Update of the ECOWAS revised master plan for the development of power generation and transmission of electrical energy

Final Report

Volume 4: Generation and Transmission Master Plan

December 2018

Financing

European Union
11th EDF Regional Indicative Programme
Financing agreement EDF/2017/ 039-384

TRACTEBEL ENGINEERING S.A.
Boulevard Simón Bolívar 34-36
1000 - Brussels - BELGIUM
tel. +32 2 773 99 11 - fax +32 2 773 99 00
engineering@tractebel.engie.com
tractebel-engie.com

TECHNICAL DOCUMENT

Our ref.: **WAPP-MP/4NT/0626321/003/03**
TS:
Imputation: P.011966/0004

INTERNAL

Client:

Project: **ECOWAS MASTER PLAN FOR THE DEVELOPMENT OF REGIONAL POWER GENERATION AND TRANSMISSION INFRASTRUCTURE 2019-2033**

Subject: VOLUME 4: Generation and Transmission Master Plan

Comments:

REV.	YY/MM/DD	STAT.	WRITTEN	VERIFIED	APPROVED	VALIDATED
03	2019 01 15	FIN	*F. Sparavier	*L. Charlier	*J. Dubois	
02	2018 10 31	FIN	*F. Sparavier	*L. Charlier	*J. Dubois	
01	2018 10 05	FIN	*F. Sparavier	*L. Charlier	*J. Dubois	

*This document is fully completely signed on 2019.01.15

TABLE OF CONTENT

Final version

Final version

TABLE OF FIGURES

Final version

Final version

Final version

TABLE OF TABLES

Final version

ACRONYMS

ADB	*Asian Development Bank*
AFD	*Agence française de développement*
BIO	*Biomass Plant*
CAPEX	*Capital Expenditure*
CAPP	*Central Africa Power Pool*
CC	*Combined Cycle*
CEB	*Communauté Electrique du Bénin*
CEET	*Compagnie Energie Electrique du Togo*
CFB	*Circulating Fluidized Bed*
CIE	*Compagnie Ivoirienne d'Electricité*
CI-ENERGIES	*Côte d'Ivoire Energies*
CLSG	*Côte d'Ivoire – Liberia – Sierra Leone – Guinea loop*
COAL	*Coal*
COD	*Commercial operation Date*
CSP	*Concentrated Solar Plant*
CUE	*Cost of Unserved Energy*
DAM	*with Dam*
(D)DO	*Ordinary Diesel*
DFI	*Development finance institutions*
DI	*Diesel group*
DNI	*Direct Normal Irradiation*
DSO	*Société de distribution d'électricité (Distribution System Operator)*
EAGB	*Electricidade e Aguas da Guine-Bissau*
ECOWAS	*Economic Community of West African States*
EDG	*Electricité de Guinea*
EDM	*Electricité du Mali*
EDSA	*Electricity Distribution Supply Authority*

Final version

(E)ENS	*(Expected) Energy Not Served*
EGTC	*Electricity Generation and Transmission Company*
EIB	*European Investment Bank*
ERERA	*Ecowas Regional Electricity Regulatory Authority*
EU	*European Union*
EUR (or €)	*Euro*
FCFA	*Francs CFA*
FSRU	*Floating Storage and Regasification Unit*
GDP	*Gross Domestic Product*
GENCO	*GENenration COrporation*
GHI	*Global Horizontal Irradiation*
GO	*Gasoil*
GRIDCo	*Electricity Transmission Company of Ghana*
GT	*Gas Turbine*
GWh	*Giga Watt heure*
HFO	*Heavy fuel oil*
HRSG	*Heat Recovery Steam Generator*
HYD	*Hydroelectric plant*
ICC	*Information and Coordination Center*
IEA	*International Energy Agency*
IFI	*International Funding Institution*
IMF	*International Monetary Fund*
IPP	*Independent Power Producer*
IPT	*Independant Power Transporter*
IRENA	*International Renewable Energy Agency*
JET	*Jet A1*
LCO	*Light Crude Oil*
LCOE	*Levelized Cost of Electricity*
LEC	*Liberia Electricity Corporation*
LFO	*Light Fuel Oil*

LHV	*Low Heating Value*
LNG	*Liquefied Natural Gas*
LOLE	*Loss of Load Expectation*
LOLP	*Loss of Load Probability*
MMBTU	*Million British Thermal Unit*
MMCFD	*Million Cubic Feet per Day*
MRU	*Union de la Rivière Mano (Mano river Union)*
N/A	*Not Available*
NAWEC	*National Water and Electricity Company*
NBA	*Niger Basin Authority*
NDC	*National Determined Contribution*
NG	*Natural Gas*
NIGELEC	*Société nigérienne d'électricité*
NTP	*Notice to proceed*
O&M	*Operation & Maintenance*
OC	*Open Cycle*
OECD	*Organisation for Economic Co-operation and Development*
OLTC	*On Load Tap Changer*
OMVG	*Organisation de Mise en Valeur du fleuve Gambie*
OMVS	*Organisation de Mise en Valeur du fleuve Sénégal*
ONEE	*Office National de l'Electricité et l'Eau Potable (Morocco)*
OPEX	*Operating Expenditure*
PC	*Pulverized Coal*
PPA	*Power Purchase Agreement*
PPP	*Private Public Partnership*
PSS	*Power System Stabilizer*
pu	*per unit*
PV	*Photovoltaic plant*
RES	*Renewable Energy Sources*
ROR	*Run of river*

Final version

SAIDI	*System Average Interruption Duration Index : Indicateur de la durée moyenne de coupures sur le système*
SAIFI	*System Average Interruption Frequency Index : Indicateur de la fréquence moyenne de coupures sur le système*
SBEE	*Société Béninoise d'Energie Electrique*
SENELEC	*Société nationale d'électricité du Sénégal*
SOGEM	*Société de Gestion de l'Energie de Manantali*
SONABEL	*Société nationale d'électricité du Burkina*
ST	*Steam Turbine*
SV (or VS)	*Standard Value*
SVC	*Static Var Compensation*
TCN	*Transmission Company of Nigeria*
TSO	*Transmission System Operator*
USD (or US$ or $)	*US Dollar*
VRA	*Volta River Authority*
WAGP(A)	*Western Africa Gas Pipeline (Association)*
WAPP	*West Africa Power Pool*
WT	*Wind Farm*

Final version

1. INTRODUCTION

1.1. Context

The Economic Community of West African States (ECOWAS) is a regional community with a surface of 5.1 million of square km which represents about 17% of the African continent. With a population of more than 300 million inhabitants in 2017, ECOWAS Member States are home to about one-third of the population of sub-Saharan Africa.

ECOWAS has been created with a mandate of promoting economic integration in all fields of activity of the constituting countries. The fifteen-member countries making up ECOWAS are Benin, Burkina Faso, Cape Verde, Cote d'Ivoire, The Gambia, Ghana, Guinea, Guinea Bissau, Liberia, Mali, Niger, Nigeria, Sierra Leone, Senegal and Togo. The ECOWAS treaty (also known as treaty of Lagos) established the Community during its signature in Lagos (Nigeria) on May 28th, 1975.

One of the most important steps of economic integration in the field of energy was the creation, in 2006 of the Western African Power Pool (WAPP). The WAPP promotes the integration of the national power systems of the fourteen inland countries into a unified regional electricity market with the ultimate goal of providing, in the medium and long-term, a regular and reliable energy at competitive cost to the citizenry of the ECOWAS region

However, the region, which is characterized by a great diversity in terms of culture, language, demography and resources, faces enormous challenges in providing access to sustainable energy for its population. But the 15 ECOWAS Member States are driven by a common desire to offer "affordable, reliable, sustainable and modern energy for all", as per the three main goals of the Sustainable Energy for All (SE4All) initiative, launched by the United Nations Secretary-General.

West-African countries have a great opportunity to reach their objectives thanks to the vast untapped potential in renewable energy (including solar, wind, bioenergy and hydro-power). The Energy Transformation will happen both on-grid and off-grid. It involves the development of mini-grids with hybrid power generation, centralized and decentralized renewable projects potentially coupled with a more flexible demand side, enabled by storage and smart-metering technologies.

Several initiatives like the *African Renewable Energy Initiative* and the *ECOWAS policy on Renewable Energy* support this transformation. However, such a revolution requires financing, leadership and international cooperation. In this context the West African Power Pool is playing a significant role by supporting the development of major energy projects in the region.

Final version

1.2. Objectives of the project

The West African Power Pool promotes cooperation and supports the development of regional projects. In 2012, the Authority of the ECOWAS Heads of State and Government approved, through Supplementary Act A/SA.12/02/12, a list of 59 Priority Projects for the subregion that emanated from the update of the ECOWAS Revised Master Plan for the Generation and Transmission of Electrical Energy prepared by Tractebel. .

Considering the evolution of the energy landscape,the socio-economic context of West Africa over the last 5 years and the difficulty in mobilizing public and concessional financing in the sub-region, the development of the power system in West Africa deviated from what was foreseen in 2011. A lot of challenges affect the utilities efficiency on several aspects including financial, regulatory, technical and organizational points of view.

Another key parameter which should affect the energy development roadmap of WAPP region is the expected increase penetration of Renewable Energy Sources (RES). Thanks to the significant decrease of costs and increased willingness for the transition to sustainable energy, many WAPP countries have revised their RES targets and launched RES projects.

Consequently, while some flagship generation and transmission projects were developed in the region, some of them are still under development or were strongly delayed while, in parallel new non-anticipated projects emerged.

In this context, the study presents four different main objectives:

- Assessing the **implementation status** of the priority projects identified in 2011, understanding the main challenges and barriers to the development of these projects and identifying the lessons learned that will be taken into account when updating the Master Plan;
- Identifying the **main challenges and critical factors** affecting the performance of utilities in their activities as a public service and proposing a new action plan and mitigation measures to address these constraints in a long-term perspective;
- Assessing the opportunities and constraints for the deployment of **Renewable Energy Sources** in the sub-regional power system (potential, economics, grid constraints…);
- Presenting a clear, comprehensive and coherent view of the future development of power generation and transmission facilities with a list of **priority projects** for West Africa that takes into account the new drivers of electricity generation and consumption, while integrating the current development of the power system at national and regional level and while providing recommendations for facilitating the implementation of the projects.

This will lead to an **update of the ECOWAS Master Plan for Generation and Transmission of Electrical Energy**, a comprehensive study providing a rational basis for decision making and implementation in the power sector.

1.3. Organisation of the report for the update of the ECOWAS revised master plan for the development of power generation and transmission of electrical energy

The report is divided into five main volumes corresponding to the five main deliverables of the study.

VOLUME 1: Executive Summary

Volume 1 is the synthesis of the Final Report of the update of the revised ECOWAS Master Plan. It contains the main recommendations of the study concerning the future development of the electricity generation and transmission infrastructures as well as a list of priority projects and the implementation strategy of these projects.

VOLUME 2: State of play of the current situation of the electricity system and perspectives

Volume 2 consists of a synthesis of data collected and assumptions used in the context of this project, and in particular for the update of the generation and transmission master plan.

VOLUME 3: Challenges and Action Plans for electricity Companies

Volume 3 aims at presenting the main challenges and critical factors affecting the performance and the sustainability of utilities members of WAPP and at recommending a new action plan and mitigation measures to address these critical factors from a transversal perspective...

VOLUME 4: Generation and Transmission Master Plan

Volume 4 is devoted to the results of the generation and transmission master plan: It presents a robust and economically optimal development plan while taking into account the current state of the energy sector in West Africa and opportunities for developing renewable energy sources in the region while ensuring the technical stability of the interconnected system

VOLUME 5: Priority Investment Program and Implementation Strategy

Volume 5 focuses first on carrying out a review of the implementation of the ECOWAS 2012-2025 Master Plan and assessing the causes of the gaps between what was initially planned and what was concretely achieved, allowing some effects to be taken into consideration for the development of the 2017-2033 updated master plan. Then, a new list of priority investment projects is drawn up on the basis of the generation-transmission master plan and a strategy is recommended for the progressive implementation of these projects.

Final version

1.4. Objectives of Volume 4

This volume is dedicated to the results of the development phase of the electricity sector and aims to present the optimal generation and transmission master plan for West Africa.

The objective of this master plan is to find the combined optimum between the development of generation facilities on a regional scale and the development of the intra-regional transmission system to allow the supply of electricity reliably and at a lower cost. This optimization shall take into account from a technological point of view the classification of renewable and hydroelectric resources, the optimum thermal technologies for the region and appropriate interconnection standards. It shall rely on the existing regional, sub-regional and national generation master plans. It shall also take into account the emergency plans identified at the regional level or at the level of each country. This generation master plan has also been accurately verified by evaluating the static and dynamic performance of the overall system (generation and transmission) to ensure optimal operation of the interconnected system.

Note that the master plan focuses on the West African system. Nevertheless, for the sake of completeness, the impact of a WAPP connection with other power pools is also mentioned in this report:

- From the technical and economic point of view for a potential interconnection with Morocco via Mauritania;
- From the economic point of view for a potential interconnection with the Central African Power Pool.

Final version

2. GENERATION MASTER PLAN

2.1. Introduction

The generation master plan corresponds to the optimal investment plan in the different units of generation on the short, medium and long term.

This master plan is derived from a complex optimization, the aim of which is to determine the optimal investments to be achieved in order to obtain the system with the lowest discounted costs.

At the level of generation, the optimization focuses solely on the selection of the candidate units, which are currently under study, or standard units proposed by the consultant. Existing and decided units are indeed part of the master plan in a mandatory manner.

Regarding the presentation of the results of the master plan done in this report, the approach chosen here is to highlight the major trends that emerge in the short term (2018-2022), the medium term (2022-2029) and the long term (beyond 2030). The aim of this approach is to allow the readers of this report to be able to have a direct overview of the optimum evolution of the region's generation capacity.

The master plan presented below focuses on the reference scenario, in which no interconnection with other non-ECOWAS countries is considered. Then, the impacts of possible interconnections with Morocco or PEAC are analyzed in dedicated sections further in the report.

2.2. Methodology

The establishment of a generation-transport master plan is based on the development of a mathematical model representing the region's energy system in an adapted software.

The software used in this study is PRELE. The latter, developed by Tractebel, is dedicated to long-term system planning and therefore aims to determine the investments and operating conditions of the system in such a way as to minimize the overall cost of the system.

2.2.1. Power system modeling

The West African power grid was thus modelled in PRELE, in the form of various electrical nodes connected to each other by means of transport lines.

2.2.1.1. ELECTRIC NODE

Each electrical node represents a geographical area which comprises the electrical load as well as the generation available. The appropriate choice of the number of electrical nodes results from a compromise between the increasing complexity with the number of nodes and the level of detail required.

For example, some member states whose network size is relatively small are represented in the form of a single node: This is the case of The Gambia, Guinea-Bissau, Liberia, and Sierra Leone.

Other member states with larger networks were modelled using several nodes. In particular, two nodes were used to represent Benin (north and south), Burkina Faso (Ouagadougou and Bobo-Dioulasso), Côte d'Ivoire (north and south), Ghana (north and south), Guinea (north and southeast), Mali (Bamako and Sikasso), Niger (Niamey and north), Senegal (Dakar and Tambacounda) and Togo (North and south). Nigeria is separated into three different nodes (south, north and east).

Figure 1: Electrical nodes selected for the generation master plan

For each of these nodes, the evolution of the load as well as of the generation are filled in the model.

2.2.1.2. DEMAND MODELING

The demand is modelled in PRELE using a typical daily load curve for each member state, whose peak load evolves on the horizon considered according to the forecast of the demand made in the data collection report.

When a member state is made up of more than one node, a pro-rata[1] was made on the total demand to spread it on these different nodes.

[1] Made on the basis of the demand for the different geographic areas

2.2.1.3. MODELING OF GENERATION UNITS

The generation units are, for their part, distributed within the different nodes of the PRELE model, taking up their main characteristics, namely:

- Available power
- Technology
- Fuel consumption
- Downtime for maintenance
- Downtime due to accidental failure
- Investment costs
- Operational costs
- Date of commissioning
- ...

At this level, the existing units, which are part of the system as of the starting year, should be distinguished from the project units that can be integrated into the system in future years. As a reminder, the generation units in the project were themselves classified during the data collection phase in projects decided or candidates according to the following criteria:

- **Decided units**: units whose construction is underway or has been decided for a specific date of commissioning (completed studies and insured financing)
- **Candidate units**: units for which the studies are not yet completed or for which funding has not yet been found

The decided units must be incorporated into the investment plan, taking into account their date of commissioning. The candidate units, for their part, can be selected by PRELE to enlarge the existing generation capacity, if it makes sense economically, from a given date of commissioning.

It should still be mentioned that PRELE may also decide to invest in **standard generation units**, which are not part of the lists of projects collected from Member States, but which may reveal interesting on the techno-economic level.

2.2.1.4. RENEWABLE ENERGY GENERATION

The renewable energy generation units considered in the study are:

- **Hydroelectric power plants**
- **Solar photovoltaic power plants**
- **Wind turbines**

For each of these technologies, a generation curve is considered in the optimization according to:

- Site and project characteristics in the case of hydroelectric power plants;
- The geographical location for photovoltaic solar power plants and wind turbines. In particular, the following curves are taken in consideration:
  - Solar curves representing the evolution of solar irradiation during the 24 hours of the day in the different geographical areas of the study
  - Wind curves representing wind speed during the 24 hours of the day in the different geographical areas of the study

Final version

2.2.1.5. TRANSMISSION LINE

The different electrical nodes are connected by transmission lines. Again, the same approach is used for the lines **existing, decided and candidate**. PRELE can therefore decide to invest in a candidate transmission line if this investment lowers the total cost of the system.

These lines are inserted into the model by mentioning their main characteristics:

- Transfer capacity
- Length
- Losses (per unit)
- Investment costs
- Voltage
- Date of commissioning

2.2.2. Gas network modeling

In parallel with the electric model, PRELE allows the integration of a gas network, in order to realistically model the generation of gas units.

Similarly to the power grid, the gas network is based on the existence of nodes that may be connected by pipelines.

Under this master plan, the following gas network was considered:

- **Gas nodes:**
  - The following countries were considered to be **gas producers,** given their existing gas resources :
    - Nigeria
    - Ghana
    - Côte d'Ivoire
    - Senegal
  - Beyond 2025, it becomes possible to invest in **LNG-type gas projects** ("Liquefied natural gas") in the following countries:
    - Ghana
    - Côte d'Ivoire
    - Senegal
    - Benin
    - Togo
  - Finally, the **consumer gas nodes** cover the following countries:
    - Nigeria
    - Ghana
    - Côte d'Ivoire
    - Senegal
    - Benin
    - Togo
    - **Pipeline** : The only pipeline that was considered in the study is the WAGP (West African Gas pipeline) from Nigeria and linking Benin, Togo and Ghana.

Final version

The resources associated with each node and pipeline are those mentioned in the volume 2 of this document.

2.2.3. Optimization

The PRELE model described earlier forms a linear program under constraints whose objective function is to minimize the current total cost of investments and operations.

The main results of the optimization are, for each year of the planning period:

- The installed power of the generation units to be installed at each node with their investment costs;
- The transfer capacities of the different transmission lines to be installed between the different nodes with their investment costs;
- The energy produced by each generation unit with their generation costs;
- The power provided by each unit at the different hours of the day and the power transmitted each hour on the different lines;
- The depletion of gas resources at each node and the associated cost of gas consumption
- The quantities of gas passing through the pipeline

These results serve as a basis for the development of the generation-transmission master plan that is proposed in this document.

2.2.4. Investment and Operational constraints

Some additional constraints have been introduced in the optimization regarding the investment opportunities in different types of generation units, in order to make the investment programme more realistic.

2.2.4.1. CONSTRAINTS INVESTMENTS FOR COMBINED CYCLES IN NIGERIA

It was also decided to impose in Nigeria an annual investment constraint in the combined cycle units of up to 1000 MW per year[2], this limit rising to 1500 MW per year from 2030. The goal of this constraint is to limit the investments in this standard technology in order to have a realistic investment plan.

2.2.4.2. CONSTRAINTS PROJECT CANDIDATE COAL

With regard to coal projects, the reference scenario of the generation master plan which is presented below considered only the decided coal projects, leaving aside the investment opportunities in the candidate units.

This choice was made in order to take into account the reluctance of the various funding partners against this technology, given the negative impact of the latter on the environment.

Final version

[2] This limit being taken from the last master plan of Nigeria

2.2.4.3. TECHNICAL MINIMA

Technical minima were also considered in the optimization for the following units:

- Hydroelectric power plants: minimum 30% for irrigation reasons
- Combined cycles: minimum 40% for technical reasons
- Coal units: minimum 40% for technical reasons

2.3. Optimum short-term investment plan 2018-2022

2.3.1. The implementation of the decided projects to meet the growing demand

This first period of the master plan is naturally dominated by the commissioning of **decided projects**. These account for a total of **8 386 MW** of installed power whose distribution by technology is shown in the figure below. Natural gas installations represent the bulk of these decided investments (53%, i.e. 4 455 MW). The availability of gas will therefore be a major issue for the next five years and will have to be ensured to guarantee the viability of this master plan.

Most of these decided gas units are developped in Nigeria (Azura 450 MW, Okpai II 300 MW and AFAM III 240 MW) and in Ghana and Côte d'Ivoire (Cenpower 360 MW, Rotan 330 MW, Amandi 240 MW in Ghana; Ciprel V 412 MW and Azito 253 MW in Côte d'Ivoire).

Many hydroelectric power plants are also planned in the short-term, particularly in Guinea (Souapiti 450 MW, Fomi 90 MW, Kogbedou 58 MW and Frankonedou 22 MW), but also in Mali (Gouina 140 MW), Niger (Kandadji 130 MW), The Senegal (Sambangalou 128 MW), Côte d'Ivoire (Gribo-Popoli 112 MW, Singrobo 44 MW) and Nigeria (Zungeru 700 MW, Kashimbilla 40 MW).

At the level of the photovoltaic technology, most of the projects decided are developed in Niger (210 MW), then in Burkina Faso (105 MW), in Ghana (102 MW), in Côte d'Ivoire (100 MW) and Mali (50 MW).

Final version

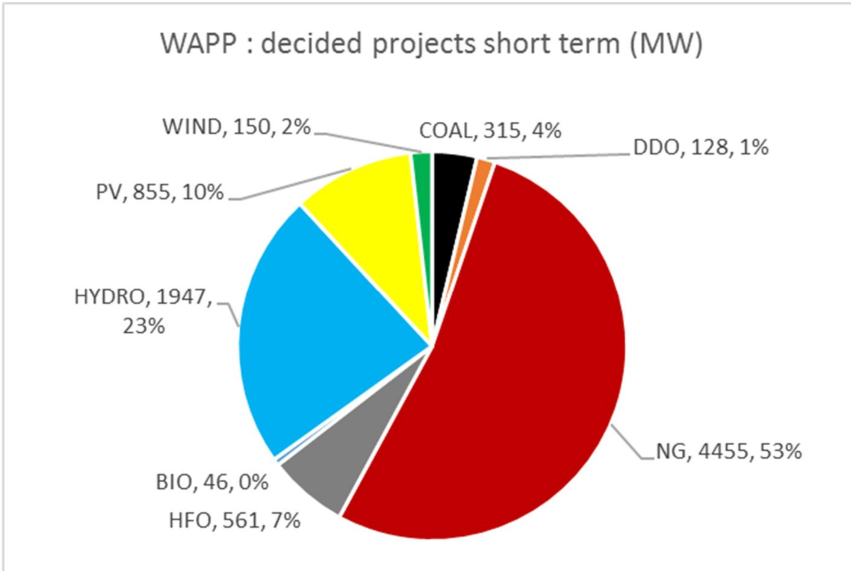


Figure 2: Distribution of the decided projects by technology at horizon 2022 (MW)

In addition to these projects, 1633 MW of new thermal and hydro units are necessary to meet the demand. Therefore, the most important candidate projects that emerge from short-term optimization are the combined cycle of Egbin 2+ (first phase of 1200 MW) in Nigeria, as well as the hydroelectric power unit of Boutoubre (156 MW) in Côte d'Ivoire.

Alongside those investments, the consultant has identified potential PV solar projects up to 2602 MW that could be developed on this short term period, in order to reduce the energy costs in the), given the important decline of prices for this technology on the horizon considered[3].

The volume of potential projects depends on the solar potential of the region but also on the limits of investment and exploitation, which are proportional to the demand.

Final version

[3] It should be noted that the decline in wind prices is not yet significant enough to invest in this technology in the short term.

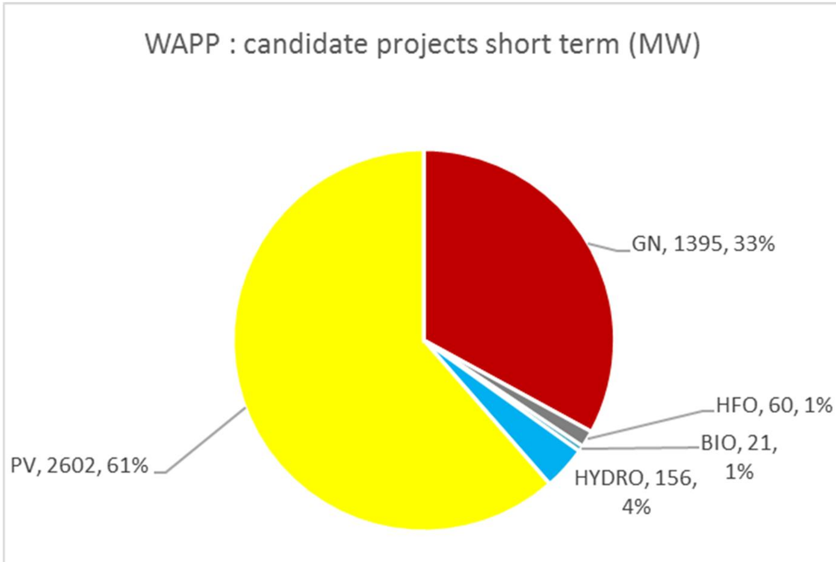


Figure 3: Distribution of selected candidates projects by technology, at horizon 2022 (MW), including the solar projects identified

Finally, the optimum energy mix which results from the optimization is represented on the Figure 4: Energy Mix WAPP, by technology, at horizon 2022 (MW) below. We observe that PV technology represents 4% of the annual energy generation, given the intermittent nature of the resource. It appears also very clearly that natural gas continues to play a major role in the energy supply of the sub-region.

The detailed list of the invested projects by State-Member can be found in appendix A.

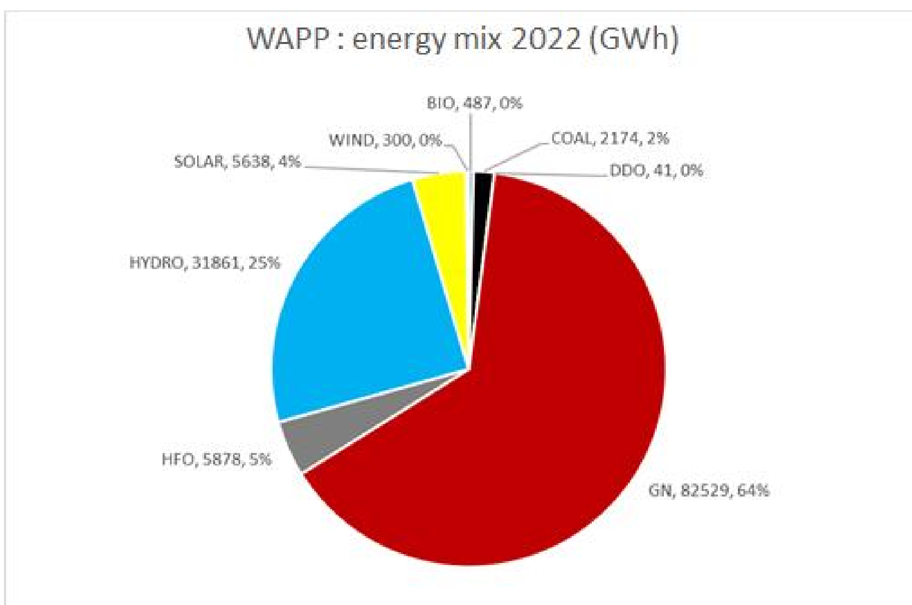


Figure 4: Energy Mix WAPP, by technology, at horizon 2022 (MW)

Final version

2.3.2. Towards a progressive deployment of renewable energies

As it was already mentionned above, it is recommended to increase the share of renewable in the generation master plan for the region on the short-term horizon.

Therefore, the hydroelectric plants should play a more and more important role in the conventional energy mix of the subregion. Moreover, an important volume of potential photovoltaïc plants were identified, such that this technology should already occupy a significative place in the generation capacity of the region, in complement with conventional thermal and hydroelectric decided units.

Wind energy and biomass should remain marginal on the short-term, given the cost structure and the limited potential in the region.

2.3.2.1. DEVELOPMENT OF HYDROELECTRIC POWER PLANTS

This short-term horizon is characterized by the commissioning of many hydroelectric generation units totalling 2103 MW. Of these, most are decided units (1947 MW) and only Boutoubre (156 MW) is chosen from the candidate projects by the optimization.

However, most hydro projects will be commissioned on the medium term, as detailed below. This is explained by the duration of construction of this kind of large-scale projects that are often of the order of 4 years, exceeding the short-term horizon as defined in this study.

2.3.2.2. DEVELOPMENT OF PHOTOVOLTAIC SOLAR POWER PLANTS

The penetration of photovoltaic solar power plants into the region is due to several factors.

The first is attributable to the rising costs associated with thermal power plants, particularly in view of the expected increases in the price of the various fuel oils used (see Volume 2).

The second is related to the saturation of hydro projects that amount to 2100 MW on the short-term horizon.

The third factor is the significant fall in prices expected for solar photovoltaic technology, as is recalled at the figure below. Indeed, while the average cost of a solar project at the beginning of the study is 1500 USD/kW, this falls to only 1000 USD/kW in 2022, a reduction of 33% in 5 years.

Nevertheless, despite this significant fall in prices, the development of this technology on a large scale is generally justified only in the north of the region on the short-term, given that the conditions of irradiation in the south are not enough to make significant investments on the horizon up to 2022.

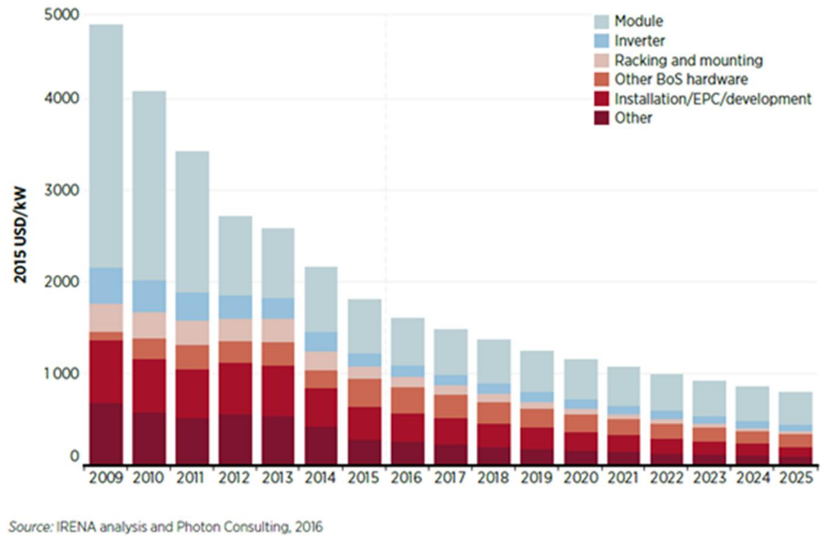


Figure 5: Expected Evolution of investment costs for solar photovoltaic projects. Source: IRENA

Of the 3 457 MW of proposed solar projects, 855 MW are decided, 1352 MW are candidate projects already identified by the state members and chosen by the optimization, and 1250 MW are potential additional standard projects. The list of these potential standard projects should vary from 50 to 250 MW, depending on the location of the project, the local demand, the capacity to export the power and the availability of land.

Final version

2.3.2.3. MARGINAL DEVELOPMENT OF WIND ENERGY

In addition to the decided projects (150 MW in Senegal), the economic analysis does not recommend the development of wind turbine project as a short-term priority. Indeed, given the relatively low wind potential of the subregion and the cost of technology, the other alternatives of solar energy and hydropower appear more interesting from an economic point of view.

Regarding the costs, wind turbines are recognized as a mature technology and trends in cost reduction are less important than those observed for photovoltaic. Nevertheless, scale effects will allow a gradual reduction of the cost for wind turbines, which, combined with the saturation of other resources, could pave the way for this technology in the longer term.

2.3.2.4. INVESTMENTS IN LINE WITH THE TARGETS SET FOR RENEWABLE ENERGY

The energy mix 2022 of the region shows that the renewable generation can potentially reach up to 29% (25% from hydro and 4% from solar), which is slightly below the ECOWAS 2020 objective (35% renewable generation including large hydro). This slight delay is due to the backlog in recent years in the implementation of the projects. This delay should be gradually absorbed, in particular through the acquired experience of member states in monitoring such projects.

2.3.3. The availability of natural gas, a challenge for the next five years

As already noted above, investments in gas plants represent the most important part of the investments with 5 780 MW to be installed by 2022 in the whole region, i.e. 46% of the total investment considered.

With these new investments, the share of technologies using the natural gas in the energy mix rises to 64% in 2022. It appears hence clearly that gas availability will play a crucial role in ensuring the viability of the management plan presented in this report.

Lower risk approach to meet gas demand

Given the importance of the gas resource for the reliable supply of electricity in West africa, the impact of the unavailability of this resource on the results of the master plan and the variability in the cost of gas was investigated.

With regard to the **availability of the resource**, the dependence of the subregion on a single source of supply creates a major risk for countries.

The majority of these needs are obviously concentrated in Nigeria, accounting for 77% of the region's gas consumption on average on the study horizon.

Final version

In addition to Nigeria accounting for 77% of the region's gas consumption on average on the study horizon, the countries for which gas availability is also crucial are Ghana, Côte d'Ivoire and Senegal. Ghana and Côte d'ivoire are characterised by indigenous reserves that are decreasing over time. These countries will therefore have to guarantee the security of supply via other gas sources, whether LNG units or WAGP. The exploitation of gas resources in Senegal is planned to start in 2025 and gas requirements are expected to grow up to 183 Mmscfd on the horizon 2033.

In Benin, the development of combined-cycle gas power plant projects, including the 450 MW regional WAPP project, also calls for the development of gas supply infrastructures. The proposal made in this master plan is to enhance the reliability of the WAGP, providing for gas supply opportunities not only from Nigeria but also from Ghana. Togo could also benefit from such a development of the gas network.

In conclusion, it is advisable to diversify the sources of supply: indigenous sources in Nigeria, Ghana, Côte d'ivoire and, in the medium term, in Senegal, to which are added gas sources imported via LNG terminals recommended in Côte d'Ivoire and Ghana, or via the WAGP.

Finally, from the point of view of the **cost of gas**, the analyses conducted showed that a variation of this factor did not significantly alter the optimal investment plan on the horizon of the study. A slight slippage of renewable projects (hydro and solar PV) is nevertheless observed during the period. However, given that the cost of natural gas accounts for approximately 45% of the total cost (investment + operation) of the master plan over the study period, any change in the cost of the resource will affect the total cost of operations in a significant way.

2.3.3.1. THE IMPORTANCE OF SECURING NATURAL GAS SUPPLY

Given that the possibilities of investment in LNG projects start only in 2022, the availability of gas over the period will depend largely on the reliability of the country-specific resources (Nigeria, Ghana, Côte d'ivoire and Senegal), as well as of the West Africa Gas Pipeline.

In the absence of gas resources, countries would be forced to exploit the power plants with heavy fuels or, in the worst case, to halt the operation of thermal power plants, which would have negative consequences for the economy and population.

Therefore, the short-term priority objective lies in securing the gas supply.

2.3.3.2. INVESTMENTS IN LNG TERMINALS FROM 2022

As presented in the methodology section, the master plan considers investment in LNG units starting from 2022. The installation of such infrastructure must however be justified economically given the investment costs as well as the higher cost of gas for these facilities.

Nevertheless, despite these relatively large costs, the optimization indicates that it is interesting to invest in LNG units from 2022 **in Ghana and Côte d'Ivoire**, in order to be able to supply combined cycles that are not running fully due to the lack of gas available. As a reminder, Ghana and Côte d'Ivoire will actually have 2040 MW and 1468 MW of combined cycles in 2022, respectively.

The estimated needs in MW thermal (MWth) of LNG for Ghana and Côte d'Ivoire on the horizon of the study (in 2033) are respectively of 3500 Mwth and 2500 Mwth.

It is recommended to install a first phase of 1000 Mwth of these units from 2022 in these two countries in order to be able to fully utilize the combined cycle units.

It should still be noted that it is recommended that the terminal LNG of Ghana serve also to feed Benin via the West Africa Gas Pipeline, in order to supplement the insufficient supply from Nigeria, given the relatively large size of combined-cycle projects in Benin (BID, Maria Gleta regional project).

2.3.3.3. THE IMPORTANCE OF INVESTING IN COMBINED CYCLES

As a reminder, a combined-cycle power plants consists of one (or several) gas turbine turbines combined with a steam turbine. The operating principle is based on the use of the heat from the heat of the exhaust fumes out of the gas turbines to produce steam which is then relaxed in the steam turbine.

This technique allows to achieve efficiency up to 62% with the current technology, which is more important than the efficiency associated with the use of a gas turbine alone (known as open-cycle) that is around 34%.

These combined-cycle power plants are nevertheless less flexible than open-cycle power plants. However, if one considers in this master plan that these plants are mainly intended to run in base, it is more economically interesting to invest in combined cycle units.

This is verified in the optimization as the two candidate projects of gas-fired power plants that emerge are the combined-cycle plants of Egbin In Nigeria and Maria Gleta (regional project of the WAPP) in Benin.

According to this principle, it will also be interesting to convert the many open-cycle plants of Nigeria into combined cycles in the medium and long term.

2.3.3.4. THE GAS TO REPLACE THE HFO AND THE DDO

Finally, one can also note that the increase in the use of gas in the energy mix is mainly at the expense of the consumption of HFO and DDO which only contributes up to 5% in 2022 (whereas they still accounted for 14% in 2017).

However, in the absence of a possible short-term alternative, countries in the western part of the region (Senegal, The Gambia, Guinea-Bissau, Sierra Leone and Mali) still rely on these heavy fuels until 2022 to ensure their energy needs.

This is mainly due to the fact that the development of local gas in Senegal, as well as most of the hydro projects in Guinea (over 1300 MW), arrive only on the medium term.

The two figures below illustrate the need for natural gas to power the sub-region's thermal power plants throughout the horizon of the study. These triple over the 15-year horizon considered and pass from 1133 Mmscfd in 2017 to 3470 Mmscfd In 2033 (cfr the table listed below). However, there is a slight expected decrease of these needs during the year of commissioning of the Mambilla plant of 3050 MW in 2024.

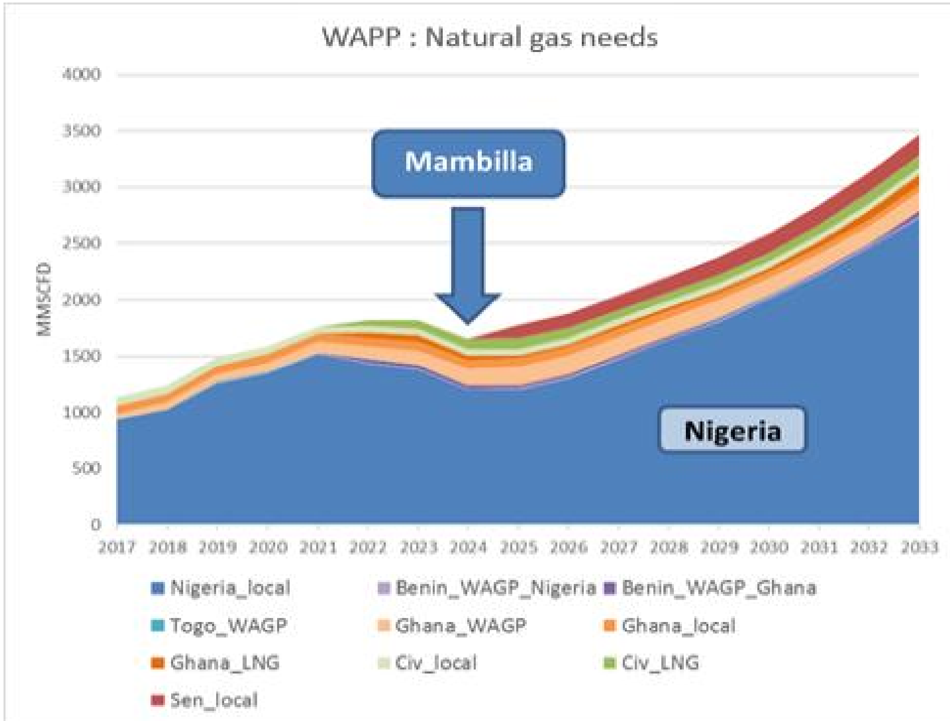


Figure 6: Evolution of natural gas needs in the WAPP region

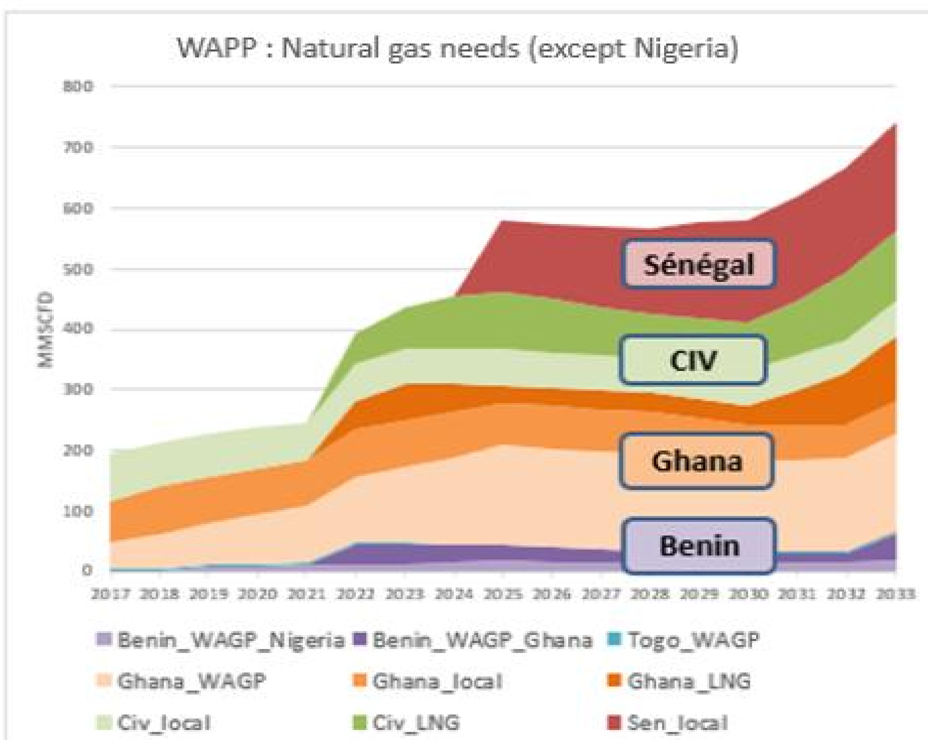


Figure 7: Evolution of natural gas needs in the WAPP region (except Nigeria)

Final version

Sources	Nigeria Local	Benin WAGP (Nigeria)	Benin WAGP (Ghana)	WAGP Togo	Ghana WAGP	Ghana Local	Ghana LNG	Local CIV	Vic LNG	Senegal Local	Total
2017	938	0	0	3	44	70	0	77	0	0	**1133**
2018	1025	0	0	4	59	77	0	75	0	0	**1242**
2019	1260	7	0	4	68	77	0	72	0	0	**1491**
2020	1350	8	0	5	80	77	0	67	0	0	**1593**
2021	1517	9	0	6	93	77	0	62	0	0	**1776**
2022	1428	11	32	6	108	77	48	61	48	0	**1833**
2023	1377	13	30	3	126	77	61	59	67	0	**1830**
2024	1196	14	29	3	144	75	45	59	87	0	**1667**
2025	1199	17	26	1	165	68	32	58	95	119	**1781**
2026	1302	16	22	0	165	70	30	58	89	122	**1878**
2027	1474	16	19	1	164	69	32	57	80	131	**2047**
2028	1641	16	17	1	162	66	33	56	73	141	**2213**
2029	1804	16	17	3	158	60	33	56	76	160	**2389**
2030	2006	16	15	3	152	56	33	56	80	169	**2592**
2031	2223	15	15	3	152	56	59	56	91	174	**2851**
2032	2465	14	15	3	155	55	84	57	109	174	**3140**
2033	2729	17	43	3	159	55	107	57	115	183	**3470**

Table 1: Natural gas needs by source (units: Mmscfd)

2.3.4. Opportunities and challenges for a 100% interconnected network

The region of West Africa is characterized by disparities in terms of energy resources. Indeed, some country dispose for instance of gas resources, mainly in the eastern part of the region (Nigeria, Ghana, Côte d'Ivoire) and soon in Senegal[4]. Others, further north, benefit from conditions of favorable solar irradiations for the development of photovoltaic technologies (Mali, Burkina Faso, Niger). Still others have important hydroelectric potential, as is the case for Guinea, Sierra Leone and Liberia.

These differences therefore naturally call for the setting up of a large network interconnecting all countries in the region. This recommendation which was already one of the great messages of the previous master plan, is all the more true with the introduction of renewable energy, such as solar photovoltaic, in the energy mix of the region.

An interconnected network will allow the transfer of this solar energy from the north to the south of the region during the day, and in the opposite direction during the evening and at night, using hydroelectric or thermal power plants.

Final version

[4] Following the discovery of a gas field on the site of Grand-turtle-Ahmeyim on the border between Senegal and Mauritania.

On the short-term horizon considered in this section, most of the interconnection projects are decided, which will be addressed in detail in the transmission master plan. At this point, it can be mentioned that these interconnections will allow to lower the marginal cost of the region from 96 USD/MWh in 2017 to 75 USD/MWh in 2022, a decrease of more than 21% over 5 years.

The distribution of the marginal costs in 2022 is shown in the figure below.

The lowest marginal costs are observed in the south-east of the region (Côte d'Ivoire, Ghana, Togo, Benin and Nigeria) which has access to gas resources and has developed numerous combined cycle projects on the 2022 horizon. Niger is also part of the low marginal cost countries, given the development of the coal-fired power plant in Salkadamna.

Then the countries in which many renewable projects are developing (Guinea, Burkina Faso, Mali) have higher marginal costs given the use of thermal units using heavy fuel that need to be activated when the renewable is no longer usable[5].

Finally, countries in the western part of the region are facing the most significant marginal costs, given the use of heavy fuel thermal units running in base (Senegal, The Gambia, Guinea Bissau, Sierra Leone, and Liberia).

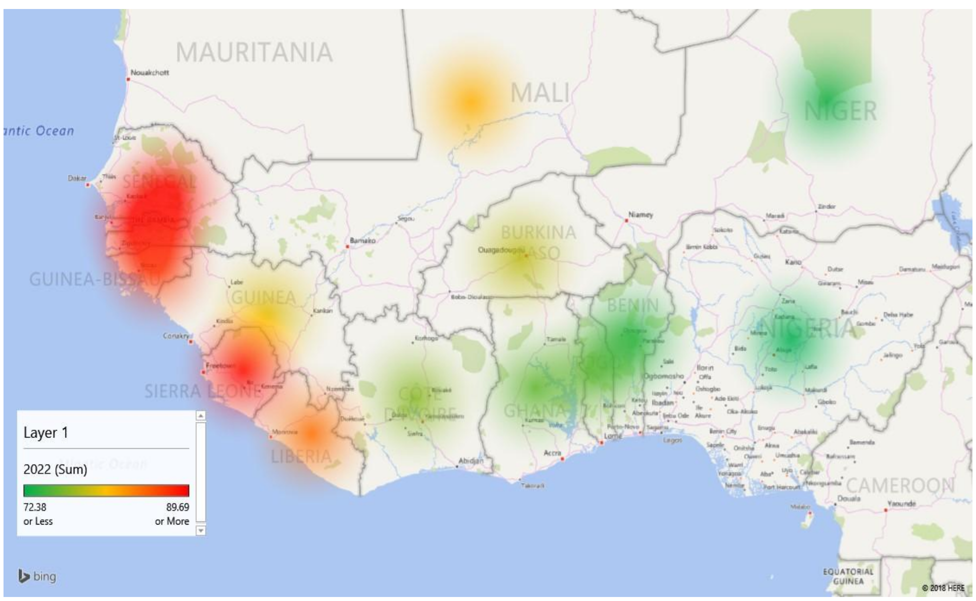


Figure 8: Distribution of average marginal costs by country in 2022

Final version

[5] Night for solar photovoltaic units, or dry season periods for hydroelectric units.

The main challenge for the medium and long-term horizon that follow in this analysis will be to continue to develop the network in order to be able to exploit and share the different resources of the region : the hydroelectric power with the expected implementation of many hydroelectric projects on the medium term horizon; in terms of solar resources whose exploitation with photovoltaic technology will expand massively in the medium and long term; finally, in terms of gas resources with new resources in Senegal for which the exploitation is supposed to begin in 2025.

2.4. Optimal medium-term investment Plan 2023-2029

The medium-term horizon considered in this master plan ranges from 2023 to 2029. Over this period, most of the projects that will be implemented are candidate projects, since the main part of the decided projects was put into service before 2023.

Indeed, on the 13 721 MW of decided generation projects identified during the data collection, 8 386 MW are expected to be put in service before 2023, which leaves 5357Mw for the medium and long-term horizon.

On these 5357 MW of decided projects, the most important is the hydroelectric plant of Mambilla In Nigeria, with an installed capacity of 3050 MW. Other projects include 1322 MW of hydroelectric projects of smaller size, 2x350 MW for the two phases of San Pedro coal plant in Côte d'Ivoire and 285 MW for the ALAOJI 2+ gas plant in Nigeria.

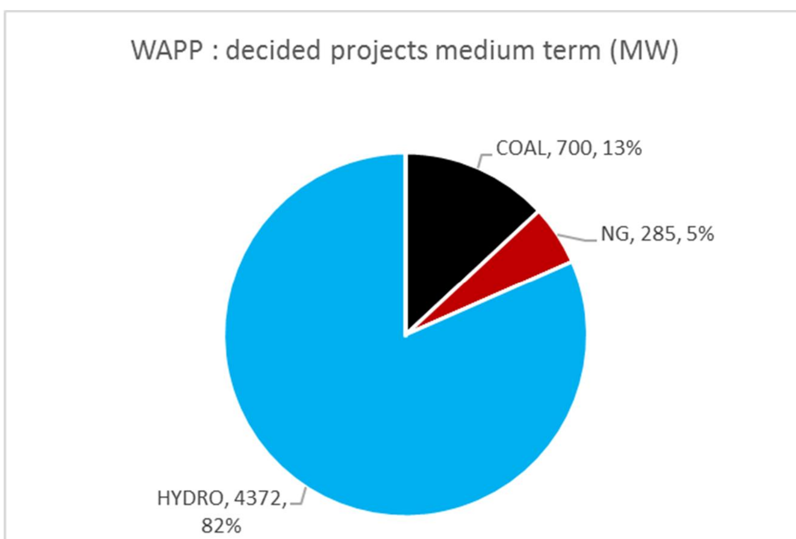


Figure 9: Distribution of the projects decided in the medium term for WAPP per fuel type

Final version

Given that the peak load is supposed to increase from 21 331 MW in 2022 to 36 397 MW in 2029 according to the load forecast presented in tome 2, the decided projects will not guarantee the security of supply in the region. Therefore, an additional investment of 9868 MW in conventional units is required (8872 MW thermal and 996 MW hydro).

Besides these investments in conventional plants, the master plan has identified up to 15 828 MW of potential solar projects that should allow to reduce the cost of electrical energy drastically and contribute to the development of sustainable development in the region.

Of these 15.8 GW of potential projects, the network studies carried out in the transmission master plan below validated the integration of 5.4 GW, and more precisely, 3.4 GW between 2022 and 2025 and 2.0 GW between 2025 and 2029, thus bringing the installed capacity in solar photovoltaic at 6.8 GW in 2025 and 8.8 GW in 2029. Further technical studies will however be necessary to confirm the integration of the remaining 10.4 GW.

Finally, several potential wind projects have been also identified at the end of the medium-term horizon considered here.

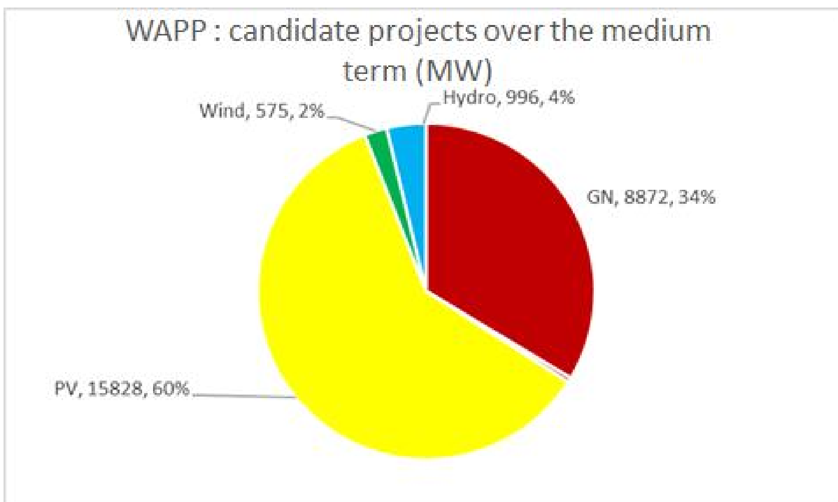


Figure 10: Distribution of the projects decided in the medium term for WAPP, per fuel type, including the potential solar projects identified

The impact of this investment plan on the energy mix at the end of the mid-term horizon (in 2029) is shown in the figure below. Solar photovoltaic technology has the largest increase compared to the 2022 situation, accounting for 13% of the region's total energy generation if the total identified potential is actually exploited (corresponding to an installed power of 19.2 GW in 2029). However, taking into account only solar projects whose integration has been technically proven (corresponding to an installed power of 8.8 GW in 2029), the contribution of this technology to the mix of the sub-region would be 6%.

Gas-fired power plants still produce most of the electricity (60%). Hydroelectricity is stable and revolves around 24% generation. Wind technology appears in the medium-term energy mix, but still weakly with only 1% of the total energy produced in the region.

The other highlight is the almost disappearance of the use of heavy fuels and diesel on the 2029 horizon. The exploitation of gas resources now both in the east and in the west of the region[6], as well as the development of interconnections between the different member states allow to do without these expensive and polluting fuels in the medium term.

The detailed list of the invested projects by State-Member can be found in appendix A.

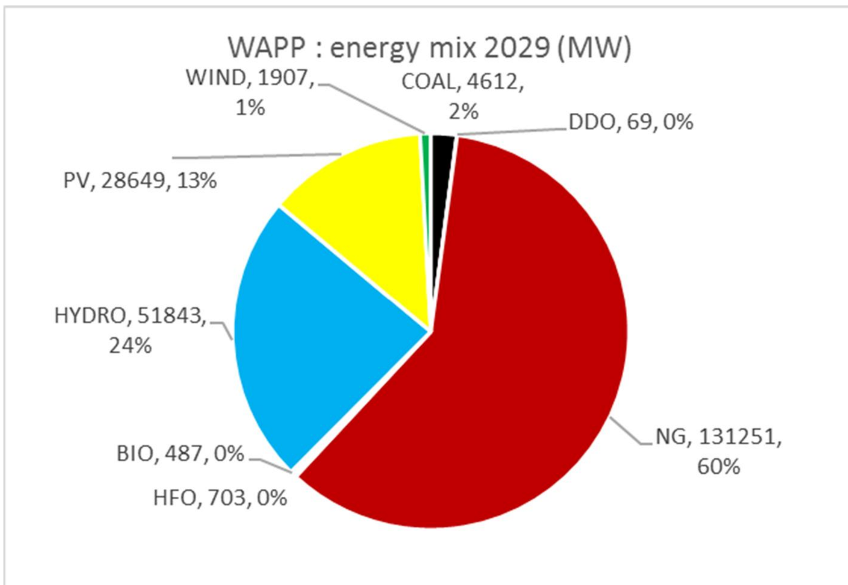


Figure 11: Energy Mix of the WAPP at then of the medium-term, including the potential solar projects identified

2.4.1. The exploitation of regional hydropower potential: a priority

The mid-term period referred to in this section is characterized by the commissioning of many hydroelectric power plants. Indeed, as was mentioned in the introduction, over 5000 MW has to be put into service on the 2023-2029 horizon (of which a majority of decided projects).

The countries concerned with this development are mainly Nigeria, Guinea and Sierra Leone. Some projects are also planned in Côte d'Ivoire and Togo. The list of these projects can be found in the table below.

Final version

[6] Following the discovery of a major gas field on the border between Senegal and Mauritania

Country	Project	Status	Technology	Installed power (MW)	Commissioning
Côte d'Ivoire	Louga	Decided	Hydro	224	2023
Côte d'Ivoire	TIBOTO	Decided	Hydro	112.5	2026
Guinea	Amariah	Decided	Hydro	300	2023
Guinea	MORISANAKO	Selected	Hydro	100	2023
Guinea	GRAND KINKON[7]	Selected	Hydro	291	2023
Guinea	KOUKOUTAMBA	Decided	Hydro	294	2024
Guinea	BONKON Diaria	Selected	Hydro	174	2025
Guinea	TIOPO	Selected	Hydro	120	2028
Guinea	DIARAGUÔLA	Selected	Hydro	72	2029
Nigeria	Mabon	Selected	Hydro	39	2023
Nigeria	MAMBILLA	Decided	Hydro	3050	2024
Sierra Leone	BUMBUNA II	Decided	Hydro	132	2023
Sierra Leone	BUMBUNA III (Yiben)	Decided	Hydro	66	2023
Sierra Leone	BENKONGOR I	Selected	Hydro	34.8	2023
Sierra Leone	BENKONGOR II	Selected	Hydro	80	2025
Sierra Leone	BENKONGOR III	Selected	Hydro	85.5	2026
Togo	ADJARALA	Decided	Hydro	147	2026
Togo	SARAKAWA	Decided	Hydro	24.2	2023
Total Hydro				5357	

Table 1: List of hydroelectric projects over the medium-term

Among all these projects, Mambilla in the east of Nigeria is the one with the most important size, with 3050 MW. In Guinea, the master plan foresees the commissioning of 1351 MW in the medium term including Amaria (300 MW), Koukoutamba (294 MW) and Grand Kinkon (291 MW). In Sierra Leone, the sites of Bumbuna and Benkongor will welcome 400 MW. Finally, we will also note the decided projects of Louga and Tiboto in Côte d'Ivoire and Adjarala in Togo.

[7] Recent studies have determined that the capacity of the Grand Kinkon unit could be somewhat lowered

2.4.2. Strong integration of renewable energies for an optimal energy mix

As we have shown above, the share of renewable in the energy mix over the medium-term horizon will grow significantly. In fact, in 2029, the electricity attributable to renewable energy sources could reach up to 38%, including 24% hydropower, 13% solar photovoltaic and 1% wind energy.

Risk analysis for the integration of intermittent renewable energies

In the absence of any constraint, economic optimization selects the option at lower cost to meet the demand on the horizon of the study. In this context, there is a cost threshold below which the PV solar option becomes marginally more interesting than the thermal options in West Africa. The existence of this level has two effects:

§ On the one hand, before the crossing of this threshold which will intervene around 2025 according to the assumptions of the master plan, investments in PV solar projects in the subregion remain marginal if one refers to economic criteria only

§ On the other hand, at the pivotal year (year when the investment threshold is crossed), the investment volumes are considerable (several tens of GW invested in a single year)

Taking the risk into account in the master plan allows us to deviate from this scenario, which, although economically optimal, is difficult to implement in practice. In order to take into account the limited financial capacities of the Member States of the WAPP, particularly in view of the fact that renewable projects have a high capital intensity; in order to take into account also the technical limits linked to the integration into the still fragile network of the WAPP, it was decided to set a limit on the annual investment by country. As such, the macimum capacity that can be invested each year for each technology (wind and solar PV) has been defined at 10% of national peak demand. This limit has several effects:

§ It has been defined in such a way as to achieve, on the horizon of the study, a volume of renewable investment close to that observed in the optimal case from the economic point of view

§ It allows a better distribution of investments in time, before and after the pivotal year

§ It allows for a better geographical distribution of investments, as the countries of the north of the region are no longer solely responsible for all renewable projects

The optimization program used to carry out this master plan has identified an important need for potential solar photovoltaic projects over the medium-term up to 15.8 GW over the 7 years considered, which represents more than 2 GW each year in the region.

Final version

The geographical repartition of the investments depends, on one hand, of the solar irradiance of the country, and on the other side of the level of the demand, the latter point having the objective to spread the investments in order to limit the risks and to facilitate the access to capital. As such, important potential solar projects have been identified in Burkina Faso, Mali and Niger, but also in the northern region of Nigeria, Benin, Togo, Ghana, and Côte d'Ivoire. Moreover, the expected fall in costs of the PV technology implies that investments in the south of the region are beginning to be profitable on the end of the mid-term horizon (i.e., from 2026).

Concerning wind turbine technology, some projects are starting to be justified at the end of the medium-term horizon, notably in Nigeria

The typical economic dispatch of the peak day in 2029 is shown on the figure below, taking into account the whole potential solar projects identified. The predominance of solar photovoltaic energy appears clearly during the day, the latter providing almost 50% of the energy consumed in the region at midday.

This figure illustrates also the possible synergy between hydroelectric and solar resources. Hydroelectricity is mainly reserved for the evening peak as well as during the night, when solar energy is unavailable. During the day, though, some hydroelectricity is produced, given the technical minimum imposed, especially for irrigation issues.

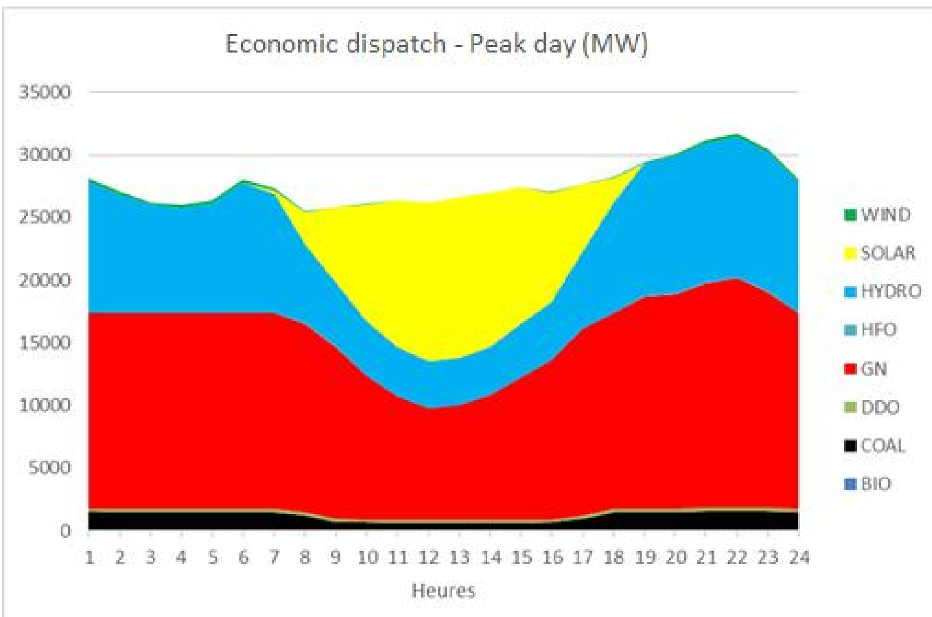


Figure 12: Typical dispatch at the end of the medium-term (2029), including the potential solar pojects identified

2.4.3. Diversifying thermal resources to limit exposure to risk and volatility

Alongside the investments in renewable, it is essential to continue to invest in thermal units in order to meet the ever-growing demand of the region when renewable resources are unavailable, but also to increase the reliability of the power system.

Final version

The medium term is thus also characterized by the development of gas-fired power plant, and this, not only in the eastern part of the region, but also in the western part, following the discovery of a gas field in Senegal.

The region's needs in thermal units on the medium-term horizon are estimated to 9.2 GW. The bulk of this capacity is to be developed in Nigeria, with nearly 8 GW to install between 2023 and 2029. For Senegal, the optimization proposes the development of combined cycles for a total power of 750 MW in 2025. Finally, a combined gas cycle project of 450 MW is also recommended in Ghana[8] for the end of the period (i.e. on the 2029 Horizon).

In Nigeria, 4.8 GW of combined cycles have been identified during the data collection (including Egbin, Ethiopia, Caleb Inland, Alaoji, Geregu, Omotosho, Calabar Odukpani and Gbarain Ubie). Nevertheless, this is insufficient to cover the 8 GW needed over the period. Therefore 3.2 GW of complementary combined cycle projects are necessary in Nigeria between 2023 and 2029. From a practical point of view, it is recommended to develop these projects on sites of existing open-cycle gas plants in order to transform them into combined cycle.

As far as coal is concerned, we will note the commissioning in 2026 of the coal-fired plant of San Pedro I in Côte d'Ivoire, with a capacity of 350 MW, with a second phase foreseen in 2029.

The geographical diversity of the proposed thermal projects and the variety of fossil resources used (domestic or imported) allow for a greater security of supply, guaranteeing the electricity supply of the sub-region even in case of lack of supply from one of the sources;

2.4.4. The interconnected network to better share the resources

The potential renewable energy projects in the medium term as well as the development of the interconnected network pulls the marginal costs of the whole region downwards. These could indeed evolve from 80.6 USD/MWh in 2022 down to 49 USD/MWh in 2029.

Final version

[8] Potentially on the site of Aboadze

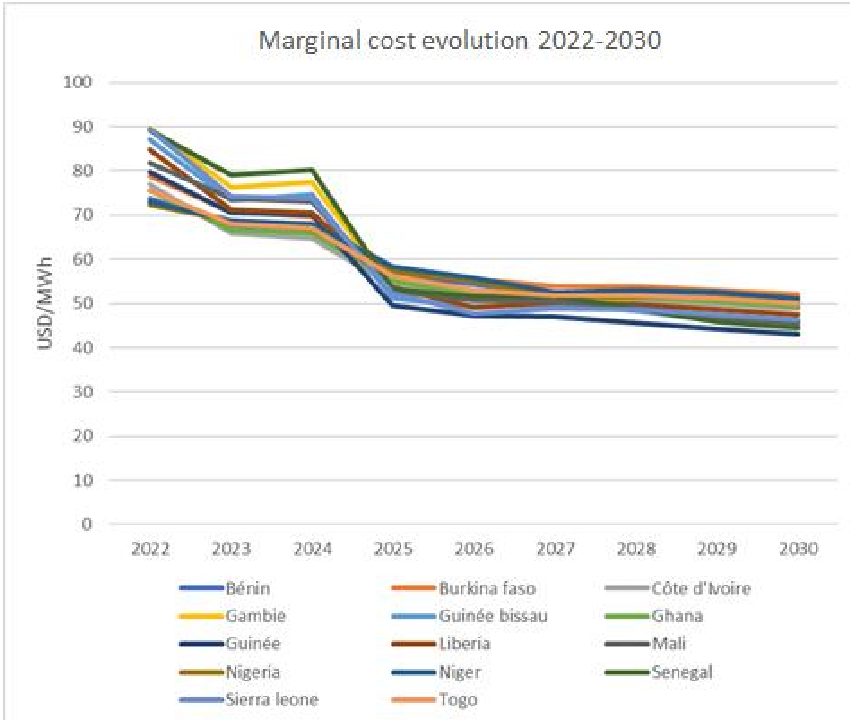


Figure 13: Evolution of average marginal costs by country between 2022 and 2030

Beyond this widespread decline in marginal costs in the region, it can be noted also that the latter vary greatly depending on the time of the day considered. Indeed, if we analyze the situation during the day at 12h, the marginal costs as shown in the figure below are observed. These are naturally lower in the north of the region (where the electricity comes mainly from solar photovoltaic technology) as well as in Guinea and Sierra Leone in which many hydroelectric power plants are now active.

We therefore clearly see the importance of developing the interconnected network so that we can share these renewable resources and in particular the axes attached to Guinea, as well as the southern backbone connecting Nigeria to Benin, Togo, Ghana and Côte d'Ivoire and the north backbone between Nigeria, Niger and Burkina Faso.

Final version

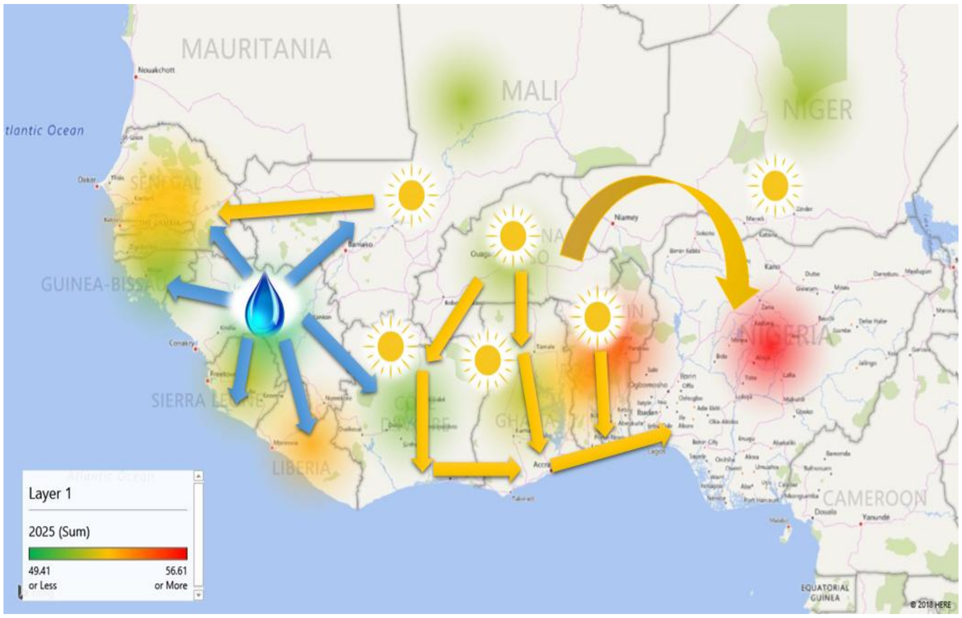


Figure 14: Distribution of the average marginal costs at 12h in 2025

During the evening peak of 9 pm, the situation is different. The northern countries, such as Mali, Burkina Faso and Niger must now import, given the lack of solar energy. They therefore face the most important marginal costs at this moment. These imports come mainly from the countries disposing of gas resources which use their combined-cycle power plants (mainly Nigeria, Ghana, Côte d'Ivoire and Senegal). We observe on the figure below that the flows are effectively reversed in the evening.

Thus, Nigeria exports during evening via the south and north backbones, while Senegal exports to Mali and The Gambia. Let's note that the situation around Guinea remains relatively stable throughout the day (i.e. a situation of quasi permanent export to its neighbouring countries).

Final version

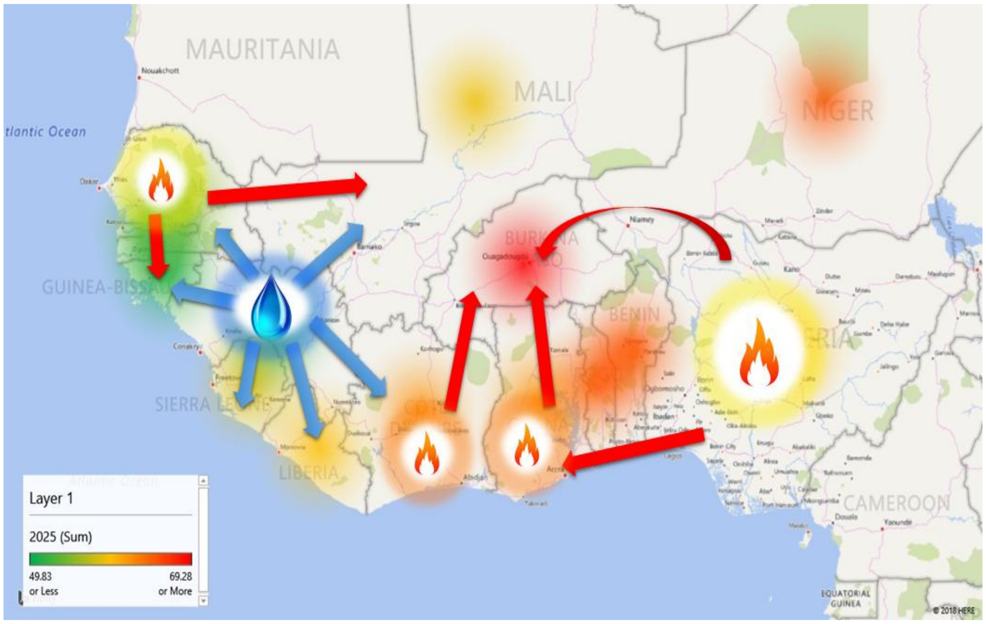


Figure 15: Distribution of the region's average marginal costs at 21h in 2025

These considerations regarding the exchanges will be discussed in more details in the the transmission master plan below, but it already shows the major trends that will guide the evolution of the network.

2.5. Optimal long-term investment plan 2030-2033

The long-term period considered in this study covers the years 2030 to 2033. Over this interval, demand continues to grow exponentially in the region. The forecast of the synchronous peak demand of the region evolving from 36.4 GW in 2029 to 50.8 GW in 2033.

The investments needed to cope with this surge in demand are estimated to 14981 MW for thermal generation and 562 MW for hydroelectric generation.

Besides those conventional projects, potential solar PV and wind projects have been identified in the context of this master plan, for an amount up to 16 700 MW for solar PV and 750 MW for wind turbine.

Concerning solar projects, the technical simulations carried out in the transmission master plan developed in Chapter 3 below have validated the integration of 1.9 GW between 2030 and 2033, bringing the total solar capacity of the subregion to at least 10.7 GW at the end of the study. In-depth technical studies will however be necessary to confirm the integration of the remaining 14.8 GW over 2030-2033.

Final version

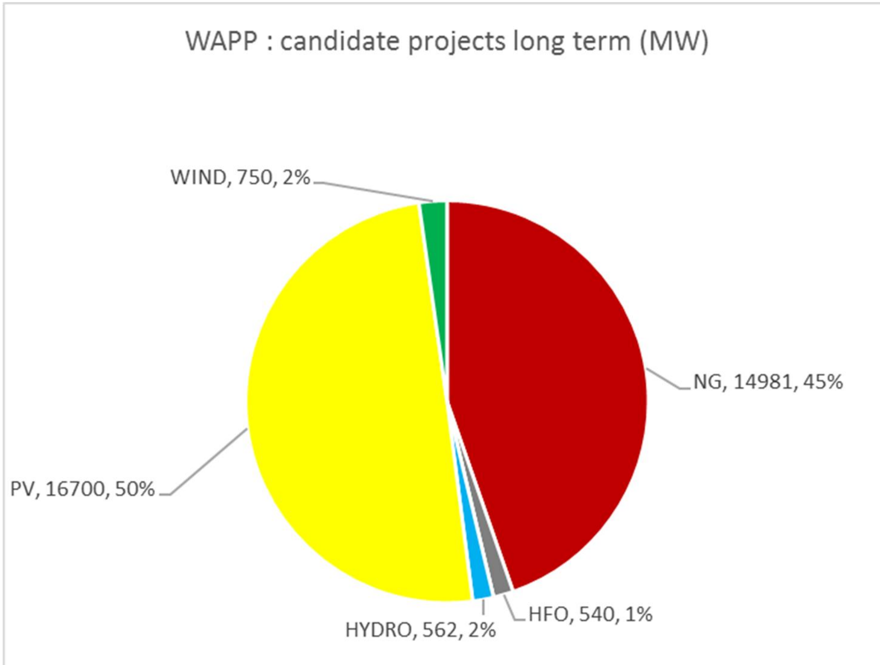


Figure 16: Distribution of long-term investments by fuel type, including the potential renewable projects identified

Compared to the mid-term period, it can be seen that investments in hydroelectric plants are proportionately very small. Indeed, the most economically interesting projects have been taken into account in the mid-term and the remaining projects do not appear to be an economically viable option for the sub-region's power supply up to the 2033 horizon.

On the other hand, the investments in thermal power plants are proportionately more important. This is required to guarantee the reliability of the interconnected network, these challenges of reliability increasing as the renewable share takes a growing importance in the energy mix of the region.

The energy mix at the end of the study horizon is illustrated below. The share of generation attributable to renewable energies is 36% in 2033, of which 18% for hydroelectric power plants, 17% for solar photovoltaic, if the entire solar potential projects were effectively developed (corresponding to an installed capacity of 36 GW in 2033) and 1% for wind energy.

However, if one takes into account only solar projects whose integration has been technically proven (corresponding to an installed power totalling 10.7 GW in 2033), the contribution of this technology to the mix of the subregion would go from 17% to 5 percent.

Still, most of the electricity generated in the region comes from the gas-fired plants (62%), of which 77% is provided by Nigeria. Coal-fired power plants finally produce 2% of the total energy.

The detailed list of the invested projects by State-Member can be found in appendix A.

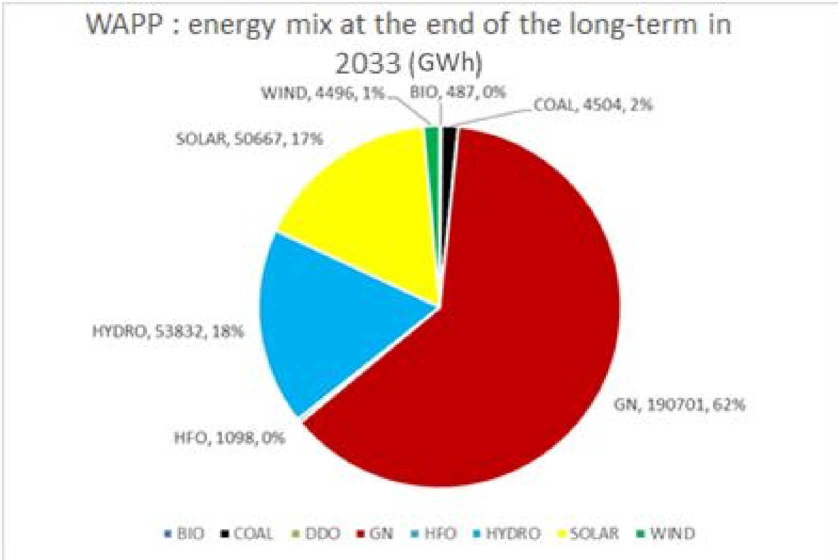


Figure 17: Energy mix of the region at the end of the study (2033) , including the potential renewable projects identified

2.5.1. Towards optimal exploitation of economically profitable hydroelectric resources

Some hydroelectric projects come out of the optimization on this long-term horizon, including 3 in Guinea (Boureya, Fetor and Lafou) and 1 at the border between Liberia and the Sierra Leone (Mano). These plants amount to 562 MW in total, to which one can add the Saint-Paul river projects for an expected capacity between 360 and 585 MW, which is currently under study.

Country	Project	Status	Technology	Fuel	Installed power (MW)	Commissioning
Guinea	Boureya	Selected	Hydro	Hydro	160	2030
Guinea	Fetor	Selected	Hydro	Hydro	124	2031
Guinea	Lafou	Selected	Hydro	Hydro	98	2032
Liberia	Mano	Selected	Hydro	Hydro	180	2032
Liberia	Saint-Paul	Under study	Hydro	Hydro	360-585	>2030

Table 2: Investments in hydro projects in the long term

These projects are selected in the current master plan in the light of their economic interest, but also for their ability to compensate for the variability of renewable energies (solar and wind turbines).

Final version

Nevertheless, it is necessary to mention that the two reasons given above (i.e. economic reason and integration of renewable) are not the only ones justifying investments in hydroelectric power plants. Therefore, some projects that don't come out of the present optimization, and which therefore do not have a regional vocation, could nevertheless be developed for other uses (such as irrigation for instance).

2.5.2. Towards a meshed network

The potential solar photovoltaic projects identified in northern regions of the WAPP as well as the development of the hydro potential in the west of the region (Mainly around Guinea) make even more obvious the differences in marginal costs in the middle of the day at 12h, as can be seen in the figure below.

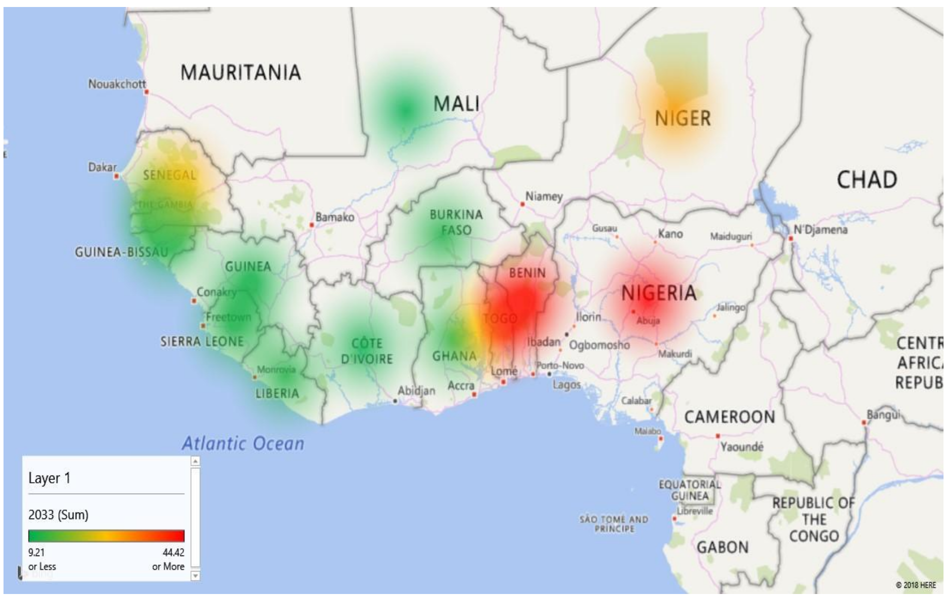


Figure 18: Average marginal costs at 12h at the end of the study (2033)

It is actually observed that the west and north of the region are characterized by the lowest marginal costs at noon given the abundance of solar and hydro resources.

In the west of the region, hydroelectric resources are used, mainly in Guinea, Sierra Leone, Liberia and the Mali. It makes sense that these resources are shared via the OMVS, OMVG and CLSG networks.

The east of the region is exposed to higher marginal costs, particularly in Nigeria where gas-fired power plants are running in base. Therefore, there is an economic interest in exporting this low-cost electricity generated in the countries from the north (Burkina Faso and Niger) and west (Côte d'Ivoire and Ghana) to Nigeria, through Togo and Benin.

This reinforces the recommendation done in the medium term to develop the network in this eastern part of the region, to transfer power from the northern and western countries to Nigeria (through Togo and Benin).

Final version

At the evening peak (at 9pm), the situation is virtually reversed (see figure below). Indeed, we see that the countries in the north which used mainly solar energy at noon (such as Mali, Burkina Faso and Niger) are now facing far greater marginal costs. These countries will now import mainly from the countries which have gas resources (Nigeria, Ghana, Côte d'Ivoire and Senegal) or Hydropower (Guinea mainly).

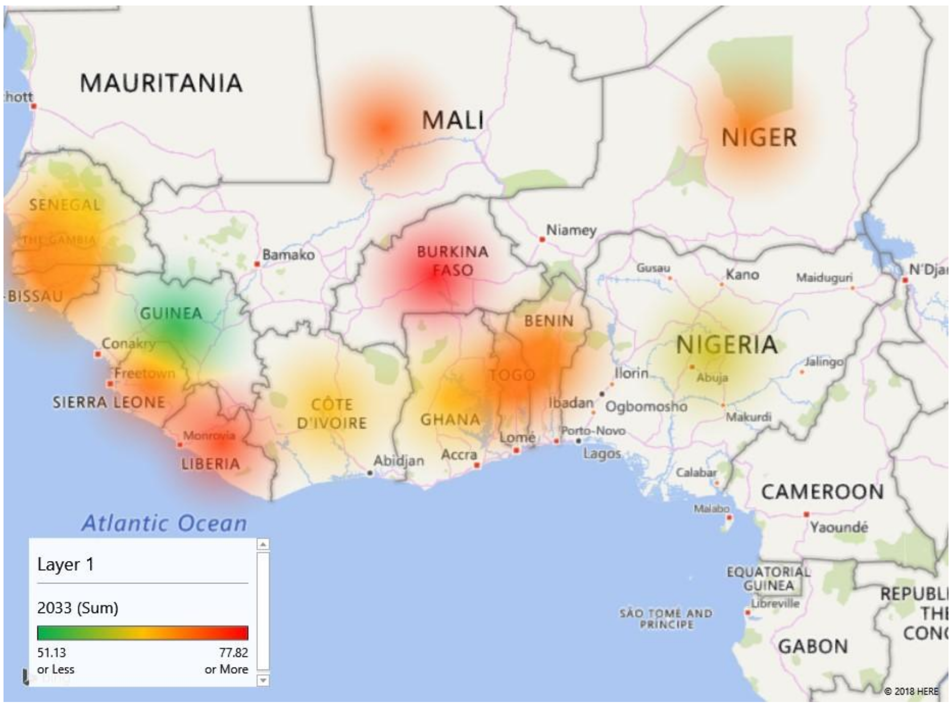


Figure 19: Average marginal costs at 9pm at the end of the study (2033)

2.5.3. Flexibility and reliability issues on the long-term

The present master plan is designed to bring the Loss of Load Expectation (LOLE[9]) to 24 hours a year in the whole region at the end of the study in 2033, while considering an interconnected system where mutual support is possible to compensate for the lack of generation in a given country.

The LOLE is a probabilistic criterion that indicates the expected number of hours in a year in which the demand exceeds the available generation capacity, resulting in the inability to provide the full load without mitigation measures.

This criterion has been integrated into the simulations. The result is that additional investments must be made in thermal units essentially from 2030. This explains in particular why the investments in gas power plants are proportionately more important on the long-term horizon compared to other horizons, as was mentioned at the beginning of this section. These investments are included in appendix.

[9] Loss of load expectation

Regarding the combined cycles, Nigeria accounts for 9000 MW. A 369 MW CC project is also recommended in Côte d'Ivoire (Songon). Lastly, it is recommended that Senegal continue its development of combined-cycle power plants up to 900 MW in the long run.

Alongside these combined cycle projects, we see that the generation master plan also provides the development of open-cycle gas turbines, particularly in Nigeria for 3500 MW, in Ghana for 300 MW and Côte d'Ivoire for 300 MW. These investments are necessary for flexibility reasons, but also for reliability reasons, in order to guarantee compliance with the LOLE of 24h/year.

Also, it should also be mentioned that, for the same reasons of flexibility and reliability, but also for reasons of security of supply, it is recommended to the country which have no gas resources to develop combined cycles of small size (typically 60 MW). These are included in the detailed table of the geenration master plan in Appendix A of this document.

All these extra investments in thermal units imply that the marginal costs remain stable from 2030 to 2033, around 49 USD/MWh.

Finally, the battery storage will have to play a major role in improving flexibility and increasing the security of supply of the sub-region. In view of the expected changes in the cost of batteries, they could supplant part of the investments in gas turbines on the horizon of the study.

2.6. Synthesis

In order to meet the electrical demand, supposed to reach 50.8 GW in 2033, the present master plan indicates that the installed capacity of thermal units should reach 45.4 GW in 2033 and the hydroelectric plants 12.8 GW.

In order to reduce the costs of electricity and to reduce the ecological footprint of the sector, several renewable energy projects (solar PV and wind turbine) have been identified and recommended for a total capacity reaching 37.5 GW. The simulations carried out in the transmission master plan in chapter 3 below validated the technical integration of 12.1 GW of these intermittent renewable projects at the end of the study. The development of the additional 25.4 GW (to cover the 37.5 GW) can be carried by the countries and will therefore require additional technical studies.

Regarding the energy mix, the solar photovoltaïc technology would contribute up to 17% of the energy generated in the region at the horizon 2033, if the entire potential solar projects were to be developped.

The large part of gas in the energy mix is also striking, which replaces HFO and DDO at the horizon of the study. Finally, it appears that the part of hydroelectricity in the mix, after exhibiting an increase over the medium term, finally tends to decrease, given the fact that all the economically interesting projects were implemented.

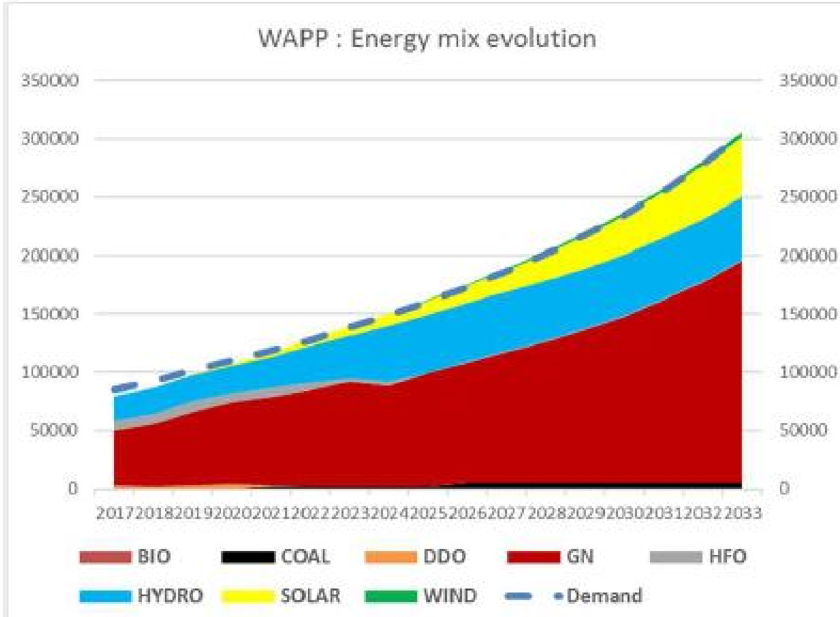


Figure 20: Evolution of the energy mix (in GWh), taking into acocunt the entire solar projects identified

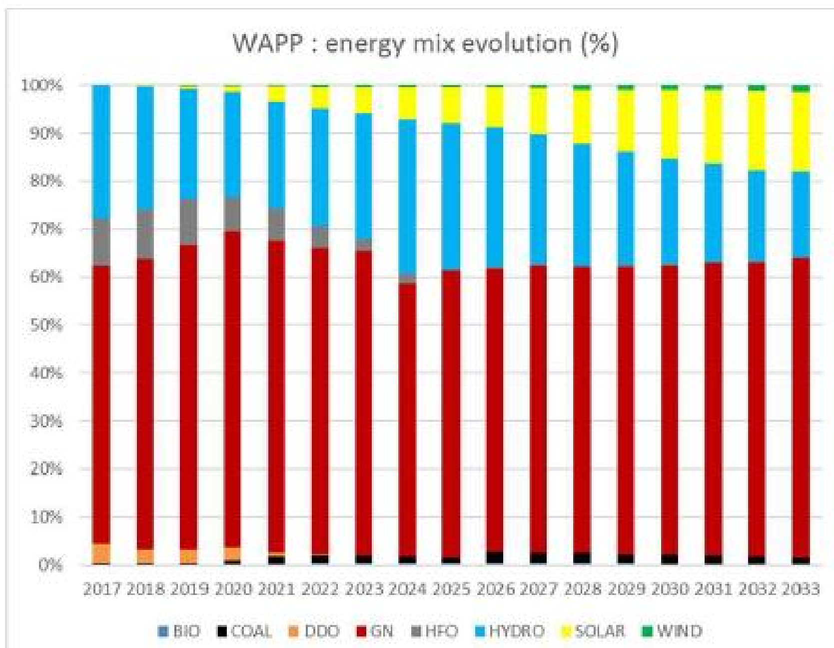


Figure 21: Evolution of the energy mix (in %)), taking into acocunt the entire solar projects identified

Final version

3. TRANSMISSION MASTER PLAN

The aim of this chapter is to present the transmission network and its evolution over the study period. This analysis directly follows the economic analysis and the objective is to validate that the economic results are technically feasible over the study period.

This technical feasibility will be studied over 3 different time horizons (selected with the Member States during the project meeting in May 2018); respectively 2022, 2025 and 2033. Different scenarios will be evaluated over these different target years in order to test the system and asses its limits. Static analysis will be carried out for all three target years and dynamic analysis will be carried out for the two first target years.

The 2022 time horizon which comprises mainly of decided generation and transmission projects will be studied. The main objective of this study year is to analyze and identify the weakest points of the network in order to connect the different blocks together which are currently not synchronized. The conclusions of these analysis will serve as the basis for the priority investments which should be conducted in order to synchronize the region securely.

The objective of the study year of 2025 is to verify that the economic exchanges planned are feasible on the technical point of view and to solve the weak points determined in the study of the year 2022 in order to create a network which can operate within the operational limits under the N-1 condition.

Finally, the year 2033 will be studied to determine the reinforcement needs expected in the long term which would satisfy the economic exchanges and the level of renewable integration given from the economic analysis. The reference grid structure of 2033 has been built on:

- For the national power system: information extracted from the master plan studies and collected during the data collection phase;
- For the reinforcement of the interconnections, the economic study assessed the optimal size of transfer capacities between the different areas.

This chapter first described the methodology adopted and the assumptions done for the modelling of the WAPP network. The different scenarios and the results from the different analysis are then explained in the rest of the chapter and the different investment priorities are detailed.

Final version

3.1. Methodology

3.1.1. Static analysis

The objective of the static analysis is to visualize the flows on the lines and voltages at all substations in the interconnected network. Based on the load flow results, the necessary reinforcement can be performed in order to best satisfy the operational constraints.

The N-1 security criteria is applied starting from the study year of 2025. The operational limits allowed in normal situation (N) and in single contingency situation (N-1) is shown in the following table. The list of contingencies analyzed concern all equipment of voltage levels 225 kV and higher.

Maximum load of transmission infrastructure

Works	State N (Normal Situation)	State N-1 (Under Incident)
	% nominal power	% nominal power
Lines	100 %	110 %
Transformers	100 %	120 %
Voltages	± 5 %	± 10 %

Table 3: Operational limits

3.1.1.1. MODEL CREATION

The model of the high voltage grid was built starting from the 2017 existing situation which was validated with each country during the dedicated workshop.

The objective of the WAPP Master Plan is to identify, on the regional level, the reinforcement needs and to challenge the existing high voltage grids of each countries against the interaction that could appear between countries. For this reason, only the parts of the network which are meshed and which could be directly impacted by the interconnection of the West African countries has been modelled.

The Table 4 below summarizes the voltage level that were modelled for each country. The picture below shows a typical example of the modelling that was done. The high voltage (red in the example) network was modelled as well as the meshed network level (green in the example) which can be impacted in the regional exchange of power. The load is connected on the low voltage level through distribution transformers.

The full load flow model as it was developed is shown in Figure 23 where the top part represents the Western part of the WAPP and the bottom part represents the Eastern part. It is clear that these two networks are interconnected under one single synchronous model in the studies that were performed.

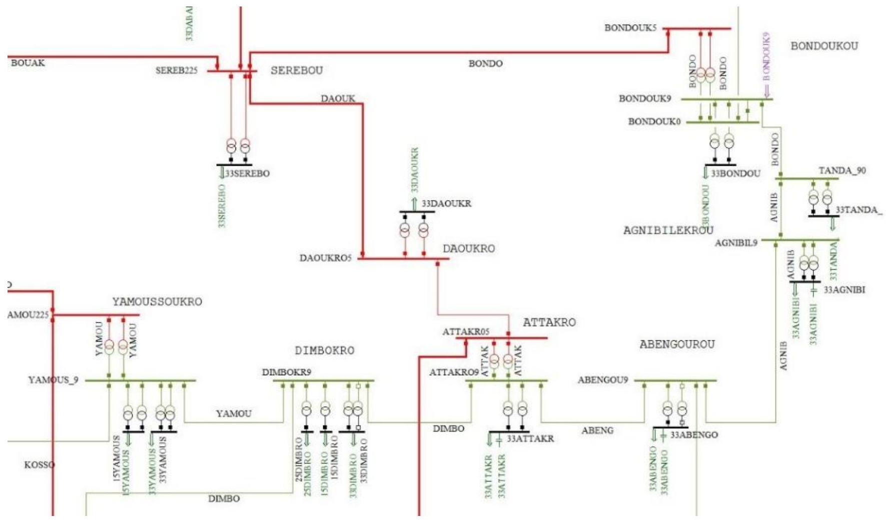


Figure 22: Typical detail level of modelling of a country's high voltage grid

Country	Voltage Levels Modelled
Senegal	225 & 90 kV
The Gambia	225 & 132 kV
Guinea Bissau	225 kV
Guinea	225 & 110 kV
Mali	225 & 150 kV
Liberia	225 kV
Sierra Leone	225 & 161 kV
Côte d'Ivoire	225 & 90 kV
Ghana	330 & 161 kV
Togo	330 & 161 kV
Benin	330 & 161 kV
Burkina Faso	225 & 90 kV
Niger	330 & 132 kV
Nigeria	330 &132 kV

Table 4: Voltage levels modelled for each country

Final version

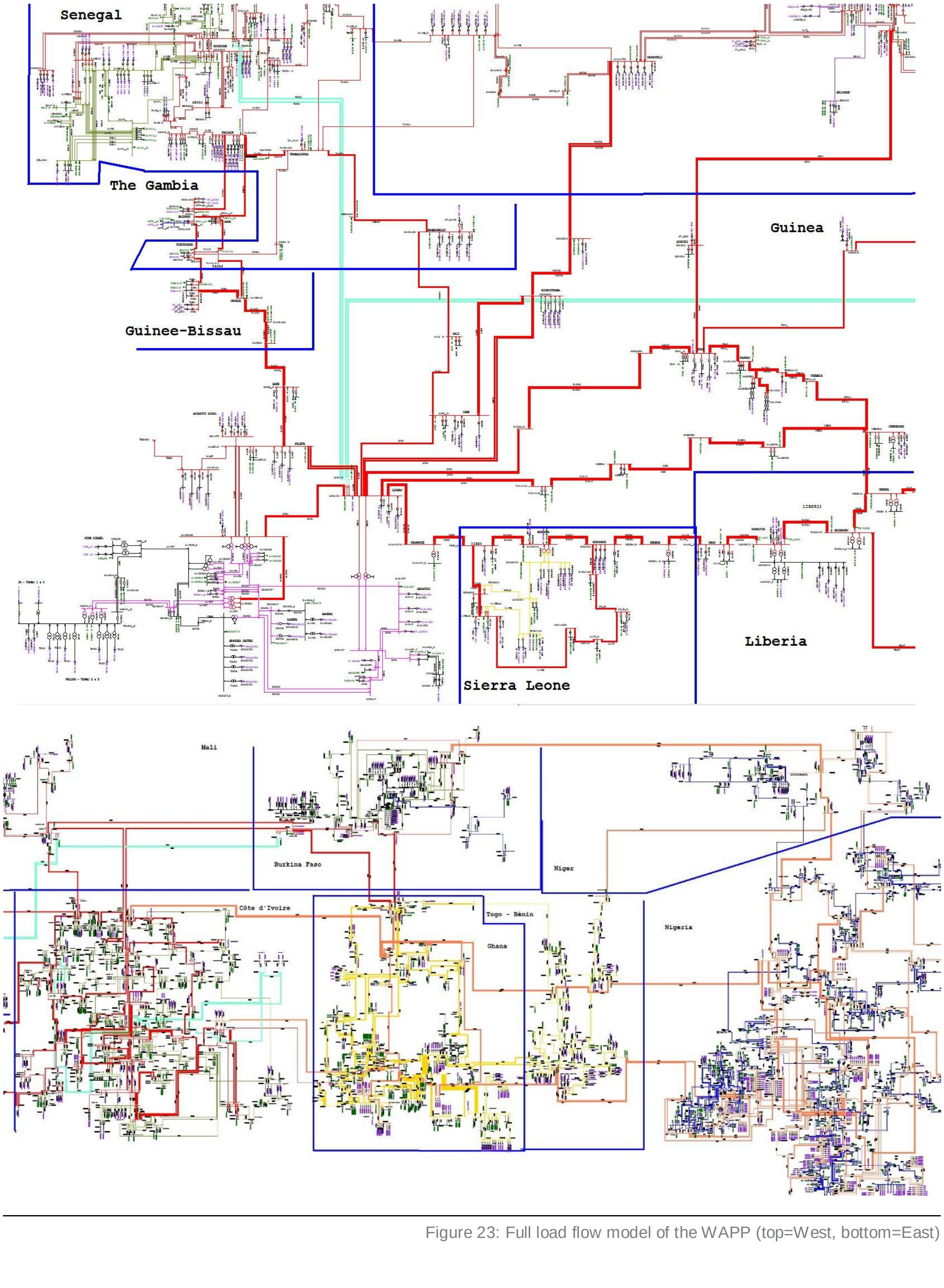


Figure 23: Full load flow model of the WAPP (top=West, bottom=East)

Final version

3.1.1.2. LOAD

The load level which is modelled is based on the results of the load demand forecast presented in Tome 2.

The power factor which was modelled in the model of the existing network (2017) was used for the following years and kept constant until 2025. Load with a power factor of less than 0.9 were however set to 0.9 in 2033. For this study year of 2033, the power factor of Nigeria was adapted to 0.95 accordingly to the TCN Master Plan.

For each country, national master plans were used when available in order to evaluate the spreading of the future loads on the high voltage grid.

3.1.1.3. GENERATION

Each generation unit is modelled behind its step-up transformer as shown in the following Figure 24.

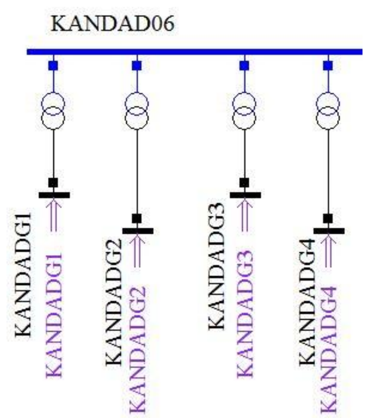


Figure 24: Connection model of generators

The modeling of new power plants was done considering that rotating machines (Hydro units, thermal units, and biomass) have a cosφ of 0.85 for their production of reactive power and a cosφ (power factor) of 0.95 in absorption. The step-up transformer is modelled with an apparent power of the size of the unit that is connected.

Renewable generation such as wind turbines and PV parks are modelled with a cosφ of 0.95 in both absorption and production of reactive power. It is assumed that new technology to this day allows such reactive power range and newly built capacities should be installed with the specificities.

3.1.1.4. TRANSMISSION

New transmission lines are modelled using the same parameters (per km) as similar lines recently constructed in the country or region of interest.

Final version

3.1.2. Dynamic Analysis

The objective of the dynamic analyses is to assess the stability margins of the system to ensure its secure synchronous operation. The results of the static analysis is taken as input. The analyses carried out are the following:

- Small Signal Stability analysis: aimed at evaluating the response of the system to small variations typical of normal operation, such as breaker switch and load variation. The outcome of the analysis will highlight power oscillations insufficiently damped that might endanger the stability of the system. Methodology is detailed in Annex.
- Dynamic Security analysis: aimed at evaluating the ability of the system to endure electrical transients and recover a sustainable operating point. This analysis can be seen as an extension of the N-1 security criteria. Following the loss of several key transmission network elements, the transient and voltage stability of the system will be assessed. Methodology is detailed in Annex.
- Frequency Stability analysis: aimed at evaluating the ability of the system to endure transients involving unbalances of power and to stabilize system frequency without activating defensive measures. In this analysis, the inertial and primary response of the system is tested. Methodology is detailed in Annex.

A description of the dynamic model implemented is presented in Annex.

3.2. Short term development plan - 2022

3.2.1. Towards an interconnected system

The West African electrical network being currently operated in multiple different blocks, exchanges between countries are currently limited to the sharing of the resources between one country and its close neighbors. This sharing of resources requires **high voltage transmission lines** to be built between countries in order to allow for the sharing of resources from the most Eastern part of the region to the most Western part (from Nigeria to Senegal) and the operation of the West African power grid in **one single synchronous network**.

Currently, as of January 2018, the different synchronous blocks are as follows:

- Block A: Burkina Faso, Ghana, Côte d'Ivoire, part of Mali (up to Bamako) and part of Togo/Benin.
- Block B: Senegal, Mauritania and part of Mali (up to Bamako)
- Block C: Nigeria, Niger and part of Togo/Benin
- The other countries of the WAPP are not connected to each other through the High Voltage (HV) grid and operate in an isolated way. These countries are Guinea, Guinea Bissau, The Gambia, Liberia and Sierra Leone.

In the short term, these three asynchronous blocks are due to be interconnected in order to function under one synchronous interconnected system. Additionally, countries currently isolated will be connected to the single synchronous zone, allowing them to share with and profit from their neighboring countries' resources.

Currently, the three existing blocks which are operated asynchronously are being operated in this matter due to technical and stability issues. In fact, interconnection lines are constructed and available, but the currently unstable nature of the system does not make it possible to operate under one synchronous area.

In the short term, the objective of operating under one synchronous network is mainly related to the stability of the system. In order to increase the system stability and reach a safe operation of one synchronous zone, the commissioning of new interconnection lines is primordial. Secondly, the importance of the ICC is here put forward due to its different roles in order to operate an interconnected network. These two aspects are clearly a necessity in the short-term horizon and should be a priority to operate the WAPP network synchronously.

In terms of stability, the synchronous operation of the WAPP system will be the most challenging in its first years of operation. The network presents long distances, different topologies and few weakly interconnected borders, generally at the interface between the current synchronous blocks.

The major stability issues have been detected at the interfaces between the existing synchronous blocks, in particular:

- The interconnected WAPP system will be subject to interarea modes (large groups of generation units swinging in opposition to each other following small disturbances on the network) due to long distances. The recently finalized "WAPP synchronization study" already recommended installing additional PSS but this measure should be extended before the synchronisation of the entire WAPP system with dedicated tuning to damp interarea oscillations. In particular, a dangerous interarea mode has been detected between the synchronous block C and the rest of WAPP.
- The interface between Block C and B is not secure. The stability of the entire system is compromised whenever one of the lines is faulted. A Special Protection Scheme (SPS) is recommended in order to operate safely considering the economic exchanges planned between Nigeria and the rest of the WAPP.
- The interface between Block A and B is not secure as it's composed of only two single-circuit transmission lines. The stability of the entire system is compromised whenever one of the lines is faulted. A minimum set of reinforcements is proposed to secure the interface.
- Voltage support is insufficient in different zones of the WAPP system. Once synchronized, voltage instabilities can easily evolve in system-wide issues. Thus, the most problematic zones have been identified and remedial actions proposed.

The criticalities identified in the static and dynamic studies are represented in the figure below.

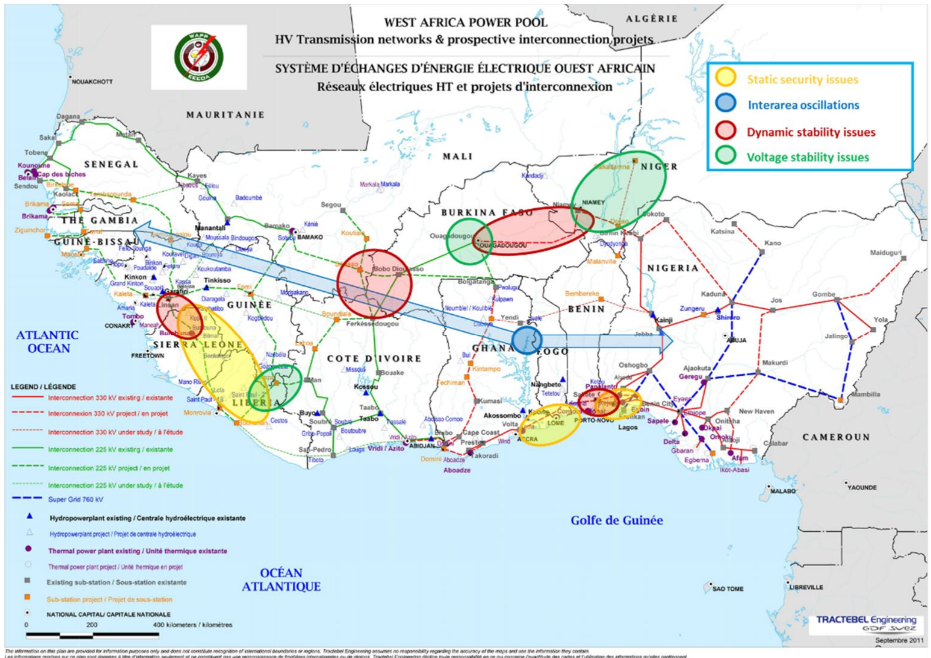


Figure 25: Transmission network criticalities at short-term - 2022

3.2.2. Modelling of the 2022 WAPP network

The hypothesis and information that was used to create the 2022 model of the WAPP are described in the following sections.

3.2.2.1. DECIDED INTERCONNECTION PROJECTS

The model of the existing grid was taken as the starting point to create the 2022 model of the WAPP network.

In the short-term horizon of 2022, the following interconnections shown in Table 5 have been decided and will be present. These interconnecting lines are considered to be constructed and fully operational by 2022. In such a way, block A will be connected to block C with the commissioning of the Sakete (Benin) – Davié (Togo) – Volta (Ghana) 330 kV line and the North Core (Nigeria – Niger – Burkina). The commissioning of the OMVG line and the Guinea – Mali line will interconnect Guinea to Mali and to block A and B. Additionally, this interconnection between Guinea and Mali will create a direct link to CLSG. The isolated countries of Sierra Leone and Liberia will be connected through the first circuit of the CLSG line. The same saying is true for the countries of The Gambia and Guinea Bissau which will be interconnected through the OMVG line.

Country	HV Interconnection	Voltage Level [kV]	Rated Power [MVA]	Commissioning Year	Length [km]	Single (SC) / Double Circuit (DC)
CI-LI-SL-GU	CLSG	225	330	2020	1303	DC
GH-BU	Bolgatanga-Ouagadougou	225	330	2018	198	SC
GH-TO	Volta-Davié (Lomé)	330	1000	2019	340	SC
TO-BN	Davié-Sakete	330	1000	2019		SC
BU-NR-NI-BN	Dorsale North	330	777	2022	832	DC
SE-GA-GB-GU	OMVG	225	330	2020	1677	SC
MA-SE	Kayes-Tambacounda	225	330	2020	288	DC
SE-MAU	Noukchott-Tobene	225	330	2020	425	DC
MA-MAU	Kayes-Kiffa	225	330	2021	420	DC
TO-BN	Porga-Dapaong	161	178	2022	83	SC
TO-GH	Dapaong – Bawku	161	178	2022	53	SC
GU-MA	N'Zérékoré – Fomi – Bamako	225	330	2022	1074	DC

Table 5: Decided interconnections (After 2017)

3.2.2.2. NATIONAL REINFORCEMENTS

Additionally to these interconnections, the elements which are added to the existing model to create the 2022 network are summarized by country in the Annex. These reinforcements are based on the national and regional master plans and based on the information collected during the model validation workshop. It should be noted that most of these national projects were considered as decided and were not subject to an optimization due to the short-term horizon of 2022 and the regional vision of this master plan.

3.2.2.3. DEFINITION OF THE SCENARIOS – TARGET YEAR 2022

The load levels which were modelled in the different scenarios that were studied for 2022 are details in the following paragraph.

For the target year of 2022, two different scenarios were analyzed:

- Asynchronous peak evening situation
- Synchronous Off-peak with maximum renewable infeed scenario

In the peak load scenario, the load modelled corresponds to the yearly **asynchronous peak load** of every country. This scenario where every country observes their peak load at the same time is a conservative way of analyzing the reinforcement needs on the grid. This active load level is presented in Table 6. The same power factor as the existing model (2017) was kept for this study year.

Country	Peak Load 2022
BENIN	359 MW
BURKINA	471 MW
CÔTE D'IVOIRE	2013 MW
GAMBIE	140 MW
GHANA	3217 MW
GUINEE	551 MW
GUINEE BISSAU	105 MW
LIBERIA	166 MW
MALI	680 MW
NIGER	430 MW
NIGERIA	11500 MW
SENEGAL	944 MW
SIERRA LEONE	428 MW
TOGO	328 MW
TOTAL	21331 MW

Table 6: Load level - Peak 2022

The load level modelled in the off-peak scenario is such as shown in Table 7. This load level is the lowest yearly **synchronous load**.

Country	Off-peak Load 2022	Percentage of peak load (%)
BENIN	165 MW	46 %
BURKINA	269 MW	57 %
CIV	1047 MW	52 %
GAMBIE	62 MW	44 %
GHANA	2155 MW	67 %
GUINEE	242 MW	44 %
GUINEE BISSAU	46 MW	44 %
LIBERIA	73 MW	44 %
MALI	415 MW	61 %
NIGER	228 MW	53 %
NIGERIA	5980 MW	52 %

Final version

Country	Off-peak Load 2022	Percentage of peak load (%)
SENEGAL	548 MW	58 %
SIERRA LEONE	188 MW	44 %
TOGO	151 MW	46 %
TOTAL	11568 MW	51 %

Table 7: Load level - Off-peak 2022

3.2.2.4. NORTH CORE COMPENSATION

The compensation scheme of the North Core project has been reviewed recently. In addition to the shunt compensation already foreseen and included in the model, serie compensation could be added on the line. This series compensation is not included in the study model. However it should be noted that it could impact the maximum power transfer between Niger/Nigeria and WAPP and the required means in terms of voltage control, albeit not to such extent as to change the results of this regional planning study.

3.2.3. Static studies

This section presents the simulation results for the different scenarios that were tested in 2022. The balance of each country is presented as well as the generation dispatch and the results for each scenario. A special attention will be given here to the analysis of the synchronization of the WAPP in 2022 and the investments needed in order to successfully operate the synchronous network in a stable way.

3.2.3.1. ASYNCHRONOUS PEAK 2022

In this scenario, it is considered that no renewable power is produced by PV plants due to the fact that the peak appears during the evening hours. This aspect is represented in Figure 26.

Final version

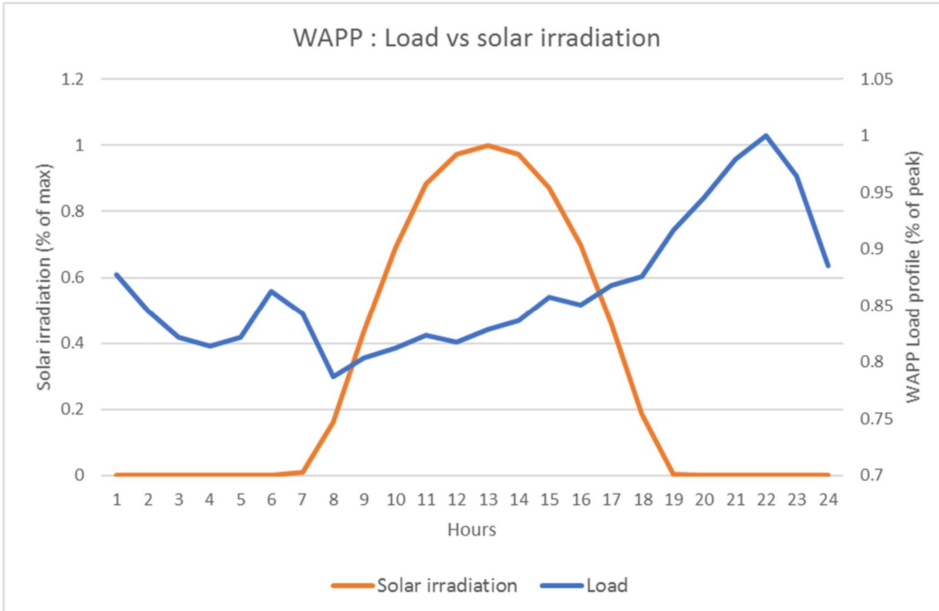


Figure 26: Load vs solar irradiation curve

The available generation units as well as the peak dispatch are based on the results of the economic analysis. The country balances which are represented in Table 8 are a direct consequence of the results of the economic analysis. In this peak scenario, similarly to solar power, wind power is also assumed to be inexistent. Furthermore, it is assumed that hydro power plants are dispatched at their maximum capacity.

Country	Peak Balance
BURKINA	- 361 MW
CIV	141 MW
GAMBIE	- 28 MW
GHANA	21 MW
GUINEE	464 MW
GUINEE BISSAU	- 62 MW
LIBERIA	- 84 MW
MALI	- 60 MW
NIGER	- 62 MW
NIGERIA	663 MW
SENEGAL	- 91 MW
SIERRA LEONE	- 299 MW
TOGO - BENIN	- 229 MW

Table 8: Country balance – Asynchronous Peak 2022

Final version

Line Name	Voltage level (kV)	Country - Sending Node	Country - Receiving Node	Active Power Flow (MW)	Loading - Current (%)
Ikeja West_330-Sakete_330-1	330	NI	TB	302.6	52.9
Goroubanda_330-Ouaga Est_330-1	330	NR	BU	140.7	44.4
Goroubanda_330-Ouaga Est_330-2	330	NR	BU	140.7	44.4
Birnin Kebbi_330-Zabori_330-1	330	NI	NR	129	40.7
Birnin Kebbi_330-Zabori_330-2	330	NI	NR	129	40.7
Linsan_225-Kamakwie_225-1	225	GU	SL	117.4	34.5
Linsan_225-Kamakwie_225-2	225	GU	SL	117.4	34.5
Kayes_225-Bakel_225-1	225	MA	SE	95.4	37.4
Katsina_132-Gazaou_132-1	132	NI	NR	78.5	85.2
Boke_225-Salthinho_225-1	225	GU	GB	73.2	22.2
Siguiri_225-Sanakoroba_225-1	225	GU	MA	66.6	20.7
Siguiri_225-Sanakoroba_225-2	225	GU	MA	66.6	20.7
Man_225-Yekepa_225-1	225	CI	LI	56.4	18.5
Man_225-Yekepa_225-2	225	CI	LI	56.4	18.5
Bolgatanga_330-Bobo_330-1	330	GH	BU	53.5	11.3
Bolgatanga_330-Bobo_330-2	330	GH	BU	53.5	11.3
Davié_330-Dawa_330-1	330	TB	GH	49.2	5.6
Tanaf_225-Soma_225-1	225	SE	GA	30.3	9.1
Mano_225-Kenema_225-1	225	LI	SL	30.1	8.8
Mano_225-Kenema_225-2	225	LI	SL	30.1	8.8
Birnin Kebbi_132-Dosso_132-1	132	NI	NR	28.1	30.8
Cinkassé_161-Bawku_161-1	161	TB	GH	27.6	16.5
Mansoa_225-Tanaf_225-1	225	GB	SE	27.5	11.3
Zabori_330-Malanville_330-1	330	NR	TB	24.1	7.4
Lomé (Aflao) 1_161-Aflao Ghana_161-1	161	TB	GH	19.9	29.3
Bobo_330-Sikasso_330-1	330	BU	MA	17.8	2.5
Bobo_330-Sikasso_330-2	330	BU	MA	17.8	2.5
N'Zérékore_225-Yekepa_225-1	225	GU	LI	13.9	4.3
N'Zérékore_225-Yekepa_225-2	225	GU	LI	13.9	4.3
Kayes_225-Tambacounda_225-1	225	MA	SE	11.7	6.5
Kayes_225-Tambacounda_225-2	225	MA	SE	11.7	6.5
Ferkéssédougou_225-Sikasso_225-1	225	CI	MA	11.2	3.4
Ferkéssédougou_225-Kodeni_225-1	225	CI	BU	10.9	3.5
Asiekpe PST_161-Lomé (Aflao) 1_161-1	161	GH	TB	3.1	17.7
Soma_225-Kaolack_225-1	225	GA	SE	2.4	3.9
Mali_225-Sambangalou_225-1	225	GU	SE	2.4	2.3
Bolgatanga_225-Ouaga Sud_225-1	225	GH	BU	1.9	7.6
Elubo_225-Bingerville_225-1	225	GH	CI	1.7	10.2

Final version

Table 9: Flows on interconnection – Asynchronous Peak 2022

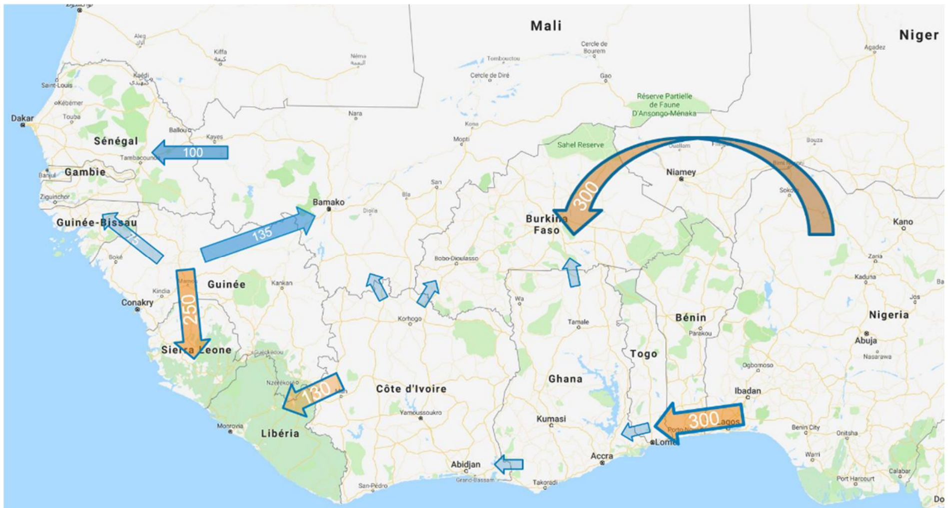


Figure 27: Visualization of the active power flows - Peak 2022

From the load flow simulations at the peak it is observed that the East-West flows are significant due to the importance of the exports of Nigeria. With most of the power exported from Nigeria being sent to importing countries of Togo, Benin and Burkina, the North Core and the Ikeja West – Sakete interconnection are both loaded at around 50% of their thermal capacity.

On the Western part of the region, the exporting country of Guinea is sending mainly its power through CLSG to the countries of Sierra Leone and Liberia which lack generation capacities to satisfy their peak load economically.

A general observation made is that most of the interconnections lines are not highly loaded at the peak which gives space for greater exchanges between countries in the case of emergency situations or unlikely scenarios. It has to be noticed that the dynamic simulations presented in the next section 3.2.4. highlights further limitations due to stability limits and that the conclusions can be far different.

It was seen that the voltages in Niger cannot be held to the operational limits in the eastern part where long 132 kV lines are present. The increase of load in the east creates a voltage drop in Zinder which is below .95 p.u. In the short-term horizon, these voltage problems were solved by the addition of capacitor banks in areas radially connected by long 132 kV lines.

Considering the short time period up to 2022 and the number of lines already decided and needing to be built, the application of the N-1 criterion is not realistic and was not applied to the 2022 network. The list of problematic N-1 equipment is shown here forth. Only the contingencies and overloads having a regional interest are shown in the table below. These identified weaknesses are further analyzed and detailed in the dynamic analysis (next section).

Contingency	Overload
CLSG	Voltage collapse at the extremity which became radially connected
Ikeja West 330 kV – Sakete 330 kV - 1	Voltage collapse in Lagos region
Volta 330 kV – Asogli 330 kV - 1	Overload of double circuit Davié – Lomé 161 kV
Ouaga South East 225 kV – Ouaga Sud 225 kV - 1	Overload of Patte D'Oie-Ouaga South East 132 kV

Table 10: List of problematic contingencies – Peak 2022

Figure 28: Non-secure N-1 contingencies - 2022 static peak scenario

3.2.3.2. SYNCHRONOUS OFF-PEAK 2022

The results of the synchronous off-peak scenario which was studied is shown hereunder. Table 11 shows the balances of each country in this scenario. Theses balances are representative of the economic dispatch and exchanges that result from the optimization.

Final version

Country	Off-peak Balance
BURKINA	- 1 MW
CIV	29 MW
GAMBIE	18 MW
GHANA	32 MW
GUINEE	264 MW
GUINEE BISSAU	24 MW
LIBERIA	- 2 MW
MALI	- 103 MW
NIGER	134 MW
NIGERIA	-252 MW
SENEGAL	49 MW
SIERRA LEONE	- 55 MW
TOGO - BENIN	- 125 MW

Table 11: Country balance - Off-peak 2022

In the off-peak case studied here, renewable infeed is considered to be of 100% for the concerns of PV units and wind turbines. This scenario allows to identify if the totality of possible infeed that can be evacuated through the grid.

The flows on the interconnection lines are shown in the table below.

Line Name	Voltage level (kV)	Country - Sending Node	Country - Receiving Node	Active Power Flow (MW)	Loading - Current (%)
Dawa_330-Davié_330-1	330	GH	TB	131.5	20.3
Zabori_330-Birnin Kebbi_330-1	330	NR	NI	88.7	28.4
Zabori_330-Birnin Kebbi_330-2	330	NR	NI	88.7	28.4
Sakete_330-Ikeja West_330-1	330	TB	NI	77.1	12.6
Siguiri_225-Sanakoroba_225-1	225	GU	MA	70	22.4
Siguiri_225-Sanakoroba_225-2	225	GU	MA	70	22.4
Bobo_330-Bolgatanga_330-1	330	BU	GH	66.2	15.3
Bobo_330-Bolgatanga_330-2	330	BU	GH	66.2	15.3
Bingerville_225-Elubo_225-1	225	CI	GH	63.6	20.2
Sikasso_330-Bobo_330-1	330	MA	BU	56.1	12.6
Sikasso_330-Bobo_330-2	330	MA	BU	56.1	12.6
N'Zérékore_225-Yekepa_225-1	225	GU	LI	49.4	14.5
N'Zérékore_225-Yekepa_225-2	225	GU	LI	49.4	14.5
Yekepa_225-Man_225-1	225	LI	CI	42.1	12.4
Yekepa_225-Man_225-2	225	LI	CI	42.1	12.4

Final version

Line Name	Voltage level (kV)	Country - Sending Node	Country - Receiving Node	Active Power Flow (MW)	Loading - Current (%)
Ferkéssédougou_225-Kodeni_225-1	225	CI	BU	40.4	16.5
Asiekpe PST_161-Lomé (Aflao) 1_161-1	161	GH	TB	29.2	23.7
Bakel_225-Kayes_225-1	225	SE	MA	28.7	14.1
Aflao Ghana_161-Lomé (Aflao) 1_161-1	161	GH	TB	26.4	23.2
Bawku_161-Cinkassé_161-1	161	GH	TB	23.5	22.2
Linsan_225-Kamakwie_225-1	225	GU	SL	21	7.7
Linsan_225-Kamakwie_225-2	225	GU	SL	21	7.7
Soma_225-Kaolack_225-1	225	GA	SE	20.8	11.2
Tambacounda_225-Kayes_225-1	225	SE	MA	17.6	5.4
Tambacounda_225-Kayes_225-2	225	SE	MA	17.6	5.4
Ouaga Est_330-Goroubanda_330-1	330	BU	NR	17	34.5
Ouaga Est_330-Goroubanda_330-2	330	BU	NR	17	34.5
Salthinho_225-Boke_225-1	225	GB	GU	16.5	7.2
Katsina_132-Gazaou_132-1	132	NI	NR	16.1	38.2
Mansoa_225-Tanaf_225-1	225	GB	SE	14.4	9.1
Dosso_132-Birnin Kebbi_132-1	132	NR	NI	13.3	12.7
Ferkéssédougou_225-Sikasso_225-1	225	CI	MA	13.3	7.5
Bolgatanga_225-Ouaga Sud_225-1	225	GH	BU	12.8	4.2
Mano_225-Kenema_225-1	225	LI	SL	6.7	5.6
Mano_225-Kenema_225-2	225	LI	SL	6.7	5.6
Malanville_330-Zabori_330-1	330	TB	NR	6.7	6.8
Tanaf_225-Soma_225-1	225	SE	GA	2.7	3.3
Mali_225-Sambangalou_225-1	225	GU	SE	1.6	2.5

Table 12: Flows on interconnection - Off-peak 2022

Table 13 shows the contingencies which are problematic in the 2022 off-peak case. It can be noted that the contingency shown here in the table is linked to the production of Asogli 2 and that changing the dispatch of this one could remove the observed overload.

Contingency	Overload
Asogli 330 kV -Dawa 330 kV - 1	Overload of Akosombo – Lomé Aflao 161 kV

Table 13: List of problematic contingencies – Off-peak 2022

3.2.4. Dynamic studies

3.2.4.1. SMALL SIGNAL STABILITY

This section presents the results of the small-signal stability analysis of the WAPP interconnected network for target-year 2022, at peak and off-peak load conditions.

3.2.4.1.1. Peak Load - Simulation results

Starting from the initial load flow solution (base case), the eigenvalues of the network in normal operation conditions are computed.

The foreseen PSS scheme, as communicated by the Client, provides sufficient damping for the vast majority of modes, except for one interarea mode and few local modes, presented in Table 14. Modes with a damping ratio higher than 5% are not included in the table.

Mode ID	Eigenvalue	Damping Ratio [%]	Frequency [Hz]	Participating plants
230	-0.204 + 10.8434j	1.8807	1.7258	Boutubre (CIV)
231	-0.204 + 10.8434j	1.8807	1.7258	Boutubre (CIV)
228	-0.2102 + 10.5608j	1.9901	1.6808	Boutubre, Gribo Popo (CIV)
229	-0.2153 + 10.65j	2.0212	1.695	Gribo Popo (CIV)
280	-0.0384 + 1.7201j	2.232	0.2738	Interarea: Nigeria/Niger vs. WAPP

Table 14: List of modes with damping ration below 5% - 2022 peak

A badly dampened interarea mode of 0.27 Hz is detected at peak load condition. The remaining local modes in Côte d'Ivoire can easily be solved by adding a PSS.

The current eastern synchronous block oscillates against the rest of the WAPP. The mode shape is shown in Figure 29

2022 Peak – initial case – Results of Small Signal Stability analysis

Interarea Mode NI/NR/TB vs WAPP	Eigenvalues

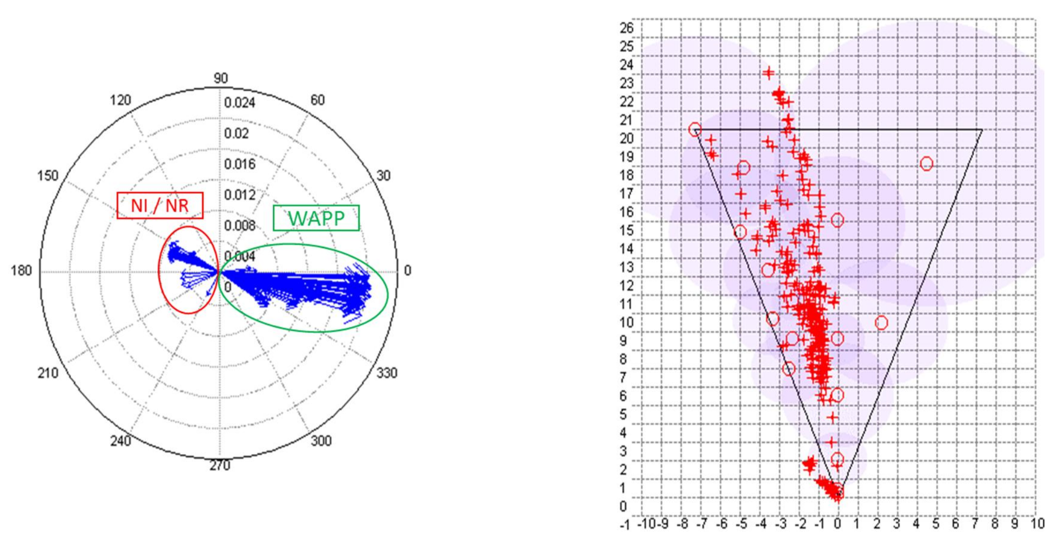


Figure 29: Results of Small Signal Stability analysis - 2022 peak.

The insufficient damping of the interarea mode causes power oscillations of increasing magnitude following a small variation of the operating point. The units at the extremities of the WAPP system, especially hydro ones, are subject to the largest power oscillations. Figure 30 shows the speed of the units of Manantali (Mali) and Egbin 1 (Nigeria) following the loss of a unit in Egbin 2 (Nigeria).

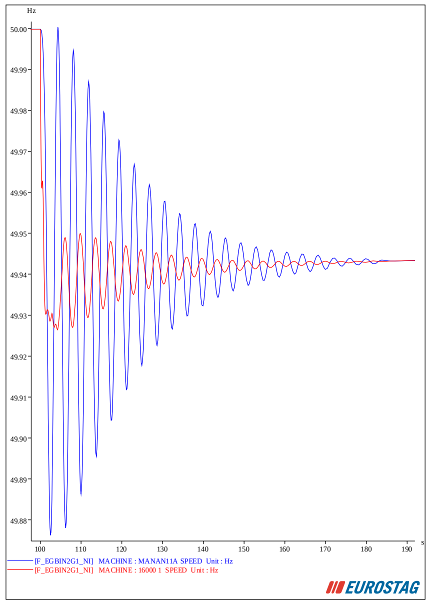


Figure 30: Machine speed of Manantali (MA) and Egbin 2 (NI) following loss of one unit of Egbin 2 – 2022 peak.

In the following sections of this document, the abbreviation **(Rx)** will be used to refer to the set of recommendations that should be implemented by 2022.

The damping of the interarea mode is improved by reinforcing the network. With both reinforcements R2 and R4 in place, the interarea mode results damped to 4.94% at peak load, close to the target but still insufficient.

However, improving the damping by additional reinforcements proved to be inefficient as too many investments would be required by 2022. Therefore, the Consultant recommends to expressly tune PSS of some large units at the extremities of the WAPP system (e.g. in Guinea / Mali on one side and in Nigeria on the other side) to improve the damping of the critical interarea mode to a value above 6% **(R1)**.

3.2.4.1.2. Off-peak Load - Simulation Results

Off-peak load conditions are less challenging in terms of small signal stability. The results of the eigenvalues computation with the reinforcements in place are reported in Table 15 and Figure 31. The interarea mode is well dampened at off-peak load.

Mode ID	Eigenvalue	Damping Ratio [%]	Frequency [Hz]	Participating plants
35	-0.2138 + 10.665j	2.0045	1.6974	Boutubre, Gribo Popo (CIV)
3	-0.8124 + 15.7435j	5.1532	2.5057	Kaduna (NI)
1	-0.7842 + 14.9396j	5.2416	2.3777	Azura (NI)
106	-0.1815 + 3.4553j	5.2464	0.5499	Interarea: Nigeria/Niger vs. WAPP

Table 15: List of modes with damping ration below 5.5% - 2022 off-peak

2022 Off-Peak – reinforced R2, R4 and R5– Results of Small Signal Stability analysis

Interarea Mode NI/NR/TB vs WAPP	Eigenvalues

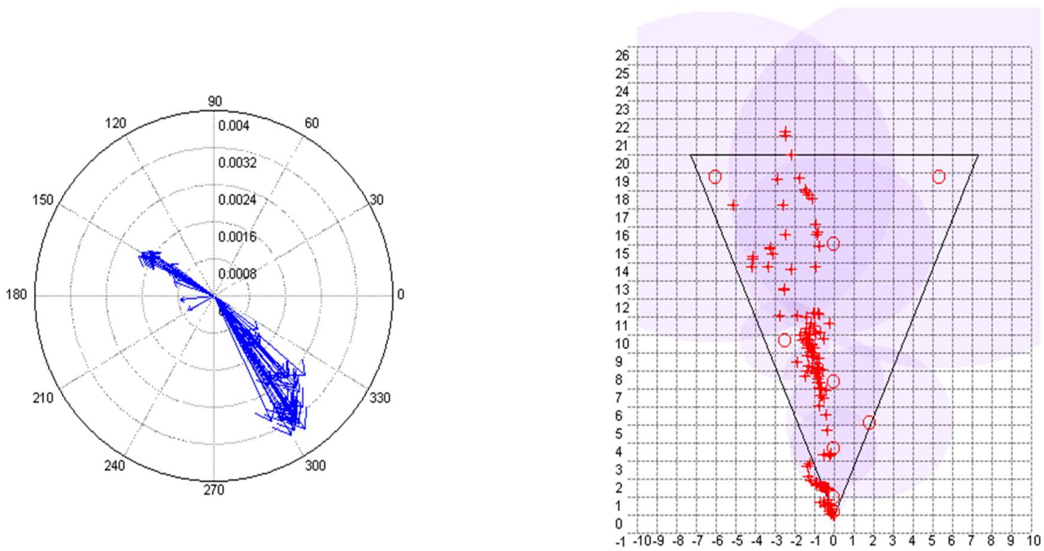


Figure 31: Results of Small Signal Stability analysis - 2022 off-peak.

3.2.4.2. DYNAMIC SECURITY ANALAYSIS

The objective of the dynamic security analyses is to verify the ability of the system to endure faults in the transmission network without loss of synchronism of generating units and other destabilizing phenomena such as voltage collapses.

The transmission system at 2022 presents two critical interfaces, corresponding approximately to the borders between the current synchronous blocks. These interfaces are illustrated in Figure 40 and are characterized by the following criticalities:

- **Critical Interface 1 - Nigeria / Niger with the rest of WAPP**: about half of the exported power from Nigeria (670 MW total in peak base case) is exported along the southern corridor through a single circuit 330 kV transmission line. On the other hand, the northern corridor connects two weak parts of Burkina Faso and Niger.

Final version

- **Critical Interface 2 - Central WAPP with western WAPP**: while the power transferred through the interface is not significantly high, the two blocks will be interconnected by only two circuits by 2022.

Three-phase short circuits cleared in 100 ms base time are simulated on interconnection lines at these interfaces and on other relevant branches. The full DSA methodology is presented in Annex.

3.2.4.2.1. Peak Load – Simulations Results

Critical Interface 1 – Block C with the rest of WAPP

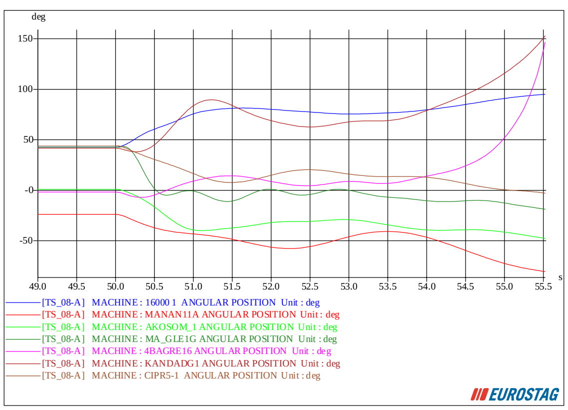
Faults cleared in 100 ms by tripping the faulted lines are simulated on the single circuit of the NI-TB interconnection and on one circuit of the North Core interconnection.

Losing the NI-TB interconnection causes a split of the system, a coherent group of machines in Nigeria, Niger and Burkina will lose synchronism with the machines of the rest of WAPP, as shown in Figure 32.

The split is caused by the redistribution of power flows following the loss of the NI-TB interconnection. The exported power from Nigeria is forced to pass entirely through the North Core causing angular and voltage instability (in Burkina Faso and Niger).

2022 Peak – initial case – loss of NI-TB interconnection

Machine angle [deg]



Voltage at Ouagadougou [p.u.]

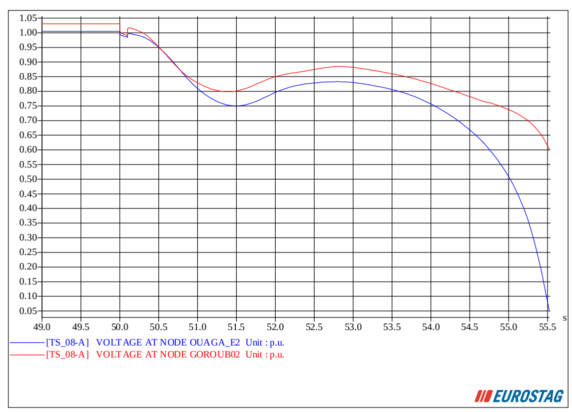


Figure 32: Voltage and angle transients the following loss of NI-TB interconnection - 2022 peak initial case.

Following the same pattern, voltage instability is detected also following the loss of one circuit of the North Core. The flow on the remaining circuit and on the NI-TB interconnection increases, violating voltage stability limits and causing voltage collapses in Burkina Faso and Niger. Eliminating these instabilities requires:

- Increasing the reactive power compensation in Burkina by adding a 100 MVAr SVC at Ouagadougou substation (R5);
- Installing a Special Protection Scheme (SPS) to allow the expected energy exchanges between Nigeria and the rest of WAPP (**R4**). The flows being exported from Nigeria would then be reduced to less than 350 MW in case of critical contingencies on the interface 1. In normal operation, higher exchanges could be maintained.

In these conditions, the response of the system to the loss of the NI-TB interconnection (worst case) is satisfactory, as presented in Figure 33.

2022 Peak – Reinforcements R4 and R5 – loss of NI-TB interconnection

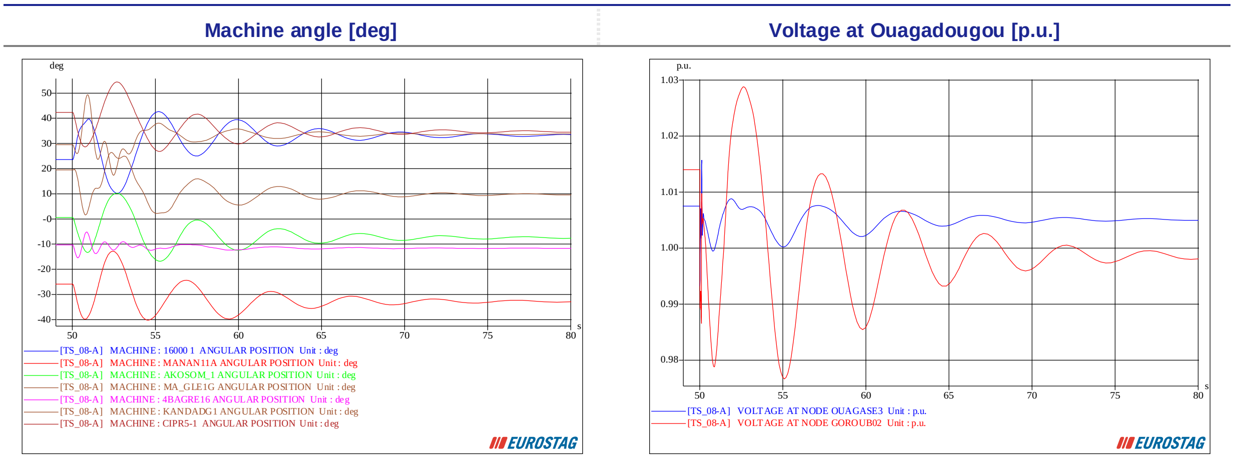


Figure 33: Voltage and angle transients the following loss of NI-TB interconnection, 2022 peak with R4 and R5.

Critical Interface 2 - Central with western WAPP

The interface between Côte d'Ivoire and the western part of WAPP is composed on two single circuit interconnections. Losing any one of these interconnections leads to instabilities. Figure 34 shows the response of the system to the loss of the Sikasso (Mali) – Ferke (Côte d'Ivoire) interconnection.

2022 Peak – Reinforcements R4 – R5 – Loss of MA - CIV interconnection

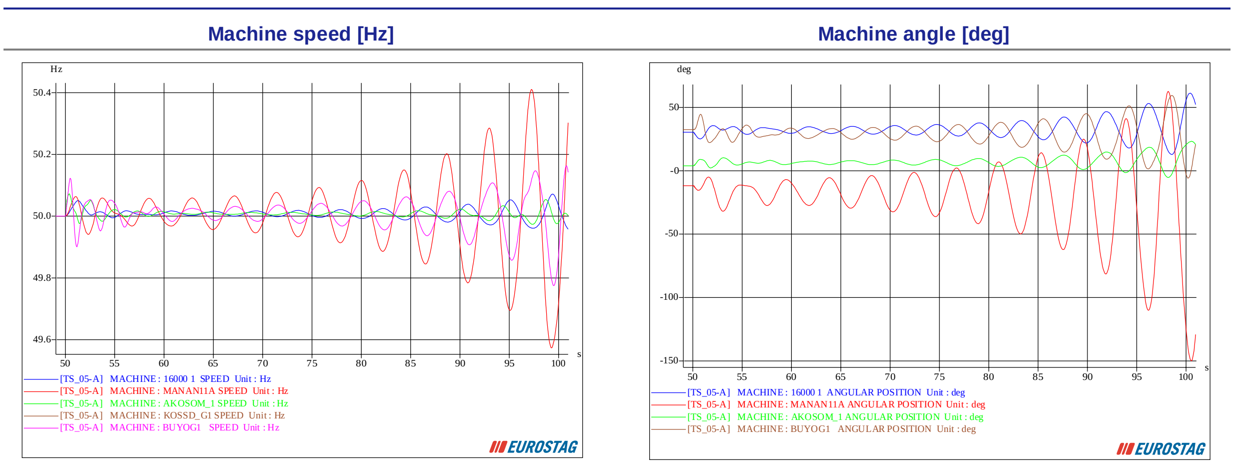


Figure 34: Machine speed and angular transients following loss of MA - CIV interconnection, 2022 peak with R4 and R5.

Unstable oscillations are observed due to the excitation of the interarea mode. These undamped oscillations leads to voltage collapse at the border between Côte d'Ivoire and Liberia and along the CLSG route. Afterwards, the increasing angular deviation would end up in loss of synchronism and splitting of the system.

Final version

Figure 35 shows the response of the system to the loss of the other interconnection, between Man (Côte d'Ivoire) and Yekepa (Liberia), part of the CLSG project.

2022 Peak – Reinforcements R4 and R5 – Loss of LI - CIV interconnection

Machine speed [Hz]	**Machine angle [deg]**

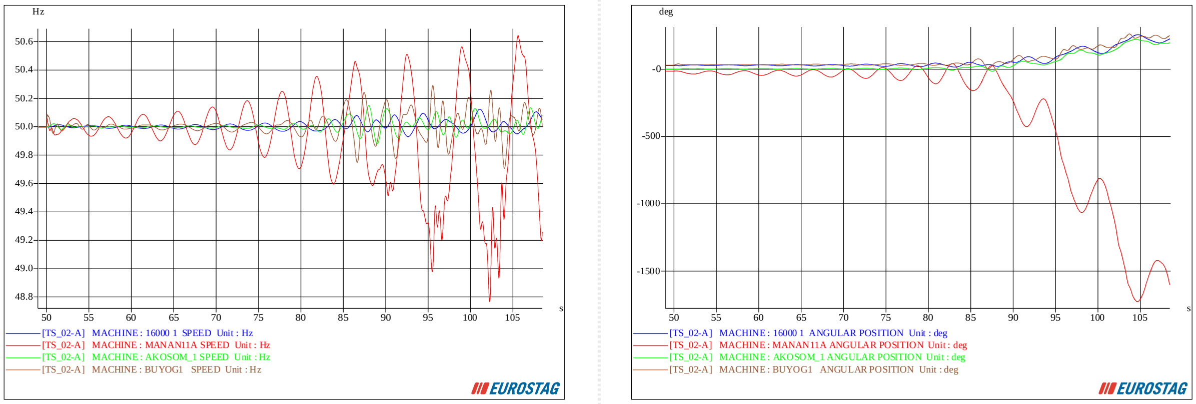


Figure 35: Machine speed and angular transients following loss of MA - CIV interconnection, 2022 peak with R4 and R5.

In this case, it can be observed how the oscillations causes loss of synchronism in the system.

These unstable operating conditions can be mitigated by increasing the damping of the interarea mode **(R1)** and by anticipating the investment of the 330 kV interconnection between Sikasso (Mali), Bobo (Burkina Faso) and Bolgatanga (Ghana) **(R2-A).**

This investment also brings the added benefit of improving the dynamic stability of the North Core being its continuation. Figure 36 shows the satisfactory response of the system with the reinforcements in place.

2022 Peak – Reinforcements R4, R5 and R2-A – Loss of LI - CIV interconnection

Machine speed [Hz]	**Machine angle [deg]**

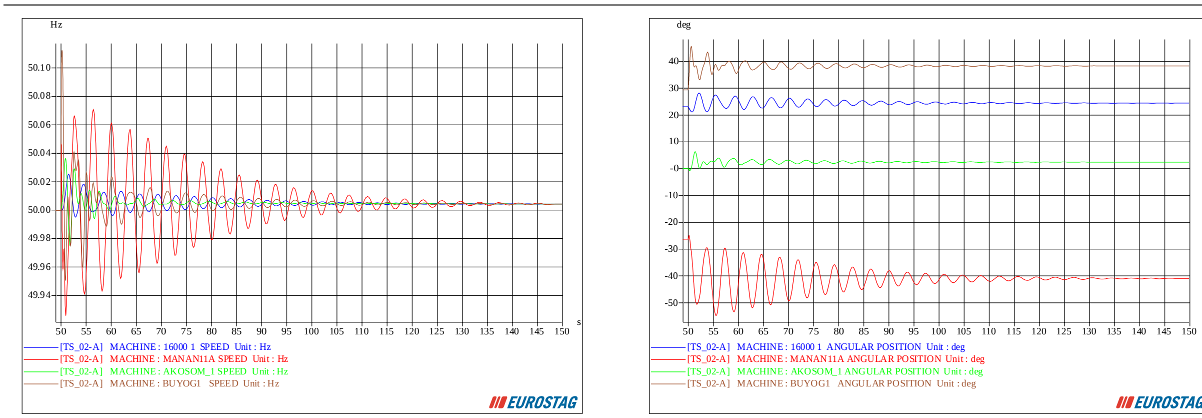


Figure 36: Machine speed and angular transients following loss of MA - CIV interconnection, 2022 peak with R4, R5 and R2-A.

Other results of the DSA analysis

The reinforced system has been tested against the loss of several other key transmission lines. The list of selected incidents and the results of the analysis are reported in Annex.

The analyses show voltage stability issues along the CLSG transmission line. When the single-circuit interconnection between Linsan (GU) and Kamakwie (SL) or between Kamakwie (SL) and Yiben (SL) is tripped, voltage collapses are detected in several substations in Liberia and Sierra Leone, as presented in Figure 37.

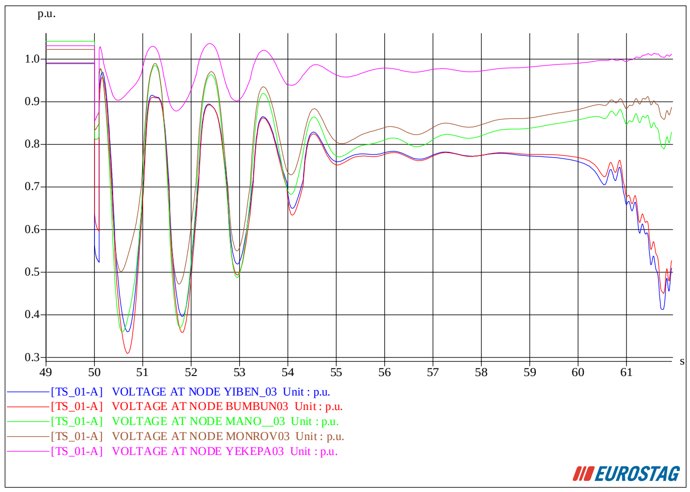


Figure 37: Voltage transients along CLSG following the tripping of the Linsan (GU) – Kamakwie (SL) line – 2022 peak R4, R5 and R2-A.

To address this issue, the Consultant recommends to:

- Anticipate the second circuit of CLSG project (building CLSG directly with 2 circuits), interconnecting Guinea to Cote d'Ivoire, in order to ensure N-1 security on that border (**R2-B**);

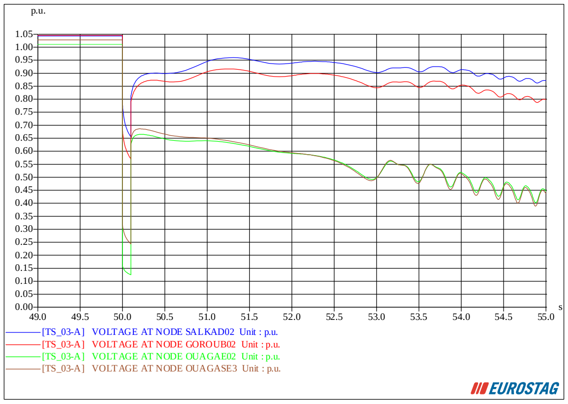
These recommendations have to be intended as minimal remedial actions.

A dynamic security analysis has been carried out on the reinforced network implementing a dynamic load model with 40% of rotating loads. For the loss of one circuit of the BU-NR North Core interconnection, voltage collapses are observed in Burkina Faso and Niger. Additional dynamic voltage support is required. The best option is to install a 200 MVAr SVC at Salkadama (Niger) **(R5)**. This substation is suitable because it's connected to the rest of the system through very long 330 kV AC lines and it might serve as connection point for future interconnections, maximizing the technical benefits of the SVC. The results with and without the SVC are presented in Figure 38.

Final version

2022 Peak – Reinforcements R4, R5 and R2 – Loss of BU - NR interconnection

Voltage transients in BU and NR **without** new SVC [p.u]



Voltage transients in BU and NR **with** new SVC [p.u]

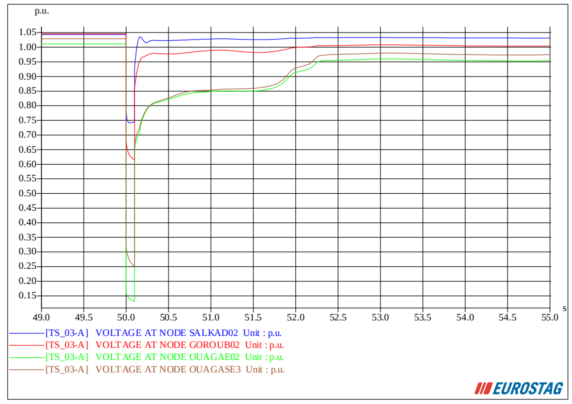


Figure 38: Voltage transients in BU and NR following loss of one circuit of the BU - NR interconnection, 2022 peak with R4, R5 and R2.

Other relevant results are the following:

- For a 100 ms fault on the 225 kV single-circuit line connecting Man (Cote d'Ivoire) and Yekepa (Liberia), the interarea mode is excited causing voltage oscillation at Ferke (Côte d'Ivoire);
- For a 100 ms fault on the 132 kV single-circuit line connecting Gazaou (Niger) and Katsina (Nigeria), the substations from Maradi (NR) downwards will find themselves at the end of a long feeder. Localized voltage under-voltages will take place. The phenomenon has no impact on the regional operation of the WAPP system.

3.2.4.2.2. Off-Peak Load – Simulations Results

At off-peak load, the results do not show signs of transient instability except what has already been detected for peak load. The results are reported in detail in Annex.

3.2.4.3. FREQUENCY STABILITY

The objective of the frequency stability analyses is to verify the ability of the system to endure transient phenomena caused by active power unbalances such as the loss of the large generators and loads in various zones of the WAPP system. The methodology is detailed in Annex.

3.2.4.3.1. Peak load – Simulation Results

The results of the frequency stability simulations for the loss of the following generation units and large loads is detailed in Table 16. Fault time is at 50 seconds.

Country	Type (unit / load)	Plant / Load	Lost Power (MW)	Machines speed				Stable	Comments
				Min (Hz)	Time of min (s)	Max (Hz)	Time of max (s)		
NI	unit	Egbin 2	285	49.886	52.505	50.000	50.338	yes	damped oscillations
CIV	unit	Soubre 3	87	49.926	50.233	50.004	50.646	yes	excited oscillations
GH	unit	Akosombo 1	140	49.885	419.796	50.057	421.534	yes	excited oscillations
GU	unit	Souapiti	112.5	49.864	50.526	50.062	52.011	yes	excited oscillations
MA	unit	Albatros	92	49.897	50.262	50.030	52.287	yes	excited oscillations
TB	unit	Maria Gleta	100	49.937	143.292	50.012	172.867	yes	excited oscillations
BU	unit	Ouagadougou	50	49.925	50.153	50.033	50.456	yes	damped oscillations
NI	load	Benin	340	50.000	50.187	50.081	52.489	yes	damped oscillations
SL	load	Bumbuna	174	49.912	50.411	50.283	50.150	yes	damped oscillations

Table 16: Results of frequency stability analysis - 2022 peak with R2, R3 and R4

All simulated incidents resulted in acceptable frequency transients. The inertia of the interconnected WAPP system and the allocated operating reserve is sufficient to prevent excessive frequency drops and overshoots. For instance, the rate of change of frequency amount to approximately 0.04 Hz/s.

However, the loss of certain units excites the interarea mode causing frequency oscillations. The worst cases are presented in red in the table above. Figure 39 shows the speed of one machine in Nigeria and one in Mali oscillating in phase with each other. The frequency of the oscillations is 0.28 Hz, in line with the observed interarea mode.

Final version

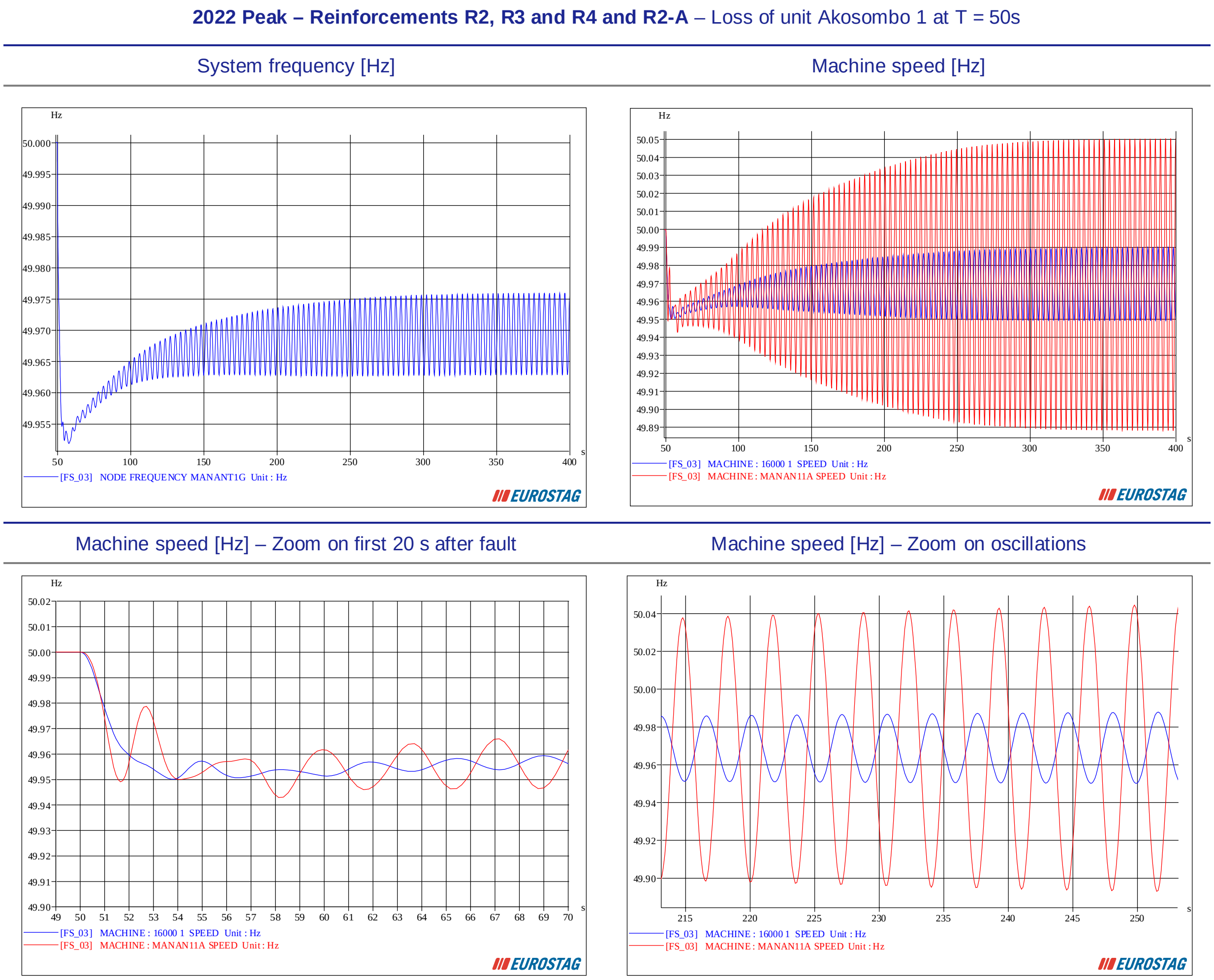


Figure 39: System response to the loss of one unit at Akosombo at T = 50s, 2022 peak with R4, R5 and R2.

It is also observed that the worst cases involve the southern corridor. Nevertheless, reinforcing the 330 kV backbone has proved to be inefficient. Thus, the preferred solution is to accurately dampen the interarea modes of the system.

3.2.4.3.2. Off-Peak load – Simulations results

At off-peak load the frequency transients remain within acceptable ranges, as shown in Table 17 (fault time at 50s). The inertia and operating reserve of the interconnected WAPP network are sufficient at off-peak conditions;

Final version

Country	Type (unit / load)	Plant / Load	Lost Power (MW)	Machines speed Min (Hz)	Time of min (s)	Max (Hz)	Time of max (s)	Stable	Comments
NI	unit	Egbin 2	285	49.797	51.491	50.001	50.181	yes	
CIV	unit	Soubre 1	61	49.938	52.154	50.008	51.165	yes	
GH	unit	Akosombo 1	140	49.861	52.331	50.000	50.016	yes	
GU	unit	Souapiti	108	49.715	50.321	50.023	50.717	yes	required voltage support at Manantali, operate always at least 2 hydro units
MA	unit	Manantali 5	38	49.951	50.158	50.006	50.973	yes	
NI	load	Benin	177	49.999	50.130	50.083	53.081	yes	

Table 17: Results of frequency stability analysis - 2022 off-peak with R2, R4 and R5

The following operational recommendations are drawn from the off-peak results:

- Dynamic voltage support is a critical issue when a generation unit is lost at off-peak. To this end, it is recommended that the hydro power plant of Manantali should be operated with at least two units in operation.
- The Mauritanian system is subject to voltage collapses following the loss of a generating units in several locations in the WAPP.

3.2.5. Technical operation of the network in 2022

It should be noted that for the study year 2022, the network is not yet N-1 compliant.

In 2022, the network studies have highlighted steady-state security issues concerning the import and export of high amounts of power from and to Nigeria. As seen from the economic study, Nigeria should export up to 700 MW at the evening peak. Considering that in 2022, only two evacuation corridors are present (the double-circuit North Core going through North of Nigeria, through Niger and to Burkina Faso; and the single circuit 330 kV line from Nigeria to Benin), losing one of these two corridors causes steady-state problems to continue evacuating the 700 MW from Nigeria to the rest of the WAPP. The issue is confirmed by the dynamic analyses.

Considering the economic exchanges and the investments from the economic analysis, it is seen that only one circuit is necessary for the CLSG line in 2022. However, the investment in the double circuit is justified by 2022 for the system stability and should thus be a priority.

Several challenges to the dynamic stability of the synchronous WAPP system have been identified. The long-distance power flows will subject the system to **interarea modes** (large groups of generation units swinging in opposition to each other following small disturbances on the network). The existing Power System Stabilizer scheme dampens most of these dangerous modes, except for one interarea mode at 0.27 Hz between the current eastern part of WAPP (from Nigeria to Ghana) against the rest of WAPP.

Final version

The recently finalized "WAPP synchronization study" already recommended installing additional PSS but this measure should be further extended before the synchronisation of the entire WAPP system. Dedicated tuning of PSS is required to damp interarea oscillations. In particular, the Consultant recommends to expressly tune PSS on large units at the extremities of the WAPP system to improve the damping of a critical 0.27 Hz interarea mode **(R1)** and reduce dangerous oscillations.

Stability issues have been detected at the interfaces between the existing synchronous blocks.

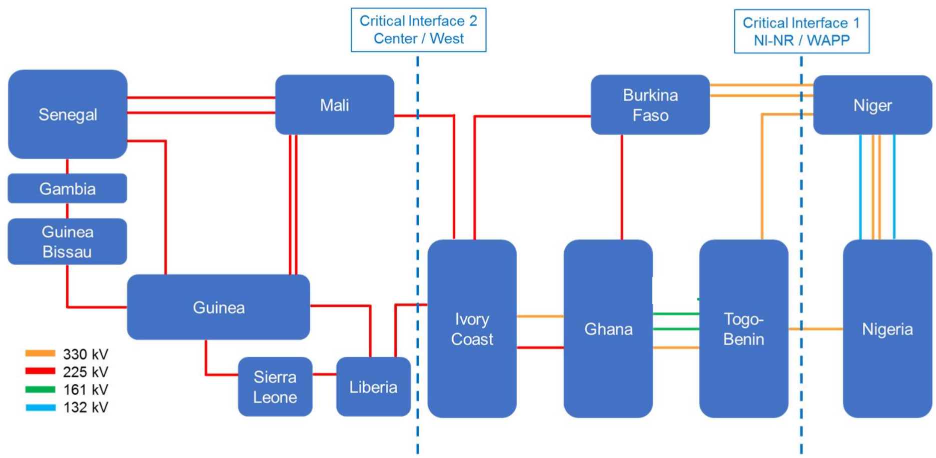


Figure 40: Scheme of the interconnected WAPP system by 2022.

These interfaces are characterized by the following criticalities:

- **Critical Interface 1 - Nigeria / Niger with the rest of WAPP**: The economic study demonstrated the need of a strong interface to allow energy exchanges in both directions (up to 700 MW), importing solar energy during the day and exporting gas-based energy at peak load conditions. With such level of energy exchanges, voltage stability limits of the interconnections are violated when one of them is tripped. In the short term, reinforcing this interface might not be feasible. It is recommended to install a Special Protection Scheme (SPS) in order to reduce the total exported power from Nigeria to 350 MW in the case of a single line contingency on this interface, until cross-border transfer capacity is reinforced (**R4**). Additional dynamic reactive power compensation should be implemented in Burkina Faso and Niger as well (**R5**).
- **Critical Interface 2 - Central WAPP with western WAPP**: the central part of WAPP is expected to be interconnected with the western part through two single circuit 225 kV transmission lines: the initial part of the CLSG project and the single circuit interconnection between Cote d'Ivoire and Mali. Also in this case, the border is not secure even with limited cross-border flows, as losing one key transmission lines nearby would cause instabilities. Two investments can be anticipated:
  - **R2-A**: The 330 kV interconnection between Sikasso (Mali), Bobo (Burkina Faso) and Bolgatanga (Ghana);
  - **R2-B**: The second circuits of the CLSG project, this CLSG line should be directly built with the double circuit to ensure the stability of the system.

Final version

The response of the interconnected system to **frequency transients** is sufficient in all tested cases. The inertia of the system is high enough to avoid triggering any UFLS threshold.

In terms of **voltage stability**, critical areas are detected: the eastern side of Burkina Faso and the CLSG sections in Liberia and Sierra Leone.

In addition to the recommendations of the synchronization study, it is recommended to evaluate further measures of voltage support **(R5)** such as installing two additional SVCs: 100 MVAr at Ouagadougou (Burkina Faso) and 200 MVAr at Salkadama (Niger).

Based on the dynamic simulations, the following set of remedial actions is recommended to achieve sufficient stability of the interconnected WAPP system at the short term:

ID	Recommendations
R1	Tune PSS of some large units at the extremities of the WAPP system to improve the damping of a critical 0.27 Hz interarea mode between eastern WAPP and the rest of WAPP
R2	Reinforcing the Central / Western WAPP interconnections by anticipating two investments: a. 330 kV interconnection between Sikasso (Mali), Bobo (Burkina Faso) and Bolgatanga (Ghana); b. Second circuit of the CLSG project;
R3	Update the Operational Manual of WAPP to ensure a smooth synchronization and harmonize the defence action plan (UFLS, interconnection protections)
R4	Installing a Special Protection Scheme (SPS) to allow the expected energy exchanges between Nigeria and the rest of WAPP
R5	Improve dynamic voltage compensation by adding one SVC at Ouagadougou (BU) and one at Salkadama (NR)

Table 18: List of recommendations to improve dynamic stability at the short term.

Final version

3.3. Mid term development plan - 2025

3.3.1. Increasing the security of the system

In the medium term, at the horizon of 2025, the WAPP's electricity network is becoming more and more interconnected with the increase of the demand level and of exchanges between countries.

In order to satisfy the security of supply, the WAPP network is now moving to a N-1 secure network for which the loss of any high voltage equipment in the network should not cause any major problem on the grid.

From the 2022 dynamic analysis, several weak points of the system were highlighted. These different weak links should be reinforced by 2025 in order to operate the system within the acceptable security limits under any single contingency. The studies realized for the target year 2025 will have as main conclusions of confirming the list of needed investments in order to properly operate the synchronous network under the economic exchanges and the defined security criteria.

To achieve this challenging objective, the following high voltage projects should be prioritized.

NEW DOUBLE CIRCUIT 225 KV GUINEA – CÔTE D'IVOIRE INTERCONNECTION

With the arrival of the Morisanako hydro power plant of 100 MW which should economically be commissioned in 2025, the interconnection line between Côte d'Ivoire and Guinea going through the Morisanako site should be put in service. This 380 km double circuit line will connect the 225 kV Boundiali substation (Côte d'Ivoire) with the 225 kV Fomi substation in Guinea. The line will allow the evacuation of the power from the Morisanako site which comprises of the 100 MW hydro power plant and an additional 100 MW PV park which should be commissioned at the same time. Additionally, considering the potential of the Northern part of Côte d'Ivoire, this line will allow the sharing of renewable energy from Côte d'Ivoire with hydro power from Guinea. Finally, as mentioned in the dynamic analysis of year 2022, this link brings big benefits in the system stability towards an N-1 secure network.

NEW MEDIAN BACKBONE

This double circuit 330 kV line is to be built between Nigeria, Benin, Togo, Ghana and Côte d'Ivoire. The line will connect at the existing 330 kV substation of Shiroro (Nigeria), to the existing 330 kV substation of Kainji (Nigeria), to the new 330 kV substation in Parakou (Benin), the new 330 kV substation in Kara (Togo), the new 330kV substation at Yendi (Ghana), the existing 330 kV substation in Tamale (Ghana) and the new 330 kV substation in Ferkéssédougou (Côte d'Ivoire). The total distance of this line is approximately 1350 km.

This line is of crucial importance for the integration of renewable energy in the long term. By 2033, the needs of Nigeria to import renewable energy from the north of Ghana, the north of Côte d'Ivoire, Mali and Burkina Faso shows the importance of such a new corridor which links these regions together. The connection of the median backbone in Benin and Togo allows for the sharing of renewable potential in these regions whose load is less significant, and possibilities of export are existent. The connection at Kainji proposes the possibility of exporting the hydro power from Nigeria which is located in the North and in the East (Mambilla). Finally, this interconnection offers the advantage of reducing the flows on the North Core when Nigeria is importing a lot of power from the Northern countries, which facilitates the operation and security of the network.

The approximate path of this line and connection points is shown in the illustration below

Figure 41: Median backbone connection points

The dynamic simulations for the 2022 horizon have shown that the maximum transfer capacity of Nigeria to the rest of the WAPP is of around 350 MW under contingency N-1 and without SPS. Considering the economic exchanges that are expected in 2025 which account for maximum exports of more than 400 MW and maximum imports of more than 800 MW, an additional interconnection from Nigeria to the rest of the WAPP is necessary. This interconnection will greatly increase the system stability and allow for a better sharing of resources between Nigeria and the rest of the WAPP.

The increase of transfer capacity brought by the commissioning of this interconnection is evaluated in Table 19.

$$TTC = NTC - TRM$$

Where TTC is the total transfer capacity we are evaluating, NTC is the total possible transfer under N-1 secure rule between country A and country B and the TRM is a reliability margin which is typically taken of around 10%.

Country A	Country B	TTC increase
WAPP	Nigeria	+ 850 MW[10]
Nigeria	WAPP	+ 700 MW

Table 19: Increase of TTC between Nigeria and WAPP

Dynamic analyses have confirmed the positive impact of the median backbone on the stability of the system. The median backbone improves the transfer capacity on the border between Nigeria and the rest of WAPP, unlocking more import and export potential (see 3.3.4.2)

NEW 225 kV DOUBLE CIRCUIT LINE LINSAN – KOUKOUTAMBA – MANANTALI

A new 225 kV interconnection is planned between Guinea and Mali in the 2025 horizon. With the commissioning of the Koukoutamba hydro power plant of close to 300 MW during the 2022-2025 period, a new interconnection line to export this power is necessary. This new double circuit interconnection will connect at the existing 225 kV substation in Linsan (Guinea) on one side and at the existing 225 kV Manantali substation (Mali) on the other. A new substation will be created at Koukoutamba in order to evacuate the power from Koukoutamba on this line. Additionally, the path of this line should go through the future site of Boureya which will be commissioned in the long term. This line will then serve at the evacuation of both of these hydro power plants and increase the exporting capabilities of Guinea to Mali.

NEW 225 kV DOUBLE CIRCUIT LINE LABÉ - KOUKOUTAMBA

From the generation master plan detailed in Chapter 2, it is seen that investments in Fetore (124 MW), Bonkon Diara (174 MW - 2025) and Grand Kinkon (291 MW - 2023) should be realized by 2033 and are economically justified. The connection of these power plants was assumed to be done at the Labé substation. In order to securely evacuate the power from these hydro power plants (total of 589 MW), the existing OMVG loop is not sufficient in N-1 situation. The commissioning of a new connection in Labé is thus necessary in order to respect the N-1 condition.

A new 225 kV double circuit of approximately 115 km is thus proposed from Labé to Koukoutamba. This line creates a direct link between the OMVG loop and the Linsan-Manantali interconnection between Guinea and Mali where the generation from Koukoutamba and Boureya are also injected. This line is proposed to be commissioned in 2025 at the same time as the Bonkon Diara project which will increase the installed capacity at Labé from 291 MW (Grand Kinkon only) to 465 MW (Grand Kinkon and Bonkon Diara).

[10] These values were calculated from the static analysis at the 2033 horizon

Figure 42: Labé - Koukoutamba line

3.3.2. Modelling of the 2025 WAPP Network

The hypothesis and information that was used to create the 2025 model of the WAPP are described in the following sections.

3.3.2.1. NATIONAL REINFORCEMENTS

The list of national reinforcements that were done on the high voltage grid for each country in 2025 is described in Annex.

3.3.2.2. DEFINITION OF THE SCENARIOS – TARGET YEAR 2025

The load levels which were modelled in the 2025 scenario is detailed in this paragraph. The modelled load corresponds to the yearly peak load of every country. This scenario where every country observes their peak load at the same time is a conservative way of analyzing the reinforcement needs on the grid. The resulting active load levels are presented in Table 20. The same power factor as the existing model was kept for this study year.

Country	Peak Load 2025

Final version

BENIN	431 MW
BURKINA	613 MW
CIV	2434 MW
GAMBIE	173 MW
GHANA	3597 MW
GUINEE	666 MW
GUINEE BISSAU	129 MW
LIBERIA	218 MW
MALI	778 MW
NIGER	554 MW
NIGERIA	15000 MW[11]
SENEGAL	1356 MW
SIERRA LEONE	487 MW
TOGO	397 MW
TOTAL	26834 MW

Table 20: Load level – Peak 2025

3.3.2.3. DYNAMIC MODEL

The dynamic model of 2025 is derived from the 2022 one. The additional generating units have been modelled using parameters of similar units (size and type). Standard controllers have been implemented.

Each new hydro units have been equipped with a wide-range standard PSS. It is noted that for transient stability analysis, the interarea mode has been artificially damped. A proper tuning should be carried out at a later stage.

A distribution type load model is adopted for the 2025 dynamic analyses.

3.3.3. Static Studies

Similarly as for 2022, the asynchronous peak, in which every country experiences its peak at the same time, has been modelled. The country balances resulting from the economic exchanges is presented in Table 21. Negative values indicate import.

Country	Peak Balance 2025
BURKINA	- 506 MW

[11] The same load level as in 2022 was modelled with a modification of the import/export balance based on the simulations of the economic optimization. The needed internal reinforcements by 2025 are based on the TCN master plan.

Final version

CIV	34 MW
GAMBIE	- 111 MW
GHANA	69 MW
GUINEE	1150 MW
GUINEE BISSAU	-87 MW
LIBERIA	- 131 MW
MALI	- 380 MW
NIGER	- 149 MW
NIGERIA	451 MW
SENEGAL	-25 MW
SIERRA LEONE	- 74 MW
TOGO - BENIN	- 230 MW

Table 21: Country balance – Peak 2025

It is seen that in the evening peak of this target year 2025, Burkina Faso is importing up to almost 80% of its load. Also Mali is importing a lot. On the other hand, Guinea is exporting a large part of their hydro generation which is clearly in excess compared to their national load. Nigeria is also exporting more than 450 MW thanks to the gas availabilities.

The flows on the interconnection lines are shown here in Table 29.

Line Name	Voltage level (kV)	Country - Sending Node	Country - Receiving Node	Active Power Flow (MW)	Loading - Current (%)
Bolgatanga_225-Ouaga Sud_225-1	225	GH	BU	159.5	50.5
Boureya_225-Manantali_225-1	225	GU	MA	152.1	45.5
Boureya_225-Manantali_225-2	225	GU	MA	152.1	45.5
Kainji_330-Parakou_330-1	330	NI	TB	129.6	17.1
Kainji_330-Parakou_330-2	330	NI	TB	129.6	17.1
Dawa_330-Davié_330-1	330	GH	TB	128.6	12.6
Boke_225-Salthinho_225-2	225	GU	GB	125.7	38.4
Siguiri_225-Sanakoroba_225-1	225	GU	MA	122.1	36.4
Siguiri_225-Sanakoroba_225-2	225	GU	MA	122.1	36.4
Morisanako_225-Boundia_225-1	225	GU	CI	89.5	26.9
Morisanako_225-Boundia_225-2	225	GU	CI	89.5	26.9
Ferkéssédougou_225-Kodeni_225-1	225	CI	BU	88.4	25.8
Mali_225-Sambangalou_225-1	225	GU	SE	77.9	23.3
Sikasso_330-Bobo_330-1	330	MA	BU	77.9	13.9
Sikasso_330-Bobo_330-2	330	MA	BU	77.9	13.9
Kaolack_225-Soma_225-1	225	SE	GA	76.3	23.4

Final version

Line Name	Voltage level (kV)	Country - Sending Node	Country - Receiving Node	Active Power Flow (MW)	Loading - Current (%)
Birnin Kebbi_330-Zabori_330-1	330	NI	NR	75.3	11.5
Birnin Kebbi_330-Zabori_330-2	330	NI	NR	75.3	11.5
Bingerville_225-Elubo_225-1	225	CI	GH	69.9	31.2
Linsan_225-Kamakwie_225-1	225	GU	SL	69.1	20.3
Linsan_225-Kamakwie_225-2	225	GU	SL	69.1	20.3
Katsina_132-Gazaou_132-1	132	NI	NR	64.6	72.1
Kara_330-Yendi_330-1	330	TB	GH	61.6	8.1
Kara_330-Yendi_330-2	330	TB	GH	61.6	8.1
Goroubanda_330-Ouaga Est_330-1	330	NR	BU	58.7	11.4
Goroubanda_330-Ouaga Est_330-2	330	NR	BU	58.7	11.4
Sakete_330-Ikeja West_330-1	330	TB	NI	57.4	14.7
Kayes_225-Bakel_225-1	225	MA	SE	50.3	23.3
Aflao Ghana_161-Lomé (Aflao) 1_161-1	161	GH	TB	47.9	40.1
N'Zérékore_225-Yekepa_225-1	225	GU	LI	44.7	13.0
N'Zérékore_225-Yekepa_225-2	225	GU	LI	44.7	13.0
Mansoa_225-Tanaf_225-1	225	GB	SE	37.6	16.3
Tanaf_225-Soma_225-1	225	SE	GA	36.6	11.2
Kenema_225-Mano_225-1	225	SL	LI	32	9.7
Kenema_225-Mano_225-2	225	SL	LI	32	9.7
Birnin Kebbi_132-Dosso_132-1	132	NI	NR	27.6	27.4
Ferkéssédougou_225-Sikasso_225-1	225	CI	MA	26.4	7.8
Malanville_330-Zabori_330-1	330	TB	NR	25.5	5.7
Yekepa_225-Man_225-1	225	LI	CI	11.2	6.3
Yekepa_225-Man_225-2	225	LI	CI	11.2	6.3
Asiekpe PST_161-Lomé (Aflao) 1_161-1	161	GH	TB	10	10.9
Cinkassé_161-Bawku_161-1	161	TB	GH	9.4	5.3
Tambacounda_225-Kayes_225-1	225	SE	MA	7.1	2.7
Tambacounda_225-Kayes_225-2	225	SE	MA	7.1	2.7
Bobo_330-Bolgatanga_330-1	330	BU	GH	4.2	11.0
Bobo_330-Bolgatanga_330-2	330	BU	GH	4.2	11.0

Table 22: Flows on interconnection - Peak 2025

In 2025, the security analysis has shown that no contingency is problematic on the regional high voltage grid. The list below shows the contingencies which can cause a problem on the national grid. These contingencies do not have a regional impact and should be treated by the national master plans of the country impacted. The observed N-1 problems should be treated on the national level.

Contingency	Country	Overload
Bondoukou 225 kV – Serebou 225 – 1 (NATIONAL)	CI	Voltage Collapse in the area of Bouna

Toulepleu 225 kV – Zagne 225 kV – 1 (NATIONAL)	CI	Voltage Collapse in the area of Mine Ity
Dueckoue 225 kV – Zagne 225 kV – 1 (NATIONAL)	CI	Voltage Collapse in the area of Mine Ity
Toulepleu 225 kV - Toulepleu 90 kV -1 (NATIONAL)	CI	Voltage Collapse in the area of Mine Ity

Table 23: List of problematic contingencies (NATIONAL) – Peak 2025

3.3.4. Dynamic studies

3.3.4.1. INTERAREA OSCILLATIONS

Regardless of the added network equipment, the interarea mode detected in 2022 is still present in 2025. This is due to the commissioning of several new hydro units in Guinea that contribute to the interarea oscillations.

It is recommended to implement PSS to the planned hydro units, properly tuned to dampen the interarea mode.

3.3.4.2. CRITICAL INTERFACE 1 - IMPACT OF THE MEDIAN BACKBONE

The addition of the median backbone greatly improve the transient stability of the system following a fault on the border between Nigeria and the rest of WAPP, unlocking higher transfer capacity levels. This impact is estimated in the following sections.

3.3.4.2.1. Export from Nigeria

At peak load conditions with an export from Nigeria of 700 MW, without the Median Backbone, losing the single circuit 330 kV interconnection between Ikeja (NI) and Sakete (TB) will results in the violation of the voltage stability limits of the North Core interconnection. With the Median Backbone in place, these limits are not trespassed. Figure 43 shows the two situations.

2025 Peak – Export of 700 MW from Nigeria - loss of NI-TB interconnection - Voltage in BU and NR [p.u.]

WITHOUT Median Backbone	**WITH Median Backbone**

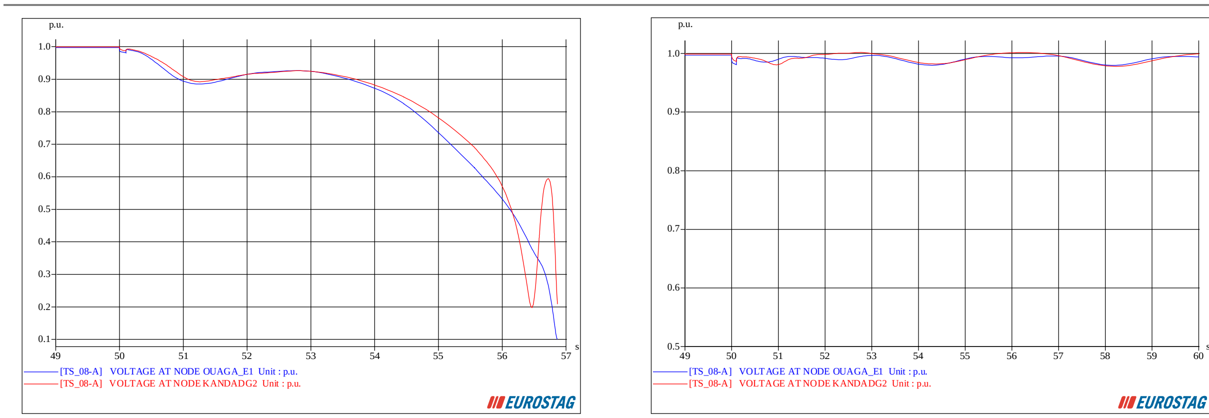
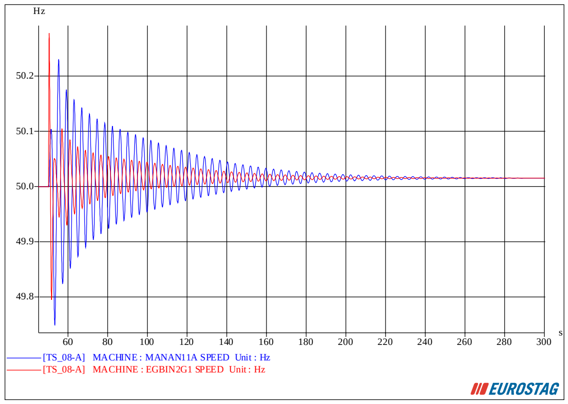


Figure 43: Voltage transients following loss of NI-TB interconnection with and without median backbone- 2025 peak.

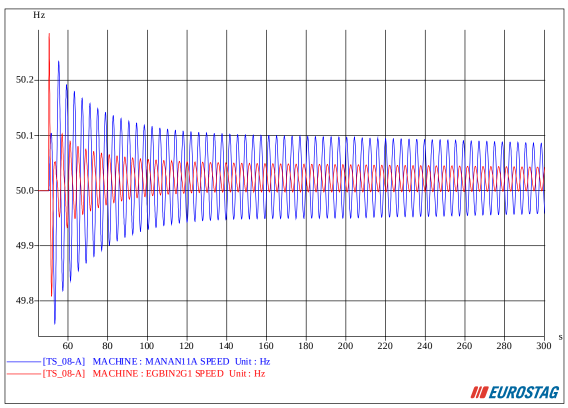
Moreover, the median backbone enables higher export capacity, up to 900 MW. As shown in Figure 44, an export of 900 MW excites the interarea mode but the oscillations will dampen relatively quickly. For higher levels of export, the oscillations will be progressively amplified, leading to loss of stability.

2025 Peak – Export limits of Nigeria - loss of NI-TB interconnection – Machine speed [Hz.]

Export of 900 MW



Export of 950 MW



Export of 1000 MW

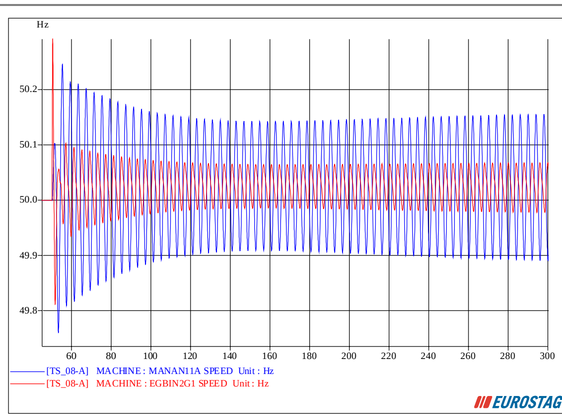


Figure 44: Machine speed transients following loss of NI-TB interconnection with median backbone for different export levels of Nigeria- 2025 peak.

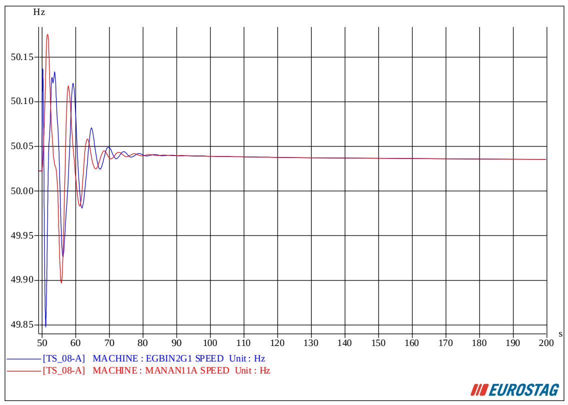
Final version

3.3.4.2.2. Import to Nigeria

The import capacity to Nigeria has been tested with and without median backbone. The results show a definite increase in dynamic performance with the backbone in place. For instance, with an import level of 850 MW, losing one large unit in Nigeria or the single circuit 330 kV interconnection between Nigeria and Togo-Benin would result in a stable response of the system, as shown in Figure 45.

2025 Peak – Import of 850 MW to Nigeria -– Machine speed [Hz.]

Loss of NI-TB interconnection



Loss of one unit at Egbin (~190 MW of lost generation)

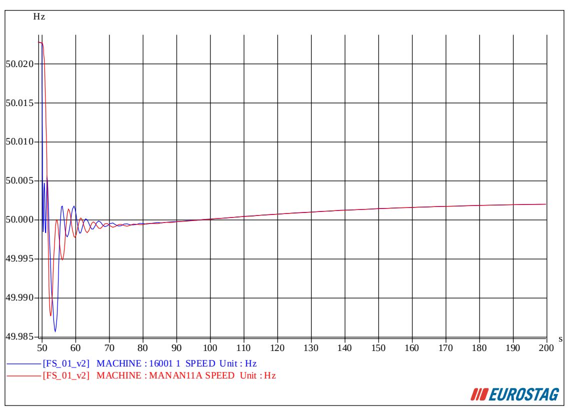


Figure 45: Machine speed transients with median backbone for 850 MW of import, under different contingency - 2025 peak.

Final version

3.3.4.3. CRITICAL INTERFACE 2 – SECURITY VERIFICATION

The interface between Ivory Coast and the western part of WAPP poses security challenges in 2022. Different remedial actions have been proposed to eliminate the risk.

The results of dynamic analyses have proven that this interface remains secure in 2025. In fact, the border between Côte d'Ivoire and Guinea will be further strengthened with the commissioning of a 225 kV interconnection line between Boundiali (CIV) and Fomi (GU) by 2025.

The simulation results for the loss of the Sikasso (Mali) – Ferke (Ivory Coast) interconnection (most critical fault in 2022) are presented in Figure 46.

2025 Peak – Loss of MA - CIV interconnection

Machine speed [Hz]	**Machine angle [deg]**

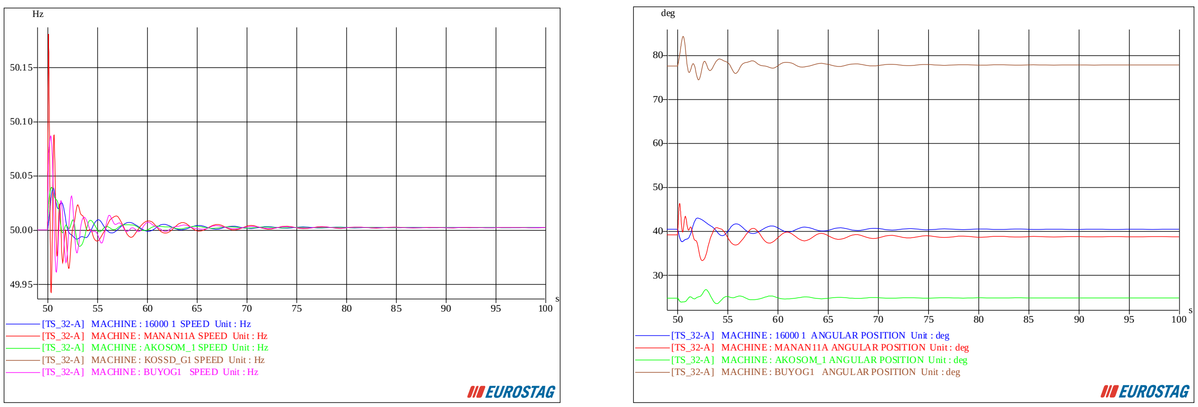


Figure 46: Machine speed and angular transients following loss of MA - CIV interconnection, 2025 peak.

Final version

3.3.5. Conclusions and recommendations for 2025

As it is seen in the studies realized for the target year of 2025, the objective of satisfying the N-1 security rule over the whole high voltage network is very challenging in 2025. Many high voltage investments are necessary in order to operate under the defined security limits and cope with the load increase as well as the increased exchanges.

The different recommendations presented in the results of the target year 2022 are fully confirmed my 2025 simulations and should remain a priority in order to stabilize the grid.

The connection of Nigeria-Niger with the rest of WAPP and the maximum power transfer of this section are significantly improved thanks to the Median Backbone from Cote d'Ivoire to Nigeria. The stability limits in contingency N-1 is increased up to 900MW.

3.4. Long term development plan - 2033

3.4.1. Increasing the sharing of resources

In the long term, the integration of renewable energy has increased significantly to a level of about 18 % in the energy mix. The intermittent and variable nature of these renewable sources makes for large variations in the exchanges that are observed over a typical day. One good example of this phenomenon is the case of Nigeria which export about 1.5 GW of power during the evening peak and imports more than 2 GW of power during times of high renewable infeed in the WAPP.

In order to allow for this increase of exchanges, the network will need to be further reinforced. Based on the results from the economic analysis giving the optimal exchanges between countries, the technical analysis will allow to determine the reinforcement needs in order to securely satisfy these exchanges. The objective of the analysis of this target year 2033 is to define the best **structure for the WAPP interconnected network** and to verify the ability of this network to operate with an increasing share of renewable energy.

The following projects should be set as the priority for developing a stable structure for the WAPP to operate their interconnected network considering the load increase, the increase of renewable penetration on the system and the increase of the economic exchanges between countries.

WESTERN BACKBONE

Starting in 2025 with the great increase of available gas resources in Senegal and the increase of the installed capacity from CCGTs, it is expected that Senegal will become an exporting country during times of the year. In the same way, the hydro potential of Guinea being so large, the country will export large amounts of hydro power over the year. Simultaneously, Mali, Burkina and the north of Côte d'Ivoire and Ghana will be exporters of large amounts of renewable energy at times of high solar radiation.

Final version

Considering this spreading of the resources, the sharing of power from these three resources (gas from Senegal, Hydro from Guinea and RES from the Central-North) becomes primordial and a high voltage corridor can significantly increase the security of the grid.

In order to evaluate the benefits of creating a high voltage backbone connecting these different western countries, total transfer capacities were calculated between these different countries. This total transfer capacity was calculated under the N-1 security rule and the following expression:

$$TTC = NTC - TRM$$

Where TTC is the total transfer capacity we are evaluating, NTC is the total possible transfer under N-1 secure rule between country A and country B and the TRM is a reliability margin which is typically taken of around 10%.

Country A	Country B	TTC increase
Senegal	Guinea	+ 650 MW[12]
Guinea	Mali	+ 325 MW
Senegal	Mali	+ 500 MW

Table 24: Increase of TTC with the 330 kV Western backbone

Considering these transfer capacities of the existing grid, it was concluded that the following substation could be good candidates for the sharing of resources through this high voltage 330 kV line. The substation of Tobène where the interconnection with Mauritania is planned as well as a possible future interconnection with Morocco. Furthermore, this substation is at the crossroad of many of the existing 225 kV line (to Sakal, Kounoune, Touba, Taiba …) and thus seems as a good injection point to a higher voltage level. Additionally, its proximity to the sea makes it a good candidate for the future connection points of new CCGTs.

The substation of Linsan also makes for a good candidate substation in Guinea due to the large capacity of hydro power plant located close to this substation. Additionally, it can be noted that this substation is the starting point of the CLSG interconnection to Sierra Leone and Liberia. It should be noted that Linsan is a major crossroad in Guinea with many interconnection lines. The creation of a second substation close to Linsan with a direct connection between the two should thus be looked at. This will increase the safety and the security of the network.

The substations of Sikasso is a good connection point in Mali due to its high potential for renewable energy and the existing interconnections to neighboring countries. This line will thus connect to the Mali-Burkina-Ghana 330 kV line which should be commissioned by 2022.

Final version

[12] Les valeurs présentées sont soumises à l'hypothèse initiale de flux et de production et sont données ici comme moyen d'identifier les avantages de la nouvelle interconnexion

The total distance of this line from Tobene, Linsan and Sikasso is of approximately 1600 km. Due to the long distances between these potential substations, additional substations should be created in order to increase the transmission capabilities of the line and allow for an easier operation of this one. For the sake of the simulations performed, intermediate substations were modelled at Soma, in The Gambia, and at Mansoa in Guinea Bissau. These intermediary substations and the precise path of the line should be defined based on detailed specific environmental and technical studies. The transfer capacity of this 330kV backbone should be further increased thanks to these intermediate substations coupled with an adequate compensation scheme.

Figure 47: Proposed path of the 330 kV Western backbone

It is noted that the construction of this new 330 kV double circuit western backbone avoids the construction of several other sections along its path. These sections include the Linsan – Manantali – Bamako – Sikasso lines as well as the 225 kV Senagal lines connecting Tobene to the OMVG line as well as sections of its eastern part (Kaolack-Tambacounda-Kedougou-Mali-Labé-Linsan). It was seen that considering the load levels for the study period and the planned exchanges, these lines are overloaded in N-1 conditions if the western backbone is not constructed.

An AC solution is here preferred compared to a DC one for two main reasons. First, the region being still slightly meshed, this new AC corridor will allow to increase the grid stability and reinforce the synchronization of the neighboring countries together. Secondly, operating an HVDC line in parallel with AC line is a new challenge for the region and necessits some specific actions to be implemented to support a contingency in the area. Furthermore, creating intermediate HVDC substations is more difficult and costly.

CONNECTION OF WESTERN AND MEDIAN BACKBONES

New 330 kV double circuit line Bobo – Ferkéssedougou. This new line will create a direct link between both the Western Backbone and the Median backbone in order to create a single 330 kV double circuit link running from Senegal to Nigeria. The new line will follow the path of the existing 225 kV line from Bobo to Ferkéssedougou.

Final version

SECOND LINE OF THE COASTAL BACKBONE (NIGERIA – GHANA)

As seen in the conclusions of the dynamic studies realized for 2022, this project is of great importance for the synchronization of Nigeria to the rest of the WAPP and to allow for a stable operation of the network under contingency and consideration of the large economic exchanges planned. Additionally to the level of imports and exports planned from Nigeria, the location of the new CCGT unit at Maria Gleta, connected on this line justifies the second line in order to allow a secure evacuation of the power in case of contingency. Furthermore, during times when countries from the center of the WAPP (Côte d'Ivoire, Mali, Ghana, Burkina Faso) are exporting a lot of power to Nigeria, the loss of the Ghana – Nigeria coastal single circuit is not sufficient to securely operate and overloads are seen on the 161 kV grid of Togo and Benin.

The exact path of the line as well as the substations between Benin and Nigeria are still to be determined. The connection of this line to Sakete and to the Lagos region seems the most reasonable at this time considering the load levels expected. Due to environmental and technical feasibility constraints, a new path may be necessary. It is here noted that the substation of Onigbolo has been determined as a potential substation by the WAPP.

NEW 330 KV DOUBLE CIRCUIT LINE SALKADAMNA – KATSINA

This new 330 kV double circuit line connects in the existing 330 kV substation of Salkadamna (Niger), to a new 330 kV substation in Malbaza (Niger) and Gazoua (Niger) and to the existing 330 kV substation in Katsina (Nigeria). The total length of the line is estimated to be of around 500 km. This line is needed in the long term horizon in order to allow for the increase of load in the NCE (Niger Centre-Est) region of Niger. Due to the long distances currently connected through 132 kV lines, the voltage drops in the region are significant and this new voltage level will hold the voltage in the operating range in this region.

Furthermore, at the 2033 horizon, this line will allow to export the solar power from the Northern region of Niger to Nigeria.

NEW 225 KV LINE SAN PEDRO – TIBOTO - BUCHANAN

This interconnection line between Liberia and Côte d'Ivoire along the coast is expected to be commissioned in 2026 at the same time as the Tiboto power plant and goes hand in hand with this hydro project. The line will connect at San Pedro 225 kV substation in Côte d'Ivoire and at Buchanan in Liberia.

NEW 225 KV LINE TENGRELA – SYAMA - BOUGOUNI

Mali and Côte d'Ivoire both have the intention of connecting mines to their interconnected network. These mines are located in the North of Côte d'Ivoire around Tengrela and in the South of Mali around Syama. Due to the short distance of about 40 km between these two sites, it is clear that there is a regional interest in connecting both of the sites together and thus creating a new interconnection between Mali and Côte d'Ivoire. This new single circuit line will run from Bougouni (Mali) to Syama (Mali) and Tengrela. This line will allow to satisfy the security of supply of these mines by respecting the N-1 rules and will increase the system stability in the case of the loss of the interconnection between Sikasso and Ferkéssedougou.

NEW 330 KV DOUBLE CIRCUIT LINE BOLGATANGA – JUALE – DAWA

This 330 kV double circuit line connecting the North and the South of Ghana has been defined as a WAPP priority project. This project is planned from Bolgatanga in the north of Ghana and to Juale and Dawa to the south. In order to double the Bolgatanga – Tamale corridor, it is proposed that this line drops down to connect at the 330 kV substation in Tamale and in Yendi to connect with the median backbone and avoid a possible bottleneck on the Yendi – Juale 161 kV line. This line offers the advantage of doubling the North-South corridor in Ghana which proves to be a necessity considering the N-1 security criteria. Furthermore, this line creates a more direct path to conduct the renewable energy from Burkina and the North of Ghana to the South of Ghana near Accra, where a large part of the load is located.

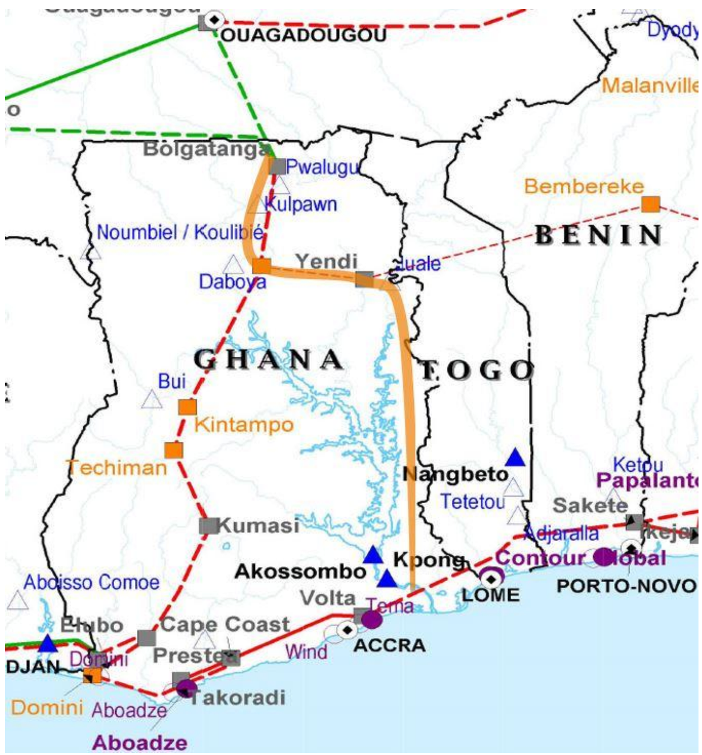


Figure 48: New 330 kV line Bolgatanga - Juale – Dawa

EASTERN BACKBONE

This 330 kV double circuit line has as objective to connect the Northern region of Nigeria to the Southest region. The line which has an estimated length of 1856 km will connect at the substations of Calabar, Ikom, Ogoja, Kashimbilla, Mambilla, Jalingo, Yola, Hong, Biu, Damaturu, Potiskum, Azare, Dutse, Jogana as well as a section from Sokoto to Kaura and Katsina. This project is in line with the TCN master plan and will allow for:

- A smooth integration of renewable energy (hydro (Mambilla), solar and wind)
- A significant increase of the load in all regions of Nigeria
- An increase of the security of supply in Nigeria
- An increase in the exchanges in the WAPP region

Additionnaly, this line will be of necessity in the case of a connection of the WAPP to the Central African Power Pool (CAPP).

REINFORCEMENT OF OMVG LOOP WEST

At the 2033 horizon, Guinea Bissau and The Gambia are both expected to be importing a large part of their power from Guinea and Senegal. In the short term, both of these countries are planned to be interconnected through the single circuit OMVG loop which allows for a thermal capacity of around maximum 330 MVA. Considering the imports of The Gambia and Guinea Bissau in 2033 at the peak evening time which account for up to around 350 MW, it is clear that the single circuit becomes insufficient to respect the N-1 criteria with such levels of import. In order to satisfy the security of supply in these countries, a second line is planned on the western part of the OMVG loop connecting Kaolack to Kaleta. Depending on the possibilities and specific studies to be undertaken, the possibility of connecting the second line of double circuit directly through Kaolack – Brikama – Soma - Tanaff – Mansoa – Bambadinca – Saltinho and Kaleta is presented in the following figure.

Figure 49: Proposed path of the second circuit of OMVG West

Up to 2025, due to the importing nature of Senegal before the apparition of combined cycles, the OMVG single circuit line is loaded to levels which do not support the N-1 criteria. The most critical sections of this line concern the parts between Linsan and Guinea Bissau which are loaded to higher levels due to the imports of Senegal, The Gambia and Guinea Bissau.

Final version

3.4.2. Modelling of the 2033 WAPP network

The hypothesis and information that was used to create the 2033 model of the WAPP are described in the following sections.

3.4.2.1. NATIONAL REINFOCEMENTS

The list of national reinforcements that were done on the high voltage grid for each country in 2033 is described in Annex.

3.4.2.2. DEFINITION OF THE SCENARIOS – TARGET YEAR 2033

The load levels which were modelled in the different scenarios that were studied for 2033 are details in the following paragraph.

For the target year of 2033, three different scenarios were analyzed:

- Asynchronous peak evening situation
- Peak renewable scenario
- Synchronous Off-peak scenario

The load levels modelled in each of these scenarios is presented here under.

In the peak load scenario, the load modelled corresponds to the yearly peak load of every country. This scenario where every country observes their peak load at the same time is a conservative way of analyzing the reinforcement needs on the grid. This active load level is presented Table 25. The same power factor as the existing model was kept for this study year.

Country	Peak Load 2033
BENIN	704 MW
BURKINA	1043 MW
CIV	3981 MW
GAMBIE	297 MW
GHANA	4957 MW
GUINEE	1104 MW
GUINEE BISSAU	215 MW
LIBERIA	411 MW
MALI	1118 MW
NIGER	1063 MW
NIGERIA	20850 MW[13]
SENEGAL	2065 MW

[13] As the demand forecast for Nigeria was based on the TCN Master Plan, the same load level was modelled as in this reference. This allows for a close accordance of the reinforcement needs between both studies.

Final version

Country	Peak Load 2033
SIERRA LEONE	696 MW
TOGO	646 MW
TOTAL	**39151 MW**

Table 25: Load level – Peak 2033

The objective of the renewable scenario is to evaluate if the grid is sufficiently meshed to evacuate all renewable power while respecting the N-1 criteria. For this matter, the average daily solar peak of 13h is chosen to represent this situation. The demand level of each country in this scenario is shown in Table 26.

Country	% of Peak Load	Renewable Scenario Load
BENIN	67 %	476 MW
BURKINA	59 %	616 MW
CIV	71 %	2834 MW
GAMBIE	82 %	244 MW
GHANA	67 %	3330 MW
GUINEE	82 %	906 MW
GUINEE BISSAU	82 %	177 MW
LIBERIA	82 %	337 MW
MALI	54 %	602 MW
NIGER	38 %	399 MW
NIGERIA	85 %	17787 MW
SENEGAL	66 %	1371 MW
SIERRA LEONE	82 %	571 MW
TOGO	67 %	436 MW
TOTAL	**77 %**	**30087 MW**

Table 26: Load level – Renewable scenario 2033

In this scenario, the power generation from PV plants reaches a level of more than 60% of the power generation. Such a level of renewable penetration may cause some problems for the system stability. These problems which are described in more details in section 3.4.4 are not captured in the static analysis which are performed for the target year of 2033. A dedicated study is required to define the operational constraints and measures to be taken to allow this important share.

Final version

The off-peak scenario was analyzed for the 2033 network which was developed. Based on the average load curve of the WAPP, this synchronous off-peak situation appears around 9am. Based on this information, the following assumptions were made concerning the production dispatch and the load. The load level modelled in this scenario is presented in Table 27.

Country	% of Peak Load	Off-peak Load
BENIN	46 %	324 MW
BURKINA	57 %	595 MW
CIV	52 %	2070 MW
GAMBIE	44 %	131 MW
GHANA	67 %	3321 MW
GUINEE	44 %	486 MW
GUINEE BISSAU	44 %	95 MW
LIBERIA	44 %	181 MW
MALI	61 %	682 MW
NIGER	53 %	563 MW
NIGERIA	52 %	10842 MW
SENEGAL	58 %	1198 MW
SIERRA LEONE	44 %	306 MW
TOGO	46 %	297 MW
TOTAL	51 %	21091 MW

Table 27: Load level – Off-peak 2033

3.4.3. Static Studies

The results of the static studies realized for the target year of 2033 for the different scenarios are shown in the following paragraphs. The methodology and assumptions taken for those scenarios were described in the previous section.

3.4.3.1. ASYNCHRONOUS PEAK 2033

Similarly as what was done for 2022 and 2025, the asynchronous peak, in which every country experiences its peak at the same time, has been modelled in the peak scenario. The country balances resulting from the economic exchanges is presented in Table 28.

Country	Peak Balance
BURKINA	- 901 MW
CIV	- 13 MW

Final version

GAMBIE	- 148 MW
GHANA	39 MW
GUINEE	1287 MW
GUINEE BISSAU	- 133 MW
LIBERIA	- 145 MW
MALI	- 516 MW
NIGER	- 540 MW
NIGERIA	1528 MW
SENEGAL	119 MW
SIERRA LEONE	- 248 MW
TOGO - BENIN	- 316 MW

Table 28: Country balance – Peak 2033

It is seen that in the evening peak of this target year of 2033, Burkina Faso is importing up to almost 90% of its load. The other importing countries are mainly Mali and Niger. On the other hand, Nigeria is exporting more than 1500 MW thanks to the gas availabilities and the construction of CCGTs and Guinea is exporting a large part of their hydro generation which is clearly in excess compared to their national load.

The flows on the interconnection lines are shown here in Table 29.

Line Name	Voltage level (kV)	Country - Sending Node	Country - Receiving Node	Active Power Flow (MW)	Loading - Current (%)
Birnin Kebbi_330-Zabori_330-1	330	NI	NR	283.1	35.5
Birnin Kebbi_330-Zabori_330-2	330	NI	NR	283.1	35.5
Bolgatanga_225-Ouaga Sud_225-1	225	GH	BU	239.4	71.1
Kainji_330-Parakou_330-1	330	NI	TB	227.8	28.8
Kainji_330-Parakou_330-2	330	NI	TB	227.8	28.8
Kara_330-Yendi_330-1	330	TB	GH	146.1	19.9
Kara_330-Yendi_330-2	330	TB	GH	146.1	19.9
Linsan_330-Sikasso_330-1	330	GU	MA	145.2	25.2
Linsan_330-Sikasso_330-2	330	GU	MA	145.2	25.2
Goroubanda_330-Ouaga Est_330-1	330	NR	BU	138.7	20.3
Goroubanda_330-Ouaga Est_330-2	330	NR	BU	138.7	20.3
Boureya_225-Manantali_225-1	225	GU	MA	135.8	39.8
Boureya_225-Manantali_225-2	225	GU	MA	135.8	39.8
Ikeja West_330-Sakete_330-1	330	NI	TB	118.8	28.9
Linsan_225-Kamakwie_225-1	225	GU	SL	111.9	32.3
Linsan_225-Kamakwie_225-2	225	GU	SL	111.9	32.3

Final version

Line Name	Voltage level (kV)	Country - Sending Node	Country - Receiving Node	Active Power Flow (MW)	Loading - Current (%)
Sikasso_330-Bobo_330-1	330	MA	BU	105.4	13.4
Sikasso_330-Bobo_330-2	330	MA	BU	105.4	13.4
Katsina_330-Gazaou_330-1	330	NI	NR	101.4	13.1
Katsina_330-Gazaou_330-2	330	NI	NR	101.4	13.1
Tiboto _225-Buchanan_225-1	225	CI	LI	96.6	30.7
Mali_225-Sambangalou_225-1	225	GU	SE	81	25.7
Siguiri_225-Sanakoroba_225-1	225	GU	MA	80.1	24.3
Siguiri_225-Sanakoroba_225-2	225	GU	MA	80.1	24.3
New Agbara_330-Sakete_330-1	330	NI	TB	71.7	27.2
New Agbara_330-Sakete_330-2	330	NI	TB	71.7	27.2
Morisanako_225-Boundia_225-1	225	GU	CI	69.4	22.3
Morisanako_225-Boundia_225-2	225	GU	CI	69.4	22.3
Davié_330-Dawa_330-1	330	TB	GH	63.5	6.4
Davié_330-Dawa_330-2	330	TB	GH	63.5	6.4
Davié_330-Dawa_330-3	330	TB	GH	63.5	6.4
Boke_225-Salthinho_225-1	225	GU	GB	61.7	18.2
Boke_225-Salthinho_225-2	225	GU	GB	61.7	18.2
Boke_225-Salthinho_225-3	225	GU	GB	61.7	18.2
Asiekpe PST_161-Lomé (Aflao) 1_161-1	161	GH	TB	57.9	45.3
Tamale_330-Ferkessedougou_330-1	330	GH	CI	51.7	11.8
Tamale_330-Ferkessedougou_330-2	330	GH	CI	51.7	11.8
Ferkéssédougou_225-Kodeni_225-1	225	CI	BU	42.5	14.2
Tobene_330-Linsan_330-1	330	SE	GU	39.9	23.3
Tobene_330-Linsan_330-2	330	SE	GU	39.9	23.3
Bolgatanga_330-Bobo_330-1	330	GH	BU	39.2	8.8
Bolgatanga_330-Bobo_330-2	330	GH	BU	39.2	8.8
Birnin Kebbi_132-Dosso_132-1	132	NI	NR	38.6	40.9
Kaolack_225-Soma_225-1	225	SE	GA	36.3	14.2
Ferkessedougou_330-Bobo_330-1	330	CI	BU	34	5.4
Ferkessedougou_330-Bobo_330-2	330	CI	BU	34	5.4
Mansoa_225-Tanaf_225-1	225	GB	SE	28.7	9.2
Mansoa_225-Tanaf_225-2	225	GB	SE	28.7	9.2
Mansoa_225-Tanaf_225-3	225	GB	SE	28.7	9.2
Aflao Ghana_161-Lomé (Aflao) 1_161-1	161	GH	TB	27.8	26.2
Dunkwa_330-Bingerville_330-1	330	GH	CI	27.2	5.4
Kaolack_225-Brikama_225-1	225	SE	GA	27	9.7
Kaolack_225-Brikama_225-2	225	SE	GA	27	9.7
Man_225-Yekepa_225-1	225	CI	LI	25.8	7.6
Man_225-Yekepa_225-2	225	CI	LI	25.8	7.6

Line Name	Voltage level (kV)	Country - Sending Node	Country - Receiving Node	Active Power Flow (MW)	Loading - Current (%)
Tengrela_225-Syama_225-1	225	CI	MA	23.5	7.5
Tanaf_225-Soma_225-1	225	SE	GA	19.3	5.9
Tanaf_225-Soma_225-2	225	SE	GA	19.3	5.9
Tanaf_225-Soma_225-3	225	SE	GA	19.3	5.9
Mano_225-Kenema_225-1	225	LI	SL	13.6	4.5
Mano_225-Kenema_225-2	225	LI	SL	13.6	4.5
N'Zérékore_225-Yekepa_225-1	225	GU	LI	13	7.5
N'Zérékore_225-Yekepa_225-2	225	GU	LI	13	7.5
Katsina_132-Gazaou_132-1	132	NI	NR	13	13.8
Sikasso_225-Ferkéssédougou_225-1	225	MA	CI	11.9	8.6
Cinkassé_161-Bawku_161-1	161	TB	GH	9	6.9
Bakel_225-Kayes_225-1	225	SE	MA	7.2	9.1
Zabori_330-Malanville_330-1	330	NR	TB	3	0.7
Tambacounda_225-Kayes_225-1	225	SE	MA	1.9	0.6
Tambacounda_225-Kayes_225-2	225	SE	MA	1.9	0.6
Elubo_225-Bingerville_225-1	225	GH	CI	0.5	4.6

Table 29: Flows on interconnection - Peak 2033

In 2033, the security analysis has shown that no contingency is problematic on the regional high voltage grid. The list below shows the contingencies which can cause a problem on the national grid. These contingencies do not have a regional impact and should be treated by the national master plans of the country impacted.

Contingency	Country	Overload
Sikasso 225 kV - Koutiala 225 kV-1 (NATIONAL)	MA	Voltage Collapse in Mopti
Toulepleu 225 kV – Zagne 225 kV – 1 (NATIONAL)	CI	Voltage Collapse in the area of Mine Ity
Dueckoue 225 kV – Zagne 225 kV – 1 (NATIONAL)	CI	Voltage Collapse in the area of Mine Ity
Kounoune 225 kV – Cap des Biches 225 kV (NATIONAL)	SEN	Overload of second circuit (>110%)
Mboro 225 kV – Tobene 225 kV (NATIONAL)	SEN	Overload of second circuit (>110%)

Table 30: List of problematic contingencies (NATIONAL) – Peak 2033

3.4.3.2. RENEWABLE INTEGRATION SCENARIO

The results of the scenario in which a maximum renewable injection on the grid was assumed is shown in this section. Based on the results of the economic analysis, the balances of each country in this scenario is shown in Table 31. It can be seen that this scenario assumes that Nigeria is importing a lot of generation: up to 2500 MW.

Final version

Country	Renewable scenario - Balance
BURKINA	283 MW
CIV	300 MW
GAMBIE	- 37 MW
GHANA	1205 MW
GUINEE	-22 MW
GUINEE BISSAU	- 7 MW
LIBERIA	- 123 MW
MALI	433 MW
NIGER	1007 MW
NIGERIA	- 2515 MW
SENEGAL	- 242 MW
SIERRA LEONE	- 190 MW
TOGO - BENIN	- 92 MW

Table 31: Country balance – Renewable Scenario 2033

It is seen that in this scenario, the situation of Burkina and Nigeria have been completely inversed compared to the evening peak situation. This can be explained by the renewable potential of the different countries and their load levels. Furthermore, the exporting countries are now Niger, Ghana, Guinea and Côte d'Ivoire.

In this scenario, renewable infeed from wind turbines is set to 100 % and that from PV parks is set to 63 % which correspond to a typical maximum production from a PV park in West Africa. For irrigation purposes, the hydro production was set to 10% of the maximum producible. The rest of the generation is produced by thermal units such as must run units and most economic combined cycle units.

Final version

Generation type	Generated Active Power (MW)
Hydro	1230 MW
Solar	20037 MW
Wind	1700 MW
Thermal	8456 MW

Table 32: Generation dispatch – Renewable Scenario 2033

As mentioned in the modelling section for the 2033 target year, such level of renewable penetration as presented in this renewable scenario should be the point of dedicated studies to assess the feasibility of operating stably under these conditions.

Table 33 shows the flows on each interconnection line in the renewable scenario for the 2033 target year.

Line Name	Voltage level (kV)	Country - Sending Node	Country – Receiving Node	Active Power Flow (MW)	Loading - Current (%)
Zabori_330-Birnin Kebbi_330-1	330	NR	NI	322.8	42.0
Zabori_330-Birnin Kebbi_330-2	330	NR	NI	322.8	42.0
Parakou_330-Kainji_330-1	330	TB	NI	300.8	37.8
Parakou_330-Kainji_330-2	330	TB	NI	300.8	37.8
Sakete_330-Ikeja West_330-1	330	TB	NI	294.4	42.1
Yendi_330-Kara_330-1	330	GH	TB	290.7	36.0
Yendi_330-Kara_330-2	330	GH	TB	290.7	36.0
Dawa_330-Davié_330-1	330	GH	TB	235.4	25.7
Dawa_330-Davié_330-2	330	GH	TB	235.4	25.7
Dawa_330-Davié_330-3	330	GH	TB	235.4	25.7
Sakete_330-New Agbara_330-1	330	TB	NI	225.7	32.9
Sakete_330-New Agbara_330-2	330	TB	NI	225.7	32.9
Gazaou_330-Katsina_330-1	330	NR	NI	217.3	27.9
Gazaou_330-Katsina_330-2	330	NR	NI	217.3	27.9
Sikasso_330-Linsan_330-1	330	MA	GU	119	26.2
Sikasso_330-Linsan_330-2	330	MA	GU	119	26.2
Ferkessedougou_330-Tamale_330-1	330	CI	GH	102.1	19.9
Ferkessedougou_330-Tamale_330-2	330	CI	GH	102.1	19.9
Ouaga Est_330-Goroubanda_330-1	330	BU	NR	84.5	20.3
Ouaga Est_330-Goroubanda_330-2	330	BU	NR	84.5	20.3
Kayes_225-Bakel_225-1	225	MA	SE	83.9	42.3
Bawku_161-Cinkassé_161-1	161	GH	TB	81.8	47.3
Gazaou_132-Katsina_132-1	132	NR	NI	76.6	89.8
N'Zérékore_225-Yekepa_225-1	225	GU	LI	68.8	22.2
N'Zérékore_225-Yekepa_225-2	225	GU	LI	68.8	22.2

Final version

Line Name	Voltage level (kV)	Country - Sending Node	Country – Receiving Node	Active Power Flow (MW)	Loading - Current (%)
Linsan_225-Kamakwie_225-1	225	GU	SL	64.7	19.4
Linsan_225-Kamakwie_225-2	225	GU	SL	64.7	19.4
Manantali_225-Boureya_225-1	225	MA	GU	64.6	23.1
Manantali_225-Boureya_225-2	225	MA	GU	64.6	23.1
Bolgatanga_225-Ouaga Sud_225-1	225	GH	BU	64.1	18.6
Bobo_330-Bolgatanga_330-1	330	BU	GH	57.3	18.3
Bobo_330-Bolgatanga_330-2	330	BU	GH	57.3	18.3
Dunkwa_330-Bingerville_330-1	330	GH	CI	56.9	5.8
Linsan_330-Tobene_330-1	330	GU	SE	55.9	17.4
Linsan_330-Tobene_330-2	330	GU	SE	55.9	17.4
Asiekpe PST_161-Lomé (Aflao) 1_161-1	161	GH	TB	50.6	39.1
Bobo_330-Sikasso_330-1	330	BU	MA	38.2	11.4
Bobo_330-Sikasso_330-2	330	BU	MA	38.2	11.4
Mali_225-Sambangalou_225-1	225	GU	SE	31.9	10.5
Sanakoroba_225-Siguiri_225-1	225	MA	GU	31.2	15.7
Sanakoroba_225-Siguiri_225-2	225	MA	GU	31.2	15.7
Mano_225-Kenema_225-1	225	LI	SL	30.5	10.8
Mano_225-Kenema_225-2	225	LI	SL	30.5	10.8
Dosso_132-Birnin Kebbi_132-1	132	NR	NI	30.1	65.9
Boundia_225-Morisanako_225-1	225	CI	GU	27.5	10.4
Boundia_225-Morisanako_225-2	225	CI	GU	27.5	10.4
Tiboto _225-Buchanan_225-1	225	CI	LI	27.4	12.9
Bingerville_225-Elubo_225-1	225	CI	GH	24.2	18.7
Mansoa_225-Tanaf_225-1	225	GB	SE	21.2	7.9
Mansoa_225-Tanaf_225-2	225	GB	SE	21.2	7.9
Mansoa_225-Tanaf_225-3	225	GB	SE	21.2	7.9
Aflao Ghana_161-Lomé (Aflao) 1_161-1	161	GH	TB	18	17.8
Ferkéssédougou_225-Sikasso_225-1	225	CI	MA	17.5	6.0
Tanaf_225-Soma_225-1	225	SE	GA	17.4	5.9
Tanaf_225-Soma_225-2	225	SE	GA	17.4	5.9
Tanaf_225-Soma_225-3	225	SE	GA	17.4	5.9
Kayes_225-Tambacounda_225-1	225	MA	SE	16.4	8.7
Kayes_225-Tambacounda_225-2	225	MA	SE	16.4	8.7
Boke_225-Salthinho_225-1	225	GU	GB	14.1	4.2
Boke_225-Salthinho_225-2	225	GU	GB	14.1	4.2
Boke_225-Salthinho_225-3	225	GU	GB	14.1	4.2
Tengrela_225-Syama_225-1	225	CI	MA	13.3	4.8
Soma_225-Kaolack_225-1	225	GA	SE	11.1	8.0
Man_225-Yekepa_225-1	225	CI	LI	10.1	4.2

Final version

Line Name	Voltage level (kV)	Country - Sending Node	Country – Receiving Node	Active Power Flow (MW)	Loading - Current (%)
Man_225-Yekepa_225-2	225	CI	LI	10.1	4.2
Ferkéssédougou_225-Kodeni_225-1	225	CI	BU	3.9	13.0
Malanville_330-Zabori_330-1	330	TB	NR	2.9	5.1
Ferkessedougou_330-Bobo_330-1	330	CI	BU	2.9	1.8
Ferkessedougou_330-Bobo_330-2	330	CI	BU	2.9	1.8
Brikama_225-Kaolack_225-1	225	GA	SE	2	10.0
Brikama_225-Kaolack_225-2	225	GA	SE	2	10.0

Table 33: Flows on interconnection - Renewable Scenario 2033

No regional security problems were detected when analysis this renewable scenario. The additional national contingencies recorded compared to the peak scenario are defined in Table 34.

Contingency	Country	Overload	Mitigation measure
Akoupe Zeudji – Abobo 225 kV Yopougon 3 – Azito 225 kV Azito – Vridi 225 kV Abobo – Djibi 225 kV	CI	The loss of one of these lines gives an overload on one of the others. The reason for this is that no generation is dispatched in Abidjan.	Turn on some thermal generation in Abidjan in order to remove the overload.

Table 34: List of problematic contingencies (NATIONAL) – Renewable scenario 2033

3.4.3.3. SYNCHRONOUS OFF-PEAK 2033

The generation dispatch considered is similar to the one presented in the renewable scenario. Production from solar PV parks was however put to 50 % of the production of the renewable case. Generation from hydro power plants was set to 10% for irrigation purposes.

Generation type	Generated Active Power (MW)
Hydro	1230 MW
Solar	10019 MW
Wind	1700 MW
Thermal	8923 MW

Table 35: Generation dispatch – Off-peak 2033

Based on these assumptions reflecting the results of the economic analysis and the daily load curves, the country balances in the 2033 off peak situation is shown in the following table.

Final version

Country	Off-peak scenario - Balance
BURKINA	-114 MW
CIV	-21 MW
GAMBIE	- 28 MW
GHANA	-124 MW
GUINEE	225 MW
GUINEE BISSAU	- 11 MW
LIBERIA	- 61 MW
MALI	- 50 MW
NIGER	322 MW
NIGERIA	527 MW
SENEGAL	- 419 MW
SIERRA LEONE	- 85 MW
TOGO - BENIN	- 149 MW

Table 36: Country balance – Off-peak Scenario 2033

The flows on the lines is represented in the table below.

Line Name	Voltage level (kV)	Country - Sending Node	Country - Receiving Node	Active Power Flow (MW)	Loading - Current (%)
New Agbara_330-Sakete_330-1	330	NI	TB	183.7	30.2
New Agbara_330-Sakete_330-2	330	NI	TB	183.7	30.2
Dunkwa_330-Bingerville_330-1	330	GH	CI	169.9	18.7
Ikeja West_330-Sakete_330-1	330	NI	TB	137.6	37.4
Bobo_330-Sikasso_330-1	330	BU	MA	123.7	16.7
Bobo_330-Sikasso_330-2	330	BU	MA	123.7	16.7
Kara_330-Yendi_330-1	330	TB	GH	108.8	14.8
Kara_330-Yendi_330-2	330	TB	GH	108.8	14.8
Davié_330-Dawa_330-1	330	TB	GH	105.8	11.6
Davié_330-Dawa_330-2	330	TB	GH	105.8	11.6
Davié_330-Dawa_330-3	330	TB	GH	105.8	11.6
Sikasso_330-Linsan_330-1	330	MA	GU	103.1	26.7
Sikasso_330-Linsan_330-2	330	MA	GU	103.1	26.7
Kainji_330-Parakou_330-1	330	NI	TB	92.3	13.1
Kainji_330-Parakou_330-2	330	NI	TB	92.3	13.1
Linsan_330-Tobene_330-1	330	GU	SE	91.6	19.2
Linsan_330-Tobene_330-2	330	GU	SE	91.6	19.2
Mali_225-Sambangalou_225-1	225	GU	SE	82.3	25.2

Line Name	Voltage level (kV)	Country - Sending Node	Country - Receiving Node	Active Power Flow (MW)	Loading - Current (%)
Kayes_225-Bakel_225-1	225	MA	SE	74.3	40.3
Goroubanda_330-Ouaga Est_330-1	330	NR	BU	73.9	15.2
Goroubanda_330-Ouaga Est_330-2	330	NR	BU	73.9	15.2
Bolgatanga_330-Bobo_330-1	330	GH	BU	69	9.9
Bolgatanga_330-Bobo_330-2	330	GH	BU	69	9.9
Lomé (Aflao) 1_161-Aflao Ghana_161-1	161	TB	GH	55.6	47.2
Soma_225-Kaolack_225-1	225	GA	SE	49.7	15.7
Gazaou_330-Katsina_330-1	330	NR	NI	45.9	13.5
Gazaou_330-Katsina_330-2	330	NR	NI	45.9	13.5
Gazaou_132-Katsina_132-1	132	NR	NI	42.7	82.6
Mansoa_225-Tanaf_225-1	225	GB	SE	39.8	12.3
Mansoa_225-Tanaf_225-2	225	GB	SE	39.8	12.3
Mansoa_225-Tanaf_225-3	225	GB	SE	39.8	12.3
Tamale_330-Ferkessedougou_330-1	330	GH	CI	39.3	12.9
Tamale_330-Ferkessedougou_330-2	330	GH	CI	39.3	12.9
Boke_225-Salthinho_225-1	225	GU	GB	38.5	11.6
Boke_225-Salthinho_225-2	225	GU	GB	38.5	11.6
Boke_225-Salthinho_225-3	225	GU	GB	38.5	11.6
Tanaf_225-Soma_225-1	225	SE	GA	35.2	11.7
Tanaf_225-Soma_225-2	225	SE	GA	35.2	11.7
Tanaf_225-Soma_225-3	225	SE	GA	35.2	11.7
Bolgatanga_225-Ouaga Sud_225-1	225	GH	BU	34	17.7
Ferkéssédougou_225-Sikasso_225-1	225	CI	MA	33.9	22.9
Tiboto _225-Buchanan_225-1	225	CI	LI	33.3	14.2
Boundia_225-Morisanako_225-1	225	CI	GU	30	13.6
Boundia_225-Morisanako_225-2	225	CI	GU	30	13.6
Elubo_225-Bingerville_225-1	225	GH	CI	29.9	9.5
Man_225-Yekepa_225-1	225	CI	LI	28.5	8.5
Man_225-Yekepa_225-2	225	CI	LI	28.5	8.5
Tengrela_225-Syama_225-1	225	CI	MA	27.3	8.3
Asiekpe PST_161-Lomé (Aflao) 1_161-1	161	GH	TB	26.5	21.5
Ferkessedougou_330-Bobo_330-1	330	CI	BU	26.2	6.6
Ferkessedougou_330-Bobo_330-2	330	CI	BU	26.2	6.6
Mano_225-Kenema_225-1	225	LI	SL	23.7	11.5
Mano_225-Kenema_225-2	225	LI	SL	23.7	11.5
Linsan_225-Kamakwie_225-1	225	GU	SL	19	7.5
Linsan_225-Kamakwie_225-2	225	GU	SL	19	7.5
Zabori_330-Birnin Kebbi_330-1	330	NR	NI	18.3	16.0
Zabori_330-Birnin Kebbi_330-2	330	NR	NI	18.3	16.0

Line Name	Voltage level (kV)	Country - Sending Node	Country - Receiving Node	Active Power Flow (MW)	Loading - Current (%)
Zabori_330-Malanville_330-1	330	NR	TB	16.3	2.8
Brikama_225-Kaolack_225-1	225	GA	SE	13.9	7.3
Brikama_225-Kaolack_225-2	225	GA	SE	13.9	7.3
Birnin Kebbi_132-Dosso_132-1	132	NI	NR	12.1	39.5
Boureya_225-Manantali_225-1	225	GU	MA	11.1	4.6
Boureya_225-Manantali_225-2	225	GU	MA	11.1	4.6
Kodeni_225-Ferkéssédougou_225-1	225	BU	CI	10	9.7
Siguiri_225-Sanakoroba_225-1	225	GU	MA	9.5	7.5
Siguiri_225-Sanakoroba_225-2	225	GU	MA	9.5	7.5
N'Zérékore_225-Yekepa_225-1	225	GU	LI	9.2	5.3
N'Zérékore_225-Yekepa_225-2	225	GU	LI	9.2	5.3
Kayes_225-Tambacounda_225-1	225	MA	SE	8.7	6.2
Kayes_225-Tambacounda_225-2	225	MA	SE	8.7	6.2
Bawku_161-Cinkassé_161-1	161	GH	TB	2.1	11.9

Table 37: Flows on interconnection Off-peak Scenario 2033

In these simulations, it was observed that all voltages were maintained in the correct operating range. However, it can be seen that many generators are absorbing reactive power during this off-peak scenario. Specific dynamic analysis should be carried out to determine whether this situation cause stability issues. As the WAPP network is made of an increasing number of high voltage lines, specific reactive power compensation studies should be done to determine the amount of inductances required for the commissioning of each new high voltage line.

Contingency	Country	Overload
Yopougon 3 225 kV – Songon 225 kV (NATIONAL)	CI	Overload of second circuit when the power of Songon is at its maximum

Table 38: List of problematic contingencies (NATIONAL) – Off peak 2033

3.4.4. Operating the network with an increasing share of renewables

With the new capacity of renewable power generation which is planned to connect to the grid in the 2033 horizon, new operational limits can be reached.

Operating a power system with high instantaneous penetration of renewables poses numerous operational challenges which must be addressed to ensure a high system reliability. These operational challenges can be classified depending on the timescale of interest. A short non-exhaustive overview is given below. These different aspects should be studied in a dedicated study to define the operational constraints and measures to be taken to allow the important share of renewable. These studies should comprise of a review of the grid code, such as the WAPP Operational Handbook, as well as a renewable integration study which will study the points mentioned in the following paragraphs.

Within the timescale of minutes to hours, both the variability and especially the limited predictability of renewables (PV and wind power) may have a direct impact on the required operating reserves guaranteeing the balance between generation and demand.

First, the variability of such units adds to the overall power imbalance that drives the amount and flexibility of the reserves. Forecast errors on the other hand create an uncertainty and require real-time relatively higher load following or ramping reserves.

Secondly, especially with a very high penetration, such units will replace traditional power plants, which normally guarantee the provision of the required reserves and ancillary services. Additional measures have therefore to be taken to guarantee the balance between generation and demand at all times.

Operational impacts at faster timescales (seconds to minutes) are mainly related to the way these units are interfaced with the network. The strong coupling of a traditional synchronous generator to the grid ensures a high short-circuit power as well as an inertial response. On the contrary, converters typically transform direct current (DC) electricity to AC power by controlling semiconductor devices at a high switching frequency. Due to this intermediate DC link which decouples the generator from the grid, no inertial response is provided, and the converter interface also inherently weakens or eliminates the response to grid faults.

Instead of the physical characteristics of the synchronous machine, the control strategy of the converter predominately determines the electrical dynamic interaction with the system. However, both the high short-circuit power as well as the inertial response are essential for the operation of current transmission grids. A high and sustained short-circuit current during grid faults, will limit the impact area of voltage dips and triggering fault detection by protection relays. The inertial response on the other hand will limit the rate of change of frequency (ROCOF) after a power imbalance in the system and as such inherently provides time for the governors and turbines to react in order to stabilize the system frequency. Less inertia immediately leads to higher ROCOF values and lower minimum frequencies for the same considered incident as given in the figure below. Without taking additional measures, this will lead to large scale load shedding or tripping of protection relays.

Final version

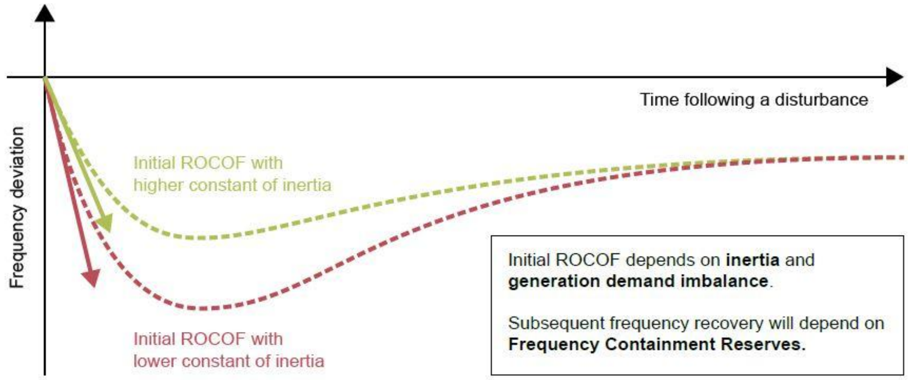


Figure 50: Impact of inertia on the rate of change of frequency (ROCOF) [Entso-e]

Final version

4. OPPORTUNITIES BEYOND THE BORDERS OF THE WAPP

4.1. Possible interconnection with North Africa

In parallel to the main study, the consultant was asked to carry out a pre-feasibility study on an interconnection between North-Africa and WAPP. This study includes a technical and an economic part.

The objective of **the technical study** is to study the technical feasibility of an interconnection between the North-African power grid and the WAPP electricity grid. In particular, it analyzes the impact of technology (AC or DC) on stability of the system as a whole.

Based on the results and recommendations from the technical analysis, an **economic study** is carried out. The objective of this study is to establish, on the one hand, the optimal exchanges on interconnection, and on the other hand the benefits for the West African system of an interconnection with North-Africa.

4.1.1. Technical study

4.1.1.1. INTRODUCTION

In this study, the prefeasibility of the connection between the North-African power system and the WAPP-system is further analysed. This part of the study focuses on the technical aspects, and more specifically on the way the system stability is influenced when an AC or DC line is used to link both systems.

The goal is mainly to address the question whether it is possible to use AC technology for the connection, taking into account the long distances and assumed power transfers between the two systems.

Secondly, also the options to use DC technology are shortly addressed and the main advantages and disadvantages of using LCC or VSC are presented.

Finally, the congestions within the Moroccan power system are investigated considering 1000 MW export produced by renewable energy sources (e.g. PV) close to the 400kV bus LAAYOUNEII.

4.1.1.2. MODELLING

4.1.1.2.1. Morocco and WAPP-system

The WAPP model has been developed in the power system simulation tool Eurostag. The power system of Morocco is provided in PSS/E. Therefore, a conversion from the static and dynamic model of Morocco is firstly been done to merge the two systems in Eurostag. As a starting point, each system is balanced by itself such that no large power transfers will take place in case the systems are linked by an AC line.

Final version

4.1.1.2.2. European system equivalent

In this prefeasibility study, the European power system is represented by an equivalent model which will mimic the behaviour of the European network and its dynamic interactions with the Moroccan system. The applied modelling detail is considered to be sufficiently accurate for the type of studies presented in this report.

The equivalent model is connected to the substation PINARREY (Spain). All other lines linking this bus with the remaining Spanish system are being disconnected. Only the lines with TARIFA (1&2) remain in operation in the study. See also Figure 51 below.

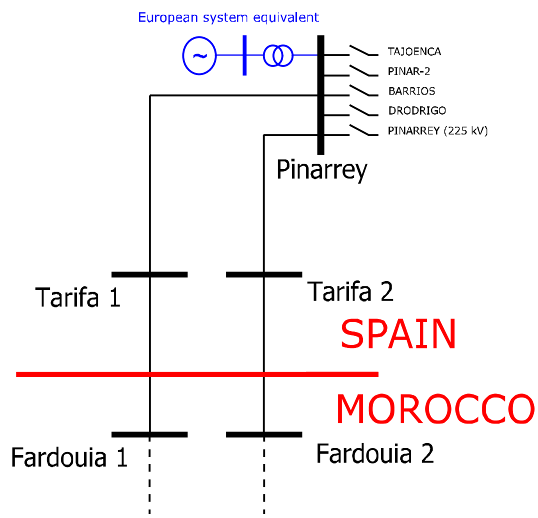


Figure 51: European system equivalent and surrounding network

For the static simulations, such as the AC load flow, an equivalent generator linked with a transformer and an active power setting equal to the net transfer from PINARREY to TARIFA (within the fully detailed system model this is set equal to 0 MW) is applied.

For the dynamic simulations, the generator is equipped with a governor (IEEEG1) and a voltage regulator (IEEET1). The parameters for these regulators and generator as well as the type of model used are based on the consultant experience and are shown in the tables below. These parameters are the one usually applied in system studies. Due to the type of study requested, the most important parameters are the inertia, the equivalent size of the unit and the K parameter of the model IEEEG1.

Parameter	Value	Parameter	Value
SN (MVA)	360 000	H	5
Pmax MW)	306 000	D	0,0
Pmin (MW)	0	Xd	2.3
Qmax (MVar)	190 000	Xq	2
Qmin (MVar)	-190 000	X'd	0,29

Final version

Parameter	Value	Parameter	Value
Xsource	0,2	X'q	0,3
T'd0	6,5	X''d=X''q	0,2
T''d0	0.03	Xl	0,15
T'q0	0,5000	S(1.0)	0,2
T''q0	0,15	S(1.2)	0,4

Table 39: Generator parameters for the ENTSO-E (European) system equivalent

Parameter	Value	Parameter	Value
K	2,2400	K2	0,0000
T1	0,0000	T5	0,0000
T2	0,0000	K3	0,0000
T3 (> 0)	0,5000	K4	0,0000
Uo	0,1000	T6	0,0000
Uc (< 0)	-0,1000	K5	0,0000
PMAX	1,0000	K6	0,0000
PMIN	0,0000	T7	0,0000
T4	0,5000	K7	0,0000
K1	1,0000	K8	0,0000

Table 40: Governor (IEEEG1) parameters for the ENTSO-E (European) system equivalent

Parameter	Value	Parameter	Value
TR (sec)	0	KF	0,2
KA	400	TF (>0)(sec)	1
TA	0,02	Switch	0,0000
VRMAX	6,02	E1	2,8875
VRMIN	-6,02	SE(E1)	0,39
KE	1	E2	3,85
TE (>0)(sec)	0,015	SE(E2)	0,5630

Table 41: Exciter (IEEET1) parameters for the ENTSO-E (European) system equivalent

Final version

4.1.1.2.3. Interconnection

The connection will link the Moroccan/European system and the WAPP-system, more specifically, the south of Morocco and Senegal with an intermediate tapping to Mauritania. The minimum distance and optimal power evacuation capability of the surrounding network are the main criteria for determining the different connection points and routing of the line.

In Morocco, it is chosen to use the substation named DAKHLA as starting point of the interconnection as it is one of the most southerly located 400 kV substations in the country. It is also directly linked with the long 400 kV (double circuit) backbone going from south to north Morocco.

In Senegal different connection options do exist, but in this study the substation TOBENE is chosen as it is linked to the 225 kV grid of the country. Furthermore, as it is one of the largest substations in the country, it can be assumed to become part of any 330/400 kV network upgrade, linking Senegal and the rest of the WAPP-system.

The intermediate tapping in Mauritania is located at the Nouakchott substation which is part of the 225 kV network. The line length DAKHLA-NOUACKCHOTT is estimated to be equal to 800 km, the length between NOUACKCHOTT-TOBENE is taken equal to 450 km. Figure 52 gives an overview of the link and the connection points.

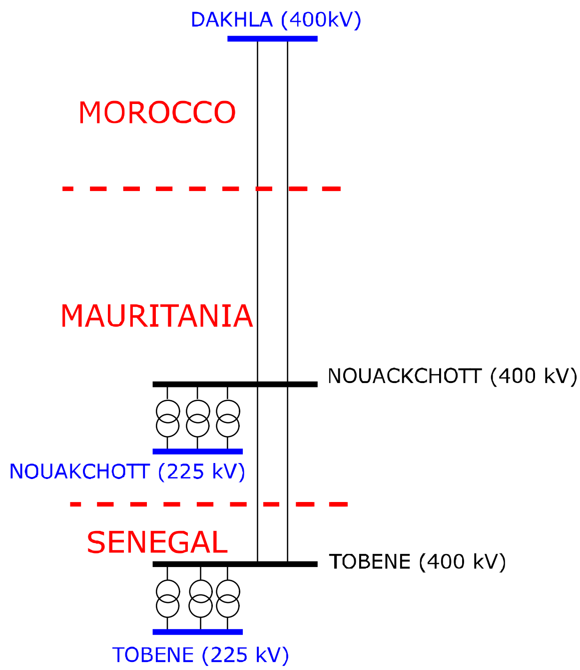


Figure 52: Proposed 400 kV AC interconnection linking the existing system (new equipment is shown in black, the existing busses are coloured in blue)

Final version

4.1.1.3. ANALYSIS OF THE AC OPTION

4.1.1.3.1. Description and approach

A double-circuit overhead line operated at 400 kV is applied with a maximum capacity of 1000 MVA each. As such, in an N-1 situation, still 1000 MVA can theoretically be transferred over the interconnection. To connect the line with the 225 kV substation in TOBENE, three transformers of 500 MVA each are used (see also Figure 52). The same applies for the connection with the NOUACKCHOTT substation. For the lines and transformers, standard parameters are being used as given in the table below.

Parameter	Value	Parameter	Value
R	0,033 Ω/km	Length DAKHLA-NOUACKCHOTT	800 km
X	0,33 Ω/km	Length NOUACKCHOTT-TOBENE	450 km
B/2	1,54 µS/km		

Table 42 : Parameters of 400 kV line

When operating such a long AC overhead line, several (dynamic stability) issues may occur. A non-exhaustive list is presented below:

- Due to the Ferranti effect, reactive power compensation (e.g. in the form of shunt reactors) need to be installed to prevent overvoltages on the line during energization.
- During loading, voltage control may become an issue: with such long AC lines, compensation is often needed, which can give rise to new problems, such as subsynchronous resonance (i.e. the resonant frequency of turbine generator shafts coincides with a resonant frequency of the system.)
- Fault protection issues: timing problems due to communication delays between the different parts of the protection equipment (measurement devices, circuit breakers, …) may lead to untimely fault clearance or maloperation of the protection system.
- Transient stability issues may occur. Especially during high loading of the line, generators can lose synchronism after a fault occurs on the interconnection due to the low synchronizing power between the two systems (Morocco/Europe & WAPP). Even in case a fast fault clearance is ensured, a system split is difficult to prevent and additional measures have to be taken to enhance the transient stability.

In this report, the latter form of stability is investigated in more detail. To this end, a short-circuit is applied on one of the lines between DAKHLA and NOUAKCHOTT (95% of the line length starting from DAKHLA) for different loading levels of the line. The fault is cleared after 100 ms by opening both ends of the line. It is investigated whether the system is able to remain in synchronism. The line loading is increased by installing a (dummy) generator and load at both ends of the line and gradually increase the active power setting of both.

In the model, shunt reactors are installed at the three busses to compensate for the generated reactive power during low loading of the line. A simple approach to calculate the required size is applied, i.e. the reactors fully compensate the susceptance of the line. More elaborate ways to compensate the line during different loading levels using switched reactors/, series compensations or SVC's are possible but are out of the scope of this study.

4.1.1.3.2. Simulation results

Firstly, the transient stability is investigated for (almost) zero active power transfer over the lines. Nevertheless, it became clear that, even for such low transfer, the generators closely located to NOUAKCHOTT lose synchronism after the fault was cleared.

This is clearly shown in Figure 53 and Figure 54 (simulation results may assumed to be valid until system loses synchronism, thereafter protection systems are triggered, which are not included in the EUROSTAG model). In these figures, the angles of some generators spread over the system and the power transfers (active and reactive) over the AC interconnection are given. All angles are expressed with respect to the centre of inertia (since Europe has such high inertia, this centre lies closely to the border of Spain). Although most of the generators stay synchronized, the machines inside Mauritania go out-of-step.

In case no connection to NOUAKCHOTT is made (by disconnecting the transformers), a higher active power transfer is feasible without jeopardizing the transient stability considering the assumed fault location/duration, see also Figure 55 and Figure 56 for an active power transfer of 200 MW.

This simulation is repeated to identify the maximum power transfer at which the system is still capable of remaining synchronized. A value of **280 MW** is found to be the limit. Increasing the limit would be possible by a faster fault clearing or by implementing different measures to increase the transient stability (fast-valving, SVC's, more and stronger interconnections between the system,…). Going beyond that limit, a clear system split will occur after fault clearance. See for instance Figure 57 and Figure 58 for a power transfer of 500 MW; the generator angles inside the WAPP and Moroccan system completely diverge from each other (simulation results may assumed to be valid until system loses synchronism, thereafter protection systems are triggered, which are not included in the EUROSTAG model).

Considering the simulation results and all the former listed issues that may occur, it can be concluded that, from a system stability point of view, it will be very challenging to operate such a long AC link connected to two weak points in the network. Additional investments will be required, such as several intermediate substations, voltage control devices, series compensation, …

Final version

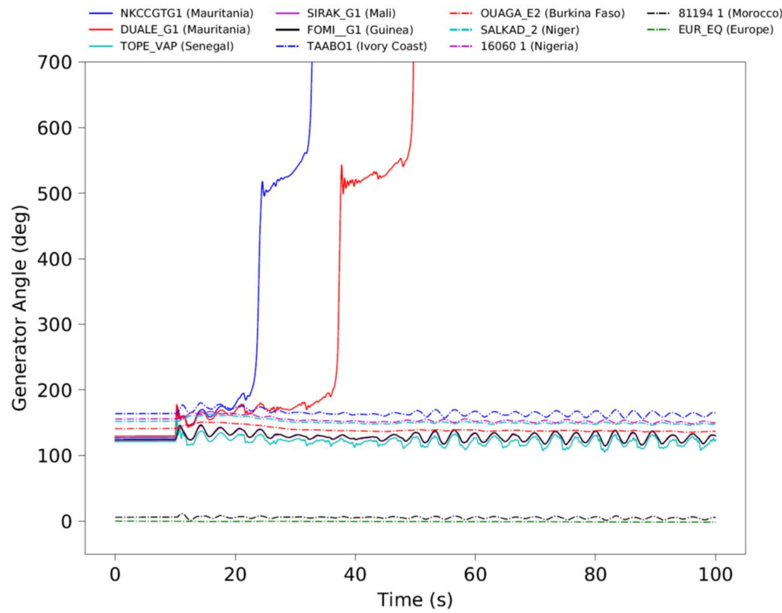


Figure 53: Generator angles - Three-phase short circuit at 10s (clearance at 10.1s) - intermediate connection at NOUAKCHOTT – 0 MW power transfer

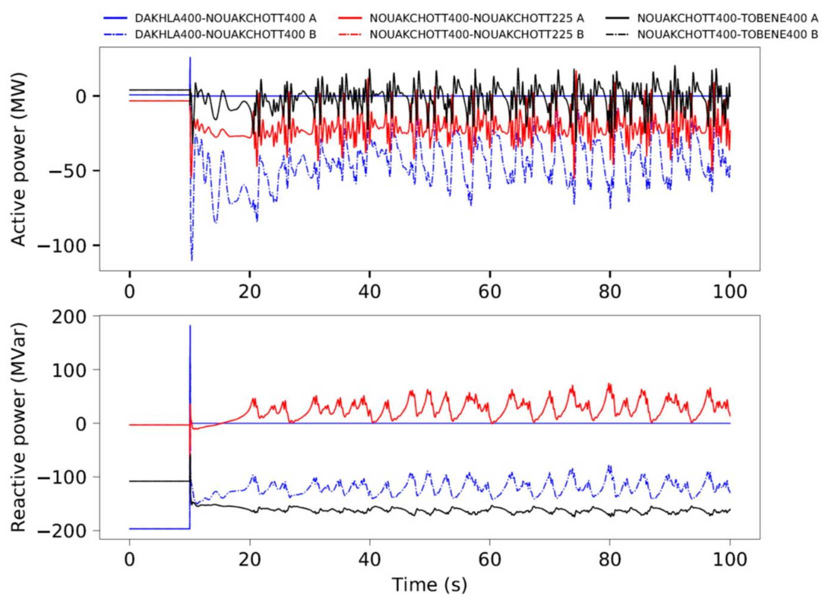


Figure 54: Active and reactive power flow over the AC interconnection - Three-phase short circuit at 10s (clearance at 10.1s) - intermediate connection at NOUAKCHOTT – 0 MW power transfer

Final version

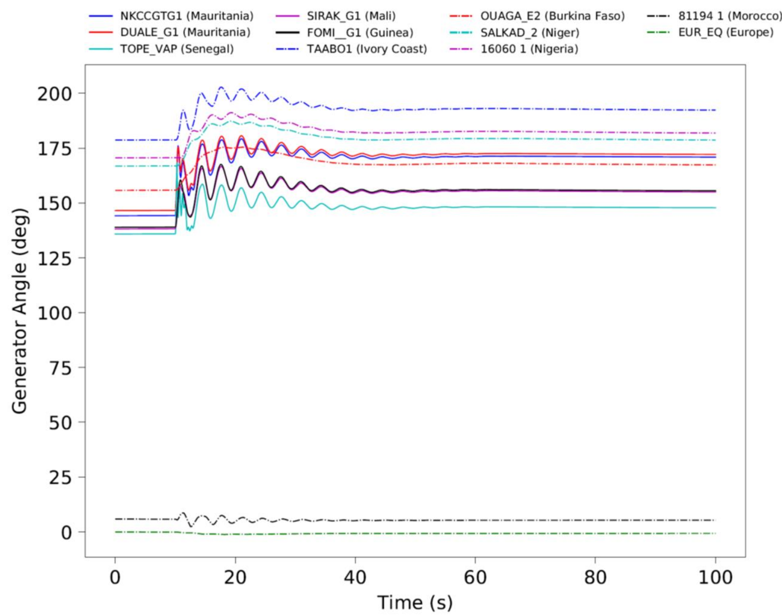


Figure 55: Generator angles - Three-phase short circuit at 10s (clearance at 10.1s) - No intermediate connection at NOUAKCHOTT – 200 MW power transfer

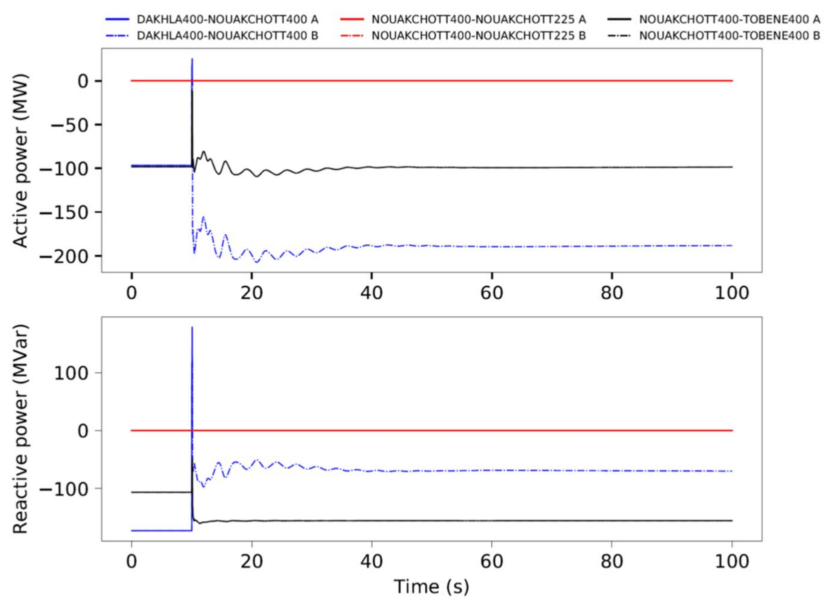


Figure 56: Active and reactive power flow over the AC interconnection - Three-phase short circuit at 10s (clearance at 10.1s) – No intermediate connection at NOUAKCHOTT – 200 MW power transfer

Final version

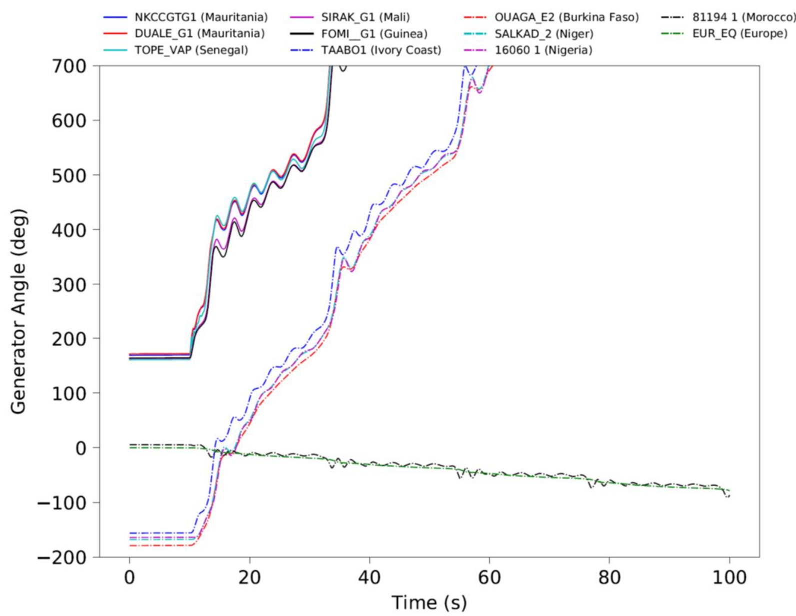


Figure 57: Generator angles - Three-phase short circuit at 10s (clearance at 10.1s) - No intermediate connection at NOUAKCHOTT – 500 MW power transfer

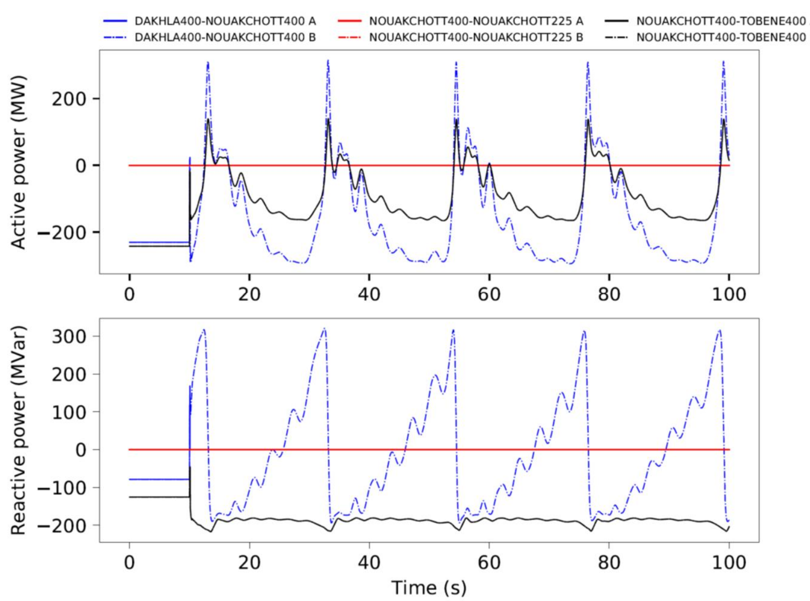


Figure 58: Active and reactive power flow over the AC interconnection - Three-phase short circuit at 10s (clearance at 10.1s) – No intermediate connection at NOUAKCHOTT – 500 MW power transfer

Final version

4.1.1.4. ANALYSIS OF THE DC OPTION

4.1.1.4.1. Overview of different options: technology and lay-out

Besides considering an AC connection, it is interesting to look at the options of linking both systems by using HVDC technology. HVDC offers many advantages in this specific case compared to the long AC lines. It provides for instance a decoupling of both systems (system dynamics due to faults are not directly transferred from one system to the other), enhanced controllability, lower line losses (no skin effect and no reactive power transfer), … just to name a few.

Independently of the specific converter technology (VSC: voltage source converter or CSC: current source converter), it is firstly important to look at the main lay-out of the DC connection.

Different lay-outs can be applied for the considered HVDC link, such as a monopolar or bipolar system with ground return or metallic return. A bipolar system with ground return is chosen as it offers increased redundancy and allows some flexibility for future tappings/extensions. The increased redundancy is achieved because the system can still operate at 50% of its nominal rating in case of an outage of one converter or line. Future tappings can consist out of a bipolar layout or can be build using a single converter (monopolar tapping with ground return).

The proposed lay-out is presented in Figure 59. In this figure, an intermediate tapping is foreseen at NOUAKCHOTT. However, to reduce cost and control complexity of the link, this tapping could be added in a later stage and a standard point-to-point connection would be constructed in a first step.

Final version

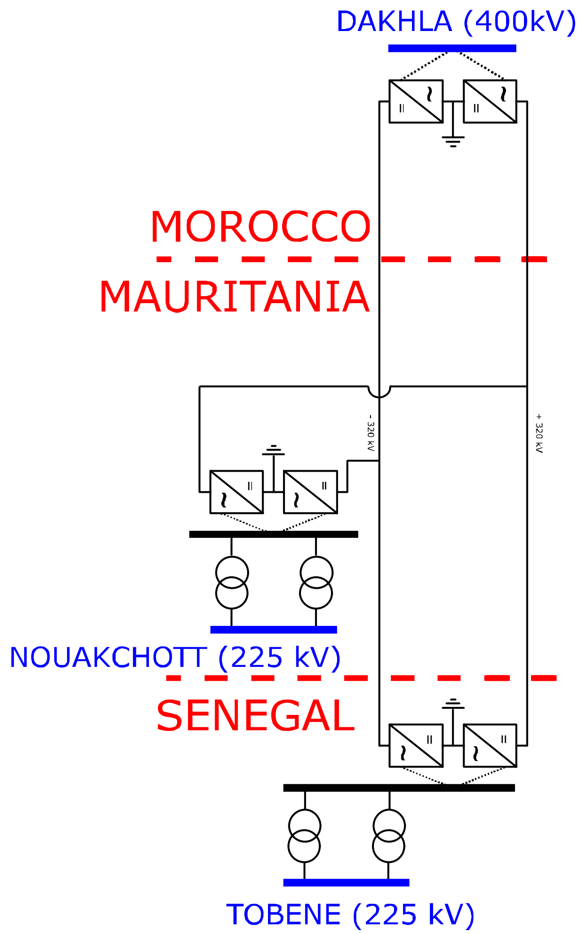


Figure 59: Proposed bipolar HVDC link ±320 kV (new equipment is shown in black, the existing busses are coloured in blue, the connection between the converters and AC grid is not presented in detail)

With respect to the applied HVDC technology, one can chose between CSC and VSC converters. A list with the main differences of interest is presented in the table below:

CSC	VSC
Lower cost	Higher cost
Lower converter losses	Higher converter losses
Requires strong AC system	Operates into weaker AC systems
DC network extension is not straightforward	More flexibility in terms of DC network extension (tappings/multi-terminal) and control
Consumes always reactive power	Flexible reactive power support + other ancillary services

Table 43: Comparison between CSC and VSC technology

Final version

Besides it additional cost and losses, VSC offers many advantages over CSC, especially for the investigated system. For CSC for instance, a relatively strong AC system at the point of common connection (PCC) is required, commonly expressed in terms of the short circuit ratio (SCR). In general, it is assumed that a SCR of 2-3 is required to ensure a proper operation of the CSC. For lower SCR, commutation failures may occur.

Taking into account the weak connection points (low short circuit power at DAKHLA: **1.459 GVA**, NOUACKCHOTT:**1.321 GVA** TOBENE: **3.480 GVA**), additional measures (adding synchronous condensers, STATCOMs, …) have therefore to be taken to apply CSC technology for a rating of 1 GVA. VSC looks thus the most appropriate solution for the system especially when grid support is required or future extensions (and tappings) of the system are foreseen.

4.1.1.4.2. Grid support by HVDC: simulation results

HVDC links not only decouple both AC systems such that faults in one system do not propagate to the other system, they can also provide grid support after an incident takes place. One of such support mechanismwhich would be of interest is to provide frequency control to the WAPP system. Since the Moroccan system is linked with Europe, it has a substantial amount of inertia and primary reserve which it can be offered to the WAPP system by modifying the power controller which is demonstrated in the simulation results presented below.

A VSC HVDC connection is integrated in the system, connected between DAKHLA and TOBENE. In our power system simulation tool EUROSTAG, different standard control blocks are applied to model both VSC as CSC HVDC connections. The layout itself (bipolar, monopolar, ground return of metallic return) of the point-to-point HVDC link doesn't have that much influence on the way it is represented in the software. As long as we investigate standard forms of power system stability (voltage, angle, frequency, … stability) in which we are mainly interested in the dynamic interaction of the converters with the system, the same model is used for different layouts. Regarding the main (upper) controllers of the link: the converters of DAKHLA are in DC voltage control mode, the ones at TOBENE in active power control. Both converters operate at a fixed reactive power exchange, although the controllers can easily be modified to offer also AC voltage control at both sides of the link.

By adding an additional control signal to the active power control loop which acts on the frequency deviation in the system, the VSC converter mimics the primary frequency control of a classical power plant. The additional power to offer this support is coming from the Moroccan/European system and transferred over the DC links. This support is demonstrated by simulating an outage of KADUNA G (Nigeria, loss of 215 MW) in case the power is transferring 300 MW from TOBENE to DAKHLA. The frequency at both sides of the HVDC connection together with the power output of the VSC at TOBENE is given in Figure 60 and Figure 61.

Final version

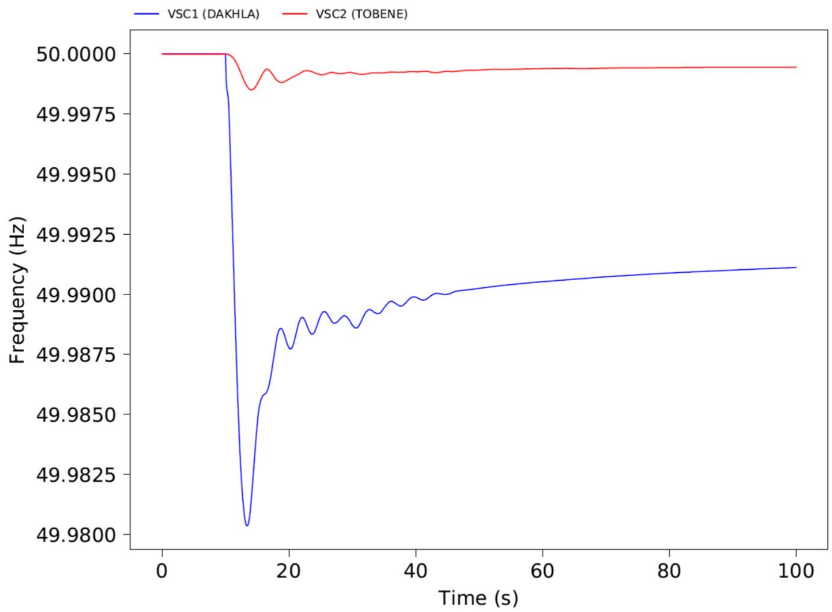


Figure 60: Frequency at both HVDC terminals when offering frequency support after an outage of KADUNA G at t=10s

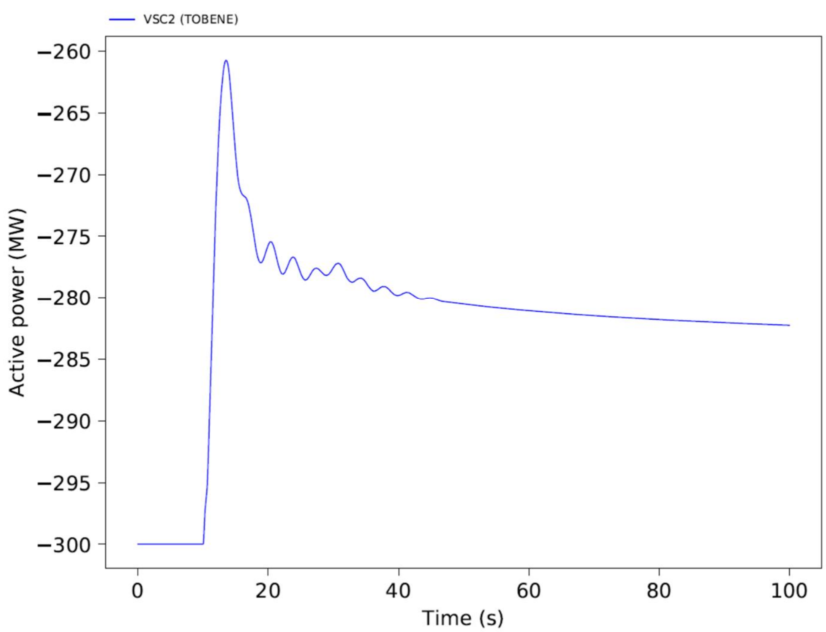


Figure 61: Active power flow over the HVDC link when offering frequency support after an outage of KADUNA G at t=10sNetwork congestions within the Moroccan power system considering 1000 MW export

Final version

In the following section, it is assumed that we start from the peak load scenario and add an additional (future) 1000 MW of solar power close to bus LAAYOUNEII. This surplus of 1000 MW is exported through the link towards the WAPP system (assume HVDC connection). Some additional assumptions have been made:

- Voltage control devices are added to the bus LAAYOUNEII (so modelled as a PV bus)
- HVDC terminal at DAHKLA is controlled to export 1000 MW and offers AC voltage control (DAHKLA is also modelled as a PV bus)
- To simplify the modelling: HVDC is represented as a load in parallel with a generator offering voltage control and 0 MW output (only valid for static simulations!)

This results in the following power flow for the case with and without the 1000 MW export (only the part close to DAHKLA and LAAYOUNEII has been shown):

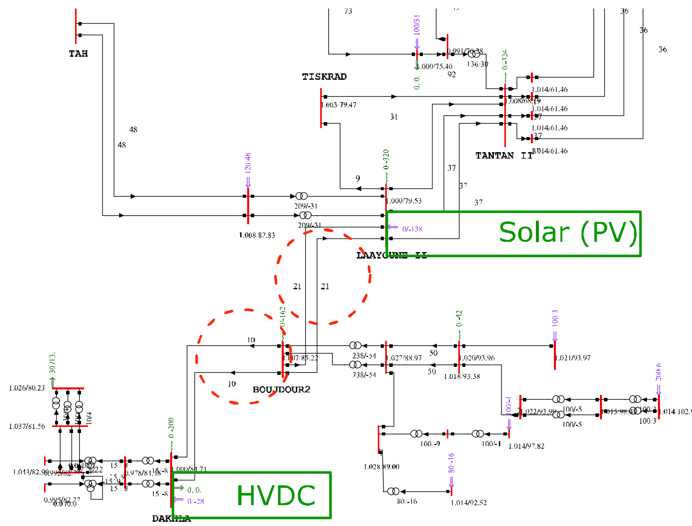


Figure 62: Power flow for an export of 0 MW – No solar pv power (purple numbers represent MW/MVar of loads, green numbers represent MW/MVar of generation, .../... close to the busses represent bus voltage and angle, numbers close to the lines represent the loading in %)

Final version

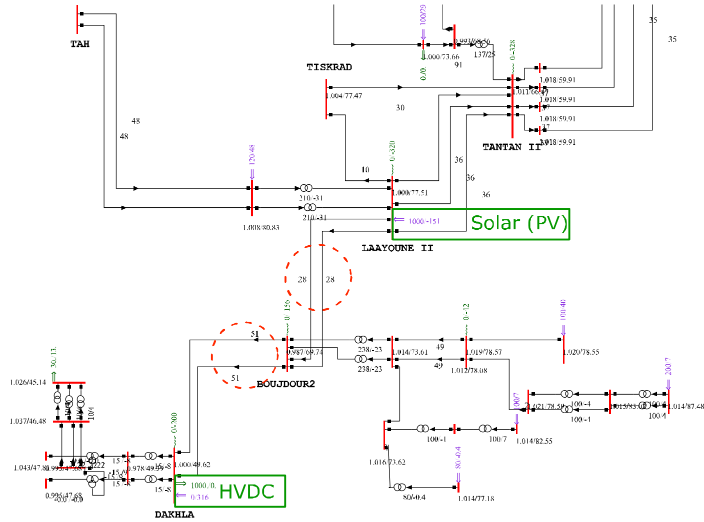


Figure 63: Power flow for an export of 1000 MW – 1000 MW solar pv (purple numbers represent MW/MVar of loads, green numbers represent MW/MVar of generation, …/… close to the busses represent bus voltage and angle, numbers close to the lines represent the loading in %)

One may notice that the main influence of the export of 1000 MW is the loading on the 400 kV double circuit from LAAYOUNEII to DAKHLA (see red circles in figure). Other parts of the network are less influenced. But even if 1000 MW is transferred, the double circuit (1070 MVA each) are only loaded by 28% or 51% (for respectively LAAYOUNEII-BOUJDOUR2 and BOUJDOUR2-DAKHLA). However, for an N-1 situation (losing for instance one circuit of BOUJDOUR2-DAKHLA, the other circuit is overloaded (116% loading).

This considered outage is repeated for different power transfers and it is concluded that maximum 900 MW can be transferred in order to be N-1 secure. (More research is required in case the solar (pv) power is linked to bus within a more meshed part of the system. In that case, different line outages must be investigated for a detailed N-1 analysis.)

4.1.1.5. CONCLUSION

To link the WAPP system with the North-African system, different interconnection options have been analysed and compared from a techno-economic point of view.

Taking into account the weak connection points, additional measures have therefore to be taken to apply HVDC CSC or AC technology for a rating of 1 GVA. HVDC VSC in a bipolar configuration looks thus the most appropriate solution for the system especially when grid support is required or future extensions (and tappings) of the system are foreseen.

Final version

4.1.2. Economic study

This study looks at the impact of interconnection with North-Africa by adding the Moroccan system to the model using the generation development plan transmitted by ONEE during the data collection and by adding a new interconnection. This Moroccan generation park is frozen in the economic analysis (no modification of the installed capacity). This park is shown in the figures below at the beginning as well as at the end of the study horizon, for the years 2017 and 2033.

At the beginning of the study period, in 2017, the generation fleet was made up mostly of coal units (43%). Then come the thermal power plants using heavy fuel oil (26%), hydroelectric power plants (19%) including the pumping station-turbine of Afourer and finally the gas-fired power plants (12%).

During the period under review, investments by Morocco in renewable energies are very important, with 5.1 GW of investment in Solar power plants Photovoltaic and 6.5 GW in wind units, these two technologies representing respectively 27% and 29% of Morocco's 2033 installeed capacity.

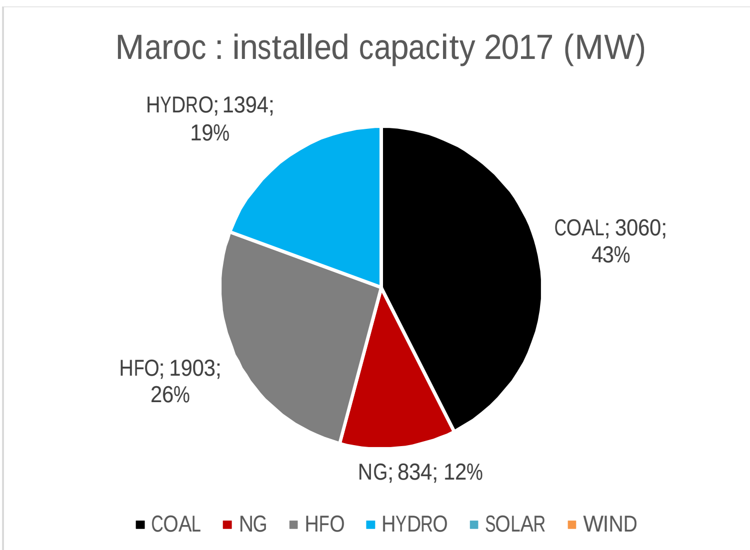


Figure 64: Generation installed capacity Morocco in 2017, by type of fuel

Final version

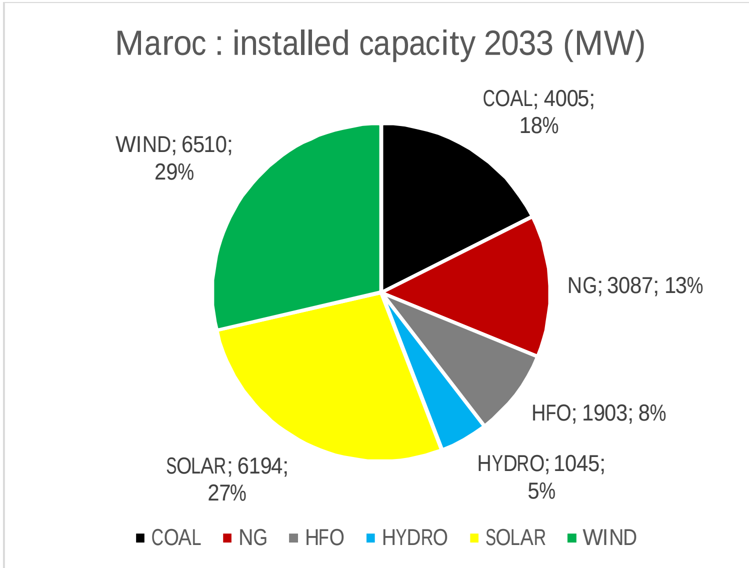


Figure 65: Generation installed capacity in Morocco in 2033, by type of fuel

The load load demand forecast for Morocco considered in the study is the one that was transmitted to the consultant by ONEE during the data collection phase. The peak demand evolves from 5992 GW in 2017 to 10 882 MW in 2033, an average annual growth of 4%. Energy consumption goes from 37 990 GWh En 2017 to 68 129 GWh in 2033, an average annual growth of 4% as well.

Based on the comparison of situations with and without interconnection, the benefits for the West African system of interconnecting with North-Africa via Morocco and Mauritania are estimated.

The economic study of the interconnection between North-Africa and the WAPP begins by doing a first estimate of investment costs. Then the optimal exchanges on the interconnection are analyzed. Finally, this part of the study closes by addressing the benefits for the West African system of interconnection with North-Africa .

It should be noted that the economic study focuses mainly on HVDC – VSC technology, since it was selected as the preferred solution by the technical study and using a first analysis of the costs as is developed below.

4.1.2.1. COST ESTIMATE

A first basic cost estimation[14] of the presented options can be found below (for a direct connection between DAKHLA and TOBENE). Only investment costs are considered in this calculation, no operational, maintenance, ... costs are included. Furthermore, the cost of the AC substations which have to be built for all studied options are not included as well (for instance additional substation TOBENE 400kV). Therefore, the costs as given below are merely to compare the different options and give not a good estimate of the final cost.

AC (400 kV):

- Lines + compensation (400 kV double circuit): 1.5*1250 km*0.40 M$ = 750 M$
- (Additional intermediate substations used for voltage control (2): 64.4 M$)
- **Total: Double circuit ± 814.4 M$ (Single circuit ± 564.4 M$)**

HVDC (CSC - 1GW – without intermediate tapping):

- Converter stations: 2x130 M$ = 260 M$
- Lines: 1250 km*0.29 M$ = 362.5 M$
- **Total: ± 622.5 M$**

HVDC (VSC - 1GW – without intermediate tapping):

- Converter stations: 2*144 M$ = 288 M$
- Lines: 1250 km*0.29 M$ = 362.5 M$
- **Total: ± 650.5 M$**

Since the cost of an HVDC overhead line is generally less then an AC overhead line with the same capacity (a factor of 0.72 is assumed here), the cost of the converters is compensated by the reduced line costs for long connections, see also Figure 66. The cricitcal distiance at which there is a break-even in cost between AC and DC is generally in the order of 600-800km. As the line is much longer, the above cost calculation confirms the presumption that HVDC is the most economic option for such long distance.

As indicated by the calculation, the CSC option is the cheapest option. However, when assuming that also additional investments are required to increase the SCR at the connection points, this option would possibly be as expensive or even more expensive as the HVDC VSC link (more detailed studies are required). Also, when comparing the AC and HVDC options, it should be kept in mind that the AC double circuit is fully N-1 (1000 MVA capacity in case of an outage of one circuit), while the bipolar DC link can only transfer 500 MW in case of an outage (DC converter or DC line).

[14] Voltage Source Converter (VSC) HVDC for Power Transmission - Economic Aspects and Comparison with other AC and DC Technologies, Cigré, Technical Brochure, 2012. & Modular Development Plan of the Pan-European Transmission System 2050: Technology assessment from 2030 to 2050, e-Highway 2050, Technical Brochure, 2014.

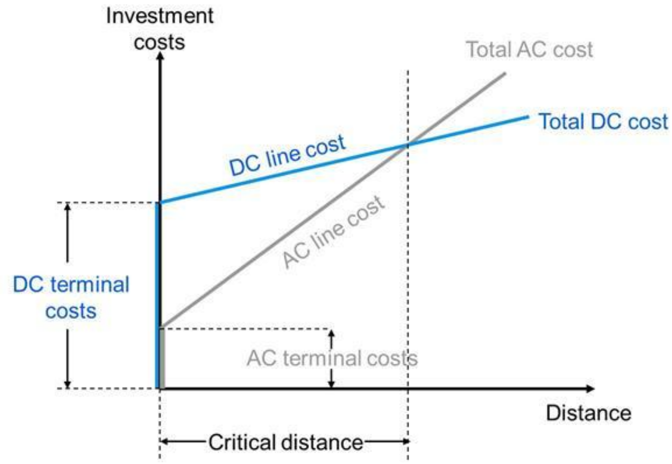


Figure 66: Schematic illustration of the cost comparison between HVDC and AC connections (source: ABB)

4.1.2.2. ANALYSIS OF OPTIMAL ENERGY EXCHANGES

To determine the level of optimal trade between WAPP and the North-African power system, the methodology consisted adding Morocco as a new node of the PRELE model developed for the analysis of the reference case presented in the master plan above. The Moroccan generation assets were modeled according to the information received from the ONEE during the data collection (no modification of the installed capacity).

Then on the basis of the cost estimates made by the technical analysis, the possibility of investing in a HVDC line between North-Africa and WAPP was also introduced into the economic model. The commissioning of this line is considered from 2023 (the economic model could not invst before).

The purpose of optimization is to determine if there is an economic interest in investing in such a line, and to establish optimal flows in such case.

The results of the economic simulations indicate that there is indeed an economic interest to interconnect the WAPP with North-Africa. These results, however, will have to be confirmed by a detailed feasibility study that would optimize the systems on both sides and include potential trade with Europe.

The figure here below illustrates the evolution of optimal exchanges during a typical day at the end of the study horizon, in 2033. It is observed that, most of the time, ernegy flows are from North-Africa to West-Africa, especially during the evening and the night during which the coal units of North-Africa are in service (Base operation), but also during the day, where the energy flows from North-Africa coming mainly of solar photovoltaic power plants. The export of solar energy from North-Africa is explained by a better solar productible. Indeed, it is possible to reach 2000kWh/kW in the region while the producible does not generally exceed 1600kWh/kW in West Africa. It should therefore be noted that the volume of exchange on the interconnection is limited by the availability of solar energy in North-Africa. Thus, if aditionnal solar energy projects were installed in that region, there would be an economic interest for West Africa to import this aditionnal solar energy.

In the evening, On the other hand, trade is the other way around, and Senegal exports the electricity produced by gas power plants, this resource being more economically optimal (local ressources comparing to GNL) than the other thermal options available in North-Africa.

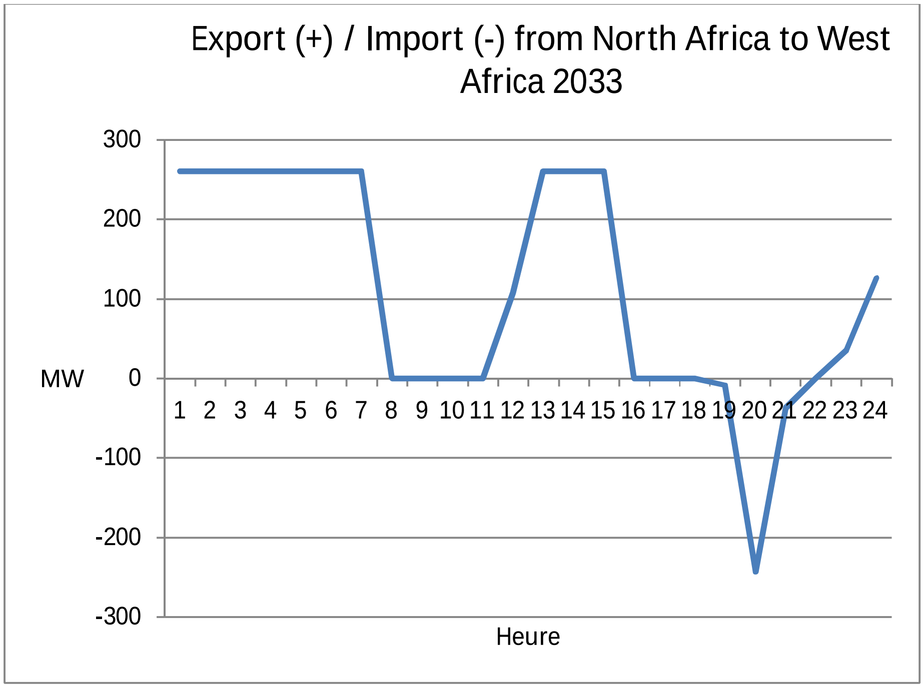


Figure 67: Optimum exchange between North-Africa and West Africa En 2033

From an energy point of view, the export from North-Africa to West-Africa are estimated at 1050 GWh per year from 2023, and to 105 GWh per year In the opposite direction, so that the net export from North-Africa to West-Africa amounts to 945 GWh annually and the optimum capacity of the link resulting from the optimsation tool is about 260 MW.

Again, from a purely economic point of view, the flows to West Africa could be significantly higher if solar energy was available in greater quantities in North-Africa (potentially coming from Europe). It is worth mentioning that the economic interest of exporting wind resources available to North Africa should also be studied as part of the feasibility study.

Final version

4.1.2.3. ANALYSIS OF IMPACTS OF INTERCONNECTION SUR THE WEST AFRICAN SYSTEM

From the economic point of view, the operating cost is reduced during the day in West Africa. The import of solar energy replaces the local thermal generation between 11am and 4pm. On the other hand, during the evening peak, the export of thermal energy from Senegal increases the generation costs in the sub-region. The balance sheet is therefore relatively neutral in terms of operating costs. Note, however, that If more solar energy could be imported, Operational gains could be more important. One could also observe a shift of solar projects from West Africa to the more northerly regions, given the more abundant resources, which would have the effect of reducing the capacity installed in the sub-region

4.1.3. Conclusion

This pre-feasibility study of the interconnection between WAPP and North Africa analysed the various possible technical possibilities for this interconnection.

On the basis of this technical analysis, it appeared that the preferred solution is a HVDC – VSC line of 1GW capacity.

The economic analysis confirmed there is an economic justification for intyerconnecting both system but with a rather limited capacity of about 260 MW. Energy flows are mainly from North-Africa to West-Africa during the night and the day, and in the opposite direction for a few hours during the evening peak.

A detailed feasibility analysis should, however, be carried out which would take into account the significant solar and wind potential of North Africa as well as exchange opportunities with Europe.

4.2. Interconnection opportunities with the Central African Energy Pool

After analyzing the possibilities of interconnecting WAPP with Morocco, this scenario explores the possibility of interconnecting WAPP with the Central African Energy Pool (PEAC).

This road is part of the INGA project. The system would transfer the future power generated by the Inga III and Grand Inga dams and one of the export routes is West Africa via the interconnection between Inga in DRC and Nigeria.

Concerning the Inga project, the development of the site is addressed in 7 successive phases; Inga Iii Low Falls, Inga Iii High Falls, then Inga 4 to Inga 8 to reach the total generation of 42 000 MW. The first phase currently underway concerns Inga 3 low falls with a power of 4 800 MW.

It should be noted that, besides of Inga, other important projects, mainly hydroelectric, should be also developed in the PEAC region and it justifies the interests of the various interconnections studied by the PEAC.

With regard to the interconnection between the Inga site and Nigeria, the line would be connected to Calabar, in the southeast of the country. This line is a priority project of PEAC, as well as a PIDA priority project also for 2020 (infrastructure development program in Africa). The 8 countries concerned by this interconnection, namely the DRC, the Republic of the Congo, Gabon, Equatorial Guinea, the Cameroon, Chad, the Central Republic of Africa and Nigeria signed a memorandum of understanding. Currently, the project is in the process of collecting funding for studies, and few information is available concerning the expected transfer capabilities, the volumes of energy exchanges or the tariffs to be applied.

Final version

Figure 68: Project to route the Inga-Calabar interconnection

4.2.1. Methodology

In view of limited available information available on the charactistics of this project, the following methodology was used.

The PRELE economic model developed for the reference case has been extended by adding, on the one hand, an area representing the PEAC and, on the other hand, an interconnection line linking Nigeria to this new PEAC zone.

Nigeria has been able to import from PEAC Zone at a certain cost and at the level of a certain transfer capacity considered.

- Concerning **the costs of import**, 3 different rates were studied: 40 USD/MWh, 60 USD/MWh and 80 USD/MWh (costs including also transmission tariffs)
- Concerning **the transfer capacity of the interconnection** it was assumed to be 1 GW starting from 2024[15] and increased to 2 GW in 2030. It should be noted that the transfer Power can only flow from the PEAC to WAPP, since the PEAC as such has not been modelled, either at the level of its load demand forecast or generation assets.

The purpose of the study is to analyze the impact on investments as well as on the operating costs for WAPP depending on thes different rates considered.

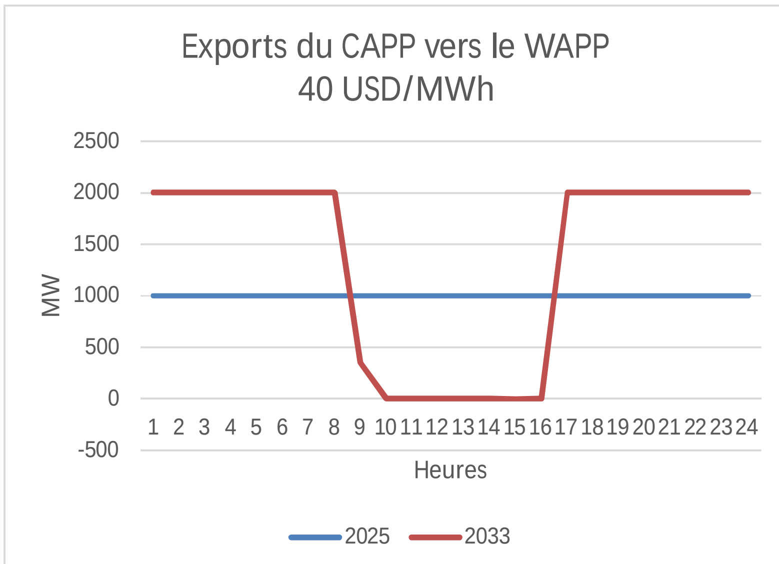
Final version

[15] This date of commissioning is taken from the regional energy Policy strategy paper Of the Central African Energy Pool

4.2.2. Results

Different uses of interconnection are observed according to the tariffs applied.

§ **For 40 USD/MWh,** the optimization program uses the full capacity of the interconnection is 1 GW at any time of the day until 2029. At the end of the study period, it uses the full capacity of 2 GW at disposal during the evening and at night. During the day, it appears that the interconnection line is not used, given that massive investments in solar photovoltaic technology are carried out in southern Nigeria and overall the WAPP region in the long term.



§

Figure 69: ExportAtions from the CAPP to The Wapp For a fee of 40 USD/MWh

§ **For 60 USD/MWh,** the line is used mainly during the evening peak between 7pm and midnight and also during the night and early morning at the end of the study horizon (2033).

Final version

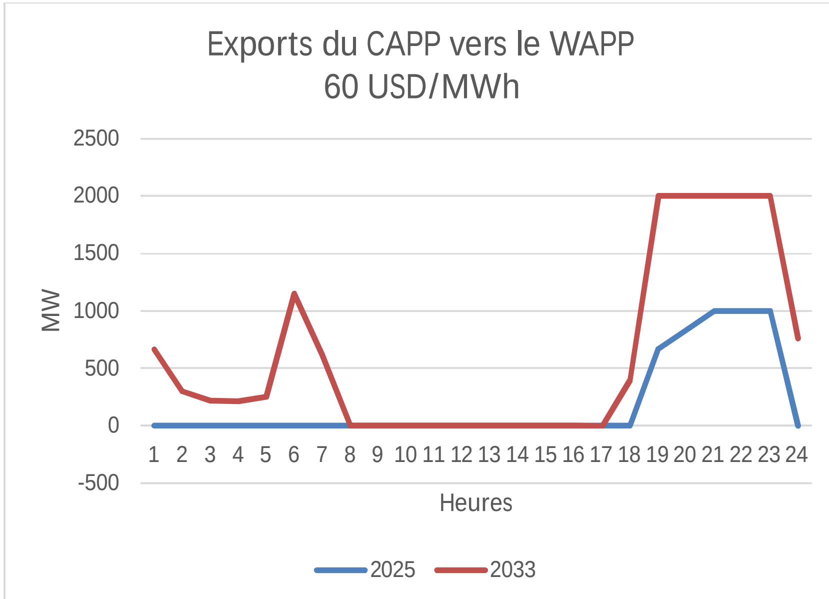


Figure 70: Exports from CAPP to WAPP for a fee of 40 USD/MWh (2033)

§ **For 80 USD/MWh,** no more imports are practically realized, except under special conditions, such as dry years during which Mambilla cannot deliver all of its hydroelectric potential.

In terms of impact on the investments in installed capacity, the introduction of the interconnection of a transfer capacity of 2 GW at the end of the study is logically reduced the required installed capacity in peak units, mainly in Nigeria. The interconnection allows to ensure a reserve role and participate in the Security Supply system for the West African.

With regard to the impact on operational costs, the results differ according to the rates considered, as summarized in the table below. With a rate of 40 USD/MWh, the intensive use of interconnection can lower Operational costs of WAPP region of 5.5%. For 60 USD, the use of the line during the evening peak reduces these costs of 3.3%. For 80 USD/MWh, the impact on operational costs is virtually nil, since this line is used only in exceptional situations.

Final version

		40 USD/MWh	60 USD/MWh	80 USD/MWh
Impact on the Investments		-2 GW	-2 GW	-2 GW
Impact on operational costs		-56	-33	-0.2%
Energy Annual Exchanged GWh	**1 GW Transfer capacity**	5.507	2, 114	221
	2 GW Transfer capacity	11.013	6.228	443
Estimated cost of imports (% of operational costs)		3.4%	2.3%	0.2%

Table 44: Results of the study On The interconnection of the WAPP with The PEAC

4.2.3. Conclusion

As a conclusion, it can be said that there is an economic interest in interconnecting areas of WAPP and PEAC in order to share important cheap ressources from Inga and other hydroelectric sites, notably, of the PEAC region.

The economic study carried out indicates that this interest exists provided that the purchase price of energy is not too high. According to the first estimates, 80 USD/MWh appears to be an upper limit on the tariffs to be applied. The energy exchanges and the optimal capacity are directly depending of the applied tariff. Also, beyond savings in terms of operational costs, the line also allows savings in terms of investment costs, since this interconnection allows replacing some additional thermal units, which were installed in the reference case for reasons of reliability mainly[16].

However, it is still worth mentioning that the present study considered only part of the problem, since the PEAC was not modelled and the fluxes were therefore only considered in the direction of the export of the PEAC to the WAPP. But it could be also Interesting for WAPP exporting to PEAC, which would therefore further strengthen the interest of this line of interconnection.

4.3. Connection Opportunities with Cap Vert

Given its insular nature, Cape Verde is not an active member of WAPP and is therefore not studied in detail in this study. The purpose of this paragraph is to present the country's connection options with the rest of ECOWAS.

[16] Among them, the OCGT plants in Nigeria

There is no interconnected network in the country. Given the island nature of Cape Verde, the transport and distribution networks are decentralized. Thus, in each island transport and distribution networks are installed according to the source of generation. Nevertheless, the access to electricity remains difficult in the Verdean territory of fragmentation of the power grid.

The project for the development of the electricity transmission and distribution system in 6 Islands will contribute to the improvement of technical, commercial and financial performances of The Company National of electricity (ELECTRA). The Project concerns 492 000 Inhabitants (94% of total Population of Cap Vert). It will increase The rate of Electricity access from 88% in 2010 to 98% at horizon 2018.

Interconnection with the rest of ECOWAS could benefit the sub-region in two aspects:

- On the one hand, the sharing of solar and wind resources on the island ;
- On the other hand the improvement of the security of supply to Cape Verde.

Nonetheless, such a (costly) interconnection is not a priority at the horizon of the study. Indeed, the city of Praia, capital of Cape Verde, is located in 650km from the Senegalese coast. Such a distance requires using HVDC cables to connect the two countries electrically, the cost of which is prohibitive with regard to the exchanges that could take place on this axis. Indeed, the level of demand, currently less than 100MW which is much lower than the typical transfer capabilities of the HVDC cables. On the other hand, the island's renewable potential was estimated at 2600 MW of which 650 MW usable. The development of this potential should be the priority to meet the increase of national demand.

Before the interconnection with the continent, the main thing for Cape Verde is therefore(e) developing an inter-island interconnected network to improve the security of supply in the territory, to better exploit the many renewable projects of the country and to reduce costs.

APPENDIX A : GENERATION MASTER PLAN

This annex takes up the Summary of investments by country for each time horizon, distinguishing the projects decided, the selected candidate projects. The time phase is finally presented.

Short term investment per country

BÉNIN

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
BID Benin	Decided	CCGT	Natural Gas	120	2019
Parakou	Decided	Engine	DDO	30	2019
CAI Maria Gleta (Extension 50 MW)	Decided	CCGT	Natural Gas	70 + 50 (120)	2020
PV AFD	Decided	PV		25	2020
PV MCA SUD	Decided	PV		15	2020
PV INNOVENT DJOUGOU	Decided	PV		1.5	2020
PV MCA NORTH	Decided	PV		30	2020
PV Benin North Standard	Selected	PV		50	2021
Maria Gleta WAPP	Selected	CCGT	Natural Gas	150	2022
Biomasse 1	Selected	Biomass		10	2022
Biomasse 2	Selected	Biomass		11	2022
Total Benin				373	

Table 2: Short term invesmtents up to 2022 in Bénin

BURKINA FASO

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
Fada	Decided	Engine	HFO	7.5	2018
SAMENDENI	Decided	Hydro		2.76	2019
Kossodo	Decided	Engine	HFO	50	2020
Kaya	Decided	PV		10	2020
Zina	Decided	PV		26.6	2020
Foot PIE 1	Decided	PV		51.25	2020
Zagtouli 2	Decided	PV		17	2020
Ouaga-Est	Decided	Engine	HFO	100	2021
Koudougou	Selected	PV		20	2021
AFD	Selected	PV		50	2022
PV Bobo standard	Selected	PV		50	2022
Total Burkina Faso				385	

Table 3: Short term invesmtents up to 2022 in Burkina Faso

Final version

CÔTE D'IVOIRE

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
Azito IV_GT	Decided	CCGT	Natural Gas	170	2019
Ciprel V_GT	Decided	CCGT	Natural Gas	276	2019
Korhogo Solar (RECA)	Decided	PV		20	2019
Azito IV_ST	Decided	CCGT	Natural Gas	83	2020
Ciprel V_ST	Decided	CCGT	Natural Gas	136	2021
Poro Power (CANADIAN SOLAR)	Decided	PV		50	2020
Centrale solaire BOUNDIALI (KFW)	Decided	PV		30	2020
Centrale solaire FERKE	Selected	PV		25	2021
BOUNDIALI 2	Selected	PV		70	2021
ODIENNE	Selected	PV		20	2021
KORHOGO 2	Selected	PV		30	2021
SINGROBO	Decided	Hydro		44	2022
GRIBO POPOLI	Decided	Hydro		112	2021
Aboisso (Biokala)	Decided	Biomass		23	2022
Aboisso (Biokala)	Decided	Biomass		23	2022
LABOA	Selected	PV		100	2022
FERKE 2	Selected	PV		75	2022
BOUTOUBRE	Selected	Hydro		156	2022
Total Côte d'Ivoire				1443	

Table 4: Short term invesmtents up to 2022 in Côte d'Ivoire

THE GAMBIA

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
Brikama I _G7	Decided	Engine	Diesel	6.4	2018
Brikama III_G1	Decided	Engine	Diesel	10	2019
Brikama III_G2	Decided	Engine	Diesel	10	2020
World bank PV	Decided	PV		20	2019
Brikama PV	Decided	PV		10	2020
Standard CC Gambia	Selected	CC	HFO	60	2022
PV Gambie standard	Selected	PV		50	2022
Total Gambie				166.4	

Table 5: Short term invesmtents up to 2022 in The Gambia

Final version

GHANA

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
KPONT_ST	Decided	CCGT	Natural Gas	120	2018
CENPOWER_CC	Decided	CCGT	Natural Gas	360	2018
EARLY POWER	Decided	CCGT	Natural Gas	147	2019
TROJAN 3	Decided	OCGT	Natural Gas	50	2018
MI ENERGY	Decided	PV		20	2018
BUI PHASE 1	Decided	PV		50	2018
GPGC	Decided	CCGT	Natural Gas	170	2019
EARLY POWER	Decided	CCGT	Natural Gas	153	2019
KALIOU LORA	Decided	PV		12	2019
BIO THERM	Decided	PV		20	2019
AMANDI	Decided	CCGT	Natural Gas	240	2020
BUI PHASE 2	Selected	PV		200	2021
BONGO SOLAR	Selected	PV		40	2021
ROTAN	Decided	CCGT	Natural Gas	330	2022
PV Ghana north Standard	Selected	PV		250	2022
Total Ghana				2162	

Table 6: Short term invesmtents up to 2022 in Ghana

GUINÉA

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
ENDEAVOR	Decided	Engine	DDO	50	2019
Khoummaguély PV	Decided	PV		40	2019
Sougéta PV	Decided	PV		30	2019
KALETA extension reservoir	Decided	Hydro		0	2021
SOUAPITI	Decided	Hydro		450	2020
PV Guinea North standard	Selected	PV		100	2021
PV Guinea South East standard	Selected	PV		100	2021
FOMI	Decided	Hydro		90	2022
KOGBEDOU	Decided	Hydro		58	2022
FRANKONEDOU	Decided	Hydro		22	2022
Touba	Decided	Hydro		5	2022
Touba PV	Decided	PV		5	2022
Total Guinea				950	

Table 7: Short term invesmtents up to 2022 in Guinea

Final version

GUINÉA-BISSAU

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
Bor (BOAD)	Decided	Engine	HFO	15	2019
BADEA	Decided	Engine	DDO	22	2019
Standard CC Guinee Bissau	Selected	CC	HFO	60	2022
PV Guinea Bissau Standard	Selected	PV		50	2020
Total Guinea Bissau				147	

Table 8: Short term invesmtents up to 2022 in Guinea Bissau

LIBÉRIA

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
Extension reservoir Mount Coffee	Selected	Hydro		0	2022
PV Liberia standard	Selected	PV		50	2022
Total Liberia				50	

Table 9: Short term invesmtents up to 2022 in Liberia

MALI

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
ALBATROS (Kayes)	Decided	Engine	HFO	92	2018
Bamako (Sirakoro)	Decided	Engine	HFO	100	2020
GOUINA	Decided	Hydro		140	2020
KITA PV	Decided	PV		50	2020
Kati PV	Decided	PV		65	2021
Segou PV	Decided	PV		33	2021
Sikasso PV	Selected	PV		50	2022
Total Mali				530	

Table 10: Short term invesmtents up to 2022 in Mali

Final version

NIGER

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
Malbaza PV	Decided	PV		7	2019
Lossa PV	Decided	PV		10	2019
NCE (Maradi) PV	Decided	PV		30	2019
Zinder PV	Decided	PV		60	2019
Dosso PV	Decided	PV		10	2019
Niamey PV	Decided	PV		30	2019
Goroubanda PV 2	Decided	PV		30	2019
GOROUBANDA 2	Decided	Engine	HFO	20	2020
Diesel North	Decided	Engine	HFO	6	2020
Goroubanda PV 1	Decided	PV		20	2020
Agadez PV	Decided	PV		13	2020
SALKADAMNA phase 1_1	Decided	Charbon		50	2021
SALKADAMNA phase 1_2	Decided	Charbon		50	2021
SALKADAMNA phase 1_3	Decided	Charbon		50	2021
SALKADAMNA phase 1_4	Decided	Charbon		50	2021
KANDADJI	Decided	Hydro		130	2021
PV standard Niamey	Selected	PV		100	2022
PV standard Niger North	Selected	PV		100	2022
Total Niger				766	

Table 11: Short term invesmtents up to 2022 in Niger

Final version

NIGERIA

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
EGBEMA I - NIPP	Decided	OCGT	Natural Gas	113	2018
OMOKU - NIPP	Decided	OCGT	Natural Gas	113	2018
AZURA	Decided	OCGT	Natural Gas	450	2018
AFAM III	Decided	OCGT	Natural Gas	240	2018
EGBEMA I - NIPP 1	Decided	OCGT	Natural Gas	113	2019
EGBEMA I - NIPP 2	Decided	OCGT	Natural Gas	113	2019
KADUNA IPP	Decided	OCGT	Natural Gas	215	2019
OMOKU - NIPP	Decided	OCGT	Natural Gas	113	2019
KASHIMBILLA	Decided	Hydro		40	2019
OKPAI IPP II - AGIP 1	Decided	CCGT	Natural Gas	300	2020
OKPAI IPP II - AGIP 2	Decided	CCGT	Natural Gas	150	2020
Nova solar	Selected	PV		100	2021
Nova scotia power	Selected	PV		80	2021
Pan africa solar	Selected	PV		75	2021
Lr aaron solar power plant	Selected	PV		100	2021
Egbin 2+ phase 1	Selected	CCGT	Natural Gas	1200	2022
ZUNGERU	Selected	Hydro		700	2022
Quaint energy solutions	Selected	PV		50	2022
Nigeria solar capital partners	Selected	PV		100	2022
Afrinergia solar	Selected	PV		50	2022
PV Nigeria East Standard	Selected	PV		150	2022
Total Nigeria				4565	

Table 12: Short term invesmtents up to 2022 in Nigeria

Final version

SÉNÉGAL

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
Diass	Decided	PV		25	2018
Wind turbine 1	Decided	Wind Turbine		50	2019
Touba (scaling solar)	Decided	PV		30	2019
Kaloack (scaling solar)	Decided	PV		30	2019
Sendou IPP CES I	Decided	ST	Charbon	115.1	2020
Malicounda	Decided	Engine	HFO	120	2020
SAMBANGALOU	Decided	Hydro		128	2022
Wind turbine 2	Decided	Wind Turbine		50	2020
Wind turbine 3	Decided	Wind Turbine		50	2021
Scaling solar	Selected	PV		40	2021
Kayar Kounoune	Decided	CCGT	Natural Gas	115	2022
World Bank project	Selected	PV		100	2022
PV Dakar Standard	Selected	PV		50	2022
PV Tambacounda Standard	Selected	PV		50	2022
Total Sénégal				953	

Table 13: Short term invesmtents up to 2022 in Sénégal

SIERRA LEONE

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
Newton Solar	Decided	PV		6	2019
CEC Africa Phase 1	Decided	Engine	HFO	50	2020
Heron Energy	Selected	PV		5	2021
Bo PV	Selected	PV		5	2021
PV Freetown Standard	Selected			100	2022
Total Sierra Leone				166	

Table 14: Short term invesmtents up to 2022 in Sierra Leone

TOGO

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
Lome TG	Decided	OCGT	Natural Gas	60	2020
PV Dapaong	Selected	PV		30	2021
Total Togo				90	

Table 15: Short term invesmtents up to 2022 in Togo

Final version

Medium term investments per country

BÉNIN

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
Maria Gleta WAPP	Selected	GT (CC)	Natural Gas	150	2023
Maria Gleta WAPP	Selected	ST (CC)	Natural Gas	150	2024
GREENHEART POWER AFRICA	Selected	PV		10	2025
PV Benin North Standard	Selected	PV		150	2024-2026
Total Benin				460	

Table 16: Medium term investments 2023-2029 in Bénin

BURKINA FASO

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
WAPP PV Ouagadougou	Selected	PV		150	2022-2024
PV Bobo standard	Selected	PV		50	2025
Foot PIE 2 Ouagadougou	Selected	PV		100	2026
PV Ouaga standard	Selected	PV		150	2029
Projet Wind Ouaga	Selected	Wind Turbine		75	2029
Total Burkina				**525**	

Table 17: Medium term investments 2023-2029 in Burkina Faso

CÔTE D'IVOIRE

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
WAPP PV CIV	Selected	PV		150	2022-2024
PV CIV North standard	Selected	PV		150	2022-2024
Louga	Decided	Hydro		224	2023
TIBOTO	Decided	Hydro		112.5	2028
San Pedro I_ST 1	Decided	ST	Charbon	350	2026
PV CIV North standard	Selected	PV		100	2027
PV CIV Sud standard	Selected	PV		100	2028
San Pedro I_ST 2	Decided	ST	Charbon	350	2029
Total Côte d'Ivoire				1536	

Table 18: Medium term investments 2023-2029 in Côte d'Ivoire

NORTH

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
WAPP PV Gambie	Selected	PV		150	2023-2025
Total Gambie				150	

Final version

Table 19: Medium term investments 2023-2029 in The Gambia

GHANA

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
PV Ghana north standard	Selected	PV		250	2023
PV Ghana north standard	Selected	PV		250	2025
WAPP PV Ghana	Selected	PV		150	2026
PV Ghana north standard	Selected	PV		250	2028
PV Ghana sud standard	Selected	PV		100	2029
CCGT Aboadze	Selected	CCGT	Natural Gas	450	2029
Total Ghana				1450	

Table 20: Medium term investments 2023-2029 in Ghana

GUINÉA

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
AMARIA	Decided	Hydro		300	2023
MORISANAKO	Selected	Hydro		100	2025
GRAND KINKON	Selected	Hydro		291	2023
KOUKOUTAMBA	Decided	Hydro		294	2024
BONKON DIARIA	Selected	Hydro		174	2025
TIOPO	Selected	Hydro		120	2028
PV Guinea South East	Selected	PV		100	2028
DIARAGUÔLA	Selected	Hydro		72	2029
Total Guinea				1451	

Table 21: Medium term investments 2023-2029 in Guinea

Final version

GUINÉA-BISSAU

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
PV Guinea Bissau	Selected	PV		50	2024
PV Guinea Bissau	Selected	PV		50	2028
Total Guinea Bissau				100	

Table 22: Medium term investments 2023-2029 in Guinea Bissau

LIBERIA

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
PV Liberia standard	Selected	PV		50	2025
Total Liberia				50	

Table 23: Medium term investments 2023-2029 in Liberia

MALI

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
Kurikolo PV	Selected	PV		50	2023
Koutiala PV	Selected	PV		25	2024
WAPP Regional Project	Selected	PV		150	2022-2024
Fana PV	Selected	PV		50	2025
PV Bia	Selected	PV		40	2026
Tenkele PV	Selected	PV		40	2027
Medium PV	Selected	PV		40	2028
Total Mali				395	

Table 24: Medium term investments 2023-2029 in Mali

NIGER

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
PV standard Niamey	Selected	PV		100	2024
PV standard North	Selected	PV		150	2025
Projet wind standard Niamey	Selected	Wind Turbine		150	2026
PV standard Niamey	Selected	PV		100	2027
PV standard North	Selected	PV		100	2028
PV standard Niamey	Selected	PV		100	2029
Total Niger				700	

Table 25: Medium term investments 2023-2029 in Niger

NIGERIA

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING

Final version

EGBIN 2+ 2	Selected	ST (CC)	Natural Gas	700	2023
ETHIOPE 1	Selected	GT (CC)	Natural Gas	344	2023
MABON	Selected	Hydro		39	2023
KVK power nigeria LTD PV	Selected	PV		55	2023
Anheed kafachan solar IPP PV	Selected	PV		100	2023
CT cosmos PV	Selected	PV		70	2023
Oriental PV	Selected	PV		50	2023
ETHIOPE 2	Selected	ST (CC)	Natural Gas	156	2024
CALEB INLAND	Selected	CCGT	Natural Gas	500	2024
ETHIOPE 3	Selected	GT (CC)	Natural Gas	344	2024
MAMBILLA	Decided	Hydro		3050	2024
EN consulting - Kaduna	Selected	PV		100	2024
Kazure (Kano disco) phase 1	Selected	PV		500	2024
ETHIOPE 4	Selected	ST (CC)	Natural Gas	156	2025
CALEB INLAND 2	Selected	CCGT	Natural Gas	500	2025
ALAOJI 2+ NIPP	Decided	CCGT	Natural Gas	285	2025
Standard CC Nigeria South 1	Selected	CCGT	Natural Gas	450	2026
Standard CC Nigeria South 2	Selected	CCGT	Natural Gas	450	2026
Standard CC Nigeria South 3	Selected	CCGT	Natural Gas	450	2026
Motir dusable	Selected	PV		100	2026
Middle band solar	Selected	PV		100	2026
WAPP PV Nigeria	Selected	PV		1000	2025-2029
GEREGU NIPP 2	Selected	ST (CC)	Natural Gas	285	2027
OMOTOSHO II 2+	Selected	ST (CC)	Natural Gas	254	2027
CALEB INLAND 3	Selected	CC	Natural Gas	500	2027
Standard CC Nigeria South 4	Selected	CCGT	Natural Gas	450	2028
Standard CC Nigeria South 5	Selected	CCGT	Natural Gas	450	2028
Standard CC Nigeria South 6	Selected	CCGT	Natural Gas	450	2028
Projet Wind standard North	Selected	Wind Turbine		350	2028
GEREGU FGN1-2	Selected	GT (CC)	Natural Gas	414	2029
CALABAR / ODUKPANI - NIPP	Selected	ST (CC)	Natural Gas	254	2029
GBARAIN / UBIE 2	Selected	ST (CC)	Natural Gas	115	2029
Standard CC Nigeria South 7	Selected	CCGT	Natural Gas	450	2029
Total Nigeria				13471	

Table 26: Medium term investments 2023-2029 in Nigeria

Final version

SÉNÉGAL

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
Standard PV Dakar	Selected	PV		100	2023
Standard PV Dakar	Selected	PV		150	2024
Standard CCGT Sénégal	Selected	CCGT	Natural Gas	450	2025
Standard CCGT Sénégal	Selected	CCGT	Natural Gas	300	2025
Standard PV Dakar	Selected	PV		50	2029
Total Sénégal				1050	

Table 27: Medium term investments 2023-2029 in Sénégal

SIERRA LONE

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
BUMBUNA II Decided	Decided	Hydro		132	2023
BUMBUNA III (Yiben) Decided	Decided	Hydro		66	2023
BENKONGOR I Candidate	Selected	Hydro		34.8	2023
BENKONGOR II Candidate	Selected	Hydro		80	2025
BENKONGOR III Candidate	Selected	Hydro		85.5	2026
PV Standard Sierra Leone	Selected	PV		50	2023
PV Standard Sierra Leone	Selected	PV		50	2028
Total Sierra Leone				498	

Table 28: Medium term investments 2023-2029 in Sierra Leone

Final version

TOGO

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
Sarakawa	Decided	Hydro		24.2	2023
PV Blitta	Selected	PV		20	2023
Adjarala	Decided	Hydro		147	2026
WAPP PV Togo	Selected	PV		150	2028-2030
Total Togo				341	

Table 29: Medium term investments 2023-2029 in Togo

Long term investments per country

BÉNIN

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
Standard CC Benin North	Selected	OCGT	HFO	60	2030
PV Benin Sud Standard	Selected	PV		100	2030
Total Benin				260	

Table 30: Long term investments 2030-2033 in Benin

BURKINA FASO

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
Standard CC Bobo-Dioulasso	Selected	OCGT	HFO	60	2029
PV Ouaga standard	Selected	PV		150	2030
Total Burkina				210	

Table 31: Long term investments 2030-2033 in Burkina Faso

Final version

CÔTE D'IVOIRE

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
CC Songon	Selected	CC	Natural Gas	369	2031
Standard TAG Côte d'Ivoire Sud	Selected	OCGT	Natural Gas	300	2030
PV CIV Sud standard	Selected	PV		250	2030
Standard CC Côte d'Ivoire North	Selected	OCGT	HFO	60	2033
Total Côte d'Ivoire				979	

Table 32: Long term investments 2030-2033 in Côte d'Ivoire

GHANA

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
PV Ghana Sud standard	Selected	PV		300	2030-2033
Projet Eolien Standard Ghana North	Selected	Wind Turbine		200	2030
Standard TAG Ghana Sud	Selected	OCGT	GN	300	2033
Total Ghana				800	

Table 33: Long term investments 2030-2033 in Ghana

Final version

GUINEA

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
BOUREYA Candidate	Selected	Hydro		160	2030
PV Guinea North standard	Selected	PV		100	2030
Standard CC Guinea North	Selected	OCGT	HFO	60	2030
FETORE	Selected	Hydro		124	2031
LAFOU	Selected	Hydro		98	2032
Total Guinea				542	

Table 34: Long term investments 2030-2033 in Guinea

GUINEA-BISSAU

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
Standard CC Guinea Bissau	Selected	OCGT	HFO	60	2030
Total Guinea Bissau				60	

Table 35: Long term investments 2030-2033 in Guinea Bissau

LIBERIA

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
PV Libéria standard	Selected	PV		50	2030
Standard CC Libéria	Selected	OCGT	HFO	60	2030
Mano	Selected	Hydro		180	2032
Total Libéria				290	

Table 36: Long term investments 2030-2033 in Liberia

MALI

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
Standard CC Mali	Selected	OCGT	HFO	60	2030
PV Mali Bamako standard	Selected	PV		100	2031
Total Mali				160	

Table 37: Long term investments 2030-2033 in Mali

NIGER

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
PV Niger Niamey standard	Selected	PV		150	2030
PV Niger North standard	Selected	PV		150	2030
Projet Eolien Standard Niger Niamey	Selected	Wind Turbine		150	2030
Standard CC Niger	Selected	OCGT	HFO	60	2030

Projet Eolien Standard Niger North	Selected	Wind Turbine		50	2031
Total Niger				560	

Table 38: Long term investments 2030-2033 in Niger

NIGERIA

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
EGBEMA II	Selected	ST (CC)	Natural Gas	127	2030
IHOVBOR (EYAEN) 2 - NIPP	Selected	ST (CC)	Natural Gas	254	2030
Standard CC Nigeria	Selected	CC	Natural Gas	1500	2030
Standard OCGT Nigeria	Selected	OCGT	Natural Gas	500	2030
Kazure (Kano disco) phase 2	Selected	PV		500	2030
PV Nigeria South standard	Selected	PV		400	2030-2033
Standard CC Nigeria	Selected	CC	Natural Gas	2500	2031
Standard OCGT Nigeria	Selected	OCGT	Natural Gas	1000	2031
Standard CC Nigeria	Selected	CC	Natural Gas	2500	2032
Standard OCGT Nigeria	Selected	OCGT	Natural Gas	1000	2032
Standard CC Nigeria	Selected	CC	Natural Gas	2500	2033
Standard OCGT Nigeria	Selected	OCGT	Natural Gas	1000	2033
Total Nigeria				13781	2033

Table 39: Long term investments 2030-2033 in Nigeria

SÉNÉGAL

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
Standard CC Sénégal	Selected	CC	Natural Gas	450	2030
Standard CC Sénégal	Selected	CC	Natural Gas	450	2030
PV Dakar standard	Selected	PV		150	2031
PV Wind Dakar standard	Selected	Wind Turbine		150	2031
PV Wind Dakar standard	Selected	Wind Turbine		200	2033
Total Sénégal				1400	

Table 40: Long term investments 2030-2033 in Sénégal

TOGO

PROJECT	STATUS	TECHNOLOGY	FUEL	INSTALLED POWER (MW)	COMMISSIONING
Standard CC Togo North	Selected	OCGT	HFO	60	2030
Total Togo				60	

Final version

ANNEXE B: TRANSMISSION MASTER PLAN

National Reinforcements – 2022

Senegal

- Line 225 KV Mbour Fatick Kaolack and substationFatick 225 KV
- New Line 225 KV double circuit Sendou Kounoune
- New Line 225 KV double circuit Tobene Kounoune
- New Cable Underground 225 KV double circuit Patte D'Oie Kounoune and 225 kV substation Patte D'Oie
- New Line 225kV Tambacounda Kolda Ziguichor
- New Line 225kV Damniado - Aprosi and creation of the two substations in 225kV
- New Line 225kV Double circuit Tobène Saint-Louis Nouakchott and related substations
- New 225 kV line Tobene - Thies – Diass (decided project)
- OMVG Line and associated substations

The Gambia

- New 132 kV double circuit line Brikama - Jabang - Kotu
- Two new 225/132 kV transformers in Brikama
- OMVG line and associated substations

Guinea Bissau

- OMVG line and associated substations

Guinea

- Second circuit 225 kV Kaleta - Linsan
- Second SVC 15 MVAr at Linsan
- Two new transformers 225/110 kV at Linsan
- OMVG line and associated substations
- CLSG line and associated substations

Mali

- Bamako loop : New double circuit line 225 kV Sikasso - Bougouni - Sanakoroba - Dialakorobougou - Kenie - Banconi - Kati - Kodialani – Sanakoroba

- Mining loop – New double circuit line 225 kV Kayes - Diamou - Sadiola - Loulo - Manantali
- New double circuit line 225kV Manantali – Bamako through Kita and Kati
- New substation 150kV at Dialakorobougou on break in of line Fana-Segou
- New transformer 225/150 kV Kodialani

Sierra Leone

- CLSG line and associated substations
- New 225 kV line Yiben - Waterloo and Waterloo 225kV substation
- New 161 kV line Waterloo - Freetown and 2 new 225/161 kV transformers in Waterloo

Liberia

- CLSG line and associated substations

Côte D'Ivoire

- New Line 400kV Bakre - Akoupe Zeudji PK24
- New Line 400 KV Azito IV- Bakre
- New Line 400 KV Azito IV- Akoupe Zeudji PK24
- New Line 400 KV Bakre -Bingerville
- New Line 400 KV Akoupe Zeudji PK24 -Bingerville
- Two new Transformers 400/225 KV Akoupe Zeudji PK24
- Three new Transformers 400/225 KV Bingerville
- Second line 225 KV San Pedro- Soubre passing through Boutoubre and Gribo Popoli
- New 225kV substation Yopougon 1 in cut-in of Abobo-Azito
- Upgrade of lines 90 kV Treichville-Vridi to 225 kV
- New Line 225 KV Akoupe Zeudji PK24 -Yopougon 3-Azito
- New Line 225 KV Boundiali- Tengrela
- Second circuit 225 KV Vridi- Bia Sud - Riviera
- New substation 225 KV Bia South in cut-in of Vridi-Riviera line
- New Line 225 KV Akoupe Zeudji PK24 Anyama Adzope - Attakro Daoukro - Serebou -Dabakala-Kong- Ferke
- New Line 225 KV Bouake- Serebou -Bondoukou
- New Line 225 KV double circuit Bingerville- Anani and substation Anani 225 KV
- New substation 225 KV Gagnoa and Divo
- Break in the second line Taabo -Abobo by Akoupe Zeudji PK24
- New Line 225 KV Laboa -Boundiali-Korhogo- Ferke
- New Line 225 KV Buyo - Dueko - Man
- New Line 225 KV Dueko - Zagne - Toulepleu
- Second circuit Buyo - Soubre 225 KV
- New Line 225kV Taabo -Yamoussoukro-Kossou
- New Line Bouake-Bouake 3-Kossou and new substation Bouake 3
- New Line 225 KV Buyo -Daloa
- New substation Katiola 225 KV in line break Ferke – Bouake

- CLSG Line and associated substations

Ghana

- New 330kV line Bolgatanga - Tamale - Kintampo - Kumasi - Dunkwa – Aboaze and associated 330 kV substations and 330/161 kV transformers
- New 330 kV substation Dawa and B5+ on the line Volta - Davié
- Two new 330/161 kV transformers at Dunkwa
- New 161 kV line Yendi - Juale - Kadjebi - Kpandu – Asiekpe (Convertion of the existing 69 kV line Kadjebi - Kpandu to 161 kV)
- Upgrade of 161 kV line Takoradi - Tarkwa to 364 MVA
- New Accra Central substation and update 2 circuits Volta-Accra East-Achimota-Accra Central-Mallam to 488 MVA
- New 161 kV substation at Berekurum
- New 330 kV line Karpower - Aboaze
- New 161 kV double circuit line Aksa - Smelteri II

Niger

- Two new 330/132 kV transformers Goroubanda
- Nouvelle ligne 330kV double terne Gorou Banda - Salkdamna
- Nouvelle ligne 132 kV double terne Kandadji - Niamey
- Nouvelle ligne 132 kV Salkadmna - Tahoua - Keita - Malbaza
- Remplacement de la ligne 132 kV Gazaou - Zinder vers 109 MVA

Burkina

- New Line 132 KV Zano - Koupela and substation Koupela 132 KV
- New SVC 50 MVAr decided at Pa
- 3 Transformers 330/225 KV at Ouaga East
- New double circuit line 225 kv Ouaga East-Ouaga South East and 225/132 KV Ouaga South East substation in break of line 132 kv Patte D'Oie - Zano
- New Line 225 KV Ouaga South East-Ouaga South
- New Line 225 KV Ouaga south- Zagtouli In Parallel Of the Ghana-Burkina Faso interconnection, which breaks in at Ouaga Sud

Benin

- New Line 161 KV Malanville - Bembereke and related substations (Malanville - Guene - Kandi – Bembereke)
- Break in of 20 Km of the Maria Gleta CCGT on the 330 KV line Ghana-Nigeria
- New double circuit line 161 KV Onigbolo – Parakou
- New Line 330 KV Davié – Sakete
- New Line 161 KV Benin-Togo and related substations (Dapaong Mandou - Porga - Tanguieta – Natitingou)
- Upgrade of 161 KV conductors Mome Hagou - Maria Gleta To 178 MVA

Togo

- New Line 330 KV Davié - Sakete
- New Line 161 KV Ghana North-Togo and associated substations (Bawku - Cinkasse -Dapaong-Mango – Kara)

- New Line 161 KV Benin-Togo and related substations (Dapaong Mandou - Porga - Tanguieta – Natitingou)
- New 161 KV substation Notse and 161kV Line Notse-Atakpame and line 161 KV Notse - Davié
- New substation 161 KV Legbassito and 161kV line double circuit Legbassito - Davié
- Replacement of 161 KV conductors from Mome Hagou - Maria Gleta to 178 MVA

Nigeria

The recent master plan from TCN was utilized as the main source for reinforcements and it was agreed that the 2022 model would be based on the situation described in the TCN master plan for the study year 2020.

- Second circuit line Benin - Omotosho - Ikeja West – Egbin
- New 330 kV substation at Katsina and two 330/132 kV transformers
- New double circuit 330 kV line Katsina – Kano
- New double circuit 330 kV line Akangba – Alagbon
- New double circuit 330 kV line Onitsha - Nnewi - Owerri - Egbema - Omoku
- New double circuit 330 kV line Alaoji - Owerri
- New single circuit 330 kV line Osogbo - Akure - Ihovbor
- Two new 330/132 kV transformers in Akure
- New Epe substation and new double circuit 330 kV line Aja - Epe - Omotosho

Second circuit line Benin - Omotosho - Ikeja West - Egbin

- Second circuit line Egbin - Aja
- New 330 kV substation at Port Harcourt and two 330/132 kV transformers
- New double circuit 330 kV line Delta - Port Harcourt - Afam - Ikot Ekpene - Ikot Abasi
- New 330 kV substation Ikot Abasi and three 330/132 kV transformers
- New double circuit 330 kV line Lokaja - Obajana
- New double circuit 330 kV Gwagwalada - Eastmain and associated substation and transformer
- New double circuit 330 kV line Katsina – Kazaure – Dutse - Bauchi
- Second circuit 330 kV line Katampe - Shiroro
- Second 330 kV line Kaduna - Kano
- New 330 kV substation at Zaria and connection with a single circuit 330 kV line to Kano and to Kaduna and two new 330/132 kV transformers in Zaria
- Second and third 330 kV line Kaduna - Jos and two new 330/132 kV transformer at Jos
- New 330 kV substation at Katsina and two 330/132 kV transformers
- New double circuit 330 kV line Katsina - Kano
- Two new 330/132 kV transformers in Damaturu
- New 330/132 kV transformer in Asaba
- New 330/132 kV transformer in Benin
- Extension of the 132kV lines such as proposed in the TCN Master Plan
- Reconductoring of 28 132 kV lines to a higher capacity
- New 330 kV substation at Bauchi
- New single circuit 330 kV line Jos - Bauchi - Gombe
- New 330 kV substation at Abakaliki and two new 330/132 kV transformers
- New double circuit 330 kV line Ugwaji - Abakaliki
- New double circuit 330 kV line Akangba - Alagbon
- New 330/132 kV transformers in Delta, Osogbo, Katampe, Ajaokuta(x2), Omoku, Ayede and New Haven
- New 330 kV substation Lafia on the line Jos-Makurdi and two new 330/132 kV transformers

Final version

- New 330 kV substation Aliade on Ugwaji-Makurdi and new 330/132 transformer

National Reinforcements – 2025

Senegal

- Second OMVG line Kaolack to Brikama

The Gambia

- Second OMVG line through Brikama

Guinea Bissau

- Second OMVG line through Bissau - Mansoa - Bambadinca - Salthinho

Guinea

- New double circuit 225 kV Maneah - Linsan
- New circuit 225 kV Amaria - Kaleta
- New loop and associated substations: Faranah - Kissidougou - Guekedou - Macenta - Nzerekore
- New 225 kV interconnection circuit Fomi - Morisanako - Boundiali
- New 225 kV double interconnection circuit Linsan - Koukoutamba - Boureya - Manantali
- New 225 kV double circuit Labé-Koukoutamba
- New 110 kV substation of Sonfon in between Matoto - Tombo

Mali

- New 225 kV circuit Sikasso - Syama
- New 225 kV circuit Koutiala - San - Mopti
- Increase of the voltage level of the circuit Segou - Fana – Dialakorobougou
- from 150 kV to 225 kV
- New 225/150 kV transformers at Fana et Dialakorobougou
- New 225/150 kV transformer Kodialani
- Second 150 kV circuit Sirakoro - Dialakorobougou

Sierra Leone

- Second circuit of 225 kV line Yiben - Waterloo
- New Porto Loko 225/161 substation on Yiben Waterloo line and new 161kV line to Lunsar
- New 225 kV line Waterloo - Moyamba - Lanti - Bo - Baomahun
- Second 225/161 kV transformer Bumbuna and upgrade of the first transformer

Liberia

- New 225/66 kV transformers at Monrovia

Côte D'Ivoire

- New substation at Grand Bassam 225 kV and
- adjecent 225 kV circuit Anani-Grand Bassam
- Second circuit on the 225 kV line Anani-Grand Bassam
- Second circuit on the 225 kV line Bondoukou - Serebou

Ghana

- New 161 kV line New Aberim - Akwatia
- Second circuit 161 kV Volta - Kpong
- Change conductor of 161 kV line CapeCoast - Aboaze to 488 MVA
- Change conductor of 161 kV kine Dunkwa-New Obuasi to 364 MVA
- New 330/161 kV transformer in Volta
- Change conductor of 161 kV kine Akosombo - Asiekpe to 364 MVA
- New 161 kV substation Atebubu and associated lines
- New 161 kV substation Salaga and Kete-Krachi and associated lines

Burkina Faso

- Upgrade of 225 kV interconnection Bolgatanga – Ouaga to double circuit
- New 225/90 kV transformers at Pa

Benin

Togo

- New 161 kV line Kara - Badjeli
- New 161 kV line Kara - Atakpame

Niger

- New 330 kV double circuit Salkadamna - Sonichar and 2 new 330/132 kV transformers at 330kV substation of Sonichar

Nigeria

- New double circuit 330 kV line Wukari Lafia - Apo
- New double circuit 330 kV line Obajana - Ganmo
- New 330/132 kV transformers at EastMain, Alagbon, Omotosho (x2), Onitsha, Lokaja, Ihiala, Gombe

Final version

National Reinforcements – 2033

Senegal

- New 225 kV line Tambacounda-Bakel
- New 225 kV line Matam 2- Linguere -Touba
- New Transformer 225/90 KV Tobene
- New 225 kV substation at Cap des Biches on break in of line Kounoune – Patte D'Oie
- Second circuit of 225 kV line Tobene Sakal

- New Transformers 225/90 kV in Kounoune
- New 225 kV double circuit line Mboro-Tobene

Guinea

- New 225 kV line double circuit Maneah - Matoto and three transformers 225/110 KV
- New 225 kV substation in Boureya

Mali

- New 225 kV interconnection line Tengrela - Syama

Côte d'Ivoire

- New 400 kV substation in San Pedro and 2 transformers 400/225 KV New 400 kV line double circuit San Pedro- Akoupe Zeudji (PK24)
- New 400 kv line San Pedro to Man and two transformers 400/225 KV in Man
- New double circuit line 225 kV Yopougon 3-Songon
- New 225 kV line San Pedro- Tiboto - Buchanan
- New transformer 400/225 kV at Akoupe Zeudji
- Second circuit 225 KV Yopougon 3-Azito
- New 225 kV line Daloa – Kossou
- New 225 kV interconnection line Tengrela - Syama

Ghana

- New Pokuase 330/161 KV substation and associated transformers
- New 161 kV line Pokuase - Mallam
- Second Circuit of 330 KV line Aboaze - Dunkwa -Kumasi and new 330/161 KV transformers
- New 330 KV line Kumasi- Pokuase
- New 330 KV line Bolgatanga- Juale - Dawa and new 330/161 KV transformers at Bolgatanga, Dawa and Juale
- Change Conductor of 161 KV line Dunkwa-Ayanfuri-Asawinso to 364 MVA
- New 330/161 KV transformers in Bolgatanga, Kumasi and Kintampo (x2)
- New 161 KV Substation Atebubu and associated lines
- New 161 KV substations Salaga and Kete-Krachi and associated lines

Burkina Faso

- New 225 kV substation Ziniare and transformers 225/90 kV associated
- New line 225 KV Ouaga East Ziniare - Zagtouli
- Second circuit of the line Ouaga South East-Patte D'Oie 132 kV
- New Transformers 225/132 KV Ouaga south East
- New double circuit interconnection line Bolgatanga-Bobo
- Second line 225 KV Pa-Bobo

Benin

- New Transformer 330/161 kV Sakete
- New Line 161 KV Adjarala -Bohicon
- New double circuit line 161 KV Adjarala - Avakpa

Togo

- New Transformer 330/161 KV Davié
- New Line 161 KV Adjarala - Nangbeto
- New Line 161 KV Adjarala -Bohicon
- New Line 161 KV Adjarala - Notse
- New Line 161 KV Adjarala - Mome Hagou
- New double circuit line 161 KV Adjarala - Avakpa

Niger

- New Line 330 KV Salkadamna - Goudel Gorou and transformer 330/132 KV at Goudel Gorou
- New Line 330 KV double circuit Salkadamna - Malbaza - Gazoua -Katsina and related substations
- Two new transformers 330/132kV Goroubanda

Nigeria

- New 330/132 KV Transformers in Ikeja, Jos, Ganmo, Egbin, Benin Ayede, Delta, Katampe, Adiabor, New Agbara, Akangba
- New 330 KV Line Owerri Egbema
- New 330 KV Line Geregu – Ajaokuta
- New 330 KV Line Ikeja- Akangba – Omotosho
- New 330 KV Line Gwagwadala – Katampe
- New 330/132 KV transformers in Delta and Abakaliki
- New Dual circuit 330 KV line New Agbara - Akangba
- New 330 KV Line Yola-Gombe

Development of the dynamic model

GENERATING UNITS

The dynamic models of generating units have been created from the information collected from each Country and from the data already available to the Consultant. Each model includes the following parts:

- Parameters of the **alternator**: GENSAL model for salient pole machine and GENROU model for round rotor units;
- Type and parameters of the **Governors**: several types of governor are implemented in the model, depending on the characteristics of each unit.
- Type and parameters of the **Exciters**: several types implemented depending on the structure of the excitation systems and its controllers, according to IEEE standardization.

Particular attention has been put on combined cycle (CC) units. The selected CC model represents each component unit as a single machine, matched with each other through output power instead of exhaust flows. This simplification is acceptable given the uncertainties present in planning studies.

The solar photovoltaic plants have been modelled through an aggregated standard model based (PVGEN80).

The wind farms have also been represented by an aggregated model for each wind farm (WINDFEQ).

DYNAMIC LOAD MODEL

For producing realistic results, two load models have been used in dynamic simulations, taking into account the behaviour of the distribution network. This model represents loads aggregated at the MV voltage level.

A key factor for load modelling is the **proportion of induction motors**, which represent **rotating loads**. It is assumed that induction motors amount to **40%** of the load.

Therefore, two types of load model will be considered: an impedance model (60%) and a "distribution network" type model (40%).

- **Impedance type load model**

  The impedance load model is frequently used to represent the response of active and reactive power to frequency and voltage variations. Mathematically, the behaviour of this load model is described by the following equations:

$$P(t) = P_o . \left(\frac{V(t)}{V_0}\right)^a . \left(\frac{\omega(t)}{\omega_0}\right)^c$$

$$Q(t) = Q_o . \left(\frac{V(t)}{V_0}\right)^b . \left(\frac{\omega(t)}{\omega_0}\right)^d$$

  Where a, b, c and d are constants whose values are set depending on the type of load (residential, industrial…). In the framework of this study, the following assumptions will be taken:

  - Active/reactive **power** varies with the **square of the voltage** (a=b=2)
  - Variation of active/reactive **power with frequency** are **neglected** (c=d=0)

- **"Distribution network" type load model**

  This model represents the distribution network downstream of the HV/MV step-down transformer, characterised by a significant proportion of rotating loads.

  Figure 71 shows the structure of the distribution network type model.

Final version

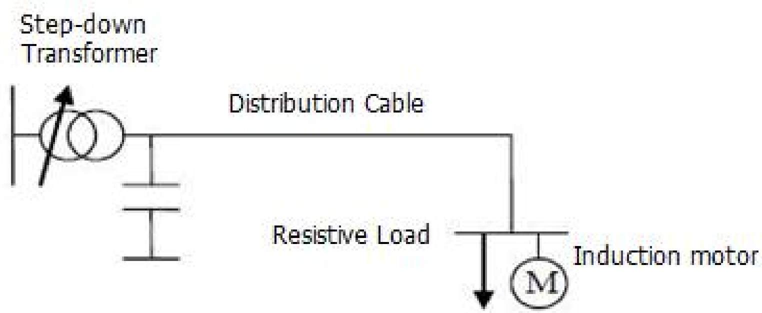


Figure 71: Distribution network type load model

The model includes:

- A step-down transformer with a continuous under load tap changer.
- A distribution cable modelled by an impedance.
- A shunt compensator connected to the secondary of the transformers.
- A generic induction motor connected at the end of the distribution cable.
- A resistive load connected at the end of the distribution cable.

The shunt compensator is adjusted to align the active power absorbed by the load model with the results of the static simulations. Standard values of small induction motors are used for the parameters of the model.

Transformers	
Min turn ratio [pu]	0.9
Max turn ratio [pu]	1.22
Time constant [s]	20
TFO loading [%]	60
Nominal voltage [pu]	1.03
Resistance [pu]	0.005
Leakage Reactance [pu]	0.035
Feeder	
Voltage drop [pu]	0.01
X/R [-]	0.5
Load Mix	
Loading of motors [%]	100
Rotating load [%]	100
Inertia H [MW.s/MVA]	0.5
efficiency [-]	95

Final version

Nominal mech power [pu]	0.87
Starting torque [pu]	0.77
Maximum torque [pu]	2.3
Nominal speed [t/min]	2959
Starting current [pu]	5.6

Table 45: Step-down transformers parameters in distribution network type load model

EXISTING AND PLANNED PSS SCHEME

The dynamic model includes generic PSS models, damping a wide range of frequencies, installed in various power plants in the WAPP system according to the information collected from the Client, as presented in the Table 46.

Country	Power Plant	Type	# Units
Cote d'Ivoire	Ciprel	Thermal	7
Cote d'Ivoire	Azito CCGT	Thermal	3
Cote d'Ivoire	Kossou	Hydro	3
Ghana	Akosombo	Hydro	6
Ghana	TAPCO	Thermal	3
Ghana	TICO	Thermal	2
Ghana	Bui	Hydro	3
Ghana	Kpong	Hydro	4
Ghana	TT1PP	Thermal	1
Ghana	Sunon Asogli I	Thermal	6
Ghana	Kpone	Thermal	3
Mali	Manantali	Hydro	6
Mali	Felou	Hydro	3
Nigeria	Egbin	Thermal	6
Nigeria	Kainji	Hydro	8
Nigeria	Okpai	Thermal	3
Nigeria	Afam IV	Thermal	2
Nigeria	Afam V	Thermal	2
Senegal	Bel Air	Thermal	7
Senegal	Kaolac	Thermal	6
Senegal	Cap des Biches C4	Thermal	4
Mali	Selingue	Hydro	4
Niger	Salkadamna	Thermal	4
Niger	Maradi	Thermal	3

Table 46: List of units with PSS installed - 2022

Final version

Small Signal Stability

THEORETICAL BACKGROUND

The majority of power system components such as generators, excitation systems, governors and load have very nonlinear characteristics. These components and their associated controls include saturation and output limitations. Despite the fact that the nonlinear systems theory can be used to study such a system, this is only valid for small and simple systems, which is not the case of power systems.

On the other hand, the theory of linear systems can provide useful insight into the operating behavior of an interconnected power system. However, this theory is only applicable under the assumption that the dynamic behavior of the system is linear or quasi-linear. Fortunately, low frequency oscillations in a power system are fairly linear when caused by disturbances of small magnitude such as the random fluctuation of generation and load. The variations in system dynamic variables such as machine rotor angle and speed are also small under these circumstances and the assumption of a linear system model around an operating equilibrium point provides valuable results. These conclusions are generally consistent with that is observed in the field under similar operating conditions.

The advantage of assuming a linear model for the system is that the theory of linear systems is in a mature state, which means that methodologies, algorithms and tools able to deal with very large systems in reasonable computation time are available.

In power systems, the study of system stability using linear models is commonly referred to as "small-signal stability analysis". This type of study allows the analysis of the so-called steady-state stability. The following types of oscillation modes can be detected and identified through small-signal stability analysis:

- **Local modes (machine-system modes):** associated with the oscillations of units at a generating station with respect to the rest of the system (oscillation frequency typically between 1 Hz and 2 Hz). These oscillations are localized at one station or a small part of the system.
- **Inter-area modes:** associated with the swinging of many machines in one part of the system against machines in the other parts (oscillation frequency typically between 0.1 Hz and 1 Hz). Caused by two or more groups of electrically close machines being interconnected by weak a weak transmission network.
- **Control modes:** associated with generating units and other controls. The usual causes of instability of such modes are badly tuned excitation systems, speed governors, HVDC converters and SVCs.
- **Torsional modes:** associated with the turbine-generator shaft system rotational components. The usual causes of instability of such modes are interactions with excitation controls, speed governors, HVDC controls, and series-capacitor-compensated lines.

It must be emphasized that the small-signal stability is a necessary (but not sufficient) condition for the power system operation. As consequence of not being a sufficient condition, the results of small-signal stability analyses must be assessed through nonlinear time-domain simulations (electromechanical transients simulations).

The following section presents a set of definitions related to linear systems theory and small-signal stability that will be used for the definition of the methodology to be adopted in this study.

In the sequel it is presented a brief description on the linear system theory aspects applied to power system small-signal stability problem.

Low-frequency electromechanical oscillations usually range from less than 1 Hz to 3 Hz other than those with sub-synchronous resonance (SSR). Multi-machine power system dynamic behavior in this frequency range is usually represented by a set of nonlinear differential and algebraic equations (DAE) in the form of:

$$\dot{\mathbf{x}} = \mathbf{f}(\mathbf{x}, \mathbf{z}, \mathbf{u})$$
$$\mathbf{0} = \mathbf{g}(\mathbf{x}, \mathbf{z}, \mathbf{u})$$
$$\mathbf{y} = \mathbf{h}(\mathbf{x}, \mathbf{z}, \mathbf{u})$$

Where

- **f** and **g** are vectors of differential and algebraic equations
- **h** is a vector of output equations
- **x**, **z**, **u** and **y** are the vectors of state variables, algebraic variables, inputs and outputs, respectively.

The linearization and elimination of the algebraic variables of this system of nonlinear DAEs results in a linear system in the form of:

$$\dot{\mathbf{x}} = \mathbf{A}\mathbf{x} + \mathbf{B}\mathbf{u}$$
$$\mathbf{y} = \mathbf{C}\mathbf{x} + \mathbf{D}\mathbf{u}$$

Eigenvalues and Oscillation Modes

The eigenvalues (**λ**) of the state matrix (**A**) describe the dynamic performance of the linearized system. These eigenvalues may be real or complex numbers. Complex eigenvalues always occur in conjugate pairs:

$$l_i = s_i \pm j w_i$$

The eigenvalues of the state matrix correspond to the system modes (oscillation mode, if l_i is complex). The real part (**s**) relates to the mode damping and the imaginary part (**± *jw***) relates to the oscillation frequency of the mode.

The relationship between the eigenvalues and the system stability is defined by the absolute stability criteria, which follows:

"*A system is stable according to the absolute stability criteria if all eigenvalues of the system are located in the left semi-plane of the complex plane (all eigenvalues must have negative real parts)*".

When the system is stable, the analysis of the eigenvalues (computation of their damping ratio) indicates the damping level of the system. The requirement thereby is that the oscillations get damped rapidly enough.

The frequency of oscillation of a mode, in Hertz, is given by:

$$f_i = \frac{w_i}{2p}$$

The damping ratio of a mode is given by:

$$z_i = \frac{-s_i}{\sqrt{s_i^2 + w_i^2}}$$

Eigenvectors and Mode Shapes

In power system literature, the right eigenvector associated to an eigenvalue l_i is known as the mode shape of l_i. The mode shape provides important information on the participation of an individual ma-chine or a group of machines in a particular mode.

The mode shapes are very useful for the identification of coherent groups of machines, as well as for the identification of inter-area modes.

Participation Factors

In large power systems, it is important to quantify the role of each generator on each mode. A method generally employed for this purpose is the calculation of the participation factors of each mode. The participation factor is a measure of the relative participation of the *k*-th state variable on the *i*-th mode, and vice-versa.

The participation factor of a state variable in a given mode is calculated by means of combining the left and right eigenvectors associated to that mode. Through this combination it is possible to produce a dimensionless measure, which is essential when comparing state variables of different physical units.

Through the calculation of the participation factors it is possible to determine the generators that have more contribution to a given oscillation mode. The generators with highest participation factor on poorly damped low frequency modes are potential candidates for power system stabilizer allocation (PSS).

One drawback of the participation factors is that they are related only to the state and do not take into account the input/output (I/O) relationship. It cannot effectively identify a controller site and an optimal feedback signal without information on the input and output which is more important when output feedback is employed.

However, the effectiveness of control can be indicated through controllability and observability factors, as described in the following.

Modal Controllability and Observability

Considering the linearized dynamic system given by

$$\dot{\mathbf{x}} = \mathbf{Ax} + \mathbf{Bu}$$
$$\mathbf{y} = \mathbf{Cx}$$

where

- **x** is the system state vector,
- **u** is the input vector and
- **y** is the output vector.

Denoting by **F** the matrix where each column is an eigenvector of **A** then the change of variable **z** = **F x** leads to the following system of equations:

$$\dot{\mathbf{z}} = \mathbf{\Lambda z} + \mathbf{\Phi}^{-1}\mathbf{Bu}$$
$$\mathbf{y} = \mathbf{C\Phi}\,\mathbf{x}$$

where **L** is a diagonal matrix composed by the eigenvalues of **A**. One can see that:

- If the *i*-th row of $\mathbf{F}^{-1}\mathbf{B}$ is not zero, then it is possible to control the *i*-th mode through the control **u**. If there are different potential controls (**u** is a vector), then the different elements of the *i*-th row give indication on which inputs have the largest impacts on the *i*-th mode.
- If the *i*-th column of **CF** is not null, then it is possible to observe the *i*-th mode trough the output **y**. If there are different potential observers (**y** is a vector) then the different elements of the *i*-th column give indication on which output provides the more information on the *i*-th mode.

This means that the controllability of the input signal and the observability of the feedback signal are basic requirements for PSS allocation.

METHODOLOGY FOR SMALL-SIGNAL STABILITY ANALYSIS

The first step for the small-signal stability analysis is the linearization of the power system dynamic model around a steady-state operating point. The linearized system is then used to compute the following quantities:

- System eigenvalues and eigenvectors;
- Participation factors;
- Controllability indices;
- Observability indices.

Final version

Identification of Inter-Area and Critical Oscillation Modes

Critical oscillation modes are defined as modes with low damping level (a CIGRE "task force"[17] about the oscillations in networks recommends a minimum damping of 5%). The identification of critical oscillation modes starts by the computation of the system eigenvalues. As the power system model is very large, the computation of all system eigenvalues through orthogonal decomposition-based methods (i.e. QR factorization) is not recommended due to the large computational time and memory usage required by these methods.

In this project, the method used for eigenvalue calculation is based on the calculation of all eigenvalues within a predefined region of the complex plane (by employing an eigenvalue computation algorithm based on the Arnoldi method). This region is defined by the user and must comprise the modes with oscillation frequency up to 3.0 Hz and damping ratios at least up to 35%. This allows the calculation of all critical electromechanical modes of the system, as well as the inter-area modes.

The result of eigenvalues computation is a table containing all information related to the modes: real and imaginary parts, damping ratio and oscillation frequency.

Critical modes are identified as the ones whose damping ratio is less than 5%. **Inter-area modes** are pre-identified by selecting the modes whose frequency lie in the range between 0.1 Hz and 1.5 Hz. To get the final decision on which modes are in fact inter-area modes, a second step is needed: analysis of the mode shapes, which is explained in the sequel.

Participation Factor and Mode Shape Analysis

In this project, the goal of participation factor and mode shape analysis is to identify the inter-area modes within the modes with frequency between 0.1 Hz and 1.5 Hz.

Analysis of participation factors:

The participation factors provide an indication of the contribution of the machines in a given mode. This is very useful for identifying the machines that have major contributions to the critical modes as well as to the inter-area modes.

In this study, the participation factors of all modes classified as critical ($\zeta < 5\%$) in the eigenvalue computation phase are calculated and analyzed in order to provide indications on which machines have most participation on the critical modes.

Analysis of mode shapes

As previously described, the mode shapes give the relative magnitude and phase of the oscillations as seen from a given state variable. Since the objective of this project is to analyze electromechanical oscillations, the rotor speed or angle must be chosen as state variable.

Final version

[17] Source: "Analysis and Control of Power System Oscillations", Task force 07, Study Committee 38, December 1996.

In this study, the mode shapes of all oscillation modes with frequency between 0.1 Hz and 1.5 Hz are calculated and analyzed in order to identify all inter-area modes. After the identification of these modes, their respective damping ratios are carefully analyzed. In case of poorly damped inter-area modes, the necessary measures to improve the damping are recommended.

Determination of Candidate Machines for PSS installation or retuning aiming at improving Oscillation Damping

In case of the presence of critical inter-area modes, the identification of the candidate machines for PSS installation/retuning is performed.

The choice of the machine and the input signals to be used for the improving the damping of critical modes is not straightforward. It depends on the calculation of the controllability and observability indices.

It has to be noticed that the specification and tuning of PSS in order to improve the damping of critical oscillation modes is out of the scope of this project.

Dynamic Security Assessment – Methodology

The objective of the DSA is to assess the security of the system from a dynamic point of view. It can be seen as an evolution of the static security assessment (N-1 criteria).

In this project, the focus of the DSA is on the system stability and voltage recovery after incidents occurring at the interconnection lines (tie-lines) and critical lines affecting cross-border flows. The sizing incident for the DSA is a **three-phase short-circuit to ground at the terminal of the line cleared in base-time (100 ms)** by means of tripping the faulted line (opening at both terminals), as depicted in Figure 72.

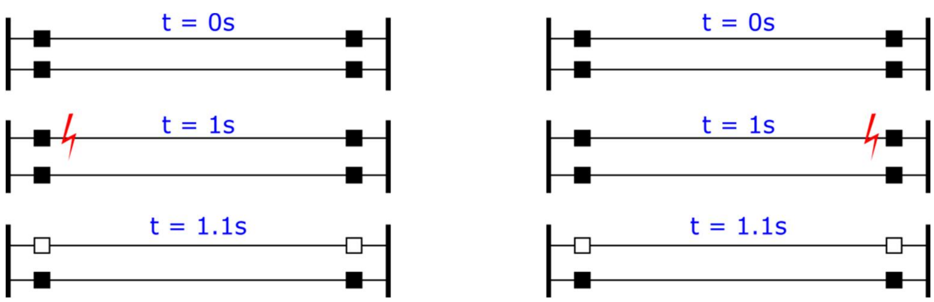


Figure 72: Sizing incident for DSA analysis.

The acceptance criteria are the following:

- No machine losing synchronism;
- No activation of over-/under-voltage, over-/under-frequency relays of the machines;
- Voltage recovery criteria:
  - V > 0.70 pu within 500 ms after fault clearance;

- V > 0.90 pu after 10 seconds.

This analysis was performed for the most critical conditions from system stability point of view: peak and off-peak load conditions:

Final version

Dynamic Security Assessment – Results

Type of line	Line name	Bus 1	Country of Bus 1	Bus 2	Country of Bus 2	Nominal Voltage (kV)	Fault at bus	Results Peak - dynamic load	Results Off-Peak - dynamic load	Comments
Interco.	KAMAKW03-LINSAN03-1	LINSAN03	GU	KAMAKW03	SL	225	1	yes	yes	-
Interco.	KAMAKW03-LINSAN03-1	KAMAKW03	SL	LINSAN03	GU	225	2	yes	yes	-
Interco.	MAN____5-YEKEPA03-2	MAN____5	CI	YEKEPA03	LI	225	1	voltage collapse at Ferke (CIV)	yes	Undamped voltage oscillations due to the interarea mode leads to voltage collapse in Côte d'Ivoire. The issue should be solved once the interarea is better dampened.
Interco.	MAN____5-YEKEPA03-2	YEKEPA03	LI	MAN____5	CI	225	2	voltage collapse at Ferke (CIV)	yes	
Interco.	OUAGAD02-NIAMRD02-1	GOROUB02	NR	OUAGAE02	BU	330	1	voltage collapse (BU)	yes	Solved by adding SVC at Salkadama (NR)
Interco.	OUAGAD02-NIAMRD02-1	OUAGAE02	BU	GOROUB02	NR	330	2	voltage collapse (BU)	yes	Solved by adding SVC at Salkadama (NR)
Interco.	1115DUNK-BINGER33-1	BINGER33	CI	1115DUNK	GH	330	1	yes	yes	-
Interco.	1115DUNK-BINGER33-1	1115DUNK	GH	BINGER33	CI	330	2	yes	yes	-
Interco.	30101L_1029VOLT-1	DAWA__02	GH	30101LOM	TB	330	1	yes	yes	-
Interco.	30101L_1029VOLT-1	30101LOM	TB	DAWA__02	GH	330	2	yes	yes	-
Interco.	13003-SAKETE02-1	13003	NI	SAKETE02	TB	330	1	yes	yes	-
Interco.	13003-SAKETE02-1	SAKETE02	TB	13003	NI	330	2	yes	yes	-
Interco.	BAKEL_03-KAYES_03-1	KAYES_03	MA	BAKEL_03	SE	225	1	yes	yes	-
Interco.	BAKEL_03-KAYES_03-1	BAKEL_03	SE	KAYES_03	MA	225	2	yes	yes	-
Interco.	GAZAOU06-52012-1	52012	NI	GAZAOU06	NR	132	1	voltage collapse in NR	voltage collapse in NR	Localized voltage collapses at the end of long radial feeder.
Interco.	GAZAOU06-52012-1	GAZAOU06	NR	52012	NI	132	2	voltage collapse in NR	voltage collapse in NR	
Interco.	ZABORI02-33002-1	33002	NI	ZABORI02	NR	330	1	yes	yes	-
Interco.	ZABORI02-33002-1	ZABORI02	NR	33002	NI	330	2	yes	yes	-
National	4_PA_225-4ZAGT225-1	4_PA_225	BU	4ZAGT225	BU	225	1	yes	yes	-
National	4_PA_225-4ZAGT225-1	4ZAGT225	BU	4_PA_225	BU	225	2	yes	yes	-
National	B5PLUS02-DAWA__02-1	B5PLUS02	GH	DAWA__02	GH	330	1	yes	yes	-
National	B5PLUS02-DAWA__02-1	DAWA__02	GH	B5PLUS02	GH	330	2	yes	yes	-

Final version

Type of line	Line name	Bus 1	Country of Bus 1	Bus 2	Country of Bus 2	Nominal Voltage (kV)	Fault at bus	Results Peak - dynamic load	Results Off-Peak - dynamic load	Comments
National	MAGLE_SAK	SAKETE02	TB	MG2	TB	330	1	yes	yes	-
National	MAGLE_SAK	SAKETE02	TB	MG2	TB	330	2	yes	yes	-
Interco.	FERKE__5-829PCRE-1	829PCRE	BU	FERKE__5	CI	225	1	yes	yes	-
Interco.	FERKE__5-829PCRE-1	829PCRE	BU	FERKE__5	CI	225	2	yes	yes	-
Interco.	BOKE__03-SALTHI03-1	BOKE__03	GU	SALTHI03	GB	225	1	yes	yes	-
Interco.	BOKE__03-SALTHI03-1	SALTHI03	GB	BOKE__03	GU	225	2	yes	yes	-
Interco.	SAMBAN03-MALI__03-1	MALI__03	GU	SAMBAG03	SE	225	1	yes	yes	-
Interco.	SAMBAN03-MALI__03-1	SAMBAG03	SE	MALI__03	GU	225	2	yes	yes	-
Interco.	SIGUIR03-SANAKO03-2	SANAKO03	MA	SIGUIR03	GU	225	1	yes	yes	-
Interco.	SIGUIR03-SANAKO03-2	SIGUIR03	GU	SANAKO03	MA	225	2	yes	yes	-
Interco.	TAMBAC03-KAYES_03-1	KAYES_03	MA	TAMBAC03	SE	225	1	yes	yes	-
Interco.	TAMBAC03-KAYES_03-1	TAMBAC03	SE	KAYES_03	MA	225	2	yes	yes	-
Interco.	837PCRE-833PCRE-1	833PCRE	MA	837PCRE	CI	225	1	yes	yes	-
Interco.	837PCRE-833PCRE-1	837PCRE	CI	833PCRE	MA	225	2	yes	yes	-

Table 47: Complete results of the DSA analysis - 2022

Frequency stability

FREQUENCY STABILITY ANALYSIS - METHODOLOGY

Frequency stability reflects the ability of the system to face unexpected active power unbalance such as the sudden loss of power infeed or large loads. Frequency stability is usually ensured through the provision of operating reserves (primary and secondary) and under-frequency load-shedding (UFLS) schemes. High probability events are secured via the operating reserves, while low probability events are secured with the support of UFLS schemes.

The sizing incident is usually determined to achieve a trade-off between reserve provision and energy production. Sufficient operating reserves with adequate technical performance must be secured to cover the sizing incident without resulting in loss of load.

The under-frequency load shedding (UFLS), only activated in case of non-normative incidents, is organized in various steps to minimize the amount of load shed following frequency transients.

In this study, the frequency stability analysis aims at:

- Assessing the adequacy of the operating reserves for covering the loss of the largest unit of the interconnected system;
- Identifying the most critical frequency transients;

ALLOCATION OF OPERATING RESERVE

The operating reserve is allocated based on the biggest machine in the interconnected network. In 2022, this biggest machine is one unit of Eglin 2 which has a size of 300 MW. For security purposes, it is a common assumption to dispatch this reserve to a value of 110% of this biggest machine.

For 2022, the reserve needs are thus evaluated to be of 330MW at the peak. This reserve is allocated to the different countries of the WAPP based on the power generated by each machine at the peak such that:

$$R_{country} = R_{total} * \frac{P_{country}}{P_{total}}$$

Where $R_{country}$ is the reserve allocated to the specific country, R_{total} is the total need for primary reserves, $P_{country}$ is the production of the specific country and P_{total} is the total production.

Final version

Country	Allocated primary reserve (MW)
Cote d'Ivoire	29
Ghana	64
Senegal	1
The Gambia	0
Guinea	10
Guinee-Bissau	0
Liberia	1
Sierra Leone	1
Mali	5
Burkina	1
Niger	11
Nigeria	206
Togo-Benin	2
TOTAL	**330**

Table 48: Reserve Allocation - Peak 2022

Once the contribution of each country is determined it is necessary to allocate this reserve among the different units of the system. To ensure adequate technical performance of the primary reserve it is required that this reserve is spread among different units of the system so that the maximum contribution of a single unit to the primary reserve should be limited to about 5% of its nominal capacity.

The following assumptions have been considered:

- For the CCs, primary reserve is allocated only on gas turbines since the output of the linked steam turbine is strictly subject to their operating points;
- PV solar and wind farms do not provide reserve;
- Every conventional unit (existing or planned) should have its governor unblocked and contribute to the operating reserve;

Final version

At the helm of the Energy Transition, Tractebel provides a full range of engineering and consulting services throughout the life cycle of its clients' projects, including design and project management. As one of the world's largest engineering consultancy companies and with more than 150 years of experience, it's our mission to actively shape the world of tomorrow. With about 4,400 experts and offices in 33 countries, we are able to offer our customers multidisciplinary solutions in energy, water and infrastructure.

TRACTEBEL ENGINEERING S.A.
Boulevard Simón Bolívar 34-36
1000 - Bruxelles - BELGIQUE
tractebel-engie.com

Laurence CHARLIER
tel. +32 2 476 31 07 92
laurence.charlier@tractebel.engie.com