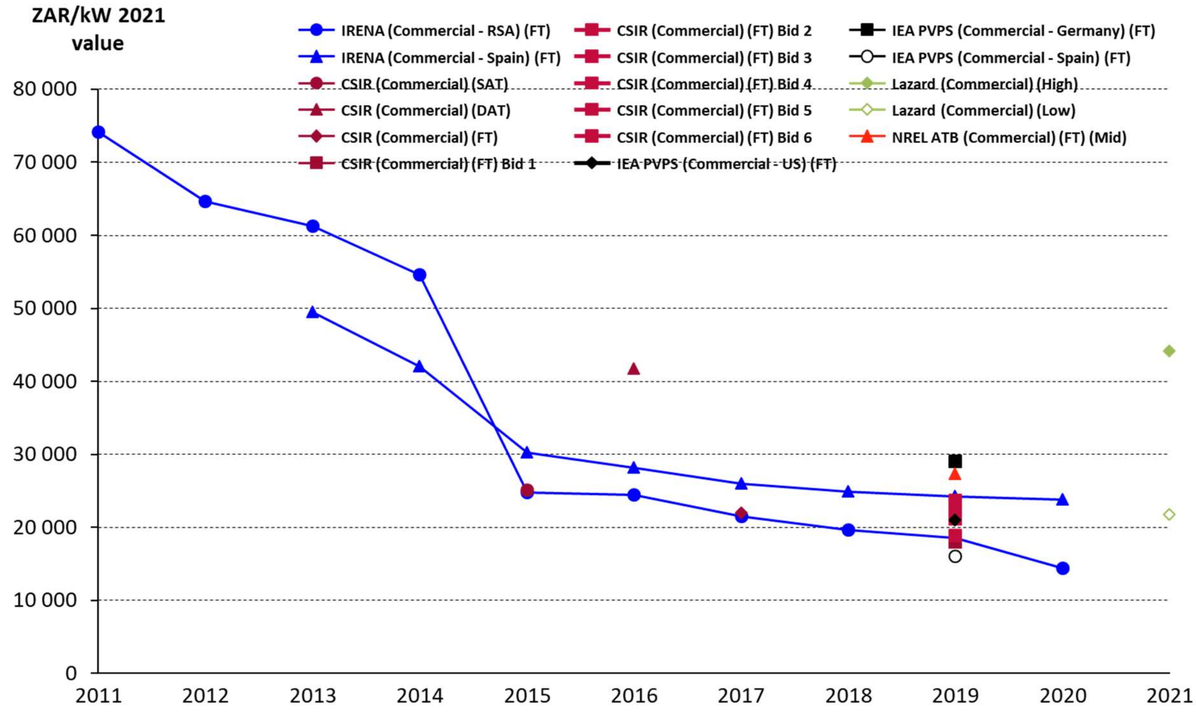

Figure 24: Solar PV system capital costs – commercial-scale

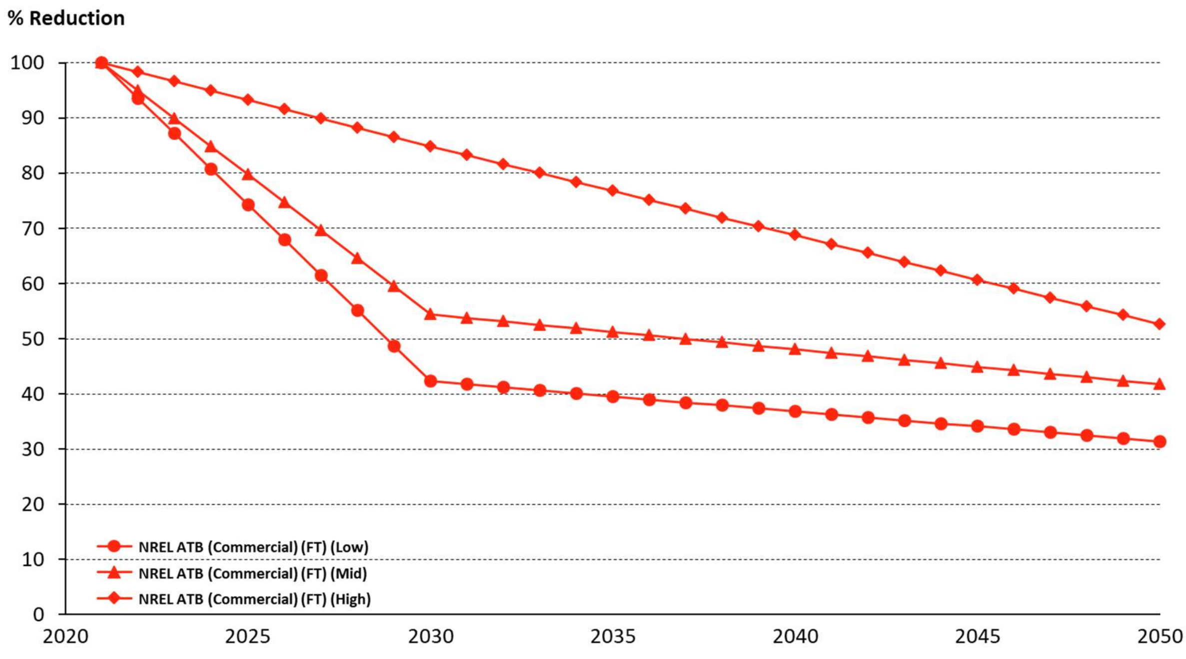

Figure 25: Solar PV learning rates - commercial-scale

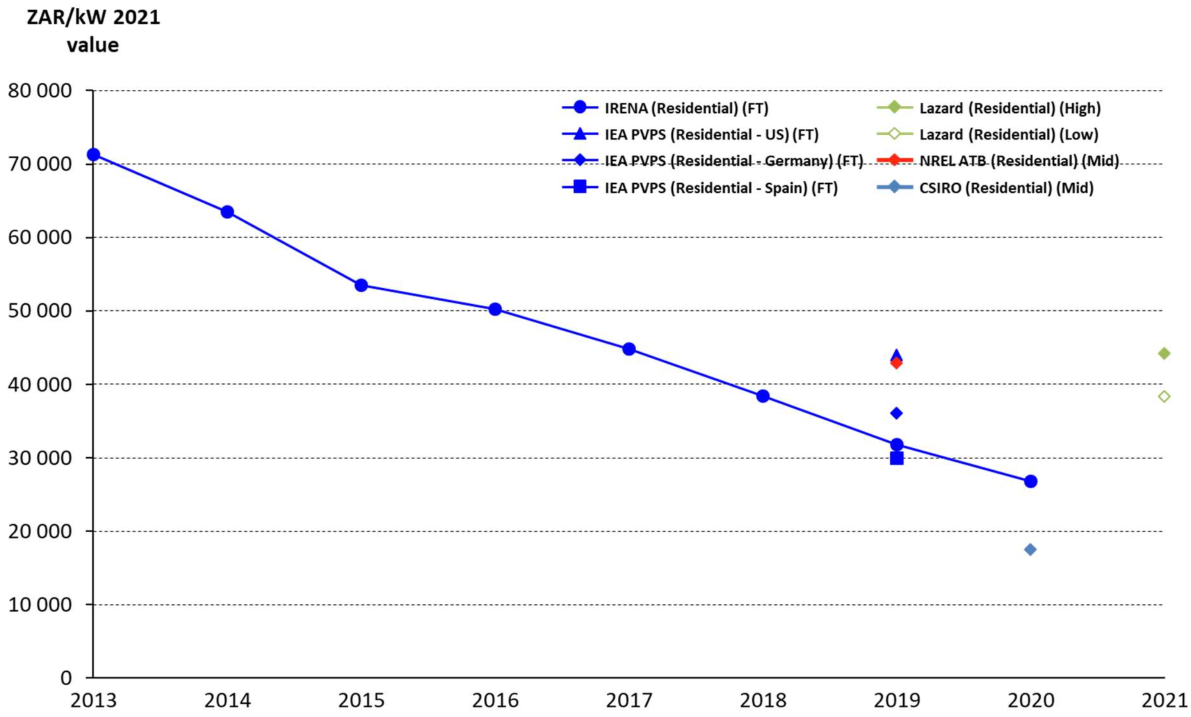

Figure 26: Solar PV system capital costs – residential-scale

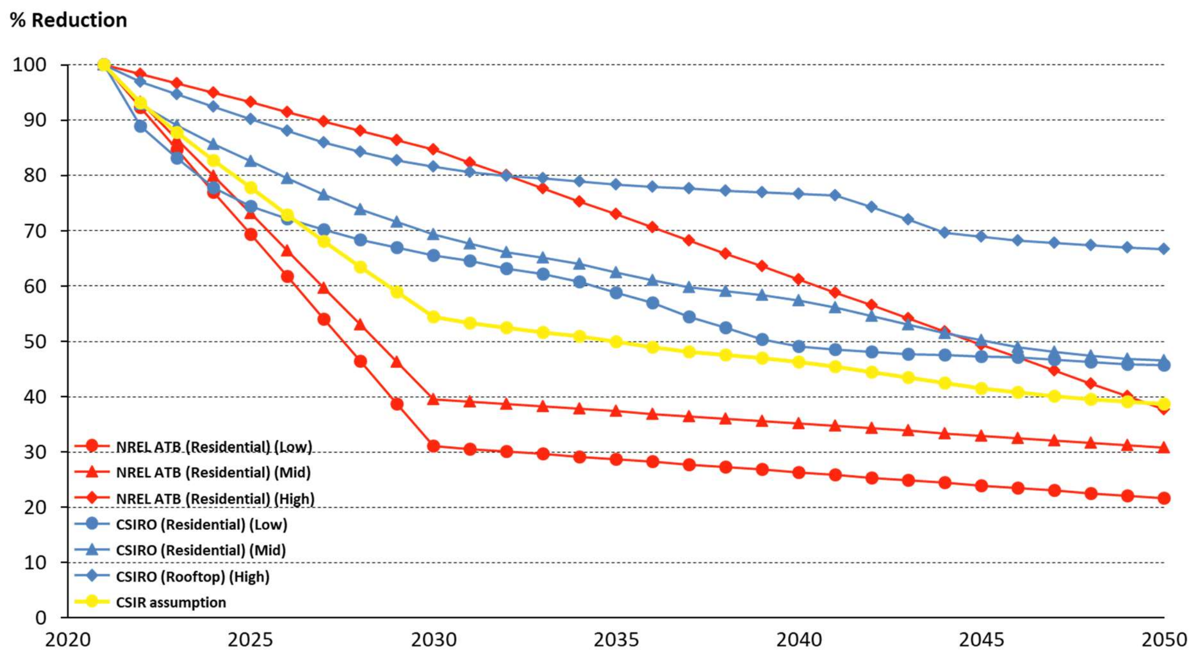

Figure 27: Solar PV learning rates - residential-scale

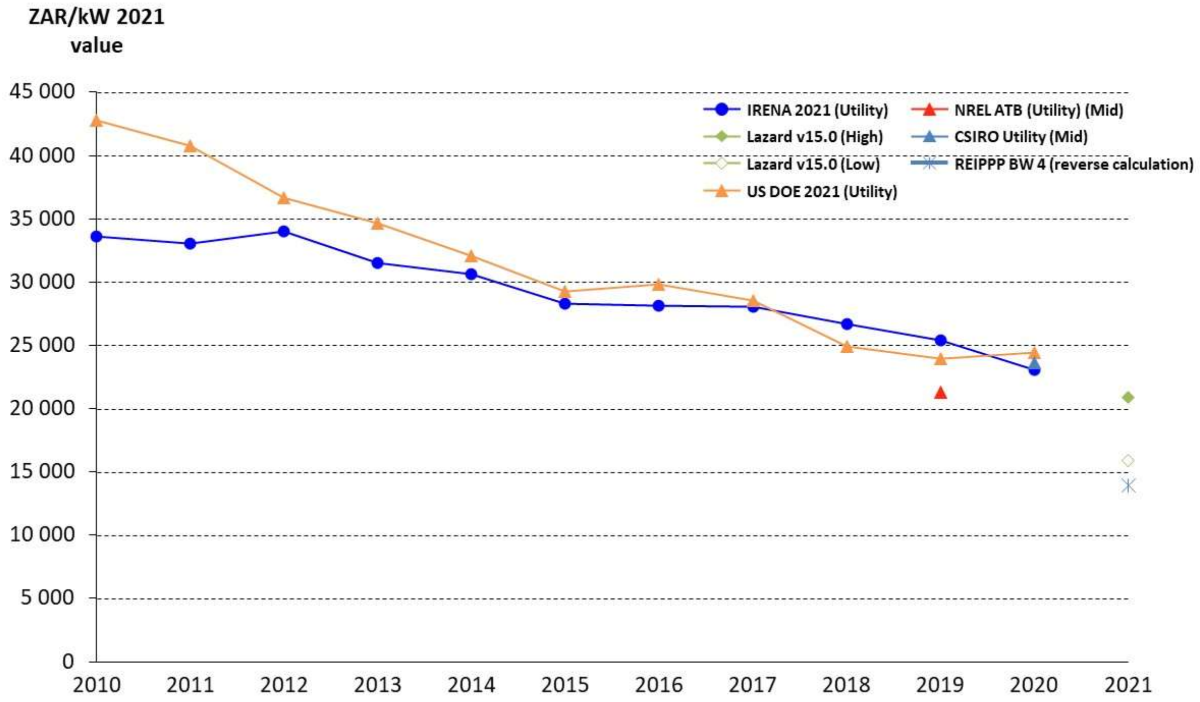

Figure 28: Utility scale wind system capital costs

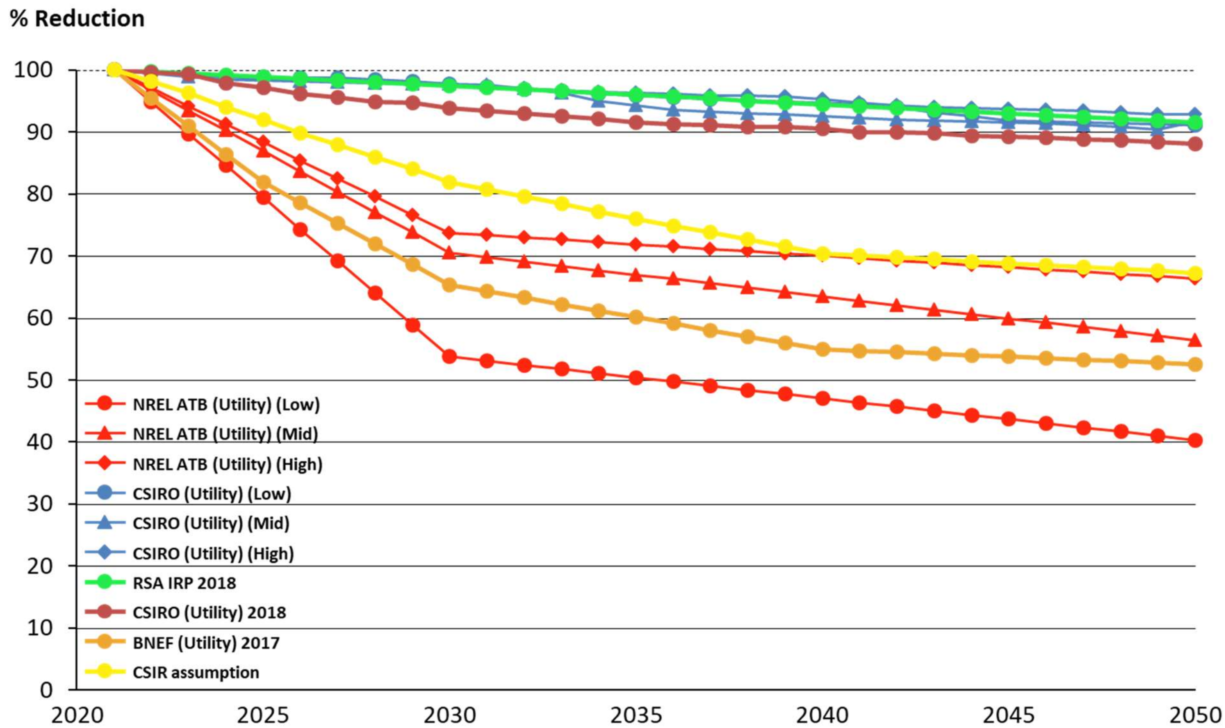

Figure 29: Utility scale wind learning rate

3.2.3. Gas Turbines and Engines

Gas turbines are engines are conventionkal generaton technologies with limiting improvement in terms of learning rates. Summary of cost and technical peformance is provided in Seciton 5.5.2.

3.2.4. Battery Storage

Figure 30 and Figure 31 presents the Utility scale solar PV capital costs in 2021 ZAR / kW value and learning rate respectively. The price hover per kW around R 22 000 to R 24 000 for the year 2019 and 2020 as published by NREL and CSIRO. Based on the international literature and local experience review, R 22 000 per kW is reasonable to be considered as a baseline cost for applications in this study. The CSIR estimates or assumes a drop of 35%, 40% and 43% by 2030, 2040 and 2050 respectively based on the learning rate published by NREL, CSIRO and BNEF.

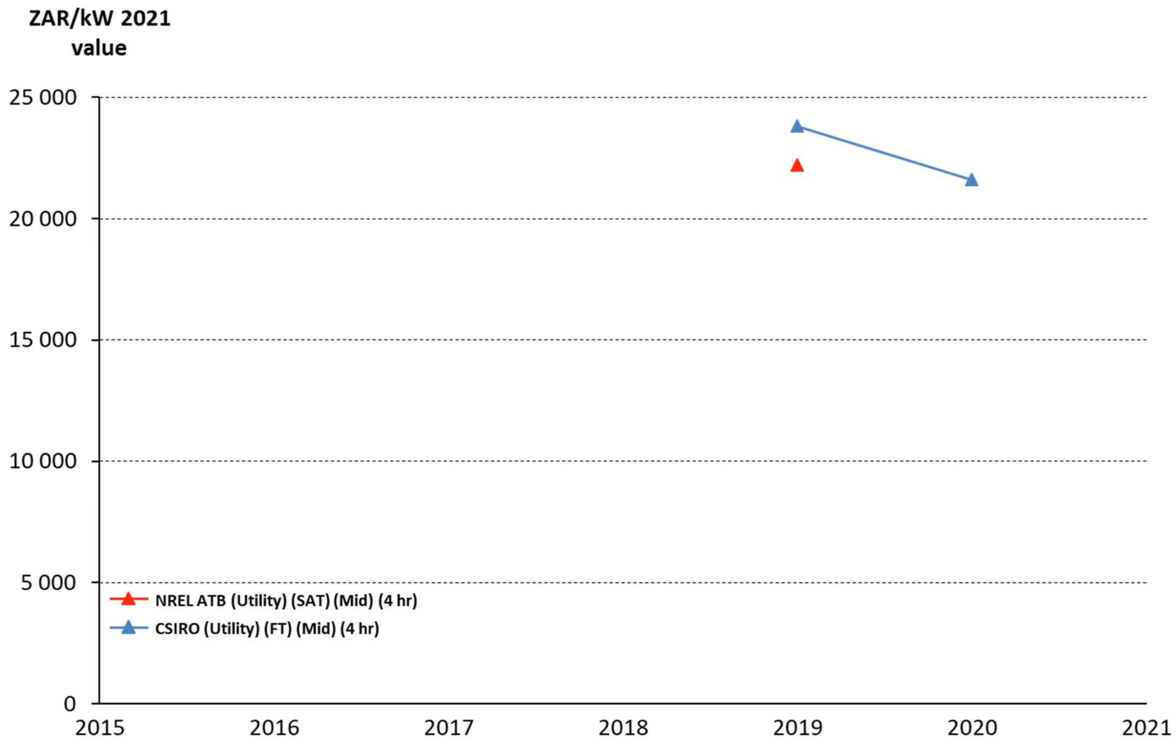

Figure 30: Utility scale Li-ion Battery storage capital costs

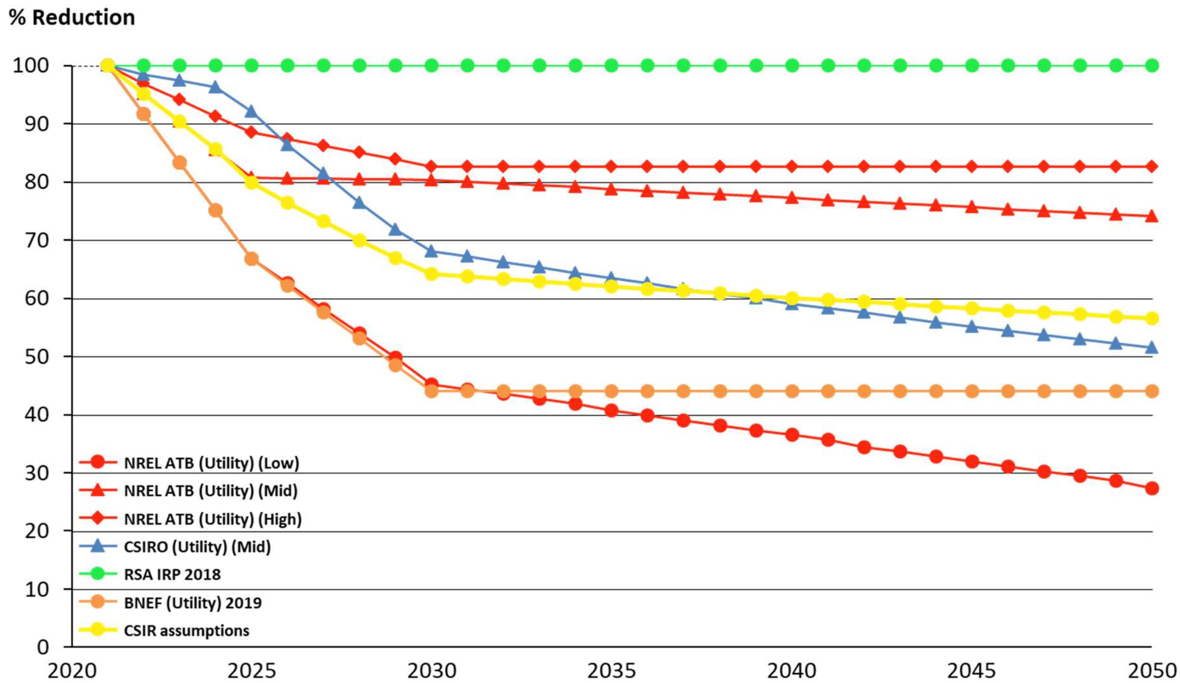

Figure 31: Utility scale Li-ion battery storage learning rate

Biomass and biogas energy projects may have potential in the region but were not included in this study as very project/site specific. Furthermore, the feedstock availability of biomass/biogas at a utility-scale would first need to be confirmed.

3.3. Local Resources

The local resources as described in Section 2.2 are assumed to remain constant. The impact of climate change should be investigated with further work.

3.4. Utility

3.4.1. Municipal Demand Profiles

The procedure to construct demand profiles for the customers and, ultimately, the municipality is described in Section 3.1. The demand profiles are depicted in Figure 32 to Figure 38.

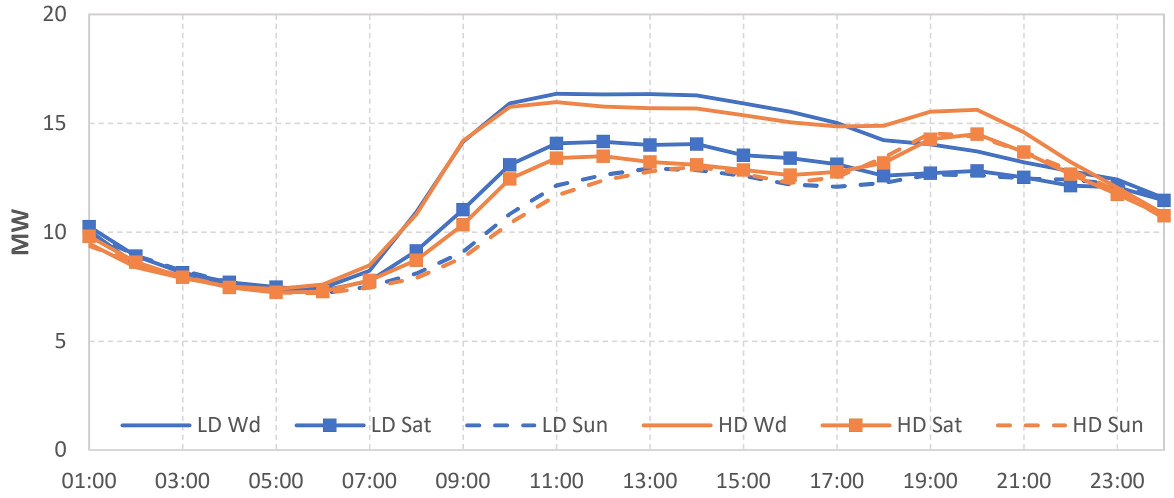

Figure 32: Hourly demand profile for Bitou

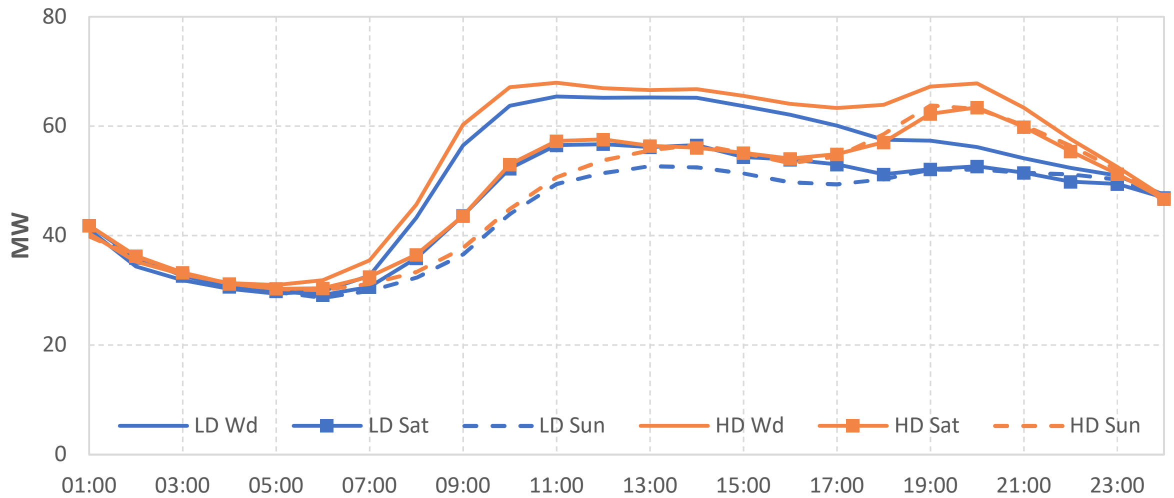

Figure 33: Hourly demand profile for George

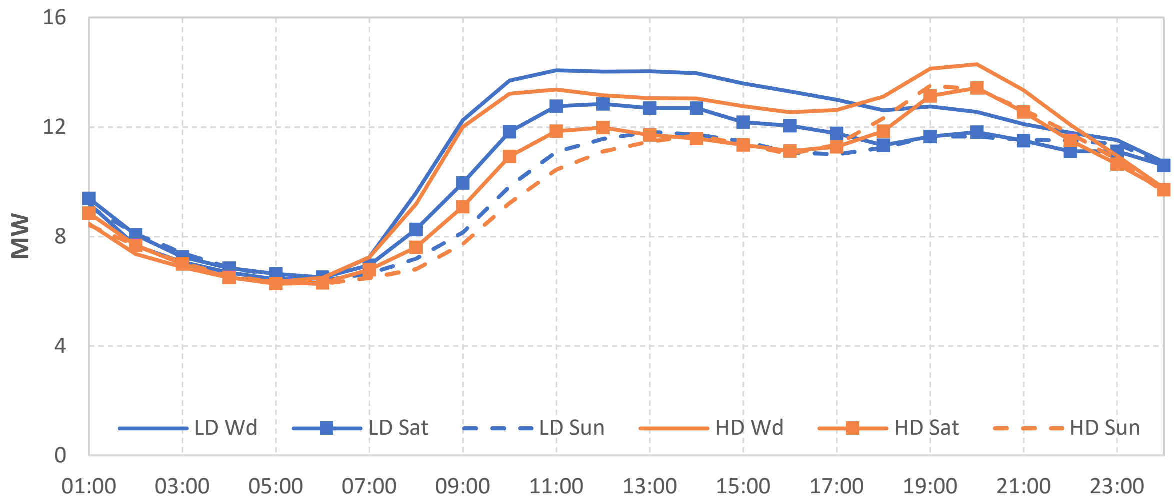

Figure 34: Hourly demand profile for Hessequa

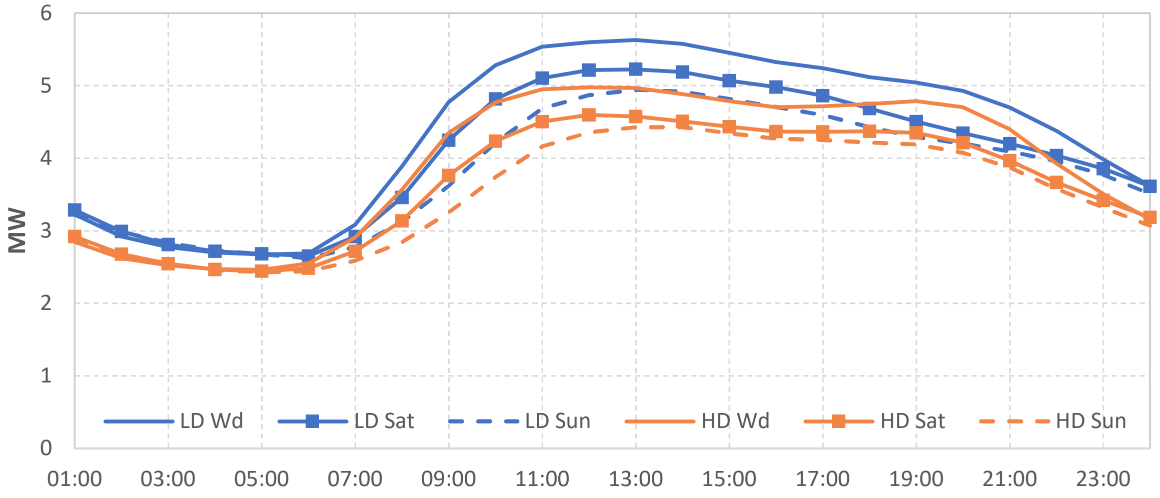

Figure 35: Hourly demand profile for Kannaland

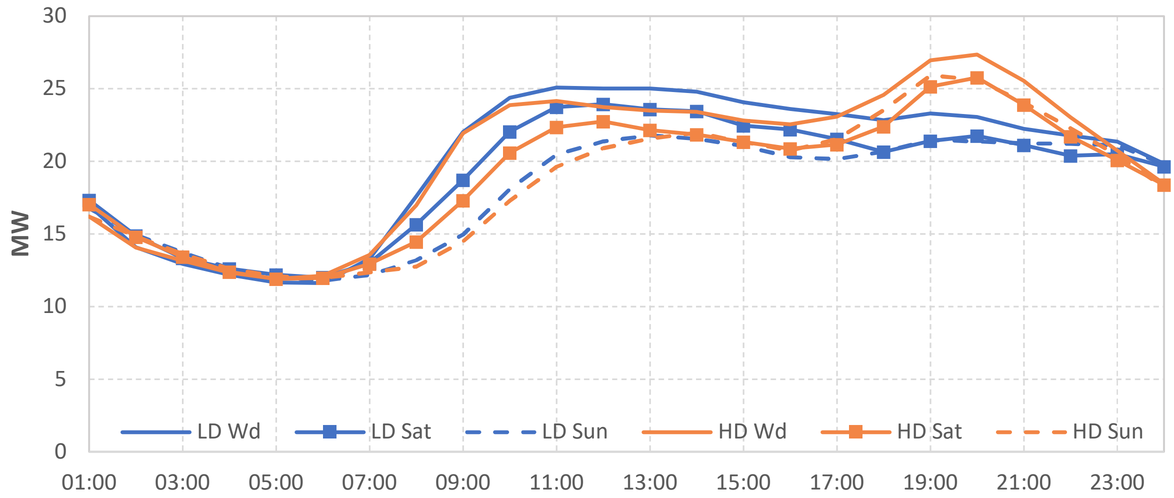

Figure 36: Hourly demand profile for Knysna

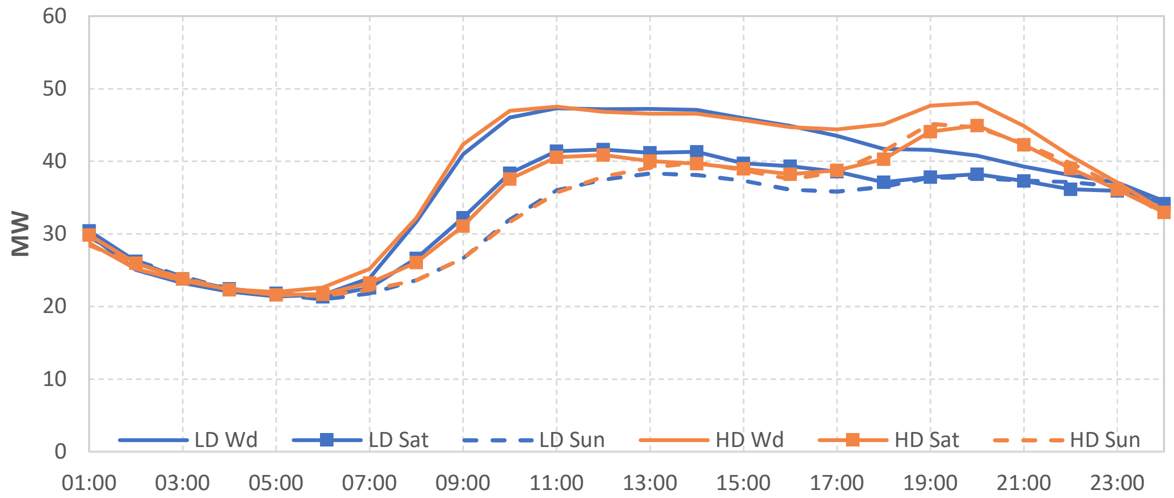

Figure 37: Hourly demand profile for Mossel Bay

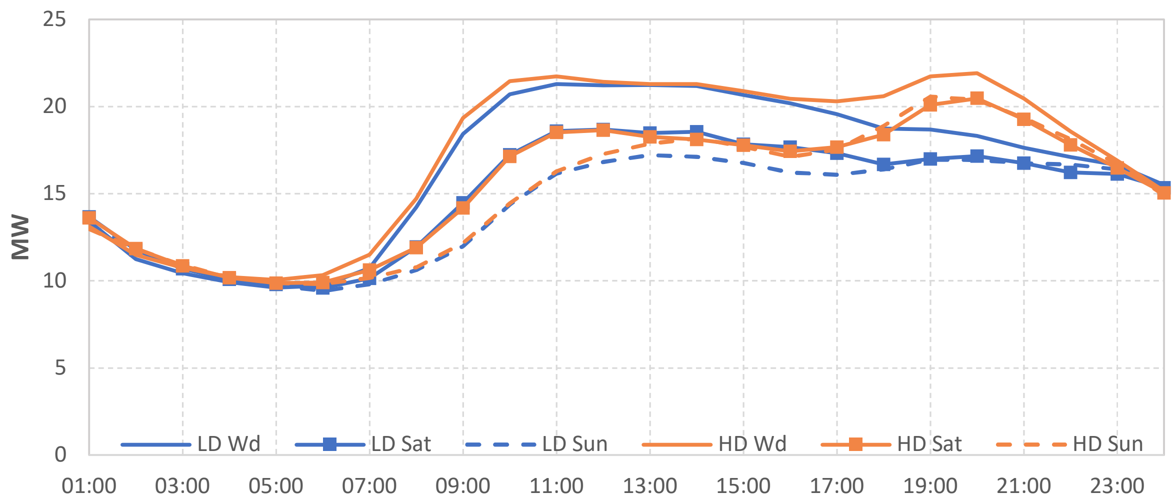

Figure 38: Hourly demand profile for Oudtshoorn

3.4.2. Demand Forecast

Demand is conveniently measured by supply provided and refers to both electrical energy (kWh) and peak demand (kVA). Demand generally refers to the supply to be provided by the utility (Utility Supply). Total Demand is calculated with the following equation which shows that without Customer Resource, for instance rooftop solar PV, then Utility Supply is equivalent Total Demand. However, with the recent adoption of embedded (behind-the-meter) technologies Utility Supply is no longer equivalent to Total Demand.

$$\text{Total Demand} = \text{Utility Supply} + \text{Customer Resource}$$

In South Africa the national demand (Utility Supply) has been slightly decreasing for around a decade, Figure 39. This could be due to a combination of factors, including higher prices (price elasticity), increased energy efficiency and poor economic growth (income elasticity). Customer Resource can reduce own consumption and provide alternative energy supply (export energy), both of which reduce the Utility Supply. In addition to a strong business case, the increasing levels of unreliability, in the form of load-shedding, are driving the deployment of Customer Resource.

Across South Africa, on average, electricity demand (Utility Supply) is decreasing. The GRDM could be seen as higher growth region and thus electricity demand might be increasing. To test this hypothesis the actual demand for George is compared to a previous forecast (GLS Consulting, 2019 [2]), Table 9. Actuals show a slight decline from 2018 to 2020, but the said forecast estimated an increase of more than 5% CAGR (compound annual growth rate). This is not to be critical of the specific forecast but to show that there is tendency to over-estimate future demand, as done with the national demand. The demand forecast proposed in this study is that Utility Supply will remain constant in the GRDM. The Total Demand will grow with the increasing Customer Resource.

Therefore, the annual Eskom sales (energy purchases) for the GRDM will remain constant at 1,298 GWh, peak demand is also fixed at 254 MVA . The hourly demand profiles, as described in the previous section, are assumed to remain the same.

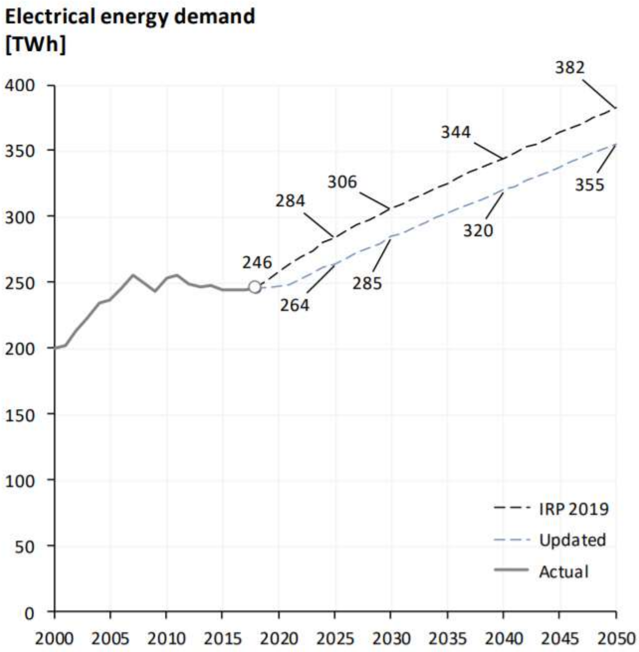

Figure 39: South African national electricity demand (Source: 2020 Meridian Report [3])

Table 9: Comparison of actual and forecasted demand for George

	Unit	Actual 2018/19	Actual 2020/21	Previous forecast 2020/21	CAGR* Actual	CAGR* Previous forecast
Annual energy consumption	GWh	471	435	496	-0.8%	5.9%
Peak Demand	MVA	87	80	93	-4.3%	6.5%

*CAGR is compound annual growth rate

3.4.3. MUNICIPALITY AND ESKOM TARIFF PROJECTIONS

A key input to energy planning is the projection of tariffs. This section considers the likely evolution of Eskom and municipal tariffs. As noted in Section 2.1.1 almost 95% of the total annual electricity share in the region is on the Megaflex tariff. Therefore, Megaflex is taken as a proxy for the Eskom tariff. For municipal tariffs the increase is calculated with:

$$\text{Munic tariff increase} = \frac{3}{4}(\text{Eskom increase}) + \frac{1}{4}(\text{inflation})$$

Figure 40 shows a graphical illustration of the 2020 electricity tariffs from Eskom for GRDM showing that the bulk of GRDM's electricity bill was concentrated in energy charges (88%) whereas the sum of peak demand charges and fixed charges make up a smaller percentage (12%).

There are several fundamental components of the Eskom Megaflex electricity tariff namely:

- Fixed Charges (R/month) to recover overhead costs and costs that vary with size of customer base;
- Demand and Network Charges (R/kW/month) to recover long-run marginal investments required to meet peak demand;
- Energy Charge (R/kWh) to recover variable costs to meet the customer load.

In this study, the Eskom tariff was escalated using CSIR's inhouse assumptions based on Eskom's current debt burden amidst a maintenance backlog (since section Municipal and Eskom tariff projection), Figure 41.

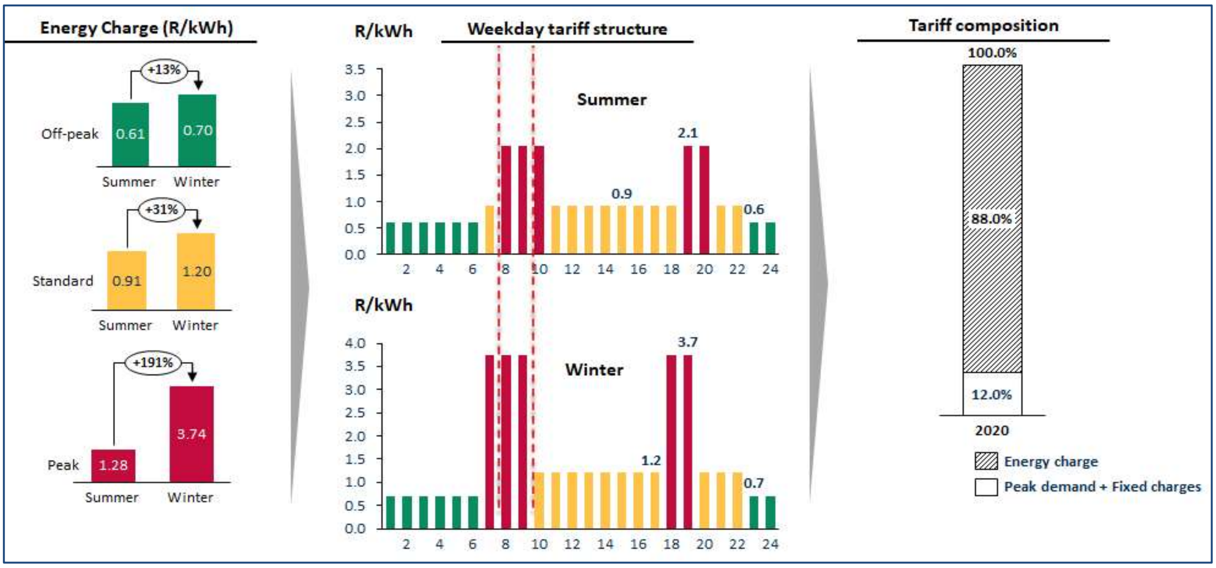

Figure 40: Eskom tariff (2020/2021) for GRDM with a seasonal time of use periods & Tariff composition

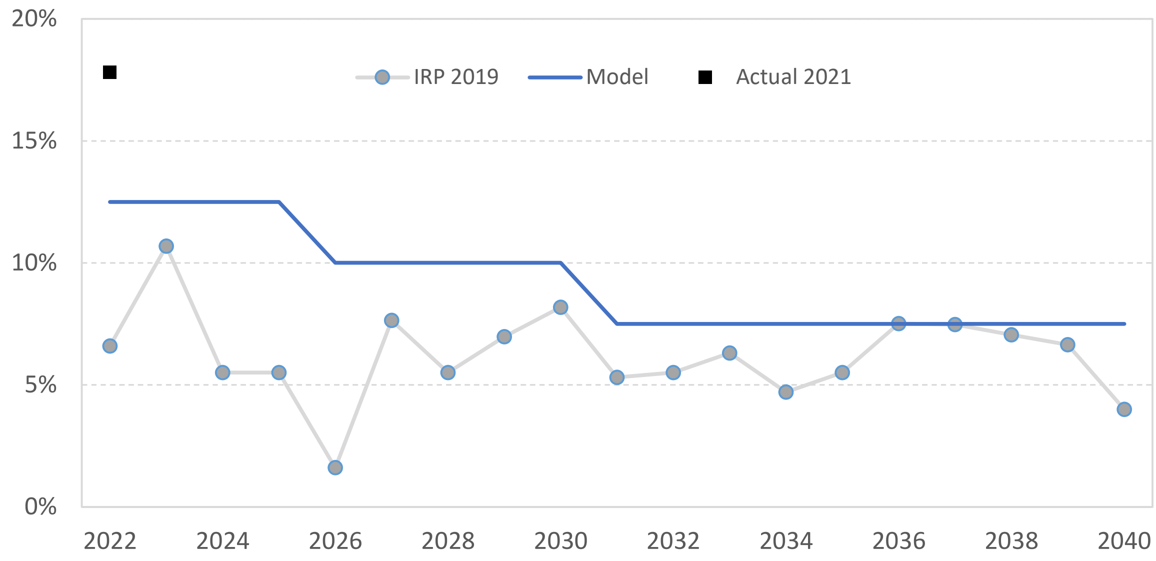

Figure 41: Assumed Eskom tariff escalation (nominal)

In 2017 and 2020, Eskom released documentation [4], [5], which sets out Eskom's strategic direction and objectives for its electricity tariff structures over the next five years to provide stakeholders with a view of Eskom's long-term plan of action for tariff structures. Some key strategic objectives for tariffs highlighted by Eskom are summarized below:

- Tariffs to be more cost-reflective in structure.
- Tariffs that incentivize customers to stay connected to the grid
- A tariff that enables better management of demand and supply-side options.

All scenarios considered in this report assumed that the structure of the electricity tariff will be altered such that the share of fixed/demand cost charges increase over time while the share of energy charges reduces, however, the energy charges will continue to make up a large amount of Eskom's revenue as shown in Figure 42 (the solid black line is the same as overall nominal increase in previous figure). Assuming the same electricity consumption structure, Figure 43 presents the resulting projected tariff composition. The current (2021) 88% energy share declines to 77% and 69% in 2030 and 2040, respectively. Lastly, the projection of the equivalent, energy rate in real terms is offered in Figure 44.

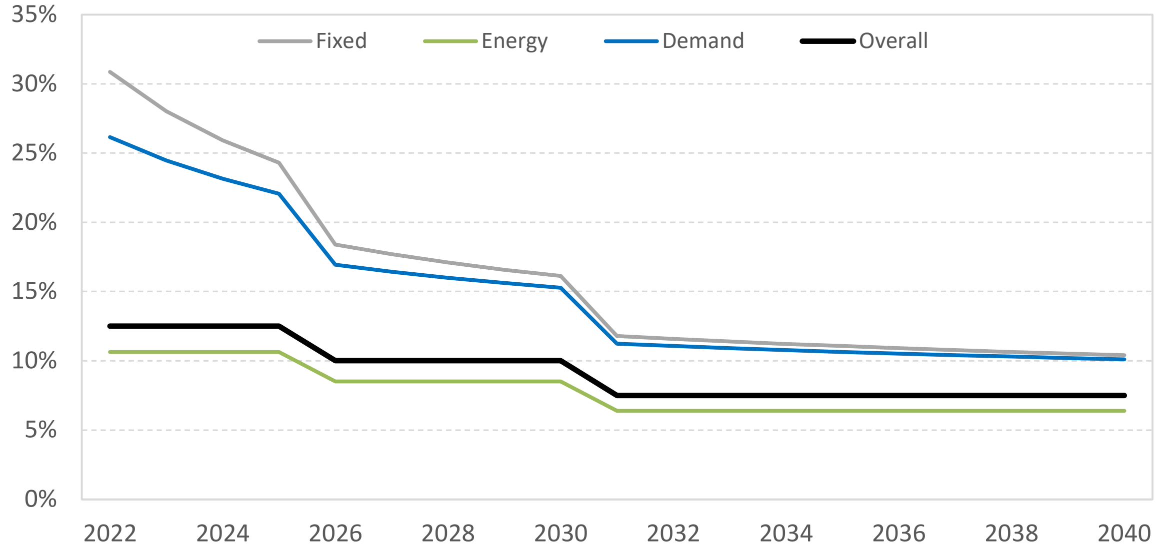

Figure 42: Adjusted tariff drivers between fixed, energy and demand (nominal)

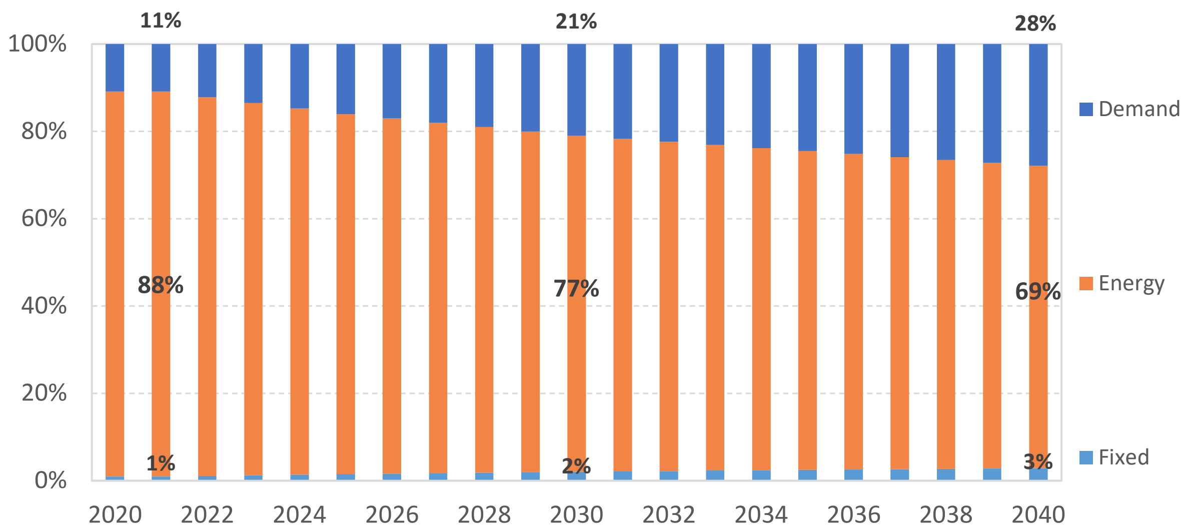

Figure 43: Projected Megaflex tariff composition

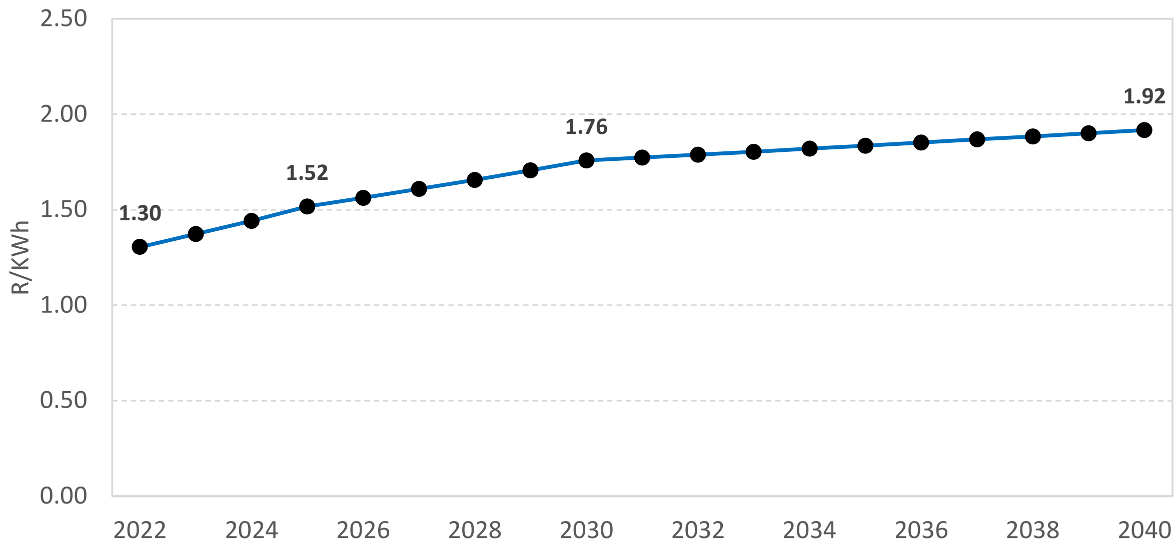

Figure 44: Projected, equivalent energy tariff (real)

3.4.4. Integration Costs

GRDM is located in the Outeniqua Customer Load Network (CLN) or load centre. The load in the Outeniqua area is forecasted to grow by 29%, from 847 MW in 2022 to 1093 by 2031 [6]. As the demand grows in an area, so does the potential to connect generation sources on the load side. Eskom's Generation Connection Capacity Assessment (GCCA 2023) report, which is limited to transmission substations, states the generation integration capacity for GRDM at Proteus substation as 1210 MW when connected at 132 kV, however when connected at 400 kV, the capacity is limited to 700 MW.

The generation connection capacity assessment method based on the transformation limit at the substation is shown in the following figure.

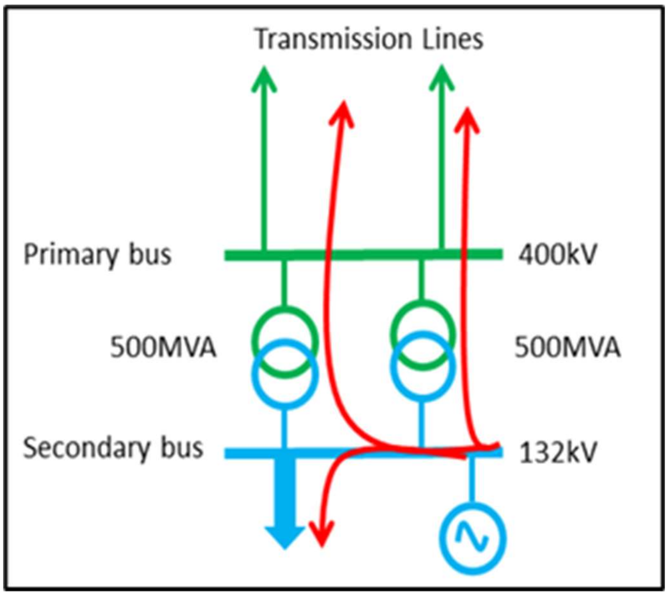

Figure 22: The connection of the generation at the 132 kV as per the GCCA (source: Eskom)

In the absence of detailed power flow studies, an initial proxy for the grid integration capacity limits for local generation is the present NMDs of the points of supply. In the case of the GRDM, the transmission and sub-transmission level estimated capacity is given in the following table.

Table 10: Estimated generation connection capacity for GRDM based on existing infrastructure

Level	Substation/load area	Capacity (MW) based on transformation limit (based on NMD)	Total estimated connection potential (MW) (limited to existing infrastructure)
Transmission level	Proteus	1210[a]	1210
	Narina (future)[b]	1000[b]	
Distribution [c]	Bitou load	57	~ 576
	George load	165	
	Hessequa	48	
	Kannaland	19	
	Knysna	81	
	Mossel Bay	142	
	Oudtshoorn	65	
([a]): Based on GCCA 2023 ([b]): only to be considered from 2030 onwards ([c]): Estimated based on MD + NMD @ unity pf			

4. Rooftop PV Analysis

4.1. Overview

Rooftop PV is a customer resource. To identify the potential of rooftop PV, and ultimately the adoption rate, in the GRDM a three-step process is followed:

1. Determine technical potential based on available rooftops
2. Calculate the business case for rooftop PV
3. Estimate the adoption rate

4.2. Technical Potential

4.2.1. Rooftop Area

To estimate available roof space for rooftop solar PV deployment in the GRDM, the following freely available spatial datasets were used:

- Open Buildings [7] – which depicts buildings footprints and area in m^2;
- South African National Land Cover [8]; and
- Local Municipality Boundaries [9].

The geospatial analysis to estimate available rooftop space for solar PV deployment in the GRDM was executed using Esri© ArcGIS Pro 2.8. The process is summarised in the following figure.

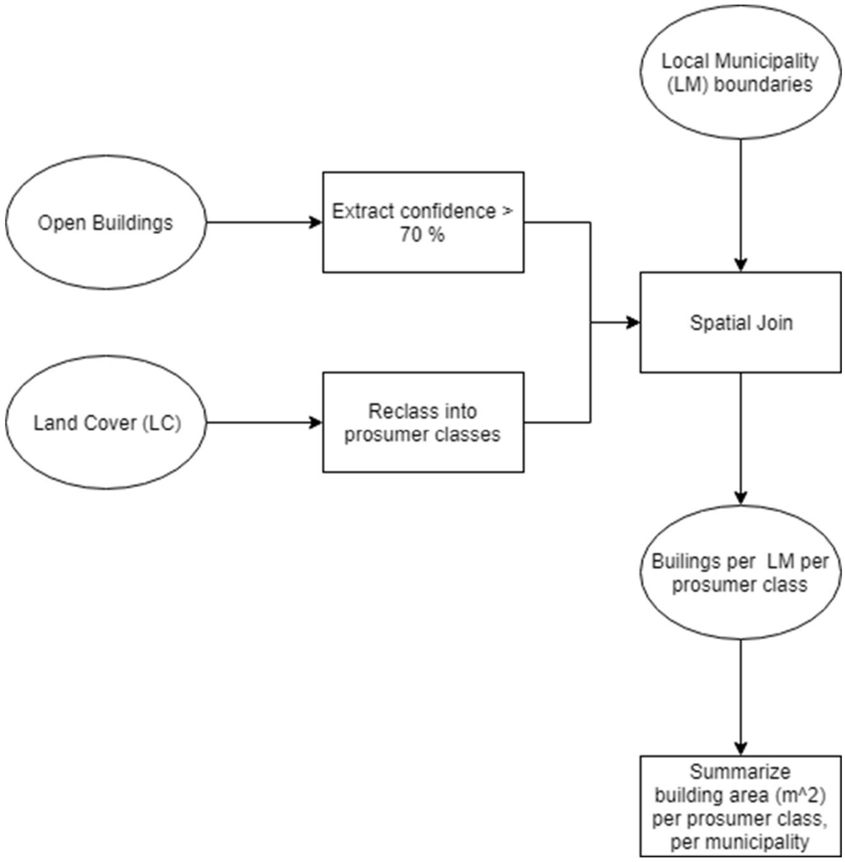

Figure 45: Geospatial analysis process for estimating available rooftop space for PV deployment

The Open Buildings data specifies a confidence rating for each identified building footprint. Building footprint confidence was inspected for 10 random 200 x 200 m samples, and subsequently a confidence of > 70 % was found to be reasonably accurate for the purposed of broadly estimating available roof space for solar PV deployment. The footprints with confidence > 70 % were extracted for subsequent analysis.

The various land cover classes contained in the National Land Cover dataset was used to classify the different customer classes per municipality. The following detailed land cover classes were categorised and reclassed to represent residential, commercial, industrial, and agricultural customers, Table 11.

.

Table 11: Land cover used to represent residential, commercial, industrial and agriculture customer classes

LC class (CLASS_NAME)	Customer class (RTPV_CLASS)
residential formal (bare)	Residential
residential formal (bush)	Residential
residential formal (low veg / grass)	Residential
residential formal (tree)	Residential
residential informal (tree)	Residential
roads & rails (major linear)	Residential
urban recreational fields (bare)	Residential
urban recreational fields (bush)	Residential
urban recreational fields (grass)	Residential
urban recreational fields (tree)	Residential
village dense (bare & low veg / grass combo)	Residential
village scattered (bare & low veg/ grass combo)	Residential
industrial	Industrial
mines: extraction pits, quarries	Industrial
commercial	Commercial
commercial annual crops non-pivot irrigated	Agricultural
commercial annual crops pivot irrigated	Agricultural
commercial annual crops rain-fed / dryland	Agricultural
cultivated commercial permanent orchards	Agricultural
cultivated commercial permanent vines	Agricultural
fallow land & old fields (bare)	Agricultural
fallow land & old fields (bush)	Agricultural
fallow land & old fields (grass)	Agricultural
fallow land & old fields (low shrub)	Agricultural
fallow land & old fields (trees)	Agricultural
fallow land & old fields (wetlands)	Agricultural
smallholdings (bare)	Agricultural
smallholdings (bush)	Agricultural
smallholdings (low veg / grass)	Agricultural
smallholdings (tree)	Agricultural

The reclassed Land Cover data was joined spatially with the Open Buildings and municipal boundary data to produce a new dataset with each building footprint assigned its corresponding customer class and local municipality in which it is located, Figure 46 provides an example. Inaccuracies in the data may be observed, for example: (a) larger buildings / buildings with complex roof structures registering as several smaller footprints; and (b) gaps where footprints with confidence levels < 70 % were excluded from the analysis, this resulted in some buildings only being partially included in the analysis.

Only intersecting features were retained in the new dataset – i.e buildings that did not intersect with one of the customer classes (often situated in remote / rural areas) were not included in the rooftop calculations.

Figure 46: View of York Street circle in George, showing commercial (yellow) and residential (blue) buildings

Subsequently the building footprint area (m^2) was summarised to produce total rooftop space, per customer class, per local municipality, Figure 47. Agriculture is included in the commercial customer class. The figure provides the total rooftop area, the next section considers how much of this is ‘usable’, and ultimately, the installable capacity.

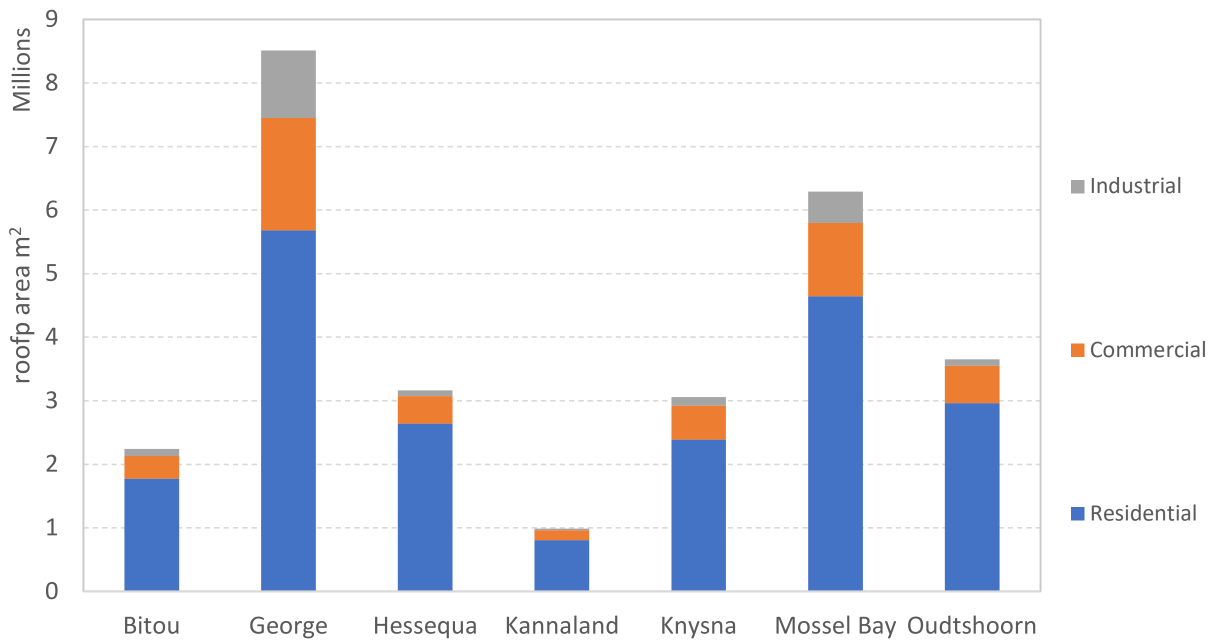

Figure 47: Estimate rooftop area (m^2) per municipality and customer class

The following assumptions and limitations underpin the rooftop area estimation:

- The spatial analysis aimed to provide an estimate of theoretically available rooftop space for solar PV deployment. It does not consider technical feasibility or uptake potential of rooftop PV.
- The spatial analysis is based on freely available spatial data, which are subject to inherent limitations with regards to accuracy and precision.
- Building footprints in the Open Buildings data are less accurate for dense built-up areas and complex roof structures.
- In some instances, larger buildings seemed to register as several smaller individual footprints in the Open Buildings data.
- Buildings that did not intersect with one of the customer classes (often situated in remote / rural areas) were not included in the rooftop calculations

4.2.2. INSTALLABLE PV

Two random sample points per customer class, per local municipality (totalling in 56 random samples across the Garden Route District Municipality) were generated for manual inspection to further determine potentially 'reasonable' rooftop space for solar PV deployment. The sample is a 200 x 200 m 'block', Figure 49 provides an example. The sampling attempts to establish how much of the GIS identified rooftop area is 'reasonable' for solar PV deployment, Figure 48. This is unique to customer class and municipality but the overall 'loss' for the region is about 35%. To account for unusable roofspace due to shading, structural and obstructions issues, packing density, etc. a 25% additional loss is applied to determine the usable roofspace (from reasonable). Therefore, around half of the identified rooftop area identified with GIS techniques is usable.

The roofspace units are area (m^2). To translate to technical potential, installable capacity (kW_{DC}), the power density of standard 325 W panel at 2 x 1 m was used. For example, if a 100 m^2 is identified as total roofspace the installable capacity is around 8 kW_{DC}.

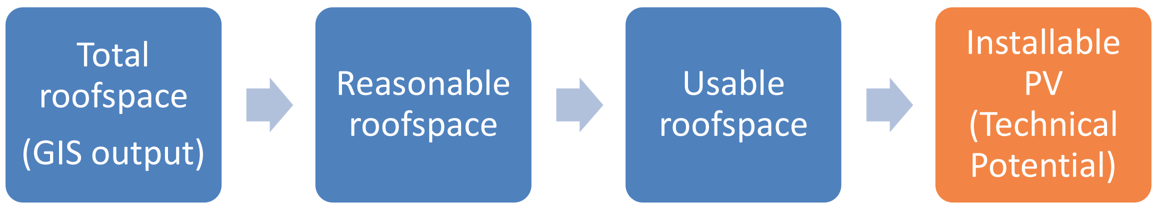

Figure 48: The process to determine installable PV

Figure 49: Example of 200 x 200 m sample

The following figure presents the installable PV capacity (AC) per customer class and municipality. For the region, the total capacity that can be installed on existing rooftops is about 1,750 MW. This is about 7 times more than the GRDM's MD (refer to Section 2.1.2). Solar PV is a variable RE (VRE) which does not provide firm capacity so the comparison to MD is not an apples-to-apples to comparison.

To provide context to the technical capacity findings, the follow question is posed: how much of the technical potential is required to provide 100% of the customers' annual electricity consumption? (Not in terms of timing but simply magnitude. Solar PV, without energy storge, cannot meet nigh time needs.). Figure 51 provide this ratio. The specific yield per municipality is applied to determine the annual electricity generated (refer to Section 2.3). Figure 51: Rooftop PV technical potential MWAC – required to provide 100% annual energy consumptionIt is evident that residential customers have ample roofspace to cover their own annual electricity consumption needs. Besides Knysna, commercial customers have adequate roofspace. Industrial customers do not have enough roofspace. This is makes sense due to industrial customers high electrical demand per area footprint. In all municipalities, the cumulative technical potential is ample to provide all customers annual energy consumption, in magnitude. Only 36% of the identified installable rooftop PV capacity could provide all the customers' annual energy consumption needs for the region.

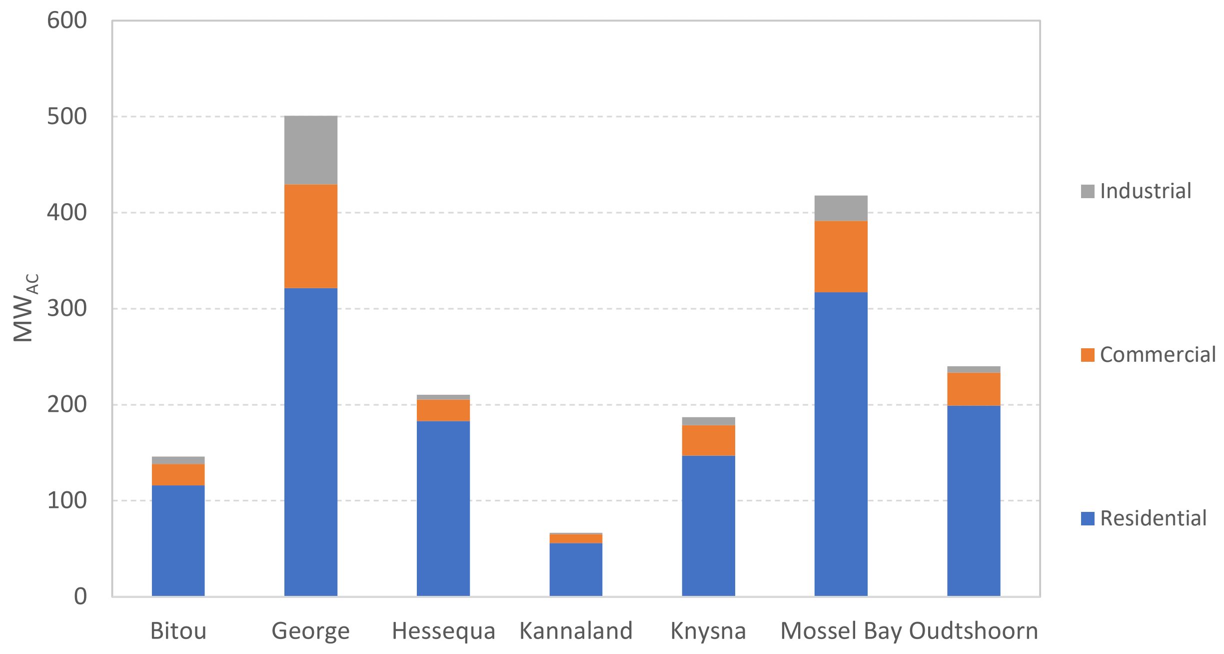

Figure 50: Rooftop PV technical potential MW_{AC}

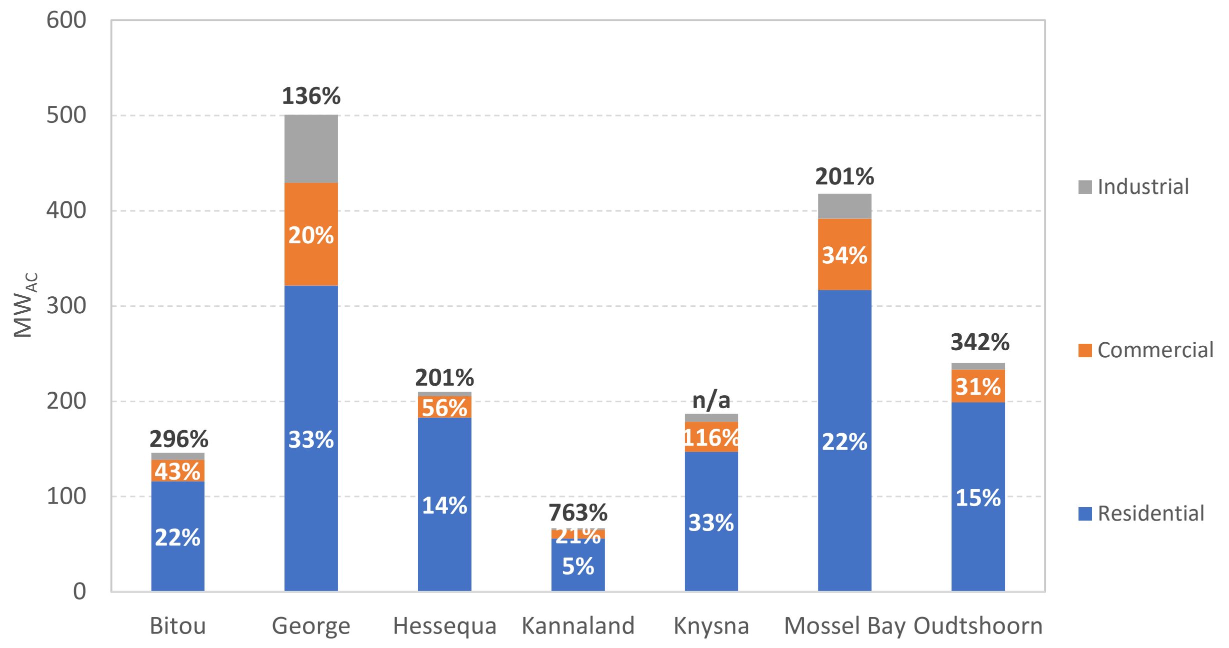

Figure 51: Rooftop PV technical potential MW_{AC} – required to provide 100% annual energy consumption

4.3. Business Case

The business case is based on the financial returns of the PV system. Several key inputs impact the business case, including the solar resource, the cost of the PV system, the load profile of the consumer, and the tariff structure.

The business case was modelled in the System Advisor Model (SAM, version 2020.11.29). The following steps were taken in developing the business case model:

1. Build the base techno-economic model for each user class: Residential (C1), Commerical (C4), and Industrial (C6). The models used the following key inputs:
    a. The location and resource files were downloaded from PVGIS unique each location.
    b. The system design assumed a DC:AC ratio of 1:2 and a total system loss of 16.7%. The tilt = 10 degrees and azimuth = 0. This orientation is representative of the average yield for systems mounted from 0 to 30 degrees tilt and 0 to 45 degrees azimuth, any of which might be installed on buildings in the real world.
    c. The annual system degradation rate was set to 1%.
    d. The price for a turn-key PV system was set to 27 R/W for residential, 20 R/W for commercial, and 15 R/W for industrial.
    e. The inflation rate was set to 5.5%.
    f. The electricity tariffs were set according to the best available data for each municipality.
    g. The electricity escalation rate was set to 4%, meaning the tariffs increase by 4% above inflation each year.
    h. The electric loads were varied by municipality and user class.
2. Export the code for each base model to use as inputs to 'NREL pySAM', a python-based library
3. Construct the 8760 hourly load profiles for each location and customer class based on outputs from the Distribution Profile Mixer (refer to Section 3.1)
4. Apply the FBE (Free Basic Electricity) factor unique to each location to scale the residential load profiles. The customer demand profiles are representative of an average residential customer per municipality. The indigent (FBE) customers are low users of electricity and thus skew the average to the left. The study aimed to estimate the future adoption of rooftop PV and thus the demand profile of potential candidates is sorted, not those that are unlikely to install such systems. The FBE factor is based on the ratio of FBE customers to the total residential customers.

5. Save the inputs for each of the 21 cases in specific folders containing weather files downloaded from PVGIS, tariff structures with sell rate, and load profiles unique to each location and customer class. The sell rate is the potential feed-in-tariff provided by the municipality, three options were considered, namely 0, 0.5 and 1 R/kWh.
6. Import the base SAM model configuration files into python using the 'NREL pySAM' library
7. Run the simulations in python across the range of locations, system sizes, and sell rates for excess generation
8. Save key metrics for analysis: NPV, payback period, SCR, SSD, LCOE, LCOE to load
9. Repeat the process for years 2022, 2025, 2030 and 2040 as tariffs are projected to increase and CAPEX is projected to decrease.
10. Export the simulation results to JMP and create the variability plots for NPV and payback period

Figure 52 shows the simulation results for residential customers in Bitou over time. The net present value (NPV) is plotted along the y-axis versus decreasing CAPEX, increasing tariffs, fixed sell rates, and system sizes. The DC system sizes vary from 1, 3, 5, 7, and 10 kWp DC. The sell rates vary from 0, 0.5, and 1 R / kWh which is the price the municipality/utility pays for excess electricity sent back to the grid. The buy rate shows the first entry of the tariff structure in place for reference, although the time of use tariff and inclined block tariffs are implemented in the model where available. In general, a positive NPV indicates a good investment. The green points indicate a positive NPV and a payback period less than ten (10) years. A rational homeowner might choose a system size with the highest NPV and a payback period less than 10 years. Adoption of solar PV systems will likely increase over time as tariff rise, CAPEX falls, and the business case grows more compelling.

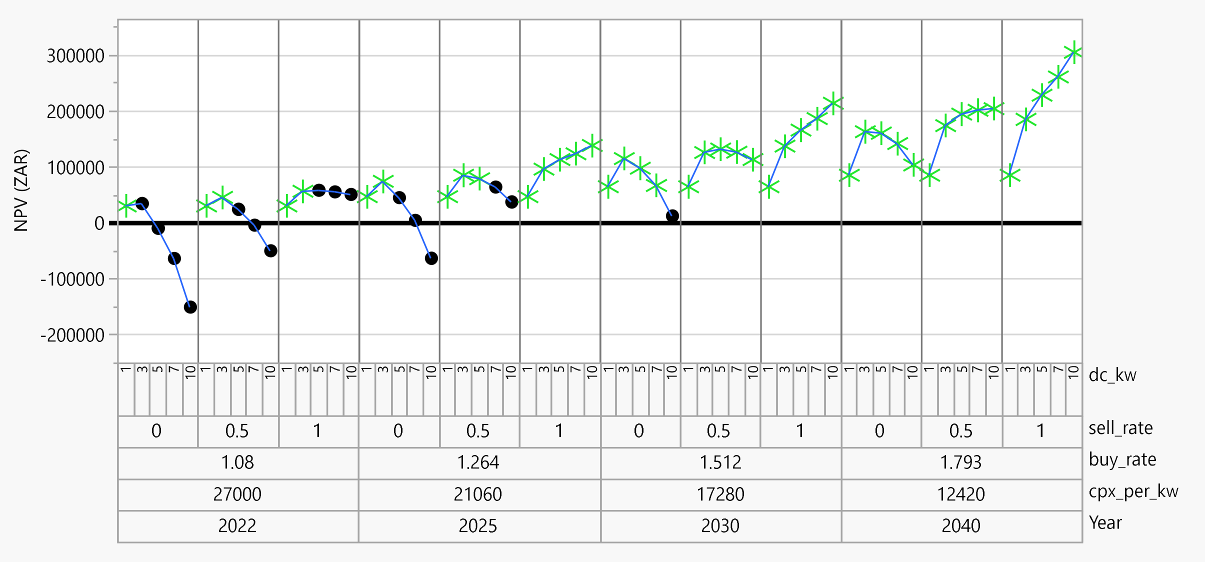

Figure 52: NPV for the residential customers living in Bitou by system price, tariff structure, and system size where green stars indicate systems with a payback period less than 10 years

Figure 53 shows the simulation results for the prosumers in the residential class for all locations assuming a 0.5 R / kWh sell rate for excess generation. The same general pattern holds across all the municipalities over time. The prosumer business case grows stronger as CAPEX decreases and the buy rate increases.

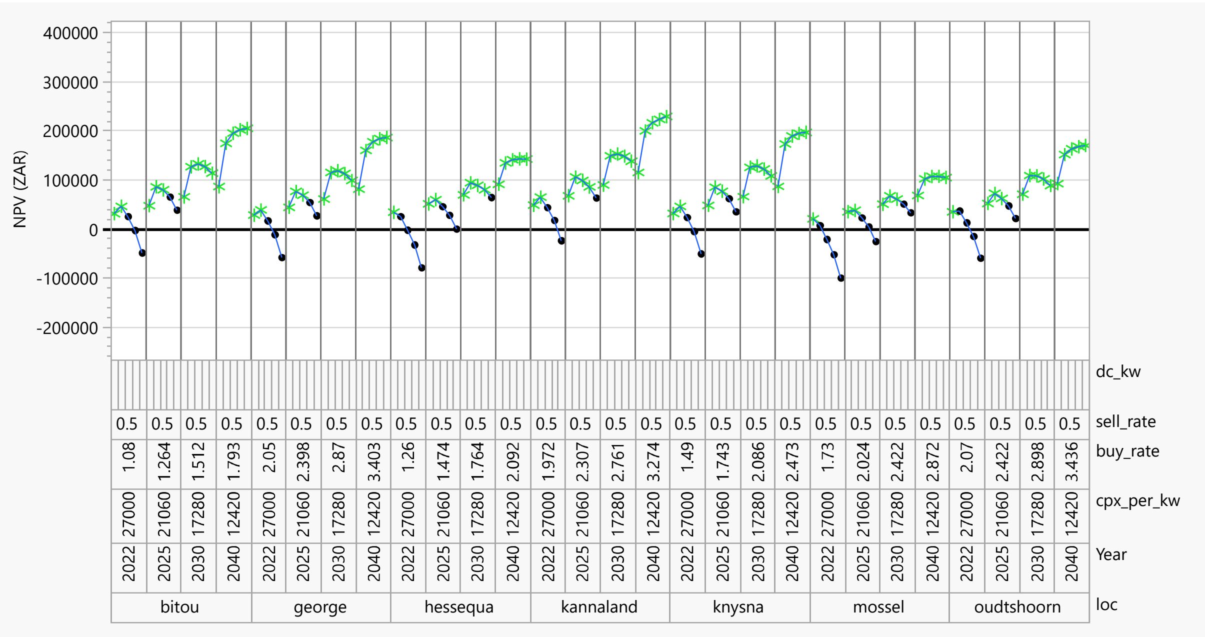

Figure 53: NPV for the residential customers by location, tariff structure, and system size where green stars indicate systems with a payback period less than 10 years

Figure 54 shows the simulation results for the commercial customers for all locations assuming a 0.5 R / kWh sell rate for excess generation. The DC system sizes vary from 3, 5, 10, 15 and 25 kWp DC. The NPV is higher and the payback period shorter when compared to the residential customer.

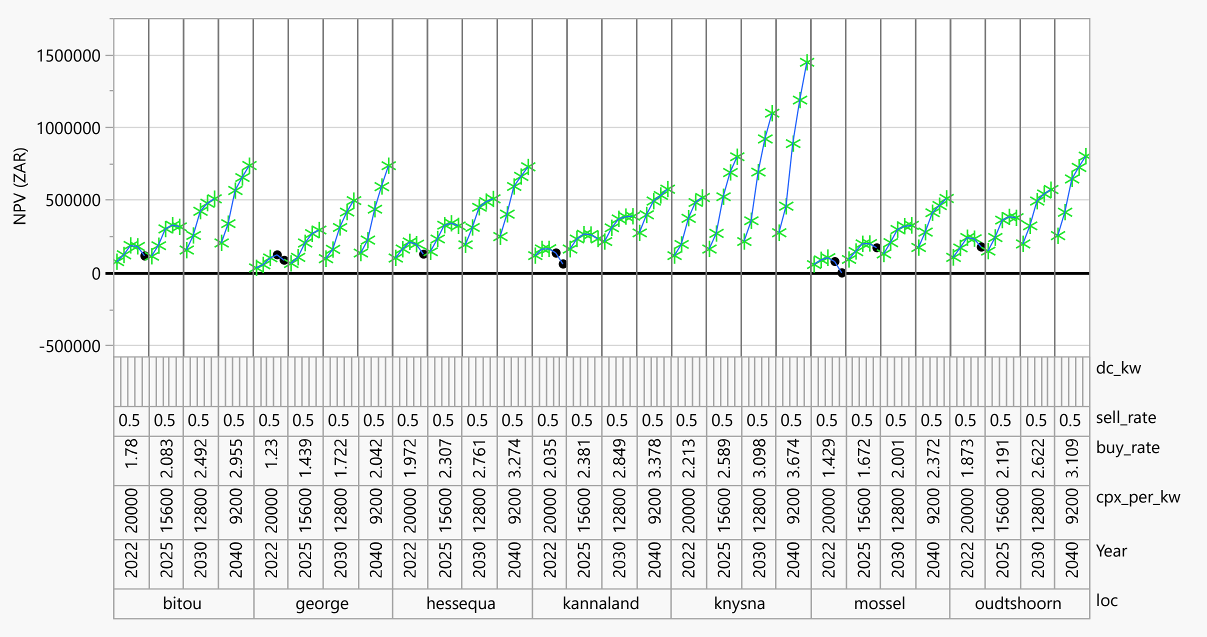

Figure 54: NPV for the commercial prosumer by location, tariff structure, and system size where green stars indicate systems with a payback period less than 10 years

Figure 55 shows the simulation results for the industrial customers assuming a 0.5 R / kWh sell rate for excess generation. The DC system sizes vary from 10, 20, 30, 50, and 100 kWp DC. Knysna had no load data for the industrial class. The customers at every location in this customer class have a strong financial incentive to build PV systems even at today's tariffs without the feed in tariffs, i.e. sell rate = 0.

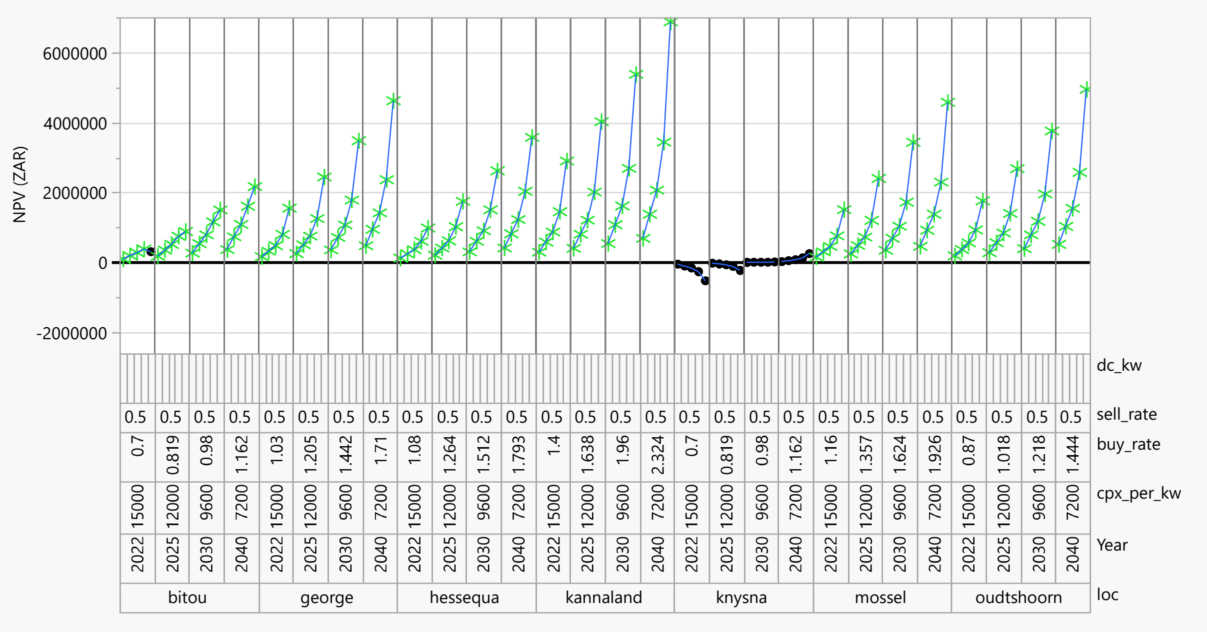

Figure 55: NPV for the industrial prosumer by location, tariff structure, and system size where green stars indicate system with a payback period less than 10 years

The business case analysis shows clear trends towards increasing levels of rooftop PV systems. As the tariffs increase and PV system prices decreases in the future, the NPV increases across all customers classes and payback periods get shorted. These trends are further accelerated as the sell rate for excess electricity increases from 0, to 0.5 to 1 R / kWh.

4.4. Adoption Rates

As noted in Section 4.1, to estimate the adoption of rooftop solar PV follows first requires quantifying the technical potential of rooftop PV. The technical potential is the physical upper limit of the amount of rooftop PV that could be installed. It is important to note that the said technical potential does not include ground-mount installations.

Section 4.2.2 found that there is sufficient technical potential to meet the customers' annual energy consumption needs in terms of magnitude. The previous section presented the business case for rooftop solar PV as a customer resource (embedded generation) which is based on energy savings and three values for a feed-in-tariff (sell rates), namely R 0, R 0.50 and R1 per kWh. This showed a strong business case for solar PV, especially for commercial and industrial customers. The business case improves with time. This section considers how much of the technical potential is likely to be adopted.

Ideally, historic adoption rates could be correlated to actual drivers of adoption. Drivers include the business case, disposable income of customer groups, land use, etc. In South Africa the adoption of rooftop PV is in the early stages, thus historic data is limited. Furthermore, in general, rooftop PV has not been promoted in South Africa by utilities/government like in other parts of the world, albeit developed countries like Germany, Spain and the USA. Many countries subsidized rooftop PV to make it financial attractive to electricity customers. This 'carrot' approach provides for better formal records. In short, there is limited good quality data in South Africa to apply statistical methods to extract drivers and trends for rooftop PV adoption.

The recent LA100 study by NREL [10] estimated rooftop solar PV adoption based on the Bass diffusion model (commonly known as a s-curve). NREL's dGen tool uses various inputs to determine the diffusion of rooftop PV. The primary economic metric employed is the payback period (does it make financial sense for me?). Non-economic factors include:

- Proximity to previous adopters (does my neighbour have rooftop PV?)
- Income (do I have the necessary funds?)
- Building type, for example single-family vs multi-family (do I 'own' the roof and will I live here long enough to reap the benefits?)

The decision to adopt is a binary one and is calculated each year. The NREL algorithm estimates the probability of adoption of each agent (single decision maker per premise) per year.

Adoption rates of PV are outside the scope of this study and, as noted, good quality data in South Africa on this subject is limited. However, a high-level review was undertaken.

It is assumed that only installations that make economic sense are 'viable' for adoption. Economic viability is taken as an installation with a payback period of less than 10 years. From the previous section it is evident that many of the instances have a payback period of less than 10 years and all by 2040. Instead of considering the individual municipalities, the adoption rate for the region is estimated by applying a s-curve. The figure below shows the categories of adopters (blue line) and the market share. The five categories are successive groups of consumers adopting a new technology, in this case, rooftop PV. The GRDM is most likely in the initial-Early Adopters stage with an estimated market share of roughly 3.5%.

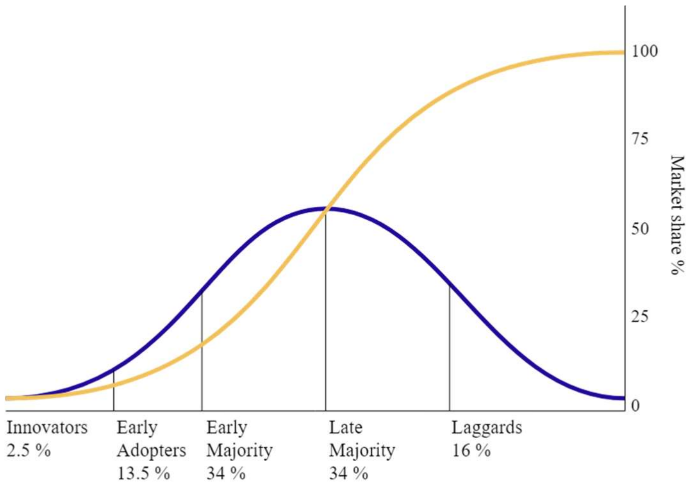

Figure 56: Diffusion of innovation (example)

LA100 predicts that customers in that region will adopt between 34% and 40% of the total economic potential by 2045. Los Angeles is a wealthier and more environmentally conscious region so the said estimate may seem high for GRDM but Los Angeles is not experiencing ongoing load-shedding. For the GRDM a 25% market share is estimated for 2040. By fitting a Bass diffusion model the market share in 2030 will be around 9%, figure below.

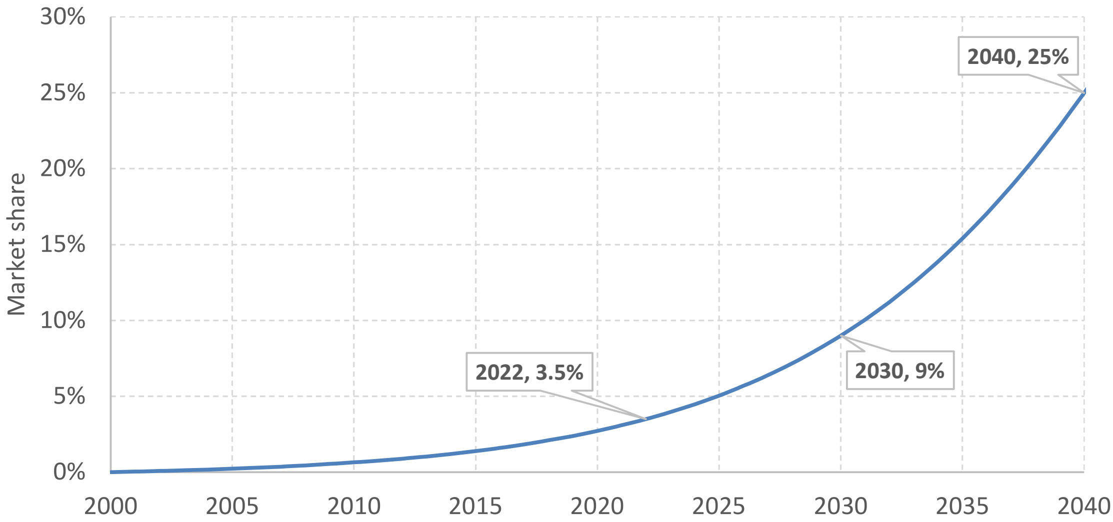

Figure 57: Bass diffusion curve for the GRDM

5. Capacity Expansion Planning

5.1. Overview/Approach

We conducted a high-level resource assessment at GRDM sites. The local resources determine the following key characteristics:

I. Expected hourly solar PV, wind production profiles, and
II. Expected solar PV, wind capacity, and energy yields

We consider and analyse the typical meteorological year (TMY) for each of the locations at GRDM, refer to Annexure A and Annexure B for details of the resource assessments. TMY is a blend of multiple years of satellite data assembled to represent an average year. The outcomes of the resource assessments described in I and II above form an input in the optimization of the electricity supply mix.

5.2. Least-Cost Optimization of the Energy Mix

The high-level methodology follows the same approach implemented at a national level integrated resource plan (IRP), as shown in the following figure.

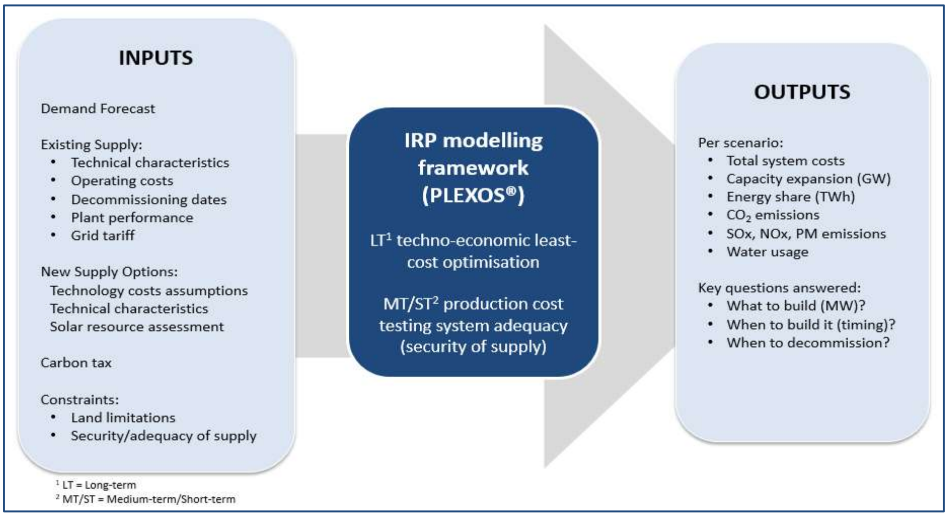

Figure 58: Methodology applied when undertaking long-term energy planning

The South African power system will be simplified to an external wholesale electricity provider of capacity, energy, and/or system services to the **GRDM municipality**. The GDRM is modelled as seven node injection points, each representing one of the municipalities in the district. Each node is provided with the representative electric demand profile which is perpetuated into the future to cover the simulation horizon 2022-2040. Power imports from Eskom at each node are competing with new supply options in the least cost optimization, the outcomes of which determine the type, quantity and the timing of new supply technologies based on performance characteristics and cost. Optimization is only done at each municipality simultaneously to determine the electricity mix for each from which we then add all of the new capacity build to get the total build for the GRDDM. This should not be confused with an optimization on the regional level.

The least-cost plan falls at the investment level which minimises the sum of the investment cost and the production cost, Figure 59 . Investment costs include new capital investment costs while production costs include all costs associated with operating existing and new generation capacity investments.

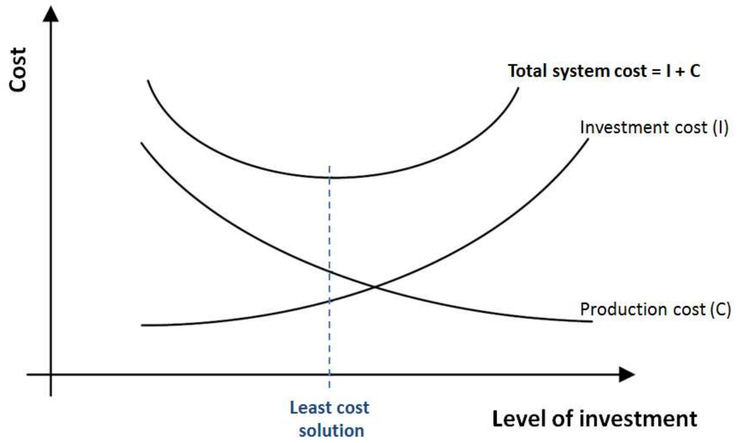

Figure 59: Illustration of the capacity expansion planning optimization

This will be simulated in a long-term capacity expansion planning modeling framework with additional unit-commitment and economic dispatch production cost modeling capability (PLEXOS) using data supplied by municipalities and supplemented with publicly available data. The expected wholesale tariff trajectory to inform the GRDM wholesale energy, capacity, and system services offtake are important parameters to consider when making investment decisions in new supply capacity. The CSIR will use the annual forecasted wholesale electricity tariff with specific reference to GRDM offtake. This will be based on CSIR's view on annual tariff escalation as discussed in the tariff section.

Detailed operational constraints are considered including, minimum up/down times for existing known generators, and hourly chronology. Other key input assumptions include the expected performance of the demand forecast which we assume to be constant, and the expected new generation capacity that is already committed/planned to come online if any. On the cost of unserved energy, this is the balancing mechanism in optimization wherein the associated cost of unserved energy (COUE) is utilized as a penalty for shortages experienced resulting in a natural balance of existing capacity, new capacity, and minimized shortages.

5.3. Scenarios

Development of an electricity system model to evaluate alternative energy mix scenarios with the current "as-is" system. This entailed the optimisation of additional supply that can compete on cost and performance characteristics with import from Eskom to minimize electricity costs.

The following scenarios were analysed:

1. Business-as-usual (BAU)
2. Least cost
3. 100% Autonomy

5.3.1. Business-as-usual (BAU)

In this scenario, the historical electric demand profile for each municipality was perpetuated to cover the study horizon 2022-2040; the demand from the seven node injection points representing each municipal demand was met by grid imports from Eskom. No additional supply/demand-side options were included in this scenario other than Eskom power imports. The current structure of the tariff composition is slightly altered by increasing the share of fixed cost charges while reducing the share of energy charges in the total cost of electricity, however, the bulk of Eskom's energy charges still makes up a large percentage compared to total fixed charges. The outcomes of this scenario included the total cost of electricity, CO_2 emissions, and water consumption which set a benchmark against which other study cases are compared.

5.3.2. Least Cost

New supply options were introduced in the BAU scenario to compete with Eskom imports for energy share at each municipality. We still assumed that the current tariff composition remained as described in the business-as-usual case.

This scenario assumed the same input assumptions as of the BAU, but with the option of building additional generation capacity (solar PV, wind turbine, open cycle diesel generator, diesel fired internal combustion turbine, battery storage) only if it was economically viable to do so. This scenario thus represented a least-cost capacity expansion of each of the individual municipalities in the GRDM under these conditions.

5.3.3. Autonomy

New supply options were introduced in a manner similar to the Least Cost plan but subject to a constraint that 100% supply autonomy must be achieved from 2030. The current tariff composition remained as described above.

5.4. Exclusions

The modelling framework considers all primary cost-drivers directly relevant within the electricity sector. It is important to note the exclusions from the modelling framework which are not included in the optimisation:

- Network infrastructure requirements for each scenario. The modelling framework is capable of this inclusion, but this has not yet been included in this scope of work.
- Power flows in the transmission and distribution network are not considered
- System services (stability, reactive power and voltage control, black-start requirements).
- Mid-life generator major maintenance and overhauls for any technology.
- End of life decommissioning costs for any technology.
- Socio-economic development opportunities of each scenario.
- Rooftop, carport, and ground stability

5.5. Input Assumptions

5.5.1. Overview

The inputs to both the rooftop PV analysis (Chapter 4) and capacity expansion planning (Chapter 5) are provided in Chapter 2 and Chapter 3. Specific to this section, the following inputs are employed:

- Technology Costing and Learning Rates (Section 3.2)
- Demand Forecast (Section 3.4.2)
- Eskom Tariff Projection (Section 3.4.3)

The economic parameters inputted for modelling are provided in Section 5.5.3.The following section provides a summary of the costing and technical performance data used for new technologies. All technology costs shown in Table 12 are in January 2021 Rands. Please note that the OCGT and ICE are assumed to be diesel-fired. Affordable gas (for instance LNG) and/or green hydrogen may provide more options/capacities for OCGT and ICE.

5.5.2. New Technology Costing and Technical Assumptions

Table 12: New-build technology cost and technical assumptions

	SOLAR PV FIXED	SOLAR PV SAT	WIND	OCGT	ICE	L-ION 4HRS
Net Rated Capacity (MW)	100	100	100	105	21	10
Total Overnight Cost, ZAR/kW (Jan 2021 Rands)	12,000[2]	13,815[3]	14,000[4]	17,236[5]	26,732[6]	24,225[7]
Lead-Times And Project Schedule, Years	1	1	4	2	2	1
Phasing In Capital Spent (% Per Year) (* Indicates Commissioning Year Of 1st Unit)	100%	100%	5%, 5%, 10%, 80%	90%; 10%	90%; 10%	100%
Fuel Cost (R/GJ)				380,3	380,2	0
Heat Rate (GJ/MWh)				11,52	8,75	
Fixed O&M Cost (R/kW/Year)	332	378	828	241,52	521,08	59,42
Variable O&M Cost (R/MWh)	0	0	0	69,59	84,34	7,56

2 Capital costs are reversed engineered using REIPPPP Bid Window 4 expedited LCOE of 0.62c/kWh 2017 cost escalated to 2021 for Solar PV

3 Cost ratios between fixed and SAT from EPRI 2017 report and NREL 2020 report (U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2020)

4 Capital costs are reversed engineered using REIPPPP Bid Window 4 expedited LCOE of 0.62c/kWh 2017 cost escalated to 2021 for Wind

5 US EIA report (Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2021)

6 US EIA report (Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2021)

7 Energy Storage Grand Challenge Cost and Performance Assessment 2020

	SOLAR PV FIXED	SOLAR PV SAT	WIND	OCGT	ICE	L-ION 4HRS
DISCHARGE CYCLES PER DAY @100% DISCHARGE						1
ROUND TRIP AEFFICIENCY						86%
PLANNED OUTAGE RATE (%)	1%	1%	3%	5,00%	5,00%	1,90%
UNPLANNED OUTAGE RATE (%)	0	0	0	7,00%	7,00%	4,00%
ECONOMIC LIFE	25	25	20	30	30	10
CO_2 EMISSIONS (KG/MWH)	0	0	0	500	491	0
NOX EMISSIONS (KG/MWH)	0	0	0	0,6	1,34	0

Key input assumptions include overnight capital cost, construction time, capital phasing schedule, Fixed Operations and Maintenance (FOM), Variable Operations and Maintenance (VOM), fuel costs and efficiency (heat rate). The modelling framework (PLEXOS®) does not consider the Levelised Cost of Electricity (LCOE) as an input parameter but considers all cost components explicitly as listed above. The LCOE can at a high level be used to compare alternative technologies which vary in cost, lifespan, and operation.

5.5.3. Economic Parameters

For economic parameters, this study assumed the following:

- January 2021 exchange rate R14.56 to $1 (USD). All technology costs shown in Table 12 are in January 2021 Rands.
- WACC of 8% as calculated by the National Treasury [11]

A Cost of Unserved Energy (COUE) value of R85.35/kWh as per the National Energy Regulator of South Africa (NERSA) study [12] is considered. COUE refers to the opportunity cost to GRDM of electricity supply interruptions and is utilized for long-term energy planning purposes as part of the least-cost objective function to balance investment in new capacity and utilization of existing capacity. The inclusion of COUE ensures that an acceptable level of system adequacy is achieved. This is because of the natural balance achieved via optimisation where the high cost of unserved energy is avoided by building additional capacity and dispatching existing capacity optimally to meet expected demand.

5.6. Results

5.6.1. Business-as-usual (BAU)

Figure 60 shows installed capacity and energy mix resulting from a constant demand forecast for GRDM to 2040 across the seven municipalities, with no alternative supply options – only Eskom. The BAU case has a net present value of R 26.2 billion over the period 2022-2040 which translates into an equivalent annuity of R 2.72 billion, Figure 61. For the year 2022 the total Eskom bill for the around 1,300 GWh supplied is R 1.9 billion, this translates to an equivalent average cost of electricity of 1.48 R/kWh. Due to increasing Eskom tariffs this escalates to 2.80 R/kWh in 2040.

Figure 62 shows indirect CO_2 emissions and water consumption for each municipality and the combined total on the secondary axis which are reducing over time because of the implementation of the national IRP which is adding more renewables into the electricity mix. The combined plan for all the municipalities has a cumulative indirect CO_2 emissions and water consumption of 16.2 mil tonne and 15.3 mil tonne respectively as a result of grid power consumption which is largely coal-dominated.

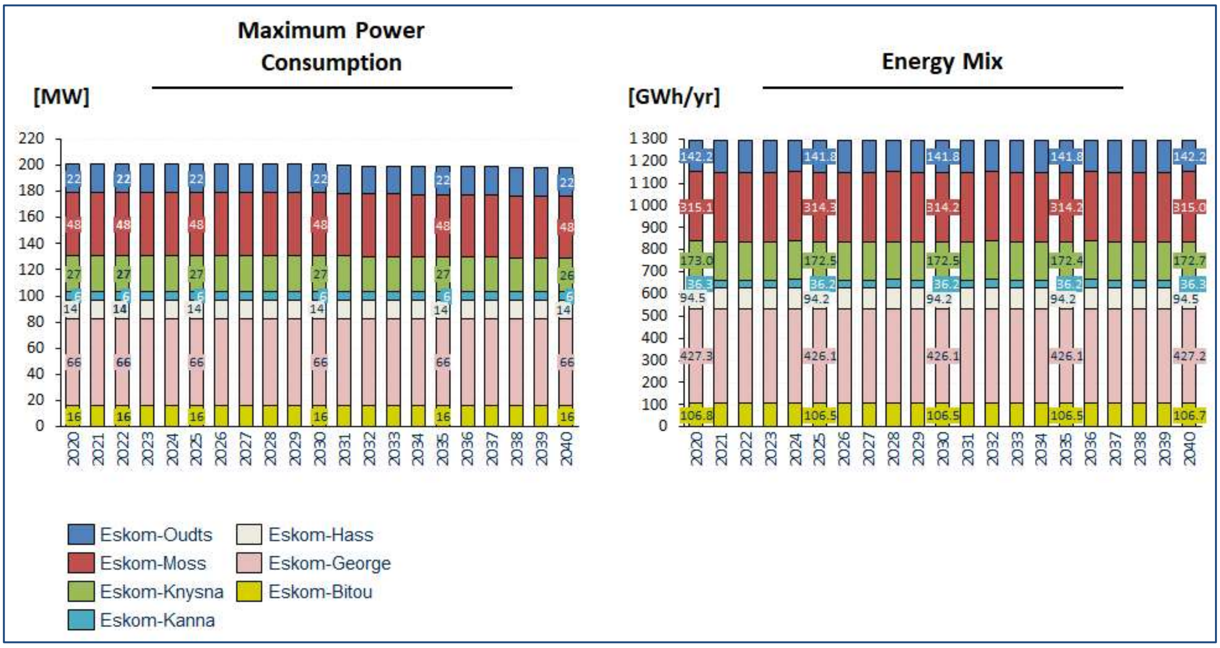

Figure 60: BAU-Installed Capacity and Energy

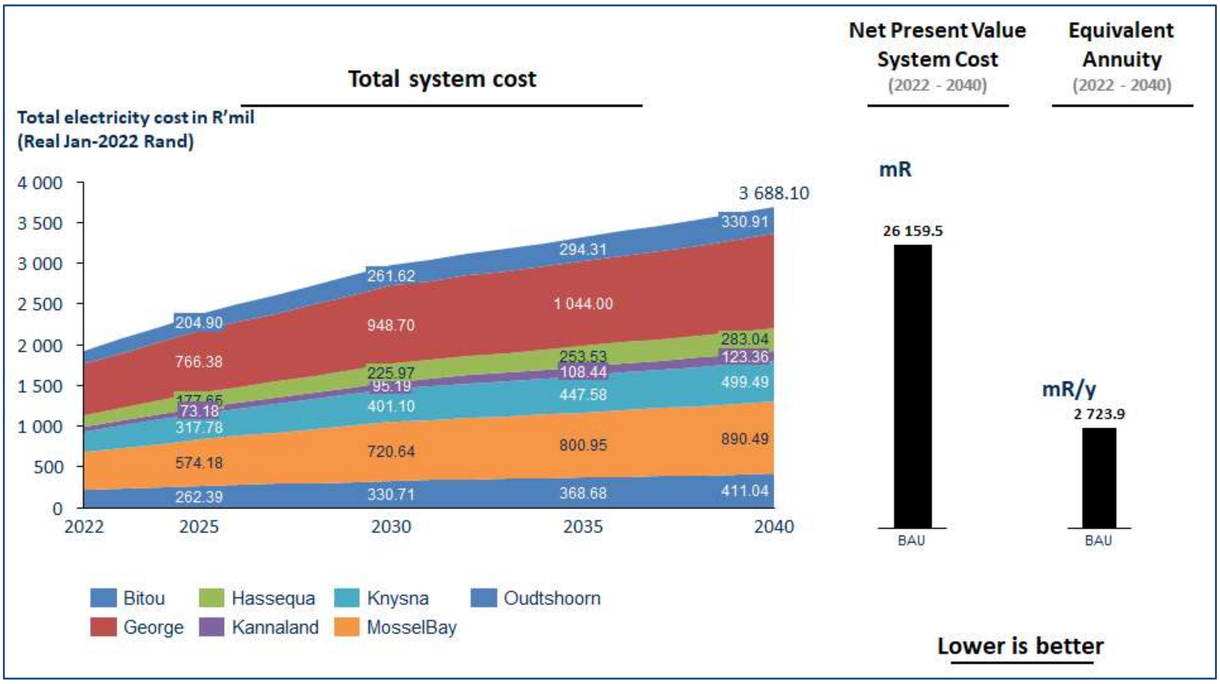

Figure 61: BAU -Total system cost

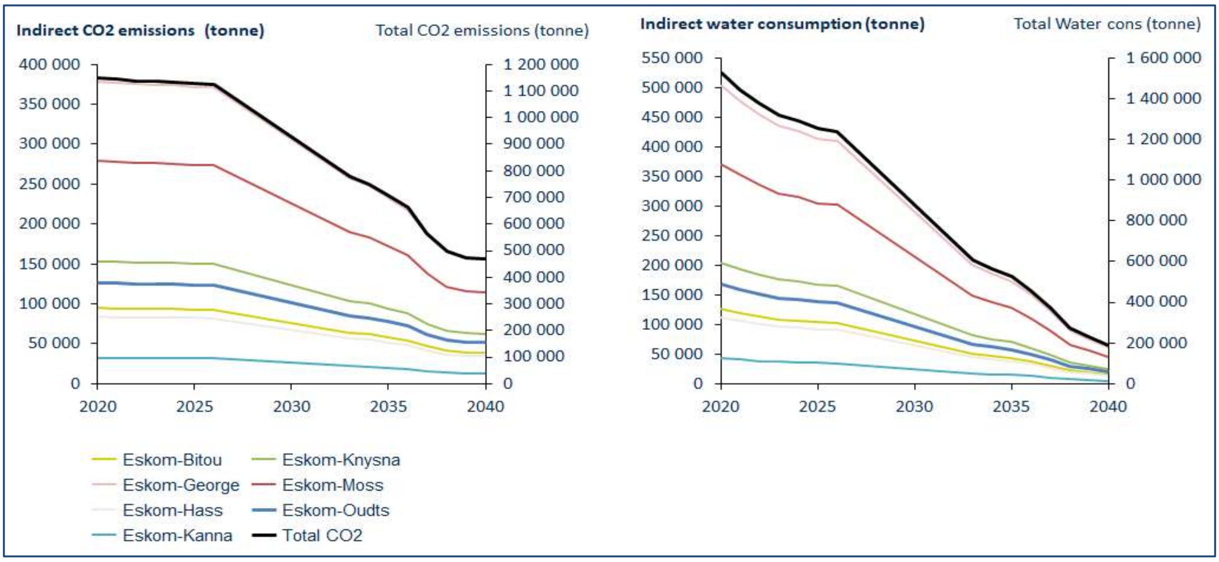

Figure 62: BAU -Total CO_2 emission and water consumption

5.6.2. Least Cost

Optimise Municipality (No Wheeling)

The results for the collective GRDM are presented which are the sum of the optimal plans per municipality. The results per municipality follow. In this section no wheeling between municipalities is possible/allowed. The next section considers the option of wheeling.

Figure 63 shows the consolidated district view of the Least cost plan resulting from optimization at each municipal level where local electric demand, electricity tariff, and resource assessment for wind and solar are taken into consideration in the optimization. The figure shows that investment in solar PV is required as soon as possible, that wind investment is also economic though not to the same extent as solar PV. It is also shown that investment in battery storage options should also be pursued at a later stage (around 2027) to allow costs to reduce from current levels and that despite increasing electricity tariff, that it is <u>not</u> economically viable for the GRDM to disconnect from Eskom.

Figure 64 shows that the Least cost plan is competitive against the business-as-usual scenario where Eskom's tariff is expected to increase sharply. The net present value of the total electrical cost for the GRDM is reduced by 24% to R20 billion, with an equivalent annuity likewise reduced to R 2.06 billion (from R 2.72 billion).

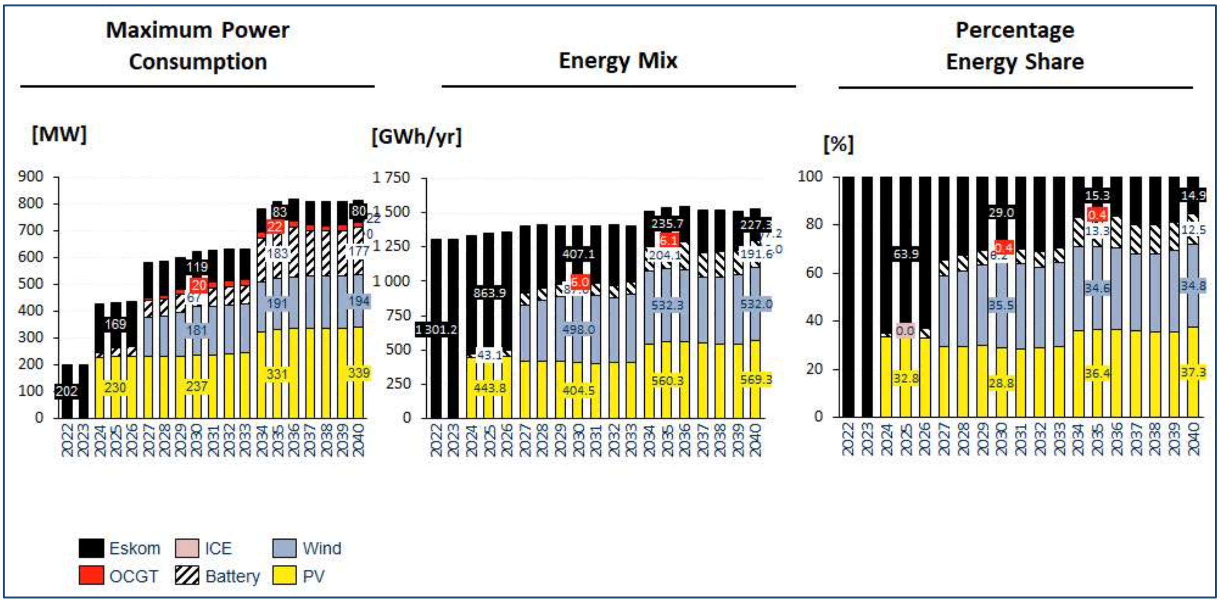

Figure 63: GRDM Installed capacity and energy share: Least Cost

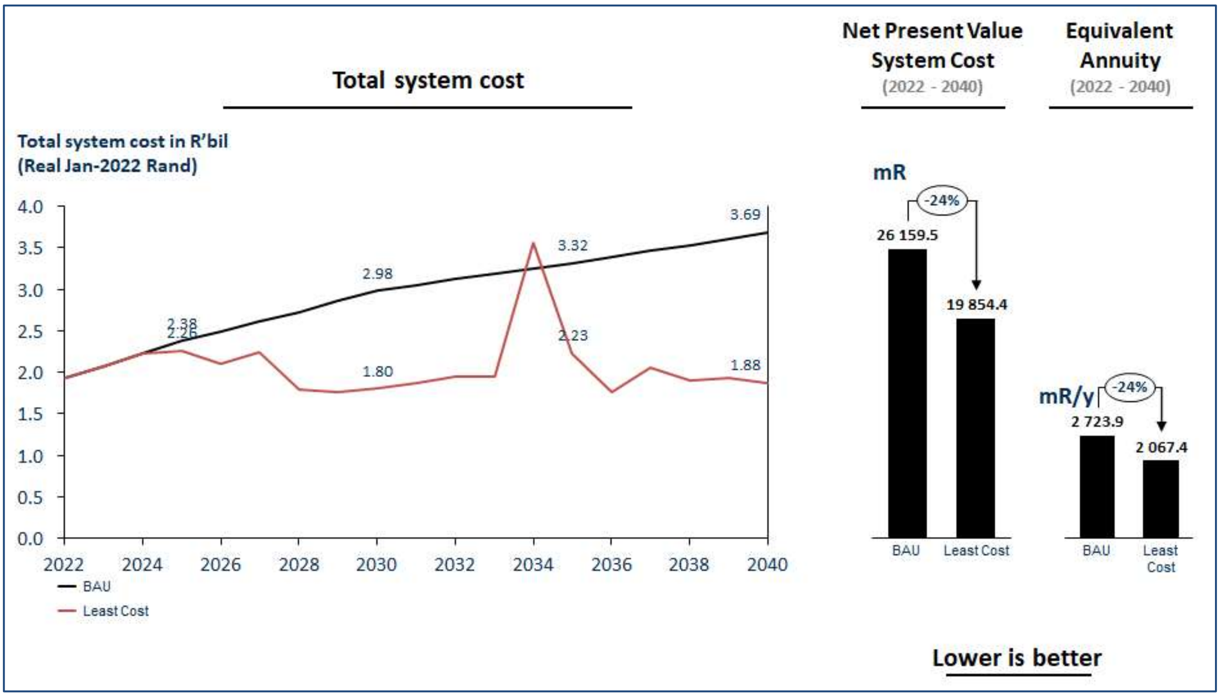

Figure 64: Total system cost: BAU and Least Cost

The Least Cost scenario has a cumulative indirect CO2 emissions and water consumption of 7.53 mil tonne and 7.83 mil tonne respectively which is lower than the business as usual by ~8 mil tonne for each. Figure 65 shows a significant reduction in the amount of indirect CO2 emissions and water consumption compared to BAU.

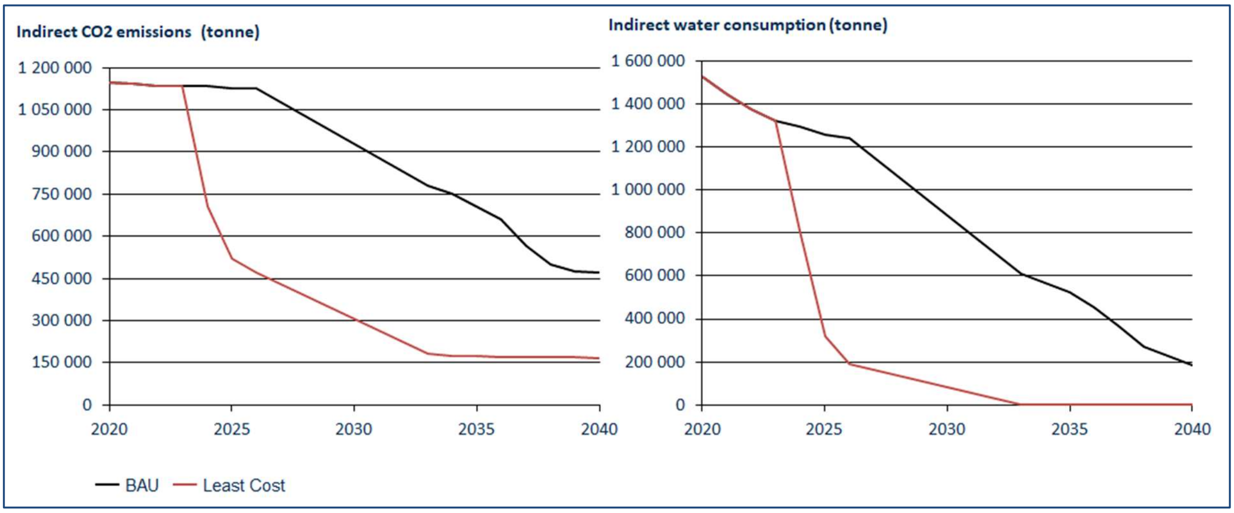

Figure 65: Total indirect CO_2 and water consumption: BAU and Least Cost

Figure 66 to Figure 69 show installed capacity and energy share for each municipality, and clearly show that a significant amount of solar PV is needed as early as 2024 and wind required from 2027 in various quantities. The investment in battery capacity ramps up from 2027 due to the assumed learning rate which makes the battery option more competitive in the latter years, consequently solar PV and wind capacity ramps up as more battery capacity is built. The figures also show small quantities of OCGT required for peaking purposes. It was shown that it is not economically viable for any of the municipalities to disconnect from Eskom, that a blend of solar PV, wind, battery, OCGT, and Eskom power imports is optimal.

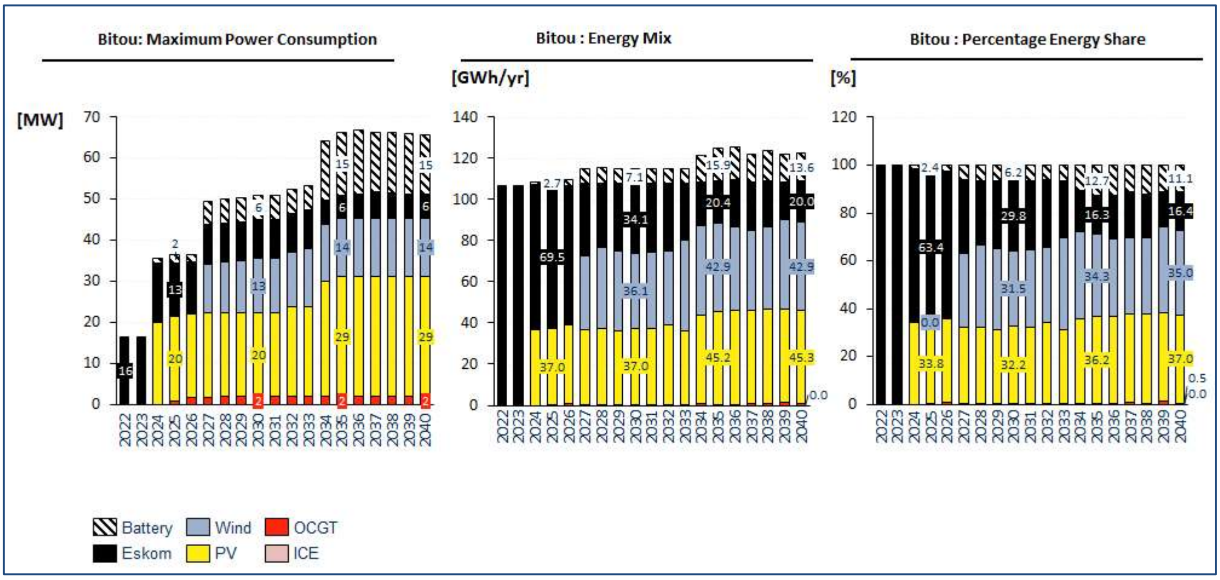

Figure 66: Bitou installed capacity and energy share: Least Cost

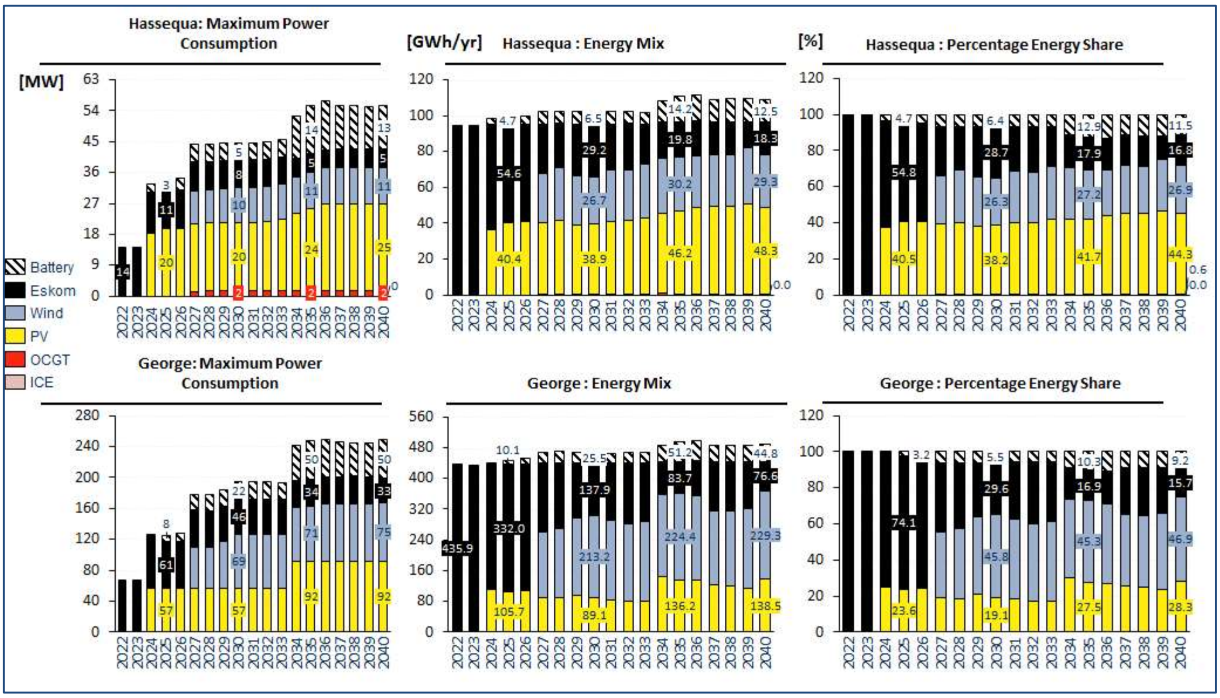

Figure 67: Hassequa and George installed capacity and energy share: Least Cost

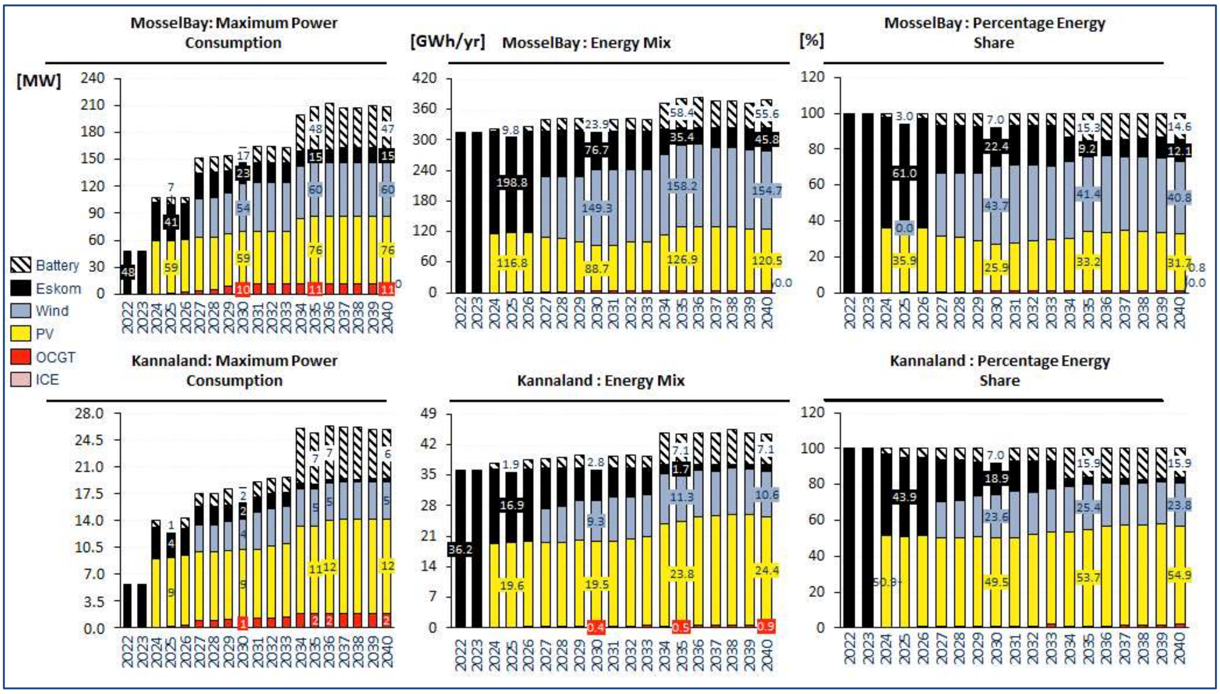

Figure 68: Mossel Bay and Kannaland installed capacity and energy share: Least Cost

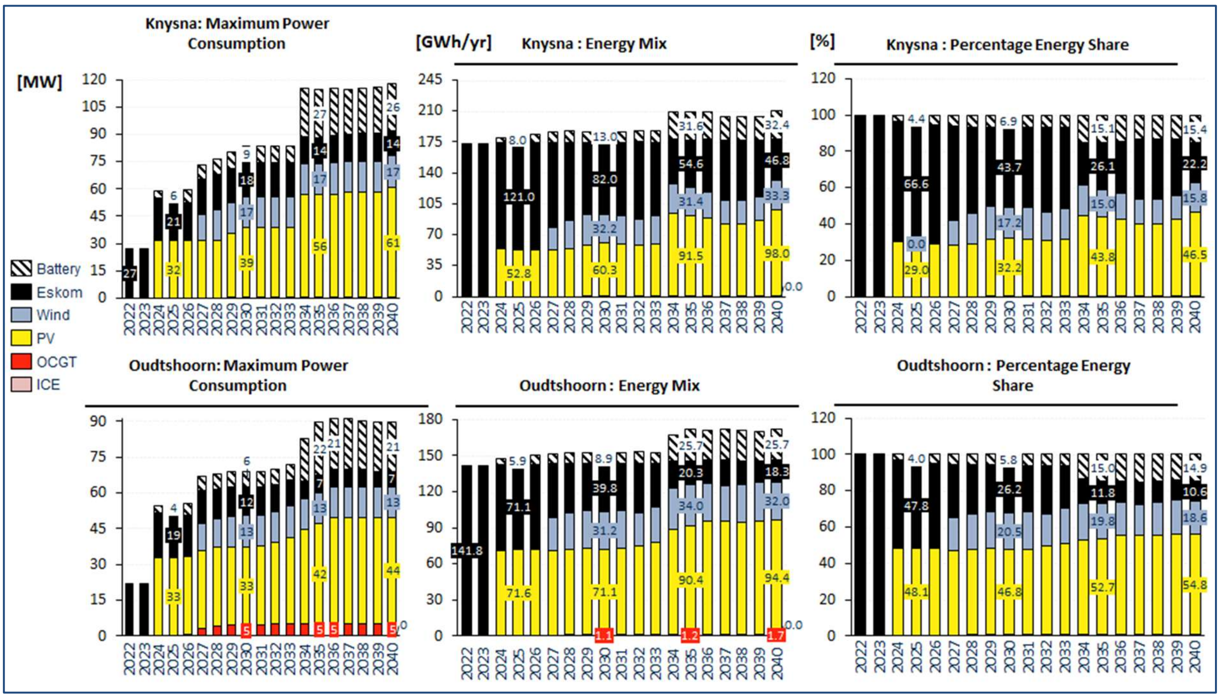

Figure 69: Knysna and Oudtshoorn installed capacity and energy share: Least Cost

Figure 70 to Figure 73 show the magnitude of cost reduction, which range from 16% to 35%, that will be realised by each municipality by adopting the Least cost plan. It is clear that building new generation capacity can significantly reduce the overall cost of electricity in the region.

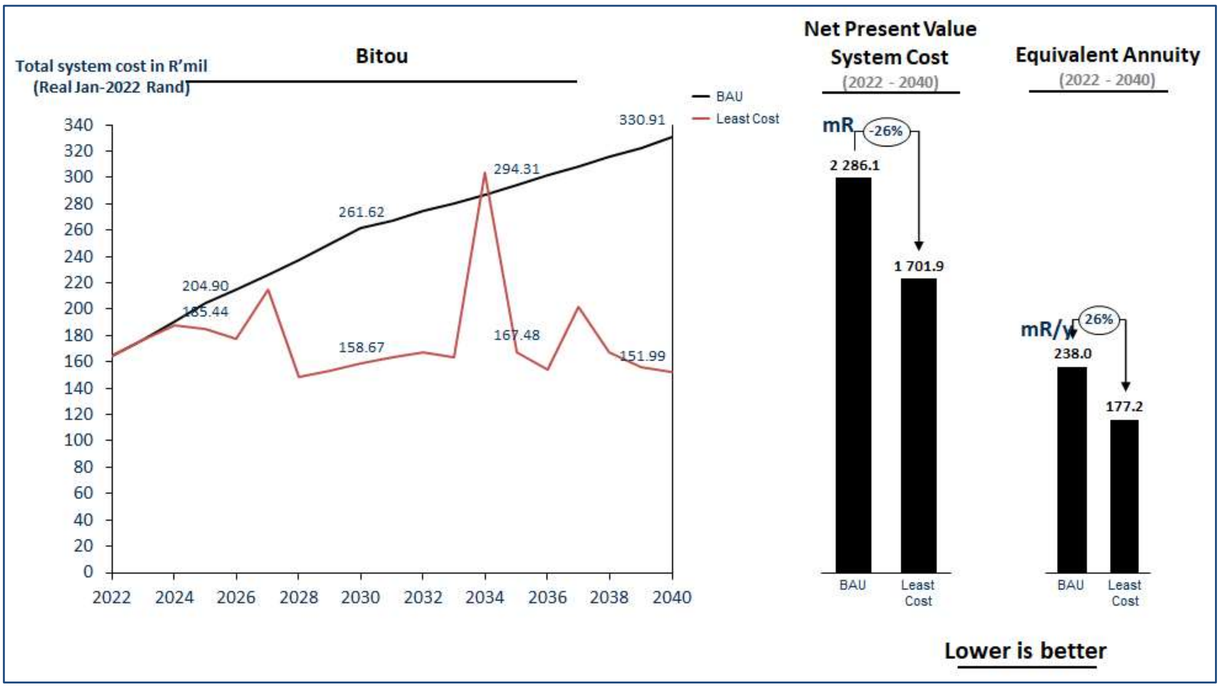

Figure 70: Bitou total system cost: BAU and Least Cost

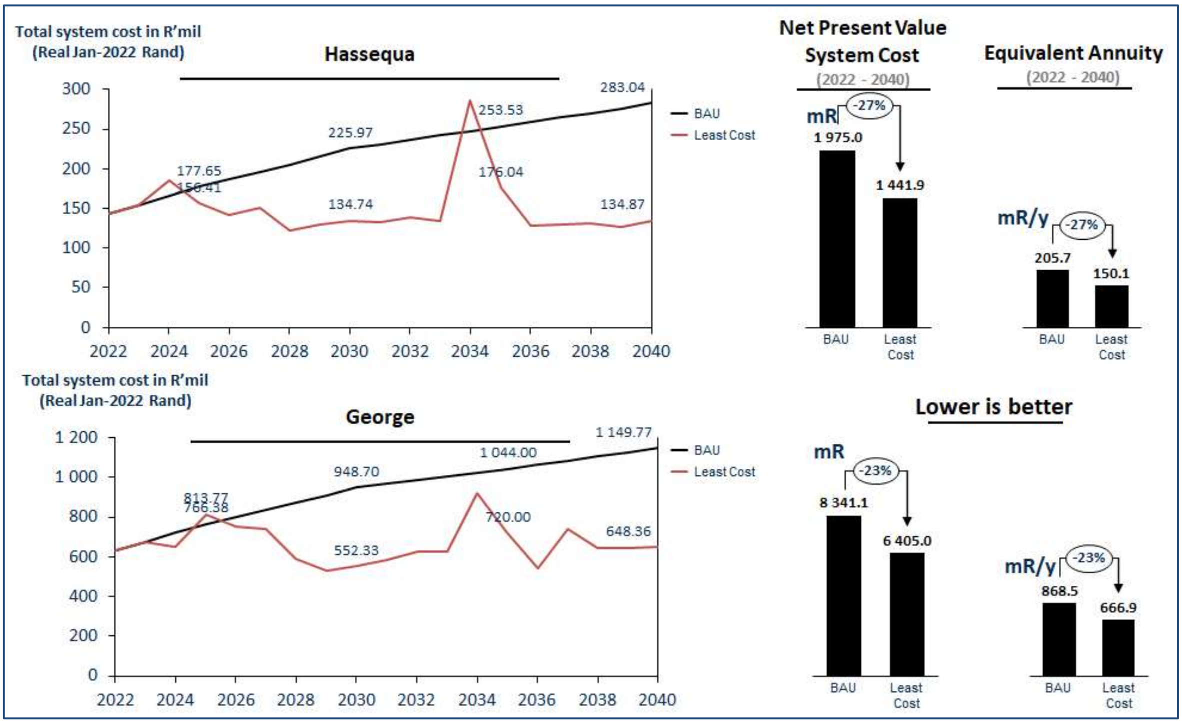

Figure 71: Hassequa and George total system cost: BAU and Least Cost

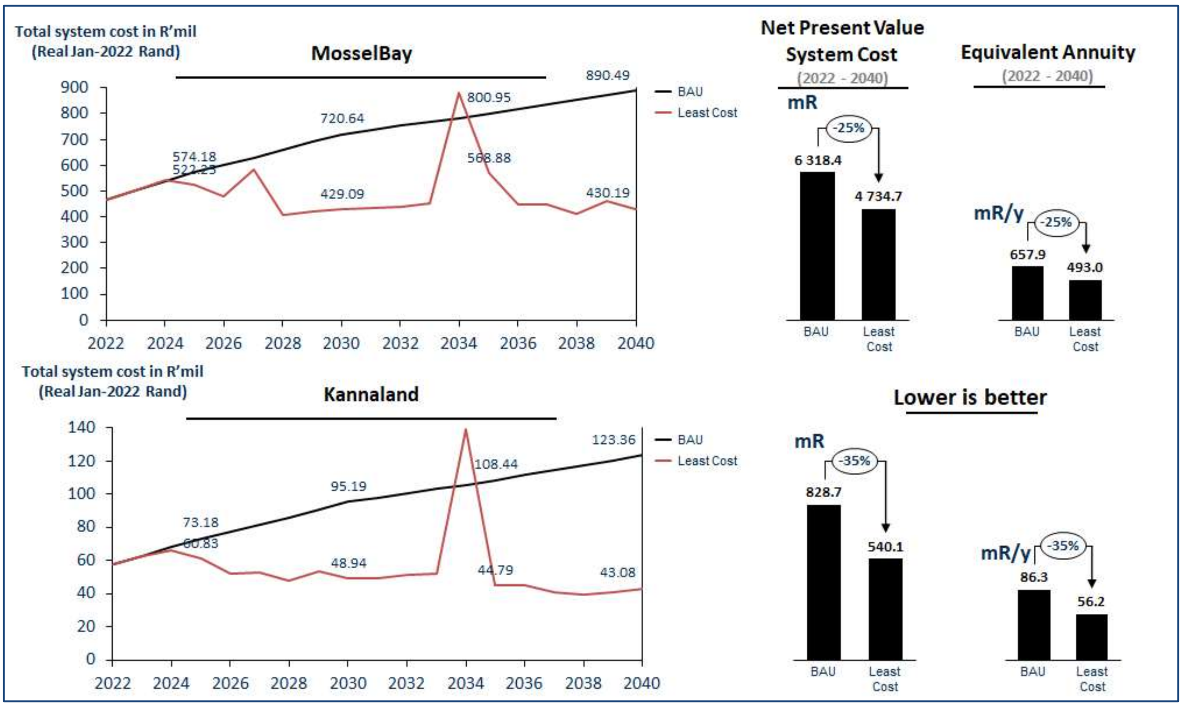

Figure 72: Mossel Bay and Kannaland total system cost: BAU and Least Cost

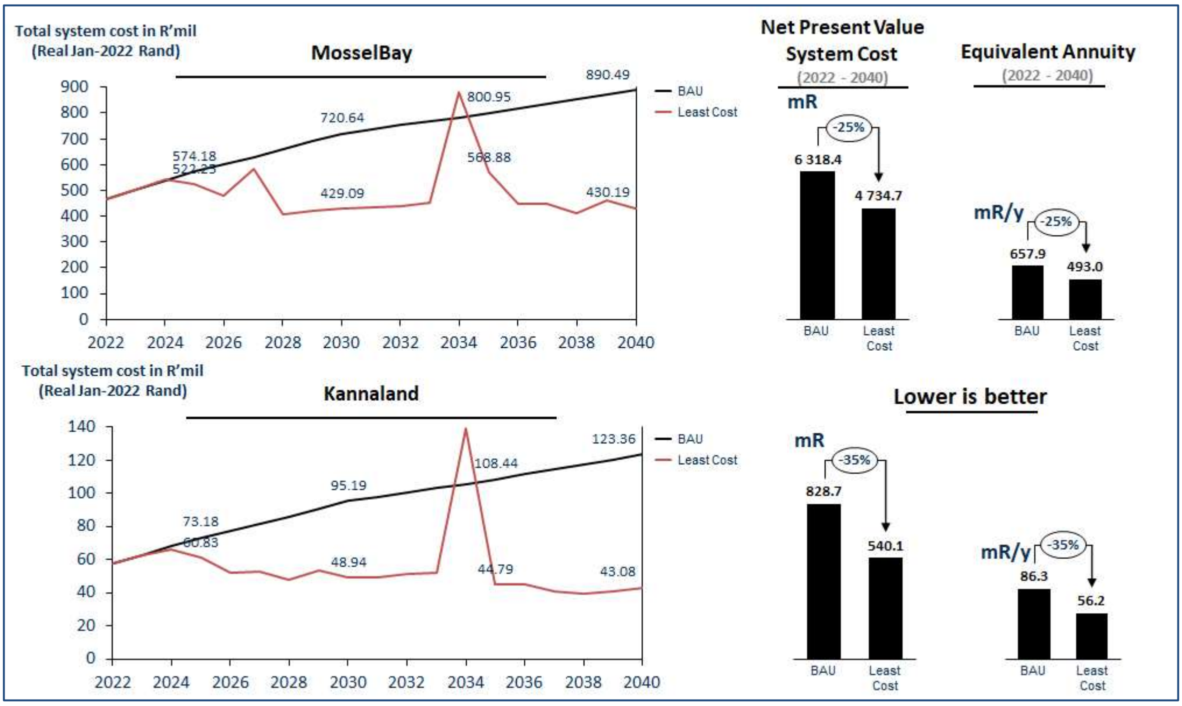

Figure 73: Knysna and Oudtshoorn total system cost: BAU and Least Cost

Figure 74 to Figure 77 show how each supply option in the Least cost plan for each municipality can be dispatched to minimise cost. New solar and wind capacity are dispatched whenever they are available, the battery option is charged by solar PV and wind and is, generally, dispatched during the morning and evening peak. The diesel-fired OCGT plants are dispatched as 'peakers'.

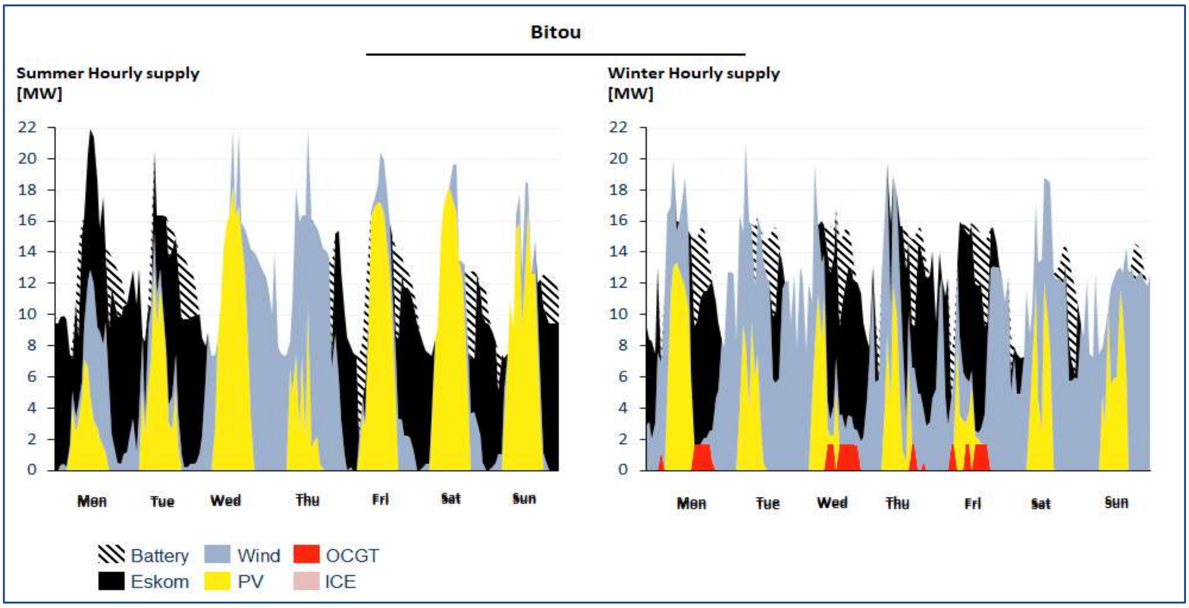

Figure 74: Bitou typical dispatch in the year 2030: Least Cost

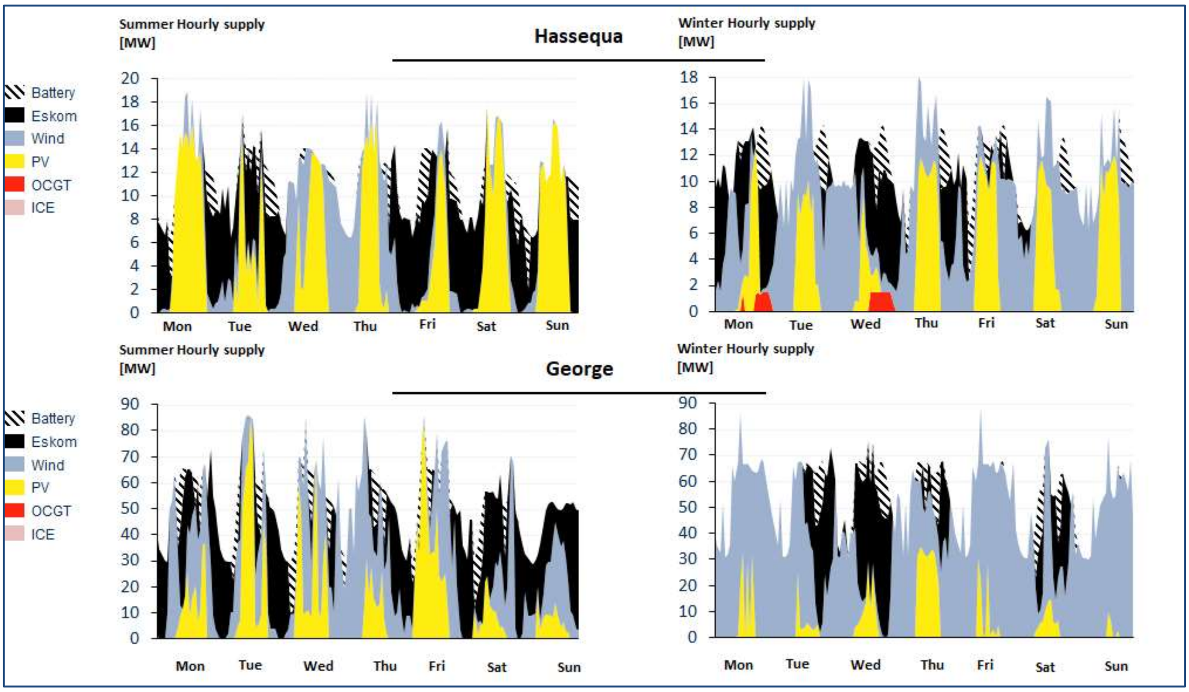

Figure 75: Hassequa and George typical dispatch in the year 2030: Least Cost

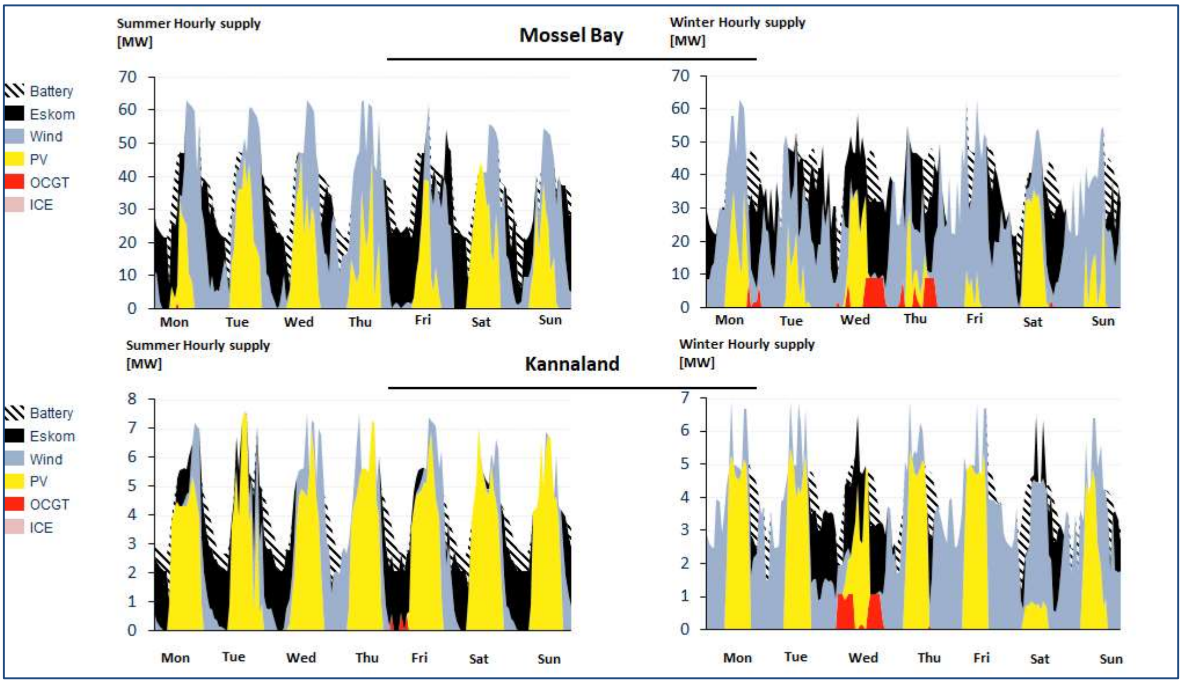

Figure 76: Mossel Bay and Kannaland typical dispatch in the year 2030: Least Cost

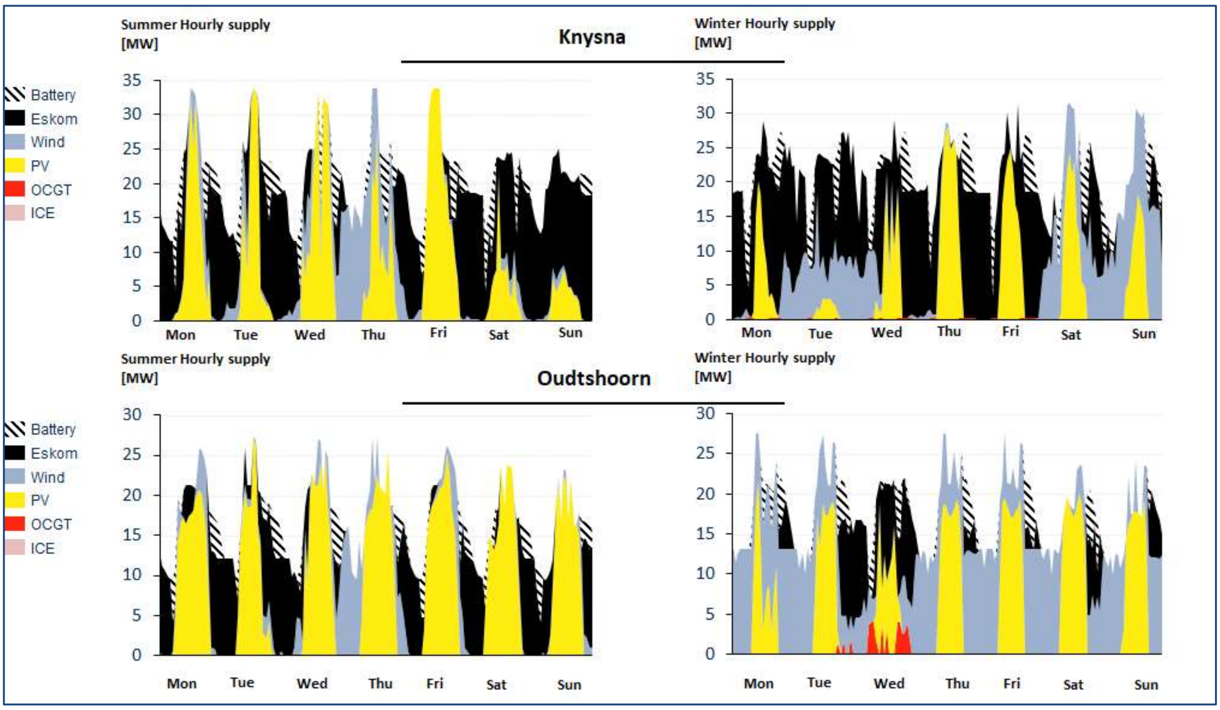

Figure 77: Knysna and Oudtshoorn typical dispatch in the year 2030: Least Cost

Optimise Region (With Wheeling)

The previous section presented the results of finding the optimal solution for each municipality, as if it is the only municipality/node. In reality, these municipalities are connected via the Eskom network. A regional optimization was also undertaken which considers the role wheeling could play in the region.

Limited technical information was available on the regional Eskom network. It is assumed that the network is unconstrained. For costing purposes, a 'wheeling' fee was added – 15% of the total Eskom cost per unit, the wheeling fee is relative to the equivalent Eskom rate = total Eskom charges / total Eskom kWh. Therefore, the wheeling fee increases with the Eskom tariff. The 15% is indicative and is informed by previous work. This translates to a wheeling fee of 23 cents/kWh in the year 2022. The wheeling cost is a 'transaction' fee, so the placement of generation capacity in better resource (solar and wind) areas must first overcome the 'fee' to wheel electricity from one municipality to its neighbour.

The results (with transmission) presented are compared to the nodal results of the previous section (without transmission) per municipality. Overall, the regional optimization provides for 3% cheaper electricity than nodal Least Cost, Figure 78. This is, *inter alia*, dependent on the wheeling fee. The regional plan also reduces CO_2 emissions by 22% and water consumption by 20%. The possibility of wheeling within the region can reduce the reliance on Eskom.

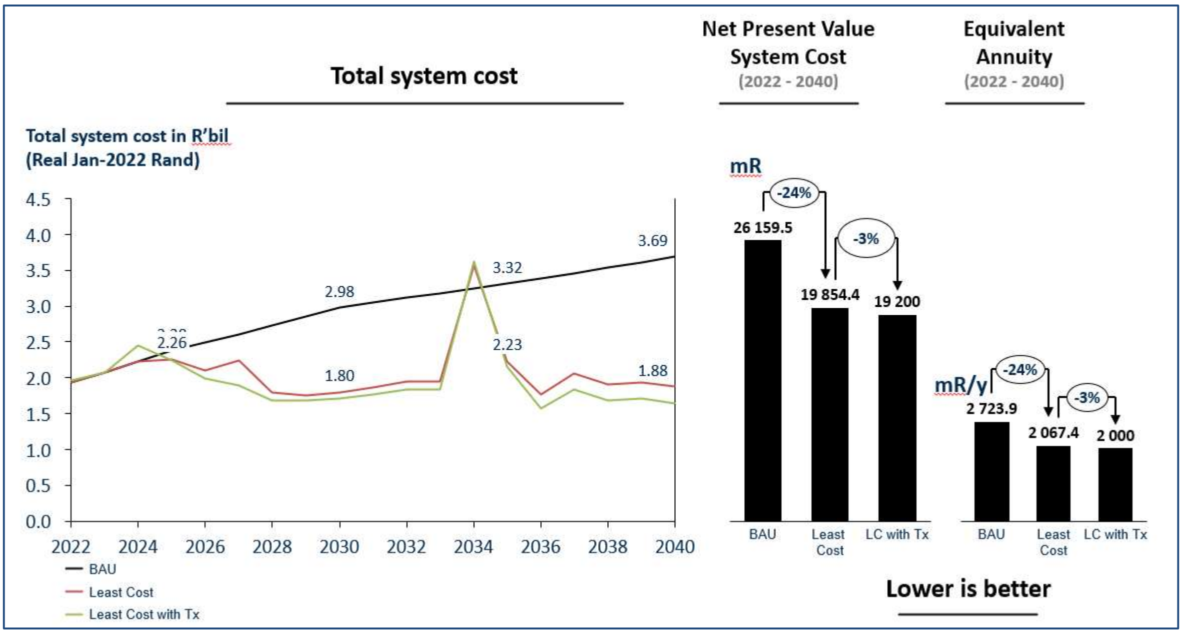

Figure 78: Total system cost: BAU, Least Cost (without Tx) and Least Cost with Tx

Table 13 provides a high-level comparison of the results of regional vs nodal optimization. The regional optimization is able to shift generation capacity to better solar and wind resource areas, for instance no wind capacity is built in Knysna if a regional view is taken. Not surprisingly, more solar PV is built in Oudtshoorn and the power is evacuated to George, the largest demand center in the region. The regional approach installs 20% more solar PV, 8% less wind, slightly less battery capacity and double the capacity of OCGT plants. Bitou, Mossel Bay and Oudtshoorn are net exporters of electricity. Knysna and George are net importers.

Table 13: Summary of regional optimisation (with wheeling) relative to nodal (without wheeling) – installed capacity

	Solar PV	Wind	Battery	OCGT	Eskom	Overall Energy
Bitou	more	more	similar	similar (later)	less	exporter (to Knysna)
George	less	more	less	more	less	importer (from Mossel Bay and Oudtshoorn)
Hessequa	more	more	more	more	less	similar
Kannaland	similar	more	similar	less	less	similar
Knysna	less	less (none)	less	more	less	Importer (from Bitou)
Mossel Bay	more	less	more	more	less	exporter (to George)
Oudtshoorn	more	less	more	similar	less	exporter (to George)
Region*	more (21%)	less (-8%)	similar (-3%)	more (double)	less (-44%)	similar

* percentages are based on installed capacity (cumulative build) at 2040

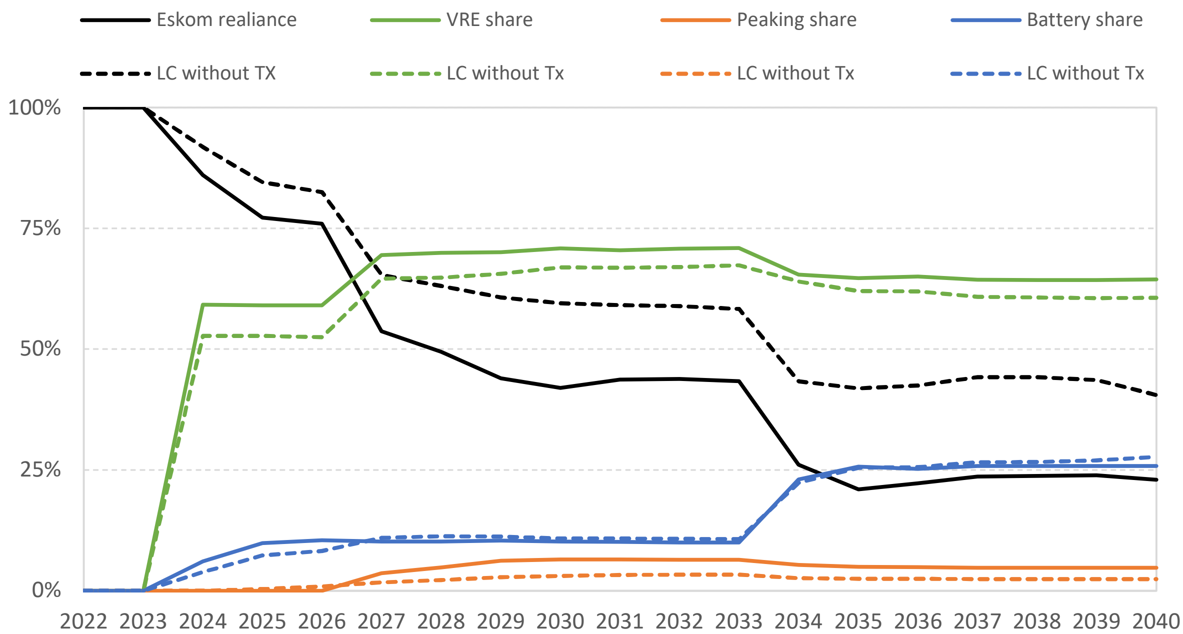

Figure 79 shows the reduction in Eskom reliance in the region with the regional approach. Solid lines represent regional/with transmission and broken lines show nodal/without transmission results. Eskom reliance is installed capacity taken relative to the start year (2022), in this case around 200 MW. Variable RE (VRE) is the sum of solar PV and wind capacities. As noted above, the OCGT (peaking share) is around double for regional vs nodal.

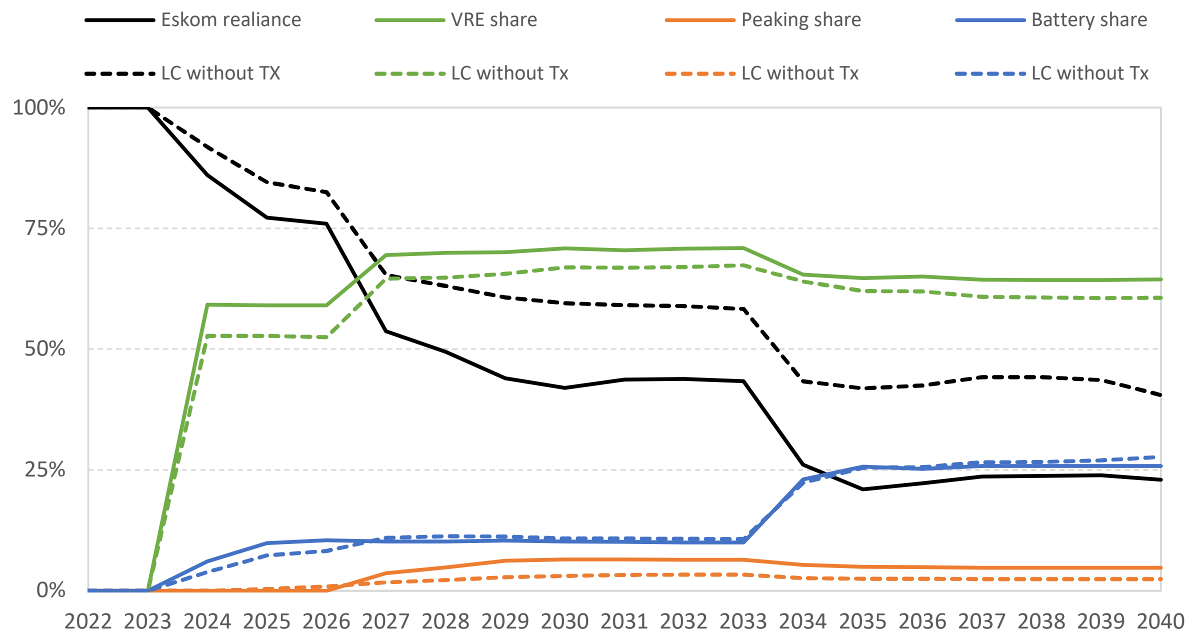

Figure 79: GRDM Eskom reliance and capacity share: Least Cost Nodal and Regional (based on installed capacity)

5.6.3. Autonomy

New supply options were introduced in a manner similar to the Least Cost plan but subject to a constraint that 100% supply autonomy must be achieved from 2030. This scenario shows what would be required if the individual municipalities are forced, or choose, to disconnect from the Eskom network.

Figure 80 shows the required installed capacity and resulting energy share for the GRDM to achieve 100% Autonomy. Significantly more solar PV, wind, battery storage and peaking capacity (both OCGT and ICE) are built to meet the load previously supplied by Eskom. Similar capacities of OCGT and ICE are included in the generation expansion plan, but ICE is deployed significantly more as shown in the relative energy shares (graph on the right). This is due to ICE's better efficiency.

Figure 81 presents the total cost for the region projected until 2040 for all four scenarios (BAU, Least Cost, Least Cost with Tx and 100% Autonomy). In 2030 there is a significant 'jump' in expenditure with new capacity coming online to replace Eskom. The cost premium for 100% Autonomy relative to Least Cost is only 9% and is still lower than BAU.

The 100% Autonomy scenario has a cumulative indirect CO2 emissions and water consumption of 6.33 mil tonne and 6.34 mil tonne respectively which is around 15% and 20% lower than Least Cost scenario, respectively.

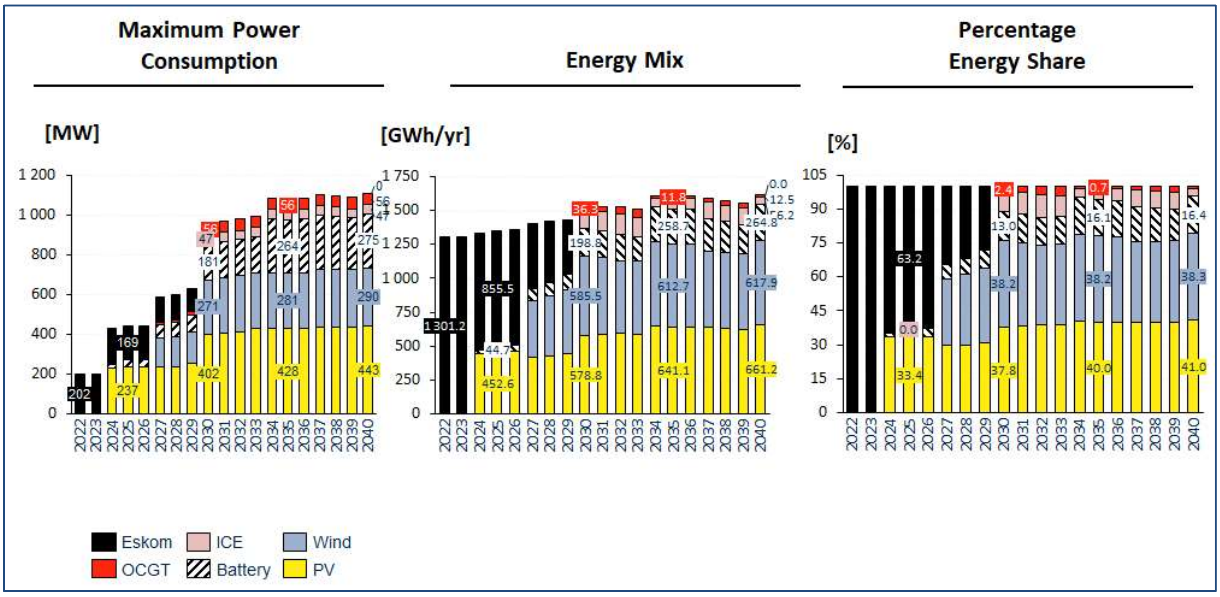

Figure 80: GRDM installed capacity and energy share: 100% Autonomy

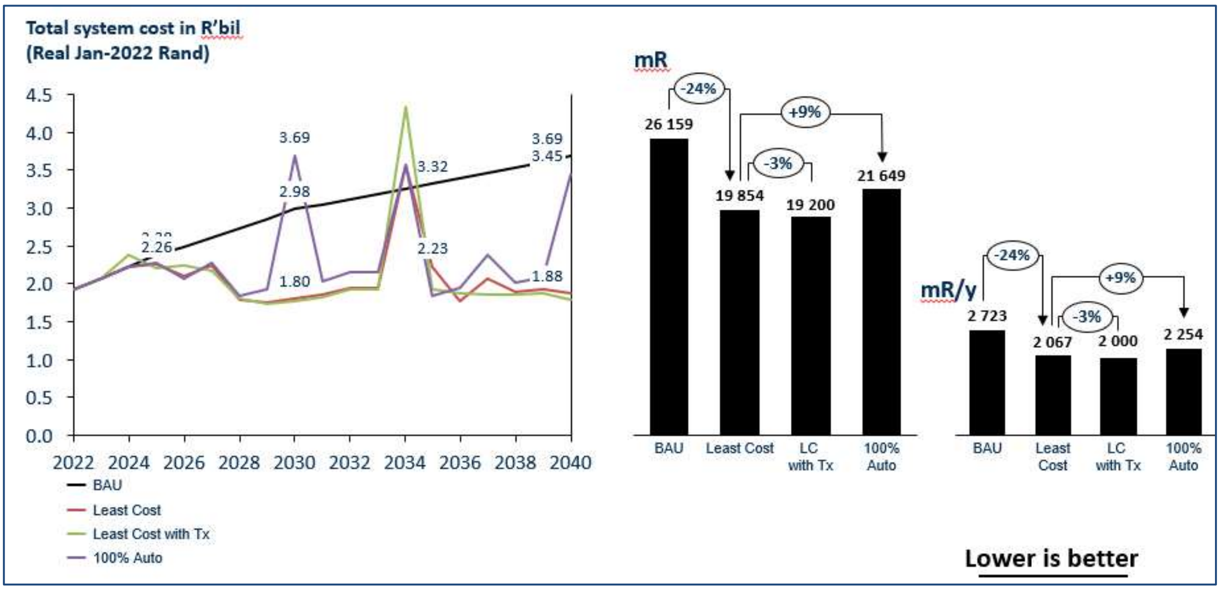

Figure 81: GRDM total system cost: BAU, Least Cost, Least Cost with Tx and 100% Autonomy

6. Summary and Conclusions

6.1. Rooftop PV Analysis

The geospatial work identified rooftop area for the individual municipalities per customer class. Residential customers ‘house’ 75% of the identified space. Through random sampling it was determined that roughly half of the GIS output area was usable for rooftop PV installation. Roofspace was translated to installable PV capacity which equates to approximately 1,750 MW of rooftop PV. This is 7 times the regions MD (maximum demand).

Only 36% of the installable PV capacity is required to meet all customers’ annual energy consumption, in terms of magnitude (not timing). Residential customers have ample roofspace to cover their own annual electricity consumption needs. Besides Knysna, commercial customers have adequate roofspace. Industrial customers do not have enough roofspace. This is makes sense due to industrial customers high electrical demand per area footprint.

The business case analysis shows that solar PV currently makes sense in many instances. The payback period influenced by the feed-in-tariff (three options were considered R0, R0.50 and R1.00 per kWh). Due to increasing municipal tariffs and declining solar PV costs the business case improves with time. By 2040 solar PV makes financial sense in all instances.

Estimating the adoption of rooftop PV in the GRDM lent heavily on the recent NREL LA100 study. Good quality data on the subject is not available in the region. The GRDM is most likely in the initial-Early Adopters stage with an estimated market share of roughly 3.5%. A 25% market share is estimated for 2040. By fitting a Bass diffusion model the market share in 2030 was shown to be around 10%.

The analysis showed that rooftop solar PV can play a significant role in the electricity future of the region. Decision makers should be mindful of this customer resource and promote the responsible and sustainable utilisation thereof.

6.2. Capacity Expansion Planning

The findings of this study showed that if the Eskom electricity tariff is escalated as per our assumptions and no interventions are taken (business as usual approach) that the net present value of total system cost for the entire GRDM will be 24% more expensive than adopting a Least cost plan. The Least cost plan has cost benefits as well as societal benefits derived from reducing CO_2 emissions and consuming less water. Figure 82 shows the cost savings, cumulative CO_2 emissions and water consumption for the combined GRDM.

If a regional optimisation approach (Least Cost with Transmission) is applied, then a further 3% cost savings could be achieved. Lastly a 100% Autonomy scenario was investigated to quantity what would be required if the individual municipalities are forced, or choose, to disconnect from the Eskom network. The cost premium for 100% Autonomy relative to Least Cost is only 9% but still lower than BAU. It was clearly shown that for the period 2022 to 2040, it is <u>not</u> economically optimal for the GRDM to disconnect from Eskom.

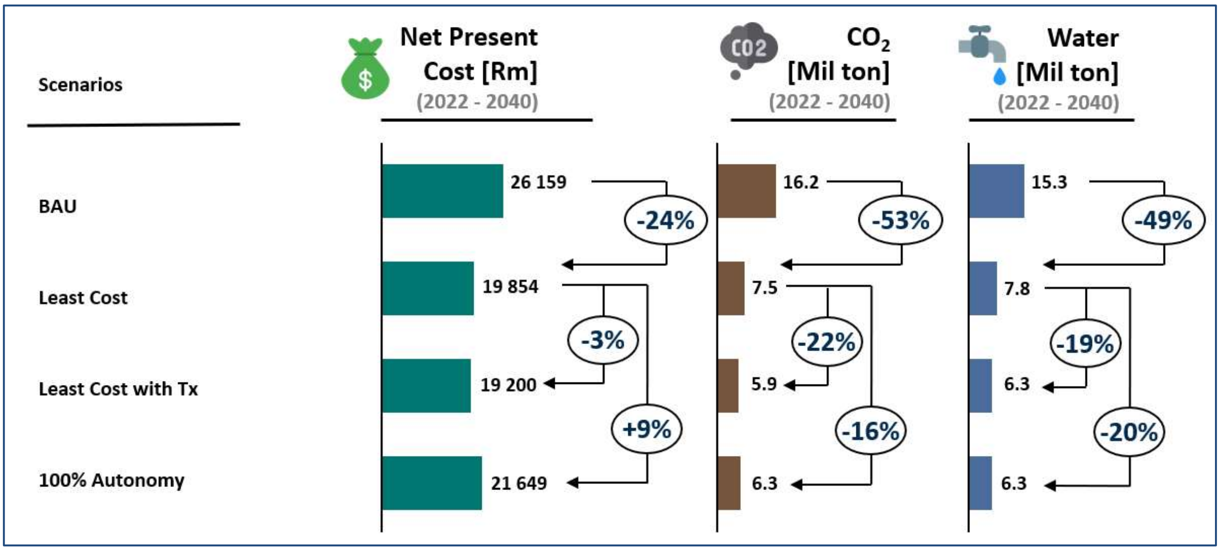

Figure 82: Net present value costs, cumulative indirect CO_2 emissions and water consumption

The findings per technology are presented:

- ✓ New solar PV: The results conclusively showed that solar PV is already competitive with the current Eskom tariff, that most of the capacity build is concentrated in the early years and ramps up in the later years as more battery capacity is added in the mix. If the grid is constrained and it is not possible to wheel between municipalities in the region, then the GRDM should consider investing a minimum of 230MW solar PV as soon as possible in the medium-term horizon. If the grid is not constrained, then the investment in solar PV can be ramped to 285 MW.
- ✓ New Wind: It is also competitive with the current Eskom tariff; new capacity is required as early as 2027 though not to the same extent as solar PV. If the grid is constrained and it is not possible to wheel between municipalities in the region, then the GRDM should consider investing in a minimum of 150 MW wind as soon as possible placed as per the Least Cost plan. In the unconstrained scenario similar quantities of wind are required.
- ✓ New Battery: The results show that a large amount of new battery capacity is built in the later years where costs are expected to reduce, we recommend tracking battery costs and consider revising the IRP before making a significant investment in the later years. The GRDM should track battery cost for alignment with our assumption before investing in a minimum of 40MW (160 MWh) by 2025, the next phase of investment post-2025 should be informed by an updated IRP which tracks cost and performance characteristics of all technology options.
- ✓ New OCGT: the Least cost plan requires some amount of peaking capacity to maintain system flexibility and also to mitigate against periods with higher Eskom tariffs. The GRDM should track how Eskom electricity tariffs increase, the investment in OCGT is required post-2025 and should be informed by an updated IRP. It is worth noting that the OCGT plants are modelled as diesel fired. Affordable gas (for instance LNG) and/or green hydrogen may provide more options/capacities for OCGT.

It is not recommended that municipalities make all the new capacity investment at once, but rather make firm investment decisions in the short to medium term and then revise the IRP once every few years to determine the next phase of investment.

The table below provides a high-level comparison of the results of regional (which includes wheeling between the municipalities) vs nodal (no wheeling) optimization. The regional optimization is able to shift generation capacity to better solar and wind resource areas as shown below. The results are dependent on the cost of wheeling. Not surprisingly when wheeling is possible, more solar PV is built in Oudtshoorn and the power is evacuated to George, the largest demand center in the region.

	Solar PV	Wind	Battery	OCGT	Eskom	Overall Energy
Bitou	more	more	similar	similar (later)	less	exporter (to Knysna)
George	less	more	less	more	less	importer (from Mossel Bay and Oudtshoorn)
Hessequa	more	more	more	more	less	similar
Kannaland	similar	more	similar	less	less	similar
Knysna	less	less (none)	less	more	less	Importer (from Bitou)
Mossel Bay	more	less	more	more	less	exporter (to George)
Oudtshoorn	more	less	more	similar	less	exporter (to George)
Region*	more (21%)	less (-8%)	similar (-3%)	more (double)	less (-44%)	similar

* percentages are based on installed capacity (cumulative build) at 2040

7. Recommendations for Further Work

Various aspects could not be considered in this study, either due to time constraints or lack of good quality data. Recommendations for further work include:

- The impact of climate change on the local solar and wind resources should be considered
- More in-depth demand forecasting should be undertaken, including the impact of electrification (for instance EVs) and energy efficiency
- Further tariff projections could consider a more aggressive shift away from the energy cost driver to fixed/demand components
- The section on adoption rates can be expanded to include consumer behaviour and potentially extract lessons learnt from other parts of the world
- If municipal land ownership could be sourced, then site selection could be undertaken
- It would be useful to municipalities to translate the findings of this study to sustainable tariff design (what impact will rooftop PV have and what should be done to promote the long-term sustainability of the utility?)
- On-site wind measurements in strategic locations
- The study provides possible electricity future scenarios, but no guidance on how to achieve this is offered. Transaction advisory assistance could assist municipalities with potential procurement programmes.

8. References

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9. Annexure A – Solar Resource Assessment Report

9.1. Locations

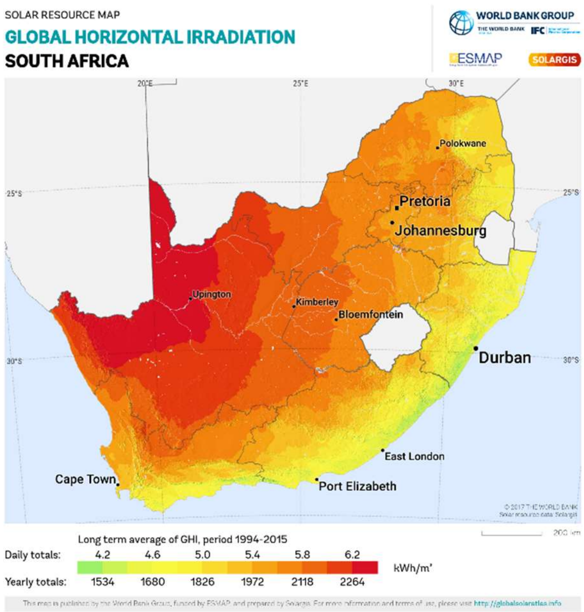
The locations of GRDM selected for the solar resource assessment as part of this study are shown in the following table. The GPS coordinates are in the vicinity of the seven municipal offices.

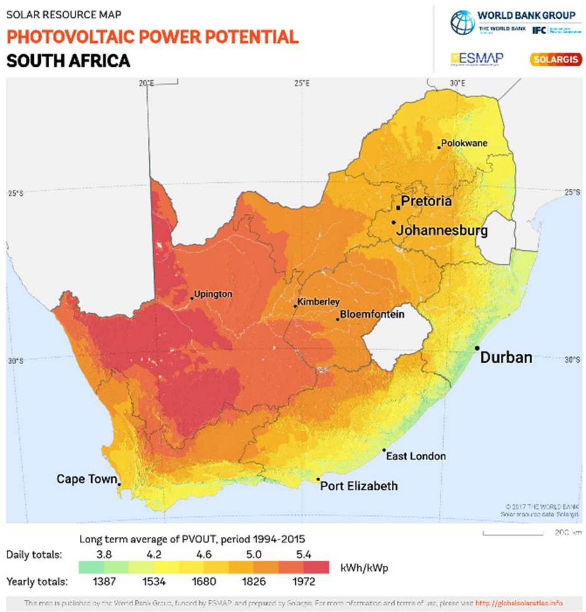
Table 14: GPS coordinates of locations selected for solar resource assessment

Municipality	Town	Latitude	Longitude
Bitou	Plettenberg Bay	-34.055	23.373
George	George	-33.961	22.454
Hessequa	Riversdale	-34.092	21.259
Kannaland	Ladismith	-33.495	21.265
Knysna	Knysna	-34.038	23.050
Mossel Bay	Mossel Bay	-34.182	22.139
Oudtshoorn	Oudtshoorn	-33.594	22.214

9.2. Solar Photovoltaic

The Global Horizontal Irradiance (GHI) and estimated photovoltaic potential is shown in Figure 83 for South Africa. Generally speaking, although not the best in the country that the solar resource is quite good with ≈1715 kWh/m^2/year in the Knysna and up to ≈1957 kWh/m^2/year in the Oudtshoorn.





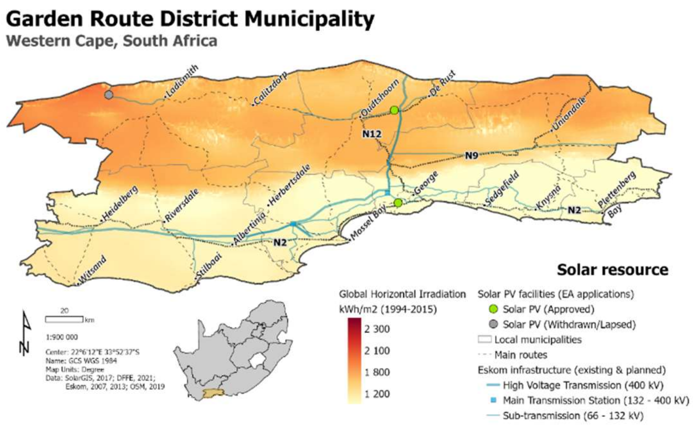


Figure **83**: Global Horizontal Irradiation (GHI) and estimated photovoltaic potential in South Africa relative to locations of GRDM locations in South Africa

9.3. Methodology and Data Description

9.3.1. Weather Data

Weather data for the GRDM locations are sourced from the European Commission PVGIS platform [13].

The typical meteorological year (TMY) is what is considered for each of the GRDM locations as part of this resource assessment. TMY is a blend of multiple years of satellite data assembled to represent a typical year. Year-to-year variability is also estimated by analysing specific years from 2007 to 2016 for one (1) site (Knysna) to demonstrate how the solar resource varies in monthly and annual cycles.

For investment level confidence in prospective solar sites, a measure of the probabilistic likelihood of a certain level of energy production being exceeded is known as a P-value and is typically expressed at reference points e.g., P50, P90 and P95. These values are the statistical likelihood of energy production levels for a particular site being exceeded 50%, 90% and 95% of the time over a defined period respectively (typically measured and reported on annually). TMY data represents the most likely conditions for a site i.e., the P50 (for a normal distribution). Hence, at this stage, the TMY data presented via this methodology can be the P50 level of confidence in solar resource and energy production presented.

The points considered for each of the GRDM locations are provided in Table 14 (and Table 5).

9.3.2. Solar PV Modelling Approach

Solar PV system modelling is undertaken in System Advisor Model (SAM) [14]. SAM is more common among researchers released by National Renewable Energy Laboratory (NREL), USA and is available free of cost for users across the globe.

The system performance estimations are based on a representative and easily scalable 1 MW_{AC} solar PV system configured with a fixed-tilt and single-axis tracking. A 1.12 multiplier for DC nameplate capacity to peak AC inverter output of 1 MW_{AC} is considered. Given the energy production of these reference systems, energy estimates for any size solar PV system can be reasonably scaled by multiplying with the expected installed capacity.

In order to remain conservative with system performance, the single-axis tracking system is modelled without backtracking. The backtracking option allows for some recovery of energy loss owing to row-to-row shading in early morning and late afternoon. An industry standard Ground Cover Ratio (GCR) of 50% for the fixed-tilt system and GCR of 40% for single axis tracker is selected. Higher GCR means more PV modules can be installed in a given area of land but offset by increased shading.

Figure 84 shows the waterfall loss diagram extracted from SAM for the fixed-tilt 1 MW_{AC} system at Knysna. The system losses start by assuming the calculated Plane of Array (POA) calculated from the available Global Horizontal Irradiance (GHI), Direct Normal Irradiance (DNI) and Diffuse Horizontal Irradiance (DHI) from the input TMY weather data. This gain for a single axis tracker system will be higher compared to the gain for a fixed-tilt system, which largely explains the additional energy output of single-axis compared to fixed-tilt systems. Next, the near shading, soiling, incident angle modifier (IAM) and bifacial losses are computed, based on inputs defining the plant configuration.

A soiling loss of 5% was assumed for the SAM models developed. The soiling loss has a significant impact on the overall system loss because the loss impacts the effective irradiance available at the solar cell junction to convert photons into electrons. Soiling from nearby industrial or agricultural operations at GRDM locations may require significant effort to maintain an annual soiling loss of 5% or less. At CSIR, soiling loss reached 20% by the end of winter in 2017 when no cleaning was conducted, and rainfall was absent during the winter period of ≈3 months. The soiling loss given in the SAM performance models are annualized values, not the worst-case soiling loss. A monthly soiling loss of 20% as measured in the worst case does not translate to an annual soiling loss of 20% (the losses are averaged over the year).

Each loss factor such as module losses, electrical losses, and inverter losses is applied to the previous step in a typical waterfall before arriving at the final AC energy production prediction. However, these losses might change when a detailed PV system design is carried out depending on area, component selected and design optimizations.

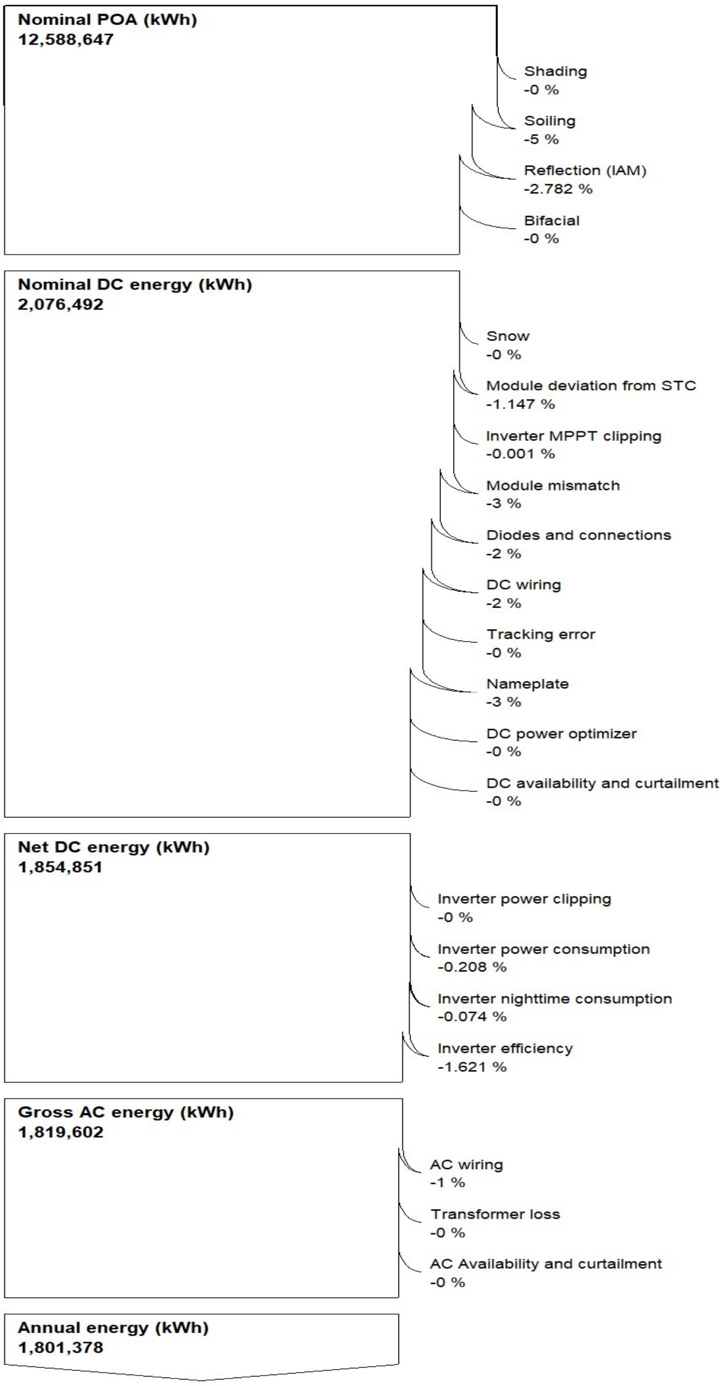


Figure **84**: Waterfall diagram for the fixed-tilt 1 MW representative solar PV system

9.3.3. Resource Assessment

The amount of sunlight that reaches the PV modules is the single most important parameter to predict AC energy production from a solar PV plant. Irradiance is typically measured and reported in a horizontal orientation and a tilted orientation, and the units are given in kWh/m2. The GHI quantifies the amount of sunlight collected over one year on a horizontal surface per square meter. The GHI is useful for simple comparisons across multiple sites, although PV modules are rarely installed horizontally. The POA irradiance quantifies the amount of sunlight collected over one year by a surface in the same plane as the PV modules, mounted according to the design of the PV plant. The POA may be fixed-tilt or tracking, as in the case for single-axis or dual-axis trackers. The POA measures the 'fuel' input to the PV plant and correlates linearly with the energy output. For example, the correlation coefficient between monthly POA and monthly energy production at Knysna is greater than 95%, whilst the correlation between GHI and energy was less than 70%.

Figure 85 and Figure 86 shows the GHI variability spatially (GRDM relative to other locations across South Africa) and temporally (monthly) for the analysed one (1) GRDM municipality location i.e., Knysna. The GHI profile for GRDM locations compares favourably to the GHI profiles of Cape Town and reasonably well to Durban (except for the winter months). The GHI profile for Upington and Pretoria record GHI well above GRDM locations. The monthly variability for Knysna is lower in the winter months relative to summer months. Both the spatial and temporal trends reveal the seasonality with lower irradiance in winter due to shorter days and lower sun elevation. The extracted 2016 hourly irradiance profile from PVGIS showed anomaly i.e., very extreme high insolation for few days during the summer months particularly. Hence the year 2016 data is excluded from the analysis.

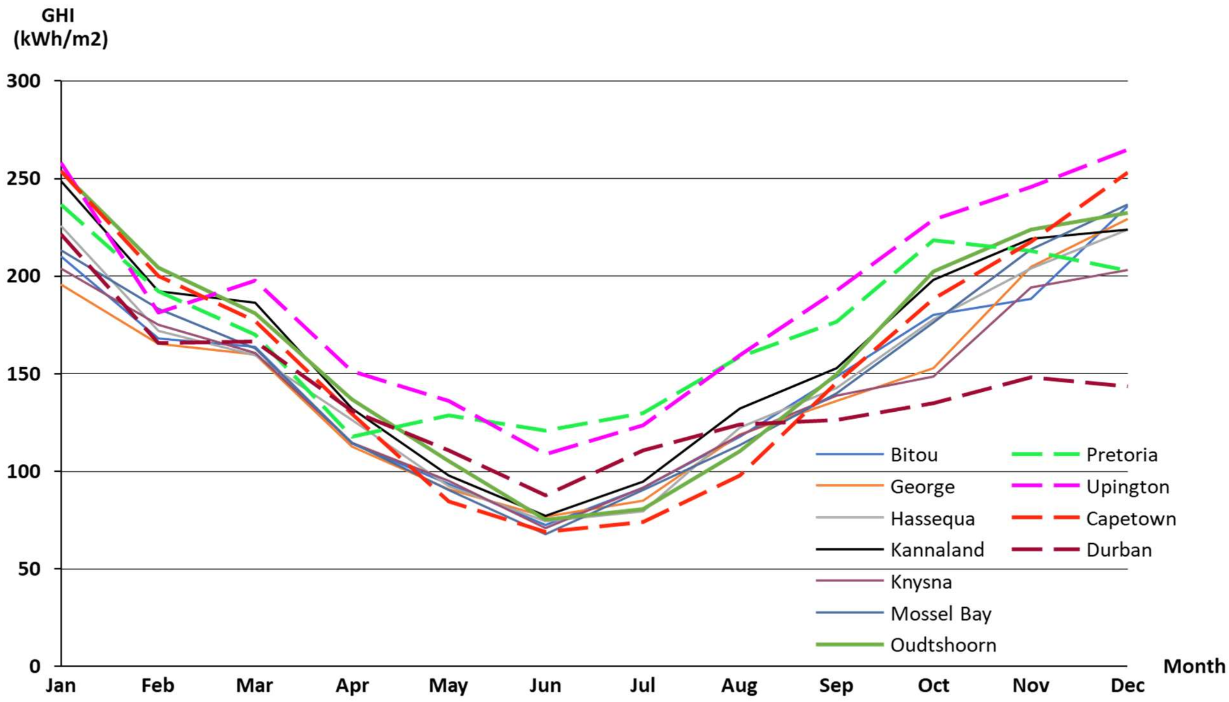


Figure 85: GRDM locations monthly GHI relative to other locations across South Africa

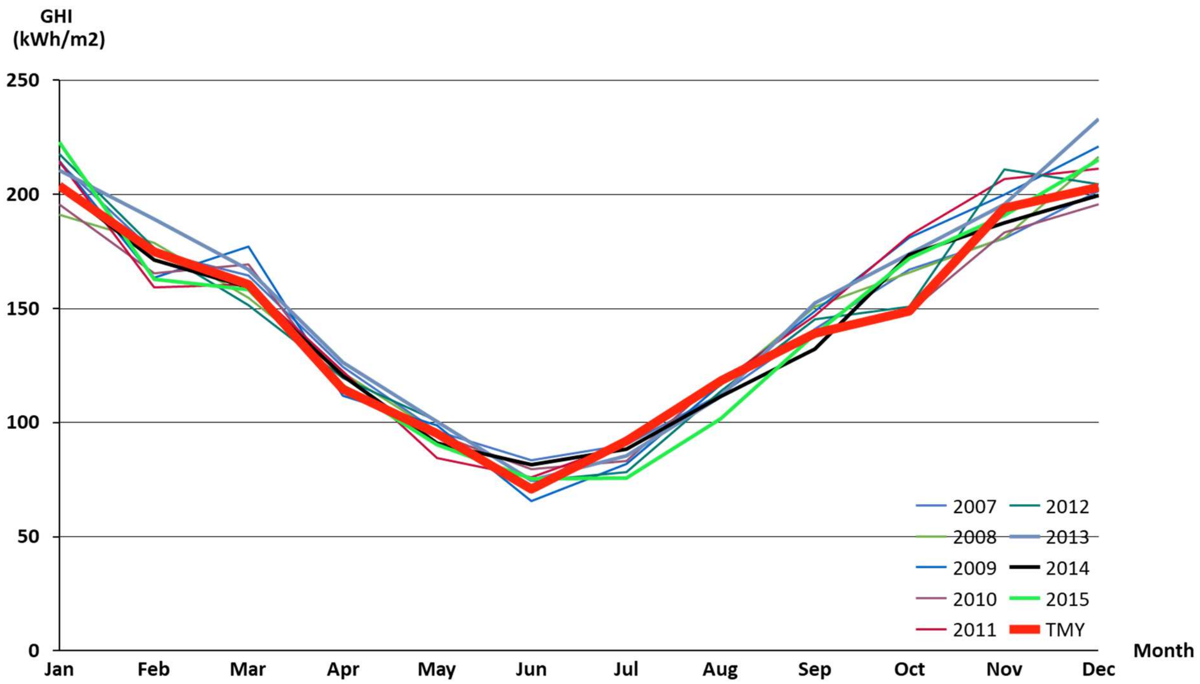


Figure 86: Multiple years monthly GHI for Knysna municipality

Table 15 presents the summary statistics of SAM simulations for a fixed-tilt solar PV system with 50% GCR. The summary statistics are based on an hourly temporal resolution considering the TMY weather data for each GRDM location for a representative 1 MW_{AC} fixed-tilt system and 1 MW_{AC} single-axis tracking system. The statistics provided include GHI, POA, resulting expected annual AC energy production (AEP) and Capacity factor. The capacity factor calculated in accordance with IEC TS 61724-3:2016 for Photovoltaic system performance – Part 3: Energy evaluation method is a metric commonly applied to power plants and facilitates comparison between PV and other power plants.

Table 15: Summary statistics across GRDM locations (fixed-tilt, GCR = 50%)

Location	GHI [kWh/m2]	POA [kWh/m2]	Annual Energy [MWh]	Capacity factor
Bitou	1786	1946	1768	20.2%
George	1729	1968	1790	20.4%
Hassequa	1801	2050	1841	21.0%
Kannaland	1956	2231	1970	22.5%
Knysna	1715	1968	1801	20.6%
Mossel Bay	1804	2053	1876	21.4%
Oudtshoorn	1957	2213	1969	22.5%

Table 16 shows the single-axis tracking system with 40% GCR generating approximately 15-19% more energy than the fixed-tilt systems. The single-axis tracking system shows a clear advantage in terms of specific energy (kWh/kWp) due to the orientation of the PV modules relative to the sun. However, the single-axis tracking system comes with additional capital expense and maintenance costs. This needs to be considered carefully when establishing an investment case.

Table 16: Summary statistics across GRDM locations (Single axis, GCR=40%)

Location	GHI [kWh/m2]	POA [kWh/m2]	Annual Energy [MWh]	Capacity factor
Bitou	1786	2393	2150	24.5%
George	1729	2309	2116	24.2%
Hassequa	1801	2450	2224	25.4%
Kannaland	1956	2687	2400	27.4%
Knysna	1715	2293	2117	24.2%
Mossel Bay	1804	2390	2200	25.1%
Oudtshoorn	1957	2213	1969	22.5%

Figure 87 and Figure 88 shows monthly AC energy generation for the Knysna location for fixed-tilt (GCR=50%), and single-axis tracking (GCR=40%). This is shown for the historical period of 2007-2015. The seasonal variability is greater for the single-axis tracking system compared to the fixed-tilt systems. The monthly production is generally higher for the single-axis tracking system relative to fixed-tilt systems, except for the month of June when the sun is relatively low in the sky. The hourly energy generation profiles of 1 MW_{AC} fixed tilt and single axis tracker with other considered technologies performance feed into the Energy System modelling determining the least cost scenario and future electricity pathways.

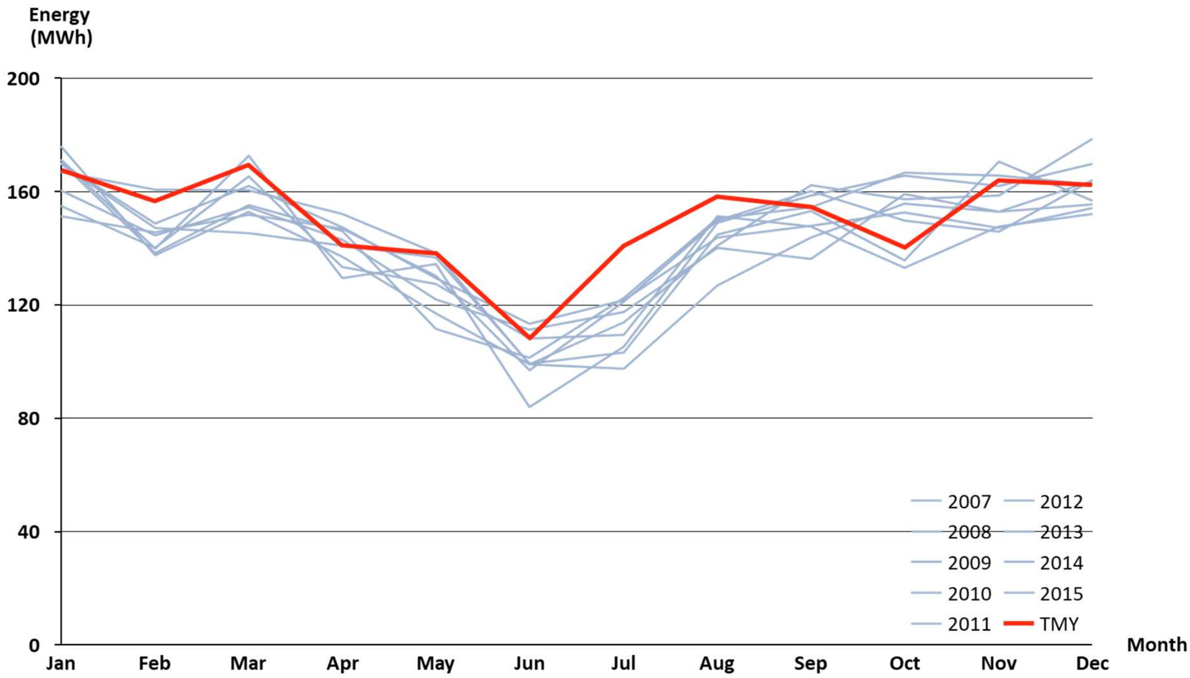


Figure 87: Monthly predicted AC energy production at Knysna under typical annual variation in weather (2007-2015) for fixed-tilt with GCR 50% (similar relative performance can be expected

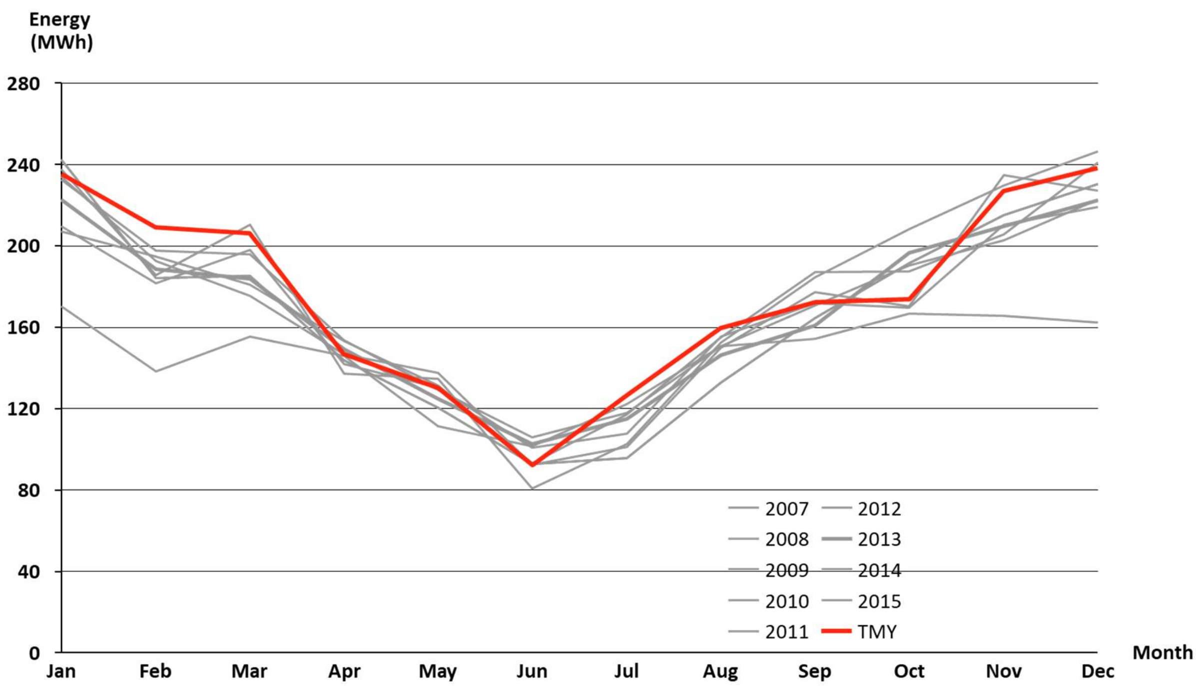


Figure 88: Monthly predicted AC energy production at Knysna under typical annual variation in weather (2007-2015) for single axis tracker with GCR 40% (similar relative performance can be expected for GRDM locations)

Figure 89 shows a relative comparison of GRDM locations solar PV capacity factor performance relative to selected other jurisdictions (locally and internationally). ALL GRDM locations exhibit good solar PV capacity factors (whether fixed-tilt of single-axis tracking) and comparable performance to the existing national level solar PV fleet (part of the REIPPPP). All GRDM locations outperform international benchmark countries considered (countries with already significant solar PV installed capacity).

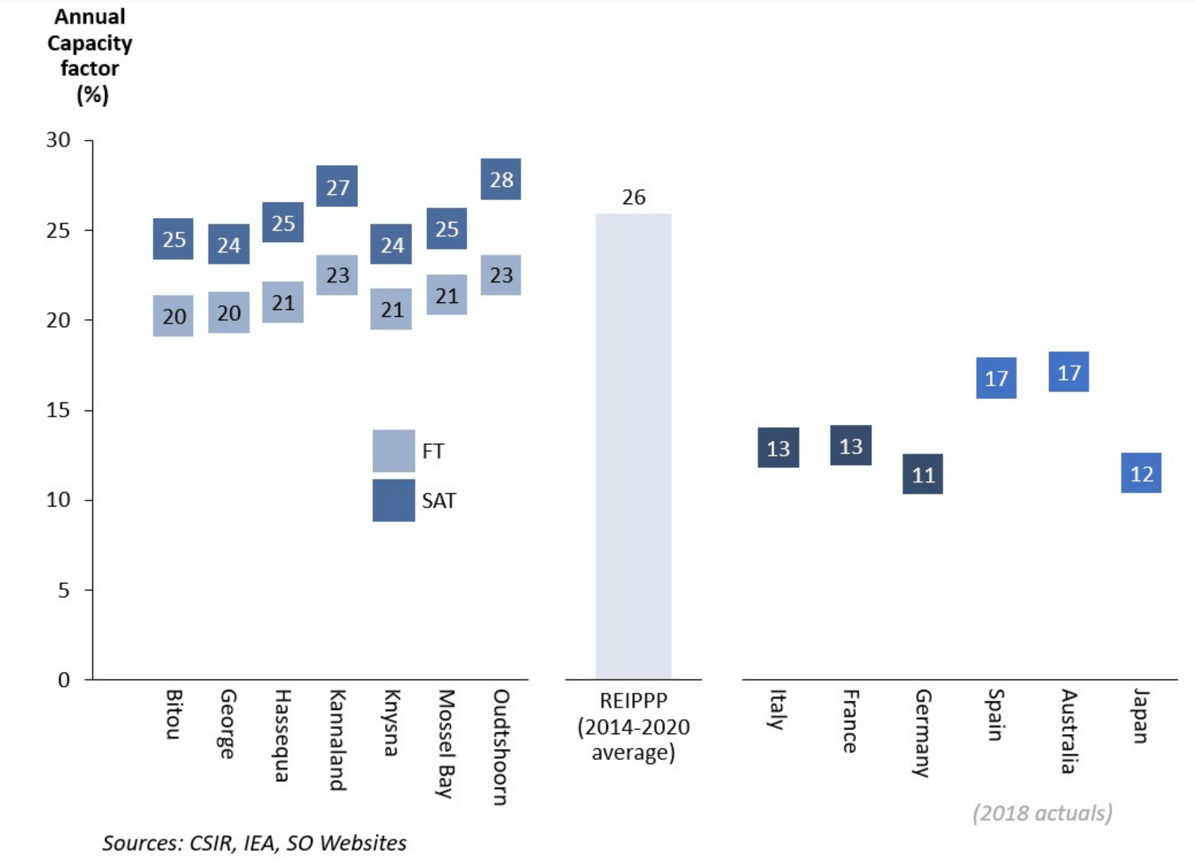


Figure 89: Relative comparison of GRDM locations expected solar PV capacity factors and selected other jurisdictions (local and international)

9.3.4. Maximum Potential Capacity and Energy Density

Table 17 shows the energy density from the fixed-tilt and single-axis tracking solar PV systems (1 MW_{AC}). Solar PV modules would cover roughly 6 398 m^2 depending on the size of the module selected relative to total land requirement (1.28 ha). Dividing the module area by the total land area results in the GCR 50% for fixed-tilt and GCR 40% for single axis tracker. A marginal amount of additional land will be required for access roads, borders, additional balance of plant and related infrastructure. Approximately 1 350 - 1 550 MWh/ha can be produced annually from a fixed-tilt system and 1 300 – 1 550 MWh/ha can be produced from a single-axis tracking system.

Table 17: Installed AC capacity density and energy density for GRDM locations (GCR = 50% for fixed-tilt, and GCR = 40% for single-axis tracking)

	Module area (sq meter)		Total Area (ha)		AC capacity (MW/ha)		AC annual energy (MWh)		AC energy density (MWh/ha)	
Location	FT	SAT	FT	SAT	FT	SAT	FT	SAT	FT	SAT
Bitou	6398	6398	1.28	1.60	0.78	0.62	1768	2150	1381	1343
George	6398	6398	1.28	1.60	0.78	0.62	1790	2116	1398	1322
Hassequa	6398	6398	1.28	1.60	0.78	0.62	1841	2224	1438	1390
Kannaland	6398	6398	1.28	1.60	0.78	0.62	1970	2400	1539	1500
Knysna	6398	6398	1.28	1.60	0.78	0.62	1801	2117	1407	1323
Mossel Bay	6398	6398	1.28	1.60	0.78	0.62	1876	2200	1465	1375
Oudtshoorn	6398	6398	1.28	1.60	0.78	0.62	1969	2437	1538	1523

10. Annexure B – Wind Resource Assessment Report

10.1. Site selection

Before detailing the site-specific wind climate, the area's, Garden Route District Municipality, wind climate is investigated at a high level. This is achieved by formulating the wind speed map (m/s) using wind speed data from Global Wind Atlas, as seen from Figure 90. From this map the winds variations across the landscape are visually depicted and allows one to make a well-informed decision for future investigation. This map provides valuable information on the energy potential of the landscape. With this new information, it is feasible to choose the location within the municipality that is best suited for future development.

Within garden route district municipality, there are seven local municipalities, namely: Bitou, George, Hessequa, Kannaland, Knysna, Mossel Bay and Oudtshoorn. Seven sites were chosen, one at each local municipality based on wind resource, constrained areas, and areas that must be avoided.

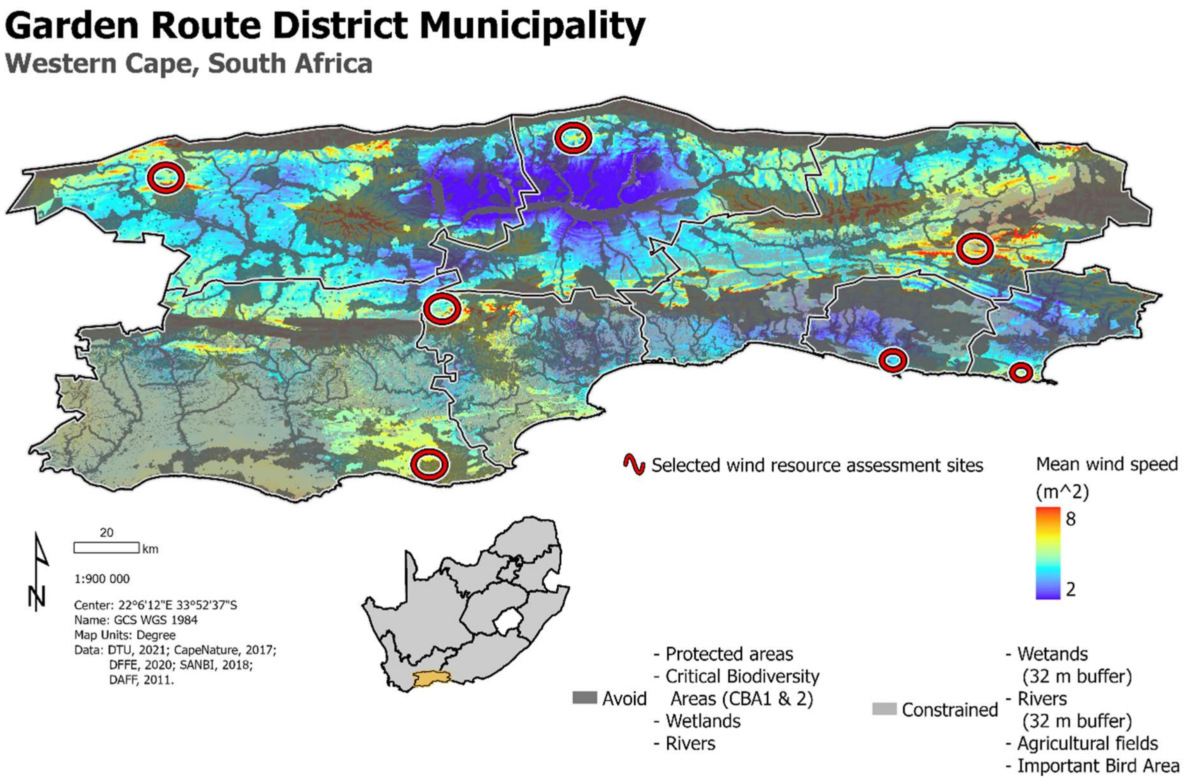


Figure 90: Wind speed across Garden Route District Municipality and well as constrained area and areas that should be avoided

10.2. SWAP dataset

To conduct a high-level assessment where the wind resource is formulated, a dataset describing the wind resource is required. For this study SWAP dataset was used. The SWAP dataset is a temporal dataset with a resolution of 15-minute, that has a 5 km spatial resolution. More specifically, this means that the dataset has a wind climate information across South Africa, spaced 5 km apart. This dataset is however limited to heights of 80, 100 and 150 meters. For these analyses the wind resource was assessed at a height of 100 meters.

Figure 91 to Figure 97 visually depicts these data points as white points positioned within each local municipality.

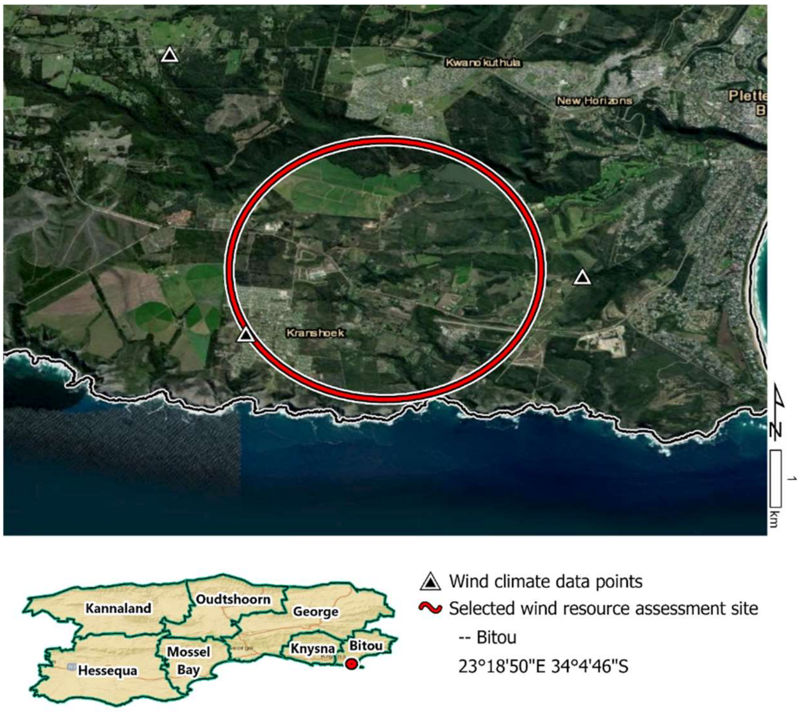


Figure 91: Bitou local municipality

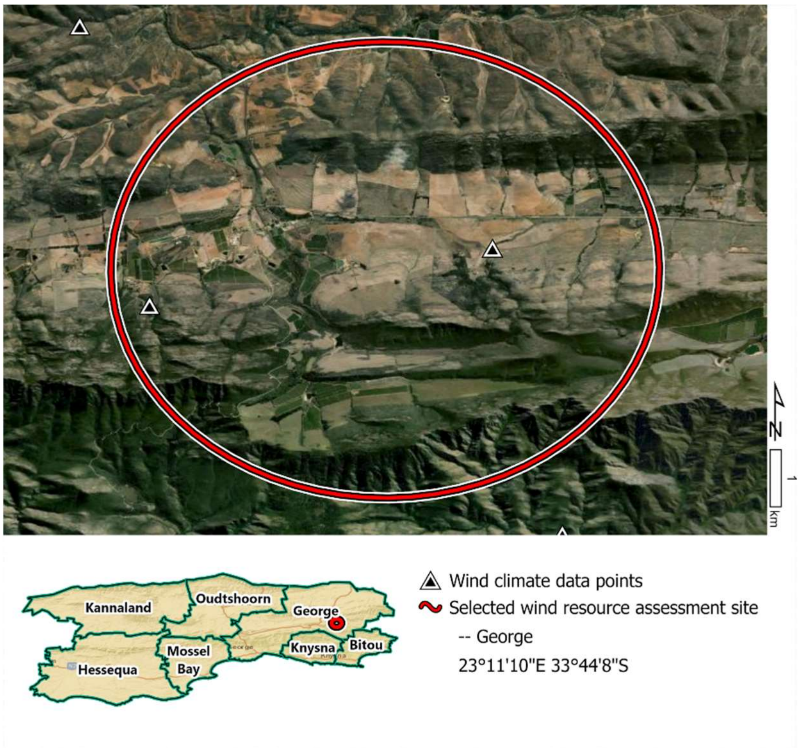


Figure 92: George local municipality

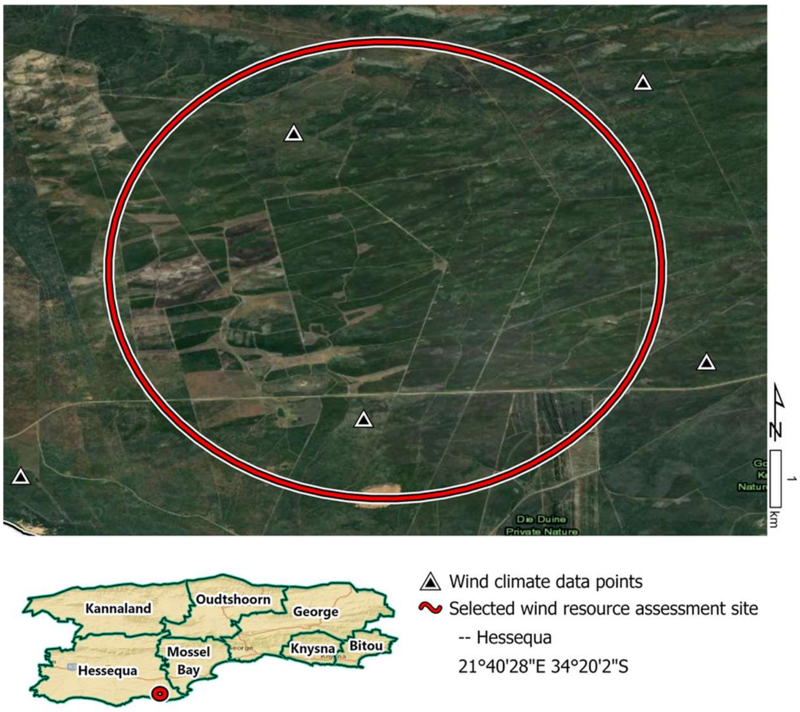


Figure 93: Hessequa local municipality

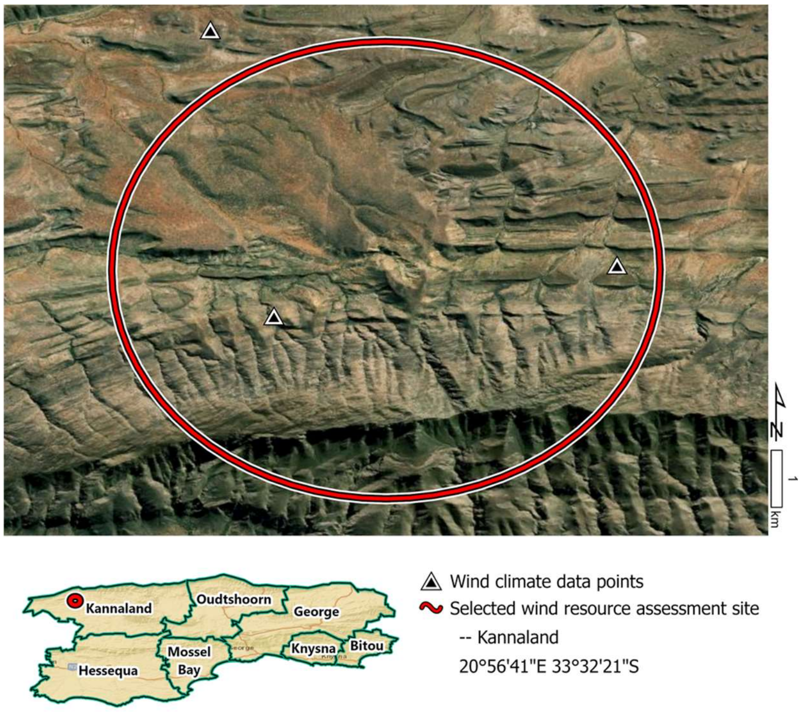


Figure 94: Kannaland local municipality

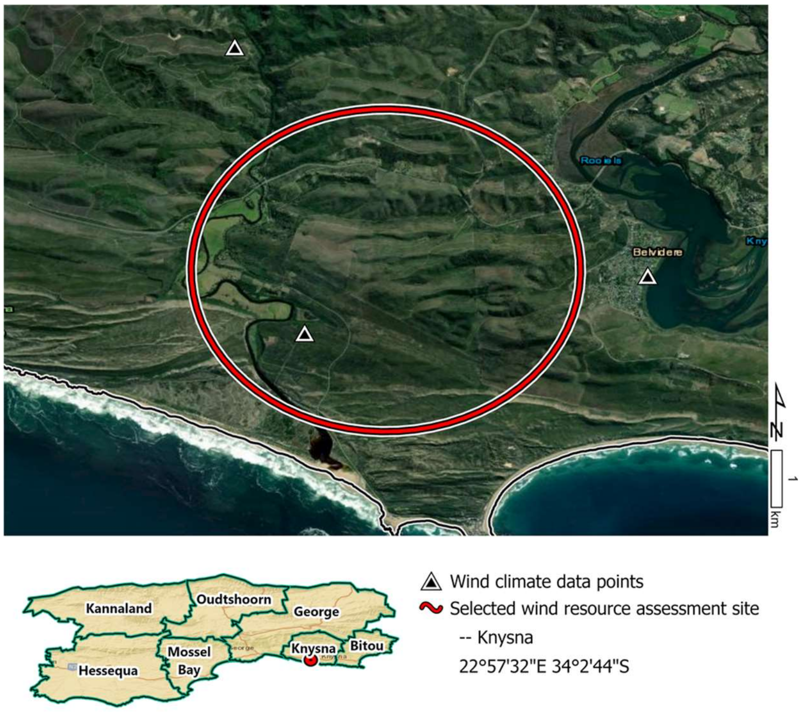


Figure 95: Knysna local municipality

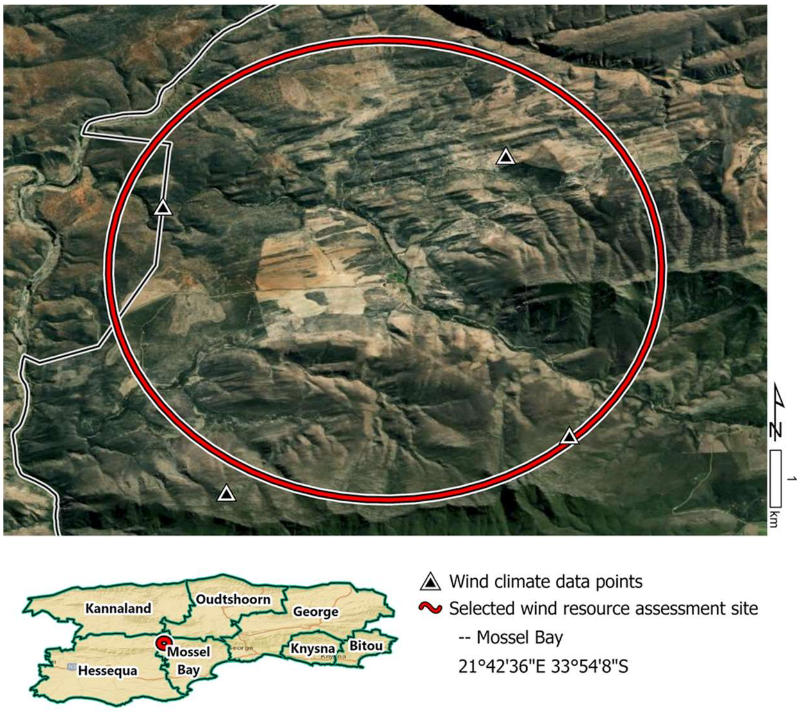


Figure 96: Mossel Bay local municipality

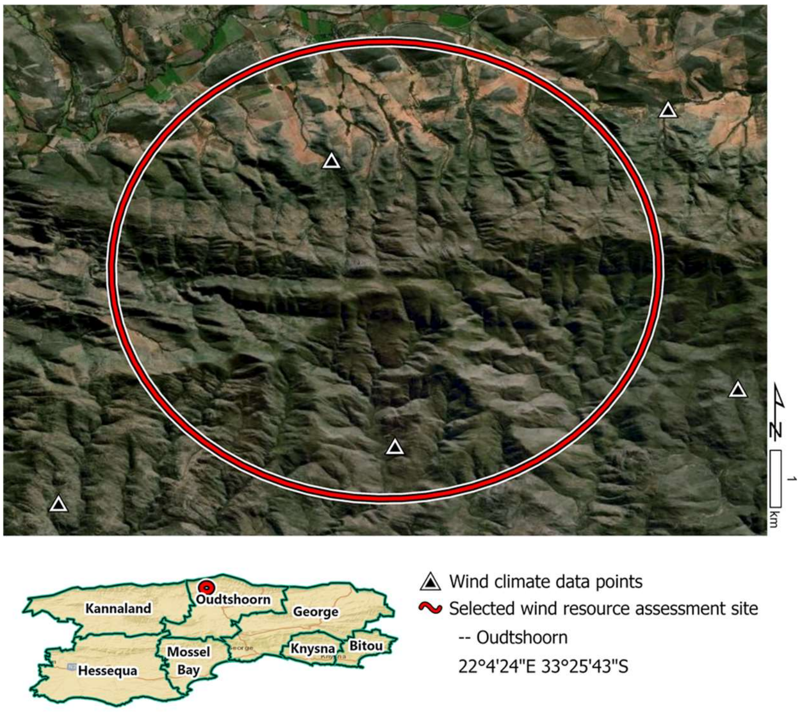


Figure 97: Oudtshoorn local municipality

The SWAP dataset to be used for each of the sites is selected by determining which data point is closest to the relevant site but also closest to the area with highest resource near the site. Coordinates of selected sites within each local municipality as well as distance from the selected data point and centre of the chosen site are tabulated in the following table

Table 18: Selected datasets and related data points for seven sites

Local municipality	Site coordinates		Dataset reference		Distance to site [km]
	Latitude	Longitude	Latitude [S]	Longitude [E]	
Bitou	34.09778	23.35889	34.089	23.292	2.46
George	33.72917	23.18028	33.741	23.149	4.33
Hessequa	34.33389	21.68389	34.357	21.671	2.95
Kannaland	33.5625	20.93417	33.591	20.937	3.95
Knysna	34.04083	22.95583	34.055	22.946	1.79
Mossel Bay	33.91	21.70361	33.937	21.685	3.26
Oudtshoorn	33.42389	22.11278	33.403	22.118	2.41

10.3. Generalised Wind Climate

The expected development capacity was not specified. The analysis will thus investigate how each selected turbine performance in the relevant energy regions. The wind data at 100 m, as detailed in the previous section will be directly formulated with the selected turbines performance curves.

For this analysis two different Wind Turbine Generators (WTG) of different capacity sizes were selected. These turbines performances are then assessed at each of the specified areas. The selected turbines are the Enercon E101-3050 kW (utility scale) and Hummer H25.0-100 kW (commercial scale). Do note that the larger E101-3050 kW WTG is assessed at the manufactured hub height (100 meters) which coincides with the wind measurement height. Alternatively, the smaller 100 kW which has a hub height of 50 meters is accessed at 100 meters. Thus, the wind speed was adjusted to the hub height of 50 meters using power law equation shown below.

$$\boldsymbol{U_{hub}} = \boldsymbol{U_{anem}} \times \left(\frac{\boldsymbol{z_{hub}}}{\boldsymbol{z_{anem}}}\right)^{\boldsymbol{\alpha}} \tag{1}$$

Where:

U_{hub} *is the wind speed at the hub height of the wind turbine* $[m/_{S}]$

U_{anem} *is the wind speed at measurement height* $[{}^{m}/_{s}]$

z_{hub} *is the hub height of the wind turbine* $[m]$

z_{hub} *is the anemometer height* $[m]$

α *is the power law exponent*

According to [15] the surface roughness is selected based on the landscape as seen from Table 19. The higher the surface roughness of the field, the slower the wind. The region surrounding a wind turbine site rarely consists of a homogeneous uniform field. Various crops, woods, forests, fence rows, and buildings are usually scattered across the area. The result is that the surface roughness changes with the wind flow approaching the turbine. The landscape up to 10 km will influence the turbine site, but the more the ruggedness increases, the less effect they will have.

Table 19: Surface roughness of different landscapes [15]

Surface roughness length [m]	Landscape
0.0002	Water surface
0.0024	Completely open landscape with a smooth surface, such as concrete runways in airports, mowed grass
0.03	Open agricultural area without fences and hedgerows and very scattered buildings. Only softly rounded hills
0.055	Agricultural land with some houses and 8-meter-tall sheltering hedgerows within about 1.2 km
0.1	Agricultural land with some houses and 8-meter-tall sheltering hedgerows within about 0.5 km
0.2	Agricultural land with some houses, shrubs and plants, or 8-meter-tall sheltering hedgerows within about 0.25 km
0.4	Villages, small town, agricultural land with many or tall sheltering hedgerows, forests, and very rough and uneven landscape
0.8	Large cities with tall buildings
1.6	Very large cities with tall buildings and skyscrapers

The selected SWAP data points for each of the sites was used to determine the generalised wind climates at the sites. The generalised wind climate is essentially a statistical summary of the wind resource at the site, showing the wind direction distribution (as a wind rose) and the wind speed distribution as a graph of wind speed probability. The wind speed distribution is usually represented as a Weibull distribution, which gives a good representation of average wind speed and the variations thereof [16].

A 5-year average annual wind climate is included in this analysis. The wind resource at seven sites as calculated for the generalised wind climate is summarised in Table 20. The annual general wind climates (wind roses and wind speed distributions), at 100 m above ground level, are depicted in Figure 98 to Figure 104 across the municipalities.

Table 20: Calculated annual mean wind speed, U [m/s], and mean power density, P [W/m2]

Site	Annual (5-year average)	
	U [m/s]	P [W/m2]
Bitou	7.0	448
George	7.5	547
Hessequa	7.9	549
Kannaland	7.2	473
Knysna	5.6	247
Mossel Bay	6.9	356
Oudtshoorn	7.3	801

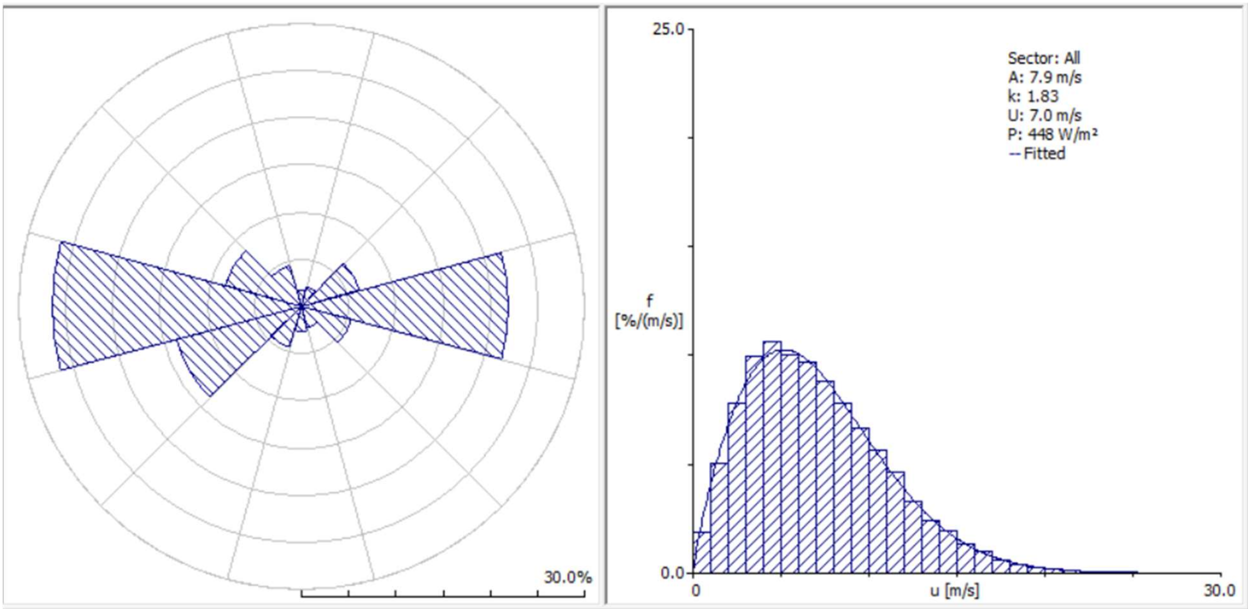


Figure 98: Bitou average annual wind climate

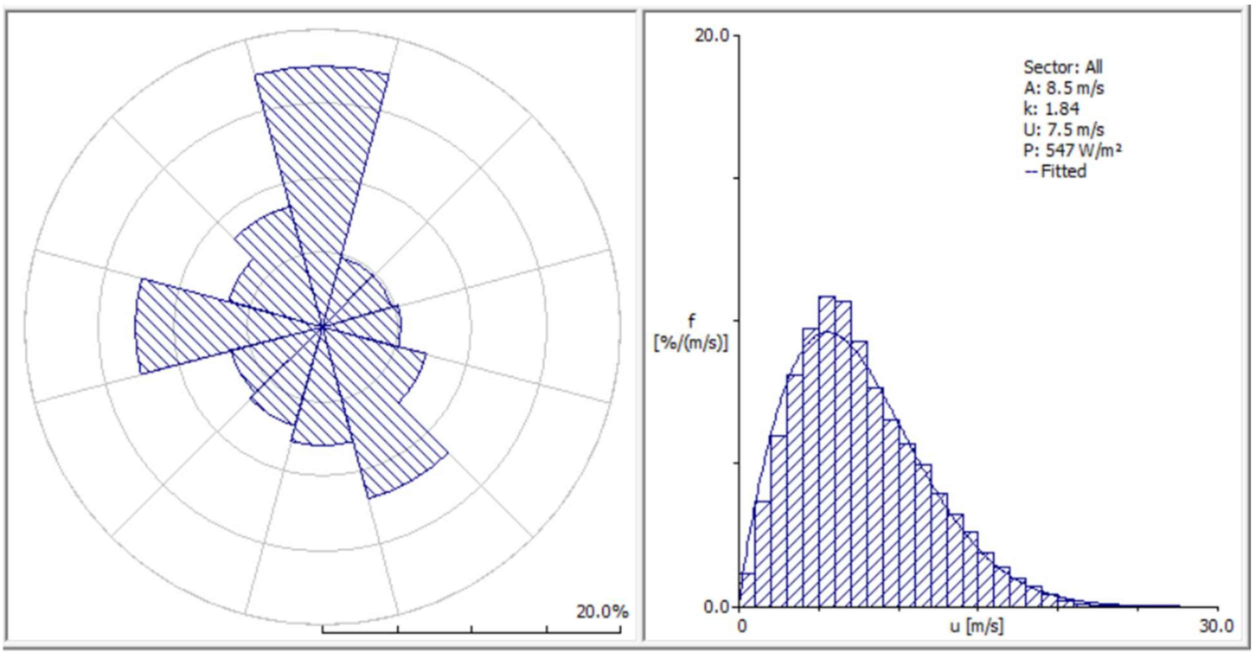


Figure 99: George average annual wind climate

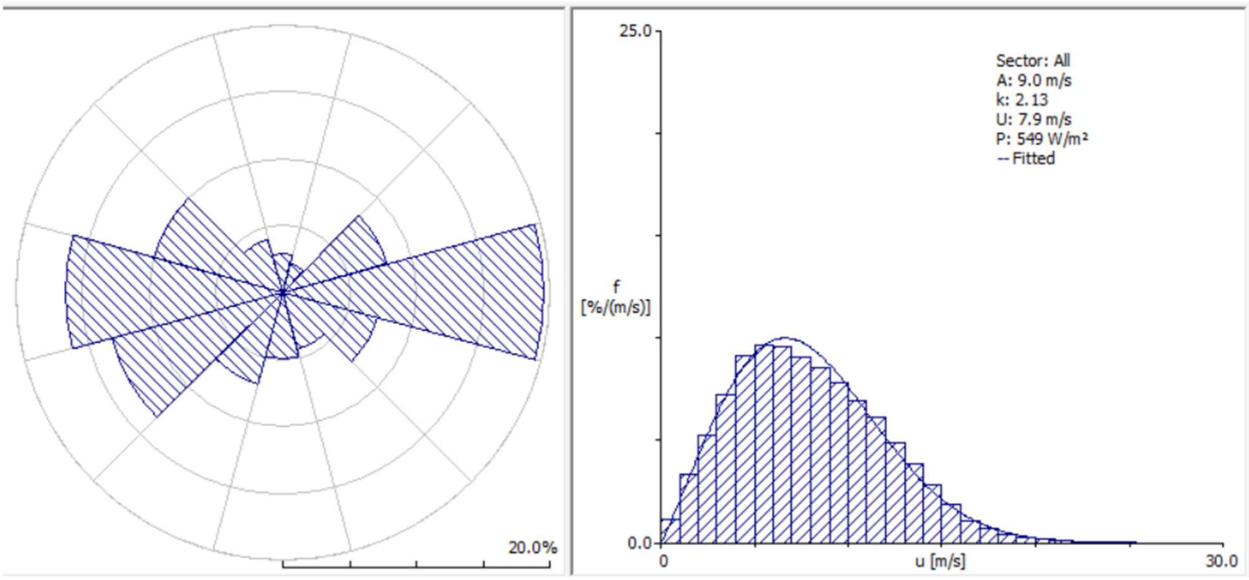


Figure 100: Hessequa average annual wind climate

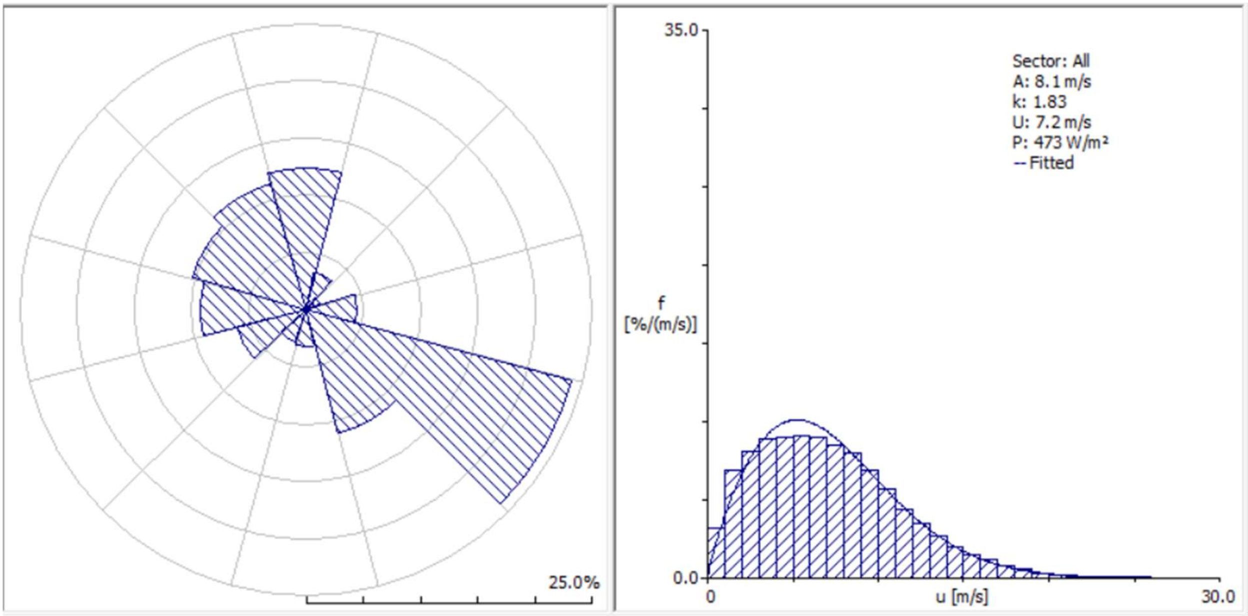


Figure 101: Kannaland average annual wind climate

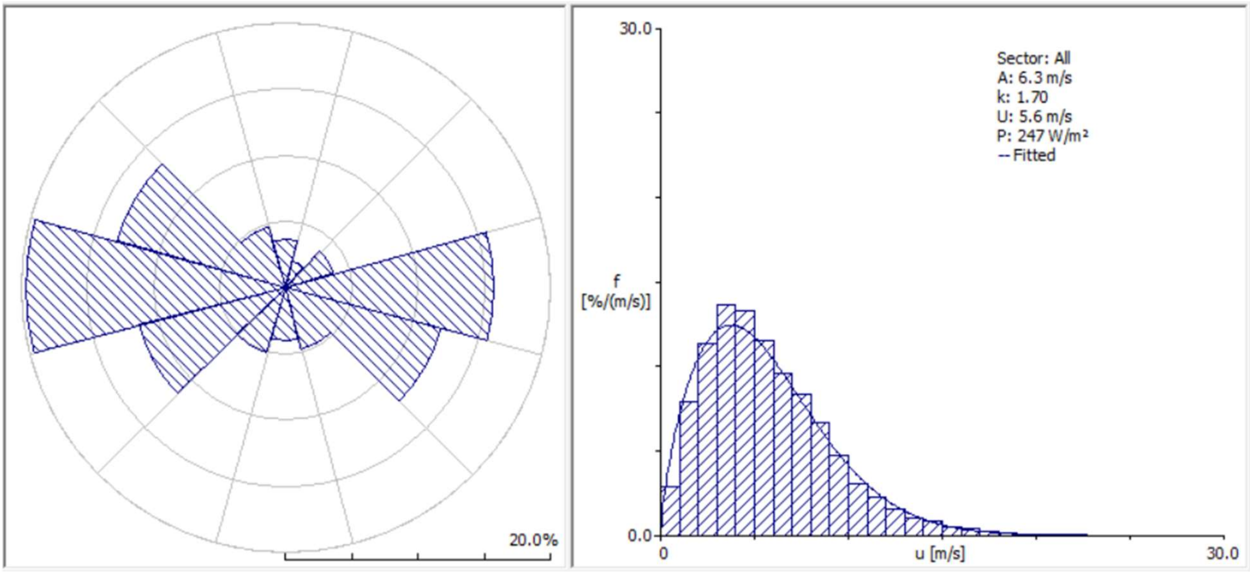


Figure 102: Knysna average annual wind climate

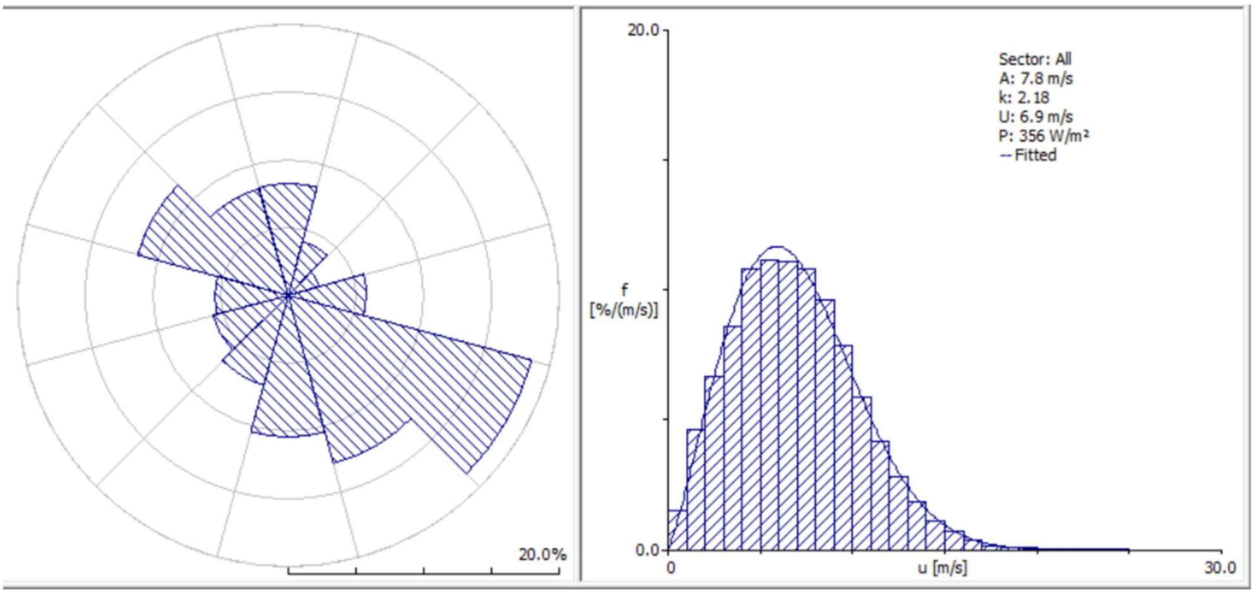


Figure **103:** Mossel Bay average annual wind climate

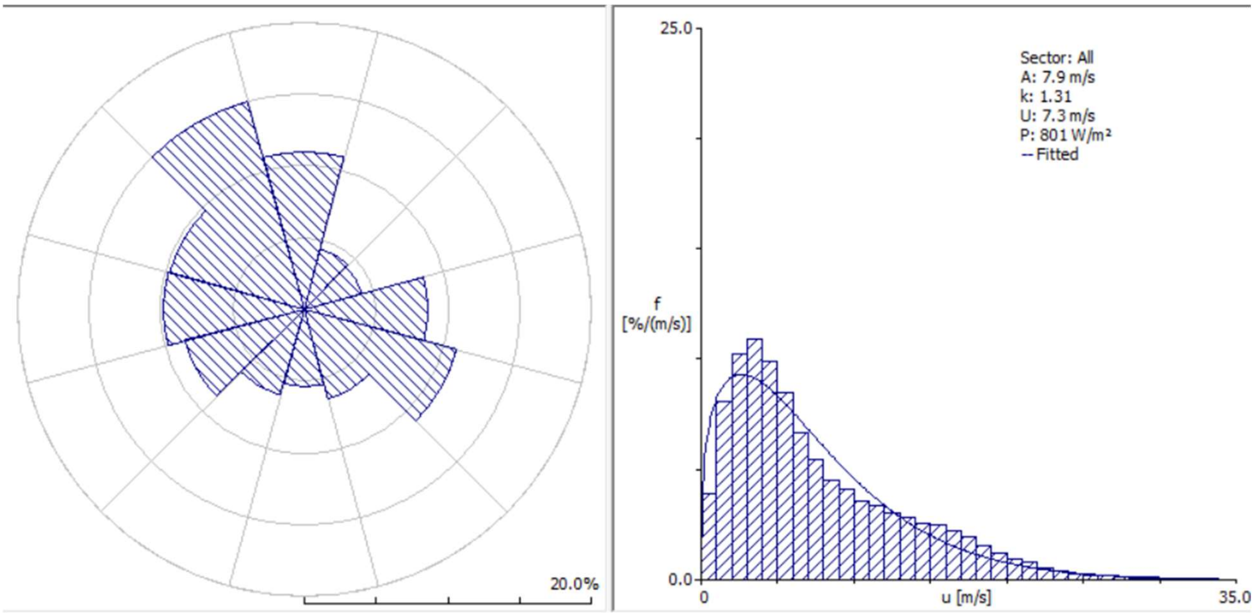


Figure **104**: Oudtshoorn average annual wind climate

10.4. Capacity Factors and Energy Production

The SWAP data set is used to calculate the capacity factors and expected energy production for the seven sites. The generalised wind climates presented in the previous section can also be used for these calculations, but the monthly resolution will be lost since the calculated climates are averaged annual. Table 21 and Table 22 present annual averaged capacity factors for the seven sites for two selected WTGs types respectively; (1) a 3.05 MW utility scale WTG, and (2) a commercial scale 100 kW WTG (see Annexure B1 for technical information on these WTGs including their power curves). Section 10.4.1 to 10.4.7 details the monthly capacity factors for each of the sites for the five years of data (2009-2013) and the normalised expected energy production calculated for (1) utility-scale 3.05 MW WTG and (2) the commercial 100 kW WTG.

Table **21**: Annual average capacity factors for utility-scale WTG (3.05 MW)

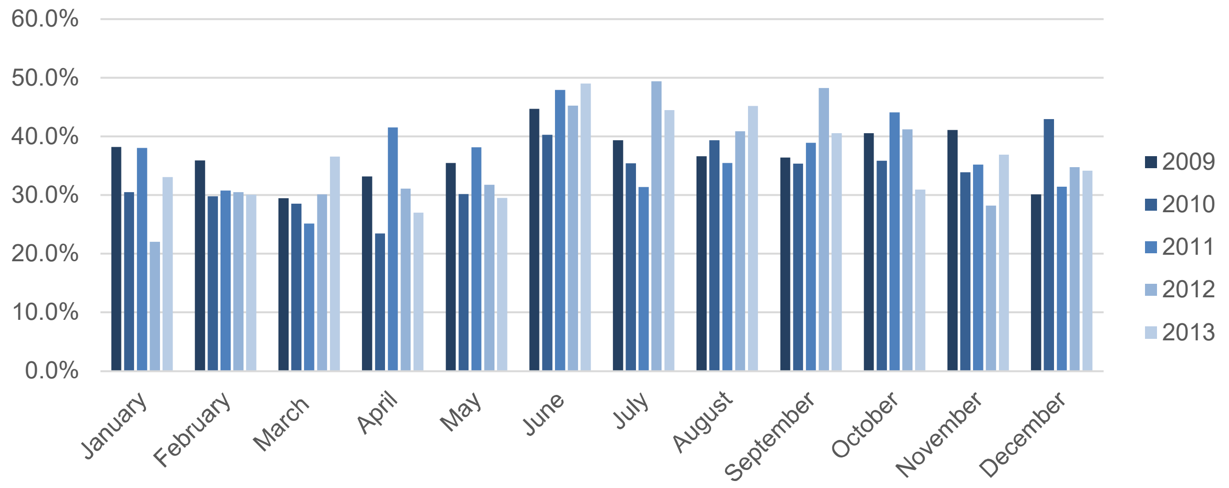
Site	Ave. Wind speed [m/s]	Capacity factor [%] (2009)	Capacity factor [%] (2010)	Capacity factor [%] (2011)	Capacity factor [%] (2012)	Capacity factor [%] (2013)	Ave. Capacity factor [%]
Bitou	7.06	36.7	33.8	36.5	36.1	36.5	35.9
George	7.68	41.9	40.8	37.7	40.0	42.4	40.6
Hessequa	7.91	45.6	42.4	43.8	43.5	43.4	43.8
Kannaland	7.06	38.3	37.2	33.5	34.6	38.9	36.5
Knysna	5.66	23.5	22.2	24.2	24.3	24.1	23.7
Mossel Bay	6.86	36.0	34.9	33.3	33.1	34.0	34.2
Oudtshoorn	7.54	39.2	37.0	32.8	36.3	40.6	37.2

Table **22**: Annual average capacity factors for commercial scale WTG (100 kW)

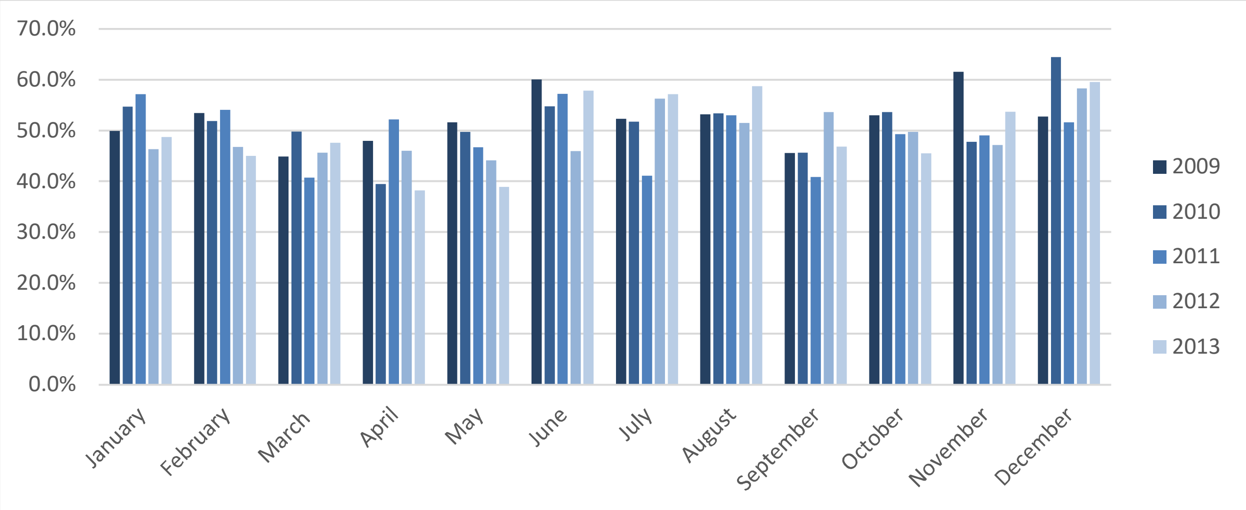
Site	Ave. Wind speed [m/s]	Capacity factor (2009)	Capacity factor (2010)	Capacity factor (2011)	Capacity factor (2012)	Capacity factor (2013)	Ave. Capacity factor
Bitou	7.06	51.4	48.4	50.8	50.4	50.8	50.3
George	7.68	56.1	55.2	52.4	54.6	56.5	55.0
Hessequa	7.91	59.7	57.4	58.4	58.4	57.8	58.3
Kannaland	7.06	51.9	51.1	47.2	48.6	52.6	50.3
Knysna	5.66	38.0	36.1	38.4	38.4	38.0	37.8
Mossel Bay	6.86	52.2	51.5	49.4	49.3	49.8	50.4
Oudtshoorn	7.54	49.6	47.5	43.7	47.5	50.7	47.8

10.4.1. Bitou

The monthly capacity factors for (1) the utility-scale 3.05 MW WTG and (2) commercial 100 kW WTG are provided in Figure 105. The hourly time-series averaged energy production profiles for (1) the utility-scale 3 MW WTG and (2) commercial 100 kW WTG are provided in Figure 106.

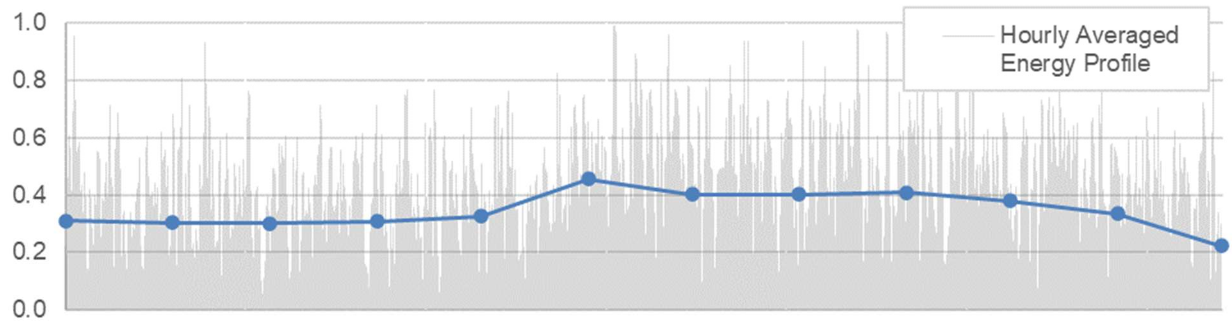


a) Utility-scale 3.05 MW WTG

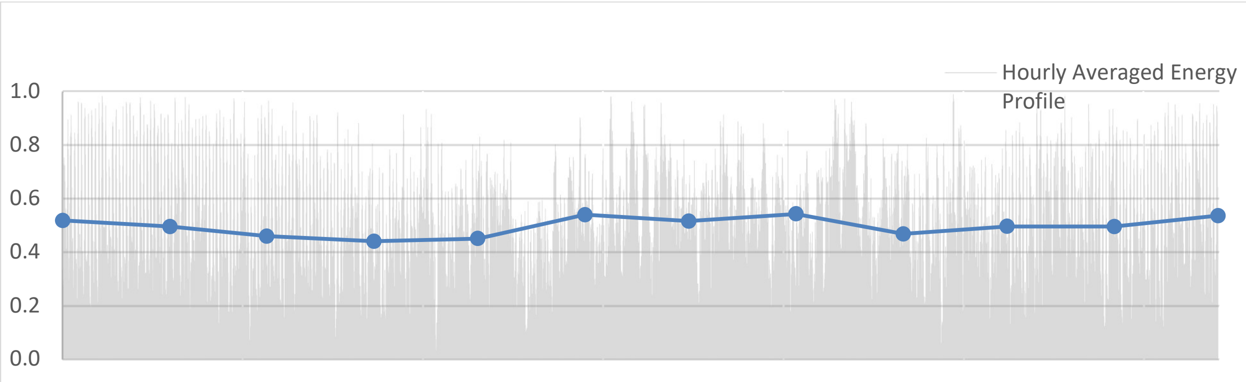


b) Commercial scale 100 kW WTG

Figure 105: Bitou monthly capacity factors



a) Utility-scale 3.05 MW WTG

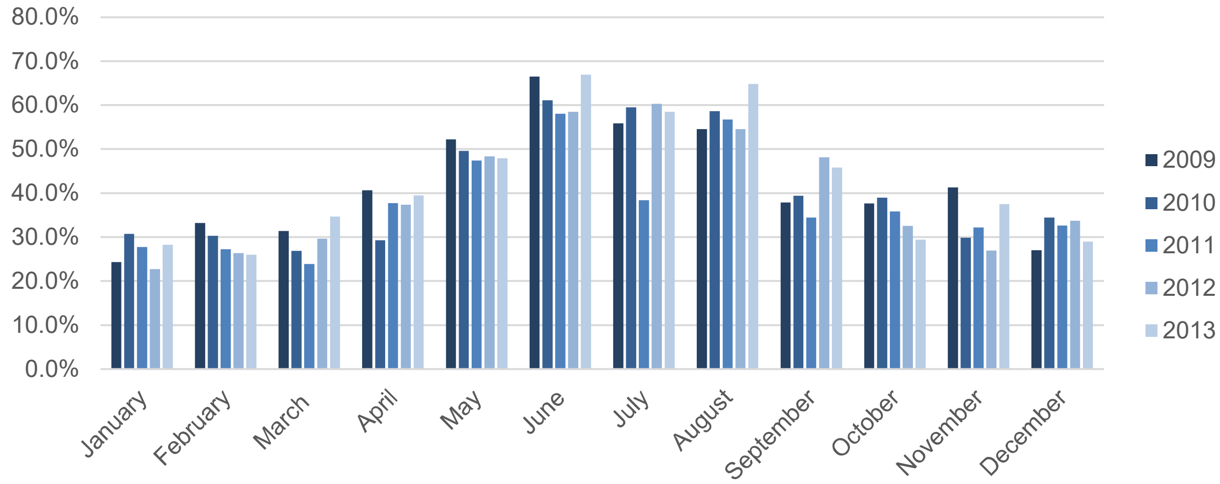


b) Commercial scale 100 kW WTG

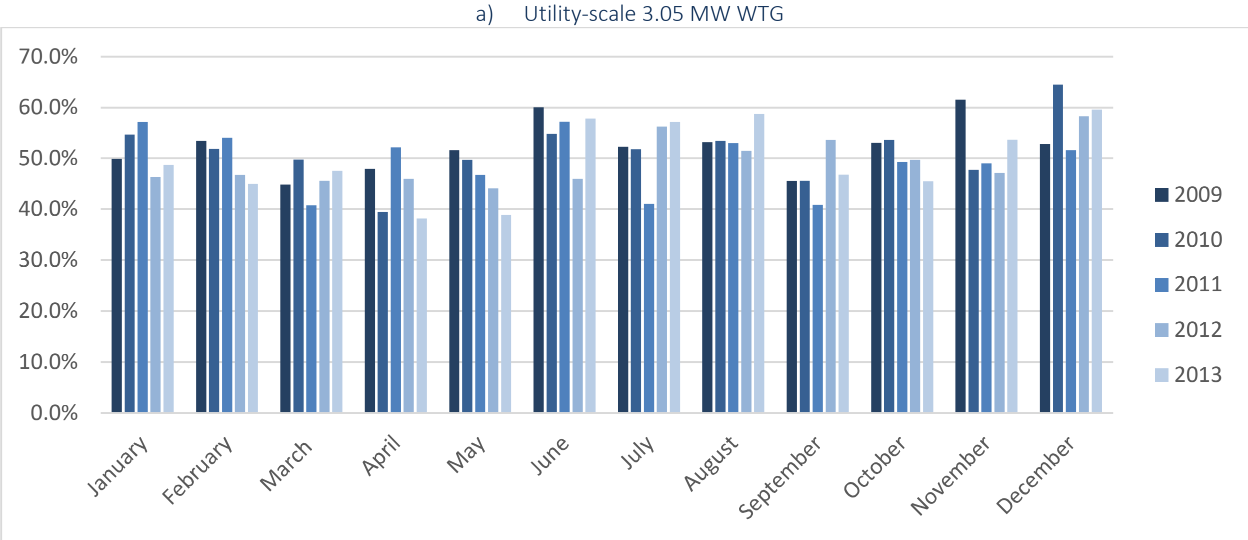
Figure **106**: Bitou normalized hourly energy production profile

10.4.2. George

The monthly capacity factors for (1) the utility-scale 3.05 MW WTG and (2) commercial 100 kW WTG are provided in Figure 107. The hourly time-series averaged energy production profiles for (1) the utility-scale 3 MW WTG and (2) commercial 100 kW WTG are provided in Figure 108.

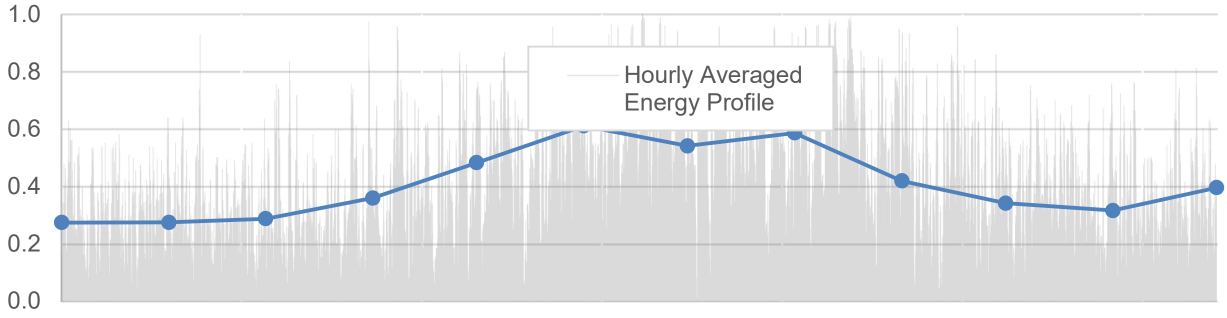


a) Utility-scale 3.05 MW WTG

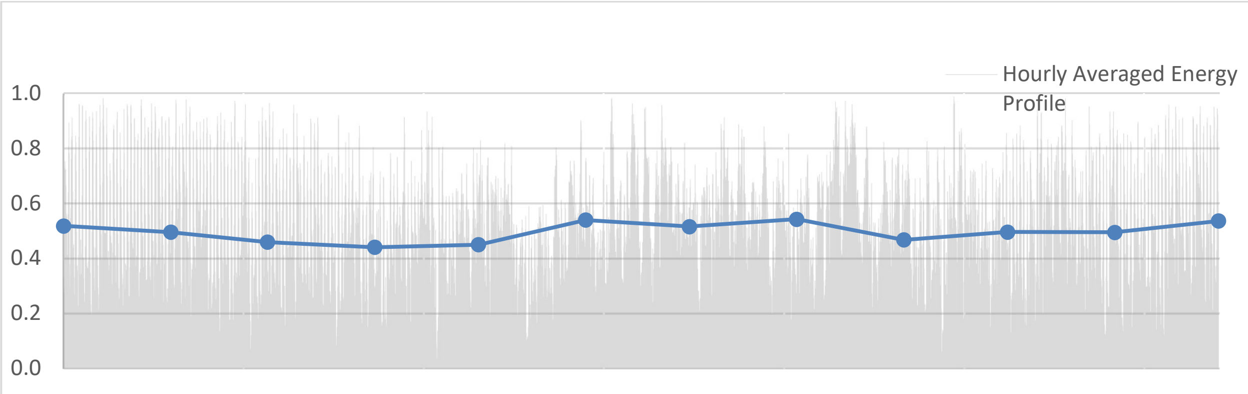


b) Commercial scale 100 kW WTG

Figure 107: George monthly capacity factors



a) Utility-scale 3.05MW WTG

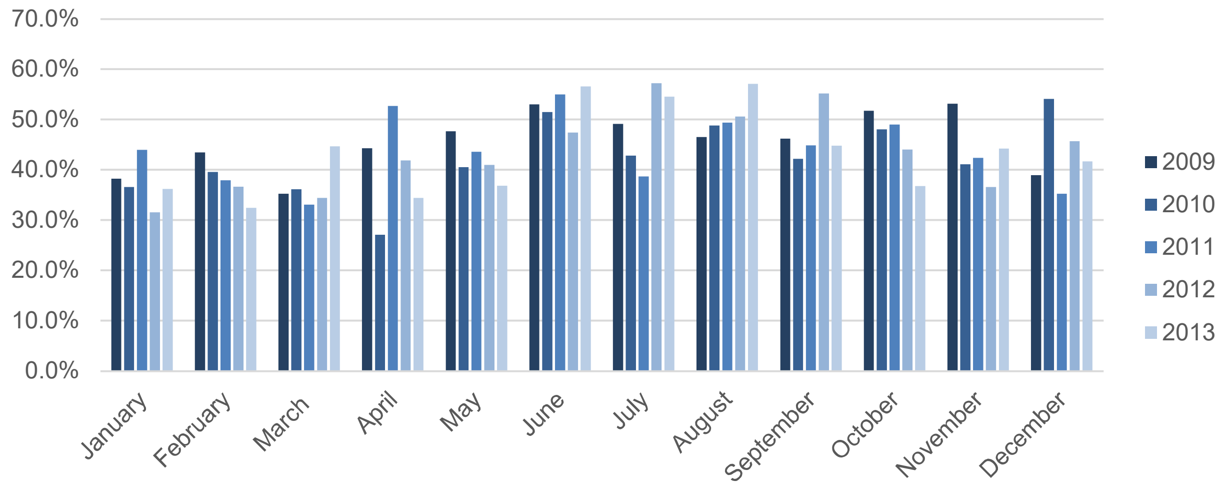


b) Commercial scale 100 kW WTG

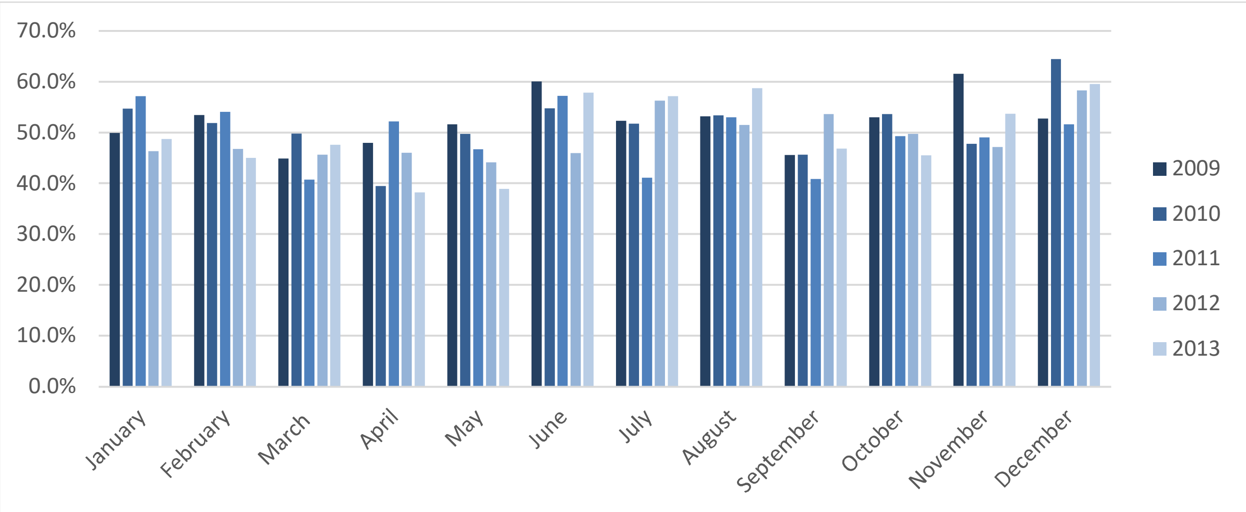
Figure 108: George normalized hourly energy production profile

10.4.3. Hessequa

The monthly capacity factors for (1) the utility-scale 3.05 MW WTG and (2) commercial 100 kW WTG are provided in Figure 109. The hourly time-series averaged energy production profiles for (1) the utility-scale 3 MW WTG and (2) commercial 100 kW WTG are provided in Figure 110.

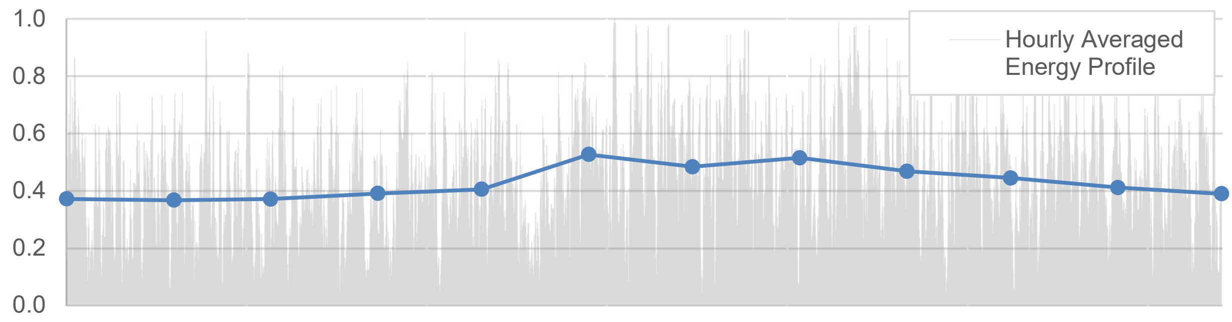


a) Utility-scale 3.05 MW WTG

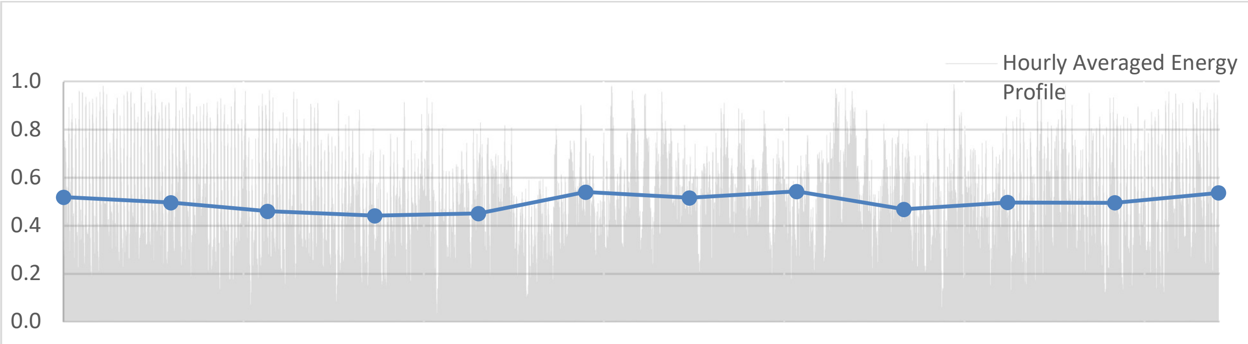


b) Commercial scale 100 kW WTG

Figure 109: Hessequa monthly capacity factors



a) Utility-scale 3.05 MW WTG

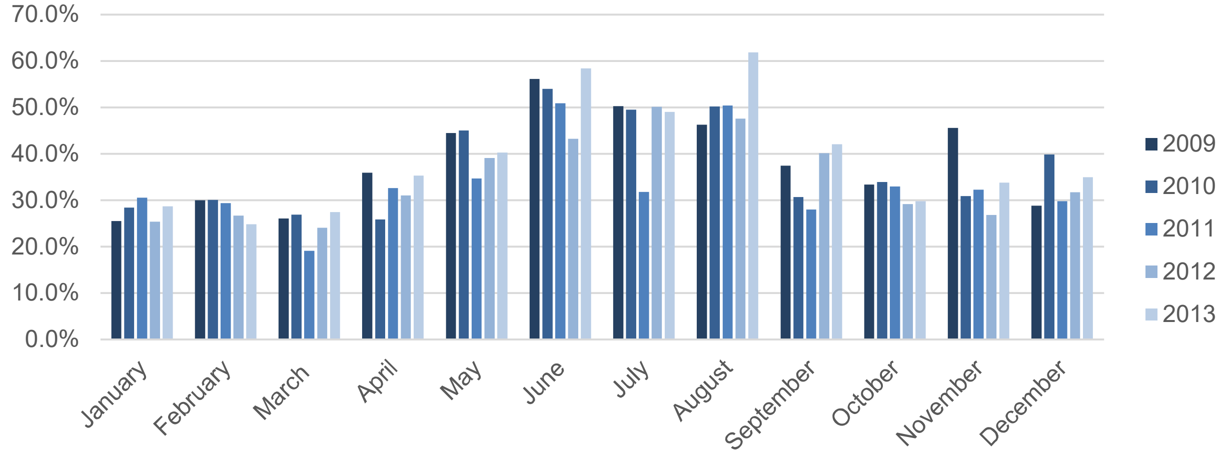


b) Commercial scale 100 kW WTG

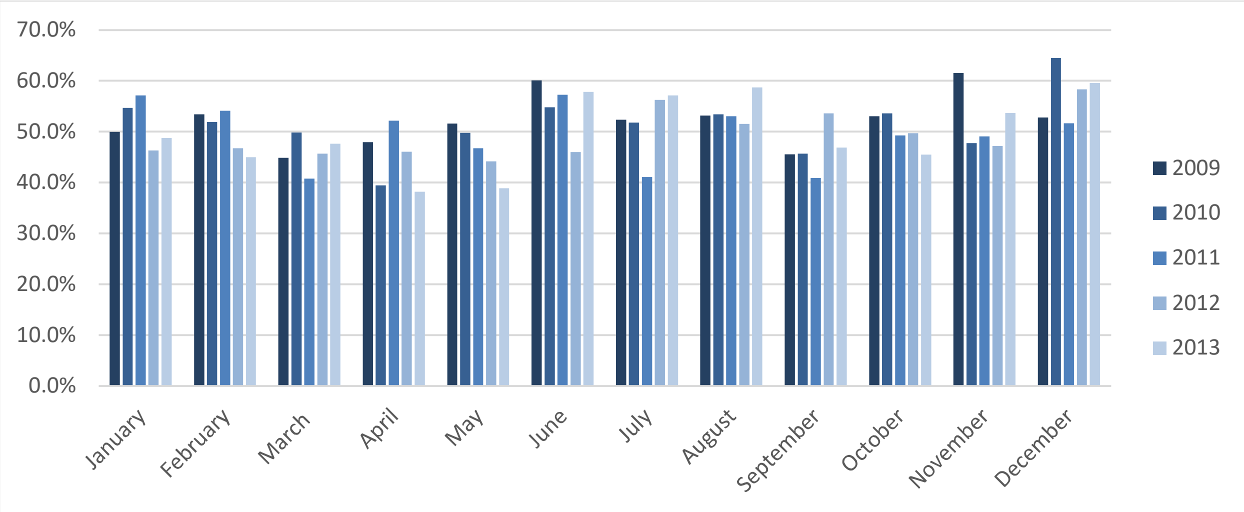
Figure **110**: Hessequa normalized hourly energy production profile

10.4.4. Kannaland

The monthly capacity factors for (1) the utility-scale 3.05 MW WTG and (2) commercial 100 kW WTG are provided in Figure 111. The hourly time-series averaged energy production profiles for (1) the utility-scale 3 MW WTG and (2) commercial 100 kW WTG are provided in Figure 112.

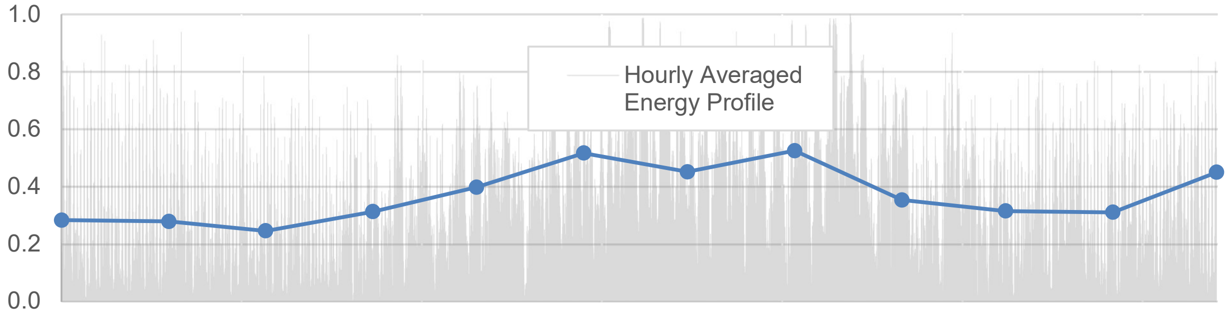


a) Utility-scale 3.05 MW WTG

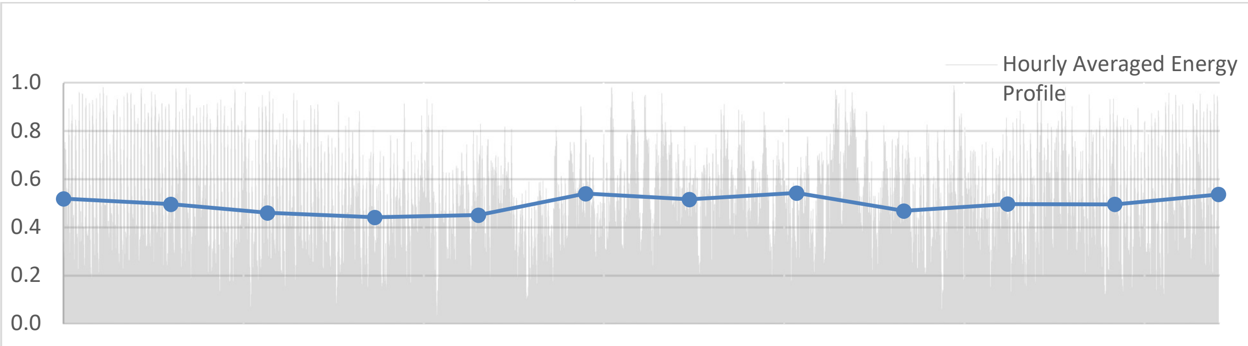


b) Commercial scale 100 kW WTG

Figure 111: Kannaland monthly capacity factors



a) Utility-scale 3.05 MW WTG

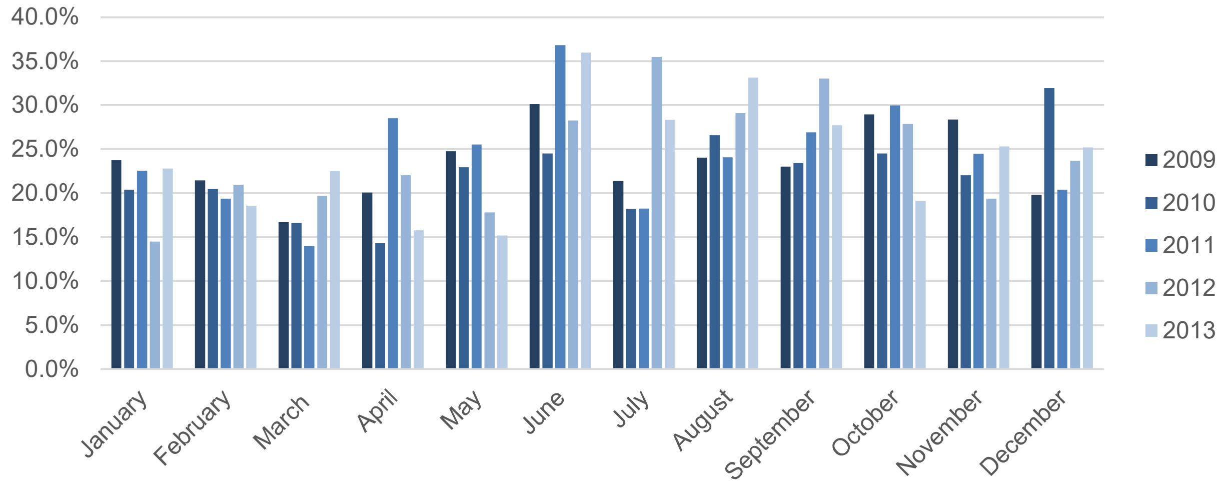


b) Commercial scale 100 kW WTG

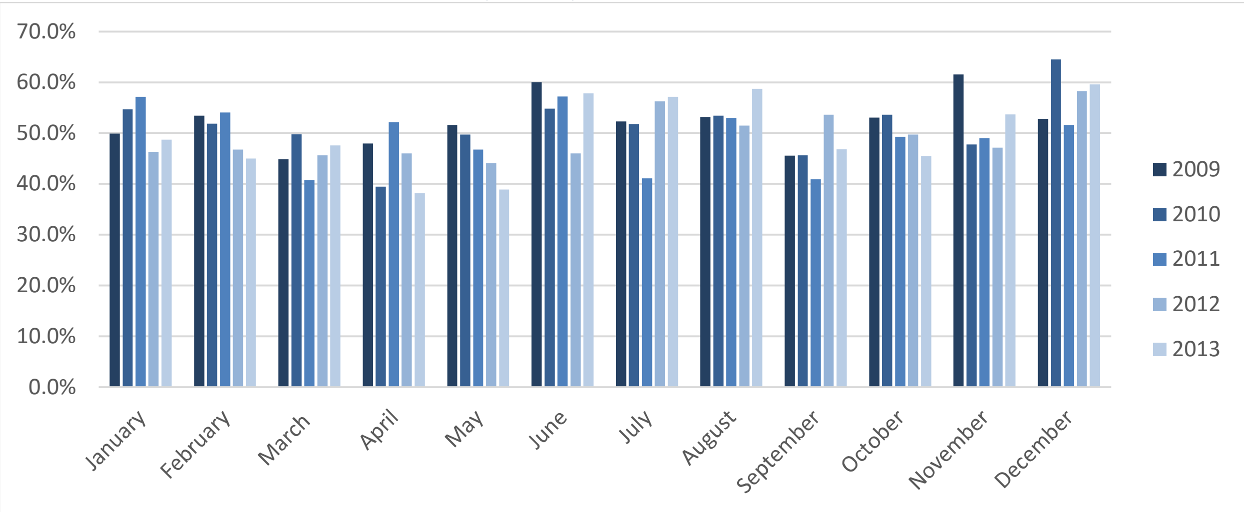
Figure 112: Kannaland normalized hourly energy production profile

10.4.5. Knysna

The monthly capacity factors for (1) the utility-scale 3.05 MW WTG and (2) commercial 100 kW WTG are provided in Figure 113. The hourly time-series averaged energy production profiles for (1) the utility-scale 3 MW WTG and (2) commercial 100 kW WTG are provided in Figure 114.

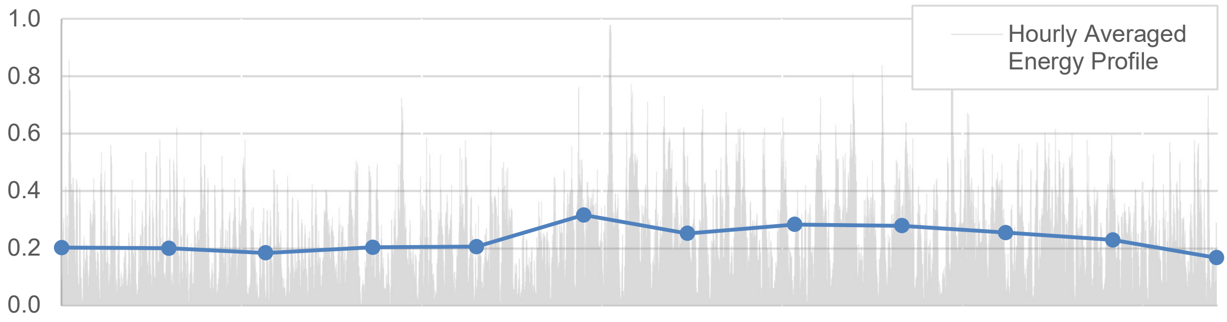


a) Utility-scale 3.05 MW WTG

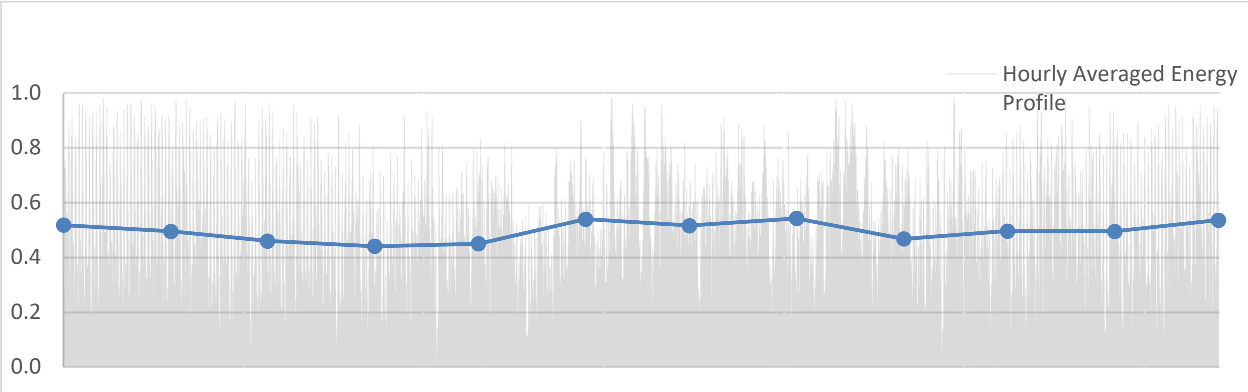


b) Commercial scale 100 kW WTG

Figure 113: Knysna monthly capacity factors



a) Utility-scale 3.05 MW WTG

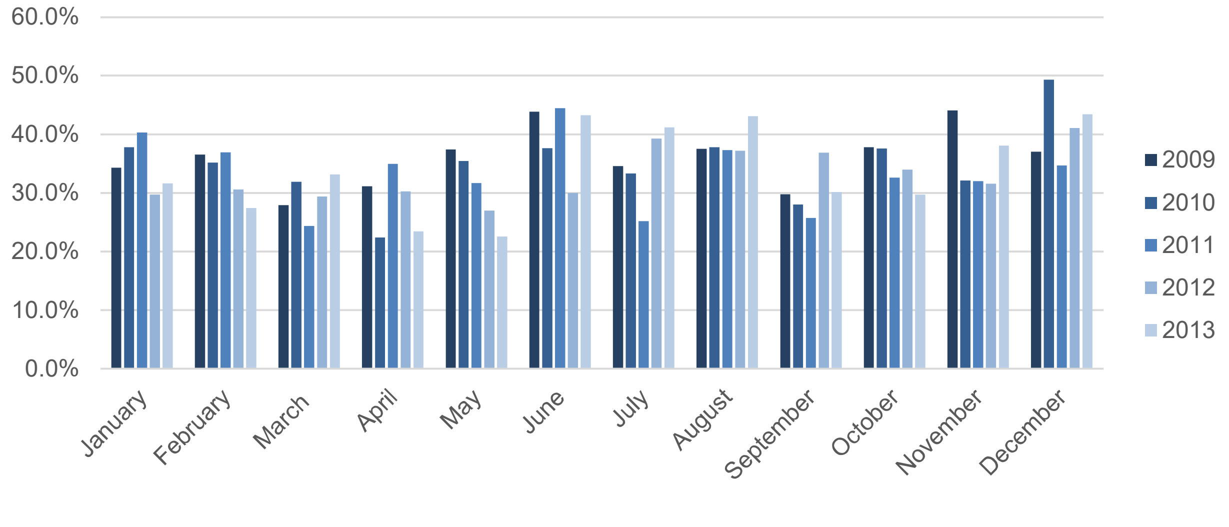


b) Commercial scale 100 kW WTG

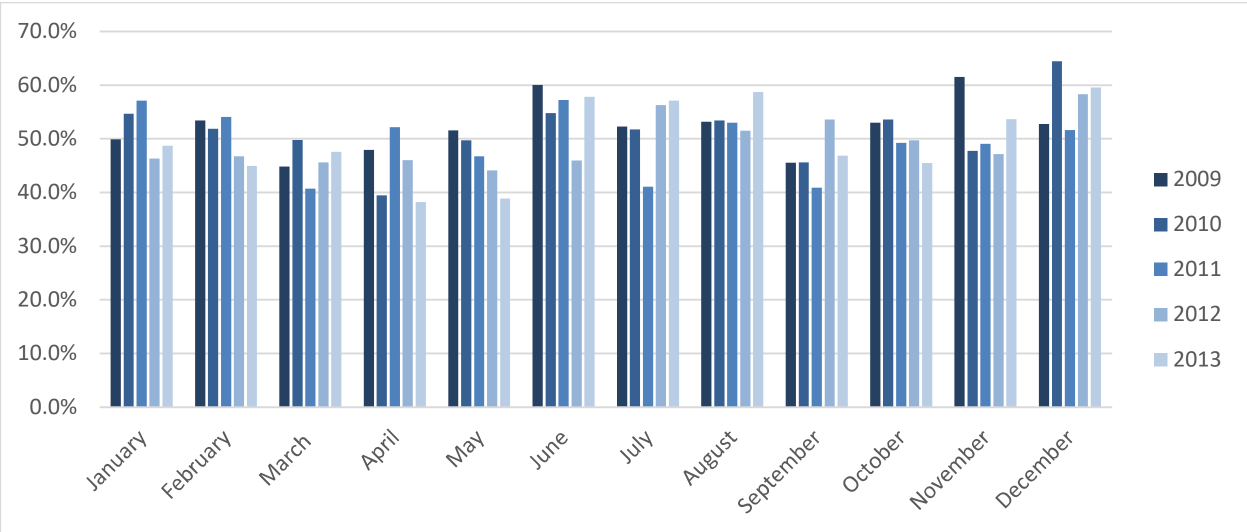
Figure **114**: Knysna normalized hourly energy production profile

10.4.6. Mossel Bay

The monthly capacity factors for (1) the utility-scale 3.05 MW WTG and (2) commercial 100 kW WTG are provided in Figure 115. The hourly time-series averaged energy production profiles for (1) the utility-scale 3 MW WTG and (2) commercial 100 kW WTG are provided in Figure 116.

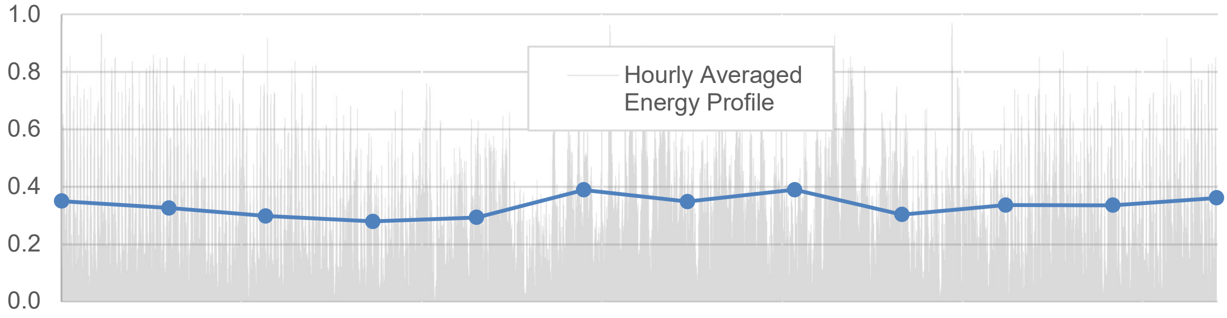


a) Utility-scale 3.05 MW WTG

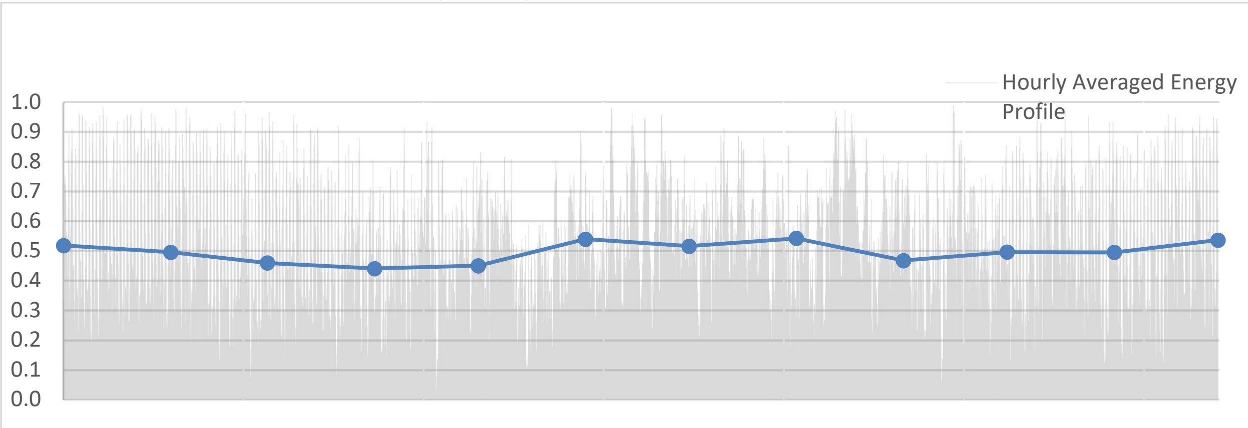


b) Commercial scale 100 kW WTG

Figure 115: Mossel Bay monthly capacity factors



a) Utility-scale 3.05 MW WTG

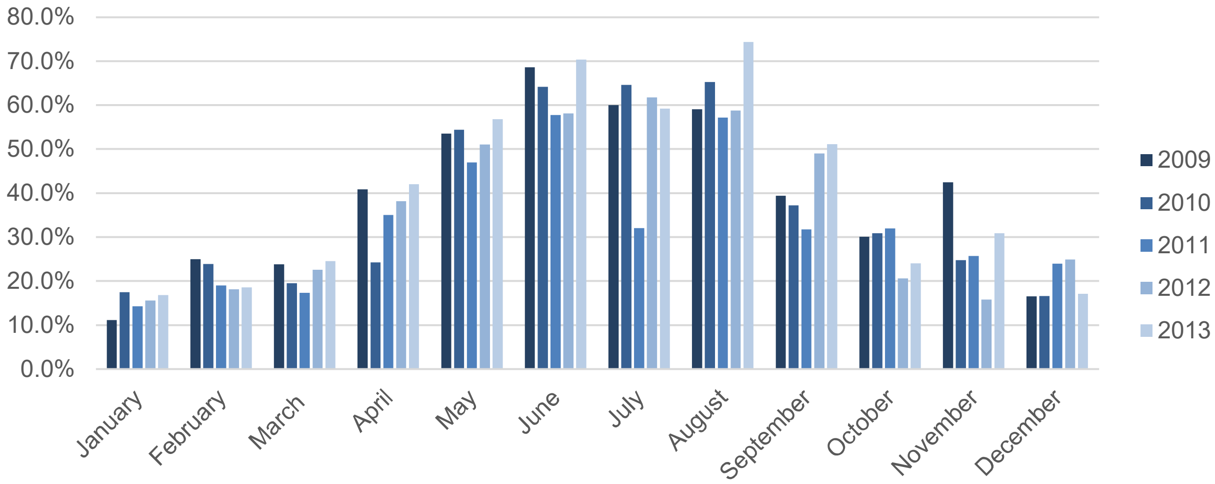


b) Commercial scale 100 kW WTG

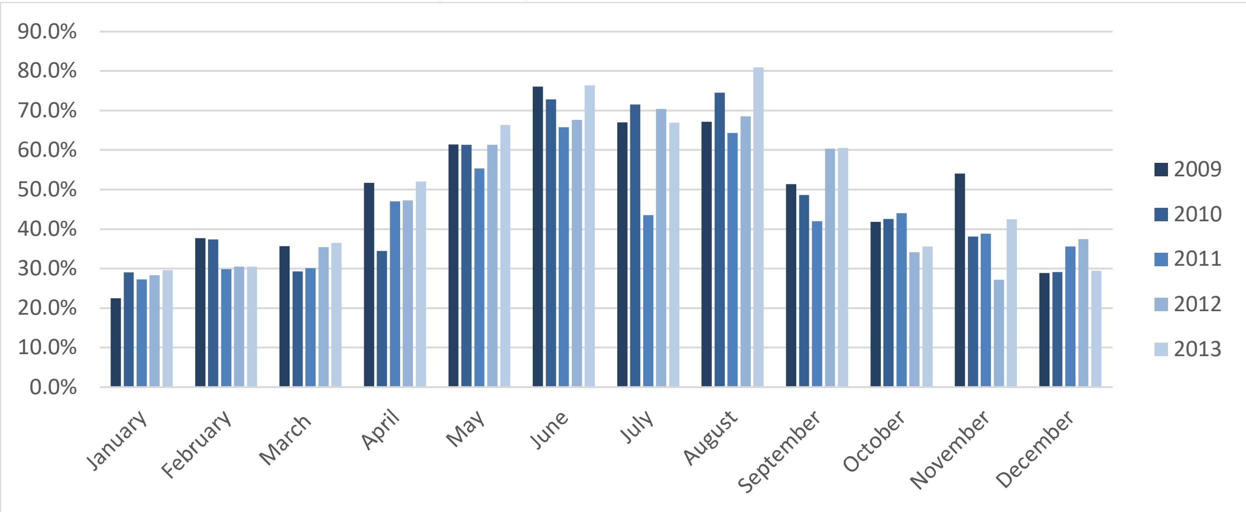
Figure 116: Mossel Bay normalized hourly energy production profile

10.4.7. Oudtshoorn

The monthly capacity factors for (1) the utility-scale 3.05 MW WTG and (2) commercial 100 kW WTG are provided in Figure 117. The hourly time-series averaged energy production profiles for (1) the utility-scale 3 MW WTG and (2) commercial 100 kW WTG are provided in Figure 118.

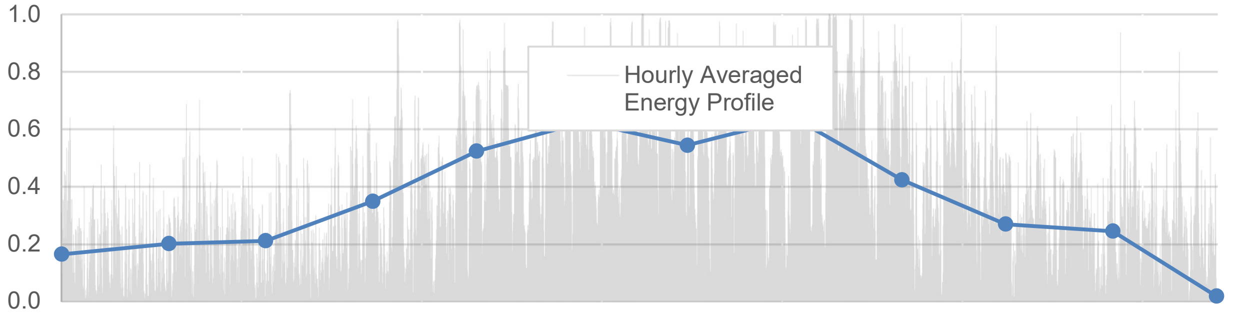


a) Utility-scale 3.05 MW WTG

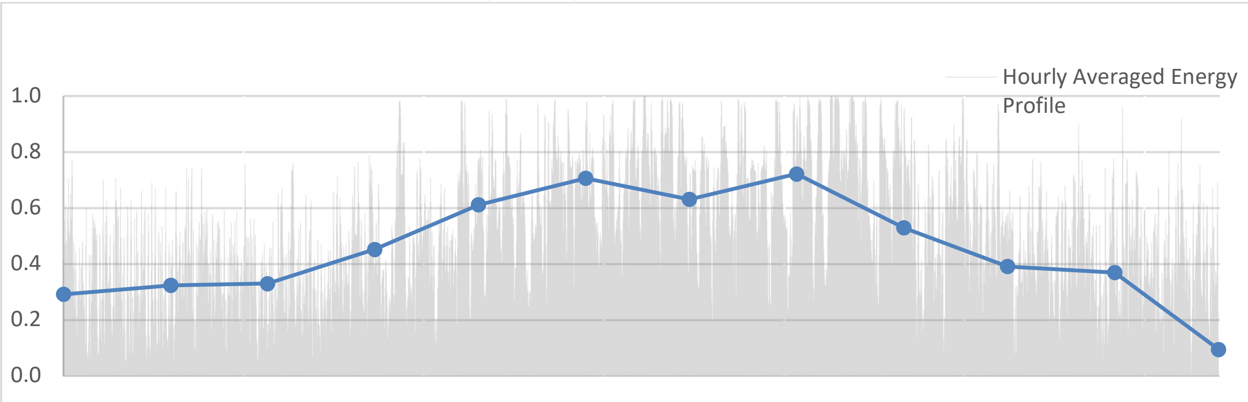


b) Commercial scale 100 kW WTG

Figure 117: Oudtshoorn monthly capacity factors



a) Utility-scale 3.05 MW WTG



b) Commercial scale 100 kW WTG

Figure 118: Oudtshoorn normalized hourly energy production profile

10.5. Maximum Potential Capacity and Energy Density

The layout of WTGs in a wind farm is usually a compromise between optimised energy production, space, and cost. As depicted in Figure 119, the internationally accepted practice for WTG spacing without detailed wind farm design is a 4-5 times multiplier of the WTG rotor diameter (4D-5D) between WTGs and a 6-7 times multiplier of the rotor diameter in-line (6D-7D) [17-19]

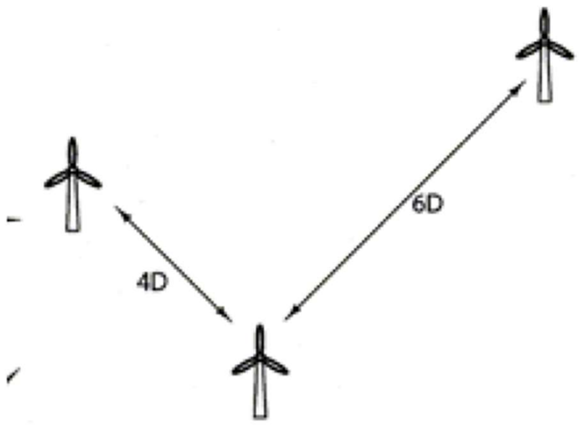


Figure **119**: Typical optimal WTG spacing for wind farm layouts

Table 23 shows power density and energy density from a wind farm. For the selected 3.05 MW WTG with a rotor diameter of 101 m, installed power density of 2.77 MW/ha is expected at all seven sites. Approximately 5345 - 10223 MWh/km^2 can be produced annually from a utility-scale wind farm.

Table **23**: Power and energy density for utility-scale WTG (3.05 MW)

Site	Area (km^2)	Capacity (MW)	Power density (MW/km^2)	Ave. annual energy production (Net) (MWh)	Energy density (MWh/km^2)
Bitou	1.11	3.05	2.77	8240	7 423
George	1.11	3.05	2.77	9 865	8 887
Hessequa	1.11	3.05	2.77	11 347	10 223
Kannaland	1.11	3.05	2.77	8 558	7 710
Knysna	1.11	3.05	2.77	5 933	5 345
Mossel Bay	1.11	3.05	2.77	7 317	6 592
Oudtshoorn	1.11	3.05	2.77	9 700	8 739

Table 24 shows power density and energy density from a wind farm. For the selected 100 kW WTG with a rotor diameter of 25 m, installed power density of 90.09 kW/km^2 is expected at all seven sites. Approximately 204 - 360 MWh/km^2 can be produced annually from a utility scale wind farm.

Table **24**: Power and energy density for commercial-scale WTG (100 kW)

Site	Area (km^2)	Capacity (kW)	Power density (kW/km^2)	Ave. Annual energy production (MWh)	Energy density (MWh/km^2)
Bitou	1.11	100	90.09	319.3	287.7
George	1.11	100	90.09	372.5	335.6
Hessequa	1.11	100	90.09	400.1	360.5
Kannaland	1.11	57.6	6.67	266.2	239.9
Knysna	1.11	100	90.09	226.6	204.1
Mossel Bay	1.11	100	90.09	340.9	307.1
Oudtshoorn	1.11	100	90.09	342.2	308.3

10.6. Annexure B1

<u>Utility Scale WTG (Enercon 101-3.05 MW)</u>

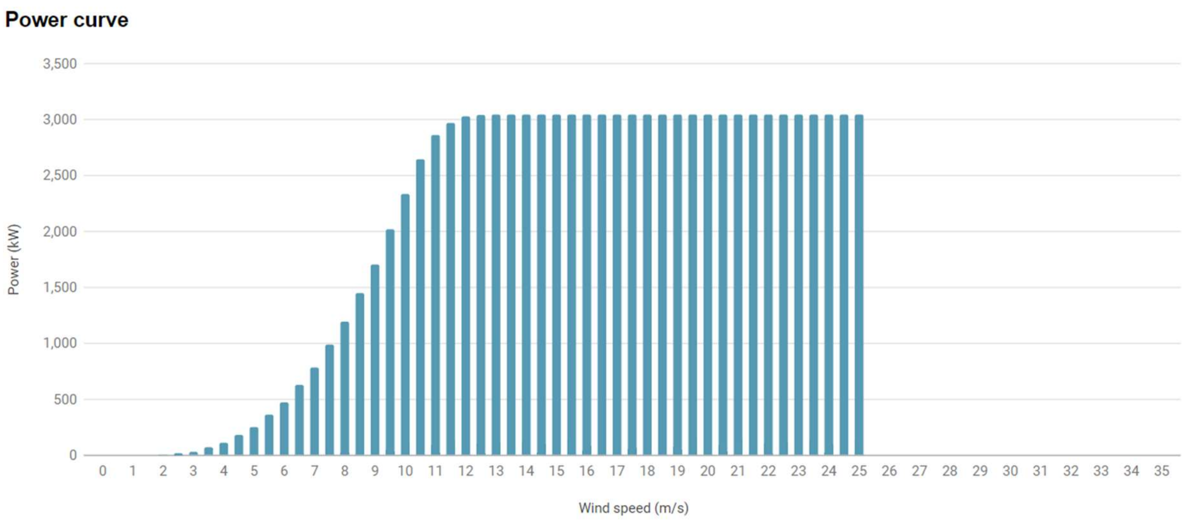


Figure 120: Enercon 101-3.05 MW power curve

General data

- Manufacturer: Enercon (Allemagne)
- Model: E101/3050
- Rated power: 3,050 kW
- Rotor diameter: 101 m
- No more available
- Wind class: IEC IIa (WZ III)
- Offshore model: no
- Swept area: 8,012 m²
- Specific area: 2.63 m²/kW
- Number of blades: 3
- Power control: Pitch
- Commissioning: 2012

Rotor

- Minimum rotor speed: 4 rd/min
- Maximum rotor speed: 14,5 rd/min
- Cut-in wind speed: 2 m/s
- Rated wind speed: 13 m/s
- Cut-off wind speed: 25 m/s
- Manufacturer: Enercon

Gear box

- Gear box: no
- Stages: -
- Gear ratio: -
- Manufacturer: -

Generator

- Type: SYNC
- Number: 1
- Maximum speed: 14,5 rounds/minute
- Voltage: 690 V
- Manufacturer: Enercon

Tower

- Minimum hub height: 99 m
- Maximum hub height: 149 m
- Manufacturer: WEC, Enercon

Figure 121: Enercon 101-3.05 MW datasheet

Commercial WTG (Hummer H25.0-100kW)

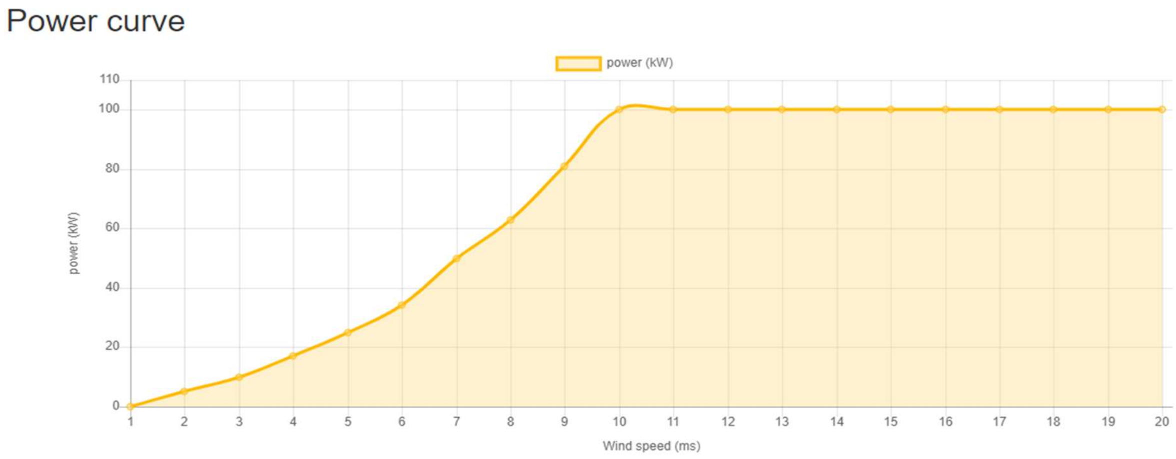


Figure 122: Hummer H25-100 kW power curve

Datasheet

Power

Rated power:	100.0 kW
Flexible power ratings:	-
Cut-in wind speed:	2.5 m/s
Rated wind speed:	10.0 m/s
Cut-out wind speed:	20.0 m/s
Survival wind speed:	50.0 m/s
Wind zone (DIBt):	-
Wind class (IEC):	-

Rotor

Diameter:	25.0 m
Swept area:	490.9 m²
Number of blades:	3
Rotor speed, max:	50.0 U/min
Tipspeed:	65 m/s
Type:	12m
Material:	Fiberglass reinforced composite
Manufacturer:	-
Power density 1:	203.7 W/m²
Power density 2:	4.9 m²/kW

Figure 123: Hummer H25-100 kW datasheet