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Scenario modelling of sustainable electricity pathways in Côte d'Ivoire: an open-source system framework

Derval Olivier Toukam[a*], Joerg Meyer[a], Frank Alsmeyer[a], Mario Adam[b]

[a]*SWK E² Institute for Energy Technology and Management, Hochschule Niederrhein, Reinarzstraße 49, 47805 Krefeld, Germany*
[b]*Faculty of Mechanical and Process Engineering, Hochschule Düsseldorf, Münsterstraße 156, 40476 Düsseldorf, Germany*

ABSTRACT

Côte d'Ivoire faces rapidly increasing electricity demand and persistent access inequalities while pursuing low-carbon development objectives. This paper presents a spatially explicit, scenario-based electricity system analysis using PyPSA-Earth, an open-source optimisation framework. The national power system is modelled with 14 spatial clusters and hourly resolution to assess long-term generation expansion, dispatch, and system costs for 2030, 2040, and 2050 under three internally consistent scenarios: Baseline (current policies), Policy (progressively tightening electricity-sector emission limits), and Renewables (near-zero emissions). Electricity demand increases from 12.27 TWh in 2030 to 26.74 TWh in 2050 across all scenarios. Solar photovoltaics emerge as the dominant expansion technology, while existing hydropower provides stable system flexibility. In the Baseline pathway, electricity-sector CO_2 emissions rise from 1.10 Mt in 2030 to 2.66 Mt in 2050. The Policy scenario limits CO_2 emissions to 1.05 Mt by 2050, whereas the Renewables scenario reaches zero annual emissions within the model boundary. Annualised system costs increase with demand, reaching 1,380 M EUR (Baseline), 1,291 M EUR (Policy), and 1,493 M EUR (Renewables) in 2050. The analysis demonstrates a transparent and reproducible framework for long-term electricity planning in data-constrained contexts.

Keywords

Electricity planning;
Renewable energy transition;
Scenario analysis;
Côte d'Ivoire;
PyPSA-Earth

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1. Introduction

Côte d'Ivoire faces a dual challenge in its electricity sector: rapidly rising demand driven by population growth, urbanisation, and economic development, alongside persistent inequalities in electricity access, particularly in rural areas. The country has a surface area of approximately 322,463 km² and exhibits pronounced north–south climatic and socio-economic gradients, which contribute to uneven population density, grid coverage, and renewable resource availability.

In 2023, national electricity generation reached approximately 13.3 TWh, primarily driven by natural gas (69%) and hydropower (30%), while solar accounted for just 1%. Despite this output, national electricity access remains at 70%, with rural connectivity significantly lower [1]. These disparities are closely associated with low load density, remoteness, affordability constraints, and the high costs of grid extension.

Demographic dynamics further intensify this planning challenge. Côte d'Ivoire's population has grown rapidly over the past decade, reaching approximately 31 million inhabitants in 2023, with sustained annual growth exceeding 2%. This trend is expected to exert continued pressure on electricity demand, infrastructure expansion, and access provision, particularly in rapidly urbanising areas and underserved regions [2]. Long-term electricity planning must therefore simultaneously address access expansion, system reliability, and cost containment under conditions of rapid structural change.

From a climate and energy policy perspective, Côte d'Ivoire's updated Nationally Determined Contribution underscores the scale of this challenge. The NDC

*Corresponding author – e-mail: derval2kam@gmail.com

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List of Abbreviations

ANARE-CI	*Autorité Nationale de Régulation du Secteur de l'Électricité de Côte d'Ivoire*
CCGT	*Combined-Cycle Gas Turbine*
ECOWAS	*Economic Community of West African States*
GADM	*Global Administrative Areas*
DGE	*Direction Générale de l'Énergie (Côte d'Ivoire)*
IEA	*International Energy Agency*
IRENA	*International Renewable Energy Agency*
LCOE	*Levelised Cost of Electricity*
RCI	*République de Côte d'Ivoire*
NDC	*Nationally Determined Contribution*
PK-NRW	*Promotionskolleg Nordrhein-Westfalen*
PV	*Photovoltaic*
PyPSA	*Python for Power System Analysis*
SSP	*Shared Socioeconomic Pathway*

outlines a business-as-usual trajectory with rising greenhouse gas emissions toward 2035 and defines both unconditional and conditional mitigation objectives relative to this baseline [3]. Within this framework, the electricity sector is identified as a central mitigation lever, with indicative targets to substantially increase the share of renewable generation, particularly solar, biomass, hydropower, and wind, supported by technology-specific capacity priorities and territorially differentiated implementation strategies. These policy orientations highlight the need for coherent, long-term electricity system planning that can jointly assess spatial deployment, system integration, and emissions trajectories.

Previous modelling efforts addressing electricity planning in Côte d'Ivoire and comparable contexts can be broadly grouped into three strands.

- First, national optimisation models, including TIMES-based frameworks, provide insights into long-term investment pathways but typically rely on aggregated representations that limit their ability to capture spatial heterogeneity, decentralised technologies, and socio-economic diversity [4].
- Second, geospatial electrification tools such as OnSSET explicitly address access gaps and off-grid or mini-grid solutions yet remain weakly integrated with system-wide optimisation of generation, transmission, and costs [5]. While well suited for access planning, these approaches generally operate outside detailed transmission modelling and hourly dispatch analysis.
- Third, complementary regional studies, such as those for Ghana and Nigeria emphasise the importance of institutional and financial constraints in shaping electricity transition pathways [6, 7], while comparative European experiences, including Germany and Poland, illustrate how governance frameworks and policy coherence influence the feasibility and pace of low-carbon transitions [8, 9, 10].

Despite these contributions, existing studies have not yet consistently combined spatially explicit system optimisation with long-term scenario analysis within a coherent national framework, particularly in contexts characterised by limited and heterogeneous data availability such as Côte d'Ivoire. As a result, national grid-based planning and decentralised electrification strategies are often analysed in isolation, and uncertainties beyond 2030, especially regarding costs, infrastructure expansion, and policy conditions, remain insufficiently explored.

Recent advances in open-source energy system models have expanded the range of tools available for scenario-based electricity planning, contributing to lower barriers to access and improved transparency in modelling workflows. However, as emphasised in the IJSEPM literature, the analytical value of such models depends less on the tools themselves than on how system boundaries, modelling assumptions, and data processing procedures are defined, documented, and aligned with concrete planning questions [11, 12]. Methodological choices can substantially influence results even when established analytical approaches are applied, particularly in data-constrained settings. Related studies published in this journal further demonstrate how spatial aggregation and open-data-based workflows can support planning under limited data availability, while making modelling simplifications and uncertainties explicit for decision-makers [13].

Against this background, this paper develops and applies an open, reproducible electricity system modelling framework for Côte d'Ivoire using PyPSA-Earth. The novelty of the contribution lies not in the modelling tool itself, but in its country-specific operationalisation under data and planning constraints. This includes:

- A spatial aggregation into 14 district-based nodes reflecting administrative and infrastructural realities;
- The integration and correction of national generation asset data, including biomass and hydropower classifications that are only partially and heterogeneously represented in global datasets and therefore require validation and correction using national sources; and
- A transparent scenario design enabling systematic comparison of costs, generation structures, and emissions trajectories across 2030, 2040, and 2050.

The framework is designed as a planning support tool, rather than a predictive forecasting instrument. The study provides insights into structural transition pathways, system-level trade-offs, and priority areas for future data and policy refinement in Côte d'Ivoire and comparable West African contexts.

2. Modelling Framework and Scenario Design

This section describes the modelling framework, data sources, assumptions, and scenario design used to analyse long-term electricity system evolution in Côte d'Ivoire. The methodological approach emphasises transparency and reproducibility by combining open international datasets with national sources and by explicitly documenting modelling assumptions, system boundaries, and constraint settings that are particularly consequential in data-scarce planning contexts. The modelling workflow was structured into five sequential steps (Figure 1).

2.1. Methodological Framework

A spatially explicit, linear optimisation model of Côte d'Ivoire's electricity system was developed using PyPSA-Earth, an open-source framework for large-scale power system analysis and planning [14]. The analysis adopts an electricity-only system boundary; sector-coupled demand (e.g. transport, heating, industry) is not modelled explicitly and is considered beyond the scope of this study.

The model solves a linear cost-minimization problem, jointly optimising generation and network dispatch under techno-economic parameters, spatial representation, and policy constraints. It employs an "overnight" capacity expansion approach for target years (2030, 2040, 2050), treating each as a static, internally consistent optimisation rather than an intertemporal pathway.

PyPSA-Earth was chosen for its integration of endogenous capacity expansion, hourly dispatch, and explicit spatial representation in a transparent, open-source environment [14]. Alternatives like Calliope and GridPath provide flexible representations [15, 16], but demand more manual customisation for comparable resolution and reproducibility in data-scarce contexts. PyPSA-Earth's modular design also supports future extensions to multi-energy systems and sector coupling, beyond this study's electricity-only focus.

The framework was adapted to the Ivorian context by leveraging internationally harmonised datasets in PyPSA-Earth's defaults, validated and refined with national planning documents and statistics. Global inputs - drawing from IRENA cost outlooks and regional assessments [17, 18] and IEA outlooks [19, 20] - provide

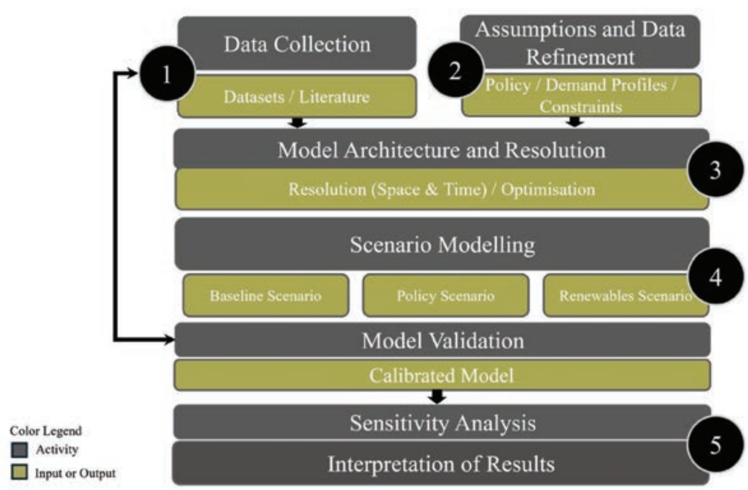

Figure 1: Five-step scenario-based electricity system modelling approach for Côte d'Ivoire.

baselines for technology costs, fuel prices, renewable resources and scenarios as implemented in public data pipelines and configuration files [21].

Where defaults lacked granularity, national sources enhanced representation: hydropower and biomass data from regulatory documents [1, 22] replaced defaults, while administrative boundaries used GADM [23]. The portfolio includes solar photovoltaics, onshore/offshore wind, hydropower, biomass generation, gas-fired plants, and storage (PHS with 6-hour max, batteries and hydrogen via PyPSA Store formulation), all competing endogenously. Configurations and overrides ensure reproducibility via documented files.

Technology selection was guided by a combination of resource availability, techno-economic maturity, data availability, and relevance to national electricity planning. Solar photovoltaics and wind technologies were included based on high solar irradiation and adequate wind potential identified in ERA5 reanalysis data, as well as favourable cost trajectories reported by IRENA and the IEA. Hydropower and biomass-based generation were included due to their established role in Côte d'Ivoire's electricity mix and the availability of national plant-level data. Gas-fired generation was retained as a dispatchable balancing option reflecting existing infrastructure and its role in current system operation.

Technologies such as coal, nuclear, geothermal, tidal, and other emerging options were excluded due to a combination of limited domestic resource potential, absence from national planning documents, insufficient or unreliable local data, and lack of relevance within the electricity-only scope of this study. The resulting technology set therefore reflects options that are both planning-relevant for Côte d'Ivoire and consistently parameterised within the PyPSA-Earth framework, ensuring transparency and reproducibility.

2.2. Data Collection (Step 1)

This step compiles the datasets and literature inputs used to parameterise the Côte d'Ivoire electricity system model. Data collection focuses on three categories: (i) weather and renewable resource inputs, (ii) electricity demand inputs, and (iii) technology cost and performance inputs.

Weather-driven inputs were obtained from an ERA5-based cutout generated within the PyPSA-Earth workflow using atlite [24]. The cutout provides hourly gridded data for Côte d'Ivoire at a spatial resolution of $0.25° \times 0.25°$ and includes key variables required for renewable resource characterisation and preprocessing, including wind speed at 100 m (wnd100m), wind shear parameters, surface roughness, solar geometry (solar altitude and azimuth), direct and diffuse irradiation proxies (influx_direct, influx_diffuse, influx_toa), albedo, and near-surface temperature variables. These datasets directly inform the representation of variable renewable technologies included in the model and implicitly constrain the technology portfolio to options for which spatially and temporally resolved resource data are available.

Hourly electricity demand time series were sourced from the PyPSA-Earth demand module and associated demand datasets under the SSP framework. Demand projections were obtained for the model target years 2030, 2040, and 2050.

2.3. Assumptions and Data Refinement (Step 2)

In the second step techno-economic, financial, and operational assumptions were harmonised to ensure internal consistency across scenarios. Specifically, investment costs, efficiencies, technical lifetimes, and marginal operating costs were adopted from the default PyPSA-Earth dataset and validated against regional estimates from IRENA [17] and the IEA [19]. A summary of the key techno-economic assumptions applied in the model is provided in Table 1. All such costs were annualised applying a uniform real discount rate of 7.1 %, as configured in PyPSA-Earth, and this was done consistently for all technologies and scenarios.

The levelised cost indicator in this study serves as a system-level proxy, distinct from conventional technology-specific LCOE. It is computed as the total annual system cost divided by the total electricity demand served (in EUR/MWh). As such, it incorporates aggregated investments, operations, and network expenditures for the entire electricity system and should not be viewed as a plant-level generation cost. This indicator is employed solely for comparing scenarios under the same modeling assumptions.

Future electricity demand trajectories are derived directly from the integrated SSP2-2.6 projections implemented within the PyPSA-Earth workflow [25]. This approach preserves the temporal structure of hourly load profiles while scaling annual demand levels in line with projected population and economic growth for the target years considered. Structural demand characteristics

Table 1: Techno-economic assumptions for electricity generation and storage technologies modelled for Côte d'Ivoire (applied in 2030, 2040, and 2050 scenario simulations). Data from [21].

Technology	CAPEX (EUR/kW)	Fixed OPEX (% of CAPEX/yr)	Lifetime (years)	Efficiency / Round-trip efficiency
Solar PV	650	2.0	25	–
Onshore wind	1,300	2.5	25	–
Hydropower	2,500	2.0	50	–
Biomass	2,200	4.0	25	30%
Gas CCGT	900	3.0	30	55%
Battery storage	400	1.0	15	90%
Pumped hydro storage	1,800	1.0	60	80%
Hydrogen storage	1,200	2.0	30	40%

specific to Côte d'Ivoire, including the negligible role of space heating and the growing importance of cooling demand, were implicitly reflected in these projections without explicit end-use modelling.

A key data refinement concerns biomass-based electricity generation. In the default PyPSA-Earth workflow (v0.7.0), renewable expansion limits are initialised using IRENA statistics, which do not report biomass electricity generation for Côte d'Ivoire in the 2023 reference year. To address this limitation, custom power plant data were compiled from national sources to explicitly represent existing and planned biomass-based generation units. These units were modelled as dispatchable renewable generators, enabling endogenous capacity expansion and dispatch within the optimisation framework.

2.4. Model Resolution (Step 3)

In the third step, the refined datasets were implemented within a spatially and temporally resolved electricity system model using PyPSA-Earth. Côte d'Ivoire was represented using 14 spatial nodes corresponding to level 1 administrative districts defined by the Global Administrative Map (GADM) [23]. This district-based aggregation aligns the model structure with national planning and governance units, supporting policy relevance while maintaining computational tractability.

The selection of 14 spatial nodes reflects a trade-off between spatial detail and feasibility in a national-scale, data-constrained context. While finer spatial resolution can better capture intra-regional variability in electricity demand, renewable resource availability, and transmission constraints, it also entails substantially higher data requirements and computational burden. District-level aggregation therefore provides a robust representation of regional demand centres and resource gradients for long-term scenario analysis, while acknowledging that residual intra-district variability, particularly along north–south climatic and demand gradients, remains a source of aggregation uncertainty. Existing generation assets were assigned to nodes based on geographic location and connected through a transmission network derived from the PyPSA-Earth workflow, with endogenous expansion of transmission links where cost-effective.

The model was solved at hourly temporal resolution over a single representative weather year (2018). Target years (2030, 2040, and 2050) were modelled independently using identical spatial representation, techno-economic assumptions, and solver settings to ensure comparability across scenarios. Hourly resolution enables explicit representation of short-term variability in electricity demand and renewable generation, while ensuring consistency between operational constraints and long-term investment decisions. The year 2018 was selected as a fully supported default weather year within the PyPSA-Earth workflow, providing internally consistent renewable resource availability and demand profile generation without bias toward extreme climatic conditions.

The analysis focuses on the grid-connected national electricity system. Off-grid and mini-grid systems are not represented explicitly, reflecting the scope of national utility-scale planning and transmission expansion strategies. This boundary choice may understate the role of decentralised renewable options in rural electrification and is therefore identified as a priority area for future extensions of the modelling framework.

2.5. Scenario Formulation and Validation (Step 4)

Three internally consistent scenarios were formulated to explore alternative long-term development pathways for Côte d'Ivoire's electricity system:

- Baseline scenario, representing continuation of current policies and investment trends without additional electricity-sector emission constraints.
- Policy scenario, incorporating progressively stricter electricity-sector emission limits consistent with national mitigation orientations.
- Renewables scenario, characterised by accelerated deployment of renewable energy technologies and favourable financing conditions.

The reference emission level applied in the model (co2base = 9.58 Mt CO_2 yr^{-1}) represents electricity-sector CO_2 emissions only. It is derived by proportionally allocating national greenhouse gas emissions to the electricity sector, using the equation co2base = (Electricity Sector Share) × National GHG Emissions, ensuring consistency between economy-wide emission statistics and the electricity-only system boundary.

Scenario-specific emission constraints applied for 2030, 2040, and 2050 are summarised in Table 2. Each scenario was evaluated independently for the three target years using a common data basis and modelling architecture. Scenario plausibility was assessed by comparing SSP2-2.6–based demand trajectories with independent regional outlooks, including IRENA projections [18].

2.6. Sensitivity Analysis and Interpretation of Results (Step 5)

Electricity system evolution was assessed using three primary indicators: annual electricity generation by technology, installed generation capacity, and total system costs. Storage technologies (batteries, pumped hydro storage, and hydrogen storage) were included endogenously and competed with generation technologies based on relative costs and system conditions.

Sensitivity considerations were addressed qualitatively by identifying key sources of uncertainty relevant to long-term electricity planning, including renewable technology cost trajectories,, hydropower availability, and policy-related parameters. These uncertainties were taken into account when interpreting scenario results and identifying robust system trends.

3. Scenario Results for Côte d'Ivoire's Electricity System

This section presents the results of the scenario-based electricity system analysis for Côte d'Ivoire and discusses their implications in relation to existing literature and planning practice. The results are structured to move from a description of the current energy system baseline to an assessment of future electricity demand, spatial system structure, technology deployment, costs, and emissions outcomes under alternative scenarios.

3.1. Current Structure of Côte d'Ivoire's Energy System

Before analysing long-term electricity system pathways, it is necessary to establish the current structure of Côte d'Ivoire's energy system as a reference point for subsequent scenario results. Figure 2 provides the 2023 economy-wide energy balance for Côte d'Ivoire and situates the electricity-sector model within the wider system. The balance is dominated by traditional biomass use in final consumption, while electricity constitutes a comparatively small share of total final energy. A sizeable residual category ("unknown demand") reflects statistical discrepancies and transformation and network losses in national energy balance accounting rather than unmet electricity demand. This context underscores that electricity decarbonisation scenarios interact with a broader energy system still shaped by biomass reliance and non-electric end-uses [22, 28].

This study applies an electricity-only optimisation framework focused on the power sector. Final electricity demand is represented as a single exogenous load without differentiation by end-use sectors (e.g., residential, commercial, industrial). Electricity consumption within the power sector itself is not modelled separately.

3.2. Spatial Representation of the Electricity System

In the model, Côte d'Ivoire's electricity system is represented as a spatially explicit network consisting of 14 clusters, aligned with the country's administrative districts. This aggregation captures regional differences in electricity demand, existing generation assets,

Table 2: Côte d'Ivoire's electricity-sector CO_2 emission reference level and scenario-specific constraints [Mt CO_2/Year]. Data from [26], [27].

Scenario	2030	2040	2050	Description
Baseline	9.58	9.58	9.58	No emission constraint; reference electricity-sector baseline
Policy	6.71	5.27	1.92	Progressive emission limits (70%, 55%, 20% of baseline)
Renewables	5.27	2.87	0.00	Accelerated decarbonisation with near-zero emissions

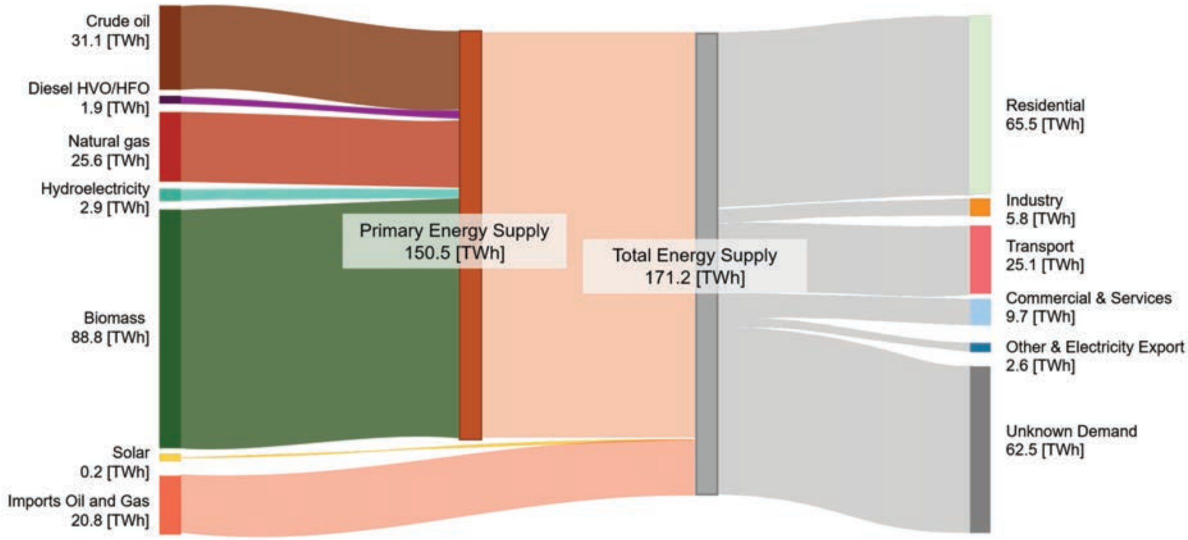

Figure 2: Energy Flow of Côte d'Ivoire in 2023, showing primary energy supply, transformation processes, and final energy consumption by sector. Data from [22], [28].

renewable resource availability, and the main transmission structure. Figure 3 shows the resulting spatial configuration, including regional nodes and their interconnections.

Each cluster represents a regional demand centre, with generation and transmission elements assigned based on geographic location. This approach enables analysis of regional patterns in capacity deployment and power flows, while remaining computationally feasible for long-term scenarios. Importantly it allows renewable expansion – particularly solar - to reflect area-specific resource potential, while respecting transmission constraints.

The spatial structure underpins the scenario results presented in the following subsections, where regional differences in demand growth, generation mix, and capacity expansion are examined within a consistent national framework.

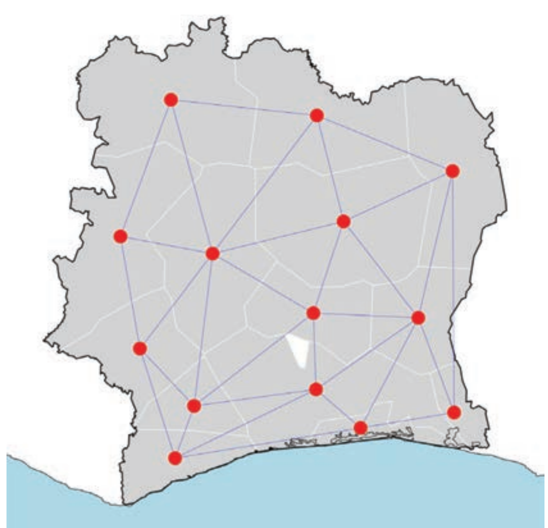

Figure 3: Spatial representation of Côte d'Ivoire's electricity system in the PyPSA-Earth model, aggregated into 14 Level 1 administrative districts (GADM) [23]. Network topology is derived from the PyPSA-Earth workflow [23], [29].

3.3. Electricity Demand Evolution Across Scenarios

Electricity demand grows substantially across all scenarios because demand is exogenously defined by the SSP2-2.6 trajectory and held constant across scenarios. Demand served increases from 12.28 TWh (2030) to 17.40 TWh (2040) and 26.74 TWh (2050). By keeping demand identical across scenarios, differences in generation mix, capacity expansion, system costs and emissions reflect scenario-specific constraints rather than divergent load assumptions (Figure 4).

3.4. Spatial Distribution of Installed Capacity

Figure 5 shows that capacity expansion is spatially uneven, reflecting both demand concentration and regional renewable resource gradients. Solar PV expands across all districts, with larger installations in higher-demand nodes. Dispatchable renewables (biomass) appear selectively where units are represented in national plant data, while hydropower remains geographically fixed. Battery power capacity becomes a central flexibility option in the constrained scenarios, with visibly larger deployments toward 2050.

3.5. Generation Mix and Technology Deployment

Across all scenarios, hydropower output remains stable at approximately 3.29 TWh per year (combined reservoir and run-of-river), while solar photovoltaics and dispatchable technologies drive structural changes in the generation mix.

Gas-fired generation provides the majority of dispatchable and balancing output in the Baseline scenario. This reflects its high operational flexibility and comparatively low variable cost under the applied techno-economic assumptions. Alternative flexibility options - including batteries, dispatchable biomass, and hydropower - are explicitly represented in the PyPSA-Earth framework but are deployed only where cost-optimal within the optimisation. Under Baseline conditions, storage deployment remains limited, and biomass expansion is moderate, leading gas to supply most firm capacity (reliable baseload equivalent) and intra-day balancing.

In quantitative terms, Baseline gas generation increases from 5.58 TWh in 2030 to 13.41 TWh in 2050, while solar rises from 2.22 TWh to 6.87 TWh. Battery capacity reaches 0.53 GW by 2050.

Under the Policy scenario, progressively tightening emission constraints reduce gas generation to 5.32 TWh in 2050. Solar expands to 17.30 TWh, biomass generation increases, and battery capacity reaches 3.90 GW. The additional deployment of dispatchable biomass and storage reduces reliance on gas relative to the Baseline.

In the Renewables scenario, gas generation is nearly eliminated by 2050. Electricity demand is met primarily by solar (16.88 TWh), supported by biomass (7.16 TWh) and stable hydropower output. Battery capacity increases further to 4.62 GW, indicating a larger role for short-duration storage in balancing variable solar generation (Figure 6 (a)). The Renewables scenario achieves approximately 100% renewable electricity share by 2050.

3.6. Installed Capacity Expansion

Installed generation capacity increases across all scenarios to accommodate rising electricity demand and the growing share of variable renewable energy. Capacity

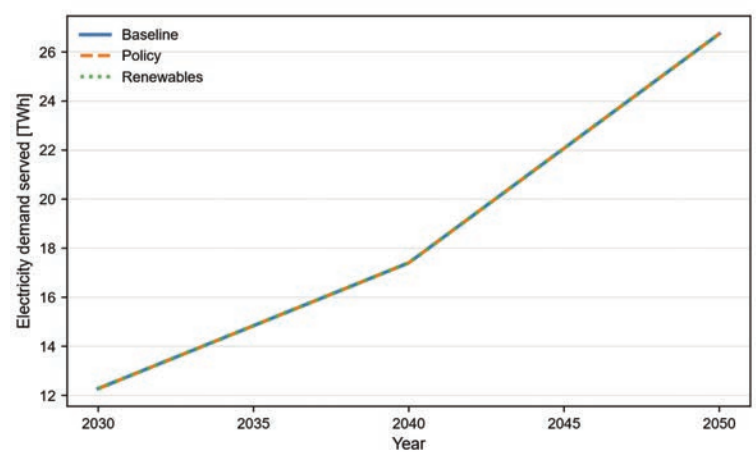

Figure 4: Evolution of annual electricity demand served in Côte d'Ivoire under the Baseline, Policy, and Renewables scenarios for 2030, 2040, and 2050. Demand trajectories are derived from SSP2-2.6 projections implemented within the PyPSA-Earth workflow and are identical across scenarios.

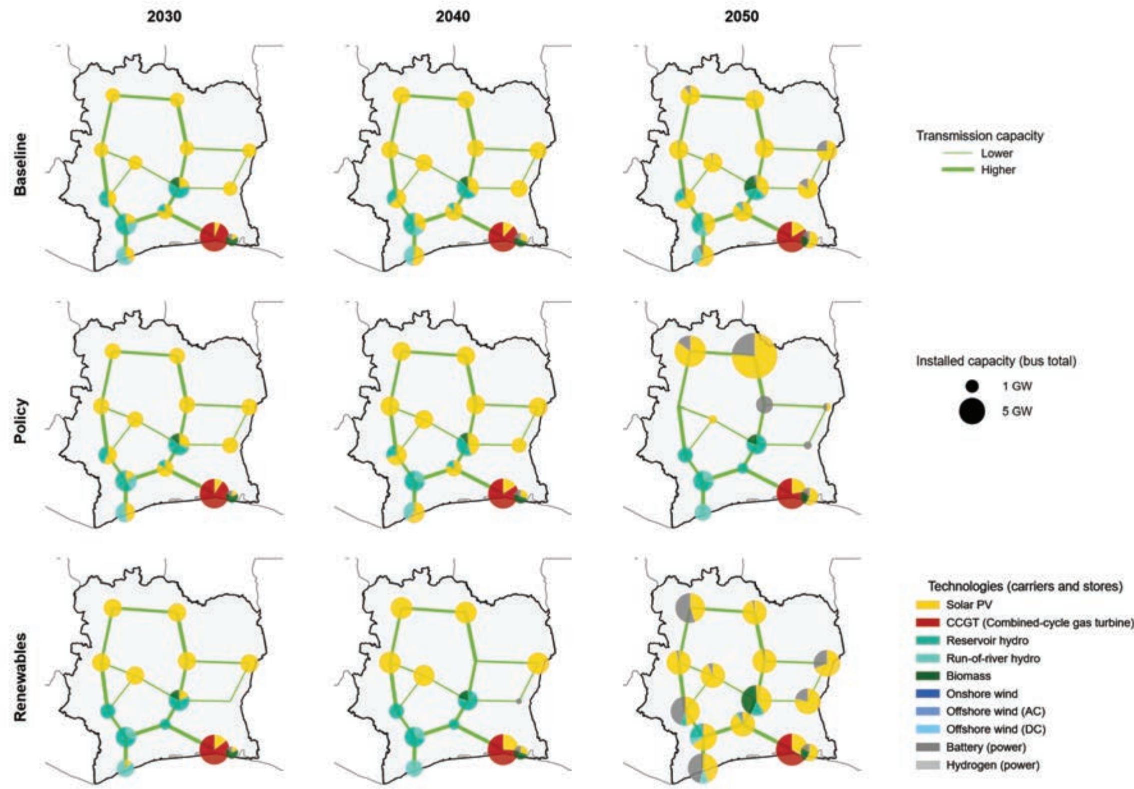

Figure 5: Evolution of spatial distribution of installed generation, storage and transmission capacity for Côte d'Ivoire across all scenarios (2030–2050). Results are based on solved PyPSA-Earth model runs.

deployment patterns differ between the Baseline, Policy, and Renewables scenarios, reflecting alternative technology choices and flexibility requirements (Figure 6).

In the Baseline scenario, capacity expansion is driven primarily by solar photovoltaics. Gas-fired capacity remains largely stable, hydropower capacity does not expand, while biomass capacity increases moderately toward 2050. Wind deployment remains negligible under the applied techno-economic assumptions.

The Policy scenario accelerates solar deployment while constraining gas capacity expansion. Biomass capacity increases selectively, while hydropower capacity remains unchanged, and wind continues to play a negligible role.

The Renewables scenario prioritises a high-penetration pathway dominated by large-scale solar and biomass expansion. By 2050, a mix of solar, biomass, and hydropower meets nearly 100% of electricity demand, relegating gas-fired plants to a minimal residual backup role. Overall, this scenario yields the highest share of renewable capacity and reflects a system structured around variable renewables supported by dispatchable low-carbon technologies.

Battery power capacity plays an increasingly important role in constrained scenarios. While remaining modest in the Baseline (0.53 GW in 2050), battery capacity expands substantially under emission constraints, reaching 3.90 GW in the Policy scenario and 4.62 GW in the Renewables scenario by 2050. This expansion reflects the growing importance of storage for providing operational flexibility as gas-fired generation is progressively reduced.

3.7. System Costs and Economic Implications

Total system cost increases across all scenarios with rising electricity demand (Figure 7). In the Baseline scenario, annual system cost rises from approximately 808 M EUR in 2030 to 1,380 M EUR in 2050. Under the Policy scenario, total cost reaches 1,291 M EUR in 2050, reflecting lower fossil dispatch and moderate additional investment. The Renewables scenario exhibits the highest 2050 cost (1,493 M EUR) due to

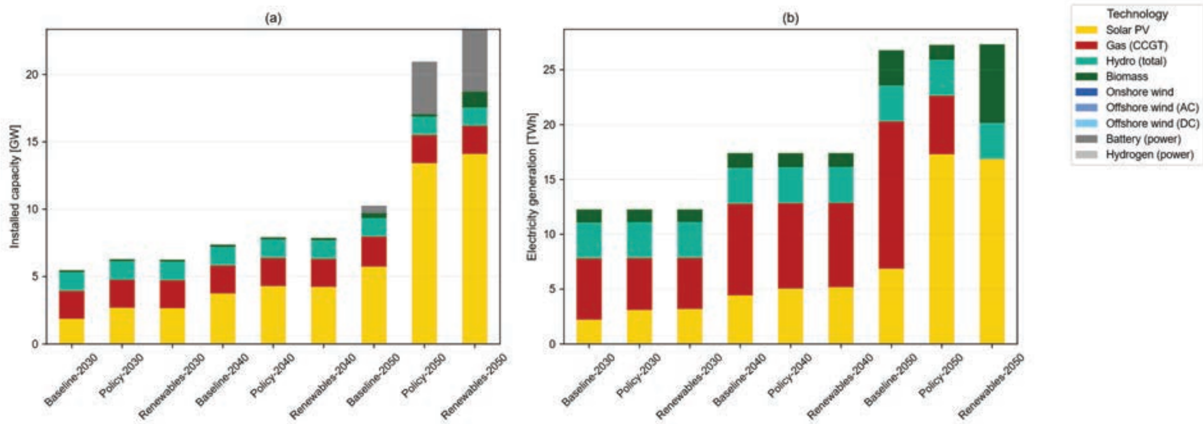

Figure 6: Installed electricity generation and storage power capacity (a) and annual electricity generation (b) by technology for Côte d'Ivoire under the Baseline, Policy, and Renewables scenarios in 2030, 2040, and 2050. Results are based on solved PyPSA-Earth model runs.

accelerated renewable deployment and flexibility investments under the near-zero emission constraint.

The LCOE proxy (solved cost objective divided by total electricity demand) declines over time in all scenarios due to demand growth and scale effects, ranging from approximately 65 EUR/MWh in 2030 to 48–56 EUR/MWh in 2050 depending on the scenario.

3.8. Emissions Outcomes Across Scenarios

Electricity-sector CO_2 emissions differ sharply across scenarios (Figure 8).

In the Baseline pathway, emissions increase from 1.10 Mt CO_2 in 2030 to 1.65 Mt CO_2 in 2040 and 2.66 Mt CO_2 in 2050. This increase occurs alongside demand growth from 12.27 TWh to 26.74 TWh. Under the Policy scenario, emissions are progressively reduced and reach 1.05 Mt CO_2 in 2050. In the Renewables scenario, emissions decline to 0.00 Mt CO_2 in 2050 under the near-zero emission constraint.

Emission constraints are implemented as upper bounds (Table 2). Because the optimisation objective is total system cost minimisation, realised emissions may fall below the imposed limits when lower-emission configurations are cost-optimal.

4. Discussion and Planning Implications

The results presented in this study provide insights into potential development pathways for Côte d'Ivoire's electricity system under alternative policy and investment assumptions. Beyond the scenario-specific outcomes, the study contributes to the academic literature

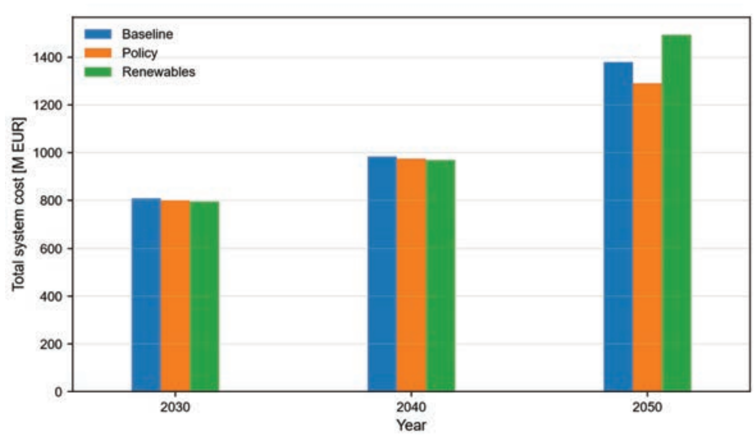

Figure 7: Total annual electricity system costs for Côte d'Ivoire under the Baseline, Policy, and Renewables scenarios in 2030, 2040, and 2050. Costs include generation, storage, and transmission investment and operating costs as represented in the PyPSA-Earth framework.

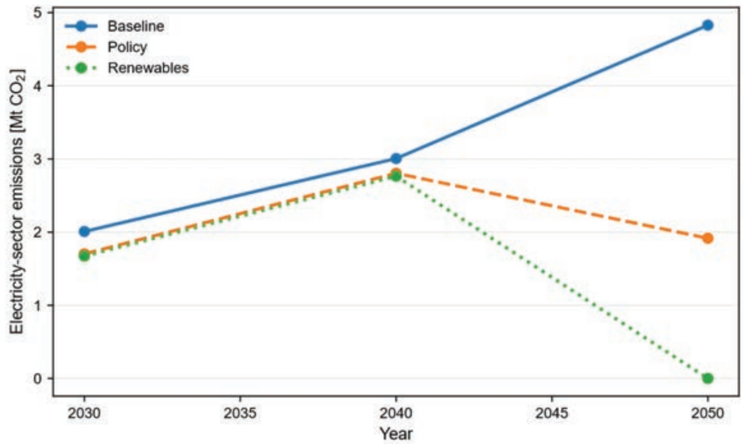

Figure 8: Electricity-sector CO_2 emissions in Côte d'Ivoire under the Baseline, Policy, and Renewables scenarios for 2030, 2040, and 2050. Emissions include CO_2 from electricity generation only.

by illustrating how an open-source, spatially explicit electricity system model can be adapted and applied in a national context characterised by limited and heterogeneous data availability.

The contribution does not lie in introducing new modelling techniques, but in the transparent integration of international datasets with national statistics, the explicit documentation of assumptions and constraints, and the systematic comparison of policy-constrained scenarios within a consistent modelling architecture. This approach aligns with recent calls for reproducible and transparent energy system modelling in data-scarce regions [30], [31] and provides a structured basis for long-term electricity system analysis in Côte d'Ivoire and comparable contexts.

4.1. Capacity Expansion Pathways and System Structure

The results indicate that Côte d'Ivoire's electricity system can accommodate rapidly rising demand through substantial expansion of renewable generation capacity, particularly solar photovoltaics. Across all scenarios, solar emerges as the dominant expansion technology, reflecting favourable resource availability and declining technology costs. This outcome is consistent with regional and continental-scale studies for West Africa, which identify solar photovoltaics as the least-cost option for new generation capacity under most demand growth assumptions [32, 33].

By contrast, wind energy does not contribute significantly in the present model runs. This outcome reflects the interaction between applied techno-economic assumptions, spatial resource representation, and transmission cost structures rather than a definitive assessment of Côte d'Ivoire's long-term wind potential. Under the applied assumptions, solar photovoltaics combined with the existing grid topology constitute the most cost-efficient expansion pathway. Alternative assumptions, such as higher transmission costs or revised material price trajectories, could alter relative technology competitiveness. Under such conditions, offshore or near-coastal wind generation may become more attractive by reducing reliance on long-distance transmission from northern solar resources.

Building on the generation mix and capacity expansion patterns outlined in Section 3.5 (e.g., Figure 6), gas-fired capacity persists as a key component across scenarios, with its operational role modulated by policy-driven emission constraints. In the Baseline scenario, gas predominantly handles balancing (short-term variability) and provides firm capacity accounting for most of the dispatchable output under unconstrained conditions. As emission limits intensify in the Policy and Renewables scenarios, gas utilization decreases, correlated with the expansion of dispatchable biomass and short-duration battery storage to meet similar flexibility needs. These results demonstrate that gas-fired generation is not exogenously assigned a balancing role but emerges as the cost-optimal flexibility provider under current assumptions. As emission constraints tighten, alternative flexibility options increasingly substitute for gas within the least-cost solution.

Biomass plays an increasingly important role in constrained scenarios. Its explicit modelling as a dispatchable renewable technology enables substitution for gas during periods of low solar availability, consistent with findings from other African energy system studies emphasising the role of firm renewables alongside variable generation [34]. Furthermore, hydropower, while limited in expansion potential, continues to provide spatially fixed flexibility within the existing fleet, complementing solar deployment [33]

Across scenarios, electricity demand increases from approximately 12.27 TWh in 2030 to 26.74 TWh in 2050. In the Baseline case, emissions rise from 1.10 Mt CO_2 in 2030 to 2.66 Mt CO_2 in 2050, while total system cost increases from approximately 808 M EUR to 1,380 M EUR. The Policy scenario limits 2050 emissions to 1.05 Mt CO_2 at a total system cost of 1,291 M EUR. The Renewables scenario achieves near-zero emissions by 2050, with total system cost reaching 1,493 M EUR under the near-zero emission constraint.

4.2. Role of Dispatchable Renewables, Storage, and System Flexibility

The results underscore that achieving high shares of solar photovoltaic generation requires complementary sources of system flexibility. While solar photovoltaics dominate capacity expansion across all scenarios, system adequacy and operational balance are not provided by variable generation alone. Instead, flexibility emerges from a combination of dispatchable generation, existing hydropower assets, and short-term storage technologies as represented in the model. This finding aligns with broader literature emphasising that high-renewable systems require diverse flexibility portfolios rather than reliance on a single balancing option [35, 36].

For instance, battery storage is included in the modelling framework and contributes to smoothing intra-day variability in solar output. Under the applied cost assumptions, battery deployment increases under emission constraints but remains limited relative to generation capacity across scenarios. Specifically, battery capacity grows from 0.53 GW in Baseline to 3.90 GW in Policy and 4.62 GW in Renewables by 2050, driven by intra-day flexibility demands from higher solar output. Storage primarily fulfils a short-duration balancing role rather than providing large-scale seasonal energy shifting. This contrasts with scenarios for highly interconnected power systems where large-scale storage becomes a dominant flexibility option [37, 38], highlighting the importance of national context and cost assumptions.

Dispatchable generation therefore remains central to system flexibility. In the Baseline scenario, this role is largely fulfilled by gas-fired power plants, while in the Policy and Renewables scenarios it increasingly shifts toward biomass-based electricity generation. The explicit representation of biomass allows the system to accommodate high solar shares while reducing fossil fuel dependence, particularly during evening hours and seasonal low-solar periods.

In addition, hydropower provides supplementary system flexibility despite limited expansion across scenarios. Existing reservoir and run-of-river plants supply operational balancing capacity, reducing the need for additional system flexibility and limiting solar overcapacity. Taken together, the results indicate that high solar penetration does not automatically imply large-scale storage deployment and that alternative flexibility portfolios remain critical in shaping cost-effective transition pathways.

4.3. Implications for Electricity Planning in Côte d'Ivoire

The scenario results have several implications for long-term electricity planning in Côte d'Ivoire.

First, they indicate that substantial expansion of renewable generation capacity, particularly solar photovoltaics, is likely to be a central feature of the electricity system regardless of the policy pathway pursued. This suggests that planning efforts should prioritise grid integration, transmission reinforcement, and operational strategies capable of accommodating high shares of variable renewable energy, as also highlighted in recent regional planning assessments [20].

Second, scenario comparisons highlight dispatchable capacity's importance for system adequacy amid rapid demand growth. While gas-fired generation fulfils this role in unconstrained pathways, alternative scenarios indicate that dispatchable renewables such as biomass can partially substitute fossil-based flexibility [39, 40]. This finding supports planning approaches that emphasise diversification of flexibility options rather than exclusive reliance on thermal generation or storage technologies [33].

4.4. Methodological Limitations and Future Research

Several limitations should be considered when interpreting the results. These include:

- Renewable generation profiles are based on a single historical weather year, which may underrepresent interannual variability and extreme events.
- Hydropower plants are differentiated between run-of-river and reservoir-based technologies, improving the representation of operational flexibility relative to aggregated hydropower modelling. However, inflows are represented using static profiles due to data limitations in harmonising hydropower plant identifiers across international and national datasets, constraining the assignment of plant-specific inflow time series.
- Biomass is represented through explicit plant assumptions rather than endogenous resource constraints. While this allows transparent modelling of dispatchable renewable capacity, it does not capture competition with other biomass uses or uncertainties in long-term feedstock availability. Future modelling should therefore integrate biomass supply constraints and competing uses to improve system realism [40].
- The present analysis focuses exclusively on the electricity sector. Côte d'Ivoire's broader energy system remains dominated by non-electric energy uses, particularly traditional biomass in the residential sector and fossil fuels in transport. Electricity-sector decarbonisation therefore provides only a partial view of overall transition dynamics, especially regarding interactions between modern biomass use, clean cooking, and agricultural value chains. In addition, the centralised nodal, structure of the PyPSA-Earth framework may underrepresent decentralised electrification dynamics in rural and peri-urban areas.

Future work will extend the modelling framework through targeted sensitivity analyses on transmission costs, material price trajectories, and grid reinforcement requirements. Further analysis of constrained transmission expansion and elevated material costs will assess how infrastructure limitations may alter technology competitiveness. Further extensions will integrate full sector coupling by incorporating transport, industry, and residential demand. Additional sensitivity analyses will address technology costs, storage deployment, biomass availability, and policy instruments such as explicit CO_2 pricing mechanisms.

5. Conclusion

This paper presents a scenario-based electricity system analysis for Côte d'Ivoire using the open-source PyPSA-Earth framework. Instead of delivering predictive forecasts, it provides a structured comparison of alternative development pathways under consistent techno-economic and policy assumptions.

Across all scenarios, the electricity system undergoes significant structural transformation. Solar photovoltaics emerge as the principal expansion technology, while existing hydropower assets continue to provide geographically anchored flexibility. The role of gas-fired generation diverges across scenarios: it remains a central balancing resource under the Baseline pathway but is progressively displaced by dispatchable biomass and storage under more stringent emission constraints. Deep decarbonisation is technically feasible within the model structure, although it requires substantial investment in renewable capacity and flexibility options by 2050.

The primary contribution of this study lies not in the application of PyPSA per se, but in the adaptation of a globally standardised optimisation framework to a data-constrained national context. This includes the harmonisation of international cost and resource datasets with national statistics, the translation of scenario assumptions into electricity-sector-specific emission constraints, and the use of spatial clustering to retain regional heterogeneity while maintaining computational tractability. Such an integration of global and national data addresses an important methodological gap in energy system modelling for Sub-Saharan Africa.

Beyond the national case, the findings highlight structural insights that are relevant to other rapidly growing electricity systems. High shares of solar generation do not eliminate the need for firm capacity to ensure adequacy and reliability. Dispatchable renewable technologies can substitute fossil-based balancing resources when supported by credible policy constraints. At the same time, storage deployment proves highly sensitive to relative cost assumptions and grid configuration. Furthermore, emission caps implemented as optimisation constraints may lead to realised emissions below policy ceilings where lower-emission system configurations are economically optimal.

Several limitations should be acknowledged. Renewable generation profiles rely on a single historical weather year, hydropower inflows are represented in simplified form, and biomass availability is treated exogenously. The analysis is confined to the electricity sector and does not incorporate broader financial risk premiums, institutional capacity constraints, or distributional impacts. These factors may significantly influence real-world transition dynamics and investment feasibility.

Future research should therefore extend the framework in three directions. First, sectoral integration should incorporate transport, industry, and clean cooking pathways in order to capture cross-sectoral interactions. Second, robustness analysis should include multi-year weather variability, transmission cost sensitivities, material price trajectories, and explicit biomass supply constraints. Third, institutional and financial dimensions should be embedded more explicitly, including differentiated costs of capital and the modelling of carbon pricing instruments.

By combining spatial optimisation, transparent scenario design, and documentation of assumptions, this study establishes a reproducible foundation for long-term electricity planning in Côte d'Ivoire. It also contributes to the broader discourse on sustainable energy planning in data-constrained and rapidly growing electricity systems.

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Appendix A: Spatial Distribution of Installed Generation Capacity

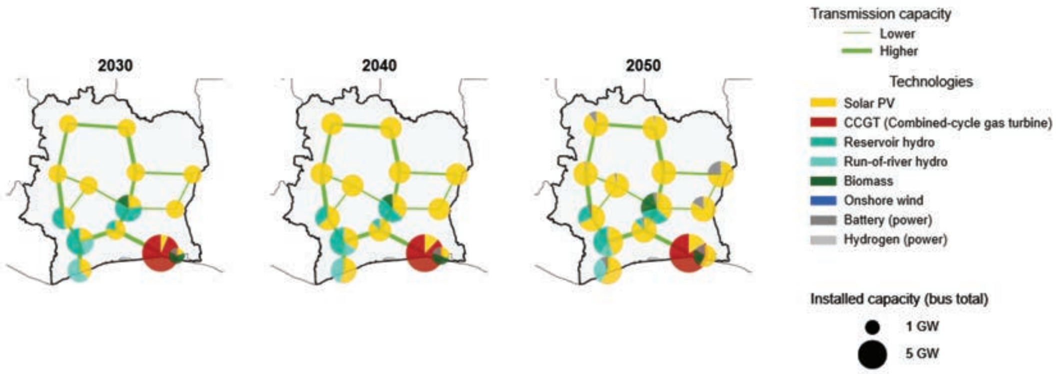

Figure A1: Evolution of spatial distribution of installed generation, storage and transmission capacity in the Baseline scenario (2030–2050). Results are based on solved PyPSA-Earth model runs [23].

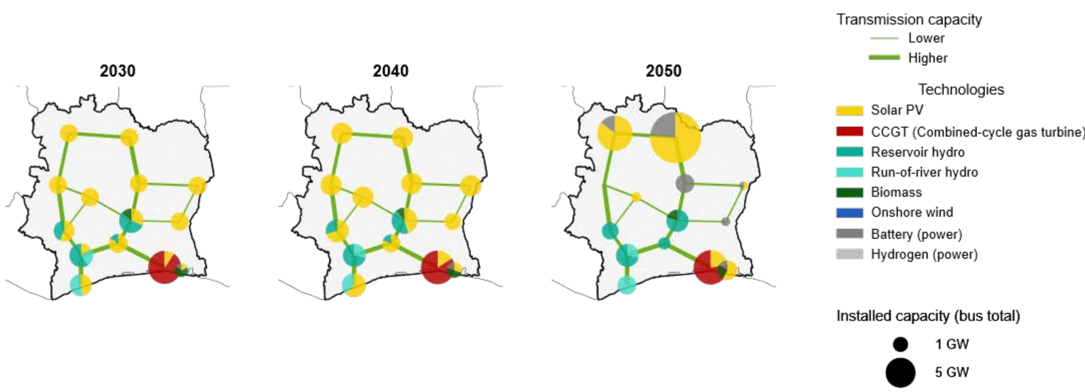

Figure A2: Evolution of spatial distribution of installed generation, storage and transmission capacity in the Policy scenario (2030-2050). Results are based on solved PyPSA-Earth model runs [23].

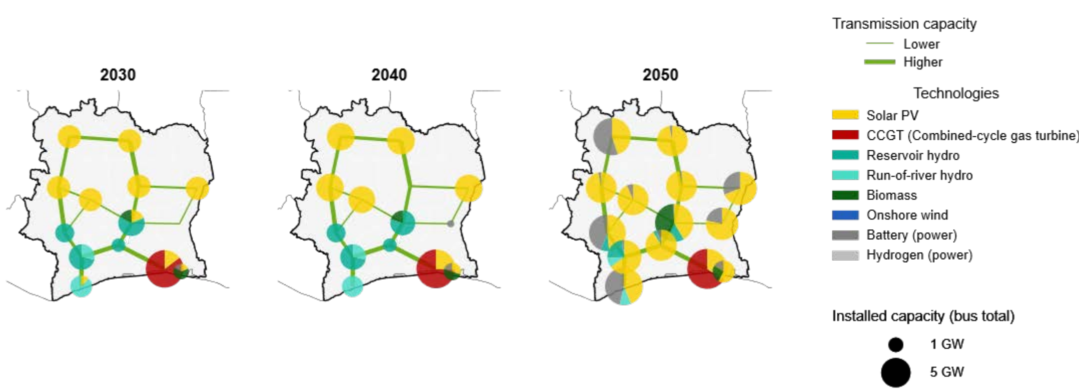

Figure A3: Evolution of spatial distribution of installed generation, storage and transmission capacity in the Renewables scenario (2030-2050). Results are based on solved PyPSA-Earth model runs [23].

Appendix B: System Cost and Emissions Key Performance Indicators

Table B1: Electricity system key performance indicators derived from solved PyPSA-Earth optimisation runs (electricity-only boundary).

Scenario	Year	Demand (TWh)	Generation (TWh)	Emissions (Mt CO_2)	Total system cost (M€)	LCOE (€/MWh)
Baseline	2030	12.27	12.28	1.10	808.0	65.82
Baseline	2040	17.40	17.40	1.65	983.3	56.50
Baseline	2050	26.74	26.79	2.66	1,379.8	51.60
Policy	2030	12.27	12.28	0.94	799.7	65.15
Policy	2040	17.40	17.40	1.54	974.8	56.01
Policy	2050	26.74	27.27	1.05	1,291.0	48.28
Renewables	2030	12.27	12.28	0.92	794.5	64.73
Renewables	2040	17.40	17.40	1.52	968.2	55.63
Renewables	2050	26.74	27.32	0.00	1,493.4	55.85

Notes:

- Total system cost corresponds to the PyPSA optimisation objective and represents annualised system cost, including investment and operational expenditures across generators, storage, transmission lines, and links.
- Electricity-sector CO_2 emissions are calculated from generator dispatch according to:

$$E = \sum_{t,g} p_{g,t} w_t \frac{\epsilon_{c(g)}}{\eta_g}$$

where
$p_{g,t}$ denotes generator output (MW)
w_t represents snapshot weighting (hours),
$\epsilon_{c(g)}$ is the carrier-specific CO_2 intensity (t CO_2/MWh_{fuel}, and
η_g is generator efficiency.

- Storage technologies (battery and hydrogen) are assigned zero direct CO_2 emission factors. Emissions are therefore attributed exclusively to fuel-based generation technologies.
- Levelised cost of electricity (LCOE) is computed as:

$$LCOE = \frac{Total\ system\ cost}{Total\ demand\ served}$$

expressed in EUR/MWh.