Congo Epela Project

Village Site Mapping in ETDs and Mini-Grid Modelling, with Population and Demand Update for Epela Platform

Gregory Ireland (M.Sc.)
Avia Linke (M.Sc.)
Catherina Cader (Ph.D.)

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1. Introduction

This work falls under the "Congo Epela Project" in which researchers are working with partner organisations to support electricity access planning in the Democratic Republic of Congo. Alongside this building energy system modelling, they are also improving the Congo Epela online visualisation platform, updating data and producing case studies on decentralised power supply options at local level. The project is the third phase of an ongoing project in which the RLI has already been involved since November 2020. The RLI is part of a project consortium that works with numerous local actors including national and local government, civil society representatives and the private sector. The project is funded by a grant from the American Jewish World Service "11th Hour Project" fund. The aim of this program is to raise awareness about climate change, fair resource management and use, and the promotion of modern, sustainable renewable energy sources.

In this report, case studies on electrification with mini-grids and detailed site mapping have been conducted. The RLI team has prepared four case studies on electrification with mini-grids for several locations in the DRC that reside in ETDs with mining royalties that could be directed to electrification projects. The study results help to make information from the visualisation platform and its connections with real electrification measures more understandable. As part of the studies, we have, for example, identified and prioritised locations, prepared detailed GIS site maps of buildings and economic activities, and techno-economic optimisation of mini-grid configurations based on renewable energy potentials and estimated demand profiles, and incorporated on-site data collection activities for several villages that were possible to be visited by project partners. They take into account combinations of energy supply options such as solar PV, battery storage, diesel backup systems, and hybrid systems combining several of these options together.

In parallel, we made improvements to the previous cluster-based national population and demand models used in the Congo Epela platform electrification planning platform. This included current and future population data updates with custom calibration possible for each of the 26 DRC provinces with customizable population totals. Demand updates were also made to the heavy industry sector including more detailed mining demand estimations in the Katanga region using new projections from related research, and heavy industrial demands now also allocated to several additional locations.

This report summarizes and explains the used methodology and the results of our work. It starts with an introduction, then the second section describes the study's approach and methodology, then results are presented in the third section, and finally, the report ends with discussions and conclusions.

Model input and output files including techno-economic assumptions, GIS mapping data, hourly solar generation profiles, as well as full model output breakdowns and hourly time series files, scripts and code, and spreadsheet customization tools are provided separately to the report.

2. Methodology

The energy system modelling methodology adopted in this pre-feasibility study is summarised in Figure 1 below and includes the five main sections of "Data Collection and Literature Review", "Remote Mapping", "Solar PV Potential Analysis", "Demand Modelling", and finally "Energy System Optimisation" (Figure 1). Each of those methods are described in this chapter.
This full process is carried out for four remote villages using combinations of data collected from satellite imagery, literature review, and field visits.

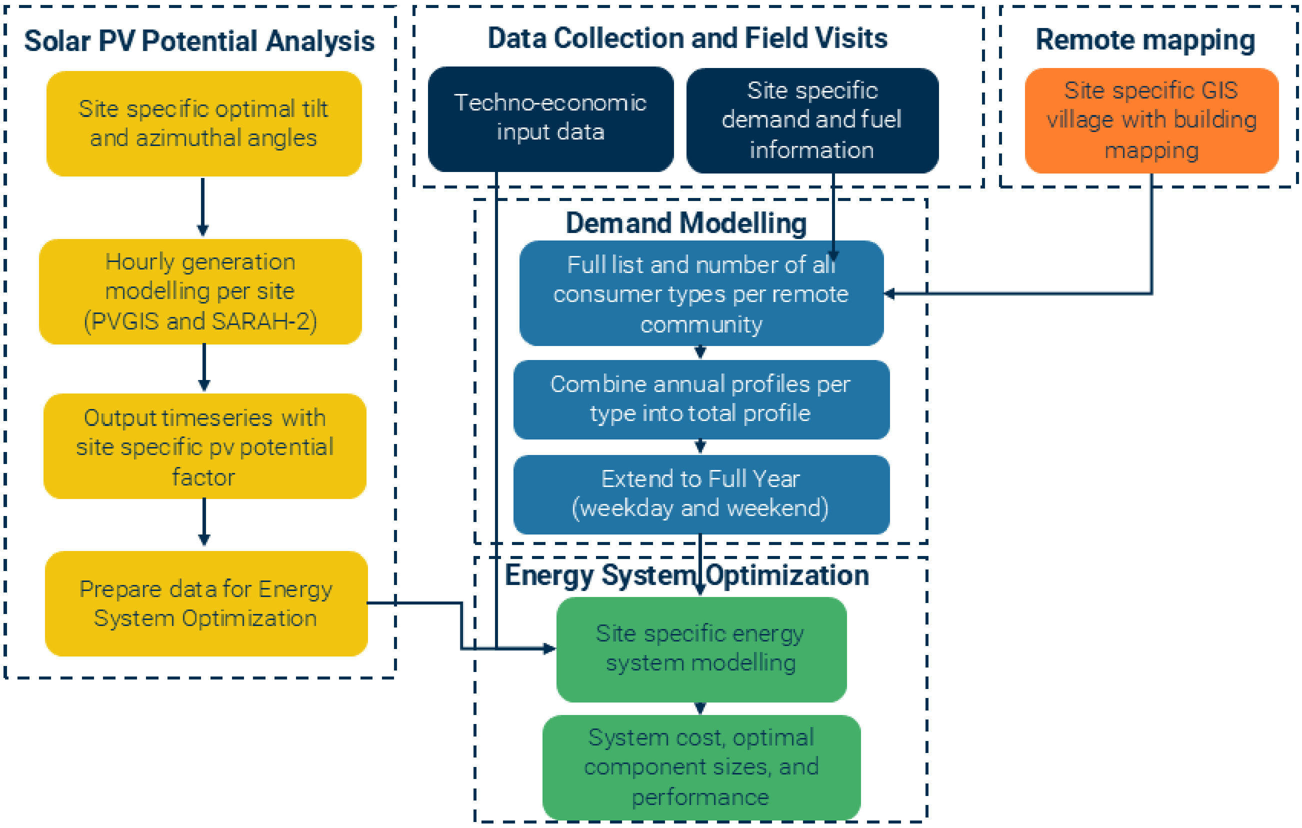


Figure 1. Overview of modelling methodology for remote villages

2.1 Data Collection and Field Visits

This subsection outlines the methodology employed for collecting data, conducting literature reviews, and performing field visits during the research project.

Field visits played a crucial role in obtaining accurate information about electricity consumer types and demand patterns in the villages studied. During these visits, a comprehensive list of all expected electricity consumer types in each village was compiled, along with the total number of each type. Any unclear or ambiguous building classifications were investigated and clarified, including remote mapped buildings that were assessed to determine their energy demand potential. Special attention was given to agricultural/animal enclosures, toilets, non-energy activity structures, concealed buildings under trees, and unfinished buildings under construction.

The type of energy consumer expected at each building location was identified, focusing on enterprises, public services such as health centres or schools, places of worship such as churches, and other relevant consumer categories. For villages that lacked validated site-visit data, recent data from GRID3, which mapped schools, churches, and health centres in the Democratic Republic of Congo (DRC), was used to determine the totals of these specific customer types. For other consumer types, assumptions or estimates were made based on satellite-based mapping, typically classifying larger buildings as non-household users. Where possible, relative proportions of certain enterprises to households from available site visits were used to estimate user numbers in unvisited sites.

2.2 Remote Mapping and Site Selection

Our previous work has shown that in many areas across the DRC mini-grids would be the most cost-effective option to electrify a population group. More detailed modeling of a sample of mini-grids, for instance in villages where our local partners engage in partnership, makes planning more concrete, easier to grasp, and relevant for investors and policy makers.

Key aspects considered for site selection for further mapping and modelling were the following:

- They are located in ETD's with mining royalties and an interest in mini-grid development
- In general, the sites have been chosen to maximize their economic, political, and social applicability to support the overall viability of a potential mini-grid development
- The sites are potentially accessible for site visits for further data collection if chosen for modelling, and also more accessible for eventual project development rather than very deep rural areas.
- The villages are feasible to fully manually map all buildings remotely in high detail from satellite imagery with the project resources and time available (i.e. not too many buildings)
- Ideally sites are selected in the ETD for further mapping/visit/modelling where the chief of the ETD is believed to live within the site themself (discovered where possible from communication with local partners)
- There are enterprises expected to be present that could both be income generating activities that could improve potential future project socio-economic outcomes and could also potentially be economically interesting for project developers as the enterprises could form "anchor loads" in a mini-grid improving financial viability a potential project

Spatial mapping, e.g. on OpenStreetMap (OSM)[1] of houses and/or geotagging of defined customer groups is a first step to support a detailed site assessment. Based on that and the knowledge gained from the surveys during field visits in terms of projected demand, detailed system configurations can be calculated to identify the optimal solutions and evaluate their performance alongside defined key performance indicators. As some sites of interest were not yet available in OSM, a detailed mapping of several sites has been conducted. Here, we describe the method applied for this, which uses available satellite data as input, QGIS[2] and JOSM[3] as open-source software products and OSM as medium to publish the digitized building footprints under the open OSM license and compliant to OSM standards.

[1] https://www.openstreetmap.org
[2] https://qgis.org
[3] https://josm.openstreetmap.de/

For the mapping, Google Satellite imagery has been used as base imagery. By using the Digitizing and Shape Digitizing toolbars the buildings have been digitized and added to a new layer. Shadows of buildings have been considered to digitize the correct share as well as trees, where buildings footprints must be estimated sometimes, if tree cover is dense. The OSM key “building” will be added to each feature in the attribute table. The file was then saved in a .geojson format which will be uploaded to JOSM in the next step. In this software it will be converted to an .osm file format.

The next step requires the downloading of the actual OSM representation of that site before the conflation tool is used to prevent duplicates and avoid ambiguities. Once this was done the validation tool was applied to avoid general errors e.g. in the attribute table or the geometry of the mapped objects.

The last step required here is the upload to OSM for which a registration and log in to OSM is required. In addition to the mapping of buildings as input for the demand modelling also the boundary shapes of the villages are adapted to reflect the actual spatial coverage of the site.

2.3 Solar PV Potential Analysis

An analysis of the potential for photovoltaic (PV) solar energy generation was conducted in several steps for each modelled village location to provide the key PV energy generation performance data for use in the energy system modelling and optimization step. The solar generation timeseries are created for each village combing all estimated input data values and using the PVGIS[4] (v5.2) API with SARAH-2 derived satellite data, and the specific location of each site. This result takes the form of an hourly timeseries representing an entire year (8760 hours) of expected solar PV generation at each specific location that takes into account the different weather conditions in each location over the year and the latitudes of the locations which affects the relative sun positions over the year. No specific limitations for the size of the solar arrays were included in the modelling and the energy system optimization is free to chose any size of solar PV array as satellite based investigations determined that space limitations for building a solar PV system would not be expected. Details on which parameters were used and set to which values in the PVGIS API are listed in Table 4 later in that section. The solar PV timeseries results (.csv) for all modelled villages are provided along with this report.

2.4 Demand Estimation and Modelling

A full year of hourly typical electricity demand profiles was developed or obtained for every consumer type included in the study. For household demand, survey-based bottom-up household demand profiles created with RAMP[5] and energy surveys in six DRC provinces from Phase 2 of the project were utilized. The same estimated wealth classification for each village was applied, matching the Phase 2 modelling approach for consistency. RAMP modelling from the Enershelf project was employed for different health centre types. Profiles from the PeopleSuN project were used for various enterprise consumers. For churches, schools, and other energy-intensive applications such as agricultural milling, profiles were created using literature research from the PeopleSuN[6] and CP-Nigeria[7] projects.

[4] https://joint-research-centre.ec.europa.eu/photovoltaic-geographical-information-system-pvgis_en

[5] F. Lombardi et. al, RAMP: stochastic simulation of user-driven energy demand time series, Journal of Open Source Software (2024).

[6] https://www.peoplesun.org/

[7] https://community-minigrid.ng/en/

Finally, a total village electricity demand profile for each modelled site was created by multiplying and combining the relative amounts of each typical demand profile multiplied by the expected number of those consumer types. This process was carried out using a spreadsheet where consumer numbers could be customized, but the typical annual hourly demand profiles for each consumer type remained fixed. Following this methodology, demand profiles for each village were prepared and ready for use in the subsequent energy system optimization step.

This comprehensive approach ensured a thorough understanding of electricity demand patterns across various consumer types in the studied villages, providing a solid foundation for further analysis and planning.

2.5 Energy System Optimization

All of the previous steps and data sources are then combined into an energy system optimisation tool named offgridders[8] (based on the oemof framework – "open energy modelling framework") that is used to simulate the various system configurations and scenarios developed. The model incorporates the potential solar PV generation from the village locations, along with the energy demand, to create an optimized system that balances energy supply and demand over every hour of the year. The tool simulates each system configuration over a full year of 8760 hours, with the objective of achieving the minimum total system cost over the lifetime of the system. The goal was to find the most cost-effective solution that could reliably meet the energy needs of the villages to achieve electricity access through solar mini-grids.

2.6 Study limitations and caveats

This pre-feasibility study for the electrification of four remote villages in the Democratic Republic of Congo using PV-diesel and PV-diesel-storage mini-grids has several important limitations and caveats that should be considered:

One major limitation is the absence of economies of scale considerations for different mini-grid sizes. Larger systems typically benefit from reduced costs per unit of capacity, which may alter the economic viability of certain configurations. This oversight means that our analysis may underestimate the potential benefits of scaling up mini-grid projects, particularly in larger communities where anchor loads can significantly impact the economics and affordability of the system.

Another critical aspect not accounted for in this study is location-specific logistics costs. These expenses can be substantial for remote locations far from main economic centres and may significantly impact the overall viability of mini-grid projects in isolated areas. Without incorporating these site-specific costs, our analysis may overestimate the feasibility of certain projects, especially those in extremely remote regions.

The study also focuses solely on PV, diesel, and battery storage technologies, limiting the scope of potential energy solutions. While also other renewable energies such as micro-hydroelectric power should be considered where feasible based on site location, other renewable energy sources like wind, biomass, CSP, and geothermal are not evaluated. This narrow focus may overlook viable alternatives that could be more suitable for specific contexts or locations.

[8] https://offgridders.readthedocs.io/en/latest/Home.html

Furthermore, the analysis assumes 100 % connection rates from year one, which rarely occurs in real-world mini-grid projects. Many rural mini-grids connect only a proportion of users, typically focusing on centrally located higher-income households and anchor loads such as health centres, schools, businesses, mines, manufacturing facilities, agricultural processing units, churches, community centres, and government offices. This assumption may lead to overestimation of immediate demand and revenue potential, potentially skewing the financial projections for the mini-grid systems.

Additionally, the study relies on simplified demand models that may not accurately reflect real-world variations in electricity usage patterns across different seasons, days of the week, and time of day. Without detailed measured site-specific information on solar irradiance and local electricity demand patterns, the study relies on general assumptions that may not hold for individual locations. This simplification could lead to inaccuracies in sizing the mini-grid components and predicting operational efficiency.

It's also worth noting that the study does not account for potential social and cultural factors that may influence the adoption and utilization of mini-grid systems. Local preferences, existing energy habits, and community dynamics can play a crucial role in determining the success of electrification projects, yet these aspects are not explicitly addressed in our analysis.

Lastly, the study does not delve into legal and regulatory challenges that may arise during the implementation and operation of mini-grid systems. Issues related to land acquisition, environmental permits, and compliance with national energy policies could significantly impact project timelines and costs but are not explored in depth here.

These limitations underscore the importance of conducting thorough site-specific studies and consulting with local experts before proceeding with actual system implementation. Real-world conditions may vary significantly from the modelled scenarios, potentially affecting the feasibility and optimal configuration of mini-grid systems in specific villages. It is essential to recognize that each village presents unique challenges and opportunities, necessitating a tailored approach to electrification that goes beyond the generalized findings presented in this pre-feasibility study.

2.7 Summary of Key Input Data

Scenarios for Each Remote Site

Our energy system optimization study focuses on four remote sites: Kapanda, Mimbilu 1, Debungi, and Mamfu/Mamfwe. These locations present varying energy demands and geographical characteristics, necessitating tailored scenario analyses for each site. Our modelling approach considers three main system configurations: PV + genset minigrid, PV + genset + storage minigrid, and PV + genset minigrid.

The Kapanda site, located at (-10.48825, 25.63729), has the smallest energy demand among the four sites. Its peak demand reaches 28 kW, with a total annual consumption of 102 MWh. We modelled three scenarios for this location, considering different fuel prices (1.2 $, 1.8 $, and 2.4 $ per litre) and maximum demand shortage allowances (0 %, 5 %, and 10 %). These variations allow us to assess the impact of fuel costs and reliability requirements on the optimal system design.

Mimbilu 1, situated at (-11.73495, 27.34502), presents a significantly higher energy demand profile. Its peak load reaches 134 kW, with an annual consumption of 514 MWh. Similar to Kapanda, we applied the same range of fuel prices and demand shortage allowances to evaluate the sensitivity of the optimized solutions to these variables.

Debungi, located at (-6.28014, 23.31696), exhibits the highest energy demand among all sites studied. With a peak load of 336 kW and an annual consumption of 1,343 MWh, this location requires careful consideration of system capacity and configuration. Again, we modelled scenarios with varying fuel prices and demand shortage allowances to identify the most cost-effective and reliable solutions.

Lastly, the Mamfu/Mamfwe site, positioned at (-10.65565, 25.70321), falls between Kapanda and Mimbilu 1 in terms of energy demand. Its peak load is 51 kW, with an annual consumption of 198 MWh. We applied the same methodology as the other sites, examining the impacts of different fuel prices and demand shortage allowances on the optimized energy systems.

Across all sites, our modelling approach consistently evaluates the performance of PV + genset minigrid and PV + genset + storage minigrid configurations under various economic and reliability constraints (see

Table 1). This comprehensive analysis enables us to compare the benefits of incorporating energy storage and to determine the optimal balance between renewable energy generation and conventional power sources for backup systems for each remote location. By considering the unique characteristics of each site and the potential impacts of future fuel price fluctuations and reliability requirements, our study aims to provide actionable insights for energy planners and policymakers seeking to develop sustainable and resilient energy systems for these remote communities.

Table 1. Scenario summary of key variables used for energy system optimisations

Location	System Configurations	Demand	Sensitivities
Kapanda - Luilu ETD (-10.48825, 25.63729)	PV + genset minigrid PV + genset + storage minigrid PV + genset minigrid	Peak: 28 kW Total: 102 MWh per year	Max demand shortage allowed: 0 , 5 & 10 % Fuel price: 1.2, 1.8 & 2.4 $/litre
Mimbilu 1 - Kaponda ETD (-11.73495, 27.34502)	PV + genset minigrid PV + genset + storage minigrid PV + genset minigrid	Peak: 134 kW Total: 514 MWh per year	Max demand shortage allowed: 0 , 5 & 10 % Fuel price: 1.2, 1.8 & 2.4 $/litre
Debungi - Kakangayi ETD (-6.28014, 23.31696)	PV + genset minigrid PV + genset + storage minigrid PV + genset minigrid	Peak: 336 kW Total: 1,343 MWh per year	Max demand shortage allowed: 0 , 5 & 10 % Fuel price: 1.2, 1.8 & 2.4 $/litre
Mamfu/Mamfwe - Luilu ETD (-10.65565, 25.70321)	PV + genset minigrid PV + genset + storage minigrid PV + genset minigrid	Peak: 51 kW Total: 198 MWh per year	Max demand shortage allowed: 0 , 5 & 10 % Fuel price: 1.2, 1.8 & 2.4 $/litre

Key techno-economic input assumptions for energy system optimization modelling

A summary of the most important techno-economic input parameters is included in the table below (Table 2). Not every parameter is included to improve report clarity. The complete full list of all techno-economic input parameters is shared in the attached excel input sheets.

Table 2: Summary table of most significant input parameters. All parameters included in attached model files.

Parameter	Value	Unit	Link/Source
Solar PV – Investment Cost	441	$/kW	https://www.esmap.org/mini_grids_for_half_a_billion_people_the_report
Solar PV – O&M Cost	10	$/kWp/a	https://www.esmap.org/mini_grids_for_half_a_billion_people_the_report
Inverter and EMS	415	$/kW	https://www.esmap.org/mini_grids_for_half_a_billion_people_the_report
Storage – Investment Cost	314	$/kWh	https://www.esmap.org/mini_grids_for_half_a_billion_people_the_report
Storage – O&M Cost	10	$/kWh/a	https://www.esmap.org/mini_grids_for_half_a_billion_people_the_report
Storage – Round-Trip Efficiency	92%	percentage	https://www.esmap.org/mini_grids_for_half_a_billion_people_the_report
Diesel Genset – Investment Cost	359	$/kW	https://autolubumbashi.com/product/groupe-electrogene-12kw/
Allowed Shortage	[0, 5, 10]	%	Assumption - to test allowing the option of not serving between 0 and 10% of the total annual demand. Can significantly reduce required system sizing and costs.
Fuel Price – Thermal Generator	[1.2, 1.8, 2.4]	$/l	https://de.globalpetrolprices.com/Democratic-Republic-of-the-Congo/ (1.2 taken at date of model runs, others used as sensitivities)
Fuel – Energy Value	9.8	kWh/l	https://www.energie-lexikon.info/dieselkraftstoff.html
Fuel – CO2 Emission Factor	2.68	kgCO2eq/l	https://www.umweltbundesamt.de/sites/default/files/medien/1968/publikationen/co2_emission_factors_for_fossil_fuels_correction.pdf
Discount Rate	9.6%	percentage	https://www.esmap.org/mini_grids_for_half_a_billion_people_the_report
Project Economic Lifetime	20	years	Assumption. Typical guarantee period and economic lifetime of PV systems. Used in most PV energy system optimisations.

3. Results and discussion

3.1 Detailed village site mapping

As part of the identification of load centres and collection of input data for energy modelling, we carried out satellite image based manual remote mapping of selected sites across the DRC in ETDs with mining royalties. Sites were selected based on several characteristics, including the general economic and political viability of a mini-grid, the feasibility of manual remote mapping, the accessibility for site visits, the presence of enterprises and large. In close exchange with our partners we decided to map the sites depicted in Figure 2. In total 9 villages were mapped with all of their building data uploaded and verified on Open Street Maps (OSM), and of these 9 villages 4 villages were selected for detailed energy system modelling and optimisation as seen in the later sections of the report.

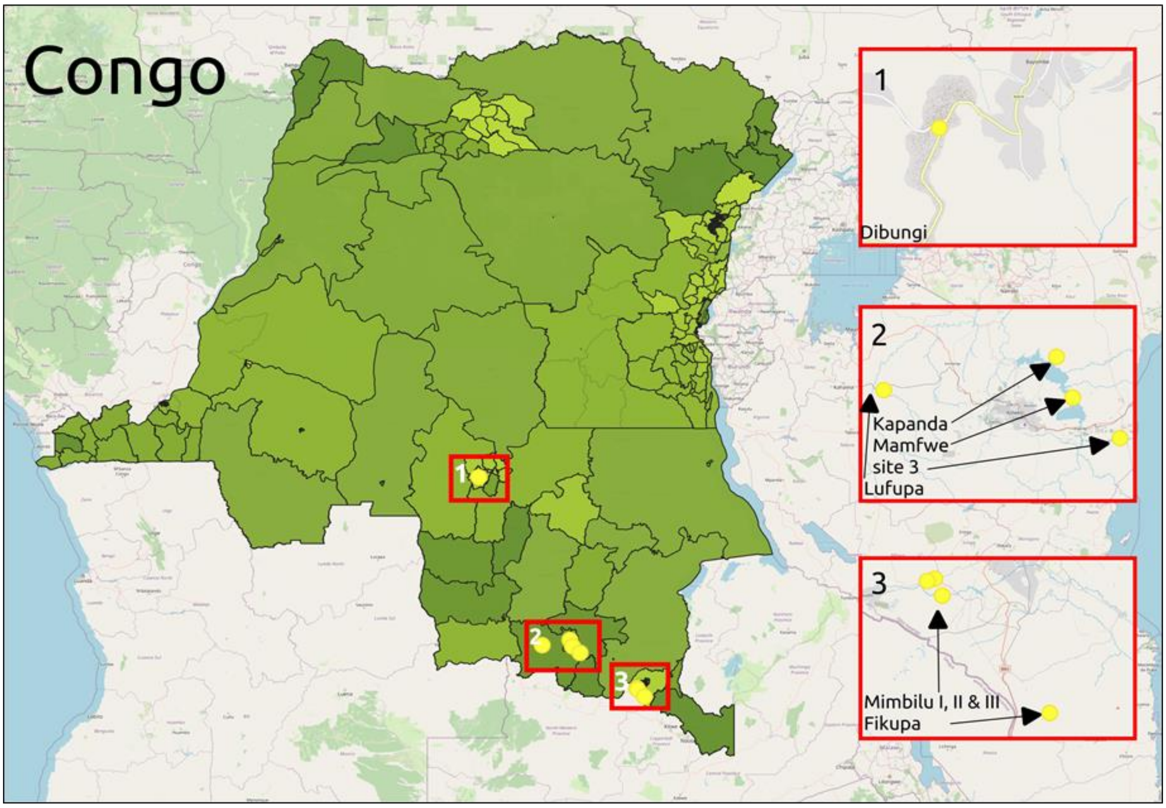


Figure 2 Overview of mapped villages sites and their relative locations within the DRC. Inset maps 1, 2, and 3 are included to show zoomed maps of the clustered villages.

The mapping efforts were split into 2 parts, and in the first part of the mapping process, we mapped four sites in the province of Lualaba, around the province's capital Kolwezi. The first site in this cluster is a village named Kapanda and is located at the northern shore of Nzilo lake, around 25 km to the northeast of Kolwezi (-10.487833, 25.637500). We were able to identify a total number of 373 buildings, of which 346 were "sure buildings" that we had very high confidence in, and the remaining 27 were "unclear buildings" that we were uncertain if they were in-fact buildings or if they were structures that were unlikely to have energy requirements such as toilets, storage, or animal enclosures etc. Kapanda was also the site where we had the best access to detailed information from a site visit field data collection from project partners, allowing us to identify uses of non-residential buildings. Kapanda was one of the 4 sites that was selected for further energy system modelling and optimisation given that we had on-site collected data for the village.

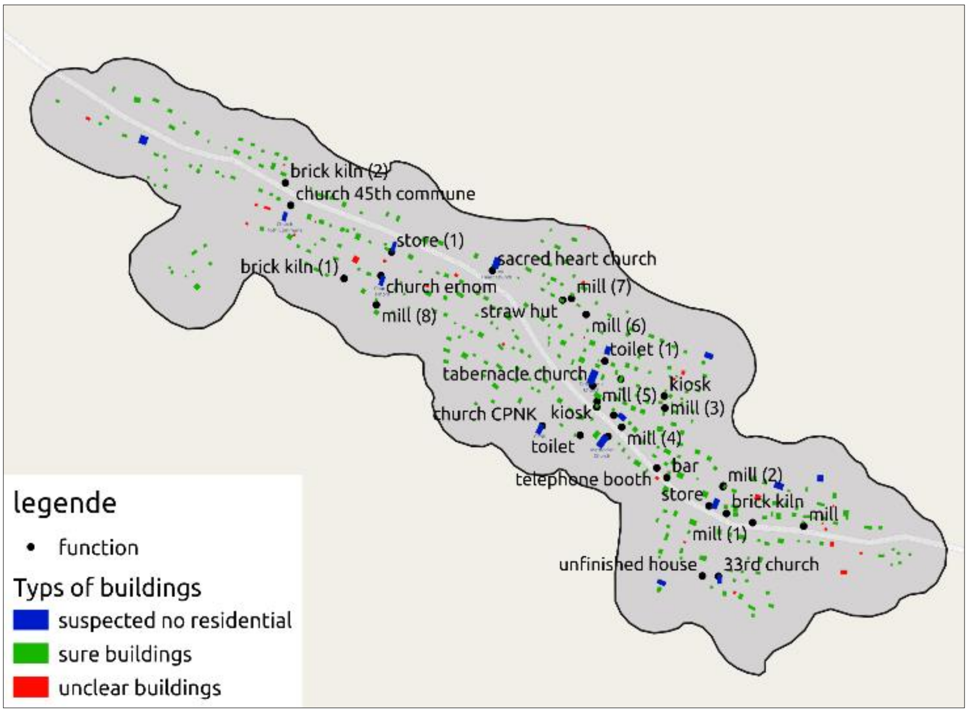


Figure 3: Map of Kapanda showing the identified buildings and overlaid field-visit data key points of interest

The second village called Mamfwe is located in the south of the first site (-10.655361, 25.702861), on the other side of the lake (Figure 4). It is located directly next to a power transmission line. It has a total number of 738 buildings, 654 could be identified with certainty, and 84 are uncertain. Mamfwe was selected for further energy system modelling as it was expected to be more accessible for future project development (on a reasonable quality road) compared to some of the other villages even though it has electricity transmission lines nearby and visible in the map.

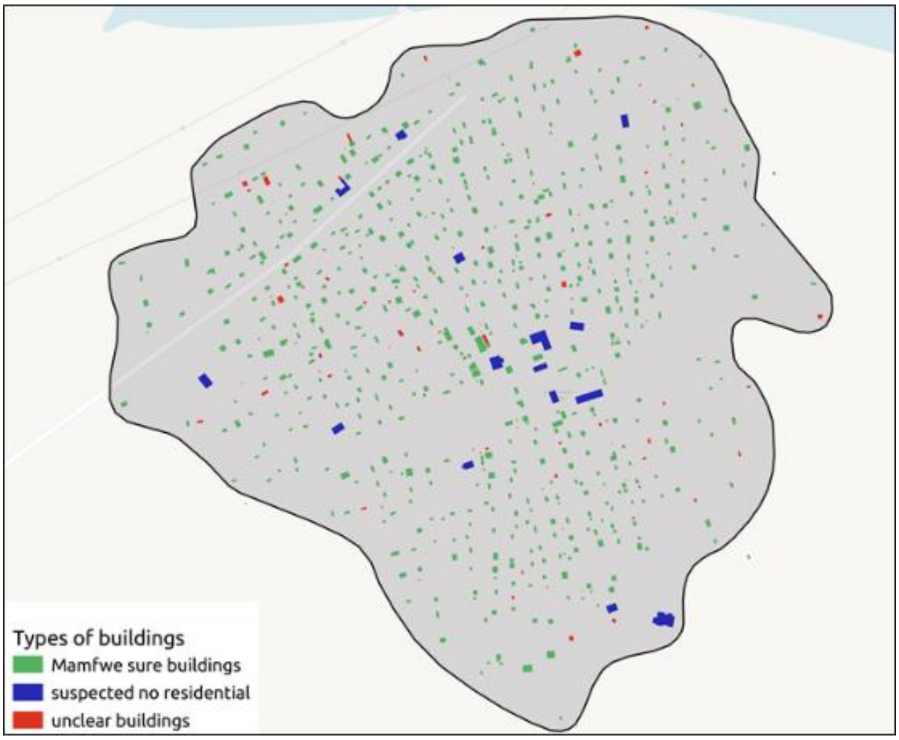


Figure 4: Map of Mamfwe showing the identified buildings and visible electricity transmission lines.

The third site is located around 40 km east of Kolwezi, near Kando River (-10.823222, 25.894722) shown in Figure 5, named by us as "site 3" as we did not know the village name. We encountered difficulties mapping the site due to a large number of very small buildings, leading to a higher share of unclear buildings. In total, 813 buildings were identified, 645 are certain and 168 unclear.

Figure 5: Map of "site 3" showing the identified buildings

The last village in the Lualaba province that was mapped was Lufupa, which is located in the west of Kolwezi (Figure 6). We could identify a total number of 541 buildings, including 492 certain ones and 49 unclear ones. The village is located on a railway line.

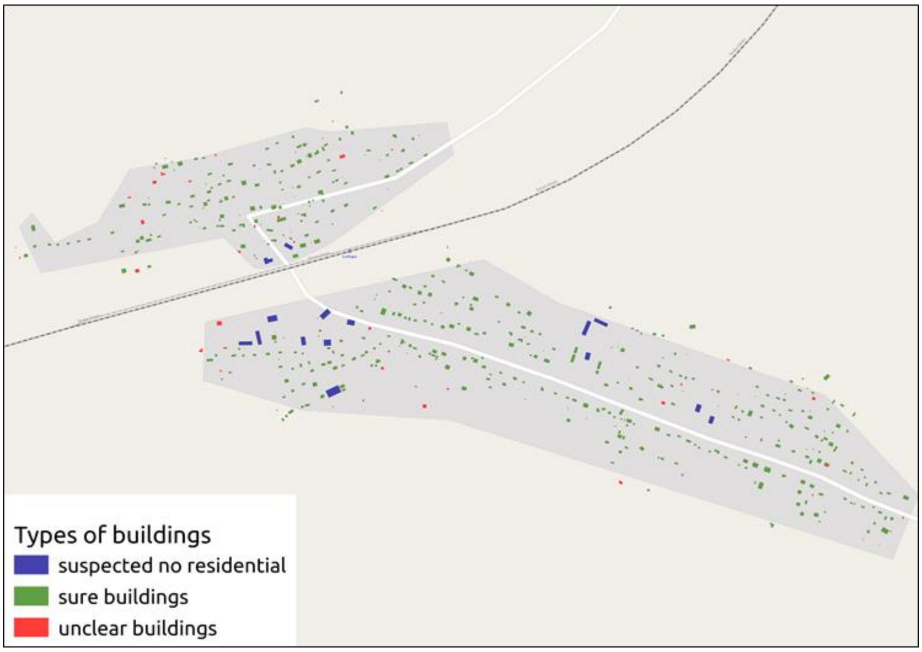


Figure 6: Map of Lufupa showing the identified buildings

In the second part, we mapped four additional sites in the province of Haut-Katanga in the south-east of the country. The first site in this cluster was a settlement called Fikupa (Figure 7). Fikupa has 1,130 buildings we can be certain about and 87 unclear ones, taken together totalling 1,241. It furthermore has a school and a medical centre already marked on OSM data.

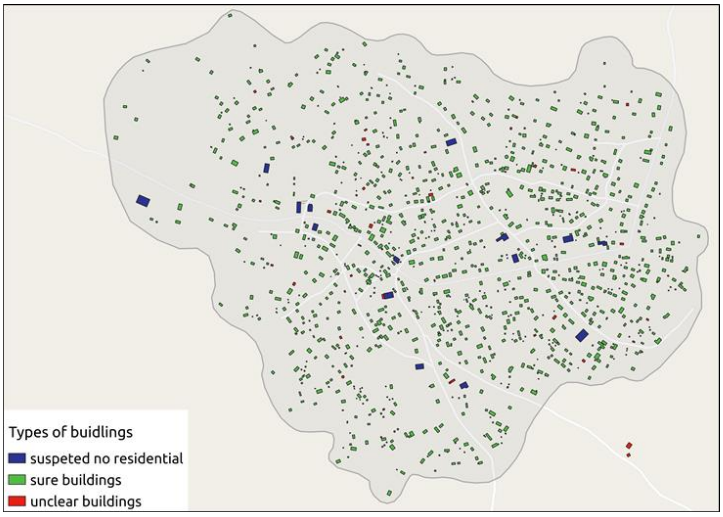


Figure 7: Map of Fikupa showing the identified buildings

Next, three different parts of the Mimbilu village were mapped (Mimbilu I, II, and III). In Mimbilu I, we identified 1,160 certain buildings, and 113 suspected ones, resulting in a total number of 1,273 (Figure 8). This village was visited by project partners with additional field data points of interest collected that were used in the demand profile modelling step. From personal communications with project partners and local contacts is expected that the chief of the ETD lives in Mimbilu III, however Mimbilu I is the largest village of the 3 and has the administrative offices located there, and was selected for further energy system modelling and optimisation.

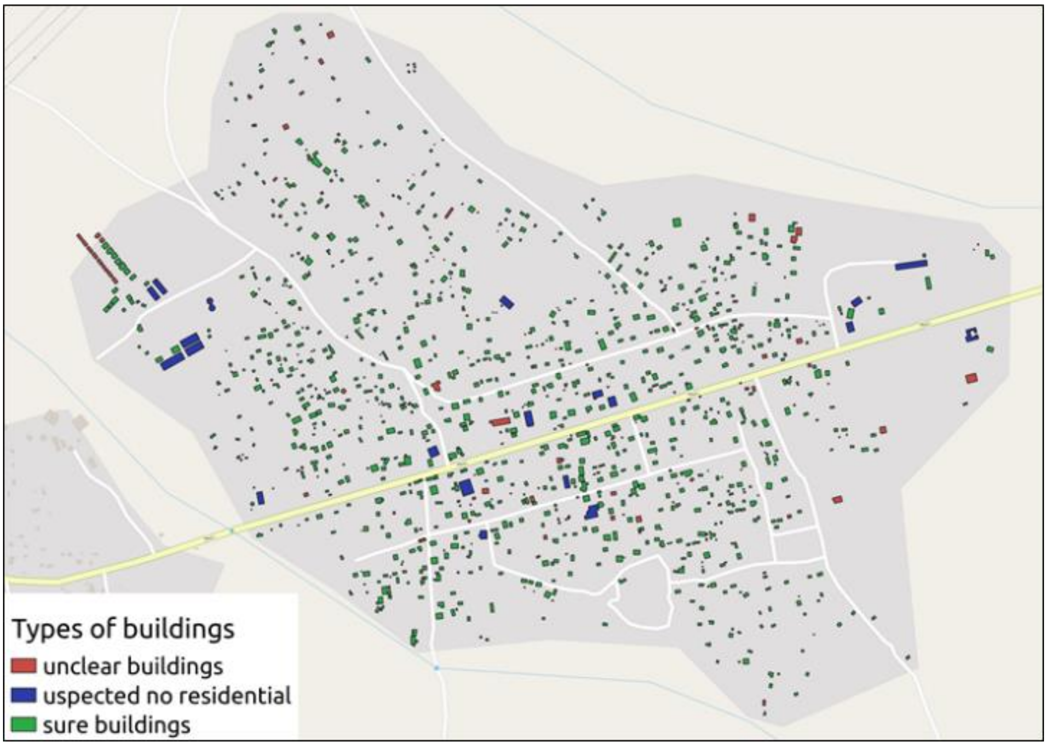


Figure 8: Map of Mimbilu I showing the identified buildings. Field visit data not shown in this figure.

Based on the buildings mapped, the shape of the Mimbili I village shown in OSM was adapted, since previous entries in OSM showed a significantly smaller outline of the built-on area (Figure 9). The figure also shows a demonstration of the "before and after" with no buildings mapped on OSM previously and now all buildings are mapped and included back into the open-source community for similar or related development efforts.

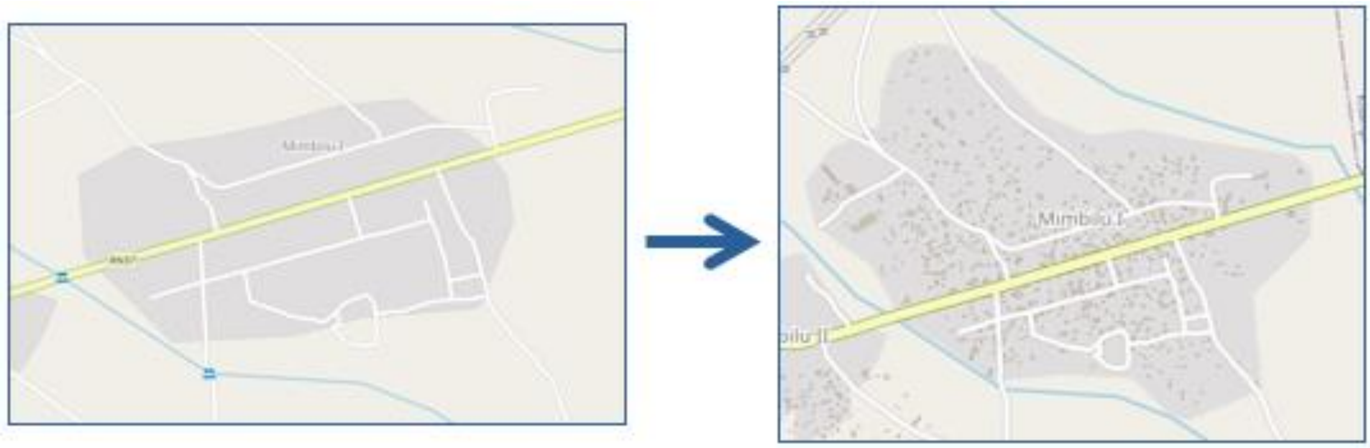


Figure 9: Changes in the outline and "before and after" on OSM of Mimbilu I

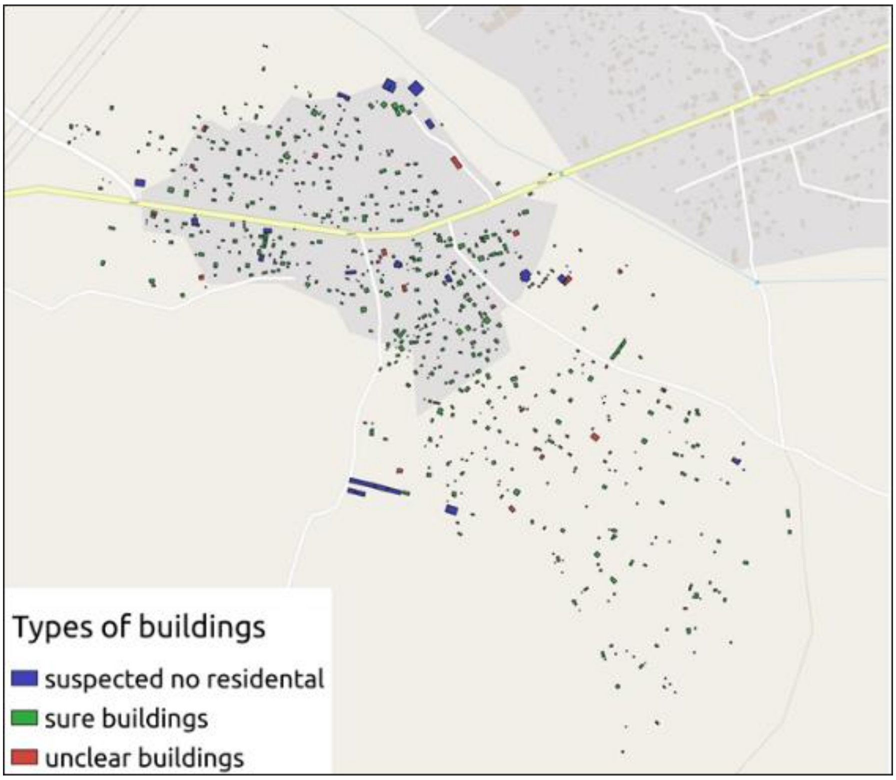


Figure 10: Map of Mimbilu II showing the identified buildings

The second site in Mimbilu counts 723 buildings, among which 601 are certain and 122 suspected buildings (Figure 10). When uploading the mapped buildings in OSM, the shape of the settlement that was shown did not match with the extent of the buildings we mapped, which was much larger. Thus, we assume that the site is growing fast and requires an updated boundary shape in OSM.

The last site in the cluster is also part of Mimbilu, but significantly smaller than the other two sites. It has a total number of 226 buildings, split into 195 certain ones and 31 unclear ones (Figure 11).

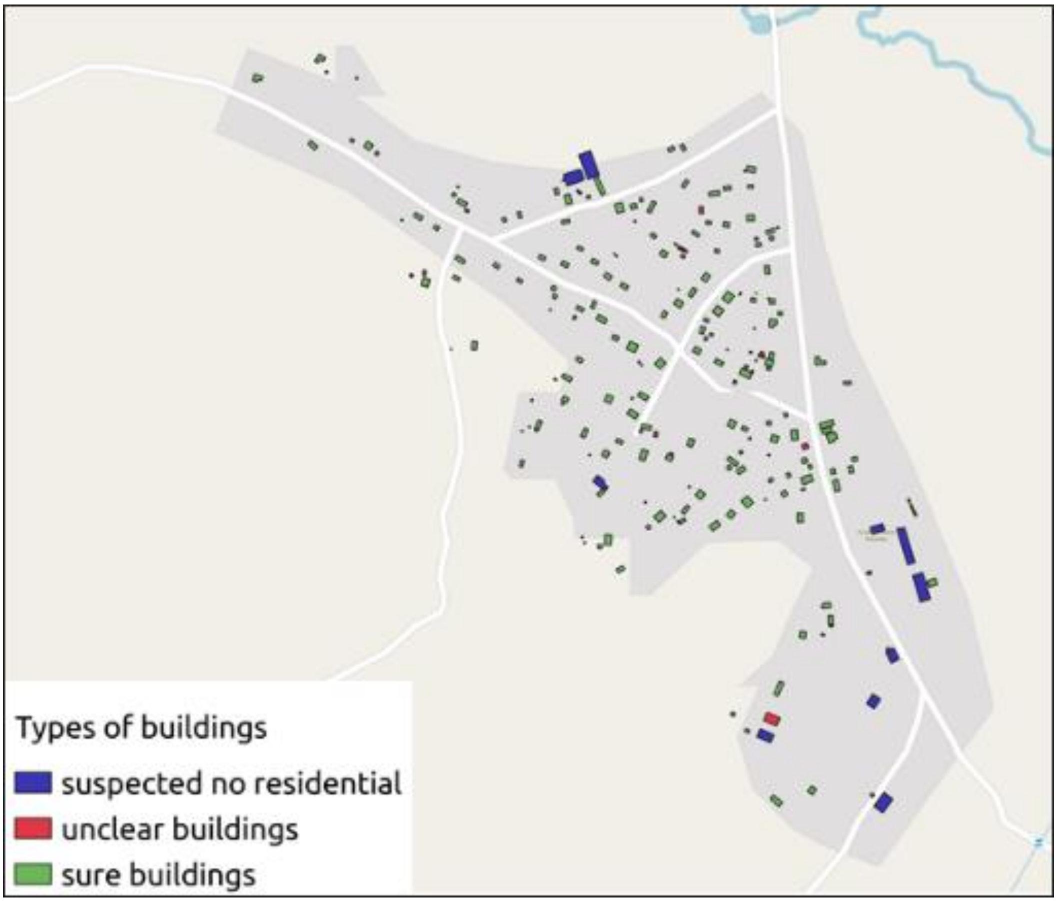


Figure 11: Map of Mimbilu III showing the identified buildings

Lastly, the village of Debungi in the province Kasaï-oriental was mapped (Figure 12). It was the largest site we mapped with 1,701 certain buildings, 204 unclear buildings, as well as several market buildings in the central market area, resulting in 1,956 buildings in total. Personal communications with project partners indicated that the chief of the ETD lives in Debungi, and Debungi was selected as one of the 4 villages with detailed energy system optimisation for mini-grid development.

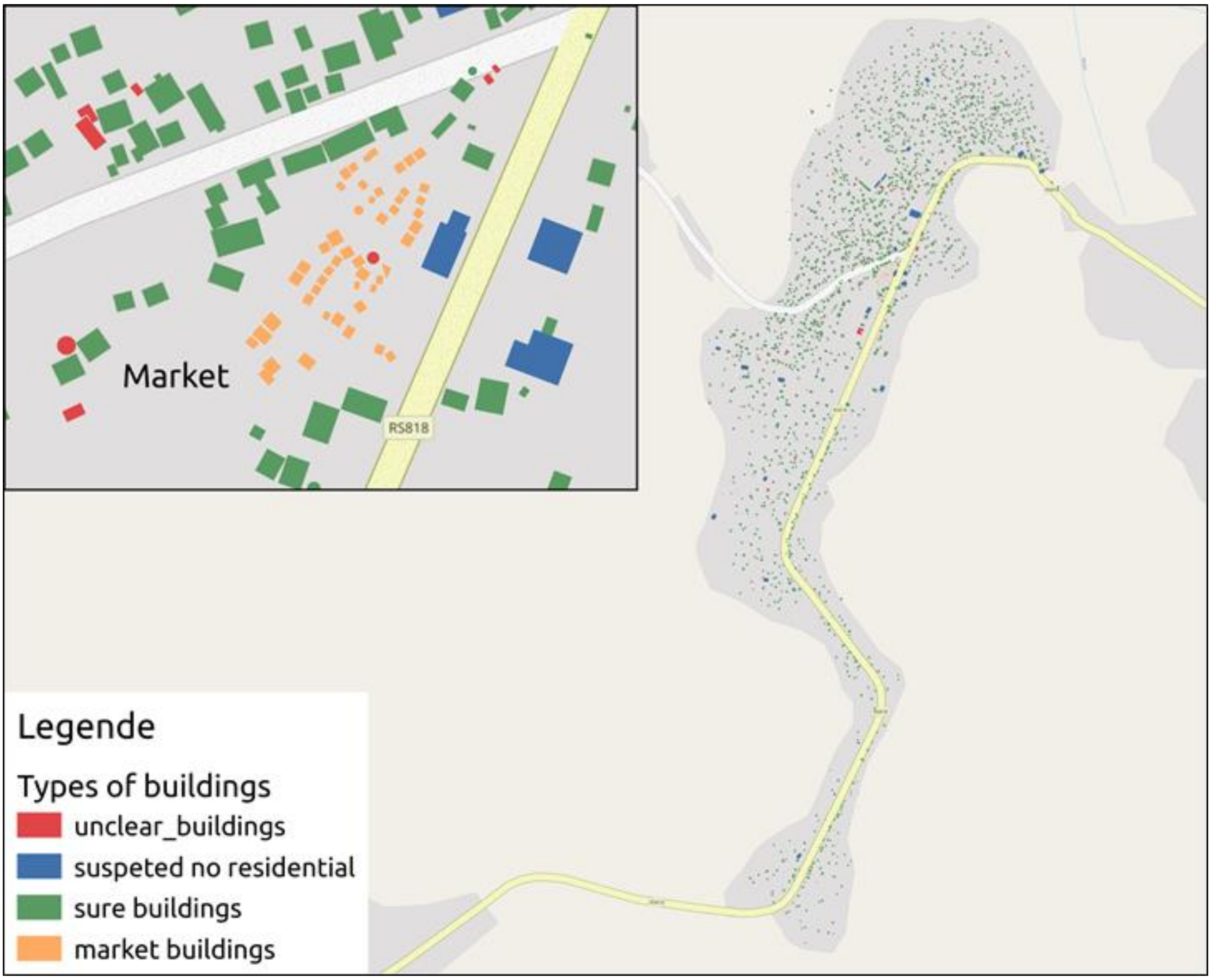


Figure 12: Map of Debungi showing the identified buildings, zoom on the marketplace in the top left corner

Overall, we mapped and published 2,465 buildings (2,137 certain ~~buildings~~ and 238 unclear buildings) in the three sites around Kolwezi mapped in the first part, and 5,344 buildings (4,787 clear buildings and 557 unclear ones) in the sites of second part.

3.2 Site-specific PV generation potential

Following the PV performance estimation and modelling approach described in the methodology section above, the key performance results for the 4 modelled villages are summarized presented below in Table 3. To demonstrate the typical solar production profiles of the 4 locations' full years of data comparatively to each other an annual heatmap of each location is shown in Figure 13 – the differences in total production can be seen between the sites with the dry season generally persisting in the middle of the year that was modelled. It can also be seen from the maximum in the colour scale legend that the maximum output capacity factor of a potential solar PV plant in any single hour typically peaks at roughly 80% which is typical for a system of this type in normal operating conditions.

Table 3: Modelled PV performance of each of the 4 village sites

Site Name	Location (lat, long)	Average PV Capacity Factor (%)
Kapanda	(-10.48825, 25.63729)	17.913
Mimbilu	(-11.73495, 27.34502)	19.057
Debungi	(-6.28014, 23.31696)	16.914
Mamfwe	(-10.65565, 25.70321)	18.026

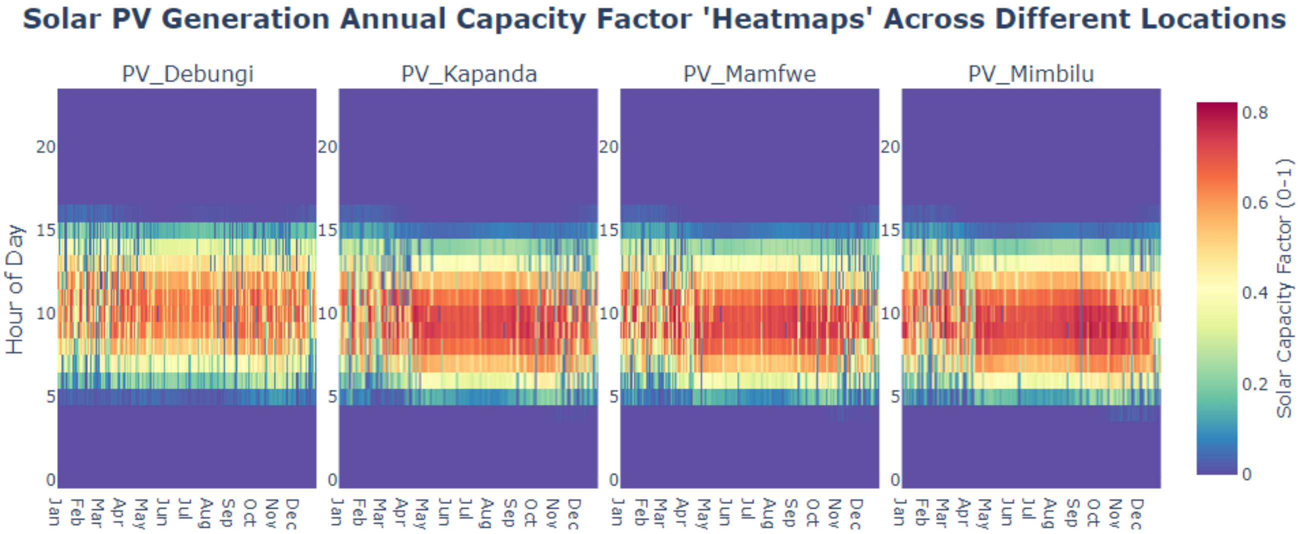


Figure 13:Solar PV generation annual capacity factor 'heatmaps' across all 4 modelled village locations showing location and seasonal trends and differences.

The solar PV timeseries results (.csv) for all modelled villages are provided along with this report. These timeseries are "normalized" with their values ranging from 0 to 1 in each timestep and are not the expected output of the sites after modelling and sizing with the energy system optimization as the model is free to choose any size of PV system that would be economically optimal in each scenario, sensitivity, or system configuration. This normalized timeseries and can be thought of as a timeseries representing the capacity factor of a potential PV site in each hour, or the kilowatt output expected in each hour if a 1kWp PV plant were to be installed at that location. In this form the average of the entire 8,760 hours timeseries will be the same as the average capacity factor.

In addition, several of the key input parameters used in the PVGISv5.2 API are also included in Table 4 below with additional details of their selection or typical default values.

Table 4: Summary of Parameters used in the PV potential and performance calculations for villages

Parameter	Value	Description
PVGIS Model version	5.2	Version of PVGIS used in the analysis. V5.2 was the latest available at the time of the study. Link: [PVGIS user manual - European Commission (europa.eu)]
Latitude	"per site"	Latitude of the location (in decimal degrees).
Longitude	"per site"	Longitude of the location (in decimal degrees).
System loss factor	14%	Additional other system losses as a fraction, including cabling, inverters, aging, dirt/soiling - not thermal, shading or storage based losses. (PVGIS v5.2 default 14% losses – typical for PV systems of this type).
Roof orientation angle	"optimized per site"	The azimuth, or orientation of the PV system, in the PVGIS system this is the angle of the PV modules relative to the direction due South. - 90° is East, 0° is South and 90° is West. This is optimized by the PVGIS system for each site, and is typically in most locations a value close to pointing "towards the equator".
Roof Tilt angle	"optimized per site"	The tilt angle of the solar panels relative to the ground. This is optimized by the PVGIS system for each site. Typically this value is close to the latitude degrees.
Mounting Place	"free field"	The location where the PV panels are mounted (building or free field).
PV Technology	"crystSi"	PV technology type (e.g., "crystSi" for crystalline silicon). Here only affects system performance and spectral characteristics, not cost.
Radiation Database	"PVGIS-SARAH2"	The satellite database used for the calculations to obtain solar radiation components, cloud coverage, windspeed, and ambient temperature (PVGIS-SARAH2).
Historical Data Year	2014	Historical year of satellite solar irradiation and weather data used for the PV simulation.

3.3 Demand profile creation for selected villages including field visit data

The process of determining electricity demand profiles for villages involves several steps of integrating satellite-based mapping data, field visit observations, data analysis, and demand profile combination modelling.

In combination with the satellite-based mapping and digitization, on-site field visits provide an improved understanding of energy needs in the village for identifying consumer types needed for quantifying demand. First, the types and quantities of expected electricity consumers are listed. This includes households, enterprises, public services such as schools and health centres, and places of worship. Any ambiguous structures (e.g., agricultural enclosures, toilets, or buildings under construction) are clarified for their energy requirements. For remote or unmapped buildings, energy demand is assessed based on expected use.

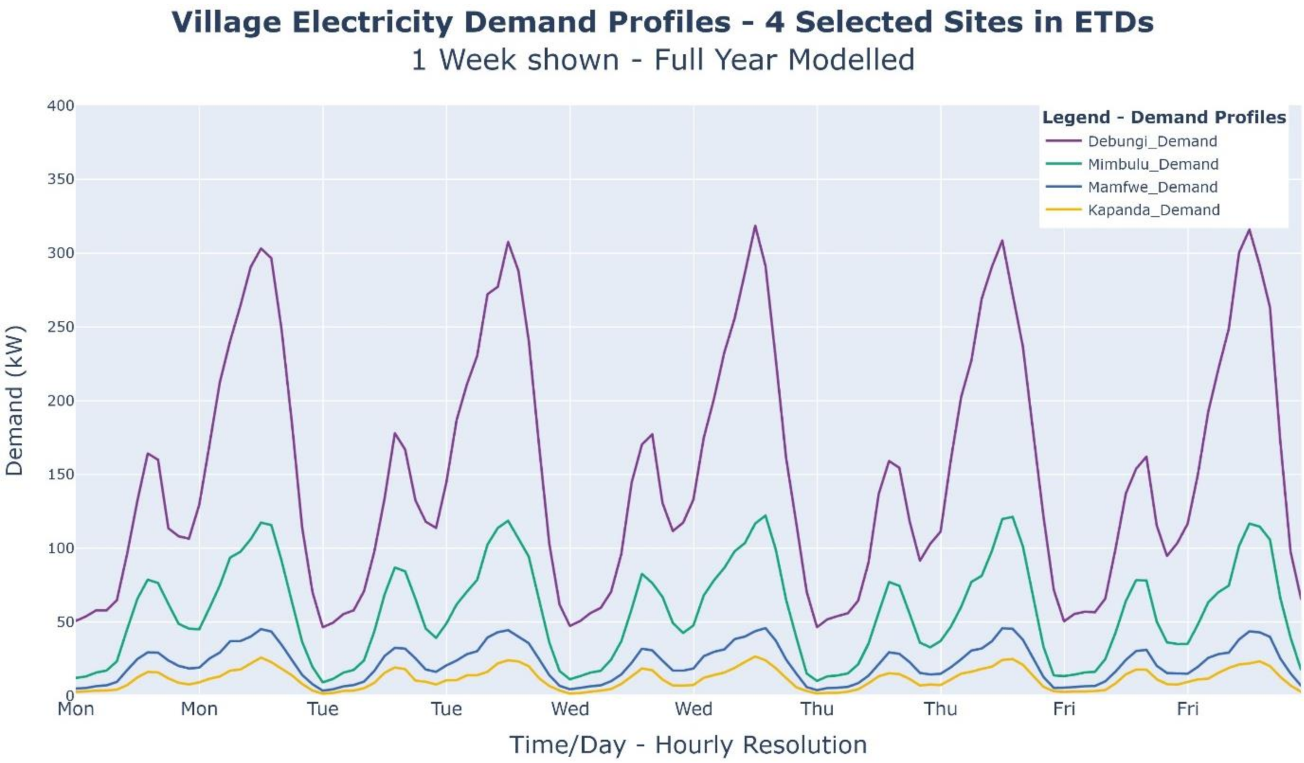
In cases where site-visit data is unavailable, alternative sources like GRID3 mapping for schools, churches, and health centres are used. Other consumer types are estimated from satellite data, often designating larger buildings as non-household users. When possible, proportions of consumer types from site visits are applied to estimate demand for unvisited sites.

Hourly electricity demand profiles are created or sourced for each consumer type over a full year. For households, survey-based bottom-up profiles developed during the previous Phase 2 of this project are used, ensuring consistency with the estimated village wealth classifications. For health centres, RAMP modelling from the Enershelf project provides tailored demand profiles. Enterprise consumer profiles rely on data from the PeopleSuN project, while demand for churches, schools, and energy-intensive applications like agricultural milling is derived from literature research, including findings from PeopleSuN and CP-Nigeria projects.

The final step involves aggregating the demand data for all consumer types in a village. This is done by combining the respective annual hourly demand profiles with the expected quantities of each consumer type. A customizable spreadsheet facilitates this process (shared with the report), allowing adjustments to consumer numbers while keeping the typical demand profiles fixed, allowing easy changes to the demand profiles without the need for detailed RAMP modelling or demand profile acquisition.

Once combined into a total electricity demand profile for the villages, the hourly demand profiles are ready for use in the energy system optimization modelling stage. Example weeks of the resulting hourly demand profiles for each of the 4 modelled villages, as well as demand summary statistics are included in Figure 14. The large differences in total sizes of the villages as well as different estimated levels of wealth (influencing consumption levels) results in large differences in the final 4 village profiles.

The data files with customizable consumer totals and typical profiles (.xlsx), building mapping files, site visit points of interest, and GRID3 supplementary facility data (.gpkg), as well as the final 8760 timestep hourly demand profiles per village (.csv) are shared along with this report. The original national scale cluster data is also available in (.gpkg) format with estimated wealth levels per village.



Site Name	Estimated Wealth (3 levels)	Demand Annual Total (GWh)	Demand Peak (kW)	Demand Minimum (kW)
Debungi	"High"	1.343	336.3	45.5
Mimbilu I	"Middle"	0.514	133.7	8.2
Mamfwe	"Middle"	0.198	51.0	3.1
Kapanda	"Low"	0.102	27.9	1.4

Figure 14. Modelled total electricity demand profiles (top) and summary statistics (bottom) for the 4 sites that were selected for more detailed energy system optimisation. The top timeseries figure shows 1 week of the modelled demand profiles although a full year of 8760 hours was modelled and used.

3.4 Energy Modelling Optimization Results

This section presents the results of our energy system modelling analysis for remote villages in the Democratic Republic of Congo. Our study focuses on hybrid PV-diesel-storage microgrid systems, examining their operation dynamics, optimal component sizing, and economic viability. We analysed various system configurations, including genset-only, PV+genset, and PV+genset+storage setups, considering different fuel prices and demand shortage allowances.

Our analysis covers four remote sites: Kapanda, Mimbilu 1, Debungi, and Mamfu/Mamfwe. For each site, we modelled electricity flow dynamics over both short-term (4-day) and long-term (365-day) periods to gain insights into the interaction between PV generation, battery storage, and diesel generator operation. These simulations provide valuable information on the effectiveness of hybrid systems in meeting energy demands while minimizing diesel usage and associated costs.

Key aspects of our analysis include:

1. Optimal system component sizing (PV capacity, battery storage capacity, etc.)
2. Initial investment costs for different system configurations
3. Operational aspects such as fuel use, renewable energy share, and overall system performance
4. Sensitivity tests on input variables like fuel prices and maximum allowed demand shortages

To present our findings comprehensively, we have included both tabular and graphical representations of the results. Table 5 summarizes all scenarios, configurations, and key input variables for easy reference. Table 6 provides a detailed breakdown of the most relevant results and configurations for each site, focusing on scenarios with a diesel price of $1.2/litre and no demand shortages allowed.

The electricity flow dynamics and storage state of charge (SOC) for the remote villages were modelled over both short-term (4-day) and long-term (365-day) periods. These analyses provide valuable insights into the operation of hybrid PV-diesel-storage microgrid systems for remote off-grid villages in the Democratic Republic of Congo. Short-term operation dynamics, as depicted exemplary for two sites in Figure 15, reveal regular daily cycles in electricity demand, peaking during morning and evening hours typical of rural usage patterns. Both sites show similar demand profiles, suggesting comparable energy consumption habits among these communities. Nevertheless, the total peak demands are not in the same range for both sites as Kapanda has less population than Debungi. PV generation peaks around midday, closely matching daytime demand but often exceeding it, particularly in Kapanda. This excess generation indicates the potential for additional energy storage or curtailment strategies. Battery storage effectively captures surplus PV energy during daylight hours and discharges primarily during evenings and early mornings when solar power is unavailable. The storage system demonstrates efficient load-shifting capabilities, aligning discharge periods with demand peaks outside PV generation times. Diesel generators play a minimal role, acting mainly as backup sources to maintain supply when PV and storage cannot meet demand. Long-term analysis over 365 days (see Figure 16) reveals seasonal variations in PV generation, more pronounced in Kapanda. Battery SOC displays substantial seasonal fluctuations, adapting to changes in PV availability and demand patterns. Diesel generator usage remains low throughout the year, primarily serving as a supplementary energy source during periods of insufficient PV output or storage depletion.

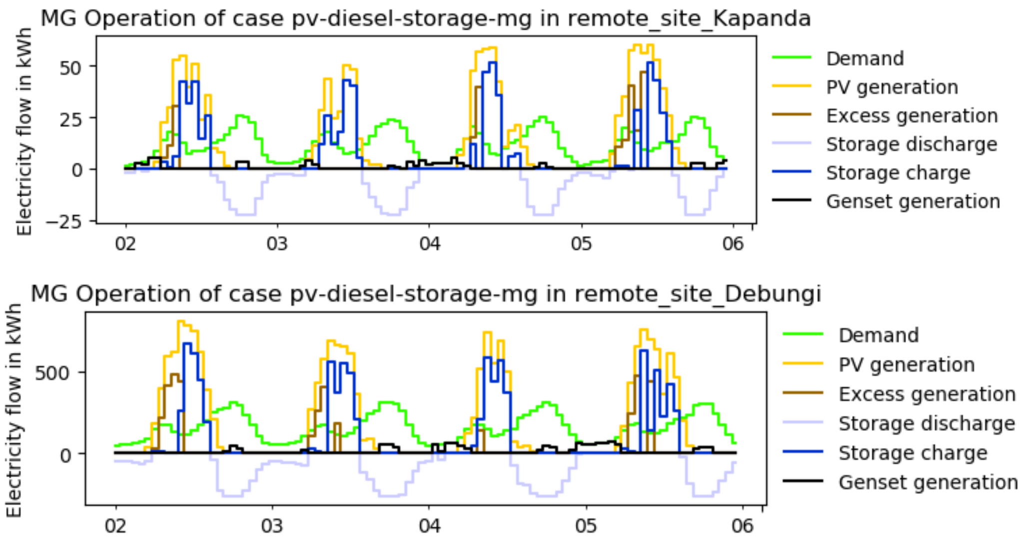


Figure 15: Exemplary hourly modelling outputs for two different remote sites demonstrating the hourly operation dynamics for 4 days (of full year). Top: Kapanda. Bottom: Debungi.

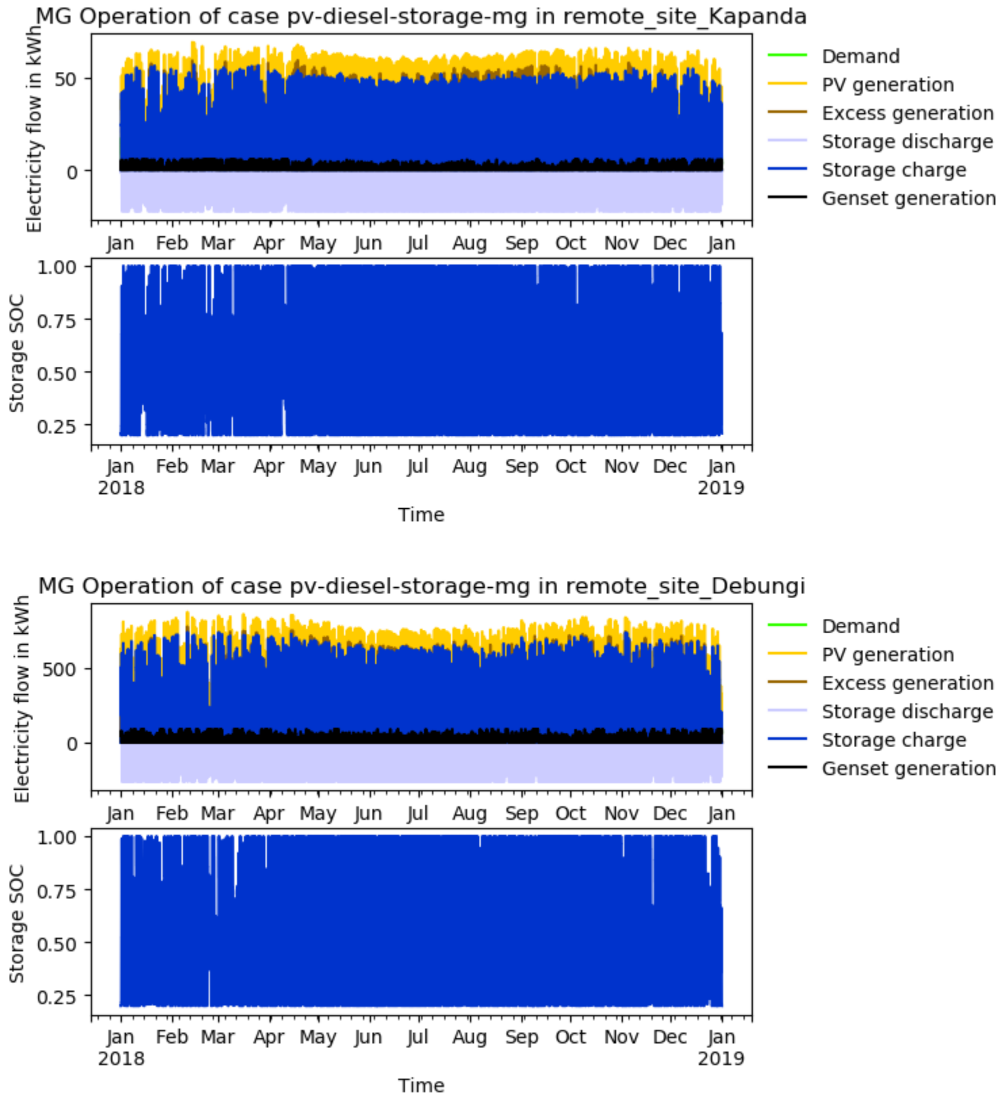


Figure 16: Exemplary hourly modelling outputs for two different remote sites for full year of the scenario pv-genset-storage minigrid. Full 365 days hourly profile and storage shown. Top: Kapanda. Bottom: Debungi.

Table 5 summarizes all the scenarios, configurations, sensitivities, and other key input variables for the four remote sites (Kapanda, Mimbilu 1, Debungi, and Mamfu/Mamfwe) for easy reference. All system configurations are required to meet all the demand in all hours of the day of the assumed demand time series, even during periods of high demand or potential outages. We tested all system configurations with fuel prices of 1.2 $/l, 1.8 $/l and 2.4 $/l. The "genset minigrid" scenario serves as a baseline to compare the other scenarios against, representing a typical existing energy system setup. The results summary in Table 6 shows the most relevant results and configurations for each site, focusing on scenarios with a diesel price of 1.2 $/l and no demand shortages allowed. We excluded configurations and sensitivities that had minimal impact on the key output variables listed. For instance, configurations with storage that also have the genset available are not shown separately, as they did not significantly alter the optimal system designs. Several of the results listed in Table 6 are also presented graphically in Figures 16, 18, and 19 for visual comparison across the various scenarios. These figures provide a clear overview of how different system setups perform in terms of renewable share, fuel usage, upfront costs, and Levelized Cost of Electricity (LCOE) for each remote site. By presenting both tabular and graphical representations of the results, we aim to offer a comprehensive understanding of the optimal energy system configurations for each remote location, taking into account their unique demand profiles and geographical characteristics. This approach allows for a thorough evaluation of the trade-offs between system components, costs, and environmental impact, ultimately informing decision-makers about the most suitable energy solutions for these off-grid communities.

Table 5. Scenario summary of key variables used for energy system optimisations

Location	System Configurations	Demand	Sensitivities
Kapanda (-10.48825, 25.63729)	genset minigrid PV + genset + storage minigrid PV + genset minigrid	Peak: 28 kW Total: 102 MWh per year	Max demand shortage allowed: 0 , 5 & 10 % Fuel price: 1.2, 1.8 & 2.4 $/litre
Mimbilu 1 (-11.73495, 27.34502)	genset minigrid PV + genset + storage minigrid PV + genset minigrid	Peak: 134 kW Total: 514 MWh per year	Max demand shortage allowed: 0 , 5 & 10 % Fuel price: 1.2, 1.8 & 2.4 $/litre
Debungi (-6.28014, 23.31696)	genset minigrid PV + genset + storage minigrid PV + genset minigrid	Peak: 336 kW Total: 1,343 MWh per year	Max demand shortage allowed: 0 , 5 & 10 % Fuel price: 1.2, 1.8 & 2.4 $/litre
Mamfu/Mamfwe (-10.65565, 25.70321)	genset minigrid PV + genset + storage minigrid PV + genset minigrid	Peak: 51 kW Total: 198 MWh per year	Max demand shortage allowed: 0 , 5 & 10 % Fuel price: 1.2, 1.8 & 2.4 $/litre

Our analysis examines how varying allowed demand shortages and fuel prices impact the levelized cost of energy (LCOE) for different energy system configurations in four remote villages: Kapanda, Debungi, Mamfe, and Mimbilu (see Figure 17).

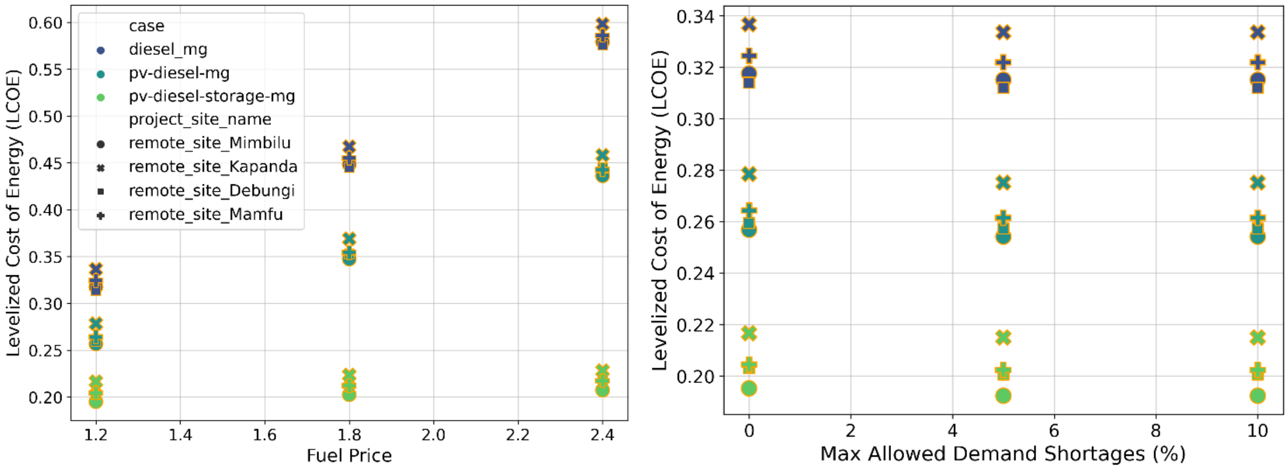


Figure 17. LCOE of different system configurations for modelled sites. With no demand shortages (left) and a fixed fuel price of 1.2 $/litre (right)

Allowing for demand shortages has a limited effect on reducing LCOE (see Figure 17 right), especially when compared to the much greater impact of fuel price fluctuations and different system setups. While allowing a small percentage of unmet demand can slightly lower costs, it is not a viable long-term solution for achieving affordable, clean, and reliable energy access (SDG 7). Relying on demand shortages to reduce electricity costs compromises reliability, which is essential for sustainable development. Therefore, cutting demand should only be considered an emergency measure to prevent system overload or damage, rather than a strategy to reduce costs. In contrast, fuel price changes have a significant influence on LCOE, especially for diesel-dependent systems, which see sharp cost increases as fuel prices rise (see Figure 17 left). For example, LCOE differences due to fuel price changes can reach approximately 0.3 $/kWh within the same site and system setup, while variations due to demand shortages only reach around 0.12 $/kWh. For further analysis, we will focus on systems with 0% allowed demand shortage and a fuel price of 1.2 $/litre, reflecting today's typical conditions and aiming to provide continuous and affordable energy.

The key results from the energy system optimisation modelling analysis for the remote sites are presented in this section and the key output variables are summarised in Table 6 below, which shows the most significant system configuration results and cost estimations for the four villages. The results show three system configurations for each village - PV+genset microgrid, PV+genset microgrid, and PV+genset+storage microgrid - assuming a diesel price of 1.2 $/litre and no demand shortages allowed.

Across all villages, increasing the share of renewables consistently leads to lower Levelized Costs of Electricity (LCOE). Notably, PV+genset+storage systems offer the highest share of renewables and lowest LCOE in every case. While these systems come with significantly higher total upfront costs due to the addition of storage, they also result in markable lower LCOEs and substantial fuel savings over time.

In Kapanda, transitioning from a genset-only system to a PV+genset microgrid reduces LCOE by 17 %. However, implementing a PV+genset+storage system achieves a remarkable 95 % share of renewables and lowers LCOE by 35 %, making it the most cost-effective option in the long run. This pattern holds true for the other villages as well.

Table 6. Energy system modelling results for the four remote sites with a diesel price of 1.2 $/litre and with no demand shortages allowed.

Remote Site	System Setup	PV System Capacity (kWp)	Battery Storage Capacity (kWh)	Share of Renewables (%)	Fuel Use per Year (l)	PV Upfront Cost (USD)	Battery Upfront Cost (USD)	Inverter Upfront Cost (USD)	Genset Upfront Cost (USD)	Total Upfront Cost (USD)	LCOE ($/kWh)
Kapand	genset mg	0	0	0	31,534	0	0	0	46,913	46,913	0.34
	PV+genset mg	36.8	0	45	22,090	18,937	0	7,098	38,894	64,929	0.28
	PV+genset +storage mg	83.9	197.9	95	2,274	43,153	95,979	11,353	5,973	156,458	0.22
Mimbil	genset mg	0	0	0	159,055	0	0	0	231,484	231,484	0.32
	PV+genset mg	163.2	0	43	111,593	83,929	0	34,312	191,187	309,428	0.26
	PV+genset +storage mg	377.4	970.1	93	14,082	194,145	470,546	50,995	38,579	754,265	0.20
Debungi	genset mg	0.0	0.0	0	415,406	0	0	0	595,262	595,262	0.31
	PV+genset mg	449.1	0.0	41	300,614	231,039	0	75,154	497,798	803,991	0.26
	PV+genset +storage mg	1,131.2	2,614.6	93	38,628	581,881	1,268,218	133,675	96,239	2,080,013	0.20
Mamfu	genset mg	0.0	0.0	0	61,334	0	0	0	88,898	88,898	0.32
	PV+genset mg	70.0	0.0	44	42,755	36,009	0	13,023	73,124	122,156	0.26
	PV+genset +storage mg	156.4	372.2	93	5,475	80,436	180,558	19,502	13,821	294,317	0.20

Mimbilu sees a 19 % reduction in LCOE with the PV+genset microgrid compared to the genset-only system, and a further 37 % decrease with the PV+genset+storage configuration, achieving a 93 % renewable share. Debungi experiences similar improvements, with the PV+genset microgrid reducing LCOE by 16 %, and the PV+genset+storage system lowering it by 35 % while achieving a 93 % renewable share. Mamfu follows this trend as well, with a 19 % reduction in LCOE for the PV+genset microgrid and a 37 % decrease for the PV+genset+storage system, reaching a 93 % renewable share.

The results depicted in Figure 17 further reinforce the trends outlined in the analysis of system configurations for the four remote sites. The scatter plot shows three distinct system configurations—diesel-only, PV+diesel microgrid, and PV+diesel+storage microgrid—across all the project sites: Mimbilu, Kapanda, Debungi, and Mamfu. The vertical clustering of points at different cost values highlights the variation in LCOE across the different system setups and villages. Notably, the "diesel-only" system has the highest LCOE across all locations, confirming its inefficiency relative to the hybrid configurations.

The PV+diesel microgrid shows a clear reduction in LCOE, with further drops when storage is added, evident from the points representing the PV+diesel+storage systems clustered at lower cost values. For instance, in Kapanda and Mamfu, the LCOE decreases are especially significant with the introduction of storage, mirroring the substantial renewable share and long-term savings outlined previously. Mimbilu and Debungi demonstrate similar patterns, with their most cost-effective setups combining PV and storage. This visual representation underscores the economic benefits of integrating renewable energy and storage in hybrid systems, validating the previous conclusion that PV+genset+storage microgrids consistently offer the lowest LCOE and highest renewable shares across all remote sites, despite the higher initial investment costs.

The analysis of various system setups exemplary for the Mamfu site highlights the impacts on fuel expenditures, CO_2 emissions, electricity generation sources, and investment costs when adding storage to PV-diesel systems.

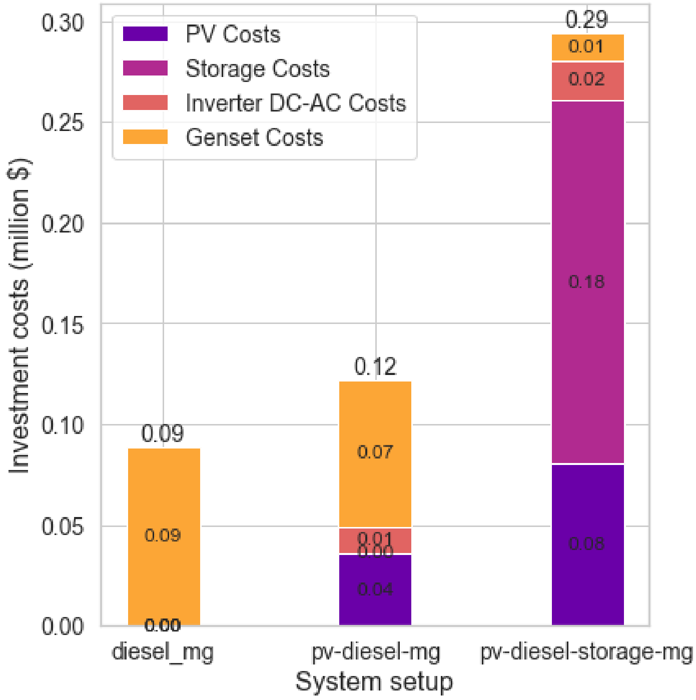


Figure 18. System component investment costs by system setup for Mamfu

As depicted in Figure 18, investment costs vary significantly across system setups. Diesel-only systems require minimal initial investment but incur high ongoing fuel costs. PV-diesel systems demand moderate upfront investments in PV and inverter components, while PV-diesel-storage setups require the largest initial investment—approximately 0.29 $ million due to substantial PV and storage costs. Although PV-diesel-storage systems have higher upfront costs, they reduce long-term fuel costs and emissions, offering a more sustainable option for remote sites like Mamfu.

Total CO_2 emissions decrease considerably with PV and storage integration (see Figure 19 right). While diesel-only systems emit over 160 tons of CO_2 annually, PV-diesel systems reduce emissions to around 100 tons, and PV-diesel-storage systems lower it to nearly zero. This shift underscores the environmental benefit of reducing diesel reliance through renewable energy and storage. Electricity generation sources also shift in favour of PV with storage integration (see Figure 19 left). In diesel-only and PV-diesel setups, diesel generation is a major contributor, but PV-diesel-storage systems supply nearly all electricity demand through PV generation, eliminating dependency on diesel. This increases the system’s autonomy and aligns with clean energy goals.

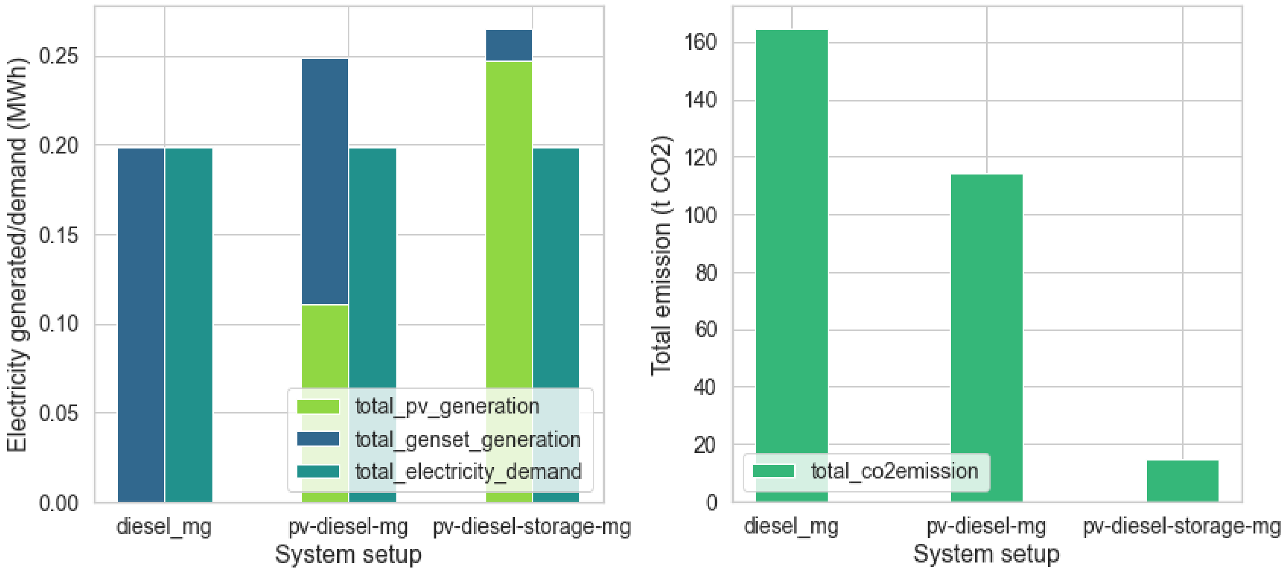


Figure 19. Annual generated/used electricity amount (left) and CO2-emissions (right) by system setup

When planning energy systems for the future, the likely increases in diesel prices need to be included again. Figure 20 shows that switching from diesel-only to PV-diesel or PV-diesel-storage configurations significantly reduces fuel costs. For example, with a fuel price of 1.20 $/litre, annual fuel expenditures drop from approximately 250,000 $ in a diesel-only setup to near zero in the PV-diesel-storage configuration. Even as fuel prices increase to 2.40 $/litre, the storage-based system maintains negligible fuel costs, while costs for diesel-only and PV-diesel setups rise sharply, emphasizing the financial stability provided by PV and storage options.

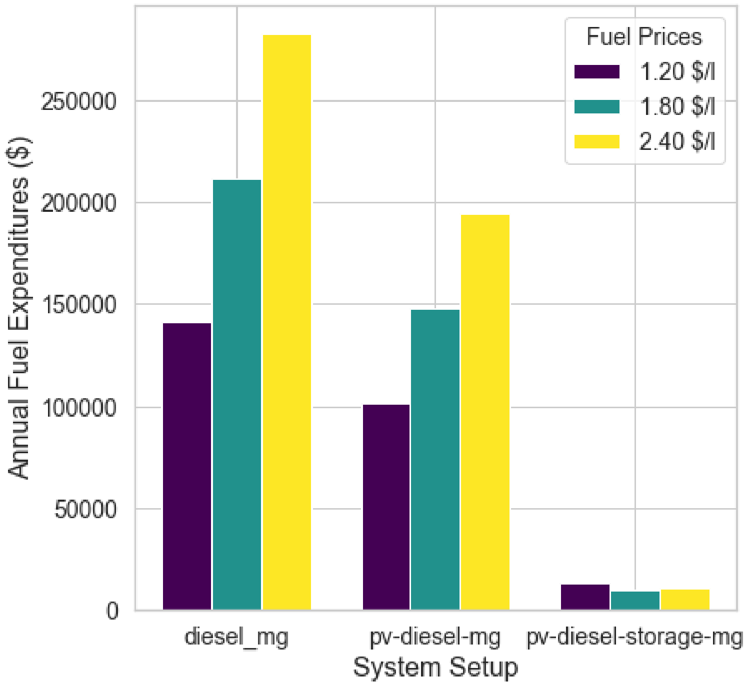


Figure 20: Annual expenditures for diesel fuel in Mamfu

These results show that integrating PV and storage significantly improves sustainability and long-term financial stability, even with higher initial costs, supporting clean energy objectives in remote off-grid areas.

4. National population data and demand updates for the Congo Epela platform

Separately to the village mapping and energy system modelling in the rest of this report, updates where made to the national scale cluster-based population and demand estimates which are used in the least-cost electrification OnSSET planning activities presented on the Congo Epela platform. The key updates made include adding customizable provincial and national population calibration capability while updating the previous estimates to match OSCHA[9] published totals, and updating the heavy industrial demand estimates to use new custom projections for mining electricity demand in the Katanga region and heavy industrial demands added to additional places after feedback on the previous estimates.

Overall, the demand modelling methodology used here remains unchanged compared to the previous version which is described in detail in previous reports, however a high-level visual abstract summarizing the key steps is included in Figure 21. The same survey-based household electricity demand estimates for different household consumer types and levels are used again here, which are also used as described above for the village demand estimations to ensure methodological alignment between approaches as far as possible.

The cluster population values can now be flexibly re-calibrated to ensure that provincial totals match any custom given set of totals for the base year of 2020. This is incorporated into a simple spreadsheet interface as shown in Figure 22. In this version we have used OCHA provincial demand estimates, which we consider a good source. However, given that population totals can often be a contested issue and can be difficult to determine accurate numbers agreed by all affected stakeholders, the customizable calibration functionality was included to ensure they can be adjusted if required.

The heavy industrial demand from mining in the Haut Katanga and Lualaba provinces now comes directly from the mining demand estimates developed by Mashaka Lubenga[10] in his PhD research, and no longer a fixed ratio of the total demand. The scenarios of how these demand projections are translated into the "min", "mean", and "max" demand scenarios, using 25 %, 50 % and 100 % of the demand are depicted in Figure 23 below for Copper and Cobalt mining and processing.

The city of Goma and the Kibali gold mining complex now also have heavy industrial demands (in addition to Kinshasa, Matadi, Boma, and Muanda as before) using the "share of total demand" method as described in previous reports and do not use the new Katanga region mining estimates. Of the non-Katanga heavy industrial demand, Kinshasa now takes 46.5 %, with Matadi, Boma and Muanda taking 46.5 % together, Goma takes 5 %, and Kibali gold takes 2 %, with these shares being adjustable if needed.

Following all of the above updates the overall demand estimates are now about 34.5 % higher than the previous version in the mean scenario and are graphically compared in Figure 24. The increase is due mostly to the new mining demand for the Katanga region which is significantly greater than before, as well as the 2020 and 2030 population totals with the updated OCHA values (instead of previous UN values) are now greater, which has generally increased the overall demand of most other sectors.

[9] "UN OCHA - DRC - Subnational Population Statistics" https://data.humdata.org/dataset/cod-ps-cod
[10] PhD thesis forthcoming.

Although the total demand estimates here are now higher, it is important to remember that these are "latent" demand estimates of what "could be" if 100% electrification is achieved in the estimated future years. They are not estimates of what the actual demand will be then.

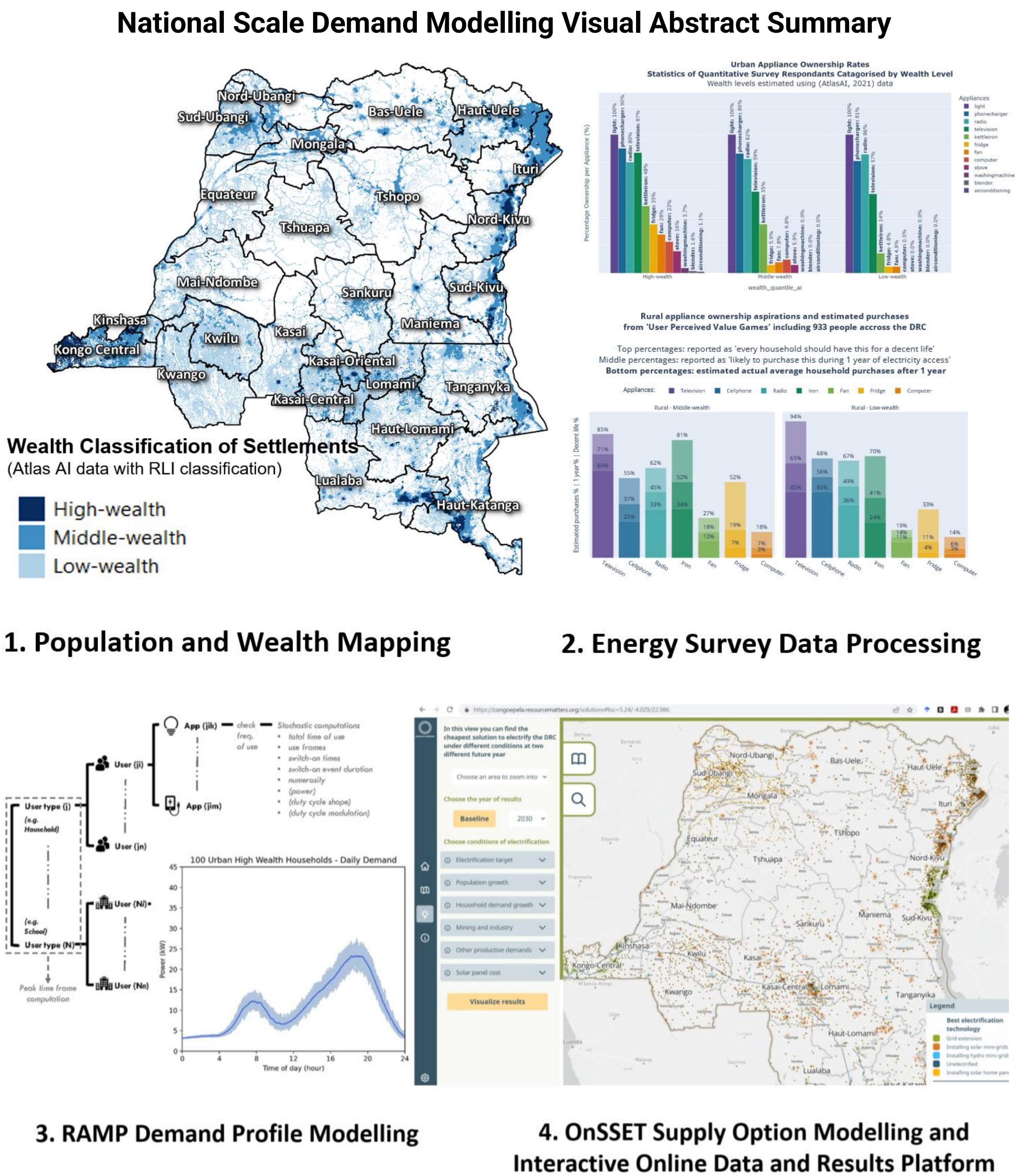
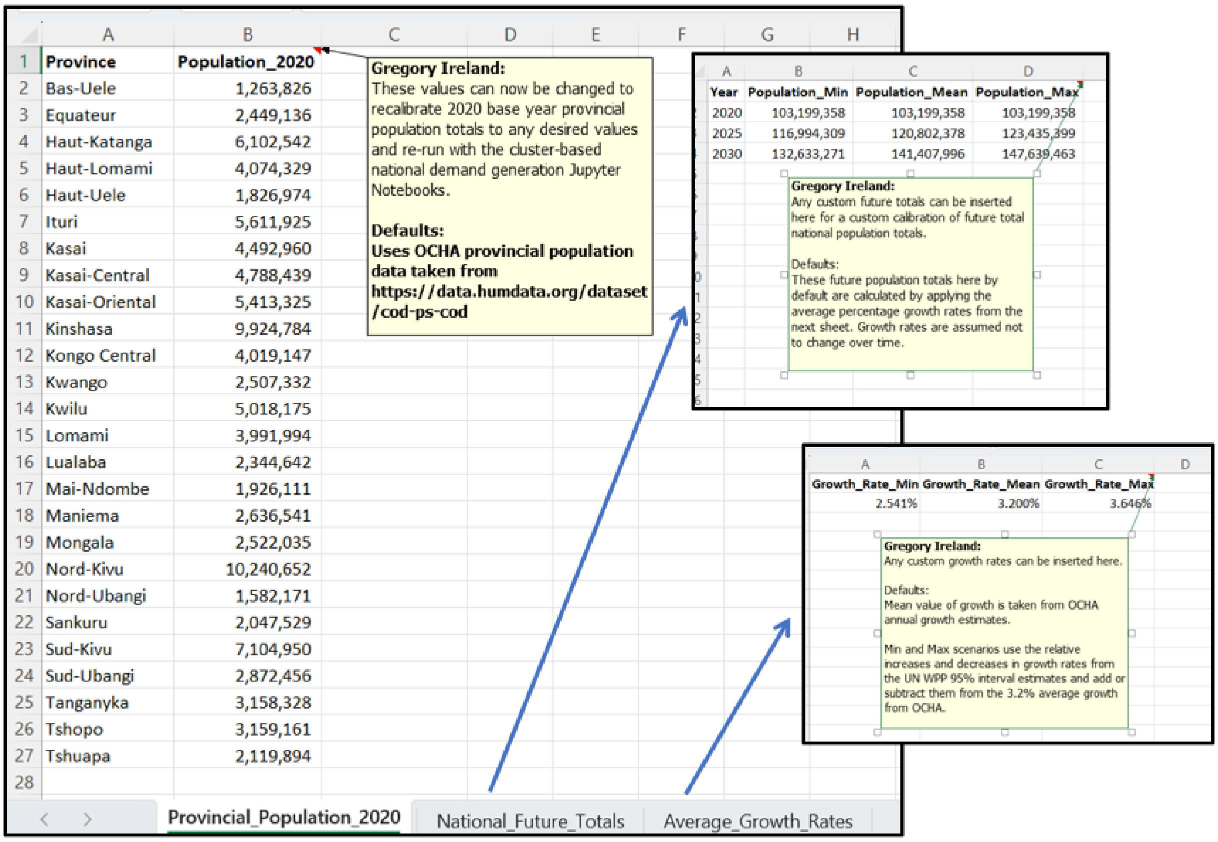


Figure 21: National scale demand modelling summary visual abstract as used for the Congo Epela online platform.



Province	Population_2020
Bas-Uele	1,263,826
Equateur	2,449,136
Haut-Katanga	6,102,542
Haut-Lomami	4,074,329
Haut-Uele	1,826,974
Ituri	5,611,925
Kasai	4,492,960
Kasai-Central	4,788,439
Kasai-Oriental	5,413,325
Kinshasa	9,924,784
Kongo Central	4,019,147
Kwango	2,507,332
Kwilu	5,018,175
Lomami	3,991,994
Lualaba	2,344,642
Mai-Ndombe	1,926,111
Maniema	2,636,541
Mongala	2,522,035
Nord-Kivu	10,240,652
Nord-Ubangi	1,582,171
Sankuru	2,047,529
Sud-Kivu	7,104,950
Sud-Ubangi	2,872,456
Tanganyka	3,158,328
Tshopo	3,159,161
Tshuapa	2,119,894

Gregory Ireland:
These values can now be changed to recalibrate 2020 base year provincial population totals to any desired values and re-run with the cluster-based national demand generation Jupyter Notebooks.

Defaults:
Uses OCHA provincial population data taken from https://data.humdata.org/dataset/cod-ps-cod

Year	Population_Min	Population_Mean	Population_Max
2020	103,199,358	103,199,358	103,199,358
2025	116,994,309	120,802,378	123,435,399
2030	132,633,271	141,407,996	147,639,463

Gregory Ireland:
Any custom future totals can be inserted here for a custom calibration of future total national population totals.

Defaults:
These future population totals here by default are calculated by applying the average percentage growth rates from the next sheet. Growth rates are assumed not to change over time.

Growth_Rate_Min	Growth_Rate_Mean	Growth_Rate_Max
2.541%	3.200%	3.646%

Gregory Ireland:
Any custom growth rates can be inserted here.

Defaults:
Mean value of growth is taken from OCHA annual growth estimates.

Min and Max scenarios use the relative increases and decreases in growth rates from the UN WPP 95% interval estimates and add or subtract them from the 3.2% average growth from OCHA.

Figure 22: Population calibration spreadsheet screenshot. Includes separate sheets for total population values per province, future national population projection totals, and percentage annual population growth rate option. All values are customizable by the user. Starting year for calibration is 2020, and future years for projection are 2025 and 2030.

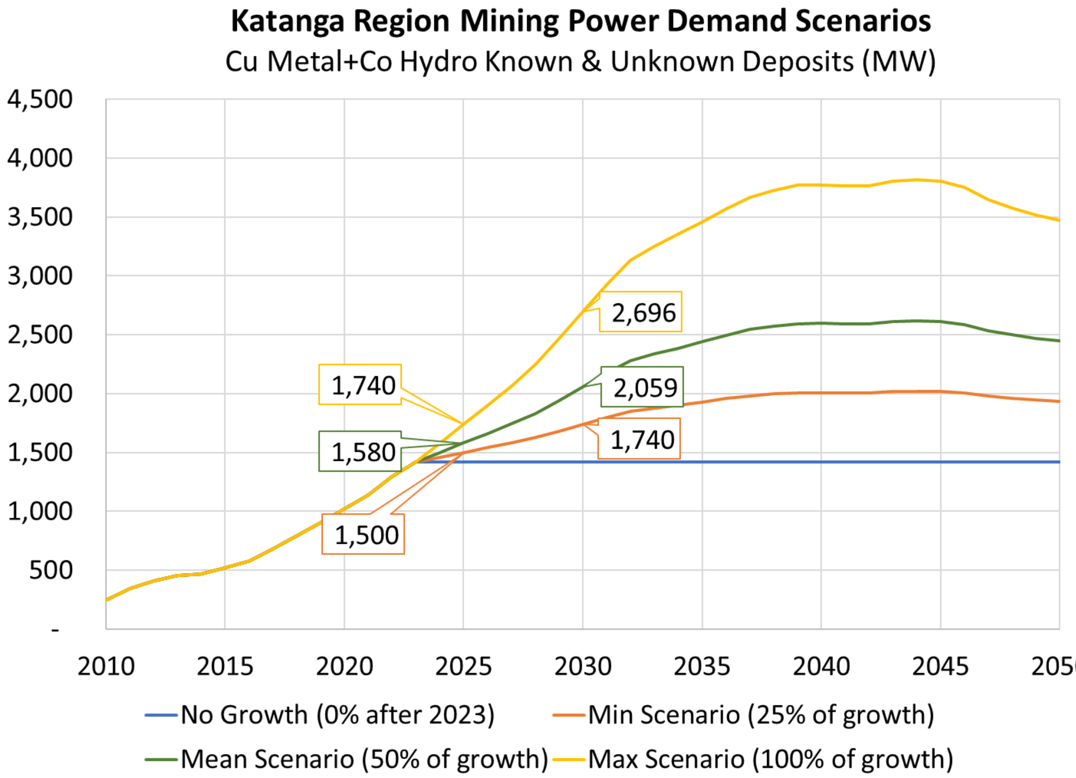
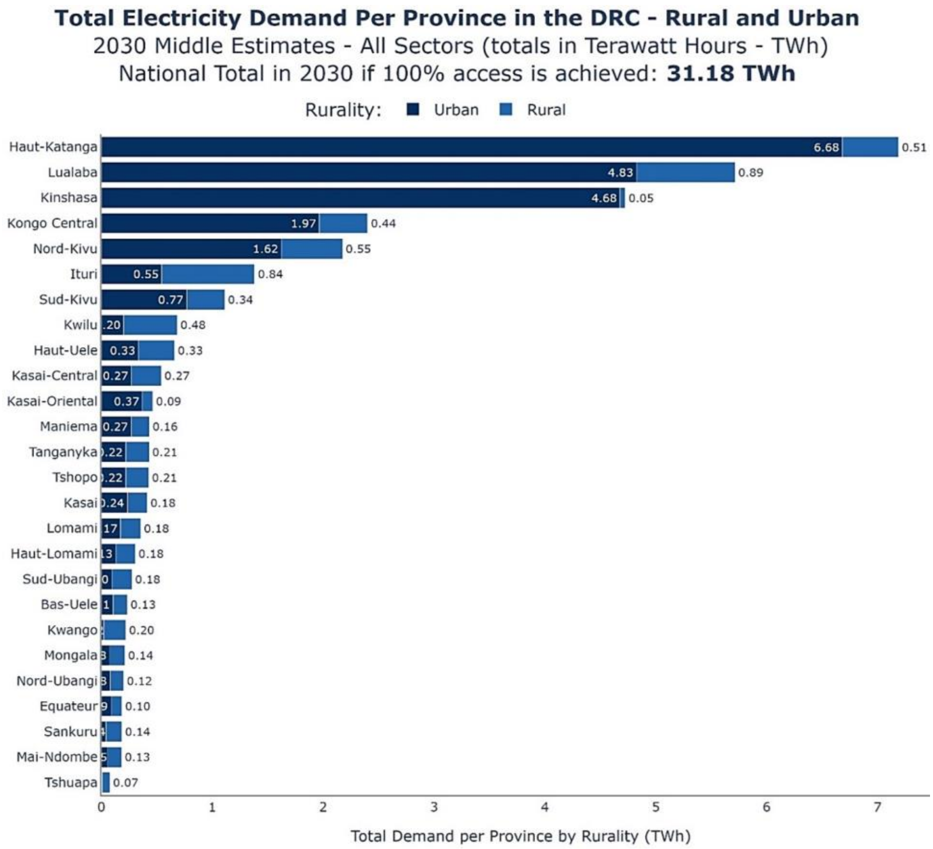


Figure 23: Katanga region mining power demand estimates with the min, mean, and max scenarios indicated until 2030. Adapted from Mashaka Lubenga's PhD research (forthcoming).



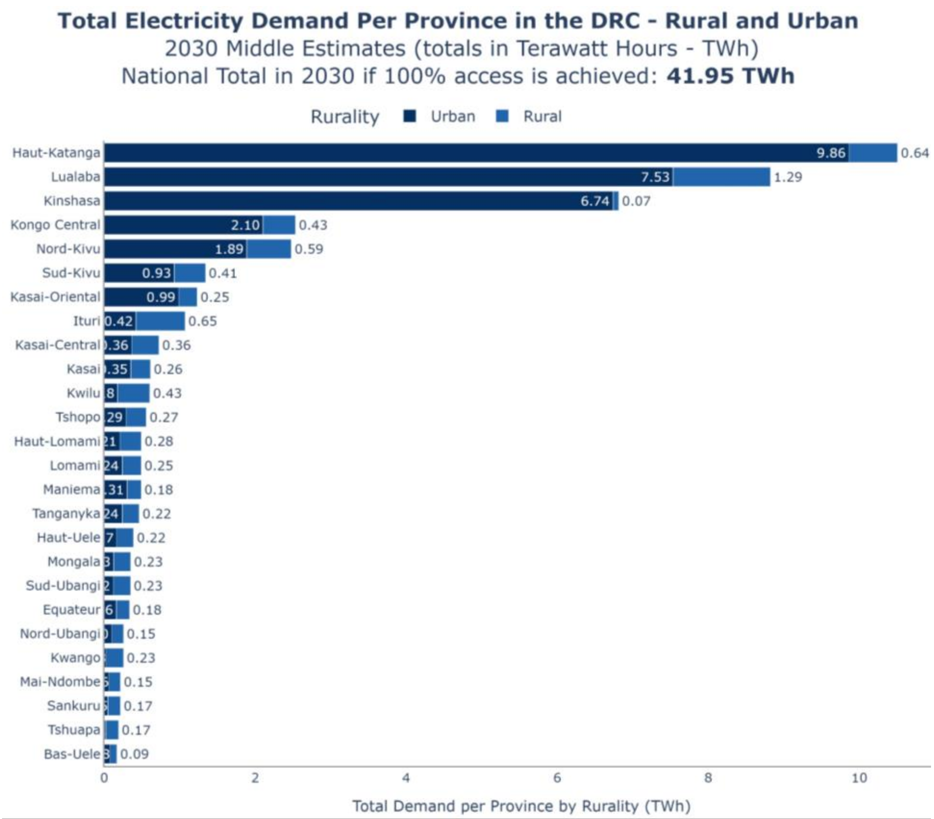


Figure 24: National total latent electricity demand estimate comparisons split by province and rurality for 2030, with the previous estimates (top -v3) and the updated estimates (bottom – v4). Both represent the potential demand if 100% electrification rate is achieved and all latent demand is met.

5. Conclusion

The overall least-cost mini-grid option, over the total project lifetime, for all villages is to implement hybrid PV+genset+storage mini-grid systems despite their high upfront costs. While these systems come with high initial investment - particularly due to battery storage costs - they offer substantial long-term benefits including lower operating costs, reduced fuel consumption, and a dramatic increase in the share of renewable energy in the mix. However, it's crucial to address the high upfront costs associated with these systems. This could involve exploring financing mechanisms or subsidies that can help bridge the gap between short-term expenses and long-term savings. Implementing energy efficiency measures alongside the new systems will maximize the benefits of renewable energy integration. Furthermore, exploring local manufacturing and assembly options for system components could potentially reduce costs and contribute to economic development in the region. Regular monitoring and evaluation of system performance, with local community engagement, will be essential to assess the effectiveness of these systems and inform future electrification planning efforts.

These recommendations aim to balance short-term costs with long-term sustainability goals, prioritizing renewable energy integration while considering the unique challenges of remote village electrification in the Democratic Republic of Congo. By adopting PV+genset+storage microgrids, these villages can significantly improve their energy access, reduce reliance on fossil fuels, and contribute to economic development and improved service accessibility in these remote communities.

Despite the limitations mentioned in section 2.6, this pre-feasibility study provides insights into the potential for PV-diesel and PV-diesel-storage mini-grids in remote villages of the Democratic Republic of Congo. The findings suggest that mini-grid solutions could offer a viable path towards electrification in these areas. However, it is crucial to recognise that actual project costs and outcomes may vary significantly depending on factors such as economies of scale, anchor loads, location-specific challenges, and realistic connection rates. To move forward effectively, stakeholders should prioritise site-specific studies that take into account local conditions, potential economies of scale, and realistic connection rates. By addressing these limitations and incorporating more nuanced assessments, future projects can build upon the initial investigations explored by this study to create more robust and sustainable electrification solutions for remote communities in the DRC.

The updates to the national-scale cluster-based population and demand estimates for the Congo Epela platform have enhanced the flexibility of the demand estimations and their underlying population estimations. These improvements include the addition of customizable provincial and national population calibration capabilities, allowing for better alignment with various data sources and stakeholder requirements. The incorporation of new mining demand estimates for the Katanga region provides a more accurate representation of industrial energy needs in this critical sector. Overall demand estimates have increased by approximately 34.5 % compared to the previous version, however it's crucial to note that these estimates represent latent demand, reflecting potential electricity consumption if 100 % electrification is achieved. These updates emphasize the need for regularly refining energy demand projections at both national and local levels, particularly in regions with rapidly evolving economic sectors and dynamic population growth.