Generation capacity expansion planning with spatially-resolved electricity demand and increasing variable renewable energy supply: Perspectives from power pooling in West Africa

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Abstract

Power pooling has emerged as a regional strategy for accelerating generation capacity expansion in West Africa with the aim of leveraging vast domestic energy resources and promoting investment in regional power infrastructure. As part of their climate action pledges, most West African countries have committed to increasing the shares of variable renewable energy (VRE), particularly solar photovoltaics and wind power, in their generation mix. It, however, appears that approaches to utility-scale capacity expansion planning tend to overlook the inherent temporal intermittency and spatial variability of VRE-based generation. Moreover, despite influencing the techno-economic rationale for grid expansion and off-grid electrification, as well as the trade-offs between high renewable supply areas and grid expansion, the spatial distribution of demand has been overlooked in planning approaches, leading to conservative and weak prospects for the contribution of utility-scale VRE. Such inconsistencies with the region-wide potentials and policy ambitions highlight that it is paramount for West Africa to design its power pooling such that spatial and temporal fluctuations of VRE supply are duly considered in capacity expansion planning while taking advantage of complementarities between VRE supply and national electricity demand profiles. To address this, the present paper applies a long-term generation capacity expansion model, OptGen, soft-linked to a least-cost operation module, the SDDP tool, which is enhanced by geospatial electrification analysis using the OpeN Source Spatial Electrification Tool (OnSSET), to a subset of four member countries of the West African Power Pool – Burkina Faso, Cote d'Ivoire, Ghana, and Mali – for the 2023-2040 time horizon. The results highlight that current frameworks lead to missed opportunities for bridging the supply-demand gap in all countries, not only in terms of VRE generation capacity, but also of cross-border power trade.

Keywords: Variable renewable energy; Spatial granularity; Time granularity; Stochastic Dual Dynamic Programming; Investment modeling; West Africa.

1. Introduction

The West African Power Pool (WAPP) which was created in 2000 as a specialized agency of the Economic Community of West African States (ECOWAS), essentially gathers power utilities from fourteen (14) countries with national electrification rates ranging from 19.3% to 85.9% [1]. The region has a relatively long history of bilateral imports/exports between neighboring countries with contrasting generation mixes, costs, and demand levels. Power pooling has emerged to create economies of scale in countries with relatively small power systems to integrate them into a non-discriminatory competitive market to reduce generation costs and electricity tariffs [2]. Moreover, the current political agenda for sustainable development has recently culminated in region-wide recognition of the urgency of tapping into the huge endowment of variable renewable energy (VRE), such as solar photovoltaics (PV) and wind power to expand generation capacity [3], [4]. Notwithstanding, only a handful of VRE projects are considered in the approved list of WAPP priority projects to be implemented by 2033 [4]. Additionally, the technical analysis for their selection relies on conservative assumptions (annual VRE generation capacity limited to a maximum of 10% of peak demand in each country) on top of their final selection process being carried out by high-level decision-makers in collaboration with the Donor Coordination Committee [5]. This goes to support the remarks by [6]–[8] revealing that besides financial constraints, a severe challenge to scaling up electrification levels in West Africa remains poor planning processes stemming from the lack of resources and unsound methodology and objectives, especially with regards to VRE.

Hence, the ambitions for higher VRE shares appear to translate in practice into weak prospects for the contribution of utility-scale VRE which are inconsistent with countries' endowment, with power systems expected to remain dominated by hydro-thermal generation. This stems from the time and spatial dimensions of VRE supply and electricity demand being overlooked by conservative assumptions based on the widespread consideration that VRE fluctuations render their contribution to capacity and peak demand marginal. A study by [9] brought forth the limitations of considering average wind speeds for VRE deployment and demonstrated through hourly time steps analysis that quality wind energy resources are not limited to the Northern part of West Africa but can rather potentially be harnessed across an extended geographical area, stretching from Senegal to Nigeria. It also shows that higher wind speeds at night-time, particularly over the dry season, offer an exploitable potential for complementing PV plants thus suggesting that the idea of VRE plants being unsuitable for contributing to meeting baseload demand, used as an argument to conservatively limit their share in the supply mix, becomes irrelevant as argued in [10]. Indeed, baseload is an inherent characteristic of (variable) demand rather than supply which should be contemplated considering the future.

Planning for higher shares of utility-scale VRE in expanding generation capacity, therefore, ought to consider both the spatial and temporal variabilities of these resources. Doing so provides insights not only into the techno-economic rationale for either expanding the grid or implementing off-grid solutions, but also into the necessary trade-offs between high renewable supply areas and capacity expansion. Very few ECOWAS countries have individually been considered in the power systems literature with most countries featured in only one study [11], [12]. However, WAPP has slowly been attracting growing interest in literature. Interestingly, research has started expanding post-Covid-19, albeit slowly, with a wider geographical scope, particularly in Liberia [13], Burkina Faso [14], Côte d'Ivoire [15] and Mali [16]. The most relevant studies include [17]–[21] with limitations on either the time granularity or the spatial resolution of the models. The study by [20] improved the spatial resolution of their least-cost dispatch model but remained limited to the existing and planned interconnection nodes. The same authors later developed, for the first time, a bottom-up model for electricity demand forecasts in West Africa ([22]) which, among others, contributed to addressing the data availability limitation of [17] whereby demand profiles were not country-specific. However, even in [22], the spatial distribution of demand was overlooked.

In [23], the authors developed a linear programming model to determine an hourly resolved least-cost supply path for a 100%-renewables-based power system for sub-Saharan Africa. It was found that a 100% RE electricity supply system is techno-economically feasible, yet it will require a shift from traditional business models and unwavering policy commitment to phasing out conventional generation. Using TIMES-Nigeria, the authors in [24] sought to evaluate the impact of Nationallyy Determined Contributions targets on CO_2 emissions reduction and the induced effects on the national energy system. An Energy Diversity Index was developed and shown to reach its highest value (i.e., higher energy security) under the emissions trading scenario owing to a higher penetration of VRE. Using PLEXOS to solve the economic dispatch problem in a European region covering Germany, France, Belgium, Netherlands, Luxemburg, Great Britain and Ireland, [25]found that good interconnection combined with low-carbon (nuclear and RE) generation enhances a country's export market. In Brazil, a multi-objective optimization model based on the Interactive Multi-Objective Linear Progamming Explorer (iMOLPe) shows that solar PV generation is the optimal solution when considering government ambitions and seeking to meet peak demand, however, the current national energy plan does not reflect this opportunity [26]. In [27], OptGen was applied to the 6 countries of the Central American Regional Electricity Market. The authors demonstrated that an integrated generation capacity expansion planning of a multi-country system accounting for each country's resource endowment and regional interconnections yields lower short-run marginal costs, as well as investment costs. Hybrid optimization models through hard-linking and soft-linking have marginally been used across sub-Saharan Africa. The use of LEAP (Long-range Energy Alternatives Planning System), a built-in hard-linking simulation package, has risen in recent years, focusing on Ghana [28]–[31], Nigeria [32]–[34], Côte d'Ivoire [35], Mali [36], Sierra Leone [37]. Some studies soft-linked a long-term generation capacity expansion model to an economic model ([38] for South Africa) or a spatial electrification tool ([39] for Kenya). Extensive reviews of power systems modeling were performed by [12], [40], [41]. It is worth noting that most studies on power systems planning tend to overlook the uncertainties of hydro inflows and VRE supply. As demonstrated in [42]–[44], models with a stochastic methodology such as the Stochastic Dual Dynamic Programming allow modeling a more realistic system operation than mere deterministic investment models, particularly under high shares of intermittent VRE generation. Overall, despite acknowledging the potentially pivotal role of renewables and power pooling in attaining universal access to electricity in West Africa, planning models are yet to fully capture both the temporal and spatial intermittency of VRE. The present study aims to contribute to filling this gap by answering the following questions: (i) to what extent can the conservative 10% limit to VRE shares in generation capacity be optimally challenged? (ii) can increasing VRE penetration disrupt the traditional characterization of importing versus exporting countries and effectively catalyze power pooling? This is done by modeling a two-scenario least-cost investment plan for generation capacity expansion, using the OptGen tool, considering the spatial and time operational constraints of increasing VRE supply, using the SDDP tool [43], [44] enhanced by the results of a previous study by the same authors [11] which applied the OpeN Source Spatial Electrification Tool (OnSSET) to Burkina Faso and Côte d'Ivoire. The present study is extended to two additional WAPP member countries: Ghana, and Mali. The four countries display the three enabling factors for power pooling described by [45], namely different consumption profiles, different peak load periods and different climatic conditions.

Therefore, the main contribution of the present paper goes beyond expanding the scarce literature on the topic as it enhances the spatial granularity of the model by modeling twice as many nodes as the WAPP Master Plan [19] and over 30% more than [21], [46] for the study area. Moreover, the unique combination of long-term power system optimization modeling with an economic dispatch model allows accounting for the short-term temporal fluctuations of VRE to avoid overestimating their planned installed capacities, as well as to provide a more realistic estimation of the level of deployment of VRE generation, which impose high flexibility requirements on the existing/planned fleet.

2. **The remainder of the paper is organized as follows: Section 2 describes the methods and data. Section 3 presents the modeling results. Section** Error! Reference source not found. **discusses the results and Section** Error! Reference source not found. **concludes the paper, emphasizing its main conclusions.Methods and data**

Table 1 presents the criteria applied to select the power systems planning software best able to address the research questions of the present study.

Table 1 Selection criteria of the generation capacity expansion modeling tool

Criterium	Criterium description	Relevance to the research
Operation optimization	Operational constraints	Supply reliability requirements from higher penetration of VRE
Investment optimization	Project investment decisions	Long-term investment decision-making
Geographical area	Multi-country	Regional integration through interconnections between several countries
Time-step	Hourly	Integration of VRE with daily and seasonal output fluctuations
Spatial resolution flexibility	Multiple nodes (loads, resource availability, generation, and transmission infrastructure)	Multi-node approach to reflect various load levels and profiles, and model individual generation power plants and high-medium voltage transmission lines within and between case study countries
Timeframe	Several years	Yearly modeling from the base year until the year 2040
Uncertainty constraints	RE and hydro supply variations	Integration of VRE-related supply intermittency and climate change effects on hydropower

It was concluded that soft-linking SDDP and OptGen constituted the best package of software for this study. Both are commercial modeling tools developed by PSR Energy Consulting & Analytics. However, they were made available for free under the student version. Soft-linking OptGen and SDDP involved combining the powerful advantages of each tool to co-optimize long-term generation capacity expansion investments and short-term operations. The flexibility of both tools allowed user-defined constraints, and particularly the use of the outputs of a geospatial electrification model using the Multi-Tier Framework for electricity access. The detailed methodology of the latter is described in [11]. The objective function, constraints, and other mathematical equations pertaining to SDDP and OptGen are laid out in Appendix A.

2.1. Overview of OptGen and SDDP

OptGen

OptGen is a computational tool for long-term power systems expansion planning which determines the least-cost investment schedule, over a planning horizon of one year to several decades for new generation plant capacity (hydropower, thermal and renewables), transmission infrastructure (national transmission and regional interconnections), and gas networks. The least-cost expansion plan can be solved using either one of two types of solution strategies chosen by the modeler, named OptGen 1 and OptGen 2 [27], [47]–[49]. Through Benders decomposition, OptGen is capable of directly solving the expansion planning problem by integrating SDDP calculations in a strategy solution called "OptGen 1". All the inherent features of investment and operating problems, namely stochastic, multiple stages and binary variables are solved directly within a single optimization package to obtain the optimal global solution. It also allows for system reliability representation in each iteration of the expansion plan through Monte Carlo simulation. Another strategy solution is “OptGen 2”, which uses an hourly operation model and solves both investment and operation problems in the same Mixed-Integer Linear Programming (MILP). While the former is most suitable for hydro-thermal dominated systems, the latter is more relevant in systems with high penetration of RE other than hydro. The hydro-thermal dominated feature of the study region makes OptGen 1 more suitable for application.

SDDP

SDDP is a mid- to long-term dispatch model with the representation of a hydrothermal and RE system alongside the transmission network for operational decision-making. The objective function is to minimize the immediate costs of using available hydro and thermal resources, and the expected value of future costs arising from hydrological uncertainty, intermittent RE generation, and electricity demand, through a Stochastic Dual Dynamic Programming algorithm [[43], [44]], [50]. This scheduling process means that today’s operating decisions can impact long-term operation, thus affecting future operating costs, which is vital for systems with storage devices. The decision periods, also called stages, can be chosen to be weekly or monthly. For this case study, monthly stages were chosen considering the data availability of historical water inflows and computational requirements. Electricity demand may be represented by blocks of similar load levels in a non-chronological demand curve in descending order, the Load Duration Curve, as well as by a chronological hourly order. The latter allows better characterizing the time intermittency of VRE supply. Within the scope of this study, the innovation of enhanced spatial granularity of the power system operation model was introduced at two levels:

(i) Electricity demands in grid suitable areas by the time horizon were characterized and their spatial distributions were identified using the spatial electrification tool OnSSET, following the methodology in [11].
(ii) VRE generation profiles were complemented by VRE suitability zones mapping aided by existing mappings performed in [51]–[53] which were complemented by OnSSET outputs and results in [54] on solar PV and wind complementarities.

Fig. 1 presents the flowchart of the study.

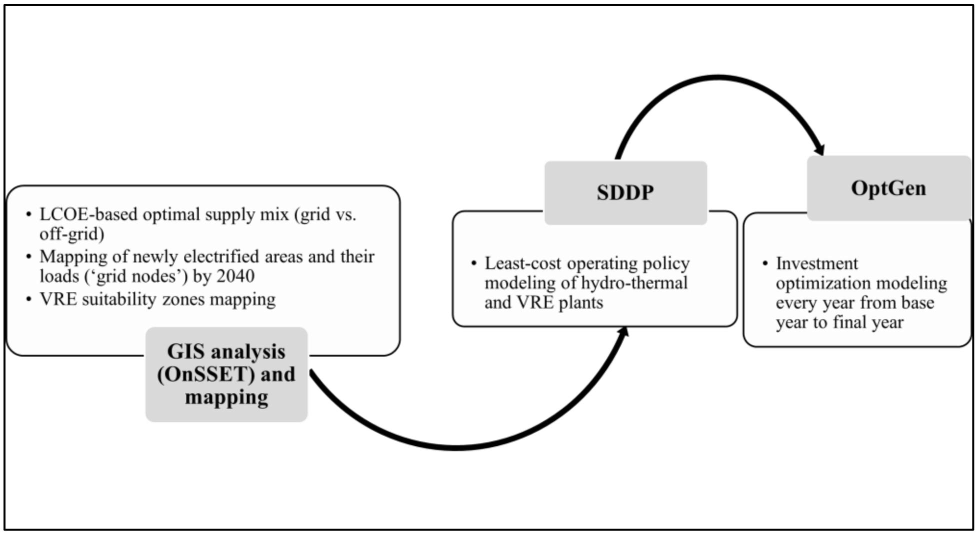


Fig. 1 Flowchart of the study

2.2. Data and assumptions

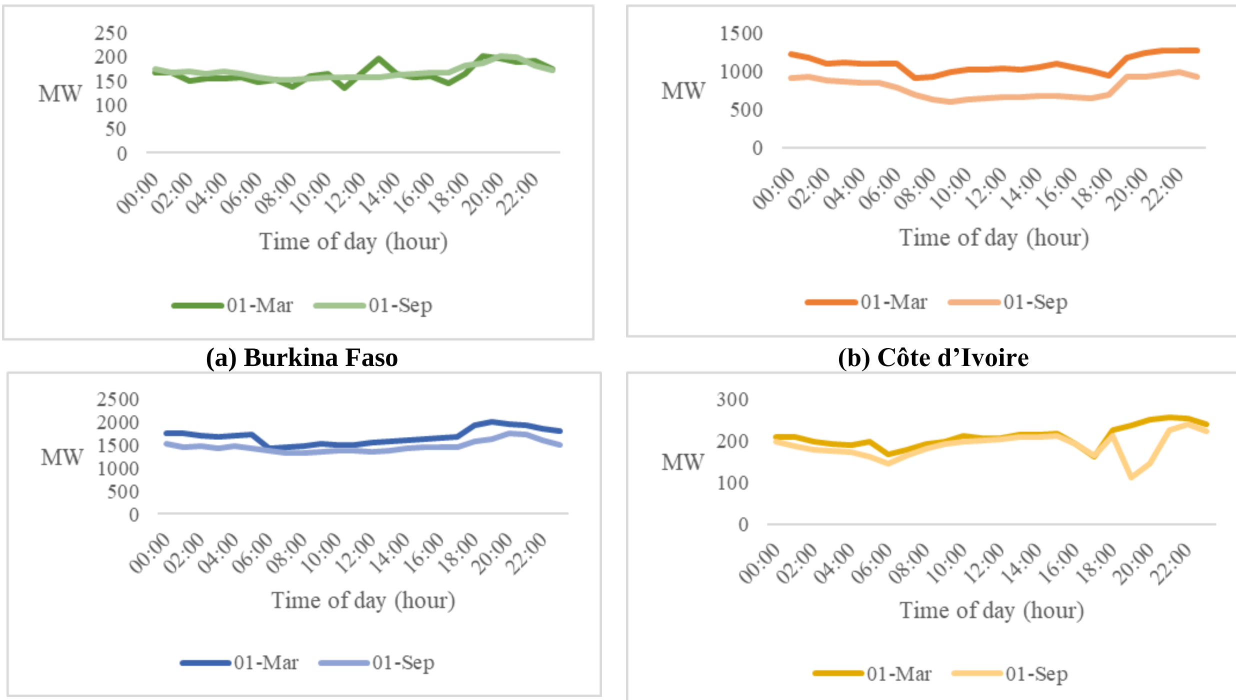
OptGen optimizes the trade-off between investment costs for new projects and operation costs (including the costs of unserved energy), using project financial data (investment costs, payment schedules, lifetime, construction time, etc.), as well as project specific data including minimum and maximum entrance dates, decision type (obligatory or optional) for future power plants (whether mere candidate/assumed or committed future plants). The complex characteristics of investment and operation problems combining continuous variables, binary variables, and uncertainty factors (RE generation, river flows, equipment availability, etc.) make such expansion planning problems both integer and multi-stage stochastic optimization problems. The difference between decided and candidate projects is reflected as follows: decided power plants are assumed to be operational by the final year of the modeling (2030, 2040), hence "existing". "Future" plants are candidate plants for which the least-cost optimization model will determine whether they are viable for investment. Future power plants include both planned (thermal, hydro, and RE) plants as per the latest WAPP Master Plan and assumed VRE plants as proposed by the characterization of REZs in the context of this research. Most power systems data was obtained from Tractebel Engineering (now Tractebel Engie), which led the consultancy work for the 2018 (and latest) update of the WAPP Master Plan.

2.2.1. Characterization of electricity demand

The characterization of electricity demand was performed at two levels to provide insights into the hourly profiles and the spatial distribution of loads in each country.

Hourly demand data

Fig. 2 illustrates hourly demand data in 2017 for selected weekdays of the dry and wet seasons. It appears that hourly load profiles are complementary between the two groups of countries. On the one hand, baseload demand in Côte d'Ivoire and Ghana mainly occurs between 9 am and 5 pm, with peak loads before 9 am and after 5 pm. Hence, demand levels appear to be at their lowest levels during the typical peak solar PV production time, assuming a bell-shaped production profile, and potentially at their highest levels during times with higher wind power outputs (which are typically late evenings, especially during the dry season in West Africa) [9]. On the other hand, higher and peak loads in Burkina Faso and Mali typically occur between 10 am and 3 pm, particularly over the dry season, therefore coinciding with a bell-shaped PV production profile.



(c) Ghana **(d) Mali**

Fig. 2 Hourly electricity demand in the study countries for selected months in 2017

Spatial distribution of demand

OnSSET was applied to determine the optimal supply path between grid extension and off-grid systems for Burkina Faso, Côte d'Ivoire, and Ghana. In-depth interpretation and discussion of the OnSSET modeling results for Burkina Faso and Côte d'Ivoire are available in [11]. The analysis for Ghana was performed following the same methodology as in [11]. Mali was not included in this spatial analysis as its surface area is estimated at over 1.24 million km² (4.5 times that of Burkina Faso, 3.8 times that of Côte d'Ivoire, and 5.2 times that of Ghana [55]), and would require a very high computational effort and memory to process high spatial resolution data, even at a 10 km x 10 km resolution (1 km x 1 km spatial resolution for the other countries). For the sake of allowing for a similar comparative base, it was deemed appropriate not to seek analyzing the cost-optimal electrification pathways of Mali. For the remaining three countries, a two-level validation approach was carried out to measure the accuracy level of the OnSSET model in representing the state of electrification in the base year, as well as its coherence with electricity demand projections performed by relevant studies considering socio-economic factors potentially affecting future trends. The first level pertains to the spatial distribution of loads and the second level to the bottom-up approach to residential demand modeling. The detailed validation process is provided in Appendix B (also including the spatial load distributions of each country). Disaggregated demand data for the selected “grid nodes” with their hourly profiles served as inputs to the optimization model as elucidated by Fig. 1.

Fig. 3 maps the electrical areas modelled in each country. Color codes represent electrical areas in each country. Color coding was performed in such a way that neighbor areas can be differentiated from each other within and between systems. Hence, no specific meaning is attached to electrical areas with the same color code. The black dots represent the buses within each electrical area with the highest load values. In the WAPP Master Plan [19], each of the case study countries is represented by 2 electrical nodes, and respectively 2, 3, 4, and 3 for Burkina Faso, Côte d’Ivoire, Ghana, and Mali in [21], [46]. By modeling 4 nodes in each country, the present study, therefore, enhances the spatial granularity

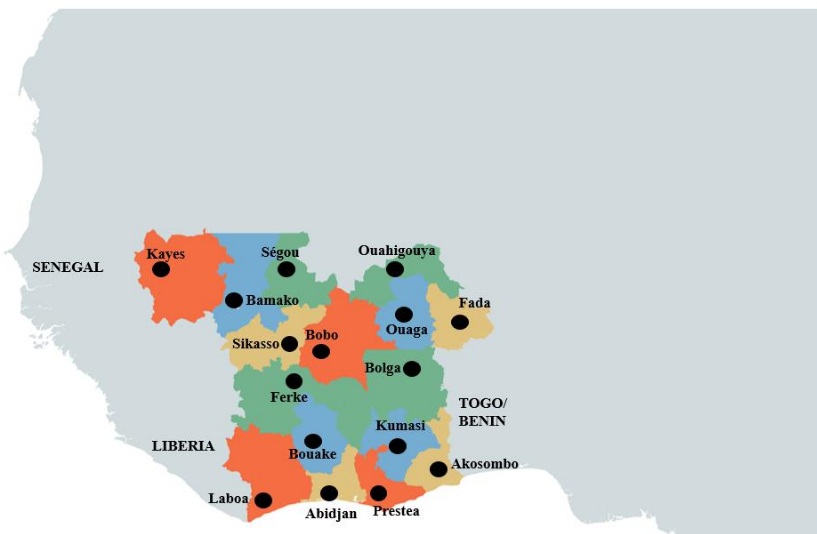


Fig. 3 Mapping of electrical areas for SDDP modeling

2.2.2. Characterization of variable renewable energy supply

Characterization of VRE supply in the study area was processed in two phases. The first phase consisted of identifying Renewable Energy Zones (REZs) from existing assessments which were overlayed with the results from the study by [54] on the complementarities of solar PV and wind power in West Africa. This allowed constructing assumed VRE power plants to be tested in the power system optimization modeling. Within the scope of this study, the REZs in [51]–[53] were used to propose candidate utility PV and wind plants which were included in the optimization model. These plants augmented future plants with full or partial funding clearance, as well as candidate plants as per national and regional Master Plans. Given that REZs spread across widespread areas, particularly in high resource countries, such as Burkina Faso and Mali, the proposed candidate plants were selected according to the solar PV-wind complementarities on diurnal timescales between 2009 and 2017 demonstrated in the first-ever high time and spatially resolved study for West Africa using ERA5 reanalysis data (see [9]). Table 2 summarizes SDDP input data features, assumptions, and sources.

Table 2 Descriptive summary of SDDP input data features, assumptions, and sources

Input data	Spatial granularity	Time resolution	Descriptive summary	Source
Historical and forecast electricity demand				
	National	Hourly	Demand levels in the base year. For Côte d'Ivoire and Ghana, historical hourly demand data were provided by the national utilities. For Burkina Faso and Mali, the modeling results of [22] were leveraged upon, as it was the first study of its kind to apply a bottom-up approach to model residential demand for individual West African countries.	Utility data and own processing
	National	Hourly	Demand forecasts to 2040 based on validated OnSSET modeling results. Hourly demand values in 2030 were obtained using the same coefficients of the base year (actual values). Demand levels in 2040 were estimated using the average annual growth rate from OnSSET analysis (between 2020 and 2030). Hourly values were obtained using the same coefficients for the year 2030.	Own processing from OnSSET results with residential shares of demand obtained in [56] and [57].
Existing and future generation infrastructure				
Fuels and thermal plants	Individual power plant	-	• Fuel prices (including transportation costs) and emission factors. • Thermal plant configuration: installed capacity, minimum and maximum generation, type (must-run or standard), forced (due to maintenance schedule) and composite (equipment maintenance and outage) outage rates.	Tractebel-Engie database [58]
Hydrology and hydropower plants	Individual power plant 0.1° x 0.1° (ca. 10 km x 10 km) for hydrological inflows	Monthly	Historical water inflows between 1980 and 2017 were obtained for each gauging station. Observed inflows of rivers in West Africa are generally poorly measured in space (number of gauging stations) and time (timesteps and continuity). To compensate for missing inflow data, particularly in Burkina Faso, Ghana, and Mali, the CMIP6 models of the Hydrological Modeling Framework for West Africa [59] were used.	Own processing from [59]

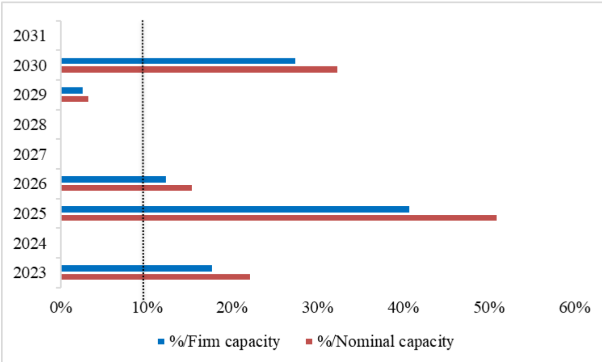
Input data	Spatial granularity	Time resolution	Descriptive summary	Source
			• Reservoir storage limits and initial condition at the beginning of the study, reservoir spillage type (controllable or not) • Monthly evaporation coefficients • Hydro plant configuration defining the technical characteristics of the generators and reservoirs, topology, storage, and flow tables.	Tractebel-Engie database [58]
VRE plants	1 km x 1 km for both PV and wind	Hourly	Solar PV and wind power plants, both existing and future. 'Candidate' future plants are drawn from the geospatial analysis, in addition to 'decided' future plants. Satellite imagery used in the Global Solar Atlas which has been validated against actual measurements on the ground with an accuracy range of ±4% to ±8. The 1 km x 1 km resolution has been shown to allow capturing small-scale spatial fluctuations of wind speeds.	**VRE Zoning:** Own processing from OnSSET, and [52], [53], [60], and [54]. **Generation profiles**: [61] for PV and [62], [63] for wind.
Transmission infrastructure				
Electric network	MV-HV transmission line	-	The electric network is represented through bus, circuit, and area configurations. For the sake of reducing the complexity of the model, the multi-nodal approach was applied, whereby each node is a composite of multiple buses within a geographical space.	Utility reports and own processing based on OnSSET outputs and GIS analysis
Extents of electric areas	-	-	They are delimited according to the geographical locations of their associated nodes. One electric area may thus cover multiple nodes, provided that the transmission line has a voltage greater than 90 kV.	Own processing from OnSSET modeling and Tractebel-Engie database.
Load per bus	-	-	Loads associated with each bus were provided for each year of the study horizon. It was assumed that for each bus, the load value remains constant throughout the year. Such values were calculated as the product of the total load of the system by the associated weight of a given node as per the OnSSET modeling. The weights of each bus load were assumed to remain constant during the entire study horizon.	Own processing using bus load values from power utility data in 2017 (latest available).

3. Results

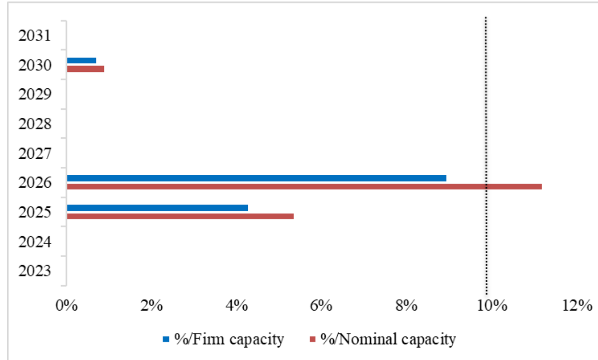
In both the base case scenario and the relaxed transmission scenario, only transmission lines greater than 90 kV were modelled. The modeling results are presented for different operating decisions per output class, and parameter as described in Table 3. In Fig. 4, each bar illustrates the share of new VRE capacity added each year in terms of installed capacity and firm capacity compared to the annual peak demand for the same year in each country. This allows comparison against the conservative limit of 10% of annual peak demand for new VRE capacity in each country used in the latest WAPP Master Plan (represented in Fig. 4 by a vertical black dotted line). In all countries, it appears optimal that all additional VRE power plants come online by 2030. It is important to note that no new VRE capacity is added every year in any country, considering both their expected commissioning dates from official sources and the optimization results based on supply/demand requirements. For each committed/candidate power plant, minimum and maximum entrance dates are specified. These are collected from the Tractebel-Engie database compiling official information on project status in each country, as well as various official websites for up-to-date information. Thus, no VRE plant can enter the generation plan before its defined minimum entrance date even if the existing generation capacity falls short of demand. The final entrance dates result from the co-optimization of investment and operation costs considering the VRE generation and load profiles. It is worth emphasizing, however, that although the 10% conservative value used in the WAPP Master Plan is given as a share of the peak demand, representing renewable penetration targets as a share of served demand provides more information to the planning process than the former. This is because renewable generation presents variability and intermittency, and therefore, their future dispatch factors are uncertain.

Table 3 Summary of outputs extracted from the set of modeling results

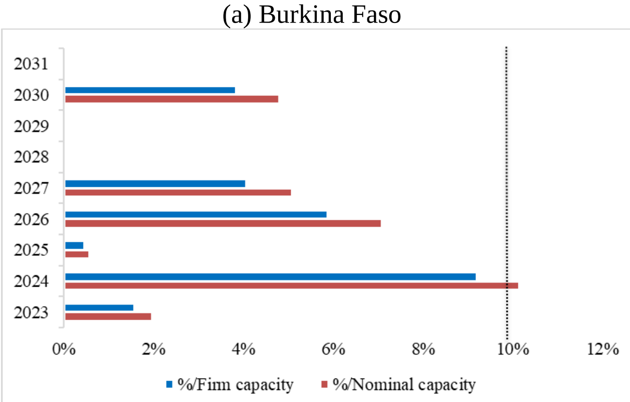
Class	Parameter	Description	Unit
Area	Export by area	Energy exports between electric areas, which in turn, are given by a set of nodes	GWh
	Import by area	Energy imports between electric areas, which in turn, are given by a set of nodes	GWh
Hydro plant	Hydro dispatch factor	Percentage of hydro utilization	%
Thermal plant	Thermal dispatch factor	Percentage of thermal utilization	%
Renewable source	Renewable source generation	Renewable source generation	GWh
	Renewable dispatch factor	Percentage of renewable utilization	%
	Renewable generation spillage	Renewable generation spillage	GWh
Interconnection	Interconnection flow	Interconnection flow between systems	GWh



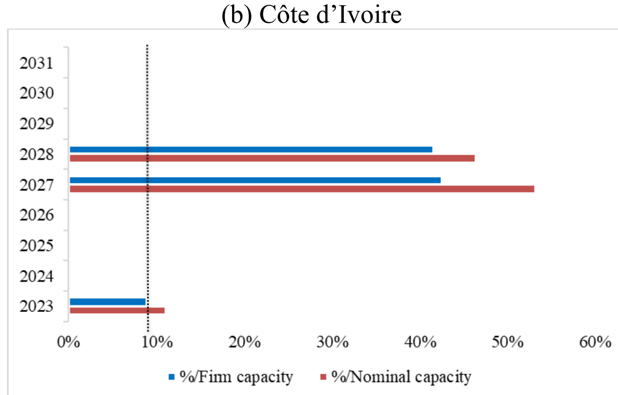
(a) Burkina Faso



(b) Côte d'Ivoire



(c) Ghana

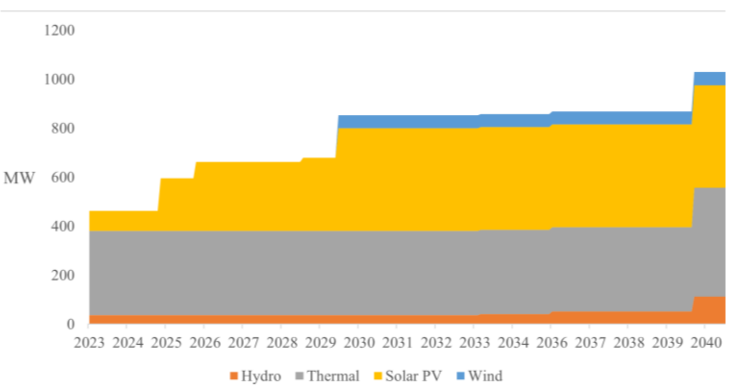


(d) Mali

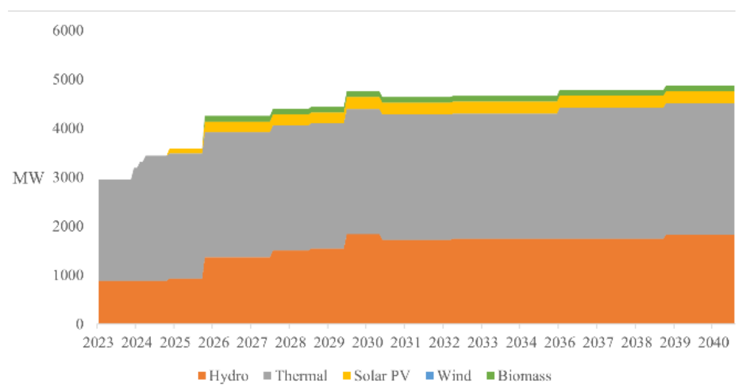
Fig. 4 VRE installed and firm capacity as a share of peak demand in each country (base case scenario). Source: OptGen result

Base case scenario: Generation capacity expansion with transmission constraints

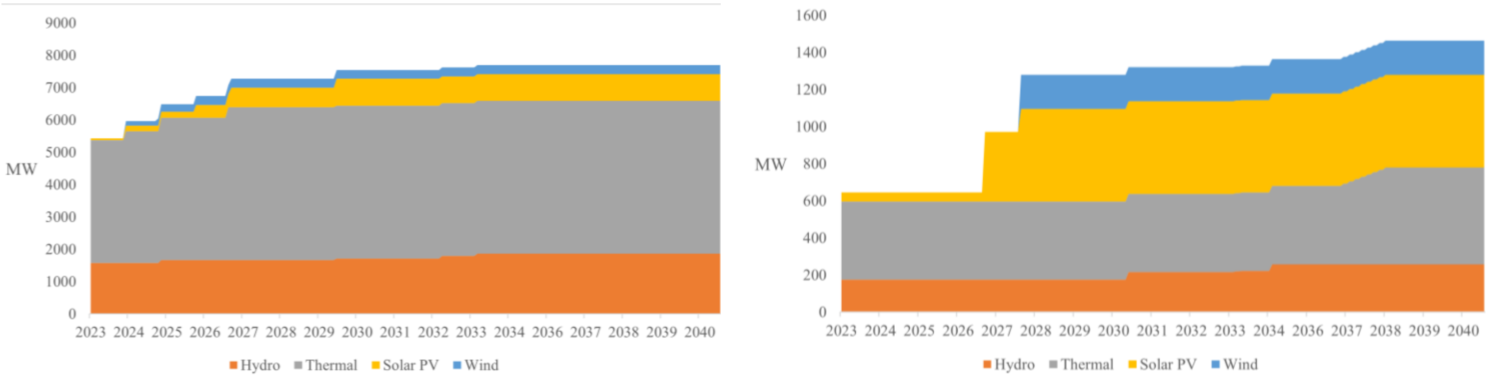
The system capacity expansion throughout the study horizon is illustrated by Fig. 5.



(a) Burkina Faso



(b) Côte d'Ivoire



(c) Ghana (d) Mali

Fig. 5 System capacity expansion between 2023 and 2040 (base case scenario)

As per the current configuration in the WAPP Master Plan, all cross-border interconnectors are single-circuits, which impose unidirectional power flows from one bus to another. The Bolga (Ghana) – Bobo (Burkina Faso) – Sikasso (Mali) line is expected to be built as a double-circuit after 2021 according to [19]. However, considering the well-documented delays in constructing cross-border transmission lines compounded with the lingering challenges of securing financing [64]–[66], the base case scenario realistically assumes that this line will be initially built as a single-circuit. In the case of cross-border interconnectors, such technical constraints mean that countries that are traditionally importers (Burkina Faso and Mali) are bound to remain so. The same applies to traditional exporting countries (Côte d'Ivoire and Ghana). Interconnection flows are detailed in Fig. 6. Dotted lines represent future interconnections. The dispatch factors of thermal, hydro, and renewable power plants, as well as the renewable generation spillage levels for selected power plants, are illustrated in Fig. 7 and Fig. 8. The selected power plants are located in electrical areas associated with cross-border interconnectors.

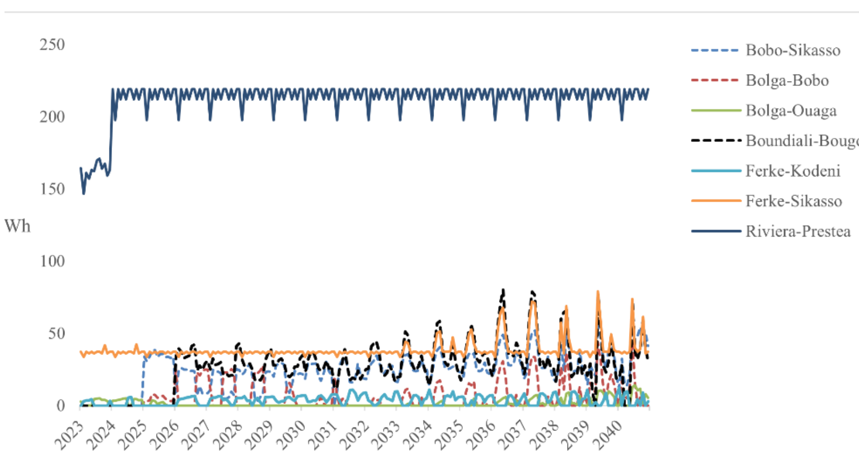
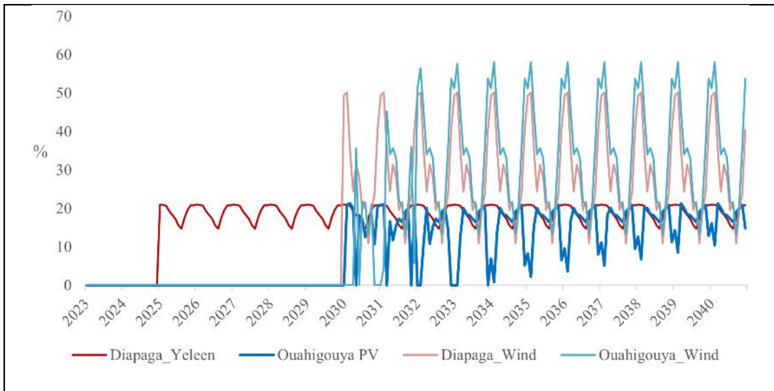
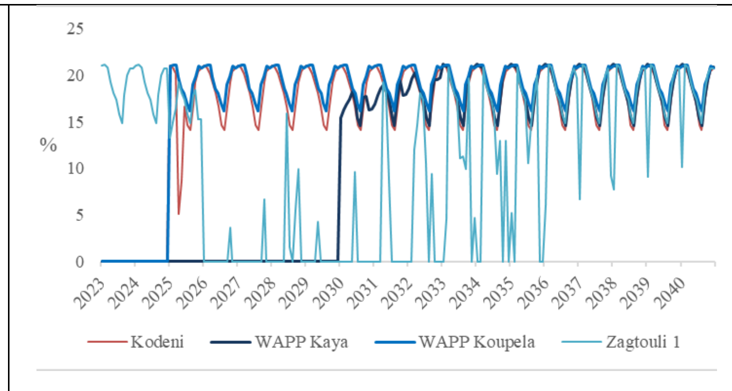


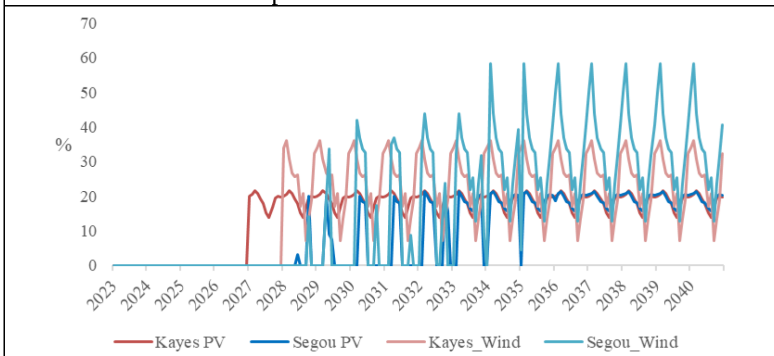
Fig. 6 Interconnection flows between Burkina Faso, Côte d'Ivoire, Ghana, and Mali between 2023 and 2040 (base case scenario)



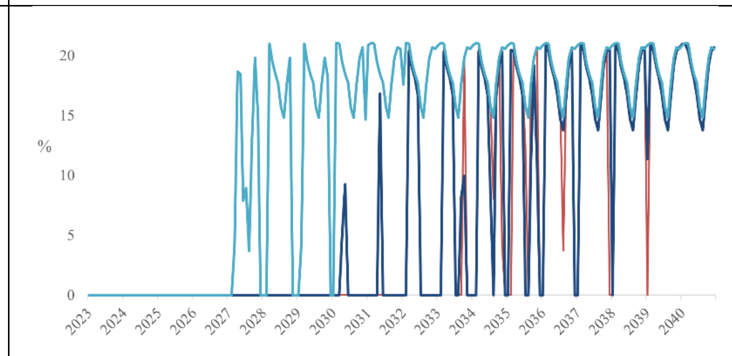
(a1) Renewable dispatch factor (%) for selected solar-wind power plants in Burkina Faso



(a2) Renewable dispatch factor (%) for selected PV plants in Burkina Faso

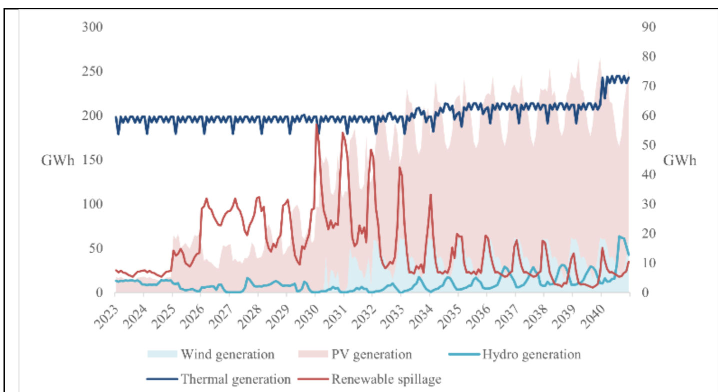


(d1) Renewable dispatch factor (%) for selected solar-wind power plants in Mali

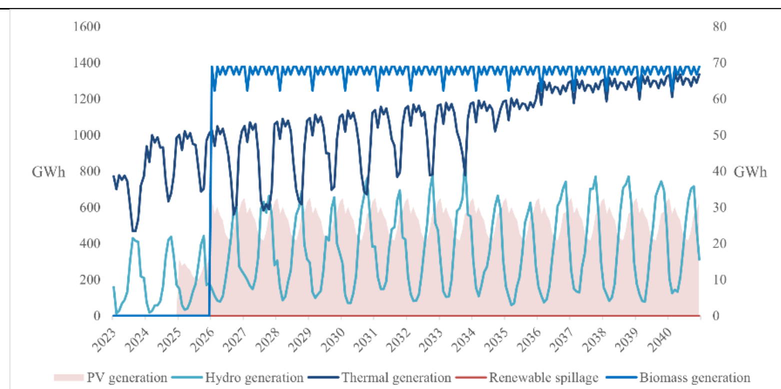


(d2) Renewable dispatch factor (%) for selected PV plants in Mali

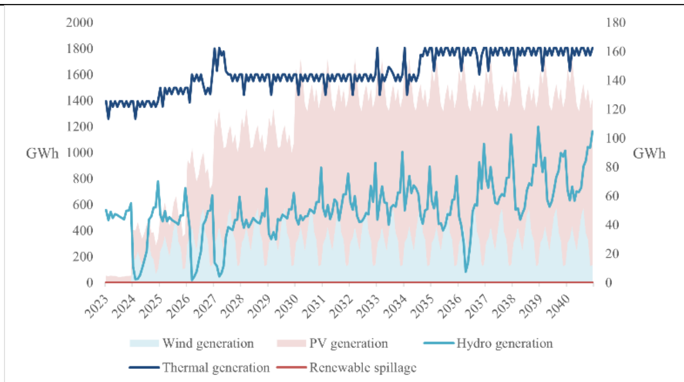
Fig. 7 Renewable dispatch factor (%) of selected plants in the study countries for the base case scenario between 2023 and 2040



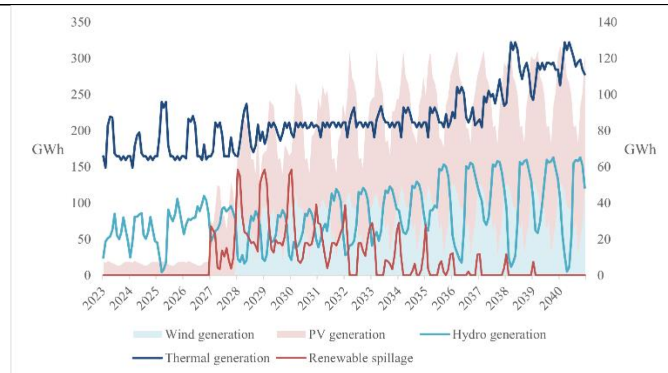
(a) Burkina Faso



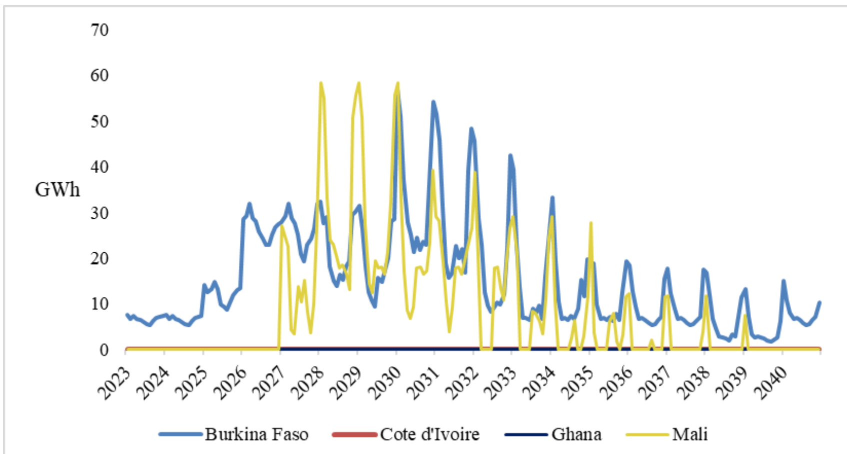
(b) Côte d'Ivoire



(c) Ghana

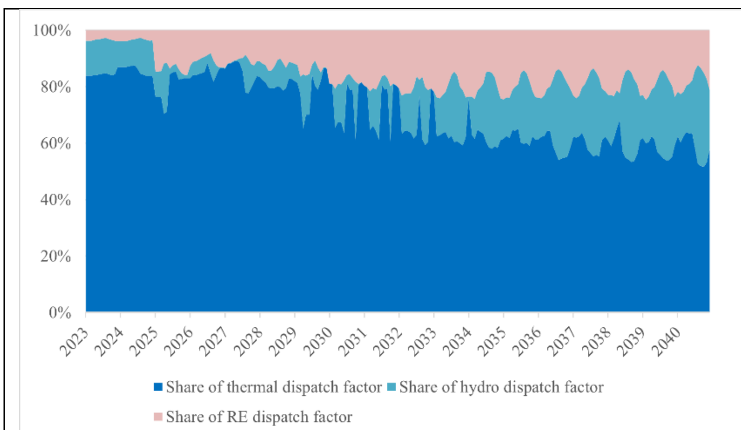


(d) Mali

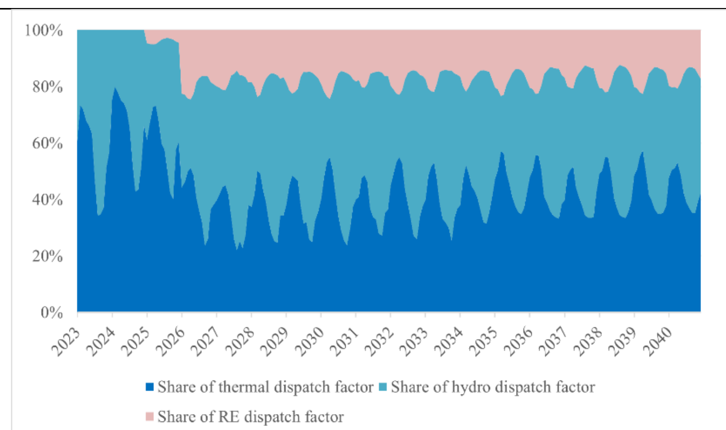


(e) Comparison of renewable spillage in the interconnected countries

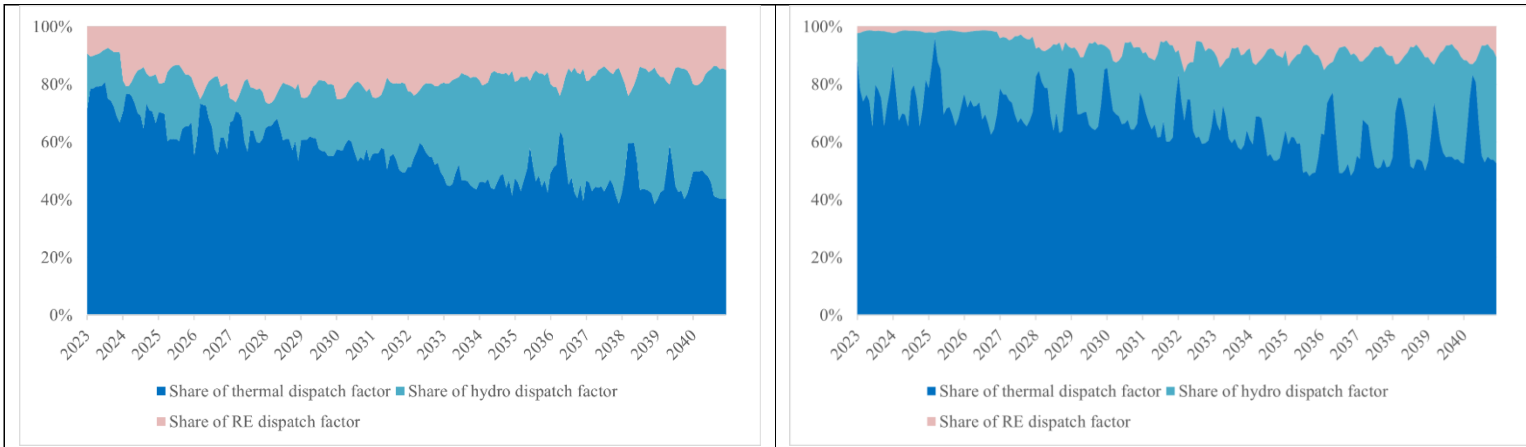
Fig. 8 Electricity generation by source (GWh) and generation spillage (GWh) in the interconnected countries between 2023 and 2040 for the base case scenario (left axis for thermal and hydropower generation; right axis for renewable generation and spillage)



(a) Burkina Faso



(b) Côte d'Ivoire

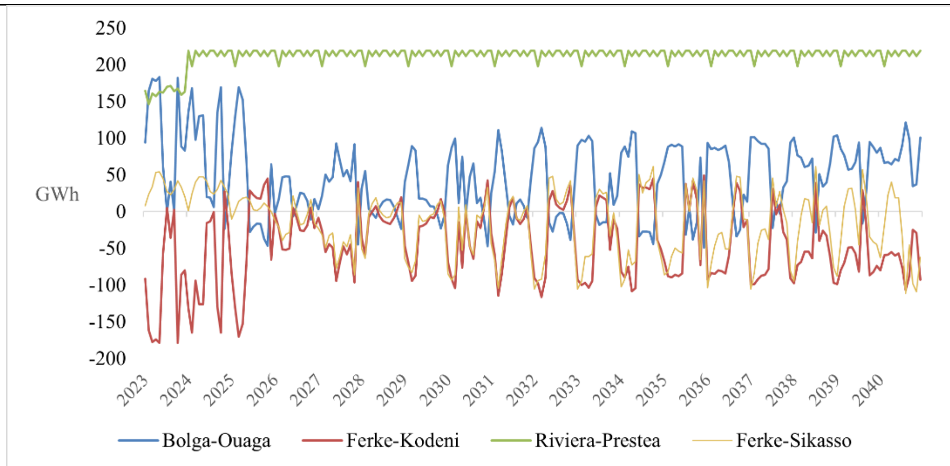


(c) Ghana (d) Mali

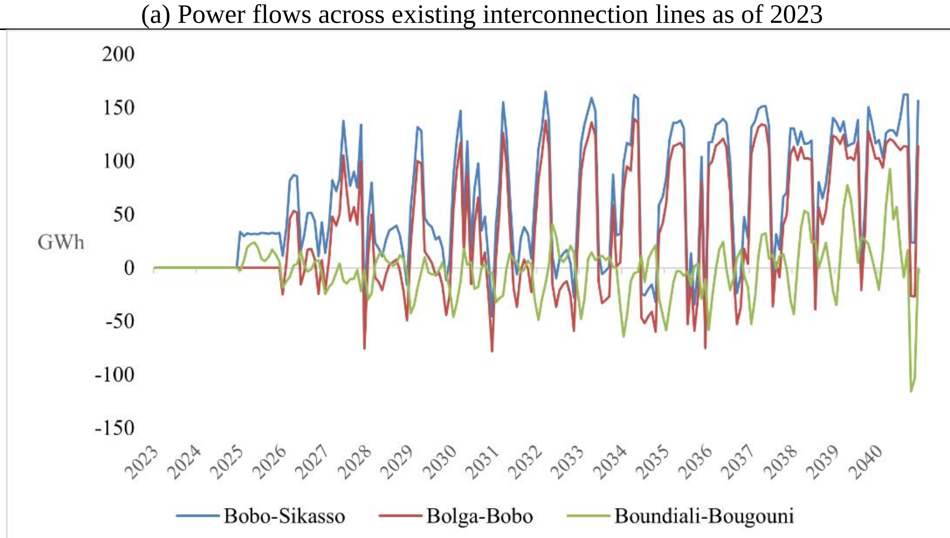
Fig. 9 Comparison of hydro, thermal and renewable dispatch factors between 2023 and 2040 (base case scenario)

Relaxed transmission scenario: Generation capacity expansion with relaxed transmission constraints

In this scenario, all existing single tie-lines between countries are assumed to be converted to double circuit lines; by doing so, bidirectional power flows would be allowed between countries by the dispatch centers. This was done to assess the extent to which higher shares of VRE may be reached and contribute to cross-border trading while enhancing system stability. Indeed, the system stability analysis performed as part of the latest WAPP Master Plan [19] highlights critical stability issues, including the interface between Block A (involving Mali) and Block B (involving Burkina Faso, Côte d'Ivoire, and Ghana). Beyond recommendations for reinforcing system voltage controls in Eastern Burkina Faso (as part of addressing the critical interface with neighboring Niger), other recommendations were made with regard to the implementation of additional interconnectors with proposals of double circuits for some lines. Fig. 10 illustrates interconnection flows across existing and planned interconnections in the relaxed transmission scenario. For selected VRE plants in the electrical areas associated with cross-border interconnectors, renewable generation spillage levels are compared to the base case scenario in **Error! Reference source not found.**.

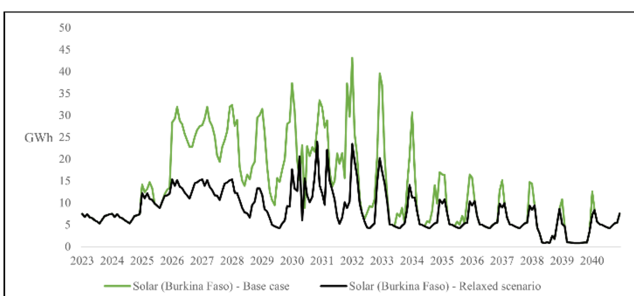


(a) Power flows across existing interconnection lines as of 2023

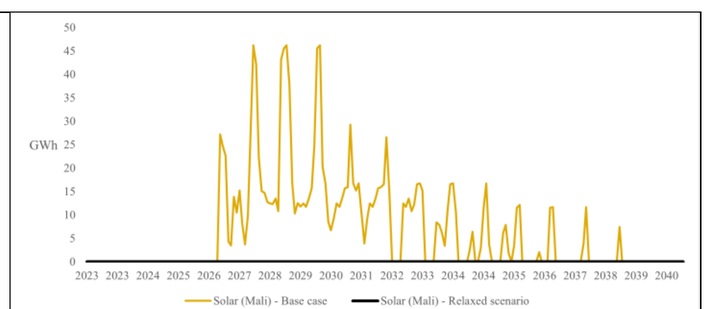


(b) Power flows across planned interconnection lines as of 2023

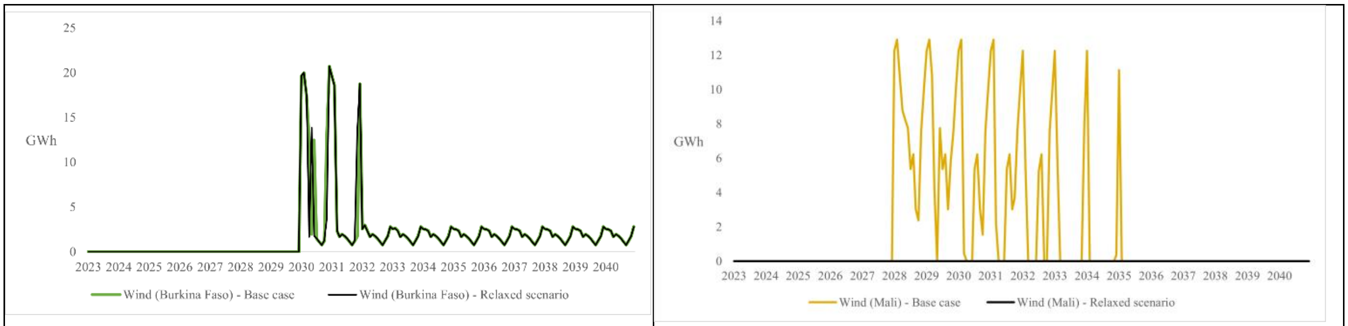
Fig. 10 Interconnection flows between Burkina Faso, Côte d'Ivoire, Ghana, and Mali between 2023 and 2040 (relaxed scenario)



(a) Solar PV spillage - Burkina Faso



(b) Solar PV spillage - Mali



(c) Wind spillage – Burkina Faso | (d) Wind spillage - Mali

Fig. 11 Comparison of renewable generation spillage (GWh) in the relaxed scenario compared to the base case scenario in Burkina Faso and Mali (2023-2040)

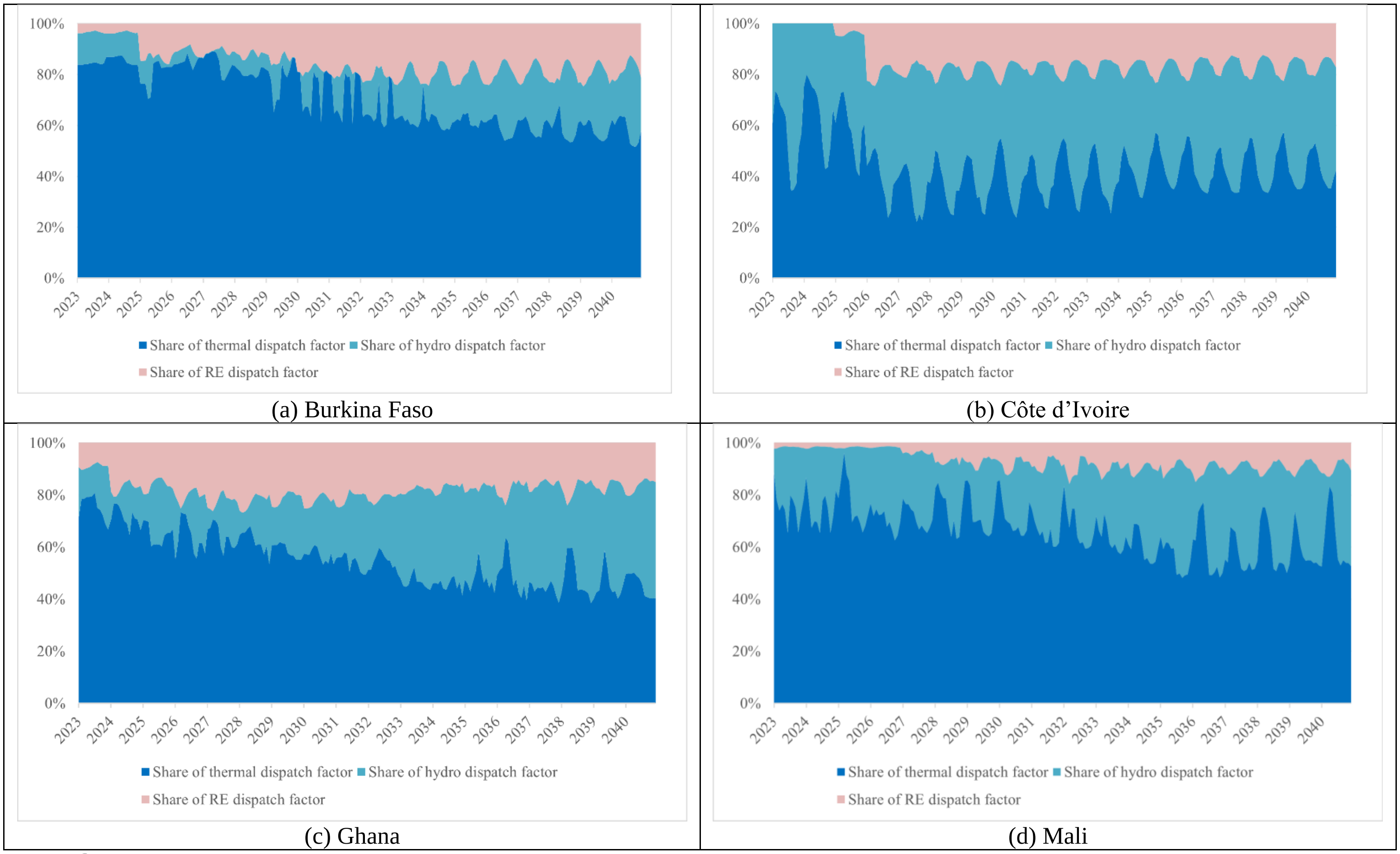
4. Discussion of results

4.1. Analysis of the results

To what extent can the conservative 10% limit to VRE shares in generation capacity be optimally challenged?

Fig. 4 shows that the 10% conservative limit applied in the 2019 (and latest) WAPP Master Plan is not optimal for Burkina Faso and Mali. For Côte d'Ivoire and Ghana, it is not optimal around the years 2025/2026 considering nominal capacities rather than firm capacities (such a difference is not specified in the Master Plan). Comparing the annual investment in new firm VRE capacity with the national peak demand, it appears that additional VRE capacity can optimally reach between 12.4% and 40.9% of annual peak demand in years when such generation capacity comes online in Burkina Faso. These shares are higher when considering installed capacity. The only exception is for the year 2029 where the share of firm VRE capacity invested represents only 2.7% of peak demand. This can be explained by the expected higher generation of hydropower during 2029, which would be curbed the following year (in 2030), leading to a drastic increase in the share of VRE compared to peak demand, as described by Fig. 8. As for Côte d'Ivoire and Ghana, the shares of additional VRE capacity compared to national peak demand are generally consistent with the 10% limit although exceptions occur around 2026/2027 when the systems become energy-constrained as hydropower generation reach exceptionally low levels with no sufficient thermal generation to compensate. Three factors can explain these stark differences between the pair Burkina Faso-Mali and the pair Côte d'Ivoire-Ghana, namely demand levels, operating costs of the existing fleet, and VRE endowment. In all countries, existing/planned VRE power plants have the same order of magnitude whereas system size and demand levels are in contrast. This means that compared to the former pair, the contribution of VRE power plants to the overall system supply can be expected to be marginal. This is all more so when considering the higher global horizontal irradiation levels across Burkina Faso and Mali, yielding higher volumes of PV generation. Additionally, the existing fleet in Burkina Faso and Mali is dominated by ageing power plants running on (imported, costly) diesel distillate oil/heavy fuel oil compared to local natural gas and hydro. Fittingly, the portfolio of planned VRE power plants with low operating costs will displace more diesel-fueled generators with high operating costs.

Considering the current dominance of thermal power in all national systems, the dispatch factors of RE plants are represented in



(a) Burkina Faso (b) Côte d’Ivoire (c) Ghana (d) Mali

Fig. 9 using the thermal dispatch factors as a benchmark. It appears that for all countries, increasing RE dispatch factors mean lower thermal reliance on the generation mix by the end of the study horizon in the base case scenario. The most considerable increase of RE dispatch factors by 2040 (compared to 2023 levels indexed to thermal dispatch factors) occurs in Côte d’Ivoire (ca. 40%), followed by Burkina Faso (ca. 32%), Ghana (ca. 24%), and Mali (ca. 17%). The highest difference noticed in Côte d’Ivoire is due to the lack of RE capacity as of 2023, with most additional PV and biomass capacity not expected to come online before 2025-2030. In Côte d’Ivoire, hydro dispatch factors exceed thermal dispatch factors early on, with peaks around the period 2027-2031. Although large hydro reservoirs may be employed as flexibility sources for VRE integration, this is less the case in Côte d’Ivoire where all hydropower plants (as well as dispatchable biomass power plants) are sited in the lower South of the country whereas PV power plants are planned in the upper North. In fact, the largest share of renewable dispatch is from biomass power plants rather than PV, with the share of the latter oscillating around 30% of the RE generation starting in 2026 with the expected commissioning of the first biomass plant. Furthermore, the existing single circuit interconnection lines allow excess power generation to flow from Côte d'Ivoire to Ghana, Burkina Faso, and Mali.

In Ghana, hydropower dispatch starts competing with thermal dispatch in the second half period of the study horizon, sensibly exceeding it from the year 2035. Although similar to Côte d'Ivoire, hydropower plants are sited in the lower half of the territory, some of Ghana's PV and wind power plants are also located South with some planned pumped hydro plants able to provide more flexibility for VRE integration. As hydro dispatch factors increase after 2035 in Ghana, VRE dispatch sensibly decreases and corresponds to a period of high RE dispatch factors in Burkina Faso, as well as higher power flows across the Bolga (Ghana) – Ouaga (Burkina Faso) interconnection line (Fig. 6). This suggests that although RE dispatch rises in Burkina Faso, their temporal fluctuations leading to lower supply-demand adequacy are compensated through increased power flows from more flexible power generation in Ghana (and Côte d'Ivoire). As for Mali, hydropower dispatch significantly competes with thermal dispatch, especially during the second half of the study period. VRE dispatch is less significant than in the other three countries despite reaching its highest levels from 2035, coinciding with higher power flows from inward interconnection lines with Côte d'Ivoire and Burkina Faso. Within the scope of this study, historical hydro inflows have been used as future samples throughout the study horizon. Notwithstanding, there is a large body of evidence describing the historical disruptions of water inflows in the region, as well as forecasting further disruptions as a result of the adverse effects of climate change, a topic that is out of the scope of this work. Hence, linkages between renewables and hydropower generation can result in hydro basins being used as virtual storage facilities for solar PV and wind power [67]. This topic is increasingly gaining interest in the Southern African scientific community for the integration of wind power in the region, with a particular focus on the adverse effects of climate change on the seasonality and magnitude of water inflows, hence on the long-term use of reservoirs for RE integration [67]. Therefore, it could be reasonably argued that for hydro-thermal power systems such as those under study, the conservative 10% limit may be further pushed in the context of more recurrent dry years.

Can increasing VRE penetration disrupt the traditional characterization of importing versus exporting countries and effectively catalyze power pooling?

The four interconnected countries display generation mixes dominated by thermal and hydropower plants, except for Burkina Faso where hydropower plays a marginal role (Fig. 5). Overall, the base case scenario, which is reflective of the current constrained and single-circuit transmission system, inhibits power exchanges from VRE-rich and low demand countries (Burkina Faso and Mali, traditional importers) to less VRE-rich and high demand countries (Côte d'Ivoire and Ghana, traditional exporters). It is also worth noting that this occurs in a context where the latter group is experiencing an increasingly flexible generation fleet with combined-cycle gas turbines, as well as pumped hydro storage projects, thus highlighting missed opportunities for better accommodating intermittent VRE supply.

Base case scenario

The contribution of renewable generation from solar PV and wind plays an increasing role especially from as early as 2024/2025 in Burkina Faso and Ghana, and from 2027 in Côte d'Ivoire and Mali (Fig. 8). Solar PV holds the lion's share of renewable generation in all countries except for Côte d'Ivoire where electricity generated from biomass outgrows that of PV from as early as 2026. Côte d'Ivoire is also the only country where wind generation plays no role in the country's mix. In Ghana and Mali where some wind power plants are already planned, the least-cost investment plan shows that from 2026 (in Ghana) and 2028 (in Mali), they will start contributing to the mix, essentially complementing PV generation. Although Burkina Faso has currently no official investment plan for wind power plants, the OptGen model shows that from 2031, the two assumed plants in the Northern and Eastern parts of the country would cost-effectively complement PV generation in those areas, thus ensuring higher and more reliable power supply.

However, as expected in this scenario, traditional importing countries such as Burkina Faso and Mali remain importers despite the excess generation of low marginal cost PV. Indeed, renewable generation spillage is prevalent in the studied countries and is particularly significant in countries with the highest potential and generation levels, Burkina Faso and Mali (Fig. 8). Ghana also experiences high spillage levels particularly between 2025 and 2037 with no possibility to export to high-demand areas in Côte d'Ivoire through the Côte d'Ivoire-Ghana one-directional transmission line. The PV dispatch factors oscillating around 20% in the interconnection areas in Burkina Faso and Mali even during peak times in these countries, highlight that the current single-circuit transmission system inhibits potential power exports to countries such as Côte d'Ivoire and Ghana at high demand periods (Fig. 2). Moreover, the renewable dispatch factors in these countries are higher for wind power plants than for PV plants, with solar-wind complementarities from the year 2030 (Fig. 7).

Hence, similarly to previous studies such as in [46], the role of PV generation is expected to be significant in the coming years. It is worth noting that contrary to the present base case scenario, the baseline scenario in [46] allows two-directional cross-border flows. In their renewable scenario, electricity flows increase by at least 500 GWh by the year 2025 in non-traditional directions, compared to the baseline scenario: Burkina Faso to Ghana and Mali to Côte d'Ivoire. Exports from Ghana to Burkina Faso remain in the same category, which does not necessarily mean that their levels increase or decrease, whereas exports from Côte d'Ivoire to Mali decrease by one category. Exports from Mali to Burkina Faso increase by one category whereas they remain in the same category for the reverse direction. As for exchanges between Côte d'Ivoire and Ghana, they are reduced by at least 500 GWh, corresponding to a drop of two categories. The two directional cross-border flows in[46] are, however, not consistent with the characteristics and operation modeled in the present base case scenario. A direct quantitative comparison of the two scenarios would. It would, therefore, not be appropriate.

Relaxed transmission scenario

With regards to future interconnection lines between Ghana and Mali through Burkina Faso, and between Côte d'Ivoire and Mali**,** Fig. 10b shows that such lines could cost-effectively be built as double-circuit lines from the year 2026 although most of the exchanges would follow the initial unidirectional flow. This would allow exports of excess renewable generation from/to Ghana to/from Burkina Faso, to/from Mali. This bidirectional feature would also allow flows of excess PV and wind generation from Mali to Côte d'Ivoire during evening peak times, thus enhancing renewable dispatch factors and reducing spillage. Fig. 10a shows that on existing transmission lines, power flows could optimally occur from traditional importing countries (Burkina Faso and Mali) to Côte d'Ivoire and Ghana. This is particularly true for the existing Ferke-Kodeni line connecting Côte d'Ivoire to Burkina Faso and the Ferke-Sikasso (Mali) line for which the "to-from" flows largely surpass "from-to" flows, suggesting a significant opportunity for relieving the current "from-to" constraint. PV generation spillage in Burkina Faso consistently decreases by 50% on average during the period 2026-2034 from the commissioning of the Kodeni-Ferke interconnector in 2025, compared to the base case scenario. PV spillage reductions oscillate between 20% and 50% for the remaining period. During the same periods, excess PV generation can be exported to Ghana through the planned Bobo-Bolga line and Côte d'Ivoire through the existing Ferke-Kodeni line. However, wind spillage remains the same in both scenarios for Burkina Faso (Fig. 11c). This stems from the lack of modeled cross-border interconnectors in the wind plant locations to transmit excess generation. In practice, the future commissioning North Core transmission line aimed at connecting Burkina Faso to the Eastern part of the WAPP through Niger could be a suitable corridor for reducing wind spillage. Indeed, it is worth recalling that the scope of the present study was limited to 4 countries out of 14 in the WAPP. Therefore, the cross-border interconnectors not modeled herein represent additional opportunities for power trade, including wheeling.

In addition, imports from Côte d'Ivoire to Burkina Faso would be cut down by up to 63% compared to 2020 levels amounting to 488.9 GWh [68] (Fig. 10a). Most of the imports would occur during the rainy season (May-September) with some occurrences in the early dry season months in Burkina Faso (October and November). These periods usually correspond to high hydropower generation in Côte d'Ivoire and lower PV/wind generation in Burkina Faso during the rainy season, as well as marginal hydropower generation in the dry season in Burkina Faso. Power exchanges along the Bolga (Ghana)-Ouaga (Burkina Faso) line present opposite trends to those of the Ferke-Kodeni line with imports from Ghana mostly taking place during exports to Côte d'Ivoire, and exports to Ghana during imports to Côte d'Ivoire.

Burkina Faso will continue to import electricity from Ghana almost all year long across the study horizon with peaks of up to 27% (compared to 2020 levels at 990.5 GWh [68]. This could be explained by the spatial load distribution in Burkina Faso where the electrical area "Ouaga" represents over 60% of the total load compared to only 20% for the "Bobo" area (including the "Kodeni" node). Notwithstanding, after 2030, imports from Ghana could be reduced by up to 48% compared to 2020 levels with the increasing penetration of PV and wind generation in Burkina

Faso. The Ferke (Côte d'Ivoire)-Sikasso (Mali) interconnection line displays similar trends to the Ferke-Kodeni line, therefore the same interpretation applies. Mali witnesses the most significant spillage reductions for both PV and wind generation compared to Burkina Faso (Fig. 11). This is due to the possibility of exporting low marginal cost electricity to the North of Côte d'Ivoire through the existing Ferke-Sikasso line, and the planned Boundiali (Côte d'Ivoire)-Bougouni (Mali) expected to be commissioned by 2025. In addition, the power flows from Mali to Burkina Faso and from Burkina Faso to Ghana through the Bolga-Bobo-Sikasso interconnector suggest power wheeling opportunities through Burkina Faso, resulting in lower VRE spillage. As for the Riviera (Côte d'Ivoire)-Prestea (Ghana) line, power flows do not differ from the base case scenario. This implies that the excess generation from renewable plants in Ghana would rather be cost-effectively transmitted to Burkina Faso and Mali, particularly considering the commissioning of the Bolga (Ghana)-Bobo (Burkina Faso)-Sikasso (Mali) interconnection line.

4.2. Comparison with other studies

Given that the characteristics of the present alternative scenario (the relaxed transmission scenario) are distinct from those of other relevant studies, only the results of the base case scenario could be compared with that of [46] and the WAPP Master Plan [19], particularly the country generation mixes. As for the cross-border power flows between Burkina Faso, Côte d'Ivoire, Ghana, and Mali, only [46] provided a detailed description of cross-border exchanges between interconnected nodes. However, these flows were categorized into large intervals (for instance, 0-500 GWh, 1501-2000 GWh, etc.), thus preventing any sound quantitative comparison with the results of the present study. Table 4 summarizes the comparison between the modeling results of the present base case scenario with those of [46] and [19]. Values between brackets represent the difference with the results of the present study. The final modeling year in [46] was 2025 and its "baseline scenario" was similar to the base case scenario in the present research, considering the existing constraints on the cross-border transmission capacities. However, the two scenarios differ in the levels of RE generation capacities modeled. Although a detailed list of the individual power plants considered in this study was provided, it was possible to argue that [46] overlooked some planned RE generation capacities between the initial and the final modeling years. For instance, [46] considered a peak PV generation capacity of 53 MW for Burkina Faso by 2025. However, by 2022, the installed utility-scale PV capacity was already at 64.1 MWp (Zagtouli – 33 MWp, Ziga – 1.1 MWp and Nagreongo – 30 MWp). For this reason, it follows logic that most RE generation capacities resulting from the present research are higher than those in [46]. This has an incidence on the shares of thermal and hydropower plants. Yet, the overall mixes remain similar in that they reflect the overreliance on thermal power plants, including in countries with high PV and wind endowments such as Burkina Faso, Mali, and Ghana.

As for the WAPP Master Plan, the results are not scenario-based, hence they may be only compared with the base case scenario of the present research for the year 2033 i.e., the final modelling year of the Master Plan. Compared to the base case scenario, the WAPP Master Plan generally underestimates thermal and hydropower generation capacities, and overestimates the additional PV generation capacities. Wind power generation capacities are also slightly underestimated in Burkina Faso and Ghana whereas they are underestimated by 14% in Mali compared to the present research. This may be explained by the use of average values of wind speeds instead of spatially and temporally resolved values, as discussed in [9]. The overestimations of additional PV generation capacity by the WAPP Master Plan might emerge from the commissioning dates of such power plants which are mostly delayed.

Table 4 Comparison of the shares of generation capacity by source of the baseline results from two relevant studies with the base case scenario results

		Thermal	Hydro	PV	Wind	Biomass
Study by [46]	Burkina Faso	93% *(+35%)*	3% *(-3%)*	4% *(-32%)*	0% *(0%)*	0% *(0%)*
	Côte d'Ivoire	54% *(-17%)*	42% *(+16%)*	1% *(-2%)*	0% *(0%)*	3% *(+3%)*
	Ghana	71% *(+3%)*	28% *(+2%)*	<1% *(-2.5%)*	< 1% *(-2.5%)*	0% *(0%)*
	Mali	49% *(-16%)*	46% *(+19%)*	5% *(-3%)*	0% *(0%)*	0% *(0%)*
WAPP Master Plan	Burkina Faso	34% *(-6%)*	2% *(-2%)*	59% *(+10%)*	5% *(-1%)*	0% *(0%)*
	Côte d'Ivoire	55% *(0%)*	25% *(-12%)*	19% *(+14%)*	0% *(0%)*	1% *(-1%)*
	Ghana	59% *(-3%)*	18% *(-6%)*	21% *(+10%)*	2% *(-2%)*	0% *(0%)*
	Mali	32% *(0%)*	23% *(+7%)*	45% *(+7%)*	0% *(-14%)*	0% *(0%)*

In summary, this paper shows that the optimal dispatch schedule found by SDDP uses the tie-lines between countries in a better way than the current operation in addition to saving system operating costs and reducing renewable curtailments of the entire region.

5. Policy implications and conclusions

The region of West Africa exhibits an obvious dichotomy between the regional endowment of renewable energy and the practical implementation of its sustainable energy policy aspirations. The current frameworks modeled under this study's base case scenario show missed opportunities for bridging the supply-demand gap in all countries, not only in terms of VRE generation capacity, but also of transmission capacity.

On the one hand, enhancing the generation capacity expansion modeling with geospatial electrification analysis allowed considering the realities of demand distribution across territories, as well as characterizing VRE resource spatial and time distribution. In particular, the latter led to unravelling the potential for wind generation in three countries with strong wind-PV complementarities, including coastal Ghana, which has otherwise been long excluded from being wind suitable areas based on average values. This is consistent with the outcomes of the growing body of literature on VRE development in West Africa. It is worth mentioning that the REZs considered in Burkina Faso do not account for the instability and insecurity dimensions resulting in the loss of state territory due to terrorism in the Sahel region, recently approaching 40%, and primarily concerning the Northern and Eastern parts of the country [69]. Notwithstanding, it is to be highlighted that the Desert to Power initiative led by the African Development Bank with the technical and financial support of the EU, the Green Climate Fund, and the French Development Agency among others, precisely intends to spur socio-economic growth through grid and off-grid energy solutions as a way to counteract with a pivotal root cause of youth and women wide recruitment into terrorist groups [70].

On the other hand, West Africa must design its power pooling so that spatial and temporal variations in VRE supply are properly taken into account in capacity expansion and investment planning if it is to achieve its ultimate goal of creating a regionally competitive area. Comprehensive planning is an important exercise that can help mobilize both local and foreign investment to fund cross-border power projects. Indeed, sound planning of power pooling beyond reducing the transaction costs of trade, is a key enabling factor for enhancing cross-border power trading. Burkina Faso, Côte d'Ivoire, Ghana, and Mali are increasingly seeking public-private investment in power infrastructure and have expressed the need for greater involvement of the private sector, as a means to tackle the lack of financial resources faced by governments and to promote private sector participation and boost their confidence in the sector. Recent trends indicate that these countries will attract more local and international private investors for energy infrastructure development [3]. In such countries where the generation segment is unbundled, IPP generation is expected to increasingly contribute to new VRE capacity additions. Hence, raising the much-needed investment in these countries and other WAPP countries, in general, will necessitate effectively creating an enabling environment for private sector participation as prescribed by the ECOWAS Energy Protocol [71]. This implies building an institutional infrastructure that promotes an efficient market design yielding adequate economic signals for encouraging cross-border power trade and incentivizing investment in the physical power infrastructure. This is especially true in the case of large-scale penetration of VRE generation which disrupts the traditional cost structure and operations of power systems by their lower predictability leading to supply fluctuations in time and space, and requires power system flexibility [72]–[75].

Current frameworks suggest that WAPP is set to follow the traditional path of developed countries. Clearly, there is a dormant opportunity for leapfrogging in the region to design suitable mechanisms for high penetration of intermittent RE. However, this should in fact build on the past and current experiences of more advanced regions that reveal complexities in addressing the imperfections of 20th-century approaches partially stemming from uncoordinated RE national policies and regulations. While models and lessons learnt may be leveraged upon to inform a successful design of the WAPP for the benefit of the countries and their people, past and current landscapes clearly highlight that each region and country have their own specificities and challenges which need to be duly accounted for on an individual basis. As such, ECOWAS Member States participating in the WAPP should endeavor in developing their signature solution regional electricity market which makes provision for the specific opportunities and challenges of the countries involved. Thus, scholarly research in this field should dutifully evolve to provide evidence-based analyses and proposals able to guide the WAPP organization, power utilities, national policymakers, regulatory authorities, and VRE business developers into co-creating and implementing West Africa's signature solution to regional electricity trade as a powerful tool for sustainable and just socio-economic development.

It is important to note that achieving universal access to electricity alone will not be sufficient to achieve socioeconomic development goals because it demands broader reforms in the macroeconomic environment [39], [40], particularly in terms of corporate regulation. Indeed, Sub-Saharan Africa has long been the region with the least business-friendly environment, trailed by South Asia, despite significant advances in recent years [42], [43]. In 2017 for instance, the region's gap between regulatory efficiency and regulatory quality improved three times as much as the average of OECD high-income countries compared to 2016, according to the World's Bank Doing Business Report [76]. However, the 2020 rankings (the latest) show that West African countries made the cut only for the bottom half of the 190 countries assessed, ranked between 110th (Cote d'Ivoire) and 174th (Guinea Bissau) [77]. The predicted economies of scale with competitive power pooling and increased private sector participation will be difficult to accomplish in the face of resource mobilization issues without macroeconomic settings favorable to the large growth of national electricity market sizes. Future research should aim at enhancing the power systems planning model by employing more detailed operational data for each power plant, especially the actual forced outage rates induced by the ageing power fleet and fuel supply disruptions, beyond standard values for each plant category. Doing so could potentially yield higher displacement of diesel-fueled plants with high operating costs, leading to higher penetration of VRE with low marginal costs. Moreover, the methodology propounded by this study could be extended to the remaining 10 WAPP countries in view of better quantifying VRE dispatch factors and spillage and highlighting additional opportunities for power trade. Green hydrogen applications from VRE spillage should also be explored.

Appendix A

- Problem formulation in SDDP

The stochastic hydrothermal scheduling formulation will be illustrated for one hydro plant and the three-stage inflow tree of Fig. A-1.

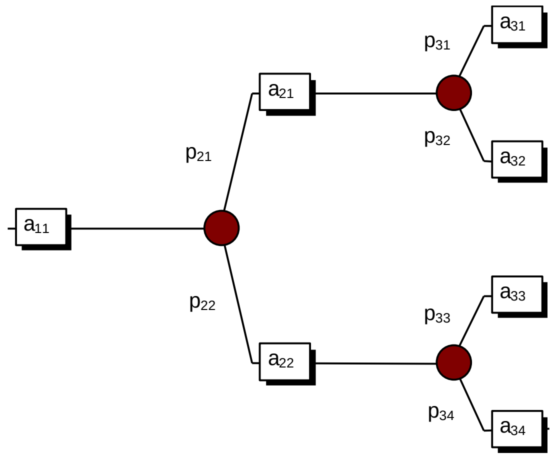


Fig. A-1: Inflow scenario tree

where:

a_{ts}	inflow in stage t, scenario s	m^3	D
p_{ts}	conditioned probability of inflow in stage t, scenario s	p.u.	D

The stochastic scheduling problem is formulated as:

$$\text{Min} \quad c_1(u_{11}) + p_{21}[c_2(u_{21}) + p_{31}c_3(u_{31}) + p_{32}c_3(u_{32})] + p_{22}[c_2(u_{22}) + p_{33}c_3(u_{33}) + p_{34}c_3(u_{34})$$

subject to

(a) water balance constraints

$$v_{21} = v_{11} - u_{11} - s_{11} + a_{11}$$
$$v_{31} = v_{21} - u_{21} - s_{21} + a_{21}$$
$$v_{41} = v_{31} - u_{31} - s_{31} + a_{31}$$
$$v_{42} = v_{31} - u_{32} - s_{32} + a_{32}$$
$$v_{32} = v_{21} - u_{22} - s_{22} + a_{22}$$
$$v_{43} = v_{32} - u_{33} - s_{33} + a_{33}$$
$$v_{44} = v_{32} - u_{34} - s_{34} + a_{34}$$

(b) constraints on storage and outflow

$$v_{t+1,s} \leq \overline{v}; \qquad u_{t,s} \leq \overline{u} \qquad \text{for all stages } t\text{; all scenarios } s$$

where:

$u_{t,s}$	hydro scheduling decision (turbined outflow) in stage t, scenario s	m^3	V
$c_t(u_{t,s})$	thermal generation cost required to complement the hydro scheduling decision	$	V
$v_{t+1,s}$	reservoir storage at the end of stage t, scenario s	m^3	V
$s_{t,s}$	spilled outflow in stage t, scenario s	m^3	V

The thermal complement function $c_t(u_{t,s})$ is implicitly represented as the solution of the following linear programming problem:

$$c_t(u_{t,s}) = \quad \text{Min} \quad \sum_{j=1}^{J} c_t(j) \times g_t(j)$$

subject to

(c) load supply constraints

$$\sum_{j=1}^{J} g_t(j) = d_t - \rho \times u_{\text{ts}} \qquad \text{for } t = 1, \dots, T$$

(d) thermal generation limits

$$g_t(j) \leq \overline{g}(j) \qquad \text{for } j = 1, \dots, J \text{ , for } t = 1, \dots, T$$

where:

j	indexes thermal plants		
J	number of thermal plants		
$c_t(j)$	unit operating cost of plant j	$/MWh	D
$g_t(j)$	energy production of plant j in stage t	MWh	V
$\overline{g}(j)$	energy production capacity of plant j	MWh	D
d_t	energy demand in stage t	MWh	D
ρ	hydro plant production coefficient (assumed to be constant in this example)	MWh/m^3	D

SDDP allows the representation of renewable energy sources such as solar power, wind power, small hydro plants, biomass and geothermal. It is assumed that the energy generation of these plants is variable, but independent from one stage to the next, that is, there is zero serial correlation.

In turn, the spatial correlation in each stage is preserved, for example, it is possible to represent the spatial correlation of wind energy plants in a given region, where the wind patterns are similar.

In the mathematical model, the renewable energy production is subtracted from the demand, as shown next:

$$\text{Min} \quad cg + \alpha$$

$$g + r = d'$$

$$r \leq d'$$

where $d' = d - ER$, where ER is the sum of the power production of renewable sources in this stage and series.

- Problem formulation in OptGen

Objective function

$$\text{Min} \quad ci \cdot \boldsymbol{x} + co \cdot \boldsymbol{g} + cd \cdot \boldsymbol{d} \tag{5.1}$$

ci	projects investment cost	M$
co	projects operation cost	M$
cd	system deficit cost	M$
$\boldsymbol{x}$	projects investment decision	p.u.
$\boldsymbol{g}$	projects energy production	MWh
$\boldsymbol{d}$	system energy deficit	MWh

Decision variables limits

$$\boldsymbol{x} \leq 1$$

Load supply

$$\boldsymbol{g} + \boldsymbol{d} = D$$

D	system energy demand	MWh

Operational limits

$$\boldsymbol{g} - \overline{g} \cdot \boldsymbol{x} \leq 0$$

$\overline{g}$	projects maximum energy production	MWh

As we can see, this problem is block structured, which is suitable for the application of decomposition techniques.

$$
\begin{array}{lcccl}
 & \textbf{Investment variables} & & \textbf{Operation variables} & \\
\text{Min} & \boxed{ci \cdot \boldsymbol{x}} & + & \boxed{co \cdot \boldsymbol{y}} & \\
\text{s/t} & \boxed{A \cdot \boldsymbol{x}} & & & \geq b \\
 & & & \boxed{C \cdot \boldsymbol{y}} & \geq d \\
 & \boxed{E \cdot \boldsymbol{x}} & + & \boxed{F \cdot \boldsymbol{y}} & \geq h
\end{array}
$$

This scheme separates the stochastic / integer optimization problem into two optimization *modules*, which are solved iteratively until reaching the optimum global solution: (i) the so-called *investment* module, where a candidate expansion plan is determined through the solution of a mixed integer linear (MILP) optimization problem; and (ii) the *operating* module, which calculates the expected value of the operating costs resulting from each candidate plan produced by the investment module, through the solution of a multistage stochastic optimization problem. The figure below illustrates the Benders decomposition scheme.

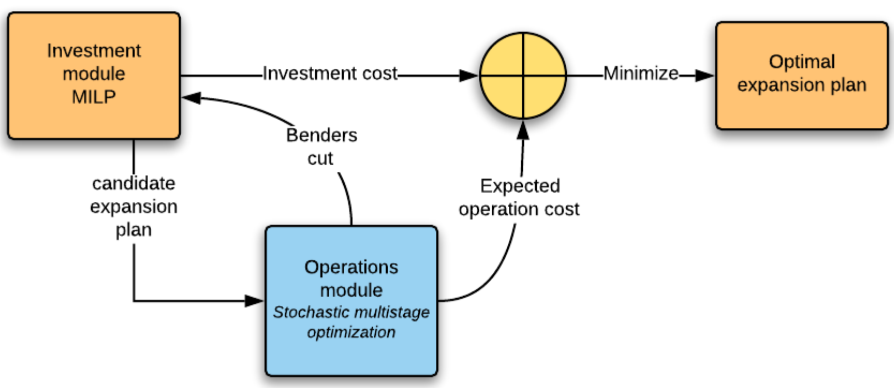
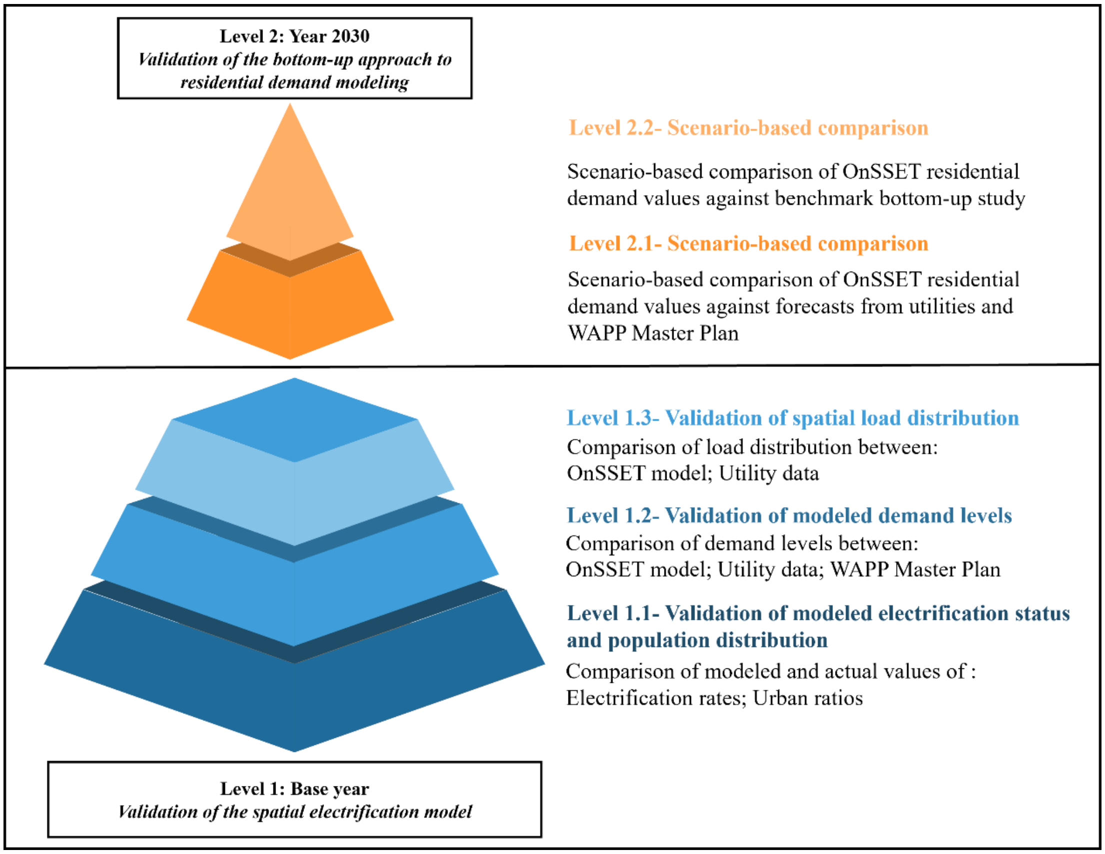


Fig. A-2. Optimization of the expansion planning problem by Benders decomposition

Appendix B

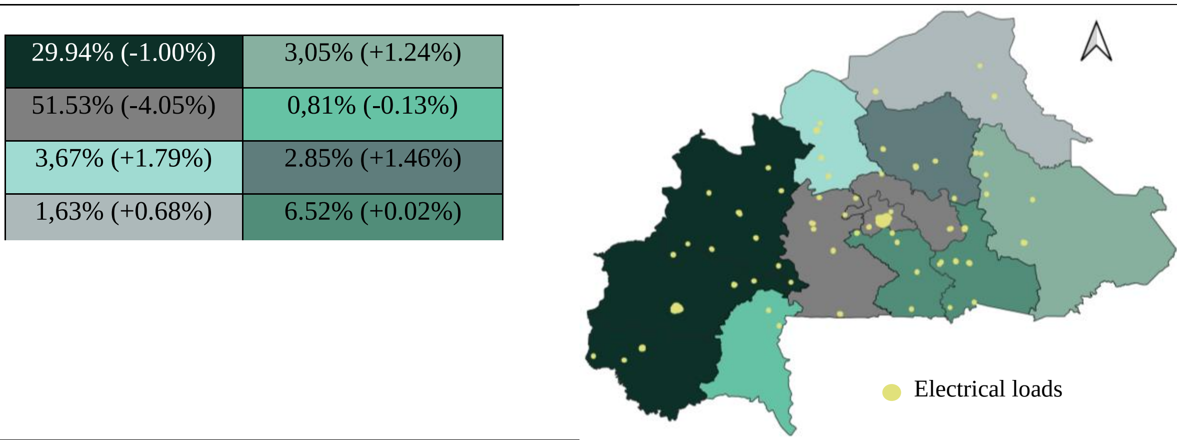
- Two-level validation process of spatial electrification analysis for use as spatially-resolved demand input data in SDDP



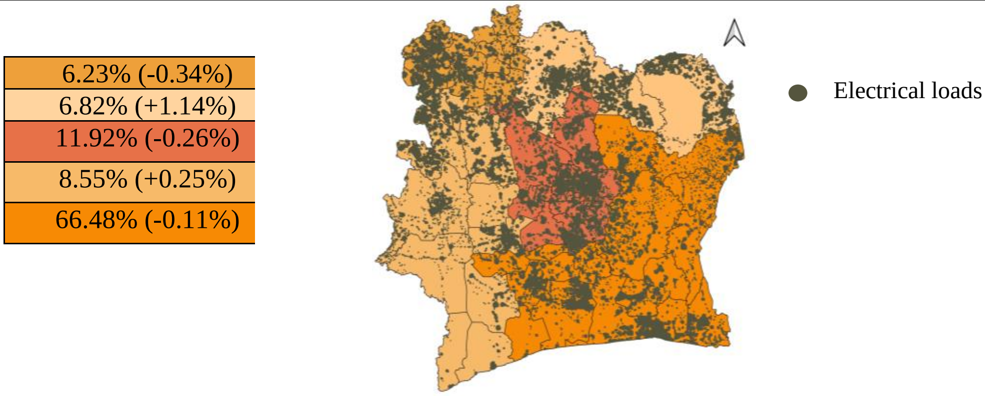
The results show that:

(1) In the base year, the actual and modeled values of national electrification rates and urbanization are close enough, hence demonstrating the ability of OnSSET to accurately model urban and rural areas, as well as to estimate electrification levels.
(2) In the base year, the OnSSET modeled demand levels utility data are similar to those in the WAPP Master Plan and the power utility data.
(3) In the base year, the spatial distributions of demand levels modeled by OnSSET (represented as weights in the total grid demand) are close to actual values of bus data provided by the respective national utilities.
(4) In the final year, the OnSSET modeling yields appreciable results which are consistent with utility forecasts for national demand and with the first-ever bottom-up study [22] for demand at household level.

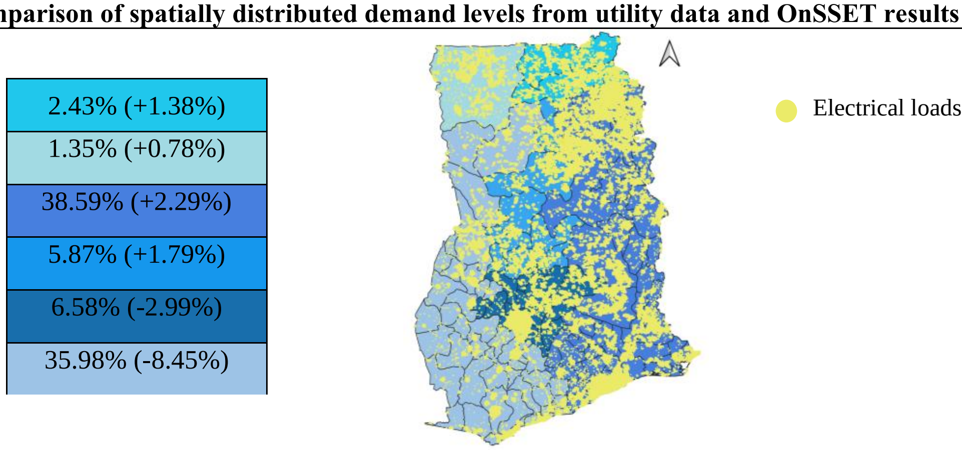
- Spatial load distributions in each study country



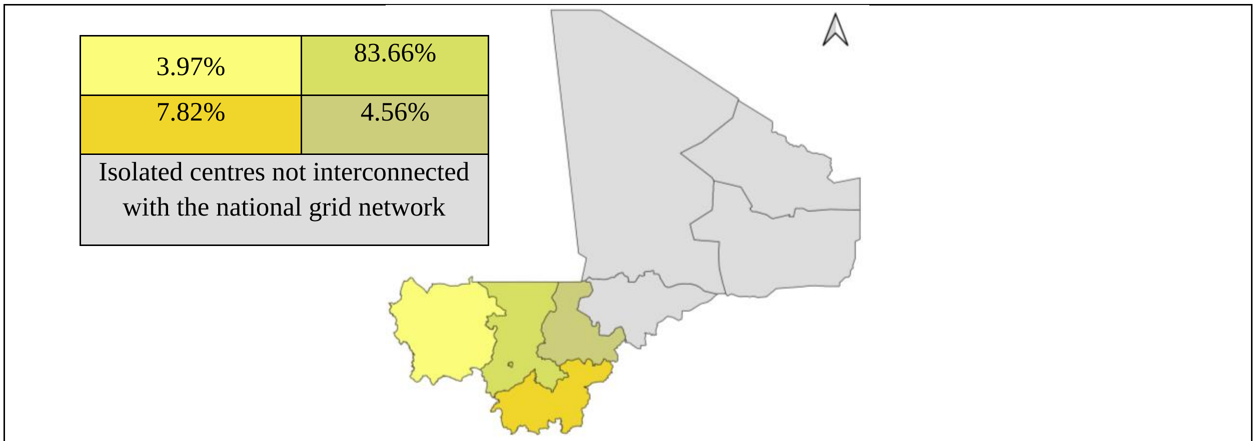
Comparison of spatially distributed demand levels from utility data and OnSSET results for Burkina Faso



Comparison of spatially distributed demand levels from utility data and OnSSET results for Côte d’Ivoire



Comparison of spatially distributed demand levels from utility data and OnSSET results for Ghana



Mapping of electrical loads in Mali

The spatial distribution of loads is based on utility data from 2017 (the latest year available). Considering that OnSSET modeling could not be performed and that the insecurity situation in Northern Mali, which is not yet interconnected with the national grid, it was deemed appropriate, to lay the hypothesis that electricity demand will not increase sufficiently to justify large-scale grid interconnection investments. Indeed, with the insecurity environment prevailing in this region for over a decade [78], it could be reasonably expected that the investment risks would constrain such commitments from technical and financial partners, who currently dominate investment in the sector. Therefore, it is assumed that until 2040, no isolated center will be connected to the grid.

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