Ayobami Solomon Oyewo

TRANSITION TOWARDS DECARBONISED POWER SYSTEMS FOR SUB-SAHARAN AFRICA BY 2050

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Dissertation for the degree of Doctor of Science (Technology) to be presented with due permission for public examination and criticism in Room 1318 at Lappeenranta-Lahti University of Technology LUT, Lappeenranta, Finland on the 25th of May, 2021, at noon.

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Abstract

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Globally, power systems are undergoing significant structural changes, spurred primarily by declining cost of renewable energy technologies, changing demand patterns, energy security concerns, increasing scarcity of fossil fuels, and above all, efforts to mitigate climate change. Energy crisis and high vulnerability to climate change are projected to hinder Africa's development goals. For these reasons, this thesis investigates the integration of large shares of renewables, such as solar and wind energy, into African power systems on a national and regional resolution, in view of tackling the two major challenges faced globally; climate change and widespread of energy poverty. Pathways towards a decarbonised power system for sub-Saharan Africa is researched on an hourly resolution, incorporating all current energy technologies accessible in the market.

The aim of this research is to model and analyse scenarios for countries and regions in Africa from an energy system perspective, without violating the United Nations' Sustainable Development Goals. This study builds on profound techno-economic principles and relies firmly on power system engineering logic for designing a least-cost power system. The techno-economic analysis of the transition is carried out with the LUT Energy System Transition Model, while the socio-economic aspects are examined in terms of job creation, greenhouse gas emission reduction and improved energy access.

The results of this thesis show that it is cost-competitive, low greenhouse gas emitting, less water-intensive and most job-rich option to gradually transition Africa's power system from fossil fuels dominated to renewables, with an evolving dominant share of solar photovoltaics, complemented by wind energy, bioenergy and hydropower. Such a transition is coherent with the Paris Agreement and Sustainable Development Goals of the United Nations, which is an important fact for African countries to realise the Africa's Vision 2063. Furthermore, it is shown that the growth of variable renewable energy sources in the power system necessitates the need for system flexibility to ensure a reliable electricity supply. However, these flexibility measures are not too expensive to annul the economics of renewables. Africa shows an excellent prerequisite for energy and land resources to technically host a renewable led electricity generation, while meeting the growing demand with the greatest societal welfare. The techno-economic prospects for transitioning Africa's power system as illustrated in this research presents a platform for meaningful policy dialogue. This study is the first of its kind for Africa.

Keywords: Africa, sub-Saharan Africa, renewable energy, energy transition, flexibility

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Ayobami Solomon Oyewo
May 2021
Lappeenranta, Finland

This thesis is dedicated to my parents, Mr Christopher Olaoye Oyewo and late Mrs Esther Anike Oyewo, Prince Adedayo and Princess Afolashade Ajayi, and to all my family members for their endless love and support.

Contents

List of publications

This dissertation is based on the following publications. The rights have been granted by the publishers to include the publications in this thesis.

I. Oyewo, A.S., Aghahosseini, A., Bogdanov, D., and Breyer, C., 2018. Pathways to a fully sustainable electricity supply for Nigeria in the mid-term future. *Energy Conversion and Management*, 178, pp. 44–64.
II. Oyewo, A.S., Aghahosseini, A., Ram, M., Lohrmann, A., and Breyer, C., 2019. Pathway towards achieving 100% renewable energy powered electricity sector by 2050 for South Africa. *Solar Energy*, 191, pp. 549–565.
III. Mensah, T.N.O., Oyewo, A.S., and Breyer, C., 2020. The role of biomass in sub-Saharan Africa's fully renewable power sector – The case of Ghana. *Renewable Energy*, 173, pp. 297–317.
IV. Oyewo, A.S., Aghahosseini, A., Ram, M., and Breyer, C., 2020. Transition towards decarbonised power systems and its socio – economic impacts in West Africa. *Renewable Energy*, 154, pp. 1092–1112.
V. Oyewo, A.S., Farfan, J., Peltoniemi, P., and Breyer, C., 2018. Repercussion of Large-Scale Hydro Dam Deployment: The Case of Congo Grand Inga Hydro Project. *Energies*, 11(4), 972.
VI. Barasa, M., Bogdanov, D., Oyewo, A.S., and Breyer, C., 2018. A cost optimal resolution for sub-Saharan Africa powered by 100% renewables in 2030. *Renewable and Sustainable Energy Reviews*, 92, pp. 440–457.
VII. Bertheau, P., Oyewo, A.S., Cader, C., Breyer, C., and Blechinger, P., 2017. Visualizing national electrification scenarios for Sub Saharan Africa. *Energies*, 10, 1899.

The publications are numbered throughout the thesis using the Roman numerals. Reprints of each publication are included at the end of this thesis.

Author's contribution

Ayobami Solomon Oyewo is the main author and investigator in Publications I, II, IV and V. In Publication III, Theophilus Mensah carried out the data analysis, bioenergy estimation and paper writing, Ayobami Solomon Oyewo applied the bioenergy potential in the power system modelling, and supervised the first author. In Publication VI, Maulidi Barasa was the corresponding author and Ayobami Solomon Oyewo made significant contributions throughout the research and writing processes. In Publication VII, Paul Bertheau carried out the main part of the research, including the development of methods, analysing the results and writing the manuscript, Ayobami Solomon Oyewo applied the methods for all countries in sub-Saharan Africa, analysed the results and visualised most of the figures.

Lists of all publications

The publications included in this dissertation are in bold.

1. **Oyewo, A.S., Aghahosseini, A., Bogdanov, D., and Breyer, C., 2018. Pathways to a fully sustainable electricity supply for Nigeria in the mid-term future. *Energy Conversion and Management*, 178, pp. 44–64**.
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8. Breyer, C., Bogdanov, D., Aghahosseini, A., Gulagi, A., Child, M., Oyewo, A.S., Farfan, J., Sadovskaia, K., and Vainikka, P., 2018. Solar Photovoltaics Demand for the Global Energy Transition in the Power Sector. *Progress in Photovoltaics: Research and Applications*, 26, pp. 505–523.
9. Bogdanov, D., Farfan, J., Sadovskaia, K., Aghahosseini, A., Child, M., Gulagi, A., Oyewo, A.S., Barbosa, L.S.N.S., and Breyer, C., 2019. Radical transformation pathway towards sustainable electricity via evolutionary steps. *Nature Communications*, 10, 1077.
10. Bogdanov, D., Ram M, Aghahosseini, A., Gulagi, A., Oyewo, A.S., Child, M., Caldera, U., Sadovskaia, K., Farfan, J., De Souza Noel Simas Barbosa, L., Fasihi, M., Khalili, S., Traber, T., and Breyer, C., 2021. Low-cost renewable electricity as the key driver of the global energy transition towards sustainability, *Energy*, 227, 120467.

Nomenclature

Abbreviations

A-CAES	Adiabatic Compress Air Energy Storage
AfDB	African Development Bank
APV	Africa Power Vision
AREI	Africa Renewable Energy Initiative
AU	African Union
bbl	Barrel
BPS	Best Policy Scenario
CAPEX	Capital Expenditure
COMELEC	Comité Maghrébin de L'Electricité
CPS	Current Policy Scenario
CHP	Combine Heat and Power
CSP	Concentrated Solar Power
EAPP	Eastern African Power Pool
ECOWAS	Economic Community of West African States
ESM	Energy System Model
FLH	Full Load Hour
FSS	Faecal Sewage Sludge
GHG	Greenhouse Gas
GIS	Geographic Information System
GW	Gigawatt
HVDC	High Voltage Direct Current
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
kWh	Kilowatt-hour
LUT	Lappeentanta University of Technology
LCOE	Levelised Cost of Electricity
MW	Megawatt
MSW	Municipal Solid Waste
OPEX	Operational Expenditure
PEAC	Pool Energétique de l'Afrique Centrale
PHES	Pump Hydro Energy Storage
PtX	Power-to-X
PtG	Power-to-Gas
PV	Photovoltaic
PIDA	Program for Infrastructure Development in Africa
RE	Renewanle Energy
SAPP	Southern African Power Pool
SSA	sub-Saharan Africa
SDG	Sustainable Development Goal
SHS	Solar Home System

TES	Thermal Energy Storage
tcm	trillion cubic metre
UN	United Nations
UNEP	United Nation Environmental Program
VRE	Variable Renewable Energy
WACC	Weighted Average Cost of Capital
WAPP	West African Power Pool
WB	World Bank

1 Introduction

1.1 The need for renewable energy integration in the future energy systems

Globally, power systems are undergoing significant structural changes, spurred by decreasing cost of renewable energy (RE) technologies, energy security concerns, increasing scarcity of fossil fuels, changing demand patterns, and above all, efforts to mitigate climate change (IEA, 2019a; Rogelj et al., 2018; Kozarcanin et al., 2019). A transition from conventional dispatchable fossil-based sources to a system that is based on RE sources is of paramount importance, in order to limit the rise in global temperature well below 2 ^{o}C above pre-industrial levels and pursuing efforts to limit this to 1.5 ^{o}C (IPCC, 2018). Low carbon energy targets and various policies interventions are driving the global energy transition (REN21, 2019). Prevalent energy crisis and high vulnerability to climate change are anticipated to hinder Africa's development goals (Niang et al., 2014). At the global level, efforts to mitigate the threat of climate change and expand energy access are the key features of both the Sustainable Development Goal 7 (SDG 7) on energy access and the Paris Agreement on climate change (Delina and Sovacool, 2018). Over the past decades, extreme weather conditions and climate change have caused unprecedented damage in many African countries (Niang et al., 2014). The most visible manifestations are floods in West Africa, droughts in Southern Africa, desertification in the Maghreb region, East Africa stands the risk of flooding, concurrent health impacts, infrastructure damages and the plague of locusts (Niang et al., 2014; Serdeczny et al., 2017; Salih et al., 2020). In Africa, significant effort is directed towards the interconnected challenges of climate change, energy poverty and security, driven mainly by increasing demand, lack of access to modern energy services, huge dependence on fossil fuels and high use of unsustainable biomass (UNEP, 2017). In so doing, many African countries have adopted measures to scale-up RE and integrate energy efficiency strategy in their national and regional energy master plans in order to address the continent's energy need in a sustainable manner (IRENA, 2015; UNEP, 2017; REN21, 2019).

Africa's energy transition faces two major challenges, transition and expansion (IEA, 2019b). The transition of the African energy system requires exploiting the continent's huge RE resources, such as solar, wind, bioenergy, geothermal, and hydropower (IEA, 2019b; Pappis et al., 2019; Ram et al., 2019; Sterl et al., 2019). The energy transition would be accompanied by significant expansion of the region's power sector especially in the sub-Saharan Africa (SSA) countries due to huge under-capacity and rising energy demand (IEA, 2019b; Ram et al., 2019). In Africa, solar and wind energy are expected to emerge as the new bulk electricity provider in the region's energy transition, due to huge potential of these resources and continuous decline in cost associated with solar photovoltaic (PV) and wind turbine technologies (Breyer et al., 2018; Bogdanov et al., 2019a). Transitioning to a system dominated by variable RE (VRE), in particular solar and wind energy, raises the challenge of balancing demand and supply mismatch in the power grid, particularly in hours of low generation from solar and wind, given the fact that these energy sources are generating during periods of low demand (IEA, 2019a; Sterl et al., 2019). The future energy system based on RE sources will not be constrained by energy resource availability, but rather the security of supply (IRENA, 2019a; IEA 2019a; Sterl et al., 2019).

Furthermore, the security of supply is persistently expressed as a concern in power systems dominated by VRE (Sterl et al., 2019; Jurasza et al., 2020). Nevertheless, the variability of RE supply can be overcome by designing an optimal system (Jurasza et al., 2020), with appropriate enabling technologies, if resources scarcity enforces dependence on limited VRE resources (Solomon et al., 2018; Gulagi et al., 2020), and that exploit resource complementarity to reduce its impact and the need for enabling technologies for regions with diverse resources (Breyer, 2012; Breyer et al., 2018). In addition, detailed energy system analyses based on techno-economic principles are vital when assessing low-cost electricity options and pathways for developing nations (Gulagi et al., 2020; Taliotis et al., 2014; 2016). Recent studies have established the possibility of switching to a fully renewable system for various countries (Solomon et al., 2018; Gulagi et al., 2020), regions (Bogdanov & Breyer, 2016; Aghahosseini et al., 2019) and global (Breyer et al., 2018; 2020a; Bogdanov et al., 2019a). These studies have shown the feasibility and viability of deep decarbonisation of the future power system while taking into account all sustainability criteria. Transitioning to a RE-based system is the most efficient and cost-effective option with utmost societal welfare (Wright et al., 2019; Ram et al., 2019). Furthermore, both the ambitious Paris Agreement and the SDG 7 targets can be realised by switching to RE for all purposes, in view of combating the two main problems faced globally: prevalent energy poverty and climate change (Ramanathan et al., 2016). Universal energy access and sustainable energy transition are the key features of both the SDG 7 and the Paris Agreement on climate change (Delina and Sovacool, 2018). It is noteworthy that the 17 SDGs are integrated, implying, they identify that action in one area will affect outcomes in others, and that development must balance the three spheres of sustainability (United Nation, 2015a). The transition pathways presented in **Publications I-VI** comply with the SDGs (United Nation, 2015a) and sustainable guardrails, as described by Child et al. (2018).

Up to now, there is a lack of high levels of geo-spatial and temporal resolution sustainable energy transition studies for many African countries and regions besides the articles included in this dissertation, which examines the effects of large shares of RE in meeting the rising demand in the region under the operation of the African electricity markets. For the foregoing reasons, this research explores the roles and benefits of flexible electricity generation technologies, power transmission and flexible energy storage options, also considering large-scale hydropower options and coal-based environments in transitioning to a fully RE power system and modern energy services for African countries and regions, within the time horizon of 2015-2050.

1.2 Motivation and objectives

The focus of this research is to model and analyse detailed energy transition pathways for countries and regions in Africa from an energy system viewpoint. The analysis takes into account the continent, in particular SSA, with special attention to sustainability issues. This research examines the **integration of large shares of variable generation from RE sources** into African countries or regions' power systems for decarbonising the power sector, while meeting the rising demand. This study provides more insights on the energy transition for Africa, which is incredibly understudied and not well understood for the years to come and also the mid and long-term. Literature research shows that almost no research and studies exist for the energy transition in Africa towards highly sustainable energy systems, even more, based on hourly resolution.

Assessment of system flexibility and supply security is an essential prerequisite in power or energy systems with large shares of VRE resources. Thus, **this research investigates how a mix of operational flexibility sources** such as energy storage, dispatchable renewables (mainly biomass and hydropower), power transmission, and curtailment can facilitate the integration of high shares of VRE in African power systems. Dispatchable RE are sources of electricity that can adjust their power output supplied to the electricity grid, on demand.

A special focus is on **rural electrification analysis**. A geospatial information system (GIS) based model was used to investigate electrification options for unelectrified people for pico/ solar home systems, renewable-based mini-grids and grid extensions to meet the aim of the research. Various research questions and also suit the region under consideration.

Beyond the techno-economic analysis, **the socio-economic aspect of the transition is also well investigated**. Undoubtedly, energy transition cannot be considered in isolation, there is a link between the energy sector and socio-economic systems, which changes the socio-economic footprint and offers multiple co-benefits such as greenhouse gas (GHG) emissions reduction, job creation and societal welfare.

1.3 Scope of the current research

The overall scope is broken down into specific research questions posed in each of the publications included in the dissertation. **The main research focus involves the modelling of large-scale integration of RE into African power systems**. In light of the main objective, the sub-objectives of the dissertation aim to address specific research questions as follows:

1. How African countries can transition to a renewables-based system was addressed in **Publications I – III**. National energy transition modelling is undertaken to understand how individual countries can transition to a renewables-based system and obtain the possibility of complete energy autonomy. The country power systems analysis was carried out for the case of Nigeria in **Publication I**, South Africa in **Publication II** and Ghana in **Publication III**. Each of these power systems shows distinctive transition routes as their current power architecture differs. South Africa from coal-based to solar PV and wind dominated, while Nigeria and Ghana transition from a fossil gas and hydropower dominated system to a solar PV dominated system. Furthermore, the results would somehow differ, if the examined power systems were modelled with interconnections with neighbouring countries. However, system solutions would not be structurally different, as solar PV and battery would still emerge as the mainstay of the power system.

2. Systematic analysis of larger geographic areas is covered in **Publications IV – VI**. The case of West Africa in **Publication IV** and SSA in **Publications V-VI**. Regional energy transition is investigated to understand the underlying behaviour of power systems which cover a larger geographic area. What are the benefits of cross-border electricity trade, in terms of cost savings, GHG emission reduction and capacity requirements? **(Publications IV-VI)**

3. If high VRE shares are to be integrated into African power systems, system flexibility analysis is a vital precondition. Various system flexibility sources are examined in this study, such as storage, grid networks, dispatchable RE, flexible generators and curtailment in **Publications I-VI**. The role of bioenergy as a balancing and flexibility component is examined in **Publication III**. Furthermore, integration of synthetic inertia in a power system dominated by VRE is confirmed as an attractive option for

a SSA 100% renewable power system in **Publication V**. What are the various flexibility options that can facilitate the integration of high shares of RE? (**Publications I-VI**)

4. Energy-based water demand is researched by assessing the water footprint in **Publication II.** Currently, thermal power generation technologies heavily depend on water availability. Coal, nuclear, gas and oil-based power plants require water for cooling purposes. In **Publication II**, water demand of thermal power generation technologies was analysed for the case of South Africa's power system, due to water scarcity and huge dependence on water-intensive coal-fueled power plants in the country. What is the interplay between energy and water consumption? (**Publication II**)

5. Energy transition cannot be considered in isolation, there is an interaction between the energy sector and the socio-economic systems. In this context, what will be the impact of the transition on job creation? (**Publications II and IV**). Furthermore, the GHG emissions trajectory during the transition is computed by the LUT model in **Publications I – IV**.

6. For unelectrified people, especially in rural areas, a special study on electrification planning was conducted. **Publication VII** distinguishes three categories of technology penetration for rural electrification. What are the various electrification options for the unelectrified across SSA? (**Publication VII**)

1.4 Contribution of research

The main contribution of this research is to provide more insights and broaden the discourse on the energy transition for SSA countries and regions. Various transition pathways and scenarios are analysed that could cater, for instance, to policy decisions for decarbonising the SSA power system within the time horizon of 2015 to 2050. In order to answer the main question of this research, the following scenarios were defined to understand the transition pathways:

- Current Policy Scenario (CPS): this scenario is linked to the latest energy policy of SSA countries and furthermore develops according to the spirit of current energy policy.

- Best Policy Scenario (BPS): this scenario shows how a cost optimised energy transition scenario reflecting the Paris Agreement and Sustainable Development

Goals would look like. Target by 2050 is a 100% RE system and growth rates of RE are high but limited to empiric growth experience.

This research is the first of its kind integrating large shares of RE into SSA power systems on an hourly resolution. The BPS shows that it is the least GHG emitting, cost-competitive, less water-intensive and most job-rich option to gradually transition Africa's energy system into one dominated by solar PV, complemented by wind, bioenergy and hydropower. This study identifies investment requirements, timing and operation for countries and regions in SSA. Such information is relevant for policymakers and energy system planners in Africa for setting investment targets. The power system transition is the least-cost option for Africa without specific subsidy needs. However, subsidisation would be inevitable if a policy-triggered drift from this techno-economic low-cost pathway is followed.

This research contributes and advances scientific knowledge on energy system modelling at country and regional level in Africa. The need for energy system modelling is crucial to understand the underlying behavioural pattern and dynamics of future energy systems, particularly when integrating large shares of VRE resources in power generation. Thus, a comprehensive techno-economic analysis of the transition was investigated on a national and regional resolution to provide insights on optimal resource mixes in a sustainable manner.

This study identifies the need for system flexibility to ensure the security of electricity supply in power systems dominated by VRE. Various integration measures are adopted to facilitate the penetration of RE, however, these measures are not too expensive to annul the economics of RE. This research demonstrates that technical feasibility is no longer a concern in systems dominated by VRE. It is noteworthy that the decarbonised electricity can be furthermore coupled to energy-consuming sectors, while demand that cannot be directly electrified can be supplied by power-to-X (PtX) solutions.

Furthermore, this research provides insights on socio-economic aspects of the energy transition. It is noteworthy that the benefits of energy transition transcend the energy sector itself, given the many-sided links and interactions with the broader economy. Energy transition cannot be considered in isolation. The energy sector and socio-economic system are strongly linked, which alters the socio-economic footprint and offers multiple co-benefits such as GHG emissions reduction, job creation and societal welfare. Job creations during the transition are instrumental in achieving a broader societal goal and stability. Job creations during this transition is noteworthy for governments and policymakers in Africa.

1.5 Structure of this thesis

The thesis is structured as follows: Chapter 1 of this thesis presents the objectives, scope and contribution of this research. Information on the geographical scope and current energy situation in the region is presented in chapter 2. Chapter 3 presents the applied methods, introduces the modelling tool, the LUT Energy System Transition model. The model features, setup, applied technologies and input data are described in chapter 3. The key results of the publications that comprise this thesis are presented in chapter 4. Chapter 5 discusses the results and policy implications of the energy transition in Africa. The conclusions are drawn in Chapter 6. References and the original publications that comprise this dissertation are included at the end of this thesis.

2 sub-Saharan Africa electricity outlook

2.1 Economy, demography and governance

Africa is comprised of 54 nations and is characterised by diverse demographic, socio-economic, and social background, each of which influences energy demand and supply in the continent (IEA, 2019b).

Africa's economic performance continues to improve, with real gross domestic product (GDP) growth estimated at 3.4% in 2019 and is projected to accelerate to 3.9 % in 2020 and 4.1% in 2021 (AfDB, 2020). Nonetheless, economic growth will be uneven across countries and power pools (IEA, 2019b; AfDB, 2020). In 2019, East Africa continued its lead as Africa's fastest-growing region with average growth estimated at 5.0%, followed by North Africa with 4.1%, West Africa with 3.7%, Central Africa with 3.2% and Southern Africa with 0.7% (AfDB, 2020).

The growing African population has a major implication for the development of the energy sector (IEA, 2019b). With an expanding population of about 1.194 billion in 2015, occupying an area of over 30 million square kilometres (United Nation, 2015b); Africa's population is projected to reach 2.5 billion by 2050, representing more than a quarter of the world's population growth from now up until 2050 (United Nation, 2015b), and even more in the following decades. This significant increase is concentrated mainly in East and West Africa, accounting for 35% and 32% of the total African population by 2050 respectively (United Nation, 2015b).

An effective system of governance is a fundamental requirement to enable African countries to realise their development goals (AfDB, 2012). In order to achieve Africa's development goals, it is vital to address the continent's energy needs. This will require huge investments to build the essential infrastructure and most importantly, the establishment of an effective governance system (AfDB, 2012; IEA, 2014; 2019b). Broad improvement in governance, effective regulatory and legal frameworks are important for increasing competition and attracting investments in the energy sector; however, poor governance continues to hinder the progress and performance in the energy sector (AfDB, 2012; IEA, 2014; 2019b).

2.2 Electricity gap in Africa

Africa still faces significant energy crises, driven mainly by increasing demand, lack of access to modern energy services and high use of unsustainable biomass (IEA, 2019b).

The total number of people in the continent without access to electricity is around 600 million mainly in SSA (IEA, 2020). Electricity access in SSA has increased from 24% in 2000 to 45% in 2018 (IEA, 2020). In 2018, access rate to electricity was below 50% in 31 of the 54 nations, with Chad, the Central African Republic and South Sudan occupying the bottom with 9%, <5% and <5% respectively (IEA, 2020). The average annual electricity consumption in Africa remains very low at 550 kWh and is 370 kWh in SSA (IEA, 2019b). Nevertheless, electricity consumption per capita is uneven across the power pools. In 2018, electricity consumption per capita was 135 kWh in Central Africa, 116 kWh in East Africa, 130 kWh in West Africa, 1370 kWh in Southern Africa and 1486 kWh in North Africa (AEP, 2020). The rate of electricity access and clean cooking in Africa is visualised in Figure 1.

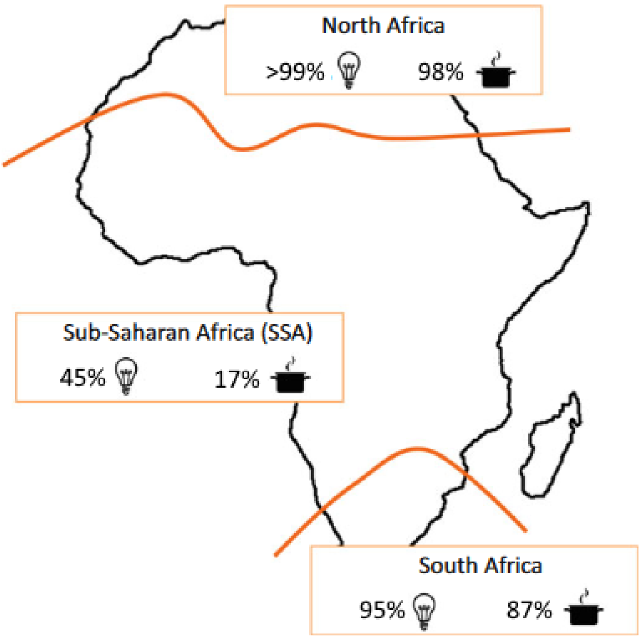

Figure 1. Access to electricity and clean cooking in 2018 for Africa. Map source (Hafner et al., 2018) and author improved with data based on IEA energy database for 2018.

Furthermore, the future electricity demand in Africa is anticipated to grow significantly, driven by urbanisation, fast-growing population, rising income levels and industrialisation (IEA, 2014; 2019b). Electricity demand in the region grew from 560 TWh in 2010 to 705 TWh in 2018 and is anticipated to double by 2040 in the IEA Stated Policies Scenario to over 1600 TWh and to reach 2300 TWh in the Africa Case Scenario

(IEA, 2019b). The current electricity generating capacity is insufficient to cover the power demand resulting in frequent load shedding, blackouts, and increased use of costly backup generators running on gasoline or diesel (IEA, 2014). In 2018, 40 TWh of power was generated from 40 GW of backup generators in SSA, which is approximately 8% of electricity generation (IEA, 2019b). Nigeria accounted for nearly half, generating 18 TWh from about 9 GW of back-up generators. Furthermore, the overall population relying on traditional use of solid biomass for cooking was 853 million (66%) in 2018 (IEA, 2020).

2.3 Energy resource potential in Africa

Reliable energy resource estimates are a fundamental prerequisite of energy system planning. Africa has a huge energy potential widely spread across the region, a diversity of renewable and non-renewable energy resources sufficient to meet its electricity demand (Hafner et al., 2018).

Renewable energy resource potential

The region has an abundant renewable energy potential, varying in type and unevenly distributed across diverse geographical areas as illustrated in Figure 2.

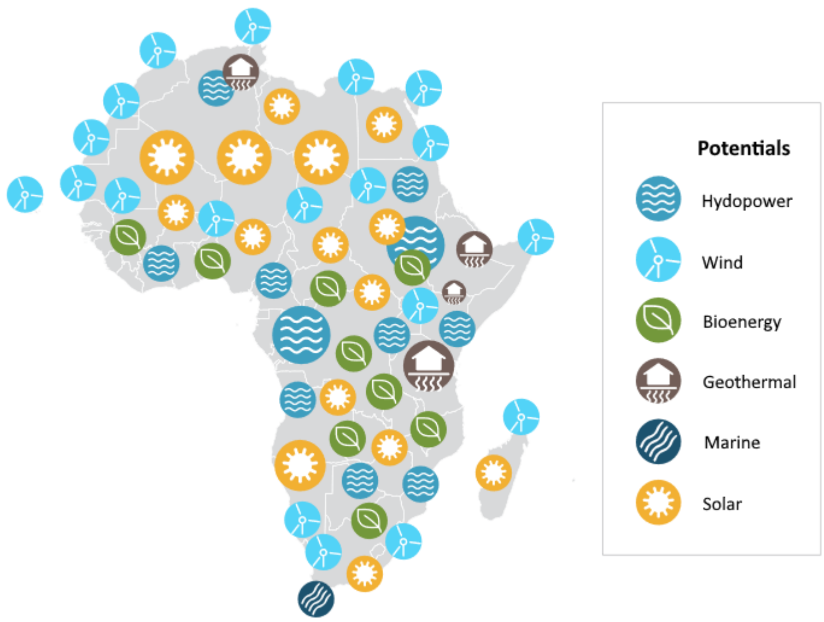

Figure 2. Distribution of identified renewable energy potential in Africa (IRENA, 2013).

The solar resource potential is naturally high and fairly uniform across Africa, although areas of Sahel, the south-west tip of the continent, Sahara, and the Horn of Africa are very sunny (Hafner et al., 2018; IRENA, 2011; 2015). Africa has a huge hydropower potential resource, around 92% of the technically feasible potential is yet to be exploited (Gernaat et al., 2017). The highest hydropower potential is found in Central Africa followed by East Africa, South Africa, and West Africa (Hafner et al., 2018; IRENA, 2015). The Congo basin has the largest hydropower resource potential, largest with regards to water discharge, which represent 40% of the entire continent's potential, followed by the Zambezi, the Niger and the Nile (Hafner et al., 2018; IRENA, 2015). The biomass potential is abundant in wet, forest central and southern regions, while agricultural activities occurs predominantly in East and West Africa (Hafner et al., 2018; IRENA, 2015). The geothermal potential is highest in East Africa, along the Great Rift Valley (Hafner et al., 2018). Wind power and wave power resources are abundant in the North, East (Somalia, Kenya, and Ethiopia are great for wind) and South of Africa (Hafner et al., 2018; IRENA, 2015). Africa is rich in energy resources. According to IRENA (2011; 2014), the potential for power generation from solar PV is about 656,728 TWh/year, 457,665 TWh/year wind, 471,587 TWh/year concentrated solar power (CSP), 1,585 TWh/year hydropower, 2631 TWh biomass and 88 TWh geothermal across the continent. Africa shows an excellent prerequisite for a nearly 100% RE supply (Bogdanov et al., 2019a). With a fast decline in RE technology costs and excellent resource conditions in the continent, countless opportunities exist in Africa for low-cost energy supply (Breyer et al., 2018).

Non-renewable energy resource potential

A huge discrepancy and uncertainty are surrounding the hydrocarbon endowment in Africa, especially in SSA where hydrocarbons are explored to a lesser extent (Hafner et al., 2018). According to Modelevsky & Modelevsky (2016), the upper bound of Africa's oil and natural gas potential is estimated at 2.2 million TWh (1,273 billion bbl) and 0.8 million TWh (82 tcm), while the technical and economical feasible recoverable oil and natural gas is about 0.6 million TWh (381 billion bbl) and 0.7 million TWh (73.8 tcm) respectively. Conversely, proven reserves according to BP stood at 0.2 million TWh (128 billion bbl) of oil and 0.1 million TWh (14 tcm) of gas (UNEP, 2017). Whereas, according to IEA the remaining recoverable oil and natural gas resources potential is estimated at 0.8 million TWh (450 billion bbl) and 1.03 million TWh (100 tcm) respectively (IEA, 2019b). The proven coal reserves in Africa are estimated at 1.4 million TWh (120 billion tonnes) and is concentrated in the southern part of the continent (Hafner et al., 2018).

2.4 Regional electricity integration

Today, there are five existing power pools in Africa, namely, Pool Energétique de l'Afrique Centrale (PEAC) in Central Africa, the West African Power Pool (WAPP), Comité Maghrébin de L'Electricité (COMELEC) in North Africa, the Eastern African Power Pool (EAPP), and the Southern African Power Pool (SAPP) (IEA, 2014). The power pools vary greatly with regards to the scale of operation, governance and effectiveness (IEA, 2019b). The establishment of regional interconnections presents several benefits and opportunities (Wu et al. 2017; Taliotis et al., 2014; 2016; Sridharan et al., 2019; Eberhard et al., 2011; Brinkerink et al., 2019), such as the reduced discrepancy between main consumption centres and areas with high RE potential, inherent variability in the generation of RE sources and variability in locational demand can be smoothened by utilising regional interconnectors, improved diversity and security of energy supply, weak local grids can be bypassed by direct interconnections to regions with high RE resource potential, and reduced overall required capacity and cost of electricity. Regional cooperation can be helpful for countries with a very small load, where economies of scale are hard to obtain (IRENA, 2015).

Furthermore, various studies have demonstrated the possibility and profitability of regional grid interconnection in Africa (Wu et al. 2017; Taliotis et al., 2014; 2016; Sridharan et al., 2019; Eberhard et al., 2011; IRENA, 2013). Wu et al. (2017) identified, characterised and valued solar and wind electricity resources for 21 countries in the EAPP and SAPP. They conclude that many of the countries in these power pools possess a huge potential for utility-scale wind and solar energy development, with specific countries having sufficient no-regrets-low-cost, accessible, and low-impact-potential areas that can rapidly provide low-carbon electricity. However, because the most competitive solar and wind resources are spatially heterogeneous, inter-country transmission infrastructure could allow resource sharing. The current emphasis on building mega hydropower plants in some of the SAPP and EAPP countries could result in a set of interconnection plans that may fail to support the development of low-cost wind and solar PV options in the region. Sridharan et al. (2019) concluded that inter-country transmission stands to play a crucial role in balancing electricity price within the EAPP. According to IRENA (2018a), the development of almost all the regional electricity interconnector projects already in the pipeline proves to be beneficial for West African countries. The World Bank (WB) estimates that regional electricity trade in WAPP could lead to cost savings in the range of 5-8 bUSD per annum. The potential benefits of regional power trade in SSA was examined over a 10-year period from 2005 to 2015 by Vennemo & Rosnes (2009). They examined two scenarios: (I) trade stagnation: in this scenario, countries make no further investments in cross-border trade, and (II) trade expansion: in this scenario trade occurs whenever the benefits outweigh the costs associated with system expansion. The results of the study show that the trade expansion scenario would be 3 – 10% lower in cost, while annual cost savings are estimated at 2.7 bUSD. The cost savings came largely from replacing hydropower for thermal plants (Vennemo & Rosnes 2009). In addition, regional electricity trade benefits two types of countries, trade allows countries with expensive domestic power cost to import cheaper electricity (Vennemo & Rosnes 2009). An expansion of the current transmission network in Africa can help in reducing expensive fossil-based generation, as countries with unexploited RE potential in diverse sources can actively trade with neighbouring countries (Taliotis et al., 2014; 2016). In this manner, foreign investments can be attracted to finance such projects as part of power purchase agreements (Taliotis et al., 2016). Saadi et al. (2015) conclude that regional cooperation on promoting trade of RE would substantially reduce GHG emission and overall system costs.

Beyond the potential benefits of regional power cooperation, substantial institutional, economic, political and financial challenges need to be addressed by policymakers, which includes building political consensus, strengthening regional institutions, prioritising regional infrastructure, developing regional regulatory frameworks, facilitating projects preparation and enable cross-border finance (Eberhard et al., 2011).

2.5 Africa’s electricity mix: status and major trends

Installed electricity capacities in Africa are dominated by fossil-fuelled technologies as shown in Figure 3. The total installed by the end of 2014 was 186 GW, therefore coal (27%) and gas (41%) power plants were the major electricity sources. The high share of coal in the African electricity sector is primarily due to its predominance in the Republic of South Africa.

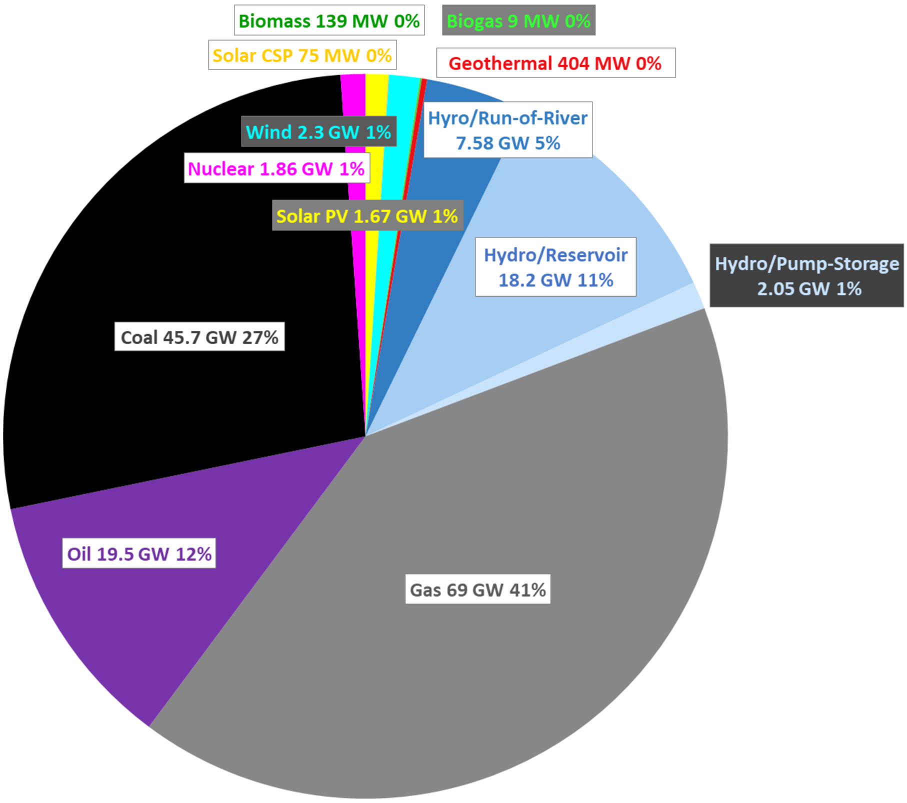

Figure 3. Overall active electricity installed capacities (in GW) by the end of 2014 in Africa (Farfan & Breyer, 2017)

In 2018, the total operating capacity in the continent was 201.6 GW, while capacity under construction and planned was 73.9 GW and 270.1 GW respectively. Figure 4 illustrates the power plants operating, under construction and planned by regions in Africa. North Africa followed by Southern Africa dominates the total operating capacity in the region, whereas almost half of the capacity under construction is located in North Africa. Gas power plants dominate the installed power generation capacity in the continent, with 84.3 GW and 313 operating gas-fired plants, another 39 plants are under construction (with a total capacity of 32.9 GW) and 156 are planned (66.9 GW) (AEF, 2018).

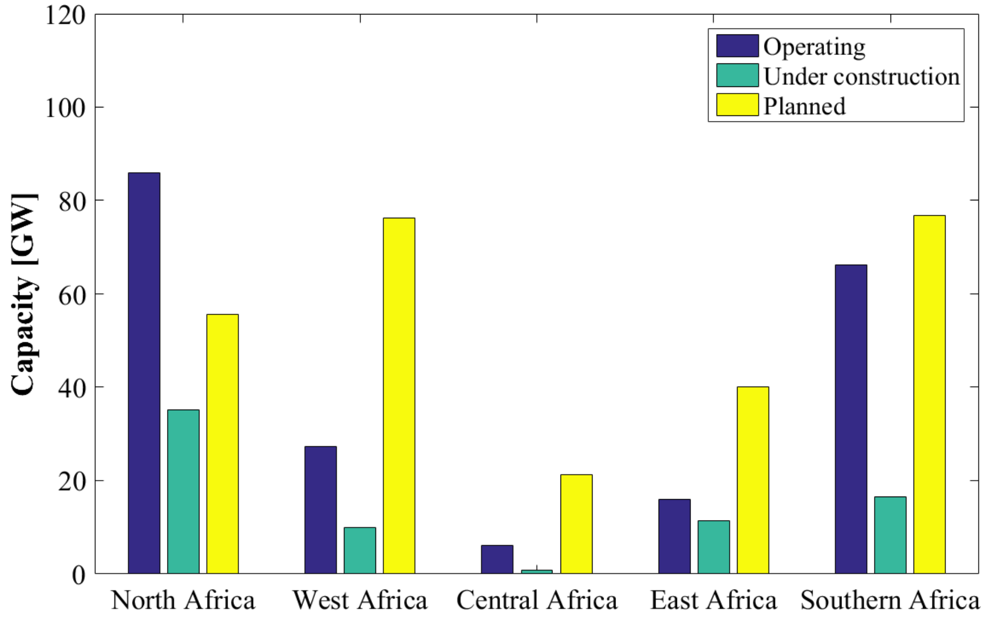

Figure 4. Power plants operating, under construction and planned in 2018 (AEF, 2018).

Growth in electricity generation from 2000 to 2016 is illustrated in Figure 5. Electricity generation in Africa increased by 81% between 2000 and 2016. Coal and gas-based generation increased by 70% of the total generation. Coal-based electricity generation is predominant in South Africa, while North and West Africa account for the bulk of growth in oil-based electricity generation. It appears that gas-based generation increased significantly when compared to other technologies, expanding primarily in North Africa.

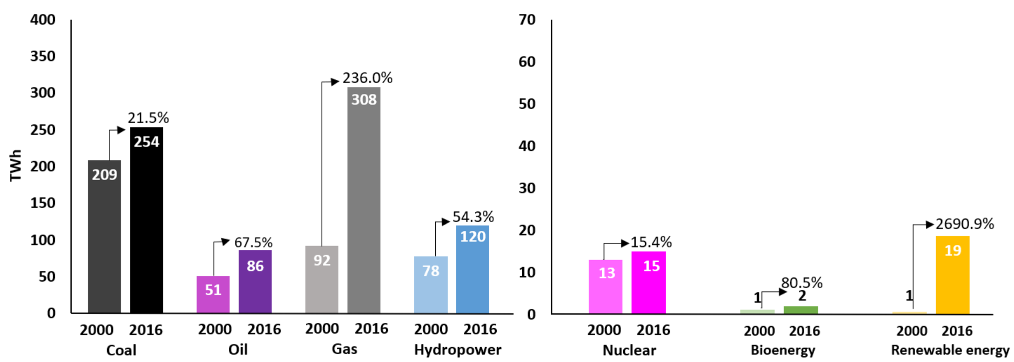

Figure 5. Growth in electricity generation (2000 – 2016). Data Source IEA statistic.

2.6 Current status and prospect of renewables in African electricity sector

Renewable energy installed capacity in Africa has expanded significantly in recent years (IRENA, 2019c). The total installed capacity increased by a factor of 2 between 2000 (23.5 GW) and 2018 (49.4 GW) as shown in Figure 6. Figure 7 depicts the trends in installed renewable energy capacity from 2000 to 2018. Hydropower accounted for over 70% of the total installed capacity in 2018, however, solar PV and wind have expanded significantly from 2010 onwards as shown in Figure 7. In 2018, among the non-hydro renewables, solar PV represents the largest installed capacity (12%), followed by wind (11%), bioenergy (3%) and geothermal (2%). In relative terms, solar PV has experienced the most impressive growth with installed capacity by a factor 559 between 2000 and 2018.

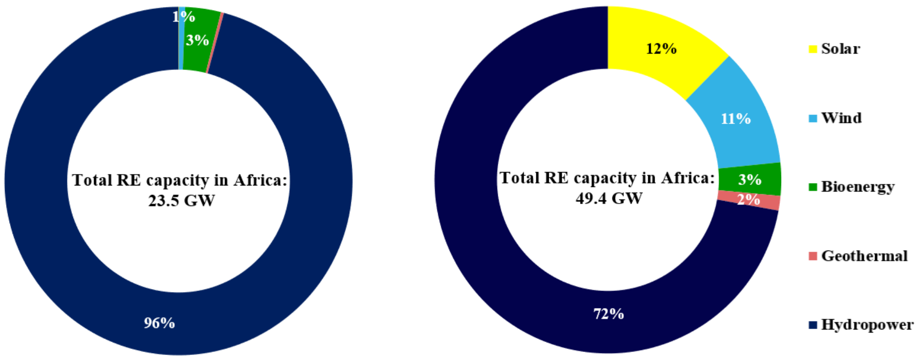

Figure 6. Renewable energy capacity in 2000 (left) and 2018 (right). *Source* author's elaboration on IRENA renewable capacity statistics 2019 (IRENA, 2019c).

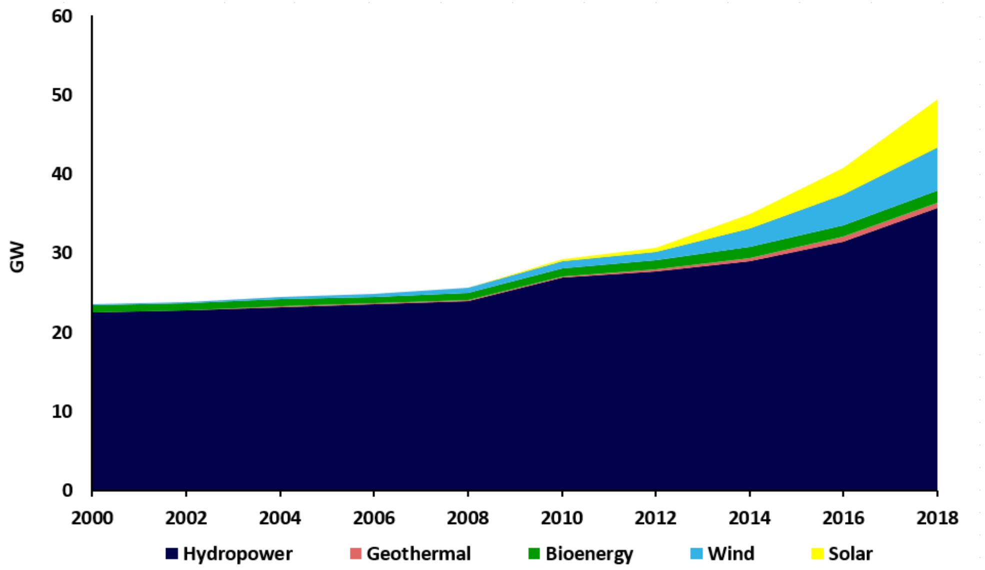

Figure 7. Trends in installed renewable power capacity from 2000 to 2018. *Source* author's elaboration on IRENA renewable capacity statistics 2019 (IRENA, 2019c).

Currently, RE resources are becoming strategic assets globally, as in Africa, as the cost of the technology declines dramatically (IRENA, 2016; IEA, 2019b). In Africa, the RE resource potentials are particularly evident and abundant, this huge endowment of RE is strategic for the continent and the prospect for utility-scale RE power generation may be a real option for many countries in the region (IRENA, 2011; Wu et al., 2017; IEA, 2019b). It is now obvious from all indications that renewables have a key role to play in the electrification process (on-grid and off-grid) of many countries in Africa (IRENA, 2013). Hydropower has dominated RE electricity supply in Africa until now. The hydro-dependence is plagued with risks of climate vulnerability, transboundary water crisis, cost overrun and high socio-environmental impacts (McDonald, 2009; Winemiller et al., 2016; Sovacool et al., 2014). Amongst the alternatives, geothermal is considered geographically limited and under-developed, while solar and wind have historically been dismissed as too costly and temporally variable. However, solar and wind are becoming more cost-competitive and are now leading large-scale RE power generation across the world, out-competing with traditional fossil fuels alternatives (IRENA, 2019b). For instance, the current tariffs for new solar PV and wind (0.041 €/kWh) are now 40% cheaper than new base generation coal (0.069 €/kWh) in South Africa (Bischof-Niemz & Creamer, 2018). As a result of these competitive costs, RE deployment is growing in several African countries (IRENA, 2016; 2019a). Over the past decade, the global trend in installed RE capacities has grown significantly from 1056 GW in 2008 to 2356 GW at the end of 2018 and is dominated by solar PV and wind energy (IRENA, 2019c). In Africa, renewable electricity installed capacity grew from around 26 GW in 2008 to 49 GW at the end of 2018. Much of the added capacities comes from solar PV (6.0 GW), wind (4.9 GW) and hydropower (11.7 GW) (IRENA, 2019c).

2.7 Integration of renewables in Africa: benefits and challenges

The current electricity deficit and growing demand in most African countries require a quick response in closing the gap between demand and supply. The supply gap is likely to widen due to population growth and unprecedented economic progress in the continent (IEA, 2014; 2019b). In order to tackle the energy woes in the continent in a way that is economically sustainable and safeguard livelihood, investment in large and small-scale RE projects in Africa is a key solution with multiple co-benefits (IRENA, 2013; IEA, 2019b). Several studies have demonstrated the possibility and benefits of integrating large shares of RE into the African power system (IRENA, 2015; Breyer et al., 2018; Bogdanov et al., 2019a; IEA, 2019b). With the declining cost and technological advancements, large scale deployment of RE offers African countries a cost-effective path to rapid, sustainable and equitable growth (IRENA, 2013). Integration of large-scale RE can unlock economies of scale, improve energy diversification, create jobs and bring health benefits (IRENA, 2013; 2015).

In Africa, solar and wind energy are expected to emerge as the new bulk electricity provider in the region's energy transition, due to huge potential of these resources and continuous decline in cost associated with solar PV and wind turbines (IRENA, 2016; 2019a; IEA, 2019b). Transition to a system dominated by VRE, in particular solar and wind energy, raises the challenge of balancing demand and supply mismatch in the power grid, particularly in hours with low generation from solar and wind, given the fact that these energy sources are generating during periods of low demand (IEA, 2019a, Sterl et al., 2019). Given the variability and uncertainty of solar and wind energy sources, the security of supply is often expressed as a concern in an energy system dominated by VRE (IRENA, 2019a; IEA, 2019a, Sterl et al., 2019). However, a wide range of solutions have been proposed, such as developing optimal mixes of RE supply to circumvent intermittent issues, sector integration, grid extensions, demand response solutions, energy storage, and supply-side management of dispatchable RE (Haas et al., 2017; IRENA, 2019a; IEA, 2019a; Solomon et al., 2019; Hansen et al., 2019, Brown et al., 2018).

Up to now, there is a lack of high levels of geo-spatial and temporal (hourly) resolution sustainable energy transition studies for Africa, which examine the effect of large-scale integration of RE in meeting the rising demand in the region under the operation of the

African electricity market. Despite the abundant RE sources in Africa, several challenges need to be overcome, which includes technical issues, local political economy and markets, and policy-related challenges. Furthermore, the establishment of regional power pools and RE transmission corridors is a crucial aspect for the future expansion of RE. To ensure the cost-effective integration of RE, it is vital to identify regions or areas with high resource potential and develop high grid interconnection to load centres (Saadi et al., 2015; Wu et al., 2017; Taliotis et al., 2014; 2016; Sridharan et al., 2019).

2.8 Secure and sustainable power systems in Africa

The technology and resources required to achieve a secure and sustainable power system in Africa exist, but political will at all levels of governance is required for the shift to renewable power (IRENA, 2015; IEA, 2019b). Transitioning to an all-renewable power system in the continent will require significant political intervention (IRENA, 2015). Globally, policies and targets will continue to be a critical and strategic component to advance the development of RE and energy efficiency solutions (REN21, 2019). In order to curb the predominant energy crisis in the continent while contributing to the aims of the Paris Agreement on climate change and SDG 7, many African countries have expressed the need to scale-up RE and integrate energy efficiency strategy in their national and regional energy master plans (IRENA, 2015; REN21, 2019). Several countries in the region have adopted RE policies, mainly involving public investment, fiscal incentives, grants and loans (IRENA, 2015; REN21, 2019). Regulatory policies, such as net metering and auctions, are gaining more attention, validating the growing maturity of African markets (IRENA, 2015; REN21, 2019). Over the past decade, RE targets have witnessed rapid adoption in Africa. To date, nearly all countries in the continent have introduced at least one type of RE target for specific technologies or sectors as well as dedicated off-grid policies for rural electrification and sustainable cooking (IRENA, 2015). Table 1 presents the RE targets and supportive policies in Africa (REN21, 2019). In 2018, the African power sector has received most of the RE focus policy attention as illustrated in Figures 8 and 9, and presented in Table 1.

Table 1. Renewable energy targets and support policies in Africa (IRENA, 2015; REN21, 2019).

Region/ country	RE targets	RE in INDC or NDC	Regulatory policies							Fiscal incentives and public financing				
			Feed-in tariff	Electricity utility quota	Net metering	Biofuels mandate/obligation	Heat mandate/obligation	Tradable RE certificate	Auctions	Capital subsidy, grant or rebate	Investment tax credits	Reductions in sales, energy CO_2, or VAT	Energy production payments	Public investment, loan or grant
North Africa														
Algeria	E, P	x	x						o				x	x
Egypt	E, P	x	x		x				o	x		x		x
Libya	E, P, HC									x		x		
Morocco	P, HC	x			x				x					x
Tunisia	P	x			x				o	x		x		x
Mauritania	E													
Western Sahara														
West Africa														
Benin	E, P								o					
Burkina Faso	P	x							x	x	x	x	x	
Cabo Verde	P	x			x				x	x	x		x	
Côte d’Ivoire	E, P	x							x	x		x		
Gambia	P	x								x		x		
Ghana	E, P	x	x	x	x	x		x		x		x		x
Guinea	E, P	x								x		x		
Guinea-Bissau	P													
Liberia	E, P, T	x				x								
Mali	E, P	x								x		x		x
Niger	E, P	x							o	x		x		
Nigeria	P	x	x	x					x	x		x		x

Senegal	P	x	x	x	x				o	x		x		
Sierra Leone	P, HC													
Togo	E, P	x								x		x		
Central Africa														
Cameroon	P	x								x		x		
Central Afr. Rep.														
Chad														
Congo DR	P													
Equatorial Guinea														
Gabon	E, P													
Rep. of Congo	P													
Sao Tome and Principe	P													
East Africa														
Burundi	E, P													
Djibouti	E, P													
Eritrea	P													
Ethiopia	P					x			o					
Kenya	P, HC	x	x		x		–		x	x		x	x	x
Uganda		x	x						x	x		x		x
Rwanda		x	x						x	x	x	x		x
Sudan	E, P	x				x								
South Sudan	P													
Somalia														
Tanzania	E, P	x	x		x				o	x		x	x	x
Southern Africa														
Angola	E	x				x								x
Botswana									x	x		x		x
Comoros	P													
Lesotho	P	x			x				x	x	x		x	x
Malawi	E, P, HC	x				x	x		o	x		x		x
Mauritius	P	x			x				x	x		x		x
Mayotte														
Madagascar	E, P	x							o	x		x		
Mozambique	P, HC	x				x				x		x		x

Namibia	P	x					x							
Réunion														
South Africa	P	x		x		x	x		o	x		x		x
Swaziland									o					
Seychelles	P				x					x	x	x		x
Zambia		x	*						o	x		x		x
Zimbabwe		x				*								

Targets: Energy (E), Power (P), Heat or cooling (HC), Transport (T)
Policies: Existing national policies (x), National tender held in 2018 (o), Policies revised (*), Policies removed (–)

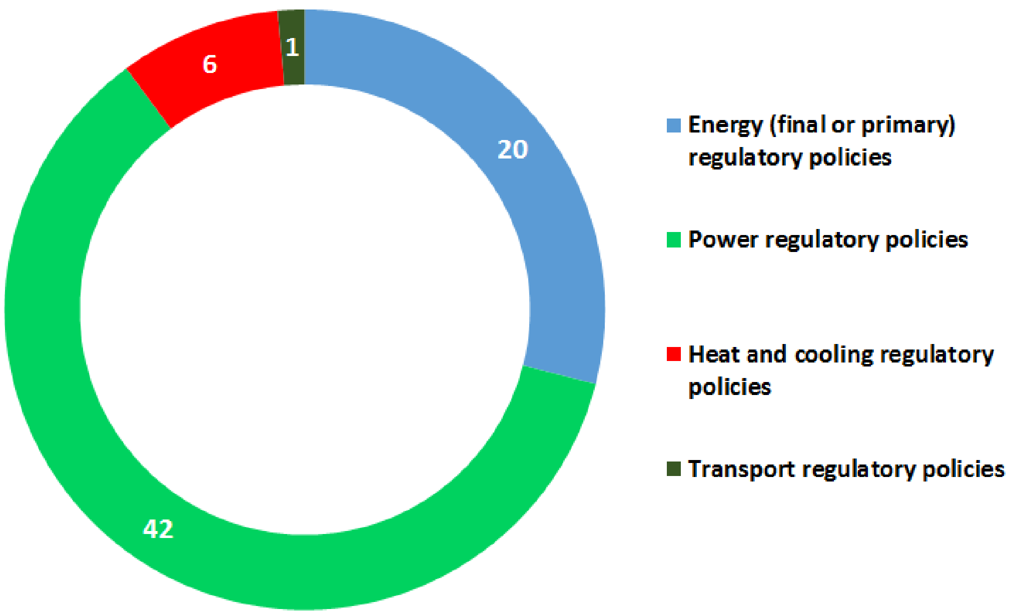

Figure 8. Number of African countries with RE regulatory policies in 2018 (REN21, 2019).

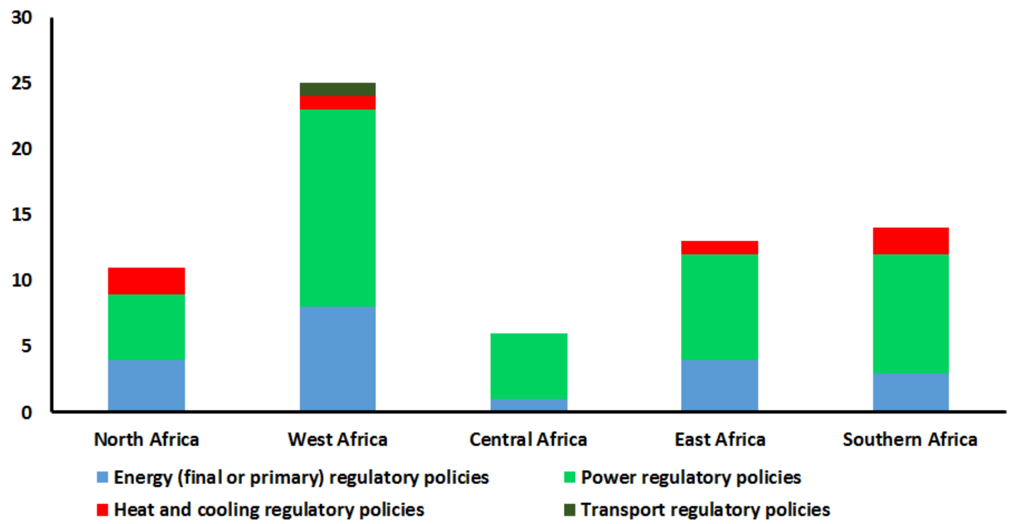

Figure 9. Regional outlook of RE regulatory policies in 2018 (REN21, 2019).

Implementation of national energy plans faces political and economic setbacks, as several African countries are land-locked, and some are characterised by small energy or power sectors (IRENA, 2015; UNEP, 2017). Thus, considering the small power sector and economic size of many Africa countries, regional energy integration and markets are crucial to attracting investments, for the security of the energy mix and supply, and to reduce the cost of doing business and cost to consumers (IRENA, 2011; 2013; 2015; UNEP, 2017). Regional energy cooperation provides economic solutions to energy generation and consumption, because energy is produced where it is most economically supported and supplied to where it is needed (IRENA, 2015; UNEP, 2017). To facilitate RE policies in Africa at continental and regional levels, a succession of ministerial declarations has been held to attest the growing political commitment among the African decision-makers, articulated through national and regional institutions and plans; such as the Maputo declaration in 2010, Lomé declaration in 2017 and Cairo declaration in 2019 (IRENA, 2015).

Furthermore, improving the socio-economic and energy situation in Africa is a top priority for the Heads of State and Government of the Africa Union (AU, 2015). In this light, the Africa Union's (AU) Agenda 2063 indicate frameworks for Africa's socio-economic transformation, the challenges posed by climate change and goals of African countries (AU, 2015). Harnessing the continent's RE resources to ensure modern energy services in a sustainable way is well described in the Agenda (AU, 2015). The AU Agenda 2063 has inspired a few initiatives to stimulate access to modern energy; one of such initiatives is the Africa Power Vision (APV), based on the Program for Infrastructure Development in Africa (PIDA) (UNEP, 2017). The APV is a long-term vision to increase access to affordable and reliable energy, with the sole aim to drive and rapidly accelerate the implementation of critical energy projects in Africa under PIDA (UNEP, 2017). The Africa Renewable Energy Initiative (AREI) is another Africa-led platform to accelerate the exploitation of the RE potential in the continent, thereby also increasing access to energy (AREI, 2016). AREI is AU's mandate and endorsed by African Heads of States, as the initiative is set to achieve at least 10 GW new RE generation capacity by 2020 and envisage increasing the continent's installed capacity to 300 GW by 2030 (AREI, 2016). Spurred by the need to address energy crises in the continent, in 2016, the African Development Bank (AfDB) approved its energy initiative, the New Deal on Energy for Africa (NDEA) to achieve universal access by 2025. The NDEA target includes adding 160 GW new capacity to on-grid generation, creating 130 million new connections on-grid, creating 75 million new connections off-grid and reaching 130 million households with access to clean cooking (AfDB, 2018).

In addition, a detailed energy system analysis based on techno-economic principles is crucial when assessing the low-cost electricity options and pathways for developing nations. This kind of study will help to better understand the transition in the power sector or the entire energy system in Africa, which is not yet well understood for the years to come but also on the mid and long-term. A recent review article on 100% RE systems, which covers 180 articles published since 2004, shows that Africa, in particular SSA, is one of the major regions in the world that is not yet covered by 100% RE research (Hansen et al., 2019). The growing share of solar and wind energy in the power system leads to a full hourly consideration of the energy system based on a reasonable high spatial resolution. The hourly resolution allows modelling of power or energy system flexibility with a sufficient degree of detail, primarily involving energy storage, grids, dispatchable RE, demand response and sector coupling. Literature research shows that almost no research and studies exist for the energy transition in Africa towards highly sustainable energy systems based on hourly resolution (Hansen et al., 2019). This research gap is addressed by this doctoral thesis and further research will be required in the future.

3 The modelling framework

Modelling a power or energy system with high shares of RE requires integration or flexibility measures, which involve investments in energy infrastructure such as transmission networks, storage and flexible generation technologies. In order to analyse and evaluate VRE integration in power or energy systems, a mathematical representation, i.e. a modelling tool is required. Such a model must have the functionality of delivering energy at a least-cost, with available supply options, respective costs and technical characteristics. This section introduces the energy system model used for this research.

Many RE generation technologies exhibit some variability of power feed-in, varying from short timescales, i.e. minutes or seconds, to very long timescales, i.e. seasons or even years. Furthermore, the significant advance of solar PV and wind energy in the future energy system creates concerns on how to manage power systems that will face increasing variability and uncertainty (Lund et al., 2015; IEA, 2019a). Simulating an energy system with a high share from RE requires a high spatial resolution to account for a county-wide potential variability, as well as a high temporal resolution to capture the short-term variability, especially those of VRE resources.

In this thesis, an hourly resolved optimisation tool is used to simulate power systems, which is able to capture and resolve the VRE integration challenges and ensure flexibility with a sufficient level of detail, mainly involving storage, grids and dispatchable RE. In addition, the energy system model required for this kind of research should be able to identify and determine the optimal investment and generation technology mix that is beneficial based on sustainability criteria. Furthermore, the model features should include capacity expansion, hourly power plant dispatch in different model regions and technologies, cost optimisation and sector coupling.

3.1 Model: uniqueness, features and suitability for this research

This section describes the unique features and suitability of the LUT Energy System Transition Model (Bogdanov et al., 2019a), referred to as, LUT model, for this research. Unlike the Long-range Energy Alternatives Planning model (LEAP) (Heaps, 2020) and Markal/TIMES (Pursiheimo et al., 2019), the LUT model has the ability to perform simulations on an hourly resolution like EnergyPlan (Lund, 2017). The hourly temporal resolution for an entire year is one of the most important features of the LUT model. This allows the model to capture short time and seasonal variation of variable RE supply. The hourly temporal resolution of the model increases computation time substantially; however, it guarantees a power or energy system that is very close to reality and enables a more accurate system description that includes synergy between various components of the system. Furthermore, the LUT model has advantages of modelling a power or energy system transition using optimal dispatch of generation, storage technologies and transmission between several nodes. In addition, the model has the ability to utilise various types of energy storage technologies that are lacking in other transition models. The multi-nodal feature of this model allows a continent, country, and region to be divided into different sub-regions or nodes, which can be interconnected to form a transmission network. The model is based on the linear cost optimisation of energy parameters under certain constraints. The properties of the power or energy systems are described via boundary conditions to the cost minimisation. In the same time, capacity expansion during the transition can be optimised and therewith a cost-optimal system design proposed.

Furthermore, the LUT model has the capability to integrate several energy sectors, which includes power, heat, transport, industry and desalination sectors (Ram et al., 2019; Bogdanov et al., 2020). An inter-temporal optimisation can be achieved with the LUT model; thus, the model can be used to study a long-term (several years or decades) development of a power or energy system. The comprehensive features of the LUT model result in a very large number of variables, which can be in the tens of millions. Due to very comprehensive optimisation problems, a linear optimisation approach is adopted in the LUT model, and all the system parameters are described with linear mathematical equations, and standard solvers applied, such as Gurobi (Gurobi, 2020) and CPLEX (Cplex, 2009).

In this thesis, the LUT Energy System Model is applied in modelling the power systems of African countries and regions, based on its unique features described previously. The model is considered robust and suitable to evaluate the integration of high shares of VRE resources in power or energy systems. The LUT model can achieve a 100% RE system by 2050. In the following sections, the model is introduced, and its mathematical equations described.

3.2 Model: setup and formulation

Model overview and setup

The LUT model is a multi-nodal, multi-sectoral, multi-scenario, technology-rich, transition, and linear optimisation tool, which performs with an hourly resolution of the energy system parameters for an entire year under certain operational constraints and assumptions, for the future RE powered system and demand. The key function of the model is to optimise the system so that the total annual energy system cost is minimised.

To minimise the energy system cost, the sum of various annual cost is optimised, which includes energy generation costs, costs of generation ramping and the costs of installed capacities of various technologies. The simulation of the energy system occurs in 5-year steps, typically for the period 2015 to 2050.

The key constraints for the optimisation are the matching of all types of generation and demand values on an hourly basis of the applied year and the optimisation condition is to reduce the overall annual system cost of the entire system (or a sector if only one sector is optimised). The model is built using MATLAB software R2016b (MathWorks, 2016) in the LP file format, which can be read by most standard solvers. The linear programming model was solved with a third-party solver. Currently, the main option is MOSEK ver. 8 (Mosek, 2017), but other solvers such as Gurobi, CPLEX, etc. (Gurobi, 2020; Cplex, 2009) can also be used. After the simulation, results are returned back to the Matlab data structure and post-processed. The overall model structure of the modelling procedure is illustrated in Figure 10.

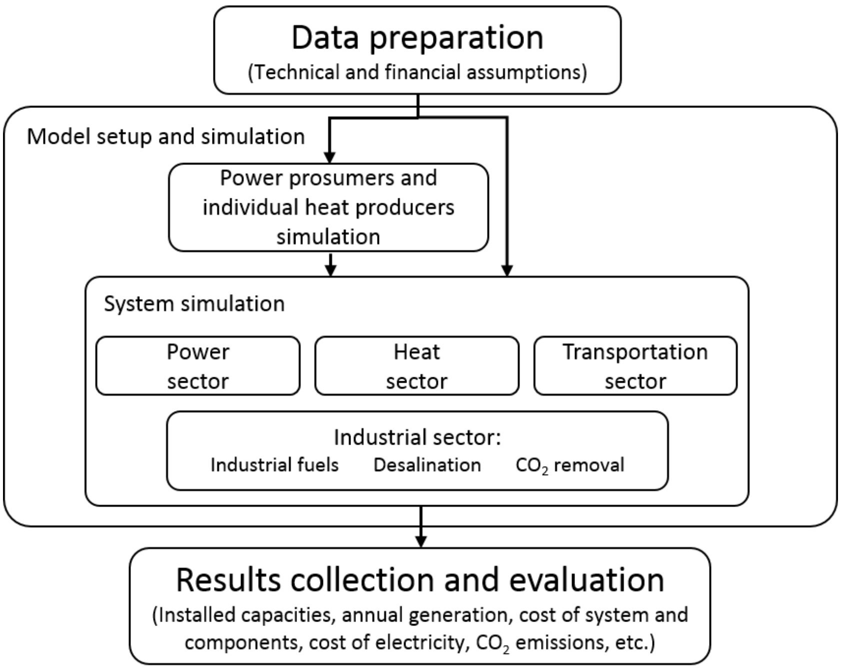

Figure 10. The overall modelling structure and procedure (Bogdanov et al., 2019a).

In addition, the energy system considers power prosumers including residential, commercial and industrial end-users. Individual heating system and power prosumers are optimised exogenously in hourly resolution. The prosumers can install their own rooftop PV systems, lithium-ion battery, buy power from the grid, or sell excess generated electricity after satisfying their own demand. The prosumer target function is to minimise the cost of consumed electricity, which includes the cost of generation and the cost of electricity brought from the grid. After prosumer demand is satisfied, excess generation is sold to the grid and is deducted from the total annual cost (Bogdanov and Breyer, 2016).

The model operates under specific constraints:

1. No new coal, nuclear and oil-based power and heat generation capacities could be built after the starting period. However, gas turbines could be built due to their high efficiency, lower GHG emission factors, and possibilities to switch to synthetic gas and biomethane during the transition. This applies to BPS conditions but can be varied to other scenario types.
2. Hydropower plants are refurbished every 35 years and typically not decommissioned based on empirical observation (Farfan & Breyer, 2017).
3. In order to avoid system disruptions, the renewable capacity share cannot grow more than 4% per year (3% per year from 2015 to 2020) based on empirical observation (Farfan & Breyer, 2017).
4. Maximum PV prosumers share is limited to 20% of the total power sector demand, but half of the total prosumer electricity generation can be fed into the grid for small financial compensation. The prosumer generation is constrained in a stepwise progression from a maximum of 3% in the initial time step to 6%, 9%, 15%, 18% and 20% in the subsequent time steps. This applies to BPS conditions but can be varied for matching other scenario types. Full blocking of the prosumer functionality is also possible.
5. Bioenergy constraint is set to regulate the biogas and waste resource potentials that could be exploited, 33% by 2020, 66% by 2025 and 100% by 2030 onwards. This constraint limits bioenergy technologies from being installed too quickly.

Model formulation

This sub-section describes the main mathematical equations applied for the linear optimisation in the model. The objective function of the system optimisation is the minimisation of the total annual system cost of the various sectors (power, heat, transport, industry, and desalination) considered in the analysis, which is calculated as the total cost of the annualised cost of installed capacities of all technologies accounting for investments and operation, production ramping, fuels, and GHG emission costs.

The boundary condition applied in the model for annual cost-minimisation is presented in Eq. (1) (Bogdanov et al., 2019a) and includes all hours of a year using abbreviations listed in Table 2.

$$\min\left(\sum_{r=1}^{reg}\sum_{t=1}^{tech}(CAPEX_t \cdot crf_t + OPEXfix_t) \cdot instCap_{t,r} + OPEXvar_t \cdot E_{gen,t,r} + rampCost_t \cdot totRamp_{t,r}\right) \tag{1}$$

Table 2: List of abbreviations applied in Eq. (1).

Description	abbreviations
sub-regions	*r, reg*
generation, storage and transmission technologies	*t, tech*
capital expenditures for technology *t*	$CAPEX_t$
capital recovery factor for technology *t*	crf_t
fixed operational expenditures for technology *t*	$OPEXfix_t$
variable operational expenditures technology *t*	$OPEXvar_t$
installed capacity in the region *r* of technology *t*	$instCap_{t,r}$
annual generation by technology *t* in region *r*	$E_{gen,t,r}$
cost of ramping of technology *t*	$rampCost_t$
sum of power ramping values during the year for the technology *t* in the region *r*	$totRamp_{t,r}$

The objective function introduced in the energy model for minimising annual costs is presented in Eq. (2) (Bogdanov et al., 2019a) and covers all hours of a year using abbreviations listed in Table 3.

$$\min\left(\sum_{t=1}^{tech}(CAPEX_t \cdot crf_t + OPEXfix_t) \cdot instCap_t + OPEXvar_t \cdot E_{gen,t} + elCost \cdot E_{grid} + elFeedIn \cdot E_{curt}\right) \tag{2}$$

Table 3: List of abbreviations applied in Eq. (2).

Description	abbreviations
generation and storage technologies	*t*, *tech*
capital expenditures for technology *t*	$CAPEX_t$
capital recovery factor for technology *t*	crf_t
fixed operational expenditures for technology *t*	$OPEXfix_t$
variable operational expenditures technology *t*	$OPEXvar_t$
installed capacity of technology *t*	$instCap_t$
annual generation by technology *t*	$E_{gen,t}$
retail price of electricity	*elCost*
feed-in price of electricity	*elFeedIn*
annual amount of electricity required from the grid	E_{grid}
annual amount of electricity fed-in to the grid	E_{curt}

Energy balance constraints

The energy balance constraint is described in Eq. (3) (Bogdanov et al., 2019a) using abbreviations listed in Table 4. The constraint is applied to ensure that power generation and demand is matched for every hour of the applied year within the sub-region and electricity import covers the local electricity demand. The energy loss in the high voltage direct current (HVDC), and alternating current (HVAC) transmission grids, and energy storage technologies are taken into account in storage discharge and grid import value calculations.

$$\forall \mathrm{h} \in [1{,}8760]\ \sum_t^{tech} E_{gen,t} + \sum_r^{reg} E_{imp,r} + \sum_t^{stor} E_{stor,disch} = E_{demand} + \sum_r^{reg} E_{exp,r} + \sum_t^{stor} E_{stor,ch} + E_{curt} + E_{other} \tag{3}$$

Table 4: List of abbreviations applied in Eq. (3).

Description	abbreviations
hour	*h*
technology	*t*
all modelled power generation technologies	*tech*
sub-region	*r*
all sub-regions	*reg*
electricity generation	E_{gen}
electricity import	E_{imp}

storage technologies	*stor*
electricity from discharging storage	$E_{stor,disch}$
electricity demand	E_{demand}
electricity exported	E_{exp}
electricity for charging storage	$E_{stor,ch}$
electricity consumed by other sectors (heat, transport, desalination, industrial fuels production)	E_{other}
curtailed excess energy	E_{curt}

3.3 Modelled technologies

The main technologies introduced in the model include electricity generation (fossil, nuclear and RE technologies), heat generation (fossil and RE technologies), energy storage, power transmission and sector bridging technologies to provide additional flexibility to the entire energy system and to enable low-cost energy system solutions strongly based on electricity. Figure 11 shows the block diagram of the energy transition model.

Fossil generation technologies are nuclear power plants, coal power plants, combined cycle gas turbines (CCGT) and open cycle gas turbines (OCGT), oil-based internal combustion engine (ICE), and oil and gas based combined heat and power (CHP). While the RE generation technologies include solar PV (rooftop, single-axis tracking and optimally fixed-tilted), wind turbines, geothermal, run-of-river and reservoir hydropower, and bioenergy (waste-to-energy, solid biomass, biogas, and CHP). The fossil heat generation technologies introduced in the model are oil-based district and individual scale boilers, coal-based district heating and gas-based district and individual scale boilers. While the RE-based heat generation technologies include concentrated solar thermal power (CSP) parabolic fields, geothermal district heaters, individual non-concentrating solar thermal water heaters, and bioenergy (biogas district heat, solid biomass and individual boilers).

Energy storage technologies can be divided into three main categories: short-term storage: pumped hydro energy storage (PHES) and lithium-ion batteries; medium-term storage: high and medium temperature thermal energy storage (TES) technologies and adiabatic compressed air energy storage (A-CAES); and long-term gas storage including power-to-gas (PtG) technology, which enables the production of synthetic fuel utilised during the transition.

Energy sector bridging technologies are steam turbines, PtG, electrolysers, electrical heaters, individual and district scale heat pumps, direct electrical heaters, SWRO desalination and electric vehicles. The bridging technologies enables energy conversion from one sector into valuable products for another sector thereby increasing the entire system flexibility, efficiency, and decrease total costs of the system. A detailed overview can be found in Bogdanov et al. (2019).

The maximum potential for all RE technologies are estimated based on methods described in Bogdanov and Breyer (2016), while existing capacities are obtained from Farfan and Breyer (2017) and set as the lower limit. Key power capacities required for the energy transition for each publication is available in their respective Supplementary Material. The transmission and distribution grid losses were considered according to Sadovskaia et al. (2019).

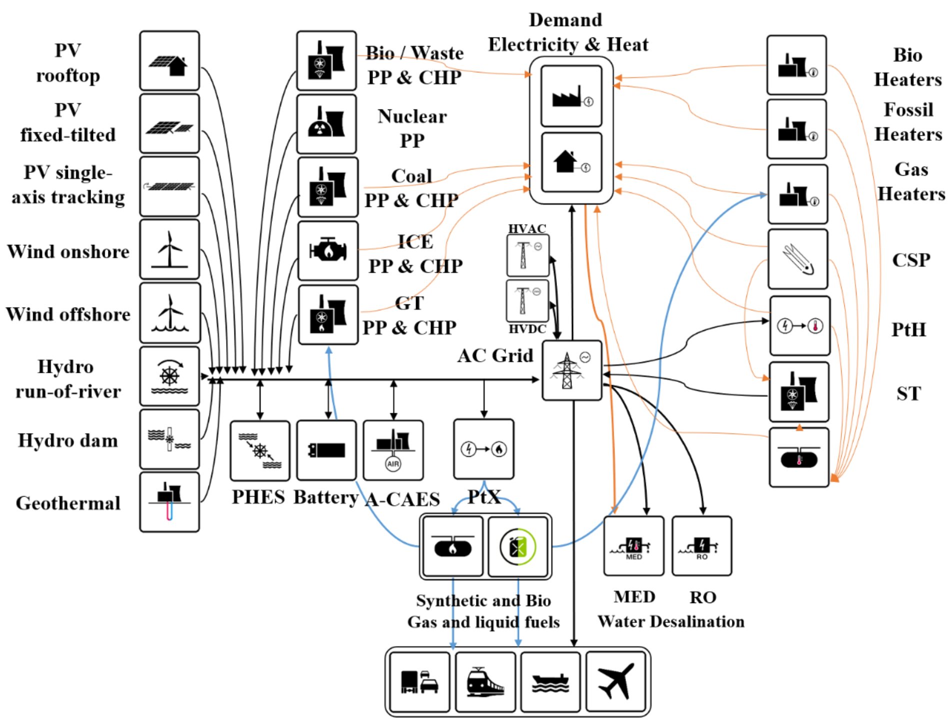

Figure 11. Block diagram of the LUT Energy System Transition model for coupled sectors power and heat (Bogdanov et al., 2019b), transport (Ram et al., 2019) and desalination (Caldera and Breyer, 2020).

3.4 Main input parameters for modelling

Assumptions on financial and technical parameters: The cost assumptions and technical parameters for all technologies applied in the modelling are available in the Supplementary Material of each publication included in this dissertation. All assumptions are based on literature with references provided in each case.

In this study, a 7% weighted average cost of capital (WACC) is assumed for all RE technologies. Whereas for residential PV prosumers, 4% WACC is assumed as a lower financial return is expected. The cost recovery is mostly considered for a wider aggregate range of investors, which includes a mix of debt and equity financing. In this context, the commercial and industrial investors require higher returns on equity margins than private investors. Therefore, WACC is split into two categories in this research.

The prices of electricity up until 2050 for the residential, commercial and industrial consumers were calculated based on the method described in Gerlach et al. (2014) and Breyer & Gerlach (2013). Future electricity prices are estimated based on the approach of Gerlach et al. (2014), which assumes that grid electricity prices will increase by 5% per annum for prices less than 0.15 €/kWh, 3% per annum for price in a range of 0.15–0.30 €/kWh and 1% per annum for prices greater than 0.30 €/kWh.

Renewable resources potential: This includes hourly generation profiles of solar PV, wind and hydropower. Generation profiles for optimally tilted PV, CSP and wind energy are calculated based on methods described in Bogdanov & Breyer, (2016) and for single-axis PV according to Afanasyeva et al. (2018), based on resource data of NASA (Stackhouse & Whitlock, 2008; 2009), reprocessed by the German Aerospace Centre (Stetter, 2012). The resource dataset obtained from NASA is in three hourly temporal resolution and spatial resolution of 1º x 1º for the year 2005, which has been reprocessed to a 1 h and 45º x 45º resolution (Stetter, 2012). The wind feed-in profile was calculated using an Enercon wind turbine (E-101) with 3050 kW rated power and 150 m hub height. The hourly data have been estimated based on the spatial aggregated method as described in Bogdanov & Breyer, (2016). It is assumed that 0-10% best areas are weighted by 0.3, 10-20% best areas are weighted by 0.3, 20-30% best areas are weighted by 0.2, 30-40% best areas are weighted by 0.1 and 40-50% best areas are weighted by 0.1%. Figure 12 shows the full load hour (FLH) of solar and wind resources maps for Africa. The generation profiles for hydropower are calculated using the daily resolved water flow data for the year 2005, as a normalised sum of precipitation in the regions. This method leads to a good approximation of the annual generation of hydropower plants (Verzano, 2009).

Figure 12 shows the annual FLH of various resources for the entire Africa. The biomass and waste resource potentials are taken from DBFZ (2010) and are further categorised to solid wastes, biogas and solid residues. The costs for biomass are calculated using data from the International Energy Agency (IEA, 2012) and the Intergovernmental Panel on Climate Change (IPCC, 2011). A gate fee of 50 €/ton was assumed for solid waste for the year 2015, which increased to 100 €/ton in 2050. Geothermal energy potential is estimated according to the method described by Aghahosseini et al. (2017).

Demand: The hourly electricity demand profiles are estimated as a fraction of the total demand for each sub-region based on synthetic load data weighted by the sub-region's population. The hourly electricity demand estimation is based on the method described by Toktarova et al. (2019). The power demand is categorised into residential, commercial and industrial end-users.

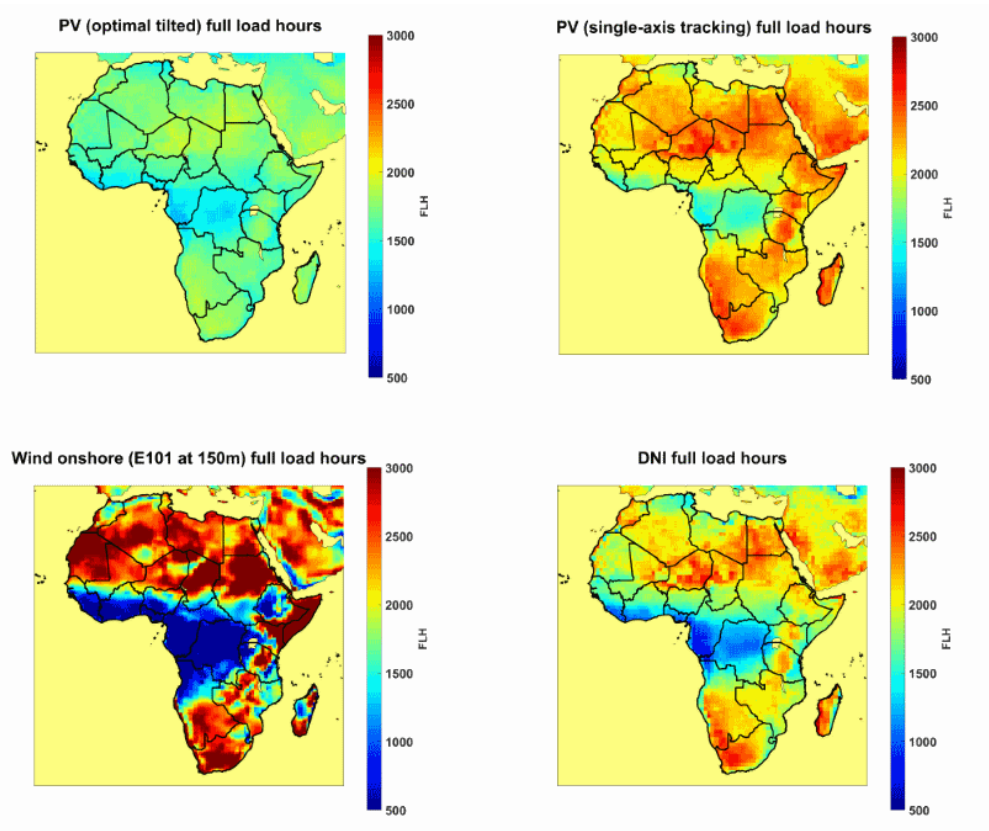

Figure 12**.** Maps of Africa showing annual full load hours for optimally tilted (top left) and PV single-axis tracking (top right), wind (bottom left), and CSP solar field (bottom right).

3.5 Positioning of the LUT model

A wide variety of energy system models (ESMs) has been developed for 100% RE systems analyses, which can cover a multi-sector energy system while enabling sector integration and full hourly resolution. Given the variety of the ESMs in terms of their characteristics, capabilities and possible overlaps, the position of the LUT model relative to other ESMs needs to be specified. Therefore, a systematic review of a set of ESMs is presented in Table 5 (Lopez et al., 2020), whether they have sufficient features for comprehensive energy system analyses. The following ESMs overview includes, EnergyPlan (Lund, 2017), the LUT model (Ram et al., 2019; Bogdanov et al., 2019a; 2020), TIMES (Pursiheimo et al., 2019), HOMER (Giatrakos et al., 2009), REMix (Gils et al., 2017), AU model (Rodríguez et al., 2014), PyPSA (Brown et al., 2018), LOADMATCH (Jacobson et al., 2019), NEMO (Elliston et al., 2014), ISA model (Lenzen et al., 2016), H_2RES (Duić et al., 2004), GENeSYS-MOD (Löffler et al., 2017), MESAP/PlaNet (Teske et al., 2018), among others, as summarized in Table 5.

Table 5. A systematic review of leading Energy Model Systems by some key functionalities, published journal articles and citations (Lopez et al., 2020).

Model	Articles	Citations	Latest use	Multi-node	Hourly resolution	Multi-sector	Detailed industry	CO_2 direct removal	Optimisation	Simulation	Transition	Overnight	Off-grid integration
EnergyPlan	55	4259	2020	✓	✓	✓	×	×	×	✓	×	✓	×
LUT model	50	795	2020	✓	✓	✓	✓	×	✓	✓	✓	✓	×
TIMES	14	341	2020	×	×	✓	✓	×	✓	✓	✓	✓	×
HOMER	14	652	2020	×	✓	×	×	×	✓	✓	×	✓	×
REMix	9	252	2018	✓	✓	✓	×	×	✓	✓	×	✓	×
AU model	16	989	2018	✓	✓	×	×	×	✓	✓	×	✓	×
PyPSA	11	142	2020	✓	✓	✓	×	×	✓	×	×	✓	×
LOADMATCSH	7	5197	2019	×	✓	✓	×	×	×	✓	✓	×	×
NEMO	7	428	2017	✓	✓	×	×	×	✓	×	×	✓	×
ISA model	7	41	2020	×	✓	✓	×	×	✓	×	×	✓	×
H_2RES	6	595	2011	×	✓	✓	×	×	×	✓	×	✓	×
GENeSYS-MOD	6	36	2019	✓	×	✓	×	×	✓	×	✓	×	×

MESAP/PlaNet	5	134	2018	✕	✕	✓	✕	✕	✕	✓	✓	✓	✕
Others	187	6311											
total	389	15494											

Indicator: Yes (✓), No (✕)

As of May 2020, 389 articles are recorded in the LUT database on 100% RE system research published in a scientific journal as presented in Table 5. While the citations are as of early January 2020. EnergyPlan and the LUT model are by far the most used ESMs for 100% RE analyses in scientific articles. Overall, only two models are capable of detailed industry modelling, thereof LUT model caught up recently. Regarding temporal resolution, most of the ESMs operates on full hourly resolution except TIMES, GENeSYS-MOD and MESAP/PlaNet. Almost all can integrate multi-sector, while half of the ESMs are able to describe interconnected nodes, thereof EnergyPlan caught up recently. Currently, no single ESMs can capture CO_2 removal options (Fuss et al., 2018). However, it is worth mentioning that the LUT model can describe direct air capture storage (DACCS) (Breyer et al., 2019; 2020b). Not a single ESM is able to capture off-grid electrification. Only half of the leading ESMs can sufficiently describe the transition pathways, which is an integral aspect of the 100% RE research. Almost all the leading ESMs can perform optimisation solutions, also all ESMs capable of optimisation can be used for simulation modelling. The LUT model maintained a top position as the only ESM combining the key features for detailed energy system analyses: optimisation, full hourly resolution, multi-node, multi-sector and transition modelling (Lopez et al., 2020; Prina et al., 2020).

3.6 Overview on job, synthetic inertia and overnight modelling method

Job creation

Employment provides an important linkage between economic growth and poverty alleviation by allowing the poor to generate income. Job creation is one of the socio-economic footprints to measure the performance of the energy transition. Job creation during the transition is analysed in **Publication II and IV.** The annualised jobs created were estimated based on the method described by Ram et al. (2020). The direct energy jobs created during the transition are estimated using the employment factor (EF) approach. The assumed EF can be found in the Supplementary Material of **Publication II and IV**. Direct employment is created across the value chain including manufacturing, construction and installation, operation and maintenance, transmission, decommissioning and fuel supply. Figure 13 gives an overview of the methods adopted to estimate jobs created.

Figure 13. Methods for estimation of job creation (Ram et al., 2020). Abbreviations: Capital Expenditure (CAPEX) and Operational Expenditure (OPEX).

Synthetic inertia

Synthetic inertia is analysed in **Publication V**. The conventional grid is known to possess large synchronous machines that can react to frequency deviations and large inertia guarantees that the rate of change of frequency (ROCOF) will be slow enough so that power generation plants can react to the change in frequency either by decreasing or increasing their power depending on whether the change in frequency is positive or negative, respectively (Chamorro et al., 2013). In fully RE power systems the inertia will become low, since rotating mass of the connected synchronous machine is reduced (Peltoniemi, 2017). The lower inertia indicates that connected frequency regulation reserve must be capable of reacting faster to frequency change in grid. In grids dominated by RE, the available frequency control capacity is mostly based on RE production considered.

In this research, the 2 Hz/s is considered as the threshold value for the SSA transmission lines configuration. Furthermore, the frequency regulation approach utilises not only synchronous generation (bioenergy power plants, hydropower and geothermal units) but also the non-synchronous generation from wind, solar PV and battery, which is known as synthetic inertia. For instance, it is a well-known fact that wind power plants can emulate the inertia property, known as inertia emulation or synthetic inertia. It is claimed that a wind turbine can produce up to 6% of the nominal additional power for about 10s (Asmine and Langlois, 2016). In this study, wind turbine contribution to frequency control as kinetic energy, is calculated according to Eq. 4 (Peltoniemi, 2017).

$$E_{k,w} = p_w \cdot \; S_w \; \cdot t_{si,w} \tag{4}$$

Where $E_{k,w}$ is the kinetic energy of wind turbine, p_w is the percentage of the nominal power, S_w is the total power of the wind turbine connected to the grid, and $t_{si,w}$ is the time on how this 10% can be extracted from the turbine.

In addition, solar PV power plants also could participate in frequency balancing by emulating the inertial property. For the solar PV, power kinetic can be estimated similarly as for wind turbine as in Eq. 5 (Peltoniemi, 2017).

$$E_{k,pv} = p_{pv} \cdot \; S_{pv} \; \cdot t_{si,pv} \tag{5}$$

Where $E_{k,pv}$ is the kinetic energy of solar PV, p_{pv} is the percentage of the nominal power and is set to 0.005, S_{pv} is the total power of the solar PV system connected to the grid, $t_{si,pv}$ is the time interval of how long the extra power is extracted from the system.

Furthermore, the battery storage can be counted for both load and generator. For the battery storage, the kinetic energy can be estimated in a similar way as for wind and solar PV in Eq. 6 (Peltoniemi, 2017).

$$E_{k,batt} = p_{batt} \cdot \; S_{batt} \; \cdot t_{si,batt} \tag{6}$$

Where $E_{k,batt}$ is the kinetic energy of battery storage, p_{batt} is the percentage available for frequency regulation, S_{batt} is the total apparent power of the battery energy storage connected to the grid, and $t_{si,batt}$ is the time interval of how long the power is extracted from the battery energy storage.

According to Enercon (2010), it is concluded that in a fully RE power grid, all power generation sources that can generate synthetic inertia must be fully utilised to maintain frequency stability. Additional information on the methods is described by Peltoniemi, (2017).

Overnight modelling approach

The LUT model was at first developed for the power sector only in an overnight design (Bogdanov and Breyer, 2016), it was further developed for describing a full transition scenario (Bogdanov et al., 2019a), and in a later step designed with a full power and heat sectors coupling (Bogdanov et al., 2019b). For the time being, the LUT model has been improved to integrate the power, heat, and transport sectors (Ram et al., 2019; Bogdanov et al., 2020), and desalination sector (Caldera & Breyer, 2020), and lastly, the industry sector (Bogdanov et al., 2020).

Research in **Publications V-VI** are conducted in the early stage of the model development, when the model was initially designed for overnight scenarios. This kind of energy system modelling is for a specific timeframe in the future. The modelling is conducted to determine the least-cost of a system in full hourly resolution, and the analysed power systems would be entirely RE-based systems for the reference year. The scenarios utilise a multi-nodal approach in the LUT model for modelling of SSA power systems. **Publication V** is based on the overnight modelling approach for the year 2030, while **Publication VI** applies the same approach for the year 2030 and 2040. It is noteworthy that the pathway to achieving a fully RE-based system, also known as energy transition pathway, is not the focus of **Publications V-VI**. Consequently, the lifetime of existing power plants and decommissioning years are not taken into consideration. In comparison to the overnight modelling approach, the transition scenarios show the effect of considering the legacy energy system in sustainable energy system analyses. The optimisation is carried out on an assumed cost basis and technological status for the reference year, and the overall building approach.

4 Results

This section presents a summary of the main objective and result of each publication that comprises this dissertation.

4.1 Publication I: Pathways to a fully sustainable electricity supply for Nigeria in the mid-term future.

Aim

The objective of **Publication I** was to model and analyse various decarbonisation pathway options for the Nigerian power sector up until 2050. A special research is conducted for the most populated country in Africa and the second largest economy in SSA, Nigeria. Despite the country's abundant energy resources, Nigeria is still unable to develop, transform and utilise these resources for optimal economic development. Furthermore, power demand exceeds the supply due to limited electricity generation capacity, which has consistently led to recurring blackouts, rationing of electricity and prevalent use of costly backup generators running on gasoline or diesel.

To curb the plague of recurring blackouts and meeting the growing power demand sustainably, the massive roll-out of renewable capacities is a feasible and viable option with multiple co-benefits. For these reasons, this study presents various transition pathway options for Nigeria up to 2050.

Method

To analyse the various transition pathway options, a linear optimisation tool was used to determine the optimal investment and electricity generation mix, needed to supply the power demand up until 2050 for Nigeria. The simulation of the power system is performed in 5-year time-steps from 2015 until 2050, using the LUT model, which can handle high levels of geo-spatial and hourly sequential temporal resolutions.

The power system analysis builds on detailed financial and technical assumptions, which are fundamental in defining the structure of the power system and a cost optimal transition pathway. The financial and technical details are provided in the Supplementary Material of this publication.

This study examines eight decarbonisation pathway options based on governmental proposed transition plans (i.e., CPSs) and the goal of the Paris Agreement (i.e., BPSs). In addition, the impacts of different features such as sector integration and GHG emissions cost were analysed for the various transition pathways.

Result

A fully RE-based electricity supply is achievable in Nigeria. The power system modelling shows that an optimal mix of renewable generation technologies supported by flexible storage option is a feasible and viable option for Nigeria, as indicated in the BPS in comparison to the CPS. The predominant role of PV-battery hybrid systems is significant to the progressive decarbonisation of Nigeria's power sector, due to highly favourable economics. The levelised cost of electricity (LCOE) decreases from around 54 €/MWh in 2015 to about 46 €/MWh in 2050 for the power sector and further reduces to 35 €/MWh with sector coupling. While the LCOE for the power sector increased substantially to about 75 €/MWh in the CPS without GHG emission cost.

The application of GHG emission costs leads to fast transition and rapid GHG emission reduction in the BPS; comparable results are achieved even without GHG emission cost. By 2050, RE supplies about 98% in no GHG emission cost scenarios, with around 2% supplied by fossil gas. The modelling outcome shows that the Nigerian power sector can be decarbonised without GHG emission cost implementation.

In addition, there is no technical barrier in delivering this kind of transition in Nigeria. Storage technologies, grid interconnection and gas turbines provide the system with the required flexibility. It is noteworthy that Nigeria has land resources to host a generation mix led by VRE.

4.2 Publication II: Pathway towards achieving 100% renewable energy powered electricity sector by 2050 for South Africa.

Aim

The aim of **Publication II** was to examine the dynamic decarbonisation pathway options for South Africa up to 2050. South Africa, just like other coal-dependent countries, is prone to huge environmental disaster, owing to extensive utilisation of coal for power generation. Transitioning from a coal-led power system to one that is built on solar and wind energy is a key option for achieving South Africa's carbon mitigation strategy and the goal of the Paris Agreement.

Water and energy are inextricably linked. Therefore, water consumption issues associated with the operation of thermal power plants, have to be addressed in countries like South Africa that is prone to water scarcity. Thus, energy-based water demand was examined by assessing the water footprint in **Publication II**. In addition, job creation during the transition is analysed for the different scenarios.

4.2 Publication II: Pathway towards achieving 100% renewable energy powered 59 electricity sector by 2050 for South Africa.

Method

The techno-economic analysis of the transition was carried out with the LUT model. The modelling is performed in 5-year intervals from 2015 up to 2050, in an hourly sequential temporal resolution which guarantees a more accurate assessment of the power generation mix.

Additionally, the water footprint of thermal plants and job creation during the transition was analysed. Energy-based water demand was estimated using the water withdrawal and consumption factors for various thermal power plants provided by Macknick et al. (2012) and using the method of Lohrmann et al. (2019).

Jobs created during the transition were estimated based on the method of Ram et al. (2020), using the employment factor approach. Details of financial and technical assumptions, employment generation factors and key electricity capacities required for the transition are available in the Supplementary Material of **Publication II**

Result

The South African energy transition is technically possible and economically viable; such a system is low-cost, less GHG emitting, consumes less water and creates more jobs. Solar and wind energy evolve as the main sources of electricity for a fully renewable power system in South Africa. Solar PV with around 75–79% tops the total generation capacities and followed by wind energy with around 11–16% by 2050. Solar PV emerges as the most versatile and low-cost source of clean power generation, contributing around 71–73% of the total electricity generation by 2050, followed by wind energy with 22–28%.

The LCOE increases from around 49 €/MWh in 2015 to about 51 €/MWh in the BPS by 2050, while it significantly increases reaching nearly 105 €/MWh in the CPS. In addition, without GHG emission costs, LCOE increases from around 44 €/MWh in 2015 to about 47 €/MWh in 2050 in the BPS, and further increases up to nearly 63 €/MWh in the CPS. Without GHG emission costs, LCOE is about 25% lower in the BPS than in the CPS, and further decreases by around 50% with GHG emission costs. It is noteworthy that without GHG emission cost, the BPS led to 96% renewables, while the remaining 4% is contributed by gas turbines and coal generation, indicating pure market economics.

The results show that transitioning to a RE power system as observed in the BPS will dramatically influence the jobs market. Jobs increased significantly from about 210 thousand in 2015 to nearly 408 thousand by 2035, due to increasing electricity installed capacity stimulated by high growth rates. However, jobs created gradually reduces to over 278 thousand by 2050 as growth rates stabilise. On the other hand, jobs created in the CPS remain rather stable with a slight decline to about 184 thousand by 2050.

A renewable-led power mix as demonstrated in the BPS will not only deliver a power system that is cheap and clean, but also consumes less water than the CPS. Water demand for energy purpose in BPS reduces by 87% in 2030, and by 99% in 2050, compared to 2015. Whereas, energy-based water use in the CPS decreases only by 38% in 2050.

4.3 Publication III: The role of biomass in sub-Saharan Africa's fully renewable power sector – The case of Ghana.

Aim

Publication III aimed to investigate the grid balancing role of bioenergy in a fully renewable power sector for SSA, using Ghana as a case study. The bioenergy potential was estimated and applied in the LUT model for the power sector analyses.

Method

Bioenergy being a dispatchable form of energy has the potential to play a significant role in balancing the power grid. To test this hypothesis, this research estimates and evaluates the sustainable bioenergy potential of Ghana and applies the yielded potential on the power sector in a fully renewable scenario. Three main biomass sources are considered, namely, forestry (forest residues), agriculture (crop residue, and livestock manure), faecal sewage sludge (FSS), and municipal solid waste (MSW) to avoid violation of biomass sustainability criteria. Bioenergy from crop and forest residues is estimated using the residue to product ratio (RPR) parameter. The use factor applied for crop and wood residues is 35% and 80%, respectively. The lower heating values are considered for the energy potential estimation. Energy from MSW and livestock manure was estimated in an anaerobic digestion process for the biodegradable portion of the waste. While the non-biogenic fraction of MSW is assumed to be treated with an incineration process for bioenergy use.

The bioenergy potential is applied in the LUT model for the power system analysis. Six alternative scenarios were developed, which aimed at investigating the role of bioenergy and greenhouse gas emissions costs.

Result

The results of this case study show that the sustainable bioenergy potential for Ghana as of 2015 is 48.3 TWh, which generated about 18 TWh of electricity for 37% of resource utilisation by 2050 when applied in the LUT model. In a scenario without bioenergy, the dispatchable power plants are hydropower reservoirs and gas turbines and bioenergy is compensated largely by solar PV. Whereas in the scenarios with bioenergy, the dispatchable power is provided mainly by bioenergy plants, followed by hydropower reservoirs and gas turbines. With bioenergy in the system, the cumulative installed capacity, total generation, storage output, curtailment and LCOE dropped by 22%, 12%, 37%, 41.6% and 27% compared to a scenario without bioenergy.

4.4 Publication IV: Transition towards decarbonised power systems and its socio-economic impacts in West Africa.

Aim

Publication IV aimed to explore the integration of large shares of RE into a regional power system, for the case of the West African power sector. Regional energy transition is investigated to understand the underlying behaviour of an energy system which covers a larger geographic area. Hitherto, there is a lack of high levels of geo-spatial and temporal (hourly) resolution sustainable energy transition studies for West Africa, which examines the effect of large shares of RE in meeting the rising demand in the region. For these reasons, this study examines the role and benefits of flexible electricity generation, power transmission and flexible storage solutions in the transition towards a fully decarbonised power system for the 15 member states of the Economic Community of West Africa States (ECOWAS), from 2015 up until 2050. In addition, the study seeks to determine the least-cost and most-job enriching power system for West Africa.

Method

The West African power system was analysed with the LUT model. The job creation during the transition was analysed based on the method described by Ram et al. (2020). The region was structured into 20 defined sub-regions based on existing cooperation. The main input parameters in determining a cost optimal transition pathway are described in the publication and data are presented in the Supplementary Material. Employment creation generation factors used for job estimation can be found in the Supplementary Material of the publication. Six different scenarios are envisioned to understand the transition pathways, which aimed at assessing the effect of various policy constraints such as regional electricity trade and GHG costs.

Result

Results of the BPSs demonstrate how high shares of solar PV in West Africa can be supported by battery storage and other flexibility measures, such as grid interconnections, dispatchable RE, curtailment and gas turbines.

Transitioning to a fully RE-based power system, as illustrated in the BPS will not only deliver the lowest cost but also emits less GHG and creates more jobs in West Africa, and is compatible with the Paris Agreement and SDGs of the United Nations. This study presents a critical aspect of the transition for West Africa, which pertains to the cost-competitiveness of RE technologies as observed in the BPSs in comparison to the CPSs. Aside, the massive and growing cost of the fossil fuel technologies in the CPS, such a power system violates sustainability ideologies that form the core of a resilient power system. Furthermore, even without GHG emission costs, the least-cost solution leads to nearly 100% renewables in the BPSs with interconnections of the West African countries, whereas 98% renewables are found without interconnection, while the remaining generation is covered by fossil-fuelled gas turbines. Cooperation of electricity exchange within the region can reduce cost by about 10%.

4.5 Publication V: Repercussion of Large-Scale Hydro Dam Deployment: The Case of Congo Grand Inga Hydro Project.

Aim

The primary aim of **Publication V** was to present an overview analysis of the impact of developing the Grand Inga hydropower project in the Democratic Republic of Congo (DRC) and SSA. Another crucial aspect of this study was to investigate the grid frequency stability of the power systems dominated by VRE resources.

Method

The LUT model was used to model the power system for the entire SSA based on an overnight approach for the year 2030 and 2040. All input parameters used in the modelling are presented in the Supplementary Material of the publication and other details are available in the main paper.

A range of scenarios were formulated in this study, to analyse the effect of the Grand Inga hydropower project on the SSA power system. To realise the objective of this study, different scenarios were defined based on announced and overnight cost assumptions. The overnight cost was based on the finding of Ansar et al. (2014) with respect to cost overruns. This study reports that the actual cost overrun of mega hydropower plant were on average 96% higher than the estimated cost. All scenarios defined were compared to a reference generated and presented in **Publication V**, simulated as an optimal future energy mix for the region. Simulations have been carried out for cost escalations from 0% to 100% in 5% steps for the Grand Inga project in 2030 and 2040.

Integration of synthetic inertia in a system dominated by VRE was investigated for SSA in a 100% renewable power system.

Result

The results show that when the cost escalation for the Grand Inga hydropower project exceeds 35% in 2030 and -5% in 2040 assumptions, the project becomes economically non-beneficial. In all scenarios, SSA can mainly be powered by solar PV to cover the electricity demand and complemented by wind energy, supported by batteries. Hydropower and biomass-based electricity can serve as complementary resources.

The LCOE obtained at the inflection point (near +35% of the announced cost for 2030 and -5% of the announced cost for 2040), i.e., the point at which the relative difference LCOE is zero for the entire region, is 54.4 €/MWh in 2030 and 41.7 €/MWh in 2040, while the LCOE obtained for a 100% Grand Inga cost overrun in the DRC region is 68.4 €/MWh in 2030 and 60.4 €/MWh in 2040. These are 79.5% and 69% higher than the reference averages, respectively.

Integration of synthetic inertia in a system dominated by VRE is confirmed as an attractive option for SSA in a 100% renewable power system. Utilisation of synthetic inertia from solar PV, wind turbines and in particular battery storage becomes essential in this study.

4.6 Publication VI: A cost optimal resolution for sub-Saharan Africa powered by 100% renewables in 2030.

Aim

This study investigates a least-cost electricity solution for SSA based on an overnight approach for the year 2030. The power system was analysed on hourly resolution and based on 100% RE technologies. The integration of seawater desalination and industrial gas production was analysed.

Method

The SSA power system was analysed with the LUT model. The region was structured into 16 sub-regions based on population, area and national grid interconnections. Four scenarios were defined to fully understand the role of grid interconnection in a fully RE based power system. In addition, the integration of seawater desalination and industrial gas demand was analysed.

Result

The modelling outcome research establishes that a 100% RE-based energy system is a technically feasible and economically viable solution for SSA. RE technologies can sufficiently provide all electricity demand in SSA for the year 2030 at a low overall cost of 47–58 €/MWh, and this depends on the intensity of geographic integration and energy sector coupling.

The results clearly reveal that a much higher RE generation is possible, mainly driven by solar PV and wind energy, while existing hydro dams serve as virtual battery storage reducing the role of storage technologies. The challenges of variability in RE technologies can be addressed with HVDC transmission lines. Furthermore, with grid interconnections, a significant reduction in solar PV shares is observed and is countered by an increase in wind capacities by 10.2%. Grid interconnection leads to a reduction in overall cost, RE capacities and storage requirements.

The results show a reduction of 15% in LCOE and 19% in electricity generation was realized as a result of integrating desalination and power-to-gas sectors into the system.

4.7 Publication VII: Visualizing national electrification scenarios for sub-Saharan Africa.

Aim

The purpose of this study was to visualise national electrification pathways for SSA countries. This research contributes to the discussion of whether a decentralised or centralised approach should be applied for electrifying vast areas of the African continent. Geographic Information Systems (GIS) based methods were applied to analyse the various electrification options suitable across SSA, which include grid extension, mini-grid and solar home system (SHS).

Method

This research applies a geospatial approach and is based on datasets on existing and planned grid infrastructure, population distribution and densities, and nightlight satellite imagery as shown in Figure 13. Finally, an electrification scenario for SHS, mini-grid and grid extension, based on grid extension distance and local population distribution, was visualised for non-electrified areas of SSA.

Figure 13. Datasets applied in this research for identifying geospatially resolved electrification options.

For this research a programming routine was developed using open-source software such as Python (Van Rossum and Drake Jr., 1995) and QGIS (Quantum GIS Development Team, 2016), the schematic of the proposed method is shown in Figure 14 and further details on methods and data collection can be found in the publication.

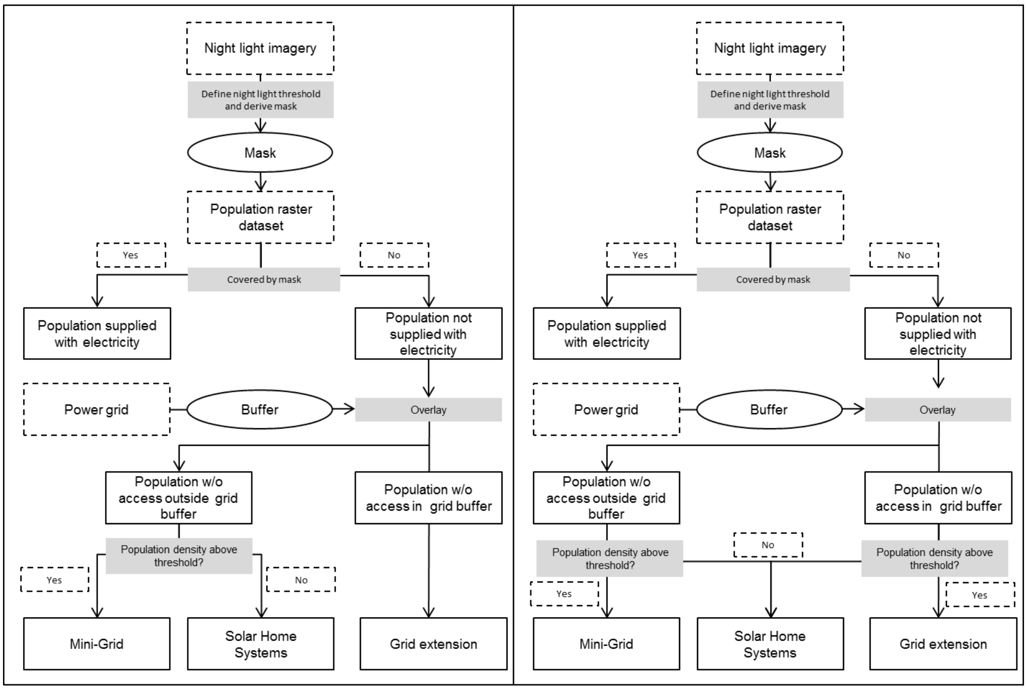

Figure 14. Schematic diagram of appropriate electrification option selection for excluding (left) and including (right) the population density within the grid buffer.

Two scenarios were developed to account for low population densities near the grid infrastructure. The first scenario assumes grid extension as an optimum electrification path for people within the grid buffer, while, mini-grid and SHS are assigned to the population outside the grid buffer depending on population density as illustrated in Figure 14 (left). In the second scenario, SHSs are defined for all locations with a population under a certain threshold, also within grid buffers as shown in Figure 14 (right). A population threshold value of 400 people per km² is chosen.

Furthermore, a sensitivity analysis was performed varying key parameters, such as grid buffers, determining the grid extension option, and population threshold, determining the SHS or mini-grid options. For the grid buffer radius, 10 km and 50 km was applied and 100 persons per km² for the population threshold sensitivity.

Result

In the first scenario considering the existing grid infrastructure, electrification options are composed of 43.3% SHSs, 10.3% mini-grids and 46.4% grid extension. In the second scenario based on planned grid extension, electrification options are composed of 32.0% SHSs, 6.5% mini-grids and 61.5% grid extension.

For the grid-based scenario, the sensitivity analysis results for a smaller grid buffer radius of 10 km lead to a higher share of SHS with 55%, a reduced share of grid extension with 26.9%, and a less than 18% share for mini-grid. A larger grid radius of 50 km leads to reverted results, grid extension increases to a share of 65.5% (+18.6%), mini-grid to 8% (-4.4%) and to SHS 26.5% (-14.3%). Furthermore, the mini-grid option rises with a lower population threshold of 100 persons per km².

The results of this research indicate that fast electrification of non-electrified people with SHS is required to achieve the SDG 7. Mini-grid appears not to be a major electrification option, but a lower population threshold shows higher deployment of mini-grids. Grid extensions are highly attractive for areas with a population density close to the existing grid infrastructure.

5 Discussion

5.1 General discussion of the presented results

Electricity generation mix

A transition towards a fully RE-based system will lead to a dramatic change in the system structure as observed in this study. Solar and wind energy emerge as the new bulk electricity provider, due to the huge potential of these resources and continuous decline in cost associated with solar PV and wind turbines. The results from **Publications I-VI** show that a mix of renewable electricity generation led by solar PV can substitute the present reliance on fossil-based electricity. For instance, the modelling results show that it is low-cost to supply 81% to 85% of West Africa's electricity demand from solar PV in the BPSs (**Publication IV)**. For the case of South Africa in **Publication II**, solar PV supply is 71 – 73% of electricity demand, while wind energy supply is 22 – 28% of the total generation by 2050. Beyond 2030 wind generation remains stable due to further cost decline of solar PV and battery storage. However, a higher percentage of wind generation could be anticipated, if the wind Capex would decline faster. The results for the entire SSA (**Publication VI)** based on the overnight approach for the year 2030 show that the region can be powered primarily by solar PV and wind energy.

It is worth mentioning that countries and regions in Africa have the land resources to technically host a generation mix led by VRE. For example, the area of land needed in Nigeria (**Publication I**) for solar PV ranged from 2409 – 4369 km^2 representing 0.3% to 0.5% of the total land area and wind capacities from 52 – 361 km^2 approximately 0.01% to 0.04% by 2050. For the case of South Africa (**Publication II**), solar PV and wind capacities require land area of 3260 km^2 and 6180 km^2 representing just 0.3% and 0.5% of the total land area by 2050. In **Publication III**, solar PV requires an area of 628 – 827 km^2 representing 0.26% to 0.35% of Ghana's total land area. In **Publication IV**, solar PV and wind capacities by 2050 require an area of 3784 km^2 and 1454 km^2 respectively, representing just 0.07% and 0.03% of the total land area of West Africa. The agro-photovoltaics system technology provides a solution to the challenges of sustainable land use in terms of food and energy production (Schindele et al., 2020). Therefore, the land required can be used for agriculture and PV (Schindele et al., 2020) or in co-location with hydropower and reservoirs (Farfan & Breyer, 2018), whereas wind farms can also be operated in co-location with agriculture.

The BPSs results of this research show that solar PV will evolve as the default technology for countries and regions in Africa. Comparable results are published in peer-reviewed articles for other Sun Belt countries and regions (Solomon et al., 2018; Gulagi et al., 2018; Bogdanov et al., 2019a). It is worth mentioning that prosumer PV contributes about 20% of the total PV generation in this study for various study cases by 2050. Decentralised power systems at the consumer end, notably rooftop PV, is expected to grow and shape the future power system (Ruotsalainen et al., 2017; Keiner et al., 2019). Solar PV prosumers with battery storage may not require as much electricity from the central grid. The continuous fall in the cost of solar PV will prompt further reductions of LCOE of PV prosumers, which will stimulate the PV self-consumption in the nearest future. Solar PV prosumer may be one of the crucial enablers of the energy transition (Campos and Marín-González, 2020; Kotilainen and Saari, 2018).

The results of **Publications I-VI** show that the transition will require a significant increase in investment, relative to historical levels. Investments in energy infrastructure are very important to sustain Africa's growth and fast-track the eradication of extreme poverty in the region (Eberhard et al., 2011). To this end, the African leaders, laid out ambitious long-term plans for closing the electricity gap in the continent, which includes a major increase in hydroelectricity power generation (Eberhard et al., 2011). Given the intention to heavily invest in hydropower in Africa, possible negative social and environmental impacts of such a massive deployment of hydropower should be considered. More importantly, hydropower plants are susceptible to climate variability as rainfall patterns are projected to change in the region (Sridharan et al.,2019; Emodi et al., 2019). Erratic rainfall and extreme water shortage could leave hydropower plants as stranded assets (Sridharan et al., 2019). Based on the foregoing discussion, solar energy is less vulnerable than hydropower to climate change risks (Emodi et al., 2019), which is an important fact for decision-makers and energy planners in Africa. Solar PV is more resilient to climate change compared to other RE resources. Hence, solar PV is anticipated to play a vital role in mitigating GHG emissions and adapt the energy system to future climate conditions (Emodi et al., 2019). The findings of this thesis show the importance of PV technologies as crucial for the African energy transition, due to the expected decline in Capex. In addition, solar PV systems are least at risk to cost overruns (Sovacool et al., 2014). Decentralised, modular and scalable systems such as solar PV and wind would see fewer cost overruns and lower risk of technical systems failures (IEA, 2007; Sovacool et al., 2014). Developing economies should prioritise agile energy alternatives to mega hydropower dams that can be built over short time horizons (Ansar et al., 2014). This will eventually improve resilience and other metrics of energy security (Azzuni & Breyer, 2020).

System flexibility

This section addresses the technical feasibility of integrating large shares of RE into Africa's energy system. A wide range of system flexibility measures are available to accommodate large shares of VRE, in energy systems (IRENA, 2019a; IEA, 2019a). A portfolio of operational flexibility options such as energy storage, power transmission, dispatchable RE, flexible generators, synthetic inertia and generation curtailment are examined in this study. These flexibility components act on different timeframes.

The results of **Publications I-VI** illustrate the indispensable role of energy storage in providing stability and flexibility, as the shares of VRE sources increases significantly in the power system, especially in the BPSs. Battery storage supplying the bulk of the electricity storage need emerges as an essential component within the storage options for overcoming the day-night cycle. The largest battery throughput is needed in the BPSs. For instance, battery throughput in the BPS is nearly 24 times higher than in CPS (260 TWh vs 11 TWh), as observed in the case of West Africa (**Publication IV)**. PV-battery hybrid systems evolve to a highly economic option in this research. The possibility of PV-storage hybrid systems dominating the future energy system is also highlighted in recent studies (Creutzig et al., 2017; Haegel et al., 2019). The cost of battery storage has declined roughly by 85% between 2010 and 2018 (BNEF, 2019). With their continuous decreasing cost (BNEF, 2019), batteries emerge as the most cost-effective electricity storage device during the transition in this study. Further cost reduction of batteries is expected (Kittner et al., 2017; Schmidt et al., 2017), which will drive PV growth (Breyer et al., 2018; Vartiainen et al., 2020), in addition to the continued PV cost decline as projected by Vartiainen et al. (2020).

The observation made in this study aligns with several other studies (Breyer et al., 2018; Bogdanov et al., 2019a; Solomon et al., 2019), which highlights the importance of storage when the share of VRE generation reaches around 50% of the power demand (Bogdanov & Breyer, 2016; Breyer et al., 2018; Bogdanov et al., 2019a; Solomon et al., 2019). Consequently, when more than 80% of the power demand is met by VRE, seasonal storage is required (Bogdanov & Breyer, 2016, Solomon et al., 2019). In this research, the long-term and seasonal storage is satisfied by TES, A-CAES, and PtG. However, it is noteworthy that such solutions and measures will be context dependent, for the case of the West African power sector (**Publication IV)**, seasonal storage input is not essential in the BPS, as long as cross-border trade is considered. For instance, the PtG share in total electricity demand is only 1% (7 TWh) without cross-border electricity trade. This rare occurrence was also observed for the case Brazil, based on an overnight modelling approach for 2030 (Barbosa et al., 2016). According to Barbosa et al. (2016), a 100% RE power system can be run with very low seasonal storage based on PtG, this unique condition is attributable not just to the equatorial weather conditions but also to very high shares hydropower. Dispatchable RE hydropower and bioenergy can operate in conjunction with VRE to provide additional flexibility in a power system as observed in this study. The exceptional growth of wind energy, plus some PV and bioenergy in Uruguay can be ascribed to its high hydropower generation share, which can cover periods of wind generation deficit, plus balancing via regional electricity trade (Wynn, 2018; IRENA, 2019a). The results of the West African power sector show that the interaction of RE resources limits storage needs, enhance system flexibility, and reduce daily and inter-annual variability of the system.

Integration of VRE resources requires an increase in flexibility as observed in this study, particularly in the BPSs. Aside from the storage technologies, transmission networks provide additional flexibility by counterbalancing regional power mismatches. Storage plays a critical role in providing the flexibility through time-shifting of energy at the same location, while power grids shift energy anywhere in the power system at the same point in time, hence providing a different type of flexibility. For example, in the case of Nigeria (**Publication I**), with grid interconnection a large amount of electricity is exported from north to south, due to excellent solar condition and low-cost of PV in the north, since LCOE is about 17% lower than in the importing region due to about 21% higher FLH. For the case of West Africa (**Publication IV**), cooperation for electricity exchange within the region can reduce cost by about 10%, comparable cost reduction has been found for Europe (Child et al., 2019). With grid interconnections the BPS shows approximately 10–12% less installed capacities, 11–70% less storage capacity and 4–22% less storage output for the case of the West African power sector, thus enabling a more efficient and optimised power system.

Generation curtailment is anticipated to increase with higher shares of VRE (Jacobsen & Shröder, 2012; Haas et al., 2017; Solomon et al., 2019) as observed in this study. The question, whether to prevent curtailment or not, is increasingly argued (Jacobsen & Shröder, 2012), premised on the notion that curtailment or 'excess energy' would be a mere waste of energy (Carbajales-Dale et al., 2014). On the contrary, curtailment is another effective means of balancing and improving system flexibility (Haas et al., 2017). A certain level of curtailment in an optimally managed energy transition brings techno-economic benefits to the system (Solomon et al., 2019). This study consolidates scientific insights on the need for flexibility in systems dominated by VRE such as BPSs, as solar PV emerges as the prime technology for low-cost bulk energy supply, especially in Sun Belt countries (Solomon et al., 2019; Bogdanov et al., 2019a; Sterl et al., 2020). The fleet of RE generators will be accompanied by flexibility from diverse resources. Furthermore, instability in grids dominated by VRE can be remedied with flexible gas turbines or engines and other emerging technologies (Klein et al., 2018). Integration of synthetic inertia in power systems dominated by VRE is observed in this research to be an attractive option for SSA.

Benefits of the energy transition

The benefits of the transition are discussed in terms of cost competitiveness, job creation and GHG emission reduction. Technology and cost are crucial factors of the future social paths. In this context, cost is an important indicator for planning and decision-making regarding investments in energy infrastructure. This study explores a least-cost energy transition pathway for countries and regions in SSA. Cost will play a crucial role in determining the needed investment levels across the whole energy system. In this research, the average financial result is expressed as LCOE. LCOE remains a robust tool, for evaluating energy sector economics (Ram et al., 2018), despite some critiques of LCOE as a tool for comparing costs across power generation technologies (Hirth et al., 2015; Schmalensee, 2016). LCOE offers some cost advantages as cost metric, which include its ability to normalise costs into a consistent format across decades and technology types (Hirth et al., 2015; Matsuo et al., 2020).

The growing capacities of RE observed in this study, is due to their continuous cost decline and increased competitiveness of RE technologies on a LCOE basis. On an individual technology LCOE basis, the cost of producing electricity from RE technologies in particular solar PV and wind are increasingly competitive with fossil-based power plants (IRENA, 2019b). The global weighted average LCOE of utility-scale solar PV has fallen by more than 70% between 2010 and 2018 (IRENA, 2019b). For instance, the current LCOE for new solar PV and wind (0.041 €/kWh) are now cheaper than new baseload coal (0.069 €/kWh) in South Africa (Bischof-Niemz & Creamer, 2018). According to (Ram et al., 2018), fossil and nuclear power generation have higher LCOE. The LCOE value of CCGT ranged from 107 to 124 €/MWh, 142 to 162 €/MWh for OCGT, 115 to 186 €/MWh for coal and 62 to 152 €/MWh for nuclear in 2030.

The system wide LCOE is based on interdependencies between different generators. The modelling process is used to determine a cost-optimal mix of power generation technologies to guide future investment decisions. From a system perspective, the LCOE obtained in BPSs are lower in comparison to the CPSs as observed in this research. In **Publications I** and **II**, the BPSs system LCOE is about 50% lower than in CPSs, whereas the BPSs system LCOE is about 57% and 60% lower than in CPSs, as observed in **Publication III** and **Publication IV**, respectively. In **Publications I-IV**, solar PV evolves as the main source of electricity particularly in the BPSs, due to its low-cost electricity. Furthermore, PV-battery systems appear as the backbone of the low-cost option for countries and regions in SSA (**Publication I-VI**) as observed in this study. Similar to solar PV, battery Capex has decreased over the years, and more cost reduction is anticipated (Kittner et al., 2017; Schmidt et al., 2017). It is worth mentioning that the declining costs of PV and battery storage make PV markedly more competitive than wind energy.

In this study, the LCOE obtained for fully RE-based systems ranged from 35 €/MWh to 58 €/MWh by 2050. Other studies have also estimated the cost of 100% renewables in Africa, including articles by Jacobson et al. (2019), Breyer et al. (2018) and Bogdanov et al. (2019). According to Jacobson et al. (2019), the obtained LCOE for Africa is about 77 €/MWh and 47 €/MWh according to Ram et al. (2019). Recent studies have shown that 100% RE systems can either be lower in cost (Breyer et al., 2018; Bogdanov et al., 2019a) or slightly higher in cost than those that do not feature large shares of RE (Connolly & Mathiesen, 2014; Mathiesen et al., 2015). The estimated cost of achieving a fully renewable based system differs significantly, which indicates that integration cost depends largely on several regional specifications, such as load factors of solar PV and wind, the ratio of these technologies in the generation mix, and other meteorological and geographical conditions (Matsuo et al., 2020).

Furthermore, no new fossil fuel and nuclear power plants would be built in the low-cost option for countries and regions in Africa. This confirms the massive and growing cost of a fossil-based system as observed in the CPSs. Aside the incremental cost such system violates the sustainability criteria that forms a framework of a resilient energy system. For instance, with GHG emission costs, the West African BPS shows approximately 55% lower cumulative system cost (378 b€ vs 842 b€) than the CPS, and it is 44% lower (369 b€ vs 627 b€) without GHG emission costs, as observed in **Publication IV**. Similarly, with GHG emission costs the BPS show approximately 27% lower cumulative system cost (788 b€ vs 1078 b€) than the CPS and it is 4% lower (639 b€ vs 663 b€) without GHG costs, for the case of South Africa as shown in **Publication II**. The results BPSs demonstrate that a renewable-led system is not only technically possible, but also economically viable. This finding aligns with the characteristics of fully renewable systems globally, as highlighted by Brown et al. (2018). Most of the cost reduction in the BPSs can be ascribed to the low cost of PV-battery hybrid systems. The cost of investing in RE technologies in the BPSs are offset by savings in fuel cost from displaced fossil-based generation. It is noteworthy that the BPSs without GHG emission costs led to 96% and 98% renewable generation shares for the case of South Africa (**Publication II)** and West Africa (**Publication IV)**, respectively. This demonstrates pure market economics, even though the huge cost for GHG emissions would be allotted fully as subsidies for the fossil system by ignoring any price for the massive climate change costs. The results of CPSs reveals the economic risk inherent in investing in fossil fuel technologies, divestment from conventional power plants is already happening (Baron & Fischer, 2015; Carbon Tracker Initiative, 2020). Furthermore, these electricity generation technologies are liable to cost escalation and schedule spill (Sovacool et al., 2014). The profitability of fossil-based technologies will be undercut by the increasing competitiveness of RE technologies (IEEFA, 2016).

The findings of **Publications II and IV** consolidate scientific insights that propose a positive link between renewable energy generation and job creation (Connolly & Mathiesen, 2014; Ram et al., 2020). Beyond the cost competitiveness of the RE transition, it will also create additional jobs than the existing system as observed in this study. The transition from fossil to renewable is naturally beneficial for the job market. Transitioning to a RE-based system will not only provide the lowest cost, but will also create new jobs, substitute current jobs and eliminate or transform certain jobs (Bischof-Niemz & Creamer, 2018). Recent studies have shown that it is now an undeniable reality that transition to a RE-based system will create more jobs (Bischof-Niemz & Creamer, 2018; Ram et al., 2019; 2020), which is comparable to the findings of **Publications II and IV** as observed in the BPSs in comparison to the CPSs. For instance, jobs created in West Africa (**Publication IV**) in the BPS is over two times more than in the CPSs (440 thousand vs 183 thousand) by 2050. For the case of South Africa (**Publication II**), jobs created in the BPS is about 51% more than in the CPS (278 thousand vs 184 thousand) by 2050.

Beyond the detailed techno-economic analysis, the LUT model also computes the emission trend through the transition. The GHG emissions pattern illustrates the trend of RE deployment under pathway options. The BPSs show that transitioning to a fully RE system is the least-GHG emitting option, reaching zero emissions by 2050. On the contrary, the CPSs did not lead to zero emissions by 2050. To achieve zero GHG emissions, the energy system must undergo a profound transition from a status largely based on fossil fuels as observed in the CPSs, to one that is based on RE as illustrated in the BPSs. Progressive decarbonisation is widely apparent as the current energy system violates economic, social and environmental sustainability criteria (Grubler, 2012). The CPSs also depict that governmental plans towards emission reduction need to be revised in order to meet the targets of the Paris Agreement.

Off-grid electrification

Access to modern energy services is vital to reduce poverty and support economic growth of SSA. Globally, more than two-thirds of people without access to modern energy services live in SSA. Over the past decade, major progress in SSA electrification access has been achieved through grid connection, while the balance has been shifting (IEA, 2019b). Access to electricity by means of decentralised options has increased considerably, being the least-cost solution for the majority of rural dwellers (IEA, 2014; 2017a; 2019b). Provision of access through SHSs in SSA increased from 2 million in 2016 to nearly 5 million in 2018, while about 25 million gained access via mini-grids (IEA, 2019b). The development of SHSs and mini-grids markets in Africa has been positively influenced by the digitalisation of communication and financial services (IEA, 2017b). The pay-as-you-go (PAYG) mobile financing and payment mechanism are widely used to provide an affordable and easy payment plan for renewable off-grid systems acquisition (IEA, 2017b). The PAYG model will continue to advance the deployment of small-scale solar assets towards sustainable off-grid electrification across Africa.

A special research was conducted in **Publication VII** to visualise electrification options for SSA. Two scenarios were modelled using geospatial methods. One scenario based on the existing grid led to electrification options composed of 40% SHSs, 5% mini-grids and 55% grid extensions. Another scenario, in which modelling was based on the planned grid, 35%, 4% and 61% can be electrified by SHSs, mini-grids, and grid extensions, respectively, hence more by grid extensions. A sensitivity analysis was carried out in **Publication VII** by varying important parameters such as grid buffer and population threshold. The results of the sensitivity analysis show that varying the grid radius has a significant impact on the share of SHSs and mini-grids, whereas varying the population threshold increased the share of mini-grids. Another study by Mentis et al. (2017), indicates that 850 million people (77%), 180 million people (16%) and 70 million people (6%) can be electrified by grid extensions, mini-grids and standalone systems in 2030, respectively, based on Tier 5 electrification criteria. According to IEA (2019b), grid extension is the most suitable option when built to serve an area with a high population density and decentralised systems for isolated areas, which confirms the findings in **Publication VII**.

5.2 Policy implication for Africa

A transition towards sustainable energy systems in Africa as illustrated in the BPSs is technically feasible and economically viable, but it may not happen on its own. Political will at the national and regional level is needed to steer this kind of transition. Energy policy frameworks and markets will continue to evolve due to changes in energy system architecture. Energy related policies, programmes and plans in Africa might need to be revised or require a fundamental shift to drive a progressive energy transition. This thesis offers the following perspectives to provide insights and guidance for sustainable energy transition planning and policy making in Africa:

Timely action is required to steer the energy transition towards a sustainable pathway

The scenarios presented in **Publications I-VI** provide insights that could cater for decision making to decarbonise the SSA power system within a time horizon of 2015 to 2050. The results of the CPSs clearly show that the current national and regional energy policies and plans will require further adjustments; such policies offer a comparatively slow path, indicating the importance of temporal dynamics of the energy transition in limiting the global temperature rise well below 2^0C by 2050. The timing of the transition is a vital element of consideration (IRENA, 2019d). The window of opportunity for mitigating climate change is gradually closing, if timely actions to lessen GHG emissions is not taken, the budget for a 1.5^0C limit, would be exhausted in less than a decade (IRENA, 2019d). The CPSs GHG emission trajectory still falls far short of the emission reduction needs. To ensure that national and regional energy plans and projections in Africa remain relevant, credible, and follow international best practices, energy plans in the region should then be subjected to regular updates based on a system planning logic for least-cost. Energy planning in many African countries requires periodical updates to ensure that future investment decisions are made considering the current trends and developments in technology costs.

Techno-economic understanding is needed to steer a sustainable energy transition

Publications I-VI present the viability of the cost implication of various transition pathways for policy choices. It also provides policymakers and energy planners in Africa with rational techno-economic insights that could guide their future investment decisions on technologies to build, required capacities, and timeframe. The long-term perspective presented in this research informs policymakers and energy planners on systematic investment steps to avoid building assets that could be stranded in future. To this end, it is worth mentioning that no new fossil fuels and nuclear power plants will be built in the low-cost option as observed in this study. In early 2018, representatives from South Africa’s largest utility mentioned that nuclear would not be at the top of the agenda and South Africa simply could not afford nuclear (EWN, 2018), which confirms the findings of **Publication II**. The optimal pathway forward is a least-cost approach, which is an important fact for planners and decision makers in the continent. Aside from the high cost of investing in fossil-based technologies as illustrated in the CPSs, these assets are liable to cost escalation and schedule spill. However, decentralised, modular and scalable systems such as solar PV and wind would see a lower risk of time and cost escalation.

The costs of RE technologies have been substantially reduced due to technological learning, market diffusion and improved economies of scale. More importantly, it is noteworthy that the dramatic decline in the cost of solar PV and wind turbines is now an undeniable reality and will have a strong influence on the way power markets are planned and operated. These technologies will shape the future energy landscape as observed in **Publications I-VI**, particularly solar PV in Sun Belt countries and regions. From an economic perspective, it is therefore least-cost to progressively transition the SSA power system into one that is dominated by solar PV and wind energy. The future energy demand in SSA can be met at the least-cost, while remaining within the boundary conditions of system reliability and sustainability constraints as illustrated in the BPSs. The massive deployment of RE capacities in the BPSs is the least-cost option for SSA without subsidies. However, subsidisation might be unavoidable if a policy-induced deviation from this low-cost path is followed.

No technical barrier to the transition

Technical feasibility is not a concern anymore in energy systems dominated by RE, which is an important fact for policymakers and energy planners in Africa. Technical solutions are now available to ensure a stable operation of power systems dominated by VRE. These solutions are not too expensive to annul the economics of renewable. This study illustrates how a renewable-led generation mix can overcome the challenge of grid instability. An optimal resources mix guarantees a tendency towards greater flexibility and complementarity as observed in this study. Furthermore, storage technologies, transmission networks, dispatchable RE, flexible generators (gas turbines and engines), synthetic inertia and generation curtailment could provide additional flexibility as observed in **Publications I-VI**.

Storage technologies are an indispensable component of the transition, providing multiple flexibility services on short-term to long-term basis, helping to facilitate the penetration of VRE shares. Batteries are an appropriate short-term storage option; they dominate the storage output due to their daily charge and discharge profile, whereas gas storage is required for balancing seasonal variations during the transition. Besides storage technologies, grid networks provide a different kind of flexibility; they are very useful in matching supply and demand over a large geographical area and provides robust spatial interconnections. Grid interconnections facilitate the optimal use of RE and smoothen day-to-day variability. More importantly, policies to support and promote regional interconnections in Africa will expand the geographic footprint of power systems, unlock flexibility and yield significant economic benefits as observed in this research. Dispatchable RE such as hydropower reservoir and bioenergy play a critical role in providing daily and seasonal balancing. Flexible gas turbines are found to be a valuable balancing technology because their power output can be ramped up and down when required and they can operate at low output levels. The modelling approach undertaken in this research provides valuable insights on a variety of flexible options for policy dialogue and system planning in Africa.

The results of this study show that the future energy system will be designed around solar PV and wind. Consequently, policies and regulatory framework will have to be designed around them, too. Furthermore, electricity will emerge to the core of the future energy supply (Ram et al., 2019; Bischof-Niemz & Creamer, 2018). Electricity as the new primary energy carrier will lead to the reduction of primary energy demand and allow the coupling of previously separated end-use sectors. Policies to support an intelligent linkage of the power sector to other energy sectors are needed in all African countries; such policies are lacking in most, if not all, countries in the region. Residual demand in hard-to-electrify sectors, such as marine and aviation transportation, and heavy industry, can be supplied by PtX solutions.

A just transition is achievable through enabling policies

Enabling policies are vital to achieving a just transition. The components of a just transition discussed in this sub-section includes energy access, green jobs and GHG emissions reduction. Universal energy access is a key element of a fair and just transition (IRENA, 2018b). There are stark disparities at present in the energy service in urban and rural areas in Africa. About 79% have access to electricity in urban areas, while access remains low at 35% in rural areas in 2018 (IEA, 2019b; 2020). Full electrification is nearly achieved in North Africa, as over 99% in both urban and rural area are recorded, followed by the Republic South Africa with over 95% in urban area and 92% in rural area. For the rest of Africa, urban and rural electrification is 82% and 29% in West Africa, 78% and 31% in East Africa, 67% and 14% in other Southern Africa countries, while the lowest rate occurred in Central Africa at 45% in urban area and 6% in rural area, respectively (IEA, 2019b; 2020).

The results of this research highlight the significant role of solar PV in Africa's future energy system. Given the technological improvements in the energy space, the time and level of infrastructure required to increase rural electrification will significantly reduce. Emerging RE-based technologies, especially solar, will change the rural energy landscape in SSA and enable the development of clean energy in the region. Solar PV systems are a modular and durable source of electricity, ranging from watts to gigawatts; these features make PV system suitable for rural electrification (Jäger-Waldau, 2019; Sovacool et al., 2019). On the positive side, solar PV users in rural areas can also benefit more by storing electricity in batteries or for water heating purposes (Sovacool et al., 2019). The continuous decline in PV cost will further boost off-grid PV technologies relevant for rural electrification, especially in remote areas where grid connections are prohibitively expensive or national budgets are limited (Barasa et al., 2018). For unelectrified rural areas, solar PV systems appear as a better solution for providing modern energy supply (Jäger-Waldau, 2019; Sovacool et al., 2019). The results from **Publication VII** present various electrification options for SSA that could guide policy decisions and electrification plans, particularly for remote areas. Furthermore, clear targets, well-designed electrification schemes, predictable policy and regulatory frameworks, are vital to maximise the findings presented in **Publication VII**.

Access to clean cooking and heating remains a challenge in Africa. About 70% of the population depends on polluting fuels and technologies, especially biomass, which results in health and environmental problems (IEA, 2019b; 2020). Tackling climate change means shifting away from unsustainable bioenergy for cooking and fossil fuels for lighting, to zero emission innovations. Policies, programmes and plans to tackle energy injustice and promote economic development in Africa should be based on sound principles of respect, sustainability, affordability and equity. Policies to drive social equity in Africa is very important due to existing disparities in energy services between urban and rural dwellers. Such a policy should ensure social inclusiveness and capture the principles of energy justice (Sovacool et al., 2017), particularly for remote households due to their vulnerability to energy poverty.

Jobs creation is instrumental in achieving a just transition as shown in **Publications II and VI**. Employment provides an important linkage between economic growth and poverty alleviation by allowing the poor to generate income. Job creation is one of the socio-economic footprints to measure the performance of the energy transition. Jobs will be created across the value chain, including manufacturing, construction and installation, operation and maintenance, decommissioning and fuel supply. Sceptics of renewable energy often question if the sector can ever generate the same numbers of jobs as in the fossil-based system (Bischof-Niemz & Creamer, 2018). The outcomes of this study show that a switch to RE-based system has the potential to create far more jobs in the energy sector as observed in the BPSs than in the CPSs. It is noteworthy that just transition elements are needed to address those who are vulnerable to losing their jobs due to the energy transition, thus, it is important to develop active labour market policies to help such individuals or groups (IRENA, 2020).

The climate dimension of justice is discussed in terms of GHG emissions reduction. The findings of the BPSs illustrate how countries and regions in Africa can achieve zero GHG emissions by 2050; such transition pathway aligns with the implementation of the SDGs. The scenarios presented in **Publications I-VI** describe how long-term GHG emission reduction plans can be achieved, which is an important fact for policymakers in Africa. It is worth mentioning that with the application of GHG emissions costs in the CPSs, zero GHG emissions was not reached by 2050; without emission costs the GHG emissions level keep rising through the transition. The GHG emission trajectory observed in the CPS shows the need for an ambitious commitment to GHG emissions reduction in Africa, particularly in hard-to-abate segments of the energy system. The African power sector has received most of the RE focus policy attention, while little or no policy framing exists for other sectors to enable comparable progress (REN21, 2019).

5.3 Limitation of the current research and future research prospects

The main limitations and further points of research can be summarised as below:

1. From a modelling perspective, the energy transition analysis presented in **Publications I-VI** excludes other sectors such as heat, transport and industry. These additional sectors would influence the distribution of installations. Future research on the African energy transition is required, with models that can integrate off-grid electrification in energy system analyses. All sectors need to be included in future analyses for Africa. A better geographical resolution could be applied, i.e., energy system analysis covering entire Africa, integrating the countries based on power pool distribution. Flexibility analysis of energy systems with high shares of RE needs to be covered for a full continental analysis. Furthermore, PtX trade within Africa needs to be investigated, which is very important for defossilisation of the overall energy system. Such analyses will identify most economic profitable sites for synthetic fuel production in Africa.

2. The analysis in **Publication I-VI** suffered from a limited understanding of the hydropower potential, and similar to the sustainable bioenergy potential, except in **Publication III**. It is worth mentioning that the bioenergy potential estimated in **Publication III** was applied to the power sector, which may not be the case in a full sector coupling scenario. Future research on Africa’s energy transition will require a

good understanding of hydropower and sustainable bioenergy potential for better analysis.

3. Furthermore, poor data accessibility is typically a challenge for many countries in Africa, especially in SSA. A uniform assumption of 7% WACC is applied in **Publications I-VI**, which is consistent with top international reports such as IRENA and journal publications. It is noteworthy that there are no proper cost of capital (CoC) estimation methods available for the future; consequently, uniform CoC is so far the best choice available. Currently, most countries in SSA do not satisfy the WACC assumption. Nevertheless, economic progress in SSA will give rise to a more steady and lower WACC through the transition (Bogdanov et al., 2019c; Egli et al., 2019).

4. The findings of this research as demonstrated in **Publications I-VI** show the importance of PV technologies and batteries as very crucial throughout the transition, owing to the projected decrease in CAPEX. Nevertheless, it must be acknowledged that changing cost parameters would have an effect on technology roll-out, as it seems that the cost and rate of capacity installation are really correlated. Furthermore, a combination of both market development and scientific literature based technical and cost parameters, have informed the research in determining the most cost-optimal energy systems for the future. However, cost assumption may be too conservative or too optimistic over time. For instance, the latest insight in Vartiainen et al. (2020), shows that the assumed PV and battery CAPEX are somewhat conservative.

6 Conclusions

The transition of African countries' and regions' power systems was analysed based on sound techno-economic principles and relies firmly on a power system engineering logic for designing a cost-competitive power system. Africa has huge energy and land resources to technically host a mix of RE generation; however, a visionary energy policy will be required to make it happen. The techno-economic prospects for transitioning the African power system as investigated in this research, provides a platform for meaningful policy discussions. This study shows that African countries and regions can explore cheap and abundant electricity supply, and critically, without violating the principles of sustainability. The techno-economic analysis presented in this research is a low-cost solution and is unsullied by politics or policy. The optimal pathway forward for Africa is a least-cost option, and should be the fundamental logic for future system planning, by introducing low-cost electricity from RE into the system, while providing flexibility in an economic manner. A fully RE system is a most efficient, low-cost, low GHG emitting, less water consuming and the most job-rich option for Africa, and is compatible with the Paris Agreement and the Sustainable Development Goals of the United Nations.

The findings of this research consolidate scientific insights on the need for flexibility measures in systems dominated by VRE. However, there is no technical barrier to pursuing the development of high shares of RE in Africa's power or energy system. The flexibility options presented in this research are not too expensive to annul the economics of RE development even in Africa, if techno-economic principles are strictly pursued. Technical feasibility is no more a concern, but political will is crucial to delivering a fully RE system. Furthermore, Africa can defossilise its energy system by coupling its decarbonised low-cost electricity to other energy-consuming sectors. Cheap and abundant RE electricity could create new industrial opportunities in producing synthetic fuels, which are equally needed for hard-to-abate sectors that cannot be directly decarbonised by RE electricity.

Transitioning to a sustainable energy system is a real policy option for Africa, where solar PV emerges as the new bulk energy supplier, complemented by wind, bioenergy and hydropower. Energy policy in Africa should keep solar PV development at its core. In fact, solarisation of Africa should be the central objective, particularly for regions where grid extension is prohibitively expensive or national budgets for electrification is limited. Progressive energy-related policies and political will at all levels of governance in Africa is crucial in promoting the deployment and integration of RE in the continent. Policies to strengthen regional interconnection in Africa will enlarge the geographic footprint of RE-based power systems, unlock flexibility and yield significant economic benefits.

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Pathways to a fully sustainable electricity supply for Nigeria in the mid-term future

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ABSTRACT

Ambitious actions focused on rapid defossilisation of today's energy systems require greater urgency, in order to avert unmanageable impacts of climate change. Transitioning to a cost-effective and carbon-neutral energy system in Nigeria and across the globe by the second half of this century is vital. This study explores a paradigmatic pathway to a fully sustainable energy system for Nigeria, by 2050. The research approach is to simulate a cost-optimised transition pathway towards 100% renewable energy based power system for Nigeria, using a linear optimisation model. The model is based on hourly resolution for an entire year. The country researched is structured into 6 sub-regions. The optimisation for each of the 5-year time periods is carried out based on assumed costs and technological status until 2050 for all energy technologies involved. The levelised cost of electricity declines from 54 €/MWh in 2015 to 46 €/MWh in 2050 for the power sector in the Best Policy Scenario and further declines to 35 €/MWh with sector coupling. Whereas, the cost of electricity increased to 75 €/MWh in the Current Policy Scenario without greenhouse gas emission cost. The results clearly reveal that integrating a renewable energy technology mix with a wide variety of storage technologies is the most competitive and least cost electricity option for Nigeria in the mid-term future, as indicated by the Best Policy Scenario. In particular, the compatibility and predominant role of solar photovoltaics and batteries is paramount towards a rapid transition of Nigeria's power sector, due to highly favourable economics. This study concludes with the implications of a stable and supportive policy environment, transitioning to a defossiliated energy system in Nigeria could be achieved in the mid-term future. This study is the first of its kind in full hourly resolution for Nigeria, and demonstrates the need for carrying out detailed analyses in examining gaps in energy transition understanding based on various policy constraints for developing countries in comparable climates.

1. Introduction

Transitioning away from the contemporary to a net zero emission energy system around the middle of the 21st century is of paramount importance [1], in order to keep global temperature rise well below 2 °C above pre-industrial levels and pursuing efforts to limit this to 1.5 °C [2]. Staying under 2 °C requires an urgent shift towards defossiliated energy systems [3]. Renewable energy (RE) sources are vital to avoid the unmanageable impacts of climate change [4]. In addition, RE sources could address the current electricity supply gaps and future demands in many countries in Sub-Saharan Africa (SSA), as well as in Nigeria [5]. Electricity demand in West Africa grew from 29 TWh in 2000 to 61 TWh in 2012; the highest demand in the region is in Nigeria, which accounts for about 50% of the total demand [6]. By 2040, total electricity demand in Nigeria is expected to reach 291 TWh according to the International Energy Agency (IEA) [6].

Nigeria faces an enormous challenge with access to electricity [7]. In spite of the country's abundant oil and gas resources, it still suffers from huge under-capacity in electricity generation, with frequent power outages driving consumers towards wide-spread use of costly backup generators [6]. The Nigerian power sector is not yet able to meet the entire power needs of the country [8]. As Akuru et al. [7] question, whether there could ever be stable and cost-effective electricity in Nigeria. Nigeria's on-grid electricity consumption is low, at 126 kWh per capita compared to other developing countries [9]. The per capita electricity consumption of Ghana and South Africa are 2.9 times (361 kWh) and 31 times (3926 kWh) higher than that of Nigeria, respectively [9]. More than 90 million people in Nigeria still lack access to grid electricity, which represents 55% of the country's population [6]. Unmet power demand results in load shedding, blackouts, and reliance on expensive diesel backup generators [10]. In 2012, an estimated amount of 16 TWh electricity demand was served by backup

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Nomenclature

A-CAES	adiabatic compressed air storage
BPS	best policy scenario
CAPEX	capital expenditure
CCGT	combined cycle gas turbine
CHP	combined heat and power
CPS	current policy scenario
CSP	concentrating solar thermal power
DISCOs	Electricity Distribution Companies in Nigeria
ECN	Electricity Corporation of Nigeria
ESPR	electric power sector reform
FMWR	Federal Ministry of Water Resources
GENCOs	power generation companies in Nigeria
GT	gas turbine
HVDC	high voltage direct current
LCOC	levelised cost of curtailment
LCOE	levelised cost of electricity
LCOS	levelised cost of storage
LCOT	levelised cost of transmission
NDA	Niger Dams Authority
NEEAP	National Energy Efficiency Action Plan
NEPA	National Electric Power Authority
NESI	Nigerian Electricity Supply Industry
NREEP	National Renewable Energy and Efficiency Policy
OCGT	open cycle gas turbine
OPEX	operational expenditure
PHCN	Power Holding Company of Nigeria
PHS	pumped hydro storage
PV	photovoltaic
RE	renewable energy
RoR	run-of-river
SHS	solar home system
SNG	synthetic natural gas
SSA	Sub-Saharan Africa
ST	steam turbine
SWA	State Water Agency
TRANSCO	Transmission Company of Nigeria
TES	thermal energy storage
UN	United Nations
VRE	variable renewable energy
WACC	weighted average cost of capital

generators in SSA, and Nigeria accounts for about three-quarters of the electricity supplied by backup generators in the region [11]. The cost of electricity from generators (0.14–0.22 €/kWh) are more than twice as expensive as grid-based power (0.06–0.09 €/kWh) in Nigeria [9].

Furthermore, the country's economic growth is hampered by the prevalent energy crisis [11]. The Nigerian government aims at a holistic economy transformation and have identified various barriers to the country's economic development, which includes the erratic power supply, poor and crumbling infrastructure and over-reliance on the oil sector [11]. To address the erratic power supply, the Nigerian electricity vision 30:30:30 recognises the significance of RE sources to complement the current fossil fuel consumption and guarantee energy security. By 2030, on-grid capacity is expected to reach 30 GW, of which RE will contribute a 30% share of the total electricity mix [12]. There are plans underway to build nuclear and coal power plants in Nigeria [12]. Beyond environmental and public health risk of building fossil-fuelled power plants [13], most nuclear power plants incurred construction period overruns [14] and substantial cost escalation [15]. According to [16], 180 nuclear reactors representing 178 GW and 459 bUSD worth of investment, incurred almost 231 bUSD in cost overruns. In addition, the cost of providing electricity from RE technologies in particular solar photovoltaic (PV) and wind are increasingly competitive with fossil-based power plants. The global weighted average levelised cost of electricity (LCOE) of utility-scale solar PV fell by 68% between 2010 and 2017 [17]. For instance, the current tariffs for new solar PV and wind (0.041 €/kWh) are now 40% cheaper than new baseload coal (0.069 €/kWh) in South Africa [18]. A recent study on cost comparison of various power technologies for Nigeria reveals that RE technologies are one of the strongest options to meet the power need of Nigeria in the most cost competitive way [19].

Recent studies have demonstrated the possibility of achieving a 100% renewables based power systems for cases such as Nigeria [5], SSA [10], Northeast Asia [20], Europe [21] and global [22]. These studies have shown that deep decarbonisation of the future power system is possible taking into account technical, economic and societal constraints, but it is also the least cost electricity option with utmost societal welfare. In addition, the Paris Agreement and the Sustainable Development Goal 7 (SDG 7) can be well supported by the deployment of small and large scale RE technologies, in view of tackling the two main challenges faced globally; climate change and widespread energy poverty [3]. The current electricity deficit and rising demand in Nigeria necessitates rapid response in bridging the gap between demand and supply [12], due to its growing population and unprecedented economic progress [10]. Therefore, tackling the plague of recurrent power outages and rising electricity demand in a way that is economically sustainable and safeguards livelihoods in Nigeria [7], which requires the deployment of RE infrastructure as a key solution with benefits that are multifaceted [10]. Nigeria has vast untapped RE resources [8], integrating RE technology mix with a wide variety of storage technologies could be competitive and the least cost electricity option for Nigeria [19].

This research presents the importance of carrying out an analytical and comprehensive investigation, when assessing least cost electrification options and transition pathways for developing countries, like Nigeria, under various policy constraints. The analysis for Nigeria is exemplary for developing countries of comparable climates. To better understand the transition pathways, eight scenarios have been defined based on governmental intended transition plans (Current Policy Scenarios) and zero emission scenarios (Best Policy Scenarios), which full match the targets of the Paris Agreement. Further, the impact of various factors such as greenhouse gas (GHG) emissions cost and sector coupling are assessed as well. The chosen optimisation modelling approach synthesises and reflects in-depth insights on how demand of different energy sectors such as power, non-energetic industrial gas and desalination can be met. The optimisation for each period, modelled in 5-year intervals, is carried out based on assumed costs and technological status until 2050. The paper is structured as follows: Section 2 presents an overview of the Nigerian power sector. The research methodology is described in Section 3. Results are presented and analysed in Section 4. In Section 5, the results are discussed and compared with related studies. Conclusion and policy implications are presented in Section 6.

2. The Nigerian power sector

The history of electricity generation in Nigeria dates back to 1886, when two generating plants were installed to serve the Lagos Colony. In 1929, Nigeria's first utility company, the Nigerian Electricity Supply Company was established [23]. Further development in the sector, led to the establishment of the Electricity Corporation of Nigeria (ECN) in 1951 to oversee electricity distribution in the country [23]. In 1962, the Niger Dams Authority (NDA) was established to oversee hydropower development [24]. The NDA oversaw power generation, while distribution and sales were undertaken by ECN. However, the ECN and

NDA were merged in 1972 and resulted in the formation of the National Electric Power Authority (NEPA), which was responsible for generation, transmission, and distribution of electricity for the entire country. Reforms in the power sector in 2005 resulted in unbundling of the NEPA and a renaming to Power Holding Company of Nigeria (PHCN) [25].

In spite of the long existence of electricity in the country and reforms, the power sector development has been at a slow rate. Today, gas and hydropower plants dominate the on-grid power generation capacity in Nigeria, which represent 86% and 14% of the total installed capacity, respectively [19]. The country's power sector consists of three main sub-sectors [8], namely; generation companies (GENCOs), transmission company (TRANSCO) and distribution companies (DISCOs) as shown in Fig. 1 [26]. Currently, there are 22 gas and 3 hydro on-grid generating plants operating in the Nigerian electricity supply industry (NESI) as shown in Fig. 2, concentrated in Southern Nigeria, with a total installed capacity of 12,522 MW, and available capacity of 7141 MW [9]. The management of Transmission Company of Nigeria is contracted to Manitoba Hydro International (Canada). The national grid consists of about 5524 km of 330 kV and 6802 km of 132 kV transmission lines [12]. The electricity distribution company of Nigeria consists of 11 companies across the country, as shown in Fig. 1 [8]. The distribution grid is operated mainly on 33 kV (medium voltage) and 11 kV (low voltage), comprising a network of over 24,000 km [23].

The available capacity could be used for electricity generation, but is constrained by internal plant issues, majorly maintenance and repair issues. In addition, Nigeria's power grid faces daily challenges [27], due to water shortage, high frequency due to demand imbalances, insufficient gas supply, and line constraints due to inadequate grid infrastructure as shown in Fig. 3 [9]. These constraints have led to a mismatch in demand and supply, and over-reliance on backup generators, among other issues. In addition, the power industry loses an average of 6 m€ (1.4 billion Naira) in revenue daily, due to these constraints. Fig. 4 shows the revenue lost to various constraints in the Nigerian power industry.

For many years, the power sector was owned, managed and controlled by the government. The state-owned monopoly utility NEPA, throughout its existence, failed to meet the country's electricity need [25]. Upon the advent of the democratic government in 1999, the Federal Government of Nigeria has committed huge financial investments of about 14 b€ to refurbish the power sector, but without proportionate outcomes [25]. One of the key measures taken by the government to revamp the power sector was privatisation of power assets [8]. To this end, various policy measures were established in view of the privatisation [23]. In 2005, the Electric Power Sector Reform (ESPR) Act was enacted to allow private investors involvement in the previous governments' monopolised sector. Fig. 5 shows the structure of the post-reform power sector [29]. Besides hydropower, Nigeria does not yet have any large RE-based generating plants, contributing to its on-grid electricity, in spite of the country having huge RE potential and energy market prospects.

Fig. 6 shows the solar and wind resources maps for Nigeria. The data are provided by NASA [30,31], reprocessed by the German Aerospace Center [32] and converted to full load hours according to Bogdanov and Breyer [20] and Afanasyeva et al. [33]. However, a fundamental action towards RE development in Nigeria lies in a strategic and supportive policy direction by the Nigerian government towards a progressive RE master plan [7]. Such policy, legal and institutional framework are at their nascent stage in Nigeria [8] and are foreseen to foster RE development [12]. In 2015, the Federal Government of Nigeria approved the National Renewable Energy and Efficiency Policy (NREEEP), which is the country's first ever RE-specific policy, which provides the descriptive framework for energy efficiency and RE development in Nigeria. The country targets to increase its total on-grid capacity from 4 GW in 2015 to 30 GW by 2030 [12]. This target was determined through the process of developing the National Renewable Energy Action Plan (NREAP) and National Energy Efficiency Action Plan (NEEAP), as stated in the NREEEP 2015. The share of on-grid RE supply is expected to increase from its present 1.3% in 2015 to 16% by 2030 in the NREEEP 2015. However, upon the completion and endorsement of NREAP 2016, the target was revised to a 30% share of RE supply by 2030.

3. Research methods

The research approach applies linear optimisation modelling in determining the optimal investment and electricity generation technology mix, needed to satisfy electricity demand in Nigeria by 2050 [22]. A linear optimisation energy system tool, the LUT Energy System Transition model [20], is used to simulate the Nigerian power system. The model was designed and developed to analyse an energy transition from the current (as of the beginning of 2015) fossil based-system to a 100% RE-based power system by 2050, covering the demand of power, non-energetic industrial gas and desalination sectors. The transition is modelled in 5-year steps from 2015 to 2050, and is carried out based on assumed costs and technological status for all energy technologies involved. The electricity generating plants required for the energy transition from 2015 to 2050 is considered according to Caldera et al. [34] and based on Farfan and Breyer [35]. Two essential constraints are

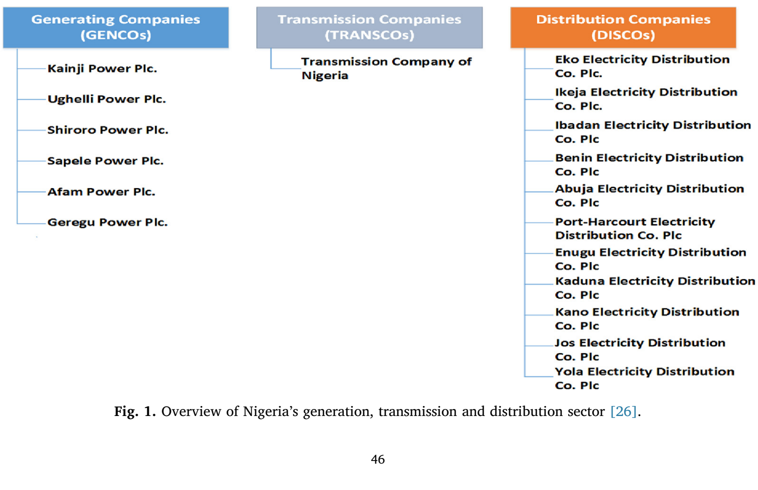

Fig. 1. Overview of Nigeria's generation, transmission and distribution sector [26].

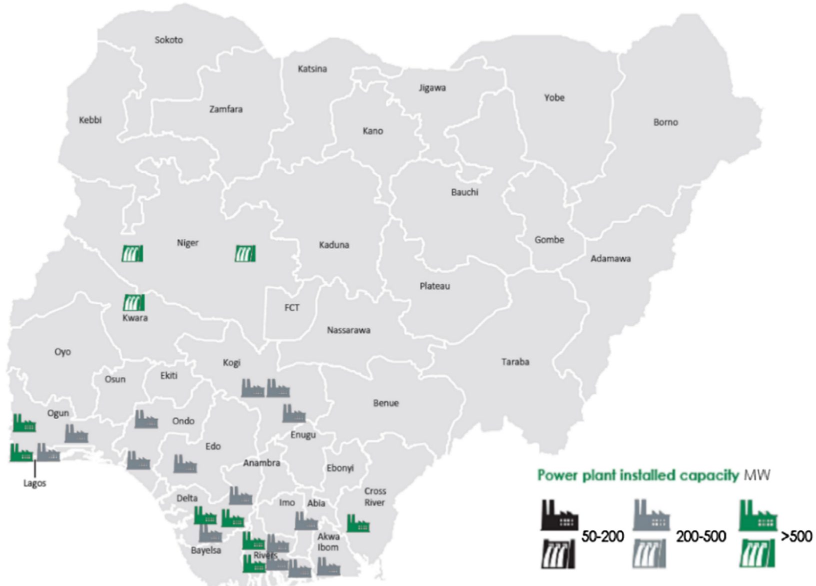

Fig. 2. Nigeria's 25 on-grid power plants locations [9].

taken into consideration as the basis for the energy system transition modelling. Firstly, after 2015, no new fossil-based power plants are installed. The existing fossil-based power plants are gradually phased out based on their technical lifetimes. However, the installation of gas turbines is permitted after 2015 due to lower carbon emission, high efficiency of the technology, and in particularly due to the possibility to accommodate bio-methane and synthetic natural gas in the system, so that a fuel shift towards sustainable fuels can be realised. Secondly, RE capacity growth cannot exceed 4% per year, in order to prevent system disruptions.

3.1. Model structure

The LUT Energy System Transition model is developed for comprehensive analyses of energy transition from current energy systems to 100% RE-based systems. The model is based on linear optimisation with an hourly resolution of the energy system parameters for an entire year, under a set of applied constraints, assumptions for the future RE powered system and demand. Detailed model description, equations and applied constraints can be found in [20]. The model is compiled using MATLAB [36], while the optimisation is carried out in MOSEK [37]. Fig. 7 shows the flow diagram of the main input parameters and outputs

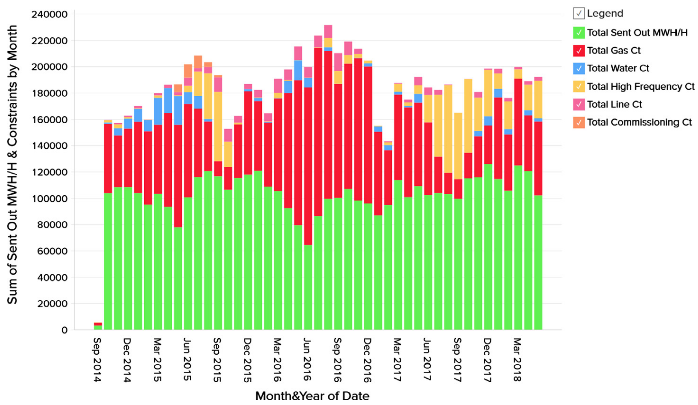

Fig. 3. Electricity generation and constraints (Ct) in Nigeria [28].

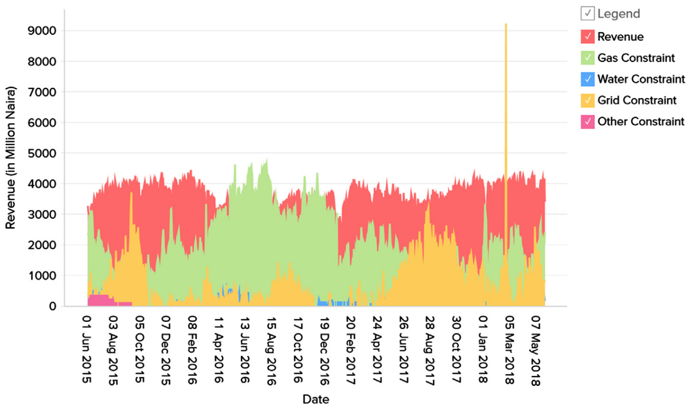

Fig. 4. Revenue lost to constraints in the Nigeria power sector [28] (1 billion Naira is equivalent to 2 m€).

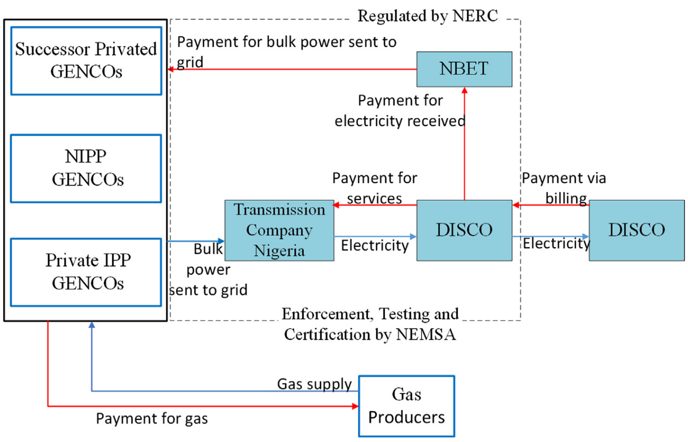

Fig. 5. Post-reform power sector structure [29].

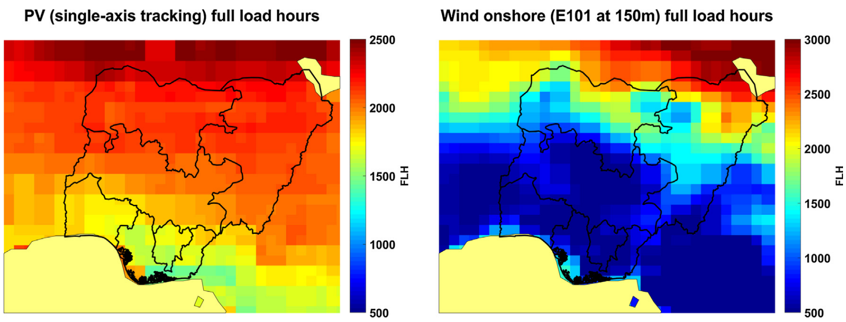

Fig. 6. Maps of Nigeria showing annual full load hours for solar PV single–axis tracking (left) and onshore wind (right) for the year 2005.

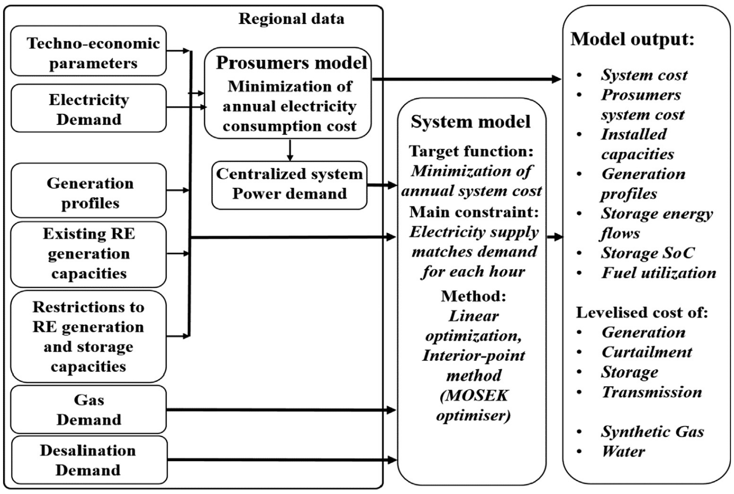

Fig. 7. Main inputs and outputs of the LUT Energy System Transition model [22].

of the model. A full set of technical and financial assumptions used in this study are presented in the Supplementary Material (Table S1). The target function of the model optimisation is to minimise the total annual energy system cost, which is calculated as the sum of annual costs of the installed capacities of each technology, costs of energy generation, and costs of generation ramping. In addition, the energy system consists of distributed generation and self-consumption of residential, commercial and industrial consumers. The transition analysis considers the potential of the prosumer market segment as an essential aspect of system planning. Thus, another mini-transition hourly model describes the prosumers PV systems and battery development capacity. Prosumers can install rooftop PV and lithium-ion batteries, depending on the cost, or buy electricity from the grid. The target function of the prosumers is the minimisation of cost of electricity consumed. This cost is calculated as the sum of self-generation cost, annual cost, and cost of electricity consumed from the grid. Excess electricity generated by prosumers can be sold to the overall energy system for 0.02 €/kWh.

3.2. Applied technologies

The main technologies applied for the Nigerian energy system modelling can be divided into four main categories:

- Electricity generation technologies
- Electrical energy storage technologies
- Electricity transmission technologies
- Energy sector bridging technologies to provide more flexibility to the energy system

Fig. 8 shows the block diagram of the energy model and all applied

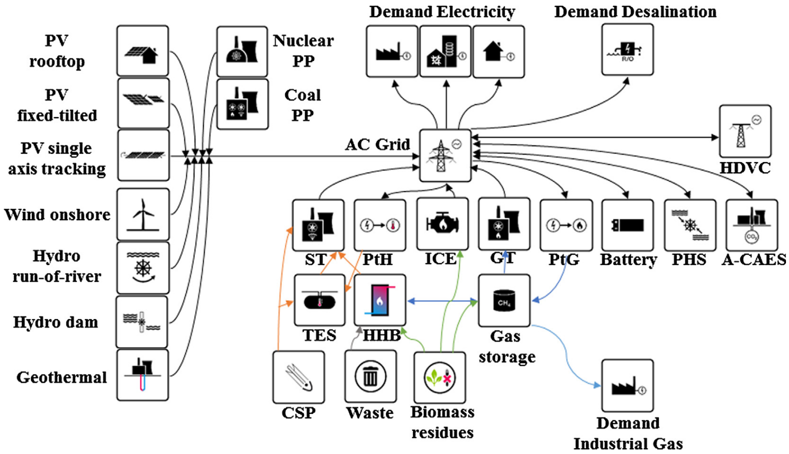

Fig. 8. Block diagram of the LUT Energy System Transition model used for Nigeria [22].

technologies for the transition. The RE generation technologies introduced in the model include various PV technologies (ground-mounted and rooftop solar PV systems), hydropower (run-of-river and reservoir based), biomass plants (solid biomass and biogas), wind onshore turbines, geothermal power plants, concentrating solar thermal power (CSP) and waste-to-energy power plants. While the fossil generation technologies are coal, oil, open cycle gas turbines (OCGT) and combined cycle gas turbines (CCGT), as well as nuclear power. Due to the variability of RE and to ensure a steady supply of electricity, the RE technologies are complemented by various storage technologies. These technologies include pumped hydro storage (PHS), Li-ion batteries assumed to serve residential and system storage, thermal energy storage (TES), adiabatic compressed air energy storage (A-CAES) [38] and power-to-gas (PtG) [39]. Energy sector bridging technologies such as gas from PtG process and seawater reverse osmosis (SWRO) desalination [34] provide more flexibility to the energy system. PtG includes synthetic natural gas (SNG): methanation, water electrolysis, gas storage, carbon dioxide (CO_2) direct air capture, and gas turbines (OCGT and CCGT). Due to the absence of hydrogen and CO_2 storage, PtG technologies operate in synchronisation. In addition, the model uses a 48-hour biogas buffer storage, and part of the biogas can be upgraded to biomethane and is introduced into the gas storage.

3.3. Country division

The multi-node approach used in the model enables description of any desired configuration. Based on this approach, Nigeria is divided into six sub-regions, according to political zoning of the country, namely, North-East (NIG-NE), North-West (NIG-NW), North-Central (NIG-NC), South-East (NIG-SE), South-South (NIG-SS) and South-West (NIG-SW). Each of the sub-regions represents a node. The nodes are interconnected via transmission lines, within the country borders, as shown in Fig. 9.

3.4. Financial and technical assumptions

The financial and technical assumptions for all the energy system components are made in 5-year time steps, which include capital expenditures (CAPEX), operational expenditures (OPEX) and lifetimes, from 2015 to 2050, and are provided in the Supplementary Material (Table S1). Weighted average cost of capital (WACC) is set to 7% in this study, but for residential PV prosumers, WACC is set at 4% due to lower financial return requirements. The technical assumptions concerning storage technologies, efficiency numbers for generation, and power losses in HDVC power lines and converters, can be found in the Supplementary Material (Tables S2–S4). The electricity prices for residential, commercial and industrial consumers for the year 2015 were retrieved from electricity DISCOs tariff document available online at the Nigerian Electricity Regulatory Commission (NERC) website [40]. The electricity price was calculated until 2050 according to Gerlach et al. [41] and Breyer and Gerlach [42]. The electricity price for all sub-regions are available in the Supplementary Material (Table S5).

The upper limits for all RE technologies were estimated according to Bogdanov and Breyer [20] and lower limits are obtained from Farfan and Breyer [35]. Upper and lower limits of RE and fossil fuels are provided in the Supplementary Material (Tables S6 and S7). For all other technologies, upper limits are not specified. However, for solid biomass residues, biogas and waste-to-energy plants it is assumed, due to energy efficiency reasons, that the available and specified amount of fuel is used during the year. Key power capacities required for the energy transition for Nigeria are provided in the Supplementary Material (Tables S8–S13). The current transmission line capacities connecting the sub-regions within the country were taken from [43]. The existing power grid, its development, and overall impact on electricity transmission and distribution losses were taken into account in the study.

3.5. Renewable resource potential

The feed-in profiles for PV optimally tilted, PV single-axis tracking, wind energy and CSP are calculated according to Bogdanov and Breyer

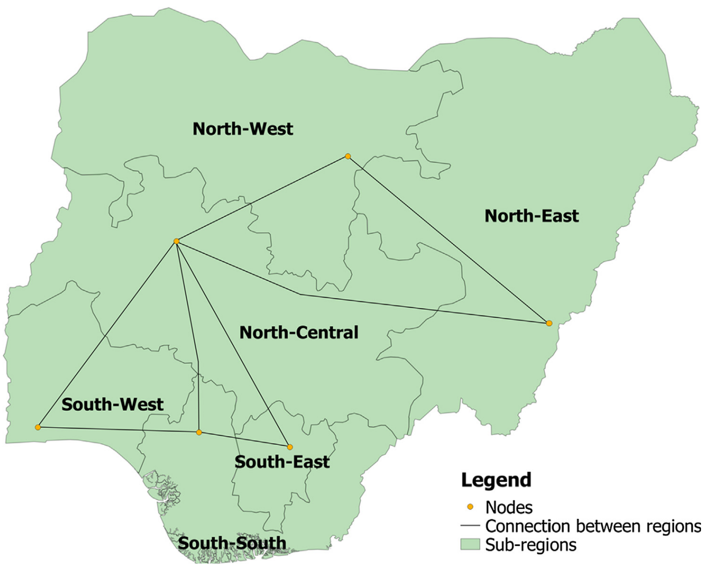

Fig. 9. Nigeria sub-regions and transmission lines configuration.

[20] and Afanasyeva et al. [33], based on resource data provided by NASA [30,31], reprocessed by the German Aerospace Center [32]. The feed-in values for hydropower are computed based on monthly resolved precipitation data for the year 2005 as a normalized sum of precipitation in the sub-regions. Such an estimate leads to a good approximation for the annual generation of hydro power plants [44]. Full load hourly data of various resources are presented in the Supplementary Material (Tables S14–S19). The resource profiles visualised in an hourly resolution can be found in the Supplementary Material (Figs. S1 and S2). In addition, the storage throughput is available in the Supplementary Material (Tables S20–S25).

The potentials for waste and biomass resources for Nigeria are taken from German Biomass Research Centre [45] and classified according to Bogdanov and Breyer [20]. The costs for biomass are calculated using data from the IEA [46] and Intergovernmental Panel on Climate Change (IPCC) [47]. For solid waste, a 50 €/ton gate fee was assumed for 2015, which increased up to 100 €/ton in 2050.

The geothermal potentials are calculated for the sub-regions based on the available information related to heat flow rate [48] and ambient temperature of the surface for the year 2005 [49]. For the sub-regions where the heat flow data were not available, extrapolation was performed to get the required data. The potential is estimated based on the available data [50], different temperature levels [51] and available heat at the mid-point of a 1 km thick deep layer and between the depths of 1–10 km globally with $0.45^{\circ} \times 0.45^{\circ}$ spatial resolution [52].

3.6. Demand

Electricity demand data are taken from [11], and are verified with data provided in [12]. The electricity demand until 2050 is provided in the Supplementary Material (Table S5). The hourly load profiles for electricity are calculated as a fraction of the total demand in each sub-region based on synthetic load data weighted by the sub-regions population [53]. For seawater desalination, SWRO is mainly used in this study due to its low-cost and energy efficiency advantages from 2020 onwards [54]. Nonetheless, multiple effect distillation (MED) dominates in the start of the transition and complements from 2020 onwards. The required desalination capacity, technical constraints and financial assumptions from 2015 to 2050 are calculated by using the methodology described in [54]. The non-energetic industrial gas demand data are taken from IEA statistics website [55] and extrapolated until the year 2050 based on IEA's assumption for non-energy gas demand growth rate for Nigeria [6].

3.7. Scenarios

In this study six scenarios have been developed, which are briefly described in Table 1. The scenarios explore pathways to a 100% RE system in the mid-term future, covering the demands of the power, non-energetic industrial gas and desalination sectors.

4. Results

This section presents the findings of the modelling outcomes for the Nigerian energy transition pathways in the mid-term future. Financial implication of the energy transition, installed capacities, electricity generation mix, transmission and storage are analysed in this section. Order of the figures in the entire paper are as follows: Figure (a) is assigned to BPS-1, Figure (b) to BPS-2, Figure (c) to BPS-3, Figure (d) to CPS-1, Figure (e) to CPS-2, and Figure (f) to CPS-3.

4.1. Levelised cost of electricity

The LCOE obtained for all the scenarios are shown in Fig. 10. The average financial results for the scenarios are expressed as LCOE, which includes all generation, storage, curtailment, transmission, fuel and GHG emission costs. The LCOE trend from now until 2050 varies for the different scenarios. Firstly, the system LCOE trend during the transition for the Best Policy Scenarios is observed as shown in Fig. 10(a)–(c). In the BPS-1 and BPS-2, the LCOE increased slightly around 2025, beyond 2025 the system LCOE further declines to 48 €/MWh and 46 €/MWh by 2050, respectively. However, the LCOE remains stable until 2030 and further declines to 34 €/MWh by 2050 in the BPS-3. The increase observed in the LCOE trend in the Best Policy Scenarios, particularly in BPS-1 and BPS-2, around 2025 are due to investment requirements. From 2030 onwards, the system LCOE steadily declines, signifying the impact of low-cost RE technologies, in particular solar PV and battery technologies in the Best Policy Scenarios. By 2050, the system LCOE is mainly dominated by cost of generation and storage, as solar PV contributes to the largest share of electricity generation and its complementarity by battery storage. Fig. 10(d)–(f) presents the corresponding LCOE for the Current Policy Scenarios. Fuel and GHG emission costs contribute to more than half of the total LCOE by 2050 in the Current Policy Scenarios, except in CPS-2 because GHG emission cost was not taken into account. This also led to LCOE deviation in 2015 for the CPS-2 in comparison to other scenarios. By 2050, the LCOE is 120 €/MWh, 75 €/MWh and 100 €/MWh in CPS-1, CPS-2 and CPS-3, respectively, as shown in Fig. 10(d)–(f). Additional financial results for all the scenarios are available in the Supplementary Material (Figs. S3–S5).

4.2. Installed capacity and electricity generation mix

As a result of under-capacity and increasing electricity demand in

Table 1
Overview of the studied scenarios.

Scenario name	Description
Best Policy Scenario (BPS-1) – Power only scenario	The target of the LUT model is to reach 100% RE by 2050. In addition, GHG emission cost is applied in the model to restrict fossil power plants. In this scenario, only electricity demand is covered
Best Policy Scenario (BPS-2) – Power only scenario (planned hydropower capacity considered)	This scenario is the same as the above scenario. In addition, the planned hydropower capacity is also considered. For instance, Zungeru hydropower project of 0.7 GW and Mambilla project of 3.0 GW are to be installed in 2020 and 2025 [56], respectively, during the transition and according to the respective planning [12]
Best Policy Scenario (BPS-3) – Integrated scenario	In this scenario, power, SWRO desalination and non-energetic industrial gas sectors demand is covered
Best Policy scenarios without GHG emission cost (BPSnoCC)	In these scenarios, GHG emission cost is not considered for the Best Policy Scenario 1 and 2. The financial implication, installed capacities and generation for Best Policy Scenario 1 no GHG emission cost (BPS-1noCC) and Best Policy Scenario 2 no GHG emission cost (BPS-2noCC) are only discussed in Section 4.9
Current Policy Scenario (CPS-1)	In this scenario, the country's target relating to electricity capacity mix up to 2030 is considered according to [12]. However, the post-2030 capacity mix is extrapolated up to 2050.
Current Policy Scenario (CPS-2) – no GHG emission cost	This scenario is the same as the previous described scenario, except that in this scenario GHG emission cost is not considered in the modelling
Current Policy Scenario (CPS-3)	After 2030, no new fossil power plants are allowed except nuclear power plants, because the country aims at reaching 4.8 GW installed capacity of nuclear by 2035

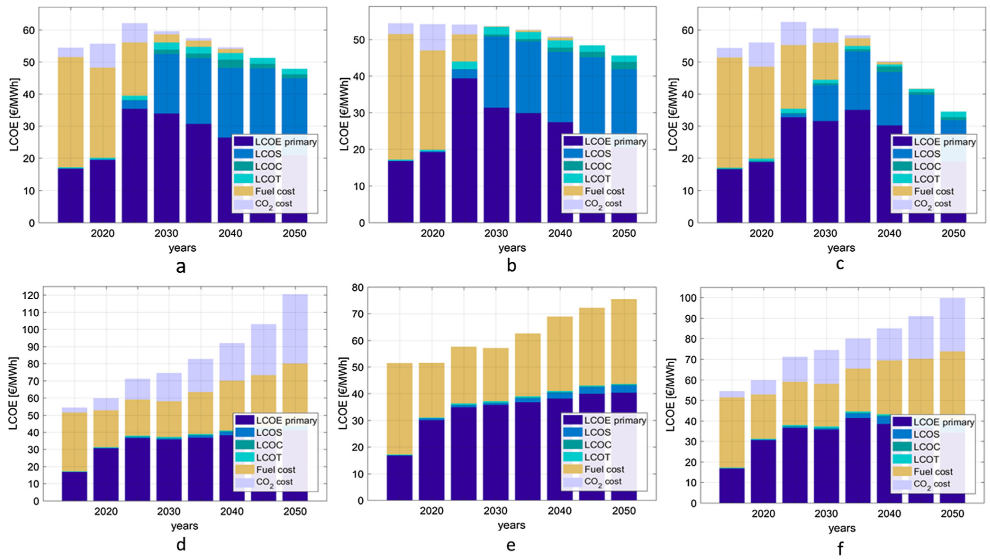

Fig. 10. Contribution of levelised cost of primary generation (LCOE primary), storage (LCOS), curtailment (LCOC), transmission (LCOT), fuel cost and GHG emission cost for BPS-1 (a), BPS-2 (b), BPS-3 (c), CPS-1 (d), CPS-2 (e), and CPS-3 (f).

Nigeria, investments in electricity generation capacity are needed. The total installed capacities for all technologies and the respective electricity generation mix are shown in Figs. 11 and 12, respectively. The installed capacities in the Best Policy Scenarios are visualised first as shown in Fig. 11(a)–(c). Fig. 11(a)–(c) shows how the fossil gas and hydropower dominated power system in 2015 gradually becomes less attractive. Solar PV contributes significantly to the power system from 2025 onwards in all the Best Policy Scenarios, in particular single-axis tracking PV. By 2050, the total solar PV capacity is 181 GW of which single-axis tracking PV contributes 125 GW in BPS-1. Whereas in BPS-2 and BPS-3, single-axis PV contributes 118 GW of 174 GW of total PV capacity and 272 GW of 328 GW of total PV capacity, respectively. PV

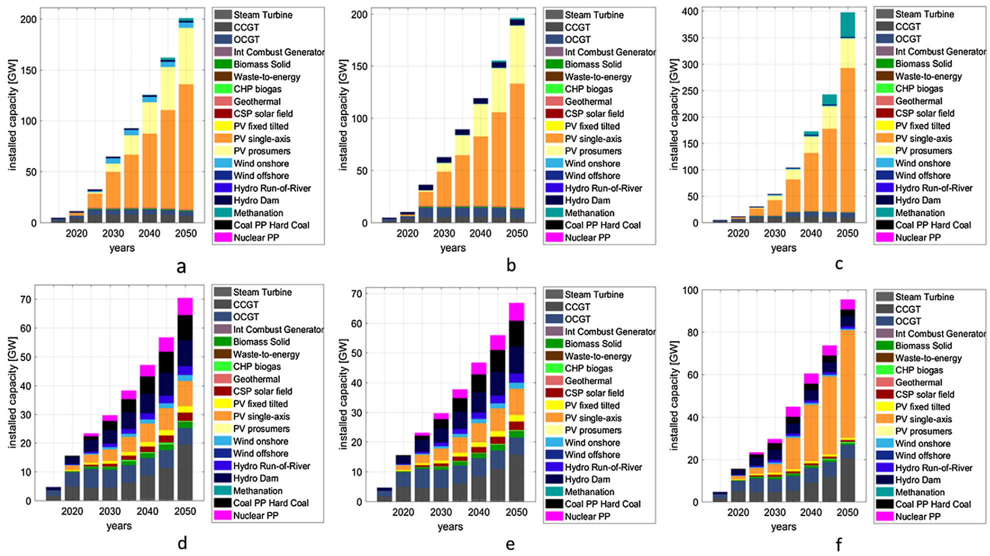

Fig. 11. Cumulative Installed capacity for all generation technologies from 2015 to 2050 for all scenarios.

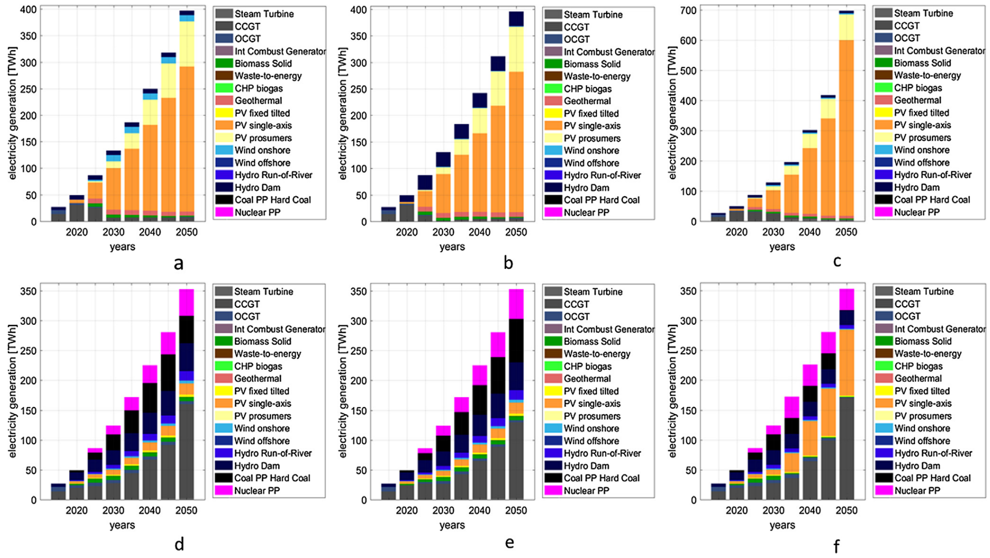

Fig. 12. Total electricity generation by technology from 2015 to 2050 for all scenarios.

prosumers account for the remaining share of the total PV installed capacities in each of the scenarios. Asides solar PV, a variety of technologies in the mix can be seen in Fig. 11(a)–(c), as investments occur in various technologies in all the Best Policy Scenarios, which includes biomass, geothermal, wind and gas turbine (OCGT and CCGT). Whereas, CSP does not feature in the energy mix, as it is less competitive in comparison to solar PV and battery energy storage. Regarding electricity generation in the Best Policy Scenarios, solar PV increasingly covers most of the power system demand as shown in Fig. 12(a)–(c), while wind, hydropower, geothermal and bioenergy complement it. The graphical results for the primary electricity generation in all scenarios can be found in the Supplementary Material (Fig. S6).

Furthermore, the installed capacities in the Current Policy Scenarios are shown in Fig. 11(d)–(f). Gas turbine dominates the Current Policy Scenarios installed capacities during the transition, while coal and nuclear are introduced into the system from 2020 and 2025 onwards,

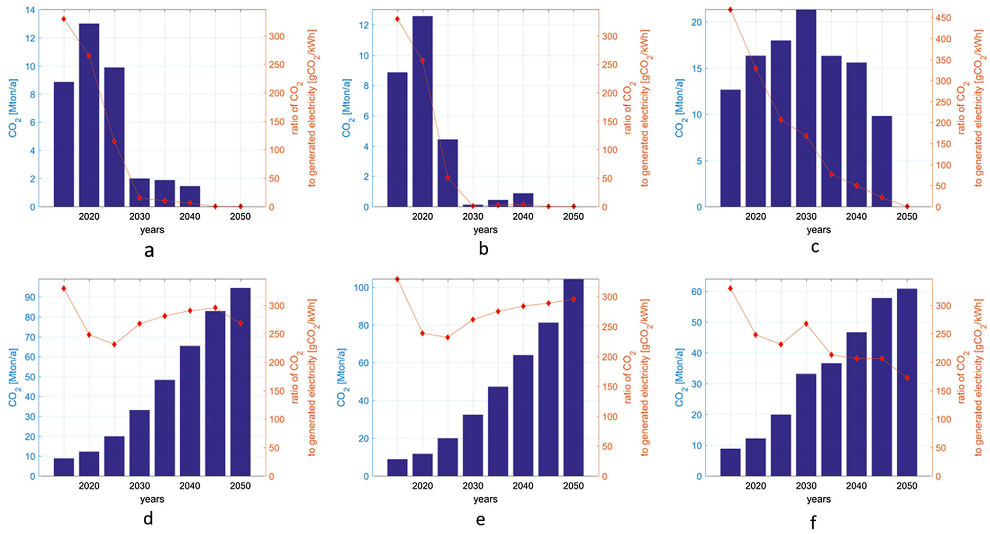

Fig. 13. GHG emissions for all scenarios from 2015 to 2050.

respectively. By 2050, gas turbines dominate except in CPS-3. In CPS-3, after 2030 no new coal is installed, whereas nuclear power plants are allowed to reach 4.8 GW in accordance with the government plan [12]. The model is allowed to decide on new capacity additions for all technologies from 2030 onwards in CPS-3. By 2050, solar PV dominates the power system in CPS-3. The impact of increased RE capacities, particularly single-axis tracking PV, observed in the CPS-3 from 2030 onwards is noticeable. The electricity generation mix in the Current Policy Scenarios during the transition are shown in Fig. 12(d)–(f). By 2050, gas turbines dominate in terms of electricity generation among other thermal power plants in all the Current Policy Scenarios. Whereas, hydropower dominates electricity generation amidst other RE technologies in all the Current Policy Scenarios, except in CPS-3 where solar PV dominates.

A noticeable difference can be observed in terms of capacity requirements in the Best Policy Scenarios and Current Policy Scenarios (Fig. 11). Higher installed capacities are required in all Best Policy Scenarios due to lower full load hours (FLH) of RE technologies, in particular solar PV. The required capacities in the Best Policy Scenarios range from about 198–350 GW, whereas the BPS-3 has the highest share due to additional demand created by desalination and non-energetic industrial gas. Whereas in the Current Policy Scenarios, the capacity requirement ranges from 64 to 95 GW, due to high FLH of thermal generators.

4.3. Annual greenhouse gas emissions in the transition period

The annual GHG emissions during the energy transition period for all the scenarios are presented in Fig. 13. The annual GHG emission reduction trend varies from one scenario to another. In the Best Policy Scenarios, carbon dioxide equivalent (CO_{2eq}) emissions reduce to zero by 2050 as shown in Fig. 13(a)–(c). In the BPS-3, the GHG emissions trend increase until 2030 due to additional electricity generation via fossil gas, to satisfy the demand of non-energetic industrial gas and seawater desalination sectors. While in the Current Policy Scenarios, GHG emissions increase until 2050 as shown in Fig. 13(d)–(f). By 2050, the Nigerian power system is completely decarbonised in all the Best Policy Scenarios.

4.4. Electrical energy storage requirement and utilisation

This section presents the storage portfolio, in terms of capacity expansion and utilisation in the energy transition as shown in Figs. 14 and 15. The storage technologies mix offers additional flexibility to the power system, due to an increased share of limited dispatchable variable renewable energy (VRE) generators in the fully renewable end-point scenarios (Best Policy Scenarios). The storage outputs are 164 TWh, 149 TWh and 179 TWh for BPS-1, BPS-2 and BPS-3, respectively, by 2050, as shown in Fig. 14(a)–(c). The plausible reason for lower storage output in BPS-2 is due to high share of dispatchable hydropower generation. Contrarily, storage output ranges from 15 TWh to 42 TWh in the Current Policy Scenarios by 2050. In addition to the foregoing analysis on storage output, battery storage dominates in all the scenarios, followed by TES, particularly in the Current Policy Scenarios as shown in Fig. 14. TES is important in the Current Policy Scenarios due to CSP installed capacities. The heat generated through CSP and power-to-heat is stored in TES. In addition, higher storage output is observed in CPS-3 in comparison to other Current Policy Scenarios, due to an increased share of solar PV from 2030 onwards. In all the scenarios, the storage outputs increased from 2030 until 2050. Battery storage becomes relevant in the energy transition due to daily charge and discharge, particularly in the Best Policy Scenarios. The high share of PV in the Best Policy Scenarios is reflected in an increase in battery storage utilisation, thus PV-battery systems emerge as the least cost combination in a fully RE powered system for Nigeria. Gas storage utilisation becomes noticeable from 2040 onwards, particularly in the Best Policy Scenarios due to increasing contribution of RE. However, gas storage output is low in comparison to the battery storage output. The reasons are mainly the very low gas storage cycles due to its seasonal characteristic and the gas storage requirement for biomethane, which is accounted for dispatchable RE and not for storing electricity.

Storage capacities required in the Best Policy Scenarios are higher

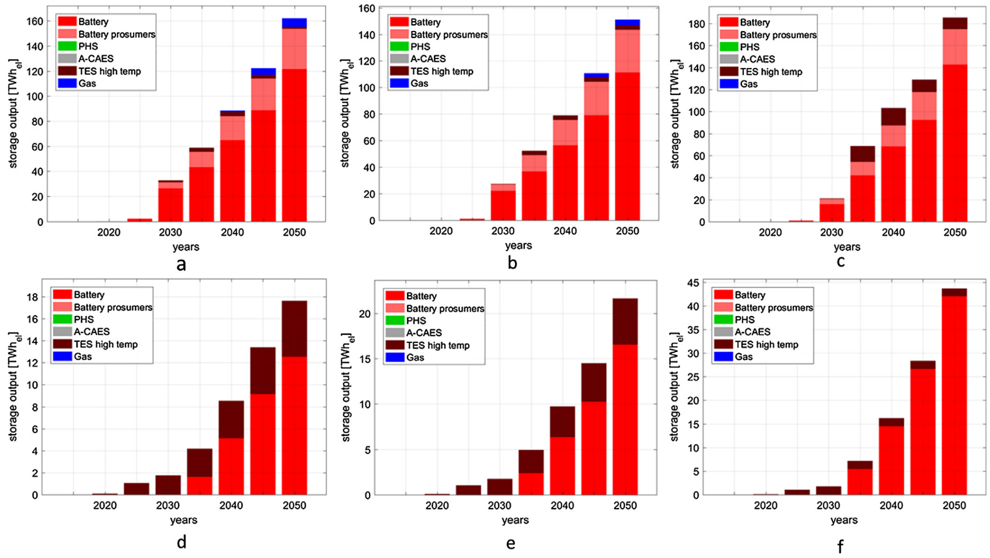

Fig. 14. Storage output of all technologies from 2015 to 2050 for all scenarios.

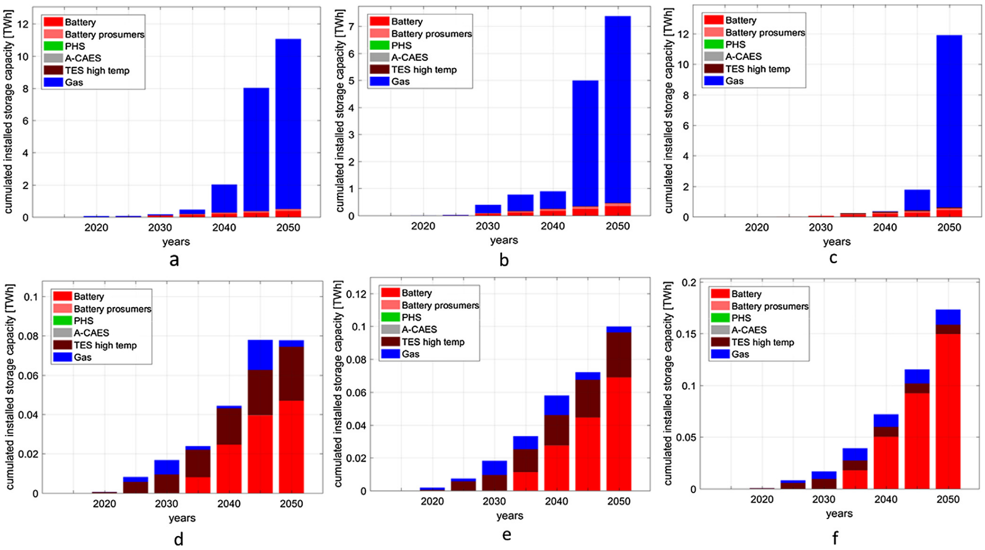

Fig. 15. Cumulative installed capacities of storage technologies from 2015 to 2050 for all scenarios.

than in the Current Policy Scenarios, as shown in Fig. 15. Gas storage dominates the total installed storage capacities in the Best Policy Scenarios, which is utilised for SNG and bio-methane, but not shown in the storage output diagram, which shows only the Power-to-Gas storage. The gas storage reacts in a flexible way to smoothen synoptic and seasonal variations of RE sources. Gas storage capacity becomes more prominent in the Best Policy Scenarios in the year 2045 and 2050 as shown in Fig. 15(a)–(c). In addition, the need for large gas storage capacity is due to replacement of fossil gas with SNG for gas turbines and gas sector demand in particular in BPS-3. In comparison to other Best Policy Scenarios, storage capacity is lower in BPS-2 due to a higher share of hydropower, which serves as virtual storage in this scenario.

Furthermore, the required storage capacities in the Current Policy Scenarios are lower in comparison to the Best Policy Scenarios; plausible reason for this is the increasing share of dispatchable hydropower and fossil-fuelled generators. On the other hand, the storage capacities in the Current Policy Scenarios are dominated by battery storage followed by TES. This study reveals that an increase in VRE shares results

Fig. 16. Battery-to-PtG discharge in the BPS-3 scenario for the year 2050.

in corresponding storage capacity increase, in order to provide the power system with required flexibility. The state of charge of all storage technologies in 2050 are presented in the Supplementary Material (Figs. S7–S12).

Excess renewable electricity goes directly to PtG. However, the battery-to-PtG effect [57] is observed in energy systems of very high renewable energy shares, such as the Best Policy Scenarios, as a means of reducing total system cost. Batteries can be used for supporting the charging of gas storage. This occurrence is visualised in Fig. 16, which shows batteries discharge to the PtG process. When demand is low, mainly at night and early morning hours, energy stored in batteries is discharged to electrolyser units to produce SNG, which is stored for a long term, so that solar electricity of the following daytime can be more effectively stored again in batteries. This optimised system design reduces overall curtailment, reduces PtG charging capacities, increases PtG charging full load hours, and thus reduces the overall energy system cost. This phenomenon does not occur or fairly happen during the rainy season, particularly around June to August. The amount of electricity discharged from batteries to PtG charging are 7 TWh, 4 TWh and 26 TWh in BPS-1, BPS-2 and BPS-3, respectively, representing 2%, 1% and 7% of the electricity demand in 2050. Results of this research show that this phenomenon occurs mainly in the later periods driven by very high PV-battery shares in the energy system.

4.5. Electricity transmission grid utilisation

Integration of VRE resources requires an increase in flexibility. Besides storage technologies, transmission grids provide flexibility to the power system, in shifting of energy from one sub-region to another within the country. Storage provides the flexibility to shift energy from one point in time to another at the same location, whereas transmission grids shift energy from one location to another at the same point in time, hence providing different classes of flexibility. Transmission grids help in balancing electricity supply and demand in various sub-regions. The six sub-regions can be categorised into two: excess-power (or exporting) and deficit-power (or importing) sub-regions. Grid interconnection within the country enhances energy shifting across the country from excess-power to the deficit-power sub-regions. Fig. 17 shows the net electricity transfer between the six sub-regions for the BPS-1 scenario in 2050. The width of the flow indicates the amount of electricity transmitted between the sub-regions. The northern sub-regions are the main exporting regions, especially the NIG-NW region exports huge amounts of electricity of about 200 TWh in BPS-1 by 2050. While the southern sub-regions are the importing regions, in particular the NIG-SW sub-region. The plausible reason for huge exports from the northern sub-region is the excellent solar resource in the region and low cost of PV, since the LCOE is about 17% lower than in the main importing regions due to about 21% higher FLH. The grid utilisation increased with the penetration of RE from 2020 onwards. The net grid export between the sub-regions in the Best Policy Scenarios 1, 2 and 3 are 204, 214 and 371 TWh in 2050, respectively. While the net electricity exchange in the Current Policy Scenarios ranges from 14 TWh to 46 TWh in 2050. This research shows that an increase in spatial-temporal generation of RE, particularly solar PV and wind, requires a powerful high voltage grid for smoothening fluctuations and gaining access to sub-regions with the highest resource potentials. Grid utilisation for all the scenarios in 2050 are presented in the Supplementary Material (Fig. S12).

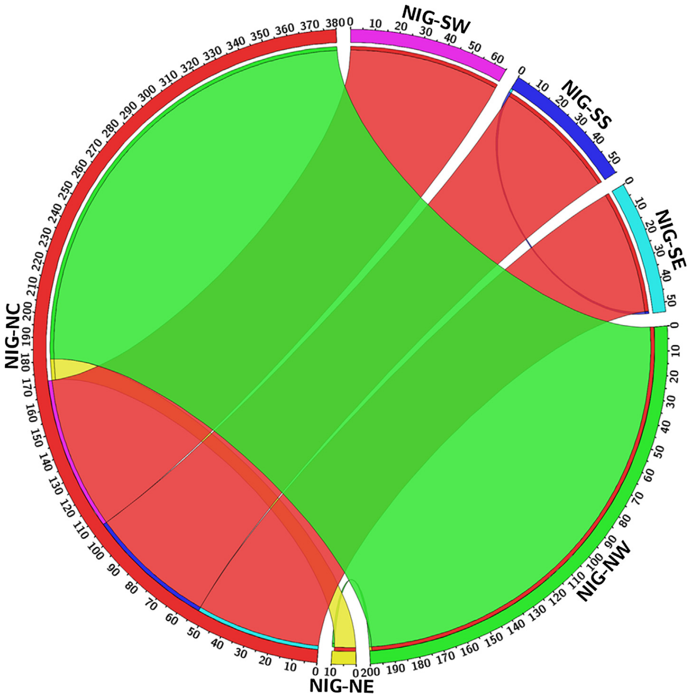

Fig. 17. Electricity exchange across Nigeria in 2050 in the Best Policy Scenario 1.

4.6. The role of gas turbines in the energy transition

Besides the outstanding role of storage technologies and the transmission grid, gas turbines also provide additional flexibility to the power system. Gas turbines are found to be a valuable and flexible balancing technology in the energy transition based on the timescale of the variation they cover, from days to months. In addition, gas turbines are allowed to be installed after 2015, due to lower GHG emissions and the possibility to substitute fossil gas with SNG or biomethane. The average FLH of gas turbines decrease from 5940 in 2015 to 668 in 2050, for the BPS-1. Similarly, the average FLH of gas turbines decline to 380 in the BPS-2, whereas the FLH decrease in the BPS-3 to almost zero, since balancing with electrolysers as a major demand response option is lower in cost. By 2050, the total dispatchable installed gas turbine capacities are 10 GW, 12 GW, and 16 GW in BPS-1, BPS-2 and BPS-3, respectively. The gas turbine generation is 7.0 TWh, 4.7 TWh and 0.02 TWh in BPS-1, BPS-2 and BPS-3, respectively, by 2050. The demand response potential of electrolysers in 2050 is documented by the installed power input capacities of 7.0 GW, 4.6 GW, and 137.1 GW in the BPS-1, BPS-2 and BPS-3, respectively.

4.7. Analysis of sub-region installed capacities in a fully renewable energy system

This section presents a more detailed view of installed capacities for a fully RE-based energy system in 2050 for the six sub-regions, as presented in Fig. 18. The Best Policy Scenarios 1 and 3 are selected for this analysis. A noticeable difference can be seen between the BPS-1 (Power only scenario) and BPS-3 (Integrated scenario) in terms of capacity requirements. The total capacity required is 198 GW and 351 GW in BPS-1 and BPS-3, respectively. Solar PV dominates the total installed capacities, in particular PV single-axis tracking. PV single-axis tracking accounts for 60% and 78% of the total installed capacities in BPS-1 and BPS-3, respectively. The role of PV prosumers are also observed in both scenarios. In BPS-3, seawater desalination and SNG production are integrated into the power system, which increases the electricity demand substantially. The additional capacity requirement due to sector coupling was supplied by solar PV, mainly PV single axis tracking. By 2050, solar PV emerges as the most relevant technology and the cheapest source of electricity for the Nigerian power system. The plausible reason for this is due to the country's location within the Sun Belt, where solar resources are fairly well distributed. However, the intensity of solar radiation exhibits significant disparity from south to north. The solar PV potential is the highest in the northern sub-region, resulting in a high share of PV capacity, particularly in NIG-NE and NIG-NW. Solar PV dominates the energy system, and is complemented by wind, hydropower, geothermal and biomass. The northern sub-regions are exporting regions due to excellent resource availability. More graphical results on regional electricity capacity and generation for each scenario in 2050 can be found in the Supplementary Material (Figs. S14–S15).

4.8. Integrated scenario – best policy scenario 3 (desalination and industrial gas sector)

This scenario integrates seawater desalination and non-energetic industrial gas sectors into the power system. The overall LCOE and capacity requirements for this scenario have been analysed in previous sections. The desalination demand for Nigeria is calculated according to [54]. Desalination demand in the country is low and remains stable at 10,344 m^3/day from 2015 until 2050, most of the demand occurs in NIG-NW and NIG-NE. According to the results of this research, the levelised cost of water (LCOW) is 0.6 €/m^3 in 2050. The LCOW and installed capacity from 2015 until 2050 are shown in Fig. 19. The LCOW includes also the water transport cost from seawater desalination sites to the sites of demand. The total electricity demand from the desalination sector is 0.02 TWh_{el} in 2050.

The total gas demand increases from 60 TWh in 2015 to 185 TWh in 2050. Fig. 20 shows the total gas demand and input by source from 2015 until 2050. Gas demand in the power sector increases until 2030. Afterwards, it begins to decline due to strong RE growth. While the gas demand in the industrial sector increases until 2050. The total annual capital expenditures in the gas sector increase from 0.4 b€ in 2015 to 19.8 b€ in 2050. The total electricity demand in the gas sector is 290 TWh_{el} in 2050.

Fossil natural gas shows a strong influence on the energy system, which is subsequently replaced with SNG during the transition. The SNG production increases in the system from 2040 onwards, and completely replaces fossil-based fuel in 2050. Fig. 21 shows the hourly resolution of the state of charge of gas storage and the operation of methanation units in 2050. SNG production occurs during the daytime almost throughout the year, due to excellent PV conditions in the country. The flexibility of PtG units is lower in cost than battery storage, since otherwise the PtG units would be run also during the night hours, utilising battery storage. The gas storage reaches the peak of charge around April to June, and starts to continuously discharge around July to September, which is the rainy season in Nigeria.

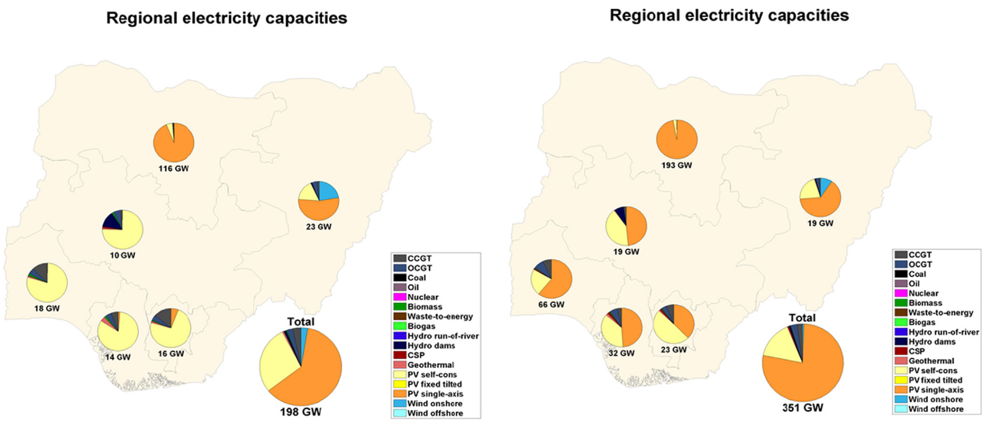

Fig. 18. Installed RE capacities for Best Policy Scenario 1 (left) and Best Policy Scenario 3 (right) for the six sub-regions of Nigeria in 2050.

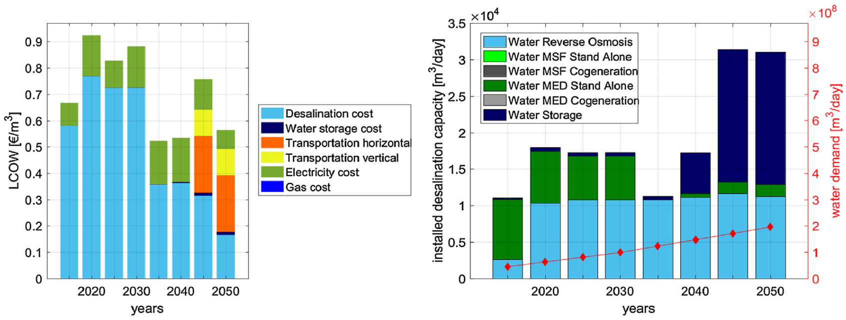

Fig. 19. LCOW components (left) and installed desalination capacities (right) from 2015 to 2050.

Industrial gas demand is nearly constant throughout the year. During the raining season, when SNG production is low or is not available at all, gas storage is discharged to meet the gas demand.

Figs. 22 and 23 present the hourly generation for a sub-region in the north (NIG-NE) and south (NIG-SW). A 2-week period is selected which shows hourly generation during the Harmattan in NIG-NE (Fig. 22) and rainy week in NIG-SW (Fig. 23). The hourly generation in NIG-NE is influenced by the Harmattan season that is characterised by prevailing northeasterly wind conditions that blow from the Sahara Desert over West Africa into the Gulf of Guinea between the end of November and the middle of March, with good solar conditions. This results in remarkable generation from solar PV and wind, while the battery units are discharged during the night hours as shown in Fig. 22. Fig. 23 presents the hourly generation profile in NIG-SW during a week in the rainy season. During this week the role of gas turbines is observed in providing flexibility to the power system due to low generation from RE. However, PV prosumers, electricity imports and battery discharge during night hours have a substantial influence in this sub-region.

Fig. 24 shows the energy flow in the Best Policy Scenario 3 (Integrated scenario). It shows the RE generators, storage technologies, transmission grids, total electricity demand for each sector and system losses. The potential usable heat and system losses include the difference between the electricity generation and final electricity demand. Both includes curtailed electricity, the heat released from biomass, biogas and waste-to-energy power plants, charge and discharge from storage technologies, electrolysers and methanation processes. Solar PV meets additional demand due to sector coupling in the Integrated scenario.

4.9. Comparison of key differences in all scenarios by 2050

This section presents key differences in all scenarios examined by 2050 as presented in Table 2. The total annualised cost of system trajectory from 2015 to 2050 is shown in Fig. 25. The modelled financial outcomes reveal that a fully decarbonised energy system is the least cost option for Nigeria. The total annualised cost of system for all Current Policy Scenarios are higher than in the Best Policy Scenarios, except in the BPS-3 due to sector coupling. The average total annualised cost of system in all Current Policy Scenarios are 42% higher than in Best Policy Scenarios. The total annualised cost of system ranges from 15 to 42 b€ in all the scenarios. The LCOE obtained in the Current Policy Scenarios are higher than in the Best Policy Scenarios. The LCOE is found to be in the range of 34.5–120.4 €/MWh. The capacity requirements are higher in the Best Policy Scenarios than in the Current Policy Scenarios. This is due to lower FLH of solar PV that dominates the overall capacities in Best Policy Scenarios, while the Current Policy Scenarios are dominated by thermal generators that run on higher FLH. On average, capacity requirements in all Best Policy Scenarios are about 70% higher than in the Current Policy Scenarios. Higher generation is observed in the Best Policy Scenarios than in the Current Policy Scenarios.

Furthermore, the Best Policy Scenario 1 no GHG emission cost (BPS-1noCC) and the Best Policy Scenario 2 no GHG emission cost (BPS-2noCC) are examined in this research. The Best Policy Scenario no GHG emission cost modelling outcome reveals that a RE-based energy system would yet be more competitive in the mid-term future in Nigeria. By 2050, RE electricity generation reaches 97.8% of total electricity generation in BPS-1noCC and BPS-2noCC. In both scenarios as GHG emission cost is not applied, natural gas is allowed to be used in gas

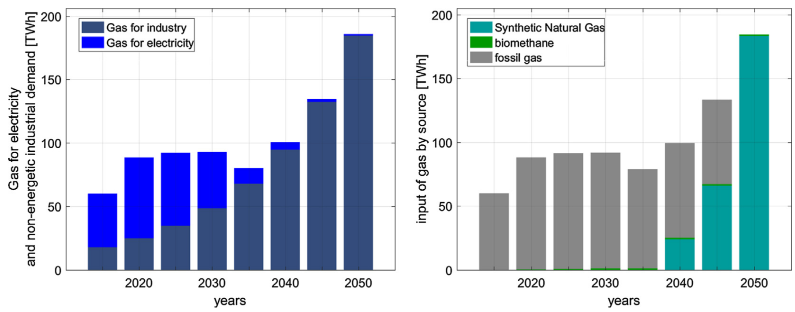

Fig. 20. Total gas demand (left) and gas input by source (right) from 2015 until 2050.

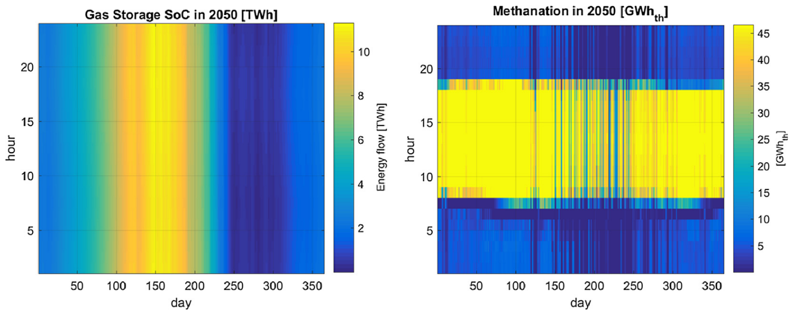

Fig. 21. Hourly resolution of state of charge of gas storage and production of methanation units in 2050.

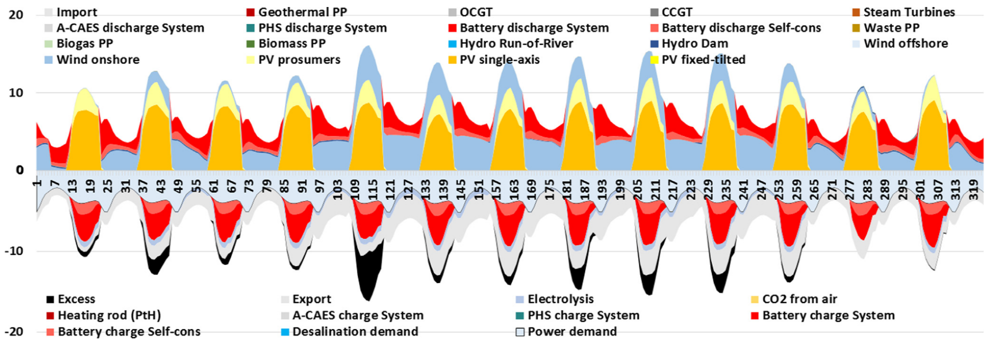

Fig. 22. Electricity generation and demand profile in full hourly resolution for the Best Policy Scenario 1 for the NIG-NE in 2050.

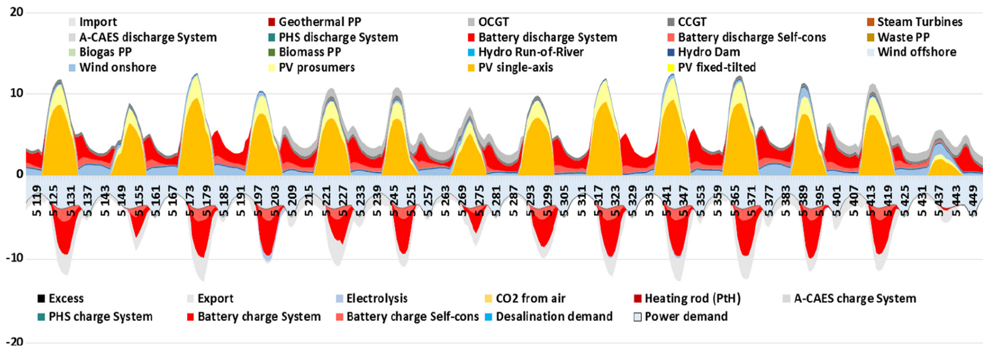

Fig. 23. Electricity generation and demand profile in full hourly resolution for the Best Policy scenario 1 for the NIG-SW in 2050.

turbines. However, the RE installed capacities slightly drop in both scenarios, due to increased FLH of gas turbines. The total annualised cost of system and LCOE decrease slightly in BPS-1noCC and BPS-2noCC as GHG emission cost is assumed to be zero throughout the transition for both scenarios as shown in Table 2. Additional information on these scenarios are available in the Supplementary Material (Tables S11–S12, S22–S23, S30–S32 and Figs. S16–S19).

5. Discussion

This study presents pathways of transitioning to a zero GHG emission energy system for Nigeria under the defined scenarios. The key objectives of this research is to show that a fully sustainable energy system is technically and economically feasible and the respective financial consequences in comparison to a fossil-based power system. Such an energy system can be achieved with abundant RE resource availability in the country, enabled by strong political support for renewable energy development.

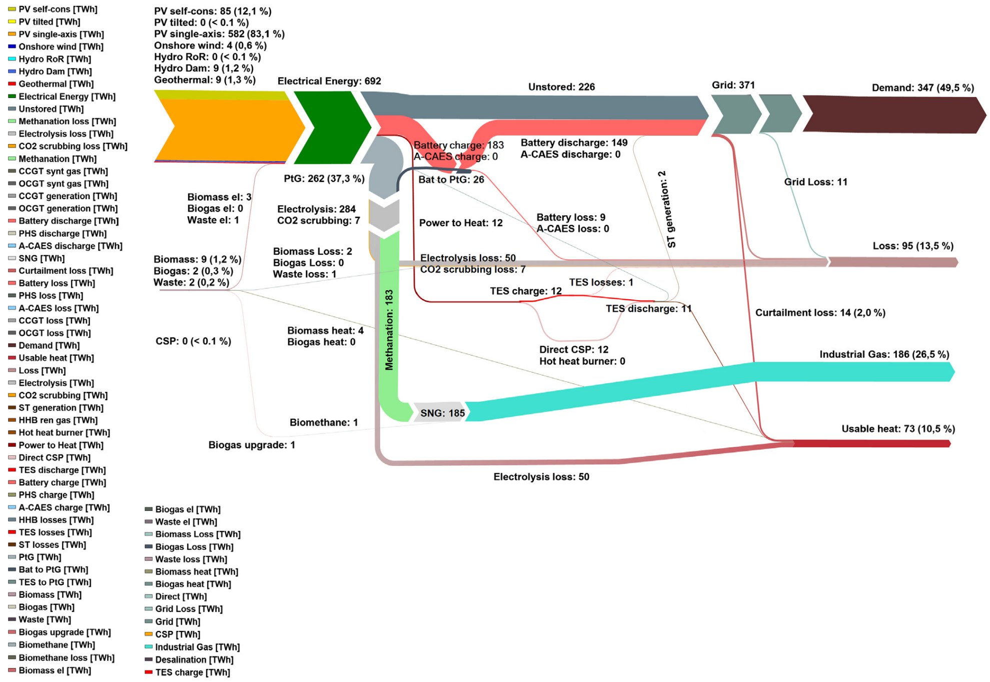

Fig. 24. Energy flow of the system for the Integrated scenario in 2050.

Table 2
Difference in key parameters and financial outcomes in 2050 for all scenarios.

			BPS-1	BPS-2	BPS-3	BPS-1noCC	BPS-2noCC	CPS-1	CPS-2	CPS-3
Financial outcome	Total annualised cost of system	[b€]	16.6	15.8	27.2	16.2	15.5	42.2	26.4	35.0
	LCOE	[€/MWh$_{el}$]	48	46	35	47	45	120	76	100
Electricity parameter	Demand	[TWh$_{el}$]	347	347	637	347	347	347	347	347
	Generation	[TWh$_{el}$]	398	396	697	395	383	353	353	353
	Installed capacity	[GW]	198	194	351	192	190	68	64	95

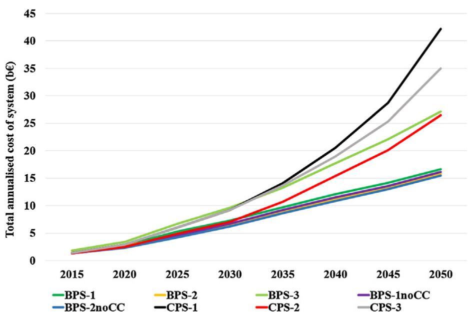

Fig. 25. Comparison of total annualised cost of system for all scenarios in 2050.

A 100% RE-based energy system is achievable in Nigeria. This study is the first of its kind to be conducted for Nigeria. The LCOE values obtained in this study indicate that cost of electricity could decrease from 54 €/MWh in 2015 to 46 €/MWh in BPS-1, 48 €/MWh in BPS-2 and 35 €/MWh in BPS-3 by 2050. Whereas in the Current Policy Scenarios, the LCOE increased from 54 €/MWh in 2015 to 120 €/MWh in CPS-1, and 100 €/MWh in CPS-3 by 2050. However, the LCOE obtained by the no GHG emission cost scenarios declined from 51 €/MWh in 2015 to 47 €/MWh in BPS-1noCC, 45 €/MWh in BPS-2noCC and 76 €/MWh in CPS-2 by 2050. Results obtained in the fully renewable end-point scenarios for Nigeria in terms of LCOE are comparable to the global average LCOE obtained using the LUT model, which shows a range of about 50–70 €/MWh [22]. The decreasing costs of RE technologies expected during the transition, particularly solar PV, contributes to the decreasing cost of electricity over the transition in the Best Policy Scenarios. In addition, sector coupling of seawater desalination, non-energetic industrial gas and electricity demand results in a further reduction in LCOE by 22% in 2050 as observed in BPS-3. Sector coupling provides additional flexibility to the power system. In addition, a higher share of low-cost generation leads to the LCOE reduction.

The additional demand required due to sector coupling is mainly satisfied by installation of low-cost solar PV. PtG technology enables the coverage of gas demand for the integrated scenario (BPS-3) creating additional electricity demand of 290 TWh_{el} in the year 2050, which results in increased generation capacity.

The outstanding role of PV technologies and batteries needs to be highlighted in the fully renewable end-point scenarios in Nigeria. By 2050, PV single-axis tracking dominates the system in the Best Policy Scenarios. While the rest of the PV capacity is met by PV prosumers. Prosumers contribute 22% of total generated PV electricity in 2050. PV-battery prosumers will reduce dependency on the centralised system in the nearest future in Nigeria according to the results of this research. In comparison to the Current Policy Scenarios, PV capacity range from 11 GW to 52 GW in 2050, the highest share of PV installed capacity is observed in the CPS-3. By 2050, PV technologies generate 364 TWh (93% of total generation), 350 TWh (89%) and 667 TWh (96%) in BPS-1, BPS-2 and BPS-3, respectively. The increased generation in BPS-3 is due to demand of three energy sectors. Whereas in the Current Policy Scenarios, PV generation ranged from 22 TWh to 112 TWh, accounting for 6–32% of the total electricity generation in 2050. The highest installed PV capacities were found in the northern sub-regions in particular the NIG-NW and NIG-NE, due to excellent solar resource conditions in the north of Nigeria and respective low cost of PV technology. In addition to the foregoing analysis, solar PV technology will play a major role in the Nigeria future power system, based on the results of this research and from resource point of view as discussed in [58]. Most studies on future energy systems in Nigeria have attempted to analyse renewables potential in meeting the growing electricity demand of the country [8], but did not investigate what this may mean in concrete power generation mix options. Brimmo et al. [59] provided an in-depth review on wind, hydropower, geothermal and nuclear energy options in Nigeria. Solar energy resource current application and the extent of utilisation is presented in [58], while Akuru et al. [7] based on literature, modeled scenarios and field experience conclude that 100% RE in Nigeria could be driven by individuals rather than sole dependence on government actions. The rest of the generation is supplied by wind energy, hydropower, geothermal and biomass in the 100% RE-based scenarios considered in this research. In the BPS-2, hydropower projects under construction such as Mambilla hydropower project in Taraba State and Zungeru hydropower project in Niger State were considered. Hydropower has been a major part of the Nigerian power fleet. The Government of Nigeria also plans to build more hydropower capacity in the nearest future. Increased hydropower capacity is one marked feature of the BPS-2. However, dispatchable hydropower contributes to lower storage needed in BPS-2. By 2050, hydropower capacity is 1.7 GW in BPS-1 and BPS-3, while it reaches 5.3 GW in BPS-2. The hydropower installed capacity is 12.1 GW each in CPS-1 and CPS-2, while installed capacity reaches 5.9 GW in CPS-3 in 2050. According to IEA New Policy Scenario, hydropower capacity is expected to increase from 2 GW (11%) in 2012 to 15 GW (19%) in 2040 [6]. The high share of hydropower in BPS-2 results in lower LCOE and storage requirement, as hydro reservoirs serves as virtual storage [60]. One of the main constraints of hydropower development is cost overruns and schedule spills [14], especially large hydropower projects [15]. According to [16], 61 hydropower dams were analysed representing 114 GW and 271.5 bUSD worth of investment experienced a mean cost overrun of 231 bUSD [16]. These projects exhibited a mean cost overrun of 70% [16]. Another study reports an average 96% cost overrun on hydropower development, where the authors report that the cost overruns figures exclude inflation, debt, environmental cost and social cost [61].

The specific capacity density derived in the LUT Energy System model is 75 MW/km^2 for optimally tilted PV and 8.4 MW/km^2 for onshore wind in [20]. Hence, the total area of land required in Nigeria for solar PV and wind capacities in 2050 is 2409 km^2 (0.3% of total land area) and 361 km^2 (0.04%) for BPS-1, 2317 km^2 (0.3%) and 53 km^2 (0.01%) for BPS-2, and 4369 km^2 (0.5%) and 209 km^2 (0.02%) for BPS-3. The land area requirement for achieving a 100% RE system should be no limiting factor, according to the results of this research.

Furthermore, there are plans underway in Nigeria to build new thermal power plants [19], mainly nuclear and coal power plants [12]. The Current Policy Scenarios are mainly dominated by thermal plants, which include gas turbines, nuclear and coal power plants. In 2017, the Nigerian government signed a multi-billion dollar contract with Rosatom, a Russian nuclear company to build four nuclear plants in Akwa Ibom and Kogi State to contribute 4.8 GW to Nigerian electricity by the year 2035 [62]. In 2000, Rosatom estimated cost to build two new pressurised water reactors of the VVER series at the Leningrad nuclear power plant 2 at 1.74 b€ for 2.17 GW. By 2011, Rosatom set price for this type of project was estimated at 3.73 b€, more than twice the original price [63]. The cost of Olkiluoto 3, Finland, which was planned to begin operation in 2009, have increased from 3.2 b€ to 8.5 b€ for 1.6 GW, and stand the risk of further cost increase [64]. Countries like Nigeria should be aware of binding nuclear contracts, similar to the contract signed in 2014 by the Hungarian government with Rosatom, incurred financial burden is always borne by the foreign government. Rosatom nuclear construction projects within Russia and other countries have not been characterised by delays and cost overruns, but also by lack of proper quality control and safety concerns [63]. Sovacool et al. [16] analysed 401 power plant projects in 57 countries, thereof 180 nuclear reactors representing 177 GW. These reactors had a mean cost overrun of 117%, and more than 9 in 10 projects suffered from cost escalation [16]. In addition, nuclear energy violates all sustainability criteria that should form a framework for a resilient energy system design discussed in [13]. Various risks are associated with nuclear energy [65], which includes environmental and health risks as witnessed in Fukushima and Chernobyl, irreparable impact on ecosystem resulting from genetic mutation plants and animals, and risk of nuclear weapons proliferation and potential terrorist attacks on nuclear facilities [13]. The Current Policy Scenarios are observed to be expensive due to high capital costs of thermal plants in particular nuclear. According to [66], the LCOE median values ranged from 79 to 112 €MWh, and LCOE including external and GHG emission cost ranged from 87 to 120 €/MWh [67]. Rather than building new nuclear and coal power plants in Nigeria, gas turbines (OCGT and CCGT) could be an option alongside with new investments in RE technologies in particular solar PV. In all the scenarios, gas power plants emerge as the dominant thermal power plant, particularly in the Current Policy Scenarios. The result obtained in the Current Policy Scenarios, is comparable to the findings of the IEA New Policy Scenario, which reports gas-fired generation will form the core of the Nigerian future power sector [6]. According to IEA [6], gas power plant capacity may be 37 GW (48%) and coal may be 8 GW (10%) by 2040. Similarly, according to the IRENA Renewable Promotion scenario about 55% electricity generation is supplied by gas power plant, hydropower supply is about 35% and remaining share is supplied by imports for the year 2030 [68]. In the Best Policy Scenarios, gas power plants are used as a very valuable and flexible balancing technology on different time scales, from days to weeks. Gas turbines can be installed after 2015, because of lower GHG emissions and the possibility to substitute the fossil natural gas with SNG or biomethane.

Storage technologies play a vital role in this study, particularly in the Best Policy Scenarios due to high shares of RE resources. Solar PV dominated power grids are usually characterised by high storage requirements [69]. In this research, high penetration RE source, in particular solar PV, is complemented by battery storage due to daily requirement. The PV-battery hybrid system emerges to become the least cost solution in a 100% RE-based powers system by 2050. In addition, the cost of batteries declined by 80% in the past 6 years [70], further cost reduction is expected [71], policies designed to strengthen market growth and innovation in battery storage can drive the future cost reduction [72]. The continued cost decline of PV-battery systems [22] combined with excellent solar resources in Nigeria are the key drivers for a high share of PV in all the Best Policy Scenarios. By 2050, battery storage output in the Best Policy Scenarios ranged from 157 TWh to 166 TWh and from 13 TWh to 42 TWh in the Current Policy Scenarios. The plausible reason for low storage output and requirement in the Current Policy Scenarios is due to higher share of dispatchable hydropower and thermal power plants. Additional battery storage demand of 106 GWh is projected in 2050 because of higher PV prosumers installed capacity. The battery prosumers output increased from 0.2 TWh in 2025 to 32.1 TWh in 2050. In terms of storage capacity, gas storage dominates in the Best Policy Scenarios, while battery storage dominates in the Current Policy Scenarios, followed by TES. The technology requirement in the Best Policy Scenarios are higher than in the Current Policy Scenarios, due to lower FLH of RE in particular solar PV and strict constraints on fossil fuel. The high gas storage capacity is required for PtG and gas turbines, as fossil natural gas is replaced by SNG. According to Fasihi et al. [73], RE-based synthetic fuels are a real option for decarbonising the power system for the year 2030 and beyond.

The role of power grids becomes prominent from 2020 onwards, and utilisation increases with penetration of RE shares in the power system, particularly in the Best Policy Scenarios. The grid interconnection enhances the shifting of energy from exporting sub-regions with high renewable resource potentials to the importing sub-regions. According to the results of this study, transmission grids are vital in reaching a fully sustainable power system in Nigeria by 2050. Brown et al. [21] show that sector coupling, together with electricity transmission networks, can reduce the total system costs by up to 37% compared to a system with none of these flexibility options. However, a mix of several flexibility options such as long- and short-term energy storage, district heating and synthetic fuels are found to be more beneficial than power transmission alone. Investments in grid expansion are vital to the development of the Nigerian power system. According to the IEA New Policy Scenario, the rate of electricity access is expected to increase from 45% in 2012 to around 85% in 2040 through grid extension due to high population density and widespread network coverage in the country [6]. However, grid extension is often a time-consuming process, which might leave many people without electricity for a long period [74]. The grid extension approach has not contributed significantly to an eradication of energy poverty in many SSA countries, including Nigeria [75]. Thus, off-grid solutions based on RE technology, particularly solar PV based technologies (solar home systems (SHS) and mini-grids), provide solutions in areas where grid extension is not cost-effective [76]. According to Bertheau et al. [77], two scenarios were modelled to understand the effects on future grid extension plans in SSA. Results of the modelling reveals that about 96 million Nigerians are un-electrified. In the first scenario based on the existing grid, 22.1 million people (23%), 38.5 million people (40%) and 35.6 million people (37%) can be electrified by mini-grids, grid extension and solar home systems, respectively. The second scenario, in which modelling was based on the planned grid, 17.3 million people (18%), 51 million people (53%) and 27.9 million people (29%) can be electrified by mini-grids, grid extension and SHSs, respectively [77]. Furthermore, SHS can serve as short-term solution until grid connection can be achieved or economic power makes the establishment of mini-grid feasible [78]. Accelerating electrification access requires in depth spatial and techno-economic analysis in identifying least cost and optimal electrification mix options in rural areas [79]. Ouedraogo [80] highlights that the electrification rate in SSA has to be increased 40-fold from today's electrification level to decrease the electricity poverty in the continent. This can be achieved by an increase of new RE-based power generation capacity and off-grid systems.

Furthermore, the water sector is fundamental to the country's development, and the government of Nigeria has made provision for water and basic sanitation the responsibility of the Federal Ministry of Water Resources (FMWR) [81]. Water availability varies across the country. According to [81], Nigeria North-West and North-East are the main regions with water scarcity. In the aforementioned regions, political and economic problems hinder water services. The Nigerian government is committed to providing water coverage to 9 million people yearly beginning from 2016 until 2030. The estimated investment requirement is 378 m€/year, based on United Nation (UN) connection price of 42 €/person to the water network. The nominal tariff charged by the State Water Agency (SWA) ranged from 1.26 to 1.68 € per family per month. Water supply from alternative providers ranges from 5.0 to 6.7 €/m^3 in the North, while prices range from 1.7 to 3.4 €/m^3 in the South [81]. According to the results of this research, LCOW declines from 0.66 €/m^3 in 2015 to 0.56 €/m^3 in 2050. The capex required in 2050 to meet the Nigerian water demand is 14.7 m€, whereas the annual opex fixed and variable is 1.1 m€ and 1.8 m€, respectively.

The results obtained are comparable to the findings of Barasa et al. [5] for the SSA region based on overnight approach for the year 2030, which conclude that SSA countries will be powered mainly by solar PV and complemented by wind energy. In addition, the LCOE obtained in the Best Policy Scenarios are comparable to the LCOE obtained in [5]. Examining the application of a carbon price during the transition, particularly in the Best Policy Scenarios, led to a rapid transition and fast GHG emissions reduction in comparison to no GHG emission cost scenarios. However, the no GHG emission cost scenarios achieved comparable results in terms of capacity, generation, costs of electricity and GHG emission trajectory to the Best Policy Scenarios. By 2050, the RE electricity generation reaches 97.8% in the no GHG emission cost scenarios, with about 2% energy supplied by fossil gas. This indicates that Nigeria's energy transition is achievable without GHG emission cost implementation. The results of this research is fully in line with the recent agreement of several African cities, such as Lagos in Nigeria, Cape Town and Johannesburg in South Africa and Accra in Ghana, to cut carbon emissions to zero until 2050 [82]. An energy system optimisation analysis for the University of Ilorin in Nigeria under several configurations show that a hybrid PV-Diesel-Battery system is the best solution to reduce the GHG emissions cost significantly, while the system costs are also the lowest compared to other configurations [83]. However, the capital cost of solar PV assumed is much higher than the current cost in Nigeria [84]. If the actual cost of solar PV was considered, it is likely that hybrid PV-Battery systems will offer the least cost, while wind energy can also complement. Akuru et al. [7] conclude that 100% RE is possible in Nigeria with the country's abundant RE resources, but that the right government backing is lacking. Though the role of the government cannot be compromised, individuals could drive the transition to 100% RE in Nigeria by installing RE systems in mega cities like Lagos, Abuja or Port Harcourt [7].

6. Conclusion and policy implications

Transition to a carbon-neutral energy system in Nigeria will require a strong political commitment at all levels of governance. Beyond technical feasibility and economic viability of an energy transition towards a zero GHG emission system, it encompasses long-term and well-designed policy interventions. A concerted and consistent policy action that would restrict new investments in fossil power plants, and facilitate RE development in a long-term perspective is exigent for the transition in Nigeria. This research offers key insights to energy system planners and policymakers in Nigeria, and demonstrates the need for a detailed analysis in determining knowledge gaps in transition pathway options under various policy constraints for developing countries of comparable climates. The results of this research demonstrate that a decarbonised energy system is quite competitive in all Best Policy Scenarios in comparison to the Current Policy Scenarios. The high competitiveness is based on an increasing share of RE technologies, particularly the high cost competitiveness of solar PV and supporting batteries. Solar PV dominates all the Best Policy Scenarios by 2050, where PV single-axis tracking contributes the most (63–83%) to the total PV installed capacities followed by PV prosumers. The high shares of PV in the Best Policy Scenarios are reflected in an increase in battery storage utilisation. The combination of solar PV and battery storage was found to be very beneficial for the power system. The need for electricity storage in the energy system is a key characteristic for high penetration levels of VRE. Short-term (Li-ion), medium-term (TES), and long-term (gas storage) storage are required to balance daily, weekly and seasonal variability of RE. Furthermore, energy storage provides flexibility to the energy system by enabling demand balancing. Grid interconnection within the country allows shifting of electricity from one point in time to another, enabling large-scale generation and demand balancing between the different sub-regions. Moreover, gas turbines provide additional flexibility to the power system, where fossil gas is substituted with SNG or biomethane from 2015 onwards in the Best Policy Scenarios. The produced gas can be either used in the power sector to balance the system when it is needed, or stored in gas storage to meet the demand of non-energetic industrial gas sector.

Energy policy in Nigeria should place solar PV at its core. The current perspective of RE utilisation, possible motivation for RE development, barriers and challenges in Nigeria require deliberate actions and strong political will. From a policy perspective, this research identifies investment requirements, timing and operations across Nigeria. Such information are relevant for policy makers and energy planners in Nigeria for setting energy investment targets. During the transition, solar PV and batteries emerge as the most important technologies, complemented by wind energy and existing hydropower. In addition, gas turbines provide flexibility to the power system. A 100% RE-based system is reachable and is the real policy option for Nigeria. RE resources can meet the electricity demand of the power, seawater desalination and non-energetic industrial gas sectors. Furthermore, based on all scenarios examined in this study, the Best Policy Scenarios present the least cost electricity pathways for Nigeria in comparison with the Current Policy Scenarios. The LCOE ranges from 34 to 48 €/MWh for the Best Policy Scenarios, whereas the LCOE for the Current Policy Scenarios lie between 75 and 120 €/MWh. The Current Policy Scenarios clearly demonstrate the need for a cleaner energy system, as a fossil dominated system violates all sustainability criteria. New investments in nuclear power plants in Nigeria are not competitive and show a high risk profile, leading to low social acceptance.

Finally, a well designed RE roadmap, an attractive environment for local and foreign investors, electricity market reforms, research and development and other emissions abatement policies would be required to drive RE development in Nigeria. Innovative financing mechanisms advancing RE development elsewhere in the world can be adopted in Nigeria as well. Further research will be conducted, incorporating other energy sectors (e.g. transport and heat sector) for a wider analysis of the energy transition in Nigeria in the future.

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Appendix A. Supplementary material

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Pathway towards achieving 100% renewable electricity by 2050 for South Africa

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Pathway towards achieving 100% renewable electricity by 2050 for South Africa

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ABSTRACT

Transition to a cost effective and fossil carbon-free energy system is imminent for South Africa, so is the mitigation of issues associated with the 'water-energy nexus' and their consequent impacts on the climate. The country's key fossil carbon mitigation option lies in the energy sector, especially in shifting away from the coal-dependent power system. Pathways towards a fully decarbonised and least cost electricity system are investigated for South Africa. The energy transition is simulated for five scenarios, assessing the impact of various factors such as sector coupling, with and without greenhouse gas (GHG) emission costs. South Africa's energy transition is simulated using an hourly resolved model until 2050. This modelling approach synthesises and reflects in-depth insights of how the demand from the power sector can be met. The optimisation for each 5-year time period is carried out based on assumed costs and technological status until 2050. The modelling outcomes reveal that solar PV and wind energy, supplying about 71% and 28% of the demand respectively in the Best Policy Scenario for 2050, can overcome coal dependency of the power sector. The levelised cost of electricity increases just slightly from 49.2 €/MWh in 2015 to 50.8 €/MWh in the Best Policy Scenario, whereas it increases significantly to 104.9 €/MWh in the Current Policy Scenario by 2050. Further, without considering GHG emissions costs, the cost of electricity slightly increases from 44.1 €/MWh in 2015 to 47.1 €/MWh in the Best Policy Scenario and increases up to 62.8 €/MWh in the Current Policy Scenario by 2050. The cost of electricity is 25% lower in the Best Policy Scenario than in the Current Policy Scenario without factoring in GHG emissions costs and further declined to 50% with GHG emissions costs. The Best Policy Scenario without GHG emissions costs led to 96% renewables and the remaining 4% is supplied by coal and gas turbines, indicating pure market economics. The results indicate that a 100% renewable energy system is the least-cost, least-water intensive, least-GHG-emitting and most job-rich option for the South African energy system in the mid-term future. No new coal and nuclear power plants are installed in the least-cost pathway, and existing fossil fuel capacities are phased out based on their technical lifetime.

1. Introduction

South Africa is the fifth most populated country in Africa, with a population of 56.7 million in 2017 and an annual average population growth rate of 1.2%, occupying an area of 1.219 million km^2 (World Bank, 2017). The country's GDP is 349b€ with a growth rate of 1.3% in 2017 (World Bank, 2017). The electricity demand is expected to increase from 245 TWh in 2015 to 522 TWh in 2050, with an annual average growth rate of 2.3% (Wright et al., 2017). South Africa, like any other coal-abundant country, is susceptible to huge environmental crises, due to over-reliance on coal-generated electricity (Baker and Sovacool, 2017; Klausbrucker, 2016). Coal-fired power plants account for over 90% of electricity production in South Africa (Menyah and Wolde-Rufael, 2010). The country is listed amongst the world's most fossil carbon-intensive economies and is ranked as the 7th largest emitter of greenhouse gas (GHG) per capita (Alton et al., 2014). In Africa, South Africa remains the largest CO_2 emitter and accounts for 42% of the continent's emissions (Alton et al., 2014). South Africa commits, as defined in national policy, a peak, plateau and decline GHG emissions trajectory range, with emissions by 2025 and 2030 in a range of between 398 and 614 Mt_{CO2eq}, as per the 2015 intended nationally determined contribution (DEA, 2015). The country's main fossil carbon mitigation option lies in shifting away from its coal dependence in the power sector (DEA, 2015), which complies with the Paris Agreement on

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Nomenclature

A-CAES	adiabatic compressed air energy storage
BPS(s)	Best Policy Scenario(s)
CAPEX	capital expenditures
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CHP	combined heat and power
CPS(s)	Current Policy Scenario(s)
CSP	concentrating solar thermal power
DOE	Department of Energy
GT	gas turbine
GHG	greenhouse gas
HVDC	high voltage direct current
IRENA	International Renewable Energy Agency
IPPs	Independent Power Producers
IRP	Integrated Resource Plan
LCOC	levelised cost of curtailment
LCOE	levelised cost of electricity
LCOS	levelised cost of storage
LCOT	levelised cost of transmission
OCGT	open cycle gas turbine
OPEX	operational expenditures
PHES	pumped hydro energy storage
PV	Photovoltaic
RE	renewable energy
RoR	run-of-river
SNG	synthetic natural gas
ST	steam turbine
TES	thermal energy storage
VRE	variable renewable energy
WACC	weighted average cost of capital
ZAR	South Africa Rand

climate change (Delina and Sovacool, 2018). Transition towards renewable energy is highlighted in the Paris Agreement for mitigating climate change (Delina and Sovacool, 2018). Fig. 1 shows the total active installed capacities, by the end of 2014 in South Africa, and illustrates the almost complete reliance on fossil fuel (Farfan and Breyer, 2017). Additional background information on South Africa is available in the Supplementary Material (Section 1).

A brief summary of various studies on the trend of RE share in the South African energy system is presented in Table 1.

This article explores the paradigmatic and dynamic pathway to a fully decarbonised and least cost electricity solution for South Africa in the mid-term future. A 100% RE scenario for South Africa is simulated using an hourly resolved model, from 2015 to 2050, covering the power sector demand. Furthermore, the water-energy nexus is explored through analysing the water footprint of the different energy scenarios. In addition, another crucial aspect for South Africa is the creation of local employment, which is further analysed for the different energy scenarios in this research. The paper is structured as follows: the research methodology is described in Section 2. Results are presented and analysed in Section 3. In Section 4, the results are discussed and compared with related studies. Conclusions and policy implications are presented in Section 5.

2. Methods

2.1. Overview

The South African energy system was modelled with the LUT Energy System Transition Model described in (Bogdanov and Breyer, 2016; Breyer et al., 2018; Bogdanov et al., 2019). The energy system model is a linear optimisation tool developed to determine the optimal investment and generation technology mix required to meet the electricity demand in South Africa from 2015 until 2050. The main objective of this research is to understand the transition pathways to a fully RE-based power system for South Africa. The optimisation for each time period (5-year intervals) is carried out on the basis of assumed costs and technological status until 2050 for all energy technologies involved. The installed capacities of the different types of power plants from 1960 to 2015 is considered according to Farfan and Breyer (2017). Additionally, the water footprint analyses are based on Lohrmann et al. (2019) and employment creation is based on Ram et al. (2017a). After 2015, there are no additional capacities of fossil fuel resources allowed. The existing fossil power plants are phased out based on their lifetimes. However, gas turbines can be installed after 2015, due to their lower GHG emissions, higher efficiency, and the possibility to accommodate bio-methane and synthetic natural gas in the power system in a later

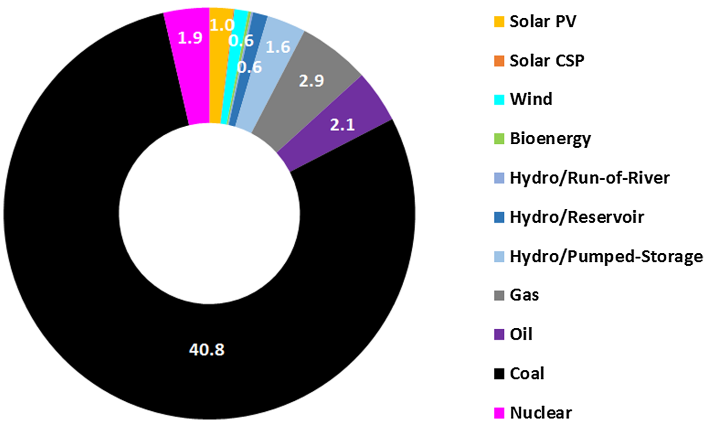

Fig. 1. Total installed active power capacities (in GW) by the end of 2014 in South Africa (Farfan and Breyer, 2017).

Table 1
Studies on trends of renewable energy shares in the South African energy system.

Reference	Findings
Greenpeace (2011)	The Advanced Energy [R]evolution scenario projects a renewable electricity share in the South African energy system of 49% by 2030 and 94% by 2050. The installed capacity of RE will reach 59 GW in 2030 and 114 GW in 2050. Solar PV, wind energy and CSP dominate the shares of installed capacity, contributing 40 GW, 27 GW and 35 GW respectively by 2050.
IEA (2015)	The South African power system is dominated by coal with 54.2 GW and 42.9 GW in the Baseline and Efficiency scenarios respectively, by 2030. RE installed capacity is 20.1 GW (23%) of 86.6 GW in the Baseline scenario, and 23.7 GW (31%) of 77.4 GW in the Efficiency scenario.
IEA (2014)	The New Policy Scenario assumes RE installed capacity of 35 GW and fossil power plants of 73 GW by 2040. Coal dominates the installed capacity with 53 GW (49%). Coal and nuclear contributes 243 TWh (61%) and 47 TWh (12%) respectively of the total electricity generation at 401 TWh by 2040.
IRENA (2013)	Under the Renewable Promotion Scenario, South Africa's RE installed capacity reached 37.5 GW (43%) and fossil is 50.2 GW (57%). Coal dominates the installed capacity with 41.5 GW (47%), followed by wind energy and solar PV with 17.3 GW (20%) and 13.9 GW (16%) respectively by 2030.
Wright et al. (2017)	The least cost ('Expected' costs) scenario achieves over 70% RE penetration by the year 2050, with a significant investment in solar PV and wind energy as expected, with gas turbines providing system flexibility and adequacy with hydropower and biomass. Storage and remaining coal capacity assist in system adequacy. By 2050, energy mix is dominated by solar PV with 140 GW and followed by wind with 73 GW. Solar PV and wind dominate in this scenario due to a further cost reduction assumed for PV and wind.
	The decarbonised scenario achieves over 90% RE penetration by 2050. Solar PV and wind energy dominate the total installed capacity, with 84 GW and 83 GW respectively by 2050. In addition, solar PV and wind energy are complemented by biomass (16 GW), CSP (13 GW), hydro (9 GW) and gas turbines (43 GW).
WWF Vision 2030 (2014)	RE capacity of 35 GW (37%) and 18 GW (24%) is projected for the high-demand and low-demand scenarios respectively, by 2030. While, renewable electricity generation is 78 TWh (19%) for the high-demand scenario and 39 TWh (11%) for the low-demand scenario.

phase. The RE capacity share increase cannot exceed 4% per year (3% per year from 2015 to 2020), in order to avoid disruptions.

2.2. Model overview

The power system used in this study was developed to match generation and power demand for every hour of the simulated year. The model is based on linear cost optimisation of energy system parameters under certain constraints. The model is compiled using MATLAB R2016a (MathWorks, 2016), while the optimisation is carried out in MOSEK version 8 (Mosek, 2017). The key target function of the model is to optimise the system, so that the total annual energy system cost is minimised. This cost is calculated as the addition of the annual costs of the installed capacities of each technology, operational expenditures, and costs of generation ramping. In addition, the energy system takes into account self-generation and consumption of electricity for residential, commercial and industrial end-users. Another mini-transition hourly model describes the PV prosumers systems and optional battery development capacity. The respective capacities of rooftop PV systems and optional batteries are installed by the prosumers. The target function for prosumers is the minimisation of cost of consumed electricity, calculated as the sum of self-generation, annual costs, and the cost of electricity consumed from the grid. Excess electricity is sold to the grid at 0.02 €/kWh by prosumers, when their own demand is satisfied, but not more than 50% of total self-generation. The prosumer demand is limited to 20% of the total demand. The prosumer constraints ensure that the 20% is not reached within the first time step. Thus, the model determines a step-wise progression from a maximum of 6% in the first

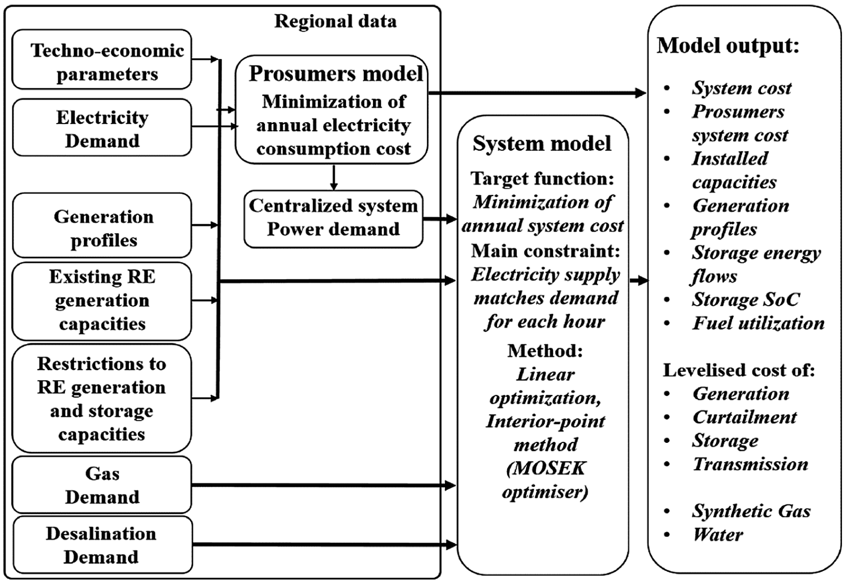

Fig. 2. Main inputs and outputs of the LUT Energy System Model (Bogdanov and Breyer, 2016).

time step to 9%, 15%, 18% and 20% in subsequent time steps if the economic model of prosumers indicates benefits of PV self-generation. PV self-consumption is considered as an exogenous input into the system optimisation. The energy system is optimised in addition to the prosumer capacities, which avoid any distortion of the overall system. The model overview is shown in Fig. 2. Detailed model description, equations and applied constraints can be found in (Bogdanov and Breyer, 2016; Breyer et al., 2018; Bogdanov et al., 2019).

South Africa was structured into 9 sub-regions based on the existing provincial structure, namely, Gauteng (ZA-GT), Mpumalanga (ZA-MP), KwaZulu-Natal (ZA-NL), North West (ZA-NW), Limpopo (ZA-LP), Western Cape (ZA-WC), Free State (ZA-FS), Eastern Cape (ZA-EC) and Northern Cape (ZA-NC). All the sub-regions are interconnected with transmission grids as shown in Fig. 3.

2.3. Applied technologies

The main technologies applied for the South African energy system modelling include electricity generation, storage, transmission and energy sector bridging technologies to provide more flexibility to the complete energy system. Fig. 4 shows the block diagram of the energy transition model.

2.4. Modelling assumptions

2.4.1. Financial and technical assumptions

The financial and technical assumptions for all energy system components are applied in 5-year time steps. This includes operational expenditures (OPEX), capital expenditures (CAPEX) and technical lifetimes from 2015 to 2050 for the applied technologies, as provided in the Supplementary Material (Table S1). The technical assumptions concerning storage technologies (efficiency and power to energy ratio), fuels, and transmission grids can be found in the Supplementary Material (Tables S2–S4).

The weighted average cost of capital (WACC) is set to 7% in this study. However, for residential PV prosumers WACC is set to 4% due to lower financial return requirements. The cost recovery is mostly considered for a wider aggregate range of investors, which includes a mix of debt and equity financing. On this basis, the commercial and industrial investors require higher returns on equity margins than private investors. Therefore, WACC is split into two categories in this study. The WACC variation does not substantially alter the cost of the energy system (Breyer et al., 2017). Additionally, the risk profile of nuclear and coal is much higher than RE, which should result in a higher WACC level for nuclear energy and coal compared to RE technologies (Ram et al., 2018), however, these higher risks are not taken into account in the research.

The electricity prices for residential, commercial and industrial consumers for the year 2015 were retrieved from (Eskom, 2015). The electricity price was calculated until 2050 according to Gerlach et al. (2014) and Breyer and Gerlach (2013). The electricity prices during the transition are calculated according to the assumptions from Gerlach et al. (2014) that grid electricity prices rise by 5% per annum for < 0.15 €/kWh, by 3% per annum for 0.15–0.30 €/kWh and by 1% per annum for < 0.30 €/kWh. The electricity prices for South Africa are provided in the Supplementary Material (Table S5). An average currency exchange rate for a period of 5 years from 2013 to 2018 was considered, at 16.67 €/ZAR (equal to 0.06 ZAR/€).

The upper limits for all RE technologies were estimated according to Bogdanov and Breyer (2016) and lower limits are obtained from Farfan and Breyer (2017). Upper and lower limits of RE and fossil fuels are provided in the Supplementary Material (Tables S6 and S7). For all other technologies, upper limits are not specified. However, for solid biomass residues, biogas, and waste-to-energy plants it is assumed, due to energy efficiency reasons, that the available and specified amount of the fuel is used during the year.

2.4.2. Resource potential for renewable technologies

The feed-in profiles for solar PV optimally tilted and single-axis tracking ground-mounted power plants, wind energy and CSP are calculated according to Bogdanov and Breyer (2016) and Afanasyeva et al. (2018), based on resource data of NASA (Stackhouse and Whitlock,

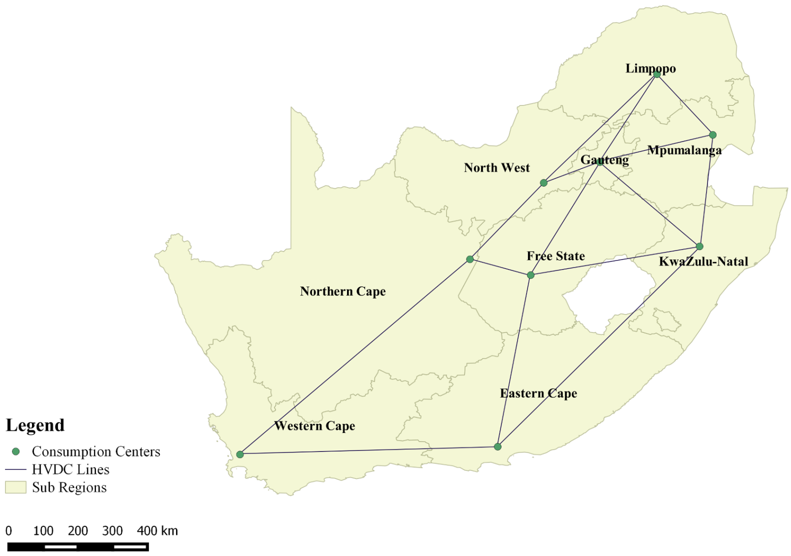

Fig. 3. South African sub-regions and transmission lines configuration.

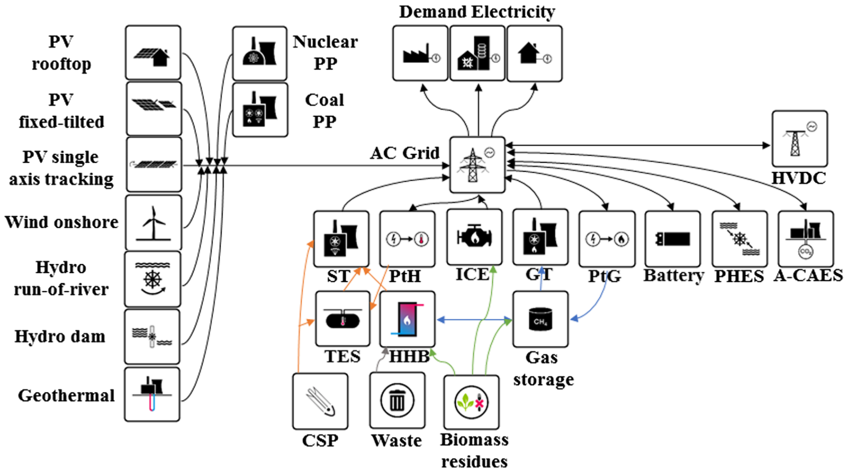

Fig. 4. Block diagram of the LUT Energy System Transition model used for South Africa (Breyer et al., 2018). Abbreviations not introduced elsewhere include PP-power plant, ST- steam turbines, PtH – power-to-heat, ICE – internal combustion engine, GT gas turbines, A-CAES – adiabatic compressed air storage, PtG – power-to-gas, PHES – pumped hydro energy storage, TES – thermal-energy-storage, HHB – hot heat burner, CSP – concentrated solar thermal power.

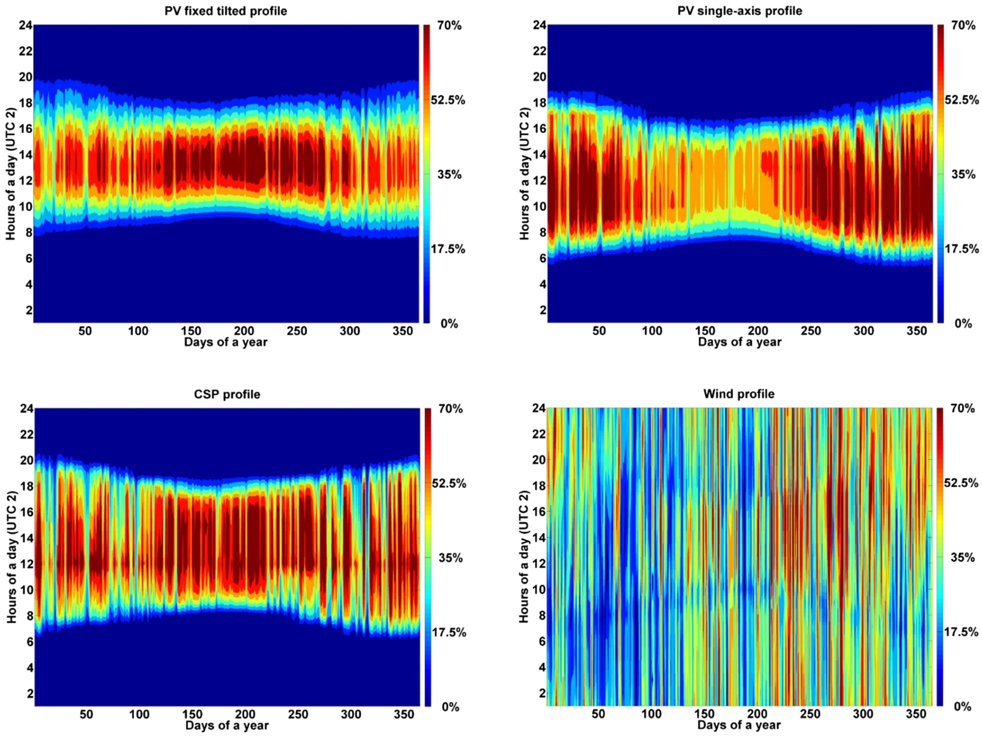

Fig. 5. Aggregated feed-in profiles for optimally tilted (top left) and single-axis tracking PV (top right), CSP solar field (bottom left), and wind power plants (bottom right) in South Africa.

2008; 2009), reprocessed by the German Aerospace Centre (Stetter, 2012). The obtained NASA dataset is in a temporal resolution of 3 h for the year 2005 and spatial resolution of 1° × 1°. An Enercon wind turbine (E-101) with a rated power of 3 MW and 150 m hub height is used to compute the wind feed-in profiles. The full load hours (FLH) feed-in profiles are calculated based on real weather conditions for the year 2005 on a 0.45° × 0.45° spatially and hourly temporally resolved data using a weighted average formula, this methodology is described in Bogdanov and Breyer (2016). It is assumed that 0–10% best areas are weighted by 0.3, 10–20% best areas are weighted by 0.3, 20–30% best areas are weighted by 0.2, 30–40% best areas are weighted by 0.1 and 40–50% best areas are weighted by 0.1%. The hydropower feed-in profiles are computed based on the monthly resolved precipitation data for the year 2005 as a normalised sum of precipitation in the regions. Such an estimate leads to a good approximation of the annual generation of hydropower plants (Verzano, 2009). Full load hours of various resources are presented in the Supplementary Material (Tables S11–S13 and Fig. S1) and visualised in an hourly resolution in Fig. 5. Fig. S1 shows the geographic diversity in wind and solar resources across the country.

The potentials for biomass and waste resources are taken from German Biomass Research Centre (DBFZ, 2010) and are classified according to Bogdanov and Breyer (2016). The costs for biomass are calculated using data from the International Energy Agency (IEA, 2012) and Intergovernmental Panel on Climate Change (IPCC, 2011). For solid waste, a 50 €/ton gate fee was assumed for 2015, which increased up to 100 €/ton in 2050.

2.4.3. Electricity demand

The hourly electricity load profile is calculated as a fraction of the total demand for each sub-region based on synthetic load data weighted by the sub-regions population (Toktarova et al., 2018). Fig. 6 shows the aggregated load curve and long-term electricity demand for South Africa. Electricity demand is taken from Wright et al. (2017). The population in South Africa is expected to grow from 54 million in 2015 to 66 million in 2050 (UN, 2015), while the average per capita electricity demand rises from 4.9 to 8.2 MWh as shown in Fig. 6 (right). The electricity demand until 2050 is provided in the Supplementary Material (Table S5).

2.4.4. Scenarios

In this study, five scenarios were studied for the South African energy transition analyses, which are briefly described in Table 2.

3. Results

3.1. Analysis of financial outcome of the transition for all scenarios

The average financial results for the studied scenarios are expressed as levelised cost of electricity (LCOE), levelised cost of electricity for primary generation (LCOE primary), levelised cost of curtailment (LCOC), levelised cost of storage (LCOS), levelised cost of transmission (LCOT), levelised cost of import (LCOI), fuel costs and CO_{2eq} emission costs, as shown in Fig. 7 from 2015 to 2050. The LCOE in the BPSs is observed as shown in Fig. 7 (a and b). The LCOE increase until 2025, due to decommissioning of fossil power plants and concurrent replacement with RE capacities. From 2025 onwards, the LCOE declines, as low-cost solar PV and wind energy dominate the system in the BPS. Whereas, the LCOE in the BPSnoCC increases until 2035 and gradually declines afterwards until 2050. By 2050, the LCOE obtained in the BPS is 50.8 €/MWh and 47.1 €/MWh in BPSnoCC, as shown in Fig. 7 (a and b). The contrary trend is observed in the CPS, as the LCOE increases throughout the transition. By 2050, the LCOE obtained in the CPS is 104.9 €/MWh as shown in Fig. 7c. Fuel and GHG emissions costs account for more than 50% of the LCOE in the CPS by 2050. Yet, the LCOE obtained in the CPS without GHG emissions costs (CPSnoCC) is 62.8 €/MWh as shown in Fig. 7d, which is still higher in comparison to the LCOE obtained in the BPSs by 24% in 2050. Additional results on costs for all scenarios are available in the Supplementary Material (Table S14 and Figs. S2–S4).

3.2. Analysis of required installed capacities and electricity generation mix during the transition

The system architecture changes gradually as the fossil generators leave the system and are replaced by RE technologies, particularly in the BPSs. Fig. 8 presents the installed capacities from 2015 until 2050 and absolute numbers are available in the Supplementary Material (Tables S8–S10) for all scenarios. By 2050, the total installed capacity is 321 GW, 295 GW and 134 GW in the BPS, BPSnoCC and CPS, respectively. In the BPSs, the solar PV and wind energy shares dominate the total installed capacity by 2050. The installed solar PV capacity is 241.7 GW, 233.4 GW and 15.8 GW in the BPS, BPSnoCC, and CPS respectively by 2050. While wind energy installed capacity is 51.2 GW, 36.8 GW and 30.4 GW in the BPS, BPSnoCC and CPS respectively by 2050. By 2050, the total installed capacity of thermal power plants is 26.6 GW, 23.8 GW and 81.3 GW in the BPS, BPSnoCC and CPS, respectively. The application of GHG emissions costs resulted in a fast and high penetration of RE installed capacities as observed in the BPS in comparison to BPSnoCC. The total capacity requirement in the BPSnoCC is low, due to the influence of thermal plants operating on high FLH. Key power

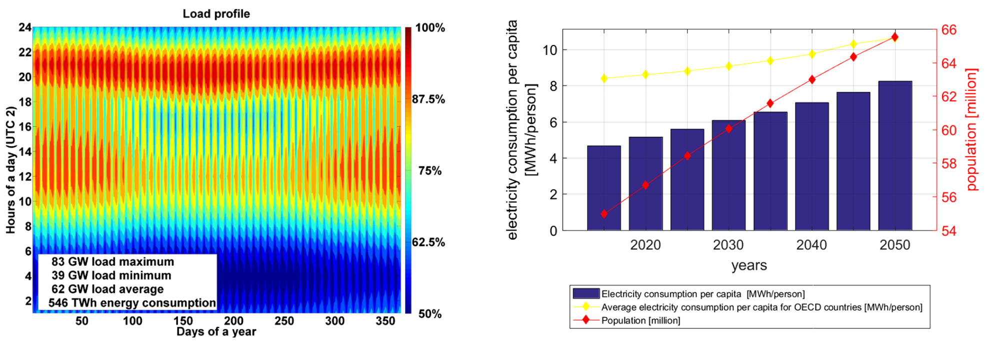

Fig. 6. Aggregated load curve for South Africa for 2050 (left) and long-term demand from 2015 to 2050 (right).

Table 2
Overview on scenarios.

Scenario name	Description
Best Policy Scenario (BPS)	This scenario targets 100% RE by 2050. In addition, GHG emissions costs are considered and only electricity demand is covered. The Best Policy Scenario naming is considered on basis of 100% RE, zero GHG emissions, most job-rich and least-water intensive characteristics.
Best Policy Scenario no GHG emissions costs applied (BPSnoCC)	In this scenario, no GHG emissions costs are assumed.
Current Policy Scenario (CPS)	In this scenario, respective installed capacities according to the Integrated Resource Plan (IRP) from now until 2050 were taken into account, in modelling the South African energy transition in the mid-term future (Wright et al., 2017).
Current Policy Scenario no GHG emissions costs (CPSnoCC)	In this scenario, no GHG emissions costs are assumed. Thus, only the financial implications of this scenario are discussed.

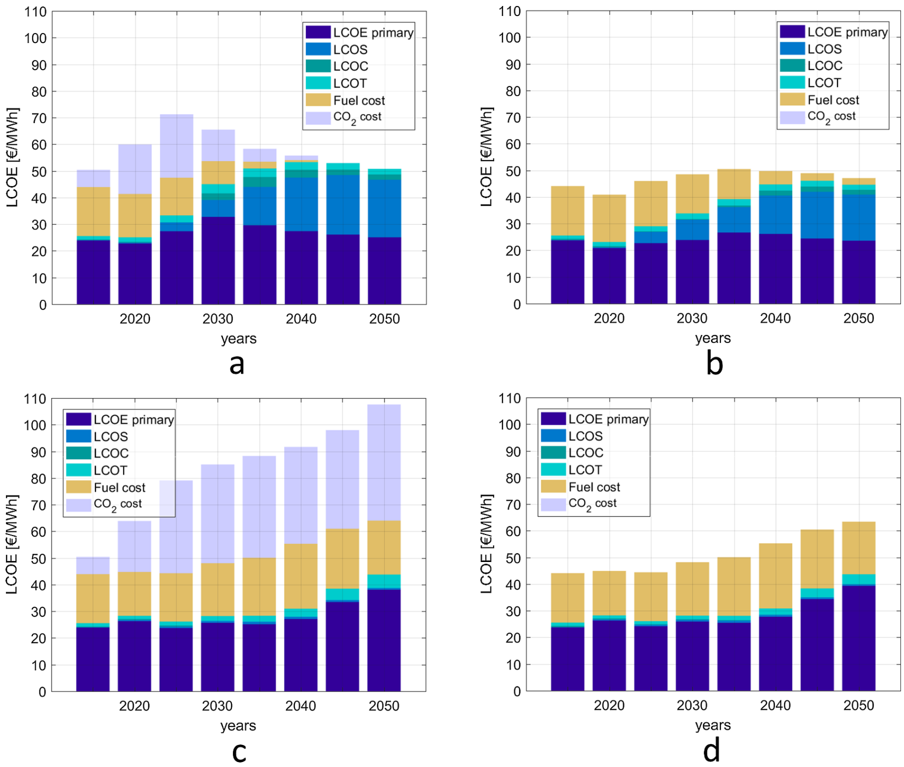

Fig. 7. Levelised cost of electricity for BPS (a), BPSnoCC (b), CPS (c), and CPSnoCC (d).

capacities required for the energy transition for South Africa are provided in the Supplementary Material (Tables S8–S10).

Fig. 9 depicts the electricity generation mix in all scenarios from 2015 to 2050. The coal-dependent power system can be substituted by a mix of solar PV and wind energy, complemented by hydropower and biomass as observed in BPS and BPSnoCC as shown in Fig. 9 (a and b). The results of this research indicate that from 2035 onwards, solar PV and wind energy can drive the deep decarbonisation of the South African power system in the BPSs. By 2050, solar PV and wind energy contributes 459 TWh and 181 TWh in the BPS as shown in Fig. 9a. Whereas, the solar PV and wind supply shares decrease to 441 TWh and 131 TWh respectively in the BPSnoCC as shown in Fig. 9b, due to the influence of fossil power plants operating on higher FLH until 2050. Nevertheless, in the BPSnoCC the share of RE generation reaches 95.6% by 2050, which implies a high cost competitiveness of RE technologies, particularly solar PV and wind energy. Wind energy contribution remains constant from 2030 onwards, which is a consequence of the continued cost decline of solar PV and battery storage, also observed for the case of Turkey (Kilickaplan et al., 2017). Fig. 9c shows the generation mix in the CPS. Coal, nuclear and wind energy dominate with 155 TWh, 152 TWh and 114 TWh of the total generation respectively by 2050. Coal-based electricity supply declines from 2030 onwards as the shares of RE capacities and gas turbines increase in the energy system, while nuclear energy contribution increases from 2040 onwards in the CPS. The share of electricity imports increases from 2030 onwards, as hydropower imports from Inga is considered according to the IRP

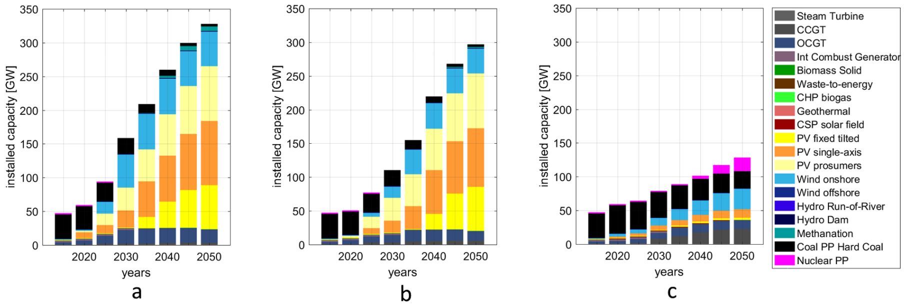

Fig. 8. Installed generation capacities for BPS (a), BPSnoCC (b) and CPS (c) from 2015 to 2050.

(Wright et al., 2017). Additional graphical results of electricity generation by technology for all scenarios are presented in the Supplementary Material (Fig. S5).

3.3. Assessments of system flexibility during the transition for all scenarios

The flexibility of the power system due to a high share of variable renewable energy (VRE) and dynamic load is analysed in this section. The power system flexibility is analysed in context of storage requirement and utilisation, grid integration and the role of gas turbines for deep decarbonisation of coal-dependent South African power system.

3.3.1. Analysis of storage utilisation and required capacities during the transition

Storage capacity requirement and utilisation are crucial in the BPSs due to high penetration of RE in these scenarios. By 2050, the cumulative installed storage capacity is 16.3 TWh, 2.5 TWh and 0.01 TWh in the BPS, BPSnoCC and CPS, respectively. Gas storage dominates the total storage capacity in the Best Policy Scenarios by 2050. By 2050, gas storage contributes 15.7 TWh in BPS, 1.9 TWh in BPSnoCC and 0.008 TWh in CPS as shown in Fig. 10. The high shares of gas storage in the BPSs are required to smoothen the synoptic and compensate the seasonal variation of RE resources. The shares of gas storage capacities increase from 2040 onwards in BPS, as the RE shares increase to about 80%. Gas storage includes the PtG technology, which allows production of SNG for the power system. The PtG option provides the system with the highest flexibility and integrates most of the excess electricity generated. The prosumer and utility-scale battery storage capacities increased from 2030 onwards in the BPSs. In the CPS, PHES provides the entire storage need for the year 2015 and contributes to the storage mix until 2050. TES dominates the storage mix from 2020 to 2045, due to CSP installed capacities. The heat generated through CSP and power-to-heat is stored in the TES. The gas storage capacity increases until 2030 and remains stable afterwards. The storage capacity in the CPS grows until 2035, and declines afterwards due to an increasing share of nuclear energy from 2040 onwards.

Fig. 11 shows the storage throughput during the transition and absolute numbers are presented in the Supplementary Material (Tables S15–S17). Battery storage dominates with respect to storage throughput during the transition in the BPS and BPSnoCC as shown in Fig. 11(a and b). Hybrid PV-battery systems evolve to a highly economic option for the energy system. The daily charge and discharge of batteries is needed due to high solar PV penetration in the system. Utility-scale and prosumer battery storage output shows huge relevance during the transition, while gas storage, TES and PHES complement depending on RE variability timescales in the system. Prosumer battery dominates in terms of output until 2030. In the CPS, PHES and TES dominate the system until 2030 as shown in Fig. 11c. Nevertheless, storage capacity requirement and utilisation in terms of throughput is low in the CPS, due to the dominance of thermal power plants. The storage requirement in terms of installed capacity and utilisation observed for all scenarios during the transition is found to be directly proportional to the level of RE penetration. More graphical results on the state of charge of storage technologies in all examined scenarios are available in Supplementary Material (Figs. S6–S10).

Battery discharge to PtG is observed in the BPSs. This phenomenon (Battery-to-PtG effect (Gulagi et al., 2018)) is observed nearly throughout the years. During the night and early hours of the day when demand is low, energy stored in batteries is discharged to electrolyser units to produce gas, which is stored for long term. By 2050, battery-to-PtG discharge is around 12 TWh in each of the Best Policy Scenarios as part of the least cost solution, representing 2% of the electricity demand in 2050. Batteries discharging to PtG is observed from 2035 onwards, when RE share is around 80% in the BPSs.

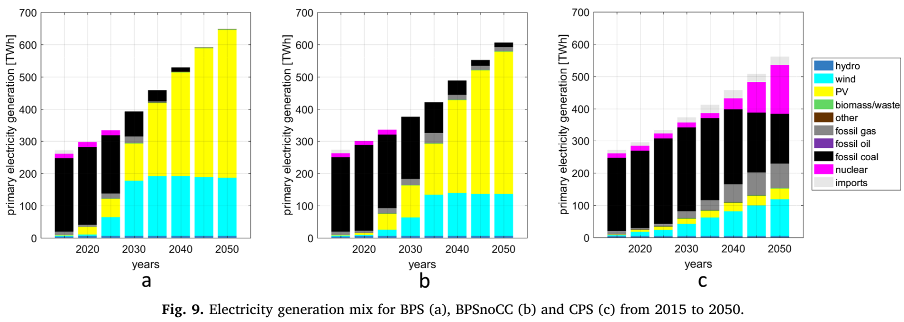

Fig. 9. Electricity generation mix for BPS (a), BPSnoCC (b) and CPS (c) from 2015 to 2050.

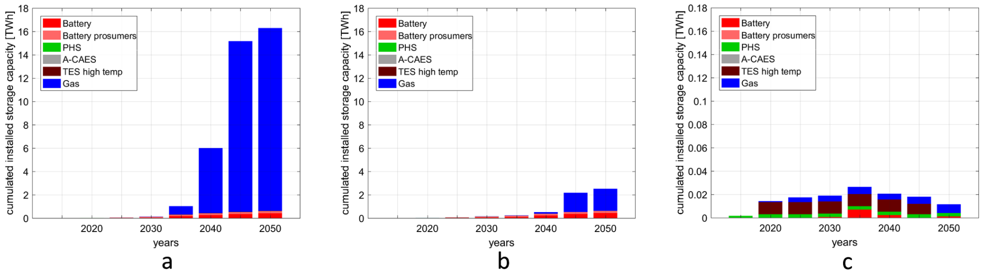

Fig. 10. Cumulative installed capacities of storage technologies for BPS (a), BPSnoCC (b) and CPS (c) from 2015 to 2050.

3.3.2. Assessment of transmission grid utilisation during the transition

The level of grid utilisation varies from time to time in BPS and BPSnoCC, while it is constant in the CPS as shown in Fig. 12. Grid utilisation in the BPS and BPSnoCC occurs mostly in the summer and spring periods, and reduces in autumn and winter times as shown in Fig. 12 (a and b). The summer and spring periods, are the best seasons for solar and wind resource availability. During the autumn and winter periods, gas storage compensates the seasonal variation of RE resources. In the CPS, thermal power plants are site specific and require maximum grid utilisation in shifting energy across the country. The grid utilisation is intense during the daytime working hours and at night, but low in the early morning hours in the CPS. The net grid export between sub-regions ranges from 167 TWh to 197 TWh in the BPSs and 242 TWh in the CPS by 2050. This implies that sub-regions are more independent in producing their own electricity in the BPSs than in the CPS. In the BPS, it is observed that sub-regions with best RE resources are net exporters and others are net importers. The Northern Cape province is the main exporting region due to excellent RE resources and low demand. Fig. 13 shows the direction and amount of electricity transmitted across the country. The thickness of the flow indicates the amount of electricity transferred between the regions in TWh. North Cape becomes the main exporting region by 2050 in a fully RE system in comparison to the current situation in which Mpumalanga province supplies almost the entire country's electricity demand due to huge power plants located in the province.

3.3.3. Analysis of gas technology relevance during the transition in the Best Policy Scenarios

The gas turbines usage is observed during low RE resource availability, particularly in the winter period. By 2050, the capacity of gas turbines is 23 GW each in BPS and 20 GW in BPSnoCC. The average FLH of gas turbines decline from about 2600 h in 2015 to 700 h in BPS and to 800 h in BPSnoCC by 2050. In addition, gas turbines are a relevant peaking technology because they are economically and technically more rampable to produce high amounts of power when required. By 2050, gas turbines generate approximately 16 TWh in the BPS and 17 TWh in BPSnoCC. Gas turbines are comprised by about 87% OCGT and 13% CCGT in the BPS as the least cost mix, with 482 FLH for OCGT and 2146 FLH for CCGT.

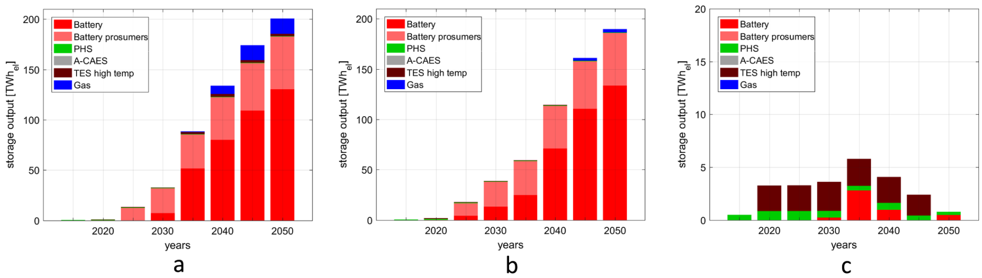

Fig. 11. Cumulative storage output for BPS (a), BPSnoCC (b) and CPS (c) from 2015 to 2050.

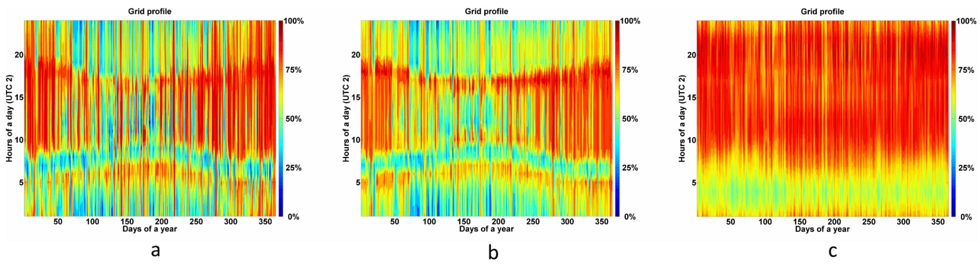

Fig. 12. Grid profile for BPS (a), BPSnoCC (b) and CPS (c) for 2050. (Grid profile is the hourly distribution of electricity demand over the entire year).

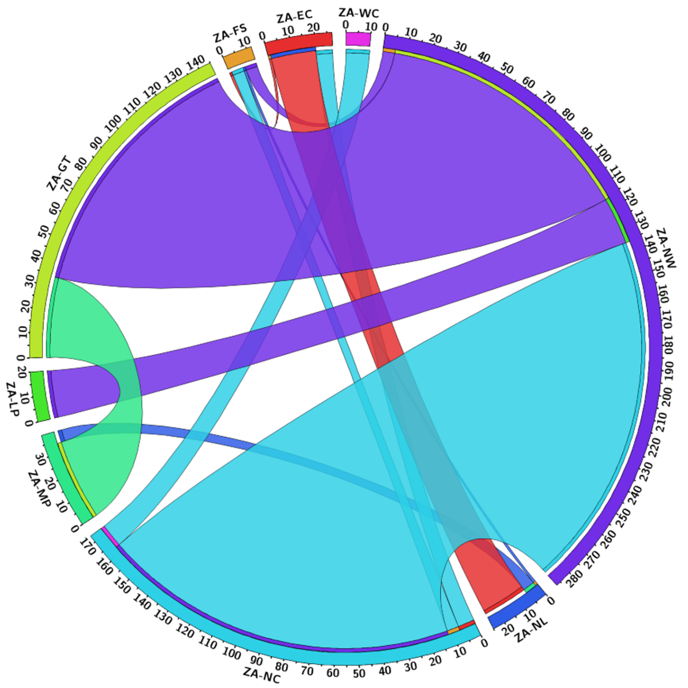

Fig. 13. Electricity transmission between the sub-regions for 2050 in the BPS.

3.4. Analysis of sub-region optimised fully renewable system structure by 2050

This section presents the sub-regional installed capacity projection for a fully RE system in 2050 as shown in Fig. 14. Solar PV dominates the share of total installed capacities, particularly solar PV single-axis tracking followed by PV prosumers. Solar PV single-axis tracking installed capacity is 95 GW in BPS, representing 39.4% of total solar PV capacity. While the installed capacity of PV prosumers is 81 GW in each of the scenarios. Solar PV installations are observed in all sub-regions due to even distribution of solar resources across the country. However, the highest share of installed solar PV capacity is found in the Northern Cape sub-region, due to excellent solar resource in this province. Solar PV emerges as the least cost option to meet electricity demand by 2050. Nevertheless, there are excellent wind sites in South Africa, particularly the Eastern Cape, Western Cape and Northern Cape. Beside solar PV, wind energy plays an important role in the transition. The total wind capacity is approximately 51 GW in BPS. Solar PV and wind energy drive most of the system in South Africa by 2050. Additional graphical results on sub-regional electricity generation, installed capacity, regional storage capacities and regional storage annual throughput in 2050 can be found in the Supplementary Material (Figs. S11–S14).

3.5. Analysis of GHG emissions under various transition scenarios

The GHG emissions trajectory during the transition for all scenarios is illustrated in Fig. 15. The red curve shows the ratio of CO_2 emitted per kWh of electricity. The emissions trend in the BPSs is visualised as shown in Fig. 15 (a and b). The emissions trend in BPS and BPSnoCC shows a similar pattern, as GHG emissions plateau by 2020 and decline afterwards in both scenarios. From 2025 onwards, emissions decrease substantially as coal-fired plants are replaced by RE capacities, mainly solar PV and wind energy in the BPSs. By 2050, a zero emissions system is achieved in the BPS. Deep decarbonisation of 75% to 71 Mt_{CO2eq} in 2030 and 98% to 10.2 Mt_{CO2eq} in 2040 as shown in Fig. 15a for BPS. The BPSnoCC shows a slower reduction in GHG emissions and zero emissions is not reached by 2050. However, deep decarbonisation of 70% to 89 Mt_{CO2eq} in 2035 and 96% to 16 Mt_{CO2eq} is still achieved for the BPSnoCC in 2050, as shown in Fig. 15b. The GHG emissions trend in the CPS is visualised in Fig. 15c. The annual GHG emissions reach its peak in 2030 and gradual decline afterwards as coal contribution in terms of capacity and generation declines in the system. In the CPS, GHG emissions decline from 214 Mt_{CO2eq} in 2030 to 151 Mt_{CO2eq} in 2050.

3.6. Water demand by power plants and job creation during the transition

3.6.1. Water demand of thermal power plants

Water withdrawal and water consumption of thermal power plants were calculated based on the water use intensity factors provided by Macknick et al. (2012) and using the methodology of Lohrmann et al. (2019). For the analysis, the subset of thermal power plants exceeding 50 MW was selected. This corresponds to 47.6 GW and accounts for 0.85% of the total thermal power generation capacity of South Africa. Fig. 16 depicts the exact location of the active thermal power plants presented for the analysis.

In 2015, total water consumption (combined freshwater and saline water) for thermal generation was 0.346 km^3, whereas total water withdrawal was 2.72 km^3. From the perspective of freshwater extractions, 0.331 km^3 of freshwater was consumed (96% of the total water

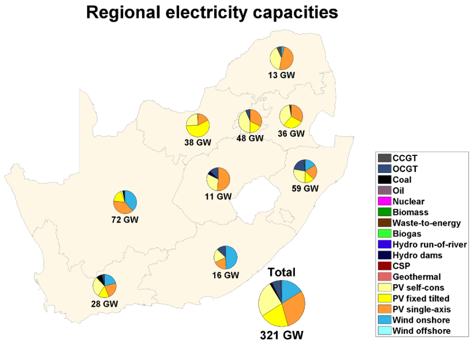

Fig. 14. Installed generation capacities for BPS across the nine sub-regions of South Africa for 2050.

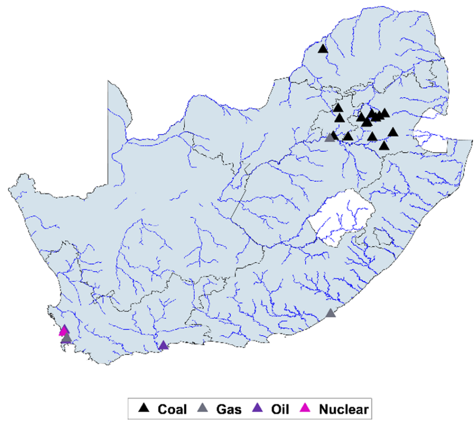

Fig. 16. Active thermal power plants exceeding 50 MW, per fuel type.

consumption) and 0.399 km^3 of freshwater was withdrawn (15% of the total water withdrawals). Currently, coal-based power plants account for 100% of the freshwater consumed. The 'leader' among regions in freshwater extractions is the Mpumalanga province constituting for 83% of all freshwater extractions for the power sector of South Africa.

The development of freshwater demand for both scenarios is illustrated in Fig. 17. According to the BPS, both freshwater withdrawal and consumption are estimated to be reduced 87% by the year 2030, and 99% by 2050, respectively, compared to the 2015 level. In 2050, gas-fired power plants consume 0.0001 km^3 of freshwater, which is expected to constitute for 100% of the countrýs annual freshwater consumption related to the power sector. Opposed to that, the projections of the CPS show a decline of only 38% in freshwater extractions by 2050. In 2050, thermal power plants consume 0.196 km^3 of freshwater, of which 99.7% is allocated for cooling of newly commissioned coal power plants. More information on the current water demand of thermal power plants and its' projected development during 2015–2050 is available in Supplementary Material (Tables S18–S21 and Figs. S15–S18).

3.6.2. Job creation for the Current Policy Scenario and Best Policy Scenario

The annualised direct jobs created in the power sector during the energy transition for the BPS, as well as the CPS were estimated based on the methodology presented by Ram et al. (2017a, 2019) and the assumed employment generation factors can be found in the Supplementary Material (Table S22). Solar PV is observed to be the prime job creator through the transition period, with 67% of the total jobs created by 2050, in the case of BPS as depicted in Fig. 17. Whereas, coal-based power generation creates the most jobs in the CPS, with 45% of the jobs by 2050 as indicated in Fig. 18. Overall, number of direct energy jobs created in the BPS are seen to grow massively from around 210 thousand in 2015 to nearly 408 thousand by 2035, with the massive capacity additions propelled by higher growth rates. Beyond 2035, as growth rates stabilise, jobs created are observed to steadily reduce to over 278 thousand by 2050. On the other hand, jobs created in the CPS remain quite stable with a marginal decrease to around 184 thousand by 2050.

Figs. 18 and 19 also indicate the distribution of jobs across the different categories during the transition period in the BPS as well as CPS. In the case of BPS, with ramp up of installations up to 2035, bulk of the jobs are created in the construction and installation of power generation technologies. The electricity demand specific jobs in the BPS increases substantially from 787 jobs/TWh_{el} in 2015 to 1148 jobs/TWh_{el} in 2025 with the rapid ramp up in RE installations. Beyond 2025, it stabilises around 1000 jobs/TWh_{el} and then declines steadily to around 511 jobs/TWh_{el} by 2050, as shown in Fig. 17. Whereas, the electricity demand specific jobs in the case of CPS decline continually from 2020 onwards to 338 jobs/TWh_{el} by 2050, as indicated in Fig. 19. The International Renewable Energy Agency (IRENA) estimated that the RE sector employed nearly 10 million people worldwide in 2016, with 62,000 jobs in Africa. Nearly half of these jobs are in South Africa and a quarter in North Africa (IRENA, 2017).

4. Discussion

Results of this research indicate that transition towards 100% RE-based system is achievable for South Africa. A 100% renewable based electricity is found to be the least cost option, consuming less water and creating more jobs than the current power system, which is mainly

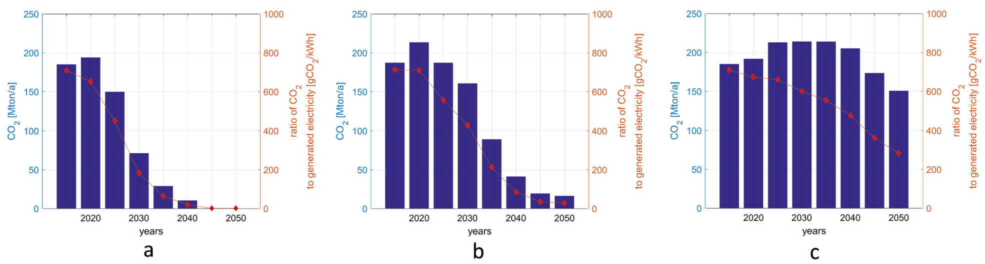

Fig. 15. The total annual GHG emissions and ratio of GHG emissions to electricity generation during the transition for BPS (a), BPSnoCC (b) and CPS (c).

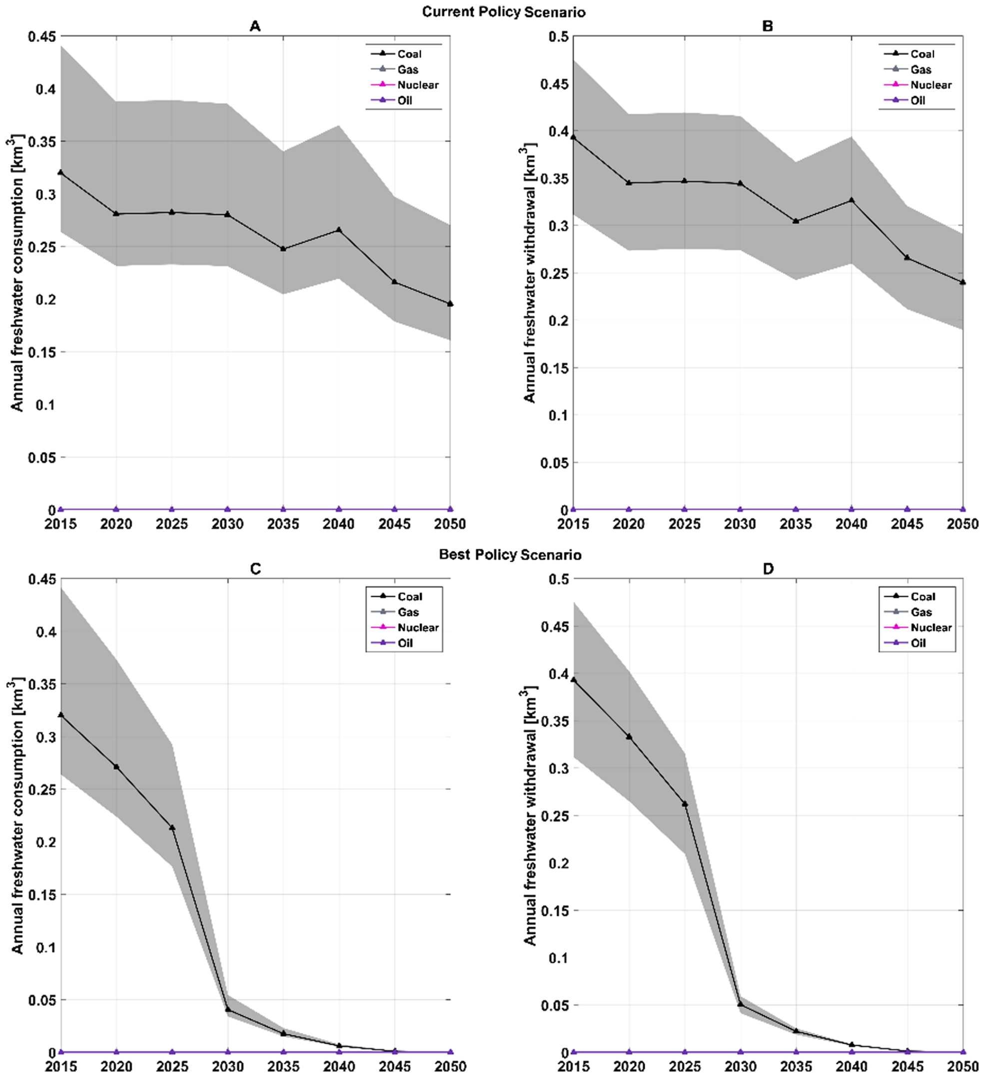

Fig. 17. Development of freshwater consumption and freshwater withdrawal (median values and min-max interval): the CPS (a and b) and the BPS (c and d).

driven by coal-fired power plants. An addition scenario is presented in the Supplementary Material, which describes the integration of the desalination sector to the power sector (BPS-DES). Additional information on the electricity generation profile and energy flow diagrams are provided in the Supplementary Material (Figs. S19–S24).

4.1. Analysis of key differences in Best Policy Scenarios and Current Policy Scenarios in 2050

This section compares the BPSs and the CPSs. Table 3 highlights the key differences in financial outcomes and selected electricity parameter for 2050. This research demonstrates that a fully decarbonised power system is the more cost optimal solution for South Africa by 2050. It reduces GHG emissions by 100% compared to the CPS. The total annualised cost of system in the CPS is 50% higher than in the BPS as show in Fig. 20. Whereas, the total annualised cost of system obtained for 2050 in the CPSnoCC is 20% higher than in BPSnoCC as show in Fig. 20. The total annualised cost of system required in CPSnoCC and BPSnoCC are relatively close until 2035, afterwards a disparity occurs as new investments in nuclear power plants are incurred in the CPSnoCC. Regarding capacity requirements, the BPSs are approximately 59% higher than required in the CPS. This is due to lower FLH of

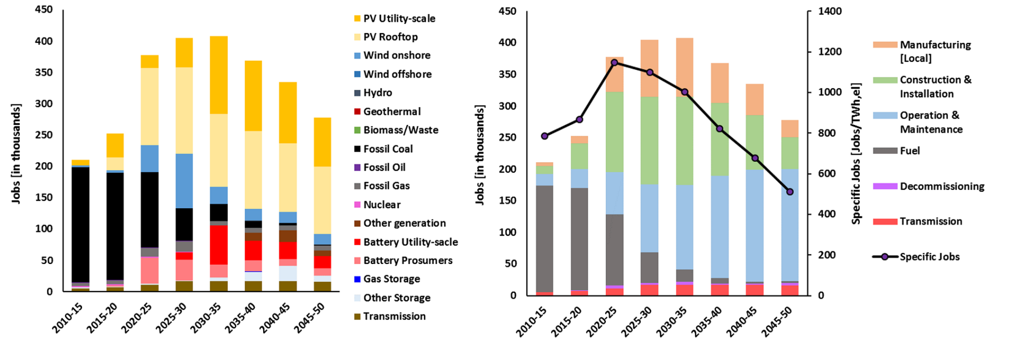

Fig. 18. Jobs created by the various power generation and storage technologies (left) and jobs created based on different categories with the development of electricity demand specific jobs (right) during the energy transition from 2015 to 2050 in South Africa for the BPS.

RE technologies, particularly solar PV and wind energy that dominate the power system in the BPS. While, the total generation in the BPSs are higher than the CPS by 16%, approximately. Results for the fully renewable end-point scenarios indicate that there is no need for high cost and high risk nuclear energy in the future South African electricity mix.

The LCOE obtained for the BPSs is comparable to Breyer et al. (2018), which shows a global range of 50–70 €/MWh. The annualised cost of system obtained for the year 2050 is 27.5b€, 25.5b€, 55.8b€ and 32.9b€ in the BPS, BPSnoCC, CPS and CPSnoCC, respectively. The financial outcomes of this research show that RE-based systems are economically feasible in South Africa. Most of the cost reduction can be attributed to low cost of solar PV, batteries and wind energy. In addition, RE has no fuel costs, which compensate for the entire system investments in the BPSs. Whereas, investments in fossil power plants in the CPSs might become a burden on the country's economy, as newly built coal or nuclear plants are likely to become stranded assets due to high relative cost, not only for the investment cost, but also the operation cost. In addition, the profitability of fossil fuel based technologies will be undercut by the increasing competitiveness of RE technologies (IEEFA, 2016). The 100% RE-based option for South Africa presented in this study is more cost competitive than the other alternative scenarios, which still have further disadvantages. South Africa is committed to reducing its GHG emissions, in pursuit of this goal, carbon capture and storage (CCS) is considered as part of its climate change mitigation strategy (Beck et al., 2013; Surridge et al., 2009). Energy system options, such as nuclear and fossil-CCS are not cost competitive (Breyer et al., 2018). According to Ram et al. (2017b; 2018), coal-CCS CAPEX are around 3891 €/kW in 2030, while the LCOE is around 105 €/MWh. For gas-CCS, the CAPEX ranges from 1934 €/kW to 2118 €/kW in 2030, the respective LCOE ranges from 94 €/MWh to 130 €/MWh. The LCOE assumed for new technologies in South Africa, shows that the tariffs in the year 2015 for solar PV and wind energy are 38% and 40% lower than LCOE for new baseload coal and nuclear (Wright et al., 2017). Furthermore, based on South Africa's decommission plan, another BPS scenario was simulated with coal and nuclear power plant decommissioning schedule set to 50 and 60 years, respectively. The result shows that by extending the coal and nuclear decommissioning schedule the power system will incur additional cost from 2030 onwards, until around 2045, in the range of 0.02–1.01b€/a (0.1–3.9% of total annualised system cost).

The high costs observed in the CPS, is due to new investments in thermal power plants, in particular nuclear power plants from 2040 onwards. In fact, the relative cost difference may be higher in the CPS than the BPS, if capex assumptions for coal are considered according to IRP 2018 (DOE, 2018). Representatives from South Africa's largest utility mentioned, in early 2018, that nuclear would not be at the top of the agenda and South Africa simply could not afford nuclear (EWN, 2018). In addition, nuclear projects are susceptible to huge cost overruns (Sovacool et al., 2014). Moreover, new investment in coal power plants in South Africa should be carefully considered, as recently added coal-based power plants have already become stranded assets in several countries (Ram et al., 2017b; Farfan and Breyer, 2017; IEEFA, 2016).

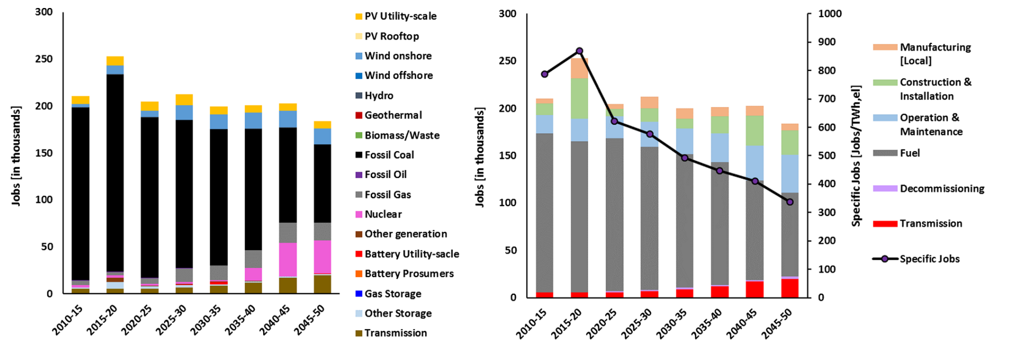

Fig. 19. Jobs created by the various power generation and storage technologies (left) and jobs created based on different categories with the development of electricity demand specific jobs (right) during the energy transition from 2015 to 2050 in South Africa for the CPS.

Table 3
Difference in electricity parameters and financial outcomes in 2050 for all scenarios.

		unit	BPS	BPSnoCC	CPS	CPSnoCC
Financial outcome	Total annualised cost of system	[b€]	27.5	25.5	55.8	32.9
	Levelised cost of electricity	[€/MWh$_{,el}$]	50.8	47.1	104.9	62.8
Electricity parameters	Demand	[TWh$_{,el}$]	539.8	539.8	539.8	539.8
	Generation	[TWh$_{,el}$]	648.1	606.2	561.1	561.1
	Installed capacity	[GW]	321.1	294.6	133.5	133.5

The results of the BPSs show that no new coal and nuclear will be required in the least-cost expansion. Furthermore, nuclear energy violates all sustainability criteria that should form a framework for a resilient energy system design (Child et al., 2018).

4.2. Role of RE and storage technologies

The power system optimisation shows solar PV followed by wind energy drive the energy system in the BPS and BPSnoCC. The outstanding role of PV technologies needs to be highlighted in RE dominated scenarios for the case of South Africa. It is least-cost to supply 71–73% of electricity demand from solar PV alone. PV prosumers contribute 22% to the total electricity generation in 2050. Based on living standards measure 7 (LSM7) households and 5 kW household installations, embedded generation residential and commercial PV in South Africa could reach 22.5 GW by 2030 (Tuson, 2014). There are already developed regulations to guide the implementation of small-scale solar PV embedded generation in South Africa (Tuson, 2014). In addition, South Africa is recognised to have a huge solar potential, which is largely untapped. Barasa et al. (2018) reported on the impact of PV prosumers on a 100% RE system for Sub-Saharan Africa for 2030 cost assumptions and concluded that the total system cost increase slightly by 3.4–3.6%, while the electricity costs of the PV prosumers go down, whereas the peak load is reduced by 5.2%, which may lead to cost reductions beyond the scope of that study. PV prosumers installed capacity increases during the transition as the retail electricity prices increase. The growth is propelled by continuous decline in PV battery capex anticipated during the transition. The PV prosumers appear to be an important enabler of the transition. A study estimates the utility-scale solar PV projects to be equivalent to 220 GW using existing environmental impact assessment, while a conservative estimation for rooftop solar PV showed a potential capacity of 72 GW (Knorr et al., 2016). Both the rooftop and utility-scale solar PV showed a conservative potential of about 292 GW. The plausible reason for a high solar PV penetration is due to excellent resource conditions, low seasonal variation unlike other countries where solar PV supply drops in winter months and continuous cost decline of PV (Bischof-Niemz and Creamer, 2018; Breyer et al., 2018). Wind energy is expected to supply 22–28% to the total generation in 2050. However, wind energy contribution remains constant from 2030 onwards, due to further costs decline of solar PV and battery storage. In addition, if the wind capex would decline faster, a higher share of wind power generation could be expected. South Africa has the solar, wind and land resources to technically host a power system led by a mix of RE technologies (Bischof-Niemz and Creamer, 2018). The specific capacity density limited in the LUT Energy System Transition model is 75 MW/km^2 for optimally tilted PV and 8.4 MW/km^2 for onshore wind (Bogdanov and Breyer, 2016). Hence, an area of 3260 and 6180 km^2 is needed for solar PV and wind capacities in 2050 representing just 0.3% and 0.5% of the total land area of South Africa. The results of this study show that solar PV and wind energy will emerge as the backbone of a fully RE-based power system in South Africa, which is comparable to the findings of Barasa et al. (2018) for entire Sub-Saharan Africa (SSA) based on an overnight scenario approach for 2030. They conclude that SSA countries can be powered mainly by solar PV and wind energy. The Greenpeace Advance Energy [R]evolution scenario (Greenpeace, 2011), projects higher annual RE growth rates, thus achieving a renewable electricity share of 94% and RE installed capacity of 114 GW by 2050. According to Greenpeace (2011), solar PV dominates the installed capacity with 40 GW (35%), followed by CSP with 35 GW (31%), and wind energy with 27 GW (24%) by 2050. However, in the generation mix CSP dominates with 259 TWh (54%), complemented by solar PV with 79 TWh (16%) and wind energy with 68 TWh (14%) (Greenpeace, 2011). The Council of Scientific and Industrial Research (CSIR) demonstrates that solar PV, wind and flexible power generators are the cheapest energy mix for South African power system (Wright et al., 2017). The study demonstrates a least cost option for the South African power system with over 70% of RE penetration by 2050, which uses less water and provides a higher number of job opportunities (Wright et al., 2017). According to Wright et al. (2017), solar PV and wind energy dominate the total

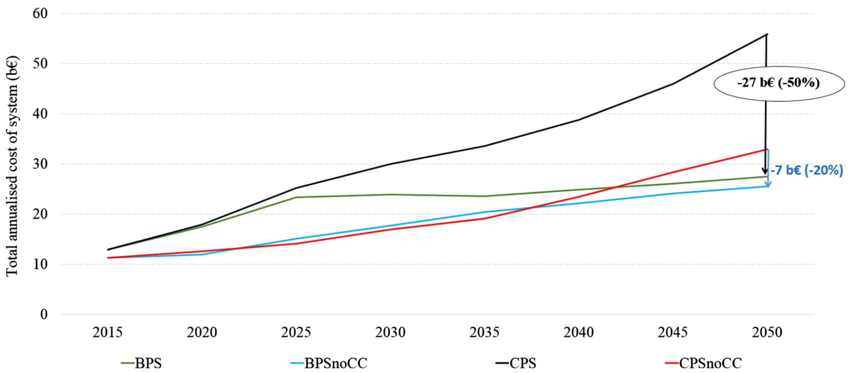

Fig. 20. Comparison of total annualised cost of system for all scenarios in 2050.

installed capacity with 140 GW (45%) and 73 GW (23%), while electricity supplied by solar PV is 213 TWh (36%) and wind is 223 TWh (38%), whereas no CSP generation is expected. The results of the BPSs in this study are comparable to the findings of Wright et al. (2017, 2019). In the CPS, fossil power plants dominate the power system accounting for 72% (383 TWh) of the total electricity generation in 2050. Among the RE technologies, wind energy emerges as a relevant resource in the CPS by 2050, which contributes 114 TWh (21%) of the total electricity generation by 2050. Upon the completion of Inga 3, 2.5 GW of the capacity is expected to be supplied by hydropower transmitted to South Africa. Electricity imports increase from 2030 onwards, in the CPS due to imports from Inga 3. The major risks associated with relying on hydropower imports are delays in the construction of the necessary grid extension as well as the hydropower plant (DOE, 2018). Oyewo et al. (2018) conclude that South Africa and other neighbouring countries can benefit from the Inga hydropower development. While the host country may bear most of the economic burden, not to mention the environmental risks. Results of the BPSs indicate that South Africa could independently meet its electricity demand without any electricity imports.

The results of this research reveal the significant role of PtG for handling high shares of RE, as discussed in (Gulagi et al., 2018; Ram et al., 2017a; Pleßmann et al., 2014; De Boer et al., 2014). The significance of battery storage is noticed from 2025 onwards, particularly in the BPSs. Regarding storage outputs, battery storage dominates due to daily requirements. By 2050, battery total output is 183 TWh (92% of total storage output) and 186 TWh (92%) in BPS and BPSnoCC, respectively. The role of prosumers and utility-scale batteries increased significantly from 2030 onwards. PV-battery hybrid systems emerge as the least cost option in a fully optimised RE system. Further cost reduction of batteries is expected (Schmidt et al., 2017; Kittner et al., 2017), which will increase PV growth (Breyer et al., 2018). Storage requirement is low in the CPS due to the dominance of thermal power plants that run on high FLH. Grid utilisation is very high in the beginning and towards the end of the year, particularly due to balancing demand in power deficit sub-regions in the BPSs. In the CPS, power plants are site specific and transmission grids are frequently utilised to supply electricity across the country. This clearly indicates the advantage of a distributed power system observed in the BPSs, as each region could produce its own electricity and import only when needed. The role of dispatchable gas technology is observed in the BPSs, as it is required to maintain balance between demand and supply in the power system. The role of gas turbines in a fully RE system is discussed in (Greenpeace, 2011). According to Greenpeace (2011), gas turbines installed capacity is 10 GW and generation is 16 TWh. Similarly in the CPS, gas technologies respond in times of high demand. A recent study on energy transition in South Africa concludes that a power grid with high RE penetration, in particular solar PV and wind energy requires flexibility that could be provided by using flexible natural gas fired turbines, if the costs of battery do not decrease (Klein et al., 2018).

4.3. Benefits of 100% RE

Examining the application of a GHG emissions cost during the transition, especially in the BPSs results in a rapid transition and fast GHG emissions reduction in comparison to no GHG emissions cost scenarios. However, the no GHG emissions cost scenarios achieved comparable results in terms of capacity, generation, cost of electricity and GHG emissions trajectory to the BPSs. By 2050, the RE electricity generation reaches 95.6% (579 TWh) in the no GHG emissions cost scenario, while the remaining 4.4% (26.9 TWh) is supplied by coal and gas turbines. The BPSnoCC is about 17% lower in total costs than the BPS, but 7% lower in costs than the CPSnoCC and 42% lower in total GHG emissions for the period 2015 to 2050. This indicates that the South African energy transition is achievable without GHG emissions cost implementation, if least cost options are chosen.

This study presents a pathway to a fossil carbon-free economy for South Africa on an hourly basis in 5-year intervals, which makes this study unique and a first of its kind. From an energy security perspective (Azzuni and Breyer, 2018), analysis of this research reveals that South Africa could achieve a secure power supply without imports. RE development in the country will foster socio-economic development, the results show that the BPS could boost employment prospects in South Africa. The direct energy jobs created in the BPS are seen to grow massively from around 210 thousand in 2015 to nearly 408 thousand by 2035, with the massive capacity additions propelled by higher growth rates. Beyond 2035, as growth rates stabilise jobs created are observed to steadily reduce to over 278 thousand by 2050. Whereas, jobs created in the CPS remain quite stable with a marginal decrease to around 184 thousand by 2050.

The findings of this research align with the perspectives of a recent review on the feasibility of 100% RE systems (Brown et al., 2018). Results of this research clearly show that a fully decarbonised South African power system can be achieved between 2040 and 2050. Deep decarbonisation of South Africa's energy system is technically and economically feasible by 2050. Owing to the low-cost electricity driven by solar PV and wind, South Africa can progressively pursue an electrification-of-almost-everything strategy by coupling the low-cost renewables-led electricity generation to the transport and heat sectors (Bischof-Niemz and Creamer, 2018). This research presents a detailed transition pathway towards a least cost and fully decarbonised power system by 2050, which complies with the Paris Agreement target of limiting temperature rise to 1.5 – 2 °C compared to the pre-industrial age.

5. Conclusion

The modelling outcomes reveal that a fully RE-based system is cost competitive and reliable as observed in the BPSs in comparison to the CPSs. The total system LCOE obtained in the BPSs ranged from 47.1 €/MWh to 50.8 €/MWh and from 62.8 €/MWh to 104.9 €/MWh in the CPSs by 2050. Much of the cost savings can be characterised by realistic ongoing cost decrease of RE technologies expected during the transition, especially high competitiveness of solar PV-battery hybrid systems and wind energy. Solar PV and wind dominate all the BPSs by 2050, solar PV contributes the most (75–79%) and wind energy (11–16%) to the total installed capacities, and (71–73%) and (22–28%) to the total electricity generation, respectively.

Storage technologies, transmission grids and gas power plants provide the required flexibility in a fully RE-based power system. The huge share of solar PV in electricity generation leads to a corresponding share of battery storage due to daily requirements. Gas storage becomes prominent when the RE share reaches 80% around 2035 in the BPS, balancing seasonal variation of wind and solar PV in the system. The existing coal and nuclear plants are expected to be phased out based on their lifetimes. However, new investments in coal and nuclear power plants may become stranded assets, which may be permanently subsidised. In addition, they stand the risk of cost overruns as in the case of Medupi and Kusile coal-fired power projects. Introducing GHG emissions cost would result in a rapid energy transition. Zero GHG emissions energy system is achieved in the BPS by 2050, when the GHG emissions cost is considered. Although, a similar emissions trajectory is observed in the BPSnoCC, but zero GHG emissions could not be achieved by 2050. The results of the BPS without GHG emissions cost indicate that RE electricity generation can reach 95.6%, while coal and gas turbines cover the remaining 4.4% by 2050

Energy policy in South Africa should place solar PV and wind energy at its core. It is clear that these technologies are set to play an active role in South Africa's future energy system as they are the least cost options for electricity supply. A 100% RE-based system is achievable and a real policy option for South Africa. The results of this research clearly show that a fully renewable power system consumes less water and creates more jobs than a fossil dominated system. South Africa's electricity demand can be met sustainably with the country's abundant renewable resources particularly solar and wind. Solar PV-battery hybrid systems and wind energy drive most of the system from 2030 onwards in a fully RE-based system. Further research has to be conducted incorporating additional energy sectors, i.e. transport, heat and industry, for a wider analysis of the South African energy transition in the mid-term future.

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Appendix A. Supplementary material

Supplementary data to this article can be found online at https://doi.org/10.1016/j.solener.2019.09.039.

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Publication III

Mensah, T.N., Oyewo, A.S., and Breyer, C.

The role of biomass in sub-Saharan Africa's fully renewable power sector - The case of Ghana

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The role of biomass in sub-Saharan Africa's fully renewable power sector – The case of Ghana

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ABSTRACT

Sub-Saharan Africa is a region with a large population living without electricity. This study investigates the grid balancing role of bioenergy in a sub-Saharan Africa's fully renewable power sector to address the energy poverty challenge in the region, using Ghana as a case country. Two methods are employed: the bioenergy estimation method, for deriving Ghana's technical bioenergy potential, and the LUT model, for the power sector transition modelling. The Ghanaian bioenergy potential of 48.3 TWh is applied on the power sector using the LUT model to develop six alternative scenarios, emphasising on the role of bioenergy, greenhouse gas emissions costs, and climate change mitigation policies. The results of the Best Policy Scenario reveal that with an electrical efficiency of 37.2%, 18 TWh of electricity, which is 16.9% of Ghana's electricity demand by 2050, could be produced from bioenergy for grid balancing. Also, the levelised cost of electricity declines from 48.7 €/MW in 2015 to 36.9–46.6 €/MWh in 2050. Whereas the cost of electricity increases to 76.4 €/MWh in the Current Policy Scenario without greenhouse gas emissions costs. The results show the viability of a relatively cheap and bioenergy balanced sustainable renewable power system for the sub-Saharan African region.

1. Introduction

In recent years, researchers have become increasingly interested in the global energy transition from a polluting and depleting fossil fuel based energy system to a renewable energy (RE) based system [1–5]. According to the International Energy Agency (IEA) [6], by 2021, the global total renewable electricity generation will exceed 7600 TWh (60%) of increase in electricity production from 2015 to 2021, of which solar photovoltaics (PV) and wind energy account for about 5700 TWh (75%) of the global renewable electricity growth [7]. The growth of RE resources in the global energy system due to cost decline [8], is a good indicator and a glimmer of hope for providing relatively clean and affordable electricity in the sub-Saharan Africa (SSA) region, which is one of the energy deficit regions in the world. To win the fight against the energy poverty challenge in SSA, a sustainable energy revolution is urgently needed. The electricity demand growth in the SSA region could be supplied with the vast RE resources available in the region [9,10].

1.1. SSA power crisis and the prospects of renewable energy

The SSA region has the lowest electricity access rate in the world, about two-third of the world inhabitants living without electricity are homed in SSA. According to the World Bank, in thirteen SSA countries, not more than 25% of people have access to electricity [11]. The demand for electricity grows twice as the global average [10]. Nearly 890 million people use traditional fuel for cooking and 600 million people lack electricity. Economic growth has been low at 3% in 2019. Sustainable development and economic growth are stifled by this dramatic lack of energy access [12–14].

In order to achieve self-sufficient, sustainable, and climate friendly power sector to conform with the Paris Agreement [10,15], the transitioning of the SSA power sector, as also discussed in the Sustainable Development Goal 7 (SDG 7) [16], is very important in reducing greenhouse gas emission (GHG). Therefore, the share of RE resources is anticipated to increase significantly in a defossilised SSA power system [10,17]. The vast renewable resources and decreasing technology costs could be a driving factor for the deployment of utility-scale and distributed PV, wind, and other renewables across the region to meet the SDG agenda by 2030 [10,18].

Moreover, the structure and generation mix of the SSA power system is less complex and costly during the transition period since

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Nomenclature

AD	anaerobic digestion
BPS	Best Policy Scenario
CAPEX	capital expenditure
CCGT	combined cycle gas turbine
CPS	Current Policy Scenario
CO_2	carbon dioxide
CHP	combined heat and power
FAO	Food and Agriculture Organization
FLH	full load hours
FSS	Faecal sewage sludge
GT	gas turbine
GHG	greenhouse gas
HVDC	high voltage direct current
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
LCOC	levelised cost of curtailment
LCOE	levelised cost of electricity
LCOS	levelised cost of storage
LHV	lower heating value
MSW	municipal solid waste
MW	Megawatt
OCGT	open cycle gas turbine
OPEX	operational expenditure
PURC	Public Utilities Regulatory Commission
GW	Gigawatt
LCOT	levelised cost of transmission
LNG	liquified natural gas
PV	photovoltaic
PJ	Petajoules
RE	renewable energy
RES	renewable energy sources
RoR	run-of-river
RPR	residue to product ratio
SNG	synthetic natural gas
SDG	Sustainable Development Goals
SHS	solar home systems
SSA	sub-Saharan Africa
TWh	Terawatt-hour
VRE	variable renewable energy
WACC	weighted average cost of capital
WB	World Bank

most countries in the region rely significantly on hydropower of 36 GW of the total 50 GW of renewable capacity as of 2019 according to IEA [10], and other studies [19–21].

1.2. Renewable energy potential and PV cost decline is a major driving factor

The SSA region is undoubtedly endowed with high potential of renewable energy resources such as wind, solar, hydro, and biomass. According to Ref. [22], the total RE potential in the SSA region is estimated to be around 370 PWh, 560 PWh, and 330 PWh for CSP, PV, and wind, respectively. About 12% of the world's hydropower potential is held in Africa, with a technical potential of 1800 TWh/year. The biomass potential is estimated to be up to 1649 TWh [22–24]. According to Ref. [25] the total primary energy demand in the SSA was 2700 TWh in 2015, and is projected to about 6800 TWh by 2050. The RE potential of the region is therefore capable of satisfying the demand in a fully RE system considering the available RE resource potential.

Furthermore, recent studies show that, the global weighted average levelised cost of electricity (LCOE) of utility-scale solar PV systems have reduced by 68% within a period of seven years (2010–2017) [8,26]. Examples for new record low cost for solar PV on LCOE basis can be found all around the world in countries like Abu Dhabi, Chile, Dubai, Mexico, Peru, the US and Saudi Arabia, all around 20 to 26 €/MWh [8,27], or even below, as for the case of Qatar [28] and Portugal [29]. It is estimated that, solar energy will provide about 87% of the total primary energy demand in SSA by 2050 [25], therefore, declining technology cost is a good indication that the needed energy revolution is forthcoming. Zero "use phase" GHG emissions, besides low-cost energy is the key driver for RE resources to address the two biggest problems: climate change mitigation [30–32], and the regional challenge of energy poverty [33–35].

1.3. The challenge of power grid imbalance due to variable renewables and the proposed solution

The amount of power generated by solar and wind energy varies over the hours of a day and seasons, hence the term variable renewable energy (VRE). This variability characteristic of solar and wind resources affects the stability and reliability requirements of the power grid. Solar energy has been projected to contribute about 87% of the SSA primary energy by 2050 [25]. Therefore, in the event of mass deployment of VRE in the SSA region, possible grid balancing challenges may occur [36–38] due to the variability characteristic of solar and wind resources.

In this regard, this research work, argued that sustainable modern bioenergy being a dispatchable form of energy has the potential to play a significant role in balancing the SSA power grid, beside other storage options. To test this hypothesis, this research work estimates and evaluates the sustainable bioenergy potential of Ghana and applies the yielded potential on the power sector in a fully renewable scenario for the case of Ghana [39]. Biomass is an essential source of energy in the SSA region; therefore, this research work seeks to explore the power grid balancing potential of bioenergy in SSA.

1.4. Biomass situation and usage in SSA

In this section, the categories of biomass considered for this study and their current usage in SSA are investigated. Currently, the major source of RE in the world is bioenergy [39]. It is reported that about 81.2% of the total primary energy demand in SSA (excluding South Africa), is supplied by solid biofuels and waste [24]. Biomass will continue to be an essential energy resource for SSA in the future [24]. According to Lynd et al. [40] and Ambali et al. [41], SSA has huge untapped arable land, which could provide more sustainable bioenergy potential, especially from crop residues.

The categories of biomass considered in this research include forestry (forest residues), agriculture (crop residue, and livestock manure), and municipal waste (faecal sewage sludge and municipal solid waste).

Feedstock from forestry and agriculture biomass category are mainly used in traditional form in SSA [24] and the leftovers are disposed by burning in open fields [42]. Traditional biomass is the unsuitable and often unsustainable use of fuel wood, charcoal, tree leaves, animal dung and agricultural residue for cooking, lighting, and space heating. Studies have shown that the use of traditional biomass culminates in catastrophic health problems, such as pneumonia, chronic obstructive pulmonary diseases or lung cancer [24].

Also, in SSA, livestock manure is poorly utilised for fertilizer purposes, but largely, manures are left on glazing field and are not used [43,44]. Similarly, faecal sewage sludge (FSS) is poorly managed. It is estimated that only 50% of the FSS is collected, transported, and treated. Sometimes, the uncollected FSS is discharged into the environment [43].

Furthermore, the management of municipal solid waste (MSW) in most SSA countries is not yet developed. MSW is generally defined as the waste generated and collected by municipalities and other local authorities. MSW includes mainly domestic waste, institutional, and commercial wastes. The physical composition of MSW can be biodegradable, recyclable, and non-biodegradable. It is one of the most common, yet underused sources of biomass in SSA [45,46]. It is estimated that 65% (81 million tonnes) of the total MSW (125 million tonnes) generated in Africa in 2012 was from SSA. MSW generation per capita in the region is expected to grow from 0.72 kg/capita in 2012 to 0.99 kg/capita in 2025. If the current solid waste generation rate persists, SSA is projected to substantially contribute to the global MSW generation. The most common method of disposing MSW is illegal dumping. Unlawful solid waste dumping results in GHG emissions, leachate to underground water, topsoil contamination, odour, and usually requires large space. Waste-to-Energy power plants are almost absent in the SSA region [45,47–49]. With appropriate investment in bioenergy technologies, it is estimated that 312.5 TWh (1125 PJ) in 2012 and 610.8 TWh (2199 PJ) in 2025 could have been obtained from MSW through landfill gas recovery and incineration respectively in Africa [50].

Certainly, the traditional usage and management of the abovementioned biomass in SSA is unsustainable. The traditional form of biomass usage in the SSA region violates most of the biomass sustainability indicators [51,52], hence the need for appropriate investments in bioenergy technologies to provide a paradigm shift from traditional to sustainable modern bioenergy.

In this regard, the need to present a pathway to transform the unsustainable traditional biomass usage in SSA to a sustainable modern bioenergy usage is urgent. Sustainable modern bioenergy is defined in this research as the energy derived from sustainable biomass, i.e. biomass streams from agriculture (crop residue and livestock manure), forestry (forest residue), and municipalities (FSS and MSW), to generate power via efficient technologies to balance the power grid. The impact of sustainable bioenergy on a fully renewable power sector of SSA has not yet been studied. Therefore, this research seeks to explore the biomass streams from residues and waste of SSA and apply the yielded bioenergy potential in a fully renewable power sector scenario using Ghana as a case study. To the best of the knowledge of the authors, no other study has investigated this area of research.

1.5. Case study

Several countries in SSA share similar tropical climate conditions. This study considers Ghana as a case for the SSA region. It is assumed that the climate and energy conditions in Ghana reflect the conditions in other SSA countries. In addition, Ghana and South Africa are among the few SSA countries that have managed to achieve a high percentage of electricity access and are among the first countries to draft a sustainable energy for all (SEforAll) action plan [53].

Ghana has very good potential to harness enough energy from RE resources, especially from solar [54], wind, hydro and biomass. Studies show that the total biomass power and solar PV capacities are still comparably low in Ghana at 8 MW and 63 MW respectively by the end of 2019, according to IRENA [55] or 144 MW of PV installed capacity at the end of 2017 according to Werner et al. [56], based on a different method.

Bioenergy has been the core of the Ghanaian energy system for decades and it is expected to play a pivotal role in the future energy system of the country due to its ready availability and GHG reduction potential [57]. In order to replace fossil fuels (natural gas and oil), which emit CO_2 and trigger climate change [58,59], modern biofuels, biogas, and solid biomass could be used to relieve the Ghanaian power sector from its strong dependence on fossils. Biomass, locally produced and often close to demand, could be used in tandem with hydropower and PV systems to balance the power system affected by the variable nature of solar energy. A variety of micro combined heat and power (CHP) plants, which burn solid biomass are available. Likewise, on a domestic level, new and appropriate technologies could be developed for biomass conversion to electricity to meet local demand.

However, it is worthwhile to mention the limited availability of biomass resources due to technical and financial barriers which has been highlighted in Refs. [60,61] as a hindrance to include high shares of bioenergy in energy policy development. Likewise, the biomass demand by other sectors of the energy system such as transport and heat (industry and cooking) may limit the biomass available for power production. As a result, this power sector study has considered the sustainability criteria and has restricted the use of biomass for power generation to 35% use-factor for crop and forest residues, and 80% use-factor for livestock manures, and 80% for kitchen waste, and FSS.

With regards to Ghana's bioenergy potential, Duku et al. [62] reported a potential of 20.8 GWh (75.2 TJ) from crop residues. Kemausour et al. [63] also reported a potential of 76.4 TWh (275 PJ) and 250 TWh (900 PJ) by 2011 and 2030 respectively from residue and waste. This study focuses on using different pathways to estimate the bioenergy potential of Ghana, considering residues and waste and further apply the yielded potential on the Ghanaian power sector in a fully renewable scenario.

Technologies such as direct combustion and anaerobic digestion has been considered in this study. According to the World Bank (WB), these technologies are viable options and alternatives for developing countries [64].

It is assumed that electricity is produced via steam turbines and gas turbines for direct combustion and anaerobic digestion, respectively. Heat recovery is not considered in this study. Additional background information on Ghana is available in the Supplementary Material.

This paper is organised as follows: Section 2 presents the research methods. Section 3 presents the results. Results are discussed in detail in section 4. Conclusions and policy implications are presented in section 5. The diagram flow of the paper in shown in Fig. 1 below.

2. Research methods

Two research methods are described in this section. The bioenergy potential method is first described, and then the LUT model for the Ghana power sector transition simulation.

2.1. Bioenergy potential estimation method

This section presents the method used for the bioenergy potential estimation. Ghana is endowed with biomass resources, which includes crop residues, wood waste, MSW, animal waste, algae, sewage sludge, and aquatic plants [62,63,65]. In order to avoid violation of biomass sustainability criteria, three main biomass sources are considered, namely, forestry (forest residues),

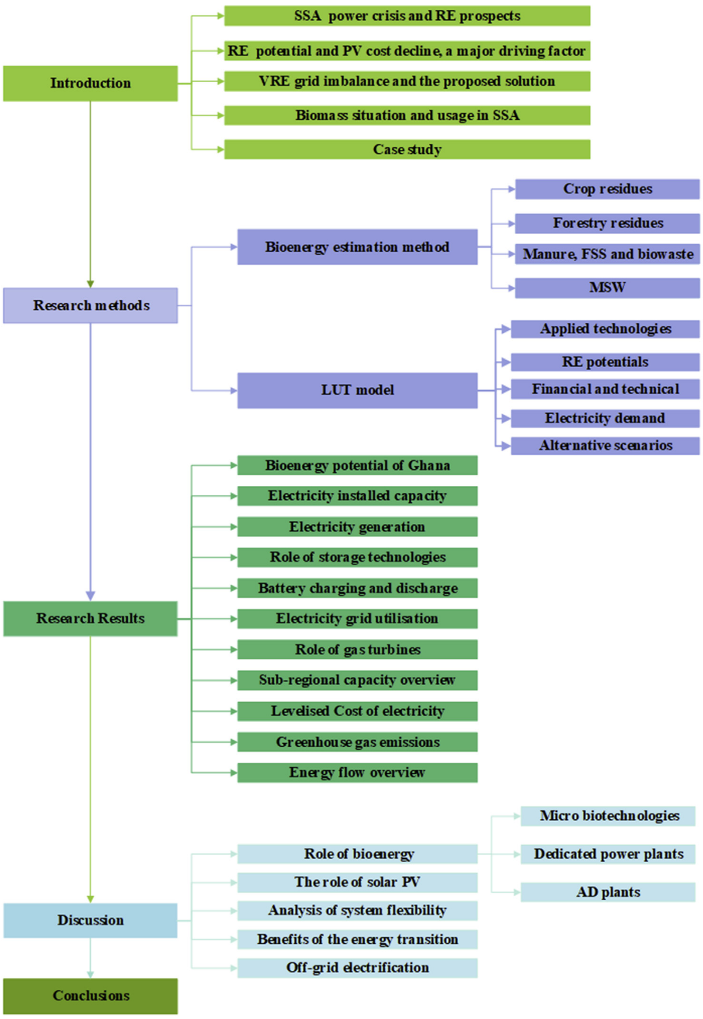

Fig. 1. Flow chart of the paper.

agriculture (crop residue, and livestock manure), and municipal waste (MSW and FSS). Algae, aquatic plants, energy crops and industrial residue are not considered in the bioenergy calculations.

The data obtained for the case of Ghana are from literature.

Fig. 2 shows the methodological pathways for the bioenergy potential estimation and evaluation.

Residues with less moisture content such as crop residues, wood residue, and MSW (excluding food waste) are treated with direct combustion technology, while those with high moisture content such as kitchen or food waste, livestock manure, and FSS are treated with anaerobic digestion technology.

2.1.1. Energy potential of crop residues

Energy from crop residues is calculated based on FAO data [66] for the Ghanaian crop production in 2015. The residue to product ratio (RPR) [67] parameter is used to estimate the amount of residues available based on the reported product yields. All energy units are accounted for the lower heating value (LHV) obtained

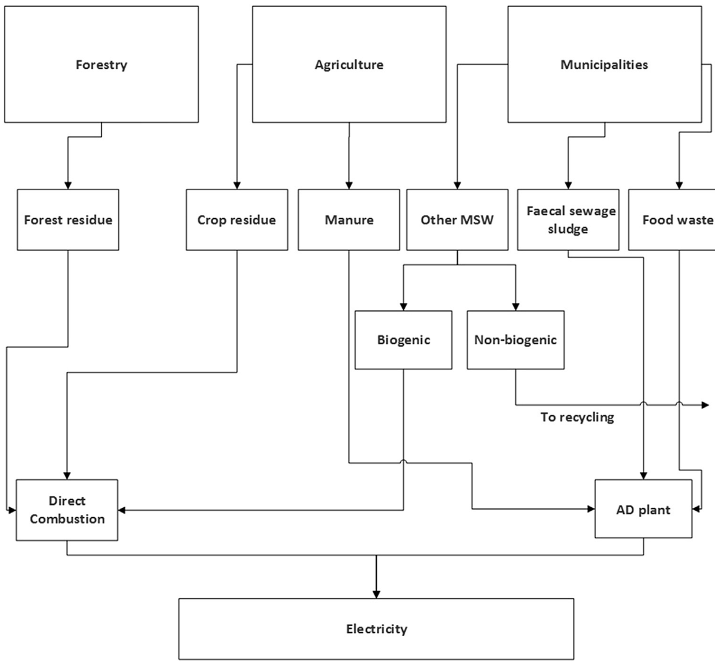

Fig. 2. Bioenergy potential estimation methodological pathways.

from Ref. [68]. It is assumed that the availability or use factor for residues is 35% [69] for the case of Ghana. Annual crop residue energy potential is calculated according to Eq. (1).

$$E_{CR} = \sum_{i=1}^{n} (CP_i \cdot RPR_i \cdot LHV_i \cdot fuse) \quad (1)$$

where (E_{CR}) is energy potential of crop residue per annum, (*CP*) is crop production for the reference year 2015, (*RPR*) is the residue to product ratio of a crop and (n) represents the total number of crops considered. *(LHV)* is the lower heating value of a specific crop residue and *(fuse)* is the use factor.

2.1.2. Energy potential of wood residues

For wood residues, the annual bioenergy potential is calculated according to Eq. (2).

$$E_{FR} = \sum_{i=1}^{n} (WP_i \cdot RPR_i \cdot LHV_i \cdot fuse) \quad (2)$$

where (E_{FR}) is the energy potential of forest residues per annum, *(WP)* is the total wood production for the reference year [70]. (*RPR*) is the residue to product ratio of a wood type [68] and (n) represents the total number of wood types considered. (*LHV)* is the lower heating value of specific wood residue [71] and *(fuse)* is the use factor.

2.1.3. Energy potential of livestock manure, FSS, and organic biowaste

The amount of livestock manure available for bioenergy is estimated based on manure per head of livestock per annum [72] and applied for the case of Ghana based on FAO [73] data on livestock for a reference year. The use factor for livestock manure is assumed to be 80% for the case of Ghana. FSS is estimated based on population data and specific faeces per person per annum. Respective data for Ghana is extracted from Ref. [74]. Bio-waste (kitchen waste) is estimated by population and generation per capita per annum [75].

Annual availability of livestock manure, FSS and food waste is estimated according to Eqs. (3)–(5) respectively. The total biodegradable feedstock allocated for anaerobic digestion is calculated with Eq. (6).

$$M_a = \sum_{i=1}^{n} (P_a \cdot M_i \cdot fuse) \quad (3)$$

$$S_s = (P_h \cdot H_f \cdot f_{use}) \quad (4)$$

$$Q_{bw} = (W_{bio} \cdot P_h \cdot f_{use}) \quad (5)$$

$$F_i = (M_a + S_s \cdot Q_{bw}) \quad (6)$$

where (M_a) is the manure available per annum, *(P_a)* is the animal population per annum, (M_i*)* is the manure per head per annum in tonnes, *(n)* is the categories of livestock considered, and (*fuse)* is the

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use factor of 80% for Ghana. (S_s) is FSS available per annum, (P_h) is human population as of the chosen reference year, and (H_f) is faeces per capita per annum, (Q_{bw}) is the total bio-waste (food waste), (W_{bio}) is the bio-waste generation per capita per annum, (P_h) is the human population and (F_i) is the total feedstock.

Livestock manure, FSS, and organic bio-waste (food and garden waste) are treated with anaerobic digestion to maximise the biogas output due to high moisture content. The energy content of the biogas is estimated with Eq. (7) below.

$$E_{BG} = \sum_{i=1}^{n} (F_i \cdot T_{s,i} \cdot V_{s,i} \cdot Bio_{vs,i} \cdot C_{CH_4} \cdot LHV_{CH4}) \tag{7}$$

where (E_{BG}) is the estimated energy content of biogas per annum, (F_i) is the total feedstock, (T_s) is the total solid share of the feedstock, factored in as a percentage value, (Vs) is the volatile solid share of the total solid, (Bio_{vs}) is the biogas yield per tonne of volatile solid, (C_{CH4}) is the methane content of biogas, (LHV_{CH4}) is the lower heating value of methane [76–78].

2.1.4. Energy potential of MSW

MSW generation per capita is obtained for the case of Ghana from Ref. [75]. MSW is assumed to be treated with an incineration process for bioenergy use. Organic bio-waste (food and garden waste) is assumed to be source-separated and treated in an anaerobic digestion process described in Eq. (5). Since the focus is renewables, only the biogenic share of the MSW is considered. Biogenic part of the MSW is the fraction of MSW which is considered to be biomass originated and therefore, considered as renewable. Examples of such fractions includes paper and cardboard, pampers, textiles from plants, rubber from plants, used wood, paper packaging, and leather [79]. The energy potential of the biogenic MSW is estimated according to Eq. (8).

$$E_{MSW} = (Q_{MSW} \cdot P_h \cdot MSW_{bio} \cdot LHV_{MSW}) \tag{8}$$

where (E_{MSW}) is the total energy potential of MSW per annum, (Q_{MSW}) is the MSW generation per capita per annum (excluding food waste which is already accounted in Eq. (5)), (P_h) is the population for the reference year, (MSW_{bio}) is the biogenic share of the MSW [80], and (LHV_{MSW}) is the lower heating value of mixed MSW fractions [50]. It is assumed that all non-biogenic fractions are recycled.

The main feedstocks considered for the Ghanaian bioenergy estimation is presented in Table 1 below.

The total bioenergy harnessed from the above feedstock is calculated with Eq. (9).

$$E_{BIO} = E_{CR} + E_{FR} + E_{BG} + E_{MSW} \tag{9}$$

The obtained technically harvestable bioenergy potential of Ghana is then applied on the Ghanaian power sector in fully renewable scenarios using the LUT model which is described below.

2.2. LUT Energy System Transition model

The Ghanaian power sector is modelled with the LUT Energy System Transition model described in Ref. [1]. The 16 administrative regions of Ghana are merged into six sub-regions forming six nodes in the model. The six sub-regions are:

- Eastern-Coastal (GH-EC): Greater Accra, Volta and Oti regions
- Western-Coastal (GH-WC): Central, Western and Western North regions
- Central (GH-CEN): Eastern and Ashanti regions
- Brong Ahafo (GH-BA): Bono, Ahafo and Bono East regions
- Northern Territory (GH-NT): Northern, North East and Savannah regions; and
- Upper North (GH-UN): Upper East and Upper West regions.

These sub-regions are interconnected through a power transmission grid as depicted in Fig. 3.

The LUT Energy System Transition model, in short LUT model, is a linear optimisation tool, which performs an hourly resolution of the energy system with parameters for an entire year, under certain operational constraints and assumptions for the future RE powered system and demand. The principal objective of the model is to reduce the energy system total annualised cost. The energy system annualised cost comprises of the following: annualised capital expenditures of all installed technologies, operational expenditures, and fuel costs if applicable for all electricity generation and storage technologies and cost of generation ramping per annum. Fig. 4 shows the input and output parameters of the LUT model. Detailed model description, applied constraints and equations can be found in Bogdanov et al. [1].

In addition, the energy system planning includes residential, commercial and industrial PV prosumers, as studied in detail in Keiner et al. [82]. Depending on the cost, prosumers can decide to purchase electricity from the national grid or to install rooftop PV and Lithium-ion batteries for self-consumption, thereby prosumers

Table 1
Main contributors and sub-contributors for Ghana's bioenergy potential.

Index	Crop residue	Wood residue	Biogas	MSW
1	Sorghum	Wood fuel non-coniferous	Cattle manure	Paper
2	Millet	Saw logs and veneer logs	Goats manure	Leather
3	Rice	Industrial round wood coniferous	Pigs manure	Rubber
4	Sugarcane	Industrial round wood non-con	Poultry manure	Textiles
5	Beans	Wood charcoal	Sheep manure	Inert
6	Cashew nuts, shell		Sewage sludge	Miscellaneous
7	Sweet potatoes		Food bio-waste	
8	Groundnuts			
9	Yam			
10	Banana			
11	Plantain			
12	Coconut			
13	Oil palm fruit			
14	Coffee			
15	Cocoa			
16	Cassava			
17	Maize			

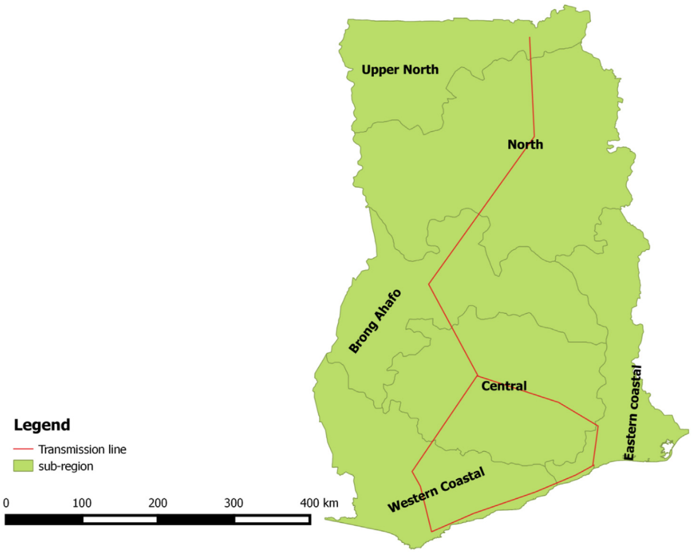

Fig. 3. The six sub-regions of Ghana and power transmission grid configuration.

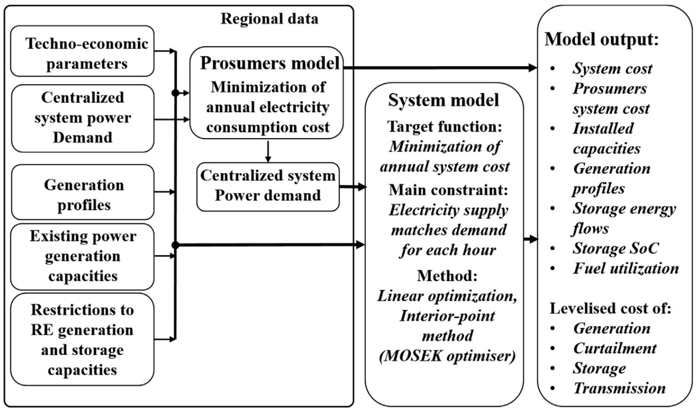

Fig. 4. Flow diagram of the LUT model [81].

can also sell generated excess electricity to the national grid for 0.02 €/kWh. The principal function of prosumers is to reduce the cost of consumed electricity. The total prosumer cost includes cost of self-generation, cost of grid electricity consumed and income for the sold excess electricity.

The model operates under certain constraints:

1. No new fossil-based power plants are installed after 2015 in the Best Policy Scenario. The existing fossil-based power plants are phased out when their economic lifetime expires. This excludes gas turbines. The installation of gas turbines is allowed after 2015 due to its lower GHG emissions, higher efficiency, and most importantly its ability to switch to biofuels and synthetic natural gas; which is actually necessary for the transition period and the zero GHG emission target.
2. To prevent system disruptions, the growth of RE capacity share cannot exceed 4% per year. This growth in share is limited to 3% between 2015 and 2020.
3. The prosumer demand is limited to 20% of the total demand, excess generation can be fed into the grid, but not more than 50% of total PV prosumer generation. The prosumer generation is constrained in a stepwise progression from a maximum of 3%

in the initial time step to 6%, 9%, 15%, 18% and 20% in the subsequent time steps.

4. Bioenergy constraint is set to regulate the biogas and waste resource potentials that could be exploited, 33% by 2020, 66% by 2025, and 100% by 2030 onwards. This constraint limits bioenergy technologies from being installed too quickly.

2.2.1. Applied technologies

The main technologies applied for the Ghanaian power sector modelling include electricity generation, power transmission, storage, and energy bridging technologies. Existing transmission grid capacity was taken from West African Power Pool [83], transmission and distribution grid losses were considered according to Sadovskaia et al. [84] and electricity load profiles were taken from Toktarova et al. [85]. The storage solutions comprise of battery, pumped hydro energy storage (PHES) [86], adiabatic compressed air energy storage (A-CAES) [87], and power-to-gas (PtG) storage [88], including electrolysers, CO_2 direct air capture [89], methanation and gas turbines. Fig. 5 shows the block diagram for the energy transition model.

2.2.2. Renewable energy potential

Several RE resources were considered for this study to ascertain the maximum potential that could possibly be harnessed to provide Ghana with long-term energy security. Key RE resources considered for this research include, solar, wind, hydro, and biomass. Geothermal, wave and tidal are not considered.

The feed-in profiles for solar PV (single-axis tracking and optimally tilted), onshore wind energy and concentrating solar thermal power (CSP) are calculated according to Refs. [81,90], based on resource data from NASA [91,92], reprocessed by the German Aerospace Centre [93]. The feed-in profile for hydropower is estimated based on monthly resolved precipitation data for the year 2005 as normalised sum of precipitation in the regions [94]. Resource potential for bioenergy is estimated according to the introduced method already described in section 2.1. Additional information on full load hours for all recourses are available in the Supplementary Material (Tables A1-A6 and Figure A3) and generation profiles in Supplementary Material (Figure A4).

2.2.3. Financial and technical assumptions

The technical and financial assumptions for all the energy system technologies, components, and sub-components are made in 5year time intervals and is provided in the Supplementary Material (Table A14). This includes the capital expenditure (CAPEX), operational expenditure (OPEX), and lifetime from 2015 onwards. For calculating the financial returns on investment, weighted average cost of capital (WACC) is set to 7% except for residential PV prosumers, which is set to 4% owing to lower returns on investment requirements.

Technical assumptions regarding power generation efficiency, storage facilities, HVAC power line losses and converters is presented in Supplementary Material (Table A15-A17). The electricity prices for residential, commercial, and industrial end-users for the base year 2015 were obtained from Public Utilities Regulatory Commission (PURC) of Ghana [95]. The electricity prices were calculated until 2050 based on [96,97]. Electricity prices applied are presented in Supplementary Material (Table A18).

The RE upper limits were calculated based on Bogdanov and Breyer [98] and lower limits were retrieved from Farfan and Breyer [99].

2.2.4. Electricity demand

The electricity demand for Ghana is projected based on IEA demand growth rate for West Africa obtained from Ref. [100]. The electricity demand projection until 2050 can be found in the Supplementary Material (Table A18). The hourly load profile is estimated according to Toktarova et al. [85].

2.2.5. Alternative scenarios

Six power sector scenarios were developed in this study as described in Table 2. The principal objective is to run a Best Policy Scenario (BPS) with bioenergy and without bioenergy to investigate the effects and significance of dispatchable bioenergy for

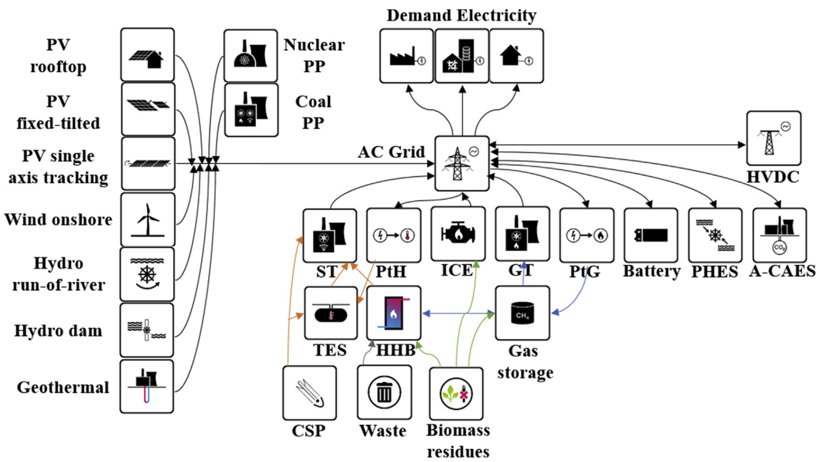

Fig. 5. Block diagram of the LUT Energy System Transition model for the power sector [81] Abbreviations: PP, power plant, ST, steam turbines, PtH, power-to-heat, ICE, internal combustion engine, GT, gas turbines, A-CAES, adiabatic compressed air storage, PtG, power-to-gas, PHES, pumped hydro energy storage, TES, thermal energy storage, HHB, hot heat burner, CHP, combine heat and power.

Table 2
Scenarios description.

Scenario	Description
Best Policy Scenario (BPS-1)	A 100% RE scenario with bioenergy and GHG emission cost
Best Policy Scenario without GHG emission cost (BPS-1noCC)	A 100% RE scenario with bioenergy without GHG emission cost
Best Policy Scenario (BPS-2)	A 100% RE scenario without bioenergy, with GHG emission cost
Best Policy Scenario without GHG emission cost (BPS-1noCC)	A 100% RE scenario without bioenergy without GHG emission cost
Current Policy Scenarios (CPS)	This scenario considers Ghana's proposed energy targets relating the power generation capacity mix to the year 2030 [76]. Subsequent years after 2030 to 2050 are extrapolated accordingly.
Current Policy Scenario without GHG emission cost (CPSnoCC)	Current Policy Scenario without GHG emission cost.

balancing the power sector with large shares of VRE resources. BPS-2 is a 100% RE scenario without bioenergy, but with GHG emission cost. This scenario was necessary to highlight the importance and benefits of modern bioenergy, and how it could be utilised to serve the national grid, than just for heating and cooking purposes, as practiced currently in Ghana and other SSA countries [24]. It is reported by Ref. [101], that less efficient and unsustainable traditional biomass and solid waste supply about 39.8% of Ghana's total primary energy demand. With the appropriate investments in bioenergy technologies, modern biomass could be more efficiently used for grid balancing as illustrated by the BPS-1 in section 4.3. The Current Policy Scenario (CPS) is modelled according to the current government plan [102] to investigate the financial and technical future implications of a business-as-usual case. In addition, the BPSs and CPS were simulated without GHG emission cost, to observe the impact of non-application of GHG emission cost on the transition. It is worth mentioning that the BPS without GHG emission cost is not expected to reach 100% RE.

3. Research results

This section presents the main findings of the research. Results of scenarios without GHG emission cost are not presented in this section due to similarities with scenarios with GHG emission cost. However, difference in key parameters and financial results for all scenarios are discussed in section 4.4.

3.1. Estimated bioenergy potential of Ghana

The results of the bioenergy estimation for Ghana is presented in Table 3. As observed in Table 3 above, the energy potential of different feedstocks is dominated by crop residue of 29.1 TWh, forest residue of 10.9 TWh, biogas of 5.3 TWh and MSW of 2.9 TWh. The total bioenergy harnessed is 48.3 TWh which is applied on the Ghanaian power sector in a fully renewable scenario using the LUT model. The results of the LUT model simulation is discussed below. Additional information on Ghanaian bioenergy potential is available in the Supplementary Material (Tables A7-A13).

Table 3
Ghanaian bioenergy potential in 2015.

Feedstock	tonne/a	Energy (PJ)	Energy (TWh)
Crop residue	5,976,634	104.6	29.1
Forest residue	2,821,729	39.5	10.9
Manure, bio-waste, sewage sludge	35,120,151	19.2	5.3
MSW	1,853,255	10.7	2.9
Total	45,771,769	174.0	48.3

3.2. Electricity installed capacity

Investments in the Ghanaian power sector are required to meet the future energy demand. Fig. 6 presents the installed capacities during the transition period. Fig. 6 (a)–(b) illustrates the installed capacities in the BPSs. The result indicates the dominance of solar PV during the transition. Solar PV contributes 47 GW (85%) in BPS-1 and 62 GW (93%) in BPS-2 by 2050. Besides solar PV, bioenergy, hydropower, and gas turbines are included in the generation mix. Fig. 6c illustrates the capacity development in the CPS. In the CPS, gas turbines and hydropower dominate the power sector until 2030. Solar PV and wind energy capacities are increased from 2035 onwards. By 2050, gas turbines dominate with 13 GW, followed by solar PV with 5 GW, wind energy with 2 GW and hydropower with 2 GW. The total installed capacities in the CPS is 22 GW, BPS-1 is 56 GW and BPS-2 is 67 GW by 2050. The plausible reason for lower capacities in the CPS is due to the influence of gas turbines running on high full load hours (FLH), followed by BPS-1 due to the influence of biomass plants, whereas higher installed capacity is required in BPS-2 due to solar PV FLH being comparably lower to other technologies. Essential power capacities needed during the transition is presented in Supplementary Material (Tables A19-A24).

3.3. Electricity generation

The electricity generation of the BPSs and the CPS is shown in Fig. 7 below. Fig. 7 (a)–(b) depicts the electricity generation mix in the BPSs. In the BPS-1, solar PV dominates the electricity supply with 84 TWh (76%), followed by bioenergy with 18 TWh (15%) and hydropower with 9 TWh (8%) by 2050, whereas in BPS-2, solar PV dominates with 113 TWh (92%) and hydropower 9 TWh (7%). Fig. 7c illustrates the generation in the CPS, which is dominated by gas turbines and hydropower until 2030. By 2050, gas turbines dominate with 87 TWh, followed by solar PV with 10 TWh and hydropower with 8 TWh. The total generation in the BPS-1 is 113 TWh, BPS-2 is 125 TWh and 107 TWh in CPS by 2050. Additional information on electricity generation is available in the Supplementary Material (Figure A5).

3.4. Role of storage technologies

The role of storage technologies increases with the shares of variable RE during the transition. Fig. 8 depicts the storage output under various scenarios. The storage output is 38 TWh in BPS-1, 52 TWh in BPS-2 and 5 TWh in CPS, respectively. Battery dominates the storage output in all scenarios. In BPS-1, prosumer battery dominates until 2035, followed by utility-scale battery from 2035 until 2050 as shown in Fig. 8a. In BPS-2 utility-scale battery dominate total storage output, followed by prosumer battery, TES and gas storage by 2050 as shown in Fig. 8b.

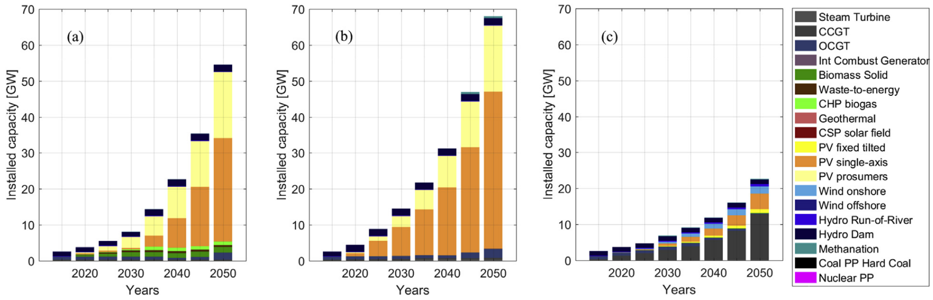

Fig. 6. Cumulative installed capacities in the BPS-1 (a), BPS-2 (b) and CPS (c) from 2015 to 2050.

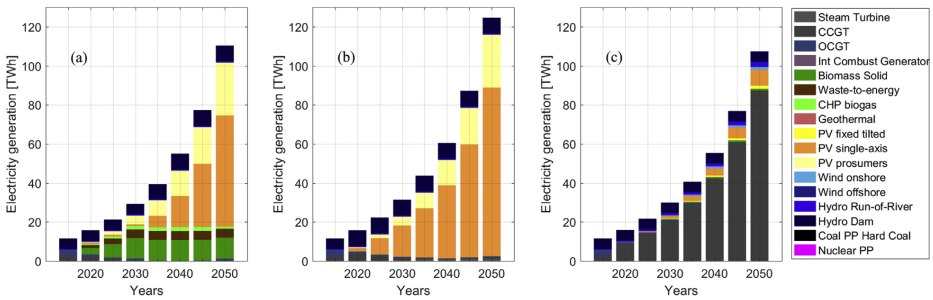

Fig. 7. Electricity generation mix by different technologies in the BPS-1 (a), BPS-2 (b) and CPS (c) from 2015 to 2050.

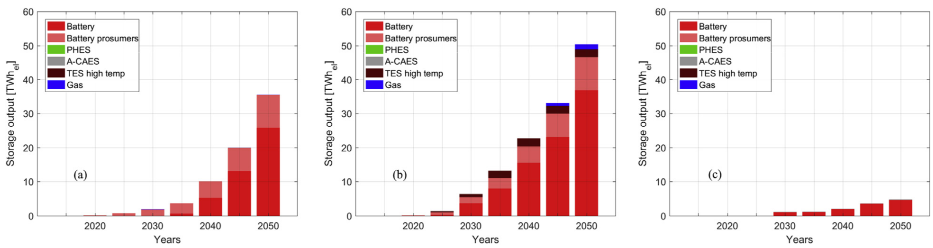

Fig. 8. Storage technologies' output in the BPS-1 (a), BPS-2 (b) and CPS (c) from 2015 to 2050.

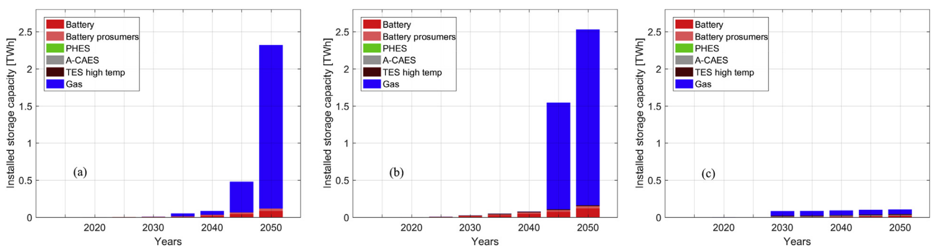

Fig. 9. Installed storage capacity in the BPS-1 (a), BPS-2 (b) and CPS (c) from 2015 to 2050.

Whereas, in the CPS utility-scale battery appears to be more relevant from 2030 onwards supported by a little share of A-CAES as shown in Fig. 8c.

Gas storage dominates the storage capacity during the transition in all scenarios considered particularly in the BPSs from 2045 onwards as shown in Fig. 9. Higher share of gas storage in the BPSs is required for seasonal balancing. The relevance of storage technologies appears to be stronger in the BPSs than in the CPS, due to high shares of RE in the BPSs.

3.5. Battery charging and discharge

The battery-to-PtG effect [36,103,104], can be observed as a means to reduce total system cost in an energy system with very high VRE shares, leading to a higher overall energy system efficiency. Battery is used to charge the gas storage via utilisation of electrolysers in off-peak hours, as demonstrated in the BPS-2 and depicted in Fig. 10. The battery powers the methanation process during low demand hours to produce synthetic natural gas (SNG) for long-term storage in order to reduce total curtailment and PtG charging capacities, and to maximise PtG FLH and reduce total energy system cost. Undischarged batteries in the morning of a sunny day would lead to curtailment of solar PV electricity, which can be effectively avoided via the battery-to-PtG effect. In addition, biomethane produced via anaerobic digestion, as shown in Eq. (7), complements the gas supply in low sunshine seasons and is delivered via a common gas grid. Additional information on curtailment can be found in the Supplementary Material (Figure A6). The discharged battery is recharged during the day when solar PV production is high. The electricity transferred from battery to PtG is 1.6 TWh in BPS-2 representing 2% of the total electricity demand in the BPS-2. Additional information on the state of charge of various technologies are available in the Supplementary Material (Figures A7-A9).

3.6. Electricity grid utilisation

The power exchange of BPS-1 and CPS is discussed in this section. Grid interconnections provide further flexibility to the power sector. The grid structure in the BPS-1 is the opposite of the CPS. Fig. 11 shows the electricity exchange in the BPS-1 and CPS. In the BPS-1, most of the generation occurs in the northern region (GH-UN) and is transmitted via transmission power lines to the central and southern regions, whereas the opposite is observed in the CPS.

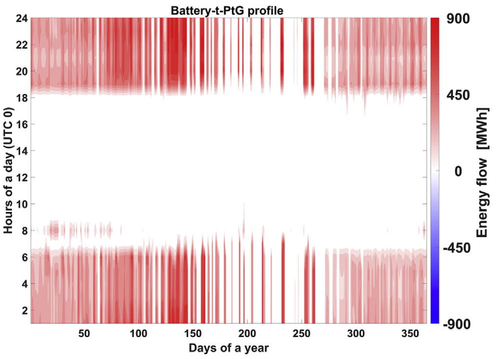

Fig. 10. Profile of battery discharge to PtG in the BPS-2 in 2050.

Electricity exchange in the BPS-1 is shown in Fig. 11 (left) and comprises about 29 TWh (77% of local generation) of exports from GH-UN by 2050. GH-UN is the main power production hub of Ghana in a fully RE power sector. Whereas in the CPS, GH-EC and GH-CN emerge as the main exporting regions as shown in Fig. 11 (right). The net grid transfer in the BPS-1 is 30 TWh, representing 28% of the total electricity demand, compared to 20 TWh representing 18% in the CPS. In Fig. 11 the size of the arrow flows specifies the value of power transmitted between respective regions. The ribbons and flows of the exporter and importer regions respectively have the same colour. Taking the BPS-1 grid exchange (Fig. 10 left) for example, the electricity flow for region GH-EC is coloured green and that of GH-CN is coloured yellow. In a power exchange between these two regions, an exporting region (GH-EC) extends a green flow, yellow ribbon of export to GH-CN. Additional information on grid utilisation profiles is presented in the Supplementary Material (Figure A10).

3.7. Role of gas turbines

Gas turbines are found to be relevant flexible technologies due to their ability to cover a large time scale of frequency variation. Gas turbines are an ideal balancing technology in the energy transition period towards 100% renewables. In the BPSs, gas turbines are permitted to be installed after the 2015 reference year, owing to lower GHG emissions and high probability to replace fossil natural gas with SNG and biomethane. The generation profiles of gas turbines (OCGT and CCGT) in the BPS and CPS are illustrated in Fig. 12. By 2050, gas turbine installed capacity is 2 GW in the BPS-1, 3 GW in the BPS-2 and 13 GW in the CPS. Gas turbines are only needed in the BPSs during the West African monsoon season, which is most heavy during the months of June to September. Whereas in the CPS, CCGT functions more as base generation power plant and OCGT contribution is required during the night times. The FLH for the gas turbine decreases from around 4890 in 2015 to 515 in the BPS-1 and about 470 in the BPS-2 by 2050. Fig. 13 shows the usage of SNG and bio-methane to operate gas turbines in the periods of low sunshine in Ghana, during the monsoon period in the BPS-1. Charging of the gas storage occurs throughout the year and is discharged at peak during the monsoon period.

3.8. Sub-regional capacity overview in a 100% renewable energy system

Fig. 14 shows the RE installed capacities projection across the country in the BPSs by 2050. GH-UN is the dominating sub-region with installed capacity of 18 GW in the BPS-1 and 27 GW in the BPS-2, as shown in Fig. 14a and b, respectively. Most of the capacity installed is solar PV due to high solar resource potential in this region. The overall installed capacities in the BPSs is dominated by solar PV single-axis tracking followed by optimally tilted PV. Bioenergy, hydropower, and gas turbines complement solar PV generation. Additional information on regionally installed capacities and generation is available in the Supplementary Material (Figures A11-A14).

3.9. Levelised cost of electricity

The main contributors to the total energy system LCOE can be seen in Fig. 15. The LCOE includes the cost for generation, transmission, GHG emissions, storage, curtailment, and fuel cost. Fig. 15 (a)–(b) show the LCOE in the BPSs during the transition period. The LCOE declines significantly from 48.7 €/MWh in 2015 to 37.0 €/MWh and 46.6 €/MWh in the BPS-1 and BPS-2 respectively by 2050. In the CPS, LCOE increases from 48.67 €/MWh to 120.5

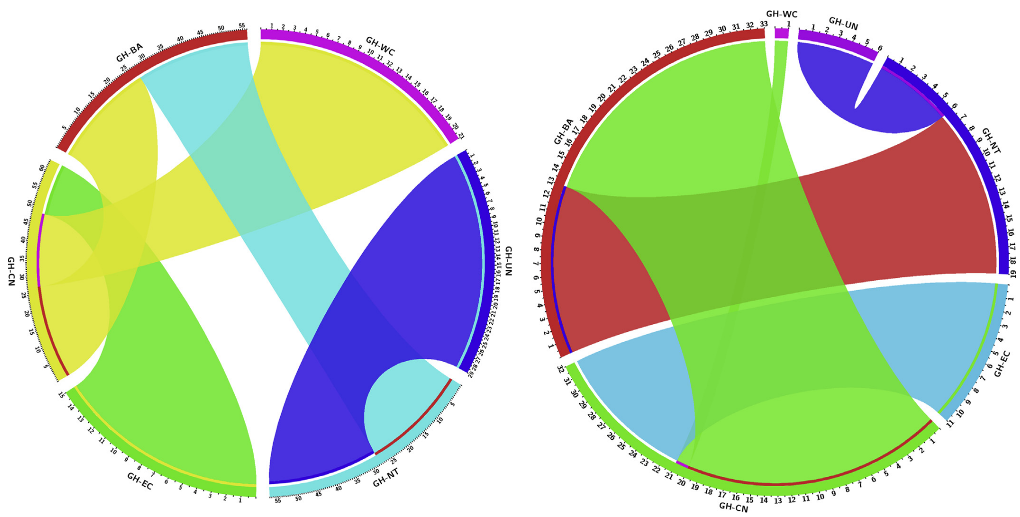

Fig. 11. Power exchange across the country in the BPS-1 (left) and CPS (right) by 2050.

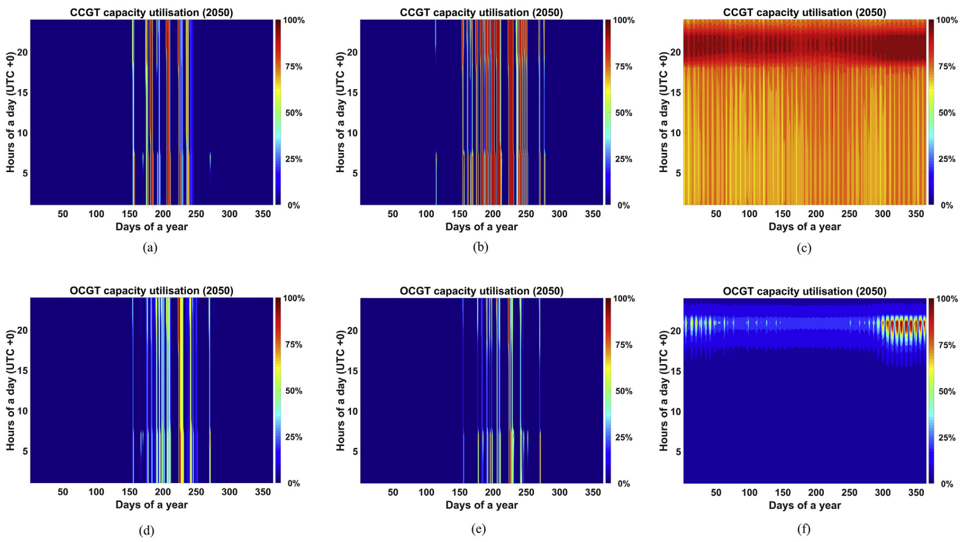

Fig. 12. Combined cycle gas turbine profiles in the BPS-1 (a), BPS-2 (b), and CPS (c); and open cycle gas turbine profiles in the BPS-1 (d), BPS-2 (e) and CPS (f) in 2050.

€/MWh as shown in Fig. 15c. Contributing components such as fuel cost and GHG emissions cost decline from 2015 and finally diminishes by 2050, in the BPSs. But storage cost increases significantly from 2030 onwards in both BPSs. The reverse situation is observed in the CPS where fuel and GHG emissions cost increase from 2015 to 2050. This can be attributed to the high presence of fossil natural gas and oil thermal power plants in the current Ghanaian power generation mix. The cost structure of the CPSs is greatly influenced by fuel and GHG emissions cost, which keeps increasing annually. Additional results on costs for all scenarios are available in the Supplementary Material (Table A25 and Figures A15-A18).

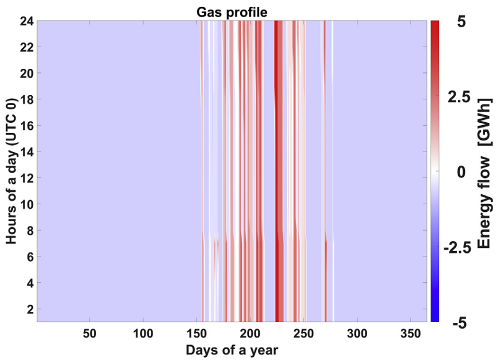

Fig. 13. Gas storage profile during an entire year in the BPS-1 for 2050.

3.10. Greenhouse gas emissions

The GHG emissions trend during the transition for all scenarios is shown in Fig. 16. Fast emissions reduction is achieved in the BPSs. GHG emissions decline from around 2.5 Mt_{CO2eq} in 2015 to 0.4 Mt_{CO2eq} in BPS-1 and to 0.8 Mt_{CO2eq} in BPS-2 by 2030, and further decline to zero in both scenarios by 2050, as shown in Fig. 16 (a)–(b). Whereas GHG emissions in the CPS increase from 2.5 Mt_{CO2eq} in 2015 to 31 Mt_{CO2eq} in 2050 as shown in Fig. 16c.

3.11. Energy flow overview

Fig. 17 illustrates the system energy flow in the 2015 reference scenarios (top) and BPS-1 by 2050 (down). It demonstrates the flow of the primary energy resources, conversion technologies, storage technologies, final electricity demand, grid, and grid losses. In the reference scenario, Fig. 17 (top), the primary energy consists of about 67% fossil fuels, which diminishes completely in the BPS-1 by 2050 as depicted in Fig. 17 (bottom). In the BPS-1, Fig. 17 (bottom),

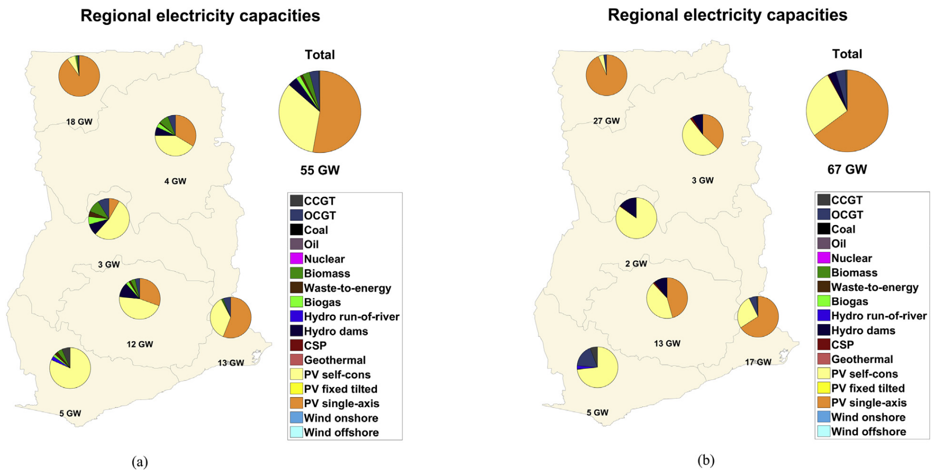

Fig. 14. Sub-regional RE installed capacities for the BPS-1 (a) and BPS-2 (b) by 2050.

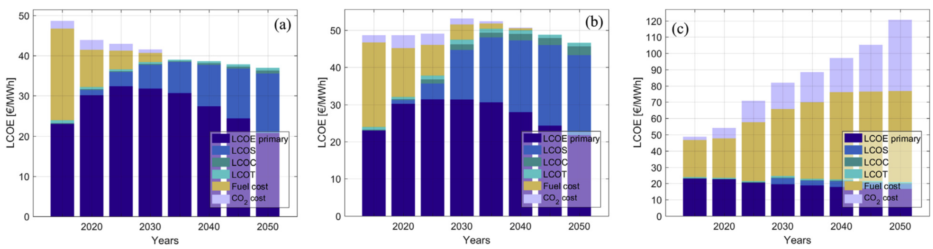

Fig. 15. Levelised cost of electricity in the BPS-1 (a), BPS-2 (b) and CPS (c) for 2050.

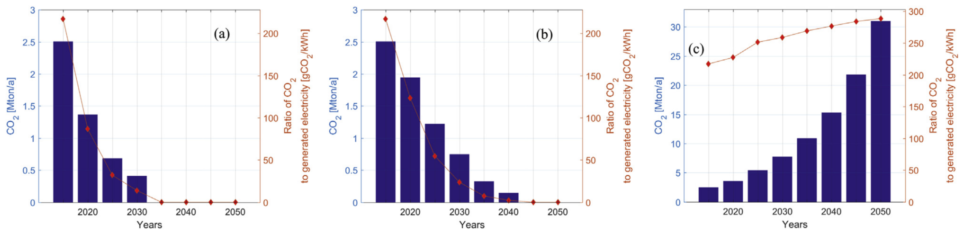

Fig. 16. The GHG emissions trajectory in the BPS-1 (a), BPS-2 (b) and CPS (c) during the transition period.

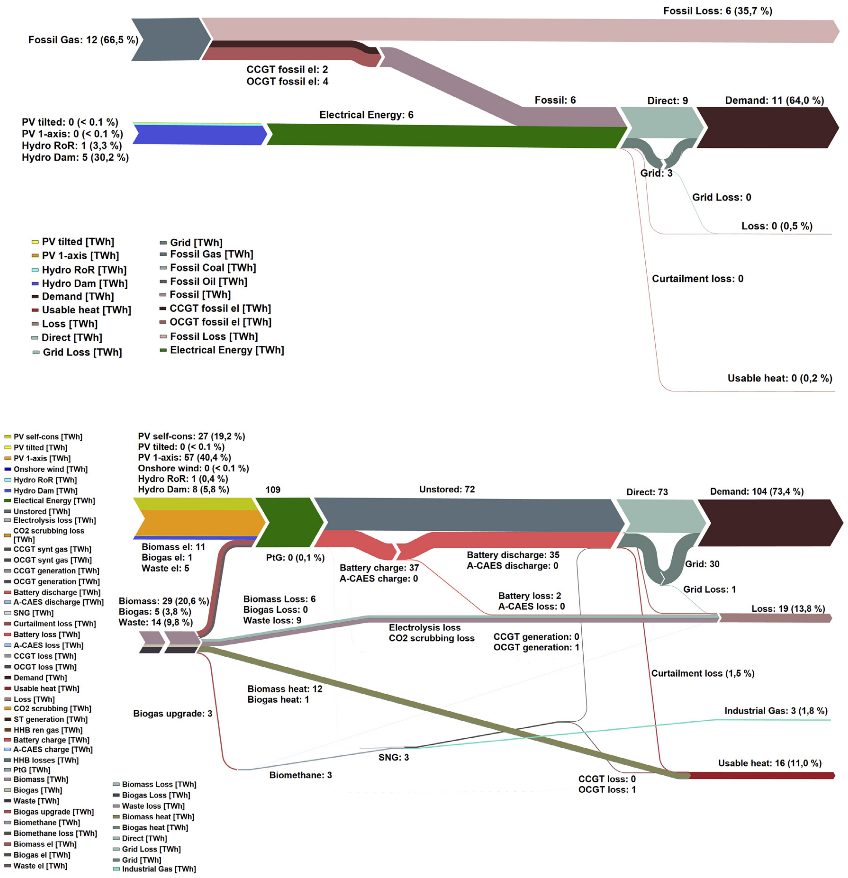

Fig. 17. Energy flow of the power sector for 2015 (top) and BPS-1 in 2050 (bottom).

the vital role of bioenergy is clearly seen as it augments the PV-battery hybrid energy system by providing flexibility to the system. Losses occur mainly in curtailed electricity, biomass power plants, waste-to-energy plants, PtG processes, and battery charging and discharging processes. Additional information on the energy flow in the scenarios BPS-2 and CPS is presented in the Supplementary Material (Figures A19-A20).

4. Discussion

This case study investigates the role of sustainable modern bioenergy and the integration of large shares of RE resources for the case of the Ghanaian power sector, as illustrated in the BPSs, in comparison to a system dominated by fossil fuelled technologies as depicted in the CPSs.

4.1. The significant role of sustainable bioenergy in RE-dominated systems

The results of this case study show that the sustainable bioenergy potential of Ghana as of 2015 is 48.3 TWh which generated electrical energy of 18 TWh by 2050 when applied to the LUT model as shown in Fig. 7. The research recognises that by 2050, the bioenergy potential of Ghana may alter due to changing climate conditions.

Solid biofuels and biogas are converted in CHP plants and gas turbines respectively, to provide short-term to mid-term and seasonal balancing of the RE resource dominated power sector. This role highlights the synergy between variable RE sources and modern bioenergy.

Bioenergy is a dispatchable form of RE generation and has the potential of providing a stabilising role in a power grid dominated by RE resources [6]. The results of this study revealed that most of the dispatchable renewable power needed in the BPS-2 is provided by hydropower and gas turbines. The missing bioenergy capacity in the BPS-2 is largely compensated by additional PV capacity as shown in Fig. 6. Whereas, in the BPS-1 dispatchable renewable power is provided mainly by bioenergy plants, followed by hydropower and gas turbines. The cumulative installed capacity requirement is lower in the BPS-1 than in the BPS-2, due to influence of bioenergy plants running on higher FLH. The LCOE is 37.0 €/MWh and 46.6 €/MWh for BPS-1 and BPS-2 respectively by 2050. The cumulative installed capacity, total generation, storage output, curtailment and LCOE dropped by 22%, 12%, 37%, 41.6% and 27% in the BPS-1 compared to the BPS-2, by 2050. The increased LCOE in the BPS-2 is mainly influenced by storage cost (LCOS) owing to high penetration of solar PV, leading to excess generation, which needs to be stored, used, or curtailed. Other contributing components are cost of curtailment (LCOC), and LCOE primary cost.

Curtailment costs are higher in the BPS-2 than in the BPS-1, due to high curtailment losses of about 10.1 TWh by 2050, as compared to 4.2 TWh by 2050 in the BPS-1. The high total curtailment losses in the BPS-2 can be attributed to excess generation from PV during low load periods, especially in the afternoon and balancing challenges due to the absence of bioenergy plants in the BPS-2. Variable RE generation and curtailment in the BPS-1, BPS-2 and CPS are shown in Fig. 18. Additional information on curtailment and generation for all scenarios are presented in the Supplementary Material (Figure A6).

Table 4
LCOE difference between BPS-1 and BPS-2 for 2050.

	Unit	BPS-1	BPS-2	Difference [%]
LCOE primary total	[€/MWh]	20.7	21.7	4.8
LCOC total	[€/MWh]	0.7	2.4	242.9
LCOS total	[€/MWh]	14.8	21.6	45.9
LCOT total	[€/MWh]	0.7	0.9	28.6
LCOE total	[€/MWh]	37.0	46.6	20.6

LCOE primary costs are equally higher in the BPS-2 than the BPS-1 since additional installed solar PV capacity is needed to compensate for the missing bioenergy capacity. About 15 GW of solar PV installed capacity is needed in the BPS-2 to compensate for the missing 4 GW of bioenergy installed capacity in the BPS-1. This is primarily due to the higher bioenergy plants FLH, the vast compensating installed capacity culminated in the higher final LCOE primary in the BPS-2. In addition, about 33.8 GWh_{cap} (29.4%) more battery storage capacity is needed in the BPS-2 compared to the BPS-1. Table 4 shows the LCOE difference between BPS-1 and BPS-2. The use of bioenergy improves the power system for a better primary electricity generation mix, less curtailment, less storage requirement, and slightly less power transmission requirement.

Power systems dominated by variable RE resources show the need for dispatchable technologies as demonstrated in BPS-2, which can be provided by bioenergy plants. The demand and supply of sustainable biomass for power generation to balance the energy system will create economic benefits, especially for the indigenous in the rural communities, where most residues are generated. Most importantly, the use of sustainable biomass will provide energy self-sufficiency (security of supply) and additional environmental and economic benefits [105]. The utilisation of Ghana's sustainable bioenergy for power production may limit the supply of biomass to other sectors of the energy system such as transport and heat (industry and cooking) even though some sustainability criteria have been considered for the bioenergy potential estimations. According to Refs. [25,106], although substantial energy demand by the transport and heat (industry, building and cooking) sectors will be supplied heavily by electricity, liquid fuel (PtL), and synthetic gas (PtG) in a fully sector coupling scenario, bioenergy may also be demanded by these sectors. Hence, the total bioenergy potential may not be available for the power sector in a fully sector coupling scenario. Thus, this study recognises this development as a limitation to the research work.

4.1.1. Important role of micro bioenergy conversion technologies

The various biomass resources listed in Table 1 can be converted via different processes such as direct combustion, gasification,

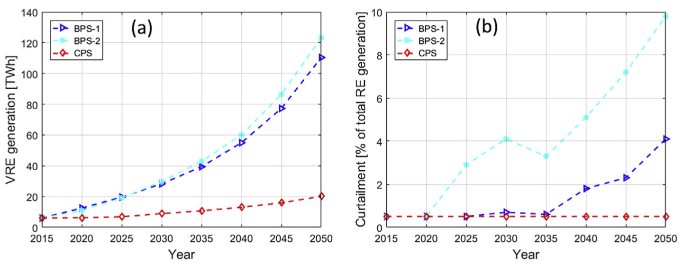

Fig. 18. Variable RE generation (a) and curtailment of generation potential (b) in TWh under various scenarios during the transition.

pyrolysis, extraction, fermentation, and anaerobic digestion to produce heat and power, ethanol, biodiesel, and biomethane [107]. This research however considered direct combustion and anaerobic digestion technologies for converting the available biomass into useful bioenergy.

4.1.2. Burning in dedicated power plants

Solid biomasses such as crop residues, forest residues, and wood residues could be burned to produce electricity via steam turbines in dedicated power plants. The produced electricity is consumed in the night or monsoon season. Currently, smaller sizes of about 100 MW or less are available in the market. Due to their ease of controllability, the CHP efficiently perform energy system balancing [6]. The CO_2 emissions of these plants are neutral since solid biofuels are biogenic. Municipal or district level MSW power plants are usually burned in a specially designed CHP plants due to their heterogeneous nature [107]. However, direct combustion of residue biomass for electricity production often results in the release of other air pollutant such as nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter (PM), sulphur dioxide (SO_2), and volatile air pollutants (VOC), But with proper boiler furnace temperature control, ash treatment, and flue gas treatment technology, these negative impacts could be overcome.

4.1.3. Anaerobic digestion plants

Wet and organic waste matter such as livestock manure, FSS, and organic kitchen waste could be converted by bacteria-induced fermentation into biogas of about 50%–75% methane, CO_2, and other impurities. Biogas produced via the anaerobic digestion process is upgraded into biomethane and subsequently fed into a national gas grid for firing the gas turbines for electricity production [107].

Ghana and other SSA countries with similar climate conditions could use this model for sustainable and reliable power production thereby addressing energy poverty challenge and ensuring economic empowerment of the locals. The application of this proposed model in Ghana and other SSA countries could provide benefits such as reduction of CO_2 emissions, energy supply security, affordability and adequate power, and most importantly economic growth [105].

4.2. The role of solar PV

The outstanding role of solar PV needs to be highlighted in the BPSs. Solar PV generates around 84–113 TWh representing 76–92% of the total electricity demand by 2050 in the BPSs. Utility-scale PV supplies 52%–70% of the electricity demand by 2050, and prosumer PV contributes around 22%–25% in the BPSs. Currently, the northern part of Ghana hosts the highest installed solar PV capacity and the first utility-scale PV in Ghana. The northern region of Ghana is expected to host more PV capacity in the future [108,109]. The plausible reason for the high share of solar PV installed capacity in the upper north in the BPS is due to high solar potential in this region [108] and the subsequent low cost. The results of this study show that solar PV emerges as the prime source of electricity supply for Ghana. These findings are comparable to that of Oyewo et al. [104] who concluded that solar PV will play a crucial role in the Nigerian future power system. Agyekum [109] analyses the benefit of solar PV systems for the Ghanaian power systems and confirms the results of this research, that single-axis tracking PV is the preferred utility-scale PV system for the conditions of Ghana. Similar insights have been obtained by studies for entire West Africa [5]. Barasa et al. [3] also conclude that most SSA countries can be powered majorly by solar PV and wind energy. The current trend of solar PV growth might be further accelerated due to continuously decreasing solar PV and battery cost [110] and the broader application of low-cost PV electricity in other energy sectors [111]. In the CPS, most of the electricity is supplied by gas turbines by 2050. Gas turbines dominate the total electricity generation with 87.1 TWh (81%), followed by solar PV with 9.8 TWh (9%), hydropower with 8.0 TWh (8%), wind energy with 1.4 TWh (1%) and biomass with 0.9 TWh (1%). It is worth mentioning that Ghana has enough land area to technically host a mix of RE-based system. The required land area for solar PV is calculated based on the capacity density assumed in the model, which is 75 MW/km^2 [98], which is conservative, given the steadily increasing PV module efficiencies. Thus, an area of 628 km^2 and 827 km^2 representing 0.26% and 0.35% of the Ghanaian total land area is need for solar PV capacities by 2050 in the BPS-1 and the BPS-2, respectively.

4.3. Analysis of system flexibility

The flexibility component of the power system includes storage technologies, the power transmission network, and dispatchable RE, particularly bioenergy resources (biogas, biomass, and waste) and hydropower. These flexibility components complement the high shares of solar PV in power generation as shown in Fig. 19. Power systems dominated by solar PV are often characterised by high storage requirement [82,112,113]. Storage technologies improve the system flexibility, particularly battery storage due to daily charge and discharge. Battery storage dominates in terms of storage output for all scenarios during the transition. Battery storage output is about 35 TWh (93% of all storage output and 34% of all demand) in BPS-1, 47 TWh (90% and 45%, respectively) in BPS-2, and 5 TWh (97% and 4.4% respectively) in the CPS. For weekly, seasonal, and long-term storage, TES, A-CAES and PtG are employed. Studies have shown that energy storage is needed in power generation with about 50% RE share [82], and the need for seasonal storage becomes apparent when RE share reaches 80% [82,112]. Instead, dispatchable RE generation, bioenergy resource and hydropower appear to be sufficient in providing the daily and seasonal balancing as shown in Fig. 19, during the monsoon period in BPS-1. As a result, only 0.08 GW of PtG capacity is required in the BPS-1 by 2050, whereas 1.7 GW of PtG is required in the BPS-2. This phenomenon is also observed for Brazil [114] and West Africa [5]. According to Refs. [5,112], a 100% RE-based power system can run with very low seasonal storage.

The power transmission grid network provides additional flexibility to the power system, particularly in balancing the spatial mismatch in generation and demand in the BPSs. The power grid facilitates the high shares of RE generation in the upper north, which are transmitted to other regions. Studies have shown the importance of transmission grid in power systems dominated by RE, which includes the potential to reduce LCOE and to facilitate high RE penetration [115]. Gas turbines appear to be relevant in the BPSs, particularly during the monsoon season. Studies have shown that gas turbines can provide flexibility in RE-based power systems, instead of coal or nuclear power plants [116].

4.4. Benefits of the energy transition

Most renewables have common economic characteristics: high fixed costs and low or almost no variable costs. Solar energy, wind energy, geothermal energy, tidal power, hydropower, and waste-to-energy conversion require substantial investment cost but no fuel cost. Their running costs include expenditures for maintenance and operations, and energy input in the case of waste-to-energy. Therefore, when a renewable power station is built, the operational costs of providing electricity to its users are low for the economic lifetime of the plant [117]. Recent plummeting prices for

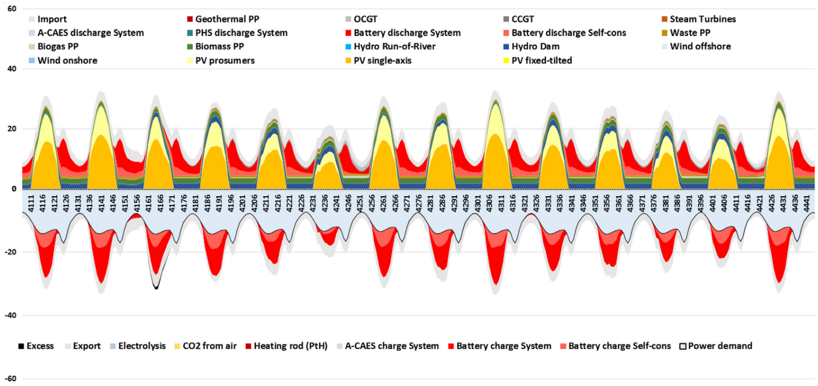

Fig. 19. Generation and demand profiles during the monsoon period in the BPS-1 for 2050.

Table 5
Key financial and technical parameters in 2050 for all scenarios.

		Unit	BPS-1	BPS-1noCC	BPS-2	BPS-2noCC	CPS	CPSnoCC
Financial outcome parameters	Total annualised system cost	[b€]	3.87	3.86	4.84	4.77	12.79	8.11
	LCOE	[€/MWh$_{el}$]	36.97	36.89	46.6	45.96	120.55	76.42
	Generation	[TWh$_{el}$]	110.35	110.37	123.2	119.5	107.42	107.4
	Installed capacity	[GW]	54.9	54.8	67.2	64.5	22.1	21.8
	Curtailment	[TWh$_{el}$]	4.21	4.29	10.12	9.98	0.53	0.53
	RE share	[%]	100	100	100	98.2	18.7	18.7

renewable technologies are influencing the capacity addition and driving more jobs in the installation, operation, and maintenance [118]. According to IRENA, the global GDP will increase by 1.1%, human well-being will be improved, as well as direct and indirect job could reach 24.4 million people by 2030, if the renewable share in the global energy mix is doubled [119].

According to the results of this study, it is empirically evident that increasing the share of renewable energy in the SSA generation mix will increase the regional GDP, reduce unemployment rates, and increase overall humane welfare due to the energy-economic growth nexus. The results, as shown in Table 5 depict that a 100% RE-based system is the least-cost option for Ghana. The LCOE obtained in the BPSs is around 37–46 €/MWh in 2050, which is comparable to the range of 35.2–47.6 €/MWh in Ref. [5]. According to Oyewo et al. [5], the Ghanaian power sector LCOE by 2050 will be in the range of 37.1 €/MWh and 46.5 €/MWh, when connected to the West African power pool and when isolated, respectively, which is similar to the results of this study. The total annualised cost of the energy system is in the range of 3.85 b€ to 12.79 b€, as presented in Table 5 for 2050.

The highest total annualised system cost occurred in the CPSs, which is 193% higher than in the BPSs with GHG emissions cost and is 88% higher without GHG emissions cost by 2050. On average, the required installed capacity in the BPSs is about 173% higher than the capacity requirement for the CPSs, due to RE technologies running on lower FLH, especially, solar PV in the BPSs. Additional information about total annualised cost can be found in the Supplementary Material (Figure A21).

Hybrid PV-battery systems used in tandem with modern biomass power appear to be the central and least-cost element for Ghana by 2050, which is comparable to the findings of Oyewo et al. [104] for the Nigerian and West African power system [5]. In addition, PV [103] and battery [120,121] costs have declined over the years, and further cost reduction is expected. The outcome of this research demonstrates the technical feasibility and economic viability of RE-based power systems in Ghana and SSA. Furthermore, the results of this study show that RE generation could reach 100% in BPS-1 and 98.2% in BPS-2 without GHG emissions cost, which indicates pure market economics, neglecting harmful impacts of conventional power generation, such as GHG emissions, but also heavy metal emissions.

The BPSs show that deep defossilisation of the Ghanaian power sector is not only cost-competitive, but also complies with the objectives of the Paris Agreement. The high costs observed in the CPSs is due to investments in thermal power plants, which run on high FLH and consumes enormous fuel, and which cannot compete anymore with low-cost PV-battery systems. The results of the CPSs show continuous dependence on gas turbines. Without GHG emissions cost, the BPSs show lower total annualised system cost, LCOE, and the installed capacity, as compared to the BPSs with GHG emissions cost. For the total annualised system cost, BPS-1noCC is lower than BPS-1 by 0.01 b€, BPS-2noCC is lower than BPS-2 by 0.07 b€. For the LCOE, BPS-1noCC is lower than BPS-1 by 0.08 €/MWh, BPS-2noCC is lower than BPS-2 by 0.064 €/MWh. For the installed capacity, BPS-1noCC is lower than BPS-1 by 0.1 GW, BPS-2noCC is also lower than BPS-2 by 2.7 GW. The minimal differences between the BPSs with and without GHG emissions cost are due to zero GHG emissions in RE resource power systems, but some deviations are induced during the energy transition. For the CPSs the differences are quite significant, the total annualised cost and LCOE are reduced by 4.7 b€ and 44.1 €/MWh from CPS to CPSnoCC. This shows the impact and influence of GHG emissions cost to the economics of the electricity market. The influence of GHG emissions cost is significantly observed between CPS and CPSnoCC, due to a high share of fossil-based technologies in the Ghanaian power generation mix. In short, GHG emissions cost does not significantly affect the LCOE of the power system with high RE resources, due to zero GHG emissions during the use phase.

The BPSs results show that Ghana can decarbonise its power sector, while reducing costs if the techno-economic analysis pathway options demonstrated in this research are pursued. It is the least-cost option for Ghana and does not require any form of subsidy. According to Ref. [122] countries such as Burkina Faso, Chile, China, Egypt, Ghana, India, Japan, Mexico, Namibia and Thailand are committed to using 100% renewable energy systems to help address the climate change crisis.

4.5. Off-grid electrification

Ghana is one of the top countries in Africa leading the progress in access to electricity. In Ghana, electrification access rose from 65% in 2010 to around 85% in 2019 [123–125]. However, majority of the population connected to the national grid are in the urban and peri-urban areas whiles rural electrification remains a barrier to Ghana's 2020 universal access target, which obviously is a mirage. About 15% of Ghana's population (4.6 million) living in less densely populated communities are not yet connected to the national grid [124]. Most of these people live in isolated locations far from the national grid, and grid extension to these isolated communities is costly and rather uneconomical [126]. Bertheau et al. [123] investigated the impacts of grid extension on electricity access in SSA, using a geospatial method, and the results indicate that for most isolated SSA rural communities which are sparsely populated, mini-grids and solar home systems (SHS) are the best solution for rural electrification. For Ghana, a scenario based on existing grid infrastructure indicates 12% SHS, 10% mini-grids and 78% grid extensions for the not yet electrified population. While another scenario assuming the planned grid indicates electrification of the not yet electrified people by 8% SHS, 8% mini-grids, and 84% grid extension to provide universal access to electricity in Ghana. Similarly, Sanchez et al. [127] conclude that, when it is too costly to build transmission lines due to distance, dispersion and maintenance issues, the use of decentralised generation is the preferred solution. Thus, off-grid solutions such as SHS and mini-grids provide a cost-effective and possibly very fast and feasible progress in rural areas for achieving universal access to electricity.

5. Conclusions and policy implications

Due to policy changes and improved market prospects, the global renewable electricity is expected to grow in the future [6]. The results of this study clearly indicate that bioenergy can provide a substantial share of the needed grid balancing required in a fully renewable power system. It is least-cost to supply electricity with RE resources by 2050, which requires continued efforts to ramp up respective capacities, starting now. Storage technologies, power transmission grid and dispatchable RE (bioenergy and hydropower) provide the system with required flexibility. Bioenergy appears to be an excellent dispatchable energy resource in a power grid dominated by solar PV, while reducing the total annualised system cost. New biomass framework conditions coupled with low feedstock prices and high CO_2 prices are needed to create a direct competition between biomass and fossil fuels. Given low prices and availability of feedstock, thermal biomass power plants could substitute fossil fuel fired power plants for the required power system balancing in a variable renewable dominated power system. However, the transport and the heat (industry, building and cooking) sectors demand for biomass may limit the availability of biomass for power production. Also, possible future constraints in biomass availability and economics due to climate change can discourage or restrict the investments in biopower technologies. Therefore, the current work can be further extended by investigating and projecting the future biomass availability in the region due to rapidly changing climate.

In addition, a 100% RE-based system can run with very low seasonal PtG storage, as seen in the BPS-1. The BPSs appear to be the least-cost options for the case of Ghana in comparison to the CPSs. The BPS without GHG emissions cost reaches 98.2% RE generation share, which indicates favourable market economics.

Policies to support RE resources integration in the power sector are very important. Likewise, policies to encourage sustainable biomass utilisation for electricity production, such as feed-in tariffs, capital subsidies, tax incentives, guaranteed market for bioelectricity among others are supportive. Beyond the technical and economic feasibility of a 100% RE-based system, strong political will and policy implementation is encouraged. Policies to limit new investments in fossil technologies are urgently needed to avoid costly and harmful stranded assets and RE development plans from a long-term perspective are required.

The results of this research on the case of Ghana have shown that: 1) A fully renewable power sector is both technically feasible and economically viable and also represents the least cost option in the long-term, when compared to a conventional power system. 2) A good synergy between PV-battery driven and dispatchable bioenergy. 3) Producing power from waste and residue biomass will provide a paradigm shift from traditional to modern biomass use, while improving waste management practices in SSA. 4) The scenario can be transferred to other SSA countries and Sun Belt regions of the world with similar climate conditions as Ghana.

CRediT authorship contribution statement

Theophilus Nii Odai Mensah: Data curation, Conceptualization, Writing – original draft, Methodology, (Bioenergy potential estimation). **Ayobami Solomon Oyewo:** Modelling, Visualization, Investigation. **Christian Breyer:** Supervision, Writing – review & 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.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.renene.2021.03.098.

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Publication IV

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Transition towards decarbonised power systems and its socio-economic impacts in West Africa

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ABSTRACT

Pathways towards a defossilated sustainable power system for West Africa within the time horizon of 2015–2050 is researched, by applying linear optimisation modelling to determine the cost optimal generation mix to meet the demand based on assumed costs and technologies in 5-year intervals. Six scenarios were developed, which aimed at examining the impact of various policy constraints such as cross-border electricity trade and greenhouse gas emissions costs. Solar PV emerges as the prime source of West Africa's future power system, supplying about 81–85% of the demand in the Best Policy Scenarios for 2050. The resulting optimisation suggests that the costs of electricity could fall from 70 €/MWh in 2015 to 36 €/MWh in 2050 with interconnection, and to 41 €/MWh without interconnection in the Best Policy Scenarios by 2050. Whereas, the levelised cost of electricity without greenhouse emission costs in the Current Policy Scenario is 70 €/MWh. Results of the optimisation indicate that a fully renewables based power system is the least-cost, least-GHG emitting and most job-rich option for West Africa. This study is the first of its kind study for the West African power sector from a long-term perspective.

1. Introduction

Energy crisis and susceptibility to climate change are foreseen to constrain the future human and economic growth of West African (WA) countries [1]. Globally, the need for harmonised efforts to alleviate the danger of climate change and eradicate widespread energy poverty is apparent in the perspectives of the Paris Agreement on climate change and Sustainable Development Goal no 7 (SDG 7) [2]. In WA, a great deal of attention is directed towards the interrelated problems of energy crisis, climate change and energy security, which is characterised by growing demand, poor access to electricity and huge dependence on unsustainable biofuel [3]. In doing so, the Economic Community of West African States (ECOWAS) has adopted measure to streamline renewable energy (RE) and energy efficiency into their energy policies to tackle the predominant energy challenges in the region [4].

ECOWAS is comprised of 15 member states, and is characterised by diverse socio-economic, demographic and cultural backgrounds, each of this factor influence the region's electricity production and consumption [5]. ECOWAS with a growing population above 300 million, accounts for almost one-third of Sub-Saharan Africa's population, occupying an area of over five million square kilometres [6]. The regional gross domestic product (GDP) rebounded, averaging about 2.5% in 2017 from 0.5% in 2016, and is expected to increase to 3.9% in 2019 [7]. In spite of the region's abundant energy potential and progress achieved in the establishment of the regional power pool, the West African Power Pool (WAPP) [8], the region's electricity sector is underpowered with inadequate generation and transmission systems [9], leaving about 175 million people (48%) in the region unelectrified in 2016. Further, the total population relying on biomass for cooking was 263 million (75%) in 2015 [10]. Studies on energy consumption and economic growth nexus conclude that energy is a critical parameter for socio-economic development [11]. The socio-economic development of most WA countries is hampered by its underdeveloped energy sector [12]. Most ECOWAS countries rank among the poorest, having Low Human Development [5]. Access to electricity in the region is at 52%, with shortages of up to 80 h/month and yet electricity prices in WA remain among the costliest in the world, at 0.21 €/kWh, more than twice of the global average [13]. In 2016, the electrification rate was below 40% in 10 of the 15 countries, with Guinea-Bissau, Liberia, Niger and Sierra Leone occupying the

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Abbreviations

A-CAES	adiabatic compressed air energy storage
BPS(s)	Best Policy Scenario(s)
CAPEX	capital expenditures
CCGT	combined cycle gas turbine
CHP	combined heat and power
CPS(s)	Current Policy Scenario(s)
CSP	concentrating solar thermal power
ECOWASS	Economic Community of West African States
GT	gas turbine
GHG	greenhouse gas
HVDC	high voltage direct current
IRENA	International Renewable Energy Agency
IEA	International Energy Agency
LCOC	levelised cost of curtailment
LCOS	levelised cost of storage
LCOE	levelised cost of electricity
LCOT	levelised cost of transmission
OCGT	open cycle gas turbine
OPEX	operational expenditures
PHES	pumped hydro energy storage
PV	photovoltaic
RE	renewable energy
RoR	run-of-river
SNG	synthetic natural gas
SDGs	Sustainable Development Goals
ST	steam turbine
TES	thermal energy storage
VRE	variable renewable energy
WACC	weighted average cost of capital
WA	West Africa
WAPP	West Africa Power Pool

bottom: with 13%, 12%, 11% and 9% respectively [14]. The average annual electricity consumption in WA was about 145 kWh/capita in 2015 [15].

Nonetheless, the electricity supply gap is likely to increase as population, urbanisation and income are expected to rise, driving up electricity demand in the nearest future [9]. Electricity demand in the region is projected to increase fivefold by 2030, to 250 TWh, based on the ECOWAS Master plan [16]. The current grid capacity is not sufficient to cover the demand implying load shedding is becoming more prominent, driving consumers towards large-scale use of costly backup generation [17]. Due to significant under-capacity in electricity generation, some countries in the region such as Benin, Burkina Faso, Niger and Togo rely on electricity imports for a substantial share of their supply. As of 2015, the power generation capacity in the ECOWAS region is about 21 GW, producing about 57 TWh of electricity [15]. As shown in Fig. 1, more than half of the grid-connected capacities in the region are natural gas powered thermal plants, mostly in Nigeria, where it is the main power generation technology [18,19]. Nigeria, Ghana and Côte d'Ivoire account for more than 80% of installed capacity and generation [18]. In addition, the operating capacity is low in comparison to the overall existing capacity in most of the countries in the region.

In order to stem the energy crisis while contributing to the objectives of the Paris Agreement, the ECOWAS region aims to

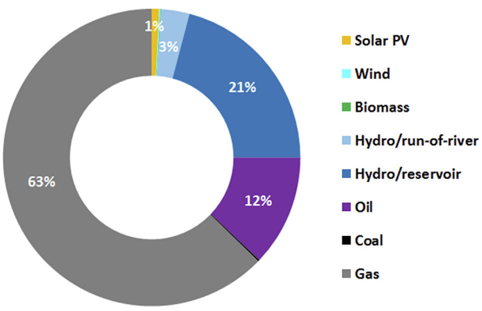

Fig. 1. West Africa power plant installed capacity by 2015 [18].

increase the share of grid-connected RE in the overall generation mix, including large hydropower, to 35% by 2020 and 48% by 2030. In addition, the share of rural population served by decentralised renewable energy systems is expected to reach 22% by 2020 and 25% by 2030 [3]. Over the period 1990–2015, CO_2 emissions in WA have increased by 68% reaching 139 Mt CO_{2eq} [20]. The electricity sector is the focus of many countries, in slowing down GHG emissions, as the sector accounts for one-third of the world's energy-related GHG emissions [21]. Therefore, a transition towards renewable electricity systems is essential, as the current systems dominated by fossil fuels are unsustainable on all accounts of social, economic and environmental criteria [22]. Over the past decades, the global trend in installed RE capacities has grown significantly from 995 GW in 2007–2179 GW at the end of 2017, and is dominated by solar photovoltaics (PV) and wind energy. In Africa, RE installed capacity grew from 23 GW in 2007 to 43 GW at the end of 2017. Much of this growth comes from solar PV (+98%), wind (+90%) and hydropower (+32%) [22]. RE has come to lead the new investments in the global power sector. As a result, the RE cost decline accelerates further, out-competing new built fossil capacities [23]. Solar PV utility-scale global levelised cost of electricity (LCOE) fell by 73% between 2010 and 2017 [24]. For instance, the differential between the LCOE for onshore wind and solar PV in South Africa is now 40% and almost 50% lower in price than newly built coal and nuclear, respectively [25].

The ECOWAS region has huge RE resource potential, widely distributed across the region and could provide low-cost and reliable energy supply [5]. Countless opportunities exist for deploying solar PV, wind energy, hydropower and biomass technologies across the region [5]. Currently, RE generation in WA is dominated by hydropower; and is even the main power source for some countries. Solar PV, wind energy and hydropower are anticipated to experience strong growth in the region's power mix [4]. However, these power sources in WA are governed by the monsoon, which causes seasonal variability [4]. Thus, the need for improved interconnections within the ECOWAS region is essential to achieve the synergetic effects by harnessing locally available RE resources, a solution to the challenges of low access and unreliable electricity supply in the region. Furthermore, the variability of RE supply may not be as significant, when viewed over larger geographic area [26]. Moreover, there is a spatio-temporal complementarity between various resources [27], which result in lower intermittency when examining the entirety of resources contribution, rather than a single resource contribution [26]. Additionally, energy system modelling is essential when assessing the least cost electricity expansion path for developing countries or regions [26]. Recent works have shown the possibility of achieving a fully renewable electricity system, as in the case of Nigeria [19], SSA [26] and global [28]. These studies have shown technical possibility and economic prospects of full defossilisation of the future power system, while considering all sustainability criteria. Both international agendas, the Paris Agreement and SDG 7 can be achieved by the deployment of RE technologies, in tackling the two major challenges of the 21st century; climate alteration and prevalent energy poverty [2]. Energy access is underlined in the SDG 7, while energy transition is highlighted in the Paris Agreement for mitigating climate change [2]. A brief review on RE share in the WA energy system is presented in Table 1.

So far, there is a lack of high temporal and spatial resolution energy transition studies for WA, which considers the impact of high penetration of RE in meeting the growing demand in the region under the operation of the WAPP electricity market. For these reasons, this study extends the investigation begun in Refs. [4,17,26,29–31], for a better understanding of the roles and benefits of flexible electricity generation, interconnected electricity networks and energy storage solutions in the transition towards a fully decarbonised power system and improved energy access for the 15 member states of ECOWAS, within the time horizon of 2015–2050. In addition, this study seeks to determine the least-cost and most-job enriching power system for WA. Furthermore, WA as an electricity island or individual country scenarios are compared towards a least-cost solution for the region. To this end, six scenarios were developed to fully understand the transition pathways for WA, under certain policy constraints, such as cross-border electricity trade and GHG emissions costs. These scenarios could cater, for instance, to policy decisions for decarbonising the WA electricity system within the time horizon of 2015–2050. The research investigates cost optimal generation mix to meet the demand based on assumed costs and technologies in 5-year intervals. The paper is organised as follows: section 2 describes the research methodology. Section 3 presents the result of the optimisation. Implications of the transition is discussed in section 4. Conclusions and policy measures are proposed in section 5.

2. Methodology

The ECOWAS power system optimisation was performed with the LUT Model described in Ref. [28,32]. The employment creation during the transition is analysed based on methodology presented in Ref. [33,34]. Fig. 2 illustrates the geographical scope of this study. West Africa was structured into 20 defined sub-regions based on the existing cooperation.

2.1. Model description

The LUT model a linear optimisation tool, which performs simulations for an entire year on an hourly resolution under certain operational conditions. The key function of optimisation algorithm is to minimise the system cost. To compute the lowest system cost, the model seeks to optimise the sum of installed capacities of each technology, operational expenditures, and costs of generation ramping. The WA power sector transition is simulated in 5-year time intervals under certain constraints. The model's main inputs and outputs are provided in Fig. 3. The model detail description can be found in Ref. [28].

In addition, the energy system takes into account electricity distributed generation by prosumers. The prosumer consumption is categorised as follows; residential, commercial and industrial. The prosumer sector is optimised exogenously on hourly resolution, the self-consumption model describes the optimal PV and storage (mainly battery) system size for the potential prosumers. The key function for self-consumers algorithm is to minimise cost of electricity consumed, estimated as the summation of prosumer generation, cost of grid electricity consumed and annual costs. Excess prosumer generation is sold to the grid at 0.02 €/kWh by prosumers, when their own demand is satisfied, but not more than 50% of total self-generation.

The model operates under two essential constraints:

1. The RE capacity share increase cannot exceed 4% per year (3% per year from 2015 to 2020), in order to avoid disruptions.
2. From 2015 onwards, no new conventional power plants would be installed, except gas turbines due to their lower carbon emissions, higher efficiency, and their ability to use sustainable synthetic biomethane and natural gas in the later phase. The current fossil-fueled plants are decommissioned based on their technical lifetimes [35].

2.2. Applied technologies

The ECOWAS power system is modelled with various technologies as show in Fig. 4, which include electricity generation, storage, and transmission. Existing transmission grid capacity was taken from Ref. [17], losses in transmission and distribution are considered during transition simulation [36]. Fig. 4 illustrates the LUT model components.

2.3. Technical and financial assumptions

The technical and financial assumptions introduced to the model are provided in the Supplementary Material (Tables S1–S4).

Table 1
Review on the share of renewable energy in West Africa.

Study	Year	Remark
IEA [17]	2014	The New Policies Scenario assumes RE installed capacity of 43 GW (38%) and fossil power plant of 70 GW (62%) by 2040. Gas dominates the installed capacity with 50 GW (44%), followed by hydropower with 24 GW (21%). Gas and hydropower contribute 249 TWh (53%) and 100 TWh (21%), respectively, of the total electricity generation at 474 TWh by 2040.
IRENA [29]	2015	RE installed capacity is 32 GW, and hydropower tops with about 22 GW by 2030 for the power sector. Hydropower dominates with 82 TWh for the total RE generation at 116 TWh (52%).
IRENA [30]	2018	This study reveals a growing share of RE in WA by 2030 under three scenarios. Depending on the scenario analysed, solar PV in the region ranges from 8.2 GW to 21.5 GW by 2030. While hydropower ranges from 11.4 GW to 11.5 GW, and wind energy remains constant at 1.6 GW for all scenarios. The remaining capacity is mainly supplied by gas in the range of 30 GW–36 GW by 2030.
Adeoye and Spataru [31]	2018	The study compares the baseline scenario of the 2025 power system with the renewable energy scenario of high penetration of solar PV. In the baseline scenario, gas-fired power plants contributes 55% of electric power generated, 27% from hydropower, 9% from coal and 8% from diesel. Under the renewable scenario, gas power plants account for 37% of electricity supply, 28% comes from solar PV, 25% from hydropower and 3% from diesel.

Fig. 2. The different sub-regions of West Africa.

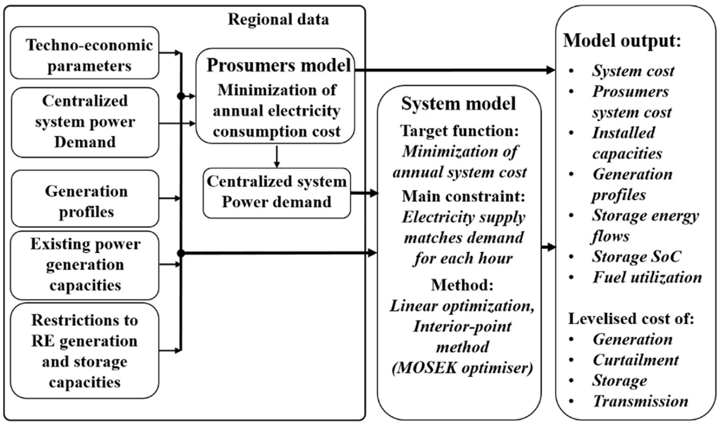

Fig. 3. Schematic of the LUT model [28].

In all the scenarios examined, a 7% weighted average cost of capital (WACC) was assumed, whereas 4% WACC is set residential PV self-consumption. A lower WACC is assumed for the PV self-consumption, as financial return expectations are lower. The residential, commercial and industrial consumers electricity prices were estimated till 2050 based on methodology described in Ref. [38,39]. The cost of electricity for each country in the region are provided in the Supplementary Material (Table S5).

The RE technologies upper limits were estimated based on methodology described in Ref. [32], existing installed capacities until 2015 are taken from Ref. [35] and set as lower limit. Absolute numbers of the upper and lower limit of all technologies are provided in the Supplementary Material (Tables S6 and S7). The required power capacities during transition for WA are provided in the Supplementary Material (Tables S8–S12).

2.4. Renewable resources potential

The wind energy, optimally tilted PV and solar CSP generation profiles, were estimated based on the methodology described in Ref. [32], and PV single-axis tracking according to Ref. [40], based on resource data of NASA [41,42] reprocessed by the German Aerospace Centre [43]. The hydropower generation profiles are estimated using daily resolved water flow data for the year 2005 [44]. The computed Full load hourly (FLH) for all resources can be found in the Supplementary Material (Tables S13–S17). Fig. 5 shows the annual FLH of various resources for entire WA. Biomass and waste potentials are provided in Ref. [45] and are classified according to Ref. [32]. Biomass costs are estimated using data from Ref. [46,47]. A gate fee of 50 €/ton was assumed for solid waste in 2015, which gradually increases up to 100 €/ton in 2050.

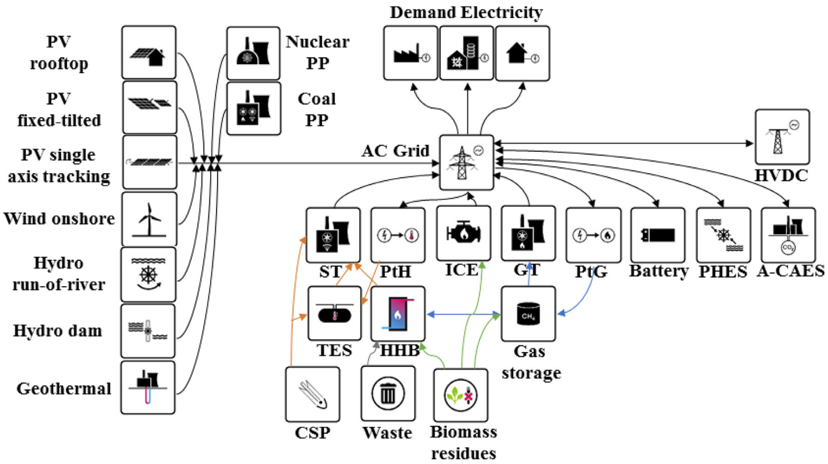

Fig. 4. Components of the LUT model [37]. Abbreviations not introduced elsewhere include PP - power plant, ST - steam turbines, PHES – pumped hydro energy storage, HHB – hot heat burner, ICE – internal combustion engine, PtH – power-to-heat, GT - gas turbines, PtG - power-to-gas, CSP – concentrated solar thermal power, A-CAES – adiabatic compressed air energy storage, TES – thermal-energy-storage.

2.5. Development of electricity demand

The WA electricity demand for the power sector is estimated to increase from 60 TWh in 2015 to about 667 TWh in 2050 [17], and absolute numbers are provided in the Supplementary Material (Table S5). Fig. 6 shows the aggregated load curve for WA. A regional compound average annual growth rate of about 7% in electricity demand drives the transition. The electricity demand is driven mainly by Nigeria, Ghana and Côte d'Ivoire, together they account for about 80% of the regional demand by 2050. The hourly load demand profiles are estimated based according to Refs. [48].

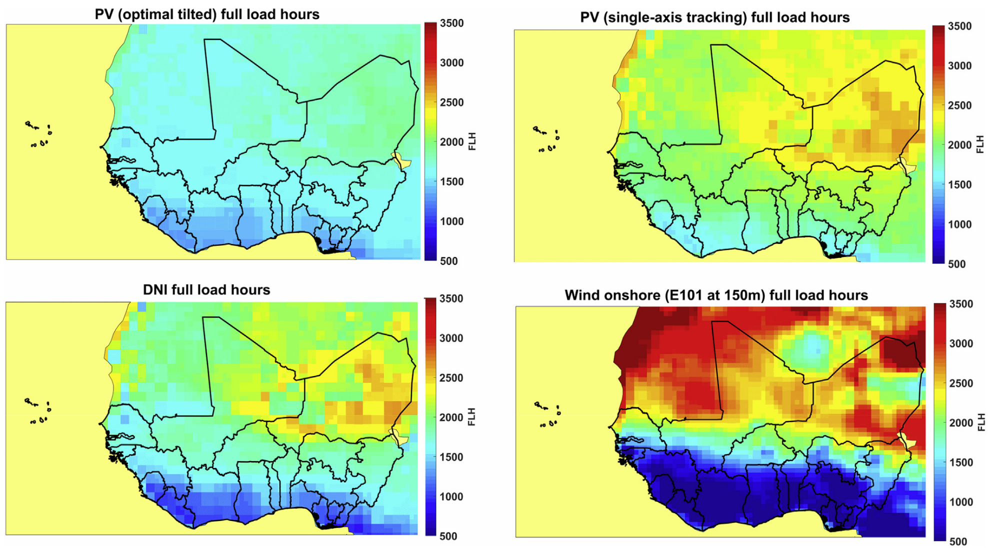

Fig. 5. Maps of West Africa showing annual full load hours for optimally tilted (top left) and PV single-axis tracking (top right), CSP solar field (bottom left), and wind (bottom right).

2.6. Scenario descriptions

In this study, six scenarios were studied for WA power system analyses, which are briefly described in Table 2.

3. Results

3.1. Electricity installed capacity and generation mix

Investments in power generation capacities are needed in WA, due to under-capacity power supply and rapid increase in electricity demand across the region. The installed capacities during the transition for all technologies under various scenarios are shown in Fig. 7 and absolute numbers are provided in the Supplementary Material (Tables S8–12). Table 3 presents the electricity installed capacity by technology for all scenarios in 2050. The respective power generation capacities in the BPSs is visualised first as shown in Fig. 7(a–d). Across the BPSs, solar PV dominates the installed capacities by 2050, with 284 GW in BPS-A, 284 GW in BPSnoCC-A, 328 GW in BPS-C, and 316 GW in BPSnoCC-C. Besides solar PV, a diverse technology mix can be observed in Fig. 7(a–d). Wind energy appears to be relevant in the BPSs across the area (BPS-A and BPSnoCC-A), while gas-based technologies contribution appears to be higher in the BPSs across the countries (BPS–C and BPSnoCC-C). The installed capacities in the CPSs are shown in Fig. 7(e–f). Gas turbines and hydropower dominates the installed capacities during the transition in the CPSs, followed by nuclear and coal, while the remaining capacities come from solar PV, wind energy and bioenergy. In 2050, gas turbine and hydropower installed capacities reach 72 GW and 28 GW, respectively, in the CPSs.

Fig. 8 shows the generation mix under various scenarios during the transition. Electricity generation increases for all scenarios to meet the demand over the transition in WA. In 2050, solar PV tops the generation mix in the BPSs, complemented by hydropower, bioenergy and wind energy as shown in Fig. 8(a–d). Solar PV contributes about 589 TWh in BPS-A, 590 TWh in BPSnoCC-A, 644 TWh in BPS-C and 619 TWh in BPSnoCC-C of the total electricity generation in 2050. Whereas, gas turbine dominates the power supply in the CPSs, followed by hydropower, coal and nuclear. By 2050, gas turbines account for 60% (407 TWh) of the generation and hydropower for 18% (120 TWh). Additional graphical results on the generation mix under various scenarios are available in the Supplementary Material (Fig. S1).

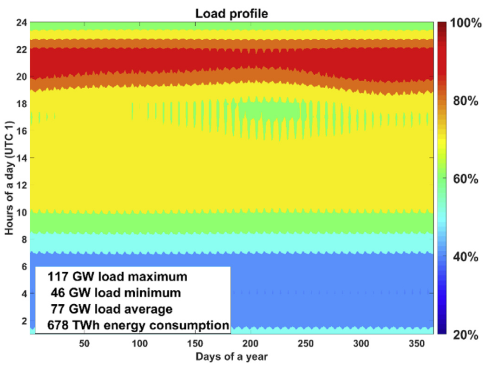

Fig. 6. Aggregated load curve for West Africa for 2050.

Fig. 9 presents the sub-regional capacities projection for 2050. Solar PV capacities are observed in all sub-regions due to very good solar irradiation across WA as shown in Fig. 9 (top) for the BPS-A. Wind capacities are predominant in Niger and Mali. Hybrid PV-battery systems dominate the power system by 2050. Batteries emerge as the major supporting storage technology for PV. Fig. 9 (bottom) shows the capacity outlook in the CPS-A, which is dominated by gas turbines and hydropower. Nigeria with 53 GW (42%) and 93 GW (29%) dominates the total installed capacity in the CPS-A and BPS-A, respectively. Gas-fired power plants (32%) and hydropower (53%) together make up 85% of the WA planned capacities in the pipeline [30]. Fossil gas is expected to be supplied via the Western African Gas Pipeline to coastal countries: Benin, Ghana, Togo, with extension to Côte d'Ivoire. Additional graphical results on regional capacity and generation outlook can be found in the Supplementary Material (Figs. S2 and S3).

3.2. System flexibility

This section analyses the system flexibility, a vital precondition for the grid integration of high shares of power feed-in from variable renewable electricity (VRE), particularly in BPSs. Solar PV, wind energy and hydropower potential in WA is influenced by the monsoon, which causes seasonal variability. The sources of operational flexibility examined in this research include storage technologies, transmission grid, flexible generators (gas turbines), but also dispatchable RE (hydro reservoir, bioenergy) and generation curtailment. These flexibility components act on different timescales.

3.2.1. Storage need and utilisation

Electrical energy storage units are observed to be valuable in providing flexibility to the power system, particularly in the BPSs due to high penetration of RE as shown in Fig. 10(a–d), visualising the electricity throughput. The residual load demand covered by storage units is 259 TWh (36%) in BPS-A, 256 TWh (35%) in BPSnoCC-A, 333 TWh (44%) in BPS-C and 266 TWh (37%) in BPSnoCC-C by 2050. Contrarily, storage units output in the CPSs is about 20 TWh (3%). Battery storage emerges as the key element of the storage units in terms of output, particularly in the BPSs throughout the transition due to daily charge and discharge. Thermal energy storage (TES) and gas storage outputs appear to be relevant in the BPSs across the countries from 2035 to 2045, respectively. Whereas in the CPSs, TES dominates storage output until 2045, due to CSP installed capacities. Absolute storage throughput numbers under various scenarios examined are provided in the Supplementary Material (Tables S19–S23). Table 4 presents the storage capacity by technology for all scenarios in 2050. Fig. 11 shows the required storage capacities under various scenarios. In terms of storage capacities requirement, gas storage dominates in the BPSs throughout the transition, followed by TES in the CPSs until 2045. The installed storage capacities are lower in the BPSs across the area in comparison to the BPSs across the countries as shown in Fig. 11. While the lower installed capacities of storage technologies in the CPSs due to increasing share of dispatchable thermal generators and hydropower.

3.2.2. Cross-border electricity trade flow

Asides from the role of energy storage units in balancing the temporal mismatch between generation and demand, the transmission network provides further flexibility to the power system. It further helps in balancing large regional differences of generation and demand, and offers strong spatial interconnections. The overall grid utilisation profile depicts the electricity generation and demand pattern under various scenarios, as shown in Fig. 12. Grid

Table 2
Description of the scenarios examined for the ECOWAS power sector transition.

Name	Description
Best Policy Scenario – Country wide (BPS–C)	Carbon emissions costs are applied to forbid new investment in fossil-fueled plants and 100% RE is achieved by 2050. In this scenario, no interconnection exist among the 15 member states. Within countries, applied for Nigeria, interconnections are free for optimisation.
Best Policy Scenario – Country wide (BPSnoCC-C)	This scenario is similar to the above. However, no GHG emissions costs are assumed.
Best Policy Scenario – Area wide (BPS–A)	This scenario is similar to the BPS-C. However, interconnection among member states is assumed with GHG emissions costs.
Best Policy Scenario no GHG cost – Area wide (BPSnoCC–A)	This scenario is similar to the BPS-A. However, no GHG emissions costs are assumed.
Current Policy Scenario – Area wide (CPS–A)	This scenario is designed according to ECOWAS RE targets [3]. The RE capacities were provided until 2030. From 2030 onwards capacity for various technologies are extrapolated until 2050. All sub-regions are interconnected. Coal, gas turbines, internal combustion engines and nuclear power plants supply the rest of the capacities required to meet the demand.
Current Policy Scenario no GHG cost – Area wide (CPSnoCC–A)	The Current Policy Scenario is simulated without GHG emissions costs.

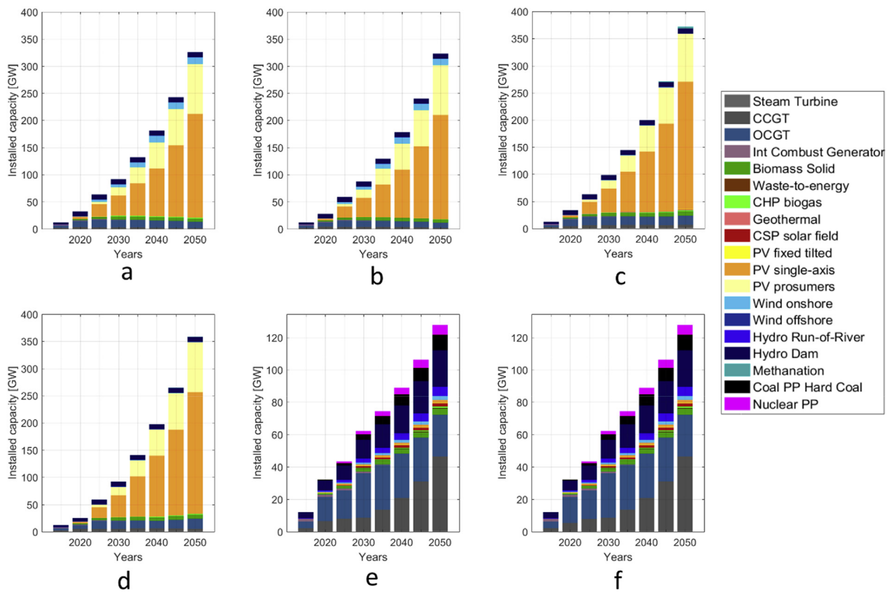

Fig. 7. Installed generation capacities for BPS-A (a), BPSnoCC-A (b), BPS-C (c), BPSnoCC-C (d), CPS-A (e) and CPSnoCC-A (f) from 2015 to 2050.

utilisation appears to be positively related to solar PV generation from around 9.00 to 18.00 per day in the BPS-A, as shown in Fig. 12 (left). Whereas, grid utilisation appears to be more vibrant during the times of higher electricity demand from around 20.00 to 22.00 in the CPS-A, as shown in Fig. 12 (right). As evident in Fig. 13, the 20 sub-regions can be classified as, exporting and importing sub-regions. The annual grid utilisation in the BPS-A is visualised first in Fig. 13 (top). In the BPS-A there are three main exporting sub-regions as shown in Fig. 13 (top); namely, Niger, Mali and NIG-NW. Niger and Mali are net exporters of solar and wind electricity, as a result of high resource potential due to diminishing monsoon influence. While, NIG-NW is a net exporter of solar electricity. Countries with good hydropower potential serve as balancing regions, which include Nigeria (NIG-NE) and Guinea. In the CPS-A, the major exporters are Guinea, Nigeria, Niger and Liberia as shown in Fig. 13 (bottom). The total grid transmission is 298 TWh in the BPS-A, representing 45% of the total electricity demand, and is 39 TWh in the CPS-A, representing 6% of the total electricity demand. The annual grid utilisation increased significantly in the BPS-A by a factor of 7.6 in comparison to CPS-A. Gambia, Sierra Leone and Guinea Bissau did not experience any changes in terms of the amount of electricity imported in the BPS-A and CPS-A. Mali changed from being an importer in the CPS-A to an exporting country in the BPS-A. Electricity imports increased significantly in most of the sub-regions of Nigeria, except NIG-NW, which emerges to be an exporting sub-region in the BPS-A, while NIG-NE maintains status quo in the BPS-A and CPS-A.

Fig. 14 shows the cross-border electricity trade directions and amounts (in TWh) among the sub-regions in the BPS-A and CPS-A. The thickness of the flow illustrates the amount of electricity

Table 3
Electricity installed capacity by technology for all scenarios in 2050.

Generation technology	Unit	BPS-A	BPSnoCC-A	BPS-C	BPSnoCC-C	CPS-A	CPSnoCC-A
PV prosumers	[GW]	92	92	92	92	0	0
PV single-axis tracking	[GW]	192	192	235	223	2	2
PV optimally tilted	[GW]	0	0	1	0	0	0
Wind energy	[GW]	12	12	0	0	2	2
Geothermal power	[GW]	0	0	1	0	0	0
CSP	[GW]	0	0	0	0	2	2
Hydropower	[GW]	10	10	10	10	28	28
Biomass PP	[GW]	5	5	8	7	4	4
Waste PP	[GW]	0	0	0	0	0	0
Biogas PP	[GW]	2	0	2	2	1	1
Biogas Digester	[GW]	1	1	1	1	1	1
Biogas Upgrade	[GW]	1	1	1	1	1	1
CCGT	[GW]	1	2	5	4	46	46
OCGT	[GW]	12	9	17	19	26	26
Steam Turbine	[GW]	0	0	2	1	0	0
Coal PP	[GW]	0	0	0	0	10	10
Oil PP	[GW]	0	0	0	0	0	0
Nuclear PP	[GW]	0	0	0	0	6	6

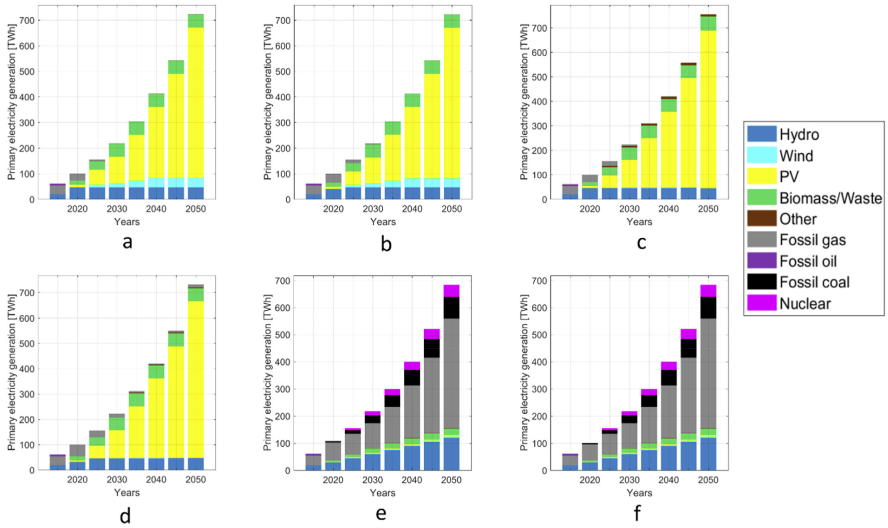

Fig. 8. Electricity generation mix for BPS-A (a), BPSnoCC-A (b), BPS-C (c), BPSnoCC-C (d), CPS-A (e) and CPSnoCC-A (f) from 2015 to 2050.

transferred between the regions in TWh. Niger dominates the net electricity trade with 204 TWh (68%), followed by 54 TWh (18%) for Mali and 34 TWh (11%) for NIG-NW in BPS-A. Whereas, Guinea dominates the electricity trade in the CPS-A with 12 TWh (31%). Benin and NIG-NC emerge as the main transit conduit in the regional electricity trade in the BPS-A, including Gambia and Guinea Bissau in the CPS-A as shown in Fig. 14 (bottom). The regional electricity trade depicts the role of grid interconnections, particularly in scenario with high shares of RE, in comparison to the one dominated by thermal dispatchable generators.

3.2.3. Role of gas turbines

The fleet of VRE generators are accompanied by flexible power plants. Gas turbines are found to be dynamic fast-responding dispatchable generators, covering some fraction of the residual load demand based on different timescales from days to weeks, particularly in the BPSs. The average FLH declined from 5470 in 2015 to 191 in 2050 for BPS-A, to 275 in BPSnoCC-A, to 417 in BPS-C and to 601 in BPSnoCC-C. This document a drastic shift in the role of gas turbines, from bulk electricity generation to peak electricity generation for the most challenging seasons of the year. By 2050, gas turbine generation is 2.5 TWh in BPS-A, 3.1 TWh in BPSnoCC-A, 9.0 TWh in BPS-C and 14.0 TWh in BPSnoCC-C. The installed gas turbine capacities are 12.9 GW, 11.4 GW, 21.7 GW and 23.3 GW BPS-A, BPSnoCC-A, BPS-C and BPSnoCC-C, respectively, by 2050. Whereas in the CPSs, the CCGT operates as baseload generators and OCGT is utilised in meeting peak loads during the night. Fig. 15 illustrates the gas turbine (CCGT and OCGT) utilisation for BPS-A, BPS-C and CPS-A by 2050. Gas turbines are most utilised during the monsoon period in BPSs as shown in Fig. 15 (a-b, d-e).

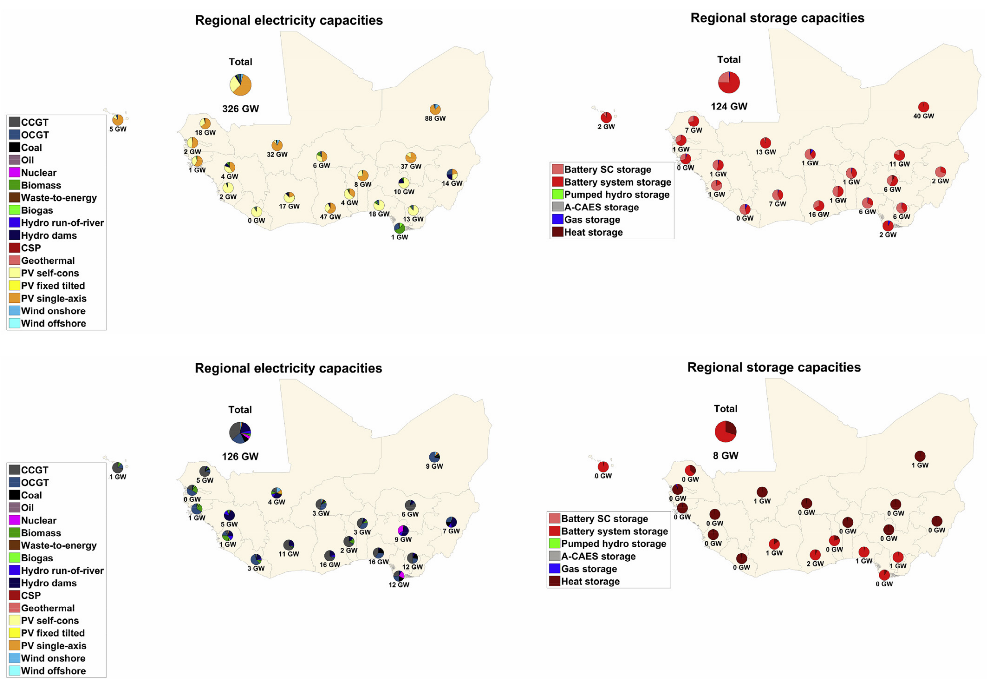

Fig. 9. Overview of the generation mix (left) and energy storage (right) for the BPS-A (top) and CPS-A (bottom).

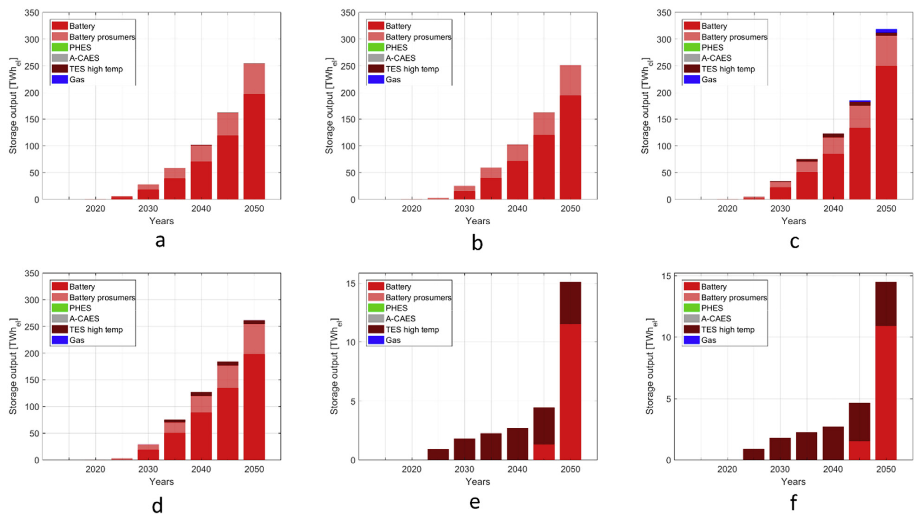

Fig. 10. Storage throughput for BPS-A (a), BPSnoCC-A (b), BPS-C (c), BPSnoCC-C (d), CPS-A (e) and CPSnoCC-A (f) from 2015 to 2050.

Table 4
Storage capacity by technology for all scenarios in 2050.

Storage technology	Unit	BPS-A	BPSnoCC-A	BPS-C	BPSnoCC-C	CPS-A	CPSnoCC-A
Battery total	[GWh]	735	737	840	800	33	31
PHS storage	[GWh]	0	0	0	0	0	0
TES storage	[GWh]	5	3	164	49	19	19
A-CAES storage	[GWh]	0	0	7	11	0	0
Gas storage	[GWh]	2403	1738	9359	1630	8	9

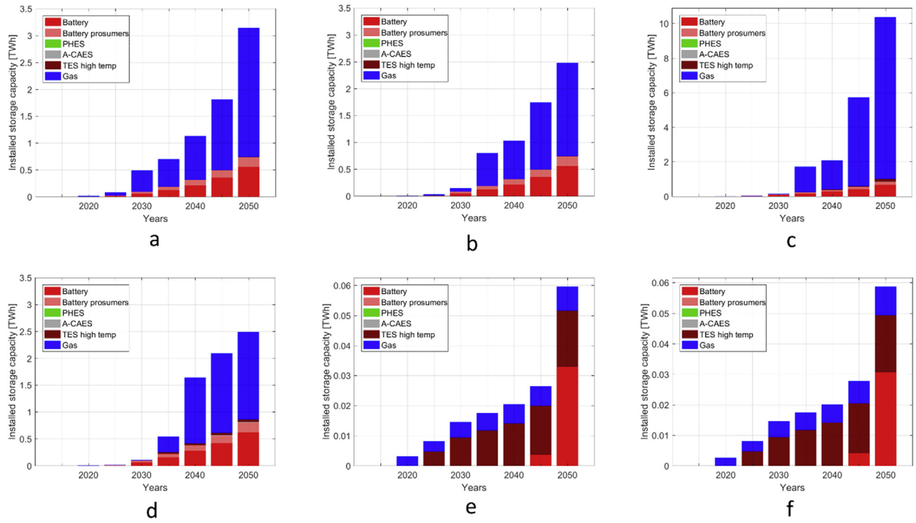

Fig. 11. Installed storage capacities for BPS-A (a), BPSnoCC-A (b), BPS-C (c), BPSnoCC-C (d), CPS-A (e) and CPSnoCC-A (f) from 2015 to 2050.

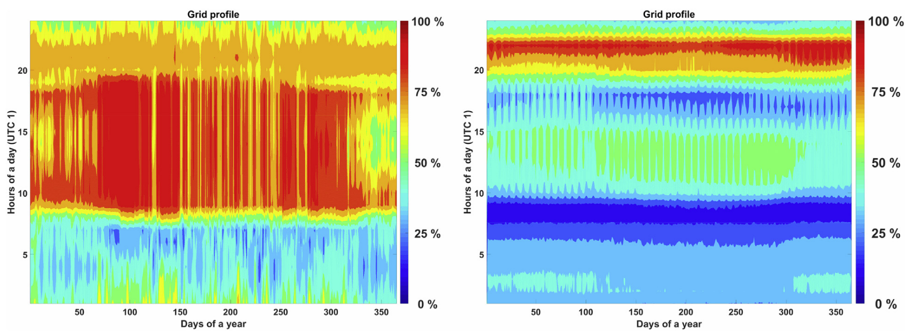

Fig. 12. Grid utilisation profiles for BPS-A (left) and CPS-A (right) in 2050.

Additionally, gas turbines are flexible power plants because their power output can be modulated sufficiently fast when needed and the robustness of their market power setup.

3.2.4. Generation curtailment

Curtailment is a flexibility option, which can be low cost in highly renewable energy systems, compared to other flexibility options [49]. In addition, sudden and unexpected power imbalance in the system is controlled by partial generation curtailment. VRE generation and curtailment under various scenarios are shown in Fig. 16. Fig. 16 (right) further shows the curtailed generation potential corresponding to VRE generation. The curtailed generation potential increases throughout the transition in BPSs, with the exception of the CPSs. It can be observed that generation

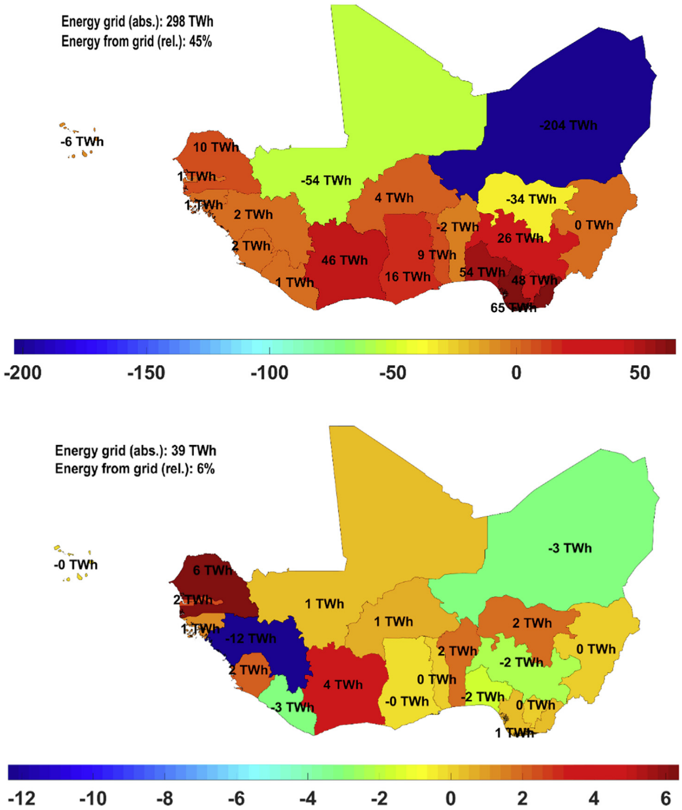

Fig. 13. Absolute annual grid utilisation in the BPS-A (top) and CPS-A (bottom) for the ECOWAS region in 2050. Net annual exports is represented by negative values, while the positive values represent the net annual imports.

curtailment is higher in the BPSs across the countries than in BPSs across the area. The high diversity of the region's power mix balances the regional electricity generation and contributes to low curtailment in the BPSs across the area. By 2050, generation curtailment is 27 TWh (4.1%) in BPS–A, 28 TWh (4.1%) in BPSnoCC–A, 41 TWh (6.1%) in BPS–C, 39 TWh (5.8%) in BPSnoCC–C and 3 TWh (0.5%) in CPSs.

3.3. Energy flow overview

Fig. 17 illustrates the energy flows for 2015 and the BPS in 2050. It shows the generation, end use and efficiency of each energy conversion process. The produced heat and losses in the system consist of the difference between the primary power generation and final demand. In 2015, electric power generation is provided mainly by gas turbines and hydropower, while RE generation, particularly solar PV, dominate in 2050.

3.4. Financial implications of the energy transition

Fig. 18 illustrates the LCOE under various scenarios during the transition. The LCOE in the BPSs is visualised first as shown in Fig. 18(a–d). The LCOE decline from about 70 €/MWh in 2015 to 36 €/MWh in BPS-A, to 41 €/MWh in BPS-C by 2050. Whereas, LCOE declines from 68 €/MWh in 2015 to 36 €/MWh in BPSnoCC-A and to 39 €/MWh in BPSnoCC-C by 2050. Lower LCOE over time during the transition in BPSs signifies the cost competitiveness of RE technologies during the transition. Fig. 18(e–f) depicts the LCOE in the CPSs. The LCOE increased significantly from about 70 €/MWh in 2015 and to 116 €/MWh in CPS-C by 2050, while the LCOE increased slightly from 68 €/MWh in 2015 to 70 €/MWh in CPSnoCC by 2050. Fuel costs and GHG emissions costs contribute to the high LCOE in the CPSs. Additional results on costs are provided in the Supplementary Material (Table S18 and Figs. S4–S6).

3.5. Socio-economic prospects of the energy transition

3.5.1. Jobs in the West African power sector

Figs. 19 and 20 depict the direct energy jobs created in the WA power sector during the transition period for the BPS and CPS. The annualised jobs created in the BPS and CPS were estimated based on the methodology presented in Ref. [33,34] and the assumed

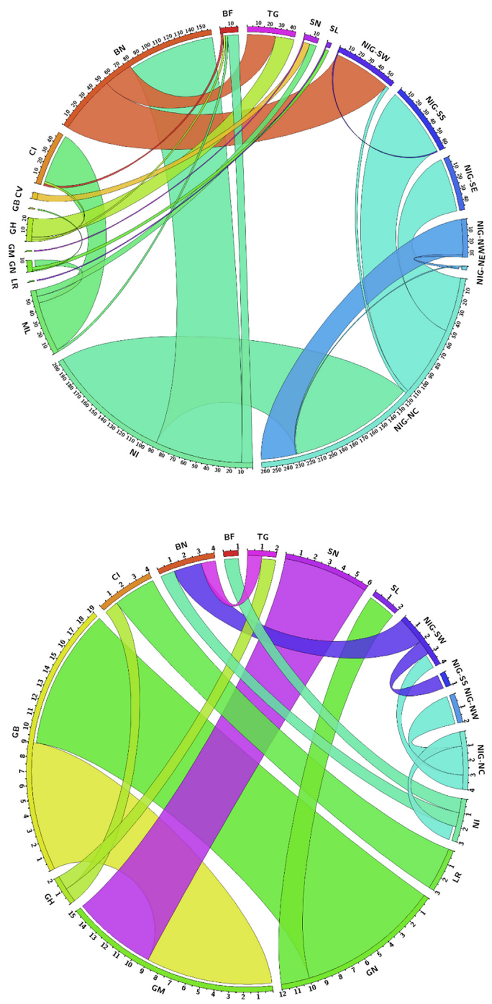

Fig. 14. Regional grid exchange within West Africa in the BPS-A (top) and CPS-A (bottom) in 2050.

employment generation factors are presented in the Supplementary Material (Table 24). About 440 thousand direct energy jobs were created in the BPS and solar PV emerges as the prime job creator with 68% of the total jobs created by 2050, as shown in Fig. 19. Whereas, fossil gas based power generation creates more jobs in the CPS, with 45% of the jobs by 2050, as shown in Fig. 20. Batteries mainly drive jobs created by storage technologies from 2025 onwards, which increases to 44 thousand by 2030 and further increases to 76 thousand by 2050 in the BPS. Overall, number of direct energy jobs created in the BPS appears to grow massively from around 20 thousand in 2015 to about 440 thousand in 2050. Similarly, jobs created in the CPS increase from around 20 thousand in 2015 to about 183 thousand by 2050.

Furthermore, the distribution of jobs by categories during the transition in the BPS and CPS is indicated in Figs. 19 and 20. In the BPS, construction and installation of renewable energy technologies create the bulk of the jobs, enabling the rapid ramp-up of capacity until 2025. The sector creates about 82 thousand jobs by 2050. Furthermore, manufacturing jobs have a relatively low share until 2020, due to higher share of imports (mainly PV, hydropower, bioenergy and fossil gas). From 2025 onwards, a higher share of local manufacturing jobs is observed, as domestic production capabilities are assumed to be increased until 2050. The operation and maintenance jobs appear to take the lead from 2035 onwards and become the main job sector by 2050 with 41% of the total jobs. On the contrary, in the CPS, fuel jobs dominate during the transition. Fuel jobs dominate with a share of 56%, followed by operation and maintenance with 25% while manufacturing, construction and installation jobs are 16% by 2050.

The least-cost option becomes the cornerstone for a vibrant and job-intensive policy option for WA, centred on decarbonisation of its power sector. The electricity demand specific jobs in the BPS increases significantly from 321 jobs/TWh_{el} in 2015 to 1238 jobs/TWh_{el} in 2025 with the rapid ramp-up in RE installations. Beyond 2015, it declines steadily to around 662 jobs/TWh_{el} in 2050 as shown in Fig. 19. Whereas, the electricity demand specifics jobs in the CPS increased from 321 jobs/TWh_{el} in 2015 to 506 jobs/TWh_{el} in 2020, and further declines to 274 jobs/TWh_{el} in 2050.

3.5.2. Greenhouse gas emissions trajectory under various transition scenarios

The GHG emissions trajectory under various scenarios are depicted in Fig. 21. The defossilisation of the WA power system appears to be rapid in the BPSs area in comparison to the BPSs country as illustrated in Fig. 21(a–d). With GHG emissions costs, emissions decline rapidly after 2025 as fossil natural gas plants are replaced with RE capacities as observed in BPS-A and BPS-C. Without GHG emissions costs, the BPSnoCC-A shows similar emission pattern with BPS-A, whereas the BPSnoCC-C deviates the emission pattern observed in BPS-C. In the CPSs, the GHG emissions increased throughout the transition as depicted in Fig. 21(e–f).

4. Discussion

This work investigates the least-cost electricity expansion option for WA, under certain policy constraints. The BPSs results show that deep-decarbonised pathways are cheaper than fossil-based CPSs. Such a system complies with the objectives set out in the Paris Agreement, in comparison to CPSs. This power system is achievable with the abundant and diverse RE resources in WA, but requires a strong political will.

4.1. Solar PV plus battery: the new workhorses of the West African power system

Solar PV emerges as the new workhorse of the WA power system in renewables-led electricity generation. A mix of RE technologies, as observed in the BPSs can substitute the current heavy dependence on gas-fired electricity. The power system optimisation results show that it is least-costing to supply 81%–85% of the electricity demand in WA from solar PV under the BPSs by 2050. In this cost-optimal expansion path, about 284–328 GW solar PV installed capacities are operational by 2050. Solar PV technologies supply 589–644 TWh in the BPSs. PV prosumers contribute 20% to the total electricity generation in 2050. The plausible reasons for a high share of PV in WA power system includes the following, the

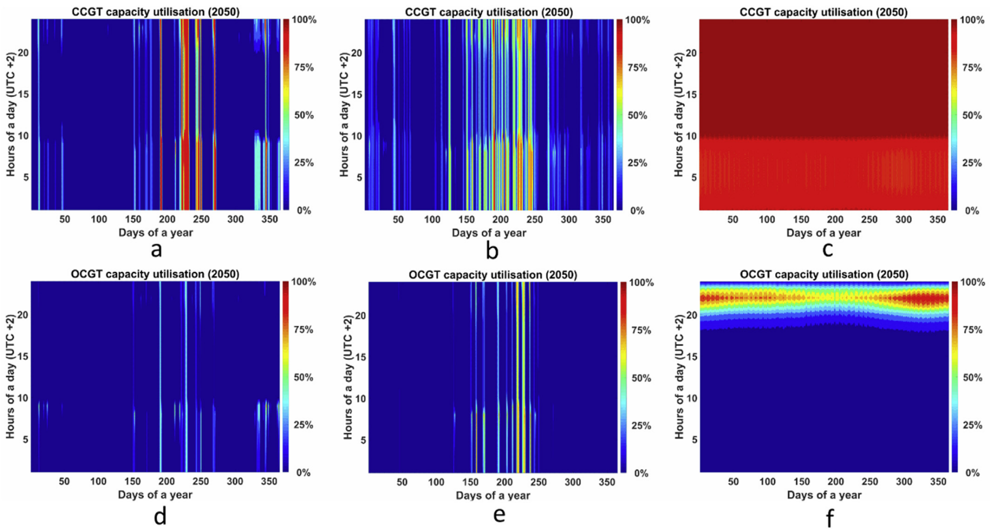

Fig. 15. Combined cycle gas turbine capacity utilisation for BPS-A (a), BPS-C (b), CPS-A (c). Open cycle gas turbine capacity utilisation BPS-A (d), BPS-C (e), and CPS-C (f) in 2050.

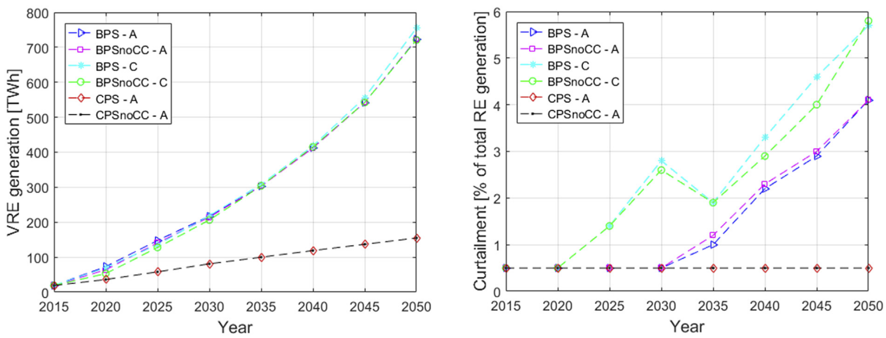

Fig. 16. Variable RE generation (left) and curtailment of generation potential (right) in TWh under various scenarios during the transition.

steep fall in solar PV and battery costs [37], excellent resource conditions and fast growing electricity demand in WA. The PV-battery combination drives most of the system from 2030 onwards. Batteries emerge as the main supporting technology for PV, battery capacities ranged from 735 GWh to 840 GWh in the BPSs. The solar resource potential increases northward due to diminishing monsoon influence. Likewise, highest wind potential is found towards the north/north-west. These factors contribute to high solar PV and wind energy installed capacities in Niger and Mali. WA has the solar and land resources to technically host a power system led by a mix of RE technologies. However, assessments of solar PV and wind power mixes for WA are rare [4]. The required land area for solar PV and wind installation is estimated based on the specified capacity density assumed in the model, which is 8.4 MW/km^2 and 75 MW/km^2 for onshore wind and optimally tilted PV respectively [32]. Therefore, an area of 1454 km^2 and 3784 and is needed for wind and solar PV capacities by 2050, representing just 0.03% and 0.07% of the total land area of WA. The results of this research reveal that solar PV will emerge as the backbone of WA power system, which is similar to the results of Oyewo et al. [19] for Nigeria. They conclude that solar PV will contribute significantly to Nigeria's future power system and it is comparable to any other developing countries with similar climates. Adeoye and Spataru [31] show that the high integration of solar PV plants will reduce the supply-demand gap and load shedding in the WA by 2025. According to Ref. [31], 71 GW of solar PV plants is assumed to be installed and in operation across WA. The BPSs results are also similar to results of Barasa et al. [26] for entire Sub-Saharan Africa (SSA) based on an overnight scenario approach for 2030 conditions, they conclude that countries in SSA

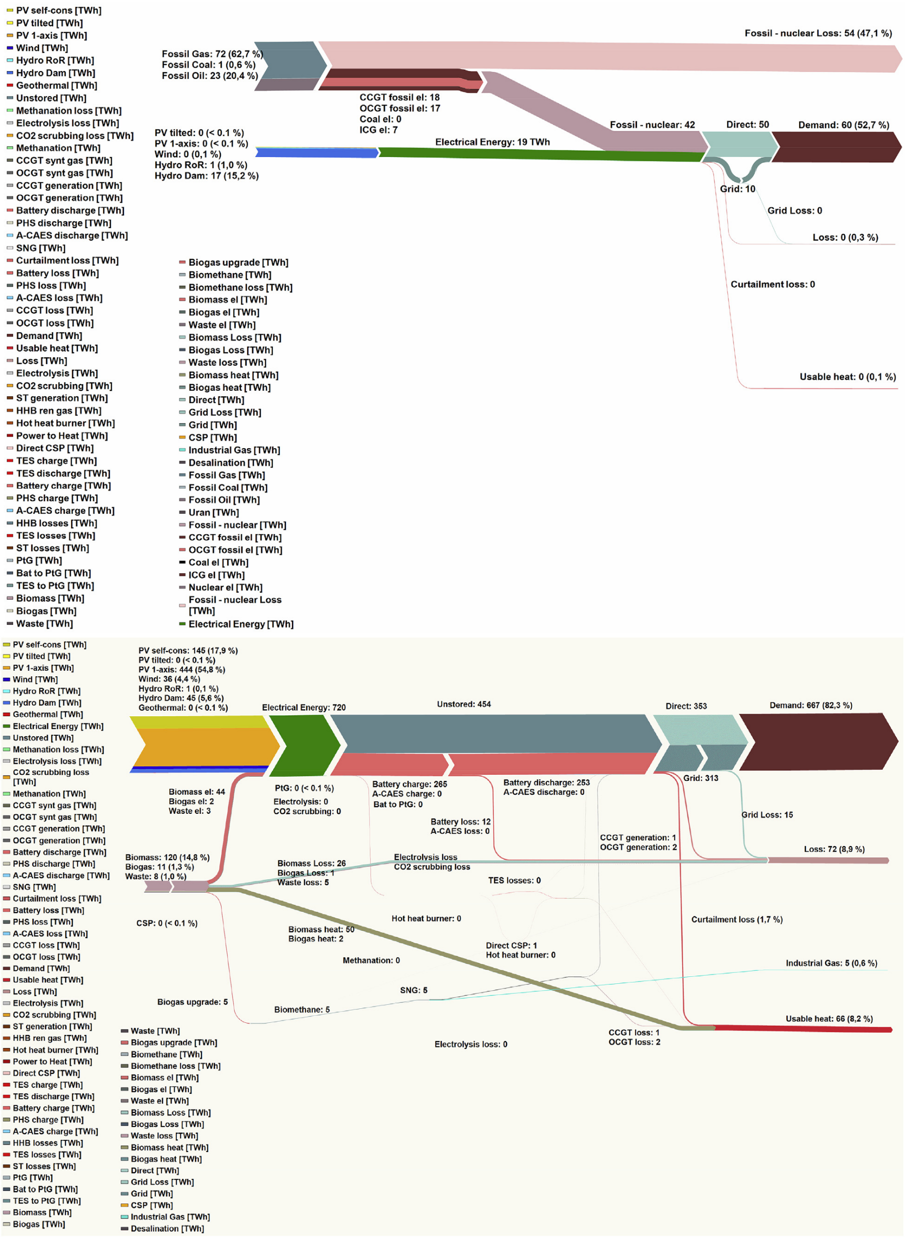

Fig. 17. Energy flows of the system for 2015 (top) and BPS in 2050 (bottom).

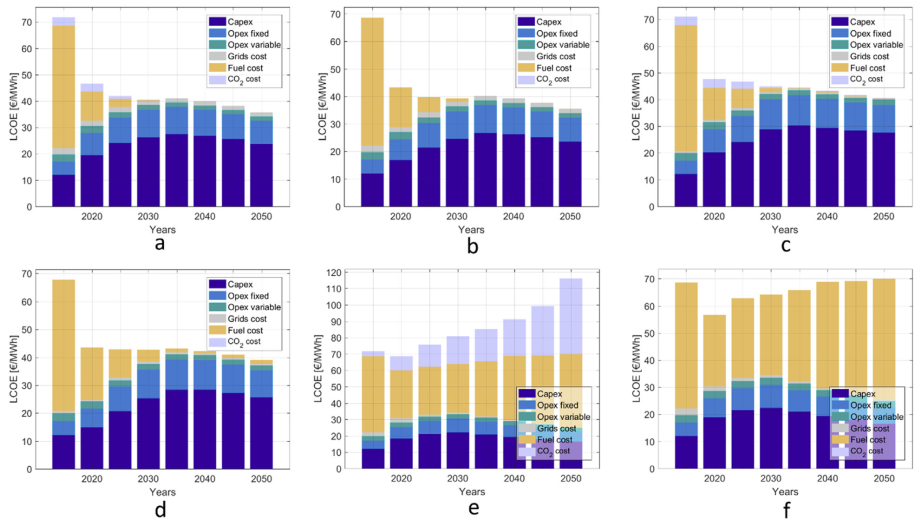

Fig. 18. Levelised cost of electricity for BPS-A (a), BPSnoCC-A (b), BPS-C (c), BPSnoCC-C (d), CPS-A (e) and CPSnoCC-A (f) from 2015 to 2050.

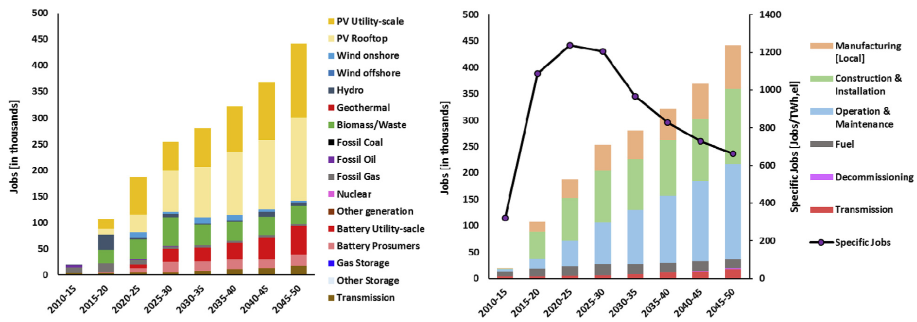

Fig. 19. Jobs created by the various power generation and storage technologies (left) and jobs created based on different categories with the development of electricity demand specific jobs (right) during the energy transition from 2015 to 2050 in West Africa for the BPS.

can be powered majorly by wind energy and solar PV. A recent study by IRENA [30], shows that the grid connected solar PV market would be over 20 GW by 2030, compared to just over 8 GW in their Reference Scenario (RS). The IRENA National targets scenario achieved a share of 37% RE. According to Ref. [30], solar PV installed capacity is 21.5 GW, wind is 1.6 GW and hydropower is 11.5 GW by 2030, the remaining generation capacity supplied by fossil generators is dominated by gas turbines with about 30 GW. In the CPSs, fossil-based thermal generators and hydropower dominate the power system accounting for 532 TWh (78%) and 120 TWh (18%) respectively by 2050. The results of the CPSs are comparable to the New Policy Scenario (NPS) of the IEA [17]. According to Ref. [17], fossil-based thermal generators dominate with 323 TWh (68%) of which, gas supply is 249 TWh (53%), followed by hydropower with 100 TWh (21%), bioenergy with 12 TWh (3%), solar PV with 17 TWh (4%) and other renewables with 21 TWh (4%). Similarly, gas and hydropower are expected to roughly triple in the IRENA Reference Scenario by 2030 to 32 GW and 11.5 GW, respectively [30]. It is worth mentioning that despite the huge potential for CSP as alternative technology to harness the Sun's energy in WA, future costs appear to be a bottleneck for CSP development. CSP installed capacities ranged from 0.1 to 1 GW, the highest installed capacities occur in the CPSs and lowest in the BPS across the countries, whereas no CSP is installed in the BPS across the area. Overall, the ECOWAS Renewable Energy Policy (EREP) targets for grid-connected capacity for solar PV, wind energy and CSP by 2030, in WA is very low at 1 GW for each [3]. It is obvious that solar PV and wind energy will be very relevant in a least-cost expansion for WA future power sector, while policies to facilitate their deployment are exigent.

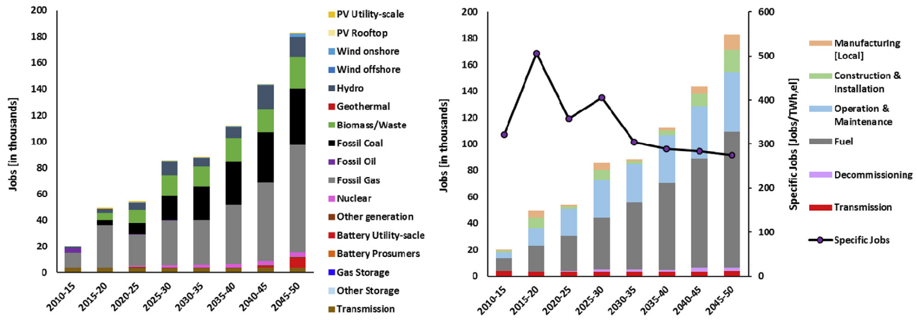

Fig. 20. Jobs created by the various power generation and storage technologies (left) and jobs created based on different categories with the development of electricity demand specific jobs (right) during the energy transition from 2015 to 2050 in West Africa for the CPS.

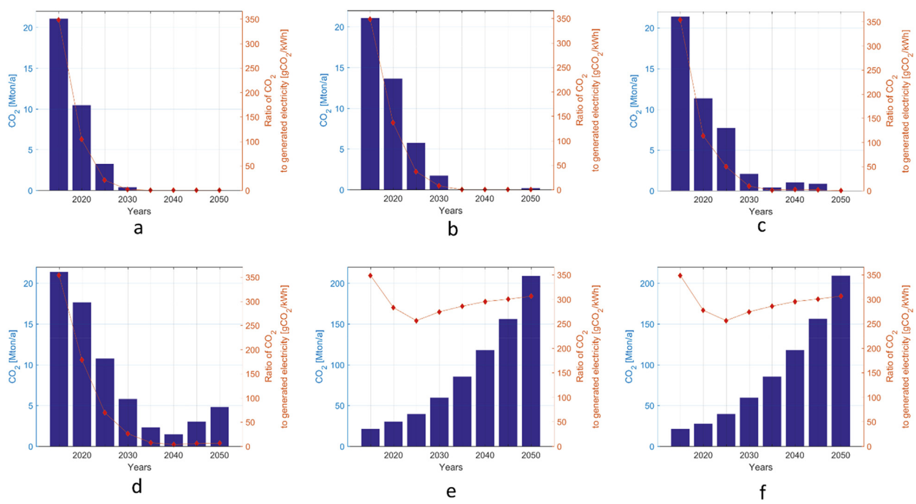

Fig. 21. GHG emissions trajectories for BPS-A (a), BPSnoCC-A (b), BPS-C (c), BPSnoCC-C (d), CPS-A (e) and CPSnoCC-A (f) from 2015 to 2050.

4.2. Flexibility requirement

Flexibility is harnessed from dispatchable renewables (mainly biomass and hydropower), transmission grid, curtailment and storage technologies, which facilitates the high shares of solar PV as seen in the BPSs. The relevance of storage technologies appears to be more vibrant in the BPSs, due to increasing shares of solar PV in the national power systems. Power grids dominated by solar PV are typically characterised by high storage needs [27]. In the BPSs, the relevance of storage technologies, particularly battery storage, increases over time. The PV-battery hybrid system appears to be a least-cost option for the WA power system by 2050, which is similar to the results of Oyewo et al. [27] for the Nigerian power system. Similar results have been obtained for the competitiveness of hybrid PV-battery plants for the case of Morocco [50]. In addition, battery cost has declined over the years, and further cost reduction is expected [51,52]. In terms of storage capacities requirement, gas storage leads in all the BPSs followed by battery storage. However, battery storage dominates when storage throughputs are considered, due to daily requirement in the absence of solar PV. Several studies have shown a need for storage, once the share of RE power generation reaches approximately 50% [28,32,37,49]. Consequently, with a share of 80% RE, seasonal storage is required [32]. The long term and seasonal storage is compensated by TES, adiabatic compressed air energy storage (A-CAES) and power-to-gas (PtG). Seasonal storage contribution is not required in the BPS across the area in comparison to BPS across the countries. Rather, bioenergy and hydropower are sufficient in compensating the seasonal variation in the BPS across the area, along with the vital flexibility provided by cross-border interconnections. As a result, only 9.5 GW PtG conversion units are needed in the BPS across the countries, whereas no PtG conversion units are needed in the BPS across the area. This rather rare phenomenon is also observed for Brazil, based on an overnight scenario approach for 2030 [53]. According to Ref. [53], a 100% RE system can be operated with extremely low seasonal storage based on PtG, this special condition is traceable to very high shares of dispatchable hydropower reservoirs and equatorial weather conditions. Hydropower reservoirs could be considered as virtual batteries, if operated in conjunction to solar PV systems [54]. The extraordinary growth of wind energy, plus some PV and bioenergy in Uruguay can be attributed to its massive hydropower, which can cover shortfall in wind, plus cross-border interconnections [55]. Under the right circumstances, as seen in the BPS area, a mix of RE appears to be a good candidate for the WA power sector. The synergies of RE resources limit the need for storage, improve system flexibility, and reduce day-to-day and inter-annual variability of the system as observed in the BPS area.

Furthermore, the flexibility function of the grid appears to be more vibrant in the BPS across the area for counterbalancing the regional power mismatches. Graphical results on grid utilisation are presented in the Supplementary Material (S7). Grids are a very important flexibility option, and their function will be discussed in more detail in the next section. Curtailment is another flexibility option. Curtailment is widely expected to increase with more VRE [49,56,57], as observed in this research. The question, whether to avoid curtailment or not, is debated increasingly [56], based on the perception that curtailment would be a mere waste of energy, despite the reported technical benefits [49]. Conversely, curtailment is another valuable resource, helping to stabilise the grid and improve system flexibility [57]. Avoiding curtailment requires investing in grid interconnection and storage solutions [56]. Contingencies in the power system can be reduced by curtailment of generation, which appears to be higher in the BPS across the countries than in the BPS across the area. The curtailment-storage-penetration nexus in the energy transition is researched in Ref. [49]. A set of two scenarios were examined in Ref. [49], the first scenario anticipates a limit on curtailment, while the other expects an optimal transition with curtailment considered as a technical solution to minimise mismatch in demand and supply. According to Ref. [49], "curtailment in optimally managed energy transition brings techno-economic opportunities to the system, while no curtailment or improper use of curtailment carriers a penalty".

The WA electricity generation depicts a tendency towards flexibility and complementarity as observed particularly in the BPSs. The need for flexibility will continue to increase in systems dominated by RE such as BPSs, as solar PV appears as the default technology choice for low-cost bulk energy in the power sector, in particular in Sun Belt countries [26,28,37,49,50]. Based on the foregoing discussion, gas power plants appear to be a valuable and flexible peaking technology when required, particularly during the monsoon periods. Several studies have identified gas turbines as a flexibility option for systems dominated by high RE shares, instead of coal or nuclear [19,28,57,58]. A recent study concludes that required flexibility could be provided by using flexible natural gas fired turbines, if the costs of battery do not decrease [59]. Furthermore, there are strong signals that electricity will contribute significantly to the future energy system. An electricity-led energy system will reduce primary energy demand and further increase system flexibility by coupling the decarbonised electricity to heat, transport and industrial sectors [25,60]. What is more, PtG and power-to-liquids solutions can be used to supply residual demand for fuels and chemicals that cannot be replaced with electricity directly [25,60].

4.3. Benefits of cross-border electricity trade

The interconnection of sub-regions in WA offers multiple benefits. Broad cost saving opportunities and increased flexibility in the power system is achieved due to grid interconnections between sub-regions of WA. The transmission network facilitates the exploitation of best RE production sites and smoothens out day-to-day variability. The transmission interconnections have the potential to reduce the LCOE, total system cost, installed capacities, storage requirements and curtailment in a highly renewable WA power system, as observed in the BPS across the area. With GHG emissions costs, the LCOE drops to 40.6 €/MWh in the BPS across the countries and to 35.7 €/MWh in the BPS across the area by 2050. Without GHG emissions costs, LCOE decreases to 39.0 €/MWh in the BPS across the countries and to 35.5 €/MWh in the BPS across the area. Likewise, the total annualised cost of system is 27.2 b€ in the BPS across the countries and it is 23.9 b€ in the BPS across the area with GHG emissions costs. Without GHG emissions costs, the total annualised cost of system is 26.1 b€ in the BPS across the countries and it is 23.8 b€ in the BPS across the area. This implies annual cost savings of 9% or 2.3 b€/a in the BPS across the area without GHG emissions costs, and is 12% or 3.3 b€/a with GHG emissions costs. This result requires special highlighting: the BPS across the area with and without GHG emissions costs lead practically identical energy system solutions. Table 5 highlights the key differences in financial outcomes and selected electricity parameters for 2050. It can be seen that the system costs are more or less the same as shown in Table 5 for the BPSs, which implies that with or without GHG emissions costs, the WA power sector can reach 100% RE as the least cost solution. What is more, the BPSs without GHG emissions costs leads to 98% and 99% RE generation in the area and country scenarios, respectively.

With transmission and GHG emissions costs, the BPS across the area shows approximately 12% less installed capacities (327.9 GW vs 370.8 GW), 70% less storage capacity (3.1 TWh vs 10.4 TWh) and 22% less storage output (259.2 TWh vs 332.9 TWh) than the BPS across the countries. Likewise, with transmission and no GHG emissions costs, the BPS across the area shows a reduction of about 10% of installed capacities (325.2 GW vs 360.5 GW), 11% less energy storage capacity (2.4 TWh vs 2.7 TWh) and 4% less storage output (256.2 TWh vs 266.5 TWh) compared to the BPS across the countries. Faster defossilisation of the power system can be achieved as observed in the BPS across the area in comparison to the BPS across the countries. The remaining cumulative GHG emissions are approximately 37% lower (75 $MtCO_{2eq}$ vs 119 $MtCO_{2eq}$) in the BPS across the area with GHG emissions costs, without GHG emissions costs it is about 51% lower (109 $MtCO_{2eq}$ vs 221 $MtCO_{2eq}$) both compared to the BPS across the countries and aggregated from 2018 to 2050.

Investments in the transmission and distribution (T&D) infrastructure are vital for any emerging power grid system, such as WA. For instance, to facilitate the export of wind production from Niger and Mali as observed in the BPS across the area from 2025 onwards, the development of the North-core interconnection linking Niger, Nigeria, Benin and Burkina Faso is significant. According to IRENA [30], the development of nearly all cross-border transmission projects between WA countries currently in the pipeline appear to be beneficial. The World Bank (WB) estimates the economic benefits of the WAPP at 5–8 bUSD per year. Through the International Development Association (IDA), 750 mUSD of current WB support is directed towards the completion of the primary interconnections in WA. About 4000 km of grid lines are currently under development, all to be completed in the early 2020s [13]. According to the IEA NPS [17], the cumulative investment in T&D lines for the WA power sector is 229.3 bUSD from 2014 until 2040.

4.4. Off-grid electrification

The development of T&D infrastructure is recognised as a solution to the challenges of low access and unstable power

Table 5
Differences in key energy system parameters and financial results in 2050 under various scenarios.

	unit	BPS-A	BPSnoCC-A	BPS-C	BPSnoCC-C	CPS-A	CPSnoCC-A
Total annual levelised cost	[b€]	23.9	23.8	27.2	26.1	78.9	47.5
Levelised cost of electricity	[€/MWh,el]	35.7	35.5	40.6	39.0	116.2	70.0
Generation	[TWh,el]	723.2	722.7	754.7	732.5	683.4	
Installed capacity	[GW]	327.9	325.2	370.8	360.5	129.7	
Storage capacity	[TWh,el]	3.1	2.5	10.4	2.7	0.06	0.06
Curtailment	[%]	4.1	4.1	6.1	5.8	0.5	

supply in the region [17]. According to Ref. [17], most of the investments in electrification expansion in SSA go towards on-grid access, new T&D lines account for more than half of the investments. WA accounts for the largest share of the investments with around 75 bUSD (37%). Bertheau et al. [61] investigate the impacts of grid expansion in SSA, using geospatial methods. The results shows that around 190 million West Africans lack access to electricity. The first scenarios based on exsisting grid indicates 17% mini-grids, 43% grid extension and 40% solar home systems (SHSs). Whereas the planned grid scenario outcome indicates 12% mini-grids, 58% grid extension and 30% SHSs, hence more by grid extensions. Another research on electrification planning in SSA by 2030 [62], shows an investment need between a low of 19.3 bUSD (20% grid expansion, 0% mini-grid and 80% SHS) and a high of 370.6 bUSD (78% grid expansion, 16% mini-grid and 6% SHS) to provide universal access in WA [62]. The grid extension approach appears to dominate in all electrification expansion scenarios [61,62]. However, this approach may not eradicate energy poverty in regions like WA, due to complexity of rural settlements, poorly developed infrastructure and costs of grid extension [63]. Thus, off-grid solutions like mini-grids and especially SHS provide a least cost and potentially very fast applicable solutions for achieving rural electrification [63,64]. A recent study analysed the complete implications of mini-grid/off-grid electrification plans with a solar PV plus battery storage technology option for Nigeria [65]. According to Ref. [65], a 233 cluster covering 7.2 million people requiring 3280 MW solar PV and 7518 MWh battery capacities was derived as the best location for mini-grids auctions in Nigeria, while LCOE ranged from low 0.18 USD/kWh in the North to a high 0.25 USD/kWh in Southern Nigeria.

4.5. Benefits of a 100% RE system

The modelling outcomes show that a 100% RE system is the least-cost, least-GHG-emitting and most job-rich option for the WA power system, as observed in the BPSs. The PV-battery hybrid system appears as the backbone of the least-cost generation mix by 2050. The LCOE obtained for the BPSs is comparable to Barasa et al. [26], which shows a range of 35.2–47.6 €/MWh for SSA. The annualised cost of the system obtained for the year 2050 is 23.9 b€, 23.8 b€, 27.2 b€, 26.1 b€, 78.9 b€ and 47.5 b€ in the BPS-A, BPSnoCC-A, BPS-C, BPSnoCC-C, CPS-A and CPSnoCC-A, respectively. With GHG emissions costs, the total annualised cost is 70% higher in CPS than in the BPS, and is 50% higher without GHG emissions costs. The cost reduction effect observed in this study matches the experience of the energy transition in Uruguay. Uruguay made dramatic shifts to about 95% electricity from RE in the past 10 years, while reducing costs, building on its existing hydropower and new RE mainly wind energy, with some solar PV and bioenergy [66]. The results of this research show that the RE-based system is not only technically feasible, but also economically viable in WA. Such a finding is characteristic for 100% RE systems all around the world as highlighted by Brown et al. [67]. Most of the cost reductions in the BPSs can be attributed to low costs of RE technologies particularly solar PV and batteries. The costs of investments in RE technologies in the BPSs are offset by savings in fuel costs from displaced fossil-based generators, which is similar to the finding of Adeoye and Spataru [68], for WA region based on overnight approach for the year 2030. However, investments in fossil-based generators, as observed in the CPSs, will continue to be a burden on the WA's economy. The high costs in the CPSs are due to new investments in thermal generators, which are finally run on high full load hours that lead to enormous fuel costs. Furthermore, investments in fossil technologies are prone to cost overruns and schedule spills [69], they violate all sustainable criteria discussed in Ref. [70] and are likely to become stranded assets [35].

Beyond the robust techno-economic analysis of WA power systems, the LUT model also computes the emissions trajectory under various scenarios. The emissions pattern depicts the trajectory of RE deployment under various scenarios. In the BPSs, zero emission is achieved by 2050, however, the BPS across the area shows a rapid decarbonisation. Consequently, GHG emissions in the CPSs increased to about 60 $MtCO_{2eq}$ in 2030, which is comparable to the findings in Refs. [30], which shows a range of 70–80 $MtCO_{2eq}$ in 2030. By 2050, GHG emissions in the CPSs are about 209 $MtCO_{2eq}$. Investigating the impact of GHG emissions costs throughout the transition, the BPSs achieved a rapid decline in GHG emission in comparison to applying no GHG emissions costs. Without GHG emissions costs, the RE electricity generation reaches 99.9% (722.2 TWh) in the BPS across the area by 2050, while the remaining 0.1% (0.5 TWh) is supplied by gas turbines using fossil gas. Conversely, the RE generation in the BPS across the countries reaches 98.4% (721.0 TWh), while the remaining 1.6% (11.5 TWh) is supplied by gas turbines using fossil gas.

The energy transition is expected to lead the creation of new jobs, transformation or substitution of existing jobs and elimination of certain jobs, either as a complete phase out or at least a significant reduction without direct replacement [25]. The RE development in WA will facilitate socio-economic development, particularly job creation. Employment creation under various scenarios is examined in this research. The BPSs will create more jobs in comparison to the CPSs. Opponents of renewable energy often question if the sector can ever realistically create the numbers of jobs as a system based on large-scale fossil generators [25]. The results of this study show that RE dominated scenarios create more than twice the jobs compared to fossil-based scenarios. A 100% RE system would employ 440 thousand people in WA and solar PV emerges as the major job creating industry, employing about 300 thousand in 2050. A study found that replacing the millions of kerosene lamps, candles and flashlights with modern solar lighting technologies for people living off-grid could create 500 thousand new light-related jobs in the ECOWAS region [71]. Several studies [25,34,71] indicate that a shift in the energy landscape from fossil to RE technologies creates more jobs, which is comparable to the findings of this research.

4.6. Impact of changing parameters on results

Our findings indicate the significance of PV technologies and batteries as vital for the transition, due to anticipated decline in CAPEX. However, it is worth mentioning that changing cost parameters would influence technology deployment, as it appears that the costs and share of installed capacities of technologies are directly related, which is a predominant aspect of cost optimal future energy systems. Latest insights of Vartiainen et al. [72] indicate that the applied PV and battery CAPEX assumptions are rather conservative.

It should be noted that a uniform WACC of 7% is applied across the region, which is in line with leading international reports such as of IEA [73], IRENA [24] and journal publications [74–76]. However, Egli et al. [77] argue that uniform cost of capital (CoC) may result in distorted results and policies. It is worth mentioning that there are no better methods on offer to estimate future CoC values, uniform CoC remains the most ideal solution available. According to Bogdanov et al. [78] “proper choice of CoC assumption has a strong impact on the results of any energy system analysis and its uncertainty has to be considered in an analysis of the results”. Further, not all countries in WA fulfil the WACC assumption today; some uncertainty is induced by the WACC assumption. However, economic development in WA will lead to a more stable and lower WACC during the transition.

5. Conclusions and policy implications

The modelling outcomes show two distinctive features for the WA power system: expansion and transition. This study foresees transition of the WA power sector in exploiting the region’s abundant RE resources, which includes solar PV, wind energy, biomass and hydropower. Solar PV emerges as the new bulk electricity provider of the WA power sector as illustrated in the BPSs. Solar PV dominates in all the BPSs by 2050, and contributes the most (87–89%) to the total installed capacities and (81–85%) overall generation mix, respectively. In WA a 100% RE-based power system can run with low seasonal storage based on PtG conversion as observed in the BPS across the countries, whereas seasonal PtG storage is not required in the BPS across the area. Dispatchable RE hydropower reservoirs and bioenergy maintain a vital functionality in balancing seasonal variations in the WA power system. The solar PV, wind energy, hydropower and bioenergy synergies lead to a substantial reduction in storage requirements. The risk of day-today variability and capacity requirements reduce with higher transmission interconnection among the sub-regions, leading to increased system flexibility, broad cost savings and rapid defossilisation.

This study shows the need for substantial power generation capacity expansion due to under-capacity and growing demand in WA. Electricity demand grows 10 times by 2050 in comparison to 2015, while the installed capacity ranges from about 325 to 370 GW in the BPSs, and is about 130 GW in the CPSs. The capacity requirements are about 3 times higher in the BPSs than in the CPSs. This is due to RE technologies running on low FLH, particularly solar PV, while total electricity generation in the BPSs is around 6% higher than in CPSs. What is more, there are on-going plans to construct new fossil-based power plants in WA. These power plants are susceptible to cost overruns and schedule spills. In addition, the discoveries of new fossil fuels might pose a challenge to RE development in the region. However, this research presents a critical dimension of the transition for WA, which has to do with the cost-competitiveness of RE technologies as observed in the BPSs in comparison to the CPSs. Aside, the monumental and mounting costs of fossil-based technologies in the CPSs, such power systems violate sustainability principles that form the basis of a resilient power system. What is more, the BPSs without GHG emissions costs lead to 99.9% renewable in the BPS across the area and 98% in the BPS across the countries, while the remaining generation is covered by fossil fuel-fired gas turbines. This indicates pure market economics, even if the massive cost for GHG emissions cost would be allocated fully as subsidies for the fossil system by neglecting any price for the massive climate change costs. It will be imprudent for WA countries to invest in new fossil technologies, particularly coal power plants, but also nuclear. The fleets of RE technologies are accompanied by flexible gas turbines in the BPSs, however with fast declining full load hours. No new coal and nuclear power plant capacities are built in the least-cost expansion pathways for WA.

The ECOWAS energy policy should place solar PV at its core. Hybrid solar PV-battery power systems appear the least-cost solution for the region. A strong transmission grid infrastructure can enable substantial wind electricity generation from Niger and Mali, which can further reduce the entire energy system LCOE of WA. This research shows that a fully renewable electricity system is technically feasible and economically viable. A 100% RE system is a most efficient, least-cost, least GHG emission and most job-rich option for WA and is compatible with the Paris Agreement and the Sustainable Development Goals of the United Nations. This kind of power system is achievable with the vast RE resources of WA and it represents a real policy option for the region. It is noteworthy that a substantial roll-out of RE capacities in the BPSs does not require any subsidies at all. It is a least-cost option for the WA power system without subsidies. Consequently, subsidies might be unavoidable if a policy-driven deviation from this techno-economic least-cost option is pursued. A well-designed policy framework that limit new investments in conventional power plants, comprehensive energy market reforms and ambitious RE targets with a long-term perspective is needful in WA. Additionally, supportive policies that will strengthen cross-border electricity trade are vital for the WAPP. Further research has to be carried out incorporating additional energy sectors, i.e. heat, transport, industry and desalination, for broader analyses and to better understand the benefits of sector coupling for developing regions like WA.

Credit author statement

Ayobami Solomon Oyewo carried out main parts of the research and writing the manuscript. Arman Aghahosseini contributed to the research development. Manish Ram contributed to the research development. Christian Breyer framed the research questions and scope of the work, checked the results, facilitated discussions, and reviewed the manuscript.

Declaration of competing interest

None.

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Appendix A. Supplementary data

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Repercussion of Large Scale Hydro Dam Deployment: The Case of Congo Grand Inga Hydro Project

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Abstract: The idea of damming the Congo River has persisted for decades. The Grand Inga project, of up to 42 GW power generation capacity, can only be justified as part of a regional energy master plan for Africa, to bridge the energy gap on the continent. Proponents of very large dams have often exaggerated potential multiple benefits of a mega dam, marginalise environmental concerns and neglect the true risk of such projects, in particular for the fragile economies of developing countries. Studies have reported the financial risks, cost overruns and schedule spills associated with very large dams. In addition, most of the dams in the region are poorly managed. Therefore, the type and scale of Grand Inga is not the solution for millions of not yet electrified people in Sub-Saharan Africa. In this research, scenarios are defined based on announced costs and expected costs. Cost escalations in the range from 5% to 100% for the Inga project in 2030 and 2040 are considered, as average cost overruns are typically at about 70% or higher for similar mega-dams. It was found that when the cost overrun for the Grand Inga project exceeds 35% and −5% for 2030 and 2040 assumptions, respectively, the project becomes economically non-beneficial. In all scenarios, Sub-Saharan Africa can mainly be powered by solar photovoltaics to cover the electricity demand and complemented by wind energy, supported by batteries. Hydropower and biomass-based electricity can serve as complementary resources. The grid frequency stability of the power system is analysed and discussed in the paper. Benefits of the Inga hydropower project have to be increasingly questioned, in particular due to the fast cost decline of solar photovoltaics and batteries.

Keywords: renewable energy; Congo River; Democratic Republic of the Congo; Grand Inga; hydropower; Sub-Saharan Africa

1. Introduction

Energy is vital to Africa's development [1]. Africa needs clean, consistent, and cost-effective energy supply to meet the current energy deficit and future demand. The currently insufficient generation capacity and growing demand require rapid response, and they should be managed in a sustainable way [2]. Therefore, investment in a sustainable energy infrastructure is a crucial link between economic growth, development and climate action. Renewable energy optimization will reduce the reliance on fossil fuel as the predominant energy source in the power system, and address socio-economic development needs and vulnerability to environmental alterations [3,4].

One proposed response to address the energy challenges and persistent infrastructural gaps in Africa is to significantly increase investment in large hydropower dams [5,6]. The scramble for hydropower development in the region can be best understood as electricity fits into the larger dynamics of capitalist accumulation and crisis in Africa [7]. So the question arises, are large dams the solution to energy insufficiency and should more dams be built in Africa? This is especially relevant when considering that most dams in Africa underperform due to poor maintenance [5].

Additionally, hydro-dependent power systems are susceptible to power cuts due to the exacerbating effect of droughts and water shortages [8]. These precarious situations have resulted in dwindling power availability in African countries with high dependence on hydropower, such as Zambia, Zimbabwe and Ethiopia [9]. Nevertheless, advocates of large dams are predictably over-optimistic about schedule, cost and benefits of hydropower project development; they often envisage and exaggerate on multiple public benefits [10,11], disregarding the true risks of the project to host communities and the consequence to fragile economies especially in Sub-Saharan Africa (SSA) [7,12], and often downplay environmental and social cost [9,13]. This occurs while facing the requirement of 100 bUSD, almost three times the Democratic Republic of Congo's (DRC) estimated GDP for the year 2011 [14].

About 95% of those living without electricity reside predominantly in rural areas of SSA and developing Asia [1], in countries often hosting of large hydropower dams, showing how ineffective the "hydro dam strategy" is as an option for electrification of rural areas [7]. For instance, the power harnessed from Grand Inga is not envisioned for supplying electricity to domestic users or increase electricity access to rural areas [15]. Instead it is intended to cover points of high demand such as cities and industrial centres, or to be exported through electricity highways [14,15]. Similarly, large hydro dams such as Kariba and Cahora Bassa on the Zambezi River, have supplied electricity to urban and industrial zones, but have mostly bypassed rural needs [16]. Thus, off-grid renewable energy (RE) technologies, particularly photovoltaic (PV) based technologies (solar home systems and mini-grids) could provide a sustainable solution to energy challenges where the cost of grid extension is not economical [17–19]. Hence, there is an imminent need to address the delusion or false prevailing perception of large hydro dams as a solution to big energy problems [8]. In addition, decision and planning for energy development in SSA should strike a balance between energy needs for industrial purpose and human development [7].

Large scale hydroelectric developments are, largely, contentious and controversial due to their social, environmental and financial impacts [10,11]. Social impact of dams have been studied since the 1960s [20], and roughly 200 million people have been displaced due to infrastructure development. Displacement due to dam development accounts for 40% (80 million) of the total displaced population [20,21]. Additionally, profound environmental impacts are associated with development of large dams [5,10,22,23]. Adverse environmental debasement such as climate change, drought, hydrological interference and associated downstream impact have been a major problems in a number of African hydropower projects [15]. Beyond environmental and social impacts, large hydropower projects are often susceptible to substantial financial risk due to cost overruns and schedule spills [10,23–28]. Hydro dams cost a great deal of capital upfront, and funding agreements are extremely leveraged with debt, usually accounting for 70 to 80% of the overall funding [11]. Previous studies on large projects reveal that the cost escalation is traceable to various reasons; political-economic influence and optimistic bias perception are major causes of overruns [10,25,26,29]. In [26], 58 dams financed by the World Bank from 1976 to 2005 were analysed. The study reports that about 78% of dams exceeded their initial estimated cost. The authors concluded that the traditional cost-benefit approach for appraising dams might not be sufficient to evaluate the level of uncertainty associated with their construction costs, which raises question on improving assessment methodology. Recent studies have recommended using reference class forecasting to improve performance of cost escalation analysis [10,25,26]. Another study analysed 61 hydropower plants and reported that these plants exhibit an average cost escalation of 71%, while 35 wind farm projects and 39 solar plants experienced 7.7% and 1.3% average cost escalation [30]. The authors reported the impact of skewed distribution of hydropower cost on their statistical analysis. According to their analysis, dams with large reservoirs incurred the most significant cost overrun, and some individual projects such as the La Grande 2 Dam in Canada, Three Gorges Dam in China, and Sayano–Shushenskaya Dam in Russia, had between 17 and 48 billion USD in cost overruns.

Nonetheless, there is a prevalent need for expansion of power generation in SSA, due to chronic power shortage and increasing demand [11,31]. Furthermore, SSA electricity demand is expected to grow over 3 times by 2040. In this time, demand from industry will double while residential demand will grow more than five times the current level [32]. Figure 1 shows the total active installed power generation capacities at the end of 2014 in SSA, and illustrates the almost complete reliance on fossil fuels and hydropower in the region [33]. The region has a huge untapped RE resource potential, sufficient to close the energy access gap, and could be achieved by stimulating new investments in RE technologies [1].

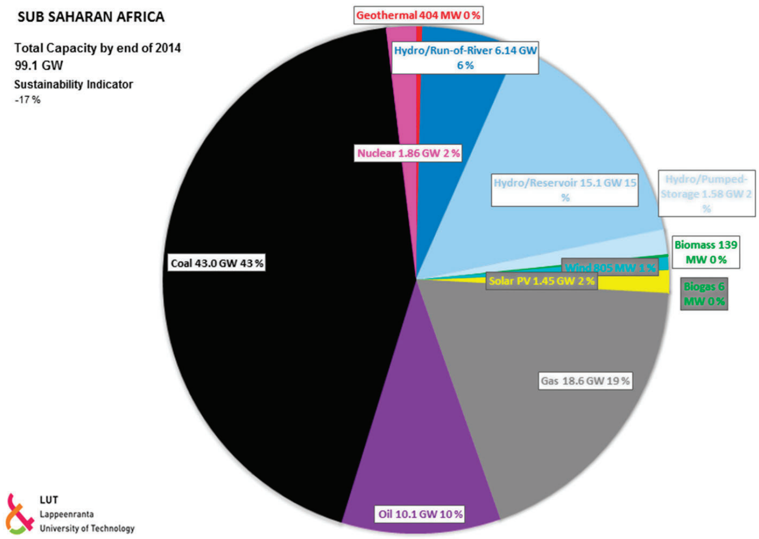

Figure 1. Total installed capacities by the end of 2014 in SSA [33].

Globally, RE technology installation capacities are growing fast due to their constantly declining costs [34]. Particularly, the price of solar PV modules has fallen by 80% since the end of 2009 [35] and continues to decline [36,37]. PV offers economic solutions in regions with already high but also low electrification rates for new capacity additions and for meeting demands on-grid and off-grid [17,35]. Recent studies have explored the possibility of 100% RE based power systems in different countries and regions [38–41]. Barasa et al. [40] described a 100% RE energy system for SSA, covering the electricity demand of the sectors power, water desalination and industrial gas. The result of the modelling of Barasa et al. determined a cost optimal mix of the various technologies for the year 2030. According to the results, the least cost energy solution for SSA will be powered mainly by solar PV and complemented by wind energy [40]. The results of Barasa et al. [40] are integrated in a global context in Breyer et al. [41]. Blechinger et al. [19] modelled two scenarios to understand the impact of future grid extension in SSA, and in both scenarios grid extension led to the highest share of electrified people followed by solar home systems and lastly mini-grids. In Africa, solar PV has transcended from the government-donor niche to a commercial based market [42].

Furthermore, in fully RE based power systems, the frequency stability (to be precise, system inertia) is regarded as one of the greatest concerns of Transmission System Operators (TSOs) around the world. The term 'inertia' is referred to the total amount of kinetic energy stored in the rotating mass of synchronous generators [43]. The system inertia is low with high penetration of variable RE since the rotating mass of the connected synchronous machines is reduced. The lower inertia means that connected frequency regulation reserves must be able to respond faster than currently [44,45]. In this study, rate of change of frequency (ROCOF) when only synchronous generation (hydropower, biomass power plants, and geothermal units) contributes to the frequency balancing was first calculated. Then synthetic inertia of wind turbines is included, then the synthetic inertia from solar PV plants. Finally, the synthetic inertia contribution from the battery units is included.

In this article, a 100% RE system in SSA will be analysed, based on the utilization of different RE resources, as well as storage and grid technologies. The primary focus of this study is to present an overview analysis of the impact of developing the Grand Inga project in the Democratic Republic of Congo (DRC) and SSA. Section 2 provides an overview of the Inga project's historical development and Section 3 discusses the sustainability concerns of hydropower development on Congo River. The methodology and model used, including assumptions, construction and formulation of scenarios, are presented in Sections 4 and 5. In Section 6, results are reported for the years 2030 and 2040. Frequency stability of the power system is analysed in Section 7. The discussion and conclusions are presented in Sections 8 and 9, respectively.

2. Grand Inga Project: The History and Development

The Inga Rapids have been long targeted for hydropower development [46]. The idea of using the Congo River for electricity production dates back to 1885, and the site was noted in a world survey in 1921 and endorsed by the Belgian colonial authorities in the 1950s [11,46,47]. The features of the Congo River make it of special interest to hydropower development; it is the second largest river in the world in terms of water flow rate (42,000 m^3/s) after the Amazon, and the second longest river in Africa after the Nile, starting from the plateaus and mounts of the Rift Valley, meandering its way around the equator, and discharging finally into the Atlantic Ocean [48]. The Inga Rapids and waterfalls give the Congo River an enormous hydropower potential, with an estimated power generating capacity of 42 GW [11]. With such a generation capacity, and if the project is ever completed, Grand Inga would emerge as the single largest source of hydropower in the world, and is intended to bridge the energy gap in Africa [11,12,49].

The details of the Grand Inga project have changed significantly over the years [50]. The project is divided into eight dams and seven phases [49]. The first two phases of the Inga electricity scheme were commissioned in 1972 and 1982, Inga 1 (351 MW) and Inga 2 (1424 MW), respectively [11,12,51]. Inga 1 and Inga 2, were built disregarding the feasibility study that found both projects to be uneconomical and far exceeded the DRC's electricity needs at that time. Power from both dams has mainly served the Katanga valley mines and the export market. It is estimated that the cost of the Inga 1 and Inga 2 dams constitutes over half of the DRC's current external debt [7]. The construction of the Inga-Kolwezi transmission line, a 1725 km long transmission line to the Katanga copper belt, accounted for the biggest share of the DRC's debt problem during the 1990s. The construction cost of the transmission line quadrupled from the initial estimated cost to reach 1 bUSD [52]. In addition the Inga 1 and Inga 2 dams have operated at continuously decaying capacity during their lifetimes, as their state of operation and maintenance have deteriorated the over time since their commissioning [49,53]. As of 2002, these dams were operating at only 40% capacity due to lack of maintenance, financial mismanagement, corruption and poor governance [51,52].

The subsequent phases of the Inga scheme is the construction of Inga 3 (low-head) with an estimated capacity of 4755 MW, which is planned to be completed in 2020 [11] but not yet started. Figure 2 shows the Congo River and Inga phases. Following phases of the Inga project, maximum installed capacities and assumed years are as follow: Inga 3 high-head (2025) 3037 MW, Inga 4 (2030) 7182 MW, Inga 5 (2035) 6970 MW, Inga 6 (2040) 6684 MW, Inga 7 (2045) 6706 MW and Inga 8 (2050) 6747 MW [11]. Three consortia have expressed interest in the development of Inga 3: China Three Gorges Corporation and Sinohydro; a consortium of South Korean (Posco and Daewoo) and Canadian (SNC Lavalin) companies; and third one is composed of Spanish companies [32].

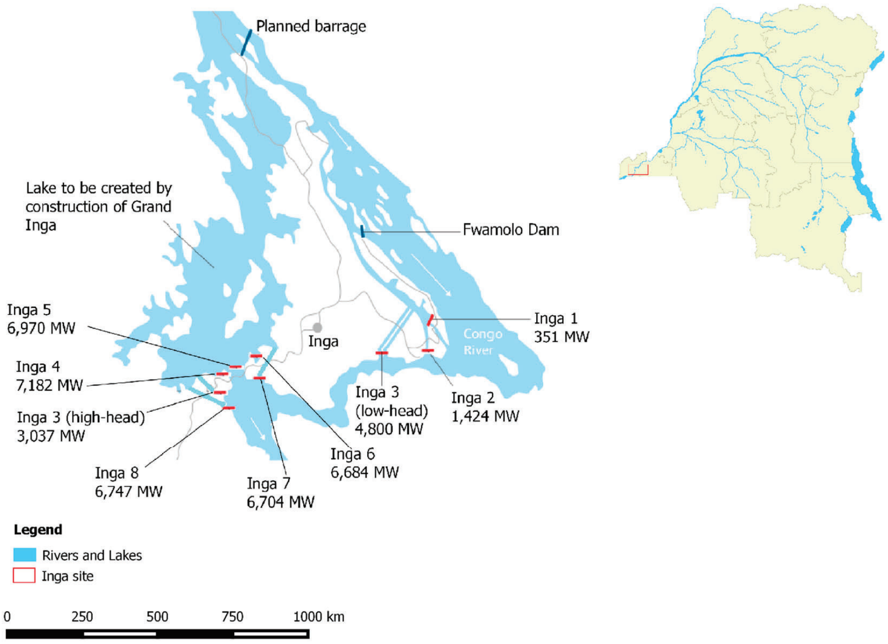

Figure 2. Congo River and all Inga plans (existing and planned phases of Inga dams) [54].

The Grand Inga project may be too costly, and it was estimated 10 years ago at over 80 bUSD, of which 12 bUSD would be for the initial Inga 3 base chute phase [53]. Projects of this scale require substantial capital, expertise and strong governance, all of which have suffered huge setbacks in SSA to varying degrees [11]. Moreover, continuing with the development of the Inga dams would be trusting capital to a government that has continuously failed to maintain and operate the already operating dams properly [7,55].

3. Energy and Environment: Hydropower Development and Congo River Sustainability Concerns

The Congo River basin is home to the second largest tropical forest and world's largest tropical swamp, altogether about 2 million km^2 [56] of area distributed over the countries of Cameroon, Congo Republic, DRC, Equatorial Guinea, Gabon and Central African Republic. This rainforest area is often referred to as "the lungs of the Earth" together with the Amazon, the only other river and tropical forest bigger than the Congo itself. The Congo River basin is the habitat of vast wildlife including 5862 species of birds, 460 species of reptiles, 552 species of mammals, including 2 species of gorillas and 2 species of chimpanzees [56], all unique to the multiple ecosystems of the Congo river basin.

Regarding vegetation, this is suspected to be the richest region of the world regarding of density of plant species per unit of area [56]. Different estimates account for as much as over 35,000 species of plants in the Congo River basin [56], of which 2427 are endemic and some of them endangered. Analysis by satellite imagery from the years 1986 to 2003 carried out by [57] shows that the deforestation rates of the Congo basin are rather small in the central region of the forest, likely due to the difficult access to the areas and low population densities. In contrast, coastal areas experience already a much higher rate of deforestation, as the jungle is vulnerable due closeness to more dense population centres and to trade routes.

Hydroelectric guiding construction protocols are lacking in some tropical developing countries, and small dams (<10 MW) are exempted in many countries from any formal decision making process [13]. In order to carry out a feasibility study and environmental and societal impact analysis of Inga 3, the World Bank approved a fund of 73 mUSD in March 2014 [58,59]. Even though the project has been in consideration for decades, this is the first time environment and societal costs were taken into consideration, and funding was dedicated to sustainability. Until now sustainability issues was disregarded by the stakeholders of the project even after the deployment of Inga 1 and Inga 2, the first two phases of the project. Already 30% of the water of the Congo River is being diverted for hydropower production at the hydropower stations Inga 1 and Inga 2 [60]. Development is greatly required in the region and development benefits are analysed and clear [61], but a more serious consideration of the ecosystem needs to be taken into account, since the organization that developed and conducts the most universally used hydropower sustainability assessment is under constant criticism for lack of transparency and deepness of the sustainability research [62].

Methane (CH_4) is the second most impactful greenhouse gas (GHG) after carbon dioxide, it accounts for over 20% of alteration in the radiative forcing due to anthropogenic GHG emission to the atmosphere [63]. Hydroelectric reservoirs, particularly in tropic regions, constitute an appreciable source of CH_4 to the atmosphere [64]. In some cases CH_4 can reach up to 70% of the total reservoir emissions [65]. Large and deep tropical reservoirs are frequently thermally stratified, which inhibits water mixing and diffusion. This situation enhances CH_4 emissions [64,65]. Global large dams have been found to release 104 ± 7.2 Tg CH_4 yearly to the atmosphere via reservoir surface, turbine and spillways [63], equivalent to 1.3–1.5% of global GHG emissions from methane sources of 2010 levels, and representing 0.2% of all global GHG emissions.

While there are techniques to diminish the impact of a hydropower plants on hydrological systems and ecosystems (such as run-of-river set ups, sludge gates, fish ladders, etc.), it is not possible to entirely eliminate all effects on hydrological systems.

4. Methodology and Model Description

4.1. Model Overview

The power system used in this study was developed to match generation and power demand for every hour of the simulated year. In addition, a model was designed based on linear optimization of energy system parameters, characterised by having an objective function for cost optimization under certain constraints [66]. The model is compiled in using MATLAB (R2016a, The MathWorks, Inc., Natick, MA, USA) [67], while the optimization is carried out in MOSEK (version 8, Mosek ApS., Copenhagen, Denmark) [68]. It is composed of electricity generation technologies, storage technologies, electricity transmission technologies and finally the bridging technologies, which provide flexibility to the energy system. The hourly modelling results in a more accurate system description, highlights flexibility, and presents a synergy effect of various power generation and storage technologies required to be installed to attain a fully RE-based power system. The model has been used before to conduct studies for several different regions so far, and a detailed description can be found in [38–41]. For this analysis, the integration of desalination and non-energetic industrial gas demand was not included. Detailed model description, equations and applied constraints can be found in Bogdanov and Breyer [39]. Additional technical and financial assumptions are provided in the Supplementary Material to this paper.

The target function of the model is to optimize the system so that the total annual energy system cost is minimized. This cost is calculated as the addition of the annual costs of the installed capacities of each technology, electricity generation costs, and costs of generation ramping. In addition, the energy system takes account of the PV prosumers for residential, commercial and industrial sectors and their respective capacities of rooftop PV systems and batteries. The target function for prosumers is the minimization of the cost of consumed electricity. This cost is calculated as the sum of self-generation cost, annual cost, and cost of electricity consumed from the grid. A multi-node approach is utilised in the model, which allows for the definition of any preferred configuration. The main optimization constraint is to guarantee electricity coverage of local demand is considered on an hourly basis for the applied year, as shown in Equation (1). The model overview is shown in Figure 3.

$$\forall \mathrm{h} \in [1,8760] \left(\sum_{t}^{tech} E_{gen,t} \right), h + (\sum_{r}^{reg} E_{imp,r}), h + \left(\sum_{t}^{stor} E_{stor,disch} \right), h = \left(E_{demand} \right), h \\ + (\sum_{r}^{reg} E_{exp,r}), h + \left(\sum_{t}^{stor} E_{stor,ch} \right), h + \left(E_{curt} \right), h \tag{1}$$

$$\min \left(\sum_{r=1}^{reg} \sum_{t=1}^{tech} (CAPEX_t \cdot crf_t + OPEXfix_t) \cdot instCap_{t,r} + OPEXvar_t \cdot E_{gen,t,r} + rampCost_t \cdot totRamp_{t,r} \right) \tag{2}$$

The key constraint of the system optimization is given in Equation (1). It is well-defined as for every hour of a year in each region, electricity generation from all the technologies ($E_{gen,t}$), imported electricity from the regions ($E_{imp,r}$) and electricity from storage discharge ($E_{stor,disch}$) should be equal to the total demand for an hour (E_{demand}), electricity exported to other regions ($E_{exp,r}$), electricity for charging storage technologies ($E_{stor,ch}$) and curtailed electricity (E_{curt}). Other abbreviations used in this equation are: hours (*h*), technology (*t*), all technologies used in modelling (*tech*), sub-region (*r*), all sub-regions (*reg*). Equation (2) provides the target function for system optimization. The abbreviations used here include ($CAPEX_t$)—capital cos of each technology, (crf_t)—capital recovery factor for each technology, ($OPEXfix_t$)—fixed operational cost for each technology, ($OPEXvar_t$)—variable operational cost each technology, installed capacity in a region ($instCap_{t,r}$), electricity generation by each technology ($E_{gen,t,r}$), ramping cost of each technology ($rampCost_t$) and annual total power ramping values for each technology ($totRamp_{t,r}$).

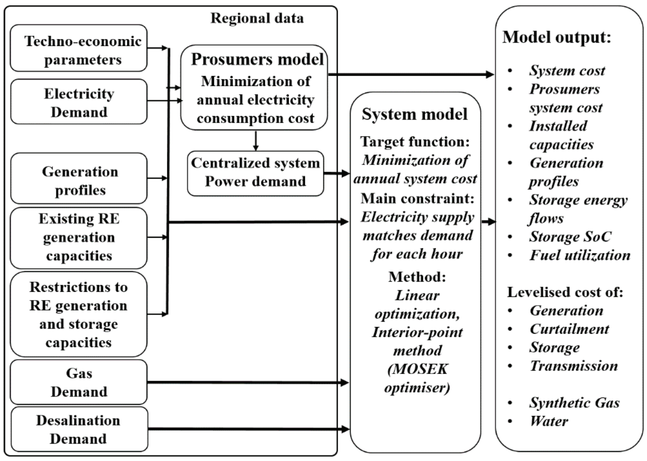

Figure 3. Main inputs and outputs of the LUT Energy System model [39].

The technologies introduced in the LUT Energy System model used to analyse the SSA region can be categorized into four main groups: technologies for electricity generation, storage technologies, bridging technologies and electricity transmission technologies.

The electricity generation technologies introduced in the model include various PV technologies (ground-mounted fixed tilted, single-axis, and rooftop solar PV systems), hydropower (run-of-river and reservoir based), biomass plants (solid biomass and biogas), wind onshore turbines, geothermal power plants, concentrating solar thermal power (CSP) and waste-to-energy power plants. Due to the intermittency of RE and to ensure steady supply of electricity, the RE technologies are complemented by various storage technologies. These technologies are pumped hydro storage (PHS), batteries, adiabatic compressed air energy storage (A-CAES), thermal energy storage (TES) and power-to-gas

(PtG). Regarding transmission of electricity, inter-regional transmission grids are modelled by applying high voltage direct current (HVDC) technology, while power distribution and transmission within the sub-regions are assumed to be based on standard alternating current (AC) grids which are not part of the model. All technologies are shown in the Figure 4.

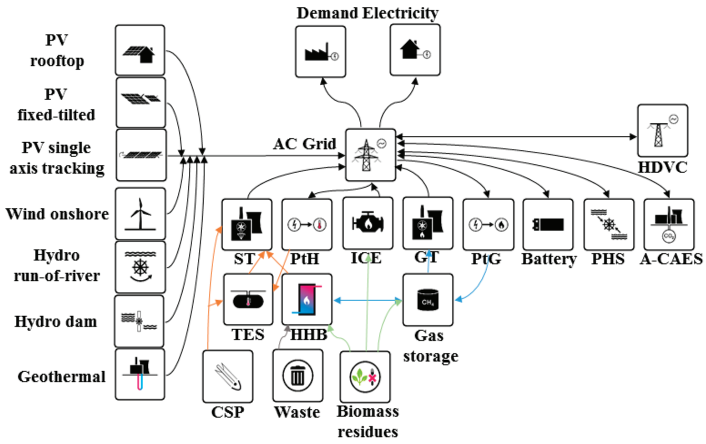

Figure 4. Block diagram of the energy system model for SSA.

4.2. Subdivision of the Region and Grid Structure

The subdivision and grid configurations of SSA are shown in Figure 5. Existing HVDC interconnections of SSA are shown by dashed lines. The structure of the assumed HVDC grid for the scenarios (solid lines) is based on the existing configuration of SSA power pools and the respective load centres. The overview of transmission line parameters is presented in the Supplementary Material (Table S1). The study considered 51 countries that are merged or subdivided into 16 sub-regions (Figure 5) and Supplementary Material (Table S2). The SSA regional network is based on area, population, and national grid connections.

Figure 5. Sub-Saharan African sub-regions and HVDC transmission lines configuration.

4.3. Technical and Cost Assumptions

The financial assumptions are made for all energy system components for the years 2030 and 2040, and include operational expenditures (OPEX), capital expenditure (CAPEX), and lifetimes as tabled in the Supplementary Material (Table S3). For all scenarios, weighted average cost of capital (WACC) is set to 7%. However, WACC is set to 4% for residential PV prosumers due to lower expectations of financial return. The technical assumptions regarding energy-to-power ratios for storage technologies, efficiency numbers for generation, and power losses in HDVC power lines and converters are presented for the years 2030 and 2040 in the Supplementary Material (Tables S4–S6). Electricity prices for commercial, residential and industrial consumers for all countries in the region for the years 2030 and 2040 are derived according to Gerlach et al. [69]. Prices are presented in the Supplementary Material (Table S7). Excess electricity generated by PV prosumers is fed into the grid and is assumed to be sold for a transfer price of 0.02 €/kWh. The overview of prosumer electricity cost, installed capacity and energy utilisation for SSA in the years 2030 and 2040 is presented in the Supplementary Material (Tables S8 and S9).

The upper limits for all RE capacities were estimated according to Barasa et al. [40] and lower limits are obtained from Farfan and Breyer [33]. Upper and lower limits of installed capacities are presented in the Supplementary Material (Tables S10 and S11). It is assumed that solid biomass, waste and biogas fuels are available throughout the year evenly. A synthetic electricity demand profile is estimated using IEA data [1], based on an electricity demand increase for the years 2030 and 2040.

4.4. Potential for Renewable Energy Resources

The generation profiles for wind energy, optimally tilted PV, single-axis tracking PV and solar CSP were calculated according to Bogdanov and Breyer [39]. The hydropower feed-in profile was based on precipitation data for the year 2005 as a normalized sum of precipitation in each of the regions [70].

The biomass and waste resource potentials are obtained from the German Biomass Research Centre [71] and classified according to Bogdanov and Breyer [35]. The cost of biomass was based on data provided by International Energy Agency (IEA) [72] and Intergovernmental Panel on Climate Change (IPCC) [73]. For solid waste a 50 €/ton gate fee was assumed. Additional information on biomass and solid waste costs is provided in the Supplementary Material (Table S12).

The geothermal potentials are calculated for the sub-regions based on the available information related to heat flow rates and ambient temperature of the surface for the year 2005 [74,75]. For the sub-regions where the heat flow data was not available, extrapolation was performed to get the required data. The geothermal heat is estimated based on the available data in [76–78]. Regional biomass and geothermal energy potentials are presented in the Supplementary Material (Table S13).

The generation, load and grid profiles can be visualised in Supplementary Material (Figures S1 and S2). In addition, the state-of-charge of storage technologies is given in Supplementary Material (Figures S3 and S4).

5. Scenario Formulation

A range of scenarios has been formulated, in order to analyse the impact of the Grand Inga project on the SSA power system. To achieve the aim of this paper, categories of scenarios were formulated based on announced and overnight cost assumptions. The overnight cost assumption was based on the findings of Ansar et al. [10] with respect to cost overruns. The study reports that the actual cost of large hydro dam developments worldwide were on average 96% higher than the estimated cost. The authors report that the overrun cost figures exclude inflation, debt, environmental cost and social cost. The defined scenarios were based on an area-wide interconnected energy system, which assumes that all sub-regions are interconnected via HVDC lines. All scenarios will be analysed from a scope of assumptions for the years 2030 and 2040 for an evolutionary perspective. Since every subsequent stage of the Grand Inga would take years (up to over a decade) to be commissioned, a long term scope is used to compare it with more realistic market conditions of the project at the point of the start of operations.

5.1. Detailed Description of Scenarios

This section presents a conceptual description of the scenarios generated. All the generated scenarios will be compared to a reference generated and presented by Barasa et al. [40], simulated as an optimal future energy mix for the region. The difference between the reference scenario and the proposed scenarios will remain in the CAPEX assumptions for individual hydro dam and hydro run-of-river plants according to the announced numbers for the specific Grand Inga stages. The cost assumptions for all other technologies remain the same as in the reference scenario, and the capacities are then optimized by the model.

5.1.1. No Inga Scenario

The base scenario proposed in this paper does not consider any of the stages of Grand Inga deployed. This scenario assumption may appear unrealistic when considering that the first two stages of the project, Inga 1 and Inga 2, have been commissioned in the year 1972 and 1982, respectively. However, it is due to continuous mismanagement and lack of maintenance [7] that the hydropower stations have been underperforming and experienced continuous shut downs. Therefore, the scenario considers no further development of the Grand Inga and possibly, if the simulation proves it optimal, the rehabilitation of the Inga 1 and Inga 2 hydropower stations. As in every other scenario, a number of renewable and sustainable alternatives, including other smaller hydropower stations, will be considered in order to achieve an optimal mix for the energy system

5.1.2. Optional Inga 3 Scenario

Despite Grand Inga (GI) being under consideration for over 60 years, after the completion of Inga 1 and Inga 2 in 1972 and 1982, respectively, the Grand Inga project has been stuck for decades. Only in recent years the concept of the Inga 3 (I3) has been revised again, and according to the World Bank [79], from the amount granted to the DRC for feasibility studies since 2014, every quarterly report has returned with "high risk" and "highly unsatisfactory" tags. So far it seems to be socially, environmentally and economically pointless to further develop the GI project. Consequently, the second scenario proposed considers the rehabilitation of Inga 1 and Inga 2, and leaves the development of I3 open for realization. The deployment of I3 is analysed from the last CAPEX announced for the hydropower plant of 14 bUSD (10.8 b€) [80], up to the estimated cost overrun of +100% (rounded from 96% as already experienced) as it is the average cost overrun of large hydropower plants found by [8,26]. Since further stages of Grand Inga depend on the installation of Inga 3, for this particular scenario any GI deployment after Inga 3 is not considered. However, other minor hydropower plants, with an added potential of 283.2 MW estimated in [40], could still be deployed.

5.1.3. Forced Inga 3 and Grand Inga Scenario

In this scenario Inga 3 is forced into operation. Subsequent phases of the Grand Inga project with a number of steps between the last announced CAPEX for further developments of Grand Inga of 100 bUSD (76.9 b€) [81], to a maximum of up to +100% CAPEX cost overruns following the same assumption as for Inga 3 according to [10,28]. Just like in previous scenarios, all other RE and sustainable RE sources are considered, including other minor hydropower projects.

6. Results

In this section an overview of the findings of the study is presented. The least cost energy configurations were derived based on certain constraints and characterised by optimized installed capacities of RE electricity generation, storage and transmission for every technology used in the model. Consequently, respective hourly generation of electricity, charging and discharging of storage technologies, sub-regional electricity trade, and curtailment were obtained. The main financial results for all the scenarios in the years 2030 and 2040 are presented in Tables 1 and 2, respectively, which include the following:

- Levelised cost of electricity for primary generation (LCOE primary),
- Levelised cost of storage (LCOS),
- Levelised cost of curtailment (LCOC),
- Levelised cost of transmission (LCOT),
- Levelised cost of electricity in total (total LCOE),
- Total CAPEX,
- Total annualized cost (ann. cost),
- Total RE capacity,
- Total primary generation.

The installed capacities of main storage and generation technologies are presented in Table 3. In comparison to other RE technologies the share of PV dominates in all the scenarios. The share of solar PV installed capacity is approximately 170 GW and 600 GW for the years 2030 and 2040, respectively, for all the scenarios. PV single-axis tracking dominates the share of total installed PV capacity in all scenarios for the years 2030 and 2040. PV single-axis tracking constitutes about 110 GW in 2030 and 400 GW in 2040. This leads to a capacity share of all PV capacity of 47% in 2030 and 84% in 2040, which translates into an electricity generation share of 38% in 2030 and 77% in 2040. The share of wind installed capacity decreases from about 130 GW in 2030 to 60 GW in 2040, in all the scenarios, which is a consequence of the increasing PV competitiveness. The installed capacities of RoR hydro remained constant at 6.3 GW for Inga 3 announced and expected scenarios, and reached 11.1 GW for the Grand Inga scenarios in the year 2030 and 2040. And the installed capacity of hydro dams was about 20 GW in all the scenarios. For the year 2030, the share of geothermal installed capacity dropped from 4.6 GW for Inga 3 announced and expected scenarios to about 3.3 GW in the Grand Inga scenarios. However, for the year 2040 the share of geothermal capacity remained constant at 3.0 GW for all the scenarios. The installed capacity of municipal solid waste incineration plants remained constant at 1.7 GW and 1.9 GW in the years 2030 and 2040, respectively, for all the scenarios, since it is driven by the waste resource. In 2030, the share of biogas decreased from about 16 GW for Inga 3 announced and expected scenarios to about 13 GW for the Grand Inga scenarios. Meanwhile, the share of biogas remained constant at 4.8 GW for all the scenarios in the year 2040. In 2030, the solid biomass contribution remained constant at 2.6 GW for Inga 3 scenarios, and stayed in the range of 1.0 GW to 1.8 GW for the Grand Inga scenarios. By 2040, there was no solid biomass contribution in any of the scenarios.

Regarding storage capacities, the gas storage share dominates in all the scenarios. Battery storage capacity increased from approximately 230 GWh in 2030 to 1500 GWh in 2040. PHS storage capacity remained constant at 3.2 GWh_{el} and 1.6 GWh_{el} for the years 2030 and 2040, respectively, in all the scenarios. The installed capacity of A-CAES declined significantly in the year 2040, when compared to the year 2030. PtG capacity is approximately 6.0 GW_{el} in the years 2030 and 2040, for all the scenarios. However, when storage throughput is considered, battery storage has a 58% and 91% share of throughput in 2030 and 2040, respectively. The highest share of battery throughput in all scenarios considered for the years 2030 and 2040 is 77 TWh and 498 TWh, respectively. The dominance of battery storage is due to its compatibility with solar PV and fast cost decline. The overview of storage capacities, output and full cycles per year for all scenarios in 2030 and 2040 are presented in the Supplementary Material (Tables S14 and S15).

Table 1. Financial results for the scenarios applied in SSA by 2030. Abbreviations: Inga 3 (I3) and Grand Inga (GI).

	2030									
Scenario	**Total LCOE (€/MWh)**	**LCOE Primary (€/MWh)**	**LCOC (€/MWh)**	**LCOS (€/MWh)**	**LCOT (€/MWh)**	**Total Ann. Cost (b€)**	**Δ in Cost (%)**	**Total CAPEX (b€)**	**RE Capacities (GW)**	**Generated Electricity (TWh)**
Reference	54.36	36.36	1.67	14.76	1.56	47.09	-	414.35	377.89	957.75
I3 announced cost	54.13	36.22	1.68	14.66	1.58	46.90	−0.4%	412.28	374.77	959.71
I3 expected cost	54.44	36.53	1.68	14.65	1.58	47.16	0.1%	416.09	374.74	959.86
GI 0%	53.95	35.79	1.77	14.37	2.02	46.68	−0.9%	411.80	371.90	970.27
GI 35%	54.36	36.24	1.78	14.41	1.93	47.04	0%	416.14	372.62	969.89
GI 50%	54.54	36.4	1.78	14.41	1.93	47.19	0.2%	417.96	372.46	969.27
GI 100%	55.46	37.16	1.82	14.54	1.96	48.01	2.0%	426.43	372.16	962.03

Table 2. Financial results for the scenarios applied in SSA by 2040. Abbreviations: Inga 3 (I3) and Grand Inga (GI).

	2040									
Scenario	**Total LCOE (€/MWh)**	**LCOE Primary (€/MWh)**	**LCOC (€/MWh)**	**LCOS (€/MWh)**	**LCOT (€/MWh)**	**Total Ann. Cost (b€)**	**Δ in Cost (%)**	**Total CAPEX (b€)**	**RE Capacities (GW)**	**Generated Electricity (TWh)**
Reference	41.72	24.07	1.42	15.73	0.50	62.89	-	625.28	745.21	1662.38
I3 Announced cost	41.67	24.14	1.42	15.61	0.50	62.82	−0.1%	624.20	742.23	1663.51
I3 Expected cost	41.85	24.31	1.42	15.61	0.50	63.08	0.3%	627.81	742.22	1663.49
GI 0%	41.74	24.58	1.42	15.13	0.60	62.90	0.02%	624.91	730.93	1666.36
GI −5%	41.72	24.57	1.41	15.14	0.60	62.87	−0.03%	624.45	731.40	1667.70
GI 50%	42.02	24.83	1.43	15.14	0.61	63.31	+0.7%	630.40	730.86	1665.96
GI 100%	42.29	25.09	1.44	15.15	0.61	63.72	+1.3%	635.92	731.36	1667.53

Table 3. Overview on installed capacities of generation and storage technologies for each scenario.

		2030				2040			
Technology	**Unit**	**Reference Scenario**	**I3 Announced Cost**	**GI 0%**	**GI 100%**	**Reference Scenario**	**I3 Announced Cost**	**GI 0%**	**GI 100%**
PV prosumer	(GW)	61.3	61.3	61.3	61.3	198.3	198.3	198.3	198.3
PV optimally tilted	(GW)	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
PV single-axis tracking	(GW)	112.6	112.0	113.0	110.2	434.0	430.9	416.9	417.3
PV total	(GW)	175.3	174.7	175.7	173.0	633.7	630.6	616.5	616.9
CSP	(GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind energy	(GW)	133.6	133.2	130.1	130.1	60.5	60.1	60.3	60.4
Biogas power plant	(GW)	19.2	16.3	13.2	16.3	4.9	4.8	4.8	4.8
Biomass power plant	(GW)	2.7	2.6	1.0	1.8	0.0	0.0	0.0	0.0
MSW incinerator	(GW)	1.7	1.7	1.7	1.7	1.9	1.9	1.9	1.9
Geothermal energy	(GW)	4.9	4.6	3.3	3.7	3.0	3.0	3.0	3.0
Hydro Run-of-River	(GW)	5.2	6.3	11.1	11.1	5.2	6.3	11.1	11.1
Hydro dams	(GW)	20.4	20.5	22.0	20.9	20.3	20.4	20.1	20.2
Battery prosumer	(GWh)	72.2	72.2	72.2	72.2	432.3	432.3	432.3	1432.3
Battery total	(GWh)	242.6	239.7	231.1	237.1	1599.1	1587.4	1539.4	1538.8
PHS	(GWh)	3.16	3.2	3.2	3.2	1.6	1.6	1.6	1.6
A-CAES	(GWh)	426.2	418.4	405.4	416.3	0.11	0.2	1.5	1.6
Gas storage	(GWh)	18,361.6	18,476.7	18,601.6	18,732.0	29,330.2	29,189.8	28,194.3	28,162.6
PtG electrolysers	(GW_{el})	6.2	6.2	6.0	6.2	6.9	6.8	6.3	6.3
CCGT	(GW)	13.1	13.1	12.6	13.2	12.4	12.4	11.3	11.2
OCGT	(GW)	9.8	9.7	7.9	9.5	13.5	12.6	10.9	10.8

Figures 6 and 7 show the total annual cost trend for the GI scenarios in 2030 and 2040, respectively. From Figure 6 it can be seen that if the cost overrun exceeds 35% (as such projects usually do at least), the cost to the system is too high compared to the reference without GI. Furthermore, Figure 7 shows that even if the cost remains as announced, the cost to the system is too high compared to the alternative without GI for 2040 assumptions. This clearly shows that with cost overrun up to around +40% and 0% for 2030 and 2040 scenarios, respectively, the project is economically beneficial (not taking into account the environmental impact). Above that limit the economic benefit disappears and turns into a burden.

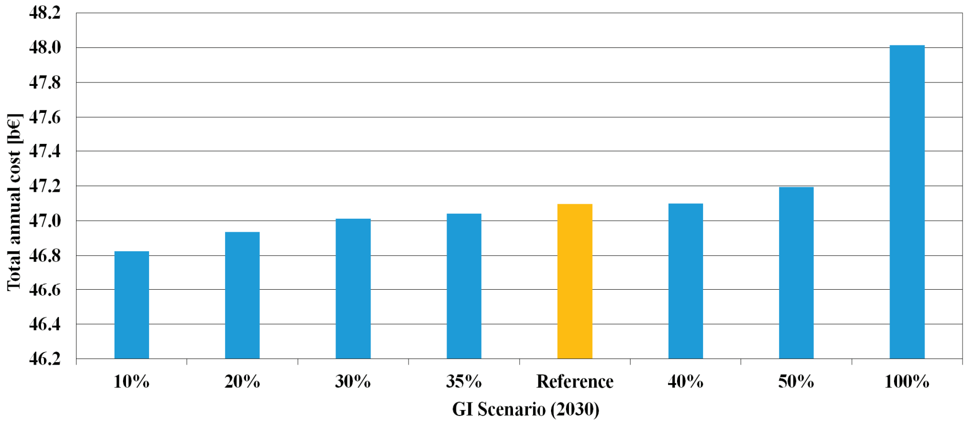

Figure 6. Total annual cost in [b€] for GI 2030 Scenario.

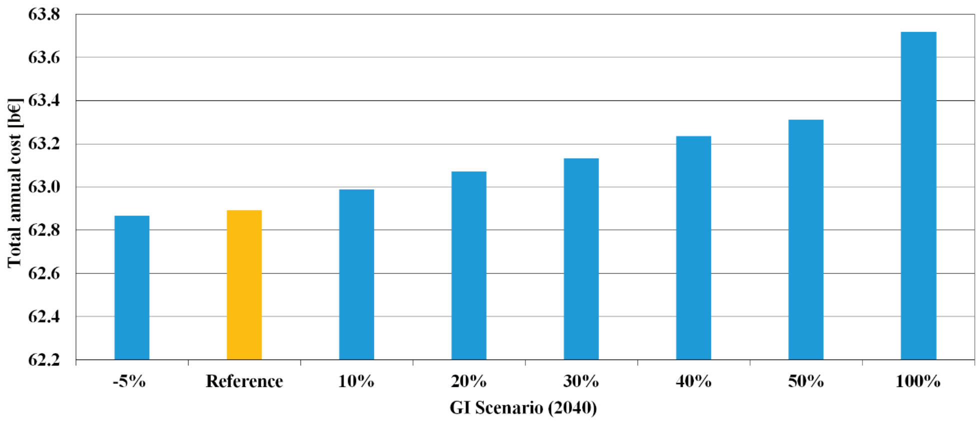

Figure 7. Total annual cost in [b€] for GI 2040 Scenario.

Figures 8 and 9 and Figures S5–S8 in the Supplementary Material, show the LCOE of all the scenarios in the years 2030 and 2040; the figures show on the left and right the absolute and relative values of the LCOE, respectively. The relative value represents the percentage difference of absolute value of the respective scenario compared to the reference scenario.

The percentage difference in the levelised cost of electricity for Inga 3 announced cost scenario is presented in Figure 8 (top right) and (bottom right), for the years 2030 and 2040, respectively. Regarding regional average LCOE, it can be deduced that the impact of Inga 3 is negligible in both 2030 and 2040 cases, and the relative percentage differences in LCOE range from −3.2% to 0.8% in 2030 and from −2.0% to 0.3% in 2040, across the regions, while the overall regional relative averages are −0.4% and −0.1%, for 2030 and 2040, respectively. The overall average LCOE is 54.1 €/MWh in 2030 and 41.7 €/MWh in 2040 as shown in Figure 8 (top left) and (bottom left), respectively. According to the 2040 scenario, DRC experienced an almost negligible decrease in LCOE of 1.3%, while neighbouring regions faced mixed effects. In the adjacent regions the highest LCOE decrease was by −1.4%, while the West North region experienced an increase of 0.8%. Somalia experiences the steepest decrease in LCOE of −3.2%, which is still almost negligible. Furthermore, for the same scenario but with 2040 assumptions, the effects on the LCOE are further reduced closer to negligible levels, being less than ±0.5% difference in the whole region with the exception of Somalia (−2%) and the Kenya-Uganda region (−0.7%).

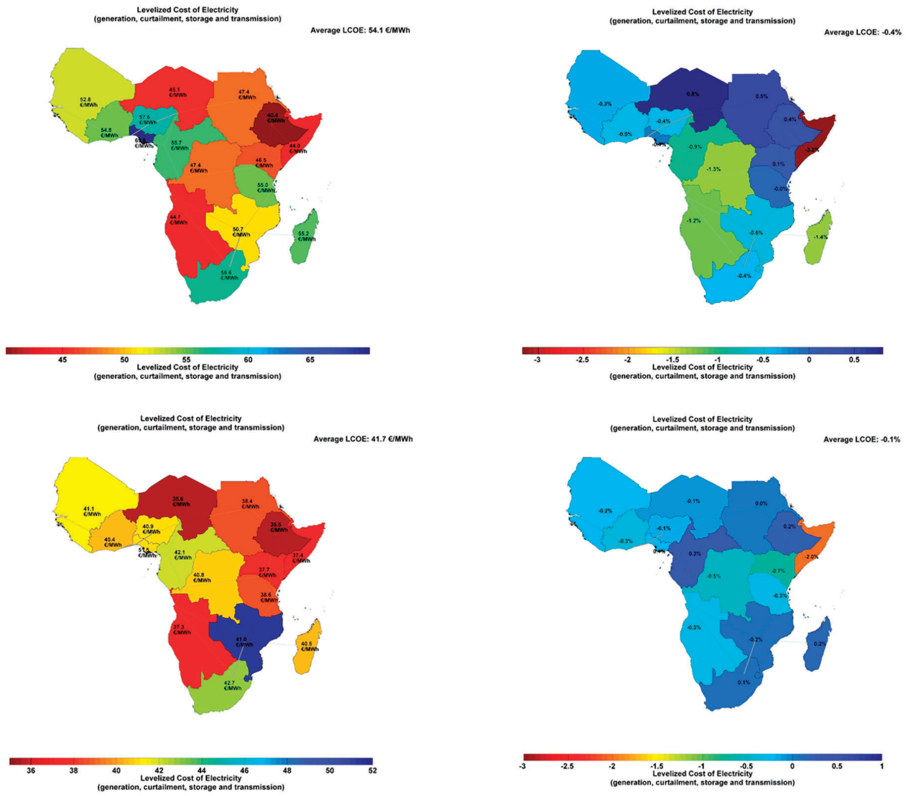

Figure 8. Scenario I3 announced cost in absolute total LCOE (**left**) and relative difference to the reference scenario (**right**) for the years 2030 (**top**) and 2040 (**bottom**).

Similarly, Figure 9 (top right) and (bottom right) shows the percentage difference in LCOE for the Inga 3 expected scenario for the years 2030 and 2040, respectively. Regarding LCOE, the regional impact of Inga 3 in these two scenarios is as well negligible, the relative percentage difference in LCOE was in the range of −3.5% to 18.4% in 2030 and from −0.7% to 11.5% in 2040. However, most of the cost burden is allocated to the DRC as LCOE increases by 18.4% and 11.5% in 2030 and 2040, respectively. The overall regional average increased by 0.2% and 0.3% in 2030 and 2040, respectively, in comparison to the Inga 3 announced cost scenario. The overall average LCOE is 54.5 €/MWh in 2030 and 41.9 €/MWh in 2040 as shown in Figure 9 (top left) and (bottom left). In this scenario, DRC experience tremendous increase in LCOE, yet the benefit impact is negligible in the whole region, again with Somalia being the country with the largest benefit, though almost negligible, of −3.5% and −2% LCOE in 2030 and 2040 scenarios, respectively.

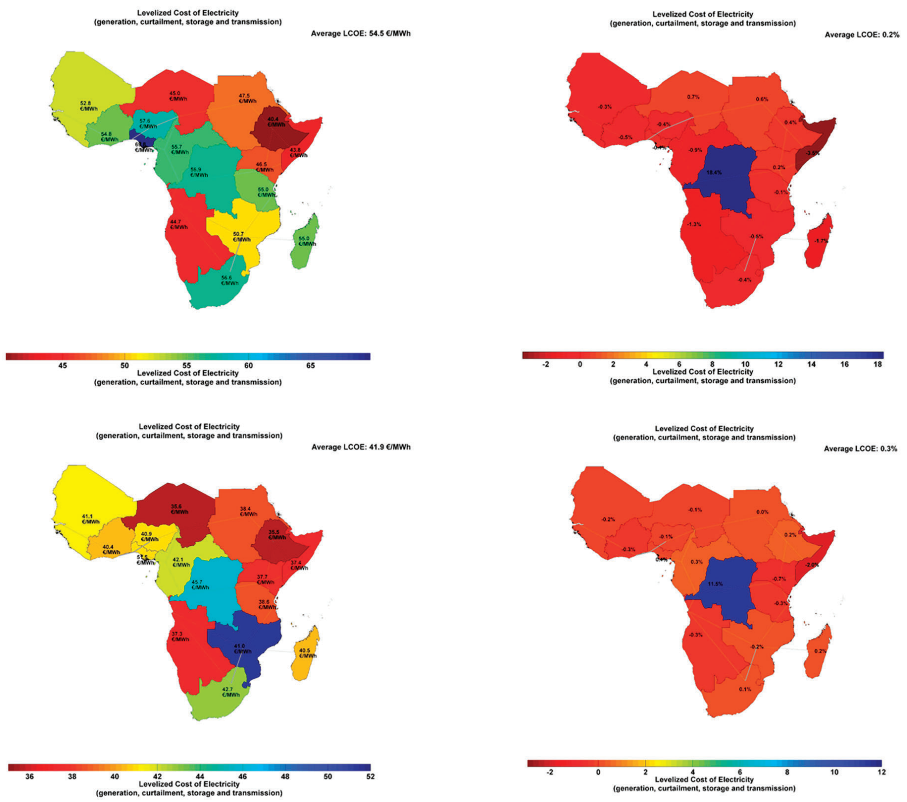

Figure 9. Scenario I3 Expected cost in absolute total LCOE (**left**) and relative difference to the reference scenario (**right**) for the years 2030 (**top**) and 2040 (**bottom**).

Furthermore, the percentage difference in LCOE for Grand Inga 0% scenario (cost as announced) for the years 2030 and 2040 is shown in Supplementary Material Figure S5 (top right) and (bottom right), respectively. The relative difference in the LCOE ranges from −11% to 12.9% in 2030 and from −7.5% to 16.1% in 2040, across the regions. With respect to LCOE, the regional impact of Grand Inga remains negligible in both years. For the year 2030, in this scenario the LCOE increases by 10.9%, 10.7% and 12.9% in Central, Congo and South West regions, respectively. By 2040, the LCOE increases by 16.1% in the host country. Meanwhile, Somalia and Djibouti experience −11.7% in 2030 and −7.9% in 2040 LCOE reductions. The overall regional relative average is −0.7% and 0.1% by 2030 and 2040, respectively. Supplementary Material Figure S5 (top left) and (bottom left) presents the LCOE numbers across SSA, where the overall average LCOE decreased from 54.0 €/MWh in 2030 to 41.7 €/MWh to 2040. Supplementary Material Figure S5 shows that in this scenario the effect of installing GI is no longer negligible. The DRC and its southern and northern neighbouring regions face a steep increase of LCOE of over 10% to a maximum of +12.9%, while the only regions receiving a non-negligible benefit are Somalia (with −11.7%) and Tanzania (−6.1%) in 2030. Furthermore, for 2040 the situation becomes more dire for DRC, as developing GI would result in a very significant increase of LCOE of +16.1%, while the neighbouring regions receive only a negligible benefit of −2% at most, even for just the announced cost of GI.

Similarly, Supplementary Material Figure S6 (top right and bottom right) shows the percentage difference in LCOE for the Grand Inga +50% scenario (cost 50% higher than announced) in the years 2030 and 2040, respectively. The relative percentage of the LCOE difference to the reference ranges from −11.7% to 29.0% in 2030 and from −7.8% to 31.1% in 2040, across SSA. The overall regional relative average increased to 0.3% and 0.7%, by 2030 and 2040, respectively. Similar to the previous scenario, LCOE declined by −11.7% in 2030 and −7.7% in 2040 in Somalia and Djibouti, while in the DRC the LCOE increased by 29% and 31% in 2030 and 2040, respectively. In this scenario the LCOE is 62.0 €/MWh in 2030 and 53.7 €/MWh in 2040 in the DRC, as shown in Supplementary Material Figure S6 (top left) and (bottom left), respectively. In this scenario, DRC bears a tremendous cost burden, while the LCOE decrease in most region was minimal, except for Somalia, in both years.

The percentage difference in LCOE for the Grand Inga +100% cost scenario (cost 100% higher than announced) is shown in Supplementary Material Figure S7 (top right) and (bottom right) for the years 2030 and 2040, respectively. The relative percentage difference in LCOE ranges from 0.0% to 42.2% in 2030 and from −7.7% to 46.9% in 2040. In this scenario, the DRC will experience 42.2% and 46.9% increase in LCOE, by 2030 and 2040, respectively. While the overall regional relative LCOE average increased by 2.0% in 2030 and 1.4% in 2040. The overall average LCOE is 55.5 €/MWh in 2030 and 42.3 €/MWh in 2040, as shown in Supplementary Material Figure S7 (top left) and (bottom left). The LCOE in DRC increased to 68.4 €/MWh in 2030 and 60.2 €/MWh in 2040, as shown in Supplementary Material Figure S7 (top left) and (bottom left). Similar to the previous scenario, the benefit impact on surrounding countries is still negligible without exception, while LCOE skyrocketed in DRC to +42.2% and +16.5% in the South-West region in 2030, resulting in an overall region increase of LCOE by +2%. For 2040 the situation for DRC only gets worse, as the increase of LCOE escalates further to +46.9%.

The percentage difference in the LCOE for the Grand Inga +35% and −5% scenarios is shown in Supplementary Material Figure S8 (top right) and (bottom right), respectively. In both scenarios the overall relative LCOE average was 0.0% for the entire region. Yet, DRC LCOE increased by 24.0% and 14.7%, in Grand Inga 35% and −5%, respectively. This implies that when cost overruns of Grand Inga increases the CAPEX by 35% in 2030 and −5% by 2040, the project brings no economic benefit to the electricity cost of SSA. The overall average LCOE is 54.4 €/MWh in 2030 and 41.7 in 2040 €/MWh, as shown in Supplementary Material Figure S8 (top left and bottom left), respectively. According to this scenario, DRC still experience an increase in LCOE; however, the impact is still negligible. In the adjacent regions the highest decrease was by 4% in 2030 and 1.4% in 2040, and a similar occurrence was noticed in regions in the West and East. Conversely, for Somalia LCOE decreased by 11.5% in 2030 and 7.8% in 2040.

Further graphical results are presented in the Supplementary Material (Figures S9–S13).

7. Frequency Stability

The conventional regulation concept is based on controlling the frequency with conventional prime movers such as thermal and hydropower generation. This conventional grid is known to possess large rotating mass due to the large synchronous machines that are directly connected to the grid. These large synchronous machines react naturally to the frequency deviations and large inertia guarantees that the ROCOF will be slow enough so that power generation plants are able to react to the change in frequency, either by increasing or decreasing their powers depending whether change in frequency is negative or positive, respectively. In fully renewable energy based power systems the inertia will become low, since the rotating mass of the connected synchronous machine is reduced [44,45]. The lower inertia means that connected frequency regulation reserves must be able to respond faster than currently. Frequency control reserves include power plants that react to frequency changes in the grid. Typically the reserves are divided into three parts: primary, secondary, and tertiary reserve. In principle, primary reserve is used to make sure that the peak change in frequency (i.e., frequency nadir) remains as small as possible and that frequency is balanced. The secondary reserves correct the frequency to its nominal value, and release the primary reserves for next possible event. Tertiary control optimises the use of reserves so that it is as economical as possible [82,83].

Here, the primary reserves are the main focus. Frequency limits how primary control reserves are activated varies from area to area. Since wind energy and solar PV plants are intermittent by nature their power production is limited by the available wind and solar irradiation. However, it has been shown that wind and solar PV can also participate into frequency regulation when so called synthetic inertia functionality is applied [84,85]. Also HVDC power lines can be utilized for balancing by applying the inertia emulation feature as shown in [86]. It is claimed that a wind turbine is capable of producing additional power up to 6% of the nominal apparent power for about 10 s [85]. In [82] it is also shown that solar PV plants could participate in frequency balancing by emulating the inertial property. It is concluded in [87] that in fully renewable power grids all the power generation sources that are capable of generating synthetic inertia must be utilized in order to maintain frequency stability.

Based on hourly connected generation capacities the ROCOF for the grid can be evaluated [88]. According to European Network of Transmission System Operators for Electricity (ENTSO-E) in Europe, 2 Hz/s is the reference value that generation units must withstand in the future [89]. This value is considered also here as a limit value that should not be exceeded. It is assumed that Sub-Saharan Africa's network is interconnected via transmission lines as shown in Figure 5. First, the ROCOF is calculated when only synchronous generation (hydropower, bioenergy plants, and geothermal units) contributes to the frequency balancing. Then synthetic inertia of the wind turbines is included, and after the synthetic inertia from solar PV plants. Finally, the synthetic inertia contribution from the battery units is included. It is assumed that in 2030, 0.1% of the connected battery capacity is available for frequency balancing services, and in 2040 the corresponding number is 0.05%. The ROCOF values are considered with 4% change in generation or load that corresponds loss of 8 GW change in 2030 and 19 GW change in 2040. For the 'I3 Announced cost' scenario in 2040 the hourly ROCOF values when different generation provided inertia is applied are shown in Figure 10. The corresponding minimum and maximum ROCOF values are given for different scenarios in Table 4. It can be noticed that relying only on synchronous generation's inertia will most likely result in unstable power networks. Therefore, utilization of synthetic inertia sources becomes mandatory in fully renewable power systems. Furthermore, it can be concluded that the role of battery energy storage systems is crucial when stability of the network is considered.

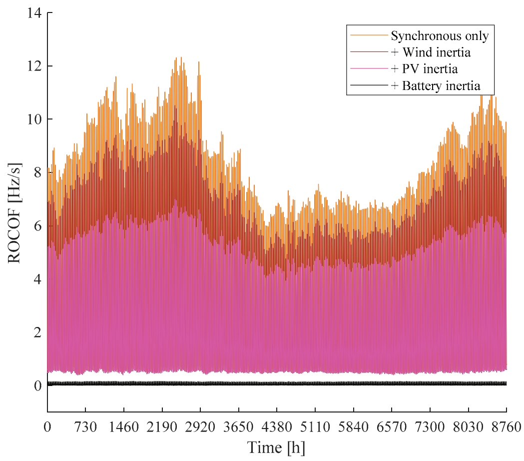

Figure 10. Hourly ROCOF values for 'I3 Announced cost' scenario 2040 for different generation technologies inertia contribution is considered. Highest ROCOF values are obtained when only synchronous inertia is utilised. Then by adding first synthetic inertia from wind then from solar PV and finally from battery the ROCOF value can be reduced to suitable levels.

Table 4. Synthetic inertia analysis and Rate-of-Change-of-Frequency (Hz/s) in Sub-Saharan Africa power system with different scenarios. Possible inertia of HVDC power lines, PtG units and demand response is not calculated, but would further improve the energy system stability in reality.

		2030				2040			
Contributing Generation		**Reference Scenario**	**I3 Announced Cost**	**GI 0%**	**GI 100%**	**Reference Scenario**	**I3 Announced Cost**	**GI 0%**	**GI 100%**
Only synchronous units	Max	4.71	4.50	3.69	3.77	12.97	12.34	10.41	10.35
	Min	0.69	0.67	0.58	0.59	0.45	0.44	0.42	0.42
+Wind inertia	Max	3.10	3.00	2.62	2.65	10.97	10.52	9.04	9.00
	Min	0.55	0.54	0.49	0.49	0.40	0.40	0.38	0.38
+PV inertia	Max	2.76	2.68	2.37	2.40	7.19	7.00	6.32	6.30
	Min	0.55	0.54	0.49	0.49	0.40	0.40	0.38	0.38
+Battery inertia	Max	0.20	0.20	0.21	0.21	0.16	0.16	0.17	0.17
	Min	0.03	0.04	0.04	0.04	0.01	0.01	0.01	0.01
+HVDC inertia	Max								
	Min								
+PtG inertia	Max								
	Min								
+Demand response	Max								
	Min								

8. Discussion

In the light of improving the energy outlook of SSA, several institutions have proposed a cross-border energy integration scheme as a top priority for tackling the pertinent energy situation [7]. Hydropower projects, in particular large hydro dams and long distance power grid systems, are envisioned as the cornerstone of the African power grid, and as solution to the region's energy woes [5,7]. Advocates of large hydro dams have often exaggerated the benefits of developing the Inga project, while the true risks of the project are neglected. However, it needs to be highlighted that a project of this scale may be overwhelming for the continent, due to several requirements that need to be fulfilled in order to realise its full completion [7,14]. To achieve a regional electricity project of this dimension, it calls for a further development of the cross-border transmission network from DRC to other regions of SSA [7]. By 2040, according to the New Policies Scenario of the IEA, the annual investment in the transmission and distribution grid should increase to about nine fold the current level [1]. Recent actions on grid expansions in SSA are undermined by increasing population growth in remote areas and by poor central grid and power generation [19]. The recipients of hydropower transmitted over long distance are not the un-electrified majority, but industries and urban centres, as happened in the case of Kariba and Cahora Bassa dams on the Zambezi River [7,16]. Yet, electricity from large hydropower will likely elude the majority of Africans who live far from the power grid, due to prohibitive cost of grid expansion [7]. In addition, power from large hydro dams such as the Inga are not intended to improve rural areas in need of electricity or supply domestic users [7,13,79]. This defers from Sustainable Development Goal 7 (SDG7) and the UN's Sustainable Energy4All initiative; to achieve universal access by 2030 [90,91]. Hence, PV-based mini-grids and stand-alone solar home system solutions are less capital intensive and can ensure electricity access to millions in SSA. More so, identifying alternative electrification options (off-grid electrification) in places of grid extension for the un-electrified people, particularly in rural areas, is pertinent [92–94]. However, there is need to consider economic viability, geographical potential, compatibility of (renewable) technology options, spatial factors, and techno-economic analysis in identifying least cost electrification options to end energy poverty in remote areas of SSA [94–96].

Furthermore, electricity expansion via grid extension has not eradicated the energy poverty in SSA. The New Policies Scenario of the IEA suggests mini-grid and stand-alone technology to account for 26 TWh and 12 TWh of energy generation, respectively, in SSA by 2040, of which solar PV contributes 37% and 47% of the technology mix, respectively [1]. According to Blechinger et al., two scenarios were modelled to understand the effects on future grid extension plans in SSA. In the first scenario based on the existing grid, 76.6 million people (12%), 290.3 million people (47%) and 252 million people (41%) can be electrified by mini-grids, grid extensions and solar home systems, respectively. The second scenario, in which modelling was based on the planned grid, 50.5 million people (8%), 381.5 million people (62%) and 187.6 million people (30%) can be electrified by mini-grids, grid extensions and solar home systems, respectively [19]. Solar PV technologies dominate the off-grid market [97]. The market for solar-powered lights, solar home systems and basic appliances has grown rapidly over the past five years, with over 24 million units sold [98]. In the past five years, Pay-as-you-go (PAYG) solar companies have raised over 360 mUSD in capital and served about 700,000 customers in East and West Africa [98]. In addition, the prominent role of PV and battery technologies, according to this current study for a RE-based power system, needs to be highlighted. Solar PV emerges as the dominating technology in all the scenarios for the years 2030 and 2040 in SSA. The highest installed capacity in all scenarios examined is 176 GW and 630.6 GW in 2030 and 2040, respectively. The increase in installed capacity of PV by 2040 can be explained by an expected ongoing steady decline in PV cost beyond the year 2030 [99]. In addition, the generation of PV for all scenarios is 364 TWh (38% of total) and 1305 TWh (78%) by 2030 and 2040, respectively. The high share of PV can be explained by the fact that PV will be the least cost RE technology in most parts of the SSA by 2030 and 2040. Also, the decreasing cost of battery storage pushes this trend. By 2040, the development becomes evident in terms of installed power capacity and electricity generation. For all scenarios considered, battery storage output reached 77 TWh and 499 TWh by 2030 and 2040, respectively. Reliance on battery storage, especially during evening and night hours, results from the use of PV. This trend is intensified from 2030 to 2040.

The total installed wind capacity has the second highest share of all power technologies in all scenarios considered. The highest capacity of wind for all the scenarios examined is 133 GW and 60 GW in 2030 and 2040, respectively. The role of wind energy is limited in SSA due to declining PV CAPEX. PV prosumers contribute with 11% in 2030 and 20% in 2040 of the total electricity generation in SSA. PV prosumers constitute 61.1 GW and 198.3 GW in 2030 and 2040, respectively, for all scenarios. In all scenarios the prosumer battery storage capacity is 72.2 GWh and 432.3 GWh by 2030 and 2040, respectively. A recent global report revealed an increase in new capacity installation of RE, from 127.5 GW in 2015 to 138.5 GW in 2016, excluding large hydro dams, which represents a 15 GW increase [98]. In the same report, solar PV and wind installations increased by 75 GW and 56 GW, respectively, more than any other technology in the same period of time [98]. Regarding land requirement, the specific capacity density derived in the LUT model is 75 MW/km^2 for optimally tilted PV and 8.4 MW/km^2 for onshore wind [39]. Hence, an area of 1501 and 5787 km^2 is needed for solar PV in 2030 and 2040 respectively, representing 0.006% and 0.02% of SSA land area. Similarly, the wind capacities require an area of 15,905 and 7202 km^2 in 2030 and 2040 respectively, representing 0.06% and 0.03% of total area of SSA. The area requirement is very small and wind energy can be even integrated in arable land.

On the other hand, the inaccurate prevalent perception is that mega dams can provide the least cost electricity to meet the energy deficits in developing countries [5,12]. Moreover, hydropower projects often do not account for social and environmental costs. Large hydropower projects are expensive: the Grand Inga project is costly, and the cost analysis of the project, carried out 10 years ago, led to estimated cost of 80 bUSD [51].Very large-scale hydropower projects are becoming more risky due to substantial cost overruns, length of construction and uncertain climate change impacts [5]. Recent studies have analysed investment risks and cost overruns among electricity generation technologies and revealed the high risks for large hydro dams, at the level of nuclear power stations. This is in contrast to a very low risk for solar and wind energy projects [10,27,28]. Hydroelectric projects exhibit an average overrun cost of 70%, and one plausible explanation for the huge costs overruns of hydro projects is the high material intensity compared to other energy sources [27]. A more recent study reported overwhelming evidence that the actual costs of large hydropower dams were on average 96% higher than initially estimated [10]. Likewise, the World Bank has noted significant cost overrun tendencies in some of their assessments of large hydropower projects [24]. In this work, categories of scenarios based on announced and expected costs were defined. Simulations have been carried out for cost escalations from 0% to 100% in 5% steps for the Grand Inga project in 2030 and 2040. An inflection point slightly over 35% was found for 2030 assumptions, i.e., the relative percent increase in LCOE was zero for the entire SSA region, meaning that a cost escalation beyond 35% for the Grand Inga project makes it economically non-beneficial. Moreover, by 2040, the inflection point dropped to below zero, with reference at −5%, i.e., by 2040, which means that even at the announced cost the Grand Inga project has a negative economic effect for the SSA region. In 2040, the result of this research reveals that solar PV dominates in terms of installed capacities, due to its fast development and continuous cost decline. The predominant role of solar PV and battery storage, due to highly favourable economics, was observed in this work. SSA can mainly be powered by solar PV and complemented by wind energy. In addition, a recent study on multi-criteria assessment for Africa demonstrates a large potential for utility-scale solar and wind energy developments [100]. Furthermore, in fully RE based power systems the inertia will become low, since the rotating mass of the connected synchronous machine is reduced. In this study, the minimum and maximum ROCOF values for all the scenarios was estimated. It was observed that relying on synchronous generation's inertia will most likely result in unstable power network. Thus, utilization of synthetic inertia source from PV systems, wind turbines and in particular battery storage becomes essential in this analysis.

Regarding LCOE, a decline occurred in LCOE in 2040 when compared to 2030 in all the scenarios examined; for instance, the overall average LCOE decreased from 54.5 €/MWh in 2030 to 42.0 €/MWh in 2040, in the case of Grand Inga +50% cost scenario as shown in Supplementary Material Figure S6 (top left and bottom left), respectively. The plausible reason for the reduction in LCOE can be attributed to the reduction in cost of RE technology, in particular solar PV and batteries, which dominate the power system.

In addition, very large-scale hydropower projects fail to realise social benefits of meeting current unserved energy needs due to their long times of construction [5,7]. Hence, solar and wind generation are capable of addressing severe energy shortage in SSA due their fast deployment and short project periods, both on-grid and off-grid [5]. Moreover, studies modelling an optimal mix of RE revealed the possibility of meeting future energy demand through operating the existing hydropower plants, and new added wind and solar capacities [40,101]. Furthermore, from an energy security point of view, it is risky for SSA to depend on a single project or technology, as power disruption is rather likely for the countries importing electricity from such a source.

The development of the Grand Inga project has only been justified as part of a regional energy master plan, for which a single country such as DRC cannot justify the need [7]. The Inga 1 and Inga 2 hydropower plants, which have caused half of the current external debt of DRC, have not functioned in their full capacity since their commissioning due to lack of maintenance [53]. Why should a project of this dimensions be built in a nearly failed state? However, external forces from developers and South Africa are the major drivers for the development of the Grand Inga hydropower project [7]. In 2008, South Africa experienced a severe energy shortage, which led to a call for major infrastructure development. Consequently, the South African government were prompted to consider new energy projects and partners. By 2011, a partnership agreement was established between South Africa and the DRC concerning the development of Inga 3 [50]. The capacity of Inga 3 is estimated to be 4.8 GW when (and if) completed, of which 2.5 GW would be dedicated to South Africa, 1.3 GW to the mining industries in the Katanga valley and the remaining 1 GW to the Congolese state utility [5]. Between 2011 and 2014, a cooperative framework for the entire project was established. Also, a memorandum of understanding and bilateral treaty was signed by both governments and approved by their respective legislatures. The document specifies that the national utilities of both countries would primarily facilitate the funding, construction and management of Grand Inga [50]. The Republic of South Africa has shown strong interest for energy that could be produced at the Inga site [59]. In order to meet its growing electricity demand and in particular for the mining industry, one of the major contributors to the South African economy, Eskom (the South Africa national utility), sees hydropower from Inga as a means to secure uninterrupted power supply for South Africa [7,59].

Beyond the substantial financial risk associated with large dams, the environmental consequences of hydroelectric dam development, which include long-term ripple effects on biodiversity and ecosystems, are rarely considered, often underestimated or largely ignored during dam planning [13,102]. Further damming of the Congo River would affect the local environment, regional ecosystem and the global climate [46–48]. The 'Congo Plume', which represents the largest carbon sink in the world, can be disrupted by additional dams, hence contributing to climate change [48]. The Congo River has vast biodiversity, and has the second highest diversity of fish species [103,104], over 450 being endemic species. The rare species of fish, plants and animals mentioned in Section 3 are at risk of being affected, or in an extreme case might be in danger of extinction [56,98]. The overall effect of GI would be severe, changing the downstream river ecology. Furthermore, flooding of the Bundi Valley to create a reservoir can lead to huge methane emissions and disease outbreaks. The unique ecological features of the Congo River basin, would be unavoidably affected, by building more dams on the river [105,106].

Regarding GHG emissions, recent investigations reveal that large dams emit GHGs, particularly in the tropic regions [63,64,107–113]. Reservoirs in tropic regions can produce up to 20 times the amount of GHGs in comparison to reservoirs in boreal regions, because of the high rate of biodegradation [111]. Lifecycle GHG emissions from reservoirs are estimated to be in the range of 0.5–152 g CO_{2eq}/kWh in boreal regions, while tropical reservoirs can produce up to 1300–3000 g CO_{2eq}/kWh [111]. Degassing CO_2 emissions from turbines and spillways account for 0–16%, and downstream emissions account for 1.6–32% of total CO_2 emissions. There are four types of GHG emissions from water reservoirs, which are degassing emissions at turbines and spillways, diffuse emissions, ebullitive emissions and downstream emissions. Ebullitive emissions represent the dominant source of methane emissions from the surface of tropical reservoirs [112]. The first global assessment on GHG emissions from reservoirs emphasised the possible significance of reservoir surfaces as a GHG source, and proposed that factors such as age, water temperature and organic input could regulate fluxes. A recent study highlights the dominant role of methane in total reservoir carbon emissions, and highlights the importance of including ebullitive methane emission in modelling efforts [113]. Therefore, the reservoir required for GI would further generate CH_4 emissions, resulting in substantial GHG emissions.

Further research will have to be conducted on the GI project with an energy transition model from 2015 to 2050. In this research the development phases of the GI project from Inga 3 to 8 will have to be considered in the transition model, with respect to proposed years of completion of each phase of the project. The development phases of the GI, maximum installed capacities and assumed years of commissioning are as follows: Inga 3 high-head (2025) 3037 MW, Inga 4 (2030) 7182 MW, Inga 5 (2035) 6970 MW, Inga 6 (2040) 6684 MW, Inga 7 (2045) 6706 MW and Inga 8 (2050) 6747 MW. In addition, it would be of high interest to analyse the benefits for South Africa, if any, in particular since South Africa has access to excellent domestic solar and wind resources, which can also represent respective low cost.

9. Conclusions

RE technologies, like solar PV and wind energy, have the potential to meet the energy demand sustainably and are also becoming increasingly cost-effective in SSA. In addition, this study confirms that hydropower as well as power generated from waste and biomass should serve only as gap-filling resources for an effective and stable power system in SSA. Hence, new investments in low cost solar PV and wind energy should be considered in SSA. The intermittency of RE can be circumvented with the integration of storage technologies, in particular battery storage, to store electricity during daytime that can be used at periods of highest demands and night hours. The integration of solar PV and battery storage was found to be cost effective. The LCOE obtained at the inflection point (near

+35% of the announced cost for 2030 and −5% of the announced cost for 2040), the point at which the relative difference LCOE is zero for the entire region, is 54.4 €/MWh in 2030 and 41.7 €/MWh in 2040, while the LCOE obtained for 100% GI cost overrun in the DRC region is 68.4 €/MWh in 2030 and 60.4 €/MWh in 2040. These are 79.5% and 69%% higher than the reference averages, respectively. The presented detailed cost analysis for SSA clearly reveals that it is highly unlikely that future Inga hydropower capacity expansions can compete with solar PV and wind energy, in particular taking into account not just the planned, but the expected investment cost. The Grand Inga project and several other hydropower projects have been proposed with little or no regard to whether they are the best option to meet the not yet electrified population of SSA. Large scale projects, like GI, are not the kind of investment required (nor intended) to electrify the unserved 600 million SSA inhabitants. This is in contrast to small scale and distributed solar PV solutions and continuous grid extensions. Energy planners for SSA should clearly strike a balance between energy needs for industrial purpose and human development. Cross-border energy supply in SSA should incorporate diverse energy resources across the region, and not on a single point project (like GI), to ensure secure energy supply. Beyond the financial risk that can be incurred from building the GI dam, severe environment disruptions would be caused from diverting river flow to create the required reservoir. This would cause further GHG emissions (particularly methane). Furthermore, river ecosystem alteration and loss of endemic species are inevitable by further damming of the Congo River.

The results demonstrate the potential for large scale deployment of RE technologies in the SSA region. Which expresses the need for cross-border cooperation and transmission infrastructure to enhance shifting of energy from one point in time to another, enabling large scale of generation and demand balancing between the different sub-regions. A 100% RE-based system is reachable and a real policy option in SSA. Policy action that will restrict new investments in fossil power plants and facilitate RE development in long-term perspective is exigent. This study shows the important role of solar PV and wind energy in a least-cost electricity supply for SSA. Thus, energy policies in the region should place solar PV and wind energy more at its core. In addition, the current emphasis on large-scale hydropower projects in some regions of SSA should be revised, whether the same electrification targets could be achieved faster, for a substantial lower risk of time and budget overruns, less environmental impact and finally even lower total cost, if more solar PV and wind energy would be part of the energy planning.

The limitations of the research are, first, the constraints of the model. The model excludes other energy sectors than the investigated power sector, such as transportation, heating, non-energetic industrial demand and water desalination. These additional sectors would affect the distribution of installations, however it is unlikely to significantly change the outcome. Also, the model operates within the constraints of the assumptions and estimations used for the calculations, while the projections of the future may develop both in different ways and even in different directions.

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Publication VI

Barasa, M., Bogdanov, D., Oyewo, A.S., and Breyer, C.

A cost optimal resolution for sub-Saharan Africa powered by 100% renewables in 2030

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A cost optimal resolution for Sub-Saharan Africa powered by 100% renewables in 2030

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ABSTRACT

This paper determines a least cost electricity solution for Sub-Saharan Africa (SSA). The power system discussed in this study is hourly resolved and based on 100% Renewable Energy (RE) technologies. Sub-Saharan Africa was subdivided into 16 sub-regions. Four different scenarios were considered involving the setup of a high voltage direct current (HVDC) transmission grid. An integrated scenario that considers water desalination and industrial gas production was also analyzed. This study reveals that RE is sufficient to cover 866.4 TWh estimated electricity demand for 2030 and additional electricity needed to fulfill 319 million m^3 of water desalination and 268 TWh_{LHV} of synthetic natural gas demand. Existing hydro dams can be used as virtual batteries for solar PV and wind electricity storage, diminishing the role of other storage technologies. The results for total levelised cost of electricity (LCOE) decreases from 57.8 €/MWh for a highly decentralized to 54.7 €/MWh for a more centralized grid scenario. For the integrated scenario, including water desalination and synthetic natural gas demand, the levelised cost of gas and the levelised cost of water are 113.7 €/MWh_{LHV} and 1.39 €/m^3, respectively. A reduction of 6% in total cost and 19% in electricity generation was realized as a result of integrating desalination and power-to-gas sectors into the system. A review of studies on the energy future of Sub-Saharan Africa provides the basis for a detailed discussion of the new results presented.

1. Introduction

The need for a revolution in the energy sector globally is vital, in view of tackling the problems of global warming, pollution, climate change, and energy security. The usage of and further dependence on fossil fuels in the pursuit of energy generation will engender an increase of greenhouse gas emissions and more extreme climate impacts. The energy sector accounts for roughly two-third of all anthropogenic greenhouse gas emissions, and there is imminent need for a paradigm shift from conventional to renewable energy resources that are sustainable, clean and cost effective [39,52,57]. Investment in sustainable energy infrastructure is a crucial link between economic growth, development, and climatic action. Renewable electricity generation will ensure the reduction of carbon dioxide emissions and meet climatic targets. A renewable energy optimization solution will reduce the dependency on fossil fuels as the predominant energy sources in the power system, and address socio-economic development needs and vulnerability to environmental change [23,46].

The region of Sub-Saharan Africa (SSA) continues to face significant energy crises. Despite the unique potential of energy sources in the region, a severe energy shortage has yet to be conquered, and access to electricity eludes millions of people [48]. Billions of dollars are spent annually on inefficient and often dangerous alternatives such as kerosene lamps, candles, flashlights, or other fossil-fueled powered stopgap technologies. In 2012 almost 16 TWh of electricity demand was served by backup generators for service and industrial activities in SSA [48,8]. The current energy challenge in Africa requires a rapid increase in energy supply (growth and development of energy) for the continent due to growing population, unprecedented economic progress and a need for reliable, modern energy services. Supply of energy is expected to at least double by 2030 and might even triple for electricity [56].

Africa's electricity generation varies significantly among African countries. North Africa (more than 99% electricity access) dominates in terms of electricity generation from a continental perspective [58], while Sub-Saharan Africa is starved for electricity. Only seven countries, Cameroon, Côte d'Ivoire, Gabon, Ghana, Namibia, Senegal and South Africa have electricity access rates exceeding 50%. The average annual consumption in Sub-Saharan Africa (except South Africa) is only about 150 kWh/capita [20]. Electricity demand in Africa was 385 TWh and 621 TWh in 2000 and 2012, respectively, and estimated to increase to about 1258 TWh and 1869 TWh by 2030 and 2040, respectively. The Sub-Saharan African demand will be about 812 TWh and 1297 TWh by

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Nomenclature

A-CAES	adiabatic compressed air energy storage
CAPEX	capital expenditures
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CHP	combined heat and power
CSP	concentrating solar thermal power
GDP	gross domestic product
GT	gas turbine
HVDC	high voltage direct current
LCOC	levelized cost of curtailment
LCOE	levelized cost of electricity
LCOS	levelized cost of storage
LCOT	levelized cost of transmission
OCGT	open cycle gas turbine
OPEX	operational expenditures
PHS	pumped hydro storage
PtG	power-to-gas
PV	photovoltaic
RE	renewable energy
RoR	run-of-river
SNG	synthetic natural gas
ST	steam turbine
SWRO	seawater reverse osmosis
TES	thermal energy storage
WACC	weighted average cost of capital

Subscript

el	electricity
fix	fixed
th	thermal
HHV	base on higher heating value of fuel
LHV	base on lower heating value of fuel

2030 and 2040, respectively [48]. According to Greenpeace [39], 95% of the electricity produced in Africa will come from renewable energy sources by 2050. Moreover, wind, solar photovoltaics (PV), concentrating solar thermal power (CSP), and geothermal energy will contribute 80% to total electricity generation. Already by 2020 the share of renewable electricity production will be 31%, and 65% by 2030. Consequently, the installed capacity of renewables will reach about 380 GW in 2030 and 1390 GW by 2050.

A brief summary of various studies on the trend of renewable energy share in African energy systems is presented in Table 1. Greenpeace [39] reveals the possibility of achieving 100% renewable energy in Africa by 2050 and WWF [81] affirms this possibility. The 2030 renewable energy map for Africa by IRENA [56] reports that the renewable share in the generation mix in the power sector can grow by 50% while the New Policies Scenario of the IEA [48] for 2040 reveals that hydropower may account for 26% of electricity generation, and other renewables will reach 12 GW (15%).

Energy demand grows as population increases in the world [3]. Africa is expected to contribute more than half of the global population growth between now and 2050, i.e. 1.3 billion people will be added in Africa of the 2.4 billion projected increase in global population between 2015 and 2050, and even more for the following decades [75]. Most developing countries and Africa need to plan a secure and sustainable means of meeting the current energy shortage problem and satisfy future energy demand, due to this fast growing and projected increase. In particular, the lack of access to affordable electricity in the Sub-Saharan Africa region requires a massive expansion of access to electricity [56,20]. Over 620 million people in Sub-Saharan Africa lack access to electricity, and nearly 730 million rely on the traditional use of solid biomass for cooking [48].

Sub-Saharan Africa has a huge untapped potential of renewable energy resources, widely spread across the region, which could provide affordable, sufficient and secure supplies of energy for the continental need. Therefore, investments in the energy system in Sub-Saharan Africa with a focus on increasing energy accessibility and affordability will improve quality of life, life expectancy and economic growth [55,75]. Africa's energy sector is vital to its development; therefore, effective energy planning, optimal design, wise utilisation of all available renewable energy (RE) resources and maximum synergy between various resources and different regions (regional electricity networking due to disperse energy resources) of Africa will have a positive impact on energy systems of the continent [56]. In view of designing and optimizing a renewable based energy system, several studies have been carried out with the aim of increasing utilisation of renewables in renewable energy rich regions (such as Northeast Asia) by utilizing high voltage direct current grids (HVDC) for interconnections within the regions [10].

Access to modern energy services can be secured by RE, especially solar PV [48]. Globally, solar PV installations have shown high growth rates, and solar PV is one of the fastest growing renewable technologies

Table 1
Studies on trends of renewable energy shares in the African energy system.

Reference	Scope	Findings
Greenpeace [39]	Global	The Energy [R]evolution scenario 2015 reveals a growing share of renewables in the African energy system till year 2050: 31%, 65%, and 100% by 2020, 2030 and 2050, respectively, in electricity generation. Increase in installed capacity from 380 GW (2030) to 1390 GW (2050).
IRENA [56]	Africa	Reduction of about 310 Mt of CO_{2eq} emission by 2030 with 50% share of RE in the power sector. Solar capacity could reach 90 GW, hydropower and wind 100 GW each.
WWF [81]	Uganda	Transition to 100% RE in Uganda requires adoption of on- and off-grid solar energy and increasing use of other RE. With a target of 60% RE system in 2030 and close to 100% by 2050.
Teske et al. [73]	Tanzania	Scenario design is based on Greenpeace [39] complemented by an Energy Access Scenario. 100% RE in Tanzania is technically and economically possible with 44.8 GW (PV), 30.0 GW (wind) installed in 2050.
IEA [48]	Sub-Saharan Africa	Electricity generation according to the 2040 New Policies Scenario is 1540 TWh; hydro accounts for 26% of the total generation and other renewable including solar, wind, bioenergy, geothermal and CSP will reach 12 GW (15%) by 2040
IRENA [53,54]	Africa	RE presents the least-cost option and provides electricity access to millions of Africans through renewable off-grid systems. RE share projected to increase from 50% to 73% by 2030 and 2050, respectively.
Bazilian et al. [5]	Sub-Saharan Africa	Reports on various levels of access and required installed capacities in Sub-Saharan Africa (excluding South Africa) by 2030. The access levels include business-as-usual, Trendline, Moderate Access, Full Access and Full Enhanced Access and required capacities are 79 GW, 374 GW, 501 GW and 1002 GW, respectively. Universal access by 2030 considering 2ºC target, renewable energy will contribute about 275 GW.

with continuously decreasing generation cost [13,67]. PV in Africa has transcended the government-donor niche to become a commercial based market development [43]. Solar PV technology currently plays a dominant role in the off-grid market, 4 million solar products were sold globally in the last half of 2015, and Sub-Saharan African sales accounted for 2.2 million (54.3%) [38]. PV will play a crucial role towards a 100% renewable energy system in Africa and requires the adoption of on- and off-grid solar energy as well as increasing the use of other RE resources [81]. In the New Policies Scenario 2040 [48], mini-grids and other off-grid technologies account for 26 TWh and 12 TWh of power generation, respectively, in Sub-Saharan Africa, and solar PV contributes 37% and 47% of the technology mix, respectively. Solar home systems and mini-grids provide technically feasible and economical solutions to energy challenges, where the cost of grid extension is not economical [66]. In Africa, solar energy has the largest RE resource potential and the high quality resource is widely available. Therefore, the PV and CSP technical potential could be as high as 6567 TWh and 4719 TWh, respectively. The rapid cost reduction for solar PV has led to increasing annual capacity additions and enhancing off-grid access [53,54]. The Sub-Saharan Africa energy sector is vital to its development. Therefore, effective energy planning, optimal design, and wise utilisation of the untapped, abundant renewable energy resources across Sub-Saharan Africa will have a positive impact on energy systems of the region.

The idea of a super grid has recently attracted more attention by Gobitec and the Northeast Asian Super Grid initiative, influenced by EU-MENA Desertec [25,63]. The super grid approach enables connections within a region or continent to attain synergetic effects by the harnessing of RE resources. This can help realize a 100% RE electricity supply system which can set the path for a 100% RE supply [10].

The main focus of this paper is to design an optimal energy system in Sub-Saharan Africa which is cost efficient and competitive. This will be found via a 100% RE-based system with optimal design and wise utilisation of all available RE resources, supportive storage and grid technologies.

2. Methodology

In this study, the power system model was developed based on linear optimization of energy system parameters under applied constraints. These parameters are composed of a set of RE generation and storage technologies, as well as water desalination and synthetic natural gas (SNG) generation sectors, which operate as flexible demands. A fully integrated scenario that further considers heat and mobility demand have to be modeled to understand the whole energy system. However, the heat and mobility sectors were not considered in this study. As the applied energy system model has already been described in Bogdanov and Breyer [10], the following sections do not include a detailed description of the model, its input data, and the applied technologies. However, it presents a comprehensive definition of all additional information that has been assumed for the model in the present study. Further technical and financial assumptions can be found in the Supplementary material in the appendix of this paper.

2.1. Model overview

The energy system model used in this study was developed with a perfect foresight of RE power generation and power demand. The use of a multi-node approach allows for the description of any desired configuration. The main study constraint for the optimization is to guarantee that for every hour of the year the total electric generation within a sub-region covers the local demand from all considered sectors and enables a precise system description including synergy effects of different system components for the power system balance.

The outcome of the system optimization is the minimization of the total annual energy system cost, calculated as the sum of the annual costs of installed capacities of the different technologies, costs of energy generation and generation ramping. The model also includes distributed generation and self-consumption of residential, commercial, and industrial electricity consumers (prosumers) by installing respective capacities of rooftop PV systems and batteries. For these prosumers the target function is the minimal cost of consumed energy

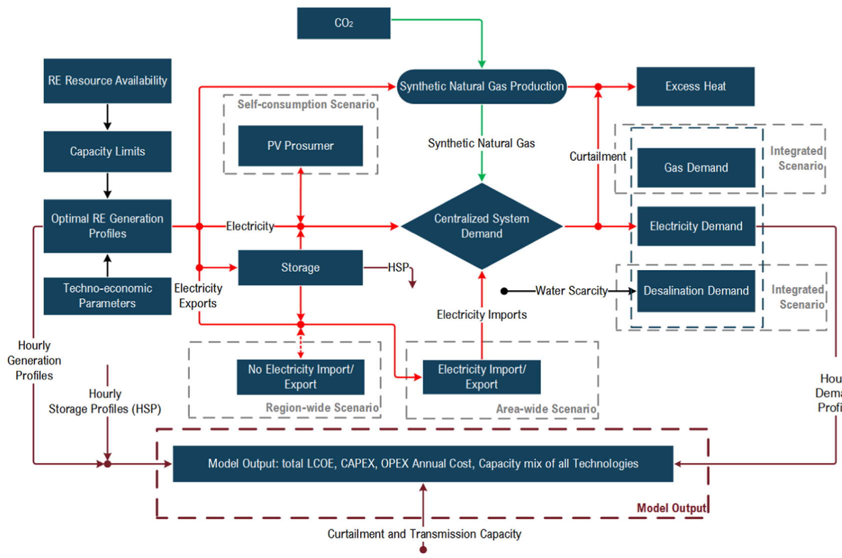

Fig. 1. Model framework diagram for the study scenarios.

calculated as the sum of self-generation, annual cost, and cost of electricity consumed from the grid, less benefits from selling excess energy. The model flow diagram that has all the considered input data, system models and model output data is presented in Fig. 1.

2.2. Input data

Additional information to Bogdanov and Breyer [10] about geothermal data, water desalination, and industrial gas demand are defined in this section. The geothermal potential is evaluated based on available information on the surface heat flow rate [1,45] and surface ambient temperature for the year 2005 globally. For areas where surface heat flow data are not available, an extrapolation of existing heat flow data was performed. Based on that, temperature levels and available heat at the middle depth point of each 1 km thick plate, between depths of 1 km and 10 km [21,22,85] globally with 0.45° x 0.45° spatial resolution, are derived.

Water desalination demand is projected based on water consumption levels and future water stress [86]. Water stress occurs when the water demand exceeds renewable water availability during a given period. It is assumed that water stress greater than 50% shall be covered by seawater reverse osmosis (SWRO) desalination. Transportation costs are also taken into account, as described by Caldera et al. [18]. The energy consumption of horizontal and vertical pumping are 0.04 kWh/(m^3 h 100 km) and 0.36 kWh/(m^3 h 100 m), respectively [18].

Present industrial gas consumption is based on natural gas demand data from the International Energy Agency statistics [49]. Natural gas consumption projections for the year 2030 were calculated considering annual industrial growth projections based on the World Energy Outlook [48].

2.3. Applied technologies

The technologies applied in the cost optimization for Sub-Saharan Africa can be classified into four main categories: conversion of RE resources into electricity, energy storage, energy sector bridging (for definition, see later), and electricity transmission. The technologies for converting RE resources into electricity applied in the model are ground-mounted (optimally tilted and single-axis north-south oriented horizontal continuous tracking) and rooftop solar PV systems, concentrating solar thermal power (CSP), wind onshore turbines, hydropower (run-of-river and dams), biomass plants (solid biomass and biogas), waste-to-energy power plants and geothermal power plants. The energy storage technologies used in this study are battery storage, pumped hydro storage (PHS), adiabatic compressed air energy storage (A-CAES), thermal energy storage (TES) and power-to-gas (PtG) technology. PtG includes synthetic natural gas (SNG) synthesis technologies: water electrolysis, methanation, CO_2 scrubbing from air, gas storage, and both combined and open cycle gas turbines (CCGT, OCGT). SNG synthesis process technologies have to be operated in synchronization because of hydrogen and CO_2 storage absence. Additionally, there is a 48 h biogas buffer storage, and a part of the biogas can be upgraded to biomethane and injected into the gas storage.

The energy sector bridging technologies give more flexibility to the entire energy system, thus reducing the overall cost. One bridging technology available in the model is PtG technology for the case that the produced gas is consumed in the industrial sector and not as a storage option for the electricity sector. The second bridging technology is seawater reverse osmosis (SWRO) desalination, which couples the water sector to the electricity sector. The technologies are represented on two levels: power distribution and transmission within the sub-regions are assumed to be based on standard alternating current (AC) grids which are not part of the model, and inter-regional transmission grids modeled by applying high voltage direct current (HVDC) technology.

Power losses in the HVDC grids consist of two main elements: length dependent electricity losses of the power lines and losses in the converter stations at the interconnection with the AC grid. An energy system mainly based on RE and in particular intermittent solar PV and wind power requires different types of flexibility for an overall balanced and cost optimized energy mix. The four broad categories are generation management (e.g. hydro dams or biomass plants), demand side management (e.g. PtG, SWRO desalination), storage of energy at one location and energy shifted in time (e.g. batteries), and transmission grids connecting different areas and energy shifted to the site (e.g. HVDC transmission). The full model block diagram is presented in Fig. 2.

3. Scenario assumptions

3.1. Regions subdivision and grid structure

This study considered 51 countries that are merged or subdivided into 16 sub-regions of the Sub-Saharan Africa super regional network based on area, population, and national grid connections. The 16 interconnected sub-regions include: West-West (Senegal, Gambia, Cape

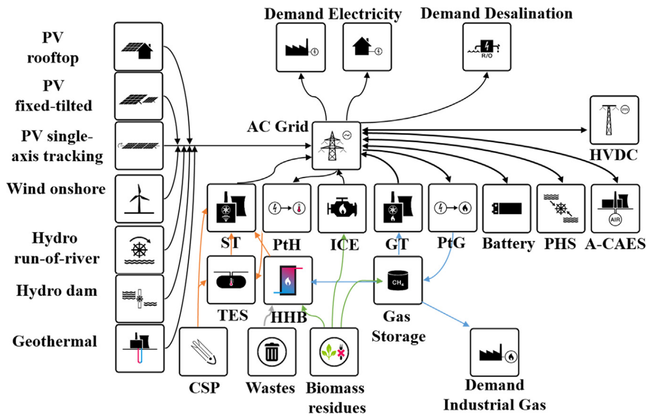

Fig. 2. Block diagram of the energy system model for Sub-Saharan Africa.

Verde Islands, Guinea Bissau, Guinea, Sierra Leone, Liberia, Mali, Mauritania and Western Sahara), West-South (Ghana, Côte d'Ivoire, Benin, Burkina Faso and Togo), West-North (Niger and Chad), South-Nigeria (South Nigeria), North-Nigeria (North Nigeria), Sudan-Eritrea (Sudan and Eritrea), Ethiopia (Ethiopia), Somalia (Djibouti and Somalia), Kenya-Uganda (Kenya and Uganda), Tanzania (Rwanda, Burundi, Tanzania), Central (Central African Republic, Cameroon, Equatorial Guinea, Sao Tome and Principe, Democratic Republic of the Congo [Kinshasa], Republic of the Congo [Brazzaville] and Gabon), South-West (Angola, Namibia and Botswana), South Africa (the Republic of South Africa and Lesotho), South-East (Malawi, Mozambique, Zambia, Zimbabwe and Swaziland) and Indian Ocean (Comoros Islands, Mauritius, Mayotte, Madagascar and Seychelles).

In this paper four scenarios for energy system development options are discussed:

1. Regional-wide, which assumes that the sub-regions operate independently (with no HVDC grid interconnections), and the electricity demand has to be covered by the respective regions' supply;
2. Country-wide energy system, which assumes that the sub-regions are interconnected via HVDC lines but within the borders of nations;
3. Area-wide energy system, which assumes that all sub-regions are interconnected via HVDC lines;
4. Integrated scenario, which takes into account additional demand sectors (SWRO desalination and industrial gas demand) to the area-wide energy system scenario. In this scenario, RE sources combined with PtG technology are used not only for electricity generation and storage options within the system but also as energy sector bridging technologies to cover water desalination and industrial gas demand, increasing the flexibility of the system.

The subdivision and grid configuration of Sub-Saharan Africa are presented in Fig. 3. Existing HVDC interconnections of Sub-Saharan Africa are shown by dashed lines. The structure of the HVDC grid for the scenarios (solid lines) is based on the existing configuration of Sub-Saharan Africa Power Pools. A typical existing line is Cahora-Bassa (1920 MW as 533 kVa and 1800 A).

3.2. Financial and technical assumptions

The model optimization is undertaken based on cost assumptions derived from technological status for the year 2030 and the overnight building approach, which is also applicable to nuclear energy [19]. The financial assumptions for capital expenditures (CAPEX), operational expenditures (OPEX) and lifetimes of all components are provided in the Supplementary material (in Table I). CAPEX and OPEX are quantified estimates by weighting the hourly LCOE per technology (generation, transmission, and storage) balanced with hourly demand for 2030. Weighted average cost of capital (WACC) is set at 7% for all scenarios, but for residential PV self-consumption, WACC is set to 4%, due to lower financial return requirements. The technical assumptions of power to energy ratios for storage technologies, efficiency numbers for generation and storage technologies, and power losses in HVDC power lines and converters are provided in the Supplementary material (Tables II, III, and IV, respectively). The electricity prices for residential, commercial, and industrial consumers in most of the Sub-Saharan Africa countries for the year 2030 are obtained from Gerlach et al. [36] and aggregated based on population weighted estimates as presented in the Supplementary material (Table V). Prosumers will use PV to supply a portion of their electricity needs. Thus, prosumers will cut the slice of electricity demand and get remunerated for any surplus generation, which does not top their annual consumption. The operation cost for prosumers depends on market conditions for the year 2030 and covers the cost of new rooftop PV systems and batteries. Excess generation, which cannot be self-consumed by the solar PV prosumers, is assumed to be fed into the grid for a transfer selling price of 2 €cents/kWh.

3.3. Feed-in for solar and wind energy

The feed-in profiles for solar CSP, PV optimally tilted and single-axis tracking, and wind energy were calculated according to Bogdanov and

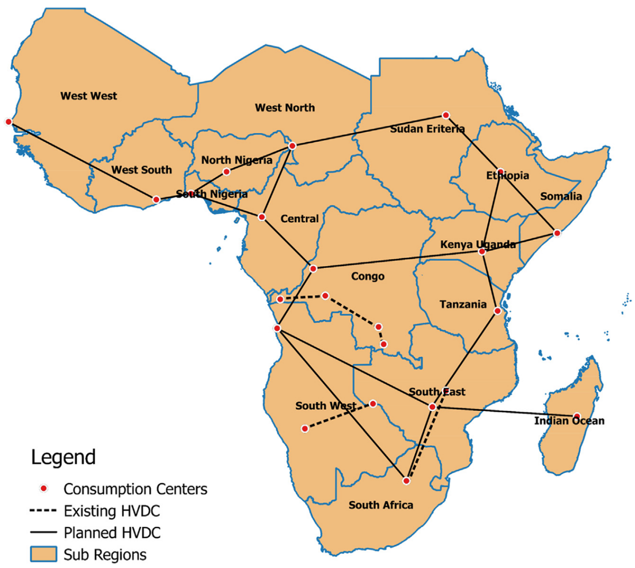

Fig. 3. Sub-Saharan African sub-regions and HVDC transmission lines configuration.

Breyer [10]. The aggregated profiles of solar PV generation (optimally tilted and single-axis tracking), wind energy power generation, and CSP solar field, normalized to the maximum capacity averaged for Sub-Saharan Africa are presented in Fig. 4. The computed average full load hours (FLH) for optimally tilted, single-axis tracking PV systems, wind power plants, and CSP are provided in the Supplementary material (Table VI). The feed-in values for hydropower are computed based on the monthly resolved precipitation data for the year 2005 as a normalized sum of precipitation in the regions. Such an estimate leads to a good approximation of the annual generation of hydropower plants.

3.4. Biomass and geothermal heat potentials

Biomass and waste resource potentials are mainly taken from DBFZ et al. [24] and classified as described in Bogdanov and Breyer [10]. Costs for biomass are calculated using data from the International Energy Agency [46] and Intergovernmental Panel on Climate Change [51]. For solid wastes a 100 €/ton gate fee for incineration is assumed. Calculated solid biomass, biogas, solid waste, and geothermal heat potentials are provided in the Supplementary material (Table VII). Prices for biomass fuels are provided in the Supplementary material (Table VIII), and price differences between countries are explained by various waste and residue component shares. Heating values are based on lower heating values (LHV). Regional geothermal heat potentials are calculated based on spatial data for available heat, temperature, and geothermal plants for depths of 1–10 km [83]. For each 0.45° x 0.45° area and depth, geothermal LCOE is calculated and optimal well depth is determined. It is assumed that only 25% of available heat will be used as an upper resource limit. The total available heat in the region is calculated using the same weighted average formula as for solar and wind feed-in explained in Bogdanov and Breyer [10], except for the fact that areas with geothermal LCOE exceeding 100 €/MWh are excluded.

3.5. Upper and lower limitations on installed capacities

Lower limits are taken from Farfan and Breyer [31] and upper limits were estimated based on Bogdanov and Breyer [10]. Lower limits on already installed capacities in Sub-Saharan Africa are provided in the Supplementary material (Table IX) and all upper limits of installable capacities are summarized in the Supplementary material (Table X). For all other technologies, upper limits are not specified. However, for biomass residues, biogas, and waste-to-energy plants it is assumed, due to energy efficiency reasons, that the available and specified amount of the fuel is used during the year, except for solid biomass which can be used up to the full resource potential.

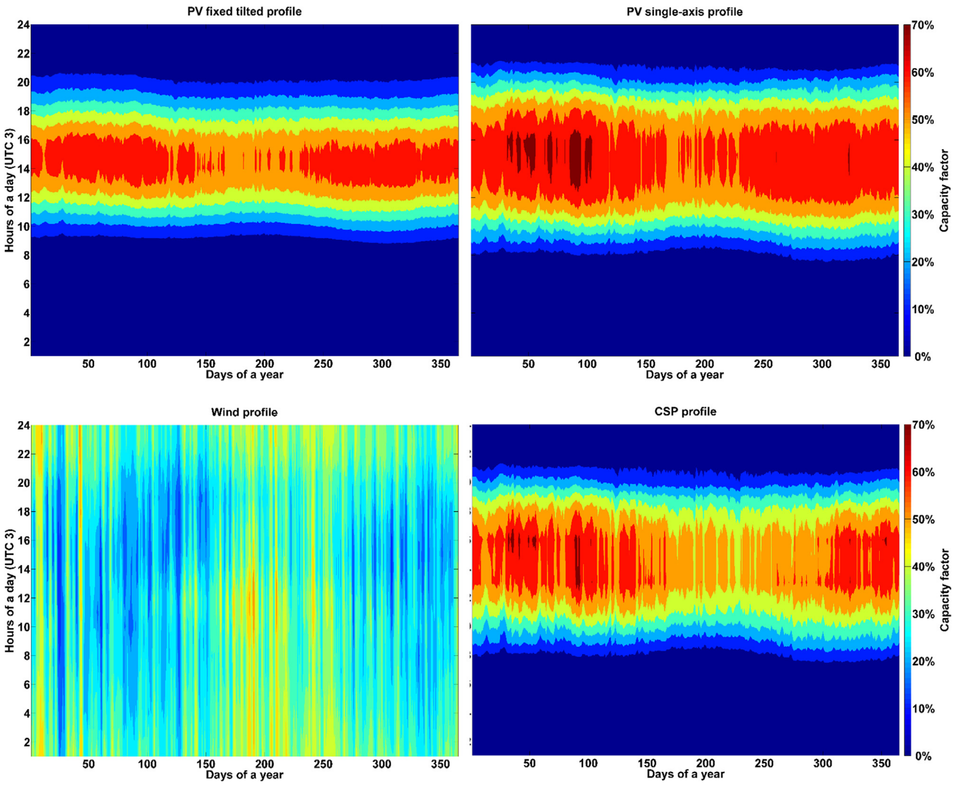

Fig. 4. Aggregated feed-in profiles for PV optimally tilted (top left), PV single-axis tracking (top right), 3 MW 150 m hub height wind turbine (bottom left) and CSP solar field (bottom right).

3.6. Load

The synthetic load data are generated based on hourly load data on a national level and takes into account local phenomena such as gross domestic product, population, temperature, and power plant structure. Fig. 5 represents the area-aggregated demand of all sub-regions in Sub-Saharan Africa. Electricity demand increase by the year 2030 is estimated using IEA data [48] and population weighted based on the countries close border proximity. Solar PV self-consumption prosumers have a significant impact on the extra load of the energy system as illustrated in Fig. 5 (right). The total electricity demand and the peak load are reduced by 11.2% and 5.2%, respectively.

Industrial gas demand values (expressed as gas demand excluding electricity generation and residential sectors) and desalinated water demand for Sub-Saharan Africa sub-regions are presented in the Supplementary material (Table XI), gas demand values are based on [49]. Desalination demand numbers are based on water stress and water consumption projections obtained from [18].

4. Results

To describe the cost structure of the different scenarios, a set of central parameters is computed according to the methodology described in Bogdanov and Breyer [10].

4.1. Key findings on the optimized energy system structure and costs

This section summarizes the findings from the optimized cost modeling approach for 100% RE in Sub-Saharan Africa. The cost minimized electric power system configurations are derived for all scenarios, the given constraints and characterized by optimized installed capacities of RE electricity generation, storage and transmission for every modeled technology. This leads to respective hourly electricity generation, storage charging and discharging, electricity export, import, and curtailment. The average financial results for the study scenarios are expressed as levelised cost of electricity (LCOE), levelised cost of electricity for primary generation (LCOE primary), levelised cost of curtailment (LCOC), levelised cost of storage (LCOS), levelised cost of transmission (LCOT), total annualized cost, total capital expenditures, total renewables capacity and total primary generation, as presented in Table 2.

Table 2 displays the financial results for all four analyzed scenarios. The role of HVDC transmission is important in achieving the least cost solution for Sub-Saharan Africa for the year 2030. It can be observed that the installation of HVDC transmission lines leads to a significant reduction of electricity cost of the entire system; a comparison of the region-wide and area-wide scenario shows a 5.4% and 5.8% decrease in LCOE and the annual expenses of the system, respectively. The same conclusion can be drawn regarding grid utilisation, which shows a reduction in installed capacities by 5.3% and in total electricity generated by 2.1%. Grid utilisation results in a considerable reduction of storage utilisation (Table 3), whereas the cost of transmission is relatively small in comparison to the decrease in the primary generation and storage costs. The power line usage is available for the entire year (8760 h), but the FLH are in the range of about 3940–7880 h, which is equivalent to a capacity utilisation of 45–90%. Storage costs decrease more significantly than curtailment costs in the case of broader grid utilisation, leading to a reduction of 18.8% in the area-wide scenario compared to the region-wide scenario; however, the impact of excess energy on total cost is rather low.

The integration of water desalination and industrial gas sectors results in a further reduction in LCOE by 23.4% compared to the area-wide open trade scenario. The cost reduction benefits are a result of a massive reduction in cost of storage and a minor decrease in the cost of curtailment. Storage cost is reduced by 48.3% since industrial gas and desalination sectors decrease the need for long-term storage utilisation, giving additional flexibility to the system. The utilisation of low-cost wind and solar electricity results in increased system flexibility as can be seen in Table 3. This results in an 8.7% decrease in primary electricity generation cost. A comparison of the area-wide and integrated scenario emphasizes the increased flexibility in the system by an additional PtG capacity of 47.0 GW. This occurs despite the availability of low cost biogas since the biogas resource potential cannot cover the full gas demand in the energy system as tabled in the Supplementary material (Tables VII and XI). The numeric values for LCOE components in all sub-regions and scenarios are summarized in the Supplementary material (Table XIV).

Regarding the RE installed capacities, all the RE technologies present a reduction of total installed capacity with an increase of grid utilisation (Table 3). Moreover, in all scenarios, solar PV technologies have the largest overall share compared to alternative technologies. The share of PV dominates as a result of interconnectivity reaching 55.5%, as the share of wind drops to 30.8%. The rest of the RE technologies make up the remainder, with hydro, biomass and geothermal taking slight shares that range from 4.7% to 6.6%, 4.5 to 7.2%, and 1.0 to 1.3%, respectively. The share for hydro and geothermal show some minor changes as a result of interconnection and integration of gas and desalination sectors. Hydro dams also act as virtual storage for the

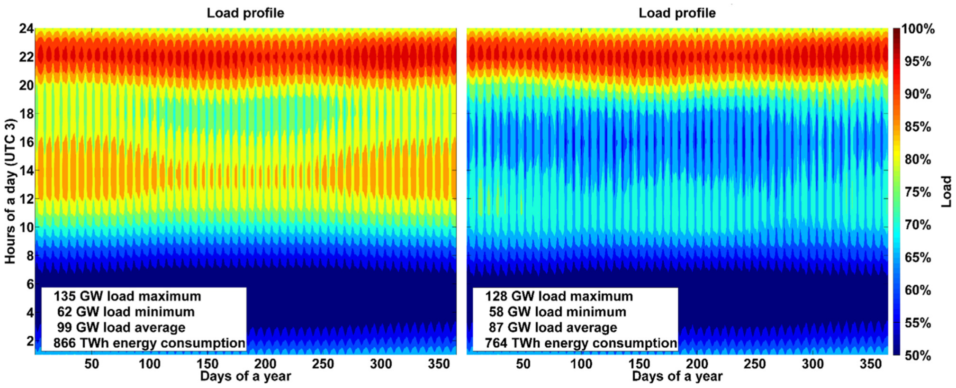

Fig. 5. Aggregated load curve (left) and system load curve with prosumers influence (right) for the year 2030.

Table 2
Financial results for the four scenarios applied in Sub-Saharan Africa.

Scenario	Total LCOE [€/MWh]	LCOE primary [€/MWh]	LCOC [€/MWh]	LCOS [€/MWh]	LCOT [€/MWh]	Total ann. cost [b€]	Total CAPEX [b€]	RE capacities [GW]	Generated electricity [TWh]
Region-wide	58	38	2	18	0	50	429	404	981
Country-wide	58	38	2	18	0	50	428	403	980
Area-wide	55	36	2	15	2	47	416	382	960
Integrated	47	34	2	9	2	62	563	544	1327

Table 3
Overview on installed RE technologies and storage capacities for the four scenarios.

RE Technology	Units	Region-wide	Country-wide	Area-wide	Integrated
PV self-consumption	[GW]	61.3	61.3	61.3	61.3
PV optimally tilted	[GW]	1.4	1.4	1.4	1.4
PV single-axis tracking	[GW]	134.6	133.9	111.5	239.1
PV total	[GW]	197.3	196.7	174.2	301.9
CSP	[GW]	0.0	0.0	0.0	0.0
Wind energy	[GW]	125.9	126.1	138.7	167.6
Biogas power plants	[GW]	4.5	4.2	1.6	1.3
Biomass power plants	[GW]	1.7	1.7	1.7	1.7
MSW incinerator	[GW]	23.1	23.2	21.5	21.5
Geothermal energy	[GW]	5.1	4.9	4.6	5.4
Hydro Run-of-River	[GW]	5.2	5.2	4.7	5.4
Hydro dams	[GW]	20.4	20.4	20.4	20.4
Battery PV self-consumption	[GWh]	72.2	72.2	72.2	72.2
Battery total	[GWh]	262.6	268.6	240.3	218.4
PHS	[GWh]	3.2	3.2	3.2	3.2
A-CAES	[GWh]	623.2	579.7	432.5	335.0
Gas storage	[GWh_{th}]	25,754	25,948	18,936	24,304
PtG electrolysers	[GW_{el}]	9.1	9.1	6.5	53.9
CCGT	[GW]	16.9	16.7	13.6	9.8
OCGT	[GW]	13.2	13.0	10.3	15.3
Steam Turbine	[GW]	30.1	29.7	23.9	25.1

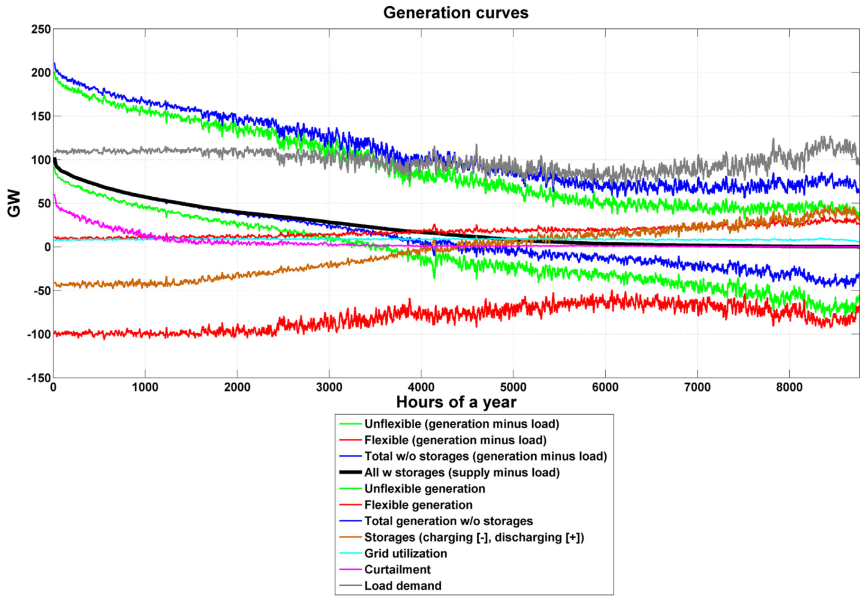

Fig. 6. Electricity generation duration curves for the area-wide open trade scenario for Sub-Saharan Africa.

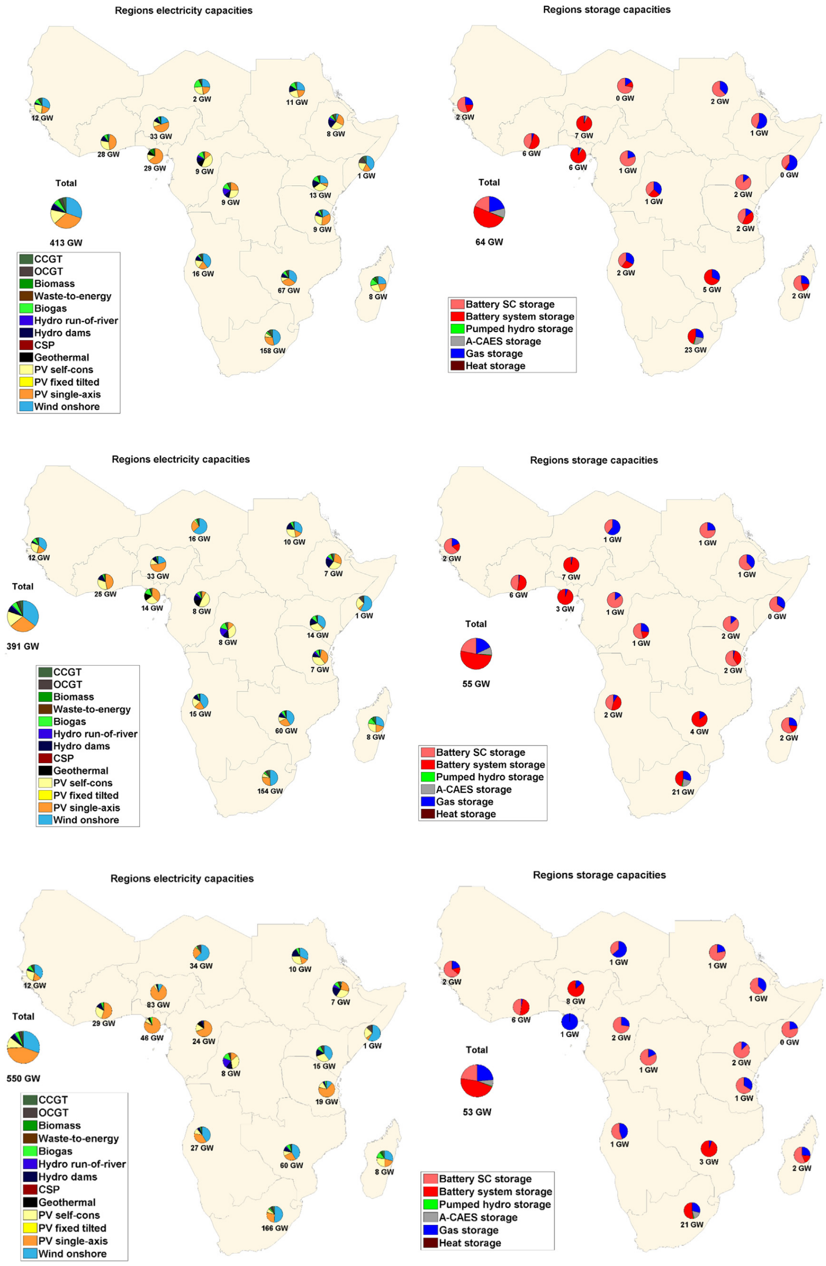

Fig. 7. Installed capacities of RE generation (left) and storages (right) for region-wide (top), area-wide (center) integrated (bottom) scenarios.

system and provide required flexibility. Interconnection and integration have considerable impacts on storage capacities.

The cost of most RE technologies has declined, and additional expected technical advances would result in further cost reductions. A PV self-consumption overview is given in the Supplementary material (Table XII). Self-generation plays a crucial role in Sub-Saharan Africa owing to high electricity prices throughout the region and low self-consumption LCOE. Self-consumption covers 84.7% of residential prosumer demand, 88.0%, and 89.4% of generated PV electricity for commercial and industrial prosumers, respectively.

Despite the fact that an upper limit 50% higher than the current capacity was considered for hydro dams and hydro RoR plants, the total hydropower plant installed capacity practically did not change in all the studied scenarios. It is not necessary to utilize all the available hydropower capacities as PV and wind seemed to be more cost competitive options for Sub-Saharan Africa.

As seen in results for the area-wide scenario, the interconnection of sub-regions in Sub-Saharan Africa has considerable impacts on storage capacities. Gas storage dominates the proportions for storage capacities in all the scenarios followed by A-CAES. However, when the storage throughputs are considered, there is a complete shift of dominance to battery storage, which is utilized especially during the night hours and in the absence of solar PV. Gas storage has a moderately low throughput of 45.9 TWh compared to battery storage, with the highest throughput of 77.5 TWh. Besides gas and batteries, other storage solutions utilized include: PHS, which has the lowest throughput of 0.83 TWh and is only utilized in the South African sub-region, and A-CAES at 10.5 TWh, which is still surpassed by batteries and gas storage. The storage capacities of batteries, PHS, A-CAES, PtG and gas turbines decrease as a result of interconnection and integration of gas and desalination sectors. However, gas storage increases from 18.9 TWh to 24.3 TWh as a consequence of the integration of gas and desalination sectors. PtG electrolysers have a rather low installed capacity in the area-wide and area-wide scenarios since PtG is not needed much for seasonal storage. Hydro dams have a key role as virtual batteries for long-term balancing of solar and wind as well as reducing interregional electricity trade, electricity transmission costs and reducing the seasonal storage contribution of PtG. The total LCOE declines from the region-wide to the integrated scenario by 18.8% as a result of geographic integration and sector coupling.

An overview of the electricity generation curves for the area-wide scenario can be seen in Fig. 6. All 8760 h of the year are sorted according to the net hourly supply (generation minus load), which is represented by the black line. Higher electricity generation than demand can be observed for 4400 h of the year, and this is used for charging storage. This is caused by high electricity generation from inflexible energy sources, due to high shares of solar PV and wind energy in Sub-Saharan Africa energy mix and a higher solar irradiation and wind speed in the region during these hours of the year. As a consequence, flexible electricity generation options (such as hydro dams, biomass, and biogas) and discharge of storage plants are needed. The inflexible electricity generation is significantly reduced in comparison to the decrease in electricity demand for the remaining hours of the year, thus increasing the need for flexible electricity generation, energy storage discharge and grid utilisation. The storage plants are deployed for about 4400 h of the year in charging mode and about 4200 h in discharging mode. Electricity curtailment occurs for only about 1000 h over the entire year and is seen at relatively low levels. This is due to the existence of storage options within sub-regions and HVDC transmission lines, which enable further storage in other sub-regions as well as effective electricity exchange between sub-regions.

4.2. Main findings on the optimized energy system structure in a sub-region analysis

Considering a sub-regional analysis, as presented in Fig. 7, noticeable differences can be observed between the scenarios, especially between the area-wide and the integrated scenarios. More demand in the

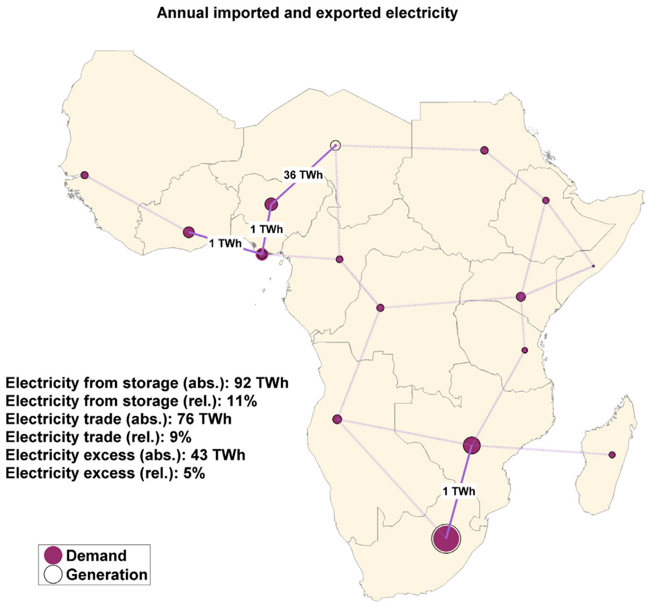

Fig. 8. Annual generation and demand diagram for the area-wide open trade scenario.

case of a RE-based energy system can change the entire system structure because of shifting optimal cost structure parameters and sub-regions being confronted with their upper resource limits. For region-wide and area-wide scenarios, the share of PV dominates in almost all the sub-regions considered. The exceptions are Kenya-Uganda, Somalia-Djibouti, and West-North, where wind energy plays a key role due to favorable wind resources. Wind plays a key role in the integrated scenario, as an additional electricity demand for water desalination and industrial SNG production was included. This was especially noticeable in the sub-regions that have excellent wind conditions and, therefore, low cost wind energy.

Broad cost saving opportunities appear available as a result of HVDC interconnection. Firstly, as water desalination and industrial gas sectors are integrated, the power system increases the electricity demand but, importantly, also the energy system flexibility. Therefore the, total installed capacities are reduced due to HVDC transmission grid interconnection, as seen in Fig. 7 and Table 3. This decrease occurs mainly because of a reduction in capacity by 17.2% for PV single-axis in Sub-Saharan Africa, which is seen when region-wide to area-wide scenarios are compared. The exceptions are North-Nigeria and West-North, which showed increases in total RE installed capacities by 9.9% and 898%, respectively. The significant reduction in PV shares is countered by an increase in wind capacities by 10.2% in the West-North sub-region, which shows a 20-fold increase from 0.49 GW to 10.4 GW. This result highlights the role played by wind as more sectors are integrated into the system. Secondly, the structure of HVDC power lines and utilized RE resources strongly influences the total storage capacity needed. In this context, the already installed hydro dams are an important RE source that can act as virtual batteries for long-term storage and seasonal balancing. The regional capacities also vary between sub- regions. Data of storage systems' discharge capacities, annual energy throughput, and full load cycles per year are summarized in the Supplementary material (Table XIII). The generation capacities of storage technologies decrease with the geographic integration and utilisation of HVDC transmission lines. State-of-charge profiles for the area-wide scenario for battery, PHS, A-CAES, gas storage and hydro dams are provided in the Supplementary material (Fig. 4 and Fig. 5). The state-of-charge diagrams show the system optimized operation mode of the different storage technologies: mainly daily (battery, PHS), mainly weekly (A-CAES) and mainly seasonal (gas, hydro dams). Additionally, the absolute and percentage hourly grid capacity profiles in the integrated scenario for the different times of a day and days of a year are as presented in the Supplementary material (Fig. 6).

4.3. Electricity import/export

In the case of the region-wide open trade scenario, all sub-regions of Sub-Saharan Africa need to match demand using only their own RE resources. Nonetheless, in the case of the country-wide and area-wide open trade scenarios, a division of sub-regions into net exporters and net importers with interregional electricity flows can be observed. An annual import and export diagram for area-wide open trade is presented in Fig. 8. Differences in generation and demand are mainly due to export and import, but also somewhat due to storage losses. For the area-wide integrated scenario, differences are due to energy consumption for SNG production. Fig. 8 also gives a good overview of sub-regional RE resources; net exporters are sub-regions with the best renewable resources and net importers are sub-regions with moderate ones.

The results in the Supplemental material (Table XIV) summarize the import/export shares in all sub-regions and for all scenarios. The share of export is defined as the ratio of net exported electricity to the generated primary electricity of a sub-region, and the share of import is defined as the ratio of imported electricity to the electricity demand.

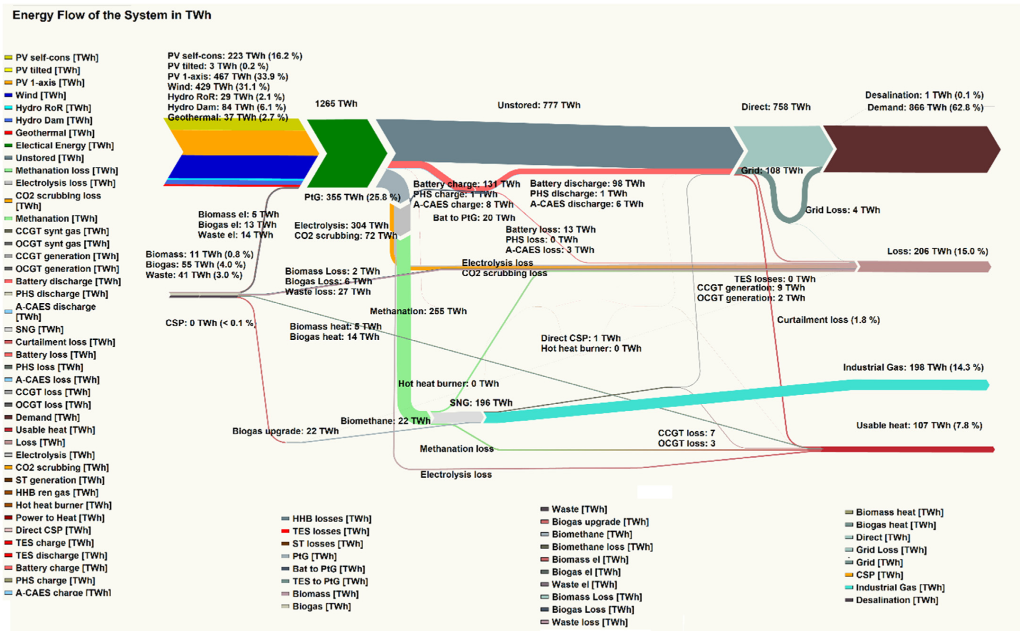

Fig. 9. Energy flow of the system for the integrated scenario.

The area average is composed of sub-regional values weighted by the electricity demand. West-North, located in the Sahara Desert, emerges as the major net exporter in Sub-Saharan Africa; the sub-region depicts a surprisingly favorable wind and solar generation with a low electricity demand. West-North exports 36 TWh of electricity to the more highly populated South-Nigeria, the major net importer in Sub-Saharan Africa. The rest of the net importing sub-regions include Tanzania, West-West, Congo, and South-East. The remaining sub-regions are classified as balancing sub-regions since electricity is both imported and exported over the short-term (hourly) and over the long-term (annually). Hourly resolved profiles of generation in an importer sub-region (South-Nigeria), a balancing sub-region (South Africa), and an exporting region (West-North) are presented in the Supplementary material (Figs. 1–3, respectively). For the integrated scenario a drastically increased electricity demand for the desalination and SNG producing sectors changes the picture dramatically; SNG producing sub-regions tend to increase the intra-regional electricity generation to fulfill the growing demand.

The Sankey flow in Fig. 9 diagram reveals more about the energy flows, all the way from generation to end use, and the efficiency of each energy conversion. The Sankey flow diagram summarizes the integrated scenario and is comprised of the primary RE resource generators, the energy storage technologies, HVDC transmission grids, the total demand for each sector and system losses. The potentially usable heat and ultimate system losses include the difference between the primary power generation and final electricity demand. Both are comprised of curtailed electricity; the heat produced by biomass, biogas, and waste-to-energy power plants; the heat of transforming power-to-hydrogen in the electrolysers, hydrogen-to-methane in methanation and methane-to-power in the gas turbines; and the efficiency losses in A-CAES, PHS, battery storage, as well as by the HVDC transmission grid. At the same time, the end use is comprised of the electricity, gas, and desalination sectors. Additional sectors in the integrated scenario cause additional capacity for generation from renewables, mainly wind energy and solar PV. An overview of the power transmission lines, their key parameters, and the percentage of grid utilisation can be found in the Supplementary material (Table XV and Fig. 6). The energy flow for the region-wide and area-wide scenarios are presented in the Supplementary material (Figs. 7 and 8).

5. Discussion

5.1. Cost implications for large-scale HVDC interconnections

From the presented results for Sub-Saharan Africa, it can be confirmed that different grid configurations as witnessed in the different scenarios will lead to several cost ramifications. Appropriate approaches for institutional, technical, and economic design and implementation are crucial to carrying out grid expansion programs in Sub-Saharan Africa. The electricity consumption in most Sub-Saharan countries is low due to a variety of reasons amidst a poorly developed grid infrastructure [84]. Thus, for the region to engage in large-scale energy projects, there must be calls for additional investment in HVDC power lines to facilitate cross-border transmission. The majority of Sub-Saharan countries have recurrent power shortages, almost 40% of the grid was built or refurbished decades ago, and it is estimated that 18 bUSD is required for the renovation of the existing grid [72].

In an effort to tackle the inefficiencies associated with the Sub-Saharan Africa power supply, joining national markets can provide the economy of scale to overcome them. Regional power pools need to be established to promote cross-border trade in electricity and incentivize capacity investment. HVDC interconnectors could enhance renewable electricity trade between power pools with diverse energy mixes [70]. Indeed, there are already discussions about interconnection across the continent and facilitating the creation of a Pan African power market [42]. The power market will be comprised of a consolidation of regional power pools, namely, Southern African power pool (SAPP), West African Power Pool (WAPP), Central African Power Pool (PEAC) and the East African Power Pool (EAPP). This study has, however, subdivided the power pools further and highlights 16 sub-regions as discussed in Section 3.1.

The linkage of these sub-regions via HVDC transmission lines can address the challenges of intermittency in RE technologies. The installation of HVDC transmission lines between sub-regions leads to a significant reduction of overall cost, storage requirements, and RE installed capacities in the 100% RE-based system. A comparison of the region-wide and country-wide scenarios shows negligible difference regarding cost since only Nigeria (with an enormous population) was subdivided. Moreover, a slight drop in the total levelized cost of electricity from 57.8 €/MWh to 57.7 €/MWh is noticeable. The same argument is feasible when the annualized cost is also compared. The annualized cost shows a slight decrease from 50.3 b€/a to 50.2 b€/a. However, when the country-wide or the region-wide scenario are compared to the area-wide scenario, a sizeable reduction in LCOE of 5.5% is observed, from about 57.8 €/MWh to 54.6 €/MWh. In addition, annualized cost decreases from around 50.2 b€/a to 47.3 b€/a. In parallel, the CAPEX requirements are also reduced in a similar manner by 3.0%, from 429.7 b€ to 416.8 b€, which is a lower reduction than the one seen for the annualized cost since the biomass fuel cost remain stable. Additional costs of HVDC transmission lines (23.1 b€ annual cost for the area-wide scenario) are compensated by a substantial decrease in generation and storage capacities enabled by lower losses and costs of energy transmission compared to energy storage, access to low-cost electricity generation in other regions, and finally a more efficient use of energy system components.

Transmission and distribution (T&D) investments are key for any developing power grid system, particularly for systems that are expanding to meet universal access goals [5]. Eberhard and Shkaratan [28] estimate about 37% of the investment cost is used for new transmission and distribution networks. Unfortunately, the use of HVDC transmission line interconnections may have limited impact in improving electricity access, especially in rural localities in Sub-Saharan Africa because of the complexity of rural settlement (geographical constraints), poorly developed infrastructure, and the cost of extending grid infrastructure. Sub-Saharan Africa has generally lagged behind other regions of the world in terms of infrastructure as well as power sector investment and performance [28].

5.2. Role of off-grid PV

The traditional approaches to electrification of Sub-Saharan Africa by grid extensions have not contributed to the eradication of rural poverty [72]. Over the years, the substantial subsidies provided by the region's utilities leave millions of African households in the dark because such a limited number of households are connected to the grid [84]. This means that much more investment would be required to achieve full electrification in Sub-Saharan Africa through grid extension options. Based on World Bank [83] calculations, a total of 280 bUSD is required for 200 million new connections to provide 100% electrification by 2030. Off-grid renewable energy technology systems, especially solar PV based technologies (solar home system and mini-grid), provide technically feasible and economical solutions to energy challenges where the cost of grid extension is not cost-effective [11,66]. Furthermore, the choice of technologies for rural electrification should consider the economic viability, geographical potential, and compatibility of (renewable) technology options. Furthermore, spatial and techno-economic analysis helps in identifying least cost electrification options for remote areas [71,72]. Access to modern energy services can be enhanced by RE, especially solar PV. Access to clean and reliable energy constitutes an important prerequisite for fundamental determinants of human development, contributing, among other things, to economic activity, income generation, poverty alleviation, health, education, and gender equality. Due to their decentralized nature, solar PV can play a major role in fostering rural electrification [51].

Solar PV technologies dominate the off-grid market. Recent market research conducted in the last half of 2015 on sales of pico-PV and solar home systems reveals that about 4 million products have been sold globally, and Sub-Saharan Africa accounts for about 2.2 million (54.3%) [61]. Additionally, mini-grid and off-grid technology account for 26 TWh and 12 TWh of power generation, respectively, in Sub-Saharan Africa, and solar PV contributes 37% and 47% of the technology mix in the New Policies Scenario 2040 [48]. Mini-grids and off-grid PV capacity are predicted to reach 100 GW, representing about 5% of total capacity by 2030 (2% by 2050), which would be a significant increase from current trends [47]. Such a low PV off-grid share seems unrealistic compared to the results for SSA, whereas the overall global installed PV capacity may reach several tens of terawatts, as indicated by Breyer et al. [15]. One of the most recent approaches for electrification planning using geospatial tools was elaborated by Bertheau et al. [7], who modeled two scenarios to investigate the effects of future grid extension plans in Sub-Saharan Africa. In the first scenario based on the existing grid, 76.6 million people (12%), 290.3 million people (47%) and 252 million people (41%) could be electrified by mini-grids, grid extensions and solar home systems, respectively. The second scenario, in which modeling was based on the planned grid, 50.5 million people (8%), 381.5 million people (62%) and 187.6 million people (30%) can be electrified by mini-grids, grid extensions and solar home systems, respectively, hence more by grid extensions. Bertheau et. al. (2017) carried out a sensitivity analysis varying grid buffer and population threshold. Results of the sensitivity analysis show that varying the grid electrification radius has a significant impact on the share of solar home systems and mini-grids. While varying the population threshold increased the relevance of mini-grids. Another study on electrification planning in Sub-Saharan Africa by 2030 [65] indicates that 850 million people (77%), 180 million people (16%) and 70 million people (6%) can be electrified by grid extensions, mini-grids and standalone systems in 2030, respectively, based on Tier 5 electrification criteria. For instance, in Uganda, on-grid electricity will become an increasingly important supplier of energy, though will still account for less than 25% of the overall energy supply by 2050 [81]. This means that 75% of Ugandans will not rely on grid connectivity for the provision of energy. Off-grid based RE solutions like mini-grids, and in particular solar home systems (SHS) provide a least cost solution for realizing the full electrification of rural people in Sub-Saharan Africa [11,12,17,6,81]. PV-based mini-grids can be established for initial electrification but also for upgrading existing and costly off-grid diesel-grids [16]. Furthermore, SHS can act as an interim solution until a grid is planned and constructed, or economic power makes the establishment of mini-grids feasible. This is due to the fact that there are no financial drawback for operators due to the very low amortization periods of SHS of 6–18 months [11,12].

5.3. Relevance of PV prosumers

PV self-consumption influences the energy sector in an interesting way. To measure the impacts of PV prosumers, region-wide, country-wide, and area-wide open trade scenarios are also calculated without PV self-consumption and the total demand is assumed to be covered by a more centralized system. A comparison of self-consumption-scenarios to base scenarios shows the following additions in the annualized costs; 48.6 b€ compared to 50.3 b€ for region-wide scenarios (+ 3.4%), 48.5 b€ compared to 50.2 b€ for country-wide scenarios (+ 3.4%), and 45.6 b€ compared to 47.3 b€ for area-wide scenarios (+ 3.6%). PV self-consumption induces additional costs because of a different target function of prosumers. However, prosumers reach their minimum annual electricity cost. The LCOE for PV self-consumption then must be lower than the grid electricity selling price, but can be higher than the total system LCOE. The cost of PV installations is projected to drop because of technological innovation, product optimization, and economies of scale, among other reasons. This trend will prompt a further cut of LCOE for PV self-consumption. PV self-consumption can also reduce the stress on local distribution and transmission grids in particular in combination with batteries, as also documented by a reduction in the Sub-Saharan African peak-load by 5.2%. Due to the high electricity prices in most of the Sub-Saharan African countries, the value of the savings brought about by PV self-consumption expands and improves the return on investment, which is further accelerated by broad use of diesel generation, even used occasionally as a substitute for base load power plants. So, the prolonged or avoided distribution and transmission capacity may result in a fast growing base of PV prosumers which could set up a component of competition with monopoly utilities in Sub-Saharan Africa.

A comparison between self-consumption and base scenarios also depicts additional battery storage demand because of PV prosumers. Electricity generation from prosumers causes some positive and negative distortion in the system demand profile (Fig. 5), i.e. the system reacts by installing more flexibility granting capacities, such as low-cost RE or further storage capacities, which increase the system costs as well. However, due to some slight inflexibility caused by constrained PV use mainly during the daytime, the impact of prosumers is constrained to a reduction of daytime peaks as opposed to night peaks. Thus, the most expensive peak hours throughout the year are substantially reduced by 5.2% by PV self-consumption, which exhibits a substantial economic value. The electricity consumption in the centralized system is higher from the morning hours till the evenings compared to a system with PV prosumers influence. For the region-wide scenario, a comparable low-cost increase due to the decentralized generation can be explained by the fact that additional disturbance cost in the system (provoked by prosumers) is compensated by access to low-cost residential electricity (for residential consumers WACC is assumed to be 4%). Finally, PV self-consumption is of particular benefit in region-wide and country-wide scenarios, particularly in areas with zero impact on rooftops. PV use for local electricity generation reduces the need to develop long-distance transmission to transmit remote RE sources to load centers. Some countries may have to carry out PV self-consumption as a policy measure for the creation of local value chains and less supply risk due to higher electricity imports.

5.4. Demand for desalination and industrial gas

The integration of water desalination and industrial gas sectors results in additional electricity generation that covers projected renewable water and natural gas demand by SWRO desalination and SNG generation, respectively. In parallel with supplying demand, such integration gives the system additional flexibility, especially for seasonal fluctuation compensation. The availability of RE in Sub-Saharan Africa is sufficient to cover additional electricity demand for producing 320 million m^3 of renewable water and268 TWh_{LHV} of SNG. Moreover, the cost of renewable water seems to be quite affordable at 1.4 €/m^3. Adding 357 TWh_{el} for SWRO desalination and gas synthesis induces an additional installation of RE generation capacities of 128 GW of PV and about 48 GW of wind energy. As well, former long-term gas storage is partly substituted by short-term battery storage. Additional effects as a result of the integration of water desalination and industrial gas sectors include an 8.4 TWh_{el} (- 17.2%) reduction of efficiency losses of storage turbines, a 15.6 b€ increase in annual system cost, 357 TWh increase in the electricity demand, and a 10.6 TWh increase in curtailed electricity. Despite the extra cost for the generation, transmission, and integrating water desalination and gas sectors, the combined benefits as a result of integration result in a 37.2% reduction in LCOS; likewise, the total LCOE decreases by 7.7 €/MWh (- 14.2%). This decrease in total LCOE can be confirmed by the substantial reduction of 37.1% in the cost of storage due to the more flexibility provided to the system by the desalination and industrial gas synthesis sectors. These results are reaffirmed by Castellano et al. [20], who determine that significantly increasing regional integration could save more than 40 bUSD in capital spending, and save African consumers nearly 10 bUSD per year by 2040, as the levelized cost of energy falls from 70 USD/MWh to 64 USD/MWh. At the same time, the cost impacts of the surplus of energy on the total cost are minimal.

5.5. Overall relevance of solar PV

Solar PV technologies emerge as the dominant technologies in Sub-Saharan Africa for the year 2030. IRENA [53,54] estimates that Sub-Saharan Africa has a technical potential of 9261 TWh for both CSP and PV with around plus or minus 50% certainty. This demonstrates that, single-handedly, solar technology is sufficient enough to power about 10 times the electricity demand for Sub-Saharan Africa (866 TWh) based on our estimates. As seen in the area-wide scenario, PV technologies generate 364.9 TWh (38%). Castellano et al. [20] conclude that higher levels of integration would result in larger regional gas options being favored over some of the smaller, in-country solar and wind additions, leading to an increase in carbon emissions. However, the results of this study show that solar PV still dominates with the integration of the desalination and gas sectors for the 100% RE case. As seen in the area-wide integrated scenario, PV technologies generate 635.6 TWh (47.8%). The high share of PV can be explained by the fact that PV is the least cost RE technology in most of Sub-Saharan Africa and the decreasing cost of battery storage further pushes this trend. The vast and desert countries, with the top five being Chad, the Democratic Republic of the Congo [Kinshasa], Mali, Niger and Sudan, hold about 40% of the solar PV potential capacity [20]. However, winds prevail in Kenya-Uganda, Somalia-Djibouti, and West-North because of the excellent wind resources. Solar PV is followed by wind onshore, which generates 138.7 TWh (36.3%). The rest of the RE technologies (including hydro, geothermal and biomass) take up the remaining 18.1% of the energy supply. Based on Breyer and Gerlach [13] and Vartiainen et al. [77], solar PV LCOE are projected to decline by a further 30–40% from 2020 to 2040 as a consequence of progressive efforts to reduce material use, improved efficiency and the development of the manufacturing processes. It is also expected that the end results of a steady decline in PV cost will be the further dominance of PV technologies in the market beyond the year 2030 [14,15,20]. These revelations are in line with the Greenpeace [39] Advanced Energy [R]evolution scenario, which projects that hydropower generation capacity will be outstripped by solar energy after the year 2020 and that hydropower will have a smaller generation proportion of 41 GW (11%) compared to solar energy at 177 GW (47%) by 2030.

All three wind energy dominated sub-regions are net-exporters. Compared to the net-importers like South-Nigeria, the net-exporters have a more favorable renewable resource mix. Cross-border energy supply often also provides greatly enhanced diversification of energy sources, a key component of energy security [42]. The results show that the gains from electricity trade differ between sub-regions depending on resource availability and the resource mix. However, electricity trade in Sub-Saharan Africa requires significant cooperation and coordination among countries. Hence, achieving optimal power trade will require a range of important political, legal, and economic commitments [28]. As the penetration levels for variable renewables connected to the grid rises, it also becomes important to consider the impact on grid stability and reliability. Africa needs a strategic approach to improve its economy based on energy security-development linkage policies. However, diversification of renewable resources, spreading their location over different climate zones, and grid interconnections with neighboring countries can all play major roles in ensuring grid stability and energy security [53,54]. In order to facilitate electricity trade exporting and importing sub-regions, the national utilities will need to engage in long-term bilateral contracts for the sourcing and consumption of electrical energy.

5.6. Large-scale hydropower in Sub-Saharan Africa

The Grand Inga project on the Congo River envisages the installation of 40 GW of hydro generating capacity, which would make it the largest hydro facility in the world [56]. IRENA [56], estimates that around 92% of technically feasible potential has not yet been developed. Given that large hydro projects often have outputs far more than the country's electricity demand, it is necessary to develop these as regional projects. The construction and successful operation of the major hydro dams in Sub-Saharan Africa usually requires cross-border co-operation between countries that may be suffering from political instability and even civil disorder. In such circumstances, achieving the necessary water access agreements across national boundaries may prove challenging. However, it can be assumed that the creation of regional power pools will boost cross-border transmission in Sub-Saharan Africa. The expansion of hydropower capacity is expected to further progress by reaching 93 GW in 2040, with several major projects (such as Inga III and the Grand Renaissance Dam) coming online incrementally over the projection period [48]. In this respect, the water footprint, human displacements as a result of large-scale hydro electricity generation, and the social costs have to be taken into account since many parts of Africa are already experiencing water shortage, with about one-third of Africa's productive area already classified as dry-land [51,74]. Thus, stakeholders have to consider the impact of hydropower development on local populations, their impacts on water use and rights, as well as issues concerning the biodiversity impacts of large-scale hydropower developments. Most refurbishment projects focus on the electro-mechanical equipment, but can involve repairs or redesigns of intakes, penstocks, and tail races. For large hydropower plants, economic lifetimes are at least 40 years, with 80 year lifetimes as the upper limit. Meanwhile, for small-scale hydropower plants, the typical lifetime can be 40 years or less. In this case refurbishment of hydro projects fall into two categories, namely, life extension and upgrades [53,54]. The costs of life extension and upgrades for old hydro plants have been estimated. Moreover, life extensions cost around 60% of electro-mechanical costs and upgrades anywhere up to 90% depending on their extent [53,54]. Considering hydropower has a particular cost advantage compared to other renewable sources that have not yet been amortized, an additional 500 €/kW CAPEX should be considered for old hydropower plants (> 50 years). Considering solar PV and wind energy are cheaper alternatives compared to hydropower, it may be not necessary to build large hydro dams to utilize all the available capacity in Sub-Saharan Africa.

Further review of the energy mix shows contradictions of the results of this research to the IEA [48] Africa Energy Outlook, which reports that the total renewable share will grow to 44% in Sub-Saharan Africa. The findings of this research is that 100% RE is already low cost based on 2030 financial assumption. According to IEA's findings, the power generation capacity in 2040 will include a dominating hydropower capacity mainly based on large-scale hydro power generation providing a 26% supply share. IEA [48] projects that the coal demand in Sub-Saharan Africa is expected to grow for power generation and coal-to-liquid production. However, the immense societal and environmental burden of coal consists of the impacts of lethal chemicals and heavy metal emissions that cause severe health problems and respective high health costs aside from mortality related to air pollutants discharged through coal combustion that is nevertheless not captured. Epstein et al. [27] and the International Monetary Fund [50] have already pointed out that these high costs represent subsidies which places coal electricity in an uncompetitive position to solar PV and wind energy due to its very high societal cost. The most direct risks and hazards are presented by coal sludge, coal slurry, and coal waste impoundments; the total contributions of nitrogen deposition due to eutrophication of fresh and coastal sea water; and the extensive appraisal of impacts owing to an increasingly unstable climate [64].

This study considers the hourly system balance between generation, demand, grid transmission, charging and discharging storage units. The storage units get charged when power generation surpasses demand, thus PV use results in reliance on battery storage, notably during night hours. This makes solar PV a key attribute of battery use. However, solar PV compliments well with wind power generation, especially during night hours to cut down on battery reliance. Additional generation from flexible biomass and hydro dam plants, as well as backup discharge from large-scale storage facilitates grid utilisation and thus significantly reducing storage needs. In the integrated scenario, installed capacities for PV and wind energy increase by 40.9% and 54.9% contrasted to the area-wide scenario, correspondingly, because of the higher demand for electricity, the low cost of PV and wind energy, and enhanced system flexibility. Based on the demand projections for 2030 by IRENA [56], forecasts have a slight dissimilarity from our results. IRENA predicts that RE generation for the whole of Africa (including North Africa) will surpass 1000 TWh, attaining 50% of the total power generation. Around one-third of total power generation will come from hydropower plants with the remainder coming from solar PV, CSP, wind energy, and geothermal. The results of this study clearly indicate that a much higher RE generation could be achieved, mainly driven by low cost solar PV and wind energy.

5.7. Sustainable biomass use

The use of biomass as a replacement for fossil fuels will have a greater impact on a global scale regarding carbon emissions because biomass is considered to be carbon neutral. Biomass is the main source of energy for well over 2 billion people living in developing countries. More than 90% of Africans rely on biomass for fuel, compared to about 20% in Europe [79]. Today, traditional biomass use meets around 60% of Africa's energy demand for heat [39]. Considerable future increases in biomass demand are expected due to the expected growth of world population, improvements in human diets, and increases related to biomass used for energy provision [59]. High, inefficient, and unregulated use of solid biomass energy is a fundamental limitation to attaining sustainability in the energy sector [81]. The growing urban population in Sub-Saharan Africa will result in higher demands for wood fuel, food, and timber, thus a potential increase in biomass use (Tilman et al., 2011). By 2050, as the world population reaches 9.1 billion, per-capita GDP almost triples, and aggregate historical trends in agricultural productivity gains continue [78]. The available land for food production has to be taken into account when biomass is used for electricity generation, especially in Sub-Saharan Africa, where the population has been increasing dramatically. Global food demand is growing rapidly, much of the world's current cropland has yielded well below its potential, and today's global trajectory of agricultural expansion has serious long-term implications for the environment [59]. Biomass can provide diverse sustainable alternatives to fossil fuels, plus new incomes and increased energy security for rural communities. However, for these benefits to be realized, its use must be carefully planned, implemented, and monitored for environmental and social sustainability [79]. Producing biomass feedstocks on highly productive agricultural land could result in food shortages and price hikes or simply displace food production, leading indirectly to more forest clearance. However, at a global level, there are many opportunities to develop plantations on marginal agricultural land and degraded landscapes [80]. The biomass figures taken from DBFZ et al. [24] take into account sustainability regarding land use and crops for food productions.

The role of bioenergy for the future energy mix in Sub-Saharan Africa is strongly debated. The biomass resources available for electricity production for all the scenarios under consideration in this study amount to 355 TWh_{th}/a, which is inadequate when compared to 866 TWh_{th}/a needed to cover the total electricity demand for both the region-wide and area-wide scenarios or to 1224 TWh_{th}/a required for the integrated scenario. However, renewable energy technologies could still play a vital role in cooking and water heating. Globally, 100% renewable energy would need bioenergy from an additional 250 million ha of crops (which represent 5% of global agricultural land) and tree plantations by 2050 plus 4.5 billion m^3 of wood from multiple sources [78]. However, a global or a regional electricity demand can be covered by an optimal renewable mix [56,20,82,32,9]. As seen in the Greenpeace [39] Advanced Energy [R]evolution scenario, renewables can provide 68% of Africa's total heat demand in 2030 and 91% in 2050. The future models will include additional demand sectors for heating, cooking, and mobility. Further review of the energy mix shows a complete contradiction to IEA [48] Africa Energy Outlook, which reports that bioenergy (biomass) use for cooking dominates the primary energy demand with 80% of household consumption. Based on IEA [48] projections, biomass use will reach 5699 TWh_{th} (40% of primary demand) and continue to dictate the energy mix in 2030. The measure at which wood fuel is renewable energy depends on how much is produced or consumed (IEA, 2014). Current biomass assessments and models do not take these land use efficiency measures into account [4]. IRENA [56], estimates that 70% of thermal energy demand will come from coal, oil, and natural gas. However, this comes with a high portion of residue use (30% is a mixture of biomass and waste products).

Forests are the main sources of firewood and charcoal in Sub-Saharan Africa. Projected population growth in regions reliant on traditional wood energy, as well as demand for wood for new biomass production technologies, could expand or intensify the harvesting of forest wood [79]. Deforestation continues to be a major source of greenhouse gas emissions, biodiversity loss and habitat destruction in Africa [60]. Globally, deforestation and forest degradation drive climate change, resulting in about 20% of global anthropogenic CO_2 emissions. Forests in Sub-Saharan Africa are currently largely in the hands of humans, and without intervention, it seems likely that rapid deforestation will continue while reforestation in protected areas is not enough to counterbalance deforestation elsewhere [10]. Around the world, unregulated biomass production is directly related to significant pressure on ecosystems including deforestation, fertilizer use, and pesticide application, with detrimental environmental effects such as groundwater depletion, ecosystem degradation, or biodiversity loss [59]. The ever increasing population in Sub-Saharan Africa requires more wood fuel, and this contributes to a higher proportion of deforestation. In Sub-Saharan Africa, insufficient forest protection policy has led to encroachment on protected forests, which has led to deforestation [60]. Further, developing countries have ambitious biomass targets, but lack supporting legislation [79]. Most Sub-Saharan Africa countries have electricity access targets and policies in place, but fewer have objectives and approaches related to clean cooking [48].

Traditional biomass use is characterized by low efficiency as well as adverse impacts on human health and living conditions from the high concentrations of particulate matter and carbon monoxide, among other pollutants (IPCC, 2012). In Sub-Saharan Africa, almost three quarters of those people using traditional biomass do not have access to energy efficient cooking stoves. The result is wasteful fuel use and serious health effects from wood smoke, which along with coal smoke kills almost 2 million people a year [79]. In this context, non-combustion-based RE power generation technologies have the potential to reduce local and regional air pollution significantly and lower associated health impacts compared to fossil-based energy production. Thus, additional generation from other sources is needed. The results show that wind energy and solar PV are more cost competitive in Sub-Saharan Africa compared to biomass. A closer look at the area-wide scenario reveals that the LCOE for the solid biomass, waste-to-energy, and biogas power plants are 60.6 €/MWh, 86.0 €/MWh and 78.2 €/MWh, respectively, compared to solar PV and wind energy LCOE, which are 26.1 €/MWh and 36.1 €/MWh. Therefore, solar PV and wind are more cost competitive in comparison to biomass when it comes to electricity production. As a consequence, the biomass usage in the model is still low, at 34.3% of the available sustainable resource potential, with solid biomass, waste, and biogas producing 58.5 TWh_{th}, or about 4% of the total generation by renewables. The synthetic natural gas and the heat generated by the system as a by-product of biogas and biomass CHP plants, waste-to-energy incinerators, gas turbines, electrolysers and methanation units has the potential to replace some biomass used for heat purposes. Based on IEA [48], the growth in gas use is insignificant and is focused on cooking and water heating in gas-rich countries, mainly Nigeria, Mozambique, and Tanzania. As illustrated in the energy flow diagrams (Fig. 9, Supplementary material Figs. 7 and 8), the usable heat increases from 74 TWh_{th} per annum for the area-wide scenario up to 106 TWh_{th} for the region-wide scenario. The higher efficiency as a result of interconnectivity plays a key role in the low amount of heat generated in area-wide scenario.

The area efficiency regarding energy yield from biomass in comparison to solar PV indicates reasons for the cost differences. According to Geyer et al. [37], regardless of the crop type and growing conditions, the sunlight conversion efficiency of plants is below 1%. According to Green et al. [41], the solar irradiation to electricity efficiency of PV modules is in the range of 20%, which is also accessible in the markets. Biomass land-use for energy purposes requires 10–40 times more land than the PV based options in same locations.

5.8. Heat and synthetic fuels demand

According to the Greenpeace [39] Advanced Energy [R]evolution scenario, higher efficiency gains can be achieved in the heating sector compared to the electricity sector. About 1000 TWh can be saved as a result of the introduction of high energy standards and highly efficient technologies, e.g. for industrial and commercial process heat, cooking and air conditioning. The waste heat from biomass and gas power plants is evenly distributed over the year. Cooling demand is mainly included in electricity demand numbers and therefore does not generate an additional demand. For the integrated scenario the amount of usable heat is slightly smaller than for the area-wide scenario, at 122 TWh_{th}, due to increased efficiency in gas turbines, which covers the heat losses in methanation and electrolysis. Synthetic fuels can also have an alternative use in mobility. Based on the Greenpeace [39] Advanced Energy [R]evolution scenario, the generation of synthetic fuels will fully substitute fossil fuels in Africa by the end of 2050. Greenpeace [39] estimates that 560 TWh will be utilized for hydrogen generation and 790 TWh for synthetic liquid fuel generation intended for the transport sector. Fasihi et al. [33,32] conclude that renewable electricity based synthetic fuels are a real option for decarbonizing the energy system for the period of the year 2030 and beyond. The findings for the Sub-Saharan Africa 100% renewable resource-based energy system clearly show the potential of the region for RE generation and for a global climate change mitigation strategy. The results of a fairly low LCOE for the year 2030 (in all the considered scenarios) added to the already existing RE policies and low carbon development plans can boost the development of a renewable power system in Sub-Saharan Africa in the coming decades.

5.9. Competitiveness of 100% RE

Renewable energy technologies are cost competitive compared to the high cost alternatives; for instance, the low carbon based energy systems and non-renewable options, such as nuclear energy, natural gas and coal carbon capture and storage (CCS), as highlighted by Agora Energiewende [2]. The LCOE of the alternatives are as follows [2]: 112 €/MWh for new nuclear (assumed for 2023 in the UK and Czech Republic), 112 €/MWh for gas CCS (assumed for 2019 in the UK) and 126 €/MWh for coal CCS (assumed for 2019 in the UK). According to Ram et al. [69], coal CCS CAPEX are around 3891 €/kW in 2030, while the LCOE is around 105 €/MWh. For gas CCS, the CAPEX range from 1934 €/kW to 2118 €/kW in 2030, the respective LCOE ranges from 94 €/MWh to 130 €/MWh. According to Breyer et al. [15], the CAPEX assumed for nuclear range from 6200 €/kW in 2015–6000 €/kW in 2020. Representatives from South Africa's largest utility and policy, where the only nuclear energy programme in SSA is operated, mentioned in early 2018 that nuclear would be not at the top of the agenda and that South Africa simply could not afford nuclear [30]. A report published by the European Commission [29] concludes that CCS technology is not likely to be commercially available before the year 2030. The findings for Europe are assumed to be also valid for Sub-Saharan Africa in the mid-term. Research from climate change modeling, such as Griffin et al. [40] conclude that not having CCS and nuclear energy would be too high in cost and therefore not possible. However, in Luderer et al. [62] and its Supplementary Material, it is stated that the 2050 CAPEX assumptions for solar PV and wind energy in Griffin et al. [40] are 1200–1400 USD/kW and 1000 USD/kW, respectively, which is fine for wind energy but fully wrong for solar PV since we already have today CAPEX which is 10–20% lower and the learning curve is continuing [13,34,77]. More realistic CAPEX assumptions would be 300–400 €/kW in 2050 according to Vartiainen et al. [77]. Such limited solar PV industrial insights are a key reason why in many energy scenarios a misleading conclusion is drawn, that fossil-CCS and/or nuclear fission would be without any alternative.

The 100% renewable resource-based energy system options for Sub-Saharan Africa presented in this work seem to be considerably lower in cost (about 48–57%) than the other alternatives, which have still further disadvantages. Globally, the end use combustion of carbon fuels is the principal source of potential CO_2 emissions, accounting for about 90% of total estimated emissions, on average [44]. Climate change mitigation is one of the key driving forces behind a growing demand for RE technologies. The price of emissions could influence electricity prices, so as to reduce fossil fuel consumption and to promote cleaner technologies with benefits related to air quality and climate change [35]. Castellano et al. [20] conclude that, if Sub-Saharan Africa aggressively promotes renewables, it could obtain a 27% reduction in CO_2 emissions; this would result in a 35% higher installed capacity base and 31% higher capital spending, or an additional 153 bUSD. The uncertain future value of CO_2 emission abatement will not affect the renewable energy drive in Sub-Saharan Africa. Bazilian et al. [5] foresee a decrease, in relative terms, of carbon-intensive resources in Africa in the coming two decades, even without an explicit focus on climate change mitigation. In addition to reducing GHG emissions, renewable energy technologies can also offer benefits with respect to air pollution, health, and overall welfare compared to fossil fuels. These benefits are related to reduced risks of nuclear melt-down and terrorism, unsolved nuclear waste disposal, remaining CO_2 emissions of power plants with CCS technology, a diminishing conventional energy resource base, and high health cost due to heavy metal emissions of coal-fired power plants. Further nuclear energy produces both operational and decommissioning wastes. The radioactive waste possesses a threat to the environment and is unsafe for humans. The Chernobyl and Fukushima nuclear melt-downs have shown the disastrous effects of nuclear radiation on humans. Nuclear energy also calls for massive subsidies required for development and operation, and loan guarantees. Dittmar [26] also emphasizes the mentioned limitations on nuclear fission, but also points out that the financial as well as human research and development resources spent towards nuclear fusion are both no help towards solving the energy problems in the world and, even worse, these resources are not available for research of pathways towards a low cost energy future.

Policies to promote renewable energy have been established in many African countries over the past decades, but the legal and regulatory frameworks remain inconsistent. Vested interests in the current fossil-based power sector and unwillingness to adjust existing business models are some of the barriers to renewable energy development in the region. However, diverse opportunities to explore renewable energy in SSA will involve establishment of regional cooperation and renewable energy transmission corridors. In addition, decentralized approaches to connect off-grid areas provides a better opportunity to harness the renewable energy resources in the region [68]. A 100% RE-based system is achievable and a real policy option in SSA. Policy action that will restrict new investments in conventional power technologies and enhance RE development is exigent from a long-term perspective.

The findings for the Sub-Saharan Africa 100% renewable resource-based energy system illustrate the capability of the region for RE generation and a global climate change mitigation scheme. The result of a rather low LCOE for the year 2030 (in all the considered scenarios), added to existing RE policies and low-carbon development programs, can boost the development of a renewable power system in Sub-Saharan Africa in the future years.

6. Conclusion

This research work establishes that a 100% renewable resource-based energy system is a technically and economically practical solution for Sub-Saharan Africa. RE technologies can generate sufficient power to provide for all electricity demand in Sub-Saharan Africa for the year 2030 at a low overall cost of 47–58 €/MWh_{el}, and this depends on the intensity of geographic integration and energy sector coupling. The power required to cover PtG technology, and SWRO desalination demand can be produced by RE resources, providing the region with 100% renewable synthetic natural gas and clean water delivery. However, the synthetic gas price is perhaps high compared to current levels, and government regulation and subsidies are still needed to ensure the commercial viability of this synthetic fuel.

In the recent past, the crucial issue of dependency on biomass energy has widely contributed to deforestation in various countries in Sub-Saharan Africa. This problem can be dealt with by shifting to a least cost energy mix with additional generation from solar PV and wind energy. The HVDC interconnection of the sub-regions and the integration of gas and desalination sectors significantly influences the mix of renewable technologies and thus the storage requirements for the energy system. This results in a reduction of the required generation and storage capacities, thus reducing the total LCOE. Meanwhile, PV self-consumption causes a moderate increase in total electricity costs of about 3–4%, which may be outweighed by other positive effects.

Industrial SNG generation as seen from the integrated scenario increases demand side flexibility and can also be used for long-term storage as a by-product service as a consequence of reducing reliance on battery storage. The system further can curtail heat losses through SNG production, and this results in flexibility and system cost reduction.

A fully integrated renewable energy system has to be simulated and deeply studied to understand the findings for Sub-Saharan Africa better. However, this research work indicates that a 100% renewable resource-based energy system is a real low cost option for the near future.

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Appendix A. Supporting information

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Visualizing National Electrification Scenarios for Sub-Saharan African Countries

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Abstract: Some 630 million people representing two-thirds of all Africans have no access to electricity, which is identified as a key barrier towards further development. Three main electrification options are considered within our work: grid extensions, mini-grids and solar home systems (SHS). A methodology is applied to all sub-Saharan African countries to identify in high geospatial resolution which electrification option is appropriate taking into account datasets for night light imagery, population distribution and grid infrastructure. Four different scenarios are considered reflecting grid development and electrification constraints due to low population density. The results clearly indicate a dominating role of SHS for achieving a fast electrification of the not supplied people. The share of supplied people by mini-grids is found to be rather low while grid extension serves a large share of the population. The decisive factors for these distinctions are population density and distance to grid. We applied several scenarios and sensitivities to understand the influence of these key parameters. The highest trade-off happens between SHS and grid extension depending on the selected thresholds. Mini-grid deployments remain in the range of 8 to 21%.

Keywords: off-grid; rural electrification; solar home systems; mini-grid; grid extension; geographic information system (GIS); sub-Saharan Africa

1. Introduction

In the last decade many interventions, projects and programmes targeting rural electrification in Africa have been initialized by international and national stakeholders. Nevertheless, in sub-Saharan Africa a population greater than 630 million people (two-thirds of all Africans) still lack access to electricity with an overall low electrification rate of 35% [1]. Additionally, the ones already connected to electric power supply are facing high costs and suffer from a poor power supply quality due to frequent power outages [2]. The low quality of supply is hindering economic growth in Africa [3,4] and estimated real GDP losses for the entire continent are at least 2% per year [5]. The absence of electricity affects the development opportunities of the African population, especially in rural areas and negatively affects healthcare supply and education. Despite successes in certain large countries such as South Africa and Ghana, the number of people without access to electricity actually rose in 37 countries in the region since the year 2000 [6]. This highlights the urgent need for developing electricity access solutions for the African continent especially as it is expected that population growth, urbanisation and digitalisation will rapidly increase energy demands [2]. Such interventions are in line with the Sustainable Development Goals (SDG) announced by the United Nations (UN) to target several development goals until 2030 with access to sustainable energy for all (Goal #7) being one of them.

Achieving SDG 7 through rural electrification in sub-Saharan Africa is a special challenge due to the large distances, a lack of capital, data paucity and a shortage of expertise [7]. The traditional approach of extending the existing grid is often not economically feasible, especially in remote rural areas with low population densities as the required investments cannot be amortized within a reasonable time frame. Additionally, many sub-Saharan African countries face a low grid quality with frequent power outages of several hours due to poor maintenance and overload of the system [7]. This concludes that the conventional approach of centralized electrification cannot solely solve the energy access challenge in sub-Saharan Africa.

In contrast to centralized approaches, decentralized approaches prove to be increasingly interesting especially with higher maturity and decreased costs of PV technologies and batteries [8]. For single households solar home systems (SHS) represent an easy way of supplying electricity to serve basic needs such as lighting, radio, digital music or mobile phone charging [9]. PV hybrid mini-grids even allow 24/7 electricity supply for communities or remote industries [10–12]. Thus, with these technologies a decentralized electrification approach seems possible in a cost-effective and environmental friendly way. Providing electricity by off-grid renewable energy technologies could allow for a leapfrogging of grid based electrification similar to the development in the telecommunication sector [13].

Despite of the opportunity that decentralized approaches such as SHS and mini-grids display for accelerating rural electrification, a big knowledge gap remains exactly where such approaches should be favoured over centralized ones which is grid extension. We contribute to overcome this knowledge gap by conducting a spatial feasibility assessment of the aforementioned electrification options; namely they are SHS, mini-grids and grid extension for different scenarios. Key parameters for assessing the feasibility are the existing and planned grid infrastructure and population density. The results enable policy makers, investors, and other stakeholders of the electrification sector to allocate their resources accordingly and to set the right framework conditions for certain electrification options. In addition this geospatial analysis allows understanding the total numbers to reach 100% electrification rates in sub-Saharan countries for the different electrification options. Therefore the results are of international interest. In addition, rural communities can better understand the local feasibility of electrification options and take action accordingly. Finally we provide comparable insights for all sub-Saharan African countries based on a geospatial analysis.

The presented paper visualizes national electrification pathways for sub-Saharan African countries. Thereby it contributes to the discussion whether centralized or decentralized approaches shall be applied for electrifying vast areas of the African continent. The paper is structured in the following way: Section 2 presents the literature review on electrification planning tools. The applied methods and datasets are described in Section 3. The results are provided in both an aggregated and detailed way for all sub-Saharan African countries in Section 4. The results are discussed in Section 5 and, Section 6 concludes the discussion.

2. Literature Review

The scientific community agrees that access to electricity is a key prerequisite for enabling economic and social development [14]. The impact of electricity access for development is confirmed by several scientific and applied case studies which revealed significant positive impacts, for example on household income, expenditure, health care, and educational outcomes [15–25]. In particular for grid [26], SHS [27] and mini-grid [28] electrification the beneficial impacts on households with regard to illumination and access to information have been underlined while a direct economic impact remains uncertain for grid [26] and SHS [27] based approaches.

Various electrification strategies from grid extension to decentralized small-scale energy generation have been analysed by Kaundinya et al. [29] and Bertheau et al. [30]. The two studies stress the complexity of the available options, which require sophisticated decision support tools to identify the optimal electrification solution. Furthermore, it is crucial to understand the socio-technical transformation that is enabled by electrification processes and renewable energies [16,31]. Therefore, decision support systems are needed for practitioners [32], especially since new stakeholders such as private investors are looking for innovative business models that match the novel opportunities in developing countries [33,34].

The complexity of electrification solutions requires advanced planning software tools and instruments to identify least-cost electrification options. Several technical planning tools exist for the design of rural electrification projects, each with different strengths and weaknesses. HOMER Energy is a frequently applied planning tool capable of optimizing and simulating hybrid mini-grid systems [35]. Its application has been demonstrated for a number of developing and emerging countries, such as Nigeria [36], Ethiopia [37], and Cameroon [38]. Furthermore, researchers developed similar tools to HOMER, e.g., Ranaboldo et al. [39,40] and Huyskens and Blechinger [41] including additional features, such as a one minute resolution. Nevertheless, these tools enable the investigation of one specific electrification scheme, while neglecting geographic comparisons for infrastructural planning. Such a spatially resolved comparison of electrification schemes (grid extension, off-grid diesel, off-grid PV) was initially introduced by Szabó et al. [42] and improved with hydro-power as a possible electrification scheme [13]. These studies can be considered as path-breaking for electrification planning despite their rudimentary character in important aspects, e.g., grid extension and cost calculation of off-grid systems. A spatial electrification planning tool specific for small hydropower was developed and applied for Müller et al. [43]. Modi et al. [44] introduced another approach (Network Planner) which enables a more detailed spatial planning for electrification concepts of entire regions or countries. One of the most recent approaches for geospatial electrification planning has been elaborated by Mentis et al. [45]: The authors state that successful electrification is based on geospatial questions and challenges and the usage of GIS potentials is not yet fully utilized [46]. Within an applied research project the Reiner Lemoine Institute (RLI) presented a methodology to combine spatial planning for electrification in Nigeria with energy system modelling, based on a detailed demand study [47]. Results for Nigeria show different results for different regions, based on their spatial relations and attributes. Regions with already existing grid dominance are suggested to be electrified rather by grid extension than by decentralized solutions, whereas electrification options in remote regions have higher shares of solar home system and mini-grid solutions. Additionally, inter-linkages between least-cost planning tools and business models for electrification are missing as well as approaches which can provide first guidelines on how a country can improve its respective electrification strategy. Therefore this study adds to the development of electrification planning tools in sub-Saharan Africa by taking into account demographic parameters for the selection of electrification options. Also, comparative analyses between different countries are lacking, since the described approaches are mostly applied to single countries only, notwithstanding that such a comparison can facilitate a better understanding which solutions might suit best for certain countries and regions.

3. Materials and Methods

The method applied in this paper pursues a geospatial approach and is based on datasets on population distribution and densities, existing and planned grid infrastructure and night light satellite imagery. Finally an electrification scenario for grid extension, mini-grids, and SHS systems, based on local population distribution and grid extension distance, is visualized for non-electrified regions of sub-Saharan Africa.

3.1. Country Selection

Initially the target countries for this study are selected. Due to the focus on electrification the selection was limited to sub-Saharan African countries leaving the North African countries and island states with relatively high overall electrification out. In total 45 countries are considered in this study (detailed information is provided in Figure A1 and Table A1 of the Appendix 7).

3.2. Data Collection

For this study an automatable programming routine is developed by applying open source software such as Python (2.7, Python Software Foundation, Beaverton, OR, USA) [48] and QGIS (2.8, QGIS.org, Grüt, Switzerland) [49]. Furthermore only freely available data on population [50], night light emission [51] and transmission grids [52,53] is utilized and processed, as visualised in Figure 1. As a result, the proposed methodology can be easily applied for further regions, adapted or evolved for more detailed studies.

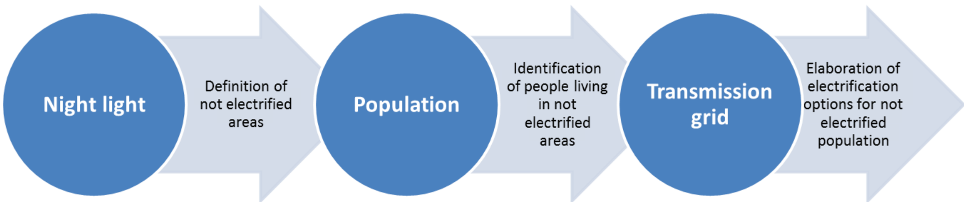

Figure 1. Datasets applied in this research for identifying geospatially resolved electrification options.

Night light imagery is applied for distinguishing the African continent in "electrified" and "not electrified" areas which are defined by light emissions respectively the absence of light emissions (step 1 of Figure 2). Based on this analysis a "mask" layer for "not electrified" areas is created. This layer serves for defining the population living with or without electricity when investigating spatial population datasets (step 2 of Figure 2). Finally for the identified population living without power supply electrification options are elaborated based on their vicinity to the grid and population density (step 3 of Figure 2).

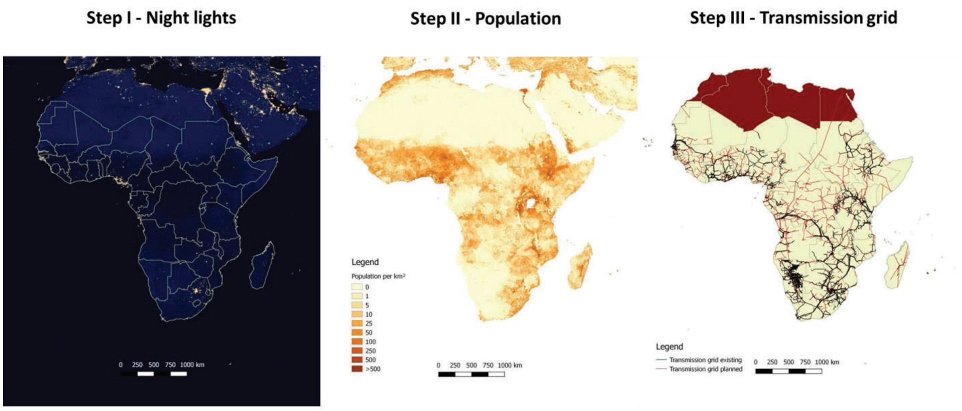

Figure 2. Visualised data used for geospatially resolved analyses structured in step I (night lights), step II (population) and step III (transmission grid).

3.3. Population

For assessing population numbers the *WorldPop* spatial population datasets was applied as shown in Table 1. This source is a compilation of various datasets based on official population estimate data and census data. Information is provided on a 100 m × 100 m resolution and the applied methodology is further described in [54–56]. Individual raster files per country were obtained from the data source. For the overwhelming part of countries recent data from 2014 or 2015 was applied besides that for Lesotho and Congo (Brazzaville) where the only data available was from 2010.

Table 1. Datasets used for analysing the geospatially resolved electrification options.

Data	Source
Population data	[50]
Night lights	[51]
Transmission grids	[52,53] Further individually researched and processed

3.4. Night Light

Night light satellite imagery provided by NASA is applied for defining areas with light emissions as electrified and areas without light emissions as not electrified. The imagery was recorded by the Suomi National Polar-orbiting Partnership (NNP) satellite over a period of 22 days in 2012. National Aeronautics and Space Administration (NASA) Earth Observatory image by Robert Simmon, using Suomi NPP VIIRS data provided courtesy of Chris Elvidge (NOAA National Geophysical Data Center). Suomi NPP is the result of a partnership between NASA (NASA, Washington DC, USA), NOAA (NOAA, Silver Spring, MD, USA), and the Department of Defense. The methodology is further described in [57].

3.5. Transmission Grids

Spatial data on transmission grids was derived from two main sources: The African Development Bank (AfDB) and the United Nations−Department of Economic and Social Affairs (UN-DESA) as shown in Table 1. Both sources provide spatial information on most high voltage transmission lines existing in Africa. Nevertheless for a number of countries no data was available. In such a case grid information was individually researched through approaching national ministries and agencies as well as other relevant sources. In cases of exclusively physical maps on the spatial distribution of transmission grids was provided, the information was digitalized by applying GIS.

3.6. Detection of Population and Definition of On- and Off-Grid Regions

Night light information is crucial for defining electrified areas through the occurrence of light emissions. However, the night light data provides no clear or binary indication on the existence of light. Instead the data is structured in a composite of three bands of which only band one is used for further analysis. Only the first band is chosen because all three bands combined did include water reflections on lakes and on certain land cover in uninhabited areas. Higher values in the first band corresponded best with settlement structures where the source is most likely artificial lighting. The values of this band range from 0 to 255 and are reclassified into binary values which are defined by light or no light. For this reclassification a threshold needs to be defined. Therefore a sensitivity analysis was conducted which compared the identified number of people living without access to electricity when applying night light imagery as indicator to values on electrification rates provided by the International Energy Agency (IEA) [58]. Subsequently, a sensitivity analysis was carried out with night light threshold values from 5 to 25. Figure 3 shows the average derivation from IEA energy access rates according to single night light bands aggregated for all 45 sub-Sahara African countries. From values higher than 12 onwards the derivation is very small. Nevertheless as the derivations are higher for single countries we finally applied a single value for each country which was the closest value compared to the values of the IEA. The individual values are disclosed in Table A2.

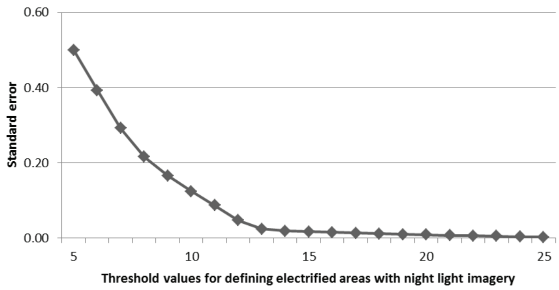

Figure 3. Standard error of calculated electrification rates to IEA statistical electrification rates [58] by using different threshold values for sensitivity analysis of night light imagery. Summary for all considered 45 sub-Saharan African countries.

3.7. Identifying of Population Living in Reach of Power Transmission Infrastructure

For assessing the percentage of non-electrified population living near the power transmission infrastructure, the area around the grid is buffered with a buffer radius of 25 km. Previous research used comparable buffer sizes for assessing grid extension scenarios [42]. Followed by that, the accumulated population number within proximity of the grid is calculated. These results clearly show that a high share of the overall population is living near existing grid infrastructure and highlights the importance of "grid densification" approaches.

3.8. Recommended Electrification Options for All Non-Electrified Regions

Based on the previous analysis of electrified and non-electrified population and respective grid infrastructure, electrification options are analysed and defined for all non-electrified regions. Considered options for electrification are grid extension, mini-grids and SHS. Two different scenarios are developed to account for the specifically low population densities near grid infrastructure (Figure 4).

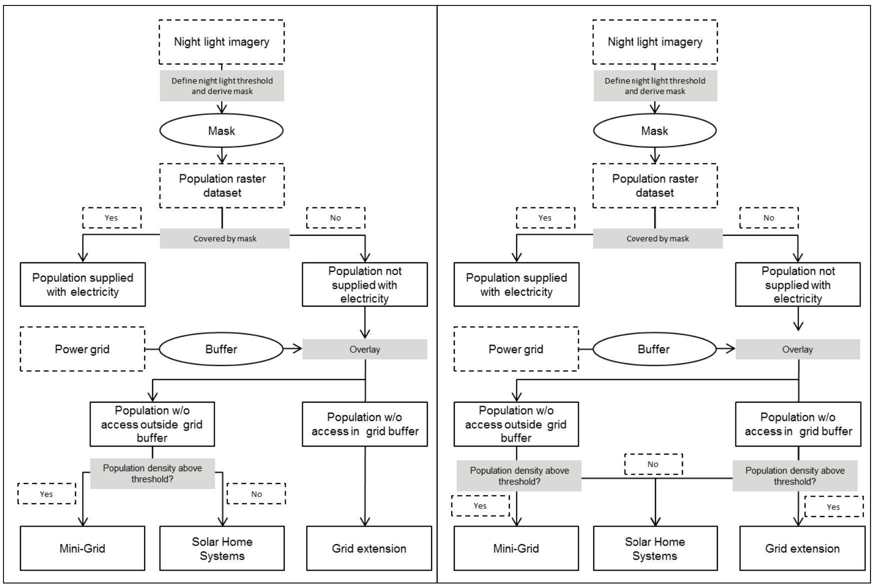

Figure 4. Flow chart of appropriate electrification option selection for excluding (**left**) and including (**right**) the population density within the grid buffer.

In the first scenario the assumed optimum electrification path for people within the grid buffer is grid extension. Outside the grid buffer, mini-grids and SHS are assigned as the best options depending on population density (left side of Figure 4). However, some regions within the grid buffers are characterized by low population densities and grid extension is unlikely the best option for these regions. A further reason for that is the necessity for transformer stations to establish a branch duct to connect a new region, even though it has only a low population density. Therefore, a second scenario is developed where SHSs are defined for all locations with population densities under a certain threshold, also within grid buffers (right side of Figure 4). After a visual sensitivity analysis by using satellite imagery, a population threshold value of 400 persons per km^2 is chosen, as this enabled the identification of larger villages. Additionally other study found that electrification options other than SHS onwards become cost effective from 100 households per km^2 which is comparable to the applied threshold [59].

4. Results-Electrification Scenarios

The applied methodology identifies a total population of 332 million living in areas with night light emissions and 620 million in areas without night light emissions. This results in an electrification rate of 35% which is in line with the official statistics provided by the IEA on energy access in sub-Saharan Africa [60].

For the first scenario considering the existing grid infrastructure our results highlight that the extension of grid by 25 km bears the potential for covering 46.9% of the currently unsupplied population (Table 2). Mini-grids are assigned to regions outside the grid extension zone with a population density higher than 400 persons per km^2. Although mini-grids have the lowest share of 12.4% they still reflect a potential of more than 76.6 million customers. Finally our projection underlines the importance of solar home systems for electrifying Africa as a population of 252.7 million representing 40.8% of the currently undersupplied shall be equipped with SHS under the applied thresholds.

Table 2. Quantification of electrification options depending on excluding (grid-based) and including (SHS-based) the population density within the grid buffer zone based on the existing grid infrastructure.

Electrification Options	Grid-Based			SHS-Based		
	SHS	Mini-Grid	Grid	SHS	Mini-Grid	Grid
Share of not supplied population	40.8%	12.4%	46.8%	71.3%	12.4%	16.3%
Absolute population in million	252.7	76.6	290.3	442.0	76.6	101.1

The relevance of SHS becomes even more emphasised with regard to the SHS based scenario. Here we have assigned areas to SHS supply even in the grid extension area if the population value was lower than the threshold (400 persons per km^2). Under this assumption SHS are the leading technology for electrification of sub-Saharan Africa with the potential of delivering electricity to almost three quarter of the not supplied population (Table 2). Results for all sub-Saharan African countries on basis of the already existing grid are depicted in Figures 5 and 6.

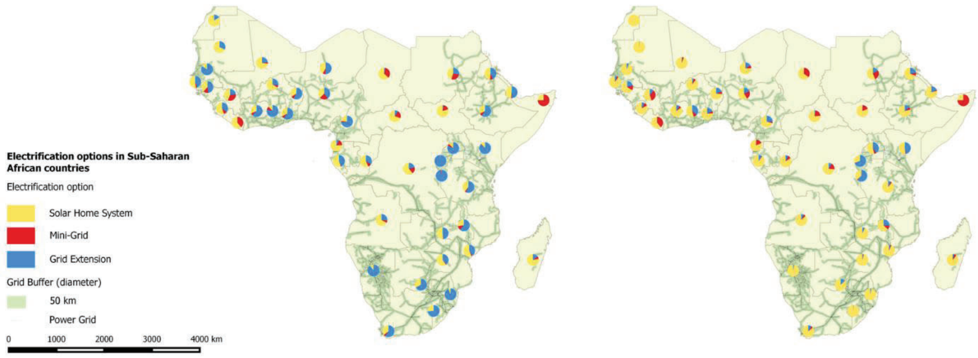

Figure 5. Geographic electrification options for excluding (**left**) and including (**right**) the population density within the grid buffer zone on basis of the existing grid infrastructure in sub-Saharan Africa.

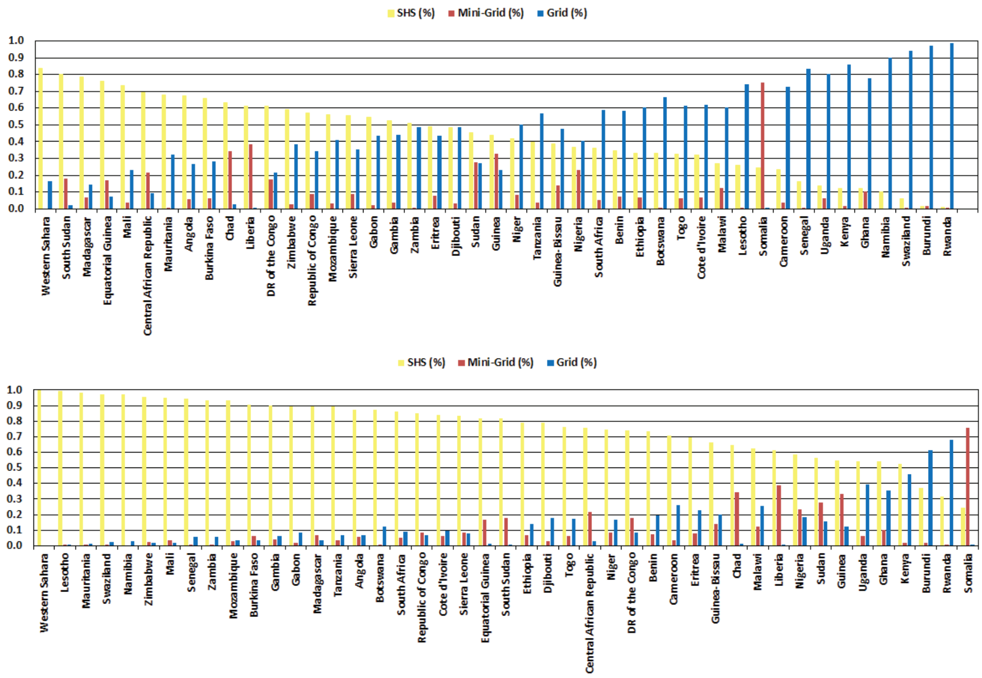

Figure 6. Population share of not yet electrified people to be electrified by SHS, mini-grids and grid extension for excluding (**top**) and including (**bottom**) the population density within the grid buffer zone on basis of the existing grid infrastructure for all countries in sub-Saharan Africa. The detailed numbers are provided in Tables A3 and A4.

In the second scenario we are considering the planned grid extensions on the African continent. When focusing on the grid-based case, the share of grid extension as the most favourable electrification option rises up to 61.6% of the currently undersupplied and covers an additional population of 26.1 million and 65.0 million covered in the first scenario by mini-grids or SHS respectively (Table 3). The results of the SHS based scenario are very remarkable. Under the assumption that grid connection costs exceed economic feasibility in very low populated areas we showcase that grid extension is only covering an additional population of 26.1 million which have been previously covered by mini-grids.

Table 3. Quantification of electrification options depending on excluding (grid-based) and including (SHS-based) the population density within the grid buffer zone based on the planned grid infrastructure.

Electrification Options	Grid-Based			SHS-Based		
	SHS	Mini-Grid	Grid	SHS	Mini-Grid	Grid
Share of not supplied population	30.3%	8.1%	61.6%	71.3%	8.1%	20.6%
Absolute population in million	187.6	50.5	381.5	442.0	50.5	127.2

Detailed data for all sub-Sahara African countries is provided in form of disclosed numbers and a set of diagrams for all four applied scenarios in the Supplementary Materials and Tables A3 and A4.

5. Sensitivity Analysis

A sensitivity analysis was conducted for studying the effects of varying key parameters on the overall results presented above. The sensitivity analysis focuses on the following key parameters: *grid buffer*—determining the extension of the centralized transmission grid and *population threshold*—determining if SHS or mini-grids are deployed for electrification. For the sensitivity analysis we only took into account the existing grid infrastructure. For the grid buffer radius two sensitivity scenarios applying 10 km and 50 km as grid buffer radius were conducted and for the population threshold a sensitivity analysis was applied taking into account a population threshold of 100 persons per km^2.

For the grid based scenario a smaller grid buffer radius of 10 km leads to a higher share of SHS with 55.1% (+14.3 percentage points compared to the base scenario) and a reduced share of grid electrification with 26.9% (−20.0 percentage points compared to the base scenario). The effect on the mini-grid share is less strong with a share of 18.0% of the population. This is an additional share of 5.7% which is assigned for grid electrification in the base scenario (grid buffer 25 km) (Figure 7).

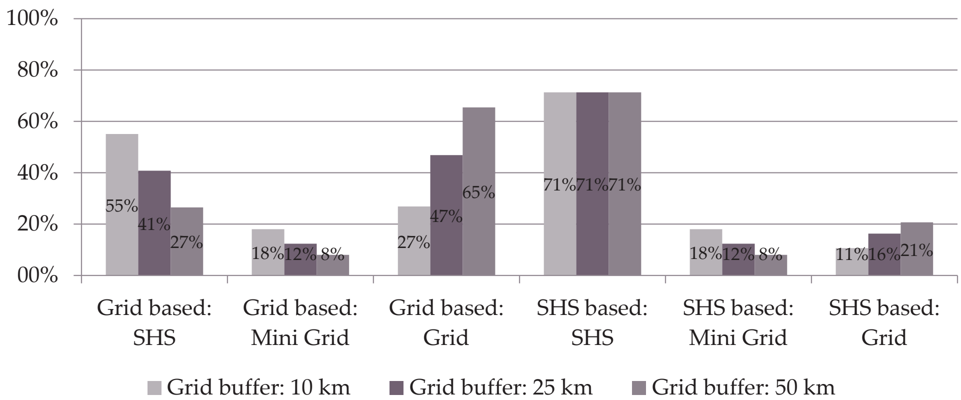

Figure 7. Results of sensitivity analysis for the parameter grid buffer radius. The bar diagram shows the results for all considered countries for a buffer radius of 10 km, 25 km (base scenario) and 50 km for grid based and SHS based scenarios.

A larger grid buffer radius of 50 km for the grid based scenario leads to reverted results: The grid as electrification option increases to a share of 65.5% (+18.6 percentage points) whereas mini-grids with 8.0% (−4.4 percentage points) and SHS with 26.5% (−14.3 percentage points) are decreasing as preferred electrification option (Figure 7).

For the SHS-based scenario the grid buffer radius has no effect on the share of SHS as electrification option since SHS are considered "under" the grid with the population threshold as the decisive parameter for deploying SHS or the grid as electrification option. Therefore the share remains equally high with 71.3% for each of the considered values (Figure 7). Consequently, only the shares for mini-grids and grid electrification are altering: If the grid buffer is set at 10 km the mini-grid share rises by 5.7 percentage points compared to the base scenario at the expense of the grid share. Vice versa when applying a grid buffer of 50 km the grid share rises by 4.4 percentage points at the expense of the mini-grid share (Figure 7).

Finally, we can summarize that varying the grid buffer radius has a significant impact on the SHS and grid share for the grid based scenario and lower impact on the mini-grid share. For the SHS based scenario altering the buffer radius leads to a minor impact solely on the shares of the mini-grids and grid electrification options.

For both grid and SHS based scenario the importance of mini-grids as electrification option rises with a lower population threshold of 100 persons per km^2. Compared to the base scenario, which considers a population threshold of 400 persons per km^2, an additional of 9.0% of the sub-Saharan African population is considered for obtaining electricity access through mini-grids. The share of SHS electrification decreases by the same value as the grid electrification is not influenced by the lower population threshold in the grid based scenario (Figure 8).

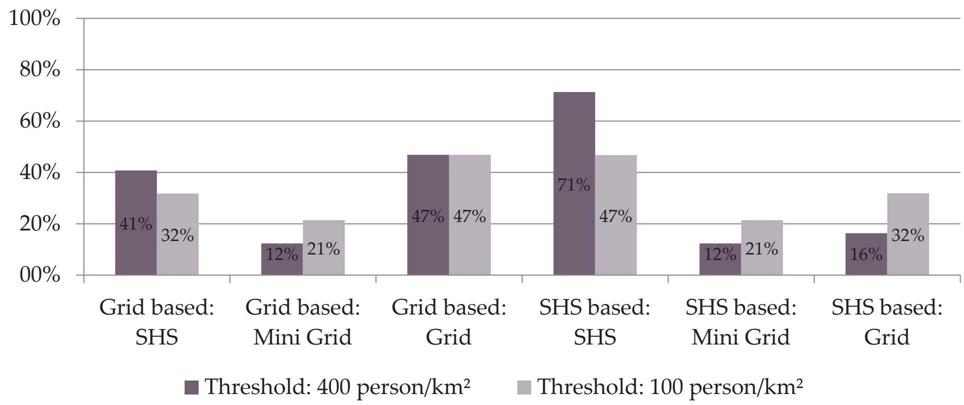

Figure 8. Results of sensitivity analysis for the parameter population threshold. The bar diagram shows the results for all considered countries for the base study with a threshold of 400 persons/km^2 (base scenario) and for comparison for a threshold of 100 person/km^2 for grid based and SHS based scenarios.

For the SHS-based scenario the impact of a lower population threshold is twofold: The share of SHS electrification decreases significantly to 46.7% (−24.6 percentage points compared to base scenario) since more areas are considered for mini-grid electrification (+9.0 percentage points) and additionally further areas within the grid buffer are considered for grid electrification (+15.6 percentage points) due to the lower population threshold (Figure 8).

Finally, we can derive that a lower population threshold would increase the relevance of mini-grids for rural electrification, but also for central grid extension. Both SHS and grid electrification still hold higher electrification shares and with this study we identify a significantly lower share of mini-grid electrification than stated by IEA with 45% [60].

6. Discussion

The presented results highlight the relevance of SHS for achieving universal energy access in sub-Saharan Africa as the share of SHS is at least 30.3% even in the most grid favourable scenario and would even reach 71% in the most SHS favorable scenario. Mini-grids instead contribute to proving electricity access to a rather small portion of the currently undersupplied in each of the scenarios (ranging from 8.1% to 12.4%). This contradicts estimations of the IEA which expect that mini-grid solutions will deliver 45% of connections for missionary electrification until 2040 [60]. Grid extension is the most preferable electrification option when considering the existing and planned grid and leaving the demographic structure of the covered areas out (46.9% and 61.6%). However, if the population density is taken into account the importance of the grid is significantly outweighed by the benefit of the SHS solution.

With our results we are aiming to highlight the complexity of developing electrification scenarios for sub-Saharan Africa. In this study we took the existing infrastructure, distances and population density into account. Certainly it is necessary to consider further parameters for determining the most feasible electrification option for a certain location such as load demands and cost structures.

From an economic perspective it is most important to take into account the necessary investment costs, renewable and conventional resource availability and energy demand structures. This would allow for comparing the different electrification options in terms of levelized costs for electricity (LCOE). Besides the necessary initial investments transportation costs for delivering technology or fuel (in the case of mini-grids) should be incorporated and can contribute to achieving a clearer picture of possible cost structures. The same is also applicable for grid extension. In our study we assume that the entire population in a zone of 25 km around the existing and planned grids could be connected. In this instance taking into account land cover, road networks and water bodies to the potential costs for grid extensions would allow for more precisely determining the costs of grid extension. Generally considering the lowest potential power generation costs allows the elimination of the decisive parameters of distance and population density applied in this study.

Another important aspect to consider in a future study is to discuss whether grid extension, mini-grids and solar home systems can be judged as comparable electrification options. Recent research highlighted that just having an electricity connection by one of the presented technological solutions is not a measure on the quality of the energy access for the households [61]. In addition, there are still some technical limitations on the use of SHS and it is questioned if SHS can supply productive loads. With regard to large demands (e.g., from productive use or newly introduced industries) grid based systems due to their broader technical reach are still considered as an important component for the transition up the energy access ladder [62].

7. Conclusions

The Sustainable Development Goal 7 sets a clear goal of bringing access to electricity to the complete population. The standard electrification option in the developed world is grid-connection for almost all households. This highly capital intensive electrification option may take far too long for developing countries to achieve a fast electrification and supply of basic electricity services. The technically well-established electrification option with mini-grids requires first of all a sufficient enough high local power demand density, which is a function of the population density and in addition substantial upfront investment cost which can imply long amortization periods and challenging financing needs and management capabilities. The basic electrification option using SHS requires comparably less capital investments, shows a fast amortisation and can diffuse comparably fast in rural areas. Based on these constraints a methodology has been developed and applied to sub-Saharan Africa to better understand the relevance of the different electrification options.

The methodology is based on geospatial night light imagery and population distribution plus grid infrastructure. It has been identified a major impact of the population density on the derived electrification options, since it may be questionable whether a sparsely populated area around power lines will be fast grid connected to power lines, given the extra investment and management requirements for transformers and additional branch ducts. This constraint may lead to about 190 million more people electrified by SHS, representing about one third of all unsupplied people. Therefore, the people to gain access to electricity by SHS range from 40.8% to 71.3%. The share of people electrified by mini-grids is not affected by this and is found to be around 12%, which equals to

76 million people. Grid extensions could be the most suited electrification option for 16% to 47% of the unsupplied population, depending on the willingness to connect also areas of a low population density to the grid.

Taking into account the planned grid expansions in sub-Saharan Africa approximately 91 million people more could be electrified by grid extensions. However, this result is relativized, if the population density is again taking into account, since then only 26 million people more could be electrified by grid extensions, instead of mini-grids.

Our results of 8.1% to 12.4% of people to be electrified with mini-grids are in stark contrast to estimates of the IEA, which estimates that 45% of electrification in sub-Saharan Africa will be achieved by mini-grids. The high SHS electrification share identified in our results implies its advantages as a potentially fast and comparably less capital intensive electrification pathway which can be more easily organised by private stakeholders and financed in a high share by the local population. These systems therefore do not need densely populated settlements compared to mini-grids and grid connections, which connect the customers via distribution grids. However the disadvantage may be limited commercial activities due to lack of powering machinery. Nevertheless, the optimised electrification strategy may require a two-step approach: first basic electrification via SHS and second, upgrades to local mini-grids after maximising the utilisation of SHS.

The results of this research indicate that a fast electrification of unsupplied people with SHS is needed to achieve SDG 7. This is based on the large rural areas of sub-Saharan Africa with many people living in scattered settlements far away from the grid. Mini-grids seem not to be a major electrification option, but changing the population threshold shows a higher deployment rate for mini-grids. Thus, with new technologies and business models which could reduce the costs of mini-grids, their implementation rate can be increased. Grid extensions are highly attractive for areas of high population density close to existing grid infrastructure. In summary, our study outlined different electrification scenarios which all underline that all three electrification options are needed to achieve 100% energy access in sub-Saharan Africa. The shares of the different options depend upon the speed of grid extension (defined by grid buffer) and the commercial viability of smaller mini-grids (defined by population threshold).

Supplementary Materials: The following are available online at www.mdpi.com/1996-1073/10/11/1899/s1.

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Author Contributions: Paul Bertheau carried out main parts of the research, including development of the methodology analysing the results and writing the manuscript. Ayobami Solomon Oyewo applied the methodology for all countries, analysed the results and visualized most of the figures. Catherina Cader developed the methodology and contributed much of the input data. Christian Breyer and Philipp Blechinger framed the research questions and scope of the work, checked the results, facilitated discussions, and reviewed the manuscript.

Conflicts of Interest: The authors declare no conflict of interest.

Appendix A

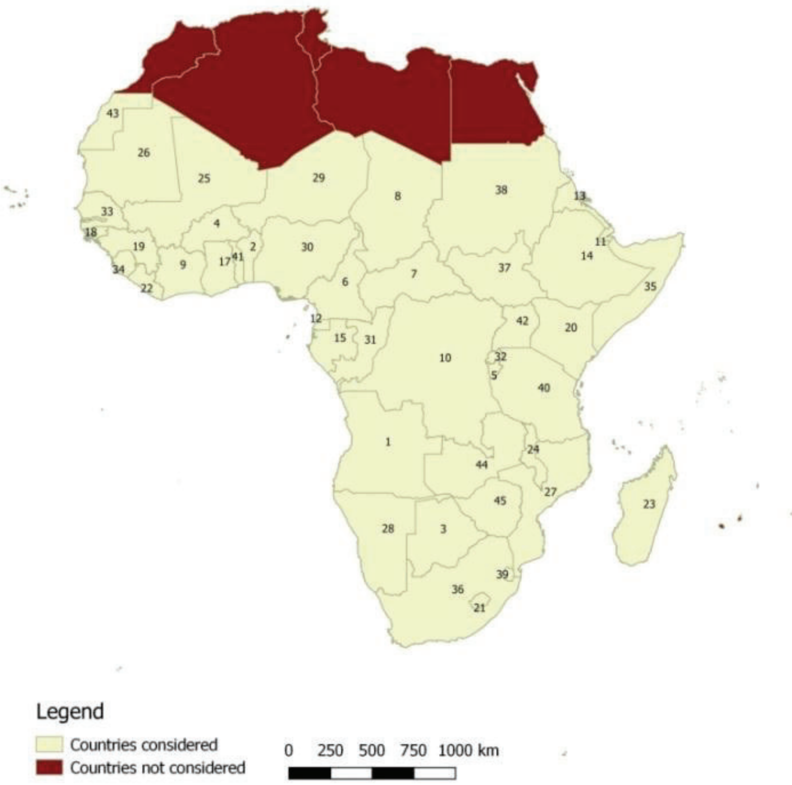

Figure A1. Sub-Saharan African countries selected for detailed geospatial analysis in this research. The numbers for the countries are identtified in Table A1.

Table A1. Sub-Saharan African countries investigated in detailed geospatial analysis in this research.

No.	Name	ISO
1	Angola	AGO
2	Benin	BEN
3	Botswana	BWA
4	Burkina Faso	BFA
5	Burundi	BDI
6	Cameroon	CMR
7	Central African Republic	CAF
8	Chad	TCD
9	Côte d'Ivoire	CIV
10	DR Congo	COD
11	Djibouti	DJI
12	Equatorial Guinea	GNQ
13	Eritrea	ERI
14	Ethiopia	ETH
15	Gabon	GAB

Table A1. *Cont.*

No.	Name	ISO
16	Gambia	GMB
17	Ghana	GHA
18	Guinea-Bissau	GNB
19	Guinea	GIN
20	Kenya	KEN
21	Lesotho	LSO
22	Liberia	LBR
23	Madagascar	MDG
24	Malawi	MWI
25	Mali	MLI
26	Mauritania	MRT
27	Mozambique	MOZ
28	Namibia	NAM
29	Niger	NER
30	Nigeria	NGA
31	Republic of Congo	COG
32	Rwanda	RWA
33	Senegal	SEN
34	Sierra Leone	SLE
35	Somalia	SOM
36	South Africa	ZAF
37	South Sudan	SSD
38	Sudan	SDN
39	Swaziland	SWZ
40	Tanzania	TZA
41	Togo	TGO
42	Uganda	UGA
43	Western Sahara	ESH
44	Zambia	ZMB
45	Zimbabwe	ZWE

Table A2. Difference of calculated electrification rate (Night light band) to statistical electrification rate (IEA) in %.

#	Country	E. Access Rate [52]	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
1	Angola	30%	55%	33%	10%	0%	−6%	−9%	−10%	−11%	−11%	−11%	−11%	−11%	−11%	−11%	−11%	−11%	−11%	−11%	−12%	−12%	−12%
2	Benin	28%	42%	23%	15%	13%	12%	12%	11%	11%	11%	11%	11%	10%	10%	10%	10%	10%	9%	9%	9%	9%	9%
3	Botswana	66%	33%	33%	32%	27%	16%	1%	−9%	−13%	−13%	−13%	−13%	−14%	−14%	−14%	−14%	−14%	−14%	−15%	−15%	−15%	−15%
4	Burkina Faso	16%	79%	73%	63%	51%	36%	23%	15%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	9%	9%	9%	9%
5	Burundi	10%	85%	71%	23%	2%	0%	0%	0%	−1%	−1%	−1%	−1%	−1%	−1%	−1%	−1%	−1%	−2%	−2%	−2%	−2%	−2%
6	Cameroon	54%	−1%	−3%	−7%	−13%	−18%	−20%	−21%	−22%	−22%	−22%	−22%	−22%	−22%	−23%	−23%	−23%	−23%	−23%	−23%	−23%	−23%
7	CAR	3%	23%	15%	13%	13%	13%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%
8	Chad	4%	82%	72%	60%	50%	43%	37%	29%	22%	14%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	9%
9	Cote d'Ivoire	26%	32%	23%	21%	20%	19%	19%	19%	19%	18%	18%	18%	18%	18%	18%	17%	17%	17%	17%	17%	17%	17%
10	DRC	9%	42%	27%	15%	10%	9%	9%	9%	9%	9%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	7%
11	Djibouti	50%	50%	50%	50%	49%	41%	26%	20%	17%	16%	16%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
12	Eq. Guinea	66%	−41%	−42%	−42%	−42%	−43%	−43%	−43%	−43%	−43%	−43%	−44%	−44%	−45%	−45%	−45%	−45%	−45%	−45%	−45%	−45%	−45%
13	Eritrea	32%	68%	68%	66%	59%	45%	20%	−4%	−16%	−24%	−25%	−25%	−25%	−25%	−25%	−25%	−25%	−25%	−25%	−25%	−25%	−25%
14	Ethiopia	23%	34%	19%	9%	1%	−4%	−8%	−10%	−11%	−11%	−11%	−11%	−11%	−11%	−11%	−11%	−12%	−12%	−12%	−12%	−12%	−12%
15	Gabon	60%	10%	9%	9%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	7%	7%	7%	7%	6%	6%	6%	6%
16	Gambia	35%	58%	47%	32%	20%	14%	13%	13%	13%	13%	13%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	11%
17	Ghana	72%	5%	−4%	−9%	−12%	−13%	−13%	−14%	−14%	−14%	−15%	−15%	−15%	−16%	−16%	−16%	−17%	−17%	−17%	−18%	−18%	−18%
18	Guinea	12%	34%	20%	16%	14%	13%	13%	12%	12%	12%	12%	12%	12%	11%	11%	11%	11%	11%	11%	11%	10%	10%
19	Guinea-Bissau	20%	40%	22%	12%	8%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	5%	5%	5%	5%
20	Kenya	20%	66%	45%	30%	20%	13%	10%	8%	7%	7%	7%	6%	6%	6%	6%	6%	5%	5%	5%	5%	5%	5%
21	Lesotho	28%	67%	56%	37%	16%	4%	−3%	−6%	−6%	−6%	−7%	−7%	−7%	−7%	−7%	−7%	−7%	−7%	−7%	−8%	−8%	−8%
22	Liberia	2%	28%	26%	25%	25%	24%	24%	23%	23%	23%	23%	23%	22%	22%	22%	22%	21%	21%	21%	21%	21%	21%
23	Madagascar	15%	56%	46%	28%	14%	9%	7%	6%	6%	6%	6%	6%	6%	5%	5%	5%	5%	5%	5%	5%	5%	5%
24	Malawi	9%	88%	80%	51%	19%	14%	14%	13%	13%	13%	13%	13%	13%	12%	12%	12%	12%	12%	12%	12%	12%	11%
25	Mali	27%	67%	61%	54%	45%	34%	21%	11%	4%	−1%	−2%	−3%	−3%	−3%	−3%	−3%	−3%	−3%	−3%	−3%	−3%	−3%
26	Mauritania	21%	79%	79%	79%	79%	76%	70%	57%	28%	12%	6%	6%	6%	6%	6%	5%	5%	5%	5%	5%	5%	5%
27	Mozambique	39%	46%	20%	−5%	−11%	−12%	−12%	−12%	−12%	−13%	−13%	−13%	−13%	−13%	−13%	−13%	−13%	−13%	−13%	−14%	−14%	−14%
28	Namibia	30%	70%	70%	70%	68%	60%	49%	35%	19%	14%	14%	14%	13%	13%	13%	13%	13%	12%	12%	12%	12%	11%
29	Niger	14%	86%	86%	85%	85%	82%	76%	63%	27%	6%	4%	4%	4%	3%	3%	3%	3%	3%	3%	3%	3%	3%
30	Nigeria	45%	38%	31%	24%	17%	12%	6%	2%	0%	0%	−1%	−1%	−1%	−1%	−2%	−2%	−2%	−2%	−3%	−3%	−3%	−3%
31	Republic Congo	35%	46%	39%	33%	32%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%	30%	30%	30%	30%	30%	30%
32	Rwanda	17%	78%	68%	40%	9%	−1%	−2%	−2%	−2%	−2%	−2%	−3%	−3%	−3%	−3%	−3%	−3%	−3%	−3%	−4%	−4%	−4%
33	Sao Tome and Principe	59%	4%	2%	0%	−2%	−2%	−2%	−2%	−2%	−2%	−3%	−4%	−6%	−8%	−8%	−8%	−8%	−8%	−9%	−9%	−9%	−9%
34	Senegal	55%	39%	34%	31%	27%	21%	15%	4%	−10%	−14%	−14%	−14%	−14%	−14%	−14%	−14%	−15%	−15%	−15%	−15%	−15%	−15%
35	Sierra Leone	5%	28%	22%	21%	20%	20%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	18%	18%	18%	18%	18%	18%
36	Somalia	15%	81%	77%	75%	69%	60%	52%	40%	21%	8%	5%	5%	5%	5%	5%	4%	4%	4%	4%	4%	4%	4%
37	South Africa	85%	66%	6%	−1%	−7%	−12%	−14%	−15%	−16%	−16%	−17%	−17%	−18%	−18%	−18%	−19%	−19%	−19%	−20%	−20%	−20%	−20%
38	South Sudan	1%	52%	24%	10%	4%	2%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
39	Sudan	35%	63%	60%	56%	52%	46%	37%	26%	11%	0%	−3%	−3%	−3%	−3%	−4%	−4%	−4%	−4%	−4%	−4%	−4%	−4%
40	Swaziland	27%	67%	57%	41%	32%	30%	28%	26%	24%	23%	22%	21%	20%	19%	18%	17%	16%	15%	15%	14%	13%	13%
41	Tanzania	24%	67%	59%	43%	28%	13%	2%	−2%	−2%	−2%	−2%	−2%	−2%	−3%	−3%	−3%	−3%	−3%	−3%	−3%	−3%	−3%
42	Togo	27%	49%	32%	20%	14%	13%	13%	12%	12%	12%	11%	11%	11%	11%	10%	10%	10%	9%	9%	9%	9%	9%
43	Uganda	15%	62%	34%	13%	4%	2%	2%	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%
44	Zambia	26%	67%	51%	30%	17%	13%	12%	12%	12%	12%	12%	12%	11%	11%	11%	11%	11%	11%	11%	11%	11%	11%
45	Zimbabwe	40%	58%	52%	36%	17%	1%	−6%	−7%	−7%	−8%	−8%	−8%	−8%	−8%	−8%	−8%	−8%	−8%	−8%	−8%	−9%	−9%

Table A3. Results on a country basis for the grid based scenario (excluding population density in the gird buffer zone).

Country	Not Supplied Population (in Million)	Existing Grid			Planned Grid		
		SHS	Mini-Grid	Grid	SHS	Mini-Grid	Grid
Angola	9.9	67%	6%	27%	46%	3%	50%
Burundi	8.2	1%	2%	97%	1%	1%	98%
Benin	6.5	34%	7%	58%	20%	3%	77%
Burkina Faso	13.1	66%	6%	28%	31%	3%	66%
Botswana	0.7	33%	1%	66%	31%	1%	68%
Central African Republic	4.1	69%	21%	9%	54%	17%	28%
Cote d'Ivoire	11.7	32%	6%	62%	29%	6%	65%
Cameroon	9.7	24%	4%	73%	17%	3%	80%
DR Congo	61.1	61%	18%	21%	36%	6%	59%
Republic of Congo	1.6	57%	9%	34%	33%	6%	62%
Djibouti	0.3	48%	3%	48%	28%	2%	70%
Eritrea	4.2	49%	8%	43%	40%	5%	54%
Western Sahara	0.3	84%	0%	16%	78%	0%	22%
Ethiopia	68.2	33%	7%	60%	25%	5%	70%
Gabon	0.5	55%	2%	43%	31%	2%	67%
Ghana	7.6	12%	10%	78%	8%	8%	84%
Guinea	9.2	44%	33%	23%	23%	17%	60%
Gambia	1.0	52%	4%	44%	36%	3%	61%
Guinea-Bissau	1.3	39%	14%	48%	31%	10%	59%
Equatorial Guinea	0.6	76%	17%	7%	39%	7%	54%
Kenya	33.5	12%	2%	86%	10%	1%	89%
Liberia	3.2	61%	39%	0%	35%	11%	54%
Lesotho	1.4	26%	0%	74%	26%	0%	74%
Madagascar	19.3	79%	7%	15%	58%	6%	36%
Mali	11.5	73%	4%	23%	65%	3%	33%
Mozambique	16.7	56%	3%	41%	49%	2%	49%
Mauritania	3.0	68%	0%	32%	50%	0%	50%
Malawi	14.1	27%	12%	61%	19%	10%	71%
Namibia	1.5	10%	0%	90%	8%	0%	92%
Niger	14.8	42%	8%	50%	36%	7%	57%
Nigeria	96.2	37%	23%	40%	29%	18%	53%
Rwanda	8.2	1%	1%	98%	0%	0%	100%
Sudan	22.1	45%	28%	27%	41%	25%	34%
Senegal	6.0	16%	0%	84%	12%	0%	88%
Sierra Leone	4.6	56%	9%	36%	42%	7%	51%
Somalia	8.3	25%	75%	0%	20%	44%	35%
South Sudan	11.3	80%	18%	2%	51%	6%	43%
Swaziland	0.8	6%	0%	94%	6%	0%	94%
Chad	11.1	63%	34%	3%	58%	30%	12%
Togo	4.1	32%	6%	61%	22%	5%	73%
Tanzania	41.4	40%	4%	57%	33%	3%	64%
Uganda	33.2	13%	6%	81%	7%	3%	90%
South Africa	16.3	36%	5%	59%	32%	5%	63%
Zambia	9.4	51%	1%	48%	41%	1%	59%
Zimbabwe	7.8	59%	2%	38%	49%	1%	49%

Table A4. Results on a country basis for SHS based scenario (including population density in the gird buffer zone).

Country	Not Supplied Population (in Million)	Existing Grid			Planned Grid		
		SHS	Mini-Grid	Grid	SHS	Mini-Grid	Grid
Angola	9.9	87%	6%	7%	87%	3%	9%
Burundi	8.2	37%	2%	61%	37%	1%	62%
Benin	6.5	73%	7%	19%	73%	3%	23%
Burkina Faso	13.1	90%	6%	4%	90%	3%	6%
Botswana	0.7	87%	1%	12%	87%	1%	12%
Central African Republic	4.1	76%	21%	3%	76%	17%	7%
Cote d'Ivoire	11.7	84%	6%	9%	84%	6%	10%
Cameroon	9.7	71%	4%	26%	71%	3%	27%
DR Congo	61.1	74%	18%	9%	74%	6%	21%
Republic of Congo	1.6	85%	9%	7%	85%	6%	10%
Djibouti	0.3	79%	3%	18%	79%	2%	19%
Eritrea	4.2	70%	8%	23%	70%	5%	25%
Western Sahara	0.3	100%	0%	0%	100%	0%	0%
Ethiopia	68.2	79%	7%	14%	79%	5%	16%
Gabon	0.5	90%	2%	8%	90%	2%	8%
Ghana	7.6	54%	10%	36%	54%	8%	38%
Guinea	9.2	55%	33%	12%	55%	17%	28%
Gambia	1.0	90%	4%	6%	90%	3%	7%
Guinea-Bissau	1.3	66%	14%	20%	66%	10%	24%
Equatorial Guinea	0.6	82%	17%	1%	82%	7%	11%
Kenya	33.5	52%	2%	46%	52%	1%	46%
Liberia	3.2	61%	39%	0%	61%	11%	28%
Lesotho	1.4	99%	0%	1%	99%	0%	1%
Madagascar	19.3	90%	7%	4%	90%	6%	5%
Mali	11.5	95%	4%	2%	95%	3%	2%
Mozambique	16.7	93%	3%	4%	93%	2%	4%
Mauritania	3.0	98%	0%	1%	98%	0%	2%
Malawi	14.1	62%	12%	25%	62%	10%	27%
Namibia	1.5	97%	0%	3%	97%	0%	3%
Niger	14.8	75%	8%	17%	75%	7%	18%
Nigeria	96.2	58%	23%	18%	58%	18%	24%
Rwanda	8.2	31%	1%	68%	31%	0%	68%
Sudan	22.1	57%	28%	16%	57%	25%	19%
Senegal	6.0	94%	0%	6%	94%	0%	6%
Sierra Leone	4.6	83%	9%	8%	83%	7%	10%
Somalia	8.3	25%	75%	0%	25%	44%	31%
South Sudan	11.3	82%	18%	1%	82%	6%	13%
Swaziland	0.8	97%	0%	3%	97%	0%	3%
Chad	11.1	65%	34%	1%	65%	30%	5%
Togo	4.1	76%	6%	18%	76%	5%	18%
Tanzania	41.4	90%	4%	7%	90%	3%	8%
Uganda	33.2	54%	6%	40%	54%	3%	42%
South Africa	16.3	86%	5%	9%	86%	5%	10%
Zambia	9.4	94%	1%	6%	94%	1%	6%
Zimbabwe	7.8	96%	2%	2%	96%	1%	3%

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