IMPACT ASSESSMENT OF A HIGH PENETRATION OF ROOFTOP PV IN CAPE TOWN

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1 Introduction

There is an increasing global trend of grid connected rooftop PV systems in urban networks. Despite the possibilities offered by the uptake of PV, its increased deployment often comes with technical constraints such as voltage violations, reverse power flow, and equipment overload. This has resulted in a growing concern amongst municipal engineers on how the increasing customer-owned rooftop PV systems will impact the existing networks. Impact studies therefore have a crucial role for distribution system operators who need to maintain specific network parameters within permissible limits and also to facilitate further uptake of residential PV systems [1].

In South Africa, the standard for embedded or distributed generator connections (NRS 097-2-3: 2014) specifies the capacity limitations for shared LV connections. This standard limits households (single phase customers) to 3.5kW/household distributed generation (DG) systems. Overly restrictive regulations can however limit the extent of PV penetration a network can accommodate. A study was conducted by Eskom, University of Cape Town, University of Stellenbosch, Cape Peninsula University of Technology and City of Cape Town, to determine the limit of PV penetration in urban networks. The purpose of this study was to determine whether NRS 097 2-3: 2014 is too conservative and can be relaxed to enable further uptake of embedded PV systems. To the extreme, the study had to provide answers on whether the City of Cape Town will first run out of roof space, or wires, if no additional investment is made into the LV and MV networks to accommodate DG.

An existing urban network is considered where the PV allocation is randomly distributed and the PV system capacities are restricted by the available roof size.

The study assumes generation back into the network and no battery penetration. It is important to note that reverse power blocking and battery storage will allow for greater PVDG (subject to further study).

2 Methodology

2.1 Network selection

An actual medium voltage feeder within the City of Cape Town supply area was selected for the study. The selection was based on areas with mainly residential customers, good solar availability, and customers that are highly likely to install solar due to their fairly high property value.

2.2 Network modeling

The selected residential network consists of seven separate LV networks, each radially supplied from an 11/0.4 kV MV/LV transformer. Each LV network supplies between 30 – 53 customers. The LV networks are modelled up to the 'kiosks' which are the points of common coupling (PCC). Each property is therefore not individually modelled. The load- and generation profile for each individual property is considered and lumped together, and represented as one LV load and one solar PV system connected to that kiosk. The kiosk is the first point in the network where solar PV distributed generation (PVDG) aggregation occurs, so it is useful to model the system up to this point in order to observe the influences of distributed solar PV generation on all parts of the LV networks. The residential network is shown in Figure 1, where black lines are MV feeders and the round objects are kiosks. The seven LV networks are shown in different colours [2].

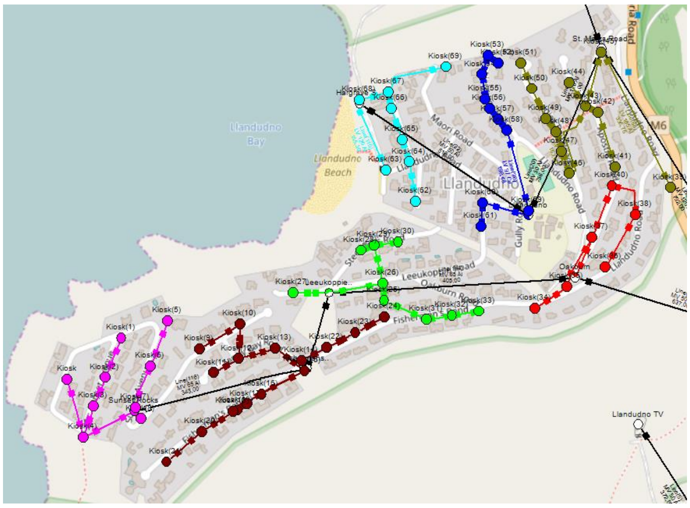


Figure 1 Residential Network [2]

It is important to note that no data was available on which property is connected to each kiosk. It was assumed that:

a) A property is allocated to the nearest possible LV kiosk
b) Connections are distributed across phases to minimize numerical phase unbalance.

2.3 Load modeling

The loading of individual MV/LV transformers, kiosk or individual LV loads is not available. The half-hourly load data for the MV feeder for 2016, as measured at the HV/MV substation, was therefore used.

The load data at MV level can be de-aggregated to LV customer level using deterministic load flow methods. These methods are mostly inadequate for analysing real power systems, due to uncertainties in power system variables, such as intermittent generation and stochastic customer load variations.

Probabilistic load flow (PLF) techniques can be used to model the uncertainties and provide a set of load flow results more representative of the range of probable network conditions. A probabilistic approach was therefore taken to analyse the network, such that the following non-deterministic characteristics of the problem are taken into account [4]:

a) stochastic variability in the load
b) variability in the PVDG output
c) the uncertainty associated with PVDG location (or uptake)
d) the uncertainty of the size of the installed PVDG system despite the knowledge of the maximum solar hosting capacity reflected by the roof-space area.

Items a) and b) are dealt with by the statistical models of load and DG and will be analysed here through the Herman-Beta-Extended (HBE) transform capable of processing random inputs and reflecting the associated uncertainty at the outputs. However, the HBE transform can only calculate feeder voltages given the inputs, which include the location of loads and DG, on top of the other parameters. Consequently, the Monte-Carlo Simulation (MCS) is used for the process of random PV sizing and location.

The Western Cape Electrical Reticulation Technical Standards (a CCT internal document) that defines the estimation of the load variance associated with a given ADMD for residential customers was used to derive the statistical models. The probability distribution of the load currents, assuming a beta pdf with a scaling factor taken as the circuit breaker size (C_b) of 80 amps (as is the norm for higher LSM customers), is defined by the shape parameters α and β. [4]

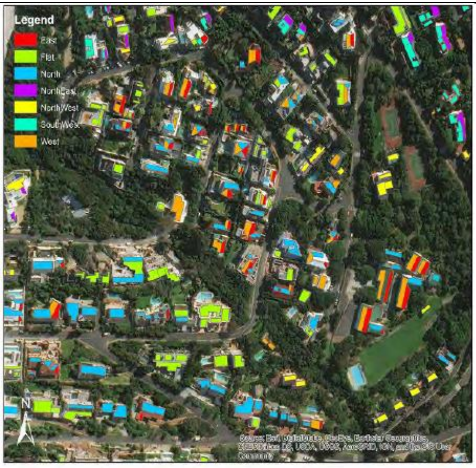
Table 1 provides the results of the calculation, specifying the beta load parameters for each feeder for winter and summer.

Table 1: Load characteristics for LV feeders [4]

Trfmr Name	ID	Rating [kVA]	Deaggregated Group Load Characteristics			Statistical Load Characteristics per household						
			Allocated Summer Demand [kVA]	Allocated Winter Demand [kVA]	Total Cust.	Summer ADD [kVA]	Winter ADMD [kVA]	CB limit [A]	Summer		Winter	
									α	β	α	β
Sunset Rocks		500	55.64	145.84	36	1.546	4.051	80	1.083	11.812	1.445	5.118
Fisherman's Bend		500	97.67	256.00	55	1.776	4.654	80	1.173	10.980	1.420	4.194
Leeukoppie		500	80.51	211.03	45	1.789	4.690	80	1.178	10.932	1.418	4.146
Oakburn		315	41.21	108.01	30	1.374	3.600	80	1.003	12.431	1.446	5.945
St. Mark's		500	72.03	188.80	46	1.566	4.104	80	1.092	11.738	1.444	5.029
Llandudno		800	80.51	211.03	53	1.519	3.982	80	1.072	11.908	1.446	5.237
Hargrave		315	101.22	265.30	44	2.300	6.030	80	1.317	9.217	1.296	2.658

2.4 Generation modeling

PVDG is randomly located on the network, considering the node and phase of placement. Further, the allocation process is bounded by two factors; the desired penetration level, and the maximum solar hosting capability (MSHC) of a given node and phase, which depend on the MSHC of the respective properties connected to that point. To determine the MSHC of a given node, GIS software was used to determine the available roof space of each property, aggregated to each kiosk. The orientation of the roof was also considered. The process of determining the maximum solar hosting capability of each property using GIS software is shown in Figure 2. The MSHC is then determined by the available roof space and the customer circuit breaker limit (80A for single phase residential customer with a high LSM).



Direction	Area (m^2)	Percentage (%)	Installable capacity (kW_p)	Predicted energy production (MWh/year)
North	5 703.1	15	1012.5	1638.9
North East	2 433.1	6.4	432.0	660.7
North West	5 349.1	14.1	949.7	1490.6
East	2 386.9	6.3	423.8	575.6
West	5 039.6	13.3	894.7	1255.3
South West	3 931.6	10.4	698.0	838.1
Flat	13 090.6	34.5	2324.1	3396.1
Total	**37 934**	**100**	**6734.8**	**9855.2**

Figure 2: Process of determining the maximum solar hosting capability of each property

3 Simulation methodology

For the purpose of this study, the PV penetration is defined as by the following equation:

$$\%\ PV\ Penetration = \frac{\sum_{i=0}^{N} PV_{Rated\ i}(kW)}{Feeder\ MD\ (kVA)}\ x\ 100\%$$

Where:

$\sum_{i=0}^{N} PV_{Rated\ i}$: Total PV capacity installed on the feeder;

Feeder MD : The maximum load that the feeder can supply before network violations (voltage or thermal) occur.

The simulation methodology followed is described in the steps below [4]:

a) Load the feeder identified with the winter load model derived in 2.3 for that feeder, and calculate the voltage profile on the feeder, applying a 10% risk (90% confidence interval) to assess the minimum voltages.

b) Increasing the winter load models, model the feeder's highest passive loading it can supply without violating the design voltage limit (CCT allows 0.92 p.u.). This is termed the FeederMD and is not the same as the allocated de-aggregated demand supplied by the feeder.

c) Using the feeder loaded with the summer load model, randomly (to node and phase, by means of the Monte-Carlo Simulation) allocate PVDG modules on the feeder and calculate the voltage rise and conductor thermal loading conditions represented by a risk level (of exceedance) of 2.5% for the respective limits (1.1 for voltage conditions and 100% for thermal loading). For each scenario calculate the transformer loading.

   Repeat this step for an adequate number of placement scenarios; in this study 800 runs.

d) Successively add further PV modules, repeating steps c) with each increment, until the feeder is 'full', having reached the limit imposed by the circuit breakers of all households.

e) Plot the results of calculated voltages, line currents and transformer loading for all scenarios against the penetration ratio on a scatter plot. Derive the maximum hosting capacity of the feeder for both voltage rise and conductor thermal loading, again with a selected confidence risk; in this study a further 2.5%.

4 Results

The scatter plots of maximum voltages and currents (at 5 % risk applied in the HBE transform) are shown in Figure 3. The red line in the voltage graph and the blue line in the current graph indicates the 95% confidence level, with only 5% of the simulations having a voltage / current above the red line. As more simulations are done, the envelope looks fairly similar, but the 95% confidence line becomes smoother.

The maximum allowable penetration without violation is about 64% (the feeder being thermally constrained). Beyond this penetration level, the proportion of scatter points above the limits increases although, at the same time, placement scenarios that result in maximum voltages and currents within the regulatory limits exist. In this analysis, considering the stochastic variance of the load, the feeder gets full with PVDG at about 420% [4].

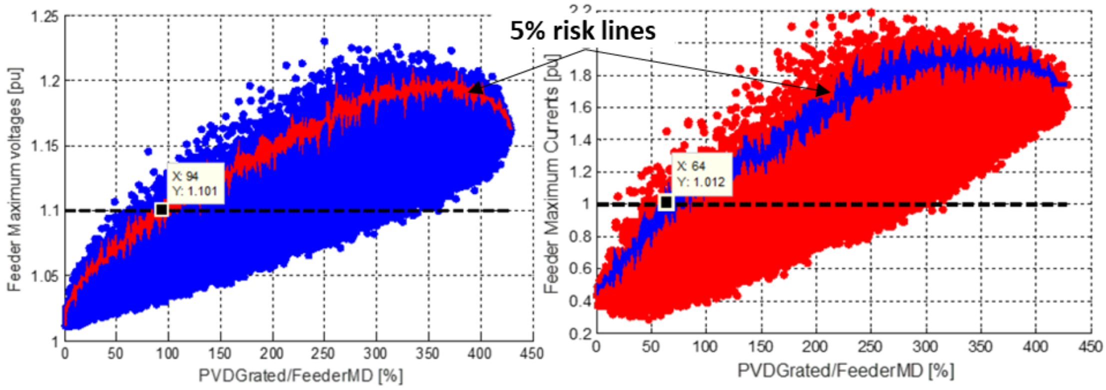


Figure 3: Maximum voltages and currents on test feeder with increasing PVDG penetration: Stochastic loads

Several conditions of PVDG limits were investigated in steps of 2.9 kWp systems (1 PVDG system) until the circuit breaker limit of 80 A is reached. For this example, the limit was reduced to 75.65 A to accommodate six 2.9 kWp PV modules or 17.4 kWp per property. However, if this limit is higher than the maximum capacity by roof space, then the latter is used. The scatter plots for maximum voltages and currents are plotted in Figure 4.

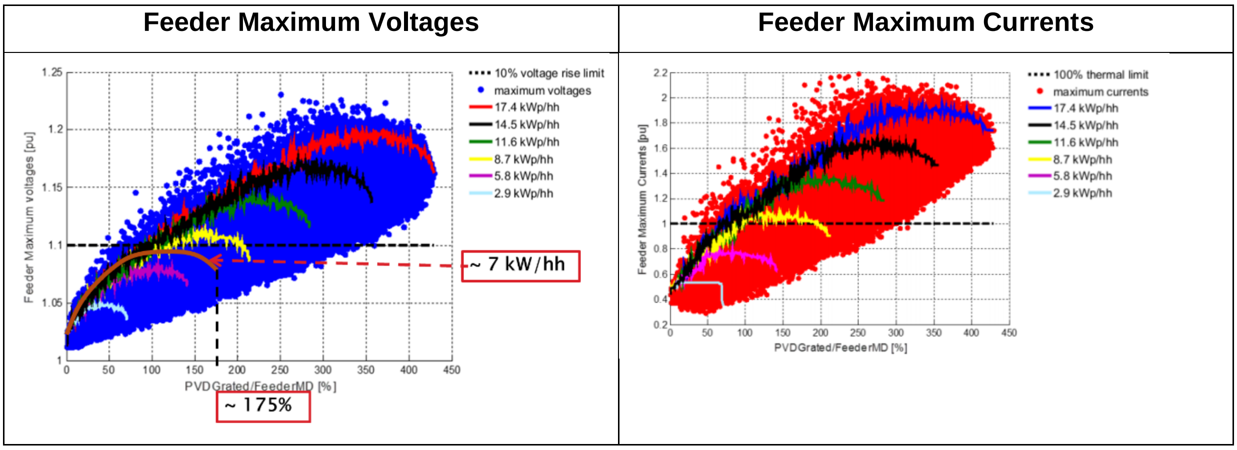


Figure 4: Practical limits of installed capacity

Looking at the marked 5% risk lines of maximum voltages, a common trend is observed. The envelope of voltages starts off with a positive correlation with PVDG penetration. The trend increases almost linearly until it approaches the 'filling' penetration (for an imposed constraint) and the trend of high voltages starts to decrease because the extreme placement combinations reduce as the feeder fills. For the full feeder, the variable random unbalance between PVDG module disappears. Moving from each penetration constraint to another, the feeders fill at different penetration values. The same applies to the envelopes of currents.

When the restriction is set to 2.9 kWp/hh, the maximum penetration of about 70% is achieved without any conditions of voltage or thermal violations. Increasing the uptake limit to 5.8 kWp/hh achieves an increased penetration of about 140% also without any violations. However, the limit of 8.7 kWp (~50% of the circuit breaker limit) introduces violations both for voltage and thermal conditions. Nonetheless, the proportion of voltages and currents above the regulatory limits is very low, and so is the extent of the violations.

As the uptake limit is further relaxed, the density of voltages and currents above the limits increase. For all cases above the 8.7 kWp limit, the allowable PVDG penetration without violations is between 65 and 70%.

From the results obtained for this particular feeder, it can be seen that a limit between 5.8 kWp (2 PVDG systems) and 8.7 kWp (3 PVDG systems), of about 7 kWp, would achieve penetrations up to 175% with 0% chance of violation (based on a 5% risk). Accordingly, the recommended uptake limit per household, avoiding mitigation measures or network reinforcement costs, for this feeder would be 7 kWp/household. However, the plots in Figure 4 for the 8.7 kWp case (yellow trace) also show that a penetration level of up to 210% is achievable with minimal mitigation measures; the latter being as a result of the minimal extent of violation (magnitude of violation voltage and currents, and the density or chance of occurrence).

5 Conclusions

The following can be concluded from the study:

a) Roof space exceeds the capacity of feeders, i.e. the City of Cape Town will run out of wires, long before all rooftops are covered with PV systems.

b) Limiting households to about 7 kW/household (for a single phase 80A customer breaker) increases the overall hosting capacity of the network. This is more than the NRS limit of 4.6 kW/household.

c) Voltage rise limits on active feeders must consider correlated voltage rise on MV feeders:

  i) 45 – 60% PV penetration if 7% LV voltage rise is allowed (limiting LV voltage rise to 7% above nominal; allows for correlated MV voltage rise of 3%)

  ii) 10 – 20% PV penetration if only 4% LV rise is allowed

d) Some passive feeders are already overloaded and not all DG alleviates overloading, but it depends on its location:

  i) Thermal limits on PV depend on the margin of the passive feeder

  ii) Every proposed installation would have to be studied before approval is granted.

6 References

[1] M. Altin, E. U. Oguz, E. Bizkevelci, and B. Simsek; Distributed generation hosting capacity calculation of MV distribution feeders in Turkey, in Innovative Smart Grid Technologies Conference Europe (ISGT-Europe), 2014 IEEE PES, 2014, pp. 1–7.

[2] A Steyn, A Rix; Investigation into the effects of distributed PV generation on electrical distribution grids: A Cape Town residential network case study, 2019.

[3] M. Dekenah and S. Heunis, "A load profile prediction model for residential consumers," *Energize,* pp. 46-49, 2010.

[4] Stellenbosch University, University of Cape Town, Cape Peninsula University of Technology, City of Cape Town and Eskom Distribution Western Cape, Potential PV Penetration study in the Western Cape, Work Package 2 Final Report, PV Uptake Potential: Technical Performance Analysis, 2018