

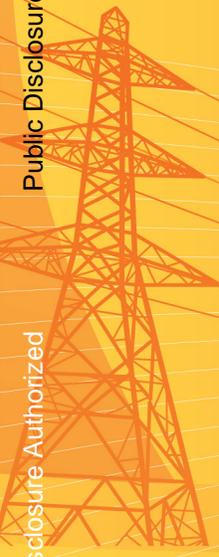
Accelerating Liquid Fuel Reduction in West Africa

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Acknowledgments

This paper was prepared by a World Bank Energy and Extractives team consisting of Yang Liu, David Loew, Rida Rizvi, Min A Lee, and Jan Kappen. The paper was prepared as part of a wider analytical program on West African utility performance led by David Loew, under the strategic guidance and direction of Ashish Khanna. The project team is grateful to Nicholas Elms, Mark Moseley, Claire Nicolas, Adam Suski, Stratos Tavoulareas, and Manaf Touati for their technical contributions.

The financial support of ESMAP is gratefully acknowledged. ESMAP is a partnership between the World Bank and over 20 partners to help low- and middle-income countries reduce poverty and boost growth through sustainable energy solutions. ESMAP's analytical and advisory services are fully integrated within the World Bank's country financing and policy dialogue in the energy sector. Through the World Bank (WB), ESMAP works to accelerate the energy transition required to achieve Sustainable Development Goal 7 (SDG7) to ensure access to affordable, reliable, sustainable, and modern energy for all. It helps to shape WB strategies and programs to achieve the WB Climate Change Action Plan targets.



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Acronyms and Abbreviations

DPF	Development Policy Financing
ECOWAS	Economic Community of West African States
ERERA	ECOWAS Regional Electricity Regulatory Authority
FSRU	Floating Storage and Regasification Unit
FX	Foreign Exchange
HFO	heavy fuel oil
IFC	International Finance Corporation
IPF	Investment Project Financing
IPP	Independent Power Producer
LC	Letter of Credit
LNG	Liquefied Natural Gas
MPA	Multiphase Programmatic Approach
PBC	Performance-based Conditions
PforR	Program for Results
PPA	Power Purchase Agreement
PV	Photovoltaic
RE	Renewable Energy
WAPP	West African Power Pool
WBG	World Bank Group



Preface

Most power utilities in West Africa are not financially sustainable. Of the 25 West African utilities included in the World Bank’s Utility Performance and Behavior Today (UPBEAT) database, only six are able to recover their operating and debt service costs—the bare minimum for financial sustainability—even when operating subsidies are included (as reported in utilities’ income statements). Without operating subsidies, this number drops to three. Poor cost recovery often drives a vicious cycle of underperformance, in which inadequate funding for investment leads to higher losses and lower service quality, which in turn reduces utility revenues.

Several interrelated factors cause these performance issues, but dependence on liquid fuels, poor governance, insufficient use of IT, and weak balance sheets are particularly common and acute challenges. Utilities with high shares of liquid fuels in their generation mixes face high and volatile power purchase costs. The resulting financial instability not only eats into utilities’ bottom lines but also impedes effective financial planning. Utilities with poor governance and inadequate use of IT tools lack robust procurement systems and are less able and incentivized to monitor and implement efficiency in operations. Weak balance sheets—arising when utilities have accumulated liabilities that they are unable to sustainably service—drive up utilities’ financing costs and make them riskier targets for investment. Together, these factors represent significant sources of inefficiency. Addressing them could reduce utilities’ costs of service and reduce or eliminate the need for higher tariffs to achieve cost-recovery.

This paper is one of a series of three that aim to help West African utilities and governments—and the development financiers that support them—better understand and respond to these issues. The focus in the papers is primarily on utilities with a distribution function (that is, distribution-only utilities, transmission & distribution utilities, or vertically integrated utilities), but examples from other types of utilities (transmission only, generation & transmission) are drawn on when instructive. Though each paper’s approach is tailored to its topic, they share common features. Each paper contains: i) a stocktaking of the scope of the challenge in West African utilities, sometimes informed by new data collected for that paper; ii) conceptual frameworks to help readers deepen their understanding of the topic; and iii) real-world country examples in the form of case studies and/or utility deep dives. The insights presented in these papers draw on lessons learned from past World Bank engagement with client utilities and, in turn, have helped shape ongoing Bank operations.



Key Findings & Recommendations

KEY FINDINGS

- ▶ **Key Finding #1: Liquid fuels impose high costs on power systems and utilities in West Africa.** Liquid fuels like diesel and HFO are widely used for electricity generation in West Africa, having contributed 4.5 GW of capacity and 12.7 TWh of generation in 2022. Many countries rely heavily on liquid fuels, with some small or fragile countries using them for up to 100 percent of their power generation, leading to high costs and fiscal burdens. Liquid fuel dependency raises the cost of electricity supply, averaging US\$ 0.26/kWh in West Africa, and accounts for 73 percent of regional generation costs. Volatile international oil prices exacerbate financial planning difficulties and subsidy requirements for utilities.
- ▶ **Key Finding #2: Enhanced regional trade offers the most economical pathway to minimize liquid fuel dependence in West Africa.** Through power trade, West African countries can cost-effectively decrease their reliance on liquid fuel-fired power and reduce energy expenses. New modeling suggests that a full-trade scenario would triple regional power trade from 9.7 TWh (10 percent of total) under a base case to 29.5 TWh (21 percent of total) in 2030, leading to an 82 percent reduction in liquid fuel power generation, even in the absence of specific policy mandates to reduce liquid fuel consumption. Compared to the baseline where trade is limited to existing capacities and contracts, full regional power trade will enable a 13 percent reduction in fuel costs and a seven percent reduction in total system cost, and avoid 20 Mt CO₂e in emissions by 2030.
- ▶ **Key Finding #3: Improved dispatch and use of existing grid assets could reduce reliance on liquid fuel use in West Africa, even in the absence of integration.** Poor coordination between generation and transmission systems, outdated infrastructure, and the absence of modern grid management tools lead to inefficient use of cheaper energy resources like gas and renewables, even when these are available. Instead, more costly liquid fuel plants are often used to meet demand or support grid stability.
- ▶ **Key Finding #4: The burden of liquid fuels in many West African countries is amplified by onerous contract terms on rental/emergency power.** Common challenges such as high power purchase costs due to sole-sourced procurement, inflexible cost structures, poor contract management, and significant financial risks from foreign currency exposure and fuel supply arrangements reduce incentives for efficiency and create financial vulnerabilities for utilities, limiting their ability to phase down liquid fuels.



RECOMMENDATIONS

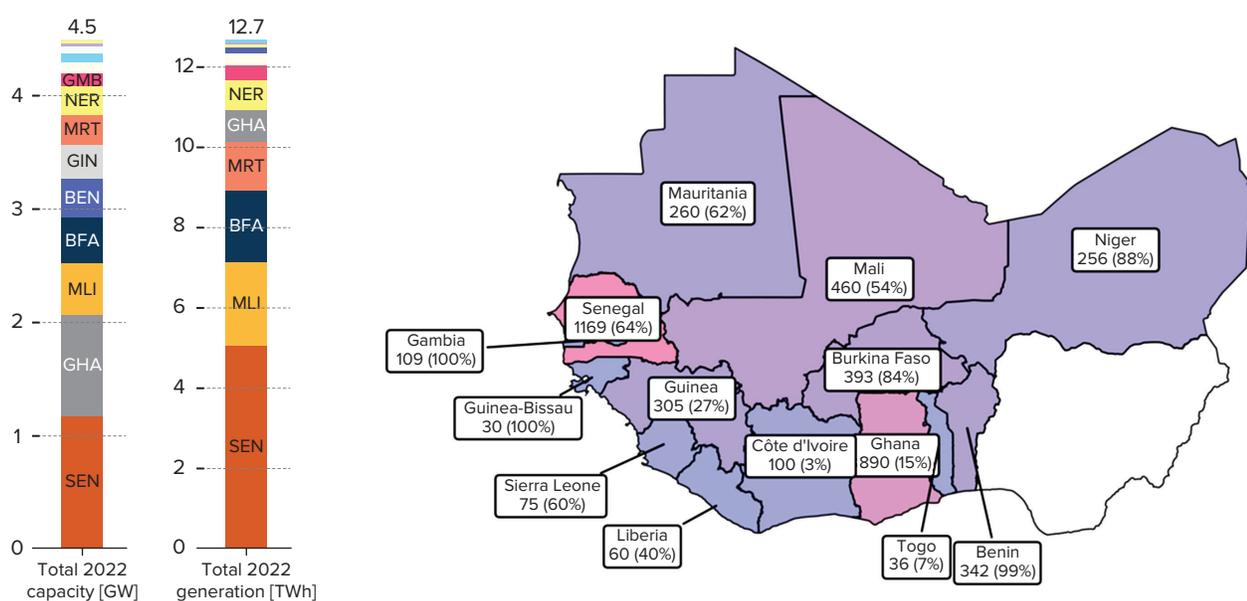
- ▶ **Recommendation #1: Reduce barriers to regional integration.** Regional integration offers the most cost-effective pathway to reduce liquid fuel dependence in West Africa. However, among the 14 countries in the West African Power Pool (WAPP), only seven percent of electricity is currently traded. Unlocking the full potential of regional trade requires national least-cost planning aligned with regional strategies, balancing domestic solutions, trading opportunities, and energy security. Strengthening trust in power trade and attracting investments requires regional infrastructure planning and independent regulatory oversight for the regional electricity market to reduce payment arrears and improve contract reliability. Adopting clear transmission pricing regimes can help mitigate financial uncertainty.
- ▶ **Recommendation #2: Optimize the use of existing network and generation resources.** There are several opportunities for West African countries to mitigate the impacts of liquid fuels in the near term by making better use of existing resources. These include implementing dispatch efficiency studies and grid stability analyses to optimize resource use and reduce liquid fuel reliance, in particular in countries that have other resources to provide baseload power. These studies are relatively low cost but have translated to significant reductions in liquid fuel usage and costs in other regions, even without the need for major new infrastructure. Similarly, opportunities exist to convert both utility-owned and rental liquid fuel generators to more cost-effective fuels such as gas (to the extent that gas resources are readily available).
- ▶ **Recommendation #3: Improve management of liquid fuel generation contracts.** Renegotiating liquid fuel contracts as they approach expiry presents opportunities to secure more favorable terms in line with international best practice, including through competitive procurement where possible. Strengthening contract management capacity and creating dedicated contract management units can help improve oversight, reduce costs, enhance transparency, and ensure that energy supply agreements are aligned with long-term national goals. Building stronger public contract management capacities will further support these objectives. Additionally, coordinating emergency power generation arrangements across multiple interconnected countries could improve capacity utilization, thus lowering costs for both offtakers and generators.
- ▶ **Recommendation #4: Make use of the growing range of innovative mechanisms tailored to different contexts to scale up solar PV and other renewables.** At the utility scale, this could involve containerized rental solar solutions that provide rapid, scalable access to solar PV + storage in situations where power is needed at short notice or where procurement frameworks aren't yet sufficiently robust for IPPs; meanwhile, at the consumer scale, this could involve solar lease rentals where customers pay for industrial-scale solar equipment over time rather than purchasing it outright. In particularly challenging environments with limited access to private capital, public financing can have an important role in securing new renewable supply, but should be accompanied by reforms and (where possible) regional procurement aggregation to reduce costs and set a pathway to private capital in future.



1. Liquid Fuels in West Africa's Current Power Generation Landscape

As of 2022, West Africa's¹ electricity generation capacity stood at approximately 26 GW. Forecasts predict a four to six percent annual growth rate until 2040, potentially reaching 104 GW, driven by the region's rapid population growth and urbanization. Liquid fuels, such as diesel and heavy fuel oil (HFO), are commonly used for baseload electricity generation due to limited or unreliable energy alternatives. In 2022, across 14 West African countries, liquid fuel oil contributed 4.5 GW of grid-connected power capacity and generated 12.7 TWh of electricity.

Figure 1.1: Utility scale liquid fuel installed capacity and energy generation in West Africa



Source: World Bank

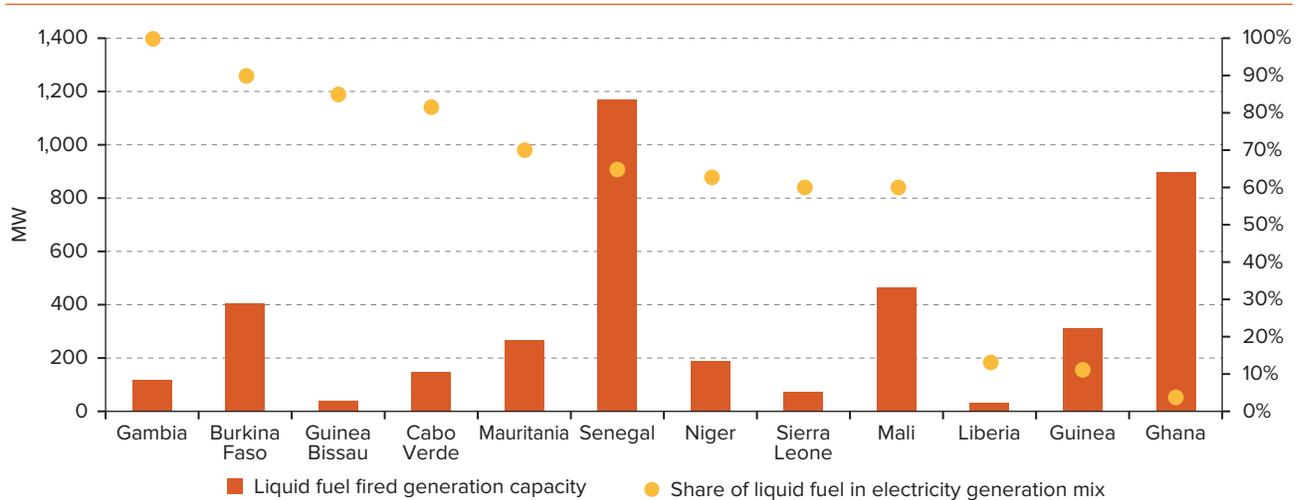
Note: The map indicates installed capacity of grid-connected liquid fuel power plants. The percentages show share of liquid fuel in total capacity. Although Nigeria is included in the power trade analysis, it does not have utility-scale liquid fuel capacity.

1 This paper's analysis covers Benin, Burkina Faso, Côte d'Ivoire, The Gambia, Ghana, Guinea, Guinea-Bissau, Liberia, Mali, Mauritania, Niger, Nigeria, Senegal, Sierra Leone, and Togo. Together, these are referred to here as "West Africa".



Senegal and Ghana lead West Africa in liquid fuel capacity, representing 1,169 MW and 890 MW respectively, which together account for around half of the region's total. Other major contributors include Burkina Faso with 393 MW, Guinea with 305 MW, Mali with 460 MW, and Mauritania with 260 MW. In contrast, Sierra Leone, Guinea-Bissau, Togo, and Liberia have lower liquid fuel capacities: nevertheless, these capacities form a substantial portion of their total power generation capacities in relative terms. Small or fragile countries like The Gambia, Guinea-Bissau, Burkina Faso, and Cabo Verde are 80–100 percent reliant on liquid fuels, while Mauritania, Senegal, Niger, Sierra Leone, and Mali have over 50 percent dependency.

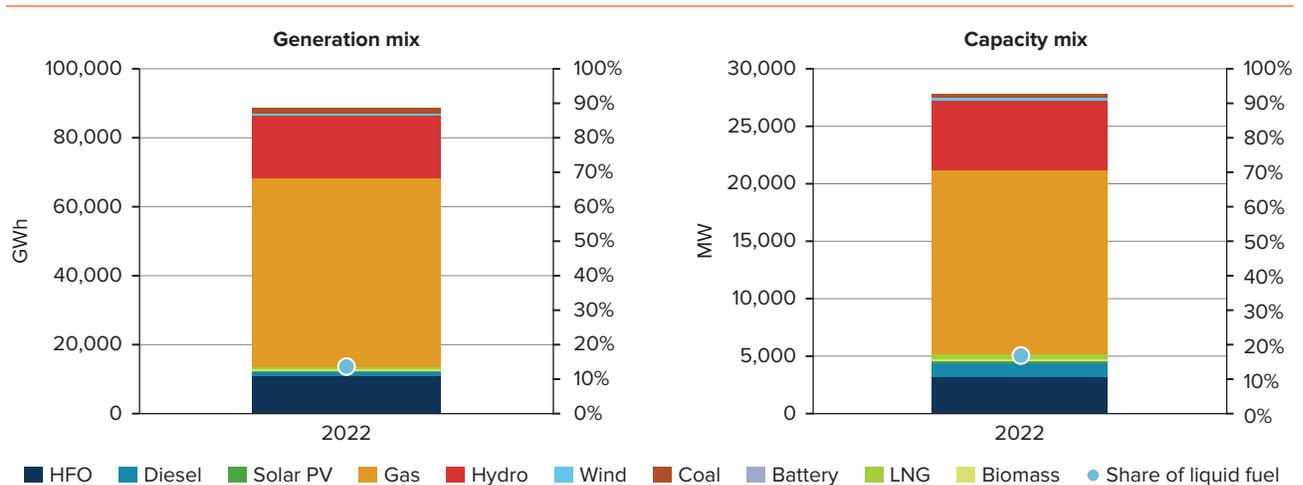
Figure 1.2: Liquid fuel power capacity and its share in energy generation mix in 2022



Source: World Bank

At the regional level, liquid fuel accounts for 14 percent of the total energy mix and 16 percent of installed power capacity. Despite gas and hydropower being primary energy sources, liquid fuel's outsized impact significantly escalates power costs and creates major fiscal challenges for the countries concerned (Figure 1.3).

Figure 1.3: Aggregate installed capacity and energy generation in 2022

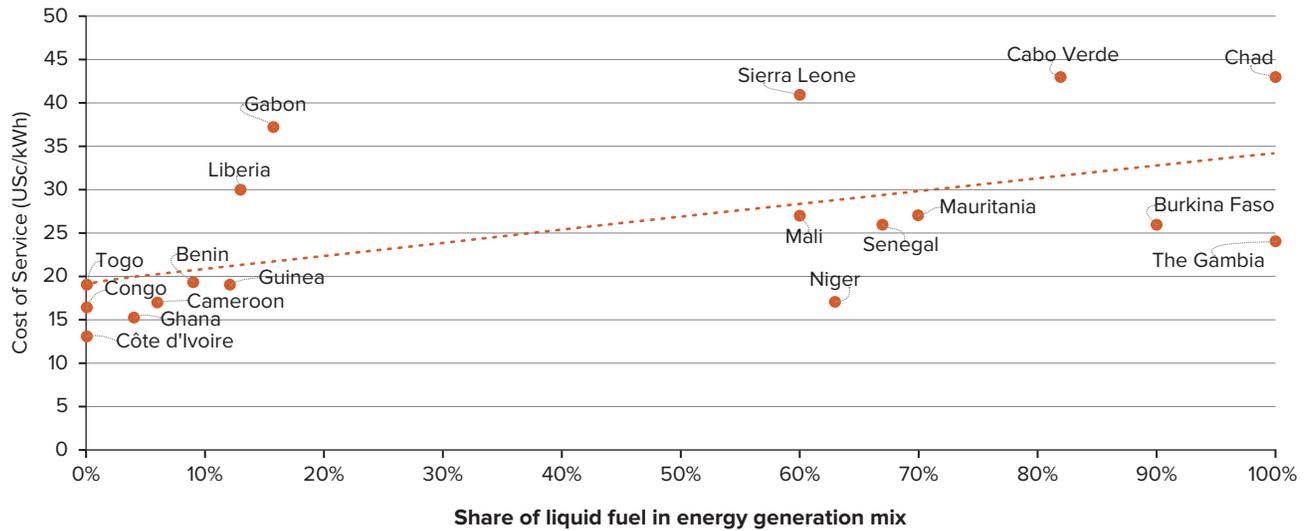


Source: World Bank, 2024



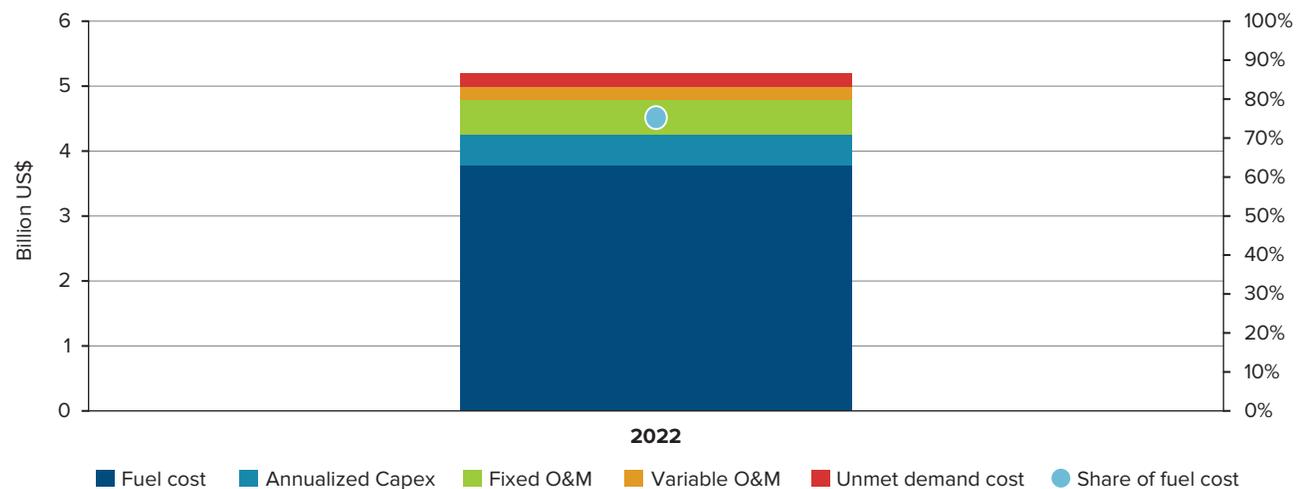
The impacts of HFO generation on sector costs and public finances can be seen across the region. The average cost of electricity service in West African countries stands at US\$ 0.26 per kWh and is correlated with reliance on liquid fuel in energy generation (Figure 1.4). Fuel costs make up 73 percent of annual power generation expenses in the region (Figure 1.5) amounting to US\$ 3.8 billion, or 1.4 percent of total GDP (excluding Nigeria).

Figure 1.4: Average cost of service in West Africa



Source: World Bank, 2024

Figure 1.5: Breakdown of 2022 annual power generation cost in West Africa



Source: World Bank, 2024

The high costs of liquid fuel generation in West Africa are exacerbated by weak planning and procurement. Liquid fuel generation in West Africa is often a stopgap measure to meet acute supply deficits resulting from inadequate long-term capacity planning and weak procurement frameworks. Governments' weak bargaining positions in these situations combined with high levels of offtaker risk



from financially unsustainable utilities often result in liquid fuel Power Purchase Agreements (PPAs) that provide high levels of protection to investors and create financial obligations for the sector and utilities that can be difficult to meet.

Liquid fuel generation also exposes countries and utilities to volatility in international oil prices.

This significantly complicates the task of financial planning for utilities, especially if they are not able to consistently procure HFO on long-term contracts or pass fuel price swings to customers through tariffs. Where utilities receive public subsidies to offset revenue shortfalls, fuel price swings also introduce volatility in subsidy requirements.

This paper presents options for countries to decrease reliance on liquid fuels in power generation.

- ▶ **Section 2** focuses on the potential for regional power trade in West Africa to leverage interconnection to enable large-scale renewable energy projects, reduce reliance on expensive liquid fuels, and bring overall energy costs down. Regional trade represents the clearest long-term path toward a durable phase-out of liquid fuel.
- ▶ Interconnection is technically and politically challenging, and may take significant time and cooperation to realize, even in a best-case scenario. **Section 3** focuses on practical steps that countries—including countries in West Africa—can take independently to reduce liquid fuel dependence, regardless of the pace of regional integration.



2. Liquid Fuel Phase-down through Regional Power Trade

West Africa, through the West African Power Pool (WAPP), already has the most interconnected regional power network in Sub-Saharan Africa, with all 14 member countries (plus Mauritania) linked, from Nigeria to Mauritania (See Figure 2.1). Despite this, only around seven percent of electricity in the WAPP region is traded. If regional energy resources were effectively pooled, there is a strong likelihood that the region could meet its energy demand without relying on liquid fuels. However, the current potential for such trade is constrained by several factors, including thermal power purchase agreements, limited transmission capacity, and a lack of trust stemming from the weak creditworthiness of offtakers. Addressing these constraints is crucial to unlocking the full potential of regional energy integration and reducing dependency on liquid fuels.

Figure 2.1: WAPP regional power network (status quo)



Source: WAPP

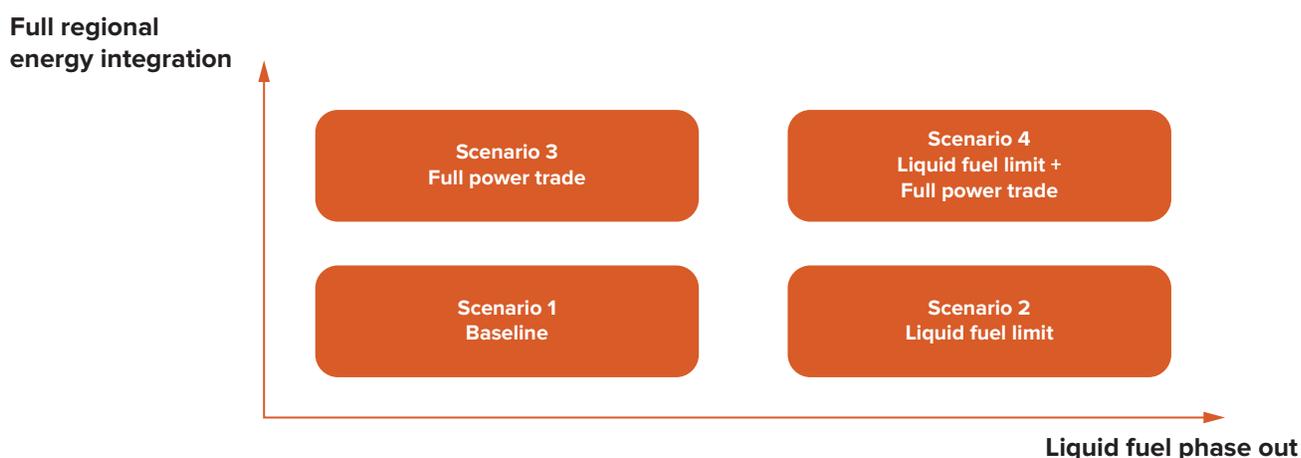


2.1 SCENARIO ANALYSIS FOR LIQUID FUEL PHASE-OUT AND REGIONAL POWER TRADE

The potential for regional power trade in West Africa to reduce cost and liquid fuel use is assessed here using the World Bank's Electricity Planning Model (EPM). This model minimizes total system operating and capital costs—as well as the costs of unmet demand—considering both the immediate need for electricity dispatch and the strategic necessity of long-term green-field investments in the power system. The model provides critical insights into the energy mix, necessary investments, and total costs of supplying electricity. It also analyzes trade flows, or the movement of electricity between different regions or countries, which helps to balance supply and demand across the network. Modeling assumptions include a horizon from 2022 (the year with the most recent data available) to 2030, no external environmental constraints or emission limits, and a spinning reserve of 10 percent of peak demand to ensure grid stability and reliability.

Four scenarios are considered (Figure 2.2).

Figure 2.2: Power system planning scenarios



Source: World Bank, 2024

Scenario 1: Baseline

In the baseline scenario, West Africa's power generation and trade are constrained by existing capacities and contractual agreements. This scenario represents the status quo, with no significant expansions or modifications to power generation and transmission systems.

Scenario 2: Liquid Fuel Limit

This scenario considers a future where West Africa largely eliminates liquid fuel power generation by 2030. Key conditions include:

- ▶ Trade remains restricted to existing capacities and contracts;
- ▶ Liquid fuel power generation is minimized by 2030; and
- ▶ Liquid fuel units are unable to provide spinning reserves by 2030.



Scenario 3: Full Power Trade

In this scenario, the focus is on expanding transmission capacities to enhance regional power trade. The conditions include:

- Transmission capacities are expanded as projected based on the WAPP master plan toward 2030; and
- Trade is limited only by the full capacity of transmission lines, without additional contract or volume limitations.

Scenario 4: Liquid Fuel Limit + Full Power Trade

This combines Scenarios 2 and 3, integrating the two objectives (zero liquid fuel power generation alongside full power trade) such that:

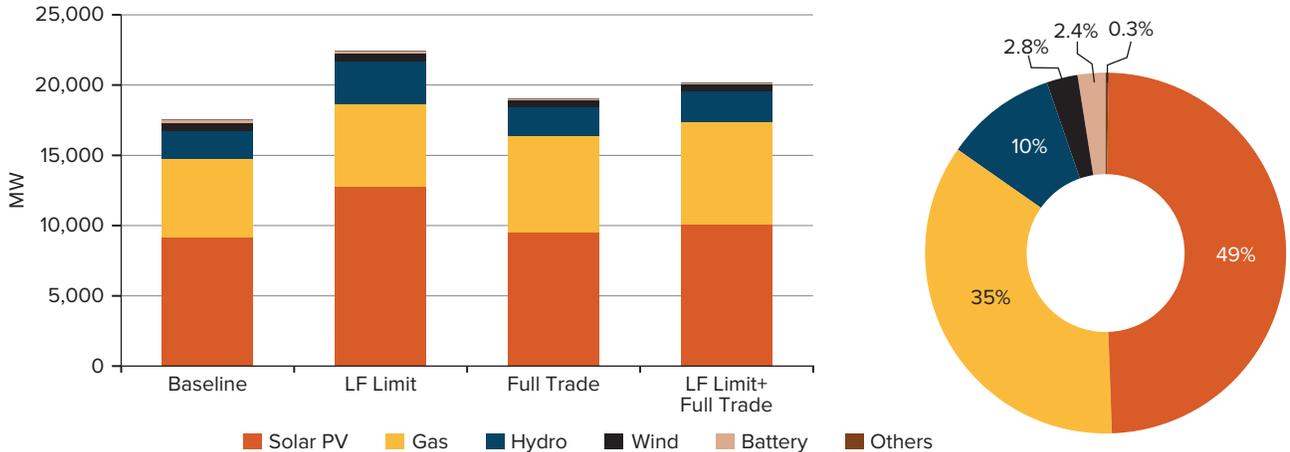
- Liquid fuel units are phased out and cannot provide spinning reserves by 2030; and
- Transmission capacities are expanded as expected toward 2030, with trade restricted only by the full capacity of transmission lines.

2.2 MODELING RESULTS AND POLICY IMPLICATIONS

Generation

Across all scenarios, solar energy emerges as the predominant source of new capacity, accounting for approximately 50 percent, followed by gas at 35 percent and hydropower at 10 percent. With restrictions on liquid fuel usage (Scenario 2), limited expansion of regional power trade will require a substantial increase in solar capacity, projected to rise by 39 percent, and a notable increase in hydropower capacity, expected to grow by 30 percent (See Figure 2.3). This shift underscores the significant role that solar, gas, and hydropower will play in meeting future energy demands and reducing reliance on liquid fuels.

Figure 2.3: Cumulative new capacity (left) and share of new capacity additions by fuel type in the full-trade scenario (right) by 2030 (MW and %)

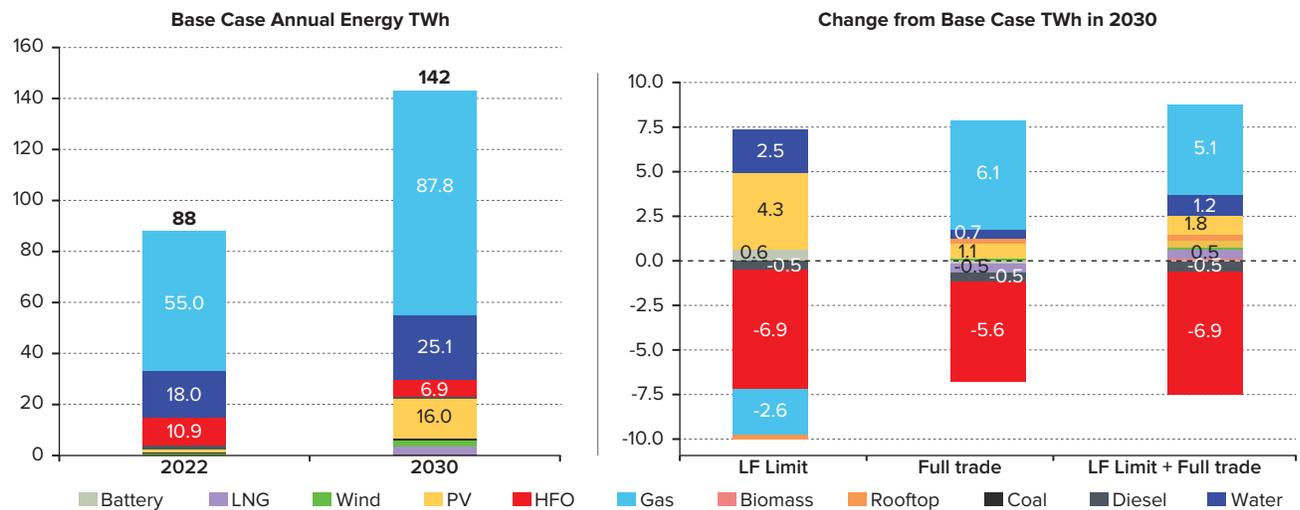


Source: World Bank, 2024



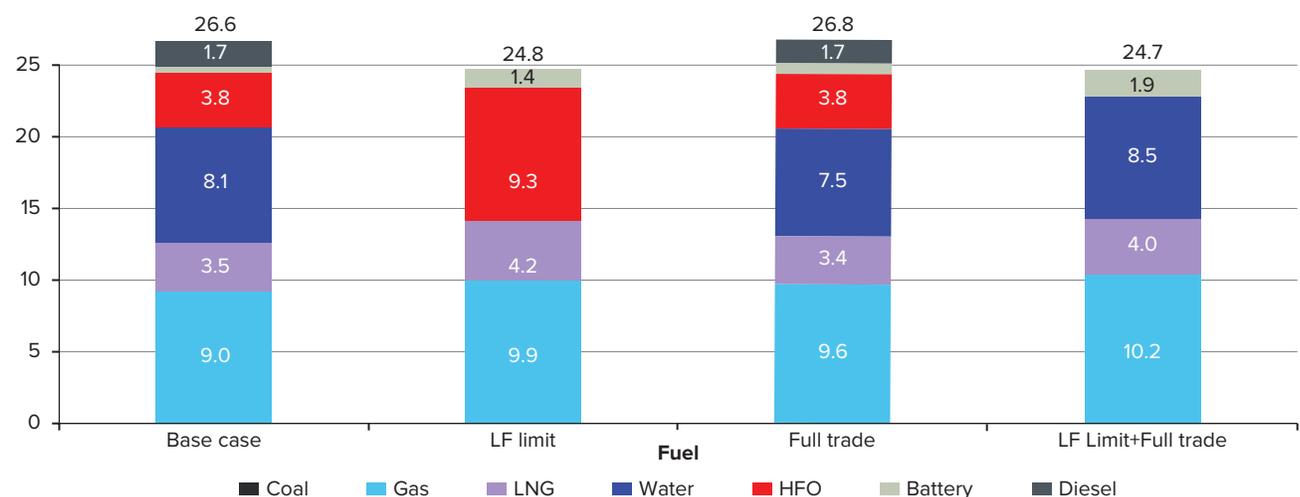
The impact on generation of imposing the constraints under the different scenarios is shown in Figure 2.4. In a scenario where liquid fuels are phased out but power trade remains limited (Scenario 2), most new generation comes from solar and some hydro (but at significantly higher cost, see below). With full power trade (Scenarios 3 and 4), most of the reduction in liquid fuel is offset by generation from gas. Notably, even without a hard target to phase out liquid fuel, full power trade alone is able to reduce liquid fuel generation in 2030 from 6.9 TWh in the base case by 5.6 TWh to 1.3 TWh—a decline of 82 percent. In all scenarios, solar PV becomes an increasingly important generation source.

Figure 2.4: Change in annual energy generation by 2030 (TWh)



The small share of liquid fuel remaining in a scenario with full trade but no hard liquid fuel limit (Scenario 3) supplies approximately 14 percent of the spinning reserve requirements in the region by 2030 (figure 2.5). This underscores the critical role of gas, battery storage, and hydropower in supporting the gradual phase-down of liquid fuels, as these alternatives would be essential in meeting spinning reserve needs and ensuring grid stability under more severe liquid fuel limits.

Figure 2.5: Provision of spinning reserves by source in 2030 (TWh)



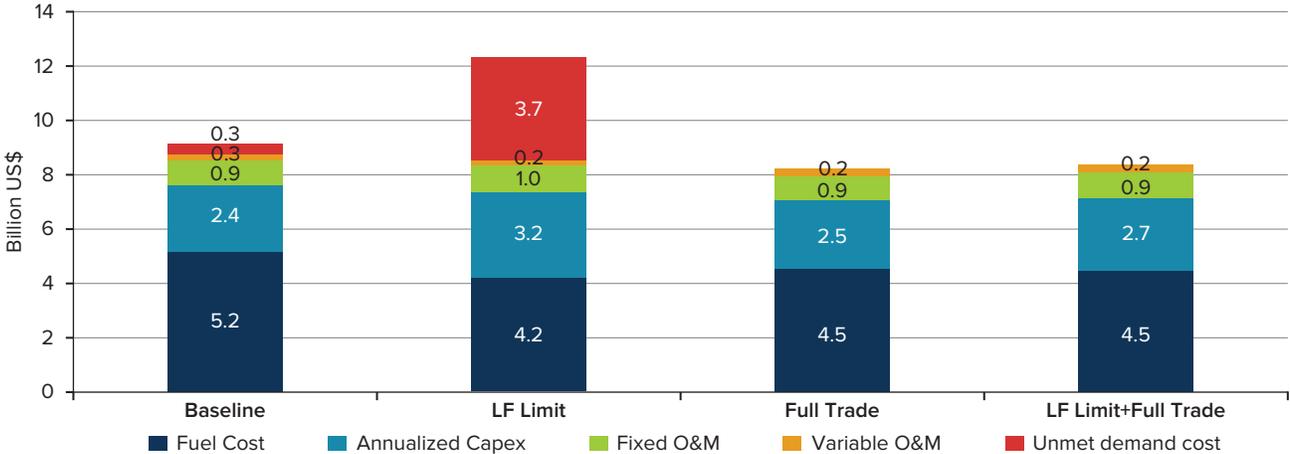
The full power trade scenario is projected to reduce baseline greenhouse gas emissions by approximately 20 million tons on a cumulative basis by 2030. In monetary terms, this reduction can be valued at US\$ 1 billion, assuming a carbon price of US\$ 50 per ton of CO₂e. Imposing a liquid fuel limit within the full-trade scenario will further reduce greenhouse gas emissions by around seven million tons on a cumulative basis by 2030.

Generation costs

Without regional power trade, shifting away from liquid fuels entails a notable increase in total system costs. Figure 2.6 shows an increase of 35 percent in total costs by 2030 between the base case (Scenario 1) and a phase-out of liquid fuels without trade (Scenario 2)—from US\$ 9.1 billion to US\$ 12.3 billion. This increase is in large part due to an increase in unmet demand between the two scenarios—valued in the modeling at US\$ 3.7 billion—as phasing out liquid fuels means that some demand can no longer be served given available resources and variability of renewables.

Conversely, in the scenarios with full trade (Scenarios 3 & 4) annual costs decrease by US\$ 0.9 billion to 8.2 billion by 2030. This is largely a result of a 13 percent decrease in fuel costs as gas replaces liquid fuels. The imposition of a liquid fuel limit on top of the full-trade scenario (Scenario 4) does not lead to additional system costs. This is because full regional power trade already achieves an 82 percent reduction in liquid fuel power generation by 2030. Any additional investment required for further reduction due to the liquid fuel limit is almost fully offset by savings in fuel costs. Notably, capex does not change much between the base case (Scenario 1) and regional integration (Scenarios 3 & 4). Both scenarios require around US\$ 20 billion in capex over the projection period. In the base case, this capex goes entirely to domestic generation. In the full-trade scenario, the capex finances some new generation as well as regional interconnection infrastructure. The latter scenario, however, results in significantly reduced operating costs, and therefore presents a far more attractive return on investment. By contrast, under a limited liquid fuel scenario without trade, capex requirements rise by 36 percent as a result of additional required investment in hydro and solar.

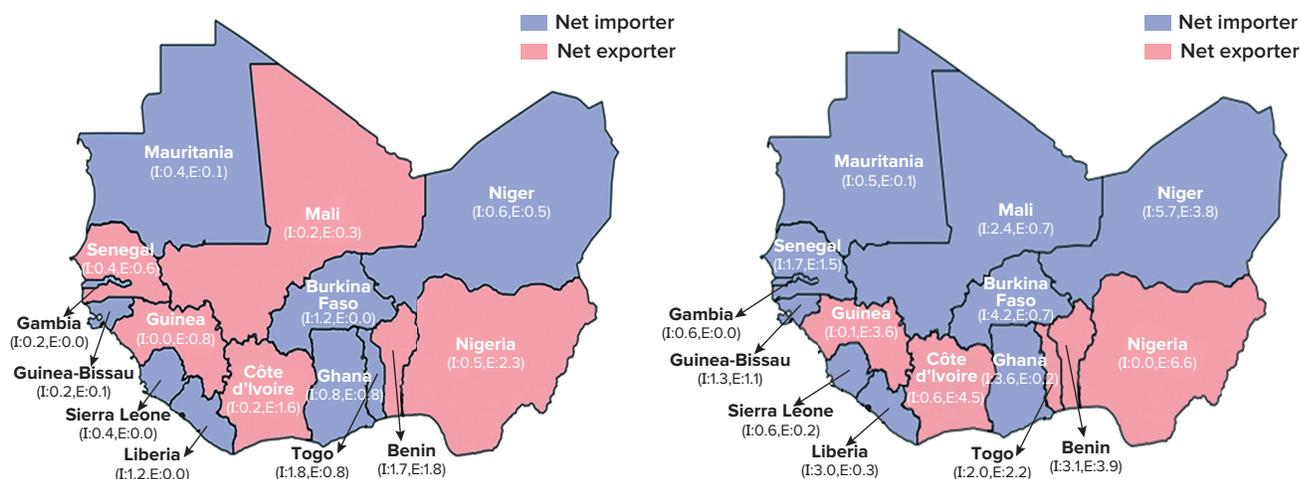
Figure 2.6: Breakdown of the annual costs by scenario (US\$, billions, annual-undiscounted)



Impact on regional trade flows

Under the full-trade scenarios, the total volume of regional power trade is projected to triple by 2030, increasing from 9.7 TWh (10 percent of the total) in the baseline case to 29.5 TWh (21 percent of the total). Most countries in the region will act as both importers and exporters, reflecting the diverse energy demands and resource availability across the region. Notably, Nigeria (through Togo and Benin), Côte d'Ivoire, and Guinea would become major net exporters due to their abundant gas and hydro resources (see Figure 2.7).

Figure 2.7: Overview of WAPP trade flows in baseline (left) and full-trade (right) scenarios in 2030 (TWh)



Implementation considerations

The modeling shows that enhancing trade is a least-cost pathway to reduce liquid fuel generation by 82 percent, fuel costs by 13 percent, total system costs by around seven percent, and CO₂ emissions by 20 million tons by 2030. Despite these economic benefits, achieving this level of integration would require major strides in regulation and coordination. Recent developments in this direction among WAPP and its member countries are encouraging. These include:

- ▶ WAPP is leading efforts to synchronize the regional network, and its newly inaugurated Information and Coordination Centre (ICC) is intended to become the System and Market Operator (SMO) for the regional power system;
- ▶ The ECOWAS Regional Electricity Regulatory Authority (ERERA), established in 2008, is updating its framework to support short-term flexible trade, and better integrate renewable energy sources. ERERA has approved the regional grid code and is soon to issue the directive to formally adopt it; and
- ▶ ERERA is also in the process of developing the regional transmission pricing framework and pricing model to facilitate trade and compensate transmission owners.



However, several barriers to deeper integration still need to be addressed:

- ▶ West African utilities' poor financial performance makes them riskier offtakers and undermines trust among trading partners;
- ▶ Past political crises in the WAPP region have resulted in nonpayment and large build-ups of arrears;
- ▶ Power planning at the national level is often still conducted toward the goal of energy autarchy. Energy security concerns—while important—need to be better balanced with least-cost trading opportunities in the planning process, and coordination among regional planners needs to be enhanced;
- ▶ Governments and utilities may be locked into suboptimal generation options through long-term PPAs, which defeat the commercial case for integration—even where there is political will; and
- ▶ Utility-scale solar and hydro resources are often found in small and fragile countries, but their limited market demand cannot support large-scale projects. This creates a chicken-and-egg problem, wherein the economic case for the interconnectors depends on new generation projects, but these new generation projects only make sense if there is sufficient certainty that their output can be sold in regional markets.

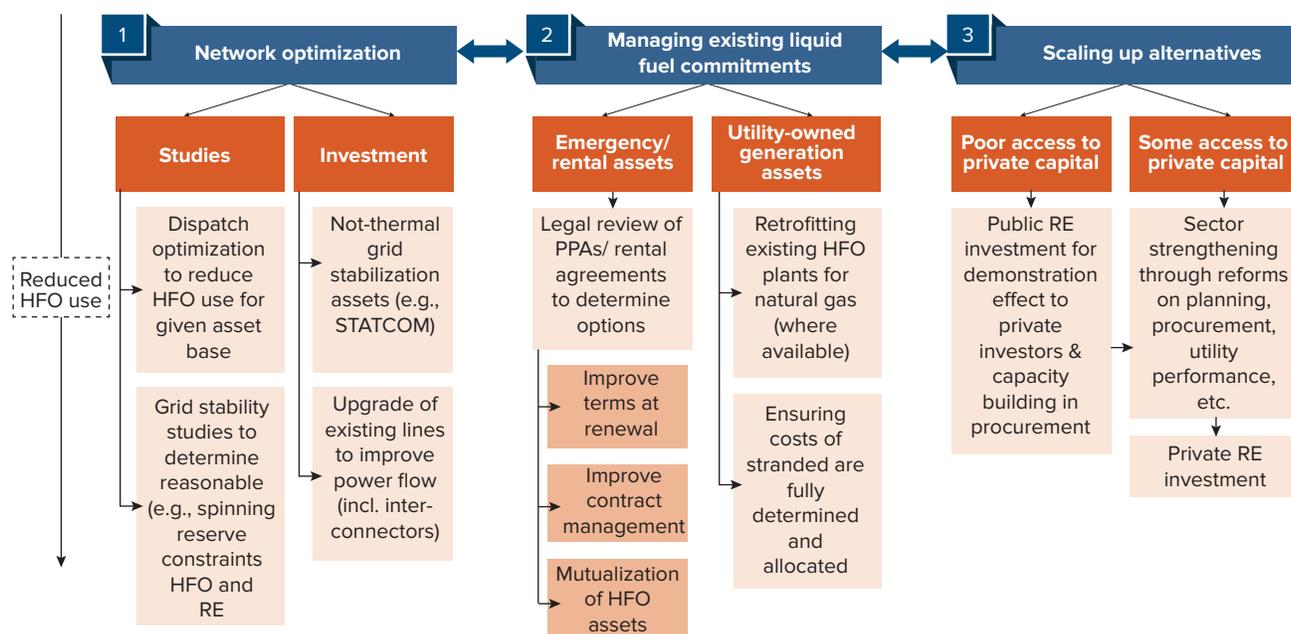


3. Developing Domestic Options for Near-term Liquid Fuel Reduction

As the region continues to work toward integration, there is still much that individual countries can do unilaterally to reduce their dependence on liquid fuels. This Section discusses some of the options potentially available to West African countries (and countries in other regions with high use of liquid fuel) to reduce the impacts of liquid fuel even if regional integration is not immediately available.² These options fall into three main pillars:

1. Optimizing existing grid assets;
2. Managing existing liquid fuel contractual commitments; and
3. Scaling up alternatives to liquid fuels, including through concessional resources.

Figure 3.1: Analytical framework for near-term liquid fuel phase-down



² More downstream interventions to reduce the amount of power generation required through demand management, energy efficiency, or transmission and distribution loss reduction are highly effective ways to reduce liquid fuel consumption but are beyond the scope of this paper. See ESMAP (2024) and World Bank (2024) for a detailed treatment of demand response in developing countries.

3.1 OPTIMIZATION OF EXISTING GRID ASSETS

Dispatch Optimization & Grid Stability Studies

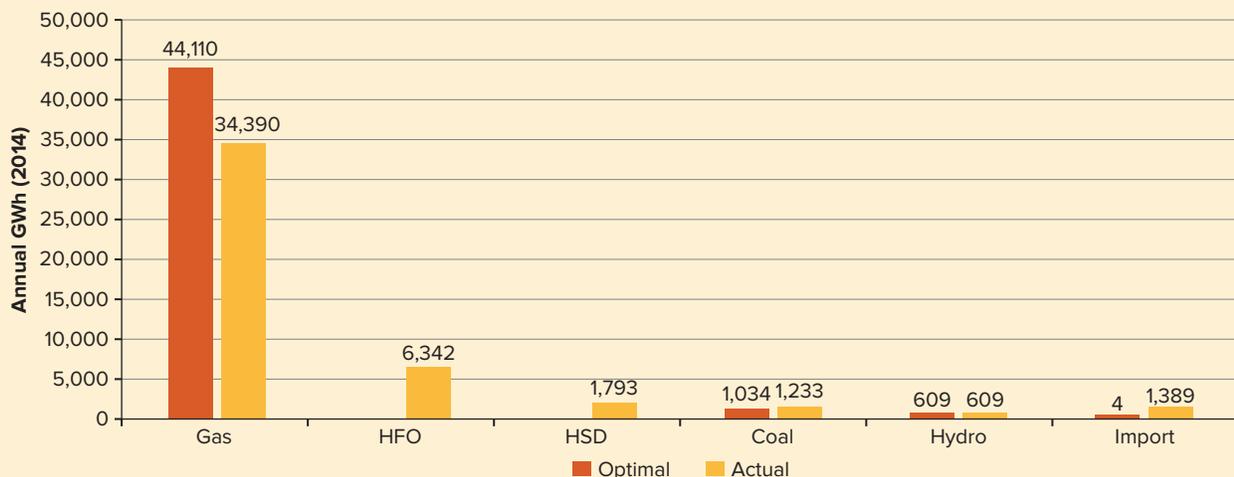
Power systems with inefficient dispatch may be consuming more liquid fuels than necessary. Dispatch systems are managed inefficiently in many developing countries, often using manual processes. Dispatch efficiency studies examine existing dispatch processes to determine whether the system is operating in a cost-effective way by comparing actual dispatch with an ideal or optimized version. Any discrepancies can highlight issues or constraints in the system, such as the lack of automation or spinning reserves, which may contribute to grid failures.

Dispatch optimization can often be achieved through improved management practices and operational procedures without requiring significant capital investments. By refining dispatch protocols, enhancing data analysis capabilities, and improving communication among operators, utilities can realize immediate efficiencies with existing systems. While some investment may enhance long-term optimization, substantial improvements are frequently possible through strategic adjustments within current infrastructure.

BOX 1: DISPATCH OPTIMIZATION IN BANGLADESH

In Bangladesh, nearly 20 percent of electricity generation in 2014 relied on liquid fuels, mainly heavy fuel oil (HFO). Initially, this was attributed to a shortage of natural gas. However, a dispatch efficiency study³ revealed that HFO was being used unnecessarily for frequency support, and that the existing gas supply could be used more efficiently (Nikolakakis et al. 2017). The study estimated potential savings with optimal dispatch of over US\$ 1 billion per year, even without increasing gas allocations. It also identified transmission congestion issues, which led to an investment project to upgrade the transmission network. Additionally, the study found that adding large-scale solar and wind generation without a proper dispatch and frequency control scheme could worsen system security issues rather than improve them.

Figure 3.2: Actual versus optimal dispatch—fuel mix



Source: T. Nikolakakis et al. (2017)

3 T. Nikolakakis, Deb Chattopadhyay, Morgan Brazilian (2017). A review of renewable investment and power system operational issues in Bangladesh. *Renewable and Sustainable Energy Reviews*, Vol. 68, Part 1, February 2017, Pages 650–658. <https://doi.org/10.1016/j.rser.2016.10.016>.



BOX 1: CONTD...

The study, as illustrated in Figure 3.2 above, showed that the actual dispatch in Bangladesh used 9.7 TWh less gas and instead relied on 6.3 TWh of HFO, 1.8 TWh of diesel, and imported fuels compared to an optimal dispatch scenario. In Bangladesh's case, optimal dispatch would have eliminated the need for HFO, without any new investments in alternative sources. Although limited gas availability was a major concern for the country, the study demonstrated that even with the same gas levels as in the actual scenario, system costs could be reduced by 63 percent through optimal dispatch.

Another challenge for Bangladesh's power system was the tight demand–supply balance, with limited spinning reserves. The study indicated that even a small increase in spinning reserves could significantly raise reserve prices, highlighting the need for investments to provide rapid-response reserves. By comparing the cost increase associated with higher reserve requirements, countries can explore economically viable investment options.

A grid stability analysis can be a useful complementary step to evaluate the ability of existing transmission infrastructure to integrate variable renewable energy sources while maintaining reliability and stability. By assessing factors such as line capacities, load demands, and the grid's response to fluctuations in generation, this analysis identifies the maximum level of renewables that can be accommodated without jeopardizing system performance. Conducting a grid stability analysis serves as a useful preliminary step toward reducing liquid fuel usage because it provides critical insights into how quickly and safely liquid fuels can be phased out.

Network Upgrades

As countries prepare to reduce their reliance on liquid fuels and transition toward cleaner energy sources, there are helpful quick-win capital investments that can be made in the shorter term. These include upgrades to existing transmission lines and interconnectors as well as targeted investments to prepare the grid to integrate growing generation for variable renewables.

BOX 2: INSTALLATION OF STATCOM IN KENYA

Kenya has set an ambitious goal of achieving 100 percent clean energy by 2030 while reducing costs and improving the quality and reliability of its electricity supply. To support this effort, Kenya and Ethiopia signed a PPA in 2022 that will increase Kenya's electricity imports from Ethiopia to 400 MW over the next three years, up from 200 MW currently. However, this increase poses significant risks of instability and outages for the Kenyan grid unless system reinforcements are implemented. Current limitations in the grid's transmission capacity and reactive power—essential for maintaining voltage levels—restrict the efficient transfer of renewable energy to major load centers, resulting in poorer supply quality and necessitating reliance on higher-cost fossil fuel generation for stability.

To enhance grid stability and reliability, Kenya is now installing a STATCOM (Static Synchronous Compensator). These devices help regulate voltage and provide reactive power support, which will be crucial for accommodating increased imports and integrating more renewable energy sources into the grid. By improving voltage stability, a STATCOM will facilitate the transition away from costly fossil fuels and contribute to achieving Kenya's clean energy objectives while enhancing the reliability of supply.



3.2 IMPROVED MANAGEMENT OF EXISTING LIQUID FUEL COMMITMENTS

Improved Management of Temporary/Emergency Power Generation Assets

Liquid fuel generation in West Africa is typically governed by short-term rental or Power Purchase Agreements (PPAs). These contracts are often signed at times of sector crises, such as supply shortages and blackouts. An increasing number of specialized private operators have identified the need for short-term (“emergency”) generation solutions to address acute supply needs as a market niche and have developed innovative business models and technical solutions to mobilize generation solutions within very short timeframes. This has clear benefits for the offtaking countries, who are able to keep the lights on, but given the weak negotiating position of governments and the high levels of risk private investors take on in these situations, the terms of these contracts can be onerous to governments.

A review of typical PPAs in West Africa performed for this paper identified several common features. These are summarized in Table 3.1, along with their implications.

Table 3.1: Summary of common features in liquid fuel PPAs in West Africa

Feature/provision	Typical terms	Why is this important?
Procurement method	Sole-sourced direct negotiation	Among the PPAs reviewed, competitively procured liquid fuel generation of similar capacities was always significantly cheaper than sole-sourced.
Cost structure	Fixed capacity charge plus variable cost for fuel and fuel handling	High fixed payments for liquid fuel contracts mean utilities have limited incentive to reduce liquid fuel usage until contracts expire and are less able to reduce costs in response to demand shocks. Fixed costs often exceed what investors require to recover capital expenditure.
Fuel supplier	The Independent Power Producer (IPP)	Liquid fuel-based PPAs often call for fuel to be provided by the IPP, with offtakers compensating the IPP for incurred fuel purchase costs. While this removes the administrative burden of fuel procurement from the offtaker, it also reduces opportunities to obtain fuel competitively at potentially more attractive prices.
Offtaker payment currency	Payment typically in USD, though some examples of local currency PPAs in FCFA region	Payment in USD transfers all foreign currency exchange risk to the offtaker. Payment in local currency transfers this risk to the IPP, but the IPP may demand a tariff premium to compensate. Therefore, where local currency PPAs are available, the offtaker may have to weigh a higher but more predictable cost against exposure to forex (FX) risk. In some cases, dual currency PPAs may be a good compromise solution.



Feature/provision	Typical terms	Why is this important?
Offtaker payment security obligations	Offtakers required to provide a letter of credit (LC) equivalent to several months' energy supply	Depending on the risk profile of the offtaker, PPAs can vary widely in the duration of the LC they require. In some cases, LCs can be as brief as one month, in other cases six or more. With the cost of longer-term LCs rapidly escalating, offtakers will have to weigh the economic advantage of short LCs against IPPs typically demanding a premium to compensate for higher offtaker risk.
Tax obligations	Offtakers reimburse the IPP for taxes paid by the IPP, including host country income taxes, sales taxes, and customs duties	Some HFO PPAs grant IPPs generous tax relief, which increases the total cost of the project to the public.

Options to optimize or otherwise improve the terms of existing short-term PPAs are generally limited as countries are dependent on them for generation. Exiting these PPAs early usually entails significant penalties (usually up to the remaining value of the contract) that would probably negate any cost savings from switching to alternative resources. Such termination would also give rise to reputational damage to the owner and may harm a country's ability to attract private investment in future.

However, countries in West Africa that have liquid fuel IPPs or rentals in their current generation mix can still consider several strategies to better manage these, including:

- ▶ **Improvement of terms upon renewal:** In many West African countries, liquid fuel PPAs that were procured on a short-term basis have become de facto long-term by being continually rolled over upon expiration. These renewals should offer opportunities to governments to achieve better terms elsewhere. Where possible, renewals should implement international competitive bidding. If this is not feasible or proves unsuccessful, offtakers should consider negotiating a short-term renewal—potentially with the support of transaction advisors—on terms that seek to address the most onerous provisions in the current PPAs.
- ▶ **Improved contract management:** It is critical for any national utility entering or currently party to an emergency-power PPA to pay close attention to contract management, which is often neglected in West Africa and elsewhere. Some of the key aspects of good contract management include:
 - When the utility first considers purchasing emergency power from an IPP, it should **establish a Contract Management Team**, that will be responsible for preparing the competitive procurement process, drafting the proposed PPA as part of bidding documents, conducting the procurement, and managing the PPA.
 - The Contract Management Team should have **adequate budget and resources**, and it should include, at a minimum: a technical specialist who is familiar with the type of power plant being considered; a legal specialist who is familiar with the PPA; and a financial specialist who is familiar with the payment arrangements contemplated in the PPA.
 - In addition, the Contract Management Team should have the **ability to engage external experts**, as required, to handle any activities with which the team does not have extensive prior experience, such as PPA drafting, the procurement process, and the resolution of disputes.



- The Contract Management Team should maintain **accurate and up-to-date records** of all documentation relevant to the PPA, including schedules and annexes, plus any amendments. As part of this task, the Contract Management Team should maintain a consolidated version of the full PPA, as amended, so that every member of the Contract Management Team is fully aware of the current provisions of the PPA in force at any given time. This avoids PPA “version control” issues that often complicate negotiations in West Africa and other countries.
 - The Contract Management Team should also **develop an internal Operations Manual**, to provide guidance on day-to-day management activities as well as exceptional situations, such as the handling of disputes. This Operations Manual will ensure the continuity of high-quality management of the PPA notwithstanding any staff turnover on the Contract Management Team.
 - The Contract Management Team should ensure, in accordance with the terms of the PPA, that **regular meetings are held with representatives of the IPP**, to discuss issues such as: the coordination of scheduled maintenance outages; the handling of Force Majeure or emergency situations; safety issues; and the status of protective measures and devices (relays, circuit breakers, and so forth) which protect the reliability and stability of the power plant. The Contract Management Team should actively monitor the performance of the IPP, to ensure that all of the IPP’s obligations under the PPA are being met.
 - The Contract Management Team must provide monthly monitoring reports to the utility’s senior management on the **performance of both parties regarding their respective obligations under the PPA** and liaise with the sector planning authorities to ensure that plans are in place to deal with the post-contractual delivery of power, well in advance of the expiry of the PPA.
- ▶ **Emergency power mutualization:** Several countries in West Africa purchase power from offshore liquid fuel generation barges. Under the status quo, each country is supplied by its barge under a separate contract, even among countries that have some interconnection infrastructure. This creates inefficiencies, as demand for each country is often well below the capacity of the barge, which means that in aggregate the barges have significant unused capacity. Aggregating supply into a smaller number of barges, and transmitting this through interconnectors, could improve the capacity utilization of generation assets (potentially liberating some barges for use elsewhere), reduce costs for both offtaker and generator, and reduce emissions. These benefits could be further enhanced by replacing what are now multiple HFO barges with a larger liquefied natural gas (LNG) barge and associated storage and regasification infrastructure (many PPAs in West Africa allow fuel switching from HFO to gas at the offtaker’s request). More detailed feasibility analysis would be required to assess the benefits against potential investment needs in additional trade infrastructure.

Improved Management of Utility-Owned assets

If liquid fuel generation assets are owned by utilities (or otherwise owned by the state and not governed by PPAs or rental agreements), phasing down use of liquid fuels will usually entail switching fuels (where possible) or preparing these assets for retirement.

Converting a liquid fuel facility to an alternative fuel source. Fuel source conversion (most often natural gas, or in some cases, biomass) can be an attractive option as it allows continued use of



undepreciated generation assets. Compared to liquid fuel plants, natural gas plants are generally faster to start up and ramp, maintain their efficiency better even at variable loads, and are cleaner and—availability of gas inputs permitting—cheaper. Figure 3.3 shows manufacturer estimates on the impact of converting HFO engines to dual-fuel (DF; combination of gas and HFO) and single-fuel (SG) gas engines.

Figure 3.3: Illustration of the impact of technology and fuel type on levelized cost of energy

	HFO engine	DF engine (DF CONVERSION)	SG engine (SG CONVERSION)
FUEL COST €/ litre or m ³	0.4	0.6 / 0.05 (LFO / Gas)	0.05
LUBE OIL COST €/ litre	2.6	3.7	3.7
LCOE €/ MWh	103.8	20.4	17.4

Source: Wärtsilä (based on a project simulation of six W18V46 engines).

Key factors to consider in this process include:

- Availability of alternative fuel:** The availability of natural gas sources significantly impacts the feasibility of conversion. Floating Storage and Regasification Units (FSRUs) offer a practical solution for coastal countries looking to convert heavy fuel oil (HFO) power plants to cleaner natural gas but without easy access to domestic or imported natural gas. FSRUs can be deployed relatively quickly and serve as mobile LNG import terminals, storing LNG and regasifying it for immediate delivery to power plants. This flexibility allows countries to access international LNG supplies and transition to gas-powered electricity generation without the high upfront costs and long development timelines associated with onshore LNG infrastructure.
- Investment requirements for fuel conversion:** The conversion from oil to natural gas or biogas generally requires minimal investment, often involving only modifications or replacements of burners. In contrast, biomass conversion is more complex, typically necessitating significant changes to the plant's design and a higher capital investment.
- Fuel price differential:** The economic feasibility of conversion can be influenced by the price of the new fuel compared to the existing one. If the new fuel source is more expensive, it may negate the benefits of conversion. Long-term fuel supply agreements can help mitigate this ambiguity.
- Performance impacts due to conversion:** The overall efficiency and maximum power output of the plant can be affected by the conversion process. This is especially true for oil-to-biomass conversions, which may result in more significant output reductions compared to conversions to natural gas or biogas, although some decrease in output may also occur with those conversions.



BOX 3: FUEL CONVERSION IN GHANA

In Ghana, the Takoradi-Tema Interconnection Project (TTIP), completed in 2020, transports natural gas from western to eastern Ghana, where approximately 60 percent of the country's thermal power plants are located. This allowed these plants to switch to natural gas, resulting in a fuel cost reduction of approximately US\$ 90 million in 2020 compared to 2019. Additionally, the relocation of a power barge from Tema to Sekondi, along with its conversion from heavy fuel oil to natural gas, contributed to estimated savings of around US\$ 412 million during the Energy Sector Recovery Program⁴ period from 2019 to 2023 (ESRP 2023).

Planning for asset retirement. While retirement of utility-owned liquid fuel assets will not be feasible before sufficient alternatives have been developed, countries and utilities can nonetheless begin planning for future asset retirement in line with longer-term liquid fuel phase-down goals (World Bank 2023).⁵ Key considerations for asset retirement include:

- ▶ **Assessment of Stranded Assets:** The first step in assessing stranded liquid fuel assets involves compiling an inventory of all relevant assets, including storage facilities, pipelines, and refineries. It is crucial to determine the book value of these assets by evaluating historical costs and accumulated depreciation, and to estimate their current market value, which may have diminished due to decreased demand or regulatory changes. Analysis should include calculating impairment by comparing the carrying value of the assets to their recoverable amount.
- ▶ **Management Strategies:** Effective management of stranded assets centers on cost mitigation, value recovery, and strategic transition. Reducing operational and maintenance expenses minimizes financial losses, while exploring options to sell, lease, or repurpose assets—such as converting storage tanks for alternative uses—can recapture value. Financial restructuring might involve writing down asset values and seeking compensation through government support, insurance claims, or carbon credits. Additionally, transitioning investments toward renewable energy projects helps phase out liquid fuel dependencies. Throughout the process, transparent stakeholder engagement and strict adherence to legal and environmental regulations are essential.

3.3 SCALING UP ALTERNATIVES

Renewables, especially solar, will provide the least-cost source for most new required generation capacity in West African countries (see Section 2). Whatever the region's longer-term ambitions for interconnectivity, its countries need to rapidly scale up new renewables even to meet demand in a business-as-usual scenario. Given investment needs and the scarcity of public capital, most new renewable energy will have to be privately financed, but development capital has an important role to play in de-risking the sector and—for countries with especially limited access to affordable private capital—financing new renewables projects to help countries build track records and capacity. Table 3.2 summarizes some of the principal approaches available to West African countries, with the backing of development finance, to allocating public and private capital.

4 <https://mofep.gov.gh/sites/default/files/reports/economic/Energy-Sector-Recovery-Programme-Document.pdf>

5 For a much more thorough treatment of phasing down thermal generation assets see the World Bank's "Scaling Up to Phase Down" paper.



Table 3.2: Approaches to Scaling Up Renewable Energy (RE) in challenging environments

	Utility scale IPP	Renewable energy rentals	Public procurement
Approach	<ul style="list-style-type: none"> • Generation assets (solar, solar + storage, wind, etc.) owned by IPPs, selling power to utilities under long-term PPAs 	<ul style="list-style-type: none"> • Mobile and modular generation assets (typically containerized solar + storage) solutions selling power to utilities under short-term rental contracts 	<ul style="list-style-type: none"> • Publicly financed and owned generation assets, typically on utility's balance sheet
Rationale	<ul style="list-style-type: none"> • Spread cost of asset over time without need for new public/utility debt • Private-sector efficiency in deployment and operation • IPP may have better access to capital than offtaking utility 	<ul style="list-style-type: none"> • Alternative to IPP in countries with weak procurement or high offtaker risk • Modular nature of asset and short-term contract reduce private-sector risk • As with IPP, remains off public/utility balance sheet 	<ul style="list-style-type: none"> • In countries with large, acute supply deficits with no reasonable prospects of attracting financing in the short term, utility-owned RE may prove only realistic option to scale up liquid fuel alternatives in short term • Experience can build critical procurement capacity and implementation track record for governments/utilities
Implementation considerations	<ul style="list-style-type: none"> • Appropriate in situations where strong utility performance creates manageable utility offtaker risk • Can lock in high prices over longer term in environments with weak procurement capacity • Typically denominated in hard currency, introducing long-term FX risk 	<ul style="list-style-type: none"> • Capacity limited and generally short-term; should not replace HFO rental with solar+PV rental at the expense of long-term planning • Needs to be managed around existing HFO rentals to avoid duplication of costs 	<ul style="list-style-type: none"> • Public procurement option should serve as a bridge, not a replacement to private investment • Needs to include complementary sector reform & utility strengthening to build capacity and track record for future private investment
Considerations for World Bank Group (WBG) support	<ul style="list-style-type: none"> • Project finance for private rental modular generation asset (International Finance Corporation—IFC; WB IPF if minority public stake in project required or desired) • Strengthening utility & enabling environment for investment (PforR, DPF) • De-risking of payment obligations from offtakers to rental (Guarantees) 	<ul style="list-style-type: none"> • Corporate level financing for providers of rental PV assets (IFC) • De-risking of payment obligations from offtakers to rental (Guarantees) • Strengthening utility & enabling environment for investment (PforR, DPF) 	<ul style="list-style-type: none"> • Direct financing of public generation assets (IPF; IPF + PBCs for conditionality on prerequisite actions) • Technical assistance for country procurement capacity & frameworks, utility performance, regulatory environment (IPF)



	Utility scale IPP	Renewable energy rentals	Public procurement
WBG examples	<ul style="list-style-type: none"> MPAs in Kenya & Zambia combining utility performance (PforR), system strengthening (IPF) & derisking new RE (Guarantees) 	<ul style="list-style-type: none"> IFC financing of SCATEC Release in various African countries 	<ul style="list-style-type: none"> WB RESPITE project – public financing for emergency solar in West Africa, aggregating procurement to achieve lower cost

Note: IPF = Investment Project Financing; PBC = Performance-Based Conditions; DPF = Development Policy Financing; PforR = Program-For-Results Financing.

Distributed Generation

Beyond utility-scale solutions, distributed energy resources (DERs) offer a significant opportunity to reduce use of liquid fuels by meeting growing power demand in West Africa through localized renewable generation. The importance of off-grid solar home systems for meeting national energy access targets is well documented and understood, but industrial scale pay-as-you-go schemes such as solar leasing offer large consumers the opportunity to immediately shift some of their consumption to lower-cost renewables without the need for high upfront capital investment. For instance, in May 2024, the West Africa Container Terminal (WACT) in Nigeria entered into a 15-year Solar Lease Agreement with Starsight Energy. This partnership aims to supply approximately 1.2 gigawatt-hours of solar electricity annually, transitioning 30 percent of the terminal's energy consumption from diesel generators to solar power (WACT 2024).⁶ WBG instruments such as MIGA political risk insurance (PRI) or breach of contract coverage could help de-risk solar leasing contracts.

⁶ <https://www.apmterminals.com/en/news/news-releases/2024/240510-west-africa-container-terminal-wact-replaces-diesel-generation-with-solar-electricity>



Annex: Summary of Country Deep Dives

Preparation of this paper was accompanied and informed by deep dives in three West African countries: Sierra Leone, Mauritania, and Senegal. These countries were selected because they each represent different facets of West Africa’s energy challenges, but are all impacted by significant shares of liquid fuels.

Table A.1: Main Deep Dive Findings

	Sierra Leone	Mauritania	Senegal
Characteristics	<ul style="list-style-type: none"> • Small power system, FCV. • Low access rate: 36%. • Total generation equals 80MW in wet season and 75 MW in dry season where 65MW in dry season and 20MW in wet season is generated from liquid fuel. 	<ul style="list-style-type: none"> • Medium power system. • Liquid fuel dependency: 62% • Significant natural resource endowment. 	<ul style="list-style-type: none"> • Large power system. • 79% of power generation from fossil fuels (2021). • Recent discovery of large offshore oil and gas reserves.
Challenges	<ul style="list-style-type: none"> • Lack of reliable, affordable, and sustainable generation assets with high dependence on heavy fuel oil. • Limited operational capacity of the country’s Electricity Distribution and Supply Authority (EDSA) due to tariffs below cost-reflective level, and high technical and commercial losses leading to high arrears and sector losses. • Mainly based on unreliable hydro generation due to high seasonality, followed by unreliable diesel-fired generation. 	<ul style="list-style-type: none"> • Facing an imminent energy crisis with an energy deficit of 50MW at peak times that could rise to 100MW. • Utility is not financially viable due to (i) technical losses; (ii) billing inefficiencies; and (iii) high supply cost, mainly due to dependence on volatile liquid fuels. • Significant RE investments but insufficient transmission capacity. 	<ul style="list-style-type: none"> • Not financially viable utility—tariffs below cost-reflective level due to high cost of supply, accumulated arrears. • Uncertain timing of domestic natural gas supply (could be as early as 2025 or not until 2030). • Weak power grid.



	Sierra Leone	Mauritania	Senegal
Regional Integration (Modeling Scenarios)	<ul style="list-style-type: none"> In 2022, the primary source of generation was hydro, followed by liquid fuel. Total generation was equal to 0.5 TWh at a total system cost of US\$ 8 million. Under business-as-usual (BAU) scenario, by 2030 Sierra Leone is expected to replace most liquid fuel with LNG—but not all. The country would still need to generate 0.48 TWh of energy while total system cost remains unchanged. Under the full-trade scenario, Sierra Leone could phase out liquid fuel completely. Less energy (0.28TWh) would need to be generated domestically and from cleaner sources like hydro and solar by 2030. A lower total system cost of US\$ 5 million is expected, which implies US\$ 3 million of saving. 	<ul style="list-style-type: none"> In 2022, Mauritania relied heavily on liquid fuels; crucially, it did not generate enough energy to meet demand (currently 0.53 TWh generated vs. 1 TWh demand). The total system cost was US\$ 192 million. By 2030, under either BAU or full-trade scenario, liquid fuel will be phased out. Under BAU, total 2.72 TWh of energy is expected to be generated from a mix of gas (as baseload), hydro, solar and wind in 2030. The expected annual system cost is about US\$ 240 million. Under the full-trade scenario, total 2.96 TWh energy is expected to be generated from gas (as baseload) with remaining demand through hydro, wind and solar in 2030 at a total cost of US\$ 222 million. 	<ul style="list-style-type: none"> In 2022, Senegal relied heavily on liquid fuels to generate energy, where 4.6 TWh out of 6.87 TWh total energy generated was from liquid fuels. The annual system cost was about US\$ 607 million. Senegal is expected to generate 10.27 TWh in 2030 under the BAU scenario where the increase in energy would come from hydro, gas, and LNG, while energy generated from liquid fuel would fall from 4.6 TWh to 1.0 TWh. The system cost is expected to mount to US\$ 921 million. Under the full-trade scenario, Senegal would be able to reduce energy generated from liquid fuels from 4.6 TWh to 0.7TWh, while generating total energy of 11.96 TWh mainly from gas, LNG, and hydro, at a total system cost of US\$ 875 million.
Complementary near-term actions	<ul style="list-style-type: none"> Urgent need for investment in nonthermal grid assets and upgrading of transmission network as well as interconnectors. Settlement of arrears with existing HFO power plants by renegotiating PPA contracts. 	<ul style="list-style-type: none"> Investments to strengthen the transmission network that will allow increased variable renewable energy (VRE) integration. Blended energy contract model PPA, which allows replacement of thermal generation capacities with renewable alternatives over time by a joint procurement of solar PV, battery energy storage system (BESS), and thermal generation, 	<ul style="list-style-type: none"> A comprehensive assessment of options on development of the optimum infrastructure for gas and electricity transport to allow transition from liquid fuel to natural gas. A balancing service assessment to identify investments to enhance grid flexibility. Continued investments in renewables (REs) and green imports (such as hydro) in parallel to gas



	Sierra Leone	Mauritania	Senegal
		<p>and allocation of responsibility of firm energy capacity to seller.</p> <ul style="list-style-type: none"> • Improvement in SOMELEC’s operational performance: reduction in technical losses and improve billing efficiency as well as collections. 	<p>development to prepare for full RE transition in the long-term.</p> <ul style="list-style-type: none"> • Improvement of financial viability of SENELEC to be a credible offtaker—this may require restructuring of its debt and guarantees for new RE PPAs and renegotiation of the existing oil PPAs.



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