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Enhancing energy models with geo-spatial data for the analysis of future electrification pathways: The case of Tanzania

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ABSTRACT

In light of a national policy aiming at satisfying a growing demand for electricity, while achieving a greater diversification of power generation technologies and full electrification by 2050, this research models and contrasts alternative electrification pathways for Tanzania in the time frame 2015–2040. The study relies on an improved model grounded on the OSeMOSYS framework. GIS data are used both to determine the electricity demand projections and to inform the decision about the optimal production technologies made by OSeMOSYS with a least-cost criterion. Findings indicate that the stated policy goals (New Policy scenario) are within reach, but they also imply an increase in installed capacity from less than 2 GW to at least 13.8 GW, corresponding to an investment of 25.3 billion USD, which is significantly above historical spending in the power sector. Also, only an additional environmental policy (450TZ scenario) would ensure that the carbon intensity of the power sector lowers from a current 440 gCO_2/kWh to around 100 gCO_2/kWh in 2040, with the additional benefit of a lower average cost of providing electricity (compared to the New Policy scenario). An Energy For All scenario where universal access is achieved two decades earlier (in 2030) is also feasible but implies more difficulties in lowering carbon intensity or the cost of providing electricity. Results for universal access are the object of a separate in-depth discussion and a sensitivity analysis looks at the effect of key assumption (e.g., on demand projections and discount rate) on the main results.

1. Introduction

As of today, a number of countries in the region of Sub-Saharan Africa continues to present a low electrification rate and limited installed generation and transmission capacity in the power sector [1]. This is in contrast with the United Nation pledge to achieve universal access to modern energy by 2030, as well as with electricity demand projections, driven by aspirations for economic development and commitments to a sustainable economic growth [2].

Statistical data and policy documents regarding the United Republic of Tanzania portray a country's profile which is, indeed, representative of this region of Africa. As of today, Tanzanian electricity production mainly depends on fossil-fuel power plants and hydropower (diesel for most rural electricity production) and the institutional framework of the power system is dominated by the state-owned monopoly company TANESCO (Tanzanian Electric Supply Company), which has a rather poor track record in providing reliable power supply [3]. According to Choumert-Nkolo et al. [4], only 33% of the Tanzanian households (65% in urban areas and 17% in rural regions) had access to electricity in 2016 – 74% of them were connected to the national grid and about 24% were supplied by solar power. At the same time, the government plans to convert Tanzania to a middle-income country by 2025 and, to avoid interference with the climate system, embarking on a sustainable development pathway is also rather high on the policy agenda [5,6].[1]

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[1] The Tanzania Development Vision (TDV) for 2025 comprises not only economic and environmental aspects, but other attributes as well, such as peace, stability, and unity, good governance, and a well-educated and learning society. Note that on July 1, 2020, the World Bank announced that the Tanzanian economy had been upgraded from low to lower-middle income status based on values of GNI per capita ($1080 in 2019, which satisfies the World Bank's threshold of $1036 for lower-middle income status). Differently, the TDV defined middle income as a GDP per capita of $2500.

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As it can be expected, the government is looking at guaranteeing a greater diversification of power generation technologies (*energy security*), while relying on locally owned energy sources. Moreover, together to a commitment to provide a reliable electricity supply to a growing industrial sector, *rural electrification* is also part of the government's vision. In this regard, the Rural Energy Agency, established by the Electricity Act of 2008, is considering different solutions, including both on-grid and off-grid technologies (micro-grids and stand-alone systems). Also, Tanzania is still a global net sink of CO_2 (up to now, the main contribution to carbon emissions has been due to land use, land use change and deforestation). Nevertheless, with projections to significantly expand the power system, *environmental issues* became relevant for a number of reasons. On the one hand, a decrease in biomass domestic consumption will contribute to slow the country deforestation rate and lower indoor and outdoor air pollution [7]. On the other hand, existing studies for Tanzania indicate that the development of the national electricity sector under a least-cost generation mix, is accompanied by an annual growth in carbon emissions in the order of 10% per year [8].

Against this background, the question of how the Tanzanian power sector might evolve in the future is a relevant one. This research models alternative pathways for the development of the Tanzanian electricity sector, with the objective to provide reliable and replicable results, in support of policy decision making. Four alternative *scenarios* are considered, each of them a plausible representation of how the Tanzanian electricity sector might evolve over time (up to 2040) under different energy policy programmes. These sets of assumptions are translated into input data for the Open Source Energy Modelling System (OSeMOSYS), an open source energy modelling framework which ensures replicability and enables the addition of modelling extensions. In particular, this study introduces a novel, agile approach to employ geospatial data of the national territory to describe the electricity demand. The same data is also instrumental to model in details the alternative technological solutions (on-grid and off-grid) that are available to cover the load (and provide new accesses) at minimum cost. To meet the paper's main objective, the model's output is used to analyse and compare alternative development pathways, in terms of: (i) installed capacity and electricity production; (ii) investment requirements and average cost of electricity; and (iii) carbon emissions and energy security.

The rest of the paper is organized as follows. A brief overview of the literature is given in Section 2. The modelling framework is presented in Section 3 and includes a focus on the use of geospatial data. The alternative scenarios for the development of the country's electricity sector are outlined in Section 4. Section 5 illustrates and discusses the model's output. Section 6 compares the results pertaining to new accesses with those proposed by the International Energy Agency (IEA) Energy Access Outlook 2017. Section 7 presents a sensitivity analysis. Concluding remarks are reported in Section 8.

2. Brief literature review

Several analyses have been conducted, in the past decade, to study the potential development of the energy (and electricity) sector in the Sub-Saharan Africa region. As summarized in Table 1, these studies rely on different approaches, have different time/space scopes, and adopt different methods.

Moving in chronological order, the *Africa Energy Outlook 2040* [9] proposed by the Africa Union defines four scenarios for the evolution of the energy sector in Africa for the time frame 2009–2040 and discusses energy security, the role of hydropower, CO_2 emissions policies, and possible bottlenecks related to capital investments availability. The study by Bazilian et al. [10] focuses instead, on the definition of strategies to achieve universal access to modern energy services for Africa in 2030 and presents electricity sector development pathways estimated with the OSeMOSYS modelling framework. In its *Southern Africa Power Pool: Planning and Prospects for renewable energy* report [11], the International Renewable Energy Agency (IRENA) proposes alternative fossil-free transition pathways based on renewable technologies for Sub-Saharan countries. Using the same System Planning Test (SPLAT) modelling tool, IRENA has conducted also a least-cost optimization analysis for Tanzania alone. This is included in its *Renewable Readiness Assessment of Tanzania* [12]. The study by Kichonge et al. [8] applies the MESSAGE energy system model to find least-cost optimal energy supply options to meet Tanzania's electricity demands projection from 2010 to 2040. Notably, the study focuses only on on-grid technologies. The 2016 *Power System Master Plan* (PSMP), published by the Ministry of Energy and Minerals (MEM) of Tanzania, finds an optimal generation expansion plan using the WASP planning tool. The analysis accommodates recent development in the economy, e.g. in the gas sub sector, and it is designed to reach several government objectives [13]. In the *Energy Access Outlook: From Poverty to Prosperity*, the IEA assesses cost efficient electrification strategies, under alternative scenarios, for all countries without universal access. The study integrates an open-access Geographic Information Systems (GIS) model with data from the World Energy Model, relying on the Open Source Spatial Electrification Tool (OnSSET) [14] and on the pan-African TEMBA model based on the OSeMOSYS modelling framework [15].

Both the OSeMOSYS and the OnSSET model are increasingly used in the recent literature looking at the electricity sector in sub-Saharan region. Applications of the TEMBA model are discussed in Ref. [16]. Moksnes et al. [17] rely on a soft-linked between OnSSET and OSeMOSYS for analysing electrification scenarios in Kenya . As for OnSSET [18], Mentis et al. [19] provide an application to Sub-Sharan Africa and Menghwani et al. [20] to the case of Tanzania, using spatial modelling to

Table 1
Summary of available modelling studies for the sub-Saharan region and Tanzania.

Year	Authors	Ref.	Time scope	Space scope	Modelling framework
2010	Africa Union (AU)	[9]	2009–2040	Africa, full energy sector	Tailored model
2012	Bazilian et al.	[10]	2011–2030	Africa, electricity sector	OSeMOSYS
2013	IRENA	[11]	2010–2030	Sub-Saharan region	SPLAT
2015	Kichonge et al.	[8]	2010–2040	Tanzania, full energy sector	MESSAGE
2016	Minister of Energy and Minerals (Tanzania)	[13]	2015–2030	Tanzania, electricity sector	WASP
2016	Taliotis et al.	[15]	2014–2040	Africa, electricity sector	OSeMOSYS
2017	IRENA	[12]	2017–2030	Tanzania, electricity sector	SPLAT-S
2017	IEA	[14]	2015–2030	Africa, full energy sector	WEM-OnSSET
2017	Moksnes et al.	[17]	2012–2040	Kenya, electricity sector	OSeMOSYS - OnSSET
2017	Mentis et al.	[19]	2015–2030	Sub-Saharan region	OnSSET
2019	Korkovelos et al.	[21]	2018–2030	Malawi, electricity sector	OnSSET
2020	Falchetta et al.	[22]	2019–2030	East Africa, electricity sector	OnSSET
2020	Menghwani at al.	[20]	2020–2030	Tanzania, electricity sector	OnSSET

incorporate fairness in electricity pricing. Korkovelos et al. [21] provide an overview of open access geospatial data and GIS based electrification models (with a focus on Sustainable Development Goal 7) and employ OnSSET for a case study in Malawi. Finally, Falchetta et al. [22] estimate the least-cost pathways to universal access to electricity by 2030 in the East Africa region again relying on OnSSET.[2]

On the basis of the existing literature, it is possible to observe the following:

- while early studies in energy modelling were based on closed source codes [11–13], the recent trend is to rely on open source energy modelling frameworks [21,22] – adopted also by the IEA [14,15] and the World Bank [23];
- existing studies often model aggregated regions (i.e. the Sub-Saharan region), averaging country-specific features and disregarding country-specific peculiarities (e.g., commodity prices, operational efficiency of production, country-specific policy and investment decisions) [11,14,22];
- the definition of future electricity demand on the basis of econometric energy demand functions, as proposed, for instance, by the Africa Union in Ref. [9], is not ideally suited for situations where a large part of the population lacks access to electricity services [10, 21];
- analyses of electricity demand in rural contexts were traditionally carried out without geo-spatialization: differences among rural areas' characteristics (population density and distance from the grid) were not considered and approximate results were provided [8–13];
- the rapid gain in competitivity of renewable energy technologies and/or the possible advantages of decentralized electricity supply systems were not always properly considered, thus disregarding the potentially relevant contributions of off-grid technologies, not only for rural areas but also for urban areas and industrial sectors [8–12], as also emphasized by the recent reviews by Musonye et al. and Bissiri et al. [24,25].

As detailed in the next section, the present study addresses the most critical points listed above by relying on open source energy modelling frameworks and integrating, in an original manner, geospatial data (also for electricity demand projections). Moreover, the study is country-specific. This means that it closely captures, together with national policy programmes, the local characteristics of the production technologies available for the Tanzanian electricity sector. In doing so, it complements other studies that have looked at the Tanzanian electricity sector, albeit from a different perspective [26]. Recent studies (from 2010 onward) have looked at the relation between the Tanzanian electricity sector and the environment [27], as well as at the vulnerability of the power sector to climate-driven changes in hydropower generation [28]. Other, more policy-oriented studies, have focused on the liberalization of the electricity sector [29], or on the barriers for the deployment of renewables, also in rural electrification [30–32]. Finally, the literature has explored the role of alternative investment vehicles and other barriers in delivering the necessary infrastructure expansion [2,33], including the difficulty with forecasting residential electricity consumption [34].

3. Methods and models

To ensure transparency and reproducibility of the results, this work is based on the OSeMOSYS open source modelling framework initially presented by Howells et al. [35] (http://www.osemosys.org/), and suited for planning the least-cost electricity dispatch and optimal expansion capacity for a given region in a defined time horizon [35,36]. In essence, the exogenous model parameters are related to the types and techno-economic specifications of: (a) available resources (e.g., availability and cost of natural gas, availability and intensity of solar radiation) and energy conversion technologies (e.g., costs and performances of coal power plants); (b) transmission and distribution infrastructures; (c) electric energy demand, assumed as perfectly inelastic with respect to energy price changes; (d) policies and/or technical constraints (e.g. political decision to ban a particular technology after a defined year). Moreover, OSeMOSYS offers the possibility to increase the space resolution of the analysed region by defining multiple sub-regions, and it accounts for the variability of available resources and demand yields over time by defining them according to time-slices: the time and space scopes and detail level of the modelled energy system depend on the available data and on the research question to be addressed. Once the demand for electricity and the electric energy supply resources and technologies are characterized, the OSeMOSYS model returns several endogenous parameters, the most relevant of which are: electricity production and installed capacity, resources consumption, investment and operative costs, as well as emissions, all defined by year and by technology.

For the scope of this work, the OSeMOSYS modelling systems is adapted in several ways. The main modification consists in novel approach to estimate electricity demand in future scenarios, as well as the least-cost technology choice, on the basis of properties provided by GIS data. Other adaptations are driven by the goal to represent plausible alternative pathways for the case study. Consistently, the scenarios are developed on the basis of country-specific, stated policy intentions of the national government. The latter are gathered from the grey literature and were discussed with experts *in situ*. Another relevant feature consists in the inclusion of country-specific data, reflecting the observed, local cost of renewable energy sources, where such figures where collected via in field research.

The detailed description of the modelling assumptions and the raw data sources employed in the study are collected and descripted in the electronic supplementary materials (file "SM_Data"). The full code of the OSeMOSYS model is also available upon request. The rest of this section focuses solely on the main modelling contribution of this study.

3.1. A focus on the use of geo-spatial data

One of the main weaknesses of OSeMOSYS (and of other long-term national energy systems modelling frameworks such as TIMES or MESSAGE) is the absence of a robust approach for addressing the geo-spatial distribution and evolution of the electric energy demand. According to recent literature the use of ground level geospatial data is of key importance to identify the most effective electrification strategies, and this is particularly relevant for developing economies, where off-grid technologies play a key role in supporting future electrification pathways [10,25].

Since its original version, OSeMOSYS has been expanded and improved via several applications, mostly focused on supply side technology (e.g. development of storage functionalities done by Palombelli et al. [37]). In particular, a soft-link between OSeMOSYS and OnSSET was recently proposed to determine the least cost technology mix to meet energy need of rural areas in future scenarios [19,38].

In a glance, the OnSSET tool is capable to determine the optimal share between on-grid and off-grid production technologies based on GIS data, selecting among grid connection, mini-grid and stand-alone solutions. The optimal choice depends on the levelized cost of generating electricity (LCOE) of the alternative technologies and the distance between each discretized GIS space square and the grid. The obtained optimal share is then assumed as an input for OSeMOSYS, which computes a new value of the on-grid LCOE. The latter value is then fed again to OnSSET, and the process iteratively repeated until convergence is reached, that is, until the difference of on-grid LCOE between two

[2] An integration of OnSSET with other energy modelling tools is also possible. For instance, Peña Balderrama et al. assess the least-cost nation-wide electrification strategies using OnSSET, RAMP and MicroGridsPy [53].

iterations is less than 10% [39]. This iterative process has two major drawbacks: first, handling GIS data through an iterative process among two different tools makes the whole process time intensive and characterized by a high computational effort. Secondly, this approach is not fully dynamic, hindering the opportunity to capture the effects of intermediate modifications of technology costs. In fact, it only models a "start year" and a "final year", assuming a linear growth rate for off-grid demand within the observed modelling period.

Differently, the approach proposed in this research uses GIS data in the following way. First of all, GIS data of the analysed region are collected for each discrete space square (10 × 10 km). Based on these data, space squares are assigned a *status* for the base year. According to the distance from major cities and from the grid, as well as population and population density, a space square can be given a 'urban' or 'rural' *status* which, in the latter case, is also declined in close/distant (from the grid) and densely/sparsely populated.

Secondly, the official projections for annual population growth rates are considered and applied to each space square, hence determining the evolution of the population in future years. From this information, using the IEA and World Bank classification in consumption tiers [40], the electricity consumption for the entire region in each year of the observed period is calculated (for details see the file 'SM_Data'), and becomes an input to OSeMOSYS.

Moreover, because of the evolution of the population, each space square may modify its *status* from one year to another.[3] This is important because in the proposed approach the choice of the least-cost production technology is determined by OSeMOSYS for each space square. In practice, the least-cost technology choice which endogenously results from OSeMOSYS, is restricted to the 'set of available electricity production technologies for the space square' which, in turn, depends on the square's (dynamic) *status*.[4]

In sum, this approach generates an aggregated and time-dependent electricity demand that is fed to OSeMOSYS which, in turn, determines the least-cost technology mix, for the whole observed time horizon in one unique run, with perfect foresight.[5] Hence, GIS data are accounted for by OSeMOSYS not only because they are a fundamental element used to build the electricity demand projections, but also because they affect (set boundaries to) the decision about the optimal technological choices in each space square.

4. The case of Tanzania: scenarios

Generally speaking, the issues at the core of the Tanzanian government's vision regarding the national electricity sector include providing a reliable electricity supply to a growing industrial sector and fostering the electrification rate of non-urban areas. Coherently, this vision is supported by plans to increase diversification in the power generation sector and to rely on local (renewable) energy sources whenever possible.[6]

To put this into perspective, the existing generation capacity by technology is graphically presented in Fig. 1 [12,41–43].[7] Note that the latest complete and reliable set of historical economic and electricity data considered in this study is related to the year 2015 (therefore, 2016 is the first year of projection). Of the almost 2 GW of installed capacity in 2015, the largest contribution to the generation mix is from natural gas (36.5%), followed by hydropower (32.6%), oil and diesel (28.7%) and biomass (2.3%). The retirement schedule of this capacity is assumed to be same in all scenarios described below, and such that only 200 MW of the current capacity will still be available in 2040 [42].

Following the recent discovery of natural gas fields, the government is planning to have up to 4 GW of gas-fired power plants by 2025 [42]. Within the same temporal horizon, the use of coal (also a domestic resource) is estimated to grow up to 1.4 GW.[8] Geothermal power is planned to reach 200 MW [44] and a significant growth is expected in solar power, but not in wind generation (planned wind projects are only around 0.5 GW) [11]. Hydroelectric generation facilities represent a great power potential for the country, but are undermined by vulnerability related to hydrological, weather and climate changes, as well as competing uses with other economic sectors. For these reasons, the forecasted hydropower potential is only about 2 GW by 2025 [42].

Accordingly, while the first scenario considered in this work is, as customary, a *Business As Usual* (BAU) one, the second scenario, *New Policy* (NP), follows closely the government's vision just described. More specifically, it simulates the adoption of technology policies supporting the realization of the capacity and generation mix envisioned in the PSMP of 2016 and other recent policy documents [42,45,46]. A third scenario, *Energy For All* (E4A), assumes the same technology policies as in the NP scenario, but it is also driven by the goal to reach universal electricity access in 2030, two decades earlier than in the BAU and NP.

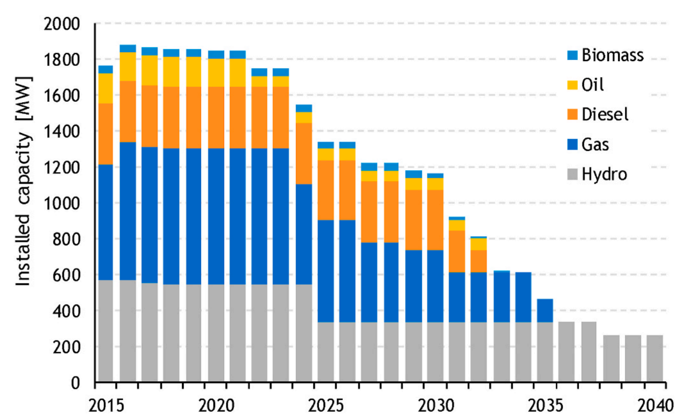

Fig. 1. Installed generation capacity (in GW) in 2015 and retirement schedule in future years.

[3] Official documents can also be used to account for the planned evolution of the transmission grid which becomes an additional, exogenous driver for future changes in *status* of the space squares.

[4] For instance, the technological choices for a 'urban' space square are: grid connection, diesel stand-alone, and PV stand-alone (with or without storage), while the choices for a 'distant but densely populated rural' space square are grid connection, diesel stand-alone, diesel mini-grid, PV mini-grid, and PV stand-alone with storage. Note that an industrial load status is also considered (grid connection). The set of available electricity production technologies per *status* of the space square is defined in compliance with the guidelines provided by the Tanzanian National Electrification Program Prospectus [54].

[5] If the *status* of a space square changes and the comparative advantage of an off-grid technology with respect to grid connection changes, then the space square will likely be connected to the grid in the years to come. However, this change occurs only at the end of the useful life of the previously installed technology.

[6] This national vision was extracted from the analysis of a number of legislative documents, including: the Energy and Water Utilities Regulatory Act (2001), the Rural Energy Act (2005), the Electricity Act (2008), the National Public Private Partnership Act (2010), the Gas Supply Act (2012), and the Petroleum Act (2015). Additional sources are: [6,42,43,45,46].

[7] Additional sources of data are the World Bank website (https://energydata.info) and the TANESCO website (http://www.tanesco.co.tz).

[8] Coal reserves in Mchuchuma, Ngaka, Kiwira, Mbeya and Rukwa can provide 297 million tons to power generation [55].

Finally, the *450TZ* scenario, simulates the expansion of the power generation sector under an environmental policy (a carbon tax), coherently with the country's environmental concerns [47]. As summarized in Table 2 (and detailed in the supplementary material, file 'SM_Data'), the specific modelling assumptions are as follows:

- The BAU scenario considers the evolution of electricity demand under both *High Demand* (HD) *and Low Demand* (LD) assumptions and, according to government plans, strives to reach full electrification by 2050. The electricity supply mix is kept constant, equal to the initial conditions, and the overnight capital costs of solar PV and wind technologies evolve according to a *Slow Learning Case*. As for the evolution of the Transmission and Distribution (T&D) infrastructure, a so-called *Grid Rate* indicator is defined as the yearly ratio of the electricity which is centrally generated or imported, and the total electricity produced within the country. In the BAU scenario the Grid Rate is kept equal to 95%.
- The NP scenario shares the same assumptions of the BAU regarding the evolution of the electricity demand and the full electrification target (2050). As for the development of the supply side, this is designed to simulate the expansion plan proposed by the government of Tanzania and includes all projects under development, planned or included in the PSMP [27]. The overnight capital costs of solar PV and wind technologies evolve according to the *Slow Learning Case*, while the evolution of the T&D infrastructure is optimised (the adoption of on-grid vs. off-grid solution for new connections is dictated by a least-cost criterion).
- The E4A scenario is equal to the NP one, but it is driven by the goal of reaching universal electricity access by 2030.
- The 450TZ scenario includes policy constraints specifically designed to meet the global climate change goals defined by the Paris Agreements. Those take the form of a carbon tax, a policy instrument not yet proposed by the Tanzania government. The starting level of the tax is set at 10 USD/ton of CO_2 in 2020, with a planned increase to 75 USD/ton in 2030 (and 125 USD/ton in 2040) [48]. As for the demand side, the assumptions are the same as in the BAU scenario, including the full electrification target (2050). The supply side is modelled with no restrictions on the choice of the generation technologies while the overnight capital costs of solar PV and wind technologies evolve according to a *Fast Learning Case*. Lastly, the development of the infrastructure follows a least-cost optimality criterion.

The technical and economic characteristics of the technological options for future developments of the power system are also collected in the file 'SM_Data'. Values of discount rate in Tanzania varied between 5% and 16% in the period 2010–2020, with average values around 10%:

Table 2
Main assumptions for the four scenarios. HD and LD refer to High-Demand and Low-Demand respectively. PSMP refers to the 2016 Power System Master Plan.

Parameter type	Parameter name	BAU	NP	E4A	450TZ
Demand side	Electricity Demand	HD, LD	HD, LD	HD, LD	HD, LD
	Electrification rate (100% in year …)	2050	2050	2030	2050
Supply side	Electricity supply mix	Constant at 2015	PSMP	PSMP	No restrictions
	PV/wind overnight capital cost decrease	Slow	Slow	Slow	Fast
Infrastructure	Grid Rate	Constant (95%)	Least-cost optimal	Least-cost optimal	Least-cost optimal

the latter value is then assumed as the reference for all scenarios.

5. The case of Tanzania: results

This section presents and contrasts the results obtained over the period 2015–2040 under the four modelled scenarios (note that the model runs until 2050 to avoid wedge effect in the last 10 years). In particular, this section focuses, first, on the installed generation capacity and on the electricity generation per technology. Secondly, a few, selected indicators are used to assess the analysed scenarios along the *economic*, *environmental* and *energy security* dimensions. All the results are presented for both the High Demand (HD) and for the Low Demand (LD) assumption – these are in line with the estimates of Ministry of Energy and Minerals of Tanzania [31] and IRENA [11], respectively. Note that the prospected changes in population and average living standard imply a growth in electricity demand by 10.5 times between 2015 and 2040 for the HD assumption and by 5.5 times for the LD assumption.

As illustrated in Fig. 2, installed generation capacity in 2015 was about 1.9 GW. Under the BAU scenario conditions and HD assumptions, installed capacity is expected to increase up to 20.6 GW in 2040, with large amounts of off-grid diesel capacity and negligible contributions from renewables (under LD assumptions installed capacity is 10.6 GW in 2040). For the NP and 450TZ scenarios, the overall installed capacity in the same time frame and under a HD assumption, grows up to 29.0 GW and 37.7 GW respectively, reflecting the lower capacity factors of the installed PV off-grid systems compared to the fossil-based technologies of the BAU (under LD assumptions installed capacity is around 13.8 GW and 17.7 GW, respectively, in 2040). Finally, the E4A scenario presents, by design, the same composition of technologies as the NP; however, greater installed capacity is needed to provide access to the entire population by 2030 (installed capacity in 2040 is 34.0 GW under HD assumptions and 15.3 GW under LD assumptions).

Fig. 3 provides the electric generation by technology for each scenario (in TWh), for both HD and LD assumptions. Depending on the analysed scenario, between 2015 and 2040 the electricity production grows between 10 and 12 times under the HD assumption (e.g., from 6.94 to 83.70 TWh in the BAU) and between 4.5 and 5 times under the LD assumption (from 6.94 to 41.90 TWh in the BAU). Such growth is driven by the prospected changes in electricity demand. Differences in electricity production across scenarios are limited and mostly driven by transmission losses and power plant efficiencies.

A first matter of interest is the differences in terms of shares of on- and off-grid technologies. With reference to the HD assumption (shares are similar under LD and HD assumptions), the off-grid generation in the BAU scenario is below 10% with respect to the overall generation, and fully supplied by diesel generators. On the other hand, the share of electricity supplied by off-grid technology in the 450TZ scenario reaches about 50%, mostly supplied by solar PV systems. The NP and E4A scenarios are quite similar, with a share of about 20% of off-grid electricity supplied by solar PV and diesel generators.

Second, the share of electricity produced by gas-fired plants is high (around 50%) in all the scenarios, except for the 450TZ one. This technology is characterized by the best trade-offs among costs, emissions, and operational flexibility (i.e. capacity to make quick load changes for regulation purposes) compared to other dispatchable technologies. For such reason, it is prominent in scenarios with no particularly relevant emissions policy constraints. Differently, in the case of the 450TZ scenario gas-fired plants become less economically competitive than renewables, reducing their weight in the electricity supply mix in favour of hydropower, wind and especially solar PV (both on- and off-grid).

Third, in the BAU scenario, on-grid diesel generators satisfy a constant share of electric energy demand (up to 8%) over the 2015–2040 horizon, and hydroelectric energy is the only renewable source until 2036, where a small share of electricity demand is supplied by

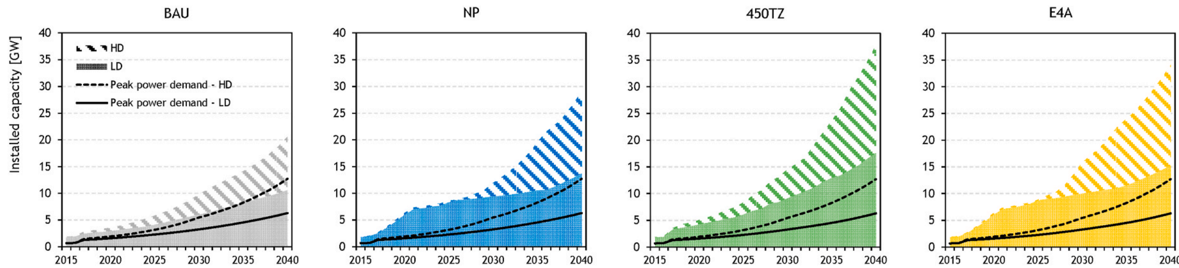

Fig. 2. Installed generation capacity (in GW) between 2015 and 2040 for the four analysed scenarios. Filled and striped areas represent respectively Low Demand (LD) and High Demand (HD) assumptions. Peak power demand is represented by the solid line (LD) and by the dotted one (HD).

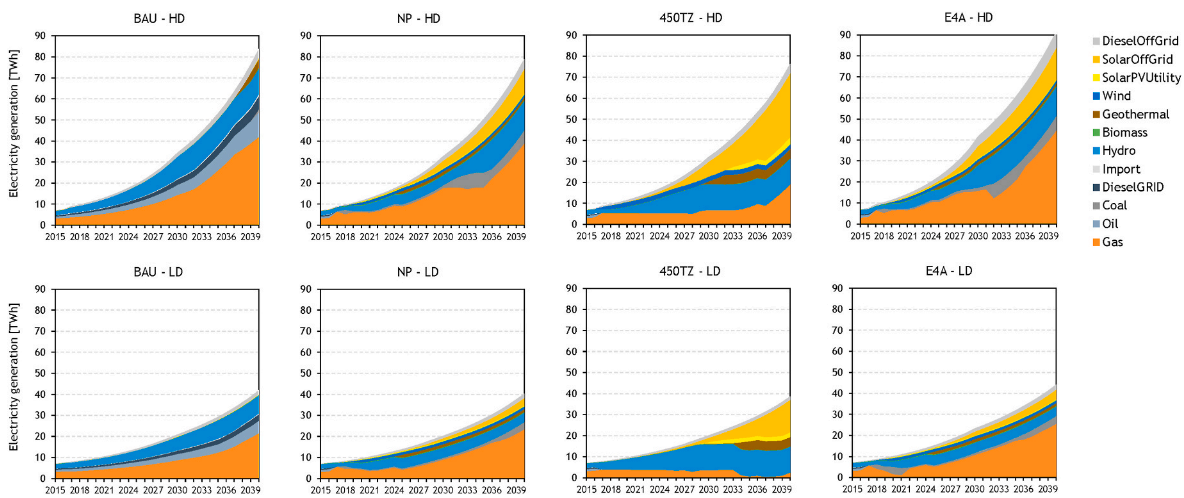

Fig. 3. Electricity generation by technology in the modelled scenarios, in TWh (upper graphs refer to the HD assumption, the bottom graphs refer to the LD assumption).

geothermal power plants. In all the other scenarios, oil plants and on-grid diesel generators are fully removed from the electricity mix. In the 450TZ scenario, coal is never selected as an alternative; penetration of renewable energy sources in the supply mix before 2025 is mostly supported by wind, while geothermal and solar PV utility systems appear in the energy supply mix only after 2030, reaching a non-negligible share of about 10% in 2040. Notably, coal becomes an option in NP and E4A scenarios, but supplying less than 10% of energy in the long run.

Finally, while electricity supply shares are similar across scenarios, a few exceptions exist. In the BAU scenario, geothermal energy is not used under LD assumptions. In NP and E4A scenarios, hydropower and wind play a more significant role with respect to off-grid solar PV systems and in the 450TZ scenario, natural gas is almost fully displaced by hydro under LD assumptions.

To capture the economic dimension, Fig. 4A provides the total cost of power supply (in Billion USD) in the time frame 2015–40. Investment costs (including generation and T&D) are quite similar across all the scenarios: in general, highest values are related to the 450TZ and E4A scenarios (between 97 and 99% of the real Tanzanian GDP in 2018 for HD assumption and in the 41–51% range for LD assumption), while lowest values are related to the BAU scenario (24% and 50% of the real Tanzanian GDP, respectively in the LD and HD assumptions). In all scenarios, the investment requirements are then higher with respect to the BAU case. The main difference among scenarios is due to fuel costs: the highest values are related to the BAU scenario, ranging from 52 up to 90 billion USD depending on the assumption on energy demand; the lowest fuel expenditures are related to the 450TZ scenario (between 8 and 17 billion USD, respectively under LD and HD assumptions). Significant investments for T&D are required in the BAU scenario under the HD assumption, mostly due to the high Grid Rate set up in the model (95%).

Fig. 4B reports the cost of power supply per kWh in each year, for all the analysed scenarios and demand assumptions. The graph presents a high number of "spikes" due to the prospective investments in generation and T&D capacity required to meet the demand, and concentrated in the first years of the simulation, especially for the NP and E4A scenarios. Beyond such non-regularities, the BAU scenario presents the highest costs of power supply in the long run (around 20 cent USD/kWh), while all other scenarios require higher investments at the beginning but guarantee lower costs in the long run (between 7 and 13 cent USD/kWh, depending on the scenario and demand assumption considered).

Fig. 4C reports the average cost of power supply for the period 2015–2040, derived as the average of the yearly ratio between the incurred costs (investment, operation, eventual carbon tax) and the electricity generated. The highest cost per kWh is associated with the BAU scenario, due to its high dependency on fossil fuels and high Grid Rate (15 and 18 cent USD/kWh, respectively, under LD and HD assumptions). The deployment of more diverse resources brings the average electricity cost down in the NP (12 and 15 cent USD/kWh, respectively, under LD and HD assumptions). The E4A scenario is characterized by higher costs (12 and 19 cent USD/kWh, respectively, under LD and HD assumptions), and the lowest electricity cost results for the 450TZ scenario (11 and 14 cent USD/kWh, respectively, under LD and HD assumptions), due to the joint effects of massive penetration of PV off-grid systems, reduction in the related PV off-grid technology investment cost, and reduction in investments in T&D.

The environmental performance of the analysed scenarios is partially assessed by looking at carbon emissions. Further relevant environmental

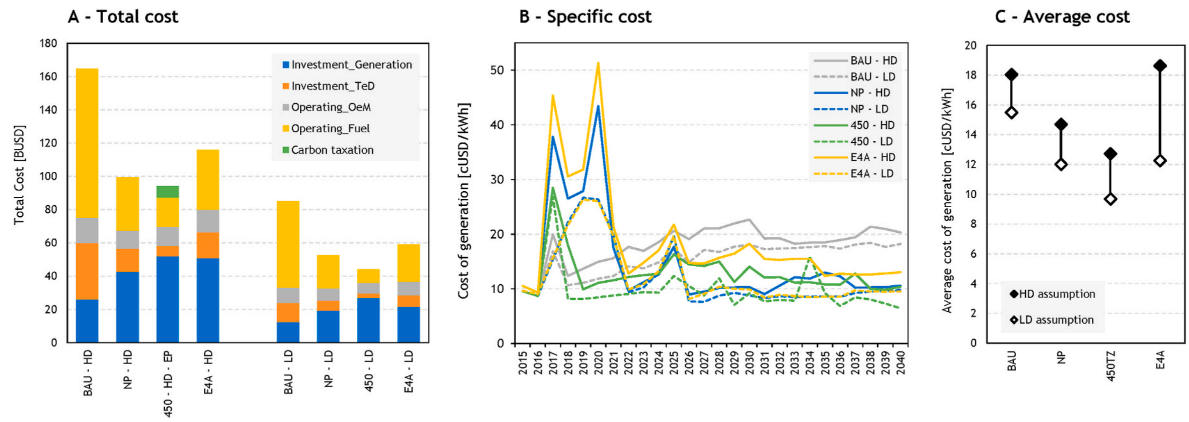

Fig. 4. A. Total costs of power supply over the time horizon 2015–2040 (billion USD); B. Annual cost of power supply per kWh over the time horizon 2015–2040 (cent USD/kWh); C. Average cost of power supply per kWh over the time horizon 2015–2040 (cent USD/kWh). All the costs are discounted, assuming an average discount rate of 10%.

categories (e.g. other emissions types, consumption of raw materials, etc.) are out of the scope of the present study. Cumulated CO_2 emissions over the 2015–2040 horizon and yearly CO_2 emission intensities are illustrated in Fig. 5. The obtained values are consistent with the technology mix: the BAU scenario is characterized by the highest cumulated emissions (250 and 400 Mton, respectively for LD and HD assumptions), followed by the E4A and the NP (between 150 and 300 Mton). Only the environmental policy assumed under the 450TZ scenario is successful in decreasing CO_2 emissions to 60 and 110 Mton, respectively for LD and HD assumptions. CO_2 emission intensity in 2040 reaches values of about 480 gCO_2/kWh for the BAU, about 300 gCO_2/kWh for the NP and E4A scenarios, and about 100 gCO_2/kWh for the 450TZ (no sensible differences between demand assumptions). Notably, the CO_2 emission intensity of the 450TZ scenario reaches minimum values around 2035, and then starts growing again, due to the increasingly relevant role of natural gas. In fact, after 2035, the emissions intensity increases for all the scenarios and demand projections: the share in non-renewable technology is mostly due to natural gas-fired power plants in the BAU and to gas- and coal-fired power plants in the NP and E4A scenarios. Once demand from industry and urban agglomerates increases, the gas-fired technology is the cheapest feasible alternative also in the 450TZ scenario.

Finally, the diversification of the supply technologies and the dependence by a portfolio of foreign countries are the two main aspects of *energy security*. In an increasingly interconnected world, the degree of country dependence has given way to diversity (of energy technology supply) as the dominant security paradigm [49]. The *Shannon-Wiener index (SWI, %)* is one of the most common indices used to provide a quantitative assessment of such diversity [50]. Indeed, power systems relying on multiple sources of primary energy and/or technologies are more robust to shocks (in prices) or other constraints affecting the supply chain of one or another form of supply (e.g., scarce availability of the fuel or natural resource, as well as scarcity of technical components for repair and maintenance of the power plant) [10,35,36].

Consistently, the SWI quantifies diversity in the electricity mix on the basis of the number of employed resources (subscript $i = 1, \dots N$), and of the share of generation by each resource, p, in each year (subscript t):

$$SWI_t = -\frac{1}{\log(N_t)} \cdot \sum_{i=1}^{N_t} p_{i,t} \cdot \log(p_{i,t}) \qquad (1)$$

A power system that relies on a single power source has a low energy security and its SWI will be far from 100%.[9] Note that the SWI indicator does not consider the spatial distribution of power technologies, i.e., it is independent by, say, the distribution of renewables across the country.

The distribution of the annual values of the SWI indicator is reported in Fig. 6 per scenario, using box plots (Sub-plot A: HD assumption, Sub-plot B: LD assumption). Starting from a yearly value of 66.6% in 2015, the NP and E4A scenarios result, on average, in relatively high energy security under both LD and HD assumptions – they present a higher diversification than the BAU. SWI values for the 450TZ scenario under HD assumptions show a high level of diversification of the supply mix, while LD assumptions keep the SWI mostly below the initial value in 2015 (and below the median of the BAU scenario).

In sum, the findings of the present modelling effort for the Tanzanian power system are mixed when observed from the point of view of the policy goals set by the national government and embodied in the NP scenario (provide a reliable electricity supply to a growing industrial sector, rely on local, renewable energy sources and increase diversification, as well as foster the electrification rate of non-urban areas).

Capacity requirements necessary to serve the load (not only the industrial one but also an increasing residential demand) are rather large (from 1.9 GW to 29.0 GW in 2040 under HD and 13.8 GW under LD assumptions), as well as the estimated increase in electricity production (from 6.94 to 79.02 TWh under HD and 40.38 TWh under LD assumptions). This implies an overall investment level in the power system which is clearly above the historical one (25.3 billion USD for LD and 56.6 billion USD under HD for the entire period, respectively the 43% and 97% of the nominal GDP of 2018).

Moreover, results show that decreasing the dependency from fossil fuels and relying on local and renewable resources is feasible (450TZ scenario), but would require a stronger focus on environmental policies (in the NP scenarios the share of gas and coal in the electricity

[9] For example, relying only on PV only will return a SWI close to 100%. Even under unlimited availability of the primary resource, this captures the risk of a limited capability to substitute old components or to change broken ones. Differently, assuming that the technological components for maintenance of the power plant are always available, relying on hydropower only would result critical in a protracted drought situation. Similarly, an economic (high prices) or physical scarcity of natural gas would affect the security of a system relying on natural gas-fired plants only.

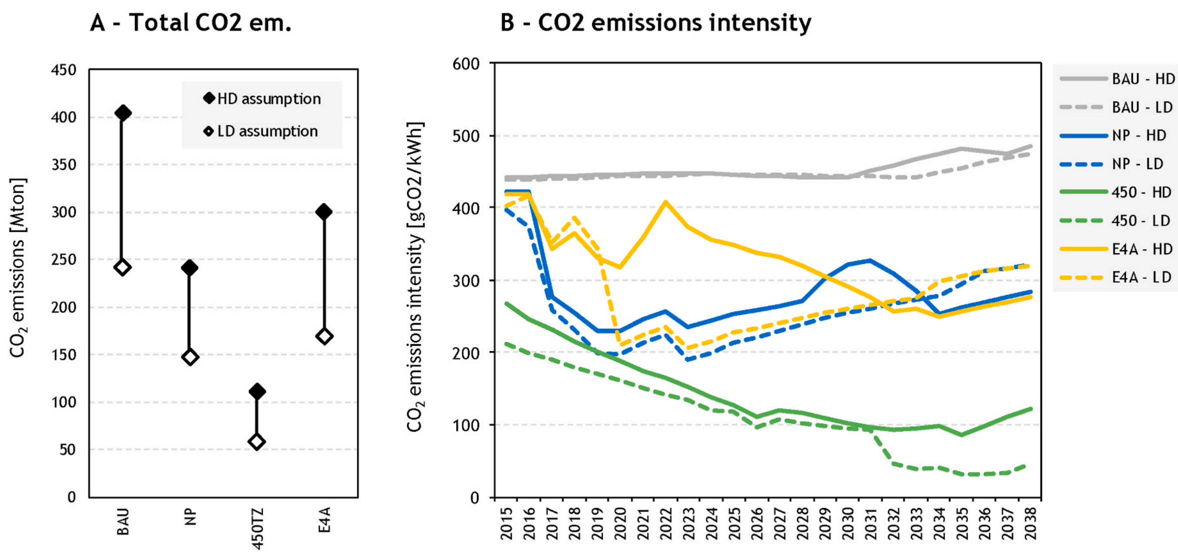

Fig. 5. – A: cumulated CO_2 emissions over the period 2015–2040, in Mton (black and white diamonds represent respectively HD and LD assumptions). B: yearly CO_2 emission intensity of electricity generation, in gCO_2/kWh (solid line refers to HD assumptions, and dotted line to LD assumptions).

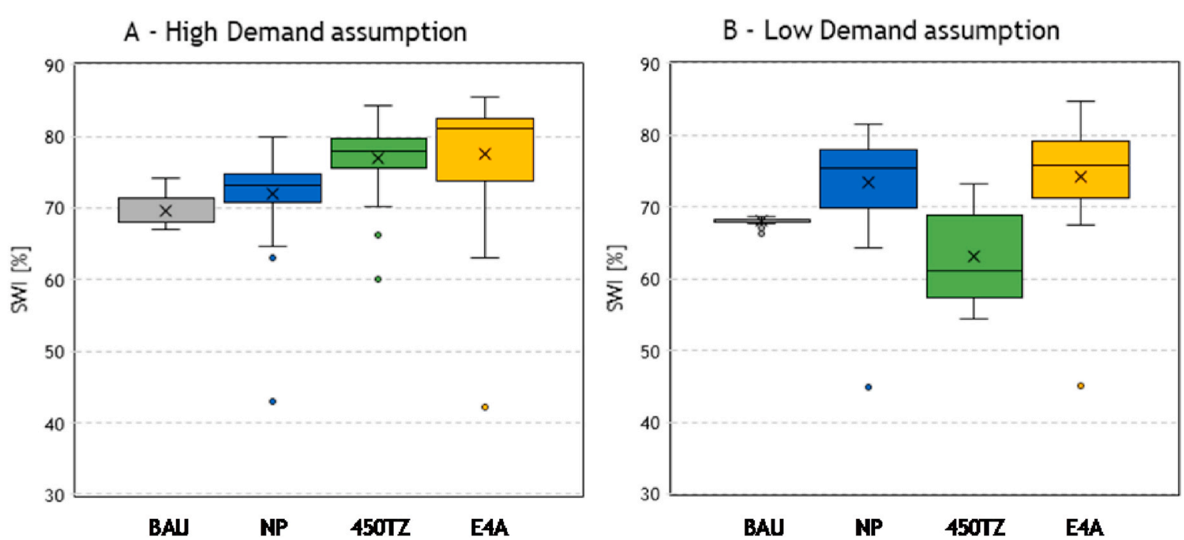

Fig. 6. Yearly values of Shannon-Wiener Index (SWI) collected in box plots, where "x" refers to median values, while "o" represents outliers. A: HD assumption; B: LD assumption.

production mix is again above 50% in 2040, while the same share is around 25% in the 450TZ-HD scenario and around 7% in the 450TZ-LD one). Notably, a decarbonization of the power system might also lead to a lower cost of providing electricity due to a decrease in operating expenditures and investments in T&D infrastructures (from 12 to 15 cent USD/kWh, under NP-LD and NP-HD assumptions to 11–14 cent USD/kWh, under 450TZ-LD and 450TZ-HD assumptions). The farther benefit of moving away from an NP scenario is the reduction in carbon intensity of the power sector, which is, in 2040, less than one half under 450TZ assumptions. Conversely, while an increase in energy security with respect to the BAU, seems possible under an NP scenario, results are mixed under a 450TZ – higher (lower) than the BAU security is found, on average, under HD (LD) assumptions.

Third, reaching universal access is certainly feasible by 2050, but the same target can also be reached two decades earlier (in 2030). In the latter case, however, the cost of providing power supply would tend to be, on average, higher (between 12 and 19 cent USD/kWh under E4A-LD and E4A-HD assumptions). Also, the carbon intensity of the power sector would be comparable to the one ensured under an NP scenario, and energy security would be higher only under HD assumptions (and quite similar to the one observed under NP, under LD assumptions). Note that, in light of the specific features of the methodological approach proposed in this study (see Section 3), the results regarding the provision of universal access are further discussed (in Section 6).

A further assessment of the robustness of all the results presented here is conducted via a sensitivity analysis (Section 7). This focuses on the impact (on a number of indicators) of alternative assumptions, not only for demand projections, but also for the Grid Rate, for the possibility of relying on domestic fuels (natural gas) and, as customary, for the discount rate.

6. Providing access to electricity

With regard to the issue of providing universal access, it is interesting to compare the findings of this work with those of a similar work conducted by the IEA and reported in the Energy Access Outlook 2017 (hereinafter EAO2017) [52]. According to the EAO2017, East Africa is the only sub-region, among those included in the report, where efforts to provide access to electricity outpace population growth [52]. The present work supports this statement, by confirming that, in all scenarios, the number of people with no access decreases over time despite the growing population. At the same time, not all the results found in this work find an exact correspondence in the EAO2017.

Specifically, this section compares the results of six scenarios: the NP and E4A scenarios computed in this work for Tanzania (under HD and LD assumptions) and the NP and the E4A scenarios computed by the IEA for the sub-Saharan region (NP-IEA and E4A-IEA). It is important to note that all statistical indicators used in this section are calculated with reference to new accesses to electricity: population already connected to a source of electricity, as well as non-residential consumption, are not included in the statistics.

One of the most relevant questions in modelling electrification scenarios is related to the choice of providing access via on-grid or with off-grid solutions and, in the latter case, which solution is preferred between a mini grid and a stand-alone system. Indicating with the term *Access Type* these three types of solutions (connection to the T&D network, mini grid and stand-alone system), Fig. 7 compares the results obtained in the six above-mentioned scenarios, over the same time interval.

As illustrated in Fig. 7A, all three NP scenarios (NP-IEA, NP-HD and NP-LD) indicate that, in the case of new accesses, the larger share of electricity is provided via a connection to the T&D network (59%–77%). Differently, when considering off-grid solutions, the results of the NP-IEA scenario suggest that a larger share of electricity is provided via stand-alone solutions (18%) rather than mini grids (9%), while the opposite is true in the present study. Similar observations can be made looking at investments in new accesses by Access Type (Fig. 7B). Most investments are devoted to connections via the T&D network (55%–69%) and results for off-grid solutions indicate that a larger share of investments goes into stand-alone system according to the IEA, while they are mixed in this study. Interestingly, when looking at new accesses in terms of population (Fig. 7C), the IEA confirms a larger role for grid connections (68%) and, among off-grid solutions, for stand-alone systems (20%). Results from the NP-DP and NP-LD scenarios indicate instead a different picture, with 40%–49% of the population connected via mini grids.

In other words, in the NP-IEA scenario most of the electricity produced and the investments made are directed to grid connections and this is consistent with most of the population gaining access for the first time via the transmission grid. Similarly, both the NP scenarios assessed in this work indicate that most of the electricity and investments are linked to grid connections. However, they also point to mini-grids as a key solution in providing access to electricity to a large share of the population. The difference between the IEA report and the present study resides in the fact that country-specific estimations were used for the investment and installation costs of solar PV stand-alone systems. Data collected from field observations show that costs of these stand-alone systems decrease with the size of the installation (see Figure SM 5 in the file 'SM-Data' in the supplementary material) and the reference value assumed for the present study corresponds to the observed cost of a 2 kWp system (most of the observed installations were of similar or smaller size). Using these values, mini-grids are often the optimal choice for electrification, apart from sparsely populated areas. A sensitivity analysis shows, however, that the share of population connected via stand-alone systems increases when considering stand-alone systems of larger size and lower costs (see the file 'SM-Results' in the supplementary material). Above a certain threshold (empirically found at 3 kWp) stand-alone systems become cheaper than mini-grids and they represent the dominant technology for off-grid solutions at 4 kWp and higher.

When the E4A scenarios are considered, the results of the EAO2017 and of the presents study are similar. With reference to Fig. 7, the largest share of electricity is still provided via the grid (46%–70%); however, mini grids connect the largest share of the population gaining access for the first time (44%–60%) and receive the largest share of the investments.[10] Indeed, higher levels of rural demand in the E4A scenarios favour off-grid solutions: variable costs of on-grid technologies increase while off-grid solutions are often based on renewable solutions. This is particularly true for Tanzania which, on one hand, has limited hydro capacity to lower the marginal cost of on-grid generation and, on the other hand, has a relatively large share of population living in remote rural areas.

In sum, regarding the electrification of rural areas in Tanzania, this works supports the view that mini-grid and stand-alone systems are viable alternatives to on grid solutions relying on fossil fuels, particularly those not domestically available. Regarding the trade-off between mini-grid and stand-alone technologies, attention should be paid to the available technologies and their costs in the specific rather than generic location, as well as to how economic parameters changes with the size and other characteristics of the technology.

7. Sensitivity analysis

For the purpose of this study, four exogenous model parameters are identified as potentially capable to affect the results significantly: *Electricity Demand* , *Discount Rate* , *Grid Rate* and the evolution of the domestic price for *Natural Gas* . While Electricity Demand ranges between Low and High Demand assumptions, two values are employed for the Discount Rate (5% and of 15%) and results compared to the baseline case of 10%. As for the Grid Rate, results are obtained for three alternative values: free (i.e. endogenously returned by the model), 80% and 95%. Finally, different values for the domestic price of Natural Gas are considered, to capture the potential effect of price shocks induced by the exploitation of new domestic reserves [11]. For all these parameters, the observed range of variability and the reference values (those used to compute the baseline results for the estimated indicators) are reported in Table 3.

Results of the sensitivity analysis are graphically represented in Fig. 8, with reference to years 2017–2040 (full numerical results are reported in the file 'SM_Results' as electronic supplementary material). For a meaningful and straightforward scenario comparison, only three intensive numerical indicators are reported: the *average investment cost* per *unit of electricity generation* (cent USD/kWh), defined as the cumulated annual investment cost divided by the electricity generated in the whole analysed time frame; the *average CO_2 emission intensity* (gCO_2/kWh), defined as the cumulated annual CO_2 emissions divided by the electricity generated over the whole analysed time frame; and the *average annual SWI index* (%), defined as the average value of the annual SWI over the whole analysed time frame.

In Fig. 8, results obtained using the reference values ('baseline results') are represented by the solid black line, while differences between the minimum and maximum values are represented by the blue coloured bars. Relative changes between minimum and maximum values for all the numerical indicators are represented by the black diamonds (expressed in % in the secondary vertical axes): this parameter is crucial, since it synthetically represents the sensibility of the analysed parameter with respect to changes in exogenous input variables. As an example, with reference to the upper left corner of Fig. 8, the average specific investment cost in the BAU scenario oscillates between less than 6 and 8 cent USD/kWh (left vertical axis), depending on the electricity demand assumption, hence resulting in a 50% of variability (right vertical axis).

The Electricity Demand assumption (LD vs. HD) significantly affects the average specific investment cost, with relative changes ranging from 20% (450TZ) up to 50% (BAU): this is mostly related to relevant

[10] The E4A-LD scenario represents the only exception in this regard: the 45% of investments is devoted to grid solutions vs. 39% to mini grids.

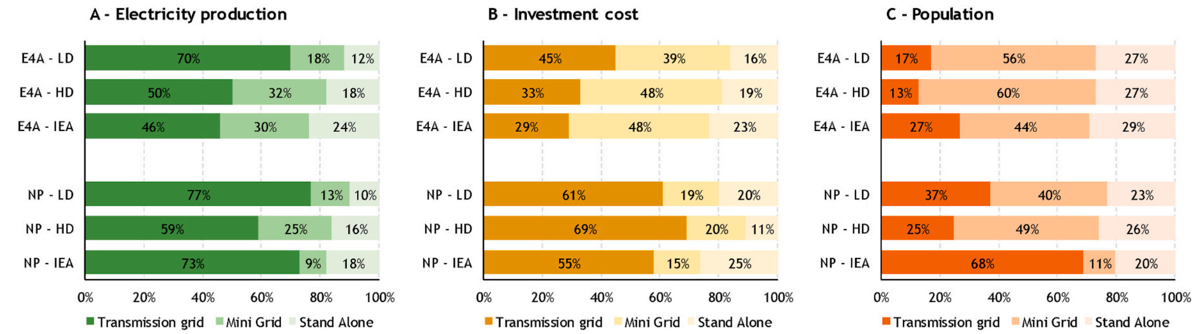

Fig. 7. Share of electricity production (Sub-plot A), investment cost (Sub-plot B) and population gaining new access (Sub-plot C) all grouped by Access Type (transmission grid, mini-grid, stand-alone), for the whole observed time horizon 2015–2040. Sources: own elaboration and [52].

Table 3
Sensitivity analysis: input variables, the related ranges of variability, and the reference values assumed for running the baseline scenarios reported in section 5.

Input variable	Range of variability	Reference values
Electricity Demand	Low – High assumption (LD – HD)	High Demand assumption
Discount Rate	5%–10% - 15%	10%
Grid Rate	Free - 80%–95%	Free (for NP, E4A, 450TZ), 95% (for BAU)
Natural Gas domestic price	Base – High price projections	Base price projections

expenditures required to develop the T&D infrastructure, that are less prominent in the 450TZ scenario. Changes in overall energy demand slightly influence specific CO_2 emissions, and this because the electricity generation mix is not much affected by demand changes. The same conclusion can be drawn for the SWI, with the only exception of 450TZ scenario, capable to satisfy low electricity demand pathways with a less diversified energy mix.

The Discount Rate affects investment costs and emissions for all the scenarios. Lower discount rates correspond to higher investment cost per unit of electricity generated, and this strongly affects the technology mix (hence CO_2 emissions and SWI) especially for the BAU and 450TZ scenarios, leading to low carbon intensive technologies in all scenarios. For the 450TZ scenario, changes of discount rate from 5% to 15% lead to a change in specific CO_2 emissions of about 300%, while other scenarios keep changes in specific CO_2 emissions below 50%.

The Grid Rate parameter has a relatively smaller effect on specific investment costs compared to other parameters, causing less than 15% of relative change for all the scenarios. Differently, it modifies CO_2 emissions significantly (around 20% for all the scenarios except 450TZ, which reaches 75%). In general, low grid rates values (indicating a preference for off-grid solutions) increase SWI while reducing carbon emissions across all scenarios. It can be stated that higher than optimal grid rates should be preferably avoided, since a higher grid rate generally leads to higher costs and carbon emissions and, at the same time, reduces the energy security index.

High projections for the domestic price of Natural Gas also have a negligible effect on investment costs, except for the BAU scenario that considers fewer alternative technologies (with relative differences up to 30%). The impact on the SWI and on CO_2 emissions is relevant only for the 450TZ scenario (here, high natural gas prices result in lower CO_2 emissions and SWI).

In sum, BAU and 450TZ scenarios appears to be more sensible than others with respect to changes in the analysed parameters. Specifically, the BAU scenario appears particularly vulnerable to an increase in domestic gas prices and electricity demand projections, as well as changes in discount rates. These parameters impact the investment costs and, less significantly, the SWI. The 450TZ scenario also appears vulnerable to occurrences where domestic prices of natural gas are high, to variations in electricity demand projections and changes in the discount rate. These parameters are likely to impact the SWI and cause significant changes in CO_2 emissions. As for the NP scenario, higher prices for domestic natural gas would favour diversification in the generation mix, leading to higher energy security, while changes in electricity demand projects would mostly impact the specific investment cost. Finally, the E4A scenario seems to be resilient to changes in the analysed parameters, except for grid rate and Energy demand, the changes of which can, respectively, significantly reduce diversification in the energy mix and increase the specific investment cost.

8. Conclusions and policy implications

Energy modelling is a critical instrument in the analysis of future electrification scenarios, providing technical support to decision makers at national and international level. The modelling approach proposed in this work contributes to this stream of research in several ways. First, the analysis is conducted relying on open-source energy modelling platform (OSeMOSYS) fed with open datasets, ensuring transparency and reproducibility of the analysed scenarios. Second, the modelling approach combines an existing model with an original geospatial characterization of the territory under investigation, thus avoiding the need to couple OSeMOSYS with other modelling platforms. Moreover, all modelling assumptions are country-specific, i.e. they are defined on the basis of the political intentions of the government of Tanzania, account for the resource potential of the country, and are derived from direct observation of the local cost of off-grid technologies. At the same time, the analysed scenarios also rely on general assumptions and constraints, often taken from IEA and IRENA, ensuring meaningful comparisons with other studies.

The estimated electrification pathways for Tanzania indicate a potential for the country to reach a wide range of policy objectives, including a diversification in production technologies, universal access, and lower carbon intensity within the power sector. Of course, the relative success in reaching these desirable outcomes, depends on the implementation of specific technology and environmental policies (i.e., on the scenario), and implies different the investment requirements. Notably, while a reduction in carbon intensity is more effectively addressed by an environmental policy (450TZ scenario) rather than by the technology policy recently drafted by the national government (NP scenario), investment requirements mostly depend on the level of the electricity demand projections (LD vs. HD assumptions). A departure from a BAU scenario, which heavily relies on fossil fuels, is nonetheless advisable not only for environmental reasons, but also to lower the cost of electricity for the end-users and to ensure higher diversification in the power system. In addition, this will subtract the national power system from the uncertainties deriving from the future evolution of both domestic and imported fossil fuels (specifically, natural gas prices). As for

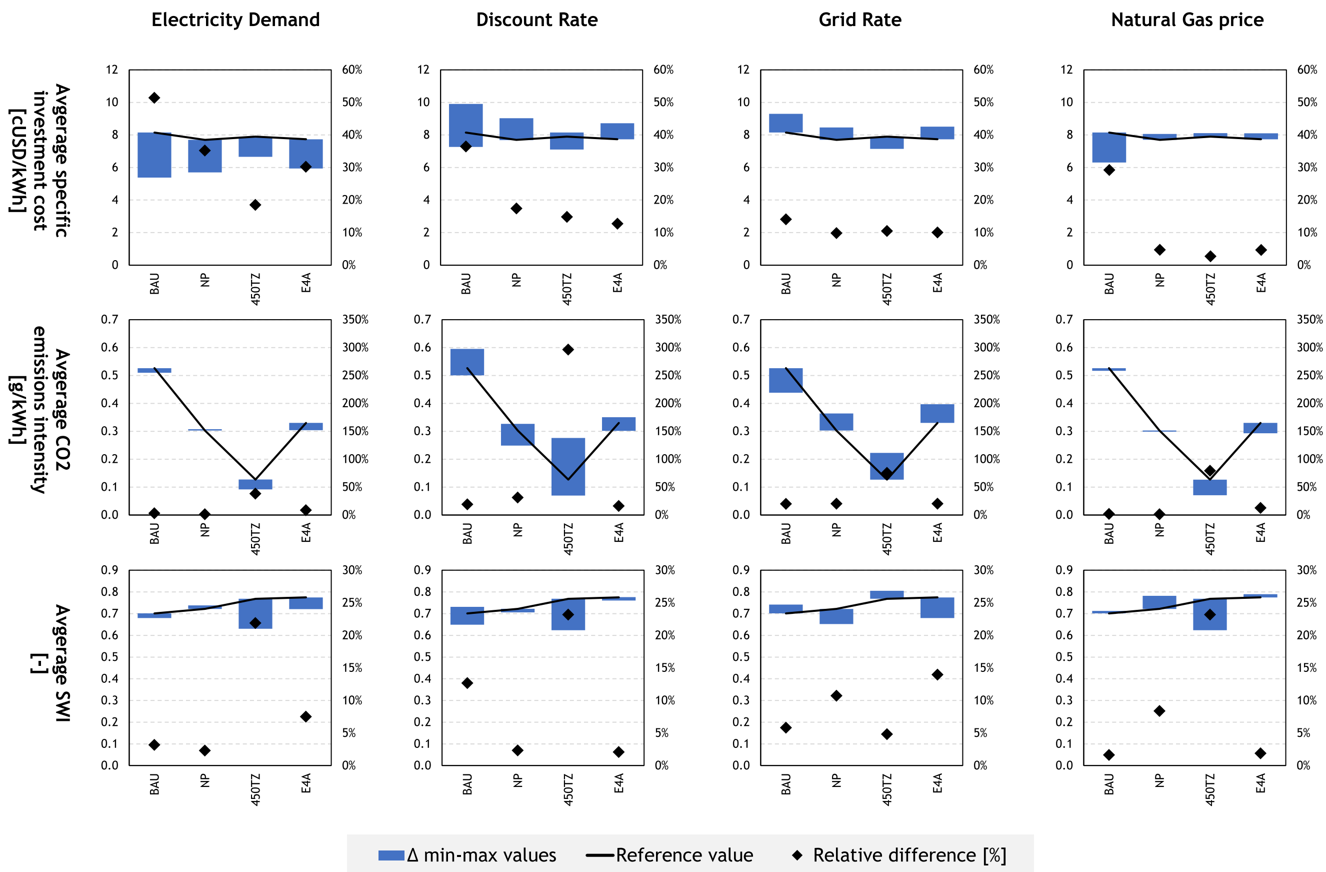

Fig. 8. Results of the sensitivity analysis on main model parameters (Electricity Demand; Discount rate; Grid Rate; Natural Gas price). Sub-plots report scenarios in columns (BAU, NP, 450TZ, E4A) and model results in rows (investment costs per unit of generation, CO_2 emissions per unit of generation, average SWI). Each sub-plot includes changes in model results (color-filled bars) with respect to reference values (solid line), and relative % change in the secondary vertical axes (black diamonds).

achieving universal access, this study shows that reaching the target already in 2030 is technically feasible but implies more difficulties in lowering carbon intensity or the cost of providing electricity. Also, while on-grid developments are essential in this regard, also off-grid (renewable) solutions should receive proper attention in order to guarantee electricity access at the minimum cost, particularly in rural areas. In this regard, up-to-date and country-specific estimations of the costs of alternative technologies should guide any planning decision.

As it is the case in all modelling exercises, the limitations of this study derive from the modelling framework and the availability of input data. As for the former, while the model used GIS data, the link between such data and the optimization of the power system is still mediated by *a priori* decisions made by the modeller (i.e., the set of available technologies per *status* of space square). Also, the model is rather rigid in the description of potential evolutions from off-grid to on-grid connections (changes are only possible after the end of life of the installed technology) and it is restricted in its potential applications for the study of new accesses to electricity by the fact that supply always follows demand (a decrease in production technology costs cannot drive an increase in demand).

As for the latter, while input data were carefully collected and elaborated, the spatial characterization of the territory has a limited number of (six) *status* categories and relatively large spatial resolution. Similarly, projections on the development of the population (including changes in living standards and urbanisation rates), which have a significant impact on electricity demand projections, can always use update and refinement. Finally, renewable production technologies and battery storage are seeing a widespread adoption, hence a rapid evolution in their technical and economic characteristics, which should constantly be reflected in modelling studies.

It is also worth noting that alternative development pathways for the power sector are expected to have significant but different implications in terms of the potential economic growth of the country, as well as in terms of the environmental sustainability of such economic growth. Further studies are needed to explore these research directions as well.

Credit author statement

Matteo V. Rocco: Conceptualization, Methodology, Formal analysis, Supervision, Writing – original draft, Writing reviewing and editing; Elena Fumagalli: Resources, Validation, Investigation, Supervision, Writing – original draft, Writing reviewing and editing; Chiara Vigone: Formal analysis, Investigation, data analysis; Ambrogio Miserocchi: Formal analysis, Investigation, data analysis; Emanuela Colombo: Conceptualization, Validation, Supervision, Writing reviewing and editing

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.esr.2020.100614.

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