2017-2035 POWER GENERATION AND TRANSMISSION MASTER PLAN FOR SENEGAL

POWER AFRICA TRANSACTIONS AND REFORMS PROGRAM (PATRP)

Submission Date: September 2017

Contract Number: AID-623-C-14-00003
Activity Start Date and End Date: MAY 23, 2014 TO MAY 23, 2019
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This publication was produced for review by the United States Agency for International Development. It was prepared by Tetra Tech ES Inc.

ACKNOWLEDGEMENTS

The Power Africa Transactions and Reform Program (PATRP) team was given a mandate of broad scope and importance for Senegal. The team could not have achieved its mandate without the close and diligent cooperation of a host of stakeholders. Despite their often busy agendas, these stakeholders dedicated the time and necessary efforts to assist in the development of a high-quality report that can serve as an informed decision-making tool for Senelec and the Senegalese government.

As PATRP would not want to forget anyone in these acknowledgements, we have chosen not to name all of our collaborators directly. These individuals certainly know who they are.

We would like to highlight the cooperation of some Senegalese government staff from organizations such as Senelec (specifically staff from the Research and Planning Branch and the Network Control Center) and from the Ministry of Energy and Renewable Energy Development.

We would also like to highlight the significant contribution of the community of technical and financial partners working in Senegal, in particular our colleagues from the World Bank and the International Finance Corporation.

Finally, a special thank you to USAID, without whom this mandate would not have been possible, and especially to Cheryl Voisard, the focal point of the Power Africa program at the U.S. Embassy in Dakar.

The PATRP team is available to discuss the findings of this report at any time.

Best regards,

THE PATRP TEAM

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POWER AFRICA TRANSACTIONS AND REFORM PROGRAM (PATRP)

CONTENT

LIST OF FIGURES

LIST OF TABLES

ABBREVIATIONS

N): Normal Network
AFRIG: African Investment - Group
AIBD: Blaise Diagne Airport
ANSD: National Agency of Statistics and Demography
APROSI: Agency for the Development and Promotion of Industrial Sites
BOS: Operational Monitoring Office
BPW: Building and Public Works
CCGT: Combined Cycle Gas Turbine
CCT: Critical Fault Clearing Time
CIMAF: Ciments de l'Afrique
COMM: Commissioning
CSP: Concentrated Solar Power
DEG: Department of General Studies
DGP: Residential High Power
DNI: Direct normal irradiation
DRCE: Central-East Regional Delegation
DRCO: Central-West Regional Delegation
DMP: Residential Medium Power
DPP: Residential Low Power
DRN: North Regional Delegation
DRS: South Regional Delegation
DS: Donnée Senelec, Senelec's investment plan
EDDC: Forecasting electricity demand in developing countries
EDG: National power utility of Guinea
EDM: National power utility of Mali
EP: Public Lighting
GDP: Gross Domestic Product
GHI: Global Horizontal Irradiation
GWh: Gigawatt Hour
HFO: Heavy Fuel Oil
HV: High Voltage
HVA: High Voltage A
HVB: High Voltage B
HZ: Hertz
ICS: Industries Chimiques du Sénégal
ILSG: Ivory Coast Liberia Sierra Leone-Guinea
IN: Interconnected Network
IPP: Independent Power Producer
IRE: Intermittent Renewable Energy
IREQ: Hydro-Québec's research institute
IVGTF: Integration of Variable Generation Task Force
kWh: Kilowatt Hour
LFO: Low frequency oscillator
LOCNG: Local Natural Gas
LOLE: Loss of load expectation
LOLP: Loss of load probability
LV: Low Voltage
LVRT: Low Voltage Ride Through

MBASE: MVA base
MEDER: Ministry of Energy and Renewable Energy Development
MMBtu: Million British Thermal Units
MV: Medium Voltage
MVA: Megavolt Ampere
MVAR: Megavolt Ampere Reactive
MW: Megawatt
MWh: Megawatt Hour
NDE: Non-distributed Energy
NERC: North American Electric Reliability Corporation
NGST: Natural Gas Steam Turbines
O & M: Operations and Maintenance
OMVG: Organization for the Development of the Gambia River
OMVS: Organization for the Development of the Senegal River
PATRP: Power Africa transactions and reform program
PD: Plan directeur Power Africa, parametric calculation
PF: Power Factor
PGP: Commercial High Power
PLP: Commercial Low Power
PMAX: Maximum Power
PMP: Commercial Medium Power
PSE: Emerging Senegal Plan
PSS/E: Power System Simulator for Engineering
PV: Photovoltaic
QMAX: Maximum Reactive Power
QMIN: Minimum Reactive Power
RE: Renewable Energy
RET: Regional Express Train
RIMA: Manantali Interconnected Network
SAED: Société Nationale d'Aménagement et d'Exploitation des Terres du Delta
SDE: Sénégalaise Des Eaux
SC: Series Capacitors
SOMETA: Société métallurgique d'Afrique
TCU: Low Usage Tariff
TG: General Tariff
TLU: High Usage Tariff
ToP: Take or Pay

EXECUTIVE SUMMARY

INTRODUCTION

Since August 2016, Power Africa transactions and reform program (PATRP) has been working on a specific mandate for Power Africa in collaboration with Senelec, the Ministry of Energy and Renewable Energy Development (MEDER) and a vast majority of Senegal's energy stakeholders, to develop the 2017-2035 Generation and Transmission Master Plan for Senegal.

The study was carried out in three phases:

- Supply and Demand Balance Report - December 2016
- Transmission network study - April 2017
- 2017-2035 investment plan and supporting financial analysis - July 2017

This document is the final report, setting out all the power generation and transmission recommendations that could be implemented by the Government of Senegal in the coming years.

This report supplements the Senelec Generation Master Plan already accepted by the Council of Ministers.

It is important to understand that PATRP's contribution involved not only taking a critical look at Senelec's generation plan and suggesting improvements, but above all conducting an analysis of the network that should allow Senelec to implement a master plan based on the government's strategic directions, within a more reliable and stable framework.

Five major energy issues were examined in the development of this report:

- The push to gain energy independence using the country's natural resources:
  - Adding approximately 400 MW of intermittent renewable energy by 2020
  - Developing local natural gas plants

- Improving network reliability and stability
- Reducing the average cost of electricity
- Having the installed generation capacity required to achieve the anticipated growth in demand to align with the goals of the Emerging Senegal Plan (PSE)
- Deploying network infrastructure to facilitate electrification

DEMAND

PATRP was involved in the first phase of the study to determine the actions that would be required for Senegal to balance its power supply and demand through 2035.

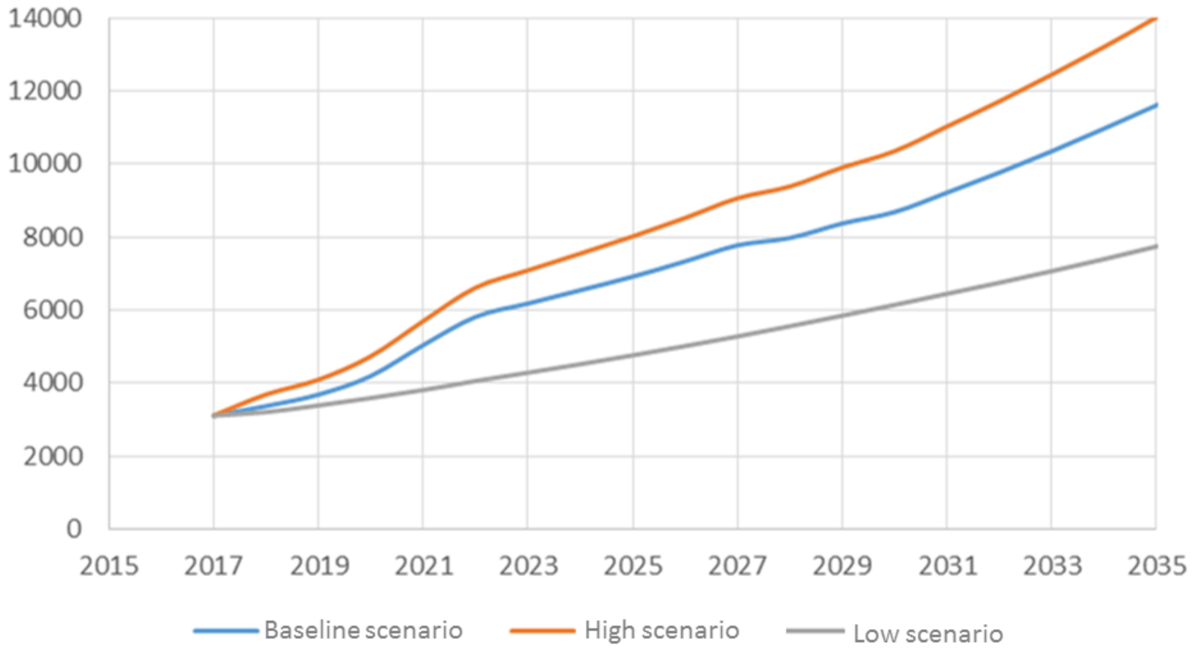
Three scenarios were identified from the growth in demand analysis: low demand, baseline demand and high demand.

These scenarios consist of three main components:

- Growth in the residential and small business sectors (Low Voltage (LV)): includes factors such as population growth, urbanization rate, electrification rate, etc.
- Commercial growth (Medium Voltage): strongly influenced by the Gross Domestic Product (GDP) growth forecast in the Emerging Senegal Plan.
- Industrial growth (High Voltage (HV)): consisting primarily of the integration of mines and other major projects into the interconnected grid.

The following graph shows the growth in demand by 2035:

Figure 0-1 : 2017-2035 Growth in yearly demand (GWh)



Demand growth is determined using three growth scenarios:

- Baseline demand scenario: 7.6% growth per annum
- Low demand scenario: 5.2% growth per annum
- High demand scenario: 8.7% growth per annum.

Considering that average growth over the last six years was 4.5%, PATRP considers these scenarios to be realistic, especially if the mining projects are developed to their full potential.

Three geographical characteristics have been identified as part of this plan:

- Consumption in the Dakar region accounts for roughly 60% of Senegal's total energy use.
- This proportion will decrease in the future with the anticipated shift of a significant segment of residential and commercial activity to the Diamniadio region.
- Energy use by mines in the Kedougou region could also cause the energy consumption hub to start shifting in 2020.

GENERATION

After several rounds of sensitivity testing, PATRP developed and compared three generation plans using the baseline demand scenario, based on the energy needs for the 2017-2035 period.

- The Senelec plan without decommissioning of generation assets
- The PATRP plan without decommissioning of generation assets
- The PATRP plan with decommissioning of generation assets

PATRP understands that Senegal's primary challenge is to install the generation needed to meet the demand at the lowest cost, and to get local gas supply operating as quickly as possible. However, the integration of intermittent renewable generation is creating network stability issues and confirms the need for an automatic synchronous reserve strategy that is better adapted to addressing the challenges of solar and wind energy development.

Therefore, we recommend the PATRP plan with decommissioning of assets, and adding 2,548 MW of capacity. The plan comprises the following elements:

- Two coal-fired steam stations (CES Sendou and Africa Energy)
- A 240 MW Dual power plant to be located at an optimal site that considers the ideal configuration for alignment with the strategy resulting from the use of local natural gas by 2025 (or the prior use of LNG), as well as of the 225 kV network
- The hydroelectric plants of Organization for the Development of the Senegal River (OMVS) (Gouina and Koukoutamba) and Organization for the Development of the Gambia River (OMVG) (Kaleta, Souapiti, Sambangalou, Amaria and Grand Kinkon)
- The addition of 530 MW of Intermittent Renewable Energy (IRE) plants, i.e. solar and wind farms
- Additional generation from local gas by 2025-2035 and conversion of Heavy Fuel Oil (HFO) Dual unit

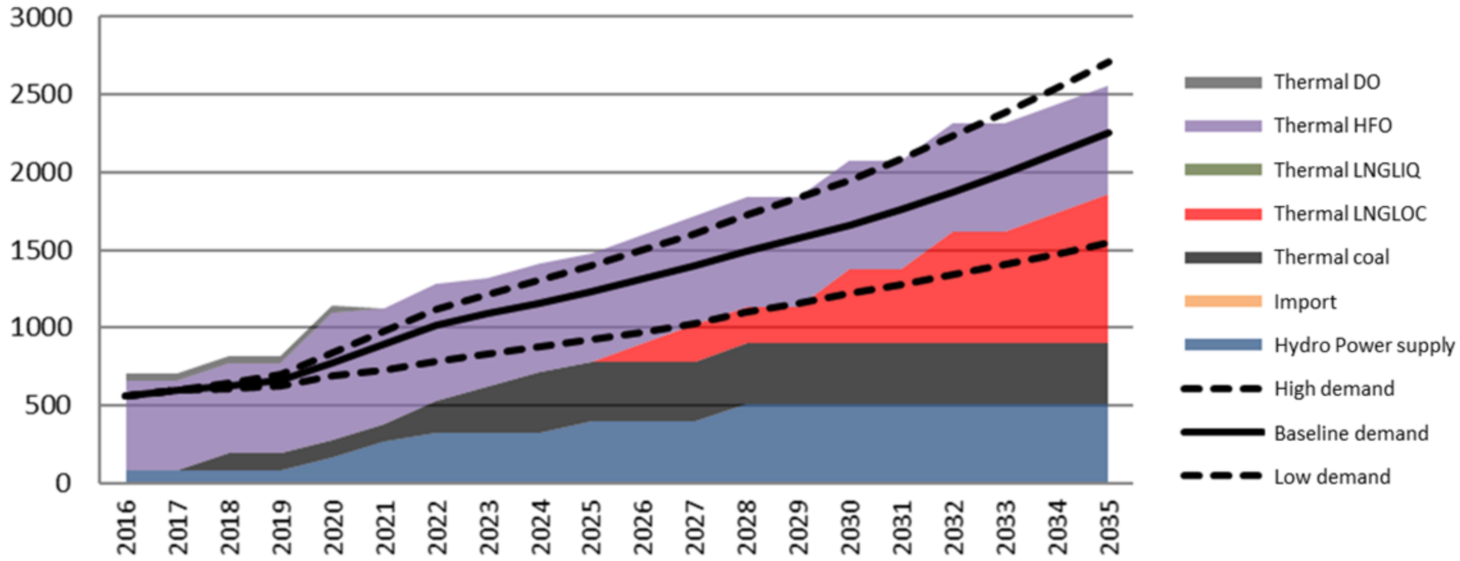
The following table presents the PATRP plan with decommissioning:

Figure 0-2 : PATRP plan with decommissioning

			MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
			2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL
MODEL 3 Baseline scenario WITH MINES PATRP plan with decommissioning	CES 1	Coal		115																		115
	Africa	Coal						90	90	90												270
	Malicounda	HFO Dual				120																120
	Additional power	Dual				120																120
	Additional power	CCGT										120	120			240		240		120	120	960
	Additional power	Hydro				83	103	61			70			118								435
	TOTAL																					**1840**
	Decommissioning						116		51													(167)
	Additional power	Solar																30				263
	Additional power	Wind		51.75	51.75	55.2							51.75					55.2				265.65
																					Total	**2381.65**

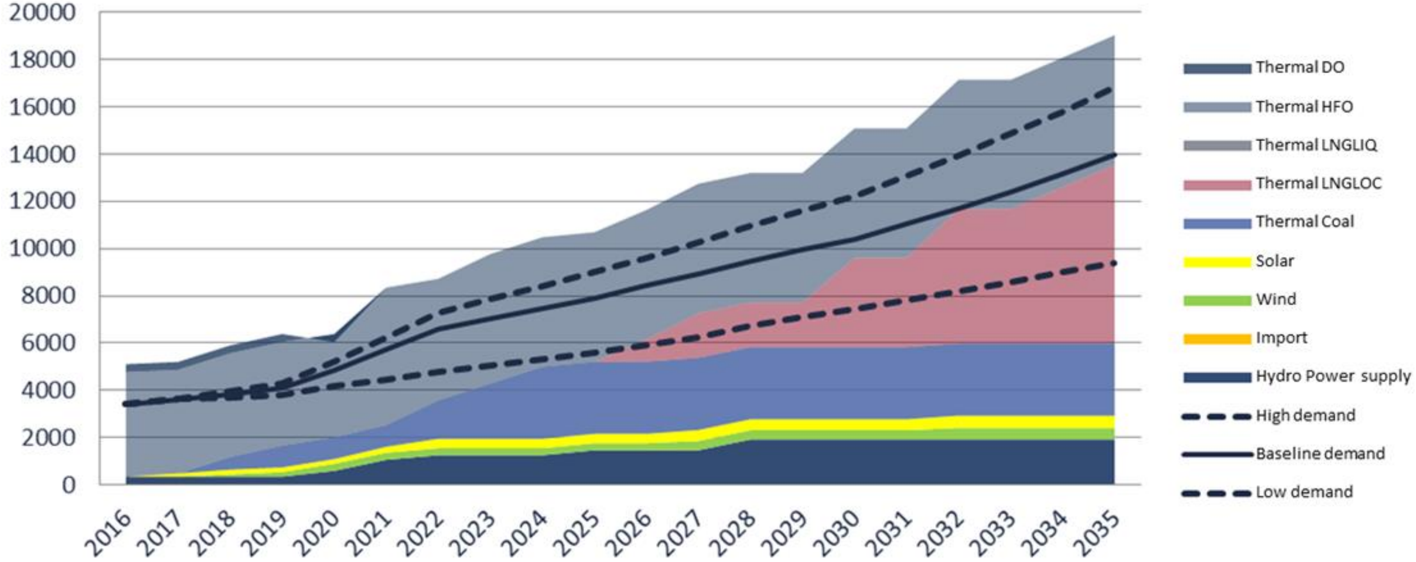
The following graph shows the makeup of the technology mix required to meet the different annual peak demands. With a peak demand of 596 MW in 2017, Senegal is expected to peak at 2,252 MW in 2035.

Figure 0-3 : Peak power 2017-2035



The following graph shows the technology mix required to meet energy demand requirements up to 2035.

Figure 0-4: 2017-2035 energy mix



It is important to note that PATRP did not choose to adopt the Senelec plan in its entirety. This plan was not chosen by our experts because of two major differences:

- The Senelec and PATRP plans do not take the same approach to the synchronous reserve. This difference in approach leads to divergences in the implementation of IREs versus generation with synchronous reserve capacity. The Senelec plan is faster with respect to the implementation of IREs, while the PATRP plans limit the integration of IREs in order to ensure adequate availability of the synchronous reserve for reliability reasons.

- The Senelec plan considers the addition of natural gas steam turbines (NGST) after 2025, taking a cautious approach with respect to the availability of local gas. The PATRP plans consider the local gas as available (or the temporary installation of LNG before the actual availability of local gas) and propose the establishment of CCGTs, which have a much lower cost than steam turbines. Senelec's approach, which it knows is more expensive, could potentially be modified following development in the gas sector.

TRANSMISSION

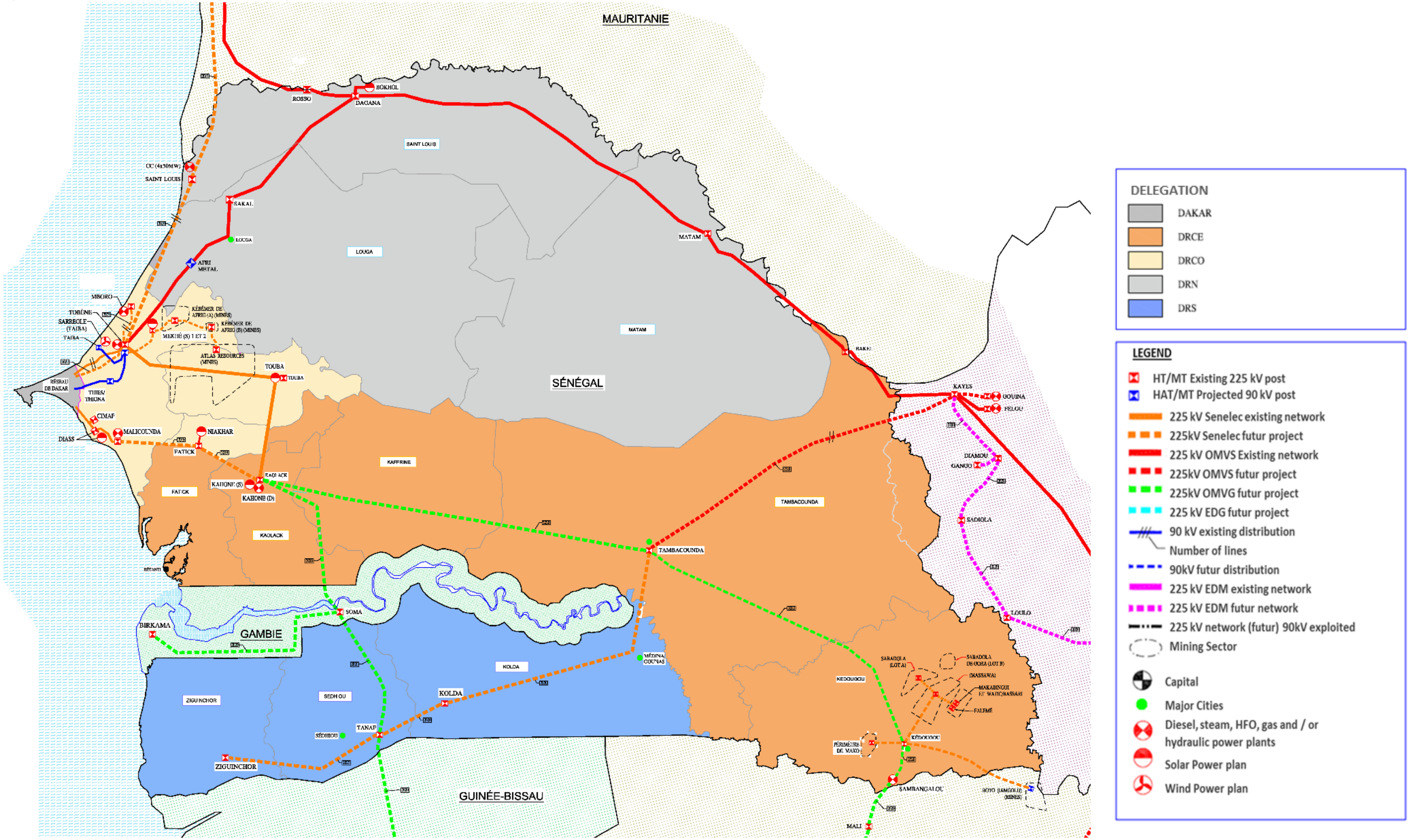
With regard to the transmission infrastructure, the main projects and directions are as follows:

- Construction by OMVS of a 252-km, 225 kV double-circuit transmission line between Tambacounda and Kayes, creating a 225 kV loop between Kayes and Tobene;
- Construction by OMVG of 1,530 km of a single-circuit 225-kV line, creating a loop with Guinea between Linsan and Kaolack. This project will also contribute to clearing generation from Guinea power plants such as: Kaleta, Souapiti, Amaria, Grand Kinkon and Sambangalou;
- These lines will also facilitate the integration of the Kédougou mines through the construction of 100 km of 90-kV line, depending on the number of mines that connect to the network;
- Connecting Tambacounda and Ziguinchor with the construction of 40 km of 225-kV line through Kolda and Tanaf. This section of line should significantly improve electrification in the surrounding areas;
- The 200-km-long 225-kV loop between Kaolack and Malicounda, making the West Central region even more reliable, as well as enhancing potential for rural electrification.

All of these projects will have to be closely monitored in order for Senegal to achieve its electrification objectives, integrate mines and reduce the cost of electricity.

The following map shows the interconnected grid by 2035.

Figure 0-5: Map of Senegal's High Voltage Transmission Network



Another strategic project for Senelec is the construction of a 225-kV loop near Dakar. This project has two objectives:

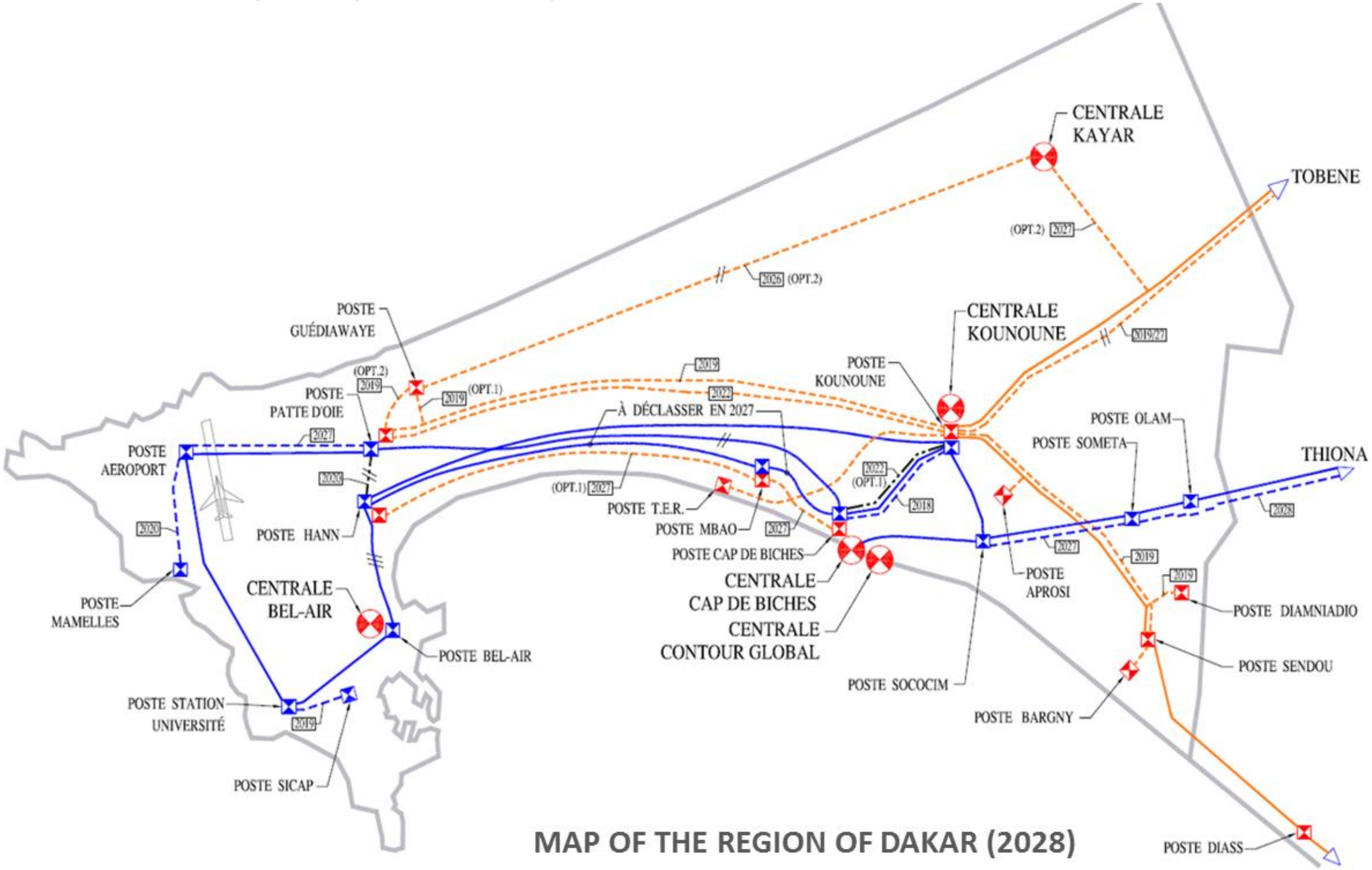
- Relieve congestion in the Dakar grid and enhance its capability to meet the increased demand.
- Make way for the addition of a second source of generation in the Dakar region, ideally from natural gas infrastructures.

As part of our analysis, a feasibility study was proposed to determine an optimal 225 kV loop.

The attached map shows both options that will be evaluated in this study:

- Option 1: Back up from the existing grid
- Option 2: 225-kV loop from a new generation source

Figure 0-6 : Map of the 225-kV Dakar loop: both options have been presented.



INVESTMENT PLAN

The investment plan includes an estimate of the funds to be committed by Senelec over the 2017-2035 period to meet the needs of the Senegalese population, based on the assumptions in the various scenarios in the previous part of the study.

Given the Senegalese government’s recent astute decision to entrust the private sector with the future development of generating facilities and related investments, the investment plan will focus on the transmission component.

We will conduct a financial analysis, however, in order to fully understand the impact of the construction of several new plants by 2035.

TRANSMISSION INVESTMENT PLAN

The transmission investment plan proposes two scenarios for the future 225 kV Dakar loop.

- **Scenario 1 - Back up from the existing loop:** As indicated in chapter 4, this is a 225-kV network that creates a loop between Kounoune-Cap des Biches-Mbao-Hann-Patte d’oie and which returns to Kounoune.
- **Scenario 2 - Installation of a loop from a second corridor:** This scenario would permit the integration of another generation source – in this case the Kayar natural gas plant – through another 225-kV corridor into Dakar's 90 kV grid. The loop would be installed between Kounoune-Patte d'Oie-Guédiawaye-Kayar and return to Kounoune.

Although our study chose the Kayar site, selecting another generation site would require the creation of a loop from another corridor.

Note that at this stage, since investments are assessed from parametric costs, the cost difference between the two scenarios is not significant.

A feasibility study would help to clarify these assessments which may be very different, mainly based on environmental and environmental acceptability studies.

The required investments for both scenarios are presented in the following table:

Table 0-1: Investment options for the transmission network (M F CFA)

INVESTMENT OPTIONS FOR THE TRANSMISSION NETWORK (M CFAF)																				
	Present value	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Option 1																				
Investments	330,134	19,080	45,716	121,789	167,459	21,107	21,861	-	689	-	2,438	26,550	3,581	-	-	-	-	-	-	-
O & M	46,124	302	1,108	2,900	5,183	5,498	5,856	5,973	6,106	6,229	6,402	6,869	7,048	7,189	7,332	7,479	7,629	7,781	7,937	8,096
Total	376,257	19,382	46,825	124,689	172,642	26,605	27,717	5,973	6,796	6,229	8,840	33,418	10,629	7,189	7,332	7,479	7,629	7,781	7,937	8,096
Option 2																				
Investments	333,004	19,080	45,716	124,910	165,930	21,107	17,555	-	689	-	21,655	15,944	3,581	-	-	-	-	-	-	-
O & M	46,432	302	1,108	2,931	5,199	5,515	5,830	5,947	6,080	6,201	6,566	6,959	7,140	7,283	7,429	7,577	7,729	7,883	8,041	8,202
Total	379,436	19,382	46,825	127,842	171,130	26,622	23,385	5,947	6,769	6,201	28,221	22,904	10,721	7,283	7,429	7,577	7,729	7,883	8,041	8,202

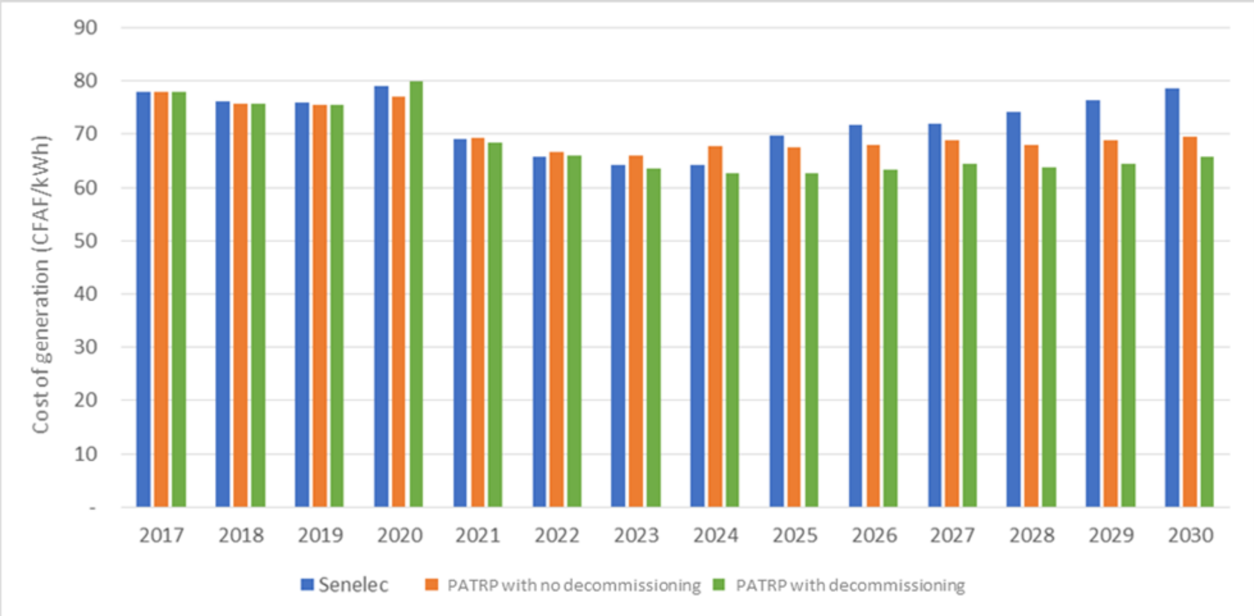
FINANCIAL ANALYSIS

The financial analysis shows that lowering generation costs in Senegal will be a significant challenge.

However, the PATRP with decommissioning scenario shows that the gross kWh cost, which was 77.9 CFAF in 2017, could drop to 65.69 CFAF by 2030 (green line in the figure below).

In constant CFA francs, this represents a nearly 39% drop in the price per kWh, considering a stable rate of inflation of two percent per year.

Figure 0-7: Cost per kWh for each scenario (Table in Appendix F.3)



The challenge will be considerable until 2021 because of potential demand management (curtailment) and load shedding, which will prevent coal from exerting maximum influence on the overall cost.

In 2021, we will start seeing the effects of the installation of the OMVS and OMVG interconnections on the overall cost caused by:

- the integration of hydroelectric energy;
- reduced demand management caused by additional hydro synchronous reserve capacity;
- the maximized usage of coal.

Thereafter, the cost will increase slightly by 2030 due to the addition of intermittent renewable energy (IRE). However, we believe that the cost of IREs may drop in the future, although this may not be the case.

CHALLENGES

Beyond the plan presented above, Senegal and Senelec should be concerned about several important issues. The following pages discuss these 13 issues:

1. Commissioning of the 115 MW CES Sendou coal-fired power plant
2. Commissioning of a 270 MW coal-fired power plant by Africa Energy
3. Commissioning of 528 MW of intermittent renewable energy
4. Development of local natural gas
5. Refurbishment plan for Senelec power plants
6. Management and collaboration with regional entities: OMVS, OMVG and WAPP
7. Establishment of a synchronous reserve strategy
8. Construction of the Tambacounda-Kolda-Ziguinchor 225 kV line
9. Commissioning of the Kaolack-Fatick-Malicounda 225 kV line
10. 225 kV Dakar loop study
11. Building Senelec's planning capacity
12. Integration plan for the various contracting parties
13. Project management process

COMMISSIONING OF THE 115 MW COAL-FIRED POWER PLANT IN SENDOU

This plant, which will be commissioned in 2018, is the first coal-fired power plant for Senelec and will allow Senegal to meet short-term demand at a lower cost.

As the variable cost associated with the use of coal is very low, it will reduce overall generation costs.

Risk: There are several possible risks at the Sendou power plant during the 2018-2021 period:

- The size of the power plant is greater than the network stability criterion. Indeed, Senelec does not have sufficient reserves to compensate for the sudden loss of the Sendou power plant since it has only one 115 MW unit. The loss of the Sendou group will therefore almost automatically lead to load shedding on the grid.
- To be able to maintain adequate automatic synchronous reserve during low demand, curtailment may be required at the Sendou plant, which will therefore have an impact on average variable costs.
    - Indeed, due to coal's lack of flexibility, it cannot be used to produce automatic synchronous reserve. IPPs under ToP contracts (IRE) are given priority among generation units, and these require some synchronous reserve. Coal-fired generation will often have to be curtailed to make room for HFO/gas thermal power, which can provide the automatic synchronous reserve required. However, the cost of operating these power plants is more expensive than coal-fired plants, at least for the time being.

To resolve this situation, Senelec will have to put in place:

- an optimal synchronous reserve management plan;
- automated remote load shedding to accommodate the Sendou power plant and guarantee grid reliability in case of accidental failure;
- short- and medium-term generation planning for coal-fired power plants as part of a rigorous process between power producers and the network control center to limit load management.

THE COMMISSIONING OF A 270 MW COAL-FIRED POWER PLANT BY AFRICA ENERGY

According to the proposed PATRP plan, the Africa Energy power plant should be commissioned in three 90-MW phases starting in 2022.

Risk: Even if the Africa Energy generation units are installed during a period when the grid is interconnected with Guinea, thus creating a more robust network, the sizing of the units will have to be validated. 45 MW or 30 MW generators would have a lower impact on the grid when there is a failure.

Senelec must monitor the changing situation and make sure that it can influence Africa Energy with respect to the sizing of the units if necessary.

COMMISSIONING OF 528 MW OF RENEWABLE ENERGY

According to the PATRP plan, 528 MW of intermittent solar and wind energy will be installed by 2035. Although this could change significantly depending on technology developments, the fact remains that Senelec must be able to manage the variability of this type of energy.

Risk: Meteorological predictions of solar and wind energy variability must be clear to avoid constraints that could harm grid operation.

- Thus, during normal variations due to sunrise/sunset, this generation capacity must be supplemented with the most cost-effective source.
- Sudden changes that could produce instability on the grid must also be monitored.

To deal with these issues, Senelec will have to:

- obtain quality meteorological data from private producers;
- develop short- and medium-term generation forecasting models;
- establish a control system of efficient networks with the automation required to take resource variability into account;
- establish an automatic synchronous reserve strategy; and
- for projects, develop a process with private producers to impose technical requirements for network integration. This process should take the form of a grid code that would be part of any electricity purchase agreement.

DEVELOPMENT OF LOCAL NATURAL GAS

The development of local natural gas is one of the most important energy strategies for Senegal in the medium term.

Developing the potential of off-shore deposits can help to position Senegal as a major player in West Africa, perhaps even providing the opportunity to export its energy wealth in the form of electricity through the OMVS and OMVG networks.

However, several steps must be taken before this can be implemented.

Risk: Several feasibility studies will be required to implement the most advantageous strategy at the lowest cost.

Senegalese authorities are being called upon to make urgent decisions regarding the development of local natural gas. These structuring decisions will also have to be accompanied by a long-term vision for the development of gas infrastructure, even though many questions remain unanswered today:

- Is it economically justifiable to develop an LNG import chain while waiting for gas to potentially arrive from Tortue or Sangomar by pipeline?
- Should consideration be given to a coexisting gas pipeline to supply the main consumption areas and an LNG chain for the most remote areas?
- Should gas demand be stimulated – with new gas-fired plants, decommissioned plant conversion projects and/or new uses – in order to achieve economies of scale in gas supply?
- Does the drop in prices and the relative decoupling between LNG prices and oil prices create economic interest in switching power generation tools from HFO or coal to natural gas?
- Are there regional opportunities for re-exporting LNG?
- Is LNG an economically viable solution to support the intermittency of renewables?
- Where are gas infrastructures the most optimal for grid stability and price per kWh?
- What would be the impact on kWh of the price of local vs. imported gas?
- How can gas transmission infrastructure be sized in a medium and long term perspective?
- Etc.

A master plan for the development of local natural gas is certainly an essential planning tool in order to see the big picture. It is also a central concern of the U.S. government, and could possibly be supported in Senegal through various initiatives operating in the country.

In the meantime, it is essential that newly commissioned power plants take this situation into account by ensuring that they have a technology in place that can easily be converted to NG as soon as the opportunity arises.

Moreover, Senelec had the foresight to require the latest power plants commissioned by Contour Global and Tobene Power could be converted from HFO to gas (Dual technology) as soon as the gas or LNG option becomes available.

As part of the PATRP master plan, 240 MW Dual should be commissioned in 2020. Senelec currently prefers the Malicounda site. However, this could potentially be changed depending on the conclusions of the natural gas master plan.

Starting in 2025, 960 MW should gradually be introduced from combined cycle plants (CCGT) using local natural gas. These facilities will need to be strategically located in relation to the gas infrastructure and considering transmission system needs.

The construction of a 225 kV loop near Dakar to unclog the grid and gas-fired power plant projects are indeed very closely interconnected.

POWER PLANT REFURBISHMENT PLAN

Senelec owns several power plants that are nearing the end of their useful life. Some of these power plants are probably too outdated to be cost-effectively refurbished. However, power plants such as C6, C7 and Kounoune can be refurbished and. Therefore, development of a power plant refurbishment plan coupled with a diagnosis of existing power plants could delay the need to decommission them or use them on cold standby, and lower costs.

Risk: Not taking advantage of the opportunity to refurbish existing power plants compared to the cost of building new ones.

Senelec must conduct a study on power plant refurbishment and, if the findings are conclusive, seriously consider the required investments.

It would also be a good idea to continue to impose the use of dual technologies to carry out these refurbishments with a view to the development of LNG or local gas.

MANAGEMENT OF REGIONAL BODIES: OMVS, OMVG AND WAPP

The OMVS and OMVG are regional bodies that have a strategic impact on the development of the energy sector in Senegal.

To efficiently plan generation and transmission infrastructures, Senelec and these regional bodies must have an optimal working relationship.

Risk: Power generation planning in Senegal is directly connected to the monthly generating potential of each watershed and these power plants. According to our recent experience in the region, little information was available from new power plants such as Souapiti, Sambangalou, Gouina, Koukoutamba, etc., despite the importance of PATRP's work for Senegal. This lack of information sharing makes it difficult to assess the required technology mix and the impact of the Senegalese government's decisions on the regional technology mix.

- The delay in collaboratively working with these organizations, both in generation and transmission, puts Senegal's planning at risk. In fact, the lack of information sharing for the planning of future stations and plants compromises the quality of Senelec's planning.
- The WAPP rules are not implemented in the different member countries, which affects the sound management of the grid. The automatic synchronous reserve is not applied at all, which contributes to triggering load shedding.

Actions that can be taken to correct this situation include:

- Developing a code in Senegal to manage the grid according to the criteria developed by WAPP.
- Ensuring that the committee in charge of coordinating OMVS and OMVG projects with member countries focuses on the timely dissemination of information on:
    - project schedules
    - project content
    - integration of electrification projects near 225 kV line rights-of-way
    - information on the monthly generation potential of power plants
    - etc.
- Asking WAPP to share the information, analyses and technical studies developed in the context of its projects. In this project, PATRP has repeatedly attempted to obtain information from WAPP for its grid simulation needs, but has been unsuccessful

IMPLEMENTATION OF A SYNCHRONOUS RESERVE STRATEGY

One key issue in the coming years will be to ensure there is an automatic synchronous reserve capacity to cope with the growth in demand, the increasing complexity of the network and the addition of IREs.

Risk: The risk of load shedding and major failures will be significantly increased if this situation is not controlled.

To mitigate this problem, Senelec will have to take the following actions:

- Conduct an operating network stability study based on actual data from the equipment in operation in order to implement an automatic synchronous reserve strategy.
- Model voltage and frequency control equipment to enhance dynamic network analysis.
- Determine which power plants will be able to generate automatic synchronous reserve.
- Purchase the necessary equipment to automate frequency regulation.
- Apply settings to speed regulators on current equipment.
- Examine alternatives to synchronous reserve application: storage unit, equipment rental, etc.
- Implement a control system of efficient networks so that operators can control networks taking into account the synchronous reserve strategy.
- Have a specialized workforce to deal with these issues.

CONSTRUCTION OF THE TAMBACOUNDA-KOLDA-ZIGUINCHOR 225 KV CONNECTION

Construction of the Tambacounda-Kolda-Ziguinchor corridor will enable the integration of major cities in southern Senegal into the main grids. Furthermore, medium voltage line (MV line) will be built to enable the electrification of suburban and rural areas.

Risk: Scheduling delays will make it difficult to achieve the objective of universal access in Senegal by 2025 and will limit the associated economic development.

Senelec must ensure that projects are managed soundly and mechanisms coordinated with the distributor in order to achieve the expected electrification objectives.

COMMISSIONING OF THE KAOLACK-FATICK-MALICOUNDA 225 KV LINE

This major project will loop the Kaolack to Malicounda 225 kV network.

This loopback will enhance the reliability of the Senelec network and the electrification of the surrounding regions.

Risk: Scheduling delays will make it difficult to achieve the objective of universal access in Senegal by 2025 and will limit the associated economic development.

Furthermore, the reliability of the High Voltage network cannot be improved because the loop may not be completed.

Senelec must ensure that projects are managed soundly and mechanisms coordinated with the distributor in order to achieve the expected electrification objectives.

225-KV DAKAR LOOP STUDY

As demand grows, Senelec will have to build a more robust network and integrate significant new sources of generation to unclog the Dakar region.

Hence, a 225-kV loop near Dakar would be a good solution to address this need. Two options are presented in the report and will need to be developed within the framework of a feasibility study.

The location of new sources of natural gas generation should be chosen in consideration of the installment of the 225-kV loop in order to vary the sources of generation supplied to Dakar.

Risk: Failing to coordinate the 225-kV loop study and the location of the natural gas power plants could lead to higher costs and lower profits.

In its next master plan update, Senelec must coordinate these two studies. Periodic updates with generation and transmission personnel will therefore be important.

BUILDING SENELEC'S PLANNING CAPACITY

To guarantee the sustainability of this master plan, Senelec will have to put in place the human and material resources required to carry out the master plan.

Risk: Loss of control over the changing environment.

To guarantee sustainability, Senelec’s General Research Department (DEG) will have to:

- Hire and train new engineers
  - Develop a training program for the development of new engineers;
  - Offer classroom training;
  - Offer coaching;
  - Organize exchanges with electrical companies that have the desired technology and expertise;
  - Provide adequate compensation to qualified personnel as an incentive to remain in the organization.

- Use and update the necessary hardware and software tools to carry out planned activities
    - Tools to perform steady state and dynamic stability analysis, and modern generation planning software will be essential for quality planning.

It would also be important to create a qualified distribution planning team to gain a better overview and coordinate the deployment of the transmission and distribution networks, thereby encouraging electrification.

INTEGRATION PLAN FOR THE DIFFERENT TECHNICAL-FINANCIAL PARTNERS (TFP)

Senelec will have an ambitious investment plan in the coming years. This investment plan will require significant funding in order to maximize the chances of its optimal achievement.

At the moment, several TFPs are interested in these projects.

In order to ensure that we benefit from the coordinated use of these different types of funding, Senelec should have a rigorous and clear integration plan with the various TFPs in order to take advantage of all available opportunities.

PROJECT MANAGEMENT PROCESS

The implementation of a project management process is key to ensure the sustainability of a master plan of this scope.

The process should provide for periodic updates of plan data as well as analyses to identify different trends and adjust accordingly.

The Senelec DEG team, which plays a key role in the application and updating of this plan, must have the organizational power and necessary leadership to implement such a plan.

CONCLUSION

The various issues outlined above will be an integral part of the day-to-day management of the master plan.

Senelec, in conjunction primarily with MEDER and CRSE, will have the challenging task of implementing this plan.

The training given during the weeks of July 3 and 10, 2017 was a first step in training Senelec's planners to be more independent in dealing with this evolving plan.

1. INTRODUCTION

This report is a continuation of the May 2017 report on the operation and stability of Senegal's transmission network. It is the final phase in the development of the Generation and Transmission Master Plan of Senelec, Senegal's national electricity company. The report includes a final investment plan, an implementation plan, and the associated financial analysis.

The project deliverables are as follows:

- Phase 1 – Inception report
- Phase 2 – Report on the supply-and-demand balance, excluding the transmission network analysis
- Phase 3 – Analysis of transmission network operation and stability
- Phase 4 – Final report, including the investment and implementation plans.

This final plan includes summary sections on demand and generation based on recent developments in our study. The transmission section includes a full operation and stability analysis report.

We then present the financial analysis of the three generation and transmission scenarios below:

- Senelec scenario
- PATRP scenario without decommissioning of generation assets
- PATRP scenario with decommissioning of generation assets that have reached the end of their useful life.

The analysis also includes the optimal investment plan to provide the generation and transmission infrastructures required to meet the growth in demand through 2035.

The last section covers rollout of the Master Plan to assist Senelec with implementation.

2. DEMAND ANALYSIS

2.1 INTRODUCTION

To guarantee a sufficient, cost-effective and stable supply of electricity, it is essential that we simulate the changing national electricity demand. A reliable demand forecast facilitates development of a plan for investments in generation plants, and transmission and distribution networks in the short, medium and long terms.

Senelec assessed the annual demand during the study period using the “forecasting electricity demand in developing countries” (EDDC) model. The methodology described herein is based on the 2016-2035 Electricity Demand Forecast (version of December 21, 2016). Power Africa used this methodology and identified key data that needed to be updated.

2.2 METHODOLOGY

2.2.1 SCOPE OF THE STUDY

The study differentiates demand from the interconnected network (IN) and demand from the Boutoute and Tambacounda networks, as well as from several off-grid centers. These networks define the boundaries of Senelec’s concession. Generation feeding the IN accounts for 95% of national power generation, and increased from 2,500 GWh to 3,406 GWh between 2009 and 2016, i.e. an average annual increase of 4.5%. The Boutoute and Tambacounda isolated networks also show steady growth, with annual growth rates of 5.7% and 3.8% respectively.

Table 2-1: Change in gross generation between 2010 and 2016 (GWh)

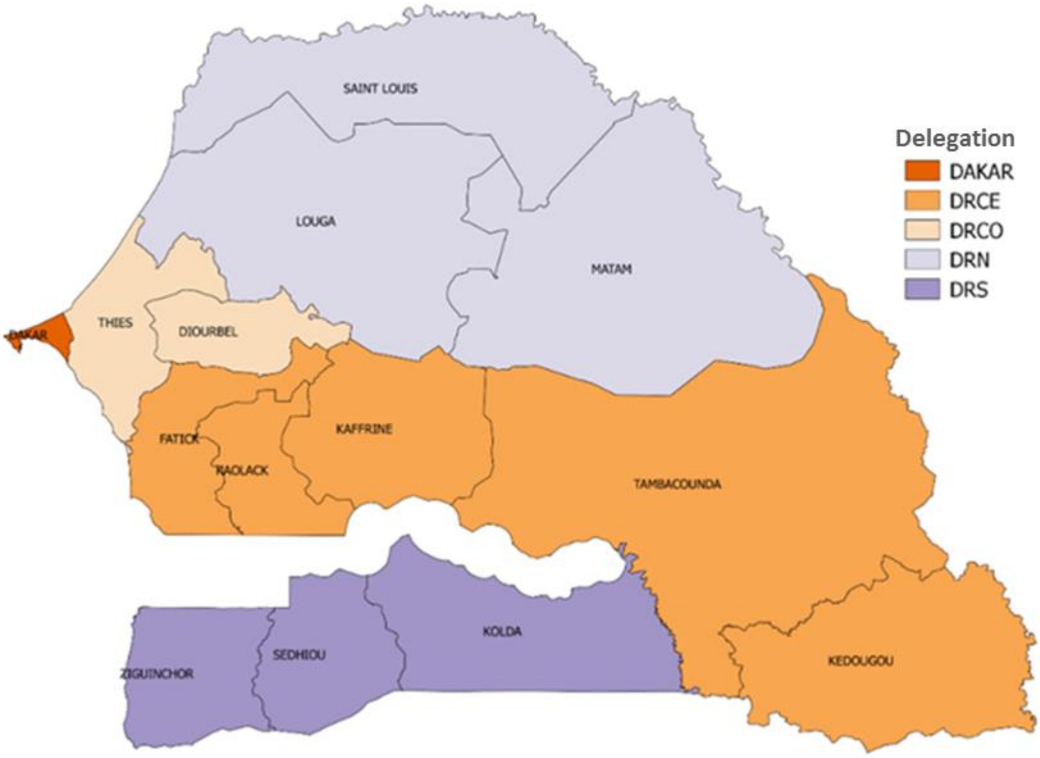
CHANGE IN GROSS GENERATION BETWEEN 2010 AND 2016 (GWh)								
Gross generation	2010	2011	2012	2013	2014	2015	2016	Growth 2010 - 2016
Interconnected Network	2,500	2,444	2,788	2,895	3,077	3,280	3,406	4.5%
Boutoute	57	62	66	69	74	81	85	5.7%
Tambacounda	26	21	26	27	31	32	33	3.8%
Off-grid centers	35	33	38	42	45	45	43	3.0%
Total	**2,618**	**2,560**	**2,917**	**3,032**	**3,227**	**3,438**	**3,567**	**4.5%**

Definition of geographic areas

Demand will be forecasted according to five areas representing the regional delegations. This simplifies the analysis and assumes consistent socioeconomic criteria for these delegations:

- Dakar: In the study, the entire Dakar region is considered to be an urban area
- Central-East Regional Delegation (DRCE) includes the regions of Kaolack, Fatick, Kaffrine, Tambacounda and Kédougou
- Central-West Regional Delegation (DRCO) includes the regions of Thiès and Diourbel
- North Regional Delegation (DRN) includes Matam, Saint Louis and Louga
- South Regional Delegation (DRS) includes the regions of Ziguinchor, Sédhiou and Kolda.

Figure 2-1: Distribution of regions by delegation



2.2.2 STUDY SECTORS

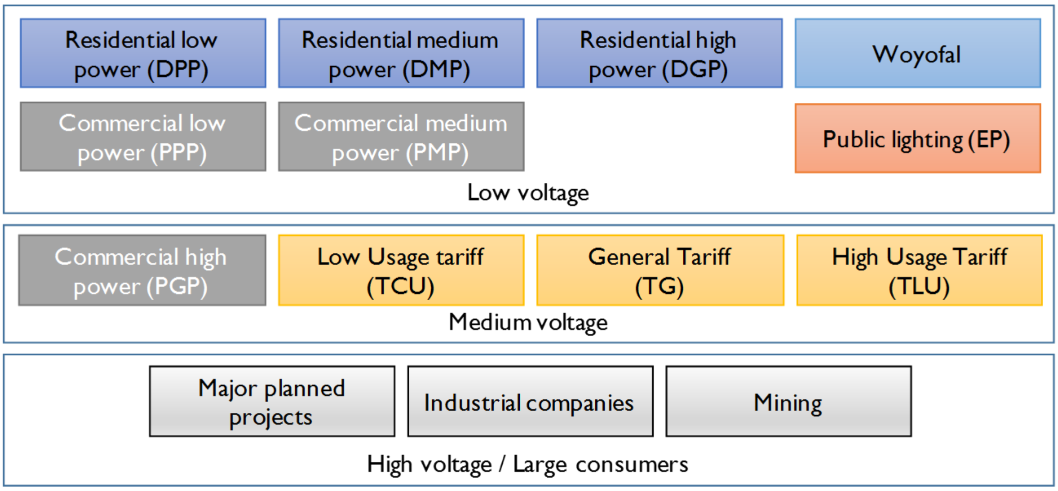
The forecasting separates electricity demand into three components:

- Low Voltage (LV) demand
- Medium Voltage (MV) demand
- High Voltage (HV) demand of large energy consumers.

Forecasting within these components is further sub-divided into five sectors:

- The residential sector (all LV customers): residential low power (DPP), residential medium power (DMPDMP), residential high power (DGPDGP), and customers in the Woyofal prepaid system
- Public lighting (EP)
- The commercial sector, sub-divided by power level: commercial low power (PPP), commercial medium power (PMP) and commercial high power (PGP); as well as Low Usage Tariff (TCU), General Tariff (TG) and High Usage Tariff (TLU) customers[1]
- The industrial sector and its HV customers (flagship projects, industrial consumers and mining).

Figure 2-2: Sectors and contract types



2.2.3 STEPS IN THE METHODOLOGY

The methodology involves conducting three types of analysis: (i) by sector, (ii) by hour, and (iii) by substation. Analysis by sector and by hour is used in the supply-and-demand balance study, while the analysis by substation is used in the transmission study. The different steps in the study are shown in the diagram below.

THREE DEMAND SCENARIOS

Initially, annual energy demand forecasts are established by considering:

i. Historical changes in electricity use
ii. Connection of new LV and MV customers across the country
iii. Estimated interconnection dates of isolated networks.

With respect to HV, future demand is determined based on the estimated dates of interconnection of large energy consumers such as mining companies and major projects under the purview of the Operational Monitoring Office (BOS) of the Emerging Senegal Plan (PSE).

[1] TCU, TG and TLU are Medium Voltage tariffs, with energy prices that vary during peak and off-peak hours, as well as monthly capacity rates in CFAF/kW. The TCU has a higher variable cost than TG and TLU, but a lower capacity rate.

Three scenarios were established within this methodology:

1. High demand scenario: Application of a wide range of ambitious government plans that are aligned with the PSE (e.g., steady growth in GDP of 7%, 2016-2019 contractual electrification rates, development of flagship projects (PSE) and sustained objectives through to 2035.
2. Baseline demand scenario: Application of government plans that are aligned with the PSE (e.g., steady growth in GDP of 7%, development of PSE flagship projects) and more conservative electrification rates than in the high demand scenario.
3. Low demand scenario: Application of more conservative assumptions that are similar to historical changes.

CHANGING PEAKS

To determine net electricity demand, certain technical factors associated with network performance are applied to sales. These include:

- To take into account the technical and commercial losses associated with transmission and distribution networks, sales are adjusted according to network performance, i.e. the ratio between sales and gross production.
- To obtain net production, gross production is adjusted by technical losses in power plant auxiliary services.
- To obtain peak demand, net generation is adjusted by the network load factor.

2.3 DEMAND OF SECTOR STUDY

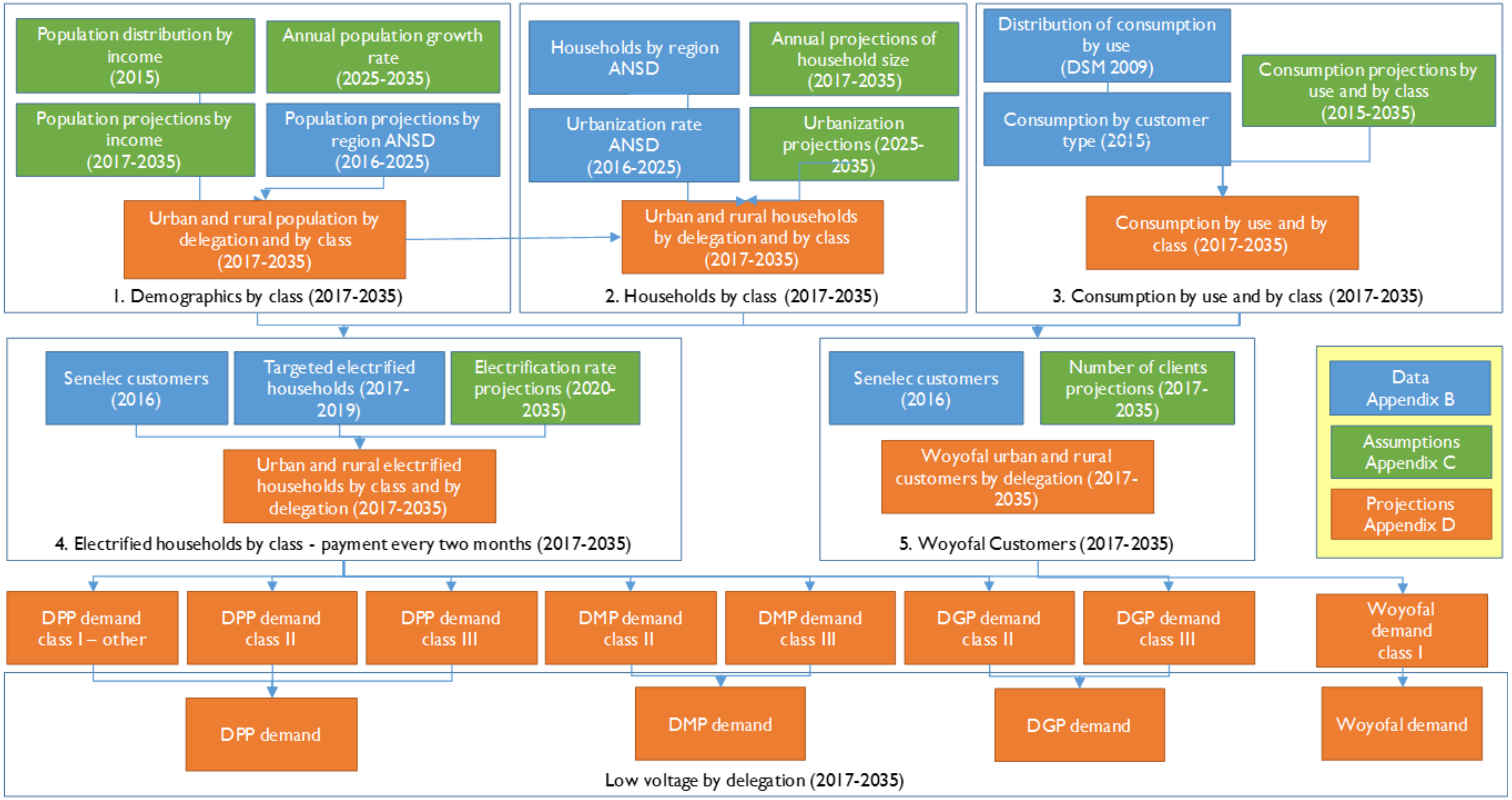
2.3.1 RESIDENTIAL SECTOR

Electricity demand in the residential sector in each delegation is tied to several factors, following the EDDC method. The figure below presents the methodology, as well as the data (in blue) and assumptions (in green) used.

Key elements in household demand forecasting include:

1. Change in Senegal's population based on data from the National Agency of Statistics and Demography (ANSD) for the years 2016 to 2025, and assumptions on growth rates for subsequent years.
2. Changing household characteristics, such as rate of urbanization and distribution of population by income (categories I, II and III), determine household income and size. These forecasts are based on ANSD data and assumptions, and on how these will change beyond the period covered by ANSD.
3. Household unit consumption is based on research conducted during the 2009 "Development of a Demand-side Management (DSM) Program", and assumptions on how these will change. Consumption is divided into the following uses: lighting, food refrigeration, TV/entertainment, air conditioning/ventilation, and other electrical uses.
4. The current level of household electrification (current number of customers paying twice per month), contractual obligations for 2016-2018, and a forecast beyond the 2016-2018 performance contract period.
5. The current forecasted level of household electrification (current number of customers in the Woyofal prepaid system), contractual obligations for 2016-2018, and a forecast beyond the 2016-2019 performance contract period.

Figure 2-3: 2016-2035 demand forecast – residential sector



2.3.2 PUBLIC LIGHTING (EP)

The demand from public lighting in each delegation was assessed based on changes in household demand and the demand elasticity observed during the reference period. Demand elasticity is the ratio between the growth rate of public lighting demand and the growth rate of household demand.

2.3.3 COMMERCIAL SECTOR

Demand from the commercial sector (small, medium and high power) are considered separately.

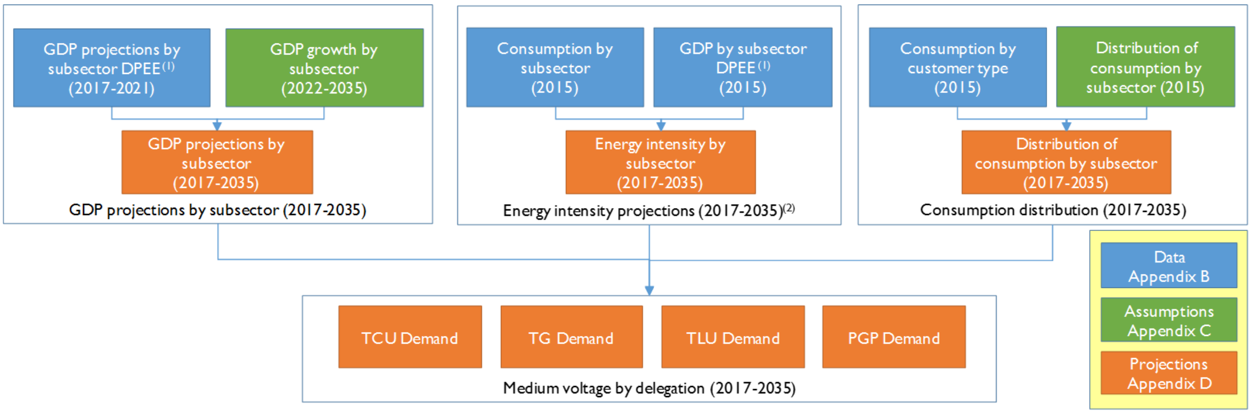
PPP and PMP demand in a given area is estimated (as is public lighting) based on demand elasticity.

Forecasted consumption of PGP and MV customers is assessed according to changes in added value in different economic sectors (GDP) in conjunction with the energy intensity of the sector.

- The primary sector includes agriculture, livestock farming, traditional fishing and forestry.
- The secondary sector includes mining, oil mills, energy, construction and public works (CPW) and other industries.
- The tertiary sector includes trade, transportation, telecommunications, education, health and other services.
- Administration is considered separately to better reflect the government's efforts to reduce its energy bill.

The energy intensity of each of these economic sub-sectors is used as the predictive factor of future energy use. It is defined as the electricity consumption in a given year, divided by the value added (GDP) of each sub-sector. This is expressed in kWh/current CFA francs.

Figure 2-4: 2016-2035 demand forecast – commercial sector



2.3.4 LARGE ENERGY CONSUMERS

Forecasts for large energy consumers include current HV consumers and projects.

The demand of customers currently connected to the HV network is based on the following assumptions:

- **Sococim**: The Sococim cement factory had backup power until the second quarter of 2016, as it had its own power plant. Starting in the third quarter of 2016, Sococim returned to using the network (due to supply difficulties). Its demand gradually increases through 2035.
- **Industries Chimiques du Sénégal (ICS):** ICS opened its own power plant to supply its energy needs for its phosphate mining and transformation to phosphoric acid processes for fertilizers manufacture. ICS has been operating its own power plant since 2016.
- **Société métallurgique d'Afrique (SOMETA):** SOMETA's consumption should continue to drop due to their continuing supply issue.
- **Sénégalaise Des Eaux (SDE**): Consumption by SDE-supported projects has been growing at 12% per year since 2009.

Demand forecasts for major projects are estimated, wherever possible, using input from project proponents, or are based on information shared by the PSE's Operational Monitoring Office and by the Ministry of Industry and Mining:

- **Dakar - Diamniadio - Blaise Diagne Airport (AIBD) regional express train (RET):** The demand required for the train is estimated using an energy intensity of 26.4 kWh/km and a frequency of 80 trains per day, i.e., 49 GWh in 2019 and 72 GWh starting in 2020, in the baseline demand scenario.
- **Blaise Diagne Airport (AIBD):** AIBD's energy requirements are estimated at 27 GWh annually in the baseline demand scenario, and 50% more in the high demand scenario. Start-up is scheduled for January 2018.
- **Bargny ore and oil port:** Start-up is scheduled for the second half of 2021, with an estimated demand of 154 GWh annually in the baseline demand scenario.
- **SDE desalination plant:** Start-up is scheduled for 2017. Demand will gradually increase to 137 GWh annually in 2020 in the baseline demand scenario.
- **Integrated Special Economic Zone:** The aim of this project is to develop infrastructures that offer companies optimal conditions for conducting business. It should get off the ground slowly in 2018 with the pilot phase (50 ha), then gradually increase to 150 GWh per year through 2030.
- **Afrimetal:** The demand of this metallurgical company is estimated at 27 GWh annually starting in January 2018.
- **Diamniadio Industrial Park:** The Agency for the Development and Promotion of Industrial Sites (APROSI) is aiming to develop and gradually implement a range of services, as and when sites are developed. Demand for this park in the baseline demand scenario is 10 GWh in 2018 and 30 GWh starting in 2019.
- **Société Nationale d'Exploitation des Terres du Delta du Fleuve Sénégal (SAED)**: SAED irrigation projects will require 3 GWh starting in 2017.
- **Ciments de l'Afrique (CIMAF):** In the baseline demand scenario, demand at the cement factory is estimated at 63 GWh annually starting in the second half of 2020, with a gradual ramp-up to 126 GWh in 2022.

Mining projects: the gradual integration of mining projects was considered, with connection starting in 2020 in the baseline and high demand scenarios.

- **Matam Phosphates:** Supply is expected in 2020. Annual consumption is estimated at 38.4 GWh in the baseline demand scenario and in the high demand scenario.
- **Sabadola - Euromine - Gold Niakafiri société - SGO**: Mining operations should be connected in 2020 at an annual consumption rate of 166 GWh at normal operating capacity. Mining is scheduled to be operating until 2028.
- **Massawa RandGold:** Annual requirements for gold mining were estimated at 197 GWh. Integration is scheduled for 2021 in the baseline and high demand scenarios, and mining is scheduled until 2029.
- **Falémé iron ore mines:** Annual needs for iron ore mining were estimated at 180 GWh at normal operating capacity. Integration is scheduled for 2021 in the baseline and high demand scenarios.
- **IAMGOLD:** Annual demand for gold mining has been estimated at 108 GWh at normal operating capacity. Integration is scheduled for 2022 in the baseline and high demand scenarios.
- **Mako Group Gold - Toro Gold Limited:** Annual demand for gold mining in the baseline demand scenario is estimated at 88.3 GWh. Integration is scheduled for 2021.
- **Makabingui Gold – WATIC:** Annual demand for gold mining in the baseline demand scenario is estimated at 18 GWh. Integration is scheduled for 2021.
- **African Investment - Group (AFRIG):** The demand from mining in the baseline demand scenario is estimated at 88.3 GWh annullay starting in 2020.
- **ATLAS Resources:** The demand from the expansion of phosphate mining and processing in the baseline demand scenario is estimated at 63 GWh annually starting in 2020.

2.3.5 RESULTS

The three scenarios (baseline, high demand and low demand) assume that the Tambacounda, Boutoute and other isolated networks will be connected to the interconnected network in 2019. The construction of the Bakel - Tambacounda - Kaolack - Tambacounda and Kaolack - Tanaf - Ziguinchor - Kolda transmission lines in 2019 would make this connection possible.

The key elements that determine demand are summarized below:

Table 2-2: Demand input parameters in each scenario

DEMAND INPUT PARAMETERS IN EACH SCENARIO				
	Unit	Baseline demand scenario	High demand scenario	Low demand scenario
Population growth rate to 2035	%	2.90	2.90	2.90
Urbanization rate, 2035	%	60	70	50
Household size, 2035	Pers./household	7.50	7.00	8.00
Electrification rate, 2035	%	80	90	70
Households with electricity, 2035	Households	2,764,680	3,332,346	2,267,836
2015-2020 economic growth	%	7.07	7.07	5.92
2020-2025 economic growth	%	7.58	7.58	5.54
2025-2030 economic growth	%	7.30	7.30	5.34
2030-2035 economic growth	%	7.13	7.13	5.11
Demand of large energy consumers in 2035	GWh	1,139	1,437	181

The figure and tables below show the yearly energy demand (in GWh) for the different scenarios using the assumptions below.

Demand for electricity is expected to increase significantly in all scenarios. Electricity consumption is expected to grow in the long term by an average of 7.6% annually (baseline demand scenario). For the high and low demand scenarios, growth is expected to be 8.7% and 5.2%, respectively. This would lead to energy use that is 20% (high demand scenario) higher and 30% (low demand scenario) lower than baseline values by the end of the study period. Therefore, the three scenarios describe a range from the worst (low) to best (high) case scenario. These scenarios will facilitate an analysis of the economic and technical impacts of the uncertainty surrounding both demand and the expansion of generation and transmission infrastructure.

The assumed electrification targets considerably increase the number of connections in any of the scenarios. Nearly 1.6 million additional household connections (on top of the existing 832,000) are required throughout the study period in the baseline demand scenario, to offset electrification targets, population growth and declining household size. One million and 2.4 million additional connections are required in the low and high demand scenarios respectively. Over the study period, 105,000 new customers will need to be added each year (72,000 and 139,000 respectively in the low and high demand scenarios). This exceeds the average number of new customers in previous years (approximately 54,700 per year) for all scenarios. It should be noted that between 2015 and 2016, Senelec added nearly 93,000 new customers, 81% of whom were Woyofal prepaid customers. An effort of almost equal magnitude would be required during the study period.

A forecasted 7% growth in the GDP over the study period in the baseline and high demand scenarios, which is consistent with the PSE, results in a MV demand increase of 7% per year. In the low demand scenario, annual growth in MV demand is expected to be 5%. It should be noted that in 2015 and 2016, the GDP grew by 6.6% in each of those years (between 4-5% in recent years). Growth of this magnitude would have to be sustained during the study period.

Figure 2-5: Forecasted sales in all three scenarios (GWH)

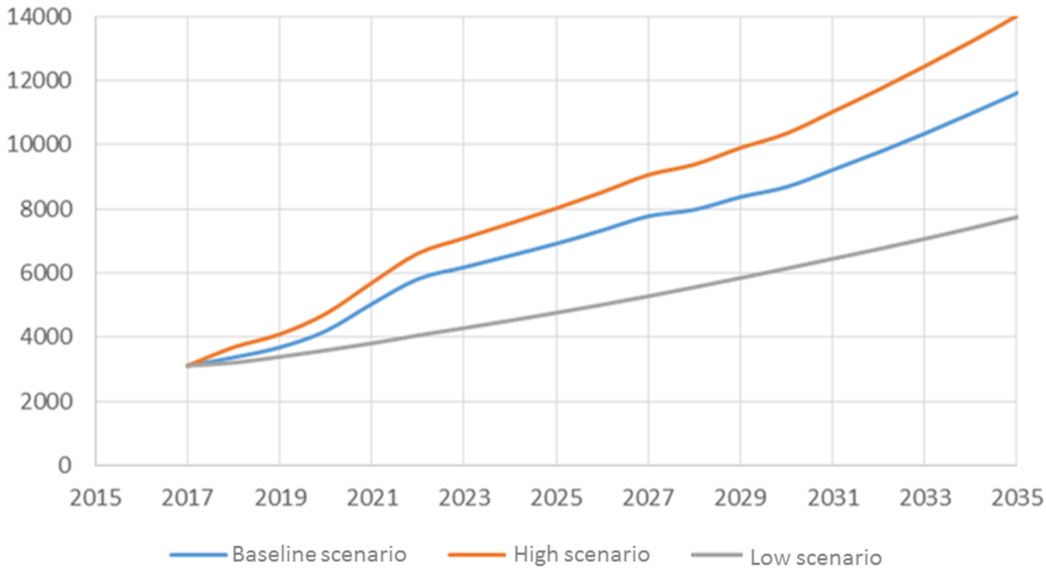


Table 2-3: Baseline demand scenario – energy requirements

BASELINE DEMAND SCENARIO – ENERGY REQUIREMENTS																				
Sales (GWh)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
IN	2,752	2,971	3,192	3,490	4,167	5,012	5,789	6,157	6,520	6,893	7,312	7,753	7,955	8,353	8,667	9,199	9,750	10,335	10,957	11,598
Boutoute	63	67	73	81	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tambacounda	25	26	28	31	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Off-grid centers	41	44	48	53	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	2,882	3,108	3,341	3,656	4,167	5,012	5,789	6,157	6,520	6,893	7,312	7,753	7,955	8,353	8,667	9,199	9,750	10,335	10,957	11,598

Table 2-4: Baseline demand scenario - energy requirements by contract type, excluding major consumers

BASELINE DEMAND SCENARIO - ENERGY REQUIREMENTS BY TYPE OF CONTRACT, EXCLUDING MAJOR CONSUMERS								
	2016	2017	2018	2019	2020	2025	2030	2035
Sales (GWh)	2,882	3,108	3,341	3,656	4,167	6,893	8,667	11,598
Low Voltage	1,849	2,000	2,098	2,271	2,418	3,552	5,190	7,285
DPP	1,052	1,074	1,144	1,256	1,344	2,058	3,100	4,428
DDMP	51	50	56	61	67	107	158	221
DGP	15	18	20	21	24	37	53	73
PPP	192	191	196	214	229	349	526	753
PMP	143	149	157	171	181	271	407	590
PGP	215	191	237	254	273	387	542	750
EP	65	73	80	81	86	115	158	212
Woyofal	115	254	210	212	214	229	245	259
Medium Voltage	851	907	964	1,031	1,143	1,593	2,206	3,026
TCU	10	8	10	11	12	17	24	33
TG	766	820	870	930	1,035	1,440	1,991	2,729
TLU	76	79	84	90	96	136	191	264

Table 2-5: Baseline demand scenario - energy requirements of large energy consumers

BASELINE DEMAND SCENARIO - ENERGY REQUIREMENTS OF LARGE ENERGY CONSUMERS

Sales (GWh)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Voltage
ICS	56	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	HV
SOCOCIM	48	104	104	104	104	105	105	105	106	107	107	108	108	109	110	111	112	113	114	116	HV
SDE	58	58	58	59	60	61	62	64	65	66	67	69	70	71	73	74	76	77	79	80	HV
SOMETA	15	33	33	33	33	33	33	33	33	33	34	34	34	34	34	34	34	35	35	36	HV
OLAM	5	5	5	5	6	6	6	6	6	6	7	7	7	7	7	8	8	8	8	9	HV
RET	-	-	-	49	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	HV
AIBD	-	-	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	MV
Ore/Oil port	-	-	-	-	-	77	154	154	154	154	154	154	154	154	154	154	154	154	154	154	HV
SDE desalination plant	-	-	-	-	39	52	80	123	137	137	137	137	137	137	137	137	137	137	137	137	HV
Special Economic Zone	-	-	68	73	78	83	89	95	101	108	115	123	132	140	150	150	150	150	150	150	HV
APROSI	-	-	10	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	HV
CIMAF	-	-	-	-	32	63	126	126	126	126	126	126	126	126	126	126	126	126	126	126	HV
Matam Phosphates	-	-	-	-	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	HV
Sabadola-Euromine	-	-	-	-	-	166	166	166	166	166	166	166	-	-	-	-	-	-	-	-	HV
Massawa RandGold	-	-	-	-	-	197	197	197	197	197	197	197	197	197	-	-	-	-	-	-	HV
Falémé iron ore mines	-	-	-	-	-	-	180	180	180	180	180	180	150	120	120	120	120	120	120	120	HV
IAMGOLD	-	-	-	-	-	-	108	108	108	108	108	108	54	-	-	-	-	-	-	-	HV
Mako Group Gold - Toro Gold	-	-	-	-	-	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	HV
Makabingui Gold - WATIC	-	-	-	-	-	-	18	18	18	18	18	18	18	18	18	18	18	18	18	18	HV
AFRIG	-	-	-	-	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	HV
ATLAS	-	-	-	-	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	HV
Total	182	200	306	381	671	1,250	1,731	1,782	1,804	1,813	1,822	1,832	1,594	1,521	1,336	1,339	1,341	1,344	1,348	1,352	

Table 2-6: Baseline demand scenario - customer by contract type

BASELINE DEMAND SCENARIO - CUSTOMER BY CONTRACT TYPE								
	2016	2017	2018	2019	2020	2025	2030	2035
Clientele (number)	1,201,079	1,278,639	1,313,575	1,428,860	1,402,062	1,819,183	2,430,808	3,212,086
Low Voltage	1,199,150	1,276,610	1,311,428	1,426,585	1,399,642	1,815,809	2,425,823	3,204,198
DPP	796,959	786,012	778,266	873,548	847,019	1,187,213	1,695,792	2,351,580
DDMP	6,447	6,222	6,902	7,639	8,431	13,368	19,732	27,751
DGP	617	600	660	724	791	1,214	1,753	2,414
PPP	176,259	167,754	174,262	187,170	183,265	226,218	286,838	359,527
PMP	17,525	18,192	19,922	22,405	21,293	29,567	42,042	59,077
PGP	6,575	6,689	7,031	7,396	7,785	10,185	13,657	18,945
EP	1,050	1,053	1,042	1,125	1,214	1,375	1,658	1,969
Woyofal	193,718	290,088	323,343	326,578	329,844	346,669	364,351	382,935
Medium Voltage	1,924	2,025	2,140	2,267	2,407	3,354	4,968	7,871
TCU	81	81	80	79	78	73	68	63
TG	1,797	1,899	2,016	2,145	2,286	3,238	4,857	7,765
TLU	46	45	44	43	43	43	43	43
High Voltage	5	4	7	8	13	20	17	17

Table 2-7: High demand scenario – energy requirements

HIGH DEMAND SCENARIO – ENERGY REQUIREMENTS																				
Sales (GWh)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
IN	2,752	2,971	3,318	3,689	4,502	5,466	6,382	6,870	7,350	7,837	8,344	8,883	9,212	9,751	10,225	10,911	11,612	12,360	13,151	13,987
Boutoute	63	67	77	87	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tambacounda	25	26	31	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Off-grid centers	41	44	51	58	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	2,882	3,108	3,341	3,656	4,167	5,012	5,789	6,157	6,520	6,893	7,312	7,753	7,955	8,353	8,667	9,199	9,750	10,335	10,957	11,598

Table 2-8: High demand scenario – energy requirements by contract type, excluding major consumers

HIGH DEMAND SCENARIO – ENERGY REQUIREMENTS BY CONTRACT TYPE, EXCLUDING MAJOR CONSUMERS								
	2016	2017	2018	2019	2020	2025	2030	2035
Sales (GWh)	2,882	3,108	3,478	3,870	4,504	7,839	10,227	13,989
LV	1,849	2,000	2,181	2,393	2,629	4,229	6,457	9,379
DPP	1,052	1,074	1,188	1,329	1,484	2,540	4,012	6,129
DMP	51	50	58	66	74	129	200	284
DGP	15	18	21	23	26	45	68	95
PPP	192	191	206	229	254	429	678	1,004
PMP	143	149	165	182	201	334	529	803
PGP	215	191	237	254	273	387	542	750
EP	65	73	80	84	91	134	193	269
Woyofal	115	254	226	226	226	231	235	46
MV	851	907	978	1,044	1,157	1,607	2,219	3,040
TCU	10	8	10	11	12	17	24	33
TG	766	820	884	944	1,049	1,453	2,005	2,743
TLU	76	79	84	90	96	136	191	264

Table 2-9: High demand scenario - energy requirements of large energy consumers

HIGH DEMAND SCENARIO - ENERGY REQUIREMENTS OF LARGE ENERGY CONSUMERS																					
Sales (GWh)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Voltage
ICS	56	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	HV
SOCOCIM	48	104	104	104	105	105	105	106	106	107	108	108	109	110	111	112	113	115	116	119	HV
SDE	58	58	58	59	61	62	64	65	67	68	70	71	73	75	76	78	80	82	84	86	HV
SOMETA	15	33	33	33	33	33	33	33	33	34	34	34	34	34	34	35	35	35	35	36	HV
OLAM	5	5	5	6	6	6	6	6	6	7	7	7	7	8	8	8	8	9	9	10	HV
RET	-	-	-	74	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	HV
AIBD	-	-	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	MV
Ore/Oil port	-	-	-	-	-	115	231	231	231	231	231	231	231	231	231	231	231	231	231	231	HV
SDE desalination plant	-	-	-	-	59	79	121	184	205	205	205	205	205	205	205	205	205	205	205	205	HV
Special Economic Zone	-	-	103	110	117	125	133	142	152	162	173	185	197	211	225	225	225	225	225	225	HV
APROSI	-	-	15	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	HV
CIMAF	-	-	-	-	32	63	126	126	126	126	126	126	126	126	126	126	126	126	126	126	HV
Matam Phosphates	-	-	-	-	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	MV
Sabadola-Euromine	-	-	-	-	-	166	166	166	166	166	166	166	-	-	-	-	-	-	-	-	HV
Massawa RandGold	-	-	-	-	-	197	197	197	197	197	197	197	197	197	-	-	-	-	-	-	HV
Falémé iron ore mines	-	-	-	-	-	-	180	180	180	180	180	180	150	120	120	120	120	120	120	120	HV
IAMGOLD	-	-	-	-	-	-	108	108	108	108	108	108	54	-	-	-	-	-	-	-	HV
Mako Group Gold - Toro Gold	-	-	-	-	-	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	HV
Makabingui Gold - WATIC	-	-	-	-	-	-	18	18	18	18	18	18	18	18	18	18	18	18	18	18	HV
AFRIG	-	-	-	-	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	HV
ATLAS	-	-	-	-	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	HV
Total	182	200	359	471	795	1,423	1,959	2,034	2,067	2,080	2,094	2,108	1,874	1,806	1,627	1,630	1,633	1,637	1,642	1,647	

Table 2-10: High demand scenario –number of customers by contract type

HIGH DEMAND SCENARIO – CUSTOMER BY CONTRACT TYPE								
	2016	2017	2018	2019	2020	2025	2030	2035
Clientele (number)	1,201,079	1,278,639	1,299,254	1,387,279	1,482,225	2,072,330	2,853,601	3,855,072
Low Voltage	1,199,150	1,276,610	1,297,107	1,385,004	1,479,805	2,068,956	2,848,616	3,847,184
DPP	796,959	786,012	768,612	843,616	924,667	1,430,960	2,105,290	3,178,883
DMP	6,447	6,222	7,292	8,288	9,372	16,285	25,461	36,765
DGP	617	600	696	785	880	1,479	2,254	3,142
PPP	176,259	167,754	172,602	182,345	192,678	253,670	328,593	419,075
PMP	17,525	18,192	19,389	21,029	22,822	34,469	51,116	74,643
PGP	6,575	6,689	7,031	7,396	7,785	10,185	13,657	18,945
EP	1,050	1,053	1,042	1,102	1,158	1,465	1,802	2,175
Woyofal	193,718	290,088	320,443	320,443	320,443	320,443	320,443	113,556
Medium Voltage	1,924	2,025	2,140	2,267	2,407	3,354	4,968	7,871
TCU	81	81	80	79	78	73	68	63
TG	1,797	1,899	2,016	2,145	2,286	3,238	4,857	7,765
TLU	46	45	44	43	43	43	43	43
High Voltage	5	4	7	8	13	20	17	17
Total	1,201,079	1,278,639	1,299,254	1,387,279	1,482,225	2,072,330	2,853,601	3,855,072

Table 2-11: Low demand scenario - LV and MV energy requirements

LOW DEMAND SCENARIO - LV AND MV ENERGY REQUIREMENTS																				
Sales (GWh)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
IN	2,752	2,971	3,055	3,227	3,584	3,804	4,053	4,282	4,516	4,759	5,014	5,279	5,557	5,848	6,144	6,447	6,752	7,070	7,401	7,747
Boutoute	63	67	70	75	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tambacounda	25	26	27	29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Off-grid centers	41	44	46	49	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	2,882	3,108	3,198	3,381	3,584	3,804	4,053	4,282	4,516	4,759	5,014	5,279	5,557	5,848	6,144	6,447	6,752	7,070	7,401	7,747

Table 2-12: Low demand scenario - energy requirements by contract type, excluding large energy consumers

LOW DEMAND SCENARIO - ENERGY REQUIREMENTS BY CONTRACT TYPE, EXCLUDING LARGE ENERGY CONSUMERS								
	2016	2017	2018	2019	2020	2025	2030	2035
Sales (GWh)	2,882	3,108	3,198	3,381	3,584	4,759	6,144	7,747
Low Voltage	1,849	2,000	2,049	2,163	2,288	3,060	4,053	5,189
DPP	1,052	1,074	1,091	1,163	1,239	1,710	2,322	3,019
DMP	51	50	53	57	61	86	119	154
DGP	15	18	19	20	21	30	41	52
PPP	192	191	190	203	216	297	405	528
PMP	143	149	152	161	171	230	308	401
PGP	215	191	233	245	259	335	429	544
EP	65	73	80	79	83	104	130	159
Woyofal	115	254	231	235	240	268	300	331
Medium Voltage	851	907	928	976	1,029	1,330	1,703	2,158
TCU	10	8	10	11	11	15	19	24
TG	766	820	836	879	926	1,197	1,533	1,942
TLU	76	79	82	86	91	118	151	192

Table 2-13: Low demand scenario – energy requirements of large energy consumers

LOW DEMAND SCENARIO – ENERGY REQUIREMENTS OF LARGE ENERGY CONSUMERS																					
Sales (GWh)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Voltage
ICS	56	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	HV
SOCOCIM	48	104	104	104	104	104	105	105	106	106	106	107	107	108	109	109	110	111	112	113	HV
SDE	58	58	59	60	61	62	63	64	65	66	67	68	69	70	71	72	74	75	76	77	HV
SOMETA	15	33	33	33	33	33	33	33	33	33	33	34	34	34	34	34	34	34	35	35	HV
OLAM	5	5	5	5	6	6	6	6	6	6	6	6	7	7	7	7	7	7	8	8	HV
RET	-	-	-	12	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	HV
AIBD	-	-	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	MV
Ore/Oil port	-	-	-	-	-	19	38	38	38	38	38	38	38	38	38	38	38	38	38	38	HV
SDE desalination plant	-	-	-	-	10	13	20	31	34	34	34	34	34	34	34	34	34	34	34	34	HV
Special Economic Zone	-	-	17	18	19	21	22	24	25	27	29	31	33	35	38	38	38	38	38	38	HV
APROSI	-	-	3	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	HV
CIMAF	-	-	-	-	8	16	32	32	32	32	32	32	32	32	32	32	32	32	32	32	HV
Matam Phosphates	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	MV
Sabadola-Euromine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	HV
Massawa RandGold	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	HV
Falémé iron ore mines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	HV
IAMGOLD	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	HV
Mako Group Gold - Toro Gold	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	HV
Makabingui Gold – WATIC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	HV
AFRIG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	HV
ATLAS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	HV
Total	182	200	228	248	274	307	351	365	372	375	379	382	386	390	395	397	399	401	404	407	

Table 2-14: Low demand scenario – number of customers by contract type

LOW DEMAND SCENARIO – CUSTOMERS BY CONTRACT TYPE								
	2016	2017	2018	2019	2020	2025	2030	2035
Clientele (number)	1,201,079	1,278,639	1,253,961	1,308,566	1,365,699	1,692,617	2,098,090	2,583,446
Low Voltage	1,199,150	1,276,610	1,251,814	1,306,291	1,363,282	1,689,252	2,093,111	2,575,564
DPP	796,959	786,012	727,333	770,436	815,679	1,077,151	1,405,244	1,800,111
DMP	6,447	6,222	6,538	7,035	7,563	10,682	14,725	19,609
DGP	617	600	631	678	725	1,000	1,351	1,751
PPP	176,259	167,754	167,351	173,487	179,844	215,137	256,558	303,670
PMP	17,525	18,192	18,545	19,556	20,628	27,053	35,567	46,574
PGP	6,575	6,689	7,031	7,396	7,785	10,185	13,657	18,945
EP	1,050	1,053	1,042	1,125	1,214	1,375	1,658	1,969
Woyofal	193,718	290,088	323,343	326,578	329,844	346,669	364,351	382,935
Medium Voltage	1,924	2,025	2,140	2,267	2,407	3,354	4,968	7,871
TCU	81	81	80	79	78	73	68	63
TG	1,797	1,899	2,016	2,145	2,286	3,238	4,857	7,765
TLU	46	45	44	43	43	43	43	43
High Voltage	5	4	7	8	10	11	11	11

2.4 HOURLY CONSUMPTION MODEL: SUPPLY STUDY

Demand was broken down on an hourly basis for the period 2017-2035. The following assumptions and steps were followed:

- We used the 2015 hourly consumption profile was used as the benchmark.
- We developed a typical hourly consumption matrix using the 2015 energy and peak power values, and increased it proportionally to 2035 based on demand growth.
- We estimated growth by customer type using the EDDC model.
- Based on annual growth in energy, we calculated the maximum peak using the 2015 load factor of 69.1%.
- We incorporated industrial and off-grid center loads with their own load factor.

All generation simulations are based on these projections, which allows us to achieve a reasonable level of accuracy in our calculations and highlight the hourly contribution of solar power plants.

2.5 SUBSTATION CONSUMPTION MODEL: TRANSMISSION STUDY

The load of each Senelec substation was assessed based on in both aggregate demand growth and network expansion. The following assumptions and steps were followed:

- Based on the annual growth in energy (LV and MV), excluding large energy consumers, we calculated the peak using the 2015 network load factor of 69.1%.
- We broke down the aggregate load, excluding large energy consumers, by substation, with the 2015 peak load distribution used as the benchmark. This distribution was applied to demand forecasts excluding large energy consumers throughout the study period.
- We incorporated the load of major HV projects using a load factor of 100%, and the load of industrial MV and off-grid centers using the 2015 load factor of 69.1%.
- The loads for large energy consumers were integrated into planned new substations or the nearest existing substations, according to Senelec's forecasted grid expansion.

The loads for existing substations were transferred based on Senelec's approved investment plan for new substations. We took the preliminary assumptions of the relevant Senelec departments (Planning and Distribution) regarding the percentage to be transferred between the different substations. Project feasibility studies will adjust these assumptions.

2.5.1 RESULTS

Table 2-15: Peak forecast by source substation in MW

PEAK FORECAST BY SOURCE SUBSTATION IN MW																					
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Bel Air	59.6	61.6	65.7	67.6	63.5	67.8	72.9	78.5	84.6	91.1	98.0	105.7	113.8	122.1	130.9	140.2	150.1	160.3	171.1	182.6	194.4
Airport	30.9	32.0	34.1	35.1	36.9	39.4	42.3	45.6	49.1	52.9	56.9	61.3	66.0	70.8	76.0	81.4	87.1	93.0	99.3	106.0	112.8
CDB	38.6	39.9	42.5	43.7	15.8	16.8	18.1	19.5	21.0	22.6	24.3	26.2	28.2	30.3	32.5	34.8	37.3	39.8	42.5	45.3	48.3
Dagana	9.3	9.6	10.2	10.5	8.9	9.5	10.2	11.0	11.8	12.7	13.7	14.8	15.9	17.1	18.3	19.6	21.0	22.4	23.9	25.5	27.2
Diass	12.4	12.8	13.6	27.3	21.2	22.3	23.5	24.9	26.3	27.8	29.4	31.2	33.0	35.0	37.1	39.3	40.5	41.7	43.0	44.3	45.8
Hann	109.9	113.5	121.0	124.5	93.6	99.9	107.4	115.7	124.6	134.2	144.3	155.7	167.6	179.8	192.8	206.5	221.1	236.2	252.1	269.0	286.4
Kaolack	25.8	26.6	28.4	29.2	27.8	29.7	31.9	34.4	37.0	39.9	42.9	46.3	49.8	53.5	57.3	61.4	65.7	70.2	74.9	80.0	85.1
Mbao	28.2	29.2	31.1	32.0	22.4	23.9	25.7	27.7	29.8	32.1	34.5	37.2	40.1	43.0	46.1	49.4	52.9	56.5	60.3	64.4	68.5
Mbour	30.9	32.0	34.1	35.1	32.3	34.5	37.1	40.0	43.1	46.4	49.9	53.8	58.0	62.2	66.6	71.4	76.4	81.6	87.1	93.0	99.0
Mékhé	13.8	14.0	14.5	14.8	15.3	15.9	16.6	17.5	18.4	19.3	20.3	21.5	22.6	23.8	25.1	26.5	27.9	29.4	30.9	32.6	34.2
Olam	0.2	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9	1.0	1.0
Sakal	33.8	34.9	37.2	38.3	30.8	32.9	35.4	38.1	41.0	44.2	47.6	51.3	55.2	59.2	63.5	68.0	72.8	77.8	83.1	88.6	94.4
Taiba	27.2	22.3	17.0	17.5	18.4	19.7	21.1	22.8	24.5	26.4	28.4	30.7	33.0	35.4	38.0	40.7	43.6	46.5	49.7	53.0	56.4
Thiona	38.6	39.9	42.5	43.7	34.0	36.3	39.0	42.1	45.3	48.8	52.5	56.6	60.9	65.4	70.1	75.1	80.4	85.9	91.6	97.8	104.1
Tobène	4.1	4.3	4.5	4.7	4.9	5.2	5.6	6.1	6.5	7.0	7.6	8.2	8.8	9.4	10.1	10.8	11.6	12.4	13.2	14.1	15.0
Touba	30.3	31.3	33.4	34.3	36.1	38.5	41.4	44.6	48.0	51.7	55.6	60.0	64.6	69.3	74.3	79.6	85.2	91.0	97.2	103.7	110.4
Université	21.2	21.9	23.4	24.0	20.8	22.2	23.9	25.7	27.7	29.8	32.1	34.6	37.3	40.0	42.9	46.0	49.2	52.5	56.1	59.9	63.7
Bakel	1.7	1.8	1.9	1.9	2.0	3.0	3.2	3.5	3.8	4.1	4.4	4.8	5.2	5.7	6.1	6.6	7.2	7.7	8.3	8.9	9.6
Matam	9.3	9.6	10.2	10.5	11.1	19.3	20.2	21.1	22.2	23.3	24.5	25.9	27.3	28.7	30.3	31.9	33.6	35.4	37.3	39.3	41.3
Kolda	0.0	0.0	0.0	0.0	0.0	7.2	7.9	8.7	9.6	10.6	11.6	13.0	14.4	16.0	17.6	19.4	21.4	23.5	25.7	28.1	30.7
Fatick	0.0	0.0	0.0	0.0	8.9	9.5	10.2	11.0	11.8	12.8	13.7	14.8	15.9	17.1	18.3	19.6	21.0	22.5	24.0	25.6	27.2
Tamba	0.0	0.0	0.0	0.0	0.0	6.8	7.4	8.2	9.0	9.9	10.9	12.2	13.6	15.1	16.8	18.6	20.5	22.6	24.9	27.3	29.9
Tanaf	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ziguinchor	0.0	0.0	0.0	0.0	0.0	17.4	19.0	21.0	23.1	25.3	27.8	30.8	34.0	37.3	41.0	44.9	49.1	53.5	58.2	63.2	68.6
Kounoune	0.0	0.0	0.0	0.0	17.6	18.7	20.1	21.7	23.4	25.2	27.1	29.2	31.5	33.7	36.2	38.7	41.5	44.3	47.3	50.5	53.7
Diamniadio	0.0	0.0	0.0	0.0	30.2	32.2	34.7	37.3	40.2	43.3	46.6	50.3	54.1	58.0	62.2	66.7	71.4	76.2	81.4	86.8	92.5
Guédiawaye	0.0	0.0	0.0	0.0	24.4	26.1	28.0	30.2	32.5	35.0	37.7	40.6	43.8	46.9	50.3	53.9	57.7	61.6	65.8	70.2	74.8
Bargny	0.0	0.0	0.0	0.0	0.0	0.0	8.9	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8	17.8
Mamelles	0.0	0.0	0.0	0.0	0.0	4.5	6.0	9.3	14.1	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8

PEAK FORECAST BY SOURCE SUBSTATION IN MW																					
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
SOCOCIM	0.0	5.3	12.0	12.0	12.0	12.0	12.1	12.1	12.2	12.2	12.3	12.3	12.4	12.5	12.6	12.7	12.8	12.9	13.0	13.2	13.4
Someta	1.9	1.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.9	3.9	3.9	3.9	3.9	3.9	4.0	4.0	4.0	4.0	4.1
RET	0.0	0.0	0.0	0.0	5.7	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
APROSI	0.0	0.0	0.0	1.2	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Afrimetal	0.0	0.0	0.0	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
CIMAF	0.0	0.0	0.0	0.0	0.0	3.6	7.3	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5
Sabadola-Euromine	0.0	0.0	0.0	0.0	0.0	0.0	19.1	19.1	19.1	19.1	19.1	19.1	19.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Massawa RandGold	0.0	0.0	0.0	0.0	0.0	0.0	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	0.0	0.0	0.0	0.0	0.0	0.0
Falémé iron ore mines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.8	20.8	20.8	20.8	20.8	20.8	17.3	13.8	13.8	13.8	13.8	13.8	13.8	13.8
IAMGold	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.5	12.5	12.5	12.5	12.5	12.5	6.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mako - Toro Gold	0.0	0.0	0.0	0.0	0.0	0.0	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Makabingui - WATIC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
AFRIG	0.0	0.0	0.0	0.0	0.0	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
ATLAS	0.0	0.0	0.0	0.0	0.0	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3
Sococim Senelec	0.0	0.0	0.0	0.0	6.5	6.9	7.4	8.0	8.6	9.3	10.0	10.7	11.6	12.4	13.3	14.2	15.3	16.3	17.4	18.6	19.8
SICAP	0.0	0.0	0.0	0.0	29.7	31.7	34.1	36.7	39.5	42.6	45.8	49.4	53.2	57.1	61.2	65.6	70.2	75.0	80.0	85.4	90.9
St. Louis	0.0	0.0	0.0	0.0	11.6	12.4	13.3	14.3	15.4	16.6	17.8	19.3	20.7	22.2	23.8	25.5	27.3	29.2	31.2	33.3	35.4
Kédougou	0.0	0.0	0.0	0.0	0.0	2.1	2.3	2.5	2.8	3.0	3.3	3.7	4.2	4.6	5.1	5.6	6.2	6.8	7.4	8.1	8.8
Total	**527.7**	**544.6**	**581.9**	**615.5**	**653.4**	**764.8**	**883.1**	**995.9**	**1063.4**	**1132.3**	**1203.9**	**1284.4**	**1369.3**	**1427.4**	**1510.4**	**1585.9**	**1689.2**	**1795.9**	**1909.2**	**2029.7**	**2154.0**

3. GENERATION PLAN

3.1 INTRODUCTION

As part of this study, PATRP has identified certain criteria for quantifying the generation capacity required to meet the demand. This generation capacity must itself meet generally applicable availability and reliability criteria. The following sections review these criteria.

3.2 TECHNICAL CRITERIA

3.2.1 SIZING OF GENERATION UNITS

The technical standards for electricity grids generally recommend that the capacity of the largest generating unit connected to the grid not exceed 15% of the instantaneous demand in order to limit the possibility of causing a widespread incident in the event the plant concerned is triggered.

Application of this criterion is limited by the direction Senelec has already taken with respect to new power plants to be commissioned, including the 115 MW net power thermal coal unit of the Sendou plant.

3.2.2 PLANNING GENERATION SUPPLY (P MAX RESERVE)

The reserve was established according to the following criteria:

- Minimum reserve capacity of 15%.
- Avoid having a reserve of less than 20% for two consecutive years through 2030. Given the length of this timeframe, during which periodic reviews of the plan will certainly result in significant changes to supply and demand levels, beyond 2030 we believe that a reserve of around 15% is sufficient.

3.2.3 STABILITY RESERVE

A common definition of stability reserve is the definition provided by the North American Electric Reliability Corporation (NERC), which specifies that it includes all reserves, whether or not they are synchronous, ready to respond within 10 minutes of an instruction from the network control center. There are three levels to the stability reserve:

Primary

- A synchronous spinning reserve which must be available instantly to supply load in sufficient quantities to prevent load shedding due to under-frequency.

Secondary (10 minutes)

- A synchronous or non-synchronous reserve that must be available within 10 minutes. This reserve must ensure that the frequency is returned to its original set-point within the prescribed time, by absorbing the residual frequency difference from the primary reserve. Part of the secondary reserve can therefore be non-spinning, such as interruptible load, or composed of generation units with a start-up capacity and generation build-up of less than 10 minutes.

Tertiary (30 minutes)

- A non-synchronous reserve which must be available within 30 minutes so that a cost-effective and sufficient level of primary reserve can be rebuilt in order to prevent load loss due to under-frequency in the event there is a new incident in the grid. Part of the tertiary reserve can therefore be non-spinning, such as interruptible load, or composed of generation units with a start-up capacity and generation build-up of less than 30 minutes.

Note that stricter criteria can be applied depending on the required stability levels for different grids or control areas.

3.2.4 ADEQUACY OF THE GENERATION FLEET (RELIABILITY)

Balancing supply and demand uses a probabilistic approach that seeks to measure the extent to which the country's generating facilities are able to meet the entire demand at all times, considering the probability of incidents within generation units.

To this end, a target reliability index for the generation fleet is used. This index, called the Loss of Load Probability (LOLP), establishes the maximum number of hours during which an imbalance between available generating capacity and demand from the grid will be tolerated. LOLP is the expected time expressed as a percentage of a year during which a loss of generation can lead to loss of load. The LOLP index multiplied by 8,760 hours gives the expected time in hours during which the generated power supply will not be able to meet demand, or the loss of load expectation (LOLE).

The reliability criteria used to analyze the adequacy of the generation fleet in Senelec's generation plan (version of January 12, 2015) are as follows:

- LOLP x 8,760 hrs: 72 hrs/year (LOLP: 0.82%).

The LOLP validates whether the planned generation capacity for a given year can reliably meet demand within the 72 hrs/year limit, and assesses the amount of energy impacted by the LOLE measurement.

3.2.5 FAILURE RATE (RANDOM UNAVAILABILITY) COMPARED TO LOLP

One of the key inputs required to calculate the LOLP is the failure rate specific to each generating plant. For Senelec's thermal power plants, PATRP will apply the data identified in the “Technical and Economic Characteristics” document (provided by Senelec) as the failure rate. We note an average failure rate of around 10%, as shown in the table below:

Table 3-1: Average failure rate

AVERAGE FAILURE RATE		
		Technical/Economic Characteristics
Facility	Group	Failure Rate (%)
C-2 Bel-Air	TAG4	10
C-6	601	8.0
	602	8.0
	603	8.0
	604	8.0
Bel-Air	605	8.0
	606	8.0
C-3	301	15
	303	15
Cap des Biches	TAG2	10
C-4	401	15
	402	15
	403	15
	404	10
Cap des Biches	405	10
C-7	701	8
	702	8
KAHONE 2	703	8
	704	8
	705	8
	706	8
KAHONE 1	93	10
	94	10
	149	10
	150	10
	AVG	10.04

For IPP thermal generation units, a standardized failure rate of 5% will be applied. This rate is in line with almost all the rates identified in the "Technical and Economic Characteristics" document. For hydroelectric generation units, a standardized failure rate of 2% will be applied.

Note that according to our standards (see table below), the failure rate specific to Senelec's generation units is considered to be high, and the failure rates set for IPPs and hydroelectric plants are in the upper zone. As various factors can influence the failure rate, such as extreme operating conditions (e.g., ambient temperature, inadequate maintenance caused by unavailability or other situation), we believe it would prudent to set the failure rate for IPPs according to the upper zone of our benchmark in the context of current rates specific to Senelec power plants, without knowing the cause(s).

Table 3-2: Standard failure rate

STANDARD FAILURE RATE		
	Hydro (%)	Thermal (%)
Low	1	2
Benchmark	2	3
High	2	5

Benchmark taken from the following document: ''Development of a Capacity Adequacy Standard'' which compiles data for over 1,500 generation units, produced by NERC - North America Reliability Council Stats (October 3, 2008) (North Island)

3.2.6 RENEWABLE ENERGY CONSIDERATIONS

REFERENCES

1. Tractebel Engineering report: Strategic study on integrating renewable energy into the technology mix and definition of implementation planning and strategy in Senegal for Senelec – September 2015.
2. "Vestas General Specifications of the Wind Turbine V126 3.45 MW" - document number PAR- # 21703609-v1.
3. NERC Report: Integration of Variable Generation Task Force (IVGTF) of the NERC Task 2.1 Report - Variable Generation Power Forecasting for Operations http://www.nerc.com/docs/pc/ivgtf/Task2-1(5.20).pdf
4. NERC Report: Flexibility Requirements and Metrics for Variable Generation: Implications for System Planning Studies. http://www.nerc.com/files/IVGTF_Task_1_4_Final.pdf
5. Integrating Renewable Electricity on the Grid - a Report by the APS Panel on Public Affairs (APS Physics).
6. NERC Report: "Accommodating High Levels of Variable Generation" August 2009
7. Managing the Wind – Wartsila.

SOLAR POWER PROFILE

Meteorological data

The solar potential in Senegal was analyzed in Tractebel's strategic study on the integration of renewable energy (section **Error! Reference source not found. Error! Reference source not found.** 1).

Senegal as a whole receives sufficient amounts of sunshine and is suited to the development of PV power plants. However, the country's northern region should be optimized as much as possible in order to increase the generation output of PV plants and thus reduce electricity generation costs.

List of existing and future solar power projects

The January 2017 Senelec generation plan anticipates a total of **323 MW** of capacity, according to the data in the table below. It should be noted that **233 MW** are to be installed by 2020 and an additional **90 MW** in the 2021-2023 period.

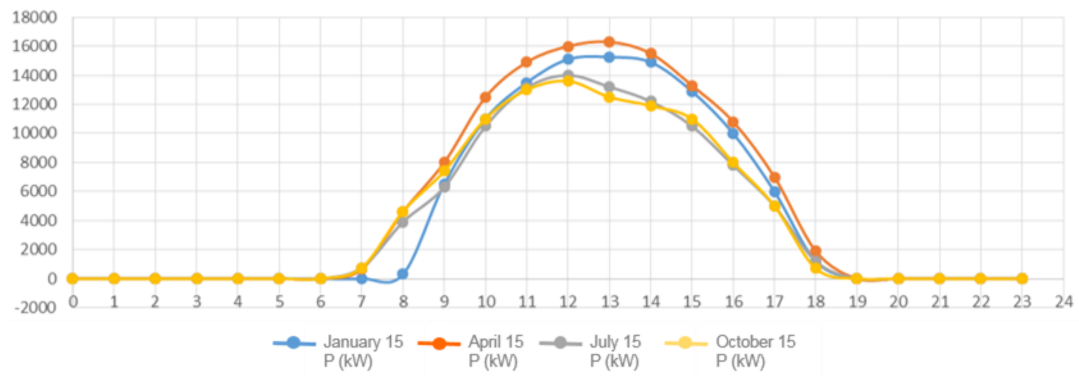
Table 3-3 : Existing and future solar power projects

EXISTING AND FUTURE SOLAR POWER PROJECTS			
Project	Power (MW)	Commissioning year	Status
Existing installed projects - End of 2016	40	2016	Installed
Solar IPP 1	29	2017	Decided
Solar IPP 2	29	2017	Decided
Solar IPP 3	20	2017	Decided
Solar Scaling 1	30	2018	Decided
Solar Scaling 2	30	2018	Decided
Solar Scaling 3	40	2019	Decided
Diass	15	2018	Decided
New Solar 1	30	2021	Planned
New Solar 2	30	2022	Planned
New Solar 3	30	2023	Planned
TOTAL	323		

Solar profile

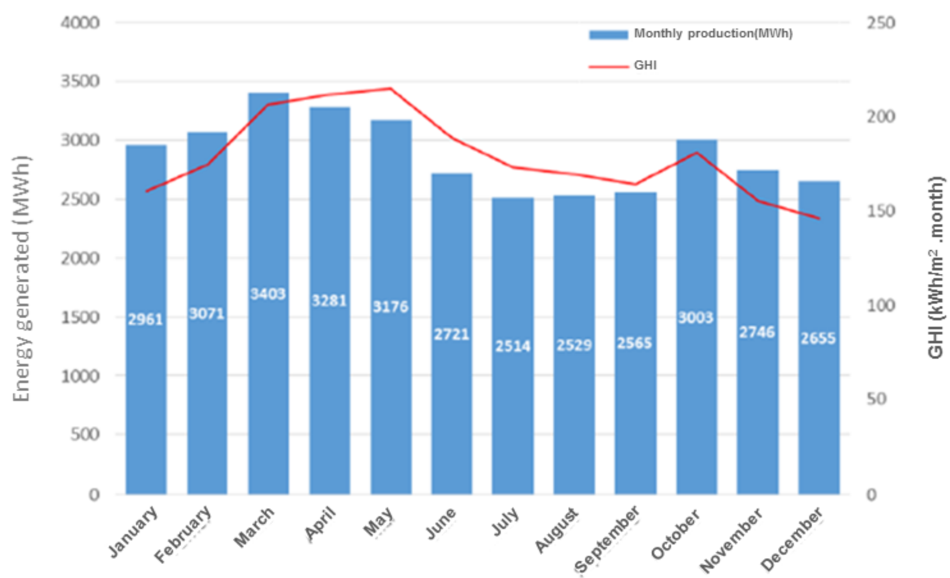
Four daily power profiles generated from typical 20 MW solar power plants for four days of the year (Figure 31 of the Tractebel study) and monthly energy (Figure 32 of the same study) were used as starting data to establish the annual solar generation output. The four days used are represented in the following graph:

Figure 3-1: Injected power (kW) for typical 20 MW facilities



Moreover, the histogram below of the monthly energy produced was used:

Figure 3-2: Generation from a typical PV plant



The monthly energy values considered and which were extracted from Figure 30 (Tractebel figure number) for typical 20 MW facilities are summarized on the next page:

Table 3-4: Monthly energy generated and GHI for a 20 MW power plant

MONTHLY ENERGY GENERATED AND GHI FOR A 20 MW POWER PLANT		
Month	GHI = Global Horizontal Irradiation (excerpt from the red curve) GHI (KWh/m²/month)	Energy Generated Monthly (MWh) (extract from Tractebel bar graph - Figure 30)
January	2,580	2,961
February	2,800	3,071
March	3,375	3,403
April	3,400	3,281
May	3,005	3,176
June	2,775	2,721
July	2,700	2,514
August	2,650	2,529
September	2,600	2,565
October	2,900	3,003
November	2,490	2,746
December	2,375	2,655

To establish the annual solar profile, the four highest daily profiles were distributed across the months of the year, then weighted by the relative difference between the daily power they produced and energy data. The last column in the table below indicates which daily profile was used for each month of the year.

Table 3-5: Daily profiles

DAILY PROFILES				
Month	Energy Generated Monthly (MWh) (extract from Tractebel bar graph - Figure 30)	# of days	Energy Generated Daily (MWh)	Daily Profile Used for Each Month
January	2,961	31	95.516	1
February	3,071	28	109.679	1
March	3,403	31	109.774	2
April	3,281	30	109.367	2
May	3,176	31	102.452	2
June	2,721	30	90.700	3
July	2,514	31	81.097	3
August	2,529	31	81.581	3
September	2,565	30	85.500	3
October	3,003	31	96.871	4
November	2,746	30	91.533	4
December	2,655	31	85.645	4

The solar hourly profile data below represents one day per month for the 12 months of the year used to calculate and establish the energy and capacity output of a 20 MW wind farm.

Table 3-6: Solar hourly profile for each month of the year (kW)

SOLAR HOURLY PROFILE FOR EACH MONTH OF THE YEAR (KW)												
Hours	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.
0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	0.0	0.0	580.9	578.2	529.5	685.5	589.1	594.5	636.0	729.8	684.9	628.9
8	265.0	308.3	4,110.7	4,091.8	3,747.0	3,564.6	3,063.1	3,091.2	3,307.0	4,500.7	4,223.7	3,878.2
9	5,742.3	6,679.5	7,149.1	7,116.1	6,516.5	5,758.2	4,948.0	4,993.4	5,342.1	7,201.1	6,758.0	6,205.1
10	9,717.8	11,303.7	11,170.5	11,118.9	10,182.0	9,597.0	8,246.7	8,322.4	8,903.5	10,704.3	10,045.6	9,223.7
11	11,926.4	13,872.8	13,315.2	13,253.8	12,137.0	12,019.1	10,328.0	10,422.8	11,150.6	12,650.5	11,872.1	10,900.8
12	13,339.9	15,517.0	14,298.2	14,232.2	13,033.0	12,796.0	10,995.6	11,096.5	11,871.3	13,234.4	12,420.0	11,403.9
13	13,472.4	15,671.1	14,56.3	14,499.1	13,277.4	12,064.8	10,367.3	10,462.4	11,193.0	12,164.0	11,415.5	10,481.5
14	13,163.2	15,311.4	13,851.4	13,787.5	12,625.7	11,150.8	9,581.9	9,669.8	10,345.0	11,580.1	10,867.5	9,978.4
15	11,396.3	13,256.2	11,885.4	11,830.6	10,833.7	9,597.0	8,246.7	8,322.4	8,903.5	10,704.3	10,045.6	9,223.7
16	8,834.3	10,276.1	9,651.3	9,606.8	8,797.3	7,129.2	6,126.1	6,182.3	6,614.0	7,784.9	7,305.9	6,708.2
17	5,300.6	6,165.7	6,255.5	6,226.6	5,701.9	4,570.0	3,927.0	3,963.0	4,239.8	4,865.6	4,566.2	4,192.6
18	1,060.1	1,233.1	1,697.9	1,690.1	1,547.7	1,096.8	942.5	951.1	1,017.5	681.2	639.3	587.0
19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 3-7 : Daily capacity and energy

TABLE 3-8: DAILY CAPACITY AND ENERGY												
	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
Average daily capacity in MW	3.9	4.6	4.5	4.5	4.1	3.8	3.2	3.3	3.5	4.0	3.8	3.5
Daily energy in MWh	94.2	109.6	108.5	108.0	98.9	90.0	77.4	78.1	83.5	96.8	90.8	83.4
# of days	31	28	31	30	31	30	31	31	30	31	30	31

Table 3-9: Annual capacity/energy and capacity factor of a typical 20 MW facility

ANNUAL CAPACITY/ENERGY AND CAPACITY FACTOR OF A TYPICAL 20 MW FACILITY				
Maximum Capacity in MW	Annual Energy in MWh	# of Hours Considered	Annual Average Capacity MW	Capacity Factor
20	33,998.6	8,760	3.88	19.4%

WIND ENERGY PROFILE

List of wind projects

We evaluated the Taïba project (Sarreole wind farm near Taïba Ndiaye), which comprises 46 V126 model wind turbines with a capacity of 3.45 MW.

Table 3-10: Wind projects

WIND PROJECTS						
Phase	Installed Capacity (MW)	Type	Status	Priority	Reference Commissioning Year	Scenario 1
Sarreole 1	51.75	Wind	Decided	2.00	2018	01-01-2018
Sarreole 2	51.75	Wind	Decided	2.00	2019	01-01-2019
Sarreole 3	55.2	Wind	Decided	2.00	2020	01-01-2020

The project has a "decided" status. It is located about 20 kilometers from the coast. It should comprise 46 wind turbines and will be built in three phases. It was decided that 15 turbines at the Sarreole wind farm would be commissioned in 2018, 15 in 2019 and 16 in 2020, for a total of 158.7 MW of installed capacity by 2020.

Power curve of the VESTAS V126 3.45 MW wind turbine

For the Taïba project, a large wind turbine (blade diameter of 126 m and hub height of 117 m) designed primarily for regions with low to medium wind speeds, was considered.

The power curve used was taken from the general specifications of the 3.45 MW V126 wind turbine, with a noise mode of 0 (see reference **Error! Reference source not found.** in the References section).

Figure 3-3 : Power curve of the VESTAS V126 3.45 MW wind turbine

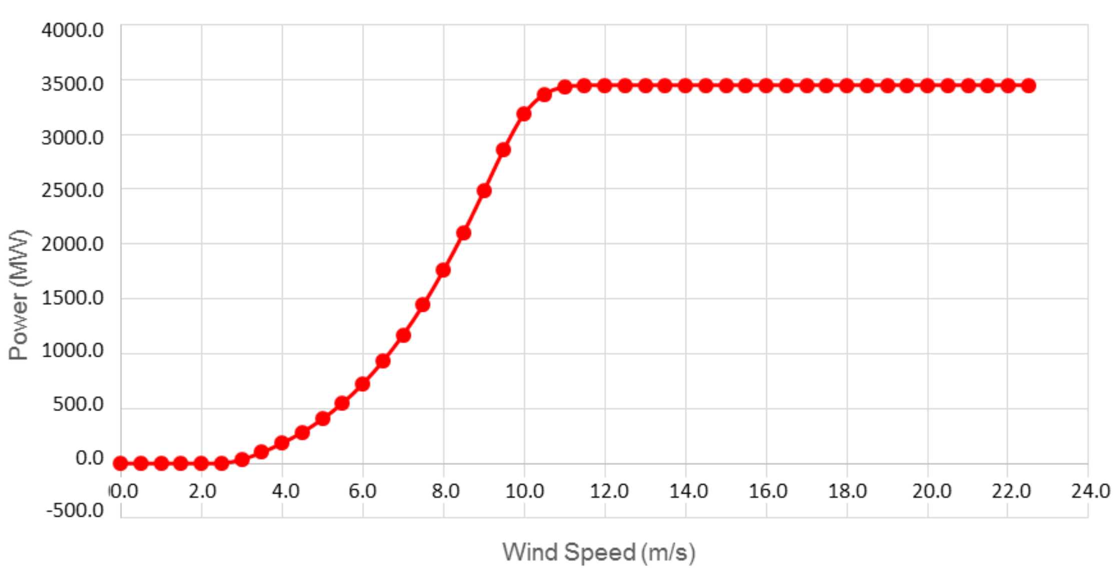


Table 3-11: Power curve of the VESTAS V126 3.45 MW wind turbine

POWER CURVE OF THE VESTAS V126 3.45 MW WIND TURBINE					
Wind Speed (m/s)	Power for Air Density of 1.225 (kg/ m^3)	Wind Speed (m/s)	Power for Air Density of 1.225 (kg/m^3)	Wind Speed (m/s)	Power for Air Density of 1.225 (kg/m^3)
0	0.0	10.5	3,366.0	21	3,450
0.5	0.0	11	3,433.0		
1	0.0	11.5	3,448.0		
1.5	0.0	12	3,450.0		
2	0.0	12.5	3,450.0		
2.5	0.0	13	3,450.0		
3	35.0	13.5	3,450.0		
3.5	101.0	14	3,450.0		
4	184.0	14.5	3,450.0		
4.5	283.0	15	3,450.0		
5	404.0	15.5	3,450.0		
5.5	550.0	16	3,450.0		
6	725.0	16.5	3,450.0		
6.5	932.0	17	3,450.0		
7	1,172.0	17.5	3,450.0		
7.5	1,446.0	18	3,450.0		
8	1,760.0	18.5	3,450.0		
8.5	2,104.0	19	3,450.0		
9	2,482.0	19.5	3,450.0		
9.5	2,865.0	20	3,450.0		
10	3,187.0	20.5	3,450.0		

Meteorological data

The meteorological and mapping data were taken from the Tractebel Engineering study on the integration of renewable energy in Senegal (ref. 1), which also analyzed the reliability of energy sources based on wind measurements.

The data used to establish the annual wind profile on an hourly basis are summarized in this section to enhance the understanding of the methodology.

It should be noted that the wind site is relatively similar on the North Shore of Senegal (Grande-Côte), as shown in the figure below:

Figure 3-4: Wind potential in Senegal on a 50 m measurement basis, taken from Figure 8 of the Tractebel study (ref. 1)

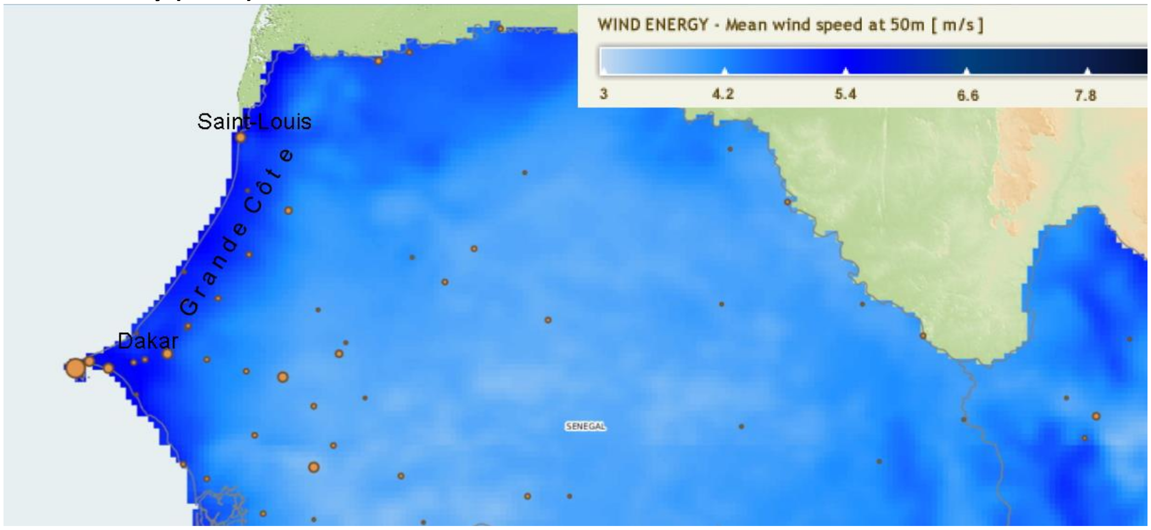
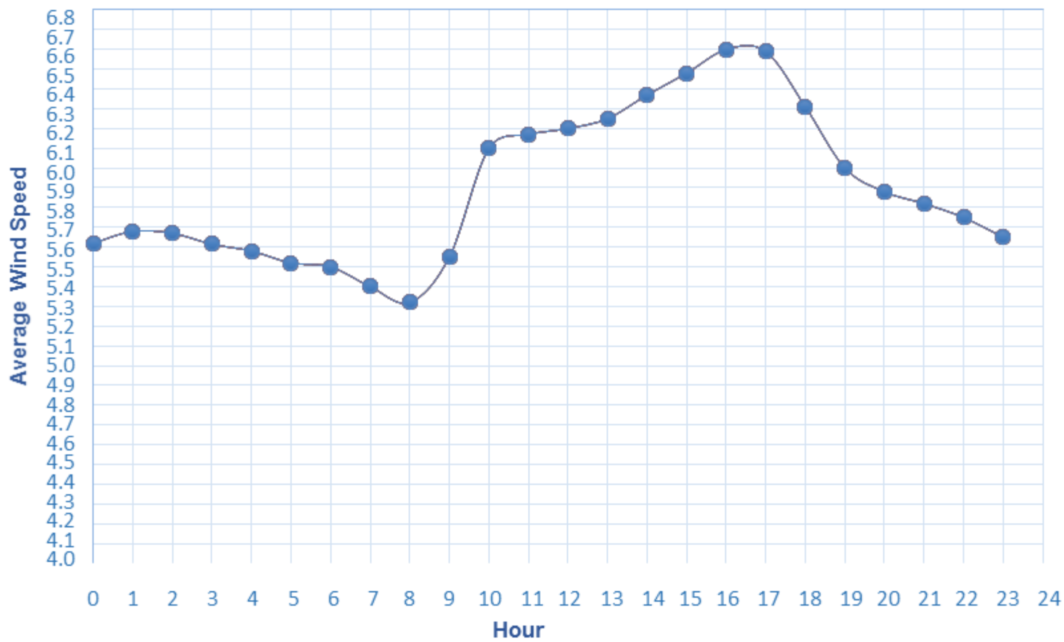


Figure 3-5: Location of the Sarreole wind farm

The Tractebel study indicates the similarity of the wind site on the North Shore. The average winds measured are between 5.2 and 5.98 m/s. These data were taken from measurements taken by a project proponent in Gantour and are considered to be reliable.

The profile shown below is of a typical day in the Gantour region, located 15 km from Saint-Louis (150 km from Taïba). A better estimate of generation output requires a breakdown of winds in number of hours per year for each wind speed. However, since these are the only data available, we used averages which are, according to the intrinsic appearance of the power curve, an underestimation.

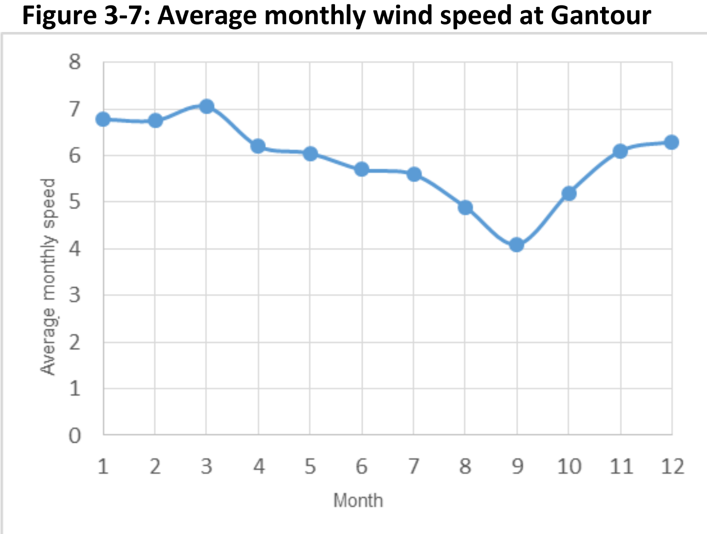
Figure 3-6: Typical daily wind profile measured at a height of 400 m, February 2007 to January 2008



Source: Tractebel Study - September 2015

The following monthly wind averages were used.

Figure 3-7: Average monthly wind speed at Gantour

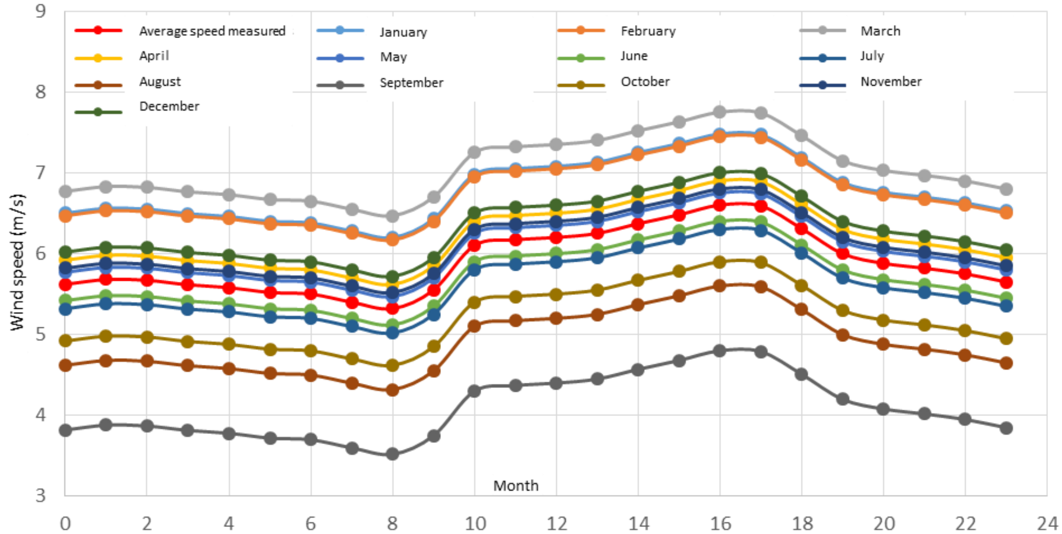


Month	Average monthly wind speed at Gantour
January	6.78
February	6.75
March	7.05
April	6.2
May	6.05
June	5.7
July	5.6
August	4.9
September	4.1
October	5.2
November	6.1
December	6.3

The data show that winds are weaker from June to October. However, it must be noted that measurements were averaged over all the days in a month. This makes it possible to determine a monthly trend. The distribution of wind speeds with their frequency and maximum/minimum values would have been more useful for the analysis.

Hourly wind values on a typical day were weighted by the monthly Gantour values to obtain an hourly profile for 12 months of the year.

Figure 3-8: Hourly wind profile for 12 months of the year



Average wind speeds are at their highest in January, February and March. This period corresponds to the load valley in Senegal. Conversely, wind generation is lower in August, September and October, the peak load period.

Wind profile

Power curves specific to the wind turbine model make it possible to calculate the hourly capacity for a typical day each month. Below are the summarized calculations for the Vestas V126 3.45 MW wind turbine. Since we considered 12 typical days, there is no need to duplicate every day of the year. Calculations were also performed for the 3.3 MW Vestas V126, 3.45 MW V117 and the 0.85 MW Gamesa G58, to compare capacity factors and critically examine assumptions and the choice of wind turbine model.

Table 3-12: Hourly power profile of a V126 3.45 MW wind turbine – by month

HOURLY POWER PROFILE OF A V126 3.45 MW WIND TURBINE – BY MONTH												
Hours	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
0	0.932	0.919	1.061	0.697	0.644	0.526	0.497	0.312	0.154	0.384	0.662	0.733
1	0.960	0.946	1.090	0.718	0.665	0.544	0.515	0.326	0.164	0.399	0.683	0.758
2	0.956	0.941	1.085	0.714	0.662	0.541	0.512	0.324	0.162	0.396	0.679	0.754
3	0.929	0.917	1.059	0.695	0.642	0.525	0.496	0.311	0.153	0.383	0.660	0.731
4	0.915	0.903	1.042	0.683	0.630	0.515	0.485	0.302	0.147	0.375	0.648	0.718
5	0.890	0.878	1.013	0.662	0.609	0.497	0.468	0.288	0.137	0.360	0.627	0.697
6	0.882	0.869	1.004	0.655	0.602	0.491	0.462	0.283	0.134	0.355	0.620	0.690
7	0.840	0.828	0.956	0.620	0.567	0.462	0.433	0.263	0.117	0.331	0.585	0.655
8	0.807	0.795	0.919	0.592	0.541	0.439	0.410	0.247	0.104	0.312	0.557	0.627
9	0.903	0.890	1.028	0.672	0.620	0.506	0.477	0.295	0.142	0.367	0.637	0.707
10	1.162	1.148	1.308	0.890	0.828	0.690	0.655	0.433	0.243	0.520	0.849	0.932
11	1.199	1.182	1.347	0.919	0.857	0.714	0.679	0.453	0.257	0.541	0.878	0.965
12	1.215	1.199	1.363	0.932	0.869	0.725	0.690	0.462	0.263	0.550	0.890	0.980
13	1.243	1.226	1.391	0.956	0.890	0.745	0.707	0.477	0.273	0.567	0.911	1.004
14	1.308	1.292	1.458	1.013	0.941	0.795	0.754	0.512	0.300	0.609	0.965	1.061
15	1.369	1.352	1.527	1.066	0.994	0.840	0.799	0.544	0.326	0.648	1.018	1.114
16	1.434	1.418	1.602	1.124	1.052	0.890	0.849	0.585	0.355	0.690	1.076	1.172
17	1.429	1.413	1.596	1.119	1.047	0.886	0.845	0.581	0.353	0.686	1.071	1.167
18	1.276	1.259	1.424	0.984	0.915	0.770	0.729	0.494	0.285	0.588	0.936	1.032
19	1.114	1.100	1.254	0.849	0.787	0.655	0.620	0.404	0.223	0.491	0.807	0.890
20	1.056	1.042	1.188	0.799	0.737	0.613	0.578	0.375	0.200	0.456	0.758	0.840
21	1.028	1.013	1.157	0.774	0.714	0.592	0.557	0.360	0.188	0.439	0.733	0.816
22	0.994	0.980	1.124	0.745	0.690	0.567	0.535	0.343	0.176	0.418	0.707	0.787
23	0.946	0.932	1.076	0.707	0.655	0.535	0.506	0.319	0.159	0.392	0.672	0.745
Average daily capacity in MW	0.895	0.882	1.012	0.674	0.624	0.515	0.486	0.314	0.167	0.382	0.640	0.709
Daily energy in MWh	25,79	25,44	29,07	19,58	18,16	15,06	14,25	9,29	5,02	11.26	18,63	20.57
# of days	31	28	31	30	31	30	31	31	30	31	30	31

Influence on capacity factor

In regions such as Quebec, wind turbines are widely spaced apart; therefore, wake effect is not taken into account. We are assuming that it is the same for installations in Senegal, especially since generation output is underestimated due to the use of average winds.

Energy and capacity factor

Annual energy, annual average capacity and capacity factor are calculated based on daily energy per month. The capacity factor is generation output divided by generation capacity, i.e. the annual power generated from the maximum wind turbine power.

Table 3-13: Generation output of a wind turbine

GENERATION OUTPUT OF A WIND TURBINE	
Wind turbine	V126 3.45 MW
Maximum capacity in MW	**3.45**
Annual energy in MWh	6,441.0
# of hours considered	8,760
Annual average power	0.735
Capacity factor	**21.3%**

Wind generation output

Based on the annual hourly profile of a wind turbine, the profiles in the modeling tool were used to conduct a supply-demand analysis. The estimate of both total and yearly wind generation output is summarized in the table below by Sarreole project phase:

Table 3-14: Generation output of wind projects

GENERATION OUTPUT OF WIND PROJECTS					
Phase	Installed Capacity (MW)	Reference Commissioning Year	Capacity Factor (%)	Estimated Annual Average Capacity MW	Estimated Annual Energy GWh
Sarreole 1	51.75	2018	21.3	11.03	96.6
Sarreole 2	51.75	2019	21.3	11.03	96.6
Sarreole 3	55.2	2020	21.3	11.76	103.1
Total in 2020	**158.7**	**2020**	21.3	**33.82**	**296.3**

INTEGRATION OF INTERMITTENT RENWABLE ENERGY (IRE) – CONTRIBUTION TO THE PEAK

Solar power considered at the peak

In Senegal, the daily peak occurs in the early evening hours, and the peak demand day occurs in mid-October, between 7:00 p.m. and 10:00 p.m. when PV power plants are not generating energy. Therefore, solar output will not contribute to the daily peak or annual peak.

Wind power considered at the peak

Peak demand occurs in mid-October. If considering the value of the typical day in October weighted by its monthly average, the value of the power produced at 8:00 p.m. would be 456 kW for one wind turbine, multiplied by the number of wind turbines commissioned during the year in question. Although possible, it is difficult to predict this value without more detailed wind data.

Furthermore, we used capacity over three months and not the hourly value since the peak is likely to occur between September and November. The potential instantaneous power over these three months is 397 kW. It must be multiplied by the number of wind turbines, which is more conservative than the peak hourly value. As stated in the projects table, it was assumed that 15 turbines would be commissioned at the Sarreole wind farm in 2018, 15 in 2019 and 16 in 2020, or 5.95 MW in 2018, 11.9 MW in 2019 and 18.24 MW in 2020.

However, considering the intermittent nature of wind power due to random weather patterns, it is recommended that wind potential be ignored in the planning mode when establishing maximum peak capacity.

SYNCHRONOUS RESERVE LEVEL WITH RESPECT TO INTERMITTENT RENEWABLE ENERGY

Considerations for the integration of IRE

This section has been condensed in the final version of this report. Therefore, we suggest that the reader consult the March 2017 report on supply and demand balance for details on the considerations involved in renewable energy fluctuations as well as the methodology.

According to the literature (NERC, PAS[1] physics report), the instantaneous generated capacity of a solar power plant can vary by 70% within a window ranging from 2 to 10 minutes, as clouds pass overhead (see the NERC report: “Accommodating High Levels of Variable Generation” - August 2009). Based on the January 2017 Senelec generation plan, the largest solar farms will be 30 MW in 2018 and 40 MW in 2019.

For solar, we have considered a 70% variation in the maximum power generated, although in fact it is the instantaneous power generated. We used the reasonable criterion of a 70% drop in the generation output of the largest solar farm, i.e. 30 MW in 2018 and 40 MW in 2019, since these solar farms are spread out.

Therefore, at the planning stage, when a cloud passes overhead, the level of solar fluctuation that should be compensated would be 28 MW in 2019. If an effective weather forecasting system can predict the fluctuation, then this fluctuation can be controlled by activating generation units at the right time, without affecting the primary reserve. Otherwise, this level will be compensated by the synchronous reserve already in place, if a sufficient quantity is available. In fact, this kind of fluctuation is managed in the same way as any other load fluctuation on the grid, the difference being that unless a highly effective weather forecasting system is in place, the fluctuation of IREs is less predictable than normal load variations, which can be better anticipated.

For wind, since only one wind farm has been decided at present, a sudden variation in wind resulting in a generation shortfall will be considered at the Sarreole wind farm, which will have an installed capacity of 158.7 MW in 2020. As for the value of the wind speed drop to be considered, it is difficult to use the increment value cited in the NERC report because the plants will not be geographically spread out in Senegal. Moreover, it also appears too conservative to consider a drop in wind affecting 100% of the installed capacity, which would imply a synchronous reserve requirement equal to the capacity of the wind farm, i.e. 158.7 MW.

Maximum wind fluctuations occur during storms, which can require the units to be shut off. These shutdown triggers result in severe variations over short periods (5 to 20 minutes). This type of storm is predictable; therefore, generation units can be added before the storm passes so that the system is ready to compensate for the variation in wind generation output forecasted by the weather forecasting system, a value that can be up to 100% of the wind farm's output.

However, in order to establish a safety criterion for daily fluctuations, and thus establish a sufficient level of synchronous reserve for most of the time, a drastic drop in wind speed of seven meters per second (speed reached 10% of the year) has been established as the criterion for this synchronous reserve requirement. This value is unlikely, and therefore the criterion is conservative but realistic.

Using the power curve of the Vestas V126 3.45 MW wind turbine, this speed is equivalent to a power output of 1,161 kW or 53.4 MW for the Sarreole farm, with a total installed capacity of 158.7 MW, or 34% of the installed wind power in 2020.

Therefore, we consider a potential fluctuation of around 54 MW for the synchronous reserve level as a basic criterion is sufficient (unless there is a storm), and the same considerations as for solar would apply as regards weather forecasting and the reserve.

Summary of maximum fluctuations in IRE versus synchronous reserve level

In summary, the potential maximum fluctuations according to the considerations indicated above are as follows:

- 28 MW, or 70% of the installed capacity of the largest solar farm
- 54 MW, or 34% of the installed capacity of the largest wind farm

These fluctuations are normally managed in the same way as load fluctuations. An effective weather forecasting system makes these fluctuations more predictable and greatly facilitates real-time management.

In managing generation, the reserve level must be adjusted according to IRE generation, but these criteria constitute an estimate of the upper limits (except in case of a storm) of reserve requirements.

Therefore, the reserve level to be considered for IRE would be a maximum of 54 MW, and this level must be taken into account when the wind reaches a speed of seven meters per second, which is the probable speed during 10% of the year. Not considering wind power, a reserve of around 28 MW would potentially be required once a day during the hour of maximum solar generation.

This upper limit estimate is valid based on our current knowledge, but will have to be readjusted depending on Senelec's experience with IRE development, especially with respect to weather fluctuations and forecasting. We recommend that Senelec obtain more recent wind speed distribution data for the siting of the planned facility and for each future facility in order to adjust these estimated values.

For optimal IRE integration, Senelec will require a weather forecasting system that is adapted to its situation, and must ensure that management of its generating facilities is flexible, primarily with respect to IRE, where contract clauses may need to be renegotiated given a more flexible utilization of generation units, both in terms of the frequency of stops/starts and reserve utilization.

RECOMMENDATIONS ON THE INTEGRATION OF RENWABLE ENERGY

Recommendations – Solar profile

It is important to note that PV generation can vary drastically over very short periods of a few minutes based on cloud passage.

Therefore, PV power plants do not provide the system operator with guaranteed power as they are inherently intermittent.

The disadvantages of that intermittence can be partially offset by implementing power storage solutions tied to the PV power plant or by integrating forecasting systems that can forecast irradiation conditions in the very short term. The forecasting system is definitely one element that Senelec must consider in order to efficiently manage its power plants.

Furthermore, an energy storage solution must be considered and will be discussed in section **Error! Reference source not found.**

Concentrated Solar Power (CSP) technology would also help to extend solar generation by a few hours and contribute to peak periods. CSP is an attractive option that can be applied particularly well in Senegal, notwithstanding economic considerations.

Recommendations – Wind profile

Using average wind speeds results in underestimating generation output. This affects the rate of penetration and hourly curtailment in the energy utilization analyses. We recommend to obtain wind speed distribution based on the number of hours per year in order to estimate a more realistic capacity factor.

The estimate is conservatively low. Knowing the distribution of wind speeds in number of hours per year is crucial to the appropriate choice of wind model and a more realistic calculation of potential wind energy generation in MWh. The Tractebel "Typical Meteorological Year TMY" study cites meteorological data over a 20-year period, which could be useful, once analyzed, in establishing a wind speed distribution in number of hours per year.

In daily generation planning, it is standard practice for the wind farm operator to install one or two weather towers at the farm to forecast and manage the farm’s energy.

Senelec must predict generation output within as short a window as possible for maximum accuracy (see section 3.2.6) using an effective weather forecasting system and historical data that is useful to establish wind project potential, instead of having these data remain private to wind farm owners.

Weather forecasting system recommendation

Weather forecasting is a vital tool for integrating IRE into an electricity grid if the grid is to maintain its flexibility and address the intermittent and uncertain nature of IRE.

The absence of proper forecasting and planning magnifies the challenges encountered during real-time operation. Furthermore, all the forecasting time windows (by year, week, day, hour, 30 minutes, 5 minutes, and second) are important, as explained above based on the NERC report "Flexibility requirements and metrics for variable generation: implications for system planning studies (August 2010)".

Given NERC's forecasting recommendations, and as there is no dispersion in Senegal since IRE generation is geographically concentrated (particularly with respect to wind energy), NERC recommends that these small systems, which have limited capability to exchange with neighboring networks, consider forecasting windows of one minute or second because of the impact of the imbalance from IRE fluctuations on the grid load and/or frequency. In these situations, it is advisable to consider forecasting systems specifically designed for the grid and its constraints, and to ensure these systems cover a sufficient amount of terrain in order to give network operators a warning of potential reliability risks. Different methods are discussed in this report.

In our opinion, it is essential that Senelec have the ability to predict generation output in as short a time window as possible for maximum accuracy, by using an effective weather forecasting system and historical data that is useful to the generation output of solar and wind projects.

3.2.7 ENERGY STORAGE

INTRODUCTION

Energy storage is a growing field with a wide range of applications, including the integration of intermittent renewables. Electricity storage is a complex field of expertise with multiple solutions.

First, let's start with one very important point: storing energy during periods when the sun and wind produce a lot of it in order to reuse it when solar/wind energy are not available is no longer an obstacle to the development of intermittent renewable energy; this was demonstrated in 2015 at COP21. It is also important to note that electricity storage is a tool that contributes to reducing greenhouse gas emissions, a major issue on which countries, industries, utilities, cities and municipalities are increasingly placing greater emphasis.

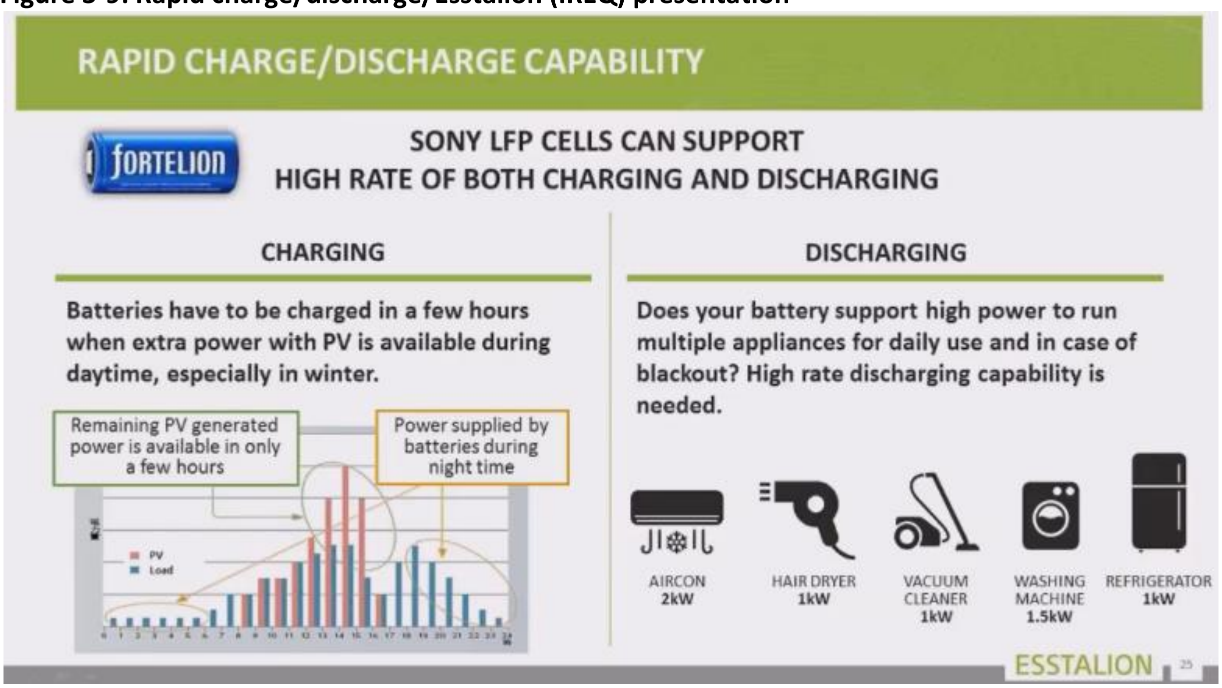
This section of the report takes stock of existing solutions that are installed or close to being commissioned. This section will give the reader a snapshot of the market and some appreciation of the possibilities. Examples of applications will be cited, particularly concerning intermittent renewable energy integration or electricity management, and all references are listed at the end of this section. This section will also discuss solutions that are thought to be applicable in Senegal with respect to IRE integration, isolated manufacturers and developing reserve capacity. We will primarily discuss high-capacity batteries, transforming electricity into a gas, solid or liquid hydrogen, flywheels, and hybrid diesel generator solutions coupled with solar power in remote locations. This section provides information to help understand the complexity and wide range of applications. The end of this section contains a number of recommendations that our research has led us to believe would be of interest and relevance to Senegal. A feasibility study specific to Senegal will certainly need to be carried out.

BATTERY SYSTEMS

Quebec has over 40 years of world-renowned expertise in battery technologies. Hydro-Québec and Sony Corporation – through the establishment of Esstalion Technologies – have developed a large-scale battery installed on the distribution network at the IREQ, Hydro-Québec's research institute.

At a conference, Karim Zaghib, Director General of the IREQ's Center for Excellence in Transportation Electrification and Energy Storage, made the point that a battery system can, among other things, compensate for fluctuating renewables and extend clean energy generation over a period of a few hours. This is particularly interesting since we know that peak demand in Senegal occurs in the early evening when solar generation is no longer possible. Below are some figures from Karim Zaghib's presentation (webinar available on YouTube; see References).

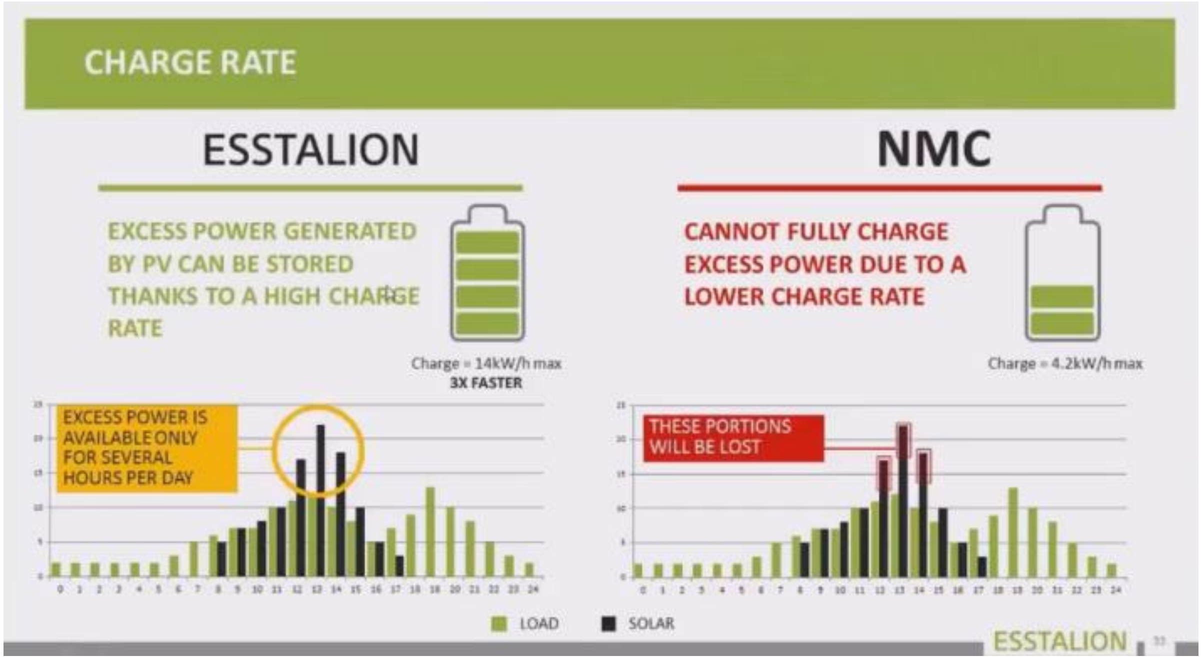
Figure 3-9: Rapid charge/discharge/Esstalion (IREQ) presentation



One of the most important factors for IREQ is safety. The researcher explains the benefits and especially the safety of the technology as a primary criterion for marketing. Historically, the stain on the battery's reputation has been that it is a significant fire hazard. Below is an example of a project that had to be halted because of a manufacturer's battery recall due to fire hazard. However, new batteries are becoming safer, such as the battery used by Tesla.

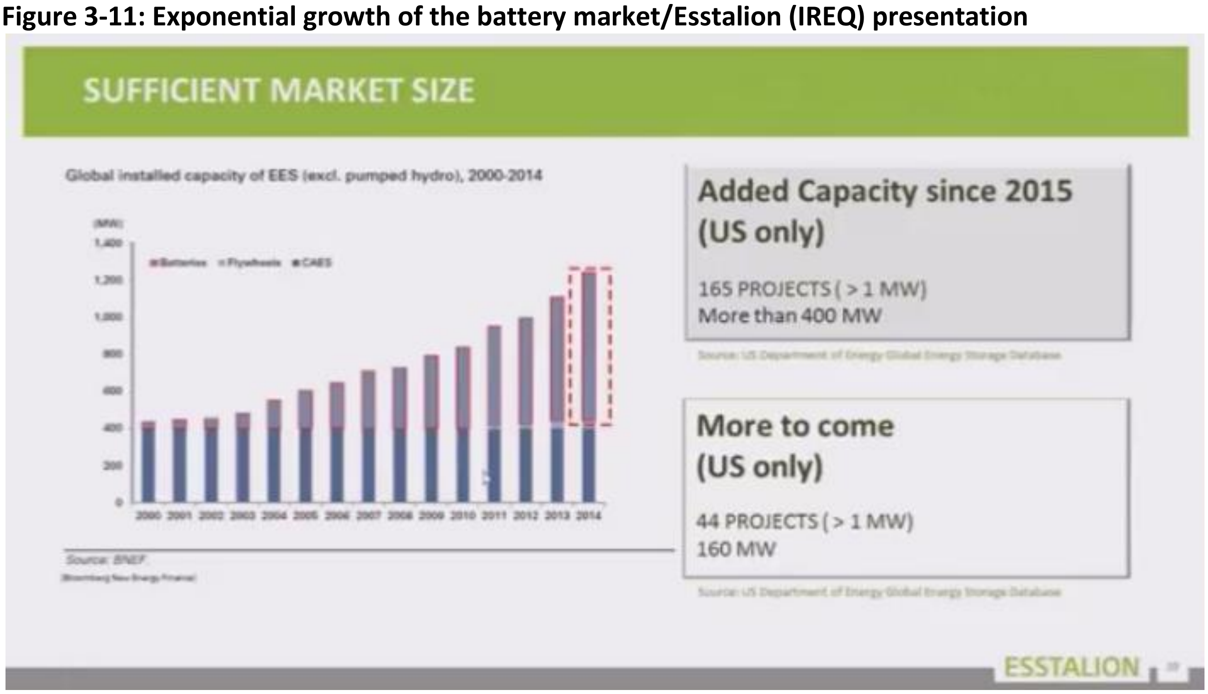
Batteries are becoming more thermally stable, and rapid charging is a key factor when looking at applications designed to compensate for IRE, which the latest battery technologies can do. The figure below compares the ESSTALION battery with TESLA's NMC battery, showing its ability to integrate IRE.

Figure 3-10: Batteries = a complement to IRE/Esstalion (IREQ) presentation



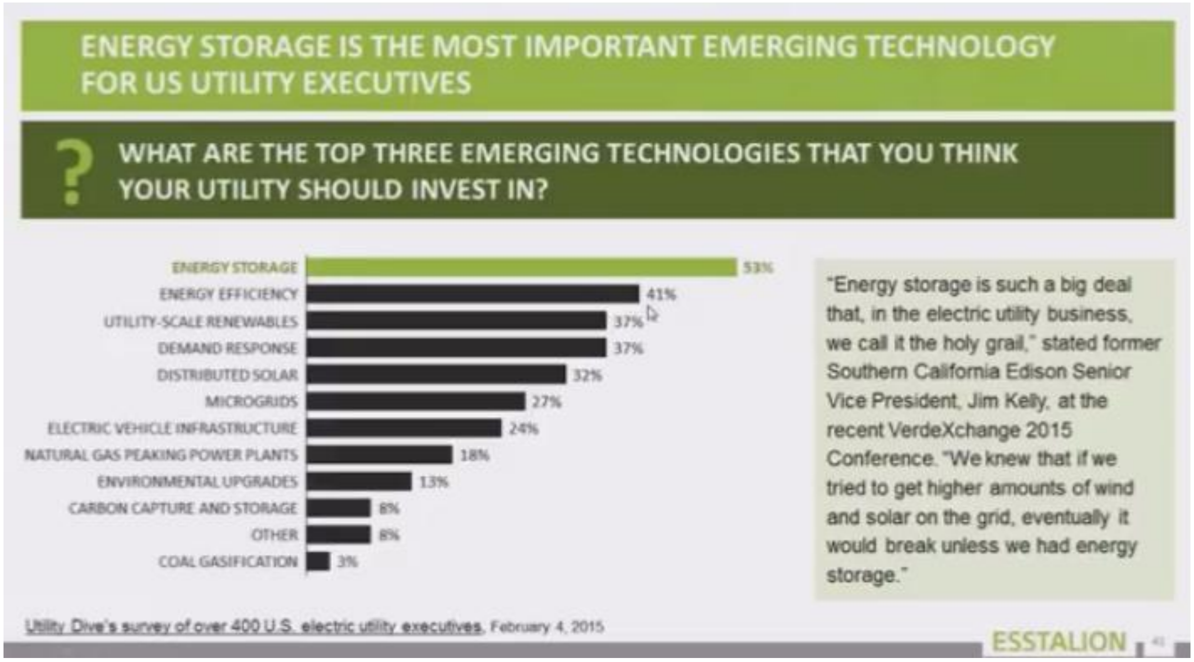
In the 2000s, the focus was on developing the flywheel. Today, the trend seems to be towards batteries. The market share of lithium ion batteries is growing exponentially, with increasingly broader applications.

Figure 3-11: Exponential growth of the battery market/Esstalion (IREQ) presentation



Investments are also turning towards energy storage. Over 400 North American utilities were asked the question: what is the top investment sector in the next 10 years? Energy storage topped the list with a score of 53%.

Figure 3-12: Energy storage is the top investment driver of North American firms/Esstalion (IREQ) presentation



As energy storage becomes more and more efficient, it has become a real strategy that utilities are already putting into action.

According to Mr. Zaghib, "solar, wind + batteries" and/or "battery connected to the electricity grid" applications will see strong development in the next 10-15 years, and Africa as a region is conducive to its development.

Figure 3-13: Off-grid vision = coupling of IRE + batteries + isolated grids/Esstalion (IREQ) presentation

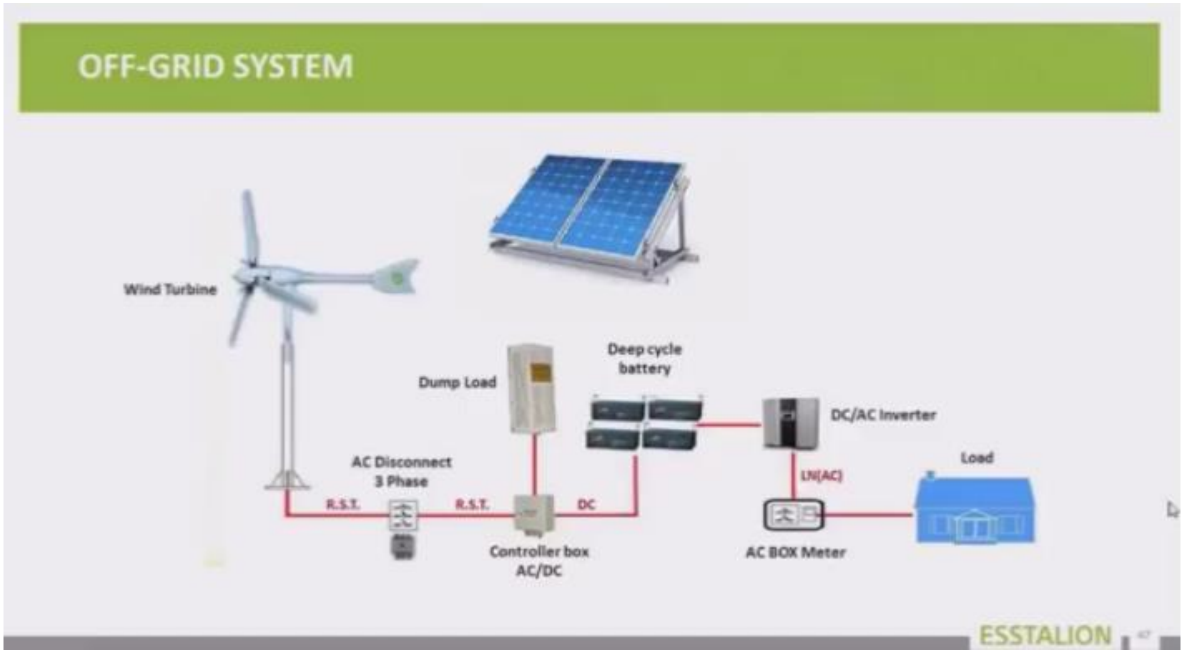
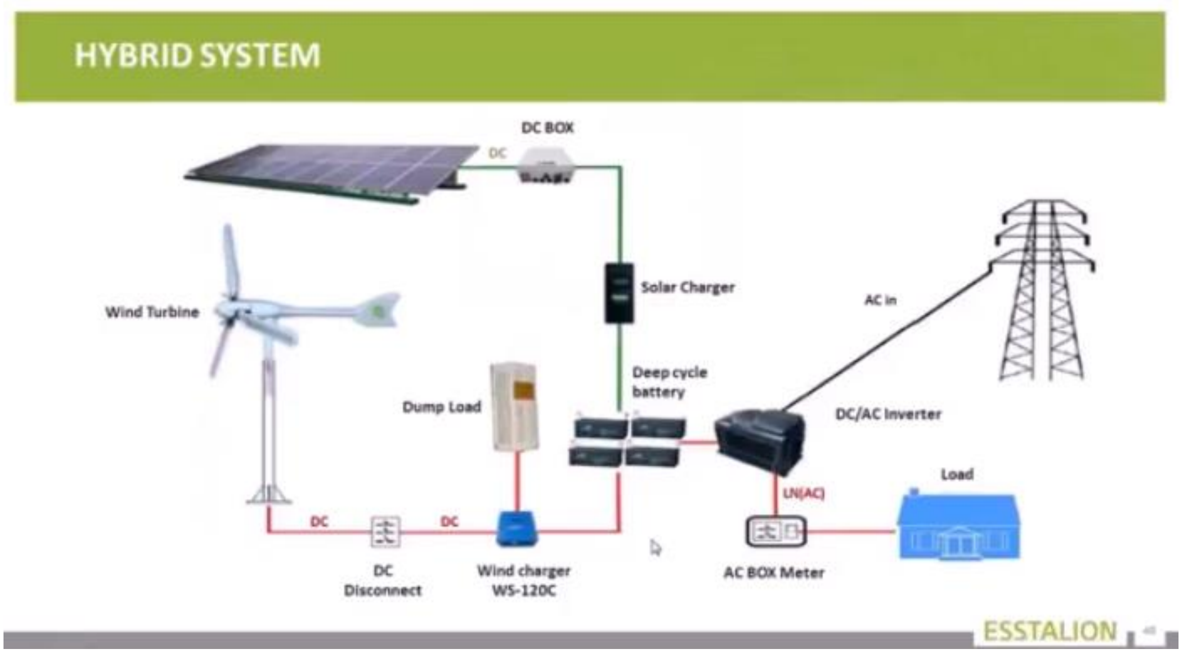


Figure 3-14: Hybrid vision = coupling of IRE + batteries + integrated grid/Esstalion (IREQ) presentation

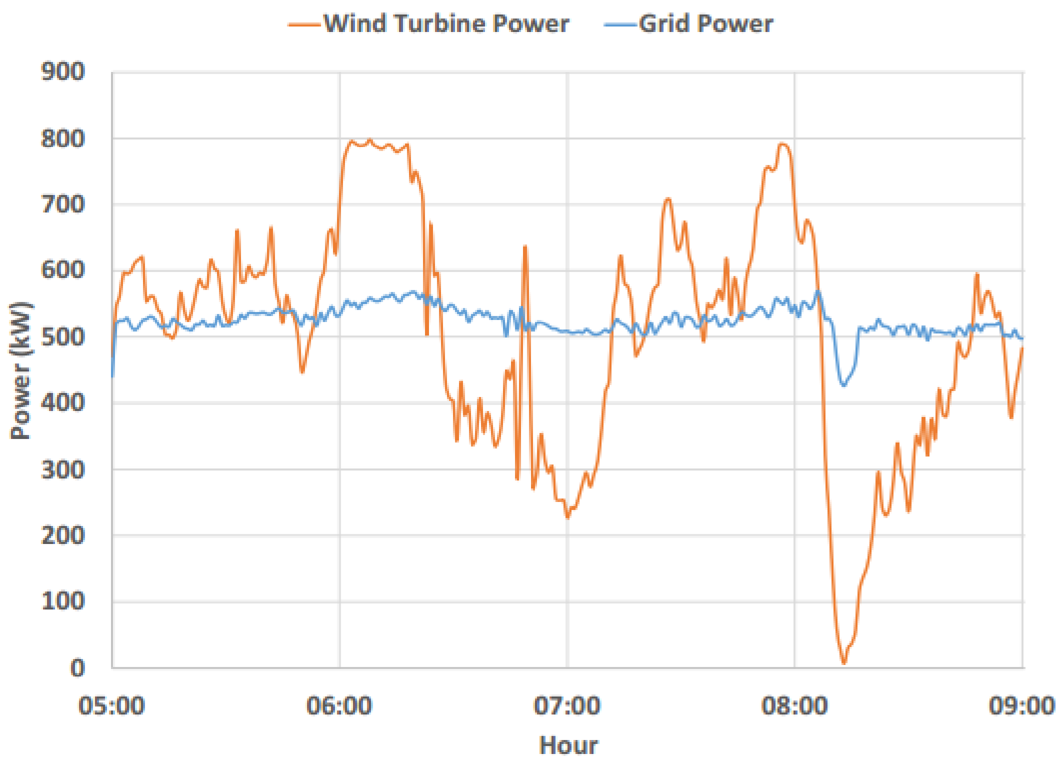


Wind + battery system

A demonstration of wind energy and energy storage was carried out in a Cowessess First Nations community in Saskatchewan, Canada.

An 800 kW ENERCON wind turbine was connected to a 400 kW Saft Battery system, for 744 kWh of capacity. Over the period of a year between 2014 and 2015, this wind turbine + battery system produced 2,158 MWh of energy, with a capacity factor of 30.8%. The capacity factor of the turbine alone was 31.8%. The study successfully demonstrated that the wind turbine + battery system can balance wind generation output. The lithium ion battery system responds to wind fluctuations in under one second, and regulates the variable output of the wind turbine by 65% to 78%. The figure below shows the regulation over a four-hour period, stabilizing generation at around 500 kW. Notice the rapid fluctuations in wind power, including a significant drop in wind that brings the power generated down to 0 kW in just minutes. This figure shows that the battery system can effectively compensate for wind fluctuations and can increase the penetration levels of solar and wind in an electric network.

Figure 3-15: Wind + battery to balance generation output/Case Study of the Saskatchewan Research Council, Canada



If the data from this experiment were extrapolated to a region with high wind potential, our analysis would show that a battery equivalent to half the power of the wind turbine (400 kW of battery for a 800 kW wind turbine) yields a capacity factor of 30.8%, close to that of the turbine alone, which would be 31.8%. This makes it possible to very effectively balance generation output and offset fluctuations almost completely.

Battery system integration for wind farms is an effective option, even if the technology is still in development. It should be noted that this technology has some issues, especially related to a battery system's fire hazard.

XCEL Energy carried out a similar project in 2009 by XCEL Energy in Luverne, Minnesota. It was the first project in the U.S. that installed a 1 MW battery system at an 11 MW wind farm. The article indicates that in the period 2009-2011, the system successfully stored and distributed energy. However, PATRP could not find specific data on the results of this project, both regarding generation output or the capacity factor. Therefore, it is difficult to assess without further research. However, the article states that due to defective batteries, the project had to be halted for 15 months, after two years of operation. The project has apparently resumed, but this could not be confirmed. The Japanese manufacturer "NGK Insulators of Nagoya" reportedly told its customers to stop using its batteries due to a fire hazard, as there had been a fire in Japan.

Finally, the "Notrees battery storage project" carried out in Texas in January 2013 involved a 36 MW battery sized for a 153 MW wind farm. This is the largest battery installed at a wind farm in the United States. Duke Energy reportedly paid US$ 22 million to install the battery system. The data indicates that the battery system could respond in 50 ms, but PATRP could not obtain more specific data on the capacity factor, regulation, and battery capacity in Ampere hours.

Solar + battery

<u>Lakeland Solar and Storage Project, near Cooktown, Queensland: commissioned in April 2017.</u>
In Australia, the Lyon Group has completed solar projects with a battery system.

This project is a 33 MWp solar park (PV panels) with a 1.4 MW/5.4 MWh lithium battery system. The project is connected to the grid by the 66 kV Lakeland substation.

After Lyon Group sold the project, Coenergy (building this AUD$ 42.5 million project) indicated that the aim of the project was to test operation of the solar farm + battery in off-grid mode. The battery system would provide up to five hours of power.

Figure 3-16: Photo of a solar park in Australia

PHOTO: The Lakeland project will comprise 41,440 solar panels and generate up to 13 megawatts of power. (Supplied: Conergy)

Kingfisher solar storage: under construction for an off-grid site and to power mines

On the heels of the success of the Cooktown project in northern Queensland, the Lyon Group is also developing one of the most sophisticated facilities in Kingfisher, combining PV panels, battery storage and a generation output management system. This project is located in the mining heartland of South Australia and will be connected to a network of operating mines.

The first phase is a 20 MWp farm of PV panels with a 2 MWh lithium battery system. This phase involves analyzing and evaluating the performance of the power plant, which operates under harsh desert conditions. Commercial operations are expected to begin in September 2017.

The second phase is a 100 MW solar park with a minimum 20 MWh of storage, which should begin commercial operations in late 2017. It should be noted that battery storage could be increased to 40 MWh considering fluctuations in the South Australian electricity market.

Lyon Group is also planning the largest facility of its kind with the following two projects, indicating that financing has been secured and construction is imminent:

- 330 MW solar park with a 100 MW/400 MWh battery system in Morgan, South Australia.
- 120 MW solar park with a 100 MW/200 MWh battery system in Roxby Downs, South Australia.

Tesla's Powerpack for solar projects

At present, Tesla has completed two solar park projects using the Powerpack system – one in Connecticut and one in Hawaii.

Hawaii

In early March 2017, Tesla completed a storage project that sells solar energy at night. The selling price is lower than Kauai Island Utility's cost of generation using diesel. The Kapaia Installation project has 13 MW of photovoltaic panels with a storage capacity of 52 MWh. Tesla has a 20-year contract with the utility at a price of 13.9 cents/kWh, cheaper than diesel plants at 15.48 cents/kWh and approximately half of 27.68 cents, the price consumers were paying for electricity in December 2016. The project is the largest by Tesla since the US$ 2 billion acquisition of the SolarCity Corp panel installer.

Figure 3-17: Photo of the PV + battery solar farm/TESLA (Hawaii) Kapaia Installation

Source: Kapaia Installation on Kauai Island

To put it in context, Hawaii has the highest electricity prices in the United States and has made the decision to move to 100% intermittent renewables by 2045. Therefore, in January 2017, AES Corp agreed to build a 28 MW solar park with a 20 MW battery.

Connecticut

A 15 MW project with a 1.5 MW/6 MWh Powerpack system for the Connecticut Municipal Electric Energy Cooperative is the largest combined project of its kind in the northeastern United States.

Powerpack for Southern California Edison

Tesla installed a 20 MW/80 MWh Powerpack system at the Mira Loma substation within a three-month period, in response to a gas leak at the Aliso Canyon gas storage facility.

The Powerpack's main application is to provide capacity and rapid response when natural gas is unavailable, resulting in increased network reliability that is improved during peak periods.

SCE will also be able to supply Powerpack energy to California's energy markets, including ancillary services for frequency regulation and spinning reserves.

Cost of projects using battery systems

PATRP developed the table below using the examples provided above. Where project costs were available, they were added in the "A few figures" column; they were then converted to euros. These costs are often taken from news articles or promotional fact sheets on the websites of the industries concerned; therefore, the accuracy of the costs is not guaranteed, but the table gives an idea of the order of magnitude.

Figure 3-18: A few figures on battery storage projects

Description	Place	Date	Some numbers	In euros
Wind				
800kW ENERCON wind turbine with 400 kW (Saft Battery) battery system for 744 KWh recharge	Regina. Saskatchewan, CANADA	2014	Wind turbine + battery: $5.5 million CAD (3.74 million euros) Wind turbine alone (800 * 1500 = 1.2 million euros)	2.54 million euros for the battery system
A 1 MW battery system installed in 2008 for an 11 MW wind farm	Luverne, Minnesota, USA	2009	Battery: $4.7 million USD (4.32 million euros)	4.32 million euros
A 36 MW battery system has been sized for a 153 MW wind farm	Notrees, Texas, USA	2013	Battery: $22 million USD (20.2 million euros)	20.24 million euros
Solar PV				
33 MWdc PV solar park + 1.4 MW / 5.4 MWh battery for isolated city	Lakeland solar project near Cooktown in far north Queensland	2017	$42.5 million AUD	28.9 million euros
120 MW solar park + 100 MW battery / 200MWh (the largest installation in the world: 3.4 million PV panels and 1.1 million batteries	Roxby in South Australia's Riverland	In progress	$250 million AUD for the solar park $100-150 million for storage	68-102 million euros
330 MW solar park + 100 MW / 400MWh battery (the world's largest installation: 3.4 million PV panels and 1.1 million batteries	Morgan in South Australia's Riverland	In progress	Battery + solar park: $1 billion AUD $700 million for the solar park $200-300 million for storage	136-204 million euros
TESLA				
13 MW solar park with 13 MW / 52MWh powerpack system Utility: KIUC	Kauai Island, Hawaii, USA	2017	?	
15 MW solar park with 1.5 MW / 6MWh powerpack system Utility: Connecticut municipal electric energy cooperative	Norwich, CT, USA	2016	?	
IREQ				
The prototype has a capacity of 1.2 MW and can store 1.2 MWh	Varenne, Quebec, CANADA	2015	The cost of the equipment is more than $2 million CAD and a lifespan of up to ten years	1.5 million euros
TESLA				
Installation of a 20 MW / 80 MWh powerpack system at the Mira Loma substation within 3 months in response to a gas leak at "Aliso Canyon gas storage" Utility: Southern California Edison (SCE)	Ontario, CANADA	2016	?	

Source: Notrees battery storage project

- An 800 kW ENERCON wind turbine with a 400 kW Saft Battery system, for a 744 kWh load.
    - Total project cost = CAD$5.5 million
- Wind to Battery Project (XCEL Energy Company) in Luverne, Minnesota, 2009.
    - Cost of the one megawatt battery system installed in 2008: **USD$4.7 million**
- Notrees Battery Storage Project (Duke Energy Company), Texas, 2013
    - Cost of the 36 MW battery system installed in 2013: **USD$22 million**
- Australia – 120 MW solar park with a 100 MW/200 MWh battery system, 330 MW with a 100 MW/400 MWh battery system - See table below:

Figure 3-19: A few figures on the largest solar + battery projects in Australia

Location	Morgan	Roxby Downs
Solar		
Capacity	330MW (max active power injection 160MVA plus 110MVA (two lines)	120MW (max active power injection 80MVA)
Approximate investment value	$700m	$250m
People during construction	270	200
Number of panels	3.4 million	1.3 million
Number of foundations required	273,000 (combined)	273,000 (combined)
Kilometres or wiring in total required	1,847Km of AC & DC cabling (combined)	1,847Km of AC & DC cabling (combined)
Estimate of the value of services that will be sourced from SA*	$100 million	$48 million
Storage		
Capacity	100MW / 400MWh (depending on config.)	100MW / 200MWh (depending on config.)
Approx. investment value	$200-$300m	$100m - $150m
Number of batteries	1.1 million	1.1 million

Source: Project to build the largest solar park (330 MW) with a 100 MW battery system in Australia

Comparative cost of different battery manufacturers/technologies

IREQ has produced a comparative table of battery costs per MWh. Note that the costs are between USD$109 and USD$168 per MWh.

Figure 3-20: Battery cost comparison/Esstalion (IREQ) presentation

COST ANALYSIS OF ESS MARKETED PRODUCTS : PRODUCT COST

USD $

Items	ESSTALION	NEC/A123	BYD	LG	Samsung	Kokam	Tesla
Battery Type	LFP/Gr	LFP/Gr	LFP/Gr	NCM/Gr	NCM/Gr	NCM/Gr	NCM/Gr
Battery Cost (kWh)	400	450	350	150	180	200	180
Module Cost (kWh)	600	650	450	350	380	350	380
Initial 1MWh/1MW System cost (US$k)	1 160	1 210	1 010	910	940	910	940
<1MWh keep after 15,000 cycles>							
Initial Capacity Required	1,79 MWh	2,15 MWh	3,59 MWh	3,83 MWh	3,83 MWh	3,83 MWh	5,15 MWh
*DOD Calculation	100%	100%	80%	60%	60%	60%	50%
15y Remaining cap.	60%	50%	40%	50%	50%	50%	40%
*PCS Efficiency	93%	93%	87%	87%	87%	87%	97%
System cost 1 MWh after 15k cycles (US$k)	1 635	1 958	2 176	1 901	2 016	1 901	2 519
Lifetime energy stored	15 000 MWh	15 000 MWh	15 000 MWh	15 000 MWh	15 000 MWh	15 000 MWh	15 000 MWh
Lifetime energy cost (/MWh)	US$109	US$131	US$145	US$127	US$134	US$127	US$168

Source: Esstalion (IREQ) presentation

DIESEL GENERATOR + SOLAR PANEL HYBRID SOLUTION FOR OFF-GRID SITES

It is necessary to discuss diesel generator and solar panel hybrid solutions, whether or not they are connected to the grid, since this solution allows large manufacturers that self-power to drastically reduce their electricity generation and maintenance costs, as well their greenhouse gas emissions.

DEIF India recently commissioned a 3.6 MW project using DEIF's ASC plant management solution for systems powered by the grid, diesel, and solar energy. The end customer wanted to use solar energy even when the grid is unavailable. Backup energy was provided by diesel generators, and the solar equipment was designed to supply energy at the same time, with load sharing between both groups. The ultimate goal was to allow the consumer to distribute the load between the solar PV group and the diesel generator, with or without energy from the electricity grid, making maximum use of solar energy to optimize savings, even in the event of grid failure.

Another example is the announcement by Toronto mining giant IAMGOLD of a large-scale hybrid solar-fuel project for their Essakane mine in Burkina Faso. The company plans to build a 15 MW solar power plant coupled with the existing 57 MW thermal plant, and is aiming for a 15% solar generation rate within two to three years (the article referred to is from January 2017). However, this is not their first project of this kind; they have developed another similar project at the Rosebel gold mine in Suriname, South America, with a 5 MW PV solar park.

FLYWHEEL

This is a very old method of converting electrical to kinetic energy, with the advantage of an instantaneous charge/discharge. This method has been implemented in recent years to facilitate the integration of renewable energy.

For example, in one business area in Toulouse, Levisys tested ten storage machines on a 170 kW solar panel field and on a 15 kW wind farm.

Below is an excerpt from the article found at www.industrie-techno.com (see reference):

Physicists Michel Saint-Mleux and Pierre Fessler have added their grain of salt to the latest technologies. Their cylindrical flywheel, developed in partnership with Airbus Industries, is made of carbon fiber and kept in magnetic levitation in a vacuum chamber, limiting energy loss as much as possible. It is set in motion by an electric motor that reaches 14,000 revolutions per minute in a few minutes, yielding ten kilowatts of power with an optimal efficiency of 98%, according to its designers. The kinetic energy accumulated can be converted to electricity on demand by stopping the flywheel, which will then feed supply to an electric generator.

Thus, in the event of a drop in wind or sunlight due to a cloud, for example, the flywheel will almost instantaneously take over from the wind turbines or solar panels, to even out generation output and maintain the correct voltage. A photovoltaic power plant and a wind farm managed by Cofély Ineo near Toulouse will be regulated by ten Levisys flywheels (100 kW/hr) plus lithium ion batteries that will store surplus generation. For Pierre Fessler, a former researcher at CNRS and CERN, the battery is effective, but the flywheel is more environmentally friendly and sustainable. He promises his system will provide 500,000 cycles without maintenance, equal to 20 years of use. Levisys has raised 14.6 million euros to build a 4,000 m² factory that should produce a hundred flywheels each year in its production workshops starting in summer 2016. [Our translation]

STORING ENERGY AS HYDROGEN – SUPPLY FOR BUILDINGS (AT CURRENT STAGE)

Below is an excerpt from an article on the website of French company Sylfen: http://sylfen.com/en/technology/

THE REVERSIBLE ELECTROLYSER

At the heart of Sylfen's technology lies a reversible electrolyzer that brings new functionalities: (i) it works as an electrolyzer to store electricity in the form of hydrogen and (ii) as a fuel cell to produce electricity and heat from that hydrogen or biogas.

With a single device, we are now capable of storing large quantities of energy, and give it back to users whenever there is a need. This makes both installation and maintenance more economical.

This technology, developed in France, has demonstrated the best electrolysis performance in the world.

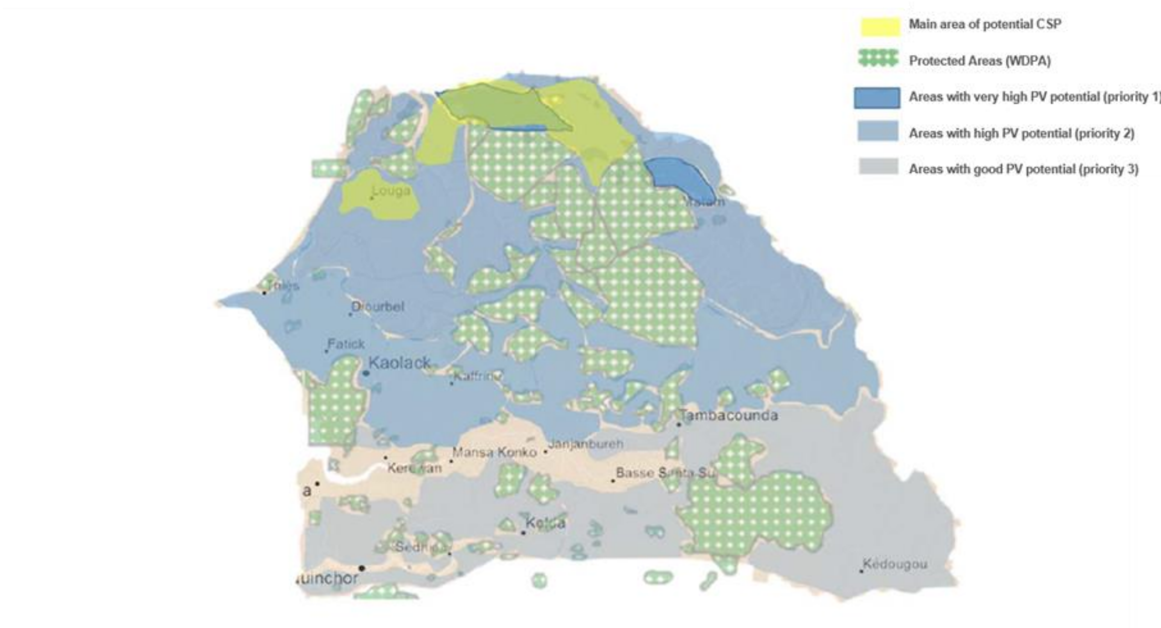
CONCENTRATED SOLAR POWER (CSP) TECHNOLOGY

Tractebel has already conducted an assessment of the CSP potential:

Following an analysis of the most important elements that determine the feasibility of CSP plants, it appears that the region with the best theoretical CSP potential is Senegal's northern region, which has the highest DNI in the country. The proximity of the electricity grid will be another condition of the feasibility of CSP plants to ensure that the energy produced has somewhere to go. However, since the maximum annual DNI (1,650 kWh/m²) is 15% lower than the minimum annual DNI value commonly accepted by CSP project developers (1,900 kWh/m²), the cost of electricity produced by CSP plants in Senegal is expected to be high. [Our translation].

The map below summarizes the areas most conducive to the development of PV and CSP plants.

Figure 3-21: Areas in Senegal most conducive to solar PV and CSP batteries/Tractebel



In conclusion, Senegal has significant and promising potential for the development of PV plants. The potential for the development of CSP plants is however limited and does not constitute a preferred development axis.

Source: Tractebel

In our opinion, although Tractebel indicates that it is not a priority area of development, we recommend examining the solutions implemented in Spain in particular, and evaluating the investment costs before discarding this very promising technology, for the following reasons:

- Given the amount of sunshine it gets, Senegal is conducive to this technology.
- Periods of high electricity demand are in the early evening. CSP technology would integrate solar generation during peak demand.

Below is an excerpt from an article on Les Échos:

http://m.lesechos.fr/redirect_article.php?id=19780-168-ECH&fw=1

"They anticipate a worldwide installed capacity of more than 6,000 MW by 2015 (354 MW today), with an ultimate generation cost of solar thermal kWh of 5.5 cents euro. Meanwhile, the cost of PS10 should be between 14 and 20 cents euro. This price will nonetheless be profitable given the very favorable Spanish tariff structure: solar electricity will be purchased at 18 cents per kWh." [Our translation]

PUMPED HYDRO ENERGY STORAGE

This technology accounts for 97% of the world's electricity storage. Pumped storage is a method of electricity storage based on the principle of pumping water into storage basins when energy demand is low. Pumped storage power plants (PSP) are proven and very effective at present. Hydraulic pumping for energy transfer is the most mature method of stationary energy storage. However, it is not particularly suited to the integration of IRE or applicable in regions of the world with no hydroelectric capacity or sufficient elevation change.

ENERGY STORAGE RECOMMENDATIONS

Energy storage to limit curtailment, increase the penetration rate and provide additional reserve

In Senegal's situation, knowing the generation planning and results of the grid stability study, there are situations in which IRE and/or thermal coal generation should potentially be curtailed. It is obvious that an energy storage system would be beneficial to help even out generation output, making renewable energy output easier to control and less sensitive to or even independent of weather fluctuations, within the design limits of the storage system (capacity, charging speed and autonomy). The implementation of a storage system connected to a power plant or distribution network covering several IRE sources requires a more in-depth analysis. According to current data, wind power certainly has a greater need for reserve capacity. Installing a battery system to reduce fluctuations to be covered is undoubtedly the direction to pursue. However, there is a considerable advantage to a storage system that uses a large capacity battery, for example, as the IREQ is proposing, on the flexibility this provides to the grid and which can be used to offset IRE with additional reserve capacity in the event of an outage at a generating plant, and also assist with frequency regulation since new technologies respond almost instantaneously (within a second).

More careful reflection is required, however, since failures can be unpredictable, and the battery system must be relied on at all times in order to be considered a synchronous reserve. On the other hand, if the battery is used during peak demand periods, its charge level cannot be guaranteed for the synchronous reserve. However, given the rapid charging and response of the latest battery technologies, it has been technically proven that an energy storage system can help to maintain the frequency of an electricity grid.

An energy storage feasibility study in Senegal with a technical and economic component should cover frequency regulation, and facilitating the integration of intermittent renewable energy. In our opinion, this study should also calculate the size of a battery system for the 158 MW Sarreole wind farm, and assess the expenses and cost-effectiveness of such a system.

Hybrid solar panel solutions for large off-grid energy consumers and reduced electricity generation costs

Given that a number of large energy consumers such as mines are self-powered, hybrid solutions coupled with a PV panel farm require further examination. Evidence of reductions in electricity generation costs has been demonstrated in several places around the world.

Solar power plants using CSP technology

In addition to the economic aspect, and since CSP technology is less sensitive to weather fluctuations, its use in Senegal, where electricity demand is highest in the early evening, can extend generation time by several hours. Obviously we think that in the short term it would be prudent to carry out an economic feasibility study (perhaps with stakeholders in Spain who recently took this direction) primarily to assess the investment costs before ruling out this technology that is promising and adequate to Senegal's weather conditions.

Energy storage references.

Wind turbine + battery

1. Case Study - of Wind and Storage Demonstration in a First Nations Community, Cowessess First Nation

- CANADA, close to Regina
  http://www.nrcan.gc.ca/energy/funding/current-funding-programs/cef/4983
- Video of Saskatchewan Research Council (a partner)
  https://www.youtube.com/watch?v=UE7varh2VZY

2. 11 MW farm with a 1 MW battery
   Wind-to-battery project, Luverne Minnesota, USA

Risk of batteries catching fire – Wind-to-battery project stops then restarts

- Article in the Star Tribune:
  http://www.startribune.com/minnesota-wind-farm-battery-going-back-online/188416921/

3. Notrees battery storage project
   https://www.duke-energy.com/our-company/about-us/businesses/renewable-energy/wind-energy/notrees-battery-storage-project

Solar + battery

Australia

Lakeland Solar Project near Cooktown - Built

http://reneweconomy.com.au/worlds-biggest-solar-storage-projects-planned-australia-95528/

http://www.lyoninfrastructure.com/cooktown.html

http://www.abc.net.au/news/2017-03-24/experimental-solar-battery-could-take-regional-towns-off-grid/8383900

Kingfisher Project 120 MW (20 MW Stage 1 and 100 MW Stage 2) – Under construction

http://www.abc.net.au/news/2016-07-23/solar-plant-to-store-power-in-shipping-container-sized-batteries/7654856

Project to build the largest solar park (330 MW) with a 100 MW battery system in Australia –financing completed

Kapaia Installation on Kauai Island, Hawaii

https://www.bloomberg.com/news/articles/2017-03-08/tesla-completes-hawaii-storage-project-that-sells-solar-at-night

Video

https://www.bloomberg.com/news/articles/2016-02-16/solarcity-to-use-tesla-s-batteries-to-enable-solar-at-night

Tesla's Powerpack + renewable energy

https://www.tesla.com/fr_CA/utilities

https://www.tesla.com/sites/default/files/pdfs/en_US/Tesla_KIUC-Case%20Study-2017.pdf

Battery + substation

TESLA POWERPACK + substation

https://www.tesla.com/sites/default/files/pdfs/en_US/Tesla-SCE-Powerpack%20Case%20Study-2017.pdf

Hydro-Québec and Sony Corporation - through Esstalion Technologies:

http://news.hydroquebec.com/en/press-releases/799/a-first-prototype-for-esstalion-technologies-inc/

Webinar hosted by the Global Sustainable Electricity Partnership and presented by Dr. Karim Zaghib, Director of Energy Storage and Conversion at Hydro-Québec's research institute, IREQ.

https://www.youtube.com/watch?v=YlFdDHZdXJU

Videos below:

https://www.youtube.com/watch?v=WO6S1SM029M

https://www.youtube.com/watch?v=WJ7E1ogQIsI

https://www.youtube.com/watch?v=ORiqyCQUGYg

http://news.hydroquebec.com/en/press-releases/799/a-first-prototype-for-esstalion-technologies-inc/?fromSearch=1

Figure 3-22 : Article on the Hydro-Québec site/ESSTALION project (IREQ)

Montréal, June 8, 2015

Press Release Share Tweet

Esstalion Technologies Inc.

Testing of the first large-capacity energy storage prototype

Large-capacity energy storage system prototype

Esstalion Technologies will soon begin testing the first prototype of a large-capacity energy storage system. The prototype has a capacity of 1.2 MW and can store 1.2 MWh, equivalent to the daily consumption of 23 Québec homes.

This large-scale energy storage system will meet electricity demand during peak consumption periods and facilitate the integration of renewable energy onto the grid.

The prototype is made up of a container measuring 16.2 metres (53 feet) that consists of 576 battery modules, an inverter to convert the current, a transformer to adjust the storage system voltage to that of the grid, and control and protection equipment. The battery modules are manufactured by Sony and use Hydro-Québec's lithium iron phosphate technology.

Using a container (see photo) will allow the storage system to be moved by truck for quick on-site deployment.

Testing begins this summer

Tests will be carried out in summer 2015 to analyze storage system performance during charging and power and energy injection onto the grid.

Initially, testing will be done on the low-voltage network of the Esstalion Technologies laboratory, set up at Hydro-Québec's research institute in Varennes, Québec. Trials will then be conducted on a 25-kV distribution test line at the research institute.

This is a milestone for this joint venture, set up by Sony Corporation and Hydro-Québec in June 2014.

Source: ESSTALION project (IREQ)

Flywheel

Gabriel-Octavian Cimuca. Flywheel energy storage system associated with the wind generators. Engineering Sciences [physics]. Arts et Métiers ParisTech, 2005. English.

https://tel.archives-ouvertes.fr/pastel-00001955/document

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https://www.sciencesetavenir.fr/nature-environnement/developpement-durable/un-stockage-qui-pallie-aux-intermittences-du-soleil-et-du-vent_18425

Knowing how to store energy when the sun and wind produce a lot of it to replenish energy when they run out is no longer an obstacle to the development of renewable energies. Research continues on high-capacity batteries, converting electricity to gas or solid/liquid hydrogen, and electricity management using smart grids.

The commercial launch of two innovations, one from a French startup and the other from a multinational, were announced at COP21. They have entered segments that were still stagnant. In December 2015, Levisys launched the first real-life experimentation of its "flywheel". The flywheel is not a new concept. Flywheel technology converts electrical to kinetic energy, and has the advantage of instantly charging/discharging. Levisys is currently testing 10 storage machines on a solar panel field with a capacity of 170 kWh and on a 15 kW wind farm.

Storing energy as hydrogen – Supply for buildings (at current stage)

http://sylfen.com/en/technology/

THE REVERSIBLE ELECTROLYZER

At the heart of Sylfen's technology lies **a reversible electrolyzer** that brings new functionalities: (i) it works as an **electrolyzer** to store electricity in the form of hydrogen and (ii) as a **fuel cell** to produce electricity and heat from that hydrogen or biogas.

With a single device, we are now capable of storing large energy capacities, and give it back to users whenever there is a need. This makes both installation and maintenance **more economical**.

This technology, developed in France, has demonstrated **the best electrolysis performance in the world**.

Energy storage for off-grid sites = complementary battery storage (short term) and hydrogen (long term)

http://encyclopedie-energie.org/articles/stockage-d%E2%80%99%C3%A9nergies-renouvelables-sous-forme-d%E2%80%99hydrog%C3%A8ne-pour-sites-isol%C3%A9s

Products for off-grid sites

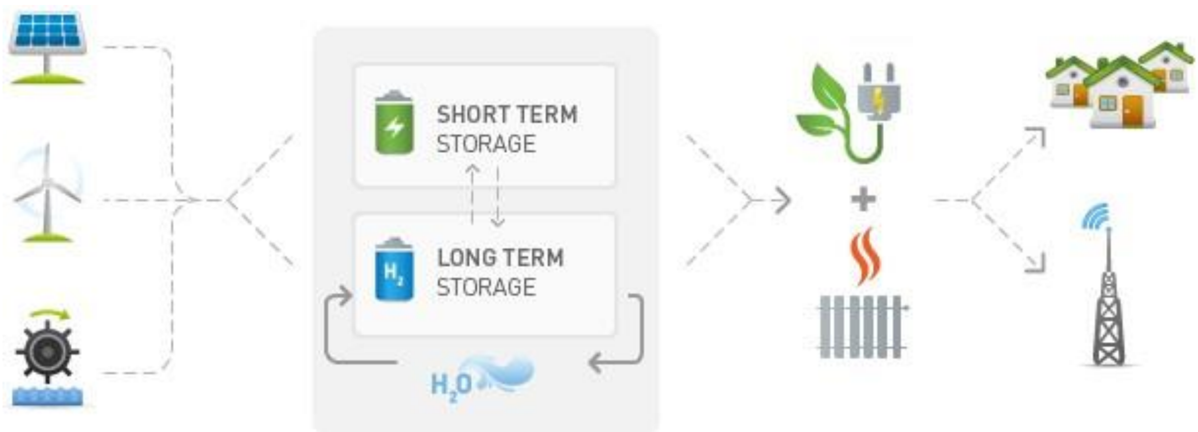
http://atawey.com/en/produit.html

TWO-PHASE OPERATION:

1- During periods of high production, the system stores all the renewable energy in batteries. When these batteries are full, **the excess energy is converted into hydrogen** by electrolysis, and then securely stored at low pressure and in large quantities for several months.

2- During periods of low energy production (winter, rainy season, etc.), when demand is at its highest and the production of intermittent renewable energy at its lowest, **the energy is restored via a fuel cell**. It is therefore possible to avoid the use of fossil fuels (electric generator).

With the ATAWEY system, **energy adapts to uses, and not the reverse**.



Hybrid fuel project

http://energyandmines.com/2017/01/powering-iamgolds-essakane-mine-in-burkina-faso-with-solar/

http://energyandmines.com/2017/03/new-renewable-energy-for-mine-project-iamgold-essakane-to-benefit-from-largest-hybrid-plant-in-africa/

https://www.chadbourne.com/Renewable_Energy_Near_Mines_projectfinance

http://www.danvest.com/wind-diesel.pp

http://www.danvest.com/documenten/Study.pdf

Hybrid solution: Diesel generator coupled with solar via an SMA controller

https://www.sma.de/en/industrial-systems/hybrid.html

Video

https://www.youtube.com/watch?v=eK73eXvXRvE

https://www.deif.fr/land-power/cases/ground-breaking-solution-in-hybrid

Concentrated solar panels

Tractebel report

http://m.lesechos.fr/redirect_article.php?id=19780-168-ECH&fw=1

Wind turbine regulation

Thesis: Ye Wang. Evaluation of the performance of wind turbine frequency adjustments in the electrical system: application on an island [Original title: *Évaluation de la performance des réglages de fréquence des éoliennes à l'échelle du système électrique : application à un cas insulaire*] Autre école centrale de Lille, 2012. French.

https://tel.archives-ouvertes.fr/tel-00778698/document

3.2.8 HYDRAULIC GENERATION CONSIDERATIONS

Hydroelectric generation using retention dams can generally increase available capacity on demand, and all the more so during peak demand. On the other hand, this type of generation cannot deliver this capacity continuously if the available energy is limited by annual precipitation. The contribution required to cover peak capacity load will be established in the capacity balance. In the case of the energy balance, it must be verified that there are enough additional generating facilities available to supply the energy demand of the load.

It is important to note that hydroelectric plants have average annual and monthly generation output profiles that differ according to the specific water-flow conditions of the waterway on which they are installed and the presence or absence of a storage tank. In the absence of average monthly profiles, for the purposes of this study, PATRP considered that the hydraulic plants' capacity would be available at the peak for calculating the P Max reserve. Note that the concept of average power is considered for different daily or hourly analyses, including with respect to the level of IRE penetration or curtailment of coal-fired power.

Senelec will have to obtain the average monthly profiles of all the hydroelectric power plants and apply them to the different models, and thus confirm that the average monthly capacity levels can meet the demand with the necessary margins in each month of year.

Of course, flexibility in managing the capacity of these facilities will also have to be considered in conjunction with other stakeholders based on the time of year or even time of day.

3.2.9 THERMAL GENERATION CONSIDERATIONS

INTRODUCTION

Thermal generation, when available, i.e. outside of planned and random outages, can deliver capacity and energy on demand. However, each generating plant has different technical and economic characteristics, and the use of these generation units must be planned taking into account different technical and economic characteristics, such as the variable cost of generation. It is important to consider that contractual obligations may also dictate usage priority according to take-or-pay clauses.

The placement of generation units taking demand into consideration will be discussed in section 3.3.1, and in section 3.5.4, on supply and demand balance in the different models.

CHARACTERISTICS OF THERMAL GENERATION COMPARED TO INTERMITTENT RENEWABLE ENERGY

Generation units must be added to achieve supply and demand balance. In this context, the objective of this section is to compare the different types of thermal generation added, to ensure optimal compatibility with intermittent renewable energy sources. This compatibility is expressed in the thermal energy source's ability to both compensate for rising/falling solar levels each day and also to provide a synchronous reserve to offset IRE fluctuations (passing clouds, increased/decreased winds).

References

- A May 2014 brochure produced by ENEA CONSULTING on electrical and thermal generation ("*Les moyens de production d'énergie électrique et thermique* ») for Plan Éco Énergie Bretagne.
  http://www.plan-eco-energie-bretagne.fr
- **Black and Veatch** report ***"Cost and performance data for power generation technologies"***
- Article on wind management and backup, on a Belgian website: "*Gestion de l'éolien et son backup*"
  http://www.leseoliennes.be/economieolien/yieldBU.htm
- Wartsila - Combustion Engine vs. Gas Turbine – Part Load Efficiency and Flexibility
  http://www.wartsila.com/energy/learning-center/technical-comparisons/combustion-engine-vs-gas-turbine-part-load-efficiency-and-flexibility
- Wartsila - Combustion Engine vs. Gas Turbine – Ramp Rate
  http://www.wartsila.com/energy/learning-center/technical-comparisons/combustion-engine-vs-gas-turbine-ramp-rate

Overview

This section provides context for different types of generation that can contribute to a generation reserve within the framework of IRE management. For a description of the different types of generation, we recommend reading the May 2014 brochure on electrical and thermal energy by ENEA CONSULTING for Plan Éco Énergie. It is available in French only at the following website: www.plan-eco-energie-bretagne.fr

Normally, the most efficient power plants (ramp-up capacity and high efficiency) are used in stock as synchronous reserves. The practice involves running thermal power plants at below their nominal capacity and varying the capacity of all thermal power plants slightly around this set-point.

So-called "fired" thermal power plants (coal, fuel oil, gas) supplying a steam turbine have a low ramp rate at start-up. It takes about an hour to reach maximum capacity.

In the electricity grid, the ramp rate of combustion turbines (gas/fuel oil) is therefore often used to supply peak electricity.

Combined cycle plants have the advantage of achieving higher efficiencies compared to simple cycle combustion turbines, and provide an alternative to thermal power plants, as well has having less of an environmental impact.

Combustion engines are highly responsive: it takes just a few minutes for them to reach maximum power and the units are very flexible and easy to install.

Hydroelectric stations have a high ramp rate and start in a few seconds. Therefore, when coupled with storage capacity, hydroelectric stations offer great power generation flexibility with the same responsiveness.

Assumptions

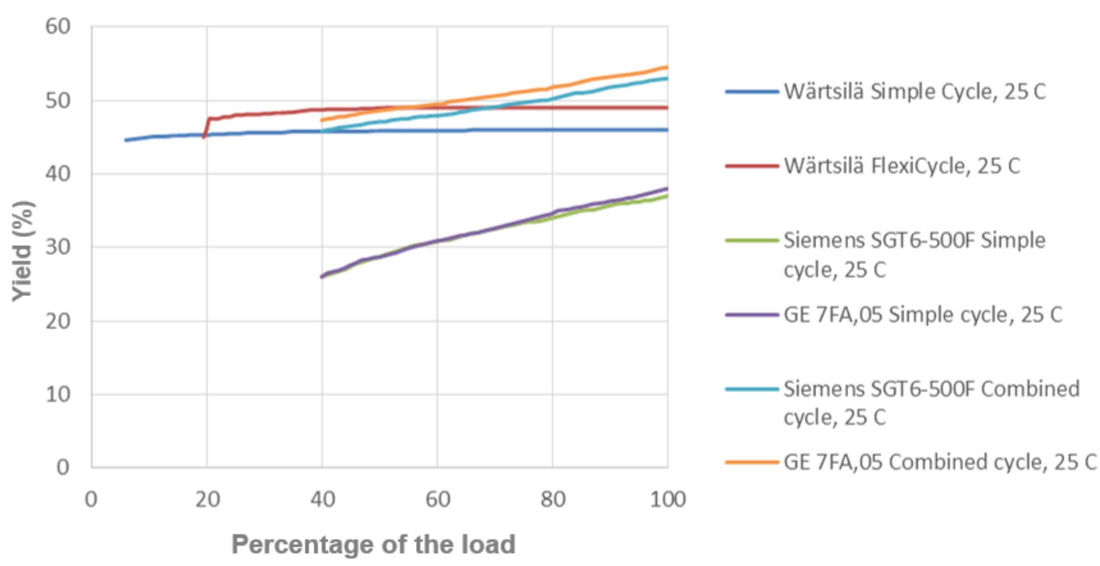
The best types of power plants that can supply a generating reserve to help manage IRE are as follows:

- Combustion engine (in our case, DUAL convertible natural gas unit)
- Simple or Combined Cycle Gas Turbine (CCGT)
- Hydroelectric plants

Efficiency

Detailed information on efficiency can be found in the March 2017 supply and demand balance report. In summary, according to Wartsila, after conducting a study comparing partial load performance (see 3.2.9, tab **Error! Reference source not found.**, References section), the efficiency of combined cycle turbines decreases to below 50% when the load is lower than 60% of capacity. The efficiency of combustion, simple and combined cycle turbine engines are shown below.

Figure 3-23: Efficiency of gas turbines and combustion engines according to load



Source: Graph from Wartsila website (see references).

Gas, simple and combined cycle turbines cannot operate below a partial load of 40%; however, efficiency at partial loads is much better with combined cycle turbines, with a performance that is similar and even superior to combustion engines. Wartsila's generation type on this comparative graph is a "Flexicycle" plant with several combustion engines connected to a steam turbine. As the load decreases, individual engines within the Flexicycle generating unit can be shut down, and the engines that remain in operation can generate at full load, retaining the generating unit's high efficiency. Unlike gas turbines, Flexicycle power plant efficiency is above 48% all the way down to 23% of full load. Beyond the minimum load for the Flexicycle steam turbine, the engines will operate in simple cycle mode. Thus, the output of a 300 MW Flexicycle plant, for example, can be turned down to only 18 MW, thereby providing greater output flexibility than gas turbines.

Ramp-up and start rates

Thermal or conventional coal-fired power plant

According to Black and Veatch's “Updated Cost” report, the full load rate of thermal power plants is about 2% per minute in spin mode (low ramp rate) and the minimum load is about 40%.

Figure 3-24: Cost and performance projection - pulverized coal-fired power plant

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-Yr)	Heat Rate (Btu/kWh)	Construction Schedule (Months)	POR (%)	FOR (%)	Min Load (%)	Spin Ramp Rate (%/min)
2008	3040	–	–	–	–	–	–	–	–
2010	2890	3.71	23.0	9,370	55	10	6	40	2.00
2015	2890	3.71	23.0	9,370	55	10	6	40	2.00
2020	2890	3.71	23.0	9,370	55	10	6	40	2.00
2025	2890	3.71	23.0	9,000	55	10	6	40	2.00
2030	2890	3.71	23.0	9,000	55	10	6	40	2.00
2035	2890	3.71	23.0	9,000	55	10	6	40	2.00
2040	2890	3.71	23.0	9,000	55	10	6	40	2.00
2045	2890	3.71	23.0	9,000	55	10	6	40	2.00
2050	2890	3.71	23.0	9,000	55	10	6	40	2.00

Table 9. Emission Rates for a Pulverized Coal-Fired Power Plant

SO_2 (Lb/mmbtu)	NO_x (Lb/mmbtu)	PM10 (Lb/mmbtu)	Hg (% removal)	CO_2 (Lb/mmbtu)
0.055	0.05	0.011	90	215

Source: Black and Veatch, Cost and Performance Projection for Pulverized Coal-Fired Power Plant (606 MW)

Gas turbines

According to Wartsila data, the fastest gas turbine models can produce 30% of their capacity in seven minutes and 100% in thirty minutes. This must be put into context using the order of magnitude in the Black and Veatch report, which is noticeably faster at 22.2% per minute. The Black and Veatch report lists the start capabilities and ramp rates of various conventional generation units. The start rate for a gas turbine is 8.33% per minute in spin mode, with a 23% quick start ramp rate.

These ramp-up variations are possible when the steady state of the turbine is reached (at autonomous speed).

The ramp rate for a combined cycle plant is a combination of the combustion turbine ramp rate and steam turbine ramp rate, which will be explained below. Start times can be faster from one manufacturer to another, but the rate is a compromise between ramp-up capacity and start time. For example, according to the Black and Veatch report, the water heating start will take about 76 minutes from start-up to full load on the combined cycle. The combined ramp rate from minute 62 to minute 76 is shown by GE to be about 5% per minute for a conventional hot start. Some combined cycle turbines have a faster start-up (around 54 minutes compared to a 76-minute conventional start), but in this case the high load combined ramp rate is 2.5% compared to 5%. Once the unit is online and up to temperature, the expected ramp rate is 5%.

Below is an excerpt from the Black and Veatch report "Cost and performance data for power generation technologies”.

Gas Turbine (211 MW): spin ramp rate 8.33% per minute and quick start ramp rate 22.2%.

Figure 3-25: Cost and Performance Projection for a Gas Turbine Power Plant

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (Btu/kWh)	Construction Schedule (Months)	POR (%)	FOR (%)	Min. Load (%)	Spin Ramp Rate (%/min)	Quick Start Ramp Rate (%/min)
2008	671	–	–	–	–	–	–	–	–	–
2010	651	29.9	5.26	10,390	30	5.00	3.00	50	8.33	22.20
2015	651	29.9	5.26	10,390	30	5.00	3.00	50	8.33	22.20
2020	651	29.9	5.26	10,390	30	5.00	3.00	50	8.33	22.20
2025	651	29.9	5.26	10,390	30	5.00	3.00	50	8.33	22.20
2030	651	29.9	5.26	10,390	30	5.00	3.00	50	8.33	22.20
2035	651	29.9	5.26	10,390	30	5.00	3.00	50	8.33	22.20
2040	651	29.9	5.26	10,390	30	5.00	3.00	50	8.33	22.20
2045	651	29.9	5.26	10,390	30	5.00	3.00	50	8.33	22.20
2050	651	29.9	5.26	10,390	30	5.00	3.00	50	8.33	22.20

Table 3. Emission Rates for a Gas Turbine Power Plant

SO_2 (Lb/mmbtu)	NOx (Lb/mmbtu)	PM10 (Lb/mmbtu)	CO_2 (Lb/mmbtu)
0.0002	0.033	0.006	117

Source: Black and Veatch, Cost and Performance Projection for a Gas Turbine Power Plant (211 MW)

Combined cycle plants

A combined cycle start rate is around 2.5% per minute. In spin mode, the ramp rate can reach 5% per minute in a combined cycle. Note that the ramp rates for gas turbine alone are still faster (the same as indicated above).

Figure 3-26: Cost and Performance Projection for a Combined-Cycle Power Plant

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-Yr)	Heat Rate (Btu/kWh)	Construction Schedule (Months)	POR (%)	FOR (%)	Min. Load (%)	Spin Ramp Rate (%/min)	Quick Start Ramp Rate (%/min)
2008	1250	–	–	–	–	–	–	–	–	–
2010	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2015	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2020	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2025	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2030	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2035	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2040	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2045	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2050	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50

Table 5. Emission Rates for a Combined-Cycle Power Plant

SO_2 (Lb/mmbtu)	NO_x (LB/mmbtu)	PM10 (Lb/mmbtu)	CO_2 (Lb/mmbtu)
0.0002	0.0073	0.0058	117

Source: Black and Veatch, Cost and Performance Projection for a Combined-Cycle Power Plant (580 MW)

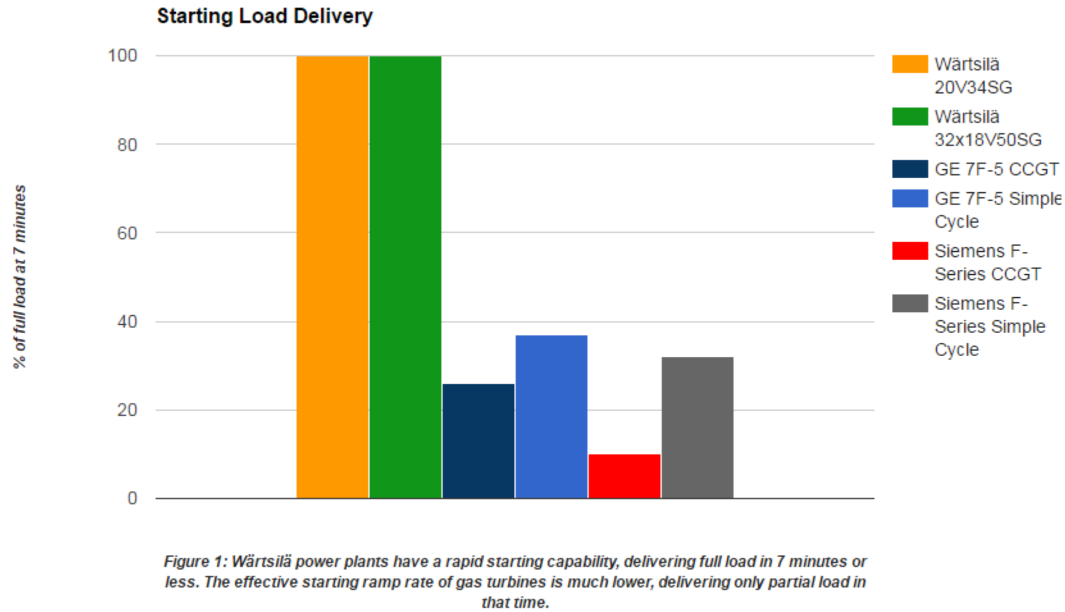
Combustion engine

Combustion engines have a high start speed. Some manufacturers such as Wartsila report a ramp rate of 50% of engine power per minute, which is considerably faster than gas turbines.

Combustion engines can make up for a loss in wind generation output, and have a quick start.

With solar generation, the variation in solar power throughout the day is known, and generation can be planned by regulating capacity and the number of generation units.

Figure 3-27: Starting load comparison



The high speed of Wartsila engines would therefore provide a significant advantage over gas turbines.

Integration of IRE and reserve capacity of less than 10 minutes

To integrate solar generation, ramp-down thermal production must be decreased at sunrise and ramp-up thermal generation increased at sunset.

For solar power, the highest hourly ramp-up is 31% of the installed capacity of the facility, and the greatest variation is 26% when the sun goes down, according to the typical curves of a 20 MW facility (data from the Tractebel report).

As indicated, rapid fluctuations in wind must be covered by synchronous reserves. However, since decreased wind speeds can be predicted through short-term weather forecasting, generating units that perform well over a wide range of capacities and can start in less than 10 minutes would be suitable for managing foreseeable variations in wind and solar output.

For rising and falling levels of sunshine, the system must have a reserve capacity from inactive power plants that can start quickly or unused capacity from a power plant operating at partial load (i.e. synchronized with the grid).

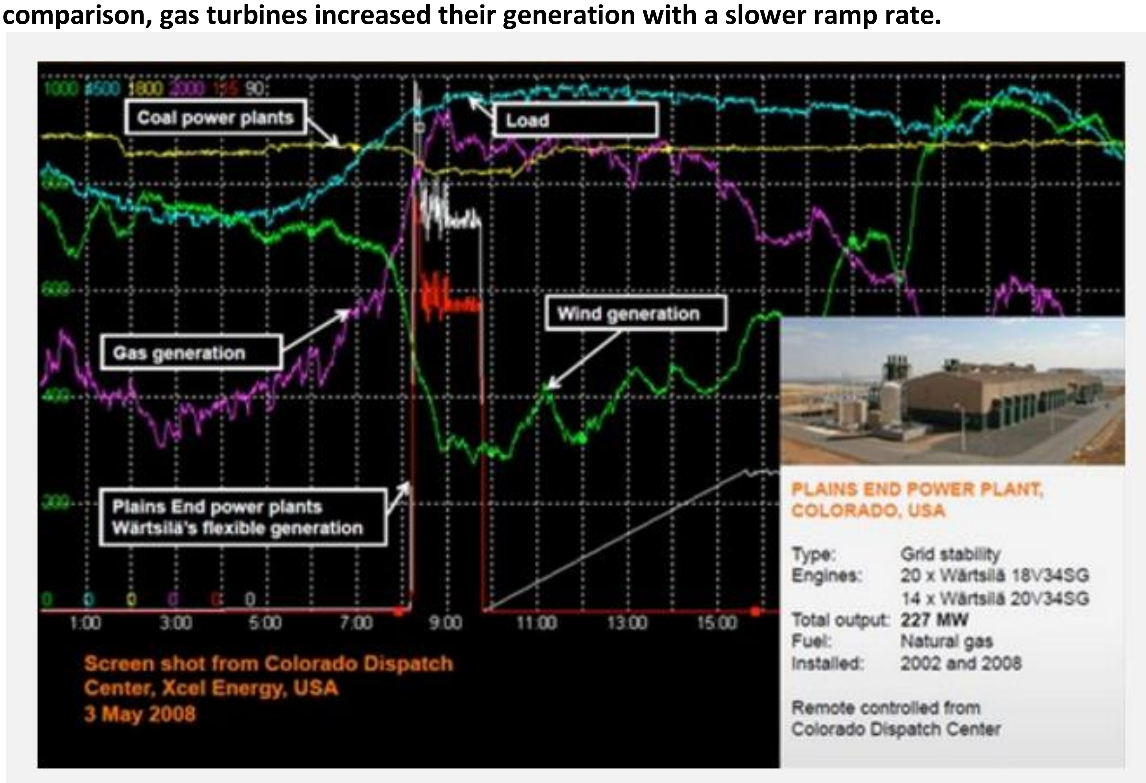
Given the previous analysis of efficiency curves based on the fraction of utilized capacity, starting rates and manufacturers' literature, it is combustion engines – whether or not combined with a steam turbine – that would prove to be the most effective choice for integrating solar generation into the grid, and also for supplying a synchronous reserve for fluctuating solar and wind, in combination with a weather forecasting system.

Combustion engines (diesel engines) can operate at variable speeds without losing efficiency (Wartsila curve reference) and have a high ramp rate, enabling a quick start.

Some manufacturers have developed technologies (simple combustion engines or combined combustion/steam turbine engines) for the specific purpose of managing intermittent energy sources and providing generating reserves. Several of the referenced articles refer to the integration of intermittent renewable energy with these combustion engines. These engines are optimized to perform well over a wide range of capacities (such as Wartsila engines).

Below is an excerpt from an article comparing the efficiency of gas turbines and combustion engines. The following figure shows that combustion engines start much faster than gas turbines to compensate for a drop in wind speed. One notable difference is that gas turbines operate at a downgraded efficiency, while combustion engines maintain the same efficiency regardless of the load.

Figure 3-28: Screen shot from a dispatch center in Colorado, USA showing a drop in wind (in green) offset by a rapid rise in generation from a natural gas combustion engine power plant. In comparison, gas turbines increased their generation with a slower ramp rate.



Another example of dual combustion engine development is the "ME-GI-S" and "ME-LGI-S" models made by MAN B & W – in this case , the manufacturer produces combustion engines that are designed and equipped from the outset to operate using either fuel oil (HFO/LFO) or natural gas.

Proposed solution

In summary, to manage IRE integration, the first thing required is an effective weather forecasting system (see **Error! Reference source not found.**, Weather forecasting system recommendation), and the second is to add thermal generation units capable of offsetting the rise and fall in solar generation while providing synchronous reserves.

The most effective solution for IRE integration is to add several small combustion engine plants operating in combined cycle with a steam turbine, thus offering the greatest generating flexibility over the broadest load range (faster start-up and better partial load efficiency). Having several combustion engines operating in simple cycle is also a viable solution, but efficiency will be lower, as explained above.

Therefore, having several small plants makes it possible to control the integration of solar generation by starting the number of units gradually and increasing their load, while helping to ensure there is sufficient synchronous reserve for fluctuating IREs (passing clouds, decreases in wind). With the weather forecasting system, a drop in wind can quickly be offset by the quick ramp rate of combustion engines, and as their efficiency does not decline with the load, they can better contribute to synchronous reserves.

3.2.10 CONSIDERATIONS FOR BIOMASS RENEWABLE GENERATION

As documented in the supply and demand balance report issued in March 2017, this type of generation is not considered in this study.

3.2.11 CONSIDERATIONS FOR LIQUEFIED NATURAL GAS AND LOCAL NATURAL GAS GENERATION

As documented in the supply and demand balance report issued in March 2017, natural gas generation will be available starting in 2025, according to Senelec's generation plan, starting with local natural gas. The generation plants developed will consider the potential conversion to natural gas (DUAL engines), which is in line with the direction taken by Senelec for the Tobene Power and ContourGlobal IPP, as well as the planned Malicounda IPP.

3.2.12 DECOMMISSIONING OF GENERATION UNITS

The decommissioning of generation units may depend on several factors, including equipment condition and reliability, maintenance costs and consumption. The Senelec generation plan identifies cold standby dates, which we associated with decommissioning dates in our preliminary analysis. The assumption being that these generation units would no longer be in use as of the year of cold standby, but not to be scrapped if their condition was considered adequate enough to return to service in an emergency or for a specific need. The table below shows the generation units identified and their cold standby dates as indicated in the Senelec generation plan.

Table 3-15: Year of cold standby of generation units

YEAR OF COLD STORAGE OF GENERATION UNITS					
Power plant and Plant Name	Type	Installed Capacity (MW)	Fuel	Year of Commissioning	Cold Standby
Bel-Air					
TAG4	Gaz	35	Diesel	1999	2018
Centrale C6					
G601	Diesel*	16.45	Heavy Fuel	2006	2031
G602	Diesel	16.45	Heavy Fuel	2006	2031
G603	Diesel	16.45	Heavy Fuel	2006	2031
G604	Diesel	16.45	Heavy Fuel	2006	2031
G605	Diesel	16.45	Heavy Fuel	2013	2038
G606	Diesel	16.45	Heavy Fuel	2013	2038
Cap des Biches					
Centrale C3					
G301	Steam	27.50	Heavy Fuel	1966	2018
G303	Steam	30.00	Heavy Fuel	1978	2018
TAG2	Gas	20.00	Diesel	1984	2018
TAG3	Gas	18.00	Kerosene	1995	2018
Centrale C4					
G401	Diesel	21.00	Heavy Fuel	1989	2025
G402	Diesel	21.00	Heavy Fuel	1989	2025
G403	Diesel	23.00	Heavy Fuel	1997	2025
G404	Diesel	15.00	Heavy Fuel	2003	2025
G405	Diesel	15.00	Heavy Fuel	2003	2025
IPP					
Kounoune Power	Diesel	9 x 7.5	Heavy Fuel	2007	2023
Manantali	Hydro	66	Hydro	2002	2053
Felou	Hydro	15	Hydro	2013	2063
Kahone 1	Diesel	15	Fuel	1982	2018
Kahone 2					
G701	Diesel	15,613	Heavy Fuel	2008	2031
G702	Diesel	15,613	Heavy Fuel	2008	2031
G703	Diesel	15,613	Heavy Fuel	2008	2031
G704	Diesel	15,613	Heavy Fuel	2008	2031
G705	Diesel	15,613	Heavy Fuel	2013	2038
G706	Diesel	15,613	Heavy Fuel	2013	2038
* Diesel = combustion engine					

In the absence of a formal decommissioning plan, no decommissioning was considered in the preliminary supply and demand balance analysis.

In the final analysis and based on comments from Senelec, some decommissioning will be applied to specific scenarios, which will be detailed in the modeling analysis.

Finally, at this stage we recommend that Senelec develop a decommissioning or rehabilitation plan for its own power plants. The plan should first assess equipment condition, then evaluate the work required to ensure proper operation over different time horizons, and evaluate cost-effectiveness in relation to decommissioning and replacement with new generation units or facilities. The plan should then be included in the generation plan.

A sustainable investment plan should be developed and synchronized with the generation master plan in order to choose the best investment plan based on technical risk.

3.2.13 LOSS ANALYSIS

Energy losses on African power grids are generally significant, representing around 20% of the gross energy produced. This means that 20% of the energy is lost between power plant generation and consumer use, as follows:

- Technical losses in power plant auxiliary services
- Technical losses associated with HV transmission network
- Technical losses in the MV and LV distribution network
- Commercial losses and electricity theft in the MV and LV network

With regard to Senegal's interconnected network, the average loss for the period 2011-2015 is 20.9%, as shown in the table below:

Table 3-16: Change in overall efficiency by grid

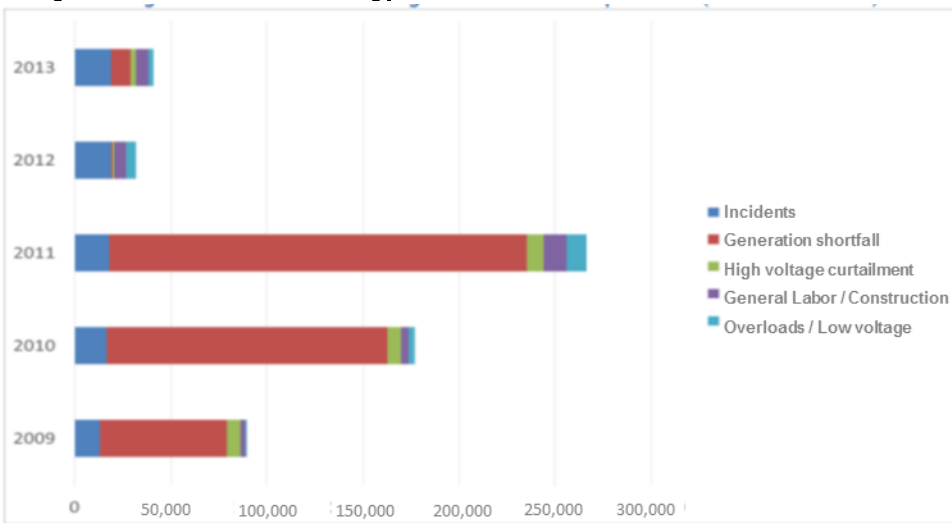
CHANGE IN OVERALL EFFICIENCY BY GRID											
Gross efficiency	**2010**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2025**	**2030**	**2035**
RI	78.4%	78.9%	80.8%	81.9%	83.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%
Boutoute	81.0%	80.0%	81.9%	81.9%	81.9%	81.9%	-	-	-	-	-
Tambacounda	75.6%	76.6%	85.2%	85.2%	85.2%	85.2%	-	-	-	-	-
Off-grid centers	85.0%	92.5%	89.5%	89.5%	89.5%	89.5%	-	-	-	-	-
Total	78.5%	79.1%	81.0%	82.0%	83.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%

3.2.14 NON-DISTRIBUTED ENERGY (NDE)

The analysis of non-distributed energy (NDE) over the past five years leads us to conclude that Senelec has put in place the required mechanisms to reduce NDE and remain in control of the situation.

As shown in the table below, the 2011 NDE rate was close to 11% of total IN generation, mainly due to generation shortfall and curtailment.

Figure 3-29: Change in non-distributed energy 2009-2013



Source: Senelec

The table below shows the decrease in the level of NDE up to 2015, when it sat at around 1% of total generation, of which only 0.1% was caused by a generation shortfall and curtailment. It also presents the monthly results of energy generated and consumed in 2015, and the different types of non-distributed energy. This was a 16.95% improvement over 2014.

Table 3-17: 2015 generation and distributed energy results

GENERATION AND DISTRIBUTED ENERGY RESULTS, 2015							
Month	Senelec IN Generation (MWh)	Energy Purchased (MWh)	Total Shortfall (MWh)[1]	Other NDE (MWh) [2]	Total NDE (MWh)	IN Demand (MWh) [3]	Peak (MW)
January	153,007	75,910	128	1,093	1,221	226,089	436
February	135,573	72,120	172	1,722	1,893	206,584	446
March	159,482	85,330	458	1,554	2 012	243,060	457
April	167,463	79,487	125	2,305	2 430	244,999	462
May	180,080	91,653	379	4,327	4,706	271,650	491
June	188,247	106,380	1,133	4,016	5,149	295,154	514
July	197,005	120,767	773	3,982	4,755	317,828	522
August	193,177	109,449	176	4,874	5,033	302 765	507
September	173,972	124,309	194	3,588	3,782	297,499	526
October	183,320	134,392	6	3,100	3,075	315,812	533
November	173,066	115,458	-	2,029	2 026	286,476	525
December	175,946	84,363	18	1,155	1,172	257,648	480
Year	**2,080,338**	**1199,618**	**3,562**	**33,744**	**37,254**	**3,265,564**	**533**
Year-1	1,991,494	1,085,910	16,293	28,616	44,908	3,074,797	507
CHANGE (%)	4.46	10.5	-78.1	17.9	-16.9	6.2	5.2

[1] Total shortfall represents load shedding due to a generation shortfall and curtailment.

[2] Other NDE includes non-distributed energy due to incidents, maintenance and work, and due to transformer or line overloads and load shedding as a result of low voltage.

[3] Demand = Senelec IN Net Generation + Energy Purchased + Total NDE

Given the generation shortfall, Senelec had to rent generation units to meet demand. At the same time, it initiated several power plant construction projects effective as of 2016, and that in 2017 will help to significantly reduce the high cost of generating unit rental.

Special attention should be paid to transmission and generation incidents, which increased by 26% between 2014 and 2015, as shown in the table below.

Table 3-18: Non-distributed energy, 2014-2015

NON-DISTRIBUTED ENERGY, 2014-2015					
Nature	2015 Interruptions		2014 Interruptions		Change in NDE (%)
	Number	NDE (MWh)	Number	NDE (MWh)	
Incidents	18,193	25,773	15,416	20,457	26
Generation shortfall	1,322	1,682	5,773	11,909	-86
HVB customer curtailment	216	1,880	240	4,384	-57
Maintenance/Work	3,503	4,073	6,393	6,368	-36
Overload	744	1,347	389	1,786	-24
Low voltage	1,663	2,500	8	5	499
Total interruptions	25,641	37,254	28,219	44,908	-17

The greatest risk of increased NDE in the coming years will come from the shortage of automatic synchronous reserve. This problem will continue to grow given the integration of intermittent renewable energy and the addition of the Sendou plant (115 MW) which, during a failure, will systematically trigger load shedding.

This master plan will aim to deploy the necessary generation capacity by 2035 to prevent increased load shedding, except for load shedding due to Sendou.

3.2.15 LOAD FACTOR

The load factor is established using the formula:

$$\text{Load Factor} = \frac{\text{Net Generation (MWh)}}{\text{Peak (MW) x 8760 (hrs)}}$$

The 2016 load factor will be based on the 2015 value of 69.1 and will be maintained throughout the study.

However, when mines are integrated, a unit load factor will be considered given the mining companies' desire to operate 24 hours a day, 365 days a year.

Moreover, when isolated grids such as Tambacounda and Boutoute are integrated into the interconnected network, we will use the load factor of the isolated grid.

Table 3-19: Change in load factor, 2009-2015

CHANGE IN LOAD FACTOR, 2009-2015								
Load Factor	**2009**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Interconnected Network	62.4%	67.3%	69.3%	68.2%	69.1%	69.1%	69.1%	69.1%
Boutoute	50.0%	53.0%	48.4%	49.4%	54.4%	54.4%	54.4%	54.4%
Tambacounda	61.2%	67.8%	66.2%	71.7%	66.2%	66.2%	66.2%	66.2%

3.3 ECONOMIC CRITERIA

3.3.1 VARIABLE O&M COSTS AND PLACEMENT OF GENERATION UNITS

Part of this study involves planning the placement of generation units to meet the demand according to the concept of least-cost of generation. As fixed costs do not, by definition, vary according to the energy generated, only variable costs are considered in connection with the placement of the different units.

In our model, generation units are placed on an hourly basis to meet the demand. It is important to note the following order of placement:

1) Intermittent renewable energy
2) Hydropower
3) Other types of generation will be placed, with top priority given to generation units that must contribute to the synchronous reserve, and then taking into account the variable costs of generation.

IREs are prioritized due to their Take or Pay (ToP) nature so that all generation output is paid, whether used or not. Hydropower is prioritized because of its lower cost. Meeting the synchronous reserve requirement then determines the placement order with the generation units contributing to the synchronous reserve and finally, the remaining load is filled by the other generation units according to their respective variable costs.

Variable generation costs are composed of the following three elements:

- Fuel consumption per kWh
- Price of fuel
- O&M costs associated with the variation in generation (variable O&M/kWh costs)

The fuel consumption data for each generating unit were identified either from the documentation submitted by Senelec or from generic values.

VARIABLE OPERATION AND MAINTENANCE (O&M) COST

For variable O&M costs, we identified the data in the table below for IPP plants:

Table 3-20: Variable O&M costs

TABLE 3-21: VARIABLE O&M COSTS	
Facility	**Data identified in contracts consulted CFAF/kWh**
CES Sendou	1.26
Africa Energy	0.81
Average	**1.035**
ContourGlobal	5.0
Tobene Power	8.2
Kounoune Power	5.7
Average	**6.3**

We assume that, for IPPs, the data identified represented all of the variable costs associated with the operation and maintenance of these generation units.

For Senelec's own power plants, in the absence of data for some of the generation units operated by Senelec, the following direction was taken:

Since the characteristics of Senelec's power plants are relatively comparable to those of the Tobene, Kounoune and Contour IPPs for the fuel used, individual capacities and type of generation, we applied a variable O&M cost of 6.3 CFAF/kW, equal to the average of these three IPPs, to Senelec's plants. This cost is understood to include all variable costs in accordance with our IPP assumption.

PLACEMENT OF GENERATION UNITS

For the placement of generation units, as previously indicated, we will use the formula below to establish the variable cost of generation for each of the plants that contribute to generation supply. Placement priority will be determined based on the plants with the lowest variable cost.

Variable cost/kWh = (fuel quantity x fuel price) + variable O&M cost

3.3.2 VARIABLE COSTS OF HYDROELECTRIC GENERATION

The variable costs identified in the documentation consulted (*Technical-economic characteristics of limited-generation equipment*) for hydroelectric plants are shown in the table below.

Table 3-22: Variable costs for hydroelectric plants

VARIABLE COSTS FOR HYDROELECTRIC PLANTS	
Power plant	**Variable cost CFAF/kWh**
Manantali	21.00
Félou	21.00
Gouina	24.14
Kaléta	19.50
Koukoutamba	21.00
Sambangalou	21.50
Souapiti	34.66

3.3.3 EXCHANGE RATE

The exchange rates used in this study are those identified in Senelec's January 2017 Generation Plan and are summarized as follows:

- USD$1 = 600 CFAF
- €1 = 655.957 CFAF

3.3.4 FUEL PRICES

The fuel prices considered in this study are those identified in Table 2-1, 2017 Fuel Prices in Senelec's January 2017 Generation Plan, and are summarized as follows:

For **coal**, a price of **31.257 CFAF/ton**.

The price of **liquefied natural gas** delivered to the power plant is USD$12/MMBtu (**7,200 CFAF/MMBtu**).

The price of **local gas** used was USD$5/MMBtu, to which must be added the cost of gas pipelines to power plants, assessed at USD$3/MMBtu, for a total of **4,800 CFAF/MMBtu**.

For petroleum products, the different prices are listed in the table below:

Table 3-23: Fuel prices

FUEL PRICES	
	CFAF/Ton
HFO 380 HTS (F/ton)	213,014
HFO 380 BTS (F/ton)	216,611
DO (F/ton)	343,659
Gasoil (F/ton)	387,008

3.3.5 TOP CONTRACT TRANSFER COSTS

The only ToP-type contracts identified are those related to intermittent renewable energy, namely solar and wind power. The transfer costs for these energy sources come from the data in a financial analysis conducted by PATRP, and are as follows:

- Wind: 65.04 CFAF/kWh
- Solar: 69.38 CFAF/kWh

3.3.6 USEFUL LIFE

The economic life for decided, planned or potential future generation units were established in accordance with the data in the October 21, 2016 final draft of Senelec's generation plan, and are summarized as follows:

- 25 years for coal-fired power plants
- 20 years for diesel power plants and gas turbines
- 20 years for wind and solar power plants
- 50 years for hydroelectric plants.

3.3.7 COST OF THE SYNCHRONOUS RESERVE

Establishing the cost of the synchronous reserve is a complex exercise because it is dependent on several factors. The following elements must be considered:

- The level of synchronous reserve required
- The level of synchronous reserve provided by an integrated grid
- The level of synchronous reserve that must come from a combination of Senelec/IPP power plants
- The generation units that will be used to supply this synchronous reserve and the percent of eligible utilization in the synchronous reserve
- The hour-by-hour change in the reserve requirement according to the probability of loss of generating units, either due to an outage or because of IRE fluctuations
- Efficiency characteristics, minimum utilization level, and load ramp-up/ramp-down rate of the different generation units
- The characteristics and operating condition of the ancillary equipment associated with regulation
- Etc.

In this case, the reserve level that can be associated with the integrated grid, or more specifically with hydroelectric plants, is the basic input required to evaluate the potential cost of the synchronous reserve. Once this data has been established and subtracted from the reserve requirement, the contribution level required from Senelec and IPP generation units can be determined.

Once this level of contribution has been established, and combined with the knowledge of which generation units will be contributing to the synchronous reserve, then it might be possible to assess the cost of the synchronous reserve.

However, this implies that it will be possible to estimate, based on different technical characteristics of the generation units in combination with an operating model, the reserve levels required for each hour of the year, which plants will be contributing at the same time and the impact on generating costs. For the most part, the biggest impact on generating costs is the need to use generation units with higher variable costs for reserve requirements at the expense of plants with lower variable costs.

Please refer to the following document:

Technical Report NREL/TP-6A20-58491 **Fundamental Drivers of the Cost and Price of Operating Reserves** (July 2013)
http://www.nrel.gov/docs/fy13osti/58491.pdf

We identified the following information in the conclusion of the document:

The total cost of providing reserves in our simulation added about 2% to the total cost of energy provision.

Abstract

"Operating reserves impose a cost on the electric power system by forcing system operators to keep partially loaded spinning generators available to respond to system contingencies and random variation in demand. In many regions of the United States, thermal and hydropower plants provide a large fraction of the operating reserve requirement. Alternative sources of operating reserves, such as demand response and energy storage, may provide these services at lower cost. However, to estimate the potential value of these services, the cost of reserve services under various grid conditions must first be established.

This analysis used a commercial grid simulation tool to evaluate the cost and price of several operating reserve services, including spinning contingency reserve, upward regulation reserve, and a proposed flexibility/ramping reserve. These reserve products were evaluated in a utility system in the western United States, considering different system characteristics, renewable energy penetration, and several other sensitivities.

Overall, the analysis demonstrates that the price of operating reserves depends greatly on many assumptions regarding the operational flexibility of the generation facilities, including ramp rates and the fraction of the fleet available to provide reserves. In addition, a large fraction of the regulation price in this analysis was derived from the assumed generator bid prices (based on the cost of generators operating at non-steady state while providing regulation reserves). Unlike other generator performance data (such as heat rate), information related to an individual generator's ability to provide reserves is not publicly available. Therefore, reproducing the cost of reserves in a production cost model involves significant uncertainty.

While variable renewables increase the total reserve requirements, the additional operational cost of these reserves appears modest in the evaluated system. Wind and solar generation tend to free up generation capacity in proportion to its production, largely canceling out the net cost of the additional operating reserves. However, further work is needed to address issues, such as down reserves and implementation of fast-response regulation, which were not included in this study. Finally, this analysis points to the need to consider how the operation of the power system and composition of the conventional generation facilities may evolve if wind and solar power reach high penetration levels."

Conducting this type of study in Senelec's specific case would require the use of a commercial production cost model, as in the case of the report cited above, and this type of study is not within the scope of this mandate.

It should also be noted that the reserve requirement is greatly affected by the level of grid integration and that rapid growth in the level of integration is foreseen in the coming years with the addition of several hydroelectric plants.

Therefore, the cost of the Senelec reserve with a more integrated grid could be around the same scale as in the benchmark study.

However, for the years prior to 2022, i.e. the years with the least amount of grid integration, this reserve cost could be higher, but this cannot be assessed until we have defined the amount to be provided by Senelec once the guaranteed contribution of hydropower is known. It will then be necessary to evaluate which equipment will be able to provide the reserve, and initiate a program to upgrade the associated equipment in Senelec's facilities. Finally, the contribution from IPPs must be confirmed and guaranteed through specific agreements or contracts if current contracts do not cover this aspect and finally, a price formula will have to be established, again, if current contracts do not cover this aspect.

In the context of a broader study on the synchronous reserve supply, the pure and simple addition of generation units dedicated to this function could also be considered. Note that rental is also an option to cover the years of least grid integration, i.e. the years leading up to 2022.

Finally, talking to providers helped to identify some solutions that, while offering the required technical characteristics, also have very short commissioning timelines, which would allow Senelec to quickly ensure there is sufficient synchronous reserve capacity and enable optimal management of its generation.

Below are a few links with quick examples and general information on such generation units:

https://powergen.gepower.com/products/aeroderivative-gas-turbines/tm2500-gas-turbine-family.html

https://powergen.gepower.com/products/aeroderivative-gas-turbines/lm2500-gas-turbine-family.htmlhttps://powergen.gepower.com/products/aeroderivative-gas-turbines/lm6000-gas-turbine-family.html

In summary, the synchronous reserve cost will depend on the level of reserve to be provided by Senelec's facilities and IPPs, once contribution from the integrated grid (essentially hydroelectric plants) has been clearly identified. At that point, various options will have to be examined, including upgrading Senelec generation units and the possible contribution level of IPPs. Finally, the direction chosen for future generating facilities to be put in place over time will also be decisive.

3.4 SUPPLY STUDY

3.4.1 INTRODUCTION

In order to meet the demand, a sufficient quantity of generation supply that meets all the established technical criteria is required. To do this, we must quantify the current or existing supply, identify the gaps between supply and demand, and aim to address these gaps with generation units that offer the best combination of technical and economic characteristics and that can guarantee available and reliable generation at the lowest cost. If specific orientations regarding the use of renewable energies or Senegal's own resources are identified, these will form an integral part of all the elements to be considered.

3.4.2 EXISTING GENERATION SUPPLY

The existing generation supply is divided into four main categories: generation from IPPs, from OMVS hydroelectric plants, imported generation, and generation from Senelec's own power generating facilities. The total power associated with these four categories, considering the nominal power of Senelec's generation units, would be **740.36 MW** as of January 2017.

Detailed information on all characteristics can be consulted in the Excel tool developed for this study.

EXISTING IPP SUPPLY

The existing IPP supply is 247.5 MW of contractual capacity and consists of 20 generation units spread out over three IPPs, as shown in the table below. All of these generation units are considered to be in service in January 2017.

Table 3-24: Existing IPP supply

EXISTING IPP SUPPLY		
IPP	# Generating units	Total Contractual Capacity (MW)
Kounoune Power	9	60
Tobene Power	6	105
ContourGlobal	5	82.5
Total	20	247.5

EXISTING HYDRO SUPPLY

The existing hydro supply is 81 MW, distributed across eight generation units and two plants, as shown in the table below:

Table 3-25: Existing hydro supply

EXISTING HYDRO SUPPLY		
Existing Hydro	# Generation units	Share of Clean Energy in Senegal (MW)
Manantali	5	66
Félou	3	15
Total	8	81

EXISTING IMPORTED SUPPLY

No existing imported supply is considered in this report.

SUPPLY FROM EXISTING GENERATION FACILITIES

Based on nominal power, Senelec's generation facilities account for around 411.86 MW of supply, as shown in the table below. It is important to mention, however, that certain generation units no longer supply their respective nominal capacities.

This aspect was incorporated in the analysis model and is considered in the supply and demand balance according to the data identified in the documentation consulted.

Table 3-26: Supply from existing Senelec generation facilities

SUPPLY FROM EXISTING SENELEC GENERATION FACILITIES			
Site	**Facility**	**Group**	**Nominal Capacity (MW) MW**
Bel-Air		TAG4	35.00
	C-6	601	16.45
		602	16.45
		603	16.45
		604	16.45
		605	16.45
		606	16.45
C-D-B	C-3	301	27.50
		303	30.00
		TAG2	20.00
	C-4	401	21.00
		402	21.00
		403	23.00
		404	15.00
		405	15.00
	Kahone 2 C-7	701	15.61
		702	15.61
		703	15.61
		704	15.61
		705	15.61
		706	15.61
	Kahone 1	93	3.00
		94	3.00
		149	3.00
		150	3.00
		Total	**411.86**

3.4.3 FUTUR GENERATION SUPPLY OF DECIDES, PLANNED OR POTENTIAL PROJECTS

For future generation supply, we refer directly to Senelec's January 2017 Generation Plan.

We also considered hydro potential based on the information in the OMVS 2015 Master Plan. Therefore, we have identified the following supply categories:

- IPP supply (conventional energy)
- Hydroelectric supply
- Imported supply
- Supply from Senelec generation facilities
- Intermittent renewable energy supply.

FUTUR IPP SUPPLY (CONVENTIONAL ENERGY) AND CHOICE/SIZING OF GENERATION FACILITIES, 2019-2035

Future IPP supply (conventional energy) (Senelec Plan)

The future IPP supply (2017-2022) to the January 2017 Senelec Generation Plan comprises conventional power plants, for contractual capacity of around 505 MW, as shown in the table below:

Table 3-27: Future IPP supply (conventional energy)

FUTURE IPP SUPPLY (CONVENTIONAL ENERGY)				
	Contractual Capacity (MW)	Fuel	Completion Date	Status
CES Sendou phase 1	115	Coal	07-01-2018	Decided
Africa Energy 1	90	Coal	01-01-2020	Planned
Africa Energy 2	90	Coal	01-01-2021	Planned
Africa Energy 3	90	Coal	07-01-2021	Planned
Malicounda	120	HFO	07-01-2020	Planned
Total	505			

Note: for the Malicounda IPP, in the absence of data specific to this plant, for the purposes of this study we used the characteristics applicable to the ContourGlobal IPP.

For the period 2025-2030, the same generation plan provides for the installation of seven 115 MW thermal gas plants. Three plants in 2025, followed by one plant in each of the following years: 2026, 2028, 2029 and 2030. No additional generation was identified for the period 2030-2035.

Choice and sizing of generation facilities, 2019-2035

Considering the local natural gas available as of 2025, the choice of generating facility for the period 2025-2035 points to NG generation by means of CCGT generation units which, from a cost perspective, is very comparable to thermal coal generation, considered to be the second most economical type of generation, after hydroelectric. The sizing of the generation units is in the 50-60 MW range.

For the years 2019-2022, Senelec's current choices regarding ongoing projects were considered. Recall that in addition to the choice of thermal coal made with the CES 1 plant which, according to information provided by Senelec, will be commissioned in 2018, the remaining options are more thermal coal plants or a dual HFO power plant in Malicounda.

Figure 3-30: Investment, O&M and generating costs in $USD/MWH

Type of production	MW power	Variable Costs (O&M) and Fuel USD (Rounded)	Fixed costs (O&M) and Capital - Interest USD (Rounded)	Total Cost USD (Rounded)	USD / MWh
Coal steam single cycle	125	$ 24,684,336	$ 52,317,919	$ 77,002,254	78 $
NG combined cycle	120	$ 56,764,800	$ 21,654,962	$ 78,419,762	83 $
NG combustion engine	120	$ 68,129,430	$ 23,915,879	$ 92,045,309	97 $
NG vapor single cycle	115	$ 70,991,478	$ 25,366,687	$ 96,358,165	106 $
HFO combustion engine	120	$ 80,429,359	$ 24,116,625	$ 104,545,984	111 $

These estimates are based on the following references, premises and notes:

- Specific consumption based on data in section 3.8 of this report
- Fuel prices based on data in section 3.3.4 of this report
- 90% load factor
- Useful life based on data in section 3.3.6 of this report
- Financing interest rate of 8%
- Equipment costs taken mainly from the following references: "Updated Capital Cost Estimates for Utility Scale Electricity Generation Plants", USEIA, USDOE, April 2013; "Cost & Performance Data for Power Generation Technologies", Black & Veatch for National Renewable Energy Laboratory, February 2012; "Study of Equipment Prices in the Power Sector", ESMAP Technical Paper 122/09, World Bank 2009; "Front-End/Conceptual Estimating Yearbook", 15the Edition, Compass International Inc., 2016 (Section B1 - Cost-Capacity Equations/Exponents).

FUTUR HYDROELECTRIC SUPPLY AND PRIORITIZATION

Future hydroelectric supply

Future hydroelectric supply is divided into two categories: decided or planned, and potential supply. We first identified the decided or planned power plants, with a total of **317 MW** of clean power in Senegal, as shown in the table below:

Table 3-28: Future hydroelectric supply of decided and planned projects

FUTURE HYDROELECTRIC SUPPLY OF DECIDED AND PLANNED PROJECTS				
	Capacity (MW)	Clean Power in Senegal (MW)	Completion Date	Status
Kaléta	240	48	01-01-2019	Decided
Gouina	140	35	01-01-2020	Decided
Souapiti	515	103	01-01-2021	Decided
Sambangalou	128	61	01-01-2021	Decided
Koukoutamba	280	70	01-01-2025	Planned
Total	**1303**	**317**		

The completion dates indicated correspond to the dates given in the January 2017 Senelec Generation Plan. These dates could be modified according to the different scenarios; if necessary, the relevant information will be provided in said scenarios.

It should also be noted that some energy and capacity data used for modeling purposes differs from the data presented in the Senelec Generation Plan. The differences are shown in the following figure:

Figure 3-31: Hydroelectric-differences between energy and capacity

	Senegal capacity under Senelec plan	Modeled power	Senegal energy under Senelec plan	Modeled energy
Power plant	MW	MW	GWh	GWh
Kaleta	48	48	189	189
Gouina	35	35	140	155
Souapiti	100	103	350	379
Sambangalou	61	61	193	194
Koukoutamba	70	70	175	213

We found discrepancies in the data from several sources, including the OMVS 2015 Master Plan, Senelec's Generation Plan, and information on the Internet. For example, for Souapiti, capacity and energy as identified in section 4.4.2.7 of Senelec's January 2017 plan are 450 MW and 1,898 GWh/year, with a 20% share of Senegal. This would represent 90 MW and 379 GWh for Senelec. Yet Table 4.1 of the same plan indicates 100 MW and 350 GWh. It was therefore decided that the analysis should use the figures of 515 MW and 1,898 GWh (OMVS data and web references), which represents 103 MW and 379 GWh for Senelec. Thus, after correlating the information, the data deemed most relevant was selected.

Combined with an analysis of average monthly generation output–as already recommended, Senelec should validate the capacity and energy data and make any required adjustments to the modelling and/or its generation plan.

Finally, we identified the supply category of the potential power plants, for a potential capacity specific to Senegal of around **443.67 MW**.

Table 3-29: Future hydroelectric supply of potential projects

FUTURE HYDROELECTRIC SUPPLY OF POTENTIAL PROJECTS						
Power Plant	**Origin**	**Capacity (MW)**	**Percentage Specific to Senegal**	**Senegal Capacity (MW)**	**Potential Year of Commissioning**	**Status**
Gourbassi	OMVS	18	25	4.50	2023	Potential
Fello Sounga	OMVG	82	40	32.80	2023	Potential
Saltinho	OMVG	20	40	8.00	2023	Potential
Digan	OMVG	93.3	40	37.32	2023	Potential
Fomi	GUINEA	90	20	18.00	2022	Potential
Amaria	GUINEA	300	20	60.00	2024	Potential
Morisanako	GUINEA	100	20	20.00	2025	Potential
Kogbedou	GUINEA	44	20	8.80	2021	Potential
Kassab	GUINEA	135	20	27.00	2031	Potential
Poudaldé	GUINEA	90	20	18.00	2032	Potential
Bouréya	OMVS	114	25	28.50	2023	Potential
Badoumbé	OMVS	70	25	17.50	2025	Potential
Balassa	OMVS	181	25	45.25	2026	Potential
Lafou	GUINEA	98	20	19.60	2025	Potential
Bonko Diaria	GUINEA	174	20	34.80	2026	Potential
N'zébéla	GUINEA	27	20	5.40	2028	Potential
Grand Kinkon	GUINEA	291	20	58.20	2029	Potential
			Total	443.67		

Prioritizing hydroelectric supply

There are many advantages to hydroelectric generation: it is a renewable energy, has higher energy efficiency, low greenhouse gas emissions and above all, generation costs per kWh are generally lower than any other source of generation. Thus, decided or planned hydroelectric projects are always considered the priority in the supply and demand balance.

Note that the Souapiti and Gouina power plants are in the construction phase, and there is no doubt as to their commissioning. The Kaleta power plant is built and in operation; therefore, its integration into Senegal's grid depends only on the commissioning of the transmission line.

At the current stage of our study and based on the following three references:

- U.S. Energy Information Administration 2013
- OMVS 2015 Master Plan
- Embassy of France in Ethiopia and to the African Union, Economic Service for Ethiopia and Djibouti, the Economic Adviser, Addis Ababa Service Manager, September 13, 2016.

We assume the following data for hydropower generation:

Investment cost (Capex): USD$ 2.22 million/MW

Operation and maintenance costs (Opex): USD$10,570/MW/yr

On the basis of these assumptions and considering a 50-year useful life in combination with an interest rate of 8%, for two power plants to supply generation, namely Amaria and Grand Kinkon, we obtained the per MWh generation costs shown in the figure below:

Figure 3-32: Hydropower generation cost $USD/MWH

Power Plant	Power	Utilization Factor	MWh/ Yr	Invest	O & M/ Yr	Lifetime	Interest rate	TOTAL	USD/MWh
	MW	Operation		MUSD	USD/Yr			USD/Yr	
Amaria	300	0.48	1,261,440	666	$ 3,171,000	50	8%	$ 57,458,592	$ 45.55
Grand Kinkon	291	0.4	1,019,664	646	$ 3,075,870	50	8%	$ 55,733,202	$ 54.66

Thus, in terms of generation costs, hydropower is considered to have a significant advantage over any form of thermal generation.

FUTUR IMPORTED SUPPLY

Even though there is a high potential for importing power from Mauritania (the development of the Banda reserve natural gas field has led Mauritania to estimate a potential of 600 MW in capacity by 2025), at present, relevant information regarding the capacity or energy used to model the imported supply from Mauritania could not be confirmed.

SUPPLY FROM FUTURE SENELEC GENERATION FACILITIES

No future supply to increase the capacity level of the Senelec generation facilities has been identified.

FUTURE SUPPLY (INTERMITTENT RENEWABLE ENERGY)

There are two distinct categories of intermittent renewable energy supply: wind and solar. The total capacity determined is around **481.7 MW** based on the information in Senelec's January 2017 Generation Plan, and includes 40 MW of installed solar capacity at the end of 2016.

With respect to wind, we calculated a total capacity of **158.7 MW** for three facilities (three phases of Sarreole), as shown in the table below:

Table 3-30: Future wind energy supply

FUTURE WIND ENERGY SUPPLY			
Phase	Installed Capacity (MW)	Completion Date	Status
Sarreole 1	51.75	01-01-2018	Decided
Sarreole 2	51.75	01-01-2019	Decided
Sarreole 3	55.20	01-01-2020	Decided
Total	158.70		

With regard to solar, we calculated a total capacity of **323 MW** based on the data in the table below and considering the 40 MW installed at the end of 2016:

Table 3-31: Future solar supply

FUTURE SOLAR SUPPLY			
Project	Capacity (MW)	Year of Commissioning	Status
Installed solar	40	End of 2016	Installed
Solar IPP 1	29	2017	Decided
Solar IPP 2	29	2017	Decided
Solar IPP 3	20	2017	Decided
Solar Scaling 1	30	2018	Decided
Solar Scaling 2	30	2018	Decided
Solar Scaling 3	40	2019	Decided
Diass	15	2018	Decided
New Solar 1	30	2021	Planned
New Solar 2	30	2022	Planned
New Solar 3	30	2023	Planned
Total	323		

3.5 ANALYSIS OF THE SUPPLY AND DEMAND BALANCE

3.5.1 INTRODUCTION

PREVIOUS MODELING

During initial supply and demand balance analyses, modeling was conducted to measure the level of adequacy of different supply and demand scenarios. Each model was analyzed, followed by additional, more specific evaluations such as the availability of the generation units according to specified maintenance requirements. The models identified at this stage were as follows, and can be found in the March 2017 supply and demand balance report:

- Model 1 - Supply based on baseline demand
- Model 1A - Supply based on baseline demand, excluding mines
- Model 2 - Supply based on low demand
- Model 3 - Supply based on baseline demand, excluding loss improvement (19.38%: data used for our preliminary report).

Next, sensitivity analyses were carried out using the following assumptions:

- Model 4 – Delays in the commissioning of hydroelectric plants (baseline demand)
- Model 5 – Failure to achieve target loss improvements (baseline demand)
- Model 6 – Non-availability of imported energy from Mauritania (baseline demand).

For the purposes of this report, the different options will be modeled using baseline demand only, incorporating the concepts of loss and synchronous reserve resulting from the grid study.

NEW TARGETED MODELING

Since the release of the supply and demand balance report in March 2017, a grid study has been completed and is a key part of this report. This study helped to clarify some of the information related to losses associated with the transmission network and synchronous reserve requirements.

This new information, combined with feedback from Senelec, led to the identification of three models that will take into account this new information and will allow more in-depth analysis on synchronous reserve concepts and issues, in combination with the interaction between IRE and thermal coal generation.

Models will be developed using the same demand basis, that of baseline including mines.

The new models will therefore be differentiated according to the supply used to meet demand, and will be analyzed on the basis of the criteria listed in the next section.

The three new models are as follows:

- Model 1 - Senelec plan supply scenario (see note)[2]
- Model 2 - PATRP supply scenario (without decommissioning)
- Model 3 - PATRP supply scenario (with decommissioning)

3.5.2 EVALUATION CRITERIA

For each of the models, the following two criteria will be evaluated individually:

1) Supply planning:
    a. Minimum 15% Pmax capacity reserve (supply minus demand)
    b. Avoid two consecutive years below 20%, except for the period 2030-2035, where 15% is permitted
2) Prioritization and curtailment of generation.

The following criteria will be evaluated once for all three models:

3) Adequacy of supply to meet demand
4) Loss of load probability (LOLP) assessment
5) Sizing of generation units and generation reserves
6) Availability for maintenance.

[2] Important note: Model 1 has taken the Senelec plan supply with no decommissioning considered. The Senelec plan covers the supply adjustment up to 2030 compared with the PATRP supply scenarios, which cover supply adjustment up to 2035. The relevant information on the direction of generating unit decommissioning can be found in section **Error! Reference source not found.**.

3.5.3 ASSUMPTIONS

GENERAL ASSUMPTIONS CONCERNING SUPPLY

- The CES 1 power plant is under construction, and due to be commissioned in June 2018.
- Hydroelectric plants are prioritized for supply, for the reasons stated in paragraph 3.4.3 of the Futur hydroelectric supply and prioritization section, under Prioritizing hydroelectric supply.
    - This includes the Amaria and Grand Kinkon plants by 2028.
- Model 1 is based on the supply identified in the January 2017 Senelec Generation Plan.
- Local natural gas is not considered available until 2025.
- The addition of wind farms considers the use of the same criterion of 34% in extreme fluctuations to be offset by the synchronous reserve.
    - Note that the same wind turbine model (VESTAS V126) is used for all facilities and that the location is similar to Sarreole.

ASSUMPTIONS CONCERNING THE REQUIRED SYNCHRONOUS RESERVE AND AVAILABLE SYNCHRONOUS RESERVE

Required synchronous reserve

In supply planning, the required synchronous reserve is dictated by the level of synchronous reserve that can be associated with the need to compensate for potential fluctuations in IRE.

Thus, the following data are considered for required synchronous reserve:

- 70% of the capacity of the largest solar park in use
- 34% of the capacity of the largest wind farm in service

As a reminder, detailed information about this assumption is provided in the section **Error! Reference source not found.**.

Also note that for the Sendou (115 MW) and Africa Energy (90 MW each according to Senelec's current planning) generation units, load shedding will occur during any outage, in the absence of sufficient synchronous reserves, at least until the grid is integrated enough to provide the required synchronous reserve (around 2025). Given the sizing of the other generation units, the synchronous reserve requirement is therefore conditional upon the potential fluctuation of IREs.

Available synchronous reserve

With regard to the available synchronous reserve, for each year a synchronous reserve of around 3% of the installed hydropower capacity was assumed to be available at all times. For a specific year, the reserve is calculated on the basis of the installed capacity on January 1 of that year. For example, considering the commissioning dates in the January 2017 Senelec Generation Plan, we obtained the hydropower synchronous reserve levels shown in the following figure:

Figure 3-33: Synchronous reserve with hydropower

	MW	% SR	SR (MW)
2017	260	3%	8
2018	260	3%	8
2019	500	3%	15
2020	640	3%	19
2021	1283	3%	38
2022	1283	3%	38
2023	1283	3%	38
2024	1283	3%	38
2025	1563	3%	47

It is important to mention that these reserve levels, although considered within the framework of the different models, have to be negotiated.

With regard to the synchronous reserve capacity that can or should be considered in Senelec and IPP generation facilities, we used 12.5% of the capacity in our models, according to information received from Senelec that 24 MW of synchronous (non-automatic) reserve was used at C6 and C7, that is, generally two megawatts per generating plant, and according to the data in the following figure:

Figure 3-34: Senelec synchronous reserve

Power Plant	Unit	Installed capacity MW	Synchronous reserve MW	%
C6	601	16.45	2	12.16%
	602	16.45	2	12.16%
	603	16.45	2	12.16%
	604	16.45	2	12.16%
	605	16.45	2	12.16%
	606	16.45	2	12.16%
C7	701	15.613	2	12.81%
	702	15.613	2	12.81%
	703	15.613	2	12.81%
	704	15.613	2	12.81%
	705	15.613	2	12.81%
	701	15.613	2	12.81%
	Total	192.4	24	12.48%

It was also brought to our attention that the same 2 MW per plant was also applied to IPP Contour Global. The installed capacities of these plants being substantially similar to those of C6 and C7, the ratio of 2 MW is close to 12.5%.

Therefore, for planning purposes we used 12.5% as the synchronous reserve percentage to be considered. For modeling purposes, we established the contribution to the synchronous reserve at 2 MW per generating plant.

For planning purposes, the synchronous reserve could be different from the 12.5% used. Ideally, the synchronous reserve that can and should come from hydropower would first be established, and then Senelec's own capacities would be assessed from the perspective that the equipment associated with the reserve would be assessed and restored to normal operating conditions. Finally, the contribution that should come from IPPs would be established. Remember that we are talking here about an automatic synchronous reserve which, in the context of managing the challenges of real-time IRE management, should be coupled with an automated and efficient network management system.

It is important to note that, for modeling purposes, the following facilities in the following order were identified for contribution to the synchronous reserve:

- Contour
- C6, C7
- Tobene.

Also note that the synchronous reserve capacity will be automated by performing the required upgrading work and/or by negotiating these reserve levels with the relevant IPPs.

Finally, when new plants with the characteristics required to supply synchronous reserve are commissioned through our different models, these are automatically prioritized, and the 2 MW per plant requirement will be maintained, excluding CCGT plants to be commissioned after 2025.

ASSUMPTIONS CONCERNING IRE COMMISSIONING PLANNING

For the model of the January 2017 Senelec generation plan, commissioning is assumed in the year identified in the plan, for anything planned prior to 2021, with no further consideration. This is applicable for both solar and wind energy. For commissioning identified after 2020, i.e. 90 MW of solar in the period 2021-2023, 30 MW per year was applied in 2021, 2022 and 2023.

With regard to PATRP models, all solar projects planned by Senelec prior to 2018 are considered to be commissioned as planned, and any wind power projects planned up to 2020 commissioned.

Next, according to the planning criteria, an assessment is made as to when the other solar parks planned by Senelec can be commissioned, with the exception of the 90 MW identified during the period 2021-2023.

Finally, the intention is to increase the level of IRE in the period 2025-2035 to ensure a level of 20% of installed capacity, in accordance with the objective identified in the documentation submitted by Senelec. The IRE level could be further increased, with the ultimate limit being grid stability.

Also note that the plan is to ensure that IRE curtailment is minimal and, in this sense, planning will be based on the most demanding day of the year, namely the load valley day, and for the most demanding hour of the day (12:00 noon), when solar is considered to be at its maximum.

The IRE planning criteria applied are based on the following data for each year analyzed:

- Load at noon on the load valley day, as this is the hour considered to have maximum solar potential
- A level of solar generation equal to the installed capacity
- A level of wind generation equal to the maximum identified in the wind profile, i.e. 46% of the installed capacity. The load valley day occurs at a time when average winds are the strongest, hence the use of the maximum identified in the profile as a conservative criterion
- A level of hydropower generation equal to the average hydropower
- A level of required synchronous reserve equal to 70% of the largest solar park installed or 34% of installed wind capacity, whichever is highest
- The expected contribution of hydropower to the synchronous reserve
- The contribution considered to be required for the synchronous reserve from Senelec and IPP power plants
- The Senelec and IPP contribution to making up the load
- Thermal coal generation is considered for curtailment.

Therefore, if we take the year 2021 as an example, then the progression is as follows:

- Data on the levels of installed solar capacity, installed wind capacity and average hydropower generation are as shown in the following figure:

Figure 3-35: 2021 - Solar, wind and average hydropower capacity levels

Load at 12:00 Load valley day (MW)	Solar installed capacity on January 1st (MW)	Wind installed capacity on January 1st (MW)	Average Hydro Power (MW)
485	118	158.7	121.7

The synchronous reserve requirement is 54 MW and is influenced by the wind turbine, as shown in the figure below:

Figure 3-36: 2021 - Synchronous reserve requirement

Largest solar park installed (MW)	Largest wind farm installed (MW)	Synchronous reserve required Solar (MW)	Synchronous reserve required Wind (MW)
30	158.7	21	54

The contribution required from Senelec and IPPs to the synchronous reserve will be 19 MW, as shown in the figure below:

Figure 3-37: 2021 - Synchronous reserve requirement of IPPs and Senelec

Hydro power capacity on January 1st (MW)	Hydro power synchronous reserve to consider (MW)	Synchronous reserve required (MW)	Hydro power synchronous reserve (MW)	Synchronous reserve required Senelec and IPP (MW)
1155	35	54	35	19

For the 19 MW synchronous reserve requirement from Senelec and IPP generation, 152 MW will have to be in service, of which 133 MW will contribute to load filling as shown in the figure below:

Figure 3-38: h2021 – Capacity contributing to load filling (Senelec + IPP)

Synchronous reserve required Senelec and IPP (MW)	In-service generation for 19 MW synchronous reserve at 12.5% (MW)	Contributing load filling (MW)
19	152	133

Based on these data, it was determined that for a load of 485 MW, a solar contribution of 118 MW (100% of the installed capacity), a wind contribution of 73 MW (46% of the installed capacity), a contribution of 121.7 MW representing average hydropower capacity, and finally a contribution of 133 MW from Senelec and IPP plants (for 19 MW of synchronous reserve at 12.5%), there would be a remaining load to fill of around 39 MW in order to increase the power capacity of IREs, as shown in the figure below:

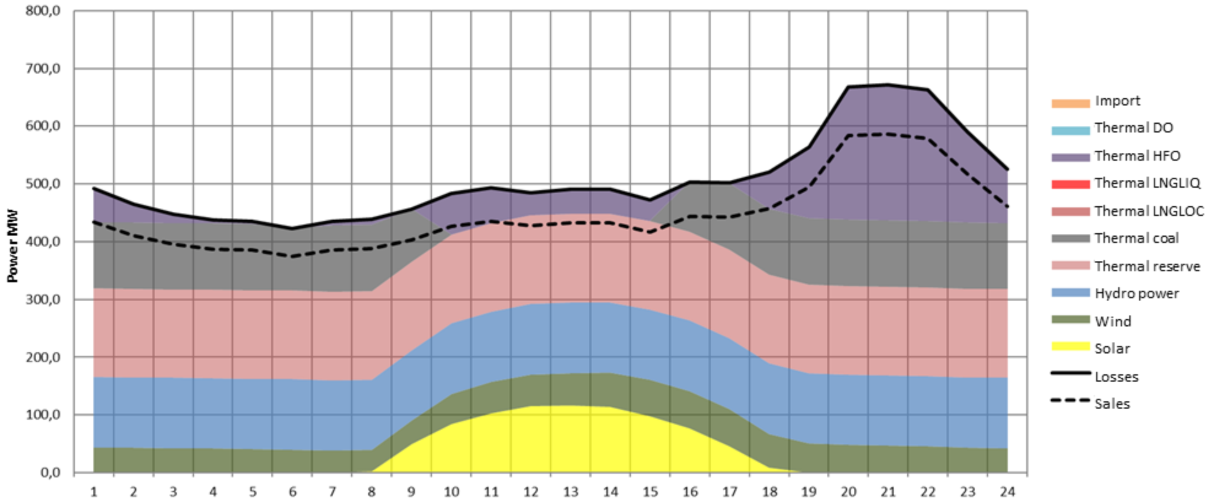
Figure 3-39: 2021 - Remaining load enabling the addition of IRE

	MW
Load to be filled	485
Solar contribution	118
Wind contribution	73
Hydro power contribution	121.7
Senelec and IPP contribution	133
Remaining load	39.3

In this case, and according to the stated assumptions, the plan was to add a 30 MW solar park on January 1, 2021.

A graphical representation of this 2021 load valley day, once the 30 MW solar park is added, is shown in the figure below:

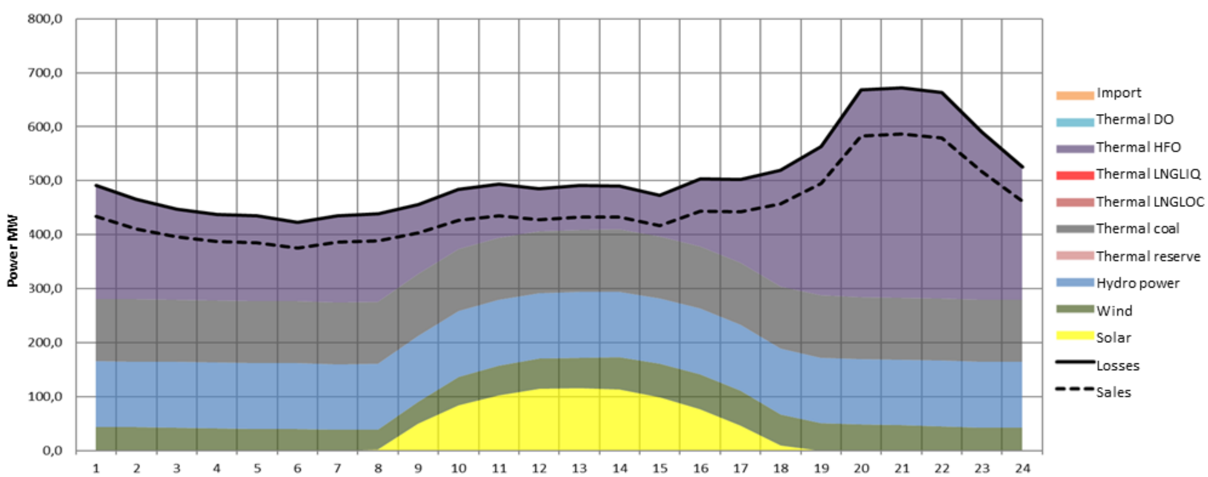
Figure 3-40: 2021-Daily analysis of the load valley



We determined priority use of IRE without curtailment, followed by a hydro contribution corresponding to average hydropower, a thermal contribution corresponding to the level that provides load filling to guarantee the synchronous reserve (2 MW/unit), a contribution from thermal coal plants within the associated technical minimum and finally, a contribution from other thermal plants, until the load is completely filled.

Without consideration for the synchronous reserve for the same 2021 valley day, the allocation would then be as shown in the figure below:

Figure 3-41: 2021-Daily analysis of the load valley



This still prioritizes IRE without curtailment, followed by a hydro contribution corresponding to average hydropower. The difference compared to the previous scenario is in the maximum contribution of thermal coal plants, followed by the use of the other forms of thermal power, prioritizing the least expensive generating types with regard to variable costs.

ASSUMPTIONS ON IRE PENETRATION RATES

For modeling purposes, an IRE penetration rate must be determined for each year. Recall that, ideally, the penetration rate would have been determined before IRE planning so as to target the non-curtailment of IREs by taking into account available synchronous reserve levels, the load at different periods in the year and other criteria. In this case, we need to establish a penetration rate based on the load, the requirement and the capacity of the synchronous reserve, and accept IRE curtailment if the installed IRE capacity exceeds permissible levels.

To do this, as in planning, the penetration level will be established according to the most demanding moment in the year, namely the load valley day, the time with the highest solar potential, and according to maximum wind generation output. Note that this penetration rate is restrictive for this specific hour and is an example of a potentially extreme case. Therefore, for the other hours in the day and/or year, the load could be higher or IRE generation theoretically lower.

Thus, if we take the year 2021 as an example and, considering the same inputs as those used above for IRE planning, then the progression is as follows:

We have determined that the remaining load to be filled is the estimated load (485 MW) minus the average hydro capacity (121.7 MW) plus the Senelec - IPP contribution that provides synchronous reserve (133 MW). Therefore, we obtain 230 MW of remaining load to be filled, as shown in the figure below:

Figure 3-42: 2021 - Load to be filled and penetration rate

Load (MW)	Average Hydro (MW)	Contribution Senelec-IPP (MW)	Remaining load to be filled (MW)
485	121.7	133	230

Considering that this 230 MW could be filled by IRE, we determined a penetration rate of 48%, i.e. 230 MW of IRE for a 485 MW load.

It is important to note that operating with planning criteria in combination with the mandatory implementation of solar or wind farms results in some distortion in our analysis. For example, according to the established criteria, the mandatory wind capacity modelled for 2018-2020 of 158.7 MW leads to a synchronous reserve requirement of 54 MW in 2020, although the network is still not highly integrated. This results in a high contribution obligation to the synchronous reserve for Senelec's plants. The same Senelec contribution, on a basis of 12.5%, leads to a high level of generation contributing to load filling, which translates into a need for IRE curtailment. Considering that our model applies a constant level of reserve throughout the year, it is accepted that in operating mode, things would be different from what is shown in our analysis. Nevertheless, due to the combination of IREs proposed by Senelec, the synchronous reserve capacity as recommended by Senelec is very ambitious. According to the planning criteria used in our modeling, the same level of solar and wind IRE would have been installed by 2022 instead of by 2020, as identified in the Senelec plan.

3.5.4 SUPPLY AND DEMAND BALANCE

MODEL 1 – BASELINE DEMAND AND SUPPLY SCENARIO, SENELEC GENERATION PLAN

This model is intended to evaluate the capacity of the Senelec generation plan to meet the evaluation criteria. We will also assess whether there are generation management challenges based on installed IRE capacities, in combination with the other forms of generation identified.

The analytical parameters specific to this model were established in accordance with the previously stated assumptions, and are shown in the figure below:

Figure 3-43: Evaluation of Senelec and IPP reserve and penetration rates from 2018 to 2035

SENELEC	Required reserve (MW)	Hydro reserve (MW)	Senelec reserve	In service (MW)	Contributory (MW)	Load (MW)	Average hydro (MW)	Possible RE	Penetration (%)
2018	21	8	13	104	91	304	40	173	57%
2019	35.19	15	20.19	161.52	141.33	327	61.4	124	38%
2020	53 958	19	34 958	279 664	244.71	394	78.9	71	18%
2021	53 958	38	15 958	127 664	111.71	485	143.6	230	47%
2022	53 958	38	15 958	127 664	111.71	572	143.6	316	55%
2023	53 958	38	15 958	127 664	111.71	607	143.6	351	58%
2024	53 958	38	15 958	127 664	111.71	641	143.6	385	60%
2025	53 958	47	6 958	55 664	48.71	675	167.7	459	68%
2026	53 958	47	6 958	55 664	48.71	714	167.7	497	70%
2027	53 958	47	6 958	55 664	48.71	755	167.7	538	70%
2028	53 958	47	6 958	55 664	48.71	792	167.7	575	70%
2029	53 958	47	6 958	55 664	48.71	828	167.7	611	70%
2030	53 958	47	6 958	55 664	48.71	853	167.7	637	70%
2031	53 958	47	6 958	55 664	48.71	904	167.7	687	70%
2032	53 958	47	6 958	55 664	48.71	956	167.7	740	70%
2033	53 958	47	6 958	55 664	48.71	1012	167.7	796	70%
2034	53 958	47	6 958	55 664	48.71	1071	167.7	855	70%
2035	53 958	47	6 958	55 664	48.71	1132	167.7	916	70%

It is important to note that these parameters are applied consistently over all hours in the year.

Figure 3-44: Addition of capacity (net capacities of power plants)

			MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
			2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL
MODEL 1 Baseline scenario WITH MINES SENELEC plan	CES 1	Coal		115																		115
	Africa	Coal				90	180															270
	Malicounda	HFO Dual				120																120
	Additional power	TVGN									345	115		115	115	115						805
	Additional power	Hydro			48	35	164				70											317
	TOTAL																					1627
	Additional power	Solar	78	75	40		30	30	30													283
	Additional power	Wind		51.75	51.75	55.2																158.7
																					Total	2068.70

For the period 2017-2030, we have identified the following added capacities:

- 385 MW Thermal coal
- 120 MW Dual HFO
- 805 W Thermal-Gas
- 317 MW Hydropower
- 158.7 MW Wind
- 283 MW Solar.

No additional capacity was identified for the period 2031-2035.

Figure 3-45: Pmax, Model 1

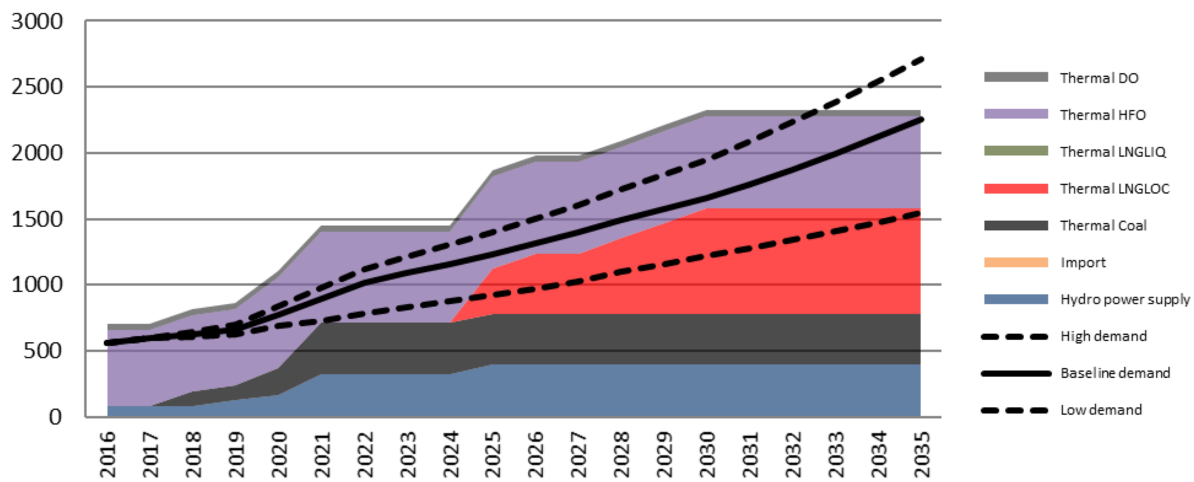
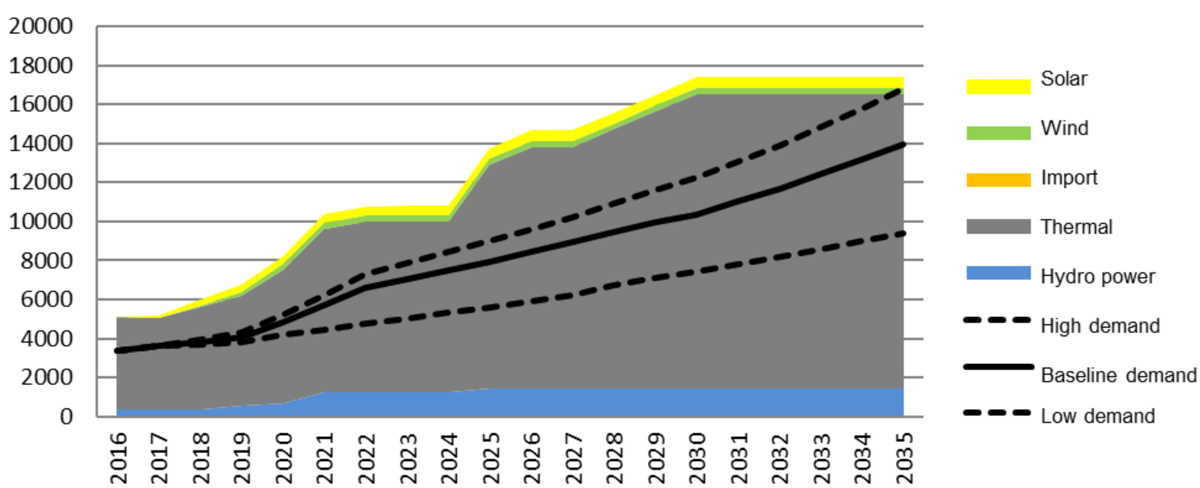


Figure 3-46: Energy (GWh), Model 1



Supply planning

Based on our various evaluation criteria, we obtained the results below.

With the added generation shown above, target reserve levels are met across the entire range, except in 2034 and 2035 as shown in the figure below:

Figure 3-47: Reserve analysis - Model 1

Analysis

Reserve Analysis

Scenario : Model 1 | Demand : Baseline | ☑ Distributed hydro power

Year	Peak x 15% MW	Valley x 15% MW	P < 25% of the time x 15% MW	P < 50% of the time x 15% MW	Pmax reserve (%)	Pmax reserve (MW)
2016	84	34	52	60	25%	141
2017	89	36	56	64	18%	105
2018	94	38	59	68	30%	190
2019	100	41	63	73	30%	198
2020	117	50	75	86	42%	329
2021	135	63	90	102	61%	552
2022	153	76	104	117	43%	434
2023	163	80	111	124	34%	364
2024	174	84	117	132	25%	293
2025	185	89	124	140	51%	634
2026	197	93	132	149	51%	666
2027	210	99	140	158	41%	578
2028	223	103	148	167	41%	606
2029	236	107	155	176	40%	634
2030	248	110	161	184	40%	669
2031	265	116	171	195	32%	561
2032	281	123	181	207	24%	449
2033	299	130	192	220	17%	330
2034	318	137	204	234	10%	204
2035	338	145	216	248	3%	73

However, it must be taken into consideration that no supply is planned beyond 2030 and that reserve levels even reaching 61% in 2021 leave room for a decommissioning program.

Prioritization and curtailment of generation (daily analysis of generating load peak/valley)

Limiting IREs

Based on the analysis parameters specific to this synchronous reserve and penetration level modeling, and considering hydropower generation distributed around an average value, we have determined curtailment of intermittent renewable energy over the period 2019- 2021 of around 222.4 GWh (sum of "Unused energy" in the figure). We also note that for 2020, 2,234 GWh would be generated by the plants contributing to the synchronous reserve, as shown in the figure below:

Figure 3-48: Utilization of available energy - Model 1

			Analysis				Hydro power		Import			
							Start :		Start : 19:00			
Scenario :	Model 1			Demand : baseline			Distributed : ☑					
		Energy used GWh						Unused energy GWh				
Year	Total demand GWh	Wind	Solar	Hydro power	Thermal reserve	Thermal	Import	Wind	Solar	Hydro power	Thermal	Import
2016	3 396	-	0	350	-	3 045	-	-	-	-	2 133	-
2017	3 618	-	140	350	-	3 125	-	-	-	-	2 041	-
2018	3 825	97	281	350	880	2 217	-	-	-	-	2 827	-
2019	4 081	172	388	537	1 345	1 639	-	21,0	7,9	-	3 441	-
2020	4 840	194	306	691	2 234	1 416	-	102,6	90,4	-	4 109	-
2021	5 740	296	447	1 259	1 064	2 674	-	0,5	-	-	5 734	-
2022	6 613	296	498	1 259	1 064	3 496	-	-	-	-	5 303	-
2023	7 044	296	549	1 259	1 064	3 876	-	-	-	-	4 919	-
2024	7 474	296	549	1 259	1 064	4 306	-	-	-	-	4 383	-
2025	7 918	296	549	1 470	535	5 069	-	-	-	-	7 032	-
2026	8 416	296	549	1 470	535	5 567	-	-	-	-	7 488	-
2027	8 942	296	549	1 470	535	6 092	-	-	-	-	6 914	-
2028	9 447	296	549	1 470	535	6 597	-	-	-	-	7 374	-
2029	9 947	296	549	1 470	535	7 098	-	-	-	-	7 839	-
2030	10 367	296	549	1 470	535	7 517	-	-	-	-	8 392	-
2031	11 018	296	549	1 470	535	8 169	-	-	-	-	7 671	-
2032	11 692	296	549	1 470	535	8 838	-	-	-	-	6 927	-
2033	12 407	296	549	1 470	535	9 536	-	-	-	-	6 151	-
2034	13 167	296	549	1 470	535	10 268	-	-	-	-	5 346	-
2035	13 952	296	549	1 470	535	10 990	-	-	-	-	4 553	-

The daily analysis for the year corresponding to maximum IRE curtailment, i.e. 2020, is shown in the figures below, starting with the load valley day.

Figure 3-49: Detailed analysis of one day - 2020 load valley - Model 1

Detailed analysis for a day

Scenario : Model 1
Demand : Baseline
Year : 2020
Day : Valley
Date : 2020-02-22

Reserve : 35
E.R. limit : 18%

Hydro power start: Distributed ☑

Import: Start 19:00 | End 08:00 | Capacity 0

Analysis

			Power used										Instantaneous power not used								
Hour	Sales	Losses	Solar	Wind	Hydro power	Thermal reserve	Thermal coal	Thermal GNLDC	Thermal GNLIQ	Thermal HFO	Thermal DO	Import	Solar	Wind	Hydro power	Thermal coal	Thermal GNLDC	Thermal GNLIQ	Thermal HFO	Thermal DO	Import
01:00	346.4	53.8	0.0	43.5	78.9	251.0	0.0			26.8	0.0					205.0			299.3	46.5	
02:00	325.6	50.1	0.0	43.3	78.9	251.0	0.0			2.4	0.0					205.0			323.6	46.5	
03:00	311.8	47.7	0.0	42.2	78.9	238.4	0.0			0.0	0.0					205.0			338.7	46.5	
04:00	303.5	46.2	0.0	41.5	78.9	229.3	0.0									205.0			347.8	46.5	
05:00	301.6	45.8	0.0	40.4	78.9	228.2	0.0			0.0	0.0					205.0			348.9	46.5	
06:00	292.1	44.1	0.0	40.0	78.9	217.4	0.0									205.0			359.6	46.5	
07:00	302.1	45.9	0.0	38.1	78.9	231.0	0.0			0.0	0.0					205.0			346.1	46.5	
08:00	304.4	46.3	3.6	36.6	78.9	231.7	0.0									205.0			345.4	46.5	
09:00	318.5	48.8	62.8	2.7	78.9	223.0	0.0						15.0	38.3		205.0			354.1	46.5	
10:00	340.0	52.7	70.1	0.0	78.9	243.7	0.0			0.0	0.0		61.6	52.8		205.0			333.4	46.5	
11:00	347.8	54.1	68.0	3.5	78.9	251.0	0.0			0.4	0.0		93.6	50.8		205.0			325.7	46.5	
12:00	341.4	52.9	69.1	1.2	78.9	245.1	0.0						111.7	53.9		205.0			332.0	46.5	
13:00	345.9	53.7	69.7	1.2	78.9	249.8	0.0						112.8	55.2		205.0			327.3	46.5	
14:00	345.4	53.6	68.1	2.6	78.9	249.4	0.0			0.0	0.0		110.2	56.8		205.0			327.7	46.5	
15:00	331.4	51.1	65.0	2.7	78.9	235.9	0.0			0.0	0.0		89.5	59.5		205.0			341.2	46.5	
16:00	356.0	55.5	70.9	2.8	78.9	251.0	0.0			7.8	0.0		48.8	62.4		205.0			318.3	46.5	
17:00	355.1	55.4	71.8	1.4	78.9	251.0	0.0			7.2	0.0			63.6		205.0			318.8	46.5	
18:00	368.8	57.8	14.4	57.9	78.9	251.0	0.0			24.4	0.0					205.0			301.7	46.5	
19:00	403.3	63.9	0.0	50.6	78.9	251.0	86.7									118.3			326.1	46.5	
20:00	486.2	78.7	0.0	47.9	78.9	251.0	187.0									18.0			326.1	46.5	
21:00	489.0	79.2	0.0	46.6	78.9	251.0	191.7			0.0	0.0					13.3			326.1	46.5	
22:00	481.8	77.9	0.0	45.1	78.9	251.0	184.7									20.3			326.1	46.5	
23:00	424.5	67.7	0.0	42.9	78.9	251.0	119.4			0.0	0.0					85.6			326.1	46.5	
00:00	372.8	58.5	0.0	42.3	78.9	251.0	0.0			59.1	0.0					205.0			267.0	46.5	

Note that in addition to the required IRE curtailment, complete curtailment of thermal coal capacity would be required for most of the day.

Figure 3-50: Detailed analysis of the day - 2020 peak load - Model 1

Detailed analysis for a day

Scenario : Model 1
Demand : Baseline
Year : 2020
Day : Peak
Date : 2020-10-14

Reserve : 35
E.R. limit : 18%

Hydro power start
Distributed ☑

Import		
Start	End	Capacity
19:00	08:00	0

Analysis

			Power used										Instantaneous power not used								
Hour	Sales	Losses	Solar	Wind	Hydropower	Thermal reserve	Thermal coal	Thermal GNLOC	Thermal GNLIQ	Thermal HFO	Thermal DO	Import	Solar	Wind	Hydropower	Thermal coal	Thermal GNLOC	Thermal GNLIQ	Thermal HFO	Thermal DO	Import
01:00	572.8	94.1	0.0	18.3	78.9	260.5	205.0			104.2	0.0					0.0			331.2	46.5	
02:00	540.3	88.4	0.0	18.2	78.9	260.5	205.0			66.0	0.0					0.0			369.3	46.5	
03:00	510.8	83.1	0.0	17.6	78.9	260.5	205.0			31.8	0.0					0.0			403.5	46.5	
04:00	524.0	85.5	0.0	17.2	78.9	260.5	205.0			47.8	0.0					0.0			387.5	46.5	
05:00	510.3	83.0	0.0	16.6	78.9	260.5	205.0			32.3	0.0					0.0			403.0	46.5	
06:00	504.4	82.0	0.0	16.3	78.9	260.5	205.0			25.6	0.0					0.0			409.7	46.5	
07:00	522.5	85.2	8.5	15.2	78.9	260.5	205.0			39.5	0.0					0.0			395.8	46.5	
08:00	519.2	84.6	52.4	14.3	78.9	260.5	197.6									7.4			435.3	46.5	
09:00	562.2	92.3	83.9	16.9	78.9	260.5	205.0			9.2	0.0					0.0			426.1	46.5	
10:00	594.5	98.0	116.7	7.8	78.9	260.5	205.0			23.6	0.0		8.0	16.1		0.0			411.7	46.5	
11:00	608.5	100.5	118.9	8.7	78.9	260.5	205.0			37.0	0.0		28.5	16.2		0.0			398.4	46.5	
12:00	606.7	100.2	124.4	2.7	78.9	260.5	205.0			35.3	0.0		29.8	22.5		0.0			400.0	46.5	
13:00	610.0	100.8	123.5	4.0	78.9	260.5	205.0			38.9	0.0		18.2	22.1		0.0			396.4	46.5	
14:00	602.4	99.4	126.2	0.0	78.9	260.5	205.0			31.2	0.0		8.7	28.0		0.0			404.2	46.5	
15:00	583.4	96.0	116.7	5.2	78.9	260.5	205.0			13.1	0.0		8.0	24.6		0.0			422.2	46.5	
16:00	599.9	99.0	90.7	31.7	78.9	260.5	205.0			32.0	0.0					0.0			403.4	46.5	
17:00	588.5	97.0	56.7	31.6	78.9	260.5	205.0			52.8	0.0					0.0			382.5	46.5	
18:00	564.9	92.7	7.9	27.1	78.9	260.5	205.0			78.2	0.0					0.0			357.1	46.5	
19:00	610.6	100.9	0.0	22.6	78.9	260.5	205.0			144.5						0.0			290.8	46.5	
20:00	643.1	106.7	0.0	21.0	78.9	260.5	205.0			184.4	0.0					0.0			250.9	46.5	
21:00	668.1	111.1	0.0	20.2	78.9	260.5	205.0			214.6	0.0					0.0			220.7	46.5	
22:00	656.9	109.1	0.0	19.2	78.9	260.5	205.0			202.3	0.0					0.0			233.0	46.5	
23:00	651.2	108.1	0.0	18.0	78.9	260.5	205.0			196.9						0.0			238.4	46.5	
00:00	602.1	99.4	0.0	17.7	78.9	260.5	205.0			139.4	0.0					0.0			296.0	46.5	

Note that for this peak day, IRE curtailment would be required, and that for a specific time of the day, slight curtailment of thermal coal generation would also be required.

The graphs corresponding to the two previous figures (2020 valley and 2020 peak) are presented in the figures below:

Figure 3-51: Daily capacity - Model 1 - baseline demand – 2020 valley

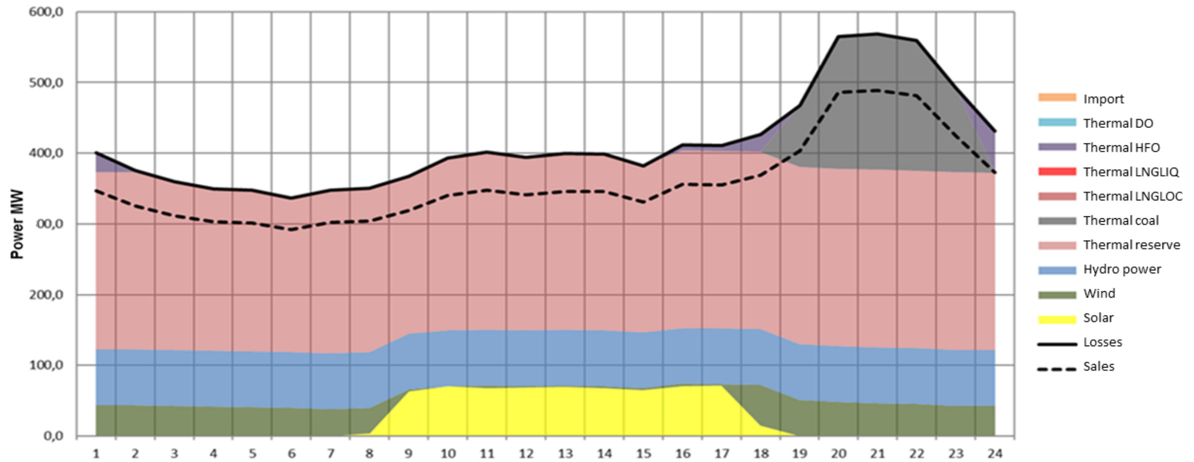
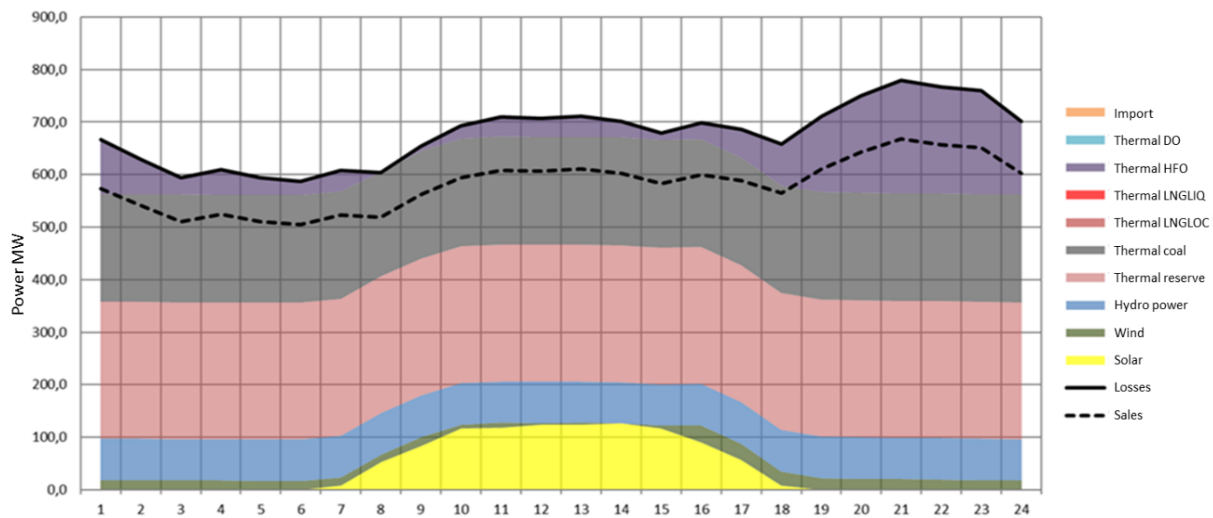


Figure 3-52: Daily capacity - Model 1 - baseline demand – 2020 peak



Finally, note that as shown in the figure above on energy utilization, the years in which the highest curtailment is required (2019, 2020, and 2021) are years in which the percentage of installed IRE capacity significantly exceeds the identified target of 20%, as shown in the last column of the following figure:

Figure 3-53: Technology mix - Model 1

Year	Wind	Solar	Thermal	Hydro Power	Import	Intermittent renewable	Others	Intermittent renewable percentage
2016			631	81		0	712	0%
2017		118	631	81		118	712	14%
2018	52	193	746	81		245	827	23%
2019	104	233	746	129		337	875	28%
2020	159	263	956	164		392	1120	26%
2021	159	293	1136	328		422	1464	22%
2022	159	323	1136	328		452	1464	24%
2023	159	323	1136	328		482	1464	25%
2024	159	323	1136	328		482	1464	25%
2025	159	323	1481	398		482	1879	20%
2026	159	323	1596	398		482	1994	19%
2027	159	323	1596	398		482	1994	19%
2028	159	323	1711	398		482	2109	19%
2029	159	323	1826	398		482	2224	18%
2030	159	323	1941	398		482	2339	17%
2031	159	323	1941	398		482	2339	17%
2032	159	323	1941	398		482	2339	17%
2033	159	323	1941	398		482	2339	17%
2034	159	323	1941	398		482	2339	17%
2035	159	323	1941	398		482	2339	17%

Curtailment of thermal coal generation

Curtailment of thermal coal generation is dependent on two main factors:

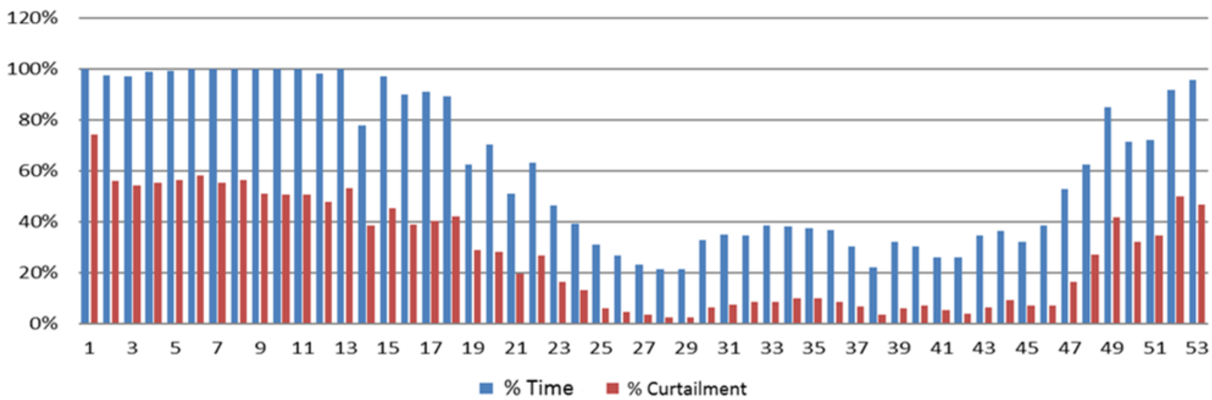
- The technical limits of each plant
- Generation to be considered a priority over other generation sources.

Thus, by prioritizing IRE generation, the non-distributed hydropower generation starting at 7:00 p.m. and the thermal generation required to provide the synchronous reserve, thermal coal generation can only be used to fill the remaining load in order to meet the demand. Once the technical limit is reached, thermal coal generation is then completely curtailed. Another factor affecting curtailment is the distribution of hydropower. Analyses were conducted considering undistributed hydropower generation around an average value.

In this context, and considering the thermal coal units available 100% of the time and applying the various analytical parameters indicated above, we obtain a curtailment level considered to be a potential annual maximum.

For 2020, this maximum curtailment would be around 481 GWh, and the curtailment percentages – either in hours or in energy – would be as shown in the following two figures:

Figure 3-54: Minimum technical curtailment with reserve - Model 1



The time percentage shows the number of hours when there is curtailment, regardless of the level of energy curtailed. The curtailment percentage shows the energy curtailed for each week.

It should be noted that the estimated level of curtailment will be reduced during maintenance periods i.e. scheduled unavailability). Thus, a maintenance program designed to carry out maintenance during the weeks when maximum curtailment is likely would significantly reduce the level of curtailment.

A rough estimate indicates that approximately 78 GWh of curtailment could potentially be avoided, which would reduce total curtailment to 403 GWh for 2020.

Using the same basis of calculation, curtailment over the period 2019-2029 would be around 1,507 GWh considering a suitable maintenance program, as shown in the following figure (see total GWh in the last column):

Figure 3-55: Thermal coal curtailment - Model 1

2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2027	2029	Total	Total
MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	GWh
	99,011	481,173	564,191	390,540	268,183	178,403	97,308	62,113	35,920	19,949	10,473	2,207,263	2,207
Maintenance gain	26,000	78,000	85,000	154,000	120,000	87,000	55,000	41,000	27,000	17,000	10,000	700,000	700,000
	73,011	403,173	479,191	236,540	148,183	91,403	42,308	21,113	8,920	2,949	473,000	1,507,263	1,507

Summary of Model 1 - Baseline demand

Model 1, which considers baseline demand in combination with the corresponding supply in the January 2017 Senelec Generation Plan, shows that:

- The sizing of thermal coal plants does not meet the established criterion and presents a grid reliability issue; in this regard, any failure will result in load shedding.
- The technical limits of these plants present an operational management challenge.
- The combination of load, IRE, thermal coal and synchronous reserve availability is not optimal, primarily in the period 2019-2022.

- The required synchronous reserve applied to the modeling requires rapid action to ensure they are implemented by upgrading equipment and agreements with IPPs and entities responsible for hydropower generation.

MODEL 2 – BASELINE DEMAND AND PATRP SUPPLY SCENARIO (WITHOUT DECOMMISSIONING)

The aim of this model is primarily to satisfy the reserve criterion of 20% or at least a minimum of 15%, by adding the required capacity levels (additions are listed in another figure below), compared to Model 1, which analyzed the Senelec plan with no adjustment.

It is important to note that the following added capacities cannot be considered:

- Sendou 1 (115 MW in June 2018)
- Solar IRE planned by Senelec by December 2017
- Wind IRE planned by Senelec by December 2020.

The analytical parameters specific to this model were established in accordance with the previously stated assumptions, and are shown in the figure below:

Figure 3-56: Evaluation of Senelec and IPP reserve and penetration rates from 2018 to 2035

PATRP	Required Reserve (MW)	Hydro Reserve (MW)	Senelec Reserve	In Service (MW)	Contributor y (MW)	Load (MW)	Average Hydro (MW)	Possible RE	Penetration (%)
2018	20.3	8	12.3	98.4	86.1	304	40	178	59%
2019	35.19	8	27.19	217.52	190.33	327	40	96	29%
2020	53 958	12	41 958	335.7	293.71	394	57.5	43	11%
2021	53 958	35	18 958	151.7	132.71	485	121.7	231	48%
2022	53 958	38	15 958	127.7	111.71	572	143.6	316	55%
2023	53 958	38	15 958	127.7	111.71	607	143.6	351	58%
2024	53 958	38	15 958	127.7	111.71	641	143.6	385	60%
2025	53 958	47	6 958	55.7	48.71	675	167.7	459	68%
2026	53 958	47	6 958	55.7	48.71	714	167.7	497	70%
2027	71.55	47	24.55	196.4	171.85	755	167.7	415	55%
2028	71.55	65	6.55	52.4	45.85	792	219.12	527	67%
2029	71.55	65	6.55	52.4	45.85	828	219.12	563	68%
2030	71.55	65	6.55	52.4	45.85	853	219.12	588	69%
2031	71.55	65	6.55	52.4	45.85	904	219.12	639	71%
2032	90.32	65	25.32	202.6	177.24	956	219.12	560	59%
2033	90.32	65	25.32	202.6	177.24	1012	219.12	616	61%
2034	90.32	65	25.32	202.6	177.24	1071	219.12	675	63%
2035	90.32	65	25.32	202.6	177.24	1132	219.12	736	65%

It is important to note that these parameters are applied equally over all hours in the year.

Figure 3-57: Addition of capacity (net capacities of power plants)

			MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
			2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL
MODEL 2 Baseline scenario WITH MINES PATRP plan without decommissioning	CES 1	Coal		115																		115
	Africa	Coal						90														90
	Malicounda	HFO Dual				120																120
	Additional power	Dual								120												120
	Additional power	CCGT										120	120			240		240		120	120	960
	Additional power	Hydro				83	103	61			70			118								435
	TOTAL																					1840
	Additional power	Solar	78				30	85					40					30				263
	Additional power	Wind		51.75	51.75	55.2							51.75					55.2				265.65
																					Total	2368.70

For the period 2017-2035, we have identified the following added capacities:

- 205 MW Thermal coal
- 240 MW Dual
- 960 MW CCGT
- 435 MW Hydropower
- 265.65 MW Wind
- 263 MW Solar.

Thus, the Malicounda plants and a thermal coal segment are prioritized for the period 2020-2022, and these projects are considered as having already been initiated by Senelec. In 2024, we are adding a dual power plant considering that conversion to NG would be applicable in the first years of its commissioning and considering that this type of generation is, as indicated in section **Error! Reference source not found.** tab **Error! Reference source not found.**, highly compatible with IRE management.

It should also be noted that in terms of hydroelectric power plants, generation from the Amaria and Grand Kinkon power plants is scheduled to arrive in 2028. These plants were selected because of their solid capacity levels. The commissioning dates established are considered to be conservative. It should be noted that for Amaria, a call for proposals was launched in May 2017 for consulting services for feasibility studies and a detailed preliminary project.

Finally, still concerning hydro power plants, the commissioning dates of the Kaleta and Sambangalou plants differ from those indicated in the Senelec plan; this is based on an assessment of the information obtained in connection with these projects, as shown in the following figure:

Figure 3-58: Kaleta - Sambangalou commissioning

Power Plant	Senelec	PATRP
Kaleta	2019-01-01	2020-07-01
Sambangalou	2021-01-01	2022-07-01

Figure 3-59: Pmax, Model 2

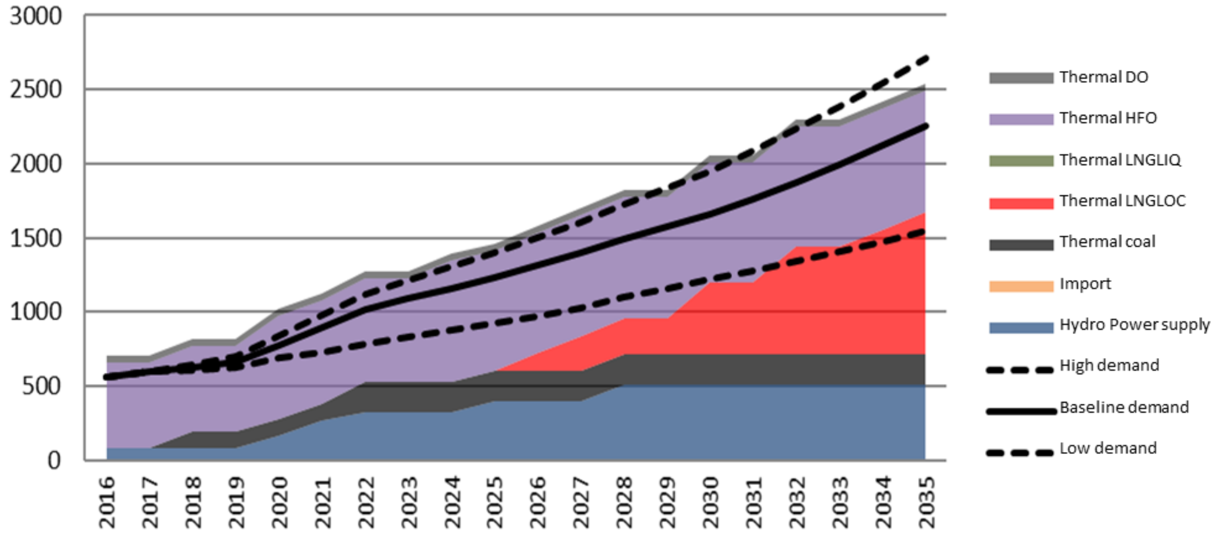
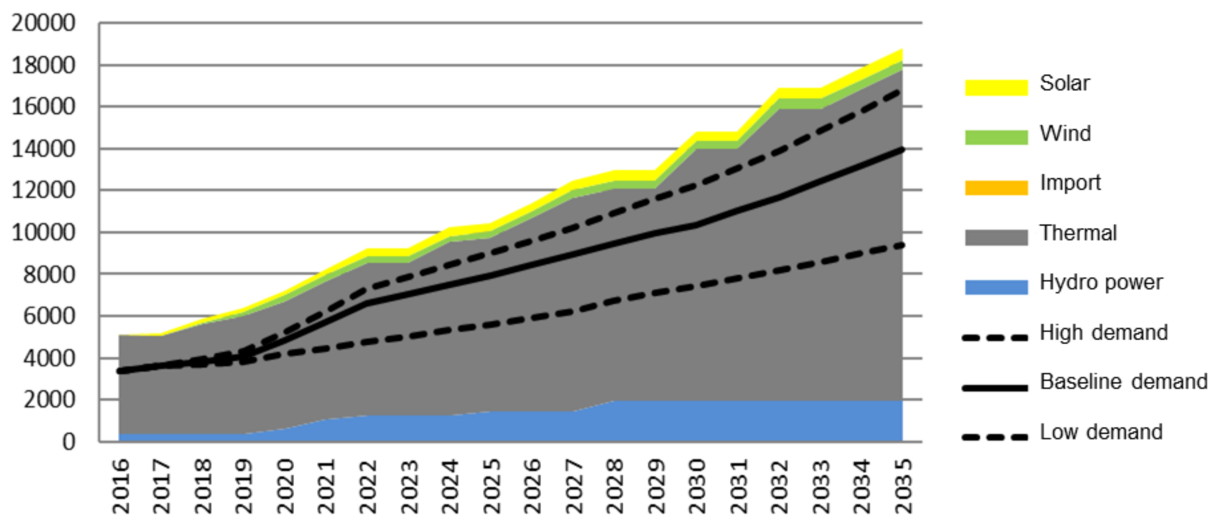


Figure 3-60: Energy (GWh), Model 2



Supply planning

Based on our various evaluation criteria, we obtained the results below.

With the added generation shown above, target reserve levels are met across the entire range, as shown in the figure below:

Figure 3-61: Reserve analysis - Model 2

Analysis

Reserve Analysis

Scenario : Model 2 | Demand : Baseline | ☐ Distributed hydropower

Year	Peak x 15% MW	Valley x 15% MW	P < 25% of the time x 15% MW	P < 50% of the time x 15% MW	Pmax reserve (%)	Pmax reserve (MW)
2016	84	34	52	60	25%	141
2017	89	36	56	64	18%	105
2018	94	38	59	68	30%	190
2019	100	41	63	73	23%	151
2020	117	50	75	86	31%	239
2021	135	63	90	102	25%	222
2022	153	76	104	117	25%	254
2023	163	80	111	124	17%	184
2024	174	84	117	132	20%	233
2025	185	89	124	140	19%	229
2026	197	93	132	149	20%	266
2027	210	99	140	158	21%	298
2028	223	103	148	167	22%	328
2029	236	107	155	176	15%	241
2030	248	110	161	184	24%	401
2031	265	116	171	195	17%	293
2032	281	123	181	207	22%	421
2033	299	130	192	220	15%	302
2034	318	137	204	234	14%	296
2035	338	145	216	248	13%	285

Prioritization and curtailment of generation (daily analysis of generating load peak/valley)

Limitation of IRE

Based on the analytical parameters specific to this synchronous reserve and penetration level modeling, and considering hydropower generation distributed around an average value, we have determined curtailment of IRE over the period 2019- 2020 of around 135.9 GWh. We also note that for 2020, 2,607 GWh would be generated by the plants contributing to the synchronous reserve, as shown in the figure below:

Figure 3-62: Use of available energy - Model 2

Use of available energy

Analysis

Scenario : Model 2 | Demand : Baseline | Hydropower Start: Distributed ☑ | Import Start 19:00

Year	Total demand GWh	Energy use GWh						Unused energy GWh				
		Wind	Solar	Hydropower	Thermal reserve	Thermal	Import	Wind	Solar	Hydropower	Thermal	Import
2016	3,396	-	0	350	-	3,045	-	-	-	-	2,133	-
2017	3,618	-	140	350	-	3,125	-	-	-	-	2,041	-
2018	3,825	97	201	350	877	2,300	-	-	-	-	2,723	-
2019	4,081	193	201	350	1,345	1,992	-	0.0	-	-	3,054	-
2020	4,840	251	198	598	2,240	1,552	-	45.3	2.3	-	3,172	-
2021	5,740	296	252	1,066	1,064	3,061	-	-	-	-	3,232	-
2022	6,613	296	396	1,259	1,064	3,598	-	-	-	-	3,460	-
2023	7,044	296	396	1,259	1,064	4,024	-	-	-	-	2,994	-
2024	7,474	296	396	1,259	1,212	4,311	-	-	-	-	3,592	-
2025	7,918	296	396	1,470	608	5,138	-	-	-	-	3,284	-
2026	8,416	296	396	1,470	465	5,783	-	-	-	-	3,779	-
2027	8,942	393	464	1,470	465	6,148	-	-	-	-	4,439	-
2028	9,447	393	464	1,922	465	6,201	-	-	-	-	4,395	-
2029	9,947	393	464	1,922	465	6,689	-	-	-	-	3,868	-
2030	10,367	393	464	1,922	465	7,123	-	-	-	-	5,491	-
2031	11,018	393	464	1,922	465	7,763	-	-	-	-	4,794	-
2032	11,692	496	515	1,922	465	8,294	-	-	-	-	6,332	-
2033	12,407	496	515	1,922	465	8,998	-	-	-	-	5,565	-
2034	13,167	496	515	1,922	465	9,753	-	-	-	-	5,793	-
2035	13,952	496	515	1,922	465	10,532	-	-	-	-	5,996	-

The daily analysis for the year corresponding to maximum IRE curtailment, i.e. 2020, is shown in the figures below, starting with the load valley day.

Figure 3-63: Detailed analysis of one day - 2020 load valley - Model 2

Detailed analysis for a day

Scenario :	Model 2		Hydropower	Import		
Demand :	Baseline		Start:	Start	End	Capacity
Year :	2020	Reserve : 42		19:00	08:00	0
Day :	Valley	E.R. limit : 11%	Distributed: ☑			
Date :	2020-02-22					

Analysis

Hour	Sales	Losses	Power used										Instantaneous power not used								
			Solar	Wind	Hydropower	Thermal reserve	Thermal coal	Thermal LOCNG	Thermal LIQNG	Thermal HFO	Thermal DO	Import	Solar	Wind	Hydropower	Thermal coal	Thermal LOCNG	Thermal LIQNG	Thermal HFO	Thermal DO	Import
01:00	346.4	53.8	0.0	43.5	57.5	296.5	0.0			2.7	0.0					115.0			277.9	46.5	
02:00	325.6	50.1	0.0	40.5	57.5	277.7	0.0							2.8		115.0			299.4	46.5	
03:00	311.8	47.7	0.0	39.4	57.5	262.5	0.0							2.8		115.0			314.6	46.5	
04:00	303.5	46.2	0.0	37.9	57.5	254.3	0.0							3.6		115.0			322.8	46.5	
05:00	301.6	45.8	0.0	37.7	57.5	252.2	0.0			0.0	0.0			2.6		115.0			324.9	46.5	
06:00	292.1	44.1	0.0	36.5	57.5	242.2	0.0							3.5		115.0			334.9	46.5	
07:00	302.1	45.9	0.0	38.1	57.5	252.4	0.0			0.0	0.0					115.0			324.7	46.5	
08:00	304.4	46.3	1.8	36.6	57.5	254.9	0.0									115.0			322.2	46.5	
09:00	318.5	48.8	39.4	0.9	57.5	269.5	0.0							40.1		115.0			307.6	46.5	
10:00	340.0	52.7	39.0	3.4	57.5	292.8	0.0			0.0	0.0		27.7	49.3		115.0			284.4	46.5	
11:00	347.8	54.1	41.6	2.4	57.5	296.5	0.0			3.8	0.0		40.2	52.0		115.0			276.8	46.5	
12:00	341.4	52.9	31.0	12.0	57.5	293.7	0.0						60.5	43.2		115.0			283.4	46.5	
13:00	345.9	53.7	31.3	12.3	57.5	296.5	0.0			2.0	0.0		61.1	44.1		115.0			278.6	46.5	
14:00	345.4	53.6	30.6	12.9	57.5	296.5	0.0			1.5	0.0		59.7	46.5		115.0			279.1	46.5	
15:00	331.4	51.1	39.8	1.4	57.5	283.8	0.0						38.4	60.9		115.0			293.3	46.5	
16:00	356.0	55.5	35.5	8.5	57.5	296.5	0.0			13.5	0.0		25.2	56.7		115.0			267.1	46.5	
17:00	355.1	55.4	36.4	8.5	57.5	296.5	0.0			11.5	0.0			56.5		115.0			269.1	46.5	
18:00	368.8	57.8	7.3	39.0	57.5	296.5	0.0			26.3	0.0			18.9		115.0			254.3	46.5	
19:00	403.3	63.9	0.0	50.6	57.5	296.5	0.0			62.6						115.0			218.0	46.5	
20:00	486.2	78.7	0.0	47.9	57.5	296.5	115.0			47.9	0.0					0.0			232.7	46.5	
21:00	489.0	79.2	0.0	46.6	57.5	296.5	115.0			52.7						0.0			228.0	46.5	
22:00	481.8	77.9	0.0	45.1	57.5	296.5	115.0			45.6	0.0					0.0			235.0	46.5	
23:00	424.5	67.7	0.0	42.9	57.5	296.5	95.3			0.0	0.0					19.7			280.6	46.5	
00:00	372.8	58.5	0.0	42.3	57.5	296.5	0.0			35.0	0.0					115.0			245.6	46.5	

Note that in addition to the required IRE curtailment, complete curtailment of thermal coal capacity would be required for most of the day.

Figure 3-64: Detailed analysis of the day - 2020 peak load - Model 2

Detailed analysis for a day

Scenario : Model 2
Demand : Baseline
Year : 2020
Day : Peak
Date : 2020-10-14

Reserve : 42
E.R. limit : 11%

Hydropower
Start:
Distributed ☑

Import		
Start	End	Capacity
19:00	08:00	0

Analysis

			Power used										Instantaneous power not used								
Hour	Sales	Losses	Solar	Wind	Hydropower	Thermal reserve	Thermal coal	Thermal LOCNG	Thermal LIQNG	Thermal HFO	Thermal DO	Import	Solar	Wind	Hydropower	Thermal coal	Thermal LOCNG	Thermal LIQNG	Thermal HFO	Thermal DO	Import
01:00	572.8	94.1	0.0	18.3	78.9	300.0	115.0			154.7						0.0			241.9	46.5	
02:00	540.3	88.4	0.0	18.2	78.9	300.0	115.0			116.6	0.0					0.0			280.0	46.5	
03:00	510.8	83.1	0.0	17.6	78.9	300.0	115.0			82.3	0.0					0.0			314.2	46.5	
04:00	524.0	85.5	0.0	17.2	78.9	300.0	115.0			98.4	0.0					0.0			298.2	46.5	
05:00	510.3	83.0	0.0	16.6	78.9	300.0	115.0			82.8						0.0			313.7	46.5	
06:00	504.4	82.0	0.0	16.3	78.9	300.0	115.0			76.2	0.0					0.0			320.4	46.5	
07:00	522.5	85.2	4.3	15.2	78.9	300.0	115.0			94.2	0.0					0.0			302.3	46.5	
08:00	519.2	84.6	26.6	14.3	78.9	300.0	115.0			69.0	0.0					0.0			327.6	46.5	
09:00	562.2	92.3	42.5	16.9	78.9	300.0	115.0			101.2	0.0					0.0			295.4	46.5	
10:00	594.5	98.0	63.2	13.0	78.9	300.0	115.0			122.5				10.9		0.0			274.1	46.5	
11:00	608.5	100.5	74.6	3.2	78.9	300.0	115.0			137.2				21.6		0.0			259.4	46.5	
12:00	606.7	100.2	64.8	12.6	78.9	300.0	115.0			135.5			13.2	12.6		0.0			261.1	46.5	
13:00	610.0	100.8	71.8	6.2	78.9	300.0	115.0			138.9				19.8		0.0			257.7	46.5	
14:00	602.4	99.4	68.3	8.5	78.9	300.0	115.0			131.1				19.5		0.0			265.5	46.5	
15:00	583.4	96.0	63.2	11.0	78.9	300.0	115.0			111.4	0.0			18.8		0.0			285.2	46.5	
16:00	599.9	99.0	45.9	30.3	78.9	300.0	115.0			128.7				1.4		0.0			267.9	46.5	
17:00	588.5	97.0	28.7	31.6	78.9	300.0	115.0			131.3						0.0			265.2	46.5	
18:00	564.9	92.7	4.0	27.1	78.9	300.0	115.0			132.7						0.0			263.9	46.5	
19:00	610.6	100.9	0.0	22.6	78.9	300.0	115.0			195.1						0.0			201.5	46.5	
20:00	643.1	106.7	0.0	21.0	78.9	300.0	115.0			235.0						0.0			161.6	46.5	
21:00	668.1	111.1	0.0	20.2	78.9	300.0	115.0			265.2						0.0			131.4	46.5	
22:00	656.9	109.1	0.0	19.2	78.9	300.0	115.0			252.9	0.0					0.0			143.7	46.5	
23:00	651.2	108.1	0.0	18.0	78.9	300.0	115.0			247.4	0.0					0.0			149.1	46.5	
00:00	602.1	99.4	0.0	17.7	78.9	300.0	115.0			189.9	0.0					0.0			206.7	46.5	

Note that for this peak day, partial IRE curtailment would be required, but thermal coal generation could be used at its maximum all day.

The graphs corresponding to the two previous figures (2020 valley and 2020 peak) are presented in the figures below:

Figure 3-65: Daily power - Model 2 - baseline demand – 2020 valley

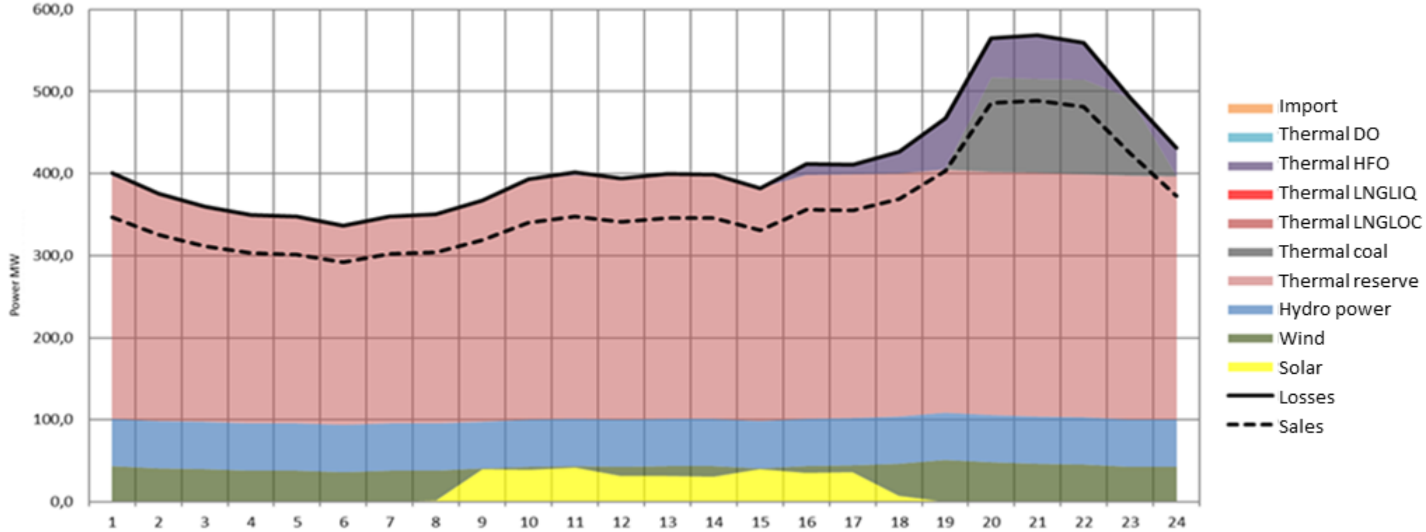
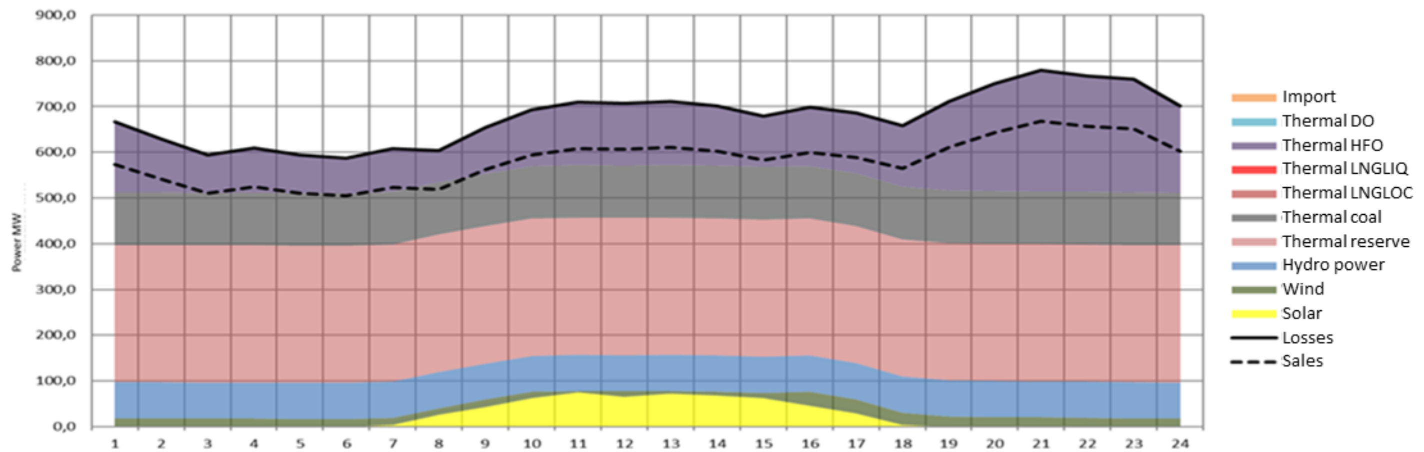


Figure 3-66: Daily power - Model 2 - baseline demand – 2020 peak



Finally, it should be noted that the level of IRE curtailment remains significant due to the combination of wind, load and high synchronous reserve level that needs to be provided by Senelec and IPPs. However, the percentage of IRE is more in line with the target of 20%, as shown in the following figure:

Figure 3-67: Technology mix - Model 2

Year	Wind	Solar	Thermal	Hydro Power	Import	Intermittent renewable	Others	Intermittent renewable percentage
2016			631	81		0	712	0%
2017		118	631	81		118	712	14%
2018	52	118	746	81		170	827	17%
2019	104	118	746	81		222	827	21%
2020	159	118	866	164		277	1030	21%
2021	159	148	866	267		307	1133	21%
2022	159	233	956	328		392	1284	23%
2023	159	233	956	328		392	1284	23%
2024	159	233	1076	328		392	1404	22%
2025	159	233	1076	398		392	1474	21%
2026	159	233	1196	398		392	1594	20%
2027	210	273	1316	398		483	1714	22%
2028	210	323	1316	517		483	1833	21%
2029	210	323	1316	517		483	1833	21%
2030	210	323	1556	517		483	2073	19%
2031	210	323	1556	517		483	2073	19%
2032	266	323	1796	517		569	2313	20%
2033	266	323	1796	517		569	2313	20%
2034	266	323	1916	517		569	2433	19%
2035	266	323	2036	517		569	2553	18%

Curtailment of thermal coal generation

Curtailment of thermal coal generation is dependent on two main factors:

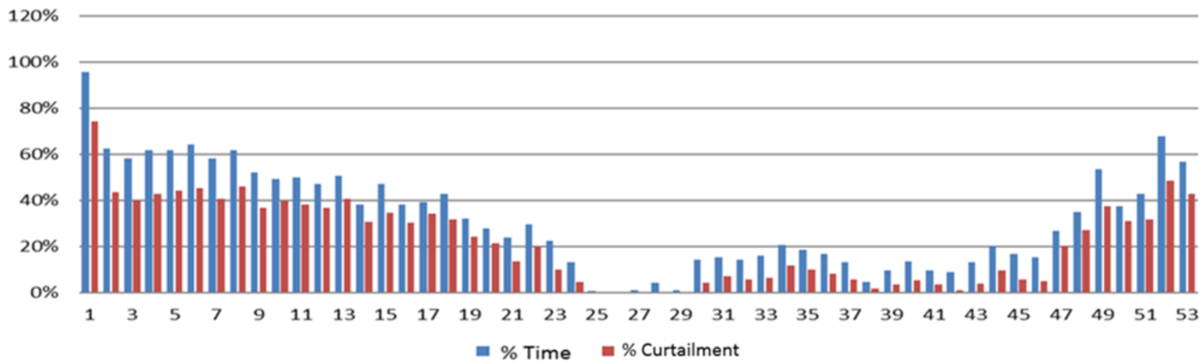
- The technical limits of each plant
- Generation to be considered a priority over other generation sources.

Thus, by prioritizing IRE generation, the non-distributed hydropower generation starting at 7:00 p.m. and the thermal generation required to provide the synchronous reserve, thermal coal generation can only be used to fill the remaining load in order to meet the demand. Once the technical limit is reached, complete curtailment of thermal coal generation is then applied. Another factor affecting curtailment is the distribution of hydropower. Analyses were conducted considering undistributed hydropower generation around an average value.

In this context, and considering the thermal coal units available 100% of the time and applying the various analytical parameters indicated above, we obtain a curtailment level considered to be a potential annual maximum.

For 2020, this maximum curtailment would be around 215 GWh, and the curtailment percentages – either in hours or in energy – would be as shown in the following two figures:

Figure 3-68: Minimum technical curtailment with reserve - Model 2



The time percentage shows the number of hours when there is curtailment, regardless of the level of energy curtailed. The curtailment percentage shows the percentage of energy curtailed for each week.

Note that the estimated level of curtailment will be reduced during maintenance periods. Thus, a program designed to carry out maintenance during the weeks when maximum curtailment is possible would significantly reduce the level of curtailment.

A rough estimate indicates that for 2020, around 34 GWh could thus avoid curtailment, which would reduce the annual curtailment level to 181 GWh (see figure below).

Using the same basis of calculation, curtailment over the period 2019-2029 would be around 366 GWh considering a suitable maintenance program, as shown in the following figure (see last column):

Figure 3-69: Curtailment - thermal coal - Model 2

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total	Total
MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	GWh
123 180	214 952	52 608	52 829	27590	12 565	4 931	1 035	18 657	7 413	2 855	518 615	519
32 200	34 000	16 000	17 000	19 000	10 000	3 700	800	12 000	5 400	2 200	152 300	152
90 980	180 952	36 608	35 829	8 590	2 565	1 231	235	6 657	2 013	655	366 315	366

Summary of Model 2 - Baseline demand

Recall that Model 1 analyzed the Senelec plan with no adjustment. Model 2 primarily aims to satisfy the 20% reserve criterion, or at least a minimum of 15%, by adding the required capacity. An analysis of the applicable criteria highlights the following elements regarding Model 2:

- The sizing of the thermal coal plants does not meet the established criterion and presents a grid reliability issue. In this sense, any failure will result in load shedding.
- The technical limits of these plants present an operational management challenge.
- The combination of load, IRE, thermal coal and synchronous reserve availability is not optimal, primarily over the period 2019-2022.
- The synchronous reserve levels required and applied to the modeling require rapid action to ensure they are implemented by upgrading equipment and agreements with IPPs and entities responsible for hydropower generation.

This model, which automatically does not consider any decommissioning, adds generation at the required time to meet the demand while optimizing added IRE capacity over time and favoring, after 2022, the installed capacity that is more compatible with IRE and easily convertible to NG.

All of these elements achieve lower curtailment levels compared to Model 1 (based on Senelec planning), for both IRE and thermal coal generation. However, it provides little or no flexibility for a decommissioning program. Nonetheless, the IRE percentage in model 2 is considered to be more in line with the target of 20% than in model 1.

MODEL 3 – BASELINE DEMAND AND PATRP SUPPLY SCENARIO (WITH DECOMMISSIONING)

This model aims primarily to satisfy the reserve criterion of 20%, or at least a minimum of 15%, by adding the required capacity levels (additions are listed in another figure below), as with model 2. However, it takes into account the possible decommissioning of generation units according to SENELEC formulations.

It is important to note that the following added capacities cannot be considered:

- Sendou 1 (115 MW in June 2018)
- Solar IRE planned by Senelec by December 2017
- Wind IRE planned by Senelec by December 2020.

To this we add the following three directions provided by Senelec in their feedback on the supply and demand balance report issued in March 2017:

- Costly and old generating units such as 301, 303, TAG2 and TAG4, and even the first three plants in C4, must be decommissioned.
- The Africa Energy project is 270 MW, comprised of three 90 MW plants. This configuration data is valid at this time, if we rely on the implementation status of the contract already signed (do not consider 90 MW only).
- The size of Africa Energy has already been established. Senelec must instead move towards negotiations on the commissioning and phasing dates. Make recommendations in this regard.

The analytical parameters specific to this model were established in accordance with the previously stated assumptions, and are shown in the figure below:

Figure 3-70: Evaluation of Senelec and IPP reserve and penetration rates from 2018 to 2035

PATRP	Required Reserve (MW)	Hydro Reserve (MW)	Senelec reserve	In Service (MW)	Contributory (MW)	Load (MW)	Average Hydro (MW)	Possible RE	Penetration (%)
2018	20.3	8	12.3	98.4	86.1	304	40	178	59%
2019	35.19	8	27.19	217.52	190.33	327	40	96	29%
2020	53.958	12	41.958	335.7	293.71	394	57.5	43	11%
2021	53.958	35	18.958	151.7	132.71	485	121.7	231	48%
2022	53.958	38	15.958	127.7	111.71	572	143.6	316	55%
2023	53.958	38	15.958	127.7	111.71	607	143.6	351	58%
2024	53.958	38	15.958	127.7	111.71	641	143.6	385	60%
2025	53.958	47	6.958	55.7	48.71	675	167.7	459	68%
2026	53.958	47	6.958	55.7	48.71	714	167.7	497	70%
2027	71.55	47	24.55	196.4	171.85	755	167.7	415	55%
2028	71.55	65	6.55	52.4	45.85	792	219.12	527	67%
2029	71.55	65	6.55	52.4	45.85	828	219.12	563	68%
2030	71.55	65	6.55	52.4	45.85	853	219.12	588	69%
2031	71.55	65	6.55	52.4	45.85	904	219.12	639	71%
2032	90.32	65	25.32	202.6	177.24	956	219.12	560	59%
2033	90.32	65	25.32	202.6	177.24	1012	219.12	616	61%
2034	90.32	65	25.32	202.6	177.24	1071	219.12	675	63%
2035	90.32	65	25.32	202.6	177.24	1132	219.12	736	65%

It is important to note that these parameters are applied consistently over all hours in the year.

Figure 3-71: Addition of capacity (net capacities of power plants)

			MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
			2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL
MODEL 3 Baseline scenario WITH MINES PATRP plan with decommissioning	CES 1	Coal		115																		115
	Africa	Coal						90	90	90												270
	Malicounda	HFO Dual				120																120
	Additional power	Dual				120																120
	Additional power	CCGT										120	120			240		240		120	120	960
	Additional power	Hydro				83	103	61			70			118								435
	TOTAL																					**1840**
	Decommissioning						116		51													(167)
	Additional power	Solar																30				263
	Additional power	Wind		51.75	51.75	55.2							51.75					55.2				265.65
																					Total	**2381.65**

For the period 2017-2035, we have identified the following added capacities:

- 385 MW Thermal coal
- 240 MW Dual
- 960 MW CCGT
- 435 MW Hydropower
- 265.65 MW Wind
- 263 MW Solar

Thus, the Malicounda and Africa Energy power plants are considered. In 2020, we are adding a 120 MW dual power plant, considering that this type of generation is, as indicated in section **Error! Reference source not found.** Characteristics of thermal generation with respect to intermittent renewable energy, highly compatible with IRE management. Moreover, this added capacity will permit the decommissioning of the generation units specified by Senelec while providing, in combination with Malicounda, the availability of generation units with the capacity and technical characteristics to provide the synchronous reserve, and thus guarantee Senelec a certain level of autonomy.

The decommissioning considered for Model 3 is shown in the figure below:

Figure 3-72: Decommissioning, Model 3

Power Plant	Type	Decommissioning date
KAHONE 1-149-A	Thermal	2020-12-30
KAHONE 1-150-A	Thermal	2020-12-30
KAHONE 1-93-A	Thermal	2020-12-30
KAHONE 1-94-A	Thermal	2020-12-30
C-301-A	Thermal	2020-12-30
C-303-A	Thermal	2020-12-30
C-2 TAG4-A	Thermal	2020-12-30
TAG2-A	Thermal	2020-12-30
C-401A	Thermal	2022-12-30
C-402-A	Thermal	2022-12-30
C-403-A	Thermal	2022-12-30

These 11 generation units are considered to have the highest variable generation costs according to the criteria applied in the models.

It should also be noted that in terms of hydroelectric power plants, the Amaria and Grand Kinkon stations are scheduled to start operating in 2028. These stations were selected for their attractive capacity levels, and the commissioning dates established are considered conservative.

Finally, still concerning hydro power plants, the commissioning dates of the Kaleta and Sambangalou plants differ from those indicated in the Senelec plan; this is based on an assessment of the information obtained about these projects, as shown in the following figure:

Figure 3-73: Kaleta – Sambangalou commissioning

Power Plant	Senelec	PATRP
Kaleta	2019-01-01	2020-07-01
Sambangalou	2021-01-01	2022-07-01

Figure 3-74: Pmax, Model 3

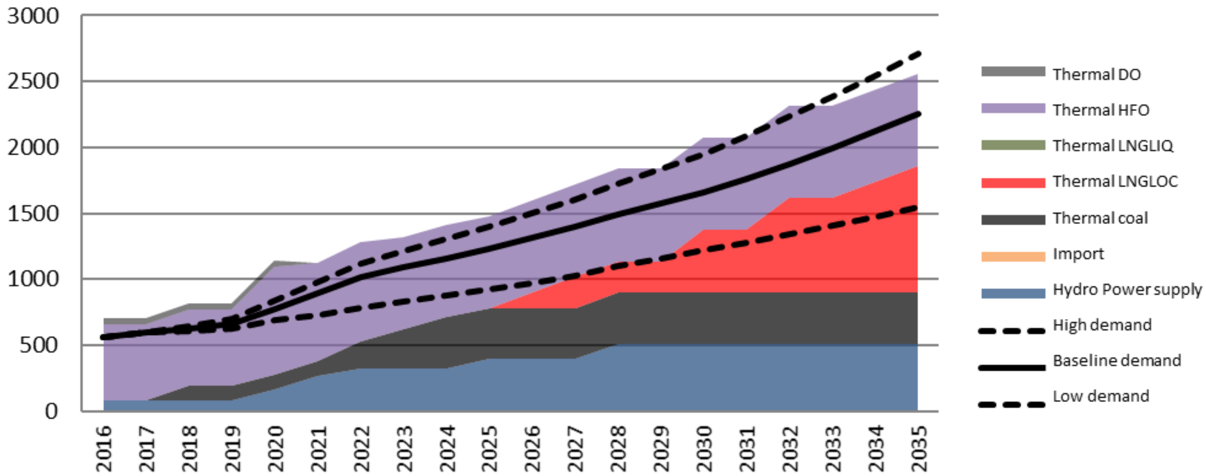
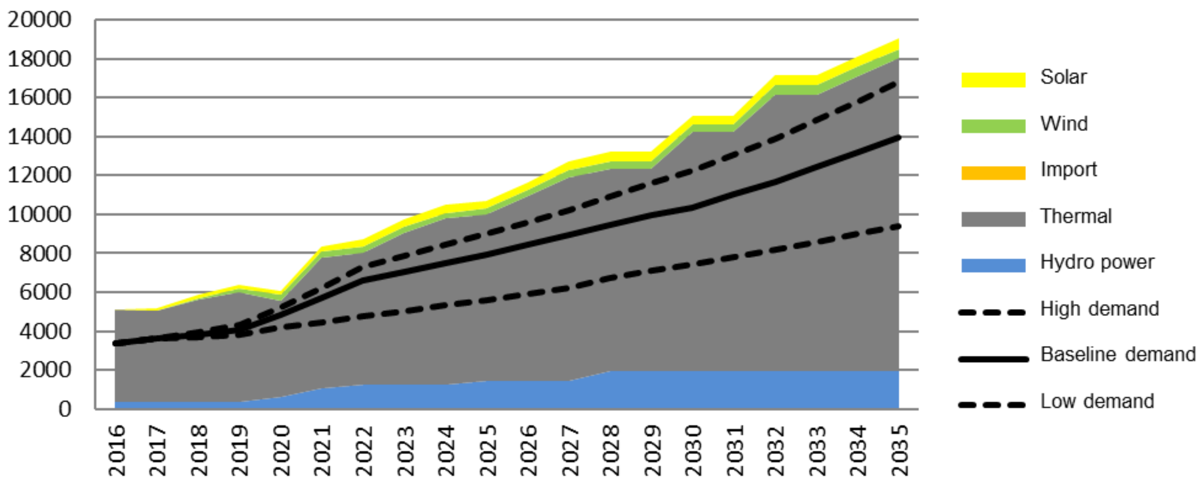


Figure 3-75: Energy (GWh), Model 3



Supply planning

Based on our various evaluation criteria, we obtained the results below.

With the added generation shown above, target reserve levels are met across the entire range, as shown in the figure below:

Figure 3-76: Reserve analysis - Model 3

Analysis

Reserve Analysis

Scenario : Model 3 | Demand : Baseline | ☐ Distributed hydropower | Reduced demand

Year	Peak x 15% MW	Valley x 15% MW	P < 25% of the time x 15% MW	P < 50% of the time x 15% MW	Pmax reserve (%)	Pmax reserve (MW)	Reserve of 15% (MW)	Reserve of 20% (MW)
2016	84	34	52	60	25%	141	-	-
2017	89	36	56	64	18%	105	-	12
2018	94	38	59	68	30%	190	-	-
2019	100	41	63	73	23%	151	-	-
2020	117	50	75	86	46%	359	-	-
2021	135	63	90	102	26%	230	-	-
2022	153	76	104	117	26%	262	-	-
2023	163	80	111	124	21%	233	-	-
2024	174	84	117	132	22%	252	-	-
2025	185	89	124	140	20%	248	-	-
2026	197	93	132	149	22%	285	-	-
2027	210	99	140	158	23%	317	-	-
2028	223	103	148	167	23%	347	-	-
2029	236	107	155	176	16%	260	-	46
2030	248	110	161	184	25%	420	-	-
2031	265	116	171	195	18%	312	-	34
2032	281	123	181	207	23%	440	-	-
2033	299	130	192	220	16%	321	-	65
2034	318	137	204	234	15%	315	3	91
2035	338	145	216	248	14%	304	29	122

Prioritization and curtailment of generation (daily analysis of generation during load peak/valley)

Limitation of IRE

Based on the analytical parameters specific to this synchronous reserve and penetration level modeling, and considering hydropower generation distributed around an average value, we have determined curtailment of IRE over the period 2019- 2020 of around 135.9 GWh. We also note that for 2020, 2,722 GWh would be generated by the plants contributing to the synchronous reserve, as shown in the figure below:

Figure 3-77: Use of available energy - Model 3

Use of available energy

Analysis

Scenario : Model 3 | Demand : Baseline

Hydropower — Start: Distributed ☑ | Import — Start 19:00

		Energy use GWh						Unused energy GWh				
Year	Total demand GWh	Wind	Solar	Hydropower	Thermal reserve	Thermal	Import	Wind	Solar	Hydropower	Thermal	Import
2016	3,396	-	0	350	-	3,045	-	-	-	-	2,133	-
2017	3,618	-	140	350	-	3,125	-	-	-	-	2,041	-
2018	3,825	97	201	350	877	2,300	-	-	-	-	2,723	-
2019	4,081	193	201	350	1,345	1,992	-	0.0	-	-	3,054	-
2020	4,840	251	198	598	2,359	1,433	-	45.3	2.3	-	3,713	-
2021	5,740	296	252	1,066	1,212	2,914	-	-	-	-	3,319	-
2022	6,613	296	396	1,259	1,212	3,451	-	-	-	-	3,547	-
2023	7,044	296	396	1,259	1,212	3,880	-	-	-	-	3,462	-
2024	7,474	296	396	1,259	1,212	4,310	-	-	-	-	3,834	-
2025	7,918	296	396	1,470	608	5,134	-	-	-	-	3,472	-
2026	8,416	296	396	1,470	465	5,779	-	-	-	-	3,959	-
2027	8,942	393	464	1,470	465	6,145	-	-	-	-	4,627	-
2028	9,447	393	464	1,922	465	6,197	-	-	-	-	4,584	-
2029	9,947	393	464	1,922	465	6,684	-	-	-	-	4,054	-
2030	10,367	393	464	1,922	465	7,122	-	-	-	-	5,685	-
2031	11,018	393	464	1,922	465	7,760	-	-	-	-	4,989	-
2032	11,692	496	515	1,922	465	8,293	-	-	-	-	6,526	-
2033	12,407	496	515	1,922	465	8,994	-	-	-	-	5,761	-
2034	13,167	496	515	1,922	465	9,750	-	-	-	-	5,989	-
2035	13,952	496	515	1,922	465	10,529	-	-	-	-	6,192	-

The daily analysis for the year corresponding to maximum IRE curtailment, i.e. 2020, is shown in the figures below, starting with the load valley day.

Figure 3-78: Detailed analysis of one day - 2020 load valley - Model 3

Detailed analysis for a day

Scenario : Model 3
Demand : Baseline
Year : 2020
Day : Valley
Date : 2020-02-22

Reserve : 42
E.R. limit : 11%

Hydropower
Start:
Distributed ☑

Import Start	Import End	Import Capacity
19:00	08:00	0

Analysis

			Power used										Instantaneous power not used								
Hour	Sales	Losses	Solar	Wind	Hydropower	Thermal reserve	Thermal coal	Thermal LOCNG	Thermal LIQNG	Thermal HFO	Thermal DO	Import	Solar	Wind	Hydropower	Thermal coal	Thermal LOCNG	Thermal LIQNG	Thermal HFO	Thermal DO	Import
01:00	346.4	53.8	0.0	43.5	57.5	296.5	0.0			2.7	0.0					115.0			277.9	46.5	
02:00	325.6	50.1	0.0	40.5	57.5	277.7	0.0							2.8		115.0			299.4	46.5	
03:00	311.8	47.7	0.0	39.4	57.5	262.5	0.0							2.8		115.0			314.6	46.5	
04:00	303.5	46.2	0.0	37.9	57.5	254.3	0.0							3.6		115.0			322.8	46.5	
05:00	301.6	45.8	0.0	37.7	57.5	252.2	0.0			0.0	0.0			2.6		115.0			324.9	46.5	
06:00	292.1	44.1	0.0	36.5	57.5	242.2	0.0							3.5		115.0			334.9	46.5	
07:00	302.1	45.9	0.0	38.1	57.5	252.4	0.0			0.0	0.0					115.0			324.7	46.5	
08:00	304.4	46.3	1.8	36.6	57.5	254.9	0.0									115.0			322.2	46.5	
09:00	318.5	48.8	39.4	0.9	57.5	269.5	0.0							40.1		115.0			307.6	46.5	
10:00	340.0	52.7	39.0	3.4	57.5	292.8	0.0			0.0	0.0		27.7	49.3		115.0			284.4	46.5	
11:00	347.8	54.1	41.6	2.4	57.5	296.5	0.0			3.8	0.0		40.2	52.0		115.0			276.8	46.5	
12:00	341.4	52.9	31.0	12.0	57.5	293.7	0.0						60.5	43.2		115.0			283.4	46.5	
13:00	345.9	53.7	31.3	12.3	57.5	296.5	0.0			2.0	0.0		61.1	44.1		115.0			278.6	46.5	
14:00	345.4	53.6	30.6	12.9	57.5	296.5	0.0			1.5	0.0		59.7	46.5		115.0			279.1	46.5	
15:00	331.4	51.1	39.8	1.4	57.5	283.8	0.0						38.4	60.9		115.0			293.3	46.5	
16:00	356.0	55.5	35.5	8.5	57.5	296.5	0.0			13.5	0.0		25.2	56.7		115.0			267.1	46.5	
17:00	355.1	55.4	36.4	8.5	57.5	296.5	0.0			11.5	0.0			56.5		115.0			269.1	46.5	
18:00	368.8	57.8	7.3	39.0	57.5	296.5	0.0			26.3	0.0			18.9		115.0			254.3	46.5	
19:00	403.3	63.9	0.0	50.6	57.5	296.5	0.0			62.6						115.0			218.0	46.5	
20:00	486.2	78.7	0.0	47.9	57.5	296.5	115.0			47.9	0.0					0.0			232.7	46.5	
21:00	489.0	79.2	0.0	46.6	57.5	296.5	115.0			52.7						0.0			228.0	46.5	
22:00	481.8	77.9	0.0	45.1	57.5	296.5	115.0			45.6	0.0					0.0			235.0	46.5	
23:00	424.5	67.7	0.0	42.9	57.5	296.5	95.3			0.0	0.0					19.7			280.6	46.5	
00:00	372.8	58.5	0.0	42.3	57.5	296.5	0.0			35.0	0.0					115.0			245.6	46.5	

Note that in addition to the required IRE curtailment, complete curtailment of thermal coal capacity would be required for most of the day.

Figure 3-79: Detailed analysis of the day - 2020 peak load - Model 2

Detailed analysis for a day

Scenario : Model 3
Demand : Base
Year : 2020
Day : Pointe
Date : 2020-10-14

Reserve : 42
E.R. limit : 11%

Hydropower
Start:
Distributed ☑

Import		
Start	End	Capacity
19:00	08:00	0

Analysis

			Power used										Instantaneous power not used								
Hour	Sales	Losses	Solar	Wind	Hydropower	Thermal reserve	Thermal coal	Thermal LOCNG	Thermal LIQNG	Thermal HFO	Thermal DO	Import	Solar	Wind	Hydropower	Thermal coal	Thermal LOCNG	Thermal LIQNG	Thermal HFO	Thermal DO	Import
01:00	572.8	94.1	0.0	18.3	78.9	327.0	115.0			127.7	0.0					0.0			360.5	46.5	
02:00	540.3	88.4	0.0	18.2	78.9	327.0	115.0			89.6	0.0					0.0			398.6	46.5	
03:00	510.8	83.1	0.0	17.6	78.9	327.0	115.0			55.3	0.0					0.0			432.8	46.5	
04:00	524.0	85.5	0.0	17.2	78.9	327.0	115.0			71.4	0.0					0.0			416.8	46.5	
05:00	510.3	83.0	0.0	16.6	78.9	327.0	115.0			55.8	0.0					0.0			432.3	46.5	
06:00	504.4	82.0	0.0	16.3	78.9	327.0	115.0			49.2	0.0					0.0			439.0	46.5	
07:00	522.5	85.2	4.3	15.2	78.9	327.0	115.0			67.2	0.0					0.0			420.9	46.5	
08:00	519.2	84.6	26.6	14.3	78.9	327.0	115.0			42.0	0.0					0.0			446.2	46.5	
09:00	562.2	92.3	42.5	16.9	78.9	327.0	115.0			74.2	0.0					0.0			414.0	46.5	
10:00	594.5	98.0	63.2	13.0	78.9	327.0	115.0			95.5	0.0			10.9		0.0			392.7	46.5	
11:00	608.5	100.5	74.6	3.2	78.9	327.0	115.0			110.2	0.0			21.6		0.0			378.0	46.5	
12:00	606.7	100.2	64.8	12.6	78.9	327.0	115.0			108.5	0.0		13.2	12.6		0.0			379.7	46.5	
13:00	610.0	100.8	71.8	6.2	78.9	327.0	115.0			111.9	0.0			19.8		0.0			376.3	46.5	
14:00	602.4	99.4	68.3	8.5	78.9	327.0	115.0			104.1	0.0			19.5		0.0			384.1	46.5	
15:00	583.4	96.0	63.2	11.0	78.9	327.0	115.0			84.4	0.0			18.8		0.0			403.8	46.5	
16:00	599.9	99.0	45.9	30.3	78.9	327.0	115.0			101.7	0.0			1.4		0.0			386.5	46.5	
17:00	588.5	97.0	28.7	31.6	78.9	327.0	115.0			104.3	0.0					0.0			383.8	46.5	
18:00	564.9	92.7	4.0	27.1	78.9	327.0	115.0			105.7	0.0					0.0			382.5	46.5	
19:00	610.6	100.9	0.0	22.6	78.9	327.0	115.0			168.1	0.0					0.0			320.1	46.5	
20:00	643.1	106.7	0.0	21.0	78.9	327.0	115.0			208.0						0.0			280.2	46.5	
21:00	668.1	111.1	0.0	20.2	78.9	327.0	115.0			238.2	0.0					0.0			250.0	46.5	
22:00	656.9	109.1	0.0	19.2	78.9	327.0	115.0			225.9	0.0					0.0			262.3	46.5	
23:00	651.2	108.1	0.0	18.0	78.9	327.0	115.0			220.4						0.0			267.7	46.5	
00:00	602.1	99.4	0.0	17.7	78.9	327.0	115.0			162.9						0.0			325.3	46.5	

It appears that for this peak day, partial IRE curtailment would be required, but no coal curtailment. Thermal coal generation be used at its maximum all day.

The graphs corresponding to the two previous figures (2020 valley and 2020 peak) are presented in the figures below:

Figure 3-80: Daily power - Model 3 - baseline demand – 2020 valley

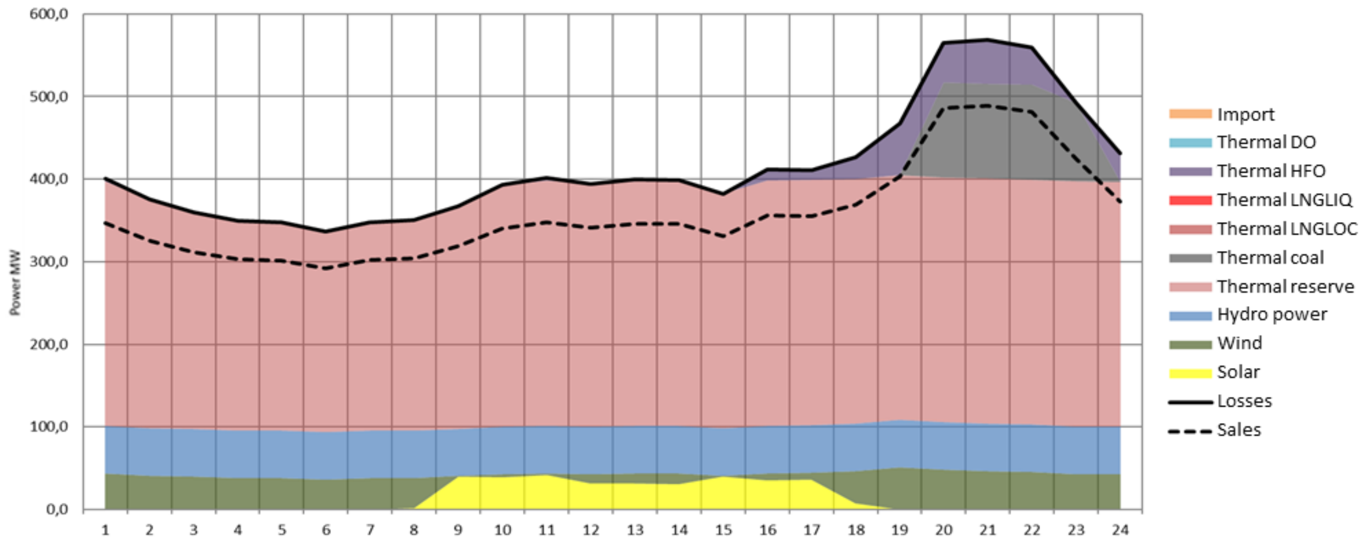
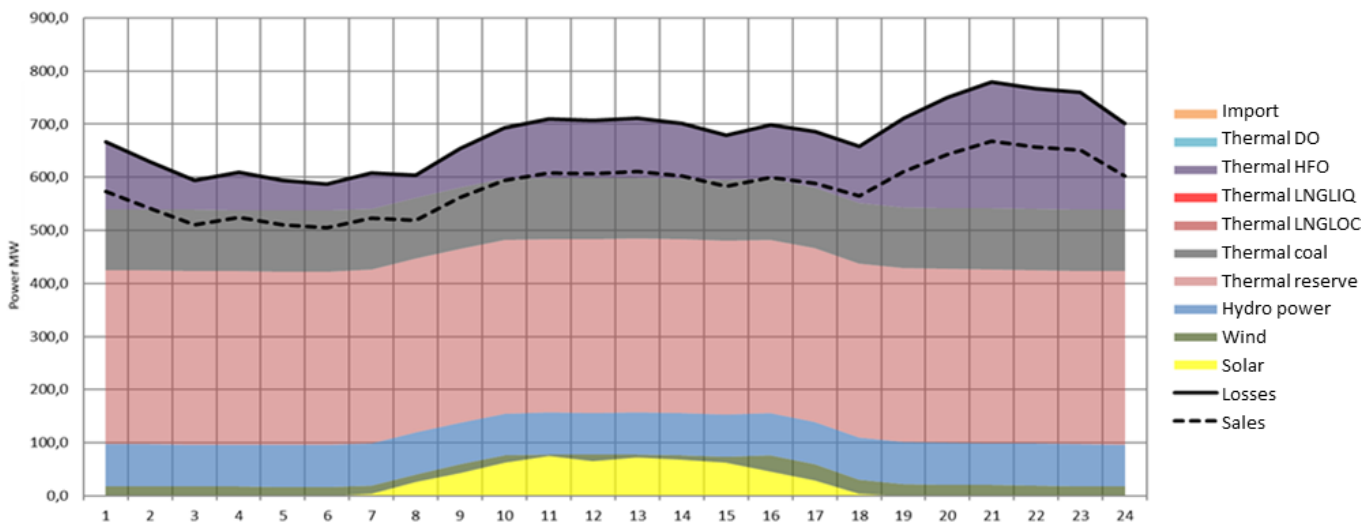


Figure 3-81: Daily power - Model 3 - baseline demand – 2020 peak



Finally, note that the level of IRE curtailment remains high. This is due to the combination of wind IRE, load and high synchronous reserve that must be provided by Senelec and IPPs. However, the percentage of IRE is more in line with the target of 20%, as shown in the following figure:

Figure 3-82: Technology mix - Model 3

Year	Wind	Solar	Thermal	Hydro Power	Import	Intermittent renewable	Others	Intermittent renewable percentage
2016			631	81		0	712	0%
2017		118	631	81		118	712	14%
2018	52	118	746	81		170	827	17%
2019	104	118	746	81		222	827	21%
2020	159	118	986	164		277	1150	19%
2021	159	148	869	267		307	1136	21%
2022	159	233	959	328		392	1288	23%
2023	159	233	998	328		392	1327	23%
2024	159	233	1088	328		392	1417	22%
2025	159	233	1088	398		392	1787	21%
2026	159	233	1208	398		392	1607	20%
2027	210	273	1328	398		483	1727	22%
2028	210	273	1328	517		483	1845	21%
2029	210	273	1328	517		483	1845	21%
2030	210	273	1568	517		483	2085	19%
2031	210	273	1568	517		483	2085	19%
2032	266	303	1808	517		569	2325	20%
2033	266	303	1808	517		569	2325	20%
2034	266	303	1928	517		569	2445	19%
2035	266	303	2048	517		569	2565	18%

Curtailment of thermal coal generation

Curtailment of thermal coal generation is dependent on two main factors:

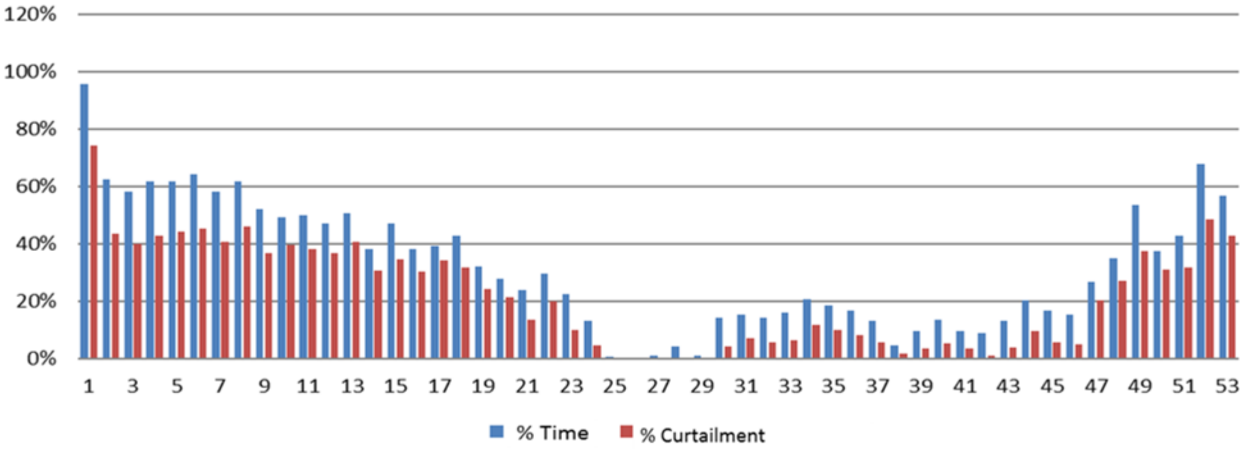
- The technical limits of each plant
- Generation to be considered a priority over other generation sources

Thus, by prioritizing IRE generation, the non-distributed hydropower generation starting at 7:00 p.m. and the thermal generation required to provide the synchronous reserve, thermal coal generation can only be used to fill the remaining load in order to meet the demand. Once the technical limit is reached, complete curtailment of thermal coal generation is then applied. Another factor affecting curtailment is the distribution of hydropower. The analysis was conducted taking into account undistributed hydropower generation around an average value.

In this context, and considering the thermal coal units available 100% of the time and applying the various analytical parameters indicated above, we obtain a curtailment level considered to be an annual maximum.

For 2020, this maximum curtailment would be around 215 GWh, and the curtailment percentages – either in hours or in energy – would be as shown in the following two figures:

Figure 3-83: Curtailment - technical minimum with reserve - Model 3



The time percentage shows the number of hours when there is curtailment, regardless of the level of energy curtailed. The curtailment percentage shows the percentage of energy curtailed each week.

Note that the estimated level of curtailment will be reduced during maintenance periods. Thus, a program designed to carry out maintenance during the weeks when maximum curtailment is likely would significantly reduce the level of curtailment.

A rough estimate indicates that approximately 34 GWh of curtailment could potentially be avoided, which would reduce total annual curtailment for 2020 to 181 GWh.

Using the same basis of calculation, curtailment over the period 2019-2029 would be around 721 GWh considering a suitable maintenance program, as shown in the following figure:

Figure 3-84: Curtailment - thermal coal - Model 3

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total	Total
MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	GWh
123,180	214,952	52,608	52,829	96,932	160,971	96,150	61,859	146,797	88,764	61,792	1,156,835	1,157
32,200	34,000	16,000	17,000	35,000	58,000	53,000	38,000	65,000	48,000	40,000	436,200	436
90,980	180,952	36,608	35,829	61,932	102,971	43,150	23,859	81,797	40,764	21,792	720,635	721

Model 3 results in 366 GWh of curtailment, higher than in model 2 (more thermal coal plants are added in model 3 - 270 MW vs. 90 MW), but lower than model 1 due to the delay in the implementation of IRE.

Summary of Model 3

This model aims primarily to satisfy the reserve criterion of 20%, or at least a minimum of 15%, by adding the required capacity, as with model 2, but considering the possible decommissioning of generation units, according to Senelec's comments. This scenario highlights the following:

- The sizing of the thermal coal plants does not meet the established criterion and presents a grid reliability issue. In this sense, any failure will result in load shedding.
- The technical limits of these plants present an operational management challenge.
- The combination of load, IRE, thermal coal and synchronous reserve availability is not optimal, primarily over the period 2019-2022.
- The synchronous reserve levels required and applied to the modeling require rapid action to ensure they are implemented by upgrading equipment and agreements with IPPs and entities responsible for hydropower generation.

This model, considering decommissioning, adds generation at the required time to meet the demand while optimizing added IRE capacity over time. In 2020, it promotes the installation of capacity that is both compatible with the integration of IRE and easily convertible to natural gas, which gives Senelec greater autonomy in terms of the synchronous reserve capacity. All of these elements promote lower curtailment levels compared to Model 1 (based on Senelec planning), for both IRE and thermal coal generation.

JOINT ASSESSMENT OF THE THREE MODELS

The following criteria will be evaluated once for all three models. Recall that in the supply and demand balance report submitted in March 2017, these analyses were carried out for each model, and no significant issues were identified.

Matching supply to demand

For all three models, peak reserve levels are sufficient to cover several contingencies, including unavailability of the largest generating unit, which is 115 MW.

Loss of load probability (LOLP) assessment

For all three models, the LOLP criterion does not represent a significant issue given the sufficient reserve levels identified.

Sizing of generation units and generation reserves

The 15% criterion for the load valley cannot be met as early as 2018, as this is dependent upon the commissioning of a 115 MW plant in accordance with Senelec's generation plan.

With reference to Model 2, such a plant would fall outside the criteria until 2030.

Availability for maintenance

Given the high reserve levels, availability for maintenance is not an issue for the 2018-2030 period.

Maintenance can be done for each plant, respecting the number of days scheduled for each unit and with the necessary margins of failure coverage.

OVERALL ANALYSIS OF MODELS 1 TO 3

The different models show the differences in the generation supply required to meet baseline demand, based on the assumptions and criteria identified for each of the models.

The IRE/thermal coal/synchronous reserve combination will be a significant challenge in the period 2018-2022 for each of the models. This is the result of the combination of additional IRE and thermal coal capacity that has been planned and/or cannot be postponed because of existing or signed contracts.

For each model, the same synchronous reserve criteria are applied, but the curtailment result is different depending on the level of IRE and thermal coal installed over time. Also note that the power plant commissioning dates directly affect the synchronous reserve available. The models consider synchronous reserve levels that must be put into operation, negotiated or added.

Model 1,[3] as concerns Senelec planning, has the highest levels of required curtailment, both for IRE and thermal coal generation. It does, however, leave some flexibility for potential decommissioning.

Model 2 establishes a level of additional generation that essentially reduces IRE and thermal coal curtailment as compared to the Senelec plan, but assumes that existing plants continue to operate.

Model 3 meets the decommissioning assumptions identified by Senelec and also meets Africa Energy's capacity assumptions, as stipulated by Senelec. This model also adds new synchronous reserve capacity to guarantee Senelec a certain level of autonomy starting in 2020.

[3] Note: Recall that Model 1, with respect to the Senelec generation plan, considers no decommissioning and analyzes the period 2016-2035, while the Senelec generation plan adjusts supply through 2030.

Figure 3-85: Summary of additional capacity of the models (net capacity)

			MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
			2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL
MODEL 1 Baseline scenario WITH MINES SENELEC plan	CES 1	Coal		115																		115
	Africa	Coal				90	180															270
	Malicounda	HFO Dual				120																120
	Additional power	TVGN									345	115		115	115	115						805
	Additional power	Hydro			48	35	164				70											317
	TOTAL																					1627
	Additional power	Solar	78	75	40		30	30	30													283
	Additional power	Wind		51.75	51.75	55.2																158.7
																					Total	2068.70

			MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
			2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL
MODEL 2 Baseline scenario WITH MINES PATRP plan without decommissioning	CES 1	Coal		115																		115
	Africa	Coal						90														90
	Malicounda	HFO Dual				120																120
	Additional power	Dual								120												120
	Additional power	CCGT										120	120			240		240		120	120	960
	Additional power	Hydro				83	103	61			70			118								435
	TOTAL																					1840
	Additional power	Solar	78				30	85					40					30				263
	Additional power	Wind		51.75	51.75	55.2							51.75					55.2				265.65
																					Total	2368.70

			MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
			2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL
MODEL 3 Baseline scenario WITH MINES PATRP plan with decommissioning	CES 1	Coal		115																		115
	Africa	Coal						90	90	90												270
	Malicounda	HFO Dual				120																120
	Additional power	Dual				120																120
	Additional power	CCGT										120	120			240		240		120	120	960
	Additional power	Hydro				83	103	61			70			118								435
	TOTAL																					1840
	Decommissioning						116		51													(167)
	Additional power	Solar																30				263
	Additional power	Wind		51.75	51.75	55.2							51.75					55.2				265.65
																					Total	2381.65

Thus, based on the different models, we believe that Model 3 is the recommended option for the following reasons:

- Minimizes IRE and thermal coal curtailment within the timeline adjustments permitted for certain projects
- Provides a certain level of synchronous reserve autonomy within the best timeframe
- Addresses Senelec's comments regarding the decommissioning and capacity required by Africa Energy
- Ensures IRE accounts for 20% of installed capacity by 2035
- Installs both DUAL generation units that can be converted to natural gas (2020-2025) and which are compatible with the integration of intermittent renewable energy, and natural gas plants after 2025 (announced year of availability).

For information, for model 3, the figures below show projections up to 2035 in graph form with respect to:

- the technology mix in terms of installed capacity
- the percentage of IRE capacity
- local installed capacity.

Figure 3-86: Projection of the installed capacity technology mix– Model 3

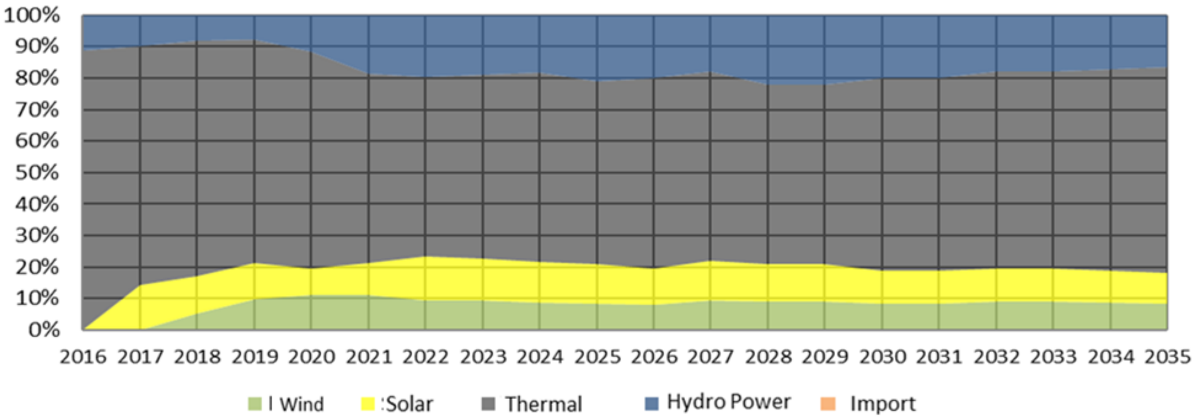


Figure 3-87: Projection of percentage of IRE capacity – Model 3

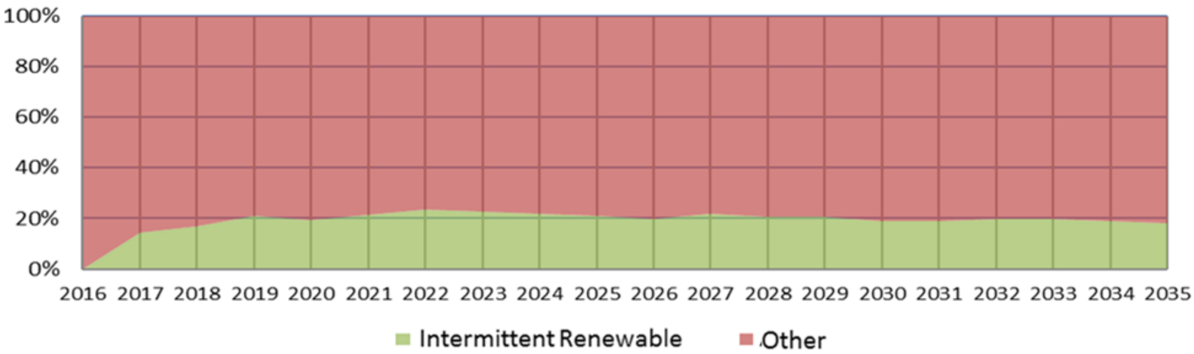
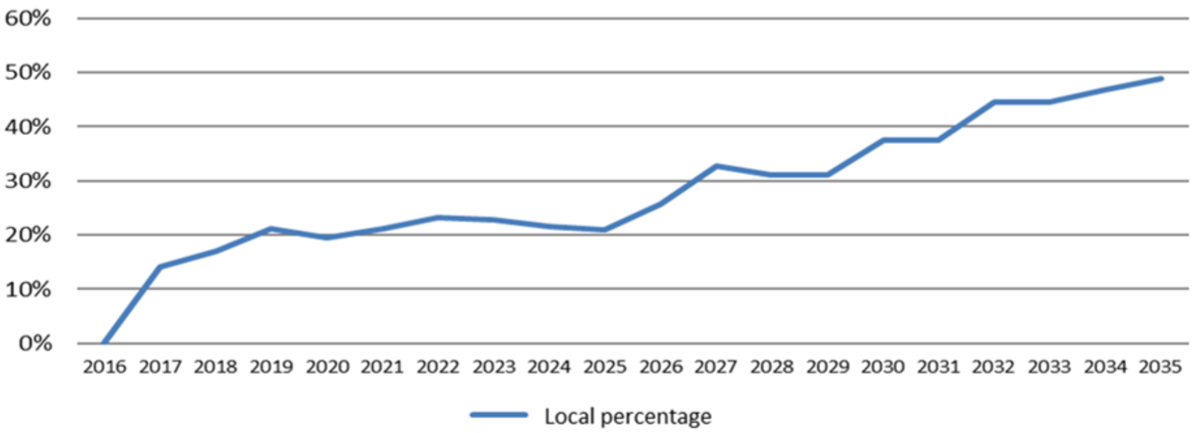


Figure 3-88: Projection of local installed capacity – Model 3



3.6 ECONOMIC ANALYSIS

This section of the report compares the variable production costs for the three models (fuel and variable O&M).

It is important to note that the variable operations and maintenance costs were established using the following values, for the new generation units added in the different models:

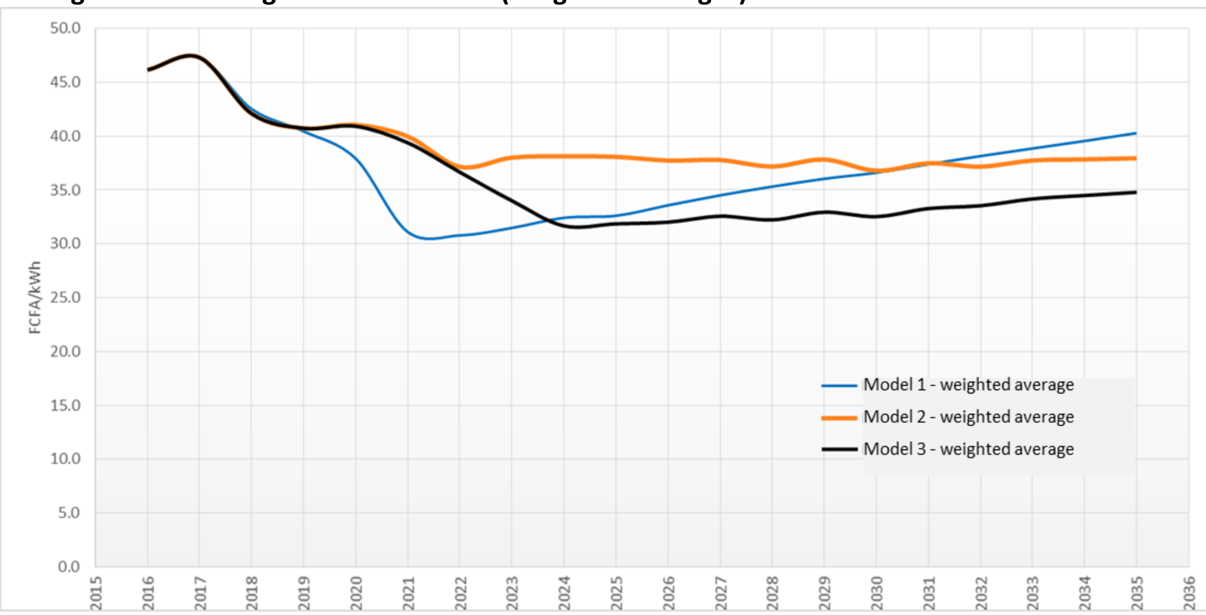
- Hydropower: 23.30 CFAF/kWh on average for hydropower plants
- LOCNG: 6.3 CFAF/kWh (average of thermal IPPs).

For solar and wind, the costs were established respectively at 69.38 and 65.04 CFAF/kWh.

Hydropower generation was considered to be distributed around an average value throughout the year.

The change in variable costs will be compared using these data, and the results are presented in the following figure:

Figure 3-89: Change in variable costs (weighted averages) for the three models



3.7 MAIN FINDINGS AND RECOMMENDATIONS FOR THE GENERATION PLAN

3.7.1 INTERMITTENT RENEWABLE ENERGY

- By 2020, Senelec plans to add nearly 390 MW of IRE to the grid through various power purchase agreements that have already been signed or are in the advanced stages of negotiation.

  There are a number of constraints with respect to the integration of IRE into the grid which must be addressed.

  - It is advisable to have wind distribution in hours per year in order to estimate a capacity factor that is more realistic.

  - Considering the rapid development of distributed solar technologies and batteries for commercial and residential applications, we are of the opinion that Senelec should examine these possibilities for electrification in off-grid areas, but also take into account the integration of these technologies into their distribution network.

  - IRE ramp-up has a negative load effect and IRE ramp-down has a positive load effect. This is managed in the same way as normal load monitoring. For solar IRE, depending on the total capacity installed by 2020, this implies a significant hourly increase. The combination of IRE ramp-up/ramp-down and load variations make real-time energy management more complex. Senelec must therefore ensure that its generation facilities have the conditions to ensure such levels of load monitoring with the associated stops/starts and synchronous reserve, including the synchronous reserve required to offset IRE fluctuations. We assume that IPP contribution is required to guarantee load monitoring and is managed efficiently. It is doubtful that current IPP contract terms are in line with such obligations.

  Recommendations:

    - Senelec should ensure that its own generation facilities are operating at optimal levels, primarily in terms of frequency control equipment.
    - Senelec should ensure, if required by contract renegotiations, that IPPs can contribute to stop-start frequency, ramp-up and synchronous reserve.
    - Senelec should define, validate and provide the synchronous reserve that must come from hydroelectric power plants and then determine the required contribution from its own generation facilities and from IPPs. Once this has been determined, it will then have to conduct an assessment to determine the best way to achieve the synchronous reserve using Senelec's existing facilities, IPPs, adding generation units or renting generation units for this specific purpose. Recall that the critical period is between 2018 and 2022, assuming that the grid will be further integrated as of 2022, and that its overall contribution will mean lower synchronous reserve levels from Senelec's own facilities.

- Power management in a context of a high level of IRE as recommended by Senelec requires an automated operating system that is suited to the situation.

- Senelec will have to evaluate the relevance of modifying and adjusting its automated operating system. Otherwise, it is recommended that Senelec acquire a high performing system.

- Owing to its intermittent nature, the system operator cannot be guaranteed IRE capacity. Intermittency could be offset through the use of different storage technologies. See Energy Storage Recommendations to compensate for IRE fluctuations in the next section **Error! Reference source not found.**.

- Effective IRE management requires input from a weather forecasting system designed for the grid and adapted to Senegal's particular characteristics. It is recommended and imperative that Senelec adopt such a system as soon as possible, based on the high level of IRE scheduled to be installed over the period 2017-2035. This weather forecasting system could be included in the terms of future IPP contracts to build IRE facilities.

3.7.2 ENERGY STORAGE RECOMMENDATIONS

Energy storage to limit curtailment, increase penetration rate and provide additional reserve

In Senegal's situation, knowing the generation planning and results of the grid stability study, there are situations in which IRE and/or thermal coal generation should potentially be capped. It is obvious that an energy storage system would be beneficial to help balance out generation output, making renewable energy output easier to control and less sensitive to or even independent of weather fluctuations, within the design limits of the storage system (capacity, charging speed and autonomy). As for the implementation of a storage system connected to a power plant or distribution network covering several IRE sources, this requires a more in-depth analysis. According to our current data, wind power certainly has a greater need for reserve capacity. Installing a battery system to reduce the value of fluctuations to be covered is certainly the direction to pursue. There is a considerable advantage to having a storage system, for example a large capacity battery as the IREQ is proposing, in terms of the flexibility this gives the grid and that can be used to offset IRE, for additional reserve capacity in the event of a failure at a generating plant, and also to assist with frequency regulation. Indeed, new technologies provide an almost instant response (within a second).

Further reflection is required, however, as failures are often unpredictable. The battery system must be reliable at all times in order for it to be considered a synchronous reserve. Furthermore, if the battery is used during peak demand periods, its load level cannot be guaranteed for the synchronous reserve. Given the rapid charging of the latest battery technologies combined with their quick response, it has been technically proven that an energy storage system can help to maintain frequency in an electrical grid.

A feasibility study on energy storage in Senegal with a technical component (sizing) and economic component should cover frequency regulation and facilitating the integration of IREs, particularly as concerns the 158.7 MW wind farm.

Hybrid solar panel solutions for large off-grid energy consumers and reduced electricity generation costs

Where a number of large consumers such as mines are self-powered, hybrid solutions coupled with a PV panel park should be considered. There is demonstrated evidence of reduced power generation costs in many places around the world.

Solar power plants using CSP technology

Apart from the economic aspect, since CSP technology is less sensitive to weather fluctuations, its use in Senegal where electricity demand is highest in the early evening can extend generation time by several hours. Obviously we think that in the short term it would be prudent to carry out an economic feasibility study to assess the investment costs before ruling out this technology that is promising and adequate for Senegal’s weather conditions.

3.7.3 COAL GENERATION

- The sizing of the 115 MW net capacity plant (CES 1) scheduled to be commissioned in 2018 (according to information provided by Senelec in January 2017) is certainly problematic in several respects, including the fact that it is not possible for Senelec to maintain a primary reserve level to avoid automatic load shedding when this unit goes off line. This situation will continue at least until the Senelec network is more integrated with other networks that can contribute to the primary reserve.
- The sizing of Africa Energy's 90 MW net capacity generation units also appears to be problematic. In this context, it is recommended that Senelec evaluate the possibility of reviewing the sizing of these plants in order to reduce their size. Plants of around 45 MW would be less restrictive in terms of network reliability.
- The contractual technical limit established for thermal coal plants is also considered to be problematic since they may have to operate below this level or comply with stop-start frequencies that are not ideal for this type of generation. This can occur depending on the level of IRE capacity, the level of load demand, the synchronous reserve required for load monitoring, potential fluctuations in IREs, or even the primary reserve required for grid stability.

3.7.4 HYDROPOWER GENERATION

- The commissioning dates of the hydroelectric power plants and the associated transmission lines present significant uncertainties for which we were unable to obtain all the desired information, particularly with regard to the Sambangalou power plant. Therefore, it is recommended that the work schedules of these plants and the associated transmission lines be monitored frequently, and that the generation plan be regularly reviewed as new inputs are identified.
- As already mentioned, the contribution of these plants to ancillary services must be assessed, determined and ensured. This is a prerequisite for the evaluation and implementation of resources related to synchronous reserve provision to come from Senelec facilities and/or from IPPs.
- Average monthly generation output must be assessed and incorporated into the generation plan in order to better assess the contribution of these plants to load filling, and more specifically the peak loads at different times of the year.

3.7.5 NATURAL GAS GENERATION

- It is believed that local natural gas (LOCNG) will be available starting in 2025. As such, generation supply has been oriented in this direction. It is recommended that regular monitoring be carried out due to the fact that any foreseeable delay will require a choice on the type of generation that can be converted to natural gas and meet demand needs for the period of 2025 until the year of effective availability of LOCNG. Any change in the availability of natural gas will have to be included in the generation plan, which may lead to new choices of generating facilities.
- One way to mitigate the potential delay in the arrival of the local resource would be to promote installation as soon as possible of the necessary infrastructures that can also use liquefied natural gas (LNG).
  - The nature of the infrastructure required for LOCNG is to a great extent similar to that required to import LNG.
  - This approach would make it possible to convert several power plants now, and to have generation units with a higher efficiency and lower generation costs, and to guard against probable upswings in the price of hydrocarbons, the dependence on which was one of the government’s top reasons for diversifying the technology mix.

3.7.6 CHOICE OF GENERATION PLANTS

- For the period 2025-2035, natural gas generation is prioritized since it provides the best efficiency and lowest generation cost for thermal generation facilities. As already mentioned, the actual availability of natural gas will have to be closely monitored and, depending on how the situation evolves, adjustments will have to be made to the generation plan. Note that if natural gas were to become available earlier, the planned generation facilities to be implemented in the period 2020-2025 could be re-assessed. The location of these power plants will have to take into account proximity to available NG in combination with optimal integration with the transmission network.
- Senelec's direction to establish thermal coal generation is maintained with respect to the sizing of the plant as specified by Senelec; however, as already stated, it is recommended that Senelec evaluate the possibility of reviewing the sizing of the generation units.
- Senelec's direction for the future Malicounda power plant is maintained, but it is recommended that the location of this station be re-evaluated in the context of future conversion to NG. In fact, Senelec will have to determine the best location for this power plant depending on where NG will eventually be available and where its transmission infrastructure will be located. This recommendation is also valid for other DUAL power plants involved in the planned supply in the different models. The location of the power plants will have an impact on the network which will have to be covered by transmission network planning.
- If the Malicounda power plant is relocated and Model 3, which uses 240 MW of dual power is selected, it is recommended that the suitability of a single 240 MW facility be evaluated in order to achieve significant savings.
- IRE implementation should ideally be planned according to well-established criteria from a technical point of view, while ensuring that this energy is contributing to the reduction of generation costs, or at least not contributing to an increase in costs. It is recommended that Senelec adopt a clear and stringent process with respect to the implementation of new IRE capacity, this before implementing new capacity identified by 2021-2023 (90 MW solar).

3.7.7 SENELEC GENERATION FACILITIES AND IPP

It is recommended that Senelec develop a decommissioning or rehabilitation plan for its own power plants. The plan should first assess equipment condition, evaluate the work required to ensure proper operation over different time horizons, and evaluate cost-effectiveness in relation to decommissioning and replacement with new generation units or facilities. The plan should then be included in the generation plan. Recall that according to the conclusions of Model 3, it is more advantageous in the long term to decommission non-performing plants (or to renovate them to significantly decrease operating costs) and replace them with modern plants.

A sustainable investment plan should be developed and synchronized with the updated Generation Master Plan in order to choose the best investment plan based on technical risk.

Also note that the monitoring of sustainability among IPPs is recommended. For example, the decommissioning of the Kounoune power plant, identified by Senelec in its comments and not included in the modeling, certainly requires a more precise evaluation before deciding on a possible decommissioning after only 15 years of service.

3.8 GENERIC DATA

3.8.1 SPECIFIC CONSUMPTION BY FUEL AND BY TYPE OF GENERATION

The following table shows generic data related to specific consumption for different types of generation in combination with different fuel types. When Senelec's documentation specified data, they were prioritized; otherwise the data in this table were applied.

Figure 3-90 : Specific consumption by fuel and by type of generation

TETRA TECH	SUMMARY - PERFORMANCE OF THERMAL POWER PLANTS								By:		1
									J.D.	Date:	11/28/2016
	PCS *		Density		Thermal Efficiency	Specific consumption					
						Thermal E/ electric E **			Volume-Mass/ electric E		
	kJ/kg	Btu/lb	kg/m3	lbs/bbl		Btu/kWh	kJ/kWh	MMBtu/MWh	m3/Mwh	bbl/MWh	g/kWh
Combustion engine - HFO	43,800	18,850	1,010	353.8	0.432	7,900	8,335	7.9	0.188	1.184	190.3
Combustion engine - Natural gas	50,400	21,700	0.707		0.5	6,825	7,200	6.82	202		142.9
Combustion turbine - HFO	43,800	18,850	1,010	353.8	0.305	11,200	11,816	11.2	0.267	1.679	269.8
Combustion turbine - LFO	45,300	19,500	850	297.8	0.311	10,960	11,563	10.96	0.3	1.887	255.3
Combustion turbine - Natural gas	50,400	21,700	0.707		0.314	10,850	11,447	10.85	321		227.1
Combined cycle - Natural gas	50,400	21,700	0.707		0.484	7,050	7,438	7.05	209		147.6
Combined cycle - HFO	43,800	18,850	1,010	353.8	0.46	7,420	7,828	7.42	0.177	1.112	178.7
(Combustion engine)											
Combined cycle - HFO	43,800	18,850	1,010	353.8	0.4	8,531	9,000	8.53	0.203	1.279	205.5
(turbines)											
Combined cycle - LFO	45,300	19,500	850	297.8	0.45	7,583	8,000	7.58	0.208	1.306	176.6
(turbines)											
Steam cycle - Coal	27,650	11,900			0.388	8,800	9,284	8.8			395
Steam cycle - HFO	43,800	18,850	1,010	353.8	0.375	9,099	9,599	9.1	0.217	1.364	219.2
Steam cycle - Natural Gas	50,400	21,700	0.707		0.375	9,099	9,599	9.1	269		190.5

Notes:

* Average value from "Steam, its Generation and Use", The Babcock & Wilcox Company, 41rst Edition. 2005

** Values taken from the following references: "Updated Capital Cost Estimates for Utilities Scale Electricity Generation Plants", US Energy Information Administration, April 2013; MAN Diesel & Turbo SE, Power Plants, website of the company; "Mark's Standard Handbook for Mechanical Engineers" 10th Edition, 1996

4. TRANSMISSION NETWORK STUDIES

4.1 TRANSMISSION NETWORK OPERATING STUDIES

4.1.1 INTRODUCTION

A master plan has been developed to guide future major investments in components such as new transmission lines and transformer stations. These are the results of the master plan and the actions required to achieve that goal.

Voltage management in the grid model studies of a master plan consists of keeping voltage within the established criteria without necessarily identifying optimal quantities and location of compensation equipment.

This approach does not affect the results of the master plan and provides guidance on the required shunt compensation. Voltage management is optimized each time a new project identified in the investment plan is reviewed.

The operating study identifies the investments required to ensure that the selected solutions meet the established criteria and guarantee stable grid operation.

We have developed several models of the Senelec/OMVS/OMVG interconnected network and models of some of the components of grids in neighboring countries that have a significant impact. We based the 2019 and 2022 grid models on Senelec's 2016 existing transmission infrastructure as the baseline, then included all decided projects. The 2028 grid model builds on the 2022 model and the recommendations that came out of its analysis.

For Senelec, the model configuration considers loads and power generation at their actual connection voltages. Connection interfaces with OMVS, OMVG, Somelec, EDM and EDG are also taken into consideration.

Numerous simulations were carried out on various generation scenarios to test the grid and assess its limitations. The study covers both static and transient elements that take into account the Senelec/OMVS/OMVG investment program, according to the information available to PATRP.

More specifically, these simulations consisted of analyzing contingencies, reactive compensation, short circuits and transient stability. The simulations revealed weaknesses in the system and identified solutions to increase operating limits to a level that meets international standards.

This report outlines the results and conclusions of the operational analysis and transmission network performance. It presents details and assumptions, in addition to describing the criteria and methodology used. This report then goes on to explain the results of the different scenarios and simulations. Finally, the report concludes with recommendations and proposed investments.

4.1.2 DESCRIPTION OF EXISTING NETWORK

SENEGAL

Senegal's current power grid (Senelec) is connected to Mali by a 225-kV line that connects the Kayes (Mali) and Bakel (Senegal) substations via the OMVS grid, adding to the Matam, Dagana, Sakal and Tobene substations in Senegal. Senelec's high-voltage transmission network is operated at 225 and 90 kV. The grid components are shown below.

Figure 4-1: Current Senelec network

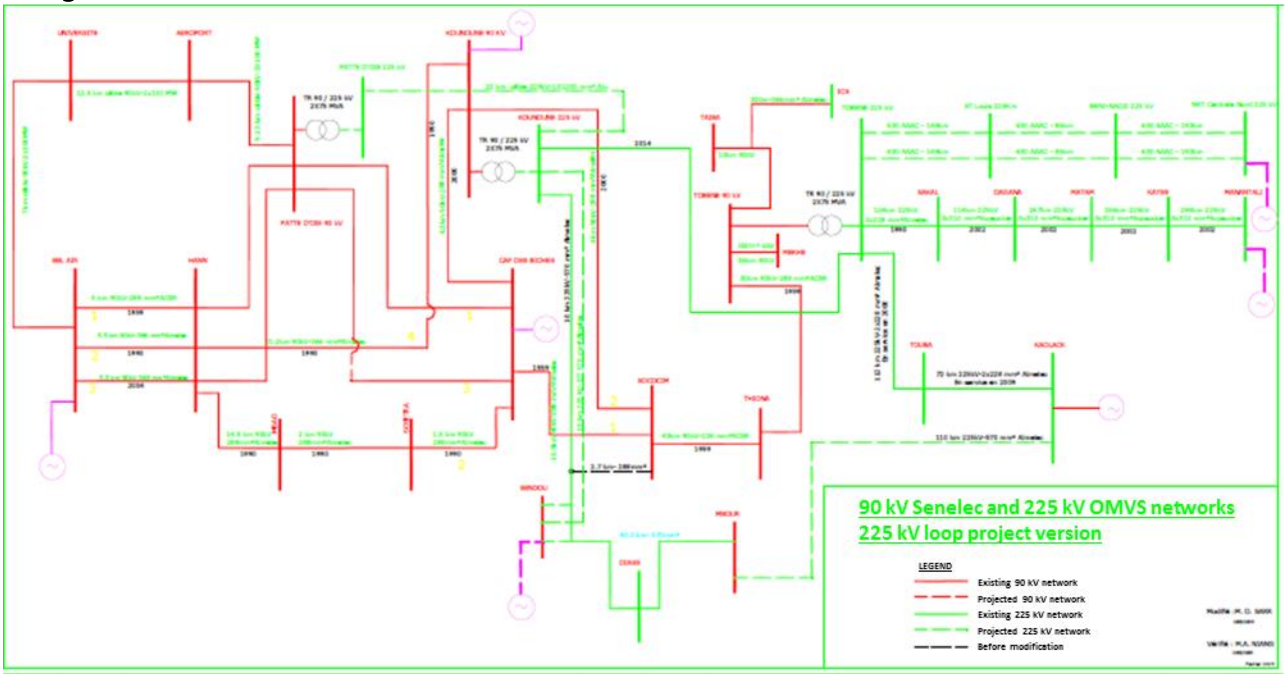


Figure 4-2: Geographical map of the Senelec transmission network

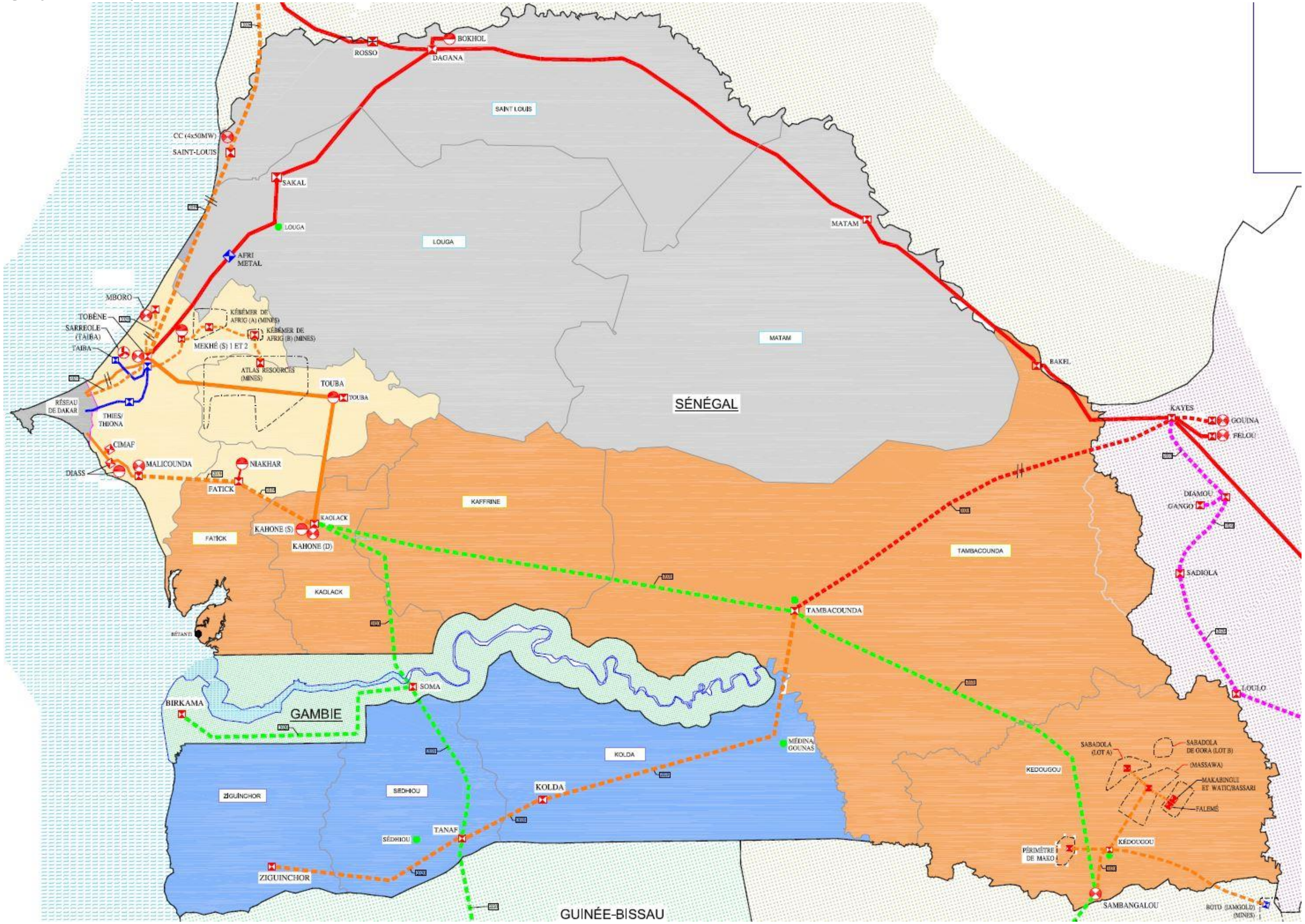


Table 4-1 : Existing substations

EXISTING SUBSTATIONS		
Bus	Substation	kV
1122	TOBENE	90
1301	BELAI	90
1302	CAPDB	90
1307	KOUNOUNE	90
1310	HANN	90
1311	PDOIE	90
1312	THIONA	90
1313	MBAO	90
1314	AEROP	90
1315	UNIVER	90
1316	SOCOC	90
1317	TAIBA	90
1318	SOMET	90
1319	MEKHE	90
1351	OLAM	90
2118	BAKEL	225
2119	MATAM	225
2120	SAKAL	225
2121	DAGAN	225
2122	TOBENE 03	225
2304	TOUBA	225
2305	KAOLA	225
2307	KOUNOUNE 03	225
2308	DIASS	225
2309	MALICOUNDA	225

Table 4-2 : List of Transformers

LIST OF TRANSFORMERS							
Bus	Substation/HV	Bus	Substation/LV	Id	Id name	MVA	Conn.
1118	BAKEL 90.00	2118	BAKEL 225.00	1	TR2 BAKEL	20	YNyn0
1119	MATAM 90.00	2119	MATAM 225.00	1	TR1 MATAM	20	YNyn0
1301	BELAI 90.000	4301	BELAILD1 33.000	1	TR1	80	YNyn0
1301	BELAI 90.000	4350	BELAIRLD3 33.000	1	TR3	80	YNyn0
1301	BELAI 90.000	5301	BELAIRLD2 6.6000	1	TR36MVA	36	YNd11
1301	BELAI 90.000	7301	CBELAIR1G 15.000	1	TR601	50	YNd11
1301	BELAI 90.000	7320	BELAIR4G 11.000	1	TR TAG4	46	YNd1
1301	BELAI 90.000	7323	BELAIR2G 15.000	1	TR602	50	YNd11
1301	BELAI 90.000	7324	BELAIR3G 15.000	1	TR603	50	YNd11
1302	CAPDB 90.000	4302	CAPDBLD1 33.000	1	TR1 CAPDB	74.8	YNd11
1302	CAPDB 90.000	4302	CAPDBLD1 33.000	2	TR2 CAPDB	74.8	YNd11
1302	CAPDB 90.000	7302	CDB401 6.6000	1	TR401	30.5	YNd11
1302	CAPDB 90.000	7304	CDB403 6.6000	1	TR403	30.5	YNd11
1302	CAPDB 90.000	7308	CDB402 6.6000	1	TR402	30.5	YNd11
1302	CAPDB 90.000	7309	CDB404-5 11.000	1	TR404-5	40	YNd5
1302	CAPDB 90.000	7310	CDB301 12.500	1	TR301	36	YNd11
1302	CAPDB 90.000	7311	CAPDB CG 11.000	1	TRCG	67	YNd11
1302	CAPDB 90.000	7312	CDB303 12.500	1	TR303	36	YNd11
1302	CAPDB 90.000	7334	CDB_TAG2 11.000	2	TR_TAG2	27	YNd11
1302	CAPDB 90.000	7349	CG EXT 11.000	1	TR CGEXT	45	YNd11
1302	CAPDB 90.000	7350	APR CDB 33.000	1	TR APR	100	YNd11
1307	KOUNO 90.000	7307	KOUNO 1G 15.000	1	KOUN 1G	95	YNyn0
1310	HANN 90.000	4310	HANNLD1 30.000	1	TR1 HANN	80	YNyn0
1310	HANN 90.000	4310	HANNLD1 30.000	1	TR1 HANN	80	YNyn0
1310	HANN 90.000	4311	HANNLD2 33.000	1	TR2 HANN	80	YNyn0
1312	THIONA 90.000	4312	THIONALD1 33.000	1	TR1 THIONA	80	YNyn0
1312	THIONA 90.000	4318	THIONALD2 33.000	1	TR2 THIONA	80	YNyn0
1313	MBAO 90.000	4313	MBAOLD1 33.000	1	TR1 MBAO	80	YNyn0
1313	MBAO 90.000	4313	MBAOLD1 33.000	2	TR2 MBAO	80	YNyn0
1314	AEROP 90.000	4314	AEROPLD1 33.000	1	TR1 AEROP	80	YNyn0
1314	AEROP 90.000	4316	AEROPLD2 33.000	2	TR2 AEROP	80	YNyn0
1315	UNIVER 90.000	4315	UNIVERLD1 33.000	1	TR1 UNIVER	40	YNyn0
1315	UNIVER 90.000	4317	UNIVERLD2 33.000	2	TR2 UNIVER	40	YNyn0
2118	BAKEL 225.00	4118	BAKELLD1 30.000	1	TR1 BAKEL	20	YNyn0
2119	MATAM 225.00	4119	MATAMLD1 30.000	1	TR2 MATAM	20	YNyn0
2120	SAKAL 225.00	4120	SAKALLD1 33.000	1	TR1 SAKAL	50	YNyn0
2121	DAGAN 225.00	4121	DAGANLD1 30.000	1	TR1 DAGAN	20	YNyn0
2122	TOBENE 03 225.00	7348	TP_70MW 15.000	1	TR1 TP	90	YNd11
2122	TOBENE 03 225.00	7348	TP_70MW 15.000	2	TR2 TP	90	YNd11
2122	TOBENE 03 225.00	4322	TOBENE 03 33.00	2	TR2 TP	75	YNd11
2304	TOUBA 225.00	4304	TOUBALD1 33.000	1	TR1 TOUBA	40	YNyn0
2304	TOUBA 225.00	4304	TOUBALD1 33.000	2	TR2 TOUBA	40	YNyn0
2305	KAOLA 225.00	4305	KAOLALD1 33.000	1	TR1 KAOLA	40	YNyn0
2305	KAOLA 225.00	4305	KAOLALD1 33.000	2	TR2 KAOLA	40	YNyn0
2305	KAOLA 225.00	7335	KAHON 1 15.000	1	TR1 KAH1	18	YNd11
2305	KAOLA 225.00	73051	KAHON1G 15.000	1	TR1 KAH2	50	YNd11
2305	KAOLA 225.00	73052	KAHON2G 15.000	2	TR2 KAH2	50	YNd11
2305	KAOLA 225.00	73053	KAHON3G 15.000	3	TR3 KAH2	50	YNd11

LIST OF TRANSFORMERS							
Bus	Substation/HV	Bus	Substation/LV	Id	Id name	MVA	Conn.
2308	DIASS 225.00	4308	DIASSLD1 33.000	1	TR1 DIASS	40	YNyn0
2308	DIASS 225.00	4308	DIASSLD1 33.000	2	TR2 DIASS	40	YNyn0
2309	MALICOUNDA 225.00	4309	MBOURLD1 33.000	1	TR1 MBOUR	40	YNyn0
2309	MALICOUNDA 225.00	4309	MBOURLD1 33.000	2	TR2 MBOUR	40	YNyn0

Table 4-3: List of lines on Senegalese soil, including those of OMVS from Kayes

LIST OF LINES ON SENEGALESE SOIL, INCLUDING THOSE OF OMVS FROM KAYES							
Bus	Substation	Bus	Substation	ID	Section	MVA	km
1122	TOBENE 90.000	1312	THIONA 90.000	1	L 90 kV 228 mm² ALAC	72	30
1122	TOBENE 90.000	1317	TAIBA 90.000	1	L 90 kV 36 mm² ALAC	98	13
1122	TOBENE 90.000	1319	MEKHE 90.000	1	L 90 kV 288 mm² ALAC	88	13
1301	BELAI 90.000	1310	HANN 90.000	1	L 90 kV 366 mm² ALM	98	5
1301	BELAI 90.000	1310	HANN 90.000	2	L 90 kV 366 mm² ALM	98	5.5
1301	BELAI 90.000	1310	HANN 90.000	3	L 90 kV 366 mm² ALM	98	5.5
1301	BELAI 90.000	1315	UNIVER 90.000	1	Cable 90 kV 1200 mm² ALU	155	7
1302	CAPDB 90.000	1307	KOUNO 90.000	1	L 90 kV 288 mm² ALM	85	6.4
1302	CAPDB 90.000	1311	PDOIE 90.000	1	L 90 kV 288 mm² ALAC	78	16
1302	CAPDB 90.000	1311	PDOIE 90.000	2	L 90 kV 366 mm² ALM	98	18
1302	CAPDB 90.000	1313	MBAO 90.000	1	L 90 kV 288 mm² ALM	85	7.2
1302	CAPDB 90.000	1316	SOCOC 90.000	1	L 90 kV 288 mm² ALAC	78	6.6
1307	KOUNO 90.000	1310	HANN 90.000	1	L 90 kV 366 mm² ALM	98	23
1307	KOUNO 90.000	1316	SOCOC 90.000	1	L 90 kV 288 mm² ALM	85	4.7
1310	HANN 90.000	1311	PDOIE 90.000	1	L 90 kV 288 mm² ALAC	78	1.2
1310	HANN 90.000	1311	PDOIE 90.000	2	L 90 kV 366 mm² ALM	98	1.2
1310	HANN 90.000	1313	MBAO 90.000	1	L 90 kV 288 mm² ALM	85	11
1311	PDOIE 90.000	1314	AEROP 90.000	1	Cable 90 kV 1200 mm² ALU	155	9
1312	THIONA 90.000	1318	SOMET 90.000	1	L 90 kV 288 mm² ALAC	78	23.7
1314	AEROP 90.000	1315	UNIVER 90.000	1	Cable 90 kV 1200 mm² ALU	155	12.5
1351	OLAM 90.000	1318	SOMET 90.000	1	L 90 kV 288 mm² ALAC	78	10.5
1316	SOCO 90.000	1351	OLAM 90.000	1	L 90 kV 288 mm² ALM	78	1.23
2104	KAYEM 225.00	2118	BAKEL 225.00	1	L 225 kV 2 x 310 mm² AMS	312	133
2118	BAKEL 225.00	2125	MATAM_CS 225.00	1	L 225 kV 2 x 310 mm² AMS	312	123
2119	MATAM 225.00	2125	MATAM_CS 225.00	1		195	0
2119	MATAM 225.00	2126	MATAM_CS 225.00	1		195	0
2120	SAKAL 225.00	2122	TOBENE 03 225.00	1	L 225 kV 2 x 228 mm² ALM	312	124
2120	SAKAL 225.00	2128	DAGAN_CS 225.00	1	L 225 kV 2 x 310 mm² AMS	312	114
2121	DAGAN 225.00	2127	DAGAN_CS 225.00	1		195	0
2121	DAGAN 225.00	2128	DAGAN_CS 225.00	1		195	0
2122	TOBENE 03 225.00	2304	TOUBA 225.00	1	L 225 kV 2 x 228 mm² ALM	312	105
2122	TOBENE 03 225.00	2307	KOUNO 03 225.00	1	L 225 kV 2 x 228 mm² ALM	312	55
2126	MATAM_CS 225.00	2127	DAGAN_CS 225.00	1	L 225 kV 2 x 310 mm² AMS	312	269
2304	TOUBA 225.00	2305	KAOLA 225.00	1	L 225 kV 2 x 228 mm² ALM	312	72
2307	KOUNO 03 225.00	2308	DIASS 225.00	1	L 225 kV 1 x 570 mm² ALM	327	22
2308	DIASS 225.00	2309	MALICOUNDA 225.00	1	L 225 kV 570 mm² ALM	327	23.5

Table 4-4: List of Generators, including at Manantali and Felou

LIST OF GENERATORS, INCLUDING AT MANANTALI AND FELOU								
Bus	Substation	Id	PMax (MW)	QMax (MVAR)	QMin (MVAR)	Mbase (MVA)	R Source (pu)	X Source (pu)
6101	CFELO 10.500	1	20.0	16.0	-10.6	25.0	0.0025	0.25
6102	CFELO 10.500	1	20.0	16.0	-10.6	25.0	0.0025	0.25
6104	CFELO 10.500	1	20.0	16.0	-10.6	25.0	0.0025	0.25
7301	CBELAIR1G 15.000	1	17.1	12.6	-4.0	21.3	0.0019	0.262
7301	CBELAIR1G 15.000	2	17.1	12.6	-4.0	21.3	0.0019	0.223
7302	CDB401 6.6000	1	21.1	15.6	-4.0	26.4	0.0028	0.265
7304	CDB403 6.6000	1	23.3	17.2	-4.0	29.2	0.0028	0.265
7307	KOUNO 1G 15.000	1	8.0	5.5	-0.8	9.4	0.002	0.17
7307	KOUNO 1G 15.000	2	8.0	5.5	-0.8	9.4	0.002	0.17
7307	KOUNO 1G 15.000	3	8.0	5.5	-0.8	9.4	0.002	0.17
7307	KOUNO 1G 15.000	4	8.0	5.5	-0.8	9.4	0.002	0.17
7307	KOUNO 1G 15.000	5	8.0	5.5	-0.8	9.4	0.002	0.17
7307	KOUNO 1G 15.000	6	8.0	5.5	-0.8	9.4	0.002	0.17
7307	KOUNO 1G 15.000	7	8.0	5.5	-0.8	9.4	0.002	0.17
7307	KOUNO 1G 15.000	8	8.0	5.5	-0.8	9.4	0.002	0.17
7307	KOUNO 1G 15.000	9	8.0	5.5	-0.8	9.4	0.002	0.17
7308	CDB402 6.6000	1	21.1	15.6	-4.0	26.4	0.0028	0.265
7309	CDB404-5 11.000	6	15.7	11.6	-4.0	19.7	0.0019	0.162
7309	CDB404-5 11.000	7	15.7	11.6	-4.0	19.7	0.0019	0.162
7310	CDB301 12.500	1	33.2	23.0	-6.0	39.0	0.002	0.225
7311	CAPDB CG 11.000	1	17.0	11.8	-5.0	20.0	0.002	0.265
7311	CAPDB CG 11.000	2	17.0	11.8	-5.0	20.0	0.002	0.265
7311	CAPDB CG 11.000	3	17.0	11.8	-5.0	20.0	0.002	0.265
7312	CDB303 12.500	2	23.8	16.5	-6.0	28.0	0.002	0.145
7320	BELAIR4G 11.000	1	29.2	21.5	-6.0	36.5	0.0022	0.223
7323	BELAIR2G 15.000	1	17.1	12.6	-4.0	21.3	0.0019	0.262
7323	BELAIR2G 15.000	3	17.1	12.6	-4.0	21.3	0.0019	0.262
7324	BELAIR3G 15.000	1	17.1	12.6	-4.0	21.3	0.0019	0.262
7324	BELAIR3G 15.000	2	17.1	12.6	-4.0	21.3	0.0019	0.262
7334	CDB_TAG2 11.000	1	15.2	11.2	-5.0	19.0	0.00222	0.128
7335	KAHON 1 15.000	1	14.0	10.3	-10.5	17.5	0.00222	0.237
7348	TP_70MW 15.000	1	17.5	11.8	-5.0	20.0	0.002	0.2
7348	TP_70MW 15.000	2	17.5	11.8	-5.0	20.0	0.002	0.2
7348	TP_70MW 15.000	3	17.5	11.8	-5.0	20.0	0.002	0.2
7348	TP_70MW 15.000	4	17.5	11.8	-5.0	20.0	0.002	0.2
7348	TP_70MW 15.000	5	17.5	11.8	-5.0	20.0	0.002	0.2
7348	TP_70MW 15.000	6	17.5	11.8	-5.0	20.0	0.002	0.2
7349	CG EXT 11.000	1	17.0	12.7	-4.0	21.5	0	0.2
7349	CG EXT 11.000	2	17.0	12.7	-4.0	21.5	0	0.2
7350	APR CDB 33.000	1	50.0	36.9	-15.0	62.5	0.002	0.27
61031	MANAN 11.000	1	40.0	24.7	-24.7	47.0	0.0025	0.25
61032	MANAN 11.000	2	40.0	24.7	-24.7	47.0	0.0025	0.25
61033	MANAN 11.000	3	40.0	24.7	-24.7	47.0	0.0025	0.25
61034	MANAN 11.000	4	40.0	24.7	-24.7	47.0	0.0025	0.25
61035	MANAN 11.000	5	40.0	24.7	-24.7	47.0	0.0025	0.25
73051	KAHON1G 15.000	1	15.5	12.6	-6.4	21.3	0.00222	0.222
73051	KAHON1G 15.000	2	15.5	12.6	-6.4	21.3	0.00222	0.222
73052	KAHON2G 15.000	3	15.5	12.6	-6.4	21.3	0.00222	0.222
73052	KAHON2G 15.000	4	15.5	12.6	-6.4	21.3	0.00222	0.222
73053	KAHON3G 15.000	5	15.5	12.6	-6.4	21.3	0.00222	0.222
73053	KAHON3G 15.000	6	15.5	12.6	-6.4	21.3	0.00222	0.222

ORGANIZATION FOR THE DEVELOPMENT OF THE SENEGAL RIVER (OMVS)

- Commissioned in 2002, the Manantali Interconnected Network (RIMA) is composed of:
  - The Manantali hydroelectric station
    - Comprising five power plants with an installed unit capacity of 40 MW each, for a total of 200 MW
  - The Félou hydroelectric station
    - Installed capacity of 60 MW
  - High voltage transmission lines with a total length of nearly 2,000 km
    - 225-kV single-circuit connections that serve delivery points in Mali (Kodialini, Kita, Kayes and Manantali), Mauritania (Nouakchott, Rosso, Kaédi, Boghé) and Senegal (Tobene, Sakal, Dagana, Matam)

ORGANIZATION DOR THE DEVELOPMENT OF THE GAMBIA RIVER (OMVG)

The OMVG project will interconnect Senegal with Gambia, Guinea-Bissau and Guinea through a 225-kV single-circuit line. This project will be implemented in two phases:

- Phase 1: Inland interconnection with a 225-kV line from Kaolack (Senegal) to Linsan (Guinea), via Sambangalou.
  - This phase is essential for the evacuation of power to Senegal from the Sambangalou, Grand Kinkon and Koukoutamba power plants.
- Phase 2: Interconnection along the west coast via a 225-kV line between the Linsan and Kaolack substations; this phase closes the loop.
  - The second phase is important because it permits evacuation of power from the Kaleta, Souapiti and Amaria plants to Senegal. It is also a solution for evacuation from the Koukoutamba, Sambangalou and Grand Kinkon power plants.

GUINEA

Guinea is currently outside the OMVS grid. However, interconnections are planned through OMVG and CLSG projects, and the Guinea-Mali interconnections. The Linsan substation will be interconnected with Sierra Leone (Bumbuna), and the Fomi substation with Liberia (Yéképa), Ivory Coast (Boundiala) and Mali (Sanankoroba).

Note that several substations and lines in the OMVG loop are located in Guinea.

MALI

Mali is currently connected to Senegal's grid via a 225-kV OMVS line. Its network is concentrated in the southwestern part of the country. There is also a 225-kV interconnection line with Ivory Coast, from Sikasso (Mali) to Ferkessédougou (Ivory Coast).

Two other interconnection lines have already been planned. Mali will be connected to Ghana and Burkina Faso via a 225-kV line from Sikasso (Mali) to Bobo Dioulasso (Burkina Faso) and to Guinea from Sanankoroba (Mali) to Fomi and Linsan (Guinea) by another 225-kV line.

A third 225-kV interconnection line, which would connect Manantali (Mali) to Linsan (Guinea), is planned and will be used to evacuate power from the Koukoutamba power plant.

MAURITANIA

Mauritania is currently connected to the OMVS grid via a 225-kV line connected to the Rosso and Nouakchott substations, which can import power from the Manantali and Félou power plants, or export it to Senegal. The Duale power plant requires a 225-kV interconnection with Senegal, running from Duale to the Tobene substation for evacuation. Senelec's facilities consist of the new 225/33 kV Saint-Louis substation and a 225-kV line between the Saint-Louis and Tobene substations. A contract to export 30 MW to Senegal is in effect.

4.1.3 PLANNING AND MODELING CRITERIA

RELIABILITY

The quality of service depends on grid reliability. The first stage of the study involves analyzing the normal grid (n) with all components in service. This is to ensure that voltage and equipment loading criteria are met under normal operating conditions.

The main transmission network (225 and 90 kV) will be examined for the loss of a single element of the grid (n-1), or a single contingency. The grid must meet all loading and voltage criteria under emergency conditions and be free from any voltage collapse or instability.

To guarantee reliability, the basic rules are as follows:

- The normal grid (n) must have enough flexibility to meet demand.
- The main grid (225 and 90 kV) with a single contingency (n-1) must maintain operating conditions without interruption or load shedding, and without placing undue stress on the grid.
- Load shedding or generation must be controlled to limit major service interruptions.

Two approaches can be used to guarantee reliability: the deterministic approach and the probabilistic approach.

Deterministic approach

This approach is based on the consequences of an event rather than on the event itself, its probability, frequency, severity or duration. As such, the grid (transmission and generation) is structured so that events have no impact on day-to-day operations and, therefore, a single contingency will have no impact on customers. The grid must meet the static and dynamic criteria at all times, without the assistance of an operator.

Probabilistic approach

The probabilistic approach takes into consideration the risk, severity and likelihood of occurrence of an event. Although it cannot provide absolute reliability, it can achieve an acceptable level of reliability at a lower cost.

A combination of both approaches in grid planning can provide an acceptable level of reliability and service continuity to customers while keeping required investments down.

For example, as there is frequent loss of certain components (n-1) such as a line or a transformer, which can cause lengthy service interruptions, a deterministic approach can be used. Conversely, a three-phase fault has a low rate of occurrence, and measures to mitigate the duration of the interruption as well as the costs (protection and automated load shedding) are acceptable. In this case, a probabilistic approach can be taken to save on major investments that would normally be required under the deterministic approach.

PLANNING CRITERIA

Each grid is analyzed in static operation (power flow) to identify any issues that may occur during the different scenarios considered.

This involves analyzing different scenarios under peak load conditions, and according to different generation plans. In order to replicate the most stringent grid conditions, some scenarios use intermittent renewable energy (IRE) while others do not.

One peak load limit scenario may prioritize hydroelectric generation from the OMVS and OMVG power plants to replicate a restrictive condition, since they are the furthest away. Another scenario may consider low output near the load to replicate a different restrictive condition.

The grid must be functional in the event of single contingency (n-1), that is to say, during the loss of a single piece equipment at a time, such as a line, transformer or generator. This static analysis covers the disconnection of each branch (lines and transformers) from the 90 and 225 kV grid.

This is required primarily for looped networks, compared to a radial network where the opening leads to the loss of load. A looped network delivers increased reliability to customers, however, a contingency (n-1) is likely to cause overloads or undervoltages on nearby grid components.

When a branch is open, two types of problems can arise which are caused by new power flows in the grid when it has reached its new stable state: branch overload and voltage variations.

At this stage, the power flow must meet the grid criteria set out in the following sections. Depending on the results, recommendations are made for each grid in order to meet the operating criteria. These recommendations may include adding or reinforcing equipment (lines or transformers), or adding capacitors or reactors to maintain voltages within the desired operating range.

Voltage variation

Whether under normal or contingency conditions, voltages vary across the grid. Therefore, it is important to have clearly defined voltage constraints. Voltage constraints, when the grid is operating under normal conditions, are more stringent so that the grid can cope with different voltage variations under different operating conditions or contingencies. In general, when voltages are close to one pu, the reactive power margin of generators is maximized (better dynamic behavior).

Substation loss is an extreme contingency and is not considered in a grid's design; only normal contingencies are simulated for this purpose. Therefore, extreme contingencies have no financial impact other than the implementation of automation.

The voltage limit under normal operating conditions is ±5% of the nominal voltage, whereas the maximum acceptable variation in the event of a single contingency is ±10% of the nominal voltage.

Under certain conditions, the grid cannot meet the voltage variation criteria. In this situation, changes are made to the grid, which can include adding shunt compensation or additional equipment such as lines or transformers.

Equipment capacity

Permissible equipment currents or overloads depend on several factors, including the condition, load profile and environment (e.g. ambient temperature) of the equipment. These factors cause the overload capacities of the equipment to fluctuate (overload intensity and duration). An in-depth review is required to determine permissible currents during equipment overloads and, therefore, is not part of this study.

Transformers

Transformer load limits are the capacity limits indicated by Senelec during data collection. Nominal equipment capacities must be respected, both under normal operating conditions and under single contingency conditions. PATRP has not applied an overload factor to the equipment. In most cases, the cooling stages of the transformers are not provided; therefore, it is considered that the capacity supplied is the capacity reached in the last stage of cooling.

Table 4-5: Configuration of transformer substations provided by Senelec

CONFIGURATION OF TRANSFORMER SUBSTATIONS PROVIDED BY SENELEC		
90/30 kV substation	225/30 kV Substation	225/90 kV Substation
2 x 20 MVA	2 x 40 MVA	2 x 75 MVA
2 x 40 MVA	2 x 80 MVA	-
3 x 80 MVA	-	-

Lines

For transmission lines, the capacity limit is that of the permissible current indicated. Unlike a transformer, which has thermal inertia, transmission lines have none.

Table 4-6: Thermal capacities of transmission lines provided by Senelec

THERMAL CAPACITIES OF TRANSMISSION LINES PROVIDED BY SENELEC			
90 kV Voltage		225 kV Voltage	
Conductor (Alu-Steel)	Thermal Capacity (*)	Conductor (Almelec)	Thermal Capacity (*)
228 mm^2	72 MVA (460A)	228 mm^2	199 MVA (511A)
288 mm^2	86 MVA (550A)	288 mm^2	218 MVA (560A)
		366 mm^2	245 MVA (630A)

Inputs

The basic data of the EDG, EDM, SOMELEC, OMVS and OMVG networks come from the "Master Plan for the Development of the OMVS Transmission Network for 2015-2030 - Cima International - October 2015".

More specifically, the OMVG network data come from a 2014 study entitled "*Actualisation des ETI réalisées par Coteco – APD/DAO de 2007/2008 du projet Énergie de l'OMVG*" carried out by Sofreco for OMVG. The data on networks in neighboring countries, other than Somelec and EDM, come from the 2014 map "HV Electrical Grids and WAPP Interconnection Projects in Guinea" and the 2011 map "West African Power Exchange System, HV Electrical Grids and WAPP Interconnection Projects".

Senelec supplied the following inputs:

- Master Plan for the Development of the OMVS Transmission Network for 2015-2030 - Cima International - October 2015
- A PSSE model, representing the peak on October 4, 2016, led to the update of the 2016 PSSE of the Senelec 225/90 kV grid
- Matrix of Transmission Projects on 08-01-2016, indicating the decided projects
- Preparation of transmission master plan file, indicating the decided projects
- 10-21-2016 - 2017-2030 Generation Plan, Version 15, indicating the decided projects
- Additional answers, October 26, 2016 version from Senelec's Department of General Studies (DEG)
- 2015-2030 Generation and Transmission Master Plan
- Criteria for transmission network planning
- Lines and transformers database
- Grid Code OMVS grid (PGRIO)
- Operating conditions for a PV power plant

Modeling assumptions

The static analysis study was carried out using PTI Siemens PSSE software, version 34. It covers the behavior of Senelec's 225kV and 90 kV integrated grid and other 225 kV electrical infrastructures in Senegal, as well as interactions with interconnected networks.

The OMVS, OMVG and Somelec networks are modeled in their entirety. The EDM network has been reduced completely to the Kodialini 225-kV bus, and is represented by an equivalent based on the OMVS master plan. The EDG grid south of Kaleta has been partially reduced to the 225-kV Kaleta bus, and is represented by an equivalent calculated based on the OMVS master plan.

The Linsan CLSG network in Yéképa, the Yéképa EDG grid portion in Fomi and the grid further west of Yéképa to Mali, have been reduced to the 225-kV Linsan and Kodialini buses according to the equivalents in the OMVS master plan. PATRP conducted a sensitivity study, and the impact of the reduction in this grid on the OMVS and OMVG grids is negligible, and zero on the Senelec grid.

EDG's Linsan-Fomi line, which will not be completed in 2022 (not until 2025 according to our information), was modeled on the 2028 grid as well as the section of the Fomi to Kodialini grid in Mali, with an equivalent of the Fomi 225-kV substation bus to represent the western part. Therefore, for the 2028 grid, the equivalents are the 225-kV buses of the Linsan, Fomi and Kodialini substations.

Once the models are established, they are supplemented with data from the generation plan and peak load. Senelec's internal output is adjusted according to the desired imports. Imports are established for each of the years studied based on Senelec's country allocation of the OMVS and OMVG power plants in the generation plan.

The models do not contain details on low voltage levels (33 kV or less). Only components likely to interact at high voltages will be modeled, such as low-voltage (33 kV or less) connected generation or load sources. In cases where data is missing, a value will be assigned based on similar equipment, best practices and experience.

Considering loads at 33 kV instead of 30 kV creates a certain buffer before a voltage collapse would occur after a contingency; however, during the static and stability study for the master plan we did not observe any issues following the addition of a few capacitor banks. However, this aspect must be validated with the distribution network.

Overview

Loads are connected to low voltage busbars (33 kV and less). In the model, all HV/LV transformers are modeled to serve load.

Rules are established to facilitate modeling and ensure consistency:

Unless otherwise indicated:

- Network transformer regulation is on the primary side (firmly grounded Y connection)
- There is no tap changer on generator transformers, and the connection is delta Y to ground, with delta winding on the generator side
- The transformer rating supplied by Senelec corresponds to the last stage of cooling
- The tap changer has 17 positions, with a regulation range of ±10%. Voltage is regulated between 1.017 and 0.983 pu at the secondary bus.

Note the comments below provided by Senelec following the preliminary report. In this project, the regulators of all transformers are set to automatic mode.

  - The new power plant transformers have tap changers, but they are not triggered automatically.
  - The old transformers have no- tap changers.

- A transformer's impedance is as provided by Senelec. Otherwise, it is 12.5%, R1 = X1/12 for transformers under 20 MVA, X1/20 for transformers between 20 and 60 MVA and X1/30 for transformers over 60 MVA.
- Line impedances are as provided by Senelec. In case of non-compliance with typical values, a value is assigned based on similar lines according to the impedance table below.
- The data relating to generators are as provided by Senelec. The voltage is regulated to a value of one pu at the generator busbar.
- The conductors of the new 90 kV or 225 kV lines are the same size as those of the existing line when it comes to the construction of a new single-circuit line in parallel with an existing line.

If possible, the other new 90 kV or 225-kV lines (single-circuit or double-circuit) will be built using the standard conductors in the Senelec planning criteria or those commonly used on the Senelec grid.

Line impedances

Table 4-7: PU values based on 100 MVA

PU VALUES BASED ON 100 MVA						
Line Length (km): 1				Direct Linear Characteristics		
	Rtd. Voltage	Current	MVA	R'	X'	B'
	kV	kA	MVA	PU	PU	PU
L 225 kV 2 x 228 mm² ALM	225	0.80	312	0.00015	0.00061	0.00185
L 225 kV 2 x 310 mm² AMS	225	0.80	312	0.00010	0.00061	0.00185
L 225 kV 380 mm² ALAC	225	0.30	117	0.00017	0.00084	0.00136
L 225 kV 366 mm² ALM	225	0.63	246	0.00019	0.00083	0.00140
L 225 kV 570 mm² ALM	225	0.84	327	0.00012	0.00080	0.00145
L 225 kV 2 x 570 mm² ALM	225	1.68	655	0.000058	0.000575	0.001996
225 kV 1200 mm² ALU Cable	225	0.99	385	0.000064	0.000333	0.002162
90 kV 1200 mm² ALU Cable	90	0.99	154	0.00040	0.00208	0.00035
L 90 kV 288 mm² ALAC	90	0.57	88	0.00143	0.00469	0.00024
L 90 kV 288 mm² ALM	90	0.57	88	0.00142	0.00453	0.00024
L 90 kV 228 mm² ALM	90	0.48	75	0.00178	0.00499	0.00024
L 90 kV 228 mm² ALAC	90	0.46	72	0.00211	0.00519	0.00024
L 90 kV 366 mm² ALM	90	0.63	98	0.00114	0.00477	0.00025
L 90 kV 570 mm² ALM	90	0.84	131	0.00073	0.00499	0.00023

Areas and interconnections

The interconnected network in PSS/E is divided into six areas:

1- OMVS
2- EDM
3- SENELEC
4- SOMELEC
5- EDG
6- OMVG (the 225-kV loop, even if part of it is in Guinea)

The interconnection lines are:

OMVS – SENELEC

- 2127-2121 at the Dagan substation
- 2104 (Kayes) – 2624 (Tambacounda)

SOMELEC – SENELEC

- 2114 (Rosso) – 2121 (Dagan)
- 2415 (Beni-Nadji) – 2327 (St-Louis)

OMVG – SENELEC

- 2636 (Mansoa) – 2332 (Tanaf)
- 2525 (Sambangalou) – 2624 (Tambacounda)

Load and power factor

The load peak is modeled on the low voltage buses (33 kV) of the substations. The load is modeled at constant power, which is common practice for static studies, and represents a significant number of motor loads on the grid, such as refrigeration and air conditioning.

The load forecast by substation and HV customer was taken from the supply and demand study. The peak load of each substation provided by Senelec is considered to match the grid peak.

HV customers

Table 4-8: Connection of HV customers

CONNECTION OF HV CUSTOMERS						
Bus	Bus Name	Bus	Bus Name	Connection Line		
Source		HV Customers	HV Customers	Section	MVA	KM
1318	SOMET 90.000	1351	OLAM	L 90 kV 288 mm² ALM	88	1.23
2307	KOUNOUNE 225.000	2361	TER	L 225 kV 366 mm² ALM	246	5
23071	Diass-Kounou Bypass	2362	APROSI	Diass-Kounoune	246	5
21201	Sagal-Dagana Bypass	2359	AFRIMETAL	Middle of 225 kV Sakal-Dagana	246	10
23091	Mbour-Diass Bypass	2369	CIMAF	Mbour-Diass Center Line		7
2338	Sendou	2367	BARGNY	L 225 kV 366 mm² ALM	246	5
1314	Airport	2368	MAMELLES	90 kV 1200 mm² ALU Cable	154	2

Mines

Table 4-9: Connection of new mines

CONNECTION OF NEW MINES							
Bus	Bus Name	Bus	Bus Name	Name	Connection Line		
Source		Mines	Mines		Section	MVA	KM
Kedougou region (Massawa HUB)							
2351	Kédougou	2355	Makó	Makó (Toro Gold Limited)	366 mm² ALM	246	30
2351	Kédougou	2356	IAMGold	IAMGold	366 mm² ALM	246	100
2351	Kédougou	2357	Massawa	Massawa (RandGold)	366 mm² ALM	246	40
2357	Massawa	2358	Makabingui	Makabingui société WATIC	366 mm² ALM	246	20
2357	Massawa	2360	Sabadola	Sabadola Euromine	366 mm² ALM	246	20
2357	Massawa	2358	Falémé	Mines de Fer Falémé	366 mm² ALM	246	40
Tobene region							
2364	Afrig B	2366	Atlas	Atlas Ressources	366 mm² ALM	246	40
2122	Tobene	2365	Afrig A	Kébémère De Arfig (B))	366 mm² ALM	246	25
2365	Afrig A	2364	Afrig B	Kébémère De Arfig (A)	366 mm² ALM	246	30

Power factor

In terms of grid voltage management, the first principle is to compensate VAR as close to the load as possible, preferably directly on the distribution network or on the substation's low voltage bus (e.g. 33 kV).

Due to the low reactive compensation of 33 kV networks, which is noted by an average peak power factor of 96% at the peak in October 2016, shunt capacitors will be added to some low voltage busbars based on the 2019 model in order to obtain a voltage close to one pu at the substations' primary busbar, while maintaining a comfortable VAR margin at the alternators.

The power factor (PF) was kept at an average of 96% in 2019 and 2022, but due to load expansion and inherent voltage issues, we recommend that Senelec increase reactive compensation over its distribution network in order to achieve an average PF of 98% by 2028. This is why the load PF in the 2028 model is 98%.

Reactive compensation is needed on the Senelec distribution network to avoid the transmission of a reactive current on the transmission network, and its generation by generating plants. This will minimize losses and equipment load, and promote network stability.

Solar and wind renewable energy

Senegal plans to build several solar power facilities in the country, given the significant potential and environmental sustainability of this type of power generation. These facilities were modeled using the various scenarios examined. Solar energy is variable and therefore cannot deliver a guaranteed level of generation on the grid at the peak.

The Senelec grid will rely on a wind farm connected to the Tobène substation to complement its future generating facilities. Like solar, wind energy is also variable and likewise cannot deliver a guaranteed level of generation on the grid at the peak.

The purpose of a master plan is to provide information on the investments required to ensure that the grid can still perform in the worst operating conditions. The worst operating conditions for some components of the grid at the peak can occur when the facility does not generate any energy and it must be transported from remote power plants, or when the facility produces maximum peak energy and generation at certain power plants is reduced or even shut down, depending on the location of the solar facility and of the power plants.

Therefore, we have conducted an analysis using scenarios that include and do not include intermittent renewable energy (IRE).

4.1.4 STATIC STUDY AND MODELING

METHODOLOGY AND SCENARIOS

Four scenarios depict the most restrictive situations for the Senelec grid for the years under study.

Base case demand scenario

Base case scenario without mines or IRE

We define the base case scenario with no mining load, and IRE power plants off. Importing from the OMVS and OMVG grids is determined based on the maximum of the Senelec power plant country allocation power, in order to simulate a restrictive situation when generation is remote. It should be noted that the import in the generation plan was established in consideration of the mining load, which brings an additional constraint. Issues encountered in the contingency analysis are addressed as top recommendations and applied to the base case to obtain the top recommended grid.

Scenario with IRE

Top recommended grid, without mines and with IRE

On the top recommended grid without mines, IRE power plants are turned on at maximum capacity, and power plants on the 90 kV grid are shut down to simulate a restrictive situation on the 90 kV grid with the impact of IREs. Thermal power plants on the 90 kV grid are the most likely to be shut down and replaced by IRE. With the integration of IRE, importing is reduced because the shutdown of thermal power plants on the 90 kV grid is lower than what the IRE power plants generate.

Although this is a deterministic situation, we recommend this approach in order to achieve a high level of reliability. Issues encountered in the contingency analysis are addressed as the number two recommendations, and are applied to the base case to obtain the number two recommended grid.

Import limitation scenario

Import limits of the number two recommended grid, without mines or IRE (except 2019)

In order to meet the contractual limits of GWH imported for OMVS and OMVG power plants, the required MW imported may be higher than those of the country allocation power.

An analysis was performed based on the number two recommended grid to determine which element will reach its thermal capacity limits during contingencies first. The analysis consists in gradually increasing imports from the OMVS and OMVG grids based on the base case, while increasing the Senelec load proportionally.

The importing boundary condition encountered is then simulated and used in the dynamic stability study to determine potential overload and voltage issues with this boundary condition.

Scenario with mines

Number two recommended grid, with mines and without IRE (except 2019)

An analysis was conducted of the number two recommended grid, with mines and without IRE. Issues encountered in the contingency analysis are addressed as the number three recommendation, and applied to the base case to obtain the number three recommended grid.

In this project, no issues were observed with the grid + mines model. In fact, adding the mining load, 80% of which is located in the Kédougou region, makes the grid less restricted in terms of voltages and overloads.

This is explained by the fact that the import quantity in the generation plan is calculated taking mining loads into account. In the grid + mines model versus the model without mines, Senelec's generation is increased by the same amount as the mining load to maintain the supply-demand balance. The result is that the same import quantity is consumed in southern Senegal near the Sambangalou power plant, and does not need to be transported to the Dakar region.

2016 GRID

The 2016 grid is modeled from the 2015 PSS/E model and the reduced Master Plan for the Development of the OMVS Transmission Network, as previously discussed. The Senelec grid is updated with the PSS/E model data of the peak on October 4, 2016 and other data provided by Senelec.

Table 4-10: Load of the 2016 model

LOAD OF THE 2016 MODEL			
Bus	Substation	Pload (MW)	Qload (MVAR)
1316	SOCOC 90.000	5.3	2.0
1317	TAIBA 90.000	22.3	0.0
1319	MEKHE 90.000	14.0	4.0
1351	OLAM 90.000	0.6	0.0
4118	BAKELLD1 30.000	1.8	0.8
4119	MATAMLD1 30.000	9.6	3.0
4120	SAKALLD1 33.000	35.0	8.0
4121	DAGANLD1 30.000	9.5	2.0
4301	BELAILD1 33.000	26.0	7.6
4302	CAP DBLD1 33.000	40.0	7.7
4304	TOUBALD1 33.000	31.0	10.5
4305	KAOLALD1 33.000	27.0	10.3
4307	KOUNO 30.000	0.5	0.1
4308	DIASSLD1 33.000	13.0	4.0
4309	MBOURLD1 33.000	32.0	9.9
4310	HANNLD1 30.000	53.0	16.2
4311	HANNLD2 33.000	60.0	14.0
4312	THIONALD1 33.000	30.0	7.5
4313	MBAOLD1 33.000	29.0	9.6
4314	AEROPLD1 33.000	16.0	4.2
4315	UNIVERLD1 33.000	11.0	3.0
4316	AEROPLD2 33.000	16.0	4.2
4317	UNIVERLD2 33.000	11.0	3.0
4318	THIONALD2 33.000	10.0	2.2
4322	TOBENE 30.000	4.0	1.0
4350	BELAIRLD3 33.000	26.0	7.6
5301	BELAIRLD2 6.6000	10.0	2.0

Observations

In order to consider the worst-case operating scenario with respect to voltage loss and drop, the OMVS hydroelectric power plants (Manantali and Félou) were considered at their maximum output. Senelec imports 81 MW according to the country allocation.

The 2016 base case model analyses show overloads on the 90-kV Tobene-Thiona line when the 225-kV Tobene-Kounoune transmission line is lost. The main observations are listed in the table in the next section.

Status report

The status report below shows the overloads encountered in the 2016 peak load scenario. The overloads vary according to the contingencies. The table presents only the contingencies that caused the worst overloads or largest voltage deviation in each of the locations.
The table below shows the generation, load and loss report for the base case scenario:

Table 4-11: Generation, load and loss report – 2016 base case, peak

GENERATION, LOAD AND LOSS REPORT – 2016 BASE CASE PEAK						
Utility	Generation				Load	Losses
	MW generated	Maximum MW	MVAR generated	MW	MVAR	MW
OMVS	260	260	31	N/A	N/A	11.3
SENELEC	468	593	145	542	144	7

Exchanges

According to the country allocation, imports are as follows:

Table 4-12: Imports – 2016 base case scenario, peak

IMPORTS – 2016 BASE CASE, PEAK		
Senelec	Imports	81 MW from OMVS N/A MW from SOMELEC N/A MW from OMVG
	Total	81 MW

Overload

Overloads observed on the equipment following an analysis of the base case scenario:

Table 4-13: Overload report - 2016 grid, peak

OVERLOAD REPORT - 2016 GRID, PEAK					
Line or transformer				Overloads	
2017 substation	Bus	Substation	Bus	%	Contingencies
Hann 90 kV	1310	Hann 33 kV	4310	157	1310-4311 (xfo Hann)
Tobene 90 kV	1122	Thiona 90 kV	1312	137	2122-2307 (Tobene-Kounoune)

Compensation

No additional shunt capacitors are considered for 2016.

2017 Grid recommendations

The overload observed on the Tobene-Thiona line will be resolved by the approved new 225-kV Tobene-Kounoune transmission line project, scheduled for completion in 2019.

2019 GRID

The model was developed based on the 2016 model, with the addition of the planned grid projects to be commissioned in 2019 or earlier.

Table 4-14: Load of the 2019 model

LOAD OF THE 2019 MODEL				
Bus	Substation	Id	Pload (MW)	Qload (MVAR)
1316	SOCOC 90.000	HV	12	3
1317	TAIBA 90.000	HV	18	5
1318	SOMET 90.000	HV	4	1
1319	MEKHE 90.000	HV	15	4
1351	OLAM 90.000	HV	1	0
2359	AFRIMETAL 225.00	HV	3	1
2361	TER 225.00	HV	6	2
2362	APROSI 225.00	HV	4	1
2367	BARGNY 225.00	HV	26	9
4118	BAKELLD1 33.000	1	2	1
4119	MATAMLD1 33.000	1	11	3
4120	SAKALLD1 33.000	1	30	6
4121	DAGANLD1 33.000	1	9	2
4301	BELAILD1 33.000	1	27	6
4302	CAP DBLD1 33.000	1	16	3
4304	TOUBALD1 33.000	1	18	5
4305	KAOLALD1 33.000	1	28	7
4306	TOUBALD2 33.000	2	18	5
4308	DIASSLD1 33.000	1	21	4
4309	MBOURLD1 33.000	1	32	8
4310	HANNLD1 30.000	1	93	28
4312	THIONALD1 33.000	1	27	7
4313	MBAOLD1 33.000	1	22	6
4314	AEROPLD1 33.000	1	37	9
4315	UNIVERLD1 33.000	1	21	6
4318	THIONALD2 33.000	1	7	2
4322	TOBENE 33.000	1	5	1
4323	KOUNOULD2 33.000	2	17	4
4327	STLOUIS 33.000	1	12	4
4329	FATICK 33.000	1	9	3
4352	DIAMNIA 33.000	1	30	8
4354	GUADIAW 33.000	1	24	6
4370	SICAP 33.000	1	30	8
5301	BELAIRLD2 6.6000	1	10	2

Table 4-15: Planned substation projects, 2019

Planned SUBSTATION PROJECTS, 2019									
Bus	Substation/HV	Bus	Substation/LV	Id	Id name	MVA	Conn.	Year	Source
2311	PDOIE 225.00	1311	PDOIE 90.000	1	TR1 PDOIE	75	YNyn0	2017	1,2,3
2311	PDOIE 225.00	1311	PDOIE 90.000	2	TR2 PDOIE	75	YNyn0	2017	1,2,3
2307	KOUNO 03 225.00	1307	KOUNO 90.000	1	TR1 KOUNK	200	YN0yn0d	2019	1
2307	KOUNO 03 225.00	1307	KOUNO 90.000	2	TR1 KOUNK	200	YN0yn0d	2019	1
1301	BELAI 90.000	4301	BELAILD1 33.000	2	TR2 BELAI	80	YNyn0	2019	2
2304	TOUBA 225.00	4306	TOUBALD2 33.000	3	TR3 TOUBA	80	YNyn0	2019	2,3
2304	TOUBA 225.00	4306	TOUBALD2 33.000	4	TR4 TOUBA	80	YNyn0	2019	2,3
1307	KOUNOUNE 90.000	4323	KOUNOULD2 33.000	3	TR3 KOUNOU	80	YNyn0	2019	2,3
1307	KOUNOUNE 90.000	4323	KOUNOULD2 33.000	4	TR4 KOUNOU	80	YNyn0	2019	2,3
1354	GUEDIAW 225	4354	GUEDIAW 33.000	1	TR1 GUEDIAW	40	YNyn0	2019	2,3
1354	GUEDIAW 225	4354	GUEDIAW 33.000	2	TR2 GUEDIAW	40	YNyn0	2019	2,3
2338	DIAMNIA 225.00	4352	DIAMNIA 33.000	1	TR1 DIAMNIA	40	YNyn0	2019	3
2338	DIAMNIA 225.00	4352	DIAMNIA 33.000	2	TR2 DIAMNIA	40	YNyn0	2019	3
1370	SICAP 90.00	4370	SICAP 33.00	1	TR1 SICAP	80	YNyn0	2019	5
1370	SICAP 90.00	4370	SICAP 33.00	2	TR2 SICAP	80	YNyn0	2019	5
2329	FATICK 225.00	4329	FATICK 33.000	1	TR1 FATICK	40	YNyn0	2019	1,2,3
2329	FATICK 225.00	4329	FATICK 33.000	2	TR1 FATICK	40	YNyn0	2019	1,2,3
2327	STLOUIS 225.00	4327	STLOUIS 33.000	1	TR1 STLOUIS	40	YNyn0	2019	1,2,3
2327	STLOUIS 225.00	4327	STLOUIS 33.000	2	TR2 STLOUIS	40	YNyn0	2019	1,2,3

Table 4-16: Planned transmission line projects, 2019

Planned TRANSMISSION LINE PROJECTS, 2019									
Bus	Bus Name	Bus	Bus Name	ID	Section	km	MVA	Year	Source
2307	KOUNOUNE 225.00	2311	PDOIE 225.00	1	225 kV 1 200 mm^2 ALU Cable	23	385	2019	1,2,3
2307	KOUNOUNE 225.00	2338	SENDOU 225.00	2	L 225 kV 570 mm^2 ALM	10	327	2017	1,2,3
2122	TOBENE 03 225.00	2307	KOUNOUNE 225.00	2	L 225 kV 2 x 228 mm^2 ALM	53	312	2019	1,2,3
1310	HANN 90.00	1301	Belair 90.00		L 90 kV 366 mm^2 ALM	5	98	2017	
1302	CAPDB 90.000	1307	KOUNO 90.000	2	L 90 kV 366 mm^2 ALM(1)	6.4	98	2018	1
1354	GUEDIAW 225	13541	DGUEDIAW 225	1	225 kV 1200 mm^2 ALU Cable	12	385	2019	2,3
2122	TOBENE 03 225.00	2327	STLOUIS 225.00	1	630 mm^2	144	350	2019	1,2,3
2122	TOBENE 03 225.00	2327	STLOUIS 225.00	2	630 mm^2	144	350	2019	1,2,3
2305	KAOLA 225.00	2329	FATICK 225.00	1	L 225 kV 570 mm^2 ALM	55	327	2019	1,2,3
2309	MALICOUNDA 225.00	2329	FATICK 225.00	1	L 225 kV 570 mm^2 ALM	55	327	2019	1,2,3
1315	UNIVER 90.000	1370	SICAP 90.000	1	90 kV 1 200 mm^2 ALU Cable	2	154	2019	5

(1) With the addition of the second Kounoune-Cap des Biches 366 mm2 line, we recommend that the 288 mm2 conductor on the first line be replaced with a 366 mm2 conductor.

1 2017-2035 Generation Plan
2 List of major transmission projects
3 Preparation of the Generation and Transmission Master Plan
4 Interconnection Review - OMVG Energy Project - Sofreco 03-27-2014
5 Interconnected network

The 2019 network includes the 115 MW Sendou power plant and the following solar and wind power plants:

Table 4-17 : 2019 Solar and wind power plants

2019 SOLAR AND WIND POWER PLANTS		
Facility - Plant	Connection	Capacity (MW)
Solar 1	Malicounda	20
Senergy 2	Bokhol	20
Scaling Solar 1	Touba	23
Scaling Solar 2	Kahone	30
Scaling Solar 3	Niakhar	47
Solar 2	Mekhé	29.5
Solar 3	Mekhé	29.5
Solar 7	Diass	15
Sarreole 1	Tobene	51.75
Sarreole 2	Tobene	51.75

The new substations included in the 2019 model are:

- Fatick 225/33 kV substation
- Kounoune 90/33 kV substation
- St-Louis 225/33 kV substation
- SICAP 90/33 kV substation, radially connected to the Université substation
- Diamniadio 225/33 kV substation, connected to the Sendou-Kounoune line near Sendou
- Guédiawaye 225/33 kV substation, connected to the Kounoune-Patte d'Oie line (1)

(1) Recent information provided by Senelec shows us that the Guédiawaye substation is connected to the Kounoune-Hann 90 kV line. The 90 kV grid is seeing increased flows as a result of a decrease in generation from thermal power plants and an increase in IRE power plants. We recommend that the substation be connected to the 225 kV Kounoune-Patte d'Oie line. By considering Option 2 in 2026, namely locating the local gas power plant in Kayar and the 225-kV Kayar-Tap Tobene-Patte-d'Oie loop, the Guédiawaye substation is then directly connected to the 225-kV Patte-d'Oie substation.

Somelec

In 2019, Mauritania will have completed an expansion of its 225-kV grid by adding double-circuit transmission lines between Duale, BeniNadji and Saint-Louis. For its part, Senegal will have extended this corridor by adding lines between Saint-Louis and Tobene.

Table 4-18: New lines in 2019 – Somelec

NEW LINES IN 2019 – SOMELEC							
Bus	Bus Name	Bus	Bus Name	ID	Section	MVA	KM
2401	DUALE 225.00	2415	BENI-NADJI 225.00	1	630 mm²	350	193
2401	DUALE 225.00	2415	BENI-NADJI 225.00	2	630 mm²	350	193
2327	STLOUIS 225.00	2415	BENI-NADJI 225.00	1	630 mm²	350	76
2327	STLOUIS 225.00	2415	BENI-NADJI 225.00	2	630 mm²	350	76

Observations

Base case scenario without RE

Considering the recommendations for the 2016 grid, no observations or recommendations were made for the peak base case scenario, without mines or IRE, in 2019.

Grid with IRE

For the grid without mines and with IRE, overloads were observed on:

- Hann-Patte d'Oie 90 kV lines.

In the list of investment plans (decided projects), 150 MVA transformers are planned for the Patte d'Oie substation. The integration of IRE into the grid before 225-kV voltage arrives at the Hann substation in 2027 justified the choice of the 225/90 kV 200 MVA transformers.

The integration of IRE also justifies the addition of a Hann-Patte d'Oie 90-kV line. This transmission line is already one of the decided projects, with commissioning scheduled for 2020 based on the information we have. Since this is a rather deterministic scenario, the risk of issues due to a one-year delay is low. If this were the case, then a temporary solution would be to keep one unit at the Bel-Air power plant in service. By considering Option 2 in 2028, namely locating a local gas power plant in Kayar and the 225-kV Kayar-Tap-Tobene-Patte-d'Oie loop, and according to recent information from Senelec, the two 90-kV lines are replaced by two cables that we recommend be insulated to 225 kV.

Status report

The status report below shows the overloads encountered for the 2019 peak load scenarios defined in the methodology. Overloads or voltage issues vary depending on the contingencies. The table presents only the contingencies that provoke the worst overloads or largest voltage deviation in each of the locations.

The two tables below show the status of exchanges, generation, load and losses on the base case network without IRE:

Table 4-19: Generation, load and loss report – base case scenario, 2019 peak

GENERATION, LOAD AND LOSS REPORT – BASE CASE, 2019 PEAK						
Utility/Association	Generation			Load		Losses
	MW Generated	Maximum MW	MVAR Generated	MW	MVAR	MW
OMVS	260	260	-41	N/A	N/A	7.6
SENELEC	538	627	87	643	169	6.51
OMVG	N/A	N/A	N/A	N/A	N/A	N/A

Exchanges

According to the country allocation, imports are as follows:

Table 4-20: Imports – base case scenario, 2019 peak

IMPORTS – 2019 BASE CASE, PEAK		
Senelec	Imports	81 MW from OMVS 30 MW from SOMELEC N/A MW from OMVG
	Total	111 MW

Overload

Overloads observed on the grids, with and without IRE:

Table 4-21: Overloads - 2019 grid, peak

OVERLOADS - 2019 GRID, PEAK					
Line or transformer				Overloads	
Substation	Bus	Substation	Bus	%	Contingencies
Patte d'oie 90 KV	1311	Hann 90 kV	1310	108	Line 1

Compensation

The following shunt reactors are among the planned projects:

Table 4-22: Addition of shunt reactors - 2019 grid, peak

ADDITION OF SHUNT REACTORS - 2019 GRID, PEAK			
Shunt reactors			
Substation Name	Substation Number	Capacity	Type
Kaolack	2305	25	Switchable
Touba	2304	25	Switchable

The addition of shunt capacitors near the load improves the power factor and provides enhanced static and dynamic stability.

Table 4-23: Shunt capacitor additions - 2019 grid, peak

SHUNT CAPACITOR ADDITIONS - 2019 GRID, PEAK							
Substation Name	Bus Number	Capacity (MVAR)	Type	Substation Name	Bus Number	Capacity (MVAR)	Type
Airport	4314	7	Fixed	Hann	4310	28	Fixed
Diass	4308	4	Fixed	Mbao	4313	6.5	Fixed
Université	4315	11	Fixed	M'Bour	4309	9	Fixed
Cap des Biches	4302	10	Fixed	Thiona	4312	7	Fixed
Bel-Air	4301	12	Fixed				

Line

2019 Grid recommendations

It is recommended that two 225-kV 200 MVA transformers be installed initially at the Patte d'Oie substation.

It is recommended that the 90-kV 288 mm^2 conductor be replaced with a 366 mm^2 conductor between Kounoune and Cap des Biches, and that a second 366 mm^2 conductor be added in 2018. Two 1,600 mm^2 cables are already decided between the Patte-d'Oie and Hann substations in 2020.

It is recommended that shunt capacitors be added on the distribution lines of the substations concerned.

Table 4-24: Shunt capacitor additions - 2019 grid, peak

SHUNT CAPACITOR ADDITIONS - 2019 GRID, PEAK							
Substation Name	Bus Number	Capacity (MVAR)	Type	Substation Name	Bus Number	Capacity (MVAR)	Type
Airport	4314	7	Fixed	Hann	4310	28	Fixed
Diass	4308	4	Fixed	Mbao	4313	6.5	Fixed
Université	4315	11	Fixed	M'Bour	4309	9	Fixed
Cap des Biches	4302	10	Fixed	Thiona	4312	7	Fixed
Bel-Air	4301	12	Fixed				

2022 GRID

This model was developed based on the 2019 model, with the addition of planned grid projects to be commissioned between 2020 and 2022.

Table 4-25: Load of the 2022 model

LOAD OF THE 2022 MODEL				
Bus	Substation	ID	Pload (MW)	Qload (MVAR)
1316	SOCOC 90.000	HV-LV	18	6
1317	TAIBA 90.000	HV	21	7
1318	SOMET 90.000	HV	6	2
1319	MEKHE 90.000	HV	20	7
1351	OLAM 90.000	HV	1	0
2355	MAKO 225.00	M	10	3
2356	IAMGOLD 225.00	M	12	4
2357	MASSAWA 225.00	M	23	8
2358	MAKA_FALEME 225.00	M1	2	1
2358	MAKA_FALEME 225.00	M2	21	7
2359	AFRIMETAL 225.00	HV	5	2
2360	SABADOLA 225.00	M	19	6
2361	TER 225.00	HV	12	4
2362	APROSI 225.00	HV	5	2
2365	AFRIG A 225.00	M	10	3
2366	ATLAS 225.00	M	7	2
2367	BARGNY 225.00	HV	26	9
2368	MAMELLES 225.00	HV	14	5
2369	CIMAF 225.00	HV	21	7
4118	BAKELLD1 33.000	1	3	1
4119	MATAMLD1 33.000	1	21	4
4120	SAKALLD1 33.000	1	36	5
4121	DAGANLD1 33.000	1	10	1
4301	BELAILD1 33.000	1	31	12
4302	CAP DBLD1 33.000	1	18	3
4304	TOUBALD1 33.000	1	22	6
4305	KAOLALD1 33.000	1	32	14
4306	TOUBALD2 33.000	2	21	6
4308	DIASSLD1 33.000	1	29	4
4309	MBOURLD1 33.000	1	38	14
4310	HANNLD1 30.000	1	109	39
4312	THIONALD1 33.000	1	31	9
4313	MBAOLD1 33.000	1	36	12
4314	AEROPLD1 33.000	1	43	10
4315	UNIVERLD1 33.000	1	24	7
4318	THIONALD2 33.000	1	9	3
4322	TOBENE 33.000	1	6	1
4323	KOUNOULD2 33.000	2	20	7
4324	TAMBA 33.000	1	9	2
4327	STLOUIS 33.000	1	14	5
4329	FATICK 33.000	1	10	3
4330	ZIGUIN 33.000	1	27	13
4331	KOLDA 33.000	1	9	3
4350	BELAIRLD3 33.000	1	31	12
4351	KEDOUG 33.000	1	2	1
4352	DIAMNIA 33.000	1	35	11
4354	GUADIAW 33.000	1	28	9
4370	SICAP 33.000	1	35	11
5301	BELAIRLD2 6.6000	1	12	1

The planned substation projects for 2022 are:

Table 4-26: Planned substation projects, 2022

PLANNED SUBSTATION PROJECTS, 2022									
Bus	Substation/HV	Bus	Substation/LV	ID	ID Name	MVA	Conn.	Year	Source
2351	KEDOUG 225.00	4351	KEDOUG 33.000	1	TR1 KEDOUG	40	YNyn0	2020	2,3
2351	KEDOUG 225.00	4351	KEDOUG 33.000	2	TR2 KEDOUG	40	YNyn0	2020	2,3
2624	TAMBA 225.00	4324	TAMBA 33.000	1	TR1 TAMBA	40	YNyn0	2020	4
2624	TAMBA 225.00	4324	TAMBA 33.000	2	TR2 TAMBA	40	YNyn0	2020	4
2330	ZIGUIN 225.00	4330	ZIGUIN 33.000	1	TR1 ZIGUIN	40	YNyn0	2020	1,2,3
2330	ZIGUIN 225.00	4330	ZIGUIN 33.000	2	TR2 ZIGUIN	40	YNyn0	2020	1,2,3
2331	KOLDA 225.00	4331	KOLDA 33.000	1	TR1 KOLDA	40	YNyn0	2020	1,2,3
2331	KOLDA 225.00	4331	KOLDA 33.000	2	TR2 KOLDA	40	YNyn0	2020	1,2,3

The planned transmission line projects for 2022 are:

Table 4-27: Planned transmission line projects, 2022

PLANNED TRANSMISSION LINE PROJECTS, 2022									
Bus	Bus Name	Bus	Bus Name	ID	Section	km	MVA	Year	Source
2331	KOLDA 225.00	2624	TAMBA 225.00	1	L 225 kV 2 x 570 mm² ALM	200	655	2020	2,3
2330	ZIGUIN 225.00	2332	TANAF 225.00	1	L 225 kV 366 mm² ALM	100	246	2020	2,3,4
2331	KOLDA 225.00	2332	TANAF 225.00	1	L 225 kV 2 x 570 mm² ALM	60	655	2020	2,3,4
2351	KEDOUG 225.00	2625	SAMBAN 225.00	1	L 225 kV 366 mm² ALM	31	246	2020	2,3
1310	HANN 90	1311	PDOIE 90	1	L 225 KV 1600 m²(1) Cable	1,2	200	2020	
1310	HANN 90	1311	PDOIE 90	2	L 225 KV 1600 m²(1) Cable	1,2	200	2020	
2122	TOBENE 03 225.00	2337	MBORO 225.00	1	L 225 kV 366 mm² ALM	30	246	2021	1
2122	TOBENE 03 225.00	2337	MBORO 225.00	2	L 225 kV 366 mm² ALM	30	246	2021	1

(1) The cables must be insulated to 225 kV, but operated at 90 kV while awaiting the addition of the 225 kV voltage at the Hann substation.

1 2017-2035 Generation Plan
2 List of major transmission projects
3 Preparation of the Generation and Transmission Master Plan
4 Interconnection Review - OMVG Energy Project - Sofreco 03-27-2014
5 Interconnected network forecast

The 2022 grid includes the following power plants:

Senelec

- Malicounda 122.5 MW connected to the Malicounda substation (Mbour)
- IPP Africa 90 MW, connected to the Mboro substation, which is connected to the Tobene substation (30 km)
- Sarreole 3 55.2 MW, connected to the Tobene substation

OMVS

- Gouina 140 MW, Senelec's share according to the 35 MW country allocation.

OMVG and others

- Kaléta 240 MW connected to the Kaléta substation (1.5 km), Senelec's share according to the 48 MW country allocation
- Sambangalou 128 MW connected to the Sambangalou substation, Senelec's share according to the 61.5 MW country allocation
- Souapiti 515 MW connected to the Kaléta substation (20 km), Senelec's share according to the 103 MW country allocation

The new substations included in the 2022 model are:

- Ziguinchor 225/33 kV substation
- Kolda 225/33 kV substation
- Kédougou 225/33 kV substation
- Tambacounda 225/33 kV substation

OMVS and OMVG

The 225-kV grid includes the 225-kV transmission lines of the OMVG loop between Linsan and Kaolack, a north-east network enabling evacuation of power from the Sambangalou power plant, and a south-west network to evacuate power from the Kaleta and Souapiti power plants. This loop is interconnected with Guinea at the Kaleta substation and with Mali via the OMVS 225-kV double-circuit line between Tambacounda and Kayes.

The OMVS and OMVG transmission line projects are:

Table 4-28: New lines in 2022 – OMVS

NEW LINES IN 2022 – OMVS										
Bus	Bus Name		Bus	Bus Name		ID	Section	MVA	km
2104	KAYEM	225.00	2624	TAMBA	225.00	1	L 225 kV 2 x 570 mm² ALM	655	252
2104	KAYEM	225.00	2624	TAMBA	225.00	2	L 225 kV 2 x 570 mm² ALM	655	252

Table 4-29: New lines in 2022 - OMVG

NEW LINES IN 2022 – OMVG										
Bus	Bus Name		Bus	Bus Name		ID	Section	MVA	km
2305	KAOLA	225.00	2624	TAMBA	225.00	1	L 225 kV 2 x 570 mm² ALM	655	264
2624	TAMBA	225.00	2625	SAMBA	225.00	1	L 225 kV 2 x 570 mm² ALM	655	225
2625	SAMBA	225.00	2626	MALI	225.00	1	L 225 kV 2 x 570 mm² ALM	655	40
2626	MALI	225.00	2638	LABE	225.00	1	L 225 kV 2 x 570 mm² ALM	655	76
2615	LINSAN	225.00	2638	LABE	225.00	1	L 225 kV 2 x 570 mm² ALM	655	85
2517	KALETA	225.00	2615	LINSAN	225.00	1	L 225 kV 2 x 570 mm² ALM	655	94
2517	KALETA	225.00	2535	CKALET	225.00	1	L 225 kV 366 mm² ALM	245.5	1.48
2517	KALETA	225.00	2535	CKALET	225.00	2	L 225 kV 366 mm² ALM	245.5	1.48
2517	KALETA	225.00	2637	BOKE	225.00	1	L 225 kV 2 x 570 mm² ALM	655	124
2636	MANSOA	225.00	2637	BOKE	225.00	1	L 225 kV 2 x 570 mm² ALM	655	183
2632	TANAF	225.00	2636	MANSOA	225.00	1	L 225 kV 2 x 570 mm² ALM	655	67
2632	TANAF	225.00	2639	SOMA	225.00	1	L 225 kV 2 x 570 mm² ALM	655	90
2627	BRIKA	225.00	2639	SOMA	225.00	1	L 225 kV 366 mm² ALM	245.5	146
2305	KAOLA	225.00	2639	SOMA	225.00	1	L 225 kV 2 x 570 mm² ALM	655	105
2628	BISSAU	225.00	2636	MANSOA	225.00	1	L 225 kV 366 mm² ALM	245.5	28

Observations

Base case scenario without mines or RE

Considering the recommendations of the 2019 grid, we observe an overload on:

- The 225/90 kV 75 MVA transformers at the Tobene substation
- The 90/33 kV 40 MVA transformers at the Mbour substation (Malicounda)
- The 225/33 kV 40 MVA transformer of the Matam substation.

Top recommended grid, without mines and with IRE

For the top recommended grid without mines and with IRE, overloads were observed on:

- the CapDB-Mbao 90 kV line
- the 225/90 kV Kounoune transformers.

Import limits of the number two recommended grid, without mines or IRE

The analyses show that the components that reach their maximum thermal capacities during contingencies, when importing is increased, are the OMVS grid series capacitors. They have a maximum capacity of 195 MVA. Their capacity is reached when imports from OMVS reaches 160 MW in combination with an OMVG imports of 300 MW

Number two recommended grid, with mines and without IRE

No observations for the number two recommended grid with mines.

Status report

The report below shows the overloads encountered for the 2022 peak load scenarios defined in the methodology. Overloads or voltage issues vary depending on the contingencies. The table presents only the contingencies that caused the worst overloads or largest voltage deviation in each of the locations.

The two tables below show the report of exchanges, generation, load and losses on the base case scenario without mines or IRE:

Table 4-30: Generation, load and loss report –base case scenario, 2022 peak

GENERATION, LOAD AND LOSS REPORT –BASE CASE, 2022 PEAK						
Utility/Association	Generation				Load	Losses
	MW Generated	Maximum MW	MVAR Generated	MW	MVAR	MW
OMVS	400	400	-90	N/A	N/A	10.6
SENELEC	561	620	146	900	283	16.3
OMVG	548	N/A	-126	N/A	N/A	5.4

Exchange

According to the country allocation, imports are as follows:

Table 4-31: Imports – base case scenario, 2022 peak

IMPORTS – 2022 BASE CASE, PEAK		
Senelec	Imports	116 MW from OMVS 30 MW from SOMELEC 212 MW from OMVS
	Total	358 MW

Overload

Overloads observed on the grids without mines or IRE:

Table 4-32: Overloads - 2022 grid, peak

Overloads - 2022 grid, peak					
Line or transformer				Overloads	
Substation	Bus	Substation	Bus	%	Contingencies
Tobene 90 kV	1122	Tobene 225 kV	2122	100	Transformer 1 or Transformer 2
Malicounda 225 kV	2309	Mbour 33 kV	4309	104	Transformer 1 or Transformer 2
CapDB 90kV	1302	MBAO 90 kV	1313	132	Kounoune-Patte d'oie 225 kV
Kounoune 90 kV	1307	Kounoune 225 kV	1307	106	Kounoune-Patte d'oie 225 kV
Matam 225 kV	2119	Matam 33 kV	4119	110	Base case

Compensation

Table 4-33: Addition of shunt reactors - 2022 grid, peak

ADDITION OF SHUNT REACTORS - 2022 GRID, PEAK			
Shunt reactors			
Substation Name	Substation Number	Capacity	Type
Boké	2637	20	Switchable
Kolda	2331	2 x 20	Switchable
Mansoa	2636	2 x 20	Switchable
Sambangalou	2625	20	Fixed
Tambacounda	2624	2 x 30	Switchable
Tanaf	2632	20	Switchable
Ziguinchor	2330	10	Switchable
Mali	2626	20	Switchable

No addition of shunt capacitors for the 2022 grid.

2022 Grid recommendations

- The overload of the 225/90 kV 75 MVA transformers at the Tobene substation requires the addition of a third 75 MVA transformer.
- The overload of the 90/33 kV 40 MVA transformers at the Mbour (Malicounda) substation requires the addition of a third 40 MVA transformer.
- The loss of the 225-kV Kounoune-Patte d'Oie line causes overloads on the CapDB-Mbao line and the 225/90 kV Kounoune transformers. A second line needs to be added to prevent these overloads. Note that the first line is one of the decided projects, with commissioning expected in 2019.
- The Matam substation contains a single 225/33 kV 20 MVA transformer that is overloaded. In order to comply with criterion n-1, the 20 MVA transformer will need to be replaced with two 40 MVA transformers.

We recommend adding the following shunt reactors:

Table 4-34: Addition of shunt reactors - 2022 grid, peak

ADDITION OF SHUNT REACTORS - 2022 GRID, PEAK			
Shunt reactors			
Substation Name	Substation Number	Capacity	Type
Sambangalou	2625	20	Fixed
Kolda	2331	2x20	Switchable
Tambacounda	2624	2x30	Switchable
Tanaf	2632	20	Switchable
Ziguinchor	2330	10	Switchable

In summary, adding a third 225/90 kV 75 MVA transformer to the Tobene substation, a second 225 kV 1,200 mm^2 cable between the Kounoune and Patte d'Oie substation, in addition to the two 90 kV 366 mm^2 lines between Kounoune and Cap des Biches in 2018 and the two 1,600 mm^2 cables between Patte d'Oie and Hann in 2019, will provide reliable grid operation in 2022.

2028 GRID

The model was developed based on the recommended 2022 model.

Power factor

The increased MW load also implies an increase in MVARs. As previously indicated, in order to minimize voltage issues, we assume that Senelec will improve its reactive compensation on the distribution network. The load power factor in 2028 is established at 98%, which keeps the MVAR load on the transmission network at the same level as in 2022.

Table 4-35: Load of the 2028 model

LOAD OF THE 2028 MODEL				
Bus	Substation	ID	Pload (MW)	Qload (MVAR)
1316	SOCOC 90.000	HV-LV	25	8
1317	TAIBA 90.000	HV	34	11
1318	SOMET 90.000	HV	4	2
1319	MEKHE 90.000	HV	24	8
1351	OLAM 90.000	HV	1	0
2355	MAKO 225.00	M	10	4
2356	IAMGOLD 225.00	M	6	2
2357	MASSAWA 225.00	M	22	8
2358	MAKA_FALEME 225.00	M1	2	1
2358	MAKA_FALEME 225.00	M2	17	6
2359	AFRIMETAL 225.00	HV	5	2
2361	TER 225.00	HV	8	3
2362	APROSI 225.00	HV	4	1
2365	AFRIG A 225.00	M	10	3
2366	ATLAS 225.00	M	7	3
2367	BARGNY 225.00	HV	18	6
2368	MAMELLES 90.000	HV	16	5
2369	CIMAF 225.00	HV	15	5
4118	BAKELLD1 33.000	1	6	1
4119	MATAMLD1 33.000	1	21	4
4120	SAKALLD1 33.000	1	59	12
4121	DAGANLD1 33.000	1	18	4
4301	BELAILD1 33.000	1	51	10
4302	CAPDBLD1 33.000	1	30	6
4304	TOUBALD1 33.000	1	35	7
4305	KAOLALD1 33.000	1	54	11
4306	TOUBALD2 33.000	2	35	7
4308	DIASSLD1 33.000	1	35	7
4309	MBOURLD1 33.000	1	62	12
4310	HANNLD1 33.000	1	180	36
4312	THIONALD1 33.000	1	50	10
4313	MBAOLD1 33.000	1	43	9
4314	AEROPLD1 33.000	1	71	14
4315	UNIVERLD1 33.000	1	40	8
4318	THIONALD2 33.000	1	15	3
4322	TOBENE 33.000	1	10	2
4323	KOUNOULD2 33.000	2	34	7
4324	TAMBA 33.000	1	15	3
4327	STLOUIS 33.000	1	22	5
4329	FATICK 33.000	1	17	4
4330	ZIGUIN 33.000	1	37	8
4331	KOLDA 33.000	1	16	3
4350	BELAIRLD3 33.000	1	51	10
4351	KEDOUG 33.000	1	5	1
4352	DIAMNIA 33.000	1	58	12
4354	GUADIAW 33.000	1	47	9
4370	SICAP 33.000	1	57	11
5301	BELAIRLD2 6.6000	1	20	4

The 2028 grid includes the following power plants:

Senelec

- IPP HFO Dual 122 MW power plant connected to the Kounoune 225 kV substation
- IPP CCGT Local Gas 200 MW power plant located in St-Louis 225 kV - Option 1
- IPP CCGT Local Gas 200 MW power plant located in Kayar - Option 2
- S6 40 MW solar power plant connected to the 225 kV Sakal substation
- New wind power plant 1, 51.75 MW connected to the 225 kV Tobene substation

OMVS

- Koukoutamba 294 MW connected to the Manantali 225 kV (270 km) and Linsan 225 kV (200 km) substations, Senelec's share according to the 73.5 MW country allocation

OMVG and others

- Amaria 300 MW connected to the Kaléta substation 225 kV (40 km)
- Senelec's share according to the country allocation: 60 MW
- Grand Kinkon 291 MW connected to the 225-kV Labé substation (30 km)
- Senelec's share according to the country allocation: 58.2 MW

For evacuation from the Koukoutamba power plant to Mali and Guinea, a new 225-kV double-circuit transmission line between Manantali and Koukoutamba and another between Koukoutamba and Linsan have been added. A new 225 kV single-circuit line from Linsan to Fomi and Fomi to Kodialini in Mali is also added to the model, as they have a significant impact on flows on the OMVS and OMVG grids.

The OMVS and Guinea transmission line projects are:

Table 4-36: New lines in 2028 - OMVS

NEW LINES IN 2028 – OMVS							
Bus	Bus Name	Bus	Bus Name	ID	Section	MVA	km
2103	MANAN 225.00	2108	KOUKO 225.00	1	L 225 kV 2 x 570 mm² ALM	655	270
2103	MANAN 225.00	2108	KOUKO 225.00	2	L 225 kV 2 x 570 mm² ALM	655	270
2107	BALAS 225.00	2108	KOUKO 225.00	1	L 225 kV 2 x 570 mm² ALM	655	100
2107	BALAS 225.00	2615	LINSAN 225.00	1	L 225 kV 570 mm² ALM	327	100

Table 4-37: New lines in 2028 - Guinea

NEW LINES IN 2028 – GUINEA							
Bus	Bus Name	Bus	Bus Name	ID	Section	MVA	km
2107	BALASSA 225.00	2531	FOMI 225.00	1	L 225 kV 570 mm² ALM	327	210
2531	FOMI 225.00	2230	SANANK 225.00	1	L 225 kV 570 mm² ALM	327	628
2106	KODIALINI 225.00	2230	SANANK 225.00	1	L 225 kV 2 x 570 mm² ALM	655	23

Observations

Base case scenario without mines or IRE

SC – OMVS

We observe an overload on the series capacitors (SC) of the OMVS 225 kV grid. Our analysis shows that the thermal capacity of the series capacitors must be raised to that of the line, i.e. 312 MVA, between 2025 and 2027, starting with the capacitors at the Matam substation in 2025. In the 2028 model, we have considered the thermal capacity of the Kayes, Matam, Dagana and Sakal substation series capacitors at 312 MVA.

Considering the recommendations for the 2022 grid, between 2024 and 2028 we observe an overload on:

2024 – Addition of the IPP HFO dual power plant (122 MW)

- 225/33 kV 40 MVA transformers at the Diamniadio substation
- 225/33 kV 40 MVA transformers at the Kaolack substation

2026 – Addition of the IPP CCGT local gas power plant (100 MW) and Koukoutamba (294 MW) in 2025

- 225/33 kV 50 MVA transformer at the Sakal substation
- 225/33 kV 40 MVA transformers at the Guédiawaye substation

2026 – Addition of the IPP CCGT local gas power plant (100 MW), Solar S6 (40 MW) and Wind 1 (51.75 MW)

- 90/33 kV 40 and 20 MVA transformers at the Thiona substation
- 90/33 kV 80 MVA transformers at the Hann substation
- CapDB-Mbao 90 kV line
- 90-kV Patte d'Oie-Airport line
- Bélair-Université 90-kV line
- Tobene-Thiona 90-kV line
- Tobene-Kounoune 225-kV line
- 225/90 kV 200 MVA transformers at the Patte d’Oie substation

2028 – Addition of the Grand Kinkon (291 MW) and Amaria (300 MW) power plant

- 90/33 kV 40 MVA transformers at the Université substation
- Tobene-Thiona 90-kV line.

This scenario is not the most restrictive because all thermal power plants on the 90-kV grid are in service. Overloads are observed in 2027 on several 90-kV lines, on several 90/33 kV transformers, and the 225/90 kV transformers at Patte d’Oie. A quick analysis with IRE (scenario two) shows additional overloads on the Hann- Patte d’Oie 90-kV and Kounoune-Patte d’Oie 225 kV transmission lines. All these overloads in addition to the voltage issues associated with a large number of 90 kV lines mean that a new 225 kV energy corridor is needed.

Two options were considered: Option 1 located in Saint-Louis, using local gas generation and a 225-kV Kounoune-CapDB-Hann-Patte d’Oie loop, and Option 2 located in Kayar, using local gas generation and a 225-kV Kayar-Tap-Tobene-Patte d’Oie loop.

Option 1

One of the transmission lines between the Kounoune and CapDB substations will have to be built using a 1,200 mm^2 225-kV cable in 2022. The Hann-Patte d'Oie lines are already being built with a 225-kV cable (2022). Overloads are observed on the 90-kV CapDB-Mbao line and on the 90/33 kV transformers at the Hann substation. As a result, we are considering converting the Kounoune-CapDB-Hann-Patte d'Oie loop to 225 kV in 2027.

With this 225-kV loop, in addition to avoiding the abovementioned additional 90-kV transmission lines and transformers, it would also not be necessary to install an additional Hann-Patte d'Oie 90-kV, Kounoune-Patte d'Oie 225-kV line and a 225/90 kV 200 MVA transformer at the Patte d'Oie substation, in addition to reducing losses. The new grid with the 225-kV loop has improved thermal capacity and is more robust and stable.

However, in order to achieve this, a new Mbao-Hann 225-kV line, two 225/90 kV transformers at the Hann substation, and two 225/33 kV transformers at the Mbao substation must be installed.

With the addition of the 225/90 kV 230 MVA transformers at the Hann substation, although it is not necessary to install the 225/33 kV transformers, this is still highly recommended to prevent losses and achieve better voltage regulation. Given the significant cost of these transformers, in this model we consider four 90/33 kV 80 MVA transformers.

Although voltage conversion from 90 to 225 kV is planned for 2027, the analysis will be carried out on the 2028 model since this is the model chosen for the impact assessment of the new generating plants.

Option 2

Installing local gas generation in Kayar provides a different grid topology for evacuation. The 225 kV Tobene-Kounoune line is located near Kayar, and with this option the plan is to connect local gas generation to a 5-km 225 kV 2 x 228 mm^2 bypass in the middle of the line, and a second 35-km 225 kV 2 x 228 mm^2 double-circuit line at the Guédiawaye substation.
See Appendix B.1, diagram 1.

The need for a Kayar-Guédiawaye double-circuit transmission line is initially not to bolster energy transit on the line, but to ensure there is sufficient transit on this line when one of the two Kounoune-Patte d'Oie 1200 mm^2 cables is lost, so as not to overload the other cable. This 225-kV double-circuit transmission line could be built along the coast, passing by Lake Retba and Malika and connecting to the new Guédiawaye substation further south. There would potentially be a small 1,200 mm^2 section of underground cable to connect to the Guédiawaye substation from the coast.

With this option, the 225-kV connection to the Guédiawaye substation will have to be reconsidered. It must be connected directly to the 225-kV Patte d'Oie substation via a 1,200 mm^2 underground cable. Thus, local gas generation from Kayar will be evacuated to the Patte d'Oie substation in a loop with a bypass on one of the 225-kV Tobene-Kounoune lines. If one of the components of the loop is lost, the generated power can be evacuated from Kayar at any time. Consideration may be given to building the Kayar-Tap-Tobene bypass line as a double-circuit line, if export to Mauritania or Mali is being considered.

This loop makes it possible to maintain the 90-kV Kounoune - CapDB 366 mm^2 lines as well as all the other 90-kV lines and the Mbao substation, since the Patte d'Oie-Hann lines are already built using two 225-kV 1,600 mm^2 cables. However, although two 225/90 kV 200 MVA transformers still need to be installed at the Hann substation, two 225/33 kV 200 MVA transformers must also be installed to replace the three

90/33 kV 80 MVA transformers and prevent overloads on the 225/90 kV 200 MVA transformers when one of them is lost.

Furthermore, the installation of two 225/33 kV 200 MVA transformers at the Hann substation to replace the three 90/33 kV 80 MVA transformers will provide better voltage regulation and reduce losses. Otherwise, the capacity of the two 225/90 kV 20 MVA transformers will need to be increased in addition to adding a fourth 90/33 kV 80 MVA transformer. It is recommended that consideration be given to the location of a third 225/33 kV 200 MVA transformer.

Top recommended grid with a 225-kV loop, without mines and with IRE

For the top recommended grid with a 225-kV loop, without mines and with IRE, overloads were observed on:

- the Tobene-Kounoune 225-kV lines.

Importing limits of the number two recommended grid with a 225-kV loop, without mines or IRE

The analyses show that the components that reach their maximum thermal capacities during contingencies, when importing is increased, are the OMVS grid series capacitors. They now have a maximum capacity of 312 MVA. Their capacity is reached when importing from OMVS reaches 240 MW.

The analyses conducted on an OMVG import of 385 MW show no issues. These limits provide acceptable flexibility.

Number two recommended grid, with mines and without IRE

No observations for the number two recommended grid with mines.

Status report

The report below shows the overloads encountered for the 2028 peak load scenarios defined in the methodology. Overloads or voltage issues vary depending on the contingencies. The table presents only the contingencies that caused the worst overloads or largest voltage deviation in each of the locations.

The two tables below show the report of exchanges, generation, load and losses on the base case without mines or IRE:

Table 4-38: Generation, load and loss report – base case, 2028 peak

GENERATION, LOAD AND LOSS REPORT – BASE CASE, 2028 PEAK						
Utility	Generation				Load	Losses
	MW Generated	Maximum MW	MVAR Generated	MW	MVAR	MW
OMVS	694	694	-78	N/A	N/A	32
SENELEC	828	1270	209	1345	289	38
OMVG	903	1043	-96	N/A	N/A	18

Exchange

According to the country allocation, imports are as follows:

Table 4-39: Imports – 2028 base case, peak

IMPORTS – 2028 BASE CASE, PEAK		
Senelec	Imports	190 MW from OMVS 30 MW from SOMELEC 330 MW from OMVS
	Total	550 MW

Overload

Overloads observed on the grids without mines or IRE:

Table 4-40: Overloads - 2024 grid, peak

OVERLOADS - 2024 GRID, PEAK					
Line or transformer				Overloads	
Substation	Bus	Substation	Bus	%	Contingencies
Kaoloack 225 kV	2305	Kaolack 33 kV	4305	103	T1 or T2
Sendou 225 kV	2338	Diamniadio 33 kV	4352	107	T1 or T2

Table 4-41: Overloads - 2026 grid, peak

OVERLOADS - 2026 GRID, PEAK					
Line or transformer				Overloads	
Substation	Bus	Substation	Bus	%	Contingencies
Sakal 225 KV	2120	Sakal 33 kV	4120	104	T1 or T2
Guédiaw 225 kV	1354	Guédiaw 33 kV	4354	103	T1 or T2

Table 4-42: Overloads - 2027 grid, peak

OVERLOADS - 2027 GRID, PEAK					
Line or transformer				Overloads	
Substation	Bus	Substation	Bus	%	Contingencies
Patte d'oie 90 kV	1311	Patte d'oie 225 kV	2311	103	T1 or T2
Hann 90 kV	1310	Hann 33 kV	4310	106	T1 or T2
CAPDB 90 kV	1302	MBAO 90 kV	1313	107	Kounoune-Hann (1307-1310)
Patte d'oie 90 kV	1311	Airport 90 kV	1314	113	Bélair-Université (1301-1315)
Bélair 90 kV	1301	Université 90 kV	1315	113	Patte d'oie- Airport (1311-1314)
Tobene 90 kV	1122	Thiona 90 kV	1312	107	Sococim-Someta (1316-1318) Tobene-Kounoune (2122-2307)
Tobene 225 kV	2122	Kounoune 225 kV	2307	127	L1- L2

Table 4-43: Overloads - 2028 grid, peak

OVERLOADS - 2028 GRID, PEAK					
Line or transformer				Overloads	
Substation	Bus	Substation	Bus	%	Contingencies
Université 90 KV	1315	Université 33 kV	4315	103	T1 or T2
Tobene 90 kV	1122	Thiona 90 kV	1312	102	Tobene-Someta (1312-1318)

Compensation

Table 4-44: Shunt capacitor additions - 2028 grid, peak

SHUNT CAPACITOR ADDITIONS – 2028 GRID			
Shunt reactors			
Substation Name	Substation Number	Capacity MVAR	Type
Guédiawaye	4354	5	Switchable
Kounoune	4323	5	Switchable
Sicap	4370	5	Switchable
Diamniadio	4352	5	Switchable

A 20-MVAR shunt reactor was added to the Patte d'Oie substation for the 2028 grid.

Load valley

We analyzed Option 2 of the baseline 2028 grid, with a load valley (40% of the peak) and no importing. No voltage higher than 1.05 pu is observed. However, multiple lines and cables must be operated open at one end to avoid generating excessive VAR. A 20-MVAR shunt reactor was added to the Patte d'Oie substation to prevent excessive VAR absorption by the Bel-Air substation units. However, this investment will have to be validated by an operating analysis when projects are examined for the construction of the substation in 2019.

2028 Grid recommendations

2024

- The overload of the 225/33 kV 40-MVA transformers at the Diamniadio substation requires the addition of a third 40-MVA transformer. As the substation load is increasing to 30 MW in 2019 and to 43 MW in 2024, we recommend initially installing 80 MVA transformers.
- The overload of the 225/33 kV 40-MVA transformers at the Kaolack substation requires the addition of a third 40-MVA transformer.

2026

- The overload of the 225/33 kV 50 MVA transformer at the Sakal substation requires that the transformer be replaced by another transformer with a capacity of 80 MVA. The application of criterion n-1 requires the addition of a second 80 MVA transformer to ensure continuity of service when a transformer is lost.
- The overload of the 225/33 kV 40 MVA transformers at the Guédiawaye substation requires the addition of a third transformer. As the substation load is increasing to 24 MW in 2019 and to 41 MW in 2026, we recommend initially installing 80 MVA transformers.

2027

- As part of the implementation of a new 225-kV Kounoune-CapDB-Hann-Patte d'Oie loop (Option 1), we recommend replacing both 90/33 kV 80 MVA transformers with two 225/33 kV 80 MVA transformers.
- The overload of the 90/33 kV 80-MVA transformers at the Hann substation requires the addition of a fourth 80 MVA transformer. The 90 kV voltage step can be replaced by a 225 kV voltage step, substituting two 90 kV transformers for two 225/33 kV 200 MVA transformers. In this study, the addition of a fourth 90/33 kV 80 MVA transformer is considered for Option 1 of the 225 kV loop and two 225/33 kV 200 MVA transformers for Option 2.
- The overload of the 90-kV CapDB-Mbao line requires additional or increased thermal capacity. As part of the implementation of a new 225-kV Kounoune-CapDB-Hann-Patte d'Oie loop (Option 1), we recommend replacement with a 1,200 mm^2 225 kV cable. With Option 2 of the 225-kV loop,

the overload on the 90-kV transmission line can be eliminated. The overload on the 90-kV Patte d'Oie-Airport line requires a second 90-kV line. There is a possible alternative to adding this new line, but this depends on the space available at the Patte d'Oie substation. A new 225/33 kV transformer capacity at the Patte d'Oie substation could reduce load at the Airport and Université substations, if it is feasible to build new 33-kV lines and transfer the load to the distribution network between substations. This solution would also avoid having to add 225/33 kV transformers to the Hann substation in the future.

- The overload on the Bélair-Université 90-kV line is resolved if the second Patte d'Oie-Airport 90-kV line is added.
- The overload on the Tobene-Thiona 90-kV line is resolved by adding a second Sococim-Someta line. As stated in the methodology, any new parallel line added is of the same size as the current one. The project study should analyze the best solution between replacing the current line or adding a new parallel line. In this study, a new parallel line of the same size as the current one was considered.
- The overload on the 225-kV Tobene-Kounoune line caused by the development of power plants east of Tobene requires a third line.
- The overload of the 225/90 kV 200 MVA transformers at the Patte d'Oie substation is resolved by the 225-kV loop, Option 1 or 2.

Kounoune-Cap DB-Hann-Patte d'Oie 225-kV loop

Considering that in 2022 the new Hann-Patte d'Oie lines were built at a voltage of 225 kV, completion of the loop requires:

- adding a 1,200 mm^2 225-kV cable between the Kounoune and Cap des Biches substations
- adding a 1,200 mm^2 225-kV MBAO-Hann cable plus two new 225/90 kV 200 MVA transformers at the Hann substation.

2028

- The overload of the 90/33 kV 40-MVA transformers at the Université substation requires a third 90/33 kV 40 MVA transformer. This third transformer may not be necessary if a new 225/33 kV transformation step is added to the Patte d'Oie substation.
- The overload on the Tobene-Thiona 90-kV line is resolved by adding the Thiona-Someta line. As stated in the methodology, any new parallel line added should be the same size as the current one. The project study should analyze the best solution between replacing the current line or adding a new line. In this study, a new line of the same size as the current one was considered.

Reactive compensation

It is recommended that a 20 MVAR shunt reactor be added to the Patte d'Oie substation when it is built in 2019, and that capacitors be added to the substations below, in addition to maintaining a minimum power factor of 98% at each of the Senelec distribution stations. These investments will have to be validated by an analysis when the projects are further examined.

Table 4-45: Shunt capacitor addition - 2028 grid

SHUNT CAPACITOR ADDITION – 2028 GRID			
Shunt reactors			
Substation Name	Substation Number	Capacity MVAR	Type
Guédiawaye	4354	5	Switchable
Kounoune	4323	5	Switchable
Sicap	4370	5	Switchable
Diamniadio	4352	5	Switchable

4.1.5 ASSESSMENT OF SHORT CIRCUIT CURRENTS

The assessment of short-circuit currents is an essential step which aims to adequately size the power grid's equipment. The equipment should be able to withstand the short-circuit current following a fault on the grid, for a minimum period corresponding to the fault clearing time. Protection equipment must be designed to interrupt fault currents without fail in order to properly protect power grid equipment.

Three-phase short-circuit currents are calculated taking into account the 2028 peak with the presence of all generators in the grid. It was not necessary to perform the assessment of the single-phase short-circuit, as it is generally lower than the three-phase fault on the high-voltage transmission network.

Calculation methods

Short-circuit currents are calculated according to the IEC 60909 standard.

Assessment of the adequacy of the nominal short-circuit breaking current

The short-circuit breaking capacity is the short-circuit current that the circuit breaker must be able to interrupt under the conditions of use and behavior prescribed in this standard.

Breaking capacity

The short-circuit rating levels currently applied depend on the voltage level. These short-circuit current values are shown in Table 1. According to Senelec, the old circuit breakers installed on the 90-kV network will be replaced by new breakers with a breaking capacity of 31.5 kA.

Table 4-46: Typical breaking capacity values

TYPICAL BREAKING CAPACITY VALUES	
Voltage Level	Breaking Capacity
90 kV	31.5 kA
225 kV	40 kA

The results of three-phase short-circuit current calculations for the 2028 horizon are shown in Table 4-47 and Table 4-48:

Table 4-47: Three-phase short-circuit currents for the 90-kV network by 2028

THREE-PHASE SHORT-CIRCUIT CURRENTS FOR THE 90-KV NETWORK BY 2028					
Location	Bus	Vn (kV)	Peak		Capacity Exceedance
			Sym. (kA)	Asym. (kA)	
TOBENE	1122	90	15.5453	16.4855	NO
BELAIR	1301	90	19.8277	20.5314	NO
CAPDB	1302	90	22.4914	24.9529	NO
KOUNO	1307	90	19.9848	21.1613	NO
HANN	1310	90	22.9663	24.6967	NO
PDOIE	1311	90	22.9772	24.6169	NO
THIONA	1312	90	8.3104	8.3104	NO
AEROP	1314	90	18.8076	19.1653	NO
UNIVER	1315	90	16.7062	16.8887	NO
SOCOC	1316	90	17.1406	17.1707	NO
TAIBA	1317	90	6.5799	6.5806	NO
SOMET	1318	90	11.8599	11.8603	NO
MEKHE	1319	90	2.9778	2.9778	NO
OLAM	1351	90	10.8009	10.801	NO
SICAP	1370	90	15.2404	15.3387	NO
SICAP	1370	90	15.2404	15.3387	NO
ICS	2363	90	6.491	6.4916	NO
MAMELLES	2368	90	16.9593	17.1306	NO

Table 4-48 illustrates the short-circuit currents in the 225 kV network by 2028:

Table 4-48: Level of short-circuit currents on the 225 kV grid - 2028 horizon

LEVEL OF SHORT-CIRCUIT CURRENTS ON THE 225 KV GRID - 2028 HORIZON					
Location	Bus	Vn (kV)	Peak		Capacity Exceedance
			Sym. (kA)	Asym. (kA)	
SAKAL	2120	225	4.8585	4.8586	NO
DAGAN	2121	225	4.7728	4.7729	NO
TOBENE 03	2122	225	12.7536	13.1396	NO
DAGAN_CS	2128	225	5.6811	5.6811	NO
CAPDB	2302	225	12.4723	13.3204	NO
TOUBA	2304	225	5.4188	5.4194	NO
KAOLA	2305	225	6.0183	6.0381	NO
KOUNO 03	2307	225	13.1498	14.2472	NO
DIASS	2308	225	9.8209	10.0474	NO
MALICOUNDA	2309	225	7.6488	7.8337	NO
HANN	2310	225	12.1759	12.8083	NO
PDOIE	2311	225	12.2275	12.8789	NO
STLOUIS	2327	225	6.5553	6.8872	NO
FATICK	2329	225	5.3972	5.4127	NO
ZIGUIN	2330	225	1.7517	1.7518	NO
KOLDA	2331	225	2.9678	2.9785	NO
TANAF	2332	225	3.5331	3.5478	NO
MBORO	2337	225	9.0017	9.0898	NO
SENDOU	2338	225	12.2463	12.9477	NO
KEDOUG	2351	225	2.7942	2.8003	NO
MAKO	2355	225	2.232	2.2332	NO
IAMGOLD	2356	225	1.5185	1.5186	NO
MASSAWA	2357	225	2.0916	2.0924	NO
MAKA_FALEME	2358	225	1.8579	1.8583	NO
AFRIMETAL	2359	225	6.0565	6.0567	NO
SABADOLA	2360	225	1.8579	1.8583	NO
TER	2361	225	11.1349	11.3458	NO
APROSI	2362	225	12.1662	12.8243	NO
AFRIG B	2364	225	4.1351	4.1353	NO
AFRIG A	2365	225	6.6008	6.6031	NO
ATLAS	2366	225	2.7602	2.7602	NO
BARGNY	2367	225	10.464	10.6133	NO
CIMAF	2369	225	8.4615	8.6238	NO
TAMBA	2624	225	5.0088	5.0413	NO
SOMA	2639	225	3.7709	3.7834	NO
GUEDIAW	1354	225	8.1986	8.2321	NO
MBAO	1313	225	12.1751	12.8549	NO

Based on the results presented in Table 4-46, the highest circuit current is less than 25 kA on the 90 kV grid. This short-circuit current is much lower than the 31.5 kA breaking capacity provided for the 90 kV level.

As for circuit breakers installed on the 225-kV network, even with a breaking capacity of 20 kA, which is very conservative, they are still adequate and compliant. Everything must be validated with the actual characteristics of the Senelec devices.

Another simulation was carried out in 2022 to determine at what horizon the short-circuit current becomes problematic for the circuit breakers installed on the 90 kV grid in the Dakar region.

The results presented in the table below show that even in 2022, the short circuits remain below the breaking capacity (value of 31.5 kA).

Table 4-49: Level of short-circuit currents on the 90 kV grid in the Dakar region - 2022 horizon

LEVEL OF SHORT-CIRCUIT CURRENTS ON THE 90 KV GRID IN THE DAKAR REGION - 2022 HORIZON					
Location	Bus	Vn (kV)	Peak		Capacity Exceedance
			Sym. (kA)	Asym. (kA)	
TOBENE	1122	90	14.41	15.29	NO
BELAI	1301	90	17.64	18.21	NO
CAPDB	1302	90	19.66	21.12	NO
KOUNO	1307	90	19.22	20.38	NO
HANN	1310	90	20.07	21.18	NO
PDOIE	1311	90	20.34	21.73	NO
THIONA	1312	90	6.27	6.27	NO
AEROP	1314	90	15.86	15.90	NO
UNIVER	1315	90	15.09	15.23	NO
SOCOC	1316	90	14.83	14.97	NO
TAIBA	1317	90	15.60	15.64	NO
SOMET	1318	90	6.34	6.34	NO
MEKHE	1319	90	8.74	8.74	NO
OLAM	1351	90	3.26	3.33	NO
SICAP	1370	90	8.15	8.15	NO
SICAP	1370	90	13.66	13.74	NO
ICS	2363	90	6.49	6.49	NO
MAMELLES	2368	90	16.96	17.13	NO

In terms of the circuit breakers on the 90-kV grid in the Dakar region, the short-circuit currents exceed 20 kA starting in 2022. Therefore, the old circuit breakers will need to be replaced by ones with a breaking capacity of over 20 kA.

Finally, in 2019, the results show that there is no exceedance of the breaking capacity (typical value 20 kA) for the circuit breakers installed on the 90 kV grid in the Dakar region.

Table 4-50: Level of short-circuit currents in the Dakar region in 2019

LEVEL OF SHORT-CIRCUIT CURRENTS IN THE DAKAR REGION IN 2019					
Location	Bus	Vn (kV)	Peak		Capacity Exceedance
			Sym. (kA)	Asym. (kA)	
TOBENE	1122	90	10.58	11.21	NO
BELAI	1301	90	15.59	16.12	NO
CAPDB	1302	90	17.71	19.45	NO
KOUNO	1307	90	17.13	18.39	NO
HANN	1310	90	17.40	18.28	NO
PDOIE	1311	90	17.65	18.76	NO
THIONA	1312	90	5.81	5.81	NO
AEROP	1314	90	12.85	12.86	NO
UNIVER	1315	90	13.58	13.72	NO
SOCOC	1316	90	13.38	13.53	NO
TAIBA	1317	90	14.39	14.45	NO
SOMET	1318	90	5.46	5.46	NO
MEKHE	1319	90	8.26	8.26	NO
OLAM	1351	90	3.04	3.11	NO
SICAP	1370	90	7.73	7.73	NO
SICAP	1370	90	6.14	6.18	NO
ICS	2363	90	12.42	12.51	NO

The simulation results show that the short-circuit current level is not a problem for circuit breakers installed on the 90 kV and 225 kV grid.

It should be noted that the circuit breakers that meet standards are sized to withstand an asymmetrical peak fault current equal to 2.6 times the symmetrical fault current.

4.1.6 SUMMARY OF RECOMMENDATIONS

2017

The overload observed on the Tobene-Thiona line is resolved by the approved project under construction, namely the 225-kV Tobene-Kounoune single-circuit line. During the presentation of the preliminary report, we learned that commissioning has been postponed to 2019. Senelec will have to pay close attention to these overloads during the 2017 and 2018 peaks.

2019

It is recommended that two 225/90 kV 200 MVA transformers be installed initially at the Patte d'Oie substation while awaiting the integration of a 225/90 kV step at the Hann substation.

As specified during the presentation of the preliminary report, the commissioning of the 225/90 Patte d'Oie substation has been postponed to 2019, and the decided projects include the replacement of the two 90-kV Hann-Patte d'Oie lines by two 1,600 mm^2 cables in 2020. We recommend that both cables be insulated to 225 kV. According to our analysis, an overload caused by the loss of one of the lines may occur in 2019. However, this overload can be managed for one year by keeping at least one unit of the Bel-Air power plant in service during the peak

2022

As a result of the increased load, overloads are expected at the Tobene 225/90 kV, Matam 225/33 kV and Mbour (Malicounda) 225/33 kV substations. Additional transformation is required.

Replacement of the existing 90 kV line and adding another 366 mm^2 line between the Kounoune and CapDB substations in 2018, in addition to the replacement of both lines with two 1,600 mm^2 225 kV cables in 2020, eliminate the need to add a third CapDB-Kounoune line and a fourth Hann-Patte d'Oie 90 kV line. According to Option 1 of the 225 kV loop, it is advisable to consider installing these two cables insulated to 225-kV and operating at 90 kV pending completion of the 225 kV Kounoune-CapDB-Hann-Patte d'Oie loop, scheduled for 2027.

The loss of the 225-kV Kounoune-Patte d'Oie line causes overloads on the CapDB-Mbao line and the 225/90 kV Kounoune transformers. The second line is needed to prevent these overloads.

2024

As a result of the increased load, overloads are expected at the Diamniadio and Kaolack 225/33 kV substations. Additional transformation is required.

Given the rapid load increase at the Diamniadio substation, we recommend installing two 80 MVA transformers.

2026

As a result of the increased load, overloads are expected at the Diamniadio and Kaolack 225/33 kV substations. Additional transformation is required.

Given the rapid load increase at the Diamniadio substation, we recommend installing two 80 MVA transformers.

2027

The increased load and the addition of a wind and a solar power plant significantly increase transit on the 90 kV grid.

Several overloads are observed on the 90 kV lines, the 225/90 kV transformers at the Patte d'Oie substation and the Kounoune-Patte d'Oie 225 kV line. Implementing a 225-kV Kounoune-CapDB-Hann-Patte d'Oie loop as in Option 1 and a Kayar-Tap-Tobene-Patte d'Oie loop as in Option 2 solves the overload issue, in addition to improving grid capacity and robustness in the future.

As part of the implementation of a new 225-kV Kounoune-CapDB-Hann-Patte d'Oie loop (Option 1), we recommend replacing both 90/33 kV 80 MVA transformers at the MBAO substation with two 225/33 kV 80 MVA transformers. However, this replacement is not required with Option 2.

The overload of the 90-kV CapDB-Mbao line requires additional or increased thermal capacity. As part of the implementation of a new 225-kV Kounoune-CapDB-Hann-Patte d'Oie loop (Option 1), we recommend replacement with a 225 kV cable. However, this replacement is not required with Option 2.

The overload on the 90-kV Patte d'Oie-Airport line requires a second 90-kV line. The overload on the Bélair-Université 90-kV line is resolved if the second Patte d'Oie-Airport 90-kV line is added.

The overload on the Tobene-Thiona 90-kV line is resolved by adding a second Sococim-Someta line.

The overload on the Tobene-Kounoune 225 kV line caused by the integration of power plants east of Tobene requires a third line.

The overload of the 225/90 kV 200 MVA transformers at the Patte d'Oie substation is resolved by the Kounoune-CapDB-Hann-Patte d'Oie 225-kV loop in Option 1 or 2.

As a result of the increased load, overloads are expected at the Hann 225/33 kV substation. Additional transformation is required.

Kounoune-Cap DB-Hann-Patte d'Oie 225-kV loop – Option 1

Considering that the new Kounoune-CapDB and Hann-Patte d'Oie lines will be built at a voltage of 225 kV in 2018 and 2020 respectively, the completion of the loop requires a new Mbao-Hann 225 kV line and two new 225 -90 kV 200 MVA transformers at the Hann substation.

Kayar-Tap-Tobene-Patte d'Oie 225 kV loop – Option 2

With this option, local gas generation is located in Kayar instead of St-Louis, as in Option 1. This modifies the grid's topology, and it is recommended that local gas generation be evacuated from Kayar via a 5-km 225-kV 2 x 228 mm^2 bypass in the middle of the line, and a second 35-km 225-kV 2 x 228 mm^2 double-circuit transmission line at the Guédiawaye substation. See Figure 4-2.

It is recommended that the 225/33 kV Guédiawaye substation be connected directly to the 225-kV Patte d'Oie substation via an approximately 5-km 1,200 mm^2 cable and a 225-kV double span to receive the 225-kV double-circuit transmission line from Kayar.

It is recommended that two 225/90 kV 230 MVA transformers and two 225/33 kV 200 MVA transformers be installed at the Hann substation to replace the three 225/90 kV 80 MVA transformer, to prevent overloading the 225/90 kV 200 MVA transformers as well as achieve better voltage regulation and reduce losses.

It is recommended that a third 225/33 kV 200 MVA transformer at the Hann substation and a Kayar-Tap-Tobene bypass line be considered, if export to Mauritania or Mali is being considered.

2028

As a result of the increased load, overloads are expected at the Université 90/33 kV substation. Additional transformation is required.

The overload on the Tobene-Thiona 90 kV line is resolved by adding the Thiona-Someta line.

Possible solutions for transferring load from the Hann, Airport and Université substations

Possible solutions that should be analyzed based on available space, would be a new 225/33 kV transformation step at the Patte d'Oie substation or the Bel-Air substation in order to transfer load from the Hann, Airport and Université substations, depending on the feasibility of building new 33 kV lines and transferring load between substations on the distribution network.

A special study should be conducted on the installation of a 225/33 kV step at the Bel-Air substation since the 225/90 kV transformer should be installed at the Bel-Air substation instead of the Hann substation.

Furthermore, the Kounoune-Hann and CDB-MBO-Hann 90 kV lines should be detached from the Hann substation and attached to the MBAO substation to take over (n-1), and the distribution network completely reorganized. The 90 kV Hann-Bélair lines would then be dismantled and replaced by a 225 kV cable or a transmission line, if possible.

This would eliminate the need to build a second 90-kV Patte d'Oie-Airport line (as well as the Airport-Université-Bel-Air lines, as stipulated in the comments of the preliminary report) and thus eliminate the installation of a third 225/33 kV 200 MVA transformer at the Hann substation in the future.

Beyond 2028

Looking beyond 2028, there is a lot of uncertainty with respect to the amount of generation and load, and its location. However, we wanted to carry out a summary analysis to identify hot spots on the Senelec grid. The analysis was based on the 2028 baseline model (excluding mines) with local gas generation in Kayar. Normal network (N) simulations show that beyond 2032, the 2028 model has difficulty converging and shows signs of weakness. The analysis is then carried out in 2032.

2032 model analyzed

- 2032 load – 1,714 MW
- Base case without IRE - Senelec generation 1,200 MW (2028 generation plan), 565 MW imported

Scenarios with and without IRE were analyzed. Without IRE, all of Senelec's generation is at its maximum, and the importing level is, according to the country allocation, at the same level as in 2028. It is unrealistic to believe that all of Senelec's generation can be exploited to its full potential, but the goal is to target overloads on HVB lines and transformers.

Overloads are observed on the following transmission lines during contingencies (with and without IRE):

- 225kV Touba-Kaolack line (109%)
- 90 kV Kounoune-Sococim line (107%)
- 90 kV Tobene-Thiona line (111%)
- 225 kV Malicounda-Diass line (105%)
- 225 kV Kounoune-Patte d'Oie lines (110%)
- 225kV Hann-Patte d'Oie lines (126%)

Possible solutions

The Touba-Kaolack and Tobene-Thiona lines should be strengthened, which will also prevent overloading on the Malicounda-Diass and Kounoune-Sococim lines.

OVERLOAD OF 225 KV KOUNOUNE-PATTE D'OIE LINES AND 225 KV HANN-PATTE D'OIE LINES, OPTION 2 AND OPTION 2A.

Option 2 (Kayar -2026)

Transit on the 225 kV Kounoune-Patte d'Oie corridor is preferred over the 225 kV Kayar-Guédiawaye corridor. One way to promote transit on the Kayar-Guédiawaye corridor is to make the Kayar-Tap-Tobene bypass a double-circuit transmission line, build the Kayar-Guédiawaye line (2026) using a 2 x 570 mm^2 conductor, and plan for two 1,200 mm^2 cables between Guédiawaye and Patte-d'Oie.

Option 2A (Kayar-2026)

In the event there are crossing restrictions or environmental constraints to building a 225 kV line along the coast in Option 2A (this is the continuation of Option 2 - 2027, to which must be added a third 225 kV 1,200 mm^2 cable between the Kounoune and Patte-d'Oie substations), then only one Guédiawaye-Patte-d'Oie cable is required.

As for the overload on the 225 kV Hann-Patte-d'Oie lines, the solution would be to add a third 1,600 mm^2 cable or a 225/33 kV transformation step at the Patte d'Oie substation.

225 kV Matam-Touba corridor

A new 225 kV Matam-Touba line was discussed during the presentation of the preliminary report. This line would be used to feed some of the local load in the Louga region. The need for the line was not identified in the master plan, but would be used to split energy transit and share it with the Matam-Tobene-Touba line. If this line is connected at the Matam substation, upstream from the series capacitors near Kayes, raising the thermal capacitance of the Matam, Dagana and Sakal series capacitors could be delayed until much later in the future. Its impact on power in Dakar and the surrounding area would not be felt until after 2032, according to our analysis and assumptions, unless it increases imports from OMVS and OMVG.

In summary

The new 225/90 kV Patte d'Oie substation is the cornerstone of future investments to create a 225 kV energy corridor to Dakar, and we recommend that it be composed of two 225/90 kV 200 MVA transformers. This capacity is needed until the 225 kV step is installed at the Hann substation in 2027. The installation of a 20 MVAR 225-kV shunt reactor would have to be confirmed during the project study.

The Patte d'Oie substation will be commissioned in 2019 and will be connected to the 225/90 kV Kounoune substation via a 1,200 mm^2 225-kV cable; we recommend a 1,600 mm^2 cable if the schedule permits. A second cable is planned for 2022, which will also be connected to the Hann substation by two 1,600 mm^2 cables. We recommend that these two cables be insulated to 225 kV, and conduits provided for a third cable, if a 225/33 kV step cannot be built at the Patte d'Oie substation.

There are also plans to build a new 225 kV 2 x 228 mm^2 line between Tobene and Kounoune in 2019; we recommend a second line in 2027. Senelec plans to build a double-circuit transmission line in 2019. It should be noted that according to the summary analysis of Option 2 (local gas generation at Kayar) of the 225 kV loop in 2032, it is preferable that this 225 kV double-circuit transmission line be built with a 2 x 570 mm^2 conductor between Tobene-Kayar-Guédiawaye and that the Guédiawaye substation be connected to the Patte d'Oie substation by two 1,200 mm^2 cables. However, the Tobene-Kayar portion of the double-circuit transmission line could remain at 2 x 228 mm^2 if the engineering is too far along.

The 225 kV energy corridor to the Hann substations is scheduled to be completed in 2027. In the meantime, the existing 90 kV Kounoune-CapDB 288 mm^2 line is to be replaced by a 366 mm^2 line. In Option 2 of the 225 kV loop, a second 366 mm^2 line can be installed, but in Option 1, the second line must be a 225 kV 1200 mm^2 cable. In 2027, a 225 kV step consisting of two 225/90 kV 200 MVA transformers must be installed at the Hann substation, and in Option 2 the three 90/33 kV transformers must be replaced by two 225/33 kV 200 MVA transformers, unlike Option 1 where the 90/33 kV step can be kept.

The two 225/90 kV 200 MVA transformers at the Hann substation are crucial to ensuring that the Hann-Bel-Air-Université-Airport- -Patte d'Oie 90-kV loop is powered by a 225 kV energy corridor from the Hann and Patte d'Oie substations, thus relieving the 90 kV network.

We prefer Option 2 (Kayar) of the 225 kV loop, even though there is no installed local gas generation in Kayar, because it diversifies the energy flow to the Patte d'Oie substation. This all depends on the feasibility and acceptability of a 225 kV overhead line along the coast. We are in favor of a 2 x 570 mm^2 conductor. It should be noted that a 2 x 228 mm^2 conductor would require smaller pylons and, therefore, have a smaller environmental footprint. However, in the long term this option will require a third 225-kV cable between Kounoune and Patte d'Oie.

To achieve sound voltage management, it is recommended that Senelec install automatic voltage regulators on all HVA transformers, in addition to installing shunt capacitors on the distribution lines in order to obtain a factor power at the substation of at least 98%.

Table 4-51: List of recommended new transformers

LIST OF RECOMMENDED NEW TRANSFORMERS							
Bus	Substation/HV	Bus	Substation/LV	ID	MVA	Cost	Notes
2016							
1310	HANN 90.000	4310	HANNLD1 33.000	3	80		Third xfo 80 MVA
2022							
2122	TOBENE 03 225.00	1122	TOBENE 90.000	3	75		Addition of a third xfo
2309	MALICOUNDA 225.00	4309	MBOURLD1 33.000	3	40		Addition of a third xfo
2119	MATAM 225.00	4119	MATAMLD1 33.000	1	40		Replacement of xfo 20 MVA
2119	MATAM 225.00	4119	MATAMLD1 33.000	2	40		Addition of a second xfo (n-1)
2024							
2305	KAOLA 225 kV	4305	KAOLALD1 33	3	40		Addition of a third xfo
2026							
2120	SAKAL 225	4120	SAKALLD1 33	1	80		Replacement of xfo 50 MVA
2120	SAKAL 225	4120	SAKALLD1 33	2	80		Addition of a second xfo (n-1)
2027							
1310	HANN 90	4310	HANNLD1 33		80		Addition of the fourth xfo 80 MVA Option 1
1310	HANN 90.000	2310	HANN 225.00	1	200		**225 kV loop**
1310	HANN 90.000	2310	HANN 225.00	2	200		**225 kV loop**
1310	HANN 225.000	4310	HANN 33.00	1	200		**225 kV loop Option 2**
1310	HANN 225.000	4310	HANN 33.00	3	200		**225 kV loop Option 2**
2028							
1315	UNIVER 90	4315	UNIVERLD1 33		40		Addition of the third xfo 40 MVA

Table 4-52: List of new recommended lines

LIST OF NEW RECOMMENDED LINES									
Bus	Bus Name	Bus	Bus Name	ID	Section	Km	MVA	Cost	Notes
2019 Option 2									
1354	GUEDIAW 25.00	2311	PDOIE 225.00	1	225 kV 1 200 mm² Cable	5	385		New substation
2022									
2311	PDOIE 225.00	2307	KOUNO 225.00	2	225 kV 1 200 mm² Cable	12	385		Addition of the second line
2027									
1311	PDOIE 90.000	1314	AEROP 90.000	2	90 kV 1 200 mm² Cable	9	155		Addition of the second line
1316	SOCOC 90.000	1318	SOMET 90.000	2	L90 kV 288 mm² ALAC	11	78		Addition of the second line
2122	TOBEN 225.00	2307	KOUNO 225.00	3	L 225 kV 2 x 228 m² ALM	55	312		Third 225 kV line
225 kV loop Option 1									
2310	HANN 225.00	2311	PDOIE 225.00	1	225 kV 1 600 mm² Cable	1.2	385		Not required if installed in 2020
2310	HANN 225.00	2311	PDOIE 225.00	2	225 kV 1 600 mm² Cable	1.2	385		Not required if installed in 2020
2302	CAPDB 225.00	1313	MBAO 225.00	1	225 kV 1 200 mm² Cable	1.5	385		
1313	MBAO 225.00	2310	HANN 225.00	1	225 kV 1 200 mm² Cable	17	385		
2302	CAPDB 225.00	2307	KOUNO 225.00	1	225 kV 1 200 mm² Cable	6.5	385		Not required if installed in 2020
2026 225 kV loop Option 2 Kayar generation in 2026									
2340	KAYAR 225.00	23401	DKAYAR	1	L225 kV 2x228 mm² ALM	5	312		
2340	KAYAR 225.00	1354	GUEDIAW	1	L225 kV 2x228 mm² ALM	35	312		
2340	KAYAR 225.00	1354	GUEDIAW	2	L225 kV 2x228 mm² ALM	35	312		
2028									
1312	THIONA 90.000	1318	SOMET 90.000	2	L90 kV 288 mm² ALAC	24	78		Addition of the second line
2032 225kV loop Option 2A									
2311	PDOIE 225.00	2307	KOUNO 225.00	3	225 kV 1 200 mm² Cable	23	385		Addition of the third cable
2032 225kV loop Option 2									
1354	GUEDIAW 25.00	2311	PDOIE 225.00	2	225 kV 1 200 mm² Cable	5	385		Second cable
2340	KAYAR 225.00	23402	DKAYAR	2	L225 kV 2 x228 mm²	5	312		Second bypass
2340	KAYAR 225.00	1354	GUEDIAW	1	L225 kV 2 x570 mm² ALM	35	665		
2340	KAYAR 225.00	1354	GUEDIAW	2	L225 kV 2x570 mm² ALM	35	665		

In this scenario, the conductors installed at Kayar-Guédiawaye in 2026 must be 2 x 570 mm^2, and the Tobene-Kounoune double-circuit transmission line open at the Kounoune substation.

4.2 ANALYSIS OF THE DYNAMIC BEHAVIOR OF THE SENELEC NETWORK

4.2.1 PURPOSE OF STUDY

Simulations of the dynamic behavior of Senelec's interconnected network are required to ensure that, following extreme events dictated by the design criterion, the network can withstand the event with no additional equipment losses, and return to a stable steady state within acceptable voltage and frequency limits. These simulations, typically 20 seconds long, will result from different disturbances applied at critical points on the Senelec network. These critical points will be identified during the power flow contingency analysis and, by experience, according to the topology of the network.

4.2.2 METHODOLOGY AND CRITERIA

The stability study was carried out on scenarios created and validated by the static study. In some cases, variants were used in order to make recommendations. This dynamic behavior analysis will cover the following types of stability:

VOLTAGE STABILITY STUDIES

This analysis will help confirm that system voltages remain below allowable limits (usually + 10/-10% for dynamic studies) after a system disturbance and that, consequently, there is no voltage collapse.

STUDY OF TRANSIENT STABILITY (ROTOR ANGLE)

This analysis will help confirm that alternators are still synchronized after a major disturbance. Note that the impact of photovoltaic (PV) or wind turbine facilities on transient stability is observed by an indirect effect: the loss of synchronism of another synchronous facility. In fact, they are asynchronous generating facilities.

FREQUENCY STABILITY STUDIES

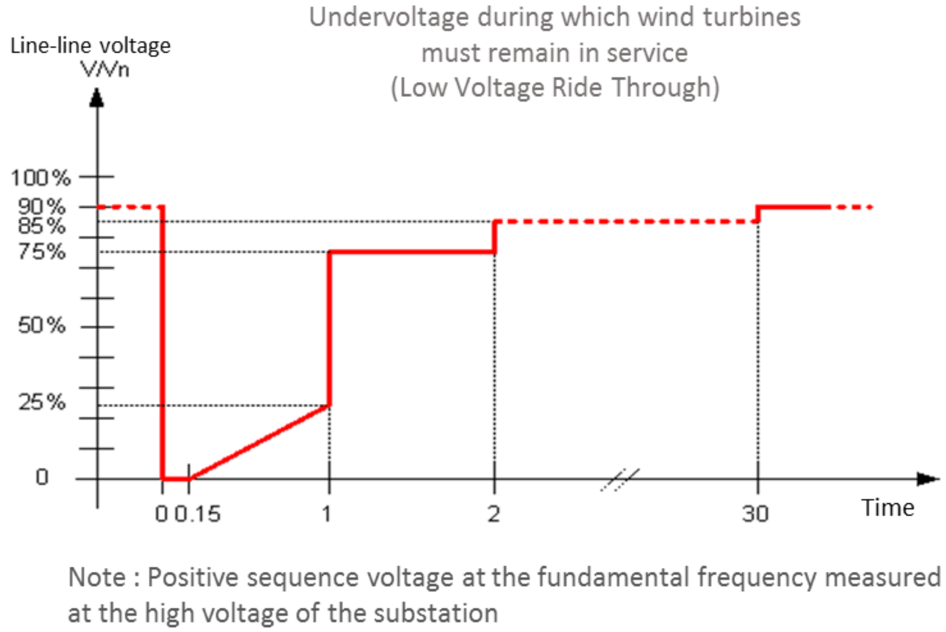
This analysis will help confirm that frequency-sensitive equipment such as thermal plants, photovoltaic inverters, and wind farms will continue to operate without interruption during severe events that cause a significant disturbance of the system's rated frequency (for example, due to loss of load or loss of a generator). Consequently, for each “normal” event, the grid’s frequency behavior must be maintained above the underfrequency load shedding and plant trip thresholds at all times. In all cases, the frequency must be reduced to the nominal frequency of ± 0.25 Hz within 10 minutes following an event.

UNDERVOLTAGE STUDIES (LOW VOLTAGE RIDE THROUGH-LVRT)

This particular analysis for solar and wind renewable energy will confirm whether these installations will remain connected for faults at or close to the connection point. Note that the generic dynamic models provided in the PSS/E model library can be used for this analysis.

Thus, for the integration of wind and PV farms, we will have to make sure that the grid can supply a minimum recovery voltage if there is a fault, according to the curve in the figure below. In addition, PV and wind facilities will have to remain in service following a disturbance, when the direct component voltage on the High Voltage side of the initial substation stays above this curve.

Figure 4-3: Undervoltage during which wind turbines must remain in service (Low Voltage Ride Through)



SIMULATED CONTINGENCIES

The simulated disturbances dictated by the design criterion are in the "normal" category, and include events such as the failure and tripping of transmission equipment, including a transmission line circuit or power transformer, loss of load, a loss of a generator, circuit breaker, etc. These so-called normal disturbances can justify additions to the network, in contrast to so-called extreme disturbances (loss of a substation, corridor or plant, etc.). For this type of contingency, automation can be used to minimize the impact on the grid and reduce the possibility of power outages in the country. Furthermore, we will need to model underfrequency and undervoltage load shedding systems, if they exist. This approach aims to ensure that they do not react during normal contingencies.

For all scenarios and certain variants, we simulated more than 31 'normal' events, i.e. the application of a three-phase fault lasting 100 msec (six cycles) followed by clearing of the fault caused by the loss of the 225-kV line.

The list of 31 simulated events is as follows:

lll2104Tamba	lll 6cy. Kayem loss of Kayem-Tamba 225 kV line cir. 1
lll2114Dagan	lll 6cy. Rosso loss of Rosso-Dagan 225 kV line cir. 1
lll2119Bakel	lll 6cy. Matam loss of Matam-Bakel 225 kV line cir. 1
lll2120Tobene	lll 6cy. Sakal loss of Sakal- Tobene 225 kV line cir. 1
lll2121Matam	lll 6cy. Dagan loss of Dagan-Matam 225 kV line cir. 1 Series compensation line
lll2121Sakal	lll 6cy. Dagan loss of Dagan-Sakal 225 kV line cir. 1 Series compensation line
lll2122Kouno	lll 6cy. Tobene loss of Tobene-Kounoune 225 kV line cir. 1
lll2122Mboro	lll 6cy. Tobene loss of Tobene-Mboro 225 kV line cir. 1
lll2122Sakal	lll 6cy. Tobene loss of Tobene-Sakal 225 kV line cir. 1
lll2122StLou	lll 6cy. Tobene loss of Tobene-St-Louis 225 kV line cir. 1
lll2122Touba	lll 6cy. Tobene loss of Tobene-Touba 225 kV line cir. 1
lll2304Koala	lll 6cy. Touba loss of Touba-Kaolack 225 kV line cir. 1
lll2305Fatic	lll 6cy. Kaolack loss of Kaolack-Fatick 225 kV line cir. 1
lll2305Soma	lll 6cy. Kaolack loss of Kaolack-Soma 225 kV line cir. 1
lll2305Tamba	lll 6cy. Kaolack loss of Kaolack-Tamba 225 kV line cir. 1
lll2307Pdoie	lll 6cy. Kounoune loss of Kounoune-Patte d'oie 225 kV line cir. 1
lll2307Sendu	lll 6cy. Kounoune loss of Kounoune-Sendou 225 kV line cir. 1
lll2308Malic	lll 6cy. Diass loss of Diass-Malicounda 225 kV line cir. 1
lll2308Sendu	lll 6cy. Diass loss of Diass-Sendou 225 kV line cir. 2
lll2309Fatic	lll 6cy. Malicounda loss of Malicounda-Fatick 225 kV line cir. 1
lll2327BeniN	lll 6cy. St-Louis loss of St-Louis-Beni-Nadj 225 kV line cir. 1
lll2332Kolda	lll 6cy. Tanaf loss of Tanaf-Kolda 225 kV line cir. 1
lll2332Manso	lll 6cy. Tanaf loss of Tanaf-Mansoa 225 kV line cir. 1
lll2332Soma	lll 6cy. Tanaf loss of Tanaf-Soma 225 kV line cir. 1
lll2624Kolda	lll 6cy. Tamba loss of Tambacounda-Kolda 225 kV line cir. 1
lll2625Kedoug	lll 6cy. Samba loss of Sambangalou-Kedougou 225 kV line cir. 1
lll2625Tamba	lll 6cy. Samba loss of Sambangalou-Tambacounda 225 kV line cir. 1

We have added these new events for the 2028 grid:

lll2310Pdoie	lll 6cy. Hann loss of Hann-Pdoie 225 kV line cir.1
lll2307CDB	lll 6cy. Kounoune loss of Kounoune-Cap des Biches line cir.1
lll2302CDB	lll 6cy. Cap des Biches loss of Hann-Cap des Biches line cir.1
lll2122Kouno	lll 6cy. Tobene loss of Tobene-Kounoune line cir.1

We also simulated generation losses as a result of damage to a component (either a transformer or a line), integrating this generation into the grid and, exceptionally, the loss of the bus bar.

PerteAfri	Loss of generation @ MBoro Africa Energy Steam turbine unit 1 x 45 MVA
PerteBelair	Loss of generation @ Bel-Air Two diesel units = 36 MVA
PerteC301	Loss of generation @ Cap des Biches Steam turbine unit C-301 28 MVA
PerteC303	Loss of generation @ Cap des Biches Steam turbine unit C-303 28 MVA
PerteC403	Loss of generation @ Cap des Biches Diesel unit C-403 20 MVA
PerteCDB	Loss of generation @ Cap des Biches Diesel unit C404 C405 x 18 MVA = 36 MVA
PerteCont	Loss of generation @ Cap des Biches IPP Contour Global Three Diesel units x 20 MVA = 60 MVA
PerteKaho2	Loss of generation @ Kahone 2 Diesel untis C-701 21.3 MVA
PerteKouno	Loss of generation @ Kounoune IPP 9 Diesel units 9 x 21.3 MVA = 191,7MVA
PerteSendu	Loss of generation @ Sendou Steam turbine unit 147 MVA
PerteTAG4	Loss of generation @ Bel-Air TAG-4 Gas turbine units 34 MVA

PerteEole Loss of generation @ Taïba 158 MW wind farm x 46% = 72 MW max

Note that some of these events are not applicable because these power plants may not be in service for the scenario simulated, and we paid special attention to these events in the frequency stability analysis. The loss of the bus bar is, however, treated as an exceptional event that may require and permit the use of underfrequency load shedding. Therefore, this type of event is not used for the sizing of the spinning reserve. It is the same situation for a loss of power plant where the use of automatic remote load shedding is recommended instead. Therefore, despite the importance of covering these types of events, they have little impact on the investment plan of Senelec's transmission master plan.

CAPACITY CONSIDERED FOR RENEWABLE ENERGY POWER PLANTS

For the wind power plant, despite an installed capacity of 158 MW in 2022, the maximum capacity considered is 72 MW, or 46% of the installed capacity. This maximum capacity is based on a minimum wind of 7 m/s, which happens 10% of the time.

For 2019, we have an installed capacity of 51.75 MW x 2 = 103.5 MW, which gives a maximum of 47.6 MW.

For solar power facilities, we considered the moment of maximum irradiation, for a maximum generation equivalent to the MW installed capacity.

Table 4-53: Installed and injected capacities of wind farms and solar power facilities

INSTALLED AND INJECTED CAPACITIES OF WIND FARMS AND SOLAR POWER FACILITIES				
	Installed Capacity (MW)	Injected Capacity (MW)		
		2019	2022	2028
EOLSN TAIBA 0.6500	158	47	72	72
EOL_1 0.7000	51.75			24
SNIAKHAR 11.000	47	47	47	47
SDIASS 11.000	15	15	15	15
SKAHONE 11.000	30	30	30	30
SMEKH 11.000	29.5	29.5	29.5	29.5
SMEKH 11.000	29.5	29.5	29.5	29.5
SBOKHOL 11.000	20	20	20	20
STOUBA 11.000	23	23	23	23
SMALICOU 11.000	20	20	20	20
SOL_6 11.000	40			40
TOTAL	463.75	261	286	350

This maximum capacity is only possible during off-peak periods. Thus, the load level used is the load observed during peak generation at the solar power facilities.

EVENTS TO BE COVERED TO ESTABLISH THE SPINNING RESERVE

The 10-minute reserve is the reserve required to meet the frequency criterion. It consists of a spinning (synchronous) and non-spinning (asynchronous) reserve. By definition, at any time on the grid, it must normally be equal to the largest loss of generation after a single contingency. Moreover, the objective here obviously is to minimize the amount of spinning reserve as it is the most expensive to generate.

Since this spinning reserve is part of the 10-minute reserve, through an instant reaction of the generators and frequency deviation, its role is to prevent load loss by underfrequency shedding when the largest generator is lost as a result of a single contingency.

According to grid expansion across the three study horizons, the biggest generation losses are found around:

- Sendou 115 MW coal-fired generating plant
- Taïba wind farm, nominal capacity of 158 MW for 2022, but with a maximum of 72 MW
    - 72 MW being the maximum according to the hourly profile, as defined in the supply-and-demand balance report
- Mékhé solar power facilities 2 x 30 MW, for a total of 60 MW
- Taïba wind farm, nominal capacity of 103.5 MW for 2019, but with a maximum of 47.6 MW
    - 47.6 MW being the maximum according to the hourly profile, as defined in the supply-and-demand balance report
- Niakhar 47 MW solar park
- Africa-Energy 90 MW coal-fired generating plant (since this is planned, due to the impact, the size of the units can be reduced to 2 x 45 MW or 3 x 30 MW to minimize the frequency of a significant amount of spinning reserve)
- Loss of two C404-C405 generators on the same transformer at Cap des Biches, for a total loss of 31.5 MW
- Loss of the TAG-4 gas turbine at Bélair, for a loss of 30 MW.

RESERVE ASSUMPTIONS

At this time, the available spinning reserve is supplied by the C6 and C7 power plants, for an available total of 24 MW (12 MW each). Thus, we will prioritize these plants for the spinning reserve of the Senelec grid. Thereafter, the power plants below and their spinning reserve capacities will be used if necessary. We kept the same reserve factor as for C6 and C7, i.e., around 12% of the rated capacity:

- IPP HFO DUAL Malicounda 15 MW
- IPP Contour Global 10 MW
- IPP Tobene 14 MW

Therefore, if we can count on a potential reserve of 51 MW and contributions from C6 and C7, we obtain a maximum spinning reserve of 63 MW. Note that to obtain a reserve level of 50 MW, for example, this would imply a network generation of around 400 MW: the C6, C7, Malicounda and Contour power plants. In 2028, to produce additional reserve, we can count on the new combined cycle generation for an additional total of 24 MW.

Furthermore, we can consider the possibility of spinning reserve from OMVS hydroelectric plants, knowing that some can be imported from this hydroelectric complex and some spinning reserve extracted from it. Subsequently, we can also consider a contribution from the OMVG hydroelectric complex, knowing that some can also be imported from this complex. We have established the spinning reserve contribution at three per cent of installed capacity. Therefore, our analysis will consider the following spinning reserve availability:

Table 4-54: Spinning reserves from neighboring grids

SPINNING RESERVES FROM NEIGHBORING GRIDS						
	2019 Horizon		2022 Horizon		2028 Horizon	
Utility	Installed (MW)	Synchro. Reserve (MW)	Installed (MW)	Synchro. Reserve (MW)	Installed (MW)	Synchro. Reserve (MW)
OMVS	260	8	400	12	694	21
OMVG	-	-	883	26	1474	44
Total	260	8	1283	38	2168	65

For 2019:

- OMVS: 3% of 260 MW = 8 MW

For 2022:

- OMVS: 3% of 400 MW = 12 MW
- OMVG: 3% of 883 MW = 26 MW

For 2028:

- OMVS: 3% of 694 MW = 21 MW minimum
- OMVG: 3% of 1474 MW = 44 MW minimum

For the study results and recommendations to be consistent with the simulations, Senelec will therefore have to ensure that this minimum reserve amount from neighboring grids is kept in operation at all times. Note that we intentionally did not consider a reserve contribution from Somelec.

Furthermore, to evaluate the short-term impact, variants are examined in 2019 and 2022, considering no input from these two hydroelectric complexes, a situation which, we agree, is pessimistic.

SPINNING RESERVE FOR FLUCTUATING RENEWABLE ENERGY

Another aspect that establishes a minimum amount of spinning reserve is the fluctuation of this type of generation, either an abrupt drop in wind for the wind farm or the passage of clouds over the solar power facility.
Thus, the following values are cited in the supply-and-demand balance report for the years 2019, 2022 and 2028:

Summary of maximum fluctuations in IRE versus synchronous reserve level

In summary, the potential maximum fluctuations according to the considerations indicated above are as follows:

- 41 MW, or 70% of the installed capacity of the largest solar power facility (Mékhé 2 x 29.5 MW).
- 54 MW, or 35% of the installed capacity of the largest wind farm.

This is the case for the 2022 and 2028 simulations. For 2019, with a 103.5 MW wind farm, the fluctuation would instead be 36 MW.

Therefore, a spinning reserve equivalent to this fluctuation is initially required on the interconnected network in order to regulate frequency correctly.

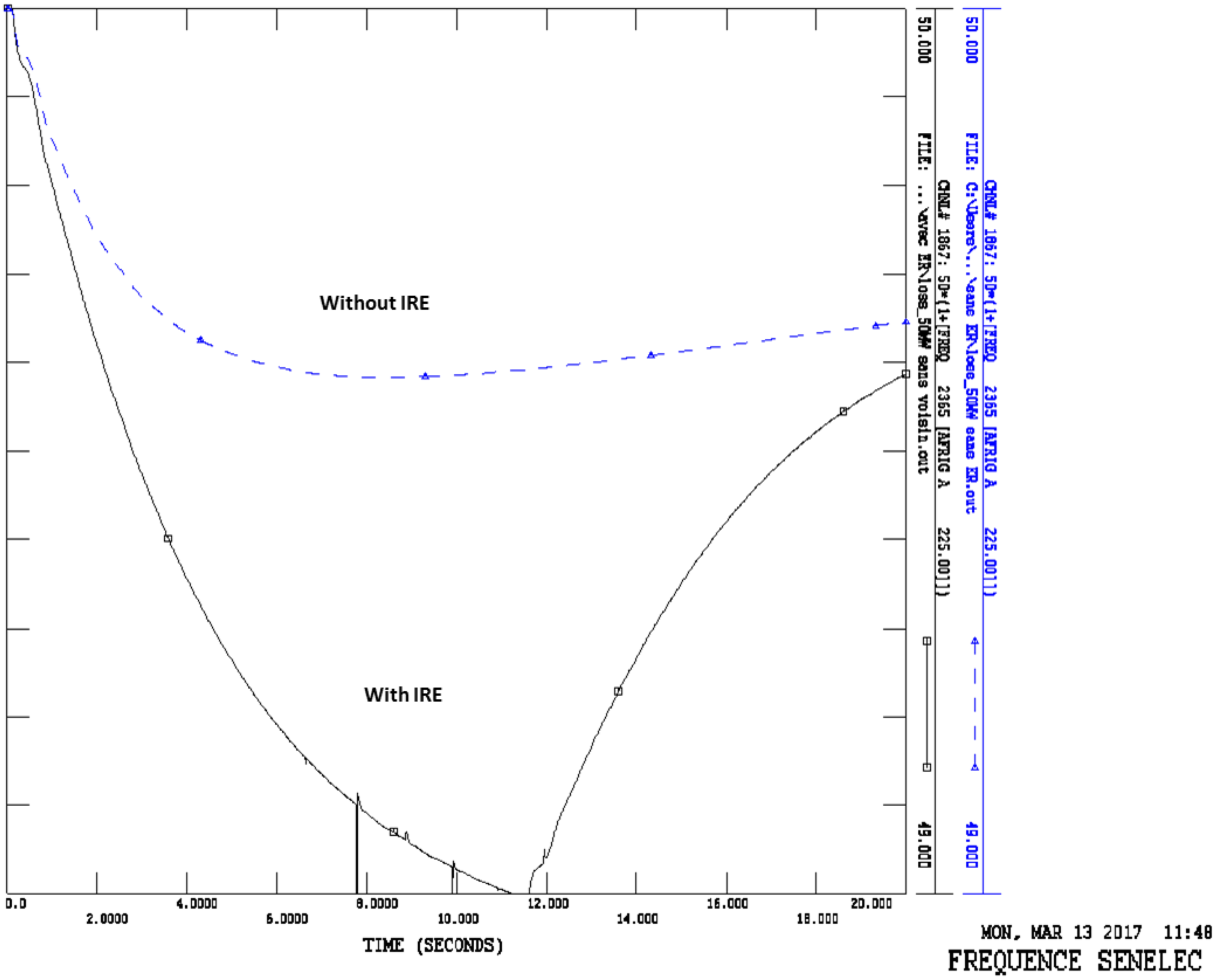
LEVEL OF RENEWABLE ENERGY PENETRATION

The level of penetration of renewables such as wind and solar energy as a replacement for thermal generation has a significant impact on the reserve level required to meet the frequency criterion. The particular feature of this type of energy, which is not to supply spinning or non-spinning reserve, can impose a maximum amount of intermittent renewable energy on the grid. Furthermore, if poorly managed and without balancing means (normally provided temporarily by the 10-minute reserve), the fluctuations in generation inherent to this type of the energy source will further exacerbate the problem of meeting the frequency criterion.

Certain scenarios and variants were examined to determine the reserve required to meet the frequency criterion and to determine whether the level of renewable energy penetration proposed in the supply-and-demand balance report (30% of the load) is acceptable at all times.

First, it is important to note that the use of intermittent renewable energy deteriorates the frequency behavior of an isolated grid (without interconnection). The absence of inertia, especially for solar power plants, increases the frequency slope and thus increases the risk of hitting the underfrequency load shedding threshold. The figure below clearly demonstrates this phenomenon.

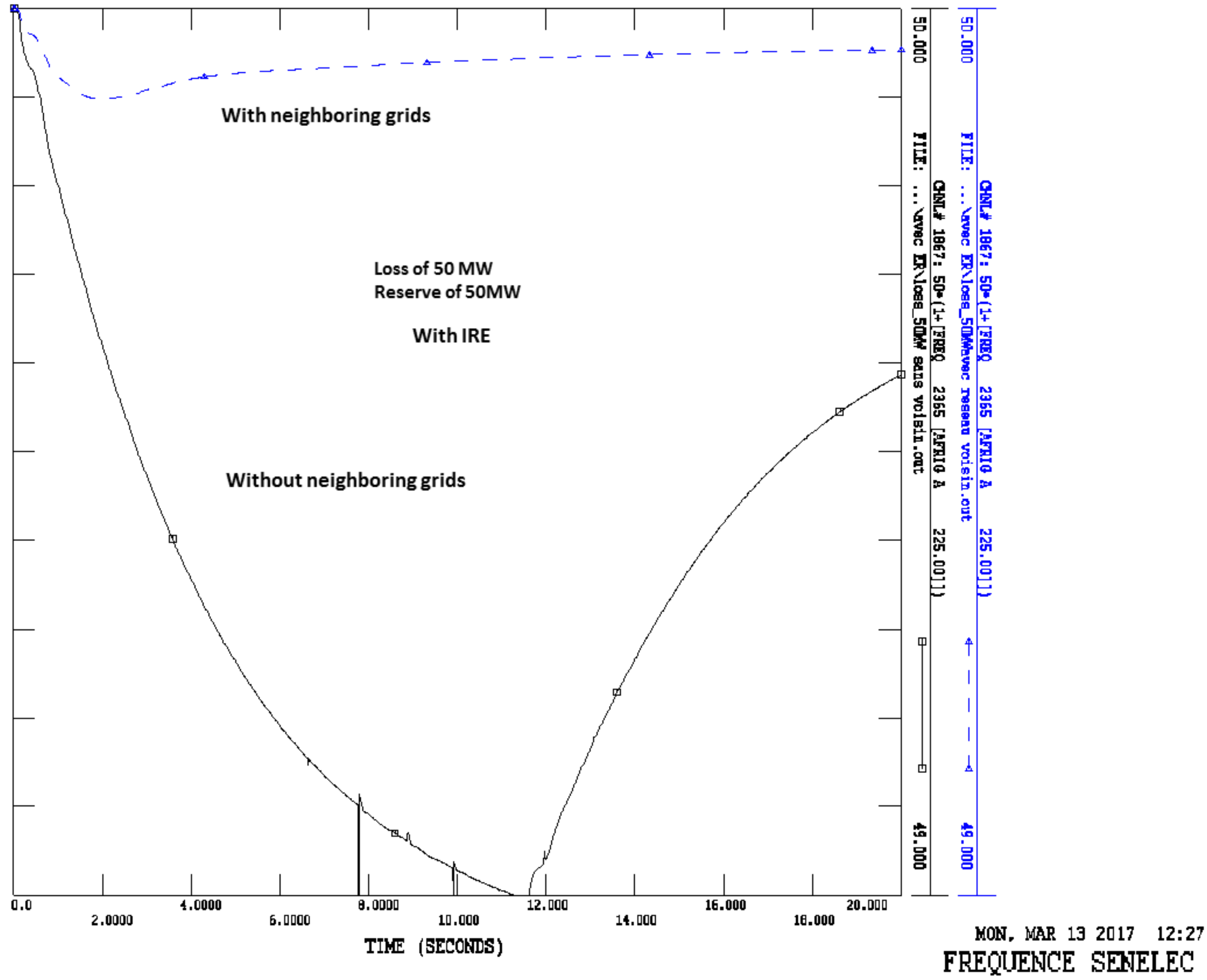
Figure 4-4: Impact of renewable energy on frequency behavior (Hz)



In the figure above, we replaced the solar and wind power plants with thermal power plants while keeping the same spinning reserve of 50 MW. We observe that for the renewable energy scenario, following the loss of 50 MW, we hit the load shedding threshold. For the scenario without renewable energy, the increased inertia makes it possible to slow down the frequency drop and extract available reserve through the speed regulators before hitting the underfrequency load shedding threshold. Without interconnections, it is therefore essential to maintain a minimum level of inertia on the Senelec grid in all circumstances.

Another aspect to consider is the presence of neighboring synchronous grids, which can contribute inertia and spinning reserve. Their presence has a major impact on the frequency behavior of the Senelec grid.

Figure 4-5: Impact of neighboring grids on frequency behavior (Hz)



Indeed, as shown in the previous figure, interconnecting with neighboring grids and allowing them to contribute to the reserve greatly improves the grid's frequency behavior. Therefore, it will be important for Senelec to ensure that there is a minimum spinning reserve from neighboring grids and that the presence of interconnections is prioritized at all times.

4.2.3 DATA AND SIMULATION MODELS

DYNAMIC POWER PLANT MODELS

Data was collected to obtain all information relevant to the modeling of the dynamic components (turbine, alternator, regulator, exciter, stabilizer, etc.). If unknown or incomplete, we used typical parameters and models available in the PSS/E library. Furthermore, when possible to do so, we obtained the models and data recommended for their installations from the manufacturer.

Appendix A shows the data and models used for Senelec's existing power plants. The block diagrams corresponding to the models used are all available in the PSS/E (Model Library) documentation.

Then we integrated the hydroelectric and thermal power plants planned and proposed in the supply-and-demand balance report, into the dynamic models.

For IRE power plants, we will use the following models for the Master Plan:

Wind farm

The following models are found in the PSS/E library:

- **WT4G1 Wind Generator Model with Power Converter (Type 4)** for the converter
- **WT4E2 Electrical Control for type 4 wind generator** for controls
- **WTDTA1 Generic Drive Train Model type 4** for the turbine

This type of wind farm is very efficient and seems to be the one proposed for the TAÏBA wind farm.

According to the available documentation on the wind farm, it would ultimately consist of three collector networks that can be represented by an equivalent.

These equivalent impedances are expressed in "pu" for a base capacity of 100 MVA and a voltage of 33 kV:

Table 4-55: Equivalent circuits for the Taïba wind farm

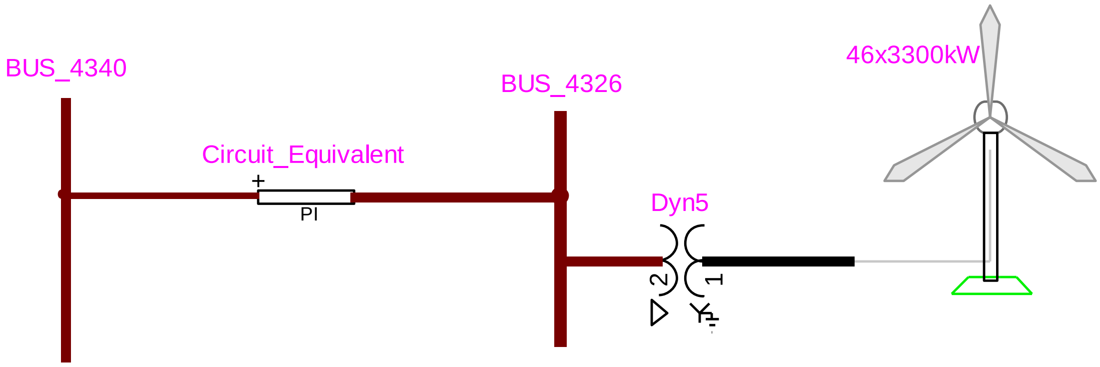
EQUIVALENT CIRCUITS FOR THE TAÏBA WIND FARM				
R_1 (pu)	X_1 (pu)	R_0 (pu)	X_0 (pu)	B (pu)
0.001959	0.002332	0.006989	0.002326	158837.3

Moreover, for the equivalent transformer associated with the 46 grouped wind turbines, we obtain the following parameters:

Table 4-56: Data from the equivalent transformer of the Taïba wind farm

DATA FROM THE EQUIVALENT TRANSFORMER OF THE TAÏBA WIND FARM		
Parameters	Value	Description
Apparent power	172.5 MVA	
Primary voltage	33 kV	
Secondary voltage	0.65 kV	
Z1	9%	
Z0	0.7%	
Connection	Dyn5	
Inrush current	8 x In	
Copper losses	1,403 kW	Full load
Off-cycle loss	26.8 kW	

Figure 4-6 : Equivalent network of the Taïba wind farm



Solar power facility

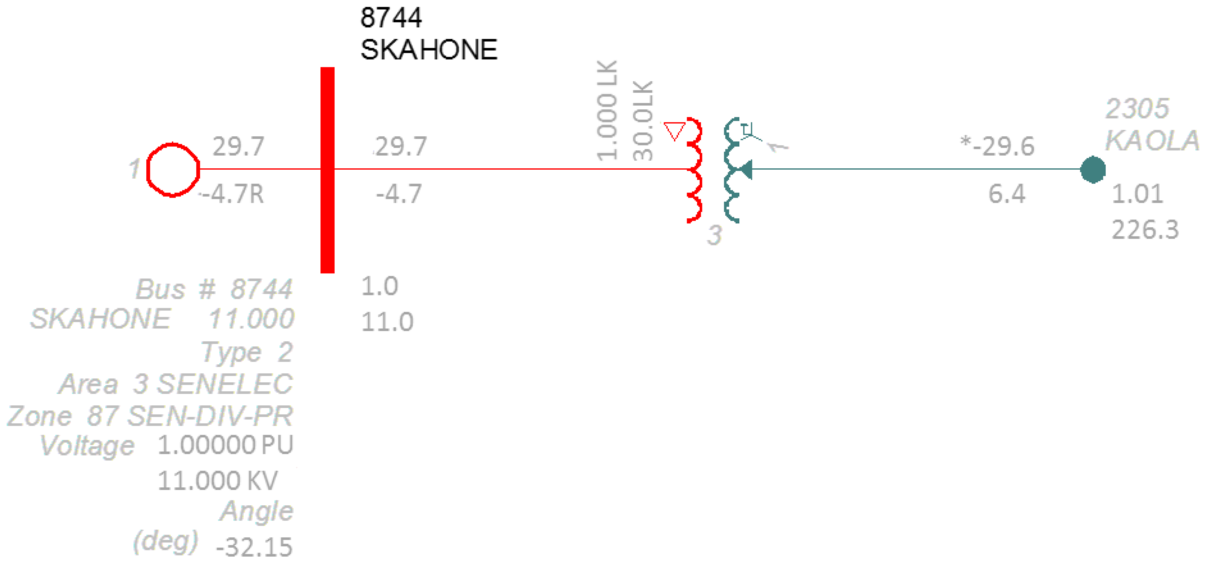
For photovoltaic plants, we will use a model similar to type 4 wind farms, with the ability to change the output power depending on the sun.

- **PVGU Power Converter/Generator Module** for the converter
- **PVEU Electrical Control Module** for controls
- **PANEL Linearized Model of a Panel's Output Curve** for solar panels
- **IRRAD Linearized Solar Irradiance Profile** for solar irradiance

It is unlikely that we will use these last two models, which modulate the power output of the PV plant depending on the sun because the most restrictive situation for the grid is when the plant is producing at its maximum.

For the equivalent grid of solar power facilities, we limited ourselves to typical values and a simple configuration. For example, we have the following representation at the Kahone solar power facility:

Figure 4-7: Grid representation of the Kahone solar power facility



REPRESENTATION OF THE LOAD

The dynamic model of the load that is used for the study is as follows:

$$P = P_{load}(a_1V^{n_1} + a_2V^{n_2} + a_3V^{n_3})(1 + a_7\Delta f)$$

$$Q = Q_{load}(a_4V^{n_4} + a_5V^{n_5} + a_6V^{n_6})(1 + a_8\Delta f)$$

We are using the following parameters for all Senelec loads:

$$P = P_{load}(V^1)(1 + 1\Delta f)$$
$$Q = Q_{load}(V^2)$$

These parameters correspond to a grid with a high amount of motor loads (air conditioning, mining industries, etc.).

Furthermore, to obtain a truer frequency behavior for the grid, all the electrical characteristics used, such as transmission lines, power transformers, shunt components and alternator parameters, depend on the grid frequency.

UNDERFREQUENCY LOAD SHEDDING

We need to model the underfrequency load shedding system to make sure it does not react during "normal" contingencies. The data used refer to the most recent load shedding plan in our possession, dated August 8, 2016. In Appendix (B.1) you will find the model and parameters used for the load shedding plan.

REMOTE LOAD SHEDDING

In the situation where the generation loss exceeds the synchronous reserve, it is obvious that simple regulation systems are not enough. Therefore, the load side will have to be reduced fairly quickly. It is important to note that the faster the correction, the less transient operation there will be. Thus, a ready-made system is preferable for some circumstances as there is no need to wait for underfrequency load shedding to react in order to restore the supply-demand balance. On a specific event such as the loss of a large amount of capacity, it is best to give a remote shedding command to preselected feeders as quickly as possible to restore the balance. In order to avoid unnecessary load shedding during an event that exceeds the spinning reserve, significant generation losses must be monitored in order to pre-determine the number of feeders that must be triggered to restore the balance.

For some events, we used this automation with a total reaction time for detection of the generation loss at the start of the 20th cycle.

REPRESENTATION OF NEIGHBORING GRIDS

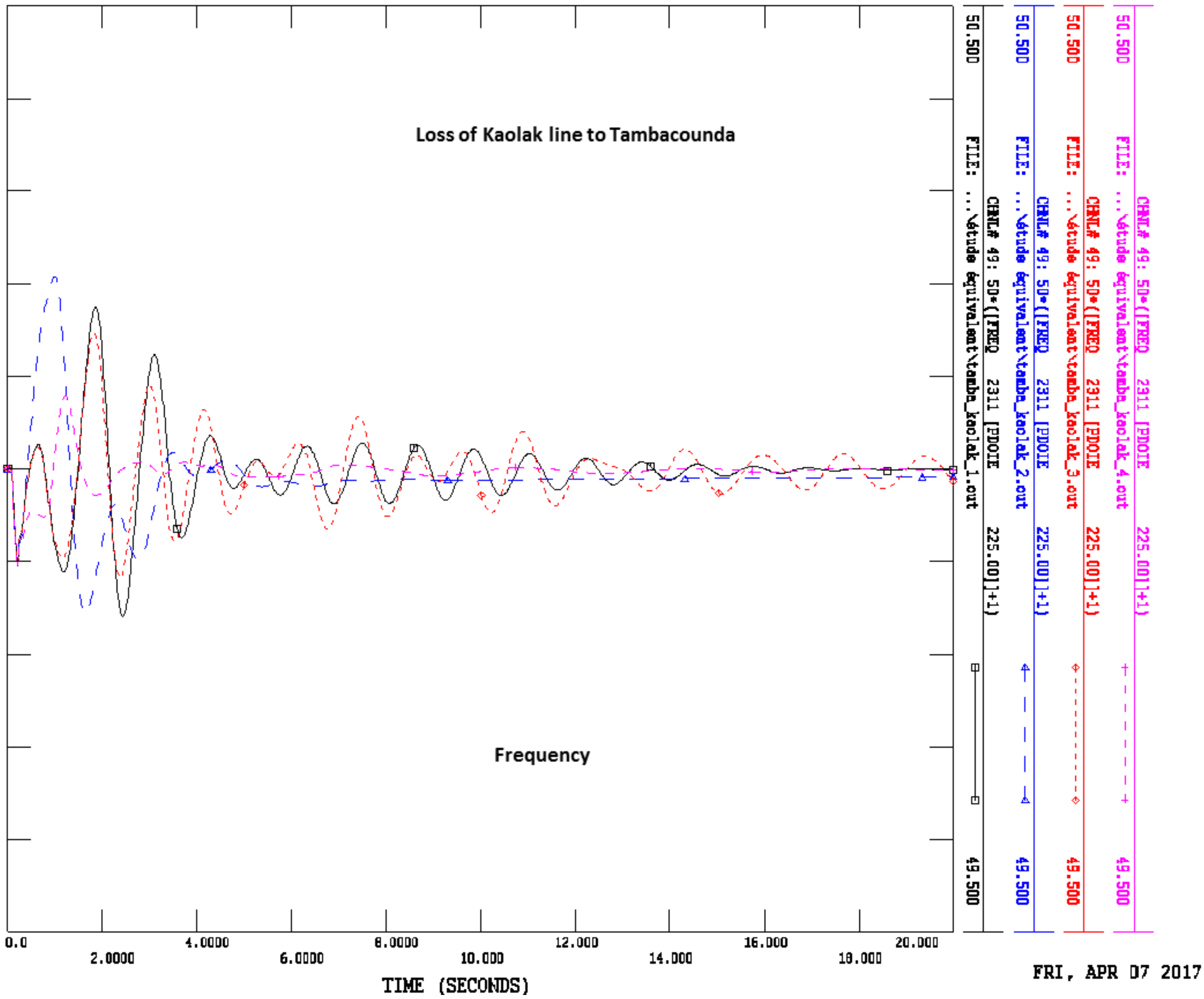
The grid representation must extend far enough on the interconnected network, i.e. to interconnection points that are not sensitive to disturbances on the Senelec grid. These interconnection points will be represented by a dynamic model with inertia and a damping coefficient. The table below describes MVA equivalents of the contribution from neighboring grids.

Table 4-57: Parameters of equivalent neighboring grids

PARAMETERS OF EQUIVALENT NEIGHBORING GRIDS							
				KATI	DIALAKDJ		
				2238	<-------2234		
	R	X	X/R	abs (Z)	If 3ph (pu)	If 3Ph (kA)	PCC (MVA)
Zpu	0.001	0.012	9.583	0.012	86.487	22.193	8648.694
				Kodia	SENANK		
				2106	<-------2230		
	R	X	X/R	abs (Z)	If 3ph (pu)	If 3Ph (kA)	PCC (MVA)
Zpu	0.001	0.013	10.154	0.013	75.393	19.346	7539.283
				Kaleta	Manhea		
				2517	<-------2506		
	R	X	X/R	abs (Z)	If 3ph (pu)	If 3Ph (kA)	PCC (MVA)
Zpu	0.0215	0.0956	4.4465	0.0979878	10.2053515	2.618694425	1020.535154
				LINSAN	BUMBA		
				2615	<-------2806		
	R	X	X/R	abs (Z)	If 3ph (pu)	If 3Ph (kA)	PCC (MVA)
Zpu	0.019	0.131	6.763	0.133	7.540	1.935	753.997
				SENANK	BOUGOU		
					DIALAK		
				2230	<-------2229	(2 Lines)	
					<-------2231	(2 Lines)	
Circuit 1	R	X	X/R	abs (Z)	If 3ph (pu)	If 3Ph (kA)	PCC (MVA)
Zpu	0.008	0.074	9.827	0.074	13.499	3.464	1349.880
Circuit 2	R	X	X/R	abs (Z)	If 3ph (pu)	If 3Ph (kA)	PCC (MVA)
Zpu	0.0075	0.0737	9.83	0.074	13.499	3.464	1349.880
Circuit 1	R	X	X/R	abs (Z)	If 3ph (pu)	If 3Ph (kA)	PCC (MVA)
Zpu	0.0015	0.0145	9.908	0.015	68.783	17.650	6878.291
Circuit 2	R	X	X/R	abs (Z)	If 3ph (pu)	If 3Ph (kA)	PCC (MVA)
Zpu	0.00146	0.01447	9.91	0.01	68.78	17.65	6878.29
Ztot (pu)	0.00061	0.00605	9.908	0.0061		Total (MVA)	16456.34347
				FOMI	KANAKN		
					DMORISA		
				2531	<-------2530	1 Line	
					<-------25431	1 Line	
Circuit 1	R	X	X/R	abs (Z)	If 3ph (pu)	If 3Ph (kA)	PCC (MVA)
Zpu	0.0161	0.1094	6.795	0.1105783	9.04336211	2.3205278	904.3362113
Circuit 1	R	X	X/R	abs (Z)	If 3ph (pu)	If 3Ph (kA)	PCC (MVA)
Zpu	0.0051	0.0348	6.8235	0.0351717	28.4319321	7.295637177	2843.193209
Ztot (pu)	0.00387	0.0264	6.8166	0.0266842		Total (MVA)	3747.529421

The use of short-circuit capacity for stability studies may not be appropriate under certain circumstances, as shown in the figure below.

Figure 4-8: Impact of equivalent grids on the behavior of the Senelec grid



The figure above shows the behavior of the grid with different representations of equivalent neighboring grids for an event near a neighboring grid. Using an equivalent for neighboring grids with a significant MVA without appropriate voltage regulation can create new modes of oscillation that do not actually exist or, conversely, lead to overly optimistic damping. Consequently, to avoid the use of equivalents, it is better to represent the entire interconnected network.

4.2.4 VALIDATION OF DYNAMIC DATA

To begin, we validated the stability for each generating plant to a response in their controls.

The results of this first step can be found in Appendix (C.1). You will find the following demonstrations:

- Response of the voltage exciter and regulator to a set-point voltage change. The data used has been modified, corrected and validated for a stable response of the voltage regulator.
- Response of the voltage exciter and regulator to a maximum set-point of the regulator. This test confirms the reaction time of the regulator, and you will see two types of response time: one relatively slow and one fast, as well as the regulator cap.
- Response of the speed regulator to a 10% change in the power set-point. The data used has been modified, corrected and validated for a stable response of the speed regulator.

These simulations are carried out for all Senelec power plants individually, without any interaction with the transmission network.

The following simulation considers the transmission network and its potential interaction with power plants. The transmission network considered is limited to the Senegal border, as there is no simulated disturbance.

- Simulation without disturbance for 10 seconds to ensure a stable network response, and no unstable interaction is observed between the different power plants in the grid. All the scenarios examined underwent this simulation before the stability study was initiated.

4.2.5 RESULTS

We selected the years 2019, 2022 and 2028 to validate stability compliance. Several variants, with and without mines, and with and without IRE power plants were also simulated to observe their impacts. We also validated stability for extreme variants such as maximum importing from neighboring grids. You will find all the simulations for the three years studied as well as certain variants in Appendix (D.1). However, before we started, we determined the critical fault clearing time.

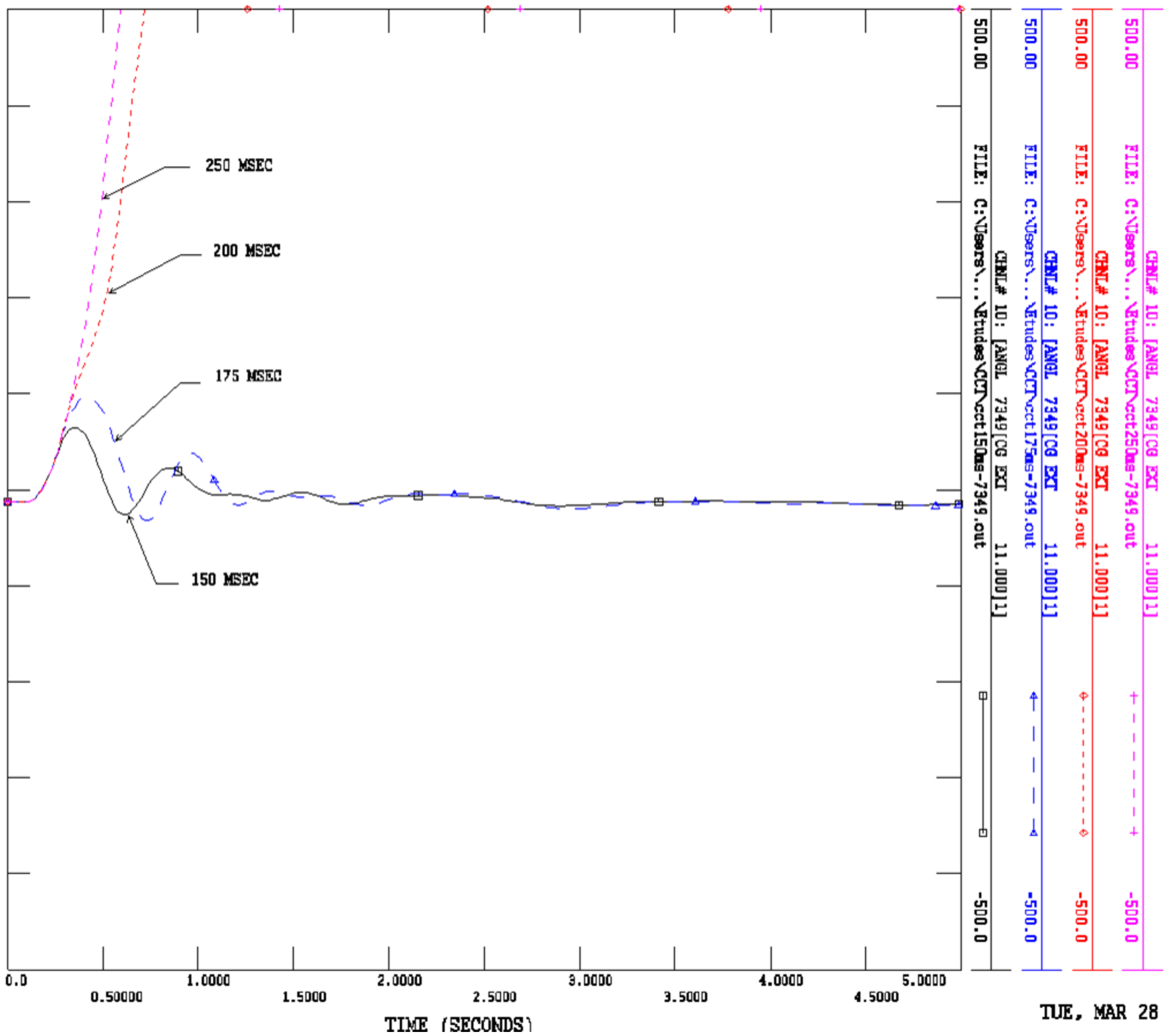
DETERMINATION OF CRITICAL FAULT CLEARING TIME

This analysis consists in determining the maximum three-phase fault clearing time for each plant (Critical Fault Clearing Time - CCT). The chosen grid has no influence since we are only considering the acceleration effect and not the topology of the grid. This aspect is validated during the angle stability study. For the angle stability and voltage study, it is common practice to use a fault clearing time of 100 msec for normal protection, and 300 msec for backup protection. Therefore, these CCT times will need to be compared to and greater than the actual operating time of existing protections, and will also be used for the implementation of new protections.

Our initial observations on the disturbance simulations carried out thus far indicate a significant lack of damping due to incorrect settings of the stabilizers, which in this case are out of service according to the information received. As a result, they were taken out of service for the study.
Obviously, this reduces the robustness of the grid and its ability to transmit or exchange power with neighboring grids. Therefore, it is recommended that as part of another study, data be collected to confirm the validity of the data and subsequently optimize the controls, in this case of the stabilizer.

We therefore evaluated the various existing power plants and planned the maximum fault clearing time. A sample result is shown in the following figure for the power plants at Cap des Biches. For these stations, we obtain a maximum time of 175 msec (8.75 cy.) for the three-phase fault. While acceptable, there is little leeway. As previously indicated, the use of stabilizers will increase voltage regulator gains to improve synchronism and thus give more leeway in the duration of fault clearing.

Figure 4-9: Maximum three-phase fault clearing time at the Cap des Biches CCT power plant



We performed the same exercise for the other existing and planned power plants. The table below gives the maximum fault clearing times (CCT).

Table 4-58: Maximum fault clearing times (CCT) for Senelec power plants

MAXIMUM FAULT CLEARING TIMES (CCT) FOR SENELEC POWER PLANTS	
Power plant	CCT (msec)
Bel Air	175
Sendou	175
Malicounda	200
Cap des Biches	175
Kounoune	250
IPP Tobene	175
IPP Africa	200
Kahone II	150
IPPCCGT St-Louis	375

As previously indicated, the times obtained are acceptable because they are greater than the fault clearing time normally used and implemented on the grid. However, the margin is a bit low and could be significantly improved if stabilizers already available on most existing and futures plants were used.

2019 GRID

The first grid examined is the planned grid in 2019, from the static study.

Peak load

The first scenario is the peak load condition without the presence of IRE plants. The grid conditions are as follows:

Table 4-59: 2019 peak load

2019HORIZON: PEAK LOAD									
538.5 MW of generation (by technology)					Load (MW)	Losses (MW)	Imported: 110.5 MW		
Solar	Wind	Coal	Other Thermal	Sync. Res.			OMVS	OMVG	SOMELEC
0	0	115	423.5	50	643.4	5.4	81.6	0	28.9

Table 4-60: Generation plan: Peak load

GENERATION PLAN: PEAK LOAD					
Bus Num	Bus Name	Id	Pgen	Pmax	Reserve
7301	CBELAIR1G 15.000	1	29.98546	34.152	4.166544
7302	CDB401 6.6000	1	0	0	0
7304	CDB403 6.6000	1	21.0569	21.184	0
7307	KOUNO 1G 15.000	1	0	0	0
7308	CDB402 6.6000	1	0	0	0
7309	CDB404-5 11.000	1	27.67706	31.4512	3.774144
7310	CDB301 12.500	1	0	0	0
7311	CAP DB CG 11.000	1	45.3264	45.6	0
7312	CDB303 12.500	1	0	0	0

GENERATION PLAN: PEAK LOAD					
Bus Num	Bus Name	Id	Pgen	Pmax	Reserve
7313	CMALICOU 15.000	1	0	0	0
7314	CMALICOU 15.000	2	0	0	0
7320	BELAIR4G 11.000	1	34.93488	35.04	0
7322	CAPRKOU 13.800	1	0	0	0
7323	BELAIR2G 15.000	1	30.05376	34.152	4.09824
7324	BELAIR3G 15.000	1	30.05376	34.152	4.09824
7332	IPPAFRI 33.000	2	0	0	0
7333	CC3 12.500	1	0	0	0
7333	CC3 12.500	2	0	0	0
7334	CDB_TAG2 11.000	1	0	0	0
7335	KAHON 1 15.000	1	0	0	0
7336	CIPPAFICA 33.000	1	0	0	0
7337	IPPAFRI 33.000	1	0	0	0
7338	CSENDOU 11.000	1	114.77	115	0
7339	SENDOU 11.000	2	0	0	0
7340	IPPAFRI 33.000	2	0	0	0
7341	CNDIAYE 11.000	1	0	0	0
7341	CNDIAYE 11.000	2	0	0	0
7348	TP_70MW 15.000	1	45.14	51.4416	6.301596
7349	CG EXT 11.000	1	24.32	34.32	10
7350	APR CDB 33.000	1	0	0	0
7826	EOLSN 0.6500	1	0	0	0
8742	SNIAKHAR 11.000	1	0	0	0
8743	SDIASS 11.000	1	0	0	0
8744	SKAHONE 11.000	1	0	0	0
8745	SMEKH 11.000	1	0	0	0
8745	SMEKH 11.000	2	0	0	0
8746	SBOKHOL 11.000	1	0	0	0
8747	STOUBA 11.000	1	0	0	0
8748	SMALICOU 11.000	1	0	0	0
73051	KAHON1G 15.000	1	30.14176	34.252	4.11024
73052	KAHON2G 15.000	2	30.14176	34.252	4.11024
73053	KAHON3G 15.000	3	30.05376	34.152	4.09824
73481	TP_70MW 15.000	2	45.14	51.4416	6.301596
	Total (MW)		538.7955	590.59	51.0591

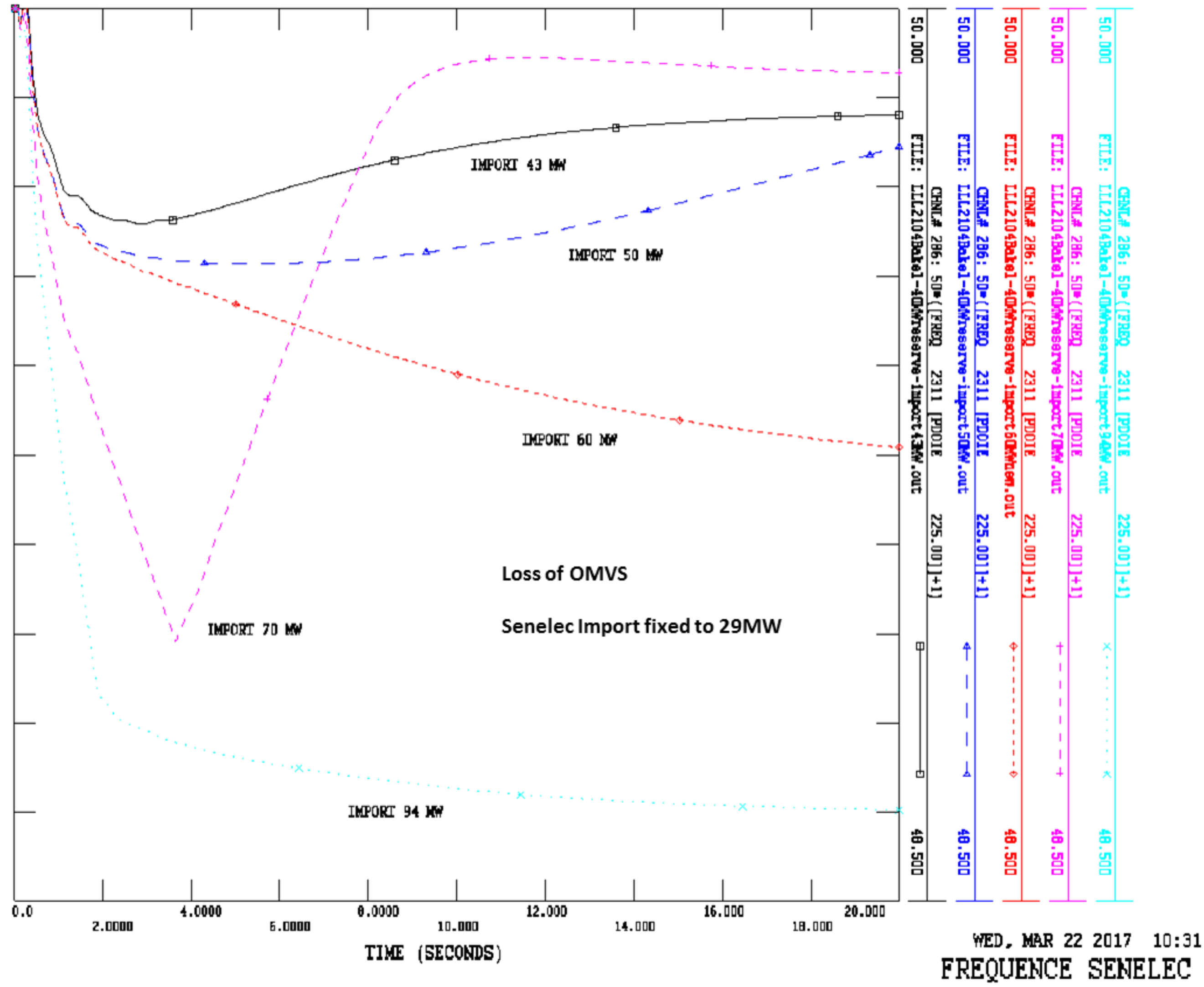
We started with a spinning reserve at 51 MW. This amount is the product of about 12% of the capacity of the plants in service in this scenario.

Stability study

We simulated the list of normal contingencies for the peak load network. The behavior of the interconnected network demonstrated a stable and damped voltage and frequency response, except for one event, namely the loss of interconnection with the OMVS complex.

Thus, of all the simulated contingencies, the worst case scenario is the loss of import from the OMVS complex because, in addition to losing injected power to feed the Senelec load, its contribution to the reserve is also lost, resulting in an instantaneous drop in grid inertia. We have indeed observed that for initial import in this 110 MW scenario, and despite a reserve increase to 60 MW, this amount of spinning reserve was not sufficient to prevent underfrequency load shedding. Therefore, we reduced the import level and, with a more realistic spinning reserve of 40 MW, we observe the grid frequency behavior as shown in the following figure:

Figure 4-10: Maximum imported from OMVS



We therefore note that maximum import with some margin is about 50 MW, of which 21 MW comes from OMVS and 29 MW from Somelec. There is a significant frequency drop with this type of contingency because of the significant loss of inertia initially present from OMVS. There is also another phenomenon to consider since in this scenario, with total importing of 50 MW, 35 MW of load along the OMVS line is fed by the hydraulic complex. Following the loss of the Bakel line to Kayes, this load must be fed instantaneously by Senelec's power plants, causing significant losses in MW transmission, and thus exacerbating the frequency drop.

All the other simulated contingencies are the result of stable and damped grid behavior. However, we observed significant oscillations, particularly for contingencies at the Tobene substation and, although damped, stabilizers could greatly improve the performance of the Senelec grid.

IRE and without coal

In this scenario, we introduce IRE power plants to replace some thermal power plants. The grid conditions are as follows:

Table 4-61: 2019 horizon: off-peak load, IRE and without coal

2019 HORIZON: OFF-PEAK LOAD, IRE AND WITHOUT COAL									
282 MW of generation (by technology in MW)					Load (MW)	Losses (MW)	Import: 70.2 MW		
							OMVS	OMVG	SOMELEC
Solar	Wind	Coal	Other Thermal	Sync. Res.					
212	47.5	0	22.5	1.5	345	5.4	70.2	0	0

Table 4-62: Generation plan: off-peak load, renewable energy and without coal

GENERATION PLAN: OFF-PEAK LOAD, RENEWABLE ENERGY AND WITHOUT COAL					
Bus Num	Bus Name	Id	Pgen	Pmax	Reserve
7301	CBELAIR1G 15.000	1	0	0	0
7302	CDB401 6.6000	1	0	0	0
7304	CDB403 6.6000	1	0	0	0
7307	KOUNO 1G 15.000	1	7.92	8	0
7308	CDB402 6.6000	1	0	0	0
7309	CDB404-5 11.000	1	0	0	0
7310	CDB301 12.500	1	0	0	0
7311	CAP DB CG 11.000	1	0	0	0
7312	CDB303 12.500	1	0	0	0
7313	CMALICOU 15.000	1	0	0	0
7314	CMALICOU 15.000	2	0	0	0
7320	BELAIR4G 11.000	1	0	0	0
7322	CAPRKOU 13.800	1	0	0	0
7323	BELAIR2G 15.000	1	0	0	0
7324	BELAIR3G 15.000	1	0	0	0
7332	IPPAFRI 33.000	2	0	0	0
7333	CC3 12.500	1	0	0	0
7333	CC3 12.500	2	0	0	0
7334	CDB_TAG2 11.000	1	0	0	0
7335	KAHON 1 15.000	1	0	0	0
7336	CIPPAFICA 33.000	1	0	0	0
7337	IPPAFRI 33.000	1	0	0	0
7338	CSENDOU 11.000	1	0	0	0
7339	SENDOU 11.000	2	0	0	0
7340	IPPAFRI 33.000	2	0	0	0

GENERATION PLAN: OFF-PEAK LOAD, RENEWABLE ENERGY AND WITHOUT COAL					
Bus Num	Bus Name	Id	Pgen	Pmax	Reserve
7341	CNDIAYE 11.000	1	0	0	0
7341	CNDIAYE 11.000	2	0	0	0
7348	TP_70MW 15.000	1	0	0	0
7349	CG EXT 11.000	1	15.66	17.16	1.5
7350	APR CDB 33.000	1	0	0	0
7826	EOLSN 0.6500	1	47.51157	47.6068	0
8742	SNIAKHAR 11.000	1	46.52654	46.9965	0
8743	SDIASS 11.000	1	14.8599	15.01	0
8744	SKAHONE 11.000	1	29.7198	30.02	0
8745	SMEKH 11.000	1	29.20535	29.5004	0
8745	SMEKH 11.000	2	29.20535	29.5004	0
8746	SBOKHOL 11.000	1	19.79753	19.9975	0
8747	STOUBA 11.000	1	22.76951	22.9995	0
8748	SMALICOU 11.000	1	19.79753	19.9975	0
73051	KAHON1G 15.000	1	0	0	0
73052	KAHON2G 15.000	2	0	0	0
73053	KAHON3G 15.000	3	0	0	0
73481	TP_70MW 15.000	2	0	0	0
			282.973	286.788	1.5000

On this grid, because of the presence of the IRE plants, very little thermal generation is obviously required to meet the demand. Consequently, the minimum inertia and spinning reserve is virtually non-existent on the Senelec grid. Thus, only the reserve from neighboring grids is available to counteract any generation/load imbalance. With an installed capacity of 280 MW at the OMVS complex, we set the available reserve of this complex at 3%, or 8 MW, which is clearly insufficient to provide adequate frequency control with the wind farm operating at its maximum.

Therefore, we will analyze a second variant that will maximize the presence of thermal on the Senelec grid by interrupting the imports used to feed the Senelec load. In this situation, we can only increase the spinning reserve by 8 MW, for a total of 10 MW.

IRE without imports and without coal, with a 10-MW reserve

As previously indicated, for this variant we increased the spinning reserve by reducing imports. The grid conditions are as follows:

Table 4-63: 2019 off-peak load, renewable energy, without coal, 10 MW imported, 10 MW synchronous reserve

2019 OFF-PEAK LOAD, RENEWABLE ENERGY, WITHOUT COAL, 10 MW IMPORTED, 10 MW SYNCHRONOUS RESERVE									
342.5 MW of generation (by technology in MW)					Load (MW)	Losses (MW)	Import: 10 MW		
							OMVS	OMVG	SOMELEC
Solar	Wind	Coal	Other Thermal	Sync. Res.					
212	47.5	0	83	10	345	7	10	0	0

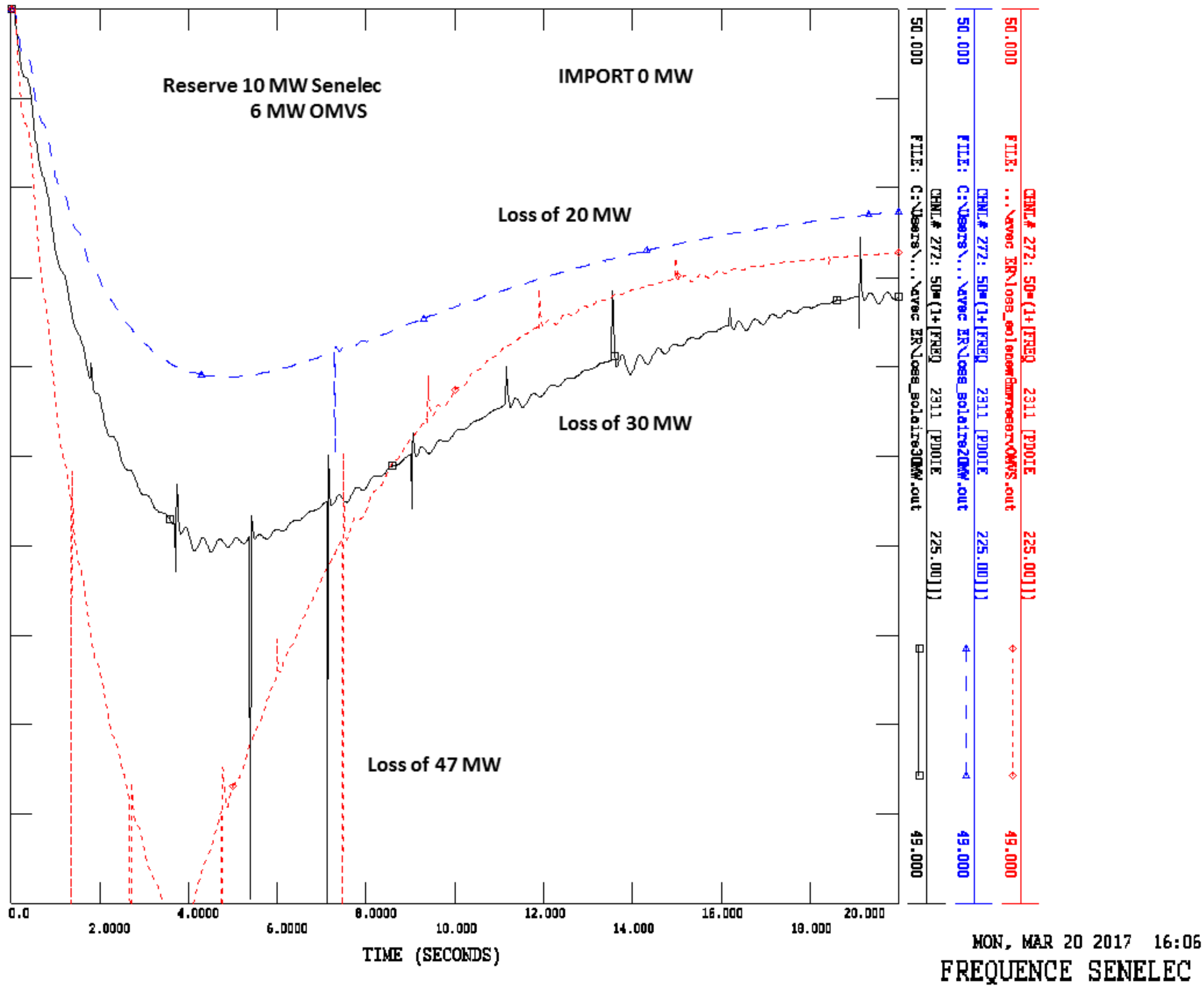
Table 4-64: Generation plan: off-peak load, renewable energy, without coal, 10 MW imported, 10 MW synchronous reserve

GENERATION PLAN: OFF-PEAK LOAD, RENEWABLE ENERGY, WITHOUT COAL, 10 MW IMPORTED, 10 MW SYNCHRONOUS RESERVE					
Bus Num	Bus Name	Id	Pgen	Pmax	Réserve
7301	CBELAIR1G 15.000	1	30.05376	34.152	4.09824
7302	CDB401 6.6000	1	0	0	0
7304	CDB403 6.6000	1	0	0	0
7307	KOUNO 1G 15.000	1	7.92	8	0
7308	CDB402 6.6000	1	0	0	0
7309	CDB404-5 11.000	1	0	0	0
7310	CDB301 12.500	1	0	0	0
7311	CAP DB CG 11.000	1	0	0	0
7312	CDB303 12.500	1	0	0	0
7313	CMALICOU 15.000	1	0	0	0
7314	CMALICOU 15.000	2	0	0	0
7320	BELAIR4G 11.000	1	0	0	0
7322	CAPRKOU 13.800	1	0	0	0
7323	BELAIR2G 15.000	1	15.02688	17.076	2.04912
7324	BELAIR3G 15.000	1	0	0	0
7332	IPPAFRI 33.000	2	0	0	0
7333	CC3 12.500	1	0	0	0
7333	CC3 12.500	2	0	0	0
7334	CDB_TAG2 11.000	1	0	0	0
7335	KAHON 1 15.000	1	0.00	0.00	0.00
7336	CIPPAFICA 33.000	1	0	0	0
7337	IPPAFRI 33.000	1	0	0	0
7338	CSENDOU 11.000	1	0	0	0
7339	SENDOU 11.000	2	0	0	0
7340	IPPAFRI 33.000	2	0	0	0
7341	CNDIAYE 11.000	1	0	0	0
7341	CNDIAYE 11.000	2	0	0	0
7348	TP_70MW 15.000	1	0	0	0
7349	CG EXT 11.000	1	30.2016	34.32	4.1184
7350	APR CDB 33.000	1	0	0	0
7826	EOLSN 0.6500	1	47.51157	47.6068	0
8742	SNIAKHAR 11.000	1	46.52654	46.9965	0
8743	SDIASS 11.000	1	14.8599	15.01	0
8744	SKAHONE 11.000	1	29.7198	30.02	0
8745	SMEKH 11.000	1	29.20535	29.5004	0
8745	SMEKH 11.000	2	29.20535	29.5004	0
8746	SBOKHOL 11.000	1	19.79753	19.9975	0
8747	STOUBA 11.000	1	22.76951	22.9995	0
8748	SMALICOU 11.000	1	19.79753	19.9975	0
73051	KAHON1G 15.000	1	0	0	0

GENERATION PLAN: OFF-PEAK LOAD, RENEWABLE ENERGY, WITHOUT COAL, 10 MW IMPORTED, 10 MW SYNCHRONOUS RESERVE					
Bus Num	Bus Name	Id	Pgen	Pmax	Réserve
73052	KAHON2G 15.000	2	0	0	0
73053	KAHON3G 15.000	3	0	0	0
73481	TP_70MW 15.000	2	0	0	0
	Total		342.5953	355.176	10.2658

In this scenario, a maximum of 30 MW can be lost, i.e., the second largest generation loss, which in this variant is the solar power facility. As the biggest loss of generation is the 47-MW wind or solar facility, the reserve shortage leads to load shedding. The figure below shows the frequency for different generation losses:

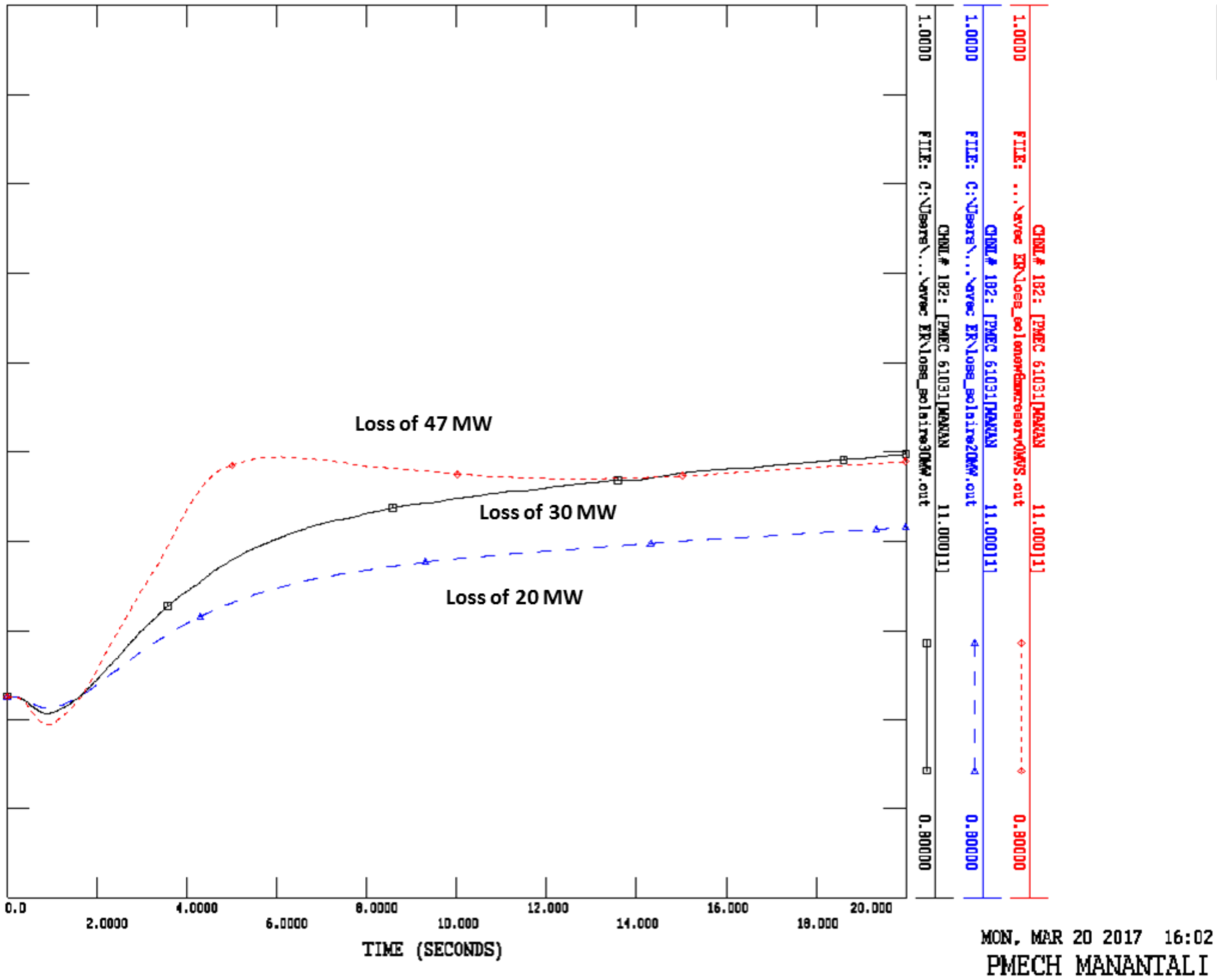
Figure 4-11: Frequency behavior on different generation losses (Hz)



We therefore observe load shedding for the loss of the wind farm in this variant, and maximum generation loss is roughly 30 MW.

The figure below clearly shows the contribution of the Manantali power plant for different generation losses. Despite their significant contributions to inertia, the slower reaction time of speed regulators than of the Senelec thermal power plants, coupled with the electrical distance from Senelec's Manantali and Felou power plant, reduce the efficiency of their capacity contributions.

Figure 4-12: Behavior of the Manantali power plant on different generation losses (MW)



It is important to note that in the first moments, the OMVS complex reserve varies according to the amount of generation loss, and that this phenomenon must be considered in the establishment of the Senelec reserve.

Finally, we find that the reserve is insufficient to cover the loss of the wind farm or the largest solar power facility. To obtain additional reserve, solar power facilities must be removed from the planned 214 MW. We thus obtain the following scenarios:

IRE reduced by 53% without imports and with a 21-MW reserve

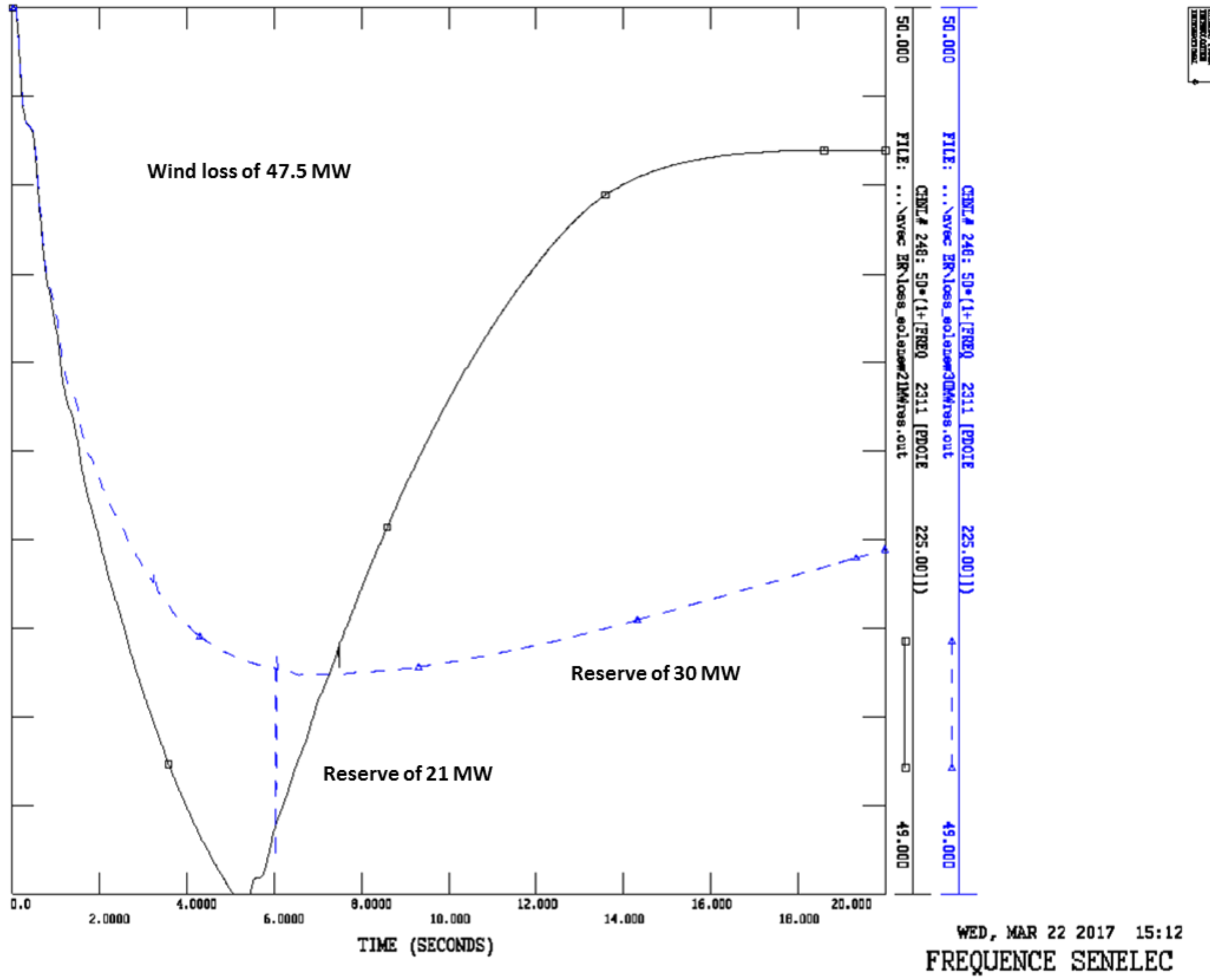
For this variant, we have once again increased the spinning reserve by reducing the number of solar power facilities. The grid conditions are as follows:

Table 4-65: 2019 off-peak load, solar reduced by 53%, without coal, 11 MW imported, 21 MW synchronous reserve

2019 OFF-PEAK LOAD, SOLAR REDUCED BY 53%, WITHOUT COAL, 11 MW IMPORTED, 21 MW SYNCHRONOUS RESERVE									
337 MW of generation (by technology in MW)					Load (MW)	Losses (MW)	Import: 11 MW		
							OMVS	OMVG	SOMELEC
Solar	Wind	Coal	Other Thermal	Sync. Res.					
100	47.5	0	179.5	21	345	3.2	11	0	0

As shown in the figure below, this scenario with a 21-MW reserve is not enough to prevent load shedding for the loss of the wind farm.

Figure 4-13: Frequency behavior on wind farm loss (Hz)



It is therefore necessary to remove more solar power facilities to increase the reserve to a sufficient level, i.e., 30 MW to prevent load shedding on loss of the wind farm. Therefore, the following variant was used:

IRE reduced by 62% without imports, without coal and with a 30-MW reserve

For this variant, in order to reach the required spinning reserve, we once again reduced the solar power plants. The grid conditions are as follows:

Table 4-66: 2019 off-peak load, solar reduced by 62%, without coal, 11 MW imported, 30 MW synchronous reserve

2019 OFF-PEAK LOAD, SOLAR REDUCED BY 62%, WITHOUT COAL, 11 MW IMPORTED, 30 MW SYNCHRONOUS RESERVE									
337 MW of generation (by technology in MW)					Load (MW)	Losses (MW)	Import: 11 MW		
Solar	Wind	Coal	Other Thermal	Sync. Res.			OMVS	OMVG	SOMELEC
82	47.5	0	207.5	30	345	3.2	11	0	0

Table 4-67: Generation plan: off-peak load, solar reduced by 62%, without coal, 11 MW imported, 21 MW synchronous reserve

GENERATION PLAN: OFF-PEAK LOAD, SOLAR REDUCED BY 62%, WITHOUT COAL, 11 MW IMPORTED, 21 MW SYNCHRONOUS RESERVE					
Bus Num	Bus Name	Id	Pgen	Pmax	Réserve
7301	CBELAIR1G 15.000	1	30.05376	34.152	4.09824
7302	CDB401 6.6000	1	0	0	0
7304	CDB403 6.6000	1	0	0	0
7307	KOUNO 1G 15.000	1	0	0	0
7308	CDB402 6.6000	1	0	0	0
7309	CDB404-5 11.000	1	0	0	0
7310	CDB301 12.500	1	0	0	0
7311	CAP DB CG 11.000	1	0	0	0
7312	CDB303 12.500	1	0	0	0
7313	CMALICOU 15.000	1	0	0	0
7314	CMALICOU 15.000	2	0	0	0
7320	BELAIR4G 11.000	1	0	0	0
7322	CAPRKOU 13.800	1	0	0	0
7323	BELAIR2G 15.000	1	30.05376	34.152	4.09824
7324	BELAIR3G 15.000	1	30.05376	34.152	4.09824
7332	IPPAFRI 33.000	2	0	0	0
7333	CC3 12.500	1	0	0	0
7333	CC3 12.500	2	0	0	0
7334	CDB_TAG2 11.000	1	0	0	0
7335	KAHON 1 15.000	1	0	0	0
7336	CIPPAFICA 33.000	1	0	0	0
7337	IPPAFRI 33.000	1	0	0	0
7338	CSENDOU 11.000	1	0	0	0
7339	SENDOU 11.000	2	0	0	0
7340	IPPAFRI 33.000	2	0	0	0
7341	CNDIAYE 11.000	1	0	0	0
7341	CNDIAYE 11.000	2	0	0	0
7348	TP_70MW 15.000	1	45.26861	51.4416	6.172992

GENERATION PLAN: OFF-PEAK LOAD, SOLAR REDUCED BY 62%, WITHOUT COAL, 11 MW IMPORTED, 21 MW SYNCHRONOUS RESERVE					
Bus Num	Bus Name	Id	Pgen	Pmax	Réserve
7349	CG EXT 11.000	1	28.2016	34.32	6.1184
7350	APR CDB 33.000	1	0	0	0
7826	EOLSN 0.6500	1	47.51157	47.6068	0
8742	SNIAKHAR 11.000	1	46.52654	46.9965	0
8743	SDIASS 11.000	1	14.8599	15.01	0
8744	SKAHONE 11.000	1	0	0	0
8745	SMEKH 11.000	1	0	0	0
8745	SMEKH 11.000	2	0	0	0
8746	SBOKHOL 11.000	1	0	0	0
8747	STOUBA 11.000	1	0	0	0
8748	SMALICOU 11.000	1	19.79753	19.9975	0
73051	KAHON1G 15.000	1	0	0	0
73052	KAHON2G 15.000	2	0	0	0
73053	KAHON3G 15.000	3	0	0	0
73481	TP_70MW 15.000	2	45.26861	51.4416	6.172992
	Total (MW)		337.5956	369.27	30.7591

In conclusion, for the 2019 grid, the maximum from solar power facilities to meet the frequency criterion is 82 MW out of the 214 MW planned, or a 62% reduction of planned solar energy. However, the amount of spinning reserve initially required is 35 MW due to the potential maximum fluctuation of the wind farm. It would therefore be necessary to further reduce solar penetration by 42 MW to obtain a sufficient level of spinning reserve, ultimately a reduction of 81% (40 MW from remaining solar facilities).

Reducing the maximum installed capacity of the wind farm or a solar power facility to a value of 30 MW, and at the same time reducing the fluctuation to 20 MW, would increase solar penetration. Thus, the scenario without imports and with 21 MW of spinning reserve on the Senelec grid, i.e. 100 MW from solar facilities instead of 40 MW, would therefore be viable. This grid condition was described as follows:

IRE reduced by 53% without imports or coal

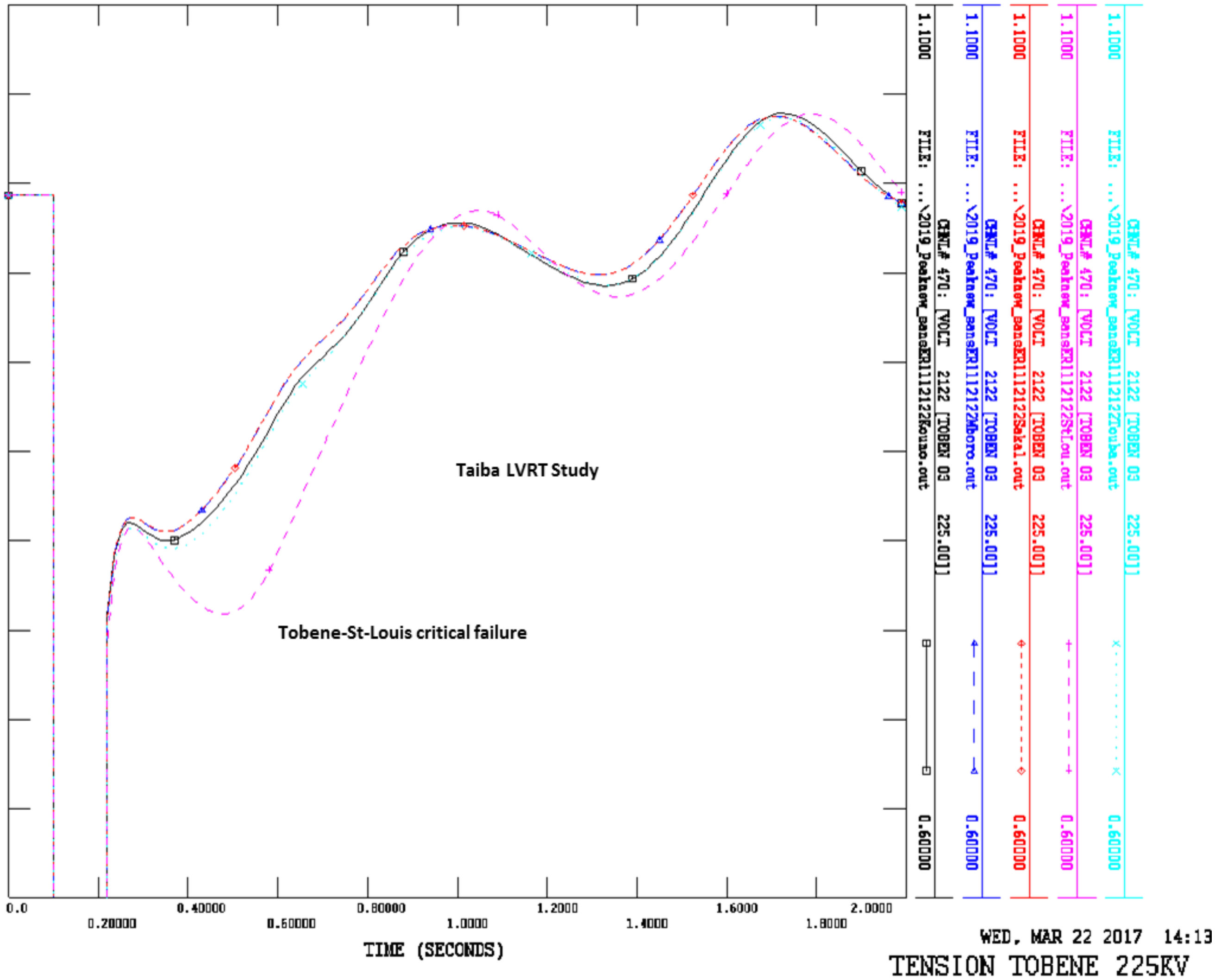
Table 4-68: 2019 off-peak load, solar reduced by 53%, without coal, 0 MW imported, 21 MW synchronous reserve

2019 OFF-PEAK LOAD, SOLAR REDUCED BY 53%, WITHOUT COAL, 0 MW IMPORTED, 21 MW SYNCHRONOUS RESERVE									
347 MW of generation (by technology in MW)					Load (MW)	Losses (MW)	Importation: 0 MW		
							OMVS	OMVG	SOMELEC
Solar	Wind	Coal	Other Thermal	Sync. Res.					
100	47.5	0	199.5	21	345	3.2	0	0	0

LVRT study for the Taiba wind farm

With respect to the integration of wind and PV facilities, we will need to ensure that the grid can provide a minimum recovery voltage when there is a fault, and that the PV and wind facilities also remain in service following a disturbance. Of all the simulated contingencies at the Tobene substation, the worst contingency for this analysis of the Taiba wind farm is, according to the figure below, a three-phase fault at the Tobene substation, followed by the loss of the Tobene line to the Saint-Louis substation.

Figure 4-14 : Voltage behavior for different events at the Tobene substation (PU)



We therefore simulated this contingency to observe the voltage behavior at the interconnection point of the facility.

Figure 4-15: Voltage behavior with respect to the LVRT (PU) envelope and voltage recovery following a three-phase 6-cycle fault (intervals 0 to 30.5 s)

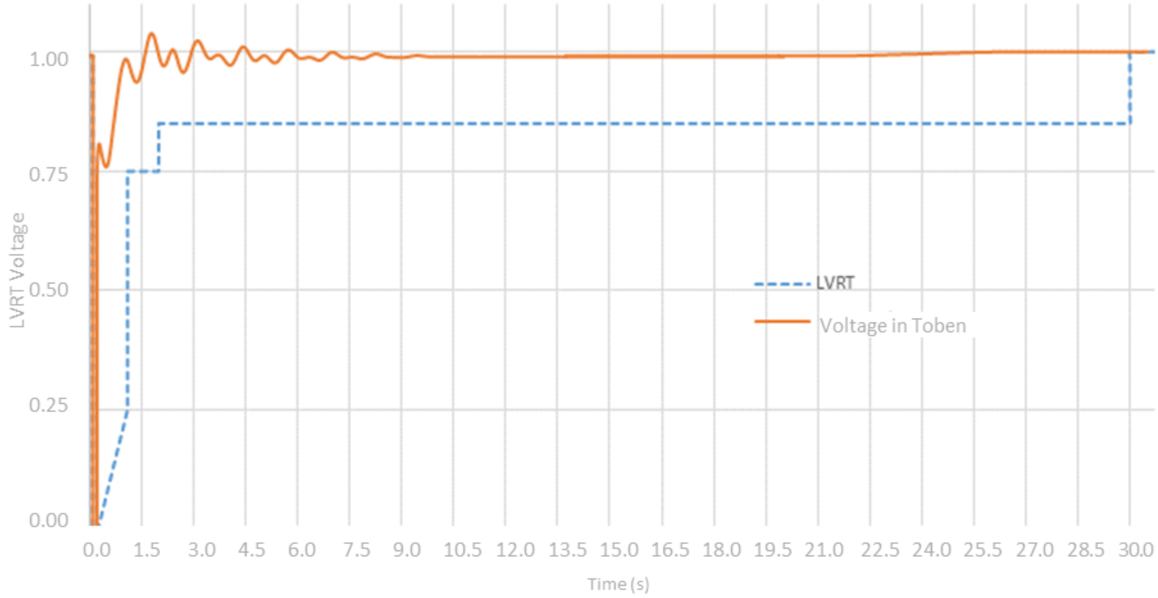
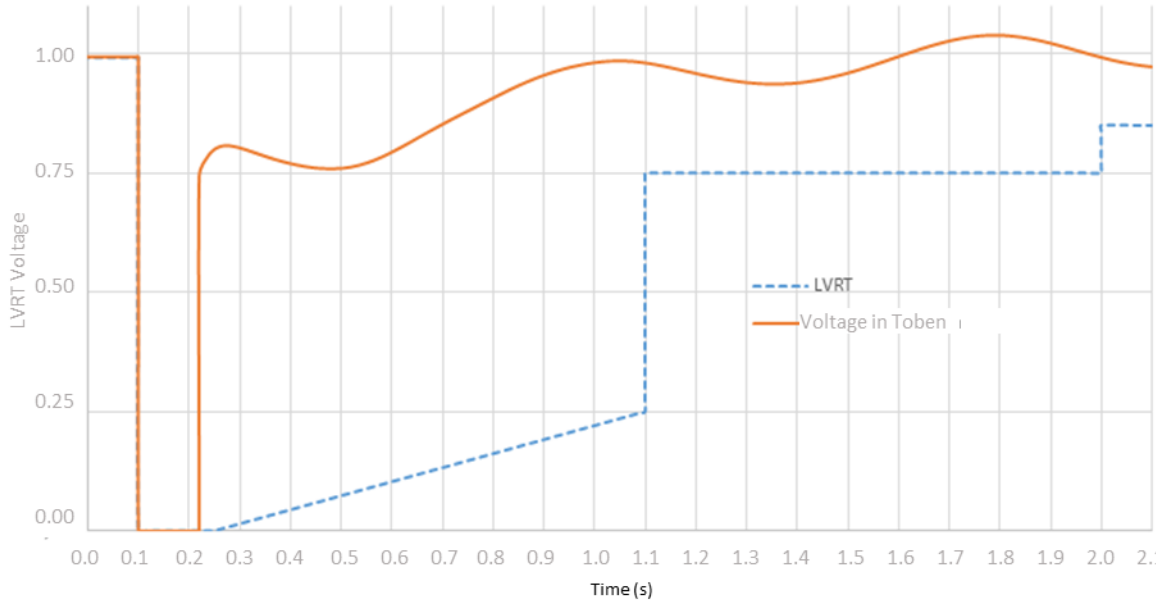


Figure 4-16: Voltage behavior with respect to the LVRT (0 to 2 s.) (PU) envelope and voltage recovery following a three-phase 6-cycle fault (intervals 0 to 2.1 s)



In this figure we see that the recovery voltage is well above the voltage envelope limit that would activate the facility. The grid therefore offers sufficient robustness for the integration of the wind farm.

2022 GRID

The second grid examined is the grid planned for 2022, which comes from the static study. We also validated the scenario's compliance including variants with and without mines. Furthermore, we validated the stability of the Senelec grid for an extreme variant, that of maximum importing. This import limit level was determined through the static study.

Peak load without mines with normal and maximum importing

The first scenario is the peak load grid condition and a variant with maximum importing. The grid conditions are as follows:

Table 4-69: 2022 peak load without mines, with normal and maximum importing

2022 PEAK LOAD WITHOUT MINES, WITH NORMAL AND MAXIMUM IMPORTING						
Normal importing						
Generation (MW)	Load (MW)	Losses (MW)	Reserve (MW)	Import (353.6 MW)		
				OMVS	OMVG	SOMELEC
561.4	899	16.0	52	114.6	210.4	28.1

Maximum importing						
Generation (MW)	Load (MW)	Losses (MW)	Reserve (MW)	Import (446.6 MW)		
				OMVS	OMVG	SOMELEC
479.0	903.5	22.4	28	112.6	305.9	28.1

Table 4-70: Generation plan: peak load without mines, with normal and maximum importing

GENERATION PLAN: PEAK LOAD WITHOUT MINES, WITH NORMAL AND MAXIMUM IMPORTING					
Bus Num	Bus Name	Id	Pgen	Pmax	Reserve
7301	CBELAIR1G 15.000	1	30.652	34.152	3.5
7302	CDB401 6.6000	1	0	0	0
7304	CDB403 6.6000	1	0	0	0
7307	KOUNO 1G 15.000	1	7.92	8	0
7308	CDB402 6.6000	1	0	0	0
7309	CDB404-5 11.000	1	31.13669	31.4512	0
7310	CDB301 12.500	1	0	0	0
7311	CAP DB CG 11.000	1	0	0	0
7312	CDB303 12.500	1	0	0	0
7313	CMALICOU 15.000	1	42.24	48.24	6
7314	CMALICOU 15.000	2	55.32	64.32	9
7320	BELAIR4G 11.000	1	31.54	35.04	3.5
7322	CAPRKOU 13.800	1	0	0	0
7323	BELAIR2G 15.000	1	30.652	34.152	3.5
7324	BELAIR3G 15.000	1	30.652	34.152	3.5
7332	IPPAFRI 33.000	2	0	0	0
7333	CC3 12.500	1	0	0	0
7333	CC3 12.500	2	0	0	0
7334	CDB_TAG2 11.000	1	0	0	0
7335	KAHON 1 15.000	1	0	0	0
7336	CIPPAFICA 33.000	1	59.82	60	0
7337	IPPAFRI 33.000	1	0	0	0
7338	CSENDOU 11.000	1	108.1	115	0
7339	SENDOU 11.000	2	0	0	0
7340	IPPAFRI 33.000	2	0	0	0

GENERATION PLAN: PEAK LOAD WITHOUT MINES, WITH NORMAL AND MAXIMUM IMPORTING					
Bus Num	Bus Name	Id	Pgen	Pmax	Reserve
7341	CNDIAYE 11.000	1	0	0	0
7341	CNDIAYE 11.000	2	0	0	0
7348	TP_70MW 15.000	1	44.4416	51.4416	7
7349	CG EXT 11.000	1	24.32	34.32	10
7350	APR CDB 33.000	1	0	0	0
7826	EOLSN 0.6500	1	0	0	0
8742	SNIAKHAR 11.000	1	0	0	0
8743	SDIASS 11.000	1	0	0	0
8744	SKAHONE 11.000	1	0	0	0
8745	SMEKH 11.000	1	0	0	0
8745	SMEKH 11.000	2	0	0	0
8746	SBOKHOL 11.000	1	0	0	0
8747	STOUBA 11.000	1	0	0	0
8748	SMALICOU 11.000	1	0	0	0
73051	KAHON1G 15.000	1	0	0	0
73052	KAHON2G 15.000	2	0	0	0
73053	KAHON3G 15.000	3	32.152	34.152	2
73481	TP_70MW 15.000	2	32.4378	36.4378	4
			561.4341	620.859	52.0000

The 52 MW spinning reserve is primarily located at the C6 and C7 power plants. For the scenario with maximum importing, the equivalent reduction in thermal output reduces the possibility of spinning reserve by as much.

Peak load with mines

The second scenario is the peak load grid condition, but this time with the mines planned in 2022. We obtain the following grid conditions:

Table 4-71 : 2022 peak load with mines

2022 PEAK LOAD WITH MINES						
Generation (MW)	Load (MW)	Losses (MW)	Reserve (MW)	Import (356.2 MW)		
				OMVS	OMVG	SOMELEC
660.5	1003.8	13	63	116.2	212.0	28.1

Table 4-72 : Generation plan: Peak load with mines

GENERATION PLAN: PEAK LOAD WITH MINES					
Bus Num	Bus Name	Id	Pgen	Pmax	Reserve
7301	CBELAIR1G 15.000	1	30.652	34.152	3.5
7302	CDB401 6.6000	1	21.0569	21.184	0
7304	CDB403 6.6000	1	0	0	0
7307	KOUNO 1G 15.000	1	7.92	8	0
7308	CDB402 6.6000	1	0	0	0
7309	CDB404-5 11.000	1	31.13669	31.4512	0

GENERATION PLAN: PEAK LOAD WITH MINES					
Bus Num	Bus Name	Id	Pgen	Pmax	Reserve
7310	CDB301 12.500	1	0	0	0
7311	CAP DB CG 11.000	1	0	0	0
7312	CDB303 12.500	1	0	0	0
7313	CMALICOU 15.000	1	42.24	48.24	6
7314	CMALICOU 15.000	2	55.32	64.32	9
7320	BELAIR4G 11.000	1	31.54	35.04	3.5
7322	CAPRKOU 13.800	1	0	0	0
7323	BELAIR2G 15.000	1	30.652	34.152	3.5
7324	BELAIR3G 15.000	1	30.652	34.152	3.5
7332	IPPAFRI 33.000	2	0	0	0
7333	CC3 12.500	1	0	0	0
7333	CC3 12.500	2	0	0	0
7334	CDB_TAG2 11.000	1	0	0	0
7335	KAHON 1 15.000	1	0	0	0
7336	CIPPAFICA 33.000	1	59.82	60	0
7337	IPPAFRI 33.000	1	0	0	0
7338	CSENDOU 11.000	1	110.55	115	0
7339	SENDOU 11.000	2	0	0	0
7340	IPPAFRI 33.000	2	0	0	0
7341	CNDIAYE 11.000	1	0	0	0
7341	CNDIAYE 11.000	2	0	0	0
7348	TP_70MW 15.000	1	44.4416	51.4416	7
7349	CG EXT 11.000	1	24.32	34.32	10
7350	APR CDB 33.000	1	0	0	0
7826	EOLSN 0.6500	1	0	0	0
8742	SNIAKHAR 11.000	1	0	0	0
8743	SDIASS 11.000	1	0	0	0
8744	SKAHONE 11.000	1	0	0	0
8745	SMEKH 11.000	1	0	0	0
8745	SMEKH 11.000	2	0	0	0
8746	SBOKHOL 11.000	1	0	0	0
8747	STOUBA 11.000	1	0	0	0.0
8748	SMALICOU 11.000	1	0	0	0
73051	KAHON1G 15.000	1	31.002	34.252	3.25
73052	KAHON2G 15.000	2	31.002	34.252	3.25
73053	KAHON3G 15.000	3	30.652	34.152	3.5
73481	TP_70MW 15.000	2	47.6567	54.6567	7
	Total (MW)		660.6139	728.766	63.0000

This additional load makes it possible to increase generation and the spinning reserve. The latter is obviously too high, but serves as an available value to satisfy the frequency criterion.

Therefore, the scenario that does not consider mines as an additional load is the most pessimistic. In this case, capacity from the thermal power plants is minimal. Thus, there are also minimal candidates to produce reserve.

Stability study

We simulated the list of normal contingencies for both peak load grids, with and without mines. The behavior of the interconnected network demonstrated a stable and damped voltage and frequency response. Some events are more severe than others, but in general, the events simulated in the scenario without mines proved to be the most severe. The overvoltages observed were always under 1.05 pu. As a result, the voltage at the end of the 20-second simulation remains within the acceptable range of ± 10% of the nominal voltage. The loops created by the OMVG complex and with OMVS significantly improve the behavior of the Senelec grid. Thus, the problem observed in 2019 with the loss of the Kayes line to Bakel is greatly diminished by the loopback with the OMVG complex in the south.

However, for the scenario with maximum importing and without mines, the loss of the Tambacounda line to Sambangalou has a major impact, and leads to the loss of synchronism of the Sambangalou power plant. In this scenario, the flow on this line is initially 169 MVA and, when this line is lost, power is transferred to the Kaleta line to Boké, Guinea.

In this scenario, this line already has a flow of 172 MVA, resulting in a total of 320 MVA imported from OMVG.

Thus, as shown in the figure below, when the Tambacounda line to Sambangalou is lost, this power transfer creates a voltage dip at the Mansoa substation, amplified by the radial load of the Bissau substation that it feeds.

Figure 4-17: Voltage behavior following the loss of the Tambacounda line to Sambangalou, with and without one generation unit rejection (PU)

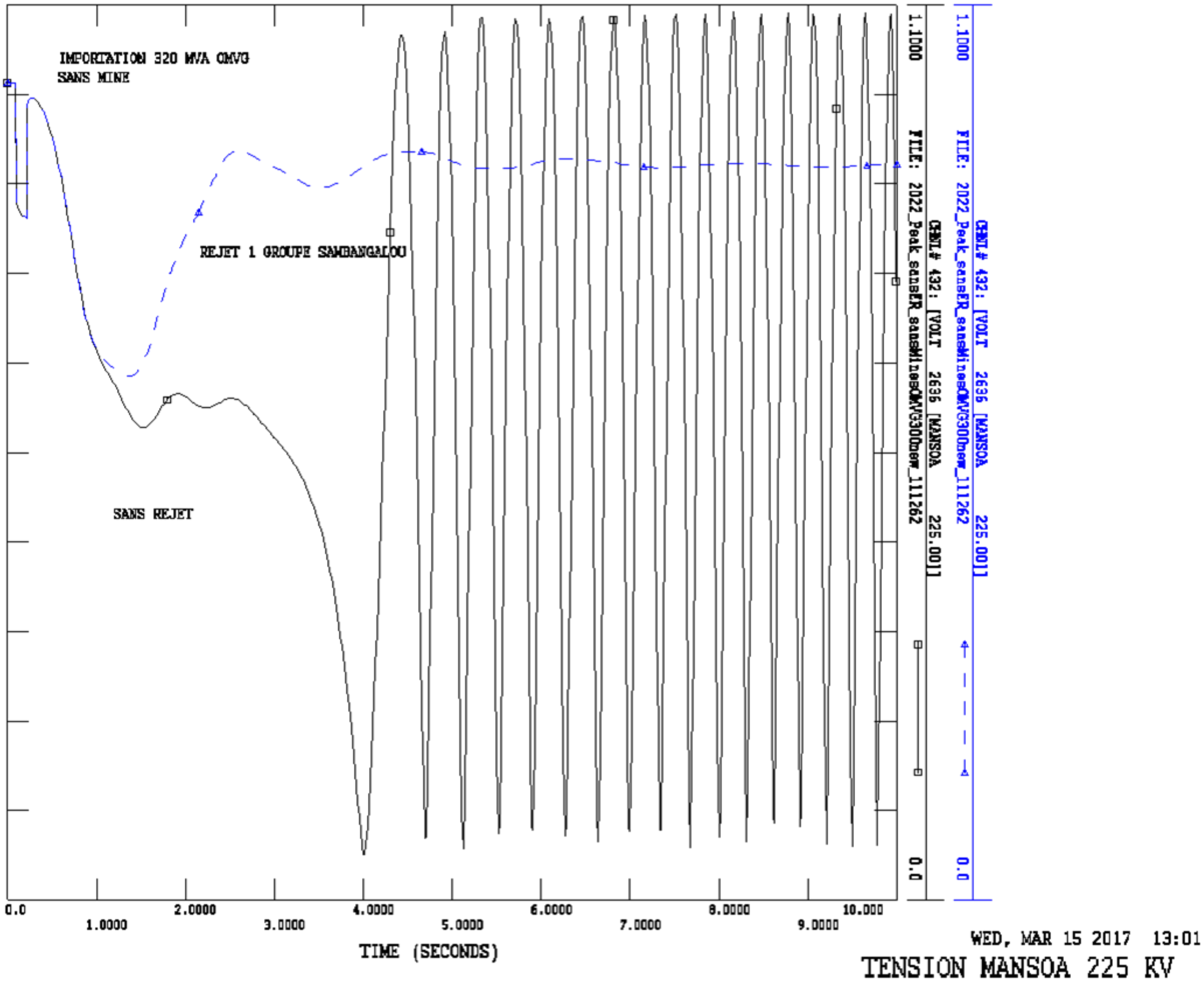
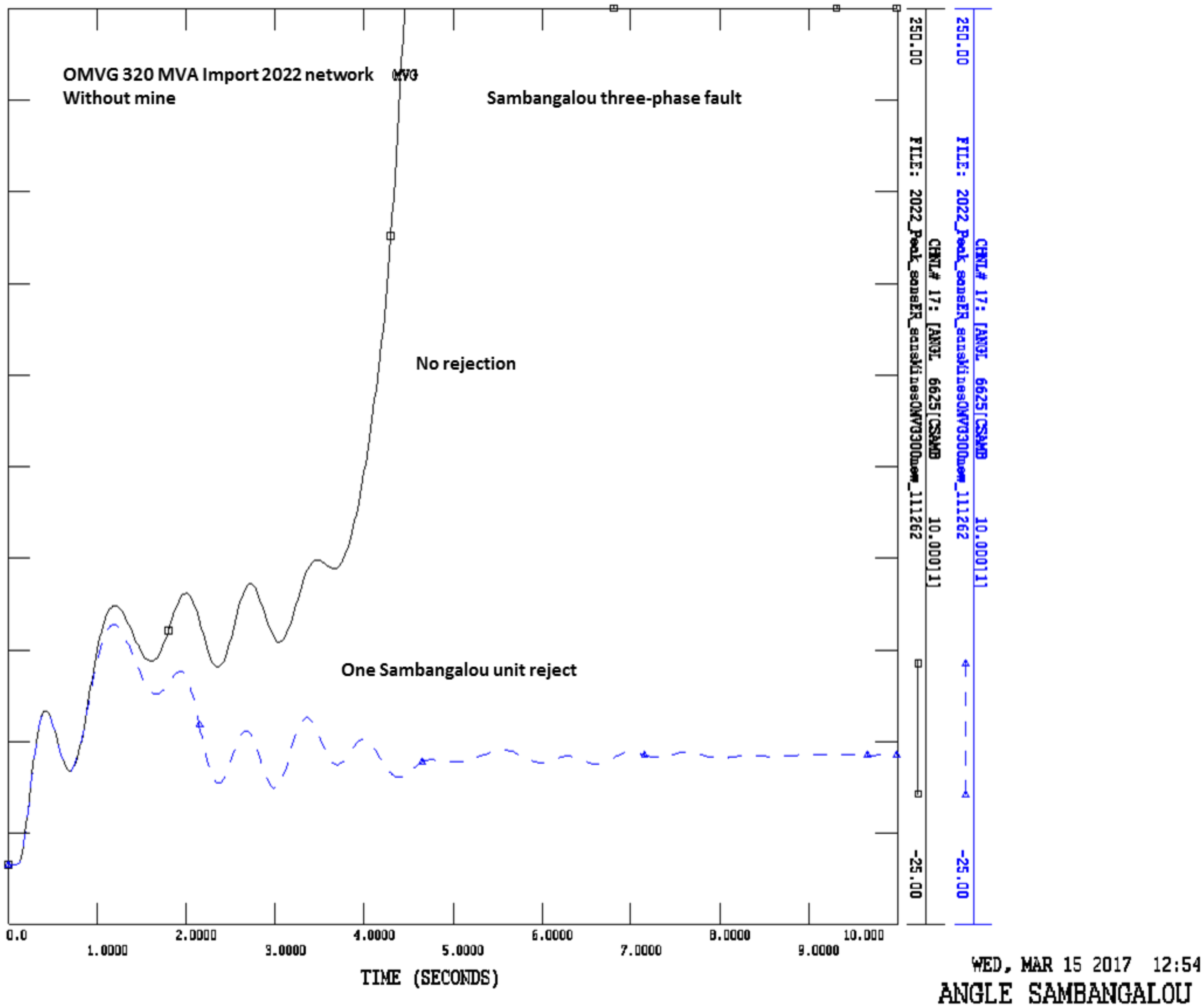


Figure 4-18: Angle behavior following the loss of the Tambacounda line to Sambangalou (deg)



Generation rejection set at 0.5 seconds after an event is sufficient to remain stable. However, the use of automation for a normal event is contrary to the design criterion normally used for the transmission network.

The consequence of reducing import to an average level of 230 MVA is that the flow on the Kaleta line to Boké in Guinea is 130 MVA and, in this situation, the grid remains stable but near the limit. In fact, removing a single unit from the Sambangalou power plant and importing 290 MVA from OMVG is enough to keep the grid stable after the event, as shown in the two figures below:

Figure 4-19: Angle behavior following the loss of the Tambacounda line to Sambangalou, with and without generation unit rejection (deg)

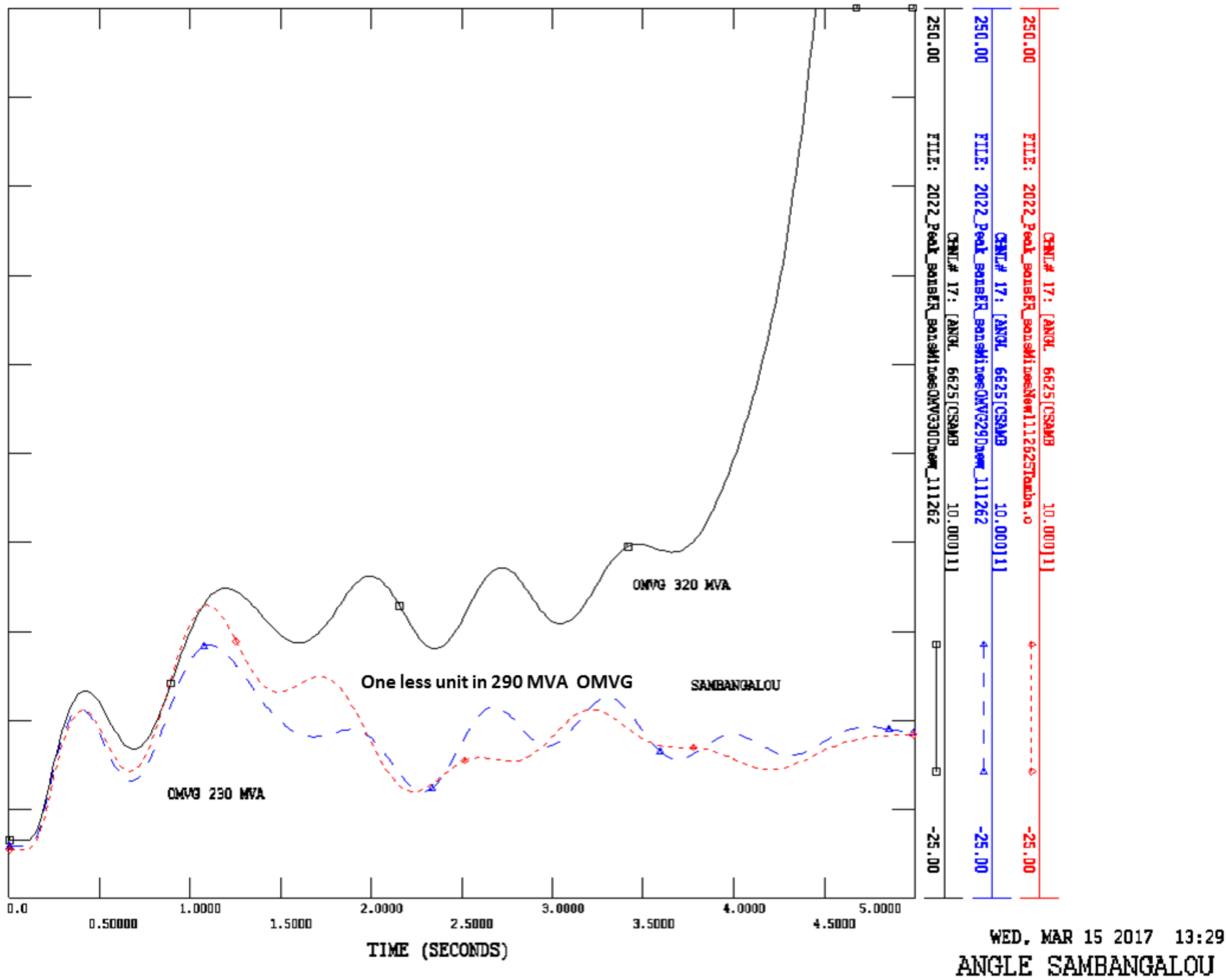
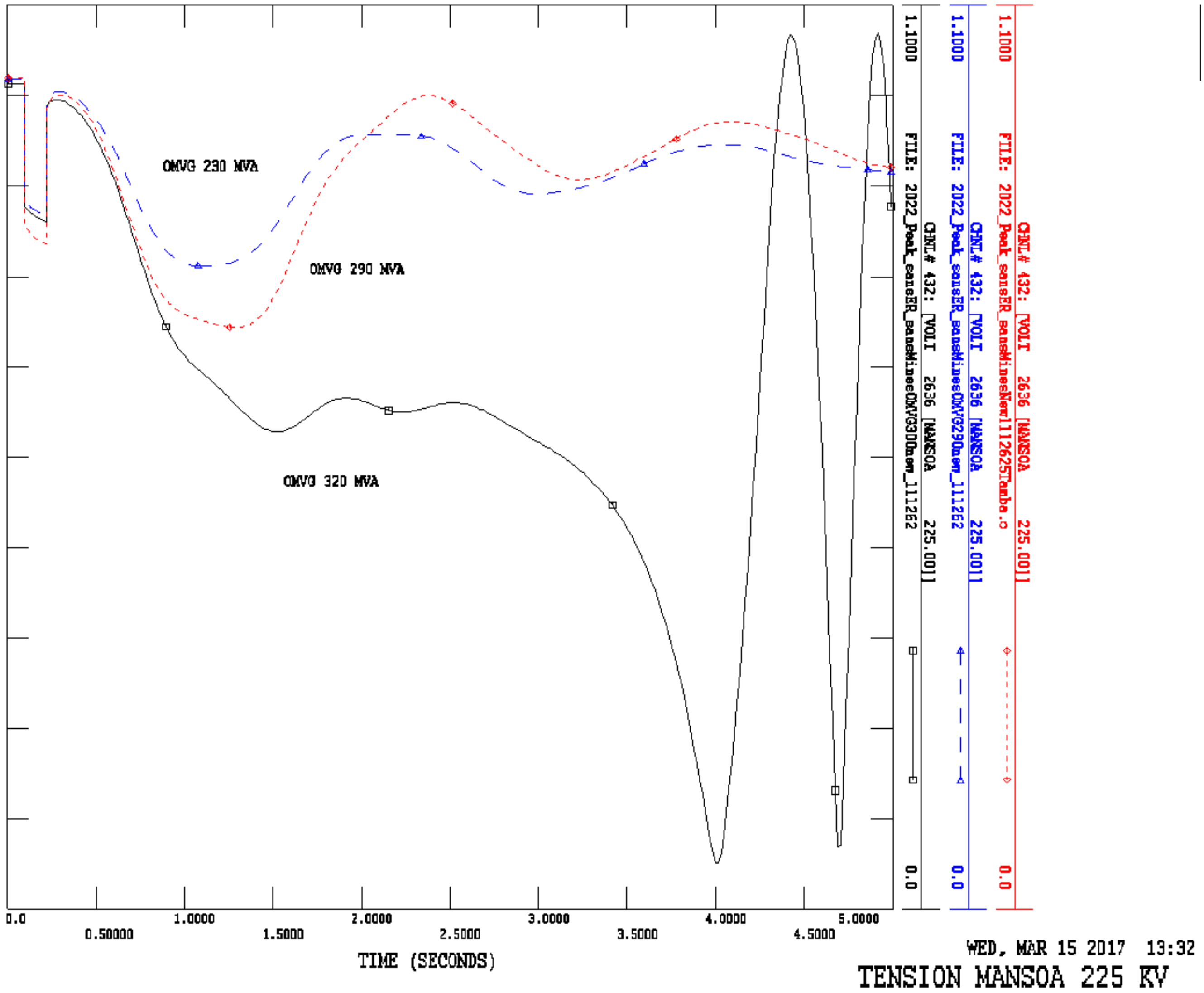


Figure 4-20: Voltage behavior following the loss of the Tambacounda line to Sambangalou, with and without a flow reduction (PU)



Therefore, the OMVG import limit is not thermal but voltage related. Therefore, reducing importing by 30 MW is enough to maintain stable voltage after an event.

With IRE, without mines and without importing

In this scenario, we introduce IRE power plants to replace thermal power plants. The grid conditions are as follows:

Table 4-73: 2022 off-peak load, with IRE and 0 MW imported

2022 OFF-PEAK LOAD, WITH IRE AND 0 MW IMPORTED									
516 MW of generation (by technology in MW)					Load (MW)	Losses (MW)	Import: 0 MW		
Solar	Wind	Coal	Other Thermal	Sync. Res.			OMVS	OMVG	SOMELEC
214	72	79 *	155	17	464	8	0	0	0

* Without mines, the Africa IPP power plant is not planned. Thus, by imposing the Sendou power plant close to its technical minimum (75 MW), generators with spinning reserve can be favored.

Table 4-74: Generation plan: Off-peak load, with IRE and 0 mw imported

GENERATION PLAN: OFF-PEAK LOAD, WITH IRE AND 0 MW IMPORTED					
Bus Num	Bus Name		Pgen	Pmax	Reserve
7301	CBELAIR1G	15.000	30.752	34.152	3.4
7302	CDB401	6.6000	0	0	0
7304	CDB403	6.6000	0	0	0
7307	KOUNO 1G	15.000	0	0	0
7308	CDB402	6.6000	0	0	0
7309	CDB404-5	11.000	0	0	0
7310	CDB301	12.500	0	0	0
7311	CAP DB CG	11.000	0	0	0
7312	CDB303	12.500	0	0	0
7313	CMALICOU	15.000	28.96	32.16	3.2
7314	CMALICOU	15.000	0	0	0
7320	BELAIR4G	11.000	32.04	35.04	3
7322	CAPRKOU	13.800	0	0	0
7323	BELAIR2G	15.000	0	0	0
7324	BELAIR3G	15.000	0	0	0
7332	IPPAFRI	33.000	0	0	0
7333	CC3	12.500	0	0	0
7333	CC3	12.500	0	0	0
7334	CDB_TAG2	11.000	0	0	0
7335	KAHON 1	15.000	0	0	0
7336	CIPPAFICA	33.000	0	0	0
7337	IPPAFRI	33.000	0	0	0
7338	CSENDOU	11.000	79	114.8	0
7339	SENDOU	11.000	0	0	0
7340	IPPAFRI	33.000	0	0	0
7341	CNDIAYE	11.000	0	0	0
7341	CNDIAYE	11.000	0	0	0
7348	TP_70MW	15.000	15.4472	17.1472	1.7

GENERATION PLAN: OFF-PEAK LOAD, WITH IRE AND 0 MW IMPORTED					
Bus Num	Bus Name		Pgen	Pmax	Reserve
7349	CG EXT	11.000	30.92	34.32	3.4
7350	APR CDB	33.000	0	0	0
7826	EOLSN	0.6500	72.23294	72.9626	0
8742	SNIAKHAR	11.000	46.52654	46.9965	0
8743	SDIASS	11.000	14.8599	15.01	0
8744	SKAHONE	11.000	29.7198	30.02	0
8745	SMEKH	11.000	29.20535	29.5004	0
8745	SMEKH	11.000	29.20535	29.5004	0
8746	SBOKHOL	11.000	19.79753	19.9975	0
8747	STOUBA	11.000	22.76951	22.9995	0
8748	SMALICOU	11.000	19.79753	19.9975	0
73051	KAHON1G	15.000	0	0	0
73052	KAHON2G	15.000	0	0	0
73053	KAHON3G	15.000	15.376	17.076	1.7
73481	TP_70MW	15.000	0	0	0
			516.6096	571.679	17.1296

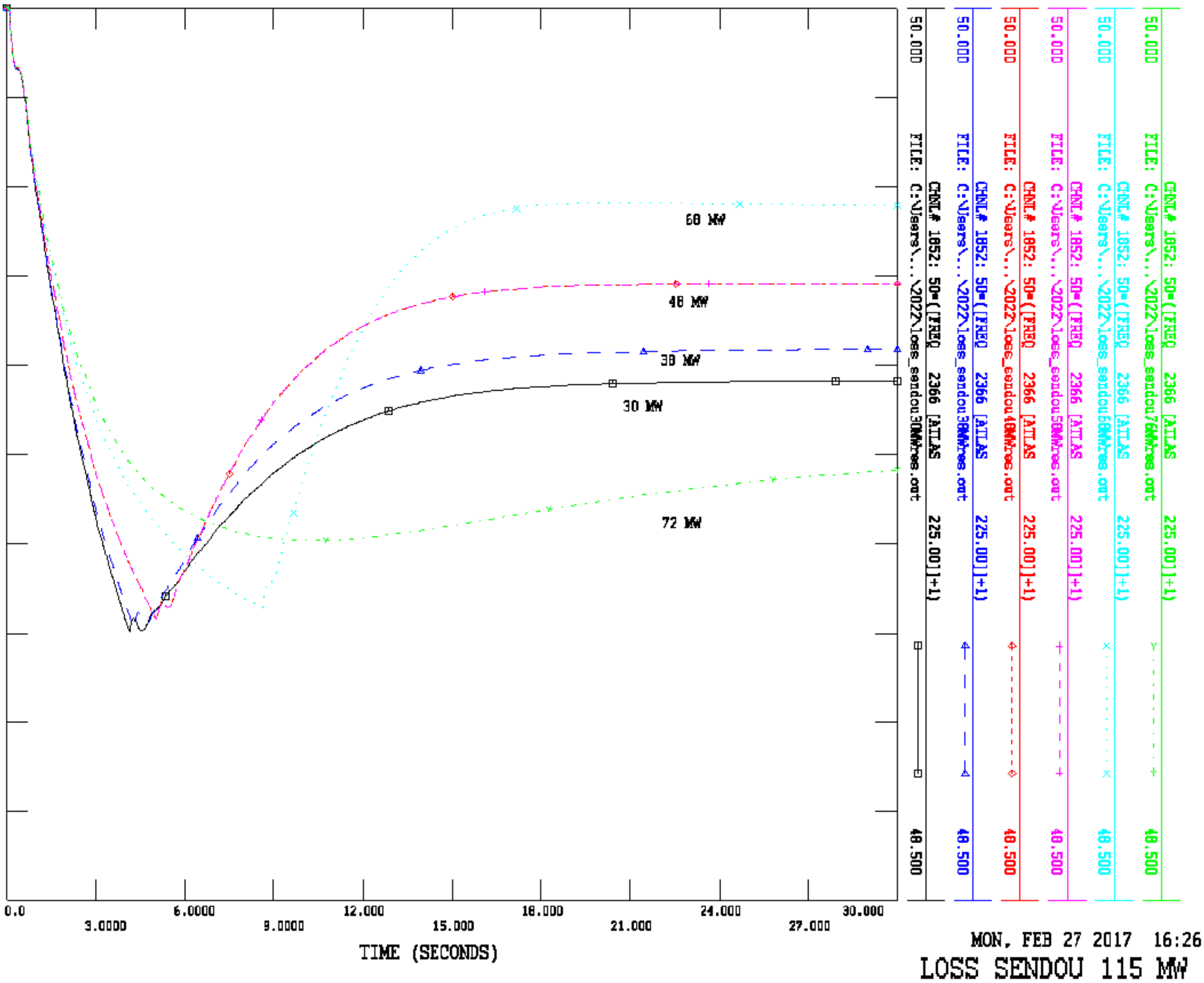
By limiting importing and reducing the Sendou coal-fired power plant to near the technical minimum of 75 MW, it is possible to obtain a maximum spinning reserve of only 17 MW. Note that this quantity is already lower than the spinning reserve required to regulate frequency with respect to renewable energy fluctuations.

The mines variant, which increases the load by about 105 MW, keeps the Sendou power plant at its maximum of 115 MW, and increasing the spinning reserve slightly.

Stability study

For the 2022 grid with IRE, in addition to simulating the list of normal contingencies, note that we obtained a stable and damped response of the interconnected network for all the contingencies simulated. At the end of the simulation, voltages are within the acceptable voltage range of ± 10%. We also evaluated the frequency behavior of the grid, which helps to determine the spinning reserve requirement. The simulated contingencies were limited to generation losses from the loss of a single grid component.

Figure 4-21: Frequency behavior on the loss of the Sendou power plant (Hz)

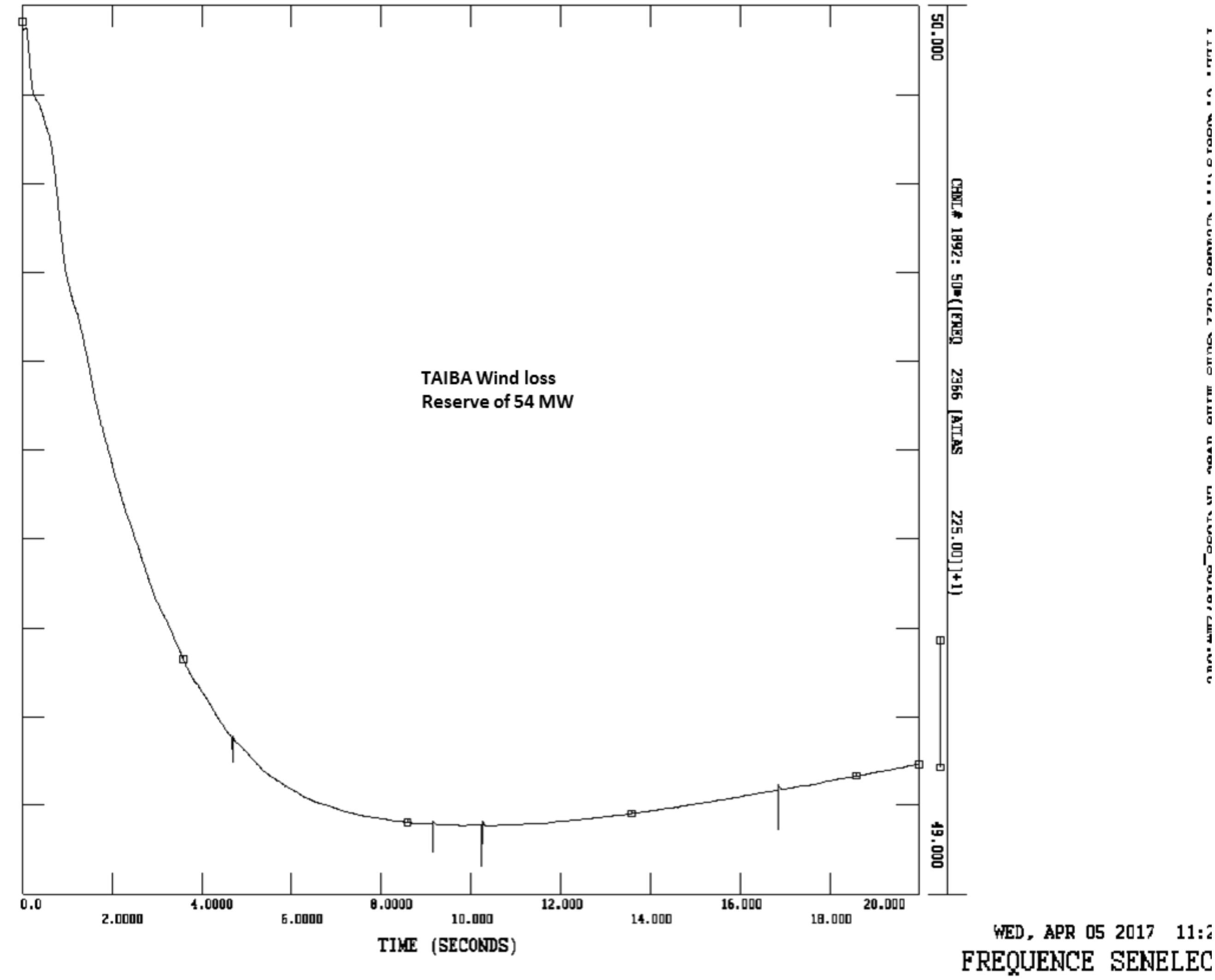


With the mines variant, the loss of the Sendou coal-fired power plant (115 MW) requires more than 70 MW of spinning reserve to avoid load shedding.

It is also noted that for the second largest generation loss, namely the loss of the wind turbine (72 MW), a spinning reserve of 54 MW is sufficient (49.075 Hz) to avoid underfrequency load shedding. Note that the spinning reserve required for the loss of the wind farm is equal to the spinning reserve required to compensate for fluctuations at the wind farm. Furthermore, depending on the type of generation lost, in the first seconds we see that the impact on the frequency slope is more severe for the loss of the Sendou power plant. This is due to the fact that we also lose inertia, contrary to the loss of the wind farm, and thus it proves to be a more severe event.

The figure below shows that for the second largest generation loss, namely wind (72 MW), a spinning reserve of 54 MW is sufficient (49.075 Hz) to avoid underfrequency load shedding.

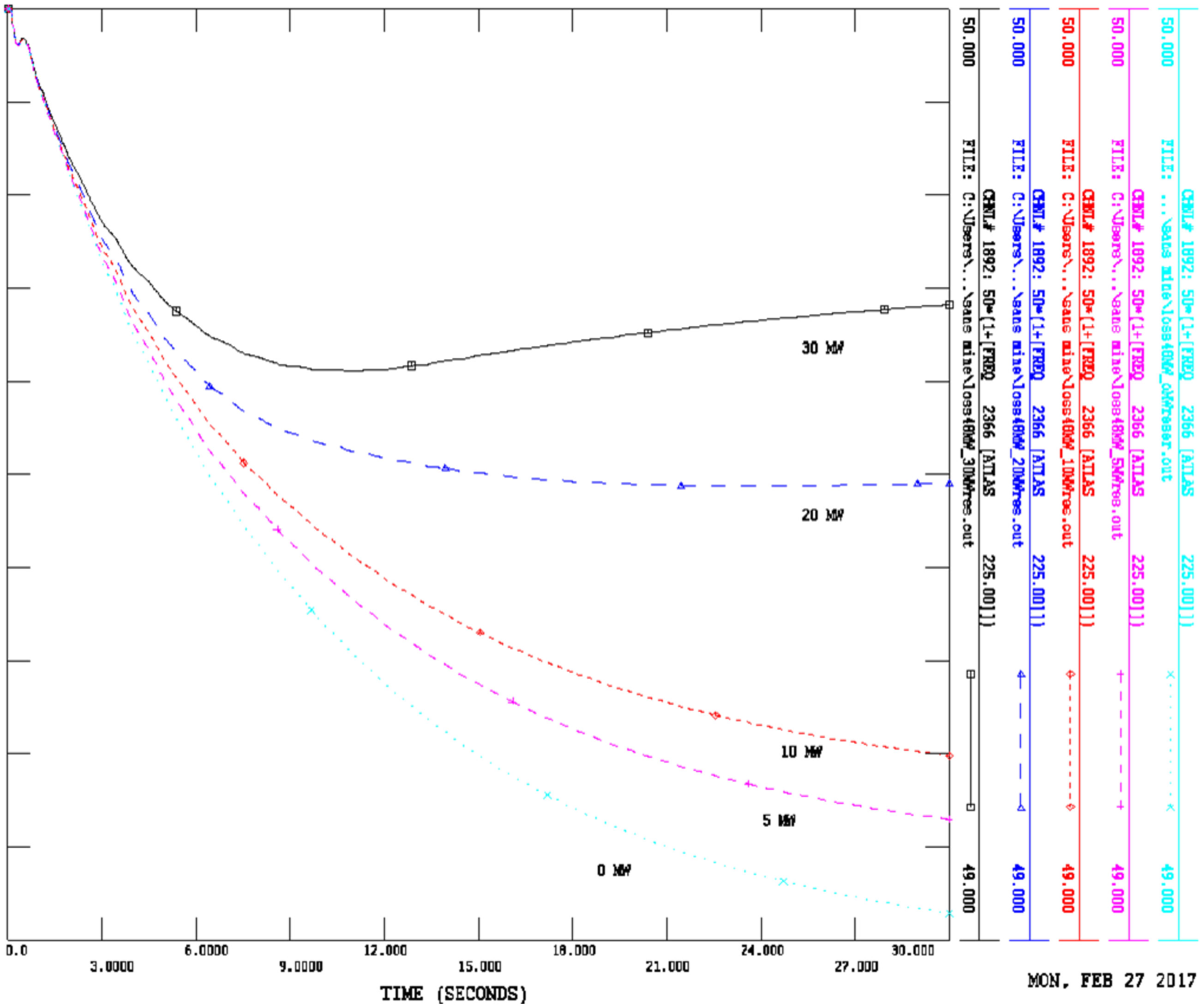
Figure 4-22: Frequency behavior on the loss of the Taïba wind farm (Hz)



Note that this spinning reserve required for the loss of the wind farm is equal to the spinning reserve required to compensate for its fluctuations. Furthermore, depending on the type of generation lost, in the first seconds we see that the impact on the frequency slope is more severe for the loss of the Sendou power plant. This is due to the fact that we also lose inertia, contrary to the event of the loss of the wind farm.

The figure below shows the frequency behavior following a generation loss of 48 MW, which is the third largest generation loss, with different spinning reserves.

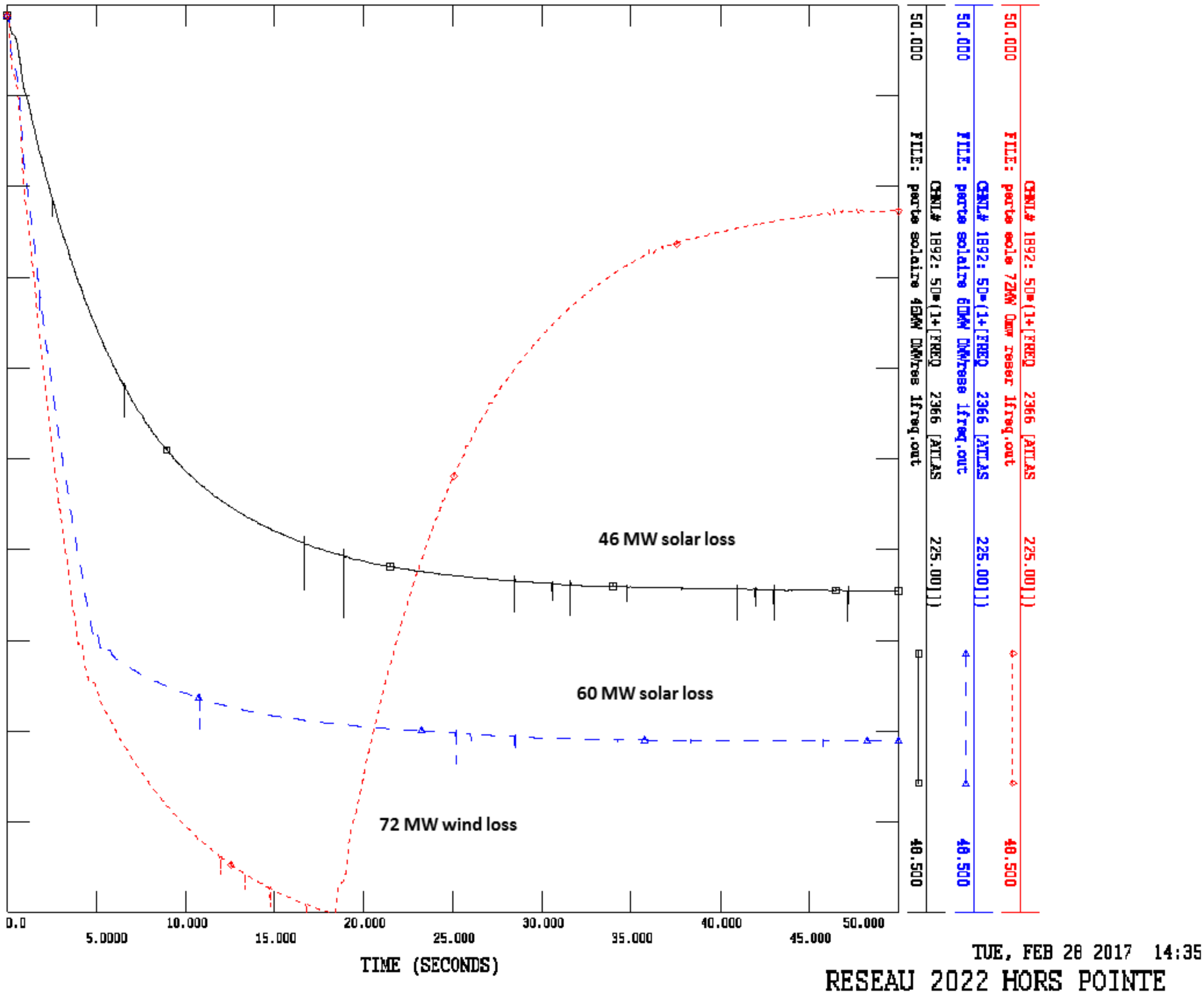
Figure 4-23: Frequency behavior with different reserves for the loss of 48 MW (Hz)



We see that without spinning reserve but with sufficient inertia, however, it is possible to lose a maximum output of 48 MW. However, the 10-minute reserve still needs to be activated to restore nominal frequency.

In the figure below, and within the framework of a grid including renewable energy, we see the frequency behavior for various solar/wind power plant losses without spinning reserve and without contribution from neighboring grids.

Figure 4-24: Frequency behavior for different generation losses, without spinning reserve (Hz)



We see that, for a grid without spinning reserve and without contribution from neighboring grids, we can lose up to 46 MW of generation from a solar power facility without hitting the load shedding threshold. In this situation, we have about half of the MVA load connected to the grid as inertia and, therefore, a thermal output of about 234 MW on the 460 MW load.

With IRE, without mines and without thermal generation, but with importing

This scenario is a variant of the previous scenario. The added import from the OMVS hydraulic complex replaces Senelec's thermal generation. This situation implies that no spinning reserve is generated on the Senelec grid and that grid inertia is minimal. The grid conditions are as follows:

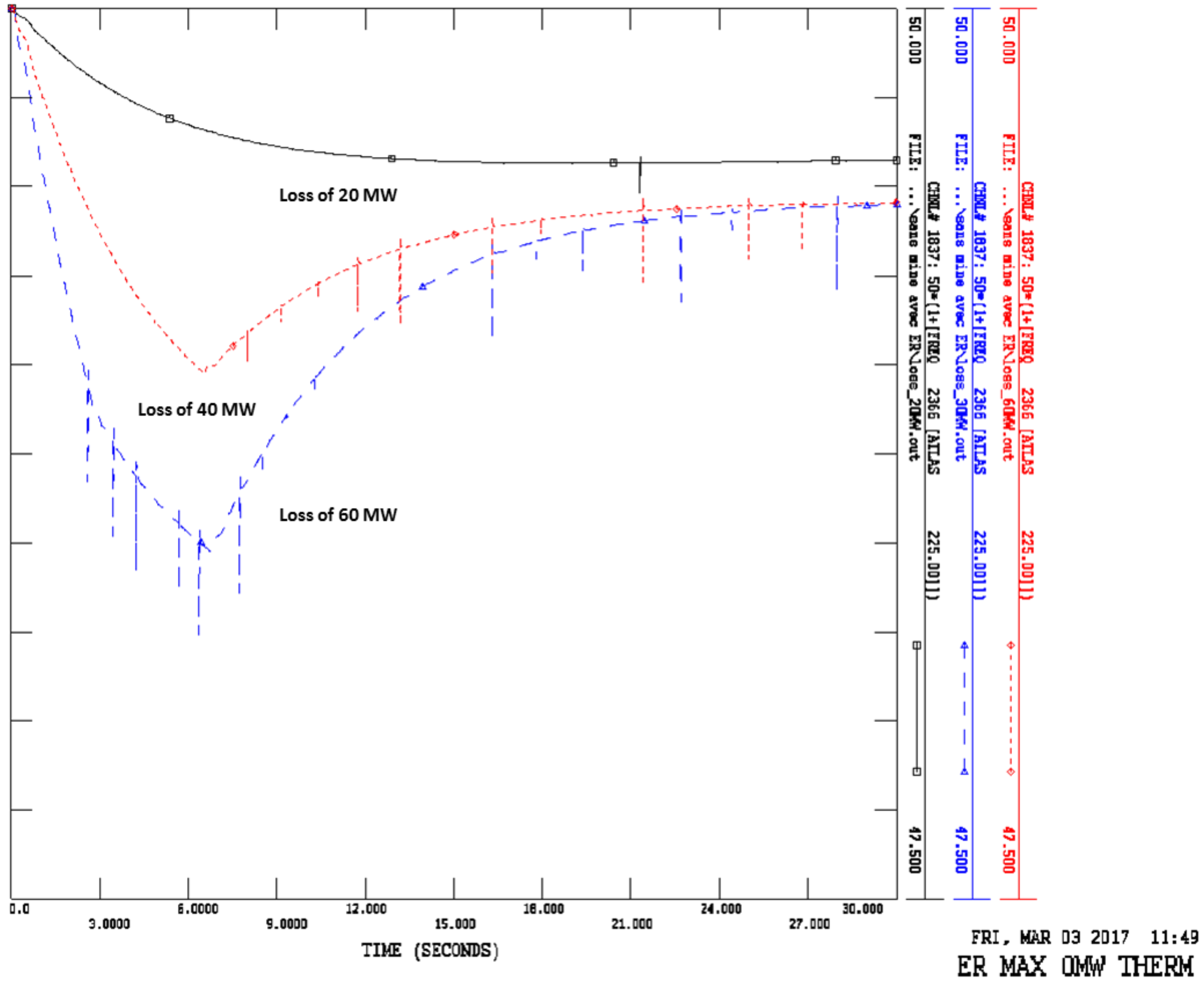
Table 4-75: 2022 off-peak load, with IRE, without thermal generation except coal, with importing

2022 OFF-PEAK LOAD, WITH IRE, WITHOUT THERMAL GENERATION EXCEPT COAL, WITH IMPORTING									
485 MW of generation (by technology in MW)					Load (MW)	Losses (MW)	Import: 136 MW		
Solar	Wind	Coal	Other Thermal	Sync. Res.			OMVS	OMVG	SOMELEC
214	72	202	0	0	610.2	11	136	0	0

Frequency stability study

Here, we assess the impact on frequency stability resulting from the elimination of the Senelec grid's spinning reserve and relying strictly on the neighboring grid to stabilize the frequency of the interconnected network. Considering only IREs and the contribution of the OMVS complex to feed the load, the Senelec grid therefore finds itself without thermal generation and, therefore, with very low inertia and no available spinning reserve from coal-fired power plants. Only a spinning reserve contribution initially set at 3% of installed capacity, or about eight megawatts from the OMVS complex, provides some frequency stability.

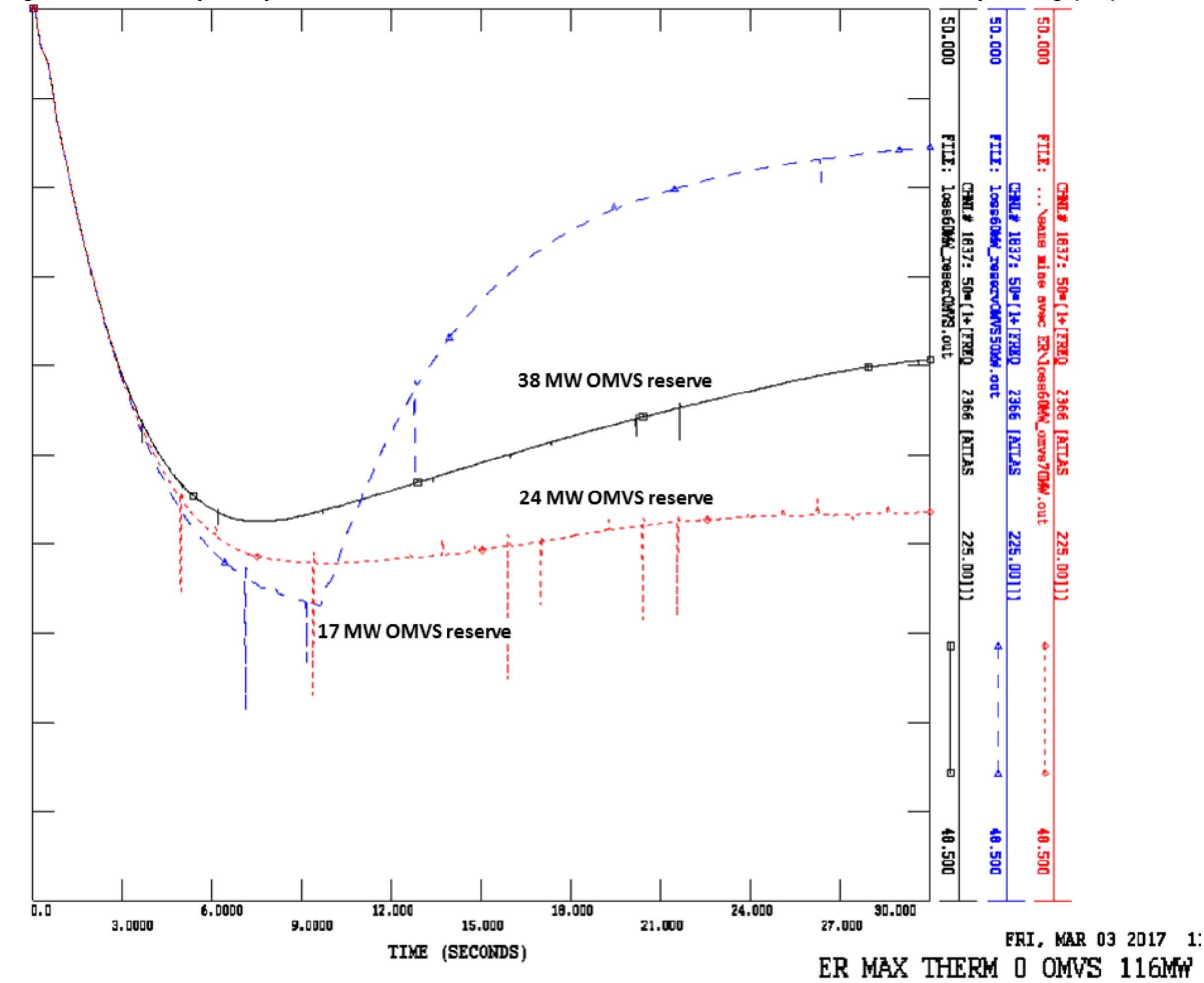
Figure 4-25: Frequency behavior for different power facility losses, without thermal generation (Hz)



In this situation, we note a strong deterioration in the frequency behavior of the grid, while the maximum generation loss is only 20 MW without load shedding.

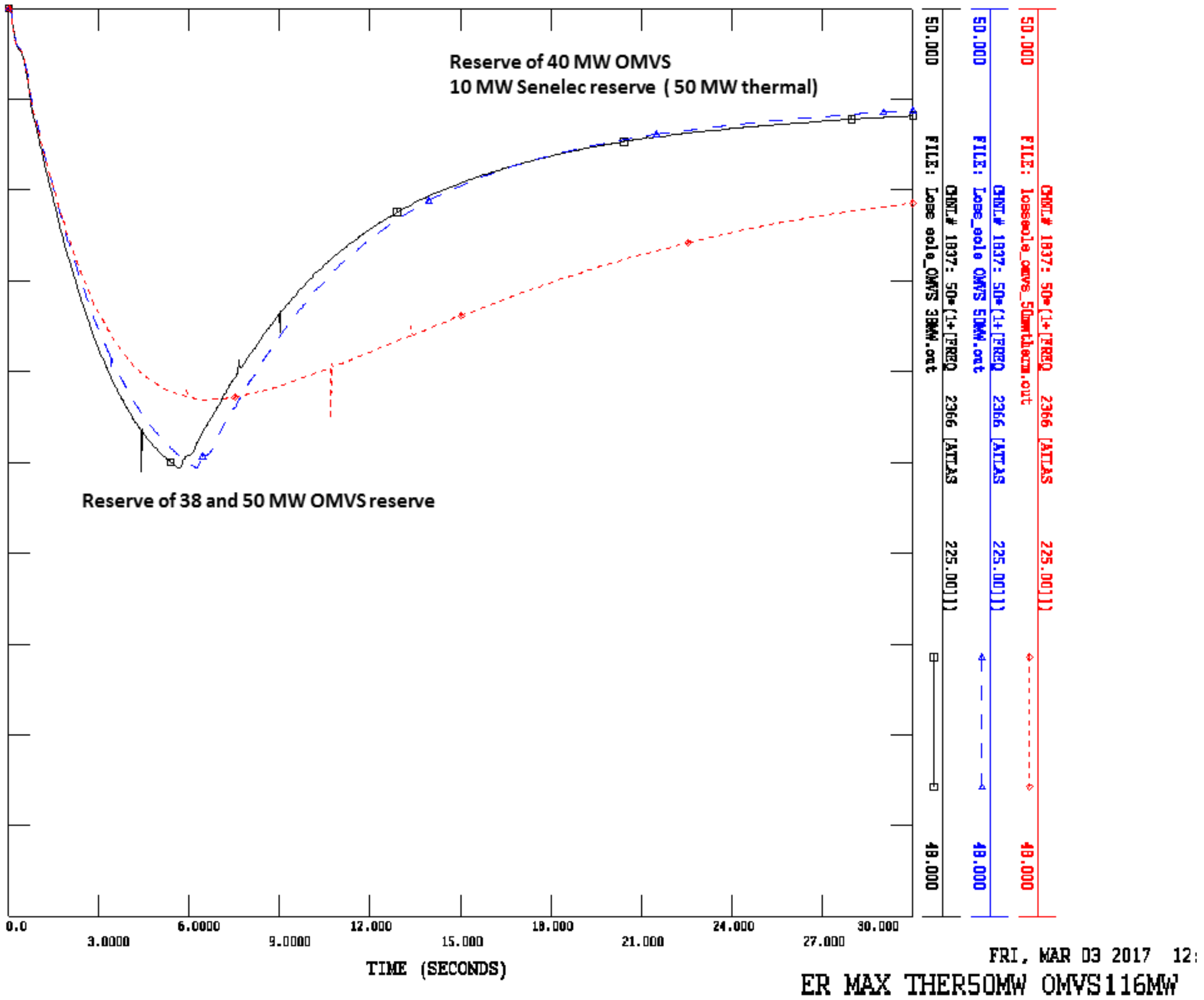
In the figure below, we have added a reserve capacity contribution from the OMVS complex. Thus, this time we can increase the generation loss without load shedding.

Figure 4-26: Frequency behavior for a loss of 60 MW without thermal but with importing (Hz)



With a minimum reserve of 24 MW from OMVS, we can lose up to a maximum of 60 MW without hitting the underfrequency load shedding threshold. Nevertheless, it remains lower than the second largest generation loss, that of the wind power plant (72 MW).

Figure 4-27: Frequency behavior for the loss of the wind farm, without thermal but with OMVS imports (Hz)



We still see underfrequency load shedding on the loss of the 72-MW wind farm, despite an increase in the OMVS reserve. The response time of the power plants is too slow to offset the more pronounced frequency drop. It is therefore necessary to have a minimum reserve on the Senelec network to prevent load shedding on the loss of the wind farm. Hence, minimum generation of 90 MW to obtain a minimum of 10 MW reserve is sufficient to avoid load shedding on the loss of the wind farm.

To achieve the optimal 10 MW reserve, the C6 or C7 power plants must generate at full capacity, i.e., around 90 MW. In this case, we obtain the following report:

Grid condition with IRE at its maximum.

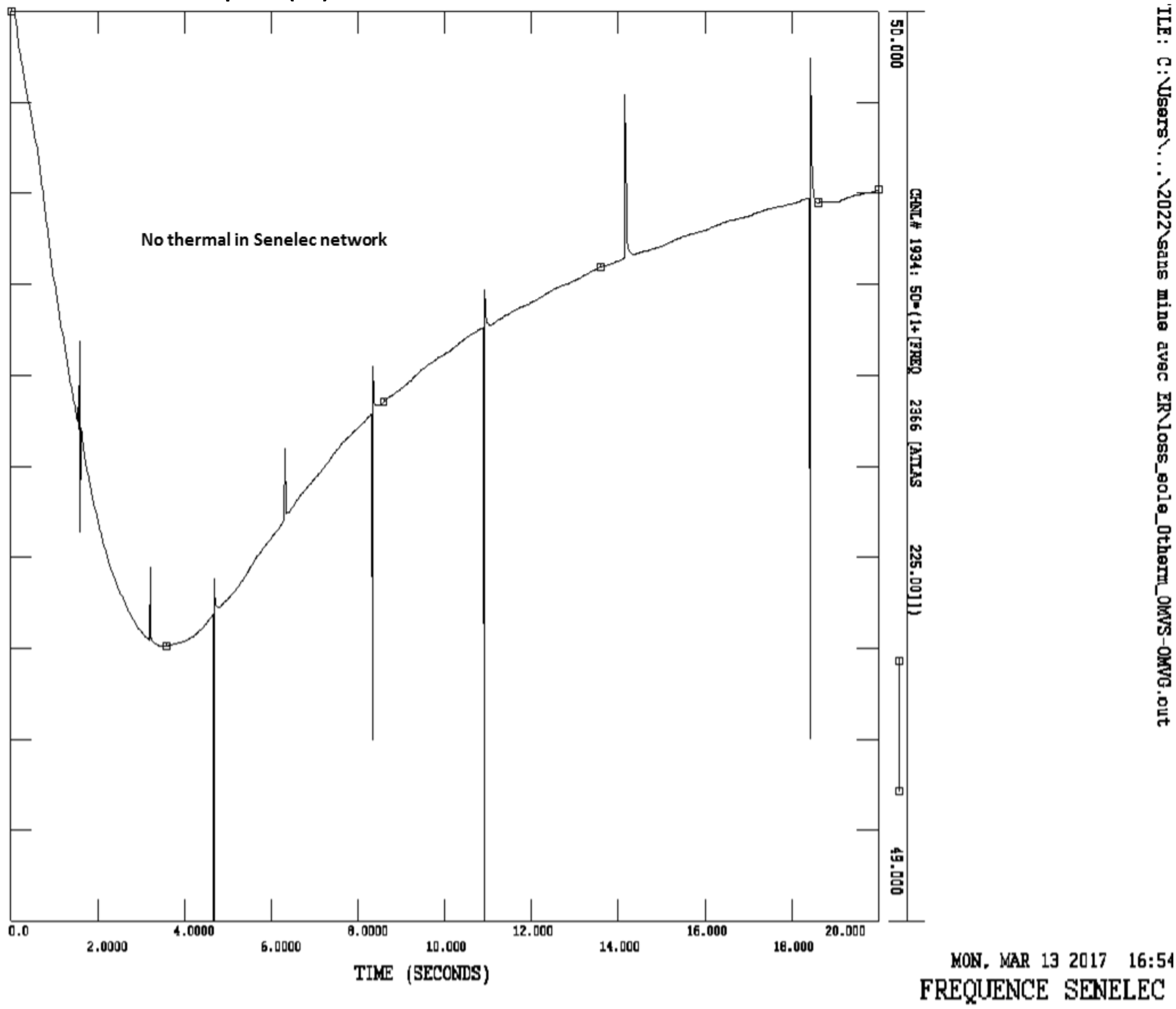
Table 4-76: 2022 off-peak load, with IRE, without thermal generation except coal, with importing

2022 OFF-PEAK LOAD, WITH IRE, WITHOUT THERMAL GENERATION EXCEPT COAL, WITH IMPORTING					
Load	Generation (MW)			Import	MW remaining for thermal
MW	Solar	Wind	Coal	MW	(load) - (gen + import)
620	214	72	115+90	116	13

Thus, in order to obtain the 10 MW reserve needed for the loss of the wind farm, more generation is needed on the Senelec grid. Either we remove 90 MW from the coal-fired power plant and replace it with diesel, which has a spinning reserve capacity, or reduce the solar power facilities by 90 MW – 13 MW = 77 MW. Once again, this is true if we consider a significant spinning reserve contribution (40 MW) from OMVS.

However, there is other potential contribution from the OMVG complex. Indeed, given a contribution that would be possible if the coal-fired power plant were shut down, the wind farm can be lost without load shedding, as shown in the next figure.

Figure 4-28: Frequency behavior for the loss of the 72 MW wind farm, without thermal but with OMVS and OMVG imports (Hz)



We conducted the same exercise, this time without imports from OMVS.

Grid condition with IRE at its maximum:

Table 4-77 : 2022 off-peak load, with renewable energy, without thermal except coal, without importing

2022 OFF-PEAK LOAD, WITH IRE, WITHOUT THERMAL EXCEPT COAL, WITHOUT IMPORTING					
Load	Generation (MW)			Import	MW remaining for thermal
MW	Solar	Wind	Coal	MW	(load) - (gen + import)
620*	214	72	115 +90	0	129

* Off-peak load with mines + losses

Only 129 MW of thermal power is lacking in order to get the 50 MW reserve needed for the loss of the wind farm.

To obtain this amount of reserve, however, the C6, C7, Malicounda, Contour, and IPP Tobene plants must be optimally connected to the grid, for a total of 420 MW. This is impossible without removing coal and reducing solar generation.

It is therefore necessary to reduce solar power facilities by 420 MW - 205 MW = 215 MW, that is to say no more solar, keeping only the wind farm. Once again, this is true if we do not consider a spinning reserve from OMVS, and that we want to cover the loss of the wind farm without load shedding. However, as soon as the thermal power plants are connected to the grid, grid inertia increases and improves the frequency behavior of the grid, which means that the reserve requirements decrease slightly, but still remain around 50 MW. Note that 41 MW of spinning reserve is also needed to offset the fluctuating capacity of the wind farm.

2028 GRID

For the 2028 grid, we limited the analysis to the most severe scenarios from the static study. Consequently, the first scenario without renewable energy is that in peak load condition without mines. The grid conditions are as follows:

Peak load without mines

Table 4-78: 2028 Peak load without mines or IRE

2028 PEAK LOAD, WITHOUT MINES OR IRE									
828 MW of generation (by technology in MW)					Load (MW)	Losses (MW)	Import: 560.6 MW		
							OMVS	OMVG	SOMELEC
Solar	Wind	Coal	Other Thermal	Sync. Res.					
0	0	203	625	20	1344.8	44.2	190.5	341.9	28.3

Table 4-79: Generation plan: peak load, without mines or renewable energy

GENERATION PLAN: PEAK LOAD, WITHOUT MINES OR RENEWABLE ENERGY					
Bus Num	Bus Name	Id	Pgen	Pmax	Reserve
7301	CBELAIR1G 15.000	1	32.152	34.152	2
7302	CDB401 6.6000	1	0	0	0
7304	CDB403 6.6000	1	0	0	0
7307	KOUNO 1G 15.000	1	7.92	8	0
7308	CDB402 6.6000	1	0	0	0
7309	CDB404-5 11.000	1	0	0	0
7310	CDB301 12.500	1	0	0	0
7311	CAP DB CG 11.000	1	0	0	0
7312	CDB303 12.500	1	0	0	0
7313	CMALICOU 15.000	1	48.14	48.24	0
7314	CMALICOU 15.000	2	64.22	64.32	0
7320	BELAIR4G 11.000	1	0	0	0
7323	BELAIR2G 15.000	1	32.152	34.152	2
7324	BELAIR3G 15.000	1	32.152	34.152	2
7332	IPPAFRI 33.000	2	0	0	0
7334	CDB_TAG2 11.000	1	0	0	0
7335	KAHON 1 15.000	1	0	0	0
7336	CIPPAFICA 33.000	1	89.82	90	0
7337	IPPAFRI 33.000	1	0	0	0
7338	CSENDOU 11.000	1	112.8943	114.8	0
7339	SENDOU 11.000	2	0	0	0
7340	IPPAFRI 33.000	2	0	0	0
7341	CNDIAYE 11.000	1	0	0	0
7341	CNDIAYE 11.000	2	0	0	0
7348	TP_70MW 15.000	1	51.18439	51.4416	0
7349	CG EXT 11.000	1	33.32	34.32	1
7370	IPPHFODUAL 15.000	1	0	0	0
7371	IPPHFODUAL 15.000	1	0	0	0
7372	IPPCCGT_26 15.000	1	47	50	3
7373	IPPCCGT_26 15.000	1	47	50	3
7374	IPPCCGT_27 15.000	1	47	50	3
7375	IPPCCGT_27 15.000	1	47	50	3
7826	EOLSN 0.6500	1	0	0	0
7897	EOL_1 0.7000	1	0	0	0
8742	SNIAKHAR 11.000	1	0	0	0
8743	SDIASS 11.000	1	0	0	0
8744	SKAHONE 11.000	1	0	0	0
8745	SMEKH 11.000	1	0	0	0
8745	SMEKH 11.000	1	0	0	0
8746	SBOKHOL 11.000	1	0	0	0
8747	STOUBA 11.000	1	0	0	0

GENERATION PLAN: PEAK LOAD, WITHOUT MINES OR RENEWABLE ENERGY					
Bus Num	Bus Name	Id	Pgen	Pmax	Reserve
8748	SMALICOU 11.000	1	0	0	0
8793	SOL_6 11.000	1	0	0	0
73051	KAHON1G 15.000	1	17.1	17.2	0
73052	KAHON2G 15.000	2	34.3	34.4	0
73053	KAHON3G 15.000	3	34.3	34.4	0
73481	TP_70MW 15.000	2	50.12	51.12	1
	Total(MW)		827.7747	850.698	20.0000

For this scenario, we used a target reserve that is close to Senelec's obligation to produce about 16 MW of spinning reserve, as agreed with WAPP for an interconnected network.

Peak load without mines and maximum import

The second scenario examined is a variant of the previous scenario and includes maximum import of 600 MW, without exceeding the thermal capacity of the lines after contingency. The grid conditions are as follows:

Table 4-80: 2028 peak load, without mines or renewable energy and with maximum import

2028 PEAK LOAD, WITHOUT MINES OR RENEWABLE ENERGY AND WITH MAXIMUM IMPORT									
789 MW of generation (by technology in MW)					Load (MW)	Losses (MW)	Import: 601.2 MW		
							OMVS	OMVG	SOMELEC
Solar	Wind	Coal	Other Thermal	Sync. Res.					
0	0	201	588	50	1345	45	203.5	369	28.7

Table 4-81: Generation plan: Peak load, without mines or IRE and maximum import

GENERATION PLAN: PEAK LOAD, WITHOUT MINES OR IRE AND MAXIMUM IMPORT					
Bus Num	Bus Name	Id	Pgen	Pmax	Reserve
7301	CBELAIR1G 15.000	1	30.902	34.152	3.25
7302	CDB401 6.6000	1	0	0	0
7304	CDB403 6.6000	1	0	0	0
7307	KOUNO 1G 15.000	1	0	0	0
7308	CDB402 6.6000	1	0	0	0
7309	CDB404-5 11.000	1	31.13669	31.4512	0
7310	CDB301 12.500	1	0	0	0
7311	CAP DB CG 11.000	1	0	0	0
7312	CDB303 12.500	1	0	0	0
7313	CMALICOU 15.000	1	46.24	48.24	2
7314	CMALICOU 15.000	2	60.32	64.32	4
7320	BELAIR4G 11.000	1	0	0	0
7323	BELAIR2G 15.000	1	30.902	34.152	3.25
7324	BELAIR3G 15.000	1	31.152	34.152	3
7332	IPPAFRI 33.000	2	0	0	0
7334	CDB_TAG2 11.000	1	0	0	0
7335	KAHON 1 15.000	1	0	0	0

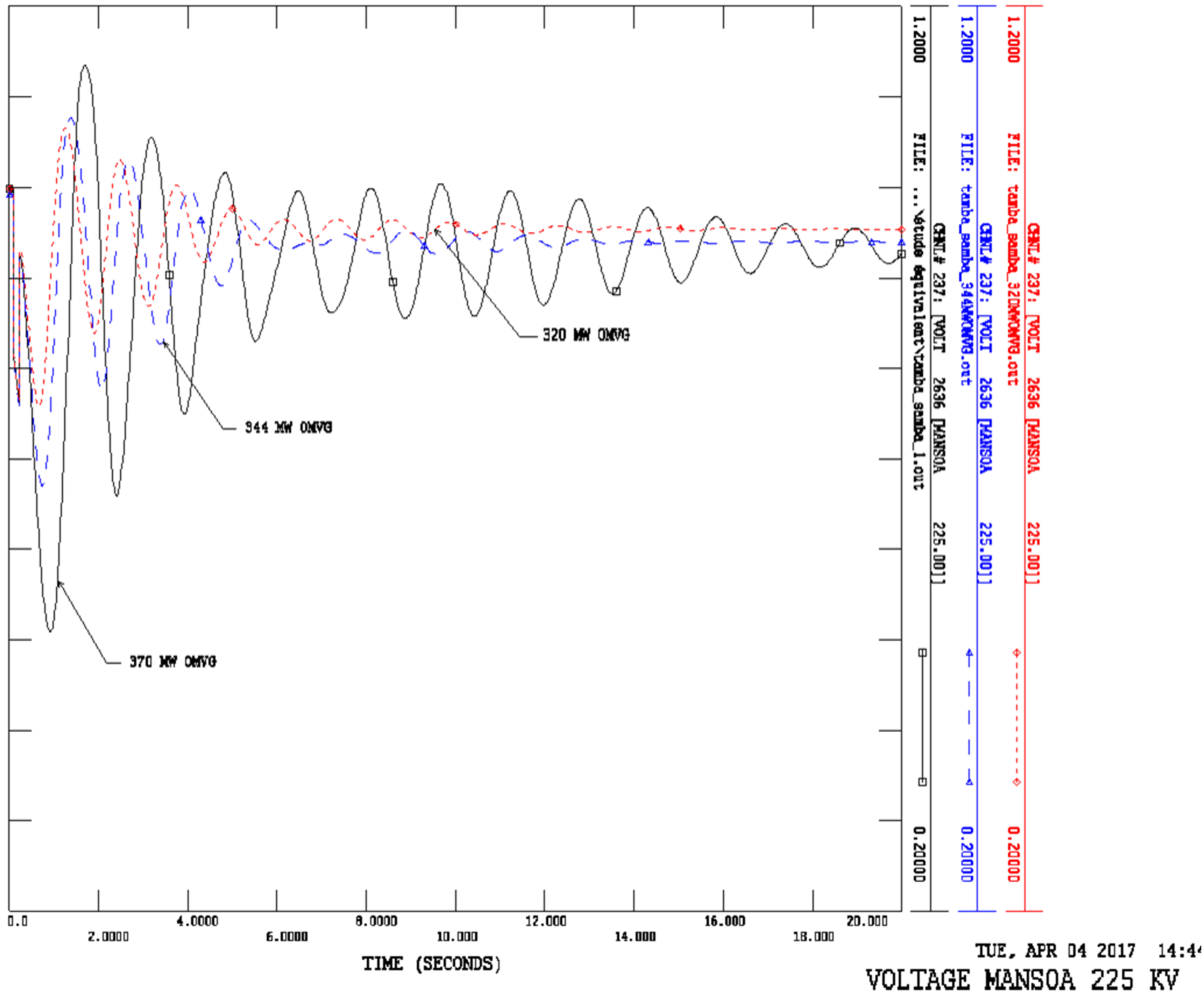
GENERATION PLAN: PEAK LOAD, WITHOUT MINES OR IRE AND MAXIMUM IMPORT					
Bus Num	Bus Name	Id	Pgen	Pmax	Reserve
7336	CIPPAFICA 33.000	1	89.82	90	0
7337	IPPAFRI 33.000	1	0	0	0
7338	CSENDOU 11.000	1	111	115	0
7339	SENDOU 11.000	2	0	0	0
7340	IPPAFRI 33.000	2	0	0	0
7341	CNDIAYE 11.000	1	0	0	0
7341	CNDIAYE 11.000	2	0	0	0
7348	TP_70MW 15.000	1	46.4416	51.4416	5
7349	CG EXT 11.000	1	30.32	34.32	4
7370	IPPHFODUAL 15.000	1	0	0	0
7371	IPPHFODUAL 15.000	1	0	0	0
7372	IPPCCGT_26 15.000	1	46	50	4
7373	IPPCCGT_26 15.000	1	46	50	4
7374	IPPCCGT_27 15.000	1	46	50	4
7375	IPPCCGT_27 15.000	1	46	50	4
7826	EOLSN 0.6500	1	0	0	0
7897	EOL_1 0.7000	1	0	0	0
8742	SNIAKHAR 11.000	1	0	0	0
8743	SDIASS 11.000	1	0	0	0
8744	SKAHONE 11.000	1	0	0	0
8745	SMEKH 11.000	1	0	0	0
8745	SMEKH 11.000	1	0	0	0
8746	SBOKHOL 11.000	1	0	0	0
8747	STOUBA 11.000	1	0	0	0
8748	SMALICOU 11.000	1	0	0	0
8793	SOL_6 11.000	1	0	0	0
73051	KAHON1G 15.000	1	15.7	17.2	1.5
73052	KAHON2G 15.000	2	15.8	17.3	1.5
73053	KAHON3G 15.000	3	15.7	17.2	1.5
73481	TP_70MW 15.000	2	49.315	54.315	5
	Total (MW)		788.7493	843.244	50.0

As previously indicated, we set the spinning reserve at 50 MW, even though the obligation is for 16 MW.

Stability study

We simulated the list of normal contingencies for the peak load and maximum import scenario variant. The behavior of the interconnected network demonstrated a stable and damped voltage and frequency response. The overvoltages observed have always been less than 1.05 pu, and the voltages at the end of the simulation are within the acceptable range of ± 10% of the nominal voltage. As with the 2022 grid, the loops created by the OMVG complex and with OMVS significantly improve the behavior of the Senelec grid. Thus, the issues observed in 2019 with the loss of the Kayes line to Bakel are completed eliminated by the loopback with the OMVG loop in the south. Furthermore, the loss of the Tambacounda line to Sambangalou remains the most severe event, as shown in the following figure:

Figure 4-29: Voltage behavior on the loss of Tambacounda to Sambangalou



To achieve acceptable grid behavior, importing from OMVG must be reduced by 50 MW in the maximum imports scenario determined by the static study.

With renewable energy, without mines or thermal

In this scenario, we introduce IRE power plants to replace thermal power plants, still without mines and at an average level of import. If the sole coal-fired plant is kept, there can be no contribution of spinning reserve from the Senelec grid. The grid conditions are as follows:

Table 4-82: 2028 Off-peak load, without mines, without thermal and with renewable energy

2028 OFF-PEAK LOAD, WITHOUT MINES, WITHOUT THERMAL AND WITH RENEWABLE ENERGY									
450 MW of generation (by technology in MW)					Load (MW)	Losses (MW)	Import: 273 MW		
Solar	Wind	Coal	Other Thermal	Sync. Res.			OMVS	OMVG	SOMELEC
254	95	105 *	0	0	673	14	101	108	28

*Without mines, the Africa IPP power plant is not planned. Thus, only the Sendou power plant is considered.

Table 4-83: Generation plan: Off-peak load, without mines, without thermal and with renewable energy

GENERATION PLAN: OFF-PEAK LOAD, WITHOUT MINES, WITHOUT THERMAL AND WITH RENEWABLE ENERGY					
Bus Num	Bus Name	Id	Pgen	Pmax	Reserve
7301	CBELAIR1G 15.000	1	0	0	0
7302	CDB401 6.6000	1	0	0	0
7304	CDB403 6.6000	1	0	0	0
7307	KOUNO 1G 15.000	1	0	0	0
7308	CDB402 6.6000	1	0	0	0
7309	CDB404-5 11.000	1	0	0	0
7310	CDB301 12.500	1	0	0	0
7311	CAP DB CG 11.000	1	0	0	0
7312	CDB303 12.500	1	0	0	0
7313	CMALICOU 15.000	1	0	0	0
7314	CMALICOU 15.000	2	0	0	0
7320	BELAIR4G 11.000	1	0	0	0
7323	BELAIR2G 15.000	1	0	0	0
7324	BELAIR3G 15.000	1	0	0	0
7332	IPPAFRI 33.000	2	0	0	0
7334	CDB_TAG2 11.000	1	0	0	0
7335	KAHON 1 15.000	1	0	0	0
7336	CIPPAFICA 33.000	1	0	0	0
7337	IPPAFRI 33.000	1	0	0	0
7338	CSENDOU 11.000	1	105	115	0
7339	SENDOU 11.000	2	0	0	0
7340	IPPAFRI 33.000	2	0	0	0
7341	CNDIAYE 11.000	1	0	0	0
7341	CNDIAYE 11.000	2	0	0	0
7348	TP_70MW 15.000	1	0	0	0
7349	CG EXT 11.000	1	0	0	0

GENERATION PLAN: OFF-PEAK LOAD, WITHOUT MINES, WITHOUT THERMAL AND WITH RENEWABLE ENERGY					
Bus Num	Bus Name	Id	Pgen	Pmax	Reserve
7370	IPPHFODUAL 15.000	1	0	0	0
7371	IPPHFODUAL 15.000	1	0	0	0
7372	IPPCCGT_26 15.000	1	0	0	0
7373	IPPCCGT_26 15.000	1	0	0	0
7374	IPPCCGT_27 15.000	1	0	0	0
7375	IPPCCGT_27 15.000	1	0	0	0
7826	EOLSN 0.6500	1	72	72	0
7897	EOL_1 0.7000	1	23.5	23.8	0
8742	SNIAKHAR 11.000	1	46.53	47	0
8743	SDIASS 11.000	1	14.86	15	0
8744	SKAHONE 11.000	1	29.72	30	0
8745	SMEKH 11.000	1	29.21	30	0
8745	SMEKH 11.000	1	29.21	30	0
8746	SBOKHOL 11.000	1	19.80	20	0
8747	STOUBA 11.000	1	22.77	23	0
8748	SMALICOU 11.000	1	19.80	20	0
8793	SOL_6 11.000	1	40	40	0
73051	KAHON1G 15.000	1	0	0	0
73052	KAHON2G 15.000	2	0	0	0
73053	KAHON3G 15.000	3	0	0	0
73481	TP_70MW 15.000	2	0	0	0
	Total (MW)		452	462	0

Therefore, in this scenario there is no spinning reserve from Senelec, and only the Sendou power plant contributes to the Senelec grid inertia.

Stability study

We simulated the list of normal contingencies for the scenario with IRE. The behavior of the interconnected network demonstrated a stable and damped voltage and frequency response.

We also evaluated the frequency behavior of the grid. This makes it possible to determine the spinning reserve requirement and to confirm that the WAPP recommendation is satisfactory, i.e., that a spinning reserve of 16 MW is sufficient considering contributions from neighboring grids. Nevertheless, we checked the frequency stability in a situation where there is no spinning reserve on the Senelec grid. Once again, the simulated contingencies were limited to generation losses due to the loss of a single grid component.

The figures below show the frequency of the Senelec grid in 2028 following the loss of the Sendou power plant and the 72-MW wind farm. Despite the lack of reserve and inertia on the Senelec grid, the inertia contribution of neighboring grids is enough to avoid the load shedding threshold for recovery to nominal frequency. The contribution of neighboring grids exceeds 3% of the initial installed capacity in our reserve assumptions.

Figure 4-30: Frequency behavior on the loss of the Sendou power plant (Hz)

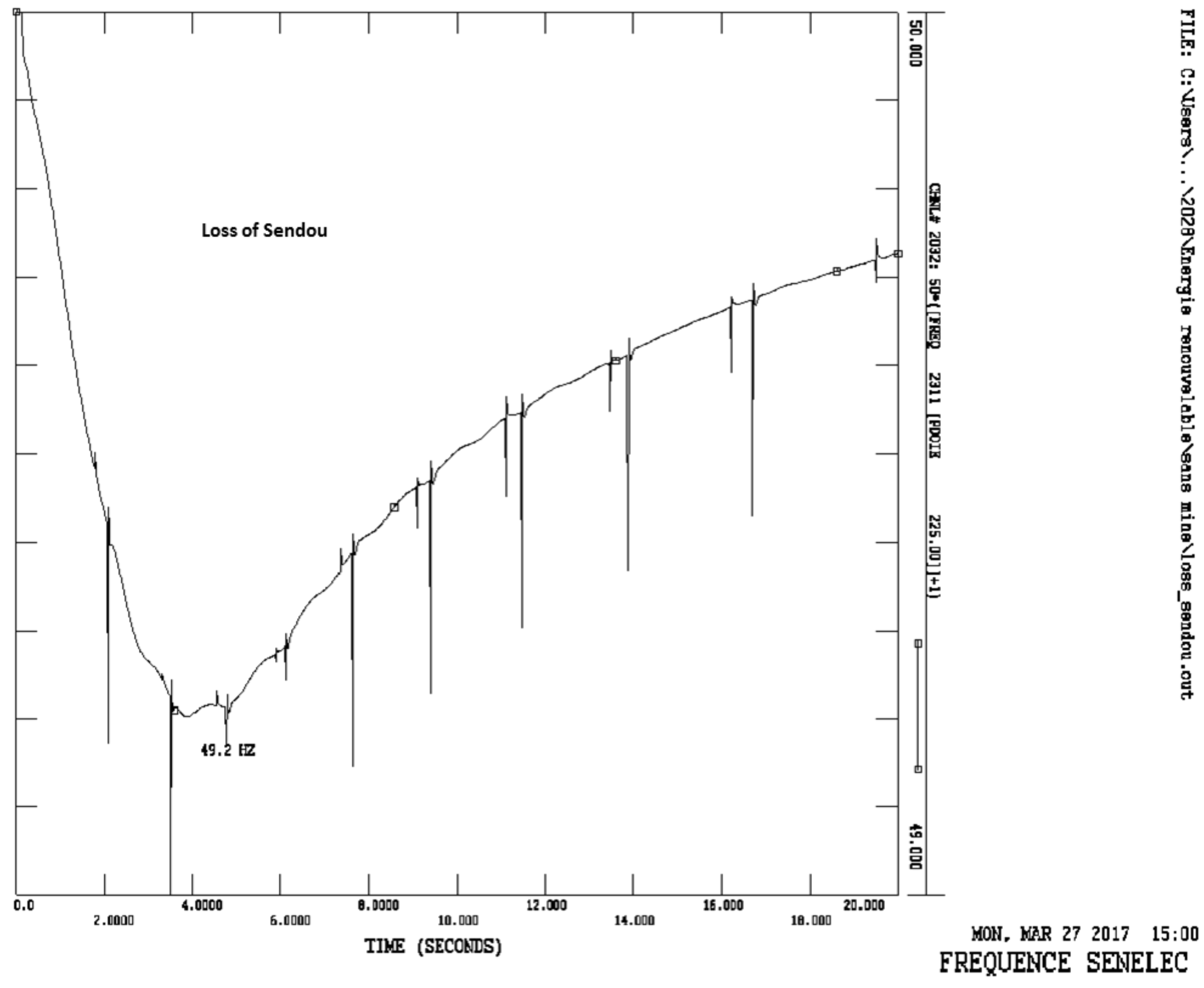
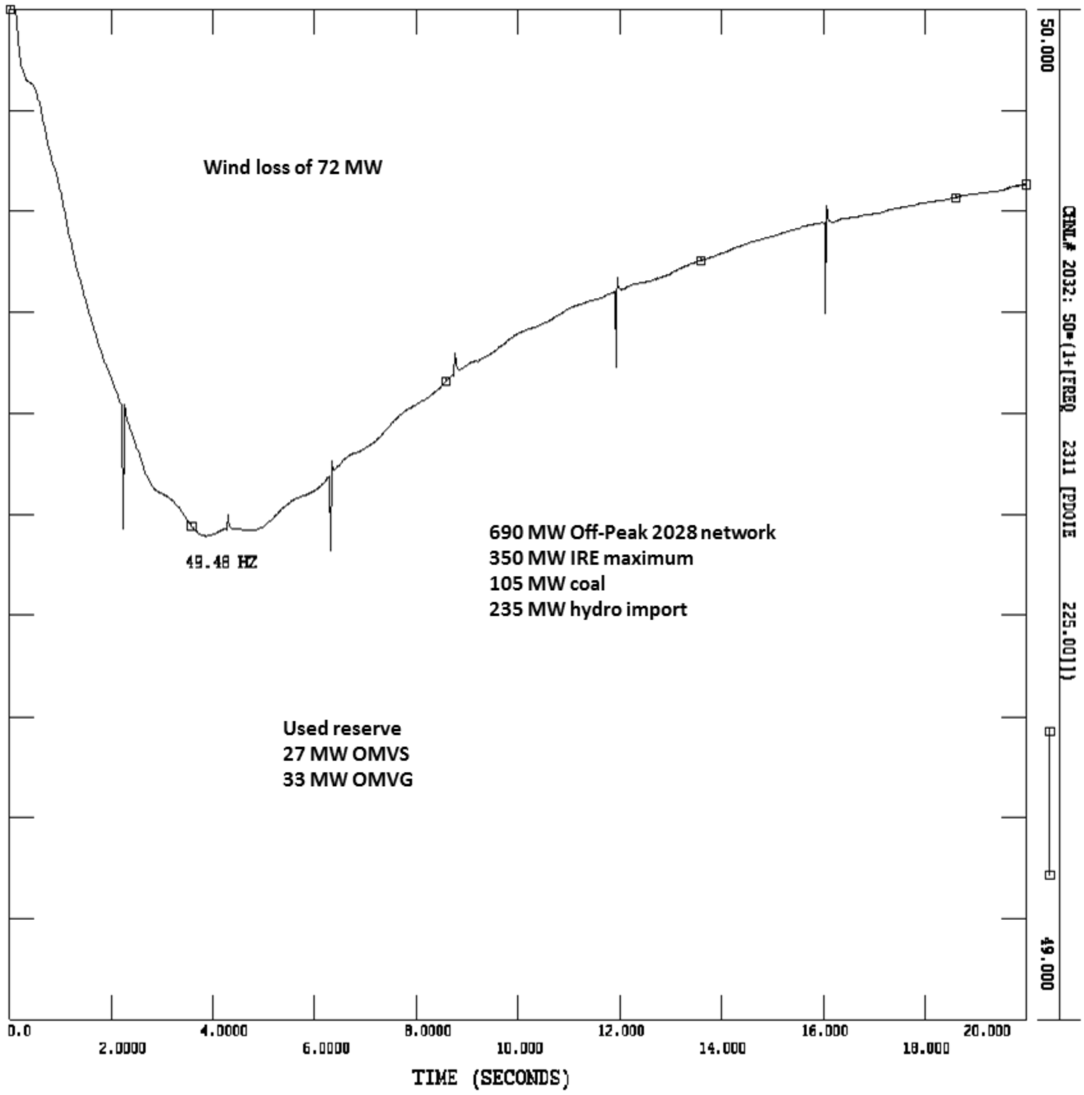


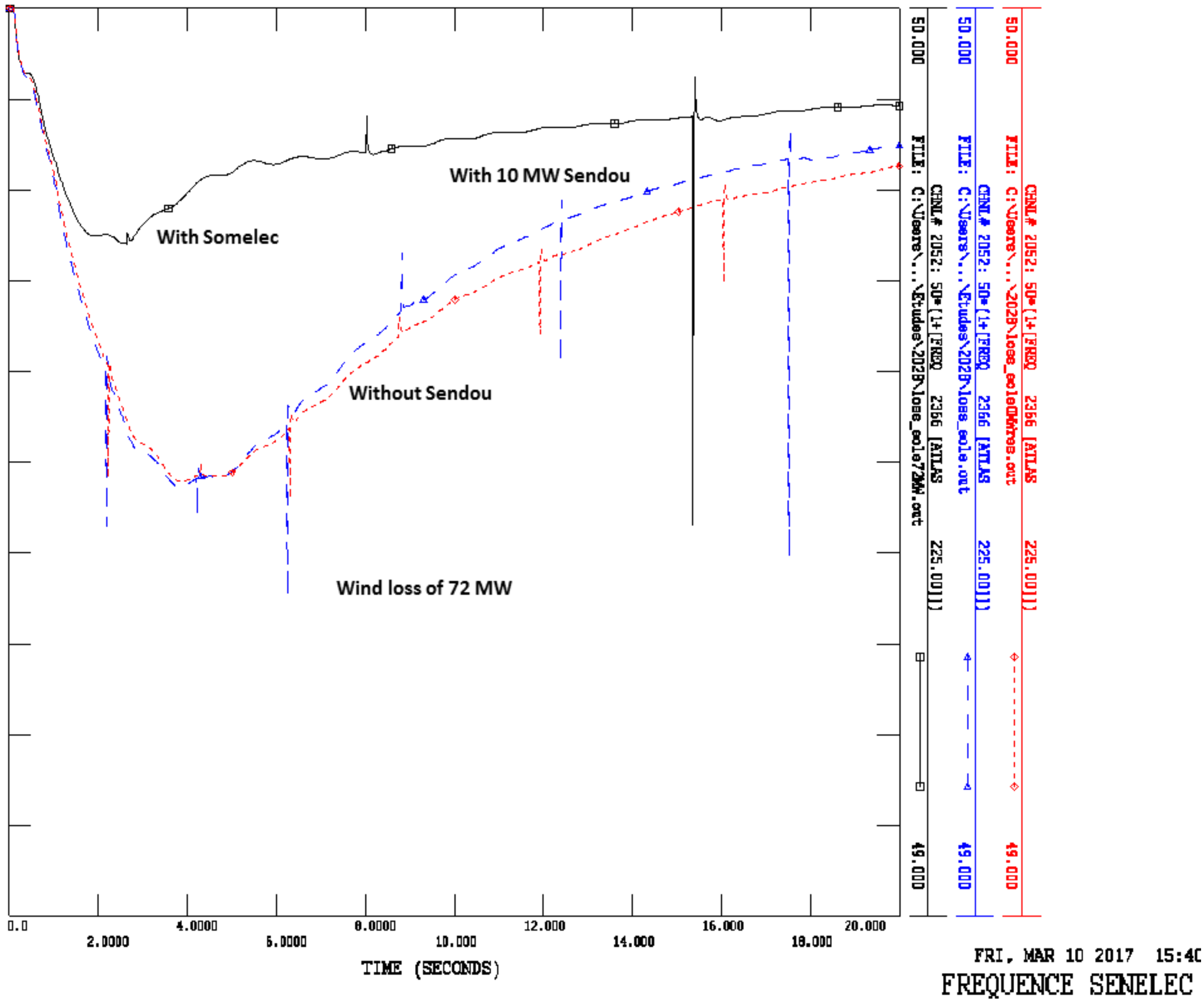
Figure 4-31: Frequency behavior on the loss of the Taïba wind farm (Hz)



In both cases, we can see that the inertia on neighboring grids is enough to offset the frequency drop.

The figure below shows that the impact of adding reserve from the coal-fired power plant does not eliminate the risk of hitting the load shedding threshold due to slow generation of additional power. Depending on the time constants used for the simulation of the coal-fired plant speed regulator, the effect of this additional reserve is observed only after about seven seconds. Furthermore, if we consider a more realistic rate of rise of about one megawatt per minute, the effect of this reserve would be observable only much later, namely a few minutes.

Figure 4-32: Frequency behavior on the loss of the Taïba wind farm with and without the Sendou power plant (Hz)



Another important observation is that despite the absence of inertia caused by the withdrawal of the only power plant on the Senelec grid, i.e. the Sendou power plant, there is no notable impact due to the significant contribution of inertia from neighboring grids. Consequently, thanks to the interconnection links, there is no obligation to maintain a minimum amount of inertia on the Senelec grid. However, a minimum spinning reserve is required to regulate frequency in relation to fluctuations with this type of energy, which is 54 MW caused by the wind farm. Moreover, the 10-minute reserve needs to be activated to restore nominal frequency.

Recall that voltage is relatively well controlled by IRE power plants. Therefore, for all the simulated contingencies, we obtain a voltage after contingency that is within acceptable ranges.

4.2.6 OBSERVATIONS

For all scenarios and variants, we simulated the contingency list to ensure a stable and damped grid response within acceptable voltage and frequency ranges.

Initially, the interconnected network is required to have a spinning reserve equivalent to the capacity fluctuation observed at wind or solar power plants in order to regulate frequency correctly. These potential maximum fluctuations are as follows:

- 41 MW, or 70% of the installed capacity of the largest solar power facility (Mekhe 2 x 29.5 MW)
- 54 MW, or 35% of the installed capacity of the largest wind farm

This is the case for 2022 and 2028. For 2019, with a 103.5 MW wind farm, the fluctuation would instead be 35 MW.

Throughout the exercise, we validated whether this spinning reserve is enough to comply with the frequency criterion.

2019 RECOMMENDATIONS

We simulated the list of normal contingencies for the peak load grid. The behavior of the interconnected network demonstrated a stable and damped voltage and frequency response, except for one event, namely the loss of interconnection with the OMVS complex.

- Despite a spinning reserve on the Senelec 40 MW grid, maximum imports from OMVS must be 50 MW to prevent load shedding as a result of the loss of import.

We observed significant oscillations, particularly for contingencies at the Tobene substation and, although damped, the use of stabilizers could significantly improve the performance of the Senelec grid.

Frequency criterion:

IRE without coal:

- There is insufficient reserve to offset the loss of Sendou or the wind farm; thermal must be increased by reducing imports.

IRE without importing or coal, providing a 10-MW reserve:

- The maximum generation loss is 30 MW; therefore, there is insufficient reserve for the loss of the largest generation, namely the 47 MW wind farm.

IRE reduced by 53% without importing or coal, providing a 21-MW reserve:

- The 21 MW reserve is sufficient to offset the loss of the second largest generation, the 47 MW wind farm, but is still not enough to offset fluctuations.
- Apart from the Sendou power plant, reducing the size of the generators to a maximum of 30 MW would make this scenario acceptable.

IRE reduced by 62% without importing or coal, providing a 30-MW reserve:

- A drastic reduction of IRE is required to meet the frequency criterion, and an additional reduction of 19%, therefore 81% of total IRE, is required to regulate frequency correctly in response to fluctuating IRE capacity.

Summary for 2019

Table 4-84: 2019: Synchronous reserves required for different power generation losses

2019: SYNCHRONOUS RESERVES REQUIRED FOR DIFFERENT POWER GENERATION LOSSES			
Max. Generation Loss (MW)	Reserve (MW)		Maximum Solar Facility (MW)
	synchronous	fluctuation	
115	70	-	Impossible
-	-	35	40
47	30	-	82
30	20	20	100

2022 RECOMMENDATIONS

Peak grid, with and without mines

We simulated the list of normal contingencies for the two peak load grids with and without mines; the behavior of the interconnected network demonstrated a stable and damped response within acceptable voltage and frequency ranges. Some events are more severe than others, but in general, the events simulated in the scenario without mines proved to be the most severe. The loops created by the OMVG complex and with OMVS significantly improve the behavior of the Senelec grid. However, for the scenario with maximum import and without the mines determined by the static study, the loss of the Tambacounda line to Sambangalou has a major impact, resulting in the loss of synchronism of the Sambangalou power plant.

Therefore, the import limit for OMVG is not thermal but voltage related, and is limited to 290 MW out of a total of 447 MW imported by Senelec.

Frequency criterion:

Loss of Sendou (115 MW)

- 70 MW spinning reserve is required. This level of spinning reserve can be achieved without an IRE power plant. However, it would be more appropriate to use remote load shedding to restore nominal frequency for this contingency.
- Loss of 48 MW: No spinning reserve is required for this level of power generation loss.

With IRE, with mines (zero megawatt import)

Loss of Sendou (115 MW)

- 54 MW of reserve is insufficient; the requirements are closer to 70 MW to prevent load shedding. For a grid with all the planned IRE having no spinning reserve capacity, it is therefore impossible to cover this power generation loss without remote load shedding.

Loss of the wind turbine (72 MW)

- 54 MW of reserve is sufficient (49.075 Hz) to prevent underfrequency load shedding. However, it remains difficult, if not impossible, to achieve this level of reserve if we only consider a contribution from the Senelec thermal power plant reserve. It is therefore necessary to impose the shutdown of the coal-fired power plant and eliminate all the solar power plants, and replace them with thermal power plants in order to achieve about 450 MW of generation from these power plants. This spinning reserve level is also required to regulate frequency fluctuations caused by the wind farm.

With IRE, with mines (import of 116 MW)

- The presence of the OMVS complex and its contribution to the spinning reserve makes it possible to reduce the need for reserves from the Senelec grid. Thus, considering a contribution of 40 MW of spinning reserve from the OMVS complex, the requirement is limited to 10 MW, i.e. 90 MW of thermal generation. However, to generate this reserve, the Africa Energy coal-fired power plant must be shut down or the number of solar facilities reduced by 90 MW (out of the 214 MW planned) and replaced with thermal power plants.
- It would be risky to rely on such a contribution from OMVS. Hence, a contribution of 12 MW (3% of 400 MW installed) would be more realistic and, by the same token, would require a significant reduction of solar power facilities to be replaced by thermal power plants.
- A contribution of 26 MW (3% of 883 MW installed) from OMVG out of the required 54 MW would avoid a significant reduction of solar power facilities.

With IRE, without mines

- Failure to include mines reduces the grid load by 138 MW and, consequently, power generation. However, according to the supply-and-demand balance report, the absence of mines delays Malicounda's commissioning by one year and eliminates the need for another 90 MW coal-fired power plant. As a result, the balance becomes roughly a 48 MW reduction of generation and, as a result, fewer thermal generators to generate the required reserve.
- In the OMVS complex no-import with mines scenario, we had 129 MW of available thermal generation to generate the reserve; without mines, we have only 81 MW to generate the same 54 MW spinning reserve requirement. Therefore, the presence of IRE must be further reduced, i.e., a reduction of 40 MW of the wind farm for a maximum of 32 MW. Obviously, a reduction of the wind farm reduces the power generation loss to be covered by as much and, consequently, the need for a spinning reserve.

Summary for 2022

Table 4-85: 2022: Synchronous reserves required for different power generation losses

2022: SYNCHRONOUS RESERVES REQUIRED FOR DIFFERENT POWER GENERATION LOSSES

Maximum Loss (MW)			Reserve (MW)	Reserve Requirement for Fluctuation (MW)	Solar Power Facility Maximum (MW)
Without RE	Senelec	OMVS	OMVG		
115	70	0	0	0	N/A
46	5	0	0	0	N/A
With RE					
20	0	0	0	54	214
60	0	24	0	54	214
72	0	24	26	54	214
72	10	40	0	54	137
72	54	0	0	54	0
With RE without mines					
72	54	0	0	54	32 wind*

* 32 MW wind farm out of the 72 MW planned.

2028 RECOMMENDATIONS

Peak grid without mines

We simulated the list of normal contingencies for the peak load scenario and maximum imports variant. The behavior of the interconnected network demonstrated a stable and damped voltage and frequency response within acceptable ranges. However, for the peak load scenario without mines and maximum imports of 600 MW determined by the static study, the loss of the Tambacounda line to Sambangalou has a major impact, and results in an insufficiently damped power oscillation. Therefore, as with the 2022 grid, the limit on OMVG imports is not thermal but voltage related. A 50 MW reduction in OMVS imports, limited to 320 MW out of a total of 600 MW in imports by Senelec, causes acceptable behavior of the interconnected network.

Frequency criterion:

Loss of Sendou (115 MW)

- With the minimum spinning reserve of 16 MW as required by the WAPP regulations, and even without reserve from the Senelec grid, the loss of Sendou, the largest generation loss, does not trigger load shedding. Thus, we meet the frequency criterion if the 10-minute reserve is activated to restore nominal frequency within 10 minutes.

With IRE

- With the use of IRE power plants, the only power plant on the Senelec grid, the Sendou plant, can be removed. We did not observe any significant impact, owing to the significant contribution of inertia from neighboring grids. Consequently, thanks to the interconnection links, there is no obligation to maintain a minimum amount of inertia on the Senelec grid. However, a minimum spinning reserve is required to regulate frequency in relation to the fluctuation of this type of energy, which is 54 MW, caused by the wind farm. The 10-minute reserve needs to be activated to restore nominal frequency.
- Voltage is relatively well controlled by IRE power plants. Therefore, for all the simulated contingencies, we observe a voltage after contingency that is within the acceptable ranges.

5. FINANCIAL ANALYSIS

5.1 FINANCIAL ANALYSIS OF THE SCENARIOS

The drafting of this investment plan includes a financial analysis to show the reader which of the different assumptions and scenarios will yield the lowest electricity cost.

Several scenarios will be examined in order to confirm which of the assumptions set out in previous reports offers SENELEC and the Senegalese government the best cost of generation according to a variety of factors.

The modeling will be based on the following scenarios:

1. **"Senelec with no decommissioning" scenario:** Senelec Master Plan as approved by the Council of Ministers in January 2017.
2. **"PATRP with no decommissioning" scenario:** using solar power according to the implementation timelines reviewed by PATRP.
3. **"PATRP with decommissioning" scenario:** using solar power according to the implementation timelines reviewed by PATRP and considering decommissioning of the least efficient generation units.

Furthermore, these scenarios will also include some sensitivity analyses calculated outside the scenarios to measure the financial impact of decisions as important as:

- Whether or not to accept load shedding as a management tool as a result of grid instability
- The impact of capacity curtailment on the cost of energy.

The general characteristics of the different scenarios are as follows:

- Each scenario will include mining demand since previous reports have established that this aspect is essential to the country's economic development and contributes to grid stability.
- The demand scenario applied to all models will be the baseline scenario since it is the scenario most likely to be encountered.
- After some thought, PATRP chose to limit the period analyzed in this report to 2017-2030 (instead of to 2035). Indeed, while the original terms of reference required offering options up to the PSE horizon, for comparison purposes we had to tie the main analysis to the Senelec scenario, which only covers the period 2017-2030.

The three scenarios show a different capacity level, and the basic assumptions of the Senelec scenario are different from the PATRP scenarios:

- PATRP with no decommissioning assumes, for example, that coal is not fully deployed and that more wind and less solar (IRE) is being used (energy generated by wind power is higher per MW of installed capacity than solar).
- Both PATRP scenarios use more hydroelectric and fewer fuel plants.
- The PATRP with decommissioning scenario takes into account the decommissioning of some of Senelec's least efficient units, among other things.

The description of the capacity scenarios is as follows:

Figure 5-1: Comparison of the 3 scenarios

			MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
			2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL
MODEL 1 Baseline scenario WITH MINES SENELEC plan	CES 1	Coal		115																		115
	Africa	Coal				90	180															270
	Malicounda	HFO Dual				120																120
	Additional power	TVGN									345	115		115	115	115						805
	Additional power	Hydro			48	35	164				70											317
	TOTAL																					1627
	Additional power	Solar	78	75	40		30	30	30													283
	Additional power	Wind		51.75	51.75	55.2																158.7
																					Total	2068.70

			MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
			2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL
MODEL 2 Baseline scenario WITH MINES PATRP plan without decommissioning	CES 1	Coal		115																		115
	Africa	Coal						90														90
	Malicounda	HFO Dual				120																120
	Additional power	Dual								120												120
	Additional power	CCGT										120	120			240		240		120	120	960
	Additional power	Hydro				83	103	61			70			118								435
	TOTAL																					1840
	Additional power	Solar	78				30	85					40					30				263
	Additional power	Wind		51.75	51.75	55.2							51.75					55.2				265.65
																					Total	2368.70

			MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
			2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL
MODEL 3 Baseline scenario WITH MINES PATRP plan with decommissioning	CES 1	Coal		115																		115
	Africa	Coal						90	90	90												270
	Malicounda	HFO Dual				120																120
	Additional power	Dual				120																120
	Additional power	CCGT										120	120			240		240		120	120	960
	Additional power	Hydro				83	103	61			70			118								435
	TOTAL																					1840
	Decommissioning						116		51													(167)
	Additional power	Solar																30				263
	Additional power	Wind		51.75	51.75	55.2							51.75					55.2				265.65
																					Total	2381.65

We of course know the costs of selling existing power plants, be they thermal (HFO, Diesel) or intermittent renewable energy (IRE).

In this part of our mandate, we will use technical and financial models to establish the following information:

- The energy produced per power plant annually
- Energy sales costs for each of the power plants
- Renewable energy curtailment costs per year (with a synchronous reserve) in the Senelec and PATRP scenarios
- Coal curtailment costs per year (with a synchronous reserve) in the Senelec and PATRP scenarios
- In the Senelec scenario, lost revenues from load shedding due to outages at coal-fired, solar and wind power plants without the synchronous reserve
- In the Senelec scenario, lost revenues from load shedding due to critical fluctuations at IRE plants without the synchronous reserve
- Lost revenues from the decision of large energy consumers not to connect to the grid

5.1.1 METHODOLOGY OF THE FINANCIAL ANALYSIS

RECOSTING

The calculations of each of the sensitivity tests will in some cases be included in the models for calculating the cost of energy throughout the period from 2017 to 2035. In order to compare the scenarios, we will calculate total future costs of each scenario in 2017 CFA francs.

As already explained, the results will be presented on an annual basis for the period 2017-2030, instead of the period used in the previous reports and initial objectives of the PSE, which included up to 2035.

Information on the capitalization calculation is the information currently available to the CRSE and was provided to us by Senelec. Thus, the discount rate used for each of the scenarios is 9.73%, according to the methodology outlined in Appendix **Error! Reference source not found.**.

CALCULATION METHOD APPLIED TO THE FINANCIAL ANALYSIS

PATRP calculated the operating costs of each of the power plants in Senegal's generation fleet using the data at its disposal. Where these data did not exist, assumptions were made based on the different operating costs listed in some of the reference documents. Appendix F.2 presents the method of calculating the cost per kWh used for each scenario.

The final result will therefore be a sum of the total costs incurred by Senelec to operate its generation fleet, including the plants it owns outright and those under a power purchase agreement.

IPP power plants are affected by constraints resulting from two factors:

- Take or Pay (ToP) or the obligation to pay for any energy that might be generated, regardless of whether it is accepted to the grid by Senelec or curtailed (as a result of Senelec's refusal to take power because of a surplus or technical incapacity).
    - This ToP involves the entire electricity sales tariff of renewable IPPs.
- The establishment of a capacity premium that must be paid provided the power plant is able to generate (is not in technical shutdown or an unscheduled shutdown due to a problem with the plant itself), whether or not this power is accepted to the grid by Senelec or curtailed (as a result of Senelec’s refusal to take power because of a surplus or a technical incapacity).
    - This capacity premium generally corresponds to the "fixed costs" portion of the business of a fuel-based plant, including both administrative and financing overhead, and operating and maintenance expenses.

DETERMINATION OF COSTS IN EACH SCENARIO

The costs used in this report will be determined based on the following information:

- Total fixed costs of Senelec power plants:
    - As assessed by PATRP based on data provided by our generation models and on the fixed and variable costs of existing power plants (Kounoune, Contour Global and Tobène)
        - Indexing factor on the operation and maintenance (O&M) portion, on a basis of 2% per year
        - Depreciation reduction of 5% per annum on the fixed premium portion
- Total fixed costs of thermal IPP power plants (HFO - Diesel - Coal - NG):
    - As confirmed by the IPP contracts and based on the minimum contractual capacity factor
        - Indexing factor on the O&M portion of 2% per year
- Total fixed costs for IPP IRE facilities:
    - As confirmed by the IPP contracts and based on the minimum contractual capacity factor
    - Based on the capacity projections of each of the power plants
- Variable costs of each thermal power plant according to its generation
    - Coal-fired power plants
    - Based on the construction cost point of the power plants as previously discussed in Section 3 (Figure 3-30)
    - Other thermal power plants:
        - Modulated according to the following priorities:
            - Synchronous reserve requirements:
                - The synchronous reserve requirement could force Senelec to use some power plants that are less cost-efficient but can provide reserve, at the expense of more cost-efficient plants that are unable to provide this type of reserve.
            - The economic priority of power plants in service:
                - Up to the maximum required by synchronous reserve requirements:
                    - Currently, the Contour Global IPP is first on the list of plants that can supply synchronous reserve.
                    - The various Senelec power plants that can supply synchronous reserve are then required on the grid.
                    - Finally, depending on demand, the other power plants (IPP and Senelec) are added to the grid.
        - Depending on their intended use
        - In both cases (synchronous reserve requirements and economic priority), this includes changing costs according to the forecasted change in O&M and fuel costs.

As soon as gas-fired plants start operating, they will naturally be designated as the synchronous reserve generator due to their generally lower cost and the fact that they can quickly ramp generation up or down with minimal loss of efficiency, and at a lower cost.

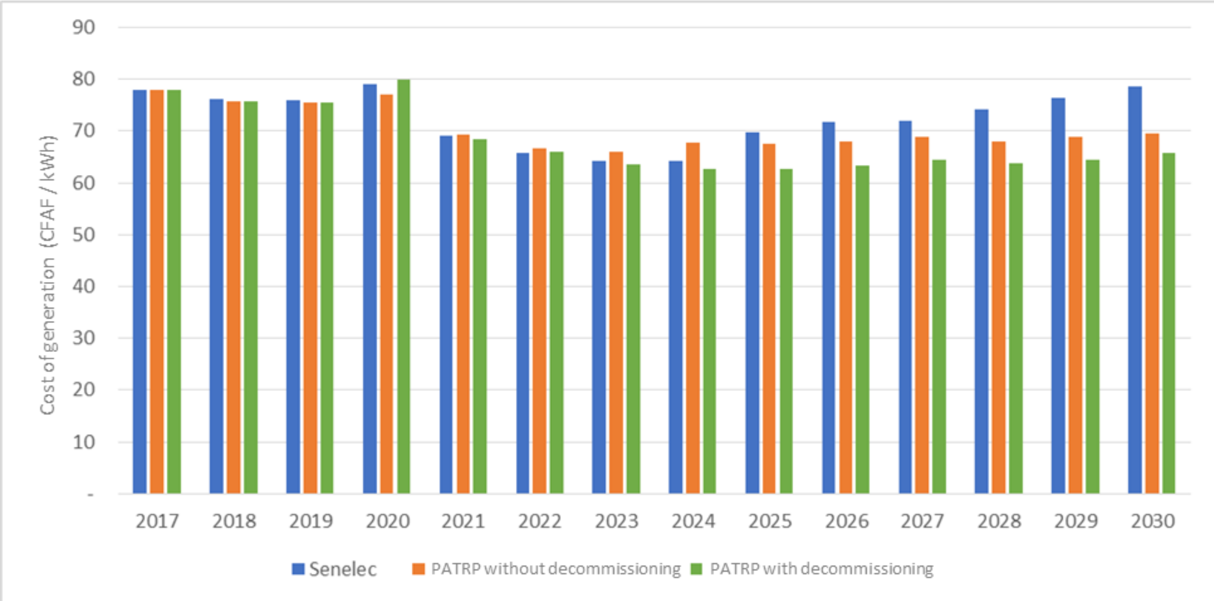
5.1.2 RESULTS OF THE DIFFERENT SCENARIOS

The calculations of the different models yielded the following values per kWh for each updated scenario, and the values by year:

Table 5-1: Present value per kWh for each scenario

	PRESENT VALUE PER kWh FOR EACH SCENARIO		
	Senelec scenario	PATRP scenario with no decommissioning	PATRP scenario with decommissioning
Present value of costs (M CFAF)	3,673,766	3,581,216	3,464,280
Present energy (GWh)	54,033	54,013	54,006
Present value per kWh (CFAF/kWh)	67.99	66.30	64.15

Figure 5-2: Cost per kWh for each scenario 2017-2030 (Table in Appendix F.3)



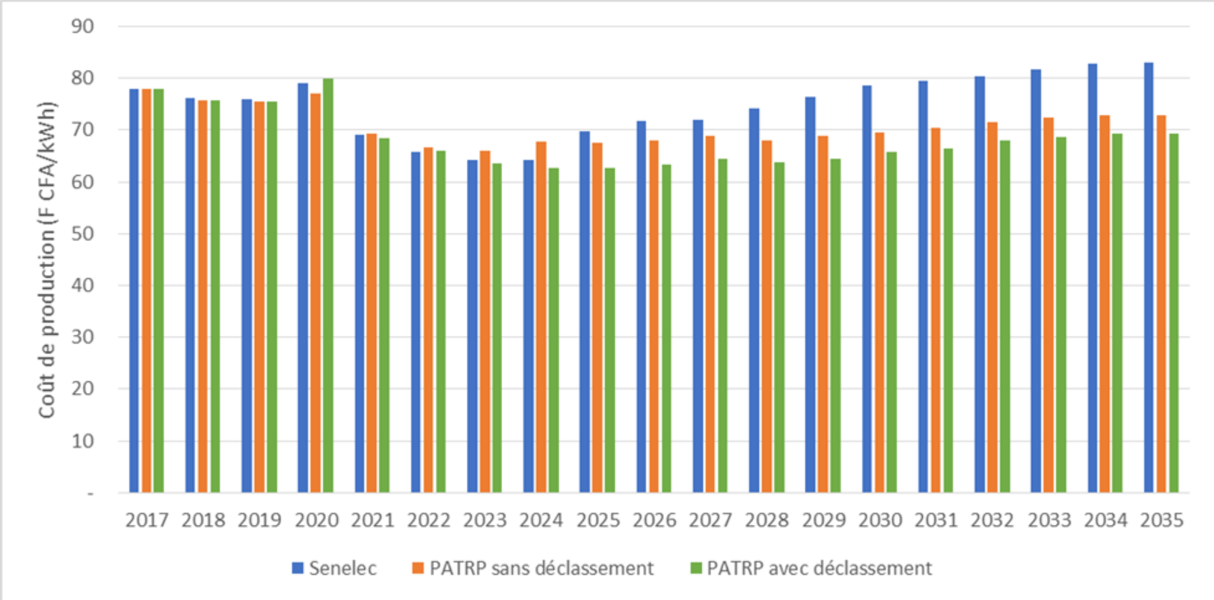
1. **"Senelec" scenario:** Senelec Master Plan as approved by the Council of Ministers in January 2017.
   - The overall cost per kWh in this scenario is 67.99 CFAF/kWh.
   - This is actually the most expensive of the three scenarios proposed due to the following factors:
     - The accelerated timeline for IRE project implementation up to 2020 requires capacity curtailment, which is more common for the Sendou and IRE power plants.
     - The use of a second coal-fired power plant starting in 2020 reduces the average cost of generation but imposes stability constraints on the grid, increasing capacity curtailment in the short and medium term.
     - Implementation starting in 2025 of gas turbine plants, which are more expensive to operate than the CCGT plants proposed by PATRP.
     - Keeping less efficient and more costly generators in operation.

2. **PATRP with no decommissioning scenario**: using solar energy according to the implementation timelines reviewed by PATRP, and reducing coal-based installed capacity.
   - The overall cost per kWh in this scenario is 66.30 CFAF/kWh.
   - This scenario is less expensive than the Senelec scenario because a CCGT unit is added instead of a steam turbine, as in the Senelec scenario.
   - Compared to the most economical scenario (PATRP with decommissioning), using lower levels of coal generation is certainly a factor that contributes to increasing the average cost of generation.
   - Continuing to operate less efficient generators that are more expensive to maintain is another significant contributing factor.

3. **PATRP with decommissioning scenario**: using solar energy according to the implementation timelines reviewed by PATRP, adhering to the number of megawatts of coal power, modifying the implementation timeline, and considering decommissioning of the least efficient generation units.
   - The overall cost per kWh in this scenario is 64.15 CFAF/kWh.
   - The key points are as follows:
     - PATRP recommends staggering the installation of IRE power plants because of Senelec's current difficulties providing the synchronous reserve necessary to integrate all IRE projects within the time frame recommended in its plan. Limiting synchronous reserve requirements would help maintain grid stability and ensure a smoother integration of IRE. Only the implementation of solar energy is staggered.
     - PATRP suggests decommissioning more than 167 MW in Senelec units that no longer meet the operating conditions necessary for cost-efficient operation.
       - To offset this loss, PATRP is proposing to increase the installed capacity of the next Dual power plant to 240 MW, the location of which must be reviewed. This decision is based on the following postulates:
         - The cost of operating this power plant will be much lower than the cost of operating plants that have been put in cold standby.
         - This plant should be equipped to automatically provide synchronous reserve at the lowest possible cost. Furthermore, this plant will give Senegal more autonomy in its capacity to develop automatic synchronous reserve.
         - The introduction of this power plant postpones the obligation to implement the second coal-fired power plant, and will strengthen the grid and take advantage of the interconnection with neighboring grids to limit load shedding due to potential generator faults.
         - This plant also helps to guard against any delays in the implementation of the OMVS and OMVG hydroelectric plants.
     - Finally, PATRP suggests keeping IREs at around the rate prescribed by the Senegalese government, i.e. 20%:
       - As a result, IRE plants are added throughout the period covered by this analysis. They are added gradually depending on the grid's ability to integrate the plants and stay within the 20% limit.
       - However, even though we used a maximum of 20% in our modeling, this rate can increase significantly once integrated into the main grid. A penetration above 50% could even be conceivable depending on the capacity of the grid to provide sufficient automatic synchronous reserve.

Changing the period of analysis by limiting it to 2017-2030 instead of to 2035 conceals a trend that is clearly shown in the historical chart in the figure below.

Figure 5-3 : Cost per kWh for each scenario 2017-2035 (Table in Appendix F.3)



Unless it wishes to follow the most costly scenario, Senelec will clearly have to change its direction in the years following 2022 since it is at this point that its average generation costs start to climb steadily year over year, widening the gap with the other scenarios. This gap widens even further after 2030.

Variations presented by the other scenarios, such as the use of CCGT rather than TV technology or confirmation of decommissioning of the least efficient generators, would be plausible alternatives to keep generation costs down.

5.2 SUPPLEMENTARY FINANCIAL ANALYSIS

The various supplementary financial analyses provide a better understanding of the impact of Senelec's various options for managing its grid.

It must be explained here that curtailment corresponds to the energy that could have been generated but was not due to excess supply in times of low demand. This situation is particularly costly in the case of generation under ToP or capacity contracts.

The results are as follows:

1. The IRE curtailment costs per year (with a synchronous reserve) in the Senelec and PATRP scenarios.

Table 5-2 : Cost of solar curtailment

COST OF SOLAR CURTAILMENT					
		Unit	2018	2019	2020
Senelec Scenario					
With curtailment	**Cost**	M CFAF	19,335	27,741	28,346
	Energy	GWh	281	389	306
	Cost per kWh	CFAF/kWh	68.7	71.4	92.6
With no curtailment	**Cost**	M CFAF	19,335	27,741	28,346
	Energy	GWh	281	397	397
	Cost per kWh	CFAF/kWh	68.7	69.9	71.5
Cost of curtailment		CFAF/kWh	-	-	1.5
PATRP scenario with no decommissioning					
With curtailment	**Cost**	M CFAF	13 ,877	14 ,186	14,502
	Energy	GWh	201	201	169
	Cost per kWh	CFAF/kWh	69.1	70.6	86.0
With no curtailment	**Cost**	M CFAF	13 ,877	14,186	14,502
	Energy	GWh	201	201	201
	Cost per kWh	CFAF/kWh	69.1	70.6	72.2
Cost of curtailment		CFAF/kWh	-	-	13.8
PATRP scenario with decommissioning					
With no curtailment	**Cost**	M CFAF	13,877	14,186	14,502
	Energy	GWh	201	201	169
	Cost per kWh	CFAF/kWh	69.1	70.6	86.0
With curtailment	**Cost**	M CFAF	13,877	14,186	14,502
	Energy	GWh	201	201	201
	Cost per kWh	CFAF/kWh	69.1	70.6	72.2
Cost of curtailment		CFAF/kWh	-	-	13.8

Table 5-3: Cost of wind curtailment

COST OF WIND CURTAILMENT					
		Unit	2018	2019	2020
Senelec Scenario					
With curtailment	Cost	M CFAF	6,297	12,903	20,272
	Energy	GWh	97	173	194
	Cost per kWh	CFAF/kWh	65.1	74.8	104.4
With no curtailment	Cost	M CFAF	6,297	12,903	20,272
	Energy	GWh	97	194	297
	Cost per kWh	CFAF/kWh	65.1	66.7	68.3
Cost of curtailment		CFAF/kWh	-	8.1	36.1
PATRP scenario with no decommissioning					
With curtailment	Cost	M CFAF	6,297	12,903	20,272
	Energy	GWh	97	191	196
	Cost per kWh	CFAF/kWh	65.1	67.6	103.5
With no curtailment	Cost	M CFAF	6,297	12,903	20,272
	Energy	GWh	97	194	297
	Cost per kWh	CFAF/kWh	65.1	66.7	68.3
Cost of curtailment		CFAF/kWh	-	0.9	35.2
PATRP scenario with decommissioning					
With no curtailment	Cost	M CFAF	6,297	12,903	20,272
	Energy	GWh	97	191	196
	Cost per kWh	CFAF/kWh	65.1	67.6	103.5
With curtailment	Cost	M CFAF	6,297	12,903	20,272
	Energy	GWh	97	194	297
	Cost per kWh	CFAF/kWh	65.1	66.7	68.3
Cost of curtailment		CFAF/kWh	-	0.9	35.2

- IRE curtailment only affects the years prior to OMVG interconnection. Indeed, the reserve provided by the OMVG helps to stabilize the grid and limit curtailment.
- In the Senelec scenario, curtailment is due to the higher level of IRE installed capacity prior to interconnection, combined with the addition of base generation which, in terms of power generation capacity, exceeds the increase in demand.
- In the PATRP scenarios, curtailment is much less substantial since implementation of IRE projects has been delayed.

2. Coal curtailment costs per year (with a synchronous reserve) in the Senelec and PATRP scenarios.

Table 5-4: Cost of coal curtailment

COST OF COAL CURTAILMENT								
		Unit	2018	2019	2020	2021	2022	2023
Senelec Scenario								
With curtailment	**Cost**	M CFAF	25,387	40,683	69,184	122,879	140,998	143,096
	Energy	GWh	589	814	1 175	2,387	2,925	3,037
	Cost per kWh	CFAF/kWh	43.1	50.0	58.9	51.5	48.2	47.1
With no curtailment	**Cost**	M CFAF	25,415	42,221	75,767	128,026	142,864	143,339
	Energy	GWh	591	925	1,634	2,741	3,053	3,053
	Cost per kWh	CFAF/kWh	43.0	45.7	46.4	46.7	46.8	46.9
Cost of curtailment		CFAF/kWh	0.1	4.3	12.5	4.8	1.4	0.2
PATRP scenario with no decommissioning								
With curtailment	**Cost**	M CFAF	25,412	41,115	39,728	42,504	76,052	76,307
	Energy	GWh	590	845	738	925	1,634	1,634
	Cost per kWh	CFAF/kWh	43.0	48.6	53.9	46.0	46.5	46.7
With no curtailment	**Cost**	M CFAF	25,415	42,221	42,362	42,504	76,052	76,308
	Energy	GWh	591	925	925	925	1,634	1,634
	Cost per kWh	CFAF/kWh	43.0	45.7	45.8	46.0	46.5	46.7
Cost of curtailment			0.0	2.9	8.1	0.0	0.0	0.0
PATRP scenario with decommissioning								
With curtailment	**Cost**	M CFAF	25,413	41,115	39,234	42,503	76,052	109,823
	Energy	GWh	590	845	702	925	1,634	2,344
	Cost per kWh	CFAF/kWh	43.0	48.6	55.9	46.0	46.5	46.9
With no curtailment	**Cost**	M CFAF	25,415	42,221	42,362	42,504	76,053	109,824
	Energy	GWh	591	925	925	925	1,634	2,344
	Cost per kWh	CFAF/kWh	43.0	45.7	45.8	46.0	46.5	46.9
Cost of curtailment			0.0	2.9	10.1	0.0	0.0	0.0

- Coal capacity curtailment results from an insufficient level of load given IRE generation, which is always prioritized in generation due to the nature of ToP contracts.
- The cost of capacity curtailment at coal-fired plants is, therefore, directly affected by IRE penetration and by the introduction of the first phase of Africa Energy in 2020. These two factors explain why this cost is significantly higher in the Senelec scenario.
- In the PATRP scenario with no decommissioning, the later introduction of the first phase (and the only one proposed in this scenario) of Africa Energy and some IRE projects accounts for the positive cost difference.
- With regard to the PATRP scenario with decommissioning, the magnitude of the increase in the cost per kWh for 2020 is a result of the introduction of the Malicounda power plant and the installation of a new 120 MW Dual power plant. This second power plant generates fixed costs for Senelec, which will not be reduced until 2021 owing to the decommissioning of the least efficient Senelec plants.
- Starting in 2024, trips at Sendou would not cause additional load shedding given the high inertia provided by the interconnection of the OMVG and OMVS networks.

5.2.1 ANALYSIS OF COSTS ARISING FROM A MANAGEMENT DECISION NOT TO USE THE SYNCHRONOUS RESERVE

The financial costs that Senelec could tolerate in the context of grid management that uses load shedding rather than an adequate synchronous reserve are analyzed in the next section.

This analysis was conducted for the Senelec scenario only since it has been shown that this is the most constraining scenario, particularly when it comes to costs.

The analysis touched on three aspects:

1. Revenue losses from load shedding due to outages at coal-fired, solar and wind power plants without access to the synchronous reserve.

Table 5-5: Revenue losses from load shedding due to outages, in the Senelec scenario

REVENUE LOSSES FROM LOAD SHEDDING DUE TO OUTAGES, IN THE SENELEC SCENARIO (K CFAF)										
	Pres. Val. (2017)	2017	2018	2019	2020	2021	2022	2023	2024	2025
One outage annually										
Lost revenues (K CFAF)	**163,936**	1,271	14,790	18,730	27,213	49,398	35,503	35,845	35,882	36,526
Resulting from coal load shedding (%)	**83.7%**	0.0%	56.5%	48.9%	60.6%	72.2%	100.0%	100.0%	100.0%	100.0%
Resulting from IRE load shedding (%)	**16.3%**	100.0%	43.5%	51.1%	39.4%	27.8%	0.0%	0.0%	0.0%	0.0%
Three outages annually										
Lost revenues (K CFAF)	**488,827**	3,813	41,098	56,190	81,638	148 194	106,510	107,535	107,645	109,577
Resulting from coal load shedding (%)	**83.3%**	0.0%	61.0%	48.9%	60.6%	72.2%	100.0%	100.0%	100.0%	100.0%
Resulting from IRE load shedding (%)	**16.7%**	100.0%	39.0%	51.1%	39.4%	27.8%	0.0%	0.0%	0.0%	0.0%
Five outages annually										
Lost revenues (K CFAF)	**810,029**	6,356	68,496	93,649	133,045	243 514	177,517	179,225	179,409	182,628
Resulting from coal load shedding (%)	**83.7%**	0.0%	61.0%	48.9%	62.0%	73.3%	100.0%	100.0%	100.0%	100.0%
Resulting from IRE load shedding (%)	**16.3%**	100.0%	39.0%	51.1%	38.0%	26.7%	0.0%	0.0%	0.0%	0.0%

- We hypothesized a certain number of outages per year to explain the three scenarios proposed, namely one outage per year (low scenario), three outages per year (median scenario) and five outages per year (high scenario) - (see Appendix G.1).
- We applied the rule that each of these outages, no matter how long it lasts, results in only one hour of load shedding, assuming that the grid can compensate for the loss of capacity with other means of generation within this period.
- These revenue losses are mainly due to the grid's inability to compensate immediately for coal-fired power plant trips (resulting from the fact that the Sendou and Africa Energy engines are too large compared to the grid's capacity to provide an adequate synchronous reserve, among other things).
- Between 2017 and 2021, these revenue losses include the impact of the IRE power plant and are influenced by the addition of Africa Energy's coal capacity. Starting in 2022, interconnection to the OMVG network will provide enough inertia and capacity to reduce the impact of IRE losses to zero. For the period 2022 to 2025, the only revenue losses will therefore come from coal-fired power plants.
- It is considered that as of 2024, potential trips at coal-fired power plants will no longer cause additional load shedding given the high inertia of the interconnected network.

2. Revenue losses from voltage fluctuations without the synchronous reserve in the Senelec scenario.

Table 5-6: Revenue losses from IRE fluctuations in the Senelec scenario

REVENUE LOSSES FROM IRE FLUCTUATIONS IN THE SENELEC SCENARIO (K CFAF)										
	Pres. Val. (2017)	2017	2018	2019	2020	2021	2022	2023	2024	2025
Two critical events	113,369	2,647	12,421	25,188	29,565	37 926	13,465	13,595	13,609	13,853
One critical event	56,685	1,323	6,210	12,594	14,782	18,963	6,733	6,798	6,804	6,927
Three critical events	170,054	3,970	18,631	37,781	44,347	56,889	20,198	20,393	20,413	20,780

- As in the previous table, we assumed an annual number of critical fluctuation events leading to load shedding to explain the three scenarios proposed, namely one event per year (low scenario), two events per year (median scenario) and three events per year (high scenario) - (see Appendix G.2).
  - We applied the rule that each of these events, no matter how long it lasts, results in only one hour of load shedding, assuming that the grid can compensate for the loss of capacity with other means of generation within this period.
- The high level of IRE penetration and the grid's inability to compensate for fluctuations within the required time range account for the revenue losses caused by not using the automatic synchronous reserve.
- In the median scenario, which we consider to be the most probable, Senelec's revenue loss could amount to more than 113 billion CFA francs in present value terms for the period 2017-2025.
- Once again, we distinguish two phases, namely for the period 2017-2021, and then another between 2022 and 2025.
- Costs rise in the first phase due to the increasing penetration of IRE. However, in 2022, we note a significant decline in annual costs, coinciding with the addition of the OMVG interconnection, which will stabilize the grid until local natural gas plants are installed in 2025. These plants would provide sufficient stability that could theoretically be enough to offset any imbalance.

3. Revenue losses from the decision of large energy consumers not to connect to the grid (or simply not to implement their project) because of the unreliability of the interconnected network (resulting from the use of load shedding rather than the appropriate synchronous reserve).

Table 5-7 : Revenue losses from large energy consumers lost due to unreliability

REVENUE LOSSES FROM LARGE ENERGY CONSUMERS LOST (M CFAF)															
Senelec Losses	Pres. Val. (2017)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Medium Voltage	20,380	-	-	-	3,281	3,836	3,873	3,906	3,904	3,962	3,855	3,746	3,642	3,539	3,448
High Voltage	376,980		4,066	6,046	17,533	57,812	86,119	86,940	86,764	88,405	85,659	82,849	63,451	56,092	42,390
Total	397,360	-	4,066	6,046	20,814	61,648	89,992	90,846	90,669	92,367	89,514	86,595	67,092	59,632	45,839

- We have already established that large energy consumers are more independent than other types of consumers. In fact, they generally have the means to operate under alternate solutions if the performance criteria of the grid do not meet their requirements.
- On the other hand, if the cost of the alternate solution is not competitive, the project may also simply be abandoned. Mining, where the cost and reliability of power supply are critical, is a good example.
- The revenues that may be lost by Senelec as a result of load shedding rather than use of the synchronous reserve could therefore be considerable, and far beyond the mere cost of using this reserve or not.

As part of this analysis, almost 400 billion CFA francs in revenues could be lost over the period 2017-2030 (see the list of consumers and associated assumptions in Appendix G.4).

5.2.2 MACROECONOMIC STATEMENT

Above and beyond the costs borne by Senelec, there is a significant macroeconomic impact of not using an adequate synchronous reserve. Undeniably, the additional costs borne by Senelec are only one of the disadvantages that the country as a whole will suffer.

From a macroeconomic point of view, a recent report by the African Development Bank revealed that manufacturing companies in Africa are losing 56 days of productivity annually due to the unreliability of the power grid. Even a five-minute outage can have considerably longer effects in the form of lost productivity.

According to the same report, the impact on the national GDP could be a 2% to 4% reduction. Taking into account Senegal's GDP in 2016, this loss could have been between 113 billion and 227 billion CFAF.

This significant impact would result in lost income for the population and, as a result, the government. If we were to calculate just the VAT shortfall associated with this loss, we are talking about revenue losses for the government that could range between 20 and 40 billion CFAF annually.

5.2.3 SYNCHRONOUS RESERVE

As presented in chapter **Error! Reference source not found.**, the synchronous reserve maintenance costs are relatively difficult to assess given the data availability and the limitations imposed by the terms of reference of the study.

However, following our research, PATRP was able to confirm one assumption that is based on an analysis conducted by the National Renewable Energy Laboratory (NREL) as part of a similar study. The study found that the costs of maintaining an efficient synchronous reserve that fulfills its role as a grid stabilizer are generally around 2% of total generation costs during a given period. In the three scenarios presented, these maintenance costs would be as follows:

Table 5-8: Present value per kWh with synchronous reserve maintenance costs (2%)

	PRESENT VALUE PER kWh FOR EACH SCENARIO		
	Senelec scenario	PATRP scenario with no decommissioning	PATRP scenario with decommissioning
Present value of costs (M CFAF)	3,732,812	3,640,261	3,502,931
Synchronous reserve costs (M CFAF)	74,656	72,805	70,059
Present energy (GWh)	54,033	54,013	54,038
Synchronous reserve costs (CFAF/kWh)	1.38	1.35	1.30

It is clear that the synchronous reserve cost is dependent on several variables. Among other factors, it is always dependent on the level of reserve to be supplied by the generation fleet. The different generation means available that can provide this reserve also have an impact on the cost of the reserve. Finally, the direction chosen for future generating facilities that will be built over time will also be pivotal.

Given the conclusions of the NREL study and the data in the table above, we can claim that it would be more expensive to maintain an adequate synchronous reserve in the Senelec scenario than in the PATRP scenarios. However, although this trend may be indicative, it is clear that subsequent studies will be required to support this conclusion, without which our decision-making tool would be incomplete.

Nevertheless, due to the economic opportunity cost across the country, it would be wise for the Senegalese government to seriously consider using an adequate synchronous reserve, even if the required amount of annual support (if necessary) provided to Senelec has to be adjusted.

5.2.4 TEMPORARY OPTIONS AND INSTALLATION COSTS OF AN ADEQUATE SYNCHRONOUS RESERVE

We are exploring four realistic options that could provide Senelec with the synchronous reserve required to meet its grid stabilization needs. These options stem from the fact that synchronous reserve availability must be automated, which is not currently the case in Senegal.

1- The first option is to upgrade Senelec's speed regulators:

   a. A proposal for this work has been submitted to Senelec and would be financed by USAID.

   b. The cost of this operation should be determined soon, but it would not be an investment. This type of operation is considered to be maintenance, albeit extraordinary, but still maintenance.

2- If it were not technically possible to upgrade current equipment (outdated and/or underperforming equipment) and the Senelec speed regulators had to be replaced, the cost could be roughly 120 million CFA francs per generator (upper range of estimate).

   a. To ensure there is an adequate reserve, this replacement could be required on a dozen generators, requiring an investment of roughly 1.44 billion CFA francs.

3- Senelec could decide to impose an obligation that each IPP must provide a portion of the synchronous reserve required for the grid.

   a. Senelec would then have to negotiate to reach an agreement for the provision of complementary services.
   b. This solution, which is probably the least expensive, would be a purchase of service, and not an investment. Therefore, this would have to be included in the calculation of the operating costs of the generation facilities.

4- Senelec could decide to add new generators dedicated to providing synchronous reserve.

   a. Two 35 MW generators that can provide 50% of capacity to the synchronous reserve could be considered, for a total of 70 MW.
   b. According to existing data, a decision to purchase would require an investment of 35 billion CFAF.
   c. The idea of using batteries to generate reserve **needs to be studied or evaluated**, especially if the battery system could have several uses (balancing, peak, reserve, etc.).
   d. It is too early to discuss the investment required for this potential solution since the costs vary greatly depending on the reference considered. In the examples of the systems considered below, the cost of installing a 36 MW battery system was approximately 13 billion CFA francs.

Figure 5-4: Cost of installing options consisting of battery systems coupled with solar power plants (see reference section 3.2.7)

Location	Morgan	Roxby Downs
Solar		
Capacity	330MW (max active power injection 160MVA plus 110MVA (two lines)	120MW (max active power injection 80MVA)
Approximate investment value	$700m	$250m
People during construction	270	200
Number of panels	3.4 million	1.3 million
Number of foundations required	273,000 (combined)	273,000 (combined)
Kilometres or wiring in total required	1,847Km of AC & DC cabling (combined)	1,847Km of AC & DC cabling (combined)
Estimate of the value of services that will be sourced from SA*	$100 million	$48 million
Storage		
Capacity	100MW / 400MWh (depending on config.)	100MW / 200MWh (depending on config.)
Approx. investment value	$200-$300m	$100m - $150m
Number of batteries	1.1 million	1.1 million

5.3 CONCLUSION AND RECOMMENDATIONS FOR THE FINANCIAL ANALYSIS PORTION

After analyzing the three scenarios and their variants, we have come to the following conclusions:

- The characteristics of the PATRP scenario with decommissioning are the most likely to give Senegal an economic solution to manage its generation costs.
- Despite the associated costs, managing the grid without an adequate synchronous reserve is not recommended.
  - The risk of jeopardizing the projects of large customers should be reason enough on its own.
  - Senelec's service quality priorities should take precedence over the costs associated with the use of the synchronous reserve if Senegal wishes to distinguish itself as an exemplary grid manager in the sub-region.
  - Connection to neighboring grids could be significantly disrupted if Senegal does not manage its own grid with an adequate synchronous reserve.
  - WAPP is currently working on implementing solutions that could stabilize the grids. It is hard to imagine that Senegal could go its own way.

6. INVESTMENT PLAN

6.1 INTRODUCTION

The investment plan includes an estimate of the funds to be committed by Senelec over the 2017-2035 period to meet the electricity needs of the Senegalese population, based on the assumptions in the various scenarios proposed in the previous part of the study.

Given the Senegalese government's recent sound decision to entrust the private sector with the development of the future generation fleet and related investments, we will therefore focus on the transmission component. This plan will include all the recommendations made by PATRP experts concerning the additions and reinforcements necessary to ensure optimal grid stability.

This document could serve as the basis for ensuing discussions with technical and financial partners to secure financing for this ambitious program, which should make the Republic of Senegal a leader in grid management.

6.2 METHODOLOGY OF THE INVESTMENT PLAN

The methodology for calculating the various elements of the investment plan will be based on the costs of the various additions to be included in order to achieve Senelec's objectives to incorporate international standards.

Remember the context:

- The first step of the transmission network operating study consisted in analyzing the normal network (n) with all components in service, to ensure that the voltage and load criteria of the equipment are met under normal conditions.
- A constraint was examined for the main transmission network (225 and 90 kV): the loss of one component of the grid (n-1), or a single contingency.
- The grid had to meet the load and voltage criteria under emergency conditions and be free from any voltage collapse or instability.

To guarantee reliability, the basic rules are as follows:

- The normal grid (n) must have enough flexibility to meet demand.
- The main grid (225 and 90 kV) with a single contingency (n-1) must maintain operating conditions without interruption or load shedding, and without placing undue stress on the grid.
- Load shedding or generation must be controlled to limit major service interruptions.

PATRP developed several models of the Senelec/OMVS/OMVG interconnected network and of some of the grid components in neighboring countries that have a significant impact.

The years 2019, 2022 and 2028 were selected as simulation years because they represent pivotal years for grid dynamics.

Thus, 2019 has the current grid integrating almost 300 MW of renewable energy and the addition of the Sendou 115 MW coal-fired power plant.

The recommendations for this year are focused in the area of operation rather than planning since no investments that might be made during this period could offset the potential issues. Therefore, the recommendations focused more on modifications to current equipment.

It is in 2022 that the 225 kV grid is to be extended east to Guinea from the Kaolack substation, passing through Gambia and Guinea-Bissau, and west towards the Kédougou region, passing through the Tambacounda substation all the way to Linsan substation in Guinea.

In 2028, the grid would integrate practically all new gas-fired plants operating on local gas produced in Senegal.

As seen in the second chapter of this report, the added components are based on a static and dynamic analysis of the grid. The plan's various components are related to this analysis:

- Static analysis:
  - The static analysis determines the grid's capacity to transport power without a load-break or voltage overload. The study identifies the weaknesses and proposes arrangements that could correct the inadequate situation based on generally accepted international planning criteria.
- Dynamic analysis:
  - The dynamic analysis simulates load losses on the grid and assesses the level of synchronous reserve required to offset extreme fluctuations in frequency and voltage resulting in network failure, thereby avoiding load shedding.

PATRP will therefore use the results of both analyses to develop its investment plan, which will naturally have repercussions on the financial model of the kilowatt-hour costs.

6.3 FINANCIAL ASSESSMENT

The investment plan proposes two scenarios for the future 225 kV Dakar loop.

- **Scenario 1: Back up from the existing loop**: As indicated in chapter 4, this is a 225-kV network that creates a loop between Kounoune-Cap des Biches-Mbao-Hann-Patte d'Oie and back to Kounoune.

- **Scenario 2: Installation of a loop from a second corridor:** This scenario would permit the integration of another generation source – in this case the Kayar natural gas plant – through another 225-kV corridor into Dakar's 90 kV grid. The loop would be installed between Kounoune-Patte d'Oie-Guédiawaye-Kayar and back to Kounoune.

  Although our study chose the Kayar site, selecting another generation site would require a loop from another corridor.

  Note that at this stage, since investments are assessed from parametric costs, the cost difference between the two scenarios is not significant.

  A feasibility study would clarify these estimates, which may be very different, primarily depending on the environmental assessments and acceptability studies.

The required investments for both scenarios are presented in the following table:

Table 6-1: Investment options for the transmission network (M CFAF)

INVESTMENT OPTIONS FOR THE TRANSMISSION NETWORK (M CFAF)																				
	Net Present Value	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Option 1																				
Investments	330,134	19,080	45,716	121,789	167,459	21,107	21,861	-	689	-	2,438	26,550	3,581	-	-	-	-	-	-	-
O & M	46,124	302	1,108	2,900	5,183	5,498	5,856	5,973	6,106	6,229	6,402	6,869	7,048	7,189	7,332	7,479	7,629	7,781	7,937	8,096
Total	376,257	19,382	46,825	124,689	172,642	26,605	27,717	5,973	6,796	6,229	8,840	33,418	10,629	7,189	7,332	7,479	7,629	7,781	7,937	8,096
Option 2																				
Investments	333,004	19,080	45,716	124,910	165,930	21,107	17,555	-	689	-	21,655	15,944	3,581	-	-	-	-	-	-	-
O & M	46,432	302	1,108	2,931	5,199	5,515	5,830	5,947	6,080	6,201	6,566	6,959	7,140	7,283	7,429	7,577	7,729	7,883	8,041	8,202
Total	379,436	19,382	46,825	127,842	171,130	26,622	23,385	5,947	6,769	6,201	28,221	22,904	10,721	7,283	7,429	7,577	7,729	7,883	8,041	8,202

6.4 INVESTMENTS IN TRANSMISSION

The following table shows the investments that will be required for substations and transmission lines up to 2035.

The tables present the investments per year and specify the criteria that would trigger these investments.

The two options are presented separately in Table 6-1 and Table 6-2 below, and associated infrastructure is marked in orange and yellow respectively:

Table 6-2: Option 1 - Lines

OPTION 1 – LINES																		
From	To	Type	Trigger		KM	KM	KM	KM	KM	KM	KM	KM	KM	KM	KM	KM	KM	Million US$ 2017
					2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	**2029-2035**	**TOTAL**
Patte d'Oie	Airport	90 kV cable	Overload	PD											9			6
Sococim	Someta	90 kV line	Overload	PD											11			1.8
Thiona	Someta	90 kV line	Overload	PD												24		4
Kounoune	Patte d'Oie	225 kV cable double-circuit	Overload	DS			23											18.3
Kounoune	Sendou	225 kV line double-circuit	Evacuation from Sendou	DS		10												4.1
Tobène	Kounoune	225 kV line double-circuit	Tobène Thiona overload	DS			55											25
Hann	Bel-Air	90 kV line (cable change)	Overload	DS	5													0.8
Cap des Biches	Kounoune	90 kV line	Overload	DS		6.4												1.1
Cap des Biches	Kounoune	90 kV line (cable change)	Obsolescence	PD		6.4												1.1
Guédiawaye	Dguédiawaye	Cable 225 kV	New line	PD			12											12
Tobène	St-Louis	225 kV line double-circuit	New line	DS			144											46.4
Kaolack	Fatick	225 kV line	New line	DS	55													12.4
Malicounda	Fatick	225 kV line	New line	DS		55												12.4
Université	Sicap	90 kV cable	New feed	DS			2											5

OPTION 1 – LINES

From	To	Type	Trigger		KM	KM	KM	KM	KM	KM	KM	KM	KM	KM	KM	KM	KM	Million US$ 2017
					2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	**2029-2035**	**TOTAL**
Kolda	Tambacounda	225 kV line	New line	DS				200										77.0
Ziguinchor	Tanaf	225 kV line	OMVG, OMVS connector	RO				100										38.5
Kolda	Tanaf	225 kV line	OMVG, OMVS connector	RO				60										23.1
Kedougou	Sambangalou	225 kV line	New line (Mines)	DS				31										8.6
Aeroport	Mamelles	90 kV cable	New feed (HV customer)	DS				2										5
Hann	Patte d'Oie	225 kV cable (90KV)	225 kV loop	DS				1.2										1.2
Hann	Patte d'Oie	225 kV cable (90 KV)	225 kV loop	DS				1.2										1.2
Tobène	Mboro	225 kV line	New feed (wind farm)	DS					30									10.5
Cap des Biches	Mbao	225 kV cable	225 kV loop	PD											1.5			**1.5**
Mbao	Hann	225 kV cable	225 kV loop	PD											17			17
Cap des Biches	Kounoune	225 kV cable 2 cables	225 kV loop	PD						6.5								6.5
Kedougou	Mines	225 kV line	Connection to mines	PD				100										22
Kedougou	Mines	225 kV line	Connection to mines	PD					100									22
Kedougou	Mines	225 kV line	Connection to mines	PD						100								22
																		406.5

Table 6-3: Option 1 – Substations and transformers

OPTION 1 – SUBSTATIONS AND TRANSFORMERS																		
Substation Name	Voltage (KV)	Equipment			MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	Million US$
					2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	**2029-2035**	**TOTAL**
Patte d'Oie	225/90	2 transformers	225 kV loop	DS			200											8.5
Kounoune	225/90	2 transformers	225 kV loop	DS			200											8.5
Bel-Air	90/33	Transformer	Overloads	DS		80												2
Touba	225/33	Transformer	Expansion	DS		80												1.3
Touba	225/33	Transformer	Expansion	DS		80												1.3
Kounoune	90/33	Transformer	Overload	DS			80											2
Kounoune	90/33	Transformer	Overload	DS			80											2
Guédiawaye	90/33	Substation 2 transformers, GIS	We recommend 225/33 substation, too late	DS		40												46.4
Guédiawaye	90/33	Transformer	Overload	DS										40				0.8
Diamnadio	225/33	Substation 2 transformers	New substation	DS			80											29.3
Sendou	225/33	Substation 2 transformers	New power plant	DS		40												5
Sicap	90/33	Substation 2 transformers	New	DS			80											12
Fatick	225/33	Substation 2 transformers	New substation	DS	40													18.6
St-Louis	225/33	Substation 2 transformers	New substation	DS			40											18.6
Mamelles	90/90		New substation	DS				80										12
Kedougou	225/33	Substation 2 transformers	New substation	DS				40										18.6
Tambacounda	225/33	Substation 2 transformers	New substation	DS				40										18.6
Ziguinchor	225/33	Substation 2 transformers	New substation	DS				40										18.6
Kolda	225/33	Substation 2 transformers	New substation	DS				40										18.6

OPTION 1 – SUBSTATIONS AND TRANSFORMERS

Substation Name	Voltage (KV)	Equipment			MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	Million US$
					2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	**2029-2035**	**TOTAL**
Tobène	225/90	Transformers	Overloads	PD						75								1.5
Malicounda	225/33	Transformers	Overloads	PD						40								**1**
Matam	225/33	Transformer replacement	Replacement	PD						40								**1**
Matam	225/33	Transformer	Overloads	PD						40								**1**
Kaolack	225/33	Transformer	Overload	PD								40						**1**
Sakal	225/33	Transformer replacement	Overload	PD										80				1.3
Sakal	225/33	Transformer	Overload	PD										80				1.3
Hann	90/33	Transformer	225 kV loop	PD											80			2
Hann	225/90	Transformer	225 kV loop	PD											200			4
Hann	225/90	Transformer	225 kV loop	PD											200			4
UNIVER 90	90/33	Transformer	Overload	PD												40		0.8
Control center	Improvement	Scada	Obsolescence	PD			7.5											7.5
																		269.1

Table 6-4: Option 2 - Lines

OPTION 2 – LINES																	
From	To	Type	Trigger	KM	KM	KM	KM	KM	KM	KM	KM	KM	KM	KM	KM	KM	Million US$
				2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029-2035	TOTAL
Patte d'Oie	Airport	90 kV cable	Overload											9			6
Sococim	Someta	90 kV line	Overload											11			1.8
Thiona	Someta	90 kV line	Overload												24		4
Kounoune	Patte d'Oie	225 kV cable Double-circuit	Overload			23											18.3
Kounoune	Sendou	225 kV line Double-circuit	Evacuation from Sendou		10												4.1
Tobène	Kounoune	225 kV line Double-circuit	Tobène Thiona overload			55											25
Hann	Bel-Air	90 kV line	Overload	5													0.8
Cap des Biches	Kounoune	90 kV line	Overload		6.4												1.1
Cap des Biches	Kounoune	90 kV line (cable change)	Obsolescence		6.4												1.1
Guédiawaye	Dguédiawaye	225 kV cable	New line			12											12
Tobène	St-Louis	225 kV line Double-circuit	New line			144											46.4
Kaolack	Fatick	225 kV line	New line	55													12.4
Malicounda	Fatick	225 kV line	New line		55												12.4
Université	Sicap	90 kV cable	New feed			2											5

OPTION 2 – LINES

From	To	Type	Trigger	KM	KM	KM	KM	KM	KM	KM	KM	KM	KM	KM	KM	KM	Million US$
				2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029-2035	TOTAL
Kolda	Tambacounda	225 kV line	OMVG. OMVS connector				200										77.0
Ziguinchor	Tanaf	225 kV line	OMVG. OMVS connector				100										38.5
Kolda	Tanaf	225 kV line	OMVG. OMVS connector				60										23.1
Kedougou	Sambangalou	225 kV line	OMVG. OMVS connector				31										8.6
Aeroport	Mamelles	90 kV cable	New feed				2										5
Tobène	Mboro	225 kV line	Overload					30									10.5
Kayar	Tap Kou-Tob	225 kV line Double-circuit	225 kV loop										32				12.8
Kayar	Guédiawaye	225 kV line Double-circuit	225 kV loop										35				14
Guédiawaye	Patte d'Oie	225 kV cable	225 kV loop			5											5
Kedougou	Mines	225 kV line	Connection to mines				100										22
Kedougou	Mines	225 kV line	Connection to mines					100									22
Kedougou	Mines	225 kV line	Connection to mines						100								22
																	410.9

Table 6-5: Option 2 – Substations and transformers

OPTION 2 – SUBSTATIONS AND TRANSFORMERS																	
Substation Name	Voltage (KV)	Equipment		MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	Million US$
				2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029-2035	TOTAL
Patte d'Oie	225/90	2 transformers	225 kV loop			200											8.5
Kounoune	225/90	2 transformers	225 kV loop			200											8.5
Bel-Air	90/33	Transformer	Overloads		80												2
Touba	225/33	Transformer	Expansion		80												1.3
Touba	225/33	Transformer	Expansion		80												1.3
Kounoune	90/33	Transformer	Overload			80											2
Kounoune	90/33	Transformer	Overload			80											2
Guédiawaye	90/33	Substation 2 transformers, GIS	We recommend 225/33 substation		40												46.4
Guédiawaye	90/33	Transformer	Overload										40				0.8
Diamnadio	225/33	Substation 2 transformers	New substation			80											29.3
Sendou	225/33	Substation 2 transformers	New power plant		40												5
Sicap	90/33	Substation 2 transformers	New			80											12
Fatick	225/33	Substation 2 transformers	New substation	40													18.6
St-Louis	225/33	Substation 2 transformers	New substation			40											18.6
Mamelles	90/90		New substation				80										12
Kedougou	225/33	Substation 2 transformers	New substation				40										18.6

OPTION 2 – SUBSTATIONS AND TRANSFORMERS																	
Substation Name	Voltage (KV)	Equipment		MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	Million US$
				2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029-2035	TOTAL
Tambacounda	225/33	Substation 2 transformers	New substation				40										18.6
Ziguinchor	225/33	Substation 2 transformers	New substation				40										18.6
Kolda	225/33	Substation 2 transformers	New substation				40										18.6
Tobène	225/90	Transformer	Overloads						75								1.5
Malicounda	225/33	Transformer	Overloads						40								**1**
Matam	225/33	Transformer replacement	Replacement						40								**1**
Matam	225/33	Transformer	Overloads						40								**1**
Kaolack	225/33	Transformer	Overload								40						**1**
Sakal	225/33	Transformer replacement	Overload										80				1.3
Sakal	225/33	Transformer	Overload										80				1.3
Hann	225/33	Transformer	225 kV loop											200			3
Hann	225/33	Transformer	225 kV loop											200			3
Hann	225/90	2 Transformers	225 kV loop											200			8
UNIVER 90	90/33	Transformer	Overload												40		0.8
Control center	Improvement	Scada	Obsolescence			7.5											7.5
																	273.1

6.5 CONCLUSION

This transmission investment plan is ambitious but necessary to guarantee reliability and stability of the grid in response to the growing demand.

Increasing the grid to 225 kV will solidify Senelec’s role as a transmission utility and will require that coordination mechanisms be established with neighboring grids, mainly OMVS and OMVG.

For a stable grid, Senelec will also need to have rigorous ties with private producers. Thus, future investments in generation will have to be regulated by technical criteria enabling the establishment of a synchronous reserve and ensuring grid stability.

This plan is expected to evolve and will have to be adjusted according to the changing energy situation in Senegal, and in this sense, Senelec’s transmission network planners will have to have sufficient and competent resources to carry out these updates.

The training that will be given to Senelec staff as part of the project should allow personnel to acquire some expertise in the field.

7. IMPLEMENTATION OF THE INVESTMENT PLAN

7.1 INTRODUCTION

Senegal's 2017-2035 generation and transmission master plan requires the implementation of a number of activities that will enable Senelec to achieve its objectives.

Thus, all the projects proposed in this plan will have to go through the typical stages of a project:

- Feasibility study
- Detailed preliminary study, if necessary
- Financing
- Engineering
- Tenders for manufacturing
- Tenders for construction
- Commissioning of equipment
- Operation of equipment or facilities

To enable the completion of each project, Senelec must be involved at every stage, be it an internal project like the majority of transmission and distribution projects, or for generation projects entrusted to private producers.

It is very important that private-sector generation projects contain technical requirements that allow Senelec to maintain grid reliability and stability.

In this master plan, the key projects include:

In the generation sector:

- Commissioning of the 115 MW Sendou coal-fired plant
- Commissioning of 263 MW of solar power
- Commissioning of 265 MW of wind power, mainly in Taiba Ndiaye
- Commissioning of a 240 MW HFO/gas plant in 2020, currently in Malicounda, but which could be built elsewhere depending on the study on the optimal development of natural gas
- Commissioning of a 270 MW coal-fired power plant by Africa Energy
- Development by OMVS and OMVG of 435 MW of dedicated hydroelectric generation for Senegal
- Establishment of 960 MW of generation associated with natural gas development
- Study on the optimal location of a site to deliver natural gas
- Study on development of LNG potential
- Study on a synchronous reserve strategy
- Study on the installation of a storage unit in Taïba Ndiaye to balance generation and reduce fluctuations that contribute to grid instability.

In the transmission sector:

- Construction of the Tambacounda-Kolda-Ziguinchor 225 kV line
- Commissioning of the Kaolack-Fatick-Malicounda 225 kV line
- Construction of high voltage lines between the Kédougou substation and the various mines in the region
- Construction of a second 225 kV link between Tobène and Nouakchott in Mauritania via Saint-Louis
- Establishment by OMVS of a 225 kV link between Kayes and Tambacounda
- Construction by OMVG of a 225 kV loop with Guinea allowing for evacuation from the Sambangalou, Kaléta and Souapiti power plants
- Reinforcement of the 90 kV lines in the Dakar region
- Study of a 225 kV loop connected to natural gas generation.

These projects demonstrate the magnitude of the task at hand. It is important to understand that this plan was prepared according to the inputs obtained during its development. The situation is constantly evolving and Senelec's research department must put in place the processes to control the evolving situation.

The main issues to be controlled can be covered in a feasibility study that will redirect the plan. These main issues include:

- Operation of the natural gas rigs scheduled for 2025 and the location of generation infrastructures
- Controlling IRE-based generation and its impact on the grid
- A good understanding of synchronous reserve requirements
- Integrating mining potential into grids
- Improved planning with organizations such as OMVS, OMVG and WAPP.

The following pages explain the key actions that need to be implemented to achieve this plan.

It is important to note that the directions and timelines differ somewhat from Senelec's plan. However, our recommendations apply regardless of timeline.

7.2 MAJOR PROJECTS

7.2.1 COMMISSIONING OF THE 115 MW SENDOU COAL-FIRED PLANT

This plant, which will be commissioned in 2018, is the first coal-fired power plant for Senelec and will allow Senegal to meet short-term demand at a lower cost.

As the variable cost associated with the use of coal is very low, it will reduce overall generation costs.

Risk: There are several possible risks at the Sendou power plant during the 2018-2021 period:

- The size of the power plant is greater than the network stability criterion. Senelec does not have sufficient reserve to compensate for the sudden loss of the Sendou power plant since it has only one 115 MW unit. The loss of the Sendou unit will therefore almost automatically lead to load shedding on the grid.
- To be able to maintain adequate automatic synchronous reserve during periods of low demand, curtailment may be required at the Sendou plant, which will in turn have an impact on average variable costs.
    - Indeed, due to coal's lack of flexibility, it cannot be used to generate automatic synchronous reserve. As IPPs under ToP contracts (IRE) are given priority among generators, and since they require a synchronous reserve, coal generation will often have to be curtailed to make room for HFO/gas thermal power, which can provide the automatic synchronous reserve required. However, the cost of operating these power plants at this time is more expensive than coal-fired plants.

To resolve this situation, Senelec will have to put in place:

- An optimal synchronous reserve management plan
- Automated remote load shedding to guarantee grid reliability in case of unplanned failures
    - This automatic system would replace the manual system currently in use at Senelec. It operates automatically and is more selective about the loads to be shed.
- Short- and medium-term generation planning for coal-fired power plants as part of a rigorous process between power producers and the network control center to limit load management.

7.2.2 COMMISSIONING OF A 270 MW COAL-FIRED POWER PLANT BY AFRICA ENERGY

According to the proposed PATRP plan, the Africa Energy power plant will be commissioned in three 90-MW phases starting in 2022.

Risk: Even if the Africa Energy generators are installed during a period when the grid is interconnected with Guinea, thus creating a more robust network, the sizing of the units will have to be validated. 45 MW or 30 MW alternators would have a lower impact on the grid.

Senelec must monitor the changing situation and make sure that it can influence Africa Energy with respect to the sizing of the units if necessary.

7.2.3 COMMISSIONING OF 528 MW OF RENEWABLE ENERGY

According to the PATRP plan, 528 MW of intermittent solar and wind energy will be installed by 2035. Although this could change significantly depending on technology developments, the fact remains that Senelec must be able to manage the variability of this type of energy.

Risk: Meteorological predictions of solar and wind energy variability must be clear to avoid constraints that could harm grid operation.

- Thus, during normal variations due to sunrise/sunset, this generation capacity must be supplemented with the most cost-effective source.
- Sudden changes that could produce instability on the grid must also be monitored.

To deal with these issues, Senelec will have to:

- Obtain quality meteorological data from private producers
- Develop short- and medium-term generation forecasting models
- Establish a control system of efficient networks with the automation required to take resource variability into account
- Establish an automatic synchronous reserve strategy
- For projects, develop a process with private producers to impose technical requirements for network integration. This process should take the form of a grid code that would be part of any electricity purchase agreement.

7.2.4 ESTABLISHMENT OF AN ENERGY STORAGE STRATEGY

In Senegal's situation, knowing the plan for generation and the results of the grid stability study, there are situations in which IRE and/or thermal coal generation should potentially be capped. It is obvious that an energy storage system would be beneficial to help balance generation output, making renewable energy output easier to control and less sensitive or even impervious to weather fluctuations, within the design limits of the storage system (capacity, charging speed and autonomy). As for the implementation of a storage system connected to a power plant or distribution network covering several IRE sources, this requires a more in-depth analysis. According to our current data, wind power certainly has a greater need for reserve capacity. Installing a battery system to reduce the value of fluctuations to be covered is certainly the direction to take. There is a considerable advantage to having a storage system such as a large capacity battery, as the IREQ is proposing. Not only in terms of the flexibility it gives the grid, but also because it can be used to offset IRE, supply additional reserve capacity in the event of an outage at a generating plant, and assist with frequency regulation. New technologies are able to respond almost instantaneously (within a second).

Further reflection is required, however, as outages can be unpredictable. The battery system must be reliable at all times in order for it to be considered a synchronous reserve. On the other hand, if the battery is used during peak demand periods, its load level for the synchronous reserve cannot be guaranteed. Given the rapid charging of the latest battery technologies combined with their quick response, it has been technically proven that an energy storage system can help to maintain frequency in an electrical grid.

A feasibility study on energy storage in Senegal with a technical component (sizing) and economic component should cover frequency regulation and ways to facilitate the integration of IREs, particularly as concerns the 158.7 MW wind farm.

This study should be conducted quickly so that it can be implemented in connection with the organization of the solar and wind farm investment plan.

7.2.5 DEVELOPMENT OF LOCAL NATURAL GAS

The development of local natural gas is one of the most important energy strategies for Senegal in the medium term.

Developing the potential of off-shore deposits can help to position Senegal as a major player in West Africa, perhaps even providing the opportunity to export its energy wealth in the form of electricity through the OMVS and OMVG networks.

However, several steps must be taken before this can be implemented.

Risk: Several feasibility studies will be required to implement the most advantageous strategy at the lowest cost.

Senegalese authorities are being called upon to make urgent decisions regarding the development of local natural gas. These structuring decisions will also have to be accompanied by a long-term vision for the development of gas infrastructure, even though many questions remain unanswered today:

- Is it economically justifiable to develop an LNG import chain while waiting for gas to potentially arrive from Tortue or Sangomar by pipeline?
- Should consideration be given to a coexisting gas pipeline to supply the main consumption areas and an LNG chain for the most remote areas?
- Should gas demand be stimulated – with new gas-fired plants, decommissioned plant conversion projects and/or new uses – in order to achieve economies of scale in gas supply?
- Does the drop in prices and the relative decoupling between LNG prices and oil prices create economic interest in switching power generation tools from HFO or coal to natural gas?
- Are there regional opportunities for re-exporting LNG?
- Is LNG an economically viable solution to support the intermittency of renewables?
- Where are gas infrastructures the most optimal for grid stability and price per kWh?
- What would be the impact on kWh of the price of local vs. imported gas?
- How can gas transmission infrastructure be sized in a medium and long term perspective?
- Etc.

A master plan for the development of local natural gas is certainly an essential planning tool in order to see the big picture. It is also a central concern of the U.S. government, and could possibly be a support project in Senegal through various initiatives operating in the country.

In the meantime, it is essential that newly commissioned power plants take this situation into account by ensuring that they have a technology in place that can easily be converted to NG as soon as the opportunity arises.

Moreover, Senelec had the foresight to require the latest power plants commissioned by Contour Global and Tobène Power could be converted from HFO to gas (Dual technology) as soon as the gas or LNG option becomes available.

As part of the PATRP master plan, 240 MW Dual should be commissioned in 2020. Senelec currently prefers the Malicounda site. However, this could potentially be changed depending on the conclusions of the natural gas master plan.

Starting in 2025, 960 MW should gradually be introduced from combined cycle plants using local natural gas. These facilities will need to be strategically located in relation to the gas infrastructure and considering transmission system needs.

The construction of a 225 kV loop near Dakar to unclog the grid and gas-fired power plant projects are indeed very closely interconnected.

7.2.6 POWER PLANT REFURBISHMENT PLAN

Senelec owns several power plants that are nearing the end of their useful life. Some of these power plants are probably too outdated to be cost-effectively refurbished. However, power plants such as C6, C7 and Kounoune can be refurbished. Therefore, development of a power plant refurbishment plan coupled with a diagnosis of existing power plants could delay the need to decommission them or use them as cold standby, and lower costs.

Risk: Not taking advantage of the opportunity to refurbish existing power plants compared to the cost of building new ones.

Senelec must conduct a study on power plant refurbishment and, if the findings are conclusive, seriously consider the required investments.

It would also be a good idea to continue to enforce the use of dual technologies to carry out these refurbishments with a view to developing local gas.

7.2.7 MANAGEMENT OF REGIONAL BODIES: OMVS, OMVG AND WAPP

The OMVS and OMVG are regional bodies that have a strategic impact on the development of the energy sector in Senegal.

To efficiently plan generation and transmission infrastructures, Senelec and these regional bodies must have an optimal working relationship.

Risk: Power generation planning in Senegal is directly connected to the monthly generation output of each watershed and these power plants. According to our recent experience in the region, little information was available from new power plants such as Souapiti, Sambangalou, Gouina, Koukoutamba, etc., despite the importance of PATRP’s work for Senegal. This lack of information sharing makes it difficult to assess the required technology mix and the impact of the Senegalese government's decisions on the regional technology mix.

- The delay in collaboratively working with these organizations, both in generation and transmission, puts Senegal's planning at risk. In fact, the lack of transparency in the planning of future substations and plants compromises the quality of Senelec's planning.
- The WAPP rules are not implemented in the different member countries, which affects the sound management of the grid. The automatic synchronous reserve is not applied at all, which contributes to triggering load shedding.

Actions that can be taken to correct this situation include:

- Developing a code in Senegal to manage the grid according to the criteria developed by WAPP
- Ensuring that the committee in charge of coordinating OMVS and OMVG projects with member countries focuses on the transparent dissemination of information on:
    - project schedules
    - project content
    - integration of electrification projects near 225 kV line rights-of-way
    - information on the monthly generation output of power plants
    - etc.
- Asking WAPP to share the information, analyses and technical studies developed in the context of its projects. In this project, PATRP has repeatedly attempted to obtain information from WAPP for its grid simulation needs, but has been unsuccessful.

7.2.8 IMPLEMENTATION OF A SYNCHRONOUS RESERVE STRATEGY

One key issue in the coming years will be to ensure there is an automatic synchronous reserve capacity to cope with the growth in demand, the increasing complexity of the network and the addition of IREs.

Risk: The risk of load shedding and major outages will be significantly increased if this situation is not controlled.

To mitigate this problem, Senelec will have to take the following actions:

- Conduct an operating network stability study based on actual data from the equipment in operation in order to implement an automatic synchronous reserve strategy
- Model voltage and frequency control equipment to enhance dynamic network analysis
- Determine which power plants will be able to generate some automatic synchronous reserve
- Purchase the necessary equipment to automate frequency regulation
- Apply settings to speed regulators on current equipment
- Examine alternatives to synchronous reserve application: storage unit, equipment rental, etc.
- Implement an efficient network control system so that operators can control networks taking into account the synchronous reserve strategy
- Have a specialized workforce to deal with these issues.

7.2.9 CONSTRUCTION OF THE TAMBACOUNDA-KOLDA-ZIGUINCHOR 225 KV LINE

Construction of the Tambacounda-Kolda-Ziguinchor corridor will enable the integration of major cities in southern Senegal into the main grids. Furthermore, MV lines will be built to enable the electrification of suburban and rural areas.

Risk: Scheduling delays will make it difficult to achieve the objective of universal access in Senegal by 2025 and will limit the associated economic development.

Senelec must ensure that projects are managed soundly and mechanisms coordinated with the distributor in order to achieve the expected electrification objectives.

7.2.10 COMMISSIONING OF THE KAOLACK-FATICK-MALICOUNDA 225 KV LINE

This major project will loop the Kaolack to Malicounda 225 kV network.

This loopback will enhance the reliability of the Senelec grid and the electrification of the surrounding regions.

Risk: Scheduling delays will make it difficult to achieve the objective of universal access in Senegal by 2025 and will limit the associated economic development.

Furthermore, the reliability of the High Voltage network cannot be improved because the loop may not be completed.

Senelec must ensure that projects are managed soundly and mechanisms coordinated with the distributor in order to achieve the expected electrification objectives.

7.2.11 225 KV LOOP STUDY

As demand grows, Senelec will have to build a more robust network and significant new sources of generation to unclog the Dakar region.

Hence, a 225-kV loop near Dakar would be a good solution to address this need. Options are presented in the report and will need to be developed within the framework of a feasibility study.

The location of new sources of natural gas generation should be chosen in consideration of the installment of the 225-kV loop in order to vary the sources of generation supplied to Dakar.

Risk: Failing to coordinate the 225-kV loop study and the location of the natural gas power plants could lead to higher costs and lower profits.

In its next master plan update, Senelec must coordinate these two studies. Periodic updates with generation and transmission personnel will therefore be important.

7.2.12 BUILDING SENELEC'S PLANNING CAPACITY

To guarantee the sustainability of this master plan, Senelec will have to put in place the human and material resources required to carry out the master plan.

Risk: Loss of control over the changing environment.

To guarantee sustainability, Senelec’s General Research Department (DEG) will have to:

- Hire and train new engineers
  - Develop a training program for the development of new engineers
  - Offer classroom training
  - Offer coaching
  - Organize exchanges with electrical companies that have the desired technology and expertise
  - Etc.

- Use and update the necessary hardware and software tools to carry out planned activities
  - Tools to perform steady state and dynamic stability analysis, and modern generation planning software will be essential for quality planning.

It would also be important to create a qualified distribution planning team to gain a better overview and coordinate the deployment of the transmission and distribution networks, thereby encouraging electrification.

7.2.13 INTEGRATION PLAN FOR THE DIFFERENT TECHNICAL – FINANCIAL PARTNERS (TFP)

Senelec will have an ambitious investment plan in the coming years, which will require funding to carry out.

At the moment, several TFPs are interested in these projects.

In order to ensure optimal use of these different types of funding, Senelec should have a clear integration plan for the various donors in order to take advantage of all available opportunities.

7.3 PROJECT MANAGEMENT PROCESS

The implementation of a project management process is key to ensure the sustainability of a master plan of this scope.

The process should provide for periodic updates of plan data as well as analyses to identify different trends and adjust accordingly.

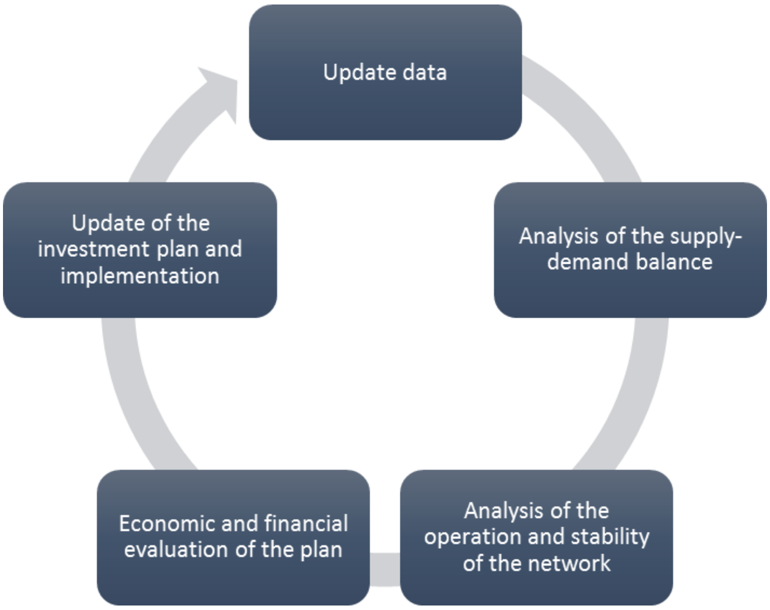
The Senelec DEG team, which plays a key role in the application and updating of this plan, must have the organizational power and necessary leadership to implement such a plan.

7.3.1 PROCESS

The process consists of six steps:

- Update of technical, economic and demand data
- Analysis of the supply-and-demand balance
- Analysis of transmission network operation and stability
- Economic and financial calculation associated with the plan
- Redefining priorities based on analysis
- Update of the investment plan and implementation.

Figure 7-1: Project management process



7.3.2 UPDATE OF TECHNICAL, ECONOMIC AND DEMAND DATA

At the beginning of the year, DEG must promptly share the schedule of plan updates with all of Senelec's internal and external stakeholders to inform them that the process has been initiated and to allow them to share the available resources required for the update.

Plan managers must then produce a list of the information to be updated:

- Review of strategic directions
- New studies on residential, commercial or industrial demand
- Changes in generation supply
- Review of planning criteria
- Characteristics of substations, power plants and lines
- Changes in stages of the different projects in the master plan
- Update of sustainability projects
- Update of various software applications
- Etc.

7.3.3 ANALYSIS OF THE SUPPLY AND DEMAND BALANCE

Data updates must facilitate an analysis of the supply and demand balance, which constitutes the foundation of the master plan.

The plan should highlight the contribution of Senelec and of the private sector in bridging the country's energy and peak power gaps.

At this stage, it is important that action is taken to ensure that generation analysis software is available and updated to the most recent versions. A training session can be scheduled as needed.

7.3.4 ANALYSIS OF GRID OPERATION AND STABILITY

To guarantee grid reliability, which is Senelec's core mission, it is important that grid studies be repeated, even if few changes are anticipated. Any changes will have to be added or removed from the investment plan.

Senelec will have to ensure that the planning software, in this case Siemens PSS/E, is kept up to date.

Subsequently, DEG transmission planners will need to update the single-line diagrams in order to conduct proper grid analysis.

7.3.5 ECONOMIC AND FINANCIAL CALCULATION

This step will update the economic data as well as the investments required over the next 20 years in order to optimize the plan in accordance with the country's changing financial objectives and the associated tariffs.

7.3.6 UPDATING THE PROJECT LIST

Finally, the master plan may be revised as the analyses change.

The list of projects will include:

- All new generation projects
- New transmission network projects
- Additions required by the results of the stability studies
- Investments in sustainability, which are required to maintain grid service quality
- The list of studies required to implement the plan.

7.3.7 PROJECT IMPLEMENTATION AND MONITORING

Following the plan update, any new project must be implemented or others must be delayed to ensure the plan runs smoothly.

A monitoring system will have to be put in place to update project information and to periodically inform all stakeholders of plan developments. Statutory meetings will have to be established to ensure good governance.

7.3.8 ORGANIZATION

With respect to project achievement, Senelec must take responsibility for:

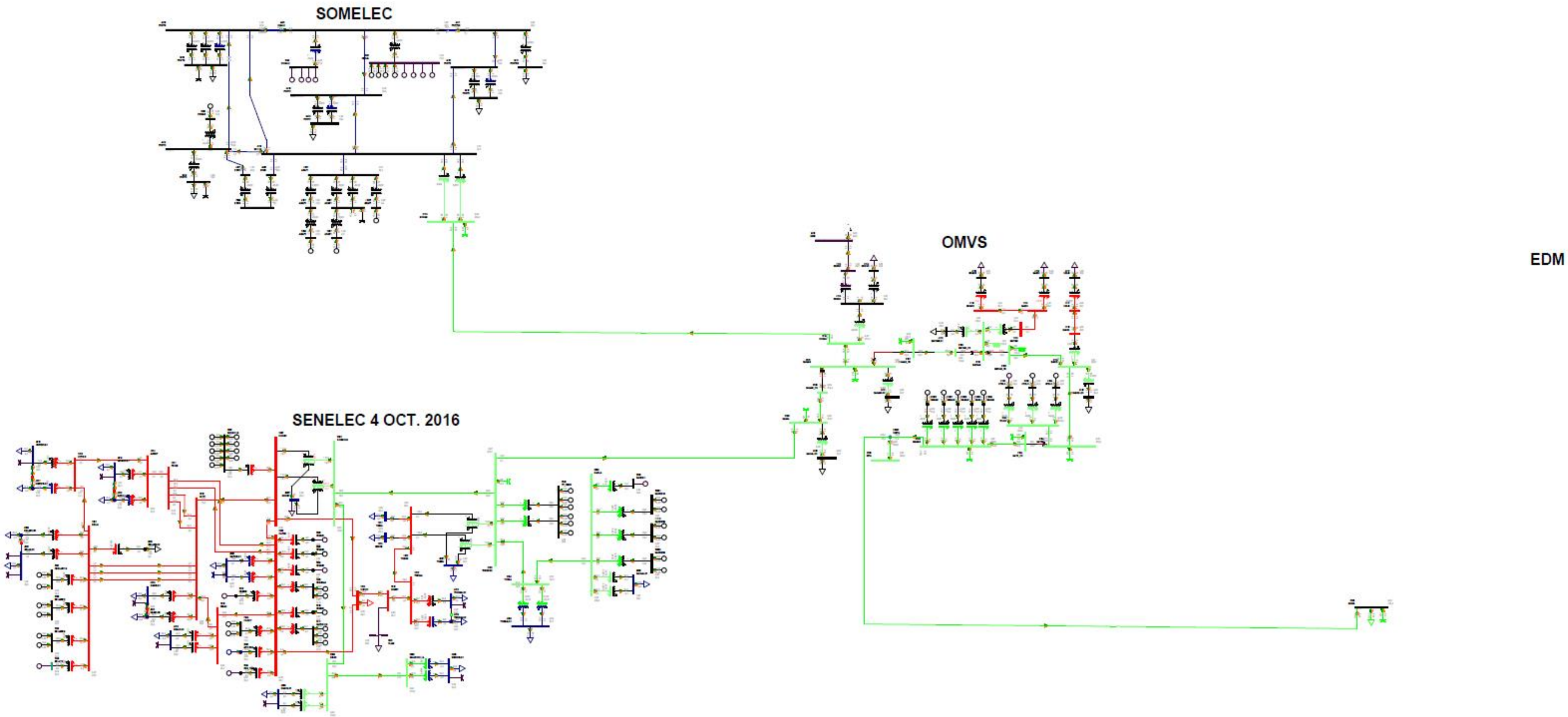
- Commissioning teams for the feasibility studies and various transmission projects
- Establishing requirements for maintaining grid stability in generation projects
- Monitoring the different stages of the master plan
- The integration plan for the various donors.
- Project monitoring

7.3.9 GOVERNANCE

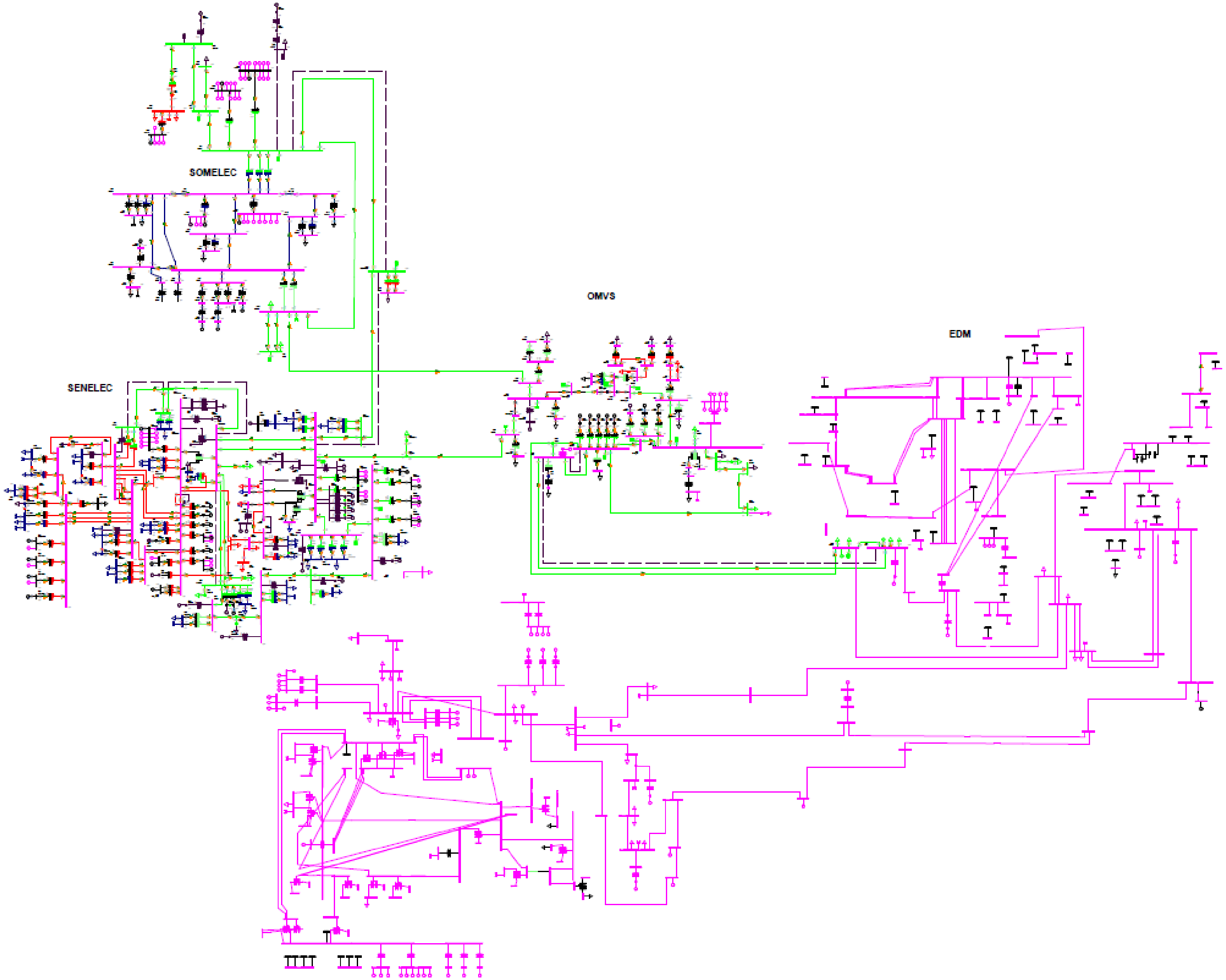
Plan achievement requires the establishment of a multi-level governance process to be defined by Senelec. It will have to cover both operational and strategic aspects.

8. APPENDIX A: PSS/E BASELINE SINGLE-LINE DIAGRAMS

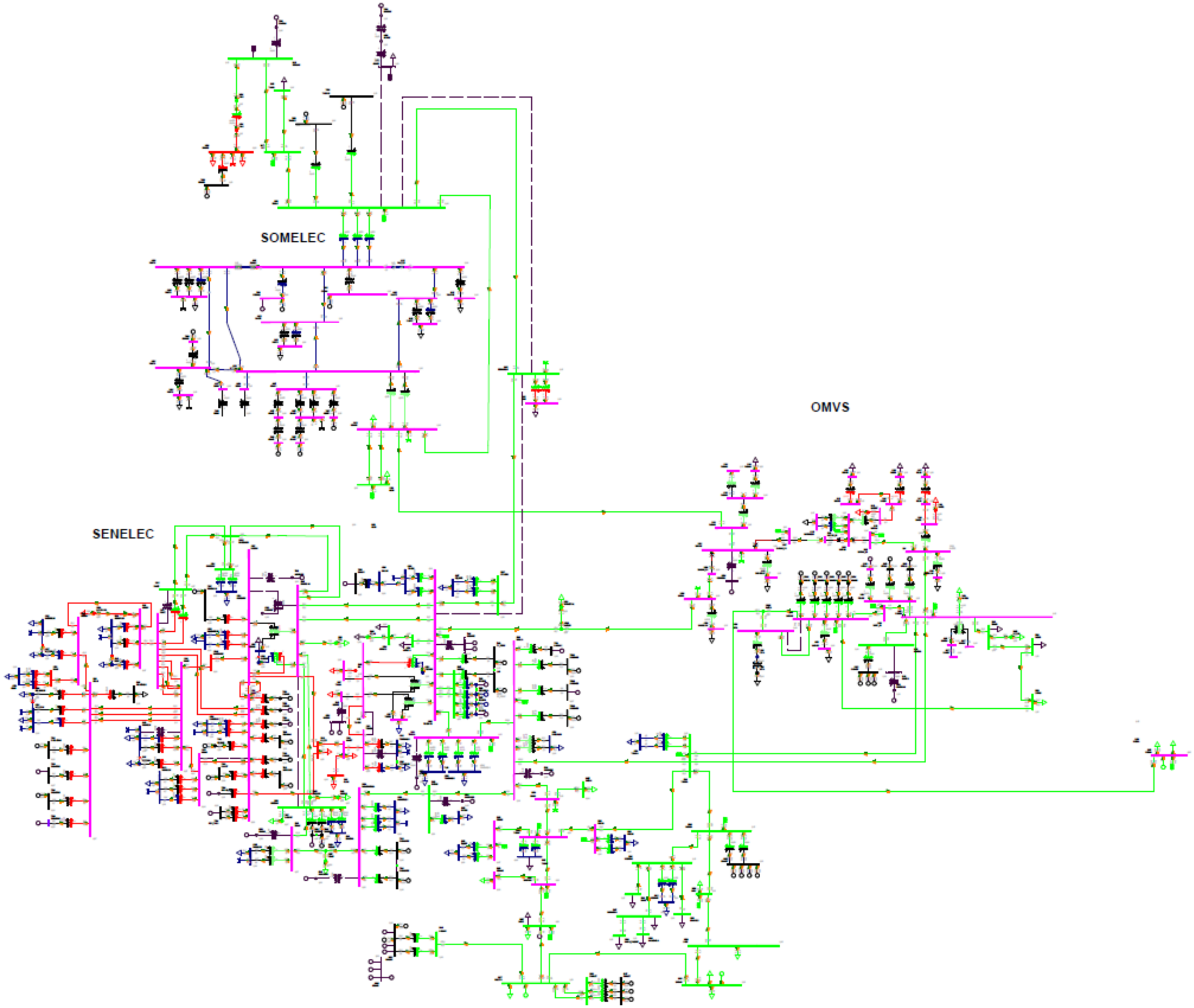
A.1 : 2016_PEAK_170406



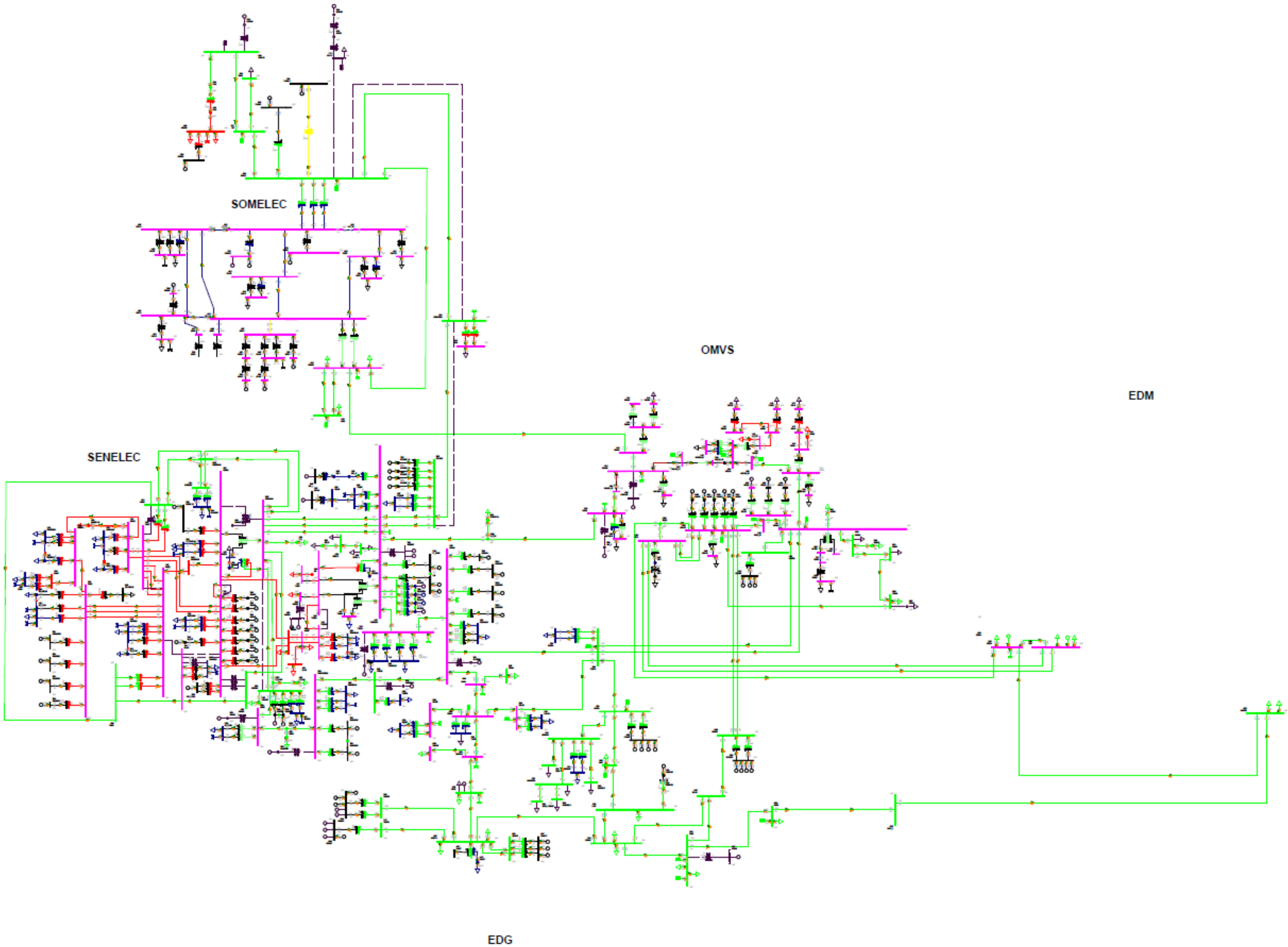
A.2 : 2019_PEAK_170406



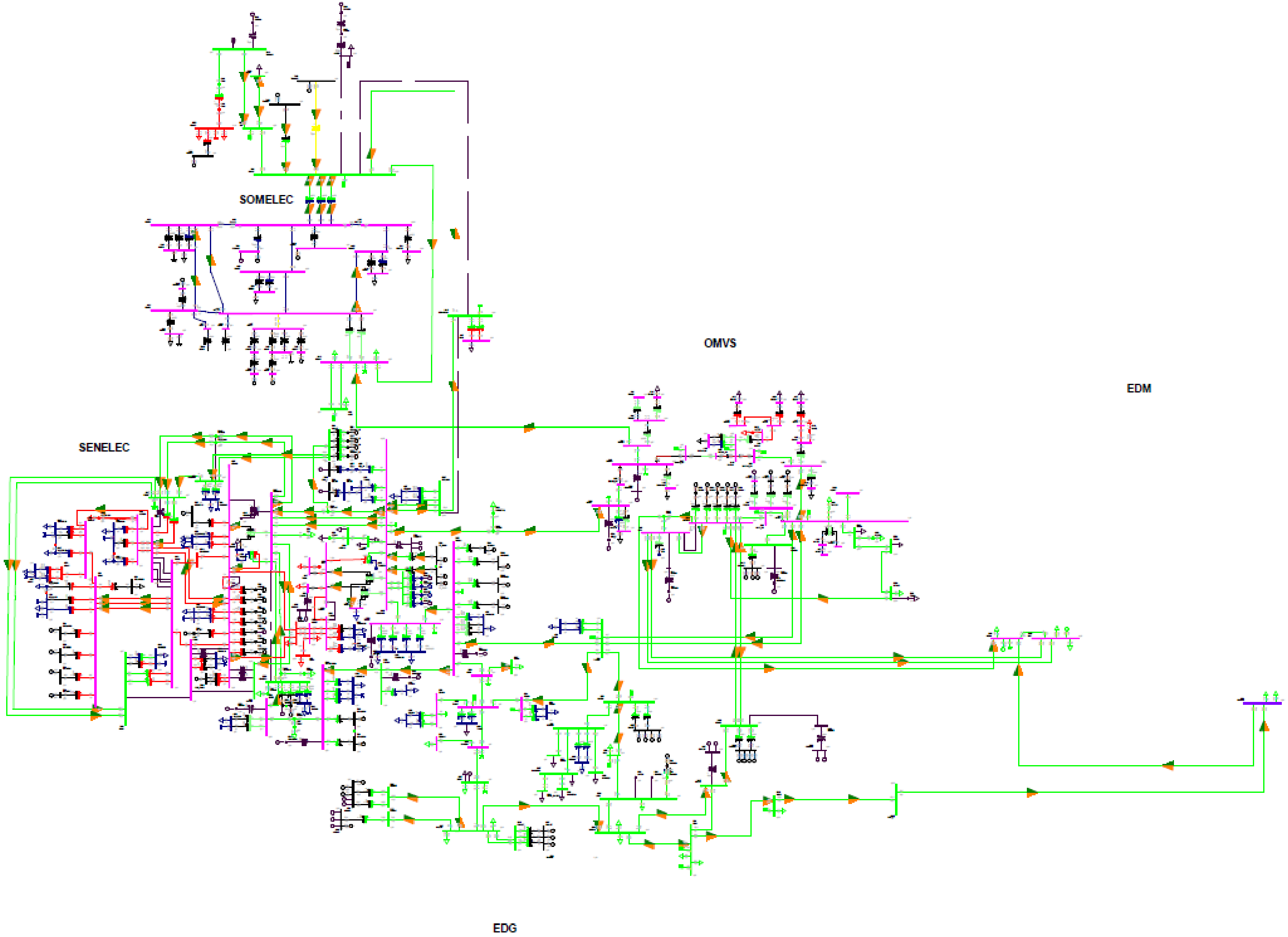
A.3 : 2022_PEAK_170406



A.4 : 2028_PEAK_170406

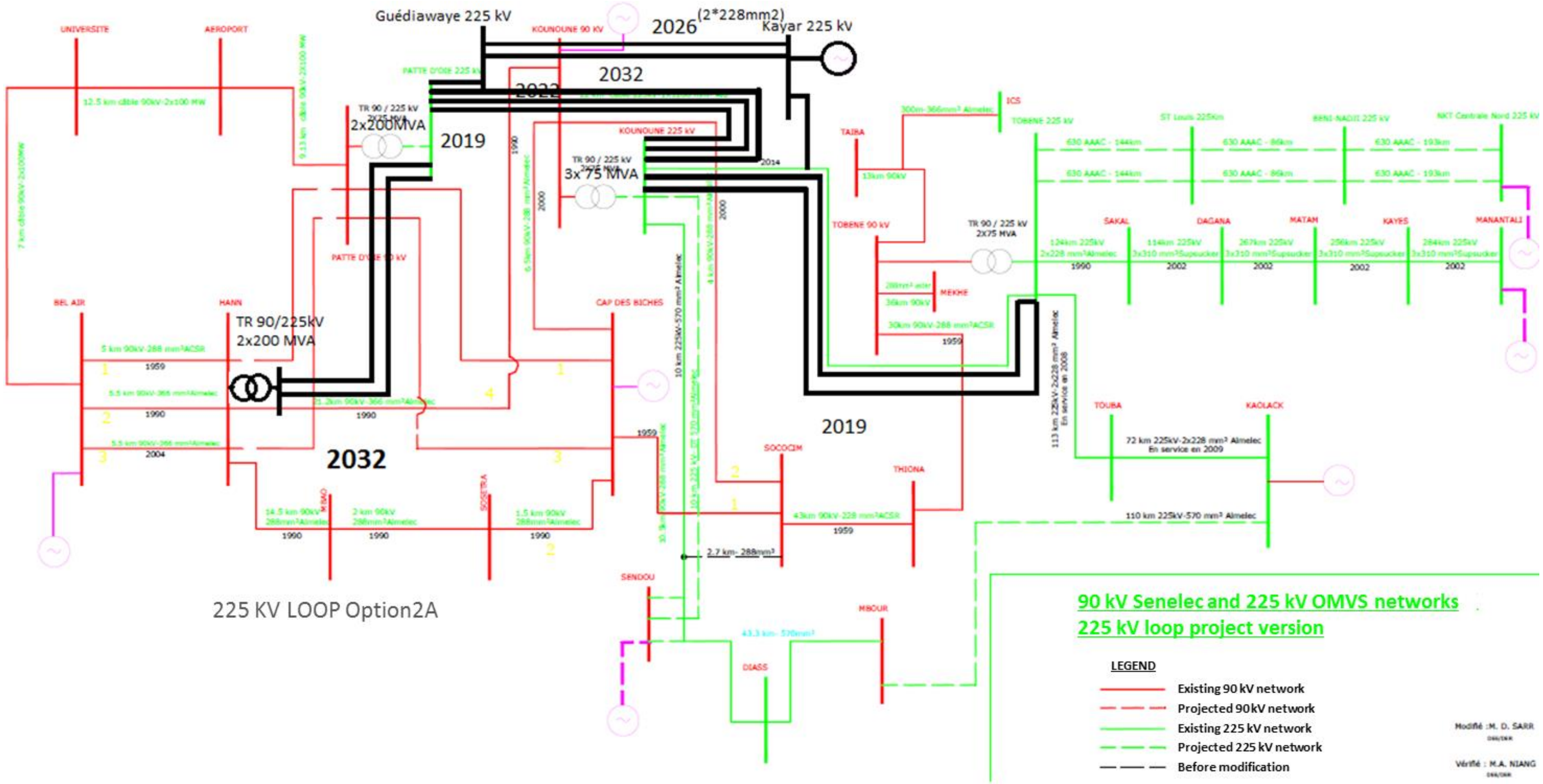


A.5 : SENELEC_2028_PEAK_KAYAR170509

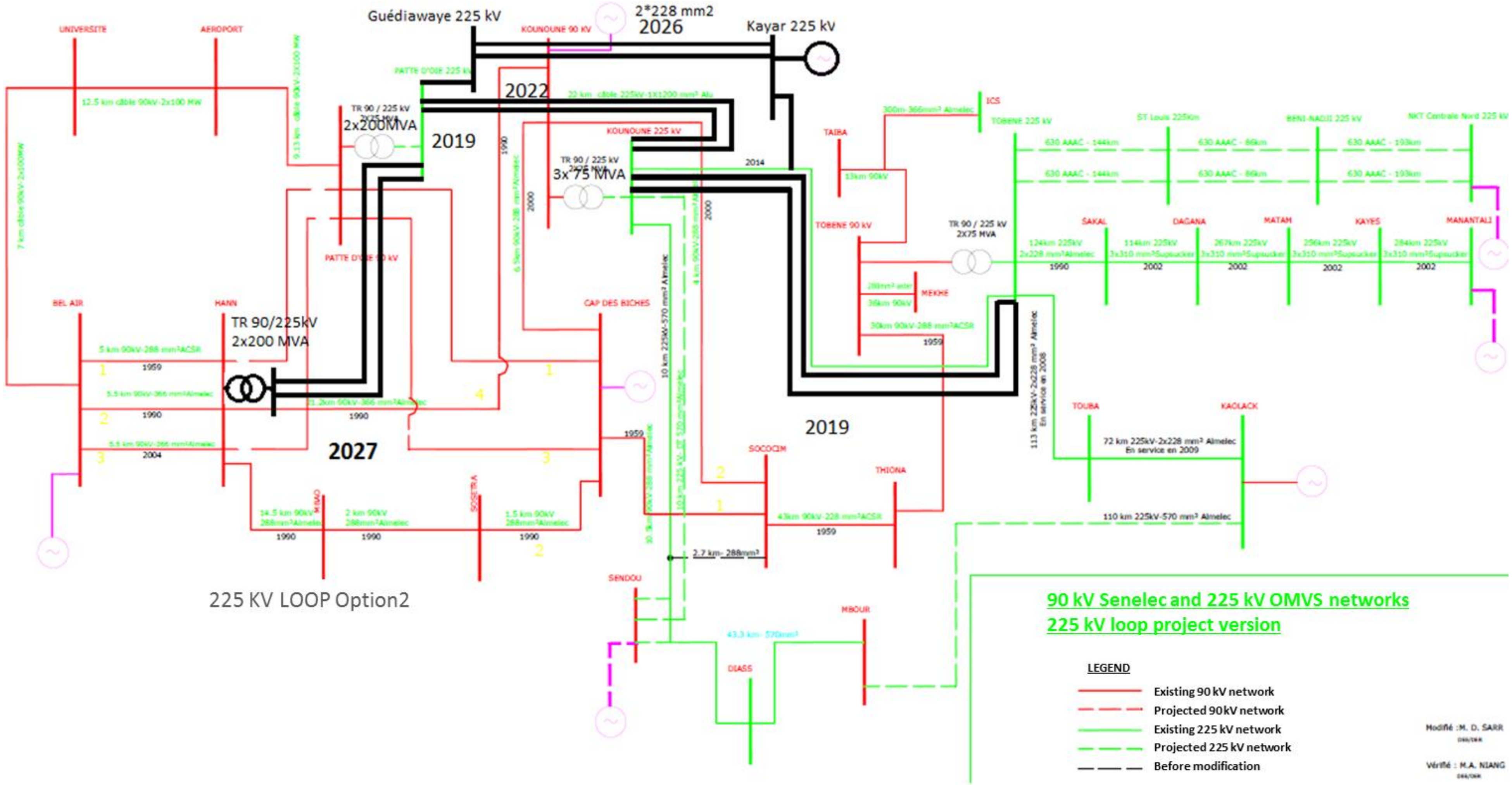


9. APPENDIX B: SINGLE-LINE DIAGRAMS – DECIDED AND RECOMMENDED TRANSMISSION LINE PROJECTS

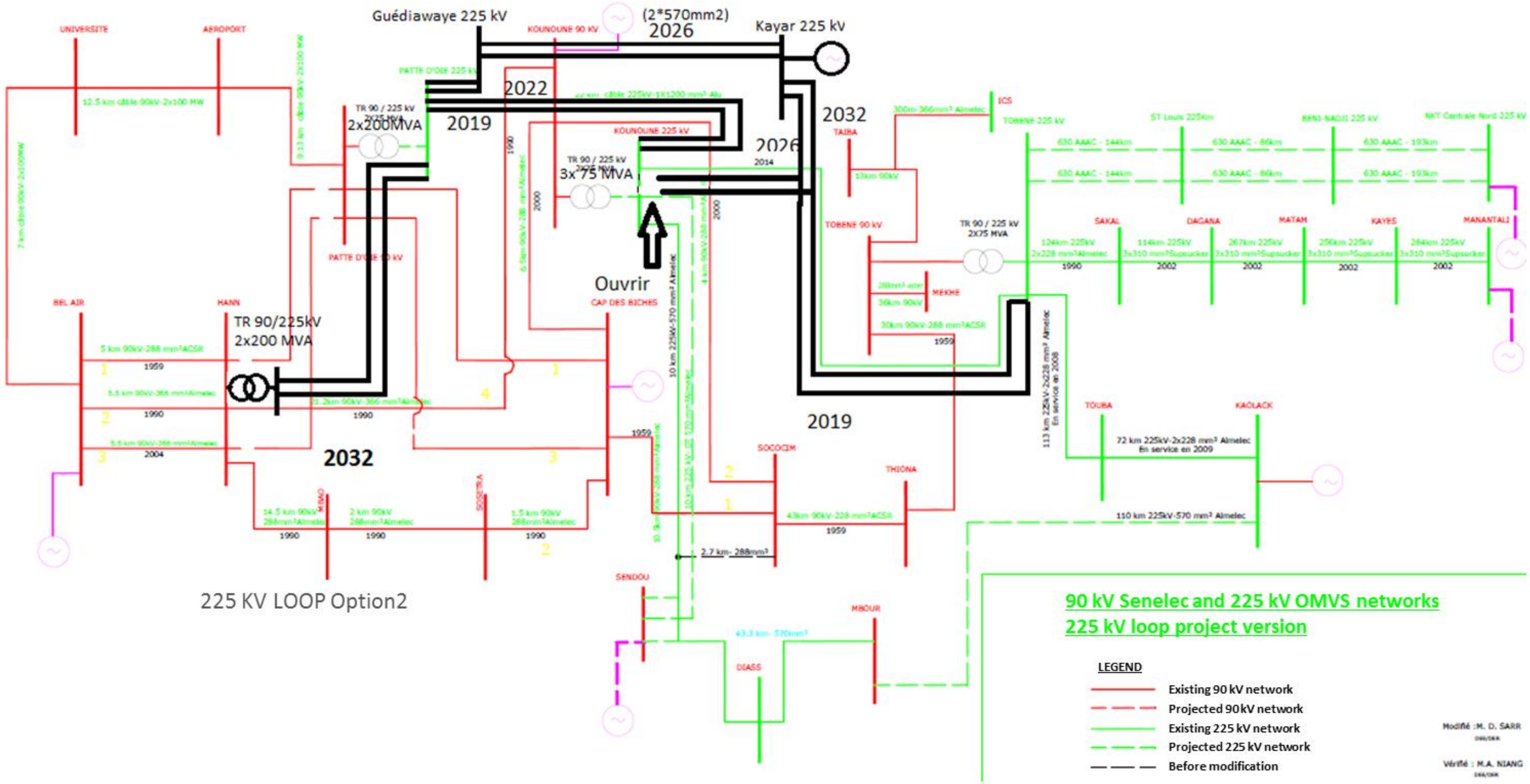
B.1 SENELEC_SU_2016_2032_OPTION2A



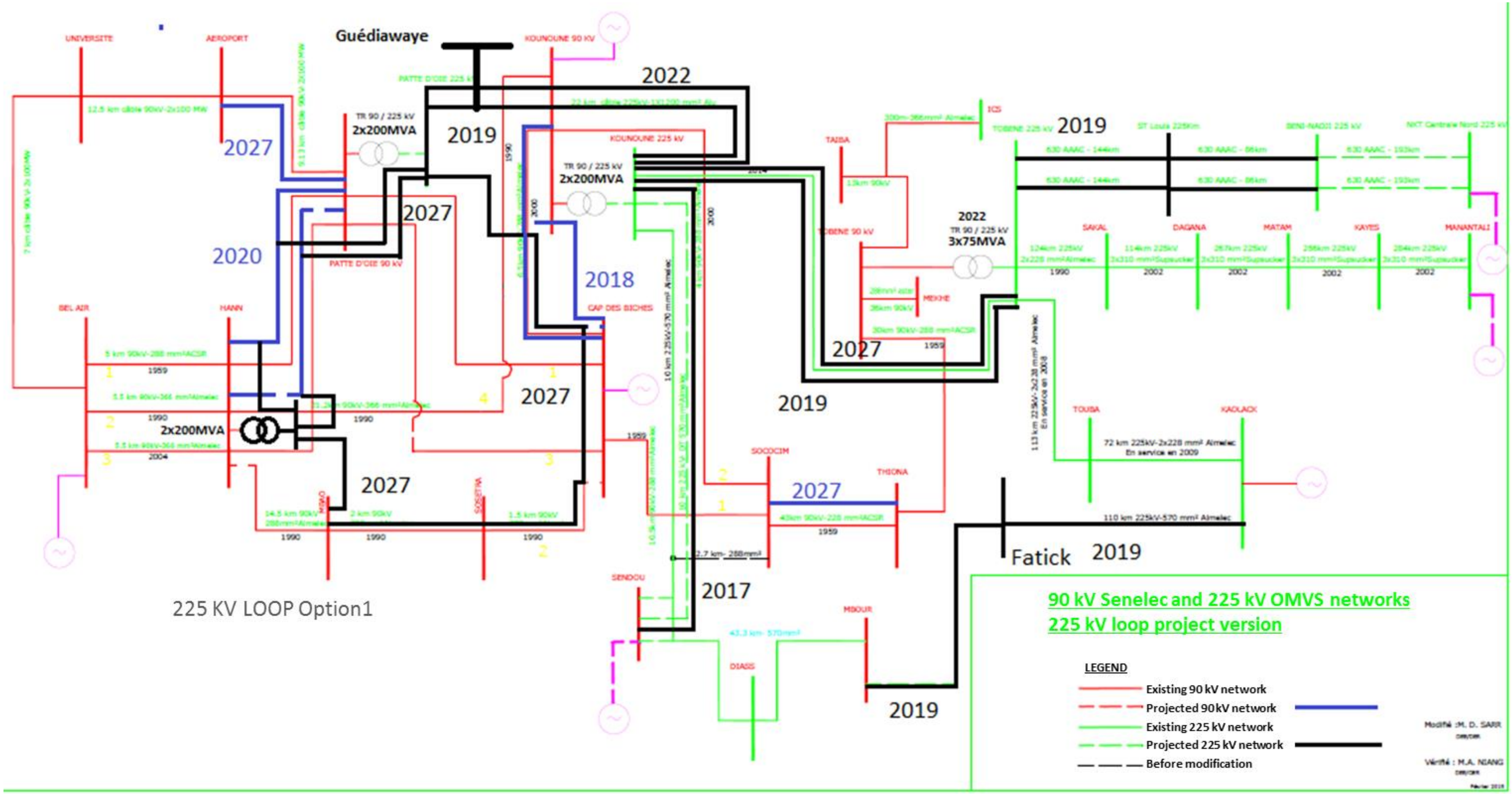
B.2 SENELEC_SU_2016_2027_OPTION2



B.3 SENELEC_SU_2016_2032_OPTION2



B.4 SENELEC_SU_2016_2027_OPTION1



10. APPENDIX C: LOAD SHEDDING

C.1 LOAD SHEDDING MODEL DATA

LOAD SHEDDING MODEL DATA														
Name		Bus	Type	Id	f1	t1	frac1	f2	t2	frac2	f3	t3	frac3	Tb
BELAILD1	33.0	4301	LDSHBL'	1	49	0.2	0.269	48.5	0.2	0.238	48	0.2	0.439	0.1
CAP DBLD1	33.0	4302	LDSHBL'	1	49	0.2	0.131	48.5	0.2	0.137	48	0.2	0.212	0.1
TOUBALD1	33.0	4304	LDSHBL'	1	49	0.2	0.078	48.5	0.2	0.091	48	0.2	0.352	0.1
KAOLALD1	33.0	4305	LDSHBL'	1	49	0.2	0	48.5	0.2	0.085	48	0.2	0.034	0.1
DIASSLD1	33.0	4308	LDSHBL'	1	49	0.2	0	48.5	0.2	0.329	48	0.2	0	0.1
MBOURLD1	33.0	4309	LDSHBL'	1	49	0.2	0.155	48.5	0.2	0.124	48	0.2	0	0.1
HANNLD1	33.0	4310	LDSHBL'	1	49	0.2	0.142	48.5	0.2	0.14	48	0.2	0.155	0.1
THIONALD1	33.0	4312	LDSHBL'	1	49	0.2	0.087	48.5	0.2	0.132	48	0.2	0.234	0.1
MBAOLD1	33.0	4313	LDSHBL'	1	49	0.2	0.242	48.5	0.2	0.235	48	0.2	0	0.1
AEROPLD1	33.0	4314	LDSHBL'	1	49	0.2	0.027	48.5	0.2	0.14	48	0.2	0.12	0.1
UNIVERLD1	33.0	4315	LDSHBL'	1	49	0.2	0.138	48.5	0.2	0.39	48	0.2	0.429	0.1
TOBENE	33.0	4322	LDSHBL'	1	49	0.2	0.464	48.5	0.2	0	48	0.2	0	0.1
STLOUIS	33.0	4327	LDSHBL'	1	49	0.2	0	48.5	0.2	0.613	48	0.2	0.173	0.1

Note: * LDSHBL: Underfrequency Load Shedding Model

49 HZ FIRST FREQUENCY THRESHOLD LOAD SHEDDING													
		2019 Horizon				2022 Horizon				2028 Horizon			
		Off-peak		*Peak*		*Off-peak*		*Peak*		*Off-peak*		*Peak*	
Name		Load (MW)	Load shedding (MW)	Load (MW)	Load shedding (MW)	Load (MW)	Load shedding (MW)	Load (MW)	Load shedding (MW)	Load (MW)	Load shedding (MW)	Load (MW)	Load shedding (MW)
BELAILD1	33.0	13.69	3.68	26.46	7.12	15.85	4.26	31.17	8.38	22.30	6.00	51.00	13.72
CAP DBLD1	33.0	8.26	1.08	15.97	2.09	9.36	1.23	18.41	2.41	13.12	1.72	30.00	3.93
TOUBALD1	33.0	9.30	0.73	17.97	1.40	10.97	0.86	21.57	1.68	15.09	1.18	34.50	2.69
KAOLALD1	33.0	14.46	0.00	27.95	0.00	16.52	0.00	32.48	0.00	23.61	0.00	54.00	0.00
DIASSLD1	33.0	10.85	0.00	20.97	0.00	14.99	0.00	29.48	0.00	15.31	0.00	35.00	0.00
MBOURLD1	33.0	16.53	2.56	31.95	4.95	19.21	2.98	37.77	5.85	27.11	4.20	62.00	9.61
HANNLD1	33.0	48.03	6.82	92.85	13.18	55.58	7.89	109.28	15.52	78.71	11.18	180.00	25.56
THIONALD1	33.0	13.94	1.21	26.96	2.35	15.67	1.36	30.82	2.68	21.86	1.90	50.00	4.35
MBAOLD1	33.0	11.36	2.75	21.96	5.32	31.03	7.51	35.96	8.70	18.80	4.55	43.00	10.41
AEROPLD1	33.0	19.11	0.52	36.94	1.00	21.91	0.59	43.08	1.16	31.05	0.84	71.00	1.92
UNIVERLD1	33.0	10.85	1.50	20.97	2.89	12.37	1.71	24.32	3.36	17.49	2.41	40.00	5.52
TOBENE	33.0	2.58	1.20	4.99	2.32	2.93	1.36	5.75	2.67	4.37	2.03	10.00	4.64
STLOUIS	33.0	5.94	0.00	11.48	0.00	6.88	0.00	13.52	0.00	9.62	0.00	22.00	0.00
Total (MW)		184.9	22.0	357.4	42.6	233.3	29.7	433.6	52.4	298.4	36.0	682.5	82.3

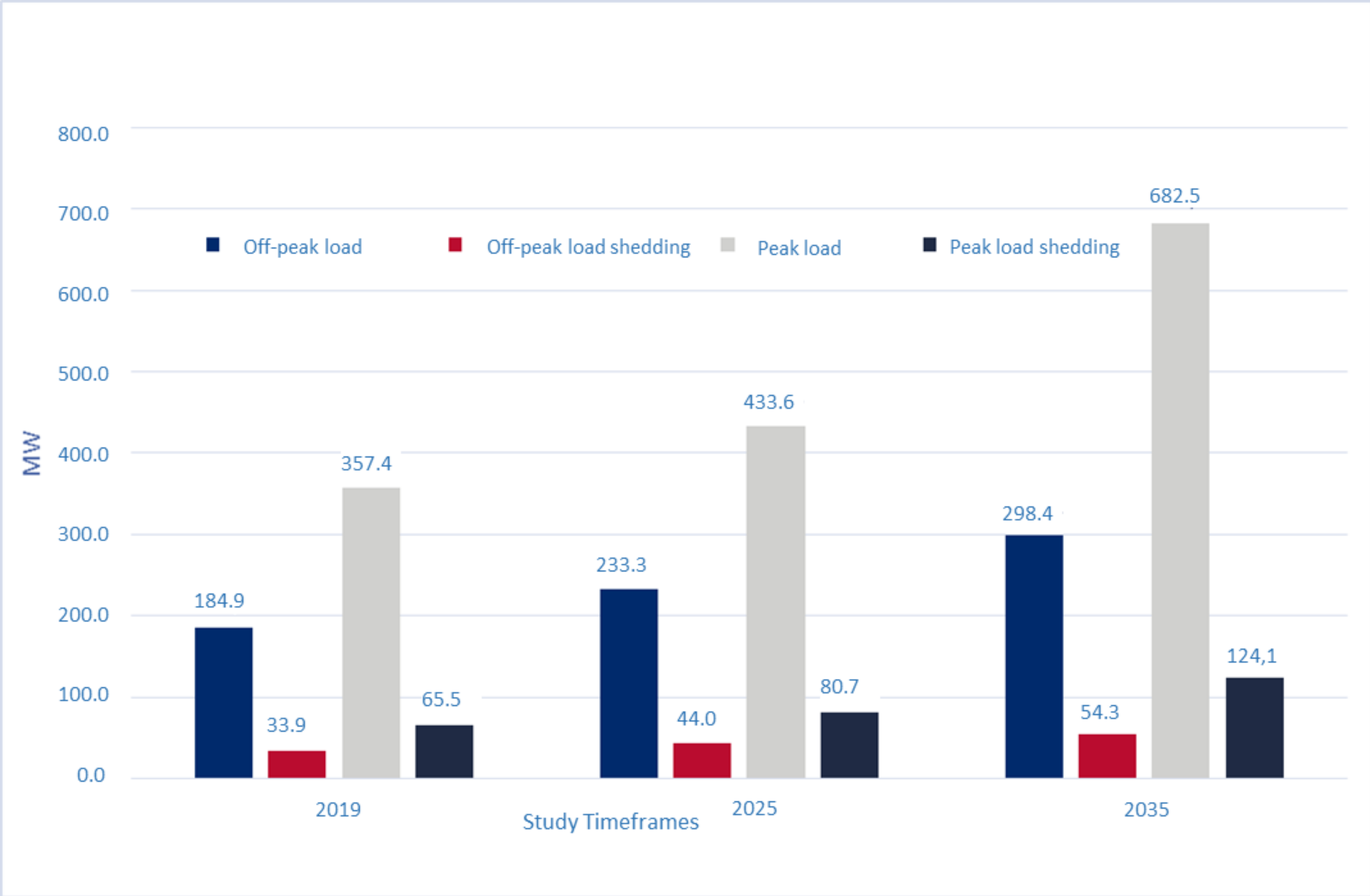
Figure illustrating load shedding for the first threshold f=49 Hz for the three study horizons and for two load situations: peak and off-peak.

Frequency load shedding for the first threshold f=49 Hz: 2019 (1), 2022 (2) and 2028 (3) horizons

48.5 HZ FIRST FREQUENCY THRESHOLD LOAD SHEDDING													
		2019 Horizon				2022 Horizon				2028 Horizon			
		Off-peak		*Peak*		*Off-peak*		*Peak*		*Off-peak*		*Peak*	
Name		Load (MW)	Load shedding (MW)	Load (MW)	Load shedding (MW)	Load (MW)	Load shedding (MW)	Load (MW)	Load shedding (MW)	Load (MW)	Load shedding (MW)	Load (MW)	Load shedding (MW)
BELAILD1	33.0	13.69	3.26	26.46	6.30	15.85	3.77	31.17	7.42	22.30	5.31	51.00	12.14
CAP DBLD1	33.0	8.26	1.13	15.97	2.19	9.36	1.28	18.41	2.52	13.12	1.80	30.00	4.11
TOUBALD1	33.0	9.30	0.85	17.97	1.64	10.97	1.00	21.57	1.96	15.09	1.37	34.50	3.14
KAOLALD1	33.0	14.46	1.23	27.95	2.38	16.52	1.40	32.48	2.76	23.61	2.01	54.00	4.59
DIASSLD1	33.0	10.85	3.57	20.97	6.90	14.99	4.93	29.48	9.70	15.31	5.04	35.00	11.52
MBOURLD1	33.0	16.53	2.05	31.95	3.96	19.21	2.38	37.77	4.68	27.11	3.36	62.00	7.69
HANNLD1	33.0	48.03	6.72	92.85	13.00	55.58	7.78	109.28	15.30	78.71	11.02	180.00	25.20
THIONALD1	33.0	13.94	1.84	26.96	3.56	15.67	2.07	30.82	4.07	21.86	2.89	50.00	6.60
MBAOLD1	33.0	11.36	2.67	21.96	5.16	31.03	7.29	35.96	8.45	18.80	4.42	43.00	10.11
AEROPLD1	33.0	19.11	2.68	36.94	5.17	21.91	3.07	43.08	6.03	31.05	4.35	71.00	9.94
UNIVERLD1	33.0	10.85	4.23	20.97	8.18	12.37	4.82	24.32	9.48	17.49	6.82	40.00	15.60
TOBENE	33.0	2.58	0.00	4.99	0.00	2.93	0.00	5.75	0.00	4.37	0.00	10.00	0.00
STLOUIS	33.0	5.94	3.64	11.48	7.04	6.88	4.21	13.52	8.29	9.62	5.90	22.00	13.49
Total (MW)		**184.9**	**33.9**	**357.4**	**65.5**	**233.3**	**44.0**	**433.6**	**80.7**	**298.4**	**54.3**	**682.5**	**124.1**

Figure illustrating load shedding for the second threshold f=48.5 Hz for the three study horizons and for two load situations: peak and off-peak.

Frequency load shedding for the second threshold f=48.5 Hz: 2019, 2022 and 2028 horizons



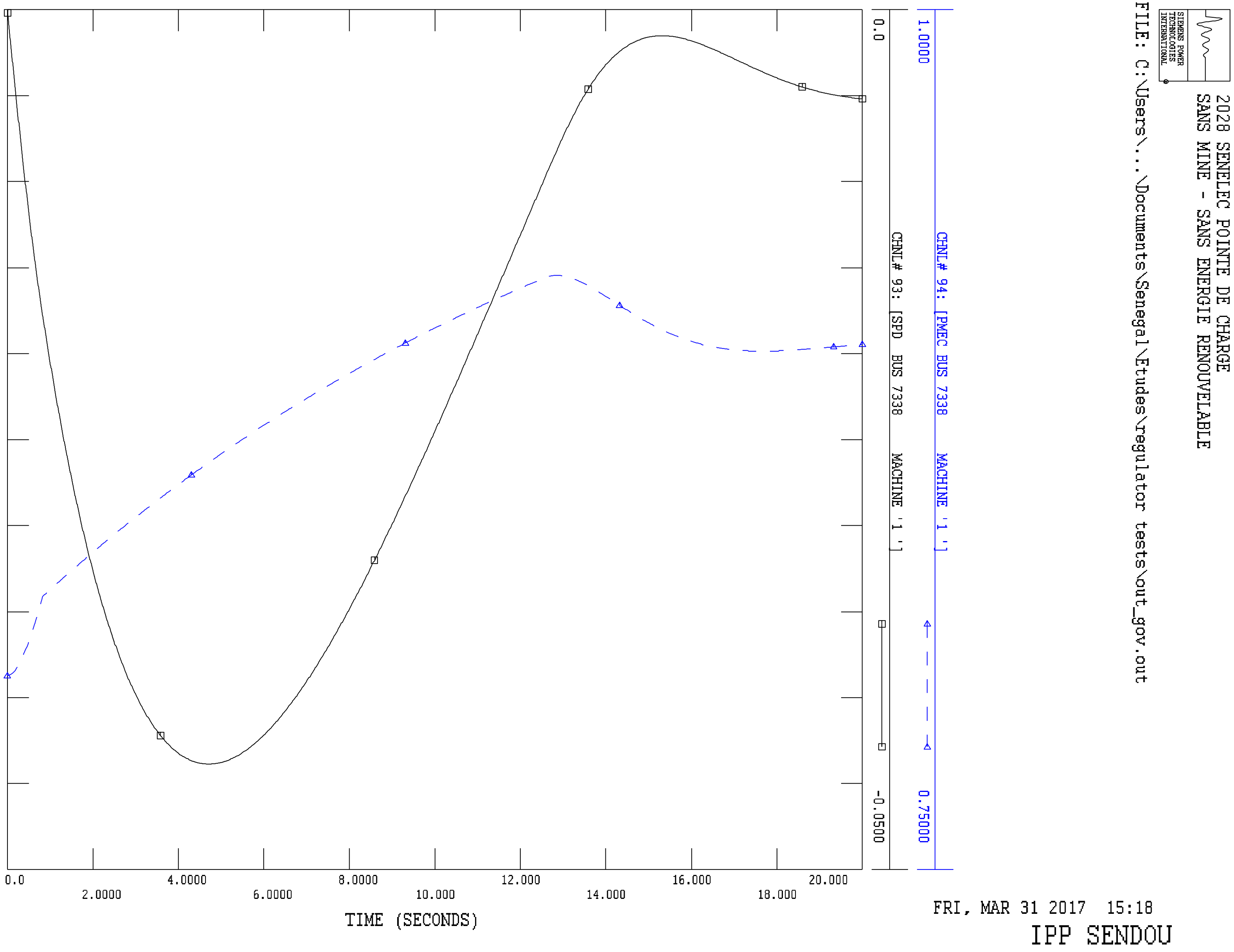
48 HZ FIRST FREQUENCY THRESHOLD LOAD SHEDDING													
		2019 Horizon				2022 Horizon				2028 Horizon			
		Off-peak		*Peak*		*Off-peak*		*Off-peak*		*Peak*		*Off-peak*	
Name		Load (MW)	Load shedding (MW)	Load (MW)	Load shedding (MW)	Load (MW)	Load shedding (MW)	Load (MW)	Load shedding (MW)	Load (MW)	Load shedding (MW)	Load (MW)	Load shedding (MW)
BELAILD1	33.0	13.69	6.01	26.46	11.61	15.85	6.96	31.17	13.68	22.30	9.79	51.00	22.39
CAP DBLD1	33.0	8.26	1.75	15.97	3.39	9.36	1.98	18.41	3.90	13.12	2.78	30.00	6.36
TOUBALD1	33.0	9.30	3.27	17.97	6.33	10.97	3.86	21.57	7.59	15.09	5.31	34.50	12.14
KAOLALD1	33.0	14.46	0.49	27.95	0.95	16.52	0.56	32.48	1.10	23.61	0.80	54.00	1.84
DIASSLD1	33.0	10.85	0.00	20.97	0.00	14.99	0.00	29.48	0.00	15.31	0.00	35.00	0.00
MBOURLD1	33.0	16.53	0.00	31.95	0.00	19.21	0.00	37.77	0.00	27.11	0.00	62.00	0.00
HANNLD1	33.0	48.03	7.44	92.85	14.39	55.58	8.61	109.28	16.94	78.71	12.20	180.00	27.90
THIONALD1	33.0	13.94	3.26	26.96	6.31	15.67	3.67	30.82	7.21	21.86	5.12	50.00	11.70
MBAOLD1	33.0	11.36	0.00	21.96	0.00	31.03	0.00	35.96	0.00	18.80	0.00	43.00	0.00
AEROPLD1	33.0	19.11	2.29	36.94	4.43	21.91	2.63	43.08	5.17	31.05	3.73	71.00	8.52
UNIVERLD1	33.0	10.85	4.65	20.97	8.99	12.37	5.30	24.32	10.43	17.49	7.50	40.00	17.16
TOBENE	33.0	2.58	0.00	4.99	0.00	2.93	0.00	5.75	0.00	4.37	0.00	10.00	0.00
STLOUIS	33.0	5.94	1.03	11.48	1.99	6.88	1.19	13.52	2.34	9.62	1.66	22.00	3.81
Total (MW)		**184.9**	**30.2**	**357.4**	**58.4**	**233.3**	**34.8**	**433.6**	**68.4**	**298.4**	**48.9**	**682.5**	**111.8**

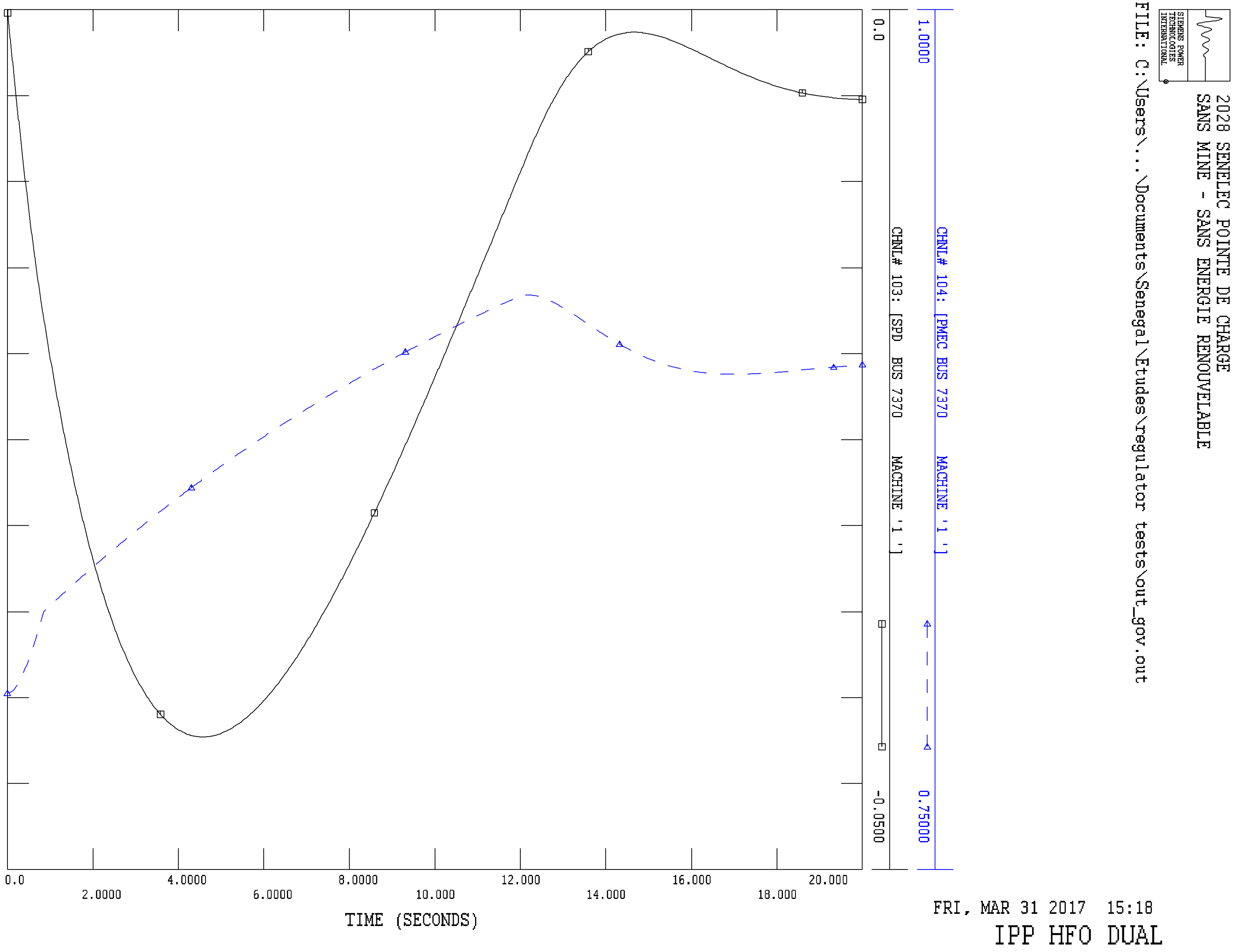
Figure illustrating load shedding for the third threshold f=48 Hz for the three study horizons and for two load situations: peak and off-peak.

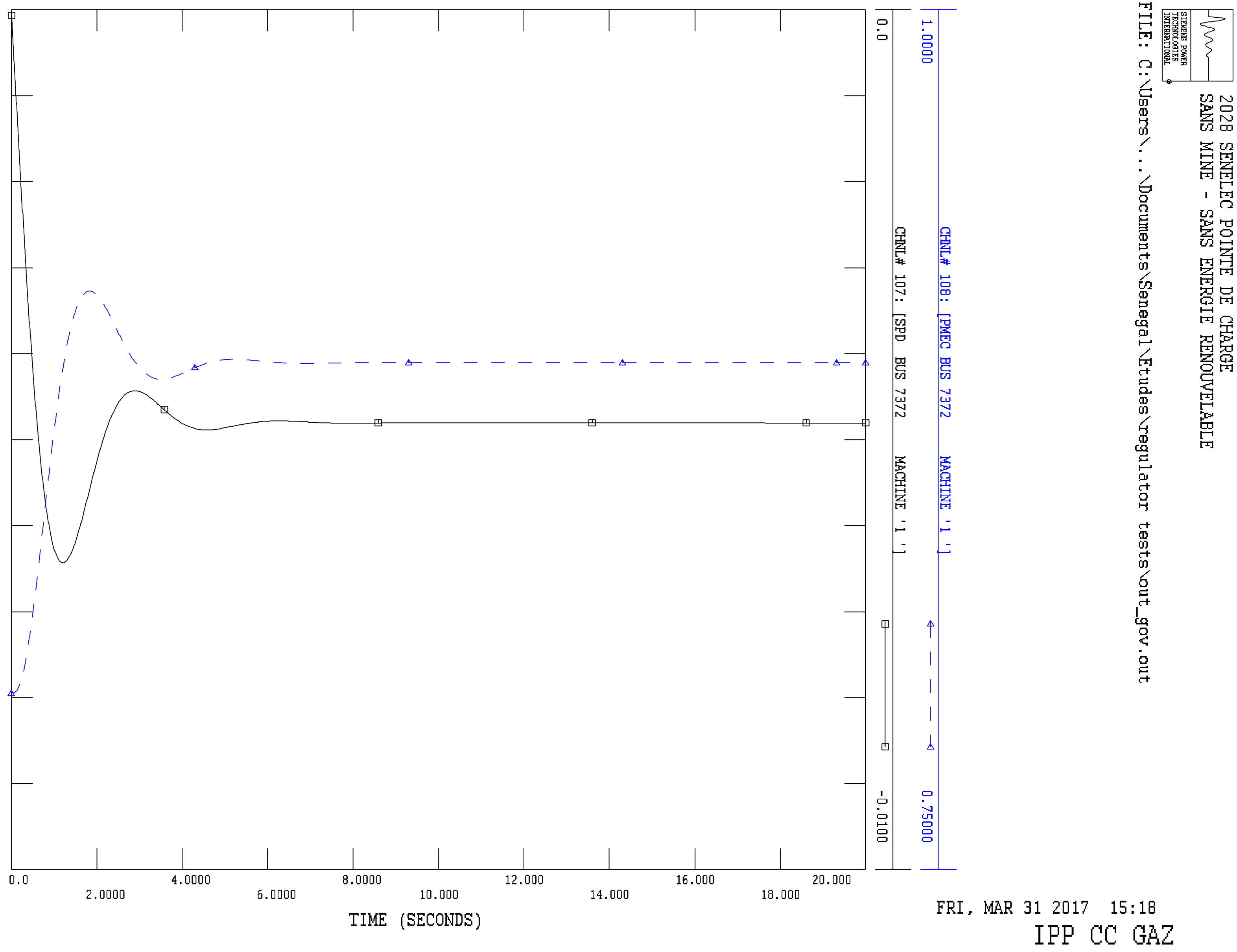
Frequency load shedding for the third threshold f=48 Hz: 2019, 2022 and 2028 horizons

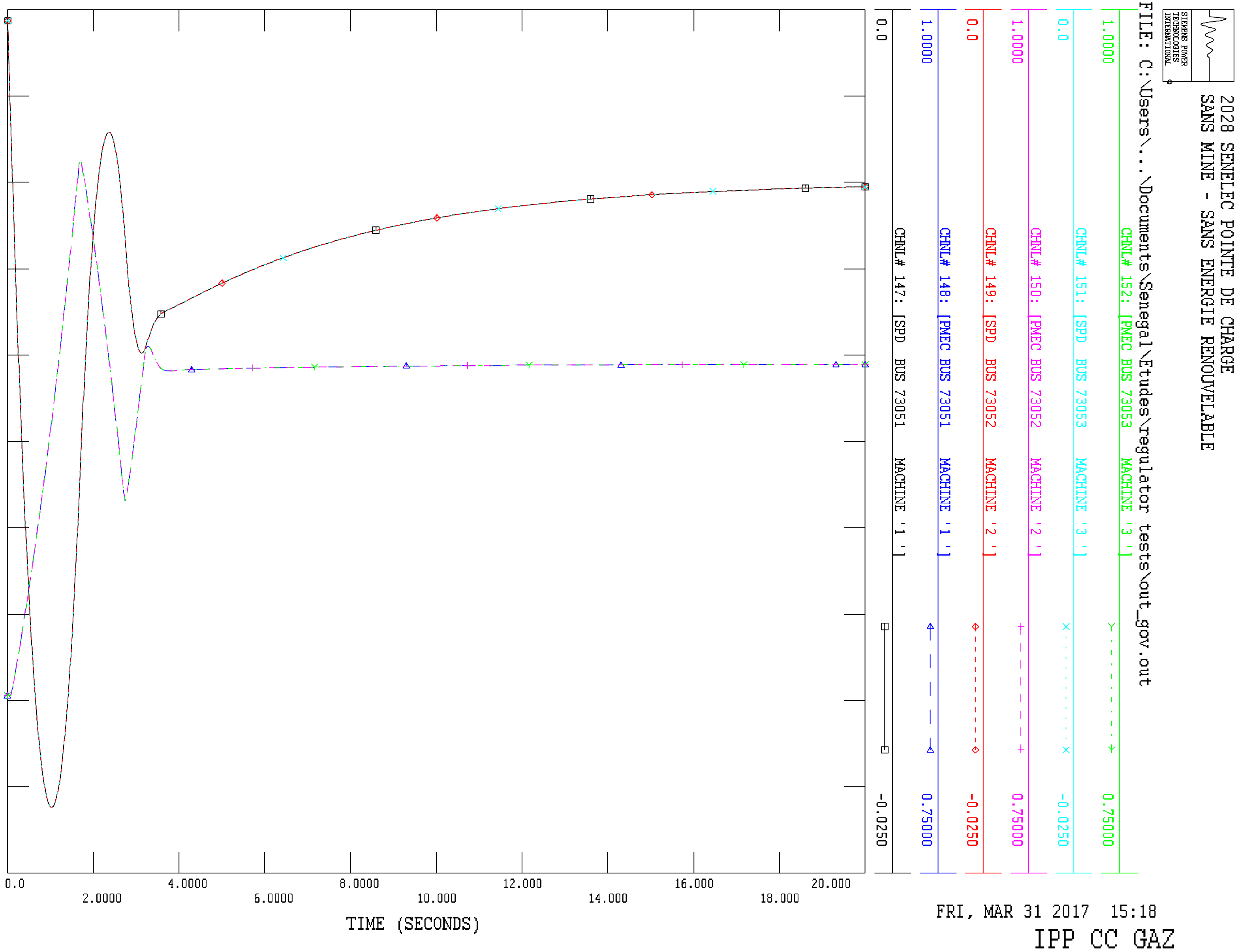
11. APPENDIX D: RESPONSES TO REGULATOR LEVELS

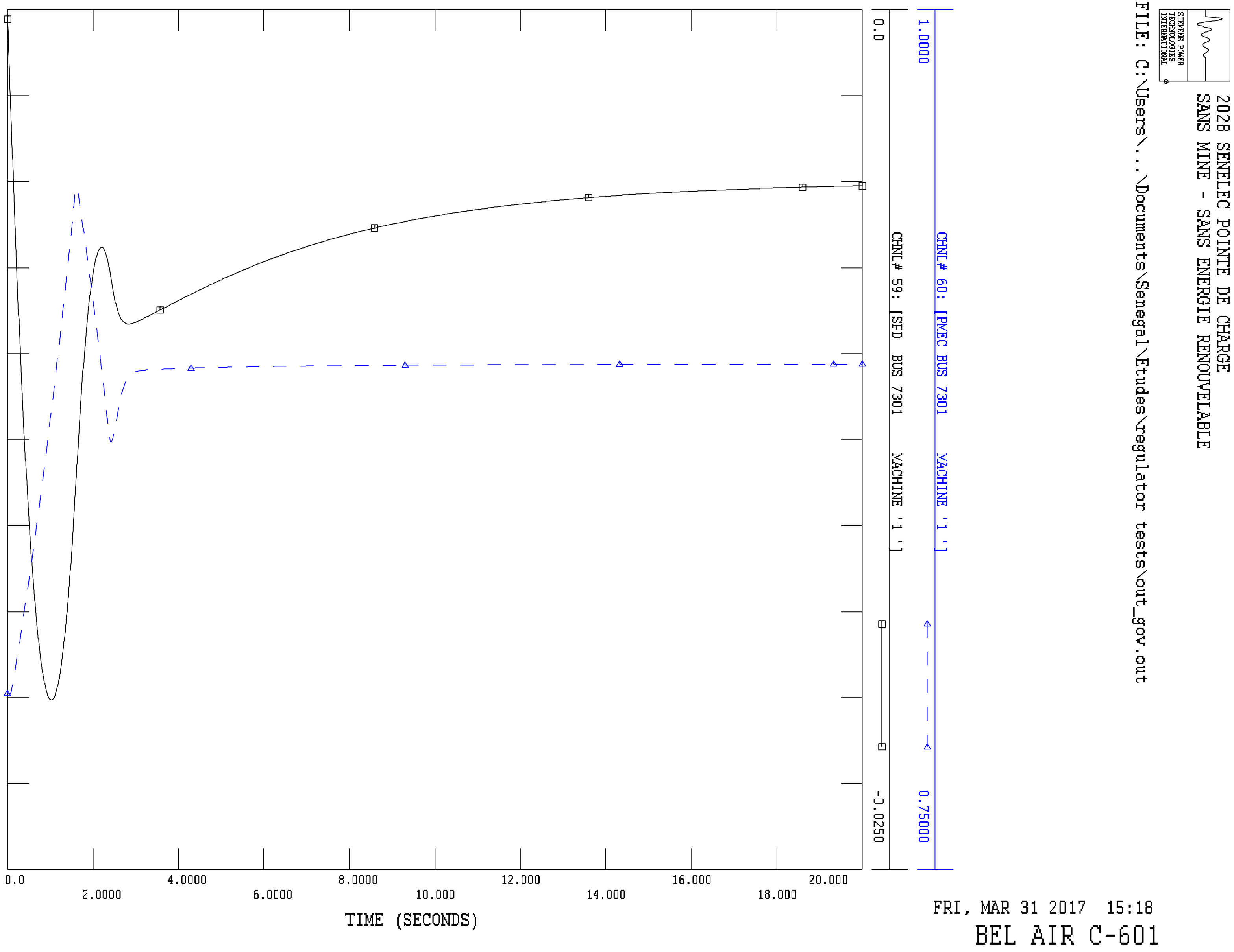
D.1 GOVERNOR RESPONSE TIME AT 10%

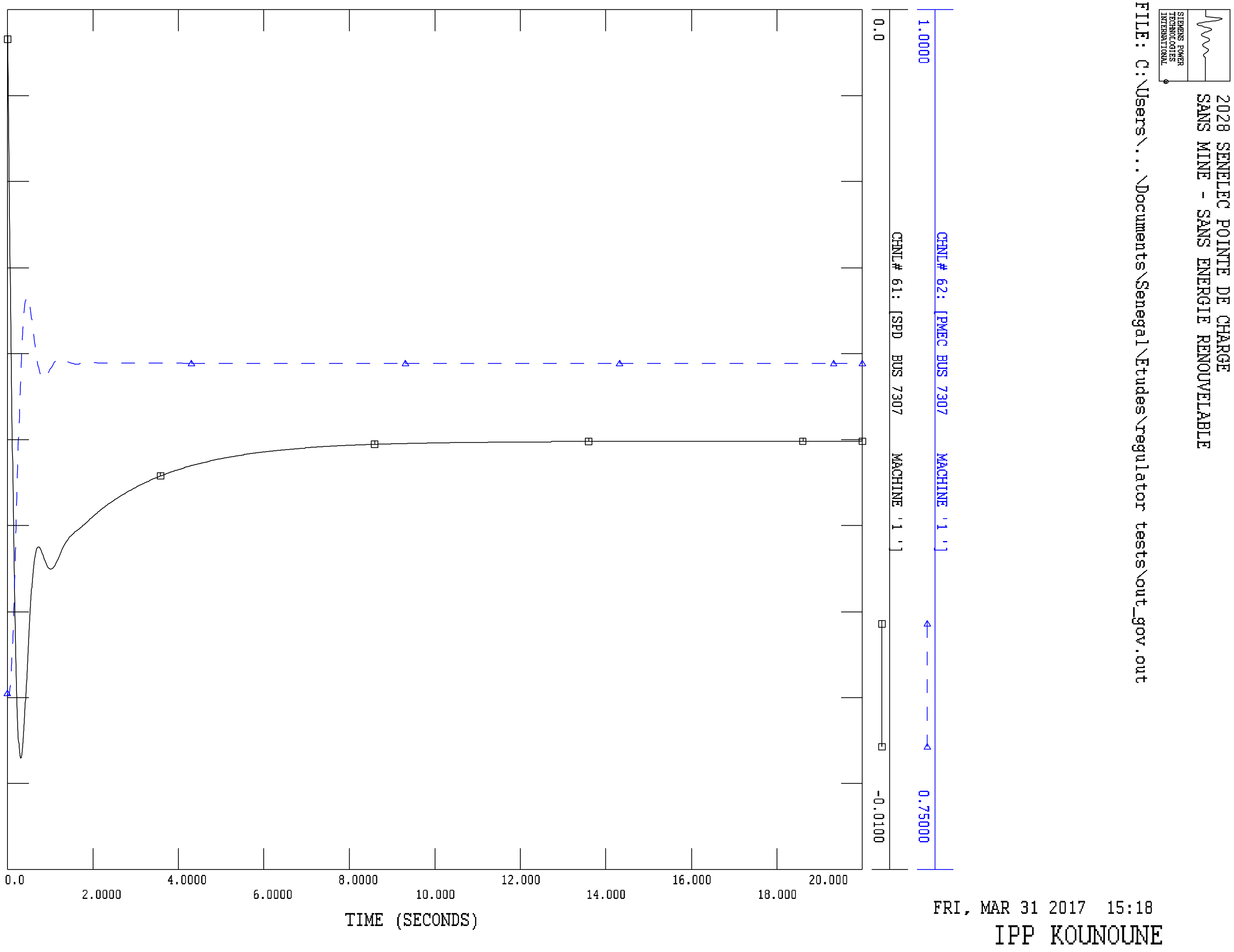

2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Documents\Senegal\Etudes\regulator tests\out_gov.out
CHNL# 93: [SPD BUS 7338 MACHINE '1 ']
0.0
-0.0500
CHNL# 94: [PMEC BUS 7338 MACHINE '1 ']
1.0000
0.75000
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 15:18
IPP SENDOU

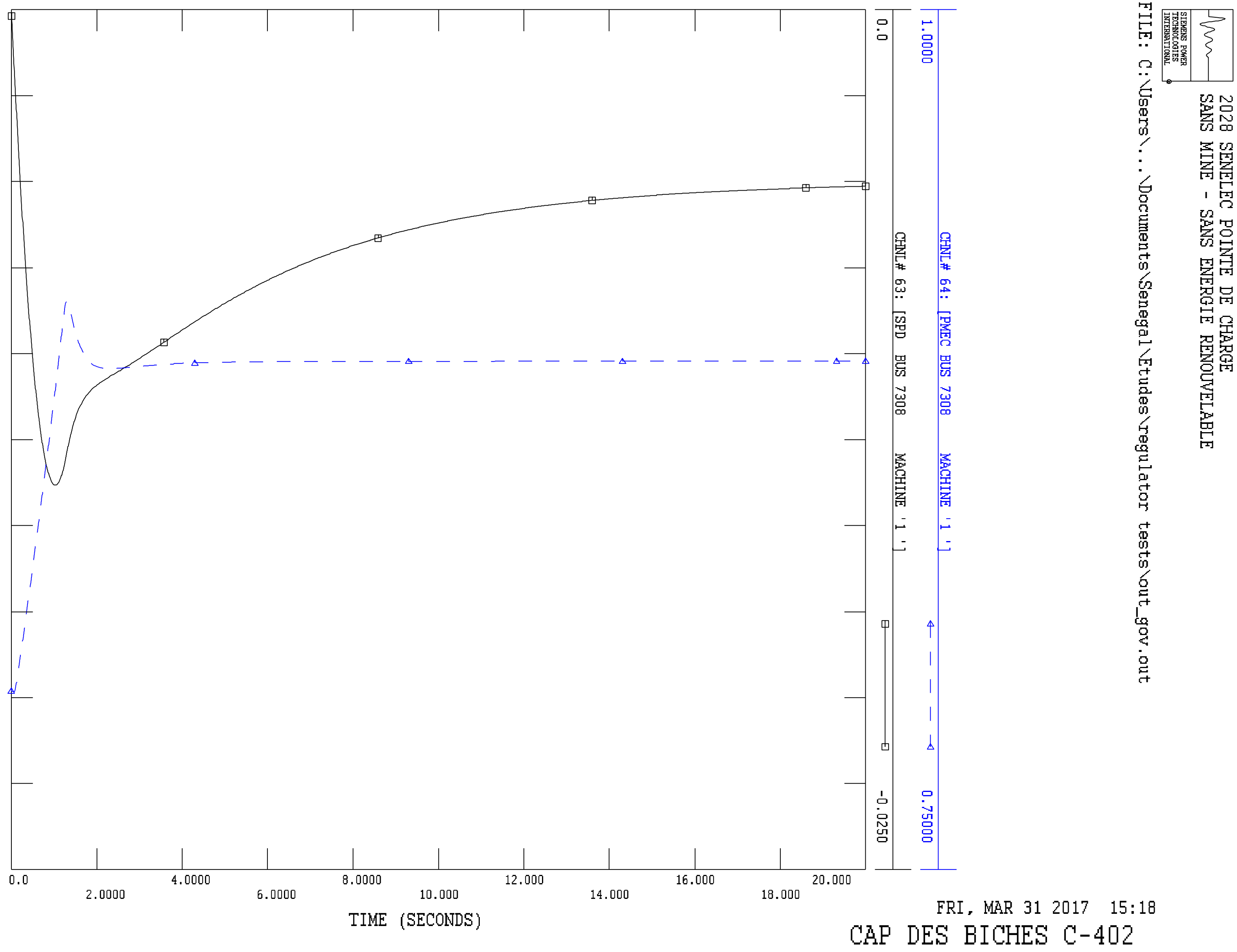

2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Documents\Senegal\Etudes\regulator tests\out_gov.out
CHNL# 103: [SPD BUS 7370 MACHINE '1 ']
0.0
-0.0500
CHNL# 104: [PMEC BUS 7370 MACHINE '1 ']
1.0000
0.75000
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 15:18
IPP HFO DUAL

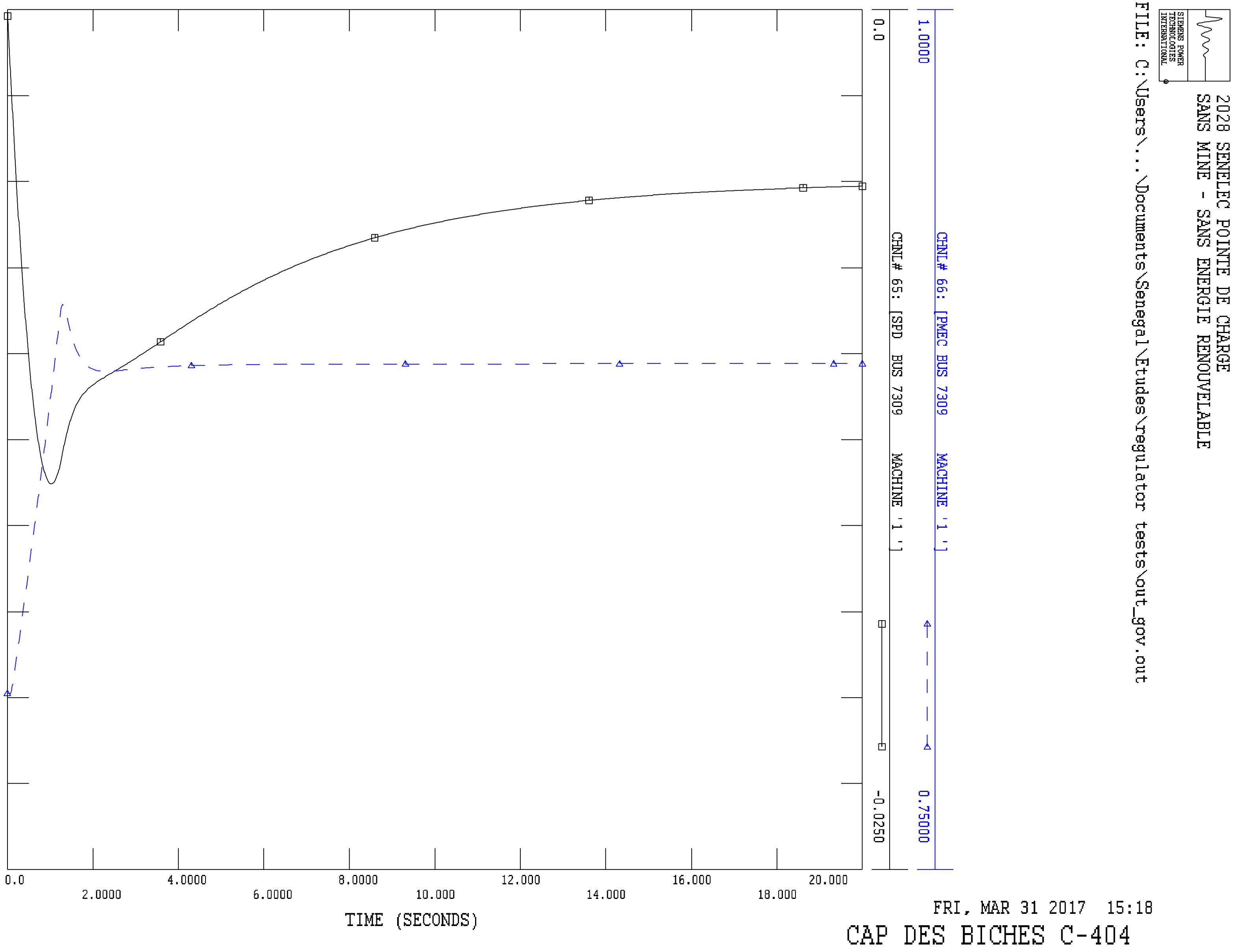

2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Documents\Senegal\Etudes\regulator tests\out_gov.out
CHNL# 107: [SPD BUS 7372 MACHINE '1 ']
0.0
-0.0100
CHNL# 108: [PMEC BUS 7372 MACHINE '1 ']
1.0000
0.75000
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 15:18
IPP CC GAZ

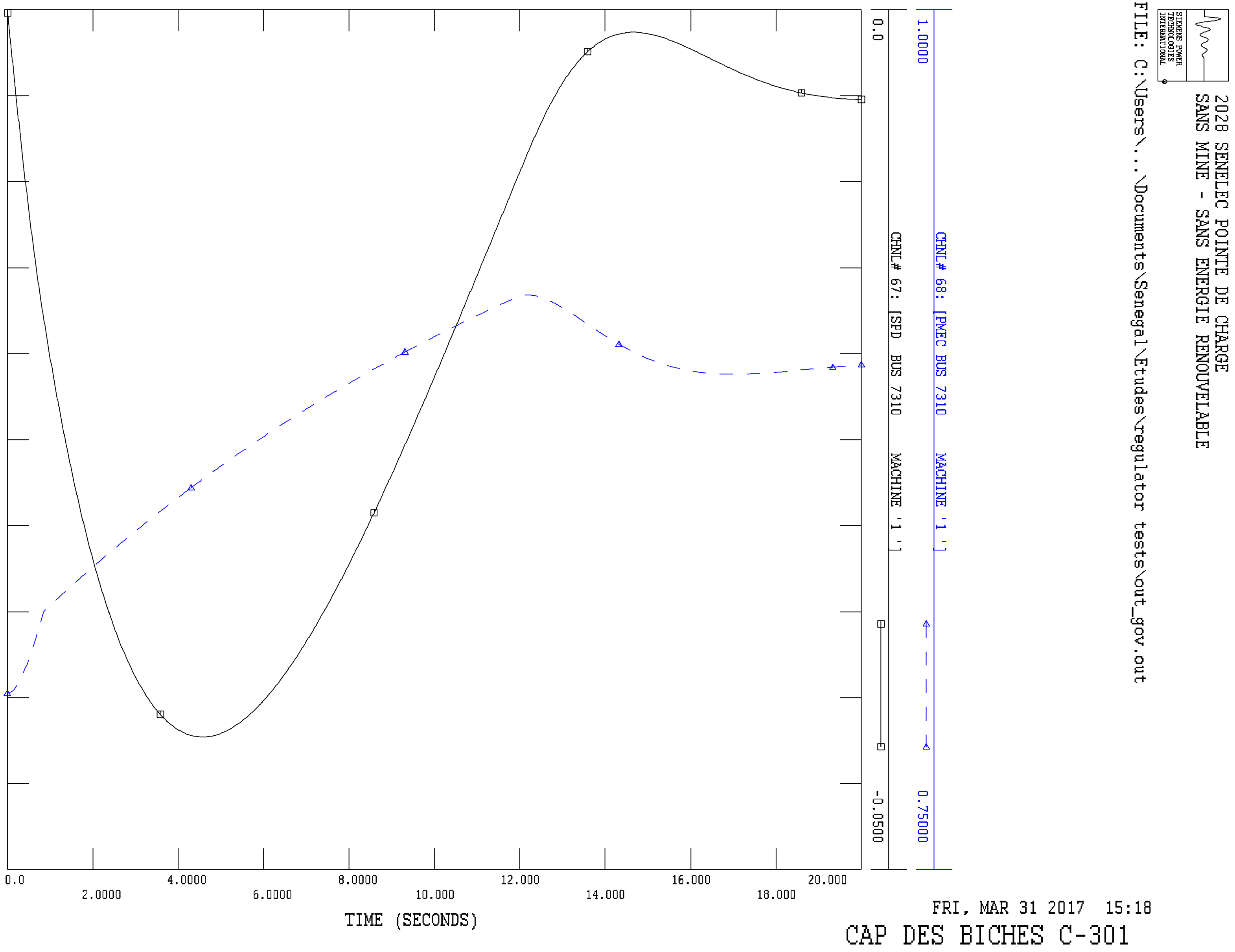

2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Documents\Senegal\Etudes\regulator tests\out_gov.out
CHNL# 152: [PMEC BUS 73053 MACHINE '3 ']
CHNL# 151: [SPD BUS 73053 MACHINE '3 ']
CHNL# 150: [PMEC BUS 73052 MACHINE '2 ']
CHNL# 149: [SPD BUS 73052 MACHINE '2 ']
CHNL# 148: [PMEC BUS 73051 MACHINE '1 ']
CHNL# 147: [SPD BUS 73051 MACHINE '1 ']
1.0000
0.75000
0.0
-0.0250
TIME (SECONDS)
FRI, MAR 31 2017 15:18
IPP CC GAZ

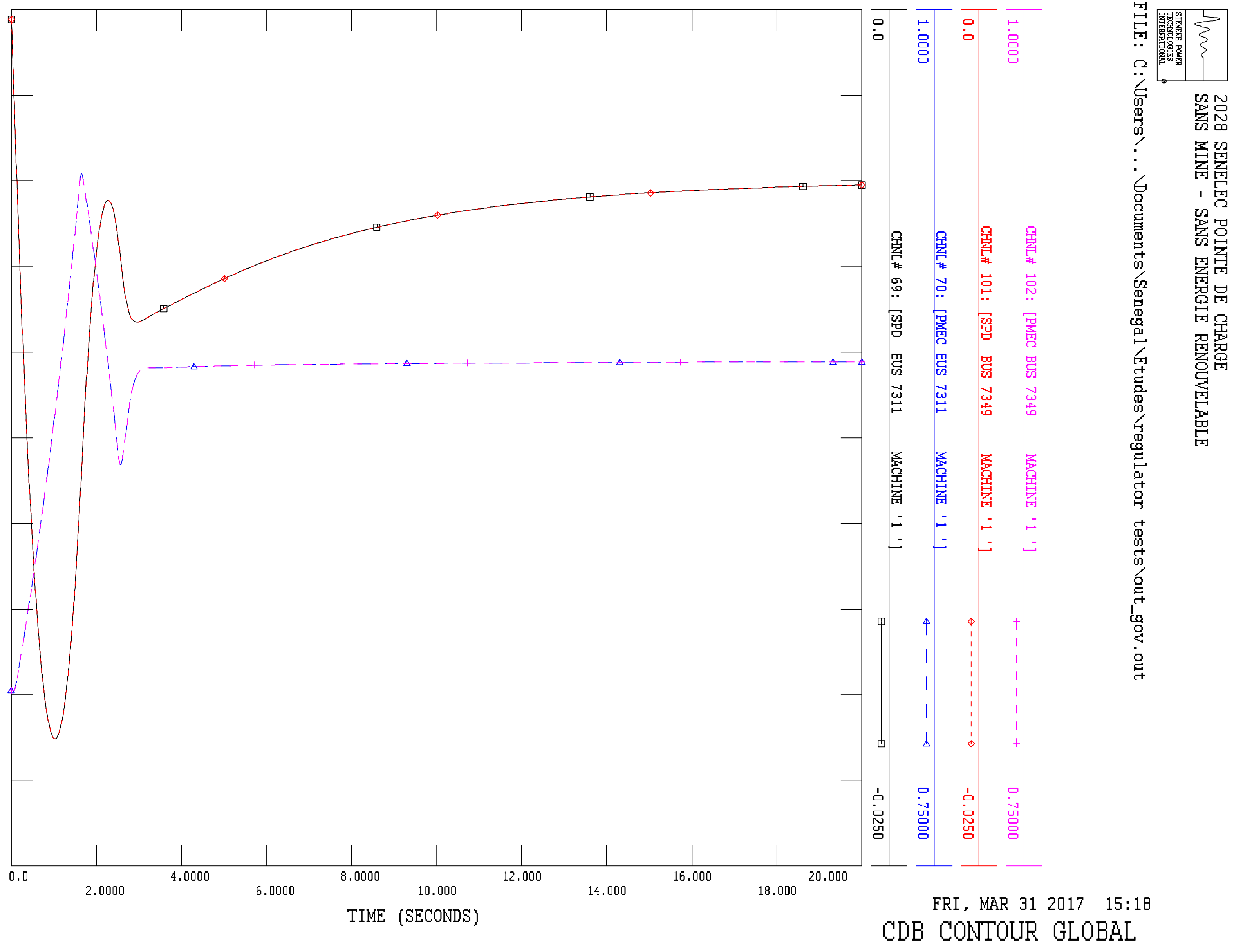

2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Documents\Senegal\Etudes\regulator tests\out_gov.out
SIEMENS POWER TECHNOLOGIES INTERNATIONAL
CHNL# 60: [PMEC BUS 7301 MACHINE '1 ']
1.0000
0.75000
CHNL# 59: [SPD BUS 7301 MACHINE '1 ']
0.0
-0.0250
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 15:18
BEL AIR C-601

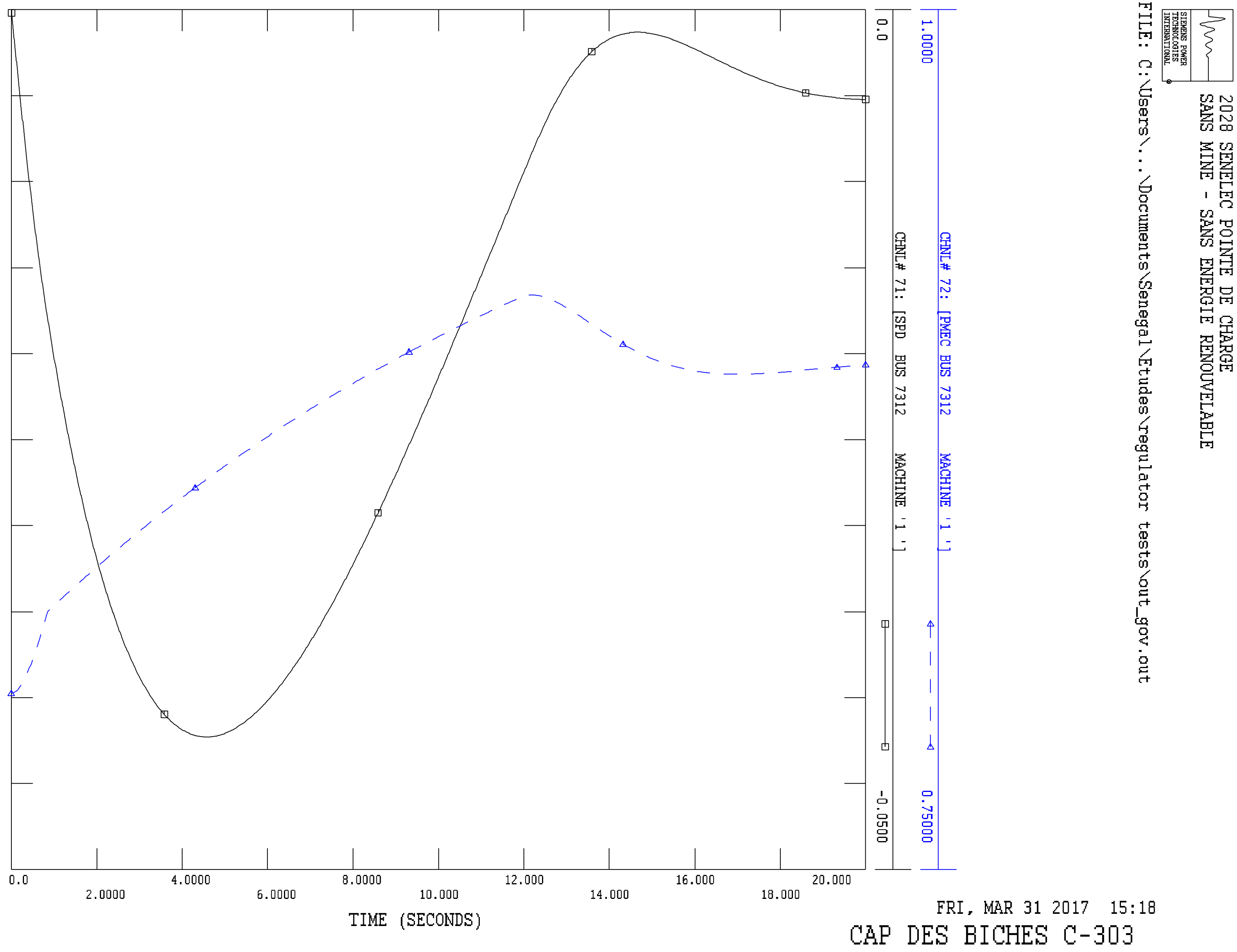

2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Documents\Senegal\Etudes\regulator tests\out_gov.out
CHNL# 61: [SPD BUS 7307 MACHINE '1 ']
0.0
-0.0100
CHNL# 62: [PMEC BUS 7307 MACHINE '1 ']
1.0000
0.75000
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 15:18
IPP KOUNOUNE

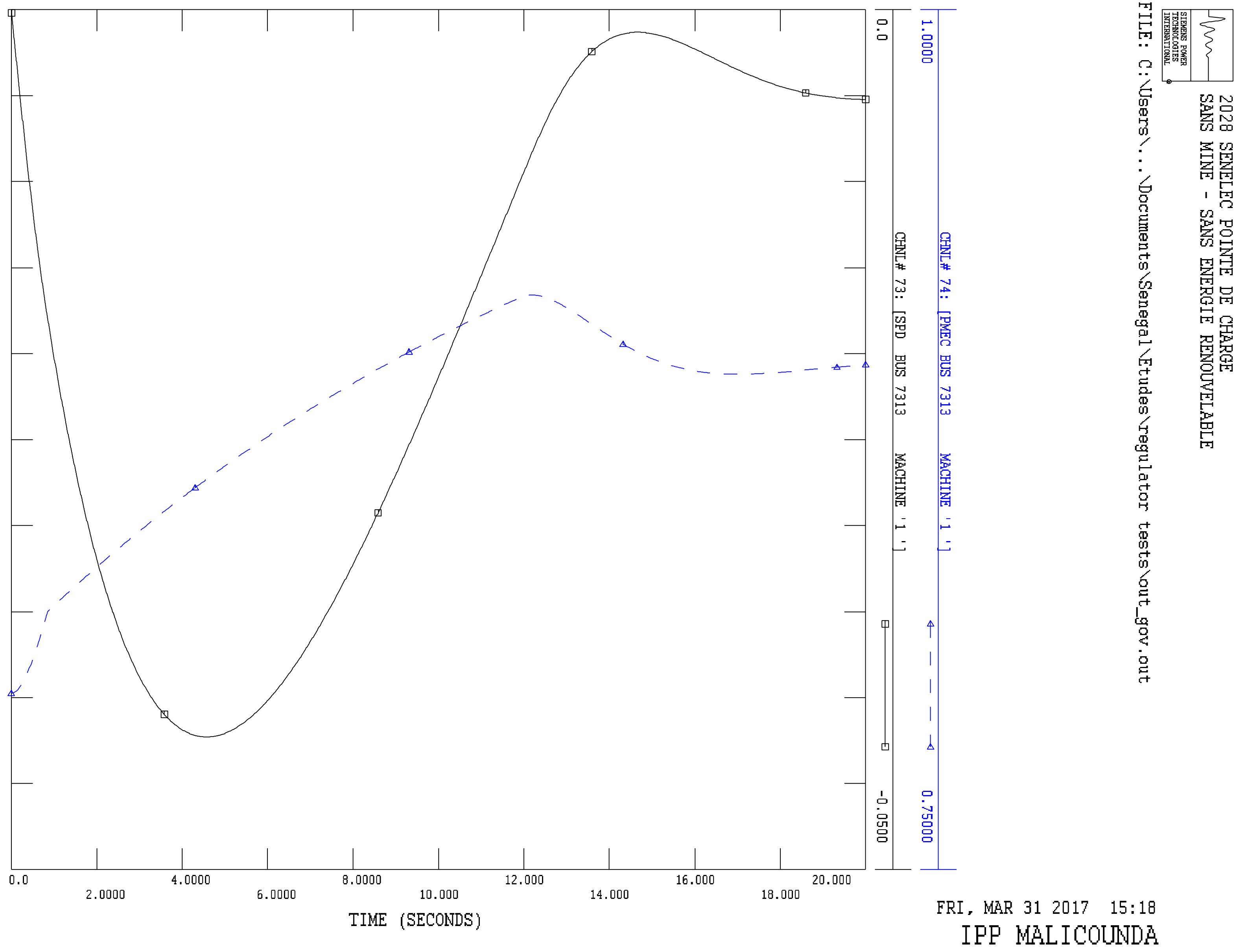

2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Documents\Senegal\Etudes\regulator tests\out_gov.out
CHNL# 63: [SPD BUS 7308 MACHINE '1 ']
CHNL# 64: [PMEC BUS 7308 MACHINE '1 ']
0.0
-0.0250
1.0000
0.75000
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 15:18
CAP DES BICHES C-402


2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Documents\Senegal\Etudes\regulator tests\out_gov.out
SIEMENS POWER TECHNOLOGIES INTERNATIONAL
CHNL# 65: [SPD BUS 7309 MACHINE '1 ']
0.0
-0.0250
CHNL# 66: [PMEC BUS 7309 MACHINE '1 ']
1.0000
0.75000
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 15:18
CAP DES BICHES C-404

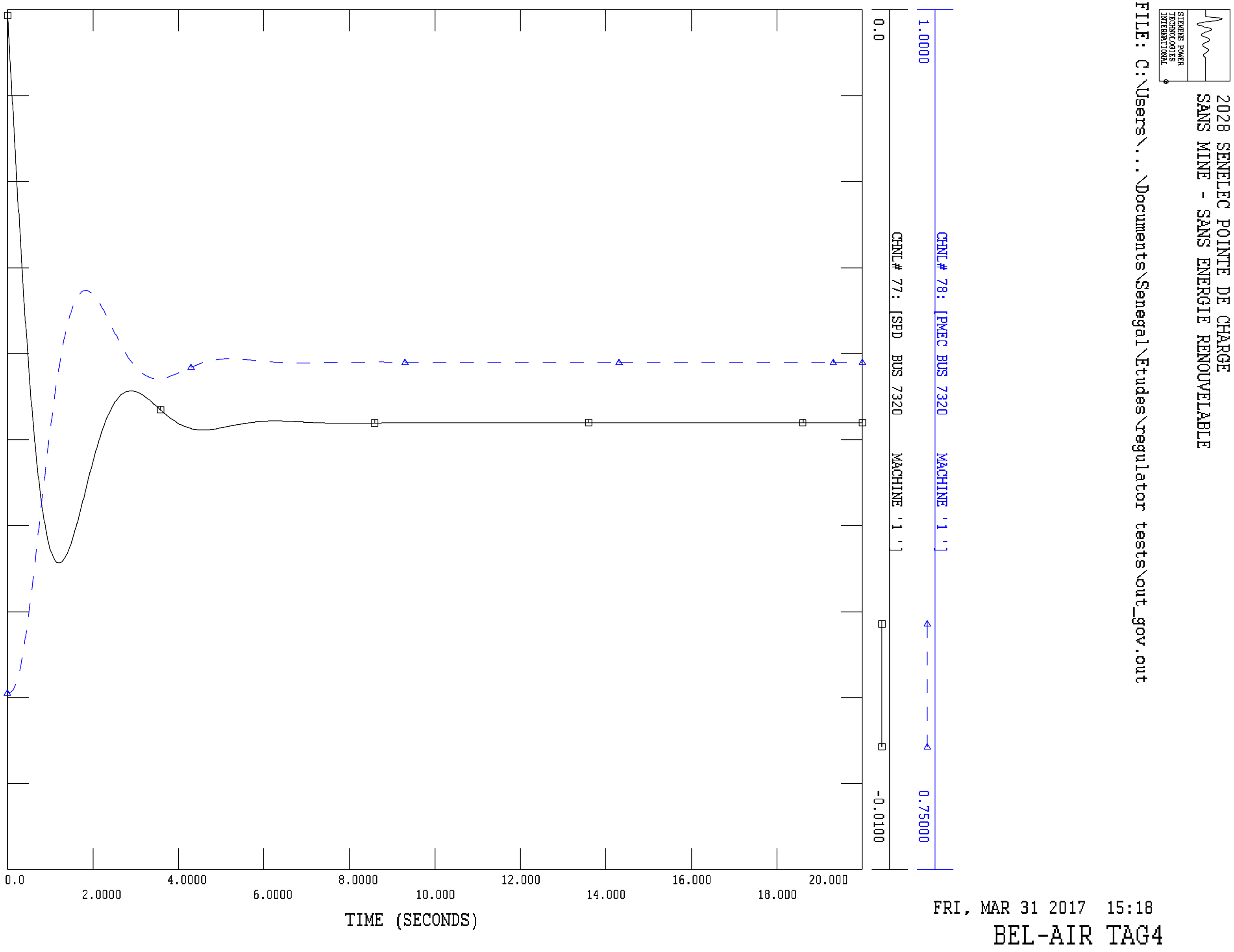

2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Documents\Senegal\Etudes\regulator tests\out_gov.out
CHNL# 67: [SPD BUS 7310 MACHINE '1 ']
CHNL# 68: [PMEC BUS 7310 MACHINE '1 ']
0.0
-0.0500
1.0000
0.75000
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 15:18
CAP DES BICHES C-301


2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Documents\Senegal\Etudes\regulator tests\out_gov.out
SIEMENS POWER TECHNOLOGIES INTERNATIONAL
CHNL# 102: [PMEC BUS 7349 MACHINE '1 ']
1.0000
0.75000
CHNL# 101: [SPD BUS 7349 MACHINE '1 ']
0.0
-0.0250
CHNL# 70: [PMEC BUS 7311 MACHINE '1 ']
1.0000
0.75000
CHNL# 69: [SPD BUS 7311 MACHINE '1 ']
0.0
-0.0250
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 15:18
CDB CONTOUR GLOBAL

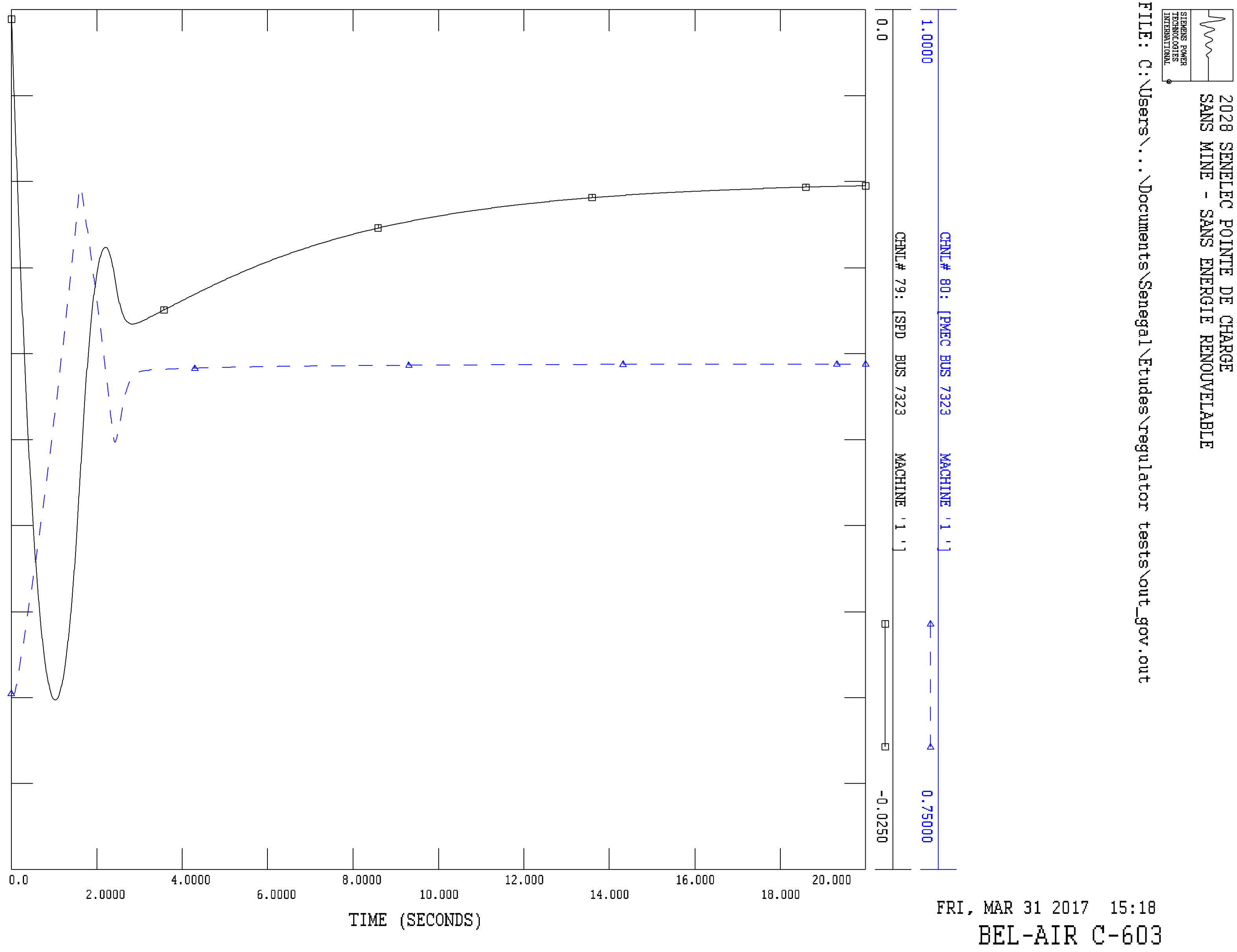

2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Documents\Senegal\Etudes\regulator tests\out_gov.out
CHNL# 71: [SPD BUS 7312 MACHINE '1 ']
0.0
-0.0500
CHNL# 72: [PMEC BUS 7312 MACHINE '1 ']
1.0000
0.75000
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 15:18
CAP DES BICHES C-303

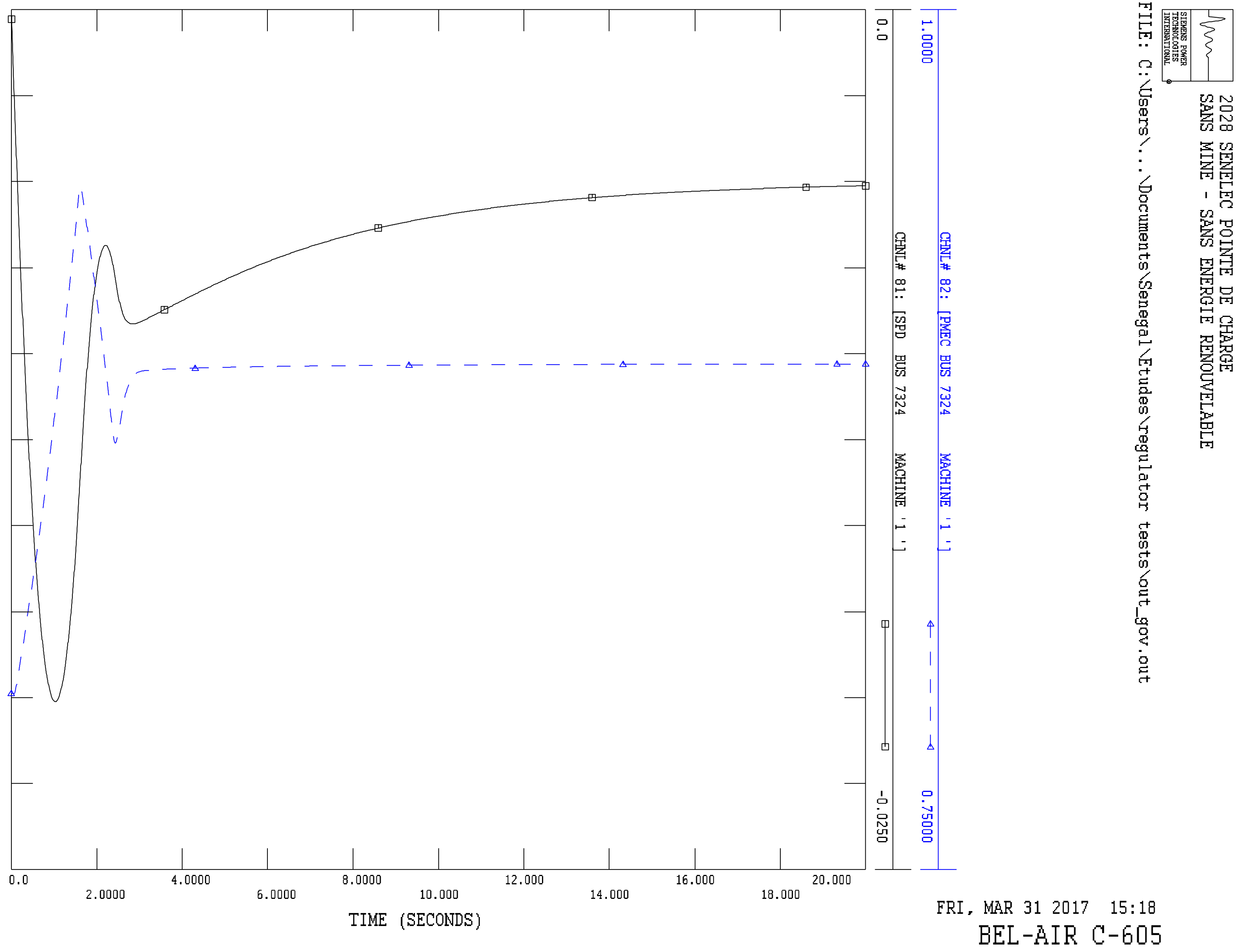


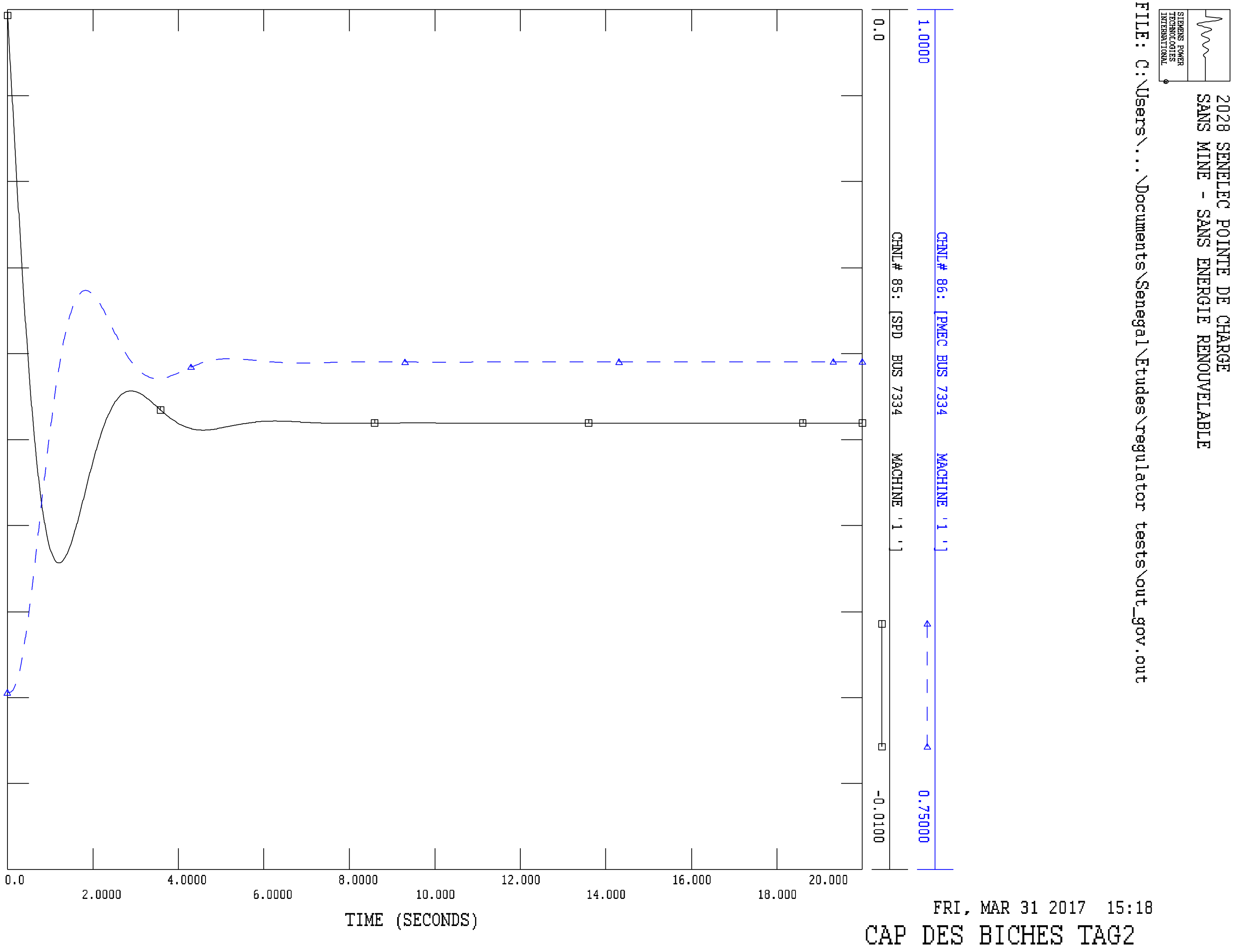
2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Documents\Senegal\Etudes\regulator tests\out_gov.out
CHNL# 74: [PMEC BUS 7313 MACHINE '1 ']
1.0000
0.75000
CHNL# 73: [SPD BUS 7313 MACHINE '1 ']
0.0
-0.0500
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 15:18
IPP MALICOUNDA

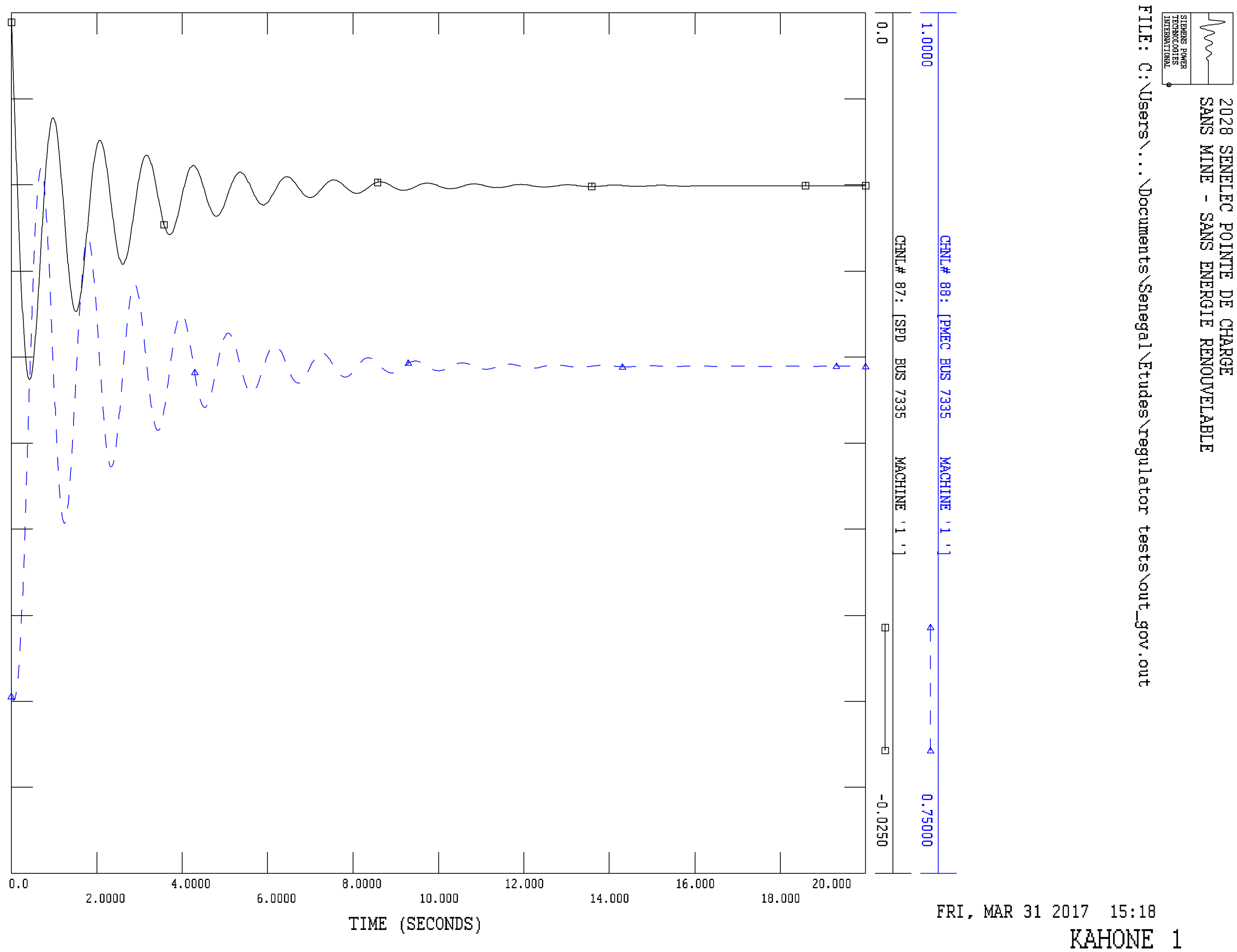


2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Documents\Senegal\Etudes\regulator tests\out_gov.out
CHNL# 78: [PMEC BUS 7320 MACHINE '1 ']
1.0000
0.75000
CHNL# 77: [SPD BUS 7320 MACHINE '1 ']
0.0
-0.0100
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 15:18
BEL-AIR TAG4

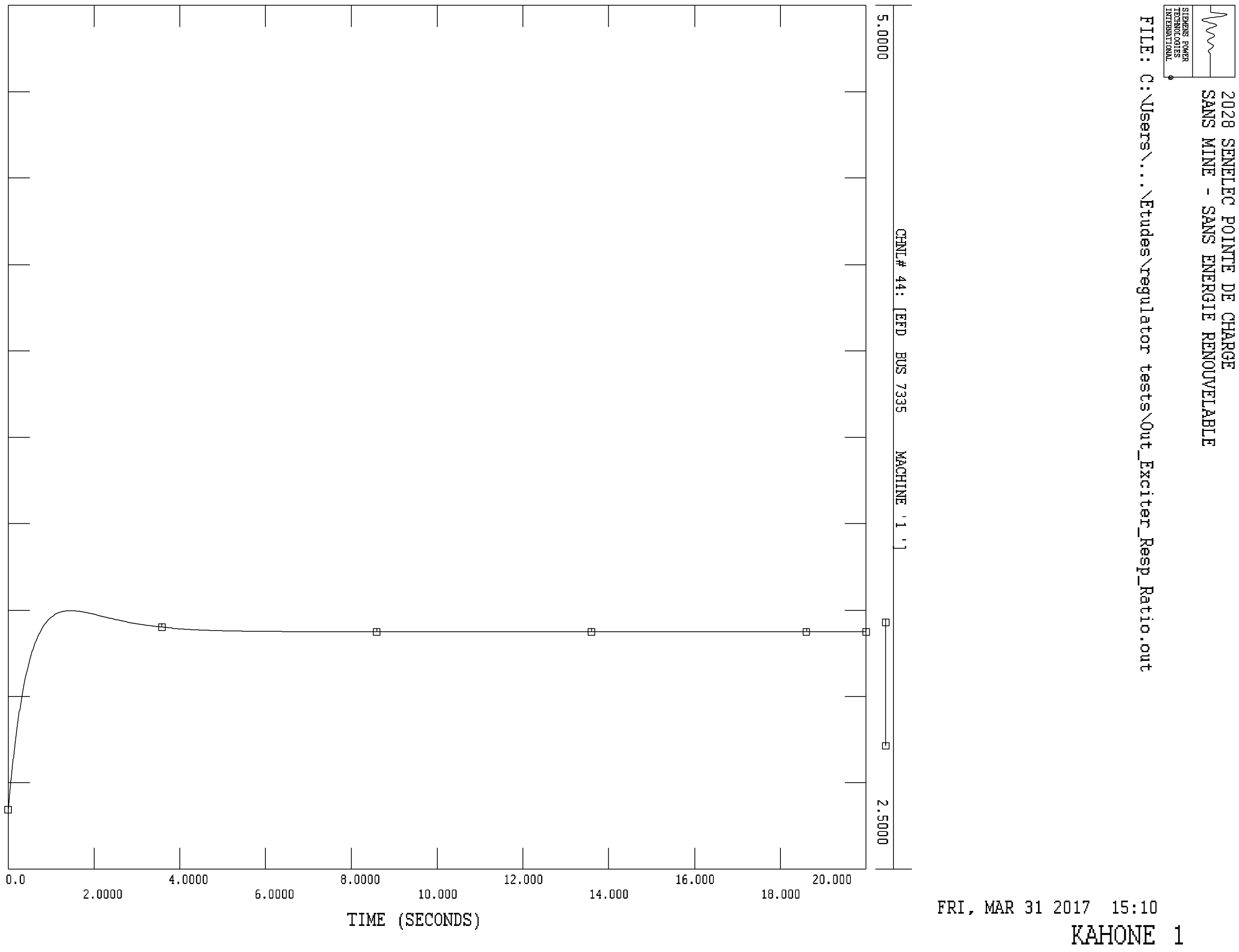

2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Documents\Senegal\Etudes\regulator tests\out_gov.out
CHNL# 79: [SPD BUS 7323 MACHINE '1 ']
0.0
-0.0250
CHNL# 80: [PMEC BUS 7323 MACHINE '1 ']
1.0000
0.75000
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 15:18
BEL-AIR C-603

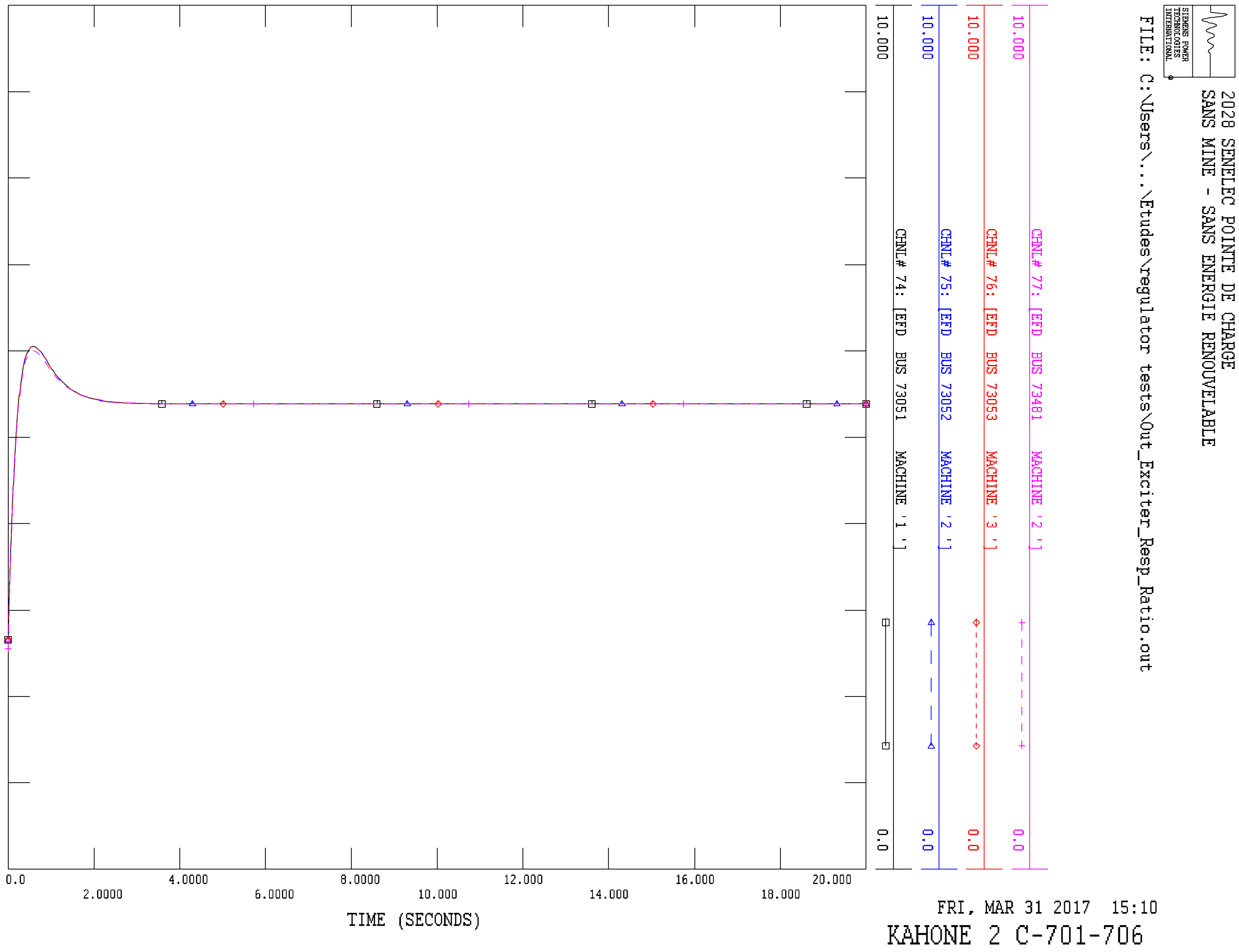

2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Documents\Senegal\Etudes\regulator tests\out_gov.out
CHNL# 82: [PMEC BUS 7324 MACHINE '1 ']
CHNL# 81: [SPD BUS 7324 MACHINE '1 ']
1.0000
0.75000
0.0
-0.0250
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 15:18
BEL-AIR C-605

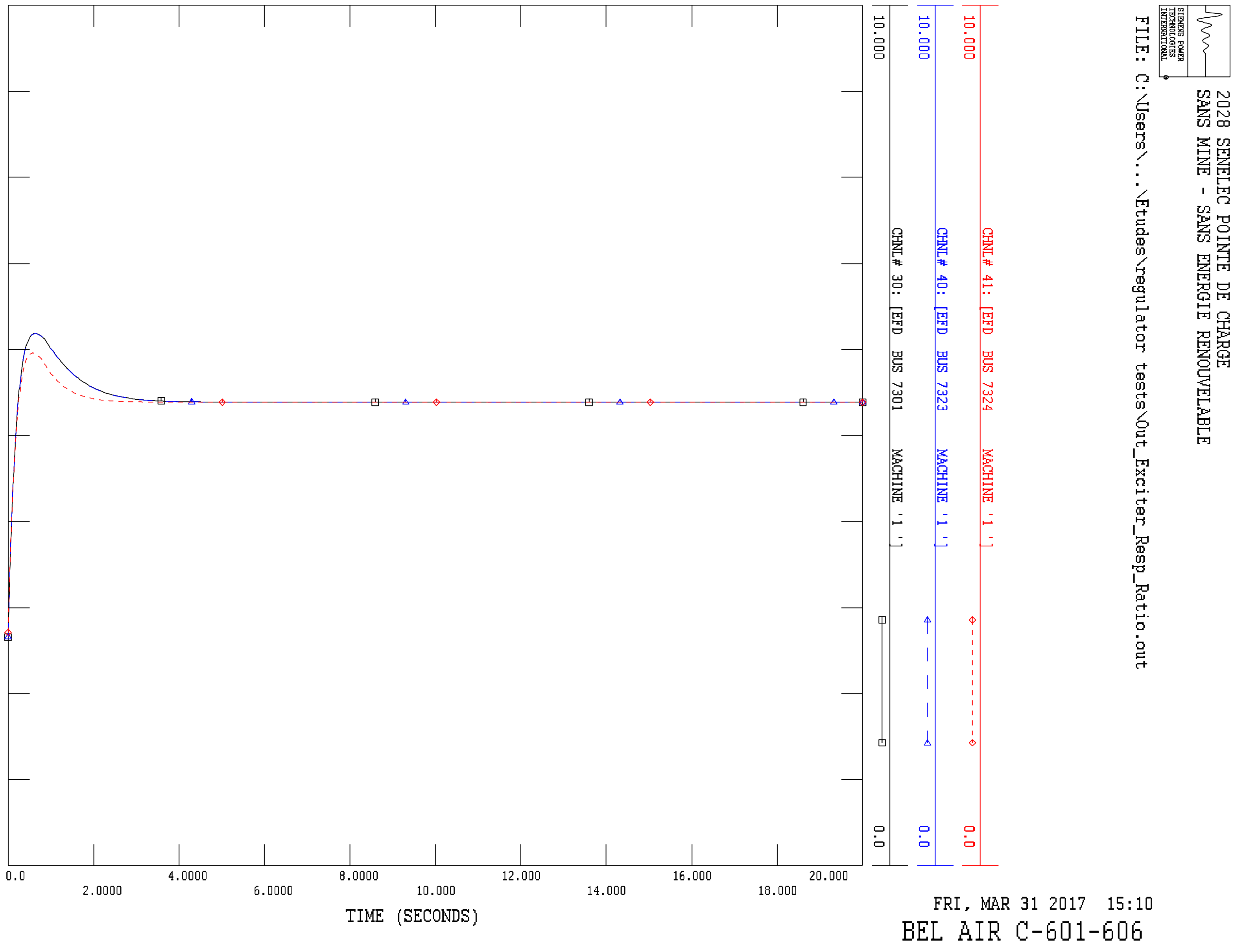

2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Documents\Senegal\Etudes\regulator tests\out_gov.out
SIEMENS POWER TECHNOLOGIES INTERNATIONAL
CHNL# 85: [SPD BUS 7334 MACHINE '1 ']
0.0
-0.0100
CHNL# 86: [PMEC BUS 7334 MACHINE '1 ']
1.0000
0.75000
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 15:18
CAP DES BICHES TAG2

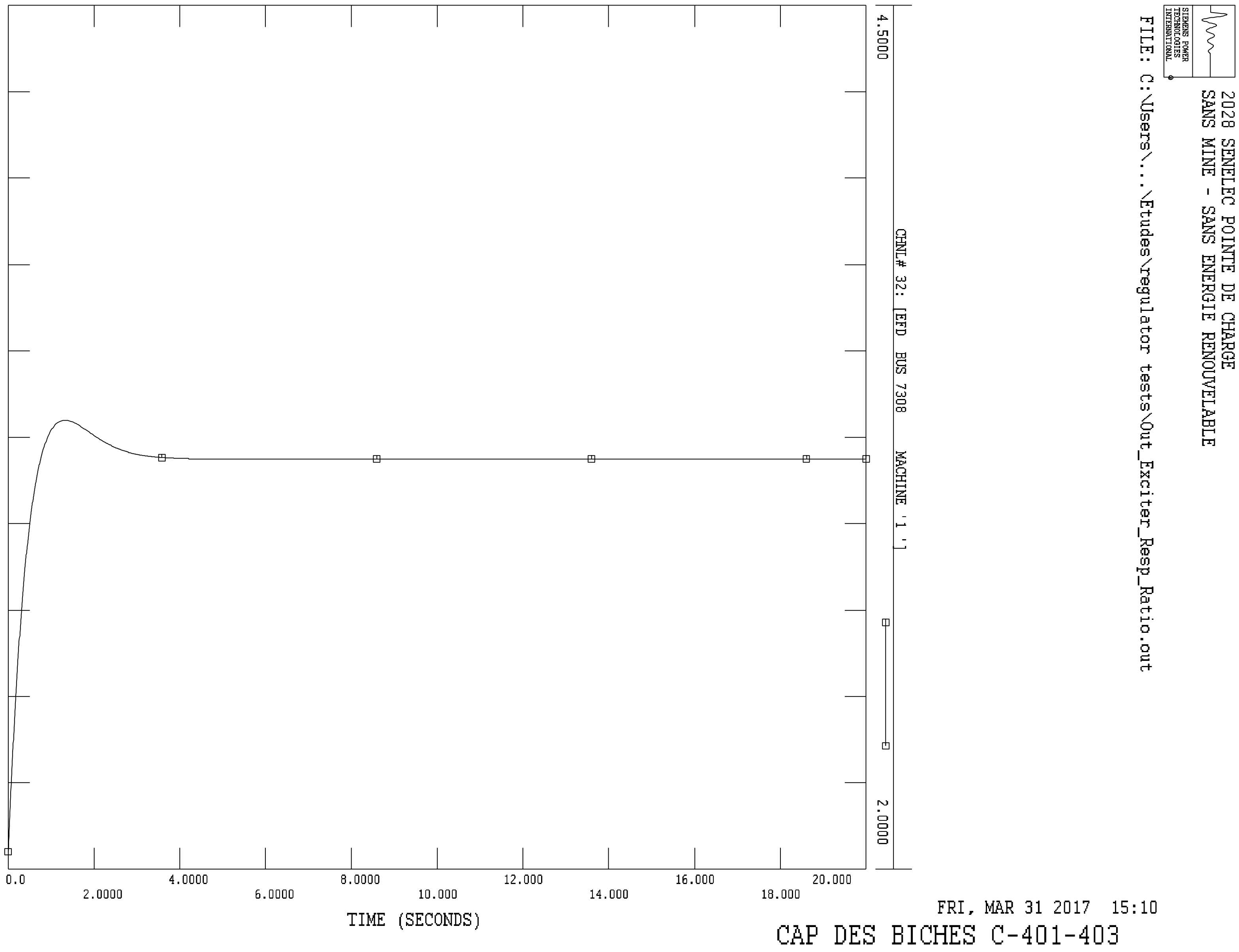

2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Documents\Senegal\Etudes\regulator tests\out_gov.out
SIEMENS POWER TECHNOLOGIES INTERNATIONAL
CHNL# 87: [SPD BUS 7335 MACHINE '1 ']
CHNL# 88: [PMEC BUS 7335 MACHINE '1 ']
0.0
-0.0250
1.0000
0.75000
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 15:18
KAHONE 1

D.2 EXCITER RESPONSE TIME AT UPPER LIMIT

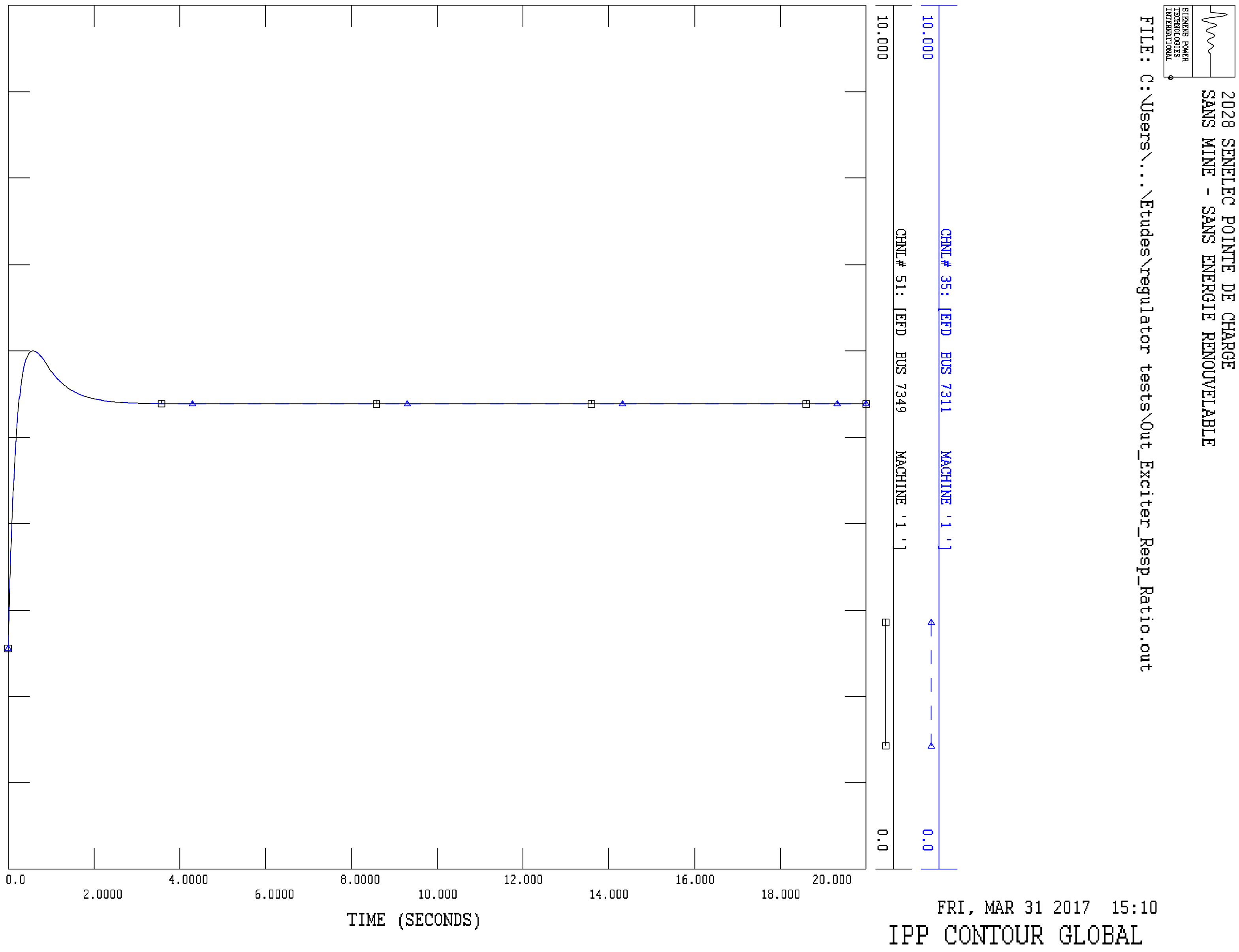

SIEMENS POWER TECHNOLOGIES INTERNATIONAL
2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Etudes\regulator tests\Out_Exciter_Resp_Ratio.out
CHNL# 44: [EFD BUS 7335 MACHINE '1 ']
5.0000
2.5000
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 15:10
KAHONE 1

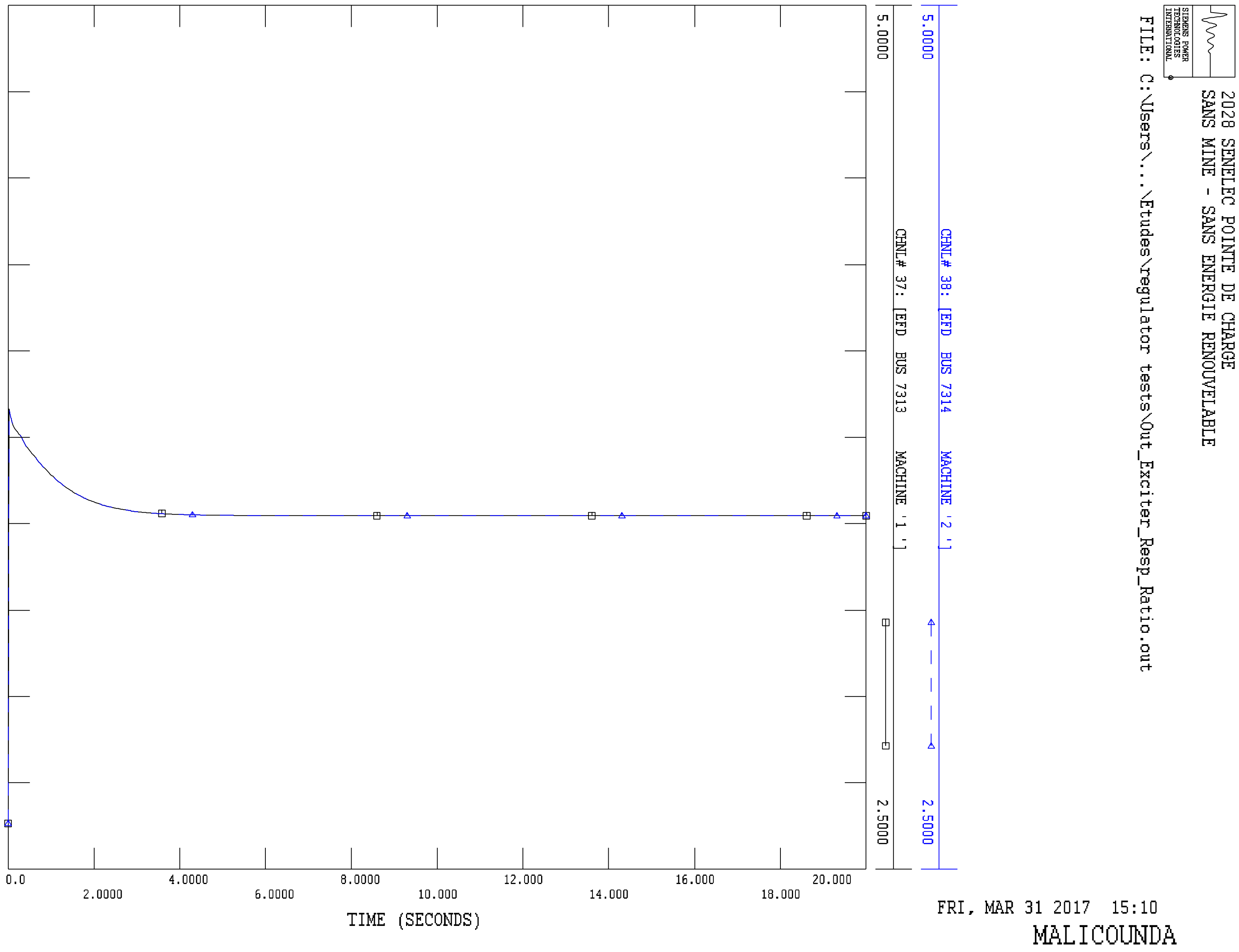

2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Etudes\regulator tests\Out_Exciter_Resp_Ratio.out
CHNL# 74: [EFD BUS 73051 MACHINE '1 ']
10.000
0.0
CHNL# 75: [EFD BUS 73052 MACHINE '2 ']
10.000
0.0
CHNL# 76: [EFD BUS 73053 MACHINE '3 ']
10.000
0.0
CHNL# 77: [EFD BUS 73481 MACHINE '2 ']
10.000
0.0
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 15:10
KAHONE 2 C-701-706

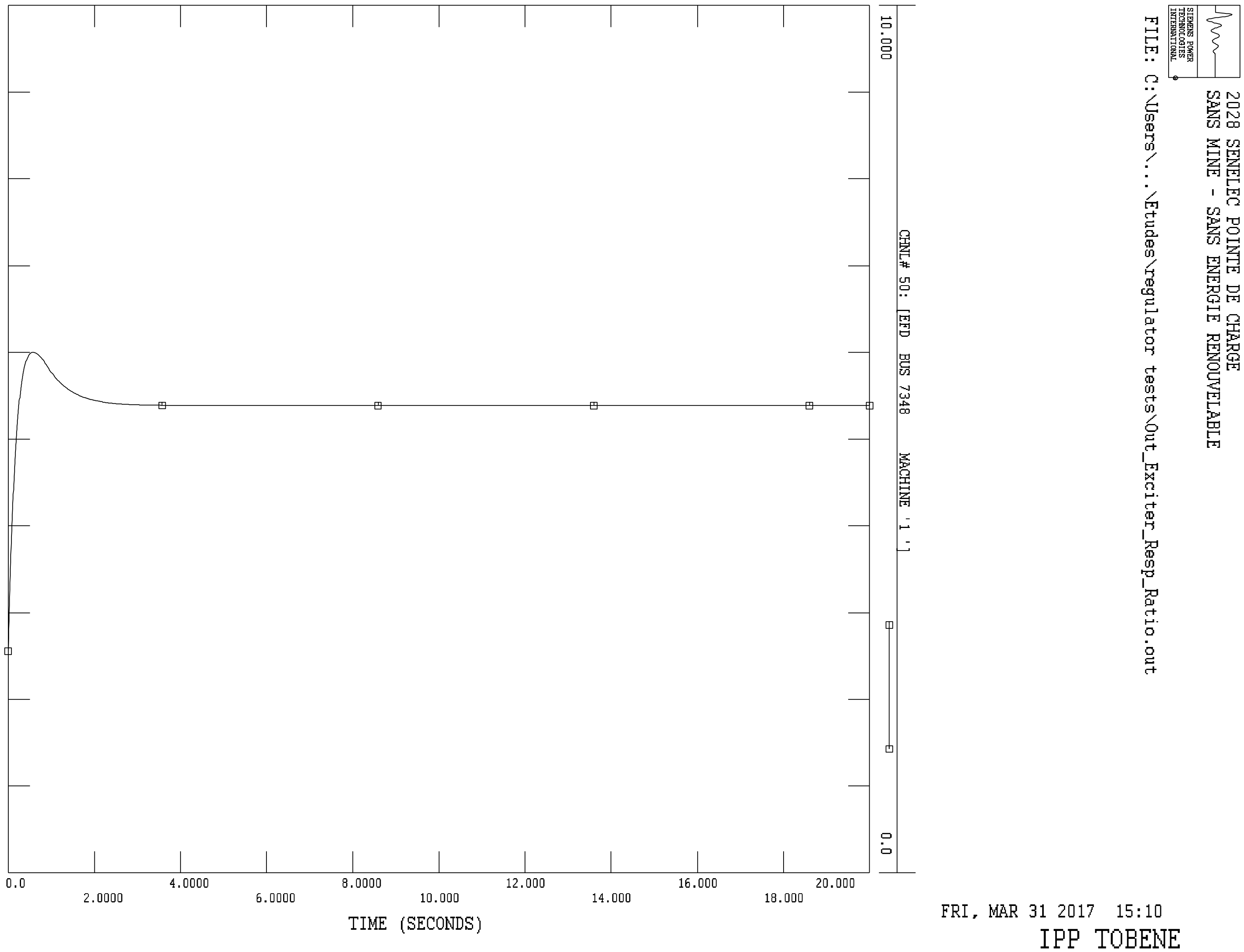

2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Etudes\regulator tests\Out_Exciter_Resp_Ratio.out
CHNL# 41: [EFD BUS 7324 MACHINE '1 ']
10.000
0.0
CHNL# 40: [EFD BUS 7323 MACHINE '1 ']
10.000
0.0
CHNL# 30: [EFD BUS 7301 MACHINE '1 ']
10.000
0.0
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 15:10
BEL AIR C-601-606

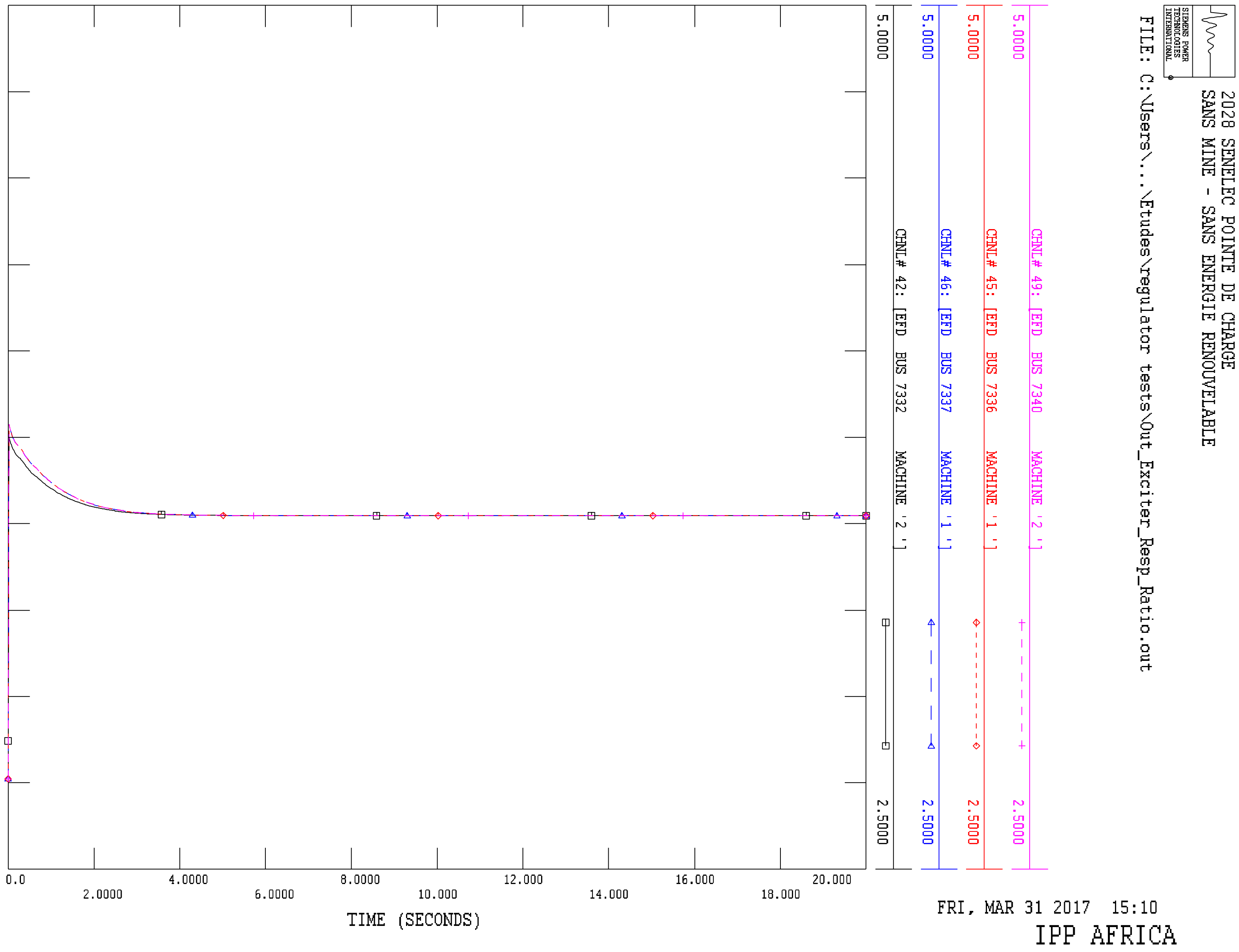


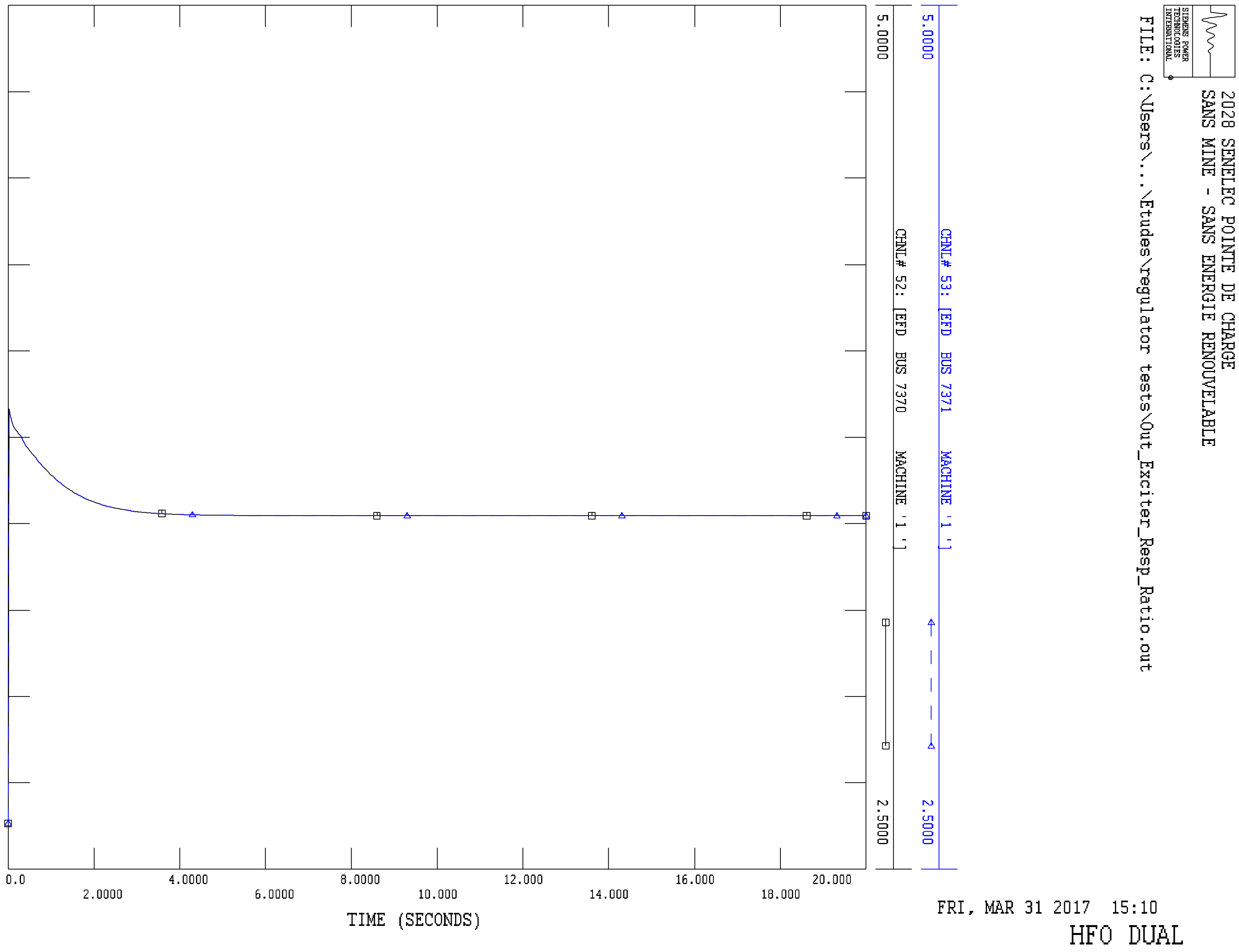
2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Etudes\regulator tests\Out_Exciter_Resp_Ratio.out
SIEMENS POWER TECHNOLOGIES INTERNATIONAL
CHNL# 32: [EFD BUS 7308 MACHINE '1 ']
4.5000
2.0000
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 15:10
CAP DES BICHES C-401-403

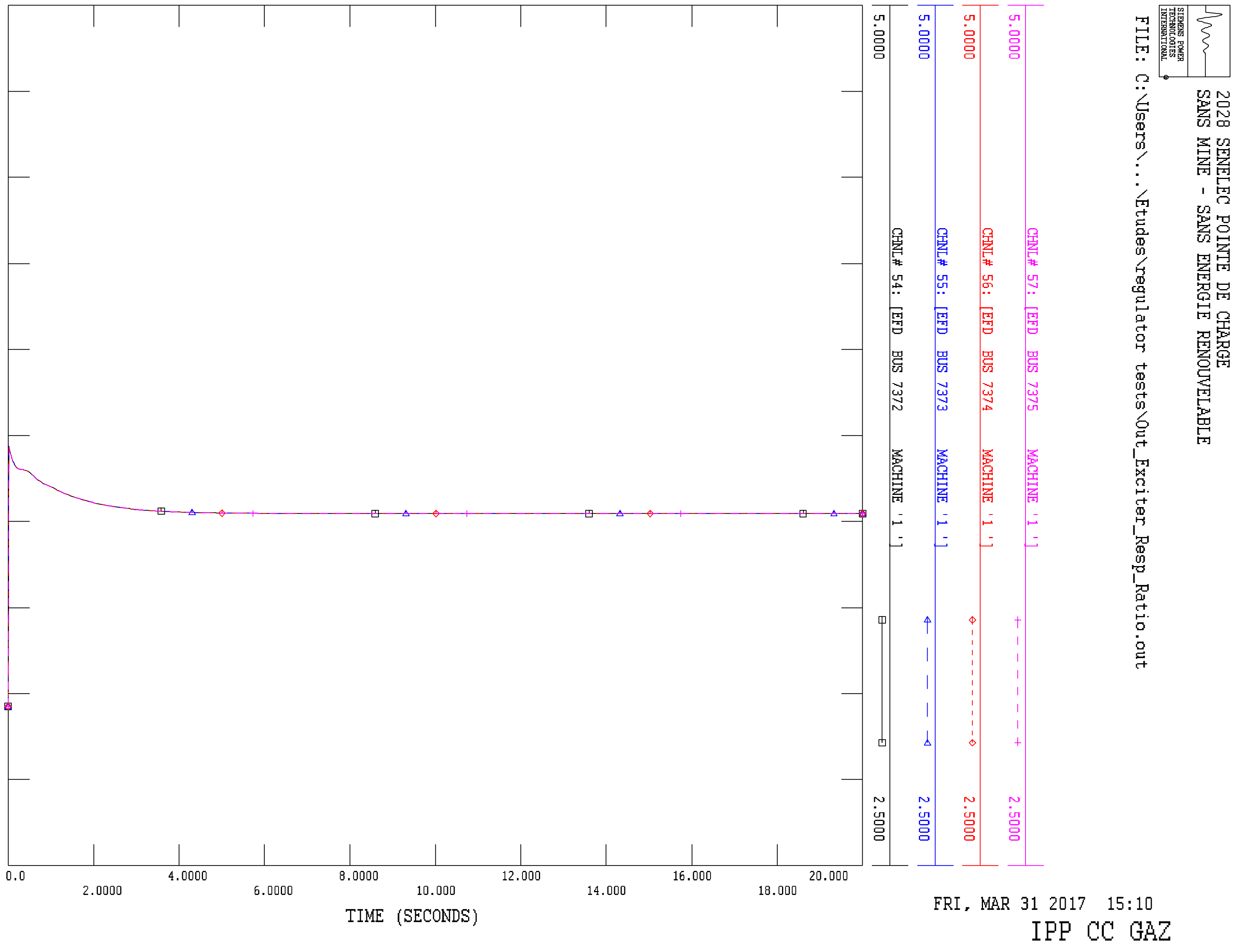

2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Etudes\regulator tests\Out_Exciter_Resp_Ratio.out
CHNL# 35: [EFD BUS 7311 MACHINE '1 ']
10.000
0.0
CHNL# 51: [EFD BUS 7349 MACHINE '1 ']
10.000
0.0
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 15:10
IPP CONTOUR GLOBAL

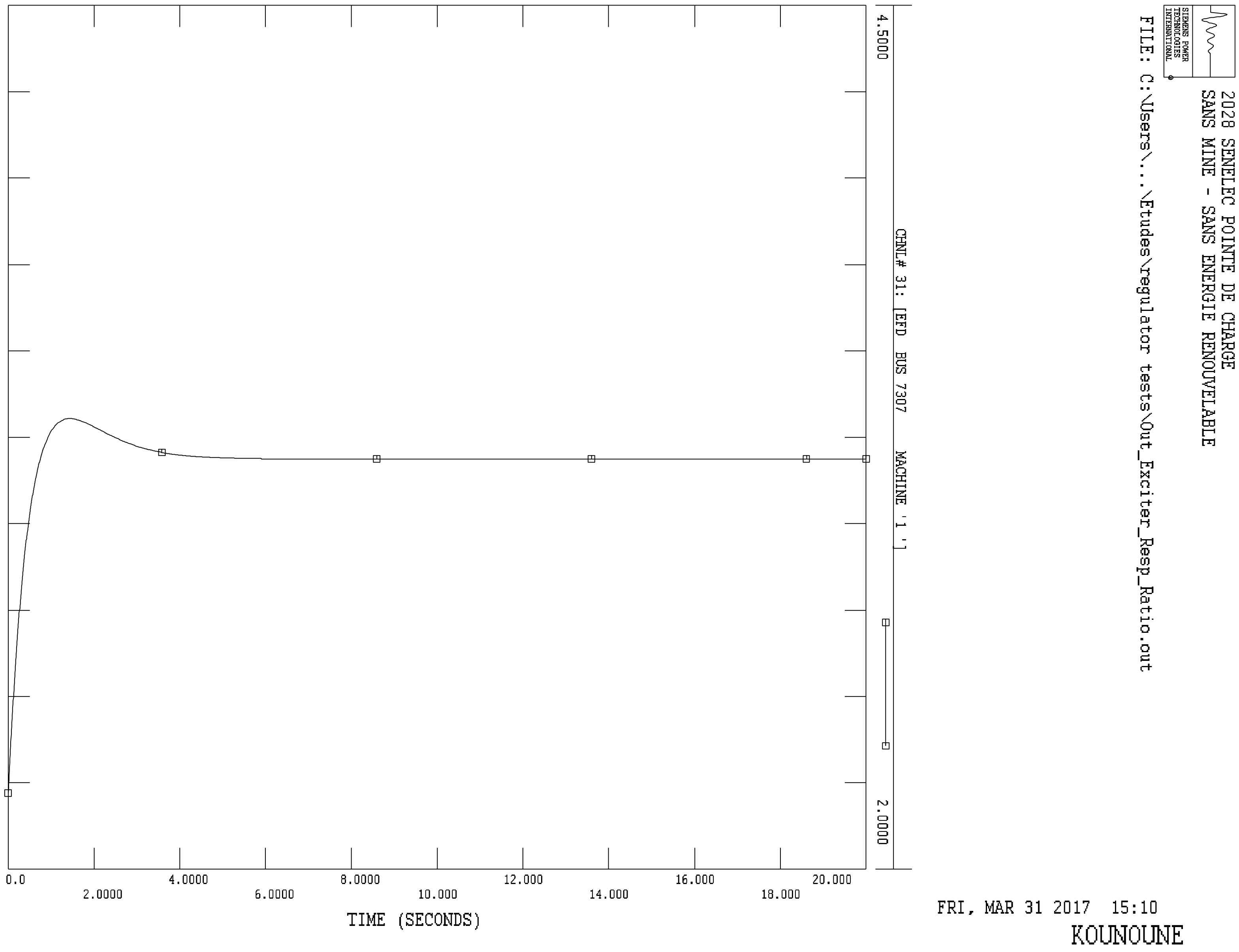

SIEMENS POWER TECHNOLOGIES INTERNATIONAL
2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Etudes\regulator tests\Out_Exciter_Resp_Ratio.out
CHNL# 37: [EFD BUS 7313 MACHINE '1 ']
5.0000
2.5000
CHNL# 38: [EFD BUS 7314 MACHINE '2 ']
5.0000
2.5000
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 15:10
MALICOUNDA

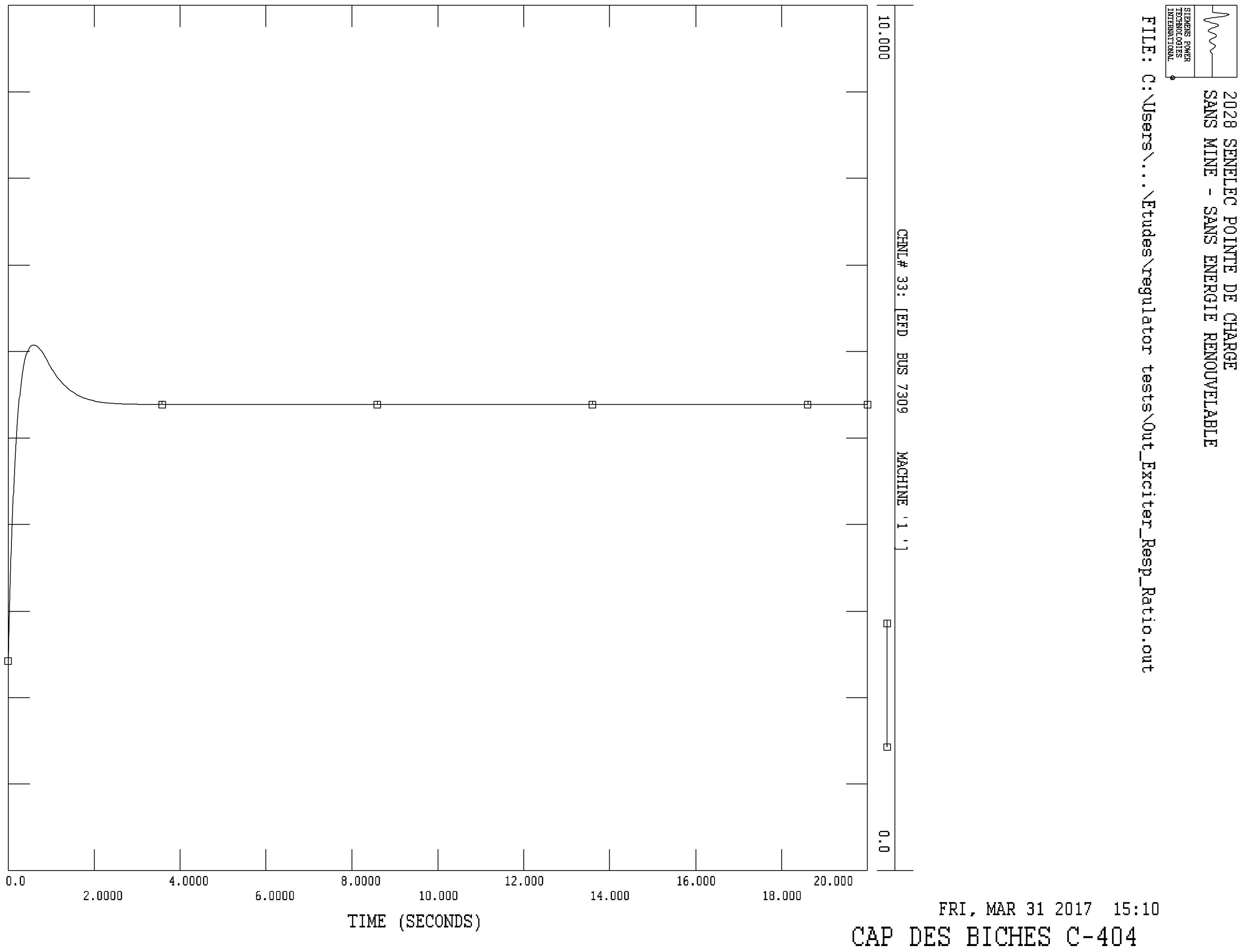

2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Etudes\regulator tests\Out_Exciter_Resp_Ratio.out
SIEMENS POWER TECHNOLOGIES INTERNATIONAL
CHNL# 50: [EFD BUS 7348 MACHINE '1 ']
10.000
0.0
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 15:10
IPP TOBENE

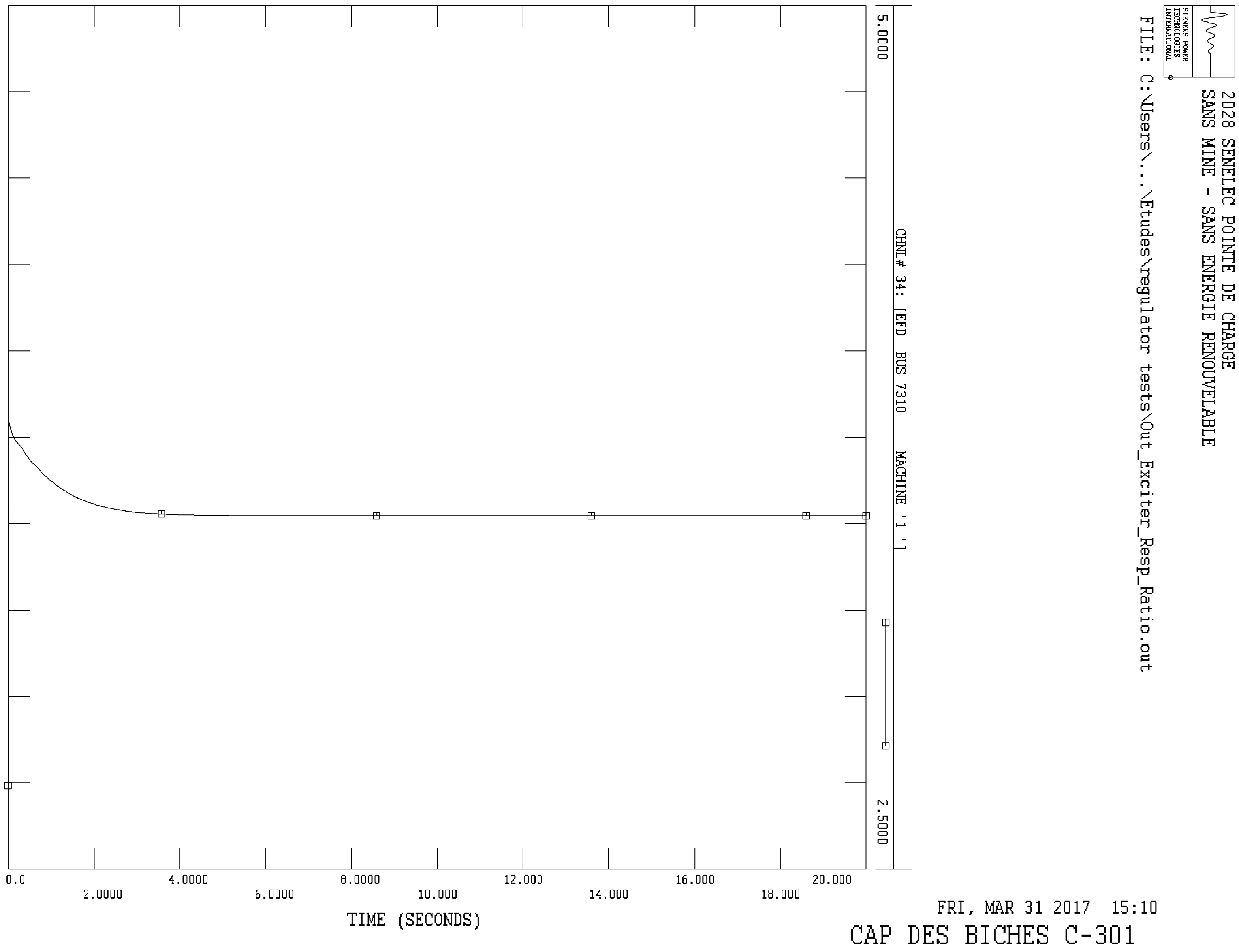

2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Etudes\regulator tests\Out_Exciter_Resp_Ratio.out
SIEMENS POWER TECHNOLOGIES INTERNATIONAL
CHNL# 49: [EFD BUS 7340 MACHINE '2 ']
5.0000
2.5000
CHNL# 45: [EFD BUS 7336 MACHINE '1 ']
5.0000
2.5000
CHNL# 46: [EFD BUS 7337 MACHINE '1 ']
5.0000
2.5000
CHNL# 42: [EFD BUS 7332 MACHINE '2 ']
5.0000
2.5000
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 15:10
IPP AFRICA

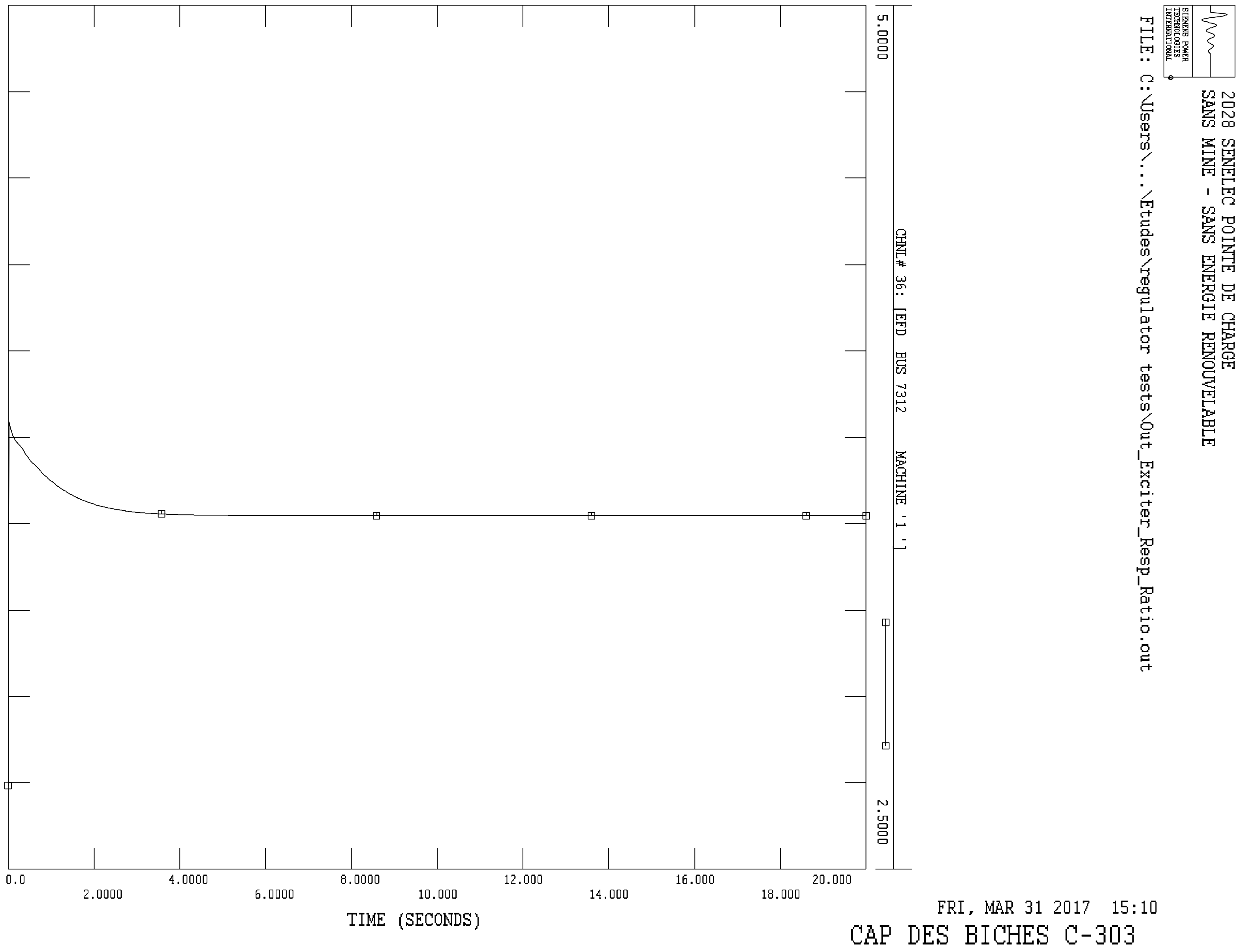

2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Etudes\regulator tests\Out_Exciter_Resp_Ratio.out
CHNL# 53: [EFD BUS 7371 MACHINE '1 ']
5.0000
2.5000
CHNL# 52: [EFD BUS 7370 MACHINE '1 ']
5.0000
2.5000
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 15:10
HFO DUAL

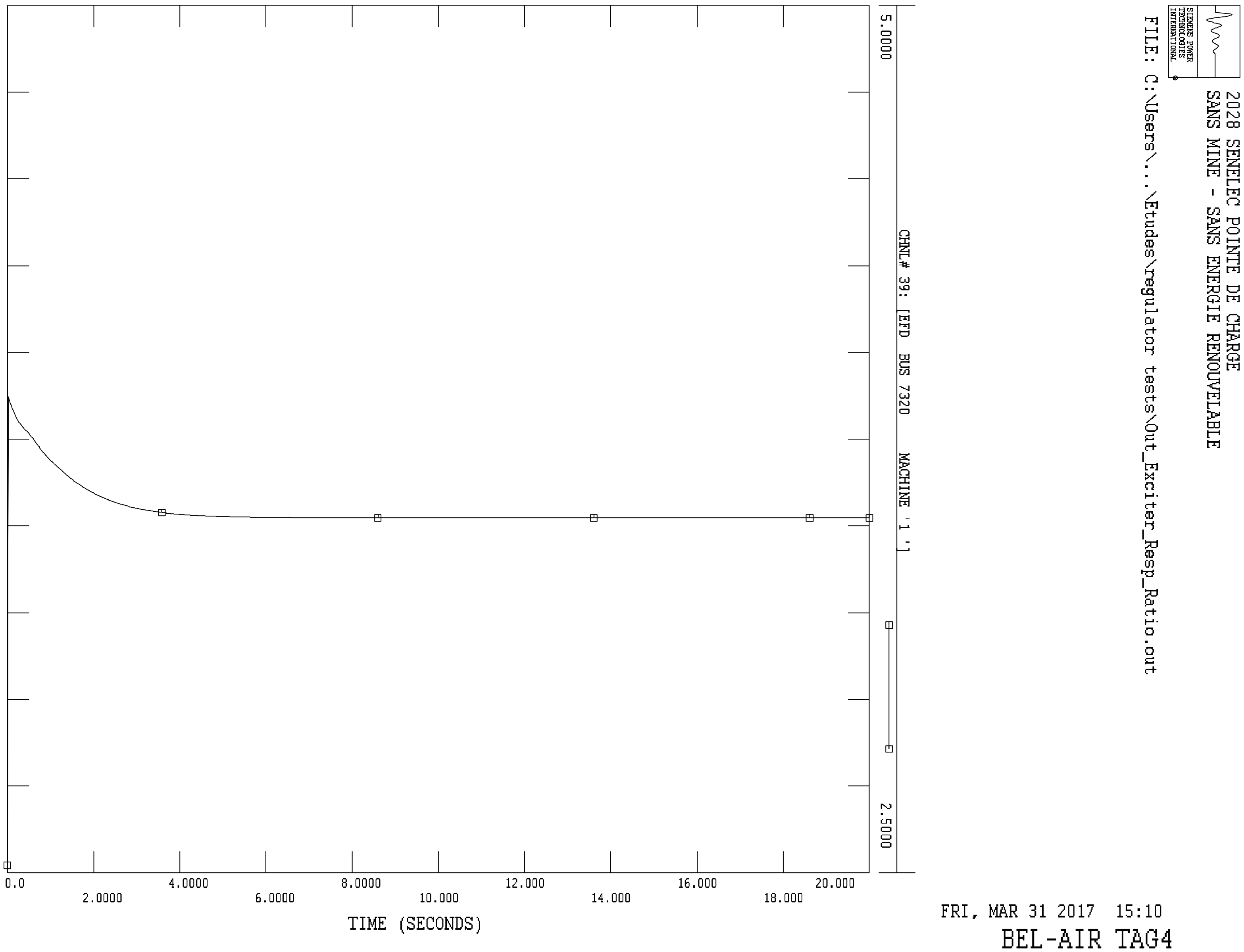

2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Etudes\regulator tests\Out_Exciter_Resp_Ratio.out
CHNL# 57: [EFD BUS 7375 MACHINE '1 ']
CHNL# 56: [EFD BUS 7374 MACHINE '1 ']
CHNL# 55: [EFD BUS 7373 MACHINE '1 ']
CHNL# 54: [EFD BUS 7372 MACHINE '1 ']
5.0000
2.5000
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 15:10
IPP CC GAZ


2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Etudes\regulator tests\Out_Exciter_Resp_Ratio.out
SIEMENS POWER TECHNOLOGIES INTERNATIONAL
CHNL# 31: [EFD BUS 7307 MACHINE '1 ']
4.5000
2.0000
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 15:10
KOUNOUNE

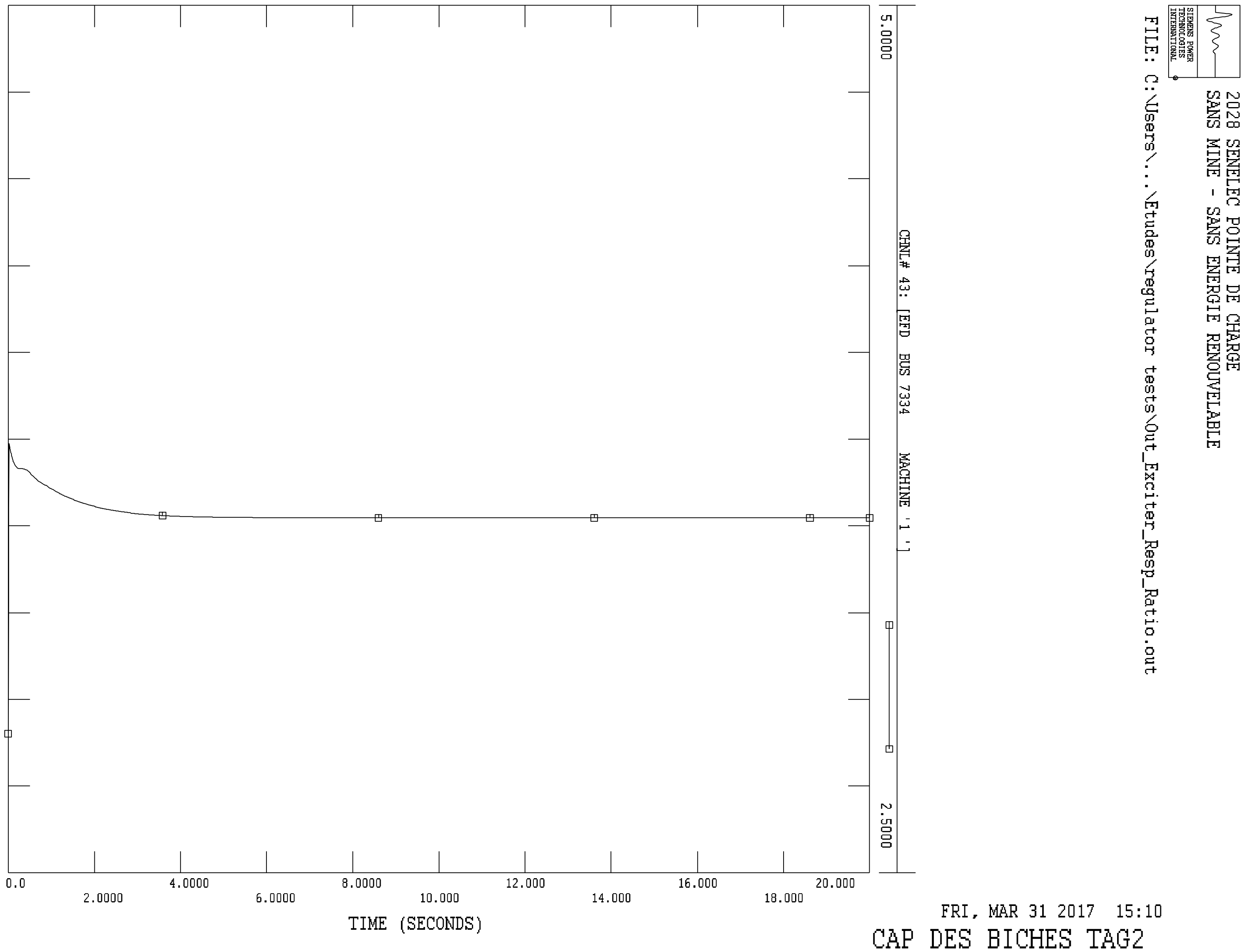

2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Etudes\regulator tests\Out_Exciter_Resp_Ratio.out
CHNL# 33: [EFD BUS 7309 MACHINE '1 ']
10.000
0.0
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 15:10
CAP DES BICHES C-404


2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Etudes\regulator tests\Out_Exciter_Resp_Ratio.out
CHNL# 34: [EFD BUS 7310 MACHINE '1 ']
5.0000
2.5000
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 15:10
CAP DES BICHES C-301

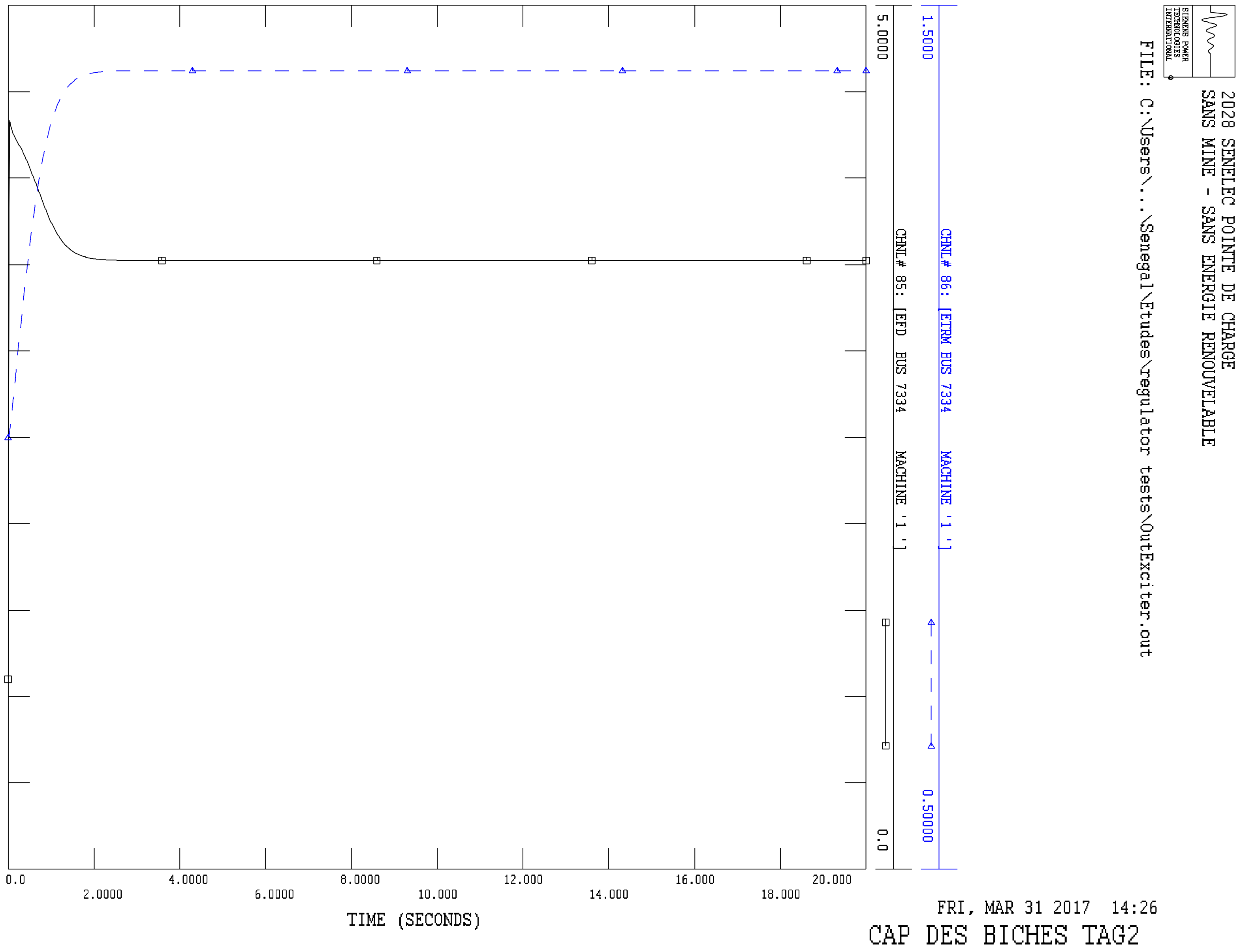

2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Etudes\regulator tests\Out_Exciter_Resp_Ratio.out
SIEMENS POWER TECHNOLOGIES INTERNATIONAL
CHNL# 36: [EFD BUS 7312 MACHINE '1 ']
5.0000
2.5000
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 15:10
CAP DES BICHES C-303

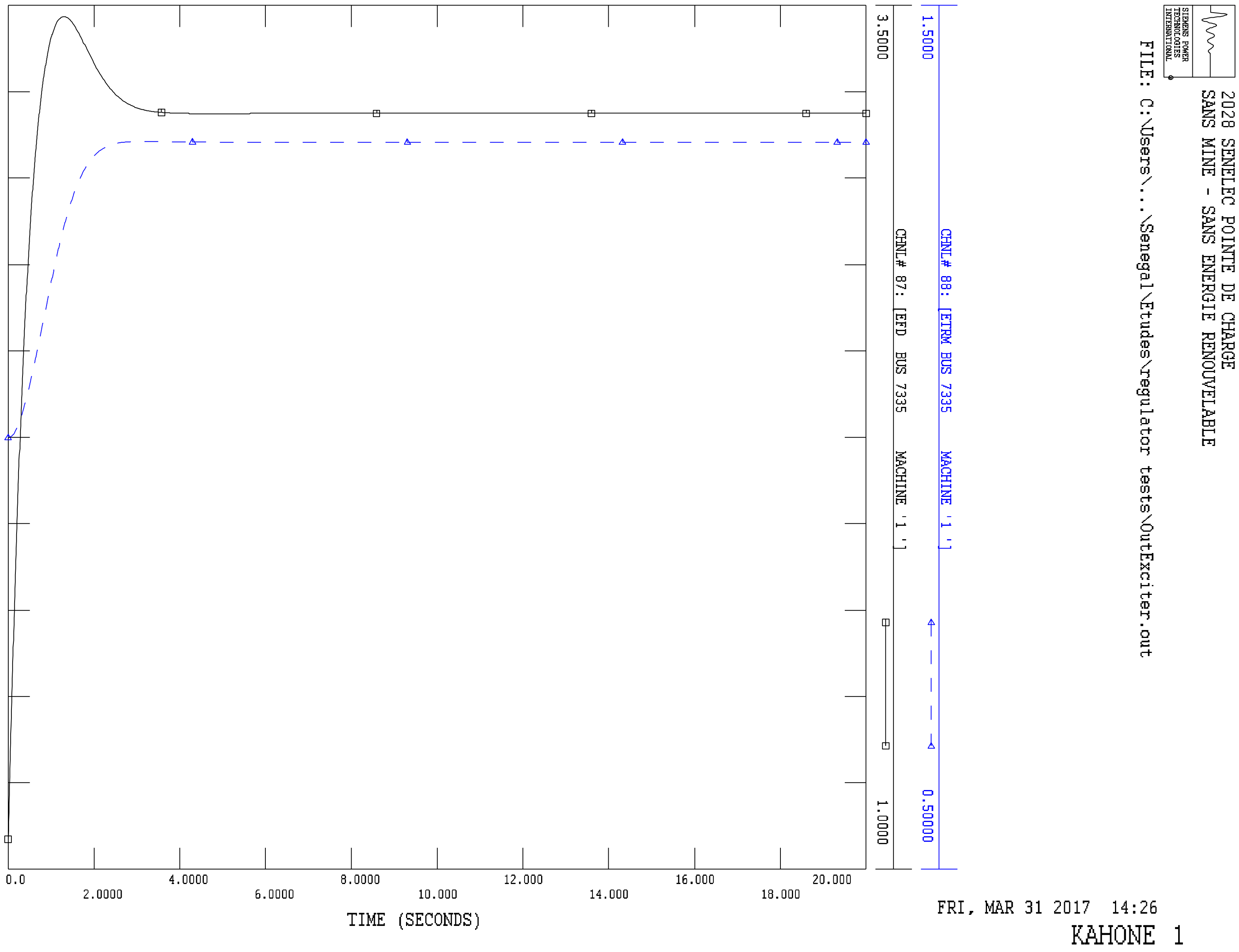


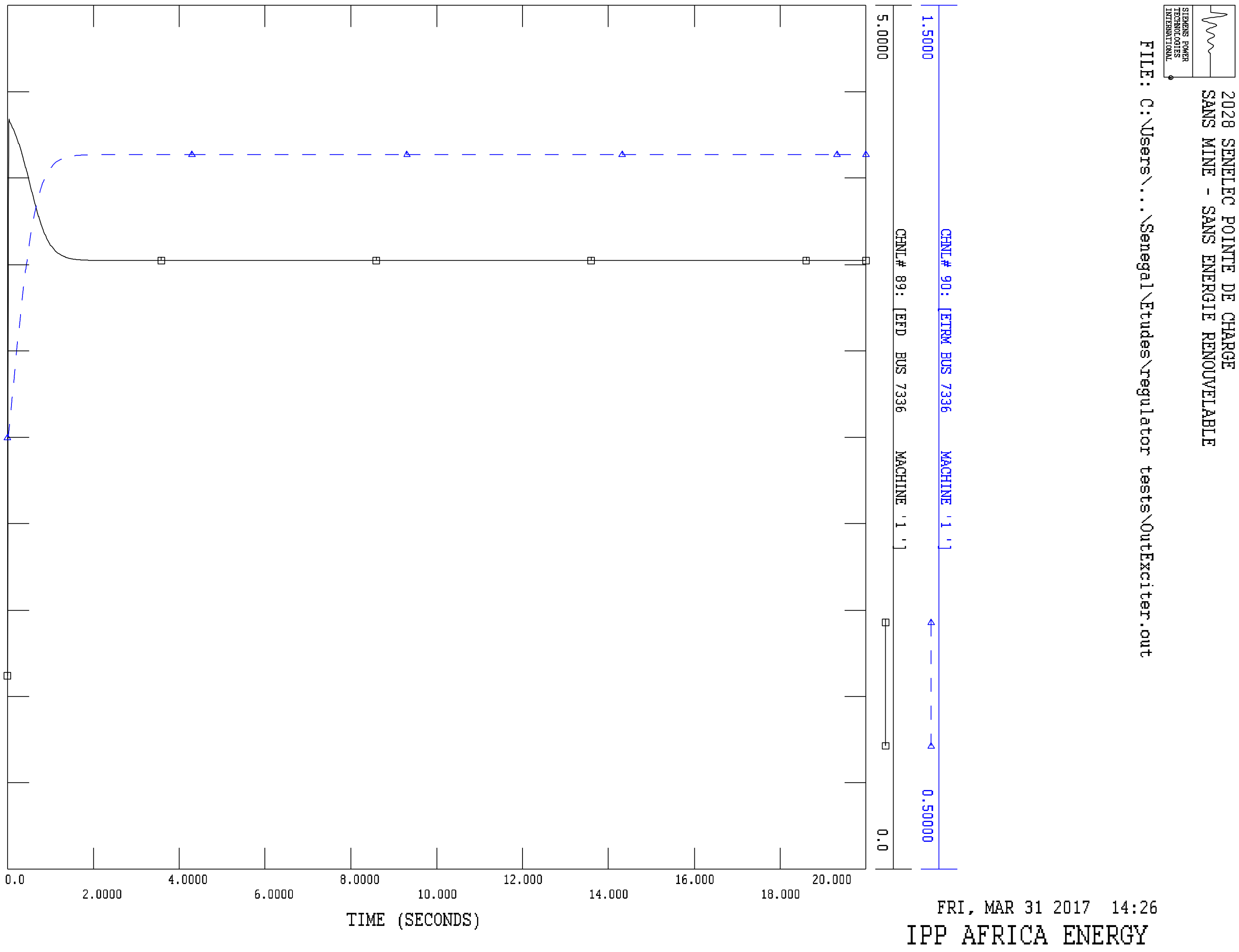
2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Etudes\regulator tests\Out_Exciter_Resp_Ratio.out
CHNL# 39: [EFD BUS 7320 MACHINE '1 ']
5.0000
2.5000
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 15:10
BEL-AIR TAG4


2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Etudes\regulator tests\Out_Exciter_Resp_Ratio.out
CHNL# 43: [EFD BUS 7334 MACHINE '1 ']
5.0000
2.5000
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 15:10
CAP DES BICHES TAG2

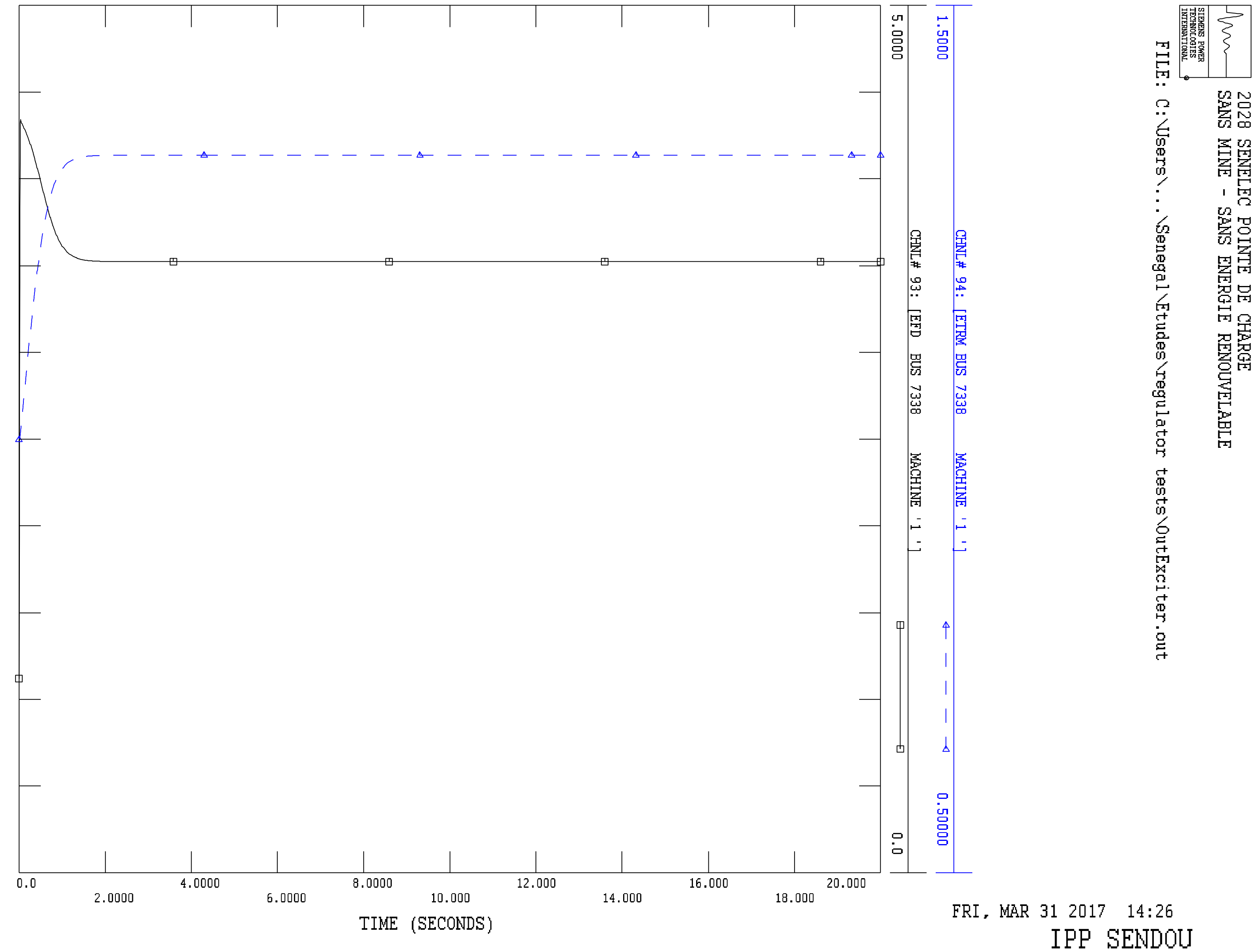
D.3 EXCITER RESPONSE TIME AT FIVE PERCENT LEVEL


2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Senegal\Etudes\regulator tests\OutExciter.out
CHNL# 85: [EFD BUS 7334 MACHINE '1 ']
CHNL# 86: [ETRM BUS 7334 MACHINE '1 ']
5.0000
0.0
1.5000
0.50000
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 14:26
CAP DES BICHES TAG2

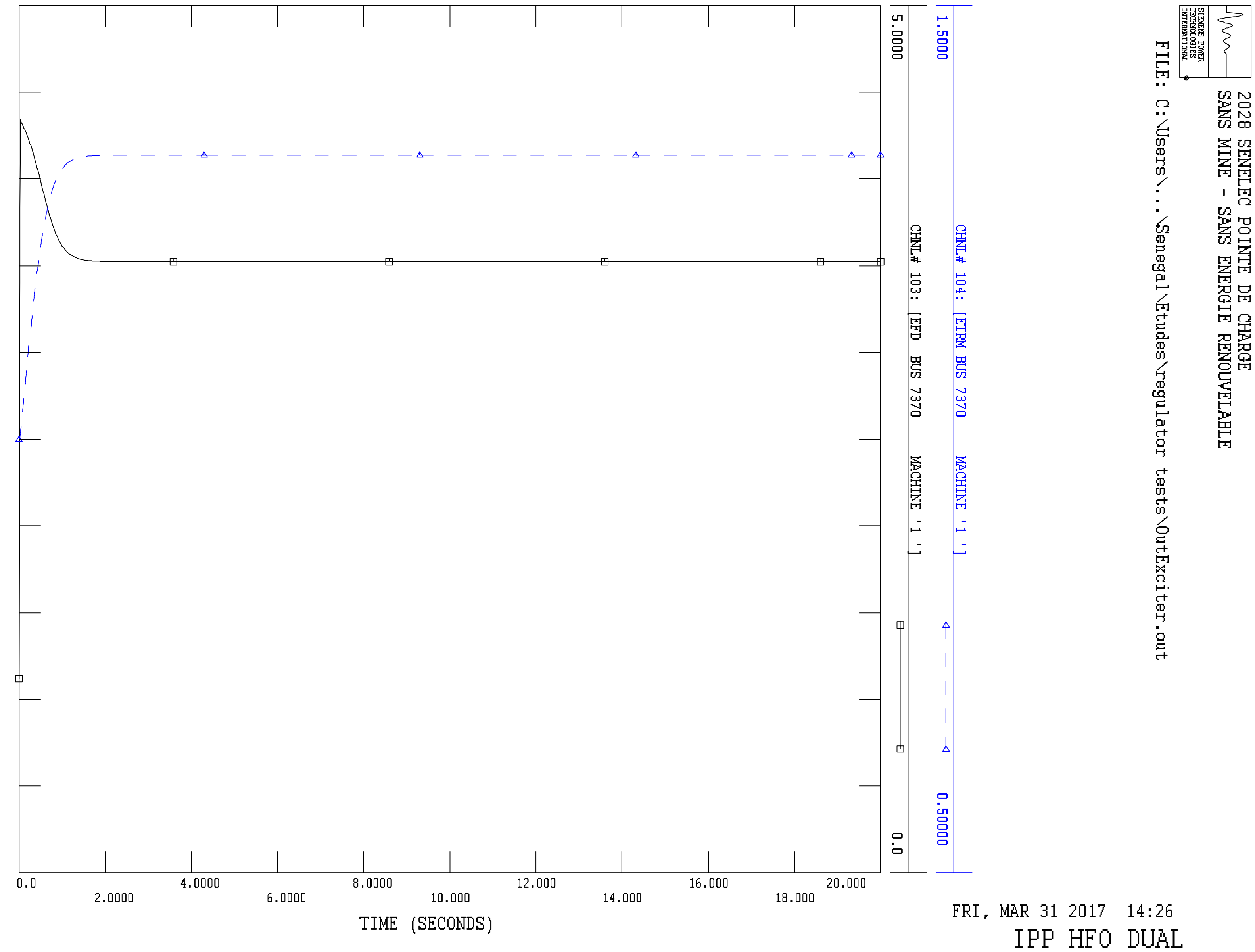

2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Senegal\Etudes\regulator tests\OutExciter.out
CHNL# 87: [EFD BUS 7335 MACHINE '1 ']
CHNL# 88: [ETRM BUS 7335 MACHINE '1 ']
3.5000
1.0000
1.5000
0.50000
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 14:26
KAHONE 1


2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Senegal\Etudes\regulator tests\OutExciter.out
CHNL# 90: [ETRM BUS 7336 MACHINE '1 ']
CHNL# 89: [EFD BUS 7336 MACHINE '1 ']
1.5000
0.50000
5.0000
0.0
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 14:26
IPP AFRICA ENERGY

E


2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Senegal\Etudes\regulator tests\OutExciter.out
CHNL# 93: [EFD BUS 7338 MACHINE '1 ']
5.0000
0.0
CHNL# 94: [ETRM BUS 7338 MACHINE '1 ']
1.5000
0.50000
0.0
2.0000
4.0000
6.0000
8.0000
10.000
12.000
14.000
16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 14:26
IPP SENDOU

F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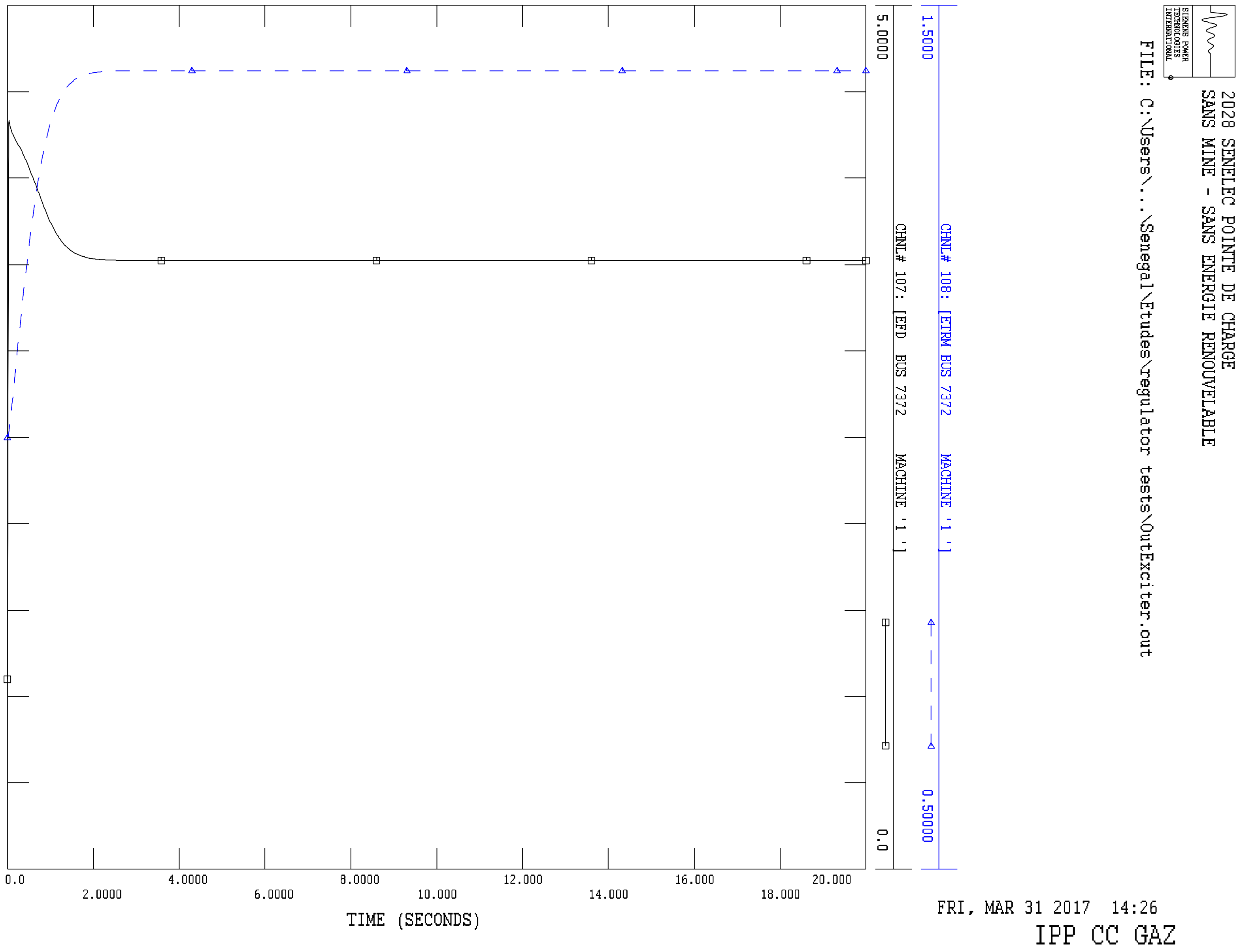
IPP HFO DUAL

G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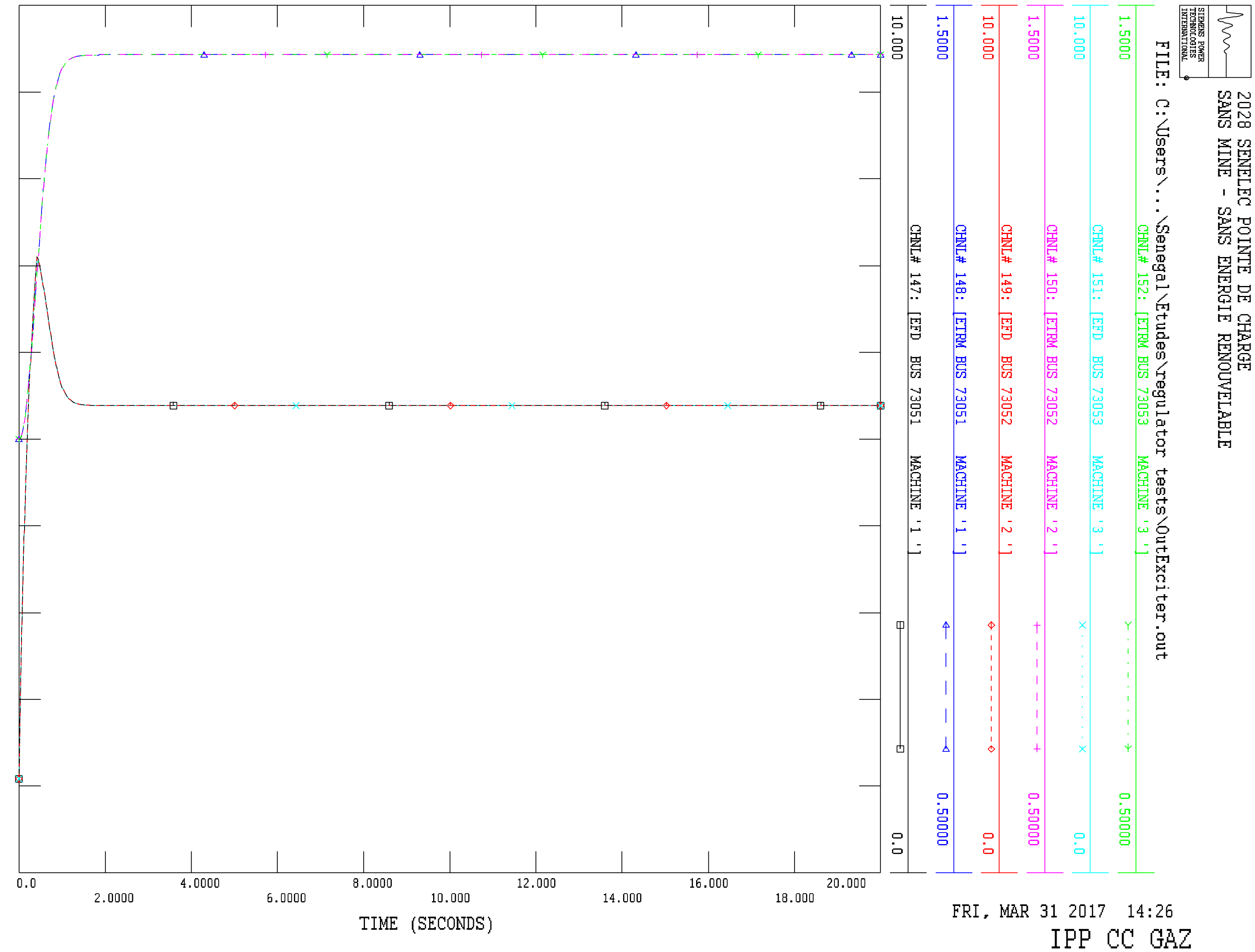
IPP CC GAZ

H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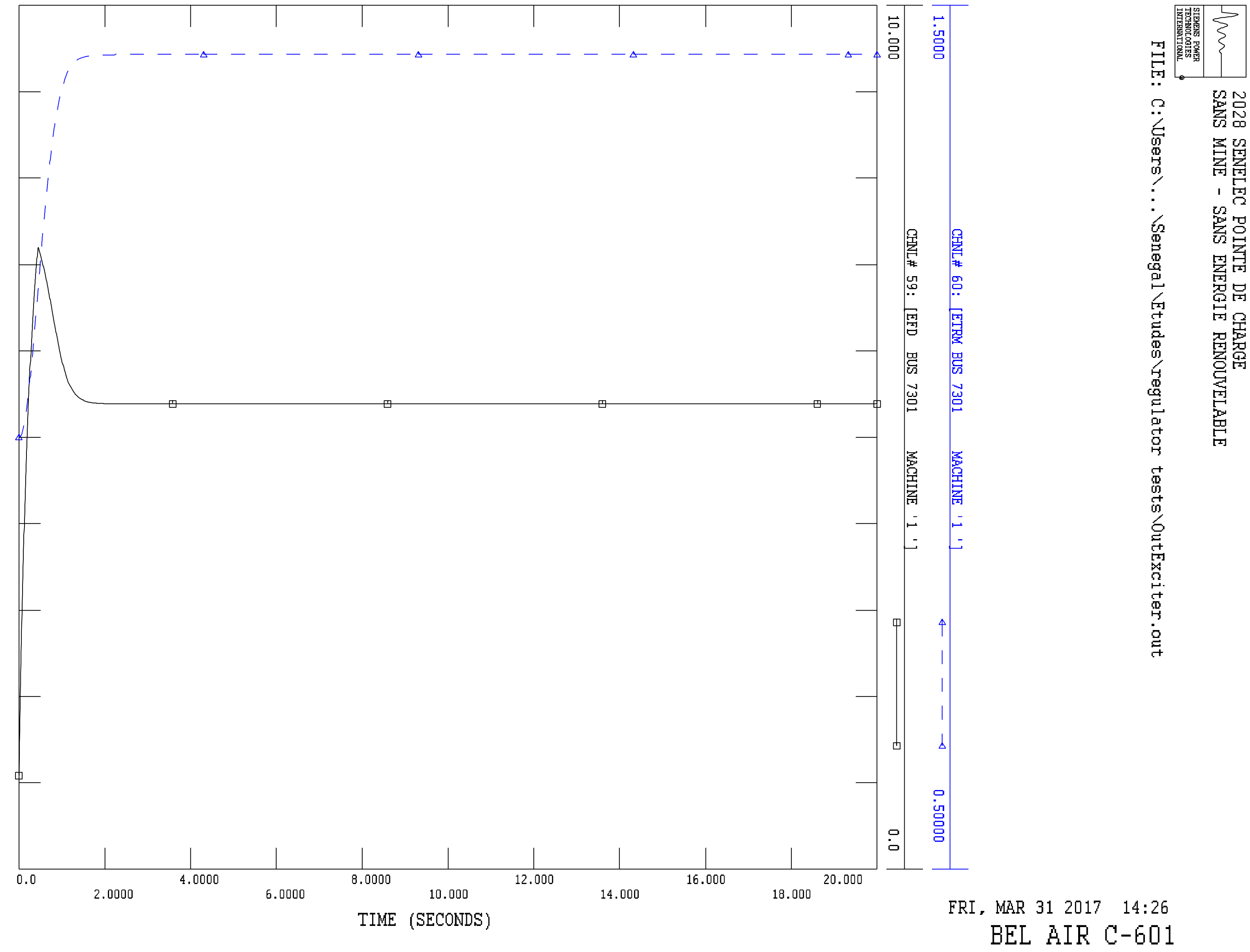

SIEMENS POWER TECHNOLOGIES INTERNATIONAL
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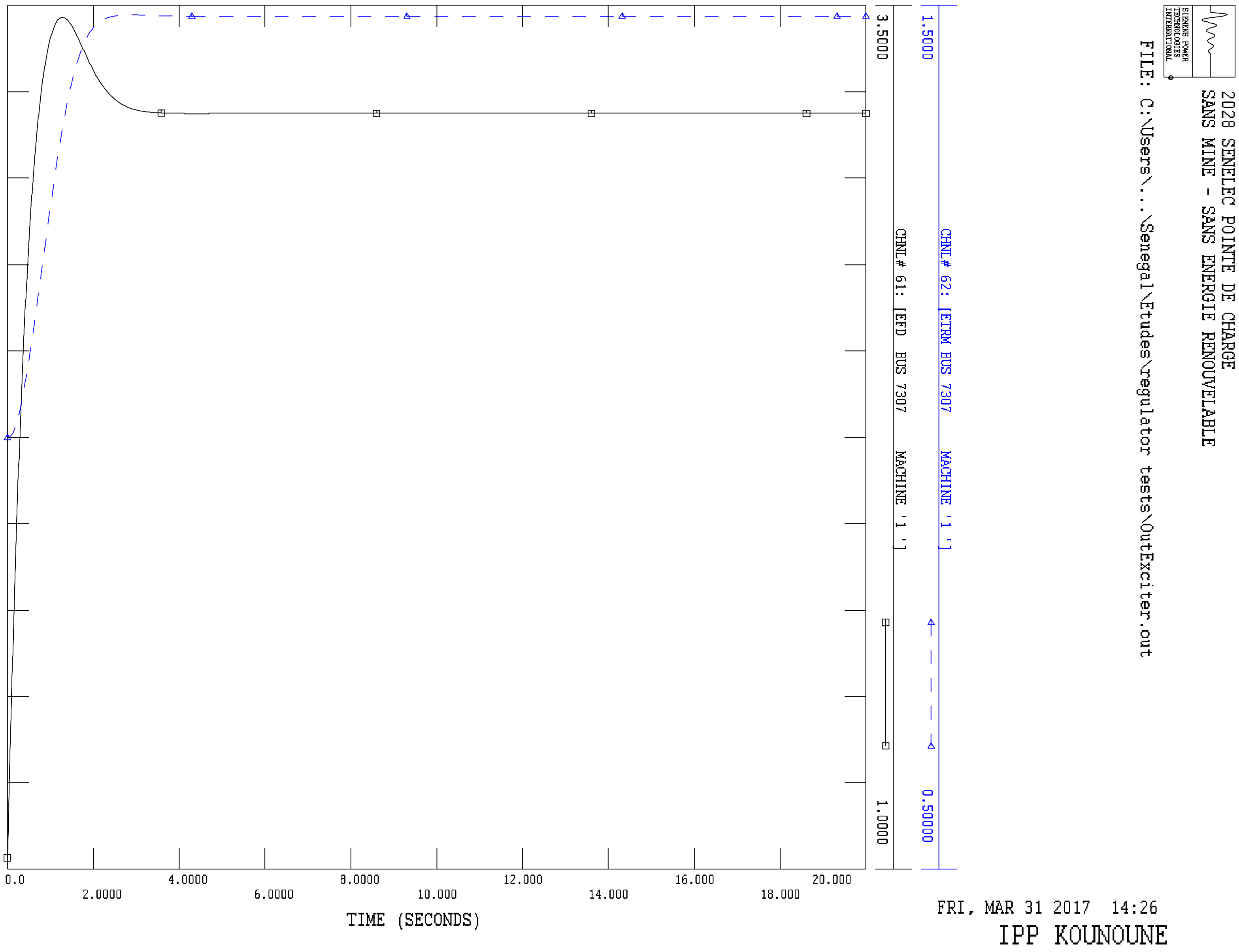
BEL AIR C-601

J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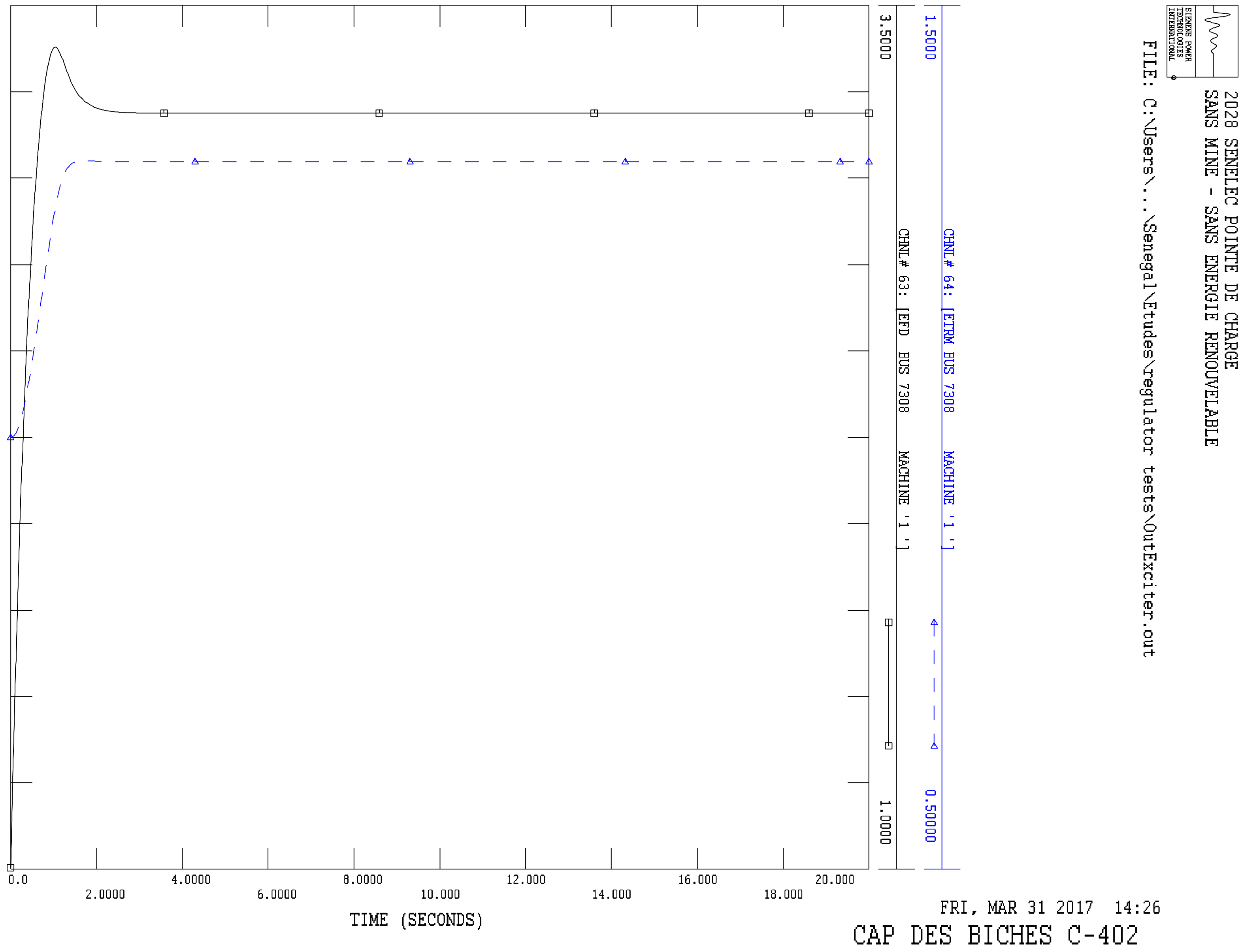
IPP KOUNOUNE

K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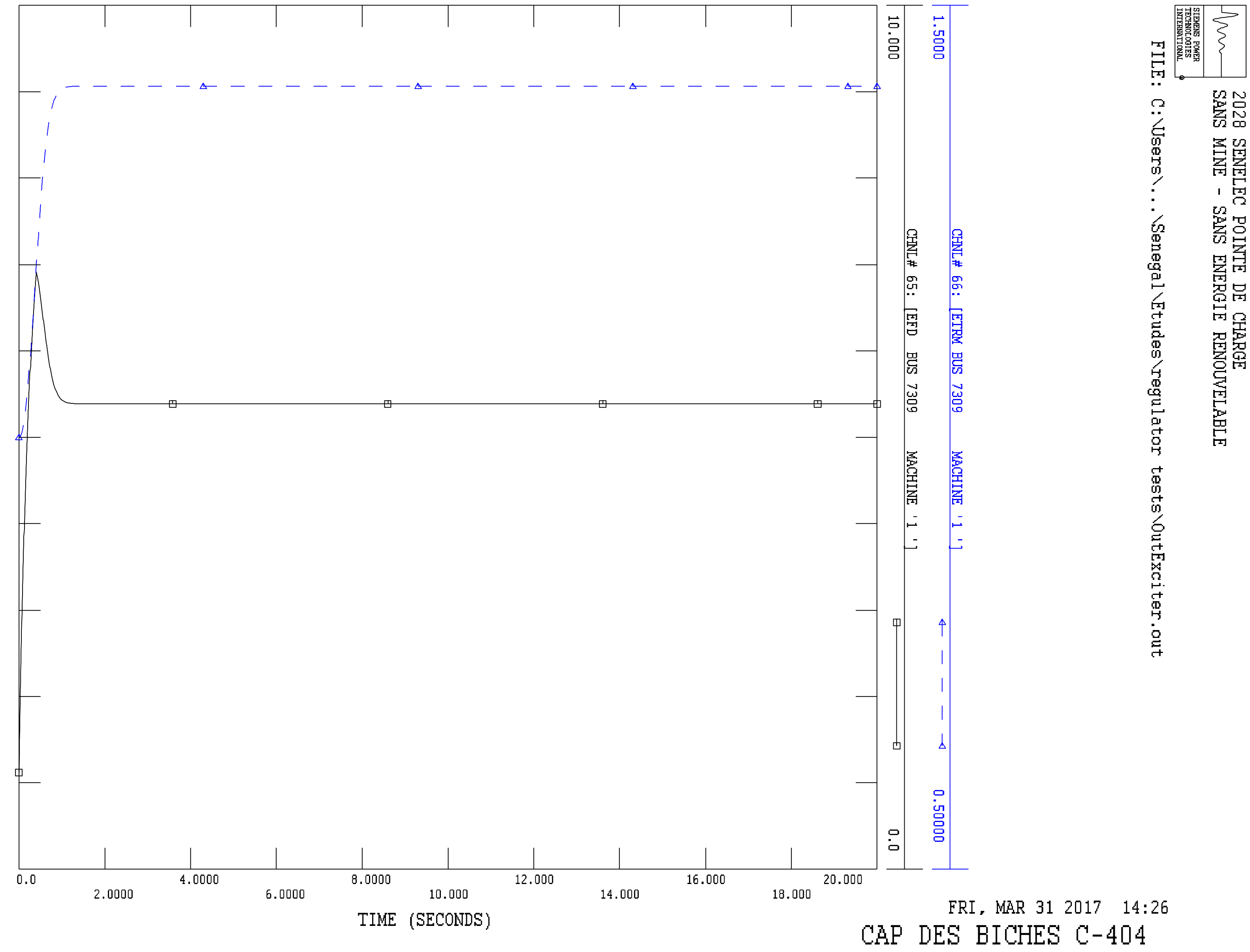
CAP DES BICHES C-402

L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CAP DES BICHES C-404

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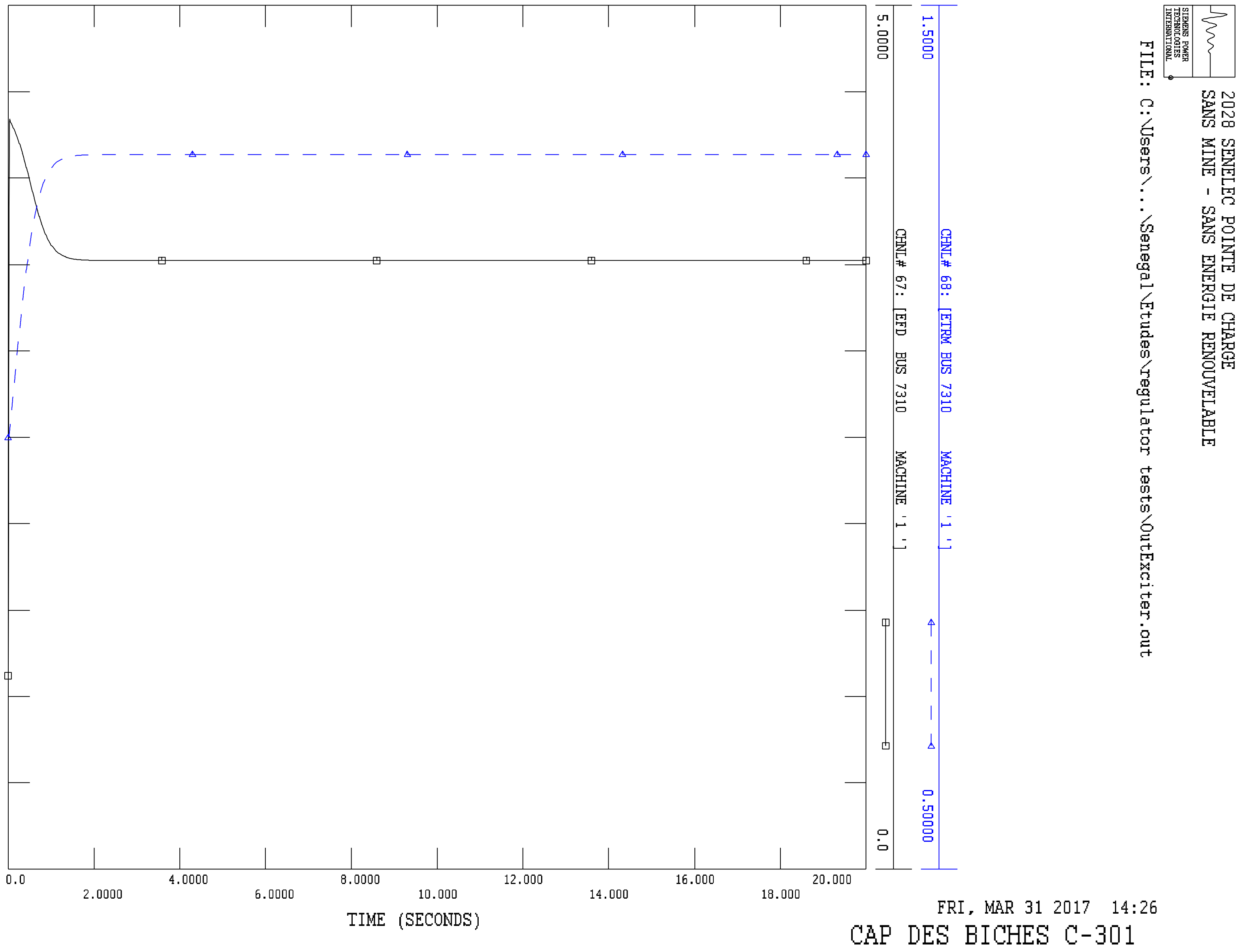
2028 SENELEC POINTE DE CHARGE
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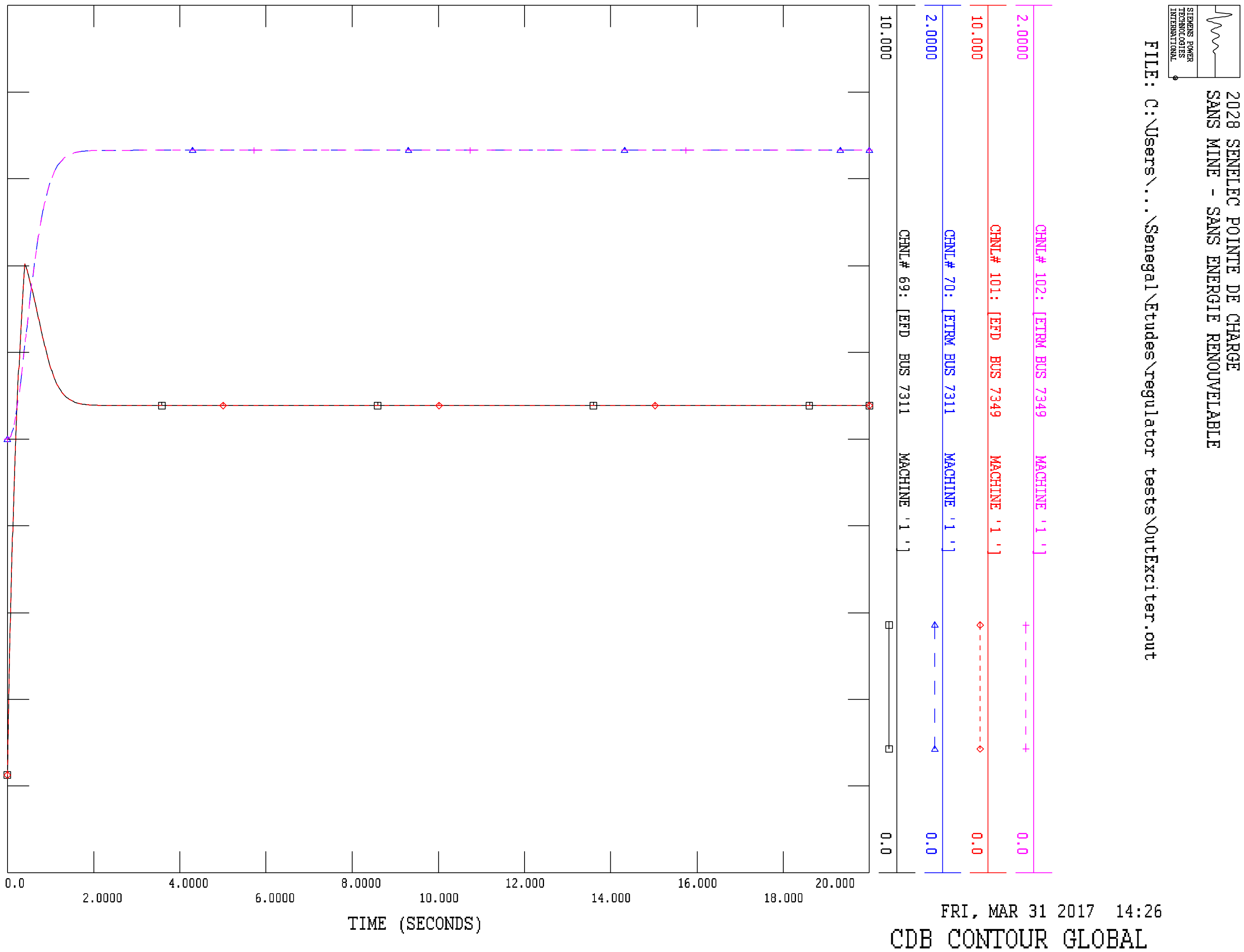
CAP DES BICHES C-301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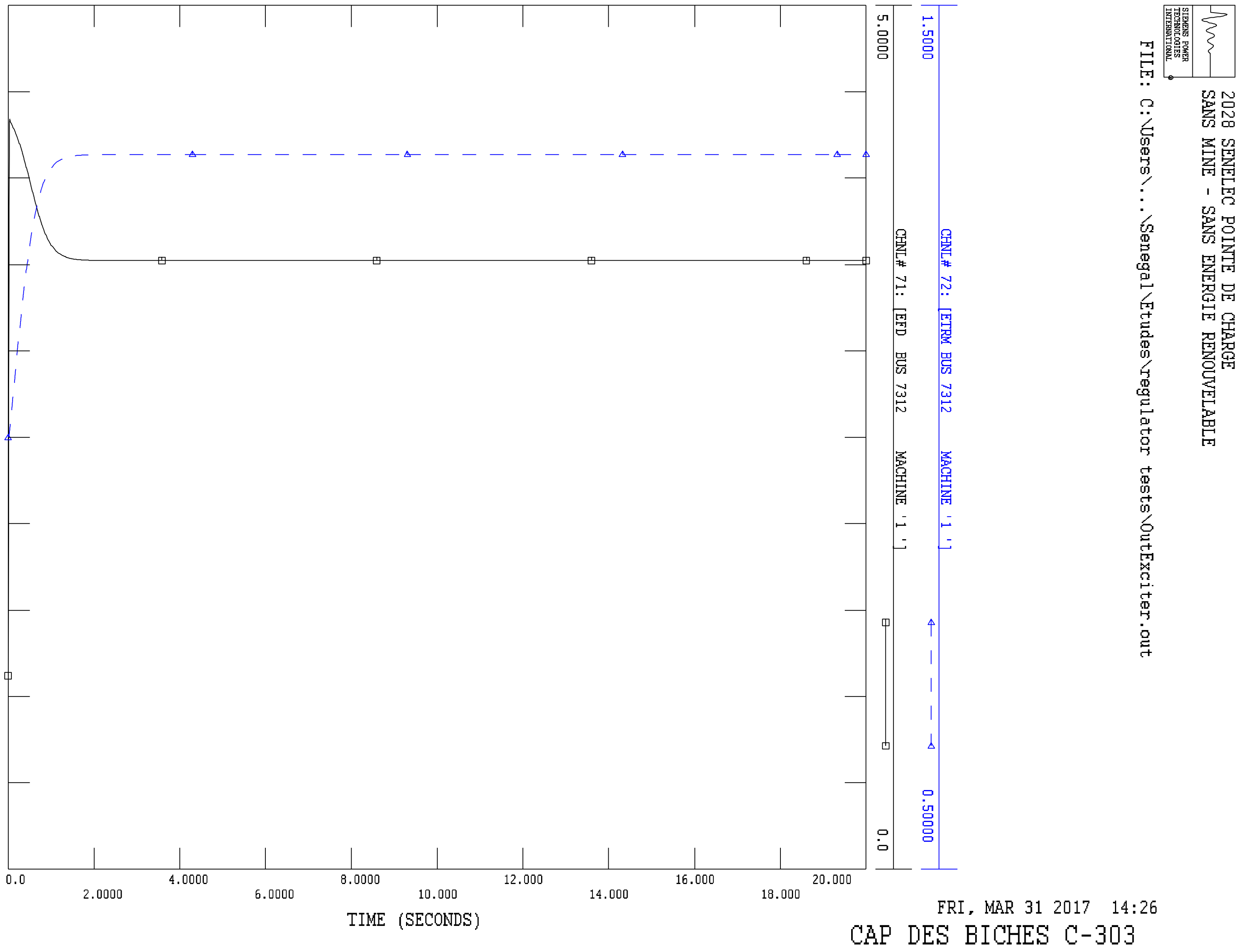
FRI, MAR 31 2017 14:26
CDB CONTOUR GLOBAL



2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
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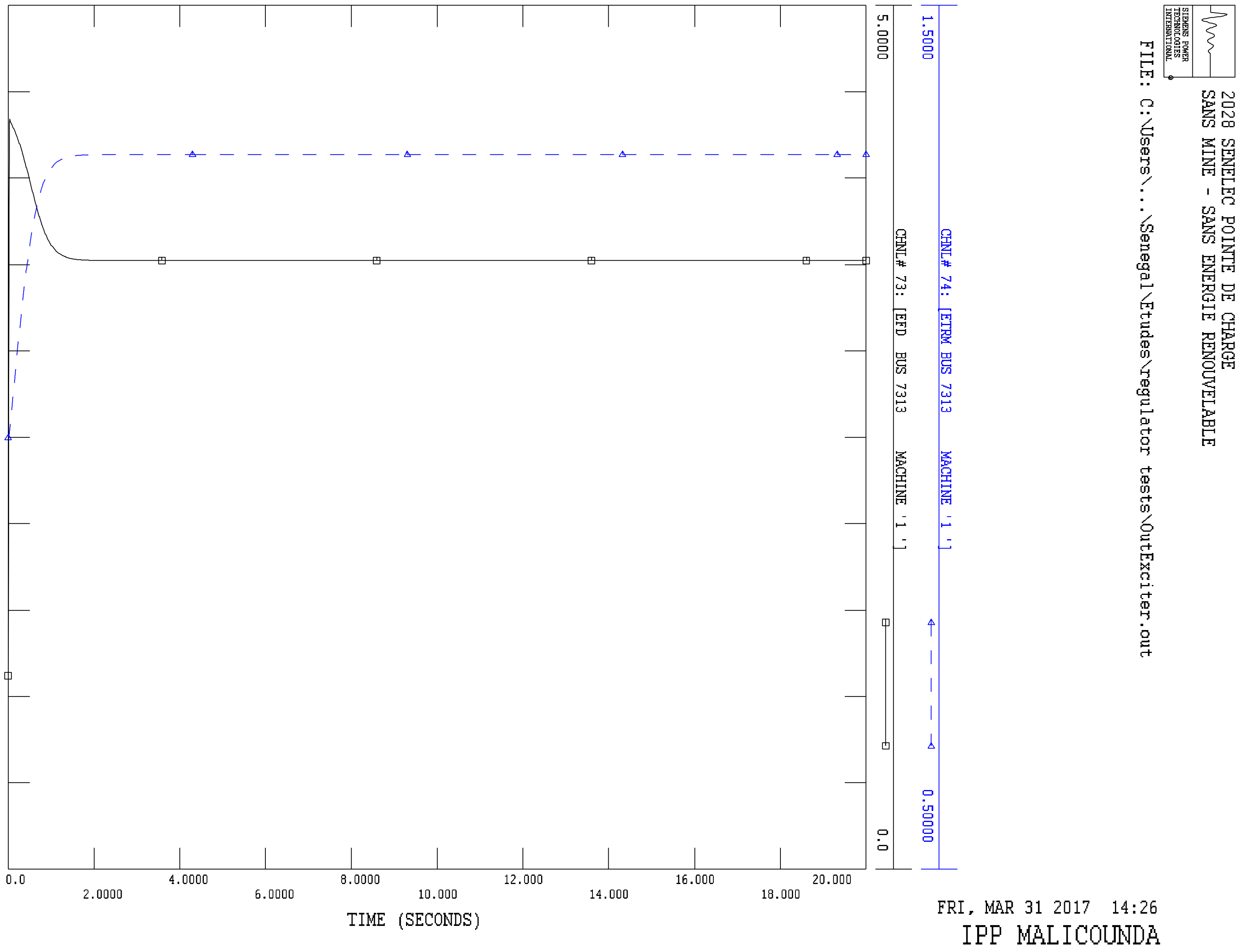
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SANS MINE - SANS ENERGIE RENOUVELABLE
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4.0000
6.0000
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14.000
16.000
18.000
20.000
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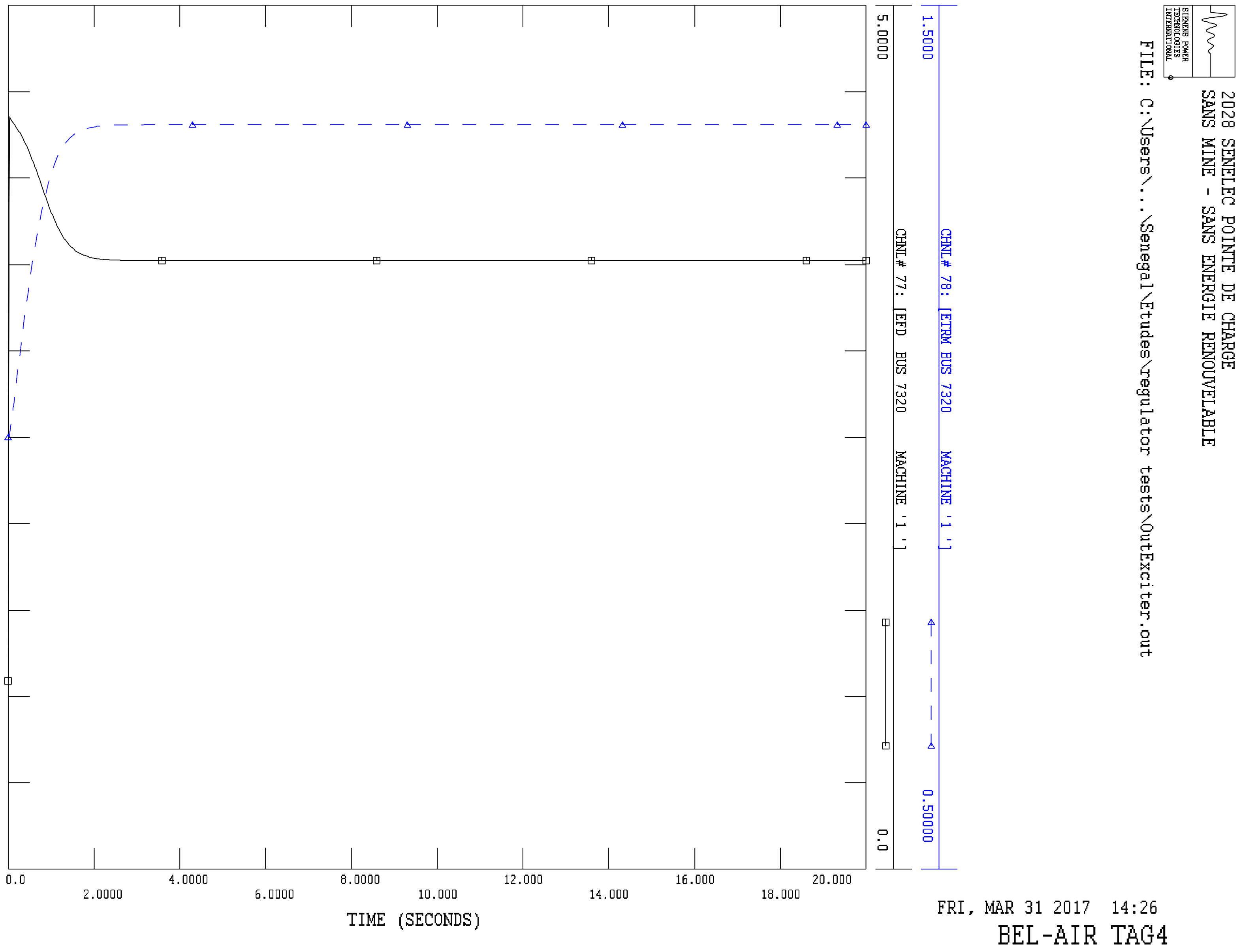
IPP MALICOUNDA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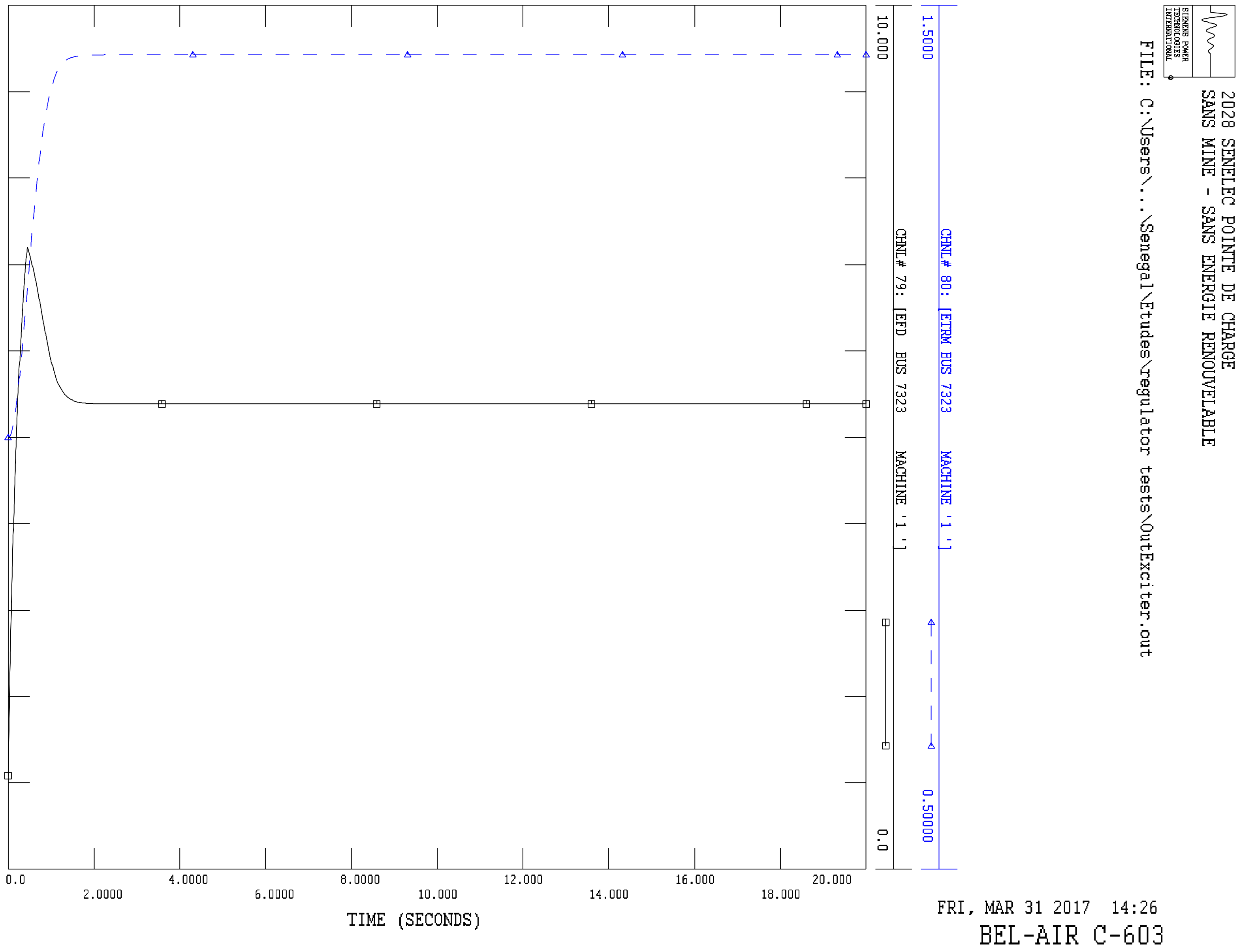
FRI, MAR 31 2017 14:26
BEL-AIR TAG4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SANS MINE - SANS ENERGIE RENOUVELABLE
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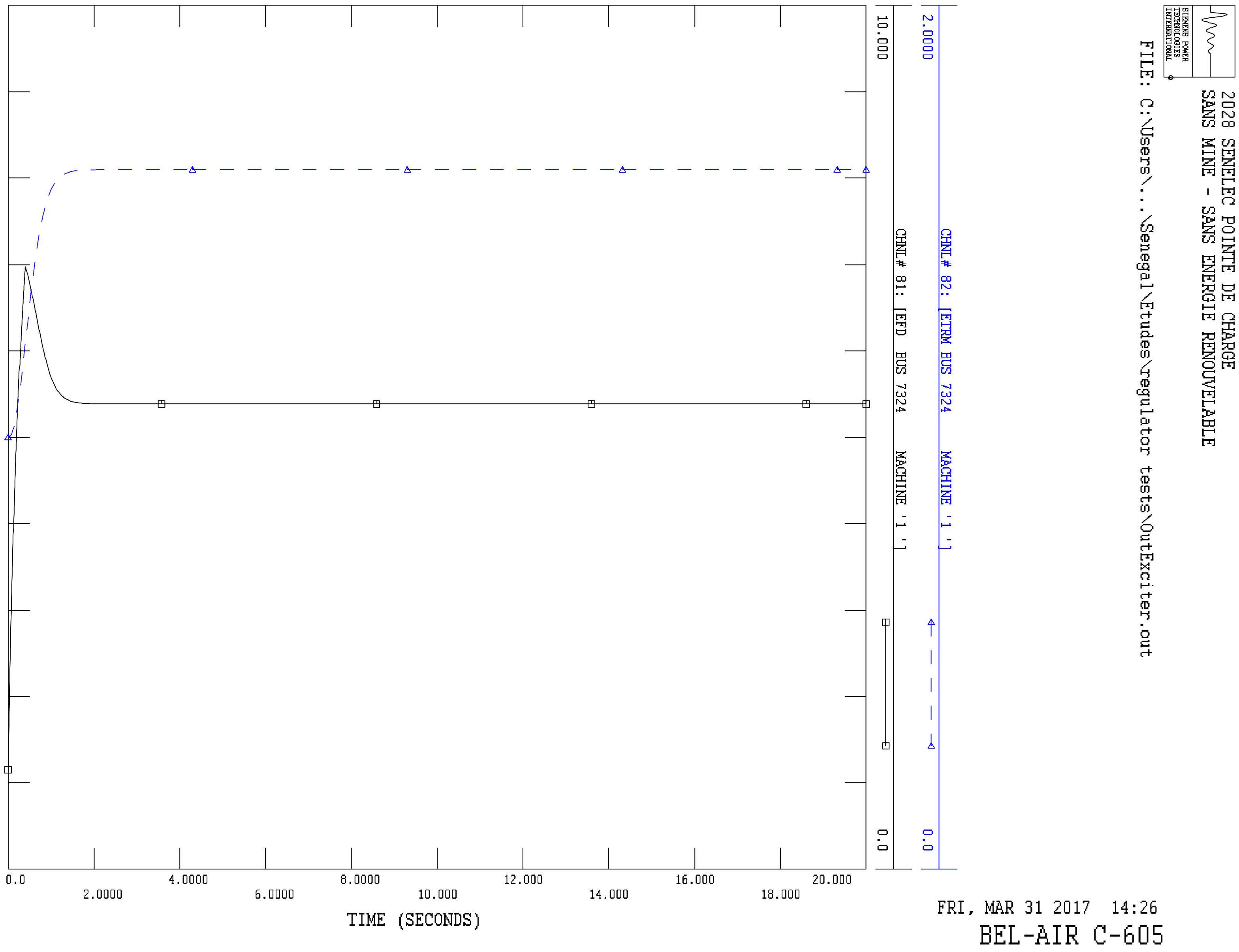
TIME (SECONDS)
FRI, MAR 31 2017 14:26
BEL-AIR C-603



2028 SENELEC POINTE DE CHARGE
SANS MINE - SANS ENERGIE RENOUVELABLE
FILE: C:\Users\...\Senegal\Etudes\regulator tests\OutExciter.out
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4.0000
6.0000
8.0000
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16.000
18.000
20.000
TIME (SECONDS)
FRI, MAR 31 2017 14:26
BEL-AIR C-605

12. APPENDIX E: SIMULATION RESULTS

Given the size of the files, the appendix is available on a USB drive.

13. APPENDIX F: FINANCIAL ANALYSIS METHODOLOGY

F.1 DISCOUNTING

For discounting calculations, we used the most recent data that Senelec provided to CRSE. The main data are as follows:

- Risk-free investment rate after tax: 6.9% - R_f
- Market risk premium: 5% - (R_m-R_f)
- Beta related to the risk: 80% - β
- Cost of debt after taxes: 8.3% - r_d
- Project debt/equity ratio: 45%/55%: D/E

Based on these data, we can determine the desired Return on Equity (RoE) using the following formula:

RoE = $R_f + \beta \times (R_m - R_f)$
RoE = 10.9%

As for the discount rate (DR) for each scenario, we will use the following formula:

DRn = (r_d x D) + (RoE x E)
DRn = 0.0973, or 9.73%

Where "DRn" equals the nominal discount rate.

Note the very high level of equity required for Senelec's projects. Currently at 55%, this is much higher than the equity required for standard IPP projects, which is usually between 20% and 30%. It therefore significantly affects the discount rate and also reduces the net present value of projects.

F.2 FINANCIAL ANALYSIS METHODOLOGY

The method of calculating the cost per kWh in each scenario will include the following:

- Total fixed costs of Senelec power plants: **(FCs)**
  - These costs will be the same for each power plant in each of the scenarios.
- Total fixed costs of thermal IPP power plants (HFO, Diesel, Coal, NG): **(FCi)**
  - We estimated these costs by type of power plant, and will be the same for all scenarios.
- Variable costs of each Senelec thermal power plant based on its generation: **(VCs)**
  - Including cost behavior according to the projected change in fuel costs based on the assumptions in the Senelec Master Plan.
- Variable costs of each thermal power plant according to its projected output: **(VCi)**
  - Including cost behavior according to the projected change in fuel costs.
- Total fixed costs for IPP IRE power plants: **(FCire)**
  - Based on the capacity and generation projections of each of the power plants.

The general formula for calculating the cost of each model should therefore be as follows:

$$\frac{(FCs + FCi + VCs + VCi + FCire) \times (1 + DRn)^{n}}{kWhT \times ((1 + DRn) / (1+ IR)-1)^{n}}$$

Where "kWhT" equals the total kWh generated during the number of years in the period 2017-2035 (n), and where "IR" is the projected average Inflation Rate for period "n".

F.3 COST PER KWH FOR EACH SCENARIO

COST PER KWH FOR EACH SCENARIO	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Senelec																			
Total costs (M CFAF)	281,594	291,152	309,858	382,710	397,019	434,808	452,512	479,617	552,070	602,975	643,221	699,990	759,022	814,664	874,935	939,921	1,010,771	1,084,841	1,149,525
Total energy (GWh)	3,615	3 825	4,081	4,840	5,739	6,613	7,044	7,474	7,918	8,416	8,942	9,447	9,947	10,367	11,018	11,687	12,386	13,118	13 840
Value per kWh (CFAF/kWh)	77.90	76.11	75.92	79.07	69.17	65.75	64.24	64.17	69.72	71.64	71.93	74.10	76.30	78.59	79.41	80.42	81.61	82.70	83.06
PATRP with no decommissioning																			
Total costs (M CFAF)	281,594	289,846	308,139	372,452	397,422	440,503	464,613	506,257	533,991	571,657	615,902	641,862	683,052	720,945	773,841	836,675	896,971	959,041	1,014,397
Total energy (GWh)	3,615	3 825	4,081	4,840	5,739	6,613	7,039	7,473	7,908	8,409	8,942	9,443	9,931	10,365	11,005	11,692	12,403	13,161	13,941
Value per kWh (CFAF/kWh)	77.90	75.77	75.50	76.95	69.24	66.61	66.00	67.74	67.53	67.98	68.88	67.97	68.78	69.56	70.31	71.56	72.32	72.87	72.76
PATRP with decommissioning																			
Total costs (M CFAF)	281,594	289 846	308,139	386,510	392,793	436,878	447,259	468,924	494,639	532,192	576,299	601,212	638,688	680,841	729,889	795,548	852,247	913,013	966,946
Total energy (GWh)	3,615	3 825	4,081	4 840	5 740	6,613	7,042	7,472	7,904	8,405	8,941	9,440	9,926	10,364	11,002	11,692	12,401	13,159	13,939
Value per kWh (CFAF/ kWh)	77.90	75.77	75.50	79.85	68.44	66.06	63.51	62.75	62.58	63.32	64.46	63.69	64.34	65.69	66.34	68.04	68.73	69.38	69.37

14. APPENDIX G: METHODOLOGY AND ASSUMPTIONS OF THE SUPPLEMENTARY FINANCIAL ANALYSIS

G.1 REVENUE LOSSES FROM LOAD SHEDDING DUE TO OUTAGES AT COAL-FIRED, SOLAR AND WIND POWER PLANTS

The following tables show the assumptions of the number of outages per year to explain the three scenarios proposed, namely the energy losses corresponding to one outage (low scenario), three outages (median scenario) and five outages (high scenario) per year. These assumptions make it possible to estimate the energy losses for each scenario, and then to estimate the revenue losses (Appendix **Error! Reference source not found.**).

ENERGY LOSSES FROM LOAD SHEDDING DUE TO OUTAGES IN SENELEC SCENARIO (MWH) - ONE OUTAGE PER YEAR													
Commissioning	Power plant	# of outages	Max. Power MW	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
2018	Sendou	1	115		115	115	115	115	115	115	115	115	920
2020	Africa Energy	1	90				90.0	90.0	90.0	90.0	90.0	90.0	540.0
2021		1	90					90.0	90.0	90.0	90.0	90.0	450.0
2021		1	90					90.0	90.0	90.0	90.0	90.0	450.0
2017	Solar 3	1	29	7.3	14.5	14.5	14.5	14.5					58.0
2017	Solar 4	1	29	7.3	14.5	14.5	14.5	14.5					58.0
2017	Solar 5	1	20	5.0	10.0	10.0	10.0	10.0					40.0
2018	Solar 6	1	30		15.0	15.0	15.0	15.0					60.0
2018	Solar 7	1	30		15.0	15.0	15.0	15.0					60.0
2018	Solar 8	1	15		7.5	7.5	7.5	7.5					30.0
2019	Solar 9	1	40			20.0	20.0	20.0					60.0
2021	Solar 10	1	30					15.0					15.0
2022	Solar 11	1	30										0.0
2023	Solar 12	1	30										0.0
2018	Taiba 1	1	23.81		11.9	11.9	11.9	11.9					47.6
2019	Taiba 2	1	23.81			11.9	11.9	11.9					35.7
2020	Taiba 3	1	25.39				12.7	12.7					25.4
Total				19.5	203.4	235.3	338.0	533.0	385.0	385.0	385.0	385.0	2849.7

ENERGY LOSSES FROM LOAD SHEDDING DUE TO OUTAGES IN SENELEC SCENARIO (MWH) - THREE OUTAGES PER YEAR													
Commissioning	Power plant	# of outages	Max. Power MW	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
2018	Sendou	3	115.0		345	345	345	345	345	345	345	345	2760.0
2020	Africa Energy	3	90.0				270.0	270.0	270.0	270.0	270.0	270	1620.0
2021		3	90.0					270.0	270.0	270.0	270.0	270	1350.0
2021		3	90.0					270.0	270.0	270.0	270.0	270	1350.0
2017	Solar 3	3	29.0	21.8	43.5	43.5	43.5	43.5					174.0
2017	Solar 4	3	29.0	21.8	43.5	43.5	43.5	43.5					174.0
2017	Solaire 5	3	20.0	15.0	30.0	30.0	30.0	30.0					120.0
2018	Solar 6	3	30.0		22.5	45.0	45.0	45.0					157.5
2018	Solar 7	3	30.0		22.5	45.0	45.0	45.0					157.5
2018	Solar 8	3	15.0		22.5	22.5	22.5	22.5					90.0
2019	Solar 9	3	40.0			60.0	60.0	60.0					180.0
2021	Solar 10	3	30.0					45.0					45.0
2022	Solar 11	3	30.0										
2023	Solar 12	3	30.0										
2018	Taiba 1	3	23.8		35.7	35.7	35.7	35.7					142.9
2019	Taiba 2	3	23.8			35.7	35.7	35.7					107.1
2020	Taiba 3	3	25.4				38.1	38.1					76.2
Total				59	565	706	1014	1599	1155	1155	1155	1155	8504.2

ENERGY LOSSES FROM LOAD SHEDDING DUE TO OUTAGES IN SENELEC SCENARIO (MWH) - FIVE OUTAGES PER YEAR													
Commissioning	Power plant	# of outages	Max. Power MW	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
2018	Sendou	5	115		575	575	575	575	575	575	575	575	4600.0
2020	Africa Energy	5	90				450.0	450.0	450.0	450.0	450.0	450	2700.0
2021	Africa Energy	5	90					450.0	450.0	450.0	450.0	450	2250.0
2021	Africa Energy	5	90					450.0	450.0	450.0	450.0	450	2250.0
2017	Solar 3	5	29	36.3	72.5	72.5	72.5	72.5					290.0
2017	Solar 4	5	29	36.3	72.5	72.5	72.5	72.5					290.0
2017	Solar 5	5	20	25.0	50.0	50.0	50.0	50.0					200.0
2018	Solar 6	5	30		37.5	75.0	37.5	37.5					187.5
2018	Solar 7	5	30		37.5	75.0	75.0	75.0					262.5
2018	Solar 8	5	15		37.5	37.5	37.5	37.5					150.0
2019	Solar 9	5	40			100.0	100.0	100.0					300.0
2021	Solar 10	5	30					75.0					75.0
2022	Solar 11	5	30										0.0
2023	Solar 12	5	30										0.0
2018	Taiba 1	5	23.81		59.5	59.5	59.5	59.5					238.1
2019	Taiba 2	5	23.81			59.5	59.5	59.5					178.6
2020	Taiba 3	5	25.39				63.5	63.5					127.0
Total				97.5	942.0	1176.6	1652.5	2627.5	1925.0	1925.0	1925.0	1925.0	14098.6

G.2 REVENUE LOSSES FROM LOAD SHEDDING DUE TO FLUCTUATIONS IN IRE

As in the previous section, the tables below show the annual number of critical fluctuation events leading to load shedding to explain the three scenarios proposed, namely energy losses corresponding to one event per year (low scenario), two events per year (median scenario) and three events (high scenario) per year. Using these assumptions we can estimate the energy losses for each scenario, and then estimate revenue losses (Appendix **Error! Reference source not found.**).

REVENUE LOSSES FROM FLUCTUATIONS IN IRE IN THE SENELEC SCENARIO (MWH) – ONE CRITICAL FLUCTUATION															
Commissioning	Power plant	Fluctuations	Max power (MW)	Max fluctuations	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
2017	Solar 3	1	29	20.3	10.2	20.3	20.3	20.3	20.3					81.2
2017	Solar 4	1	29	20.3	10.2	20.3	20.3	20.3	20.3					81.2
2017	Solar 5	1	20	14.0										0.0
2018	Solar 6	1	30	21.0		10.5	21.0	21.0	21.0					73.5
2018	Solar 7	1	30	21.0		10.5	21.0	21.0	21.0					73.5
2018	Solar 8	1	15	10.5										0.0
2019	Solar 9	1	40	28.0			28.0	28.0	28.0					84.0
2021	Solar 10	1	30	21.0					21.0					21.0
2022	Solar 11	1	30	21.0										0.0
2023	Solar 12	1	30	21.0										0.0
2018	Taiba 1	1	23.81	23.8		23.8								23.8
2019	Taiba 2	1	23.81	47.6			47.6							47.6
2020	Taiba 3	1	25.39	73.0				73.0	73.0	73.0	73.0	73.0	73.0	438.1
Total					20.3	85.4	158.2	183.6	204.6	73.0	73.0	73.0	73.0	923.9

REVENUE LOSSES FROM FLUCTUATIONS IN IRE IN THE SENELEC SCENARIO (MWH) –TWO CRITICAL FLUCTUATIONS														
Commissioning	Power plant	Fluctuations	Max power (MW)	Max fluctuations	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
2017	Solar 3	2	29	20.3	20.3	40.6	40.6	40.6	40.6					162.4
2017	Solar 4	2	29	20.3	20.3	40.6	40.6	40.6	40.6					162.4
2017	Solar 5	2	20	14.0										0.0
2018	Solar 6	2	30	21.0		21.0	42.0	42.0	42.0					147.0
2018	Solar 7	2	30	21.0		21.0	42.0	42.0	42.0					147.0
2018	Solar 8	2	15	10.5										0.0
2019	Solar 9	2	40	28.0			56.0	56.0	56.0					168.0
2021	Solar 10	2	30	21.0					42.0					42.0
2022	Solar 11	2	30	21.0										0.0
2023	Solar 12	2	30	21.0										0.0
2018	Taiba 1	2	23.81	23.8		47.6								47.6
2019	Taiba 2	2	23.81	47.6			95.2							95.2
2020	Taiba 3	2	25.39	73.0				146.0	146.0	146.0	146.0	146.0	146.0	876.1
Total					40.6	170.8	316.4	367.2	409.2	146.0	146.0	146.0	146.0	1847.8

REVENUE LOSSES FROM FLUCTUATIONS IN IRE IN THE SENELEC SCENARIO (MWH) –THREE CRITICAL FLUCTUATIONS														
Commissioning	Power plant	Fluctuations	Max power (MW)	Max fluctuations	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
2017	Solar 3	3	29	20.3	30.5	60.9	60.9	60.9	60.9					243.6
2017	Solar 4	3	29	20.3	30.5	60.9	60.9	60.9	60.9					243.6
2017	Solar 5	3	20	14.0										0.0
2018	Solar 6	3	30	21.0		31.5	63.0	63.0	63.0					220.5
2018	Solar 7	3	30	21.0		31.5	63.0	63.0	63.0					220.5
2018	Solar 8	3	15	10.5										0.0
2019	Solar 9	3	40	28.0			84.0	84.0	84.0					252.0
2021	Solar 10	3	30	21.0					63.0					63.0
2022	Solar 11	3	30	21.0										0.0
2023	Solar 12	3	30	21.0										0.0
2018	Taiba 1	3	23.81	23.8		71.4								71.4
2019	Taiba 2	3	23.81	47.6			142.9							142.9
2020	Taiba 3	3	25.39	73.0				219.0	219.0	219.0	219.0	219.0	219.0	1314.2
Total					60.9	256.2	474.7	550.8	613.8	219.0	219.0	219.0	219.0	2771.7

G.3 REVENUE LOSS ESTIMATION RESULTING FROM ENERGY LOSSES

The method of calculating revenue loss will include the following:

- Losses of energy or non-distributed energy over the study period **(NDE)**
  - Arising from outages at coal-fired, solar and wind power plants (Appendix G.1); and load shedding due to fluctuations in IRE (Appendix **Error! Reference source not found.**)
- Proportion of annual energy sales for different types of customers over the study period **(SPij)**
  - Based on 2017-2035 demand forecasts, we evaluated the proportion of energy sales for different types of customers. This simplifies the analysis and assumes a homogeneity of average rates among these groups, confirmed in the achieved 2016 sales and revenue provided by Senelec.
- Annual rates for different types of customers over the study period **(CTij)**
  - Senelec provided the 2017-2019 rates according to the second CRSE public consultation on Senelec's tariff review.
  - A two per cent inflation rate was subsequently applied.
- The annual variable costs per kWh of generation for each scenario over the study period **(VCj)**
  - As estimated by the supply-demand model for each scenario.
  - Only variable costs are applied as a Senelec opportunity cost because we assumed that Senelec will make the investments required to meet expected demand.
- DRn is the nominal discount rate as calculated in Appendix F.1

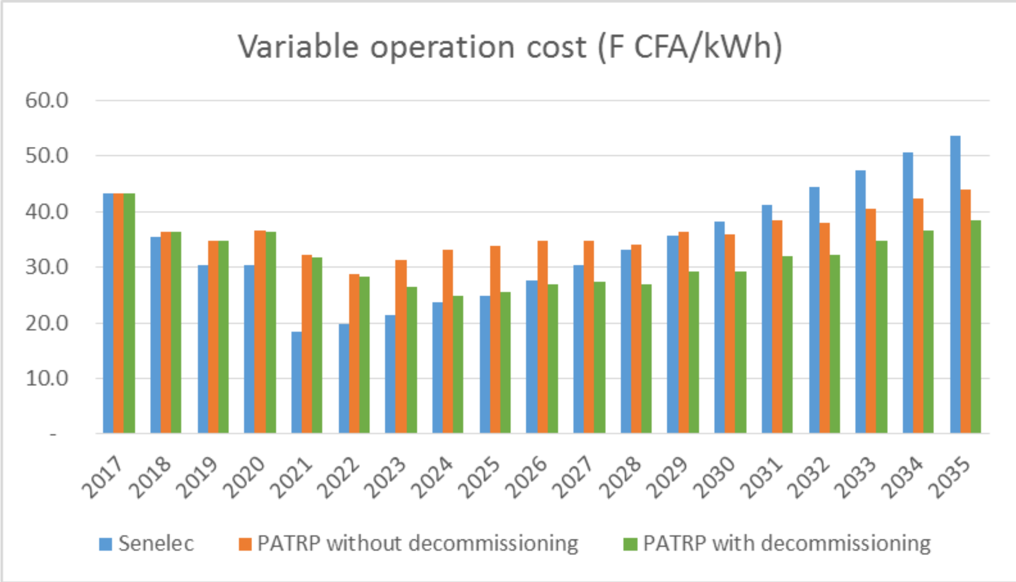
The general formula for calculating revenue loss is as follows:

$$\sum_{j}^{n}\sum_{i}^{5}\frac{NDE_j \times SP_{ij} \times (CT_{ij} - VC_j)}{(1+DRn)^j}$$

PROPORTION OF SALES BY TYPE OF CUSTOMER DURING THE STUDY PERIOD (SPIJ)																				
Sales (%)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Residential (DPP, DMP, DGP)	43%	45%	43%	42%	40%	35%	33%	34%	35%	35%	36%	37%	39%	40%	41%	42%	42%	42%	43%	43%
Small industrial/commercial (PPP, PMP, PGP)	19%	17%	18%	17%	16%	15%	14%	14%	14%	15%	15%	15%	16%	16%	17%	17%	17%	18%	18%	18%
Medium industrial/commercial (TCU, TG, TLU)	30%	29%	29%	28%	27%	24%	23%	23%	23%	23%	23%	23%	24%	25%	25%	26%	26%	26%	26%	26%
Large industrial (HV)	6%	6%	8%	10%	15%	24%	29%	28%	27%	25%	24%	23%	19%	17%	15%	14%	13%	12%	12%	11%
Public lighting (EP)	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%

AVERAGE PRICES (CFAF/KWH)																				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Residential (DPP, DMP, DGP, Woyofal)	107.90	96.16	95.02	96.92	98.86	100.84	102.85	104.91	107.01	109.15	109.15	109.15	109.15	109.15	109.15	109.15	109.15	109.15	109.15	109.15
Commercial - Small (PPP, PMP, PGP)	152.72	142.99	141.90	144.74	147.63	150.59	153.60	156.67	159.80	163.00	163.00	163.00	163.00	163.00	163.00	163.00	163.00	163.00	163.00	163.00
Commercial - Medium (MP: TCU, TG, TLU)	115.35	110.34	111.40	113.63	115.90	118.22	120.58	122.99	125.45	127.96	127.96	127.96	127.96	127.96	127.96	127.96	127.96	127.96	127.96	127.96
Commercial - Large (HV)	87.70	86.62	87.23	88.97	90.75	92.57	94.42	96.31	98.24	100.20	100.20	100.20	100.20	100.20	100.20	100.20	100.20	100.20	100.20	100.20
Public lighting	133.53	125.21	124.14	126.62	129.16	131.74	134.37	137.06	139.80	142.60	142.60	142.60	142.60	142.60	142.60	142.60	142.60	142.60	142.60	142.60

FIXED AND VARIABLE COST OF GENERATION																			
Cost per kWh (CFAF/kWh)	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Senelec																			
Fixed costs	34.30	37.84	40.60	44.10	43.27	41.19	41.28	41.76	43.17	42.56	41.17	40.72	40.38	40.15	39.82	37.70	35.72	33.63	30.90
Variable costs	43.20	35.36	30.29	30.47	18.31	19.72	21.29	23.78	24.78	27.57	0.42	33.13	35.79	38.17	41.31	44.42	47.56	50.72	53.79
Generation costs	77.51	73.19	70.89	74.56	61.58	60.91	62.57	65.54	67.95	70.14	71.59	73.85	76.18	78.31	81.12	82.12	83.28	84.35	84.69
PATRP with no decommissioning																			
Fixed costs	34.30	36.41	38.58	39.85	36.94	39.19	36.03	35.98	35.17	34.74	35.80	35.66	34.08	35.39	33.50	35.18	33.35	32.21	30.40
Variable costs	43.20	36.44	34.69	36.59	32.20	28.71	31.20	33.12	33.83	34.80	34.70	33.97	36.38	35.89	38.53	38.08	40.64	42.30	43.97
Generation costs	77.51	72.85	73.27	76.44	69.14	67.89	67.23	69.11	69.00	69.54	70.49	69.63	70.47	71.28	72.03	73.26	73.99	74.51	74.38
PATRP with decommissioning																			
Fixed costs	34.11	36.37	38.54	42.83	36.02	38.63	37.72	38.71	37.75	37.16	38.05	37.80	36.12	37.32	35.32	36.88	34.95	33.71	31.81
Variable costs	43.26	36.46	34.71	36.50	31.66	28.32	26.48	24.82	25.66	27.04	27.32	26.82	29.18	29.34	31.99	32.12	34.72	36.60	38.47
Generation costs	77.37	72.83	73.25	79.33	67.68	66.95	64.20	63.52	63.42	64.20	65.37	64.62	65.30	66.67	67.31	69.00	69.67	70.31	70.28



Variable operation cost (F CFA/kWh)
60.0
50.0
40.0
30.0
20.0
10.0
-
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
Senelec
PATRP without decommissioning
PATRP with decommissioning

G.4 REVENUE LOSS FROM LARGE ELECTRICITY CONSUMERS LOST DUE TO UNRELIABILITY

The method of calculating revenue loss includes the following:

- Demand forecasts for large consumers (Medium Voltage, **CMVj** and High Voltage, **CHVj**)
  - We chose the customers most likely not to connect to the grid (or simply not implement their project) due to the unreliability of the interconnected network, such as mining companies and private industry.
  - We used the 2017-2035 demand forecasts (see chapter 2).
- Annual rates of medium voltage and high voltage customers over the study period (**TMVj** and **THVj**)
  - Senelec provided the 2016-2018 rates according to the latest CRSE public consultations on Senelec's tariff review.
  - A two per cent inflation rate was subsequently applied.
- The annual variable costs per kWh of generation for each scenario over the study period (**VCj**)
  - As estimated by the supply-demand model for each scenario.
  - Only variable costs are applied as a Senelec opportunity cost because we assume that Senelec will make the investments required to meet the expected demand.
- DRn is the nominal discount rate as calculated in Appendix F.1

The general formula for calculating revenue loss is as follows:

$$\sum_{j}^{n} \frac{CHV_j \times (THV_j - CV_j) + CMV_j \times (TMV_j - CV_j)}{(1 + DRn)^j}$$

15. APPENDIX H: GENERATION MODELING TOOL

See attached Excel spreadsheet.