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Participatory mapping of local green hydrogen cost-potentials in Sub-Saharan Africa

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ABSTRACT

Green hydrogen is a promising solution within carbon free energy systems with Sub-Saharan Africa being a possibly well-suited candidate for its production. However, green hydrogen production in Sub-Saharan Africa is not yet investigated in detail. This work determines the cost-potential for green hydrogen production within this region. Therefore, a potential analysis for PV, wind and hydropower, groundwater analysis, and energy systems optimization are conducted. The results are evaluated under local socio-economic factors. Results show that hydrogen costs start at 1.6 EUR/kg in Mauritania with a total potential of ~259 TWh/a under 2 EUR/kg in 2050. Two third of the region experience groundwater limitations and need desalination at an added costs of ~1% of hydrogen costs. Socio-economic analysis show, that green hydrogen deployment can be hindered along the Upper Guinea Coast and the African Great Lakes, driven by limited energy access, low labor costs in West Africa, and high labor potential in other regions.

1. Introduction

The subject of using green hydrogen to balance seasonal variations of variable renewable energies and to decarbonize challenging sectors [1] has continued to be on the headlines in the last couple of years. This derives from the fact that the variable nature of electricity feed-in from wind turbines and solar photovoltaics requires energy storage across several time horizons. Hydrogen when produced green is believed to be the oil of the future, in one way in addressing the issue of decarbonization and climate change and in another way ensuring sustainable and affordable energy supply [2]. With huge renewable energy potential, Sub-Saharan Africa has the possibility of producing green hydrogen to contribute to its decarbonization agenda and transition to green energy while also exporting across the world.

This topic has raised substantial attention in science resulting in multiple studies investigating the production potential, cost and further implications of green hydrogen on local, national and even global level. Several factors such as groundwater availability, available wind and solar energy resources, local socio-economic context and energy use-demand profiles affect green hydrogen production in terms of cost of

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production and quantity that can be produced Athia et al. [3]. Identifying both qualitatively and/or quantitatively the effect of these factors on green hydrogen production remains a subject of debate due to their variability with climate and location. Here we investigate these factors with special focus on Sub-Saharan Africa. Several studies have analyzed the production costs of green hydrogen on a global scale. Hampp et al. [4] analyzed the cost of energy transport to Germany for six specific pathways and for different carrier types using an energy system model. Moritz et al. [5] calculate a global atlas of export costs for different green hydrogen carriers on a country resolution, not considering transportation costs. Their technical potentials from solar PV and wind sources are taken from Brändle et al. [6] based on a GIS analysis. Franzmann et al. [7] investigated the cost-potentials for liquid hydrogen based on a holistic energy system optimization approach including the whole infrastructure of renewable energy sources, storages, transmissions, electrolysis and hydrogen liquefaction until an export harbor. They illustrated for select countries (Namibia and Libya) that liquid hydrogen exports from Africa exceeding 10 PWh annually could be feasible, with costs starting at 2 EUR/kgH$_2$ in 2050 and local gaseous hydrogen costs starting at 1.50 EUR/kgH$_2$. Meanwhile, IRENA [8] established local gaseous hydrogen costs for the African continent, starting at 1.1 USD/kgH2 in 2050.

Majority of the studies above did not consider water supply limitations in detail or the socio-economic effect of hydrogen production. Only recently, the representation of water limitations has changed towards a more quantitative approach. Mukelabai et al. [9] have considered quantitative water limits per country and concluded that only Namibia, Malawi, Botswana, Gabon and Chad can face issues with water availability for hydrogen production, but neglected environmental flow requirements in their analysis. Tonelli et al. [17] have then set aside also environmental flow requirements for realistic water availability at national level, however, without further disaggregating numbers regionally. Most studies focusing on hydrogen potential in arid regions consider water limitations of some kind by now, however, mostly a qualitative approach is employed [8,14–16] such as an exclusion of countries or regions based on coastal distances or on water scarcity maps like from Kuzma et al. [10]. There also exist studies, investigating hydrogen export potential of single plant projects on a sub-country scale. In the example case of Nigeria, Kamil et al. [11] determine the green hydrogen potential of PV plants in Nigeria in combination with ammonia production simultaneously. Ayodele and Munda [12] investigates the cost of green hydrogen production for 15 different wind parks for South Africa being at 1.33 EUR/kgH$_2$ to ~38 USD/kgH$_2$ for the cost year of 2019. Even as hydrogen generation costs for Sub-Saharan Africa are still uncertain in literature, its economic relevance is perceived as high [13]. Therefore, a detailed and consistent analysis of green hydrogen production potential and costs for Sub-Saharan African considering water supply constraints and socio-economic implications is needed to allow for direct comparison of sub-regions and decision support to develop a green hydrogen economy in Sub-Saharan Africa.

While there is still a lack of integrating water supply constraints in green hydrogen cost-potentials on a sufficient level of detail, assessing groundwater availability is an ongoing research challenge on its own. Groundwater assessments analysis have been performed at global, continental, and regional scales mostly by the hydrology and water resources community. However, these analyses are not directly associated with the energy domain, as evidenced by the absence of a direct link to the energy domain (e.g., hydrogen production projects). For instance, research conducted on groundwater at the regional level has yielded significant findings across various regions of the African continent, including southern Africa [18,19], northern Africa [17–22], and western Africa [23–26]. A detailed and long-term groundwater recharge (i.e., the amount of precipitation that reaches the aquifers [27]) map for the entire African continent, spanning from 1970 to 2019, was developed using ground-based measurements [28]. Recently, a relatively high-resolution (i.e., 10 km) groundwater recharge and sustainable yield maps have been generated spanning five decades (1965–2014) in Africa to assess groundwater sustainability and promote its sustainable use [29]. However, there remains a strong interest in not only quantifying groundwater recharge and sustainable yield under current and future climatic conditions but also linking such resources to hydrogen production, particularly for the African continent. This is of particular importance for understanding the potential and limitations of groundwater resources to better plan for the sustainable production of hydrogen in Africa. To the best of our knowledge, high-resolution, projected groundwater sustainable yield maps quantifying the climate change impacts specifically for Africa and making use of them in hydrogen production have not been published to date.

Similarly, integrating socio-economic considerations remains a challenge, particularly in regions like Sub-Saharan Africa, extending beyond hydrogen production alone. Ensuring energy access, aligned with SDG-7, is a critical component that must be integrated into the evaluation of green hydrogen initiatives. Addressing energy access not only promotes equitable development but also strengthens the societal acceptance of renewable energy projects by directly improving local living standards. This perspective is reinforced by recent findings from surveys conducted with African partners, which reveal that stakeholders prioritize energy access, employment generation, and economic added value over hydrogen production for export [30]. When it comes to evaluating the impact of energy projects, including hydrogen projects, most studies concentrate on national-level analysis, with only a few focusing on higher resolution local impact in the Sub-Saharan African case. Overall, recent research proved that energy projects have positively impacted local populations in Sub-Saharan Africa. These benefits include increased income levels [31], improved education [32,33], and job creation [34,35]. Furthermore, electrification has been linked to poverty reduction by enabling income-generating activities and thus enhancing the quality of life [36,37]. Additionally, energy projects improve health outcomes by reducing indoor air pollution from traditional biomass cooking [38].

In addition to being limited to national level analysis, existing literature focused primarily on the socio-economic impacts of power generation. For instance, Ondraczek et al. [39] studied the socio-economic impacts of solar power projects in East Africa. The impact of wind energy projects on local development was assessed by KR Rao [40]. Kirchherr et al. [41] investigated the economic growth, population displacement effects and environmental impacts of large-scale hydropower projects. While Mariita et al. [42] discussed the socio-economic impact of geothermal power plants on poor rural communities in Kenya. When it comes to green hydrogen projects, there is agreement that these projects can stimulate local economies, however, most studies have focused on the region's readiness to adopt green hydrogen technologies [30,43]. Against this background, the detailed socio-economic impact analysis aims, on the one hand, to assess at a higher spatial resolution the locations of renewable energy projects with the highest potential for promoting energy access. On the other hand, it evaluates the impact of green hydrogen project locations on job creation through direct local employment analysis.

Hence, summarizing the identified gaps in research, developing a green hydrogen economy in Sub-Saharan Africa is a multifaceted challenge calling for joint efforts of different disciplines within one joint approach. All decision and strategy making crucially depends on reliable and detailed data on green hydrogen cost-potentials and further possible environmental and socio-economic implications. Hence, this study applies a multidisciplinary approach based on Ishmam et al. [44] to 31 countries in Sub-Saharan Africa in order to close the existing research gap by providing these urgently needed database. The findings of this study demonstrate that by integrating datasets from the socio-economic, environmental, and energy optimization domains, a comprehensive approach to addressing the multifaceted challenge of hydrogen production in the African context can be formulated. This is further supported by making the obtained results available via a web-based GUI and within the Appendix and within the Supplementary.

2. Methodology

The methodology employed to ascertain the cost-effectiveness of green hydrogen in select regions of Sub-Saharan Africa integrates a range of assessments from multiple scientific domains, as illustrated in Fig. 1. As green hydrogen cost-potentials are contingent on renewable energies, the approach commences with the identification of suitable locations for open-field photovoltaic and onshore wind parks within the study areas. The selection of suitable locations is based on local preferences derived from extensive in-person and online workshops with African stakeholders in policy, industry, energy, and researchers from energy, water, and economics from all considered countries. Beyond open-field PV and onshore wind turbines, which are recognized as the predominant pillars in most greenhouse gas-neutral energy scenarios, we also consider existing and planned hydropower plants as a potential cost-effective renewable energy source. This incorporation is informed by local preferences and does not include any future expansions beyond the existing plans, as outlined in Kirchherr et al. [41]. This approach is aimed at averting the environmental and socio-economic repercussions frequently associated with large-scale hydropower projects. Additionally, geothermal power is incorporated into the Kenyan energy matrix, aligning with local preferences. The simulation of all considered renewable energies is performed on a location-specific basis to derive a highly resolved feed-in time-series. This approach enables the optimization of thousands of local energy systems to meet a gradually increasing hydrogen demand, thereby facilitating the determination of local cost-potential curves for green hydrogen. This process yields numerous model runs, contributing to a comprehensive dataset. The availability of sustainable water supply for hydrogen production is of crucial importance. To this end, a parallel detailed analysis of groundwater sustainable yield is performed using physically based modeling under both present and future climate projections. The technical green hydrogen potential is subsequently constrained by the availability of groundwater. Additionally, the option of seawater desalination is considered as an alternative water source, taking into account its cost. The methodology underpinning these analyses encompasses a comprehensive consideration of socio-technical and socio-economic factors, utilizing composite indicators that have been historically underappreciated in existing research. This approach acknowledges the capacity for local economic development through energy projects, while concurrently addressing potential conflicts and fostering constructive collaboration. A thorough exposition of each step is available in the following subsections, with comprehensive details provided in Ishmam et al. [44].

2.1. Land eligibility assessment for open-field photovoltaic and onshore wind turbines

A comprehensive analysis of land eligibility is conducted to identify suitable areas for renewable energy facilities, with the analysis encompassing 33 criteria and buffer distances for onshore wind turbines and open-field PV (see Table 1 in Ishmam et al. [44]). The analysis generally considers several criteria, including land use, topography, environmental constraints, and social and economic criteria. These criteria are used to exclude areas where wind turbines and PV modules cannot or should not be placed. The land eligibility datasets for this study are derived from Ryberg et al. [45] and Franzmann et al. [7] and are well benchmarked [46,47]. For each African country within the scope of this analysis, local preferences are taken into account through the implementation of specific buffer distances, which are based on contributions from local partners and regional stakeholders. The elicitation of these preferences involved the execution of online and physical workshops, which were supported by the introduction of the stakeholders involved in the underlying methodology, with the aim of enhancing general understanding. The specific exclusion types and buffer distance criteria are summarized in Table 14 of the Appendix.

These local preferences serve as an input for the land eligibility model GLAES [48] and the open-source general-purpose geospatial toolkit GeoKit [49]. These tools offer a high spatial resolution of 100 m^2. The application of exclusion criteria and buffer distances to these suitable areas forms the basis for evaluating the potential for renewable energy. Across these suitable areas, location-specific wind turbines and PV parks are distributed and individually simulated. For a more detailed explanation of the criteria used and the methodology, please refer to Ishmam et al. [44].

2.2. Renewable energy potential assessment

PV and onshore wind energy assessments consist of hourly-resolved electricity generation simulations over a 20-year period (2000–2019) using reanalysis weather data from ERA5 [50], the Global Solar Atlas[1] [51], or the Global Wind Atlas [52] for PV and onshore wind, respectively. The selected 20-year time span allows for the derivation of robust levelized cost of electricity at each individual location, which was derived from the preceding land eligibility assessment. The simulations were performed using the RESKit Python model [53]. Given the significance of hydropower as a primary energy source for numerous African nations, this power source was duly considered following consultation with the project's collaborative partners. For the hydropower assessment, the "normal" generation scenario and hydropower fleets larger than 10 MW of generation capacity for conventional (with dam) and run-of-river hydropower plants derived by Sterl et al. [54] were used. The source time series were then resampled to an hourly resolution to align with PV and onshore wind data. Geothermal energy modeling was executed based on an approach delineated in Franzmann et al. [55].The techno-economic parameters utilized to ascertain the levelized cost of electricity and further particulars are enumerated in the methodology publication Ismam et al. [44] and listed in Table 13 in the Appendix.

2.3. Sustainable water supply assessment

In the finally utilized optimization model to derive the green hydrogen cost-potentials, each region (GID-2) requires a groundwater constraint by providing the groundwater sustainable yield data along with the associated groundwater supply cost. This ensures that groundwater usage is limited to the defined extent. Beyond this threshold, seawater desalination serves as an alternative, unrestricted water supply option with a slightly higher cost. The cost of seawater desalination also accounts for water transport from the nearest coastline, including cross-border transport where applicable. For the assessment of groundwater water availability, the groundwater sustainable yield was first calculated for 2020, 2030, and 2050 under RCP2.6 and RCP8.5 scenarios. As an alternative water supply option for regions without sufficient groundwater sustainable yield, the costs of seawater desalination and water transport via pipeline were considered.

2.3.1. Sustainable groundwater supply

To ensure a sustainable water supply for green hydrogen production, we quantified the long-term (2015–2100) groundwater sustainable yield. The averages from 2015 to 2035, 2015–2045, and 2036–2065 are considered as representative of 2020, 2030, and 2050, respectively under RCP2.6 and RCP8.5 scenarios. The determination of groundwater sustainable yield has been carried out, taking into consideration three key aspects (Bayat et al., 2023): simulated groundwater recharge, estimated environmental flow (i.e., minimum ecological water

[1] "Data obtained from the Global Solar Atlas 2.0, a free, web-based application is developed and operated by the company Solargis s.r.o. on behalf of the World Bank Group, utilizing Solargis data, with funding provided by the Energy Sector Management Assistance Program (ESMAP)."

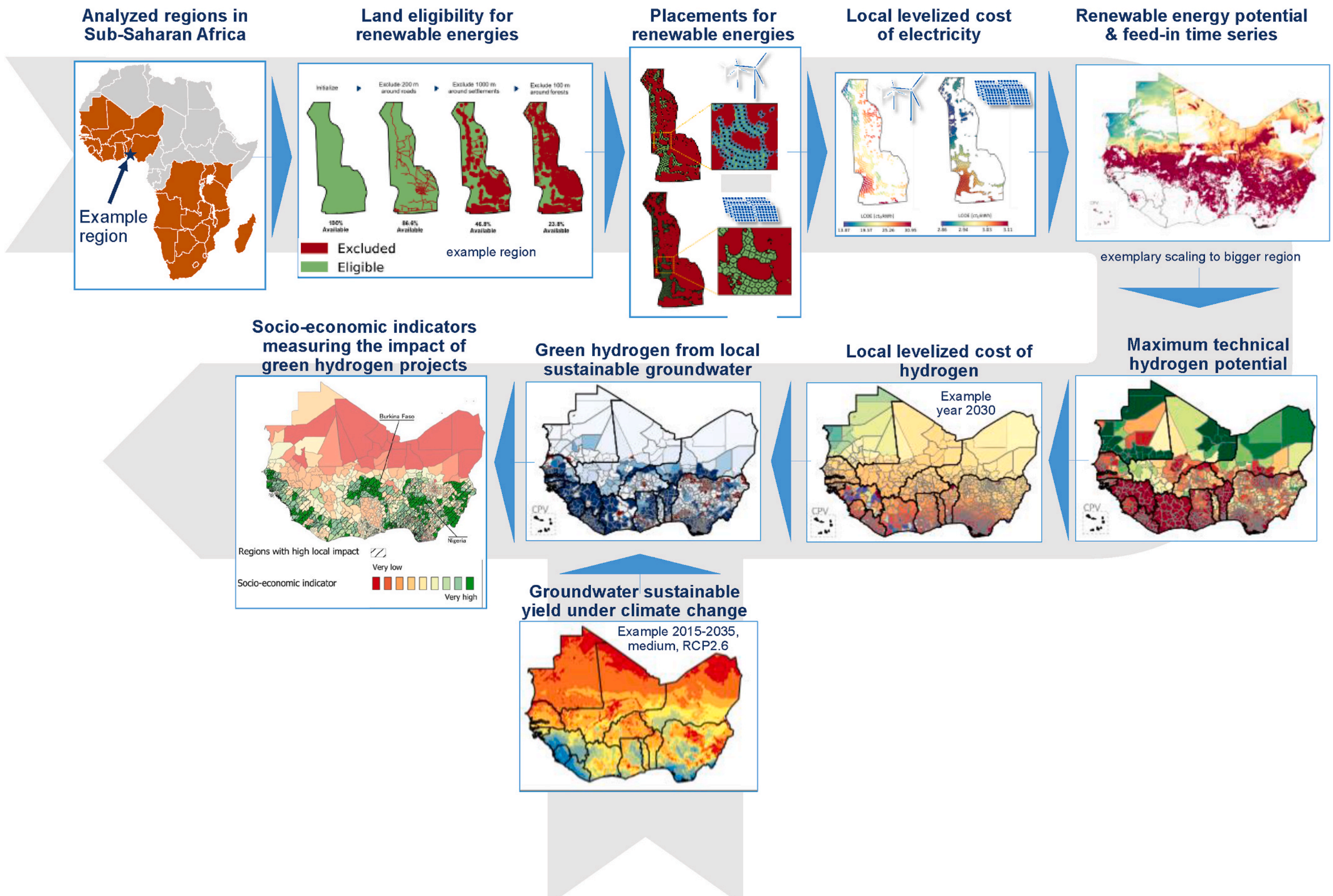

Fig. 1. Stepwise overview of applied methodology based on Ishmam et al. [44].

requirement), and all sectoral water consumptions. Therefore, we accounted for all competing water users by calculating the sustainable yield of groundwater. As a result, the groundwater sustainable yield represents the remaining groundwater available for further usage (e.g., green hydrogen production) after accounting for all human and ecosystem water demands in the regions. In addition, two climate scenarios were considered for the purpose of assessing groundwater sustainable yield: RCP2.6, which is regarded as an optimistic scenario, indicating a limited increase in greenhouse gas concentrations, and RCP8.5, which is regarded as a pessimistic scenario, indicating a prolonged increase in greenhouse gas concentrations to higher values. Climate scenarios are hypothetical representations of future climatic conditions based on greenhouse gas (GHG) emissions, which are used to assess vulnerability to climate change [56]. These hypothetical representations are captured in different setups designed to represent a range of possible emissions trajectories and corresponding radiative forcing levels. These setups are called representative concentration pathways (RCPs). There are four primary RCPs, each delineating distinct radiative forcing levels anticipated by the year 2100 [57]. Noteworthy are the implications of the RCPs on temperature. Projections indicate that the global mean surface temperature will increase by a range of 0.3 °C–0.7 °C for the period 2016–2035. By the end of the 21st century, under the RCP2.6 scenario, the increase is projected to reach 1.7 °C, while under the RCP8.5 scenario, the increase is projected to reach 4.8 °C compared to the historical industrial period. This study utilizes RCP 2.6 and RCP 8.5, representing optimistic and pessimistic emission scenarios, respectively. Additionally, we have calculated three different scenarios for groundwater sustainable yield: (i) a conservative case assuming only 10% of the annual recharge is allowed for green hydrogen production, (ii) a medium case where up to 40% of the annual recharge can be used and (iii) an extreme case where about 70% of annual recharge is allowed for green hydrogen production. Finally, the levelized cost of groundwater extraction was modeled geospatially and assigned to each region individually.

2.3.2. Desalinating seawater and water transport

In regions where sustainable groundwater yields are inadequate, seawater desalination and water transport via pipeline are considered as an alternative. To this end, the cost of water transport to the centroid of each region is based on electricity costs for pumping as well as distance to shore and elevation and the cost for seawater desalination are implemented in the optimization models to derive the green hydrogen potential. As long as the sustainable groundwater potential is not exceeded, the model will select the most economical option among the two water provision options.

2.4. Local green hydrogen potential assessment

The cost-potential curves for local green hydrogen are derived through an optimization model, taking into account the renewable cost-potentials and water supply options. The delineation of each region is based on the "GID-2" definition from GADM (Database of Global Administrative Areas) [58], and each region is modeled as an independent energy system within the ETHOS.FINE framework [59,60]. This framework is designed to minimize overall system costs for each region independently. Each regional energy system has the capacity to utilize onshore wind turbines, open-field photovoltaics (PV), and existing hydropower plants up to their maximum regional potential as renewable electricity input. The production of green hydrogen is modeled using a cost-effective balance of potential curtailment of renewable energies

Table 1
Overall land eligibility for countries in western, southern and eastern Africa.

Country	Onshore Wind Eligiblity		Open-field PV Eligiblity	
	%	km2	%	km2
Benin	0.7	793	0.7	786
Burkina Faso	6.1	16652	25.5	69790
Cote d'Ivoire	0.1	203	0.8	2515
Cape Verde	22.1	905	21.2	866
Ghana	5.8	13749	6.5	15484
Guinea	0.1	143	0.1	299
Gambia	4.6	493	21.4	2278
Guinea-Bissau	0.2	68	13.2	4471
Liberia	0.002	2	2.2	2084
Mali	50.5	632070	48.7	609590
Niger	48.4	573744	49.9	590072
Nigeria	8.9	81385	22.3	202245
Senegal	18.4	36188	21.7	42787
Sierra Leone	0.5	366	8.1	5849
Togo	2.5	1437	33.5	19099
Mauritania	55.6	579261	63.2	585476
Angola	10.5	131131	33.9	1270166
Botswana	50.4	291008	12.7	220637
DR Congo	3.9	92003	21.0	1465824
Comoros	0.2	3	3.3	164
Lesotho	1.5	457	7.9	7223
Madagascar	13.3	78669	9.2	162343
Mozambique	11.7	92247	35.5	839530
Mauritius	0.2	5	5.9	362
Malawi	0.03	30	14.4	50983
Namibia	44.8	369242	9.1	224865
Swaziland	1.2	209	13.4	7009
Seychelles	0	0	0.1	2
Tanzania	1.7	15544	17.3	488083
South Africa	29.8	363378	34.9	1277897
Zambia	5.2	38755	24.6	553623
Zimbabwe	19.4	75937	23.1	271203
Kenya	20.3	117872	31.2	151617
Rwanda	9.0	2275	6.0	153
Uganda	6.3	14950	23	39149

using PEM electrolysis and Li-ion battery storage. The cost-potential curve is achieved by conducting cost minimizations for different expansion steps of the energy systems based on approaches like in Franzmann et al. [7]. This means that the hydrogen demand is increased stepwise until its technical maximum. Further details regarding the cost assumptions can be found in Ishmam et al. [44] and in Table 13 of the Appendix.

It is imperative to prioritize national electricity and hydrogen demand over potential export schemes to ensure a just energy transition [30] and to enhance acceptance [61]. Fig. 2 provides a schematic

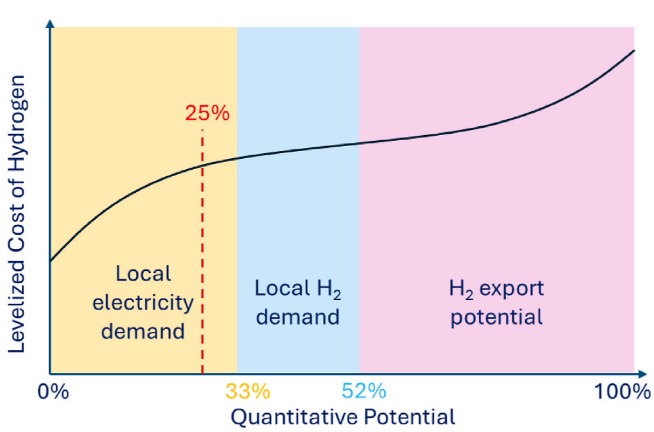

Fig. 2. Exemplary Cost-Potential Curve with 25% potential expansion shown in red and exemplary energy shares set aside to cover local electricity and hydrogen demand first. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

representation of the energy potential that must be allocated to meet domestic energy demands, including their projected growth. This is necessary to assess a nation's capacity for self-sufficiency in energy. The national level is regarded as the more suitable framework for this analysis, as opposed to the GID-2 regions. Consequently, the regional outcomes are aggregated for the purpose of this particular analytical segment. The projected national demands for electricity and hydrogen are based on the "Net Zero 2050″ scenario from the NGFS Climate Scenarios Database [62]. To quantify both electricity demand and hydrogen demand together, relative to the available maximum technical hydrogen potential, the electricity demand value is converted to the equivalent value in hydrogen quantity by applying the conversion efficiency. The comparison between hydrogen potential and demand is performed at the national level under the assumption that national energy policies will seek to cover local demand first.

2.5. Socio-economic impact assessment

Socio-economic impacts were assessed by constructing composite indicators to provide a comprehensive and quantifiable measure of green hydrogen impact on sustainable development goals. The focus of the study was on datasets that provide an indication of sustainable development performance, hence, the sustainable development goals (SDGs) most impacted by green hydrogen projects were chosen as a reference, whether directly or indirectly. In particular, data was collected and cross-checked from a variety of sources to address concerns about incomplete or inadequate data, both during data selection and subsequent analysis. To evaluate the feasibility of using socio-economic indicators to measure the specified SDGs, additional research was conducted, along with spatial data analysis. Prioritization of social development goals based on local visions, as revealed by stakeholder interviews conducted during the project, was also reflected in the study from Brauner et al. [30]. The socio-economic indicator is aggregated based on three sub-indicators as developed in Ishmam et al. [44] including access to energy, macroeconomic effects and other indirect effects (biomass dependence and poverty).

3. Results

This chapter shows key results and findings along the steps of the applied approach. Starting with the land eligibility, the renewable energy potentials for all considered technologies depending on the eligible areas are presented. Afterwards, the sustainable groundwater availability is shown, and the local green hydrogen potentials are described based on all previously presented results. This is complemented by the local socio-economic impact of the green hydrogen production.

3.1. Land eligibility assessment

The distribution of local preferences collected and the resulting land areas eligible for open-field photovoltaics, onshore wind turbines and geothermal power plants (where applicable) are presented. Within these results eligibility patterns and underlying drivers are analyzed.

3.1.1. Land eligibility assessment for open-field photovoltaic and onshore wind turbines

The local preferences for the set of 33 land eligibility criteria, collected and processed accordingly are shown in Fig. 3 with buffer values normalized per criterion. The highest values per criterion are represented by 1 while the lowest are represented by 0. The absolute values of the buffer values received and subsequently applied are listed in the supplementary Table S1 and Table S2. Each gray dot in the figure represents the buffer value received from the countries that responded to the survey. The distribution of local preferences for each criterion highlights the different inclinations of regional stakeholders, including community members, government agencies, and international

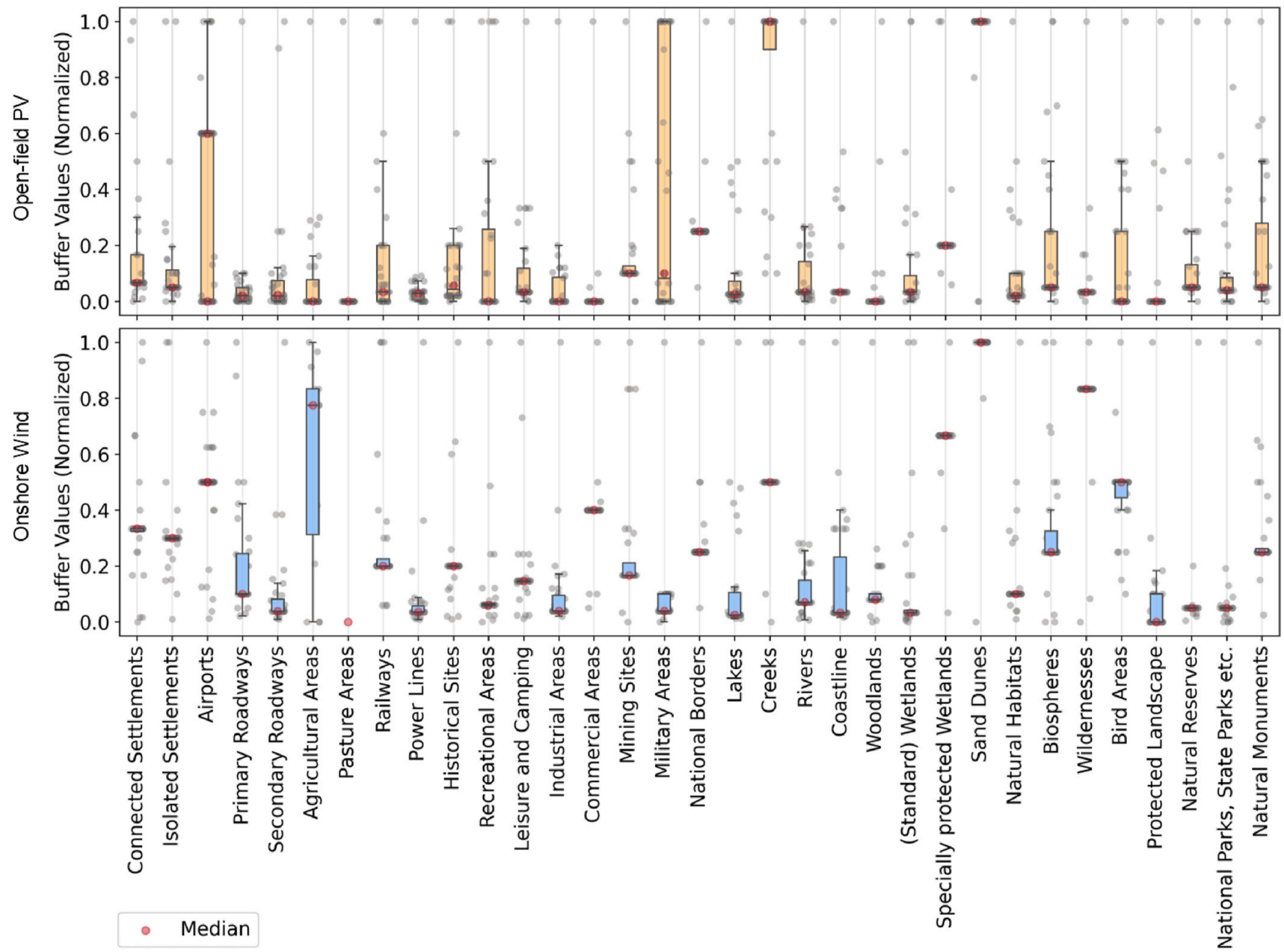

Fig. 3. Distribution of buffer values received for each criterion from partner countries and their resulting medians

institutions in each country.

When comparing the buffer values for open-field PV and onshore wind turbines, it is evident that open-field PV has greater variations. In particular, the buffer values for the criteria "Airports", "Historical Sites", "Military Areas", "Natural Habitats", "Biospheres", "Bird Areas", and "Natural Monuments" show the largest distributions. Conversely, the buffer values selected for onshore wind show the largest deviations for the criteria "Military Areas", "Coastline", and "Protected Landscape".

In order to gain a comprehensive understanding of the process of determining a country's total land eligibility, it is necessary to examine each individual land exclusion criterion separately. Using this method, it becomes clear that certain criteria, such as "Woodlands", "Isolated Settlements", "Connected Settlements", "Agricultural Areas", and "Pasture Areas", lead to the exclusion of large areas of land (over 40–50%) when considering open-field PV (see Fig. 4). On the other hand, for onshore wind, the majority of the excluded land area (over 40–50%) in most countries can be attributed to "Woodlands" and "Isolated Settlements", as illustrated in Fig. 5. Very low overall eligibility in countries such as Guinea resulted from the combined high exclusions of land area by criteria such as "Agricultural Areas", "Pasture Areas", "Secondary Roadways" and "Woodlands".

Fig. 6 (a) provides an overview of the potential land areas identified as potentially eligible for open-field PV parks in West, Southern and East Africa. In the case of West Africa, approximately 36% of the available land is eligible for open-field PV, with larger eligible areas in the northern part of the region and smaller patches throughout the southern part. Eligibility rates per country vary from ~0.1% in Guinea to around 50% in Niger, Mali, and Mauritania. In Southern and East Africa, larger areas of eligibility are found in the central and southern parts of the region. Approximately 24% of the available land in Southern and East Africa is eligible for open-field PV, with eligibility rates per country ranging from ~0.1% in Seychelles to about 36% in Mozambique. In both regions, protected forests and pastures are a major constraint on eligible land, while sand dunes in West Africa also exclude large areas from eligibility.

(b)

Fig. 6 (b) shows the land area eligible for onshore wind turbines, taking into account local preferences. West Africa has an eligibility rate of 32%, while Southern Africa has an eligibility rate of approximately 16%. Within West Africa, eligibility ranges from 0.06% (in Côte d'Ivoire and Guinea) to about 55% (in Mauritania). In southern and eastern Africa, eligibility rates range from 0% (in the Seychelles) to about 50% (in Botswana), with particularly high eligibility rates in the border region between Namibia, Botswana and South Africa. It's worth noting, however, that in both cases most of the largest land areas are excluded due to isolated and connected settlements, forests, and pastures. Detailed eligibility results per country and per technology are summarized in Table 1. These land eligibility results represent potential limited by technical, sociological and environmental criteria, hereafter referred to as "geographic potential". In general, it is not possible to exploit them to their maximum. It should be noted that economic exclusions were deliberately not considered here, as the economic viability of renewable

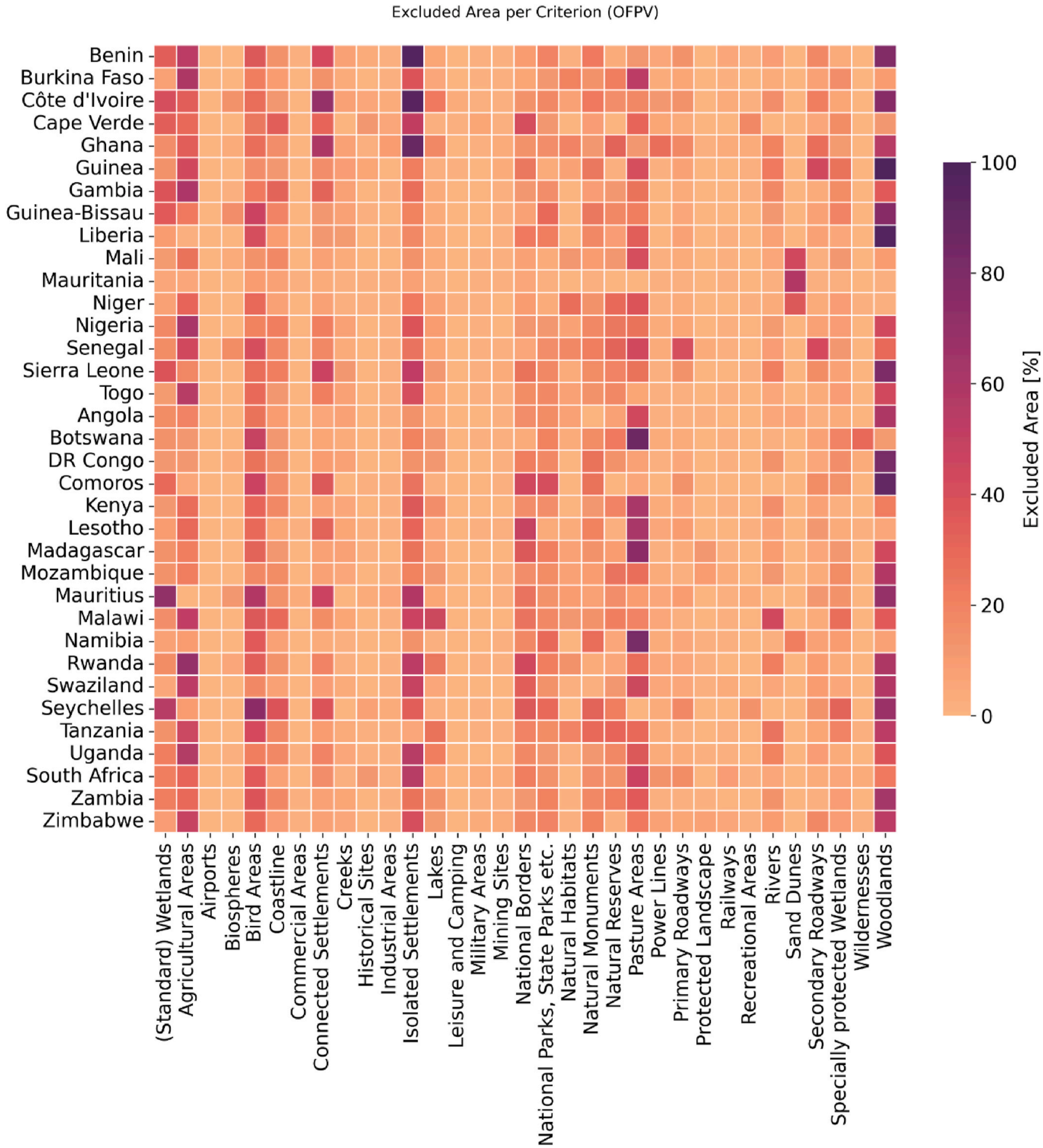

Fig. 4. Excluded area per criterion and country in western, southern, and eastern Africa for open-field PV

energy installations depend significantly on the systemic context. A location with a given high energy cost may be uneconomic in a country or region with abundant low-cost resources and low demand but may be critical in a country with high demand and limited potential and limited cross-border transmission capacity.

3.1.2. Land eligibility assessment for geothermal power plants in Kenya

Due to the central role of geothermal energy in Kenya's energy strategy [63], the study also assessed the potential for geothermal power. The land eligibility assessment revealed an average eligible land area of 42% across the country. Most of these areas are concentrated in the sparsely populated north and northeast of the country. Exclusions in the southwest and south are mainly due to human settlements, where a relatively large safety distance of 2 km should be maintained to avoid structural damage from reservoir stimulation. The central to western part of the country is also ineligible due to mountain slopes, and throughout the country large contiguous exclusion zones for nature protected areas can be seen (Fig. 7). Areas with high and extremely high

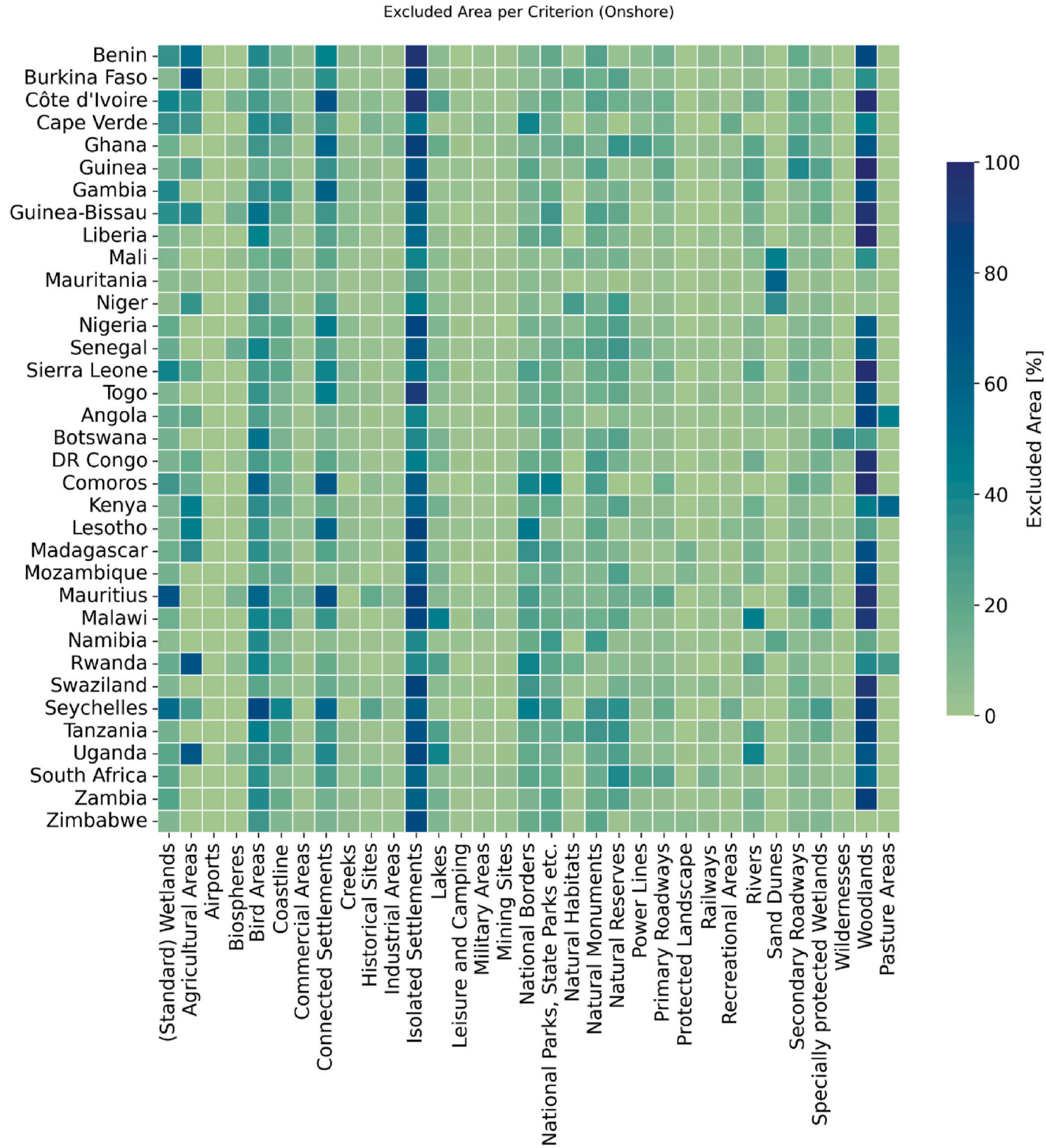

Fig. 5. Excluded area per criterion and country in western, southern, and eastern Africa for onshore wind

water stress according to the Aqueduct Water Risk Atlas [64] were also excluded due to the water consumption of petrothermal plants during stimulation and water losses during operation [65].

3.2. Renewable energy potential assessment

The following section discusses the available capacity potential for the major renewable energy sources, namely open-field PV, onshore wind, hydropower, and geothermal. In addition, the levelized cost of electricity patterns are analyzed to shed light on the underlying drivers and connections.

3.2.1. Open-field photovoltaics

The total installable capacity potential of open-field photovoltaics amounts to 107 TW in West Africa and 123 TW in Southern and East Africa respectively. The pattern in Fig. 8 reflects the land eligibility restrictions that were discussed in Section 3.1.1. The vast majority of the potential is concentrated in the desert regions of the Sahara and the

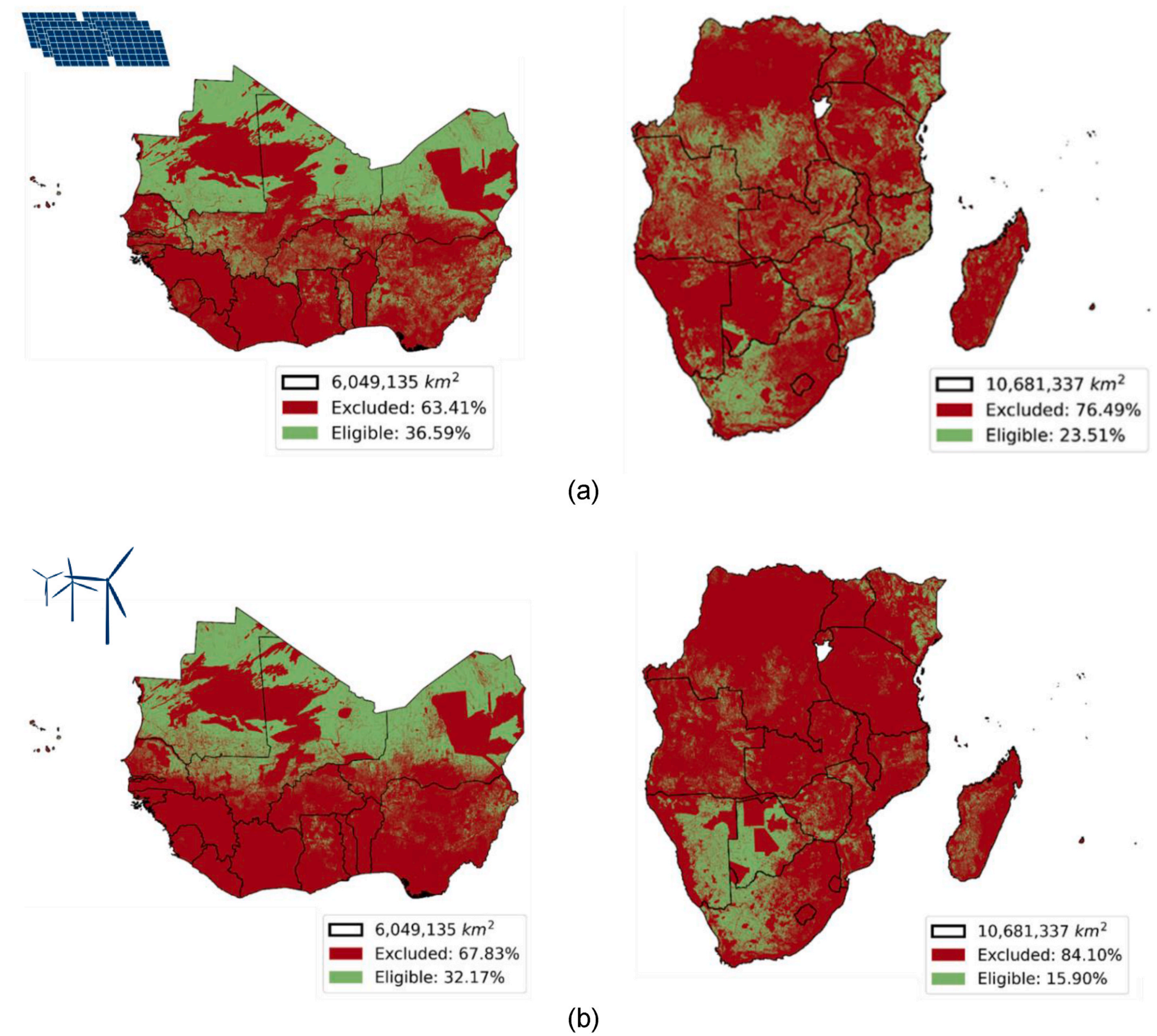

Fig. 6. Land eligibility within west (left) and south-eastern Africa (right) according to the local preferences for (a) open-field PV and (b) onshore wind parks

Nama Karoo in South Africa, extending into Namibia and Botswana. Other notable concentrations of capacity are found in the scrublands and bushlands of Angola, extending into the southern provinces of the Democratic Republic of Congo.

While there is installable potential in all countries, there are some clear zones of greater installable capacity. For example, West Africa has the greatest accumulation of potential in its northern areas whereas Southern and East Africa have it in the south. Compared to these desert provinces, which reach the terawatt range, the capacity potential in most coastal and equatorial countries is much smaller by comparison. It should be noted, however, that the capacity potential is directly related to the available area of the country, which favors the potential in countries with large areas. In addition, densely populated countries tend to have less areas available for PV installations. These countries tend to be in southern West Africa and many equatorial countries. National aggregated potentials (see Appendix Section 1.A.2 or the online GUI [66]) should therefore always be consulted.

Based on the solar farm locations determined in the placement distribution step after the land eligibility assessment, hourly time series and average energy yields were simulated for 20 years using ERA-5 [50] and Global Solar Atlas[2] [51] weather data inputs. The average yield was then used together with the techno-economic parameter assumptions to calculate the levelized cost of electricity for each site, once for each reference decade from 2020 to 2050.

The plant locations in Fig. 9 clearly reflect the land eligibility patterns in Fig. 6. The simulation results reveal achievable levelized costs of electricity (LCOE) between 3.5 Ct€/kWh and 2 Ct€/kWh by 2030 in the best locations in the Nama Karoo ecoregion in South Africa and Namibia, extending into Botswana. In West Africa, the cheapest solar power can be produced in the northern desert regions of Niger and Mauritania. Full-load hours in this region can be 50% higher than along the southern coast, where clouds and higher precipitation near the

ii “Data obtained from the Global Solar Atlas 2.0, a free, web-based application is developed and operated by the company Solargis s.r.o. on behalf of the World Bank Group, utilizing Solargis data, with funding provided by the Energy Sector Management Assistance Program (ESMAP).”

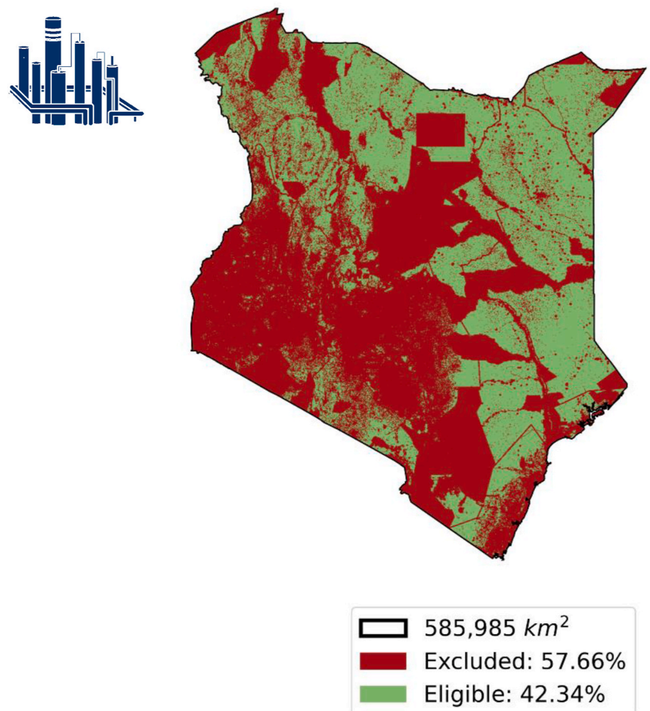

Fig. 7. Land eligibility for geothermal power plants in Kenya

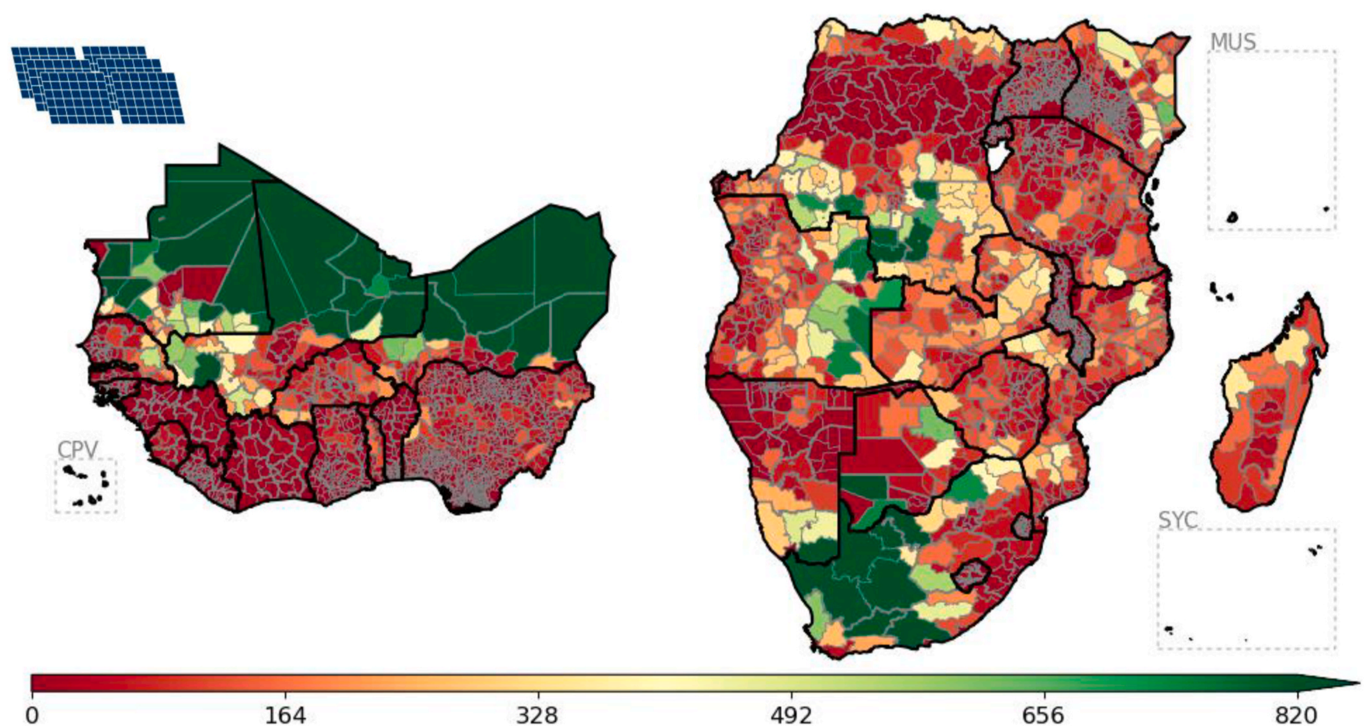

Fig. 8. Open-field photovoltaics capacity potential [GW] in West (left) and Southern/East Africa (right)

equator are the main reasons for the lower energy yield [67]. The above difference translates into an additional 800 FLH/a or a reduction in levelized cost of up to 1.5 Ct€/kWh. This concentration of large available areas and high full-load hours leads to large-scale and low-cost solar electricity potential in the northern parts of West Africa, whereas the demand is mainly along the southern coast. In Southern and East Africa, reduced full-load hours resulting in higher LCOE can be observed near the equator, such as in the Congo Basin especially along the Congolese and northern Angolan Atlantic coasts. To a lesser extent this can be observed all along the Pacific coast as well. The Congo Basin can be

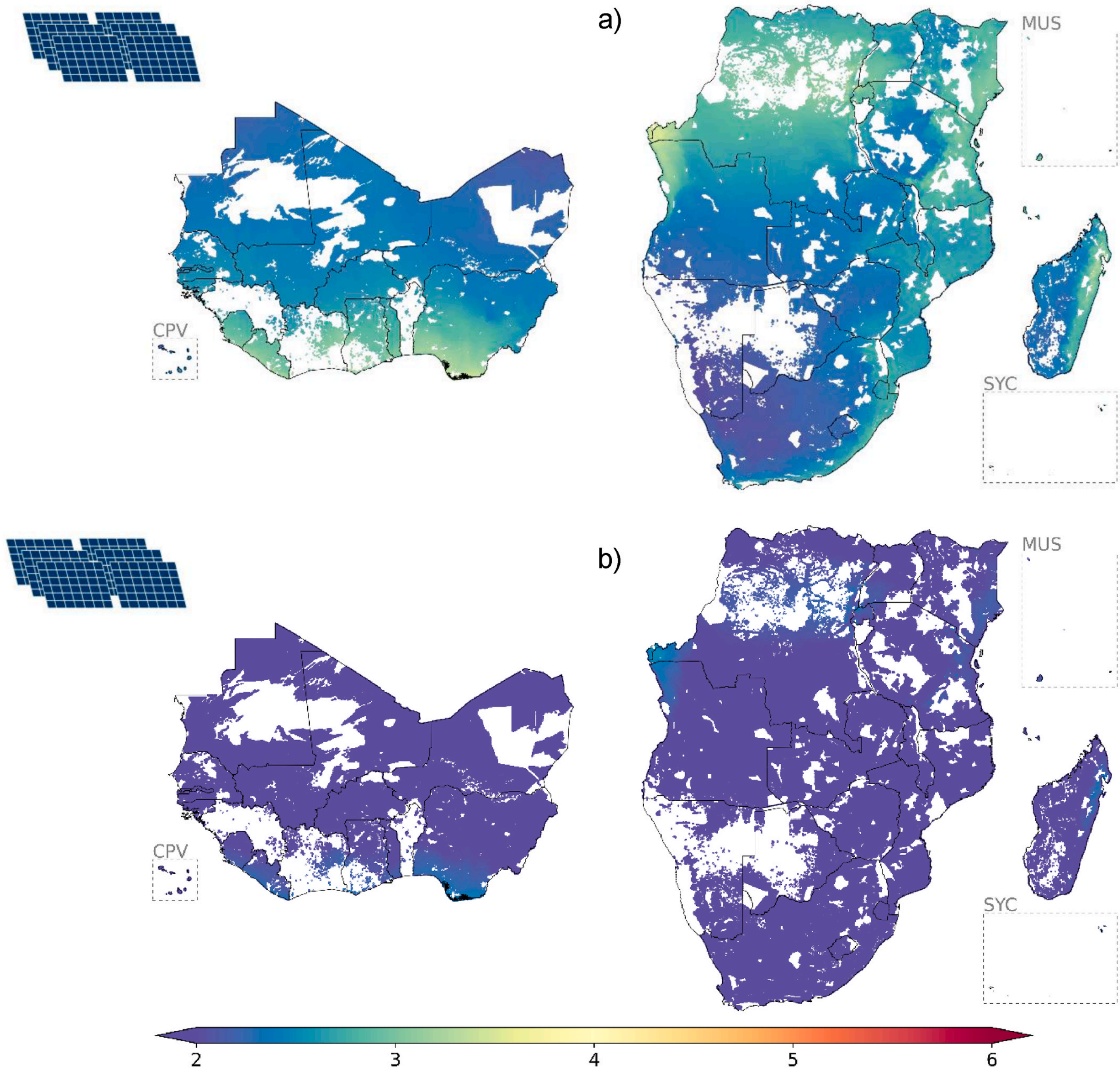

Fig. 9. Levelized cost of electricity [Ct€/kWh] from open-field PV for two years: a) 2030 and b) 2050.

explained by clouds and higher precipitation due to the ITZC [67] while the latter is caused by weather influences due to the Indian Ocean [68].

By 2050, the levelized cost of electricity is expected to decrease further by about 25%, or 0.5–1.0 Ct€/kWh, and then fall below the 2 Ct€/kWh mark in most regions throughout the study area. As a result, the LCOE difference between high- and low-cost regions is narrowed to approximately 1 Ct€/kWh, ultimately causing a progressive but slow reduction in the competitive advantage of the desert regions.

3.2.2. *Onshore wind turbines*

The total installed onshore wind capacity found is 15.4 TW in West Africa and 14.6 TW in Southern and East Africa respectively. Similar to open-field PV, onshore wind turbine capacity is concentrated in the sparsely populated and vegetated desert areas of northern West Africa and the arid border area between South Africa, Namibia and Botswana. Again, the capacity differences between regions are very large. Regions with limited potential, shown in shades of red to orange in Fig. 10, can reach up to 32 GW, which is a very high absolute value for a district-level region. Such regions exist in most countries, especially in Southern Africa.

An analysis of the simulated levelized cost of electricity for onshore wind shows that, on average, the LCOE is significantly higher than for solar PV in the same regions. The amount of onshore wind installations with LCOE in the same range as PV in 2030 (2 Ct€/kWh to 3.5 Ct€/kWh) is about 5% and 9% of the total (71.9 GW in West Africa and 1.3 TW in Southern and East Africa), respectively. In 2050, due to the proportionally larger capacity cost reductions expected for PV, the amount of onshore installations at the corresponding PV LCOE range (1.5 Ct€/kWh to 3 Ct€/kWh) is further reduced to 64.3 GW and 970 GW, respectively.

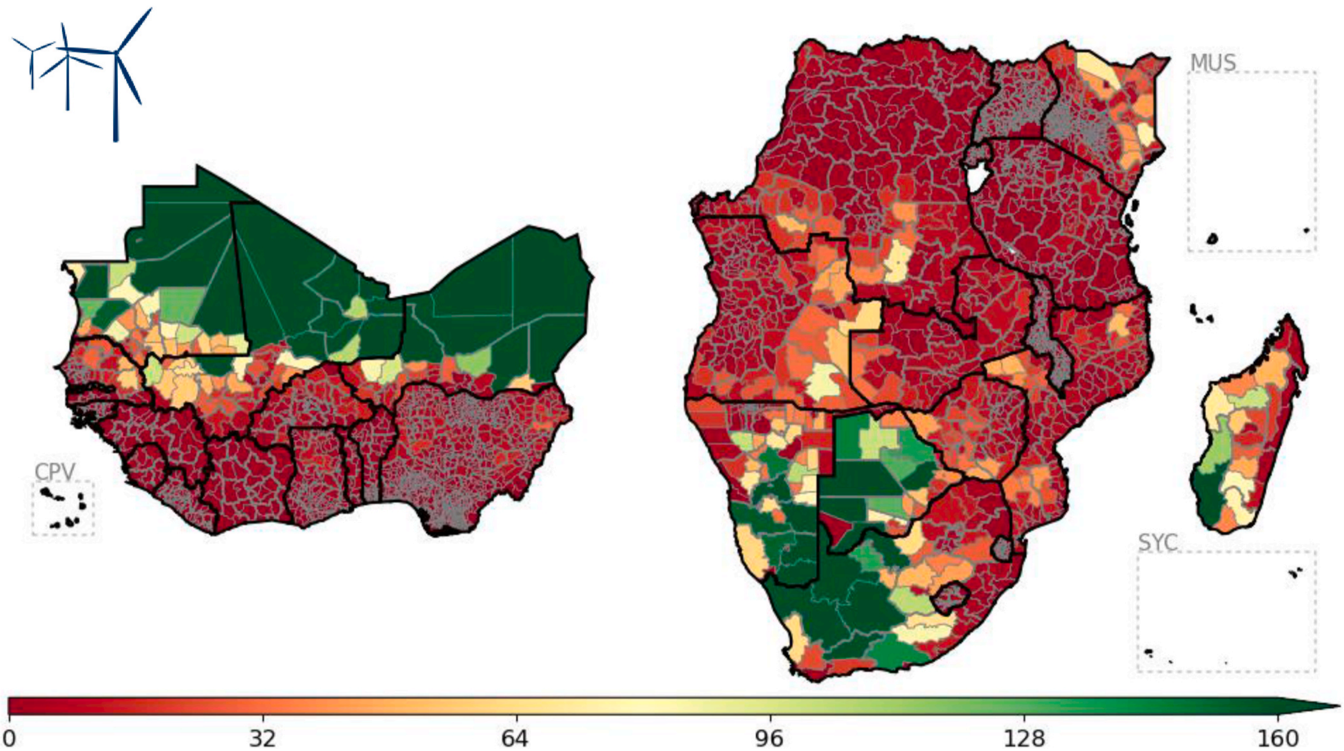

Fig. 10. Onshore wind capacity potential [GW] in West (left) and Southern and East Africa (right)

This means that only about 5% or 9% of the regional onshore wind potential has a LCOE comparable to PV,[3] and its competitiveness is expected to decline over time. A more representative LCOE for onshore wind could be between less than 3 Ct€/kWh and 6 Ct€/kWh, where 10.9 TW can be installed in West Africa and 1.7 TW in Southern and East Africa in 2030. The remaining installations (30% in West Africa and 89% in Southern and East Africa) are located in unfavorable sites, with LCOEs more than double those of PV, although the latter is more constant across the study area (see Fig. 11). Interestingly, the region with the lowest wind power costs coincides in several cases with the best solar locations, most notably the northern West Africa, where large wind potentials meet very low LCOEs. Northwest Mauritania in particular has excellent wind resources, as do some sites in Kenya and Cabo Verde. To a lesser extent, this also applies to the north of Niger and Mali, several locations in South Africa and Madagascar. The subtropical belt along the southern coast of West Africa, similar to the Congo Basin, but also most of the landlocked regions of Southern and East Africa, except for those mentioned above, again has a very low wind energy yield. Towards 2050, the levelized cost of electricity again decreases for wind power plants averaging about −12%, although this is less significant compared to the solar cost reductions discussed above.

3.2.3. Hydropower

In contrast to open-field photovoltaics and onshore wind, the hydropower potential is mainly based on an assessment of existing hydropower plants together with locations under construction or in the planning stage [54]. In 2050, 23 GW were found in West Africa and 61 GW in Southern and East Africa. These future potentials represent almost 17 GW and 47 GW additional installations to the current hydropower fleet respectively. The chosen approach takes into account the fact that theoretical and technical assessments of hydropower potential tend to be overly optimistic, and that their realization would lead to significant environmental and social impacts [69]. By relying on practical and thus feasible locations, a trade-off between sensitive capacity additions and the advantages of hydropower for low-carbon energy generation could be achieved.

Fig. 12 shows in general terms which countries have the most hydropower potential. It shows that countries that were previously less competitive are now the most prominent hydropower locations: DR Congo and Nigeria have the largest feasible capacities at approximately 22 and 10 GW, respectively. This can also be seen when comparing the location of hydropower projects in Fig. 13.

Countries such as Angola, Zambia, Mozambique, and to a lesser extent Tanzania and the much smaller Guinea follow suit. While the precipitation surplus along the equatorial belt may be a limiting factor for solar potential [67], it is beneficial for hydropower potentials. Countries such as Ghana, Côte d'Ivoire, Zimbabwe, and Uganda also use of this opportunity. However, hydropower capacity in the previously low-cost regions of the Sahara, the entire southern tip of Africa, and Kenya is now marginal due to the predominantly arid climate in these regions.

Similar patterns emerge when looking at the achievable levelized cost of electricity (see Fig. 13). Since hydropower costs are assumed to be constant over time, there is no change in LCOE and only 2050, the year with the most locations, is shown in the figure. The lowest cost can be achieved in the Congo Basin, where hydropower is competitive with other renewable energy sources. The main reasons for this are the large discharge quantities combined with comparatively low seasonality in the rainforest. Especially in the eastern Congo, the mountainous terrain also allows for favorable pressure heads.

In regions with higher seasonality hydropower plants cannot operate at full capacity during the dry season, especially if there is no significant reservoir storage available. As a result, annual full load hours are reduced and levelized cost increase. This effect can be seen in the savannas of southern Africa, but also as a south-north gradient in the coastal countries of West African. Several hydropower plants along the

[iii] This percentage refers to the for the total potential of the regions (Western and south and eastern Africa respectively) of Wind compared to PV installation capacity (not generation). Individual countries and sub-regions will have their own proportions.

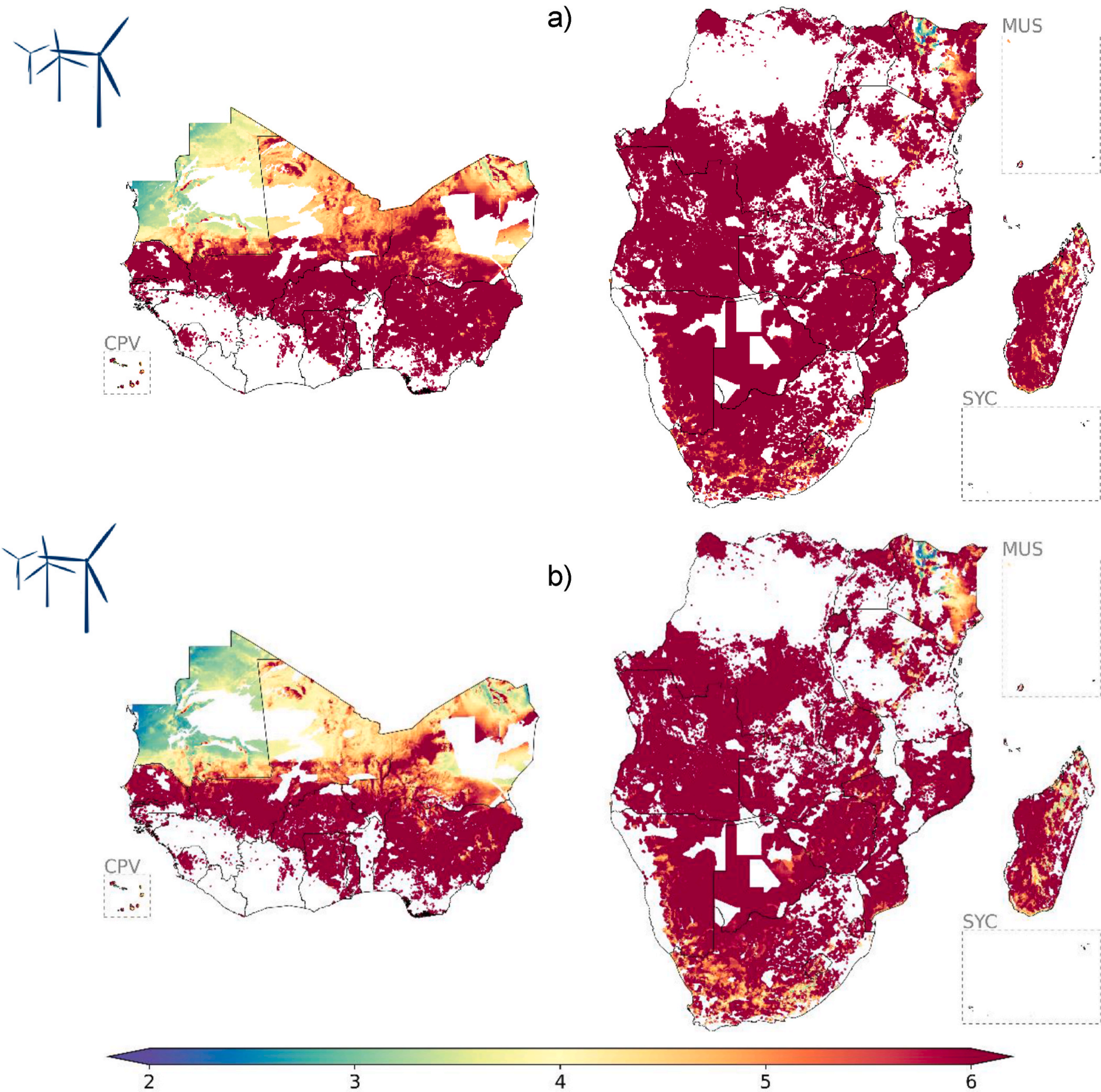

Fig. 11. Levelized cost of electricity [Ct€/kWh] from onshore wind for two years: a) 2030 and b) 2050

Niger river in arid areas of Mali and Niger can serve as an example. The opposite is true for very large rivers where only a minor part of the discharge is required for hydropower plant, for instance those located in the Congo basin and Lake Victoria.

3.2.4. Geothermal power

Given the great importance of geothermal energy to Kenya's energy strategy, geothermal power potentials for Kenya were assessed within the scope of the study. The capacity potential is highest in the northern regions (see Fig. 14). The very low capacities in the southern and southwestern regions of Kenya can be attributed to high population densities and, in the south to the exclusion of protected areas (see Section 3.1.1). The central regions are mainly affected by the exclusion of mountain slopes. The total geothermal capacity potential in Kenya amounts to slightly over 187 GW. This capacity potential is about 116 times that of Kenya's hydropower installations (1.6 GW), about 20% of onshore wind (895 GW), or almost 2.5% of PV (7.5 TW).

The levelized cost of electricity is lowest in the northeast along the Great Rift Valley starting at ~6.8 $Ct_€$/kWh, but to a lesser extent also east of the central mountain ranges towards the Somali border and partly. As these low-cost regions coincide well with the highest capacity potentials, it can be stated that the main geothermal potentials in Kenya are in Turkana and Wajir county, and to a lesser extent also in Garissa and Marsabit. Low-cost locations can also be identified in the southern Rift Valley Province, but the capacity potential in this area is comparatively low, with costs between 6.8 and 15 $Ct_€$/kWh. Beyond these regions, the cost-potential curve rises sharply. In general, geothermal power is more expensive than wind or solar resources in Kenya but has the advantage of being dispatchable. Subsequent processes can therefore achieve almost ideal utilization rates and therefore low costs. The

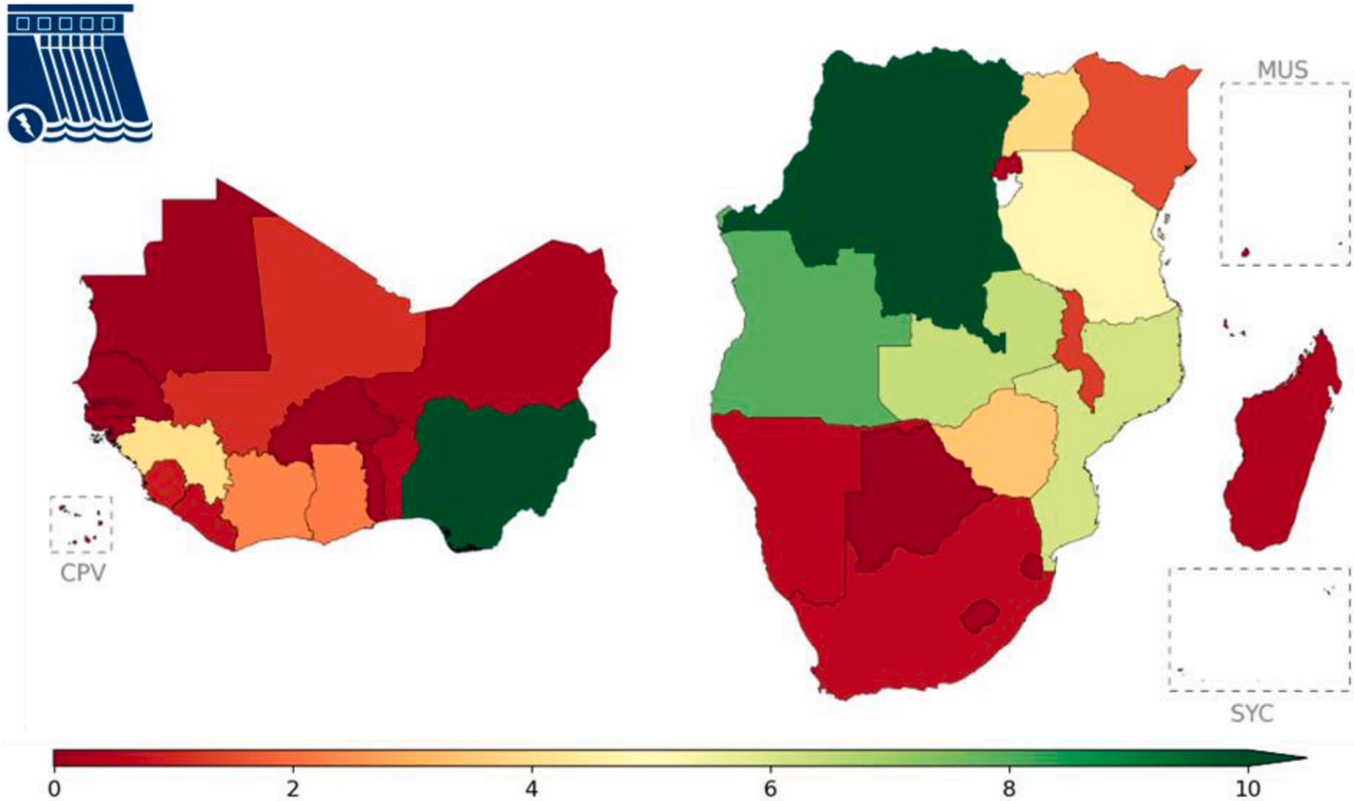

Fig. 12. Hydropower capacity potential [GW] in 2030 in West (left) and Southern and East Africa (right)

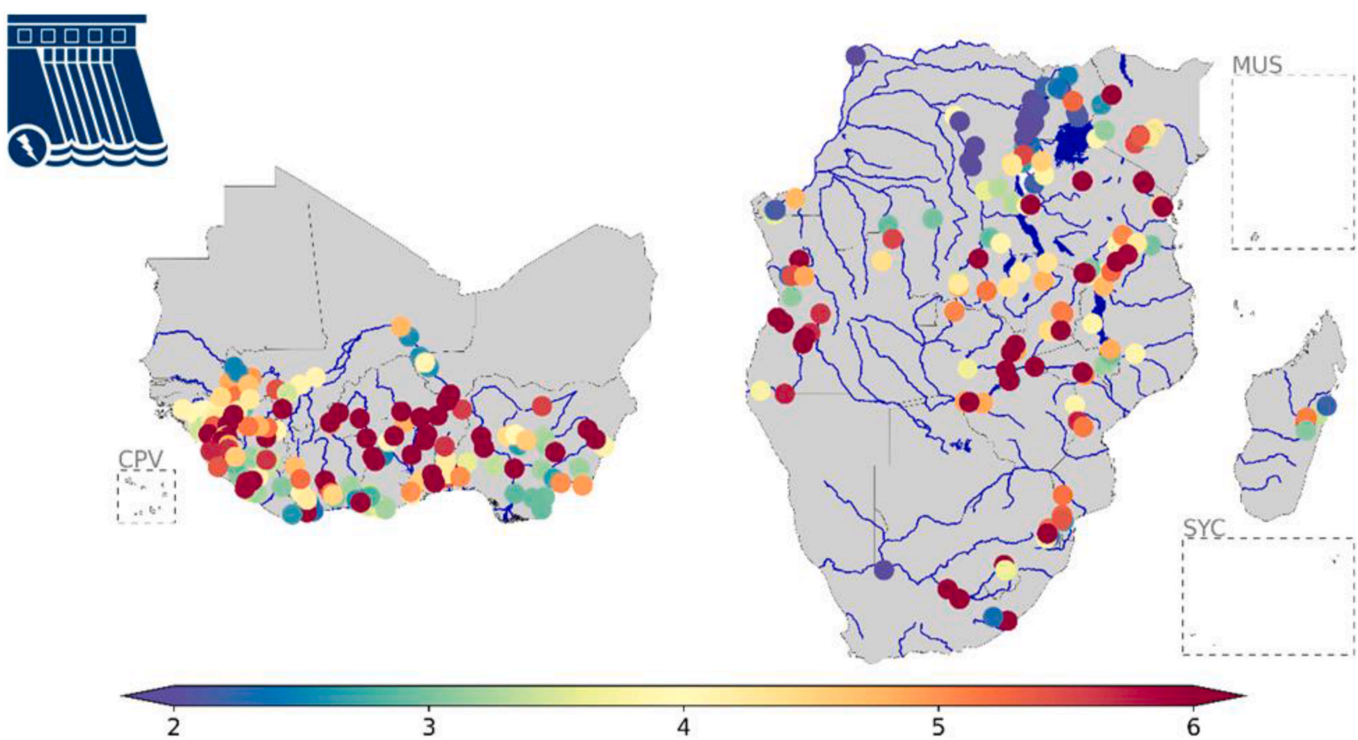

Fig. 13. Levelized cost of electricity [Ct€/kWh] from hydropower for the year 2050.

economic viability of geothermal power for hydrogen production in Kenya therefore depends on the achievable full load hours based on solar and wind power. 70% of the total potential is feasible below 10 Ct€/kWh.

3.3. Sustainable water supply assessment

The water availability assessment was conducted by taking into account the average groundwater sustainable yield for the following

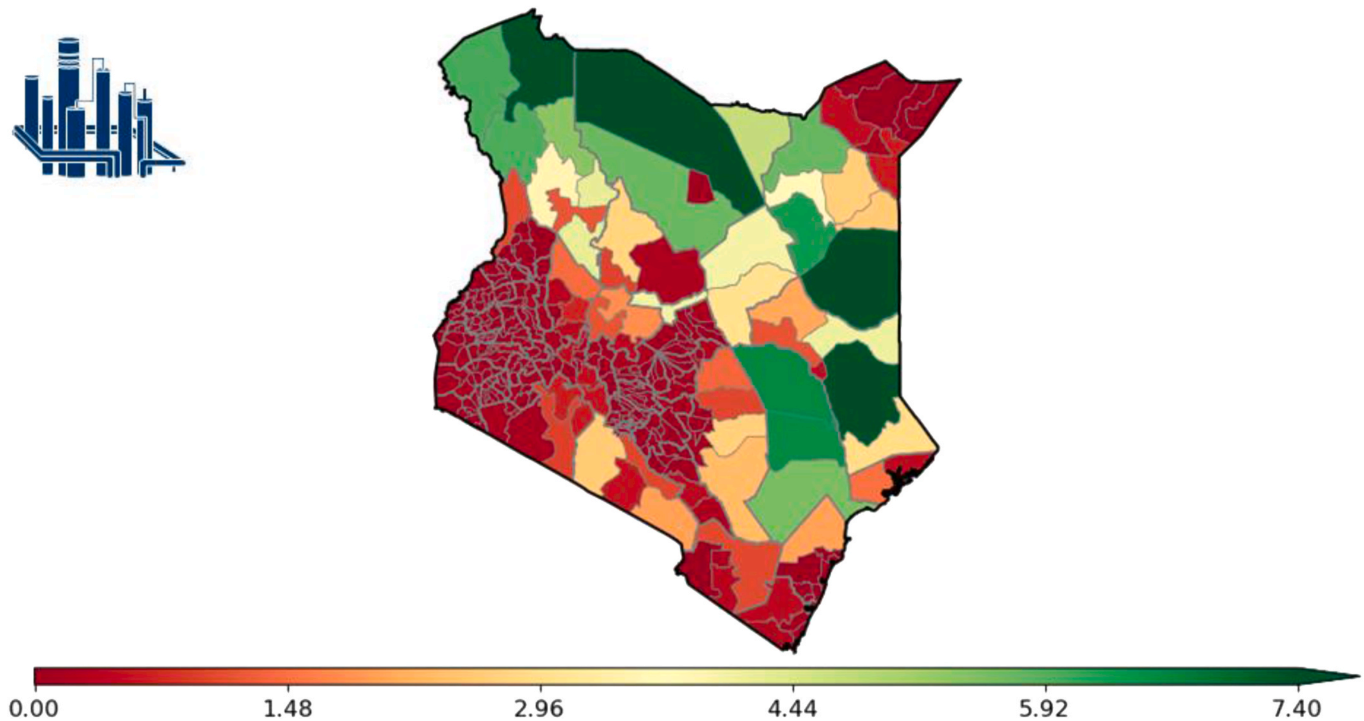

Fig. 14. Regional geothermal capacity potentials [GW] in Kenya

timeframes: 2020 (2015–2035), 2030 (2015–2045), and 2050 (2036–2065). Additionally, the assessment encompassed the process of seawater desalination, which includes the transportation of water.

3.3.1. Groundwater sustainable yield in 2020

The long-term average (2015–2035) groundwater sustainable yield maps representative for the year 2020 are presented in Fig. 15, considering two climate scenarios: RCP2.6 (Fig. 15a and c & e), and RCP8.5 (Fig. 15b and d & f). For each climate scenario, three cases are investigated: conservative (Fig. 15a and b), medium (Fig. 15c and d), and extreme conditions (Fig. 15e and f) based on the scenarios described in Ishmam et al. [70]. The findings indicate a substantial increase in groundwater sustainable yield from the conservative scenario (Fig. 15a and b) to the extreme scenario (Fig. 15a and b). The medium scenario (Fig. 15c and d), situated between the conservative and extreme cases, could be considered as the most favorable scenario for green hydrogen production. In West Africa, the coastal regions (e.g., Gambia, Guinea, Sierra Leone, Liberia, and Cote d'Ivoire) and those located in the southern part (e.g., Nigeria, Benin, and Ghana) exhibit higher groundwater sustainable yield for RCP2.6 and RCP8.5 across all three cases. The regional analysis (Table 2) demonstrates that in the selected West Africa region, the average groundwater sustainable yield for the year 2020 RCP2.6 (RCP8.5) would be 7.4 (6.9) mm yr^{-1} (conservative scenario), 34.9 (33) mm yr^{-1} (medium scenario), and 63 (59.7) mm yr^{-1} (extreme scenario) based on the method and scenarios described in Ishmam et al. [70].

In Southern East Africa, the results suggest that countries such as Angola, Democratic Republic of Congo, Zambia, Tanzania, and Madagascar consistently exhibit high sustainable yield across all scenarios (Fig. 15). Furthermore, the southern part of the region (e.g., South Africa, Lesotho, Namibia, and Botswana) demonstrated higher groundwater sustainable yield in 2020 (RCP2.6 and RCP8.5). According to the RCP2.6 (RCP8.5) scenarios, the average groundwater sustainable yield in Southern East Africa (Table 3) would be 17.9 (17.1) mm yr^{-1} (conservative scenario), 75.8 (72.6) mm yr^{-1} (moderate scenario), and 134.2 (128.6) mm yr^{-1} (extreme scenario).

3.3.2. Groundwater sustainable yield in 2030

Regarding 2030, the sustainable yield of groundwater based on Ishmam et al. [70] is averaged over the 2015–2045 period and presented in Fig. 16 under two different climate scenarios: RCP2.6 (Fig. 16a and c & e) and RCP8.5 (Fig. 16b and d & f). It also illustrates three scenarios: conservative (Fig. 16a and c), medium (Fig. 16b and d), and extreme (Fig. 16e and f). In West Africa, as was the case in 2020, the higher groundwater sustainable yield values are present along the western coastal regions (e.g., Gambia, Guinea, Sierra Leone, Liberia, and Cote d'Ivoire), as well as in the southern part (e.g., Nigeria, Benin, Ghana). Our analysis indicates that the average groundwater sustainable yield in 2030 would be slightly lower than the 2020 level under both RCP2.6 and RCP8.5 scenarios (Table 2). When considering the entire region, our findings highlight the potential for groundwater sustainable yield in West Africa under RCP2.6, with average values of 6.8 mm yr^{-1} (conservative scenario), 33.3 mm yr^{-1} (medium scenario), and 60.6 mm yr^{-1} (extreme scenario). For RCP8.5, the groundwater sustainable yield changed to 6.4 mm yr^{-1} (conservative scenario), 31.8 mm yr^{-1} (medium scenario), and 58 mm yr^{-1} (extreme scenario). Regarding Southern East Africa, as illustrated in Fig. 16, the higher sustainable yield values are observed in Angola, the Democratic Republic of Congo, Zambia, Tanzania, and Madagascar, particularly in medium and extreme scenarios. Similar to the West Africa region, the average groundwater sustainable yield in 2030 under RCP2.6 and RCP8.5 has slightly decreased compared to 2020 RCP2.6 and RCP8.5 (Table 3). Across the entire Southern African region, the average rates were found to be 17.3 (16.8) mm yr^{-1} (conservative scenario), 73.7 (71.9) mm yr^{-1} (medium scenario), and 130.8 (127.6) mm yr^{-1} (extreme scenario) under RCP2.6 (RCP8.5).

3.3.3. Groundwater sustainable yield in 2050

The long-term average (2036–2065) groundwater sustainable yield was calculated as a representative of 2050 (Fig. 17) for the climate scenarios RCP 2.6 (Fig. 17a and c & e) and RCP8.5 (Fig. 17b and d & f), and for three cases: conservative (Fig. 17a and b), moderate (Fig. 17c and d), and extreme (Fig. 17e and f). The findings indicate that the average groundwater sustainable yield in 2050 is clearly lower than in

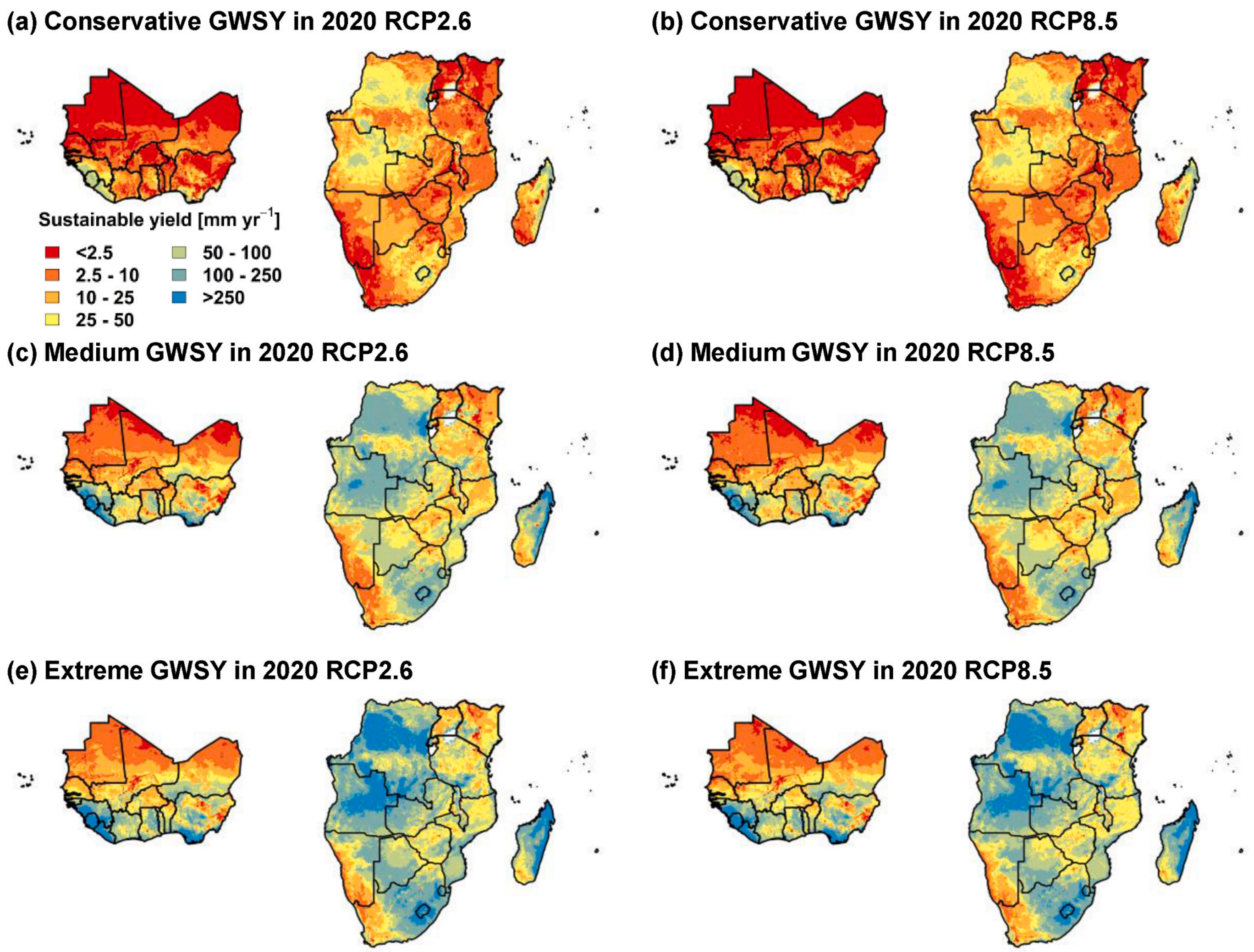

Fig. 15. The groundwater sustainable yield for 2020 (the average of 2015–2035) under two climate scenarios: RCP2.6 (left panels) and RCP8.5 (right panels). Each scenario considers three cases: conservative (a & b), medium (c & d), and extreme conditions (e & f) (compare method in Ishmam et al. [70]).

Table 2
The average estimates of groundwater sustainable yield in the West Africa region for 2020 (2015–2035), 2030 (2015–2045), and 2050 (2036–2065) considering two climate scenarios: RCP2.6 and RCP8.5 under conservative, medium, and extreme conditions (based on method and scenario definition in Ishmam et al. [70]).

Scenario	West Africa groundwater sustainable yield [mm yr^{-1}]					
	2020		2030		2050	
	RCP2.6	RCP8.5	RCP2.6	RCP8.5	RCP2.6	RCP8.5
Conservative	7.4	6.9	6.8	6.4	5.6	5.1
Medium	34.9	33	33.3	31.8	29.6	27.2
Extreme	63	59.7	60.6	58	55.1	50.9

Table 3
The average estimates of groundwater sustainable yield in the Southern East Africa region for 2020 (2015–2035), 2030 (2015–2045), and 2050 (2036–2065) considering two climate scenarios: RCP2.6 and RCP8.5 under conservative, medium, and extreme conditions (based on method and scenario definition in Ishmam et al. [70]).

Scenario	Southern East Africa groundwater sustainable yield [mm yr^{-1}]					
	2020		2030		2050	
	RCP2.6	RCP8.5	RCP2.6	RCP8.5	RCP2.6	RCP8.5
Conservative	17.9	17.1	17.3	16.8	15.6	15.4
Medium	75.8	72.6	73.7	71.9	68.6	67.8
Extreme	134.2	128.6	130.8	127.6	122.3	121

2020 under both RCP2.6 and RCP8.5 scenarios, and this is true for all conservative, medium, and extreme cases (Table 2) and Table 3). The regional analysis (Table 2) provides an average West African groundwater sustainable yield in 2050 under RCP2.6 of 5.6 mm yr^{-1} (conservative scenario), 29.6 mm yr^{-1} (medium scenario), and 55.1 mm yr^{-1} (extreme scenario). Moreover, the groundwater sustainable yield in 2050 for RCP8.5 is lower than for RCP2.6 for all three scenarios, particularly over the Northern part of the region. The results show indicate that the Southern part of the region (e.g., Nigeria, Benin, and Ghana) consistently receives a lower sustainable yield in all three scenarios (Fig. 17b and d & f) than compared to in 2020 for RCP8.5. In 2050 under RCP8.5, the region is expected to exhibit average groundwater sustainable yield values of 5.1 mm yr^{-1} (conservative scenario), 27.2 mm yr^{-1} (medium scenario), and 50.9 mm yr^{-1} (extreme scenario), which is less than in 2020 under RCP8.5 (Table 2).

For Southern East Africa, the spatial pattern of groundwater sustainable yield for the three scenarios in 2050 under RCP2.6 (Fig. 17a and c & e), and RCP8.5 (Fig. 17b and d & f) is similar to 2020. However, the absolute amount of sustainable yield is expected to be lower in 2050 than in 2020, both for RCP2.6 and RCP8.5. According to the 2050

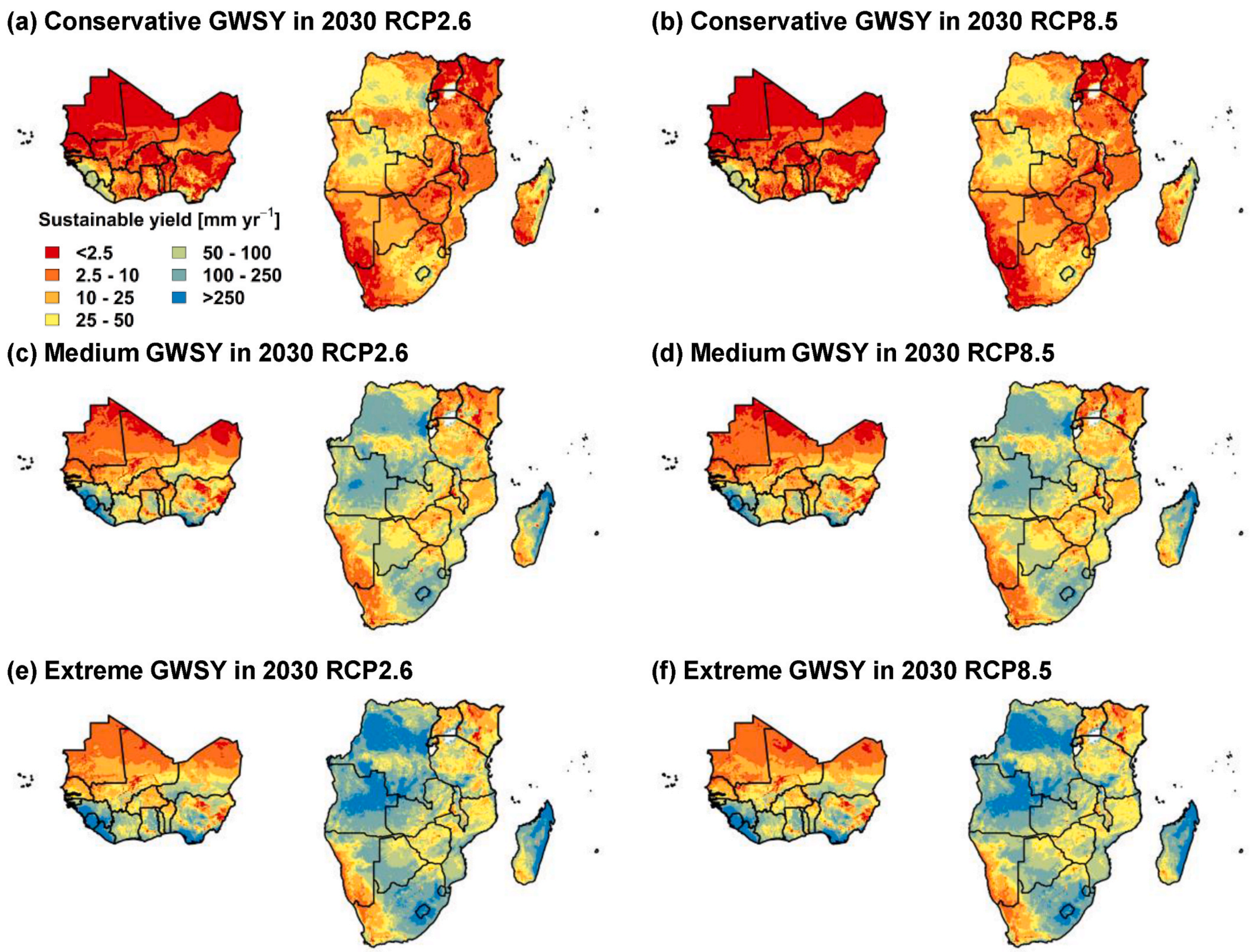

Fig. 16. The groundwater sustainable yield for 2030 (the average of 2015–2045) under two climate scenarios: RCP2.6 (left panels) and RCP8.5 (right panels). Each scenario considers three cases: conservative (a & b), medium (c & d), and extreme conditions (e & f) (based on method and scenario definition in Ishmam et al. [70].

RCP2.6 scenario, the average groundwater sustainable yield in the Southern East region is projected to be 15.6 mm yr^{-1} (under conservative conditions), 68.6 mm yr^{-1} (under moderate conditions), and 122.3 mm yr^{-1} (under extreme conditions). This is lower than the yield under the RCP2.6 scenario in 2020 (Table 3). Furthermore, the region is projected to exhibit average groundwater sustainable yield values of 15.4 mm yr^{-1} (conservative scenario), 67.8 mm yr^{-1} (medium scenario), and 121 mm yr^{-1} (extreme scenario) for RCP8.5, all of which are lower than those observed in 2020 under RCP8.5 (Table 3).

3.4. *Local green hydrogen potential assessment*

In the following, quantitative hydrogen potential will be analyzed and compared to the amount of hydrogen that can be produced from local sustainable groundwater potentials. The cost of hydrogen and the cost contribution of water will be presented, and the reasons for hydrogen cost differences will be discussed. Further information will be provided by cost-potential curves, which will then be explained in detail based on an in-depth analysis of the region- and time-dependent optimal system designs for the production of green hydrogen.

3.4.1. *Degree of potential expansion*

For the analysis of the levelized cost of hydrogen (LCOH) and for system design considerations, the dependence of the cost on the degree of potential expansion is first discussed. The lowest cost potentials are exploited first, with costs increasing along the cost-potential curve as the quantity of produced hydrogen is increased. Typically, e.g. for regions with a large quantity of wind turbines, costs start comparatively low and rise sharply at the beginning, with a decreasing slope within the first quartile. The second and third quartiles show very moderate increases, and the last quarter shows a sharp increase towards the end (compare exemplary distribution in Fig. 2). While very high degrees of expansion at the end of the curve describe economically unrealistic solutions, the very low degrees of expansion describe entry-level costs. These are defined by the most favorable locations and system configurations. Typically, these are also locations that could be occupied by first movers, which may have implications for the economy of scale and learning rate assumptions. However, in an approach with independent regions and high spatial resolution, the economy of scale and learning effects in any given region may depend not only on the region itself, but also on installations in neighboring regions or the entire country. Therefore, it is not possible to reliably quantify the cost effects of first-mover projects in an atlas approach, and costs at very low potential expansion degrees must be interpreted with caution. In addition, renewable energy simulation tools are always subject to statistical errors. While medians and average values are very reliable, potential outliers may further influence the initial costs. For these reasons, the following analysis focuses on a potential expansion rate of 25% when

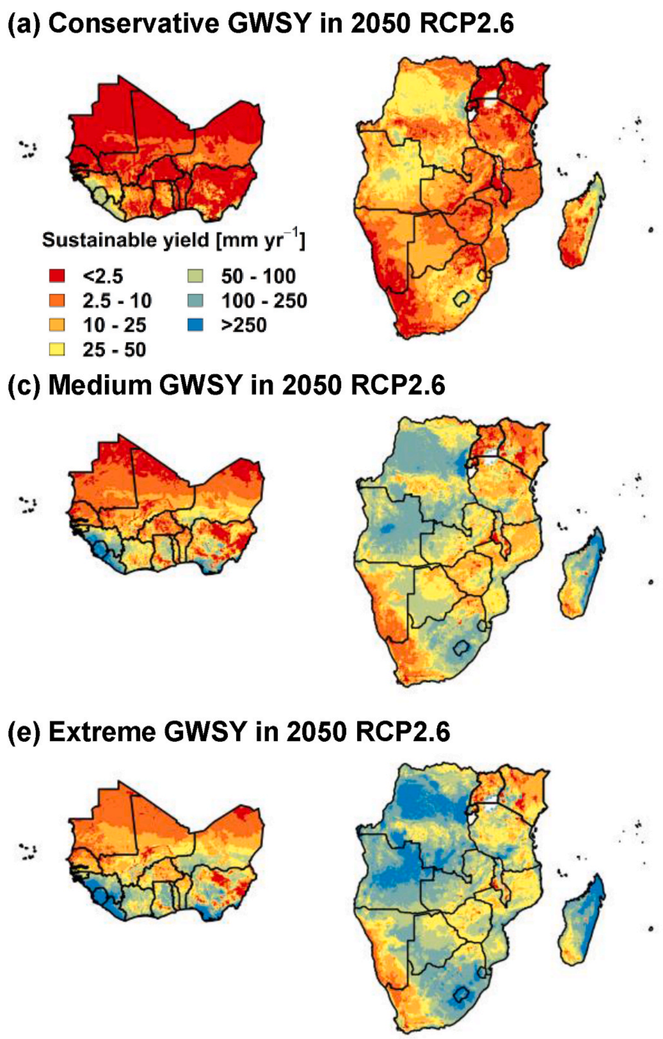

Fig. 17. The groundwater sustainable yield for 2050 (the average of 2036–2065) under two climate scenarios: RCP2.6 (left panels) and RCP8.5 (right panels). Each scenario considers three cases: conservative (a & b), medium (c & d), and extreme conditions (e & f) (based on method and scenario definition in Ishmam et al. [70]).

comparing the levelized costs of hydrogen and system designs. Costs in this range are still comparatively low, but very reliable and fairly stable as the production quantity increases.

3.4.2. Quantitative hydrogen potentials

The following quantitative hydrogen potentials were calculated based on the local preference exclusions defined with the national specialists and renewable energy simulations. Subsequently, the hydrogen potential was determined based on optimal system designs per district level node. The aggregate maximum hydrogen potential in West Africa, in conjunction with Southern and East Africa, is estimated to exceed 400,000 TWh/a, which is more than double the present global primary energy consumption (165,319 TWh/a in 2021 [71]). The cumulative projected local electricity and hydrogen demands in 2050 for the analyzed regions based on the "Net Zero 2050″ scenario from the NGFS Climate Scenarios Database [62,72] amount to only 0.5% of the total potentials. The present analysis, therefore, does not concentrate on the total quantitative potential of the entire project region. Rather, it focuses on regional and national potential constraints, as well as available quantities at defined production costs.

The distribution of regional potential per area is illustrated in Fig. 18. Fig. 18 circumvents the potential distortion of the potential values by the region size and instead reflects the limitations and results described in the land eligibility and renewable energy potentials sections. The analysis indicates that the greatest potential is found in the sparsely populated desert regions of the Sahara and Nama Karoo, yet significant area potential is identified across the entirety of the study area. Notable exceptions to this pattern are the densely populated and forested regions along the Southern coast of West Africa, the Congo basin, and rangeland areas in Southern Africa, which exhibit low wind potentials. It is noteworthy, however, that the requisite area potentials may be minimal, even for industrialized nations such as Germany, where an area potential of less than 6 kWh/m^2 would suffice to meet the total projected final energy demand of 2164 TWh/a in 2045 [73]. It is notable that approximately 54% of the project regions exceed this threshold.

The absolute hydrogen potentials (see Fig. 19) demonstrate a comparable trend (refer to the GUI [66] for regional values), a phenomenon that is further accentuated by the observation that remote desert regions tend to encompass significantly larger areas.

The national and total potentials were calculated, and local electricity and hydrogen demands were considered as detailed in section 2.4. The national aggregate values are enumerated in the appendix in section 1.A. The analysis revealed that, due to limitations imposed by land eligibility and theoretical energy potential, only three of the thirty-five countries under consideration may experience challenges in meeting their own electricity and hydrogen demands in the year 2050. This is contingent upon maintaining a fifty percent feasibility threshold for the maximum potential. This number is reduced to two out of 35 countries

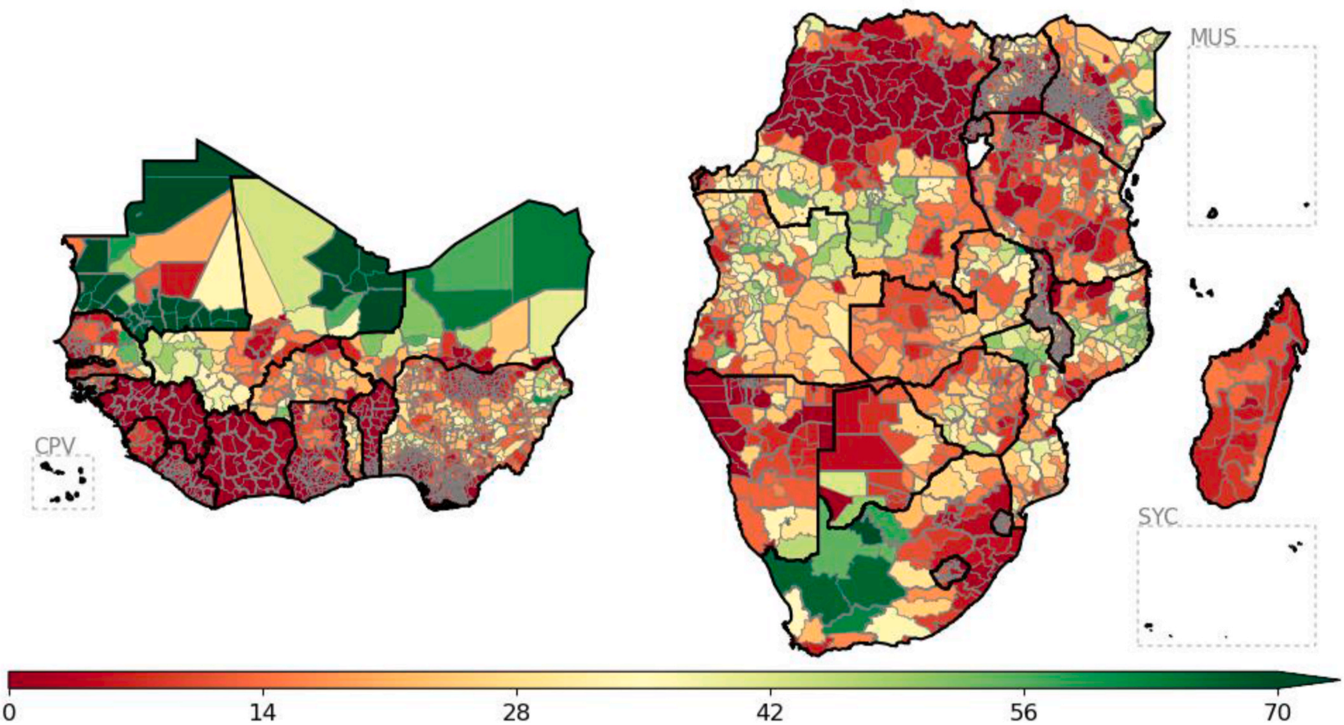

Fig. 18. Hydrogen potential per area [kWh/(a*m^2)] at district level in 2030, limited only by energy.

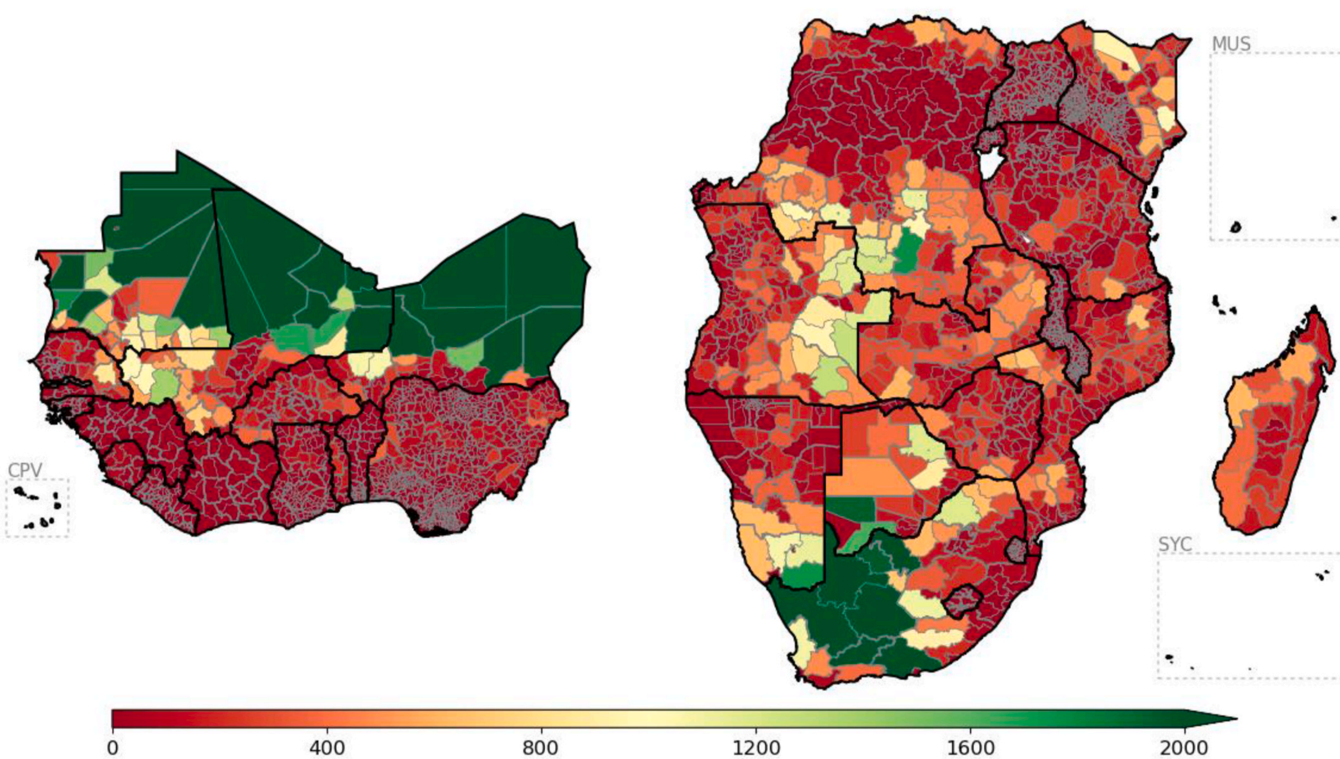

Fig. 19. Absolute technical hydrogen potentials [TWh/a] at district level, limited only by energy.

in the unlikely case of a 100% expansion of the potential. However, regulatory decisions may alter this landscape, particularly in regions with minimal overall eligibility, such as island nations like the Seychelles or Mauritius, where such decisions may have a substantial relative impact on potential. For instance, in the Republic of Guinea, the import of energy from neighboring countries would be a viable and efficient solution. The implementation of transmission infrastructure projects within the West African Power Pool (WAPP) framework [74] is already underway.

3.4.3. Impact of sustainable water yield on hydrogen potentials

When hydrogen production is based on local sustainable

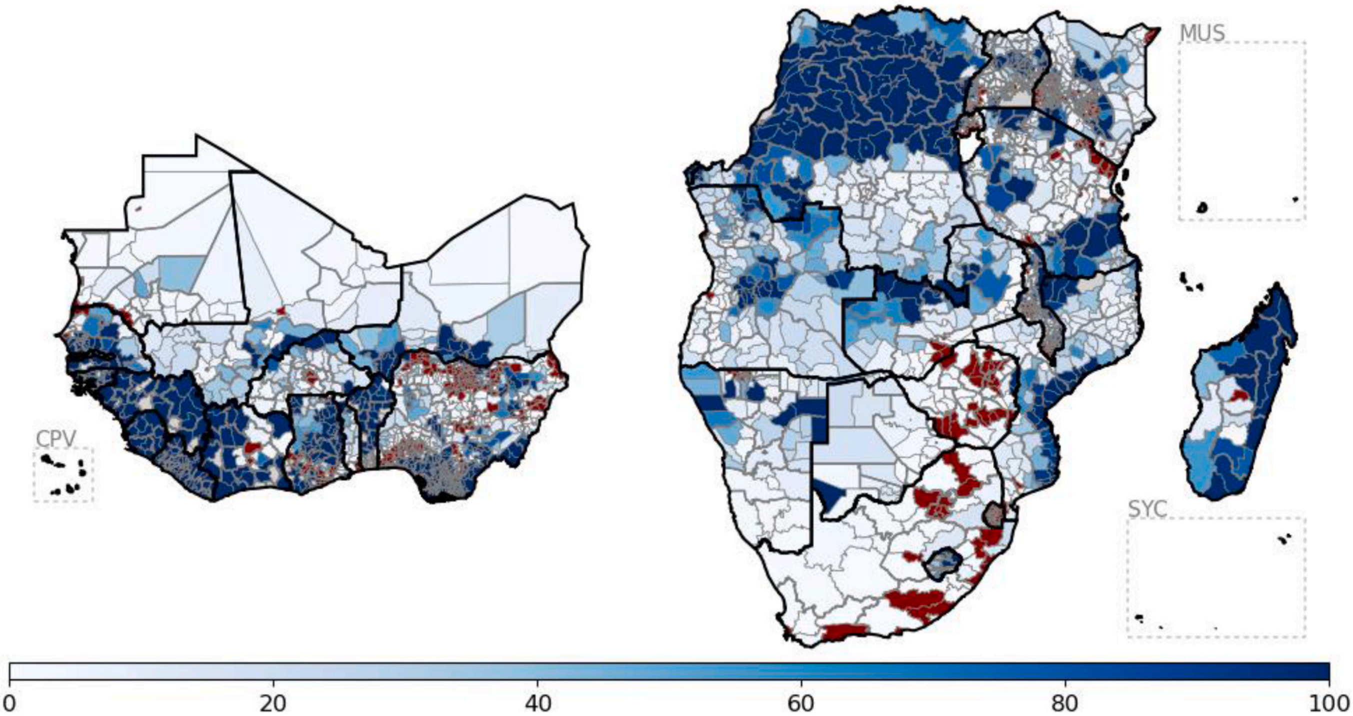

Fig. 20. Percentage share of hydrogen [%] producible from local sustainable groundwater.

groundwater, the quantitative potential is significantly reduced (see Fig. 20). A mere 42% of all regions possess sufficient sustainable groundwater to accommodate an expansion degree of 25% of the maximum energetic potential. Notably, regions with both low-cost and high-potential, such as desert areas, are particularly impacted due to their limited precipitation. When the analysis is further restricted to regions with an average LCOH below 2.7 EUR/kg in 2030, the proportion of regions with sufficient groundwater is further diminished to 28%. The hydrogen potential derived from sustainable groundwater is estimated to account for approximately 16% of the total technical hydrogen potential, with energy constraints serving as the primary limiting factor. This percentage may be further diminished if water-intensive cooling methods replace air cooling. The impact of the cooling method on water consumption cannot be quantified in general, since it depends on the specific cooling method and environmental conditions, as well as the reuse options for the cooling water return flow. When assessed based on sustainable water potential, the average levelized cost of hydrogen is 4–5% higher than the overall LCOH without water limitations.

However, this does not explicitly imply that sustainable hydrogen production is not feasible beyond the limit of sustainable groundwater potential. In certain instances, surface water can be utilized when it is consistently available throughout the year. However, its sustainability must be evaluated on a case-by-case basis. A particular emphasis should be placed on the seasonality of water availability for hydrogen production in these cases. Water requirements may be particularly pronounced during the dry season in systems with a preponderance of solar photovoltaics (PV). Alternate water sources, such as desalinated seawater, may also be utilized, provided that renewable energy is employed for treatment and transportation, and that water intake and brine outlet are strategically optimized to minimize ecological impact. According to the present assessment, attaining 100% of the overall technical potential would necessitate 84% of the water consumed to be derived from such alternative sources. In the case of desalinated water, this would correspond to the construction of 755 new large-scale desalination plants with a capacity of 367,000 m^3/d each, as suggested in Heinrichs et al. [75], or 1846 plants of the 2020 UAE reference size, as proposed by Eke et al. [76]. The additional cost for water treatment is not significant, given the high value of hydrogen and the relatively low amount of water that is needed to produce it via electrolysis: Even in north-eastern Mali, where the levelized cost of water including pipeline transport reaches nearly 2.50 €/m^3 in combination with comparably low LCOH, the share of water cost does not exceed ~1% of the total levelized cost of hydrogen. Consequently, the primary focus should be directed towards assessing the viability of pipeline water transportation over long distances and across national borders, particularly in the context of large-scale sustainable hydrogen production in inland countries such as Niger and Mali, which are characterized by substantial potential. Alternatively, power export from these countries to coastal locations via a power grid in conjunction with electrolysis near the coast would be a viable option. However, the implementation of transnational power lines would necessitate meticulous planning and cooperation, resulting in higher costs compared to pipeline alternatives. Mauritania, South Africa, Namibia, Kenya, Madagascar, and Cabo Verde are notable examples of countries with substantial low-cost potential along the coast, as well as small island nations such as Cabo Verde.

3.4.4. *Levelized cost of hydrogen (LCOH)*

First, the levelized cost of hydrogen, which is primarily based on onshore wind, open-field photovoltaics, and geothermal power supply, will be discussed. These represent the large-scale, widely untapped renewable energy resources. Subsequent discourse will address regions characterized by hydropower dominance, which often exhibit cost outliers at the local level.

The analysis indicates that the lowest levelized cost of hydrogen, excluding hydropower contributions, is achieved in Mauritania at 25% of the regional maximum potential, with the cost of production reaching 1.6 €/kg in 2050. If the actual entry level cost is considered, LCOH of approximately 1.8 €/kg in 2030 and 1.5 €/kg in 2050 may be feasible without hydropower, provided that the economy of scale persists. The most economical hydrogen production is located in the Sahara region, particularly towards the Mauritanian coast and in the Nama Karoo region in the border area between Southern Africa, Namibia and Botswana (see Fig. 21), but also in smaller countries such as Cabo Verde and Lesotho. Additionally, hydrogen can be produced at a lower cost in

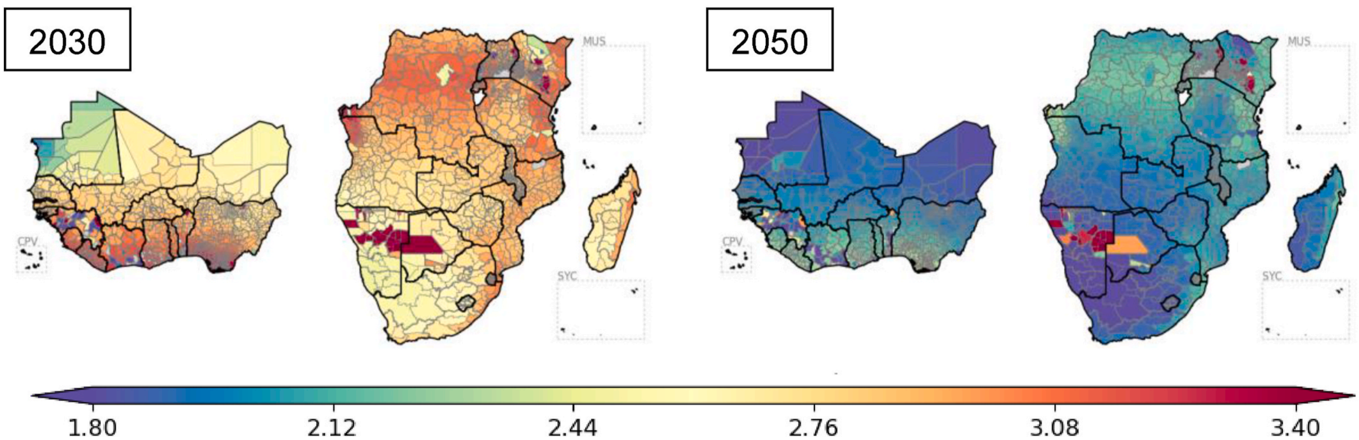

Fig. 21. Regional Levelized Cost of Hydrogen [EUR/kg] at 25% potential expansion in the years 2030 (left) and 2050 (right)

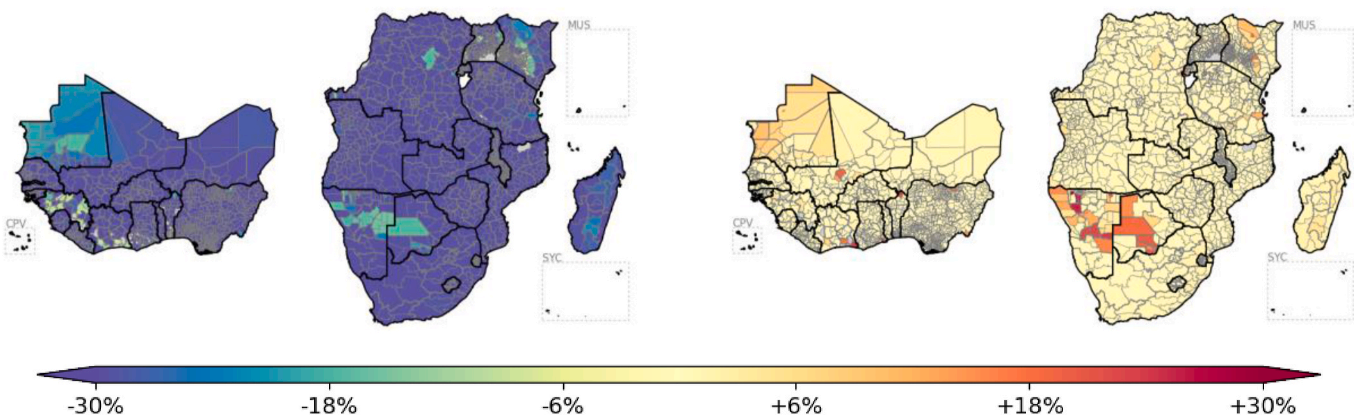

Fig. 22. Percentage change [%] of levelized cost between 2030 and 2050 at 25% of technical potential (left) and between 25% and 50% of technical potential in 2030 (right).

Kenya and, to a lesser extent, in Madagascar. A cost comparison of the project regions reveals that West Africa has a slight cost advantage (~1.9 €/kg) due to its comparatively large, low-cost potential in the Sahara, as opposed to Southern and East Africa (~2 €/kg), which has higher cost-potentials near the equator. The study's findings indicate that the overall potential-weighted average levelized cost of hydrogen across the entire study area, at 25% of the respective regional technical potential, is estimated to be approximately 2.7 €/kg in 2030 and 1.9 €/kg in 2050.

A direct comparison of the levelized cost of hydrogen at 25% expansion between 2030 and 2050 (Fig. 22 on the left) demonstrates that the LCOH reduction over the decades is most significant in regions with solar-dominated hydrogen production (see section 3.2.1). However, the majority of the most cost-effective hydrogen regions in 2030 are characterized by a combination of solar and wind generation fleets, and they demonstrate a decline in cost reduction over time. Consequently, alternative solar-driven regions have the potential to achieve cost reductions comparable to those observed in the solar- and wind-mixed regions of North-Eastern Mauritania, which continue to be among the most economical options. The analysis indicates that 64% of the projected cost reductions, as predicted by the techno-economic parameters of the technologies, are to be realized within the initial decade, specifically by the year 2040.

In order to quantify the dependency of the levelized cost of hydrogen on the production quantity, the relative cost increase of the LCOH at 50% potential expansion compared to the standard potential expansion of 25% is analyzed for the year 2030 (see Fig. 22 on the right). The differences are marginally higher yet very similar in 2050. The findings suggest that LCOH in regions dominated by wind power is particularly sensitive to variations in production capacity. In regions predominantly reliant on wind power generation, the levelized cost of hydrogen exhibits a median increase of approximately 6% when production capacity is augmented from 25% to 50% of the technical potential. In contrast, solar-dominated systems exhibit a distinct pattern, with cost exhibiting minimal change with increased production capacity (~0.1% median cost increase). In regions where the capacity limits of the least expensive generation technology are exceeded and more costly alternatives must be used, production quantity increases may also have a significant impact on average LCOH.

An examination of the hydrogen cost map in Fig. 21 reveals several cost outliers that are worthy of discussion. On the one hand, regions primarily in central Namibia and Botswana, but also isolated cases across the study area, stand out due to their elevated levelized cost of hydrogen. These regions are predominantly situated in areas with minimal wind energy potential and are constrained by limitations on land eligibility that preclude the viability of adequate photovoltaic capacity. In the case of the Kalahari region, which is shared by Namibia and Botswana, the primary factors contributing to this phenomenon are the preservation of rangelands for wildlife and the maintenance of pastures for cattle farming. The latter can be integrated with wind turbines; however, this is not the case with solar open-field photovoltaics. Consequently, elevated combined costs, attributable to high wind shares and high LCOEs in these regions, are observed. A similar scenario may be observed in regions heavily reliant on geothermal energy in Kenya.

Conversely, there are isolated regions with very low costs that are dispersed throughout the area, particularly in southern West Africa.

These regions are characterized by a predominant reliance on hydropower, a strategy that enables the production of hydrogen with a levelized cost that is highly competitive. However, the overall hydrogen potential in southern West Africa is constrained by limited land eligibility and comparatively small region sizes, resulting in a significant reliance on low-cost hydropower, thereby yielding a notably low overall LCOH. The primary benefit of hydrogen derived from hydropower is the high utilization rate of hydropower plants and electrolyzers, particularly at low expansion grades, where the available river discharge remains consistent throughout the year. This results in the cost of electricity and hydrogen that is notably low. In contrast, conventional reservoir hydropower systems can enhance the consistency of their output by storing and releasing excess water, although this approach entails higher investment costs. The lowest entry-level LCOH in 2030 is achieved by run-of-river hydropower at approximately 1.1 EUR/kg in 2030 and 0.9 EUR/kg in 2050. However, it should be noted that this cost is only feasible in the most optimal locations and for projects with limited potential. In most regions and at higher potential expansion degrees, hydrogen derived from run-of-river hydropower is more expensive than reservoir hydropower. In 2030, the cost of hydrogen from run-of-river hydropower was estimated to be approximately 1.5 EUR/kg, while reservoir hydropower was projected to be around 1.3 EUR/kg.

It is imperative to acknowledge that these values should be regarded exclusively as theoretical lower bounds. In reality, reservoir hydropower plants typically play a pivotal role in ensuring grid flexibility, a role that is difficult to substitute. In the majority of cases, hydrogen production is therefore limited to periods of excess electricity, which would significantly reduce electrolysis full load hours. The current cost of electrolysis contributes 25% of LCOH (median value) in low-cost conventional hydropower regions (35% in run-of-river hydropower systems).

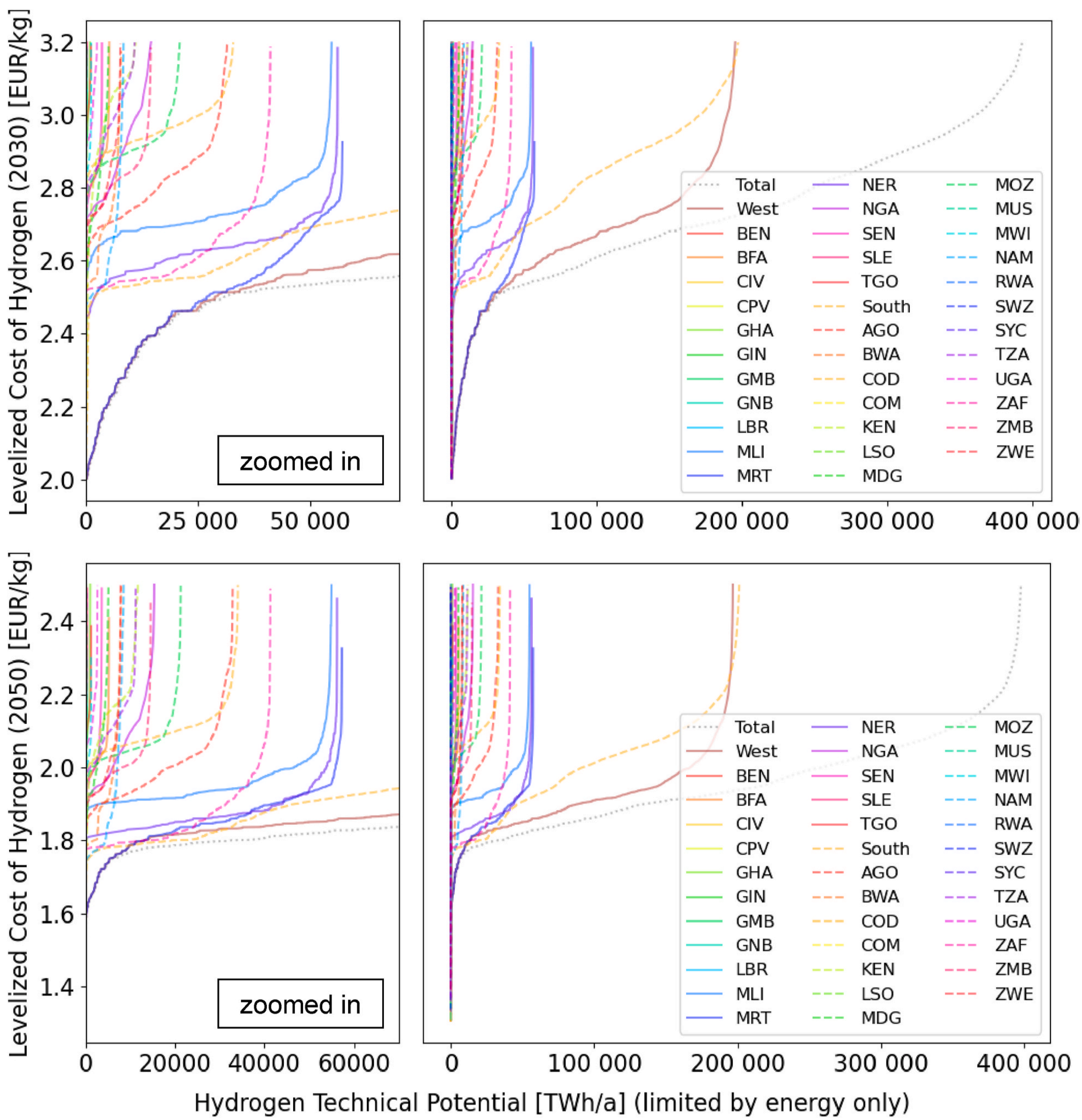

Fig. 23. National cost-potential curves for West Africa (continuous) and Southern and East Africa (dashed lines) in the year 2030 (top) and 2050 (bottom), zoom on country level curves on the left.

Consequently, a 50% reduction in electrolyzer utilization rate would result in a 25–35% increase in hydrogen cost. This systemic effect cannot be reflected in an atlas approach, where regions are independent of each other. Consequently, the economic viability and quantitative potential of green hydrogen produced from hydropower must be assessed on a plant-by-plant basis within an (inter-)national energy system model, incorporating temporal demand patterns and other generation capacities within the system.

3.4.5. Hydrogen cost-potential curves

The integration of the aforementioned findings on quantitative hydrogen potentials and levelized cost into cost-potential curves facilitates a more profound analysis of quantity-dependent aspects. A comparative analysis of the West, Southern, and East African curves presented in Fig. 23 reveals that the aggregate hydrogen potentials in the West Africa, and combined potentials in Southern and East Africa project regions are closely analogous, with an approximate value of 200,000 TWh/a. It is important to acknowledge that this is a theoretical estimate, as it is implausible that all renewable energies will be utilized exclusively for hydrogen production. In 2030, West Africa is projected to have a slightly lower levelized cost of hydrogen, primarily due to the substantial areas and conducive energy conditions in Mauritania, with smaller effects observed in Niger and Mali, all exhibiting comparable technical potentials of approximately 56,000 TWh/a. In addition to the countries in the Sahara region and Cabo Verde in West Africa, South Africa, Lesotho, Namibia, and Botswana also exhibit notably low entry-level cost-potential levels, with the most substantial quantities observed in South Africa.

While the cost-potential curves in Niger and Mali exhibit significant similarity, with relatively flat trends across most regions, indicating stability over a wide range of costs, the pattern in Mauritania differs. The cost potential in Mauritania is notably lower, with an entry cost of approximately €2.0/kg by 2030. This suggests the strategic utilization of favorable wind locations during the initial phase of expansion. Conversely, in South Africa, a substantial proportion of the more expensive wind potentials contributes to higher degrees of expansion, resulting in a near-constant solar-driven cost in the initial phase and a steady increase in the cost slope in the subsequent phase.

A comparison of the 2030 values and the 2050 data presented in Fig. 23 reveals that the overall cost level is lower in 2050, and the cost differential between entry-level and high-potential expansion degrees has significantly diminished. Consequently, the average cost dependency on production quantity is reduced in 2050. This decline in cost is attributed, in part, to an increase in the adoption of solar power in low-expansion steps, driven by the declining costs of solar photovoltaic (PV) technology over time. When considering only the low-cost technical potentials across the whole project region, the producible green hydrogen under 2.5 €/kg in 2030 amounts to ~31 TWh/a. By 2050, the production capacity is projected to reach nearly 260 TWh/a, with a cost of under 2.0 €/kg.

3.4.6. Hydrogen production system design

An analysis of the region-specific designs of an optimal hydrogen production system reveals significant differences that explain the cost patterns previously observed. As illustrated in Fig. 24, solar photovoltaics are identified as the predominant or exclusive power source in the majority of regions within the study area. Notable exceptions to this predominance include the Sahara region, Madagascar, Northern Kenya, and multiple regions in Southern West Africa, as well as some regions in Namibia and Botswana. The latter can be explained by the lack of photovoltaic potential in the Kalahari region, where either rangeland for the natural fauna or pastures for cattle herding forbid open-field photovoltaics. Instead, onshore wind turbines with a comparatively high Levelized Cost of Electricity (LCOE) are employed, contributing to elevated overall hydrogen costs in these regions. Conversely, regions in southwestern West Africa, characterized by their restricted solar and

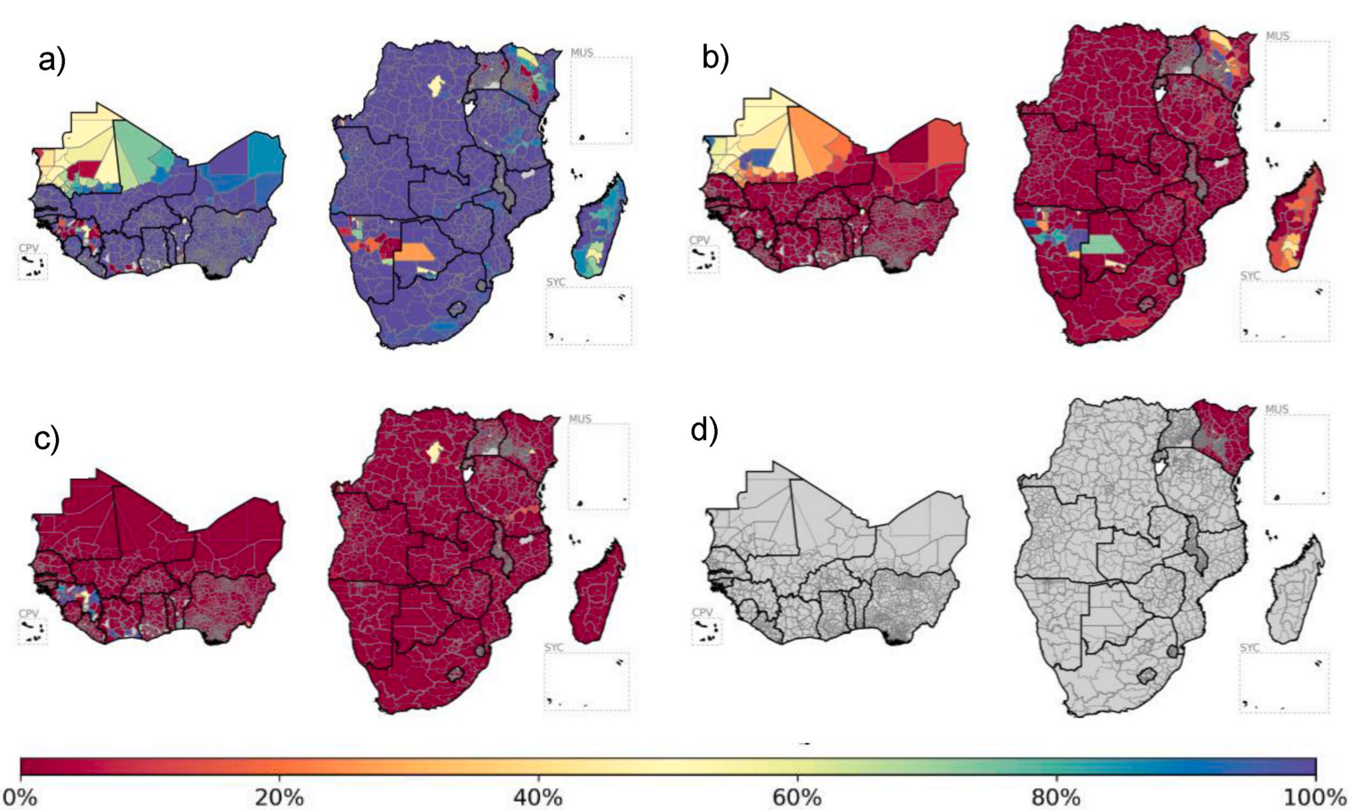

Fig. 24. Share of (a) solar photovoltaics, (b) onshore wind, (c) hydropower and (d) geothermal power in [%] of total renewable generation capacity at 25% potential expansion in the year 2030.

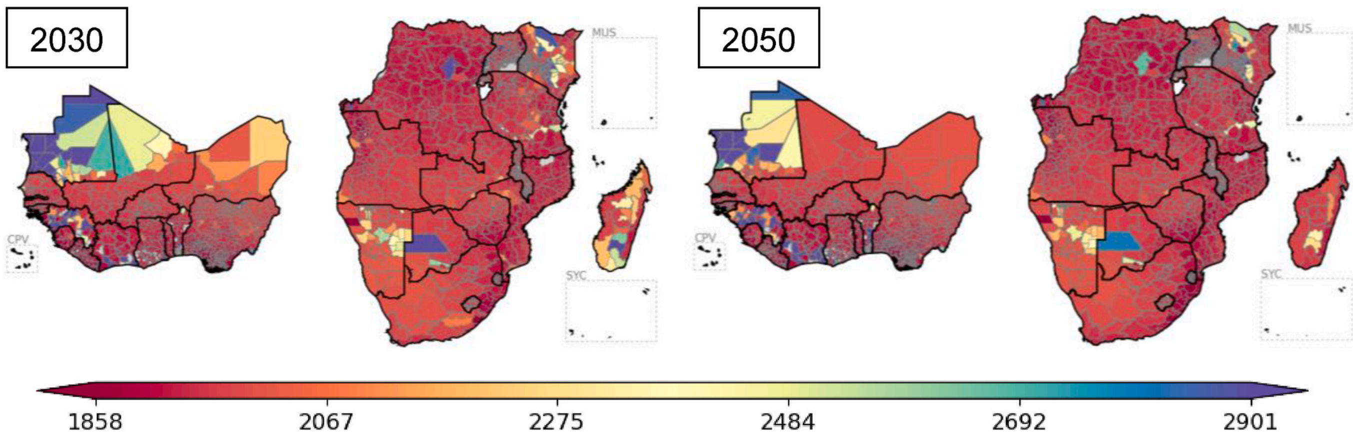

Fig. 25. Electrolysis full load hours [h/a] in the years 2030 (left) and 2050 (right) in comparison.

wind potentials, are well-suited for hydropower, which can contribute significantly to local hydrogen production. In regions where hydropower is also present, this relative share is reduced due to the greater overall potential. Given the significance of geothermal power in Kenya, it was identified as an additional power source for hydrogen production. However, its role remains modest, as it is primarily utilized in regions where solar and wind potentials are limited. Nevertheless, it is anticipated that as the demand for constant hydrogen output increases, geothermal power may become a more cost-effective option, especially when compared to other generation sources that are more susceptible to variability. This is due to the fact that geothermal power does not incur the same additional storage costs that are associated with more variable electricity generation.

The most salient pattern pertains to the tradeoff between solar photovoltaics and wind energy, driven by cost considerations rather than quantitative potential limits. This phenomenon is most evident in the Sahara region, as well as in Kenya, Madagascar, and with limited presence in South Africa. In these regions, the presence of substantial wind energy resources, particularly during nocturnal hours, enhance the viability of solar power generation. This synergy between wind and solar power results in an increase in the full load hours of the electrolyzer leading to a reduction in the necessary investment for electrolysis. In conjunction with elevated full load hours of wind farms in these regions, this synergy equalizes the higher investment for wind farms and consequently reduces the levelized cost of hydrogen. The most cost-effective hydrogen is produced in regions with wind capacity shares ranging from 70% to 95%. This trend is most evident in Mauritania along the northern coastline and on the central Tagant plateau, owing to the exceptionally high local wind speeds, but is also discernible in Southern Madagascar and in northern and central Kenya. The impact on electrolysis full load hours is substantial, as illustrated in Fig. 25 on the left. Regions with high wind shares exhibit electrolysis full load hours that exceed those of the best solar-only regions by up to 60%. A similar high full load hours are achieved in regions dominated by reservoir hydropower plants, which can flexibly shift or smoothen generation peaks.

However, as illustrated in the right-hand side of Fig. 25, a decline in electrolysis full-load hours towards 2050 is projected for many of the wind regions discussed above. This decline is attributed to a shift in energy supply toward solar photovoltaics, as evidenced by the optimal system designs projected for the year 2050 (see Fig. 26). With the exception of wind capacities in the Kalahari region, which are attributable to limitations in suitable land for open-field photovoltaics, wind will play a significant role by 2050 only in Mauritania, Kenya, and two central regions of Madagascar. In Mali and Niger, for instance, wind power has been entirely superseded by open-field photovoltaics by the year 2050. In Kenya and central Madagascar, as well as in several regions of Mauritania, the share of wind has been reduced to a significant extent. This transition is primarily driven by the substantial cost reductions witnessed in photovoltaic technology between 2030 and 2050, when compared to the already mature wind turbine sector. This shift has implications for electrolysis full load hours, which decline in tandem with the wind share compared to 2030 levels. The cost advantage of photovoltaics, when considered in conjunction with the reduced capital expenditures (CAPEX) for electrolysis in 2050 as compared to 2030, results in a net benefit that outweighs the additional capacity required for electrolysis.

It is important to acknowledge the proposal of lithium-ion batteries

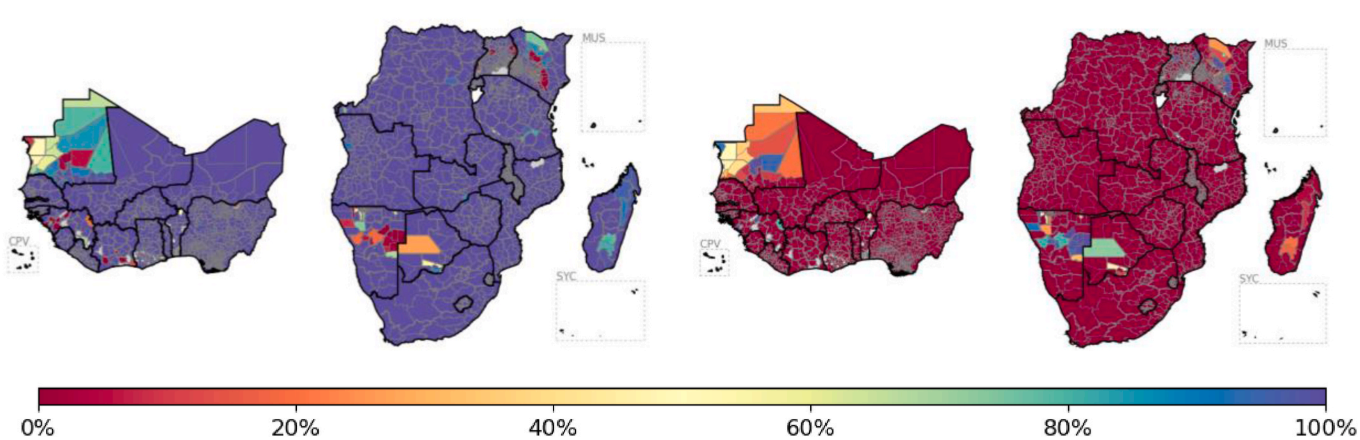

Fig. 26. Share of solar photovoltaics (left) and onshore wind (right) in [%] of total renewable generation capacity at 25% potential expansion in the year 2050.

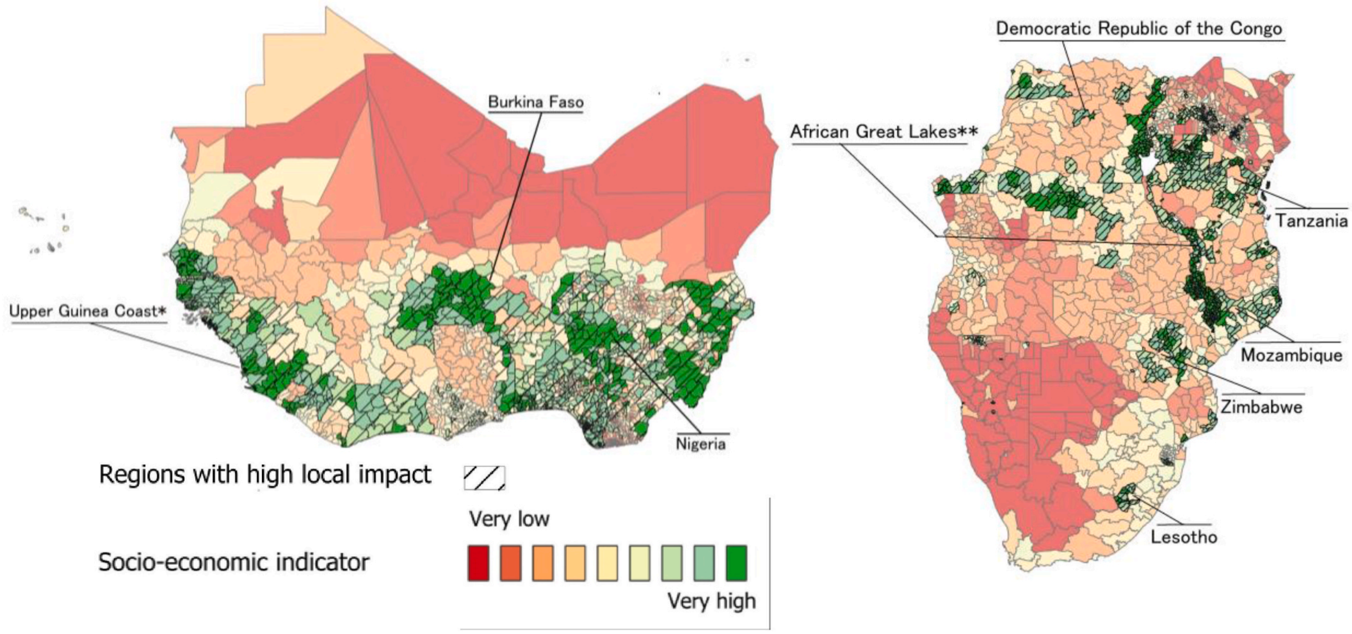

Fig. 27. Socio-economic indicator measuring the impact of green hydrogen project. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

as a system component. However, it should be noted that this is not the most optimal solution. When considering the cost assumptions for the coming decades and the local generation profiles, it is more economical to overbuild generation capacities and/or operate electrolysis at reduced utilization rates. This approach is predicated on the assumption of a time-independent, lowest-cost hydrogen generation process; however, it is acknowledged that this may be subject to modification as specific demand profiles of electricity or hydrogen must be met.

3.5. Mapping local impact of green hydrogen projects

For this analysis of socio-economic development in Africa, the socio-economic indicator (Fig. 27) provides a comprehensive overview of the composite indicator research, with high results indicating potential areas of interest for further green hydrogen and renewable energy projects.

As demonstrated in Fig. 27, the most significant local impact (highest values) of green hydrogen and renewable energy projects is evident around the African Great Lakes region of East Southern Africa, including Lake Malawi, Lake Tanganyika, and Lake Victoria. Similar results can be identified in inland regions near the southern and eastern borders of the Democratic Republic of the Congo, northern Tanzania, and parts of Mozambique, Zimbabwe, and Lesotho. For Western Africa, the coastal regions of Upper Guinea and the inland regions encompassing Nigeria and Burkina Faso demonstrate a notable local impact. This high local impact in the regions described is primarily attributable to a

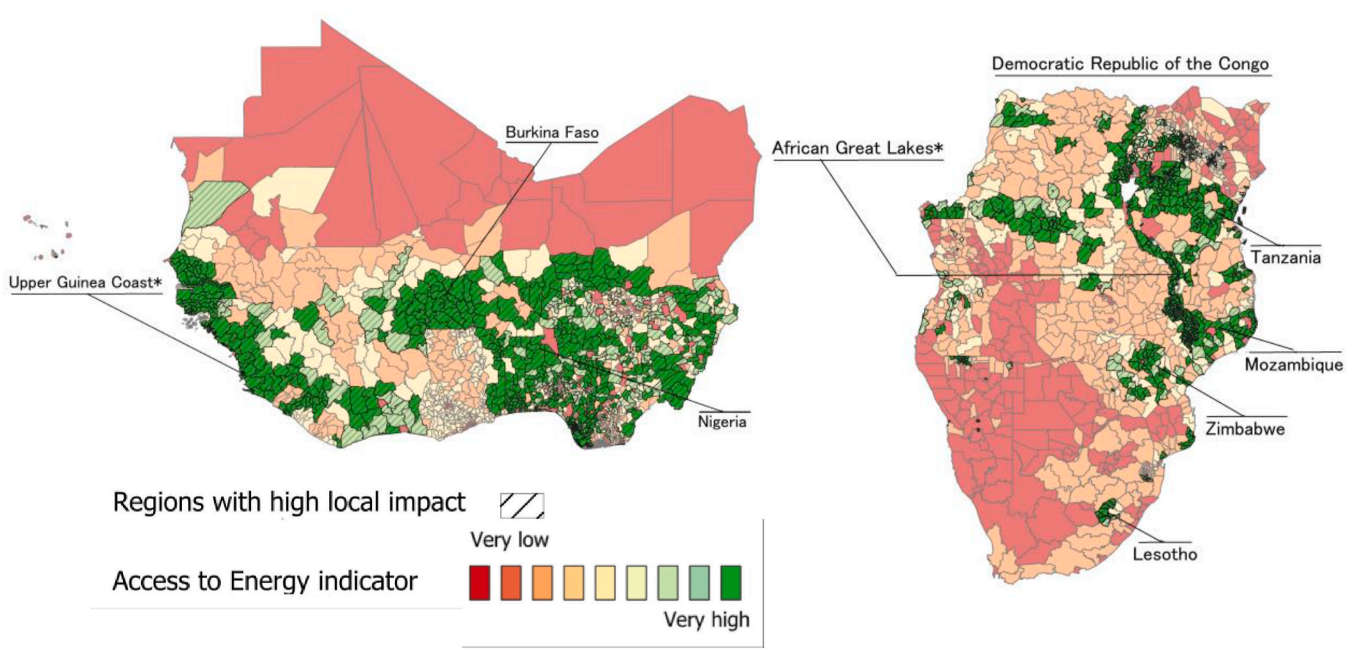

Fig. 28. Mapping the energy access indicator.

Table 4
Energy access indicator statistics results along national energy access averages for West (W), East and Southern (S-E) regions.

Country	CN	Region	AE indicator statistics				Energy access	Density
			Median	Q25	Q75	IQR	Average in %	Average in c/km2
Benin	BEN	W	48.3	31.8	79.4	47.7	42.0	110.0
Burkina Faso	BFA	W	45.4	33.5	74.7	41.2	19.0	79.0
Cabo Verde	CPV	W	5.0	3.0	9.7	6.7	95.5	139.0
Côte d'Ivoire	CIV	W	26.0	16.4	30.7	14.3	71.1	85.0
Gambia	GMB	W	130.1	23.4	194.0	170.6	63.7	246.0
Ghana	GHA	W	19.7	7.9	24.0	16.2	86.3	139.0
Guinea	GIN	W	32.2	24.0	40.4	16.4	46.8	55.0
Guinea-Bissau	GNB	W	40.8	28.0	49.8	21.8	35.8	72.0
Liberia	LBR	W	22.0	12.2	35.2	23.1	29.8	54.0
Mali	MLI	W	14.2	5.2	23.8	18.5	53.4	17.0
Mauritania	MRT	W	0.7	0.3	6.9	6.6	47.7	5.0
Niger	NER	W	38.4	15.6	63.7	48.1	18.6	20.0
Nigeria	NGA	W	126.1	54.8	268.9	214.1	59.5	232.0
Senegal	SEN	W	39.8	12.7	54.6	41.9	68.0	89.0
Sierra Leone	SLE	W	68.5	46.8	73.3	26.5	27.5	113.0
Togo	TGO	W	43.0	34.3	49.7	15.4	55.7	156.0
Angola	AGO	S-E	6.8	1.7	17.7	16.0	48.2	27.0
Botswana	BWA	S-E	0.2	0.0	1.5	1.5	73.3	4.0
Congo DR	COD	S-E	14.5	0.1	30.5	30.4	20.8	41.0
Eswatini	SWZ	S-E	15.0	13.5	21.7	8.1	82.9	68.0
Kenya	KEN	S-E	36.0	21.2	56.8	35.6	76.5	97.0
Lesotho	LSO	S-E	37.8	27.2	44.4	17.2	50.4	71.0
Malawi	MWI	S-E	149.4	101.1	254.6	153.5	14.2	208.0
Mozambique	MOZ	S-E	20.0	8.6	31.0	22.3	31.5	41.0
Namibia	NAM	S-E	5.8	1.0	47.5	46.5	55.2	3.0
Rwanda	RWA	S-E	397.6	256.2	465.2	209.0	48.7	538.0
South Africa	ZAF	S-E	2.5	0.0	5.2	5.1	89.3	49.0
Tanzania	TZA	S-E	55.0	26.6	90.8	64.1	42.7	69.0
Uganda	UGA	S-E	140.0	64.5	240.1	175.5	45.2	235.0
Zambia	ZMB	S-E	11.0	7.8	15.4	7.6	46.7	25.0
Zimbabwe	ZWE	S-E	27.4	15.0	37.1	22.2	49.0	39.0

combination of factors, including access to energy and macroeconomic potential impacts, as illustrated by the following two sub-indicators:

The local impact in terms of the socio-economic indicator is reflected in the composition of AE, which depicts the energy access indicator in capita/km^2; ME, which highlights the macroeconomic effect in Jobs/(Mwp*km^2); and OE, which summarizes the score of the other effect. The underlying indicator results for AE and ME for the two regions are presented in the form of normalized score maps and statistical summaries in the subsections below.

3.5.1. Energy access indicator (AE)

The energy access sub-index considers a combination of regional access to energy, and the access density. A combination of factors, mainly low access to essential services such as electricity and clean fuel, contributes to a high local impact value. The regional distribution is shown in Fig. 28, along with the indicator statistics, energy access, and population density average at the national level.

Malawi, the northern regions of Tanzania, the southern areas of Mozambique, and western Zimbabwe, as well as the southern part of the Democratic Republic of Congo, exhibit a significant local impact in this regard. For West Africa, the high impact extends to the entire southern region, except Ghana, the Ivory Coast, and sparsely populated areas in the central region (Fig. 28). Notably, countries such as Burkina Faso, Sierra Leone, and Liberia are showing particularly low access rates, with an average of less than 30% access to electricity and less than 20% access to clean fuels. Nevertheless, the significance of considering the

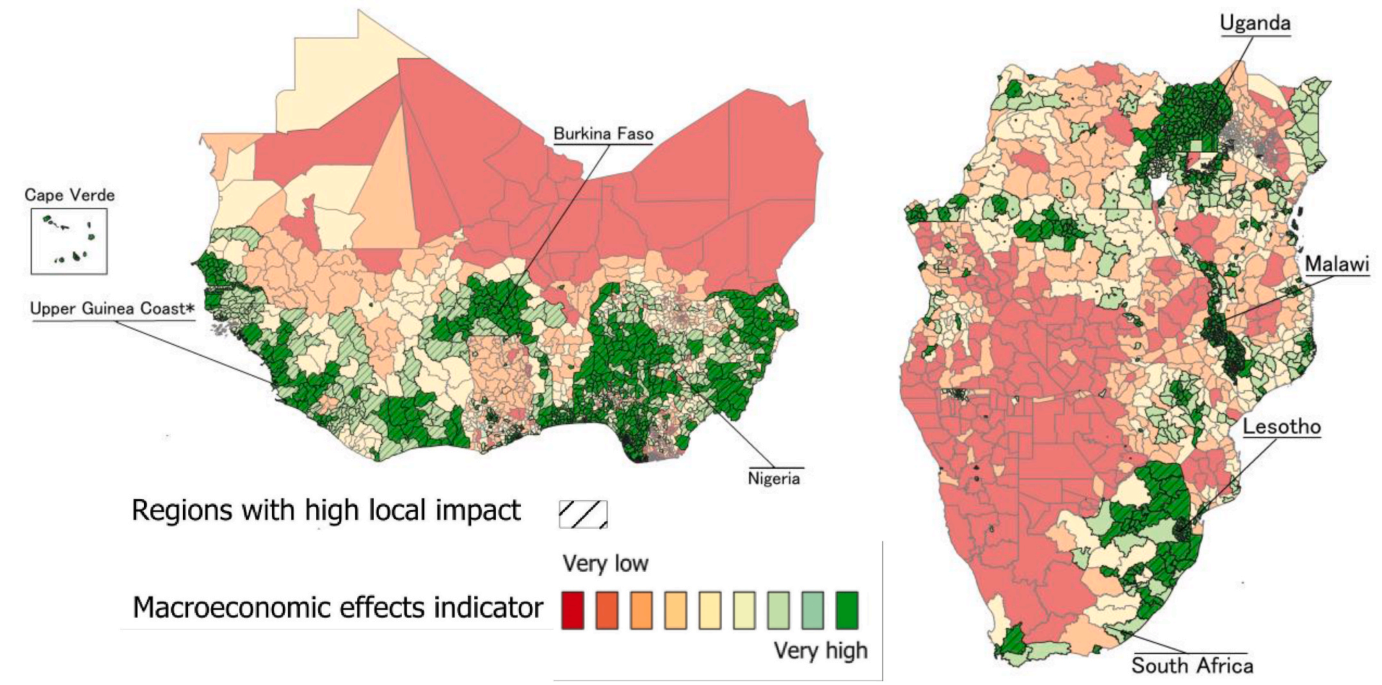

Fig. 29. Mapping of the macroeconomic effects indicator.

population density is exemplified by the case of Niger. In this instance, despite the low access to electricity, which is below 20% on average, the sub-index value remains relatively low for Niger due to the sparsely populated or nomadic areas.

A comparison of the AE indicator statistics at the national level (Table 4) reveals that in the Western region, Nigeria, Gambia, and Sierra Leone, followed by Benin and Burkina Faso, have the greatest potential impact. This impact arises primarily from two factors: the high population density in the first two countries and the low levels of energy access for the remaining. It is also relevant to highlight that the interquartile range (IQR) for Gambia and Nigeria is higher than that of other countries due to regional inequalities in terms of electrification and population distribution, which is particularly evident in the case of Nigeria. Accordingly, it can be argued that these countries would greatly benefit from the implementation of distributed energy projects that aim to enhance renewable energy potential. Conversely, some countries will not benefit from a direct local impact of similar energy projects, such as Cape Verde and Ghana, as they already have high levels of energy access.

In the depicted Southern and East regions (Table 4), due to a combination of low average access to electricity and high population density, Malawi, Rwanda, and Uganda report the highest averages, followed by Tanzania. By contrast, countries such as Botswana and South Africa show lower values due to their high electrification rates.

3.5.2. Macroeconomic effects indicator (ME)

The macroeconomic effect sub-index is evaluated in terms of the regional impact on employment, with unemployment data serving as one of the main indicators (Fig. 29). This index demonstrates that the most significant possible macroeconomic developments in West Africa are possible in Nigeria, Burkina Faso, and Cape Verde, as well as in regions such as the Upper Guinea Coast. Similarly, Eswatini, Lesotho, Malawi, Uganda, and the north-west of South Africa emerge as key areas with high employment impact in the Southern African context. Nigeria stands out as a state with the highest employment impact, due to its large labor force and dispersed but dense population. Nevertheless, countries such as Angola and the Democratic Republic of Congo exhibit a lower impact on employment levels despite comparable labor forces. This disparity occurs because of a mismatch between the distribution of energy potential and the population. It should be noted that Botswana has the lowest local employment impact, which is largely attributable to a sparse labor force, population distribution disparities, and high labor costs.

At the national level, the ME indicator statistics (Table 5) demonstrate that in the Western region, the macroeconomic effect values are primarily related to the employment factor of increased electrical power and their potential for job creation. Burkina Faso, Gambia, Ghana, Nigeria, and Togo are notable countries in this region. Cabo Verde, despite having good energy access, exhibits a high macroeconomic effect value due to its high unemployment rate (13.3%). The results indicate that Kenya, Eswatini, Lesotho, Malawi, and Rwanda have a noteworthy potential for job creation from renewable energy projects (high macroeconomic effect). In this regard, for South Africa, it is mainly the unemployment rate that could be tackled with development of green hydrogen projects. In contrast, to other countries, the macroeconomic effect is attributable to the employment factor here in terms of potential job creation per megawatt-peak in these countries higher than 5.8 job/Mwp.

For this analysis, the focus is on the local labor forces in construction or operations and maintenance (OM), with manufacturing jobs being excluded. Nevertheless, the potential for competitive regional solar and wind industries to create an additional 30% and 11% of jobs, respectively, represents a significant opportunity for economic growth. Furthermore, due to data constraints and the fact that the analysis is conducted using local employment factors, indirect and induced jobs are not accounted for. This limitation analysis does not conflict with a local impact indicator that aims to analyze direct local jobs without population displacement.

Whereas Nigeria's potential stems primarily from its large workforce, West Africa's potential stems from its comparatively lower labor costs. Thus, for instance, green hydrogen production from wind, even with a lower employment impact than solar hydrogen production, still generates up to 11 times more jobs per megawatt peak than in the EU due to lower labor cost. In contrast, countries in Southern Africa, such as South Africa, Botswana, and Namibia, have labor costs that are on average only two to three times higher than in the European Union.

Table 5
Macroeconomic indicator statistics results along employment national indicators for West (W), East and Southern (S-E) regions.

			ME indicator statistics				Unemployment	Employment Factor
Country	CN	Region	Median	Q25	Q75	IQR	Average in %	Average in job/MWp
Benin	BEN	W	6.4	2.0	14.6	12.6	1.6	5.9
Burkina Faso	BFA	W	6.7	4.8	10.8	6.0	5.0	6.0
Cabo Verde	CPV	W	26.2	15.4	53.9	38.5	13.3	4.5
Côte d'Ivoire	CIV	W	5.6	3.2	8.0	4.9	2.7	5.8
Gambia	GMB	W	16.3	13.2	27.4	14.2	4.6	5.9
Ghana	GHA	W	13.7	8.2	36.1	28.0	3.7	5.8
Guinea	GIN	W	6.0	4.1	9.0	4.9	5.5	5.8
Guinea-Bissau	GNB	W	5.4	3.7	6.1	2.4	3.5	6.0
Liberia	LBR	W	4.1	2.0	6.1	4.0	3.4	5.7
Mali	MLI	W	1.0	0.4	1.9	1.5	2.4	5.9
Mauritania	MRT	W	1.5	0.3	3.3	2.9	10.9	5.8
Niger	NER	W	0.6	0.2	1.1	0.9	0.6	6.0
Nigeria	NGA	W	29.1	13.3	81.9	68.6	5.6	5.4
Senegal	SEN	W	3.8	2.9	14.2	11.3	3.4	5.6
Sierra Leone	SLE	W	11.3	7.1	12.9	5.8	3.5	5.7
Togo	TGO	W	7.7	5.8	14.3	8.5	3.9	5.9
Angola	AGO	S-E	1.0	0.4	2.2	1.8	10.0	1.8
Botswana	BWA	S-E	0.2	0.0	22.1	22.1	20.6	0.3
Congo DR	COD	S-E	3.8	1.5	26.8	25.2	4.8	5.9
Eswatini	SWZ	S-E	29.4	18.7	30.7	12.0	23.9	3.1
Kenya	KEN	S-E	17.0	7.8	36.0	28.1	5.2	5.8
Lesotho	LSO	S-E	6.3	4.0	12.8	8.8	17.7	2.3
Malawi	MWI	S-E	22.1	14.3	45.8	31.4	5.4	5.9
Mozambique	MOZ	S-E	2.4	1.1	4.2	3.1	3.7	5.9
Namibia	NAM	S-E	0.7	0.1	4.7	4.6	20.6	1.4
Rwanda	RWA	S-E	162.4	121.4	189.1	67.8	12.8	5.9
South Africa	ZAF	S-E	7.8	4.1	16.7	12.6	26.5	1.4
Tanzania	TZA	S-E	5.1	2.2	11.5	9.3	2.5	5.9
Uganda	UGA	S-E	16.4	7.8	25.9	18.1	4.0	5.8
Zambia	ZMB	S-E	0.6	0.3	1.2	1.0	5.8	1.6
Zimbabwe	ZWE	S-E	3.9	1.9	6.2	4.3	7.6	4.2

Nevertheless, even in these countries, particularly in the northwestern region of South Africa with a high population density, the high labor cost is offset by soaring unemployment rates exceeding 20% over the past two decades. This highlights the necessity for strategic interventions to leverage green hydrogen and renewable energy deployment as a potential employment catalyst.

4. Discussion and conclusions

The results of the study yielded several findings and permitted the formulation of various conclusions. These findings are presented here in a step-by-step manner, with each analysis step being addressed in succession. This structured approach underscores the outcomes of individual assessments and emphasizes the synergies derived from the multidisciplinary methodology employed in this study. The limitations of the study are discussed to guide future research and applications.

4.1. Results findings and conclusions

This section delineates the key findings and conclusions derived from the various analyses. Each aspect is examined to provide a comprehensive understanding of the green hydrogen potential in Sub-Saharan Africa, offering insights into both technical feasibility and developmental opportunities.

4.1.1. Land eligibility and renewable electricity potentials

The present study provides valuable insights into the land eligibility for renewable energy technologies in the selected African regions, taking into account technical, sociological, and ecological criteria. The results of the study indicate the distinct inclinations of regional stakeholders, including community members, governmental bodies, and international institutions in every country. It is noteworthy that eligibility rates vary significantly across different countries, ranging from approximately 0.1% in Seychelles to around 50% in Niger, Mali, and Mauritania. Protected forests and pastures emerged as significant constraints on eligible land areas in both regions, while sand dunes in western Africa also excluded substantial areas from eligibility.

The results of this study indicate that among renewable energy sources in the analyzed regions in Sub-Saharan Africa, open-field photovoltaics have the largest installable capacity potential. This is particularly evident in desert regions of the Sahara and the Nama Karoo region in South Africa, Namibia, and Botswana. However, it should be noted that the capacity potential varies significantly across different regions. Even regions that initially appear to have low potential can exhibit substantial absolute potentials resulting in levelized cost of 3.5 $Ct_€$/kWh down to 2 $Ct_€$/kWh by 2030 with a further reduction of approximately 25% until 2050 in the optimal locations within the Nama Karoo ecoregion in South Africa and Namibia, extending into Botswana. By 2050, with projected cost reductions in investment, a further decline in LCOE of 25% can be attained, thereby narrowing the spatial disparity and gradually reducing the competitive advantage of the desert regions.

Despite the relatively modest potential of onshore wind energy, which is estimated to be approximately 13% of photovoltaic (PV) energy, it has been demonstrated to satisfy multiple times the local demand in numerous countries. Furthermore, its capacity to supply energy during periods of insufficient sunlight, such as during nighttime hours, enhances its viability as a complement to and a diversification of the energy mix. The optimal locations for this technology are primarily situated in close proximity and outside the intertropical latitudes, such as the southern regions of Africa and the northern regions of Eastern Africa. However, scatter potential is also evident in numerous tropical countries, attributable to terrain characteristics and local wind patterns. In such instances, the land restrictions may be adapted to align with local preference for developing wind energy projects. Conversely, the potential for hydropower is even more constrained. In some regions, this potential is non-existent due to their geographical locations, while in others, such as the Democratic Republic of the Congo, it is abundant and has the potential to serve as the foundation for a robust renewable energy system. The viability of such projects is contingent on local preferences for this particular energy source. Finally, the geothermal energy in Kenya is more expensive compared to local PV, but it has the advantage of dispatchability. Consequently, the whole energy system cost is of paramount importance in this context.

4.1.2. Sustainable water supply assessment

The evaluation of groundwater sustainable yield reveals that water utilization in West and Southern East Africa is sustainable. However, notable variations exist among countries and climate scenarios concerning estimated groundwater sustainable yield. For instance, the analysis indicates that the projected groundwater availability in 2050, particularly under the RCP8.5 climate scenario, is anticipated to be lower than the projected levels observed in 2020 and 2030. The analysis suggests that the available groundwater resources hold immense potential. These resources have the potential to meet human and environmental water needs in West and Southern East Africa regions. Notably, these resources possess the capacity to support green hydrogen production. However, under future climate conditions, particularly in the pessimistic RCP8.5 scenario, which is regarded as a pessimistic scenario, there is projected to be a decline in groundwater. In the context of arid regions in proximity to the coast, seawater desalination emerges as a promising alternative. However, the cost analysis indicates that even long-distance transport is economically and technically feasible. Nevertheless, the political feasibility and safety of infrastructure might pose significant challenges in implementing these solutions.

4.1.3. Hydrogen cost, potentials and water use

The potential for green hydrogen production in the designated project area is substantial, with an estimated yield of 400 PWh/a more than double the total global primary energy consumption in 2021 [71]. These figures exceed the projected energy demands of the involved countries by a factor of 20, thereby enabling the potential for export schemes in nearly all of the countries involved, with the caveat that the satisfaction of local demands must be prioritized. The most substantial and economically viable potential is observed in the desert regions of the Sahara, particularly along the northern Mauritanian coast and in the border region between South Africa, Namibia and Botswana. Noteworthy potential has also been identified in Cabo Verde, Kenya, Madagascar, and selected isolated regions with hydropower availability. While the Sahara and Mauritania have been found to employ significant shares of wind capacity in their optimal systems, hydrogen is primarily produced from solar power in Southern Africa. Hydropower has the potential to produce hydrogen at a very low-cost hydrogen; however, it must be treated with care, as hydropower electricity will be needed for electricity supply and grid stability more urgently. The exclusive reliance on surplus energy, however, results in a diminution of the quantitative potential and an escalation in costs. Consequently, the implementation of hydropower for hydrogen production should be subject to a plant-specific evaluation.

In comparison, the cost for solar and wind-powered hydrogen is estimated to be approximately 2 EUR/kg in 2030, decreasing to 1.6 EUR/kg by 2050. The potential-weighted average for the entire study region is estimated to be approximately 2.7 EUR/kg in 2030 and slightly above 1.9 EUR/kg in 2050. The potential for green hydrogen production at a cost of less than 2.5 EUR/kg in 2030 is estimated to be approximately 31 TWh/a. By 2050, the production is projected to reach approximately 260 TWh/a under a cost ceiling of 2 EUR/kg. In contrast to wind-based hydrogen, the cost of solar-based hydrogen cost is relatively independent of the quantity produced. In comparison with the literature, this study identifies the lowest cost of hydrogen in Western and Southern Africa at 1.6 EUR/kg, while Franzmann et al. find 1.50 EUR/kgH2 and IRENA 1.05 EUR/kgH2. The primary factors contributing to these variations in hydrogen costs are the distinct techno-economic assumptions employes: Franzmann et al. [46] assume a considerably higher lifetime of PEM electrolysis of 19 years, while our assumption is 10 years, which aligns more closely with the values reported in the literature. IRENA [8] projects significantly higher cost reductions for photovoltaic, wind, and PEM electrolysis by the year 2050, resulting in costs approaching 1.05 EUR/kgH2. Additionally, both studies omit the comprehensive inclusion of water production costs in their analyses of hydrogen costs. In terms of energy supply, this approach finds a technical potential in Namibia of 10 PWh/a, while Franzmann et al. [46] find 20 PWh/a. This discrepancy can be attributed to the land exclusion criteria employes in this study, wherein the technical PV potential is constrained by local preferences, particularly for shrub land. For the broader region of Western and Southern Africa, the study estimates a technical hydrogen potential of 402 PWh/a.

In two-thirds of the regions examined, sustainable local groundwater resource prove inadequate to meet the water demands necessary for realizing the full technical hydrogen potential. Furthermore, approximately half of the regions lack the capacity to provide sufficient water even for a moderate expansion degree of 25% of the technical potential. This predominantly affects regions with high potential and low costs. However, the cost of alternative water supply options, such as desalination, is estimated to be no more than ~1% of the levelized cost of hydrogen. Consequently, it can be concluded that viable economic solutions exist to produce sustainable hydrogen beyond the limits of local groundwater potentials. However, to ensure the sustainability of local water resources for the population, the construction of additional seawater desalination capacities is often necessary to achieve cost-effective levels of hydrogen at large scale. Consequently, the strategic planning of sustainable water supply infrastructure should be an integral component of any large-scale sustainable hydrogen project in the region.

4.1.4. Mapping local socio-economic impacts of green hydrogen projects

An analysis of the local impacts of green hydrogen projects across selected regions in Africa reveals distinct regional patterns, with significant implications for both energy access and macroeconomic development. The African Great Lakes region, encompassing countries such as Malawi, Tanzania, and Mozambique, along with regions along the Upper Guinea coast, exhibit the most pronounced local impact. The primary factors contributing to this impact include limited access to essential services such as electricity and clean fuel, coupled with high population densities and significant employment impact.

Conversely, countries within West Africa, such as Nigeria, exhibit considerable potential for job creation, attributable to their substantial labor forces and comparatively lower labor costs. Concurrently, in the Southern African region, countries such as Rwanda exhibit a similar trend. Conversely, nations grappling with high unemployment among the labor force stand to benefit from the establishment of a local hydrogen economy. However, intra-country disparities, as evidenced by regional discrepancies within Nigeria, pose notable challenges. Furthermore, the emergence of competitive regional solar and wind industries, particularly in Southern and East Africa, has the potential to generate additional manufacturing job opportunities. However, addressing challenges such as data limitations and the exclusion of indirect and induced employment metrics remains imperative to ensure a comprehensive understanding of the localized impacts of green hydrogen projects.

4.2. Discussions and general conclusion

The discussion integrates the findings to emphasize the synergies between technical and cost feasibility, environmental, and socio-economic dimensions of green hydrogen development. Furthermore, it delved into the broader implications for policy, regional cooperation, and future research. The discussion concludes with strategic recommendations to maximize the socio-economic and environmental benefits of green hydrogen projects.

4.2.1. Green hydrogen potentials in sub-Saharan Africa derived by a multidisciplinary approach

In the domain of energy supply, the competition for land between electricity and hydrogen has garnered attention due to the substantial potential for both. In photovoltaic (PV) dominated systems, the costs are less impacted by the expansion rate, creating opportunities for regions with abundant resources. The identification of regions with inexpensive potential that exceeds their own demand creates the potential for these regions to become exporters within and outside of Africa. The hydrogen cost patterns observed in this study, generally align with those reported in other studies that evaluated LCOH in African countries. In comparison to the findings of Gado et al. [16], the utilization of a co-optimized PV and wind hybrid system across the considered countries can reduce the reported LCOH can be lowered by 2–3 EUR/kg in 2030.

However, it is crucial to note that excessive exploitation of groundwater resources in coastal regions can significantly exacerbate the risks of saltwater intrusion and land subsidence [77,78]. This is in addition to the environmental concerns discussed by Bierkens and Wada [79]. It is therefore imperative to strike a balance between desalination of seawater and groundwater extraction, particularly in coastal areas. It is crucial to exercise prudence in the planning of groundwater exploitation, even when cost-effective solutions appear viable. Prioritizing desalination over extensive groundwater extraction is instrumental in safeguarding these vital freshwater reserves and ensuring a more sustainable and resilient water supply. Desalination mitigates risks such as land subsidence and long-term aquifer depletion, which can have significant environmental and economic consequences. Consequently, the incorporation of desalination into comprehensive water resource management strategies is essential to maintain the integrity of coastal water supplies. Beyond its application in hydrogen production, a reasonable oversizing of the desalination and water transportation infrastructure could enhance local access to affordable and clean water.

The impact of groundwater availability is a salient factor in this regard. In addition, the overall green hydrogen cost potential is driven by the local land eligibility constraints which are tied to the local prevailing policies or regulations. For countries with similar land area, the eligibility of such land for green hydrogen production can vary substantially, resulting in significant differences in the levelized cost of hydrogen among countries, as illustrated.

Notably, the coastal regions of Western Africa and Northeastern Africa are identified as promising hubs for hydrogen production, offering not only significant potential for generating green energy but also for delivering substantial local economic benefits. These regions possess abundant natural resources, which, when combined with their strategic geographic locations, make them ideal candidates for large-scale hydrogen production and export. The region's rapidly expanding population and the sizeable labor force present a distinctive advantage, particularly in the early stages of hydrogen economy development, where there will be a significant demand for construction, installation, operation, and maintenance jobs. However, to capitalize on the full potential of this emerging technology, it is imperative to allocate resources toward capacity building to further develop a local manufacturing industry. In the long term, this development could be driven by the competitive costs of African technologies could be driven by the African Continental Free Trade Agreement (AfCFTA), which is expected to enhance cross-border trade and investment in the renewable energy sector.

The current inadequate energy access levels in many African regions could pose challenges such as increasing the risk of energy supply insecurity for hydrogen production and the potential for energy-related conflicts. The developed approach underscores the potential of green hydrogen projects to enhance energy security and broaden electricity access, thereby addressing long-standing energy deficits. This paradigm shift has the potential to mitigate the risks associated with reliance on traditional fossil fuels and imports, thereby contributing to a more sustainable and resilient energy system.

The presence of established fossil fuel and chemical industries in countries such as Nigeria, Angola and South Africa provide a solid foundation for hydrogen production and export. These industries possess existing substantial infrastructure and investment incentives that can be repurposed and upgraded to support hydrogen production. Furthermore, existing oil terminal infrastructures could be repurposed for liquid organic hydrogen carriers. This strategy is predicated on the maximization of existing assets and the reduction of the initial investment required to develop a hydrogen economy. Nevertheless, in order to circumvent the risk of technological lock-in and to facilitate a seamless transition to green hydrogen, the implementation of comprehensive decarbonization policies is imperative. These policies should aim to gradually phase out reliance on fossil fuels while promoting the adoption of clean, renewable energy sources.

4.2.2. Synergies and future Directions

This study underscores the pivotal role of green hydrogen in addressing the immediate and long-term energy requirements of the regions examined. The prioritization of electricity demand over hydrogen production signifies a dual strategy to advance Sustainable Development Goal 7 (SDG-7), concurrently enhancing economic added value and social progress. By assigning lower-cost electricity resources to satisfy local energy demands first, the framework guarantees affordability and equity, particularly in regions grappling with high energy poverty. This approach also creates a synergistic pathway where the oversizing of green hydrogen production infrastructure can indirectly expand electricity access. The complementary nature of hydrogen production and electrification emerges as a critical strategy for maximizing the socio-economic benefits of renewable energy systems.

For instance, in regions with substantial renewable energy potential, cost-effective hydrogen production can coexist with electrification initiatives. The oversizing of electrolyzers not only supports hydrogen local demand and exports but also enables the integration of surplus electricity into local grids, thereby driving electrification. Similarly, the co-development of desalination systems for hydrogen production can enhance water access, alleviating water scarcity in underserved areas. This integrated perspective ensures that the benefits of hydrogen production are not seen as disjointed from the broader objective of enhancing energy and water security.

The criteria for determining land eligibility play a pivotal role in maximizing socio-economic impacts. By adopting a more flexible approach to the constraints on land-use and applying feasible, rather than overly restrictive, buffer zones, a significant additional area can be utilized for renewable energy projects without necessitating displacement. This balanced approach promotes inclusivity and minimizes social disruption, ensuring that local communities benefit from job creation and infrastructure development.

While this study provides a robust analysis of green hydrogen potentials, it intentionally avoids making trade-offs between different objectives, such as techno-economic feasibility, socio-economic benefits and environmental impacts, to maintain an objective basis for policy-making. However, the public availability of the results allows stakeholders to overlay various data layers in the provided graphical user interface (GUI) to identify optimal locations that balance and highlight the multidisciplinary approach.

At the national level, however, a composite index methodology has been developed to assess the feasibility of hydrogen economies [80]. These indices merge the results at the national level and are expanded to incorporate regulatory and political considerations. Moreover, extending this analysis to include dynamic trade-off evaluations could provide actionable insights for policymakers seeking to optimize hydrogen investments across multiple dimensions.

CRediT authorship contribution statement

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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

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