# Pathways to 100% Electrification in East Africa by 2030

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**ABSTRACT**

In spite of abundant generation potential, as of 2019 East Africa has an electricity access level of 36%, with over 140 million people without service. Here, a bottom-up geospatial model (OnSSET) is used to estimate least-cost pathways to universal access to electricity by 2030 for different consumption-tier objectives under three regional grid electricity generation mix scenarios. Results suggest median total required investments of $57 and $110 billion for guaranteeing basic (160 and 44 kWh/person/year in urban and rural areas) and moderate—i.e. including potential to enable some productive uses—(423 and 160 kWh/person/year) consumption for newly connected households by 2030, respectively. This corresponds to an average of $5.6 billion/year, and implies median capacity additions of 12.2 GW (59% on-grid, 37% mini-grids, and 4% standalone solutions). At least further $2.7 billion/year in generation capacity are required to satisfy the projected demand growth from already electrified consumers. A grid electricity scenario with 25% lower photovoltaic costs and a higher penetration of renewables reveals to be up to 10% cheaper and 46% less carbon-intensive, while also requiring less up-front investment. To achieve such objectives, investment must be channelled within an enabling policy environment, which we discuss.

**Keywords:** Electricity access, electrification modelling, energy scenarios, utilities policy, East Africa

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## LIST OF ABBREVIATIONS

Bcm: Billion cubic meter; CBA: Cost-Benefit Analysis; CF: Capacity Factor; $CO_2$: Carbon dioxide; DR: Discount rate; EA: East Africa; EAPP: Eastern Africa Power Pool; FDI: Foreign Direct Investment; GIS: Geographical Information System; GDP: Gross Domestic Product; GW: Gigawatt; GWh: Gigawatt hour; HV: High voltage; IPP: Independent Power Producer; kWh: Kilowatt hour; LCOE: Levelised cost of electricity; LV: Low voltage MG: Mini-grid; MV: Medium voltage; MW: Megawatt; MWh: Megawatt-hour; NDCs: Nationally Determined Contributions; NG: Natural gas; OnSSET: Open-Source Spatial Electrification Tool; PPA: Power Purchase Agreement PV: Photovoltaic; RE: Renewable energy; SA: Standalone; SDG Sustainable Development Goal SSA: Sub-Saharan Africa; T&D: Transmission and distribution.

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## 1. INTRODUCTION

As of 2019, East Africa—here defined as the macro-region that includes Burundi, Kenya, Malawi, Mozambique, Rwanda, Tanzania, and Uganda—hosts 2.9% of world's population (The World Bank, 2019), but only accounts for 0.14% of global gross electricity consumption (CIA, 2017). While the share of regional population without access to electricity has fallen from 90% in 2000 to 64% in 2017 (IEA, 2018), the absolute number of people without access has instead increased by 8 million as electrification efforts have been outpaced by rapid population growth. 141 million people are estimated to live without access in the region, and high rural-urban inequality prevails in all countries. The regional final electricity consumption stood at 35 TWh in 2016 (CIA, 2017). In the same year a high-income country like Italy consumed 310 TWh of electricity, despite having less than 20% of EA's population. Table 1 reports statistics characterising the power sector and electricity access situation in the EA countries considered.

**Table 1: Power sector and electricity access situation in East African countries**

| **Country** | Burundi | Kenya | Malawi | Mozambique | Rwanda | Tanzania | Uganda |
|---|---|---|---|---|---|---|---|
| Population (million) | 10.5 | 48.5 | 18.1 | 28.9 | 11.9 | 55.6 | 41.5 |
| Installed capacity (GW) in 2016 | 0.07 | 2.4 | 0.4 | 2.6 | 0.2 | 1.6 | 1 |
| Final consumption in 2016 (TWh) | 0.4 | 7.9 | 1.3 | 12 | 0.5 | 5.7 | 3.1 |
| Electrification level (2018) | 10% | 73% | 11% | 28% | 43% | 33% | 20% |
| *Urban* | 35% | 90% | 49% | 57% | 69% | 65% | 23% |
| *Rural* | 6% | 68% | 3% | 12% | 37% | 17% | 19% |
| Electr. level target | 25% | 100% | 30% | 100% | 70% | 50% | 26% |
| Year | 2025 | 2020 | 2020 | 2025 | 2018 | 2025 | 2022 |
| Average residential power consumption of electrified population (kWh/capita/year) in 2016 | 159 | 195 | 274 | 264 | 126 | 213 | 77 |

Sources: The World Bank (2019); EIA (2017); CIA (2017)

EA countries are endowed with substantial untapped energy resources and generation potential (BP, 2017; ENI, 2017; IRENA, 2014), which is technically enough to guarantee energy security and self-sufficiency in the region: solar PV maximal technical generation potential is abundant throughout EA, and overall it stands at 219,500 TWh/year[1]. Solar CSP (176,000 TWh/year) is mostly feasible in Kenya. Untapped hydropower, both at large and small scale, is found to varying degrees in all countries (The International Journal on Hydropower and Dams, 2017). The same is true for geothermal, and in particular in the northern part of EA, in the Rift Valley, between Kenya and Malawi. Wind potential stands at 16,600 TWh/year[2]. Bioenergy for power generation purposes is a further viable option, mostly in Kenya, Uganda, Mozambique and Tanzania (IRENA, 2014). Hydrocarbon resources are also abundant, but their distribution is highly skewed: only Uganda has substantial oil reserves (2.5 billion barrels), while those of Kenya are less prominent or accessible; natural gas (NG) endowments of Mozambique and Tanzania are large (together they sum to 4,200 bcm), while those of Rwanda are limited and only partially viable (BP, 2017; ENI, 2017). Finally,

1. The following RE potential figures are drawn from IRENA (2014) and they refer to the gross sum of maximum technical potential over all suitable areas (i.e. they do not consider economic viability). They are hence insightful in comparative rather than in absolute terms.

2. Considering areas with a wind turbine capacity factor greater than 40%.

coal reserves and associated mining activity is taking place in Mozambique (according to estimates more than 20,000 Mt of reserves could exist in the country), and Tanzania (297 Mt) (BP, 2017).

Bottom-up analysis for electrification exploiting geospatial data has proved a robust methodology to assess cost-efficient strategies to achieve energy access objectives in developing countries. Modelling efforts have culminated in the release and application of a number of tools (among others, OnSSET, GEOSIM, Network Planner; refer to van Ruijven et al., 2012; Columbia University, 2017; Parshall et al., 2009; Ellman, 2015; Mentis et al., 2017; Szabo et al., 2011). However, for the case of EA—a heterogeneous and yet highly interdependent region—a paucity of integrated, region-wide, quantitative studies on electrification and energy development is witnessed. Given the tight interdependencies which already exist and will intensify in the power sector of the region and within the EAPP—it is crucial to elaborate the electrification process as an integrated, transboundary one.

Here, spatially-explicit least-cost 100% electrification scenarios by 2030 for EA (in compliance with the UN's Sustainable Development Goals' target 7.1.1) are modelled using OnSSET (Open Source Spatial Electrification Tool, Mentis et al., 2017), an open-source model allowing for high-resolution bottom-up assessment of access technologies and investment requirements. The output of the model provides insights on the changes in the level of penetration of different technologies and sources when key variables in the electrification equations are altered, as well as on the capacity additions required and on the total investments necessary to achieve universal access to electricity by year 2030 in each country of the region. Calibrated model input data are hosted in an online repository to allow reproduction of results and substitution of parameters and assumptions, also thanks to the open nature of the tool.

OnSSET is not an energy system-wide optimisation model, and thus it does not represent the evolution of the grid-based electricity generation mix. Exogenous input parameters for the average LCOE of grid-based electricity in the regional market and for the average investment requirement to add a utility-scale kW of new capacity to the system must be determined. Thus, we design three baseline scenarios (refer to Section 4 and the Appendix) as plausible pathways for the evolution of the regional grid-based power generation mix given current and planned capacity addition and energy resource endowments in the region. Furthermore, beyond new connections, we also quantify capacity additions and corresponding investment requirements to satisfy baseline power demand growth (i.e. increase in the demand from already electrified consumers and sectors other than the residential one). The relative $CO_2$ emission pathways are therefrom derived. The analysis is not limited to a modelling exercise, as specific attention is paid to the main policy and financing-related issues faced in the accomplishment of a sustainable and cost-effective full electrification in EA.

The remainder of the paper is structured as follows. In Section 2 a literature review of electrification planning and challenges in sub-Saharan Africa, including previous spatial least-cost electrification modelling, is presented. Section 3 illustrates the methodology and the datasets used as inputs by the model and it describes its functioning and the key aspects represented. The design of generation mix scenarios and the modeled pathways is detailed in Section 4. Section 5 presents the results of the analysis for both newly electrified consumers and the additional demand for power from already electrified customers, while also highlighting the main results of the sensitivity analysis. The numbers are then put in perspective with socio-economic and finance flows metrics for the region. Section 6 discusses the key policy implications deriving from the analysis for both national governments and international institutions to enable the fulfilment of investment requirements. Section 6 concludes the paper.

## 2. LITERATURE REVIEW

Electrification planning, optimal technology mix choice, and long-term demand forecasting in developing countries present multiple challenges because of data scarcity, including the lack of a current demand to anchor on and uncertainty over its future development (Mandelli et al., 2016; Lombardi et al., 2019). At the same time, electricity access planning can itself be performed with a number of different approaches (Trotter et al., 2017). These include e.g. top-down (Pachauri et al., 2013), bottom-up (Mentis et al., 2017), or system dynamics-based methodologies (Riva et al., 2018c). It also requires accounting—either in the modelling, or in the interpretation of results, or in both—for crucial aspects including: incentives and barriers to private sector participation (Rafique et al., 2019; Williams et al., 2015; Eberhard et al., 2017; Malgas and Eberhard, 2011) and public incentives (Lucas et al., 2017; Kruger and Eberhard, 2018), institutions and accountability (Ahlborg et al., 2015), barriers on the household-side (Golumbeanu and Barnes, 2013), productive uses of energy (Riva et al., 2018a), energy efficiency (Adom, 2019; Diawuo et al., 2018), and synergies with other development goals (McCollum et al., 2018; Bos et al., 2018).

Different macro-regional electrification projections have been carried out on SSA as a whole or on specific countries. van Ruijven et al. (2012) developed and applied a global model for rural electrification. They showed that the gap between the projected level of access and 100% access by 2030 is largest in sub-Saharan Africa. They estimate that \$131–226 billion are necessary to close the gap in the continent. For the specific regional case of EA, they show that—under a low-demand and both high and low-cost scenarios—a combination of SA PV and wind and diesel MG is the most economically feasible in virtually all regions. Conversely, under a scenario of high demand, investment costs have a big impact between the decision of shifting from decentralised solutions to grid connection, wich determine a broad uncertainty range (between 14.5%–61.5% for wind/diesel MG and 11.5% and 47.5% for SA solar-PV).

Dagnachew et al. (2017) extended the model of van Ruijven et al. (2012) to account for further decentralised electrification solutions, such as mini-hydro. The authors confirm that the optimal mix for providing 100% access to electricity strongly depends on the aimed per-capita yearly consumption tier, with 65% penetration of SA or MG systems at low consumption levels and 95% of on-grid electricity penetration at 3,000 kWh/household/year. For the entire SSA continent, they project a very large range of variation in required investment (between \$22 billion and \$2,500 billion), again depending on the consumption level to be achieved. Szabo et al. (2011) developed an LCOE-minimisation-based electrification model based on the demand-side, i.e. on household ability-to-pay (ATP). They find that a difference of \$0.05/kWh (from \$0.25 to \$0.30/kWh) in the ATP of rural households would greatly expand the fraction of locations where solar PV can be the key technology in achieving electrification *vis-à-vis* standalone diesel generators. They thus stress on the significance of diesel price in determining electrification solutions, and therefrom derive policy inputs on incentives and feed-in-tariffs. Bertheau et al. (2017) carried out a similar GIS-based modelling exercise and found a high relevance of solar-home-systems for achieving universal energy access, with penetration between 30% and 70% depending on the scenario considered, while they projected mini-grid solutions between 8% and 12%. The authors thus state that this finding is not in line with the International Energy Agency projection that mini-grid solutions would account for 45% of new global connections until 2040, which instead is consistent with van Ruijven et al. (2012) and Dagnachew et al. (2017).

OnSSET and other models have previously been used in a number of country-level analysis in SSA and elsewhere. Kenya has been the most assessed country (Berggren and Österberg, 2017; Lee et al., 2016; Parshall et al., 2009; Moksnes et al., 2017; Moner-Girona et al., 2019). Further studies have been carried out for Rwanda (Drouin, 2018), Ethiopia (Mentis et al., 2016), Tanzania (Khavari and Sahlberg, 2017), Zimbabwe (Krakau, 2016), Ghana (Kemausuor et al., 2014), Malawi (Korkovelos et al., 2019), Senegal (Sanoh et al., 2012), and Nigeria (Ohiare, 2015).

On the specific case of EA, to our knowledge no region-wide high spatial-resolution electrification assessments have been carried out. van Ruijven et al. (2012) included East Africa in their global assessment, but the study did not provide specific country-level output or discussion. At the same time, most country-level studies have not accounted for the additional demand growth from other sectors to calculate total required investment in the power sector beyond new electrification, while also developing different grid electricity capacity addition scenarios to show which pathways are the most capital-intensive and costly, respectively. Given the crucial interdependencies linking EA countries, an integrated regional study capable of representing a unique power market and transboundary interconnections is deemed an important and novel contribution.

## 3. MATERIALS AND METHODS

OnSSET is a bottom-up spatial optimization model that estimates the least-cost technology solution in every geographically-defined location of a given region for the achievement of electricity access goals. This analysis is carried out at a 1-km resolution, meaning that optimisation is carried out recursively for each areal unit. The model is selected for its high level of detail—which allows assessing least-cost electrification option at a fine spatial scale among an array of technologies—and its open-source nature which allows results replication and sensitivity analysis (refer to the Data Availability Appendix for the repository hosting calibrated input data to replicate the analysis with different parameters).

The framework takes as inputs spatially-explicit datasets (reported in detail in Table 2 with the corresponding sources for the data used in this analysis), including the local renewable energy (RE) potential, the price of diesel in every settlement[3] (KTH–dESA, 2019), and additional information such as distance from the currently existing transmission grid, the nearest roads, and the local nighttime light intensity. To provide a sense of some of the main data inputs, Figure 1 shows plots of EA with the corresponding (a) global horizontal irradiation (used to define solar PV potential); (b) average wind speed (employed to calculate wind CFs); (c) mini-hydropower potential sites; (d) population density.

The data are first used to calibrate number and location of the current and future projected (according to the growth rates specified in Table 12) population without access in each 1-$km^2$ grid cell, to which the model sets the objective of providing electricity access by 2030[4]. The calibration is based on an algorithm that considers the local distance to existing and currently planned grid infrastructure, the detected intensity of nighttime lights, the distance to road infrastructure and to electricity substations, according to user-defined threshold and cutoff parameters[5]. The algorithm distributes the population without access to match the national, urban, and rural electrification rates as reported by the official country statistics (Table 1).

3. The price of diesel—the main competitor of SA PV solutions—is not taken as a constant, but it is endogenously determined through an algorithm which accounts for the travel time to the nearest 50,000+ inhabitants city at each settlement and the diesel truck consumption for fuel transportation.

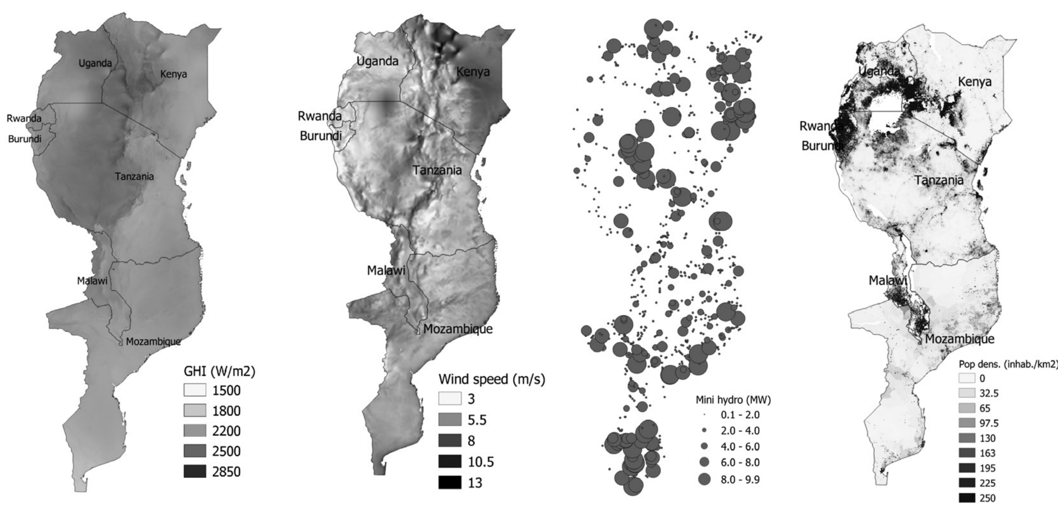
4. The model does not re-optimise access provision solutions for those who already have access.

5. In the *specs.xls* input file.

**Table 2: Input datasets**

| Dataset | Description | Source |
|---|---|---|
| Administrative boundaries | National administrative boundaries to define the spatial extent and crop other datasets | Hijmans et al. (2018) |
| Digital elevation | Elevation (in meters) | NASA LP DAAC (2011) |
| Small hydropower potential | Position, potential (MW) | Korkovelos et al. (2017) |
| Land cover | Categories of predominant land-cover define land suitability for installing different generation technologies | Channan et al. (2014) |
| Night-time lights intensity | Employed to calibrate the population without access | Elvidge et al. (1999) |
| Population | Number and position of the population within national boundaries | Tatem (2017) |
| Roads | Employed to calibrate the population without access | CIESIN–ITOS (2013) |
| Slope | Calculated from DEM datasets | Author's elaboration |
| Solar PV potential | Global horizontal irradiation to calculate solar PV potential | SolarGIS (2017) |
| Solar restrictions & Calculated from land cover dataset to restrict PV installation in certain land settings (e.g. cropland and water bodies) | Author's elaboration | |
| Electricity substations | Employed to calibrate the population without access | Enerdata (2016) |
| Current and planned electricity transmission network | Employed to define the cost and potential for new connection and grid extension | Arderne (2017) |
| Travel time to the nearest 50,000+ city | Defined to calculate the LCOE of diesel | Weiss et al. (2018) |
| Wind potential | In m/s, used to calculate the wind power capacity factor | DTU Technical University of Denmark (2017) |

**Figure 1: Maps of EA representing (a) global horizontal irradiation ($W \cdot m^{-2}$); (b) average wind speed ($m/s$); (c) mini-hydropower potential ($MW$); (d) population density ($inhab \cdot km^{-2}$). Data sources: (SolarGIS, 2017; DTU Technical University of Denmark, 2017; Korkovelos et al., 2017; Tatem, 2017).**



Thereafter, the model performs a recursive Python-based optimisation process where it calculates the levelized cost of electricity (LCOE)[6] of each generation solution at each 1-km cell. In general, the LCOE is defined as:

$$\mathrm{LCOE} = \frac{\sum_{t=1}^{n} \frac{I_t + O\&M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}} \tag{1}$$

where, for each technology, $I_t$ represents the investment cost in year $t$, $O\&M_t$ are operation and maintenance costs, $F_t$ are fuel costs, $E_t$ is the electricity generated, $r$ is the discount rate, and $n$ is the lifetime of the technology in question. In particular, each technology defines its cost depending on an array of parameters which include both local potential (for RE) and infrastructure and terrain barriers (e.g. distance to the existing and planned grid, elevation, slope, land cover). For instance, solar PV installation is limited to land cover types that exclude water bodies or cropland or with a certain gradient of slope (KTH–dESA, 2019).

Overall, in the modelling framework six key (sets of) parameters determine which is the lowest LCOE-technology at each location, namely (i) the electricity demand tier set for urban and rural areas, respectively (consistently with the World Bank Multi-Tier framework, (Bhatia and Angelou, 2015), (ii) the local population density, (iii) the distance from the nearest T&D grid and the average unit cost of on-grid electricity, (iv) the local RE potential and cost of diesel fuel, (v) the technological cost parameters and constraints, and (vi) the discount rate.

The model represents T&D grid investments by considering both the current and planned (i.e. expansions which have been reported as planned by governmental authorities and are included in (Arderne, 2017)) HV transmission electricity grid to define the cost of connecting new households to the national electricity supply network. The transmission grid investment cost is defined as a function of (i) the baseline cost of HV grid extension (set at $30,000/km); (ii) the incremental cost increase for extension of the grid from an electrified settlement to an non-electrified one (set at 10%); (iii) an upper-bound parameter, setting the maximum distance to which the grid can be extended from the existing system to electrify a settlement[7]. The model also considers MV and LV distribution lines for both grid and mini-grids, in this case as a function of the distance to the transmission grid by a constant investment for each of the two typologies of grid ($5,000 and $3,000/km, respectively). MV lines include an increase rate proportional to the length of the line in question (set at 7.5%). Also a HV/LV transformer cost (per unit) is included ($4,000/unit). Sensitivity analysis over the grid infrastructure expansion costs is carried out and reported later in the paper.

A comprehensive list of all the technological, cost, and socio-economic parameters selected for our analysis is reported in Tables 11–12. Refer to Mentis et al. (2017); KTH–dESA (2019) for an extensive illustration of the model assumptions and optimisation algorithm.

In the analysis a baseline discount rate of 15% and sensitivity values of 10% and 20% are considered. The discount rate is an important parameter in determining the results of scenario analysis, since it is the factor which measures the rate at which society is willing to trade present for future costs and benefits. At the same time, it encapsulates risks stemming from the exchange

6. *"The cost of supplying a unit of energy over a system›s lifetime that incorporates the initial investment in generation, T&D infrastructure; capital costs; and operations and maintenance costs including fuel costs. Levelized costs allow us to compare different technologies on the basis of the minimum unit price a user must pay for each system to break even.*" (Deichmann et al., 2011)

7. The parameter is supporting the convergence of the solving algorithm, but it is set sufficiently high (i.e. at 250 km) not to artificially limit the plausible technological choice set.

rate and other macroeconomic stability issues, as higher risks imply a higher cost of money. Given the crucial importance of the parameters in determining the modelling results, the sensitivity analysis section reports the results of the analysis for all the three tested values. The decision to set the baseline at 15% stems from an empirical observation of the average yield of medium to long-run governmental bonds of East African countries as of late 2019, with Kenya's yield 13%, Uganda and Tanzania's yield 15%, and Mozambique's yield in excess of 15%. The range of sensitivity values is thus centered at the rate plausibly faced by the parties that are raising capital to finance electrification (namely IPPs and the Government), and it ranges between 10%—the social discount rate generally adopted by the World Bank to assess infrastructure investments in developing countries Pueyo et al. (2016)—and 20%, a higher-bound value encapsulating potential risks stemming from events leading to increased political or monetary instability over the next ten years.

The model output reveals which 1-$km^2$ area grid cells would be most cost-efficiently served by grid connection, mini-grid construction, or standalone systems installation, and through which generation technology. The outcomes depend on the different *a priori* set parameters (Table 11) including technological costs, the baseline and local diesel price, the aimed electrification tier (i.e. the demand), and the discount rate. Given the large number of parameters and assumptions encapsulated in the model, it is necessary to design and run a number of sensitivity scenarios with different values for key parameters and produce comparative stats that show the relative impact on the final outcome.

Furthermore, crucially, OnSSET is not a country-wide energy-system model, and thus it does not optimise the grid-based electricity generation mix (i.e. the technology split of the installed capacity providing electricity dispatched by the national grid), for which instead an exogenous average grid cost of electricity parameter must be set and then compared by the model with the local LCOE of other generation solutions across every grid-cell in each country. Thus, three plausible[8] scenarios over the evolution of the on-grid generation mix until 2030 in the region are designed, suggesting different grid electricity cost and capacity addition investment costs. For each of those scenarios, we then compare how the optimal mix of new electrification solutions and the corresponding investment requirements would change.

Last, the analysis planning horizon ranges between 2016 and 2030, given that the most recent comprehensive data on country-level power consumption can be retrieved for year 2016. The objective of attaining a 100% electricity access level by year 2030 is consistent with the target 7.1.1 formulated in the Sustainable Development Goals. A scenario with a less ambitious objective of 75% electrification is also reported in the Sensitivity Analysis.

## 4. SCENARIOS DESIGN

Currently, the bulk of the grid-connected installed capacity of EA is given by hydropower, with medium and large-sized schemes providing 62% of the entire power supply of countries. Other renewables display a 13% degree of penetration, with 600 MW of installed geothermal capacity in Kenya, and some wind (e.g. the 310 MW Lake Turkana farm in Kenya) and solar (e.g. the 10 MW Tororo station in Uganda) having recently come on-line. Gas-fired generation has mainly significance only in Tanzania (more than 700 MW operating), while diesel and HFO play an important role in Kenya as they account for roughly 25% of national generation (and overall 400 MW in EA). Significant plans exist for developing coal generation in different countries (both to contribute feed-

8. Based on projects currently under construction, planned, and under consideration, as well as on the potential and cost of each technology in the region.

ing the steeply growing demand and driven by foreign investment), including Kenya, Malawi, and Mozambique, which however is still currently very limited (0.25 GW of installed capacity).

The regional power demand is expected to undergo a near three-fold increase by 2030, as a result of both electrification (new consumers who gain access), and of increased consumption by already electrified households and by an emerging industry sector. According to projections from different sources (Table 3), the compound annual growth rate of electricity consumption is projected at 7.1%, with a total increase from 40 TWh in 2016 to 112.5 TWh in 2030. Residential demand will also grow robustly (on average +10.7% per year). The largest growth rates are expected in countries that currently consume very little power, including Burundi and Rwanda, but in absolute terms the largest increase will be observed in Kenya and Tanzania, the two major economies in the region, where the emerging regional industrial sector will push the demand. Mozambique, currently the first consumer in the region due to its power-hungry mining sector (representing 70% of the total demand), displays a lower-than-average expected electricity consumption growth rate (+6.6%). This is owing to the already relatively high per-capita consumption of electrified consumers (264 kWh/capita/year) with respect to the rest of EA (which averages at 187 kWh/capita/year). The figure of Mozambique is likely affected by the hungry mining sector.

**Table 3: Current and projected demand for electricity in EA countries**

| Country | Gross power demand in 2016 (GWh)[9] | Residential power demand in 2016 (GWh) | Gross power demand in 2030 (GWh) | Residential power demand in 2030 (GWh) | Compound annual growth rate (gross) | Compound annual growth rate (residential) |
|---|---|---|---|---|---|---|
| Burundi | 300 | 150 | 3,500 | 1,500 | 18% | 17% |
| Kenya | 9,500 | 2,550 | 23,000 | 10,000 | 6% | 10% |
| Malawi | 2,000 | 600 | 8,000 | 2,500 | 10% | 10% |
| Mozambique | 13,500 | 1,650 | 34,000 | 4,500 | 6% | 7% |
| Rwanda | 500 | 400 | 4,000 | 2,500 | 15% | 13% |
| Tanzania | 11,000 | 2,500 | 30,000 | 13,000 | 7% | 12% |
| Uganda | 3,250 | 743 | 10,000 | 4,500 | 8% | 13% |
| **Total** | 40,050 | 8,600 | 112,500 | 38,500 | 7% | 11% |

Sources: Rwanda Environment Management Authority (2009); CIA (2017); IEA (2018); Keizer (2017); Lahmeyer International and Electrogaz (2004); Mahumane et al. (2012); Mawejje and Mawejje (2016); Ministry of Energy and Mineral Development of Uganda (2015); SEforALL (2013); Teske et al. (2017); Zalengera et al. (2014)

Based on current and projected figures, we design three potential generation mixes up to the planning horizon of 2030 and—accounting for potential cost profile changes of different generation technologies—we calculate the average cost of grid electricity. Reference figures for the current LCOE of different generation sources are drawn from IRENA (2018) and Santley et al. (2014). Table 4 describes three possible generation mixes scenarios compared with the status quo, defined as the current mix of EA countries as according to US EIA data. Scenarios are constructed by starting from hydropower, currently representing the bulk of the regional generation capacity, and by considering the capacity factor of operating plants and the planned capacity by country as reported in The International Journal on Hydropower and Dams (2017). In particular, the capacity factor in 2030 is set at 0.65 for already operating schemes. The value is slightly lower than that derived from historical data from US EIA and UNDATA (around 0.7) to account for potential climate-induced disruptions in the region. The literature has highlighted a likely total hydropower potential increase in the region under a warmer climate, but also a significantly higher likelihood of extreme hydro-climatic events, leading to temporary disruptions (Sridharan et al., 2019; Falchetta et al., 2019; Van Vliet et

9. Only electricity consumed in the region is considered. Thus, the ~13 TWh/year of electricity generated at Cahora Bassa dam in Mozambique but exported directly to South Africa are excluded from the calculation.

al., 2016). For new hydropower plants, the CF is set at 0.55, to account for the operational lag before long-term average efficiency is attained. Our results show that hydropower in 2030 would be able to cover between 50% and 55% of total projected demand for power, depending on the amount of planned capacity which is actually developed and on the capacity factor.

Corresponding required capacity additions for each technology ( $GW_t$ ) are calculated by solving the following linear system of equations:

$$\begin{cases} \Delta GWh_{2030}^{2016} = \sum_{t}^{N} cf_t \cdot GW_t \cdot 8760 \\ \Delta GWh_{2030}^{2016} \cdot share_t = cf_t \cdot GW_t \cdot 8760 \\ \forall t \end{cases} \tag{2}$$

where $\Delta GWh_{2030}^{2016}$ is the projected power demand growth between 2016 and 2030 and $share_t$ is the share of power consumption of each technology over total output. Capacity factors ($cf_t$) of 0.6 for NG, 0.75 for coal-fired generation, and 0.5 as a technology-weighted[10] average for RE (due to the significant role of geothermal in EA) are assumed, with values drawn from (Eberhard et al., 2016). Finally, the currently operating capacity is subtracted from the results to derive required capacity additions.

**Table 4: Regional power mix scenarios**

| | **Scenario** | Metric | Hydro (%) | REs (%) | NG (%) | Coal, diesel, and HFO (%) |
|---|---|---|---|---|---|---|
| ***2016*** | — | Generation (GWh) | 62% | 13% | 12% | 13% |
| | | *Installed capacity (GW)* | 3 | 1 | 0.75 | 0.7 |
| ***2030*** | Scenario 1 | *Generation (GWh)* | 55% | 10% | 25% | 10% |
| | | *Installed capacity (GW)* | 12.5 | 2.57 | 5.35 | 1.71 |
| | Scenario 2 | *Generation (GWh)* | 50% | 10% | 10% | 30% |
| | | *Installed capacity (GW)* | 11 | 2.57 | 2.14 | 5.14 |
| | Scenario 3 | *Generation (GWh)* | 50% | 22.5% | 22.5% | 5% |
| | | *Installed capacity (GW)* | 11 | 5.78 | 4.82 | 0.86 |

Scenario 1 represents a trajectory of only limited reduced dependency from the predominance of hydro (with hydropower capacity additions of up to +12.5 GW), implementation of on-grid REs (+1.6 GW) and some coal and diesel (+1.1 GW), and the bulk of new non-hydro capacity based on NG (+4.6 GW). It is a scenario where EA NG resources are developed for domestic use and a NG pipeline distribution network begins to be developed across the region. Overall, the shares of hydro, coal, and REs diminish, as in relative terms capacity additions are lower than those of NG and of the increase in electricity demand. Scenario 2 describes a path where NG is partially devoted to exports out of the region. Its overall share remains constant (with +1.4 GW added), while the bulk of non-hydro capacity additions is coal (or diesel)-based thermal (+4.5 GW), with both coal imports (from South Africa, DR Congo and Zimbabwe), and coal-mining activity (in Tanzania and Mozambique). As in Scenario 1, the share of REs for on-grid decreases slightly over the period (+1.6 GW). Hydropower continues to represent the majority (+50%) of total capacity (+11 GW added). Scenario

10. For utility-scale plants the following CFs are defined: solar PV: 20%, wind: 35%, geothermal: 70%. For decentralised solutions, including both MG and standalone solutions, the geospatial model calculates the local CF based on the local potential and other parameters (refer to Mentis et al., 2017).

3 is instead a pathway of rapid RE (+4.8 GW) uptake in tandem with NG production for domestic generation (+3.8 GW), where the coal and diesel combined share remains constant (5%, i.e. +0.25 GW) with respect to the current share, and hydropower share is slightly less prominent (+11 GW), with a final configuration of roughly 50% for hydro and 22.5% for each NG and REs.

Based on such scenarios, we assume that between 2016 and 2030 each generation technology's LCOE will be in line with those reported in Table 8, where current values are based on data from IRENA (2018) and Santley et al. (2014) and forecasts compare estimates from Creutzig et al. (2017), IRENA (2016), Varro and Ha (2015), and Augustine et al. (2018), including arguments from Demierre et al. (2015) over the domestic price of gas in EA over the next decade, which is projected to be in the $4–5/Mbtu. Refer to the Appendix for a summary of the screened sources to derive LCOE values for each technology in EA.

For each scenario the average cost of grid electricity generation[11] is calculated by weighting the assumed LCOE in 2030 (as in Table 8) by the share (%) of that generation technology in each of the three scenarios (as in Table 4). The resulting figures are reported in Table 9. Finally, costs are adjusted on a country-by-country basis to account for the different endowment of energy resources. This implies that countries which have local abundance of a given energy resource will display lower costs in scenarios where such resource is largely exploited. In particular, for scenarios 1 and 3, which determine a higher penetration of NG-fired generation, no additional costs accrue for Tanzania and Mozambique (which are endowed with reserves), while a cost premium for other countries which would have to import such resources is added, namely +15% for Kenya and +20% for other countries; in Scenario 3, where also REs are prominent, these are rendered costlier by 10% in smaller countries because it is assumed that scale dynamics and greater potential would imply a lower price in larger countries; finally, in Scenario 2, where coal-fired generation gains a significant share, smaller and more remote countries to coal-bearing areas (coal is found in Mozambique, Zimbabwe and DR Congo) face a 20% higher price.

A total of 12 scenarios that vary across three key dimensions are considered and summarised in Table 10, namely: (i) The baseline price of diesel in 2030, for which a low-price [A] ($0.90/l) and a higher-price [B] ($1.30/l) are defined.[12] (ii) The grid-based power generation mix scenario (as defined in Table 4 above), [1, 2, or 3]). (iii) The electricity demand tiers in urban and rural areas, respectively. A high-tier scenario [h] (with 423 and 160 kWh/person/year in urban and rural areas) and a low-tier scenario [l] (with 160 and 44 kWh/person/year in urban and rural areas) are defined. To provide a sense of what such figures mean in final use terms, 44 kWh/person/year (low-tier in rural areas) are enough to provide general lighting, air circulation and a television; 160kWh/person/year (low-tier in urban areas and high-tier in urban areas) also enable some light appliances use, such as general food processing and washing machine; 423 kWh/person/year (higher-tier in urban areas) further include medium or continuous appliances, such as water heating, ironing, water pumping, refrigeration, and microwave.

The high-tier variant can be thought as a more long-sighted scenario (i.e. where the central planner has a lower time preference for the present and is willing to invest more in the present for benefits in the future) which encapsulates a demand component that goes beyond the provision of basic household electricity. Namely, the additional demand for power for productive uses, including

11. It must be noted the cost of grid-based power generation is the cost borne by the electricity utility for power generation, not the price paid by the end-user. It does not in fact include T&D network costs, which are modelled separately in OnSSET, which generally represent a large fraction of the total cost of electricity delivered to end-consumers, or taxes and subsidies on consumption.

12. Diesel prices have been set based on the International Fuel Prices database (GIZ, 2017).

irrigation and light agro-processing, the opening of small businesses in proximity of newly connected households, and the gradual growth over time in power consumption related to the complex dynamics that link electrification and economic growth (Riva et al., 2018a). The low-tier variant scenarios are instead pathways where 100% electrification is pursued to comply with the target 7.1.1 of SDG7, i.e. a 100% electricity access level by 2030, but where energy poverty might nonetheless persist, especially among consumers electrified via standalone solutions. SA technologies are broadly unable to provide electricity, for instance, for air conditioning—one of the principal ways that tropical populations can adapt to heat waves caused by global warming. Irrespective of this, the proximity of year 2030 and the deadlock situation witnessed in parts of rural East Africa make low-tier pathways plausible and more desirable than the lack of any local generation solution. Refer to IEA (2017) for an illustration of the appliance use limitations under different access technological solutions.

All the remaining parameters are taken as constant across scenarios, and they are reported in the Appendix.

## 5. RESULTS

### 5.1 New electrification

The median investment required to provide least-cost universal access to the population currently without electricity in EA by 2030 is estimated at \$57 and \$110 billion for low and high-tier consumption scenarios, respectively. This averages at \$83.5 billion, which corresponds to about \$5.6 billion/year in the model's planning horizon between 2016 and 2030. Switching from low to high consumption tiers implies—on average—a 93% increase in the total required investment. Considering the mean investment requirement for full electrification of SSA of \$21 billion/year estimated in PBL Netherlands Environmental Assessment Agency (2017) as a benchmark, and dividing it by the share of the EA population (i.e. 21%), we find a value of \$4.4 billion/year. The proximity of the figures provides a first line of evidence of the robustness of estimates computed with different models, parameters, and methodology.

Figure 2 reports the average country-level aggregated required investment (accounting for both capacity additions and the necessary extensions of the T&D lines) for the low and high-tier consumption objectives, respectively. Tanzania, Kenya and Uganda figure as the countries with the largest overall investment required to electrify households without access by 2030. Between today and 2030, the three countries will have to electrify 72 (Tanzania), 53 (Kenya), and 55 (Uganda) million people to attain full electrification, with a significant role played by population growth in the process.

With regards to the investment distribution across technologies, our results show that grid-based capacity additions and the extension of T&D lines themselves are always the largest investment component, with a median value between high and low tier scenarios of 66% of total required investments. Those for mini-grid technologies (including PV, wind and hydro-based solutions) represent almost one-third of total mean investments, while those for standalone PV or diesel solutions account for less than 5%. Figure 3 illustrates the split of optimal mean investment requirements by access technology in both low and high-tier scenarios, revealing the increased share of the national grid in high-tier scenarios.

The technology-specific requirements are also highlighted in Figure 4, which shows a box-plot visualisation for the distribution of required capacity additions to achieve 100% electrification

**Figure 2: Total required investment by country and consumption tier for for achieving 100% electricity access by 2030. Left panel: low tier scenarios median; right panel: high tier scenarios median.**

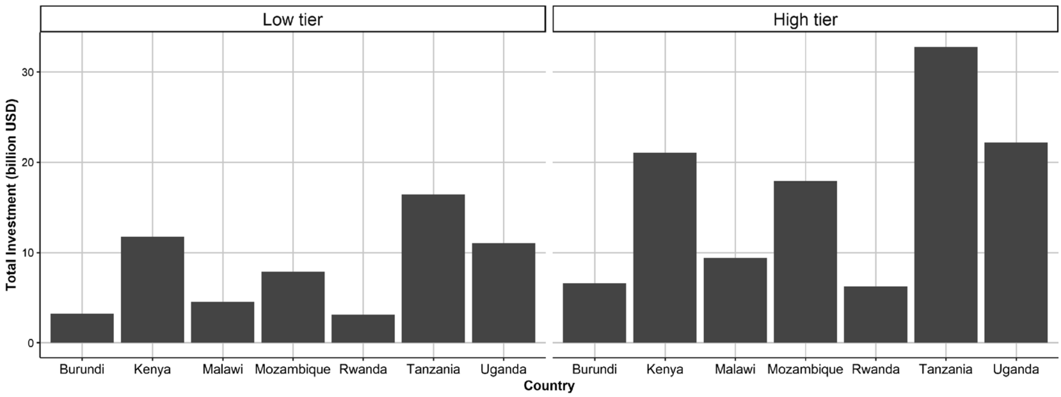
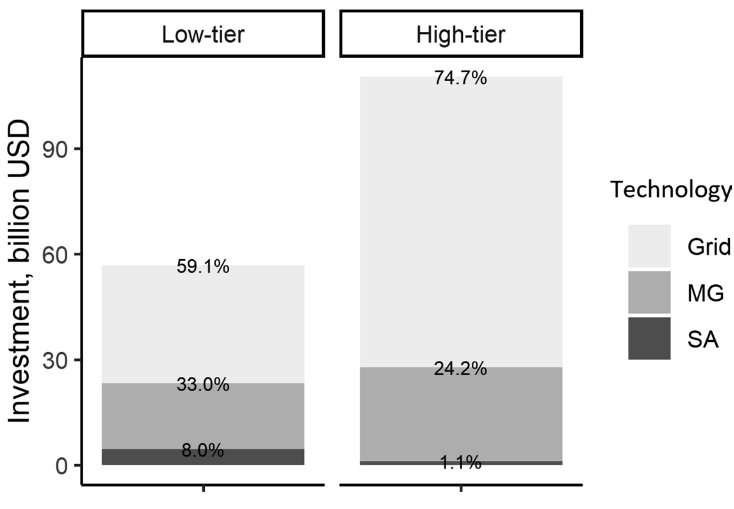



**Figure 3: Split of optimal mean investment requirements by access technology in high-tier and low-tier scenarios.**




by 2030 in each country for each specific technology across the 12 scenarios considered. Figure 4a includes requirements in grid-based capacity and mini-grid and standalone PV and diesel solutions (the unit is GW), while Figure 4b reports the capacity required in mini-grid (MG) hydropower and wind. In this case, the figures are expressed at a MW-scale.

Concerning national grid-based access expansion, it results that Tanzania and Uganda together require around half (3.8 GW) of the total (7.6 GW) new median capacity additions for delivering 100% electrification to those without access in EA. Kenya and Mozambique require a median of about 1 GW each. Interestingly, the range of uncertainty across scenarios is relatively little for Kenya and Mozambique (around 0.6—1.6 GW in both countries), while it becomes larger for Tanzania (1—3 GW) and Uganda (0.8—2.9 GW). This implies that in Kenya expanding access through grid electricity remains a relatively efficient solution as opposed to decentralised solutions under all costs and demand scenarios analysed. The result stems from the fact that among EA countries, Kenya has already the highest electricity access level, at 73%, with 90% in urban and 68% in

**Figure 4: Box plot of capacity additions for achieving 100% electricity access by 2030 (by technology and by country). (a) Technologies with a GW-scale penetration; (b) minor technologies (in MW).**

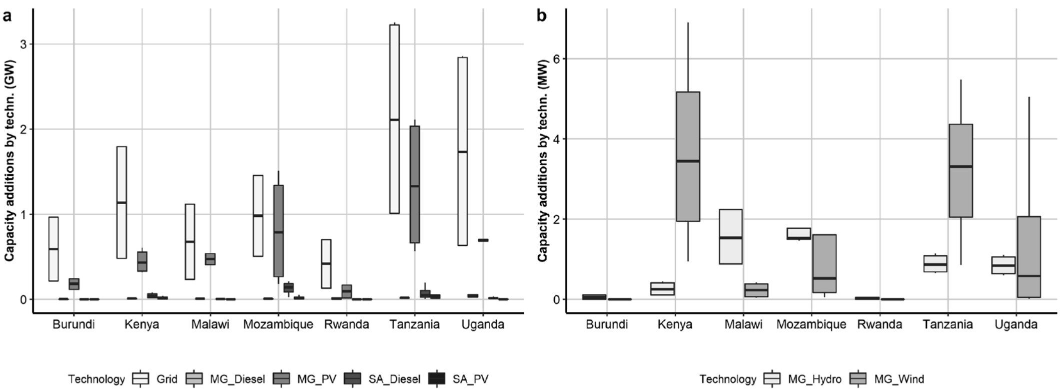
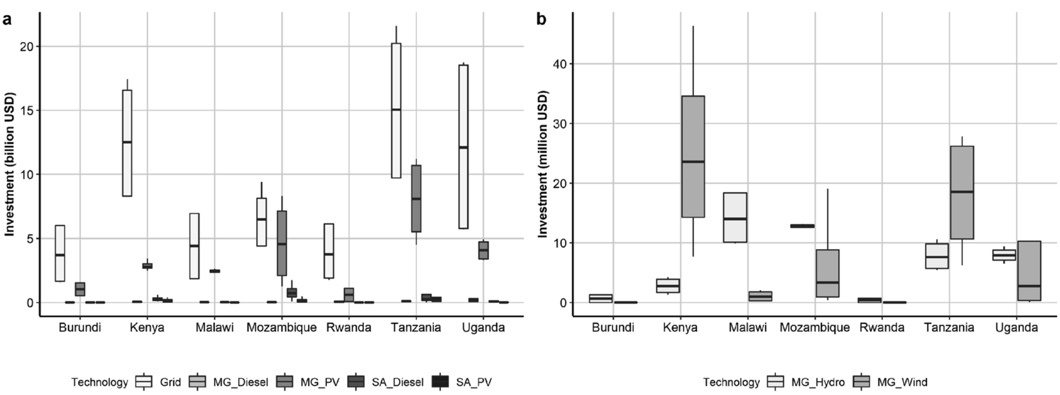



**Figure 5: Box plot of total required investment for electrification of those currently without access by 2030 (by technology and by country). (a) Technologies with a billion dollar-scale investment requirement; (b) minor technologies (in million $).**




rural areas. Thus, relatively little grid-based generation capacity is required to provide access to the remaining non-electrified urban centres.

Mozambique, which is the second largest country in terms of total surface area after Tanzania, requires less than half of the median grid-based generation capacity required by Tanzania. This is due to both its population being half of that of Tanzania (and a very low population density of 37 people/$km^2$, with an urbanisation level of 35%, as opposed to a density of 63 people/ $km^2$ in Tanzania), and to the limited extent of the electricity transmission network currently in place. In small in size but densely populated EA countries, namely Burundi and Rwanda, grid-based capacity additions take up the bulk of access expansion, with 0.6 and 0.4 GW of median on-grid capacity additions, respectively (Figure 5a). In Malawi about 0.7 GW of grid-based capacity are required, but mini-grid solutions will also play a prominent role in realising least-cost electrification (with median required capacities of 0.5 GW for MG-PV and 8 MW of MG hydro, diesel, and wind).

Comparing model results for capacity additions (Figure 4) and investment required (Figure 5), it is interesting to observe that the median required investment for grid electricity in Kenya ($13 billion) is similar to that of Tanzania ($15 billion) and Uganda ($12.5 billion), irrespective of the notably lower capacity addition required (see Figure 5a). This is due to the fact that grid expansion will constitute a major source of costs for achieving 100% access in Kenya, as the figures of required investment include investment in new transmission grid capacity. Furthermore, important MG solar investments are required in Tanzania ($7.5 billion) and in Mozambique Uganda (about $5 billion), while SA PV investment is prominent in Tanzania ($0.16 billion) and Kenya and Mozambique ($0.1 billion). MG diesel requires around $432 million, with the greatest investment required in Uganda ($0.2 billion) and Tanzania ($0.1 billion).

Concerning minor technologies (in terms of their penetration), hydro and wind-based MG will have the greatest required investments in Malawi and Uganda (median values of $11 and $15 million, respectively)—countries with substantial potential and conditions for small-scale development.

**5.2 Sensitivity analysis**

*5.2.1 Discount rate*

In the baseline results the discount rate is set at 15%. To assess the sensitivity of the results to changes in the discount rate (e.g. because of greater uncertainty raising the cost of money or time preference), we produce extra runs at 10% and 20%. The results (Figures 9–11) show that the overall investments requirements are slightly sensitive to the discount rate (with a higher discount rate discouraging investment), while the capacity requirements tend to remain relatively constant. This is the result of the increasing share of national grid-based electrification as the discount rate grows, with the figure going from a range of 49–64% across tier scenarios at a 10% DR to 52–72% at a 20% DR. This is in turn the outcome of the fact that a higher discount rate fosters the deployment of investment at $t=0$ in technologies that have higher running costs throughout their lifetime (fuel and operation and maintenance), since the present value of such future costs becomes comparatively lower. Thus, in a number of settlements, grid-based investment (which has higher fuel and operation and maintenance costs) becomes more efficient than mini-grid investment (where the bulk of the total investment occurs at $t=0$).

*5.2.2 Grid infrastructure*

Further realisations are run to assess the effect of changing grid infrastructure costs, according to the two following sets:

1. HV: $35,000; MV: $7,000; LV:$4,500
2. HV: $50,000; MV: $7,500; LV:$5,000

The results (Figures 12–14) reveal that the grid infrastructure expansion costs have a moderate effect on the investment requirements for both high (up to +$7 bn.) and low-tier scenarios (+$3.6 bn.). Furthermore, among low-tier scenarios, higher grid investment costs result in a significantly shrinking share of MG solutions (–11.2 percentage points) because of the impact on the distribution network, which are replaced by SA technology. Conversely, in high-tier scenario a moderate (about 4 percentage points) shift is observed from grid-based to SA solutions.

*5.2.3 Connection charges*

We then test the effect of lowering the average new grid connection charge (set at $450 in baseline runs), a result which could be attained via public or international subsidisation, to $200 and

$100, respectively. The results (Figures 15–17) suggest a dramatic effect of the measure on both low and high-tier scenarios, also implying the need for slightly less capacity in the high-tier scenarios of the largest countries, as a result of increasing shares of grid-based electrification. In particular, a diminishing of the charge from $450 to $200 results as the single most effective way to increase grid-based electrification (+8.1 percentage points in both low and high-tier scenarios). A further decrease from $200 to $100 per new household connected to the national grid is particularly effective in low-tier scenarios, while the effectiveness of the extra reduction is only marginal in high-tier scenarios, where a penetration of the national grid up to 76.2% is observed.

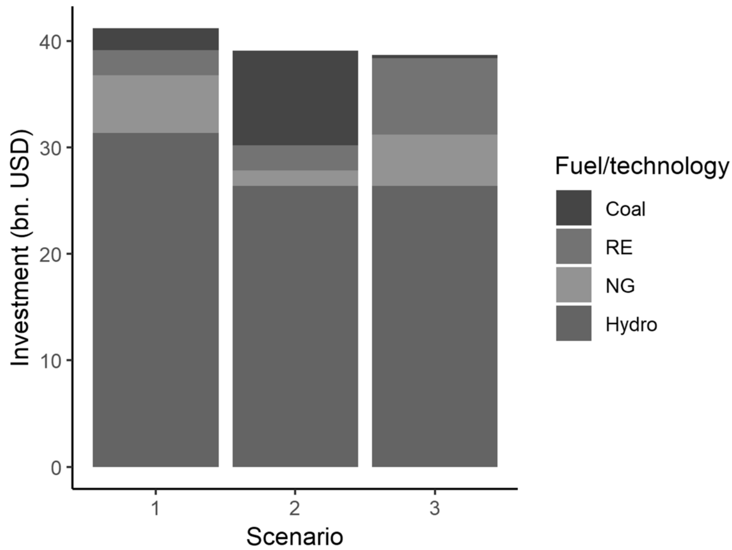
*5.2.4 75% electrification objective*

Last, we test what effect has relaxing the 100% electrification objective by 2030 to a 75% objective in terms of required investments and capacity additions. In the model this is attained by re-optimising the least-cost electrification and by selecting only those settlements which are in the bottom 75% of the electrification costs distribution. We find (Figures 18–20) that the impact on total investment requirements from attaining 25% lower national access rates by 2030 is significant and roughly linearly smaller (i.e. it represents 73.3% and 77.2% of the investment in a full electrification objective under high and low tier scenarios, respectively). This figure ranges between 70.8% in Kenya under a high tier scenario and to 80.5% in Rwanda under a low tier scenario. Thus, the analysis reveals ±5% scale effects depending on country and demand tier targeted. Generally, in low tier scenarios the adverse scale effect is more evident due to the larger penetration of decentralised solutions, which are inherently less efficient than grid connections, i.e. they require a ceteris paribus larger installed capacity and generally have higher operation and maintenance costs. In particular, we reveal a significant decline in the share of MG solutions in low-tier scenario (from 43.5% to 32.3% when going from the 100% to a 75% objective) This is likely due to the fact that the 25% of the population remaining without access in 2030 is most efficiently electrified through MG solutions, which however remain more costly than the average connection to the national grid. The 25% percent is mostly represented by distributed rural communities. In the case of high-tier scenarios, MG solutions decline even more dramatically (–13.5 percentage points relative to the initial share). This implies that the model finds significant barriers to MG connection for the residual 25% of the population not electrified (e.g. because of capital-intensiveness of new MG systems installation). Overall, this analysis implies that focusing investment on grid-based connections could be a comparatively more efficient strategy, but only by up to 5% and under specific circumstances (mostly in high-tier objective scenarios, and only in certain countries).

### 5.3 Beyond new electrification: additional demand growth

Besides new electrification, the regional demand for power is projected to grow robustly as a result of e.g. the increasing per-capita consumption of the households which already benefit from electricity access, the industrialisation process, and the mechanisation of agriculture. To consider these additional drivers, we calculate the up-front investment required to satisfy the projected demand in 2030, as well as the corresponding costs incurred over time over the three grid-electricity generation mix scenarios introduced in Table 4. This is achieved by computing—for each scenario—the required capacity additions to reach the projected consumption in 2030. The CFs are set at 0.55 for hydropower, 0.5 for REs, 0.6 for NG, and 0.75 for coal. The investment cost for each technology is drawn from Enerdata (2016)'s *Study of the Cost of Electricity Projects in Africa* report. The additional consumption figures of interest are obtained by: (i) adjusting 2030 consumption estimates from Table 3, which are assumed to include demand from newly electrified up to the governmental electrification target by 2030 (and not for 100% electrification, as in our analysis); (ii) subtracting the demand coming from newly electrified households and the current demand from 2030 consumption estimates.

**Figure 6: Investment requirements in generation capacity for power demand growth beyond new electrification.**




The median required investments range within a rather narrow range (Figure 6), i.e. between \$41.2 billion for a scenario of reduced diversification from hydropower (Scenario 1) and \$38.7 billion for a RE-NG expansion scenario (Scenario 3), with the coal-based expansion scenario (Scenario 2) requiring \$39.1 billion. It thus results that in investment terms there is very little difference across the three scenarios considered, and it corresponds to around further \$2.7 billion (or \$0.17/ year) until 2030. In all scenarios, the bulk of the required investment to cover the additional demand in EA (i.e. not stemming from new connections) is for hydropower capacity. At the same time, the projections show that required capacity addition investments[13] for covering demand growth beyond electrification are around 50% of those (mean) needed for electrification itself (which however also include the national grid extension investment for new connections).

Table 5 reports the corresponding country-level costs until year 2030 to satisfy the baseline consumption growth (i.e. not stemming from new electrification) from between 2016 and 2030. Differently from investment, costs do not accrue up-front but they are given by the discounted sum of the total cost incurred until 2030. The cost figures are estimated by multiplying baseline consumption estimates for 2030 by the regional LCOE of grid-based electricity under the mix scenarios of Table 4.

13. Thus, here, the investments in strengthening the transmission grid to deliver the increased volumes of electricity are not included.

**Table 5: Cumulated discounted grid electricity generation cost from already electrified consumers' demand growth (2016–2030)**

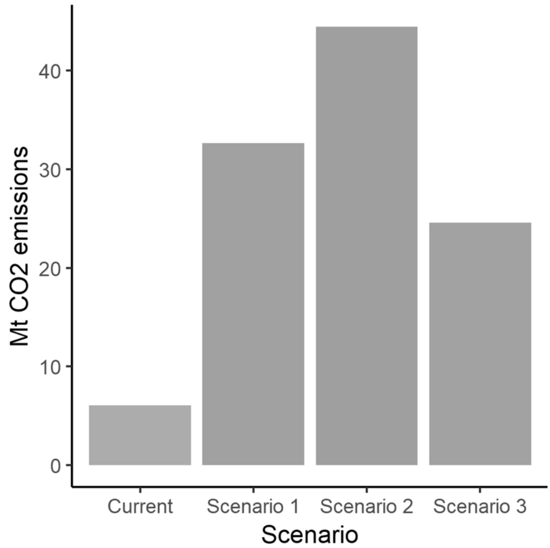
| Country | Scenario 1, demand growth only (bn. $) | Scenario 2, demand growth only (bn. $) | Scenario 3, demand growth only (bn. $) | Mean across scenarios, (bn. $) |
|---|---|---|---|---|
| Burundi | 0.14 | 0.15 | 0.13 | 0.14 |
| Kenya | 3.44 | 3.45 | 3.22 | 3.37 |
| Malawi | 0.34 | 0.34 | 0.33 | 0.34 |
| Mozambique | 0.61 | 0.67 | 0.59 | 0.62 |
| Rwanda | 0.15 | 0.16 | 0.15 | 0.15 |
| Tanzania | 1.02 | 1.23 | 1 | 1.08 |
| Uganda | 0.52 | 0.58 | 0.51 | 0.54 |
| **Total** | 6.2 | 6.58 | 5.93 | 6.24 |

The results of the analysis show that in all countries Scenario 3—that of a capacity expansion based on RE and NG—is the cheapest solution to satisfy grid-based electricity demand. Scenarios 1 and 2, i.e. those of power expansion backed by NG or coal, respectively, show instead higher costs, with Scenario 2 being the costliest (+10% vs. Scenario 3). Thus, according to the scenarios elaborated in this analysis, Scenario 3 (one of RE-NG-based expansion) would be both the one with the lowest upfront investment (although this will be very close to the upfront investment of a coal-based expansion scenario), and the cheapest over the long-run. At the same time, due to its greater technological diversification, it would allow for a wide spectrum of balancing options (both short-term, for daily demand, and seasonal), such as an exploitation of the hydro-VRE complementarity (Sterl et al., 2019) and using NG-fired thermal plants for both peak demand satisfaction and a fraction of the baseload supply.

The RE-NG scenario would also contribute to attain a substantially lower (–45% vs. the coal-based expansion of Scenario 2 and –25% vs. the NG-based expansion of Scenario 1 in year 2030) $CO_2$ emission pathway (as shown in Figure 7) and local pollution levels (since coal-fired thermal generation has significant impact on local air quality (Institute for Energy Research, 2009). The emission factors to calculate the total figures are set at 0.85 $kgCO_2kWh^{-1}$ for coal and diesel, and at and 0.58 $kgCO_2kWh^{-1}$ for NG, while they are set to null for RE and hydropower. Although the projected emissions of the EA power sector in year 2030 under all scenarios are negligible when compared to the current global emissions (they would represent a share of about 0.11% of the current global emissions), a more sustainable development path—like that of Scenario 3—allows to comply with the National Determined Contributions of the Paris Agreements (refer to the NDC registry under https://www4.unfccc.int/sites/NDCStaging) and reduce the social costs of power generation (even locally, for instance with the emission of less local pollutants such as those resulting from coal combustion). Note that external costs have not been explicitly included in our analysis.

Finally, it must be remarked that the figure for the baseline power demand growth satisfaction does not include the necessary expansion of the grid to support the new load on the transmission grid. While in this analysis we do not present a further assessment of the investment required for such expansion, previous evidence (IEA, 2016) has shown that T&D investments needed to accompany the power generation expansion are generally very similar to those of the generation investment itself. Therefore, in such cases, the total investment cost for power generation, transmission, and distribution would amount to around $80 billion dollars between 2016 and 2030, a figure close to the median required investment for new electrification.

**Figure 7: Carbon dioxide ($CO_2$) emissions of the EA power sector in 2030 by generation mix scenario.**




### 5.4 Results in perspective

Table 6 summarises the total investments required for fulfilling three distinct objectives: (i) electrifying at a low consumption tier; (ii) covering the baseline demand growth; (iii) doing both, while also providing newly electrified consumers with consumption levels comparable to those who already had access in 2016.

**Table 6: Investment requirements summary table**

| Objective | Median investment (bn. $) |
|---|---|
| Low-tier electrification | 57 |
| High-tier electrification | 110 |
| Baseline demand growth satisfaction (capacity only) | 40 |
| Baseline demand growth satisfaction (capacity) w/ low-tier electrification | 97 |
| Baseline demand growth satisfaction (capacity) w/high-tier electrification | 150 |

To put these results in perspective, the required investments per-capita and as a share of GDP have been calculated for each country and in each year until 2030. In doing so, it was assumed that investment will not be evenly distributed across the 15 years under consideration, but rather that it would non-linearly increase over time, namely at the same (compounded) rate at which electricity consumption is projected to grow between 2016 and 2030 in each country.

The figures (reported in Table 7) suggest that the per-capita investment (accounting for the entire population, even those who already have electricity access) in the initial year (i.e. 2016) for electrifying households currently without access is in the range of $8–18 per-capita, with the regional EA figure at $16. When calculating the per-capita figure exclusively for the population currently without access (thus, the amount that hypothetically each person should finance herself to gain access), the figure rises to a range of $8–26 per-capita, with only marginally higher values in many countries (as a result of low-electrification rates, which result in similar total population and

**Table 7: Investment requirements in perspective**

| Country | Total invest. (bn $) | Inv. p.c. 2016 ($) | Inv. p.c. w/out access 2016 ($) | Inv (% 2016 GDP) |
|---|---|---|---|---|
| Burundi | 4.7 | 7.5 | 8.4 | 2% |
| Kenya | 15.9 | 14 | 19.7 | 1% |
| Malawi | 6.93 | 12.4 | 14.3 | 4% |
| Mozambique | 12.3 | 17.8 | 23.5 | 4% |
| Rwanda | 4.39 | 7.8 | 11 | 0% |
| Tanzania | 24.2 | 17.5 | 22.3 | 4% |
| Uganda | 16.5 | 14.9 | 18.5 | 7% |
| Total for new electrification | 83.5 | 15.6 | 20.1 | 2% |
| Capacity invest. for addit. demand | 40 | 7.4 | — | 0.9% |
| Total investment | 123.5 | 23 | — | 2.9% |

population without access figures). The investment represents roughly 2% of the regional GDP in exchange rate terms, growing to 2.9% when factoring in also the capacity investment necessary to satisfy the baseline electricity demand growth.

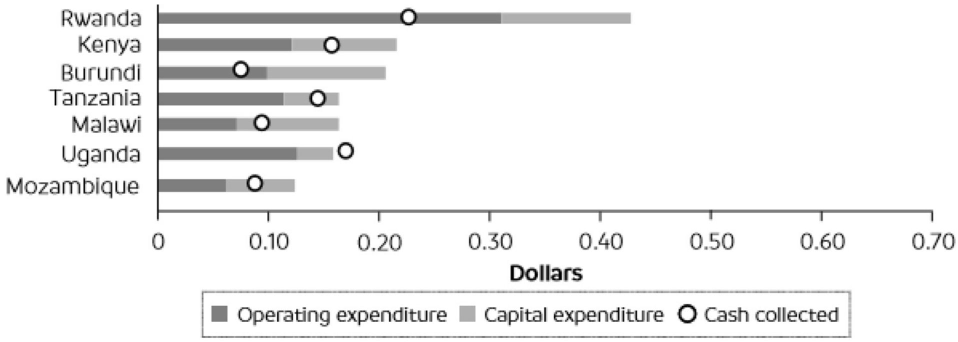
Again, it must be remarked that for newly electrified consumers we are considering a mean value between high and low tiers of consumption. If we look instead at the results for the two specific targets, the investment requirements lie in the 1.3%–2.4% range of GDP. Thus, increasing new electrification efforts between from the low to the high tier would result in around a doubling of investment requirements for bringing access to households currently without power. The high-tier scenario encapsulates a higher per-capita demand which virtually includes not only the provision of basic household electricity, but also the additional demand for power from productive uses of energy, and the gradual growth over time in power consumption from newly electrified households. All these activities would contribute to rural development, and thus to increasing the national GDP. Further macroeconomic analysis—in the form of cost-benefit analysis (CBA)—would be required to assess the economic significance of performing the larger investment to provide high-tier consumption access.

## 6. DISCUSSION AND POLICY IMPLICATIONS

Given the amount of investments required to achieve full electrification by 2030 in EA (a median of $83.5 bn for new electrification only and $40 bn for new capacity from demand growth), the financing challenge is considerable. Traditionally, electricity systems around the world are developed through investments made by national utilities, thanks to strong balance sheets developed by selling electricity from large-scale power plants and expanding grid infrastructure and generation capacity to meet rising demand (Lehr, 2013). With this financial strength, utility retained earnings generally serve as the primary financing source for the electricity sector. In many markets, utilities also serve as reliable purchasers of power, facilitating investments by independent power producers (IPPs).

In EA, as in all other regions in SSA, this traditional model is challenged by the fact that national utilities are not financially sustainable (Trimble et al., 2016). Across EA, only the distribution utility of Uganda (UMEME) fully covers operational cost and capital expenditures with the collected cash (see Figure 8). All other countires' utilities run in quasi-fiscal deficit (i.e. defined as the difference between the actual revenue collected and the revenue required to fully recover the operating costs of production and capital depreciation), and thus need to be subsidized by the state.

**Figure 8: EA utilities: comparison of electric supply costs with cash collected in 2014 ($/kWh billed). Authors' elaboration on data from (Trimble et al., 2016).**




Energy market reform is the only way to reduce these deficits, to make utilities financially viable, and therefore to enable investments (Eberhard et al., 2017). To reach operational efficiency, utilities should reduce transmission, distribution and bill collection losses, and at the same time tackle overstaffing. Then, utilities need to increase tariffs starting from large and medium-size customers, for whom affordability is not as significant a challenge as for small-consumption households (Kojima and Trimble, 2016). This equity-oriented implication is tied to the view of the authors. Our modelling analysis adopts an efficiency criterion, where costs determine the optimal electrification strategy, including the settlements that remain without access even after 2030 in our 75% electrification target sensitivity scenarios. However, from a policymaking point-of-view, following this equity-oriented approach is likely to result in spillover benefits: an uneven energy service provision would likely be responsible for an increased social inequality and would discourage economic growth among the poorest, with a likely long-run detrimental effect for the country-wide economy. As shown in our analysis (see Section 5.2.3), subsidies may be more efficiently targeted at reducing connection charges and stimulating grid-based electrification, rather than reducing unit prices of electricity. Finally, the introduction of innovative solutions, such as prepaid meters, could improve overall revenue collection. In order to reform electricity utilities and ensure implementation, EA countries should create robust and independent regulatory bodies empowered to hold electricity utilities to account.

It should be noted that, since the early 2000s, Kenya and particularly Uganda have taken a number of steps in this direction. The two countries have indeed started to phase-out universal energy subsidies, raising electricity prices to cost-recovery levels and reforming state-owned utilities. Not by coincidence, the two countries have the highest electricity prices in the region; in 2018, Kenya's electricity price stood at $0.20/kWh and Uganda's at $0.17/kWh, while the other regional countries' average stood at $0.13/kWh (World Bank, 2019).

Reforming universal energy subsidies and redirecting resources into productive energy investments represent a vital step in reshaping a country's energy system (IMF, 2013). In particular, two are the main reasons why energy subsidies should be reformed. First, universal energy subsidies are inequitable, as they mostly benefit higher-income groups that consume the most (Vagliasindi, 2012). Universal electricity subsidies are particularly regressive, because connection to the electricity grid is highly skewed toward higher-income groups. Second, universal energy subsidies are profoundly detrimental for the development of energy systems. In fact, they create a disincentive for maintenance and investment in the energy sector, perpetuating energy shortages and low levels of access.

In both Kenya and Uganda, these reforms have encouraged private investment in power sector and also led to many improvements, including increased power supply, better service, and a substantial increase in number of customers served by grid-supplied power. Putting the governance of energy sector in order is the starting point for expanding the regional energy systems, and therefore achieving 100% electrification by 2030. These reforms are also key to allow the creation of a suitable investment environment to enable independent power producers (IPPs) to operate in a competitive market (Eberhard et al., 2017) and rapidly expand the national installed capacity, while public utilities can focus of grid infrastructure planning and expansion. IPPs should be incentivised to enter the market with competitive tendering processes following principles of efficiency and cost-effectiveness, rather than be put in a direct negotiation with governmental actors (Ackah et al., 2017). Offering long-term standardised PPAs and transparent rules is key.

Furthermore, it is also important to outline the role of regional cooperation in scaling-up investment for on-grid solutions. In particular, the role of the Eastern Africa Power Pool (EAPP) in the development of the region should be boosted, and master plans long-sighted: the most effective strategies in terms of infrastructure development, market and contract design, international policy, import/export dynamics, and potential cooperation spill-overs should be identified and rendered operational. Fostering regional interconnections could in fact allow to maximize national energy potentials and integrate more generation capacity into the system, while ensuring its robustness and an efficient management of RE intermittency.

Expanding off-grid electrification might pose even higher financing challenges than on-grid electricity systems. Investing in on-grid, utility-scale, projects is more comfortable for energy companies and investors, as high density of electricity demand guarantee more stable revenue streams. Should sound reforms of electricity utilities and energy subsidies be made, there should be no major problem in the future to ensure the bankability of EA on-grid electricity infrastructure expansion. Far more problematic will be to ensure the development of small-grid and off-grid solutions needed to bring electricity to the 75% of SSA population living in rural areas (World Bank, 2019), which could not be reached by the national grid, due to either geographical constrains and/or lack of business case for grid expansion. Our results estimated the share of investments in this capacity at median values of 50% and 38% in our low and high-tier scenarios, respectively.

Declining costs and increasing performance for small hydro installations, solar PV and wind turbines, as well as declining costs and technological improvements in electricity storage and control systems, small-grid and off-grid renewable energy systems could become the game-changers for SSA rural electrification—in a decentralized and modular manner. However, these innovative energy solutions face three major barriers. First, they are characterized by low operating expenses (OPEX) and by high up-front capital investment expenses (CAPEX). Coupled with the high discount rate of countries in the region (mostly due to the uncertainty conditions, refer to the the Sensitivity Analysis on the discount rate showing the negative effect of higher discount rate on MG/SA solutions penetration), this represents a major barrier to investments. In an environment as EA, country, regulatory and commercial risks substantially increase the return expectations of investors and thus any project's cost of capital. This discourages capital-intensive energy options and encourages less capital-intensive, conventional energy technologies.

Second, they are characterized by high transaction costs. For instance, the transaction cost per kWh of electricity produced from a hydropower plant will be lower than the sum of the costs of the hundreds of transactions required for comparable capacity from solar PV or wind power. In this context, reforming the governance of EA's energy markets will not be sufficient alone to attract international investors into small-grid and off-grid energy solutions in rural areas. International support is key for crowding-in private investors in this sector, most notably via innovative public-private partnership schemes. International institutions, such as international organisations, multilateral development banks and national development agencies, have a key role to play in fostering EA's electrification (Simone and Bazilian, 2019). In fact, these institutions could channel international private investments into EA's electricity sector by putting in place dedicated blended finance tools and/or risk-sharing mechanisms. As a matter of fact, overall international financial assistance (i.e. official development assistance (ODA) + other official flows) to SSA's electricity sector has almost quadrupled over the last decade, increasing from $1.3 billion in 2005 to $4.9 billion in 2015 (OECD, 2019).

Third, while investments for already electrified and non-residential consumers will mostly be sustained directly by the consumers of such additional power (via bills), the electrification investment for new consumers will be instead affected by issues on inability-to-pay for the upfront investment required, in particular for grid-connection charges. Here, an emerging aspect deserving attention is the role that digital technologies are already playing in fostering energy development in the region. EA is indeed the first region in Africa for mobile-based services usage (WRI, 2017). Between 2005 and 2016 mobile phone subscriptions per 100 people in EA countries grew from an average of 5.7 to 60.7 (World Bank, 2019). In the last few years mobile phones have also gained increasing relevance for their potential breakthrough impact on different dimensions of energy access, including infrastructure planning and its operations, new business models, payments schemes, monitoring, data collection, and analysis (Mazzoni, 2019). For instance, pay-as-you-go mechanisms are emerging as successful approaches to enable access in peri-urban and rural areas where investment was previously seen as both too costly by the demand-side and too risky by the supply-side. These systems allow households to rent the use of power generation infrastructure when they need energy, without having to purchase it ex ante with large upfront investments, or to purchase it in weekly or monthly instalments with variable leasing length while already benefiting from it.

Finally, it must be remarked that VRE-based standalone solutions may present reliability issues in terms of guaranteeing enough storage to match peak supply and demand. Thus, it is useful to refer to the World Bank Multi-Tier framework of electricity access Bhatia and Angelou (2015), underpinning how access tier encompass multiple dimensions beyond the effective demand level (Riva et al., 2018b). Our high-tier scenarios also encapsulate the objective of increasing the reliability of supply—beyond the effective amount of power supplied to consumers, because they require technological solutions with higher capacity and thus decrease the share of SA solutions in the optimal mix. Furthermore, we have shown (Figure 20) that a less ambitious scenario of 75% electrification could but not necessarily is more efficient, with economies of scale only found is certain countries and mostly under a high-tier electrification target. It would also imply substantially reducing the penetration of MG solutions, thus leaving a large number of remote communities without access which in a large number of cases are among the most expensive to electrify.

Overall, financing full electrification in EA by 2030 is an achievable objective, provided appropriate action is taken at both national and international levels. At the national level, it is key to reform the energy market in a way to foster investments. Here, the reforms of electricity utilities and of universal energy subsidy will be key, as already illustrated by the case of Uganda. This also represent a key prerequisite to allow international private investments, for which the support of the international multilateral financing institutions will also be key in order to leverage international private investors.

## 7. CONCLUSION

This paper led to the characterisation of different pathways for achieving 100% electrification in EA, and for each of these it estimated the required investment and capacity additions throughout the region. This was achieved with a bottom-up approach at the 1-km grid cell level to assess least-cost options through the OnSSET model. Overall, the results showed that achieving electrification targets set for year 2030 presents substantial costs (a lower-bound scenario-median total of \$123.5 billion including both new electrification and new capacity additions for satisfying the growth in the demand from already electrified consumers and other sectors). Nonetheless, if such figures are put in perspective and observed in per-capita or as a share of GDP terms (\$23 per capita or 2.9% of regional GDP in the first reference year of 2016, increasing at a rate consistent with the projected compound annual growth rate of electricity demand), investment requirement figures offer greater room for a policy-oriented interpretation. Based on such findings, we have discussed diverse policy challenges necessary to unlock the required investment flows and tackle the very diverse challenges affecting currently non-electrified people and already electrified hotspots where demand will growth robustly in the coming decade.

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## DATA AVAILABILITY

Calibrated input data and scenario parameters to replicate results and produce additional OnSSET runs, as well as spatially explicit output data and summary results for each scenario are hosted at the following repository: https://doi.org/10.17632/s2xpmpvvbs.

## AUTHOR CONTRIBUTIONS

G,F. and M.H. designed the scenarios; G.F. elaborated the data, ran the model, and created tables and figures; G.F. and S.T. wrote the paper.

## DECLARATION OF INTEREST

Declarations of interest: none.

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## APPENDIX

### Generation costs and scenarios design

**Table 8: Average LCOEs between 2016 and 2030**

| Technology | LCOE 2016 ($/kWh) | LCOE 2030 ($/kWh) |
|---|---|---|
| Hydro | 0.04 | 0.04 |
| REs (solar PV, geothermal, and wind average) | 0.08 | 0.04 |
| NG | 0.06 | 0.06 |
| Coal | 0.08 | 0.08 |

Sources: projections based on data from IRENA (2018); Santley et al. (2014) and on forecasts comparing estimates from Creutzig et al. (2017); IRENA (2016); Varro and Ha (2015); Augustine et al. (2018).

Santley et al. (2014) report the current hydropower generation costs for a number of specific existing schemes in Mozambique and Tanzania. These range between $0.02 and $0.08/kWh, with a median value around $0.04/kWh. IRENA's estimate of the global LCOE of hydropower in 2017—at $0.05/kWh—is consistent with those numbers. All sources reported below Table8 estimate that the LCOE of hydropower will remain roughly constant in the next two decades, with no technological breakthroughs.

Solar PV is currently reported to have a global average LCOE of $0.09/kWh. The learning curve of the last 10 years has been very steep, with the LCOE having fell from an average of $0.36/kWh in 2010 (IRENA, 2018). However, in the context of sub-Saharan Africa, such costs have recently been even lower. For instance, Zambia issues an announcement of a contract for solar PV at $0.06/kWh under the World Bank's Scaling Solar programme (Sargsyan, 2016). Furthermore, among different solar solutions (solar-home-systems, mini-grid, and on-grid), on-grid, utility-scale PV is the cheapest, with an average of $3/W of solar panels installed between 2009 and 2016 in Africa (IRENA, 2016). According to the Augustine et al. (2018), utility-scale PV could reach a

LCOE of $0.025/kWh by 2030 in the US, while according to IRENA (2016) the global average LCOE would fall at $0.06/kWh by 2025, with project costs in the range of $0.03 to $0.12/kWh for utility-scale PV projects.

Geothermal generation currently exhibits a LCOE of $0.04–0.05/kWh. In a similar fashion to hydropower, estimates foresee the technology cost to roughly remain constant by 2030.

New on-shore wind projects reached a median LCOE of $0.06/kWh in 2017, rendering wind generation an ever more competitive alternative with the majority of other generation technologies in areas where the wind speed and the turbines capacity factor are sufficiently high. IRENA (2016) estimates a further 17% cost reduction by 2025.

With regards to coal-fired generation, Santley et al. (2014) report the current generation costs in Tanzania and Mozambique under two different coal price scenarios. In Tanzania, they consider $50 and $85/t, while in Mozambique they refer to $12.5 and $95/t. The range of uncertainty imposed by such large price differences on the LCOE is however not broad, with generation in Mozambique between $0.068–0.10/kWh and in Tanzania between $0.083–0.096/kWh. This renders coal currently only competitive under a very low-price scenario and where mining takes place in the proximity of generation sites, such as in Mozambique. Only new mining activities in Tanzania, where some reserves are found, or very cheap imports from coal-rich countries such as South Africa, DR Congo and Zimbabwe, which could create a playing field for coal as a baseload generation resource for EA in the next 20 years.

Concerning NG, the discussion is less linear since issues relating to gas pricing, specific generation technologies, and the related governmental policy are called into question. Mozambique and Tanzania are in fact both gas-rich and since relatively recently they have begun exploiting their endowments. Current gas-to-power costs drawn from Santley et al. (2014) between the two countries depend on the following: (i) Fuel price. For Mozambique the authors introduce two gas pricing scenarios: $2.50 and $7.70/Mbtu, while for Tanzania they present higher prices, at $4.40 and $8.40/Mbtu. For combined-cycle turbines, LCOEs range in the $0.044–0.083/kWh in Mozambique and in the $0.059–0.089/kWh range in Tanzania, depending on the price of gas; (ii) generation technology. Given the same gas price, combined-cycle turbines display a substantially lower LCOE than open-cycle plants, passing from $0.13 to $0.89 in Tanzania and from $0.12 to $0.83 in Mozambique under the high price scenario.Overall, our estimate for NG, based on arguments found in Demierre et al. (2015), is that the domestic price of gas in EA over the next 12 years will be in the $4–5/Mbtu, and therefore that the average LCOE of gas-fired generation will stand at $0.06/kWh.

Based on such scenarios, Table 9 reports the (weighted) average LCOE calculated under the three scenarios introduced in Table 4 and the LCOEs presented in Table 8. Finally, Table 10 reports all the baseline scenarios run in the model.

**Table 9: Average cost of grid electricity generation (2016–2030) under the generation mix scenarios**

| Scenario | Baseline cost of grid electricity generation ($/kWh) |
|---|---|
| 1 | 0.05 |
| 2 | 0.055 |
| 3 | 0.049 |

**Table 10: Scenarios overview**

| Scenario | Diesel Price ($/l) | Gen. mix scenario | SA-PV investment cost ($/kW) | Urban electr. tier (kWh /person /year) | Rural electr. tier (kWh /person /year) |
|---|---|---|---|---|---|
| A1l | 0.9 | [1] | 5,500 | 160 | 44 |
| A2l | 0.9 | [2] | 5,500 | 160 | 44 |
| A3l | 0.9 | [3] | 4,000 | 160 | 44 |
| B1l | 1.3 | [1] | 5,500 | 160 | 44 |
| B2l | 1.3 | [2] | 5,500 | 160 | 44 |
| B3l | 1.3 | [3] | 4,000 | 160 | 44 |
| A1h | 0.9 | [1] | 5,500 | 423 | 160 |
| A2h | 0.9 | [2] | 5,500 | 423 | 160 |
| A3h | 0.9 | [3] | 4,000 | 423 | 160 |
| B1h | 1.3 | [1] | 5,500 | 423 | 160 |
| B2h | 1.3 | [2] | 5,500 | 423 | 160 |
| B3h | 1.3 | [3] | 4,000 | 423 | 160 |

## Electrification analysis parameters

Table 11 reports the general baseline parameters used in the model runs. These parameters are defined directly in the model source code (runner.py file). Apart from where specified in the Sensitivity Analysis section, the parameters are constant across scenario runs.

**Table 11: Main parameters used in the OnSSET baseline scenarios runs**

| Parameter | Description | Value |
|---|---|---|
| Discount rate | To weight results from the present generations' perspective (relatively less importance is given to the future). | 15% |
| MV line cost (USD/km) | 1–66kV | 6,000 USD |
| LV line cost (USD/km) | < 1kV | 3,000 USD |
| HV line cost (USD/km) | > 66 kV | 30,000 USD |
| MV line capacity kW/line | | 50 kW |
| LV line capacity kW/line | | 10 kW |
| MV line max length | | 50 km |
| LV line max length | | 30 km |
| HV to LV transformer cost (USD/unit) | Cost of a transformer between transmission and distribution grid | 4,000 USD |
| Grid connection cost per household | The average charge to be borne by households (unless a subsidy policy is in place) to get grid electricity at home | 450 USD |
| Operation and maintenance costs of transmission and distribution lines as % of capital costs | Share of O&M costs over the total capital costs to be borne by the electricity supply company for grid O&M | 5% |
| Grid capacity investment (USD/kW of on-grid added capacity excluding the grid itself) | The average investment required to add new capacity to the national grid-connected electricity generation. | Country-level, depending also on the scenario considered to account for economies of scale (see below). |
| Diesel gen-set mini grid investment cost | Average unit (per kW) cost of installing, operating and maintaining the system | 721 USD/kW + 10% O&M costs (% of investment cost/year) |
| Small hydro mini grid plant | Average unit (per kW) cost of installing, operating and maintaining the system | 5,000 USD/kW + 2% O&M costs (% of investment cost/year) |
| Solar PV mini grid | Average unit (per kW) cost of installing, operating and maintaining the system | 3,200 USD/kW + 1.5% O&M costs (% of investment cost/year) |
| Wind turbines mini grid | Average unit (per kW) cost of installing, operating and maintaining the system | 3,000 USD/kW + 2% O&M costs (% of investment cost/year) |
| Diesel standalone investment cost | Average unit (per kW) cost of installing, operating and maintaining the system | 938 USD/kW + 10% O&M costs (% of investment cost/year) |
| Standalone PV investment cost (USD/kW) | Average unit (per kW) cost of installing, operating and maintaining the system | 5,500 USD/kW + 10% O&M costs (% of investment cost/year) |

Table 12 reports the country-specific baseline parameters, which are inputted in the specs. xls file taken as input from the model (also included in the repository linked in the Data Availability section).

**Table 12: Country-specific parameters**

| Country | Urban pop | Pop 2030 (mil.) | Urban pop. 2030 | People Per HH, rural | People Per HH, urban | Average grid Capacity Inv. Cost (USD/kW) | Grid Losses |
|---|---|---|---|---|---|---|---|
| **Burundi** | 12.06% | 17.36 | 35% | 5 | 3.5 | 2,500 | 17.65% |
| **Kenya** | 25.62% | 65.41 | 35% | 4.5 | 3.5 | 1,500 | 17.50% |
| **Malawi** | 16.27% | 26.58 | 30% | 6 | 4 | 2,000 | 17.65% |
| **Mozambique** | 32.21% | 41.44 | 50% | 5.5 | 4 | 1,500 | 14.70% |
| **Rwanda** | 28.81% | 15.78 | 40% | 4.5 | 3.5 | 2,500 | 17.65% |
| **Tanzania** | 31.61% | 82.93 | 50% | 5.5 | 4 | 1,500 | 17.65% |
| **Uganda** | 16.10% | 61.93 | 35% | 5 | 3.5 | 2,000 | 17.65% |

Note: The Average grid Capacity investment Cost (USD/kW) refers to the public or private average investment required to add new capacity to the national grid-connected electricity generation (excluding T&D and other costs).

## Full baseline results

Tables 13–15 report the complete results of baseline scenarios runs, including both the absolute figures and the percentage splits of capacity additions and investment requirements.

**Table 13: Baseline scenarios detailed results**

| Scenario | Inv (bn. $) | Grid (%) | MG (%) | SA (%) | Cap (GW) | Grid (%) | MG (%) | SA (%) |
|---|---|---|---|---|---|---|---|---|
| A1l | 57.6 | 59.7% | 32.5% | 7.8% | 6.4 | 50.1% | 41.6% | 8.2% |
| A2l | 56.8 | 59% | 33% | 8% | 6.4 | 50.1% | 41.7% | 8.2% |
| A3l | 56.8 | 59.1% | 33% | 8% | 6.4 | 50.1% | 41.7% | 8.2% |
| A1h | 112.6 | 75.4% | 23.6% | 1.1% | 17.7 | 68.5% | 29.5% | 2% |
| A2h | 110.3 | 74.4% | 24.5% | 1.1% | 17.8 | 67.9% | 30% | 2% |
| A3h | 110.4 | 74.7% | 24.2% | 1.1% | 17.7 | 68.3% | 29.7% | 2% |
| B1h | 115.1 | 74.1% | 25.3% | 0.6% | 17.8 | 68.1% | 31.2% | 0.7% |
| B1l | 59.9 | 57.6% | 36.6% | 5.8% | 6.6 | 48.9% | 45.2% | 5.9% |
| B2h | 112.9 | 73.1% | 26.3% | 0.6% | 17.9 | 67.6% | 31.7% | 0.7% |
| B2l | 59.1 | 56.9% | 37.1% | 5.9% | 6.6 | 48.9% | 45.3% | 5.9% |
| B3h | 112.9 | 73.4% | 26% | 0.6% | 17.9 | 67.9% | 31.4% | 0.7% |
| B3l | 59.1 | 57% | 37.1% | 5.9% | 6.6 | 48.9% | 45.3% | 5.9% |
| Median l tier | 58.3 | 58.3% | 34.8% | 6.9% | 6.5 | 49.5% | 43.5% | 7% |
| Median h tier | 112.7 | 74.3% | 24.9% | 0.8% | 17.8 | 68% | 30.6% | 1.4% |

**Table 14: Country-level median required investments in baseline scenarios**

| Country | Tier | Inv (bn. $) | Grid (bn. $) | MG PV (mil. $) | MG Hydro (mil. $) | MG Wind (mil. $) | MG Diesel (mil. $) | SA (mil. $) Diesel | SA PV (mil. $) |
|---|---|---|---|---|---|---|---|---|---|
| Burundi | Low | 3.2 | 1.7 | 1520 | 1.29 | 0 | 15.5 | 8.3 | 0 |
| Burundi | High | 6.2 | 5.7 | 537.8 | 0 | 0 | 1.6 | 0.2 | 0 |
| Kenya | Low | 11.5 | 8.3 | 2474.3 | 1.3 | 7.7 | 65.8 | 596.4 | 27.3 |
| Kenya | High | 19.8 | 16.5 | 2845.3 | 3.7 | 30.7 | 22.6 | 180.4 | 149.2 |
| Malawi | Low | 4.5 | 1.9 | 2518 | 9.9 | 0.2 | 31 | 87.9 | 0 |
| Malawi | High | 9.3 | 6.9 | 2371.5 | 17.8 | 1.7 | 18.7 | 11 | 0.7 |
| Mozambique | Low | 7.4 | 4.4 | 1245.8 | 13 | 0.4 | 8.6 | 1739.2 | 23.9 |
| Mozambique | High | 15.5 | 8.1 | 6749.3 | 12.9 | 5.5 | 32.9 | 558 | 130.3 |
| Rwanda | Low | 3 | 1.9 | 1100.3 | 0.7 | 0 | 90.8 | 13.9 | 0 |
| Rwanda | High | 5.7 | 5.6 | 87.5 | 0 | 0 | 2.5 | 3.9 | 0.1 |
| Tanzania | Low | 16.1 | 9.7 | 4481.4 | 5.7 | 6.2 | 113.9 | 1600.5 | 120 |
| Tanzania | High | 31.1 | 20 | 10481.5 | 9.4 | 25.3 | 83.3 | 217.8 | 199.3 |
| Uganda | Low | 11 | 5.7 | 4662.1 | 6.5 | 0.4 | 342.9 | 297.8 | 1.1 |
| Uganda | High | 21.9 | 18.4 | 3437.5 | 8.6 | 5.1 | 86.2 | 45.5 | 11.1 |

**Table 15: Country-level median required capacity additions in baseline scenarios**

| Country | Tier | Capacity (GW) | Grid (GW) | MG PV (MW) | MG Hydro (MW) | MG Wind (MW) | MG Diesel (MW) | SA (MW) Diesel | SA PV (MW) |
|---|---|---|---|---|---|---|---|---|---|
| Burundi | Low | 460.7 | 214.6 | 242.1 | 0.1 | Low | 3 | 0.9 | 0 |
| Burundi | High | 1081.1 | 964 | 120.3 | 0 | 0 | 0.6 | 0.1 | 0 |
| Kenya | Low | 868.9 | 481.9 | 313 | 0.1 | 0.9 | 9.8 | 60.5 | 2.7 |
| Kenya | High | 2413.9 | 1787 | 528.5 | 0.4 | 4.6 | 6.6 | 20 | 21.9 |
| Malawi | Low | 653.5 | 236 | 398.5 | 0.9 | 0 | 6.2 | 11.4 | 0 |
| Malawi | High | 1670 | 1116.6 | 536.8 | 2.2 | 0.38 | 6 | 3.5 | 0.1 |
| Mozambique | Low | 901.1 | 504.7 | 180.4 | 1.8 | 0.1 | 1.5 | 210 | 2.6 |
| Mozambique | High | 2932.5 | 1456.2 | 1284.1 | 1.5 | 0.8 | 8.8 | 105.4 | 20.1 |
| Rwanda | Low | 318.9 | 131.8 | 168.6 | 0 | 0 | 17.1 | 1.4 | 0 |
| Rwanda | High | 722 | 704.3 | 16.7 | 0 | 0 | 0.7 | 0.7 | 0 |
| Tanzania | Low | 1801.6 | 1011.2 | 566.6 | 0.7 | 0.9 | 16.3 | 193.3 | 12.7 |
| Tanzania | High | 5331 | 3212 | 2000.5 | High | 4.1 | 17.9 | 33.9 | 30.3 |
| Uganda | Low | 1408.7 | 630.5 | 681.9 | 0.6 | 0.1 | 62.4 | 33.2 | 0.11 |
| Uganda | High | 3563.7 | 2832.2 | 701.3 | 1.1 | 1.1 | 31.2 | 9.7 | 1.6 |

### Sensitivity analysis

Figures 9–18 show the sensitivity of the model results to the value of the parameters for the discount rate, grid infrastructure expansion costs, connection charges, and electrification objective.

**Figure 9: Discount rate sensitivity analysis on total investments.**

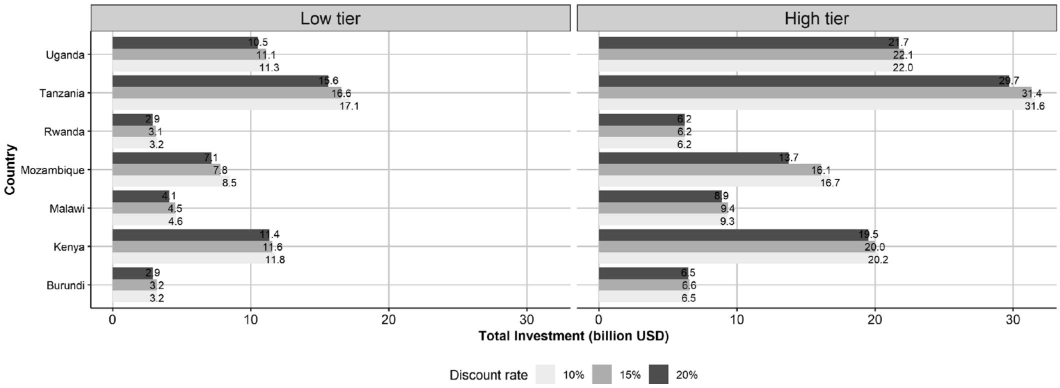


**Figure 10: Discount rate sensitivity analysis on total capacity.**

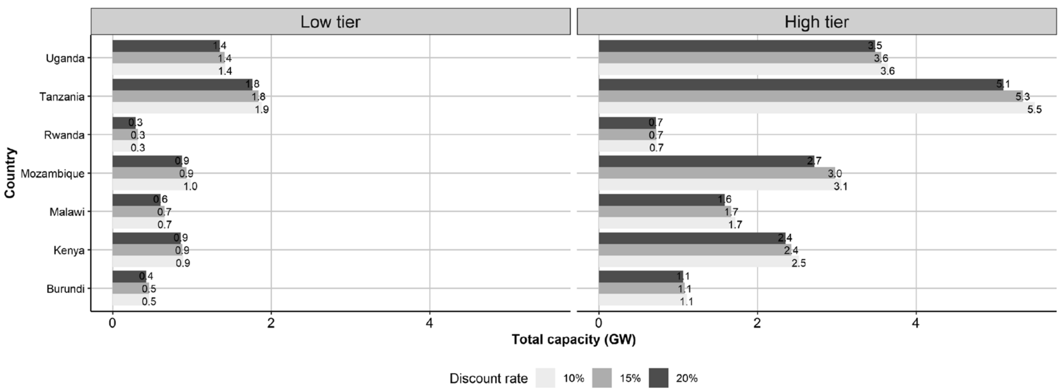


**Figure 11: Discount rate sensitivity analysis on optimal technology mix.**

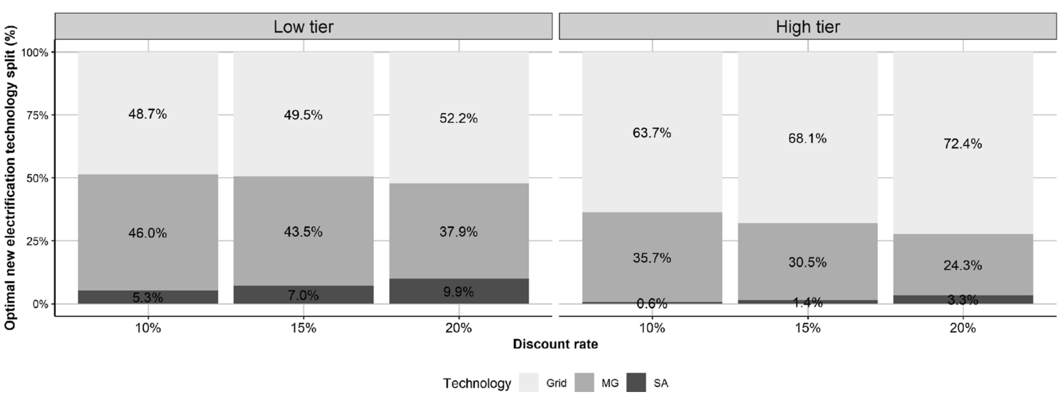

**Figure 12: Grid infrastructure expansion costs sensitivity analysis on total investments.**

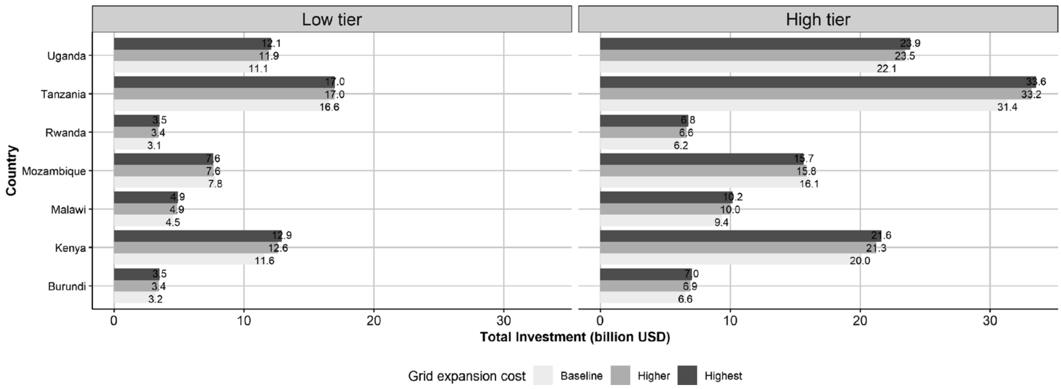


**Figure 13: Grid infrastructure expansion costs sensitivity analysis on total capacity.**

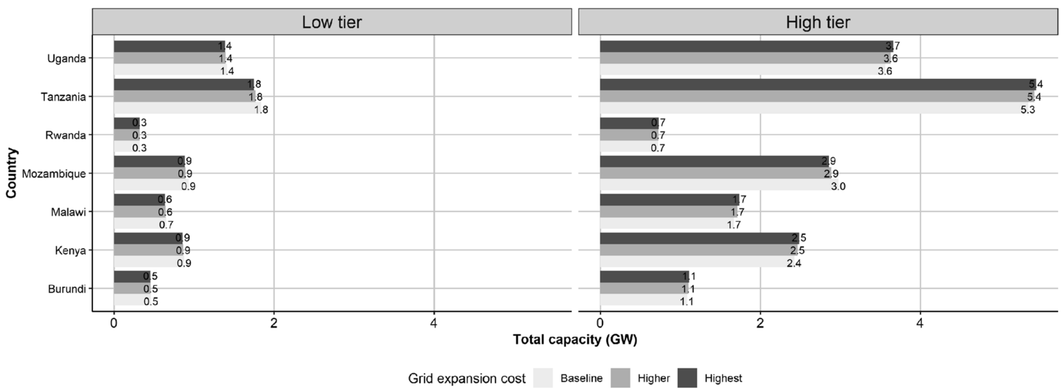


**Figure 14: Grid infrastructure expansion costs sensitivity analysis on optimal technology mix.**

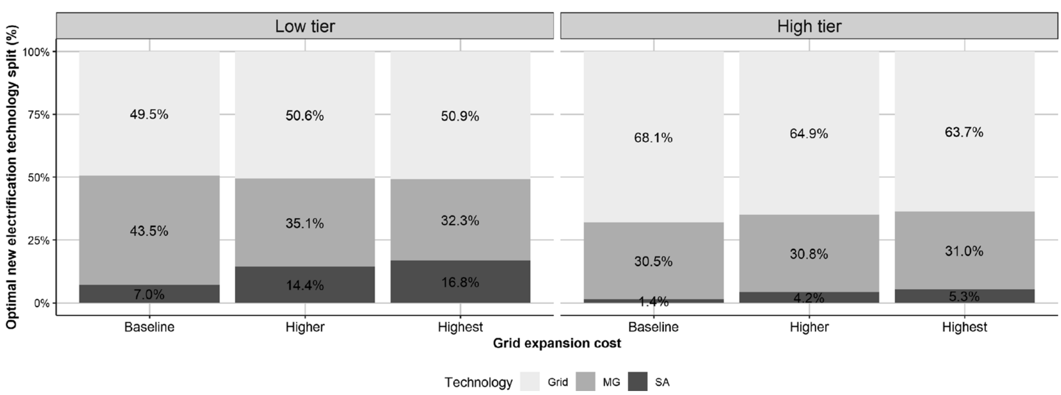

**Figure 15: Connection charges sensitivity analysis on total investments.**

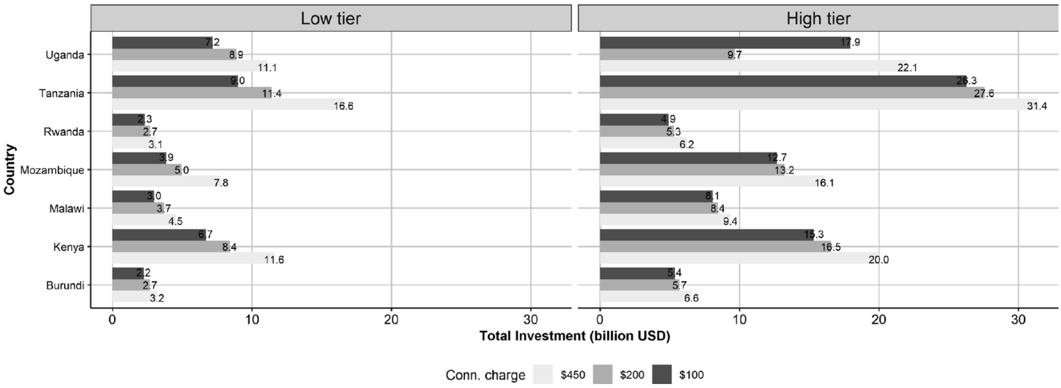


**Figure 16: Connection charges sensitivity analysis on total capacity.**

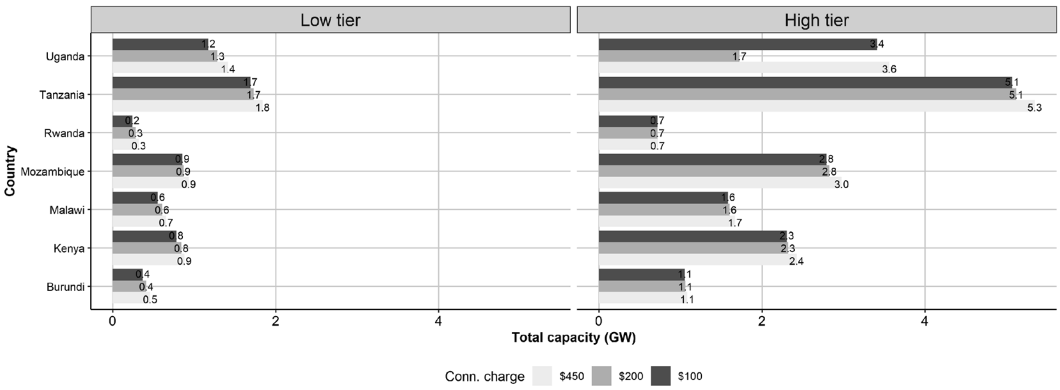


**Figure 17: Connection charges sensitivity analysis on optimal technology mix.**

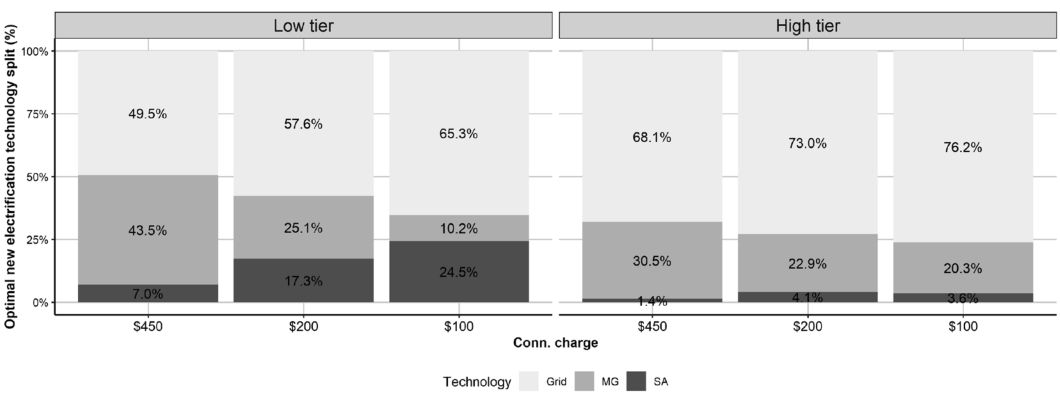

**Figure 18: Electrification objective sensitivity analysis on total investments.**

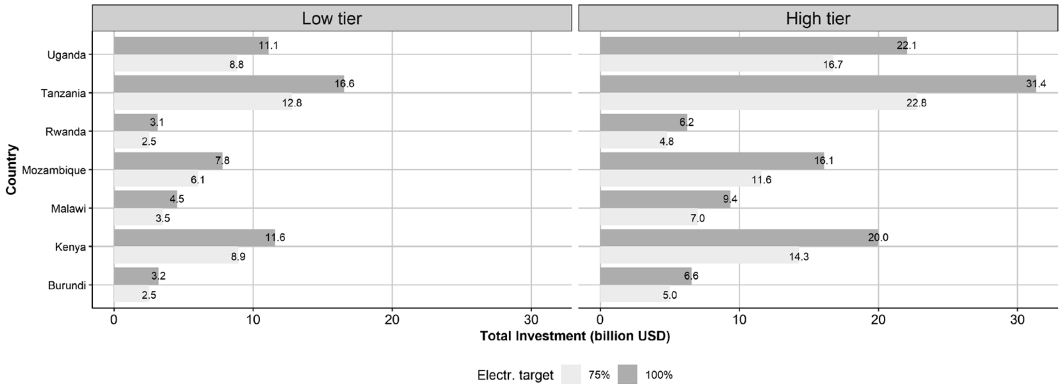


**Figure 19: Electrification objective sensitivity analysis on total capacity.**

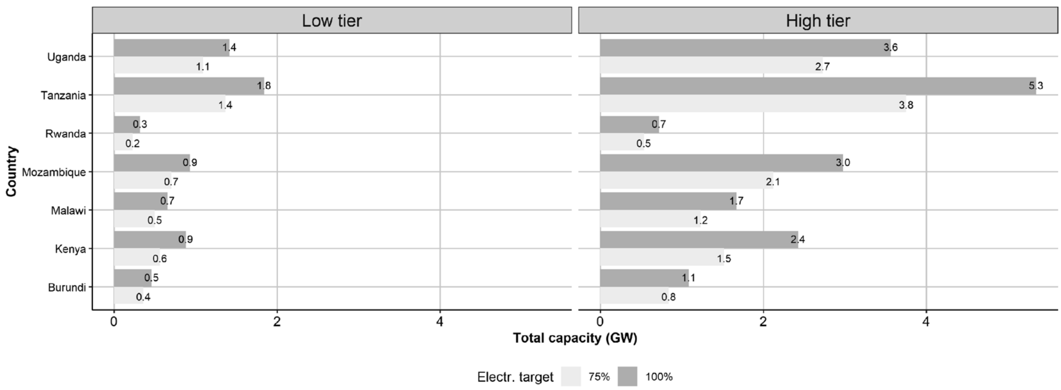


**Figure 20: Electrification objective sensitivity analysis on optimal technology mix.**