

Planning the power system of Senegal

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Abstract—This paper presents a methodology for designing the investment plan of the Senegalese power system by 2050, covering both the electrical generation and the transmission network. Using Python for Power System Analysis (PyPSA), multi-period power system optimizations are conducted to evaluate different investment strategies. Various scenarios are explored, incorporating the existing generation assets. Additionally, two sensitivity analyses are performed to quantify the impact of CO₂ emission constraints on the average cost of electricity per MWh.

Index Terms—Energy Transition, Optimal Power Flow, Planning Electrical System, Power System Analysis.

I. INTRODUCTION

Senegal is experiencing a rising electricity demand driven by urbanization, industrialization, and energy access projects. The global energy transition pushes the country to develop renewable energy sources, particularly solar and wind, while integrating recent natural gas discoveries into its energy mix and shifting from heavy fuel oil, the former being more consistent with environmental requirements [1]. Despite significant progress in the integration of renewable energy sources (RES), Senegal's potential remains vastly underutilized. With 3000 hours of sunshine per year and an irradiation level of 5.8 kWh/m²/day, the country has substantial solar resources [2]. Its wind potential is also considerable, especially along the coast between Dakar and Saint-Louis, where wind conditions are among the most stable in West Africa. A 2018 IRENA study estimates Senegal's onshore wind potential at 4.5 GW [3]. However, the energy transition goes beyond the diversification of electricity generation. It also requires a profound transformation of power infrastructure, including enhancing the transmission network, the adoption of smart grid technologies, and the improvement of capabilities to manage intermittency. An integrated system planning approach is thus essential to ensure supply security and system efficiency.

Currently, the planning of the Senegal power system relies primarily on a centralized approach that treats generation and transmission separately. Although this method remains operationally effective, it has clear limitations: it focuses on estimating capacity needs without identifying the most suitable locations for new infrastructure, and it fails to fully incorporate environmental constraints, such as CO₂ emissions, as well as the spatial and temporal characteristics of renewable resources.

To address these challenges, this paper proposes an optimal development plan for the Senegal power system by 2050,

aligned with the country's energy transition goals. It adopts an integrated approach that considers technical, economic and environmental dimensions to anticipate infrastructure needs and ensure a reliable and sustainable electricity supply.

The proposed methodology is based on the open source tool PyPSA (Python for Power System Analysis) [4], which enables the simultaneous modeling and optimization of generation, storage and transmission infrastructures. PyPSA accounts for temporal and geographical variations in renewable resource availability, introduces realistic constraints (such as CO₂ emissions limits, existing capacities, and committed investments), and supports multi-scenario sensitivity analyses to facilitate long-term strategic decision-making.

The scientific contribution of this work is threefold:

- It develops an optimized techno-economic model of Senegal's power system through 2050;
- It compares multiple investment pathways by evaluating their impacts in terms of costs, CO₂ emissions, and the composition of the energy mix;
- It identifies the most suitable geographical locations for the deployment of new generation capacities, taking into account the constraints of the grid and the local characteristics of the energy resources.

II. METHODOLOGY

A. Demand forecasting

Accurate electricity demand forecasting is crucial for infrastructure expansion planning, optimizing power plant operations, and defining tariff structures [5]. Significant forecast deviations may lead to excessive infrastructure development or insufficient supply to meet customer demand [6].

In this study, demand forecasting is performed on an hourly basis using a historical dataset provided by Senegal's national electricity company (Senelec) that includes hourly demand records from 2010 to 2023. An analysis of historical electricity demand trends in Senegal reveals daily, weekly, and annual demand patterns:

- Daily demand exhibits two peaks, with the highest occurring in the evening, mainly due to high residential consumption.
- Weekly demand shows a slight decrease during weekends due to reduced economic activity.
- Annual demand increases during high temperature periods, with the peak demand typically recorded in October.

According to [5], although numerous forecasting methods and models have been developed to achieve accurate load predictions, finding a suitable model for a specific power system remains challenging, and no single model can be universally applied to all demand patterns. As noted in [5] and [7], electricity load forecasting models can be categorized into multifactor and time series forecasting methods. Multifactor forecasting relies on cause-and-effect relationships between multiple factors, whereas time series forecasting is based on historical data. The latter is preferred, as it avoids the complexity and subjectivity associated with external factors in multifactor methods. As a result, time series forecasting is often simpler and faster to implement [5], [7].

In [8], a comparative study of several peak monthly demand forecasting models is conducted, among which *SARIMA*, *LSTM*, *RNN*, and *Prophet* [9] are compared. This study concludes that *Prophet* performs better in capturing real-time trends and seasonality in time series data. Therefore, the *Prophet* model is selected for demand forecasting in this study.

B. Power system planning

The Python for Power System Analysis (PyPSA), an open-source Python environment for power systems modelling [4], is used to identify investment needs in generation and transmission infrastructures. This tool focuses on optimizing energy generation and transmission while considering spatial and temporal variations in renewable resources in the grid.

Data was also provided by Senegal's national electricity company Senelec. This dataset includes the technical and economic characteristics of Senegal's power system infrastructure, particularly generators, storage units, transmission lines, and substations. The proposed modeling also incorporates approved projects, mainly gas-fired combined cycle power plants (CCGT), substations, and new transmission lines. These approved projects are defined by specifying each commissioning year, capacity, and operational lifespan.

A bottom-up approach is followed, meaning that the global model is constructed from basic units. In this context, the global power system comprises all generation and storage infrastructures, transmission lines, shunt elements, and distribution transformers. Senegal's transmission network operates at two voltage levels: 90 kV and 225 kV. In 2023, the transmission network is reported to span 1406 km, consisting of approximately 22% of 90 kV lines and 78% of 225 kV lines [10]. Considering planned projects, the transmission network is expected to increase by approximately 1000 km, excluding OMVS (Organisation for the Development of the Senegal River) and OMVG (Gambia River Basin Development Organization) networks. Table I presents the statistics of the power system model developed in PyPSA, incorporating both existing infrastructure and planned projects up to 2030.

C. Optimization model

1) *Objective*: PyPSA minimizes the total system costs, which include the variable and fixed costs of generation,

TABLE I
PyPSA MODEL STATISTICS (2030).

Network Components	Number	Network Components	Number
Nodes	74	Loads (HV/MV)	48
Lines and cables (HV)	93	Storage units	6
Generation units	78	Transformers HV/HV	7

storage, and transmission infrastructure. Mathematically, the objective function is defined as follows:

$$\sum_l c_l \cdot F_l + \sum_{n,s} c_{n,s} \cdot \bar{g}_{n,s} + \sum_{n,r} c_{n,r} \cdot \bar{h}_{n,r} + \sum_{n,s,t} (w_t \cdot o_{n,s} \cdot g_{n,s,t}) \quad (1)$$

where

- branch capacities are denoted F_l for each branch l and their associated annualized fixed costs c_l
- generator capacities are denoted $\bar{g}_{n,s}$ at each bus n for generation technology s and their associated annualized fixed costs $c_{n,s}$
- storage unit power capacities are denoted $\bar{h}_{n,r}$ at each bus n for storage technology r and their associated annualized fixed costs $c_{n,r}$
- the generation dispatch is denoted $g_{n,s,t}$ at time t and associated variable costs $o_{n,s}$

Fixed costs include capital investment, as well as fixed operation and maintenance costs. These costs are annualized over the total period for 1-year simulation, $\sum_t w_t = 8760$ h, where w_t is the time weighting factor in the objective function. The model presented is a simplified version, which considers a single year of investment and operation. In reality, in the full problem solved by PyPSA, reinvestments are carried out in each period, and a discount rate is applied to account for the time value of economic flows.

D. Constraints

The optimization process in PyPSA is subject to the constraints listed below.

1) *Power balance*: Energy balance equations ensure power equilibrium at each bus n and every time step t :

$$\sum_s g_{n,s,t} + \sum_r h_{n,r,t}^+ - \sum_r h_{n,r,t}^- + \sum_l K_{n,l} f_{l,t} = \sum_t d_{n,t} \quad \forall n \in \mathcal{N}, t \in \mathcal{T} \quad (2)$$

Where:

- $\mathcal{N}$ is the set of all network buses.
- $\mathcal{T}$ is the set of all time steps for the considered simulation.
- $d_{n,t}$ is the demand at bus n and time t .
- $f_{l,t}$ represents the power flow through branch l at time t .
- $\mathbf{K}$ is the incidence matrix (size $n \times l$) of the power network:
 - $K_{n,l} = 1$ if line l is connected to node n , and power is injected in n .

- $K_{n,l} = -1$ if line l is connected to node n , and power is retrieved from n .
- $K_{n,l} = 0$ if line l is not connected to node n .

2) *Generators limits constraints*: The generation $g_{n,s,t}$ at node n , for technology s , at time t is limited by their installed capacities $\bar{g}_{n,s}$ and their availability factor $g_{n,s,t}^{\min}$ and $g_{n,s,t}^{\max}$, expressed as percentages of $\bar{g}_{n,s}$

$$g_{n,s,t}^{\min} \cdot \bar{g}_{n,s} \leq g_{n,s,t} \leq g_{n,s,t}^{\max} \cdot \bar{g}_{n,s}. \quad (3)$$

For conventional generators, it is assumed that $g_{n,s,t}^{\min} = 0$ and $g_{n,s,t}^{\max} = 1$. For renewable generators (e.g., wind and solar), $g_{n,s,t}^{\max}$ represents power availability based on weather conditions, and $g_{n,s,t}^{\min} = 0$. For extendable generators, the optimal capacity is constrained between a minimum $\tilde{g}_{n,s}$ and a maximum $\hat{g}_{n,s}$:

$$\tilde{g}_{n,s} \leq \bar{g}_{n,s} \leq \hat{g}_{n,s}. \quad (4)$$

3) *Ramp rate constraints*: Generators are also constrained by ramp-up $ru_{n,s}$ and ramp-down $rd_{n,s}$ limits, expressed as a percentage of the nominal power:

$$-rd_{n,s} \cdot \bar{g}_{n,s} \leq (g_{n,s,t} - g_{n,s,t-1}) \leq ru_{n,s} \cdot \bar{g}_{n,s}. \quad (5)$$

4) *Storage units constraints*: The charge and discharge power $h_{n,r,t}^{\pm}$ are limited by $\bar{h}_{n,r}$:

$$0 \leq h_{n,r,t}^{-} \leq \bar{h}_{n,r} \quad (6)$$

$$0 \leq h_{n,r,t}^{+} \leq \bar{h}_{n,r} \quad (7)$$

The state of charge $soc_{n,r,t}$ must remain within the storage capacity limits:

$$0 \leq soc_{n,r,t} \leq r_{n,r} \cdot \bar{h}_{n,r} \quad (8)$$

where $r_{n,r}$ is the number of hours of autonomy at nominal power.

The state of charge evolves according to the following equation:

$$soc_{n,r,t} = \eta_{stand,n,r}^{wt} \cdot soc_{n,r,t-1} + \eta_{store,n,r} \cdot w_t \cdot h_{n,s,t}^{-} - \eta_{dispatch,n,r}^{-1} \cdot w_t \cdot h_{n,r,t}^{+} \quad (9)$$

with

- $\eta_{stand,n,r}^{wt}$ the self-discharge loss factor
- $\eta_{store,n,r}$ the charging efficiency
- $\eta_{dispatch,n,r}$ the discharging efficiency.

The state of charge is assumed to be cyclic, meaning that the SOC at the first time step is assumed to be the same as the SOC at the final time step (i.e., $t = T$),

$$soc_{n,r,0} = soc_{n,r,T} \quad (10)$$

5) *CO₂ Emission constraints*: Constraints on primary energy consumption, such as CO₂ emission limits, can be applied:

$$\sum_{n,s,t} \frac{g_{n,s,t} \cdot e_{n,s}}{\eta_{n,s}} \leq CAP_{CO_2} \quad (11)$$

where

- CAP_{CO_2} represents the CO₂ emission limit
- $e_{n,s}$ is the specific CO₂ emission factor expressed in tons per thermal MWh
- $\eta_{n,s}$ is the efficiency of technology s at bus n .

In this study, CO₂ constraints can be applied either globally across investment periods or to specific investment periods.

6) *Transmission lines constraints*: The power flow $f_{l,t}$ in each branch is bounded by the transmission line capacity F_l

$$|f_{l,t}| \leq F_l. \quad (12)$$

III. SIMULATION PARAMETERS

In this study, an analysis was conducted over different investment periods, specifically for the years 2030, 2035, 2040, 2045, and 2050. Due to the model size, a simulation interval of 3 hours (i.e., $w_t = 3h$) was adopted; otherwise, the model was too computationally expensive. Consequently, for each investment period, simulations will be performed over 2,920 time steps, resulting in 14,608 time steps when accounting for the leap year in 2040. A fixed discount rate of 3% is considered, which represents the average recorded over the past ten years [11].

IV. INVESTMENT ASSESSMENTS

A. Generation and storage

To identify investment in generation and storage, candidate infrastructures were modeled. The identified power plants include renewable energy installations (photovoltaic solar and wind power) as well as combined-cycle gas turbine (CCGT) plants, which provide increased flexibility to maintain power system stability. Regarding storage, battery systems were considered. Currently (in 2025), no storage device has yet been deployed in the Senegalese power system, and batteries are the only technology currently being considered. This study, therefore, focuses exclusively on battery-based storage.

Fig. 1 presents the locations of the various candidate power plants based on their technology. Regarding storage batteries, they are installed at the same locations as the candidate solar power plants. The generation profiles of the candidate wind and solar power plants correspond to the average generation profiles of existing power plants recorded in 2023 for each technology.

Table II presents the investment costs considered for each technology. Data was requested from the national electricity company, but was not available at the time of this study. The data used are thus from the PyPSA datasheet¹. The marginal costs of CCGT, including operation and maintenance expenses, average 48.28 €/MWh over the entire period. Marginal costs are considered negligible for wind, solar, and battery storage.

B. Transmission network

For transmission lines, the load rate is limited to 80%. The optimization calculation determines the necessary expansion capacity for each line to ensure compliance with this limit. However, PyPSA does not modify line impedance while reinforcing the grid.

¹Available at: <https://github.com/PyPSA/technology-data>

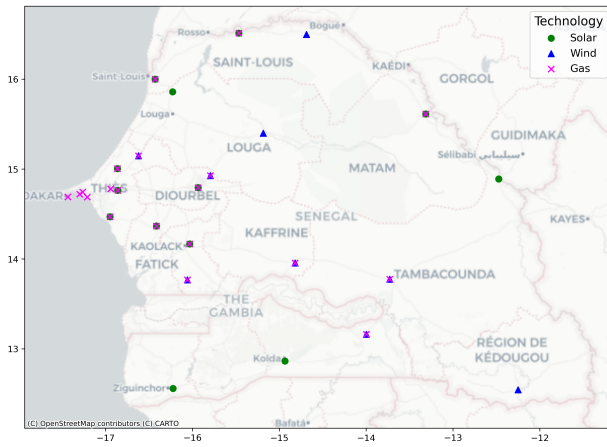


Fig. 1. Candidate power plants locations, by technology. Produced by the authors.

TABLE II
INVESTMENT COSTS CONSIDERED FOR EACH TECHNOLOGY.

Year	CCGT k€/MW	Wind k€/MW	PV k€/MW	Battery Storage k€/MWh	Battery Inverter k€/MW
2030	878	1 096	543	150	169
2035	870	1 065	497	125	138
2040	862	1 034	450	99.4	106
2045	855	1 027	430	89.4	84.7
2050	847	1 019	409	79.4	63.5

V. SCENARIOS

In this study, different scenarios are considered to determine the investment plan for the Senegalese power system. These scenarios are defined as follows:

- **Scenario 1:** Power system optimization without any constraints on existing power plants.
- **Scenario 2:** Scenario 1 with a constraint on total generation of existing renewable energy plants.
- **Scenario 3:** Scenario 2 with existing thermal power plants operating at 30% of their capacity.

For each scenario, the study presents the evolution of the average cost per MWh, the distribution of generated electricity, the investment cost of the generation fleet by technology, and the evolution of CO₂ emissions.

VI. RESULTS

This section presents the main results of the investment plan of the Senegalese power system by 2050. First, the electrical demand is briefly commented on, then the three scenarios are compared, followed by two sensitivity analyses of CO₂ emissions. Finally, the locations of the generation and storage assets and the grid reinforcement investment are presented.

A. Electrical demand evolution

Table III presents the evolution of the electrical demand over the 5 investment periods considered.

The energy demand increases from 14.39 TWh in 2030 to 30.04 TWh in 2050, representing an average annual growth

rate of 3.75%. Similarly, peak load rises from 1,903 MW in 2030 to 3,692 MW in 2050, corresponding to an average annual increase of 3.37%.

B. Scenarios comparison

1) *Scenario 1:* The results presented in Table IV indicate a significant investment in installed solar and wind capacity, reaching 1,436 MW and 1,600 MW, respectively, as early as the first investment period. This leads to a reduction in operating costs, decreasing the average cost of produced electricity from €50.3/MWh in 2030 to €36.8/MWh in 2050. Given the defined investment costs, it appears more economically viable to develop new power plants rather than continue operating existing ones, whose high operational costs outweigh their fixed capacity costs when distributed over their lifespan.

A global analysis of all investment periods shows that wind power remains dominant, decreasing from 42% to 31% of total production between 2030 and 2050. It is followed by gas-fired power plants, which see a increase, rising from 30% to 44% of total production. Solar energy ranks third, with a nearly constant contribution of around 21% throughout the entire period. Finally, the share of hydroelectric production declines, dropping from 6.10% to 3.15%. Additionally, 1.18 GWh of battery storage will be required by 2030. CO₂ emissions increase progressively from 2.12 million tons in 2030 to 6.52 million tons in 2050, corresponding to an average annual growth rate of 5.77%. This is due to the increase in demand despite massive investment in renewable energy. Specific emissions follow the same trend, reaching 0.218 t/MWh in 2050, driven by the gradual rise in gas-fired generation. Estimated emissions in 2024 show a carbon intensity of 0.563 t/MWh per MWh produced [12].

2) *Scenario 2:* To avoid a massive investment starting in 2030, a constraint was added to the optimization, requiring the full utilization of existing renewable power plants until the end of their operational life. Wind and solar power plants

TABLE III
ELECTRICAL DEMAND EVOLUTION.

Year	Energy Demand (TWh)	Peak Demand (MW)
2030	14.39	1903
2035	18.45	2370
2040	22.37	2810
2045	26.18	3251
2050	30.04	3692

TABLE IV
SCENARIO 1: KEY RESULTS.

	2030	2035	2040	2045	2050
CAPEX (M€)	406	432	428	468	468
OPEX (M€)	315	433	532	545	636
LCOE (€/MWh)	50.3	47.0	43.1	38.8	36.8
CO ₂ (Mt)	2.12	3.37	4.48	5.49	6.52
CO ₂ (g/kWh)	148	183	201	210	218
Gas (MW)	0	42.2	359	324	621
Solar (MW)	1436	277	509	471	805
Wind (MW)	1600	271	334	720	353

are typically subject to "Take or Pay" contracts, meaning their production is billed regardless of consumption. Hydropower plants, on the other hand, are shared between the countries of the OMVS and OMVG, with defined quotas for each country. The results presented in Table V show a reduction in investment costs but an increase in operating costs, leading to a higher average production cost compared to Scenario 1. Specifically, the existing hydroelectric, wind, and some solar power plants are characterized by relatively high costs. As a result, the average electricity cost increases compared to Scenario 1, rising from 62.81 €/MWh in 2030 to 42.81 €/MWh in 2050. Solar and wind primarily dominate the energy mix in terms of installed capacity. However, over the entire investment period, electricity generation is primarily dominated by gas-fired power plants, covering 29% in 2030 and 44.4% in 2050 of electricity demand. Wind power plants have a relatively stable contribution, representing an average of 26% of demand in each period. The contribution of solar power decreases slightly, from 15.6% in 2030 to 18.1% in 2050. Finally, hydroelectric power plants contribute 26.8% in 2030, but this share declines over time, reaching 12.8% in 2050. Additionally, 1.13 GWh of battery storage will be required by 2030. Furthermore, CO₂ emissions rise from 2.05 million tons in 2030 to 6.55 million tons in 2050, representing an average annual growth rate of 5.97%. Emissions also increase, reaching approximately 0.218 t/MWh in 2050.

3) *Scenario 3*: Starting from Scenario 2, a requirement was added, imposing the model to maintain a minimum production of 30% from the existing thermal plants until the end of their operational life. This, as depicted in Table VI, results in a decrease (compared to other scenarios) in investment costs but an increase in operating costs, leading to a higher average production cost compared to Scenarios 1 and 2. Specifically, the average cost of electricity goes from €66.6/MWh in 2030

TABLE V
SCENARIO 2: KEY RESULTS.

	2030	2035	2040	2045	2050
CAPEX (M€)	353	380	373	413	411
OPEX (M€)	546	663	766	779	872
LCOE (€/MWh)	62.81	56.74	51.12	45.66	42.81
CO ₂ (Mt)	2.05	3.29	4.43	5.49	6.55
CO ₂ (g/kWh)	143	179	199	210	218
Gas (MW)	0	44	357	343	642
Solar (MW)	965	278	523	475	713
Wind (MW)	1052	276	287	687	347

TABLE VI
SCENARIO 3: KEY RESULTS.

	2030	2035	2040	2045	2050
CAPEX (M€)	315	344	340	402	394
OPEX (M€)	638	750	838	816	917
LCOE (€/MWh)	66.6	59.5	52.8	46.7	43.7
CO ₂ (Mt)	3.02	4.21	5.24	5.92	7.08
CO ₂ (g/kWh)	211	229	235	227	236
Gas (MW)	0	46	359	368	682
Solar (MW)	708	272	476	764	418
Wind (MW)	635	311	333	919	321

to €43.7/MWh in 2050. The expansion of the production capacity is primarily dominated by wind and solar in terms of installed capacity. However, in terms of production, gas-fired power plants remain dominant, with a nearly constant contribution of around 46% of total production between 2030 and 2050. Hydroelectric production accounts for 27% by 2030, but will gradually decline to 13% by 2050. The share of wind power production increases progressively, rising from 18% in 2030 to 23% in 2050. Finally, solar power production also follows an upward trend, increasing from 12% in 2030 to 16% in 2050. Additionally, 1.03 GWh of battery storage will be required by 2030. CO₂ emissions have increased, rising from 3.02 million tons in 2030 to 7.08 million tons in 2050, representing an average annual growth rate of 4.36%. Emissions per unit of production remain almost constant, hovering around 0.228 t/MWh, despite a slight increase in 2040 and 2050 and a slight decrease in 2030.

C. Sensitivity analysis on CO₂ emission constraints

The CO₂ emission constraint is applied in two ways:

- **A1**: The constraint is imposed across all investment periods.
- **A2**: The constraint is applied only in the year 2050.

This sensitivity analysis, conducted using Scenario 2, assesses the impact of CO₂ limitations on the average cost of electricity (€/MWh). Table VII and Table VIII illustrate the evolution of the average cost per MWh based on the CO₂ emission constraints applied in cases A1 and A2.

TABLE VII
CASE A1: AVERAGE COST OF ELECTRICITY (€/MWh), REGARDING THE REDUCTION ON CO₂ EMISSION APPLIED.

Year	0%	25%	50%	75%
2030	63	67	427	913
2035	57	60	358	790
2040	51	54	298	676
2045	46	48	256	582
2050	43	45	226	506

TABLE VIII
CASE A2: AVERAGE COST OF ELECTRICITY (€/MWh), REGARDING THE REDUCTION ON CO₂ EMISSION APPLIED.

Year	0%	25%	50%	75%
2030	63	135	534	886
2035	57	112	421	701
2040	51	96	349	577
2045	46	82	298	490
2050	43	85	366	637

A significant increase in the cost per MWh is observed as CO₂ emissions are more constrained due to substantial investment in renewable energy sources. This increase is more pronounced when the constraint is applied solely in 2050 (A2). In this case, the cost per MWh rises sharply between 2045 and 2050.

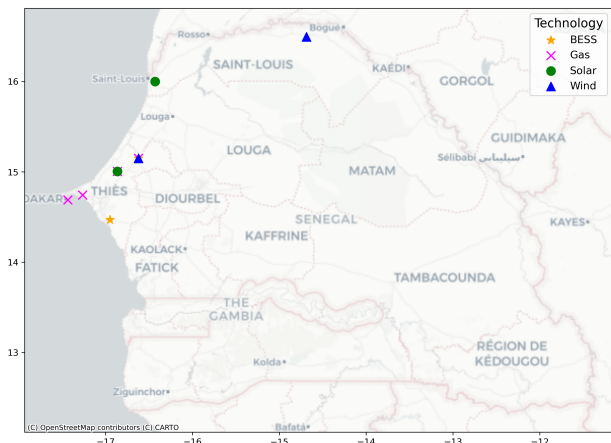


Fig. 2. Locations of investment in generation and storage assets (same for all scenarios). Produced by the authors.

D. Locations of investment in generation and storage

PyPSA enables the identification of the optimal investment locations by considering the spatial distribution of the demand on the considered electrical network. Fig. 2 presents the locations of the various candidate power plants based on their technology. The results indicate that wind power projects are primarily planned for connection at the 225 kV substations in Pékésse and Ndoum, while solar investment are more concentrated in Tobène and Saint-Louis. Gas-fired power plants are predominantly located in Kounoune, Tobène, Bel-Air and Pékésse. Due to space constraints, no wind or solar candidate plants are projected for the Dakar region. The Malicounda and Pékésse substations have been identified as optimal connection points for energy storage.

E. Network investment

In addition to generation investment, grid reinforcement investment are computed, particularly for 90 kV and 225 kV networks, in order to maintain their loading levels below 80%. The results presented in Table IX indicate that the reinforcement requirements for the 225 kV network are significantly higher than for the 90 kV network, indicating a substantial increase in power transfers on the 225 kV system. Network reinforcements are most extensive in Scenario 1, due to the greater generation capacity expansion. By limiting the installation of new power plants, the need for grid reinforcement and associated costs can be reduced.

TABLE IX
NECESSARY GRID REINFORCEMENT TO MAINTAIN LOADING LEVELS BELOW 80%,
IN KM OF LINE, FOR THE SCENARIOS CONSIDERED.

Voltage level	S1	S2	S3
90kV	344	466	473
225kV	3302	1717	1715

VII. CONCLUSION

This paper presents a methodology for planning Senegal's power system. The approach is based on demand forecast-

ing using the *Prophet* tool and identifying investment needs through cost optimization of the power system using the PyPSA model. Various scenarios were analyzed based on the utilization of existing power plants. For each scenario, the study evaluated the average generation cost, the required investment in generation and transmission infrastructure, the distribution of installed and generated capacity, and the level of CO₂ emissions. A sensitivity analysis was also conducted by testing different CO₂ emission limits to assess their impact on the cost per MWh. However, it is crucial to emphasize that the results depend significantly on the formulated assumptions, particularly regarding investment costs and the marginal costs of candidate generation and storage units. The current optimization focuses primarily on costs and emissions, but integrating renewable energy sources also introduces grid flexibility and stability challenges. An extension of the model could include constraints on variability management. Furthermore, the use of representative days could improve the accuracy of the analyses by capturing the temporal variations in intermittent production more accurately with shorter time steps. This approach would enable a more rigorous assessment of the impact of renewables' intermittency and enhance investment decision-making. Finally, performing AC power flow calculations is essential to account for reactive power flows within the network. This would refine investment decisions in generation and transmission while incorporating the necessary investment for voltage regulation.

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