The Republic of Liberia
Liberia Electricity Corporation (LEC)

The Project of capacity Development for Diesel Generator Maintenance (Detailed Planning Phase) in The Republic of Liberia

Project Completion Report

April 2023

JAPAN INTERNATIONAL COOPERATION AGENCY
（JICA）

YACHIYO ENGINEERING CO., LTD.

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Photo of Activities (1/4)

	
<u>Power Plant (Exterior)</u> Heavy oil diesel power plant constructed in September 2016 with Grant Aid by the Government of Japan. The power generation capacity is 5MW x 2 units, but it is normally operated with the output of 4MW. Mainly operated with heavy oil, which is cheaper than diesel oil. (March 2023)	<u>Power Plant (Interior)</u> There is an auxiliary machinery and electrical room on the ground floor, and a diesel generator and control room on the second floor. The inside of the power plant was cleaned at the time of 8,000 hours OH. (March 2023)
	
<u>Diesel Generator Unit 1</u> As of the end of February 2023, the operating hours are 9,112 hours. Any particular problems are seen at this moment. The operator turns the crankshaft once a week with the lubricating oil pump in operation, and that maintenance is being carried out so that the lubricating oil circulates inside the engine even in the standby state. (March 2023)	<u>Diesel Generator Unit 2</u> As of the end of February 2023, the operating hours are 7,666 hours. In the 8,000 hours OH maintenance, countermeasures against the cooling water contamination trouble were carried out. In March 2023, the JICA experts checked the inside the engine (B4 cylinder) which was the most damaged and the lubricating oil system and confirmed that no further trouble was observed. (March 2023)
	
<u>Overhaul Inspection of Turbocharger</u> Turbocharger is a machine that feeds the compressed air necessary for combustion into the engine. The manufacturer's SV conducted training for engineers. (November 2022)	<u>Generator Panel</u> The panel is responsible for the engine start-up and alarms for major and minor failures. A panel mainly used by operator. The manufacturer's SV conducted training for engineers. (November 2022)

Photo of Activities (2/4)

Electrical Room

Circuit breakers, Disconnecting switch, MCC, etc. are installed, and air conditioning is always controlled by air conditioners. Spare parts are also stored in this room. In this phase, guidance on inspection methods has been provided, and circuit breaker maintenance training is planned for 12,000 hours of OH. (March 2023)

MCC

MCC is the power switch for each device such as the pump, and if it deviates from the threshold range set by the MCC, an alarm will sound in the control room. (March 2023)

Disconnecting Switch for Neutral Earthing Resistor

Operate before maintenance to release electrical equipment from high voltage. LECs are unfamiliar with operation procedures, so continued training is required. (March 2023)

6.6kV Circuit Breaker

A circuit breaker between a generator and a trainsformer, installed to protect the generator. To prevent accidents, it must be opened and pulled out before the maintenance. LECs are unfamiliar with operation procedures, so continued training is required. (March 2023)

22kV Circuit Breaker

A circuit breaker between a transformer and a 22kV bus. It is responsible for protecting power generator. In this phase, training on inspection methods has been provided, and the overhaul maintenance is planned in 12,000 hours maintenance. (March 2023)

Pump Motor

A pump is arranged in each system, and the fluid is circulated in the piping. In order to prevent troubles such as abnormal noise, fluid leakage, aged deterioration of insulation resistance, and to detect them at an early stage, the training of daily/periodically inspection will be continued. (March 2023)

Photo of Activities (3/4)

<u>Auxiliary Equipment (Fuel System)</u>

Due to the use of low-quality oil, the filter cleaning is frequently required, and JICA experts recommended LEC to include the items into the regular inspection items. The fuel properties check before installing the engine is recommended. (March 2023)

<u>Auxiliary Equipment (Lubricating Oil System)</u>

JICA experts recommended LEC to include the filter cleaning and exchange if necessary into the regular inspection items. The oil properties check before installation is recommended. (March 2023)

<u>Auxiliary Equipment (Cooling Water System)</u>

Since the clogged radiator fins reduce the fuel efficiency, JICA experts recommended LEC include the cleaning into the regular inspection items. The water properties check is recommended. (October 2022)

<u>Purifier for Heavy Fuel Oil</u>

There are two heavy fuel oil purifiers installed. Due to the low quality fuel and the rainwater mixed into the fuel, LEC encounters many challenges in operation. The training by the manufacturer's SV is conducted in 8,000 hours OH maintenance and planned in 12,000 hours OH maintenance as well. (March 2023)

<u>Purifier for Lubricating Oil</u>

There are three lubricating oil purifiers installed. In the 8,000 hours OH maintenance, since some parts of purifier No.3 were transplanted to other purifiers, the maintenance couldn't be completed. In the 12,000 hours OH maintenance, it is planned to be completed. (March 2023)

<u>Spare Parts Storage Status</u>

The spare parts of engine, electrical equipment, HFO purifier and LO purifier are stored separately. The inventory list and cards were prepared in 8,000 hours OH maintenance but the inventory system has just started so will be followed up in the implementation phase. (March 2023)

Photo of Activities (4/4)

Store Status of tools

Large tools are stored in the power station, and testing equipment is stored in the maintenance manager's room. The inventory list has been maintained in the 8,000 hours OH maintenance, but the shelves has not been installed. (march 2023)

Classroom Training

The classroom training was conducted with 25 participants. The lecture content is based on the premise that it will be returned to practice. In the implementation phase, it is also assumed that the creation of manuals actually used by LEC will be implemented in a workshop format (March 2023).

Practical Training

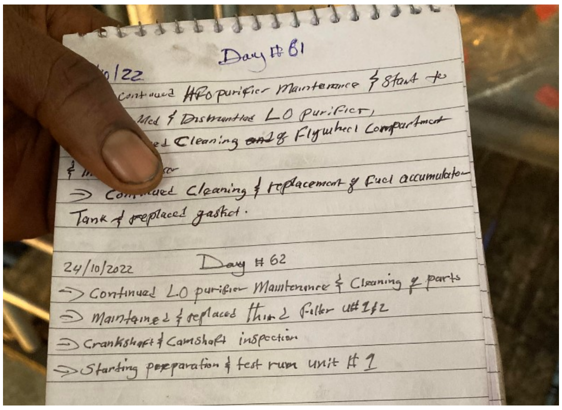
The classroom lectures was conducted in the morning and practical training on site was conducted in the afternoon in a way that the participants could immediately put into practice what they had learned. (March 2023)

Training on Electrical Equipment

As a basis for accident prevention, the training is given starting with cleaning methods. During the implementation phase, more advanced training such as role and protection of devices is planned. (March 2023)

Defects Confirmed during 8,000 hours OH Maintenance

Although regular overhaul is recommended every 4,000 hour, due to the impact of COVID-19, after a significant overdue, 8,000 hours overhaul was conducted as the first maintenance and many damages were confirmed. Various trainings is planned during the implementation phase to thoroughly prevent recurrence, and the trouble shooting system is desired to be built. (March 2023)



Handwritten record

LEC records are basically handwritten, which makes it difficult to analyze time-course changes and share information smoothly. The need for digitalization is raised by LEC so the support is planned in the implementation phase. (March 2023)

LIST OF FIGURES AND TABLES

ABBREVIATION

CEO	Chief Executive Officer
CLSG	Côte d’lvoire-Liberia-Sierra Leone-Guinea
DEG	Diesel Engine Generator
EGTC	Electricity Generation & Transmission Company
FO	Field Office
F/S	Feasibility Study
G/A	Grant Agreement
GDP	Gross Domestic Product
GOL	Government of Liberia
JCC	Joint Coordinating Committee
JICA	Japan International Cooperation Agency
LCDP	Least Cost Development Plan for Generation in Liberia
LEC	Liberia Electricity Corporation
MG	Management Group
MME	Ministry of Mines and Energy
OH	Overhaul
PLC	Programmable Logic Controller
PPA	Power Purchase Agreement
R/D	Record of Discussions
RREA	Rural and Renewable Energy Agency
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
TBM	Tool Box Meeting
TMT	Technical Management Group
WB	World Bank
WDT	Watch Dog Timer

Chapter 1 Overview of Planning Survey

1-1 Background and purpose of the survey

The Republic of Liberia (hereinafter referred to as “Liberia”) has continued to grow since its reconstruction after the civil war in 2003, recording an average GDP growth rate of 7.6%[1] in 2004-13. However, the Ebola epidemic in 2014-15 and the decline in international resource prices weakened the social and economic foundations, and as a result, the average GDP growth rate in 2014-19 fell to 0.5%[2] , and civic life and economic activities declined. COVID-19 further worsened the economic situation, and the GDP growth rate fell to -2.9% in 2020.

Electrical facilities are one of important social infrastructure for economic growth. Ever since the Electricity Law was revised in 2015, the the environment for power supply has been improved such as the establishment of a new power organization, renovation of Mt. Coffee Hydro power plant, and the construction of international transmission line named Cote d’Ivoire, Liberia, Sierra Leone and Guinea (CLSG) for the West Africa Power Pool (WAAP) regional energy network. However, as of 2018, the electrification rate is still at a low level of 12%[3] , and as of 2020, the electricity rate is high at 0.35$/kWh[4] . Under this situation, electricity theft and non-payment of electricity bills are rampant, which causes the deterioration of electricity business and unpaid salary and the demonstrations. Additionaly, since the power supply capacity is less than the potencial power demands, and the existing power plant cannot be used due to the malfunctions, the load sheding has been implemented almost everyday. One of the reason for this situation is the shortage of the staffs who can operate and maintain the power plant in a coordinated way that makes it difficult to utilize the power plant as much as efficiently.

Donor countries and agency, including Government of Japan, have continued to provide support for the development of electrical facilities and technical cooperation for many years. Government of Japan implemented the Grant Aid named " The Project for Rehabilitation of Monrovia Power System" (G/A in 2012, grant amount of 2.037 billion yen[5]), and supplied diesel power plant (5 MW x 2 units). The Liberia Electricity Corporation (LEC), which is responsible for the maintenance and management of power plant, does not have much experience in operation and maintenance and the daily maintenance system was insufficient. In addition, the chronic deficits has been continued and funds for equipment renewal and maintenance are inadequate. Therefore, from January 2018 to July 2022, the management service contract by ESB international was implemented to improve the management system.

In order to improve this situation, the Government of Liberia has requested the Government of Japan for the technical cooperation project to improve the capacity of planning and implementation of

1 World Bank national accounts data, and OECD National Accounts data files, World Bank

2 World Bank national accounts data, and OECD National Accounts data files, World Bank (2014-2018)
African Economic Outlook, 2020, African Development Bank (2019)

3 Power Africa Liberia Fact Sheet, 2018, USAID

4 Liberia Electricity Corporation

5 Ministry of Foreign Affairs of Japan

appropriate operation and maintenance of diesel power generator. In this project, a detailed plan for pilot activities (8,000 hours overhaul, heavy oil operation) and full-scale activities (maintenance for 12,000 hours and 16,000 hours) will be formulated for the above-mentioned Bushrod Power Station diesel power generation equipment, and then pilot activities will be carried out. The regulatory agency is the Ministry of Mines and Energy (MME).

In the detailed planning survey, comprehensive information collection on the power sector, confirmation of the maintenance status of the Bushrod power plant facilities, confirmation of future operation prospects, confirmation of the ability level and training needs of engineers, midium- to long-term maintenance plan (draft)).

Pilot activities included remote technical support related to engine maintenance, classroom training, and practical training through 8,000 hours of maintenance.

1-2 Implementation Policy of the Project

The project purpose and output are shown in Table 1-1.

Table 1-1 Project Goals

Overall Goal	Engineers and technical staff (electricians, operators, mechanics), who are engaged in O&M of HFO power plants in LEC, acquire the knowledge and experiences to undertake proper O&M works.
Project Purpose	Engineers and technical staff (electricians, operators, mechanics), who are engaged in the Project at Bushrod Island Power Plant, acquire the knowledge and experiences to undertake proper O&M works.
Output 1	Engineers and Technical staff improve skills for regular O&M works of diesel generator.
Output 2	Engineers and technical staff acquire know-how and practical skills of trouble shooting of diesel generator.
Output 3	Engineers and technical staff acquire knowledge and skills for preventive maintenance and methodologies for sustainable power supply.

Source: Prepared by JICA experts in consultation with JICA and LEC.

In the original plan, JICA Experts planned to travel to the site immediately after signing the contract, check the condition of the power generation equipment, and formulate a detailed plan. Since the COVID-19 spread rapidly and and it was expected that JICA Experts seemed not to be able to travel to the site for a long period of time, the project work and schedule were reviewed and adopted the following implementation plan.

A) Remote information gathering from Japan

B) Remote technical support while travel is not possible due to the COVID-19

C) Preparations for starting pilot activities after travel banned period (Checking tools and parts on site)

D) Procurement of equipment that requires additional procurement due to increased operating hours

E) Implementation of classroom training before the start of overhaul

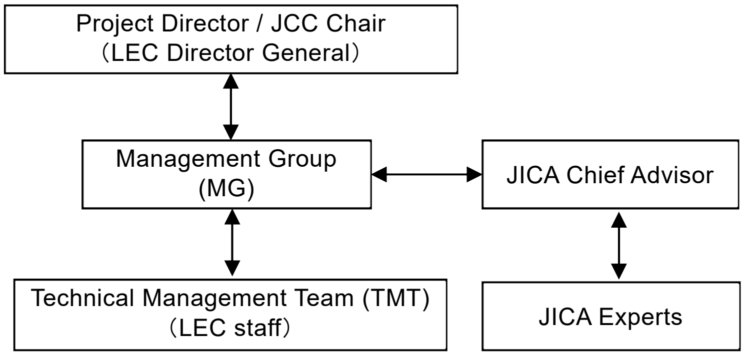
F) Overhaul implementation

G) Formulation of detailed plans based on the pilot activities (classroom training, overhaul implementation)

H) Classroom training and practical training, JCC implementation

1-3 Project Implementation Structure

This project has beem implemented with the system described in Figure 1-1. The structure of the JCC is described in the R/D.



Source: Record of Discussion of this project

Figure 1-1 Implementation System

1-4 Composition of JICA Experts

The composition of JICA Experts is shown in the Table 1-2.

Table 1-2 Composition of JICA Experts

No.	Name	In charge	Affiliation
JICA Experts			
1.	Kyoji FUJII	Chief Advisor / Technical Planning and Management	Yachiyo Engineering Co., Ltd.
2.	Noboru MATSUMURA	Mechanical Engineer	Yachiyo Engineering Co., Ltd.
3.	Yasuharu TAKAHASHI	Mechanical Engineer 2	Yachiyo Engineering Co., Ltd.
4.	Hiromi NAKANO	Mechanical Engineer 3	Yachiyo Engineering Co., Ltd. (West Japan Engineering Consultants, Inc.)
5.	Toshio OYAGI	Electrical Engineer	Yachiyo Engineering Co., Ltd.
6.	Tatsuhiro URABE	Assistant Technical Planning Engineer	Yachiyo Engineering Co., Ltd.
7.	Mikiko IWAGO	Assistant Mechanical Engineer	Yachiyo Engineering Co., Ltd.
8.	Kenji SAKEMURA	Assistant Mechanical Engineer 2	Yachiyo Engineering Co., Ltd. (West Japan Engineering Consultants, Inc.)
9.	Atsushi KUBOTA	Assistant Mechanical Engineer 3	Yachiyo Engineering Co., Ltd. (West Japan Engineering Consultants, Inc.)

1-5 Outline of Activity Schedule

In this project, due to travel restrictions due to the impact of the new coronavirus, it was assumed that the start of field work would be significantly delayed from the initial schedule. In order to conduct a smooth survey even under such circumstances, a kick-off meeting was held online on June 30, 2020 with the JICA Headquarters, Ghana Office, Liberia Field Office, LEC, and JICA experts, and discussions began.

After the kick-off meeting, JICA Experts and LEC held online meetings and email-based surveys and discussions, and after the travel restrictions were lifted, JICA Experts conducted the first field survey in May 2021, but due to the impact of the COVID-19, JICA Experts were forced to suspend it again. In addition, during the first field survey, it was confirmed that there was a shortage of tools necessary for overhaul, and additional procurement was required. In June 2022, classroom training and overhaul preparations were carried out during the second trip, and during the third trip from August to November 2022, an overhaul was carried out. Efforts were made to ascertain levels and training needs. In addition, during the 4th trip, classroom training was conducted mainly on routine maintenance, and a JCC meeting was held to confirm the degree of achievement of the project with the Liberian side. Details of the dispatch of experts are shown in Attachment 6.

1-6 List of Main Counterpart

1) Ministry of Mines and Energy (MME)	
Mr. Wilmot Thompson	Deputy Minister
Mr. Prince Cephus Wilson	Assistant Director for Off-Grid/Renewable Energy

2) Liberia Electricity Company (LEC)	
Mr. Monie Captan	Chairman of the Board/Acting CEO
Mr. Adam S. Sheriff	Chief Financial Officer
Mr. Kwame Kpekpena	Chief Operating Officer
Mr. Pastor George K Zeokpo	EPD Analyst, Thermal plant
Mr. Perry D. Brown	Training & Development Sr. Manager
Mr. Doveflee E. Kollie	Sr. Manager, Thermal Plant
Mr. Thomas F. V. Wonder, I	Administrative Assistant / Generation
Mr. David Johnson	Fuel Attendant
Mr. Amadu L. Kaidii	Maintenance
Mr. Alphonso D. Dorleyan	Maintenance
Mr. William S. Lawubah	Electrical Operator
Mr. Saidu S. K. Jalibah	Foreman
Mr. Peter N. Waie	Maintenance
Mr. Henry L. J. Collins	Maintenance Manager
Mr. Jordan V. Jannell	Maintenance Engineer
Mr. William K Tarnue	Operator SV
Mr. Matthew W. Nagbe	Operator
Mr. Genesis Howard	Maintenance
Mr. John Nana	Operator
Mr. Alfred G. Shannon	Operator SV
Mr. John Kandakai	Maintenance
Mr. Desmond S. Kinyea	Operator
Mr. Henry Bandah	Operator
Mr. John Kollie	Operator
Mr. John S. Martu	Safety Officer
Mr. Aaron Juluto	Compliance
Mr. Freeman T. Dornor	Operator
Mr. Joseph K. Nguafua	Operator
Mr. Richard P. Mulbah	Maintenance / Fabricator
Mr. Thomas F. Kerkula	Maintenance
Mr. Victor G. Playeah	Operator
Mr. Dequency P. Zankpah	Electrical Engineer
Mr. Nathan G. Craig	Electrician

Chapter 2 Activities

2-1 Detailed Planning Survey Report

As a detailed planning survey, JICA Experts investigated the maintenance status of the Bushrod power station, the current state of the power sector and future development plans, and formulated an activity plan for the entire project period.

2-1-1 Current state of the power sector in Liberia

The power generation capacity connected to the Monrovia metropolitan area power system is 126 MW (thermal power 38 MW, hydro power 88 MW). According to the LEC, power demand in Greater Monrovia will be approximately 50 MW as of June 2022, and is expected to increase to approximately 75 MW by the end of 2022 with the completion of transmission and transformation projects by other donors. In addition, according to LEC's estimation, demand is expected to reach around 300 MW in 2025, including potential demand from consumers who currently use private generators.

On the other hand, hydroelectric power output drops to around 10 MW in the dry season, and thermal power plants have been out of service for a long time due to troubles and overhauls. There is a shortage and it affects people's lives. The current situation of the electric power sector in Liberia is detailed below.

2-1-1-1 Structure of power sector

The competent authority for electricity business is the Ministry of Minerals and Energy (MME). Electricity is provided by the Liberian Electricity Corporation (LEC). Another power-related organization is the Rural and Renewable Energy Authority (RREA), which promotes rural electrification.

Supervising Ministry	: Ministry of Mines and Energy (MME)
Power Utility Company	: Liberia Electricity Corporation (LEC)
Related Organization	: Rural and Renewable Energy Agency

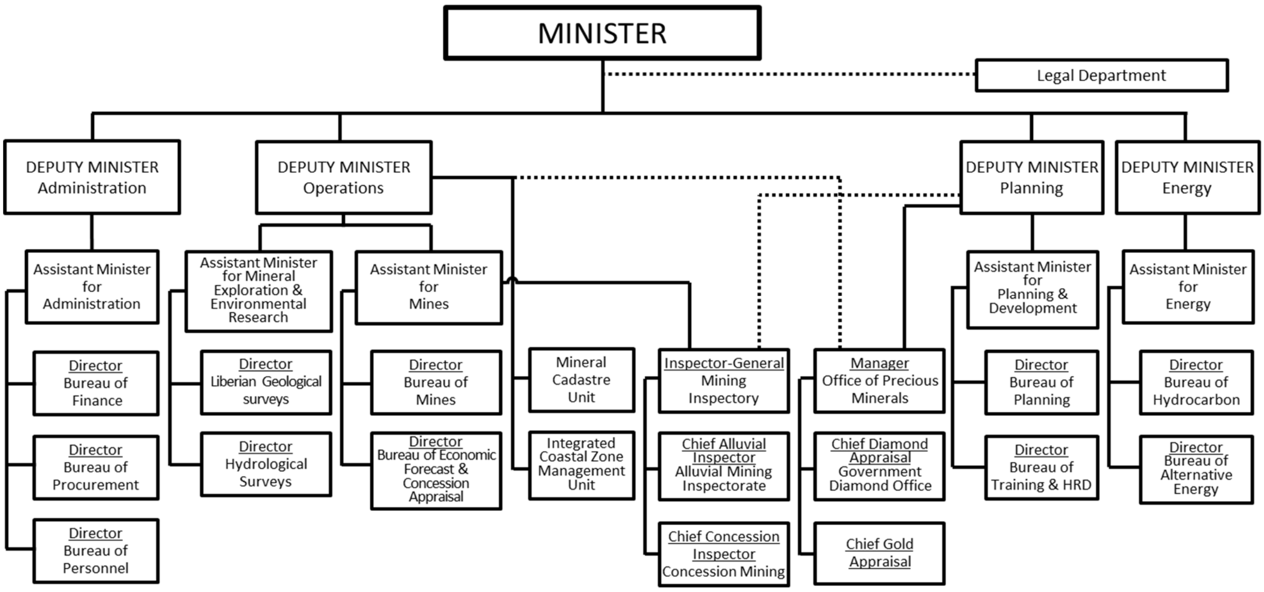


Figure 2-1 Organization Chart of Ministry of Mines and Energy (MME)

2-1-1-2 Challenge in the electric power sector and their solutions

(1) Power Supply

Table2-1 shows the amount of power generation from 2016 to 2021. Since 2016, the amount of power generation has been increased year by year, and especially from 2021 onwards, the amount of power generated by JICA power plant has increased. The LEC evaluates JICA's power generation equipment as highly reliable compared to other diesel engines. In addition, Table 2-1 shows the amount of power generated for each month in 2021. During the dry season from December to May, the output of the Mt. Coffee hydroelectric power station drops, so the power supply continues to be tight every year.

Table 2-1 Electricity generated by each power source from 2016 to 2021

MWh

	2016	2017	2018	2019	2020	2021
Mt. Coffee	2,831	121,678	181,716	184,582	218,701	223,742
JICA	7,895	3,792	6,596	7,132	6,248	18,375
Other thermal	76,310	7,972	12,739	22,483	16,468	30,579
Total	87,036	133,442	211,051	214,197	241,417	272,696

Source: LEC

Table 2-2 Changes in annual power generation in 2021

MWh

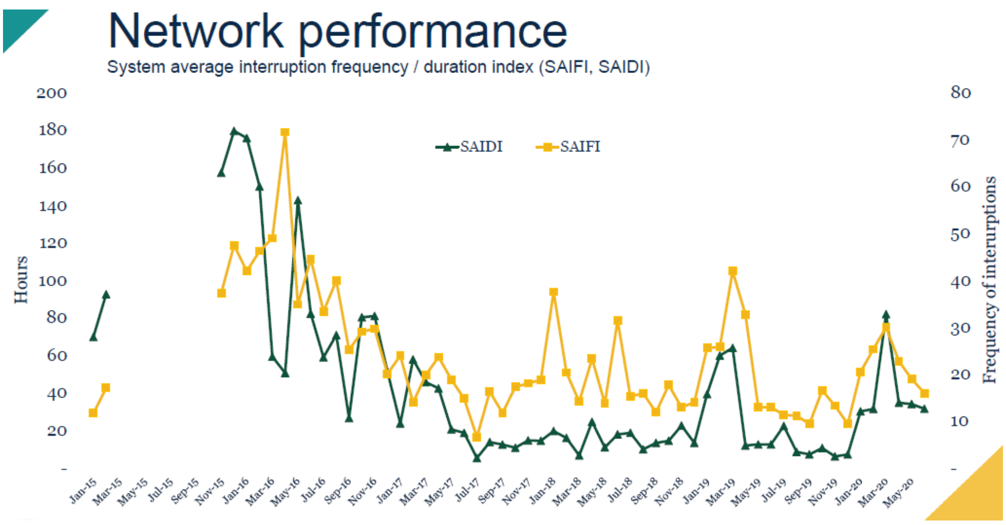
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Mt. Coffee	16,744	8,670	13,269	9,653	14,993	21,358	21,633	22,807	22,441	23,533	24,607	24,034
JICA	4,043	3,986	2,898	3,133	1,609	86	9	48	0	634	0	1,929
GOL	3,607	5,545	5,742	6,903	3,816	169	116	118	0	937	0	2,490
WB	0	0	0	710	420	7	0	0	0	0	0	0
Others	0	0	0	0	0	0	0	0	0	0	0	0
Total	24,394	18,201	21,909	20,399	20,837	21,620	21,758	22,974	22,441	25,103	24,607	28,454

Source: LEC

Figure 2 2 shows the monthly changes in SAIFI (average number of outages index) and SAIDI (average outage duration index), which are indicators related to power outages. The power outage situation is improving, but it is still at a high level (TEPCO 2019 SAIDI: 19 minutes, SAIFI: 0.13 times). The power supply shortage in the dry season is particularly serious. In the dry season in 2022, the power demand will be about 50 MW, and the power supply capacity will be about 48 MW (JICA: 10 MW, GOL: 18 MW, World Bank: 10 MW, hydropower: 10 MW). Some power sources, including the JICA engine, were inoperable due to failures or maintenance, and rolling blackouts were implemented. Table 2 3 shows the overview of LEC's power plant.

At the end of 2022, a PPA for the CLSG interconnector will be signed, and power imports into Liberia are scheduled to start. The contract is expected to guarantee the supply of 27 MW from Côte d'Ivoire to Liberia, but the tariff is high at about 14 cents/KWh (currently estimated), and domestic power sources will become increasingly important in order to meet the growing power demand that is expected to rise. In addition, according to the LEC, from the perspective of energy security, excessive reliance on electricity imports poses risks, so the importance of the JICA engine will continue to be high.

In order to improve this situation, the development of hydropower and solar power is planned as described later in 2-3-2.



Source: Liberia Energy Sector Interim Findings October 2020

Figure 2-2 Monthly changes in SAIFI (average power outage frequency index) and SAIDI (average power outage duration index)

Table 2-3 Overview of LEC's power plant

Power Plant	Rated Output	Generation Capacity	Workable Units	Abolished Units	Stopped Units	Operation Situation	Remarks
Bushrod Power Plant (Norway)	15MW (1MW×15)	0.5MW×15	15	0	15	Normally Stop (Only Use for Black Start)	It has practically stopped operating and is only used during a black start.

Power Plant	Rated Output	Generation Capacity	Workable Units	Abolished Units	Stopped Units	Operation Situation	Remarks
Bushrod Power Plant World Bank (Chinese Capital) (HIMSEN 6H32/40)	10MW (2.5MW×4)	2.5MW×4	4	0	0	Operational	There is a problem with heavy oil operation equipment, and only light oil operation is possible.
Bushrod Power Plant JICA	10MW (5MW×2)	4MW×2	2	0	0	Operational	Standby during rainy season
Bushrod Power Plant Government of Liberia (GOL) (Wartsilla)	18MW (9MW×2)	8.2 MW×2	2	0	0	Operational	There is a problem with the PLC for heavy oil switching, and only light oil operation is possible.
Mt. Coffee Hydro Power Plant	88MW (22MW×4)	80MW	3	0	1	Operational	One unit stopped due to burnt out stator winding.
Kru Town Power Plant	-	-	-	5	-	Abolished	
Congo Town Power Plant	-	-	-	2	-	Abolished	
Paynesville Power Plant	-	-	-	2	-	Abolished	

Source: LEC

Table 2-4 shows changes in the annual cumulative operating hours of JICA power plant (5 MW x 2 units). In addition to responding to the increasing demand from around 2021, the operation hours of JICA power plant are increasing due to malfunctions of WB power plant[6] and GOL power plant[7]. Since the cumulative operating hours of each JICA power generation facility exceeded 4,000 hours after 2020, JICA experts recommended that load operation should be avoided. As of November 2022, the cumulative operating time of each engine is about 9,100 hours for Unit 1 and about 7,600 hours for Unit 2.

Table 2-4 Changes in annual operating hours of JICA power plant (total of 2 units)

	2016	2017	2018	2019	2020	2021	2022
Operation hours	2,545	940	1,800	1,994	1,573	4,750	3,111

Source: LEC

Due to the impact of the COVID-19, the JICA power generation facility continued to operate without overhaul for 4,000 hours, and performed maintenance for 8,000 hours from August to November 2022. Many problems were discovered due to the lack of 4,000 hours overhaul, but after 8,000 hours maintenance, both Units 1 and 2 were restored to a state where they could be restarted. In the practical training for 8,000 hours maintenance, guidance on daily maintenance is provided, and LEC is working even harder on maintenance.

After 8,000 hours of maintenance, it is expected to operate at full capacity as the main power source in the dry season of 2023. As of September 2022, the power sources owned by the LEC are unable

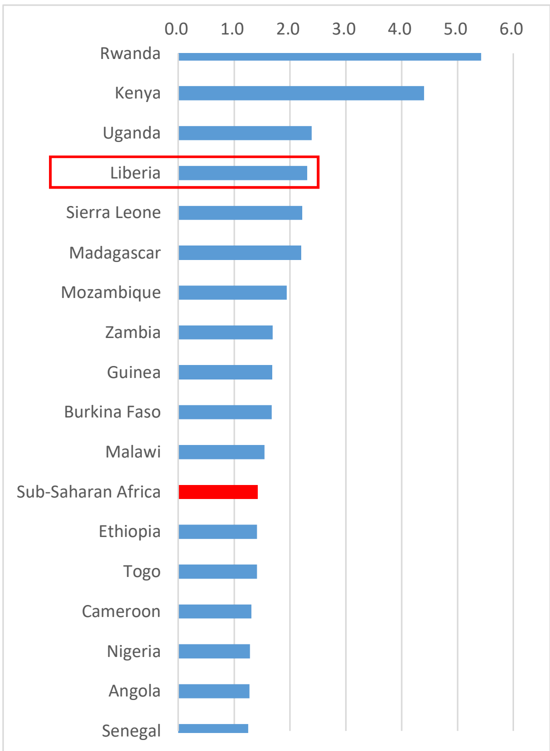
[6] Constructed by the support of World Bank, 2.5MW x 4 units, HIMEN
[7] Constructed by Government of Liberia, 9MW x 2 units, Wartsilla

to operate with heavy oil at the GOL power plant due to PLC failure, and at the WB power plant due to a malfunction of the boiler that overheats the heavy oil line. Also, as of November, the circuit breaker connected to the transformer for WB plant had burned out, so the dependence on JICA power plant is increasing.

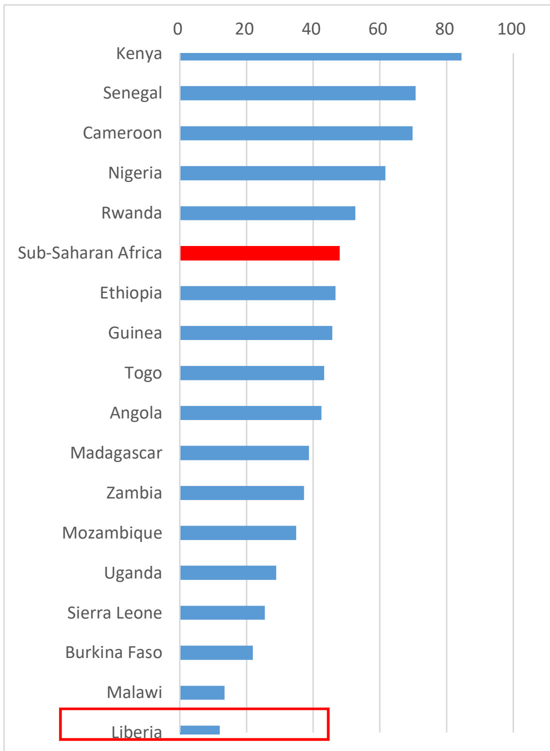
According to the LEC, power demand is expected to increase to around 75MW by the end of 2022. In response to this, the PPA for the interconnector CLSG was signed, and power supply started on December 1, 2022. The contract guarantees up to 27 MW of power imports from Côte d'Ivoire, and according to LEC information as of September 2022, the contract rate is about 14 cents/kWh. Future operation policies will be reviewed from the perspective of comparison with domestic power generation costs and energy security. The need for operation has been confirmed, and it is assumed that the plant will be operated for about 4,000 hours per year.

(2) Power Access Ratio

As shown in Figure 2 3, the rate of increase in access to electricity in Liberia is more than doubled from 2013 to 2019, and the electrification rate has increased in recent years even in the Sub-Saharan region. However, the electrification rate is 12% (2019), which is the lowest level in the Sub-Saharan region.



Rate of increase in access to electricity (2019 compared to 2013)



Comparison of electrification rates (2019)

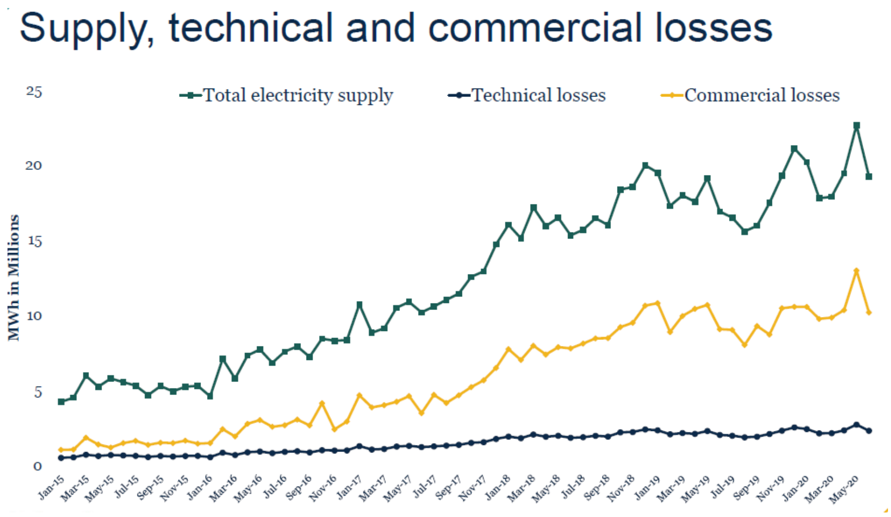
Source: IEA

Figure 2-3 Comparison with neighboring countries (increase rate of access to electricity and electrification rate)

The Rural and Renewable Energy Agency (RREA) has set a target of 100% electrification by 2050. It plans to connect 89% of the Liberian population (96% of electricity consumption) to the grid, with the remaining 11% supplied by 7,000 off-grid hamlets.[8]

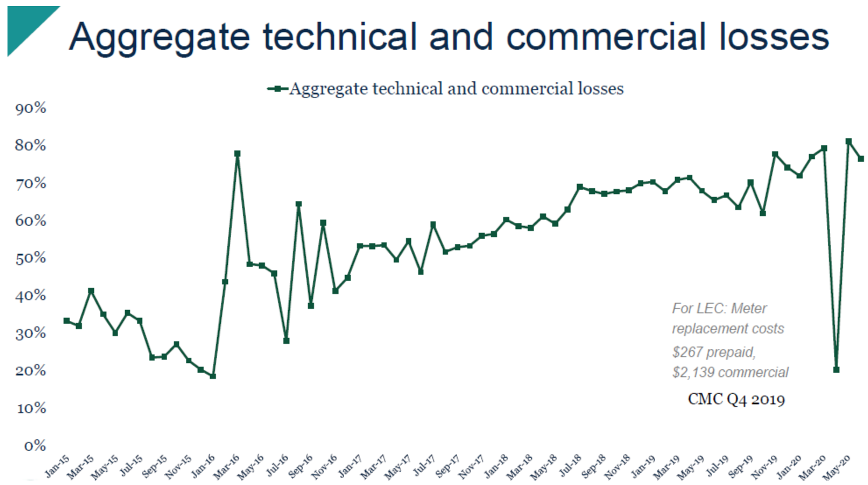
(3) Power Supply Loss

As shown in Figure2-4 and Figure2-5, the power supply loss has become extremely large, and the loss due to non-collection of power charges has become a particularly serious problem, putting pressure on the management of LECs. As a countermeasure, LEC is promoting the introduction of prepaid meters, etc.



Source: Liberia Energy Sector Interim Findings October 2020

Figure 2-4 Power supply and power loss (technical loss/commercial loss)



Source: Liberia Energy Sector Interim Findings October 2020

Figure 2-5 Total value of technical loss and commercial loss

[8] RURAL ENERGY STRATEGY AND MASTER PLAN FOR LIBERIA UNTIL 2030

2-1-1-3 Laws and policies related to the power sector

The position of LEC, which was established as a public corporation in charge of power generation, transmission, distribution, and sales of power and power-related equipment under the Public Authority Law of 1973, changed to a business operator that received a power business license under the Power Law of 2015. LEC's position as a transmission company and national grid operator remains unchanged. In addition, the 2015 Electricity Law sets a licensing system for the electric power business and establishes an electric power regulatory agency, aiming to divide the electric power sector, privatize it, and introduce the principle of competition.

2-1-1-4 Power Sector Development Plan

The current electricity policy in Liberia is the National Energy Policy and an Agenda for Action and Economic and Social Development 2009, which has been in place for more than 10 years, and is not suitable for the current situation. The National Energy Policy aims to electrify 30% of urban areas and 15% of rural areas by 2015, and aims to achieve carbon neutrality by 2050.

(1) Overview of the National Power Master Plan

The LEC Electric Master Plan was formulated in 2012 as an electricity master plan. According to MME, there is information that an additional version is being formulated, but the details are unknown. The LEC Electric Master Plan is a development plan up to 2015, and there is no current electric power master plan in Liberia. The LEC Electric Master Plan forecasted that electricity demand would increase to 67 MW by 2015, and indicated an investment plan for WB's power plant of 10 MW.

As a rural electrification power master plan, there is Liberia Rural Energy Strategy and Master Plan until 2030, which shows the rural electrification plan until 2030.

(2) Power Development Plan for Capital Monrovia/Positioning of Bushrod Power Station

A Directive was announced on the MME website that the Optimization Study for the Development of Power Generation in Liberia was adopted as the Least Cost Development Plan for Generation in Liberia (LCDP) in 2020.[9]

Base-case results of the Optimization Study, the development of SP2 hydropower (154MW) and solar power (75MW) on the St. Paul River system is the most economical and has the highest priority. For the time being, the plan is to rely on imported power during the dry season, when hydroelectric power output declines, and the focus is on the development of renewable energy. However, the upper limit of imported power is assumed to be 108 MW, and in order to meet the future demand increase, it is recognized that heavy oil power plant will be necessary as a base power source.

[9] https://mme.gov.lr/energy-news/

Table 2-5 Investment Plan (Base Case) (MW)

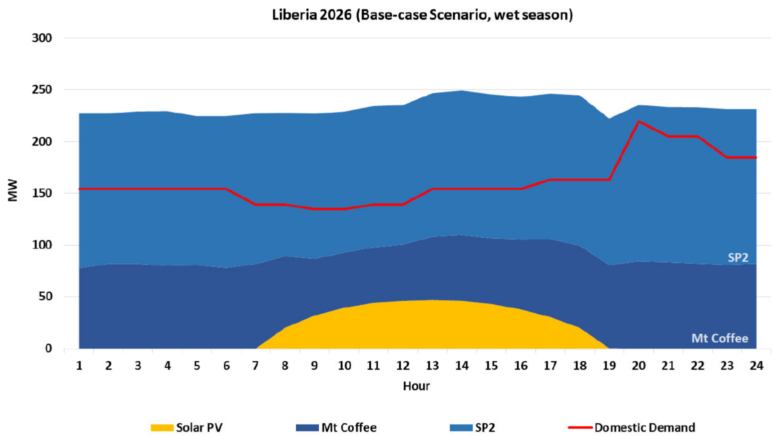
Table 8-5 Investment sequence by technology – Base-case Scenario (MW)

Modelled year	DI HFO	Solar PV*	SP2	Mt Coffee Extension	SP2 Extension
2026		75	154		
2034	75	75		44	
2040	98	75			96

** Solar PV capacity is presented in MWac*

Source: Multiconsult (2020) "Optimization Study for the Development of Power Generation in Liberia"

As shown in Figure2-6, during the rainy season, hydro power generation at the two locations, Mt. Coffee and SP2, and solar power alone are sufficient to meet the power demand, resulting in surplus power generation.

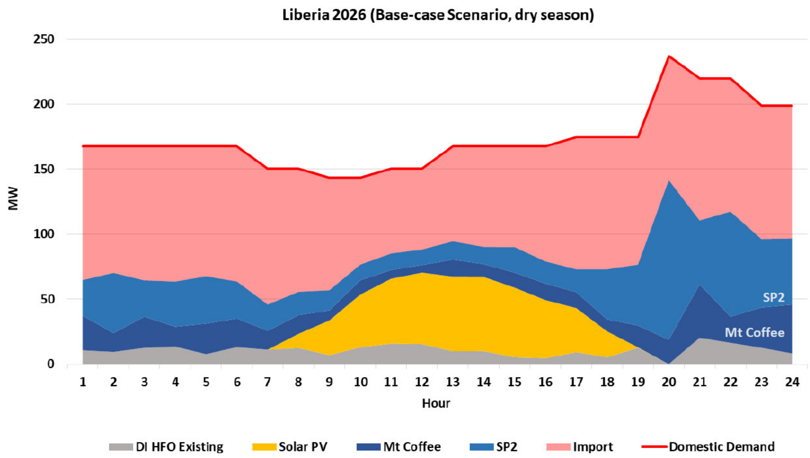


Source: Multiconsult (2020) "Optimization Study for the Development of Power Generation in Liberia"

Figure 2-6 daily Load and Supply Curves in the Rainy Season

During the dry season, as shown in Figure2-7, the output of hydro power drops significantly, and most of the supply has to be imported. Electricity imports depend on the surplus supply of other countries, but countries with similar climates in West Africa are connected by CLSG interconnectors, and all countries rely on it because hydropower output declines during the dry season. The country will experience supply shortages as well. Only Côte d'Ivoire's thermal power generation is expected to be the source of power imports, but it is thought that the exportable amount will fluctuate depending on the supply and demand balance of the country.

The diesel power plant of Bushrod power plant is responsible for a certain amount of supply during the dry season and plays an important role as the country's power source during the dry season.



Source: Multiconsult (2020) "Optimization Study for the Development of Power Generation in Liberia"

Figure 2-7 Dry season daily load and supply curve

2-1-1-5 Response by other aid agencies

A list of ongoing or recently completed projects in the power sector by other donors is shown in Table2-6. In addition to the following, CLSG interconnectors have been constructed and power supply started in December 2022.

Also, F/S for SP2 hydropower (154MW) and photovoltaic power generation (75MW) is underway as future projects not included in Table2-6. In addition, according to the LEC, there is a plan to build a 20MW solar power plant near the Mt. Coffee hydro power plant with the support of the World Bank. The World Bank will decide to adopt the project, and they hope to start procurement in 2023.

Table 2-6 List of projects of other donors on-going or recently completed

No.	Projects	Financier	Scope of Works	Completion Date	Contract Sum (in Million)	Funds Disbursed (in Million)
A						
1	Lot 1 66kV Transmission Lines and Substations	World Bank	Supply and construct 54 km of 66 kV Transmission from Paynesville to Kakata. Supply and installation of 66/33kV substation in Kakata. Supply and Installation of 33kV / 400V/ 230V distribution network and customer connections in Kakata Connect 15,000 customers Paynesville up to Kakata & Weala. Consist of the following communities and towns- Peter Town, Duo, Isreal, Caresburg, 15 Gate, Number 7, Moni Captain, Morris Farm, Kakata City, Weala, Weala Laymale, Borkey Town / Clinton, Jeaneta Town, Copper Farm, Konola and Tovia, Soul Clinic, Morris Farm, Omega, Bernard Farm – F.D.A Community, Mount Barclay,	2021	USD 8.91	USD 7.78 (87%)

No.	Projects	Financier	Scope of Works	Completion Date	Contract Sum (in Million)	Funds Disbursed (in Million)
			Johnsonville, Pipeline, Wood Camp, Zay Community, Goba Chop, Zuba Town			
2	Lot 2 66kV Transmission Lines and Substations	World Bank	Extension of Paynesville Substation	2020	USD 1.24	USD 1.05 (85%)
3	Lot 3 continuation of 22kV Distribution network construction	World Bank	Supply and Installation of 22kV / 400V/ 230V distribution network and customer connections in Paynesville and selected large users.	2021	USD5.54	USD 3.78 (68%)
B						
1	Substation Lot1, Lot2, Lot3	World Bank	Supply and installation of 2 X 20/26MVA 66/22kV Gardnerville substation. Supply and Installation of 2 X 10/13MVA 66/22kV transformers at Stockton Creek Substation, 10MVA 66/22kV transformer at Virginia Substation, 10/13MVA 66/33kV Kle substation. Extension of Paynesville with 10/13MVA 66/22kV Power Transformer and Bushrod	July 2022	USD 9.75	USD 7.29 (75%)
2	Transmission Lines: Lot 1 and 2	World Bank	66 kV lines route: Bushrod Substation-Virginia Substation -Kle Substation and Stockton Creek Substation –Gardnerville Substation- Paynesville Substation	July 2022	USD 6.00	USD 2,28 (38%)
3	Distribution Network Lot 1: The supply and construction of 22kV/400/230V distribution network	World Bank	The coverage areas; Gardnerville, Barnesville, New Georgia, Communities along the Somalia Drive, Clara Town, Doe Community, Johnsonville, Logan Town, Caldwell, New Kru Town, Virginia, Brewerville City up to Po River.	July 2022	USD18.80	USD 15.07 (80%)
4	Lot 2: The supply and construction of 33kV/0.4/230V distribution network	World Bank	The coverage areas; Towns & Villages along the Po River to Bomi, From Kie Via Medina to Robertsport, Bo Waterside and other Towns and Villages in Bomi and Cape Mount Counties.	July 2022	USD 5.04	USD 1.31 (26%)
5	Lot 3: Customer connections	World Bank	33,000 households/Customers are to be connected under this project within coverage areas mentioned for both the 22/0.4 kV and 33/0.4 kV Network to be constructed	July 2022	Part of lot1 above	
C						
1	Lot 1 Substation 2x20 MVA Congo Town substation	EU	The supply and installation of 2x66 kV lines Bushrod to Stockton Creek on a double circuit tower 1x66kv line to Capitol, 1x66 kV line Bushrod to Kru Town a double circuit line on existing towers from Capitol Substation to Congo Town Substation 2X20MVA Congo Town substation	September 2022	EUR 18.53	EUR 2.80 (15%)
2	Transmission Line	EU	feasibility on the old existing 66kV line route from Congo Town Substation to Paynesville Substation	September 2022	EUR 18.99	EUR 6.48 (34%)
3	Lot 2 22/0.4kV Distribution Network and Connections	EU	22 /0.4 kV distribution lines in Central Monrovia, Sinkor up to Paynesville. Network to connect 39,000 Residential customers:- Peace Island, Congotown, Old Road, Duport Road, AB Tolbert Road, SKD Complex, Thinker Village, King Gray	September 2022		

No.	Projects	Financier	Scope of Works	Completion Date	Contract Sum (in Million)	Funds Disbursed (in Million)
D						
1	Transmission	AfDB	Lot 1A– Transmission Line Package (46km) Construction of 16 km of Double circuit 66 kV of transmission lines on Monopoles from Paynesville 66/22kV to Schefflin 66/22kV substations Construction of 29 km of Double circuit 66 kV of transmission lines on Lattice Towers from Schefflin 66/22kV to 66/33kV Robert International Airport (RIA) substations	December 2022	USD 13.62	USD 2.77 (20%)
2	Substations	AfDB	Lot 1B. – Substation Package Construction of 2nos x 66 kV transmission line extensions at Paynesville 66/22kV. Construction of 2nos x 10 MVA, 66/22kV transformer substation at Schefflin. Construction of 2nos x 10 MVA, 66/33kV transformer substation at RIA	December 2022		
3	Distribution and Customer Connections	AfDB	Lot 2. 22/0.4 kV distribution Network from Scheffllin substation (66/22 KV) to Marshall, Schefflin Town and back to Paynesville. 33/0.4 KV distribution Network from the RIA substation (66/33 kV) to the Airport, Charlesville, Dolo Town, Peter Town, Cotton Tree, Owensgroove, Unification Town back to Schefflin Town Customer connections of 13,500 Street Lights	December 2022	USD 10.05	USD 1,01 (10%)
4	Distribution and Customer Connections	AfDB	Lot 3. 105 km of 33kV Distribution extension from Pleebo (Maryland) to Fish Town (River Gee) along with 0.4kv distribution network. 4,500 Customers to be connected under the project. Installation of Street Lights	November 2022	USD 3.99	USD 0.40 (10%)
E	CLSG-RE	AfDB	CLSG - Rural Electrification Design, Supply, & Installation of MV and LV Distribution Network, Customer Connections & Street Light in Rural Areas: Using the Shield Wire System (SWS) Technology and Conventional MV at 33kV, to provide power to towns within 3 km of the constructed CLSG TRANSCO 225kV HV network at three (03) 225/33kV substations at (Yekepa, Mano and Buchanan Substations) in Liberia. The 130 Communities (in Towns and Villages) that will be connected covers five Counties (Nimba, Grand Bassa, Montserrado, River Cess and Bong) where the CLSG 225kV Transco Project runs through and 23,000 are targeted for connections The installation of 900 Street lights within these 130 communities (towns and villages)	December 2024	USD 15.99	NIL

No.	Projects	Financier	Scope of Works	Completion Date	Contract Sum (in Million)	Funds Disbursed (in Million)
F	Monrovia Electrification Project	KfW	Construct MV/LV distribution network in gap areas Connect at least 16,000 customers Procure 15,000 pre-paid energy meters for LEC operations Procure CT Meters and other materials for LEC operations	September 2022 (It probably postpone to early next year)	EUR 15.95	USD 0.42 (3%)
G	Ganta – Gbarnga Project	USAID	Extend 77. 82 Km of 33kV MV lines from Ganta to Gbarnga and Construct 25.5 Km of 19 KV medium Voltage from Ganta to Gbarnga. Construct 10 Km of LV distribution network in Gbarnga/Suakoko areas To Connect about 2,700 customers	2021	USD 13.2	USD11.38 (90%)

Source: LEC

2-1-1-6 Aid Policy and Achievements of the Government of Japan

Table 2-7 shows the achievements of the Government of Japan in the electric power sector since 1990.

The Government of Japan has so far provided aid through grant aid, centered on the fields of food production, health and medical care, road construction, and electric power, acceptance of trainees, and technical cooperation centered on the dispatch of Japan Overseas Cooperation Volunteers. However, since May 1990, bilateral aid has ceased due to the intensification of the civil war. After the civil war, the city of Monrovia was in a state of chronic power shortage due to the civil war, and frequent blackouts became an obstacle to the lives of citizens and the country's economic development. Even at the Bushrod Power Station, which supplies electricity to the city of Monrovia, generators and other equipment were destroyed during the civil war, and power generation capacity was extremely limited. Therefore, the "Monrovia City Electricity Restoration Plan" was implemented in hopes of improving the stability of the power supply, improving the lives of citizens, and contributing to economic development.

Table 2-7 Government of Japan Assistance in the Power Sector

Project Name	Fiscal year	Grant Limit	Project Overview
The Project for Rehabilitation of Monrovia Power System	2012 fiscal year	2.037bilion yen	Heavy fuel oil diesel generators (5 MW x 2 units) will be installed at the Bushrod Power Station, the main power plant that supplies electricity to Monrovia.

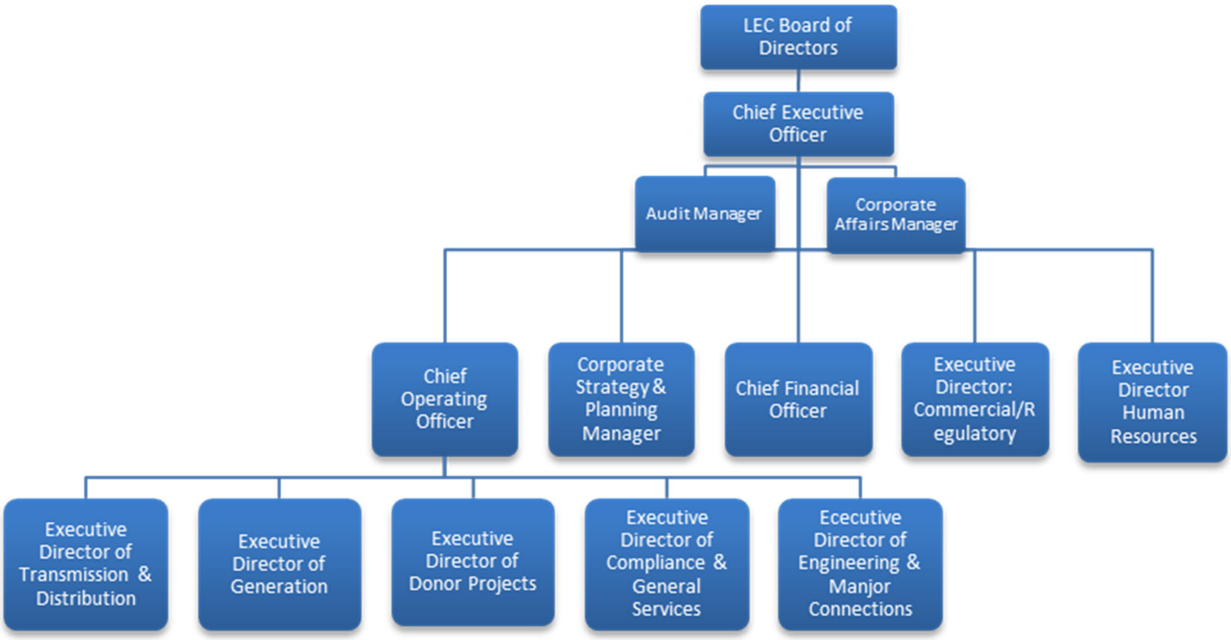
Source: Ministry of Foreign Affairs of Japan

2-1-2 Operation and Maintenance Status of Power Supply Facilities

2-1-2-1 Management of Bushrod Power Station

(1) Organization

Figure 2-8 shows the organizational chart of the LEC management. The management contract was ended in July 2022, and a new system will be established. As of December 2022, the power generation manager is absent, and both the hydropower and thermal power department managers are present at meetings with management.



Source: LEC

Figure 2-8 LEC Management Organization

(2) Business overview, medium to long-term plan

LEC's income statement is shown in Table2-8. It has been operating at a loss since 2017, and most of its income is dependent on subsidies, including assistance from donors. According to the LEC Business Plan 2019-2023, it plans to become profitable in 2023, but it can be said that the situation is tough. One of the factors that puts pressure on management is loss due to uncollected electricity charges.

The maintenance and management costs are included in the cost of sales in the same table, and 6 million USD was recorded in 2019. In the future, when large-scale overhauls of 24,000 hours and 32,000 hours are to be carried out, it is expected that the purchase of spare parts will exceed 1 million USD. It is thought that budgetary measures will be necessary in general.

Table 2-8 LEC Income Statement

Unit：1,000 USD

Subject	2019	2018	2017
Revenue	22,848	25,443	24,007
Cost of Sales	(30,261)	(20,252)	(22,904)
Total Profit	**(7,413)**	**5,191**	**1,103**
General Expenses	(15,125)	(29,059)	(16,897)
Other income	24	240	105
Other profit	(272)	(116)	（65）
Subsidy Income （Including donor aid financial income）	14,344	21,250	15,965
Financial Income	1,584	1,303	-
Financial Spending	(1,101)	(1,330)	(2,080)
Total loss（Excluding corporate tax）	**(7,959)**	**(2,521)**	**(1,869)**
Corporate tax	-	-	-
Total loss (Including Corporate Tax)	**(7,959)**	**(2,521)**	**(1,869)**
Other Total Profit	834	745	495
Annual Total Profit	**(7,125)**	**(1,776)**	**（1,374）**

(3) Current situation and Challenges / training needs

At the LEC, a meeting is held once a week for all department heads and above to exchange information. In addition, when overhaul is implemented, the progress of overhaul is reported to management as appropriate, and the procurement of necessary spare parts is quickly determined. In addition, it was confirmed that the Safety Management Department and the Training Department are working together on maintenance, and that organizational cooperation is being taken.

On the other hand, there are some aspects of management that are not well managed, such as the management of spare parts and tools. Regarding the management of spare parts and tools, the issue is that the management method within the JICA power plant is not sufficiently developed. As for the lack of management methods, the same applies to the daily engine patrol items, and it is considered necessary to prepare a checklist and create a system to manage daily implementation.

Regarding overhaul preparation, it is required to formulate a long-term ovrehaul plan and to be able to plan individual overhaul in cooperation with the manufacturer. In addition, it is necessary to be able to execute the process of requesting estimates for spare parts, tools, consumables, and SV dispatch costs ⇒ Budget measures ⇒ Ordering ⇒ Procurement management ⇒ Inventory management at the necessary time based on the plan. Looking back on the current situation of the LEC, there are issues with budget measures and schedule management.

In addition, it is necessary to understand the flow and the required period so that preparation for implementation ⇒ implementation ⇒ recording after implementation (obtaining the manufacturer's report) ⇒ sorting out the parts to be procured for the next overhaul can be implemented without delay.

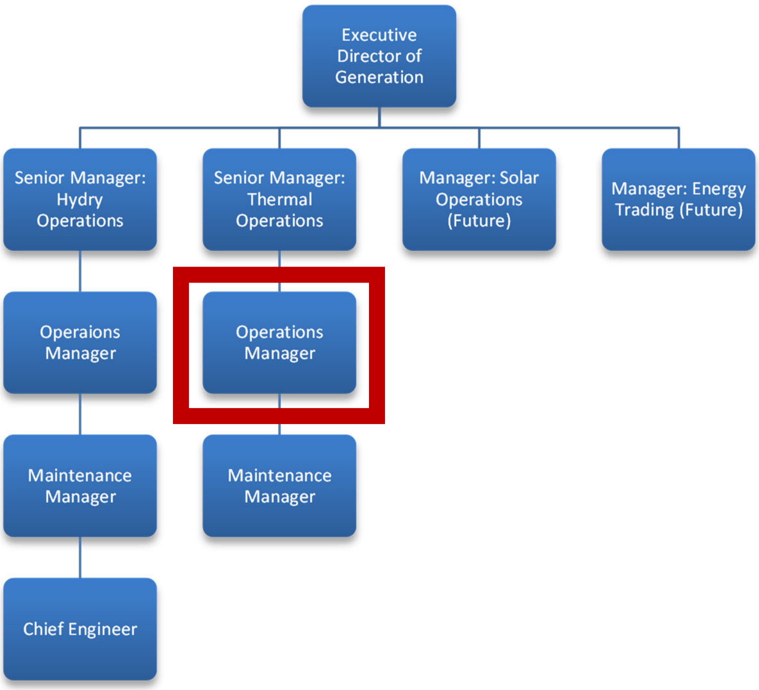
Table 2-9 Ability Levels and Training Needs of LEC staff

Item					Explanation	Ability	Training Needs
Generation	Operation				Operation from start to stop. • starting operation • operation • stop operation • Adjustment of engine power • On/off of various levers • Switching between diesel oil and heavy oil • Driving status monitoring • Recording and analysis of operating data	Most of the minimum operations from start to stop can be performed. However, it is necessary to confirm that the water system and air system levers are turned on before operating the purifier, but there are times when this confirmation is forgotten. Continued guidance is required as it is one of the causes of oil leakage from purifiers. It is necessary to improve the method of recording and analyzing operation data. Implementation of patrols such as drain check during operation is insufficient.	There is a need for training on items to be checked in patrols during operation and how to record and analyze operation data. Specifically, it is a method of confirming changes over time such as temperature and pressure, and how to utilize it. In addition to making a graph and checking whether the change is constant or abnormal, it is necessary to provide guidance so that it can be confirmed whether it is changing within the standard values specified by the manufacturer. The recording of operating data is also used for preventive maintenance.
Maintain the Power Generation Facilities	Adjustment				Make necessary maintenance for continuous operation. • Replenishment of fuel, lubricating oil and cooling water • Fine tuning of equipment and facilities	LEC has not analyzed the properties of fuel, lubricating oil, and cooling water, and has not been able to obtain fuel property tables from oil manufacturers. Regarding the fine adjustment of the equipment and facilities, there are some parts that are well adjusted by ourselves, but since the temperature settings were changed to parts that should not be adjusted, we still need guidance.	There is a need for training on property analysis of fuel, lubricating oil, and cooling water. Specifically, it is guidance on how to use the oil test kit and how to conduct a cracking test (confirmation of moisture content). As for water quality, guidance on how to use the ph. test kit is necessary. Engineering knowledge about what happens when the setting temperature is changed to the out of range of manufacturer's manual such as the generator bearing temperature and the purifier temperature
	Daily Maintenance				To keep equipment and facilities in operation in good condition. • Maintenance and management of various ledgers • Checking the operating status of equipment and facilities • Daily check	LEC has not analyzed the properties of fuel, lubricating oil, and cooling water, and has not been able to obtain fuel property tables from oil manufacturers. Regarding the fine adjustment of the equipment and facilities, there are some parts that are well adjusted by ourselves, but since the temperature settings were changed to parts that should not be adjusted, we still need guidance.	Regarding the ledger, we are planning to check whether the inventory ledger and card prepared in 8KOH have been updated and whether they have been procured at the next maintenance, and if necessary, we will give advice on the operation method. Regarding daily inspections, there is a daily inspection sheet created and operated by LEC itself, but it is rough, so we thought it would be better to discuss with LEC and increase the number of check items a little in a way that LEC can continue. Regarding electrical equipment, rather than advanced content, guidance is required from the level of regular cleaning to prevent fires and electric shocks.
	Maintenance	Preventive Maintenance	Small Repair		Inspection, repair, parts replacement, etc., when signs of failure are confirmed during daily inspections. • Retightening bolts that have been confirmed to be loose • Replacing the watertight rubber of piping where water leakage has been confirmed • Replacing the turbocharger cartridge when the pressure exceeds the threshold	Defects occurred in the parts of the fuel purifier and air compressor, but the replacement machine was used without replacing the parts. It was in a situation where the necessary replacement was not done due to the failure of the pressure gauge and the wear of the bushing part of the bolt. LEC also didn't know that spare parts were in the warehouse. Exchange instruction was carried out in 8KOH. In the future, it is necessary to continue to confirm whether or not they can make decisions on replacement by themselves.	Regarding pressure gauges and bolt wear, although LEC staffs understand how to replace them, they seem to be unsure about the replacement decision. For items that require regular lubrication, such as fuel racks, it is necessary to confirm during the next maintenance whether they continue to do so.
			Regular Maintenance	Time-based	Make a maintenance plan based on operating hours, and perform inspections, repairs, and parts replacement on a regular basis. The purpose is to prevent troubles and extend the life of equipment by systematically replacing parts before troubles occur. • Inspection, repair, parts replacement, etc. described in the manufacturer's instruction manual.	Due to the new coronavirus, many problems occurred in 8KOH due to driving for about 8K hours without maintenance and replacement that should not be performed without 4KOH, and parts and wear that were scheduled to be replaced in 16KOH Additional procurement and replacement of even non-standard parts occurred. Basically, if the prescribed OH items are implemented every 4K hours, there will be no major exchanges at other times. Regarding the friction clutch of the purifier, it may be necessary to replace it before 4KOH depending on the wall thickness while watching how the rotation speed rises with state-based maintenance. 8KOH instructed how to check and replace, but it is necessary to continue checking. Filters have not been properly cleaned or replaced, and the use of pirated products is also recognized, so it is necessary to understand the importance of properly maintaining and using genuine products.	8KOH generally understands how to maintain parts that are large in quantity and do not require high accuracy, but for parts that require high accuracy and parts that require high accuracy measurement, how to use calipers, etc. It is a situation where further guidance is required.
				Condition-based	Based on the degree of deterioration and wear, systematically implement necessary measures such as polishing and replacement of parts. The purpose is to prevent troubles and maximize machine life by checking the condition of the equipment and replacing parts before troubles occur. • Wear of the valve stem and valve seat can be dealt with by polishing to some extent, and replaced before the thickness falls below the standard thickness.		
		Corrective Maintenance			Investigate the cause and take corrective action when a problem occurs in equipment or facilities. • Responding to failures caused by factors that cannot be detected by preventive maintenance. • Dealing with failures caused by continued operation beyond the standard time for regular maintenance.	Inappropriate measures were confirmed, such as adjusting the fuel rack when an increase in exhaust temperature was observed. In addition to lack of experience and knowledge of troubleshooting, a cautious attitude is required, such as contacting the manufacturer. Many defects were confirmed in 8KOH, but it can be said that it was an opportunity for LEC to deepen their understanding by actually seeing many defects.	Preventive maintenance is a major premise for the operation of power plants, and it is desirable that corrective maintenance should not occur as much as possible. In order not to forget the troubles experienced with 8KOH, we will keep it in a form that can be shared within the organization, and look back on the 8KOH cases in future classroom instruction, etc. Continuous guidance is necessary so as not to fall into it again.

2-1-2-2 Operation of JICA Power Plant

(1) Operation System and Engineers

The organization chart of the power generation department is shown in Figure 2-9. The operation of the power plant at the Bushrod Power Station is carried out by three shifts of about 20 operators under the Operation Manager ((1) 8:00-15:00, (2) 15:00-22:00, (3) 22:00-8:00) is supported.



Source: LEC

Figure 2-9 Organization Chart of LEC Power Generation Division

(2) Major troubles to date

In 2020, the cumulative operating hours of JICA's power plant exceeded 4,000 hours, requiring an overhaul. However, due to the pandemic of the new coronavirus, the operation continued until 2022 without being able to carry out an overhaul. Major troubles among reported troubles are shown below.

Table 2-10 Defects confirmed in 2021

Target part	Contents
Malfunction of Unit 2	In April 2021, the LEC reported that black smoke was emitted from the exhaust chimney and a large amount of drain water was emitted from the intake trunk drain pipe. In June 2021, when a JICA expert confirmed the situation on-site, it was confirmed that water was gushing from the indicator cock, and that water had accumulated inside the combustion chamber. In addition, the emergency measures was implemented such as checking the drain, but there was a risk of a serious accident due to water hammer, etc., so JICA Experts strongly recommended to LEC not to operate until overhaul was implemented. It was operated for just under 1,000 hours to make up for the shortage of

Target part	Contents
	power during the dry season. The cause of the water leak is being investigated during an 8,000 hours overhaul.
VCB burnout	The VCB inside the 22kV Switchgear connected to the 22kV line was burnt out. Looking at the operation history of the protective relay, WDT (Watch Dog Timer) was recorded. When a failure such as a ground fault occurred, it is thought that the CPU in the protective relay ran out of control due to some influence and could not cut off the VCB. In addition, the cable tray near the limiting resistor in the EVT Panel was melted, and it is presumed that the ground fault current was flowing for a considerable period of time. Although the relevant parts have been replaced and operation is continuing, the cause of the damage has not been identified, and a detailed investigation and countermeasures are required.

Table 2-11 Defects confirmed in 2022

Target part	Contents	
	Unit 2	Unit 1
Cylinder head	B4 Intake side clack A1Exhaust side clack	-
Intake Valve	Blowout of B4	-
Exhaust Valve	Blowout of A1,A3,A5,A8, B1, B2	Blowout of A1,2,5,6,8,B1,2,5,6,7
Valve Guide	Some of the guide are deformed. Need to be replaced,	-
Exhaust Valve Seat（water cooled）	Deformation of all exhaust valve seats, burning, carbonization, and cracking of O-rings, In all Cylinders B1, 2, 3 and 4 for which the water pressure test was performed, water leakage was confirmed around the insertion part of the exhaust valve seat into the cylinder head due to the above event.	Clack of A1,A2, A5, A6, A8, B1, B2, B6
Piston Pin	For A6,7,B3,4,5,6,7, there is surface corrosion due to rust, and replacement is recommended. Temporary use up to 12,000 hours is considered possible.	-
Connecting rod	B3,5 has a large degree of surface corrosion due to rust, and replacement after 12,000 hours is strongly recommended. A6,7,B6,7 have smaller rust marks than B3,5, but replacement after 12,000 hours is recommended.	-
Fire ring	Damaged on B2, 6, 7	-
Fuel Injection Valve	Pressure drop and atomization failure due to exhaustion of the fuel injection valve.	Injection pressure after parts replacement is not appropriate and needs adjustment.
Fuel Injection Valve	O-ring damage	Same as left
Fuel Injection Valve	Gasket damage	Same as left
Fuel Injection Pump	Broke three seal rings while cleaning	-
Fuel Injection Pump	One set of A3 washers was damaged.	-
Indicator Cock Safety Valve	-	B2 seat damage
Thermo Couple (Thermo Sensor)	Two thermos couples are damaged.	-
Turbo Charger	They were very dirty and corroded. Nozzle ring and seal cover need to be replaced.	No big problem but dirty

Target part	Contents	
	Unit 2	Unit 1
Purifier (HFO)	Missing orifice of HFO PF No.2	
Purifier (HFO)	Missing Magnetic Contactor of HFO PF No.2	
Purifier (LO)	Speed Sensor Damage of LO PF No.1	
Purifier (LO)	Loss of parts for LO PF No.3 (Spare for No.1 and No.2 Failure)	
Generator	-	Damaged bearing thermometer gauge cover and sensor cover
Generator	Cable damage in the terminal box. Need monitoring.	Same as left
Generator Control Panel	4 alarm buzzer malfunction. Replacement required.	
Filter	FO primary filter is damaged. Scheduled for replacement in early 2023.	-
Filter	Pirated version used for FO 3rd order filter. Replaced.	Same as left
Pump	Worn bushings of coupling bolts for Water Treatment Pump No.1 and No.2. Replaced.	
Pump	Pump pressure gauge failure of No.2 LT Water Circulating Pump. Replaced.	No.1 LT Water Circulating Pump pressure gauge failure, bolt bushing wear. Replaced.
Pump	Pressure gauge failure of No.2 Fuel oil Circulating Pump. Replaced.	Pressure gauge failure of No.1 Fuel Oil Circulating Pump. Replaced.
Pump	Bushing wear of coupling bolts of HFO Booster Pump No.1, No.2. Replaced.	

(3) Situation and issues/training needs before 8,000 hours overhaul

Table 2-12 summarizes the operation status and issues of the JICA power plant before 8,000 hours overhaul (as of June 2022).

Table 2-12 JICA power generation facility operation status and issues

Item	Situation（Before 8,000hours OH）	Challenge
(1) Unit 1 and 2 engine long-term non-opening operation	Since both Units 1 and 2 started operation, overhaul has not been performed for 4,000 hours, and over 7,000 hours of non-overhaul operation has been carried out. In addition, since the exhaust temperature of both Units 1 and 2 is abnormally high, there are concerns about poor combustion, contamination and damage around the combustion chamber and intake/exhaust system.	[Necessary work for Units 1 and 2] Cylinder head opening, inspection and cleaning Fuel injection valve, inspection of fuel pump, cleaning and replacement of parts Opening, inspection, cleaning, regrinding, and parts replacement of intake/exhaust valves and valve seats Start valve. Opening, inspection, cleaning, regrinding, parts replacement of the indicator valve Replacement of piston ring and oil ring Cleaning the air cooler Turbocharger opening, inspection, cleaning
(2) Water intrusion into the combustion chamber of Unit 2	In June 2021, water intrusion into the combustion chamber of all cylinders in Unit 2 B Bank was confirmed. There was water dripping in the crankcase, and JICA experts requested LEC not to operate any more, but due to the power situation, they were forced to operate occasionally. Furthermore, at the time of inspection in June 2022, it was confirmed that water had entered the combustion chambers of all cylinders in Unit 2, and an increase in the	[Necessary work for Unit 2] Air cooler water pressure test Cylinder head opening, water pressure test Opening, inspection, cleaning, regrinding, and parts replacement of intake/exhaust valves and valve seats Cylinder liner inspection and maintenance Inspection, cleaning, maintenance, parts replacement of pistons, piston rings, oil rings, connecting rods, piston pins, piston pin

Item	Situation（Before 8,000hours OH）	Challenge
	amount of water dripping inside the crankcase was confirmed.	bearings, crankpins, crankpin bearings, crankshafts, main bearings, etc. Crankcase cleaning/inspection, oil change Turbocharger opening, inspection, cleaning, parts replacement Intake trunk and exhaust pipe cleaning Lubricating oil change [Construction of Unit 1] No water intrusion into the combustion chamber has been confirmed, but depending on the situation, construction will be carried out in accordance with Unit 2.
(3) LO and HFO purifier	It has been used for a long time without being overhauled, and there are concerns about staining of various parts and wear and tear of parts.	[Necessary work] Disassembly, inspection, cleaning, and parts replacement for 3 LO purifiers and 2 HFO purifiers
(4) Radiator, various pumps, filters	It has been used for a long time without daily inspection and repair, and there are concerns about staining of each part, wear and deterioration of parts, etc.	[Necessary work] Radiator, cooling water pumps, LO pumps, FO pumps, LO filters, FO filters disassembly/inspection/cleaning/part replacement
(5) Generator	Normally, it is constantly driven at 4,000 ㎾. No problem is seen in the current and other parameters. The temperature of the stator coil shows a stable transition with little change over time. The change in bearing temperature is also small, and no tendency to become a problem can be seen.	Not checking for changes in log data over time.
(6) Maintenance status	Basic maintenance work for electrical equipment is cleaning, drying, and visual inspection of equipment. Dust accumulation was observed inside the board, and maintenance work was not properly carried out.	Electrical equipment items are not included in the daily inspection sheet used by LEC.

2-1-2-3 Maintenance and management of JICA power plant

(1) Maintenance record and maintenance plan

There is no document that summarizes maintenance records and plans etc. In view of the achievement goal of reliably maintaining and managing the power plant, the current state of maintenance of the power plant at the Bushrod Power Station is still at a sufficient level as a whole through planning, preparation, judgment, and implementation, confirmation, recording and reporting. Continuous and step by step efforts is required.

(2) Maintenance system and engineers

About 20 maintenance engineers work under the maintenance manager. Table 2-13 summarizes the roles of each.

Table 2-13 Positions and roles related to maintenance

Position	Role
Maintenance manager	・Maintenance instructions ・Procurement of items necessary for maintenance ・Management of expensive instruments such as measuring instruments ・Manager of spare parts and tools
Foreman	- A coordinator for engineers and technicians. ・Disseminate the details of the work and determine the division of roles. ・Maintenance work is also performed.
Engineer	・Considering maintenance methods and issuing work instructions to technicians. ・Maintenance work is also performed.
Technician	- Carry out maintenance work under the direction of the foreman and engineer.

(3) Challenge / Training Needs

Engineers and technicians working at the Bushrod Power Station are highly motivated to learn new technologies for power generation equipment. It can be expected to be effective in improving the skills and motivation of all management personnel.

Table 2-14 JICA power generation equipment maintenance status and issues

Item	Situation（Before 8,000 hours OH）	Challenge
1. Organization System	LEC lacks planning for the maintenance of power facilities, and it is necessary to improve management such as planning, technical judgment, and budgetary measures.	Appropriate preparations should be made by grasping the expected overhaul timing, organization, costs, etc., so that necessary maintenance plans and budgetary measures can be taken.
	There are few opportunities for information exchange between management and field staff.	It is necessary to provide opportunities for information exchange such as regular meetings.
	Overtime and holiday pay are not paid properly. There were also delays in the payment of regular salaries. Therefore, even if necessary work remains, no overtime is required.	Management needs to improve so that salaries are paid appropriately.
	The daily work of operation and maintenance personnel is insufficient, and the management on the management side is not well managed.	It is required to prepare a checklist for operation and maintenance, clarify the daily work of the operation and maintenance personnel, and manage it. In addition, regular meetings will be held to raise the awareness of operation and maintenance personnel.
	Communication between staff members is mainly through phone calls and face-to-face conversations, and since no records are kept, there are many cases where correspondence is interrupted in the middle.	The management side is required to respond to the contact method.
	Most records are paper-based, such as driving records and ledgers, and there are still many parts that have not been digitized.	It is desirable to digitize and manage ledgers.
	When a problem occurred at Unit 2, when it was strongly recommended to stop operation until overhaul was carried out, LEC also understood that technically it should be stopped, but operation was forced due to political reasons.	It is necessary to improve the management's awareness of maintenance and to improve the power supply capacity.

Item	Situation（Before 8,000 hours OH）	Challenge
2. Management and Budget	LEC is operating at a loss due to the large transmission and distribution loss due to non-collection of electricity charges, and the loss is covered by government subsidies. Electricity theft by bribing LEC employees from the community or those in power is being viewed as a cause of uncollected electricity charges.	The CEO, who took office in July 2022, has clearly stated that he will strengthen the crackdown within the LEC as a response to uncollected electricity bills. Bribes, which have been overlooked until now, will be severely punished if they are discovered.
	Appropriate budget is not allocated for maintenance of power plant.	It is necessary to set aside a budget for future maintenance.
	Procurement and budgetary measures for spare parts used in this project	LEC was unable to purchase the spare parts and tools required for the 8,000 hours overhaul in the pilot activity, so JICA decided to procure them. Budgetary measures are insufficient and need to be improved in order to operate for a long time in the future.
3. Technical Aspect	There is no proper response when problems occur. For example, inappropriate measures were taken, such as adjusting the amount of fuel injection when the exhaust gas temperature of Unit 1 rose.	Improve knowledge and experience related to troubleshooting.
	Accident repair records are not managed collectively.	Should be recorded
	Only the manufacturer's manual is available, and LEC's own work instructions have not been prepared.	The LEC itself needs to prepare work instructions.
	Ledgers (equipment ledger, tool ledger, spare parts ledger, fuel ledger, etc.) are not maintained.	It is necessary to develop a ledger for JICA power plant in order to properly grasp and manage the quantity of spare parts and tools, storage locations, etc.。
	Inspection records are recorded on log sheets.	On the other hand, the daily inspection is inadequate because the necessary items are not covered. It is necessary to review the inspection checklist.
	The operator's understanding of each device is insufficient.	
	Troubleshooting manuals are limited to the content described in manuals created by manufacturers, and lack experience and know-how to handle minor troubles. In addition, only a few trouble records are recorded in the operation records, and the details are unknown and there is no compiled record.	
	There is almost no experience of overhauling by dispatching SV from the manufacturer, and improvement of overhaul skill is required.	
4. Facilities	Ledgers of spare parts and tools are not maintained. The loss of the special tool was confirmed before the 8,000 hours overhaul was implemented.	
	There are no PCs or printers available for field staff to use.	It is desirable to have shared PCs and printers that can be used by field staff.

2-1-2-4 Positioning of this project

As mentioned above, LEC recognizes JICA's power plant as important facilities, and has operated and maintained them by themselves for up to 8,000 hours. In this situation, there is a situation where the user may mistakenly assemble the device when performing maintenance on their own, or continue to use the device without performing the necessary maintenance. Technical cooperation from experts will be required to ensure stable operation in the future, and this project is expected to improve practical operation and maintenance management capabilities through classroom training and practical training.

2-1-3 Activities during the entire project period

2-1-3-1 Pilot Activity

As a pilot activity in the detailed planning phase, activities related to outputs 1 to 3 shown in Table 1-1 are being implemented.

(1) Object and Contents

Capacity development of LEC through pilot activities in order to improve LEC's planning and implementation capacity for proper operation of LEC's diesel power plant at Bushrod Power Station was enhanced. As activities related to Output 1 and Output 2, in addition to capacity building related to regular operation, maintenance, and troubleshooting of diesel power plant, capacity development related to heavy oil operation will be implemented. As an activity related to Output 3, capacity development technology transfer will be conducted through 8,000 hours overhaul in order to acquire regular overhaul skill.

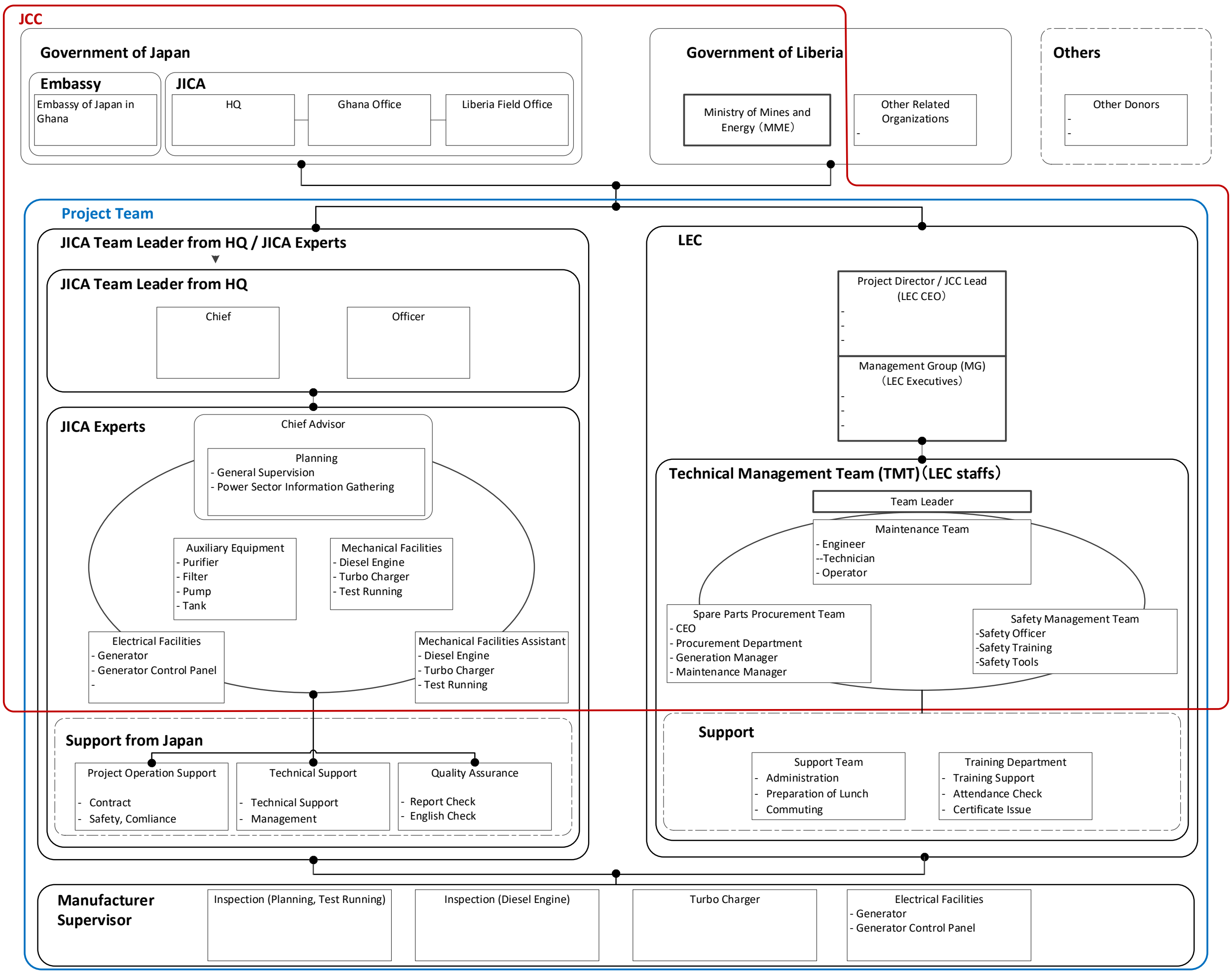
(2) Implemntation System

The implementation system is shown in Figure 2-10. The project team indicated by the blue frame consists of JICA and LEC. The Joint Coordinating Committee (JCC) shown in the red frame is chaired by the LEC president and consists of the project team, the Japanese government agencies, and MME.

On the Japanese side, JICA Headquarters and JICA experts played a central role, and the JICA Ghana Office, Liberia FO, and the Japanese Embassy in Ghana supported the project. In addition, JICA has a system of 2 people from the headquarters, a general manager and a deputy general manager, and 5 JICA experts: Chief Consultant/Electric Power Planning, Mechanical Equipment, Electrical Equipment, Electric Power Planning Assistant, and Mechanical Equipment Assistant.

On the Liberian side, the LEC was at the center of the system, with support from the MME and Liberian government agencies. LEC organizes a Management Group (MG) centered on executives in charge of business management and a Technical Management Team (TMT), centered on LEC staff who are the practical units for operation, and maintenance. In order to incorporate the opinions of staff in various positions, JICA and LEC have devised ways such as holding a meeting once a week centered on the core members of TMT and holding a morning meeting before the start of each day's work, in which all staff involved in overhaul participate. This system is planned to be maintained even in full-scale activities.

In addition, a manufacturer engineer was dispatched to take charge of overhaul inspection (planning and technical guidance), so JICA Experts were able to formulate a highly feasible plan that incorporated the manufacturer's views.



Source: JICA Experts Team

Figure 2-10 Implementaion System Chart of Detailed Planning Survey

(3) Implementation Schedule

Table 2-15 shows the implementation schedule of the power generation equipment maintenance guidance at the Bushrod Power Station.

The project research and preparation period is from April 2020 to June 2022, and the implementation period of the pilot activities is from June 2022 to February 2023.

The pilot activity is positioned as a stage to acquire basic skill and technique before the implementation of the full-scale phase, and it also serves as an understanding of LEC's technical capabilities for formulating a detailed plan.

In this project, LEC will be able to maintain and manage the power supply facilities on their own, so it is important to understand the current situation of LEC, provide step-by-step guidance until the skill is established, and confirm their independence.

Table 2-15 Classroom/practical training schedule/content

Stage	Period	Target	Item	Achievement Goal
Survey and Preparation	2020/4～ 2022/6*	Bushrod Power Plant MG、TMT	1. Survey of current status of LEC facility maintenance and management 2. Consideration of project implementation plan, schedule, etc., planning of preventive maintenance 3. Long-term continuous technical guidance through OJT: ・Basic management method ・Daily inspection, confirmation of operation status ・Technical guidance for TMT 4. Remote technical support	1. Preparation of detailed project implementation plan 2. Started managing MG ・Maintenance and storage of logbooks and operation/maintenance records ・Preparation of operation and maintenance plan, spare parts purchase plan, and maintenance budget ・Thorough compliance with instructions and orders 3. Collaboration with LEC Headquarters 4. The maintenance and management of the power plant during the period of suspension due to the impact of Covid-19 is properly carried out.
Basic Skill Period	2022/6 (Two weeks)	Bushrod Power Plant TMT	Classroom lecture: ・Diesel power generation equipment and power generation system ·Electrical equipment ・Auxiliary equipment ·Trouble shooting	TMT: Improving Basic Technical Skills
	2022/8～ 2023/1 (Six Month)	Bushrod Power Plant MG （TMT）	Long-term continuous technical guidance through OJT: ・Management method ・Driving situation analysis, prediction, judgment ・Advance preparation for annual operation and maintenance ・Securing spare parts and consumables ·troubleshooting	1. Acquisition of MG (TMT) management skills ・Annual operation and maintenance plan creation ・Preparation of annual spare parts purchase plan ・Draft annual maintenance budget ・Securing annual budget ・Spare parts, consumables, tool management ledger creation 2. Collaboration with LEC headquarters
	2022/8～ 2022/11 (3.5 months)	Bushrod Power Plant TMT （MG）	1. Technical guidance for 8,000 hours inspection by engine manufacturer engineers: ・Cylinder head open ・FO valve nozzle replacement ・Piston extraction, inspection 2. Inspection technical guidance by auxiliary equipment manufacturer (purifier) engineers 3. Inspection technical guidance by generator manufacturer engineers 4. Technical guidance by electrical equipment experts 5. Technical guidance related to heavy oil operation	MG: Securement of spare parts, advance preparation, improvement of advanced technical decision-making ability TMT: Mastering advanced maintenance skills (Cylinder head open inspection parts replacement, restoration, operation check)

Stage	Period	Target	Item	Achievement Goal
			6. troubleshooting	
	2023/2 (Two weeks)	Bushrod Power Plant TMT	Lecture: Technical guidance related to daily operation and inspection 1. Technical guidance related to heavy oil operation 2. Inspection items in daily operation 3. troubleshooting	TMT: Improvement of basic technical skills related to daily operation

* The implementation period includes the suspension period due to the impact of COVID-19.

2-1-3-2 Activity Plan of Implementation Stage

In order to further establish the knowledge and experience acquired in the pilot activities, to experience new maintenance items, and to improve daily operation and maintenance skills, a plan for full-scale activities was formulated. Details are given in Chapter 5.

2-2 Pilot Activity

2-2-1 Remote Technical Support

In this project, the initial schedule was to perform 4,000 hours of maintenance on the JICA power plant from July 2020 to prepare for regular operation in the dry season. However, due to the impact of COVID-19, travel prospects are uncertain, so at the kick-off meeting on June 30, 2020, the LEC requested support for the operation and maintenance of JICA's power plant until the start of travel of JICA Experts. In response to the request, the remote technical support for the purpose of supporting proper maintenance was implemented during the JICA power generation facility standby period (September to December 2020).

(1) Contents of remote technical support

1) Implementation period, frequency

- Implementation period: Power generation facility standby period (from September to December 2020)
- Frequency: Once a month feedback

2) Method

A) The LEC will fill in the check sheet and operation log sheet provided by the JICA expert and send it to the JICA expert by e-mail. (See Attachment 9 for the check sheet and driving record sheet forms.)

B) JICA experts confirm and analyze the check sheet with the cooperation of the engine manufacturer, IHI Power Systems. In the case of load operation, the state of the engine is analyzed based on the operation record data.

C) Feedback analysis results to LEC through web meetings and give advice as appropriate.

(2) Findings of remote technical support activities

Attachment 9 is the LEC's comments and feedback from JICA experts to the LEC. The particular concern are the following;

- Lubricating oil leaking from the turbocharger was found, and requested LEC to inform us of the specific condition and location of the lubricating oil leak. However, since it was not possible to identify the specific location where the lubricating oil leak occurred, JICA experts gave instructions on checking the operation of the pressure gauge, etc., and if there was no problem with the pressure gauge. Then it was checked during the filed work. As a result, during the 8,000 hour maintenance, it was confirmed that the lubricating oil leak was occurring from the insertion part of the speed sensor of the turbocharger, and it was resolved by tightening the relevant part.
- It has been reported that vibration and smoke occur during load operation of 4,500 kW

(90% of rated output) or more. Guidance was given based on supplementary materials, such as vibration measurement, bolt tightening confirmation, and video request. No abnormalities were found during the test run after 8,000 hours of maintenance.

- The lubricating oil pressure of the turbocharger dropped to 0.08 MPa in Unit 1 against the lower limit of 0.18 MPa. JICA Experts recommended them not to operate until proper measures were taken, as it could lead to damage to the turbocharger and serious accidents. The cause of the pressure drop is assumed to be a malfunction of the pressure gauge, a lubricating oil leak from the piping, or a malfunction inside the turbocharger. Therefore, JICA Experts asked LEC to check the operation of the pressure gauge. Also, if the pressure gauge is working properly, there is also a problem with the supercharger lubricating oil pressure alarm system and emergency stop system.

The pressure drop was thought to have been caused by the above-mentioned lubricating oil leak, and no abnormalities were observed during the test run after 8,000 hours of maintenance.

(3) Result

In particular, the problem of the lubricating oil pressure drop in the turbocharger was confirmed, and the necessary countermeasures was provided to the LEC before it led to a serious accident. In addition, the checklist for power plant in routine maintenance and the operation record form were improved.

2-2-2 Classroom training (first session)

2-2-2-1 Achievements and results of classroom training

The first classroom training was held in June 2022, before the start of the 8,000 hours maintenance. Table 2-16 shows the contents of the lectures. In addition to basic lectures on the composition and roles of diesel power generation equipment and power generation systems, basic maintenance skills required for power plant operation, such as maintenance planning methods and work procedure manuals were also conducted during the training. In addition, after the classroom training, the content was designed with consideration given to the flow of practical experience through OJT during 8,000 hours of maintenance. A total of 20 people, including 12 mechanical engineers from the maintenance team, 3 electrical engineers, 3 from the operator team, and 2 interns, participated.

The staff who participated in the training were eager to improve their skills and showed a strong motivation to deepen their knowledge of diesel engines and improve their technical skills. In order to check their level of understanding, the training included questions to the participants, and lectures were arranged to their level of understanding. In addition, by incorporating on-site practical training, the participants' level of understanding increased. Through practical training in crank case inspection, rust removal cleaning, draining, and equipment corrosion prevention measures, the importance of diesel engines maintenance was conveyed and a good relationship was established between the LEC engineers and JICA expert team. It is required that LEC revise and utilize the work procedures and various checklists explained in the training program for Bushrod power plants.

Table 2-16 Contents of classroom training in pilot activities (first)

Item	Plan	Output	Challenge toward the Core Activity
Mechanical Facilities			
Classroom training #1			
Outline of Diesel Engine Generator facilities	Explain the structure of the main equipment and the role of the main parts based on the structural drawing	Understanding basic structure. Clarification of overhaul inspection points	Improved understanding of overhaul inspection points
Troubleshooting	Explanation of typical trouble cases, causes, and pre- and post-maintenance measures for diesel engines of the same type	Understanding failure cases and countermeasures	Establishment and practice of countermeasures for various failure cases
Basics of maintenance	Maintenance system flow chart, maintenance concept, annual plan, medium- and long-term maintenance plan, regular maintenance preparation, human resource development, etc.	Basic understanding of maintenance.	Implementation and updating of various plans
Preparation of maintenance manual	The purpose of work standards and the need for operation management based on maintenance management standards	Understanding the method and purpose of preparing maintenance manuals	Updating work standards in line with LEC
Periodic Overhaul Inspection Item Checklist of Diesel Engine	Overview and usage of the periodic overhaul inspection item checklist	Understand the purpose and use of checklists	Update the maintenance manual
Inspection and maintenance procedures for 8,000 hours overhaul inspection	Understanding work items and procedures for 8,000 hours overhaul inspections	Understand the work outline of each maintenance	Establishment of practices and techniques
Contents of next periodical overhaul inspection work	Procedures, precautions, etc. for the next periodic overhaul inspection work	Understanding of procedures and precautions for each work	Establishment of practice and skill. Understanding of work contents after 16,000 hours overhaul inspection.
Maintenance of record of periodic overhaul inspection	Contents of Periodic Overhaul Inspection Record and How to Use It	Understanding the contents and purpose of use of the periodic overhaul records	Examination and review of practices and records
Daily check	Overview of daily inspection items and engine performance tests	Understanding of daily inspection items and purpose of engine performance tests	Implementation of daily inspection and engine performance test and update of contents
On-site practical training	Crank chamber inspection, combustion chamber inspection, engine water drainage, piston skirt, liner rust removal cleaning, combustion chamber cleaning, practice of grease application method	Improving understanding by practicing part of the content of overhaul inspections	Establishment of practices and techniques
Electrical Facilities			
Basics of Generator	Basic composition and structure of the generator	Understand basic configuration	Understanding control and protection systems

Item	Plan	Output	Challenge toward the Core Activity
Operation of Generator	Generator usage limit and actual operation	Understand the outline, but need more training on the theoretical background.	Understanding of points for daily and periodic inspections. Understanding the theoretical background
Calculation of short circuit current	Generator short circuit current Estimation of short-circuit current on each panel	Understand the outline but cannot calculate by themselves	Calculate and analyze by themselves
Estimated short-circuit current and circuit breaker	Ensuring selective tripping	Understand the outline but cannot calculate by themselves	Calculate and analyze by themselves
Trouble example	Starting failure Abnormal pressure of T/C LO line	It is a case that LEC has actually experienced, but understanding from the drawing is insufficient.	Drawing analysis through various cases
Vacuum Circuit Breaker Burned out	Burnout of VCB and Estimation of Accident Factors	Understand the process of examining the causes of VCB burnout accidents.	Detailed investigation and analysis of actual equipment
On-site practical training	Switch off operation based on the operation command slip, drawer/insert generator circuit breaker operation, handling and actual measurement of insulation resistance measuring equipment, 6.6/22 kV high voltage circuit breaker circuit operation and understanding of the circuit by creating a single line diagram	Improving understanding of the importance of operations and records based on slips, and drawings and actual circuit configurations	Establishment of practices and techniques

2-2-3 Practical Training through 8,000 hours maintenance

(1) Outline of 8,000 hours maintenance

From August to November 2022, 8,000 hours maintenance was conducted as OJT practical training. During the maintenance period, a lot of discovered work and additional procurement occurred, but owing to the hard work by LEC maintenance team and prompt procurement by the management and procurement department, the maintenance was completed within the originally scheduled period (94 days).

8,000 hours maintenance was conducted by the manufacturer's Supervisors shown in Table 2-17.

Table 2-17 Dispatch of engineers from manufacturers

In charge	Period（in–out）
Diesel Engine Overhaul	August 11th to November 9th, 2022
Auxiliary Diesel Engine Overhaul	August 11th to November 9th, 2022
Diesel Engine Overhaul Planning	August 17th to September 12th, 2022 November 7th to 17th, 2022
Turbo Charger Overhaul	September 6th to 21st, 2022 November 1st to 5th, 2022
Purifier 1	October 16th to November 6th, 2022
Purifier 2	October 16th to November 6th, 2022

In charge	Period（in–out）
Generator and Generator Panel	October 28th to November 9th, 2022
Electrical Test Running	October 28th to November 9th, 2022

As for the system on the LEC side, the following departments worked together to carry out maintenance.

A) Maintenance team consisting mainly of engineers, technicians and operators (total of 25 people)

B) Procurement-related departments such as procurement department, power generation manager, maintenance manager

C) Safety management department

D) Training division

In the overhaul implementation, LEC didn’t only performed overhaul work, but also deepened understanding of the structure and role of each component, each work procedure. Regarding the overhaul period, it was foreseen from the preliminary investigation that the damage inside the engine would be large, so the period was set longer. For this reason, various uncovered issues were discovered, and flexible schedule were required, such as rearranging the process. The main implementation items are shown in Table 2-18.

(2) Level of understanding and proficiency of LEC staff

1) General power generation equipment

A certain level of success has been achieved in improving LEC's skill through the training from manufacturer SVs and experts. For the LEC, this was the first time for regular overhaul, and it cannot be said that they mastered all the work perfectly in just this one time. However it deepened their understanding of work procedures.

LEC disassembled, cleaned, and assembled the engine, generator, turbocharger, purifier, and other auxiliary equipment. Also, as mentioned above, many problems were found in this overhaul, so in addition to the usual 8,000 hours overhaul item, a lot of troubleshooting was also conducted. It was an opportunity to see actual troubles in actual equipment, and it deepened their understanding of abnormal conditions.

In addition to the maintenance team, 8 operators also participated, deepening their understanding of the mechanism of the power plant and equipment, and using actual equipment with the maintenance team to learn how to respond when an alarm or a problem occur. It was an opportunity for the LEC staff to come to an understanding of each through the instruction from manufacturer's SVs not only about maintenance but also about operation.

The degree of understanding and proficiency of the LEC is confirmed by the JICA Experts asking the LEC staff who received instruction from the SVs about the part names, work details, and points in the work. JICA experts provided support to ensure understanding.

As for the situation before the overhaul, the minimum necessary operations were performed, but there were many challenges as shown below.

- Daily inspection and maintenance such as necessary parts replacement and drain check are not done
- There is the lack of how to use special tools for disassembling power generation equipment
- When an engine malfunction occurs, it is difficult to identify the cause and deal with it.
- Filters are cleaned by themselves, but there is the lack of knowledge of cleaning frequency.
- Electrical equipment has not been cleaned, such as dust accumulated in the panel
- Not checking the quality of water and oil
- The drain that should be drained regularly was not drained all the time and it was accumulated inside.
- Spare parts are kept in boxes and not kept in stock
- During disassembly, cleaning, and assembly, there were errors in the procedure and some parts were disassembled and placed around and left in operation without being reassembled.

As described above, it is considered that there was a high risk of serious accidents due to working without knowledge and experience.

2) Mechanical Facilities

Regarding the degree of understanding after overhaul, the LEC can make the allocation for each work and basically the right person was assigned to the right place. Therefore, LEC understood well the outline, purpose of the work and general work flow. On the other hand, the detailed procedure instruction by the manufacturer's SVs was needed due to lack of experience. Regarding the overhaul work of each component that are not required precision, LEC staff has been able to do the work on their own after instruction of the points of the each work. For the work which is required high precision the polishing work is done by the LEC, but the final confirmation by the SV is necessary for the work of rubbing parts together at a high level. From the above, it is necessary to continue to experience it repeatedly in the future to improve the understanding and skills.

3) Electrical Facilities

Due to the small number of electrical engineers, there was a lack of basic knowledge of electricity. Instructions were given to operators and others on regular cleaning inside the panel and how to measure the minimum resistance that should be measured.

4) Inventory Management

As for tools and parts, LEC organized warehouses and JICA Experts provided management guidance. After overhaul, LEC counted the number of tools and parts left in the warehouse one by one, and created and maintained an inventory card and an inventory list. There was also a review of maintenance through inventory work.

In addition, in order to borrow one cylinder head from EGTC in Sierra Leone during overhaul, the power generation manager and the maintenance manager of LEC visited the Kingtom power plant in Sierra Leone. At that time, LEC staff visited the power plant warehouse and learned that there was a position of warehouse keeper within the organization.

5) Daily inspection and operation guidance

Regarding daily maintenance, maintenance implementation is not compiled as a maintenance record, and it was not possible to check what kind of problems had occurred since the comissioning of operation of the power generation equipment, so guidance for maintenance records was provided.

JICA Experts explained the importance of maintenance records for stable operation, sharing information among staff and preventing major accidents. In addition, among the defects found during routine maintenance, the items that were to be dealt with at the next overhaul implementation should be included in the overhaul items, and the necessity of cooperation with the procurement department was explained. Continuous guidance will be necessary, but at the ceremony after the ovrehaul, the CEO of LEC expressed his gratitude to the LEC staff for the smooth procurement procedures during the overhaul, It is believed that the LEC itself is aware of the importance of collaboration among departments.

For daily maintenance, the operation log sheet currently used by LEC was checked, and JICA Experts instructed not only to record numerical values for temperature, pressure, etc., but also to plot them on graphs and observe trends. Also, it was confirmed during the overhaul that the drain was not being discharged at an appropriate frequency, so after the overhaul the drain management list has been organized. Since the drain list is covered almost all equipment, it will be possible to check such as the external appearance, abnormal sounds, odors, oil leaks, etc. without omission while checking the drain.

Table 2-18 Contents of practical training in pilot activities

Item	Plan	Output	Challenge toward implementation phase
(1) Diesel engine body	Disassemble the cylinder head of Unit 1 and 2, clean each part such as fuel valve, starting air valve, indicator valve, intake/exhaust valve and valve seat, fuel injection test, nozzle replacement, etc.	(1) Disassemble all cylinder heads of Units 1 and 2, clean, disassemble, clean, and maintain valves (2) Replace 1 indicator valve of Unit 1	(1) For the 12,000 hours and 16,000 hours overhauls, the same construction work as the plan on the left will be implemented. (2) Technical skill improvement of LEC personnel.
	Replace, grind, and adjust the intake and exhaust valve and valve seats of Units 1 and 2.	(1) 6 exhaust valves of Unit 2 were blown out and replaced with new ones. 10 exhaust valves for Unit 1 were blown out and replaced with new ones. (2) Deformation of all exhaust valve seats in Unit 2, O-ring burnout, carbonization, cracks, and water leakage. Replaced all (32 pieces). There were cracks in the 6 exhaust valve seats of Unit 1, and they were replaced with new ones. (3) One intake valve in Unit 2 was blown out and replaced with a new one. (4) All intake/exhaust valves, valve stems, and valve seats of Units 1 and 2, including those that were replaced with new ones, were reground on the seat surface and checked for contact.	(1) For the 12,000 hours and 16,000 hours overhaul work, the same overhaul work as the plan on the left will be implemented. (2) Confirmation of the status of the intake and exhaust valves after 4,000 hours and 8,000 hours of operation after this overhaul. (3) During the 16,000 hours overhaul, many valves and valve seats of intake and exhaust valves are expected to be replaced. It is necessary to confirm the quantity of replacement spare parts and purchase them in advance. (3) Technical skill improvement of LEC personnel.
	Conduct visual inspection and color check of all diesel engine cylinder heads of Units 1 and 2, and carry out effective maintenance as necessary.	(1) Conducted visual inspection, color check, and water pressure inspection for all cylinder heads of Units 1 and 2. (2) Two cylinder heads of Unit 2 had cracks and were replaced with new ones.	(1) Conducted visual inspection, color check, and water pressure inspection for all cylinder heads of Units 1 and 2. (2) Check the condition of the cylinder head after 4,000 hours and 8,000 hours of operation after this overhaul. (3) Technical skill improvement of LEC personel
	Overhaul and parts replacement of the fuel injection valves of Units 1 and 2.	Replaced all No. 1 and 2 fuel valve nozzles and adjusted injection pressure. Replace all O-rings and gaskets	(1) For the 12,000 hours and 16,000 hours overhauls, the same construction work as the plan on the left will be implemented. (2) Check the status of the fuel injection valve after 4,000 hours and 8,000 hours of operation after this overhaul. (3) Technical skill improvement of LEC personnel

Item	Plan	Output	Challenge toward implementation phase
	The pistons, piston pins, cylinder liners, and connecting rods of all diesel engine cylinders are removed, cleaned, inspected, and dimensionally measured. , maintenance of bearings, etc., and replacement of parts.	(1) Removed pistons from all cylinders of Units 1 and 2, and inspected cylinder liners, firing rings, pistons, piston rings, piston pins, piston pin bearings, connecting rods, crankpins, crankpin bearings, crankshafts, and main bearings. . (2) 7 piston pins of Unit 2 were rusted and corroded. It is recommended to replace after 12,000 hours overhaul. (3) 6 connecting rods of Unit 2 are rusted and corroded, repaired and used continuously. However, it is recommended to replace after 12,000 hours overhaul. (4) Replace piston rings and oil rings for all cylinders of Units 1 and 2. (5) Replace two fire rings of Unit 2.	(1) Normally, the pistons are not removed during the 12,000 hours overhaul, but the removal of the piston is planned only for the cylinders where the piston pin and connecting rod are to be replaced. (2) Remove the piston after overhauling for 16,000 hours. (3) Check the condition of the piston, piston pin, connecting rod main bearing, etc. after 4,000 hours and 8,000 hours of operation after this overhaul. (4) Technical skill improvement of LEC personnel
	Measure crankshaft journals, crankpins, and crank deflection of diesel engines.	(1) Visual inspection of all crankpins of Units 1 and 2 crankshafts. In addition, the crank deflection measurement was carried out, and it was confirmed that there was no abnormality.	(1)Crank deflection measurement will be implemented at 12,000 hours and 16,000 hours overhaul. (2) Check the condition of the crankshaft after 4,000 hours and 8,000 hours of operation after this overhaul. (3) Technical skill improvement of LEC personnel
	Inspect some main bearings as sample and if necessary, inspect other main bearings.	(1) Disassembled two main bearings of Unit 2 and carried out a visual inspection. Confirmed that there is no abnormality.	(1) During the 12,000 hours and 16,000 hours overhauls, the main bearings will be inspected. (2) Confirmation of the condition of the main bearing after 4,000 hours and 8,000 hours of operation after this overhaul. (3) Technical skill improvementof LEC personnel.
	Inspect some fuel injection pumps as sample, and if necessary, inspect other fuel injection pumps.	(1) Disassembled, cleaned, and maintained all fuel pumps in Units 1 and 2, and confirmed that there were no problems.	(1) At the 12,000 hours and 16,000 housr overhauls, the fuel pump will be inspected. (2) Confirmation of the status of the fuel pump after 4,000 hours and 8,000 hours of operation after this overhaul. (3) Technical skill improvement of LEC personnel

Item	Plan	Output	Challenge toward implementation phase
	Carry out a cleaning and inspection of the air cooler. Inspect the cooling pipes for damage, etc.	(1) Cleaned the air side by immersing the air coolers of Units 1 and 2 in the cleaning tank. (2) Applied water pressure from the cooling water side and confirm that there were no leaks.	(1) During the 16,000 hours overhaul, the air cooler will be cleaned and a water pressure test will be conducted. (2) Confirmation of the condition of the air cooler after 8,000 hours of operation after the overhaul. (3) Technical skill improvement of LEC personnel
	The four turbochargers will be cleaned and a disassembly inspection including measurements will be carried out.	(1) Disassemble, clean, and inspect the turbochargers of Units 1 and 2 (4 units in total). (2) The nozzles and blades of the two units on the No. 1 side were considerably damaged, but no abnormalities were observed. (3) The gas passage side of the two units of Unit 2 was heavily soiled and corroded, and the nozzle ring and seat cover were replaced with new ones.	(1) During the 16,000 hours overhaul, four turbochargers will be cleaned and inspected. (2) Check the status of the turbocharger after 8,000 hours of operation after this overhaul. (3) Technical skill improvement of LEC personnel
(2)Auxiliary equipment (purifier)	Check the condition of purifiers, filters, heaters, viscosity adjusters, etc. of heavy oil fuel system equipment, and provide guidance on fuel property analysis and disassembly maintenance.	(1) Disassembly, cleaning, inspection, and parts replacement for two HFO purifiers. (2) Check the status of HFO system viscosity adjusters, filters, heaters, etc., and provide guidance to LEC personnel.	(1) During the 12,000 hours and 16,000 hours overhauls, the HFO purifier will be disassembled, inspected, and parts will be replaced. (2) Check the status of the HFO purifier after 4,000 hours and 8,000 hours of operation after this overhaul. (3) Technical skill improvement of LEC personnel
	Check the operation records of purifiers, filters, etc. of lubricating oil system equipment, analyze lubricating oil properties, give advice on sampling points, and provide guidance on disassembly and maintenance.	(1) Disassembly, cleaning, inspection, and parts replacement for 3 LO purifiers. However, there is no replacement part for one LO Purifier, and it will be replaced. (2) Guidance to LEC such as LO cracking test method.	(1) During the 12,000 hours and 16,000 hours overhauls, disassemble, inspect, and replace the LO purifier is planned. (2) Check the status of the LO purifier after 4,000 hours and 8,000 hours of operation after this overhaul. (3) Technical skill improvement of LEC personnel
	Check the operation records of the tank, pump, radiator, etc. of the cooling water system and the condition of the cooling water, and give instructions on disassembling and repairing the pump,	(1) Cleaning of cooling water radiators and tanks, inspection of cooling water pumps, and replacement of parts. (2) Guidance on the use of anticorrosive agents for cooling water	(1) During the 12,000 hours and 16,000 hours overhauls, the cooling water radiator and tanks will be cleaned, the cooling water pumps will be inspected, and parts will be replaced as necessary.

Item	Plan	Output	Challenge toward implementation phase
	cleaning the expansion tank, replacing the cooling water, and adding anti-rust agent.		(3) Follow up the work of LEC personnel.
(3) Generator	The generator will be inspected according to the manufacturer's 8,000 hours maintenance guidelines.	Conducted all the items described in the manufacturer's maintenance guidelines.	
(4) Generator Control Panel	Inspect the generator control panel.	Conducted everything from cleaning to checking the alarm operation.	

2-2-4 Classroom training (second session)

The second classroom training was held in March 2023 after 8,000 hours of maintenance. Table 2-19 shows the contents of the lectures. (1) Strengthening of daily maintenance and inspection capabilities, (2) Consideration of 8,000 hours maintenance. It was a practical content combined with a demonstration. A total of 24 people participated, including maintenance managers, 11 mechanical engineers, 3 electrical engineers, and 9 operators.

During the 8,000 hours of maintenance, a defect leading to a serious accident was confirmed in Unit 2, and all the participating LEC employees had the intention not to make the same mistake, making the classroom training livelier than the first time. . During the classroom lectures, many questions and answers were exchanged until the training time was over. It was decided to sprout in each electrical team. In the next and subsequent phases, it is desirable to further improve accident response technology and improve the level of electrical control technology.

Table 2-19 Contents of classroom training in pilot activities (second)

Item	Plan	Output	Challenge toward the Core Activity
Second session			
Daily inspection patrol, daily maintenance	Daily inspection check, patrol check detailed procedure, daily maintenance check manual	Not completed (scheduled for February 2023)	Daily, monthly, annual inspection schedule formulation and implementation
troubleshooting	Understanding of major troubles, handling procedures for major and minor troubles, JICA No. 2 trouble analysis	Not completed (scheduled for February 2023)	Alarm factor analysis, establishment of alarm treatment skill
Engine performance maintenance management	Objectives of Engine Performance Tests, Record Tables, Records and Data Evaluation	Not completed (scheduled for February 2023)	Understanding and establishing engine performance test content
Lubricating oil, fuel oil and water quality maintenance management	Comparison of lubricating oil and fuel oil specifications, property analysis, maintenance of control standards	Not completed (scheduled for February 2023)	Understanding and establishment of lubricating oil, fuel oiliness, and water property management details
Preparation of maintenance manual	Updating the manual for the 1st classroom training	Not completed (scheduled for February 2023)	Construction of manual maintenance management system
Future maintenance planning	Maintenance plan, system etc., after 12,000 hours maintenance	Promote understanding of each overhaul inspection and maintenance parts that need to be arranged	Implementation system, implementation of budget management
On-site practical training	Thorough safety management using operation slips and safety tags when inspecting machinery and electrical equipment. Inspection of the B4 cylinder, which was the most damaged among the Unit 2 cylinders. Guidance on	Further improvement of understanding through daily inspection and disassembly inspection guidance on actual equipment.	Preparing the manual and makes it routine of inspection procedures

Item	Plan	Output	Challenge toward the Core Activity
	inspection procedures using stethoscopes, radiation thermometers, and remote hand mirrors for early detection of engine and auxiliary machine malfunctions. Guidance on how to measure vibration and determine vibration abnormalities. On-site guidance for engine performance management, oil and water quality management.		

Chapter 3 Issues, ingenuity and lessons learned in implementation of detailed planning phase

3-1 Issues, ideas and lessons learned in detailed planning phase

3-1-1 Confirmation of future operation policy for diesel engines

The future operation policy for JICA power plant is an important matter that greatly affects the schedule and content of detailed planning. JICA Experts collected information such as the development status of the power system.

After the detailed plan was formulated, operation policy for JICA power plant was changed due to reasons such as soaring fuel costs. The policy has been changed to supply large customers from JICA power plant. In this way, there is a possibility that the operation policy will change in the future due to fuel costs and external factors, so it is necessary to pay attention to it by exchanging information with the LEC.

3-1-2 Understanding the training needs of LEC staffs

The original plan was to formulate a detailed plan before the pilot activity, but it was implemented as a pilot activity in order to accurately grasp the training needs by confirming the technical level of the LEC staff and the current state of the LEC organization. Detailed planning was carried out after 8,000 hours of maintenance. As a result, in addition to reflecting technical training needs in the plan, it became possible to formulate a plan in accordance with the actual situation in terms of organization, such as preparation of various manuals.

In addition, due to travel restrictions due to the COVID-19, JICA Experts collected information online and obtained a certain amount of results, but it was essential to conduct an on-site survey to understand the actual situation.

3-1-3 Spare parts management and budget measures

Regarding the procurement of spare parts, etc., a detailed examination was carried out by confirming the LEC's financial status and business operation status, as well as whether appropriate budgetary measures are possible. As a result, it has been confirmed that the financial situation is in a severe crisis, and commercial losses such as power theft have affected management. In order to improve this situation, LEC is promoting measures such as installing power meters, and it was confirmed that as of March 2023, commercial losses have been reduced from 40% to 30%, and certain results have been obtained. In addition, it was confirmed at JCC meeting that maintenance costs for spare parts for JICA's power plant will be budgeted from income from power sales to the large customers.

Regarding budgetary measures, JICA Experts explained the necessity of midium-term and long-term maintenance plans and proposed budget leveling measures in preparation for future large-scale overhaul implementation. A specific midium-term to long-term maintenance plan will be formulated in the implementation phase.

In addition, regarding inventory management of spare parts and tools, it was confirmed that the management ledger was inadequate and the inventory card was not maintained, and this was reflected in the activity plan.

3-2 Issues, ideas and lessons learned from pilot activities

3-2-1 Remote technical support

During the period when JICA Experts could not travel due to the impact of COVID-19, JICA Experts provided remote technical support related to the maintenance and management of power plant based on the LEC's operation records. The results of the analysis were explained at an online meeting, and necessary measures were taken in consultation with the LEC. When analyzing the operation records, appropriate analysis was conducted with the cooperation of the engine manufacturer, IHI Power Systems. In addition to the analysis of operation records, guidance on preparing a checklist of equipment and review the operation record form were provided.

As for issues, as it was an attempt before the on-site activities and the lack of understanding of the skills of the LEC side, the points pointed out by the experts were not fully reflected due to the limitations of online explanations. An attempt was made to explain using supplementary materials. For some issues, direct guidance was provided on-site.

3-2-2 Classroom training

The technical challenges of the LEC are detailed in Chapter 2, and the issues, innovations, and lessons learned from the implementation and management are shown below.

A) Lectures focused on two-way communication

In order to confirm the level of understanding on the LEC side, instead of a one-way explanation from the expert, the level of understanding was confirmed by the question from the expert, and if LEC staff did not understand, a more in-depth explanation was given. Through this communication, LEC participants began to actively ask questions, and the level of understanding of the training was deepened.

In addition, a questionnaire survey was conducted at the first classroom lecture to understand the needs of the training, which was reflected in the content of the second training, such as trouble shootings and daily maintenance management.

B) Training with guidance using actual machines

In addition to classroom lectures using materials, explanations and guidance using actual equipment in the plant were also given. This has led to an improvement in the degree of comprehension by confirming the content that has been understood in the lecture on the actual machine. It is well received by the LEC side, and JICA Experts propose to continue the same method in the implementation phase.

In addition, an introduction of the safety tag system using operation command slips (safe operation) and practical guidance using safety tags, an introduction of a parts management system that manages replacement parts required for inspection, and daily patrols. LEC deepened understanding how to do it, how to store the tools by explaining the management method at an actual plant.

C) Preparation and update of various manuals and maintenance materials

The LEC does not have their own manuals related to maintenance and management, such as work standards for overhaul of each equipment and checklists for daily inspection patrols. Since it was considered difficult for the LEC to develop the system from scratch, drafts of work standards and daily inspection checklists were provided to the LEC as training materials, and the contents were explained in the classroom training. Since the pilot activities in this phase were limited to the explanation of the contents, in the implementation phase, it is necessary to update the materials according to the operation of the engine and to conduct training through actual operation.

D) Online classroom training for electrical facilities

Due to the impact of the nCOVID-19, the electrical expert of JICA could not travel to the site, so an online classroom training was conducted. Other JICA Experts also provided support at the site. JICA Experts tried the best, but it was difficult for the electrical experts to understand how the participants were doing from Japan, and it was difficult to answer the questions with illustrations. Direct training at the site is considered to be more effective in terms of confirming the understanding of the LEC side and providing detailed explanations using actual equipment and drawings. In the implementation phase, face-to-face classroom training is expected.

3-2-3 Practical Training

A) Implementation Planning

For a practical training, 4,000 hours maintenance was initially expected as a pilot activity, but the content was changed to 8,000 hours maintenance due to the postponement of travel due to the influence of the COVID-19. Since it was discovered that water had entered the combustion chamber of the engine before overhaul, it became necessary to change the plan repeatedly. Through discussions with the LEC, JICA Experts grasped the status of the engine and the auxiliaries, and after repeated discussions with the manufacturer's engineers regarding processes, etc., JICA Experts proposed the procurement of necessary additional parts and process changes. In this phase, the planning was mainly carried out by JICA Experts due to the limited preparation period, but in the implementation phase, the LEC side will be able to take the lead in formulating the plan. Further training for planning is required in the next step.

In addition, the procurement of spare parts and tools, as well as the costs of dispatching manufacturers' engineers, should have been borne by the LEC. In this phase, budget measures for maintenance costs such as the medium- to long-term maintenance plan have been explained to the LEC.

B) Schedule Management

In the 8,000 hours maintenance, discovered work was assumed before implementation of the overhaul, and two options for overhaul schedule were prepared in advance. As the construction proceeded, a number of uncovered trouble shooting actually occurred, and it became necessary to revise the process. The overhaul work was completed successfully with smooth schedule revising.

The period of the overhaul was planned with consideration given to ensuring sufficient time for training to LEC. For the next and subsequent overhauls, it is necessary to plan with ample time to spare in order to avoid being overwhelmed by the overhaul schedule and not being able to allocate time for training or making the work messy.

In terms of process management, the process chart attached in Attachment 2 was used to manage progress and share information with LEC and manufacturer engineers. JICA Experts and LEC held weekly progress management meetings with the LEC to share issues with the LEC personnel, including the power generation manager, leading to smooth implementation. In the implementation phase, the LEC side will be required to improve its process management ability as a system in which the LEC side will lead the planning the process management.

C) Responding to discovery work

As mentioned above, during the 8,000 hours maintenance, there were many uncovered works, and countermeasures were required each time. Regarding process changes, experts and manufacturers' engineers consulted with LEC, and LEC took the initiative in procuring necessary parts, with experts providing appropriate support. The overhaul work completed without delay.

In particular, when it became necessary to procure new parts due to cracks in the cylinder head, it was difficult to meet the construction schedule for marine transportation, and high transportation costs were incurred for air transportation. JICA Experts intervened with the Sierra Leone Electric Power Corporation (EGTC), since EGTC owns the same model engine, and EGTC was able to borrow the stock of the cylinder head. In addition, collaboration with EGTC, which had not been exchanged before, began from this opportunity. It is also planned to dispatch LEC engineers to the EGTC's 24,000 hours overhaul for training purposes from April 2023. Active exchanges between the LEC and EGTC are expected to promote technological improvements and strengthen cooperation between them, and contribute to the stable power supply in both countries.

D) Safety measures

During the maintenance period, the LEC stationed a safety manager from the safety management department to ensure that safety gears such as helmets, safety vests, and safety shoes were worn. In addition, a safety meeting (TBM: Tool Box Meeting) was held every morning to confirm possible hazards that could occur during the day's work and how to deal with them.

At the end of work, LEC cleaned the powerhouse every day, and removed oil from the floor in order to prevent fires and falls, and put tools back where they were.

When working at heights, the safety staff fitted the staff with harnesses. The head of the safety department made unannounced visits to the site on a regular basis to check the situation and conduct hearings. An alcohol check was also conducted unannounced. In this way, safety management was thorough.

The JICA experts explained the precautions to be taken when working with cranes, and urged safety by exemplifying accident case information. In the event of unforeseen work, JICA Experts ensured that the safety management of the work content was thoroughly confirmed by the relevant personnel prior to the start of the work, and thoroughly prevented accidents due to miscommunication and lack of understanding.

Regarding safety management, the LEC has a high level of awareness, and it is expected that work will be carried out under appropriate safety management through similar measures in the implementation phase.

Chapter 4 Results of detailed planning phase work and recommendations for technical cooperation projects

The results for Outputs 1 to 3 up to the detailed planning phase are shown below. Outputs 1 to 3 are the targets of the entire project.

4-1 Results and Recommendations of the Detailed Planning Phase for Output 1

Output 1: Engineers and Technical staff improve skills for regular O&M works of diesel generator.

A) **Generator system**

Related outcome is as follows;

- ✓ Acquisition of the basics through classroom training on the configuration of power generation equipment, the role of each component of equipment, the structure, etc.
- ✓ Improved understanding of the power generation system through overhaul work during 8,000 hours overhaul training

In the first classroom training session, lectures were given on the composition of power plant, the role of each piece of equipment, the structure, etc., and the LEC engineers in the maintenance and operation departments improved their understanding of each component of equipment and the generation system. In addition, they deepened their understanding of the structure through 8,000 hours of maintenance.

In particular, there is still some space for improving their understanding regarding the control system of power plant, and technical improvement is required in the implementation phase.

B) **Regular operation and maintenance**

Related outcome is as follows;

- ✓ Basic understanding of maintenance work
- ✓ Development of maintenance manuals and understanding of the necessity of operation management based on maintenance management standards
- ✓ Understanding the basics of daily inspection
- ✓ Basics of daily inspection check points and daily maintenance check points
- ✓ Understanding the purpose and method of engine performance tests
- ✓ Property analysis and maintenance of lubricating oil and fuel oil
- ✓ Confirmation of fuel switching conditions during HFO operation

In the 1st classroom training, a lecture was given on the basics of maintenance management, and in the 2nd classroom training, a training centered on daily maintenance was conducted, and the LEC side also understood the required level. Regarding the operation of checklists in routine maintenance, it is necessary to improve in the implementation phase.

As for the HFO operation, the operation was started before the project started, and no major problems were observed in terms of operation. However, there are issues such as not checking the fuel properties. Therefore, the continuous training is required in the implementation phase to improve operational skill.

4-2 Results and Recommendations of the Detailed Planning Phase for Output 2

Output 2: Enginerrs and technical staff acwuire know how and practical skills of trouble shooting of diesel generator.

A) **Trouble shooting of HFO operation**

Related output is as follows;

- ✓ Basic understanding of troubles during HFO operation through classroom training
- ✓ Understanding the structure and troubleshooting through regular maintenance of HFO purifiers

It was confirmed that one purifier for HFO was out of order before the overhaul and had not been repaired. It has been reported that troubles with purifiers occur frequently, and it is necessary to provide training on how to deal with troubles during the implementation phase as well as to improve skills through actual troubleshooting.

B) **Other trouble shooting**

Related output is as follows;

- ✓ Understanding major failure cases and countermeasures
- ✓ Analysis of past failures of JICA plant and understanding of countermeasures
- ✓ Understanding how to deal with major and minor failures
- ✓ Analyzing the troubles of Unit 2 through 8,000 hours overhaul, and understanding preventive measures

The biggest problem confirmed in this phase was water intrusion into the engine combustion chamber, The training related to analysis and necessary countermeasures was carried out during the overhaul. It is seems that this trouble could have been prevented if appropriate measures had been taken when the abnormal rise in exhaust gas temperature was detected, hence, continuous training is required in the implementation phase.

4-3 Results and Recommendations of the Detailed Planning Phase for Output 3

Output 3: Engineers and technical staff acquire knowledge and skills for preventive maintenance and methodologies for sustainable power supply

A) **Formulation of plans for preventive maintenance and regular maintenance**

Related output is as follows;

- ✓ Basic understanding of regular maintenance planning
- ✓ Understanding the necessity of formulating medium- and long-term maintenance plans

- ✓ Confirmation of the outline of the next 12,000 hours maintenance plan, budget measures, system, etc.

Since LEC does not have an existing regular maintenance plan, a lecture on the basics of planning was given in the pilot activity, and a draft maintenance plan was presented to prepare for future operation. It is required that the actual implementation of the plan is started in the implementation phase, and that the plan is properly formulated and managed.

JICA Experts also explained the necessity of developing a medium- to long-term maintenance plan, and obtained the understanding of the LEC. In the implementation phase, a medium- to long-term maintenance plan will be formulated, and improvements in budget measures are expected.

B) **Implementation of preventive maintenance and regular maintenance**

Related output is as follows;

- ✓ Understanding the purpose and necessity of work standards
- ✓ Understanding the overview of the periodic overhaul checklist and how to use it
- ✓ Understanding work items and procedures for 8,000 hours maintenance overhaul
- ✓ Acquisition of each work through 8,000 hours overhaul
- ✓ Confirmatino of the procedure and precautions for the next 12,000 hours overhaul
- ✓ Understanding the outline of the periodic overhaul inspection record and how to use it

8,000 hours maintenance was conducted as practical training. A certain level of success has been achieved in improving LEC staff skills through the training from manufacturer's SVs and JICA Experts. For the LEC, it was the first time for regular maintenance to be performed. It cannot be said that all the work was completely mastered in just this one time, but they deepened understanding of work procedures.

There are new work items for 16,000 hours, 24,000 hours, and 32,000 hours maintenance, and it will be necessary to improve technical skills related to maintenance in order to acquire advanced skills.

LEC does not have a work procedure manual for overhaul inspection, etc., so JICA Experts did a lecture in the pilot activity and presented a draft work procedure manual. In the implementation phase, it is necessary to update the manual and start using the manual in line with the operation of the LEC.

In addition, inventory management of parts and tools will be reviewed under the advice of experts in this phase, and further improvement in the implementation phase will be required.

4-4 Summary of experts' evaluation of LEC's understanding of detailed planning phase operations

Table 4-1 summarizes the expert's evaluation of the level of understanding of the LEC in the detailed planning phase work.

Table 4-1 Evaluation by JICA Experts of LEC understanding of detailed planning phase work

Item	Contents	Evaluation of technical level improvement
Daily operation	Daily inspection schedule and preparation of patrol record	A check sheet for daily inspections is being developed based on classroom training. Careful examination of inspection items is necessary based on the operation system and facility situation of the power plant.
	Troubleshooting for abnormal temperature and pressure based on the engine operation record	Less recognition of engine control values and operating limit values. It is necessary to provide technical support for equipment abnormality judgement and improvement of treatment capabilities, maintenance operation record. And raise awareness of equipment maintenance from a "preventive" maintenance perspective.
	Generator operation, System operation, Electrical accident treatment	The level of knowledge about electrical equipment is not enough, and it is difficult to deal with troubles. In particular, it is necessary to improve the understanding of protection equipment and system.
Diesel engine generator operation	Management of fuel, lubricating oil, and cooling water	Through the classroom training, a certain degree of understanding of the purpose and importance of property management has been gained. It is necessary to formulate clear management standards and management methods.
	Engine performance management	Daily engine performance management is important from the viewpoint of understanding the trouble signs, raising awareness of plant operating costs based on fuel consumption management. It is necessary to formulate specific management standards.
Daily maintenance	Preparation of Daily/Monthly/Yearly maintenance plan	Since there was no basic inspection plan and it was a post-maintenance after failure occurred, the classroom training deepened the understanding of the inspection schedule and the needs to formulate items. Further training is necessary to formulate a specific plan.
Periodical maintenance	Maintenance parts and spare parts management	The inventory work skill is improved through 8,000 hours maintenance. It is necessary to update the spare parts management ledgers prepared in the detailed planning phase, and to establish the work such as collecting records and assign personnel.
	Periodic maintenance plan, improvement of maintenance skill	In the classroom training, the planning, budget planning and spare parts procurement methods for periodic inspection was lectured. Building an organizational structure is required to improve governance, including LEC budgetary measures. For the current technical ability, LEC staffs can do such as the fuel injection valve inspection. Classroom training and practical training is required so that LEC can finalize the maintenance manual and get the skill for inspection of such as intake/exhaust valve and cylinder head.
	Improving regular maintenance capabilities for electrical equipment	Deepened understanding of basics of electrical equipment maintenance. About 10 years have passed since the installation of the electrical equipment, and there will be the necessity to replace to new ones. It is necessary to formulate equipment renewal standards and inspection procedures before the 12,000 hours inspection.

Based on the results of the evaluation, Table 4 2 shows the content that is required to be strengthened in the implementation phase, "basic skill establishment period" and "basic skill establishment and advanced skill acquisition period".

Table 4-2 Capacity building items in the implementation phase

Schedule	FY 2023	FY 2024	FY 2025
	Basic technic establish period		Technic establish and Advanced technics develop period
Daily Operation	✓ Preparation of daily inspection check sheet ✓ Preparation of Engine operation record ✓ Trouble shooting manual and technics improvement	✓ Improvement of generator and system protection technology ✓ Electrical accident handling training	✓ Finalization of daily inspection check sheet ✓ Finalization of the engine operation record ✓ Engine trouble shooting training
Engine Operation	✓ Preparation of fuel oil management standards ✓ Preparation of lubricant management standards ✓ Improving understanding of engine performance tests using actual equipment	✓ Development of engine management standards and performance test manuals	✓ Establishment and operation of water quality management standards and improvement of techniques for water quality measuring instruments ✓ Development of engine performance management standards and improvement of cost awareness
Daily maintenance	Daily inspection and maintenance work plan and extraction of items (including major auxiliary equipment)	Test operation of daily inspection and maintenance work plan and procedure manual (including major auxiliary equipment)	Finalization of daily inspection and maintenance work plan and procedure manual
Periodical maintenance	Preventive maintenance, engine, periodic maintenance of electrical equipment	Development of parts and spare parts management standards, plan adjustment by the manufacturer and LEC, maintenance plan, formulation of renewal standards	Technical improvement related to instrument calibration and protective device characteristic test, Finalization of regular maintenance standards, manuals and procedures.

Chapter 5 Next Activity Plan

5-1 Object and Contents

Overhaul maintenance will be carried out for 12,000 hours as a "basic skill establishment period" to review and establish the items implemented in the 8,000 hours maintenance. After that, 16,000 hours of overhaul maintenance will be carried out as a "basic skill establishment and advanced skill acquisition period", and in addition to the 8,000 hours of overhaul items, understanding of new major maintenance items will be deepened.

As a result of full-scale activities, although it is not possible to acquire all the skill related to overhaul maintenance, it is possible to plan and budget for overhaul maintenance appropriately, and LEC will get to be able to carry out overhaul maintenance on their own with the support of the manufacturer's SV. In addition, in terms of daily maintenance management, inspection checks, patrol checks, periodic parts replacement, etc. are properly implemented, and in case of trouble appropriate troubleshooting will be implemented, with the support of the manufacturer.

5-2 Implementation System

Follow the system established in the pilot activities described in 4-1-2.

5-3 Implementation Schedule

Although it depends on the operating hours of the power plant, in this study, the implementation schedule was formulated based on the assumption that the plant will operate for about 4,000 hours per year, while also referring to the interviews with LEC.

Table 5-1 Draft schedule of implementation stage

■Basic skills establishment stage	
Before 12,000 hours OH	(OH 2 months before) Inventory confirmation of spare parts and tools (OH 1 month before) Lecture
12,000 hours OH	(Starting in August 2023) 12,000hours OH implementation
After 12,000 hours OH	(2 months after OH) Lecture
■Technique establishment and advanced skill acquisition stage	
Before 16,000hoursOH	(OH 4 months before) Inventory check of spare parts and tools (OH 1 month before) Lecture
16,000hoursOH	(Starting in August 2024) 12,000hours OH implementation
After 16,000hoursOH	(3 months after OH) Lecture

5-4 Curriculum

Table5-2 shows the curriculum (draft) for the implementation stage of core activity.

Table 5-2 Curriculum of Core Activity

Stage	Implementation Period	Mechanical Equipment			Electrical Equipment		
		Subject of Instruction	Item	Achievement Goal	Subject of Instruction	Item	Achievement Goal
Basic skills establishment Stage	Before 12,000 hours OH (Classroom training)	Operation manager, Operator, maintenance manager, Foreman	Understanding the operation situation	Understanding Log Data Practice of Engine Performance Test	maintenance manager, Foreman, Engineer (electrical), operator	Basics of sequence circuits relay sequence logic sequence	Understanding various sequences
			Understanding the trouble situation	Creation of maintenance record sheet		Power plant sequence diagram MCC generator control	Understand basic control behavior
			12,000 hours OH Plan	Created based on the manufacturer's plan		Preparation of inspection sheet for heavy failure items	Read inspection points from the sequence diagram
			Necessary spare parts confirmation	Create necessary spare parts list		Necessary spare parts confirmation	Create necessary spare parts list
			Necessary spare parts purchase arrangement	Budget measures and ordering/receipt		Necessary spare parts purchase arrangement	Budget measures and ordering/receipt
			Necessary tools confirmation	Matching the actual item with the list		Confirmation of necessary tools	Matching the actual item with the list
			Work Organization Planning	Organization chart preparation		Work organization plan	Create a staffing table
	12,000 hours OH	Maintenance manager, Foreman, Engineer, Technician	Confirmation of OH implementation plan	Revision of OH plans	Foreman, Engineer (Electrical), operator	Operation check of heavy failure items	Understanding the sequence via practical work
			Confirmation of OH work item	Classroom materials, instruction manuals, etc.		Confirmation of OH work item	Classroom materials, instruction manuals, etc.
			Confirmation of work organization	Organization chart revision		Confirmation of work organization	Organization chart revision
			12,000 hours OH implementation	Acquisition of OH work skills		12,000 hours OH implementation	Acquisition of OH work skills

Stage	Implementation Period	Mechanical Equipment			Electrical Equipment		
		Subject of Instruction	Item	Achievement Goal	Subject of Instruction	Item	Achievement Goal
			Recording of OH work	Create OH implementation record		Recording of OH work	Create OH implementation record
			Spare parts delivery record	Spare parts inventory update		Spare parts delivery record	Spare parts inventory update
			Consumable tool record	Tool list update		Consumable tool record	Tool list update
	After 12,000 hours OH (Classroom training)	Operation manager, Operator	Daily inspection record	Daily, monthly, annual inspection schedule formulation and implementation Fill in the daily inspection record table Practice of Engine Performance Test	Operator	Confirmation of implementation status of daily inspection and cleaning	Update of inspection list Update of the work manual
			Daily maintenance work	Fill in the maintenance record sheet Updating work standards		Daily maintenance work	Fill in the maintenance record sheet Updating work standards
			Operation record	Log data recording and analysis		Trouble record	Fill in the maintenance record sheet
			Trouble record	Fill in the maintenance record sheet		16,000 hours OH plan	Understanding the key points of the 16,000 hours OH plan flow
			Medium- and long-term maintenance plan formulation 16,000 hours OH planning	Formulation of medium-term maintenance plan up to 32,000 hours OH, budgetary measures			

Stage	Implementation Period	Mechanical Equipment			Electrical Equipment		
		Subject of Instruction	**Item**	**Achievement Goal**	**Subject of Instruction**	**Item**	**Achievement Goal**
				Understanding the key points of the 16,000 hours OH plan flow			
Technique establishment and advanced skill acquisition Stage	Before 16,000 hours OH (Classroom training)	Operation manager, Operator, Maintenance manager	Understanding the operation situation	Understanding and analyzing log data Practice of Engine Performance Test	Maintenance manager, Foreman, Engineer (Electrical), Operator	Preparation of inspection sheet for light failure items	Create an inspection sheet
			Understanding the trouble situation	Update maintenance record sheet		Understanding the trouble situation	Update maintenance record sheet
			16,000 hours OH Plan	Prepared by LEC based on the manufacturer's plan		16,000 hours OH planning	Prepared by LEC based on the manufacturer's plan
			Necessary spare parts confirmation	Necessary Spare Parts List will be prepared by LEC		Necessary spare parts confirmation	Necessary Spare Parts List will be prepared by LEC
			Necessary spare parts purchase arrangement	Budget measures and ordering/receipt		Necessary spare parts purchase arrangement	Budget measures and ordering/receipt
			Necessary tools confirmation	Matching the actual item with the list		Necessary tools confirmation	Matching the actual item with the list
			Work Organization Planning	Organization chart preparation		Work Organization Planning	Organization chart preparation
	16,000 hours OH	Maintenance manager, Foreman, Engineer, Technician	Confirmation of OH implementation plan	Revision of OH plans	Foreman, Engineer (Electrical), Operator	Operation check for heavy and light failure items	Establishment of inspections based on inspection sheets
			Confirmation of OH work item	Classroom materials, instruction manuals, etc.		OH work content confirmation	Classroom materials, instruction manuals, etc.
			Confirmation of work organization	Organization chart revision		Confirmation of work organization	Organization chart revision
			16,000 hours OH implementation	Acquisition of OH work skills		16,000 hours OH implementation	Acquisition of OH work skills

Stage	Implementation Period	Mechanical Equipment			Electrical Equipment		
		Subject of Instruction	Item	Achievement Goal	Subject of Instruction	Item	Achievement Goal
			Recording of OH work	Create OH implementation record		Recording of OH work	Create OH implementation record
			Spare parts delivery record	Spare parts inventory update		Spare parts delivery record	Spare parts inventory update
			Consumable tool record	Tool list update		Consumable tool record	Tool list update
	After 16,000 hours OH (Classroom Training)	Operation manager, Operator	Daily inspection record	Daily, monthly, annual inspection schedule formulation and implementation Fill in the daily inspection record table Practice of Engine Performance Test	Operator	Daily inspection record	Proper implementation according to work procedures
			Daily maintenance work	Fill in the maintenance record sheet Updating work standards		Daily maintenance work	Fill in the maintenance record sheet Updating work standards
			Operation record	Log data recording and analysis		Trouble record	Fill in the maintenance record sheet
			Trouble record	Fill in the maintenance record sheet			
			Medium- and long-term maintenance plan formulation	Formulation of medium-term maintenance plan up to 32,000 hours OH, budgetary measures			

5-5 Formulation of medium- to long-term maintenance plan (draft)

The medium to long-term maintenance plan (draft) for the JICA power plant is shown below. The medium- to long-term maintenance plan will be finalized in consultation with the LEC in the full-scale phase.

5-5-1 Object and Contents

The LEC has not formulated a medium- to long-term maintenance plan for JICA's power plant, and is required to formulate a maintenance plan as soon as possible in order to secure a budget for medium- to long-term maintenance. Organize the necessary spare parts, tools, consumables, and SV dispatch costs by 32,000 hours, formulate a maintenance plan, and secure the necessary budget after examining budget leveling. Assuming that the plant will operate for 4,000 hours every year, 32,000 hours will be six years later.

Table 5-3 Overhaul Work Items

Inspection	B Inspection	D1 Inspection	D2 Inspection		D3 Inspection	E2 Inspection	
Intervals	4,000 hours	8,000 hours	16,000 hours		24,000 hours	32,000 hours	
Details	Exhaust valve inspection	Cylinder head open	Cylinder safety valve		Cylinder head open	Inspection of turning device	
	Air intake valve inspection	Starting valve inspection	Balance weight for Crank shaft		Starting valve inspection	Detailed inner inspection of various tanks	
	Fuel injection valve inspection	Main starting valve inspection	Cylinder liner jacket		Main starting valve inspection	Inspection of generator bearings	
	Crank shaft inspection	Turbocharger inspection	Damper for vibration		Turbocharger inspection	Cylinder safety valve	
	Oil purifier cleaning	Air cooler inspection	Oil mist detector		Air cooler inspection	Balance weight in crank shaft	
	Filters cleaning	Fuel injection valve	Temperature control valves, Heaters		Fuel injection valve	Cylinder liner jacket	
	Performance test	Pressure indicator valve	Exhaust gas duct, Manifold, Bottom part of stack		Pressure indicator valve	Damper for vibration	
		Crank shaft	Protective devices (Engine, Generator)		Crank shaft	Oil mist detector	
		Crank, Main metal	Inspection of generator (oil change, etc.)		Crank, Main metal	Temperature control valves, Heaters	
		Piston, Connecting rod	Fuel injection valve	Starting valve inspection	Piston, Connecting rod	Exhaust gas duct, Manifold, Bottom part of stack	
		Cylinder liner	Pressure indicator valve	Turbocharger inspection	Cylinder liner	Protective devices (Engine, Generator)	
		Governor, Link for governor	Crank shaft	Air cooler inspection	Governor, Link for governor	Inspection of generator (oil change, etc.)	
		Gear mechanism	Crank, Main metal	Exhaust valve inspection	Gear mechanism	Fuel injection valve	Starting valve inspection
		Cooling water pumps	Piston, Connecting rod	Air intake valve inspection	Cooling water pumps	Pressure indicator valve	Air intake valve inspection
		Water coolers	Cylinder liner	Fuel injection valve inspection	Water coolers	Crank shaft, Metal shaft	Turbocharger inspection
		Lube oil cooler	Governor, Link for governor	Crank shaft inspection	Lube oil cooler	Piston, Crank shaft, Liner	Air cooler inspection
		Exhaust valve inspection	Gear mechanism	Oil purifier cleaning	Exhaust valve inspection	Governor, Link for Governor	Exhaust valve inspection
		Air intake valve inspection	Cooling water pumps	Performance test	Air intake valve inspection	Gear mechanism	Air intake valve inspection
		Fuel injection valve inspection	Water coolers		Fuel injection valve inspection	Pumps, Coolers	Fuel injection valve inspection
		Crank shaft inspection	Lube oil cooler		Crank shaft inspection	Tanks, Lube oil change	Crank shaft inspection
		Oil purifier inspection/cleaning	Cylinder head open		Oil purifier inspection/cleaning	Economizer	Oil purifier inspection/cleaning
		Performance test			Performance test	Cylinder head open	Performance test

5-5-2 Schedule

Table5-4 shows the proposed schedule for formulating a medium- to long-term maintenance plan for the Bushrod Power Plant. Conduct surveys and preparations for formulating medium- to long-term maintenance plans in the detailed planning phase. At this stage, the parts and equipment required for maintenance up to 32,000 hours will be sorted out and the approximate cost will be confirmed.

In the full-scale phase, based on the operation status and plans of JICA's power plant, budget leveling, etc. will be examined, and the budget to be secured for each year will be clarified and reflected in the LEC's budget plan.

Table 5-4　Schedule and content of medium- to long-term maintenance plan formulation

Stage	Period	Target	Item	Achievement Goal
Survey and Preparation	2022/8～ 2023/2	Bushrod Power Plant MG	1. Confirmation of operation status and operation plan of power generation equipment 2. Based on the condition of the power generation equipment, organize the necessary needs by 32,000 hours · Spare parts · Tools · the expendables · SV dispatch	The condition of the power plant will be confirmed, and future maintenance and management policies will be organized. The costs required for maintenance are sorted out, and the LEC understands the costs that will be required in the future.
Maintenance plan Formulation	2023/6～ 2024/6	Bushrod Power Plant MG	1. Operational status of power plant and update of operation plans 2. Update information on equipment required for maintenance. 3. Streamline through budget leveling. Four. Reflection in the LEC budget	1. The condition of the power plant will be confirmed, and future maintenance and management policies will be organized. 2. The expenses necessary for maintenance are updated. 3. It is considered to be a reasonable plan by budget leveling. 4. LEC understands the necessary budget and reflects it in the budget plan.

5-5-3　Medium- and long-term maintenance plan (draft)

The midium-term maintenance plan (draft) is shown below based on the maintenance manuals of each equipment manufacturer and the experience of a technical cooperation project in Sierra Leone, where the same type of engine is maintained. As mentioned in 1-5-2, since the LEC is expected to operate for 4,000 hours every year, it is assumed that overhauls will be carried out during the rainy season every year. A long-term plan beyond 32,000 hours will be formulated in consultation with LEC in the full-scale phase, considering the operational status of the power plant.

Table 5-5　Medium- and long-term maintenance plan

		2023		2024		2025		2026		2027		2028	
		Engine operation hours (Estimation)											
		12000		16000		20000		24000		28000		32000	
Item	OH interval	Necessity	SV working period (number of SV)	Necessity	SV working period (number of SV)	Necessity	SV working period (number of SV)	Necessity	SV working period (number of SV)	Necessity	SV working period (number of SV)	Necessity	SV working period (number of SV)
Diesel Engine	4,000 hours	○(B2)	Approx. 60 days 2 persons	○(D2)	Approx. 80 days 2 persons	○(B3)	Approx. 60 days 2 persons	○(D3)	Approx. 120 days 3 persons	○(B4)	Approx. 80 days 2 persons	○(E1)	Approx. 120 days 3 persons
Generator	4,000 hours	○	Approx. 12 days 2 persons	○	Approx. 12 days 2 persons	○	Approx. 12 days 2 persons	○	Approx. 12 days 2 persons	○	Approx. 12 days 2 persons	○	Approx. 12 days 2 persons
Turbo charger	8,000 hours	-	-	○ Include balancing	Approx. 20 days 1 persons	-	-	○	Approx. 20 days 1 persons	-	-	○ Include balancing	Approx. 20 days 1 persons
Purifier	4,000 hours	○	Approx. 20 days 2 persons	○	Approx. 20 days 2 persons	○	Approx. 20 days 2 persons	○	Approx. 20 days 2 persons	○	Approx. 20 days 2 persons	○	Approx. 20 days 2 persons
Control panel・Switchgear	4,000 hours	○	Approx. 12 days 2 persons	○	Approx. 12 days 2 persons	○	Approx. 12 days 2 persons	○	Approx. 12 days 2 persons	○	Approx. 12 days 2 persons	○	Approx. 12 days 2 persons
Estimated OH duration		Approx. 60 days		Approx. 80 days		Approx. 60 days		Approx. 80 days		Approx. 80 days		Approx. 120 days	

5-5-4　Examination of budget optimization and leveling

One cycle of overhaul of the diesel engine is 32,000 hours, and overhaul every 8,000 hours is a large-scale maintenance, which increases the cost. In particular, 24,000hours and 32,000hours overhauls are expected to be costly due to the increase in items. Parts for up to 16,000 hours have been provided through grant aid, so it is expected that the cost of spare parts will be relatively low for the time being. Therefore, as shown in Figure5-1, an image diagram of budget leveling, JICA Experts propose leveling the annual maintenance and management budget for JICA power plant in preparation for the 24,000 hours and 32,000 hours scheduled for 2026 and 2028 respectively.

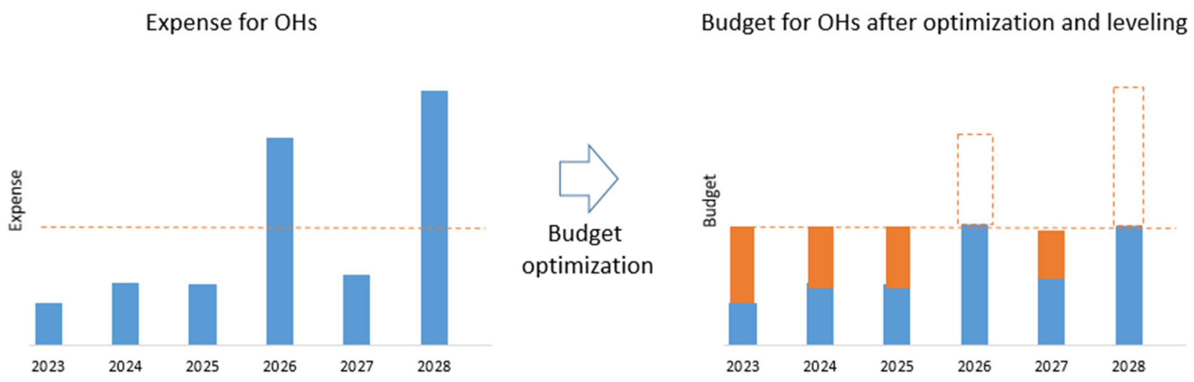


Figure 5-1 Image of budget leveling

The actual amount will be carefully examined in the full-scale phase, and after considering leveling, it will be reflected in the LEC's budget plan. There is also a case in Sierra Leone where it was necessary to procure spare parts worth more than 1 million USD for a 24,000hours overhaul for the same engine in Sierra Leone. Since the amount is expected to be large, the understanding of the LEC and early budget measures are essential.

Attachment

1. Development Plan for Power Sector Optimization Study for the Development of Power Generation in Liberia

REPORT

Optimization Study for the Development of Power Generation in Liberia

CLIENT
West African Power Pool (WAPP)

SUBJECT
Optimization Study Report

DATE: / REVISION: February 14, 2020 / 03
DOCUMENT CODE: 10207524-01-RIEn-RAP-004

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REPORT

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SUBJECT	Optimization Study Report	ACCESSIBILITY	Open
CLIENT	**West African Power Pool (WAPP)**	PROJECT MANAGER	Arne Koksæter
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03	14.02.2020	Final Report	Team	Ryan Anderson	Arne Koksæter
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01	20.09.2019	Draft Final Report	Team	Ryan Anderson	Arne Koksæter
00	11.07.2019	Optimization Study Report – first draft	Team	Ryan Anderson	Arne Koksæter
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EXECUTIVE SUMMARY

This report summarises the results and recommendations of a study to find the next hydropower generation project on the St. Paul and the Via Rivers following on from the commissioning of the Mt. Coffee Hydro Power Plant (MCHPP) in 2017. The overall objective of this Optimization Study is:

> *"To identify the Priority Investment Project (PIP) for power generation in Liberia including priority hydropower projects on the St. Paul and Via Rivers as well as production, storage, and transmission."*

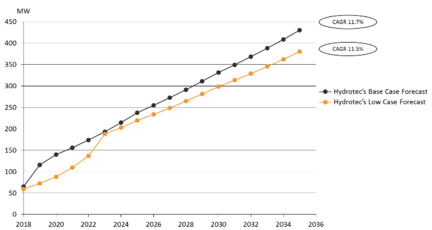
The study has taken into consideration; i) the importance of ensuring low-cost generation also to cover dry-season supply requirements, ii) the potential for cash-generating wet season export, iii) balancing energy security concerns with the benefits offered by regional trade through the nearly completed CLSG line, and iv) the critical importance of a short lead time for the delivery of the selected PIP.

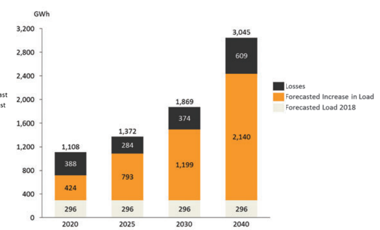
The study has systematically assessed the attractiveness of all identified sites along the entire St. Paul River basin, totalling up to 900MW in technical potential (including all possible extensions). The study has consolidated and built upon previous assessments of the river and specifically the Via reservoir. In determining the attractiveness of individual sites and recommending a build-out sequence for the river, the study has considered technical potential, total project costs, potential environmental and social impacts, supply requirements to meet future demand (including dry season) and overall system operations.

As opposed to previous assessments of the Via reservoir, the study recommends that the staged build out of the St. Paul River Basin starts with the most attractive downstream sites, with Via Reservoir coming in only once the most attractive sites are constructed. The study demonstrates that this provides both badly needed near-term capacity for Liberia and represents the least cost development path for the sector. Further, with significant uncertainties regarding developments in Liberia and the region, this strategy limits risk, as the Priority Investment Project is considered a "no-regret" investment. That is, the PIP provides low cost near-term capacity while providing a foundation for an economical build out for Via Reservoir. In addition to the most attractive sites on the St. Paul River, the PIP includes a fast-tracking of utility-scale solar. The prioritization of loss reductions and reliable power imports are pre-conditions for the successful implementation of the PIP.

The Challenge: Meeting rapidly growing demand in an affordable way

As illustrated below, assuming aggressive grid expansion and economic growth, it is anticipated that power demand will grow rapidly in the coming years – by more than 12% per year until 2040. In this regard, the Consultant has, in consultation with the client assumed, as the basis for the study, the Hydrotec's (2018) demand projections. This projection includes growth in consumption, development of losses, daily demand profiles, load factors, etc. A fundamental assumption is that all theft and system losses are reduced to a maximum 20% of energy demand by 2026 at the latest.





Towards a Long-Term Development Plan for Liberia

Based on anticipated costs of different supply options for the country (hydropower candidates, solar PV, thermal and import/export through CLSG of up to 108MW), a least cost long term development plan (LTDP) has been identified for Liberia, utilizing state-of-the-art optimization tools. The figure below illustrates the recommended investment sequence to meet rapidly growing demand until 2040. Some important observations to be had from the figure include:

- The anticipated tripling of demand until 2023/24 leaves Liberia with limited options in terms of meeting demand, especially in the dry season.
- From a least-cost perspective, imports in the dry season play a critical role in terms of meeting demand both in the short- and long-term.
- It is of utmost importance to begin detailed planning for the PIP so as to avoid substantial supply deficits from 2026 onwards.
- By focusing on the most attractive generation sites, planning for Via Reservoir can run in parallel and allow for sufficient time for construction and commissioning later in the planning period.

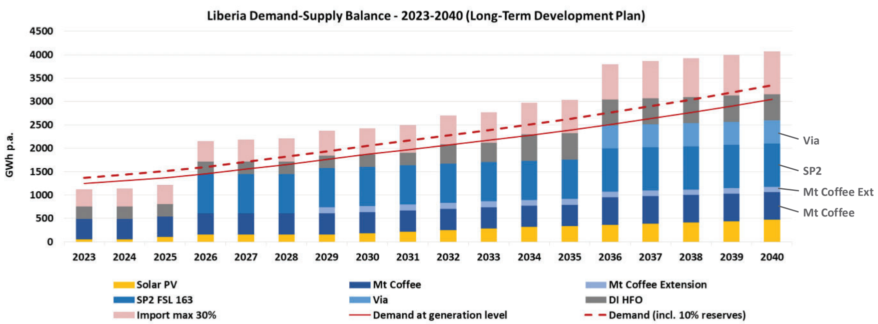


Figure 0-1 Long-Term Development Plan for Liberia (GWh)

The PIP – meeting medium-term supply requirements

As noted above, in the base case, the power demand is expected to grow rapidly in the coming years, and it is important that affordable power is made available in the near-term. As a result of the analysis, the selected PIP consists of the following individual investments and accompanying policy priorities:

1) An approximate 150MW MUSD 750 hydropower plant on the St. Paul River (SP2) providing valuable energy, including storage by 2026. Incorporate extra turbine bays into design thereby allowing rapid and cheap increase in generation once regional demand for export warrants the extra investment and /or the commercial model warrants development of the larger SP4 or Via reservoir. This is the proposed primary new development on the St. Paul River for immediate prioritization.

2) Up to 90MWp of total solar PV capacity at several sites also representing about MUSD 100 in investment. The capacity installation should start as soon as possible and be phased in over the period. An analysis of the capacity of the grid to absorb the intermittency of the solar PV power

should also be prioritized so as to determine the maximum responsible pace for this scale-up. A pilot project of 10-20 MW should be initiated as soon as possible.

3) A 44MW extension of Mt. Coffee (2 x extra intakes were incorporated into MCHPP construction). This is a very low cost source of power, but almost entirely for the wet season. This should thus be of high priority with a tentative in service date set at 2029.

Two highly prioritized policy measures are required for the successful development of the PIP:

a. **Loss and theft reductions are of utmost importance**. There is a clear requirement to build on the milestone passing of the power theft amendment. Attracting the level of responsible and manageable funding required for any large domestic generation project will remain difficult or impossible with the current levels of commercial losses standing at 60%.

b. **Firm up power trade options**. In the immediate-term, finalize PPAs with neighbouring countries and industrial off-takers in order to (i) secure dry season supply in the coming seven years and (ii) take the opportunity to sell surplus capacity from Mount Coffee in the short-term. In order to firm up long-term dry season supply at an affordable cost and ensure system flexibility, engage with WAPP partner countries preferably before Liberia is in a deficit situation.

Methodology – how these results were arrived at

The Consultant's team has utilized two modelling tools, which in combination have provided the Client with a highly insightful vehicle for understanding the optimal build out of the cascade model in light of the expected future development of the sector in the four CLSG countries.

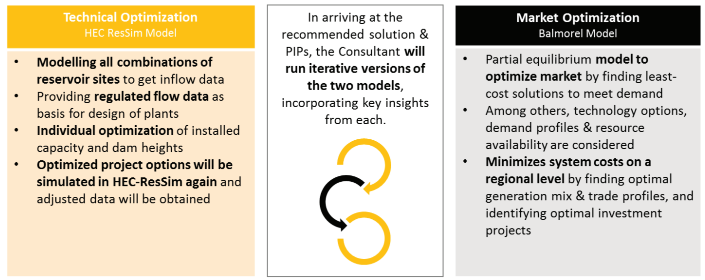


Figure 0-2 HEC-ResSim and Balmorel in successive stages

Optimisation of site locations and dam heights

As described in the following figure, a cascade of 6 different hydropower projects on the St Paul River were identified and their characteristics optimised using the LIDAR terrain map which covers the entire river length. As illustrated in the figure, the candidate sites essentially utilize the entire head of the available river basin.

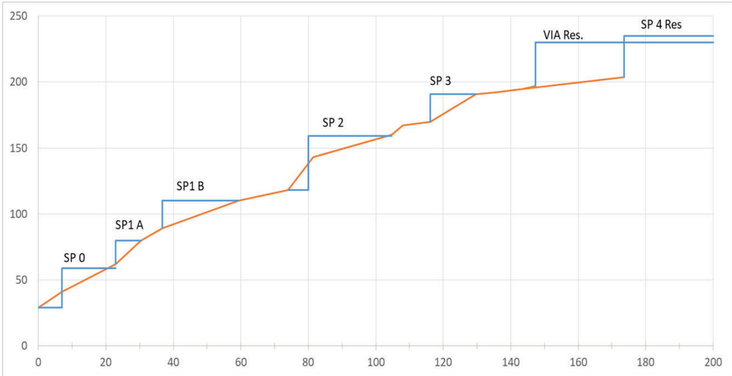


Figure 0-3 Full cascade of candidate hydropower projects along the St Paul River

All SP dams are provided with a reservoir large enough to enable synchronised daily peaking operation. Only Mt Coffee has a limited size of reservoir restricting its ability to provide peaking capacity to the power system. Some of the cascade dams can impound reservoirs large enough to provide varying degrees of regulation, and SP2 is one such dam. As highlighted in the report, a combination and synchronization of hydro and the immediate development of solar generation appears to be a highly attractive option for Liberia now and in the future.

Because of a high concentration of available head, combined with a more compact dam and attractive reservoir site, SP2 hydropower project is recommended as the main component of the priority investment project (PIP). Thus, as confirmed by the optimizations in the report, the selection of the SP2 option would be expected deliver the lowest system energy cost. The proposed FSL reservoir level for SP2 by the Consultant is 163, which provides a storage volume of 310 million m^3, enough to supplement the dry season flows and maintain continuous output of 40 MW throughout the dry season. Notably, given the lack of detailed data available for the study, the final optimization of particularly the full-supply-level will need to be more closely considered. Further, as described below, the recommended dam height would imply a required resettlement of 8 500 – 16 600 people.

The Via / SP4 reservoir seems to be better suited as a longer-term project for 15-20 years in the future. Specifically, it should be expected that these reservoir options will become more attractive once more attractive generation downstream sites on the cascade can benefit fully from them. SP2 hydropower site has also been optimized for development in two phases: initially 3 identical Kaplan units with an option to add two more when needed a few years later or when the Via / SP4 option becomes commercially viable. Alternative arrangements using Francis turbines could also be considered.

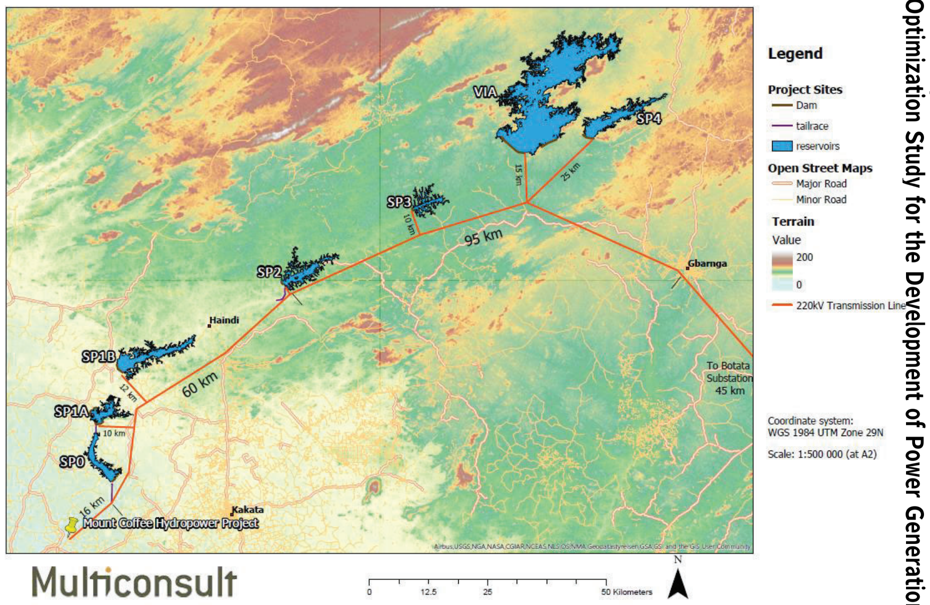


Figure 0-4 Map showing project locations and impounded areas

The map showing project locations and impounded areas is shown in Figure 0-4. To utilise as much as possible of the reservoir, a minimum operating level of 152 has been planned, meaning a maximum of 11 m drawdown during the dry season from January to April. Reservoir operation simulations show the reservoir to normally be drawn down to around 158 before the onset of the flood season begins to refill it, but during dry years the level may approach 152.

Environmental and Social Aspects

This Optimization Study has assessed the main environmental and social (E&S) risks and impacts identified for each of the candidate project sites, and this screening has been used to inform the optimization process. The present report is based on previous reports & field visit by Hydrotec and complementary fieldwork conducted in June/July 2019, which included a rapid biodiversity assessment of the Via Reservoir area, and consultations with the Environmental Protection Agency and other biodiversity stakeholders in Monrovia. It also expands the analysis of resettlement and social safeguards impacts at the PIP location (SP2 dam and reservoir site). Finally, it provides recommendations on environmental and social mitigation measures at each of the candidate hydropower sites, including SP2 and Via & SP4.

While the environmental risks and impacts are categorised as high for the Via reservoir, the impacts of the recommended PIP of SP2, at the FSL of 163, are mainly categorized in the low to medium range, and are expected to be possible to mitigate. However, the introduction of seasonal regulation with the larger reservoir size at FSL 163 does carry greater impacts on resettlement and land compensation and impacts on fish and prawn species despite mitigation in design of passages with environmental release flows. The figure below summarizes the implications of the different dam options for SP2.

Table 0-1 Total Estimated Social Safeguards Mitigation Costs for the Various Alternatives Evaluated for SP2.

SP2 Alternatives	No. of Directly Affected Villages	Est. No. of Structures	Est. No. of Houses	Est. No. of People	Estimated Cost for Direct Impacts	Estimated Cost Land Acquisition	No. of Indirectly Affected PAPs	Estimated Cost for Indirect Impacts	Estimated Cost Access Infrastructure	Total Social Safeguards Mitigation
157.5 FSL	9	300	225-270	1,125-1,620	3.5 - 5.0 MUSD	0.5 MUSD	267-320	0.6 – 0.7 MUSD	0.4 MUSD	4.9 – 6.5 MUSD
159 FSL w 1 m flood	11	350	263-315	1,313-1,890	4.1 – 5.9 MUSD	0.6 MUSD	594-713	1.2 – 1.5 MUSD	1.0 MUSD	6.9 – 8.9 MUSD
161 FSL w 1 m flood	17	1,350	1,013-1,215	5,063-7,290	15.7 – 22.6 MUSD	0.9 MUSD	723-868	1.5 – 1.8 MUSD	1.6 MUSD	19.7 – 26.9 MUSD
163 FSL w 1 m flood	20	1,575	1,181-1,418	5,906-8,505	18.3 – 26.4 MUSD	1.0 MUSD	723-868	1.5 – 1.8 MUSD	1.6 MUSD	22.4 – 30.8 MUSD
163 FSL w 2 m flood	53	3,025	2,269-2,723	11,344-16,335	35.2 – 50.6 MUSD	2.7 MUSD	1,446-1,735	3.0 – 3.6 MUSD	3.2 MUSD	44.1 – 60.1 MUSDs

All mitigation will require careful planning and budgeting and the budgets are only high-level preliminary estimates. Recommendations for the next steps of PIP development, include a fish and fisheries monitoring program, an environmental flow study, establishment of sediment transport and water quality monitoring, and development of the terms of reference for the ESIA and RAP. Such studies are often on the critical path and should be initiated as soon as possible. Estimated environmental and social mitigation costs have been included in the investment cost for the individual hydropower projects in the analysis below.

Supply Options considered

The figure below summarizes the relative attractiveness of all generation options considered for the study – by means of the LCOEs. It is important to recognize that while the ranking of LCOEs is illustrative and informative, they do not necessarily correspond with a least cost operation of a power system that must meet daily demand in light of intermittent renewables. Accordingly, the primary basis for the recommended PIP and LTDP stem from the power system optimization in Balmorel as summarized in the section below.

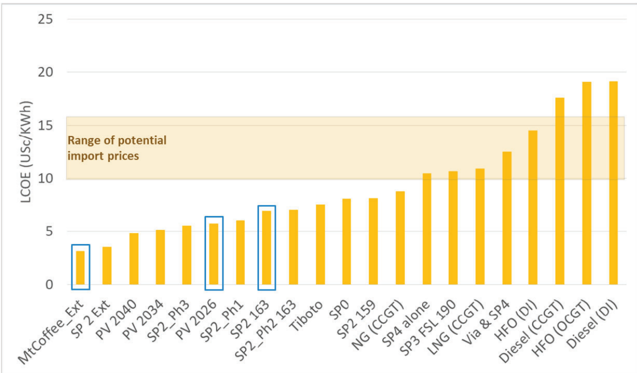


Figure 0-5 Ranking of LCOEs of individual candidate supply options considered in the study

Results of the power system expansion optimization (using the model Balmorel)

The optimization in Balmorel has confirmed the attractiveness of SP2, solar PV and the Mt. Coffee extension in the short- to medium-term, while highlighting the important roles for thermal, imports and eventually Via Reservoir in the long-term. Specifically, these daily generation profiles represent system operations following **an investment sequence which meets required demand at a minimum total system cost for Liberia** – and thus the required tariff for end-users. Accordingly, the results for 2026 provided key input for the determination of the PIP, and the results for 2034 and 2040 provided key inputs for the LTDP.

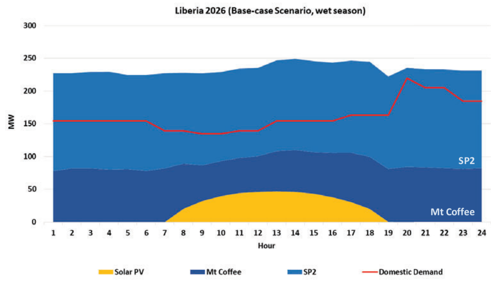


*Figure 0-6 Daily demand and supply profile during a typical day in the **wet** season in **2026 once SP2 and solar has been delivered***

Some relevant observations include:

- The daily generation mixes in the two figures demonstrate how hydro, solar and imports complement one another to meet demand profiles in the wet and dry seasons.
- In 2026, the least cost expansion plan for Liberia would imply a surplus in the wet season and sizeable deficit in the dry season, that the model determines is best served by imports. To the degree power trade is not available, this will likely motivate considerably more investment in HFO in Liberia to make up the difference in early years.

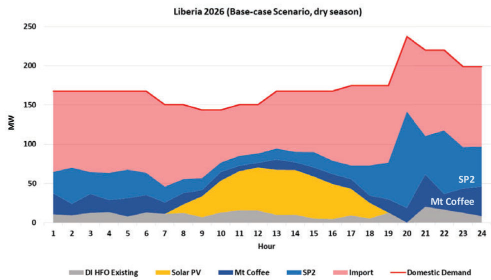


*Figure 0-7 Daily demand and supply profile during a typical day in the **dry** season in **2026***

- An investment sequence whereby Via is constructed prior to SP2 and/or Mt. Coffee extension is not economically viable and would thus put a heavy cost burden on the sector.

Development of System Costs

To the degree Liberia implements both the PIP and the LTDP, the country can expect to meet growing demand, enable access expansion and industrialization at a low cost. This should of course result in a cost of supply lower than today's level. While, the reduction of system losses will undoubtedly provide the most significant system cost reductions, so will the successful implementation of the proposed least cost developments. As illustrated by the figure below, successful implementation of the PIP (including bringing losses to an acceptable 20%), the system cost is estimated at USc 6.6 per kWh, rising slightly in long-term as more expensive projects are brought online. The figure also illustrates how a lack of availability of imports will both increase system costs considerably (about 30%) and make Liberia heavily reliant upon thermal generation in the near- to medium-term.

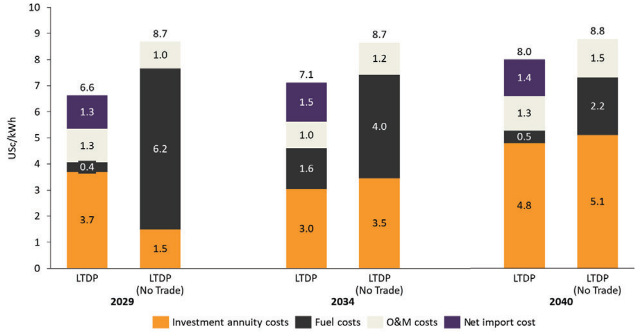


Figure 0-8 Development of total system costs (supply) for Liberia with successful implementation of the PIP and LTDP, with and without power trade on the CLSG interconnector

Risk management & resilience of proposed PIP & LTDP

It is important to recognize that this exercise has been carried out to determine the least cost expansion plan to meet demand until 2040, given best knowledge and prognosis at the time of the study. No doubt, there are considerable uncertainties as to the future and thus what the optimal choices are today. These uncertainties include: T&D build out and demand growth (currently an ambitious 12% per year), actual construction costs (currently estimated within +/- 30% range), actual E&S impacts and costs, construction timelines (currently little contingency planned for), availability of import and export, etc. In this regard, the team is of the view that the step-wise (several projects) and diversified (hydro, solar and trade) nature of the PIP is consistent with a strategy to manage risks and make required adjustments as circumstances change.

Recommended immediate priorities

1. First, Liberia has no time to waste in terms of initiating planning and implementation of the next generation projects. Even in well developed countries, such levels of investment planning and financial mobilization takes time. If Liberia is not able to plan for such investments in line with this LTDP sequence, the economic costs will be significant, either in the form of power shortages or expensive supply alternatives such as heavy reliance on imported HFO.
2. Second, given the clear attractiveness of the proposed PIP (SP2, solar PV and Mt. Coffee Extension), and Liberia's projected demand growth, these projects need to be fast-tracked. The short-term alternative to these projects would again be HFO production, increased imports, constrained demand and/or power shortages, or expensive emergency power solutions.
3. Third, for the medium- to long-term, effective planning in the sector should allow for an expansion path which underpins strong economic growth, industrialization and access expansion. But, again, effective and continuous planning is essential. This will require both fast-tracking the PIP while also, and in parallel, developing plans for future investments. In particular, given the likely future role for the Via Reservoir and the magnitude of the project, continued studies of the site should be considered.
4. Finally, the potential for solar is significant, especially if the cost of batteries continue to fall. Furthermore, and especially in the short term, solar PV's complementarity with daily hydro peaking makes it particularly attractive for Liberia. Stakeholders should start analysing more

closely the implications and limitations of the system's ability to absorb considerable amounts solar power and initiate a small pilot solar PV project as soon as possible.

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LIST OF ABBREVIATIONS AND ACRONYMS

CAGR	Compound Annual Growth Rate
CLSG	Côte d'Ivoire, Liberia, Sierra Leone, Guinea
CSG	Côte d'Ivoire, Sierra Leone, Guinea
DI	Diesel Unit
E&S	Environmental & Social
FSL	Full Supply (Water) Level
GJ	Gigajoule
GTG	Growing the National Grid
GW	Gigawatt
GWh	Gigawatt Hour
HEC	Hydrologic Engineering Center
HFO	Heavy Fuel Oil
HPP	Hydroelectric Power Plant
kV	Kilovolt
kWh	Kilowatt Hour
LCOE	Levelized Cost of Energy
LCDP	Least Cost Development Plan
LEC	Liberia Electricity Corporation
LNG	Liquefied Natural Gas
LTDP	Long Term Development Plan
MC	Marginal Costs
MCC	Millennium Challenge Corporation
MVA	Megavolt Amperel
MW	Megawatt
MWh	Megawatt Hour
N/A	Not Available
O&M	Operations & Maintenance
OMVG	Organisation pour la Mise en Valeur du fleuve Gambie
OMVS	Organisation pour la Mise en Valeur du fleuve Sénégal
PGP	Priority Generation Project
PIP	Priority Investment Project
PPA	Power Purchase Agreement
PV	Photovoltaic
RCC	Regional Control Center
SCADA	Supervisory Control and Data Acquisition
T&D	Transmission & Distribution
TA	Technical Assistance
ToR	Terms of Reference
USD	United States Dollar

1 Introduction and Background

1.1 Background and objectives of the assignment

The overall objective of the Optimization Study is to identify the Priority Investment Project (PIP) among the potential hydropower projects identified for development on the St. Paul River and including production, storage, and transmission.

The Optimization Study will identify a long-term generation development plan (LTDP) that will optimize the development of the St. Paul River cascade in the long run, with combinations of supply options including hydro candidates, thermal plants, batteries, solar energy and/or imports.

The assignment is split in the following tasks, and visualised in the figure below:

A) Market Review

B) Preliminary Assessment of Future Supply Options

C) Definition of Long Term Development Plan (LTDP) and the Priority Investment Project (PIP)

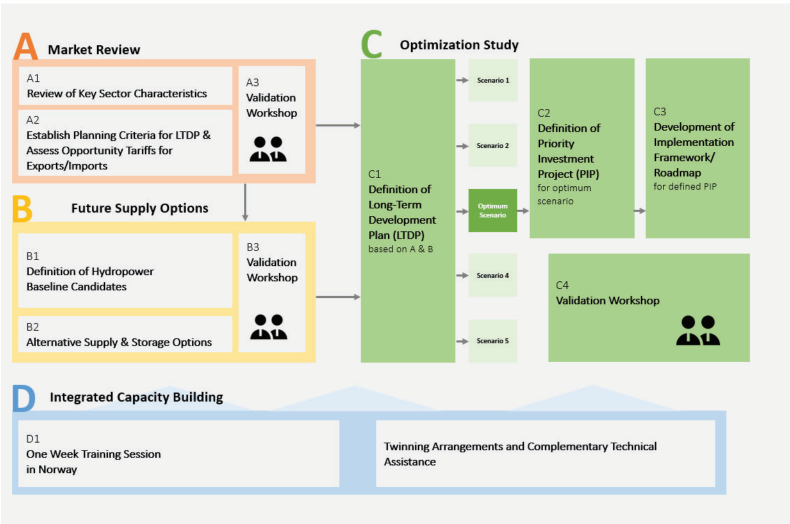

Figure 1-1 Overview of tasks and methodology

1.2 Purpose and scope of the Market Review Report (Task A)

This report is meant to provide the basis for the eventual optimization and recommendation as to the Priority Investment Projects. Accordingly, this report is the first step in building up the data, key inputs and assumptions that will be required in order to perform the modelling and analysis at both the cascade-level as well as the power-market level. Specifically, this report looks to provide a summary of, and recommendations to, the following issues:

1. Forecasted demand until 2040. This is the planning horizon determined by the ToR, and a central starting point is thus developing demand forecasts, for Liberia and the other three CLSG countries during this period. In the modelling exercise, the peak demand and daily demand profile for 2040 are central. Accordingly, this stage of the assignment has involved reviewing available data and demand forecasts and determining the most appropriate forecast to apply for this study.
2. Supply options. Which supply options Liberia and the other three countries (Sierra Leone, Cote d'Ivore, Guinea) have to meet this demand is the other primary consideration in considering the role of the St. Paul River in terms of meeting growing demand in a least cost fashion. Accordingly, this phase of the study has involved reviewing the various options available, with particular consideration of the status (e.g. existing, decided, candidate, etc.). Together with the demand forecast, this provides the team with the current and near term supply-demand balance.
3. Status of the Liberian Grid and Regional Integration. The current grid in Liberia consists of a few mini-grid systems while the main grid is a 66 kV grid between Mt Coffee and Monrovia (Bushrod and Paynesville). The main supply to the grid today is Mt Coffee and thermal plants in Bushrod, Monrovia. The grid is relatively new but has high losses, both technical and non-technical losses. There are several grid expansion plans, and the 225 kV CLSG interconnector being the most advanced and expected to connect the four countries within 2020. There is already in place a PPA on import to Liberia from Côte d'Ivoire since 2016.
4. Development of the Planning Criteria. In order to arrive at the potential role of the St. Paul River in terms of least-cost supply development, as well as the preferred technical, environmental and social solution (and timing), it is important that the Consultant and the Client agree on which key criteria will be explored and analysed in detail. Based on the review of documents, the current state, and priorities in the sector, and the nature of the modelling approaches to be utilized by the team, we have developed a proposed set of Planning Criteria to be applied in the subsequent analysis phases.

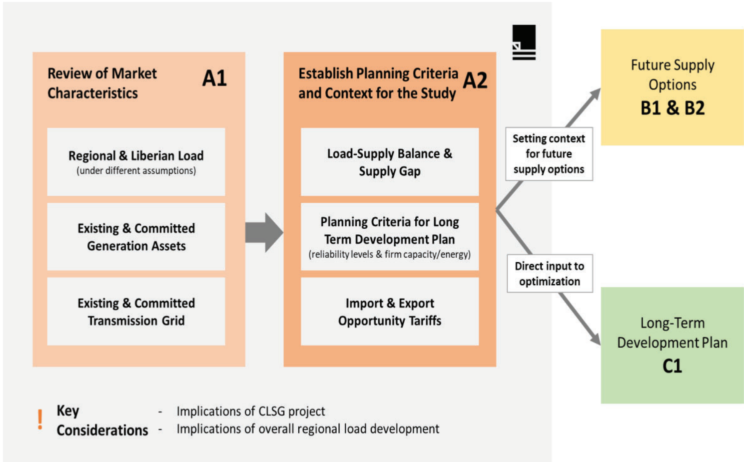

Figure 1-2 Methodological overview – Task A and interface with other tasks

As explained in the Consultant's proposal, the team has utilized two modelling tools, which in combination provide the Client with a highly insightful tool for understanding the optimal build out of the cascade in light of the expected future development of the sector in the four CLSG countries. This study has focused on the power sector of Liberia and the neighbouring countries (Côte d'Ivoire, Sierra Leone and Guinea) which are expected to have direct effect on the power system of Liberia. Trade outside the CLSG region is assumed to be constant over the studied period and subject to the sensitivity analysis. The team of technical and economic experts have developed these models, and carried out the analysis in an iterative and interactive manner, ensuring that the power market aspects inform the technical optimization, and vice versa. The very high-level summaries of the two models are presented here:

- HEC-ResSim. The St. Paul River cascade simulation study has been carried out with HEC Res-Sim software. The same model was used by Hydrotec (2018). The HEC-ResSim is the primary tool for reservoir system simulation used by the U.S. Army Corps of Engineers (USACE) Hydrologic Engineering Center (HEC). The HEC-ResSim model was updated to include the hydropower baseline candidates as defined in Task B. All combinations of reservoir sites and volumes have been modelled using inflow data for the different reservoirs and HPP options. These simulations provide the preliminary regulated flow data for the sites, which form the basis for the conceptual design of the power plants. Individual optimization of installed capacity and dam heights (reservoir volumes) based on initial cost data and energy/capacity value has been performed as a second step. Those preliminary optimised project options were again simulated in the HEC-ResSim model and adjustments made as part of this iteration process. It should be noted that the selection of hydropower baseline

candidates and the optimization of dam heights/reservoir volumes has been based on a range of sustainability criteria (i.e. environmental and social aspects).

- Balmorel. The Balmorel is a partial equilibrium model which provides a least cost solution for meeting demand by the end of the planning period. The model takes account of, among others, technology options and costs, daily and seasonal demand profiles, resource (e.g. solar, wind and hydro) availability and seasonality, inter-connectivity constraints, storage options, etc. Specifically, the model minimizes system cost of the regional power sector by i) finding optimal generation mix and trade profile for the CLSG countries, and ii) generating optimal investments in new production units to meet electricity demand. The Consultant has modelled the Liberian power system, including all realistic supply options for Liberia in the long term. Power systems of Côte d'Ivoire, Sierra Leone and Guinea have been modelled in a simplified way, only with dummy power plants, as described in Section 8 of this report.

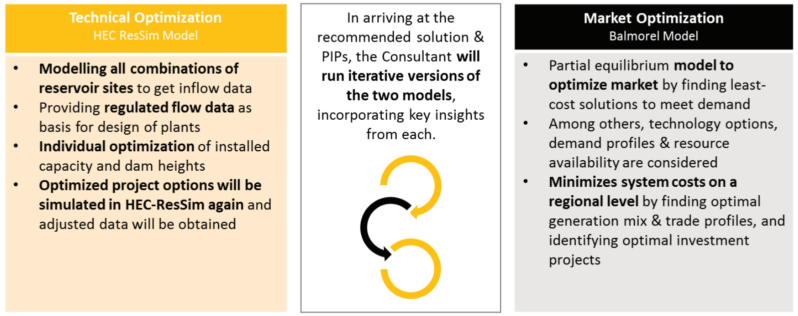

Figure 1-3 HEC-ResSim and Balmorel in successive stages

The figure above illustrates the optimisation process within the tasks and subtasks in Task B and Task C. The hydropower supply options are identified, screened and formulated to optimised sets of cascaded HPP in St. Paul River using HEC-ResSim. This selection process considers not only technical and economic criteria but also pays special attention to environmental and social impacts and costs. Other candidates from other technologies are also identified, which together with the sets of cascaded HPP run in the Balmorel optimisation model. The Balmorel model takes into account the import/export opportunities in its optimisation.

The environmental and social (E&S) risks for the various schemes have been identified based on existing documents combined with interpretation of satellite images and LiDAR data as well as field observations. The E&S screening has included both environmental issues (e.g. habitat loss, protected areas, threatened species, environmental flows, fish migrations/passage, etc.) and social issues (especially resettlement impacts and costs). These criteria have been designed to capture red flag issues as well as high-level cost estimates for mitigation/compensation. The E&S screening and costs have been included in the overall economic analysis and ranking of project candidates. The figure below describes the main activities comprising Tasks B and C, which have led to the identification of the PIP.

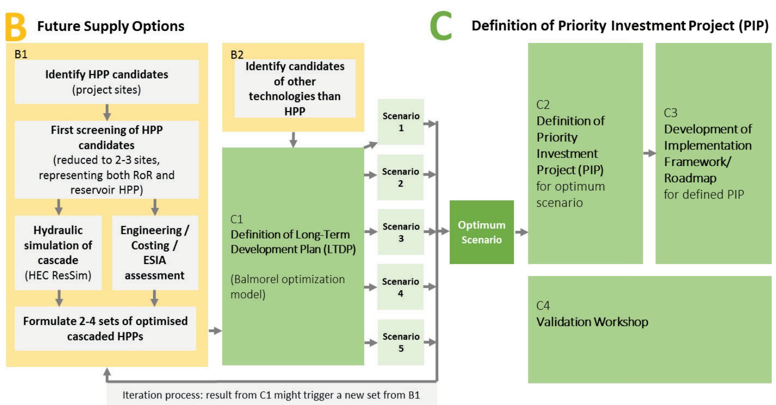

Figure 1-4 Float diagram showing the study activities

1.2.1 Overview of reports and data reviewed

In this initial stage of the Optimization Study, a comprehensive review of all files contained in the ShareFile, and relevant supporting documents was performed. For the purpose of the market review report, we have focused on a set of key documents that are relevant for the overall sector understanding, and important input for the establishment of planning criteria for the Long-Term Development Plan. An overview of key documents contained in the Sharefile is provided in the table below.

Table 1-1 List of key documents reviewed

Title	Author	Year
Commissioning Projection (September 2019 – May 2020) (Map)	TRANSCO CLSG	2019
Government of Liberia Least Cost Development Plan (LCDP) (Report)	Fichtner	August 2014
Generation, T&D Statistics for Jan 2018 (Presentation)	Liberia Electricity Corporation	February 2018

Title	Author	Year
Power Purchase and Sale Agreement between CI-ENERGIES and Liberia Electricity Corporation (Agreement)	CI-ENERGIES/ Liberia Electricity Corporation	October 2016
Presidents Delivery Unit (PDU) Energy Sector – Transmission & Distribution Priority Projects Update, Risk and Intervention Matrix (Presentation)	Presidents Delivery Unit (PDU)	February 2018
Rural Energy Strategy and Master Plan for Liberia until 2030 (Report)	Gesto Energy Consulting	April 2016
Technical Assistance for Optimizing Mount Coffee & Hydropower Production in Liberia (Report)	Hydrotec	August 2018
Technical Assistance for Optimizing Mount Coffee & Hydropower Production in Liberia – Demand Forecast (Report)	Hydrotec	August 2018
Tetratech LEC Overview (Presentation)	Tetratech	December 2017
Update of the ECOWAS revised master plan for the development of power generation and transmission of electrical energy (Report)	Tractebel	December 2018

1.2.2 Methodological note as to findings from Market Review

The Market Review comprised an interim report and had the primary purpose of providing the basis upon which the team would develop its analysis and modelling. Many of the issues presented in the report are highly complex, inter-related and ultimately uncertain. The fact that we are looking to provide guidance on "optimal" investments until 2040 means that there is a high degree of uncertainty. Further, as the team began to deploy the two central modelling tools of, HEC-ResSim and Balmorel, the team had to make adjustments and refinements compared to the early stages of the analysis, and these have been documented in later reports.

1.3 Purpose and scope of the Supply Options Report (Task B)

This report aimed to identify supply candidates to be further optimised in Task C, and lead to the Project Investment Project (PIP) and a Long-Term Development Plan (LTDP).

Three hydropower sites were identified in earlier studies and in the RfP to this study, namely: Via dam, reservoir and HPP including the SP4 transfer channel and dam, SP2 dam and HPP, and SP1B dam and HPP. The Task B study further assessed the hydropower potential of the St Paul River, including identification of additional candidate sites and optimization of the originally identified sites. The study also assessed project candidates from other technologies (e.g. solar).

1.4 Purpose and scope of the Optimization Study Report (Task C)

The objective of this report is to define the Priority Investment Project and the optimal long-term development plan for Liberia's power sector, building upon the Task A and B studies and based on power system optimization, reservoir simulations, economic analyses, and environmental and social risk criteria. The below sections provide detail on the individual tasks that have comprised development of the LTDP and definition of the PIP. In brief, these have included:

Development of the LTDP:

- Comparison of multiple combinations of supply options to meet the forecast demand, including hydropower development as well as other generation (e.g. thermal, solar, imports, etc.).
- Calculation of the levelized cost of energy for each option.
- Consideration of the regional context in order to assess the viability of each option.
- Sensitivity analysis for factors including the regional context, variability in rainfall and weather patterns, etc.

Definition of the PIP:

- Consideration of all factors given above as well as environmental and social risks to identify the PIP for the near term (2020-2025).
- Definition of all project aspects including roads, substations, and E&S mitigation measures.
- Recommendations for near-term studies that will facilitate a fast-tracked implementation of the PIP.

Development of a Road Map:

- The road map establishes the concrete steps that must be carried out to move forward on the development of the PIP.

Other, unforeseen analyses have also been carried out during the late stages of the Task C report, including deployment of a rapid biodiversity assessment in the area of the Via reservoir, and analysis of two additional hydro site options identified by the Panel of Experts.

1.5 Establishment of Planning Criteria for Long-Term Development Plan

The Consultant is required to make recommendations on an optimal/recommended build-out of the St. Paul River and a list of PIPs. This recommended build out provides conclusions as to sizes, locations, timing and costs. It is important to recognize that the recommended build-out will have implications as to the local environment and population, as well as the cost structure, operations and generation mix of the Liberian and regional power sector. Accordingly, in determining the recommended build-out, the least cost development sequence of all the various generation options which satisfy the expected future demand in Liberia has been the main consideration, but not the only one.

Environmental and social impacts of each alternative have been considered at all steps in the project planning process, and some of the considerations have included the following:

- Maximum reservoir size and resettlement needs. The limits to reservoir sizes are chosen to prevent major village resettlement where possible.
- Environmental flows. Where appropriate, environmental flow releases are introduced in the water balance modelling and tested by varying the release and seeing the effect on power production. This applies particularly for the flow below the diversion dam SP4 on the St Paul River.
- Land take by reservoirs and construction works is estimated and included in project costs with a shadow price for land of high alternative value (mainly by reservoir areas and new roads)
- The lowest reservoir in the cascade is planned as a re- regulating reservoir to reduce the impact of peaking operations on flow variability downstream.
- Sediment flushing facilities and reservoir operations all pay attention to the need to maintain sediment flows past the dam as much as possible.
- Fish passes will be incorporated and costed for both upstream and downstream migration of very important fish species, where the dam height is moderate and the passes can be expected to have a positive mitigating effect.
- Hydropower intakes are designed as high as possible under low reservoir operating level to avoid releasing anoxic water when reservoir stratification leads to such conditions.

Thus, in order to ensure a robust and transparent foundation for carrying out the analysis and arriving at key recommendations, the Consultant has developed seven Planning Criteria as given in the tables below. As described in the tables, the assessments associated with each criterion will require a mix of qualitative and quantitative approaches. Ultimately, the goal is to systematically consider the various costs and benefits of various options and thus ensure recommendations that encompass the broad range of implications from the eventual build-out.

The seven Planning Criteria take those presented in the ToR and our proposal to much higher degree of detail and specificity. Additionally, and importantly, they are formulated in a manner which have allowed the Consultant and the Client to discuss the various aspects of the options in a systematic manner.

1. Least cost options		
Purpose of Criteria	**Description**	**Methodology**
The natural starting point for determining the optimal overall build out of the St. Paul cascade and individual PIPs is the least cost solution which meets the future power demand.	The least cost solution primarily comprises of projects with the lowest cost per GWh generated over the lifespan of the investments. Additionally, considerations of both value of storage and environmental impacts and costs will be considered already under this criterion.	Based on existing data and inputs from the technical team (including site visits), the least cost option(s) will be determined by optimizing key parameters in each hydropower project utilizing the HEC ResSim model. The model will be built such that alternative values related to E&S impacts/costs, value of storage capacity and value of daily peaking can be adjusted based on outputs and load-supply analysis stemming from the Balmorel model of the generation and transmission system in the four CLSG countries.

2. Environmental and social consequences		
Purpose of Criteria	**Description**	**Methodology**
The least cost option will not be pursued at all costs. Specifically, the residual* non-quantifiable impacts and other benefits than from the power sector will be considered if any are found to be significant (e.g. flood control). E.g. cost of various environmental releases can be quantified and demonstrated by the models.	The location of construction works, the area impacted, their duration, etc. shall be assessed in terms of the local E&S impacts from the least cost option(s) described above. To the degree possible, the important impacts shall be quantitatively assessed and included as a project cost (or benefit).	The assessment of the residual negative/positive E&S impacts of various solutions will largely be based on existing data from the Hydrotec TA report combined with field observations and satellite images. E&S cost estimates will be obtained from Mt. Coffee HPP and other relevant projects. In light of this, our experts will consider the likely residual impacts and make recommendations that are likely to achieve a reasonable balance between power sector interests and other sector interests.**

** residual means after quantifiable mitigation costs have been included in the project costs*
*** It should be noted that the E&S screening may also identify red flag issues which can potentially make the projects non-bankable (irrespective of mitigation and costs).*

3. Value of seasonal storage capacity in Liberia and the region		
Purpose of Criteria	**Description**	**Methodology**
The build out of the St. Paul River is not only about achieving the least cost in terms of LCOE, but must take into consideration the role it will play in the Liberian, and regional, power systems. The optimal design should account for other values such as power system reliability, flexibility in operation etc.	This criterion particularly relates to the optimal size of the reservoir. In addition to assessing the cost (1) and E&S (2) implications of a larger reservoir, the optimal solution will also include the value of storage capacity to the power system. The total seasonal reservoir capacity will be a parameter optimized by several simulations of alternative reservoir sizes, and determining the average plant factor of each alternative. The plant factor of the entire cascade is good guide to how near optimum reservoir size we are, since it must not deviate far below the system load factor. It is important to appreciate that this value is separate to the "risk mitigation" value of reservoirs, which is dealt with in Criteria 5.	The value of storage capacity will be assessed by i. considering the overall generation mix and seasonal profiles of the 4 CLSG countries, and ii. analyzing the outputs of the Balmorel model such as system costs, levels of reservoir hydropower storage, an interplay between solar and reservoir hydropower, and levels of spinning and non-spinning reserves provided by reservoir hydropower. The seasonal generation profile for Liberia will be modelled in the HEC-ResSim model for alternative reservoir sizes in order to assess the costs and benefits of increased seasonal storage in a quantitative manner. For Sierra Leone and Guinea, a seasonal generation profile similar to Liberia's profile will be assumed. Hydropower in Côte d'Ivoire will not be considered in the optimization study, since this limited resource should be used for domestic power system development and stabilizing other WAPP transmission lines. Côte d'Ivoire gas turbines are more likely to produce electricity for export.

4. Value of daily peaking capacity in Liberia and the region		
Purpose of Criteria	**Description**	**Methodology**
Hydropower has the ability to rapidly ramp up and down power output capacity on an hourly basis to provide capacity during peak demand periods and/or compensate for loss of capacity, for example from variable renewables. Notably, as the percentage of variable renewables in the regional generation mix increases, so will the value of hydropower's flexibility will increase. Similarly to the flexible hydropower, natural gas turbines in Côte d'Ivoire also have the ability to rapidly ramp up and down power output capacity on an hourly basis and will be considered in the Balmorel model.	Firstly, the CLSG system will not be able to operate efficiently without some flexible hydropower in it. The larger the hydropower capacity with such capability, the larger the other renewable projects can be sized, making them more economic. This criterion implies that the costs of increasing installed capacity and daily storage capacity shall be weighed against the potential benefits to the CLSG system as a whole. The benefits will be determined from the daily demand profile, nature of the generation mix and the alternative sources for daily peaking capacity.	A key output of the Balmorel model is a projection as to the generation mix / typical daily dispatch of various technologies to meet the daily demand profile. This will provide at least a qualitative basis for assessing the potential value of daily peaking. To the degree the team assesses a high value to the CLSG system from daily peaking capacity, adjustments to the optimal solutions in Liberia will be considered. The marginal cost of daily storage seems to be small in all the proposed St. Paul projects. As a starting point, it will be assumed that all hydropower plants have at least 6 hours of daily storage and can therefore provide high flexibility in ramping up and down according to the hourly variability in demand and solar PV production.

5. Value of firm capacity and generation		
Purpose of Criteria	**Description**	**Methodology**
Generally, a higher value is assigned to firm capacity and annual energy generation than to the average values over time. Thus the definition of firm energy and capacity will be important planning criteria.	There are two alternative approaches to define firm energy in hydro dominated power systems: 1. Is to define a dry year of acceptably high return interval, and permit the system to have load shedding in some months of this dry year. 2. Is to set a percentage of unserved energy which consumers are expected to tolerate. We intend to use the former method initially since the second definition is very complex to model in a power	Our proposal is to define 98% of all months with reliable supply while 2% of months will experience some load shedding or rationing. This corresponds to the softer definition of the alternatives used by Hydrotec. In a 30 year series of variable hydrology, only 7 months in the one driest year will experience some rationing to avoid the reservoirs being overdrawn. This will be equivalent to only a few tenths of a percent of energy demand failing to be served. It will provide the team

	system with very few project options. The second figure is an output of the Balmorel model and not a constraint to be imposed in the model at the early stage of planning.	with the insights to both understand the vulnerability of the system as well as consider adjustments to the optimal solutions.

6. Risks associated with demand growth and regional integration risks		
Purpose of Criteria	**Description**	**Methodology**
The overall analysis and Criteria 1-5 all relate to a "base case" demand and policy development. However, one should preferably understand the implications of scenarios where sector developments differ (substantially) from this base case.	Demand growth and regional integration are key factors that will have impacts on the insights and recommendations that emerge from 1-5 above.	The team will carry out a sensitivity assessment, utilizing Balmorel, demonstrating the implications of demand growth and/or regional integration developing in a manner different than the base case. The conclusions of these risk sensitivity analyses should be of great interest to policy makers and sector planners.

7. Risks of "climate events" and value of diversification		
Purpose of Criteria	**Description**	**Methodology**
This criterion is related to (5) above, but deals more broadly and qualitatively with the issue of generation diversification. Generally, a diverse generation mix has an inherent value as it can be expected to mitigate also against "unforeseen" risks, such as the impacts of climate change on the region.	This criterion will incorporate considerations of how the build out of the St. Paul River will contribute to the overall system generation mix and vulnerability to e.g. regional droughts and/or high fossil fuel prices.	Based on the mapping as to current and future supply and the Balmorel Modeling, the team will look to do a semi-quantitative assessment of the climate risk associated with the various solutions on the St. Paul River to the system generation mix. New inflow series representing future climates will be tested in HEC-ResSim.

2 Demand and Supply Forecasts

2.1 Demand forecast

In order to perform the modelling and analysis, the team must utilize what it views and agrees upon with the client should be the forecasted supply requirements within the planning period. Specifically, this involves forecasting annual demand, peak demand, daily demand profile and approximate system losses. This, combined with an analysis of the supply options will then inform the potential role, the overall competitiveness of a build out of the St. Paul River as well as inform decisions on key design parameters of the build out.

For this assignment, it was not envisioned to carry out a separate demand forecasting exercise. Instead, the team was to critically review recent forecasts and on the basis of this review (including required adjustments) recommend a basis demand forecast to underpin the remainder of the analysis. This section summarizes findings of the team's review and concludes with the recommended forecasting approach and levels. Particular focus has been placed on Liberia in the forecasting. The team has also reviewed demand forecasts for the other CLSG countries, which are of the primary interest in terms of import/export opportunities for Liberia.

2.1.1 Liberia

The Consultant has reviewed the various documents and previous demand forecasts for Liberia. On the basis of this review, it was determined that the most recent electricity demand forecast prepared for Liberia is "Technical Assistance for Optimizing Mount Coffee & Hydropower Production in Liberia" by Hydrotec (August, 2018). Hydrotec (2018) forecasts electricity demand for various market segments from 2018 to 2035, as presented in the figures below. This forecast is chosen for the basis of the analysis, as i) it was very recently carried out, ii) built on a range of previous forecasts, and iii) involved considerable stakeholder consultations.

The figures below present the key results of Hydrotec's forecast in terms of customers and overall demand and consumption. In the remainder of this section we summarize the results of our detailed review of both the report and the Excel File. As presented below, our team would have a handful of concerns regarding some of the inputs as well as the results. However, as a bottom-up build-up of the demand forecast is not part of the scope of this assignment, and the Hydrotec forecast is so recent and involved stakeholder consultations, we have concluded that we should largely base the long-term forecast on their forecast.

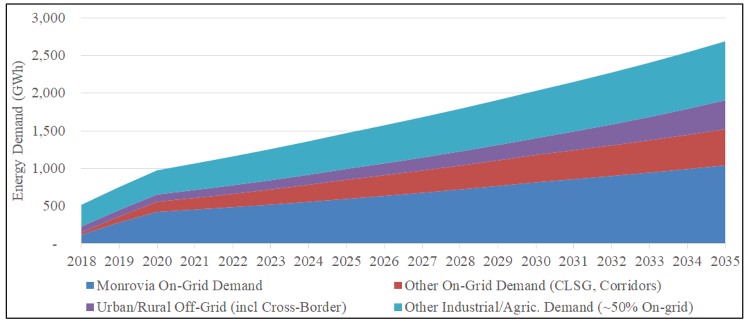

Figure 2-1 National customer energy demand forecast by market segment at consumer level (Base Case)

(Source: Hydrotec, 2018)

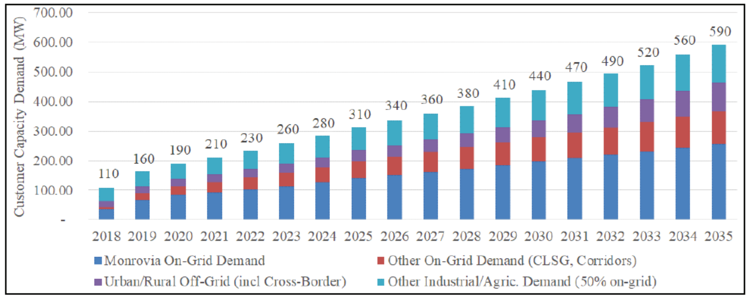

Figure 2-2 Nationwide customer peak demand capacity forecast at consumer level (Base Case)

(Source: Hydrotec, 2018)

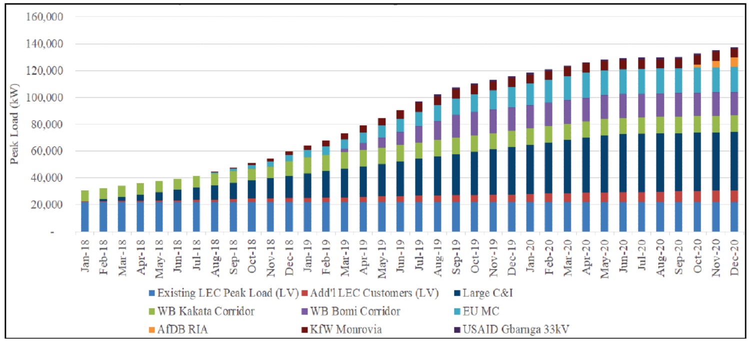

Figure 2-3 Monthly peak load growth with new on-grid customer connection schedule at consumer level (Base Case)
(Source: Hydrotec, 2018)

According to Liberia Electricity Corporation (LEC, February 2018), the peak supply in December 2017 was around 27 MW, including estimated on-grid losses as of 2017 of approximately 50%, 15% due to technical losses and 35% from unbilled energy (Tetratech, 2017). The Consultant notes that Hydrotec forecasts a dramatic increase in the electricity demand from 2018 to 2020 – a doubling. This dramatic increase is reportedly driven by the expectation of rapid grid and access expansion on the back of considerable funding from international partners. The Consultant is not fully up-to-date on the status of these on-going transmission and distribution priority projects, but our expectation is that an increase of supply requirements from an actual 29 MW in January 2018 (LEC, February 2018) to 175 MW in 2020, as projected by Hydrotec, is overly optimistic. Our assumption is that the forecast is highly optimistic for the near-term prognosis.

Despite concerns about Hydrotec's near-term forecasts, their long-term demand forecast in GWh may be achievable, even if also ambitious. Specifically, we have calculated that Hydrotec's on-grid demand projections have a 12% compound annual growth rate (CAGR[1]) between 2018 and 2035 (Figure 2-7). Again, we view this as highly ambitious but not entirely unrealistic. Accordingly, in an effort to consider a potential alternative growth path to the same level of demand in 2035, the Consultant has applied a constant growth rate of 12% over the same period. The result is the same level of demand in 2035, but much slower growth in early years. This type of growth would be more "typical", but would also imply that many supply investments would be delayed until later in the period. This 12% growth rate in each year would then lead to the same demand in the final year.

In addition to considering the overall realism of the demand forecast, we have carried out rather detailed review of the actual Excel model. While we have identified some apparent

[1] CAGR = $\left(\frac{End\ value}{Beginning\ value}\right)^{\frac{1}{n}} - 1$, where n denotes the number of years.

inconsistencies, they are likely relatively minor in terms of impacting the long-term demand projections.

In conclusion, although we think that the near-term projections of Hydrotec are overambitious, the long-term demand forecast in GWh (in 2035) appears acceptable. And given the level of detail and consultations underpinning Hydrotec's projections, the Consultant is inclined to apply them when progressing into the model. That is, it is the long-term demand projections that really matter in terms of modelling supply investment requirements. We would however propose to apply a low demand scenario as the sensitivity, as it can impact the timing of individual investments. During the Validation Workshop, the Client decided to use Hydrotec's Low Case Demand Forecast for the sensitivity analysis.

The investments are being considered for on-grid electricity supply, and thus only current off-grid demand that is assumed to be later connected to the grid is of relevance for this analysis. It is only the demand (including "suppressed demand") that is connected to the grid that will motivate investments in grid-connected utility-scale generation capacity, and is thus the only source of demand that should be considered when modelling grid-supply options. That is, the expansion of the grid takes time, considerable funding and human capacity. Until off-grid demand is able to be brought on-the-grid can it be considered in terms of determining supply requirements and optimal investment plans. In this regard, the Hydrotec forecast already incorporates ambitious grid expansion targets, and there is no purpose for considering additional off-grid demand.

The figures below present the findings of our review and key reflections around the Hydrotec forecast. We note that the figures account for Hydrotec's assumptions of on-grid losses. Specifically, Hydrotec assumes on-grid losses of 35% from 2018 to 2020, and steady decline in on-grid losses until 2026, from which point the losses are assumed to remain stable at 20%. Further, for Monrovia and other on-grid demand, Hydrotec (2018) assumes an average peak demand per connection of 0.342 kW. This assumption is derived by reducing an actual average peak demand per connection as of 2017 of 0.489 kW by 30% (an assumed percent reduction in on-grid losses from 2018-2020).

As the figure indicates, Hydrotec projected that the required capacity at generation level would increase 3x during the course of 2018. It was expected that this would be driven by new connections, electrification of large/industrial loads and increased losses. As already noted, our team is in doubt that this increase has materialized.

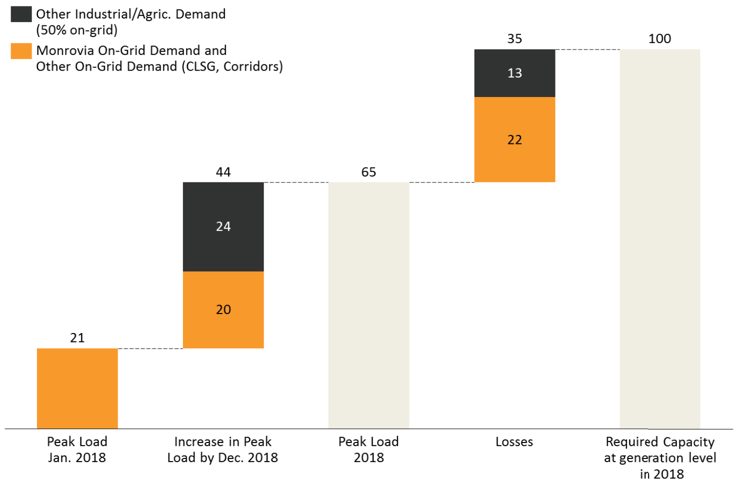

Figure 2-4 Build-up of required capacity at generation level in 2018 in MW – Very rapid growth over the course of one year is viewed as overly optimistic.

(Source: Hydrotec, 2018. Prepared by Multiconsult.)

Projected a highly ambitious growth in required capacity at generation level by 2020.

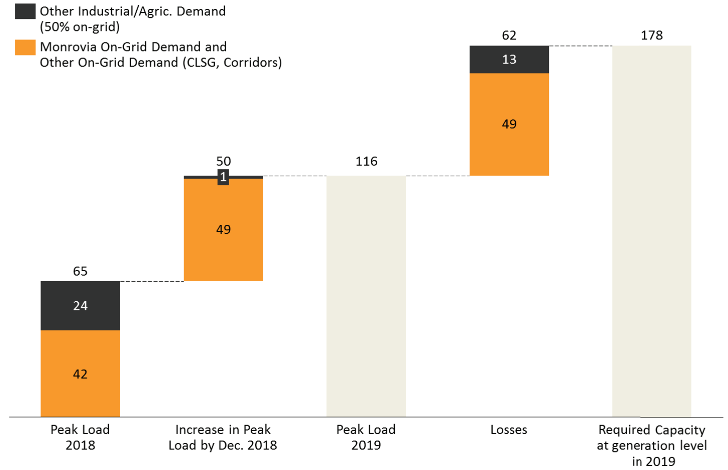

Figure 2-5 Build-up of required capacity at generation level in 2019 in MW

(Source: Hydrotec, 2018. Prepared by Multiconsult.)

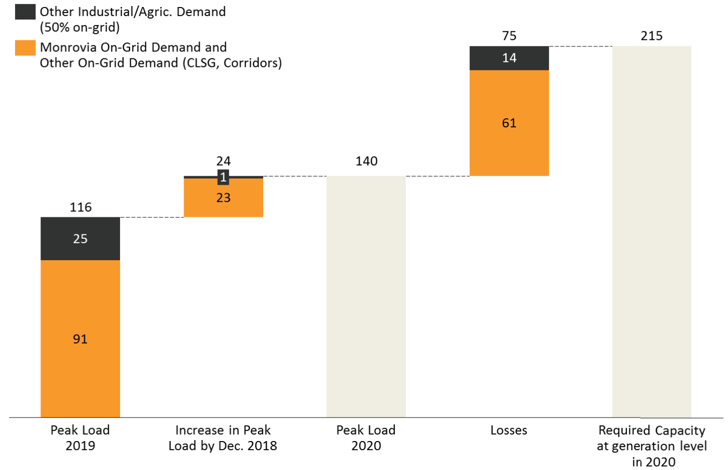

Figure 2-6 Build-up of required capacity at generation level in 2020 in MW

(Source: Hydrotec, 2018. Prepared by Multiconsult.)

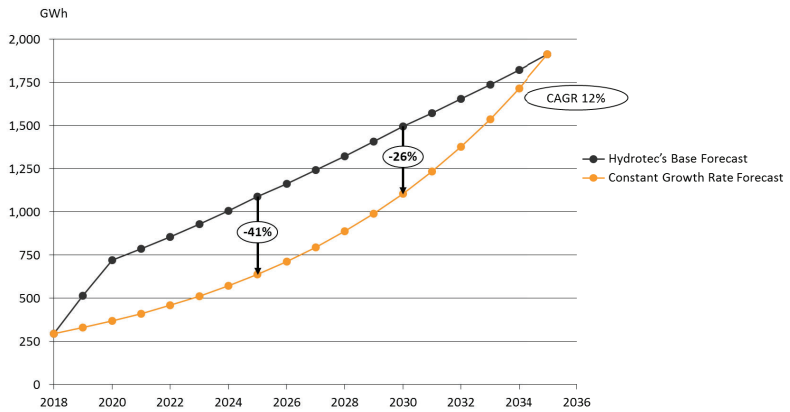

Figure 2-7 On-grid demand forecast at consumer level
(Source: Hydrotec, 2018. Prepared by Multiconsult.)

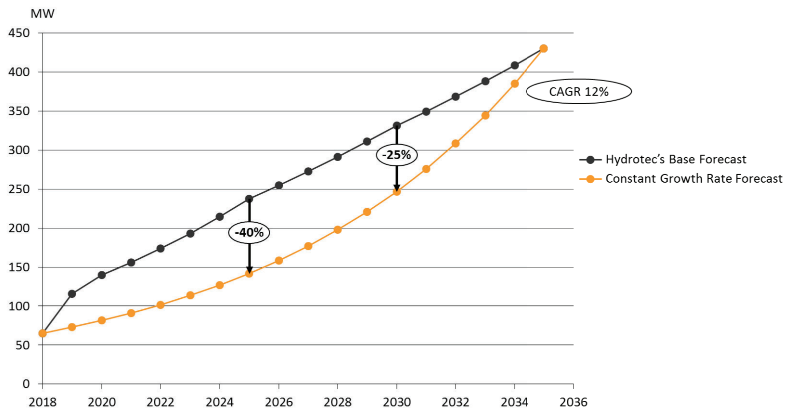

Figure 2-8 On-grid peak load requirement forecast at consumer level
(Source: Hydrotec, 2018. Prepared by Multiconsult.)

Base and Low Demand Forecasts (sensitivity analysis)

According to Hydrotec (2018), the Low Case Forecast assumes the near-term grid expansion plans take longer to complete than planned (finished by 2023) and customer acceptance of on-grid alternatives is slower than expected. Further, other industrial/agricultural growth rates are halved.

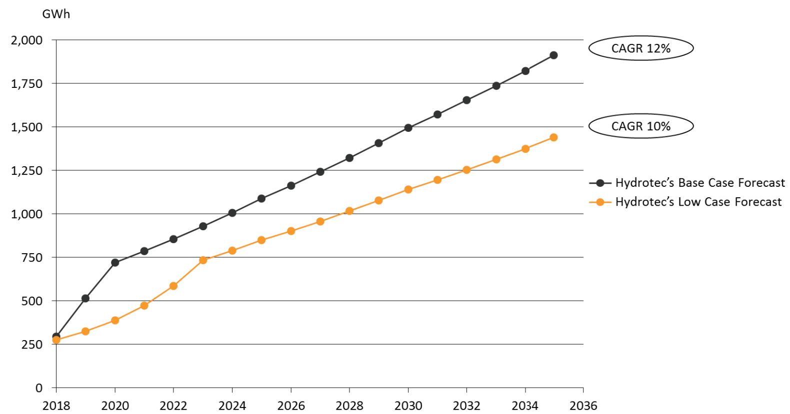

Figure 2-9 On-grid demand forecast at consumer level (Base and Low Cases)
(Source: Hydrotec, 2018. Prepared by Multiconsult.)

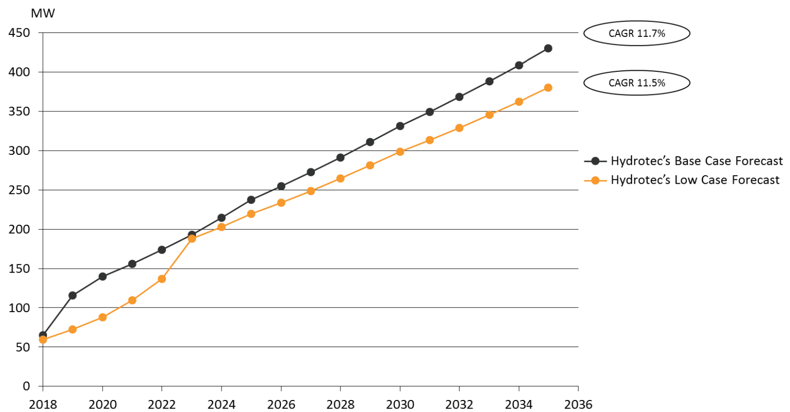

Figure 2-10 On-grid peak load requirement forecast at consumer level (Base and Low Cases)
(Source: Hydrotec, 2018. Prepared by Multiconsult.)

Load factor

The Consultant notes that Hydrotec's peak demand forecast seems to be unreasonably high relative to Hydrotec's energy demand forecast. The corresponding load factors at consumer level are low (see Figure 2-11). Specifically, in the long term, the load factor is converging towards approximately 0.5 in Hydrotec's Base Case Forecast and towards nearly 0.45 in Hydrotec's Low Case Forecast.

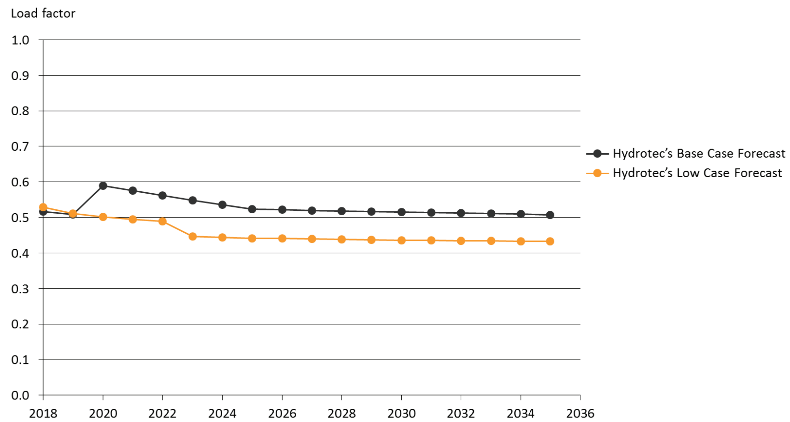

Figure 2-11 Load factor calculated based on Hydrotec's on-grid demand forecast at consumer level
(Source: Hydrotec, 2018. Prepared by Multiconsult.)

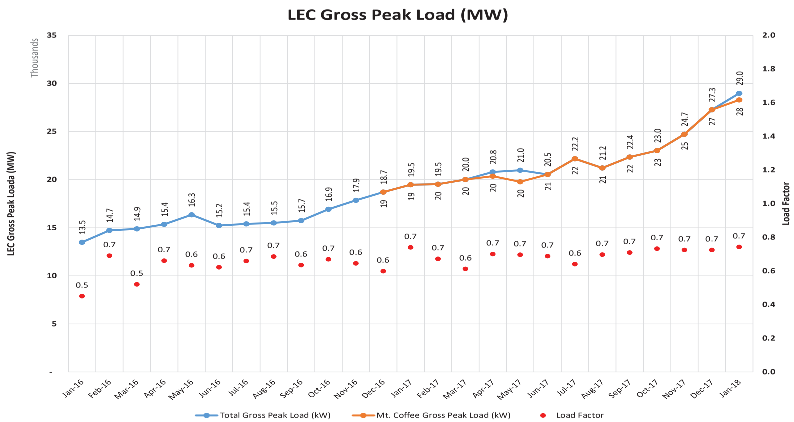

Figure 2-12 Historical monthly load factors for Liberia
(Source: LEC, February 2018)
Note: Historical monthly load factors for Liberia in 2017 were in the range of 0.7-0.75. Such high historical figures indicate that there was suppressed demand in the Liberian system.

In light of the above analysis, the Consultant proposed to drop Hydrotec's peak demand forecast, due to the low load factors. In order to determine the peak load for Liberia in 2029 and onwards – for the purpose of long-term planning – we proposed to apply a 0.7 load factor. Targeting a 0.7 load factor in the long term would allow LEC to utilize its infrastructure in a more efficient way than in a scenario with a considerably lower system load factor. The higher the load factor, the less capacity (generation and transmission) the utility has to invest in for supplying peak power. In practice, Liberia can achieve a 0.7 load factor through tariff policies and other demand side management measures.

This proposed load factor for Liberia is in line with the load factor applied for Côte d'Ivoire in the ECOWAS Master Plan. In particular, the Master Plan assumes that the load factor for Côte d'Ivoire will stabilize at 0.73 in the coming years, which corresponds to the average of the last 5 years.

Extrapolated Base Forecast

For the purpose of this study, Hydrotec's on-grid demand forecast in GWh is extrapolated until 2040. We follow Hydrotec's methodology and apply the 2035 growth rate of 5% to subsequent years, as presented in the figure below. Further, in the extrapolated years we apply the same percentage of on-grid losses (20%) as Hydrotec assumes in 2035.

The long-term peak load requirement forecast is presented in Appendix I. The peak load requirement forecast is calculated based on Hydrotec's demand forecast in GWh. A load factor of 0.7 is applied in 2029 and onwards.

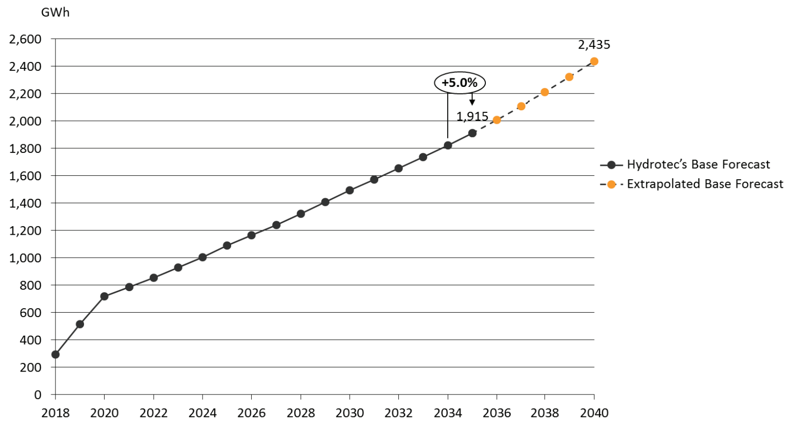

Figure 2-13 Extrapolated Base Forecast (on-grid demand at consumer level) (Source: Hydrotec, 2018. Prepared by Multiconsult.)

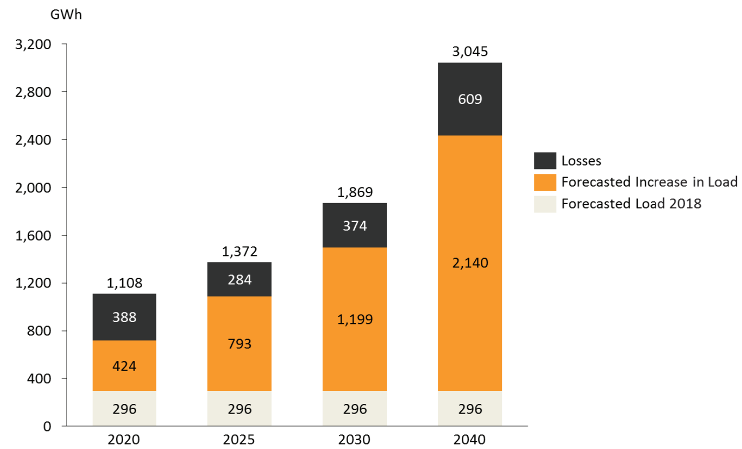

Figure 2-14 Extrapolated Base Forecast (on-grid demand at generation level) (Source: Hydrotec, 2018. Prepared by Multiconsult.)

Daily demand profile

Based on demand forecasts from the Daily Production Reports for Liberia, the Consultant analysed two weeks of data from both the dry and the wet seasons. Days from 25th of February to 10th of March, 2019 were used as proxies for the dry season, and days from 8th to 21st of July, 2018 were used as proxies for the wet season. As illustrated in Figure 2-15, there is a significant difference in the levels of the hourly demand between the dry season 2019 and the wet season 2018. However, this difference cannot be attributed to the seasonal changes in demand only, since there was also an increase in number of connections from July 2018 to March 2019. Further, the difference in the daily load shapes between weekdays and weekends is found to be insignificant and not relevant for the modelling exercise.

The Consultant also analysed daily demand profiles for Côte d'Ivoire as of 2015, presented by IRENA (2018)[2]. Specifically, daily demand profiles for three seasons, namely pre-summer (January-April), summer (May-August) and post-summer (September-December) were considered. As illustrated in Figure 2-16, the daily load shapes for Côte d'Ivoire resemble the dry season shapes for Liberia as of 2019. Further, there is a considerable difference in the levels of the hourly demand between the summer season and the pre- and post-summer seasons.

The load shapes for Liberia provided in Figure 2-15 are expected to change over time and therefore to be of less relevance for the long-term planning. For the Balmorel model, we proposed to assume that in the long term the daily load shapes for Liberia will be similar to the

[2] IRENA. (2018). Planning and prospects for renewable power: WEST AFRICA.

shapes for Côte d'Ivoire presented in Figure 2-16. In particular, the pre-summer daily shape can be used as a proxy for the dry season (from mid-December to mid-May), and the summer daily shape can be used as a proxy for the wet season in Liberia (from mid-May to mid-December).

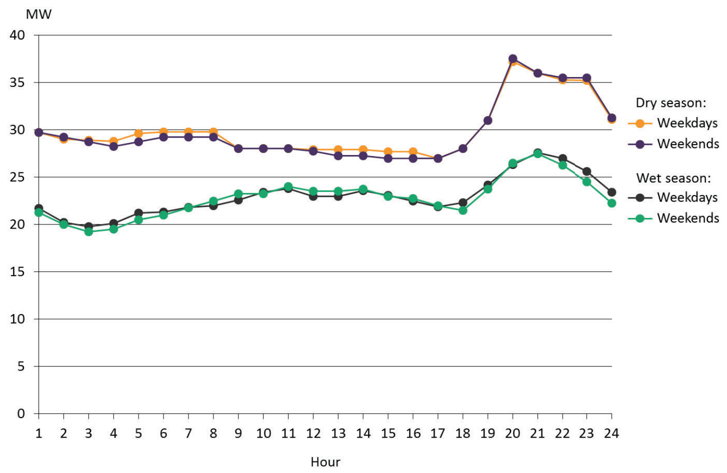

Figure 2-15 Daily demand profiles for Liberia in the dry and wet seasons
(Source: Based on demand forecasts from the Daily Production Reports. Prepared by Multiconsult.)

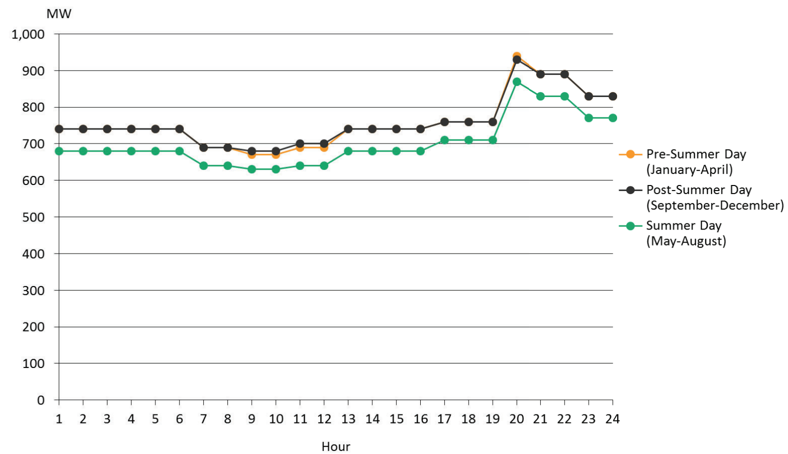

Figure 2-16 Côte d'Ivoire's demand modelled by IRENA, 2015. Côte d'Ivoire's load shapes are proposed to be applied for Liberia in the Balmorel model for the purpose of long-term planning.
(Source: Based on figures presented by IRENA (2018). Prepared by Multiconsult.)

The figures below are examples of current daily demand profiles for Liberia in the dry and wet seasons, respectively. The figures are retrieved from the Daily Production Reports. These are used as a basis for preparing Figure 2-15.

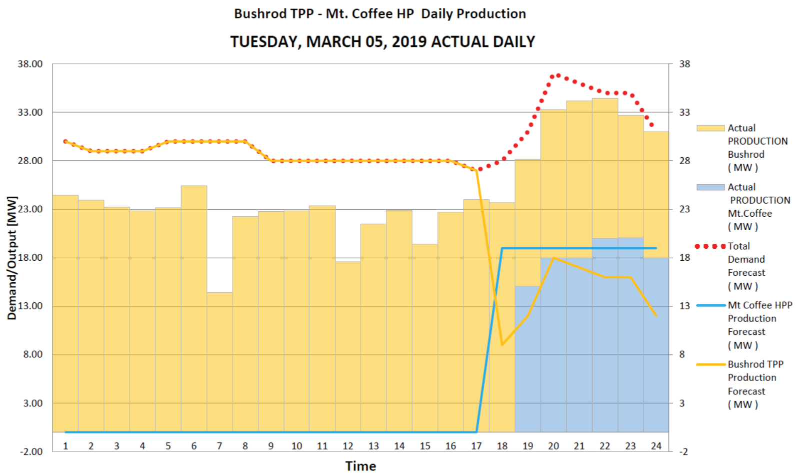

Figure 2-17 Daily demand profile dated Tuesday, March 5th, 2019 (dry season)

(Source: Daily Production Report for March 5th, 2019.)

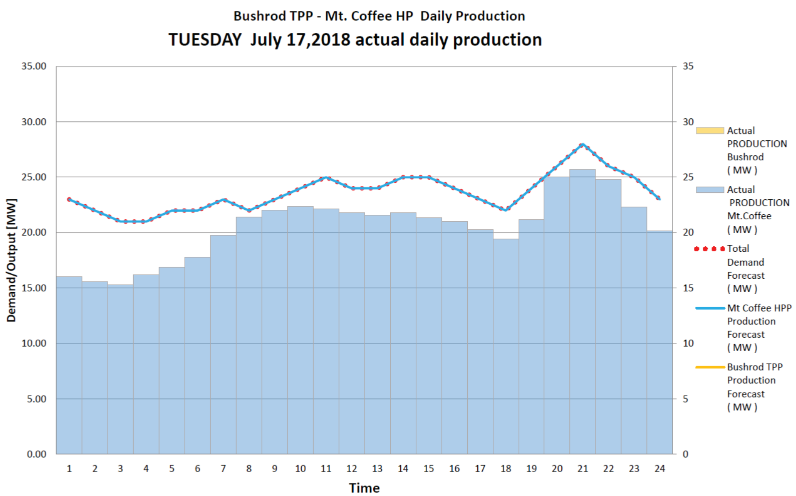

Figure 2-18 Daily demand profile dated Tuesday, July 17th, 2018 (wet season)

(Source: Daily Production Report for July 17th, 2018.)

2.1.2 Côte d'Ivoire, Sierra Leone and Guinea

Demand forecasts for Côte d'Ivoire, Sierra Leone and Guinea prepared by Tractebel for the ECOWAS Master Plan are chosen for the basis of the analysis and are presented in Figure 2-19. The Master Plan provides demand forecast of the countries' electricity consumption until 2033, including isolated consumers with own power generators who are likely to connect to the power grid once it is developed. The demand forecasts are at bus level (net of the transmission losses, but gross of the distribution and commercial losses). (Tractebel, Vol 2, 2018) Since these projections are not at generation level, the demand forecasts were adjusted by assuming transmission losses of 5% for the purpose of the load-supply analysis. Further, the demand forecasts were extrapolated until 2040 by applying the 2033 growth rates to subsequent years.

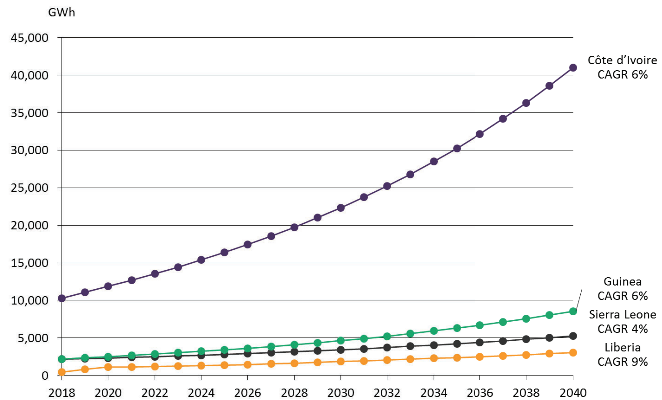

Figure 2-19 Demand forecast at generation level

(Sources: Tractebel, Vol 2, 2018; for Liberia – Hydrotec, 2018. Prepared by Multiconsult.)

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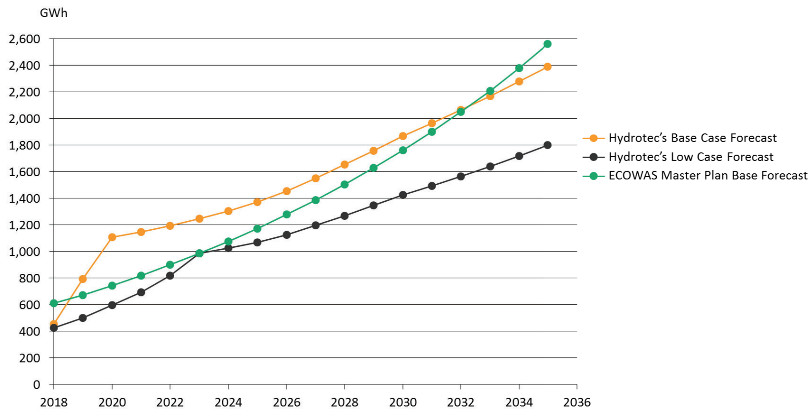


Figure 2-20 Comparison of Hydrotec's Base and Low Forecasts and ECOWAS Master Plan Base Forecast at generation level

(Sources: Hydrotec, 2018; Tractebel, Vol 2, 2018. Prepared by Multiconsult.)

2.2 Existing and decided generation assets

The ECOWAS Master Plan provides an overview of *existing* generation units and some of their characteristics such as technology type, capacity, and commissioning date and, for thermal power plants, fuel type. Further, the Master Plan identifies a project pipeline consisting of both *decided* and *candidate* Priority Generation Projects (PGPs) defined in the following way:

- *Decided units*: units whose construction is underway or has been decided for a specific date of commissioning (completed studies and secured financing);
- *Candidate units*: units for which the studies are not yet completed or for which funding has not yet been found. (Tractebel, Vol 2, 2018)

The power plant database presented by Tractebel (2018) forms the basis for the study of Côte d'Ivoire, Sierra Leone and Guinea. Specifically, the data was extracted from Annex B and Annex C of Volume 2 of the ECOWAS Master Plan. We note, however, that there are some inconsistencies in the data for power plants presented in different parts of the Master Plan. For that reason, it was assumed that the data for Priority Generation Projects from Volume 1 and Volume 5 of the ECOWAS Master Plan prevails over the data from Volume 2.

In this study, *decided* projects and their characteristics will be considered as fixed in our Balmorel cross-border power system model. The *candidate* units and their characteristics will be included in the Balmorel model as potential candidates for future supply that will be subject to optimization.

In this section, we limit our analysis to *existing* and *decided* generation assets.

2.2.1 *Liberia*

The current generation in Liberia includes 5 grid-connected power plants. Hydropower accounts for 62 percent of installed capacity (88 MW – Mount Coffee), 27 percent in heavy fuel oil (10 MW – World Bank HFO Plant, 18 MW – Government of Liberia HFO Plant, 10 MW – Japanese Int'l Cooperation Agency HFO Plant) and 11 percent in diesel fuel (9 MW – Bushrod HSD, assumed to be decommissioned in 2035). The first out of four hydropower units at Mt. Coffee was in operation from December 2016, and the last was commissioned in July 2017. During the dry season, which runs from mid-December to mid-May, there is insufficient river inflow to dispatch the full capacity. During the driest months, output has been reduced significantly, requiring thermal power augmentation. These generation assets are further detailed in Appendix I of this report.

An additional project is part of the *decided* Priority Generation Projects in the ECOWAS Master Plan, the 225 MW Tiboto Hydropower plant at the border of Liberia/Côte D'Ivoire. While the arrangements between Liberia and Côte D'Ivoire are yet to be negotiated, Tiboto is assumed to be shared 50/50% between the two countries in this study. According to Tractebel (Vol 5, 2018), the project is at the stage of studying, and a memorandum of understanding was signed with Eranove for the development of the project in 2014. The project is delayed due to the following factors: lower than forecasted demand growth, delays in the realization of the CLSG interconnector and distribution networks. This project would increase the total installed capacity to circa 254 MW, and raise the share of hydropower to approximately 80 percent. However, Multiconsult considers that the Tiboto project has not been committed at this stage. There appears to be no bilateral agreement, no license for construction in either Côte d'Ivoire or Liberia and no financing immediately available. We proposed to collect data on this project and include it in our list of alternative generation sources to be modelled.

Further, there is a 180 MW Mano hydropower plant identified as a *candidate* Priority Generation Project in the ECOWAS Master Plan. The project is situated on the border between Sierra Leone and Liberia and is expected to increase security of supply in both countries. However, the Mano project will not be considered in this study because the project development has stopped due to the current layout that inundates large national park areas.

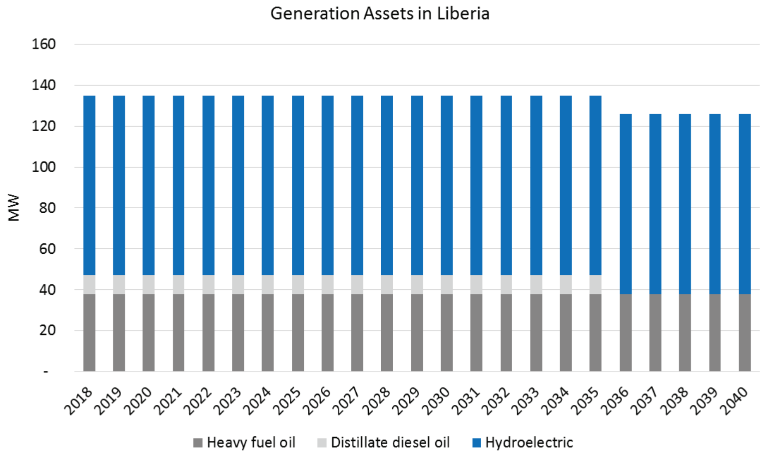


Figure 2-21 Existing and decided generation assets in Liberia
(Sources: Hydrotec, 2018; Tractebel, Vol 2, 2018. Prepared by Multiconsult.)

2.2.2 Côte d'Ivoire

Côte d'Ivoire has the highest installed capacity among the CLSG countries, with currently over 2,000 MW in installed capacity. The energy mix is comprised of natural gas and hydropower. Some natural gas plants are to be decommissioned in 2020; a range of committed hydropower, thermal and solar projects are identified in the *decided* Priority Generation Projects, and will increase the installed capacity by ca. 1,850 MW until 2029. Among these projects is a 700 MW coal plant that is expected to commission in 2028. The figure below illustrates the expected development of installed capacity in the country. As noted earlier, the 225 MW Tiboto Hydropower plant at the border of Liberia/Côte D'Ivoire is considered in this study as a non-committed project.

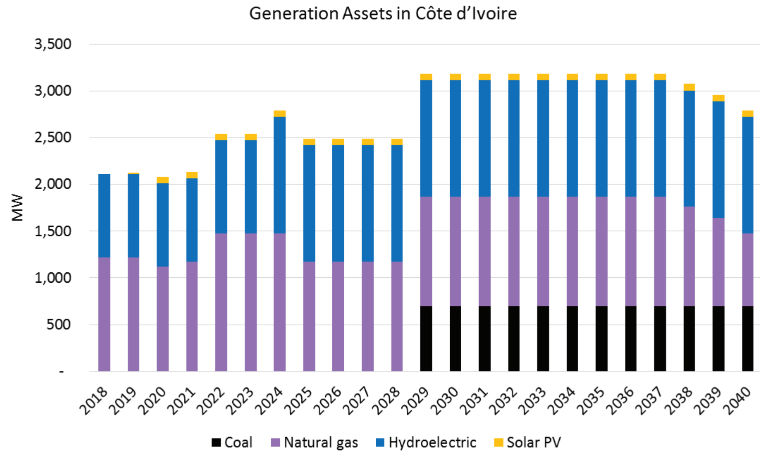


Figure 2-22 Existing and decided generation assets in Côte d'Ivoire
(Source: Tractebel, Vol 2, 2018. Prepared by Multiconsult.)

2.2.3 Sierra Leone

The profile of installed capacity of Sierra Leone is like Liberia, with a mix of thermal generation (diesel) and hydropower. Currently, the country has three hydropower plants with an installed capacity of 56 MW, and a diesel unit with 37 MW installed capacity. One additional project is included in the *decided* Priority Generation Projects by ECOWAS, a 143 MW hydropower project Bumbuna II – the second phase of the existing 45 MW Bumbuna dam. The project had been in discussion with the Government of Sierra Leone for multiple years, and signed a 25-year PPA with the Government in August 2017 (Tractebel, Vol 5, 2018), and selected an EPC contractor in early 2018[3]. Construction is expected to start by the end of 2019[3]. Additionally, there is a third phase of the Bumbuna project in discussion, with an installed capacity of 66 MW. However, this project is not included in the Priority Generation Projects identified in the ECOWAS Master Plan. Notably, the existing Bumbuna dam, despite its high design output, generates approximately 30-40 MW during the wet season and 10-18 MW during the dry season (Tractebel, Vol 5, 2018). The reasons for this include technical problems and insufficient water supply[4]. In March 2018, an additional 57 MW HFO project had a ground-breaking ceremony in Kissy Dock near Freetown. In December 2017, construction of a 6 MW solar plant in Freetown was launched.[5] These two projects were

[3] Electrifi. (2019). Electrifi commits US$3.5M of development funding for Bumbuna II hydroelectric power project in Sierra Leone. Retrieved from https://www.electrifi.eu/news/electrifi-commits-us3-5m-of-development-funding-for-bumbuna-ii-hydroelectric-power-project-in-sierra-leone/
[4] Power Technology. (n.d.). Bumbuna Hydroelectric Power Station, Tonkolili District, West Africa. Retrieved from https://www.power-technology.com/projects/bumbuna-station/
[5] Africa Energy. (2018). Sierra Leone: Ground-breaking at HFO project. Retrieved from https://www.africa-energy.com/live-data/article/sierra-leone-ground-breaking-hfo-project

included in the modelling as *decided* projects, even though they are not included in the Priority Generation Projects identified in the ECOWAS Master Plan. The development of generation capacity in Sierra Leone is illustrated in the figure below.

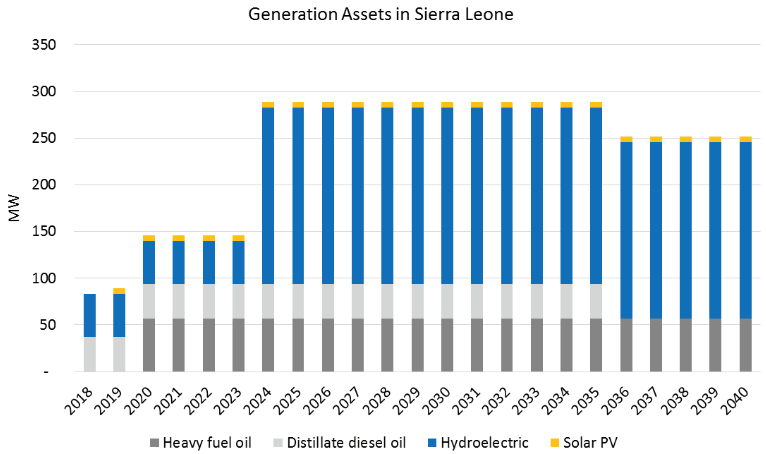


Figure 2-23 Existing and decided generation assets in Sierra Leone
(Source: Tractebel, Vol 2, 2018. Prepared by Multiconsult.)

2.2.4 *Guinea*

Guinea has approximately 590 MW in installed capacity, including multiple dams and 240 MW in run-of-river hydropower projects. Hydropower accounts for approximately 62 percent of the installed capacity in the country. The remaining capacity includes diesel- and heavy fuel-based generators. Additional hydropower projects are included in the *decided* Priority Generation Projects by ECOWAS: 450 MW hydropower is expected to commission in 2020, and further hydropower projects will increase the installed capacity in the country to circa 1,500 MW by 2025.

There are three transboundary PGP projects identified in Guinea, one from the Organisation pour la Mise en Valeur du fleuve Gambie (OMVG) at the border to Gambia, and two projects at the border to Sénégal from the Organisation pour la Mise en Valeur du fleuve Sénégal (OMVS). The projects have a total potential installed capacity of 134 MW and are to commission between 2022 and 2029. In this study, it is assumed that 25 percent of the projects count towards the installed capacity in Guinea, due to the transboundary nature of the projects.

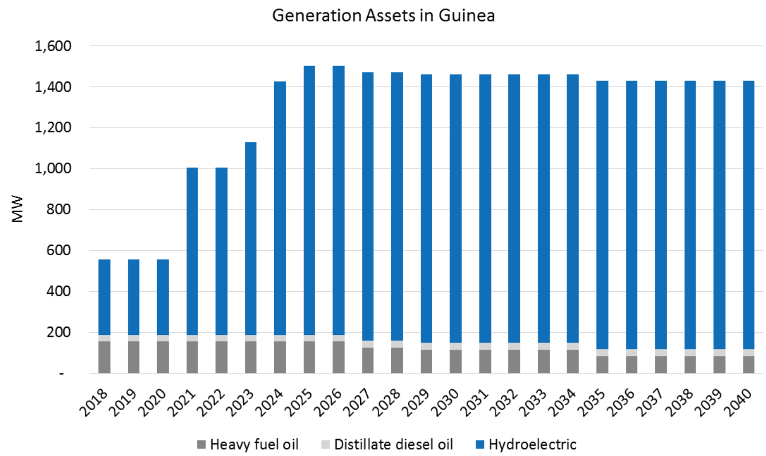


Figure 2-24 Existing and decided generation assets in Guinea
(Source: Tractebel, Vol 2, 2018. Prepared by Multiconsult.)

2.3 Load-supply balance review and gap identification

For Liberia, the following load-supply analysis is primarily based on the data from Hydrotec (2018). For Côte d'Ivoire, Sierra Leone and Guinea, the analysis is primarily based on the data from the ECOWAS Master Plan. The overview mainly includes power plants identified as the Priority Generation Projects in the Master Plan, which has to be considered when analysing the load-supply balances, particularly in later years. While only *decided* PGPs will be considered as fixed projects in the Optimization Study, the following load-supply analysis provides an overview of both *decided* and *candidate* projects.

The first figure for each country presents the load-supply balance (average energy) in GWh. The supply numbers for most of the hydropower plants are based on the project-specific data provided in the ECOWAS Master Plan. For the rest of the hydropower plants and all other generation units, a set of standard values estimated by Tractebel (2018) for *existing* power plants was applied in this load-supply analysis (Table 2-1).

Table 2-1 Key assumptions for load-supply balances

Unit Type	Combined Cycle	Gas Turbine	Steam Turbine	Diesel Unit	PV	HPP
Lifetime	25	25	35	30	25	100
Planned unavailability (h/year)	613	613	613	960		
Forced outage rate (%)	8%	8%	8%	10%		
Capacity Factor	-	-	-	-	12%-18%	49.2%
Yearly firm energy for hydro	-	-	-	-	-	76% * yearly energy average

(Source: Tractebel, Vol 2, 2018. Prepared by Multiconsult.)

For each country, two load-supply balance figures are presented. The first figure incorporates the supply of the country during an average hydrological year, which is seldom the case. Looking at firm energy in terms of the real capability of each hydropower plant is more interesting. In such a case the energy of the hydropower plant is greatly reduced, to what can be expected in a dry year. The second load-supply figure illustrates such a case (firm energy). In these graphs, firm energy numbers for most hydropower plants are based on the project-specific data provided in the ECOWAS Master Plan. For the rest of the hydropower units, it was assumed that 76% of yearly average energy is firm energy. This assumption is taken from the ECOWAS Master Plan by Tractebel (Vol 2, 2018).

Energy produced from thermal power plants is assumed to be the same in all load-supply figures for corresponding countries presented below. Further, since solar power plants can complement hydropower plants, in a dry year solar projects are assumed to contribute to saving water and providing firm energy. Therefore, in the load-supply figures, yearly average solar energy is presented as firm energy.

2.3.1 *Liberia*

Based on the demand projections for Liberia by Hydrotec (2018), a considerable supply gap is identified for the next ten years. All St. Paul River proposals and the Tiboto project were modelled under Task C to find the Priority Investment Sequence. At this stage of the study, prior to the start of the Task B analysis, these projects were not expected to be fully in operation before 2029, and the energy figures provided for each case in the Hydrotec report were used. Both average and firm energy figures were updated with our own simulated results under Task C. The diagram given below illustrates the balance methodology at the Task A stage.

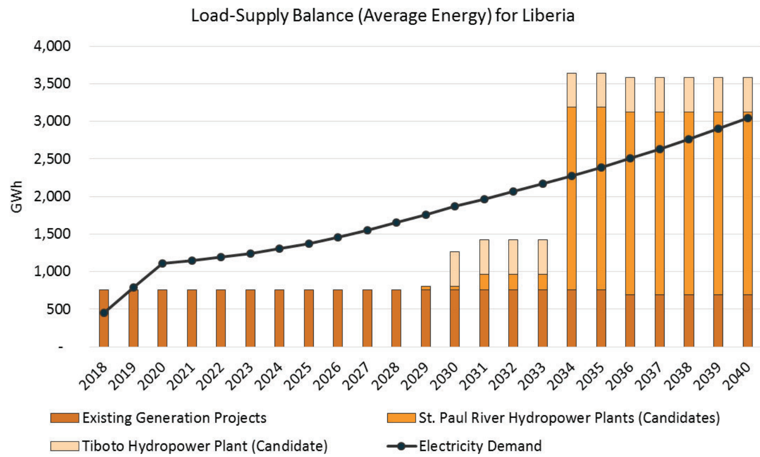


Figure 2-25 Load-supply balance (at generation level, average energy) for Liberia

(Sources: Hydrotec, 2018; Tractebel, Vol 2, 2018. Prepared by Multiconsult.)

Note: This diagram illustrates the balance methodology at the Task A stage. At this stage of the study, prior to the start of the Task B analysis, we assumed that 2029 was the first full year of commercial operation for the next hydropower project in Liberia. This included all St. Paul River proposals and the Tiboto project, all of which were modelled under Task C to find the Priority Investment Sequence. Both average and firm energy figures were updated with our own simulated results under Task C.

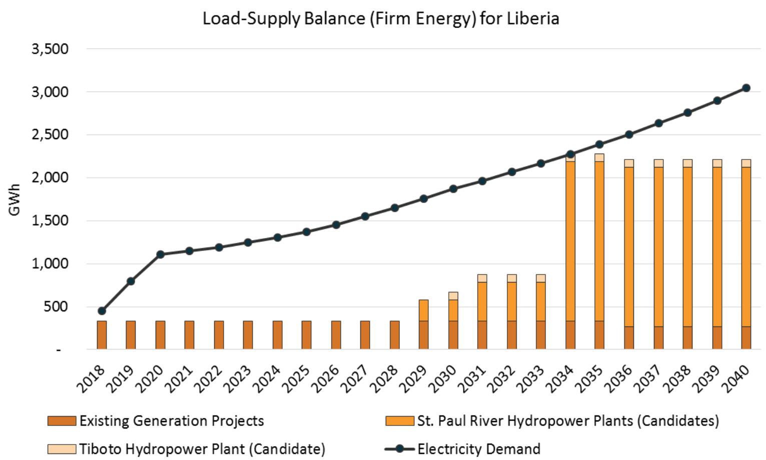


Figure 2-26 Load-supply balance (at generation level, firm energy) for Liberia
(Sources: Hydrotec, 2018; Tractebel, Vol 2, 2018. Prepared by Multiconsult.)

2.3.2 *Côte d'Ivoire*

The projections indicate that electricity supply will exceed demand in the near-term. The forecast signals that Côte d'Ivoire has potential to export excess supply to Liberia and other neighbouring countries. As Côte d'Ivoire is projected to have the strongest growth among the CLSG countries – almost quadrupling its demand in the next 20 years – the country will have a supply shortage starting around 2030 if no additional project would be commissioned. The analysis also shows a temporary supply gap between 2025 and 2029, which is also partly related to assumption that circa 400 MW in gas plants will be decommissioning in 2021/2024, after 25 years of operation. This gap is expected to be reduced by the commissioning of a 700 MW coal plant (*San Pedro Thermal*) in 2029.

The most efficient thermal power generation alternative for long term expansion of the CLSG network is probably gas fired plant based on single cycle or combined cycle technology in appropriate sizes and numbers feeding into the central transmission line. Gas supply may be limited by the domestic gas resources in Côte d'Ivoire but can be supplemented by LNG imports at a suitable harbour which can be upgraded for LNG ship docking and storage. Our cost analysis shows this to be reasonable based on world market costs of gas fired combined cycle plant and bulk LNG delivered at port and the investment cost of facilities needed to provide thermal energy in large quantities in the long term. This option will be available as one supply alternative in the Balmorel model.

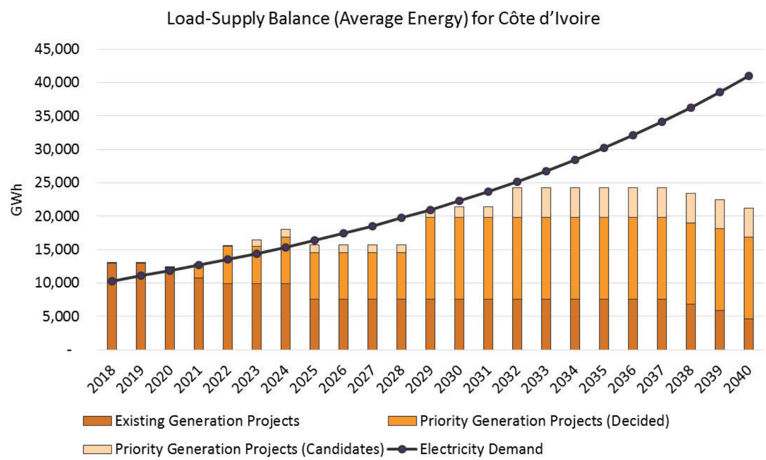


Figure 2-27 Load-supply balance (at generation level, average energy) for Côte d'Ivoire
(Source: Tractebel, Vol 2, 2018. Prepared by Multiconsult.)

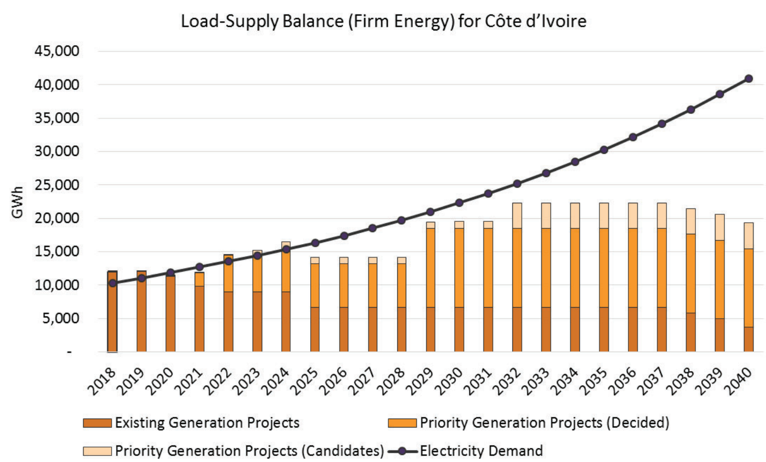


Figure 2-28 Load-supply balance (at generation level, firm energy) for Côte d'Ivoire
(Source: Tractebel, Vol 2, 2018. Prepared by Multiconsult.)

2.3.3 *Sierra Leone*

The projections indicate that electricity demand will exceed supply over the forecasted period. The identified projects are not sufficient to meet demand. If no additional generation projects are built, Sierra Leone may rely on electricity imports in order to meet domestic demand. The substantial supply gap in 2018 is related to the base case set-up of the demand forecast in the ECOWAS Master Plan: Existing mining sites in the vicinity of the CLSG line are estimated to have an estimated (equivalent) electricity consumption of circa 230 MW, which is already included in the base case scenario despite not being connected to the grid (ECOWAS, 2018). The current portfolio of Priority Generation Projects identified in the ECOWAS Master Plan do not cover the projected consumption in the country and would fall around 3,500 GWh short in 2040, if no additional projects would be developed.

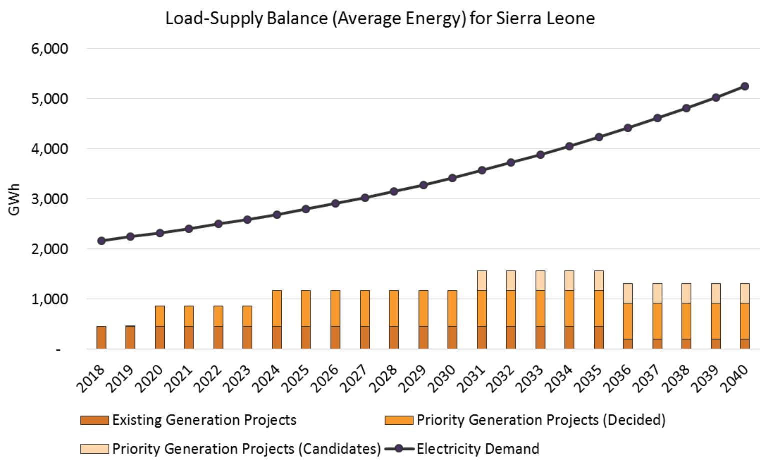


Figure 2-29 Load-supply balance (at generation level, average energy) for Sierra Leone (Source: Tractebel, Vol 2, 2018. Prepared by Multiconsult.)

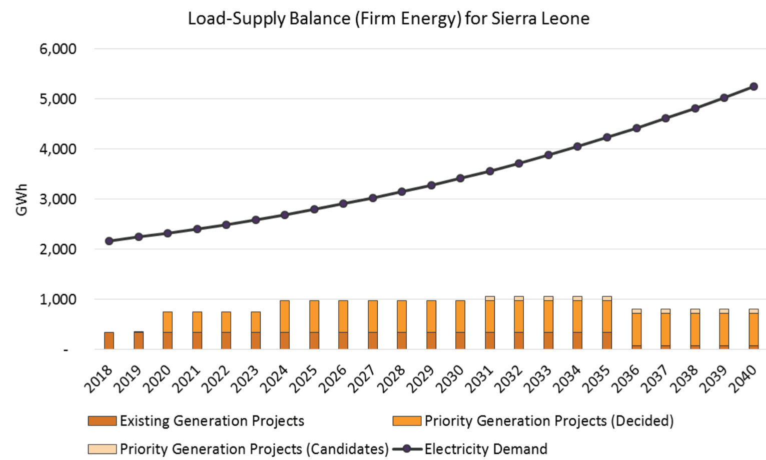


Figure 2-30 Load-supply balance (at generation level, firm energy) for Sierra Leone (Source: Tractebel, Vol 2, 2018. Prepared by Multiconsult.)

2.3.4 *Guinea*

Similar to the base case scenario applied for Sierra Leone in the ECOWAS Master Plan, approximately 74 MW of existing mining sites were identified in Guinea in the vicinity of decided transmission lines (OMVG and OMVS) (ECOWAS, 2018). With the commissioning of 450 MW hydropower in 2021, and further hydropower projects due for commissioning in the following years, the country is expected to have a relatively likely power surplus in the next two decades. However, the country might still experience occasional power shortages in dry seasons.

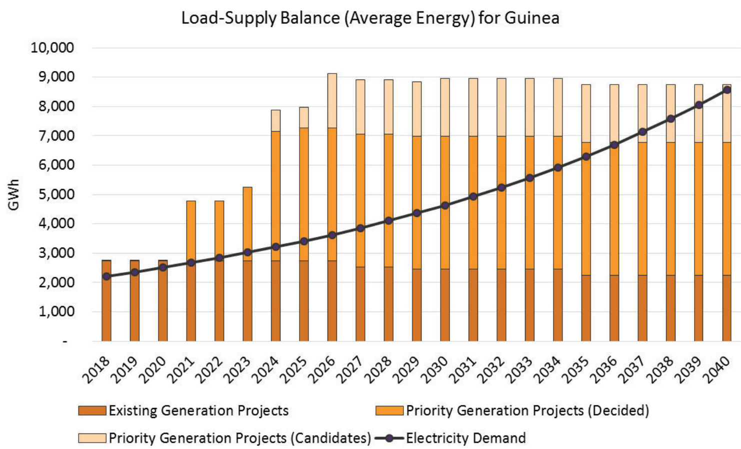


Figure 2-31 Load-supply balance (at generation level, average energy) for Guinea (Source: Tractebel, Vol 2, 2018. Prepared by Multiconsult.)

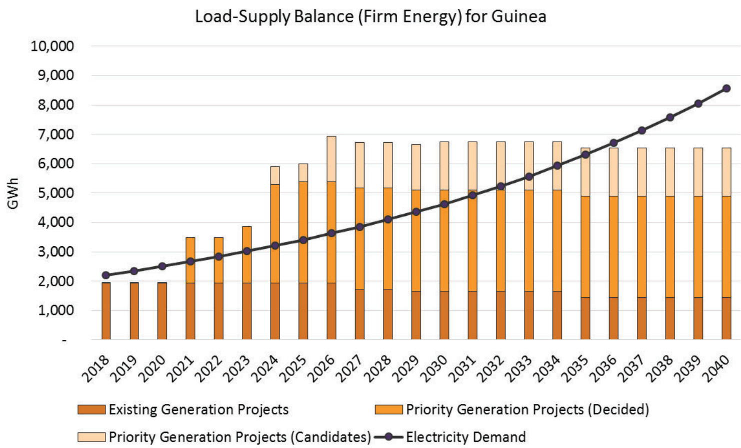


Figure 2-32 Load-supply balance (at generation level, firm energy) for Guinea (Source: Tractebel, Vol 2, 2018. Prepared by Multiconsult.)

3 Status of the Liberian Grid and Regional Integration

3.1 Status of the Liberian electricity grid

3.1.1 Today's grid

The Liberian electricity grid system has been developed since the civil war ended in 2004; during the war all infrastructure was destroyed. The first step was to supply different parts of Monrovia through small 22 kV and LV distribution systems, supplied from diesel fuelled containerized gensets (mostly 1 MW size). LEC officially revived its operations in 2007 with 2 MW of installed capacity and a small number of connections and street lights. A further 10 MW of diesel generation was installed in 2010, and the next step was to connect the 22 kV systems through the so-called Gaps project. Further, the 66 kV system in Monrovia was reconstructed around 2010, connecting the Monrovia suburbs of Paynesville, Krutown, Capitol and Bushrod, and creating a 66 kV grid connecting all generators and substations in Monrovia. Additional diesel generation was added between 2013-6, and in 2016 LEC began planning and construction of three HFO plants totalling 38 MW of installed capacity.

The next major step was the rehabilitation of the Mt Coffee HPP, with 66 kV lines to Bushrod and to Paynesville substations, securing a grid from Mt Coffee to Monrovia with necessary redundancy. The first out of four hydropower units at Mt. Coffee was in operation from December 2016, and the last was commissioned in July 2017.

This 66 kV grid has been limited to supplying the Monrovia area but is being expanded to nearby counties, including Bomi and Margibi. Other locations like Buchanan, Gbarnga, and Firestone have separate small grids operated isolated from the main grid in Monrovia.

The inflow to Mt Coffee HPP is poorly regulated and is only covering the load demand in this grid approximately 6 months per year. The remaining demand is covered from HFO and diesel generation located primarily at the Bushrod substation in Monrovia.

3.1.2 Condition of the existing grid

Basically all grid components around and in Monrovia were installed from 2007 onwards, with a big part of the 66 kV system installed between 2010 and 2015. This should indicate that the 66 kV grid should be in a reasonably good standard, with remaining lifespan from 15 to almost 25 years, assuming the maintenance is kept at a normal level in the years to come. During recent years, LEC has attempted to replace much of the LV network which has degraded (e.g. wooden poles), but it is not known to what extent this has been completed.

The operational statistics indicate that the LEC transmission system has a rather high interruption frequency, and also a long average time for rectification after faults.

3.1.3 Grid losses

The losses in the LEC grid is currently extremely high. The biggest part is non-technical losses, which is due to non-measured consumption, non-billed consumption and especially energy theft. The technical losses are above a normal level, and the grid on the lower voltage level experiences very frequent outages. This indicates that the grid design and dimensioning of components should be reviewed and possibly improved.

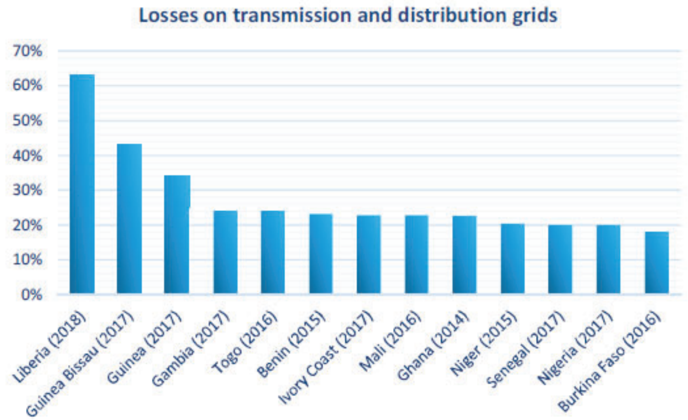


Figure 3-1 Rates of technical and non-technical losses on transmission and distribution networks (Source: Tractebel, Vol 1, 2018)

3.1.4 Development of the Liberian grid

The Rural Energy Strategy and Master Plan (Gesto, 2016) for the development of the Liberian grid is divided into phases.

Phase 1 up to 2020 is focusing on rural energy and implementation of ongoing/ planned projects, while Phase 2 up to 2025 is focusing on acceleration of the electrification and roll-out of the main initiatives, and Phase 3 will be a consolidation phase.

The strategy and master plan consists of 5 main programs, where the first is most relevant for the transmission network development. The program is named Growing the National Grid, and includes the following 4 initiatives, as illustrated in Figure 3-2:

- GTG 1: Extension of the Monrovia corridor, i.e. expand the grid towards West, North and East.
- GTG 2: Extension of the Gbarnga corridor, i.e. expand the grid around the planned Gbarnga substation. This substation is located close to the upper parts of the St. Paul River and the CLSG line.
- GTG 3: Electrification along the CLSG, supplied from the substations or from SWER solutions.
- GTG 4: Enable connection of renewable IPPs to the grid.

GTG 1 and 3 are planned to start in Phase 1.

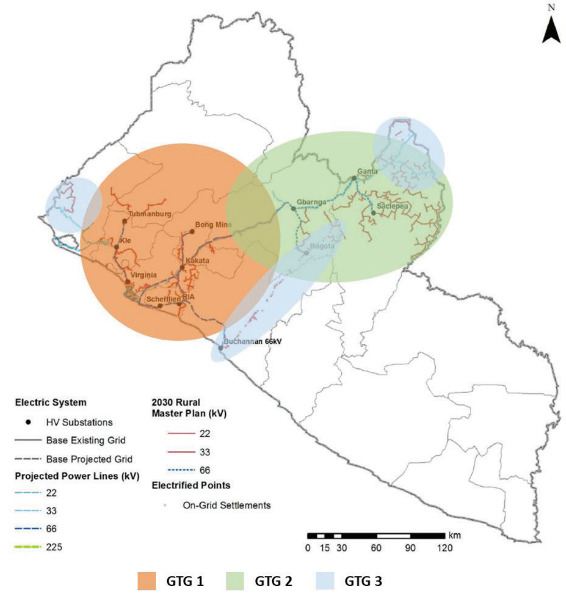


Figure 3-2 Growing the National Grid (GTG) initiatives in Liberia

(Source: Rural Energy Strategy and Master Plan for Liberia until 2030 (Gesto, 2016). Prepared by Multiconsult.)

3.2 CLSG interconnector

The CLSG Interconnector is the major ongoing investment of relevance for the power system in Liberia. This 225 kV line is planned to pass through Liberia from Côte d'Ivoire to Sierra Leone, connected to the local grid at 5 substations in Liberia.

The most important connection point today is in the Monrovia area, with a substation connected to Mt Coffee HPP and the 66 kV lines to Monrovia (ref GTG 1 above). In addition, there are plans for substations in Yekepa (close to the Côte d'Ivoire border), in Buchanan (at the coast, a major load centre/ industrial centre) and in Mano (close to the Sierra Leone border). Further, a Botota substation is planned to be connected later, this will be the connection point for a future line from the upper parts of St Paul River (Via reservoir), passing through Gbarnga substation (ref GTG 2 above).

The substations are planned with the following transforming capacity (from 225 to 66 kV):

- Mano 40 MVA
- Monrovia (Mt Coffee) 70 MVA
- Buchanan 40 MVA
- Yekepa 40 MVA
- Botota N/A (commissioning June 2020)

The line is designed as a double circuit 225 kV line on steel towers, but is built for one circuit as the first step. The line between the 4 substations in Liberia from Yekepa to Mano is planned to be commissioned in December 2019. (Transgo CLSG project, see Figure 3-3)

The operation of the interconnector will be carried out by Transco CLSG. A SCADA system will be located in a Regional Control Centre (RCC) in Linsan (Guinea) and will use modern data processing systems communicating fibre cable incorporated in the earthing wire of the line. This will provide a safe, reliable and optimal operation of the CLSG transmission line.

The transmission line is relatively long and seems to connect into the synchronised system of Côte d'Ivoire. This may cause operating problems for maintaining frequency and system voltage between normal limits, or there is a back-to-back DC break in the connection making the two grids separate and operated separately from Côte d'Ivoire. If the latter case, it is likely that frequency is determined by the hydropower units in Guinea.

A Power Purchase Agreement (PPA) on import to Liberia on the coming CLSG line was signed between Liberia and Côte d'Ivoire 19.10.2016. This agreement regulates import to Liberia, but gives no obligation for Côte d'Ivoire to receive power from Liberia (buy power).

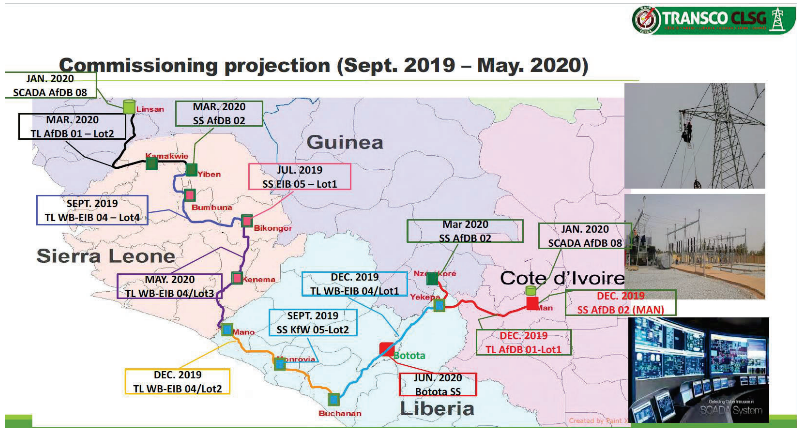


Figure 3-3 CLSG interconnector - commissioning projection
(Source: TRANSCO)

The CLSG subsection will be commissioned between September 2019 and May 2020. Both internal sublines in Liberia will be commissioned in December 2019, while the substations in Monrovia and Botota will be commissioned in September 2019 and June 2020 respectively. From Liberia three interconnection lines will be built. The two lines towards Guinea and Côte d'Ivoire will be commissioned in December 2019. The substation connected to this line in Côte d'Ivoire will be commissioned in December 2019, and the substation to the transmission line to Guinea will be commissioned in March 2020. The third interconnection line from Liberia goes towards Sierra Leone and will be commissioned in May 2020. The remaining transmission lines and substations in Sierra Leone will be commissioned by March 2020. This includes the interconnection between Sierra Leone and Guinea.

WAPP recommends to commission a second circuit of the interconnection line at the same time as the first circuit, to allow for optimal operation (Tractebel, Vol 5, 2018), and to provide operational security through realization of n-1 operation principle in the region (Tractebel, Vol 1, 2018). This is underlined by the fact that CLSG section in Liberia and Sierra Leone are two of the critical areas in regard to voltage stability in the interconnected system (Tractebel, Vol 4, 2018). However, at the current stage of development a commissioning of the second circuit at the same time as the first circuit is unlikely.

The length of the subsection will include 117 km in Côte d'Ivoire, 530 km in Liberia, 537 km in Sierra Leone and 119 km in Guinea (Transco CLSG, 2016). This results in a total length of 1303 km, with a voltage of 225 kV (Tractebel, Vol 5, 2018). The rated capacity of the line has different and confusing numbers in different sources, and there is need to get the correct capacities. The estimated cost of the first circuit is 517 MUSD (Tractebel, Vol 5, 2018). The voltage and length of the second circuit should correspond to the first circuit, and the cost is estimated to 131 MUSD (Tractebel, Vol 1, 2018). All substations in Liberia are expected to be 225/33 kV substations (Tractebel, Vol 2, 2018). Most of the demand from on-grid customers in Liberia is expected to be concentrated around Monrovia (Hydrotec, 2018). This has been reflected in the sizes of the substations. Monrovia has a size of 70 MVA, while Mano, Buchanan and Yekepa are 40 MVA (Tractebel, Vol 2, 2018).

The Studies have been conducted, financing for the project is mobilized, and the construction of the line has started (Tractebel, Vol 5, 2018). The four countries involved in the project signed a treaty in 2012, where it was decided that in order to have one organization in charge of the development and operation of the project, Transco CLSG SPV should be created (Tractebel, Vol 5, 2018). There is a commercial framework regulating the remuneration of Transco CLSG for the transmission service (Tractebel, Vol 5, 2018).

As of today, the only energy trading agreement in place is between Côte d'Ivoire and Liberia, between the companies CI-ENERGIES and Liberia Electricity Corporation, where the latter is the buyer of the energy. The agreement is valid 10 years from the commercial operation start-up date, which is expected to be Q1 2020. Discussions concerning extension of the agreement period shall take place during the 8th year from commercial date. (PPA, 2016)

The map below contains Priority Generation Projects and Priority Transmission Projects identified in ECOWAS Master Plan.

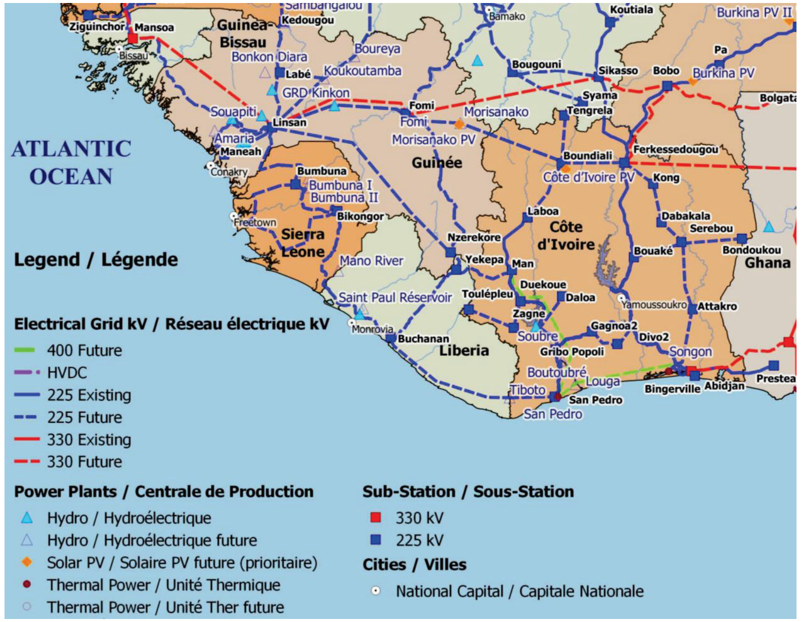


Figure 3-4 CLSG interconnector and other Priority Investment Projects

(Source: Tractebel, 2018)

3.3 Opportunity Tariffs for Imports and Exports

In the following section, the conditions of current trade agreements are presented, current tariffs of the CLSG countries are discussed, and implications for the optimization model are highlighted.

3.3.1 Current CLSG agreements

Currently, there is only one bilateral agreement (PPA) related to the CLSG line, between Liberia and Côte d'Ivoire. The Liberia Electricity Corporation is entitled to purchase up to 6.9 MWh within every fifteen-minute interval at any time of the year at *Firm Energy Price*. Additionally, depending on the consumption of the other TRANSCO CLSG customers of Côte d'Ivoire, and other clauses specified in Article IV of the PPA, the energy purchasable at the *Firm Energy Price* can be higher. The *Firm Energy Price* consists of the weighted average cost of energy delivered at substations of 51.46 FCFA/kWh, the transmission cost of 0.94 FCFA/kWh plus a margin of 10 FCFA/kWh, resulting in a *Firm Energy Price* of 65 FCFA/kWh in 2016 – corresponding to approximately 10.8

USc/kWh with an average conversion rate of 600.94 FCFA/USD[6] in 2016. Energy sold to the Liberia Electricity Corporation beyond the units that do not satisfy the *Firm Energy Price* conditions specified above will be sold at an *Extra Energy Price.* The *Extra Energy Price* is based on the highest variable price of all power plants in the system of the previous month, including the capital costs associated with the respective plant. The additional margin of the extra energy price is 1.75 USc/kWh. The formulas used to calculate the base price and the extra price can be revised every fifth year after the Signature Date, to ensure that the prices reflect the actual costs of the seller (PPA, 2016). The Client informed that the final review of the PPA is due in 2019.

3.3.2 Current service costs and tariffs

To put the above conditions for imports into perspective, Figure 3-5 presents the service cost and electricity tariffs, taken from the ECOWAS Master Plan. It becomes evident that there is currently a strong imbalance in terms of electricity tariffs and service costs. While Côte d'Ivoire has the lowest service costs in Western Africa (blue bar), and one of the lowest tariffs (red dot), Liberia has the highest service costs and highest tariffs in the region. The service costs per kWh are estimated to be around 5.5 times higher in Liberia than in Côte d'Ivoire. Sierra Leone and Guinea are also located on the upper end of service costs per kWh. Notably, electricity tariffs depend on tariff structures of the respective countries, which limits the comparability of the tariffs.

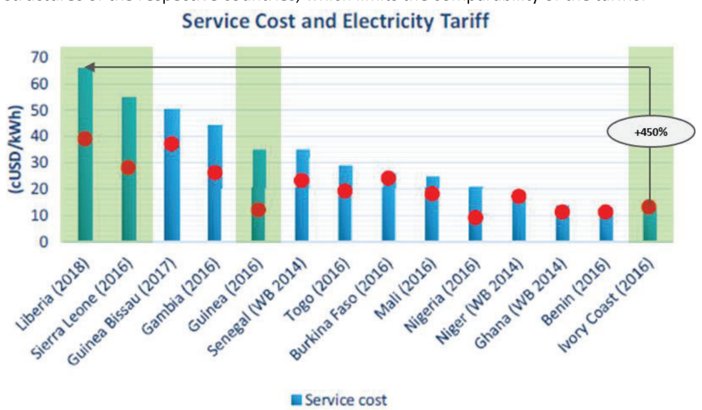


Figure 3-5 Costs of service and tariffs
(Source: Tractebel, Vol 1, 2018.)
Note: Red dots indicate electricity tariffs

[6] Retrieved from www.investing.com

3.3.3 Implications for the Balmorel optimization

While the current outlook on tariffs puts import and export opportunities into perspective in the short term, a different approach is chosen for the long-term optimization. It is important to focus all hydropower planning activities on long term forecasts and economic predictions since the operating period of the next hydropower projects is 10 to 50 years into the future. The Consultant has focused on modelling the Liberian power system, including all realistic supply options for Liberia in the long term. Power systems of Côte d'Ivoire, Sierra Leone and Guinea have been modelled in a simplified way, only with dummy power plants, as described in Appendix I of this report.

Optimal trade profiles are based on country-specific production costs calculated by the Balmorel model incorporating fuel price projections, O&M cost developments, and commissioning of new projects, etc. The optimal trade profiles for the CLSG countries have been identified by the model on a least-cost basis, taking into account the capacity of the CLSG line, among others. The production costs are subject to a certain dynamic, particularly considering (decided) larger power projects that are to be commissioned in the medium term. This approach allows for a consideration of new power project developments by considering fuel price developments, transmission costs and losses developments, etc. over the planning horizon until 2040. We believe that this approach allows for a more accurate modelling of import and export volumes, considering the implications that the CLSG line has on the long-term sector planning.

Figure 3-6 provides the basis for calculating the price set in the PPA between Liberia and Côte d'Ivoire, illustrating the separate groups of power plants and their costs per kWh. While the figure only presents a snapshot of the actual production costs of Côte d'Ivoire in 2015, the Balmorel optimization model will calculate the costs for different planning horizons for each of the CLSG countries, reflecting dynamics of various groups of technologies and associated pricing over time.

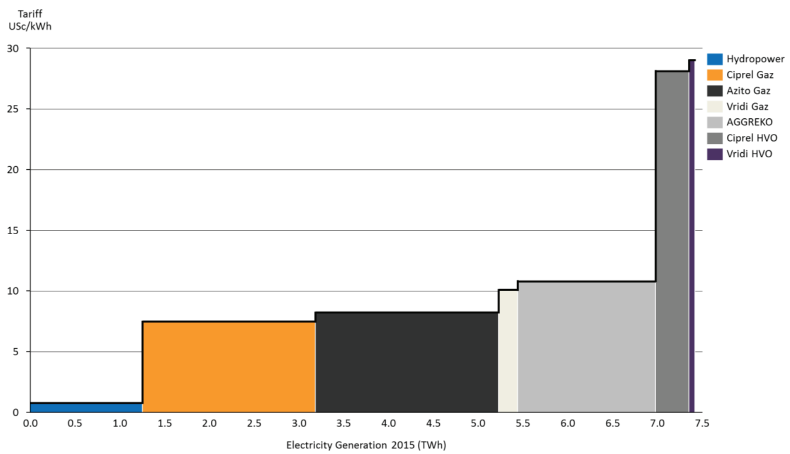


Figure 3-6 Cost of production by technology in Côte d'Ivoire as of end of December 2015 (Source: PPA between Liberia and Côte d'Ivoire dated 2016. Prepared by Multiconsult.)

4 Hydropower candidates

4.1 Summary of supply options candidate projects and their ranking

The candidate hydropower projects were described in Chapter 2 of the Supply Options report, and attached to this report in Appendix F of this report, and are summarized in Table 4-1 below. These projects were previously optimized on the assumption that Via reservoir would provide substantial seasonal regulation to all the hydropower options. Now the SP2 and SP4 projects are optimized on the assumption that Via reservoir is not constructed, and the installed capacities have been reduced to suit the unregulated river hydrology.

Table 4-1 Updated capacities and costs for each hydropower candidate project

Project	Via & SP4	SP4 alone	SP3	SP2 FSL 163	SP0	Mt. Coffee extension
FSL (masl)	235	250	190	163	60	29
Cost (MUSD)	1150	663	385	763	605	50
Turbine discharge (m^3/s)	300	230	340	420	450	216 (addition)
Avg. head (m)	34	45	19	41	27	22
Installed Capacity (MW)	88	88	55	154	105	44 (addition)
Energy (GWh/annum)	702 [*)]	484	275	840	570	126 (addition)
Plant factor	64%	63%	57%	62%	62%	33%
LCOE (USc/kWh)	12.5	10.4	10.7	6.9	8.1	3.1

[*)] Via figure includes energy gained at Mt Coffee and SP2 due to improved seasonal regulation

Note: The transmission cost to each candidate is based on an iteration process, resulting in a sequence of implementation, and the first plant will bear most of cost of the new 220kV transmission lone along the St. Paul River (MtCoffee – Gbonota – Gbarnga – Botata), such as SP2 and Via & SP4 in their respective scenarios (discussed later in the report). The other plants hence have only short transmission line to connect to the already constructed main transmission line, and has thus less costs. The first iteration had transmission cost to each projects as if they all where the first to be implemented. In the following iteration process of the candidates, the lower priority projects have gotten reduced transmission cost as they connect to an existing grid.

Several improvements have been made in the project plans since the supply options report. Primarily the changes are in installed capacity and related costs. The power system studies demonstrate that there is no need for additional wet season energy, which at best would only fetch a low price for exports along the CLSG line. Therefore the installed capacity of each of the schemes was reduced, and a standardized capacity equivalent to 0.9 times the mean inflow was found to be optimal. There is also a standard assumption that three units are a suitable number of units in each station. This decision can be revised once the feasibility study for SP2 is finalized and investment capital is being discussed. Provision is made for later installation of 2 more units in each of the power stations, since such provisions can be made at minimal extra cost.

The below table show the results of the generation potential of the hydropower cascade at different storages at Via reservoir. Further details can be seen in Appendix F.

Table 4-2 Generation figures of the hydropower cascade project by storage at Via reservoir

FSL at Via reservoir	m	235	233	230	228
Active Storage	Mm3	3109	2581	1850	1402
MC 132 MW	GWh	694	667	625	593
MC 88 MW	GWh	582	554	516	480
SP0 105 MW	GWh	776	750	701	668
SP2 FSL163	GWh	973	938	869	826
Via 88MW	GWh	493	451	406	361
Total w MC 88 MW	GWh	2824	2693	2492	2336

4.1.1 *LCOE of hydropower candidates*

All of the hydropower candidates were compared on the basis of levelized cost of average energy (LCOE). The costs estimates are dated 2018. This allows comparisons between hydropower candidates of similar type, and comparisons with new thermal plant of different types. The hydropower LCOEs are shown in Table 4-1 and the thermal LCOEs in Table 4-2. The calculation of LCOE is described in Appendix I (Balmorel data).

It can be seen that the ranking of candidate hydropower options is identical to that found using simpler economic parameters in the supply options report. The preferred candidate is SP2 with an LCOE around 7 US cents/kWh, while the next St Paul HPP is 16 % more expensive (SP0). It is also noted that SP2 has a lower LCOE than all thermal plant, although only a little less than large scale CCGT plant using natural gas. The Tiboto costs are only rough assumptions.

Table 4-3 LCOEs of thermal plant of different types

Assumption	Unit	HFO (DI)	Diesel (DI)	HFO (OCGT)	Diesel (CCGT)	LNG (CCGT)	NG (CCGT)
Capacity	MW	60	60	60	60	60	60
Plant factor	%	60 %	40 %	60 %	40 %	80 %	80 %
Annual production	MWh	315 360	210 240	315 360	210 240	420 480	420 480
Capex	MUSD/MW	1,00	1,00	0,99	1,50	1,68	1,30
Fixed O&M costs	% of capex	1,9 %	1,9 %	0,5 %	2,7 %	0,4 %	0,5 %
Variable O&M costs	USD/MWh	6,5	6,5	17,4	7,0	23,3	23,3
Fuel price	USD/MWh	47,1	61,4	47,1	61,4	29,9	22,1
Fuel efficiency	%	40 %	40 %	30 %	50 %	50 %	50 %
Lifetime	Years	20	20	25	25	25	25
Construction period	Years	2	2	2	2	2	2
LCOE	Usc/kWh	14.5	19.1	19.1	17.6	10.9	8.8

Table 4-4 LCOEs of all candidate projects for Balmorel simulations (6% discount rate)

Technology	Discounted costs (MUSD)	Discounted production (GWh)	LCOE (USc/kWh)
MtCoffee_Ext	(63)	2,036	3.1
SP 2 Ext	(141)	4,040	3.5
PV 2040	(80)	1,678	4.8
PV 2034	(86)	1,678	5.1
SP2_Ph3	(228)	4,153	5.5
PV 2026	(96)	1,678	5.7
SP2_Ph1	(347)	5,721	6.1
SP2 163	(942)	13,576	6.9
SP2_Ph2 163	(555)	7,887	7.0
Tiboto	(555)	7,370	7.5
SP0	(744)	9,212	8.1
SP2 159	(985)	12,153	8.1
NG (CCGT)	(448)	5,375	8.8
SP4 alone	(815)	7,822	10.4
SP3 FSL 190	(473)	4,444	10.7
LNG (CCGT)	(555)	5,375	10.9
Via & SP4	(1,414)	11,345	12.5
HFO (DI)	(524)	3,617	14.5
Diesel (CCGT)	(472)	2,688	17.6
HFO (OCGT)	(768)	4,031	19.1
Diesel (DI)	(461)	2,411	19.1

The extension projects comprising of simply adding new units at Mt Coffee and SP2 are obviously cheaper based on the LCOE. The LCOE parameter is highly misleading for these projects, since the energy they provide is solely wet season energy of lower value than in a future export market. The fact that they provide low cost wet season energy does not mean that they are the best alternatives or priority investments

The Via reservoir and HPP with SP4 transfer has additional benefits in the form of additional energy at Mt Coffee due to the seasonally regulated flow. This has been added to the production at the Via HPP itself.

If there are several other candidate hydropower projects built before Via reservoir, then the Via benefits will increase with the increased dry season production at each downstream plant. In this way Via may become a competitive project after construction of both SP2 and SP0. However, based on the LCOE of each candidate as the next project to be constructed, we see that Via LCOE is more than double the energy cost of SP2, even assuming that SP2 is in place and contributing to the benefit stream from Via. Despite its contribution to covering dry season energy, the Via

project is simply too expensive and too early in the development of the power system and the customer base.

4.2 Further optimization of Hydropower Candidates

The optimization exercise relates primarily to design optimization, but it also includes a review of the unit cost rates resulting in reduced cost. The energy production estimate has also been revised as part of the design optimization. Input from the Balmorel model has been used for the optimization, in particular the required peaking capacity in dry season.

No further design optimization work has been carried out on SP3 or other hydropower schemes along the St Paul River since Task B (see Appendix F), except on the Via project, SP0 and SP2 as described in the following chapters.

4.3 Optimisation of dam site and power station locations

The optimization of dam site locations was initially carried out based by analysis of the LIDAR map and previous studies and proposals. This was followed up by site visits to most of the more important dam and power station site locations to check the visible ground conditions at each site. No ground investigations were carried out. Therefore, there were blanket assumptions made at each site on depth to suitable dam foundations, based on the terrain form and the very few rock exposures visible near each proposed location.

Dam sites are proposed at narrow points where a reservoir of at least the daily storage requirement was possible without excessive length and height of dam. There are not many such locations along the St Paul River, and each of the candidate dam sites was reported in the supply options report and in the following figure.

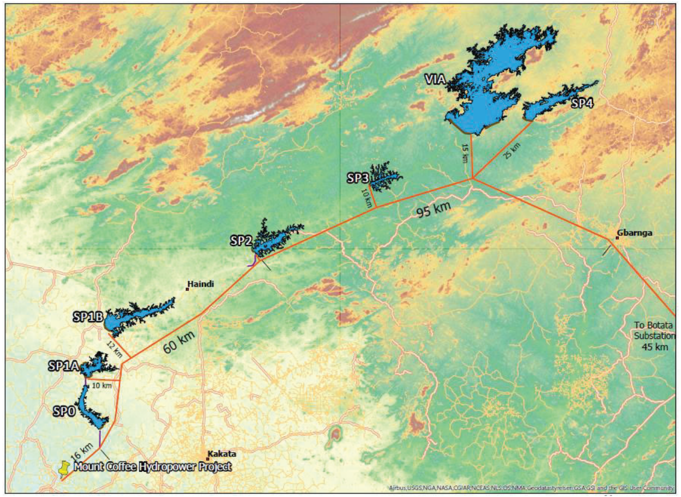


Figure 4-1 – Overview of the cascaded hydropower projects in the StPaul River

For each dam location a power station and waterway solution was devised, trying to utilize most of the head available down to the next dam on the cascade. Pressure waterways (headrace tunnels) will be very difficult to design with the prevailing ground conditions, and costly to construct with no leakage. Headrace tunnels will almost certainly require a pressure lining, making their cost per meter length excessive. Therefore, many of the proposed solutions involve tailrace canals and tunnels where pressure lining is not required and controlled water leakage in the unknown geological formations will not be a critical factor in the cost of the project. The final cascade of hydropower candidates is shown in the following figure.

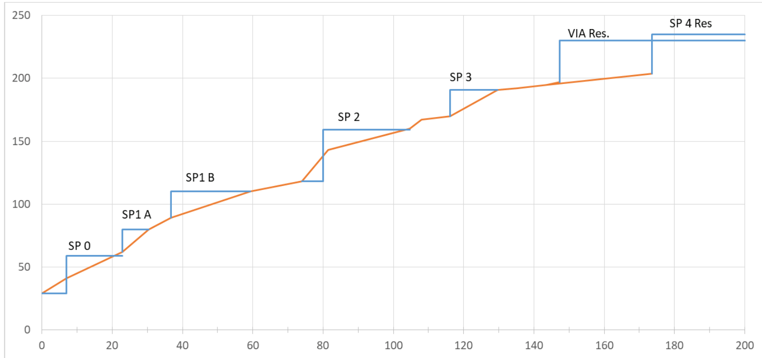


Figure 4-2 Full cascade of candidate hydropower projects along the St Paul River

4.4 Optimisation of dam height at each dam

All dams were provided with a reservoir large enough to enable all forms of daily peaking operation. In most cases, this needs only about 1m regulation zone, and the marginal cost of providing this is zero since the required size of reservoir is already provided at the optimal dam height (by optimizing the project head utilized). Thus dam height optimization is mostly based on utilized head contra cost of additional dam height.

After it was discovered that the Via reservoir was a long term project, the need for additional seasonal storage became an important factor in the optimization. This optimization is described in detail later for SP2.

SP0 uses the maximum available reservoir without impacting the tailwater of the next project upstream (SP1A). SP1B was also maximized as large as possible without affecting a large settlement and requiring complete resettlement of a community. SP1A has very limited storage possibility and was therefore optimized on the basis of head alone.

The remaining candidates SP2, SP3 and Via/ SP4 were therefore optimized based on the benefits of additional head (plus seasonal storage benefits for SP2) contra extra dam height and cost.

The primary benefit in such optimization is additional head achieved for each additional metres of dam height. A basic project was defined (as in Table 4-4) and additional meters of head were added, thus increasing the energy generated according to the increased head. A marginal cost curve of extra dam cost was derived for the extra dam heights. Examination of the terrain shows that it is very difficult to find dam sites on the St Paul River where the hillsides completely contain their reservoirs. After a certain height of reservoir is reached, the water will spill over several saddles into neighbouring valleys and around the dam. Therefore the cost curves for dams increase only gradually up to a few metres below the level of these saddles in the terrain, and the optimal dam height is close to where additional saddle dams are required of significant size and length. Construction of saddle dams becomes necessary at several places remote from the main dam site, and with no easy access. Therefore the topography itself sets a natural upper limit to the dam heights being studied.

In some cases the larger village populations also increase the cost of making a larger reservoir when it requires the relocation of an entire village. The location and elevation of several large villages also set a natural limit to how high a reservoir can come. Therefore the upper bound of the reservoir was determined for each site, and the optimal reservoir level analysed within these upper bounds.

The optimum reservoir level was found when the extra energy cost of the higher dam divided by the extra energy surpassed the average cost of the project energy (LCOE). If the dam height goes above this optimum, the LCOE for the larger project begins to rise. This type of optimization is fair for comparison of hydropower candidate projects with no seasonal reservoir potential, and allows fair comparison of the most favourable hydropower sites. All other parameters (particularly MW capacity installed) are standardized and unchanged when optimizing dam height. The exercise is best illustrated by the optimization process for SP2 described below.

4.5 SP2 Base Case Alternative (FSL 157.5) and later optimizations

In the Supply Options Stage the SP2 project was planned with a full supply level of 157.5 and a tailwater level of 118, giving a gross head of 39.5 m and a reservoir area of 28 km^2. This alternative assumed one basic type of dam, the concrete faced rockfill dam (CFRD), which was standardized for all project sites in order to be able to compare fairly the different projects with each other. This SP2 plan was based on the preliminary assumption that Via reservoir would be constructed first and that the Via River would have a higher dry season flow as a result of Via. Only a daily regulating reservoir was planned for SP2, with about 1 m of regulation under peaking operation mode.

The power system analysis has shown that Via reservoir is more suitable for long term development around 20 years from now, and that SP2 is the first hydropower project in the optimal development sequence. As a result of this, a re-optimization of the SP2 reservoir was done in order to provide some seasonal regulation. This included a review of the design outflow flood and spillway design, the fish passage arrangement and the power plant installed capacity.

One reason for not suggesting the SP2 reservoir Full Supply Level (FSL) of more than 157.5 was the need to minimise the resettlement which this reservoir entails. It was found that much resettlement would be avoided by keeping the FSL level down at 159 or lower. However, the numbers of people needing relocation increases rapidly above 159 (see Chapter 6 E&S).

Resettlement will be required for all houses below the normal flood level which occurs regularly in the middle of the rainy season in a wet year. Resettlement needs have been estimated for a high flood level, estimated at 2 m over FSL for each alternative. With normal operation of all spillway gates, this level will almost never be exceeded.

4.6 Marginal costs of increased dam height and reservoir level

Initial drawing of the alternative reservoir areas showed that optimal FSL lies in the range 159-165. Therefore 4 different alternative reservoirs with FSL at 2 m intervals were examined and

costed. The height of the dam crest was always assumed to be 4 m above FSL, and the dam volumes at all SP2 dams calculated from 3 – D models. Earthfill embankment dams were assumed with a foundation depth 1 m below the existing ground. Typical sections have a grout curtain, an impermeable fill cut off trench and drainage and rip rap layers, all as shown in the drawings in Appendix H.

Above FSL 159 requires providing a series of saddle dams both to the north and to the east of the main dam. The number and length of such saddle dams increases as the reservoir FSL approaches 165, as shown in Table 4-4 below:

Table 4-5 Characteristics of saddle dams required to retain larger volumes for SP2 reservoir

FSL	Crest level	Saddle dam No.	SD total length	Dam cost	New roads
159	163	4,5,6	1.0 km	2.9 MUSD	6 km
161	165	4,5,6,7	1.5 km	4.1 MUSD	7 km
163	167	4,5,6,7	2.2 km	6.6 MUSD	7 km
165	169	Add 1,2,3,8,9	3.0 km	11.8 MUSD	13 km

The need for many saddle dams of moderate height at SP2 means the earthfill embankment dams become more competitive than rockfill dams of the same height, mainly due to:

- Lower excavation volumes to acceptable foundation
- More readily available earthfill and filter material
- Avoiding the need for impermeable membrane in concrete or bitumen, both of which are costly in Liberia

The SP2 project was re-costed assuming earthfill embankment saddle dams and main embankment dams except for the gated spillway, overflow spillway and power station dam, all of which are concrete gravity structures. Typical plans and sections are shown in Drawing No. SP2 ---01 to 03.

The costing of each alternative is based on the basis alternative (FSL157.5) and a revised cost of the FSL 163 alternative, with additional quantities added which are dependent on the dam height (not spillway and power station structures which are assumed constant for all alternatives). The results of marginal cost analysis is shown in Table 4-5.

Table 4-6 Cost analysis of varying FSL at SP2

Item	FSL 157.5	FSL 159	FSL 161	FSL 163	FSL 165	Comments
Length saddle dam	Basis	1.0 km	1.5 km	2.2 km	3.0 km	
Extra dam cost	Basis	36	58	88	130	Incl P&G, Contingy
Extra MW E&M	Basis	2	5	8	11	Incl. contingency
Resettlem + land	Basis	1	17	20	40	2100 per PAP +land
Cost above basis	Zero	39	70	116	181	MUSD
Incl 15% for eng.	Zero	45	80	133	208	
Marginal cost	-	123	230	365	570	MUSD

It can also be seen from the map that reservoir levels above 163 cause a need for several new saddle dams, and will require resettlement of several more villages. Factors such as more access roads, remote construction from the main dam site, additional engineering and administration costs, have been added as a 15% addition to of the basic cost and it is therefore considered too risky to consider a FSL of 165 since the benefit cost ratio is only marginally greater than 1.

Table 4-7 Benefit analysis of varying FSL at SP2

Row No.	Alternative	FSL 157.5	FSL 159	FSL 161	FSL 163	FSL 165	Comments
1	FSL	157.5	159	161	163	165	
2	Dam crest	161.5	163	165	167	169	
3	Res Area km^2	25	32	41	50	59	
4	Active Vol Mm^3	105	148	220	310	420	Above 152 m asl
5	Saddle dam costs	0.8MUSD	2.9 MUSD	4.1 MUSD	6.6 MUSD	11.8 MUSD	
6	Head to 120	37,5	39	41	43	45	
7	% head incr	Basis	4%	9.3%	14.7%	20%	
8	Phase 1 (3 units)	135 MW	140 MW	148 MW	154 MW	162 MW	
9	Avge GWh	730	760	800	840	880	
10	Increase GWh	Basis	30	70	110	150	Average annual
11	Value @ 7 USc	0	2.1 MUSD	4.9 MUSD	7.7 MUSD	10.5 MUSD	
12	Firm yield m^3/s	40	45	65	80	90	99.6 % reliability
13	Dry seas GWh	Basis	12	17	20	23	Feb March
14	Extra @10 USc	Basis	1.2 MUSD	1.7 MUSD	2.0 MUSD	2.3 MUSD	Both Mt. C & SP4
15	Extra income p.a	Basis	3.3 MUSD	6.6 MUSD	9.7 MUSD	12.8 MUSD	Includes row 11
16	Capitalised @ 6%	Basis	53 MUSD	106 MUSD	155 MUSD	205 MUSD	Factor 16?
25	LCOE	7,1	7.0	6.9	6.9	7.1	US Cents/kWh
24	Extra Capital cost	Zero	45MUSD	80MUSD	133MUSD	208MUSD	From table above
26	Marginal B/C		1.18	1.32	1.16	0.99	

As can be seen by the comparative parameters in the bottom rows of Table 4-6, the marginal B/C ratio is significantly positive from 159 to 163. After 163, the benefits of the larger reservoir and the costs are similar and there is no benefit from the extra capital investment and the extra risk involved.

The B/C parameter is not the only parameter which can be used to compare alternative dam heights. An alternative approach is to increase the project size up to the marginal cost of alternative energy. This approach indicates that up to FSL 163 might be optimal. The LCOE parameter is not ideal for comparing alternatives with varying degrees of seasonal reservoir regulation. If more value is attached to dry season energy, then the tendency is to choose the largest reservoir size close to the optimal LCOE. **For this reason the optimum FSL has been identified at FSL 163**.

It is recognized that the earlier SP2 option of FSL 157.5 will involve significantly reduced need for resettling villagers, but with very small firm energy in the dry season. Raising the reservoir to 163 masl improves significantly the dry season firm energy and reduces the reliance of Liberia on power imports during the dry season months of February and March.

The active reservoir volume of 310 Mm^3 is the largest seasonal reservoir that can be economically constructed at the SP2 dam site. The initial installed capacity of 3 units will provide 154 MW at full output of 420 m^3/s. A further 2 units will increase the capacity to 250 MW when the additional wet season energy can be consumed or sold as export. Each unit has smaller output at full station capacity because of the rising tailwater.

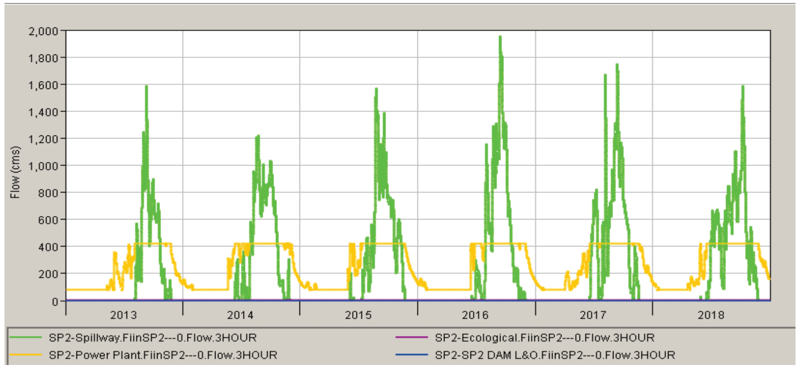


Figure 4-3 Station outflow and spill from SP2 with the 310 Mm^3 reservoir – firm yield 80 m^3/s

The outflow from the larger SP2 reservoir at FSL 163 is shown in the simulation output showing the firm yield of 80 m^3/s passing through the power plant and the SP2 spill (in green, assuming the phase 1 SP2 station capacity of 420 m^3/s). The reservoir is near empty at the end of the 2016 dry season, and the reliability criteria of 98 % is maintained in all simulations.

The optimal FSL was therefore found to be 163, inundating an area of 50 km^2 and a total impounded volume of 340 Mm^3.To maximize the active volume of this reservoir, the minimum operating level was set as low as technically possible with the current Kaplan turbine design and intake submergence, found to be 152. This gave an active reservoir volume of 310 Mm^3, which has been adopted in reservoir and power plant simulations, design and costing.

The availability of construction materials locally near the SP2 site is an important factor in the design concept of the dams. There are certainly substantial volumes of loose alluvial materials of sand and silt fractions in the riverbeds, and decomposed laterite soils with fine fractions suitable for impermeable core material. The availability of competent rock for large volumes of rockfill embankments is however in doubt. It was therefore decided to base the SP2 dam design on an earthfill embankment.

At the spillway and power station sites, the large intake and gate constructions will require foundations on sound rock and impermeable grout curtains to reduce seepage below the structures. Therefore, concrete gravity dam construction is the only viable alternative at the spillway and power station damsites. Gravity dams may be constructed in either conventional mass concrete, or RCC construction. The latter would make use of the same construction equipment being used for the earthfill dams and reduce the need for large quantities of imported cement, additives and the need for crushed rock aggregate. However, RCC requires a reliable supply of fly ash and few box outs to become competitive with conventional concrete, and it is uncertain at this stage if the dam volumes are large enough to justify RCC type of concrete. Therefore, conventional concrete gravity structures have been assumed in costing the SP2 project. Lower concrete unit rates are adopted compared with those experienced at Mt. Coffee in line with the larger quantities and greater experience of the West African construction industry 5-10 years.

The typical dam sections assumed for SP2 dams are all shown in Drawing SP2- 03. A 300 m long concrete overflow weir is assumed on the right bank at the north end of the SP2 dam. This is followed by four adjoining spillway gates and pillars before a dividing wall separates the concrete dam from the earthfill embankment across the main St Paul riverbed. It is not known at what depth competent rock can be found, but the terrain form indicates it is not very deep. An alternative spillway site can be found 1km south of the main dam if the rock foundation is shallower at that site. The gated spillway has a conventional stilling basin to dissipate energy and control bed erosion, while a shorter energy dissipation arrangement is envisaged for the low weir construction.

There are two alternative sites for power station and intake dam for the full head development alternative (one phase construction). Both result in the same depth of excavation and length of tailrace canal, so we have only shown one alternative in Drawing SP2-30. The power station will be excavated probably in sound rock at depth with substantial cut around the excavation pit. Original ground level is around 140, while the bottom of the tailrace canal is around 114 and the draft tube invert around even lower, meaning around 30 m of cut. The concrete gravity dam and intake structure is assumed founded around 130 m meaning 37 m height of the structure to the dam crest and access roadway at 167 above.

The tailrace is nearly 3 km long, initially expected to be cut in rock for the upstream half, then dug in alluvial material for the second half. Both typical sections are shown on Drawing G-03 (Appendix C). The canal is deep with an invert level of 114 and minimal bed slope. Tailwater levels are based on an assumed river level at the tailrace outlet of 120 at 700 m^3/s and 118.5 at 70 m^3/s. The turbine nominal head can be as much as 45m, but we have assumed 43 m nominal net head. The minimum head for turbine operation is 152-118.5 = 33.5 m or 78 % of the nominal design head, an acceptable range for operating head for Kaplan.

Power intakes and headraces are assumed integrated into the concrete dam body, as shown in the typical section through the power station on Drawing SP2-06 to 08.

The power station is planned for 5 units each with a capacity of 52 MW or 250 MW in total when all are operating and the tailwater is high. Phase 1 comprises only installation of 3 of these units giving a station output of 154 MW in the first phase. A typical dry season operation mode for SP2 would be 4-8 hour evening peak production using 2 units, both at maximum efficiency setting of 105 m^3/s which would give a dependable 78 MW evening peak supply throughout the dry season.

Alternatively continual production of at least 30 MW from one unit can be provided if it is found preferable to run the SP2 station as a base load plant, but this would not be an optimal operation strategy in an integrated CLSG system.

4.7 Optimising the station installed capacity

For the medium term planning, the installed capacity at each power station has to consider the power system needs, both for the dry season coverage of domestic demand and for export of wet season energy where the power demand is still being supplied by some thermal plant. This is not likely to be the case in Guinea or Sierra Leone, but may be the case for Cote d'Ivoire.

The relatively low demand and the lack of diversity in power plants supplying Liberia means that it is important that we do not choose very large units. Large units will make it difficult and costly to maintain a spinning reserve in case of one large unit falling out. Also the turbines should have the ability to run continuously on low river flows. Furthermore the economies of scale by choosing large units are not very significant when unit sizes are around 30-50MW, which is already double the size of Mt Coffee units. These criteria lead us to determine that the first phase of a project development should have 3 identical units, while the power plant should have space allocated for at least two more units of the same size.

The head available at each site being about 20- 50m at all sites means that both Kaplan and Francis units are good choices for this head. However the adjustable runner blade Kaplan type can cope with varying head and varying flow settings much better than Francis, and provides a better average efficiency over the range of flows and heads. Kaplan can operate safely down to 30 % of nominal capacity while Francis should not be operating at less than 50 %. It is recognized that Kaplan turbines can be more expensive than the Francis type of the same capacity. For analysing the production potential, optimizing the project parameters and for providing a higher cost estimate for finance applications, it is better to assume Kaplan units rather than the cheaper and more restrictive Francis type. Once the LEC and CLSG integrated system operating conditions have been established, then a new comparison of Francis and Kaplan types can be made, prior to issuing tender documents.

Therefore, the station capacity has been optimized based on assuming 3 identical Kaplan units at each station with an option to add two more some years later. The parameter to be optimized is the maximum station outflow, which is very closely related to the hydrology at each site. A preliminary optimum is provided by the flow duration curve shown in Figure 4-4. This applies to the SP2 site, but very similar shapes are found at all sites since the flow remains unregulated by upstream reservoirs.

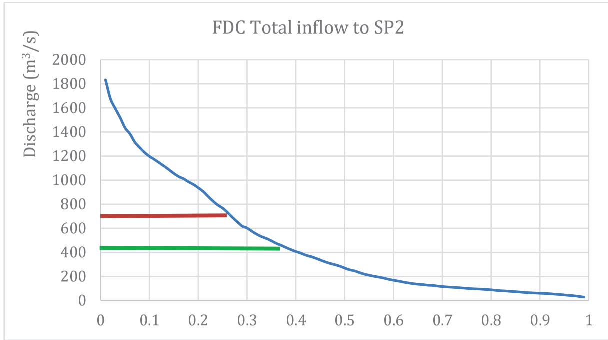


Figure 4-4 Flow duration curve at SP2 with no upstream regulation (daily flows)

The blue curve is the inflow flow duration curve and shows how the daily mean flows vary from wettest to driest. The red line shows the maximum turbine flow at the station with 5 units, while the green line shows the flow with 3 units. All the area above the red line (between the red and the blue line) is the water which must be spilled or released without providing energy. All the white area below the red line and lower blue curve represents the water that is utilized for power production. When increasing the total station installed capacity the red and green lines are raised and captures more of the flood water that is otherwise spilled. However such increased installed capacity makes no difference to production in the driest and medium flow months.

4.8 Comparing the seasonal reservoir options

Once the SP2 hydropower plant becomes operational, a firm yield release of 80 m^3/s would provide firm dry season output at SP2 of 30 MW as well as guarantee at least 12 MW firm capacity at Mt Coffee. The characteristics of the four seasonal reservoir alternatives are compared in Table 4-7 below.

Table 4-8 Comparison of upstream seasonal reservoir alternatives

Reservoir Name	Via (with SP4 transfer FSL 235)	Half Via (FSL 227)	SP4 (FSL 250)	SP2 (FSL 163)
Active res vol Mm^3	3100	1200	640	310
As % of inflow	48%	48%	9%	2%
Res firm yield (m^3/s)	210	120	85	80
Net Head (m) used at dam	32m	25m	48m	43m
Firm MW at dam	57 MW	25 MW	35MW	30 MW
Firm GWh at dam*	500 GWh	220 GWh	305 GWh	265 GWh
Firm MW at Mt C	41 MW	23 MW	15 MW	12 MW
Firm GWh at Mt C	360 GWh	200 GWh	130 GWh	105 GWh
Combined firm MW	98 MW	48 MW	50 MW	42 MW
Combined firm GWh	860 GWh	420 GWh	435 GWh	370 GWh
Res equiv GWh at Mt C	169 GWh	30 GWh	35 GWh	16 GWh
Reserv equiv GWh at SP2	279 GWh	50 GWh	58 GWh	27 GWh
Res equiv GWh at dam HPP	228 GWh	60 GWh	71 GWh	0 (incl above)
Storage value** (GWh) with SP2 without SP2	676 GWh 397 GWh	140 GWh 90 GWh	164 GWh 106 GWh	43 GWh Not applicable
Probability of refilling from empty	80%=317 GWh	80%=72GWh	100%	100%
Dam capital cost MUSD	1000 MUSD	430 MUSD	600 MUSD	250 MUSD
COST /Firm MW d/st (dam HPP & MC- without SP2)	10	9	12	6
COST/ GWh stored(noSP2)	3.2	6.0	5.7	5.8

*Annual firm energy calculated as firm capacity over 8760hrs (one year)

**Assumes one annual cycle of emptying and filling of each reservoir compared with RoR flow, assuming environmental release, multiplied by the probability of refilling the reservoir

The cost effectiveness of providing seasonal storage with each of the 4 alternative reservoirs has been compared on the basis of two separate parameters. The first parameter is based on the dry season firm MW being guaranteed by the firm yield release at the reservoir. This parameter indicates SP2 reservoir to be most cost effective per firm MW due to the reservoir, nearly half the cost of firm MW provided by Via. This is because there is much larger inflow at the SP2 site

compared with the others. The advantage of the SP2 dam is its location giving near double the inflow compared with SP4, and with nearly the same head.

It is, however, more relevant to compare the increased cost of providing additional firm MW from the upstream reservoirs where the inflow is comparable.

The other method of comparing reservoirs is to look at the energy potential by releasing the entire active volume of the reservoir through the hydropower plant at the dam and each power plant downstream. This parameter is only relevant for hydrological variations that are extremely seasonal, where only one annual cycle of emptying and refilling is possible. The full value can be applied to reservoirs with sizes up to around 30% of the annual inflow volume (given in row 3 in Table 4-7). However, for larger reservoirs the full volume cannot be utilized every year due to the risk of not refilling completely if the flood inflows are smaller than usual. Thus only 80% probability of refilling each year is assumed for the Via options, based on simulated reservoir level variations from HEC ResSim.

This parameter shows that all except the large Via reservoir have about the same cost of provide stored energy for use in the dry season. The SP2 dam has its main justification in creating head for the HPP and a daily regulating reservoir to facilitate peaking operation, while still providing significant firm capacity.

Assuming SP2 is not built first, then the other reservoirs can be fairly compared. Here we see that Via seems cheaper than SP4 and half Via is not competitive. After SP2 is built, the benefits of the seasonal regulation provided by the upper reservoir alternatives SP4 and Via increases and the apparent cost of providing reservoir storage falls significantly.

It can be safely concluded the half Via reservoir, and all alternatives that only regulate Via River inflows are the most costly to impound and regulate and can be rejected on economic grounds. When we also consider the higher environmental risk of a major reservoir on the Via reservoir, this conclusion is reinforced.

It can also be concluded that building the SP2 project first provides the cheapest firm MW, even though the dry season firm MW are smaller than with the upstream reservoirs. Provided the power system can operate without large systematic load shedding, then the SP2 project is a logical next step, which in turn increases the benefits of a larger upstream seasonal reservoir to be built later.

Assuming SP2 is built first, then the two alternative seasonal reservoirs at SP4 (lower capital cost) and Via with SP4 235 transfer (higher firm MW) are changing priority depending on which criteria is considered more important. It is therefore not possible at this stage to decide which of these two seasonal reservoirs (Via or SP4 alone at 250) will be more economic in the long term. On the basis of environmental and social risk, we have included the SP4 reservoir as an alternative to Via in the long term development plan (see Chapter 6 Environmental and social impacts and mitigation).

When the system load has grown large enough to justify further investment in dams and reservoirs, then a new optimization should be done based on better information on the costs and benefits of the alternative reservoirs at SP4 (FSL 250) and Via (FSL 235 + SP4 transfer).

Many runs were carried out to investigate how the two different data series affected the monthly and annual average production. It was found that the 7 year series gave about 1% less annual production. This series does not include enough dry years to test the hydrologic reliability, which is done using the 30 year monthly mean data series. However, the 7 year series is real daily mean data of recent date and reliable quality. This series is considered far more realistic in showing the monthly variation of energy potential, particularly in the critical months of January to March. These simulations show that a firm MW output of 30 MW can be guaranteed from SP2 and 16 MW from Mt Coffee in all but 2 months of the 30 year series. In these two months in March during the driest years, there will be several days of reduced production at both SP2 and Mt Coffee.

Table 4-9 Summary of monthly production with SP2 FSL 163, with differing hydrological data series and differing firm yield (85 m^3/s and 80 m^3/s

Month	Yield 85 SP2 30 yr months	Yield 85 SP2 7 yr days	Yield 80 SP2 30 yr months	Yield 85 Mt.C 30 yr months	Yield 85 Mt. Coffee 7 yr days	Yield 80 Mt.C 30 yr months
Jan	24.3	30.3	23.3	12.6	15.3	11.7
Feb	20.5	22.1	20.1	11.2	11.3	10.6
Mar	21.5	23.7	22.2	12.1	12.6	12.2
Apr	37.9	24.7	39.2	22.2	13.5	22.7
May	78.3	34.7	79.6	43.5	19.0	44.1
Jun	102.9	78.3	102.9	55.5	42.5	55.5
July	114.3	106.6	114.3	59.0	56.4	59.0
Aug	114.6	113.9	114.6	57.5	58.5	57.5
Sept	110.9	110.9	110.9	56.9	55.7	56.9
Oct	110.3	114.6	110.3	59.5	59.0	59.5
Nov	73.2	110.4	73.2	40.8	58.6	40.8
Dec	34.3	65.2	33.9	17.8	35.5	17.5
Annual GWh prod	**843**	**835**	**844**	**449**	**438**	**448**

Figure 4-5 SP2 reservoir levels with 80 m^3/s firm yield

4.9 Transmission assumptions and cost allocations

There are substantial costs involved in transmission of power from the different project locations to the main demand centre of Monrovia. For simplicity, all options are assumed to be connected at the 220 kV level to the Mount Coffee substation location. Although there will be additional cost in upgrading the substation and eventually the line from Mt Coffee to Monrovia, this is a common cost for all projects related to growth rate in demand and is therefore disregarded in the comparison of options and modelling the least cost option in Balmorel.

At some stage in the system development it will be preferable to construct a ring connection as shown in the main report, by feeding in at Botata substation via Gbarnga. But this is not likely to be the first connection since it would overload the line from Botata to Monrovia which is the main import line for supplying the main demand in Monrovia. Therefore the allocation of transmission costs for all options is based on their being connected solely via a main 220 kV feeder line along the St Paul River from SP4 to Mt Coffee. This line is 155km long (145 km from Via HPP) and assumes a double circuit cost of 0.9 MUSD/ km as a basis. The cost of connecting SP4 is therefore 140 MUSD (Via is 130 MUSD), but only if one of these projects is the first project constructed.

To fairly allocate the cost of this transmission line between different project options, we have to make preliminary assumptions as to the sequence of project development. In the Forced Via alternative (when the Via / SP4 Reservoirs and HPP is built first), the full 130 MUSD is allocated to Via, and the cascade projects have only short connection costs to the main line. In the base case scenario, we must allocate the cost of connecting SP2 to Mt Coffee before the main 220 kV connector is constructed. Therefore 68 MUSD is charged to the SP2 project to cover 75 km of 220 kV double circuit line to Mt Coffee. This applies to all SP2 options except the first 66 MW phase of the phased development which can manage with a single circuit.

When we enter data for Via HPP and SP4 HPP in the options analysis, we have to reduce the transmission cost of these alternatives to correspond to only the additional cost of connecting to SP2 (no longer all the way down to Mt Coffee). The costs reported in this Appendix are therefore the costs as entered in the Balmorel modelling of alternative project investment options in the base case scenario.

Gradually, the capacity of the 220 kV line will become overloaded as more projects try to feed in, and we have added a new single circuit line to the cost of SP2 extension to allow for the extra 96 MW capacity after the SP2 project is expanded to 250 MW.

It is outside the scope of this study to optimize transmission routes and costs, but we are obligated to have a fair allocation of costs between options so that any transmission cost distortions do not influence the recommended sequence. The LTDP sequence includes SP2, SP0 and Mt Coffee extension, and transmission costs have been added according to the principles described above, with SP2 covering the cost of the main line to Mt Coffee substation.

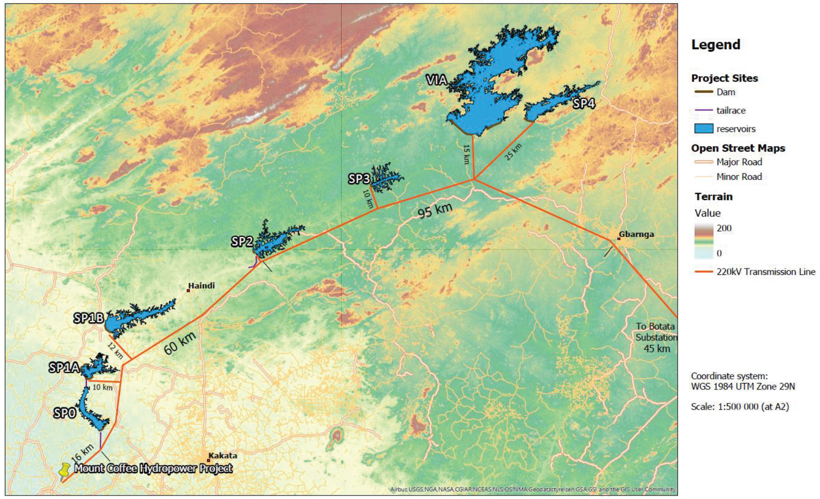


Figure 4-6. Overview of transmission routes between the hydropower candidates.

5 Other storage and supply options

The following section investigates the potential for utility scale solar PV as a viable generation source within Liberia during the timeframe under investigation in this report. Over the past two decades, solar PV has seen an enormous rise in installed capacities globally driven largely by steep price reductions and the increased convenience of the system.

5.1 Solar

Solar is quickly becoming a viable option for energy generation in developing countries due to its rapidly declining price and its lightning deployability. In contrast to large hydro power stations, which can take many years in planning, design and construction, utility scale solar plants can often be commissioned within two years of idea conception.

In the following analysis, the potential for installing solar in Liberia is explored at a high level. The analysis investigates regions that are suitable for solar installations and further predicts the potential yields that could be achieved in each region. Following this, an assessment of current utility scale PV plants is made and price assumptions for Liberian projects over the next 20 years are made. Despite the uncertainty inherent in long term forecasts, it is clear at this stage that PV projects will be highly competitive in both the short term and the long term in Liberia.

The section is finalised with a discussion around the key technical challenge to large scale deployment of PV in Liberia, namely the degree of PV penetration into the generation mix that can be achieved before stability issues are encountered.

5.1.1 Assessment of Potential Yield

At the highest level, the yield that can be extracted from a PV plant is a function of the meteorological characteristics of the site (irradiance, wind, etc) and the plant design (equipment quality, plant layout, etc.)

The following section outlines the rational behind the locations that were selected for modelling, resource estimates for these regions based on sampling of several sites within each region, an assessment of the irradiation, high level rational for the chosen technical designs and finally the indicative annual yields that would be achievable with each design and within each region.

Location Assessment

The location assessment began with an overview of the solar resource available in Liberia. Figure 5-1 below shows that the GHI (the key metric of irradiation for Solar PV) increases almost linearly as one moves inland from the coast. Thus, projects that are further inland are more likely to achieve higher yields.

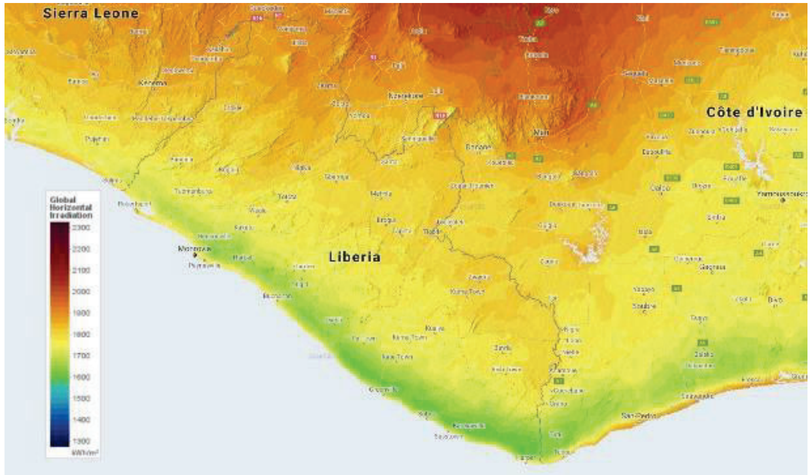


Figure 5-1- Solar irradiation map (Source: SolarGIS[7])

Although utility scale Solar PV power plants can technically be built in any location with available space, in practice, they are almost always located nearby to a suitable grid connection point, lest the high costs for transmission infrastructure render the project unfeasible. **Thus, a primary assumption in the location assessment was that the project should be in a region nearby an existing substation.**

Making reference to Figure 5-2 below, it was noted that there were substations in 5 regions that should be taken into consideration; Mano, Monrovia, Buchanan, Bototа, Yekepa

However, the Mano and the Buchanan substations were removed from consideration as the available area for a plant is limited near this substations being in a populated area.

Thus, it was concluded that a more detailed solar resource assessment would focus on the regions around Monrovia, Botota and Yekepa.

[7] https://solargis.info/imaps/

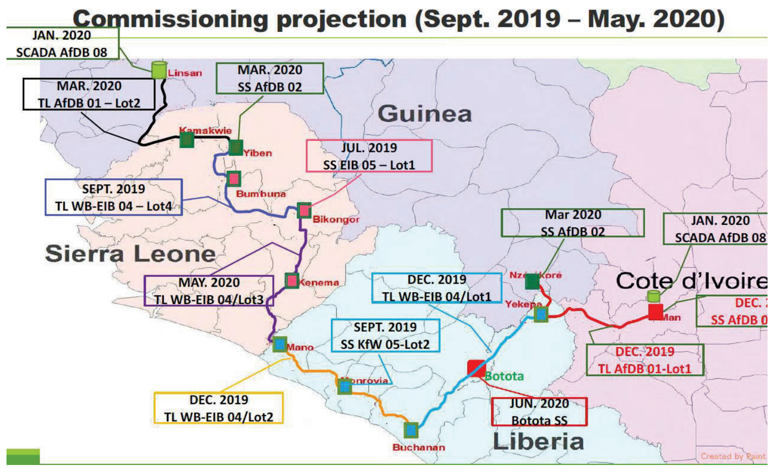


Figure 5-2- Overview of substations along the planned CLSG line

Solar resource estimate

In order to assess the solar potential at the project location, four different sources of meteorological data have been investigated:

- **Meteonorm:** Software used to generate weather statistics made by interpolation of the closest weather stations (8,325 stations registered worldwide) and satellite measurements (using five geostationary satellites). Data set for Liberia based on data between 1991 - 2010.
- **NASA-SSE:** Online service for global meteorology and solar climatology. It generates weather data from the Nasa satellites on a resolution of 1° x 1° (110 km x 110 km x cos (Lat)). Data set for Liberia based on data between 1983 - 2005.
- **Climate-SAF PVGIS:** Online service based on the results of an EU project. Data is based on satellite measurements. Climate-SAF is the new data set from PVGIS. It uses two types of weather satellite, polar (Metop) and geostationary (Meteosat), that are complementary (each type has advantages and disadvantages, and an ideal observing system combines both) and tested extensively against high-quality measurements on the ground. Data set for Liberia based on data between 2005-2014.
- **SolarGIS:** Online service for global meteorology and solar climatology. It generates empirical and semi-empirical models based on weather data from a mix of satellite and atmospheric measurements. A subscription for SolarGIS services was not purchased for this assignment and the yields were taken from the free online service. The temporal duration of the dataset is unknown.

In the case where accurate weather station measurements are not available, the above datasets extrapolate nearby weather station and satellite data to make site specific approximations, as is the case for Liberia. It is believed that the data provided was sufficient to inform the initial project design.

Due to its location near the equator, Solar irradiation in Liberia is generally high throughout the year as can be seen in Figure 5-3 below.

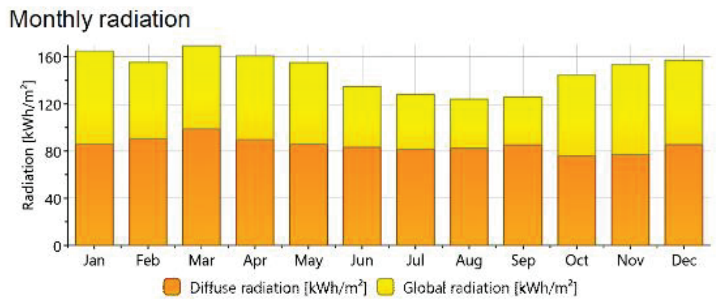


Figure 5-3- Monthly radiation in Monrovia. Source: Meteonorm Report

However, as Figure 5-4 show, this irradiation is far less stable during the wet season than it is during the dry season. It is worthwhile noting that this seasonality complements the annual rain cycle and hence the generation potential of the current Hydro power plant.

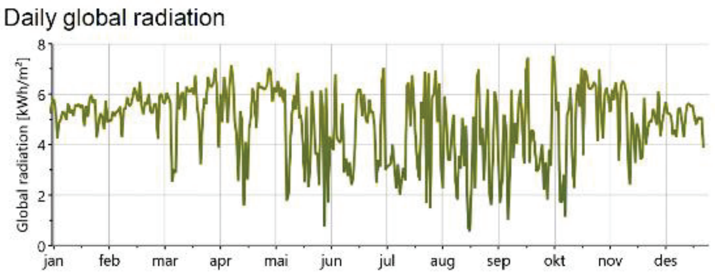


Figure 5-4- Daily global Irradiation in Monrovia. Source: Meteonorm Report

Temperature also plays a key role in PV generation as warmer modules tend to have higher internal resistance and hence produce less power. Thus, the best locations for solar should

(almost paradoxically) have high solar irradiation and low ambient temperatures. As can be seen in Figure 5-5 below, average monthly temperatures are quite high throughout the year.

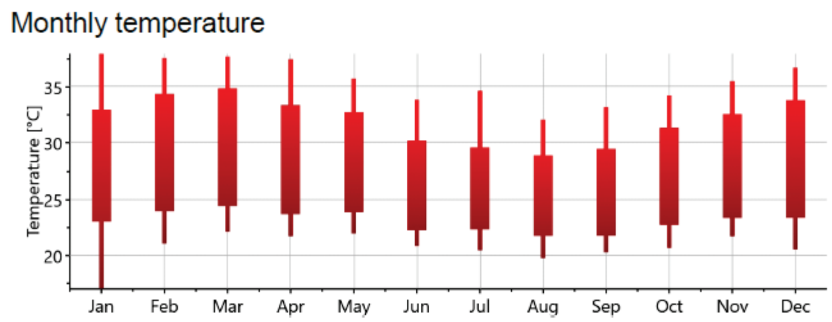


Figure 5-5- Monthly temperature distribution in Monrovia. Source: Meteonorm Report

Irradiation Assessment

Solar recourses within a given region can vary significantly depending on local conditions, thus the subsequent task was to determine a realistic estimate for an "indicative Global Horizontal Irradiance (GHI)" present in each of the regions.

As mentioned above, this was done by using GHI estimates from several sources and then finding an average value. For each region (Monrovia, Botata, Yekepa), measurements from 5 different locations were taken within a 15km radius of the regional centre and averaged. The locations of the measurement locations are shown in Figure 5-6 below.

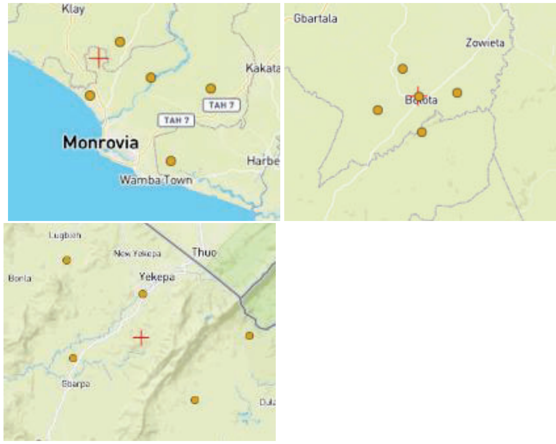


Figure 5-6 Visual representation of the 5 measurement locations at Monrovia (left), Botata (center) and Yekepa (right). Coordinates of all measurement points are given below.

The averages from each of the data sources were then compared to get an indication of the variability between the different data sources and to determine a regional average. The GHI estimates from each source and for each of the locations is summarized in the table below. Please note that the NASA data could only produce one value per region due to the 1° x 1° resolution of the service.

Table 5-1- GHI values from the various coordinates taken in the three regions of interest. The Meteonorm value highlighted in yellow are the closest Meteonorm estimates (kW/m^2) to the regional average and is hence used in the dataset used in the simulations below.

Coordinates	Meteonorm	PVGIS	SolarGIS	NASA	Regional Average
Monrovia Region	**1777**	**1802.6**	**1705.8**	**1697.0**	**1745.6**
6.504 -10.655	1774	1785	1697	1697	
6.602 -10.742	1766	1813	1703		
6.474 -10.492	1782	1770	1692		
6.454 -10.824	1783	1799	1743		
6.274 -10.602	1779	1846	1694		
Botata Region	**1852**	**1953.8**	**1793.4**	**1719.0**	**1829.6**
6.659 -9.376	1852	1964	1796	1719	
6.738 -9.424	1850	1924	1791		
6.67 -9.267	1852	1957	1800		
6.621 -9.495	1853	1973	1790		
6.558 -9.369	1853	1951	1790		
Yekepa Region	**1795**	**1935.2**	**1828.0**	**1832.0**	**1847.6**
7.56 -8.554	1788	1847	1816	1832	
7.506 -8.614	1806	1942	1821		
7.588 -8.619	1789	1933	1827		
7.524 -8.462	1784	1977	1833		
7.47 -8.509	1809	1977	1843		

For simplicity, the average value of the GHI estmates from each source are summarized in the following graph.

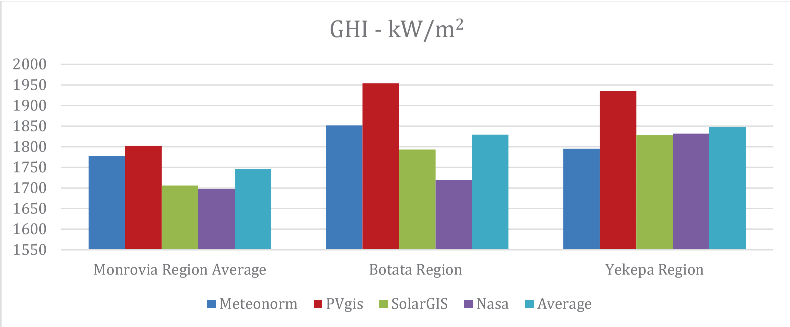


Figure 5-7- Average GHI per region as estimated from each data source

The large variation in GHI estimates above is a result of the fact that there are no reputable weather stations in Liberia that have been used to verify the predictions made from the models. The sources each use 100% satellite data for the region and then make calculations based on their own algorithms, which leads to such discrepancies (up to 12% in the case of Botata). Nevertheless, the GHI estimates are considered sufficient to support modelling done at this stage within the current level of uncertainty.

The Simulation Tool

The software package PVsyst (v6.7.9) has been used for pre-design and yield assessments of this project. The software is among the most recognized photovoltaics simulation tools worldwide and is widely used for both system design and due diligence of PV power plants. PVsyst includes advanced features for simulation of all losses that may occur in a photovoltaic power plant, including a 3D tool for near shadings simulation.

System design for indicative yield assessment

In general, two designs were considered:

- Fixed tilt system, East-West orientation.
- Single axis tracked system, North-South orientation

For the fixed tilt system, an East-West orientation was selected as opposed to a south orientation. Given the proximity of Liberia to the equator, this does not result in a large drop in the yield of the plant and instead enables the plant to utilize less space and require less materials for the substructure.

A single axis tracking system was also analysed since this has largely become the dominant design for solar plants worldwide, particularly near the equator. However, due to the increased complexity of the design and construction, as well as the higher degree of skilled labour required in its operation, it may be that these are not suitable in the first installations.

The final choice system design should be selected at a later stage of development, and at this stage it is believed that these two designs described above are sufficient to inform the Balmorel model.

A more detailed overview of system design assumptions can be found in the yield reports in Appendix D.

Indicative Annual Yields

Given the system designs described above, the following specific yields were obtained.

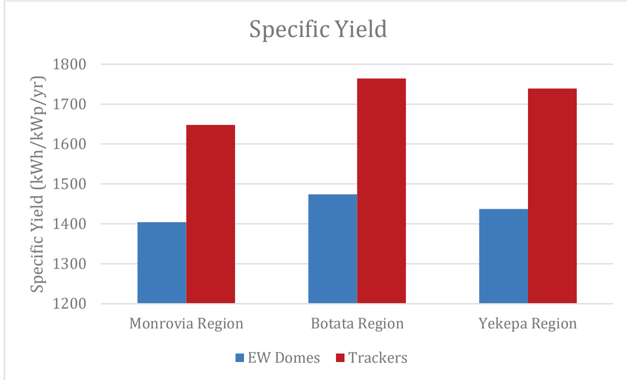


Figure 5-8- Specific yield for each region and each system design.

The specific yield of a PV plant describes the number of kWh that can be produced for each 1 kWp of installed capacity over the duration of a year. The metric is useful in that it can be scaled, almost linearly, to give the total yield of a PV plant of any size.

Table 5-2 The total yield estimates for the plants

Region	EW Domes (MWh/Year)	Trackers (GWh/Year)
Monrovia Region		
10MW Plant	14,040	16,480
50MW Plant	70,200	82,400
100MW Plant	140,400	164,800
Botata Region		
10MW Plant	14,740	17,640
50MW Plant	73,700	88,200
100MW Plant	147,400	176,400
Yekepa Region		
10MW Plant	14,370	17,390
50MW Plant	71,850	86,950
100MW Plant	143,700	173,900

It is also notable that the seasonality of solar generation is very complementary to that of hydro as shown in the following

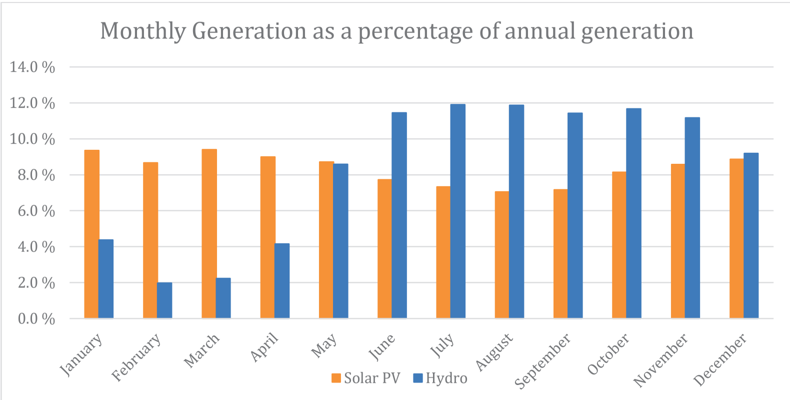


Figure 5-9- Monthly Generation as a percentage of annual generation

5.1.2 Financial Estimates

The price of Solar PV has been falling rapidly over the past decades and shows signs of continuing this decline. This price decline is driven by price declines in the vast majority of equipment required for the plant: The largest among these is the increased efficiencies in production of the modules, which are in general being produced with fewer materials and with higher efficiencies.

In addition to reduction in equipment prices, the labour required to develop, design, procure, construct and commission a PV plant is also reducing across the board.

Prices in Africa are expected to follow a similar price curve but, due to a number of factors, tend to remain more expensive than prices in developed countries. In general, this is not due to higher prices of the individual components as mentioned above, but rather due to higher costs of capital, perceived project risks leading to higher return expectations, as well as local costs such as logistics and taxes. However, it is worthwhile to note that if these barriers can be overcome, there are often significant savings to project development that can be achieved due to typically low costs of land and labour as can be seen in the recent announcement in Zambia where of 120MW of PV has been procured with the lowest price of 3.999 USDc/kWh.

Prices for PV systems are typically quoted in terms of USD per MWp (the sum of the ratings of all PV modules in the system) as opposed to the rated capacity of the inverter in MWac. However, since from a grid perspective the inverter capacity is the more relevant metric, the MWp prices will be converted to MWac prices assuming a ratio of 1.2MWp/MWac. The prices used will refer to the price of a Horizontal Single Axis Tracking system, and for simplicity, prices for fixed tilt systems are assumed to be 8USDc/Wp cheaper. This is in line with the methodology used by the 2018 Annual Technology Baseline as published by NREL[8].

CAPEX Forecasts for Liberia Solar projects

No large-scale solar PV plants have been constructed yet in Liberia, nor have any detailed and reputable studies into the current costs of installing PV into the current grid been found. Thus, price estimates for installing plants in Liberia must be extrapolated based on reasonable assumptions. Based on the cost drivers of solar PV as described above, the below analysis assumes that the PV system costs will decline over time in line with global price trends, however the price of the first round of projects will come at a premium. Following this, and assuming that the first round of projects successfully manages to mitigate perceived project risks for developers, it is assumed that projects in Liberia will manage to achieve prices in the range of the global average.

Preliminary CAPEX estimates have been made on the back of reputable publications from the National Renewable Energy Laboratory (NREL), and the International Renewable Energy Agency (IRENA)[9], who regularly publish articles on the current state of the Solar PV market, and make forecasts for future adoption rates and price estimates. Both data sources use empirical price data from operational projects worldwide.

NREL produces an Annual Technology Baseline (ATB) report which provides an up to date and relevant source of estimates for both current and future prices of solar PV. The latest ATB consolidates historical utility scale system prices in the US and makes forward price projections for the global PV market based on their analysis. In addition, this is then compared to forward price projections made by 9 separate, and reputable, institutions to arrive at a price range estimate for system prices up to 2040. The price projections made by NREL are shown in Figure

[8] https://atb.nrel.gov/electricity/2018/index.html?t=su
[9] https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2018/Jan/IRENA_2017_Power_Costs_2018.pdf

5-10 below, whilst the consolidated projections from the other institutions are shown in Figure 5-11.

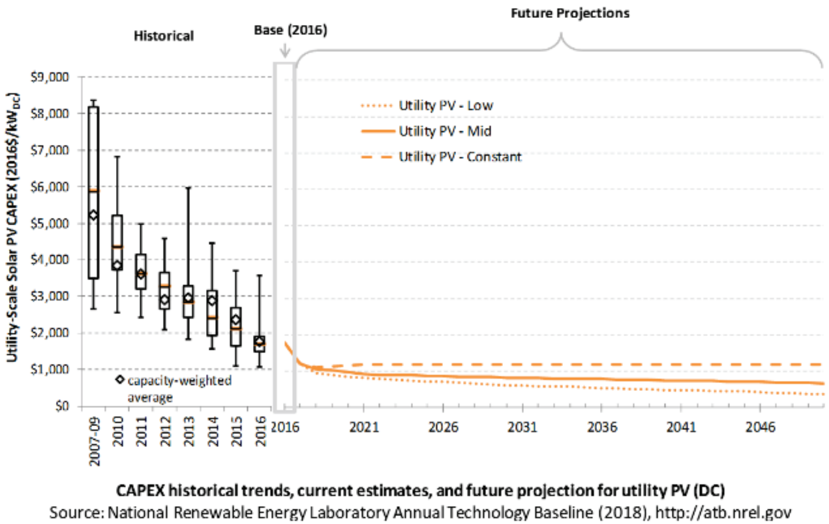


Figure 5-10: PV price projections made by NREL based on price reductions seen over the past 10 years

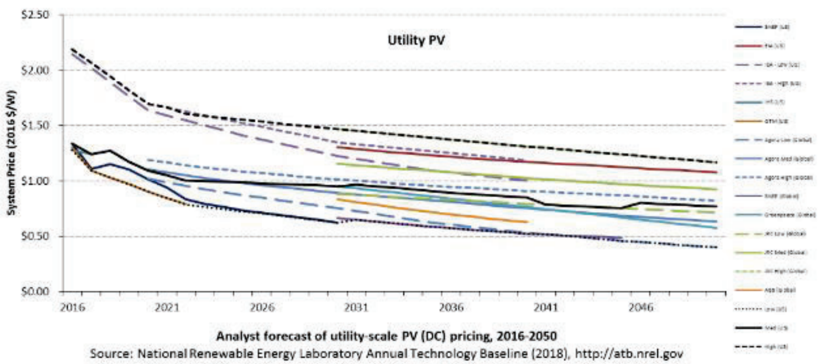
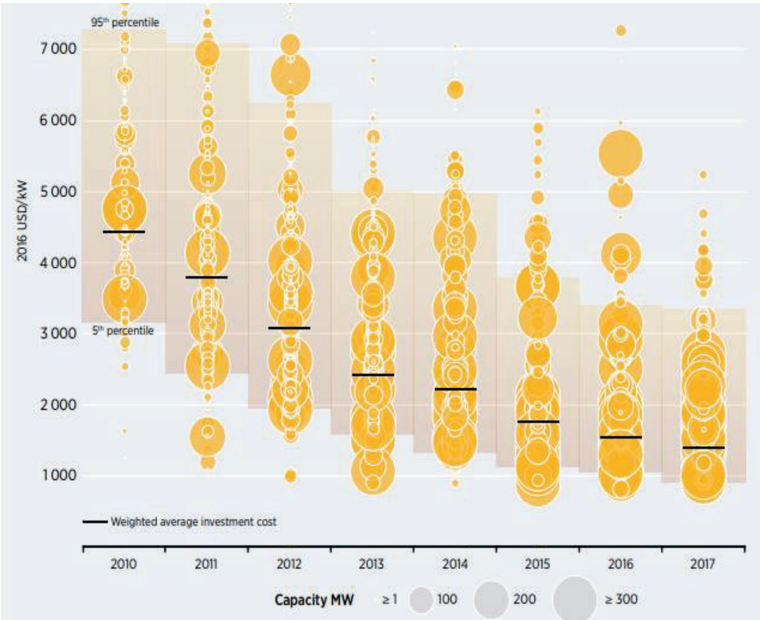


Figure 5-11: Future price projections based on estimates from 15 studies from 9 separate institutions

From the above, it is noted that in 2016, the weighted average price of utility scale PV systems was roughly 1.75USD/Wp (1.25 – 2.25).

This corresponds closely to the independent study performed by IRENA that found that the global weighted average in 2016 for Utility scale PV was around 1.55 USD/Wp.



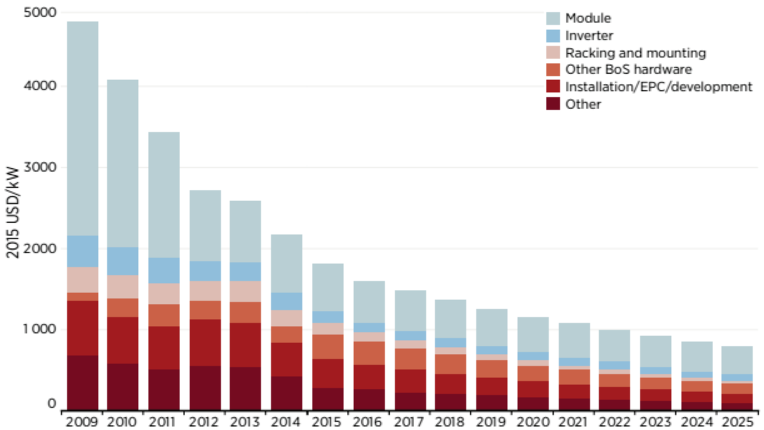
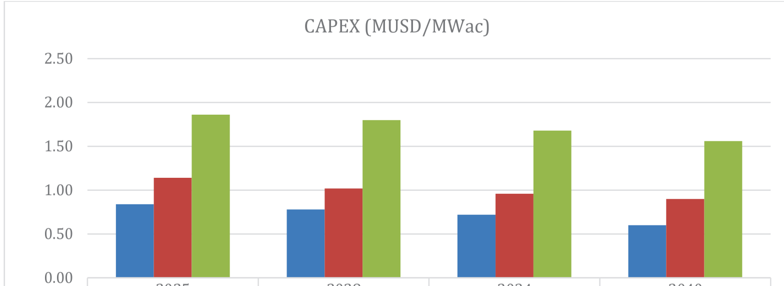


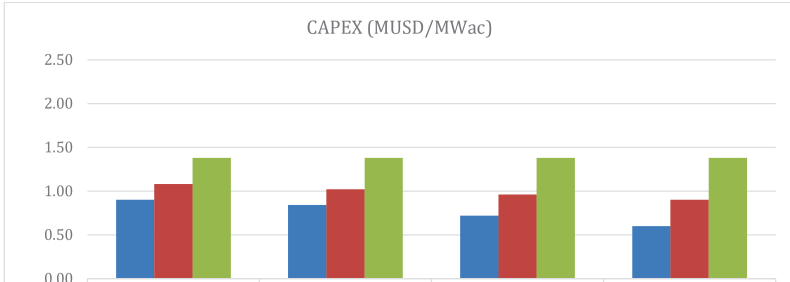
Figure 5-12- Total installed costs for utility scale solar PV projects and the global weighted average.

Sources: (top) 2010-2017: IRENA. 2018. Renewable Power Generation Costs in 2017; (bottom) 2009-2025: IRENA. 2016. The Power to Change: Solar and Wind Cost Reduction Potential to 2025.

Thus, using the price projections from the two analysis' above, we summarize the high, medium and low-price estimates for the years 2016-2040 below.



	2025	2028	2034	2040
Low	0.84	0.78	0.72	0.60
Med	1.14	1.02	0.96	0.90
High	1.86	1.80	1.68	1.56



	2025	2028	2034	2040
Low	0.90	0.84	0.72	0.60
Med	1.08	1.02	0.96	0.90
High	1.38	1.38	1.38	1.38

Figure 5-13- Summary of projections from 9 reputable institutions (top) and NREL future PV projections based on historical trends (bottom).

Whilst IRENA has not produced a forecast out to 2040, their 2016 cost reduction potential report[10] provided forecasts through to 2025 predicting investment costs at 0.79 USD/Wp, undercutting even the low estimates made by the above studies.

It is also worthwhile to note that historically, the vast majority of forecasts for solar PV future costs have been overly conservative and have consistently over-predicted the price of PV. Likewise, with the numbers above, our experience with PV both globally and within Africa compels us to note that prices are likely to be toward the lower end of the above ranges, if not lower.

Nevertheless, one issue remains that these price estimates are skewed towards the current CAPEX numbers for developed economies in Europe, Asia and the US and do not necessarily apply for more challenging regions, such as in West Africa. To correct for this, price trends for utility scale PV projects in Africa were compared to the data above to determine a suitable scaling factor, which was then used to correct for the added expenses which are often incurred by the initial projects in developing countries.

To do this, two data sources were compared. Prices for utility scale PV plants in Africa, taken from the 2016 IRENA report on Solar PV in Africa[11] and shown below in Figure 5-14, and the global weighted average for PV projects as shown in Figure 5-12 (top) Figure 5-13 above.

[10] https://www.irena.org/publications/2016/Jun/The-Power-to-Change-Solar-and-Wind-Cost-Reduction-Potential-to-2025
[11] https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2016/IRENA_Solar_PV_Costs_Africa_2016.pdf

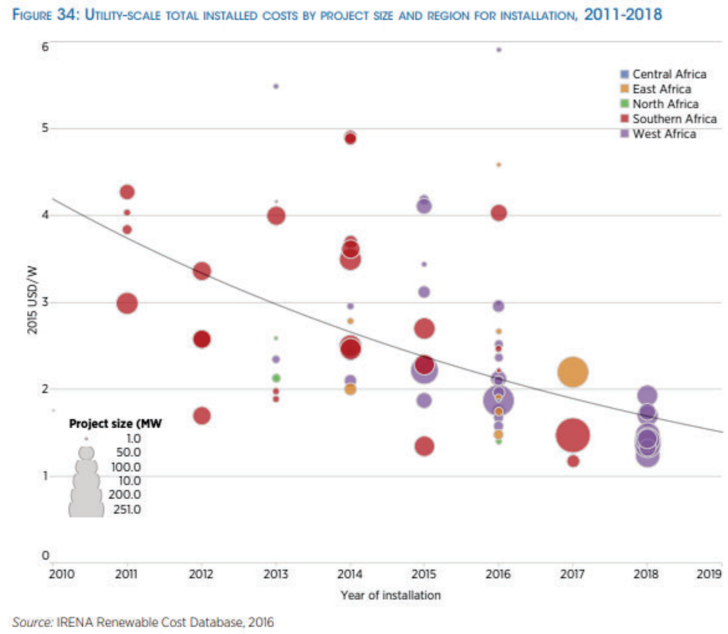


Figure 5-14- Historical prices for Utility scale projects in Africa. West African countries in this study include Ghana, Senegal, Guinea Bissau, Burkina-Faso, Nigeria, Cabo Verde, Mali, Sierra Leone.

These results are synthesized by the below graph.

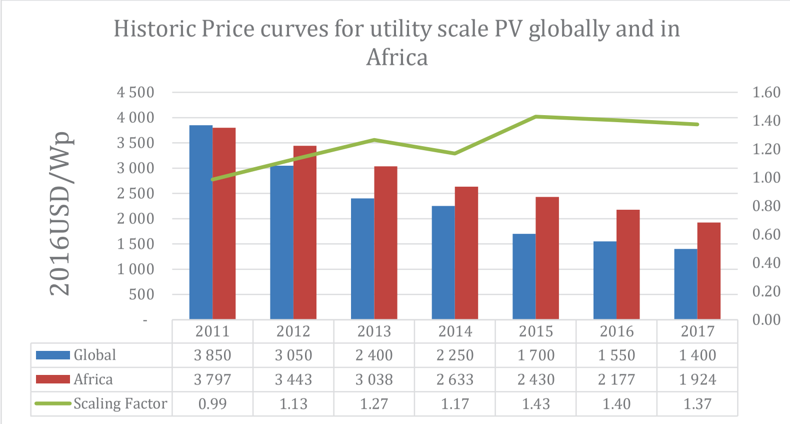


Figure 5-15- Historic Price curves for utility scale PV globally and in Africa

From this graph, we can see that the differences between CAPEX prices has grown between the two regions over the 7-year period under investigation. However, for the 20-year time horizon of this report, the average scaling factor of 1.251 will be used for the first installations in the below forecast. For simplicity, the two tables in Figure 5-13 have been averaged into a single table below.

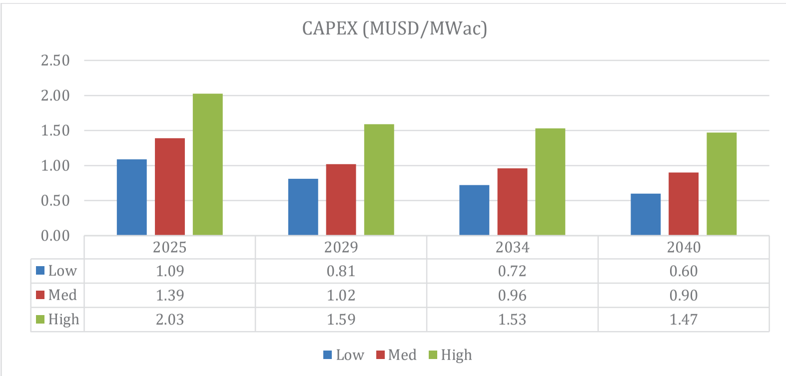


Figure 5-16- Extrapolated projections of project costs for projects in Liberia based on a scaling factor of 1.251 for the first project only.

In the model, the medium plant CAPEX numbers will be used as shown in the table below. The 2016 CAPEX numbers are converted to 2018 prices by using a factor of 1.0462 (4.62%) (ref. the Bureau of Labor Statistics' consumer price index).

Table 5-3 Extrapolated projections of project costs for projects in Liberia (data input to the Balmorel model)

(price in 2018MUSD/MWp)	2025	2029	2034	2040
Average price	1.45	1.07	1.00	0.94

LCOE

Whilst the LCOE numbers will not be used directly in the modelling of this project as the system cost is more interesting parameter, it is interesting to note what the above CAPEX numbers mean for the price of solar energy going forward. The following graph from IRENA, and the same source as was quoted in Figure 5-12 above, provides estimates on LCOE of projects both historically, and out towards 2025.

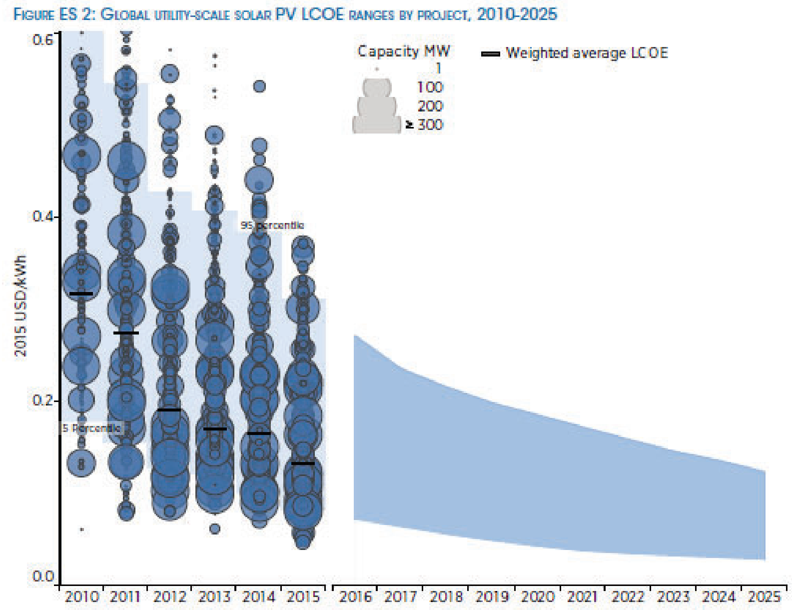


Figure 5-17- Solar PV LCOE from 2010-2025. Source: IRENA

This graph highlights the downward trend of solar PV energy prices, and estimates that by the year 2025, the LCOE of solar energy will be within the range of 3-12 USDc/kWh.

Table 5-4 Extrapolated estimates for Solar PV LCOE

(price in 2018USD/kWh)	2025	2029	2034	2040
Average price	0.09	0.06	0.04	0.03

Economies of scale

Finally, the price projections above are based on the capacity-weighted average price of projects which were sampled by NREL. In 2016, this sample size was for 88 projects with sizes that varied between 5.5 MW – 300 MWac. The source for this analysis investigated the data to distinguish the achievable economies of scale. The finding was that whilst projects did show economies of scale up to the 100MW+ project size, these economies were rather minor and did not correlate strongly.

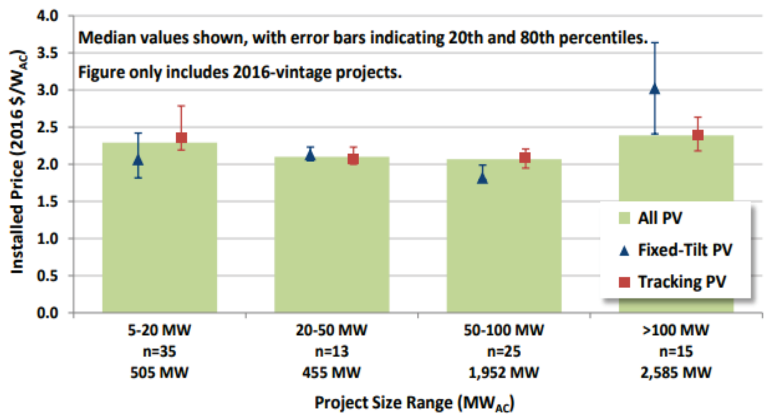


Figure 5-18- Installed price of 2016 projects by size and mounting type. Source: http://eta-publications.lbl.gov/sites/default/files/utility-scale_solar_2016_report.pdf

Likewise, the data in Figure 5-18 above appear to indicate that whilst larger projects tend to achieve lower costs on a per MW basis, it is not a primary driver of costs. Thus, the cost difference for project size has been omitted from the project model.

O&M cost estimates

From the ATB (Annual Technology Baseline), "Operations and maintenance (O&M) costs represent the annual fixed expenditures required to operate and maintain a solar PV plant over its lifetime, including:

- Insurance, property taxes, site security, legal and administrative fees, and other fixed costs
- Present value and annualized large component replacement costs over technical life (e.g., inverters at 15 years)
- Scheduled and unscheduled maintenance of solar PV plants, transformers, etc. over the technical lifetime of the plant (e.g., general maintenance, including cleaning and vegetation removal)."

Due to the above considerations, the actual O&M costs vary greatly in practice, however for the purposes of finding a balanced prediction for O&M costs up to 2040, the numbers from NREL's ATB will be used in this analysis also. This analysis also takes into account O&M estimates given by Lazard (2017), IEA (2016), and a historical study of the US market performed by Bolinger et al. (2017).

One important distinction is that the model does not predict that O&M costs will reduce year on year, but instead that projects built at a later time will have a lower annual O&M cost due to optimized designs and O&M plans.

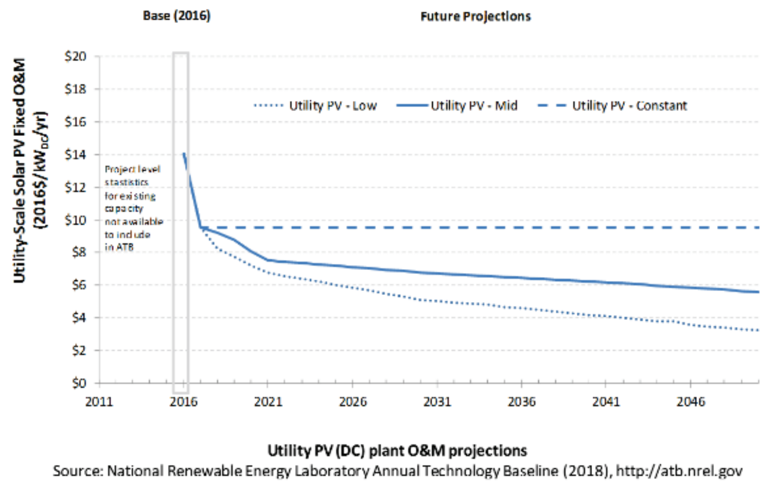


Figure 5-19- O&M estimates between 2016 and 2050. Source: NREL

Table 5-5 O&M estimates (extracted data input to the Balmorel model in Task C to this study)

Year	2025	2029	2034	2040
O&M (in 2018 kUSD/MW)	7.43	7.22	6.90	6.38

5.1.3 *Potential system Size and System Stability Considerations*

The maximum allowable size of PV within Liberia and the impact it will have on system stability is an *extremely case dependent topic*. As such we must begin with the disclaimer that all estimates made below are high level generalisations and must be confirmed with a proper grid study if solar is indeed chosen as an interesting alternative. Having said that, for the purposes of decision making, some broad assumptions can still be made based on literature on the topic and examples from other countries.

Some of these broad assumptions and notable Liberia specific characteristics are listed below:

- Due to the current makeup of the Liberian grid, the short-term variability of solar PV will most likely be compensated by either the Hydro power plant, the diesel generators or the CLSG line, as they are the fastest responding generators available.
- The main grid constraints will come in the dry season (when solar is at its peak and hydro is weakest). Thus, the firm capacity for hydro in the dry season will be used as the bottleneck when calculating the generation capacity of Liberia that is available for providing grid stability. From Hydrotec's report, this is assumed to be 0MW.
- Whilst it is highly site specific, this report from NREL[12], which investigated and modelled high PV penetration, found that in 86% of cases, penetrations up to 30% would not cause major grid problems. Likewise, Figure 5-20 below shows that the grids of Germany, Ireland, Maui and Denmark have managed to successfully integrate 20%, 22%, 35% and 42% renewables into their grids[13] respectively.
- In 2018, Multiconsult delivered a pre-feasibility report on a Mt Coffee hybrid Solar/HPP which determined that system stability could be maintained for a 35MW PV plant if hybrid operation of the HPP was designed to balance the intermittency of the solar. This would have been equal to 20% of Liberia's installed capacity. This did not include the increased stability that would have been provided by the CLSG. However, this also was not based on the findings of a full grid study.
- Hydro power and Interconnectors tend to have much shorter response times than traditional thermal generation sources and hence tend to facilitate greater penetration of solar before grid stability issues are encountered.

[12] https://www.nrel.gov/docs/fy12osti/55094.pdf
[13] https://www.nrel.gov/docs/fy17osti/68349.pdf

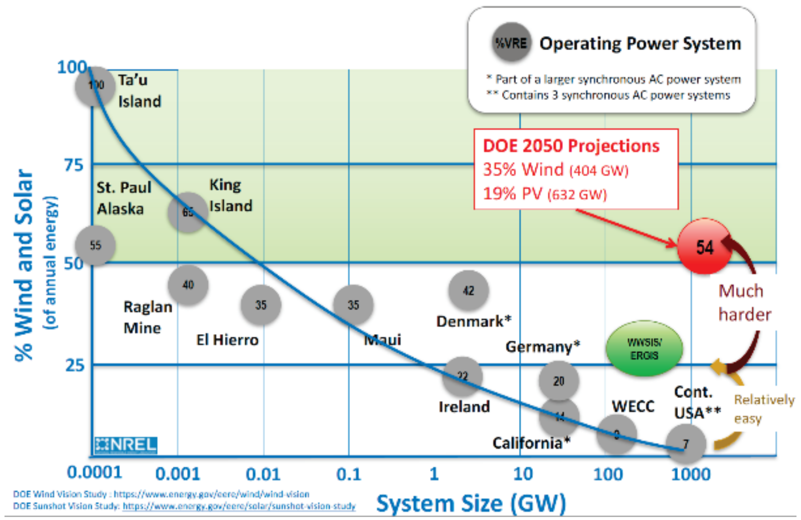


Figure 5-20- Variable renewable energy percentage of total annual consumption. (Source NREL)

Based on the above points, it is assumed that between 20%-30% of the total generation capacity available within Liberia can be from solar PV without causing major stability issues in Liberia. It is expected that the Liberian grid will be particularly constrained in the short term due to the lack of storage capacity of the Mt Coffee HPP and the rigidity of the HFO's. However, in the event that large scale HPPs with significant reservoir capacity are constructed upstream from Mt Coffee, the additional capacity and flexibility should increase the potential for solar.

The available capacities in the Liberian grid for supplying grid stability are highlighted in Table 5-6 below. One key uncertainty in these numbers is the capacity that will be available via the CLSG line. The below table considers the thermal capacity of the CLSG line that is expected to be 240MVA (or 216MW, assuming cosØ=0.9).

With this in mind, the following generation mix is assumed to be available for grid stability services in 2020-2028.

Table 5-6- Available generation capacity in Liberia

Wet Season	*Dry Season*	
80	0	MW Hydro
38	38	MW HFO
9	9	MW Diesel
127	47	MW capacity in Liberia
216	216	MW CLSG line
343	263	MW total available capacity
86	66	MW allowable solar capacity if 20% variable penetration accepted
147	113	MW allowable solar capacity if 30% variable penetration accepted

Thus, it is expected that between 66MW - 113MW of solar can be installed in the grid (following completion of the CLSG line and prior to additional hydro plants) without causing significant grid stability issues.

5.1.4 Conclusion

As the above analysis demonstrates, solar PV is already cost competitive with the other forms of energy generation currently installed, and being considered, in Liberia. Furthermore, the price reductions that are expected to continue in the market will make Solar PV one of the cheapest energy sources available. It appears prudent and inevitable that solar PV will play an important role in the future energy mix of Liberia and the region at large.

However, the key constraint to large scale deployment of solar lies in the intermittency of the generation profile and the grid stability issues that are implicit in this. Nevertheless, the current installed capacity within Liberia, in addition to the flexibility that will be added with the commissioning of the CLSG line, will enable a significant number of MW's to be installed in the short term. By doing so, Liberia could begin to develop their solar competence and begin to de-risk future projects in the minds of investors whilst simultaneously displacing generation from the existing HFO plants. In the next stage of this project, it is recommended to perform a grid integration analysis to gain more clarity on the ideal sizes and locations of such plants.

Following such a study, and provided the conclusions are favorable, it is recommended that solar PV plants begin to be rolled out in several phases in 2020-2028. Phases should be sized in line with the growing load, such that new generation can be absorbed by the grid without causing grid stability issues.

5.2 Wind

Currently, utility-scale wind development is taking place only in select markets in West Africa, such as Ghana and Senegal where 150 MW+ projects are being executed. In contrast, no utility-scale wind is currently planned or operational in Liberia[14].

5.2.1 Wind resources

The wind potential in tropical West Africa is generally poor compared to more resourceful parts of the continent, such as Maghreb, Sahel, East and Southern Africa[15]. Resource assessments are often based on models rather than on-site measurements, adding uncertainty to available estimates.

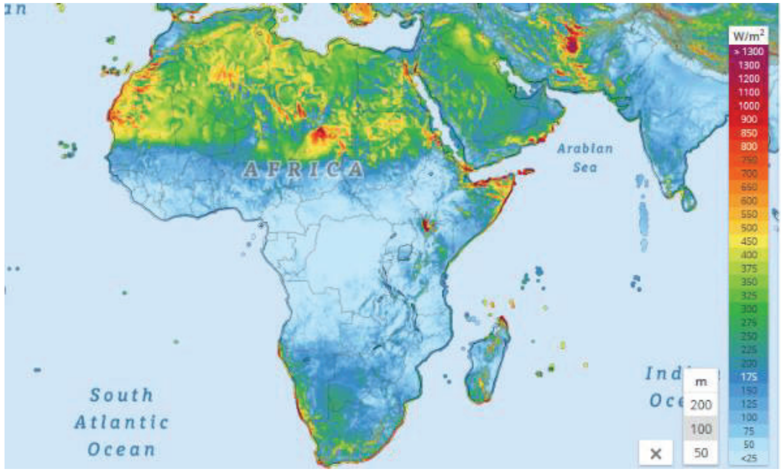


Figure 5-21 Wind resource map of Africa (W/m2 measured at 100 meters). Source: https://globalwindatlas.info/

In 2016, IRENA released "suitability maps" for grid-connected and off-grid wind and solar projects in West Africa[16]. These mapped the technical potential for such installations based on factors including population density, grid proximity and resource availability.

This study found the technical potential for Liberia on par with neighbouring countries in the region, except for "wind potential strongholds" Niger and Mali. The study also identified sites most suited for wind development in Liberia, for example in select mountainous and coastal areas of the country.

[14] https://www.irena.org/media/Files/IRENA/Agency/Publication/2018/Nov/IRENA_Planning_West_Africa_2018.pdf
[15] https://globalwindatlas.info/
[16] http://resourceirena.irena.org/gateway/dashboard/?topic=8&subTopic=56

5.2.2 The case for on-grid wind energy

Liberia prioritizes other renewables sources like hydro and solar, including in its National Renewable Energy Action Plan (NREAP) released in 2015.[17]

A poor grid transmission framework represents an important hurdle for intermittent renewables in general and wind energy in particular. Despite plans for grid expansion, the limited transmission system currently operating means significant technical potential for wind energy is located in areas where on-grid wind development is challenging. (Solar power plants may more easily be located closer to existing infrastructure.)

Poor road infrastructure and means transport of WTG components challenging, particularly for utility-scale machines. Lack of a suitable and established supply chain, both locally but also for equipment deliveries into Liberia, would likely incur substantial cost premiums both in CAPEX- and OPEX-phases. Again this is more critical for wind than for solar.

For reasons discussed above, Multiconsult finds little prospect of on-grid wind energy in Liberia, at least until substantial hurdles are addressed. Wind energy was not included in the least cost development model.

5.2.3 Other potential use cases

But wind energy could find some applications in off-grid areas in Liberia. In particular, small- and medium sized machines could lower LCOEs both in existing minigrids and at large commercial and industrial sites, for example in the mining sector. This potential for distributed wind, however, received no prominence in the country's Rural Energy Strategy and Masterplan, published by the country's Rural Renewable Energy Agency (RREA) in August 2016[18,19].

Liberia boasts a vast system of waterways and ambition for new hydro plants. Possibly, and to the extent suitable locations for such systems exist, there could be a case for hybridization with wind energy for added flexibility and pumped storage capacity.

5.3 Biomass

Biomass resources exist in large quantities in Liberia. According to "Assessment of Biomass Resources in Liberia" (USAID, 2009)[20] existing biomass resources indicates a power production potential of more than 21,000 GWh/year and the potential may more than double when more land is cultivated. Power production competes with other uses of the residues, as leaving the residues to ad nutrients to the soil, or using old rubber trees as timber. Refined products will achieve higher value as food or transportation fuel. The current use of bioenergy is mainly related to cooking and heating in form of firewood and charcoal in households. There is no existing power production of scale based on biomass.

[17] https://www.se4all-africa.org/fileadmin/uploads/se4all/Documents/Country_PANER/Liberia_national_renewable_energy_action_plans_nreap.pdf
[18] http://www.liberiaruralenergy.org/?q=content/renewable-energy-targets-and-energy-mix
[19] https://www.usaid.gov/sites/default/files/documents/1860/Liberia_-_November_2018_Country_Fact_Sheet.pdf
[20] Anelia Milbrandt, 2009, Prepared for the U.S. Agency for International Development (USAID) under the Liberia Energy Assistance Program (LEAP), https://www.nrel.gov/docs/fy09osti/44808.pdf

The utilization of some resources, as food crop residues, crude palm oil, animal manure and municipal waste may take place in small scale for power production in time. Such small-scale units with multiple stakeholders and considerable technological and economical risk, are not expected to be rolled out in numbers needed to give a contribution to the national and regional power system of a size that affects the optimization in this study. They may however have very high local interest and impact and as included in the Rural Energy Strategy and Master Plan for Liberia until 2030, highly relevant in minigrids, and not so much connected to the national grid, which is of most interest in this study.

Large-scale bioenergy plants based on cash crop and forest residues may be able to contribute to the larger energy system in a reliable way with substantial volumes. In light of existing industry and planes for agriculture and associated industry in Liberian, the most relevant fuels are residues from sugar cane and palm oil and kernels, rubber tree wood chips and coconut residues. These projects are dependent on industrial size projects with reliable supply chains of crops and residues. The figure below depicts the cash crop residues in Liberia by county.

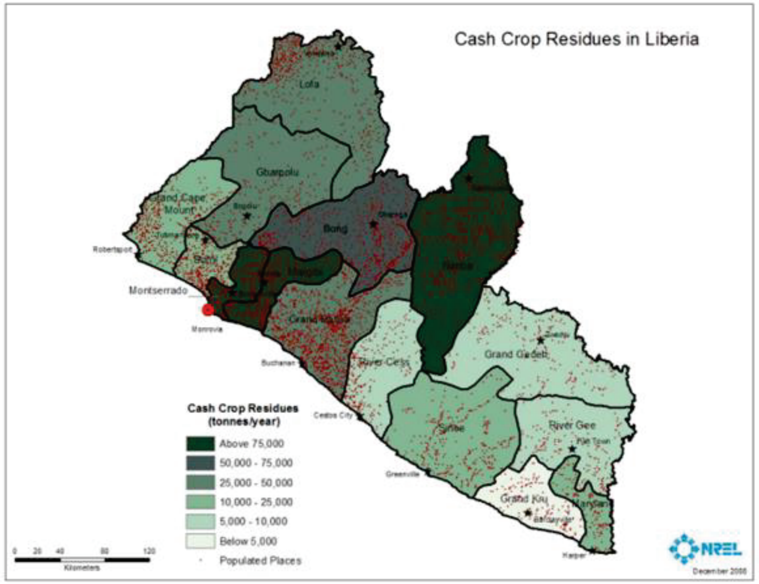


Figure 5-22 Cash Crop Residues in Liberia (NREL, 2008)

Today the industry is not using already collected residues for large-scale power production. For most crops, additional collecting of residues from the field will be necessary to ensure sufficient fuel (sugar cane excluded as the excess fibre after crushing gives sufficient volumes of the fuel bagasse). The cost of collecting residues might be substantial if the residues are not gathered together with the crop and brought to a central processing facility. To establish a reliable supply of fuel is only reckoned feasible for large plantations and not where the crop is delivered from a large numbers of small farmers. Our view is that these facilities will not materialize unless the industry finds it attractive financially, and in respect of security of supply for its own power consumption. The Rural Energy Strategy and Master Plan for Liberia[21] include at least one 5 MW biomass power plant delivering to the grid in 2020. This brief study have, however, not been able to identify existing matured plans for large-scale power production based on biomass relevant in the timeline of this study. In the light of the lack of existing plans, the complexity added by a fragmented agricultural sector and of ensuring a reliable fuel supply, we are not including biomass power production in this study.

The figure below indicate the range of costs of electricity (LCOE) based on biomass. There are large uncertainties related to these costs and a major uncertainty is related to the availability of feed stock, the cost of collecting it and ensuring a reliable fuel supply. Biomass was not included in the model.

[21] http://www.liberiaruralenergy.org/?q=content/renewable-energy-targets-and-energy-mix

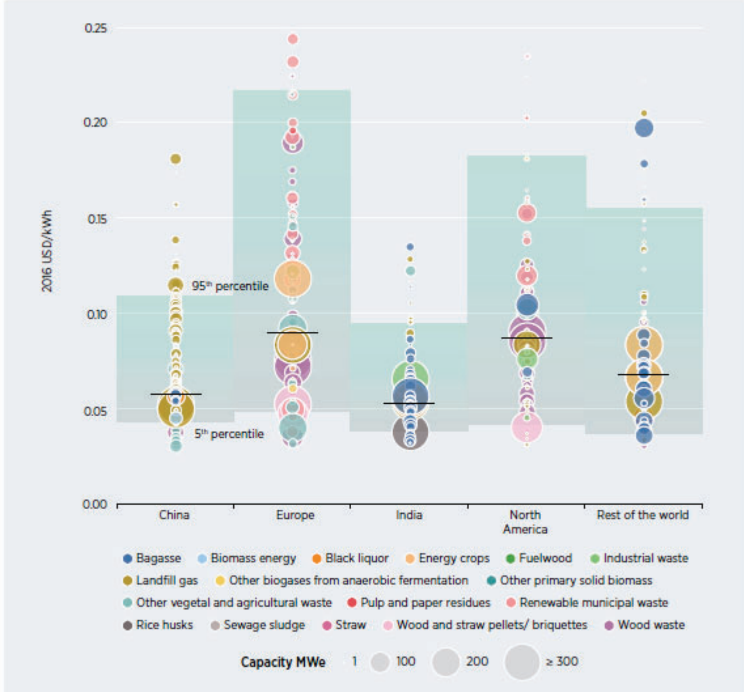


Figure 5-23 Levelised cost of electricity by project and region of bioenergy- fired electricity generation (IRENA, 2017)[22]

5.4 Thermal

More than half of Liberia's current power production is based on diesel or heavy fuel oil (HFO). The import facilities are in place as well as know-how. The simulation model includes the option to increase the diesel and HFO capacity in the cost optimization, and the tool will be able to choose from engines and turbines.

Engines might be preferred based on cost and the existing domestic knowledge and experience of the technology, however OCGT might serve a purpose as quick response and peak. The CCGT might show best values if no hydropower dams are introduced to the system and thermal power

[22] https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2018/Jan/IRENA_2017_Power_Costs_2018.pdf

will need to fill major seasonal gaps in HP generation. To ensure all year availability regardless of location, air cooled condenser is the preferred technology in the simulations.

*Table 5-7 Assumptions on new thermal generation assets**

Type	Fuel type	Plant availability %	Fuel efficiency %	Capital expenditures USD/kW	Fixed O&M costs kUSD/ MW/y	Variable O&M costs (fuel excluded) USD/ MWh
DI	HFO	85%	40%	1,000	18.5	6.5
DI	Diesel	85%	40%	1,000	18.5	6.5
CCGT	Diesel	90%	50%	1,500	39.8	7.0
OCGT	HFO	90%	30%	900	4.7	17.4

*(Sources: Tractebel (2018); Multiconsult.)*Note that the table does not include fuel cost. In the simulation the fuel cost is included with a projection.*

Having no history of nuclear power, the nuclear option is considered unrealistic. Import of coal and the construction of a first coal power plant is not considered a viable option. If any increase in coal power capacity in the region, this will be most likely established where such plants already exist.

5.5 Energy Storage Systems

5.5.1 Classifying energy storage

Energy storage can serve multiple functions in the power system, each with different size, power and functional requirements. These can be broken down into four broad categories as described below (the scales in parentheses have been generally adapted towards the Liberian context);

1. Seasonal storage – Very large energy requirements (GWh – TWh) with relatively low power requirements (MW). This is typically used to store excess energy from seasons where rainfall, wind or PV generation is high into seasons where energy generation is insufficient.
2. Daily Storage – Large energy requirements (MWh-GWh) with higher power requirements than seasonal storage (MW). This is typically used with wind & solar to ensure energy security for a number of days in the event that the respective resource is low (ie solar will underproduce if there are a few rainy days in a row). Hydro is less effected by such short-term effects.
3. Hourly storage – Medium/large energy requirements (MWh) with even higher relative power requirements than daily storage (MW). This is typically used to support peak load times in an energy system. An example of this would be to store excess energy during off peak hours and then discharge during peak hours.
4. Short term storage – This requires a rather small energy capacity (kWh – MWh) and very high relative power ratings (MW). This is typically used for grid services such as frequency

or voltage regulation that take place over very short time scales (micro seconds - seconds - minutes).

Daily and hourly storage requirements in the Liberian and CLSG power system can be accommodated at lowest cost using the SP hydropower reservoirs to regulate hourly and daily load variations. The marginal cost of providing daily storage in the planned reservoirs at Via, SP3, SP2, SP1 and SP0 is very low, since the reservoir size is primarily created to utilize the head of the dam, and can be regulated around 1-2 m to provide all required hourly and daily storage needs.

5.5.2 Type 1: Seasonal storage – alternative options

Established renewable storage technologies

Lithium or similar chemical batteries.

Lithium battery storage systems have, to date, never been utilized for seasonal storage at large scale. At present, battery costs are between 350 – 500 USD/kWh (Li-Ion). These prices are likely to decline quickly, but even if we assume a 50% reduction in the next 10 years, they could not come close to the costs of storage from the Via dam (which can achieve about 500 GWh of storage for 1000 MUSD, and thus a rough cost of storage of 2 USD/kWh). It should also be noted that Li-ion battery life is only 10-15 years, whereas a dams lifetime is 50-100 years. Finally, there are other battery chemistries (such as flow batteries) which may be better suited towards seasonal storage, however, to date there have been no examples of projects at such scales, and furthermore, these have no prospect of prices coming down to anywhere near the 2 USD / kWh cost of seasonal hydropower reservoirs

Concentrated solar is a solar technology transferring solar energy to heat energy to drive steam turbines on a continuous basis. The costs are still considerably higher than solar PV, but the energy provided is more predictable and does not suffer from short term variations in the solar resource as does solar PV. Essentially, the stored heat can be used to provide hourly and even daily storage as defined above. Nevertheless, it does require a steady solar resource in order to replenish the heat reserves and a few sequential days of overcast weather will result in a decreased output from the plant. In Liberia, it is likely that prolonged cloudy weather will significantly limit output during the rainy season, with either very large expensive heat storage or very low firm energy specification. Concentrated solar energy cannot compete with solar PV in Liberia in the planning horizon.

Seasonal pump storage

There are some seasonal pump storage schemes in Norway, used to store snowmelt floods for later use during the dry winter season. However, their reservoir sizes are the same as seasonal reservoirs for conventional power plants, and they only become economic where two large lakes can be provided close to each other with a high head difference. This is not the case in Liberia.

Compressed Air Energy Storage (CAES)

Compressed Air Energy Storage plants are largely equivalent to pumped-hydro power plants in terms of their applications, output and storage capacity. But, instead of pumping water from a lower to an upper pond during periods of excess power, in a CAES plant, ambient air is compressed and stored under pressure in an underground cavern. When electricity is required, the pressurized air is heated and expanded in an expansion turbine driving a generator for power production. There are only a few CAES projects at large scale and the price point will still be significantly higher than utilizing the flexibility in the dams.

Emerging renewable storage technologies

Tidal lagoon energy is also reliable daily energy source using reversible turbines to provide near continuous output except for 4 times a day when the ebb and flow is neutral. A landmark project on the Severn estuary will provide over 500 GWh annually and is approaching a bankable project (see https://www.theguardian.com/environment/2019/feb/04/swansea-tidal-lagoon-plan-government). However, it must be recognized that the tidal range at this site is over 5 times larger than the tidal range along the Liberian coast, and tidal lagoon storage options are therefore not viable for Liberia

Sink- Float solutions. OGRES system http://sinkfloatsolutions.com/.

This is a relatively untested technology which promises to reduce storage costs below many other storage solutions. However, it will not be economic for seasonal storage because the volumes of concrete required for providing a single cycle of seasonal storage will be enormous. The seasonal storage required for the CLSG system means that each module can only be raised and lowered once a year, making the capital cost in terms of infrastructure very high for such infrequent use. As with batteries, this technology will become economic primarily for hourly or daily storage needs where many hundreds of cycles per year can provide benefits commensurate with the capital investment cost.

5.5.3 Type 2: Daily storage.

Pump storage hydropower plants

Pump storage hydropower is also normally for daily or hourly storage needs such as load following (e.g in France and Russia where base load is provided by nuclear power). In Norway and other countries with extreme seasonal variation in flow (such as Liberia) the only pump storage type for serious consideration is seasonal. This means that the pump storage plant must use two seasonal reservoirs (compared to the one in Via). Furthermore seasonal pump storage is usually only economic when a high head (several hundreds of meters) is available. This reduces the reservoir volumes needed for the same MW output. In Liberia, we only have projects with 15-40 m head, and the availability of reservoir sites big enough to provide comparable storage as in Via reservoir is the limiting constraint.

Furthermore, pump storage is becomes relevant after all other peaking capacity hydro plants are already built. The peaking plants proposed in this report, will all meet system demand with net energy production, while pump storage will need the same reservoir sizes and still require net consumption of energy during its annual cycle of filling and emptying the reservoirs. There is therefore no need to consider pump storage options when conventional hydropower options are still available in the same river basin.

The proposed reservoir from SP2 provides more than adequate daily storage for covering cloudy periods or periods of days with prolonged line outage. In fact the SP2 reservoir is now large enough to provide a small amount of seasonal storage. The daily storage benefits of SP2 will also benefit operation of Mt coffee since the transit time for releases from SP2 is less than one day, so both power plants can be run in tandem to cover several days of increased output, irrespective of time of year or inflow.

5.5.4 Type 3. Hourly storage

Adequate hourly storage for peak load following is available for all hydropower candidates, and with no extra cost for each of the projects. The reservoirs have been planned to hold sufficient active storage for all patterns of daily load variation.

Using batteries and solar PV to *replace* these hydro dams would require increasing the size of the PV plants dramatically in addition to the battery energy system, which would become more expensive and is not cost competitive. If the hydro power plants are built, then there would essentially be no need for battery storage for this task.

Mt Coffee peaking operation

Mt Coffee has some hourly storage capability already. With 1.8 m of regulation of reservoir level at the intake, 9 million m3 of storage can be utilized. This is equivalent to 5.7 hours at maximum station capacity of 88 MW plus whatever inflow can be used to extend this period. The peaking operation would comprise of peak 88 MW output for up to 4 evening hours (approximately 1 m drawdown followed by reservoir refilling in the remaining 20 hours). This sequence can be repeated every day with an inflow of only 95 m3/s assuming 8 m3/s fish pass environmental release. As the inflow falls below 95 m3/s the duration of 88 MW peaking supply would have to be shortened, for example to only 2 hours when inflow is 50 m3/s, or 44 MW if 4 hours peak supply is required.

Mt Coffee can therefore be characterized as hourly storage, useful in covering peak evening demand for the weekday load between 20.00 and midnight. This is also useful for balancing daily solar PV input, since the substation and transmission line can carry for example 30 MW of solar capacity in the daylight hours while the reservoir is refilling with the power plant output zero in the dry season, ready for the evening peak hydropower operation.

Mt Coffee may also be able to provide spinning reserve or fast reserve (short-term storage) to balance unplanned outages either in the solar PV (clouds passing over) or CLSG line breaks, substation failures etc. However, this facility is not available in the peak load hours if Mt Coffee is already supplying at full 88 MW output. For short term storage – see battery options section.

The LEC and CLSG systems are therefore looking for other options to provide seasonal storage, and it is the seasonal load variations which require the greatest storage capacities, having to load up during the 6 wet months and unload during the 6 dry months

5.5.5 Type 4: Short term storage

In general, Hydro power and interconnectors are considered to be rather "fast responding" generators, both of which can also provide grid services to help balance the variability of solar. Despite this, it may be the case that battery storage could provide additional value in this segment. Likewise, there are several other energy storage technologies suitable for short term applications which may also be suitable for Liberia. These include capacitors/supercapacitors, Magnetic energy storage, flywheels and fuel cells. However, it is not possible to predict this at this high level of assessment and we would argue that it does not make sense to include battery storage in the Balmorel model for this purpose.

6 Environmental and Social Risk Mitigation

6.1 Introduction

The final Supply Options Report submitted by Multiconsult on June 13, 2019 contained an overview of the identified environmental and social risks for the potential hydropower projects considered for development on the St. Paul River. The aim of the environmental and social assessment was to screen the risks and potential impacts in order to identify possible red flags and/or fatal flaws that might disqualify any of the projects for consideration. The main risks and impacts considered to date included the following categories:

- Economic and political: Impacts on proposed national park land and concession agreements
- Environmental:
  - Change in downstream river flows and flooding frequencies
  - Sediment trapping and transfer affecting ecological processes
  - Watershed management requirements
- Power potential: Environmental flow requirements
- Water quality: Safeguards for White Plains treatment plant, St. Paul adjacent communities
- Biodiversity: Loss of critical habitat, both terrestrial and aquatic
- Social: Requirements for resettlement and compensation
- Mitigation and off-set costs:
  - Reservoir clearing
  - Fish passages, turbine screens
  - Watershed management
  - ESIA, RAP, oversight and monitoring
  - Resettlement and asset compensation.

Of these, the greatest risks were considered to fall under the environmental and biodiversity categories, meaning these were the categories thought to require further work to determine whether mitigation would be possible. These pertained mainly to the Via Reservoir and SP4 diversion. The team recommended several next steps toward identification of the priority project. These included conducting a rapid biodiversity assessment in the area of the Via Reservoir, where approximately 100 km2 or more of primary, untouched forest was expected to house multiple endangered, vulnerable, and charismatic species. This fieldwork was conducted between June 23 and July 6, 2019, and the report summarizing outcomes was submitted on July 16, 2019. In addition, the team recommended that consultations be furthered with the Government of Liberia in regard to the current status of the Kpo Mountain National Park as well as the concession agreements that were identified as being likely affected by the priority projects under consideration.

Field investigations related to this final report were focused on the Via reservoir in particular, since, of all the schemes considered for the long-term development of Liberia's power sector, it would have the biggest environmental and social footprint and highest related cost. These environmental and social risks and impacts would require careful and detailed studies, and costly mitigation measures. Not all impacts of the Via can be fully mitigated, and would likely affect the entire cascade.

Further optimization conducted for the alternatives previously identified has confirmed that development of SP2 represents the priority investment project (PIP) for the Liberian context. This recommended PIP carries lower environmental impacts than Via, but significant social impacts. The primary recommendation is to develop SP2 in one step with a reservoir full supply level (FSL) of 163.

However, little is known about the ground conditions at the relevant dam power station and canal sites, and the SP2 project may take on a different form once ground investigations have revealed the foundation depths, and rock and soil qualities such as permeability and particle grading curves. Therefore, several alternative sites have been sketched up, and one of these involves a two phase development with an initial run-of-river plant to shortcut a river bend where rock exposures have been observed. This would imply the later construction of the SP2 dam and reservoir as a second phase. The main impact during phase one would be an interruption in the river continuum, requiring a fish pass, which could also be developed in phases.

While the Supply Options report considered all potential projects on the St. Paul River, the current report is concerned primarily with the PIP. As summarized in Table 6-1 below, the environmental risks and impacts for the recommended PIP of SP2 are mainly categorized in the low to medium range, but are able to be mitigated. In order to achieve dry season storage capacity, a FSL of 163 masl is being recommended for SP2 reservoir development. However, this includes a safety or flood margin of just one meter. Further analysis needs to be conducted on the appropriate safety margin based on an assessment of the design flood as well as the unplanned outage level. Should the recommended safety margin exceed one meter, the resultant impacts on resettlement and compensation may require pursuit of a lower FSL. In general, the achievement of seasonal regulation with the larger reservoir size does carry greater impacts on resettlement and compensation which increase as the FSL increases. In this regard, the advantage of developing SP2 in a phased manner is that ample time would be allowed during phase one implementation to carefully design the phase two dam including resettlement mitigation measures and programs to insure the least impact on affected villages.

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Table 6-1. Environmental Risk Screening of Proposed Schemes.

E&S Criteria/Risks	SP2 Ph. 1 (3-phase approach)	SP2 Optimised	MCHPP Extension	Via and SP4 transfer
Technical Characteristics				
Installed capacity (MW)	66	156	44	88
Full supply level (FSL)	N/A	163	N/A	234
Reservoir Area (km2)	N/A	50	N/A	408
Bio-physical Indicators				
Total habitat loss (reservoir areas)	Low	Medium	N/A	Very High
Habitat Fragmentation (dry season)	Low	Medium	N/A	High
Biodiversity Loss (potential Critical Habitat)	Low	Low-Medium	N/A	Very High
Deforestation (reservoir clearing)	Low	Medium	N/A	Very High
Fish migration barrier (need for fish passage)	High	High	N/A	High
Creation of dry river beds, flood plains	Low	Potential	N/A	Medium
Environmental Flow Required	High	High	N/A	High
Biodiversity Offset Required (terrestrial)	Low	Low	N/A	High
Socio-economic Indicators				
Number of Villages Affected[4]	0	20	N/A	19
Resettlement (# of direct PAPs)	0	5906-8505	N/A	2063-2970
Loss of Structures	0	1575	N/A	550
Necessity to compensate Concessionaires	Low	Low	N/A	High
Physical Cultural Resources	Low	Potential	N/A	Likely
General E&S Performance Indicators				
Power density (MW/km^2)	0	3.1	N/A	0.2
Resettled persons/MW	0	38 - 55	N/A	23 - 34
Fatal Flaws	None	Unlikely	None	Potential (biodiversity)

It should be noted that the risks of focus in this study have been those that might disqualify a project from development in the Liberian context, and in particular the risks that differentiate one candidate project site from the next. Risks that would apply to all sites or to any infrastructure development in Liberia – such as the risks of reoccurrence of the Ebola virus – have not been evaluated here but would need to be included in the eventual ESMP for the chosen project, along with carefully prescribed mitigation measures. A list of relevant impacts and mitigation measures is included in Section 6.8 below.

The mitigation measures required for the risks of focus in this study fall into the following main categories:

I. All proposed schemes:
   1. Aquatic migration off-sets:
      a. Construction of multi-species passages
   2. Environmental protection:
      b. Environmental flows
      c. Shoreline reforestation and erosion protection
      d. Natural resource and watershed management programs
   3. Political/economic impacts:
      e. Potential compensation of concessionaires

II. All proposed schemes except for SP2 Phase 1:
   1. Social safeguards:
      f. Resettlement and compensation
      g. Replacement of lost agricultural land
      h. Handling of sacred sites

III. Via/SP4 scheme only:
   2. Terrestrial biodiversity off-sets:
      a. Creation of protected area(s) to address critical habitat loss
      b. Conservation strategies (e.g. wildlife corridors) to address habitat fragmentation.

The next sections provide greater detail on mitigation planning (and refined costing) for SP2 in particular and in general for the other sites, as well as field investigation programs that will need to be executed at the next stage of the studies.

6.2 Aquatic Migration Off-sets

The St. Paul River has been found to have a high species diversity including both freshwater and marine migratory species. An overview of fish and fisheries studies conducted at Mt. Coffee since 2014 to the present time has been provided in the previous reports.[23] Studies were ongoing during July-August 2019 through MRAG/Fishtek with funding from MCC, focused on final design of the prawn passage. However, no studies have been carried out upstream of Mt. Coffee. As noted in the Task B report, Mt. Coffee sits almost exactly at the boundary between the habitats for freshwater and marine/transitional species; during the dry season, ocean species are seen at Mt.

[23] MRAG (2019). Fishery Study for Mt. Coffee Hydroelectric Power Plant Watershed Management.

Coffee. The habitat of the fresh water fish that tend to migrate essentially ends around Mt. Coffee, meaning that Mt. Coffee represents the downstream boundary of their full range of migration. Therefore it must be emphasized that the only data available for fish and fisheries on the St. Paul River is limited to the end of the freshwater habitat range, meaning some variation will likely be found upstream.

Since MRAG/Fishtek is familiar with the lower stretches of the St. Paul River, however, Fishtek was engaged to assess mitigation options and estimate a budget for the four sites under consideration in the final Supply Options report (in task B of this study). These costs were subsequently reviewed by Norwegian experts and found to be unrealistically high. Therefore, the costs have been revised down based on international standards while the design arguments have been retained.

A fish pass aims to mitigate some of the impacts caused by a dam by maintaining longitudinal connectivity of a river to avoid fragmenting fish populations and habitats. Without efficient fish passage facilities, migratory species are at greater risk of local or absolute extinction. The key types of fish pass that have been assessed for the four priority schemes are summarized in ***Table 6-3*** below. These include two types of volitional fish pass and two types of mechanical fish pass. Volitional fish passes have been used at low-medium head sites (<10 m) with good efficiencies, and there are some examples of these being used at very large dams, such as the Canal de Piracema fish pass in South America, which is 10.3 km long with a 120 m elevation gain. Shorter length fish passes are typically more efficient than longer fish passes and sequential loss of fish in longer fish passes has been well documented.[24]

Mechanical fish passes (i.e. fish locks/lifts) offer an alternative solution with larger head drops (>20 m) and where construction space for a large volitional fish pass is limited. However, for low-medium head drops mechanical fish passes are typically less efficient than volitional fishways.[25] This is likely to be due to the fact that many existing fish locks/lifts have poor attraction flow and lack facilities to prevent fish escaping between operations. This could be overcome with appropriate modifications (i.e. additional attraction channels, in scales, fish directors/followers).

The advantage of a volitional fish pass is that it can be designed to accommodate both prawns and fin fish species. The success of such a pass is determined by its slope and the attraction flow. While these can be designed for any head, they result in exceptionally long channels at high heads (e.g. 40 meters, such as at the optimised SP2). Channels can zig-zag up the side of the dam structure, but cost becomes the determining factor at such lengths.

[24] See Agostinho, A.A., Marques, E.E., Agostinho, C.S., Almeida, D.A., Oliveira, R.J. and Rodrigues, J.B.M. (2007) Fish ladder of Lajeado Dam: migration on one-way routes? Neotropical Ichthyology, 5: 121–130; Makrakis, I.S., Gomes, L.C., Makrakis, M.C., Fernandez, D.R., Pavanelli, C.S., 2007. The Canal da Piracema at Itaipu Dam as a fish pass system. Neotropicsl Ichthyology, 5(2): 185-195; Wagner, R.L., Makrakis, S., Castro-Santos, T., Makrakis, M.C., Dias, J.H.P. and Belmont, R.F. (2012) Passage performance of long-distance upstream migrants at a large dam on the Parana River and the compounding effects of entry and ascent. Neotropical Ichthyology, 10(4): 785 -795.

[25] Noonan, M.J., Grant, J.W.A., Jackson C.D. (2012) A quantitative assessment of fish passage efficiency. Fish and Fisheries 13(4): 450-464.

The minimum design flow for the proposed passages was estimated based on international guidance and is given in ***Table 6-2*** below, deducted from the generation flows in the model. This guidance is based on the simplified principle of the ratio of fish passage attraction flow to other flows at the passage entrance. It is not necessarily appropriate to use in all situations without careful consideration of the prevailing conditions when upstream migrations of important species are taking place. It must therefore be considered as a generalised initial guidance parameter only.

Table 6-2. Minimum fish pass design flow.

Dam name	Turbine discharge (TD) / ADF (m^3/s)	Minimum fish pass discharge (m^3/s)
Via reservoir	TD= 330	5
SP4 dam/diversion channel	ADF = 251	3.8
SP2 FSL 163 final stage.	TD = 700	10
SP0	TD= 700	10

Table 6-3. Overview of Recommended Fish Pass Types.

Type	Description	Head (m)	Gradient (%)	Advantages	Disadvantages
Natural bypass channel	Naturalised bypass channels are nature-like channels that bypass a barrier and typically provide fish passage to a wide range of species. Perhaps their biggest disadvantage is their space requirement compared to more technical solutions. It is preferable that channel banks are gently sloping similar to a natural river channel (i.e. 1:3), but it is possible for one or both banks to be formalised (i.e. by forming concrete or sheet-piled retaining walls) to limit the channel footprint	Limited by gradient. Examples up to ~20 m	Characterised by their low gradients, which are typically in the region of 1 % (Larinier,2001; DVWK, 2002)	Can have a restorative effect by replacing a proportion of the free-flowing riverine habitat that has been lost through impoundment and have been shown to have a high efficiency of fish passage, although attraction to this type of fish pass can be variable (Bunt *et al.*, 2012).	Perhaps their biggest disadvantage is their space requirement compared to more technical solutions. It is preferable that channel banks are gently sloping similar to a natural river channel (i.e. 1:3), but it is possible for stepper semi-engineered banks or one or both banks to be formalised (i.e. by forming concrete or sheet-piled retaining walls) to limit the overall footprint of the channel. Given the space required to build a naturalised bypass channel at large dams they are often built in combination with other types of fish pass (i.e. fish lock/lift)
Vertical slot	Vertical slot fish passes are a type of fish pass often used to overcome low head barriers (<6 m). They are typically formed in a concrete and/or a sheet piled channel and comprise a series of pools that are separated by walls containing one or more vertical slots between the pools. Fish typically exhibit burst swimming behaviour when ascending from one pool to the next via the vertical slot but can rest within pools.	Typically, <6 m but have been used on heads of up to 18 m (to varying degrees of success)	The head difference across each slot should be ≤ 0.3 m (depending on the species of concern) and the overall gradient is typically ≤ 10%.	Vertical slot fish passes can be engineered to accommodate a wide range of species, including those with comparatively weak swimming abilities, and have been used in temperate and tropical rivers.	Pools must be suitably large enough to dissipate energy and prevent overly turbulent conditions. This can result in long fish passes in order to accommodate weaker swimming species. Vertical slot passes are typically most successful with low head schemes.
Fish lock	Fish locks work on a similar principal to navigation locks. Fish are attracted into a large downstream holding pool, which after a pre-determined amount of time is closed and filled with water. Once the water level in the pool is equal to or above the reservoir water level, upstream gates open to allow fish to exit the lock.	N/A	N/A	Fish locks can be engineered to accommodate a wide range of species, including those with comparatively weak swimming abilities, and have been used in temperate and tropical rivers to overcome medium- to high-head schemes. They are often sued in combination vertical slot passes or bypass channels. Suitable for sites with head drops much greater than 20 m, due to	The efficiency of fish locks mainly depends on the behaviour of the fish, which must remain in the holding pool until lock operation, follow the rising water level and exit the lock when the upstream gates open. Fish locks have a limited capacity in terms of the number of fish they can hold and the frequency that they can operate. Attracting and maintaining fish within the facilities before the downstream gates close can also be difficult for a diverse fish population. Some of these issues have been resolved by installing mechanical inscales to direct fish towards the holding pool (known as a crowding device) and a 'follower' that directs fish towards the surface during the filling phase (Trivade & Larinier, 2002).

				the inefficiencies associated with very long fish passes.	
Fish lift	Fish lifts adopt similar principals to fish locks, except fish are directed into a trap which is raised above the dam with a small amount of water. The trap then tilts forward and empties its contents (fish and water) into the forebay. At sites where it is necessary to pass a large biomass of fish a holding pool may be constructed before the fish trap, with a fish crowder that directs fish into the trap pre-operation. This prevents overcrowding of the trap prior to operation, which is associated with high levels of mortality.	N/A	N/A	The benefit of fish lifts at large dams is their relatively small footprint and their ability to pass species that have difficulties ascending traditional fish passes, specifically weaker swimming fish. Suitable for sites with head drops much greater than 20 m, due to the inefficiencies associated with very long fish passes.	The efficiency of fish lifts mainly depends on the behaviour of the fish, which must remain in the holding pool until lift operation. Fish lifts have a limited capacity in terms of the number of fish they can hold and the frequency that they can operate. Attracting and maintaining fish within the facilities before the downstream gates close can also be difficult for a diverse fish population. Some of these issues have been resolved by installing mechanical inscales to direct fish towards the holding pool (known as a crowding device) and a 'follower' that directs fish towards the surface during the filling phase (Trivade & Larinier, 2002).

The following tables present the preferred types of fish pass for each of the priority schemes, including approximate design parameters based on the available information and best practice guidance. It has been assumed that the head drop which the fish pass must overcome is as per the dam operating head. If there is a long, deprived reach and the fish pass is located at a spillway dam as opposed to at the turbine outfall/tail-race channel, then depending on site topography the fish pass may be shorter and also more cost-effective.

The fish pass described in **Table *6-4*** is relevant for both the Via dam/HPP and SP0, since the dam height for both is estimated at 25 meters. The fish pass described in Table 6-2 is relevant for both SP2 and SP4, since they both have heads estimated at 40 meters or higher.

The budgets for the volitional fish passes calculated by Fishtek are not included here. Section 6.9 contains estimated budgets for each of the passes. These would need to be further refined as the dam designs are developed; it should be possible to reduce the cost of constructing a fish pass at the dams by optimising the design. This may include reducing the size of the fish pass and delivering additional flow via attraction channels, reducing the length of the fish pass and combining it with a well-designed fish lift or lock, and/or optimising the flow regime so that the fish pass targets windows of peak fish migration. Other measures include installing trash removal infrastructure upstream from the intake; use of fine-screen trash racks that double as fish screens; use of a lower minimum discharge for flow attraction based on placement; phased development of the passage lowering dam height; use of local contractors, etc.

It should also be noted that the identification and design of the PIP presented in this study considers a balanced approach between the levelized cost of energy, the forecasted demand for low-cost energy, and the relative priority of mitigation measures. Decision makers in Liberia will need to prioritize design details based on available funding, and it may be that following completion of fish and fisheries studies the inclusion of an expensive fish pass may not be justified. Therefore this analysis has considered reasonable rather than conservative costs. The costs presented in Section 6.9 are based on the following assumptions:

- A base cost is assessed for each of the fish passes which is then adjusted based on the head. This maintains consistency in costs between the various options.
- The design assumes use of trash racks with a 15 mm opening and rack cleaners, which is effective for preventing fish passage through the turbines. This avoids the costs of adding fine screens to normal trash racks.

It should also be emphasized that the cost of fish passages are not stand-alone costs related to new dam construction, as some of the costs (e.g. earthworks, rock, etc.) would be reduced proportionally from the cost of the dam construction. The below analysis includes unit estimates for rock, but this may also be reduced should such material be available from excavation during dam construction.

Table 6-4. Recommended fish passage option for the Via dam/HPP and SP0.

Design feature	Description - primary fish pass
Type	Of the fish passage options detailed in ***Table 6-3***, naturalised bypass channels have the highest overall passage efficiencies (70% for naturalised bypass channel versus 45% for vertical slot - Bunt et al., 2011) and can cater for a wider range of species including freshwater prawn. A natural bypass channel would be likely to be the most suitable fish passage mitigation option for this site which has a head of 25 m. Whilst this would result in a particularly long channel, it is believed that a well-designed fish pass with heterogeneous flow conditions and habitat types could have improved efficiencies compared to some of the existing long fish passes that perform poorly.
Flow	The natural bypass channel should aim to discharge between 1.5 to 5% of the turbine discharge. The minimum design flow for the bypass channel for this site would therefore be 4.95 m^3s^{-1}.
Formation	A trapezoidal channel (6 m base width with battered back banks at a gradient of 1:2) with shallow, roughened and wetted margins that replicate the existing bank side habitat. The channel should have a very roughened wetted perimeter, achieved from using rip-rap (mostly reclaimed from site excavation) to form the channel bed. Additional roughness and habitat can be created with the inclusion of large perturbation boulders and smaller boulder clusters. It should be aimed to achieve a relatively high roughness coefficient (manning's n value) in the region of 0.040. The channel would comprise typical riffle type sections in which fish would need to exhibit sustained and/or burst swimming behaviour to ascend upstream, with dispersed pools where velocities would be much lower. A heterogenous channel with varied features (i.e. submerged vegetation and rock) would also create valuable habitat, off-setting some of the habitat lost in the reservoir and deprived reach.
Gradient & Channel length	The optimum gradient to achieve an average velocity of 0.697 m s^{-1} in the main channel is 1%, assuming a channel discharge of 4.95 m^3s^{-1} and a roughness coefficient of 0.04 and channel depths of 0.91 m at the centre. This results in a main fish pass channel that is approximately 2.5 km long. The total footprint of the natural bypass channel would therefore be approximately 13 ha.
Material Quantities	

Item	Units	Quantities
Earthworks	m^3	968,750
Concrete	m^3	3600
Rebar	t	108
Formwork	m^2	1,800
Steelwork	t	54
Rock	t	50,400

Table 6-5. Recommended fish passage option for SP2 and SP4.

Design feature	Description - primary fish pass
Type	The SP2 dam built in one step, with a head height of over 40 m, would require an exceptionally long naturalised bypass channel or volition pass for fin fish. This would necessitate a significant footprint. The SP4 dam is also considered with a head height of 40 m, with the same constraints. As such, a fish lock or lift would be the preferred option for both sites. Fish lifts and locks are often the preferred solution at sites with particularly high heads (i.e. the aforementioned Santa Clara dam has a 60 m hydraulic head), but they are not true volitional fish passes as mechanical energy is required to lift fish over the dam.
Flow	The fish lock or lift should aim to discharge between 1.5 to 5% of the turbine discharge (or transfer discharge). The minimum design flow for the fish lock or lift would therefore be at least 3 m^3s^{-1}.

Should SP2 be developed in three phases, and fish and fisheries studies conclude that a fish pass will be required for the first two phases, a natural bypass channel could be constructed at SP2 Phase 1 as an initial step. This channel would lift the migrating fish and prawns 18 m from the tailrace canal to the power intake pond on the east side of the powerhouse. By use of low-lift pumps using the tailwater, attraction flows could be created in the lower steps of the fish passage, potentially allowing for a lesser design release in the passage of 3 m^3/s. The 4 m overflow weir is low enough that fish may pass over it for downstream migration. This design could be assessed for efficacy before further investment in a fish pass would be made during Phase 2.

Despite the studies conducted at Mt. Coffee, data is lacking for the St. Paul River and for Liberia in general regarding swimming ability of fin fish, which is a necessary consideration (together with temperature of water) when designing a fish pass. While information is available on species diversity as well as food security for the area of the St. Paul River around Mt. Coffee, there is no data available for the upstream reaches. Fish passes must be built to the behaviours of the species targeted for survival. The prawn pass to be built at Mt. Coffee during late 2019/early 2020 has been designed based on an understanding of the prawn life cycle and swimming ability in other contexts; in addition, trials have been carried out at the site to assess the climbing ability of prawns in the St. Paul River. The results of the Mt. Coffee prawn pass should be monitored for lessons learned that will apply upstream.

The results of a monitoring program would apply also to downstream passage – it is not yet known whether prawns and fish are passing over the Mt. Coffee spillway and surviving, for example. For each of the sites, it will be important to consider requirements for downstream migrants. Fish may be susceptible to injury or mortality as a result of passing downstream via the spillway. Fish byway routes may be required at higher dam sites. This may cost in the region of 25-30% of the cost of upstream migration facilities.

Baseline fish surveys will need to be conducted for all sites in order to determine fish biodiversity and the life history of the species, including, but not limited to habitat requirements, swimming abilities and whether they undertake regular migration. It is also important to identify those fish that have commercial and cultural importance and species that may be endemic to the region and/or have threatened or endangered status. The surveys should include monitoring at Mt. Coffee for downstream survivorship and to assess the efficacy of the prawn pass there.

It is advised that fishery and fish passage experts be engaged early in project development in order to ensure the necessary fisheries mitigations are incorporated into the design at an early stage. This allows for better optimisation of any fisheries mitigation, which typically results in a more cost effective and efficient form of mitigation.

6.3 Environmental Protection

6.3.1 *Reservoir Stratification*

Reservoir stratification is a function of the residence time of water and the difference in temperature between the surface water and the denser water in the deeper zones. A stable temperature and density stratification layer (the thermocline) leads to reduced exposure of the bottom waters to replenishment of oxygen. This in turn leads to oxygen depletion and chemical changes in water quality, with many consequences for living organisms. Reservoir stratification occurs very rarely and is of little concern in run-of-river plants like Mt. Coffee, where the maximum reservoir depth is only about 15 meters and the turnover time of the water is about three days. It will be of great concern in the Via reservoir due to the reservoir depth, high volume of water, and the very low water turnover. The reservoirs at optimised SP2 (FSL 163) and SP0 can also be expected to experience some stratification due to the water depth.

The SP2 reservoir at a FSL of 163 masl will have a depth of 25-30 meters; insignificant wave action is anticipated, which means the reservoir may stratify during wet season months when the maximum operating level is maintained. During the dry season, when the reservoir is reduced to its minimum operating level (152 masl), the reservoir surface area will be reduced by about 80% and relatively high water velocities at the upper end will probably disturb the thermocline and disturb any stratification.

There are limited mitigation measures for preventing reservoir stratification, and these mainly comprise pre-impoundment reservoir clearing and watershed management. Determining the required extent and the timing of reservoir clearing is important, particularly in Liberia where regrowth occurs very quickly. The justification for investments in reservoir clearing must consider the local conditions, including the anticipated retention time for the reservoir water; the existing water quality; and the density of existing trees. In addition, where the area to be cleared is large (such as for SP2 and Via/SP4), the negative effects of decaying biomass in a reservoir must be weighed against the negative effects (e.g. CO2 release) of clearing and burning that biomass prior to impoundment. If water quality is adequate, reservoir clearing is often harmful because (i) submerged trees and shrubs are useful habitat for fish and other aquatic life (including birds above the water line), and (ii) soil erosion, sedimentation, and increased river turbidity can occur if the interval between biomass clearing and reservoir filling is prolonged, a negative consequence that may outweigh the benefits of the clearing itself.

When biomass is left in a reservoir, it is broken down in the early phases after inundation and this can lead to anoxic conditions (oxygen depletion) and methane (CH_4) production. Anoxic water

existing at lower levels of the reservoir can be drawn off through the turbines, but flushing this water downstream may have negative consequences for the river ecology and for the human settlements that are dependent on the water. These factors must also be considered.

Anoxic conditions may persist in future decades as well, due to inflow of nutrients from sediments and from human activities (e.g. in the latter case, agriculture, industrial activities, and urbanization, which release nitrogen and phosphorous into the environment), and erosion. Nutrient loading can result in high plant (algae) productivity close to the surface, which can create dead zones and lead to die-off of plants and animals. The resultant degradation of water quality and fisheries also affects humans living in the vicinity and downstream, posing health risks and affecting nutrition. Uncleared biomass and biomass waste that has not been hauled away can wash downstream as well, creating dangerous conditions and resulting in damage to infrastructure.

The feasibility of clearing the large area of the Via reservoir, with a total area of some 375 km^2, must be questioned. Significant resources would be required to clear it, and it is questionable whether clearing would be possible in a timely and environmentally responsible way; as noted above, the benefits and costs must be weighed. The reservoir area at the optimised SP2 (163 FSL) is smaller than Via but still significant, at around 50 km^2. Clearing this area will also require careful planning, training, and significant resources, with multiple teams working throughout the area in parallel. Clearance would need to be timed to both (a) avoid risks of erosion due to heavy rains occurring after clearing and before impoundment, and (b) avoid opportunity for vegetation re-growth due to extended time between clearing and inundation. Training of clearing teams will be critical, particularly related to chainsaw use, and the proper PPE (e.g. protective clothing) must be provided. The benefits and costs of such an effort must be weighed.

Should reservoir clearing be deemed necessary, demarcation of the area for reservoir impoundment must be undertaken first, well ahead (at least one planting season) of inundation. This is required in order for any communities dependent on the riverbanks or farming in the area to stage their relocation of assets. Census and mustering (herding and movement) of domestic animals to alternative forage areas is required well in advance. Demarcation is also required in order to demarcate the boundaries for safe human passage during and after reservoir inundation. Finally, it serves as a marker for the workers undertaking reservoir clearing to not remove vegetation above a certain point, to avoid future erosion of reservoir banks. The process of demarcation can be time-consuming and costly if not planned properly and with the right tools (i.e. site managers of workforce clearance teams must understand the boundaries and consequences, and be capable with a hand-held GPS).

While it is not possible to determine as part of this study the extent to which reservoir clearing will be required, the budget for E&S impact mitigation includes reservoir clearing costs which are based on the actual costs for clearing the Mt. Coffee reservoir, reduced by 50% in the expectation that the costs of PIP implementation will be more competitive.

Watershed management must also be included for the entire cascade and as previously noted, this has not been carried out for Mt. Coffee due to lack of funds. Watershed management should include erosion protection measures, reforestation, community mobilization and education, community-based natural resource management (e.g. land-use and catchment management), water and sanitation infrastructure improvement and training, pollutant clean-up and management, and water quality management and monitoring. Costs for watershed management are based on actual procurement carried out by MCC for Mt. Coffee, reduced to account for lack of competition at that time.

6.3.2 *Environmental Flow*

The Appendix E (HEC Res-Sim power simulations) assumed a constant year-round environmental flow value of 30 m^3/s at all potential hydropower sites with the exception of Mt. Coffee, at which an environmental flow of 8 m^3/s is being maintained. For the period 2013-2018, the assumed E-flow values vary from approximately 10% (SP4) to 4% (SP0) of average annual flows at the potential power sites and from 80% (SP4) to 40% (SP0) of average minimum monthly flows (February), as shown in Table 6-6 below. For simplification, the average has been applied at each site as a constant, and these figures have been maintained for the current evaluation.

Table 6-6 Average Monthly Flows (m^3/s) at Priority Sites.

Month	Via Dam	SP4	SP3	SP2	SP1B	SP1 A	SP0	Mt. C
Jan	17	63	88	107	116	117	118	120
Feb	10	36	51	64	70	70	71	72
Mar	11	41	57	70	76	76	77	78
Apr	14	53	75	93	101	102	103	105
May	24	83	120	153	167	169	170	173
Jun	53	175	259	335	368	372	374	381
Jul	98	323	470	591	646	653	657	670
Aug	181	541	810	1024	1120	1131	1138	1161
Sep	250	752	1112	1374	1497	1513	1521	1552
Oct	169	525	771	954	1040	1050	1056	1078
Nov	88	292	424	527	574	580	584	595
Dec	39	129	186	227	247	250	251	256
MAF	80	252	370	461	504	509	512	522

Further detailed work will be needed to establish specific required E-flows for each prioritized site during the next stages of project development. Design of environmental flows requires consideration of a range of factors for each specific ecosystem such as the spawning habitats of fish, the life-cycle needs of other wildlife, sediment transport and deposition, and the nutrition needs of local communities for maintaining livelihoods. An environmental flow study would model different power generation and environmental release scenarios for the project under consideration as well as other plants on the cascade (e.g. Mt. Coffee), to rank how the various scenarios mitigate detrimental impacts on aquatic and riparian habitats, people, and ecosystem services. The study would also seek to predict how the existing environmental and social conditions and integrity of the river ecosystem could change with different operational schemes.

In line with the requirements for 'no net loss'[26] in terms of environmental and social impacts, a cost benefit analysis would then be carried out to identify the optimum scenario. Such a study requires fieldwork assessing aquatic biodiversity, the socioeconomic context, and hydrology.

Environmental flows are largely theoretical until operationalized. It is worth emphasizing again that the E-flow at Mt. Coffee (8 m^3/s) has, after a year of monitoring by fish and fisheries experts, been determined to be inadequate for supporting minimum ecosystem health and the issues identified there should be addressed in the near term.[27] Mt. Coffee can and should be utilized for important lessons learned in the design of the upstream sites.

6.4 Political and Economic Impacts: Concessionaires

The development of the proposed hydropower projects could affect several concession agreements. These include, for the Via/SP4 reservoir, the Alpha Logging Concession and the Mining and Exploration Services gold mining concession. The Government of Liberia has confirmed that all private use permits (PUPs) have been cancelled so that is no longer a factor for the Via. Development of the SP2 scheme could affect the Sime Darby oil palm plantation, and the SP0 scheme could affect the West Peak Iron Limited mining concession.

The Alpha Logging Concession appears to be carrying out selective logging, removing only high-value trees that are marked for harvesting. The forest in the area of the Via reservoir appears fairly pristine as of the July 2019 fieldwork. Local government officials report that Alpha was made aware of the government's long-term energy sector plans many years ago, when the CLSG project was carrying out its environmental and social safeguards studies. It is possible that this knowledge guided their investment in the concession area, in anticipation of losses, because officials report that very little has been done there to date. An audit conducted by the Environmental Protection Agency in late 2018 was requested by the authors but unfortunately was not received, so there is no further information on the Alpha Logging Concession at this time.

Under the CLSG project, the government has compensated concessionaires for loss of assets in a very similar manner to the rules applied for project-affected persons. For example, Sime Darby, with its oil palm and rubber plantations, would be compensated for the trees lost to a project at the government rate (US$3.00/tree for immature trees and US$6.00/tree for mature trees). The optimised SP2 (163 FSL) could require compensation of Sime Darby.

It is not known with certainty to what extent Sime Darby has developed its concession area and how much planting has been done to date. Sime Darby's web site states it has only planted 10,000 hectares of its contracted 220,000 hectares in Liberia, only in Grand Cape Mount and Bomi Counties (SP2 sits in Bong County). This information was repeated by the Environmental Protection Agency. News reports indicate that returns on the investment have been poor, due to Ebola and stricter international controls, and that the company is considering pulling its operations from Liberia. Therefore the compensation due Sime Darby may be negligible.

[26] 'No net loss' is defined as the point at which project-related losses are balanced by gains resulting from measures taken to avoid and minimize those losses.
[27] Fishtek Consulting (2019). MCHPP Fisheries Study. Millennium Challenge Account Liberia.

For indicative purposes, the scenario is developed here as if the concession has been planted. Three options are considered, for planting areas of the reservoir equivalent to 25%, 50%, and 100% of the entire reservoir area. The analysis assumes that, over the last 10 years since the concession agreement was signed, Sime Darby has carried out the planting and therefore the area contains mature oil palm trees. A brief internet search reveals that best practice for oil palm planting is 143-145 trees per hectare. Oil palms reach maturity and are ready for harvest after 3-4 years. The loss of the trees is not a one-time loss; the foregone harvests would also be lost for a period of 3-4 years until new trees are planted and yielding fruit. Therefore, compensating the loss for the mature trees must also take into account the time it would take for Sime Darby to replant new trees and for those trees to reach maturity. The compensation due depends the amount of planting, as illustrated generally in **Table *6-7*** below.

Table 6-7. General Sample Compensation for existing palm oil plantations

km²	ha	trees/ha	total trees	$/tree (mature)	time for replanting (yrs)	compensation due
12.5	1250	143	178,750	$ 6.00	3.5	3.75 MUSD
25	2500		357,500			7.5 MUSD
50	5000		715,000			15 MUSD

It is more difficult to assess the compensation due to the other concessionaires for their lost assets under logging and mining concessions, since the land belongs to the Government of Liberia. It is anticipated that the costs would comprise foregone profit, which would require replacement at an alternate site. For the purposes of this report, and based on the available information, no cost is assessed for compensation of concessionaires under the proposed long-term development plan, since the government would have sufficient time to negotiate settlements for SP2, whether developed in a phased manner or all at once, as well as the SP0, and Via/SP4 sites, and since in none of the cases, following consultations in Liberia, does it appear that the concessions are in advanced stages at present.

6.5 Biodiversity Off-Sets: National Protected Areas

Biodiversity off-sets have been considered related to the Via Reservoir and potentially the SP4 diversion, but not the plants on the cascade due to a lower assessed risk level. To further investigate the potential fatal flaw that could result from the Via reservoir being assessed as critical habitat, a rapid biodiversity assessment was carried out over a two-week period, from June 23 through July 6, 2019. The team consisted of an internationally experienced lead primatologist, a large mammal expert from the Tacugama Chimpanzee Sanctuary in Sierra Leone, and a Community Liaison Officer from the Mt. Coffee Project in Liberia. The team covered 128 km on foot within the inundation area, as shown in **Figure *6-1***. The methodology for the survey included a combination of reconnaissance trail surveys (recces), and interviews in eight villages.

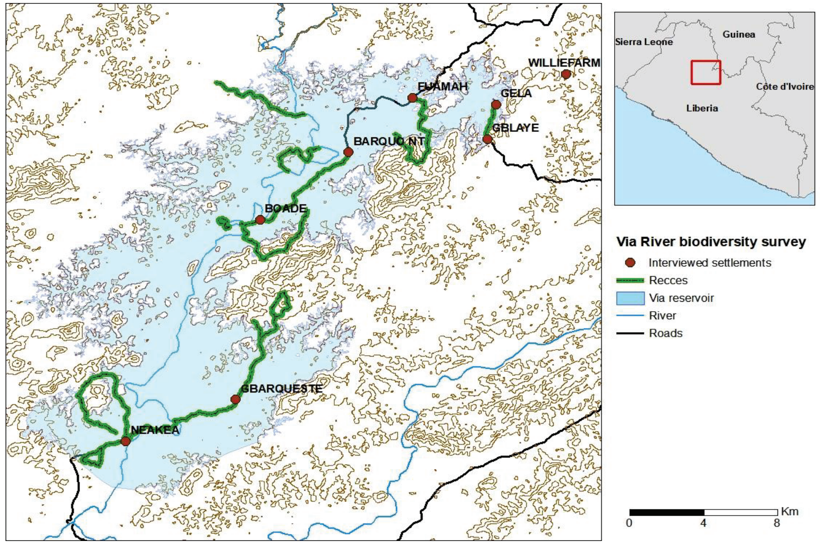


Figure 6-1 Rapid Biodiversity Survey Area, Via Reservoir.

Eight primate species were reported in total, and five were confirmed to be present in the area, six of them listed as threatened or near threatened on the IUCN Red List.[28] The presence of chimpanzees was only indicated by one old nest and a possible nut cracking site, which was considered inconclusive. The study concluded that they might be present in very low numbers, that they have a very large home range that goes beyond the study area, or that they have been exterminated from the area.

Seven other mammal species of conservation concern were confirmed present in the survey area including elephants, pygmy hippopotamus, four types of duiker, and buffalos, as shown in **Figure *6-2***. All are listed in the IUCN red list of threatened or near threatened species. The Chimpanzee is the only Critically Endangered species, and it was therefore the focus of the survey. The Pygmy Hippo, an Endangered species, is the next most critical species. The Red Colobus and Jentinks' Duiker are also Endangered. The remainder of the species confirmed to be present are all on the IUCN Red list, but in the Vulnerable, Near Threatened, and Least Concern categories.

[28] The International Union for Conservation of Nature (IUCN)'s Red List of Threatened Species is a comprehensive database on the global conservation status of animal, fungi and plant species, and includes information about range, population size, habitat and ecology, use and/or trade, threats, and potential conservation actions. There are nine clearly defined categories: 1) Extinct means that there is no reasonable doubt that the last individual has died; 2) Extinct in the Wild means that the taxon is extinct in its natural habitat; 3) Critically Endangered applies to species considered to be facing an extremely high risk of extinction in the wild; 4) Endangered applies to taxa considered to be facing a very high risk of extinction in the wild; 5) Vulnerable applies to species considered to be facing a high risk of extinction in the wild; 6) Near Threatened is applied to taxa that do not qualify as threatened now, but may be close to qualifying as threatened; 7) Least Concern is applied to taxa that do not qualify (and are not close to qualifying) as threatened or Near Threatened, but are nonetheless of conservation concern.

Figure 6-2. Species Encountered During Rapid Biodiversity Assessment.

Primates	Chimpanzee (CR)	Red Colobus (EN)	Black & White Colobus (VU)	Olive Colobus (VU)	Diana monkey (VU)	Sooty mangabey (NT)	Campbell's monkey (LC)	Spot nose monkey (LC)	Green monkey (LC)
Picture Identification	✓	✓	✓	✓	✓	✓	✓	✓	
Encountered	✓				✓	✓	✓	✓	

Ungulates	Bay duiker* (NT)	Black duiker* (LC)	Jentink's duiker (EN)	Red flanked duiker* (LC)	Zebra duiker (VU)	Yellow-backed duiker (NT)	Maxwell's duiker* (NT)	Bushbuck* (LC)	Bongo (NT)
Picture Identification			✓		✓	✓			✓
Encountered	✓	✓	✓	✓	✓	✓	✓	✓	✓

Other Mammals	Elephant (VU)	Pygmy hippopotamus (EN)	Leopard (VU)	Buffalo* (NT)	Red river hog* (LC)	Water chevrotain* (LC)
Picture Identification	✓	✓	✓			
Encountered	✓	✓		✓	✓	✓

Key	
CR	Critically Endangered
EN	Endangered
VU	Vulnerable
NT	Near Threatened
LC	Least Concern

Most of the observed actual animals were seen in villages, where they were being kept as pets or prepared for eating. The area is very suitable for animals, but appears to have been over-hunted to the point that very few animals remain. By far this is the most significant pressure on animal life. The survey recorded 160 used cartridges with an encounter rate of almost two shells per km walked. Other pressures include gold mining and logging.

The survey did not allow for definitive conclusions due to the major constraints – the extremely short study time, the timing (rainy season), and gaps in survey area. In particular, the western side of the river could not be explored due to access issues, and due to the difficult access that area could be where the animals are retreating to. The eastern side is more easily accessed and is thus more greatly affected by hunting, although the mining camps also facilitate hunting.

The absence of real evidence of chimpanzees (such as tracks, scat or sightings) was also a major constraint for any conclusions regarding critical habitat. It will be important to get more information on the chimps to verify their presence. In the meantime, it is best to take a precautionary approach and assume they are there until more is known conclusively.

A full Critical Habitat (CH) assessment will need to be done per World Bank safeguards policies, particularly IFC PS6,[29] but likely only the Chimpanzees and Pygmy Hippos will trigger Critical Habitat. The other animals (primates and duikers) have a wide enough distribution, but an analysis of the importance of that area for their species would need to be done as part of the CH assessment as well.

Biodiversity offsets would be considered following completion of a CH assessment. The inundation area for the Via Reservoir is large, and the habitat has been assessed as valuable during field observations. Due to both these factors, quite a large area will be needed for an offset. The next step for offset determination would include calculating the value of the area to be inundated in order to evaluate options. This would take the form of a feasibility study to show the options and the long-term strategy for maintaining the offset.

Kpo National Park has been identified as one feasible off-set area, and anecdotal evidence gathered during the survey did indicate that protected animal presence, including Chimpanzees, is greater there than in the Via Area. However, establishment of an offset is only effective when management of the area is effective. The experience in Liberia has shown that engaging communities, who depend on the forested areas for livelihood, is key to ensuring the sustainability of national parks and protected areas.

As has been reported previously, the World Bank is currently supporting a Protected Area Feasibility Study, including a biodiversity baseline survey and socio-economic study, of the Kpo Mountain PPA under the Bank's Liberia Forest Sector Project. As of late June 2019, the procurement evaluation had been completed and notification of award made, but the contract was not yet signed. The work is reportedly being awarded to a local firm with good experience in the sector.

Both the World Bank representatives and management of Flora and Fauna International stated that the biggest challenge for maintaining protected areas and national parks comes from the competing needs of the surrounding communities. Communities living on the boundary of these areas are not in favor of conservation, since they are dependent on the areas for livelihood. This is not only in the form of bushmeat, but also and perhaps more importantly the revenue communities can receive from agreements with third-party logging companies, and from artisanal mining. Unless the losses to livelihood are addressed and replaced, the success of protected areas will be limited.

Figure 6-3 below shows the community forests that are adjacent to the protected areas in Liberia. There are two proposed community forests and one active community forest bordering Kpo Mountain National Park on the west, and the active logging concession (Alpha) bordering the area on the east. Part of the process for confirming protected areas in Liberia is negotiating with communities to define the boundaries. This can be a lengthy process.

[29] The International Finance Corporation (IFC)'s eight Performance Standards (PS) include PS6, Biodiversity Conservation and Sustainable Management of Living Natural Resources, which classifies habitat into modified, natural and critical habitats, and specifies conditions and mitigation measures for implementation projects in such areas.

Under the Liberia Forest Sector Project, the World Bank aims to improve management of, and increase benefit sharing in, targeted forest landscapes in the northwest and southeast, using climate finance as a catalyst for forest conservation and carbon sequestration. It includes technical assistance for the FDA, EPA, and other stakeholders for implementation of REDD+; strengthened management of protected areas; and development of a forest monitoring information system.30 The component for management of protected areas is the largest in terms of financing, and includes support for on-the-ground management, comprising resources for protected area rangers, and support for alternative livelihood programs and job creation for surrounding communities. To date, the FDA has awarded consulting agreements for the Gola and Sapo protected areas, which will result in livelihood development plans for the forest communities in those areas. In addition, the Ministry of Agriculture is implementing a separate component, which is intended to reduce overall deforestation pressure by providing better alternatives to slash and burn agriculture around Sapo National Park and Grebo-Krahn National Park. These efforts may provide good pilot examples for conservation strategies going forward.

Flora and Fauna International (FFI) is also doing important work in Liberia related to identifying and protecting conservation and wildlife corridors. Understanding the movement of animals within Liberia’s forests as well as between the protected area networks of Guinea and Liberia will be important as Liberia moves forward with establishment of new protected areas and national parks. Understanding the needs and characteristics of the areas designated as multi-use areas and community forests is key to this effort and to long-term planning.

It is difficult to obtain a dollar figure for the creation and management of a protected area, and this is also dependent on the timeframe for investment. Since the development of the Via reservoir is still under consideration for the long-term development of Liberia, a lump sum has been included of US$20 million, which would be expected to cover the necessary feasibility studies, animal relocation activities, establishment of park boundaries, negotiation with local communities and development and implementation of livelihood restoration programs, training of rangers, park infrastructure and vehicles, etc. It is outside the scope of this assignment to investigate the feasibility of a biodiversity offset or propose a budget. This would be possible only after the studies described above, starting with a critical habitat assessment, have been carried out.

The findings of the biodiversity assessment conducted in June/July 2019 have been summarized in a separate report submitted July 16, 2019 (attached as Appendix J).

30 World Bank. April 19, 2016. Project Appraisal Document on a Proposed Grant in the Amount of US$37.5 Million from the Liberia Forest Landscape Single Donor Trust Fund to the Republic of Liberia for a Liberia Forest Sector Project.

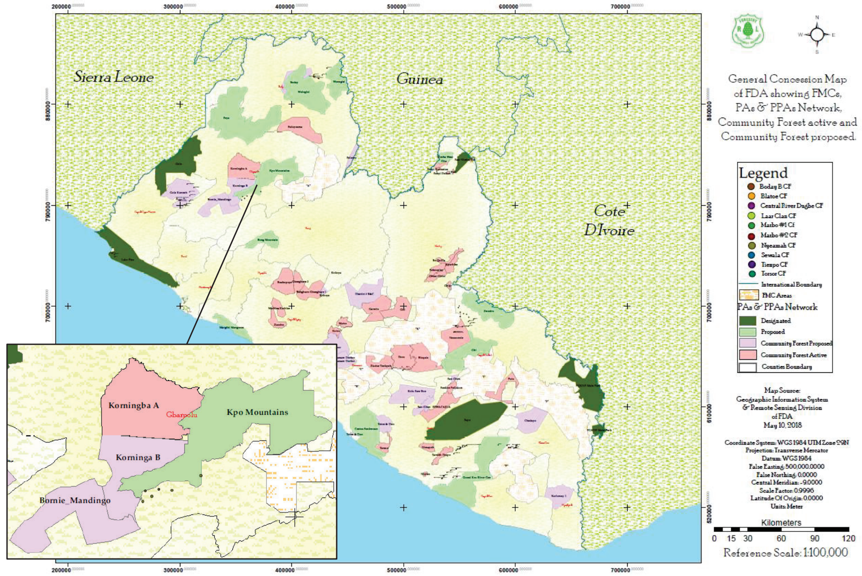


Figure 6-3. Map Showing Community Forest Areas and PPAs.

6.6 Social Safeguards and Resettlement

Earlier versoins of the report summarized the known information on project social impacts, namely resettlement and asset compensation. Much of the information was gleaned from the Hydrotec Technical Assistance report, the fieldwork for which included surveys of 14 settlements in the Via and SP4 areas, with the results extrapolated for the other candidate sites using Google Earth and LiDAR images. At that stage, the present authors identified additional potential project sites, which comprised optimized potential schemes at SP1/SP0 and SP2, and used both LiDAR and Google Maps to assess resettlement impacts there. This was done by counting the number of structures, estimating the number of houses among those structures, and from there estimating the number of project-affected persons (PAPs), as described below. The impacts for each of the potential schemes considered at that stage are given in **Table *6-8***; the lines in grey indicate resettlement impacts estimated by Hydrotec; the lines in white were estimated by Multiconsult.

Table 6-8. Resettlement Impacts for All Potential Schemes.

Project	No. of Villages	No. of Structures	Houses estimated	No. of People estimated
Via (FSL 235 masl)	11	399	291	1665
SP4 (FSL 235 masl)	8	148	117	586
SP2 (FSL 165 masl)	53	3013	2250	11250-13500
SP2 (FSL 164 masl)	52	1800	1350	6750-8100
SP2 adjusted (FSL 157.5 masl)	9	315	236	1418
SP3 (FSL 190 masl)	13	434	326	1953
SP1B (FSL 125 masl)	80	1732	1299	6500-7800
SP1B (FSL 125 masl) including access issues	80-100	2000	1500	7500-9000
SP1B adjusted (FSL 111 masl)	11	231	173	1040
SP1A (FSL 80 masl)	5	52	39	234
SP0 (FSL 60 masl)	10	188	141	846

For the optimization of the PIP at SP2 under Task C, a further assessment of social impacts has been carried out. This has included assessing resettlement at the full supply levels of 157.5 (previously presented as optimum, in the context of the development of the Via reservoir) as compared to FSLs at 159, 161, and 163 masl (without Via reservoir development in the near future). The impacts on the number of villages, structures, and calculated houses and people is presented in **Table *6-9***. Resettlement has been assessed for all structures below the normal flood level (one meter above FSL) in the middle of the rainy season in a wet year.

The design flood has a return interval of once in 1,000 years and assumes the power station is closed and one spillway gate is jammed or blocked. Capacities have been calculated and the assessment determined that normal operating conditions would never exceed one meter over FSL with the station running and all gates in operation. In the event of a 1000-year flood, all people living near or along the river would need to be evacuated, since they would be in much greater danger than anyone around still waters in the reservoir.

It should be noted that in addition to the hydrology of the river and the topography of the inundation area, the groundwater conditions of villages located close to the reservoir must be taken into consideration. The extent of flooding will be based on all of these factors.

Since design floods typically reach two meters above FSL, the below table also displays the impacts on resettlement at an FSL of 163 plus a 2-meter safety margin. As can be seen, the impacts increase dramatically, with more than double the number of people needing to be resettled.

The present analysis is by necessity theoretical since the scope did not include fieldwork to assess actual resettlement impacts. Determination of the final design flood also requires additional hydraulic analysis and other feasibility studies. The final design of the optimised SP2 dam, including the FSL of the reservoir, must be based on the completion of these studies as well as the ESIA and RAP. For the purposes of the present study, the number of resettled persons and assessed costs is based on an FSL of 163 masl with a 2-meter safety margin, which has been justified by the study calculations.

Table 6-9. Resettlement Impacts at SP2 Reservoir Alternatives.

SP2 Dam Alternatives	No. of Directly Affected Villages	Est. No. of Structures	Est. No. of Houses (75-90% of total)	Est. No. of People (5-6 persons/HH)
StPaul River reservoir				
157.5 masl FSL 2/ 1 m flood (*156.5 FSL w 2 m*)	9	300	225-270	1,125-1,620
159 FSL w/ 1 m flood (*158 FSL w/ 2 m*)	11	350	263-315	1,313-1,890
161 FSL w/ 1 m flood (*160 FSL w/ 2* m)	17	1,350	1,013-1,215	5,063-7,290
163 FSL w/ 1 m flood (*162 FSL w/ 2 m*)	20	1,575	1,181-1,418	5,906-8,505
163 FSL w/ 2 m flood	53	3,025	2,269-2,723	11,344-16,335
Wala Creek reservoir				
157 FSL w/ 2 m flood	15	520	390-468	1,950-2,808
159 FSL w/ 2 m flood	16	710	533-639	2,663-3,834

Table 6-10. Resettlement Impacts at SP2 Dam Alternatives

SP2 Dam Alternatives	Est. No. of People (5-6 persons/HH)
StPaul + Wala reservoirs combined	
157 FSL w/ 2 m flood	3,200-4,608
159 FSL w/ 2 m flood	5,851-8,424

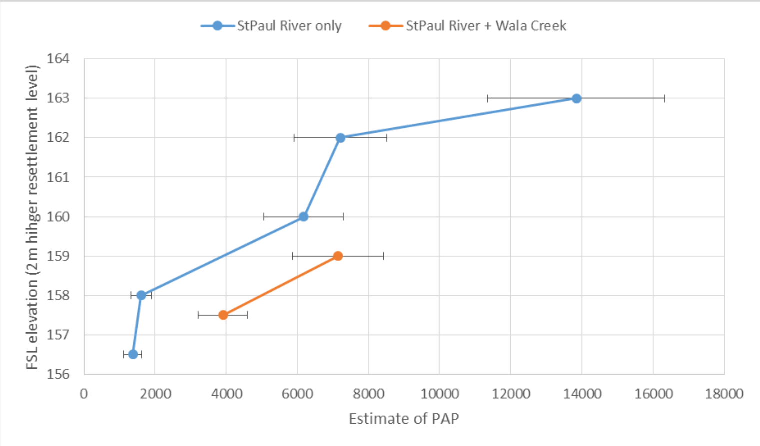


Figure 6-4: Accumulated resettlement at reservoir elevations

As can be seen, the impacts of the StPaul River reservoir at 156.5 – 158 FSL are similar, whereas they increase significantly and are similar at 160-162 FSL. At elevation 163 the impacts increase again. It can also be seen that the resettlement impacts of the main alternative (only StPaul River reservoir) at FSL 160-162 is in the same range as FSL 159 for the Wala Creek alternative).

The relative magnitude of the project's land take and resettlement impact can be assessed by comparing the size of the SP2 reservoir and number of resettled persons per MW installed capacity with other similar dam projects. Assuming that the SP2 project will cause physical displacement of an estimated 7,200 persons (the median of the range given above) and have an installed capacity of 156 MW with a reservoir surface area of approximately 50 km2, the resettlement impact can be rated as intermediate between other "good" and "bad" dam projects assessed by the study. The impoundment is relatively small compared to its benefit in terms of energy production (installed capacity), while the number of resettled persons is medium to high. There is no objective threshold for resettlement above which a project could be deemed to have a 'fatal flaw.' Rather, the feasibility of implementing the project should be based on an assessment

of whether 'no net loss' is achievable; in other words, if all livelihoods affected by the project can be restored to a better situation than pre-project, the project can be considered feasible.

The social safeguards and resettlement assessment also considered the alternative of the Wala Creek dam at the FSLs of 157 and 159, with a 2-meter safety margin based on the recommendations of the Panel of Experts. The impacts are given in Table 6-9 above and Table 6-10 below. The resettlement impacts of Wala Creek are greater than the SP2 reservoir at an FSL of 159 masl with a one-meter safety margin (or 158 FSL with two-meter safety margin) but less in terms of number of structures than the SP2 at 160+2 m flood FSL.

The Hydrotec assessment was based on the counted structures being comprised of 75% houses and 25% other structures (kitchens, communal facilities, sanitation infrastructure, etc.). The present analysis calculates impacts based on 75% of the structures being houses at the low range, and 90% of the structures being houses at the high range. Estimates of number of people are based on the average household size of five persons per household to six.

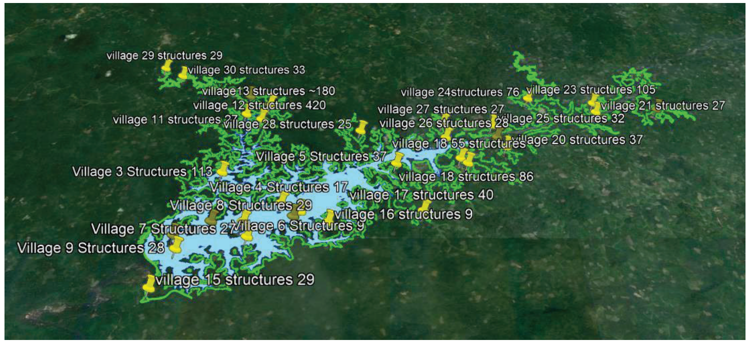
Where only parts of villages are anticipated to be affected, the assessment has assumed that the entire village would be resettled, including re-establishment of all its infrastructure (e.g. schools, clinics, etc.). This is particularly applicable where the topography of an area results in the reservoir water encroaching on a settlement from multiple sides, making future development and access difficult. An example is given in Figure 6-4 below for one of the larger villages, which would be partially affected by the SP2 dam at the 161 (yellow line) and 163 masl (green line) FSLs.

Figure 6-5. Resettlement Impacts at SP2 for higher FSLs (161 and 163 masl).

The average household size in Liberia is five persons, as given in the latest Liberian national census.[31] Household sizes in rural areas can be much larger; it was not unusual to see a household of 10 persons around Mt. Coffee. While a household of five persons would be expected to include 3-4 children, the number of PAPs has been based on the total population in each of the villages. This is because all members of the village will be affected by resettlement; infrastructure such as schools and clinics will need to be re-established; the project should consider electrification of those villages living within feasible distance of the project infrastructure. Water and sanitation programs and facilities will need to be re-established, and new areas for farming will need to be cleared.

In total, thirty villages were identified in the area of the SP2 reservoir up to the 163 FSL (see Figure 6-5 below). Though only 20 would be directly affected based on available satellite imagery, an additional 10 villages would be indirectly affected at the highest reservoir levels, including loss of farmland and loss of access routes connecting them to schools, markets, and farms. These losses result in impacts on livelihood. All such impacts will also need to be compensated.

Figure 6-6. Villages Located around Optimised SP2 (shown with 163 FSL).



Impacts on access have been assessed at a very high level. Where villages will likely not be resettled, but are located near the reservoir boundaries, it is assumed that access infrastructure (e.g. bridges, culverts, road diversions, etc.) will need to be established. A sum of US$200,000 has been assessed for access interventions for each of the villages not indicated for resettlement but indirectly affected by the project. Without detailed analysis of existing access routes, hydrology of the various tributaries, and frequency of use (e.g. definition of major vs. minor routes), it is not possible to assign a more detailed figure. Costs for access improvement at Mt. Coffee ranged from US$5,000 for dug-out canoes and $40,000 for road drifts and culverts to US$300,000 for modular steel bridges. Averaged per village, the total investment in access infrastructure was approximately $200,000/village.

[31] See LISGIS. September 2011. 2008 Population and Housing Census: Analytical Report on Population Size and Composition. Available at https://www.lisgis.net/pg_img/Population%20size%20210512.pdf.

Finally, and critically, the project will need to consider the need to purchase land for the resettled villages. Though the SP2 site falls entirely within the Sime Darby plantation area, it does not appear to have been developed by the concessionaire, and existing communities continue to carry out farming and commercial activities (e.g. mining, logging) in these areas. It is expected that most of the areas affected by SP2 will be under customary land ownership, and that villages in the area will hold tribal land certificates giving them rights to the land, including for farming and for logging. Loss of such land will need to be compensated. Reference is made to the chapter on biodiversity off-sets; communities can glean an income from cooperating with commercial logging companies, therefore their customary land has a demonstrated value. A lump sum of $50,000 has been assumed for each of the villages to be resettled, based on average costs for land purchased under Mt. Coffee (it should be noted that Mt. Coffee land values were based on a pre-project value, circa 2012).

The below **Table *6-10*** summarizes the estimated social mitigation costs for each of the SP2 dam alternatives as well as Wala Creek alternatives. The cost per PAP to be resettled, including resettlement, farm compensation, and livelihood restoration, is estimated at $3,100. These figures are taken from Mt. Coffee but are considered to be conservative, since the cost/PAP calculated for Mt. Coffee is based on persons who were directly compensated, whereas the present analysis includes all residents of each of the villages identified as at risk. This is because, as noted below, the full costs of resettlement and livelihood restoration will need to consider all residents of the villages. It should be noted that the Mt. Coffee farm compensation costs were based on a crop price list that was optimized for market values at the time (inflation has significantly increased since then), and local NGOs were employed for livelihood restoration.

The cost per PAP for indirect impacts (e.g. loss of farmland and other income, and associated livelihood restoration strategies) is based on a figure of $2,100/PAP. For the indirect impacts, it is assumed that each household includes two PAPs engaged in farming and other income-generating opportunities. Again, this is formulated based on the actual experience at Mt. Coffee.

At this stage of project development, it is impossible to predict with any certitude what the situation will be on the ground at the time of ESIA, ESMP, and RAP development. Without field investigations, for example, the availability and suitability of replacement land cannot be assessed. In addition, experience has shown in Liberia that when a project is publically known to be moving forward, there is a rush to develop areas expected to be impacted in order to capitalize on returns. Therefore, it is of advantage to the GOL and future project funders to begin the environmental and social assessment studies as soon as possible, in order to accurately assess impacts, develop budgets and schedules, and design the most effective mitigation measures.

Table 6-11. Total Estimated Social Safeguards Mitigation Costs for the Various Alternatives Evaluated for SP2.

SP2 Alternatives	No. of Directly Affected Villages	Est. No. of Structures	Est. No. of Houses	Est. No. of People	Estimated Cost for Direct Impacts	Estimated Cost Land Acquisition	No. of Indirectly Affected PAPs	Estimated Cost for Indirect Impacts	Estimated Cost Access Infrastructure	Total Social Safeguards Mitigation
157.5 FSL	9	300	225-270	1,125-1,620	3.5 - 5.0 MUSD	0.5 MUSD	267-320	0.6 – 0.7 MUSD	0.4 MUSD	4.9 – 6.5 MUSD
159 FSL w 1 m flood	11	350	263-315	1,313-1,890	4.1 – 5.9 MUSD	0.6 MUSD	594-713	1.2 – 1.5 MUSD	1.0 MUSD	6.9 – 8.9 MUSD
161 FSL w 1 m flood	17	1,350	1,013-1,215	5,063-7,290	15.7 – 22.6 MUSD	0.9 MUSD	723-868	1.5 – 1.8 MUSD	1.6 MUSD	19.7 – 26.9 MUSD
163 FSL w 1 m flood	20	1,575	1,181-1,418	5,906-8,505	18.3 – 26.4 MUSD	1.0 MUSD	723-868	1.5 – 1.8 MUSD	1.6 MUSD	22.4 – 30.8 MUSD
163 FSL w 2 m flood	53	3,025	2,269-2,723	11,344-16,335	35.2 – 50.6 MUSD	2.7 MUSD	1,446-1,735	3.0 – 3.6 MUSD	3.2 MUSD	44.1 – 60.1 MUSDs
Wala Creek Dam										
157 FSL w 2 m flood	15	520	390-468	1,950-2,808	6.0 – 8.7 MUSD	0.75 MUSD	234-281	0.5 – 0.6 MUSD	1.0 MUSD	8.3 – 11.0 MUSD
159 FSL w 2 m flood	16	710	533-639	2,663-3,834	8.3 – 11.9 MUSD	0.8 MUSD	320-383	0.7 – 0.8 MUSD	1.0 MUSD	10.7 – 14.5 MUSD

The resettlement cost are linear to the number of PAPs and affected villages. It should be noted, however, that a higher number of PAPs will increase the complexity of achieving resettlement targets (livelihood restoration) and probably also increase the unit costs. Furthermore, the maximum limit for "acceptable" number of PAPs has not been assessed. This has to be revisited at the Feasibility and ESIA stage as well as in the detailed optimisation of the inundated area and related dam height.

6.7 Benefits of Reservoir Development

While the above section has presented social safeguards risks and impacts that appear significant, particularly in terms of numbers of people affected and cost, it should be recognized that development of the reservoir proposed for SP2, which will provide seasonal regulation and storage capacity, has certain advantages for the local population and economy.

Firstly, as shown in Drawing SP2-01 (Appendix H), the difference between the minimum operating level (152 masl) and maximum operating level (163 masl) is significant; the minimum reservoir area represents about 20% of the maximum inundation, and this area effectively becomes an opportunity for 'recession' or 'river-bank' farming during the dry season when the waters recede and leave fertile ground for planting. River-bank farming in Liberia consists of fruity vegetables, such as pepper, bitter ball, eggplant, and cucumber. These crops require wet, fertile soil that retain nutrients from flooding during the rainy season. These crops are used both for subsistence and income. Seed banks could also be developed in the drawdown zone for nurseries established nearby.

The drawdown zone also represents an economic opportunity for an area that will otherwise be devoid of vegetation; unless drawdowns last several years, experience indicates that vegetation in this zone is limited to seedlings of shrubs and trees, and some herbs, which have a short lifespan. Therefore the zone will have a short-lived riparian environment, and could be barren in areas where water levels fluctuate.

Finally, the creation of reservoirs represents an opportunity for aquaculture for the production of prawns and fish that thrive in such environments. The proximity to a power source represents an opportunity for cold storage facilities, and for development of the necessary infrastructure to deliver the fish to market. A feasibility study should be carried out to assess the attractiveness of the proposed reservoir for development of aquaculture, and this could be included in future livelihood development programs.

6.8 Summary of Mitigation Measures

The key mitigation measures outlined above are specific to the environmental and social risks identified for the projects under consideration. These have been included as specific cost items in the next section. Table 6-11 below includes a short list of the typical mitigation measures that would be expected in an Environmental and Social Management Plan for the SP2 scheme. It is not intended to be exhaustive; a detailed list of impacts and mitigation measures would be described as part of an Environmental and Social Impact Assessment, which would specify the responsibilities of the owner and construction contractor(s). Specification of a terms of reference for the next phase of studies (ESIA, ESMP, and RAP) falls outside the scope of the present assignment.

Table 6-12. Typical Mitigation Measures to be Included in ESMP for PIP.

No.	Potential impact	Project Activity	Potential Mitigation Measures
1	Soil erosion	Construction	• Sediment traps, drainage channels • Prevent steep slopes, define optimum height of work evaluating the instability of the rock, soil etc. • Stabilise, compact and strengthen steep slopes • Adequate selection of road tracks • Construct drainage controls on roads in accordance with road design standards • install culverts with enough capacity for strong rains; drainage pipes and channels have to be of an adequate size and should be equipped with screens at entrance and exit points • Re-vegetation
2	Soil contamination	Construction	• Vehicle maintenance in appropriate workshops • Adequate storage of fuels, lubricants etc. • Observe standards for use of contaminating substances • Collect hazardous waste and dispose of properly • Develop a spillage contingency plan • Provide oil spill kits at strategic locations
3	Air pollution	Construction	• Vehicle maintenance • Storage
4	Noise	Construction	• Use of appropriate vehicles and machines • Work scheduling (no noisy work during night) • No transport through residential areas during night
5	Vibration	Construction	• Use state of the art techniques • Restrict access during blasting events
6	Change of water discharge pattern	Operation	• Environmental flow tailored to the ecology of the area and operational requirements
7	Water quality in the reservoir	Construction/ Impoundment	• Cutting of trees which can be used by local population • Cutting and burning of all trees which cannot be used, before impoundment • Shortly before impounding cutting of as much vegetation as possible, and burning it • Secure unstable slopes to minimize sloughing and soil erosion
8	Pollution of water	Construction Operation	• Sewage water has to be treated • Adequate storage of fuels, lubricants etc. • Proper disposal of fuels, lubricants etc. • Installation of oil traps at all drainage channels at workshops or other areas where oil, fuel and lubricants are used • Collect hazardous waste and dispose of properly • Sewage water has to be treated • Proper maintenance of installation • Proper disposal of fuels, lubricants etc.
9	Waste (domestic, solid, liquid, hazardous)	Construction Operation	• Domestic waste: collect and deposit in municipal waste deposit • Separate waste according to categories and dispose of properly • Provide specific collection points for hazardous waste • Provide instruction to staff • Waste Management and awareness raising for the communities

No.	Potential impact	Project Activity	Potential Mitigation Measures
10	Loss of habitat or private assets	Construction Operation/ reservoir impoundment	• Use material from inside of the future reservoir if suitable material is available, to reduce disturbance of other areas; dump unused, uncontaminated material in the future reservoir • Keep any additional sites which will be used only during the construction period as small as possible • Do not disturb vegetation especially trees at the riverbank downstream of the construction site • Re-vegetate the reservoir banks with native shrubs and trees • Do not use any herbicides for vegetation clearing • Illegal logging of the work force must be forbidden • Full supply level should be marked in the field • Management of forestry related issues
11	Loss of terrestrial fauna	Construction	• Hunting by members of the work force must be strictly forbidden • Reservoir clearing to be planned directionally to allow animals time to escape
12	Loss of aquatic fauna (fish and fishing)	Construction	• Precautionary measures related to water quality • Fishing activities of the workforce needs to be monitored or forbidden to reduce conflicts between local population and workforce
		Operation	• Construction of fish/prawn passes (upstream and downstream) • Fish barrier to reduce entrainment of fish through turbines • Assess how to minimise the risk of damage to fish carried downstream by spilling • Release of residual/environmental flow • Implement a protected zone near the dam • Monitoring of fish and fisheries • Stock reinforcement of selected fish species • Implementation of livelihood restoration measures
13	Loss of agricultural land Loss of crops in the reservoir area	Construction Operation	• Compensate communities that may be affected by the project • Identify alternative farm land for affected farmers that are accessible and of comparable productivity • Provide farming inputs (fertilizer, seeds, tools) and agricultural extension services to affected farmers to restart farming activities • Provide a relocation or resettlement package for affected communities • Encourage alternative livelihood activities
14	Loss of infrastructure	Construction	• Lost infrastructure will have to be relocated or compensated

No.	Potential impact	Project Activity	Potential Mitigation Measures
15	Public Health	Construction Operation	• Good housekeeping • Best practice related to maintenance of vehicles • Adequate signage, warnings and controls e.g. speed limits • Fence off the construction area • Driver training • Install a Project Information Center • Implement a flood warning system
16	Work accidents, occupational health	Mainly construction, some during operation	• Provide required health and safety equipment • Provide first aid on site • Provide training and instruction to workers
17	Communicable diseases	Construction	• Health check for workers at employment • Appropriate measures for preventing malaria • Information campaigns on HIV/AIDS • Good housekeeping • Upgrade public health clinics if warranted • HIV/ Aids Campaign in the surrounding communities
18	Possible increase in malaria prevalence	Construction Operation	• Good housekeeping • Avoid creating additional breeding places at the construction site • Vector control at the individual level (use of mosquito nets, repellents, etc.) and at the community level • Regular epidemiological monitoring
19	Possible increase in bilharziosis prevalence	Operation	• Regular monitoring of the molluscs (part of fish monitoring) and regular health monitoring of the communities • Equip clinics with kits capable of detecting bilharziosis and drugs for sufficient treatment.
20	Use, transport and storage of explosives	Construction	• Take into account the procedures established by the responsible authorities • Explosive material to be stored in a state of the art storage with precaution signs • Detonators to be stored in a different storage or at least in a different compartment of the storage • Blasting agents to be stored separately from explosives, safety fuses and detonating cords • For transport of explosives use designated closed containers with insulation. Use separate containers for the detonators • Do not allow people, workers and animals in a distance of less than 500 m • Implement suitable warning system (banners, mobiles, sirens etc.), activate an auditable alarm 15 minutes before blasting
21	Employment Opportunities	Construction Operation	• Ensure equal opportunity among affected and adjacent communities, women and men • Ensure employment contracts and wages in line with application national regulations
22	Electrocution, collision with overhead lines	Operation	• Use designs that discourage nesting in towers • Employ climb-prevention barriers • Public education campaigns
23	Salinization of soil	Operation	• Install adequate drainage systems

No.	Potential impact	Project Activity	Potential Mitigation Measures
24	Flooding	Operation	• Employ flood control operations during rainy seasons • Install flood warning system • Use overflow areas to prevent downstream sedimentation
25	Increase in population density, inequity, pressure on resources	Construction Operation	• Develop population influx plan • Assess land tenure/ownership systems and potential solutions for equity • Assess impacts and replacement measures for common land affected by project • Consider vulnerable groups especially • Consider options for benefit sharing

6.9 Mitigation Costs

The below ***Table 6-12*** provides updated cost estimates for the environmental and social impact mitigation costs identified in the optimization study. The costs have been updated from the revisions of the reports as described in the above sections.

As noted in Section 6.6 above, the costs for social safeguards impact mitigation for the PIP (SP2 @ 163 FSL) are significant but cannot be confirmed or specified further until fieldwork is conducted. Therefore, they need to be further refined as part of a resettlement framework and RAP development. It should be noted that the costs for social impact mitigation at SP0 and Via/SP4 have been adjusted, on an order of magnitude based on the average costs for the SP2 alternatives, to include access infrastructure and indirect impacts as described in the Section 6.6 above.

This study has focused on optimization of hydropower development in Liberia. Development of solar power plants would also require environmental and social mitigation, and costs would be dependent on the location of the plants, e.g. whether greenfield development or implemented on already cleared/occupied land.

Table 6-13. Estimated Environmental and Social Impact Mitigation Costs.

E&S Criteria/Risks	SP2 Ph. 1 (3-phase approach)	SP2 Main alternative (Chosen)	MCHPP Extension	Via and SP4 transfer
Aquatic Migration Off-Sets				
Fish and fisheries study (minimum one year)	0.3 MUSD	0.3 MUSD		0.5 MUSD
Construction of multi-species upstream passages	4.0 MUSD	8.0 MUSD	1.0 MUSD	14.0 MUSD
Environmental Protection				
Environmental flow study	0.2 MUSD	0.2 MUSD		0.3 MUSD
Reservoir clearing	-	3.3 MUSD	-	27.3 MUSD
Watershed management (planning and implementation)	0.5 MUSD	2.0 MUSD	-	6.0 MUSD
Biodiversity offsets including studies	-	-	-	20.0 MUSD
Social Safeguards				
Resettlement incl. livelihood restoration	-	22.4 – 30.8 MUSD	-	17.9 – 20.8 MUSD
Other E&S Management/Monitoring				
ESIA/RAP study costs	0.3 MUSD	2.0 MUSD	0.1 MUSD	4.0 MUSD
ESMP/RAP implementation and monitoring	1.0 MUSD	4.0 MUSD	0.1 MUSD	8.0 MUSD
Total costs	**5.0 MUSD**	**38.0 – 46.3 MUSD**	**1.2 MUSD**	**89.4 – 92.3 MUSD**

6.10 Next Steps: Field Investigation Programs

The proposed long-term development plan prioritizes the development of the optimised SP2 hydropower scheme at 163 FSL based on multiple factors, including investment cost, anticipated demand, feasibility of implementation, and the larger regional sector context. Development of the SP2 scheme does require mitigation of a number of environmental and social impacts as described in this report. The most critical concern from an environmental standpoint is protection of aquatic biodiversity. Therefore the most critical step in the near-term is implementation of a fish and fisheries monitoring program that draws upon the studies carried out at Mt. Coffee and creates a baseline database of the aquatic species and their habitat requirements, particularly migratory species and those important to the local economy and diet, at the SP2 site. The program should also identify those fish that have commercial and cultural importance and species that may be endemic to the region and/or have threatened or endangered status. The study should encompass both wet and dry seasons and should therefore cover a one-year period. The outcomes of this study will be critical for both the design of the fish pass and the definition of the environmental flow.

Design of the environmental flows for each of the schemes will also require consideration of the life-cycle needs of other wildlife, sediment transport and deposition, and the nutrition needs of local communities for maintaining livelihoods. While these aspects will be part of the scope of an Environmental and Social Impact Assessment (ESIA), an environmental flow assessment should be carried out as a stand-alone study. It is recommended that the E-flow assessment conducted for SP2 also take into account Mt. Coffee, to address impacts on the river ecology already underway there.

In addition, water quality monitoring should be established as soon as possible and could be carried out in concert with the Liberia Hydrological Services, utilizing their existing monitoring stations on the St. Paul River. The SP2 site falls between the Haindi and Piatta monitoring stations, and data collected at those two sites would also be useful for the future development at SP0 (it should be noted that development of SP0 will directly affect the Haindi station).

Development of the optimised SP2 scheme is anticipated to have significant social impacts. The exact scale and magnitude of these impacts can only be determined following the conclusion of stakeholder consultations and the implementation of fieldwork as part of the Environmental and Social Impact Assessment and Resettlement Action Plan. The terms of reference for these studies, as well as the Environmental and Social Management Plan, should be developed as soon as possible so that the work can be carried out prior to the conclusion of the feasibility studies, since the final design of the scheme will be shaped by the viability and cost of mitigating the direct and indirect impacts.

While it is not anticipated that the SP2 area will contain critical habitat for terrestrial fauna of concern, the ESIA should conduct a baseline evaluation and take note of the relative proximity of the site to the Bong Mountain protected area, and the current work being done by FFI and others related to the development and maintenance of wildlife corridors within the protected area network in Liberia.

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7 Description of the priority Investment Project (PIP) SP2

7.1 General layout description and characteristics of main alternative

The recommended PIP is the SP2 project optimized to include a reservoir impounded to FSL 163 and utilized for both peak load following and for seasonal regulation of flows. The results of the Balmorel simulations demonstrate this project to be the preferred option for commissioning in late 2025, and that almost all of the energy potential can be consumed domestically in 2026, while a small wet season excess is available for export.

The project comprises earthfill embankment dams of about 2.5 km length and several small earthfill saddle dams with crest level 167, as shown in Drawings No SP2 – 01, 02, 03, 04 and 05 in Appendix H. Incorporated into the main embankment is a free overflow spillway weir of 280 m length and a gate and pillar spillway containing 4 radial flood gates, WxH=11x13m, situated near the overflow spillway.

The main dam and power station structure is a concrete pillar dam containing the power intakes, intake gates, penstocks and turbines, ending with the draft tubes where water enters the tailrace canal. Principle sections are shown in Drawing No SP2 – 07, 08 and 09 in Appendix H. This design is based on five units of the Kaplan type of turbine, which is the most flexible type in operation at varying heads and output. The power station location is off-river, requiring excavation of both a headrace canal and long tailrace. The water is returned to the St Paul River at a bend in the river where river levels are typically around 118. This location for the powerhouse makes it very safe from flood damage and uncertainty about flood inundation levels, and allows all year construction activity in the powerhouse area while the river is flooding.

East of the powerhouse suitable area for construction of an operators village, substation and switchyard, and surrounding areas can be utilized for the contractors workshops and housing camp.

Access to the site will be from a new access road connecting to an existing road over a distance of 22 km from Bong Mine up to Wala River is quoted as upgrading of existing road/track. There will be a new bridge crossing the existing Wala Creek and a second bridge crossing the St Paul River below the dam site. This leads the access road up onto the saddle dams and flows contour 167 to the north of the reservoir, tailing off into an access track which reaches most of the affected villages along the north side of the reservoir. This access solution is expected to be cheaper than constructing the bridge on pillars above the 280 m long free overflow weir.

The power station will be connected to Mt Coffee via a new 220 kV line extension following the access road to connect SP2 power station (154MW, 3 units) to Mt Coffee, Monrovia and the CLSG transmission network. When installing the last 2 units (95 MW) another transmission line to the Gbarnga-Botala line has to be constructed.

7.1.1 Key design parameters

The key parameters for SP2 hydropower project are given in Table 7-1. The reservoir full supply level has been found to be optimal at FSL 163. The spillway characteristics are such that reservoir levels will normally vary between 163.5 and 164 during the flood season from July to October. For exceptional floods there may be a week or two when reservoir levels are above 164. The design flood situation shows the reservoir to peak at no higher than 165. There is 2 m freeboard above this level to the dam crest at 167. The dam will be constructed with sufficient excess height above 167 to allow for settlement and the crest level remaining above 167 in the long term.

Table 7-1: Key data for SP2 main alternative (FSL 163)

Item	Phase 1 (Chosen)	Phase 2
Catchment area (km^2)	17 682	17 682
Mean annual flow (m^3/s)	461	461
Design outflow flood, 1000-year (m^3/s)	5650	5650
Reservoir volume (mill m^3)	310	310
Full supply level (FSL, masl)	163	163
Minimum operation level (MOL, masl)	152	152
Type of dam	Earthfill	Earthfill
Total dam fill volume (mill. m^3)	2.2	2.2
Turbine discharge (m^3/s)	420	+280
Turbine type/no	3 Kaplan	+2 Kaplan
Installed capacity (MW)	154	Additional 96
Yearly energy potential (GWh)	840	Additional 250
Total cost (MUSD)	710	Additional 150

A gravel road surface will be constructed along the crest and between saddle dams to give two lane access to all parts of the dams and nearby villages. For flood safety reasons the road is not continued with a bridge across the free overflow spillway, but stops on top of the gate structure. A permanent road bridge is constructed at a narrow river section below the dam to provide access to the north bank.

7.1.2 Hydropower and Intake design

A maximum turbine capacity has been optimized at 700 m^3/s, which corresponds to 250 MW maximum station output. This is planned and costed on the basis of five identical Kaplan units each of 52 MW rated capacity. However, the Francis turbine type can also be considered, possibly with two different sizes of unit, comprising two smaller units designed for dry season operation and three or four larger units.

For both turbine types, the final two units will not be needed in the first decade of operation, but intakes and intake racks and gates will be constructed immediately and all canal excavations will be designed for the final station output. The installation of the final two units is named the SP2 Extension project, a separate investment option which can be implemented when demand for wet season energy or export is found sufficient. The first 3 units have a maximum station output of 154 MW while 96 MW is added by the final two units. The reason for lower unit output at full station capacity is the rise in tailwater when the station is operating at full output.

The penstocks are reinforced concrete structures formed through a concrete pillar dam section. They are equipped with vertical intake gates and trash racks with fine screen openings to reduce the size of fish which can be sucked into the turbines. The slow rotational speed of the Kaplan turbines and large blade opening means that survival of some fish is possible, and the Kaplan turbine is considered more “fish friendly” than the Francis type, which can be expected to result in near 100 % mortality.

The intake canal is excavated in existing ground and battered back at gentle slopes to reach the bottom of the intake structure at elevation 140. This provides sufficient submergence to permit

operation of the turbines down to reservoir level 152, but at reduced flows (which is the optimal operating procedure to conserve water when reservoir levels are low). A sediment flushing pipe will be included in the dam to enable local flushing of silt if any accumulates in front of the trash racks. A fish lift construction is planned within the dam body with an entrance immediately beside the draft tube exit. If necessary sufficient attraction flow will be provided during upstream migration periods by low lift pumps. The head is too great for a conventional step structure or artificial brook to work successfully as a fish passage.

Floating weeds and debris is to be collected by a primary boom across the narrow channel from the main part of the reservoir. Any debris which passes this boom must be mechanically removed from the trash racks. In the flood season the overflow weir will be operating continually, flushing most debris down the river. One radial gate is equipped with a flap for periodic removal of accumulated debris. To minimize floating debris to enter the intake area a boom could be installed across the intake canal at a narrow section near the upstream end of the canal.

Consideration has been given to installation of a fifth gate designed for drawdown sluicing of sediments through the reservoir. However, the four radial spillway gates can serve the same function and draw down the reservoir some few metres during a rising flood, if this is found to be a suitable operating rule. The addition of a sluicing gate was therefore considered to have little additional benefit, but can be added later in the design if found beneficial in comparison to the extra cost.

There are several option for design of the intake and power station. Drawing SP2 07, 08, 09 indicates a general layout that could be an option for several of the projects in the St. Paul River. We have looked at several options of powerhouse layout, and see that there is need for better geologic information before choosing the actually powerhouse and intake layout, as it has great cost implications between the alternatives. This has to be revised at the feasibility study of the project:

- The alternative shown has an intake structure based on a pillar dam design, and penstocks casted in concrete down to the powerhouse. It is vital for the stability to introduce drainage and grouting near the dam axis to reduce uplift of the dam / powerhouse structure.
- An alternative could be to make the intake structure as a mass concrete dam, but this would add a major amount of concrete on the downstream side, not adding much to the overall stability of the dam-powerhouse construction.
- Another alternative is to construct a tunnel under the (embankment) dam linking the intake structure inside the reservoir with the power station at minimum approximately 100m downstream the dam toe. This alternative requires sound rock at an appropriate underground depth to be feasible. However, looking at boreholes investigated by Chas T Main study in 1982, a depth to rock was found at 15-18m, and if the chosen intake location has such rock depth further analysis should be made in the feasibility study to assess if this option is feasible. If rock conditions are favourable the hydropower plant can be shifted downstream and optimised related to cost of tailrace canal compare to cost of inlet tunnels.

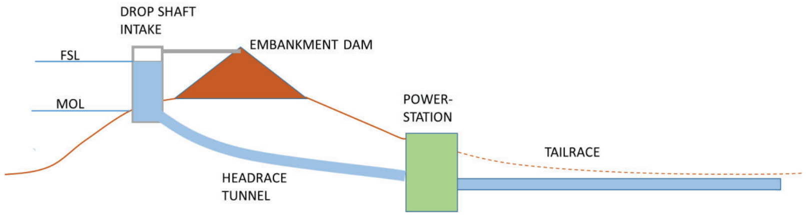

Figure 7-1 Principal sketch of intake and powerhouse connected with a tunnel

- An option of connecting a concrete intake structure with the powerhouse using a steel penstock has been assessed. This layout is similar to the existing MtCoffee plant. The alternative has the advantage of less concrete than the intake + power house integrated options discussed above, but the cost of the large steel pipes tend to cancel this cost advantage rending this option not feasible. However, a feasibility study should revisit this option too.

7.1.3 Main dam and spillway

The main dam and spillway structure is located on what is thought to be a rocky sill on the St Paul River where foundation depths for concrete structures are acceptable (see Drawing SP2-08 in Appendix H). A conventional stilling basin structure with baffle blocks is included downstream of the spillway radial gates.

On the north bank the weir is terminated with a concrete wing wall which retains the earthfill embankment. The northern embankment dam continues as required by the terrain, and is assumed founded on average 2 m below existing ground. A cut off trench and foundation grouting is envisaged at the upstream toe.

From the south end of the spillway and stilling basin structure, another retaining wall is needed at the start of the southern embankment dam, also an earthfill dam, but additional trench depth and grouting is expected here because of higher water pressures at foundation level. From this main earthfill dam, there are several alternative locations for the power house and concrete dam structure, each described in a separate section below.

7.1.4 Design of SP2 spillways

A 1000-year flood peak of 7000 m^3/s with substantial flood volume was routed through the SP2 reservoir and the peak outflow flood was found to be 5500 m^3/s. This is therefore the design capacity of the combined spillways, assuming one spillway gate closed due to repairs or jamming/ blocking by debris. Full details are described in Appendix F, Chapter 2.2 but the inflow and outflow hydrographs are shown here in Figure 7-2. The maximum flood level is 165.1 m above FSL leaving sufficient freeboard of the dam if crest is 4 m above FSL. For exposed dams where wave run-up can become a problem, and additional parapet wall can be added to the dam crest.

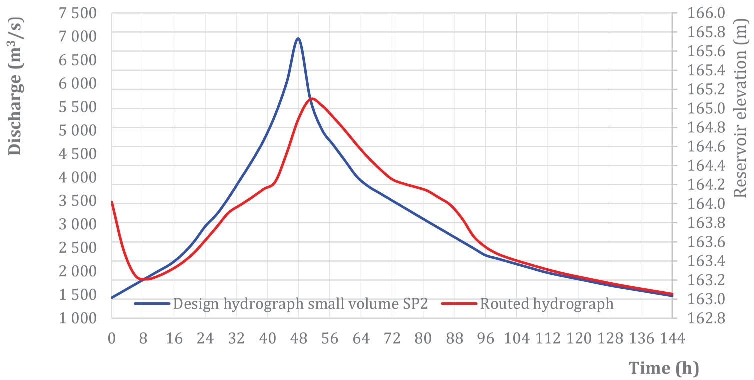

Figure 7-2: Flood wave routing for spillway design flood at SP2 dam (FSL163)

The design capacity of each spillway gate is close to 1000 m^3/s at 163 reservoir level with free surface flow and good approach conditions. This increases to 1250 m^3/s at 165 reservoir level. Assuming 3 gates in operation and the power station out of operation, then the overflow spillway will be passing 1900 m^3/s (6.3 m^3/s per meter length).

The stilling basin below the 4 spillway gates will have a length of around 50m with baffle blocks to stabilize the hydraulic jump. Alternatively we could consider a flip bucket design provided there is sound rock to resist backwards erosion undermining the structure. A deep grout curtain is proposed followed by a drainage network under the stilling basin to reduce uplift forces and seepage.

The right hand part of the free overflow weir will be designed to concentrate flow into the small depression leading back to the main river and functioning as a wet season fish migration route to enable strong swimming species to pass over the weir crest as if it was a natural rapids in the river.

7.1.5 Trap efficiency and expected pattern of reservoir sedimentation

The SP2 reservoir has a total volume equivalent to 2.3% of the annual inflow. According to the curves of Brune (1956) this means that the trap efficiency of fine sediment will be around 50% and for all sediments about 60%. In simple terms it means that half of the incoming sediments will remain in suspension and pass over the dam, and the other half will settle around the reservoir. Although sedimentation is certain to occur, the process is not likely to be very fast. We have no data on sediment load, but visual impressions, regional studies and the degree of intact forest in the catchment indicate it is not particularly high. The pattern of sedimentation will be a fine layer of silt settling over the entire reservoir, while any coarse sand and gravel fractions will accumulate at the upper end of the reservoir, and will gradually be flushed down into the dead zone as the reservoir is drawn down each year.

The dam could be designed with bottom flushing gates to allow for flushing of any sand and gravel that reaches the dam, but it appears to be unnecessary. The nature of the power station intakes, located quite remote from the main spillway means that most sediment will be either collecting in the main reservoir or being flushed downstream. There are no difficult problems with expected siltation of the reservoir or of the power intakes, but a small flushing pipe is planned incorporated in the intake dam structure

The reduction in sediment transport downstream caused by the reservoir may have impacts on the downstream morphology and aquatic ecology, as discussed in Chapter 6. Appropriate reservoir sluicing procedures during flood inflows can be implemented to reduce the impact of sedimentation. The spillway gates are deep enough and the reservoir is small enough for sluicing to be reasonably effective. The power station output need not be affected since sluicing can be applied during the 2-3 months when the power plant cannot take all the inflow and there is excess water available for sluicing of sediments.

No mineralogical analysis of the sand has been carried out, but there is no sign of wear at Mt Coffee turbines and there is no reason to fear rapid erosion on turbine parts due to sediment grain impact.

7.2 Alternative layouts of SP2

7.2.1 Wala Creek alternative

One of these alternatives was studied at the suggestion of the Expert panel, and is known as the Wala Creek alternative. This differs radically from the main alternative in that the main dam and power station are located in the Wala Creek and water is transferred south to a storage reservoir planned in the Wala Creek to the south of the St Paul River.

There is an opportunity for considerable additional storage at SP2 by building two additional dams across the Wala Creek which runs south of SP2 dam site and joins the St Paul River at the tailrace outlet for the main SP2 alternative (see Figure 7-3).

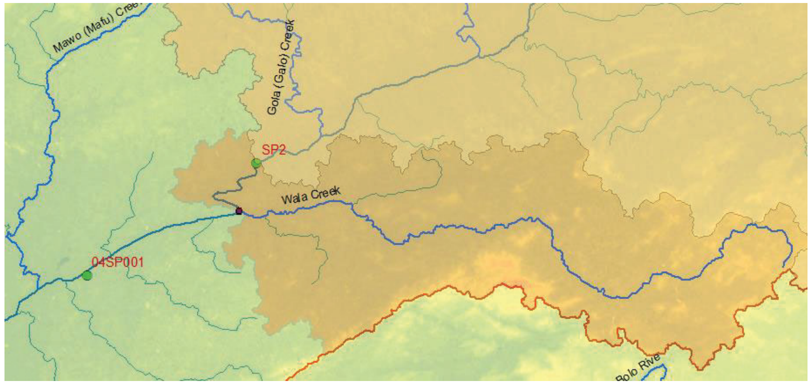

Figure 7-3: The Wala Creek tributary catchment south of SP2 dam site

The two dams needed on the Wala Creek comprise a 45 m deep concrete gravity dam nearly 1 km long and two earthfill saddle dams of 4 km length, where one part is over 30 m deep, while the remainder is usually less than 10 m in height. If these dams were to be built, one option is to locate the power station at the foot of the Wala concrete dam. This enables a 7 km long tailrace canal to be constructed along the existing Wala Creek to lead the water back to the St Paul River. A slightly larger reservoir volume can be impounded by moving this dam about 2 km downstream, shortening the tailrace canal. However, the lower Wala Creek dam site is clearly more difficult and expensive as it is aligned along a lower narrow ridge where there is unlikely to be found sufficient rock at reasonable depth for foundation of the concrete dam and power station.

To analyse this alternative, the new dams as shown in drawing SP2 - 30 were designed and costed. The reservoir FSL was kept at 159 to suit the new Wala dam site. It was found that the FSL cannot be raised much above 159 without causing the dam length to become several km longer and more risky since it follows a narrow ridge of unknown ground conditions and unknown water tightness. Therefore, a reservoir impoundment to FSL 163 seems technically difficult and costly for Wala Creek alternatives.

Another option that should be further studied is to construct the dams at Wala Creek, but keep the location of the power station as for the main alternative. For both alternatives a major canal excavation is required between St.Paul reservoir and Wala Creek to utilize the reservoir volume between FSL 159 and MOL 152.

The area and volume curves are more uncertain for the Wala Creek reservoir, since the LIDAR survey map only covers a small part. Attempts were made to match ground elevations on the Lidar map with satellite digital terrain data, but the match is poor and varies across the reservoir length. A best attempt to draw reservoir area curves at different contour height was made and a likely reservoir volume curve drawn as shown in Figure 7-4. The exact reservoir volume is unknown, and this curve should be used with knowledge of its great uncertainty. The gross reservoir volume at 159 is increased to 310 million m^3 from the 190 million m^3 in the main St Paul reservoir, an increase of 63% due to impoundment of the Wala Creek.

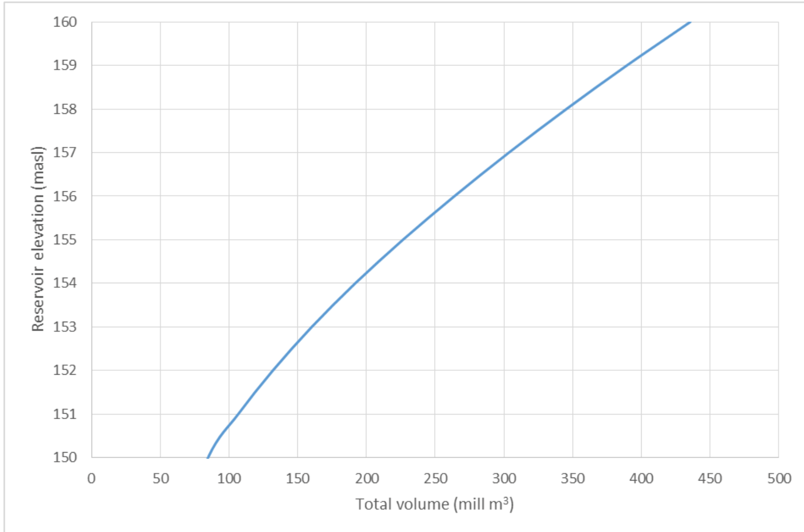

Figure 7-4: SP2 reservoir curve with the StPaul River and Wala Creek dams

It is estimated that around 260 Mm^3 reservoir is available between 159 and 152. There is very little volume below 152, so further drawdown to below 152 was not found economic. This can be compared with 148 Mm^3 available from SP2 at the same elevation. The Wala Creek dams can therefore increase reservoir volumes by 75% but not at levels above 160 where the dam construction would become extremely costly. Based on the seasonal regulation of the reservoir between 159 and 152 the alternatives were compared and results compared in Table 7-2.

Table 7-2: Comparisons between SP2 reservoir alternatives

	Wala dam FSL 159	SP2 FSL 157.5	SP2 FSL 163
Active Vol	260 Mm^3	148 Mm^3	310 Mm^3
Firm yield	75 m^3/s	60 m^3/s	80 m^3/s
SP2 MW	24 MW	20 MW	27 MW
Mt. C MW	12 MW	10 MW	13 MW
Total firm MW	36 MW	30 MW	40 MW
Project Cost	730 MUSD	580 MUSD	710 MUSD
Unit cost MUSD/firm MW	20.2	19.3	17.8

The additional 2.5% inflow from Wala Creek was included, but the additional production from Wala Creek inflow was not significant. This means that an interesting feature of this comparison is that the average annual production is almost unchanged between all alternatives (+/- 2%). The net gain in dry season energy is cancelled out by loss in production during May and June. However, dry season production has a higher value than wet season production.

7.2.2 Alternative power station locations

Eastern alternative

The topography indicates two alternative locations for the dam and power station structure. The eastern one looks to be slightly cheaper, but ground conditions and detailed mapping and design will be needed to select the best one. Both should be the subject of field investigations.

The eastern alternative has been drawn up in Drawing SP2-02 in Appendix H, and typical section through the intake and power station shown in Drawing G-04 in Appendix H.

Western Alternative

This alternative has been shown in plan, but the cross- sections will be very similar to the Eastern alternative. The difference is in the alignment of approach channel and tailrace channel as shown in Drawing SP2 – 10 in Appendix H.

Wala Creek power station alternative

This alternative is shown in Drawing SP 2 – 30. From the topography shown on the LIDAR map. It looks as if the tailrace excavation depth and longer length will make this power station site more expensive than the main alternatives further north in the SP2 dam. Furthermore the utilizable head is less, both because of higher tailrace losses and because the Wala Creek dam cannot impound higher than around FSL 159.

The higher dam at SP2 FSL 163 is therefore preferable to the Wala Creek alternative, but not so different that it can be excluded from further study. The ground investigations may reveal different ground conditions and therefore different costs than assumed here. It is therefore recommended that some investigations be carried out at the Wala Creek main dam site for the feasibility study.

7.2.3 Three-step development alternative

Rationale for three step development

The power station locations discussed above all have in common the need for deep excavations and foundation on sound rock. With no knowledge of local ground conditions at any of the alternative sites, a flexible approach to further design of the project must be adopted. Furthermore, the SP2 investment is a substantial capital outlay for Liberia/ LEC and there is a risk of overinvestment if for example the demand growth becomes slower than expected or if loss reduction programs are not successful in the years leading up to financial closure. The capital outlay, technical, financial and delayed commissioning risks are substantially reduced by dividing the project into several stages when sequential decisions can be made in later years.

We have therefore derived a plan to stagger the construction of the SP2 scheme into 3 stages, which reduces the investment needed in the first stage, reducing the project risks. The first stage has a simpler construction site to work in, less excavation and less complex and risky dam and spillway structures. Normally it is not economic to develop a hydropower site with 40 m of head into two low head power stations, but the topography at SP2 makes the three stage option an interesting alternative. Nonetheless, Balmorel simulations show that a full SP2 with FSL 163 is needed already in 2026, and the three-stage plan described here is only a fall back alternative to the full SP2 project.

The SP2 3-step scheme layout

The layout of both dams and power stations for the staged SP2 development alternative is shown in Drawing SP2-20 – 24. The first stage is to develop 18 m of head by shortcutting the natural bend in the river. No reservoir is planned and only run- of the-river production can be achieved, but as soon as the second stage is completed then normal peaking operation and seasonal regulation can be achieved identical to the full SP2 main alternative. The dam comprises two low overflow weir spillways constructed across the main river and a smaller channel to the south. Only concrete side-walls to prevent erosion around the structure are needed on each river bank. A power station and concrete gravity intake dam are constructed off river with no diversion requirements and no interruption in construction activity in the flood season. Excavation volumes for headrace canal and tailrace canal are much lower and the construction time can be up to 1 year shorter. In addition, the gradual impoundment and monitoring of embankment dams means that another 4-6 months can be saved by the first stage construction (with no embankment dam). Faster commissioning of Stage 1 with 3 of 5 units, 2- 3 years is possible.

Construction can continue on site to complete the upper dam and power station approximately 2-3 years later. This Stage 2 comprises the same dam and spillway structures for FSL 163, but a new location for the power station with a shorter less deep tailrace canal, leading water into the lower stations intake dam. Both power stations are planned to operate in tandem and have a design station outflow of 700 m^3/s in stage 3. Raising the tailwater canal by 18 m means the excavation is much less and the upper station and gravity dam are easier to found on rock and less complex to construct.

Both power stations can include room for later addition of two more units, as for the main alternative. These later units are called Stage 3 in the staged development, and should be installed at the same time so that synchronized releases of water from the reservoir can be carried out with no energy loss due to spill from lack of capacity in one station.

Replaced by two phase layout

However, the 3-phase alternative was left in favour of the one power station layout with FSL at 163, phase 1 installing 3 units (154 MW) and phase 2 installing 2 additional units (96 MW).

7.2.4 Other alternatives not studied

The optimisation of the projects and the PIP (SP2) in particular has undergone many phases and alternatives. Using the Balmorel model has helped optimising the plant, which for instance has found it feasible to include reservoir storage and reduce the first phase installed capacity making it competitive in the energy mix of Liberia. Some alternatives has been identified by the Expert panel, and with even more time and resources further alternatives will be identified and potentially more feasible.

This study is not resulting in a final design, but further optimisation will need to be done under the feasibility study including balanced environmental and social impact in addition to the technical economic criteria.

Some alternative designs have therefore not been covered, but should be analysed under the feasibility study.

During this study, some insights was seen during the process but not specifically documented:

- The PIP is more feasible with a smaller installed capacity. The current installed discharge for SP2 is 420 m^3/s (154 MW), whit the civil works on both powerhouse and waterway is design for 250 MW (700m^3/s). A revised civil design tailoring only 154 MW, not preparing space or bays for the SP2 extension at the intake and the powerhouse, might give a reduced CAPEX[32] in the range of 5-15%.
- If the tunnel intake is feasible due to favourable geology (little weathered rock overburden), the potential savings in the intake and powerhouse arrangement of 5-10% in CAPEX.
- It is further advised that the dam height optimisation is re-done in the feasibility /ESIA study, with input on acceptable resettlement footprint and costing. Input from the ground investigations will be important for choosing the dam type, foundation type and depth, and related costing.

7.3 Substation and transmission line connections

An outdoor switchyard is envisaged at a site suitable for the transmission line connection by overhead line leading south-westward towards Mt Coffee in phase 1. The switchyard will be close to the power station and the operator's camp. There are several suitable locations near each of the power station alternative sites. All options are assuming a 220 kV connection to Mt Coffee to evacuate the power, and only a double circuit transmission line cost from SP2 to Mt Coffee have been included. For extension of SP2, increasing capacity from 154 MW to 250 MW an additional 220 kV line connection to Mt Coffee or the Gbonota - Gbarnga - Botata 220 kV line is required. See figure below.

[32] CAPEX here refers to the total project including the transmission line fromSP2 to MtCoffee, which is approximately 12% of the total cost estimate.

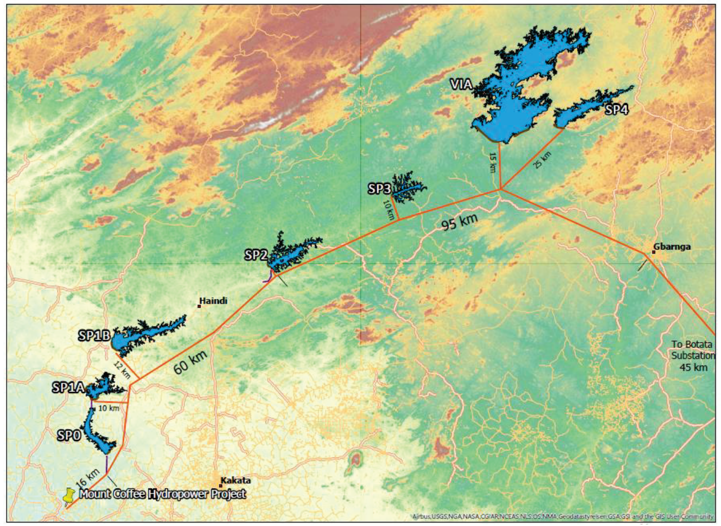

Figure 7-5: Principal layout of power evacuation along the St. Paul projects

7.4 Construction methods and schedule

7.4.1 Schedule for design and construction

Construction of the SP2 project is expected to take 3.5 to 4 years and a 1 year mobilisation and preparation time, depending on the season when mobilisation can occur, and when river diversion plans must be factored in. At least two flood seasons must be accounted for regarding the river diversion, but the location of the main power station construction site off river avoids any dependency on river diversion for construction of the power station structure, which usually is on the critical path for completion and commissioning of the units. For this reason we propose the development schedule period as shown in Table 7-3.

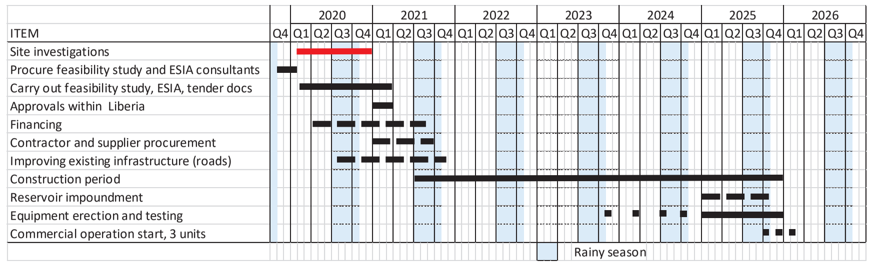

Figure 7-6: Estimated implementation schedule to complete unit 3 by Jan 2026

The construction of access roads, bridges and construction camp is also a critical activities and must be started end of 2021, and it appears that power will need to be provided by on site diesel units unless the import agreement allows for reliable supply along the CLSG line, and a branch line can be constructed to site by 2022. Another critical activity is the ground investigations program by 2020.

It may be possible to reach the planned commissioning date of Q1 2026 for the first units by letting a preliminary works contract in advance of the main contractor being chosen and mobilizing on site in 2022. This includes improving of existing roads by upgrading of some bridges and culverts currently in poor state. This will enable a fast mobilization and construction start for the main contractor. Orders for supplies of mechanical equipment, particularly generating units, will need to be placed at the latest by mid-2023. The schedule shown here is very tight and many factors can delay the commissioning date, with very little room for catching up any lost time.

7.4.2 Construction materials and methods

The design has been adapted as far as possible to make use of local materials and minimize the use of imports such as cement and steel. The environmental footprint of the construction activity has been minimized, but there are few means by which this can be achieved given the state of infrastructure and power supply in Liberia today. There will be a lot of heavy vehicle traffic and diesel emissions which cannot be avoided, but some labour-intensive construction activity can be incorporated to provide local jobs.

The main dams are earthfill embankments designed to use the local soils and alluvial deposits in various gradings for earthfill and filter zones. Some ripping (and possibly blasting) of hard rock for structural foundations and canal excavations will produce some rock for use as rip rap, but there may be a shortage of good boulders and rock for rip- rap. In such cases, a quarry site needs to be identified, preferably within the reservoir area.

Quantities of soil excavation and earthfill have been attempted matched such that no large borrow pits are expected, but this will have to be reviewed after grading curves of various deposits become known. Transport distances of large quantities of soil are minimized by the current design, using canal excavations and borrow pit in reservoir as a source of embankment fill.

The project will require an on – site concrete batching plant, and the suitability of alluvial sand and gravel for aggregates has yet to be studied. The concrete dam structure can make use of aggregate with low cement content in the mass concrete, and traditional skilled formwork is needed for intakes penstocks, spillways, pillars and power station concrete.

Transport of heavy loads such as transformers, stator, rotor, steel gates, crane etc. is not exceptional and should not require general road and bridge upgrades on highways from Monrovia. This is due to the moderately small unit sizes adopted in planning the power station.

7.5 Project cost estimates

Please note that since the first screening of hydropower candidates described in Appendix F, further optimisation has been made to the layouts and the costs. The costs presented in Appendix G should be considered the most updated costs.

Typical changes has been splitting the transmission cost more fairly between the projects, i.e. the most feasible project to be developed first is to carry the cost of the first transmission line, and the next projects can connect to with considerably shorter transmission lines. In particular SP2 has been undertaken many revision in layout, both due to the general optimisation but also several ways of staging the construction of the (full) plant (150MW first, and 100MW second stage) – which was only possible using the Balmorel model and many iterations. Minor changes to the fish pass cost, dam optimisation and powerhouse layout (SP2) has been made to the final cost estimate.

The costs estimates are dated 2018.

7.5.1 Unit rates adopted and their sources

Project cost estimates have been prepared for each of the hydropower candidates. The cost estimates have been based upon the design information currently available and are expected to be within an accuracy of ± 30% at current price levels.

7.5.2 Civil Works

For the civil works structures, major quantities have been estimated from the current conceptual designs. Quantities have been calculated for all major items including excavation, compacted fill, concrete, reinforcement and steelwork. In addition, an allowance was made for unquantified and other minor items of each structure (i.e. unmeasured items). This allowance has been calculated as a percentage.

The unit rates applied to the quantities were calculated from a number of references that included the following sources of data:

- Information obtained from the work that Multiconsult is currently undertaking on the Mount Coffee Hydropower Plant.
- Previous power projects that have been undertaken in the West African region.
- Multiconsult's in-house data base of unit rates.

All historical unit rates were escalated to represent costs at current price levels using a combination of foreign and local escalation indices. Escalation indices applied to foreign and local components have been derived from the following sources:

Table 7-3 Escalation rates

Component and weight	Index
Foreign 80%	United States Department of Labour
Local 20%	Liberia Consumer Price Index

A selection of developed unit rates used in the civil works cost estimate are presented in the following table.

Table 7-4 Unit rates civil works

Item	Unit	Adopted rate	Benchmarking with Zambian projects
		USD - 2018	USD - 2018
Compacted Earthfill	m^3	18	16 - 17
Compacted Rockfill	m^3	30	27
Concrete	m^3	500	400 - 420
Open Excavation (Soil)	m^3	15	14 - 18
Open Excavation (Rock)	m^3	45	26 - 31
Reinforcement	ton	2,500	2,500

Unit rates for the civil works is set slightly higher than recent experience from other projects in Africa, but lower than the experience from Mt Coffee reconstruction works.

7.5.3 Mechanical and Electrical Plant

For the mechanical and electrical plant, costs are obtained from the NVE database (published by Norwegian Water Resources and Energy Directorate (NVE), 2016) as well as Multiconsult' s database of power plant costs. The NVE costs are split between small (up to 10 MW) and large (greater than 10 MW) hydropower plants. Key technical parameters are used to determine a plant cost from the NVE database.

The NVE databases are compiled from the numerous hydropower plants that have been installed in Norway. Norway has over 30 GW of hydro capacity and is considered a competitive, cost efficient hydropower market, and thus a good basis for determining costs. The database is typically updated every 5 years with recent projects.

The NVE database costs cover the supply, installation and commissioning of the plant in Norway. On-costs are therefore included in the individual system costs to cover for the additional expected costs for Liberia. These on-costs include remoteness of Liberia (10 %, including additional transportation costs) and owner's costs (10%, including licencing, regulatory approval, and contracting costs).

7.5.4 On-costs

The cost estimates for civil works and mechanical and electrical plant will also include allowances for additional on-costs that would be expected to be incurred during the construction process and will be calculated as a percentage of the base rate. They will include:

- Preliminary and general items (25 %, only for civil works).
- Contingencies (15 % for civil works and 5 % for mechanical and electrical plant).
- Engineering, administration and construction management costs (10 %).

Slight adjustments to the magnitude of this P&G item have been made for projects of less complex type, and according to which sequence the hydropower projects actually are approved and built. For SP2 extension will benefit from already built access roads and camp infrastructure.

7.5.5 Environmental and social mitigation costs

These costs are derived from tables explained in Chapter 6, but with the exception of fish passage costs. The cost of fish passages has been reduced by several design measures which are intended specifically to reduce the cost while still allowing some species migrations, both in the upstream and downstream directions. The fish lift is integrated into the main dam and therefore included in the main dam cost. The trash racks and turbine speed are planned to reduce fish mortality through fish being sucked into the turbines, and finer rack spacing is also an integral part of the project cost.

Low lift pumps for increasing attraction flows, fish monitoring, reservoir fisheries planning and aquatic ecology studies and other items solely for benefitting fish populations are still costed and included with the cost of social mitigation measures.

7.6 Social impact mitigation

7.6.1 Access to all dams and villages

Actual relocation needs have not been determined yet, but estimated numbers have been given in Table 6-9 in Chapter 6. Villages close to the saddle dams will benefit from all-weather road access and bridge crossings and are likely to grow in size for this reason alone. In addition, relocation areas will need to be planned and will also become new population centres close to the reservoir. Therefore, a local network of access paths, causeways and footbridges is likely to connect existing and new villages and agricultural communities around the reservoir.

Electrification from the 220 kV grid is technically easy, but is a question of connection policy and fee rates for LEC to decide. Reservoir fish harvesting and recession agriculture are two new opportunities for increasing community livelihoods and food security, as discussed in Chapter 6.

7.6.2 Reservoir vegetation clearance and access for boats and canoes

The SP2 reservoir has now been planned with a substantial drawdown zone between 163 and 152. This is good from the viewpoint of annual mixing of stratified layers in the reservoir and replenishment of oxygen in the deepest part of the reservoir. It is however problematic for navigation and boat access. Therefore, it is proposed to identify and plan zones where boats can be beached and catches can be offloaded directly onto trucks and vehicles for transport to local markets. These beaches and boat lanes should be cleared of all substantial trees and bushes so that they do not represent a hazard to boat traffic at any reservoir level. Otherwise, reservoir clearance in general is a subject for discussion as part of the ESIA studies.

8 Analysis and Optimization: Towards a least cost development path

Having identified the most viable generation candidates for Liberia and mapped the generation mix in neighbouring countries, this chapter presents the results of the optimization and analyses carried out in order to identify the technologies and projects that are expected to constitute Liberia's least cost development path. In order to arrive at this development path, the team has applied the highly site specific characteristics and costs to an economic analysis that has involved two separate approaches as summarized below.

- **System optimization using Balmorel**. The optimization of the power system, utilizing the Balmorel power modelling tool, is the primary method employed by the team in order to determine the least cost development path. This is because the model is a much more powerful tool for such optimization and specifically addresses the weaknesses attributed to the traditional/simplified approach of comparing LCOEs. Specifically, the Balmorel model optimizes total system costs and thus ensures that the technical/resource constraints of various technologies and projects, as well as the interaction between these, are fully accounted for in the results. While an LCOE analysis makes simple, generally incorrect and/or imprecise, assumptions as to contributions to peak demand, daily variations in demand and renewable resources and complementarity between technologies, the Balmorel model is explicitly built to address these factors. Accordingly, the Balmorel model offers much more consistent and robust optimization for determining the least cost development path, while ensuring that both daily demand profiles are met and resource availability is accounted for, on an hourly basis. The results will generally be highly consistent with an LCOE analysis, but not necessarily entirely, as Balmorel does not consider projects or technologies in isolation of one another, as an LCOE analysis does.
- **A LCOE analysis of technologies and generation options**. Despite the weaknesses described above, an LCOE analysis is useful in order to fully appreciate and confirm the outputs of the Balmorel optimization. As noted above, one can expect that the modelling results will be largely consistent with the LCOE analysis, but not necessarily entirely. Nonetheless, as the form of analysis and results that are produced by the Balmorel are not entirely easy to understand or intuitive, an LCOE analysis is presented in order to further enrich the analysis and results.

The objectives of the analysis is to;

Provide a robust basis on which to evaluate, prioritize and select priority investment projects that are consistent with a least cost development path for Liberia.

8.1 System Optimization using Balmorel

8.1.1 Optimization with Balmorel

As described above, the system optimization utilizing the Balmorel model offers a much more advanced method of finding the least cost generation development path for power market than the simple comparison of LCOEs for a range of technologies or projects. This is because the utilization of the model ensures that most of the weaknesses of LCOE comparisons are accounted for, including; the constraints amongst, and complementarity between, technologies in the generation mix; the contribution of individual technologies to meeting actual daily demand profiles; seasonality and daily variation in available generation from renewables; the fact that investments in one technology

influence the decision to invest in other technologies, etc. Accordingly, given these factors, the optimization with Balmorel should be seen as a more robust and comprehensive manner for determining the least cost development solutions for the CLSG region. It should be noted however that given features, the least cost solutions may sometimes be differ from expectations from the more simple LCOE comparisons. Box to the right provides a further explanation of the optimization approach employed in the Balmorel model.

The power system model Balmorel was used to simulate how the various power plants interact to meet the forecast demand (including reserve) on an hourly basis at any time of year. Balmorel also calculates the least cost sequences of investment for meeting demand, and gives the total system cost as a result. The model is given a number of generation options to choose from in order to expand the system gradually to meet the growing demand. We have chosen to illustrate the recommended investments by simulating the demand in 2026, 2034 and 2040.

For this analysis, the Consultant has focused on modelling the Liberian power system, including all realistic supply options for Liberia in the long term. Power systems of Côte d'Ivoire, Sierra Leone and Guinea are modelled in a simplified way, only with dummy power plants. The model therefore identifies whether it is optimal to export surplus hydro energy to Côte d'Ivoire and import in the dry season from Côte d'Ivoire based on natural gas (2026, 2034) and LNG (2040).

> The Balmorel is a partial equilibrium model which provides a least cost solution for meeting demand by the end of the planning period. Specifically, the model minimizes system cost of the regional power sector by i) finding optimal generation mix and trade profile for the CLSG countries, and ii) generating optimal investments in new production units to meet electricity demand. The system costs comprise investment annuity cost, fuel costs and operating and maintenance costs, which is highly comparable with the LCOE of the system and individual technologies/projects.
>
> The model takes account of technology options and costs, daily and seasonal demand profiles, resource (e.g. solar, wind and hydro) availability and seasonality, inter-connectivity constraints, storage options, etc.
>
> The following are examples of outputs of the Balmorel model:
>
> - system costs,
> - required investments in new power plants,
> - hourly demand and supply profiles,
> - hourly power trade between countries (optimised within the given line constraints),
> - hourly levels of spinning and non-spinning reserves,
> - electricity price and short run marginal cost of technologies.

In summary, given the assumptions and inputs for the base case, the selected investments that minimize system costs in the Balmorel model shall be interpreted as those that minimize total system cost for the entire generation mix for Liberia in order to meet daily demand throughout the year.

While, the consultant relies primarily on the results of the Balmorel optimization, the results are further informed by an LCOE comparison assessment below.

8.1.2 Assumptions and inputs for the base case

In terms of the modelling, a range of assumptions regarding key inputs have been made. These inputs have been the subject of extensive consideration and analysis by the consultant, as well as with the client and Task Force. Appendix I provides a complete presentation of the range of inputs used for the Balmorel modelling, covering the following topics (among others):

- Time-frame for the modelling
- Demand growth projections
- Daily demand profiles now and in the future
- Generation options available
- Technology and specific project costs
- Fuel prices and projections
- Discount rate
- Resource availability – daily and seasonally
- Power trade scenarios and availability

The details regarding these inputs and assumptions are laid out in the Appendix. Further, as described below, several of these assumptions are subject to sensitivity analyses. Some of the more central assumptions concerning the overall frame for the optimization simulations are summarized in the table below.

Table 8-1 General framework assumptions (to be applied for the Base-case Scenario)

	Assumption
Modelled years	2026 (2029 for the Via-as-PIP Scenario), 2034 and 2040
Modelled weeks	26 weeks evenly spread over a year (every second week)
Spinning reserves	3%*Demand$_h$+5%*Productionh(Solar$_h$), where h denotes hour
Non-spinning reserves	10%*Demand$_h$, where h denotes hour
Discount rate	6% as per WB guidelines (specified in ToR)
Share of import	Limit of 30% of annual on-grid demand in Liberia can be met by imports
Electricity demand	Base demand
Inflow data	Average year

It is noted that, originally, the consultant had chosen the year 2029 as the first simulation year, as it was determined as the first possible year for full operation of the Via hydropower project. Subsequently, however, a possible fast track concept for SP2 was introduced and it was decided to run a 2026 simulation as well.

The Consultant was advised to have primary focus on the analysis in Liberia. Accordingly, the following approach and assumptions were applied to the model as to possible trade with other countries:

- A hydropower dummy plant has been added in Guinea since the country is a CLSG system operator and dispatcher, and needs to have rapid variability of output to match demand variations. Sierra Leone has also a dummy hydropower plant. Both are assumed to have the same seasonal hydrology as for St. Paul River. St Paul bears similar seasonal flow patterns to the rivers of Guinea and Sierra Leone. An identical timing of dry spells gives the most conservative worst case situation for our modelling assumptions. In reality the different timing of dry flows will simplify the need for new investment or reduce fuel use, thus reducing system cost. In addition, if there are any seasonal reservoirs in these two countries, then the unregulated pattern of St Paul flows is again a conservatively assumed constraint to the model.

- A dummy plant based on fuel and variable cost of an LNG-fuelled combined cycle is considered suitable for giving the marginal long-run cost of excess power for export from Côte d'Ivoire. The model therefore identifies whether it is optimal to export surplus hydro energy to Côte d'Ivoire and import in the dry season from Côte d'Ivoire based on LNG (after 2029 when LNG can become available).
- As to the CLSG line, it is noted that the line has a capacity of about 220MW, but based on feedback and inputs from the Task Force, the available capacity for Liberia is assumed to be 50% of this, or about 110MW. The availability of capacity, particularly during peak periods can have important implications for investment requirements and technology choices for Liberia.
- The model can also choose imports and transmission investments, but for this assignment we have assumed the 220 kV CLSG line as already constructed. Instead, we have set a defined limit on the models ability to import from abroad to meet the Liberian demand. 30% of annual energy demand was the base case assumption.

Table 8-2 Assumptions on the CLSG interconnector

	Assumption	**Source**
Thermal capacity	240 MVA = 216 MW[1]	Meeting with LEC
Design capacity for normal use	120 MVA = 108 MW[1] (50% usage, the remaining capacity is for emergencies)	Meeting with LEC
Transmission losses	5% (fraction of the power entering the transmission line)	Simplified calculations done on the contracted sales in the PPA (3 * 27.6 MW delivery)
Margin on imported power	2 USc/kWh (in addition to cost of energy production) for import from Côte d'Ivoire; 1.5 USc/kWh (in addition to cost of energy production) for any other import	Assumption; the PPA between Liberia and Côte d'Ivoire dated 2016 specifies a margin of 1.7 USc/kWh

Note: 1) Assuming cosØ=0.9. 1 MVA * 0.9 = 0.9 MW based on Tractebel (Vol 4. 2018).

The generation options available for the model to choose from are summarized in the table below.

Table 8-3 Parameters of generation options for Liberia (Base-case Scenario)

Project name	Capacity	Annual generation	Capex	Fixed O&M costs	Variable O&M costs	Fuel price 2034	Fuel cost 2034
	MW	GWh	MUSD	% of capex	USD/ MWh	USD/ MWh	USD/ MWh
Mt Coffee Extension	44	126 added (560)	50	1.5%	0		
SP0	105	570	605	1.5%	0		
SP2	154	840	763	1.5%	0		
SP2 Extension	96	250	110	1.5%	0		
SP4	88	484	663	1.5%	0		
Tiboto (50%)	112.5	456	450	1.5%	0		
Solar PV (2026)	75	158	85	0.8%	0		
Solar PV (2034)	75	158	75	0.8%	0		
Solar PV (2040)	75	158	71	0.8%	0		
HFO (DI)	Unlimited		1.00 (per MW)	1.9%	6.5	47.1	118
HFO (OCGT)	Unlimited		0.99 (per MW)	0.5%	17.4	47.1	157
Diesel (DI)	Unlimited		1.00 (per MW)	1.9%	6.5	61.4	154
Diesel (CCGT)	Unlimited		1.50 (per MW)	2.7%	7.0	61.4	123

(Sources: Multiconsult; Tractebel (2018). Prepared by Multiconsult.)

Notes: An hourly storage of maximum 5 hours is modelled for Mt Coffee Existing. It is assumed that Mt Coffee Extension does not have any hourly storage. All other hydropower plants are modelled with an hourly storage of maximum 12 hours.

The tabled CAPEX for SP2 and SP2 Extension include transmission cost to MtCoffee and to Gbarna/Botota respectively. This is a benefit to SP0 and SP4 which as a consequence has low transmission costs.

Minimum investments allowed in open cycle gas turbines (OCGT) and combined cycle gas turbines (CCGT) are assumed to be 20 MW and 60 MW, respectively. Fuel costs are calculated assuming the following fuel efficiencies: 40% for diesel units (DI), 30% for HFO (OCGT) and 50% for diesel (CCGT).

Solar PV capacity is presented in MWac.

The table below combines all information about hydropower candidates in one table for ease of comparison and checking across the scenarios. MW installed, capex and opex costs are the same for both the Base-case and the Via-as-PIP Scenarios. Via & SP4 is omitted from the base case.

Table 8-4 Parameters of hydropower generation options for Liberia (Base-case Scenario vs Via-as-PIP Scenario)

Project name	Capacity	Annual generation (Via-as-PIP Scenario)	Capex	Annual generation (Base-case Scenario)	Difference in generation
	MW	GWh	MUSD	GWh	GWh
Mt Coffee Extension	44	115 added (705)	50	126 added (560)	+11
Via and SP4 dams + Via HPP	88	493	1150		
SP0	105	630	605	570	-60
SP2	154	924	763	840	-84
SP2 Extension	96	230	110	250	+20
Tiboto (50%)	112.5	456	450		

(Source: Multiconsult.)

Notes: The main transmission cost of the StPaul projects is carried by the Via project (MtCoffee-Gbonota-Gbarnga-Botota) in the Via-as-PIP Scenario, enabling the other projects along the StPaul River to connect this line with low transmission costs. In the Base Case Scenario, SP2 carries the main burden of the transmission costs.

In the Base-case Scenario, investments in SP2 Extension and Tiboto are allowed from 2034, while investments in all other hydropower candidates are allowed from 2026. In the Via-as-PIP Scenario, the Balmorel model is forced to invest in Via and SP4 dams + Via HPP in 2029, and only Mt Coffee Extension is an investment option in 2029, while investments in all other hydropower candidates are allowed from 2034.

The existing MtCoffee hydropower plant is already included in the model, and is hence not an optional new investment, with 88MW capacity and 438GWh annual generation potential.

8.1.3 Average hydropower potential and firm hydropower energy

Firm reservoir yield and power system reliability

The hydrology of the St Paul River is such that seasonal variations are very marked and predictable. The year can be divided into two seasons, the dry season from December to April and the wet season from May to November. The lowest flows occur in February, March or April. The natural flow duration curve is shown in Figure 8-1 with a log scale. There is an unusual tailing off of flow values for some very few days in the 6 year series of daily flows. This does not seem normal compared with a normal recession curve after a prolonged dry spell throughout the catchment, when water is supplied principally from groundwater. It is possible there is a measurement error of lack of good low-flow measurements which form the rating curve. It is quite likely that flows normally never fall below 30 or even 35 m^3/s despite the few values of less than 30 in the datasets. This question has considerable impact on the definition of firm energy, but we have used the data as they are.

The firm capacity supplied by Mt Coffee is only 4.5MW at present, based on 35 m^3/s inflow, with 8 m^3/s bypass environmental release. This will be a difficult setting for one Francis unit (25% of max flow) to operate at continuously. At such low flows, it is better that the hourly reservoir at Mt Coffee is used to provide peak hour energy and be closed at night for refilling. For comparison the red line shows the regulated outflow from SP2, giving minimum 80 m^3/s flow throughout the dry season. This flow gives close to peak efficiency for Mt Coffee units around 15 MW. This can be defined as the firm capacity of

Mt Coffee after SP2 construction, while current firm capacity is actually zero since it cannot be supplied continuously without damaging the turbines.

The corresponding firm capacity of SP2 is 25 MW or more depending on the reservoir level. The firm capacity of both is therefore 40 MW continuous, or 4.5 GWh in the driest month of March. This value is very sensitive to the final decision on dry season environmental releases.

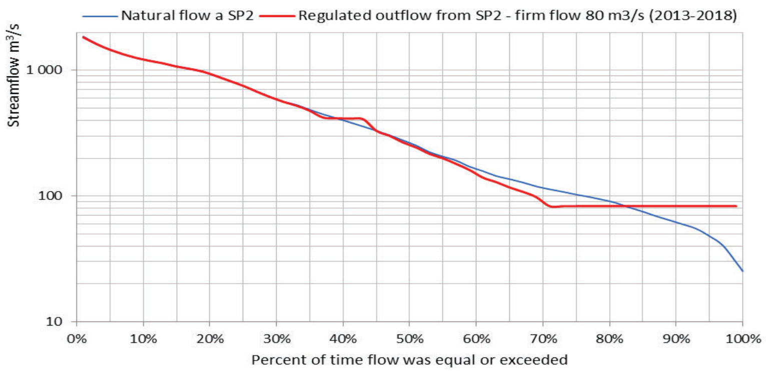

Figure 8-1 Flow duration curve at SP2 damsite (Note: This is a log scale)

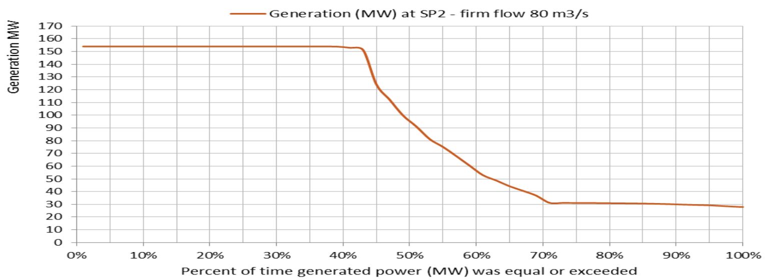

Figure 8-2 Power output duration curve from SP2 FSL 163

Correspondingly the firm yield of the larger Via & SP4 reservoirs is 210 m³/s and the firm capacity in March is 44 MW at Via with 36 MW at Mt Coffee. We can therefore conclude that the firm capacity with Via is 80 MW compared with 40 MW with SP2 FSL as the PIP.

Dry year firm hydropower energy

The year to year variation in average inflows is relatively moderate, and the year to year variation in low flows is very little. This results in consistent minimum flow values except in periods of exceptionally long prolonged drought or sequential failure of the rains over at least two dry seasons. This may apply up near the Via catchment site, but the coastal nature of rainfall prevents such drought conditions occurring in the lower reaches around Mt Coffee. To define firm hydropower energy on an annual basis we use the next driest hydrological year in the 30 year series, and the production is only 85% of the average annual production. On an annual basis firm energy for all hydropower options with little

seasonal regulation can be defined as 85% of average. The years 1980 and 1982 both have about 85% of the long term average energy production.

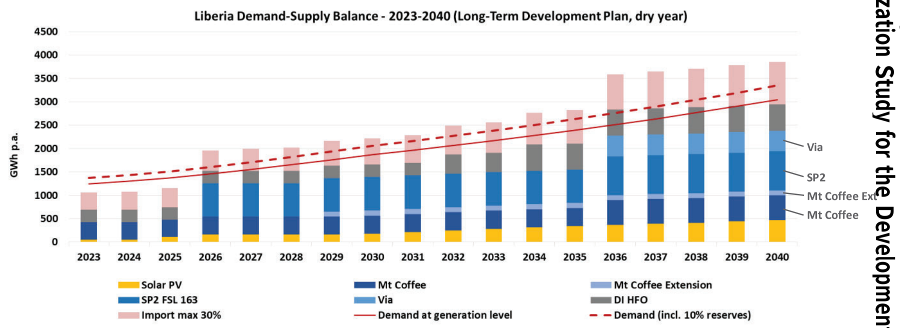

Figure 8-3 Long-Term Development Plan for Liberia in the event of a dry year (GWh)

Firm system energy

To define a meaningful value for firm system energy we must decide how much import and thermal capacity can be assumed available to firm up the very variable output in St Paul hydropower plants. The Balmorel simulations show that there is theoretically never a failure to supply the demand in 2026, given the current thermal plant remains operable and that CLSG import is not restricted below 108MW. The Balmorel model shows how the stipulated reserve requirements are fulfilled on top of generation level demand, but is not a model for fine tuning of the power system operation under strained conditions. At the same time we should relate the probability and extent of load shedding to the Liberian consumers' recent experience of load shedding due to other reasons than Mt Coffee hydrology (transmission and distribution, lack of fuel reserves, etc.). Occasional short duration load shedding has been and will continue to be accepted by most consumers. We must therefore examine only prolonged load shedding or failure to supply power over periods of a month or more due to prolonged low hydropower output. We find also that the lowest production figures occur regularly in March, and therefore we define firm energy on a monthly basis using the March monthly energy supply from all sources.

Unserved energy

The loss of load probability (LOLP) is therefore not the best characteristic for planning the Liberian system while this factor remains high, but primarily not for hydrologic reasons. LOLP of 0.1% is normal for all types of outage in an integrated and diversified power system, but could be accepted at higher levels in Liberia. Instead we examine the degree of expected unserved energy (UE) due to low March flows in the St Paul River.

We can best estimate this UE quantity by looking at the frequency of empty reservoir conditions and the resulting throttling down of the hydropower plants to avoid reservoir levels dropping further. We assume that the power plant closes during all weeks when reservoir levels are empty, implying that the only releases are environmental flows identical to the inflow. With SP2 reservoir regulation there will be 4.5 GWh production in March, but without this regulation we estimate only one third of this figure is possible to produce (8 hour daytime supply instead of 24 hour supply based on 25 m³/s station average flow compared with 75 m^3/s). Thereby we estimate unserved energy in March to be decreased by 3 GWh and only one March month every 10 years (see variations given in Appendix E).

The unserved energy due to hydrologic reasons is reduced from an average value of 0.45 GWh to 0.15 GWh as a result of SP2 (all other conditions being equal) or from 0.04% of demand to 0.013% of demand. The latter figure is acceptable for an immature power system such as in Liberia. 0.002% is an acceptable level in for example Australia (https://www.aemc.gov.au/sites/default/files/2018-04/Reliability%20Panel%20Final%20Report.pdf. It is important to distinguish between UE figures for all causes and expected UE based on generation shut down due to low inflows only. This latter figure quoted here only for low inflow causes is lower than the former which is normally quoted for complex integrated power systems.

Reserve criteria and unserved energy

The criteria for maintaining reserve generation for long term shortages is closely related to the unserved energy criterion. If the Liberian power system had remained isolated, there would be arguments for maintaining reserve thermal capacity for use only in March month in a dry year scenario. This would be a costly investment for very little benefit. Pre-warned selective load shedding or other demand side management approaches would be a much cheaper method of dealing with occasional energy shortages.

From 2020 the Liberian system can benefit from the recent interconnection with its CLSG neighbours, and can therefore choose between load shedding in March or purchase of additional imports (presumably at a high price) if a dry year is approaching. In neither situation can it be economic to invest in increased capacity for covering the generation constrained system at such high reliability levels normally used in planning complex and highly diversified power systems.

The reserve criteria adopted in the Balmorel simulations require 10 % of reserve capacity in an average hydrologic year (plus spinning reserve which is a separate issue of no relevance in the March energy shortages). If we look at the average hydropower energy in a dry year then the 10 % reserve will just about cover the shortfall from the average year. It is also relevant to note that the reserve energy available after commissioning a new project usually exceeds the 10 % criteria substantially (see Appendix I). The chances of a dry year occurring one year before commissioning the next generation project are smaller than the statistical return interval of the dry year.

We therefore argue that the base case scenario (and optimal approach for Liberia) is timing investments on the basis of average hydrologic conditions with 10 % reserve. In addition a facility to increase imports in March month (giving one month's notice) would result in a fully acceptable level of LEC system security for the short term. Much more important are the near term investments required to improve system security within transmission and distribution, and to substantially reduce total system losses.

As a sensitivity test we show how a dry year situation of 85% inflow of the average hydrologic year affects the investment stream. If no imports are available and the dry year situation occurs, we see that some investments are needed 1-2 years earlier than in the base case. In reality however, Liberia's limited access to capital, long lead time for hydropower investments, and slower demand growth than desirable continue to dictate the actual timing of investment in new generation plant. We expect there to remain a generation shortage for many years to come, and efficient use of limited capital to get the average sales tariff down as fast as possible should remain the governing factor for near term planning. This report demonstrates that the SP2 project is a far more efficient use of capital than the larger more long term hydropower investment options.

8.1.4 Base-case results

Given the assumptions and inputs summarized in Section 8.1.2 and presented in Appendix I, the Balmorel optimization for the Base-case Scenario results in the investment sequence summarized in Table 8-5. Again, in accordance with the description above, this sequence is the one that the Balmorel model simulations determine to be the least cost solution for the development of the sector in terms of total system costs, assuming that there are no investments in Via. This investment sequence, and the corresponding inputs, is labelled as the "base-case" and represents, in the Consultant's view, the primary basis for investment planning for the short- to medium-term.

As indicated in the table, a combination of solar PV and SP2 investments come out as the most cost effective options for meeting short-term demand and are thus considered the top priority investments. Again, technically speaking, these two types of investments, ***in combination with the existing generation mix, represent the least cost option for meeting demand in 2026 from a total system cost perspective. Further, the figures below demonstrate how hydropower and solar PV complement one another towards this end.***

Table 8-5 Investment sequence by technology – Base-case Scenario (MW)

Modelled year	DI HFO	Solar PV*	SP2	Mt Coffee Extension	SP2 Extension
2026		75	154		
2034	75	75		44	
2040	98	75			96

** Solar PV capacity is presented in MWac*

The figures below illustrate how the various generation sources are dispatched during a "typical day" during the wet and dry seasons, in 2026 and 2040, respectively. Specifically, the demand curve with its typical hourly variation is shown by the red line, and generation beyond the line represents potential exports, while the pink area between the demand and generation represents imports as the least cost solution.

Some important observations and takeaways from the series of figures below include:

- **In the short- to medium-term, SP2, solar PV projects (total capacity of up to 90MWp), and Mt. Coffee extension offer highly attractive investment opportunities and are therefore defined as the Priority Investment Project.** At low LCOEs, the introduction of these projects allows Liberia to maintain a relatively low system cost. It is notable from the assessment in Section 8.2 how quickly the LCOEs rise for the next attractive projects/technologies. Further, the figures below illustrate that, up to a certain level, solar PV is highly complementary to the daily peaking capacity of SP2 and Mt. Coffee existing.
- **Considerable export potential during wet season in short-term but diminishing towards 2040.** This is illustrated by the fact that generation would surpass demand and the surplus shown above the red line is available for export (if there is a market for exports during the wet season in the region). Solar and hydropower will supply all demand, and there is no need for thermal plants to operate, even during peak periods. However, as demand continues to grow after the best hydropower projects are constructed, the surplus diminishes until imports are required to cover peak demand.
- **During the dry seasons, a combination of HFO and imports is required to cover the considerable reduction in hydropower availability in the Base-case Scenario**. As long as

imports are possible, this is the least cost option for Liberia. In the short-term, only existing HFO is required, in combination with imports (imports represented by the pink area below the demand curve). However, as demand continues to grow, considerable investments are made into HFO. As indicated in Section 8.1.7, the availability of imports represents a considerable cost savings compared to self-sufficiency in the short or long-term.

- **Power trade has an important balancing role to play for Liberia.** The fact that Liberia is forced to invest in considerable new HFO plants is partly due to the constraints placed on Liberia's potential to import (maximum of 108MW). Particularly during peak periods, the availability of imports is important in terms of meeting demand in a cost-effective manner. To the degree imports cannot be relied upon for this purpose, Liberia will have to resort to even more expensive and little utilized HFO. As indicated in Section 8.1.5, an investment in Via Reservoir reduces but does not eliminate the need for imports.

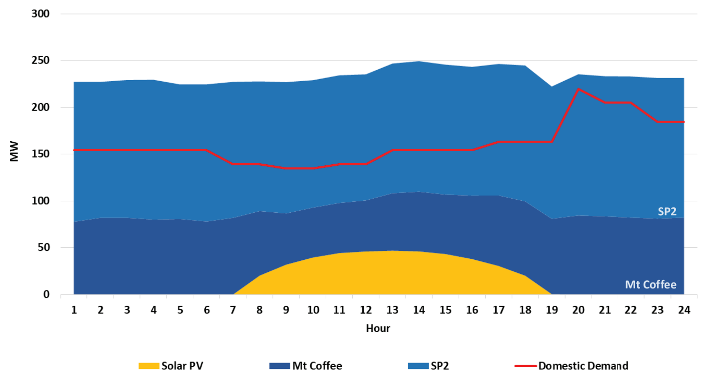

*Figure 8-4 Daily demand and supply profile during a typical day in the **wet** season in **2026** – Base-case Scenario*

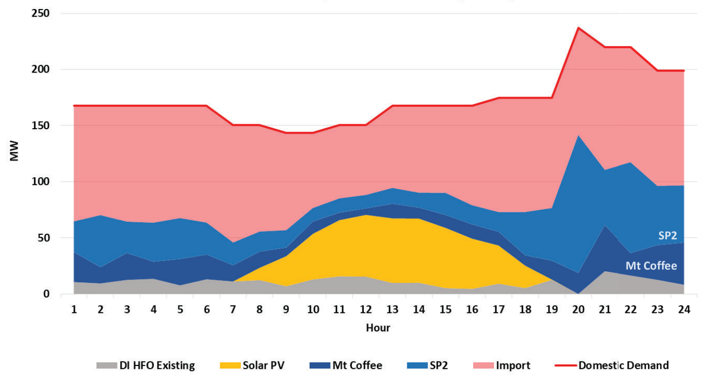

*Figure 8-5 Daily demand and supply profile during a typical day in the **dry** season in **2026** – Base-case Scenario*

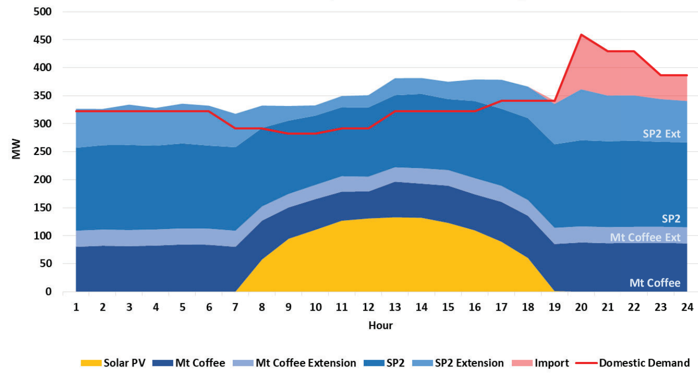

*Figure 8-6 Daily demand and supply profile during a typical day in the **wet** season in **2040** – Base-case Scenario*

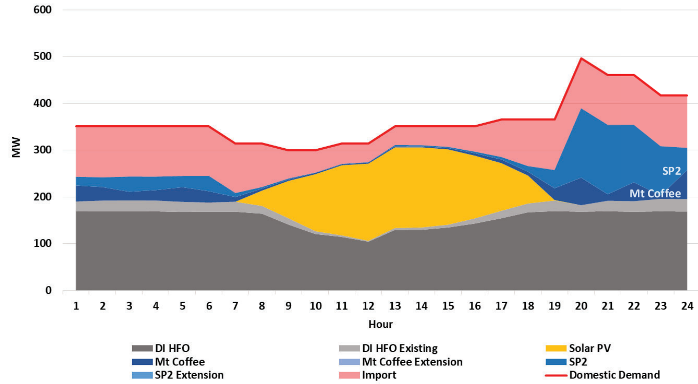

*Figure 8-7 Daily demand and supply profile during a typical day in the **dry** season in **2040** – Base-case Scenario*

As already described, the above base-case investment sequence is a product of system optimization by Balmorel which minimizes total system costs. This total system cost can be interpreted as the component of an eventual tariff that must go to paying of generation costs, covering capital and operating costs. As summarized in Figure 8-10 below, the total system cost rises from some 6.6 USc/kWh in 2026 to 8.0 in 2040. As anticipated above, the low cost of Mt. Coffee combined with the choice of low-cost options (PV, SP2 and Mt. Coffee extension) allows Liberia to keep the system cost at relatively low levels. However, as Liberia is forced to invest in less attractive alternatives and as import constraints take effect, the system cost rises noticeably over the planning period.

8.1.5 Implications for Via Reservoir as PIP

As described elsewhere in the report, for various reasons, the Via Reservoir was not considered as an option in the base-case optimization. This is, not least, due to the fact that an investment in Via cannot be simply introduced as a stand-alone option, as it would imply changes in production patterns for other downstream power plants. Nonetheless, the consultant has run a simulation of the Balmorel model in which an investment in Via is "forced" upon it. In particular, in the Via-as-PIP Scenario analysed in this section, the model is forced to invest in Via early in the planning period, and Via is assumed to be fully operational already in 2029. Given the assumptions and inputs summarized in Section 8.1.2 and presented in Appendix I, the Balmorel optimization for the Via-as-PIP Scenario results in the investment sequence summarized in Table 8.6.

Table 8-6 Investment sequence by technology – Via-as-PIP Scenario (MW)

Modelled year	DI HFO	Solar PV*	Via**	SP2	Mt Coffee Extension
2029		75	88		44
2034		75		154	
2040	32	75			

** Solar PV capacity is presented in MWac*

*** The model is forced to invest in Via by 2029*

It should be expected that the forced investment of a relatively expensive project will increase total system costs for the Liberian power sector of supplying demand. Indeed, as indicated in the figure below, the forced investment in Via early in the planning period results in about a 20% increase in the total system cost in 2029, compared with the optimal investments in 2026. In 2034, a projected 1,985 GWh/yr are produced in Liberia, and the Via-as-PIP Scenario is estimated to increase system cost by about 10%. Applying this system cost difference in 2034 reveals that the early investment in Via places an annual cost of nearly MUSD 15 onto the sector. According to these results, these MUSD 15, paid by consumers, tax payers or donors, would be avoided by following a least cost development path (the Base-case Scenario) in the short- to medium-term, including utilization of imports.

Thus, in the short- to medium-term, an investment in Via would represent a significant increase in system cost and thus cannot be considered the least-cost option for this period. However, of particular interest from the figures is that the Balmorel simulations confirm the expectation that once other downstream power stations are constructed, Via introduces a reduction in system costs (2040), primarily by reducing the need for running HFO. Accordingly, the following conclusions can be drawn:

- **In the short- to medium-term, there are two compelling economic arguments for why the Via Reservoir and power station should not be the PIP.** First, it is not the least cost alternative for the system in the short- or medium-term and would thus introduce considerable unnecessary system costs that will have to be covered by consumers. Second, as Via can only be first commissioned in 2029 (earliest and best case), Liberia will face either considerable power shortages and/or expensive temporary/emergency thermal power installations during the run-up to 2029. The economic and political costs associated with such shortages are not accounted for in the modelling but can be expected to be significant in the run up to commissioning in 2029. Delays would be very costly for Liberia.

- **Also out of practical and risk management concerns, policy makers are better served focusing on the PIP proposed in this report.** The prognoses and modelling results are inherently uncertain, as is the inputs such as demand growth and actual project costs. Our

analysis demonstrates that SP2, Mt. Coffee extension and solar PV as the PIP are robust results in light of various scenarios, including in case of the early investment in Via Reservoir (the Via-as-PIP Scenario). Indeed, as indicated in the LCOE assessment in Section 8.2, these options are economically attractive. Accordingly, these can be seen as no-regret investments, in the sense that in nearly any scenario of developments, these projects are aligned with a least-cost development path. Put another way, an alternative path of pursuing a MUSD 1,150 investment in Via over other options in the near term would represent not only substantially higher system costs, but also considerable risk. It should not be expected that Liberia, or its development partners, will have the capacity to raise the financing or carry out construction for Via in parallel with the other substantial projects in PIP.

- **In the long-term, Via Reservoir could be a part of the least cost operation of the Liberian power sector.** The analysis confirms that Via will represent a complimentary source of power and water regulation for the long-term. Based on the analysis, and the long lead-time for such a project, the Consultant would recommend consider start of construction of either Via and/or the SP4 reservoir option in the early 2030s, provided strong demand growth is realized.

- **Together with the proposed PIP, the later construction of Via and/or SP4 would represent a massive reduction in thermal production and thus also climate gas emissions.** That is by making substantial investments in hydropower, solar PV and eventually seasonal regulation, Liberia can avoid substantial fuel expenditures and the globe may avoid significant emissions. To the degree a global carbon price (or similar) is introduced, the savings could be substantial.

The above conclusions should provide a comprehensive case as to why Via is not considered the ideal candidate as the PIP, while at the same time recognizing the potentially important long-term role for the project in the sector.

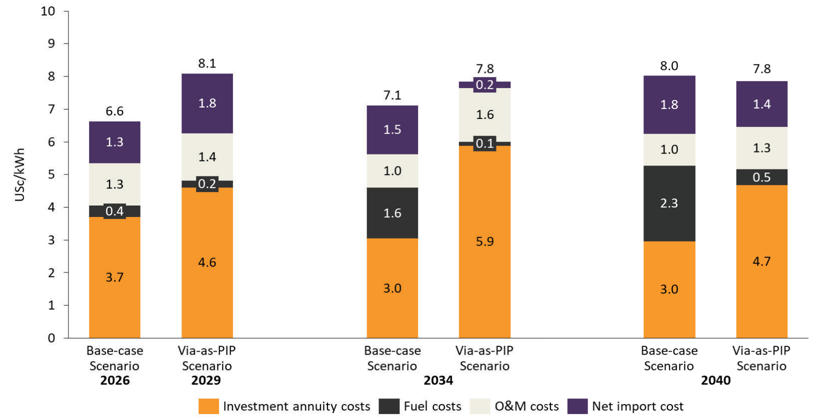

Figure 8-8 Development of total system costs (supply) for Liberia – Base-case Scenario vs Via-as-PIP Scenario

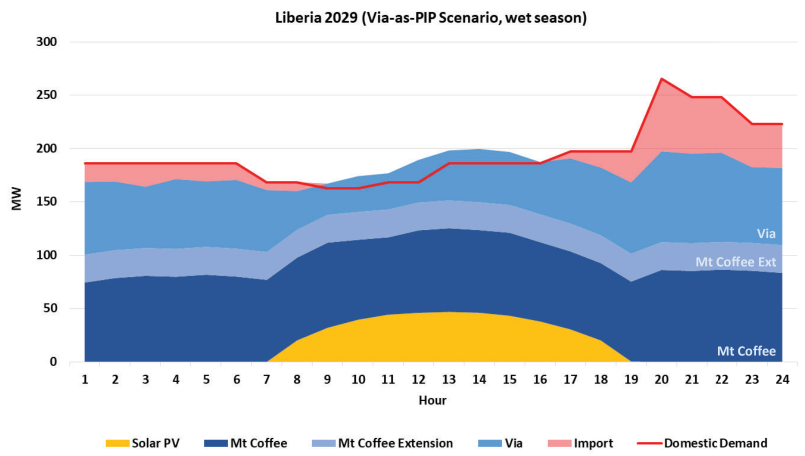

*Figure 8-9 Daily demand and supply profile during a typical day in the **wet** season in **2029** – Via-as-PIP Scenario*

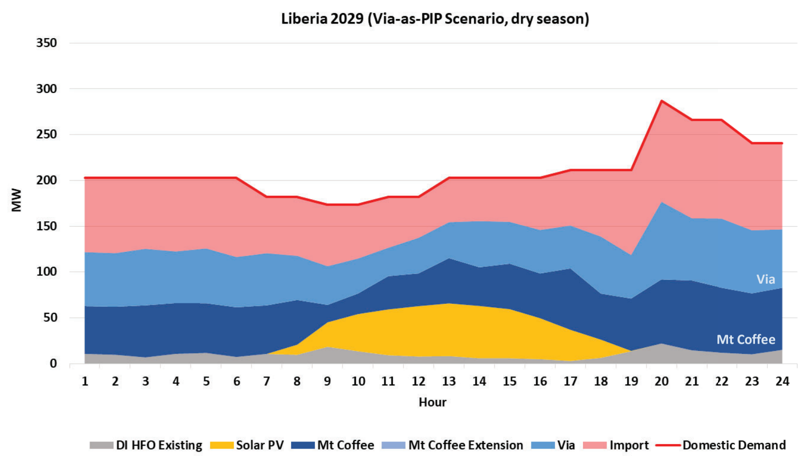

*Figure 8-10 Daily demand and supply profile during a typical day in the **dry** season in **2029** – Via-as-PIP Scenario*

8.1.6 Towards a Long-Term Development Plan for Liberia

Given the Liberian policy priority of pursuing energy independence and the results of the modelling carried out for this assignment, we are of the view that an investment in Via could be an economically viable strategy late in the planning period. Further, to the degree one wishes to avoid emissions in Liberia and/or a global carbon price is introduced, Via becomes even more viable. ***Thus, having accounted for the Liberian preference, Via (or another reservoir) is included in the recommended Long-Term Development Plan (see Table 8-6).***

Table 8-7 Investment sequence by technology – Long-Term Development Plan (MW)

Modelled year	DI HFO	Solar PV*	SP2	Mt Coffee Extension	Via
2026		75	154		
2034	75	75		44	
2040		75			88

** Solar PV capacity is presented in MWac*

Note: While the 2026 and 2034 investments are based on the simulation results for the Base-case Scenario, the 2040 investments are based on the simulation results for the Via-as-PIP Scenario

In the figure below, the team has extrapolated the investment sequence presented in Table 8-6 to demonstrate a plausible year-by-year expansion path for the Liberian power sector until 2040. While the "lumpy" nature of hydropower investments is noticeable, it is also worth noting how quickly demand growth is able to absorb the new investments. **The implications** of this picture are many:

1. First, Liberia has no time to waste in terms of initiating planning and implementation of the next generation projects. Even in well developed countries, such investment planning and financial mobilization takes time. To the degree Liberia is not able to plan for investments in line with this sequence, the economic costs can be significant, either in the form of power shortages or expensive supply alternatives. Notably, the anticipated tripling of demand until 2023/24 leaves Liberia with limited options in terms of meeting demand, especially in the dry season.
2. Second, given the clear attractiveness of the three PIPs (SP2, solar PV projects of up to 90MWp in total and Mt. Coffee extension), and the growing demand in Liberia, these projects should indeed be fast-tracked. The short-term alternative to these projects will likely be HFO production, increased imports, constrained demand and/or power shortages.
3. Third, from a least-cost perspective, imports in the dry season play a critical role in terms of meeting demand both in the short- and long-term.
4. Fourth, it should be expected that lumpy hydropower investments will result in temporary surpluses. However, these will be short-lived and it is thus important that Liberia continues planning for growing demand and thus maintains a pipeline of projects.
5. Fifth, for the medium- to long-term, effective planning in the sector should allow for an expansion path which underpins strong economic growth, industrialization and access expansion. But, again, effective and continuous planning is essential. This will require both fast-tracking the PIPs while also developing plans for future investments, in parallel. In particular, planning for Via Reservoir and/or SP4 Reservoir can run in parallel and allow for sufficient time for construction and commissioning later in the planning period.
6. Finally, the potential for solar is significant, especially if the cost of batteries continues to fall. Further to this point, and especially in the short term, solar PV's complementarity with daily hydro

peaking makes it particularly attractive for Liberia. Stakeholders should start analysing more closely the implications and limitations of the system's ability to absorb considerable solar power.

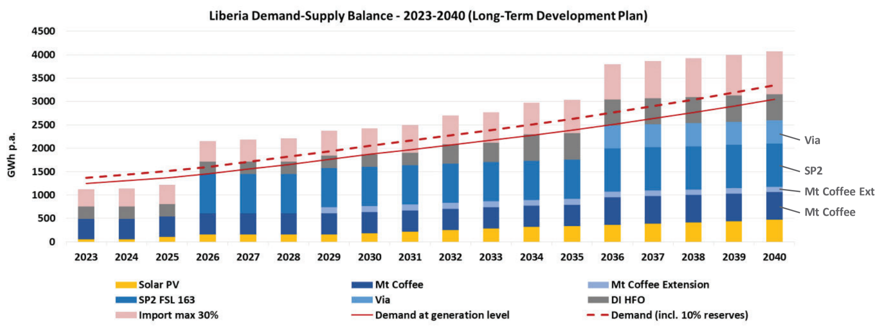

Figure 8-11 Long-Term Development Plan for Liberia (GWh)

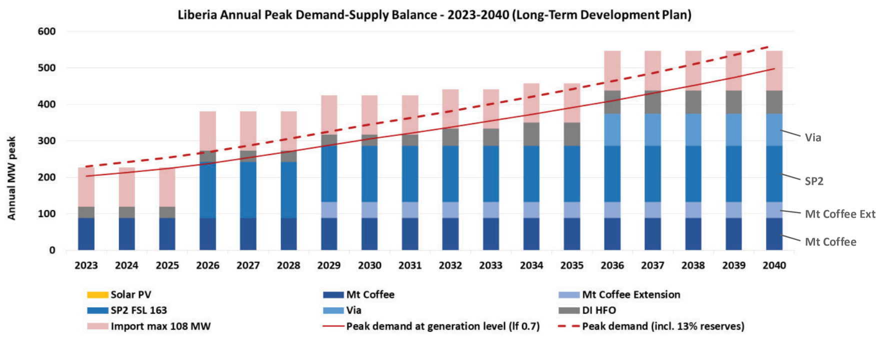

Figure 8-12 Long-Term Development Plan for Liberia (annual MW peak)

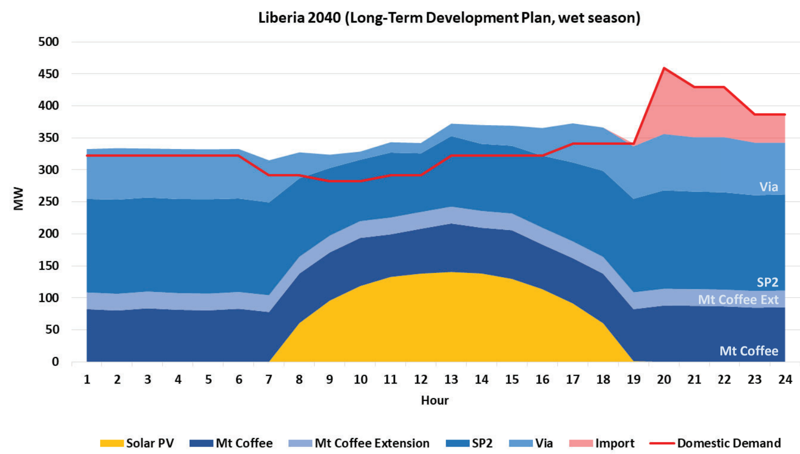

*Figure 8-13 Daily demand and supply profile during a typical day in the **wet** season in **2040** – LTDP*

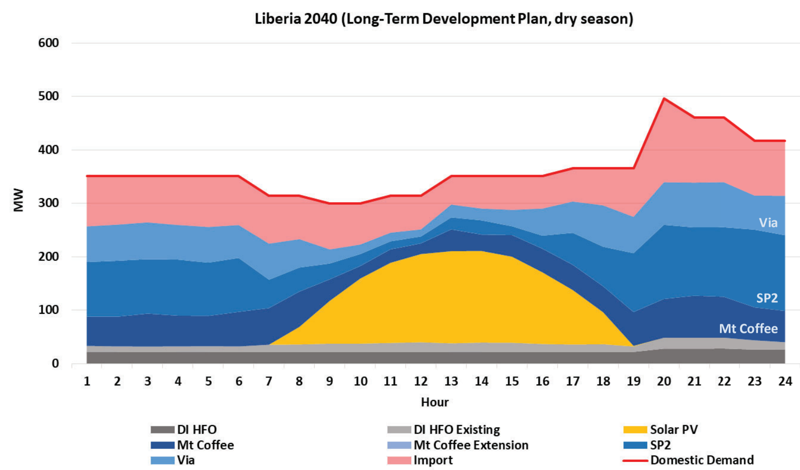

*Figure 8-14 Daily demand and supply profile during a typical day in the **dry** season in **2040** – LTDP*

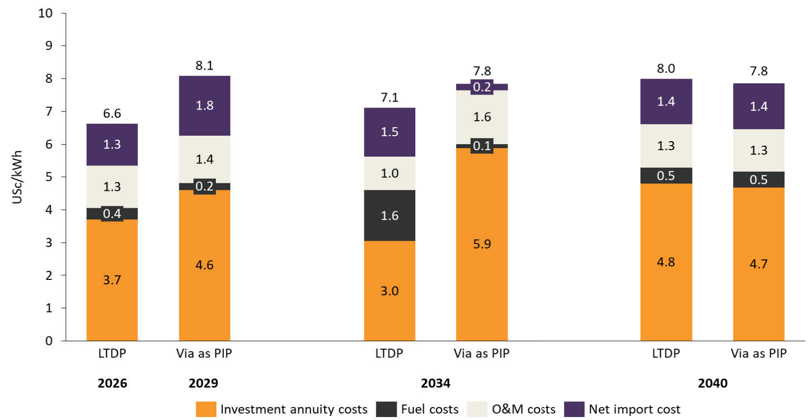

Figure 8-15 Development of total system costs (supply) for Liberia with successful implementation of the PIP and LTDP, compared to the Via-as-PIP Scenario. The difference between the system costs in 2040 is due to the costs associated with additional HFO built during the period until Via is commissioned in around 2036.

8.1.7 Implications for regional power trade

As noted above, regional power trade can play an important role for Liberia both in the near- and the long-term. In particular, as indicated in Section 8.2, the LCOE rises rather quickly following the first few (and most attractive) investment options. Despite this observation, Liberia could potentially have a number of reasons to avoid future reliance on imports, including everything from concerns about future supply availability, pricing and even energy security (political) concerns. As imports play a prominent role in balancing demand and supply in Liberia, particularly in the dry season, it should be expected that a strategy to avoid reliance on imports will come at a cost. Indeed, the Consultant's analysis of a scenario whereby power trade is not allowed demonstrates that the total system cost increases considerably. As can be seen from the figure below, the difference arises primarily from increased fuel costs, especially in early years.

It is important to reflect over the implications of these results. Specifically, they demonstrate the value added from allowing for synergies and maximum utilization of otherwise separate power systems in the region. Liberia, as with any country, can pursue an energy independence strategy, but this will come at a real economic and financial cost for the sector. Following the similar approach as for the Via-as-PIP Scenario, 1,985 GWh/yr in 2034 would imply that in that year, a no trade scenario will increase system cost by about 20%, or just over MUSD 30 per year.

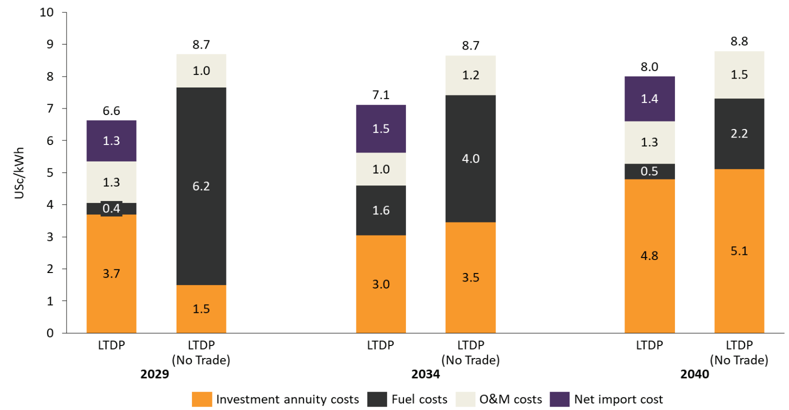

Figure 8-16 Development of total system costs (supply) for Liberia with successful implementation of the PIP and LTDP, with and without power trade on the CLSG interconnector

One key policy question that has arisen during the course of the work has been the degree to which the investment in Via could be a viable strategy to avoid reliance on imports. Accordingly, as a sensitivity, the Consultant has also run a Balmorel scenario whereby we compare the results of the Long-Term Development Plan with no trade and that with Via as the PIP and no trade. There are several interesting observations:

- First, consistent with the fact that HFO and Via have similar LCOEs, the two scenarios do not imply significantly different total system costs. In the medium-term (until 2036/37), the base case is the least cost option.
- Second, the generation mix and thus cost composition (capex v. opex) is significantly different between the two scenarios. In the base case, Liberia would have to rely considerably upon HFO in the medium-term. This implies considerable running costs but avoided up-front investments and thus loan and interest payments in the medium-term.
- Third, these results would clearly be highly sensitive to inputs and assumptions. In particular, the introduction of a carbon price or a reduction in the discount rate (from 6%) would quickly turn the balance in favour of an earlier Via investment as the preferred strategy to pursue full independence in the medium-term. It is however, once again emphasized that such a strategy would not be in line with a least cost strategy (the recommended Long-Term Development Plan) and would thus come at considerable system costs.

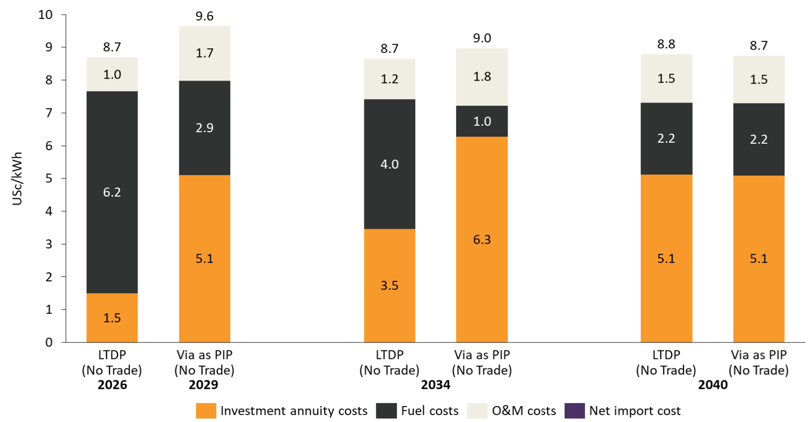

Figure 8-17 Development of total system costs (supply) for Liberia – Long-Term Development Plan (No Trade) vs Via-as-PIP Scenario (No Trade).

8.2 Assessment of LCOEs of candidate projects and technologies

The least cost development path for the sector, as determined by the Consultant, is presented in the previous sections. Further, the key differences between model optimization and LCOE comparisons is also described above. A key input to the optimization is naturally the total cost of energy from the various technologies and candidate projects. Specifically, in terms of the Balmorel optimization, a "system cost" has been utilized for each technology which, for all practical purposes, can be interpreted as the LCOE (see below).

In order to further appreciate the results of the modelling and interpret the results in light of LCOEs for individual technologies and candidate projects, an LCOE assessment is carried out below. Again, this is done so as to facilitate a deeper understanding of the results, rather than an approach to alter the results themselves.

In order to put the assessment into perspective, it is worth reviewing the typical definition of LCOE:

The levelized cost of electricity (LCOE), also known as Levelized Energy Cost (LEC), is the net present value of the unit-cost of electrical energy over the lifetime of a generating asset. It is often taken as a proxy for the average price that the generating asset must receive in a market to break even over its lifetime. It is a first-order economic assessment of the cost competitiveness of an electricity-generating system that incorporates all costs over its lifetime: initial investment, operations and maintenance, cost of fuel, cost of capital. The levelized cost is that value for which an equal-valued fixed revenue delivered over the life of the asset's generating profile would cause the project to break even. This can be roughly calculated as the net present value of all costs over the lifetime of the asset divided by the total electrical energy output of the asset.[33]

[33] Nuclear Energy Agency/International Energy Agency/Organization for Economic Cooperation and Development Projected Costs of Generating Electricity (2005 Update) Archived 2016-09-12 at the Wayback Machine

$$\text{LCOE} = \frac{\text{sum of costs over lifetime}}{\text{sum of electrical energy produced over lifetime}} = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

I_t	:	investment expenditures in the year t
M_t	:	operations and maintenance expenditures in the year t
F_t	:	fuel expenditures in the year t
E_t	:	electrical energy generated in the year t
r	:	discount rate
n	:	expected lifetime of system or power station

As already discussed, there are several constraints/weaknesses as to the implications of comparing LCOEs between technologies or individual projects. Specifically, various experts point to the limitations to the "levelized cost of electricity" metric for comparing new generating sources. In particular, LCOE ignores time effects associated with matching production to demand. This happens at (at least) two levels:

- Dispatchability, the ability of a generating system to come online, go offline, or ramp up or down, quickly as demand swings.
- The extent to which the availability profile matches or conflicts with the market demand profile.

More generally, the LCOE approach ignores how the various sources of generation can and will interact to meet the daily demand profile in a system. Further to this point, the metric does not either properly reflect the timing and general availability of resources during the day or various seasons, including the sun, water and/or wind. Thus, while one can introduce assumptions to partly account for these factors, a simple LCOE comparison will not allow one to identify the truly optimal least cost expansion plan.

Having said the above, it is generally a good idea to consider the LCOE ranking of the generation options available in order to get a clear and simple perspective of the competitiveness of the options available to Liberia.

8.2.1 Input and assumptions

Table 8-6 below summarizes the categories of assumptions applied to all technologies and specific projects. Further, Section 4.2 above summarizes the key assumptions for the most attractive hydropower sites as determined by the technical team. The full list of assumptions in are presented in Appendix I.

Table 8-8 List of assumptions applied to the various technologies in the LCOE assessment

Assumption	Unit
Capacity	MW
Plant factor	%
Annual production	MWh
Capex	MUSD/MW
Fixed O&M costs	% of capex
Variable O&M costs	USD/MWh
Fuel price	USD/MWh
Fuel efficiency	%
WACC	%
Lifetime	Years
Construction period	Years
Capex share in C1	%
Capex share in C2	%
Capex share in C3	%
Rehabilitation interval	Year
Rehabilitation costs	MUSD/MW

8.2.2 *Overall ranking and assessment*

Based on the above assumptions and inputs, the team has estimated the LCOEs for the specific hydropower projects as well as several other technologies. The results are presented in the figure below. A few key observations include:

- The **low LCOE for solar** in 2026 and beyond is striking, especially as solar potential is almost limitless. However, it is important recognize that the LCOE only accounts for the cost of solar and not the fact that solar investments will require complimentary sources of power. Despite this fact, the low LCOE and complimentary hydropower motivates rapid investments at the maximum allowable in Liberia.
- **Among hydropower projects**, the low LCOEs for the Mt. Coffee extension and SP2 options also stand in contrast with the relatively high cost options of SP3, SP4 and Via. This observation is consistent with the Balmorel results.
- **Further to Via**, the LCOE of Via is higher than that of other hydropower but is nearly on par with the LCOE of HFO. Moreover, Via's competitiveness is dependent on other downstream sites. Thus, it is more attractive to develop the lower cost downstream sites first and consider Via (or another reservoir) later, once demand surpasses the capacity of these lower cost options. Notably, the LCOE assessment does not take into account the fact that both Via and HFO have the ability to deliver energy during the dry season. Again, this confirms the simplistic nature of LCOE comparisons.
- Overall, the LCOE assessment, as summarized in the figure, largely confirms and provides further credibility to the Balmorel results and the recommended Long-Term Development Plan.

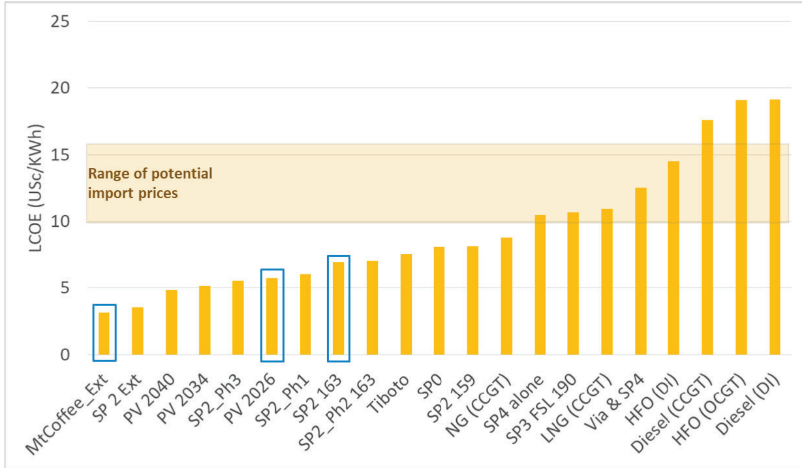

Figure 8-18 Ranking of LCOEs of individual candidate supply options considered in the study

8.2.3 *Via: cost-benefit analysis*

An eventual investment in the Via Reservoir would represent a major investment for Liberia and the region. It would require substantial capital, a massive construction effort, environmental impacts and a number of unknown/unforeseen risks. It would also represent one of the most valuable assets in all of the region and would provide benefits for generations. As such a project would have substantial implications for the country, it is important to consider closely the expected costs of the project against the expected benefits.

Accordingly, the team has carried out a cost-benefit analysis as to the investment in and construction of Via Reservoir as the PIP, utilizing the inputs and outputs of the modelling exercises carried out in this study. The results can already be partly foreseen from the LCOE assessment above, which indicates that Via is not one of the least cost options available to policy makers. In carrying out this cost-benefit analysis, the team has considered the full-scale Via Reservoir Scheme, as it was determined that this represents the most attractive/potentially viable option given conditions at the site and in the two rivers.

In terms of carrying out the cost-benefit analysis, it is important to isolate the incremental costs (capex and opex) with the incremental benefits (value of energy produced) from the Via Reservoir. In terms of the cost, the project would imply a total estimated investment of 1,150 MUSD, spread over 4 years of construction (spread as MUSD 390, 390, 270, 100). It is important to realize that this would be a major project and would be subject to considerable risks in terms of both actual capex and timeframes, particularly reflecting on capex levels of up to MUSD 390 per year. Otherwise, O&M costs of the Via scheme are assumed at 1% of the investment, i.e. 11.5 MUSD annually. It is important to recognize that the scheme is spread out over 3 locations and is likely to be a complex scheme to maintain, monitor inflows and operate optimally. Finally, a repair and partial replacement of all E&M equipment generating is assumed after 30 years with a cost of approximately 86.5 MUSD.

In terms of benefits, as noted in the Task B report, the economic analysis must capture the fact that Via Reservoir would provide not only additional energy production, but production during the dry season. More specifically, the estimated incremental increases in annual energy production is summarized as follows:

1) Energy generated at Via HPP. This has been modelled to be 493 GWh annual average production with 88 MW installed at Via. The assumption is that a transfer of St Paul flows of up to 450 m^3/s.
2) Additional energy at existing Mt Coffee. This is because dry season flows are supplemented by releases from Via and the incremental increase in annual production is estimated at 145 GWh annual average, mostly dry season energy. This figure is not altered if Mt Coffee extension is in place since it only utilizes flood waters in the wet season.
3) Additional energy due to dry season flow supplements in any future HPP on the St Paul River below the Via reservoir. This is assumed in the medium-long term (2034) to come from SP2 and is estimated at 64 GWh annual average.

Thus, in sum, the operations of Via reservoir would allow for an estimated total increase in production of some 702 GWh/year upon completion of SP2, also providing valuable dry-season energy. Placing a value on this increase in energy supply is potentially complex. In order to assign values to this, the team has considered the likely intervals for the cost of alternative power supplies for the Liberian system in the future, in both wet and dry seasons, respectively. Further, our team has utilized the LCOEs as estimated above for these likely alternative sources of power in the two seasons. ***That is, this avoided alternative cost for the power system represents the value of the energy provided at very low operational cost but a very significant investment for Via Reservoir.***

Specifically, based on the modelling results, it is reasonable to assume that the value of energy produced in the dry season is the avoided cost of HFO required to substitute the dry season energy that could otherwise be provided by Via. As indicated above, the LCOE of HFO is estimated at 14.5 USc/ kWh. For the period after 2029, it can be expected that Liberia is able to transition out of HFO and provide the energy by means of imports based on production from natural gas (NG) or LNG power plants and a transmission fee. The LCOE for NG and LNG (accounting for transmission losses) is estimated at 8.8 and 10.9 USc, respectively. With a medium-term alternative cost of 14.5 (HFO) and a longer-term cost of between 8.8-10.9, an average alternative cost of 12.5 is assumed for the dry season during the planning period. The investment in Via allows for an additional 493 GWh from new installed capacity. Accordingly, for newly installed capacity associated with Via, we assume the long-run marginal cost of alternative energy sources on the CLSG system. A reasonable proxy for this is the cost of LNG in Cote d'Ivoire of 10.9 USc / kWh. ***In summary, the value of energy provided by Via is valued at 12.5 USc / kWh during the dry season and 10.9 USc / kWh on average over the course of the year.***

Finally, it is likely that Via will provide some degree of flood control benefits. There is, however, little infrastructure or communities at risk at present along the Via River and any attempt at valuing the reduced risk due to Via reservoir would require data we do not have. The same communities will experience disadvantages with releases from the Via reservoir (possibly reduced fish catches or water quality deterioration in certain periods). It is therefore a safe assumption to say that flood control benefits and environmental losses cannot be quantified, and are assumed to cancel each other out. The net flood control benefit is assumed to be zero.

The Table below summarizes the value assigned to the energy made available by the Via Reservoir.

Table 8-9. HPP benefits summarized

Part	Component	GWh from Via	Value (USD/kWh)	Annual Benefits (MUSD)	Comment
1	Via HPP	493	10.9	53.7	All year production
2	Mt Coffee (after ext)	145	12.5	18.1	No increase due to MC Ext.
3	SP2	64	12.5	8.0	Omitted if SP2 never built
4	Flood control	N/A	0	0	
Total		702		79.9 annually (nominal)	

The figure below demonstrates the flow of costs and benefits from Via over its economic life-span. As illustrated here, the major costs are incurred up-front whereas the benefits accumulate over the fifty-year life-span. Importantly, the team has applied a 6% discount rate as stipulated by the client in terms of the rate required by the World Bank. Given the profile of the costs and benefits, the discount rate has a significant impact on the cost benefit results. Specifically, a higher discount rate (or required rate of return or cost of capital) would reduce the value of the investments and thus the overall economic viability.

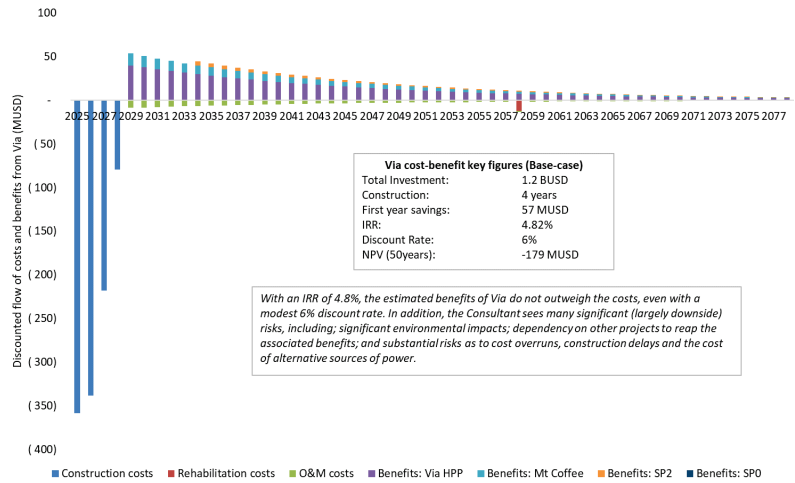

Figure 8-19 Discounted flow of costs and benefits from Via

8.2.4 Conclusions of cost-benefit

As summarized in the table below, the estimated EIRR of the flow of costs and benefits is estimated at 4.82%, resulting in a negative NPV at 6% discount rate. Thus the Via reservoir as the PIP is marginally non-viable from economic perspective. The table also demonstrates some of the sensitivities performed. These results offer a confirmation of the Balmorel simulations whereby the total system cost (LCOE) is increased in a scenario when the Via project is "forced" to be built early in the planning period.

Table 8-10. Summary of economic analysis of Via with sensitivity tests

Case	Assumption	Via EIRR	Comments
Base case	Base case (above)	4.82%	Most probable assumptions
20% Lower cost	Via 896 MUSD	6.15%	Highly optimistic cost savings leads to a marginally viable investment.
Higher value dry season	0.15 USD/ kWh	5.23%	If Via not built and poor planning could result in high sector costs – in which case Via would have been higher value opportunity.
High unit outages	Reduce production by 10% (Via 444)	4.35%	Pessimistic assumption with low availability or dry year.

The consultant views it as relevant to once again address the highly relevant issue of risk management in an uncertain environment. No doubt, there are many unknowns and risks when it comes to both what the actual cost of the Via Reservoir will be and what the value of the energy provided will be 40-50 years in the future. In addition, if one assigned a value to emission avoidance (a carbon price), the value of the energy could increase to 0.15 USD/kWh and beyond. On the other hand, it is highly likely that the project will prove exceptionally complex in the Liberian environment and it will both cost more and take more time. Further, even the 50-year life-span may be at risk in the Liberian context, if the asset is not properly maintained. In terms of developments/scenarios, the following future developments could underpin a viable project:

- **Avoidance of power shortage.** To the degree the installation of Via prevents/lessens future load shedding or constrained demand due to shortage of installed power production capacity, the value of the additional power provided by Via will be considerably higher.
- **High global carbon price.** To the degree the value/cost of emissions in Liberia are at a high level, the value of the additional production will also go up. It is noted that this value could potentially stem from either "real" market prices/values or value placed on the emissions by donors/multilaterals as a matter of policy.
- **Fast-tracked hydropower plants.** An earlier operation date for the hydropower plants would both increase the total absolute value (increased number of years with full production increase) and improve the time-value of the production, as the benefits are brought forward in time. However, according to our analysis, even if it is assumed that all the plants are operational in the same year as Via, the investment is not viable without increases to the value of the energy.

- **Multi-purpose benefits.** While the team has assumed no value from flood control, if other (real/meaningful) multi-purpose benefits from the reservoir could be identified and valued, this could increase the value of the reservoir.

As a final note, it is clear that Via is only potentially viable once SP2 and the Mt. Coffee extension are operational, as in combination the two sets of projects are mutually beneficial for one another. Further, it will probably only make economic sense with an investment in Via once additional downstream benefits are identified, including further downstream generation capacity.

In conclusion, given that the project is very much at the margins in the base case, the final decision to invest or not must reflect some "consensus" view on these future values. It is the consultant's view that given the high complexity and level of risk surrounding the project, Via as the PIP cannot be recommended at this stage. Further, it is the team's view that the scenarios that could justify the Via as PIP are too far-fetched to recommend the construction from a least-cost development plan perspective.

As to the long-term planning, however, the analysis in this report demonstrates that there is likely a case for constructing Via late in the planning period instead. Nonetheless, both the Balmorel modelling results and the above cost-benefit analysis provide a robust basis for excluding Via as the PIP.

Conclusion: After the commissioning of the CLSG line, the SP2 project is a more economic and less risky alternative to Via. Thus, it is more attractive to develop the lower cost downstream sites first and consider Via (or another reservoir) later, once demand surpasses the capacity of these lower cost options.

8.3 Consolidated key conclusions

In this chapter, the consultant has utilized the considered input from the technical team, including project specific optimizations as to a range of sizes, capacities and annual production. Utilizing the "optimal" designs of individual projects within a comprehensive market model for Liberia and the region, the team has arrived at what it views as the least cost development path for the sector. These findings from the Balmorel model have been further confirmed/supported by means of the LCOE assessment and cost-benefit analysis for Via.

The key take-aways are:

1. In terms of PIPs, there is a rather clear-cut and highly robust case for pushing forward with utility-scale solar PV, Mt. Coffee Extension and SP2. The costs of subsequent projects rise rather quickly, and these three projects appear to be "no-regret" options for Liberia and the region.
2. Preparing and implementing these PIPs will (and should) take time. It is of utmost importance to start planning for these investments to avoid high future economic costs for the sector and Liberia. The total required investments are substantial.
3. The degree to which Liberian policy makers and its partners are prepared to plan around the availability of power trade is an important framework condition for Liberia's sector development plan. Specifically, the least cost plan has a clear role for trade, particularly for imports during peak and dry periods. A strategy of energy independence, on the other hand, will have important implications for generation planning going forward and would ultimately come at a considerable cost to the sector.
4. Beyond consideration of potential E&S impacts, the viability of Via Reservoir has been tested by utilizing three separate, yet highly related approaches: i) comparing the total system

costs that result from Balmorel simulations with and without Via, ii) simple LCOE assessment, including Via and several other supply options, and iii) a cost-benefit analysis. The conclusions all point to not including Via as the PIP but a potential cost-effective role for the reservoir late in the planning period.

5. In terms of the long-term least cost development plan, the Consultant has combined the results of project specific optimizations with simulations in the Balmorel power model. By comparing with demand growth projections, this has provided a firm basis for a highly specific long-term development plan for the sector until 2040. This should provide a tool for policy makers in terms of both prioritizing efforts and funds, as well as tracking future progress.

9 Next Steps and preliminary schedule

9.1 Field investigations

9.1.1 Topographic survey

The available LIDAR topographic survey along the StPaul River was priceless for this study, identifying the HPP candidates, available head, optimisation, etc. has lifted the quality of the study to a much higher and necessary level for this study.

However, as the SP2 Wala Creek dam alternative was identified and discussed, see chapter 7.2.1 for further details, with approximately half of the Wala Creek FSL 159 reservoir area outside the LIDAR scanned area. To extrapolate the surveyed area with available satellite images has proven not to be feasible, with the terrain undulating in very different patterns between the LIDAR survey and available satellite data.

The conclusion of prioritising the SP2 with a StPaul River reservoir only as the main alternative is based on cost (CAPEX +2% for the Wala Creek option – only a marginal difference to the main alternative), energy storage potential (reservoir storage), and that the fact that the topography and hence the costing is more uncertain (unidentified saddle dams, etc.) for the Wala Creek option that it cannot be a PIP.

However, if the topography is favourable, both arguments on costs and uncertainties can be reduced and make the Wala Creek to the most feasible option.

It is therefore strongly advised to add LIDAR survey to include the Wala Creek reservoir for the optimisation in the feasibility study.

9.1.2 Ground Investigations

The study made by Chat T Main in 1982 included ground investigations for several sites (Via dam, SP4 dam, SP2 dam (previous lout), and SP1B dam.

During the optimisation of the PIP (SP2) and its many alternative layouts, it has become apparent that the geologic information is vital for choosing the layout. An example is alternative powerhouse layouts, which with favourable rock conditions potentially can reduce CAPEX in the range of 5-10%.

There will be a balance to decide on how much of the ground investigations to be taken under the feasibility stage and what remains for the detail design stage. Generally better information available for the feasibility and tendering stage, the less uncertainty and hence risk is costed and included in the construction bids for the construction phase. The total development cost reduce if there is done appropriate ground investigations in an early stage.

A proposed ground investigation program is further elaborated in Appendix K.

9.1.3 Sediment sampling and sediment transport analysis

There are practically no data available on types and quantities of sediment transported by the St Paul River. This is an important subject for the sustainability of the Mount Coffee and future reservoirs on the St Paul. We recommend an immediate start to systematic sediment sampling and analysis at the newly established LHS gauging stations, with particular emphasis on enabling sampling during high flows at each station, when most sediment transport takes place. The minerology of fine sediments should also be analysed to determine if there will be any future problems of turbine part erosion due to sediment particle impact on turbine blades, wicket gates etc.

9.2 Consultations for Project Affected people (PAP)

The increase in reservoir inundation at SP2 affects many villages, and a PAP consultation process is also a critical activity in the next 12 months. Although the access is easier to these villages than to Via reservoir area, the numbers of villages affected is greater and the consultation process will take time to complete.-It is recommended that the first step is to prepare an information document on the latest plans for SP2 with good clear maps and diagrams, and translated it into local languages.

The consultation process must take the time needed to include the PAPs in the planning process, and to enable their wishes and feedback to be taken account of in the final project designs and plans.

The new reservoir will undoubtedly have some negative impacts on their livelihoods, but this can be mitigated by making use of the positive opportunities such a reservoir may create for people living around it. There is a possibility for utilizing the drawdown zone for recession agriculture in the dry season. The timing of reservoir drawdown and refilling is predictable even though the depth of drawdown is unpredictable. There may be an opportunity to harvest one crop in the drawdown zone provided training is given on what type of crops are suited and when to plant. The drawdown zone will have its nutrients naturally replenished by fine sediment settling during the wet months of the year, and the shallow areas near the reservoir rim might become a basis for sustainable agricultural practice. The new access road provides an opportunity to transport cash crops to market, where it was not possible before.

There is a need for a baseline survey of current agricultural practice, health and livelihood, designed to be able to document if and by how much the livelihood of the PAP is improved after the project.

9.3 Fish passages, environmental flows and fisheries management

The creation of a new reservoir with an inundated area of 50 km^2 will have a major impact on the aquatic environment. About 30 km of riverine reaches will be inundated by a reservoir with considerable level variation over its annual cycle of drawdown and refilling. Coarse sediments such as sand and gravel will be inevitable trapped in the reservoir. Irrespective of whether fish passages can be made to function for several migrating species, the change in habitat which the reservoir causes will change the species distribution and dominance, and a management plan should be developed for the species likely to thrive in the pelagic zones of the new reservoir. There is likely to be a harvestable surplus for these species and this can become a valuable source of food and income for the people living around the reservoir, if there is a fisheries management program in place when the inundation actually happens in 2025.

There is a need for more baseline data collected on the aquatic ecology of the St Paul River both below and above the SP2 dam site. During the design process, attention should be paid to how the existing river can function as a wet season migration route for long distance migrating fish. There is excess water passing over the spillways and down the main river channel for several months of the year. The most difficult mitigation will be if there is a need for fish migration to continue during the dry season when all water provides valuable energy to the power system.

9.4 Access road and bridge improvements

The extension of today's access roads and an upgrade of the existing ferries or a new bridge will help to speed up the field investigations and the ensuing construction work. If this can be carried out with public funds, the process up to contractor mobilization may be shorten by around 6-12 months.

9.5 Program of activities

Taking into account the above activities, all of which will be critical for timely delivery of a bankable feasibility study with ESIA report and resettlement action plan, it is considered that the feasibility report and associated documents can be completed in no less than 20-24 months from the approval of this final report This means that the feasibility documentation, ESIA etc. will only be available for scrutiny and starting discussion on project financing around mid-2021.