Comparative Modeling of Electricity Tariff Schemes in Senegal and Implications for the Energy Transition by 2050

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Abstract

This study models and compares six electricity tariff schemes in Senegal: Reference, Progressive, Feed-in Tariff (FIT), Pay-As-You-Go (PAYG), Hybrid, and Hybrid 2050, to balance equity, viability, and transition pace. Using a Python pipeline, SENELEC observations (2020–2022) are combined with techno-economic benchmarks from IRENA/IEA and assessed through revenues, total costs, net margin, renewable-energy share, and average cost per kWh. Forward-looking projections assume declining technology costs and the deployment of storage and green hydrogen. Results show that Progressive and PAYG improve equity but compress profitability, while FIT attracts private investment with greater fiscal exposure. The Hybrid pathway offers the strongest compromise; by 2050, Hybrid 2050 reaches ~75% renewables, an average cost ≈69 FCFA/kWh (vs 83.8 in 2022), and a net margin ≈250,000 million FCFA. Falling costs (solar, wind, storage) and transitional reliance on domestic gas reinforce sustainability. The analysis highlights enabling conditions: regulatory stability, network modernization, and structured incentives, alongside constraints such as network losses (~15%) and limited storage. Implementation levers include a multi-year tariff doctrine, an IPP one-stop shop, a "Losses & Storage" programme, and scaling PAYG in rural areas. Although data granularity and static modelling remain limitations, the results support a phased Hybrid tariff, backed by social protection and climate finance, as a credible pathway toward a resilient, competitive, and low-carbon Senegalese power system.

Keywords: electricity tariff; Senegal; renewable energy; FIT; PAYG; storage; IPP/PPA; governance.

Introduction:-

Access to reliable, affordable, and sustainable energy remains a major challenge in Sub-Saharan Africa, where nearly 600 million people still lack electricity [1]. In Senegal, the national strategy simultaneously aims to increase the share of renewable energy in the power mix and to preserve the financial sustainability of the public utility SENELEC. Since the Plan Sénégal Émergent (PSE), substantial investments have been made in solar and wind, bringing the renewable share to 21.4% in 2022; however, the tariff structure remains under heavy budgetary and social pressure.

Tariff design thus emerges as a strategic lever for the energy transition: it shapes the price signals sent to private producers, equity of access for households, and the sector's self-financing capacity. International literature shows that feed-in tariffs (FIT) played a decisive role in the rise of photovoltaics in Europe (Germany, Spain), provided regulatory stability and contract bankability are ensured [2–3]. Conversely, PAYG models have been an effective instrument for rural access in East Africa by enabling micro-billing via mobile payments [4]. These two approaches: investment-oriented and social, are complementary rather than mutually exclusive.

In the Senegalese context: characterized by high solar potential but limited fiscal space, a hybrid trajectory (enhanced progressive tariff + FIT + targeted PAYG) appears most coherent, as highlighted by recent analyses of tariff governance and the energy transition in Senegal [5]. Moreover, the downward cost trends for solar, wind, and storage documented by IRENA [6] strengthen the case for high-renewables models, while the advent of domestic gas can serve as a transition technology until green hydrogen scales up around 2035–2040 [5, 6].

This study models in Python six tariff schemes applicable to Senegal:

i. reference tariff,

ii. enhanced progressive tariff,

iii. FIT,

iv. PAYG,

v. hybrid, and

vi. Hybrid 2050 projection.

Scenarios are evaluated in terms of revenues, total costs, net margins, and the share of renewables, drawing on SENELEC data (2020–2022) and IRENA/IEA techno-economic parameters. The objective is to identify tariff mechanisms capable of reconciling social affordability, economic competitiveness, and acceleration of the energy transition, thereby informing the design of a durable tariff framework tailored to Senegal.

1 Methodology-

1.1 General approach

The approach relies on a comparative economic–energy modeling framework that uses Python-based simulations to assess how several tariff schemes affect the power sector's profitability and the penetration of renewable energy (RE) in Senegal by 2050. The methodological setup draws on a triangulation of sources:

i. macro-financial data from SENELEC annual reports (2020, 2022) [7, 8];
ii. international techno-economic indicators (IRENA 2023, IEA 2022) [6, 9];
iii. tariff-policy scenarios and macro-sectoral assumptions (World Bank 2024) [10];

as well as benchmark studies on progressive, FIT, PAYG, and hybrid mechanisms [11–13].

The tracked variables are: total revenues, total costs, net margin, share of renewables, and the average cost of electricity (FCFA/kWh). This setup enables a consistent comparison of the economic performance (margin, cost/kWh) and environmental performance (RE share) across tariff schemes.

The mechanisms considered serve distinct purposes: progressive tariffs target equity of access and protection for vulnerable households; feed-in tariffs (FIT) secure project bankability for renewables; pay-as-you-go (PAYG) fosters decentralized access via micropayments; the hybrid option seeks a compromise between inclusion, incentives, and financial viability [11–13]. This diversity motivates a scenario-based analysis supported by common indicators.

1.2 Model structure and variables

Simulations are implemented in Python using pandas (processing/aggregation), matplotlib and seaborn (visualization), and openpyxl (management of Excel input files). The model is fed by a structured dataset covering six tariff scenarios: Reference, Progressive, FIT, PAYG, Hybrid, and Hybrid 2050.

Table 1: Summary of the scenarios studied.

Scenario	Description	Primary objective	Economic / social logic
Reference (2022)	Current SENELEC tariff structure	Benchmark	Short-term balance under budget constraints
Progressive	Increasing block tariffs	Protect vulnerable households	Social equity, basic affordability
Feed-in Tariff (FIT)	Guaranteed prices for RE injections	Bankability of RE projects	Private-investment signal, long-term visibility
PAYG	Pay-as-you-go / mini-grids	Rural access and inclusion	Micropayments, payment interoperability
Hybrid (2025)	Progressive + targeted incentives	Equity/viability compromise	Risk-sharing, phased steering
Hybrid 2030	Strengthened hybrid + RE ramp-up	Accelerate RE penetration	Centralized/decentralized coupling
Hybrid 2050 (prospective)	Hybrid + storage + green H_2	Long-term sustainability	RE-dominated mix, grid flexibility

Each scenario is evaluated using five key indicators: revenues (M CFA), total costs (M CFA), net margin (M CFA), RE share (%), and average cost (CFA/kWh). This set of indicators enables a multi-criteria reading of performance.

Table 2: Consolidated data by scenario (Senegal).

Scenario	Revenues (M CFA)	Total costs (M CFA)	Net margin (M CFA)	RE share (%)	Average cost (CFA/kWh)
Reference (2022)	535,800	494,900	40,000	21.4	83.8
Progressive	460,000	420,000	40,000	25	100
FIT	580,000	530,000	50,000	35	110

Scenario	Revenues (M CFA)	Total costs (M CFA)	Net margin (M CFA)	RE share (%)	Average cost (CFA/kWh)
PAYG	300,000	260,000	40,000	50	95
Hybrid (2025)	510,000	450,000	60,000	40	105
Hybrid 2030	580,000	400,000	180,000	60	69
Hybrid 2050 (prospective)	650,000	400,000	250,000	75	6

The Senegalese context: diversifying power mix, SENELEC as a pivotal operator, significant budget transfers, and high RE potential, justifies the parallel examination of progressive, incentive-based (FIT), access-oriented (PAYG), and combined (hybrid) mechanisms, in order to characterize cost–revenue trade-offs and the leverage effect on the RE share [7, 8, 10].

1.3 Model formulation

The analysis follows a scenario-based logic. In each scenario, profitability is assessed via the accounting identity:

$$Net\ margin = Total\ revenues - Total\ costs$$

For the forward-looking component, the growth dynamics of the RE share are described by:

$$E_t = E_0(1+g)^t \tag{1}$$

where E_0 is the initial RE share (21.4% in 2022, SENELEC) [8], g the average annual growth rate (7%, World Bank 2024) [10], and t the number of years elapsed. This formalism makes it possible to estimate the gradual increase in RE penetration: from ≈35% (2025) toward ≈75% (2050), under techno-economic trajectories consistent with IRENA (2023) and IEA (2022) [6, 9]. These assumptions ensure internal consistency and comparability across scenarios.

1.4 Time horizon and data sources

The analysis period spans 2020 to 2050. Historical data for 2020–2022 were used to calibrate the model, while projections for 2023–2050 were derived from international trends in technology cost declines and Senegal's energy-policy orientations. This structure both anchors the simulation in consolidated observations and enables examination of prospective trajectories aligned with recent sector scenarios.

The main sources used are: SENELEC (2020, 2022) for production, costs, and tariff structure [7, 8]; IRENA (2023) for techno-economic benchmarks (cost trajectories, capacity factors) [6]; World Bank (2024) for macroeconomic assumptions and tariff-policy scenarios [10]; and IEA (2022) for global trends (demand, mix, relative prices) [9].

For end-to-end coherence, the series were pre-processed (unit checks, label harmonization, calendar alignment) before being ingested into the simulation environment. Assumptions regarding cost trajectories and tariff policy were documented against the aforementioned institutional sources to ensure parameter traceability over the entire 2020–2050 period.

1.5 Choice of Python and simulation environment

Python was selected due to its flexibility for time-series processing, multi-scenario management, and automated production of tables/figures, while maintaining high standards of reproducibility and traceability. The working environment relied on pandas (structuring/aggregation), matplotlib and seaborn (visualization), and openpyxl (interface with Excel input workbooks). This toolchain enabled automation of import steps, unit consistency checks, calculation of indicators (revenues, costs, margin, RE share, average kWh cost), and generation of graphical outputs within a reproducible pipeline.

To ensure formal alignment between assumptions, computations, and reported indicators, the code architecture clearly separates input data, calculation functions, and visualization scripts. This organization facilitated auditability (external verification of data lineage) and rapid updating of results when new institutional datasets become available—without altering the model logic or compromising inter-scenario comparability.

1.5.1 Replicability and script transparency

Replicability served as the guiding principle for script design and rests on three complementary mechanisms:

- **Explicit parameterization:** Key assumptions (RE growth, tariff structures, time horizon, average technology costs) are centralized in a configuration file; any update is performed without modifying core functions.
- **Data/algorithm separation:** Raw datasets (SENELEC, IRENA/IEA/World Bank) are imported as independent tables; transformations are applied by deterministic functions, ensuring same inputs ⇒ same outputs.
- **Output traceability:** Results are exported as standardized tables and automated figures; each scenario can be re-executed independently, facilitating inter-scenario comparison and cross-checking.

1.5.2 Extensibility and model adaptation

The framework was designed to be extensible, allowing new parameters or tariff scenarios to be integrated without redesigning the architecture:

- **Modular scenarios:** Each scenario is encapsulated as an independent block (parameters + call functions), activable/duplicable without side effects; this supports the exploration of dynamic tariffs (time-of-use), differentiated tariffing (rural/urban), or coupling with other policy instruments.
- **Temporal scalability:** The analysis horizon is not constrained by the code; the period can be extended or shortened by adjusting parameter t, enabling regular updates aligned with national trajectories.
- **Data interoperability:** Inputs may come from heterogeneous sources (institutional databases, sector datasets, Excel/CSV formats); the normalized pandas structure enables integration of higher-resolution series (monthly/hourly) and compatibility with other tools.

Overall, this modular design provides the model with dual robustness: *scientific* (replicable, traceable) and *operational* (adaptable to tariff reforms and mix evolution). The tool goes beyond a one-off study and constitutes an evolving framework usable over successive data revisions and policy updates.

1.6 Model validation

Validation checks the consistency between simulated results and observed data (SENELEC reports 2020–2022) prior to projection. It unfolds in three steps.

1.6.1 Initial calibration

Parameters were adjusted on the following basis: average 2020–2022 revenues: 530,000 M CFA; total costs: 480,000 M CFA; observed net margin: ≈ 50,000 M CFA; RE share: 21.4% (2022); average cost: 83.8 CFA/kWh [7, 8]. These values serve as the benchmark for calibrating the Reference scenario.

1.6.2 Error comparison

After calibration, the mean absolute error between simulations and observations is < 5% for revenues and total costs. This level is acceptable for an economic simulation model with partially aggregated data and aligns with standards in macro-sector energy modeling.

1.6.3 Robustness test

A sensitivity test assessed model stability against variations in exogenous parameters. Three key variables were varied within ±10%: average solar production cost, RE integration rate, and natural gas price (affecting the marginal cost of thermal generation). Results show the model retains a stable structure and produces coherent trajectories across all scenarios studied. Although the net margin is affected by cost fluctuations, it remains proportional to observed trends, confirming the model's robustness for projections to 2050.

2 Results and analysis-

2.1 Analytical framework from the literature(concise recap)

The study of energy tariff models lies at the heart of transition policies, especially in emerging economies where social equity, economic viability, and environmental sustainability intersect. The literature distinguishes several families of mechanisms and stresses the importance of context-specific tariff choices.

Historically, three approaches dominate: marginal-cost pricing, increasing block tariffs, and cross-subsidies. Marginal-cost pricing reflects the real cost of generation and distribution and promotes economic efficiency, but it can be socially regressive where energy poverty is widespread [13]. Progressive block tariffs protect vulnerable households by making higher consumption blocks more expensive; they remain widely used in emerging countries (including Senegal via SENELEC) [7, 8]. Incentive-based models (e.g., feed-in tariffs—FIT, net metering) support RE investment: FIT guarantees a purchase price and project bankability; net metering stimulates self-consumption and decentralized production [11, 12]. Their limitations concern budget capacity (FIT) and regulatory/technical requirements (net metering).

Reforms aim to reconcile financial viability and inclusion. Progressive structures in Ghana and Kenya improved access while targeting vulnerable households, but under-compensation can weaken public utilities [14, 15]. Innovative approaches such as PAYG (mobile payments, micro-billing) have broadened rural access in Kenya, Tanzania, and Rwanda [16]. FIT in Morocco and South Africa has mainly benefited institutional investors and presupposes a robust state framework [14]. Three success factors stand out: regulatory stability, budget capacity, and alignment between incentives and equity [14, 15].

Senegal combines a diversifying mix (growing solar/wind/hydropower) with significant public subsidies, with SENELEC as the pivotal operator. Solar mini-grids show potential if tariffs truly cover O&M [17]; project durability depends on the tariff scheme (purchase price vs. costs) [18]; SMEs respond positively to incentives when purchase prices are stable/predictable [19]; and progressive tariffs must be accompanied by targeted support to avoid increasing rural household vulnerability [20].

IRENA emphasizes the catalytic role of incentive policies (including FIT) for RE deployment in emerging countries [6, 21]. IEA recommends pairing these instruments with social compensation measures [9]. The World Bank highlights budget losses from poorly targeted subsidies and advocates long-term viability [10, 22]. Cases from Germany, Spain, and India show that clear, durable tariff settings accelerate RE diffusion and investor confidence [6, 9].

This foundation justifies the comparative assessment of the Reference, Progressive, FIT, PAYG, Hybrid, and Hybrid 2050 scenarios.

2.2 Comparison of revenues and costs by scenario

To better read the economic performance of the selected options, Figure 1 below contrasts projected revenues with associated costs for each scenario.

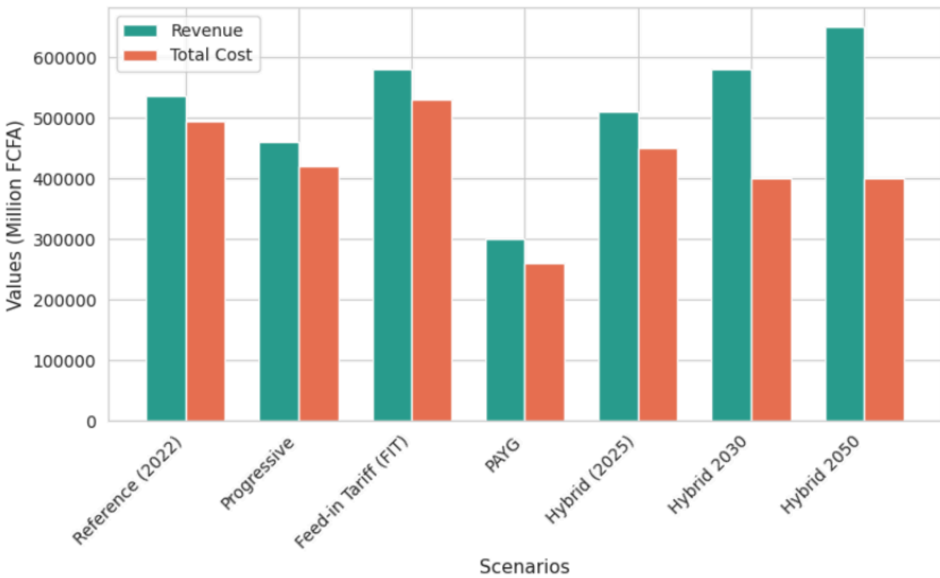


Figure 1: Revenues vs. Costs by scenario (M CFA)

Three takeaways emerge:

1. Revenues rise significantly in incentive-driven scenarios (FIT, Hybrid 2030, Hybrid 2050), reflecting how price signals spur investment and injected generation.
2. PAYG yields the lowest revenues, consistent with its access logic (rural mini-grids, micropayments) and the difficulty of breaking even without targeted support [16].
3. Hybrid 2050 shows the largest revenue–cost gap (best economic sustainability), consistent with
   i. projected cost declines in solar and storage by 2050 [6], and
   ii. synergy between centralized and decentralized supply.

These results support the idea that tariff incentives (e.g., FIT) improve overall profitability [6, 10]. Progressive tariffs protect equity but compress margins; PAYG is inclusive yet not self-sustaining without support. The Hybrid pathway appears to be a robust compromise in the Senegalese context [7, 8, 13, 14].

2.3 Net margin by scenario

To compare the relative profitability of options, Figure 2 presents the net margin (Revenues − Costs) for each scenario.

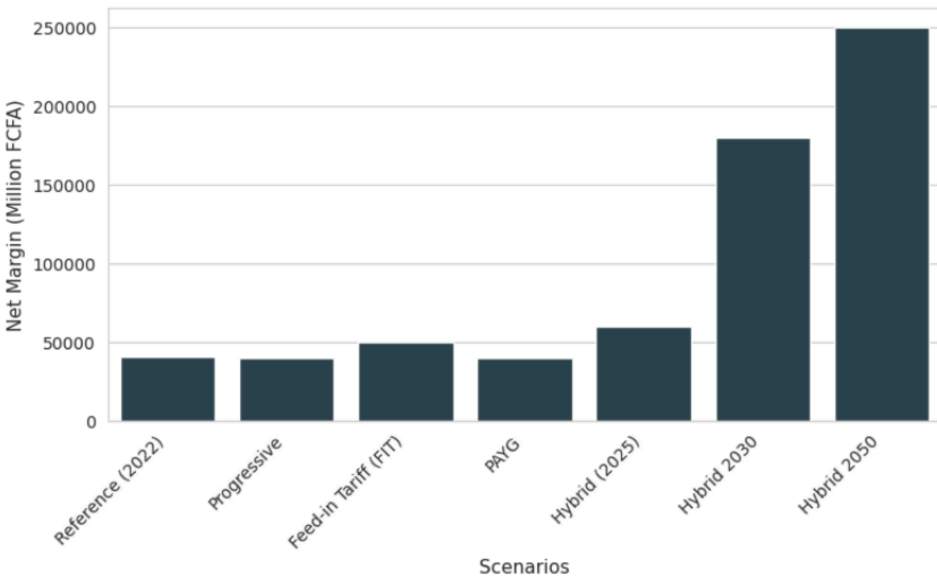


Figure 2: Net margin by scenario (M CFA)

Figure 2 shows that the Reference and Progressive scenarios yield only modest net margins, around 40,000 M CFA. FIT and Hybrid (2025) mark a notable improvement. The Hybrid 2030, and especially Hybrid 2050, trajectories post the highest margins, roughly 180,000 to 250,000 M CFA. The system's economic viability depends directly on tariff design: incentive-based and mixed schemes bolster profitability without sacrificing the RE trajectory. These findings align with studies showing that poor calibration can weaken African public utilities [17, 20]. The margin expansion in Hybrid 2050 supports the hypothesis of a just, sustainable transition when incentives, decentralization, and macro stability are combined [6, 10, 21].

2.4 Share of renewables by scenario

To visualize the transition dynamics, Figure 3 presents the RE share across scenarios.

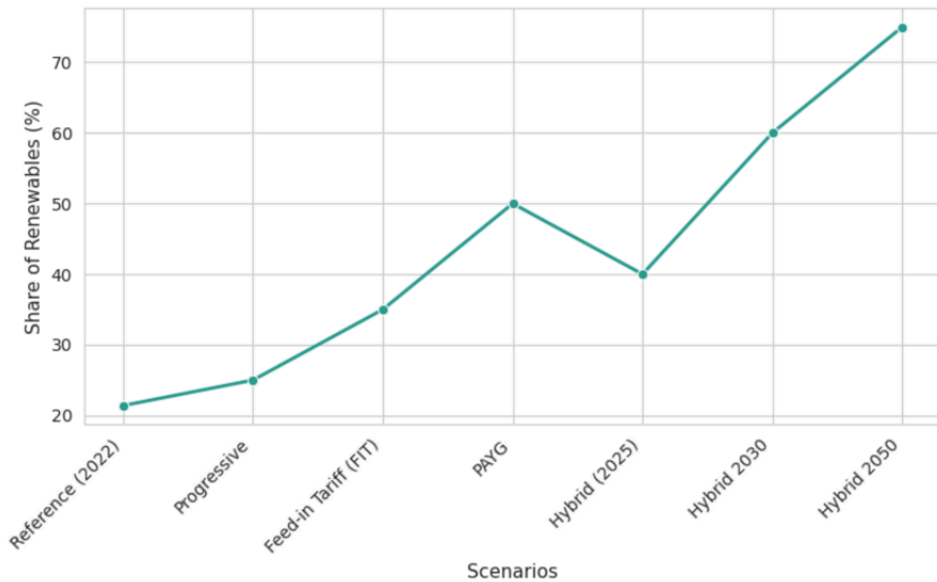


Figure 3: Share of RE by scenario (%)

Figure 3 highlights a clear upward progression in the share of renewables: from 21.4% (Reference) to 25% (Progressive), 35% (FIT), 50% (PAYG), 40% (Hybrid 2025), 60% (Hybrid 2030), and up to 75% (Hybrid 2050). This trajectory confirms a positive correlation between incentive mechanisms and RE penetration: FIT and PAYG stimulate private investment and decentralized production, accelerating renewable uptake [11, 12, 16].

Hybrid 2050 benefits cumulatively from

- falling solar (and storage) costs documented by IRENA [6], and
- the structural effect of layered incentives.

Conversely, the Progressive scheme prioritizes social stability (equity) at the cost of a more modest investment signal.

The 75% RE target by 2050 appears achievable under specific conditions: solar LCOE < 70 CFA/kWh, targeted fiscal incentives, and gradual market opening (regulatory framework + grid integration) [6, 9, 10, 22].

2.5 Synthesis of the findings

Three structural results emerge:

1. Incentive-based models (FIT, Hybrid) are financially viable in the medium term and stimulate private investment, consistent with IRENA/World Bank recommendations [6, 10].
2. Social models (Progressive, PAYG) are indispensable for equity, but must be compensated through targeted subsidies and/or transparent fiscal mechanisms to avoid weakening the utility [10, 14, 15, 20].
3. The 2025–2050 trajectory toward a 75% RE mix is realistic, provided cost declines (solar + storage) continue and incentives remain stable/predictable within a robust regulatory framework [6, 9, 10, 21, 22].

3. Discussion-

This discussion analyzes the scope, transferability, and practical implications of the results from the tariff-scenario modeling. It situates the observed performances within the Senegalese context and identifies structural obstacles likely to limit implementation of the proposed reforms.

3.1 Transferability of international models

The results confirm that incentive-based models: chief among them the Feed-in Tariff (FIT) and the hybrid scheme, deliver the best economic and energy performance when the institutional framework guarantees regulatory stability and contract bankability. This finding is consistent with experience in Germany, Spain, and India, where long-term tariff visibility, reliable contract enforcement, and predictable remuneration mechanisms catalyzed private investment and accelerated the integration of renewables [9, 11, 12].

Transposition to Senegal is nevertheless subject to several prerequisites. On the one hand, the state must have budgetary capacity compatible with the long-term commitments implied by PPAs, while the IPP market must gain maturity to reduce transaction costs and perceived risk among financiers. On the other hand, operational centralization around SENELEC requires an explicit regulatory framework for FIT: including a clear tariff doctrine, modalities for remunerating injections, and robust legal security to ensure project bankability [9, 11]. Complementarily, PAYG, proven in Kenya and Rwanda, can be transferred to rural, low-electrification areas provided it is accompanied by consumer-protection mechanisms, interoperable payment platforms, and arrears-management procedures adapted to household profiles [10].

In this context, the hybrid model appears to be the most robust compromise: it combines incentive price signals conducive to private investment with social safeguards for vulnerable households, under predictable tariff governance. Its success will depend on strengthened operational coordination among SENELEC, ANER, and CRSE, and on external financial support (AfDB, Green Climate Fund, development partners) to cushion transition costs while securing contractual commitments [9–11]. A phased implementation with annual reviews will facilitate institutional learning, adjustment of tariff parameters, and management of macro-budgetary risks, while preserving the decarbonization trajectory and the system's sustainability.

3.2 Obstacles to implementation in Senegal

Effective implementation of tariff reforms in Senegal is constrained by a set of economic, institutional, technical, and socio-behavioral factors which: if not addressed in a coordinated way, risk diluting the expected gains of incentive-based scenarios.

Economic constraints. SENELEC's structural deficit and the weight of subsidies (≈150 billion CFA/year) exert sustained pressure on margins and limit investment capacity in RE [7, 8]. In addition, social tariffs set below marginal cost, while pursuing equity, compress overall sector profitability. A credible path forward requires finely targeted support, ex-post evaluation of its effectiveness, and, ultimately, a reconfiguration of budget transfers to preserve financial sustainability [9, 10].

Institutional and regulatory hurdles. Challenges include the absence of a stabilized regime for IPPs (tariff-regulation framework, clear doctrine for remunerating injections, secure PPAs) and centralized decision-making that lengthens permitting timelines and slows new entrants [9]. An operational response is to clarify the roles of CRSE/ANER/SENELEC, establish a one-stop shop with SLAs (guaranteed timelines for permits and interconnections), and publish a multi-year tariff roadmap that reduces regulatory uncertainty and improves project bankability [10].

Technical barriers. Network losses (about ≈15% per SENELEC) weigh on system efficiency and limit absorption of new intermittent capacity [7, 8]. At the same time, insufficient transmission and storage capacity hampers solar and wind integration and raises balancing needs. A coordinated "Losses & Storage" program: gradual loss reduction, modular storage, and ramp-up of system services, is essential to accompany a higher RE share and converge toward unit-cost trajectories observed in peer emerging economies [15, 19].

Social and behavioral frictions. Upfront equipment costs for households, limited awareness of technologies, and occasional distrust of PAYG offers persist. The urban–rural divide remains, justifying targeted safety nets, information campaigns, and a consumer-protection framework for off-grid solutions (including payment interoperability and arrears-management mechanisms) [10].

Taken together, these bottlenecks must be lifted through gradual, coherent planning: targeting subsidies to restore margins; stabilizing the IPP/PPA framework to catalyze investment; modernizing grid and storage to secure RE integration; and providing social accompaniment to ensure the transition's acceptability and equity [6–10, 23].

3.3 Regional comparison and takeaways

Trajectories observed across Africa confirm that combining tariff incentives, social protections, and contractual security is a powerful lever for access and profitability. In Kenya, aligning progressive tariffs with PAYG solutions helped push the electrification rate above 75% in 2023, illustrating the role of micropayments and interoperability in extending rural access [15]. In Ghana, tariff reforms supported by a better-targeted social safety net improved operator sustainability while protecting vulnerable households, whereas in South Africa long-term FIT contracts attracted private capital and structured a credible RE industry. Morocco shows that a regulated liberalization of the power market can reduce hydrocarbon dependence, provided regulation is predictable and the investment framework is clear.

In light of these lessons, Senegal has strengths (a relatively stable institutional framework, a diversifying mix) but operates with constrained fiscal space. Its intermediate position argues for a gradual hybrid approach, aligning reform milestones with regular performance reviews (costs, losses, RE share) and backed by external financing mechanisms (AfDB, Green Climate Fund, EU/IFC), while strengthening SENELEC–ANER–CRSE coordination. To ground the prospective reading, the baseline assumptions on demand, costs, mix composition, and macro aggregates are summarized below.

Table 3: Evolution of energy parameters in Senegal (2025–2050 scenarios)

Macro-energy framework for national forecasting.

Parameter	2025	2035	2050	Main source
Electricity demand growth	+5.8%/yr	+6.2%/yr	+5.0%/yr	SENELEC (2020–2022) [7, 8]
Average solar cost (CFA/kWh)	82	65	50	IRENA (2023) [6]
Average wind cost (CFA/kWh)	90	70	55	IRENA (2023) [6]
Gas share in the mix	25%	20%	10%	MPE (2023) [23]
Green hydrogen share	0%	5%	15%	IEA (2024) [24]

Parameter	2025	2035	2050	Main source
Total RE share	35%	55%	75%	IRENA (2023) [6]
Average production cost (CFA/kWh)	90	80	69	Python model
Estimated net margin (M CFA)	60,000	120,000	250,000	Simulation

The assumptions are consistent with IRENA/IEA/World Bank, with SENELEC series for base calibration. The profile combines rising demand, declining unit costs (solar/wind), a transitional role for gas, and growth of green hydrogen after 2035. Margin improvements stem from a more efficient tariff design and a lower average cost within a more decarbonized mix.

3.4 Forward-looking analysis (2025–2050)

3.4.1 Projection assumptions

The outlook relies on LCOE trajectories, technological dynamics (storage, flexibility, hydrogen), and energy-policy orientations published by IRENA (2023), the World Bank (2024), and the Ministry of Petroleum and Energy, MPE (2023) [6, 10, 24]. These sources underpin assumptions of declining solar/wind costs, gradual scale-up of storage, and a transitional role for domestic gas, consistent with international scenarios [9, 24].

3.4.2 Projected share of renewables

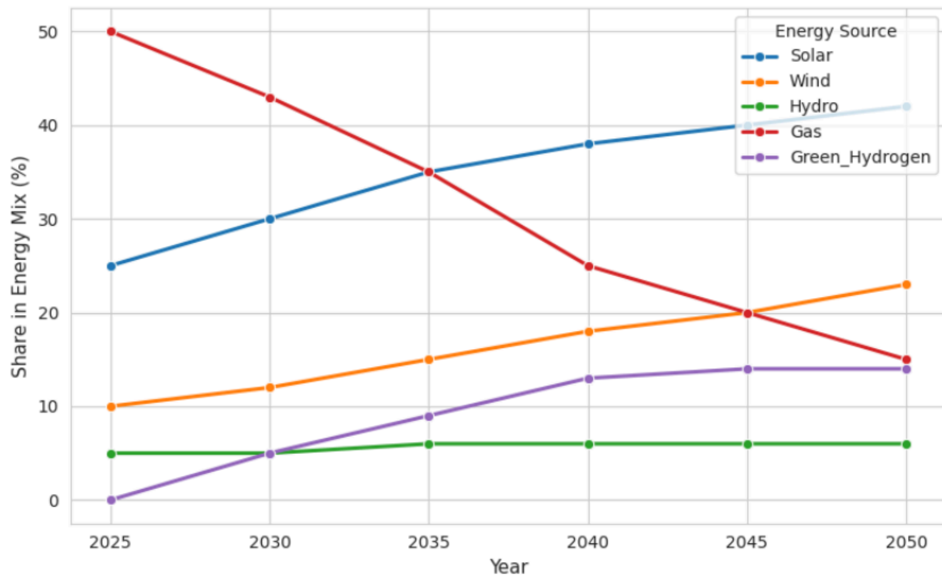
Table 4 summarizes the expected progression of the RE share and the dominant contributors at five milestones.

Table 4: Projected evolution of the share of renewables

Mix milestones and dominant contributors (2025–2050)

Year	RE share (%)	Main contributors
2025	35	Solar + Wind
2030	45	Solar + Wind + Hydro
2035	55	Solar + Wind + Renewable gas
2040	65	Solar + Wind + Storage
2050	75	Solar + Wind + Green hydrogen

Assumptions align with unit-cost declines (IRENA, 2023) and the scaling of storage; domestic gas acts as an intermittency buffer until ≈2035. The 75% RE objective by 2050 is attainable given continued LCOE reductions, storage deployment, and regulatory stability; green H_2 becomes a complementary pillar over the long term [6, 24].



To capture the system's rebalancing, **Figure 4** traces the evolution of the mix between 2025 and 2050.

Figure 4: Evolution of the power mix (2025–2050)

Figure 4 shows a gradual shift in the mix: in 2025, gas still accounts for ~50%; between 2030 and 2040, the shares of solar and wind rise steadily; by 2050, the target structure converges to ~42% solar, ~23% wind, ~15% gas, and ~14% green H_2 [9,24]. This configuration supports the relevance of the Hybrid 2050 scenario: diversification strengthens both system resilience and decarbonization.

3.4.3 Evolution of production costs

A structural decline in average costs is anticipated between 2025 and 2050, driven by:

i. efficiency gains in solar and wind technologies,

ii. a drop in Li-ion battery costs from about \$130/kWh (2023) to ≈ \$60/kWh (2050), and

iii. the integration of domestic gas, which stabilizes the baseload and reduces imports.

The average cost is estimated at ≈ 69 CFA/kWh in 2050 (vs. 83.8 in 2022), i.e., −18% to −25%, in line with IRENA [6]. *Reading*. The decline in unit cost underpins the sustainability of tariff incentives and improves overall efficiency.

3.4.4 Role of gas and green hydrogen

Gas (Yakaar–Teranga, GTA) plays a transitional role: security of supply, operational flexibility, and export revenues. After 2035, green hydrogen produced from solar/wind electricity becomes plausible: ≈ 300 kt/yr in 2050, covering ≈ 10% of domestic demand with the remainder exported; costs falling from ≈ \$7/kg (2025) to ≈ \$2.5/kg (2050) [24].

Recommendation: Develop an H_2 roadmap (sector pilots, bankability criteria, industrial interconnections).

3.4.5 Long-term revenues and margins

Table 5 summarizes the trajectory of revenues, costs, and net margins.

Tableau 5: Projection of revenues and net margins (M CFA)

Simulated economic aggregates

Year	Revenues	Total costs	Net margin
2025	510 000	450 000	60 000
2035	600 000	480 000	120 000
2050	650 000	400 000	250 000

The Python pipeline is calibrated to SENELEC (2020–2022); cost assumptions [6]; progressive scale-up of storage and centralized/decentralized orchestration. Net margin triples between 2025 and 2050, reflecting more efficient tariff design, declining unit costs, and a mix better optimized by incentives.

3.4.6 Conditions for sustainability

Sustaining the trajectory requires:

i. reducing technical losses,

ii. targeted expansion of storage (including balancing and reserve services),

iii. data governance (hourly profiles, losses by zone, IPP production) to inform planning.

Recommendation: Establish an energy data policy and publish standardized indicators annually [6,10].

3.5 Governance, financing, and implementation

The success of tariff reforms and the accelerated integration of renewables rests on an inseparable triptych: regulatory stability, operational coordination, and a financing architecture adapted to country risk. On the regulatory front, the priority is to publish a multi-year tariff doctrine specifying price-setting modalities, revision trajectories, and compensation mechanisms, while strengthening IPP/PPA frameworks (risk allocation, rules for remunerating injections, payment guarantees). This contractual visibility aims to lower the cost of capital and improve project bankability, in line with international recommendations [9,10]. For decentralized solutions, adopting PAYG standards (payment interoperability, transparent terms, arrears treatment) will bolster user trust and protect vulnerable households.

SENELEC–ANER–CRSE coordination must translate into measurable execution capacity: creation of a one-stop IPP window with enforceable SLAs (guaranteed timelines for permits, interconnection, and PPA signing), quarterly planning of grid/storage worksites, and public reporting of key indicators (average permitting times, technical losses by zone, interconnection queue, RE share). A multi-year "Losses & Storage" program: backed by quantified targets (e.g., reduce technical losses from ~15% to ≤12% within 24 months; deploy at least X MW/MWh of distributed storage for balancing and reserve services), is an immediate lever to absorb intermittency and improve system reliability. The whole effort must be supported by data governance (standards, publication frequency, quality controls) to feed planning and ex-post evaluation [6,10].

On financing, the strategy combines national resources (budgetary and parafiscal) and climate instruments. Creating a National Energy Transition Fund: endowed, where appropriate, by a carbon tax or levy on hydrocarbons, would smooth co-financing needs and kick-start structuring projects (grids, storage, flexibility). This vehicle could be embedded in a blended-finance setup mobilizing the Green Climate Fund, AfDB, EU/IFC, and concessional loans, to reduce the weighted average cost of capital and align the investment trajectory with 2030–2050 objectives [10].

In the short term (12–24 months), a phased action plan should link three priority workstreams:

i. targeted revision of social tariffs on a data-driven basis (focused subsidies, ex-post impact evaluation),

ii. effective rollout of the one-stop IPP window with quarterly publication of SLAs and observed timelines,

iii. launch of the “Losses & Storage” program with regional targets, standardized tenders, and quarterly reporting.

Success will be assessed using a core indicator set: RE share (%), technical losses (%), average costs (CFA/kWh), average permitting time (days), energy not supplied (MWh), operational storage (MW/MWh), and signed PPA pipeline (MW). Regularly updated and published, these elements embody the traceability and accountability of the reform, while giving investors visibility consistent with the sector’s long-term requirements [6,9,10,22].

3.6 Limitations of the study

3.6.1 Data

The main limitation concerns the granularity of available data. SENELEC reports are largely aggregated and do not systematically document regional marginal costs, zone-level network losses, detailed hourly demand profiles, or disaggregated IPP statistics. In addition, the non-annual updating of some indicators required extrapolation from institutional sources (World Bank, IRENA, IEA), which introduces additional uncertainty. Consequently, the results should be interpreted as structural trends rather than short-term point forecasts [6,9,10].

3.6.2 Modelling

The modelling framework is static and deterministic: it does not incorporate fine seasonal demand patterns, exchange-rate and hydrocarbon price volatility, or dynamic behavioural responses (tariff reactions, technology adoption). Moreover, dynamic tariffing (time-of-use) is not simulated, nor does the study use an optimisation solver (Pyomo/GAMS) to identify least-cost production portfolios. Future work could integrate dynamic econometrics and/or machine-learning approaches to improve shock sensitivity and demand anticipation.

3.6.3 Temporal and institutional scope

The empirical perimeter spans historical data (2020–2022) and a prospective horizon to 2050. In reality, implementation will depend on political cycles, institutional stability, and access to concessional finance. Continuity assumptions may prove optimistic if macro-fiscal conditions deteriorate or regulatory sequencing slows. Achieving the Hybrid 2050 pathway requires sustained political commitment and inter-institutional coherence across the entire horizon.

3.6.4 Social and environmental dimensions

Microeconomic impacts on households and SMEs could not be fully assessed due to the absence of local micro-data on price elasticity, affordability, employment, and welfare. Likewise, the environmental analysis does not explicitly quantify avoided CO_2 emissions or health co-benefits linked to mix decarbonisation. These dimensions require field surveys (ANSD, SENELEC) and integration of environment–health modules in the modelling chain.

3.6.5 Areas for improvement

Several avenues for deepening the analysis emerge:

1. Build a micro-data corpus for households/SMEs to estimate price elasticities and calibrate targeted social tariffs;
2. Extend the model to dynamic/optimised frameworks (MARKAL/TIMES, Pyomo) to endogenize investment decisions, time-of-use pricing, and optimal technology allocation;

3. Develop a multi-country ECOWAS simulation to capture interconnection effects (imports/exports, regional arbitrage);
4. Conduct an expanded environmental assessment (avoided CO_2, local pollution, health co-benefits);
5. Institute sectoral data governance: replicability of scripts, annual publication of standardized indicators, quality audits, to reduce parametric uncertainty and strengthen traceability [6,9,10].

Despite these limitations, the Hybrid 2050 scenario: combining tariff incentives, PAYG flexibility, transition gas, and green hydrogen, remains the most robust pathway to a sustainable, equitable, and competitive power system, provided it is backed by regulatory stability, executional coordination, and a risk-adequate financing architecture.

Conclusion-

This study modeled six tariff schemes (reference, progressive, FIT, PAYG, hybrid, and Hybrid 2050) for Senegal using SENELEC data and international techno-economic assumptions. The results show that the progressive and PAYG models improve equity but compress profitability; FIT attracts investment at the cost of public budgetary effort; and the hybrid model offers the best compromise among financial viability, inclusion, and decarbonization. The Hybrid 2050 scenario stands out with a renewable share of about 75%, an average production cost near 69 CFA/kWh (versus 83.8 CFA/kWh in 2022), and a net margin of roughly 250,000 M CFA, confirming tariff design as a strategic lever for the transition.

Operationally, a credible short-term (12–24 months) implementation rests on a phased rollout of the hybrid model with annual reviews; data-driven targeting of social tariffs with ex-post evaluations; stabilization of the IPP/PPA framework via an explicit tariff doctrine and a one-stop shop with published SLAs; and the launch of a "Losses & Storage" program to absorb intermittency. Scaling PAYG solutions and mini-grids in rural areas, framed by interoperability standards and consumer protection, and creating a National Energy Transition Fund (backed by a carbon tax or hydrocarbon levy and mobilizing climate finance) will strengthen project bankability.

Research priorities include integrating household/SME micro-data to estimate price–demand elasticities; extending toward dynamic/optimized models (time-of-use pricing, MARKAL/TIMES, Pyomo); an ECOWAS-level analysis of interconnections and trade; and a broadened environmental balance including avoided CO_2 and health co-benefits. In sum, a hybrid, social, and incentive-based trajectory: supported by data governance, grid-and-storage modernization, and climate financing, constitutes the most robust pathway toward a resilient, competitive, and low-carbon Senegalese power system.

Abbreviations

- **ANER**: National Agency for Renewable Energy (Senegal)
- **ANSD**: National Agency for Statistics and Demography (Senegal)
- **AfDB (BAD)**: AfricanDevelopment Bank
- **CAPEX**: Capital Expenditures
- **ECOWAS (CEDEAO)**: Economic Community of West African States
- **CO_2**: Carbon dioxide
- **CRSE**: Electricity Sector Regulatory Commission (Senegal)
- **RE (ENR)**: Renewable Energy
- **CFA / XOF**: West African CFA franc (UEMOA currency code: XOF)
- **FIT**: Feed-in Tariff (guaranteed purchase price)

- **GTA**: Grand Tortue Ahmeyim (Senegal–Mauritania gas field)
- **H_2 (Green H_2)**: Hydrogen (green hydrogen = produced from RE)
- **AI (IA)**: Artificial Intelligence
- **IEA**: International Energy Agency
- **IFC**: International Finance Corporation (World Bank Group)
- **IPP**: Independent Power Producer
- **IRENA**: International Renewable Energy Agency
- **kWh**: Kilowatt-hour
- **LCOE**: LevelizedCost of Energy
- **Li-ion**: Lithium-ion (batteries)
- **M**: Million (e.g., M CFA = millions of CFA)
- **MPE**: Ministry of Petroleum and Energy (Senegal)
- **MW / MWh**: Megawatt / Megawatt-hour
- **O&M**: Operations and Maintenance
- **OMVS**: Organization for the Development of the Senegal River
- **OPEX**: Operating Expenditures
- **PAYG**: Pay-As-You-Go
- **PPA**: Power Purchase Agreement
- **PSE**: Plan Sénégal Émergent
- **PS-2050**: Plan Sénégal 2050
- **REN21**: Renewable Energy Policy Network for the 21st Century
- **SENELEC**: National Electricity Company of Senegal
- **SLA**: Service Level Agreement
- **T&D**: Transmission & Distribution
- **WAPP**: West African Power Pool
- **WB**: World Bank
- **Yakaar–Teranga**: Offshore gas fields (Senegal)

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