GUYANA POWER & LIGHT INC.

DEVELOPMENT AND EXPANSION PROGRAMME

2022 – 2026

November 1, 2021

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1.2 Introduction

The Guyana Power and Light (GPL) has a critical role to play in the development of the country's economy and by extension, the livelihood of the nation. International recognition of Guyana as an emerging oil-producer has placed the country on the radar of the international community (countries and companies) desirous of seeking related commercial opportunities.

The Development and Expansion Programme is a 5-year expansion plan to satisfy the anticipated growth in the demand for electric services and also to support the demand from increased economic activities and opportunities stemming from the emerging Oil and Gas Industry. It supports Government short to long-term vision, which is guided by the Low Carbon Development Strategy (LCDS), National Energy Priorities and other Government initiatives, which informs the detailed plans to ensure adequate generation, transmission, and distribution of electricity consistent with the demand forecasts. The Programme includes targets such as reducing tariff, supporting global climate change commitment, implementing demand side management and operational efficiency strategies.

The present customer-centric programme is intended to guide the Company's efforts to deliver reliable and affordable electric services, inclusive of the development of a Smart Grid and further sustained reductions in system losses.

In view of the above, GPL has defined the following critical planning targets, which guided the development of this expansion programme:

- Generation: Loss of Load Probability (LOLP) less than 0.27% per annum, or Loss of Load Expectation (LOLE) less than 1 day per year;
- Transmission: N-1 compliant on transmission circuits and substation equipment; and
- Distribution: reduce length of circuits and thermal loading by 50%.

The programme considers all areas of the Company's operations and is intended to present the strategies and projected capital investments required to successfully position the Company to support the projected rate of economic and other forms of national developments.

1.3 Current Status of GPL's Electric Power Systems

1.3.1 Demerara Berbice Interconnected System's Generation

The GOE II 46.5 MW power plant – DP5, is currently dispatching at full capacity to the DBIS and would be commissioned within Q4 of 2021. As a result, GPL's aggregated electric power system would have 15 power plants totalling 227.5 MW of available capacity. The aggregated available capacity includes the 11 power plants or generating sites in the DBIS and 4 in the Essequibo Islands and Bartica.

A breakdown by fuel type indicates that HFO generator units account for 83.8% and LFO 16.2% of the total available capacity in the DBIS. For the Isolated Systems, 29.4% capacity is HFO and 70.6% is LFO. See Table 11 for further details.

Table 1: Breakdown of available generation capacity by fuel type

Fuel Type	Demerara	Berbice	Total DBIS	Anna Regina	Wakenaam	Leguan	Bartica	Total Isolated	Total GPL
MWs of HFO	155.9	19.0	**174.9**	5.40	-	-	-	**5.4**	**180.3**
MWs of LFO	12.3	21.4	**33.7**	6.70	1.06	0.82	4.96	**13.5**	**47.2**
MWs of Biomass	-	-	**-**	-	-	-	-	**-**	**-**
Total Available Capacity (MW)	**168.2**	**40.4**	**208.6**	**12.10**	**1.06**	**0.82**	**4.96**	**18.9**	**227.5**
Fuel Type	**Demerara**	**Berbice**	**Total DBIS**	**Anna Regina**	**Wakenaam**	**Leguan**	**Bartica**	**Total Isolated**	**Total GPL**
% of HFO	92.7%	47.0%	**83.8%**	44.6%				**28.5%**	**79.2%**
% of LFO	7.3%	53.0%	**16.2%**	55.4%	100.0%	100.0%	100.0%	**71.5%**	**20.8%**
% of Biomass			**0.0%**					**0.0%**	**0.0%**

With scheduled maintenance and efficient operation, generator units generally have a maximum operational life of 25 years, although, in most instances, their economic life is taken as 20 years, after which these units are classified as Cold Reserve Capacity. To date, a total of 57.6 MW of available capacity in the DBIS has surpassed the economic lifespan threshold of 20 years. The specifics of these generator units are shown in Table 2.

Table 2: Aged generator units in the DBIS

Generator Units	Commissioned Dates	Age of Unit (Yrs.)	Installed Capacity (MW)	Available Capacity (MW)
GOE - Niigata	**Subtotal**		**11.00**	**7.50**
# 5 Niigata	1991	30	5.50	3.50
# 6 Niigata	1996	25	5.50	4.00
GOE - DP1	**Subtotal**		**22.00**	**22.00**
# 1 Wärtsilä	1996	25	5.50	5.50
# 2 Wärtsilä	1996	25	5.50	5.50
# 3 Wärtsilä	1996	25	5.50	5.50
# 4 Wärtsilä	1996	25	5.50	5.50
Kingston I - DP2	**Subtotal**		**22.00**	**22.00**
# 1 Wärtsilä	1997	24	5.50	5.50
#2 Wärtsilä	1997	24	5.50	5.50
# 3 Wärtsilä	1997	24	5.50	5.50
# 4 Wärtsilä	1997	24	5.50	5.50
Canefield	**Subtotal**		**5.50**	**3.80**
#3DA - Mirrlees	1996	25	5.50	3.80
Onverwagt	**Subtotal**		**5.00**	**4.60**
#5 GM	1981	40	2.50	2.30

Generator Units	Commissioned Dates	Age of Unit (Yrs.)	Installed Capacity (MW)	Available Capacity (MW)
#7 GM	1981	40	2.50	2.30
Grand Total			**65.50**	**59.90**

Even though these older engines have been and continue to be well maintained and deliver availability above 95%, their continued use as baseload units is accompanied by an elevated risk of major mechanical failure resulting from the failure of components that are not renewed for the life of the engine, e.g., counterweight bolts. One engine was destroyed, suspected to result from of failed counterweight bolts, precipitating a series of other mechanical failures.

In addition to the aged engines, 46.8 MW of relatively new HFO fired generator units at Kingston and Vreed En Hoop is considered suspect capacities. This is due to technical issues encountered by the alternators at the 26.1 MW power plant at Vreed en Hoop and three units at Kingston II power plant totalling 20.7 MW. As a priority, GPL is currently working ardently to address these matters incrementally.

Combining the age of generator units and engine and/or alternator issues, Table 3 shows the annual Total Available Capacity, Reliable Capacity, Unreliable / Suspect Capacity, and Cold Reserve Capacity in MWs.

Table 3: Summary of power generation profile: 2022-2026 (DBIS Only)

DBIS Power Systems	Year	2021	2022	2023	2024	2025
Demerara	**Total Available Capacity (MW)**	**168.2**	**163.4**	**163.4**	**163.4**	**163.4**
	Reliable Capacity (MW)	**63.6**	**63.6**	**63.6**	**63.6**	**63.6**
	Unreliable Capacity (MW)	**104.6**	**99.8**	**99.8**	**99.8**	**99.8**
	Cold Reserve Capacity (MW)	-	-	-	-	-
	Accumulated Cold Reserve (MW)	-	-	-	-	-
Berbice	**Total Available Capacity (MW)**	**40.4**	**42.0**	**42.0**	**40.7**	**28.4**
	Reliable Capacity (MW)	**9.7**	**9.7**	**9.7**	**9.7**	**9.7**
	Unreliable Capacity (MW)	**30.7**	**32.3**	**32.3**	**31.0**	**18.7**
	Cold Reserve Capacity (MW)	-	-	-	**1.3**	**10.7**
	Accumulated Cold Reserve (MW)	-	-	-	**1.3**	**12.0**
DBIS Total	**Total Available Capacity (MW)**	**208.6**	**205.4**	**205.4**	**204.1**	**191.8**
	Reliable Capacity (MW)	**73.3**	**73.3**	**73.3**	**73.3**	**73.3**
	Unreliable Capacity (MW)	**135.3**	**132.1**	**132.1**	**130.8**	**118.5**
	Cold Reserve Capacity (MW)	-	-	-	**1.3**	**10.7**
	Accumulated Cold Reserve (MW)	-	-	-	**1.3**	**12.0**

Considering the demand forecast (see section 2 on page 17 for further details) and the current fleet of generator units in the DBIS, capacity reserve margin, which includes cold reserve capacity, will become negative and significant LOLP violation by 2023 (Table 4).

Table 4: Capacity reserve margin and LOLP profile for No Additional Firm Capacity

Year	Unit	2021	2022	2023	2024	2025	2026
Peak Demand (MW)	MW	138.82	185.8	236.4	288.8	407.4	478.0
Annual Peak Demand Growth Rate	%	9.9%	34%	27%	22%	41%	17%
Required Reserve Capacity Margin	MW	25.0	19.6	89.4	45.9	65.0	156.4
Stochastic Capacity Reserve Margin (%) for LOLP Target	**%**	18.0%	10.5%	37.8%	15.9%	16.0%	32.7%
No Additional Capacity							
Available Generation Capacity	MW	208.6	205.4	205.4	204.1	191.8	188.8
Capacity Reserve	MW	69.78	19.6	- 31.0	- 84.7	- 215.6	- 289.2
Capacity Reserve Margin	%	50.26	10.54	- 13.11	- 29.32	- 52.92	- 60.50
LOLP	**%**	0.18	0.66	36.60	94.11	99.71	99.76
LOLE	day	0.65	2.40	133.57	343.51	363.95	364.12

1.3.2 Isolated Systems' Generation

For the mobile LFO units in the Isolated Power Systems, GPL has realised over the years that it is considered cost-effective to replace highspeed generator units with newer units than to perform a major overhaul.

Major overhaul of a highspeed generator unit is usually conducted each 24,000 hours, which approximates to 3 calendar years. The total cost of a major overhaul is approximately 80% of the price of a factor refurbished generator unit.

After a major overhaul, returning a highspeed generator unit's performance to its original state has been a challenge. The balance 20% cost in lieu can compensate for the loss in performance and reliably justify the need to support improved efficiencies with a new generator unit.

The above concept does not apply to the fixed LFO fired generator units at Bartica because the cost of a major overhaul is approximately 50% of the price of a brand-new generator unit of the same type.

Combining the age of generator units and engine and/or alternator issues, Table 5 shows the annual Total Available Capacity, Reliable Capacity, Unreliable / Suspect Capacity, and Cold Reserve Capacity in MWs.

Table 5: Summary of power generation profile: 2021-2025 (Isolated Systems Only)

Isolated Power Systems	Year	2021	2022	2023	2024	2025	2026
Anna Regina	**Total Available Capacity (MW)**	12.1	14.6	14.6	14.6	14.6	14.6
	Reliable Capacity (MW)	5.4	5.4	5.4	5.4	5.4	5.4

	Unreliable Capacity (MW)	6.7	4.4	4.4	4.4	4.4	4.4
	Cold Reserve Capacity (MW)	-	-	-	-	-	-
	Accumulated Cold Reserve (MW)	-	-	-	-	-	-
Wakenaam	Total Available Capacity (MW)	1.06	1.06	1.06	1.06	1.06	1.06
	Reliable Capacity (MW)	0.41	0.41	0.41	0.41	0.41	0.41
	Unreliable Capacity (MW)	0.65	0.65	0.65	0.65	0.65	0.65
	Cold Reserve Capacity (MW)	-	-	-	-	-	-
	Accumulated Cold Reserve (MW)	-	-	-	-	-	-
Leguan	Total Available Capacity (MW)	0.82	0.82	0.82	0.82	0.82	0.8
	Reliable Capacity (MW)	-	-	-	-	-	-
	Unreliable Capacity (MW)	0.82	0.82	0.82	0.82	0.82	0.8
	Cold Reserve Capacity (MW)	-	-	-	-	-	-
	Accumulated Cold Reserve (MW)	-	-	-	-	-	-
Bartica	Total Available Capacity (MW)	5.0	4.96	4.96	4.96	4.96	4.96
	Reliable Capacity (MW)	3.4	3.36	3.36	3.36	3.36	3.36
	Unreliable Capacity (MW)	1.6	1.60	1.60	1.60	1.60	1.60
	Cold Reserve Capacity (MW)	-	-	-	-	-	-
	Accumulated Cold Reserve (MW)	-	-	-	-	-	-
Isolated System	Total Available Capacity (MW)	18.9	21.4	21.4	21.4	21.4	21.4
	Reliable Capacity (MW)	9.2	9.2	9.2	9.2	9.2	9.2
	Unreliable Capacity (MW)	9.8	7.5	7.5	7.5	7.5	7.5
	Cold Reserve Capacity (MW)	-	-	-	-	-	-
	Accumulated Cold Reserve (MW)						

1.3.3 Transmission and Distribution

The Transmission and Distribution section of GPL's electric power system comprises three main volage levels; 69 kV for bulk power transfer, 13.8 kV for primary power distribution and lower utilisation voltage for customer-specific applications.

GPL's present transmission and distribution network provides electricity supply coverage of approximately 96.7% on the Coastland and comprises the following:

1. The transmission voltage level of 69 kV is only present in the DBIS and has a total length of 276 km;

2. The total estimated length of primary distribution circuits in the DBIS is 809 km; and
3. The total estimated length of primary distribution circuits in the Isolated Systems is 143.56 km. A breakdown of the Isolated Systems is as follow:
    a. Anna Regina – 75.97 km;
    b. Wakenaam – 21.19 km;
    c. Leguan – 28.8 km; and
    d. Bartica – 17.6 km.

Within the total GPL power system, the majority of network-related challenges are currently experienced in the DBIS. A summary of the critical issues presently experienced are:

1. Reduced life span of pole structures due to poor poles and cross-arms material quality;
2. Impassable accesses to pole structures located in remote terrains; largely for the transmission lines and to some extent, section of primary distribution lines;
3. Frequent line trips due to vegetation encroachments on open conductors;
4. High voltage drops due to a combination of long feeder lengths, high electricity demands, and low power factor presented by maximum demand customers;
5. Widespread outages due to fault clearing by protection relay scheme at substation level for feeders without Auto reclosers;
6. Large number of and duration of outages to facilitate line maintenance and emergency switching;
7. Poor operation visibility and absence of remote control and supervision for section of primary distribution feeders result in a high dependency on customer fault reports;
8. Poor supervision of line maintenance works.
9. Lack of adequate and timely availability of T&D resources;
10. Absence of standards and specifications that are directly related to T&D line hardware materials and workmanship;
11. Lack of proper monitoring of condition and performance of T&D networks; and
12. Delayed implementation of upgrades and other corrective actions.

1.4 Demand Forecasts and Customer Growth Projection

The Company has forecasted energy demand growth of 2,310 GWh for all GPL Systems that represents a significant increase of 233.7%. The DBIS which accounts for over 95% of GPL's system demand has forecasted energy demand growth by 2,226GWh or 237.4% in the same period, as presented in Table 6.

Table 6: Energy Demand and Peak Power Forecasts for all GPL systems

System	Description	Unit	2021	2022	2023	2024	2025	2026
All GPL	**Electricity Demand**	**GWh**	988.9	1,256.9	1,590.8	2,033.1	2,732.8	3,299.7
All GPL	**Peak Power**	**MW**	147.4	196.6	249.5	304.3	428.1	501.6
DBIS	**Electricity Demand**	**GWh**	937.9	1,195.5	1,516.7	1,942.8	2,617.6	3,164.8
DBIS	**Peak Power**	**MW**	138.8	185.8	236.4	288.8	407.4	478.0
Anna Regina	**Electricity Demand**	**GWh**	34.2	41.6	50.6	62.5	81.1	96.4
Anna Regina	**Peak Power**	**MW**	6.0	7.5	9.2	10.9	14.7	17.1
Bartica	**Electricity Demand**	**GWh**	13.1	15.5	18.3	21.6	26.2	29.4
Bartica	**Peak Power**	**MW**	2.1	2.5	3.0	3.4	4.2	4.7
Leguan	**Electricity Demand**	**GWh**	1.9	2.2	2.6	3.2	4.0	4.6
Leguan	**Peak Power**	**MW**	0.4	0.5	0.6	0.6	0.8	1.0
Wakenaam	**Electricity Demand**	**GWh**	1.8	2.2	2.6	3.1	3.9	4.5
Wakenaam	**Peak Power**	**MW**	0.3	0.4	0.5	0.6	0.7	0.8

This projection is based on the expected significant stimulation in the economy that the emerging Oil and Gas Industry will provide. The Company projects an increase in its customer base from 210,732 in 2021 to potentially 261,272 by the end of 2026 (Table 7). The projected increase in the customer base is primarily due to the increased economic activities, which are expected to result from 1) population growth, 2) increased business activities and 3) providing services to all existing un-served areas.

Table 7: Customer growth

Year	2021	2022	2023	2024	2025	2026
No. of Existing Customers	210,732					
Total New Services (CH&PA + Other Potential Customers)		5,368	7,052	8,736	10,420	12,103
No. of Unserved Beneficiaries		1,945	4,611	306	-	-
Total No. of Projected Customers	**210,732**	**218,045**	**229,708**	**238,749**	**249,169**	**261,272**

1.5 Meeting Energy Demand and Peak Power Forecasts

The availability of reliable generation capacity and T&D infrastructure to satisfy the growing electricity demand is pivotal to providing the required electric energy security to support economic activities and economic growth.

Guyana is rich in renewable and sustainable energy sources (hydro, wind and solar). These generation sources have gained international recognition and embraced for their contribution to the reduction of carbon emissions and green-house-gases.

The legal and regulatory framework to guide compensation to Grid-Tie customers is expected to be completed during 2022 and will support establishing an appropriate tariff for current and future grid-tie customers.

Whilst GPL embraces the benefits expected to be realized from distributed generation, the Company will aggressively monitor the electricity exported to the grid to ensure the stability of the DBIS.

Significant generation from renewable energy resources, therefore, whilst attractive, will not entirely displace the larger volumes of the firm and the dispatchable fossil-fired generation that is required to satisfy the current and projected baseload demand during the life of this programme. Additionally, the intermittent nature of these resources with significant penetration levels would present considerable challenges to the stability of the grid in its current state. The Company will incrementally introduce and integrate generation from these renewable resources into the GPL system to ensure that system stability and service reliability are not adversely affected.

Electricity generation from hydro and biomass are potential sources of generation for GPL. However, these require lengthy studies before progressing to Expressions of Interest and ultimately power facility construction and commissioning and would not be realized during this programme's life. It, however, remains GPL's intention to continue to work closely with the Government of Guyana and with private investors in this regard.

The midterm potential of a mid-sized Hydropower facility of approximately 165 megawatts remains the Government's focus, as reflected in the Draft National Energy Policy 2016[1]. It is consistent with the Inter-American Development Bank's (IDB's) sponsored Update of the Study on System Expansion of the Generation System 2018[2]. The Company will continue to monitor its available generation capacity prudently and continue its close collaboration with the Government of Guyana on developing the first mid-sized Hydropower facility during and beyond the life of this plan.

1.5.1 Generation (Firm and Non-Firm Capacities)

1.5.1.1 Demerara Berbice Interconnected System (DBIS)

GPL has been exploring electricity generation from solar and intends to integrate a total of 55 MW of Solar PV generation capacity into the generation portfolio by 2024, as presented in Table 8 for the DBIS.

In the case of Linden, the 15 MWp Solar PV project is expected to be in service by 2023. However, given that it is planned for Linden to be interconnected with the DBIS by 2024, the Solar PV capacity is represented in Table 8 accordingly. Only the Linden Solar PV system will include a total of 15 MWh of Battery Energy Storage System.

In view of the generation planning target and need to guarantee grid stability, GPL’s recommended generation expansion plan for the DBIS is presented in Table 8.

[1] Draft National Energy Policy 2016 https://doe.gov.gy/published/document/5af72892dc677720ccdc33b8
[2] Update of Study on System Expansion of the Generation System 2018, Brugman SAS 2018

Table 8: Proposed Generation Expansion Plan – DBIS

Name of Location	Type	Installed Capacity (MW)				
		2022	2023	2024	2025	2026
100 MW NG (Advanced Capacity - N/Sophia)	Firm Capacity	-	100.0	-	-	-
Hybrid Power Generation Facility - HFO	Firm Capacity	-	30.6	-	-	-
Hybrid Power Generation Facility - Solar PV	Non-Firm Capacity	-	30.0	-	-	-
Guysol	Non-Firm Capacity	-	10.0	-	-	-
Linden (Existing Capacity)	Firm Capacity	-	-	15.8	-	-
Linden Solar PV	Non-Firm Capacity	-	-	15.0	-	-
300 MW NG (Wales) - Balance 200 MW	Firm Capacity	-	-	-	200.0	-
AFHP	Firm Capacity	-	-	-	-	165.0
Total New Additions		**-**	**170.6**	**30.8**	**200.0**	**165.0**
Total Accumulated Additions		-	**170.6**	**201.4**	**401.4**	**566.4**
Annual Non-Firm Capacity		**-**	**40.0**	**15.0**	**-**	**-**
Annual Firm Capacity		**-**	**130.6**	**15.8**	**200.0**	**165.0**
Total Accumulated Firm Capacity		**-**	**130.6**	**146.4**	**346.4**	**511.4**
Existing Firm Capacity		**205.4**	**205.4**	**204.1**	**191.8**	**188.8**
Grand Total Firm Capacity		**205.4**	**336.0**	**350.5**	**538.2**	**700.2**

1.5.1.2 Natural Gas

The emerging Oil and Gas sector has presented an opportunity for the Company's transition to natural gas for power generation. Whilst natural gas is not a renewable energy source, it is a cleaner source of energy than GPL's current energy source and offers the potential of a lower cost of generation and reduced electricity tariffs. Natural gas exploitation for electricity generation forms part of a broader national initiative, further determining the Company's immediate to medium term generation strategies.

Given the confirmed availability of excess natural gas from Guyana's offshore oil production wells and the Government's intention to direct the excess gas to shore, GPL has commenced preparatory works in transition to using this cheaper and cleaner form of generation.

The GOE II 46.5 MW power plant – DP5, is currently dispatching at full capacity to the DBIS and would be commissioned within Q4 of 2021, thus positioning the Company to initially transition 23% of its generation capacity to natural gas-fired generation as of 2022. In light of finalising gas supply to shore, careful technical and economic considerations will be given to converting 106 MW of existing HFO fired baseload capacity to natural gas-fired generation.

The Government of Guyana has commenced a 'Gas to Power' initiative, which is expected to deliver natural gas to shore before 2024 in sufficient volumes for residential, commercial, and industrial use. This gas to shore initiative is expected to realize approximately 300MW of natural gas-fired generation for export to the national grid and further boosting the Company's generating capacity.

1.5.1.3 Potential of Converting Existing HFO Plants to Dual Fuel Plants

GPL can convert Garden of Eden Wärtsilä (DP1), Kingston I (DP2), Kingston II (DP3) and Vreed-en-Hoop (DP4) plants to consume natural gas as the primary fuel and HFO as the contingency fuel.

The conversion of these power plants will result in significant reduction of their present operating costs and extension of their economic operational life by 12 to 15 years for DP1 and DP2, and 20 years for DP3 and DP4, as show in Table 9.

Table 9: Summary of Variation of key operating paraments after conversion to natural gas

Key Parameters	DP2	DP3 - W16V	DP3 - W18V	DP4
Output (kW)	-0.02%	-3.74%	-4.55%	-8.56%
Heat rate (BTU/kWh) - 100% Loading	-8.63%	0.11%	0.24%	4.94%
FO&M[3] ($/kW/yr)	-33.50%	-66.29%	-66.29%	-42.93%
VO&M[4] ($/kWh)	-59.25%	-65.86%	-68.79%	-64.35%
Maintenance Rate	-13.04%	-13.04%	-13.04%	-13.04%
Mean Time to Repair – Top Overhaul	1.19%	1.19%	1.19%	1.19%
Mean Time to Repair – Major Overhaul	-45.44%	-45.44%	-45.44%	-45.44%
Mean Time to Repair - FOR	-71.43%	-71.43%	-71.43%	-71.43%
FOR	-49.15%	-3.23%	-3.23%	-18.92%

The duration to ultimately convert a single HFO engine to natural gas would be 52 business days (almost 2 months). Given the need to ensure generation reliability is maintained, plant conversion can be executed sequentially, commencing with the engines at DP1 – Garden of Eden. As such, at any given time, only a single engine will be out of service for 2 months, after which works would commence on another engine in sequential order, moving from one completely converted plant to another. Three years is the estimated duration to convert the four existing power plants.

[3] Fixed Operation and Maintenance Cost
[4] Variable Operation and Maintenance Cost

With recommended additional generation capacity, coupled with the total available and cold reserve capacity, the DBIS will have sufficient firm generation contingency capacity as shown in Table 10 for the present planning period.

Table 10: Generation Contingency Capacity Forecast with Recommended Additions – DBIS

Existing and New Power Generators	Type	2022	2023	2024	2025	2026
DEMERARA						
Garden of Eden Power Station	Firm Capacity	7.5	7.5	7.5	7.5	7.5
Garden of Eden 46.5 MW	Firm Capacity	46.5	46.5	46.5	46.5	46.5
Demerara Power (Kingston 1)	Firm Capacity	22.0	22.0	22.0	22.0	22.0
Demerara Power, (Kingston 11)	Firm Capacity	36.3	36.3	36.3	36.3	36.3
Demerara Power 1 (GoE)	Firm Capacity	22.0	22.0	22.0	22.0	22.0
Vreed En Hoop Power Station	Firm Capacity	26.1	26.1	26.1	26.1	26.1
Sophia	Firm Capacity	-	-	-	-	-
MCG - Giftland	Firm Capacity	3.0	3.0	3.0	3.0	-
100 MW NG (Advanced Capacity - N/Sophia)	Firm Capacity	-	100.0	100.0	100.0	100.0
300 MW NG (Wales) - Balance 200 MW	Firm Capacity	-	-	-	200.0	200.0
AFHP	Firm Capacity	-	-	-	-	165.0
Demerara Total Installation Generation Capacity (MW)		**163.40**	**263.40**	**263.40**	**463.40**	**625.40**
Demerara Total Firm Generation Capacity (MW)		**163.40**	**263.40**	**263.40**	**463.40**	**625.40**
Demerara Total Non-Firm Generation Capacity (MW)		**-**	**-**	**-**	**-**	**-**
BERBICE						
Canefield						
Hyundai	Firm Capacity	5.5	5.5	5.5	5.5	5.5
No. 4 Mirrlees Blackstone	Firm Capacity	3.8	3.8	3.8	3.8	3.8
Mobile Sets	Firm Capacity	8.3	8.3	7	3.2	3.2
Hybrid Power Generation Facility - HFO	Firm Capacity	0	10.2	10.2	10.2	10.2
Hybrid Power Generation Facility - Solar PV	Non-Firm Capacity	0	10	10	10	10
Guysol	Non-Firm Capacity	0	2	2	2	2
Onverwagt						
No. 5 General Motor	Firm Capacity	2.3	2.3	2.3	2.3	2.3

Existing and New Power Generators	Type	2022	2023	2024	2025	2026
No. 7 General Motor	Firm Capacity	2.3	2.3	2.3	2.3	2.3
Mobile Sets	Firm Capacity	10.1	10.1	10.1	1.6	1.6
Hybrid Power Generation Facility - HFO	Firm Capacity	0	10.2	10.2	10.2	10.2
Hybrid Power Generation Facility - Solar PV	Non-Firm Capacity	0	10	10	10	10
Guysol	Non-Firm Capacity	0	4	4	4	4
Williamsburg						
Hybrid Power Generation Facility - HFO	Firm Capacity	0	10.2	10.2	10.2	10.2
Hybrid Power Generation Facility - Solar PV	Non-Firm Capacity	0	10	10	10	10
Guysol	Non-Firm Capacity	0	4	4	4	4
Skeldon						
SEI	Firm Capacity	9.7	9.7	9.7	9.7	9.7
Berbice Total Installation Generation Capacity (MW)		**42**	**112.6**	**111.3**	**99**	**99**
Berbice Total Firm Generation Capacity (MW)		**42**	**72.6**	**71.3**	**59**	**59**
Berbice Total Non-Firm Generation Capacity (MW)		**0**	**40**	**40**	**40**	**40**
Linden						
Linden (Existing Capacity) - Interconnect with DBIS	Firm Capacity	0	0	15.8	15.8	15.8
Linden Solar PV - Interconnect with DBIS	Non-Firm Capacity	0	0	15	15	15
Linden Total Installation Generation Capacity (MW)		**0**	**0**	**30.8**	**30.8**	**30.8**
Linden Total Firm Generation Capacity (MW)		**0**	**0**	**15.8**	**15.8**	**15.8**
Linden Total Non-Firm Generation Capacity (MW)		**0**	**0**	**15**	**15**	**15**
DBIS Accumulated Firm Generation Capacity (MW)		**205.40**	**336.00**	**350.50**	**538.20**	**700.20**
DBIS Accumulated Non-Firm Generation Capacity (MW)		**-**	**40.00**	**55.00**	**55.00**	**55.00**
DBIS Min Required Spinning Reserve (MW)		**13.95**	**25.95**	**30.45**	**30.45**	**30.45**
DBIS Net Capacity (MW)		**191.45**	**310.05**	**320.05**	**507.75**	**669.75**
DBIS Forecast Peak Demand (MW)		**185.82**	**236.39**	**300.88**	**422.19**	**494.78**
Contingency Capacity (MW)		**5.63**	**73.66**	**19.17**	**85.56**	**174.97**

1.5.1.4 Isolated Systems (Anna Regina, Bartica, Leguan & Wakenaam)

For the Isolated systems, GPL plans to have a total of 8 MWp Solar PV capacity and 8 MWh Battery Energy Storage System for the Anna Regina Power System in commercial operation by 2023.

With debt funding from the IaDB and execution by the GEA, GPL plans to have a 1.5 MW Solar PV farm with BESS in commercial operation in Bartica by 2022.

Regarding the other isolated systems, through grant funding from the United Arab Emirates, 750 kW Solar PV farm with BESS will be in commercial operation before the end of 2022 in Wakenaam. For Leguan, a 600 kW Solar PV farm is planned to be in commercial operation in Leguan by 2023.

With the need to ensure grid stability and electricity supply security, GPL also plans to install firm power generation capacities in each Isolated Systems. See Table 11 for further details.

Table 11: Proposed Expansion Plan – Essequibo Isolated Systems

Isolated System Locations	**Planned Addition Capacity (MW)**				
Anna Regina	**2022**	**2023**	**2024**	**2025**	**2026**
Total Non-Firm Capacity	-	8.0	-	-	-
Total Firm Capacity	-	8.0	-	-	-
Total Accumulated Firm Capacity	-	8.0	19.0	19.0	19.0
Existing Firm Capacity	14.6	14.6	14.6	14.6	14.6
Grand Total Firm Capacity	14.6	22.6	33.6	33.6	33.6
Bartica	**2022**	**2023**	**2024**	**2025**	**2026**
Total Non-Firm Capacity	1.50	-	-	-	-
Total Firm Capacity	0.75	1.12	-	2.00	-
Total Accumulated Firm Capacity	0.75	1.87	1.87	3.87	3.87
Existing Firm Capacity	4.96	4.96	4.96	4.96	4.96
Grand Total Firm Capacity	**5.71**	**6.83**	**6.83**	**8.83**	**8.83**
Leguan	**2022**	**2023**	**2024**	**2025**	**2026**
Total Non-Firm Capacity	-	0.60	-	-	-
Total Firm Capacity	0.41	1.21	-	0.41	-
Total Accumulated Firm Capacity	0.41	1.62	1.62	2.03	2.03
Existing Firm Capacity	0.82	0.82	0.82	0.82	0.82
Grand Total Firm Capacity	**1.23**	**2.44**	**2.44**	**2.85**	**2.85**
Wakenaam	**2022**	**2022**	**2023**	**2024**	**2025**
Total Non-Firm Capacity	0.75	-	-	-	-
Total Firm Capacity	1.15	0.41	-	0.41	-
Total Accumulated Firm Capacity	1.15	1.56	1.56	1.97	1.97
Existing Firm Capacity	1.06	1.06	1.06	1.06	1.06
Grand Total Firm Capacity	**2.21**	**2.62**	**2.62**	**3.03**	**3.03**

1.5.1.5 Summary of Power Generation Expansion – DBIS and Isolated Systems

Given that power plants have an economic operation lifespan of 20 years, GPL has ensured that the currently planned capital investment in generation expansion is well aligned with the 20 years demand forecast. The recommended generation expansion plans for the 2022-2026 planning period are summarised in Table 10 for the DBIS and Table 11 for the Isolated Systems. Each table also shows the projected energy mix of the power systems by 2026, respectively.

Table 12: GPL 5 Year Generation Expansion Plan and Energy Mix- DBIS

Planned Commissioning Year	Generation Source	Installed Capacity (Megawatts)	Location	Ownership
2023	NG	100	300 MW NG Plant - Phase 1	GOG
	Solar PV	10	Guysol	GPL
	HFO	30.6	Hybrid System	IPP
	Solar PV	30	Hybrid System	IPP
2024	HFO	13.2	Linden	GOG
	LFO	2.6		
	Solar PV	15		
2025	NG	200	300 MW NG Plant - Phase 3	GOG
2026	Hydro	165	Crab Island	GPL
Existing Capacity (MW)	HFO	171.9	DBIS	GPL
Existing Capacity (MW)	LFO	16.9	DBIS	GPL
Total Existing Firm Capacity (MW)		188.8	157.6	GPL
Total Additional Firm Capacity by 2026 (MW)		511.4		
Total Additional Non-Firm Capacity by 2026 (MW)		55		
Total Additional Capacity by 2026 (MW)		566.4		
Total Firm Capacity by 2026 (MW)		700.2		
Total Non-Firm Capacity by 2026 (MW)		55		
Total Capacity by 2026 (MW)		755.2		
Total HFO Capacity by 2026 (MW)		215.7		
Total LFO Capacity by 2026 (MW)		19.5		
Total Solar PV Capacity by 2026 (MW)		55		
Total NG Capacity by 2026 (MW)		300		
Total Hydro Capacity by 2026 (MW)		165		
DBIS HFO % Share		29%	DBIS	
DBIS LFO % Share		3%	DBIS	
DBIS NG % Share		40%	DBIS	
DBIS Solar PV % Share		7%	DBIS	
DBIS Hydro % Share		22%	DBIS	

Table 13: GPL 5 Year Generation Expansion Plan and Energy Mix- Isolated Systems

Planned Commissioning Year	Generation Source	Installed Capacity (Megawatts)	Location	Ownership
2022	Solar PV	0.75	Wakenaam	GPL
	Solar PV	1.5	Bartica	GPL
	LFO	0.41	Leguan	GPL
2023	Solar PV	8	Anna Regina	GPL
	LFO	1.12	Bartica	GPL
	LFO	0.41	Leguan	GPL
	LFO	0.41	Wakenaam	GPL
2024	HFO	11	Anna Regina	GPL
2025	LFO	2	Bartica	GPL
	LFO	0.41	Leguan	GPL
	LFO	0.41	Wakenaam	GPL
2026	LFO	0.82	Leguan	GPL
Existing Capacity	HFO	5.4	Isolated Systems	GPL
	LFO	16.04	Isolated Systems	GPL
Total Existing Capacity		21.44	Isolated Systems	GPL
Total Additional Firm Capacity by 2026 (MW)		16.99	Isolated Systems	GPL
Total Additional Non-Firm Capacity by 2026 (MW)		10.25	Isolated Systems	GPL
Total Additional Capacity by 2026 (MW)		27.24	Isolated Systems	GPL
Total Firm Capacity by 2026 (MW)		38.43	Isolated Systems	GPL
Total Non-Firm Capacity by 2026 (MW)		10.25	Isolated Systems	GPL
Total Capacity by 2026 (MW)		48.68	Isolated Systems	GPL
Total HFO Capacity by 2026 (MW)		16.4	Isolated Systems	GPL
Total LFO Capacity by 2026 (MW)		22.03	Isolated Systems	GPL
Total Solar PV Capacity by 2026 (MW)		10.25	Isolated Systems	GPL
Isolated System HFO % Share		33.7%	Isolated Systems	GPL
Isolated System LFO % Share		45.3%	Isolated Systems	GPL
Isolated System Solar PV % Share		21.1%	Isolated Systems	GPL

1.5.2 Transmission and Distribution (T&D)

The reliable delivery of electricity service from the generation stations to customers requires a robust and resilient Transmission and Distribution network. With the combined progressive expansion of the T&D System and the Company's extensive planned and executed maintenance activities, the networks are still prone to defects due to the aged sections of the network. These defects contribute to service disruptions that negatively impact the Company's ability to serve its customers and reducing technical losses reliably.

The network was partially improved in 2014, which was as a result of the construction of seven (7) new substations, one hundred and thirty-seven kilometres (137 km) of transmission lines and the interconnection of two systems: Berbice and Demerara Power Systems into the Demerara Berbice Interconnected System (DBIS). These network improvements positively and progressively improved the reliability and quality of electricity service to our customers and contributed towards the Company's technical loss reduction efforts.

In 2021, GPL continued to build on the 2020 network improvements that included:

- Constructing 95.2 km of express medium voltage feeders; and
- Installing 103 auto-reclosers and commissioned 70 to date;
- Improving distribution feeder protection and coordination;
- Installing 21 Automatic Power Factor Correction (APFC) capacitor banks, where 4 is from the JICA Grant;
- Updating distribution feeder automatic load shedding profile;
- Installing 110 km of additional conductors to facilitate the extension of electricity service;
- Upgrading a total of 25 km of conductors on the primary distribution network;
- Replacing 5 km of LV lines to customers;
- Installing 31 additional transformers on the primary distribution network (13.8 kV), and
- JICA Grant: This grant covered expenses for line conductors only. GPL financed the balance of line hardware materials, labour, and transportation costs for the following works:
    - Good Hope F4 - System Improvement: Good Hope to Enmore E.C.D Express Feeder;
    - Sophia F2 - System Improvement: Sophia to Success E.C.D Express Feeder;
    - Edinburgh F2 - System Improvement: Edinburgh to Tuschen E.B.E Express Feeder;
    - Replaced Single Wire Earth Return Transformers on the West Bank and Coast of Demerara; and
- Onverwagt F2 - System Improvement: Onverwagt to No.7 W.C.B Express Feeder. At the transmission level, with grant from JICA, successfully installed and commissioned 2 x 5 MVAr reactive compensation installed at Canefield Substation.

In view of the Transmission and Distribution planning targets and demand forecasts, a summary of improvements expected to be realized during the life of this Programme, specifically at the transmission level, include:

1. 702 km of 230 kV Double Circuit Transmission Lines;
2. 4 – 230 kV Substations;
3. 22 new 69/13.8 kV distribution substations (load centres);
4. 12 - 69/13.8kV substations upgrades;
5. 671 km of new 69 kV transmission circuits – for new substations and parallel lines;
6. 160 km of upgraded 69 kV transmission circuits (conductor upgrade); and
7. Installation of a total of 55 MVAr of Reactive Power compensators at the 69 kV level (IaDB Loan funded), and 20 MVAr GPL funded.

Interventions for improving the distribution systems' reliability, resiliency, and capacity to manage increased power flow and to deliver quality electricity supply service to customers are:

1. Improve/upgrade workforce to perform Hotline Maintenance and Upgrades;
2. Reinforce vegetation management;
3. Use of concrete pole structures in primary distribution circuits;
4. Use of steel, concrete or fibre glass cross arms;
5. Use of covered conductors in primary distribution circuits;
6. Installation and commission of a total of 12,000 kVAr (23 banks) of Automatic Power Factor Correction Capacitor Banks on 30 primary distribution feeders;
7. Upgrading of 489 km of primary distribution circuits
8. Upgrading 142.4 km of medium voltage conductors (JICA Grant and GPL Funded)
9. Construction of 809 km new primary distribution circuits (for new and existing substations in the DBIS and Isolated Power Systems);
10. Upgrade of existing SCADA and deployment of SMART Grid – expanding remote control and supervision reach into power generation and primary distribution levels;
11. Installation and commissioning of 17 Auto-Reclosers;

1.6 Metering (Technical and Non-Technical Losses)

The progressive and sustained reduction in Total System Losses remains a corporate priority, despite the notable reduction from thirty-seven percent (37%) in 2006, to twenty-four percent (24.7%) as of December 2021 – projected percentage.

The major contributors to the Company's non-technical losses are:

- Unmetered supplies;
- Defective meters;

- Street lighting; and
- Electricity theft.

The major contributors to the Company’s technical losses are:

- Aged and lengthy conductors (medium and low voltage);
- Inefficient transformers; and
- Insufficient reactive power compensation.

The Company’s Loss Reduction effort has been bolstered by an aggregated investment of US$43 million in debt and grant funding from the Inter-American Development Bank (IaDB) and the European Union (EU), respectively. This investment is in addition to the Company’s self-funded efforts. The IaDB/EU funding targets upgrading 830 kilometres of low voltage conductors, including distribution transformer right-sizing, meter replacements and service installation upgrades.

Further reductions in system losses will improve revenue and reduce operating costs. In 2018, GPL commenced Phase II of its meter upgrade program to AMI compatible meters (smart meters), to position the Company to expand its Advanced Metering Infrastructure (AMI) coverage and strengthen its ability to track losses from substation to customer and inform corrective actions. This will positively impact efforts to lower tariffs for all consumers and improve the financial strength of GPL.

The Power Utility Upgrade Programme (PUUP), GPL plans to upgrade the remaining 1,700 meters to AMI in 2022.

With the combined application of SCADA at the transmissions and primary distribution levels, and power generation, coupled with the continued implementation of AMI meters at the customer level, the Company plans to transform the power system into a smart grid in a phased manner.

In view of the benefits of having a smart grid together with the above-mentioned projects, which will reduce technical and non-technical losses, the Company’s loss projection profile indicates that by 2026, technical losses should be reduced from 11.5% to 10.2%, and non-technical from 13.2% to approximately 7.9% (Figure 1). Consequently, a total loss reduction from twenty-four-point seven percent (24.7%) in 2021 to eighteen-point one percent (18.1%) by 2026.

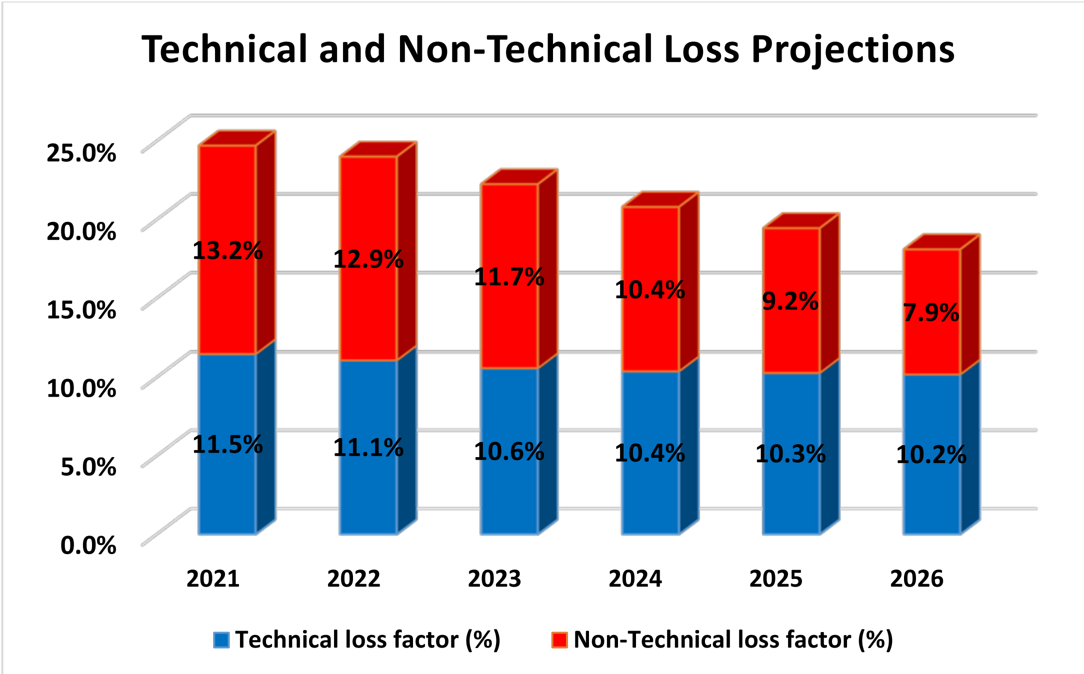

Figure 1: Loss Reduction Projections

1.7 Sales and Revenue Collection

Sales growth from 2021 to 2026 is projected to increase by 375% from 729.5 GWh to 2,656.2 for the total GPL Power Systems (Figure 2) This projection is premised on the details mentioned in section 1.4, page 17, and the projected percentage loss reduction by 2026.

The active campaign to improve Receivables will continue and GPL will maintain a cash collection rate of 99.5% (cash collections as a percentage of sales).

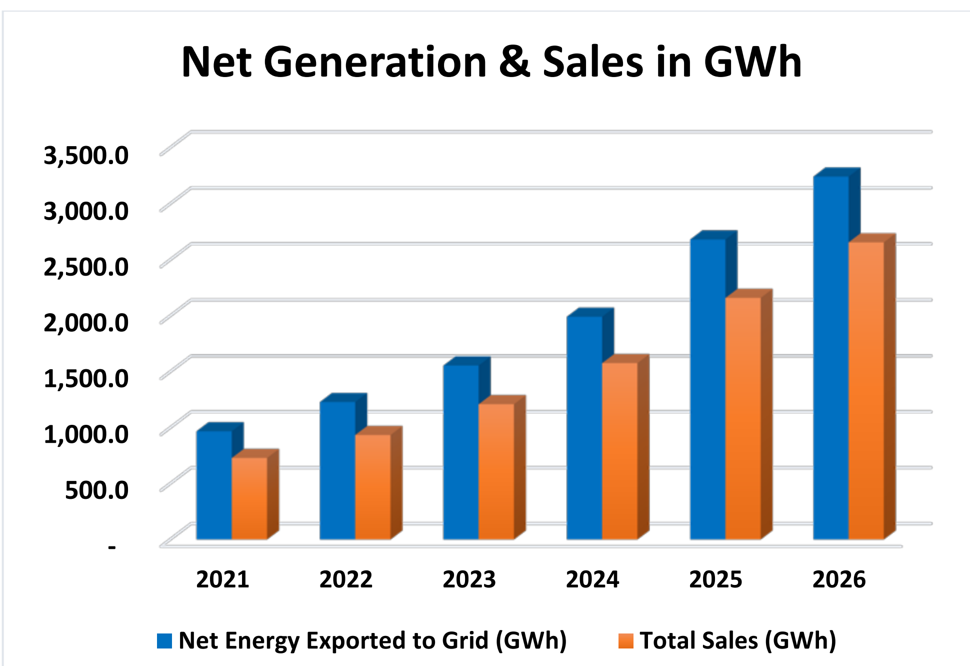

Figure 2: Net generation & Sales (GWh)

1.8 Tariffs

The reduction of tariffs remains a priority to the Company and is consistent with the corporate vision. Whilst the Company's operating license provides a tariff mechanism to adjust rates to ensure profitability and self-sustainability, GPL will continue to adopt prudent operating practices in its efforts to sustain lowered tariffs to all customers.

During 2015 and 2016, when world market fuel prices declined considerably, the Company applied a fuel rebate of five percent (5%) and ten percent (10%) respectively. In addition, tariffs were reduced by five percent (5%) in year 2016. The aggregated effect was a twenty percent (20%) reduction in tariffs over year 2014. During the year 2021, the fifteen (15%) fuel rebates were removed and concurrently the headline tariffs were reduced by the same amount thus concretising the reduction in rates.

Despite increases in world market fuel prices by approximately seventy seven percent (77%) in ensuing years (2017 – 2021), the Company has not applied any fuel surcharge or tariff increases as provided for under its license.

Whilst lowered and sustained tariffs are among the Company's primary objectives, GPL remains challenged to fund network and generation improvement projects without debt financing and grants from multi-lateral concessional lending agencies.

The Financial projections are instructive as to the measures that could be taken to facilitate a reduction in Tariffs. The key assumptions used in the projections are detailed in Table 13.

Table 14: Financial Projections – Facilitating Tariff Reduction

		Year 2021	Year 2026	Change
NET TARIFFS	US cents/kWh	**22**	**18**	18%
SALES DEMAND	GWh	729	2,656	264%
LOSSES	%	24.7%	18.1%	6.6%
FUEL PRICES				
Natural Gas Price delivered to the engines	US$/MMBTU	NA	5	
HFO CIF Price	US$/barrel	80	70	
LFO CIF Price	US$/barrel	96	84	
LOAN STOCK				
GPL Loans Debt burden	G$' billion	53	154	191%
Interest Payment 4%	G$' billion	1.10	6.16	460%
Principal Payments (15 years amortization)	G$' billion	3.53	10.27	191%
Debt Service Total	G$' billion	**4.63**	**16.43**	**255%**

These factors have a major influence on GPL's ability to lower Tariffs from the current level of approximately US 22 cents per kWh. A review of the projected financial performance for the period to Year 2026 highlights the following:

i) Growth in Sales Demand

The significant growth in demand (increase of approximately 264%) over the five (5) year period is projected to have a favourable impact on the generation of profits and operating cash flows. The projections have included a tariff reduction to US 20 cents per kWh at the beginning of year 2025, and a further reduction to US 18 cents per kWh at the start of year 2026.

ii) Losses (Technical and Commercial losses)

Losses are projected to decline from 24.7% to 18.1%. Further reductions in losses will have a positive impact on the financial performance and would improve the ability of the company to lower tariffs even further. As an example, an additional reduction in losses of 5% would allow for a reduction in Tariffs by about US 1 cent per kWh at the projected costs of generation.

iii) Cost of Generation

By year 2025, generation using natural gas supplied by way of the planned gas pipeline is projected to provide more than 80% of the required generation. The price at which gas is delivered to the engines is therefore extremely important and will have the most impact on the ability of the company to lower tariffs by 2025 as shown below:

Price of Gas:

- US$ 6 per MMBtu - Tariff reduced by 10% to US 20 cents/kWh
- US$ 5 per MMBtu - Tariff reduced by 14% to US 19 cents/kWh
- US$ 4 per MMBtu - Tariff reduced by 18% to US 18 cents/kWh
- US$ 3 per MMBtu - Tariff reduced by 22% to US 16 cents/kWh

iv) GPL's Debt Burden

The projections indicate that by the end of 2026, GPL's Loans to the Government of Guyana would increase from G$53 billion to more than G$154 billion. This will require approximately G$16 billion in annual debt service obligations.

GPL has negotiated with the Ministry of Finance, the extension of the moratorium on servicing the majority of the current outstanding debt until the year 2026. Discussions are ongoing to extend this moratorium to all of the remaining debt.

Converting this debt to equity, would allow for a further reduction of about US 2 cents after year 2026.

1.9 Capital Programmes, Investments and Financial Projections: 2022 – 2026.

Table 15: Planned Capital Programmes and Investments: 2022-2026

CAPITAL EXPENDITURE SUMMARY & SOURCE OF FUNDING						
Development and Expansion Projects: Years 2022-2026		**Annual Budget (US$)**				
	Total Project Cost	**2022**	**2023**	**2024**	**2025**	**2026**
	US$	**US$**	**US$**	**US$**	**US$**	**US$**
Conventional Generation	1,506,400,139	340,591,522	277,270,790	396,436,055	353,501,772	138,600,000
Non-Conventional Generation	90,840,517	52,209,517	38,631,000	-	-	-
Grid Automation	131,305,683	-	-	39,391,705	52,522,273	39,391,705
69 kV Transmission Lines (Include Sub. Exp. Cost)	138,170,826	10,754,439	32,080,222	42,516,094	35,850,780	16,969,291
230 kV Transmission Lines (Include Sub. Exp. Cost)	915,252,919	-	24,995,324	345,709,445	370,586,775	173,961,375
Upgrade - Existing 69/13.8 kV Substation	15,637,965	3,151,837	5,719,812	4,993,214	438,422	1,334,679
New 69/13.8 kV Substation	160,527,849	23,805,497	56,005,036	39,197,280	28,337,755	13,182,281
230 kV Substation - New	75,230,248	10,424,526	13,899,368	22,569,074	16,192,731	12,144,549
New Primary Distribution Feeders	35,962,799	4,762,513	11,670,315	11,158,544	5,964,144	2,407,283
Upgrade to Existing Primary Distribution Network (Technical Loss Reduction)	30,542,373	21,932,544	4,407,170	2,752,444	1,450,214	-
Transmission Reactive Reinforcement	679,800	-	260,040	173,360	147,840	98,560
Distribution Reactive Reinforcement	406,282	-	102,806	182,925	61,684	58,867
Power Plant Switchgear Upgrades	2,057,951	280,500	838,437	939,014	-	-
Meter Upgrades/Replacements (Non-Technical Loss Reduction)	32,802,395	6,340,270	5,650,000	6,937,375	6,937,375	6,937,375
Electrification (Unserved Areas)	3,426,067	1,212,792	1,704,556	219,987	164,990	123,743
New Services	13,212,605	1,623,760	2,133,141	2,642,521	3,151,901	3,661,281
Buildings	5,554,897	1,877,178	1,423,473	721,144	766,551	766,551
Company Vehicles and Tools	28,512,557	8,991,554	8,052,258	3,674,828	5,565,402	2,228,515
Information Technology	1,325,000	855,000	470,000	-	-	-
GRAND TOTAL - EXCLUDING GAS PIPELINE AND PROCESSING PLANT	**3,187,848,872**	**488,813,447**	**485,313,749**	**920,215,010**	**881,640,609**	**411,866,056**

SOURCE OF FUNDING		**Annual Budget (US$)**				
	Total Project Cost	**2022**	**2023**	**2024**	**2025**	**2026**
GPL Shareholder Funds (Retained earnings, Loans from Shareholder, Equity con	461,037,973	88,969,855	130,423,336	109,339,178	84,537,177	47,768,427
FDI	2,633,561,211	345,658,305	315,999,373	810,702,472	797,103,432	364,097,629
Loan	7,472,687	5,983,287	1,316,040	173,360	-	-
Grant	85,777,000	48,202,000	37,575,000	-	-	-
TOTAL	**3,187,848,871**	**488,813,447**	**485,313,749**	**920,215,010**	**881,640,609**	**411,866,056**

Table 16: Profit & Loss Account

		2021	Yr 2022	Yr 2023	Yr 2024	Yr 2025	Yr 2026
		Latest Estimate	Proj	Proj	Proj	Proj	Proj
		$'M	$'M	$'M	$'M	$'M	$'M
REVENUE							
Turnover		35,706	39,885	57,321	74,737	93,012	102,915
Rebate		1,461					
NET REVENUE		**34,245**	**39,885**	**57,321**	**74,737**	**93,012**	**102,915**
GENERATION COSTS							
Fuel & Freight		23,436	31,253	14,533	24,235	9,342	4,971
Operation & Maintenance Contract		2,807	2,772	1,789	3,283	1,566	1,133
Repairs & Maintenance - Generation Facility		765	797	753	753	753	753
Purchased Power (IPP costs)		2,755	1,977	17,800	18,371	25,157	34,570
Rental of Equipment		251	-	-	-	-	-
Fuel Agency Fee							
		30,014	**36,799**	**34,875**	**46,643**	**36,818**	**41,427**
GROSS INCOME		**4,231**	**3,086**	**22,446**	**28,094**	**56,194**	**61,488**
EXPENSES							
Employment Costs		5,094	5,619	6,181	6,799	7,479	8,227
Repairs & Maintenance T&D		534	1,880	2,702	3,523	4,384	4,851
Depreciation		3,685	3,933	5,296	7,186	8,758	9,971
Administrative Expenses		2,192	2,960	3,197	3,453	3,729	4,027
Rates & Taxes		51	50	54	58	63	68
Loss On Exchange		-	-	-	-	-	-
Bad Debts Provision		447	598	860	1,121	1,395	1,544
Puc Assessment & Licence		73	73	75	75	100	100
		12,076	**15,113**	**18,364**	**22,215**	**25,908**	**28,787**
NET (LOSS)/PROFIT FROM OPERATIONS		**(7,845)**	**(12,027)**	**4,082**	**5,879**	**30,287**	**32,701**
INTEREST EXPENSE		1,135	1,335	4,081	5,024	5,752	6,163
		(8,980)	**(13,362)**	**1**	**855**	**24,535**	**26,538**
OTHER INCOME		649	1,023	2,150	2,803	3,488	3,859
		(8,331)	**(12,339)**	**2,150**	**3,658**	**28,023**	**30,397**
TAXATION		62	60	323	549	4,203	4,560
NET (LOSS)/PROFIT FOR THE YEAR		**(8,393)**	**(12,399)**	**1,828**	**3,109**	**23,819**	**25,838**

In accordance with GPL's Licence, the Shareholder is entitled to a target rate of return on equity of 8% per annum.

Table 17: Cash Flow Statement

Guyana Power & Light Cash flow Statement for the year ended December 31st	Yr 2022 Proj $'M	Yr 2023 Proj $'M	Yr 2024 Proj $'M	Yr 2025 Proj $'M	Yr 2026 Proj $'M
OPERATING ACTIVITIES					
Profit/(Loss) before Taxation	**(12,339)**	**2,150**	**3,658**	**28,023**	**30,397**
Adjustments for:					
Depreciation	3,933	5,296	7,186	8,758	9,971
Deferred Income	3	14	14	14	8
Deferred Tax Asset	(555)	(611)	(672)	(739)	(813)
Interest Expense	1,335	4,081	5,024	5,752	6,163
Amortization of Customer Projects					
Operating (loss)/profit before WC changes	**(7,623)**	**10,930**	**15,210**	**41,808**	**45,726**
Working Capital (WC) Changes					
Change in Inventories	(262)	(275)	(289)	(303)	(319)
Change in receivables and prepayments	1,237	(2,906)	(2,903)	(3,046)	(1,651)
Change in payables and accruals	(717)	3,007	(933)	(2,969)	(2,782)
Change in related parties	0	0	0	0	0
Taxes paid	(1,002)	545	(331)	(2,754)	(4,418)
Net Cash (Outflow)/Inflow - Operating Activities	**(8,367)**	**11,301**	**10,754**	**32,736**	**36,557**
INVESTING ACTIVITIES					
Acquisition of Property, plant and equipment	(12,263)	(29,123)	(30,782)	(27,533)	(22,205)
Acquisition of Intangible assets	(166)	(200)	(240)	(288)	(345)
Increase in WIP	2,745	(3,167)	1,914	2,150	3,166
Acquisition of treasury bills	0	0	0	0	0
Increase in deposit	(4)	0	0	0	0
Net Cash Outflow - Investing Activities	**(9,689)**	**(32,490)**	**(29,108)**	**(25,670)**	**(19,385)**
FINANCING ACTIVITIES					
Movement in non current related parties	19,896	30,634	23,573	18,197	10,282
Deposit on Shares	0	0	0	0	0
Interest paid	(1,335)	(4,081)	(5,024)	(5,752)	(6,163)
Customer deposits	457	1,908	1,906	2,000	1,084
Increase in advances customer financed projects	225	940	938	985	534
Decrease in advances customer financed projects					
Net Cash (Outflow)/Inflow - Financing Activities	**19,243**	**29,400**	**21,393**	**15,429**	**5,736**
NET MOVEMENT IN CASH AND CASH EQUIVALENTS	**1,187**	**8,212**	**3,039**	**22,495**	**22,909**
CASH AND CASH EQUIVALENTS AS AT BEGINNING OF YEAR	(3,187)	(2,000)	6,212	9,251	31,746
CASH AND CASH EQUIVALENTS AS AT END OF YEAR	**(2,000)**	**6,212**	**9,251**	**31,746**	**54,654**
Represented By:					
Cash on Hand and at Bank	**(2,000)**	**6,212**	**9,251**	**31,746**	**54,654**

Table 18: Balance Sheet

Guyana Power & Light Statement of Financial Position As at December 31st	Yr 2021 Unaudited $'M	Yr 2022 Proj $'M	Yr 2023 Proj $'M	Yr 2024 Proj $'M	Yr 2025 Proj $'M	Yr 2026 Proj $'M
ASSETS						
Non Current Assets						
Property, plant and equipment	37,983	46,313	70,140	93,736	112,512	124,746
Intangible assets	832	998	1,198	1,438	1,725	2,070
Work in progress	10,920	8,175	11,343	9,429	7,279	4,113
Deferred tax assets	5,550	6,105	6,716	7,387	8,126	8,938
	55,285	**61,592**	**89,397**	**111,990**	**129,641**	**139,868**
Current Assets						
Inventories	5,241	5,503	5,778	6,067	6,370	6,689
Receivables & Prepayments	7,884	6,648	9,554	12,456	15,502	17,153
Deposits	592	588	588	588	588	588
Related parties	3,458	3,458	3,458	3,458	3,458	3,458
Investments	3,105	3,105	828	828	828	828
Cash resources	(3,187)	(2,000)	6,212	9,251	31,746	54,654
	17,093	**17,302**	**26,418**	**32,648**	**58,492**	**83,370**
Total Assets	**72,378**	**78,894**	**115,814**	**144,638**	**188,133**	**223,238**
EQUITY & LIABILITIES						
Share Capital	23,118	23,118	23,118	23,118	23,118	23,118
Accumulated deficit	(24,455)	(36,854)	(35,027)	(31,918)	(8,098)	17,739
	- 1,337	**- 13,736**	**- 11,909**	**- 8,800**	**15,020**	**40,857**
Non Current Liabilities						
Related Parties	54,007	73,670	102,027	125,600	143,796	154,078
Advances customer financed project	1,568	1,752	2,517	3,282	4,085	4,519
Provision for decommissioning	243	243	243	243	243	243
Customer deposits	3,907	4,364	6,272	8,178	10,178	11,261
Defined benefit liability	742	851	851	851	851	851
Deferred tax liability	831	947	947	947	947	947
	61,298	**81,827**	**112,857**	**139,100**	**160,099**	**171,900**
Current liabilities						
Related parties	-	-	-	-	-	-
Deferred Income	28	31	45	59	73	81
Advances customer financed project	356	398	572	745	927	1,026
Payables and accruals	11,959	11,242	14,249	13,316	10,347	7,565
Taxation	74	- 868	-	218	1,667	1,809
	12,417	**10,803**	**14,866**	**14,337**	**13,014**	**10,481**
Total Equity and Liabilities	**72,378**	**78,894**	**115,814**	**144,638**	**188,133**	**223,238**

2. Introduction

2.1 General

The Guyana Power and Light (GPL) plays a critical role in developing the country's economy sustainably, consistent with its mandate to provide reliable, affordable, and quality services to all customers, comply with all applicable regulations and standards, safely and sustainably develop, and operate the grid and develop the capabilities of its employees.

The Company currently does not have sufficient reliable generation capacity to meet the forecast electricity and peak demands. The situation is further exacerbated by the absence of backup circuits in the transmission and distribution networks to mitigate contingencies in these sections of the power grid. The problem would worsen with expected increases in electricity demand and continued use of the ageing T&D network infrastructure.

Forty-nine point five megawatts (49.5 MW) of the Company's Heavy Fuel Oil fired baseload generator units (powered by Wärtsilä[5] and Mireles Blackstone[6] engines) within the Demerara Berbice Interconnected System (DBIS) have surpassed the economic lifespan threshold of 20 years. Additionally, 16 MW of LFO fired have also exceeded this 20 years limit.

Although these older engines have been and continue to be well maintained and delivered at an extraordinary reliability level, they have become prone to mechanical and electrical failures due to the exhaustive years of continuous on-demand operation.

In addition to LFO generator units, there are 16.8 MW of LFO fired, high-speed mobile generator units in Berbice and 4.8 MW in Demerara. Although these generator units are designed and built for emergency operation, there are occasions when they are required to operate for longer hours because of system exigencies. These longer operation hours further expose the generator units to the risks of mechanical and electrical failures.

Combining the age of generator units and engine and/or alternator issues, the total unreliable power generation capacity in the DBIS (LFO and HFO fired generation) is 135.3 MW, and in the Isolated System, a total of 11.4 MW. Consequently, the Company is presented with the combined challenges of aged and unreliable generation capacity, which is not consistent with the Company's desire to satisfy the growing demand with reliable generation and sustain the Country's economy.

The Government of Guyana remains cognizant of the importance of reliable generation and has provided debt financing to GPL to facilitate the construction of the first single and largest power generation facility in the Country – 46.5 MW. This project is located at Garden of Eden and was commissioned on 1st October 2021.

Whilst the 46.5 MW at Garden of Eden would assist in improving generation reliability and supporting GPL to satisfy the immediate and short-term electricity and peak demands, in

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[5] DP1 is 25 years old and totals 22 MW, while and DP2 is 24 years old and totals 22 MW. As such, a grand total of 44 MW of available Wärtsilä Generator Units capacity.

[6] Canefield Mireles Blackstone Generator unit is 25 years old and totals 3.8 MW of available capacity.

consideration of the demand forecast, total unreliable generation capacity and LOLP target, the DBIS would require a significant amount of additional firm generation capacity between 2023 and 2024, and 2026.

As per Expression of Interest from the Ministry of Natural Resources, the Government of Guyana expects to receive a guaranteed minimum of 50 mmscfd of gas by 2024 from the Liza Area in the Stabroek block, offshore Guyana, from which methane would be produced as the primary fuel for the 300 MW Natural Gas to Power Project, located at the Heavy Industrial Area within the Wales Development Zone (WDZ) (Ministry of Natural Resources, 2021).

Further, the Government of Guyana has already activated the procurement procedure for the commencement of the Amaila Falls Hydro Power Project in 2022 and initiated measures for its successful completion by the end of 2025 (DPI, 2021).

Similarly, the Isolated Systems would also require additional firm generation capacity for similar reasons as the DBIS.

Should GPL be confronted with protracted delays in its power generation expansion plans, the supply-demand gap would dramatically widen and negatively impact Guyana's planned economic development timelines and trajectory.

2.2 Positioning the 2022 – 2026 Development and Expansion Programme

GPL is cognizant of the changing and evolving energy landscape as electricity generation from renewable resources becomes more affordable and attractive for sustainable developments. In addition, cheap and reliable electricity has become increasingly critical to national economic and socio-economic developments (Stern, Burke, & Bruns, 2016).

As the leading supplier of electricity services, the Company has comprehensively reviewed its role within the context of supporting national economic development and has revised its core objectives and identify critical issues, which form the 'building blocks of this Development and Expansion Programme. The core objectives and critical issues are presented below**:**
Corporate Objectives:

2.1.1 Customer Service

- Provide Customer Centred Quality, Reliable and Timely Products and Services.

  This is integral to improving the Company's public image and ensuring the long-term business viability of GPL; and

- Build the Market: The demand for electricity services increases while the capital cost of renewable energy self-generation technologies is becoming more affordable. The Company recognizes the importance of lower tariffs and improved service reliability to sustain and influence growth in its customer base.

2.1.2 Employee Learning and Growth

- Ensure our employees possess the requisite skills and competencies to improve the quality of our products and services continuously; and

- To stimulate, develop, and retain a highly engaged and active workforce.

2.1.3 Financials

- Ensure that there are sufficient financial resources to sustain the Company's operations within the short, medium, and long-term timeframe; and
- Mitigate against financial disruptions associated with the various risks currently being experienced by the Company, e.g., fuel price volatility and currency exchange rates.

2.1.4 Core Operations

- Provide a cost-effective electricity service: Electricity is critical to national economic and socio-economic developments. This is crucial to the positioning of the Company and dictates stakeholders' expected delivery of service in addition to competitive and affordable tariffs; and
- Provide a reliable electricity service: The Company intends to aggressively improve its reliability of service through investments in increasing its firm generation capacity, upgrade and construct new distribution feeders, transmission lines and substations and deploy modern and **S**elf-**M**onitoring, **A**nalysis, and **R**eporting **T**echnologies (SMART) to manage better, supervise and support the transmission and distribution systems remotely. These investments would improve power system reliability (SAIFI and SAIDI), mitigate transmission and distribution contingencies and congestions, and aid in reducing technical and commercial losses.

2.1.5 Critical Issues

The company focuses on four (4) critical issues and intends to prioritise them to achieve operational excellence and corporate strategic objectives. These critical issues are the need to:

1. Improve the Quality of Products and Services;
2. Strengthen Management;
3. Optimize GPL as a System; and
4. Reduce Technical and Commercial Losses.

The Company would develop and optimise expansion plans for technical merit and least cost for Generation, Transmission and Distribution to address these critical issues. With these plans realised, the Company intends to ensure the power system operates within the prescribed technical and economic limits to mitigate cost excursions, guarantee power system reliability and security, and deliver quality service to customers.

Importantly, ensure the Company has adequate human resource capacity and provides capacity building and other related upskilling opportunities to narrow competency and skill gaps to embrace the operation of a modern power system and provide reliable services to customers.

2.3 Outline of Development and Expansion Programme

Section 3 (page 40) outlines the technical operation details of the Company;

Section 4 (page 116) summarises the non-technical components of the Company;

Section 5 (page 128) defines the Corporate Key Performance Indicators and Targets of GPL;

Section 6 (page 132) presents the summary of annual expansion, upgrades, and service work plan;

Sections 7 (page 142), 8 (page 143), and 9 (page 144) outlines GPL's financial position; and

Sections 10 (page 147) and 11 (page 147) highlights risks and mitigation measures.

3. Technical Operations

3.1 Power Generation

Prior to 2019, expansion planning studies were not based on achieving critical reliability targets. In 2019, GPL successfully updated its planning study approach by procuring PLEXOS and PSS Sincal. Additionally, developed the in-house capacity and capabilities of the Planning Unit to prepare expansion plans that are geared towards achieving generation reliability targets in the form of Loss of Load Probability (LOLP) or Loss of Load Expectation (LOLE). This is a critical step towards becoming a World-Class Utility.

GPL recognizes the importance and urgent need for new power generation capacity within the DBIS to reliably satisfy the projected growth in electricity and peak demands, which are over 3,299 GWh and 501 MW within the life of this Development and Expansion Programme (2022-2026). The immediate need for a new dispatchable generation does not negate the Company's endorsement or alignment with Guyana's Energy Policy, Low Carbon Development Strategy and other Government related initiatives that seek to reduce the national carbon footprint and the electricity tariff.

The Company also anticipates that the projected electricity demand would rise above traditional levels as Guyana realizes the anticipated economic benefits of commercial crude oil production, which commenced in 2020, and the Government's current massive development plans for the residential, commercial, and industrial sectors.

3.1.1 Renewable Energy Resources

3.1.1.1 Intermittent Energy Resources (Wind and Solar)

Whilst the abundance of renewable energy from resources such as wind and solar appear as attractive sources of generation that would have a mitigating effect on imported fossil fuel, price volatility and reduce carbon emissions, the intermittent nature of these resources concomitant with significant levels of penetration would present considerable challenges to the stability of the grid at this infant stage.

While attractive globally, electricity generation from wind and solar energy systems will not entirely displace firm and dispatchable fossil fuel-fired power generation capacity but a wellbalanced technical and economic percentage. Given the Company's technical experience in this area, it plans to incrementally introduce and integrate intermittent renewable energy systems in a prudent manner to ensure that electricity service delivery and, system stability and grid security are not adversely affected.

Given the above and with funding from the Guyana REDD+ Investment Fund (GRIF), GPL intends to implement a total of 33 MWp of utility-scale Solar PV energy systems with Battery Energy Storage Systems (BESS) across its power systems, inclusive of Linden, by 2023.

3.1.1.2 Firm and Dispatchable Energy Resources (Hydropower and Biomass)

Firm and dispatchable electricity generation from energy resources such as hydropower and biomass are attractive energy options. Besides these resources being renewable, another attribute that makes these energy options attractive is their low unit cost. Currently, electricity from biomass is marketed at 10 cents per kWh, and hydropower is expected to be no higher than 7 cents per kWh.

Hydropower

Among the top five potential hydropower sites, the Amaila Falls ranks highest in the technical/economic and environmental/social preference indices. As a result, the Amailia Falls is an optimal solution for satisfying Guyana's projected electricity and peak demands (Norconsult, 2016).

This renewable energy project is expected to deliver approximately 90% of Guyana's energy needs and consequently reduces Guyana's dependency on imported fossil fuel – heavy and light fuel oils and significant reduction of carbon mission from the electricity sector (GRIF, 2011). Inevitably, the Amailia Falls Hydropower Project is a flagship project of Guyana's Low Carbon Development Strategy (LCDS). Among the numerous benefits this project would bring to the electricity sector, GPL customers would benefit from reduced tariff and insulation from tariff fluctuations due to fossil fuel price volatility on the international market.

The Government of Guyana intends to enter a 20-year BOOT concession on a design-build-finance (DBF) basis with a Project Developer.

The procurement procedure for selecting the most appropriate and least-cost Project Developer of the Amailia Falls Hydropower Project is underway. The Government of Guyana plans to commence this project in the second half of 2022. The project is expected to be completed by the end of 2025 (DPI, 2021).

To maintain Guyana's Carbon footprint in a steady state and to ensure Guyana's commitment to mitigating the effects and risks of Climate Change, the Government plans a total of 620 MW of additional hydropower capacity between 2031 and 2040.

Biomass

Presently, Guyana has 30 MW of biomass-fired power generation capacity at Skeldon. Over the years, this facility depended on the continuous operation of the Skeldon Sugar Factory and other Sugar factories within its vicinity for feedstock – bagasse. However, between 2016 and

2017, the closure of Skeldon and Rose Hall Sugar Factories adversely affected the availability of bagasse, and by extension, the generation of electricity from biomass.

As a result of the experience mentioned above, Skeldon Energy Inc. (SEI) realised the need to establish a feedstock chain independent of sugar cane. As a result, the use of Napier Grass as a feedstock to the 30 MW power generation facility was investigated.

Resulting from the investigation, SEI secured approximately 3000 acres of land for the cultivation of Napier Grass. The 207 acres first phase of cultivation was successful; however, due to the 2021 flooding in the East Canje area, the entire crop of Napier Grass was destroyed.

Notwithstanding the above, SEI is taking measures to secure the new crop of Napier Grass, which is expected to be cultivated in October 2021 and harvested six months later – Q1 of 2022. Under this re-cultivation, SEI is preparing approximately 1000 acres initially and subsequential increase cultivation to 2500 acres. Harvesting is planned twice per annum. As a result, from Q1 2022, SEI would have a continuous supply of feedstock for the steam turbine facility.

The combined benefits of the Napier Grass and harvesting procedures allow this feedstock to be attractive to SEI. At harvesting, the Napier Grass would be cut and mulched by the harvester and transported later to Guysuco Dewatering Mill for moisture extraction.

At SEI's generation facility, one boiler is planned for operation in Q1 2022 to power the steam turbine. SEI indicated that from 250 acres of Napier Grass, approximately 6.2 GWh of electricity could be generated.

SEI also informed that the Guysuco infrastructure for conveying bagasse from the dewatering mills to SEI's boiler remains intact. Should the Skeldon Sugar Factory re-commence operation, SEI would also use the bagasse to fire its boiler and use the steam to generate electricity.

The expected increase in production from biomass saw the need to upgrade the step-up substation. SEI has already installed a second step-up transformer and other ancillary substation infrastructure to bolster their grid output up to 36 MVA and its reliability.

3.1.2 Natural Gas

The growing Oil and Gas sector has presented an opportunity for natural gas to become the primary fuel source for electricity generation in Guyana. Whilst natural gas is not a renewable energy resource, it is a cheaper, cleaner, green, and indigenous source of energy for the generation of electricity than GPL's current use of liquid fossil fuel supplies, and it offers the potential of a lower cost of electricity generation, reduced electricity tariffs and carbon emissions.

The Company's 46.5 MW multifuel power plant at Garden of Eden can consume Natural Gas as its primary fuel and HFO or LFO as contingency fuels.

The Company expects the advent of an abundance of gas to replace liquid fossil fuels as the primary energy resource for electricity generation. The migration towards using natural gas would propel Guyana towards realising its national objective of energy security and reaffirms its position on global Climate Change commitments.

Natural gas consists typically of 70%-90% of methane, and it is considered the cleanest of all fossil fuels because it produces lower emissions of CO_2, NO_x and SO_x and particulate matter than HFO and LFO. Natural gas is well suited to complement intermittent renewable resources such as solar, wind, biomass, and hydropower and as a transitioning fuel towards having higher renewable energy penetrations.

A desktop review on the feasibility of tapping gas from the Liza 1 indicated that this well could produce an estimated 30-50 MMBtu of natural gas per day without adversely impacting crude oil extraction. This study also showed that a more substantial volume of gas would be expected at the end of the field life (resulting from gas reinjection).

The accumulated amount of flared gas, from December 22nd, 2019, to September 14th, 2021, is equivalent to an annual gross generation of 1,272 GWh[7]. Table x shows a comparison of GWh from flared gas to 2020 actual, and 2021 and 2022 forecasted gross generation.

Table 1: Equivalent Generation GWh from flared Natural Gas

Year	GPL Gross Generation (GWh)	% of GWh from Flared NG vs DBIS Gross Generation
2020	853.17	149%
2021	963.04	132%
2022	1233.48	103%
2023	1571.41	81%

The flaring of natural gas threatens the country's global carbon footprint and directly limits forest-based production activities. The Brugman Expansion Study indicated that Liza1 has a gas reserve of 0.2 Tcf. As such, a flow of 50 MMcf/d can power a 250-300 MW plant for approximately 11 years (K&M_Advisors, 2019). Additionally, several studies have concluded that the natural gas from Liza 1 and other wells can be used to develop a sustainable energy sector to provide secure, reliable, environmentally friendly, and affordable energy services that are especially crucial to poverty reduction and alignment with the United Nations Sustainable Development Goal (SDG) No. 7.

The 250-300 MW gas to energy project includes the construction and operation of a pipeline from the Liza Phase 1 and 2 FSPO vessels to the onshore gas processing plant (GPP), located within the Heavy Industrial Area of the Wales Development Zone.

The pipeline for this project is guaranteed to transport 50 mmscfd of wet gas to the GPP. The processing plant together would drop the gas pressure and dehydrate the gas. The Natural Gas Liquids Facility (NGL) would separate the critical commercial gas components, inclusive of treating the gas to satisfy the required fuel specifications of the 250-300 MW Plant.

[7] Based on average efficiency performance of leading CCGTs on the market.

Construction works for the 12-inch, 225 km pipeline are expected to commence around mid-2022 and to have a duration of approximately 30 months.

Construction plans for the 250-300 MW Power Plant indicate a two-phase approach, where the planned COD for Phase is by the end of 2024, and Phase 2, before the end of 2025. Each phase is expected to deliver approximately 150 MW.

The Government of Guyana has already commenced the projects, where September 14th, 2021, was the due date for submitting Expressions of Interest. The project is expected to have an economic lifespan of 25 years from the Commercial Operation Date (COD) – 2049/50.

It is planned for the Power Plant to be equipped with Combined Cycle Gas Turbines (CCGTs). CCGT offers many advantages over Reciprocating Internal Combustion Engines (RICE), including lower emissions, higher combustion efficiency, higher renewable energy penetrations, higher ramping rate, improves grid stability, and is more flexible with future fuels, for example, hydrogen. These advantages are well aligned with the Low Carbon Development Strategies (LCDS) and the United Nations Sustainable Development Goals (SDGs) and outweigh the benefits of RICE.

3.1.2.1 Possibility of Converting Existing HFO Plants to Dual Fuel Plants – DBIS

To add further value to natural gas, GPL can convert Garden of Eden Wärtsilä (DP1), Kingston I (DP2), Kingston II (DP3) and Vreed-en-Hoop (DP4) plants to use this resource as their primary fuel and HFO as contingency fuel.

The conversion of these power plants would significantly reduce their present operating costs (Table 15) and extend their economic operational life by 12 to 15 years for DP1 and DP2 and 20 years for DP3 and DP4.

Table 2: Summary of Variation of key operating paraments after conversion to natural gas

Key Parameters	DP2	DP3 - W16V	DP3 - W18V	DP4
Output (kW)	-0.02%	-3.74%	-4.55%	-8.56%
Heat rate (BTU/kWh) - 100% Loading	-8.63%	0.11%	0.24%	4.94%
Fixed O&M Cost $/kW/yr)	-33.50%	-66.29%	-66.29%	-42.93%
Variable O&M Cost ($/kWh)	-59.25%	-65.86%	-68.79%	-64.35%
Maintenance Rate	-13.04%	-13.04%	-13.04%	-13.04%
Mean Time to Repair – Top Overhaul	1.19%	1.19%	1.19%	1.19%
Mean Time to Repair – Major Overhaul	-45.44%	-45.44%	-45.44%	-45.44%
Mean Time to Repair - FOR	-71.43%	-71.43%	-71.43%	-71.43%
Forced Outage Rate	-49.15%	-3.23%	-3.23%	-18.92%

The duration to convert a single HFO engine to natural gas is 52 business days (almost 2 months). Plant conversion can be executed in sequential order, commencing with the DP1 – Garden of Eden engines, given the need to maintain generation reliability. As such, at any given time, only a single engine would be out of service for 2 months, after which works would commence on another engine in sequential order, moving from one completely converted plant to another. The total estimated duration to convert the four existing power plants is three years.

The net output from a converted plant depends on the methane number and charge air receiver temperature (Figure 1). Additionally, the output is limited due to the gas feed pressure and heating value of the gas (Figure 2). As a result, the heat rate and electric power output vary inversely. However, for the engines at DP1 to DP4, the scope of work includes increasing the cylinder bore to match the cylinder jacket for a DF34 Wärtsilä Engine, resulting in recuperating the nominal output from each generator unit.

Although it is required to increase the cylinder bore to restore the engine output, there are other significant cost-saving benefits in converting these power plants (DP1 to DP4) to operate with natural gas (Table 15).

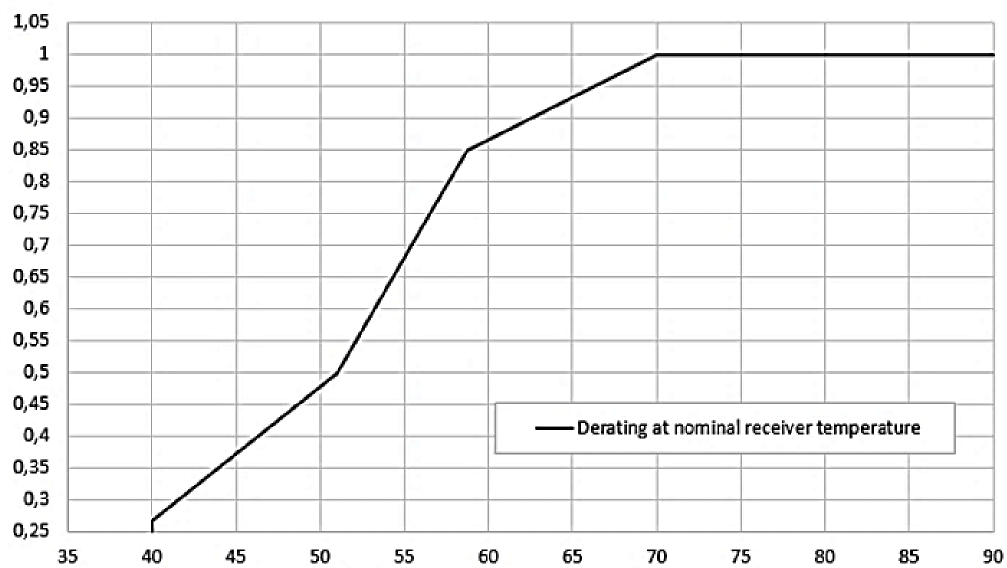

Figure 1: Output limitations due to methane number and charge air receiver temperature (*source: Wärtsilä Power Plant Gas Conversions: SG and DF Concept)*

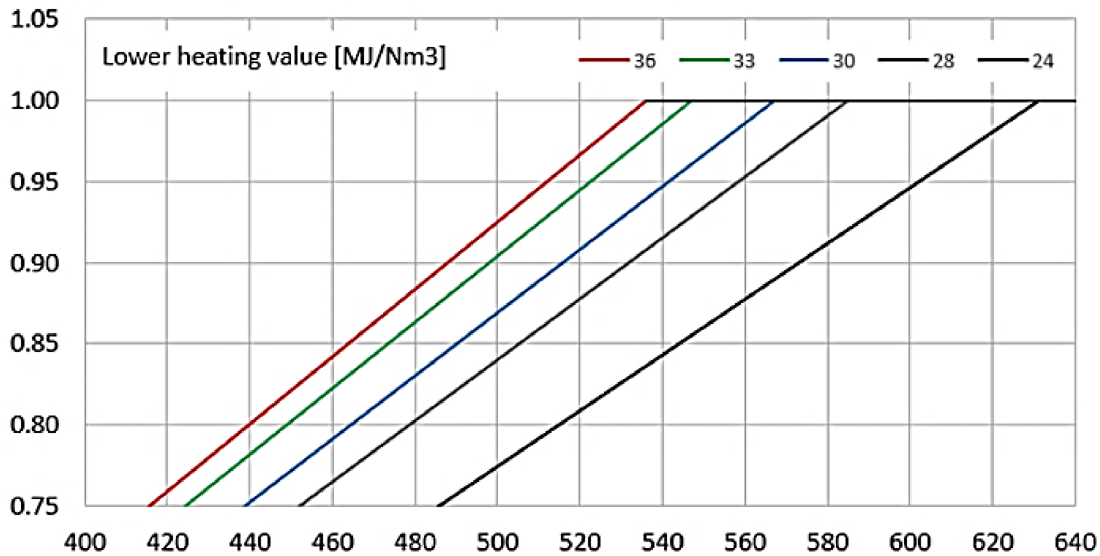

Figure 2: Output limitations for gas feed pressure and LHV, 480/500kW per cylinder (*source: Wärtsilä 34DF Product Guide*)

3.1.3 Hybrid Systems

Within the context of this Development and Expansion Programme, hybrid systems refer to a single project that constitutes a combination of different energy resources on a site.

In 2021, GPL received an unsolicited proposal from the consortium CH4 and Roraima to install 3x10 MW hybrid energy systems at three different locations – Onverwagt, Canefield and Williamsburg.

The consortium intends to install 16 MW_p ($10MW_{ac}$) of Solar PV capacity, 10 MWh BESS with 1 hr autonomy and 10 MW fossil fuel-fired generation capacity at each location. While awaiting formal approval, the consortium has already signalled their intended COD to be sometime in 2023.

The fossil fuel plant would consist of 7x1.7 MW Package Power Stations (PPS), totalling 11.9 MW baseload capacity. The guaranteed dispatch from this plant would be satisfied by 6 power modules, where one power module would be available as a backup unit on-site to achieve the guaranteed annual availability of 98%.

This hybrid facility's operation philosophy is that the photovoltaic plant would be dispatched during the effective solar hours at total capacity and the fossil plant at night. If any interference in the output from the photovoltaic plant, the system would automatically switch to the fossil fuel plant. During this transition from the photovoltaic plant to the fossil fuel plant, the BESS would be switched into service automatically to maintain the guaranteed facility capacity of 10 MW – firm capacity, to the grid.

3.2 Transmission and Distribution

GPL is cognisant of the need for reliable electricity service delivery from the power generation plants to customers, which requires a robust and resilient Transmission and Distribution (T&D)

network. The Company’s current transmission and distribution network evolved from a distribution network over forty years ago and has been progressively expanding to evacuate power from new power plants and deliver electricity to new customers and unserved areas along the coastline of Guyana.

Despite the Company’s extensive planned and executed maintenance activities, the T&D networks are still prone to defects due to aged and unmaintained line sections. These defects contribute to service disruptions that negatively impact the Company’s ability to reliably serve its customers, achieve operation standard and performance targets and reduce unacceptable levels of technical losses.

The network was partially improved in 2014, having benefitted from the construction of seven (7) new substations, one hundred and thirty-seven (137) kilometres of transmission lines and the interconnection of two power systems: Demerara and Berbice.

These network improvements positively influenced GPL customers' service reliability and contributed to the Company’s technical loss reduction efforts. Continued investments in network refurbishment and expansion are required to improve service reliability further, meet customers' expectations and position the Company to become a World-class Utility.

The current high customer tariffs limit GPL’s ability to leverage rate increases to fund the necessary investment in its system. GPL would continue to pursue alternative sources of funding to maintain its momentum of network improvements and expansions.

3.2.1 Current Major Developments

Transmission

As mentioned in sections 3.1.1.2 on page 41 and 3.1.2 on page 42, the advent of larger power generation facilities, primarily when located at a considerable distance from load centres, require a higher transmission voltage level to transfer the larger block of power efficiently. In Guyana’s case, the next transmission voltage level is 230 kV.

The main drivers of 230 kV as the new transmission voltage in Guyana are the Amaila Falls Hydropower and Arco Norte Projects. These projects and their technical ramifications were conceptualised around 2001 and 2013, respectively. As a result, the 250-300 MW natural gas project in 2021 adopted 230 kV as the transmission level for power evacuation from the facility.

With 230 kV, the current 69 kV would become sub-transmission.

The 230 kV transmission system would extend from the large power generation facilities to strategic load centres across Guyana. Electricity would be transformed and distributed at 69 kV to supply the distribution substations (69/13.8 kV) at these load centres. There may be cases where electricity would be transformed from 230 kV directly to 13.8 kV because of grid configuration constraints.

For all 230 kV transmission lines, the Company intends to utilise metallic lattice structures equipped to accommodate two circuits. At the 69 kV, the Company plans to use concrete poles structures and metallic lattice structures in remote areas where easy access for maintenance is a severe constraint.

Concerning conductor type and size, the Company would continue to optimise for long-term economic benefits and align with the current types and sizes of conductors in stock.

Distribution

Current capital investments across GPL coverage at the primary distribution level include installing 120 auto-reclosers and 17 Automatic Power Factor Correction (APFC) capacitor banks. The auto-reclosers would assist in improving distribution reliability indices and the capacitor banks, power quality to customers, and reduce technical losses and thermal loading of substation transformers.

The Company is currently perusing commercial offers from local telecommunication service providers to communicate bilaterally and remotely with all auto-recloser. GPL intends to continue investing in improving power quality and supply reliability further and reducing technical losses.

This Development and Expansion Programme details the system improvements planned for the next 5 years – see section 6 on page 132.

3.3 Smart Grid

As stated in section 2.1 on page 37, besides the lack of sufficient generation capacity, GPL has been challenged to dispatch generators economically and adequately to control and maintain generation spinning reserve from the perspectives of grid operation and control over the past years.

The only communication system between System Control and the power plants is radio–verbal communication for generator dispatch and status updates hourly.

In the event of a system disturbance, plant operators are forced to react fast – at human speed, to adjust generator units manually to stabilise the power system. While monitoring the power system's frequency, the operators at System Control cannot react at the required speed and ascertain which generator unit(s) need(s) to respond and in what magnitude to stem a cascaded system shutdown blackout.

Timely response to attenuate frequency excursion is critical to a well-operated power system for a modern economy. Currently, GPL only has primary response capability to correct reserve margin excursions – machine inertia and governor. However, the current generator unit fleet is comparatively small to those found in a modern power system. Nevertheless, as a required ancillary service, the primary response must be available within 5 seconds from the time of a frequency excursion.

The Operation Code requires for Secondary Response to be trigger 30 seconds from the time of a frequency excursion. At this moment, there is no control system in place to provide such a timely response to avoid a cascaded system shutdown.

With Guyana moving into a new economic era, the current system control modus operandi, communication mechanism, and performance of the electric power system cannot sustain the present and future planned developments within the ambient the Low Carbon Development Strategy and National Energy Priorities.

In addition to the technical challenges, GPL is struggling to take absolute control of and maintain the transmission and distribution reliability indices, SAIDI and SAIFI. As T&D expands to address the economic growth, the situation would only exacerbate for the larger grid.

In the event of a fault on a transmission line that is currently not connected to SCADA, the operator at System Control takes a longer time to ascertain the nature of the fault and to advise T&D personnel on responding and restoring the line to service.

Given the length and the total number of primary distribution feeders, the situation is more challenging in the primary and secondary distribution systems. In these sections of the distribution system, T&D personnel are forced to patrol the lines searching for evidence of the fault and perform repairs. These field exercises take time and, as a result, have a direct adverse impact on SAIFI and SAIDI.

Transmission and Distribution reliability have a direct and adverse impact on power demand and the public image of the power utility company. Additionally, reliability issues coupled with power quality resulted in having an approximate total installed capacity of about 97 MW of self-generators.

As the grid expands, continuous data analysis would become a critical cornerstone for grid operation efficiency and alignment of the electricity sector with LCDS and other National Energy Priorities.

In light of the forecasted electricity and peak demands for the DBIS coupled with the expansion plans to address these demands, in the absence of a Smart Grid, the current power system management procedures and techniques would be constrained severely in the expected modernises grid and by extensions, adversely impact the success of present and future planned developments for Guyana.

Given the above challenges and the need to ensure the DBIS is configured and secured to support the present and future planned developments for Guyana, GPL is required to adopt a modern approach to power system supervision, control, and management through the application of a Smart Grid.

The economic opportunities currently offered by the exportation of crude oil and the other growing oil and gas supporting industries are a strong indication for Guyana to have a more reliable and stable electric power system. The present and future planned developments across Guyana provide the economic opportunity for GPL to have Smart Grid.

The architecture of the Smart Grid includes a modern state of the art SCADA as the intelligence core of the power system that would have extended capabilities to integrate a host of devices across Generation, Transmission and Distribution using generation, energy, outage, and distribution management systems (see Figure 3).

Given that a Smart Grid is all-inclusive, an inadequate balance on the investments allocation in any of the three systems (Transmission, Generation and Distribution) would result in weak links that will eventually and severely limit the advantages and expected benefits derived from the rest of the capital project investments and expansion programme.

Through Automatic Generation Control (AGC), the generation management system would allow the SCADA to automatically control and economically dispatch generator units across the DBIS to satisfy load demand requirements efficiently.

While the primary response to power frequency excursions is the generator unit's inertia, the AGC, through the governor, would be the secondary response to automatically ramp up or down generator units to stabilise the power system quickly. In this manner, generator units would fully comply with the technical requirements of the National Grid Code.

The Generation Management System (GSM) is also a mission-critical tool for the power system's short-term forecast management of intermittent renewables and distributed generation resources.

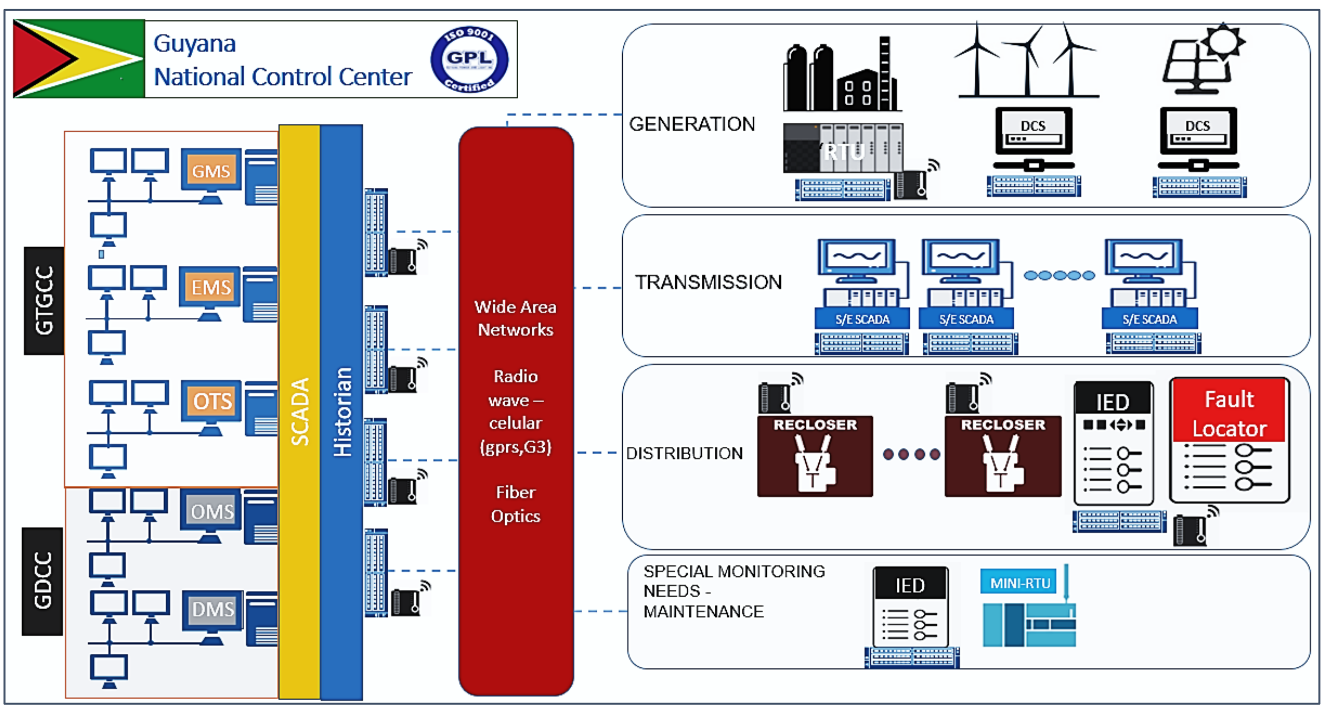

Figure 3: GNCC Real-Time Monitoring and Control Overview

The energy, outage, and distribution management systems would facilitate remote monitoring and control of all transmission lines, distribution feeder backbones, spurs, and sub-spurs. The SCADA coupled with remotely monitored and controlled switching devices through the energy, outage, and distribution management systems would allow for intelligent and automatic fast switching and isolation of faulty network(s), network sections, and failed components. In this manner, faults in the transmission and distribution systems would not result in widespread outages, and by extension, improve the SAIFI, SAIDI, and CAIDI indices (network reliability indices).

Besides the SCADA and the different management systems, the critical components in forming the Smart Grid include AMI meters, Auto-Reclosers, Sectionalizes, Scada-mate switching systems, Fault Current Indicators (FCI) and Smart Inverters – allowing for Distributed Energy Resources. See Figure 4 below.

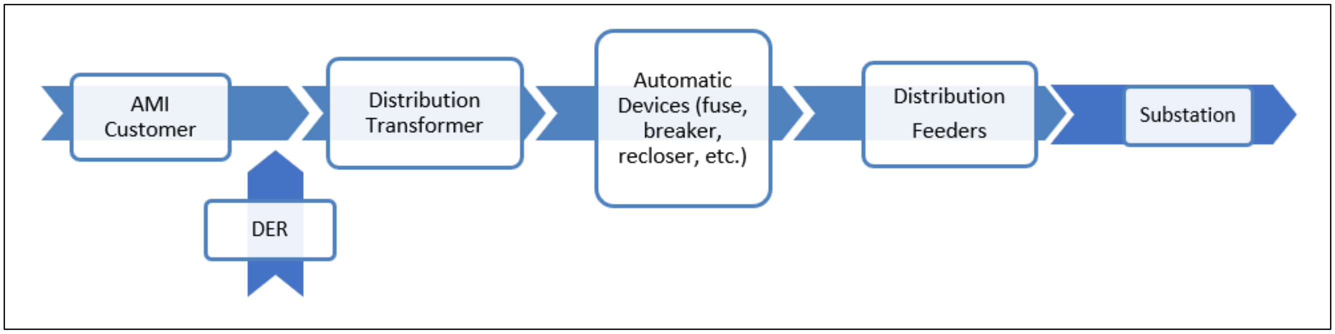

Figure 4: Proposed Smart Grid Architecture

To further improve the intelligence and self-healing capabilities of the Smart Grid, all Capacitor Banks, Voltage Regulators and Electric Vehicles (future application) would be integrated into SCADA.

The application of a Smart Grid essentially means that all control, communication and switching mechanisms within DBIS would be automated, controlled (locally and remotely) and supervised by a modern SCADA.

The Smart Grid would support the Government plans for economic and socio-economic developments and its Climate Change Commitments on a national level by optimising the power system in real-time through generator economic dispatch, transmission, and distribution load management. From a control perspective, provide the grid with fast response capability to mitigate grid operation parameter variations emanating from grid-connected intermittent renewable energy resources – allow for increasing renewable energy penetration and for Integrated Utility Service (IUS) to play an integral role in improving power system efficiency, reliability, and demand-side management.

Given the Smart Grid's scope of work, the expected duration of this project is almost 2 years. With plans for full implementation by 2028, this project is expected to commence in Q1 2026. Nevertheless, through this Development and Expansion Programme, the Company would configure and equip the transmission and distribution networks to be Smart Grid ready by 2026.

3.4 System Losses (to be updated)

The progressive and sustained reduction in System Losses remains a corporate priority. This is underpinned by the notable reduction from twenty-four-point seven percent (24.7%) in 2021 to a projected eighteen -point one percent (18.1%) in 2026. Further reductions in system losses will improve revenues and reduce operating costs. This will positively impact the Company's efforts and desire to lower tariffs for all consumers and improve the financial strength of GPL.

The major contributors to the Company's non-technical losses are:

- Unmetered supplies,
- Defective meters,
- Street lighting and
- Electricity theft.

The major contributors to the Company's technical losses are:

1. Aged and lengthy conductors (medium and low voltage),
2. Inefficient transformers and
3. Insufficient reactive power compensation.

The Company intends to reduce total losses to 18% by December 2026 from investments in feeder upgrades, transformer right-sizing, meter replacements, Installation of Advanced meter infrastructure (AMI) for all smart meters, installation of energy efficient streetlamps, reactive power compensation at both transmission and primary distribution levels, and service installation upgrades. Additional low voltage rehabilitative efforts will require a significant capital investment that continues to present a challenge to the Company's self-financing efforts. The Company will prudently pursue concessional funding sources to intensify its loss reduction efforts and progressively lower production costs and tariffs.

3.5 Tariffs

The reduction of tariffs remains a priority to the Company and is consistent with the corporate vision. Whilst the Company's operating license provides a tariff mechanism to adjust rates to ensure profitability and self-sustainability, GPL will continue to adopt prudent operating practices in its efforts to sustain lowered tariffs to all customers.

During 2015 and 2016, when world market fuel prices declined considerably, the Company applied a fuel rebate of five percent (5%) and ten percent (10%) respectively. In addition, tariffs were reduced by five percent (5%) in year 2016. The aggregated effect was a twenty percent (20%) reduction in tariffs over year 2014. During the year 2021, the fifteen (15%) fuel rebates were removed and concurrently the headline tariffs were reduced by the same amount thus concretising the reduction in rates.

Despite increases in world market fuel prices by approximately seventy seven percent (77%) in ensuing years (2017 – 2021), the Company has not applied any fuel surcharge or tariff increases as provided for under its license.

Whilst lowered and sustained tariffs are among the Company's primary objectives, GPL remains challenged to fund network and generation improvement projects without debt financing and grants from multi-lateral concessional lending agencies.

The Financial projections are instructive as to the measures that could be taken to facilitate a reduction in Tariffs. The key assumptions used in the projections are detailed in Table 13.

Table 3: Financial Projections – Facilitating Tariff Reduction

		Year 2021	Year 2026	Change
NET TARIFFS	US cents/kWh	**22**	**18**	18%
SALES DEMAND	GWh	729	2,656	264%
LOSSES	%	24.7%	18.1%	6.6%
FUEL PRICES				
Natural Gas Price delivered to the engines	US$/MMBTU	NA	5	
HFO CIF Price	US$/barrel	80	70	
LFO CIF Price	US$/barrel	96	84	
LOAN STOCK				
GPL Loans Debt burden	G$' billion	53	154	191%
Interest Payment 4%	G$' billion	1.10	6.16	460%
Principal Payments (15 years amortization)	G$' billion	3.53	10.27	191%
Debt Service Total	G$' billion	**4.63**	**16.43**	**255%**

These factors have a major influence on GPL's ability to lower Tariffs from the current level of approximately US 22 cents per kWh. A review of the projected financial performance for the period to Year 2026 highlights the following:

i) Growth in Sales Demand

The significant growth in demand (increase of approximately 264%) over the five (5) year period is projected to have a favourable impact on the generation of profits and operating cash flows. The projections have included a tariff reduction to US 20 cents per kWh at the beginning of year 2025, and a further reduction to US 18 cents per kWh at the start of year 2026.

ii) Losses (Technical and Commercial losses)

Losses are projected to decline from 24.7% to 18.1%. Further reductions in losses will have a positive impact on the financial performance and would improve the ability of the company to lower tariffs even further. As an example, an additional reduction in losses of 5% would allow for a reduction in Tariffs by about US 1 cent per kWh at the projected costs of generation.

iii) Cost of Generation

By year 2025, generation using natural gas supplied by way of the planned gas pipeline is projected to provide more than 80% of the required generation. The price at which gas is delivered to the engines is therefore extremely important and will have the most impact on the ability of the company to lower tariffs by 2025 as shown below:

Price of Gas:

- US$ 6 per MMBtu - Tariff reduced by 10% to US 20 cents/kWh
- US$ 5 per MMBtu - Tariff reduced by 14% to US 19 cents/kWh
- US$ 4 per MMBtu - Tariff reduced by 18% to US 18 cents/kWh
- US$ 3 per MMBtu - Tariff reduced by 22% to US 16 cents/kWh

iv) GPL's Debt Burden

The projections indicate that by the end of 2026, GPL's Loans to the Government of Guyana would increase from G$53 billion to more than G$154 billion. This will require approximately G$16 billion in annual debt service obligations.

GPL has negotiated with the Ministry of Finance, the extension of the moratorium on servicing the majority of the current outstanding debt until the year 2026. Discussions are ongoing to extend this moratorium to all of the remaining debt.

Converting this debt to equity, would allow for a further reduction of about US 2 cents after year 2026.

3.6 Planning Criteria, Inputs and Assumptions

One of the essential cornerstones for economic and socio-economic developments is access to and the supply of reliable electricity service. GPL plans to expand its power systems to satisfy the growing electricity demand and ensure sufficient generation contingency capacity to satisfy the demand and provide ancillary services to the grid.

The Company seeks to expand and develop in alignment with the vision of National Energy Priorities, Low Carbon Development Strategy (LCDS), and other national energy-related priorities and strategies to improve the quality and reliability of service to customers. Also, to provide support to sustain and promote national developments.

The Company has a menu of programmes geared towards improvements in sustainable efficiencies. (see section 6 on page 132 for further details).

GPL has identified two significant planning constraints to power system development and expansion: reliability and availability of capital investments.

Although capacity reserve margin provides a practical indication of the health status of the power generation system, probability-based power generation reliability metrics such as Loss of Load Probability (LOLP) or Loss of Load Expectation (LOLE) provide more accurate details on the ability of the power generation capacity to satisfy the current and future peak demands.

The LOLP is essentially the probability of the total available generation capacity being unable to satisfy the total peak demand. Within a year (365 days), the LOLE indicates the number of days the total available generation capacity is expected not to satisfy the peak demand. As a result of a high probability, there would be a high Expected Energy Not Served (EENS). Additionally, the Unserved Served Energy (USE) indicates demand that could not be met due to a shortage in generation and/or transmission capacity due to transmission congestion.

The targeted generation reliability indices vary globally and depend on the country's economic status quo and economic projections. As such, in USA, Australia and Jamaica, the LOLE is 0.1 day/year, Republic of Ireland and New Zealand, 8 hours/year (0.33 days/year or LOLP = 0.09%), the Netherlands' 4 hours/year (0.167 days/year or LOLP = 0.0457%), Barbados 0.8 days/year (LOLP = 0.219%).

The transmission system is also subject to reliability criteria. These are detailed in section 2.6 of the Planning Code of the National Grid Code.

3.6.1 Expansion Planning Criteria

Given the above and the aim of GPL becoming a World-Class Utility, the Company has defined the following planning criteria for generation and T&D expansions:

1. LOLP equal to or less than 0.27% per annum (LOLE equal to or less than 1 day/year);
2. Compliance with section 2.6 of the Planning Code for Transmission Reliability Criteria;
3. Compliance with section 2.7 of the Planning Code for Voltage Regulation Standards;
4. Compliance with section 2.8 of the Planning Code for Voltage Swing Criteria;
5. Compliance with section 2.9 of the Planning Code for Voltage Stability Criteria;
6. Compliance with section 2.10 of the Planning Code for Damping;
7. Compliance with section 2.11 of the Planning Code for Frequency Deviations;
8. Configure primary distribution feeders to achieve a thermal loading and total backbone length by at least 50%, respectively; and
9. Provide backup circuits to mitigate contingencies at the primary distribution level, where applicable and not constrained by geographical layout.

3.6.2 Operation Planning Criteria

3.6.2.1 Generator Dispatch

The DBIS has 47 generator units, of which 26 are HFO fired units and are critical for stable grid operation. The remaining 21 generator units are LFO fired units.

Each group of similar generator units has a specific variable operation and maintenance cost, heat rate and fuel cost. As a result, the HFO fired units are the first to dispatch based on an economic merit order of production cost.

The LFO units carrying higher production costs are dispatched at the tail-end of the economic merit order dispatch profile. In most cases, these units are dispatched to correct bus voltages. However, with the recent implementation of fixed reactive compensation devices at transmission and distribution levels, System Control reported the need to disconnect the majority of the LFO fired generator units, especially in the West and East Berbice Areas.

In the Essequibo Isolated Power Systems, the GPL owned generators are first dispatched, followed by rental units.

3.6.2.2 Spinning Reserve

Concerning grid operation, with the DBIS and isolated systems, there are two spinning reserve requirements: (1) spinning up reserve and (2) spinning down reserve.

Spinning up reserve is an extra generation capacity available by **increasing** the power output of grid-connected generators. This available MW of spinning reserve is used to respond to short-term variations in demand, generator unit forced outages or variations in the output of intermittent renewable energy systems. For Guyana, GPL adopted the rule of thumb by NYISO (NYISO, 2020) and PJM (NREL, 2011), which states that spinning reserve shall be 150% of the single largest contingency. In the case of the DBIS, the single largest contingency is presently equivalent to an N-G-1. With the 46.5 MW plant at Garden of Eden commissioned, the required spinning reserve for secondary response is 13.95 MW – ancillary service.

Spinning down reserve is an extra generation capacity available by **decreasing** the power output of grid-connected generators. This available MW of spinning reserve is used to respond to short-term variations in demand, generator unit forced outages or variations in the output of intermittent renewable energy systems.

The spinning down reserve is considered to be half of the spinning up reserve – 6.8 MW.

With grid-connected Solar PV and Wind energy systems, the power systems must be supported with additional spinning reserve capacity to mitigate the effects of output volatility and variability from these intermittent energy systems.

Experience gathered from WSP consultancy indicated an additional reserve capacity equivalent to 30% of installed Solar PV and/or Wind capacities. In the case of both Solar PV and Wind connected to the grid, 30% of installed Wind capacity during the night and the day, 30% of Solar PV and Wind capacities. The additional 30% of installed intermittent renewable energy capacities apply to both spinning up and spinning down reserves.

In the DBIS, the three power plants capable of providing spinning reserve are Kingston II - DP3, Vreed-en Hoop - DP4 and Garden of Eden - DP5. From experience with WSP consultancy, 27% of DP3 (9.86 MW) and DP4 (7.1 MW) installed capacity can be dedicated to providing spinning reserve - a total of 16.96 MW.

In consideration of the largest Solar PV capacity, the DBIS would have a total of 10MWp and Linden, 15 MWp. Until Linden is connected to the DBIS, the additional required spinning reserve for the Solar PV system would be 3 MW by 2023. With Linden connected to the DBIS, the total additional required spinning reserve would be 7.5 MW.

In view of the above, until 2023, the guarantee available spinning reserve would be enough to secure the grid for an N-G-1 (a total of 16.95 would be required while the guarantee available would be 16.96 MW). With Linden connected, there will be a shortage of 4.49 MW. However, an adjustment to the dispatch control mode of DP5 would address this issue.

As a result of the Essequibo Isolated Systems operating with only a few and small diesel generator units, the spinning reserve is provided by the generator unit's technical minimum to maximum capacity – full operating range.

As power generation expansion continues, especially using larger generator units, the required spinning reserve would increase. Additionally, the spinning reserve requirement from conventional generators would increase as the penetration level of intermittent renewable energy in the grid increases.

With Battery Energy Storage Systems (BESS), there can be a lesser dependency on conventional generators to provide such an ancillary service.

3.6.2.3 Transmission and Distribution

Each transmission line has its own derated capacity rating based on conductor age and frequency of maintenance. These derating influencing factors are modelling via the properties of conductor emissivity and absorptivity. As a result, each single circuit transmission line is loaded up to 75% of derated capacity.

For double circuit transmission lines, each line is loaded to 37.5%, such that, in the event of N-1 contingency, the energised line would be loaded at 75% - Rating A.

In the event a transmission line loading exceeds its Rating A on a steady-state basis, it is deemed as congested.

3.7 Recent Achievements

3.7.1 Generation

In 2018, GPL commenced essential power generation expansion projects at Canefield, Anna Regina and Bartica, and in 2020, the 46.5 MW multifuel power generation capacity at Garden of Eden and total installation of 9.6 MW of emergency generation capacity distributed across Sophia, Onverwagt and Canefield.

3.7.1.1 Garden of Eden

GPL commenced the construction of the 46.5 MW multifuel power plant at Garden of Eden. Given the 2021 forecasted peak demand, this power plant is expected to boost the capacity reserve margin to 50.27% (based on the DBIS's peak demand forecast of 138.82 MW and total available generation capacity of 208.6 MW in 2021).

3.7.1.2 Wakenaam

The Company procured 2x410 kW diesel-fired generators in 2020 to augment the planned installation of a 0.75 MWp solar PV system with 1,151 kWh BESS. The Solar PV system with energy storage is funded by a United Arab Emirates (UAE) grant. GPL intends to realize a hybrid energy system on the island.

3.7.1.3 Canefield

At Canefield, East Berbice Corentyne, GPL commissioned a 5.5 MW HFO fired power plant in March 2019. This power plant boosted the capacity reserve margin to 40% in 2018 and supported the Company's objective of reliably satisfying the growing demand in the DBIS.

In 2020, power generation capacity at Canefield was increased by 4.8 MW – 3 Mobile 1.6 MW Mobile CAT units.

3.7.1.4 Sophia

In 2020, 4.8 MW (3 x1.4MW Mobile CAT units) of LFO fired power generation capacity was added to the DBIS at Sophia.

3.7.1.5 Anna Regina

In April 2019, GPL commissioned a 5.4 MW HFO fired power plant at Anna Regina. This power plant replaced the aged, unreliable and derated 4 MW HFO fired power plant. This new power plant has resulted in significant improvement in generation reliability relative to the demand. The power plant was designed to accommodate additional power generation units to assist in narrowing the supply-demand gap based on the projected demand growth on the Essequibo Coast.

3.7.1.6 Bartica

A 3.3 MW LFO fired plant was commissioned in the first quarter of 2020. With the assistance from Cummins, GPL conducted onsite workshop training sessions, which included plant ancillaries to mitigate plant contingencies - ensuring the new power plant operates at a high percentage availability and reliability indices.

The 3.3 MW LFO fired plant replaced aged, unreliable and derated LFO fired units - containerised mobile CAT units. This new 3.3 MW plant resulted in significant improvement in power generation reliability and availability and providing firm reserve capacity for short to medium term load growth.

3.7.2 Transmission and Distribution (T&D)

In 2021 GPL successfully achieved a list of planned works to improve T&D reliability and resiliency. At the distribution level:

1. Installed 103 auto-reclosers and commissioned 70 to date;
2. Improved distribution feeder protection and coordination;
3. Installed 21 Automatic Power Factor Correction (APFC) capacitor banks, where 4 is from the JICA Grant;
4. Updated distribution feeder automatic load shedding profile;
5. Installed 110 km of additional conductors to facilitate the extension of electricity service;

6. Upgraded a total of 25 km of conductors on the primary distribution network;
7. Replaced 5 km of LV lines to customers;
8. Installed 31 additional transformers on the primary distribution network (13.8 kV), and
9. JICA Grant: This grant covered expenses for line conductors only. GPL financed the balance of line hardware materials, labour, and transportation costs for the following works:
    9.1 Good Hope F4 - System Improvement: Good Hope to Enmore E.C.D Express Feeder - 100% completed;
    9.2 Sophia F2 - System Improvement: Sophia to Success E.C.D Express Feeder - 100% completed;
    9.3 Edinburgh F2 - System Improvement: Edinburgh to Tuschen E.B.E Express Feeder - 100% completed;
    9.4 Replaced Single Wire Earth Return Transformers on the West Bank and Coast of Demerara - 100% completed;
    9.5 Onverwagt F2 - System Improvement: Onverwagt to No.7 W.C.B Express Feeder - 97% completed (to be 100% completed by November 2021); and
    9.6 Onverwagt F2 - System Improvement: No. 7 to Ithaca W.C.B Express Feeder - 9% completed.

At the transmission level, with grant from JICA, successfully installed and commissioned 2 x 5 MVAr reactive compensation installed at Canefield Substation.

The commissioning of the reactive compensation at Canefield resulted in GPL updating its standard operating procedure for generator dispatch and the overall grid performance management procedure.

For 2021, the T&D maintenance programme was developed to address known defects (from field inspections). Table 2 shows further and specific details of T&D achievements across the networks of GPL's coverage along the coastal plain of Guyana.

Table 4 T&D Achievements – Year to date 2021

T & D Achievements - Year to Date 2021					
TARGET INDICATORS			**TOTAL OVERALL (2021)**		
			AMOUNT		
ITEMS			**Plan**	**Ach**	**% Ach**
Pole replacement	**1**	PRIM.	1463.0	1732.0	118
		SEC.	2120.0	1660.0	78
Pole plumbing	**2**	PRIM.	739.0	1036.0	140
		SEC.	701.0	426.0	61
Pole treatment	**3**	PRIM.	4839.0	1676.0	35

T & D Achievements - Year to Date 2021					
TARGET INDICATORS			TOTAL OVERALL (2021)		
			AMOUNT		
		SEC.	6463.0	1685.0	26
Old pole removal	**4**	PRIM.	1129.0	1515.0	134
		SEC.	1372.0	889.0	65
Pole stubbing	**5**	PRIM.	333.0	141.0	42
		SEC.	306.0	85.0	28
Anchor block replacement.	**6**	PRIM.	307.0	156.0	51
		SEC.	328.0	133.0	41
Guy replacement	**7**	PRIM.	298.0	458.0	154
		SEC.	378.0	243.0	64
Replacement defective cross arms	**8**	PRIM.	1378.0	2722.0	198
Insulator replacement	**9**	PRIM.	1704.0	3657.0	215
		SEC.	1735.0	1637.0	94
Line/hardware transfer	**10**	PRIM.	1235.0	2167.0	175
		SEC.	1614.0	1589.0	98
Line extension (km)	**11**	PRIM.	111.9	169.7	152
		SEC.	152.4	141.8	93
Line upgrade (km)	**12**	PRIM.	220.9	67.9	31
		SEC.	153.6	22.3	15
Line retention (km)	**13**	PRIM.	609.5	222.4	36
		SEC.	468.8	120.3	26
Service line replacement (meter)	**14**		18699.0	8567.9	46
Installation/replacement (GAB)	**15**	PRIM.	320.0	867.0	271
Installation/replacement (SPD)	**16**	PRIM.	200.0	197.0	99
Installation/replacement (RCO)	**17**	PRIM.	610.0	1240.0	203
Installation/replacement (PMCO)	**18**		450.0	57.0	13
Transformer maintenance	**19**	SEC.	1022.0	1044.0	102
Installation of additional transformers	**20**	SEC.	282.0	371.0	132
Maintenance of capacitor banks	**21**		97.0	76.0	78
Jumper servicing/replacement	**22**	PRIM.	2296.0	4210.0	183
		SEC.	2798.0	4120.0	147
Service connection @ consumer	**23**		10238.0	11018.0	108
Installation of additional earths	**24**		440.0	1034.0	235
Route clearing (km)	**25**	PRIM.	179.5	473.7	264
		SEC.	178.2	129.9	73
Line inspection (km)	**26**	PRIM.	1098.3	23668.0	2155
		SEC.	1449.7	907.7	63
C.e.o.f cards	**27**	SEC.	411.0	521.0	127

T & D Achievements - Year to Date 2021			
TARGET INDICATORS	**TOTAL OVERALL (2021)**		
	AMOUNT		
Total manhours			

3.8 Demand Analysis and Forecast

A historical analysis of GPL power systems (DBIS & Essequibo Isolated Systems) shows that for the period 2014 - 2021, total energy demand, by the proxy of gross generation, increased by an annual average of 8.23%, moving from 717 GWh to 968.75 GWh for the same period.

In the same period, the associated non-coincidental Peak Demand (Peak Load) from all systems increased by an annual average of 7.87%, moving from 115.7 MW to 147.42 MW. Compared with the total energy consumed, the slower growth in peak demand explains the improvement in the power system load factor from 70.78% in 2014 to 76.6%.

The load factor (discussed in a later subsection) is used to determine the peak demand forecast.

Note that the load factor measures the annual gross generation divided by the product of peak power and 8760 hours. In other words, higher load factors indicate a relative lowering of the difference between power demand at the highest peak and its lowest trough of the year in question.

The current 30-year base-case forecast is driven by robust economic growth projections arising from Guyana's Oil and Gas sector while incorporating the most realistic and likely impacts of Covid-19 that commenced in Q2 of 2020. However, GPL continues to monitor the impacts of Covid-19 and would make the appropriate updates should it become necessary to maintain the statistical significance of the energy and peak demand forecasts.

The base-case forecast for all GPL power systems shows the combined gross demand for electrical growing by the following annual averages for the respective 5-year periods: by 27% from 2022 to 2026 (1,256.94 GWh to 3,299.72 GWh); by 16% from 2027 to 2031 (up to 6,970.91 GWh), and 8% from 2032 to 2036 (up to 10,378.08 GWh). For the 14 years from 2037 to 2050, the gross energy demand is forecasted to grow by an annual average of 6%, reaching 21,970.9 GWh.

Base case forecasted growth of peak demand for the 29 indicative years of all GPL power systems are as follows: by 28% from 2022 to 2026 (196.6 MW to 501.64 MW); by 16% from 2027 to 2031 (up to 1,049 MW); and by 8% from 2032 to 2036 (up to 1,553.52 MW). For the 14 years from 2037 to 2050, peak demand is forecasted to grow by an annual average of 5%, reaching 3,277.41 MW.

The current forecast (as of September 27, 2021) was built on, and to some extent, incorporated elements of work previously done in preparing the energy demand projections; (1) the Generation Expansion Study 2018[1] referred to as the "Brugman Study", and (2) The Demand Forecast Capacity Building Consultancy by ETS consultants (2019-2020). Reference is also made to forecasts prepared under the Gas to Power Feasibility Assessment in Guyana by K&M Advisors in 2019, mainly for comparison. A summary of the forecasts from these projects is provided in Appendix 1, page 154.

3.8.1 Disaggregated Forecast

The disaggregated forecast in this document is broken down into:

1. Gross Generation;
2. Net Generation;
3. Electricity Sales (per tariff and self-generation):
    a. Residential;
    b. Commercial;
    c. Industrial;
4. Unserved Electricity;
5. Energy Efficiency Measure

See Table 5, Table 6, Table 7, Table 8and Table 9 for details of the disaggregated electricity and peak demand forecasts of the Demerara Berbice Interconnected System.

Regarding self-generated customers, in Brugman's Study, it was assumed for these customers to become grid-connected by 2025. In this report, GPL endorses this assumption against the backdrop of recent amendments to its license to purchase power from self-generated customers.

Table 5: DBIS Disaggregated Electricity and Peak Demand Forecast 2021-2026

	select from list	*GWh values unless stated otherwise*	2020	2021	2022	2023	2024	2025	2026
Area	All GPL								
Scenario	BASE								
		Gross Gen (No New EE Measures)	**900.42**	**1,015.41**	**1,296.92**	**1,648.21**	**2,119.92**	**2,864.66**	**3,466.58**
		Energy Not served Factor (%)	*1.4%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
		Estimated Energy Not served	12.30	0.01	0.00	0.00	0.01	0.07	0.08
		Energy Efficiency factor (% of Total Demand)	*2.4%*	*2.6%*	*3.1%*	*3.5%*	*4.1%*	*4.7%*	*4.9%*
		Potential Impact of EE measures	(21.85)	(26.52)	(39.98)	(57.40)	(87.62)	(133.50)	(168.94)
		Potential Demand Post-EE	**878.57**	**988.90**	**1,256.94**	**1,590.80**	**2,032.30**	**2,731.16**	**3,297.64**
		EVs consumption (DBIS only)	-	-	-	-	0.80	1.60	2.08
		New Gross Gen. with EE &Evs	**878.57**	**988.90**	**1,256.94**	**1,590.80**	**2,033.10**	**2,732.76**	**3,299.72**
		Auxiliaries & Self-Consumption	(22.20)	(20.14)	(26.56)	(33.95)	(40.40)	(50.50)	(56.48)
		Net Energy Exported to Grid	**856.38**	**968.75**	**1,230.38**	**1,556.85**	**1,992.70**	**2,682.26**	**3,243.25**
		Technical loss factor (%)	12.0%	11.5%	11.0%	10.5%	10.3%	10.2%	10.1%
		Non-Technical loss factor (%)	14.9%	14.1%	13.6%	13.0%	12.4%	11.7%	10.9%
		Technical & Non-technical losses	(230.11)	(248.00)	(302.67)	(365.86)	(452.34)	(587.41)	(681.08)
		Total Sales	**626.27**	**720.75**	**927.71**	**1,190.99**	**1,540.36**	**2,094.84**	**2,562.16**
		of which Commercial	*211.05*	*192.44*	*250.48*	*329.90*	*432.84*	*605.41*	*757.38*
		Residential	*139.03*	*177.31*	*228.22*	*290.60*	*368.15*	*494.38*	*599.03*
		Industrial	*276.18*	*351.01*	*449.01*	*570.49*	*739.37*	*995.05*	*1,205.75*
		Demand category factors (%)							
		Commercial	33.7%	26.7%	27.0%	27.7%	28.1%	28.9%	29.6%
		Residential	22.2%	24.6%	24.6%	24.4%	23.9%	23.6%	23.4%
		Industrial	44.1%	48.7%	48.4%	47.9%	48.0%	47.5%	47.1%
		Load Factor (%)	**76.633%**	**76.57%**	**73%**	**73%**	**76%**	**73%**	**75%**
		Peak MW (with EV's & En. Efficiency)	**130.87**	**147.42**	**196.60**	**249.51**	**304.26**	**428.10**	**501.64**
		Peak MW (without EV's & En. Efficiency)	**134.13**	**151.38**	**202.85**	**258.51**	**317.25**	**448.77**	**527.00**

Table 6:Disaggregated Electricity and Peak Demand Forecast 2027-2031

	select from list	*GWh values unless stated otherwise*	2027	2028	2029	2030	2031
Area	All GPL						
Scenario	BASE						
		Gross Gen (No New EE Measures)	**4,265.51**	**5,283.23**	**5,973.47**	**6,734.55**	**7,407.16**
		Energy Not served Factor (%)	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
		Estimated Energy Not served	0.09	0.10	0.10	0.11	0.11
		Energy Efficiency factor (% of Total Demand)	*5.1%*	*5.3%*	*5.6%*	*5.8%*	*6.0%*
		Potential Impact of EE measures	(217.75)	(282.23)	(333.19)	(392.54)	(443.00)
		Potential Demand Post-EE	**4,047.76**	**5,001.00**	**5,640.28**	**6,342.01**	**6,964.17**
		EVs consumption (DBIS only)	2.71	3.54	4.61	6.00	6.75
		New Gross Gen. with EE &Evs	**4,050.47**	**5,004.54**	**5,644.89**	**6,348.01**	**6,970.91**
		Auxiliaries & Self-Consumption	(64.32)	(73.65)	(76.82)	(79.96)	(83.23)
		Net Energy Exported to Grid	**3,986.15**	**4,930.89**	**5,568.06**	**6,268.05**	**6,887.68**
		Technical loss factor (%)	9.6%	9.6%	9.6%	9.6%	9.6%
		Non-Technical loss factor (%)	10.1%	9.3%	8.5%	7.7%	6.9%
		Technical & Non-technical losses	(785.27)	(931.94)	(1,007.82)	(1,084.37)	(1,136.47)
		Total Sales	**3,200.88**	**3,998.95**	**4,560.24**	**5,183.68**	**5,751.21**
		of which Commercial	*967.31*	*1,234.88*	*1,438.30*	*1,669.15*	*1,895.60*
		Residential	*741.32*	*917.36*	*1,036.09*	*1,166.33*	*1,280.22*
		Industrial	*1,492.25*	*1,846.71*	*2,085.86*	*2,348.21*	*2,575.39*
		Demand category factors (%)					
		Commercial	30.2%	30.9%	31.5%	32.2%	33.0%
		Residential	23.2%	22.9%	22.7%	22.5%	22.3%
		Industrial	46.6%	46.2%	45.7%	45.3%	44.8%
		Load Factor (%)	**75%**	**75%**	**76%**	**76%**	**76%**
		Peak MW (with EV's & En. Efficiency)	**613.22**	**758.82**	**852.09**	**954.97**	**1,049.10**
		Peak MW (without EV's & En. Efficiency)	**645.78**	**801.08**	**901.69**	**1,013.12**	**1,114.75**

Table 7: Disaggregated Electricity and Peak Demand Forecast 2032-2036

	select from list	GWh values unless stated otherwise	2032	2033	2034	2035	2036
Area	All GPL						
Scenario	BASE						
		Gross Gen (No New EE Measures)	**8,100.07**	**8,825.88**	**9,567.98**	**10,326.38**	**11,101.07**
		Energy Not served Factor (%)	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
		Estimated Energy Not served	0.12	0.12	0.12	0.12	0.12
		Energy Efficiency factor (% of Total Demand)	*6.1%*	*6.2%*	*6.3%*	*6.5%*	*6.6%*
		Potential Impact of EE measures	(492.54)	(546.76)	(605.00)	(667.66)	(735.14)
		Potential Demand Post-EE	**7,607.53**	**8,279.12**	**8,962.97**	**9,658.71**	**10,365.93**
		EVs consumption (DBIS only)	7.59	8.54	9.60	10.80	12.15
		New Gross Gen. with EE &Evs	**7,615.12**	**8,287.65**	**8,972.57**	**9,669.51**	**10,378.08**
		Auxiliaries & Self-Consumption	(85.40)	(87.47)	(87.40)	(88.98)	(95.66)
		Net Energy Exported to Grid	**7,529.72**	**8,200.18**	**8,885.17**	**9,580.53**	**10,282.42**
		Technical loss factor (%)	9.6%	9.6%	9.6%	9.6%	9.6%
		Non-Technical loss factor (%)	6.1%	5.3%	4.5%	3.7%	2.9%
		Technical & Non-technical losses	(1,182.17)	(1,221.83)	(1,252.81)	(1,274.21)	(1,285.30)
		Total Sales	**6,347.55**	**6,978.36**	**7,632.36**	**8,306.32**	**8,997.12**
		of which Commercial	*2,140.39*	*2,406.14*	*2,689.64*	*2,990.28*	*3,238.96*
		Residential	*1,397.73*	*1,519.89*	*1,644.01*	*1,769.25*	*1,916.39*
		Industrial	*2,809.43*	*3,052.33*	*3,298.71*	*3,546.80*	*3,841.77*
		Demand category factors (%)					
		Commercial	33.7%	34.5%	35.2%	36.0%	36.0%
		Residential	22.0%	21.8%	21.5%	21.3%	21.3%
		Industrial	44.3%	43.7%	43.2%	42.7%	42.7%
		Load Factor (%)	**76%**	**76%**	**76%**	**76%**	**76%**
		Peak MW (with EV's & En. Efficiency)	**1,144.86**	**1,244.62**	**1,346.01**	**1,448.98**	**1,553.52**
		Peak MW (without EV's & En. Efficiency)	**1,217.77**	**1,325.45**	**1,435.33**	**1,547.41**	**1,661.75**

Table 8:Disaggregated Electricity and Peak Demand Forecast 2037-2041

		THIS SHEET HAS NOT BEEN UPDATED WIT					
	select from list	GWh values unless stated otherwise	2037	2038	2039	2040	2041
Area	All GPL						
Scenario	BASE						
		Gross Gen (No New EE Measures)	**11,892.06**	**12,699.35**	**13,522.93**	**14,362.81**	**15,218.99**
		Energy Not served Factor (%)	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
		Estimated Energy Not served	0.13	0.13	0.13	0.13	0.14
		Energy Efficiency factor (% of Total Demand)	*6.8%*	*7.0%*	*7.2%*	*7.4%*	*7.4%*
		Potential Impact of EE measures	(807.87)	(886.32)	(970.99)	(1,062.43)	(1,125.76)
		Potential Demand Post-EE	**11,084.19**	**11,813.03**	**12,551.94**	**13,300.38**	**14,093.22**
		EVs consumption (DBIS only)	13.66	15.37	17.28	19.44	21.87
		New Gross Gen. with EE &Evs	**11,097.85**	**11,828.40**	**12,569.22**	**13,319.82**	**14,115.09**
		Auxiliaries & Self-Consumption	(102.47)	(109.43)	(116.53)	(123.76)	(131.14)
		Net Energy Exported to Grid	**10,995.38**	**11,718.97**	**12,452.70**	**13,196.06**	**13,983.95**
		Technical loss factor (%)	9.6%	9.6%	9.6%	9.6%	9.6%
		Non-Technical loss factor (%)	2.1%	1.3%	0.5%	0.1%	0.0%
		Technical & Non-technical losses	(1,286.46)	(1,277.37)	(1,257.72)	(1,280.02)	(1,342.46)
		Total Sales	**9,708.92**	**10,441.60**	**11,194.98**	**11,916.04**	**12,641.49**
		of which Commercial	*3,495.21*	*3,758.98*	*4,030.19*	*4,289.77*	*4,550.94*
		Residential	*2,068.00*	*2,224.06*	*2,384.53*	*2,538.12*	*2,692.64*
		Industrial	*4,145.71*	*4,458.56*	*4,780.25*	*5,088.15*	*5,397.92*
		Demand category factors (%)					
		Commercial	36.0%	36.0%	36.0%	36.0%	36.0%
		Residential	21.3%	21.3%	21.3%	21.3%	21.3%
		Industrial	42.7%	42.7%	42.7%	42.7%	42.7%
		Load Factor (%)	**76%**	**76%**	**76%**	**77%**	**77%**
		Peak MW (with EV's & En. Efficiency)	**1,659.60**	**1,767.20**	**1,876.31**	**1,986.93**	**2,105.56**
		Peak MW (without EV's & En. Efficiency)	**1,778.37**	**1,897.33**	**2,018.68**	**2,142.51**	**2,270.23**

Table 9:Disaggregated Electricity and Peak Demand Forecast 2042 – 2050

	select from list	*GWh values unless stated otherwise*	2042	2043	2044	2045	2046	2047	2048	2049	2050
Area	All GPL										
Scenario	BASE										
		Gross Gen (No New EE Measures)	**16,091.46**	**16,980.23**	**17,885.29**	**18,806.66**	**19,744.31**	**20,698.27**	**21,668.52**	**22,655.07**	**23,657.91**
		Energy Not served Factor (%)	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
		Estimated Energy Not served	0.15	0.15	0.16	0.17	0.18	0.19	0.20	0.21	0.22
		Energy Efficiency factor (% of Total Demand)	*7.4%*	*7.4%*	*7.4%*	*7.4%*	*7.4%*	*7.4%*	*7.4%*	*7.4%*	*7.4%*
		Potential Impact of EE measures	(1,190.30)	(1,256.04)	(1,322.99)	(1,391.14)	(1,460.50)	(1,531.07)	(1,602.84)	(1,675.82)	(1,750.00)
		Potential Demand Post-EE	**14,901.16**	**15,724.19**	**16,562.30**	**17,415.51**	**18,283.81**	**19,167.20**	**20,065.68**	**20,979.25**	**21,907.91**
		EVs consumption (DBIS only)	24.59	27.66	31.11	34.99	39.36	44.27	49.79	56.00	62.99
		New Gross Gen. with EE &Evs	**14,925.75**	**15,751.85**	**16,593.41**	**17,450.50**	**18,323.17**	**19,211.47**	**20,115.47**	**21,035.25**	**21,970.90**
		Auxiliaries & Self-Consumption	(138.66)	(146.32)	(154.12)	(162.05)	(170.13)	(178.35)	(186.71)	(195.22)	(203.86)
		Net Energy Exported to Grid	**14,787.09**	**15,605.53**	**16,439.30**	**17,288.45**	**18,153.03**	**19,033.11**	**19,928.75**	**20,840.04**	**21,767.04**
		Technical loss factor (%)	9.6%	9.6%	9.6%	9.6%	9.6%	9.6%	9.6%	9.6%	9.6%
		Non-Technical loss factor (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
		Technical & Non-technical losses	(1,419.56)	(1,498.13)	(1,578.17)	(1,659.69)	(1,742.69)	(1,827.18)	(1,913.16)	(2,000.64)	(2,089.64)
		Total Sales	**13,367.53**	**14,107.40**	**14,861.13**	**15,628.76**	**16,410.34**	**17,205.93**	**18,015.59**	**18,839.39**	**19,677.41**
		of which Commercial	*4,812.31*	*5,078.66*	*5,350.01*	*5,626.35*	*5,907.72*	*6,194.14*	*6,485.61*	*6,782.18*	*7,083.87*
		Residential	*2,847.28*	*3,004.88*	*3,165.42*	*3,328.93*	*3,495.40*	*3,664.86*	*3,837.32*	*4,012.79*	*4,191.29*
		Industrial	*5,707.94*	*6,023.86*	*6,345.70*	*6,673.48*	*7,007.22*	*7,346.93*	*7,692.66*	*8,044.42*	*8,402.25*
		Demand category factors (%)									
		Commercial	36.0%	36.0%	36.0%	36.0%	36.0%	36.0%	36.0%	36.0%	36.0%
		Residential	21.3%	21.3%	21.3%	21.3%	21.3%	21.3%	21.3%	21.3%	21.3%
		Industrial	42.7%	42.7%	42.7%	42.7%	42.7%	42.7%	42.7%	42.7%	42.7%
		Load Factor (%)	**77%**	**77%**	**77%**	**77%**	**77%**	**77%**	**77%**	**77%**	**77%**
		Peak MW (with EV's & En. Efficiency)	**2,226.48**	**2,349.71**	**2,475.25**	**2,603.10**	**2,733.28**	**2,865.79**	**3,000.64**	**3,137.84**	**3,277.41**
		Peak MW (without EV's & En. Efficiency)	**2,400.37**	**2,532.95**	**2,667.96**	**2,805.40**	**2,945.27**	**3,087.57**	**3,232.31**	**3,379.47**	**3,529.07**

3.8.2 Electricity Demand – Essequibo Isolated Power Systems

The forecasts for Essequibo, which includes Anna Regina, Bartica, Wakenaam and Leguan, indicate that electricity and peak demand in these areas would continue to grow at a significant rate (Table 10 to Table 13). With these projections and the need to improve on generation reliability and quality of electricity service to customers, the Company plans to boost its firm generation capacity in these areas.

Table 10: Disaggregated Forecast for Essequibo: 2021-2026

	GWh values unless stated otherwise	2021	2022	2023	2024	2025	2026
Anna Regina	Gross Generation (GWh)	39.39	47.55	61.06	75.20	86.32	97.76
	Rate of Growth (%)						
	Expected Energy Not Served (%)	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
	Expected Energy Not Served (GWh)	0.04	0.05	0.06	0.08	0.09	0.10
	Anna Regina Electricity Demand (GWh)	39.43	47.60	61.12	75.28	86.41	97.86
	Peak Demand (MW)	6.90	8.59	11.08	13.15	15.69	17.30
	Rate of Growth (%)						
	Load Factor	0.65	0.63	0.63	0.65	0.63	0.65
Bartica	Gross Generation (GWh)	14.82	17.41	21.54	25.42	27.87	30.03
	Rate of Growth (%)						
	Expected Energy Not Served (%)	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
	Expected Energy Not Served (GWh)	0.01	0.02	0.02	0.03	0.03	0.03
	Anna Regina Electricity Demand (GWh)	14.83	17.43	21.56	25.45	27.90	30.06
	Peak Demand (MW)	2.33	2.81	3.49	3.99	4.51	4.75
	Rate of Growth (%)						
	Load Factor	0.73	0.71	0.71	0.73	0.71	0.72
Leguan	Gross Generation (GWh)	2.08	2.46	3.08	3.73	4.23	4.69
	Rate of Growth (%)						
	Expected Energy Not Served (%)	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
	Expected Energy Not Served (GWh)	0.00	0.00	0.00	0.00	0.00	0.00
	Anna Regina Electricity Demand (GWh)	2.09	2.46	3.08	3.74	4.23	4.69
	Peak Demand (MW)	0.43	0.52	0.66	0.77	0.90	0.98
	Rate of Growth (%)						
	Load Factor	0.55	0.54	0.54	0.55	0.54	0.55
Wakenaam	Gross Generation (GWh)	2.08	2.44	3.04	3.66	4.12	4.57
	Rate of Growth (%)						
	Expected Energy Not Served (%)	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
	Expected Energy Not Served (GWh)	0.00	0.00	0.00	0.00	0.00	0.00
	Anna Regina Electricity Demand (GWh)	2.08	2.45	3.05	3.66	4.13	4.57
	Peak Demand (MW)	0.37	0.45	0.56	0.65	0.76	0.82
	Rate of Growth (%)						
	Load Factor	0.64	0.62	0.62	0.64	0.62	0.64

Table 11: Disaggregated Forecast for Essequibo: 2027-2031

	GWh values unless stated otherwise	2027	2028	2029	2030	2031
Anna Regina	Gross Generation (GWh)	108.13	119.92	133.53	149.18	166.31
	Rate of Growth (%)					
	Expected Energy Not Served (%)	0.1%	0.1%	0.1%	0.1%	0.1%
	Expected Energy Not Served (GWh)	0.11	0.12	0.13	0.15	0.17
	Anna Regina Electricity Demand (GWh)	108.24	120.04	133.66	149.33	166.48
	Peak Demand (MW)	19.10	21.21	23.52	26.24	29.35
	Rate of Growth (%)					
	Load Factor	0.65	0.65	0.65	0.65	0.65
Bartica	Gross Generation (GWh)	31.58	33.13	34.68	36.23	37.74
	Rate of Growth (%)					
	Expected Energy Not Served (%)	0.1%	0.1%	0.1%	0.1%	0.1%
	Expected Energy Not Served (GWh)	0.03	0.03	0.03	0.04	0.04
	Anna Regina Electricity Demand (GWh)	31.61	33.16	34.72	36.27	37.78
	Peak Demand (MW)	4.99	5.23	5.45	5.69	5.99
	Rate of Growth (%)					
	Load Factor	0.72	0.72	0.73	0.73	0.72
Leguan	Gross Generation (GWh)	5.04	5.38	5.70	6.01	6.30
	Rate of Growth (%)					
	Expected Energy Not Served (%)	0.1%	0.1%	0.1%	0.1%	0.1%
	Expected Energy Not Served (GWh)	0.01	0.01	0.01	0.01	0.01
	Anna Regina Electricity Demand (GWh)	5.04	5.39	5.71	6.01	6.31
	Peak Demand (MW)	1.05	1.12	1.18	1.24	1.31
	Rate of Growth (%)					
	Load Factor	0.55	0.55	0.55	0.55	0.55
Wakenaam	Gross Generation (GWh)	4.93	5.30	5.68	6.07	6.47
	Rate of Growth (%)					
	Expected Energy Not Served (%)	0.1%	0.1%	0.1%	0.1%	0.1%
	Expected Energy Not Served (GWh)	0.00	0.01	0.01	0.01	0.01
	Anna Regina Electricity Demand (GWh)	4.93	5.30	5.69	6.08	6.48
	Peak Demand (MW)	0.88	0.95	1.02	1.08	1.16
	Rate of Growth (%)					
	Load Factor	0.64	0.64	0.64	0.64	0.63

Table 12: Disaggregated Forecast for Essequibo: 2032-2036

	GWh values unless stated otherwise	2032	2033	2034	2035	2036
Anna Regina	Gross Generation (GWh)	185.54	207.28	232.00	260.21	278.31
	Rate of Growth (%)					
	Expected Energy Not Served (%)	0.1%	0.1%	0.1%	0.1%	0.1%
	Expected Energy Not Served (GWh)	0.19	0.21	0.23	0.26	0.28
	Anna Regina Electricity Demand (GWh)	185.72	207.49	232.23	260.47	278.59
	Peak Demand (MW)	32.74	36.58	40.94	45.91	49.11
	Rate of Growth (%)					
	Load Factor	0.65	0.65	0.65	0.65	0.65
Bartica	Gross Generation (GWh)	39.13	40.45	41.72	42.94	45.38
	Rate of Growth (%)					
	Expected Energy Not Served (%)	0.1%	0.1%	0.1%	0.1%	0.1%
	Expected Energy Not Served (GWh)	0.04	0.04	0.04	0.04	0.05
	Anna Regina Electricity Demand (GWh)	39.17	40.49	41.76	42.98	45.43
	Peak Demand (MW)	6.21	6.42	6.62	6.81	7.20
	Rate of Growth (%)					
	Load Factor	0.72	0.72	0.72	0.72	0.72
Leguan	Gross Generation (GWh)	6.54	6.75	6.92	7.06	7.48
	Rate of Growth (%)					
	Expected Energy Not Served (%)	0.1%	0.1%	0.1%	0.1%	0.1%
	Expected Energy Not Served (GWh)	0.01	0.01	0.01	0.01	0.01
	Anna Regina Electricity Demand (GWh)	6.55	6.76	6.93	7.06	7.49
	Peak Demand (MW)	1.36	1.41	1.44	1.47	1.56
	Rate of Growth (%)					
	Load Factor	0.55	0.55	0.55	0.55	0.55
Wakenaam	Gross Generation (GWh)	6.84	7.21	7.56	7.89	8.38
	Rate of Growth (%)					
	Expected Energy Not Served (%)	0.1%	0.1%	0.1%	0.1%	0.1%
	Expected Energy Not Served (GWh)	0.01	0.01	0.01	0.01	0.01
	Anna Regina Electricity Demand (GWh)	6.85	7.21	7.56	7.90	8.39
	Peak Demand (MW)	1.23	1.30	1.36	1.42	1.51
	Rate of Growth (%)					
	Load Factor	0.63	0.63	0.63	0.63	0.63

Table 13: Disaggregated Forecast for Essequibo: 2037-2041

	GWh values unless stated otherwise	2037	2038	2039	2040	2041
Anna Regina	Gross Generation (GWh)	296.84	315.78	335.13	354.90	375.09
	Rate of Growth (%)					
	Expected Energy Not Served (%)	0.1%	0.1%	0.1%	0.1%	0.1%
	Expected Energy Not Served (GWh)	0.30	0.32	0.34	0.35	0.38
	Anna Regina Electricity Demand (GWh)	297.13	316.09	335.47	355.26	375.47
	Peak Demand (MW)	52.38	55.72	59.14	62.62	66.19
	Rate of Growth (%)					
	Load Factor	0.65	0.65	0.65	0.65	0.65
Bartica	Gross Generation (GWh)	47.89	50.45	53.07	55.75	58.49
	Rate of Growth (%)					
	Expected Energy Not Served (%)	0.1%	0.1%	0.1%	0.1%	0.1%
	Expected Energy Not Served (GWh)	0.05	0.05	0.05	0.06	0.06
	Anna Regina Electricity Demand (GWh)	47.93	50.50	53.12	55.81	58.55
	Peak Demand (MW)	7.60	8.01	8.42	8.85	9.28
	Rate of Growth (%)					
	Load Factor	0.72	0.72	0.72	0.72	0.72
Leguan	Gross Generation (GWh)	7.91	8.36	8.81	9.27	9.75
	Rate of Growth (%)					
	Expected Energy Not Served (%)	0.1%	0.1%	0.1%	0.1%	0.1%
	Expected Energy Not Served (GWh)	0.01	0.01	0.01	0.01	0.01
	Anna Regina Electricity Demand (GWh)	7.92	8.37	8.82	9.28	9.76
	Peak Demand (MW)	1.65	1.74	1.84	1.93	2.03
	Rate of Growth (%)					
	Load Factor	0.55	0.55	0.55	0.55	0.55
Wakenaam	Gross Generation (GWh)	8.89	9.40	9.93	10.46	11.01
	Rate of Growth (%)					
	Expected Energy Not Served (%)	0.1%	0.1%	0.1%	0.1%	0.1%
	Expected Energy Not Served (GWh)	0.01	0.01	0.01	0.01	0.01
	Anna Regina Electricity Demand (GWh)	8.90	9.41	9.94	10.47	11.02
	Peak Demand (MW)	1.60	1.69	1.79	1.88	1.98
	Rate of Growth (%)					
	Load Factor	0.63	0.63	0.63	0.63	0.63

3.9 Current Status of Power Generation Capacity

3.9.1 Demerara Berbice Interconnected System (DBIS)

The GOE II 46.5 MW power plant – DP5, is currently dispatching at full capacity to the DBIS and would be commissioned within Q4 of 2021. As a result, GPL's aggregated electric power system would have 15 power plants totalling 227.5 MW of available capacity. The aggregated available capacity includes the 11 power plants or generating sites in the DBIS and 4 in the Essequibo Islands and Bartica.

A breakdown by fuel type indicates that HFO generator units account for 83.8% and LFO 16.2% of the total available capacity in the DBIS. For the Isolated Systems, 29.4% capacity is HFO and 70.6% is LFO. See Table 14 for further details.

Table 14: Breakdown of available generation capacity by fuel type

Fuel Type	Demerara	Berbice	Total DBIS	Anna Regina	Wakenaam	Leguan	Bartica	Total Isolated	Total GPL
MWs of HFO	155.9	19.0	**174.9**	5.40	-	-	-	**5.4**	**180.3**
MWs of LFO	12.3	21.4	**33.7**	6.70	1.06	0.82	4.96	**13.5**	**47.2**
MWs of Biomass	-	-	**-**	-	-	-	-	**-**	**-**
Total Available Capacity (MW)	**168.2**	**40.4**	**208.6**	**12.10**	**1.06**	**0.82**	**4.96**	**18.9**	**227.5**
Fuel Type	**Demerara**	**Berbice**	**Total DBIS**	**Anna Regina**	**Wakenaam**	**Leguan**	**Bartica**	**Total Isolated**	**Total GPL**
% of HFO	92.7%	47.0%	**83.8%**	44.6%				**28.5%**	**79.2%**
% of LFO	7.3%	53.0%	**16.2%**	55.4%	100.0%	100.0%	100.0%	**71.5%**	**20.8%**
% of Biomass			**0.0%**					**0.0%**	**0.0%**

With scheduled maintenance and efficient operation, generator units generally have a maximum operational life of 25 years, although, in most instances, their economic life is taken as 20 years, after which these units are classified as Cold Reserve Capacity.

To date, a total of 59.9 MW of available generation capacity in the DBIS has surpassed their economic lifespan. The specifics of these generator units are shown in Table 15.

Even though these older engines have been and continue to be well maintained and deliver availability above 85%, their continued use as baseload units is accompanied by an elevated risk of major mechanical failure resulting from the failure of components that are not renewed for the life of the engine, e.g., counterweight bolts. In 2020, one engine was destroyed and suspected to be the result of failed counterweight bolts, precipitating a series of other major mechanical failures.

In addition, a total of 46.8 MW of relatively new HFO fired capacity at Kingston and Vreed-en-Hoop is considered Suspect Capacities. This is due to technical issues encountered by the alternators at the 26.1 MW power plant at Vreed-en-Hoop and three units at the Kingston II power plant totalling 20.7 MW. As a priority, while GPL continues to supervise the operation of these alternators closely, the Company is working ardently to address these technical matters incrementally.

Table 15: Aged generator units in the DBIS

Generator Units	Commissioned Dates	Age of Unit (Yrs.)	Installed Capacity (MW)	Available Capacity (MW)
GOE - Niigata	**Subtotal**		**11.00**	**7.50**
# 5 Niigata	1991	30	5.50	3.50
# 6 Niigata	1996	25	5.50	4.00
GOE - DP1	**Subtotal**		**22.00**	**22.00**
# 1 Wärtsilä	1996	25	5.50	5.50
# 2 Wärtsilä	1996	25	5.50	5.50
# 3 Wärtsilä	1996	25	5.50	5.50
# 4 Wärtsilä	1996	25	5.50	5.50
Kingston I - DP2	**Subtotal**		**22.00**	**22.00**
# 1 Wärtsilä	1997	24	5.50	5.50
#2 Wärtsilä	1997	24	5.50	5.50
# 3 Wärtsilä	1997	24	5.50	5.50
# 4 Wärtsilä	1997	24	5.50	5.50
Canefield	**Subtotal**		**5.50**	**3.80**
#3DA - Mirrlees	1996	25	5.50	3.80
Onverwagt	**Subtotal**		**5.00**	**4.60**
#5 GM	1981	40	2.50	2.30
#7 GM	1981	40	2.50	2.30
Grand Total			**65.50**	**59.90**

For the mobile LFO units in the Isolated Power Systems, GPL has realised over the years that it is considered cost-effective to replace highspeed generator units with factory refurbish units than performing a major overhaul.

Major overhauls are usually done each 24,000 hours, which approximates to 3 calendar years of operation, and the total cost is approximately 80% of the cost of a factor refurbished generator unit. After major overhauls, it has been a challenge to recuperate the performance of highspeed generator units to their original state. As such, the balance 20% cost in lieu can compensate for loss in performance and reliably justify the need to support improved efficiencies.

Although the aged units are included in the Unreliable Capacity, these generator units are considered dispatchable within the current planning period, and as such, their individual available capacity is included in the Total Available Capacity. However, LFO units that require major overhaul after 2024 and within the current planning period, would be transferred to Cold

Reserve Capacity available for emergency operations only. Table 16 shows the annual Total Available Capacity, Reliable Capacity, Unreliable / Suspect Capacity, and Cold Reserve Capacity in MWs.

Table 16: Summary of existing power generation profile: 2022-2026 (DBIS)

DBIS Power Systems	Year	2021	2022	2023	2024	2025	2026
Demerara	Total Available Capacity (MW)	168.2	163.4	163.4	163.4	163.4	160.4
	Reliable Capacity (MW)	63.6	63.6	63.6	63.6	63.6	62.1
	Unreliable Capacity (MW)	104.6	99.8	99.8	99.8	99.8	98.3
	Cold Reserve Capacity (MW)	-	-	-	-	-	-
	Accumulated Cold Reserve (MW)	-	-	-	-	-	-
Berbice	Total Available Capacity (MW)	40.4	42.0	42.0	40.7	28.4	28.4
	Reliable Capacity (MW)	9.7	9.7	9.7	9.7	9.7	9.7
	Unreliable Capacity (MW)	30.7	32.3	32.3	31.0	18.7	18.7
	Cold Reserve Capacity (MW)	-	-	-	1.3	10.7	-
	Accumulated Cold Reserve (MW)	-	-	-	1.3	12.0	12.0
DBIS Total	Total Available Capacity (MW)	208.6	205.4	205.4	204.1	191.8	188.8
	Reliable Capacity (MW)	73.3	73.3	73.3	73.3	73.3	71.8
	Unreliable Capacity (MW)	135.3	132.1	132.1	130.8	118.5	117.0
	Cold Reserve Capacity (MW)	-	-	-	1.3	10.7	-
	Accumulated Cold Reserve (MW)	-	-	-	1.3	12.0	12.0

Table 17 illustrates the impact of the GOE II – DP5 on LOLP and capacity reserve, where for 2021, there is no LOLP violation and significant amount of capacity reserve.

Table 17: Capacity reserve margin and LOLP profile for No Additional Firm Capacity

Year	Unit	2021	2022	2023	2024	2025	2026
Peak Demand (MW)	MW	138.82	185.8	236.4	288.8	407.4	478.0
Annual Peak Demand Growth Rate	%	9.9%	34%	27%	22%	41%	17%
Required Reserve Capacity Margin	MW	25.0	19.6	89.4	45.9	65.0	156.4
Stochastic Capacity Reserve Margin (%) for LOLP Target	%	18.0%	10.5%	37.8%	15.9%	16.0%	32.7%
No Additional Capacity							
Available Generation Capacity	MW	208.6	205.4	205.4	204.1	191.8	188.8
Capacity Reserve	MW	69.78	19.6	- 31.0	- 84.7	- 215.6	- 289.2
Capacity Reserve Margin	%	50.26	10.54	- 13.11	- 29.32	- 52.92	- 60.50
LOLP	%	0.18	0.66	36.60	94.11	99.71	99.76
LOLE	day	0.65	2.40	133.57	343.51	363.95	364.12

In view of the demand forecast (see section 1.4 on page 17 for further details) and the current fleet of generator units in the DBIS, capacity reserve margin, which excludes cold reserve capacity, would become negative, and there would be significant LOLP violation by 2023 (Table 17).

Considering an N-G-1 contingency, the DBIS presently experiences voltage and frequency excursions[8] that undoubtedly result in either a system shut-down or a major portion of customers on the DBIS to be without electricity due to feeder automatic load shedding. For this planning period and beyond, given Government's position and commitment on the projected economic and socio-economic developments this is an undesired situation.

3.9.2 Isolated Power Systems (Anna Regina, Bartica, Leguan and Wakenaam)

Similarly, the isolated power systems in the Essequibo presently have a combination of aged and high-speed inefficient and unreliable mobile generator units. GPL plans to perform minor and major overhauls, as specified by the manufacturer of the generator units within the current planning horizon where applicable and necessary. However, in cases where engine efficiency, availability and reliability are of a dire need, the cost difference of unit replacement would become significantly competitive to major overhaul.

Near to the end of the current planning horizon, GPL is considering interconnecting these Isolated Power Systems with the DBIS. On account of the aforementioned, the customers of the Isolated Power Systems would benefit from cheaper, cleaner, and reliable electricity generated from a mix of the new energy resources: natural gas, hydro, and solar energy. Additionally, these power systems would be delinked and become independent from fuel price volatility, fuel transportation risks and other risks that adversely influence plant availability and electricity generation reliability.

Anna Regina

At the Anna Regina Power plant, the recently installed total 5.4 MW HFO fired generator plant had to be supported by LFO fired mobile units because of the rapidly increasing electricity demand on the Essequibo Coast. Given the volatile cost of LFO coupled with the need to reduce the cost of generation, GPL plans to avoid using rental mobile LFO units and to ensure that the most efficient LFO units are available. As a result, GPL will be replacing two existing de-rated, inefficient, and unreliable LFO mobile units with newer and more efficient units from Sophia by the end of 2021.Consequently, by the end of 2021, the total available generation capacity would be 14.6 MW, where 5.4 MW is considered reliable and 4.4 MW, unreliable (from the perspective of being high-speed generator units).

Given that no generator units at this location would not surpass their economic lifespan, there will be no cold reserve capacity. See Table 18 for further details.

Bartica

In the case of Bartica, given GPL's position on mobile generator units (see section 3.9.1, page 69), the 1.6 MW LFO fired mobile unit is considered an unreliable capacity, and by 2023, it will be reassigned as cold reserve capacity.

Unlike the mobile LFO generator units, for the fixed LFO generator units their major overhaul cost is approximately 50% of unit replacement cost. As a result, GPL plans to maintain and

[8] For frequency, depending on the location and nature of the fault.

continue operating these units as part of Bartica's generator fleet for this planning period. See Table 18 for further details.

Leguan

The Company has been able to guarantee the availability, efficiency, and reliability of the 3x410 kW LFO fired generators, commissioned in 2014, through continuous preventative maintenance.

While in operation, No. 2 unit developed technical issues with its engine and alternator that are beyond repair. As a result, this unit has been decommissioned for the past two years.

While the other two generator units are approaching a major overhaul, GPL intends to replace these units in lieu of a major overhaul (see section 3.9.1 regarding major overhaul cost vs unit replacement for further details).

GPL plans to replace the defunct No. 2 unit before the end of 2021, and No.1 and No.3 by Q2 and Q3 of 2022, respectively. Consequently, there would be no cold reserve capacity for Leguan within this planning period. See Table 18 for further details.

Wakenaam

The Wakenaam power system is currently energised by 2x325 kW LFO fired generator units that were commissioned in 1997. With the US$2.3 million grant from the UAE, the Wakenaam power system would be transformed into a solar-diesel hybrid system with battery energy storage capability.

The UAE grant covers the engineering, procurement, and commissioning of a 750 kWp of Solar PV capacity and 1,151 kWh Battery Energy Storage System (BESS). With these upgrades GPL sought the opportunity to further improve generator operation reliability and efficiency by replacing the existing LFO generator units, and upgrade and modernise the power systems' management and dispatch infrastructure at the power plant.

Technical studies indicated the hybrid power system requires 2x410 kW LFO generators units. GPL has already commissioned the one of the required 410 kW generator unit. The second unit is expected to be on-site by the end of 2021.

One of the units that was commissioned in 1997 is currently experiencing technical constraints and as a result, is derate to 136 kW. Notwithstanding the aforementioned, GPL plans to address the technical issue and recuperate unit's original capacity by Q1 of 2022.

With the commissioning of the Solar PV-BESS project by Q3 of 2022, the 1997 commissioned generator units, while still operable, be reassigned as cold reserve capacity. See Table 18 for further details.

Table 18: Summary of power generation profile: 2021-2025 (Isolated Systems)

Isolated Power Systems	Year	2021	2022	2023	2024	2025	2026
Anna Regina	Total Available Capacity (MW)	12.1	14.6	14.6	14.6	14.6	14.6
	Reliable Capacity (MW)	5.4	5.4	5.4	5.4	5.4	5.4
	Unreliable Capacity (MW)	6.7	4.4	4.4	4.4	4.4	4.4
	Cold Reserve Capacity (MW)	-	-	-	-	-	-
	Accumulated Cold Reserve (MW)	-	-	-	-	-	-
Wakenaam	Total Available Capacity (MW)	1.06	1.06	1.06	1.06	1.06	1.06
	Reliable Capacity (MW)	0.41	0.41	0.41	0.41	0.41	0.41
	Unreliable Capacity (MW)	0.65	0.65	0.65	0.65	0.65	0.65
	Cold Reserve Capacity (MW)	-	-	-	-	-	-
	Accumulated Cold Reserve (MW)	-	-	-	-	-	-
Leguan	Total Available Capacity (MW)	0.82	0.82	0.82	0.82	0.82	0.8
	Reliable Capacity (MW)	-	-	-	-	-	-
	Unreliable Capacity (MW)	0.82	0.82	0.82	0.82	0.82	0.8
	Cold Reserve Capacity (MW)	-	-	-	-	-	-
	Accumulated Cold Reserve (MW)	-	-	-	-	-	-
Bartica	Total Available Capacity (MW)	5.0	4.96	4.96	4.96	4.96	4.96
	Reliable Capacity (MW)	3.4	3.36	3.36	3.36	3.36	3.36
	Unreliable Capacity (MW)	1.6	1.60	1.60	1.60	1.60	1.60
	Cold Reserve Capacity (MW)	-	-	-	-	-	-
	Accumulated Cold Reserve (MW)	-	-	-	-	-	-
Isolated System	Total Available Capacity (MW)	18.9	21.4	21.4	21.4	21.4	21.4
	Reliable Capacity (MW)	9.2	9.2	9.2	9.2	9.2	9.2
	Unreliable Capacity (MW)	9.8	7.5	7.5	7.5	7.5	7.5
	Cold Reserve Capacity (MW)	-	-	-	-	-	-
	Accumulated Cold Reserve (MW)						

3.10 Current Status of Transmission and Distribution Systems

The Transmission and Distribution section of GPL's electric power system comprise three main volage levels; 69 kV for bulk power transfer, 13.8 kV for primary power distribution and lower utilisation voltage (480 V,440 V,415 V, 240 V and 120 V) for customer specific applications.

GPL's present transmission and distribution network provides electricity supply coverage to approximately 96.7% (referencing total estimated number of beneficiaries by addressing unserved areas) of the total number of households on the Coastland, and comprises the following:

1. The transmission voltage level of 69 kV is only present in the DBIS, and there are 16 transmission lines having a total length of 276 km;
2. Total of 39 active primary distribution feeders in the DBIS having a total estimated length of approximately 809 km; and
3. For the isolated system, Table 19 provides a breakdown of the relevant details.

Table 19: Breakdown of distribution feeders in Isolated Systems

Location	Feeders	Primary (MV) Length in km	Secondary (L)V Length in km
Anna Regina	North	25.6	211
	South	32.5	
	West	17.6	
	CRM	0.27	
Total		**75.97**	**211**
Leguan	West	8.8	24
	East	8.8	
	North	11.2	
Total		**28.8**	**24**
Wakenaam	North	10.6	20
	South	10.59	
Total		**21.19**	**20**
Bartica	F1	3.2	23.5
	F2	6.4	
	F3	8	
Total		**17.6**	**23.5**

Within the total GPL power system, majority of the network related challenges are currently experienced in the DBIS. A summary of the critical issues currently experienced and which the Company is aggressively working to address within the shortest possible time frame are:

1. Reduced life span of pole structures due to poor poles and cross-arms material quality;
2. Impassable access to pole structures located in remote terrains; largely for the transmission lines and to some extent, section of primary distribution lines;
3. Frequent line trips due to vegetation encroachments on open conductors;
4. High voltage drops due to a combination of long feeder lengths, high electricity demands, and low power factor presented primarily by maximum demand customers;
5. Widespread outages due to fault clearing by protection relay scheme at substation level for feeders without Auto reclosers;

6. Large number of and duration of outages to facilitate line maintenance and emergency switching;
7. Poor operation visibility and absence of remote control and supervision for sections of primary distribution feeders result in a high dependency on customer fault reports.
8. Poor supervision of line maintenance works.
9. Lack of adequate and timely availability of T&D resources;
10. Absence of standards and specifications that are directly related to T&D line hardware materials and workmanship;
11. Lack of proper monitoring of condition and performance of T&D networks; and
12. Delayed implementation of upgrades and other corrective actions.

3.11 Scenario No. 1 Power Generation Reliability – DBIS

With consideration given **only** to the Total Available Capacity (Table 16) - **no** generation expansion project, this scenario essentially demonstrates the impact of the forecast demand on LOLP for the current planning period.

Table 20 shows that for 2022, the LOLP target would be violated by 0.39%, which can be considered negligible since the capacity reserve margin would be positive and estimated at 10.5 MW. However, from 2023, with negative capacity reserve margin, LOLP violation would become significant. The expected energy not served is considered significant, and in reality, translates to the expected amount of demand that would be shedded in order to balance supply-demand and maintain grid stability. The situation can be further exacerbated, should the Cold Reserve Capacity Units become unavailable.

Table 20: DBIS Scenario No.1 Reliability Results for 2021-2026[9]

Fiscal Year	Load (GWh)	Peak Load (MW)	Generation Capacity (MW)	Capacity Reserves (MW)	Capacity Reserve Margin (%)	EENS (MWh)	LOLE (day)	LOLP (%)
2021	937.9	138.8	208.6	69.8	50.3	55.7	0.7	0.2
2022	1,195.5	185.8	205.4	19.6	10.5	282.1	2.4	0.7
2023	1,516.7	236.4	205.4	-31.0	-13.1	59,307.9	133.6	36.6
2024	1,942.8	288.8	204.1	-84.7	-29.3	348,436.8	344.5	94.1
2025	2,617.6	407.4	191.8	-215.6	-52.9	1,125,186.7	364.0	99.7
2026	3,164.9	478.0	188.8	-289.2	-60.5	1,695,799.6	364.1	99.8

In consideration of the declining Total Available Capacity (Table 13), with no addition of firm power generation capacity for the remaining years of the current planning period, the number

[9] Details for 2021 were included for information purposes only.

of days the DBIS would not be able to satisfy demand reliably is expected to increase to durations that are considered undesirable for sustainable economic developments.

From an operation's perspective, Table 21 illustrates that with no additional generation capacity, there will be no contingency capacity from 2023. Despite reducing spinning reserve to narrow the supply-demand gap, the total available capacity would be insufficient to operate the DBIS stably.

Table 21: Scenario No.1- Available Capacity Forecast per Power Plant (considering spinning reserve) – DBIS.

Existing Capacity, MW	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
DEMERARA						
Garden of Eden Power Station	7.5	7.5	7.5	7.5	7.5	7.5
Garden of Eden 46.5 MW	46.5	46.5	46.5	46.5	46.5	46.5
Demerara Power (Kingston 1)	22.0	22.0	22.0	22.0	22.0	22.0
Demerara Power, (Kingston 11)	36.3	36.3	36.3	36.3	36.3	36.3
Demerara Power 1 (GoE)	22.0	22.0	22.0	22.0	22.0	22.0
Vreed En Hoop Power Station	26.1	26.1	26.1	26.1	26.1	26.1
Sophia	4.8	-	-	-	-	-
MCG - Giftland	3.0	3.0	3.0	3.0	3.0	-
Total Demerara	**168.2**	**163.4**	**163.4**	**163.4**	**163.4**	**160.4**
BERBICE						
Existing Capacity, MW	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Canefield						
Hyundai	5.5	5.5	5.5	5.5	5.5	5.5
No. 4 Mirrlees Blackstone	3.8	3.8	3.8	3.8	3.8	3.8
Mobile Sets	8.3	8.3	8.3	7	3.2	3.2
Sub-total	**17.6**	**17.6**	**17.6**	**16.3**	**12.5**	**12.5**
Onverwagt						
No. 5 General Motor	2.3	2.3	2.3	2.3	2.3	2.3
No. 7 General Motor	2.3	2.3	2.3	2.3	2.3	2.3
Mobile Sets	8.5	10.1	10.1	10.1	1.6	1.6
Sub-total	**13.1**	**14.7**	**14.7**	**14.7**	**6.2**	**6.2**
Skeldon						
SEI	9.7	9.7	9.7	9.7	9.7	9.7
Sub-total	**9.7**	**9.7**	**9.7**	**9.7**	**9.7**	**9.7**
Total Berbice	**40.4**	**42**	**42**	**40.7**	**28.4**	**28.4**
Total DBIS	**208.6**	**205.4**	**205.4**	**204.1**	**191.8**	**188.8**
Min Required Spinning Reserve (MW)	**13.95**	**13.95**	**13.95**	**13.95**	**13.95**	**13.95**
Net Capacity (MW)	**194.65**	**191.45**	**191.45**	**190.15**	**177.85**	**174.85**
Peak Demand (MW)	138.8	185.8	236.4	288.8	407.4	478.0
Contingency Capacity (MW)	55.8	5.6	- 44.9	- 98.6	-229.6	- 303.1

To achieve the annual LOLP target and maintaining the required operation spinning reserve for system stability and contingency purposes, firm power generation capacity needs to be urgently increased from 2023.

3.12 Scenario No. 1 Power Generation Reliability – Essequibo Isolated Power Systems

Similarly, from a planning perspective for the Isolated Power Systems in the Essequibo, Table 22 indicates that for 2024, there would be a slight LOLP violation in **Anna Regina**. However, such violation is considered insignificant due to the expected capacity reserve margin of 33.7%.

Table 22: Anna Regina Scenario No.1 Reliability Results for 2022-2026

Fiscal Year	Load (GWh)	Peak Load (MW)	Generation Capacity (MW)	Capacity Reserves (MW)	Capacity Reserve Margin (%)	EENS (MWh)	LOLE (day)	LOLP (%)
2021	34.2	6.0	12.1	6.1	102.3	0.1	0.01	0.00
2022	41.6	7.5	14.6	7.1	94.1	0.1	0.01	0.00
2023	50.6	9.2	14.6	5.4	58.7	1.8	0.11	0.03
2024	62.5	10.9	14.6	3.7	33.7	21.3	1.13	0.31
2025	81.1	14.7	14.6	-0.1	-0.9	1,010.0	35.95	9.85
2026	96.4	17.1	14.6	-2.5	-14.4	4,454.4	107.86	29.55

From 2025, the LOLP in Anna Regina would be violated significantly. As a result, there will be a significant amount of expected energy not served.

Considering that agriculture is one of the main drivers of the economy on the Essequibo coast, such an expected downward performance in generation reliability would constrain economic growth and welfare developments.

Table 23 highlights that for **Bartica,** the available generation capacity would satisfy the forecast demand and the capacity reserve will be positive for the planning period. From 2025, the capacity reserve is expected to reduce significantly. In the event of increased forced outages on generators or any critical plant element that can adversely impact production, the situation would change drastically where there would be an increase in the expected energy not served.

Within the context of providing business services, electricity must be seen as catalyst to economic development. Given that Bartica is one of the major gateways to the hinterland regions, power generation and supply of reliable electricity is critical to residents to provide essential services to sustain the mining industry. In light of the aforementioned, such an expected performance in generation reliability can constraint growth and welfare development in Bartica.

Table 23: Bartica Scenario No.1 Reliability Results for 2022-2026

Fiscal Year	Load (GWh)	Peak Load (MW)	Generation Capacity (MW)	Capacity Reserves (MW)	Capacity Reserve Margin (%)	EENS (MWh)	LOLE (day)	LOLP (%)
2021	13.1	2.1	4.96	2.9	140.8	11.2	1.72	0.47
2022	15.5	2.5	4.96	2.5	98.4	27.2	2.49	0.68
2023	18.3	3.0	4.96	2.0	67.6	97.9	12.49	3.42
2024	21.6	3.4	4.96	1.6	46.3	279.2	23.51	6.42
2025	26.2	4.3	4.96	0.7	16.7	807.9	44.88	12.30
2026	29.4	4.7	4.96	0.3	6.7	1,407.2	101.71	27.87

For **Wakenaam**, Table 24 shows that the available generation capacity would meet the annual forecast demand and there would be sufficient capacity reserve up to 2024 From 2025, the capacity reserve is expected to reduce significantly. In the event of increased forced outages on generators or any critical plant element that can adversely impact production, the situation would change drastically where there would be an increase in the expected energy not served.

Similarly, to Anna Regina, the main activity drives the local economy in Wakenaam is rice cultivation. Consequently, downward performance in generation reliability would not encourage economic and socio-economic developments on the island.

Table 24: Wakenaam Scenario No.1 Reliability Results for 2022-2026

Fiscal Year	Load (GWh)	Peak Load (MW)	Generation Capacity (MW)	Capacity Reserves (MW)	Capacity Reserve Margin (%)	EENS (MWh)	LOLE (day)	LOLP (%)
2021	1.8	0.3	1.06	0.7	221.2	1.1	0.33	0.09
2022	2.2	0.4	1.06	0.7	165.0	2.6	0.90	0.25
2023	2.6	0.5	1.06	0.6	125.5	5.4	1.60	0.44
2024	3.1	0.6	1.06	0.5	92.7	9.3	2.39	0.65
2025	3.9	0.7	1.06	0.4	49.3	26.5	6.82	1.87
2026	4.5	0.8	1.06	0.3	30.9	56.4	14.73	4.03

Table 25 illustrates that for **Leguan**, the available generation capacity would satisfy the forecast demand and the capacity reserve will be positive up to 2024. From 2025, the capacity reserve is expected to reduce significantly. In the event of increased forced outages on generators or any critical plant element that can adversely impact production during the current planning period, the situation would change drastically where there would be an increase in the expected energy not served.

Similarly, to Wakenaam, the main activity drives the local economy in Leguan is rice cultivation. Consequently, downward performance in generation reliability would not encourage economic and socio-economic developments on the island.

Table 25: Leguan Scenario No.1 Reliability Results for 2022-2026

Fiscal Year	Load (GWh)	Peak Load (MW)	Generation Capacity (MW)	Capacity Reserves (MW)	Capacity Reserve Margin (%)	EENS (MWh)	LOLE (day)	LOLP (%)
2021	1.9	0.4	0.82	0.4	115.8	8.9	1.31	0.36
2022	2.2	0.5	0.82	0.4	78.3	22.0	6.25	1.71
2023	2.6	0.6	0.82	0.3	46.4	45.8	12.66	3.47
2024	3.2	0.7	0.82	0.2	26.2	84.0	19.45	5.31
2025	4.0	0.9	0.82	0.0	-3.5	167.1	34.26	9.39
2026	4.6	1.0	0.82	-0.1	-14.6	277.8	74.86	20.51

From an operation's perspective considering spinning reserve, Table 26 illustrates the following salient points:

1. With 3x1.6 MW LFO generator units transferred from Sophia to Anna Regina as replacement to derated and aged LFO units, this power system is expected to have sufficient contingency capacity until 2024 (Table 24). By 2025, it is evident that Anna Regina would be in dire need of additional firm power generation capacity.
2. Regarding Bartica, this isolated power system is expected to have adequate contingency capacity up to 2024 (Table 26). With an increasing demand, from 2024, this isolated system would not have the required contingency capacity for stable operation and to arrest load shedding. As a result, additional firm power generation capacity will be required by 2024.
3. Given the forecast demand of Wakenaam, this isolated power system would have the required contingency capacity for 2022, only. As indicated in Table 26, Wakenaam will require additional firm power generation capacity by 2023.
4. Among the smaller isolated power systems in the Essequibo, Leguan is forecasted to have a higher annual electricity demand growth rate. At the moment, the island does not have the required installed firm capacity to guarantee the recommended contingency capacity (Table 26). Consequently, this power system will require additional firm generation capacity from 2022.

Table 26: Scenario No.1 Capacity Forecast per Power Plant (considering Operating spinning reserve) – Essequibo Isolated Power Systems

Existing Capacity, MW	2021	2022	2023	2024	2025	2026
Anna Regina						
MAN (MW)	5.4	5.40	5.40	5.40	5.40	5.40
Mobile Sets (MW)	6.7	9.20	9.20	9.20	9.20	9.20
Total Anna Regina (MW)	12.1	**14.60**	**14.60**	**14.60**	**14.60**	**14.60**
Min Required Spinning Reserve (MW)	2.7	**2.70**	**2.70**	**2.70**	**2.70**	**2.70**
Net Capacity (MW)	9.4	**11.90**	**11.90**	**11.90**	**11.90**	**11.90**

Existing Capacity, MW	2021	2022	2023	2024	2025	2026
Peak Demand (MW)	5.98	7.52	9.19	10.92	14.74	17.05
Contingency Capacity (MW)	3.42	**4.38**	**2.71**	**0.98**	**-2.84**	**-5.15**
Bartica						
Cummins (MW)	3.36	3.36	3.36	3.36	3.36	3.36
Mobile Units (MW)	1.60	1.60	1.60	1.60	1.60	1.60
Total Bartica (MW)	**4.96**	**4.96**	**4.96**	**4.96**	**4.96**	**4.96**
Min Required Spinning Reserve (MW)	**1.68**	**1.68**	**1.68**	**1.68**	**1.68**	**1.68**
Net Capacity (MW)	**3.28**	**3.28**	**3.28**	**3.28**	**3.28**	**3.28**
Peak Demand (MW)	2.06	2.50	2.96	3.39	4.25	4.65
Contingency Capacity (MW)	**1.22**	**0.78**	**0.32**	**-0.11**	**-0.97**	**-1.37**
Wakenaam						
Caterpillar (MW)	1.06	1.06	1.06	1.06	1.06	1.06
Total Wakenaam (MW)	**1.06**	**1.06**	**1.06**	**1.06**	**1.06**	**1.06**
Min Required Spinning Reserve (MW)	**0.62**	**0.62**	**0.62**	**0.62**	**0.62**	**0.62**
Net Capacity (MW)	**0.45**	**0.45**	**0.45**	**0.45**	**0.45**	**0.45**
Peak Demand (MW)	0.33	0.40	0.47	0.55	0.71	0.81
Contingency Capacity (MW)	**0.12**	**0.05**	**-0.03**	**-0.11**	**-0.27**	**-0.36**
Leguan						
Caterpillar (MW)	0.82	0.82	0.82	0.82	0.82	0.82
Total Leguan (MW)	**0.82**	**0.82**	**0.82**	**0.82**	**0.82**	**0.82**
Min Required Spinning Reserve (MW)	**0.62**	**0.62**	**0.62**	**0.62**	**0.62**	**0.62**
Net Capacity (MW)	**0.21**	**0.21**	**0.21**	**0.21**	**0.21**	**0.21**
Peak Demand (MW)	0.38	0.46	0.56	0.65	0.85	0.96
Contingency Capacity (MW)	**-0.18**	**-0.26**	**-0.35**	**-0.44**	**-0.64**	**-0.75**

3.13 Committed Firm and Intermittent Generation Capacities - DBIS

With the DBIS coverage stretching from the East Bank of the Essequibo River in the West to Moleson Creek in the East, and Camp Alpha on the Southern end – Linden/Soesdyke highway, it invariably has a significant larger coverage of the total number of customers on the Coastal Plain than the isolated power systems. Currently, the estimated coverage of the DBIS is 96.7%, which is premised on the expected number beneficiaries by providing access to electricity in the unserved areas (represents 3.3% of the total expected number of customers within the current planning period).

The major economic activities, which includes agriculture and service industries to the mining and the Oil and Gas sector, are within the coverage of the DBIS. Consequently, it is crucial for the DBIS to operate at the highest level of power generation and network (transmission and distribution) reliability in support of planned economic activities for the current planning period, and by extension, be aligned with other long-term National Energy Priorities and Government initiatives, for example, connecting Linden with the DBIS by 2024.

On the account of the above, several simulation exercises were conducted to determine the required firm generation capacity to achieve the LOLP target. The required firm generation capacities were further developed to form the expansion projects. As a result, Table 27 shows the annual firm generation capacity of the committed projects (Table 28) for the current planning period.

Table 27: Generation Reliability with Planned Expansions – DBIS

Fiscal Year	Load (GWh)	Peak Load (MW)	Generation Capacity (MW)	Capacity Reserves (MW)	Capacity Reserve Margin (%)	EENS (MWh)	LOLE (day)	LOLP (%)
2021	937.9	138.8	208.60	69.8	50.3	55.7	0.65	0.18
2022	1,195.5	185.8	205.40	19.6	10.5	282.1	2.40	0.66
2023	1,516.7	236.4	336.00	99.6	42.1	0.0	0.00	0.00
2024	2,028.2	300.9	350.50	49.6	16.5	57.9	0.35	0.10
2025	2,715.6	422.2	538.20	116.0	27.5	0.2	0.00	0.00
2026	3,276.3	494.8	700.20	205.4	41.5	8.8	0.03	0.01

With the Total Available Capacity, in 2022, the DBIS is expected to violate the LOLP target slightly. In view of the total capacity of aged and unreliable generator units (Table 16) that are available for dispatch, the situation can be further exacerbated should the forced outage rate of these units increase in 2022.

As per Gas to Power Expression of Interest, the power plant at Wales is planned in two phases: mid 2024 and mid-2025, respectively. However, primarily generation reliability results indicated that in 2023, LOLP for the DBIS would be violated and there will be a dire need for additional firm generation capacity due to the significant amount of expected energy not served – loadshedding.

In the current Development and Expansion Programme, 100 MW of the total 300 MW is considered to be advanced in 2023 and be integrated at 69 kV at New Sophia temporary. This would allow for the DBIS to satisfy the LOLP target (Table 27) and to ensure the grid operates with a substantial amount of contingency capacity – grid security (Table 29). Additionally, the project would mitigate any setback in project delivery of the Wales Site with regards to construction of the power generation facility, substation, and transmission line at 230 kV.

Further, with the planned interconnection via 230 kV at Eccles, the project will also allow for a seamless interconnection of the completed infrastructure at Wales and Eccles. As such, with the successful completion of the balance 200 MW power generation facility at Wales, and substations at Wales and Eccles, it is planned for the 100 MW at New Sophia to be transferred to Wales permanently.

At New Sophia, there is sufficient land space to accommodate such a power generation facility. Comparing with Wales or any other candidate sites, New Sophia appears to be the best candidate site for such an emergency.

Also New Sophia, currently there are two spare fully equipped 69 kV bays. The required capital investment for interconnection would be a small fraction of the 230 kV cost for a site located elsewhere.

Notwithstanding the above, GPL remains cognisant of the need to ensure there is reliable and safe fuel supply to New Sophia. The Company is currently perusing all options to make an informed decision on this planned 100 MW at New Sophia.

With the list of committed firm power generation capacities (Table 28) in the current planning period, the LOLP target would be met reliably.

In view of Government's climate change commitments through the Low Carbon Development Strategy and other National Energy Priorities, GPL plans to have in commercial operation, an aggregated capacity of 10 MWp Solar PV in Berbice, and a total of 8 MWp Solar PV capacity and 8 MWh BESS in Anna Regina by 2023.

It is also planned for a 15 MWp and 15 MWh BESS to be in commercial operation in Linden by 2023, which is planned to be part of the DBIS in 2024.

Table 28: Proposed Generation Addition – DBIS

Name of Location	Type	Installed Capacity (MW)				
		2022	2023	2024	2025	2026
100 MW NG (Advanced Capacity - N/Sophia)	Firm Capacity	-	100.0	-	-	-
Hybrid Power Generation Facility - HFO	Firm Capacity	-	30.6	-	-	-
Hybrid Power Generation Facility - Solar PV	Non-Firm Capacity	-	30.0	-	-	-
Guysol	Non-Firm Capacity	-	10.0	-	-	-
Linden (Existing Capacity)	Firm Capacity	-	-	15.8	-	-
Linden Solar PV	Non-Firm Capacity	-	-	15.0	-	-
300 MW NG (Wales) - Balance 200 MW	Firm Capacity	-	-	-	200.0	-
AFHP	Firm Capacity	-	-	-	-	165.0
Total New Additions		**-**	**170.6**	**30.8**	**200.0**	**165.0**
Total Accumulated Additions		-	**170.6**	**201.4**	**401.4**	**566.4**
Annual Non-Firm Capacity		**-**	**40.0**	**15.0**	**-**	**-**
Annual Firm Capacity		**-**	**130.6**	**15.8**	**200.0**	**165.0**
Total Accumulated Firm Capacity		**-**	**130.6**	**146.4**	**346.4**	**511.4**
Existing Firm Capacity		**205.4**	**205.4**	**204.1**	**191.8**	**188.8**
Grand Total Firm Capacity		**205.4**	**336.0**	**350.5**	**538.2**	**700.2**

The Company intends to manage and configure these additional firm generation capacities with a focus on using clean indigenous, and affordable energy to:

1. Assist GPL in satisfying the forecast demand reliably;
2. Improve power generation reliability;
3. Reduce Guyana's dependency on imported fossil fuels for electricity generation;

4. Assist in increasing the disposable income for the Government and GPL to support other critical national developments;
5. Reduce the cost of generation, and by extension customer tariffs; and
6. Facilitate Guyana moving towards the realization of its climate change commitments.

Accounting for the spinning reserve requirements (sum of 150% of largest firm generator unit and 30% of annual accumulated renewable energy installed capacity), Table 29 illustrates the DBIS performance on an annual basis in consideration of the planned additional generation capacities and the significant amount of annual contingency capacity against the projected increasing peak demand.

Table 29: Generation Contingency Capacity Forecast with Recommended Additions – DBIS

Existing and New Power Generators	Type	2022	2023	2024	2025	2026
DEMERARA						
Garden of Eden Power Station	Firm Capacity	7.5	7.5	7.5	7.5	7.5
Garden of Eden 46.5 MW	Firm Capacity	46.5	46.5	46.5	46.5	46.5
Demerara Power (Kingston 1)	Firm Capacity	22.0	22.0	22.0	22.0	22.0
Demerara Power, (Kingston 11)	Firm Capacity	36.3	36.3	36.3	36.3	36.3
Demerara Power 1 (GoE)	Firm Capacity	22.0	22.0	22.0	22.0	22.0
Vreed En Hoop Power Station	Firm Capacity	26.1	26.1	26.1	26.1	26.1
Sophia	Firm Capacity	-	-	-	-	-
MCG - Giftland	Firm Capacity	3.0	3.0	3.0	3.0	-
100 MW NG (Advanced Capacity - N/Sophia)	Firm Capacity	-	100.0	100.0	100.0	100.0
300 MW NG (Wales) - Balance 200 MW	Firm Capacity	-	-	-	200.0	200.0
AFHP	Firm Capacity	-	-	-	-	165.0
Demerara Total Installation Generation Capacity (MW)		**163.40**	**263.40**	**263.40**	**463.40**	**625.40**
Demerara Total Firm Generation Capacity (MW)		**163.40**	**263.40**	**263.40**	**463.40**	**625.40**
Demerara Total Non-Firm Generation Capacity (MW)		**-**	**-**	**-**	**-**	**-**
BERBICE						
Canefield						
Hyundai	Firm Capacity	5.5	5.5	5.5	5.5	5.5
No. 4 Mirrlees Blackstone	Firm Capacity	3.8	3.8	3.8	3.8	3.8
Mobile Sets	Firm Capacity	8.3	8.3	7	3.2	3.2
Hybrid Power Generation Facility - HFO	Firm Capacity	0	10.2	10.2	10.2	10.2
Hybrid Power Generation Facility - Solar PV	Non-Firm Capacity	0	10	10	10	10
Guysol	Non-Firm Capacity	0	2	2	2	2
Onverwagt						
No. 5 General Motor	Firm Capacity	2.3	2.3	2.3	2.3	2.3

Existing and New Power Generators	Type	2022	2023	2024	2025	2026
No. 7 General Motor	Firm Capacity	2.3	2.3	2.3	2.3	2.3
Mobile Sets	Firm Capacity	10.1	10.1	10.1	1.6	1.6
Hybrid Power Generation Facility - HFO	Firm Capacity	0	10.2	10.2	10.2	10.2
Hybrid Power Generation Facility - Solar PV	Non-Firm Capacity	0	10	10	10	10
Guysol	Non-Firm Capacity	0	4	4	4	4
Williamsburg						
Hybrid Power Generation Facility - HFO	Firm Capacity	0	10.2	10.2	10.2	10.2
Hybrid Power Generation Facility - Solar PV	Non-Firm Capacity	0	10	10	10	10
Guysol	Non-Firm Capacity	0	4	4	4	4
Skeldon						
SEI	Firm Capacity	9.7	9.7	9.7	9.7	9.7
Berbice Total Installation Generation Capacity (MW)		**42**	**112.6**	**111.3**	**99**	**99**
Berbice Total Firm Generation Capacity (MW)		**42**	**72.6**	**71.3**	**59**	**59**
Berbice Total Non-Firm Generation Capacity (MW)		**0**	**40**	**40**	**40**	**40**
Linden						
Linden (Existing Capacity) - Interconnect with DBIS	Firm Capacity	0	0	15.8	15.8	15.8
Linden Solar PV - Interconnect with DBIS	Non-Firm Capacity	0	0	15	15	15
Linden Total Installation Generation Capacity (MW)		**0**	**0**	**30.8**	**30.8**	**30.8**
Linden Total Firm Generation Capacity (MW)		**0**	**0**	**15.8**	**15.8**	**15.8**
Linden Total Non-Firm Generation Capacity (MW)		**0**	**0**	**15**	**15**	**15**
DBIS Accumulated Firm Generation Capacity (MW)		**205.40**	**336.00**	**350.50**	**538.20**	**700.20**
DBIS Accumulated Non-Firm Generation Capacity (MW)		**-**	**40.00**	**55.00**	**55.00**	**55.00**
DBIS Min Required Spinning Reserve (MW)		**13.95**	**25.95**	**30.45**	**30.45**	**30.45**
DBIS Net Capacity (MW)		**191.45**	**310.05**	**320.05**	**507.75**	**669.75**
DBIS Forecast Peak Demand (MW)		**185.82**	**236.39**	**300.88**	**422.19**	**494.78**
Contingency Capacity (MW)		**5.63**	**73.66**	**19.17**	**85.56**	**174.97**

3.14 Firm and Intermittent Generation Capacities - Isolated Power Systems

3.14.1 Anna Regina

Table 30 shows the LOLP results with committed projects. The annual firm generation capacity is as a result of:

1. 8 MWh BESS to accommodate the planned 8MWp Solar PV in 2023; and
2. A total of 11 MW HFO fired capacity by 2024.

Table 30: Generation Reliability with Planned Expansions – Anna Regina

Fiscal Year	Load (GWh)	Peak Load (MW)	Generation Capacity (MW)	Capacity Reserves (MW)	Capacity Reserve Margin (%)	EENS (MWh)	LOLE (day)	LOLP (%)
2021	34.2	6.0	12.10	6.1	102.3	0.1	0.01	0.00
2022	41.6	7.5	14.60	7.1	94.1	0.1	0.01	0.00
2023	50.6	9.2	22.60	13.4	145.7	1.8	0.11	0.03
2024	62.5	10.9	33.60	22.7	207.7	9.3	0.52	0.14
2025	81.1	14.7	33.60	18.9	128.0	26.2	0.91	0.25
2026	96.4	17.1	33.60	16.6	97.1	27.4	0.95	0.26

In view of the existing firm generation capacity, the additional generator units and BESS will result in having a firm power system in Anna Regina (Table 31).

Table 31: Proposed Generation Capacity Addition - Anna Regina

Anna Regina	Type	Installed Capacity (MW)				
		2022	2023	2024	2025	2026
8MWp Solar PV Farms	Non-Firm Capacity		8.0			
8 MWh BESS	Firm Capacity		8.0			
2x5.5MW HFO Units	Firm Capacity			11.0		
Total Non-Firm Capacity		-	8.0	-	-	-
Total Firm Capacity		-	8.0	11.0	-	-
Total Accumulated Firm Capacity		-	8.0	19.0	19.0	19.0
Existing Firm Capacity		**14.6**	**14.6**	**14.6**	**14.6**	**14.6**
Grand Total Firm Capacity		**14.6**	**22.6**	**33.6**	**33.6**	**33.6**

From an operation perspective with the planned generation expansion (Table 31), Anna Regina would have sufficient contingency generation capacity to satisfy the forecast demand and required spinning reserve, as shown in Table 32.

Table 32: Generation Contingency Capacity Forecast with Additions - Anna Regina

Anna Regina Generation Capacity		2022	2023	2024	2025	2026
Existing MAN	Firm Capacity	5.4	5.4	5.4	5.4	5.4
Existing Mobile Sets	Firm Capacity	9.2	9.2	9.2	9.2	9.2
8MWp Solar PV Farms - Addition	Non-Firm Capacity	-	8.0	8.0	8.0	8.0
8 MWh BESS - Addition	Firm Capacity	-	8.0	8.0	8.0	8.0
2x5.5MW HFO Units - Addition	Firm Capacity	-	-	11.0	11.0	11.0
Total Installed Generation (MW)		**14.6**	**30.6**	**41.6**	**41.6**	**41.6**
Total Firm Generation Capacity (MW)		**14.6**	**22.6**	**33.6**	**33.6**	**33.6**
Total Non-Firm Generation Capacity (MW)		**-**	**8.0**	**8.0**	**8.0**	**8.0**
Min Required Spinning Reserve (MW)		**2.7**	**5.1**	**5.1**	**5.1**	**5.1**
Net Capacity (MW)		**11.9**	**17.5**	**28.5**	**28.5**	**28.5**
Peak Demand (MW)		**7.5**	**9.2**	**10.9**	**14.7**	**17.1**
Contingency Capacity (MW)		**4.4**	**8.3**	**17.6**	**13.8**	**11.5**

In summary, the benefits of the planned generation expansion for Anna Regina include, but are not limited to the following:

- Provide urgently needed power generation capacity to meet the growing electricity demand on the Essequibo Coast, with peak demand already equal to the total capacity of the first three HFO units, resulting in the need for operating mobile LFO generator units to provide the required reserve capacity;
- Reduce dependency on the use of LFO to generate electricity from mobile LFO units;
- Improve generation reliability and capacity reserve margin at the plant; and
- Proposed unit will require similar parts to existing generator units in the DBIS.

3.14.2 Bartica

For the Bartica power system, the Government, with funding from the IaDB and execution by GEA, is presently constructing a 1.5 MW Solar PV farm. In 2016, an Expression of Interest for this project was published by GEA. This project is expected to be commissioned in 2022.

The existing 3 x 1.12 MW diesel-fired generators and Caterpillar LFO fired generator are not expected to satisfy the growing demand reliably, given that the mobile LFO unit is unreliable and attracts a high maintenance cost.

Table 33.shows the LOLP results with committed projects (Table 34). The annual firm generation capacity is as a result of:

1. 0.75 MWh BESS to accommodate the 1.5MWp Solar PV in 2022;
2. 1.12 MW LFO Fired Generator Unit by Q3 of 2023; and
3. 2 MW LFO Fired Generator unit by Q2 of 2025.

Table 33:Generation Reliability with Planned Expansions – Bartica

Fiscal Year	Load (GWh)	Peak Load (MW)	Firm Generation Capacity (MW)	Capacity Reserves (MW)	Capacity Reserve Margin (%)	EENS (MWh)	LOLE (day)	LOLP (%)
2021	13.1	2.06	4.96	2.9	140.8	11.2	1.72	0.47
2022	15.5	2.50	5.71	3.2	128.4	6.8	0.95	0.26
2023	18.3	2.96	6.83	3.9	130.7	2.6	0.88	0.24
2024	21.6	3.39	6.83	3.4	101.5	7.9	0.77	0.21
2025	26.2	4.25	8.83	4.6	107.8	5.6	0.62	0.17
2026	29.4	4.65	8.83	4.2	89.9	11.3	0.77	0.21

In view of the existing firm generation capacity, the additional generator units will result in having a firm power system in Bartica, as shown in Table 34.

Table 34: Proposed Generation Capacity Addition to Bartica

Bartica	Type	Installed Capacity (MW)				
		2022	2023	2024	2025	2026
Small LFO Unit (1.12MW)	Firm Capacity		1.12			
Medium Size LFO Unit (2MW)	Firm Capacity				2.00	
1.5MWp Solar PV Farm	Non-Firm Capacity	1.50				
0.75 MWh BESS	Firm Capacity	0.75				
Total Non-Firm Capacity		**1.50**	**-**	**-**	**-**	**-**
Total Firm Capacity		**0.75**	**1.12**	**-**	**2.00**	**-**
Total Accumulated Firm Capacity		**0.75**	**1.87**	**1.87**	**3.87**	**3.87**
Existing Firm Capacity		**4.96**	**4.96**	**4.96**	**4.96**	**4.96**
Grand Total Firm Capacity		**5.71**	**6.83**	**6.83**	**8.83**	**8.83**

While the BESS that will accompany this solar PV farm will support spinning reserve, the Company remains cognizant that the BESS would have an average discharge duration of 1hour. With spinning reserve required for 24hrs operation, the balance of this ancillary service must be originated from firm generation capacity. As such, from an operation perspective with the planned generation expansion (Table 34), Bartica would have sufficient contingency capacity to satisfy the forecast demand, required spinning reserve as shown in Table 35.

Table 35: Generation Contingency Capacity Forecast with Additions – Bartica

Bartica Generation Capacity		2022	2023	2024	2025	2026
Existing Cummins	Firm Capacity	3.36	3.36	3.36	3.36	3.36
Existing Mobile Units	Firm Capacity	1.60	1.60	1.60	1.60	1.60
Small LFO Unit (1.12MW) - Addition	Firm Capacity	-	1.12	1.12	1.12	1.12
1.5MWp Solar PV Farm - Addition	Non-Firm Capacity	1.50	1.50	1.50	1.50	1.50
0.75 MWh BESS - Addition	Firm Capacity	0.75	0.75	0.75	0.75	0.75
Medium Size LFO Unit (2MW) - Addition	Firm Capacity	-	-	-	2.00	2.00
Total Installed Generation (MW)		**7.21**	**8.33**	**8.33**	**10.33**	**10.33**
Total Firm Generation Capacity (MW)		**5.71**	**6.83**	**6.83**	**8.83**	**8.83**
Total Non-Firm Generation Capacity (MW)		**1.50**	**1.50**	**1.50**	**1.50**	**1.50**
Min Required Spinning Reserve (MW)		**2.13**	**2.13**	**2.13**	**2.13**	**2.13**
Net Capacity (MW)		**3.58**	**4.70**	**4.70**	**6.70**	**6.70**
Peak Demand (MW)		**2.50**	**2.96**	**3.39**	**4.25**	**4.65**
Contingency Capacity (MW)		**1.08**	**1.74**	**1.31**	**2.45**	**2.05**

Some of the key benefits of this expansion plan for Bartica include, but are not limited to the following:

- Provide firm capacity to improve the reliability of supply as well as facilitate spinning reserve for the integration of a 1.5 MWp Solar PV Project;
- Provide capacity to serve existing unserved areas (Gersham, Itabali, Del Conte, and other riverine areas within the vicinity of Bartica) and expected increases in demand over the short to medium term;
- Reduce dependency on older LFO generators;
- Improved fuel efficiency;
- Lower cost of production; and
- Allow for Bartica to have sufficient generation capacity to ride-through an N-1 contingency on the line that interconnects with the rest of the isolated system and DBIS.

3.14.3 Wakenaam

GPL has secured grant funding from the UAE to implement a 750 kW Solar PV Farm and a 1.151 MWh BESS. To guarantee there will be secure power generation capacity, GPL will install two (2) new 512.5kVA (410kW) LFO fired generators and upgrade the electrical installation of the power plant.

To further assist in boosting firm generation capacity for LOLP and to satisfy the forecast demand, two additional 410 kW units are planned for 2023 and 2025, respectively. With these projects, Table 36 shows that Wakenaam will satisfy the LOLP target for the current planning period.

Table 36: Generation Reliability with Planned Expansions – Wakenaam

Fiscal Year	Load (GWh)	Peak Load (MW)	Firm Generation Capacity (MW)	Capacity Reserves (MW)	Capacity Reserve Margin (%)	EENS (MWh)	LOLE (day)	LOLP (%)
2021	1.8	0.33	1.06	0.7	221.2	1.1	0.33	0.09
2022	2.2	0.40	2.21	1.8	452.8	1.3	0.95	0.26
2023	2.6	0.47	2.62	2.2	457.7	0.2	0.88	0.24
2024	3.1	0.55	2.62	2.1	376.5	0.4	0.77	0.21
2025	3.9	0.71	3.03	2.3	326.9	0.1	0.62	0.17
2026	4.5	0.81	3.03	2.2	274.2	0.2	0.77	0.21

In view of the existing firm generation capacity, the additional generator units will result in having a firm power system in Wakenaam, as indicated in Table 37

Table 37: Proposed Generation Capacity Addition to Wakenaam

Wakenaam	Type	Installed Capacity (MW)				
		2022	2023	2024	2025	2026
Small LFO Unit (0.41MW)	Firm Capacity		0.41			
Small LFO Unit (0.41MW)	Firm Capacity				0.41	
Solar PV Farm	Non-Firm Capacity	0.75				
1.151 MWh BESS	Firm Capacity	1.15				
Total Non-Firm Capacity		**0.75**	**-**	**-**	**-**	**-**
Total Firm Capacity		**1.15**	**0.41**	**-**	**0.41**	**-**
Total Accumulated Firm Capacity		**1.15**	**1.56**	**1.56**	**1.97**	**1.97**
Existing Firm Capacity		**1.06**	**1.06**	**1.06**	**1.06**	**1.06**
Grand Total Firm Capacity		**2.21**	**2.62**	**2.62**	**3.03**	**3.03**

From an operation perspective with the planned generation expansion (Table 37), Wakenaam would have sufficient contingency capacity to satisfy the forecast demand and required spinning reserve (Table 38).

Table 38:Generation Contingency Capacity Forecast with Additions – Wakenaam

Wakenaam Generation Capacity		2022	2023	2024	2025	2026
Existing Caterpillar	Firm Capacity	1.06	1.06	1.06	1.06	1.06
Small LFO Unit (0.41MW) - Addition	Firm Capacity	-	0.41	0.41	0.41	0.41
Small LFO Unit (0.41MW) - Addition	Firm Capacity	-	-	-	0.41	0.41
Solar PV Farm - Addition	Non-Firm Capacity	0.75	0.75	0.75	0.75	0.75
1.151 MWh BESS - Addition	Firm Capacity	1.15	1.15	1.15	1.15	1.15
Total Installed Generation (MW)		**2.96**	**3.37**	**3.37**	**3.78**	**3.78**
Total Firm Generation Capacity (MW)		**2.21**	**2.62**	**2.62**	**3.03**	**3.03**

Wakenaam Generation Capacity	2022	2023	2024	2025	2026
Total Non-Firm Generation Capacity (MW)	**0.75**	**0.75**	**0.75**	**0.75**	**0.75**
Min Required Spinning Reserve (MW)	**0.84**	**0.84**	**0.84**	**0.84**	**0.84**
Net Capacity (MW)	**1.37**	**1.78**	**1.78**	**2.19**	**2.19**
Peak Demand (MW)	**0.40**	**0.47**	**0.55**	**0.71**	**0.81**
Contingency Capacity (MW)	**0.97**	**1.31**	**1.23**	**1.48**	**1.39**

Some of the salient benefits of this planned expansion, which includes the 750 kW Solar PV and1.151 MWh BESS are:

- Displace electricity generated using fossil fuel;
- Reduce fuel consumption;
- Reduce Guyana's carbon footprint;
- Improve Guyana's grid emission factor;
- Serve as a model for maximizing energy from RE; and
- Allow for Bartica to have sufficient generation capacity to ride-through an N-1 contingency on the line that interconnects with the rest of the isolated system and DBIS.

3.14.4 Leguan

For Leguan, Government plans a 600 kW solar farm with BESS by 2023. However, with the need to ensure the LOLP target is achieved for Leguan, the annual firm generation capacity resulting from planned projects for the current planning period is shown in Table 39.

Table 39: Generation Reliability with Planned Expansions – Leguan

Fiscal Year	Load (GWh)	Peak Load (MW)	Firm Generation Capacity (MW)	Capacity Reserves (MW)	Capacity Reserve Margin (%)	EENS (MWh)	LOLE (day)	LOLP (%)
2021	1.9	0.38	0.82	0.4	115.8	8.9	1.31	0.36
2022	2.2	0.46	1.23	0.8	167.4	1.7	0.95	0.26
2023	2.6	0.56	2.44	1.9	335.7	0.2	0.88	0.24
2024	3.2	0.65	2.44	1.8	275.4	0.3	0.77	0.21
2025	4.0	0.85	2.85	2.0	235.3	0.1	0.62	0.17
2026	4.6	0.96	2.85	1.9	196.9	0.2	0.77	0.21

In view of the existing firm generation capacity, the additional generator units will result in having a firm power system in Leguan, as indicated in Table 40.

Table 40: Proposed Generation Capacity Addition to Leguan

Leguan	Type	Installed Capacity (MW)				
		2022	2023	2024	2025	2026
Small LFO Unit (0.41MW)	Firm Capacity	0.41				
Small LFO Unit (0.41MW)	Firm Capacity		0.41			
Small LFO Unit (0.41MW)	Firm Capacity				0.41	
Solar PV Farm	Non-Firm Capacity		0.6			
0.8 MWh BESS	Firm Capacity		0.8			
Total Non-Firm Capacity		**-**	**0.60**	**-**	**-**	**-**
Total Firm Capacity		**0.41**	**1.21**	**-**	**0.41**	**-**
Total Accumulated Firm Capacity		**0.41**	**1.62**	**1.62**	**2.03**	**2.03**
Existing Firm Capacity		**0.82**	**0.82**	**0.82**	**0.82**	**0.82**
Grand Total Firm Capacity		**1.23**	**2.44**	**2.44**	**2.85**	**2.85**

From an operation's perspective with the planned generation expansion (Table *38*) Leguan would have sufficient contingency capacity to satisfy the forecast demand and required spinning reserve, as shown in Table 41.

Table 41: Generation Contingency Capacity Forecast with Additions – Leguan

Leguan Generation Capacity		2022	2023	2024	2025	2026
Existing Caterpillar	Firm Capacity	0.82	0.82	0.82	0.82	0.82
Small LFO Unit (0.41MW) - Addition	Firm Capacity	0.41	0.41	0.41	0.41	0.41
Small LFO Unit (0.41MW) - Addition	Firm Capacity	-	0.41	0.41	0.41	0.41
Small LFO Unit (0.41MW) - Addition	Firm Capacity	-	-	-	0.41	0.41
Solar PV Farm - Addition	Non-Firm Capacity	-	0.60	0.60	0.60	0.60
0.8 MWh BESS - Addition	Firm Capacity	-	0.80	0.80	0.80	0.80
Total Installed Generation (MW)		**1.23**	**3.04**	**3.04**	**3.45**	**3.45**
Total Firm Generation Capacity (MW)		**1.23**	**2.44**	**2.44**	**2.85**	**2.85**
Total Non-Firm Generation Capacity (MW)		**0**	**0.6**	**0.6**	**0.6**	**0.6**
Min Required Spinning Reserve (MW)		**0.615**	**0.795**	**0.795**	**0.795**	**0.795**
Net Capacity (MW)		**0.615**	**1.645**	**1.645**	**2.055**	**2.055**
Peak Demand (MW)		**0.46**	**0.56**	**0.65**	**0.85**	**0.96**
Contingency Capacity (MW)		**0.15**	**1.09**	**1.00**	**1.21**	**1.10**

These expansion plans are expected to deliver (and are not limited) to the following:

- Provide firm capacity to improve the reliability of supply as well as facilitate spinning reserve for the integration of a 0.6 MWp Solar PV Project,
- Provide capacity to serve existing unserved areas and expected increases in demand over the short to medium term,
- Provide for generator redundancy to allow for maintenance flexibility,

Allow for Leguan to have sufficient generation capacity to ride-through an N-1 contingency on the line that interconnects with the rest of the isolated system and DBIS.

3.15 Summary of Firm and Intermittent Generation Expansion Projects

The Company remains committed to aligning its generation strategies with the National Energy Policy, Low Carbon Development Strategy, and other Government Energy Driven Initiatives. The recommended generation expansion plan for the 2022-2026 planning period is summarised in Table 42 for the DBIS and Table 43 on page 95 for the Isolated Systems. Each table also shows the projected energy mix of the power systems by 2026, respectively.

Table 42: GPL 5 Year Generation Expansion Plan and Energy Mix- DBIS

Planned Commissioning Year	Generation Source	Installed Capacity (Megawatts)	Location	Ownership
2023	NG	100	300 MW NG Plant - Phase 1	GOG
	Solar PV	10	Guysol	GPL
	HFO	30.6	Hybrid System	IPP
	Solar PV	30	Hybrid System	IPP
2024	HFO	13.2	Linden	GOG
	LFO	2.6		
	Solar PV	15		
2025	NG	200	300 MW NG Plant - Phase 3	GOG
2026	Hydro	165	Crab Island	GPL
Existing Capacity (MW)	HFO	171.9	DBIS	GPL
Existing Capacity (MW)	LFO	16.9	DBIS	GPL
Total Existing Firm Capacity (MW)		188.8	157.6	GPL
Total Additional Firm Capacity by 2026 (MW)		511.4		
Total Additional Non-Firm Capacity by 2026 (MW)		55		
Total Additional Capacity by 2026 (MW)		566.4		
Total Firm Capacity by 2026 (MW)		700.2		
Total Non-Firm Capacity by 2026 (MW)		55		
Total Capacity by 2026 (MW)		755.2		
Total HFO Capacity by 2026 (MW)		215.7		
Total LFO Capacity by 2026 (MW)		19.5		
Total Solar PV Capacity by 2026 (MW)		55		
Total NG Capacity by 2026 (MW)		300		
Total Hydro Capacity by 2026 (MW)		165		
DBIS HFO % Share		29%	DBIS	
DBIS LFO % Share		3%	DBIS	

Planned Commissioning Year	Generation Source	Installed Capacity (Megawatts)	Location	Ownership
DBIS NG % Share		40%	DBIS	
DBIS Solar PV % Share		7%	DBIS	
DBIS Hydro % Share		22%	DBIS	

Table 43: GPL 5 Year Generation Expansion Plan and Energy Mix- Isolated Systems

Planned Commissioning Year	Generation Source	Installed Capacity (Megawatts)	Location	Ownership
2022	Solar PV	0.75	Wakenaam	GPL
	Solar PV	1.5	Bartica	GPL
	LFO	0.41	Leguan	GPL
2023	Solar PV	8	Anna Regina	GPL
	LFO	1.12	Bartica	GPL
	LFO	0.41	Leguan	GPL
	LFO	0.41	Wakenaam	GPL
2024	HFO	11	Anna Regina	GPL
2025	LFO	2	Bartica	GPL
	LFO	0.41	Leguan	GPL
	LFO	0.41	Wakenaam	GPL
2026	LFO	0.82	Leguan	GPL
Existing Capacity	HFO	5.4	Isolated Systems	GPL
	LFO	16.04	Isolated Systems	GPL
Total Existing Capacity		21.44	Isolated Systems	GPL
Total Additional Firm Capacity by 2026 (MW)		16.99	Isolated Systems	GPL
Total Additional Non-Firm Capacity by 2026 (MW)		10.25	Isolated Systems	GPL
Total Additional Capacity by 2026 (MW)		27.24	Isolated Systems	GPL
Total Firm Capacity by 2026 (MW)		38.43	Isolated Systems	GPL
Total Non-Firm Capacity by 2026 (MW)		10.25	Isolated Systems	GPL
Total Capacity by 2026 (MW)		48.68	Isolated Systems	GPL
Total HFO Capacity by 2026 (MW)		16.4	Isolated Systems	GPL
Total LFO Capacity by 2026 (MW)		22.03	Isolated Systems	GPL
Total Solar PV Capacity by 2026 (MW)		10.25	Isolated Systems	GPL
Isolated System HFO % Share		33.7%	Isolated Systems	GPL
Isolated System LFO % Share		45.3%	Isolated Systems	GPL
Isolated System Solar PV % Share		21.1%	Isolated Systems	GPL

3.15.1 Integrated Utility Service (IUS)

The Guyana Power and Light Inc. is seeking to support Guyana’s Green Energy transition through the Integrated Utility Services (IUS) Model. Customers will soon be able to access a wide range energy services including energy efficiency improvements, distributed renewables (solar photovoltaic system, wind, etc.) transport electrification and— in one comprehensive package, with monthly payments on the electricity bill. To date, GPL has signed a Memorandum of Understanding (MOU) with the Organization of American States (OAS), Inter-American Institute for Cooperation on Agriculture (IICA) and the Ministry of Agriculture (MOA) which would serve as GPL's first demonstration project to supply and install a Grid Connected Solar Photovoltaic System on MOA's roof space. The second demonstration project includes the installation of Grid Connected Solar Photovoltaic System with Battery Energy Storage at some of GPL's key offices; Sophia, Main Street and Middle Street. The installations at all four locations are now complete and the systems are being tested before commissioning. Commissioning will take place before the end of 2021.

OAS	10.2 kWp Grid Tied Solar PV System with 10kW Grid Tied Inverter
IICA	20 kWp Grid Tied Solar PV System with 20kW Grid Tied Inverter
GPL MIDDLE STREET	12.24 kWp Grid Connected Solar Photovoltaic System with 10kW of Grid Tied Inverter, 14.4 kWh Battery Energy Storage System – 1 Hour Back Up Power for Cash Office
GPL MAIN STREET	7.6 kWp Grid Connected Solar Photovoltaic System with 7.7kW Grid Tied Inverter, 2 5kWh Battery Energy Storage System - 4 hours of Backup power for Lights and Computers at the cash office, front desk, and call centre
GPL SOPHIA	35.2 kWp Grid Connected Solar Photovoltaic System with 30kW Grid Tied Inverter, 104 kWh Battery Energy Storage System - 4 hours Backup Supply for the Server Room

3.15.2 Long-term Generation Expansion and International Grid Interconnection

For the long-term generation expansion plan, the Government of Guyana is currently working strenuously on the Amaila Falls Hydro Power Project (AFHP), which will significantly reduce the overall cost of generation and by extension, electricity tariff. Additionally, the AFHP Project will add significant inertia to the technical stability of the power grid.

From GPL's perspective, grid expansions will be aligned with the AFHP Project, such that, transmission voltage level can be harmonised at 230 kV. Also, for interconnection of the hydropower project to be made at various strategic points in the grid to improve power system security, resiliency, and reliability.

The 'Arco Norte' Interconnection Project[10] expects to realize the development and commissioning of a significant amount of hydropower generation capacity in Guyana. With such long-term planned development, the total generation capacity is to buttress local generation capacity, and export electricity to Brazil, connection with the State of Roraima (North-West Brazil) and Amapa (South-East Brazil).

The interconnection with the State of Roraima would be direct with Guyana, while with Amapa through Suriname and French Guyana (Figure 3).

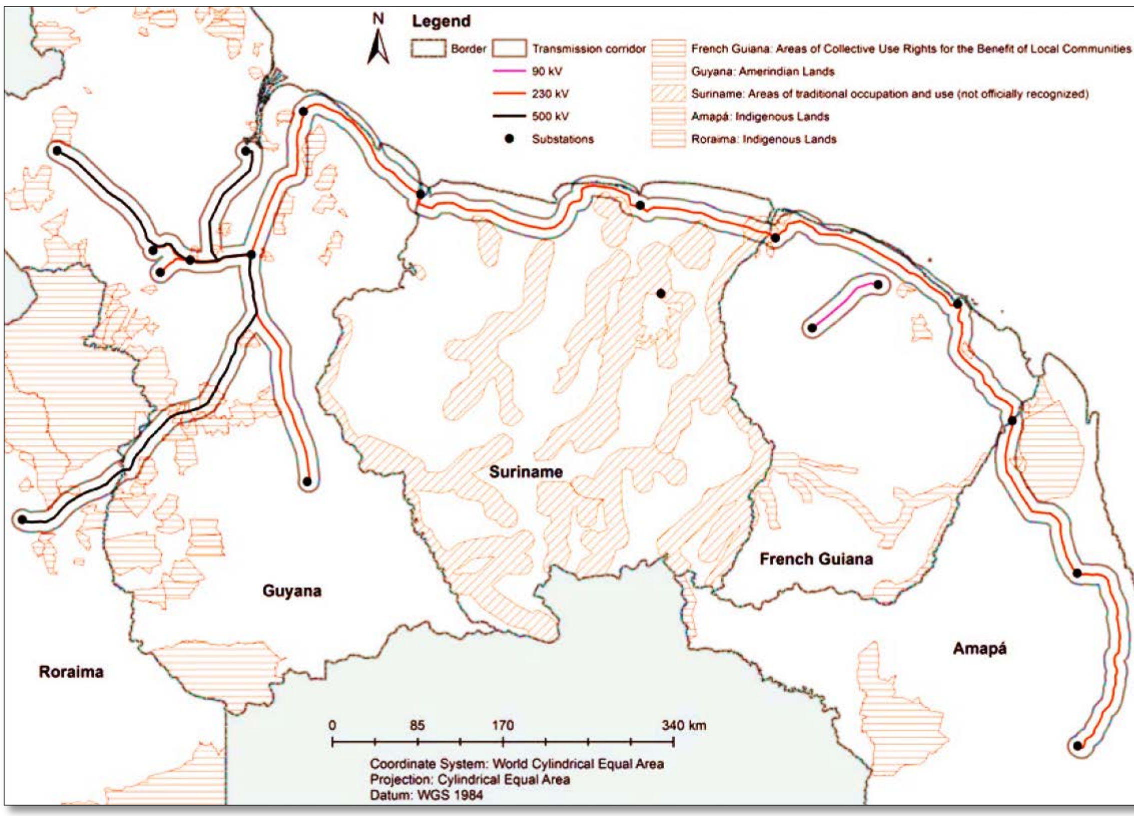

Figure 5:Illustration of the Arco Norte Interconnection Plan (*source: Arco Norte Electrical Interconnection Study – Component II*)

Some of the main benefits of this interconnection would be:

- Lower-cost generation in Guyana, French Guiana, and Suriname. A regional interconnection would allow these countries to exploit the most efficient generation sources at the regional level and meet regional demand through trade;
- Lower electricity prices for consumers in Guyana, French Guiana, and Suriname due to lower-cost generation and greater competition in the regional market (Figure 4);

[10] Development of an electrical interconnection among Suriname, Guyana, French Guiana, and Brazil

- More secure supply in all four Arco Norte countries—Guyana, French Guiana, Suriname, and Brazil. Trading across international borders would allow each country a larger reserve margin since they would have access to international electricity when domestic sources were inadequate;
- The opportunity to develop renewable energy sources in the region - gradually displacing liquid fossil fuels; and
- Export earnings, especially for Guyana. The most efficient large generation sites in the Arco Norte are potential hydro projects in Guyana. By developing these sites and exporting excess generation to Brazil, Guyana—and to a lesser extent French Guiana and Suriname—could become large energy exporters.

Currently, the 'Arco Norte' Interconnection Project is still at the feasibility stage and is currently awaiting the renewal of the MOU that binds the member states of this project.

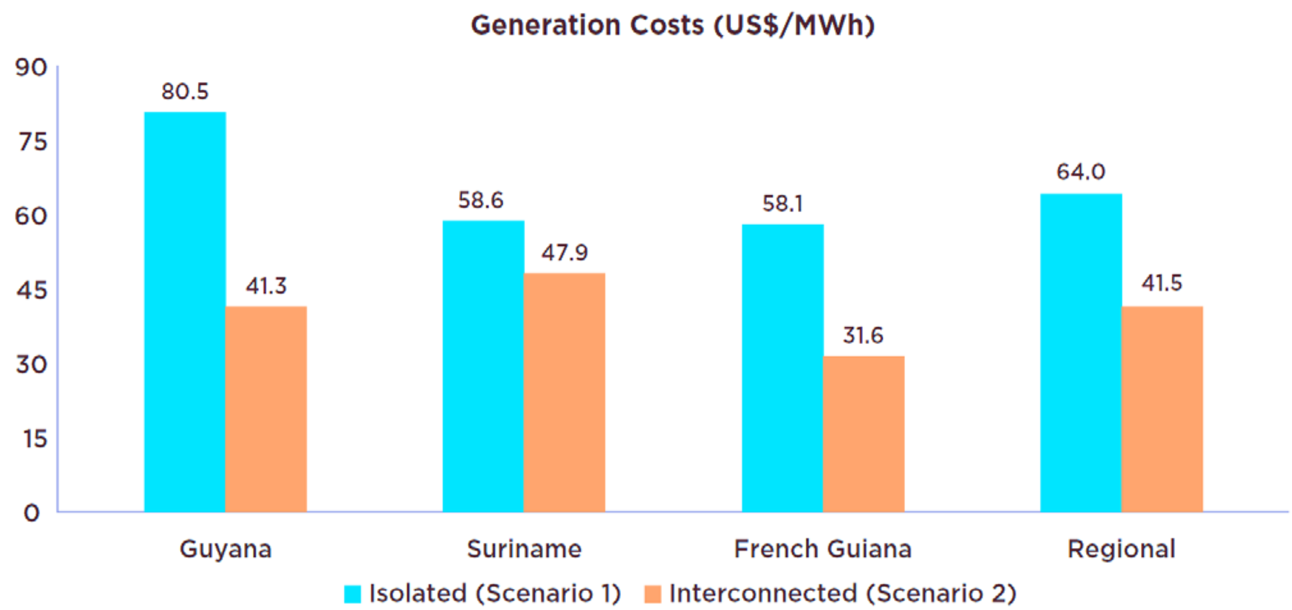

Figure 6: Average generation cost in the interconnected and isolated scenarios (*source: Arco Norte Electrical Interconnection Study – Component II, dated 2017*)

3.16 Transmission, Distribution and Substation Upgrades and Expansions

3.16.1 Short to Medium Term (2022-2026) – Transmission and Substation Expansions and Upgrades (see Figure 5 for block diagram summary)

GPLs T&D expansion programme, which includes the details shown in Table 45, totals GY$ 304.3B (US$ 1.41B) to upgrade and construct new Transmission and Distribution networks, Substations and Transmission system reinforcements (reactive power compensations) projects for the short- to medium-term planning horizon, 2022 to 2026.

The planned T&D expansion programme essentially seeks to accommodate the present and forecasted peak demand growth concomitant with efforts to reduce technical losses, improving grid security, flexibility, reliability, and resiliency. See Table 44 to Table 46 from pages 99 to 101 and Figure 7 on page 102 for further details.

The construction and upgrade of distribution substations (load centres) would allow new distribution feeders and transformers to be deployed in all geographic areas to serve the present and forecasted loads efficiently, and by extension support planned economic activities.

The expansion and construction of substations are required to deploy 230 kV and 69 kV transmission lines to connect substations, introduce parallel transmission line to mitigate N-1 contingency and to reduce technical losses (the replacement of lengthy distribution feeders, and the upgrading of feeder backbones).

The Central Housing & Planning Authority (CH&PA) 5-year residential, commercial and industrial expansion plan will result in approximately 43,678 new customers added to the grid by 2026. These expansions are across the coastland of Guyana where land spaces are available to accommodate such developments.

Regarding unserved areas, GPL is cognisant of 60 such areas where the expected total number of beneficiaries is approximately 6,862 by 2026. The unserved areas are stretched across region nos. 2, 3, 4, 5, 6 and 7. The total estimated cost to service the total number of beneficiaries is approximately GY$ 737.5M (US$3.43M).

Table 44: Short Term Transmission and Substation New, Expansions and Upgrades

Activity	Short Term T&D and Substation Expansion Projects	
	2022	2023
Transmission	GoE to G/Grove to Eccles to New/Old Sophia upgrade (L1, L2, L3, L4), New Sophia to Good Hope new and upgrade (L16P & L16).	V/Hoop to Kingston replacement (LS6), Edinburgh to Hydronie (Parika) new (L8), Old Sophia to New G/town upgrade (L10), Kingston to Merriman's Mall new (L11-1), Merriman's Mall to New G/town new (L11-2), Old Sophia to New Sophia upgrade (L12 & L13), Good Hope to Victoria/Enmore new (L17P), Enmore/ Victoria to Columbia new (L18B).

Activity	Short Term T&D and Substation Expansion Projects	
	2022	2023
Substation	Mobile Substation, GoE Substation, Old Sophia Substation, Good Hope Substation.	Hydronie (Parika) Substation, Edinburgh Substation, New G/town Substation, Good Hope Substation, Enmore/Victoria, Columbia Substation, Onverwagt Substation, Canefield Substation, Eccles Substation, Merriman's Mall Substation.

Table 45: Medium Term Transmission and Substation New, Expansions and Upgrades

Activity	Mid Term T&D and Substation Expansion Projects		
	2024	2025	2026
Transmission	No. 53 to Skeldon new (L23P), Wales Indust. to GOE new (L24 & L24P), Eccles to Ogle new (L25 & L25P), Ogle to LBI new (L26), Wales Indust. to Wales Com/Resid new (L30 & L30P), Wales Com/Resid to V/Hoop new (L31), Wales Com/Resid to Westminster new (L32), Bamia to Mackenzie (L37), Wales 300 MW NG to Eccles new (HV L1 & HV L1P), Bamia to Eccles new (HV L2 & HV L2P).	Westminster to Hydronie new (L9), Onverwagt to Canefield new (L21B), Onverwagt to Rossignol upgrade (L21-1), Rossignol to Canefield upgrade (L21-2), Canefield to No. 53 new and upgraded (22P and 22), Eccles to Lusignan new (L27), V/Hoop to Westminster new (L33), Eccles to V/Hoop new (L34), GoE to Yarrowkabra new (L35).	Columbia to Onverwagt new (L20P), Enmore/Victoria to Lusignan new (L28), Hydronie (Parika) to Leguan (L38), Leguan to Wakenaam (L39), Wakenaam to Suddie (L41), Suddie to Devonshire Castle (L42), Amelia Hydro to Bamia new (HV L3 & HV L3P), Eccles to Williamsburg new (HV L4 & HV L4P).
Substation	Westminster Substation, Eccles Substation, Ogle Substation, LBI Substation, Williamsburg Substation, Wales Com/Resid, Wales Indust, Bamia, Mackenzie Substation. Wales Industrial Substation, Bamia Substation, Wales 250-300 MW GSU Substation, Eccles 230/69 kV Substation.	Good Hope Substation, Columbia Substation, Onverwagt Substation, Skeldon Substation, Canefield Substation, No. 53 Substation, V/Hoop Substation, Lusignan Substation, Rossignol Substation, Crab Island Substation, Yarrowkabra Substation,	Devonshire Castle Substation, Suddie Substation, Wakenaam Substation, Leguan Substation, Hydronie Substation, Edinburgh Substation, Tuschen Substation, Kuru Kururu Substation, Columbia Substation. Amelia Falls Hydro Substation, Bamia Substation Williamsburg Substation, Eccles Substation.

Given the high priority placed on improving reliability, flexibility, resiliency and reducing technical losses of the transmission and distribution network, the Company has comprehensively examined and inspected the networks to update its inventory of corrective actions and improvement initiatives. The Company expects to finance these critical projects via concessional financing. See Table 44 for further details.

Table 46: Projects Financed through Grants and Loans: Short to Medium Term: 2022-2026

Activity	Location	Impact
New and Upgraded Substations	Westminster, Wales Com/Resid, Wales Industrial, Mackenzie, Bamia, Ogle, Crab Island.	Improved reliability in the transmission and distribution network by expanding the infrastructure to meet and exceed the needs of the customers.
Improve Reactive Compensation	Edinburgh, New G/town, New Sophia, and Good Hope.	The commissioning of reactive power compensators with auxiliaries, control and protection will significantly improve and stabilize transmission and distribution voltage levels on the network.
New and Upgraded Transmission Lines	V/Hoop to Kingston (LS6), Eccles to Lusignan new (L27), Wales Indust. to Wales Com/Resid new (L30 & L30P), Wales Com/Resid to V/Hoop new (L31), Wales Com/Resid to Westminster new (L32), GoE to Yarrowkabra new (L35), Bamia to Mackenzie (L37). Wales 300 MW NG to Eccles new (HV L1 & HV L1P), Bamia to Eccles new (HV L2 & HV L2P), Amelia Hydro to Bamia new (HV L3 & HV L3P), Eccles to Williamsburg new (HV L4 & HV L4P).	An improved Transmission Network will increase reliability in considering contingency scenarios and forecasted power flows across the lines whilst ensuring power is evacuated effectively from the Generation Stations to supply the various load centres.

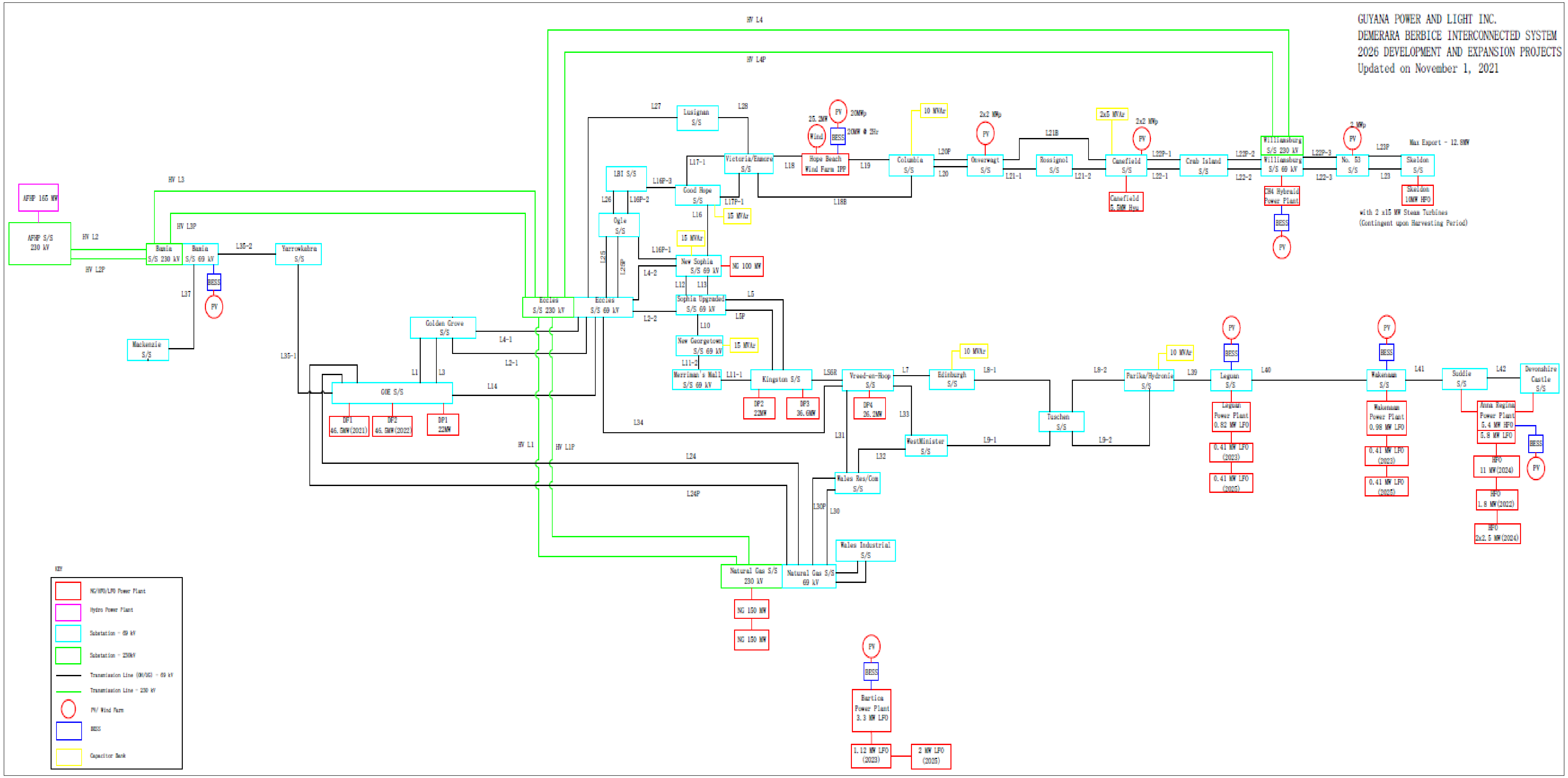

Figure 7: Block Diagram of Power System Development for the current D&E (2022-2026)

3.16.2 Short to Medium Term (2022-2026) – Distribution Expansions and Upgrades

The increase in demand for electricity stems from the consumers at the distribution level, and GPL must ensure that the primary distribution feeders are in the right condition to satisfy the needs of customers efficiently. Additionally, to improve the voltage profile along the length of the feeder, reduce technical losses and improve system reliability indices (SAIFI and SAIDI), resiliency, and capacity to manage increased power flow and deliver quality electricity supply service to customers.

Within the current Development and Expansion programme, the following are planned works at the primary distribution level:

Short-term (2022-2023):

- Construction of the following 13.8 kV Feeders:
  - Construction of new feeders coming out of Merriman's Mall Substation;
  - Construction of new feeders coming out of Eccles Substation;
  - Construction of new feeders coming out of Parika/Hydronie Substation;
  - Construction of new feeders coming out of Victoria/Enmore Substation;
  - Construction of an Express feeder from Anna Regina to Onderneeming.
- Upgrade of the following 13.8 kV Feeders:
  - Golden Grove F1;
  - Golden Grove F3;
  - New Georgetown F1;
  - Sophia F2;
  - Good Hope F4;
  - Edinburgh F2;
  - Canefield F3.
  - GOE F1.
- SCADA Upgrade & Smart Grid;
- Distribution Reactive Reinforcement:
  - DBIS Primary Distribution.
- Power Plant Switchgear Upgrades:
  - Upgrade tie-lines between DP2 -DP3;
  - Upgrade 13.8 kV Switchgear at DP2; and
  - Upgrade Grounding Transformer at DP3.
- Installation of 17 Auto-Reclosers on existing distribution feeders;

- JICA Grant: Grant covers expenses for line conductors and automatic power factor correction capacitor only. GPL to finance the balance of line hardware materials, labour, and transportation costs for these projects: The remaining projects from the JICA Grant are:
    - Construction of Golden Grove Express feeder;
    - Upgrade the existing Onverwagt F2 feeder;
    - Construct Onverwagt Express feeder to Ithaca;
- Leguan Feeder Voltage Upgrade;
- Procurement of Materials (Transformers and Switches) for GPL-PUUP.

Medium-term (2024-2026):

- Construction of the following 13.8 kV Feeders:
    - Construction of new feeders coming out of Wales Res/Com Substation;
    - Construction of new feeders coming out of Wales Industrial Substation;
    - Construction of new feeders coming out of Ogle;
    - Construction of new feeders coming out of LBI Substation;
    - Construction of new feeders coming out of Williamsburg Substation;
    - Construction of new feeders coming out of Bamia Substation;
    - Construction of new feeders coming out of Columbia Substation;
    - Construction of new feeders coming out of Good Hope Substation;
    - Construction of new feeders coming out of No. 53 Substation;
    - Construction of new feeders coming out of Yarrowkabra Substation;
    - Construction of new feeders coming out of Westminster Substation;
    - Construction of new feeders coming out of Lusignan Substation;
    - Construction of new feeders coming out of Rossignol Substation;
    - Construction of new feeders coming out of Crab Island Substation;
    - Construction of new feeders coming out of Mackenzie Substation;
    - Construction of new feeders coming out of Canfield Substation;
    - Construction of new feeders coming out of Edinburgh Substation;
    - Construction of new feeders coming out of Kuru Kururu Substation;
    - Construction of new feeders coming out of Tuschen Substation; and
    - Construction of new feeders coming out of Old Sophia Substation;
- Upgrade of the following 13.8 kV Feeders:
    - GOE F2;
    - GOE F3;
    - Anna Regina South feeder;

    - No. 53 (both feeders).
- Interconnection of the Islands (Leguan - Wakenaam - Hogg Island):
    - Express Feeder at Leguan to interconnect with Hogg Island;
    - OHL Crossing between Leguan and Hogg Island;
    - Express Feeder at Wakenaam to interconnect with Hogg Island;
    - OHL Crossing between Wakenaam and Hogg Island; and
    - Construction of 13.8 kV Feeders at Hogg Island.
- Distribution Reactive Reinforcement:
    - Leguan Distribution Network;
    - Wakenaam Distribution Network;
    - Linden Distribution Network; and
    - DBIS Primary Distribution.
- Power Plant Switchgear Upgrades:
    - Upgrade 13.8 kV Switchgear at DP3; and
    - Upgrade Grounding Transformer at DP4.

These additional critical network projects are expected to deliver a significant improvement in quality of service, feeder reliability, and strengthen the grid for the incremental penetration of electricity from renewable resources and reduce technical losses.

The cost of the proposed expansion and improvement of the T&D Systems is shown in Table 47.

Table 47: T&D Expansion and Upgrade Programme - Capital Cost

T&D Summary	**2022**	**2023**	**2024**	**2025**	**2026**	**Total**
	US$,000	US$,000	US$,000	US$,000	US$,000	US$,000
Transmission Lines	10,754.4	57,075.5	388,225.5	406,437.6	190,930.7	1,053,423.7
Transmission Lines Reinforcements	-	260.0	173.4	147.8	98.6	679.8
Substations	37,381.9	75,624.2	66,759.6	44,968.9	26,661.5	251,396.1
Distribution	26,695.1	16,180.3	14,093.9	7,476.0	2,466.2	66,911.5
T&D Tools and Equipment	8,249.8	7,310.5	2,933.0	4,823.6	1,486.7	24,803.7
Electrification	2,836.6	3,837.7	2,862.5	3,316.9	3,785.0	16,638.7
Total	85,917.7	160,288.3	475,047.9	467,170.9	225,428.6	**1,413,853.4**

3.16.3 Long Term (2027-2040)

The expanded version of the Low Carbon Development Strategy highlights Government's plan to expand the use of existing hydro potentials. In this version of the LCDS the Government of Guyana plans to construct three hydropower facilities, each having approximately 200 MW. The planned timelines of each of the above-mentioned hydropower facilities are 2031, 2035 and 2040.

For production cost and power system modelling purposes, hydro potential sites that are within the vicinity of the Amaila Falls Hydropower Project line right of way were selected as candidate hydropower facilities. These hydro potential sites are Turtuba, Arisaru and Takwari.

Given the forecasted electricity and peak demands, the Company's long-term plan currently focus on transmission, sub-transmission and substation, expansions. These long-term planned projects are primarily geared towards power evacuation, power delivery to planned substations and further strengthening the grid to transfer larger blocks of power across longer distances efficiently and supply customers reliably. See Table 48 for further details.

Table 48: Long term expansion plans

Activity	Quantity	Location
Additional 230 kV Transmission Lines Construction	8	Wales 300 MW NG to East Bank Essequibo (EBE) (HV L5 & HV L5P), Turtuba to EBE (HV L6 & HV L6P), Arisaru to Turtuba (HV L7 & HV L7P), Takwari to Amaila Hydro (x) (HV L8 & HV L8P).
Additional 69 kV Transmission Lines Construction	8	LBI to Lusignan (L29), Bamia to Yarrowkabra (L36), Mackenzie to Wismar (L38), Bartica to Del Conte (L43), Del Conte to Beribissiballi (L44), Beribissiballi to EBE (L45), EBE to Hydronie (Parika) (L46), Turtuba to Bartica (L47).
Additional Substations	16	Old Sophia, Burma 69/13.8 kV, Rossignol 69/13.8 kV, Bush Lot ECB 69/13.8 kV, Hydronie (Parika), Beribissiballi 69/13.8 kV, Del Conte 69/13.8 kV, Bartica 69/13.8 kV, Wismar 69/13.8 kV. Garden of Eden 230/69 kV, Yarrowkabra 230/69 kV, Wales 300 MW NG, Turtuba Hydro 230/69 kV, Arisaru Hydro 230 kV, Takwari Hydro 230 kV, East Bank Essequibo 230 kV.

The transmission lines and substation projects have a massive scope of works that would significantly impact GPL's operations if human resources from within the Company are to be assigned to these projects. As a result, the intention is to award EPC contracts for the execution of these projects.

The Company recognizes and endorses the importance of adequate equipment to manage its T&D work programmes effectively and will continue with its programme of prudent addition and replacement of tools and equipment deemed necessary to execute the programmed.

3.17 Network Maintenance Plan – 2021-2025

The 2021 -2025 network maintenance plan seeks to ensure that all sections of transmission lines and feeders are in optimal operating conditions for GPL to achieve its targeted reliability indices.

The outsourcing of this programme's components and investments in GPL's maintenance capacity and capability are expected to deliver reduced outages resulting from distribution feeder and transmission line trips. See Table 49 for further details.

Table 49: 2021 -2025 Network Maintenance Plan

DATE:	2022 -- 2026		2022			2023			2024			2025				
TARGET INDICATORS			T&D	Contractor	Total	T&D	Contractor	Total	T&D	Contractor	Total	T&D	Contractor	Total	T&D	C
POLE REPLACEMENT	1	PRIM.	2300	805	3105	2800	1120	3920	3000	1050	4050	3900	1560	5460	3900	
		SEC.	3600	1260	4860	3800	1520	5320	4800	1680	6480	5800	2320	8120	5800	
POLE PLUMBING	2	PRIM.	1200	420	1620	1400	560	1960	1400	490	1890	1900	760	2660	1900	
		SEC.	1450	508	1958	1550	620	2170	1550	543	2093	1850	740	2590	1850	
POLE TREATMENT	3	PRIM.	10000	3500	13500	12000	4800	16800	12000	4200	16200	14000	5600	19600	14000	
		SEC.	13000	4550	17550	14000	5600	19600	14000	4900	18900	16000	6400	22400	16000	
OLD POLE REMOVAL	4	PRIM.	1506	527	2033	1506	602	2109	1506	527	2033	1506	602	2109	1506	
		SEC.	3416	1196	4611	3416	1366	4782	3416	1196	4611	3416	1366	4782	3416	
POLE STUBBING	5	PRIM.	428	150	578	428	171	599	428	150	578	428	171	599	428	
		SEC.	400	140	540	400	160	560	400	140	540	400	160	560	400	
ANCHOR BLOCK REPLACEMENT.	6	PRIM.	300	105	405	300	120	420	300	105	405	300	120	420	300	
		SEC.	250	88	338	250	100	350	250	88	338	250	100	350	250	
GUY REPLACEMENT	7	PRIM.	420	147	567	420	168	588	420	147	567	420	168	588	420	
		SEC.	350	123	473	350	140	490	350	123	473	350	140	490	350	
REPLACEMENT DEFECTIVE CROSS ARMS	8	PRIM.	1800	630	2430	1500	600	2100	1500	525	2025	1500	600	2100	1500	
INSULATOR REPLACEMENT	9	PRIM.	7433	2602	10035	9433	3773	13206	9433	3302	12735	9433	3773	13206	9433	
		SEC.	3650	1277	4927	3650	1460	5110	3650	1277	4927	3650	1460	5110	3650	
LINE/HARDWARE TRANSFER	10	PRIM.	5585	1955	7540	5585	2234	7819	5585	1955	7540	5585	2234	7819	5585	
		SEC.	4257	1490	5748	4257	1703	5960	4257	1490	5748	4257	1703	5960	4257	
LINE EXTENSION (KM)	11	PRIM.	18	6	24	18	7	25	18	6	24	18	7	25	18	
		SEC.	52	18	70	52	21	72	52	18	70	52	21	72	52	
LINE UPGRADEMENT (KM)	12	PRIM.	95	33	128	95	38	133	95	33	128	95	38	133	95	

DATE:		2022 -- 2026	2022			2023			2024			2025			
TARGET INDICATORS			T&D	Contractor	Total	T&D	Contractor	Total	T&D	Contractor	Total	T&D	Contractor	Total	T&D
		SEC.	77	27	104	77	31	108	77	27	104	77	31	108	77
LINE RETENSION (KM)	13	PRIM.	520	182	702	520	208	728	520	182	702	520	208	728	520
		SEC.	1200	420	1620	1200	480	1680	1200	420	1620	1200	480	1680	1200
SERVICE LINE REPLACEMENT (MTS)	14		12500	4375	16875	12500	5000	17500	8500	2975	11475	6000	2400	8400	5000
INSTALLATION/REPLACEMENT (GAB/RECLOSER/SECTIONALISER)	15	PRIM.	60	15	75	70	20	90	50	15	65	25	10	35	44
INSTALLATION/REPLACEMENT (SPD)	16	PRIM.	120	42	162	150	60	210	80	28	108	50	20	70	50
INSTALLATION/REPLACEMENT (RCO)	17	PRIM.	792	277	1069	792	317	1108	792	277	1069	792	317	1108	792
INSTALLATION/REPLACEMENT (PMCO)	18		240	84	324	150	60	210	150	53	203	150	60	210	100
TRANSFORMER MAINTENANCE	19	SEC.	1170	410	1580	1170	468	1639	1170	410	1580	1170	468	1639	1170
INSTALLATION OF ADDITIONAL TRANSFORMERS (REPLACEMENT)	20	SEC.	150	53	203	110	44	154	100	35	135	80	32	112	80
MAINTENANCE OF CAPACITOR/VOLTAGE REGULATORS BANKS	21		15	12	27	26	10	36	26	9	35	26	10	36	26
JUMPER SERVICING/REPLACEMENT	22	PRIM.	1249	437	1686	1249	499	1748	1249	437	1686	1249	499	1748	1249
		SEC.	2589	906	3496	2589	1036	3625	2589	906	3496	2589	1036	3625	2589
SERVICE CONNECTION @ CONSUMER	23		12000	4200	16200	12000	4800	16800	12000	4200	16200	12000	4800	16800	12000
INSTALLATION OF ADDITIONAL EARTHS	24		725	254	979	725	290	1016	725	254	979	725	290	1016	725
ROUTE CLEARING (KM)	25	PRIM.	5	0	5	6	0	6	5	0	5	5	0	5	4
		SEC.	8	0	8	10	0	10	8	0	8	8	0	8	7
LINE INSPECTION (KM)	26	PRIM.	2500	875	3375	2700	1080	3780	3000	1050	4050	3300	1320	4620	3600
		SEC.	6000	2100	8100	6200	2480	8680	6500	2275	8775	6800	2720	9520	7000
C.E.O.F CARDS	27	SEC.	900		900	1500		1500	2500		2500	4500		4500	4500

3.18 Loss Reduction

The reduction of losses: technical and non-technical, continues to be a significant challenge facing the GPL. The Company projects total losses to be 24.7% as of December 31, 2021.

The primary reasons for not realizing the expected reductions were the later than planned execution of the IDB / EU Power Utility Upgrade Programme (PUUP) – Component III: Loss Reduction (2017 as against planned execution in 2016). The PUUP Lot A and B has realized the installation of 40,000 AMI meters over the period 2018 to 2021, which contributed to the 4% reduction in losses over the same period. The Company's Meter Replacement programmes have also realized the installation of an additional 18,000 AMI meters over the same period, also contributing to the 4% reduction in losses. The Company's Meter Replacement programmes were also negatively impacted due to a depleted amount of meter socket and conductor inventory. Replenishment of the stock is projected during the first quarter of 2022 and would herald an intensified execution of the affected work programmes.

The Company was able to achieve total losses moving from 26.5% in 2020 to 24.7% in December 2021 due to the commencement of the execution of Loss Reduction component of the PUUP which stared in 2016.

The Company intends to intensify its efforts to achieve the 2026 target of 18.1% see Figure 8 on page 113), using the combined application of SCADA at the transmissions and primary distribution levels and economic power generation dispatch, coupled with the continued implementation of AMI meters, shortening feeder lengths by constructing new feeders and upgrading the existing feeders.

3.18.1 Non-Technical Loss Reduction

The Company will continue to adopt a phased approach to establishing its Advance Metering Infrastructure (AMI). AMI meters will not be restricted to customer installations. The AMI meters will also be used for grid metering to compare energy delivered to a geographic area and the energy registered by Consumers' meters. This technology will significantly enhance GPL's theft detection capabilities and therefore reduce losses. The technology will also help identify voltage levels within the distribution network and inform a key Operational Standard and Performance Measure – Voltage Regulation.

The activities envisaged over the life of this Programme require a capital investment of US$32.8M (GY$6.83B) and include:

1. Installation of 82,000 AMI meters complete with new service lines and associated materials,
2. Installation of 25,000 energy efficient LED streetlamp as part of a proposed streetlamp upgrade programme.
3. Regular inspection of areas with new, reinforced networks to reduce illegal connections,
4. Efforts to encourage prosecution of all cases of illegal electricity extraction, and

5. Execution of a Social Management Programme to educate consumers on the impact and consequences of electricity theft.
6. Execution of a Social Management Programme to educate consumers on the use of energy efficient lighting and impact and consequences of installing illegal streetlamps.

3.18.2 Technical Loss Reduction

Planned investment in technical loss reduction is estimated to be over US$66.5M over the life of this programme. With the US$10M (GUY$2.152B grant from Japan International Cooperation Agency (JICA), pending works are related Golden Grove F1 and Onverwagt F2 (from No. 7 to Ithaca) and 3% percentage on the section between the substation and No. 7 on the Onverwagt F2.

The investment will address losses and system improvement at the distribution level, within both the Medium Voltage and Low Voltage network. The Company expects that the planned investment in new transmission lines, substations and an upgraded distribution network would improve supply quality, reduce operating costs, and ultimately deliver reduced tariffs.

3.18.3 Critical Issues

1. The current level of system losses are above sustainable levels:
   I. Losses from electricity theft by customers and unregistered “users”;
   II. Losses from customers with faulty meters;
   III. Losses from billing system (meter reading errors, under estimations); and
   IV. Losses from substandard network design and maintenance.

1.1.1. Strategies

1.1.1.1. Commercial Losses (Non-Technical Losses)

1. Reduce and deter electricity theft:
   a. Field assessment of large customers.
   b. Field assessment of zero consumption accounts
   c. Monitoring of defaulting customers
   d. Removal of illegal connections and prosecuting of persons caught.
2. Improve metering systems:
   a. Implementation of Advanced Metering Infrastructure.
   b. Replacement of all faulty meters
   c. Replacement of old meter interface.
3. Reduce billing system errors and estimations:
   d. Verification of all streetlights within NDC's and Municipalities

e. . Implementation of the Street lamp upgrade programme.

1.1.1.2. Technical Losses

1. Improving understanding of Losses. (LR, Projects and Operations Division):
    a. Progressively improve the quantity and quality of information available for losses calculation and segmentation, and for factoring losses into investment decisions.
2. Improve T&D network design and maintenance program (Projects and Operations Division)

1.1.1.3. Distribution Upgrade Programme – GPL Funded

Table 50 shows the additionally planned distribution upgrades targeting reducing technical losses in the primary distribution system.

Table 50: GPL Technical Reduction Projects – Primary Distribution Level

Target Indicators Activities		2022	2023	2024	2025	2026
Service Line Replacement (Km)		40	25	38	25	40
Line Extension/Construction (Km)	Prim.	220	255	265	170	180
Line Upgrade (Km)	Prim.	100	150	230	250	250
	Sec.	35	40	60	60	60
Replacing Inefficient Transformers		18	10	8	6	4
Replacing Under Utilised Transformers		60	30	20	10	8
Installing Additional Transformers		75	50	35	35	20
Service Connection @ Consumer/Installation of Insulink		14,000	12,000	10,000	10,000	10,000
Transformer Drops Servicing/Replacement		9,400	10,400	10,000	10,000	10,000
Jumper Servicing/Crimping/Replacement	Prim.	550	650	650	650	650
	Sec.	1,200	1,500	1,500	1,500	1,500

Note: The above programme excludes the EU / IDB funded Power Upgrade Utility Programme (PUUP) technical Loss Reduction Programme, which forms part of the Consolidated Loss Reduction plan. This IDB/EU funded programme was intended to upgrade approximately 830 kilometres of medium and low voltage conductors and include transformer rightsizing and other critical medium and low voltage network upgrades. However due to funding constraints only 629 kilometres could have been rehabilitated.

The first of two projects (Lot A) commenced in 2017 and was completed in April 2019. Lot A resulted in the upgrade of 361 kilometres of low and medium voltage network and replaced 22,348 electro-mechanical meters with AMI compatible ones. Lot B was awarded in May 2019 and works commenced in November 2019. Lot B was intended to replace 310 kilometres of low and medium voltage distribution network and replace 19,095 meters and was expected to be substantially completed by the end of 2020.

Due to delays experienced as a result of the COVID19 Pandemic and issues related to the 2020 Regional and National Elections, works were extended to August of 2021. As of August 31, 2021, 18,120 meters and 309.44 km of network were completed. The shortfall from the target of 310 km is due to the fact that GPL had already completed upgrade works in some of the project areas. It is projected that a further 1700 meters will be installed during the defects liability period, which ends on August 31, 2022.

1.1.1.4. Loss Reduction Projections

With the combined application of SCADA at the transmissions and primary distribution levels, and power generation, coupled with the continued implementation of AMI meters at the customer level, the Company plans to transform the power system into a smart grid in a phased manner.

In view of the benefits of having a smart grid together with the above-mentioned projects, which will reduce technical and non-technical losses, the Company's loss projection profile indicates that by 2026, technical losses should be reduced from 11.5% to 10.2%, and non-technical from 13.2% to approximately 7.9% (Figure 8). Consequently, a total loss reduction from twenty-four-point seven percent (27.4%) in 2021 to eighteen-point one percent (18.1%) by 2025.

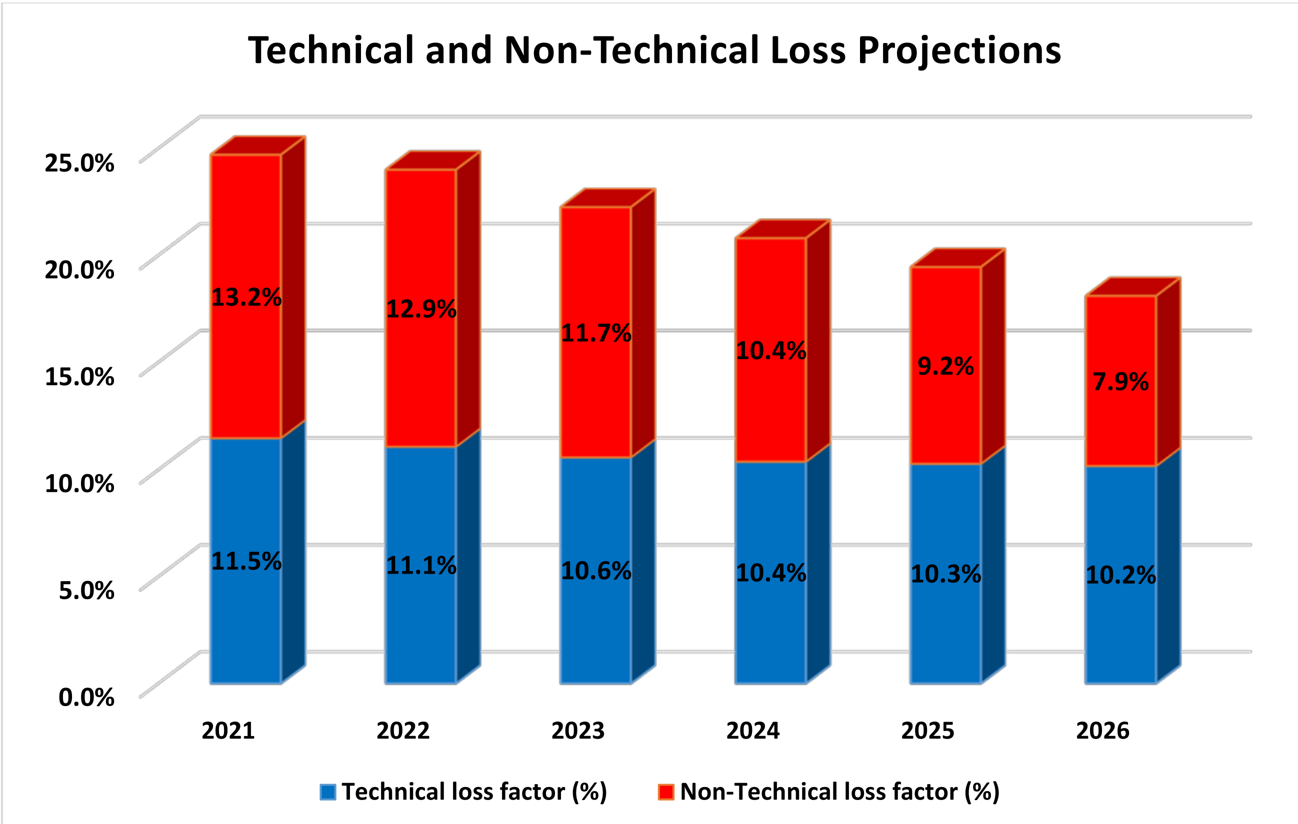

Figure 8: 2021- 2025 Technical and Non-Technical Loss Reduction Projections

3.19 Planning and Projects

3.19.1 Critical Issue

I. Inadequate processes to allow for:

a. Effective Demand Forecasting

b. Generation Unit Retirement Scheduling

c. Generation and Transmission Expansion Planning

d. Integration of Renewable Energy (Utility Scale)

II. Acquisition of planned generation and/or transmission/distribution facilities:

a. On-time and within budget.

b. Meeting quality standards and technical specifications.

3.19.2 Technical Loss Reduction

a. Inability to reasonably quantify technical losses.

b. Impact of Technical Loss Reduction emanating from SP&D is not captured.

III. Staff Training and Development

a. Inability to attract and retain staff with the required skills.

b. Inadequate training programs to address knowledge gaps.

3.19.3 Strategies

Meeting Load Demand, the Engineering Service Division has the strategic responsibility for planning new supply sources necessary to meet the future electricity needs within its defined area of responsibility. It is recognized that emerging sources of renewable energy are becoming more competitive in terms of affordability, demand-side management is being tailored to consumer trends, technological innovation is continuing at a rapid pace, and new emission regulations are changing traditional electricity market dynamics. In this continuously evolving environment, the Engineering Service Division will implement an Integrated Resource and Resilience Planning process to ensure long term electricity needs are met sustainably through the following strategies.

Power System Planning

1. Enhance coordination with Government and sectoral entities.
2. Implement Effective Demand Forecasting.
3. Determine optimized Generation Unit Retirement Schedule.
4. Implement Generation and Transmission Planning.
5. Evaluate the integration of Renewable Energy Sources (including Utility Scale systems).

Acquisition of Planned Generation, Transmission and Distribution Facilities

1. Conduct technical, economic and/or financial analysis of each project.
2. Prepare bankable project documents for proposed projects.
3. Conduct social and environmental assessments of all projects.
4. Assist in securing financing in the form of grants and loans from Multilateral Financial Institutions, Bilateral development partners and other relevant institutions to fund selected projects.
5. Meaningfully engage the relevant stakeholders at the initiation stage and throughout the duration of all projects.

3.19.4 Technical Loss Reduction

GPL has traditionally focused on non-technical losses in an effort to reduce generation costs and increase revenue. Specific focus will be placed on technical loss reduction to complement the non-technical loss reduction strategies and to enhance the understanding, modelling, and computation of technical losses. This will be done through the following activities:

1. Budgeting and acquisition of the requisite tools, software, licences, etc.
2. Software modelling of Transmission and Distribution Network Loss Profiles.
3. Optimization of Network Designs by incorporating sound engineering to address and reduce power loss.
4. Implementation of Reactive Power Compensation where appropriate.
5. Integration of Distributed Energy Resources (DER).

3.19.5 Staff Training and Development

In alignment with the core strategic objectives, this critical area focuses on building human resource capacity to execute this business plan efficiently and effectively. It is intended to accomplish this through the following strategies, including those applicable from the Organisational Assessment action plan:

1. Identify gaps where training is required.
2. Design, implement, monitor, and evaluate training programmes to address gaps.
3. Establish employee development plans based on the Performance Management System (PMS).
4. Develop and expose staff to modern technologies through conferences, webinars, etc.
5. Create partnerships with academic institutions at various levels.

3.19.6 Project and Risk Management

1. Implement action plans emanating out of the organizational assessment.
2. Utilize corporate risk register to manage risks at the Divisional and departmental levels.
3. Adopt a multi-stakeholder approach to information sharing.
4. Liaise with Supply Chain Management Department to enable the timely procurement of goods and services.

5. Ensure health, safety and environmental matters are addressed by a designated representative on all projects.
6. Institute insurance coverage for all projects as required by law.

4. Non-Technical Operations

4.1 Facilities Management Programmes

The Company projects an investment of US$3.97 M (GY$854.36M) in new accommodation facilities during the life of this programme as presented in Table 51

Table 51: Design and Construction of New Facilities

No.	TYPE OF PROJECT	LOCATION	YEAR	ESTIMATED COST US$
1	Construction of Internal Roads Sophia Complex	Sophia	2022	100,000
2	Construction of RC and chain-link fence to switch yard Sophia Complex	Sophia	2022	50,000
3	Rehabilitation of Perimeter Fences, Guard Hut and Demolition of Building at Power Station Compound, Kingston, Georgetown	Kingston	2022	60,000
4	Rehabilitation of Training School	Sophia	2022	100,000
5	Construction of a Lube Oil Bond at Onverwagt Power Station	West Coast Berbice	2022	60,000
6	Removal of Asbestos Roof Sheets from the Power Station Building and install new roofing sheets at Canefield Power Station	Canefield, Berbice	2022	116,145
7	Rehabilitation of old System Control Building at Sophia	Sophia	2022	20,000
8	Rehabilitation of Mechanical Workshop, washrooms and offices at stores building GOE	Garden of Eden	2022	50,000
9	Rehabilitation Works to Internal Roads and Drains at GPL Compound, Garden of Eden Power Station	Garden of Eden	2022	250,000
10	Repairs to access road and bridge at Canefield Berbice	Canefield, Berbice	2022	60,000
11	Construction of Pile cluster, Canefield	Canefield, Berbice	2022	60,000
12	Construction of Lube Oil Bond and Workshop at Bartica Power Station Compound	Bartica	2022	50,000
13	Rehabilitation to Perimeter Fence at Leguan Power Station.	Leguan	2022	40,000
14	Buildings and infrastructure improvements	Various Locations	2022	511,033
	2022 TOTAL			**1,527,178**
No.	**TYPE OF PROJECT**	**LOCATION**	**YEAR**	**ESTIMATED COST US$**
1	Recommence construction of T & D Main Building at Sophia	Sophia	2023	500,000
2	Recommence construction of Stores Building at Sophia	Sophia	2023	250,000
3	Complete T and D Main Building Sophia	Sophia	2023	150,000

No.	TYPE OF PROJECT	LOCATION	YEAR	ESTIMATED COST US$
4	Rehabilitation works to metering stores, engineer office, carpentry workshop building and extension of washrooms Sophia.	Sophia	2023	70,000
5	Complete the Construction of Internal Roads Sophia Complex	Sophia	2023	125,000
6	Complete the Rehabilitation Works to Internal Roads and Drains at GPL Compound, Garden of Eden Power Station	Garden of Eden	2023	150,000
7	Construction of concrete internal Drains at Canefield Berbice	Canefield, Berbice	2023	75,000
8	Rehabilitation of Building and fence at Onverwagt Engineer's Residence to house T&D	West Coast Berbice	2023	40,000
9	Buildings and infrastructure improvements	Various Locations	2023	413,473
	2023 TOTAL			**1,773,473**
No.	**TYPE OF PROJECT**	**LOCATION**	**YEAR**	**ESTIMATED COST US$**
1	Renovate and extend T & D Building at Versailles	West Bank Demerara	2024	115,000
2	Complete Construction of Stores Building at Sophia	Sophia	2024	250,000
3	Construction of RC drain to North-eastern section of the Sophia Complex.	Sophia	2024	75,000
4	Construction of Revetment to the Western Side of the Compound at GOE	Garden of Eden	2024	125,000
5	Complete the Rehabilitation of Building and fence at Onverwagt Engineer's Residence to house T&D	West Coast Berbice	2024	40,000
6	Buildings and infrastructure improvements	Various Locations	2024	116,144
	2024 TOTAL			**721,144**
No.	**TYPE OF PROJECT**	**LOCATION**	**YEAR**	**ESTIMATED COST US$**
1	Construct T and D Building at East Bank Berbice (location to be determined)	East Bank Berbice	2025	174,216
2	Construct Commercial office buildings at East Berbice, Corriverton, Grove, ECD and Parika	Various Locations	2025	406,505
3	Buildings and infrastructure improvements	Various Locations	2025	185,803
	2025 TOTAL			**766,524**
No.	**TYPE OF PROJECT**	**LOCATION**	**YEAR**	**ESTIMATED COST US$**
1	Complete the construction of T and D Building at East Bank Berbice	New Amsterdam	2026	174,216
2	Complete Commercial office buildings at East Berbice, Corriverton, Grove, ECD and Parika	Various Locations	2026	406,505
3	Buildings and infrastructure improvements	Various Locations	2026	185,830
	2026 TOTAL			**766,551**
	GRAND TOTAL		**2022-2026**	**5,554,897**

4.2 Commercial Division

4.2.1 Critical Issues

The Customer services Division has identified several key areas to enhance the customers experience and their access to services, facilities and information related to their specific services.

4.2.2 New Services

The Company plans to connect approximately 50,540 new consumers to the grid for the period of the D&E 2022 to 2026. This growth in new services recognizes the continued expansion of the housing sector, resulting from the allocation of land by the Government of Guyana for housing and the expansion of existing structures into multi-storey premises. Potential consumers will be encouraged to establish electricity accounts and desist from invitations to acquire electricity through illegal arrangements.

4.2.3 Efficiency and Customer Service Improvements

Whilst the reliability and the quality of the supply of electricity delivered to customers are of significant importance to the Company, the Company remains cognizant of the 'life blood' nature of electricity and remains equally cognizant of the importance of leveraging Information and Communication Technological (ICT) initiatives to improve the efficiencies within its operations.

GPL intends to invest in additional ICT facilities to realize these improvements over the next five years. The investments will facilitate:

- ✓ The extension of the corporate All-Dielectric Self-supporting (ADSS) optical fibre cable to the East Berbice Commercial offices, which will result in an improvement of the performance of the corporate Wide Area Network (WAN).
- ✓ The procurement and implementation of a computerised Business Intelligence System (BIS) that will support the Company's realization of a computerized Enterprise Management Information System (MIS) with strong emphasis on corporate performance against Key Performance Indicators. Implementation commenced in September of 2020 and some Management Information Dashboards were established. The complete suite of Dashboards is expected to be completed by March 2021. These systems were realized through EU/IDB funding under the Power Utility Upgrade Programme (PUUP). All expected BIS activities were completed by PUUP including the provision of a dedicated server, which GPL is still to fully activate.
- ✓ The procurement and implementation of a computerized Document Management System in 2023 to replace the current unwieldy printed document management.
- ✓ The full implementation of a modern computerized Human Resource Management and Payroll Management system within Q2 of 2021
- ✓ The further deployment of an interactive Web Portal to customers for customer account management i.e., recording meter readings, contact numbers, retrieving consumption histories etc.
- ✓ The implementation of a computerized Maintenance Management System in 2021
- ✓ The upgrade the Customer Information System from a client-server platform to a web-based platform in 2021
- ✓ The procurement and implementation of a modern computerized financial budgeting and expenditure monitoring reporting system in 2022
- ✓ The continued leveraging of the corporate GIS.

4.2.4 Customer-centred Services

Customer feedback remains important to the Company, as it forms the basis for developing strategies for correcting deficiencies and crafting strategies for continuous improvements. During the last quarter of 2017, GPL engaged a reputable Company to coordinate and conduct

Customer Satisfaction (qualitative and quantitative) surveys. These surveys will be conducted initially on a quarterly basis and analysed with a focus on improving the quality of customer service.

The Company considers effective information dissemination critical to improving its public image through improved engagements with all stakeholders. It will intensify its information dissemination programs on its electric services via the print and electronic media and from within its Commercial offices. It will also further leverage its ICT solutions in order to improve the 'electronic windows' into GPL. Customer feedback on the on the corporate online account enquiry and the electronic billing services has been encouraging and therefore the Company will continue its efforts to maximize its use of electronic services.

GPL will continue over the life of this programme and beyond to deploy and review strategies and initiatives that will support the Company's efforts to continuously improve its quality of service in order to consistently meet and exceed the Customer Service Standards (CSS) and the Operational Service and Performance Targets (OS&PT). These standards reflect the corporate Key Performance Indicators.

The menu of strategies and initiatives include:

- Further leveraging of the corporate web site www.gplinc.net to present monthly electronic bills, which customers can access and download at their leisure.
- The maximization of a cellular platform that allows customer to retrieve useful account information via the Short Message Service (SMS). This service was introduced as 'SMS Freedom' during 2017.
- The provision of an electronic platform for recording customer retrieved meter readings. This will be subject to GPL's mandatory request to retrieve a minimum of one meter read per quarter.
- One hundred percent (100%) of Advance Metering Infrastructure (AMI) compatible meters. These meters will comprehensively address meter reading issues, disconnection and reconnection, billing, and various billing related queries.
- An expansion of public education initiatives to promote electronic payments via the banking system and the increased use of Payment Agencies, thus widening the options for conducting financial transactions.
- Intensify Corporate Relations efforts using more target audience penetrative methods.

4.2.5 Demand Side Management (DSM) / Energy Efficiency (EE)

GPL continued to signal its endorsement of Demand Side Measurement by crafting information dissemination initiatives aimed at different target groups. GPL's efforts are supported by the EU / IDB funded Social Management Programme within the Power Utility Upgrade Programme (PUUP). The consolidated efforts of the Company's Public Relations Officers and the EU / IDB funded Social Management Specialists resulted in 2018/19 to Community Outreach Meetings in 70 Project Areas with 3200 participants in Regions 3,4,5 and 6 which simulative informational, interactive engagements with residents.

In addition, for the 2019/ 2020 period, the Social Management focused on project areas of Lot A and B with interventions, inclusive of Community Outreach and direct dialogue and consultation with the local democratic organs and customer base in 87 project areas with approximately 2500 participants. Efforts were augmented with information dissemination via the print and electronic media. These activities will be reviewed in order to achieve maximum penetration and will continue over and beyond the life of this plan.

Some of the initiatives deployed were:

- ✓ The Importance of Energy Conservation/Energy Efficiency/Demand Side Management.
- ✓ Benefits of Energy Conservation/Energy Efficiency/Demand Side Management. and
- ✓ Practical saving tips and industry standard best practices.

The initiatives were developed to deliver an improved appreciation of the benefits of effective Demand Side Management (DSM) and their positive effects on:

- ✓ Customers' electricity consumption and by extension electricity bills
- ✓ Reduced cost of generation

The Company continued leveraging its corporate web site to consistently disseminate DSM information within the framework of:

- ✓ Cost reduction (GPL and electricity bills)
- ✓ Reduced CO_2 emissions

GPL will also continue to work closely with the Guyana Energy Agency (GEA) for maximum penetration in the deployment of energy efficient / saving initiatives. The GEA has the national mandate to advise and to make national recommendations to the responsible Minister regarding any measures necessary to secure the efficient management of energy.

4.2.6 Plans to regain Industrial customers:

Industrial consumers expect:

1. A reliable and efficient service.
2. Competitive tariff.
3. Electric service of acceptable quality. and
4. Available capacity to meet their growing needs.

The investments in generation, transmission, sub-stations, control facilities and loss reduction are all geared towards providing a reliable, least cost service. GPL had expected to rebalance its tariffs once power became commercially available from the hydro to remove the cross subsidy currently being provided by non-residential tariffs. GPL remains optimistic of the commissioning of a large hydropower facility in the long-term planning period. Such a facility would positively impact:

- ✓ Reduction in tariffs hence gradually attracting self-generating businesses to the grid; and
- ✓ Continued support of the 'economic development' in alignment with the Government's vision

GPL is also cognizant that industrial customers may be attracted to self-generation from renewable resources (mainly solar) given that the prices are becoming more affordable. In addition, the possibility of selling excess electricity to the grid could increase the attraction to invest in these renewable energy technologies.

The potential attraction of self-generation from renewable resources will also catalyse a tariff review with the objective of establishing more attractive rates that will afford the Company an acceptable level of profitability while encouraging the larger customers to retain their contractual relationship with GPL.

4.2.7 Strategy

1. Leverage current technological platforms to increase and improve customer engagement: Service Fault reports – the ability of customers to send photos or videos of the service fault to the company's call center providing preliminary and useful information to field technicians and assist in effective emergency work scheduling with the objective of reducing the time to rectify service fault.

   (a) Application processing updates – provide customer with electronic updates on the requests for Electric services (New services) via email, WhatsApp, SMS and corporate/ Customer portal. Similarly, for other electric Service requests such as termination of service, change in service, etc.

Collaboration with the National Deeds and Commercial Registries Authority to establish electronic verification of legal documents associated with premises or land occupancy and company registration. This is to further encourage online applications for electric services and reduce the need to visit the company's commercial offices.

(b) Provision of online payments via credit cards and the deployment of Payment kiosks at strategic locations. Whilst the company has a large network of payment agents countrywide, it continues its efforts to encourage bill payments by leveraging the myriad of electronic platforms that offer heightened convenience to customers.

(c) Optimizing the Customer Service portal by ensuring the convenient accessibility to all customer account related information inclusive of consumption, bill and payment histories, bill payments and queries

(d) Ensure optimization of the corporate website, Facebook page and YouTube channels for useful customer information penetration.

2. Leverage Technology platforms for internal services

(a) Further leverage the company's Customer Information system (CIS) and GIS systems to manage customer request/ reports, i.e., use of data in CIS to understand network availability in the area to accommodate new service connections, capital work requirements, magnitude of emergency report, etc.

(b) Leverage the Corporate Customer Information System to accommodate "Fast data Capture" and real time updating by Field staff for various field activities such as new installations, meter changes, disconnected and reconnected services.

(c) Implementation of modern technology: Automated Meter reading (AMR) and a migration to Advanced Metering Infrastructure for remote meter reading retrieval and voltage monitoring and general monitoring of customer' activity at the distribution network level.

3. Reduce commercial losses

(a) Ensuring 100% accounts billed on actual readings consistently through-improved reading timelines and follow up done where discrepancies identified.

(b) Engage Community Based Representatives (CBR) in strategic areas to further support the Company's reach into all communities within served areas as part of the corporate continuous customer service improvement efforts.

4.2.8 Critical Projects

- The use of CIS as the emergency database for reporting
- Consolidation of the Berbice call centre;
- Establish a process for addressing severe instances of meter retrieval failures in excess of 3 months;
- Reviewing meter form types, technical issues with the meters where reads are not randomly available, this project is to be completed in coordination with Loss Reduction Division; and
- Ensuring the standardisation and use of standards in billing procedures.

4.2.9 Key Performance Indication

Key Performance Indicator	Target 2021	Target 2022	Target 2023	Target 2024	Target 2025	Target 2026
New Service application processing time	1 days	1 day	1 day	1 day	1 day	1 day
New Service installation implementation						
Non-Capital	12 days	10 days	9 days	8 days	7 days	7 days
Capital	50 days	40 days	35 days	30 days	25 days	20 days
Response to queries						
Queries Acknowledged - Written	3 days	2 days	2 days	1 day	1 day	1 day
Enquiries Addressed (W / T)	7 days	5 days	4 days	3 days	2 days	1 day
PUC / Legal Issues Resolved	30 days	28 days	21 days	21 days	14 days	14 days
Issuance of bills after meter reading	7 days	7 days	7 days	7 days	7 days	7 days
Meters Read	95%	96%	97%	98%	99%	100%
Reconnections After Payment	2 days	1 day	1 day	1 day	1 day	1 day
Straight connections corrected in 1 day		100%	100%	100%	100%	100%
Call Centre Response	95%	96%	97%	98%	99%	100%
Response to repair calls within 24 hrs.	100%	100%	100%	100%	100%	100%
Meters Tested within 7 days of request	100%	100%	100%	100%	100%	100%
Collection Rate (Average)	95%	96%	97%	98%	99%	100%

4.3 Finance and Supply Chain Management

4.3.1 Critical Issue

1. Delays in the Procurement process.
2. Stock out of Critical Materials.
3. Lack of a Cash Management Policy.
4. Insufficient Control of the Budgeting Process.
5. Level of Insurance coverage on the Company's assets.
6. Level of Receivables Balances and Collectability.
7. Documentation of Related Party Agreements. and
8. Inadequate Asset Management Database.

4.3.2 Strategies

9. Continuous monitoring of the internal control processes
10. Develop a Financial Model to conduct forecasting, sensitivity analysis and to monitor expenditures;
11. Implement a Budget Module to enable us to prepare variance analyses in a timely manner and to enable user departments to access data on a real time basis;
12. Focus on paperless processes by taking advantage of full integration of existing modules;
13. Develop and implement cash management system;
14. Perform cost of service study;
15. Simplify the Procurement processes by reviewing the approval levels, establishing the EOQ and JIT systems and developing electronic signatures.

16. Negotiate better payment terms and review the PPC guidelines to take full advantages of same
17. Improve the Asset Management and Inventory system
18. Perform annual reviews of Accounting Policies and Procedures to refine and enhance;
19. Perform annual reviews of insurance policies;
20. Develop core team to review receivables processes;
21. Highlight the need for the Related Party Agreements;
22. Optimize Capital Structure jointly with the Shareholder;
23. Identify unusable materials from projects and identify assets for disposal;
24. Effectively manage asset disposal process;
25. Implement offsite backup of information;
26. Assess fuel storage requirements and improve where necessary; and
27. Create better work environment and take advantage of the Performance Management System.

4.4 Information Technology Division

The overall objective of the IT Division is to facilitate the flow of current information on GPL's processes and KPI's swiftly and securely to staff, customers, suppliers, and stakeholders, where they need it. This objective will be supported by the following measures:

Figure 9: IT Division KPIs

Item No.	KPI	Target				
		2022	2023	2024	2025	2026
	Infrastructure related					
1	Mission-critical Systems (EBS, CIS, JUICE, Email, Emergency) uptime	99.9%	99.9%	99.9%	99.9%	99.9%
2	Percentage of offices connected via broadband	90%	100%	100%	100%	100%
	Client Services related					
2	Help Desk Response <=1 hour	100%	100%	100%	100%	100%
3	Percentage Help Desk Resolution <= 3 Days (Demerara locations)	95%	95%	95%	95%	95%
4	Percentage Help Desk Resolution <= 5 Days (Esseq. & Berbice locations)	95%	95%	95%	95%	95%
6	Time to complete RFP for purchase of computers	1 day	1 day	1 day	1 day	1 day
7	Time to complete RFP for purchase of phones/ smartphones	1 day	1 day	1 day	1 day	1 day
8	Percentage of computer users provisioned with necessary software	100%	100%	100%	100%	100%
9	Percentage of computer users oriented/ needs assessment/ development plan	90%	100%	100%	100%	100%
	GIS related					
10	Percentage of identified field staff/ teams equipped and oriented to collect structured, digital, geospatial, on-site data	100%	100%	100%	100%	100%
11	Percentage of T&D network documented in GIS	90%	100%	100%	100%	100%
12	Percentage of T&D network inspections documented in GIS	90%	100%	100%	100%	100%
13	Percentage of emergency response cases captured via FDCI/ GIS	90%	100%	100%	100%	100%
14	Percentage of customers documented in GIS	90%	100%	100%	100%	100%
15	Percentage of CIS customer records updated with location data	90%	100%	100%	100%	100%
16	Percentage of CIS “transformer module” updated	90%	100%	100%	100%	100%

Much of the work regarding E-Business will be project-based and would result in and may be measured by efficiency/ accuracy outcomes for Business Units

4.4.1 Critical Issues

1. Infrastructure needs improving and expanding, e.g., bandwidth, to facilitate end-users and the flow of data/ information, Distribution SCADA and AMI/ Smart Grid.
2. A modern, secure user environment needs to be revived/ expanded, including division-level systems under Critical Projects.
3. A reorientation of department managers and end-users to be more performant in data capture (digital, structured, accurate, prompt, on-site) and information-usage. and
4. Computation and data flow for effective planning and decision making.

4.4.2 Strategy

Reorganize IT Division into three teams that will:

1. Provide infrastructure;
2. Provide client services to improve the user capability and user experience;
3. Process data and deliver information, and implement e-Business approaches;

Pivot GPL towards being data-*driven* and an e-Business:

4. Capture current, accurate data about GPL assets (electrical network assets, customers, etc.) and changes regarding these assets.
5. Capture digital, geospatial data immediately when changes occur and on-site where they occur.
6. Use data not opinion or estimates for planning, and reporting operations

An example of such a pivot is the progress made by acquiring a current, field-based census of streetlamps beginning in 2018 using mobile devices (Fast Data Capture method developed by the IT Division), and comparing field counts with data in the Customer Information System (CIS), via an analytical Dashboard, as shown in the three figures below. One outcome was accurate identification of active streetlamp accounts rising from 88 to 125 between 2018 and 2019, with associated current charges increasing from GY$44.5M to GY$66.9M.

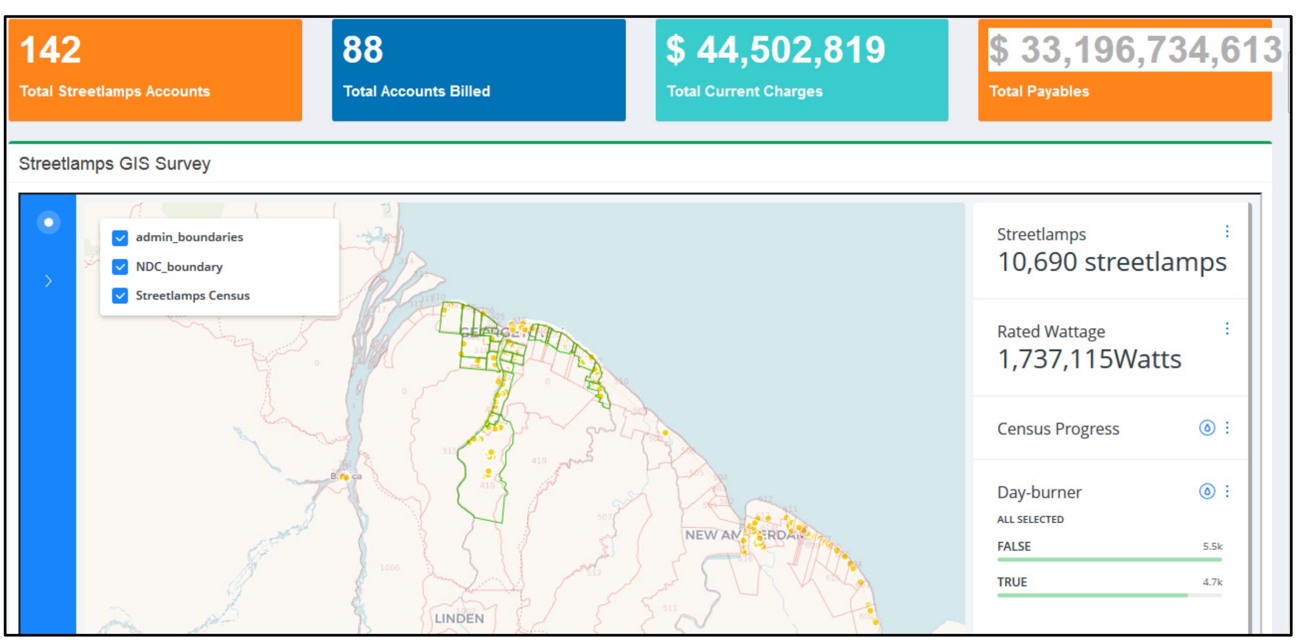

Figure 10: In Apr 2018 as the Streetlamps was underway, GPL billed only 88 of 142 accounts. Data in the CIS used 5+ year old, estimated counts, and active and total accounts were unverified.

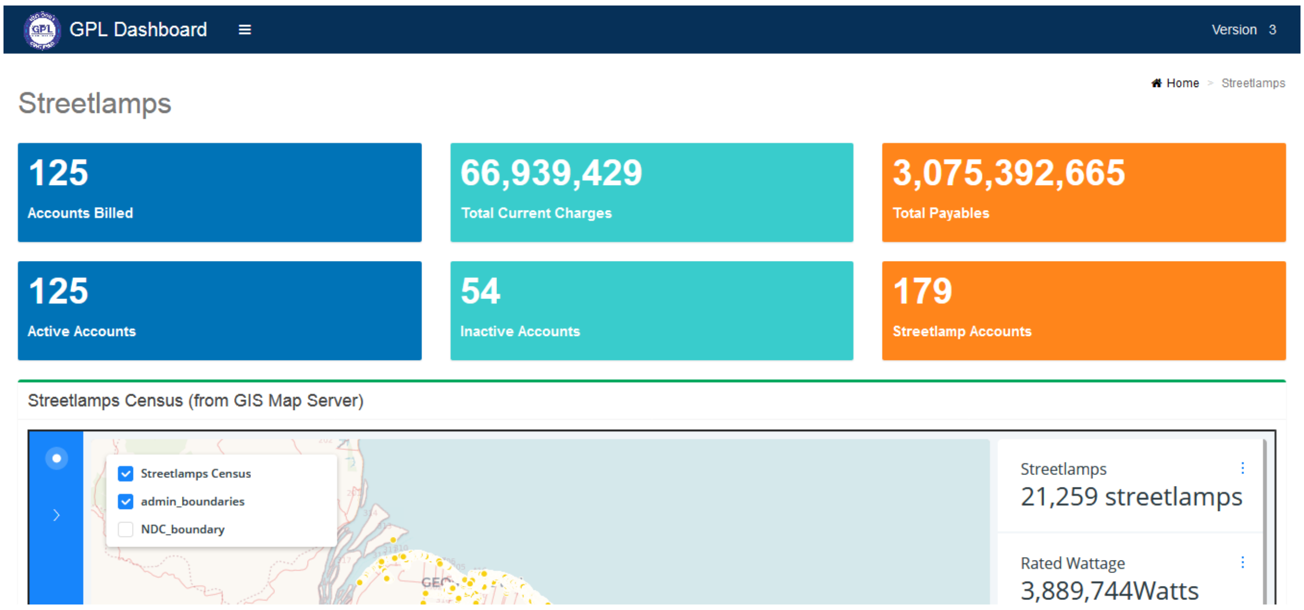

Figure 11: In Nov 2019 when the Streetlamps census completed, GPL began billing 125 of 125 discovered active accounts and 179 total discovered accounts.

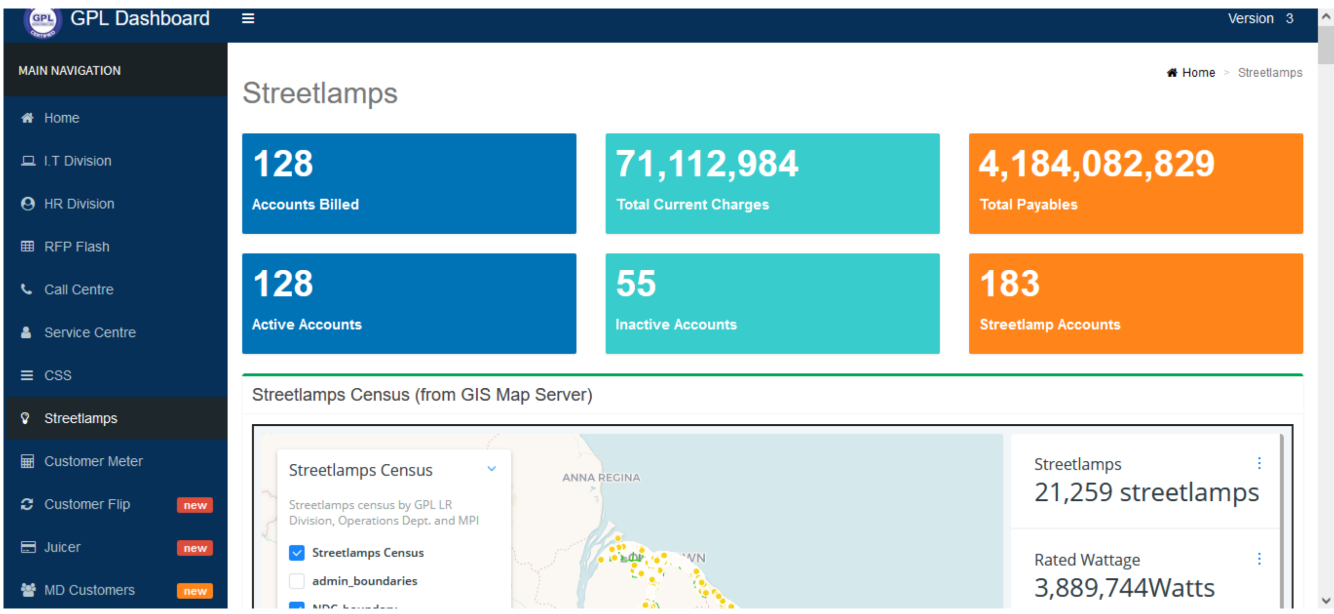

Figure 12: Current (2021) analytical dashboard of streetlamp accounts, with 128 active accounts being billed, of 183 total accounts, associated with 3.9MW of consumption and current charges of GY$71M.

4.4.3 Critical Projects:

1. **Collection and update of customer, feeder and transformer asset and geospatial data in CIS & GIS outside Georgetown**. A 2021 project successfully developed the method for accomplishing this and collected data for Georgetown, with good results.
2. **E-Tender facility**. This has been identified as a critical issue by the Executive, based on feedback from Cabinet
3. **E-Business Suite expansion (Fixed Asset, Budgeting)**. Other useful aspects of a financial system such as budgeting would be brought online
4. **Infrastructure/ WAN restructuring and upgrade**. The WAN will be restructured and upgraded for more seamless management and cybersecurity
5. **Office/ collaboration/ backup software system implementation**. The use of a tool to support to support document creation, storage/ sharing and collaboration will be expanded.
6. **GIS expansion**. The GIS has brought fast, mobile data capture and map visualization to GPL. It will continue to expand the methods/ technology that the company can use to gather data on its assets and operations and develop products/ services that improve decision-making.

7. **Comp. Maint. Mgmt. System**. A system based on accurate, complete, and updated data on electrical network assets and inventory will be put into place.
8. Document Management System
9. **Interactive Web Portal**. The web portal will continue to be a core means of providing customer services 24/ 7/ 365, and developments in this space will be pursued for greater/ wider effect.
10. **HRIS PMS**. The Human Resources Information System (HRIS), which includes payroll and has an associated time and attendance solution was successfully implemented in 2021. A solution for Performance Management will be implemented.
11. **CIS Upgrade**. The roadmap for a less expensive infrastructure/ database and additional useful modules will be implemented.
12. Others. The company will seek to implement Smart Grid and developments to implement/ support the AMI infrastructure and develop solutions for other matters using AI are likely to be necessary.

4.5 Human Resources Division

Development and maintenance of the requisite core of skills to manage the evolving electricity infrastructure that is based increasingly on automation and ICT systems would be critical for GPL. In this regard, GPL will develop and execute targeted training programs in automation engineering in areas where such systems will be introduced.

The continued heavy loss of skills is a severe challenge for the best of plans as new professionals depart after gaining some practical experience. The Company intends to maintain the Management Trainee Programme on an ongoing basis to mitigate the loss of skills at the professional entry levels.

The Company’s intention to align with the Government’s vision on economic development requires training and developing staff in both the technical and commercial components of renewable energy management. GPL will examine a plethora of local and overseas training in order to ensure that it develops and maintains that capacity to manage this evolving technology.

At the technician level, GPL would continue to invest in the apprenticeship programme and specialized six months and one-year intensive programmes to provide the requisite number of entry level technical skills. The Company also intends to review its Management Trainee programme and realign it with the required human resources requirements that is necessary to achieving the objectives outlined in this plan.

The Company will continue to provide opportunities for further tertiary education and professional training. It intends to achieve this by selectively and fairly approving time away from work to attend classes at tertiary institutions. The Company will also consider partial scholarships to employee desirous of pursuing master’s degree programmes that will support GPL’s operations.

4.5.1 Critical Issues

1. There is an urgent need to review and improve the staff recruitment process to ensure that a better quality of staff is recruited in a timelier manner to meet the skills and competencies required by GPL.
2. The induction and on-boarding of staff need to significantly improve to ensure that staff is fully aware of GPL’s personnel policies and their respective roles and responsibilities in their department.
3. The present system for identifying the developmental/training needs of staff needs to be significantly enhanced.
4. The new Performance Management System needs to be fully and effectively implemented to ensure more objective and targeted appraisal of staff.

5. A policy and related procedures for proper Succession Planning at the Management levels needs to be developed and implemented.
6. here is a critical need for a revised Disciplinary Policy and Procedures to a more effective and efficient system for dealing with disciplinary issues.
7. The present system for monitoring safety procedures and effecting remedial actions in a timelier manner needs to be significantly improved.
8. The construction and ongoing maintenance of GPL's facilities needs to be more efficient and timelier to ensure a better environment for staff and customers.

4.5.2 Strategy

1. Review and Update Human Resources Policies and Procedures.
2. Revise and document GPL Organisational Structure.
3. Acquire and implement automated Human Resources Management System.
4. Review and document Recruitment and On-Boarding procedures.
5. Enhance Employee Development and Training programs.
6. Identify and execute training programs in areas of automation engineering including Sensor technology, PLCs, smart devices etc. in consultation with training providers, and tertiary institutions.
7. Implement new Performance Management System.
8. Develop and implement a system for Succession Planning.
9. Review, document and revise Disciplinary Policy.
10. Develop and Implement Change Management.
11. Develop and negotiate proposals for staff Remuneration benefits and conditions of service.
12. Develop and implement programs for Staff Welfare and Social Activities.
13. Conduct annual Employment Engagement survey and develop and implement action plan for improvements in employee engagement.
14. Develop and implement an improved system for Safety, Health and Environmental Management.
15. Develop and implement system for the effective maintenance and construction of facilities.

4.5.3 Performance Monitoring

An affordable, stable, and continuous supply of electricity is critical to the development of Guyana's economy and must be in alignment with the National Development Strategy (NDS). It is therefore imperative for the Government of Guyana and sole shareholder of GPL to be informed of the Company's performance and the extent of its alignment with the NDS via a structured Performance Monitoring and Evaluation mechanism.

In order to formally support this Monitoring and Evaluation mechanism, a Performance Agreement was established between GPL, the Ministry of Finance, and the Ministry of Public Infrastructure, which commenced from January 1, 2017. This Performance Agreement will be reviewed and renewed annually. The agreement will focus on a number of critical Performance measures and Key Performance Indicators that GPL is expected to meet or exceed. GPL will submit performance reports on a monthly basis to the Government of Guyana, through the Ministry of Finance's Monitoring and Evaluation Unit.

In addition to the Performance Agreement, the Company intends to fully implement an objective Performance Management System (PMS) in 2021. This will be aligned with the Corporate Strategic Plan and this programme. Key Performance Indicators and targets will form an integral part of this PMS.

5. Corporate Key Performance Indicators and Targets

GPL has identified Key Performance Indicators (KPI),Table 52, for its main objectives and these have been drilled down to Divisional levels, as reflected in the Divisional Plans. The KPIs are consistent with the Company's mission and vision and cover areas relating to the Company's drive towards 'SUCCESS':

- Service quality.
- Uptime/ reliability of systems.
- Coverage / access to service.
- Compliance with applicable regulations and standards.
- Efficiency in all activities.
- Safety and security. and
- Sustainability.

Table 52: Corporate Key Performance Indicators (KPIs)

Category	Key Performance Indicator	Unit	2021	Targets				
				2022	2023	2024	2025	2026
Service Quality	New Service Application Processing Time	Days	3	2	1	1	1	1
	New Service Installation - Non-Capital	Days	12	10	9	8	7	7
	New Service Installation-Capital	Days	50	45	40	35	30	25
	Queries Acknowledged	Days	3	2	2	1	1	1
	Enquiries Addressed	Days	7	6	5	4	3	2
	PUC/Legal Issues Resolved	Days	30	28	21	21	14	14
	Issuance of Bills After Meter Reading	Days	7	7	7	7	7	7
	Meter Read	%	95	96	97	98	99	100
	Reconnection After Payment	Days	2	1	1	1	1	1
	Straight Connections Corrected in 1 day	%	100	100	100	100	100	100
	Call Centre Response	%	95	96	97	98	99	100
	Response to Repair Calls Within 24 Hours	%	100	100	100	100	100	100
	Meter Tested Within 7 Day after Request (100% in 24 Hours)	%	100	100	100	100	100	100

Category	Key Performance Indicator	Unit	2021	Targets				
				2022	2023	2024	2025	2026
	Emergency Response within 12 Hours	%	60	80	90	95	100	100
	Defective Meter Replacement	Days	60	50	40	30	20	10
Uptime (Reliability)	SAIFI	%	95	90	85	80	75	70
	SAIDI	%	100	95	90	85	80	75
	Generation Plant Availability (Average)	%	85	85	85	85	85	85
Coverage (Access)	Percentage of Households with access to electricity	%	90	92	94	96	98	99
Compliance	Required Reports Submitted on time				100	100	100	100
	Environmental Requirements Met				100	100	100	100
Efficiency	Collection Rate (Average)	%	95	96	97	98	99	100
	Generation Plant Efficiency - HFO	IG/MWh	50.41	50	50	50	50	50
	Generation Plant Efficiency - LFO	IG/MWh	61.6	60	60	60	60	60
	Overtime/Basic Pay	%	38	35	30	25	20	15
	Total Losses/Net Generation	%	27.7	26.5	25	23.5	22	20.5
	Percentage of Projects Completed on Time, while meeting quality and performance requirements	%	87	87	90	92	94	96
	Percentage of Projects Completed on Budget while meeting quality and performance requirements	%	87	87	90	92	94	96
Safety and Security	Number of reportable safety incidents	#	30	26	24	22	20	18
	Person-hours lost due to safety incidents	#	303	260	240	220	200	180
Sustainability	Renewable Energy as % of Energy Generated	%				5	10	15
	Liquidity Ratio	%	1.31	1.36	1.41	1.46	1.51	1.56
	EBITDA/Revenue	%	22	22	22	22	22	22
	Debt/Equity Ratio	%	84	84	84	84	84	84

Category	Key Performance Indicator	Unit	2021	Targets				
				2022	2023	2024	2025	2026
	Staff vacancies adequately filled within 45 days	%	85	86	88	90	92	94
	PMS Reviews completed on time	%	90	92	94	96	98	100
	Required staff training and development programs implemented as per PMS	%	85	86	88	90	92	94
	Employee Engagement Survey Score	%	80	80	82	84	86	88
	World Class Assessment Score (WC 41-50)		20	22	26	31	36	41

5.1 Generation and Network related Key Performance Indicators (KPIs)

Table 53: Operations KPIs

KPIs	Target					
	2021 Achievement	2022	2023	2024	2025	2026
SAIFI	95	90	85	80	75	70
SAIDI	90	85	80	75	70	65
Voltage Complaint	98% within 30 days	98% within 25 days	98% within 20 days	98% within 20 days	100% within 21 days	100% within 20 days
Capital Jobs	95% within 28 days	98% within 21 days	98% within 21 days	98% within 21 days	98% within 21 days	98% within 21 days
Unserved Area Electrification	95% within year	98% within year	98% within year	98% within year	98% within year	100% within year
Emergency Response	80% within 8hrs, 10% within 12hrs and 10% within 24hrs	85% within 8hrs, 5% within 12hrs and 10% within 24hrs	85% within 8hrs, 10% within 12hrs and 5% within 16hrs	90% within 8hrs, 10% within 12hrs	90% within 8hrs, 10% within 12hrs	90% within 8hrs, 10% within 12hrs

KPIs	Target					
	2021 Achievement	**2022**	**2023**	**2024**	**2025**	**2026**
Average No. of Emergency Faults Reported daily	90	80	75	70	65	60
ISO Non-Conformance address within agreed schedules	100%	100%	100%	100%	100%	100%
Annual Average Availability of Generation	85%	85%	85%	85%	85%	90%
Availability GPL	80%	89%	90%	92%	92%	94%
Availability PPDI	92%	92%	92%	92%	92%	92%
Efficiency (Btu/kWh)	9427.08	9548.93	9622.91	9631.85	9447.85	9502.06
Natural Gas (%)	0	0	0	33	53	57
HFO (%)	50	90	95	58	43	40
LFO (%)	60	10	5	10	4	3
Fuel Mix	92:08	0:90:10	0:95:5	33:58:10	53:43:4	57:40:3

6. Summary of Annual Expansion, Upgrades and Service Work Plan (See Appendix 2, page 166 for details by Geographic Areas)

The following capital program sets out to achieve the generation reliability target (LOLP) and transmission and distribution reliability target and assumes that the required funding for the current planning period would be made available.

6.1 Work Plan Summary Short Term Planning (2022-2023)

Generation Projects	
2022-2023	**Conventional Projects**
2023	Wakenaam - Phase 1- Installation of 1 x 410 kW Diesel Generator New Sophia 100 MW Natural Gas Phase 1 Bartica Plant Extension – 1 x 1.12 MW LFO Generator Leguan Plant Extension – 1 x 0.41 MW LFO Generator
2022-2023	Renewable Energy and Energy Storage Projects
2022	Wakenaam 750 kWp Solar PV with 1.151 MWh BESS Bartica 1.5 kWp Solar PV with 0.75 MWh BESS
2023	Leguan 0.6 MWp Solar Farm and 0.8 MWh BESS Total Hybrid Power Generation 30 MW in Berbice

Transmission System and Substation Projects	
2022-2023	**Transmission System**
2022	**69 kV Transmission Lines Projects** 1. New Sophia to Good Hope parallel transmission line (L16P); 2. Garden of Eden to Golden Grove transmission line upgrade (L1 and L3); 3. Golden Grove to New Sophia transmission line upgrade (L4); 4. Golden Grove to Old Sophia transmission line upgrade (L2);
2023	**69 kV Transmission Lines Projects** 1. Old Sophia to New Georgetown transmission lines upgrade (L10); 2. L12 and L13 Upgrade – to facilitate increased power transfer between Old and New Sophia Substations; 3. Splitting of L17 to accommodate Victoria/Enmore substation (L17 and L18); 4. Good Hope to Enmore/Victoria parallel transmission line (L17-P); 5. Enmore/Victoria to Columbia parallel transmission line (L18-Bypass); 6. Kingston to Merriman's Mall transmission line (L11-1);

Transmission System and Substation Projects	
2022-2023	**Transmission System**
	7. Merriman's Mall to New Georgetown transmission line (L11-2); 8. Golden Grove to New Sophia transmission line splitting into Eccles Substation (L4-1 and L4-2); 9. Golden Grove to Old Sophia transmission line splitting into Eccles Substation (L2-1 and L2-2); 10. Edinburgh to Hydronie new transmission line (L8); 11. Vreed-en-hoop to Kingston Replacement Transmission Line (LS6-R);

2022-2023	New Substation System and Substation Upgrade
	SCADA Upgrade and Capability Extension **Substation Upgrade** 1. Canefield Substation and Power Plant facility 2. Garden of Eden Substation; 3. Edinburgh Substation 4. New Georgetown Substation 5. Good Hope Substation 6. Columbia Substation 7. Onverwagt Substation 8. Vreed-en-Hoop Substation 9. Old Sophia Substation **New Substation System** 10. Hydronie Substation 11. Merriman's Mall Substation 12. Eccles Substation 13. Enmore/Victoria Substation 14. Mobile Substation

2022-2023	Transmission Reinforcements
	1. **New Sophia**-15 MVAr 69 kV De-tuned Compensation Systems 2. **Good Hope -**15 MVAr 69 kV De-tuned Compensation Systems 3. **New Geogetown**-15 MVAr 69 kV De-tuned Compensation Systems 4. **Edinburgh-**10 MVAr 69 kV De-tuned Compensation Systems

2022-2023	Electrification – Unserved Areas
2022	463 beneficiaries
2023	3911 beneficiaries
2022-2023	**New Services**
2022	3,481 services from New Housing Schemes and 6,519 services from Existing Housing Areas
2023	6,634 services from New Housing Schemes and 3,866 services from Existing Housing Areas
2022-2023	**Facilities Management**
2022	1. Recommence construction of T & D Main Building - increasing from 2 to 3 stories 2. Construct additional 45' x 30' Building (Projects and Operations) 3. Asbestos removal Canefield power Station - Roof 4. Rehabilitation of Mechanical Workshop, Stores, Power Station offices and washrooms 5. Construction of offices for Generation staff 6. Buildings and infrastructure improvements
2023	1. Complete T and D Main Building Sophia 2. Commence construction of new Training School 3. Commence construction of T and D Building 4. Buildings and infrastructure improvements
2022-2023	**Company Tools**
2022	8,991,554
2023	8,052,258
2022-2023	**Non-Technical Loss Reduction**
2022	1. Upgrade 10,595 meters to AMI meters (PUUP) 2. Replace 3,080 defective meters with AMI meters. 3. Upgrade 25,047 consumers to AMI meters 4. Replace 400 tampered meters to AMI meters
2023	5. Upgrade 7,150 meters to AMI meters (PUUP) 6. Replace 3,080 defective meters with AMI meters. 7. Upgrade 9,089 consumers to AMI meters 8. Replace 400 tampered meters to AMI meters. 9. AMI Infrastructure, implementation, and Professional fees

2022-2023	Distribution Network
2022	**Upgrade of 13.8 kV Primary Distribution Feeders** 1. Golden Grove F1 2. Golden Grove F3 3. New Georgetown F1

	4. Sophia F2 5. Edinburgh F2 6. Good Hope F4 **New 13.8 kV Primary Distribution Feeders:** 7. Parika/Hydronie - 6 new active feeders **Additional Works:** 1. Installation of 17 Reclosers 2. Procurement of switches and Transformers 3. Leguan Feeder Voltage Upgrade
2023	**Upgrade of 13.8 kV Primary Distribution Feeders** 1. Garden of Eden F1 2. Canefield F3 **New 13.8 kV Primary Distribution Feeders** 1. Eccles - 13 new active feeders 2. Merriman's Mall - 8 new active feeders 3. Enmore/Victoria - 6 new active feeders 4. Anna Regina - South Feeder - Express to Onderneeming **Reactive Compensation** 1. 10 x 600 kVar in DBIS

6.2 Work Plan Summary Medium Term Planning (2024-2026)

Generation Projects	
2024-2026	**Conventional Projects**
2024	Anna Regina Plant Upgrade - 2 x 5.5 MW HFO
2025	Anna Regina Plant Upgrade No. 2 – 2x2.5 MW HFO Bartica Plant Upgrade - 2MW, Leguan Power Plant Extension 2 (1x0.41MW), Wakenaam - Phase 2- Installation of 1 x 410 kW Diesel Generator Natural Gas Fired 200 MW Phase 2

2026	Amaila Falls Hydropower 165 MW

2024-2026	**Renewable Energy and Energy Storage Projects**
2024	Between West and East Berbice, a total of 10 MWp Solar PV System Anna Regina 8 MWp Solar PV System and 8 MWh BESS Linden 15 MWp Solar PV Farm and 15 MWh BESS

Transmission System and Substation Projects	
2024-2026	**Transmission System**
2024	**69 kV Transmission Lines Projects** 1. 69 kV Transmission Lines Projects No. 53 to Skeldon parallel transmission line (L23-P); 2. Wales Industrial to Garden of Eden transmission lines (L24 and L24-P) 3. Eccles to Ogle transmission lines (L25 and L25-P); 4. Ogle to LBI transmission line (L26); 5. Wales industrial to Wales Commercial/Residential transmission lines (L30 and L30P); 6. Wales Commercial/Residential to Vreed-en-Hoop transmission line (L31); 7. Wales Commercial/Residential to West Minister transmission line (L32); 8. Bamia to Mackenzie transmission line (L37); 9. Garden of Eden to Bamia new transmission line (L35); 10. Upgrade and splitting of L22 into Williamsburg Substation (L22-1 and L22-2); **230 kV Transmission Lines Projects** 1. Wales Natural Gas to Eccles new 230 kV double circuit transmission line;
2025	**69 kV Transmission Lines Projects** 1. Westminster to Hydronie transmission line (L9); 2. Onverwagt to Canefield bypass transmission line (L21-Bypass); 3. Upgrade and splitting of L21 into Rossignol Substation (L21-1 and L21-2); 4. Upgrade and splitting of L22 into Crab Island Substation (L22-2 and L22-3); 5. Canefield to Crab Island parallel transmission line (L22-1-P);

Transmission System and Substation Projects	
2024-2026	**Transmission System**
	6. Crab Island to Williamsburg parallel transmission line (L22-2-P); 7. Williamsburg to No. 53 parallel transmission line (L22-2-P); 8. Lusignan to Eccles new transmission line (L27); 9. Westminster to Vreed-en-Hoop new transmission line (L33); 10. Eccles to Vreed-en-Hoop new transmission line (L34);
2026	**69 kV Transmission Lines Projects** 1. Columbia to Onverwagt parallel transmission line (L20-P); 2. Enmore/Victoria to Lusignan new transmission line (L28); 3. Splitting of L35 into Yarrowkabra Substation (L35-1 and L35-2); 4. Hydronie to Leguan transmission line (L39); 5. Leguan to Wakenaam transmission line (L40); 6. Wakenaam to Suddie transmission line (L41); 7. Suddie to Devonshire Castle transmission line (L42); 8. Splitting of L8 into Tuschen Substation (L8-1 and L8-2); 9. Splitting of L9 into Tuschen Substation (L9-1 and L9-2); **230 kV Transmission Lines Projects** 1. Amaila Hydro to Bamia new 230 kV Double circuit transmission lines; 2. Bamia to Eccles new 230 kV double circuit transmission lines; 3. Eccles to Williamsburg new 230 kV Double circuit transmission;
2024-2026	**Substation Upgrade System**
2024	1. Good Hope Substation; 2. Garden of Eden Substation; 3. Columbia Substation; 4. Onverwagt Substation; 5. Skeldon Substation; 6. No. 53 Substation; 7. Vreed-en-Hoop Substation;
2025	1. Onverwagt Substation;

Transmission System and Substation Projects	
2024-2026	**Transmission System**
	2. Canefield Substation; 3. Vreed-en-Hoop Substation.
2026	1. Edinburgh Substation 2. Onverwagt Substation; 3. Old Sophia Substation; 4. Columbia Substation;
2024-2026	**New Substation System**
2024	1. Eccles 69/13.8 kV and 230/69 kV Substation 2. Westminster 69/13.8 kV Substation 3. Ogle 69/13.8 kV Substation 4. LBI 69/13.8 kV Substation 5. Williamsburg 69/13.8 kV Substation 6. Wales Residential/Commercial 69/13.8 kV Substation 7. Wales Industrial 69/13.8 kV Substation 8. Bamia 69/13.8 kV Substation 9. Mackenzie 69/13.8 kV Substation 10. Wales Natural Gas 230/69 kV Substation
2025	1. Lusignan 69/13.8 kV Substation 2. Rossignol 69/13.8 kV Substation 3. Crab Island 69/13.8 kV Substation
2026	1. Yarrowkabra 69/13.8 kV Substation 2. Hydronie 69/13.8 kV Substation 3. Tuschen 69/13.8 kV Substation 4. Leguan 69/13.8 kV Substation 5. Wakenaam 69/13.8 kV Substation 6. Suddie 69/13.8 kV Substation 7. Devonshire Castle 69/13.8 kV Substation 8. Eccles 230/69 kV Substation 9. Williamsburg 230/69 kV Substation 10. Bamia 230/69 kV Substation

Transmission System and Substation Projects	
2024-2026	**Transmission System**
	11. Amaila Hydro Substation
2024-2026	**Transmission Reinforcements**
2024	**1. Parika/Hydronie –** 1x3 and 1x2 MVAr 69 kV De-tuned Compensation Systems
2024-2026	**Electrification – Unserved Areas**
2024	550 beneficiaries
2025	0 beneficiaries
2026	0 beneficiaries
2024-2026	**New Services**
2024	1,074 services from New Housing Schemes and 9,926 services from Existing Housing Areas
2025	573 services from New Housing Schemes and 10,927 services from Existing Housing Areas
2026	340 services from New Housing Schemes and 12,160 services from Existing Housing Areas
2024-2026	**Facilities Management**
2024	1. Recommence construction of Stores Building. 2. Renovate and extend T & D Building 3. Complete construction of new Training School 4. Complete construction of T and D Building 5. Buildings and infrastructure improvements
2025	1. Complete Construction of Stores Building at Sophia 2. Commence construction of Commercial office building. 3. Commence construction of Commercial office building. 4. Commence construction of Commercial office building. 5. Commence construction of Commercial office building. 6. Commence construction of Commercial office building. 7. Buildings and infrastructure improvements
2026	1. Complete construction of Commercial office building 2. Complete construction of Commercial office building 3. Complete construction of Commercial office building 4. Complete construction of Commercial office building 5. Complete construction of Commercial office building 6. Buildings and infrastructure improvements
2024-2026	**Company Tools**
2024	US$ 3,674,828
2025	US$ 5,565,402

Transmission System and Substation Projects	
2024-2026	**Transmission System**
2026	US$ 2,228,515
2024-2026	**Non-Technical Loss Reduction**
2024-2026	1. Replace 3,080 defective meters with AMI meters 2. Upgrade 9,089 consumers to AMI meters 3. Replace 400 tampered meters to AMI meters

2024-2026	Distribution
2024	**Upgrade of 13.8 kV Primary Distribution Feeders** 1. Garden of Eden F2 **2.** Garden of Eden F3 **New 13.8 kV Primary Distribution Feeders** 1. Wales Residential/Commercial – 12 new active feeders 2. Interconnection of Leguan, Hogg Island and Wakenaam 3. Wales Industrial – 6 new active feeders 4. Ogle – 8 new active feeders 5. LBI – 8 new active feeders 6. Williamsburg – 8 new active feeders 7. Bamia – 8 new active feeders 8. Columbia – 4 new active feeders 9. Westminster – 6 new active feeders 10. Good Hope – 3 new active feeders 11. No. 53 – 3 new active feeders **Reactive Compensation** 2. 5 x 1050 kVar in DBIS 3. Leguan 3 x 450 kVAr 4. Wakenaam 3 x 450 kVAr 5. Linden 4 x 1050 and 2 x 600 kVAr
2025	**Upgrade of 13.8 kV Primary Distribution Feeders**

	1. No. 53 F2 2. No. 53 F3 3. Anna Regina - South Feeder **New 13.8 kV Primary Distribution Feeders** 1. Lusignan - 8 new active feeders 2. Rossignol - 8 new active feeders 3. Crab Island - 6 new active feeders 4. Canefield - 2 new active feeders 5. Mackenzie - 6 new active feeders **Reactive Compensation** 1. 6 x 600 kVar in DBIS
2026	**New 13.8 kV Primary Distribution Feeders** 2. Yarrowkabra - 4 new active feeders 3. Edinburgh - 3 new active feeders 4. Old Sophia - 4 new active feeders 5. Tuschen - 4 new active feeders **Reactive Compensation** 1. 5 x 1050 kVar in DBIS **SCADA integration of Auto-Reclosers and Automation of Distribution Networks**

7. Operations

7.1 Sales and Revenue Collection

Sales growth from 2021 to 2026 is projected to increase by 364% from 729.5 GWh to 2,656.2 GWh for the total GPL Power Systems (Figure 13). This projection is based on the expected significant stimulation in the economy that will be provided by the emerging Oil and Gas Industry. The Company projects an increase in its customer base from 210,732 in 2021 to potentially 261,272 by the end of Year 2026 (Table 7). The projected increase in the customer base is largely as a result of the increased economic activities, which are expected to result from 1) population growth, 2) increased business activities and 3) providing services to all existing un-served areas.

The active campaign to improve Receivables will continue and a cash collection rate of 99.5% (cash collections as a percentage of sales) has been assumed for the life of this Programme.

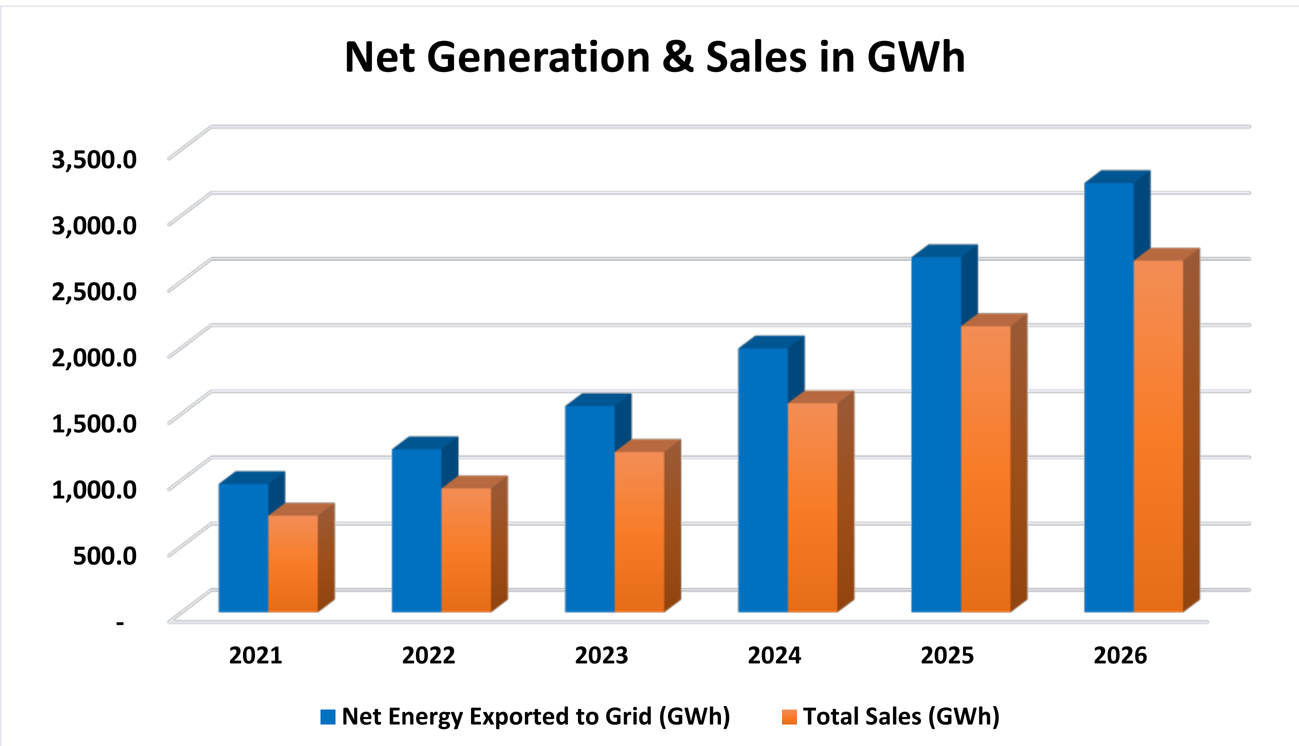

Figure 13:Net generation & Sales (GWh)

8. Projected Capital Expenditure

8.1 Summary of Capital Expenditure, US$ - GPL Funding

Table 54: Summary of Capital Expenditure, US$ - GPL Funding

CAPITAL EXPENDITURE SUMMARY & SOURCE OF FUNDING						
Development and Expansion Projects: Years 2022-2026		**Annual Budget (US$)**				
	Total Project Cost	**2022**	**2023**	**2024**	**2025**	**2026**
	US$	**US$**	**US$**	**US$**	**US$**	**US$**
Conventional Generation	1,506,400,139	340,591,522	277,270,790	396,436,055	353,501,772	138,600,000
Non-Conventional Generation	90,840,517	52,209,517	38,631,000	-	-	-
Grid Automation	131,305,683	-	-	39,391,705	52,522,273	39,391,705
69 kV Transmission Lines (Include Sub. Exp. Cost)	138,170,826	10,754,439	32,080,222	42,516,094	35,850,780	16,969,291
230 kV Transmission Lines (Include Sub. Exp. Cost)	915,252,919	-	24,995,324	345,709,445	370,586,775	173,961,375
Upgrade - Existing 69/13.8 kV Substation	15,637,965	3,151,837	5,719,812	4,993,214	438,422	1,334,679
New 69/13.8 kV Substation	160,527,849	23,805,497	56,005,036	39,197,280	28,337,755	13,182,281
230 kV Substation - New	75,230,248	10,424,526	13,899,368	22,569,074	16,192,731	12,144,549
New Primary Distribution Feeders	35,962,799	4,762,513	11,670,315	11,158,544	5,964,144	2,407,283
Upgrade to Existing Primary Distribution Network (Technical Loss Reduction)	30,542,373	21,932,544	4,407,170	2,752,444	1,450,214	-
Transmission Reactive Reinforcement	679,800	-	260,040	173,360	147,840	98,560
Distribution Reactive Reinforcement	406,282	-	102,806	182,925	61,684	58,867
Power Plant Switchgear Upgrades	2,057,951	280,500	838,437	939,014	-	-
Meter Upgrades/Replacements (Non-Technical Loss Reduction)	32,802,395	6,340,270	5,650,000	6,937,375	6,937,375	6,937,375
Electrification (Unserved Areas)	3,426,067	1,212,792	1,704,556	219,987	164,990	123,743
New Services	13,212,605	1,623,760	2,133,141	2,642,521	3,151,901	3,661,281
Buildings	5,554,897	1,877,178	1,423,473	721,144	766,551	766,551
Company Vehicles and Tools	28,512,557	8,991,554	8,052,258	3,674,828	5,565,402	2,228,515
Information Technology	1,325,000	855,000	470,000	-	-	-
GRAND TOTAL - EXCLUDING GAS PIPELINE AND PROCESSING PLANT	**3,187,848,872**	**488,813,447**	**485,313,749**	**920,215,010**	**881,640,609**	**411,866,056**

SOURCE OF FUNDING		**Annual Budget (US$)**				
	Total Project Cost	**2022**	**2023**	**2024**	**2025**	**2026**
GPL Shareholder Funds (Retained earnings, Loans from Shareholder, Equity con	461,037,973	88,969,855	130,423,336	109,339,178	84,537,177	47,768,427
FDI	2,633,561,211	345,658,305	315,999,373	810,702,472	797,103,432	364,097,629
Loan	7,472,687	5,983,287	1,316,040	173,360	-	-
Grant	85,777,000	48,202,000	37,575,000	-	-	-
TOTAL	**3,187,848,871**	**488,813,447**	**485,313,749**	**920,215,010**	**881,640,609**	**411,866,056**

9 Operating costs and Capital Expenditures

Accounts Summaries Profit & Loss Account

Table 55:Profit & Loss Account

		2021	Yr 2022	Yr 2023	Yr 2024	Yr 2025	Yr 2026
		Latest Estimate	Proj	Proj	Proj	Proj	Proj
		$'M	$'M	$'M	$'M	$'M	$'M
REVENUE							
Turnover		35,706	39,885	57,321	74,737	93,012	102,915
Rebate		1,461					
NET REVENUE		**34,245**	**39,885**	**57,321**	**74,737**	**93,012**	**102,915**
GENERATION COSTS							
Fuel & Freight		23,436	31,253	14,533	24,235	9,342	4,971
Operation & Maintenance Contract		2,807	2,772	1,789	3,283	1,566	1,133
Repairs & Maintenance - Generation Facility		765	797	753	753	753	753
Purchased Power (IPP costs)		2,755	1,977	17,800	18,371	25,157	34,570
Rental of Equipment		251	-	-	-	-	-
Fuel Agency Fee							
		30,014	**36,799**	**34,875**	**46,643**	**36,818**	**41,427**
GROSS INCOME		**4,231**	**3,086**	**22,446**	**28,094**	**56,194**	**61,488**
EXPENSES							
Employment Costs		5,094	5,619	6,181	6,799	7,479	8,227
Repairs & Maintenance T&D		534	1,880	2,702	3,523	4,384	4,851
Depreciation		3,685	3,933	5,296	7,186	8,758	9,971
Administrative Expenses		2,192	2,960	3,197	3,453	3,729	4,027
Rates & Taxes		51	50	54	58	63	68
Loss On Exchange		-	-	-	-	-	-
Bad Debts Provision		447	598	860	1,121	1,395	1,544
Puc Assessment & Licence		73	73	75	75	100	100
		12,076	**15,113**	**18,364**	**22,215**	**25,908**	**28,787**
NET (LOSS)/PROFIT FROM OPERATIONS		**(7,845)**	**(12,027)**	**4,082**	**5,879**	**30,287**	**32,701**
INTEREST EXPENSE		1,135	1,335	4,081	5,024	5,752	6,163
		(8,980)	**(13,362)**	**1**	**855**	**24,535**	**26,538**
OTHER INCOME		649	1,023	2,150	2,803	3,488	3,859
		(8,331)	**(12,339)**	**2,150**	**3,658**	**28,023**	**30,397**
TAXATION		62	60	323	549	4,203	4,560
NET (LOSS)/PROFIT FOR THE YEAR		**(8,393)**	**(12,399)**	**1,828**	**3,109**	**23,819**	**25,838**

In accordance with GPL's Licence the Shareholder is entitled to a target rate of return on equity of 8% per annum.

9.2 Cash Flow Statement

Table 56: Cash Flow Statement

Guyana Power & Light Cash flow Statement for the year ended December 31st	Yr 2022 Proj $'M	Yr 2023 Proj $'M	Yr 2024 Proj $'M	Yr 2025 Proj $'M	Yr 2026 Proj $'M
OPERATING ACTIVITIES					
Profit/(Loss) before Taxation	**(12,339)**	**2,150**	**3,658**	**28,023**	**30,397**
Adjustments for:					
Depreciation	3,933	5,296	7,186	8,758	9,971
Deferred Income	3	14	14	14	8
Deferred Tax Asset	(555)	(611)	(672)	(739)	(813)
Interest Expense	1,335	4,081	5,024	5,752	6,163
Amortization of Customer Projects					
Operating (loss)/profit before WC changes	**(7,623)**	**10,930**	**15,210**	**41,808**	**45,726**
Working Capital (WC) Changes					
Change in Inventories	(262)	(275)	(289)	(303)	(319)
Change in receivables and prepayments	1,237	(2,906)	(2,903)	(3,046)	(1,651)
Change in payables and accruals	(717)	3,007	(933)	(2,969)	(2,782)
Change in related parties	0	0	0	0	0
Taxes paid	(1,002)	545	(331)	(2,754)	(4,418)
Net Cash (Outflow)/Inflow - Operating Activities	**(8,367)**	**11,301**	**10,754**	**32,736**	**36,557**
INVESTING ACTIVITIES					
Acquisition of Property, plant and equipment	(12,263)	(29,123)	(30,782)	(27,533)	(22,205)
Acquisition of Intangible assets	(166)	(200)	(240)	(288)	(345)
Increase in WIP	2,745	(3,167)	1,914	2,150	3,166
Acquisition of treasury bills	0	0	0	0	0
Increase in deposit	(4)	0	0	0	0
Net Cash Outflow - Investing Activities	**(9,689)**	**(32,490)**	**(29,108)**	**(25,670)**	**(19,385)**
FINANCING ACTIVITIES					
Movement in non current related parties	19,896	30,634	23,573	18,197	10,282
Deposit on Shares	0	0	0	0	0
Interest paid	(1,335)	(4,081)	(5,024)	(5,752)	(6,163)
Customer deposits	457	1,908	1,906	2,000	1,084
Increase in advances customer financed projects	225	940	938	985	534
Decrease in advances customer financed projects					
Net Cash (Outflow)/Inflow - Financing Activities	**19,243**	**29,400**	**21,393**	**15,429**	**5,736**
NET MOVEMENT IN CASH AND CASH EQUIVALENTS	**1,187**	**8,212**	**3,039**	**22,495**	**22,909**
CASH AND CASH EQUIVALENTS AS AT BEGINNING OF YEAR	(3,187)	(2,000)	6,212	9,251	31,746
CASH AND CASH EQUIVALENTS AS AT END OF YEAR	**(2,000)**	**6,212**	**9,251**	**31,746**	**54,654**
Represented By:					
Cash on Hand and at Bank	**(2,000)**	**6,212**	**9,251**	**31,746**	**54,654**

9.3 Balance Sheet

Table 57: Balance Sheet

Guyana Power & Light	Yr 2021	Yr 2022	Yr 2023	Yr 2024	Yr 2025	Yr 2026
Statement of Financial Position	Unaudited	Proj	Proj	Proj	Proj	Proj
As at December 31st	$'M	$'M	$'M	$'M	$'M	$'M
ASSETS						
Non Current Assets						
Property, plant and equipment	37,983	46,313	70,140	93,736	112,512	124,746
Intangible assets	832	998	1,198	1,438	1,725	2,070
Work in progress	10,920	8,175	11,343	9,429	7,279	4,113
Deferred tax assets	5,550	6,105	6,716	7,387	8,126	8,938
	55,285	**61,592**	**89,397**	**111,990**	**129,641**	**139,868**
Current Assets						
Inventories	5,241	5,503	5,778	6,067	6,370	6,689
Receivables & Prepayments	7,884	6,648	9,554	12,456	15,502	17,153
Deposits	592	588	588	588	588	588
Related parties	3,458	3,458	3,458	3,458	3,458	3,458
Investments	3,105	3,105	828	828	828	828
Cash resources	(3,187)	(2,000)	6,212	9,251	31,746	54,654
	17,093	**17,302**	**26,418**	**32,648**	**58,492**	**83,370**
Total Assets	**72,378**	**78,894**	**115,814**	**144,638**	**188,133**	**223,238**
EQUITY & LIABILITIES						
Share Capital	23,118	23,118	23,118	23,118	23,118	23,118
Accumulated deficit	(24,455)	(36,854)	(35,027)	(31,918)	(8,098)	17,739
	- 1,337	**- 13,736**	**- 11,909**	**- 8,800**	**15,020**	**40,857**
Non Current Liabilities						
Related Parties	54,007	73,670	102,027	125,600	143,796	154,078
Advances customer financed project	1,568	1,752	2,517	3,282	4,085	4,519
Provision for decommissioning	243	243	243	243	243	243
Customer deposits	3,907	4,364	6,272	8,178	10,178	11,261
Defined benefit liability	742	851	851	851	851	851
Deferred tax liability	831	947	947	947	947	947
	61,298	**81,827**	**112,857**	**139,100**	**160,099**	**171,900**
Current liabilities						
Related parties	-	-	-	-	-	-
Deferred Income	28	31	45	59	73	81
Advances customer financed project	356	398	572	745	927	1,026
Payables and accruals	11,959	11,242	14,249	13,316	10,347	7,565
Taxation	74	- 868	-	218	1,667	1,809
	12,417	**10,803**	**14,866**	**14,337**	**13,014**	**10,481**
Total Equity and Liabilities	**72,378**	**78,894**	**115,814**	**144,638**	**188,133**	**223,238**

10 Impact of programme on Natural & Social Environment

The planned addition, replacement, upgrade, and conversion, where applicable as per current expansion plan, of thermal generation at Garden of Eden, Bartica, Canefield and Anna Regina and the current fleet of Wärtsilä generation at Kingston, Vreed-En-Hoop and Garden of Eden would be in compliance with the Environmental Protection (Amendment) Act, 2005, while older generation assets at Garden-of-Eden (Niigata generators) and Onverwagt will be retired or relegated to occasional use. GPL expects to lower its environmental impact - from the use of modern generators and the retirement of old, inefficient generators.

More importantly, the intended use of renewable resources as informed by the development and expansion programme 2022-2026 would have a net positive environmental impact. The Company will continue to ensure EPA's approval for all generation investments regardless of energy source.

Concerning the social environment, GPL will continue its cost-effective investments in addressing the electrification of unserved areas and T&D networks to improve supply reliability and quality, and customer services. The Company will establish a framework (Distribution Code) for the controlled penetration of distributed generation from renewable resources. Prudent financial management will continue balancing capital investments, operational expenditures, and tariffs. The Company expects these strategies and initiatives to impact both the society and economy positively.

GPL is, however, conscious that the removal of illegal services, prosecuting persons caught stealing electricity and taking prompt and firm steps to collect revenues would have some social consequences. These measures are likely to generate some negative social impact, especially by the perpetrators of illegal activities. To address this, the social management plan, with its three-pronged approach (before, during and after) is anticipated to improve expected results.

11 Major Risks and Contingencies

11.1 Risk: Electricity Theft

A section of the population engages in illegal electricity consumption that negatively impacts internally funded capital investments and reduces operational performance, potentially becoming worse as the network expands according to the D&E projects. This D&E Programme is targeting sustainable loss reduction, which remains a challenge to GPL. The Company embraces the investments financed jointly by the IADB and EU via its PUUP Social Management programme, yet it remains cognizant and concerned of the culture of a section of the population who persist in this illegal practice.

As a result of electricity theft, GPL may have no option but to adjust/defer the timelines of the development and expansion programme accordingly, especially in the event where the Company's cash flow becomes insufficient and necessary concessional loans/grants may become unavailable during the life of this programme. GPL's current revenue projections provide for some capacity to absorb a degree of financial loss due to electricity theft; however, excessive financial losses can significantly derail future D&E projects.

11.1.1 Contingency Measures: Electricity Theft

In terms of recovering financial loss due to electricity theft, GPL recovers money via back-billing errant customer accounts; in cases where a customer is unwilling to pay, the Company's Legal department steps in with high levels of success as long as internal commercial issues are virtually non-existent. In the case of non-customers, the Guyana Police Force engages in arrests and relevant prosecution.

Although there are no assurances that loan/grant resources to GPL would continue to be available, the Company remains optimistic of the Government's interest in the execution of this five-year programme, which is designed to improve reliability and quality of electricity service. Additionally, GPL is hopeful that the PUUP Social Management programme, in conjunction with the continued execution of corporate development plans, will mitigate this unsavoury practice.

11.2 Risk: Fuel Price Volatility

Fuel price can spike upwards due to world HFO demand, meaning it will be more expensive to operate generation assets. Such a movement in HFO price would reduce internal cash flow, as well as affect financing D&E projects. Whilst the Company's license provides for rate adjustments and fuel surcharges and rebates, GPL remains cognizant of the impact of increased rates of fuel surcharges to its customers and the economy. Nonetheless, it is unlikely that any unavoidable upward adjustment to rates or fuel charges would be significant to impact the availability of internal funding. It should be noted that GPL does not have a hedging strategy; fuel price is determined by 3-day averages from prevailing prices.

11.2.1 Contingency Measures: Fuel Price Volatility

GPL can apply rate adjustments, fuel charges and rebates to cushion financial impact; however, PUC and the Majority Shareholder need to approve this. Additionally, a subvention can be provided to further support the Company in supplying electricity to its customers. Renewable energy and natural gas initiatives are being developed to reduce dependence on foreign fuel supply and related price fluctuations. Continued use of HFO fired generation does provide baseload power. However, it is frowned upon, given the country's aggressive global climate change commitments. The Company will continue to examine power generation from natural gas and intends to use this option for planned firm capacity additions.

It should be noted that GPL is committed to broadening its energy portfolio with renewable energy – solar and wind in particular. However, the intermittent supply of electricity from these sources without significant energy storage will require the use of fossil-fired generation to satisfy the forecasted demand. Regardless, the incremental introduction of these sources of renewable energy should deliver generation cost savings and contribute to a reduction in CO2, NOx and SOx emissions - improving the grid emission factor. Also, the notable and continued decline in energy storage prices and the increased investment in this technology should reduce the degree of intermittency of electricity generation from solar and wind, thus increasing the attraction of these technologies to contribute to generation capacity, which in turn would assist satisfying the LOLE target.

11.3 Risk: Availability of Fuel Supply

Similar to fuel price, external sources continue to be the main source of fuel supply to GPL. As such, unforeseen and uncontrolled circumstances can hinder reliable fuel supply, resulting in generation shortfall and poor reliability performance. Additionally, new environmental requirements placed on marine vessels only utilize ship fuel with Sulphur 2% has a number of effects, ranging from reducing the quantity of fuel that can be supplied to GPL, to raising prices and impacting GPL's strategic fuel suppliers. This can lead to dissatisfied suppliers deciding to terminate shipment contracts with GPL, which can then increase time taken for GPL to seek other means of fuel supply – the consequence being increased late shipments, low fuel stock levels and load shedding.

11.3.1 Contingency Measures: Availability of Fuel Supply

GPL has a contract mechanism where foreign suppliers can financially compensate the Company for late fuel shipments - this can help with purchase of fuel locally. The Company is also considering spot contracts to bolster fuel availability in event of low stock levels. Additionally, GPL is focusing on RE projects with the aim to decrease dependency on imported fuels. The Company remains mindful of the risk involved in the availability of fuel supply and is currently planning to expand on-land fuel storage capacity across locations.

11.4 Risk: Foreign Exchange Rate

Global currencies tend to fluctuate; however, a weakening of the Guyana Dollar (relative to USD/Euro/Pound) can have negative impacts ranging from GPL ability to fund internal capital investments and maintain operational performance, to paying staff and servicing its debts.

Traditionally, GPL relies on loans to fund investments for infrastructural development. The funds (equity and debt) required for the high initial investment cost associated with energy infrastructure typically come from multilateral financial agencies, denominated in USD/Euro/Pound.

11.4.1 Contingency Measures: Foreign Exchange Rate

GPL intends to continue working with the Bank of Guyana and the Government of Guyana to ensure that investments for infrastructural developments projects do not adversely impact the cost of operation and to a more considerable extent, electricity tariff

11.5 Risk: Cyber Threat

Cyber threats are evolving at a tremendous pace, exploiting capabilities created by the modernisation of power systems. This is related to the transition from a centralized power system, based on large power stations and vertically integrated utilities, to a decentralized power system model, as well as the complementary evolution of advanced communication and digital systems.

As GPL modernizes the power system, it becomes increasingly dependent on communication systems for its operations, and as a result increasingly susceptible to cyberattacks. While integrating information technologies is essential to building the smart grid and realizing its benefits, the same networked technologies add complexity and introduce new interdependencies and vulnerabilities to potential attackers and unintentional errors.

The Company has noted that cyber-attacks can be dormant, widely distributed, and executed at a time pre-set by attackers. Once executed, adverse impacts may be difficult to detect. Cyber-attacks lead to unseen damage in operation, information, and control systems.

Potential cybersecurity threats include, but are not limited to the following:

- Smart meters may be used by hackers as entry points into the broader power system;
- unauthorized interference on the measurement of electricity consumption (end-users);
- trip a power-generating unit;
- cause a blackout in a large area of the grid; and
- disrupt the proper functioning of the system.

Currently, SCADA is isolated from the larger network of the Company, so risks to SCADA is perceived as minimal (known unknown risk). The IT Division has an ad hoc programme to make employees aware of cyber risks. The division is currently developing a structured programme and intends to introduce a specific Cyber Security resource into its staff complement.

11.5.1 Contingency Measures: Cyber Threat

There is a variety of technical and administrative cybersecurity best practices, which GPL must adapt and implement. These technical practices include, but are not limited to the following:

1. Network firewalls;
2. Antivirus software;
3. Application control software;
4. Encryption of communication data;
5. Securing smart grid technology upgrades; and
6. Intrusion detection systems.

GPL does have network firewalls, antivirus protection, insurance for tangible/intangible assets (digitized information and IT assets) as well as an internal awareness programme for running on a monthly basis; this is to be praised. However, GPL must now expand on these and other methods of protection against IT threats in a more structured and results-oriented manner.

Considering that GPL needs to focus its efforts on securing its assets, infrastructure and implementing advanced metering cyber security requirements, the Company will engage an IT security expert to assist it to mitigate the risks related to cybersecurity breaches by:

1. developing failure scenarios,
2. assessing GPL’s cyber resiliency,
3. conducting penetration testing on GPL systems, and

4. creating and refining a GPL cyber resiliency plan and policy.

11.6 Risk: Physical Attack

For GPL, system outages pose large adverse financial impacts on the country, across all tariff categories. Potential coordinated physical attacks (terrorism and riots) are a growing concern for the Company as it seeks to develop a resilient electric power system. With GPL moving towards the use of natural gas-fired power generation, this can pose vulnerabilities if a high-impact event disrupts the gas pipeline or gas processing infrastructure.

The Company is cognizant of the fact that it has to focus attention on enhancing physical security and resiliency against physical attacks at substations, generation, transmission and distribution facilities. It is known that transmission lines, substations, communications facilities, or natural gas supplies are susceptible to attacks with little or no risk of early detection.

Deliberate attacks can result in more-focused damage to facilities and equipment in substations compared to natural events. Substations, in particular, can be seen as targets, and power system's future dependence on natural gas pipelines and supervisory control and data acquisition (SCADA) communication systems, as attack points, are equally disruptive.

11.6.1 Contingency Measures

The following are critical parts of an effective physical security approach that the Company t seeks to adapt:

- **Physical barriers around security perimeters**: Physical barriers can prevent access to people and ground vehicles and can enclose equipment housings and supports.
- **Remote monitoring:** Remote monitoring detects intruders and monitors equipment. The Company intends to enhance its remote monitoring and surveillance capabilities of perimeters and access points detects approaching intruders and those attempting entry.
- **Vulnerability assessment**: The Company is cognisant of the benefits of a vulnerability assessment of critical components, which can include ballistic vulnerability. GPL plans to accomplish this task by coordinating a lessons-learned database on material vulnerability based on real-life examples.
- **Recovery and response**: The Company also recognises the need for and importance of effective response immediately after a physical attack is vital.

11.7 Risk: Extreme Weather Events

The resiliency of GPL's electric power system is threatened by extreme weather events that present a risk to system reliability and quality of service to customers. The major and severe weather events that are relevant to the Company are:

1. Flooding that arises out of sea-level rise,
2. Flooding that arises out of heavy rain fall,
3. Drought and heatwaves, and

4. Strong wind gusts.

In the past, these extreme weather events inflicted considerable damages to the Company's electric infrastructure and resulted in customers being without power for several days.

Flooding and Sea-level Rise

Guyana is classified as a high flood risk country, with the most significant vulnerability experienced within the coastal zone. The coastal region is prone to flooding as a result of the changes in rainfall pattern due to climate change and the fact that the coastal portions of Guyana sit about 0.5 meter to 1 meter below sea-level. Approximately 90% of Guyana's population lives along the coast, as such, the bulk of GPL's electrical infrastructure is concentrated along this region.

Consequently, GPL's generation and delivery assets, as well as the broader energy system infrastructure, are vulnerable to damages arising from flooding due to extreme events. Increases in excessive rainfall over the years have increased the frequency of flooding events in Guyana's' coastal regions. Flooding threatens coastal infrastructure and capital assets that are vital to the Company, as well as ports and other transportation networks that could affect fuel distribution or other essential resources. Current vulnerabilities could be exacerbated by the rising sea-level leading to more extensive flooding.

Drought and heatwaves

Extreme events in the form of droughts and heatwaves threaten the Company's electricity system by restricting water resource availability for power generation - cooling. Moreover, diminished surface and groundwater levels require additional energy to pump water. Drought and heatwaves result in elevated ambient temperatures that can reduce generation efficiency and reliability, as well as increase energy losses in the transmission and distribution systems, while increasing demand due to the need for ambient cooling and pumping of water. Decreased water availability directly impact cooling operations in various ways.

Droughts and heatwaves can exacerbate existing challenges related to water resource allocation, competition with other sectors (e.g., agriculture and industrial uses), and water quality.

Strong wind gusts

A wind gust can be described as a sudden, brief increase in wind speed followed by a calm to no breeze. This extreme weather event in Guyana has resulted in the Company suffering power outages and impassable paths to access the damages to conduct repair works and quick restoration of electricity. Over the years, GPL has been implementing measures to improve its infrastructure. However, in some cases, it came at a considerable cost to ensure reliable electricity service is provided in times of great needs for security, comfort, and other electric dependent utility services (water and communication).

11.7.1 Contingency Measures: Extreme Weather Events

The Company and its assets are exposed to a variety of threats. The risks presented now and, in the future, must be examined and mitigated. Protecting GPL's assets from extreme weather events can be accomplished in various ways, including reinforced towers, substations, and underground systems and other equipment. Options include raising existing - and installing new - flood walls; adding to spare parts inventory; incorporating submersible transformers, switches, and pumps; sealing manhole covers and conduit/cable penetrations, storing emergency supplies remotely, using weatherproof enclosures, and establishing a corporate emergency response centre.

Some of the resilience solutions or mitigation strategies suggested to reduce the impact of extreme weather events include:

- Ensure that there are sufficient and adequately distributed power generation facilities across the country, such that, in the event of loss of transmission lines, power can be locally generated and distributed;
- Use of concrete/steel structures with properly designed foundations on the transmission and distribution networks;
- Construction of parallel/contingency transmission network, such that the grid can be compliant with the N-1, N-2 and N-1-1 contingencies requirement of the National Grid Code;
- Implement self-healing smart distribution solution in densely populated areas/villages or communities and towns;
- Use of submarine class underground distribution network where applicable; and
- Ensure strict transmission and distribution network maintenance schedule using modern technology and methods.

12 Cost Benefit Analysis of Investment Projects

This cost benefit analysis has been premised on the understanding that investments in generation, transmission and distribution networks constitute the power system that is necessary to supply reliable electricity and generate revenues to ensure sustainability of GPL.

The proposed investment in the current Development and Expansion Programmes are geared towards not just responding to the energy demands of the nation, but to pre-emptively prove the energy that will provide a solid foundation for economic growth. In this context the interventions in this D&E will have a meaningful impact on national growth and development beyond the cost benefit analysis and other metrics provided herein.

Notwithstanding, the overall economic and financial assessment of the D&E Programme, presented below, shows that all aspects of development and expansion that relate to Generation, Transmission and Distribution, Loss Reduction and Electrification of Unserved Areas result in positive internal rate of return (IRR) and all achieve positive Net Present Values and Positive Discounted Benefit Cost Ratios, with the exception of Transmission and Distribution which has a negative net present value.

For the analysis presented here the following assumptions are incorporated:

A discount rate of 8% for Present Value calculations, an interest rate of 5% per annum for financing of investment amounts and a financing maturity period of 25 years, except for analysis on Unserved Areas which assume a 10-year maturity period for financing.

12.1 Generation

The identified generation projects for the indicative five-year period cumulatively cost US$1,597 million in nominal value equivalent to a Net Present Cost (NPC) of US$1,303 million. The key metrics from these projects are given in Table 56 and Figure 8.

Table 58: Summary of Cost-Benefit assessment – Capital Investment in Generation

Net Present Value	US$130 million
Internal Rate of Return	9.1%
Cost Benefit Ratio	9.9
Discounted Pay-Back Period	21 years

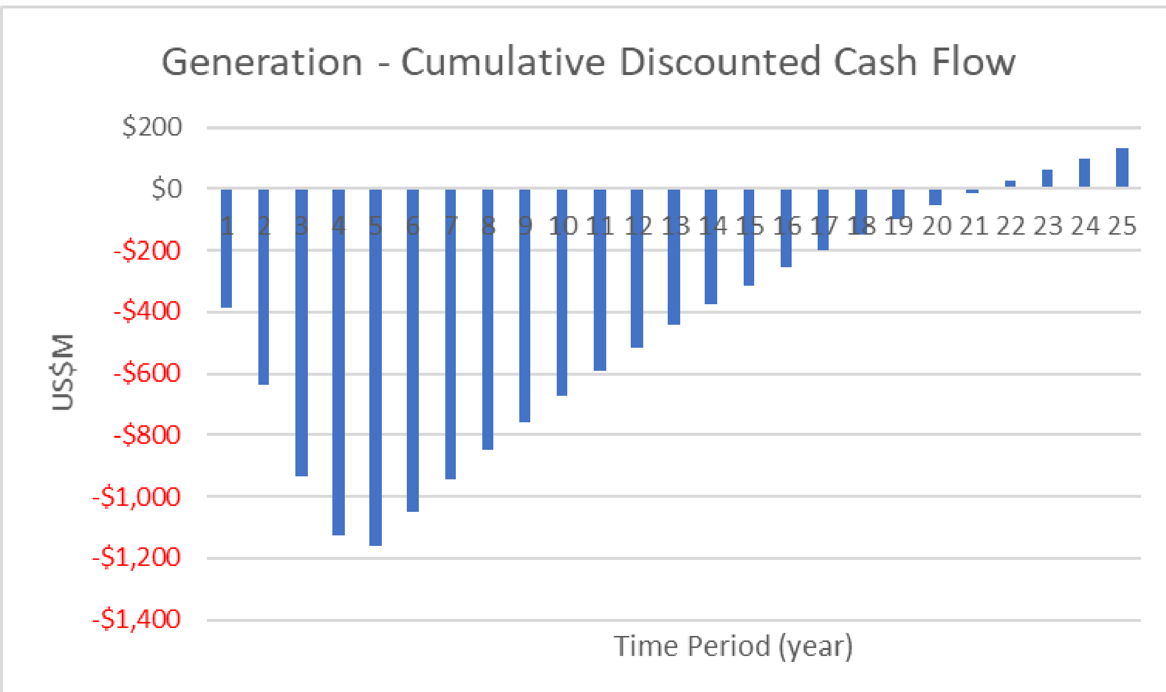

Figure 14: Cash Flow for Capital Investment in Generation

12.2 Transmission and Distribution

For analytical purposes, this category of investments includes proposed development for substations. As noted, the Net Present Value for this category is negative. This is due to the fact that T&D systems, especially in Guyana's context are expansive to cater for urban populations that do not have the density and overall energy consumption relative to more concentrated urban centres. Nonetheless, the T&D and Substations investments still achieve a positive rate of return with an IRR of 6.6%. Key metrics for this category of investments are given below in Table 57 and Figure 9.

Table 59: Summary of Cost-Benefit assessment – Capital Investment in Transmission & Distribution

Net Present Value	-US$509.62 million
Internal Rate of Return	6.6%
Cost Benefit Ratio	1.84
Discounted Pay-Back Period	-

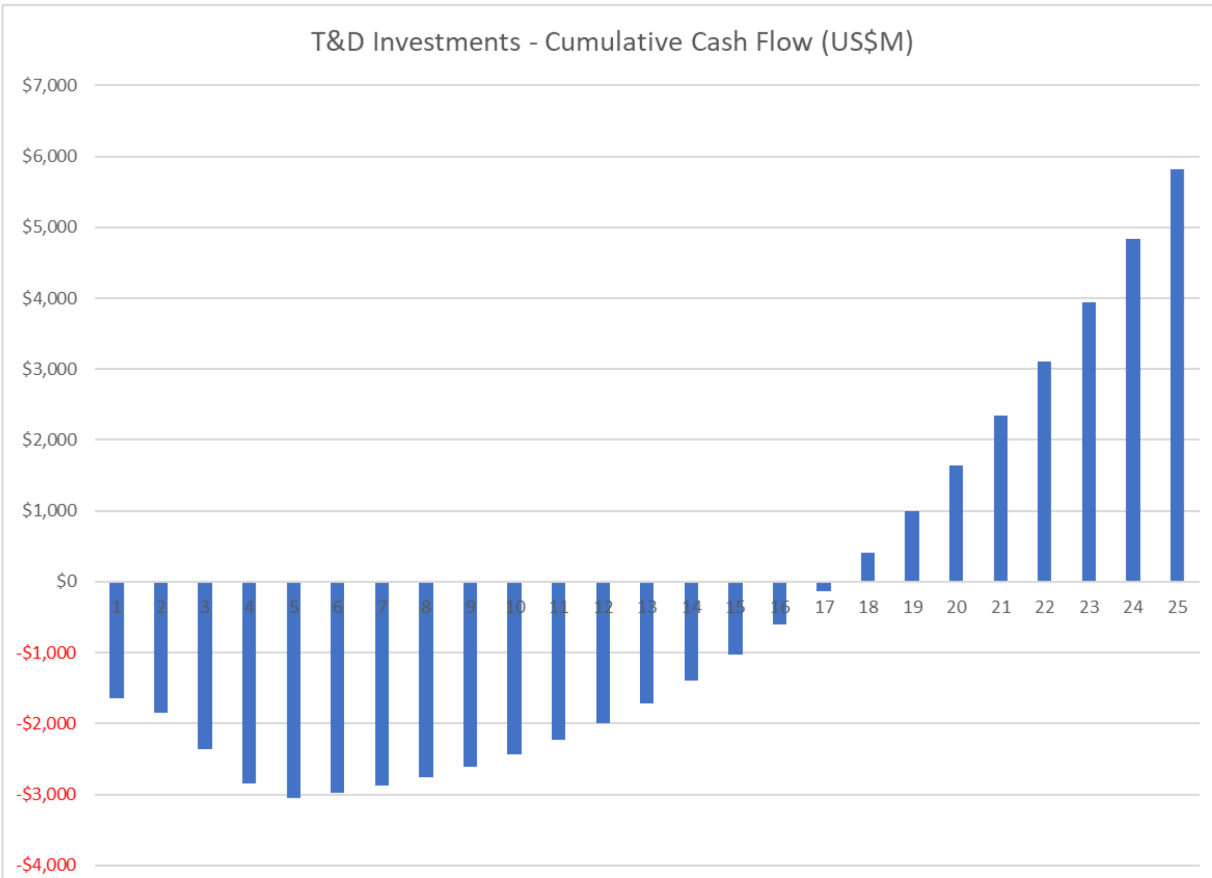

Figure 15: Cash Flow for Capital Investment in Transmission & Distribution

13 Appendix 1

13.1 Generation Expansion Study 2018 (Brugman's Study)- DBIS

The Brugman Study used historical annual data from the period 2010 to 2016 and prepared projections from 2017 until 2035. The study also incorporated scenarios for the following:

1 Self-generation migration to the DBIS commencing in 2025 and migrating at 25% per annum for the next three (3) years and level-off from 2028 to 2035 at 100% (For further details, see page 46 of the Brugman's Study),

2 Influence of Energy Efficiency (EE) measures and Renewable Energy (RE) Projects as Distribution Generation on the forecast demand, with effect commencing from 2018 up to 2035. (For further details, see pages 53 and 54 of the Brugman's Study),

3 Electric Vehicles (EV) using the grid to charge the batteries from 2024. (For further details, see page 54 and 55 of the Brugman's Study),

4 Unserved energy at 1.9% in 2014 and 1.4% from 2015 to 2035, and

5 Interconnection of Linden in 2024. (see further details on page 56 and 57 of the Brugman's Study). However, in the 2020-2024 Development and Expansion period, Linden is not considered to interconnected with the DBIS.

The Brugman Study produced an electricity demand forecast per consumer sector for 2018 to 2035, where demand is defined as the Gross Generation of GPL plus unserved energy.

13.2 The Demand Forecast Capacity Building Services Consultancy by ETS

Funded through an IDB loan to Guyana and executed under the Power Utility Upgrade Program (PUUP), this consultancy assisted GPL in acquiring the knowledge and tools of econometric forecasting and culminated in the selection of an SARIMAX[11] model applicable to preparing forecasts for a 10-years horizon (2020 to 2030). The model utilises 20-year historical monthly energy demand data as the drivers of the Autoregressive and Moving Average components of the model, with the sectoral breakdown of real GDP for Guyana over the same period being the external drivers of energy demand (the X-component of the ARIMAX model).

The model was constructed based on per-capita values which means that population growth rates would also have an impact on future energy demand coming from this model.

Forecasts for the additional 20 indicative years 2031-2050 were done by extending a polynomial trend line calculated based on the first ten years of the forecast.

13.3 The Gas to Power Study - DBIS

In this study, K&M Advisors used the Brugman's Base Case Forecast, filling the annual gaps between 2025 and 2035, and continued annually up to 2047.

13.4 GPL's Demand Forecasting Unit Projections

As mentioned above, given the urgent need to update GPL's demand and peak demand forecasts using a statistically robust model and more updated data sets, GPL's Forecasting Unit prepared a 30-year energy demand forecast using the SARIMAX model developed with support from ETS, with updated Sectoral Real GDP projections and accounting for the most realistic and likely impacts of covid-19 that were expected as of the end of 2020. However, GPL continues to monitor the impacts of covid-19 and will make appropriate updates should this become necessary in order to maintain the statistical significance of the forecast.

[1111] SARIMAX – Seasonal Autoregressive Integrated Moving Average with Exogenous explanatory Variables (X) model

The overall GPL system projections were then disaggregated into values for the DBIS, Anna Regina, Bartica, Leguan and Wakenaam, following the methodology in the diagram below (Figure 1)

Note: Projections for energy demand for Linden were taken entirely from the Brugman Study due to inadequately updated energy demand statistics from Linden at this time.

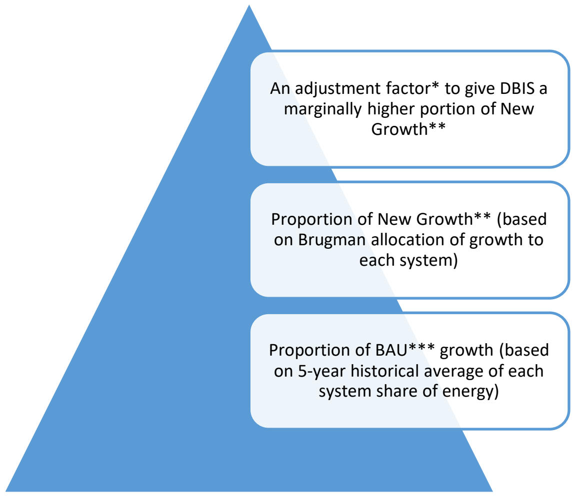

Figure 1: Methodology for calculating demand by Area System.

* The adjustment factor allocates an extra 50 basis points (i.e., 0.005) of New Growth to the DBIS system which is consistent with the expectation of concentration of oil sector related economic activities in the Demerara and Berbice areas.

** New Growth refers to the proportion of energy growth that is attributable to the growth in Real GDP. Calculated as Overall Growth forecast *less* BAU Growth forecast.

*** BAU (Business as Usual Growth) is formulated based on an ARMA model that essentially assumes that the past trend in energy demand continues without any impact from external drivers such as GDP growth.

These projections were further disaggregated following the methodology of the Brugman Study through the application of Brugman's adjustment factors to estimate the value of energy not served, the impact of energy efficiency measures (EE), electric vehicles (EV's), energy losses (technical and non-technical) and the breakdown of electrical energy sales into consumer categories (commercial, residential, and industrial).

13.5 Details of the current model

As mentioned above, the model currently applied is an ARIMAX/SARIMAX model which is a multiplicative Seasonal Autoregressive Integrated Moving Average (SARIMA) model with Exogenous explanatory variables (X).

The general specification of the SARIMAX model form is shown in Equation 1

$$y_t = \beta_t x_t + u_t$$
$$\phi_p(L)\tilde{\phi}_P(L^s)\Delta^d\Delta_s^D u_t = A(t) + \theta_q(L)\tilde{\theta}_Q(L^s)\epsilon_t \quad \text{Equation 1}$$

Where:

- $\phi_p(L)$ is the non-seasonal autoregressive lag polynomial
- $\tilde{\phi}_P(L^s)$ is the seasonal autoregressive lag polynomial
- $\Delta^d\Delta_s^D y_t$ is the time series, differenced d times, and seasonally differenced D times.
- $A(t)$ is the trend polynomial (including the intercept)
- $\theta_q(L)$ is the non-seasonal moving average lag polynomial
- $\tilde{\theta}_Q(L^s)$ is the seasonal moving average lag polynomial

and $\beta_t x_t$ is the coefficient and parameter of the X variables of the regression.

Note that for the selected model y_t is the logarithm of per capita kWh gross energy demand.

The following are the calculated parameters of the selected model:

	coefficient	std. error	z	p-value	
ϕ_{p}_9	0.152701	0.0738004	2.069	0.0385	**
$\tilde{\phi}_{P}$_1	-0.559206	0.0647029	-8.643	5.49e-018	***
$\tilde{\phi}_{P}$_2	-0.530319	0.0604105	-8.779	1.66e-018	***
θ_{q}_1	-0.430497	0.0627176	-6.864	6.69e-012	***
l_A	0.234527	0.0695516	3.372	0.0007	***
l_A_2	-0.168826	0.0755997	-2.233	0.0255	**
l_A_9	0.470200	0.130714	3.597	0.0003	***
l_B	0.0420710	0.0251196	1.675	0.0940	*
l_B_2	-0.0690839	0.0290670	-2.377	0.0175	**
l_B_3	0.0879836	0.0261713	3.362	0.0008	***
l_C_1	-0.146588	0.0501162	-2.925	0.0034	***
l_C_3	0.137650	0.0498480	2.761	0.0058	***
l_C_9	-0.403874	0.0956833	-4.221	2.43e-05	***
l_C_11	0.132673	0.0458410	2.894	0.0038	***
l_F_2	0.106513	0.0451910	2.357	0.0184	**
l_SERVICEwoK_2	0.435732	0.132746	3.282	0.0010	***

The selected model does not include a trend coefficient or a seasonal Moving Average component. The number at the end of each coefficient indicates the lag period (in months).

The exogenous variables correspond to sectoral components of Real GDP as follows:

- A – Agriculture Fishing and Forestry,
- B – Mining and Quarrying,
- C – Manufacturing, F – Construction, and
- SERVICE work – All Services except for financial services.

Note that financial services did not exhibit a statistically significant contribution to energy consumption.

The following are the results of the statistical performance of the model.

Mean dependent var	-0.000149	S.D. dependent var	0.024988
Mean of innovations	-0.000446	S.D. of innovations	0.016091
R-squared	0.992544	Adjusted R-squared	0.991985
Log-likelihood	580.4528	Akaike criterion	-1126.906
Schwarz criterion	-1069.526	Hannan-Quinn	-1103.724

Importantly, all model parameters were statistically significant at the 95% confidence level. Also, both the R-squared and adjusted R-squared were above 0.99, which indicates that the model explains 99% of the variation/changes in energy demand. This very close prediction of the historical trend in energy demand is visualised in the graph below (Figure 2)

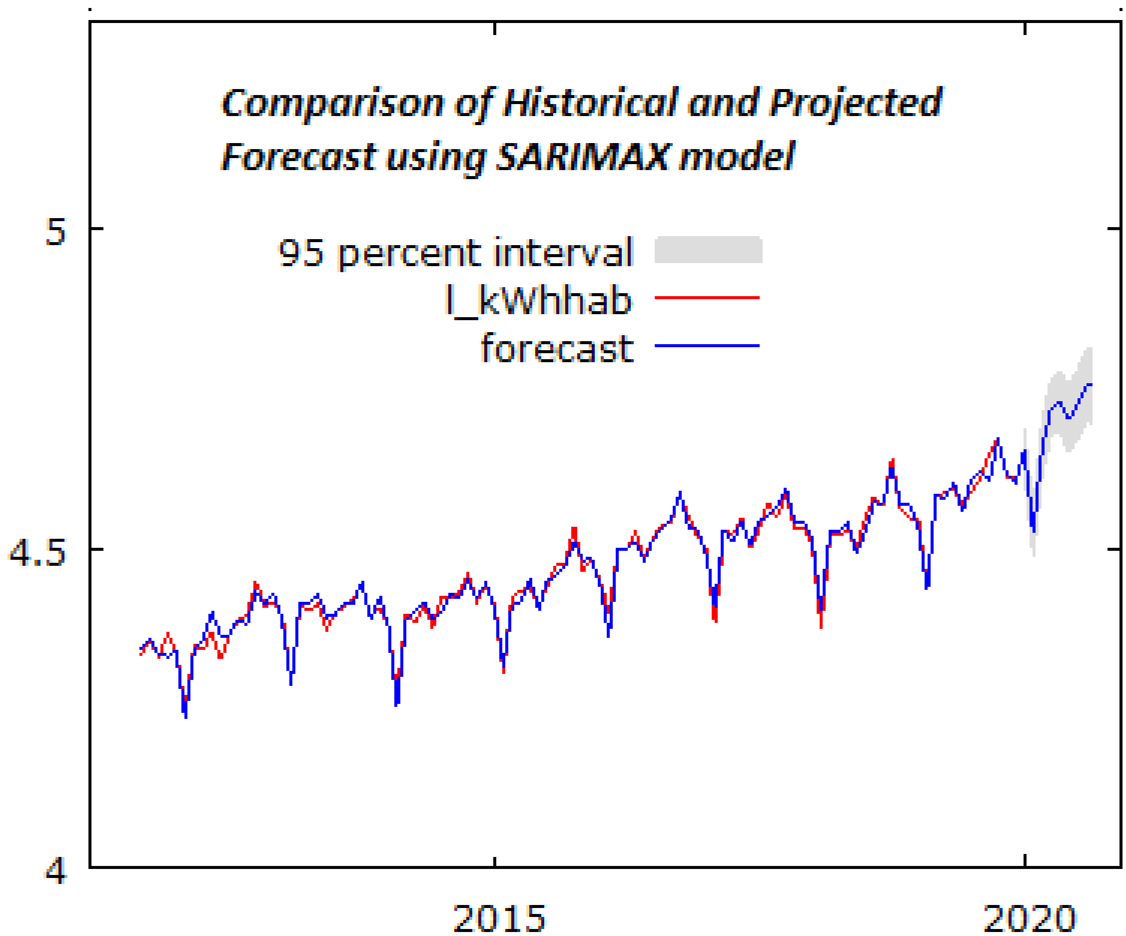

Figure 2: Graph comparing the model projections with actual historical values of the logarithm of per capita Energy Demand (l_kWhhab)

13.6 Energy Demand Forecast drivers and composition

The main external driver of energy demand is the level of Real GDP. This is plausible since Real GDP is a measure both of economic activity nationally as well as a proxy for the wealth of the nation with implications for the income levels of citizens. Theory and historical trends highlight that richer populations tend to acquire more devices (electrical loads) which increase energy demand. Also, here in Guyana, it is reasonable to expect that there will be new providers of services that directly and indirectly cater to the oil industry and increased industrial activities that respond to growth in the construction and other sectors.

Reports from the local media support this expectation of considerable growth in demand from new commercial and industrial loads, with the planned construction of several new hotels in the near term to the cost of almost US$1billion.[12] Additionally, the planned Corentyne River Bridge linking Guyana and Suriname, together with the planned deep-water harbour signals the potential for new and expanded commercial activity with businesses having easier access to the Surinamese and other markets.[13]

These developments and others will drive the significantly higher loads expected to come on the grid in the future.

Table 1 below shows the different growth rate assumptions that were included in the forecasting models used for the current set of forecasts (GPL Sept 2020) and previous forecasts generated.

Table 1: Real GDP growth assumptions used for forecasts

Year	GPL (2021)	ETS growth (2018 base)	Brugman RGDP growth (2016 base)
2021	21%	25%	7.0%
2022	40%	40%	7.0%
2023	35%	30%	7.0%
2024-2030	15.5%	11%	6%
2021	21%	25%	7.0%

The most recent projections are guided by the Ministry of Finance Budget Presentations and Press Releases, IMF WEO (2021) and recent developments regarding the projected scale and rate of development of Guyana's oil and gas sector. These projections show marginally lower real GDP growth in 2021 (21%) than previously expected, which reflecting the impact of COVID19 and other economic realities. However, it is possible that the actual growth rate may be marginally lower than this projection to fully cater for the impact of the devastating flooding across Guyana in mid-2021.

2023 to 2030 growth rates are higher in the latest (2021 based) projections primarily reflecting a significant scale up of oil projections than what was previously expected.

Notably, the 2020 base projections were premised on 3 FPSO's producing oil, while the 2021 base projections assume 5 FPSO's will be operational by 2026.

The compounding effect of the above adjustments is that energy demand for the period 2021-2024 is lower in the updated 2021 base forecasts than in the previous 2020 base forecasts.

[12] Guyana Chronicle, US$1B in hotels, November 24, 2020

[13] Stabroek News, President's Suriname visit brings MOU on Corentyne River bridge, November 27, 2020.

However, the longer term higher economic growth eventually pulls energy demand in the updated scenario above the previous scenario from 2025 onwards.

However, the impact of oil sector GDP on overall economic activity and hence energy demand is expected to be tempered in the near term (2020 to 2023) compared with the latter years of the projection period. Accordingly, energy demand mainly in these initial years of projection were lowered by addition of a smoothing mechanism termed scenario X1 which assumes a limited transfer of oil related economic activity into new energy demand.

13.7 Summary results of Base Case and other key scenarios

Due to the high economic growth rates that feed into the Base Case projections, it was considered that even higher growth numbers are not likely, as such, a High Case scenario is not included at this time.

The principal scenarios presented for this report are the Base and Low Cases, which are compared with a Business as Usual (BAU) scenario and a Smoothing Scenario termed X1.

The Base Case reflects the impact of the above RGDP projections while the Low Case assumes marginally lower RGDP growth. Both cases assume annual population growth rate of 1.44% in keeping with estimates from the Bureau of Statistics.

The X1 scenario assumes that new oil sector related economic growth would have a limited impact on energy demand. This was done by treating all oil related growth as if coming from the Mining and Quarrying sector which has a relatively low impact on energy demand. This scenario was used to dampen both the base and low case projections up until 2023 through using a weighted average such that the weight of X1 values is 80% in 2022 and reducing to 20% by 2025.

The BAU scenario assumes no impact from new economic growth and that energy demand continues to grow only based on historical trends.

Note that the implementation of energy efficiency measures, potential addition of electric vehicles and capturing energy demand not served by GPL (self-generators) are considered for the DBIS area forecast which are discussed in section 13.8, compares the Base Case energy demand and peak power projections compared with the Low Case, the Business-As-Usual case, and the Smoothing scenario - X1.

As shown in Figure 3, all cases have similar energy demand and peak demand in 2020, thereafter they diverge as per GDP projections previously described.

The BAU scenario has a relatively flat profile, increasing to 1,320GWh (energy demand) and 199MW (peak power) by 2030, then reaching 2,548GWh (energy demand) and 369MW (peak power) by 2050. The Smoothing Scenario X1 which assumes limited transfer of new oil economic activity into additional energy demand exhibits higher growth than the BAU but remains relatively flat. In the X1 scenario, by 2030 energy demand would be 1,547GWh while peak power would be 233MW, by 2050 these values are expected to increase to 3,846GWh and 556MW, respectively.

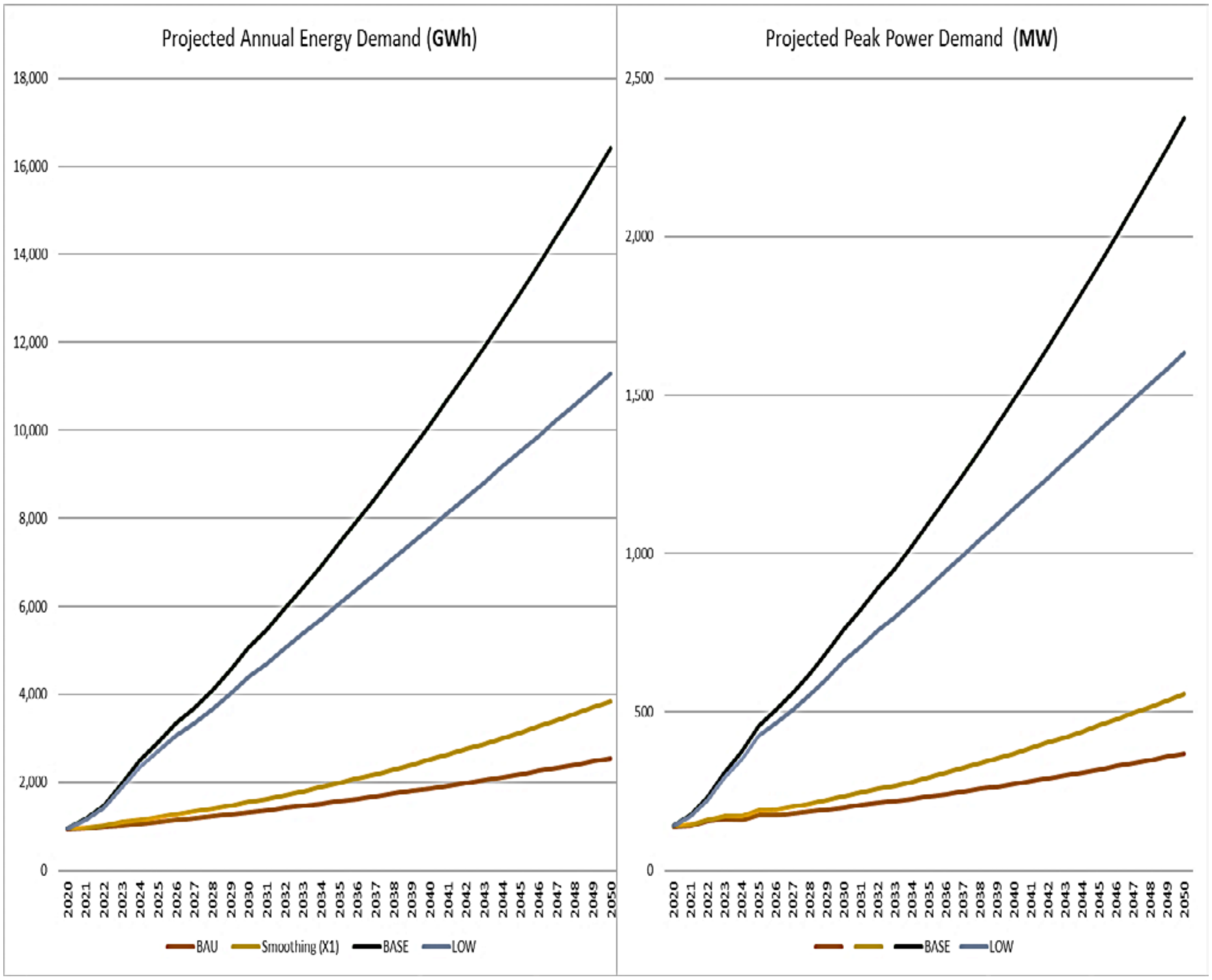

Figure 3: Showing Projected Energy Demand in GWh and Peak Power in MW for Base and Low cases compared with a smoothing scenario (X1) and the BAU case

Under the base case, energy demand and peak power rises significantly, driven by the impact high real GDP growth and the economic effects of oil related activities. While under the low case, both energy demand and peak power are lower than the base case due to assumed lower real GDP growth than in the base case. Table 2 summarises the values achieved under the base and low case scenarios for selected years.

Table 2: Energy Demand (GWh) and Peak Power (MW) under Base and Low Case scenarios for selected years

	2021 (actual)		2026		2030		2035		2050	
	Energy (GWh)	Peak Power (MW)	Energy (GWh)	Peak Power (MW)	Energy (GWh)	Peak Power (MW)	Energy (GWh)	Peak Power (MW)	Energy (GWh)	Peak Power (MW)

BASE CASE	988.9	147.4	3299.7	501.6	6348.0	955.0	9669.5	1449.0	21970.9	3277.4
LOW CASE	988.9	147.4	3065.2	466.4	5522.4	830.7	7894.0	1183.5	15104.1	2253.5

For the purpose of system planning and specifically generation planning, the Base Case scenario is considered most relevant. Figure 4 below shows the projected base energy demand according to the current GPL Systems (Anna Regina, Bartica, Leguan and Wakenaam are grouped as "Essequibo Systems") for the period 2020 to 2050.

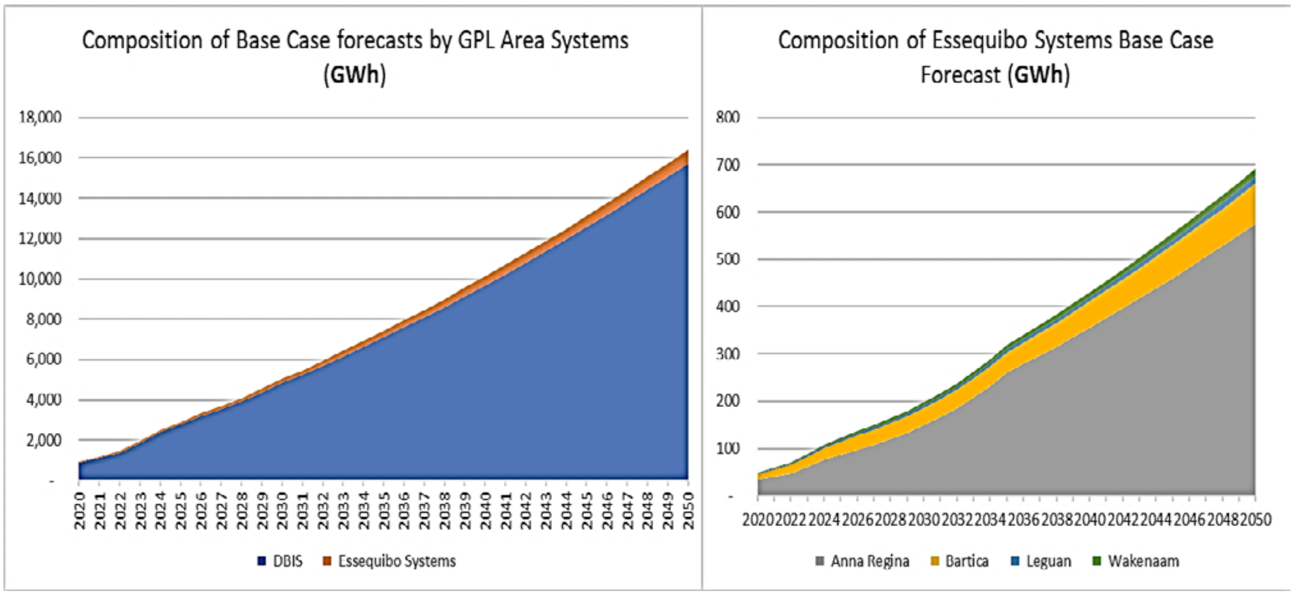

Figure 4: Base Case Forecast showing composition by area systems 2020-2050

13.8 Electricity Demand-DBIS

The current (September 2020) overall energy demand forecast scenarios have been disaggregated for the various GPL area systems and then further broken down into demand type categories. Since the Demerara Berbice Interconnected System (DBIS) accounts for over 90% of current and future energy demand, the forecasts for this area are presented in this section. As noted above, the key scenarios presented here are the Low and Base Cases.

Self-generation migration, meeting the unserved energy and accommodating electric vehicles (EVs) were included in the current forecasts based on their quantitative values obtained in the Brugman Study. While the impact of greater energy efficiency (EE) measures, loss factors and a relative breakdown of sales into consumer categories were included in keeping with their proportional values in the Brugman Study. Figure 5 shows the DBIS energy demand forecast, taking EE measures and EVs into consideration and disaggregated under the Base and Low Cases. It also includes a line to show energy demand prior to inclusion of EE and EVs.

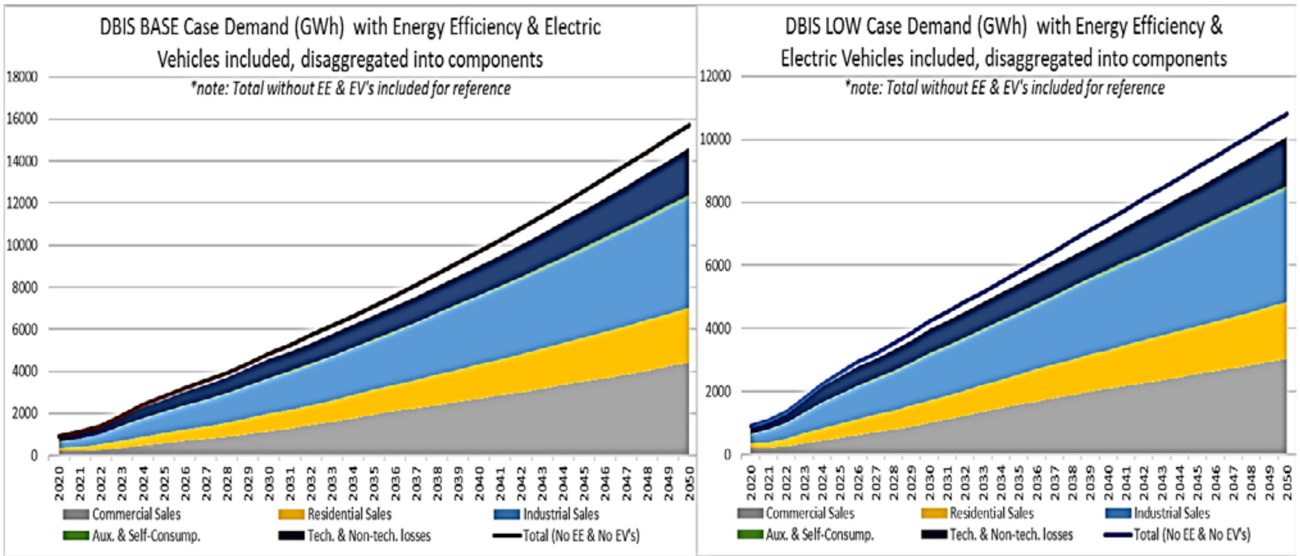

Figure 5: DBIS projections by Case, with Base Case disaggregated

13.8.1 Load Factor-DBIS

The Load Factor (LF) essentially indicates the flatness of the hourly demand (MW) curve and gives an indication of the cost-effectiveness of the load to maximise the use of the total available generation, which enables the system to meet peak demand.

Load Factor is expressed as shown in Equation 2:

$$Load\ Factor\ (\%) = \frac{1000 * Electricity\ Demand\ (GWh)/yr}{Peak\ Demand\ (MW) * 8760\ h/yr} * 100 \quad \text{Equation 2}$$

In 2014, the annual LF was calculated to be 71% and it progressively increased to 76% in 2019. In 2020, the load factor increased to 77%. The indication is that that there has been lesser variation in the hourly DBIS demand (MW), and the generators have been dispatched to higher percentage loading, thus operating more efficiently and economically.

Given the above trend in the annual load factor for the past five (5) years, it was assumed that it will remain around 76% and 77% for the expansion horizon up to 2027 and gradually increasing to 79% by 2050.

13.8.2 Peak Demand-DBIS

With the mathematical relationship shown in Equation 2, the forecast peak demands for the Base and Low Cases were calculated and graphically represented as shown in Figure 6. Additionally, in Figure 6, the forecast peak demands from the Brugman's and Gas to Power Studies forecast are also shown for easy comparison.

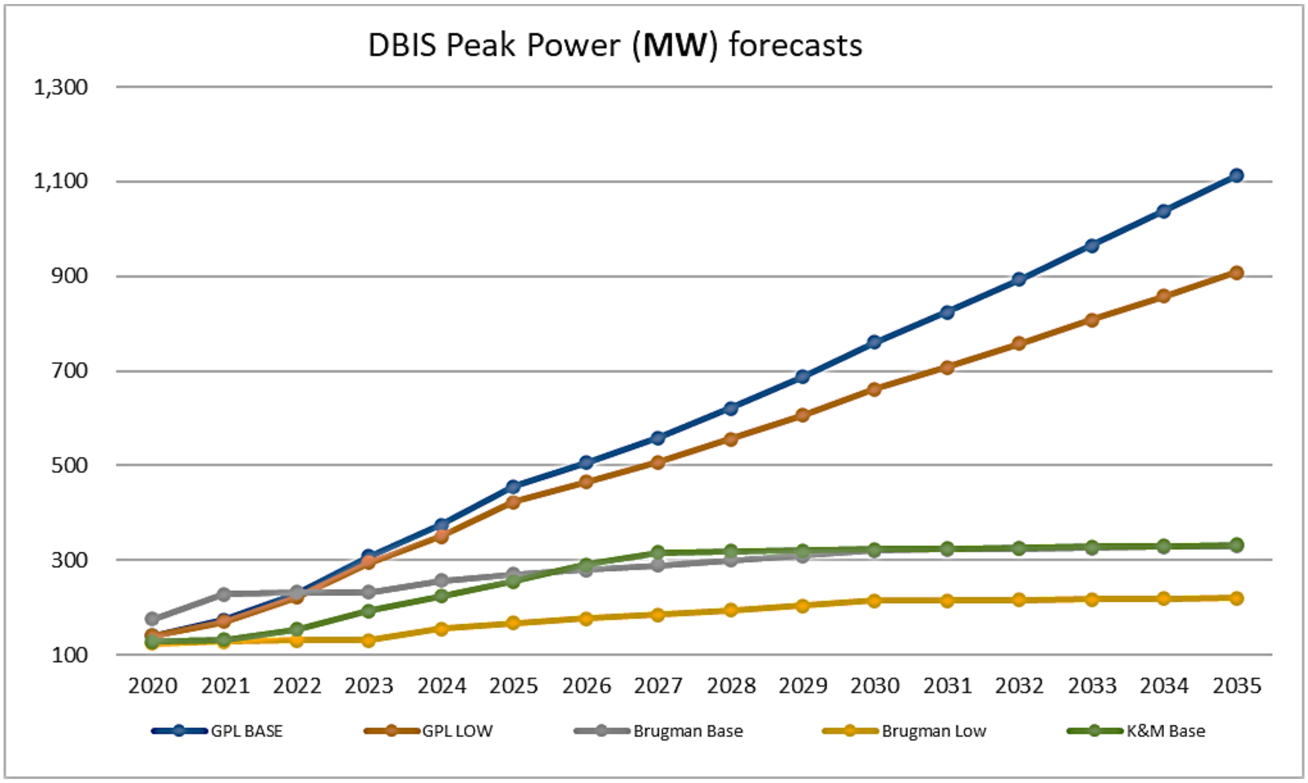

Figure 6: Comparison of Forecast Peak Demands

For the Base and Low cases, GPL's annual forecast peak power demands are comparatively higher than the Brugman and K&M forecasts. This reflects the impact from significantly higher GDP growth projections for Guyana as compared with previous forecasts. From a generation planning perspective, GPL's peak demand forecast adds security to the capacity reserve margin and Loss of Load Expectation (LOLE) and Expected Energy Not Served (EENS), while considering for any unforeseen or new self-generation migration to the grid.

14 Appendix 2

14.1 Georgetown

Kingston Substation, Kingston Power Plant, Old Sophia Substation, New Sophia Switching Substation, New Georgetown Substations, Merriman's Central Georgetown Substation

14.1.1 Generation Conventional & Renewable Projects

- No firm conventional generation and renewable project is planned for this geographic location.

14.1.2 Transmission Lines

- Upgrade to the existing L5-5 km 69 kV transmission line between Kingston and Old Sophia by Dec 2022 (Awarded and currently being executed by contractor).
- Construction of L5P-5 km 69 kV redundant transmission line between Kingston and Old Sophia by Dec 2022 (Awarded and currently being executed by contractor).
- Upgrade of existing L10 -4.4 km 69 kV transmission line between New Georgetown and Old Sophia by Dec 2023.
- Construction of 2.75 km of new 69kV transmission line between Kingston and Merriam's Central Georgetown (L11-1) Substations by Dec 2023.
- Construction of 4.62 km of new 69kV transmission line between Merriam's Central Georgetown Substations and New Georgetown Substation (L11-2) by Dec 2023.
- Upgrade the less than 0.1 km existing 69 kV link between Old Sophia and New Sophia (L12 & L13), this will increase the transfer capacity of existing link, which will be useful as the demand increases throughout the DBIS by Dec 2023.

14.1.3 Existing Substation

Old Sophia 13.8/69kV Substation- 2022

- Relocation of Tx 1- ABB 16.8 MVA-13.8/69 kV to replace the damaged Tx 1- Westinghouse 16.7 MVA-13.8/69 kV at GOE.
- Decommission of Tx 3- Westinghouse 16.7 MVA-13.8/69 kV.
- Installation of one new 35 MVA 13.8/69 kV transformer.
- Installation of 15 cubicle -15 kV Metal-clad enclosed Switchgear.
- Reconductoring of the F2 -20.5 km feeder backbone (Sophia to Success ECD-Express Feeder) using Cosmos conductor type and concrete poles structures- JICA.
- Renovation of the control room building and switchgear facility.
- Construction of four new 13.8 kV distribution feeders using conductor-type Cosmos and concrete pole structures, each with an approximate length of 4 km by the end of 2026.

- Installation of one new 35 MVA 13.8/69 kV transformer by the end of 2026.

New Sophia 69kV Switching Substation

- Installation of 15 MVAr detuned fix capacitor bank by the end of 2024; 69 kV bay is already in place.
- Termination of the L16P into the existing 69 kV bay by the end of 2022.

New G/town 13.8/69kV Substation

- Installation of 15 MVAr detuned fix capacitor bank by the end of 2024.
- Installation of one AIS 69 kV bay to accommodate the 15 MVAr fix capacitor bank.
- Installation of one AIS 69 kV bay to accommodate one new transmission line (L11-2) from Merriman's Mall Substation by the end of 2023.
- Reconductoring of the F1 -17.25 km feeder backbone using Cosmos conductor type and concrete poles structures by the end of 2022.

Kingston 13.8/69kV Substation-

- Installation of one AIS 69 kV bay to accommodate one new transmission line (L5P) from O/Sophia by the end of 2022 (Project in execution phase).
- Installation of one AIS 69 kV bay to accommodate one new transmission line (L11-2) from Merriman's Mall Substation by the end of 2023.

Kingston Power Plant DP2 & DP3

- Upgrade of tie-lines between DP2 and DP3 by installing approximately 400 meters of 1 single core 400 mm^2 XLPE cables place in cable underground raceway by 2022.
- Upgrade of 15 kV class 8 cubicle switchgear to 60 kA SC rating at DP2 by 2023.
- Upgrade of 15 kV class 18 cubicle switchgear to 60 kA SC rating at DP3 by 2024.
- Upgrade of grounding transformer at DP3 by the end of 2023.

14.1.4 New Substation

Merriman's Mall GIS 13.8/69 kV Substation -New 2023

Construction of one new AIS 13.8/69 kV substation by installing:

(1) Three-breaker and ½ 69 kV switchgear.

(2) 13 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component.

(3) Two- 60 MVA 13.8/69 kV Transformers.

(4) Six new feeder circuits utilizing cosmos conductor type on concrete structures with an approximate length of 4 km each.

14.2 East Coast Demerara

Good Hope Substation, Ogle Substation, LBI Substation, Lusignan Substation, Enmore/Victoria Substation, Columbia Substation

14.2.1 Generation Conventional & Renewable Projects

- N/A

14.2.2 Transmission

- Construction of 14.7 km of redundant 69 kV transmission line between New Sophia and Good Hope (L16P) by the end of 2022.
- Splitting of new 69 kV transmission line- L16P into Ogle Substation (L16P-1 & L16P-2) by the end of 2024.
- Splitting of new 69 kV transmission line- L16P-2 into LBI Substation (L16P-2 & L16P-3) by the end of 2024, therefore new line between Ogle & LBI- L26-P which will correspond to a parallel circuit for the L26.
- Construction of 10.6 km of redundant 69 kV transmission line between Good Hope and Victoria/Enmore Substation (L17-P) by the end of 2023.
- Construction of 16.9 km of redundant 69 kV transmission line between Enmore/Victoria and Columbia Substation (L18-Bypass) by the end of 2023.
- Construction of 9.5 km of new 69 kV parallel transmission lines between Eccles and Ogle Substation (L25 & L25P) to be completed by the end of 2024.
- Construction of 4.4 km of new 69 kV transmission lines between Ogle and LBI Substation (L26) to be completed by the end of 2024.
- Construction of 13 km of new 69 kV transmission lines between Lusignan and Eccles Substation (L27) to be completed by the end of 2025.
- Construction of 13.8 km of new 69 kV transmission lines between Lusignan and Enmore/Victoria Substation (L28) to be completed by the end of 2026.

14.2.3 Existing Substation

Good Hope 13.8/69kV Substation

- Installation of 15 MVAr detuned fix capacitor bank by the end of 2024;
- Installation of one AIS 69 kV bay to accommodate the 15 MVAr fix capacitor bank;
- Installation of one AIS 69 kV bay to accommodate one new transmission line (L16P) from Sophia Switching Substation by the end of 2022;
- Installation of one AIS 69 kV bay to accommodate one parallel transmission line (L17P) from Enmore/Victoria Substation by the end of 2023;

- Replacement of one 35-MVA 13.8/69 kV Crompton Greeves transformer by the end of 2022;
- Installation of one new 13.8/69 kV 35 MVA ONAF transformer with accompanying AIS 69 kV bay by December 2024;
- Upgrade existing 13.8 kV switchgear (25 kA SC rating) with higher SC rating (60 kA)-16 cubicle -15 kV Metal-clad enclosed Switchgear by the end of 2023;
- Construction of three new 13.8 kV distribution feeders using conductor-type Cosmos and concrete pole structures, each with an approximate length of 6 km by the end of 2024.

Columbia 13.8/69kV Substation

- Installation of one AIS 69 kV bay to accommodate one new transmission line (L18-Bypass) from Enmore Substation by the end of 2023;
- Installation of one AIS 69 kV bay to accommodate one parallel transmission line (L20P) from Onverwagt Substation by the end of 2026;
- Installation of one new 16.7-MVA 13.8/69 kV transformer with accompanying AIS 69 kV bay by the end of 2024;
- Installation of 6 cubicle -15 kV Metal-clad enclosed Switchgear by the end of 2024;
- Construction of four new 13.8 kV distribution feeders using conductor-type Cosmos and concrete pole structures, each with an approximate length of 8 km by the end of 2024.

14.2.4 New Substation

Ogle AIS 13.8/69 kV Substation - 2024

Construction of one new AIS 13.8/69 kV substation by installing:

(1) Four-breaker and ½ 69 kV switchgear;

(2) 18 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component;

(3) Two- 60 MVA 13.8/69 kV Transformers.

(4) Eight new feeder circuits utilizing cosmos conductor type on concrete structures with an approximate length of 6 km each;

LBI AIS 13.8/69 kV Substation - 2024

Construction of one new AIS 13.8/69 kV substation by installing:

(1) Three-breaker and ½ 69 kV switchgear,

(2) 13 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component,

(3) Two- 35 MVA 13.8/69 kV Transformers,

(4) Four new feeder circuits utilizing cosmos conductor type on concrete structures with an approximate length of 5 km each,

Lusignan AIS 13.8/69 kV Substation – 2025

Construction of one new AIS 13.8/69 kV substation by installing:

(1) Three-breaker and ½ 69 kV switchgear,

(2) 13 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component,

(3) Two- 35 MVA 13.8/69 kV Transformers,

(4) Four new feeder circuits utilizing cosmos conductor type on concrete structures with an approximate length of 5 km each,

Enmore/Victoria AIS 13.8/69 kV Substation - 2023

Construction of one new AIS 13.8/69 kV substation by installing:

(1) Four-breaker and ½ 69 kV switchgear,

(2) 11 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component,

(3) Two- 25 MVA 13.8/69 kV Transformers,

(4) Four new feeder circuits utilizing cosmos conductor type on concrete structures with an approximate length of 6 km each,

14.3 West Demerara

Wales 300 MW Natural Power Plant, Vreed-en-hoop Substation, Vreed-en-hoop Power Plant, Edinburgh Substation, Wales R/C Substation, Wales Industrial Substation, Westminster Substation, Tuschen Substation, Hydronie/Parika Substation

14.3.1 Conventional Generation Project

- Construction one new 300 MW Natural Gas Power Plant to be in Wales.

14.3.2 Transmission

- Construction of 16.4 km of new double circuit 69 kV transmission line between Wales 300MW-NG Power Plant Substation and Wales R/C Substation (L30 & L30P) by the end of 2024;
- Construction of 24 km of new 69 kV transmission line between Vreed-en-hoop Substation and Wales R/C Substation (L31) by the end of 2024;
- Construction of 16.4 km of new 69 kV transmission line between Wales R/C Substation and Westminster Substation (L32) by the end of 2024;

- Construction of 10.2 km of new 69 kV transmission line between Vreed-en-hoop Substation and Westminster Substation (L33) by the end of 2025;
- Construction of 16 km of new 69 kV transmission line between Edinburgh substation and Parika/Hydronie Substation (L8) by the end of 2022;
- Splitting of L8 (L8-1 & L8-2) into the Tuschen Substation by the end of 2026;
- Construction of 25.83 km of new 69 kV transmission line between Westminster substation and Parika/Hydronie Substation (L9) by the end of 2025;
- Splitting of L9 (L9-1 & L9-2) into the Tuschen Substation by the end of 2026;

14.3.3 Existing Substation

Vreed-en-Hoop 13.8/69 kV Substation

- Replacement of one 20 MVA 13.8/69 kV transformer by the end of 2023 (relocated to Edinburgh);
- Installation of one AIS 69 kV bay to accommodate one new transmission line (L31) from Wales R/C Substation by the end of 2024;
- Installation of one AIS 69 kV bay to accommodate one new transmission line (L33) from Westminster Substation by the end of 2025;
- Installation of one AIS 69 kV bay to accommodate one new transmission line (L34) from Eccles Substation by the end of 2025 (contingent on the timely construction of the New Demerara River Bridge (NDRB));

Vreed-en-hoop 13.8 kV Power Plant- DP4 2024:

- Replacement of the grounding transformer.
- Installation of 3 Neutral Earthing Resistor.

Edinburgh 13.8 /69 kV Substation

- Installation of 10 MVAr detuned fix capacitor bank by the end of 2024.
- Installation of one AIS 69 kV bay to accommodate the 10 MVAr fix capacitor bank.
- Installation of one 20 MVA 13.8/69 kV transformer (taken from Vreed-en-hoop Sub) by the end of 2022.
- Installation of one AIS 69 kV bay to accommodate one new transmission line (L8) from Hydronie Substation by the end of 2023.
- Installation of three new feeder circuits utilizing cosmos conductor type on concrete structures with an approximate length of 2 km each by the end of 2026.

14.3.4 New Substation

Westminster 13.8/69 kV Substation-2024

- Construction of one new AIS 13.8/69 kV substation by installing:
    (1) Three breaker and ½ 69 kV switchgear,
    (2) 13 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component,
    (3) Two- 25 MVA 13.8/69 kV Transformers,
    (4) Six new feeder circuits utilizing cosmos conductor type on concrete structures with an approximate length of 5 km each.

Wales Residential/Commercial 13.8/69 kV Substation-2024

- Construction of one new AIS 13.8/69 kV substation by installing:
    (1) Four breaker and ½ 69 kV switchgear;
    (2) 23 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component;
    (3) Three- 35 MVA 13.8/69 kV Transformers.
    (4) Eight new feeder circuits utilizing cosmos conductor type on concrete structures with an approximate length of 6 km each;

Wales Industrial 13.8/69 kV Substation-2024

- Construction of one new AIS 13.8/69 kV substation by installing:
    (1) Five breaker and ½ 69 kV switchgear;
    (2) 15 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component;
    (3) Two- 35 MVA 13.8/69 kV Transformers.
    (4) Eight new feeder circuits utilizing cosmos conductor type on concrete structures with an approximate length of 3 km each;
- Installation of one AIS 69 kV breaker and ½ bay to accommodate the transmission line from Wales R/C (L30 & L30P) by the end of 2024;

Tuschen 13.8/69 kV Substation-2026

- Construction of one new AIS 13.8/69 kV substation by installing:
    (1) Three breaker and ½ 69 kV switchgear;
    (2) 13 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component;
    (3) Two- 25 MVA 13.8/69 kV Transformers.
    (4) Four new feeder circuits utilizing cosmos conductor type on concrete structures with an approximate length of 6 km each;

Wales 300 MW NG Power Plant 13.8//230 kV Substation-2024

- Construction of one new AIS 13.8/230 kV substation by installing:
  - (1) Six double bus single 230 kV switchgear;
  - (2) cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component;
  - (3) Three- 3-winding 250 MVA 13.8/69/230 kV Transformers;

14.4 East Bank Essequibo

14.4.1 Generation Conventional & Renewable

- No new generation project within the D&E planning period.

14.4.2 Transmission

- No new transmission project within the D&E planning period.

14.4.3 New Substation

Hydronie 13.8/69 kV Substation-2023

- Construction of one new AIS 13.8/69 kV substation by installing:
  - (1) Two breaker and ½ 69 kV switchgear;
  - (2) 11 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component;
  - (3) Two- 25 MVA 13.8/69 kV Transformers.
  - (4) Four new feeder circuits utilizing cosmos conductor type on concrete structures with an approximate length of 6 km each;
- Installation of one AIS 69 kV breaker and 1/2 bay to accommodate the 10 MVAr fix capacitor bank and transmission line to Leguan (L39) by the end of 2026;
- Installation of 10 MVAr detuned fix capacitor bank by the end of 2026;

14.5 East Bank Demerara

Eccles Substation, Golden Grove Substation, Garden of Eden Substation

14.5.1 Generation Conventional & Renewable Projects

- No new generation project for this geographic area.

14.5.2 Transmission

- Upgrading of 58 km of 69 kV transmission line between Garden of Eden and Old Sophia and Garden of Eden and New Sophia (L1, L2,L3 & L4) by the end of 2022.
- Splitting of the L2 & L4 into the Eccles Substation by the end of 2023.

14.5.3 Existing Substation

Garden of Eden 13.8/69kV Substation- 2022

- Replace damaged Tx 1- Westinghouse 16.7 MVA-13.8/69 kV with Tx 1- ABB 16.8 MVA-13.8/69 kV from O/Sophia.
- Decommission of Tx 2- Westinghouse 16.7 MVA-13.8/69 kV.
- Installation of one new 35 MVA 13.8/69 kV transformer.
- Installation of 7 cubicle -15 kV Metal-clad enclosed Switchgear.
- Renovation of the Control Room Building and switchgear facility.
- Reconductoring of the F1 -94.3 km feeder backbone using Cosmos conductor type and concrete poles structures by the end of 2023.
- Reconductoring of the F2 -32.7 km feeder backbone using Cosmos conductor type and concrete poles structures by the end of 2024.
- Reconductoring of the F3 -19.1 km feeder backbone using Cosmos conductor type and concrete poles structures by the end of 2024.
- Installation of one AIS 69 kV double bus single breaker bay to accommodate the transmission line from Bamia-Linden Substation (L35) by the end of 2024.
- Installation of two AIS 69 kV double bus single bay to accommodate double transmission lines from Wales Industrial Substation (L24) by the end of 2024.

Golden Grove 13.8 kV Distribution Feeder Upgrades

- Reconductoring of the F1 -89.1 km feeder backbone using Cosmos conductor type and concrete poles structures by the end of 2022.
- Reconductoring of the F2 -42.5 km feeder backbone using Cosmos conductor type and concrete poles structures by the end of 2022.
- Installation of one new feeder circuit (expressed- Eccles Park) utilizing cosmos conductor type on concrete structures by the end of 2022 (JICA).

14.5.4 New Substation

Eccles 13.8/69 kV Substation-2023

- Construction of one new AIS 13.8/69 kV substation by installing:
  (1) Five breaker and ½ 69 kV switchgear.
  (2) 13 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component.
  (3) Two- 60 MVA 13.8/69 kV Transformers.

(4) Ten new feeder circuits utilizing cosmos conductor type on concrete structures with an approximate length of 5 km each.

- Installation of one AIS 69 kV breaker and ½ bay to accommodate double transmission lines from Bamia-Linden Substation (HVL2 & HVL2P) by the end of 2024.

Eccles 69/230 kV Substation- New-2024

- Construction of one new AIS 230 kV substation that consists of five double bus single breaker 230 kV switchgear.
- Expansion by one bay of the 69 kV Substation by installing one AIS breaker and ½ switchgear.
- Installation of two 2 winding 100 MVA 69/230 kV Transformers.

Eccles 230 kV Substation Expansion-2026

- Installation of two new AIS 230 kV bays to accommodate double circuit transmission lines (HVL4 & HVL4P) from Williamsburg EBC.
- Installation of two new AIS 230 kV bays to accommodate double circuit transmission lines (HVL2 & HVL2P) from Bamia- Linden.

14.6 Cross-Geographic Areas

230 kV Interconnected Transmission Line Corridor Linden/Soesdyke Highway/ EBC/Amalia Hydro

14.6.1 Generation Conventional & Renewable Projects

- Construction of 165 MW Amalia Hydropower Plant Facility by installing of five - 33 MW, Hydroelectric Generators to be commissioned at the beginning of 2026.

14.6.2 Transmission

- Construction of 26.6 km of new double circuits 230 kV transmission lines (HVL1 & HVL1P) between Wales 300 MW Natural Gas Plant and Eccles 230 kV substation to by the end of 2024.
- Construction of 95.4 km of new 230 kV parallel transmission lines (HVL2 & HVL2P) between Bamia- Linden and Eccles 230 kV Substation by the end of 2024.
- Construction of 190 km of new 230 kV parallel transmission lines (HVL3 & HVL23) between Amaila Hydro and Bamia-Linden 230 kV Substation by the end of 2026.
- Construction of 146 km of new 230 kV parallel transmission lines (HVL4 & HVL4P) between Eccles and Williamsburg 230 kV Substation by the end of 2026.
- Construction of 80.64 km of new 69 kV transmission lines between GOE and Bamia-Linden Substation (L35) by the end of 2024;
- Splitting of the L35 into the Yarrowkabra Substation by the end of 2026.

- Construction of 10 km of new 69 kV transmission lines between Bamia-Linden and Mackenzie Substation (L37) by the end of 2024;
- Construction of 11.3 km of new 69 kV transmission lines between Hydronie and Leguan substation (L39) by the end of 2026;
- Construction of 5.25 km of new double circuit 69 kV transmission line between Wales R/C Substation and Garden of Eden Substation (L24 & L24P) by the end of 2024.

14.6.3 New Substation

Mobile 13.8/69 kV Substation- New-2022

- Procurement of one new containerise 13.8/69 kV substation which includes the following:
    (1) One single breaker 69 kV switchgear;
    (2) Four cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component.
    (3) One- 35 MVA 13.8/69 kV Transformers.

Yarrowkabra 13.8/69 kV Substation- New-2026

- Construction of one new AIS 13.8/69 kV substation by installing:
    (1) Two breaker and ½ 69 kV switchgear,
    (2) 13 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component,
    (3) Two- 25 MVA 13.8/69 kV Transformers,
    (4) Four new feeder circuits utilizing cosmos conductor type on concrete structures with an approximate length of 6 km each;

Bamia-Linden Substation 38/69 kV Substation-New 2024

- Construction of one new AIS 13.8/69 kV substation by installing:
    (1) Three breaker and ½ 69 kV switchgear (L35, L37, Tx1, Tx2, TX3 (HVL2 & HVL2P),
    (2) 11 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component,
    (3) Two- 16.7 MVA 13.8/69 kV Transformers,
    (4) Termination of four transmission lines into the 69 kV facility (HVL2 & HVL2P, L35 & L37),
    (5) Two new feeder circuits utilizing cosmos conductor type on concrete structures with an approximate length of 6 km each.

Bamia-Linden 69/230 kV Substation- New-2026

- Construction of one new AIS 230 kV substation that consists of six double bus single breaker 230 kV switchgear;
- Installation of one- 2 winding 100 MVA 69/230 kV Transformers.
- Termination of 2 Double circuit transmission lines in to the 230 KV facility (HVL2 & HVL2P, HVL3 & HVL3P);

Mackenzie Substation 13.8/69 kV Substation-New 2024

- Construction of one new AIS 13.8/69 kV substation by installing:
  (1) Two breaker and ½ 69 kV switchgear,
  (2) 11 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component.
  (3) Two- 16.7 MVA 13.8/69 kV Transformers.
  (4) Six new feeder circuits utilizing cosmos conductor type on concrete structures with an approximate length of 6 km each;

14.7 West Berbice

Burma Substation, Rossignol Substation, Onverwagt Substation, CH4 Proposal 10 MW Hybrid Power Plant-Onverwagt

14.7.1 Generation Conventional & Renewable Projects

- Interconnection at Onverwagt Substation of CH4 Hybrid Power Plant: 10 MW HFO, 16 MWp Photovoltaic and 10 MWh Battery Storage- by the end of 2023.

14.7.2 Transmission

- Construction of 37.17 km of redundant transmission line (L20P) between Columbia and Onverwagt Substation by the end of 2026.
- Construction of 18 km of redundant transmission line (L21-Bypass) between Onverwagt Substation and Canefield Substation by the end of 2025.
- Reconductoring 41.5 km of existing transmission line (L21) between Onverwagt and Canefield Substation by the end of 2025.
- Splitting of the L21 into the Rosignol Substation by the end of 2025.

14.7.3 Existing Substation

Onverwagt 13.8/69kV Substation

- Installation of one AIS 69 kV double bus single breaker bay to accommodate one link from a Hybrid Power Plant Substation by the end of 2023.

- Installation of one AIS 69 kV double bus single breaker bay to accommodate one new transmission line (L21P) from Canefield Substation by the end of 2025.
- Installation of one AIS 69 kV double bus single breaker bay to accommodate one new transmission line (L20P) from Columbia Substation by the end of 2026.
- Replacement of one 16.7-MVA 13.8/69 kV Dachi transformer with a 25 MVA 13.8/69 kV transformer by the end of 2024.
- Installation of one new 25 MVA 13.8/69 kV transformer with accompanying AIS 69 kV bay by December 2024.
- Installation of 6 cubicle 15 kV Metal-clad enclosed switchgear 2024.
- Reconductoring of the F2 – (from Onverwagt to No. 7 WCB) feeder backbone using Cosmos conductor type and concrete poles structures by the end of 2022- JICA.
- Construction of new 13.8 kV distribution network express – (from Onverwagt to No. 7 W.C.B), reconductoring from No. 7 W.C.B to Ithaca using Cosmos conductor type and concrete poles structures by the end of 2022- JICA.

14.7.4 New Substation

Rosignol 13.8/69 kV Substation-New 2025

- Construction of one new AIS 13.8/69 kV substation by installing:
    (1) Two breaker and ½ 69 kV switchgear;
    (2) 13 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component.
    (3) Two- 25 MVA 13.8/69 kV Transformers.
    (4) Four new feeder circuits utilizing cosmos conductor type on concrete structures with an approximate length of 6 km each;

14.8 East Berbice

Canefield Substation, Crab Island (East Berbice) Substation, Williamsburg Substation, Bush Lot Substation, No. 53 Village Substation Skeldon Substation, CH4 Proposal 10 MW Hybrid Power Plant-Canefield, CH4 Proposal 10 MW Hybrid Power Plant-Williamsburg.

14.8.1 Generation Conventional & Renewable Projects

- Interconnection at Canefield Substation of CH4 Hybrid Power Plant: 10 MW HFO, 16 MWp Photovoltaic and 10 MWh Battery Storage by the end of 2023.
- Interconnection at Williamsburg Substation of a Hybrid Power Plant: 10 MW HFO, 16 MWp Photovoltaic and 10 MWh Battery Storage by the end of 2024.

14.8.2 Transmission

- Construction of 55.9 km of redundant transmission line (L22P) between Canefield and No. 53 Substation by the end of 2025;
- Reconductoring 55.9 km of existing transmission line (L22) between Canefield and No. 53 Substation by the end of 2025;
- Splitting of the L22 & L22P into the Crab Island Substation by the end of 2025;
- Splitting of the L22 & L22P into the Williamsburg Substation by the end of 2024;
- Construction of 21.12 km of redundant transmission line (L23P) between No. 53 Upgraded Substation and Skeldon Substation by the end of 2024;

14.8.3 Existing Substation

Canefield 13.8/69kV Substation

- Installation of one AIS 69 kV double bus single breaker bay to accommodate one link from the CH4 Hybrid Power Plant Substation by the end of 2023;
- Installation of one AIS 69 kV double bus single breaker bay to accommodate one new transmission line (L21P) from Onverwagt Substation by the end of 2025;
- Installation of one AIS 69 kV double bus single breaker bay to accommodate one new transmission line (L22P) from No. 53 Upgraded Substation by the end of 2025;
- Installation of one new 16.7 MVA 13.8/69 kV transformer with accompanying AIS 69 kV bay by December 2025;
- Installation of 6 cubicle 15 kV Metal-clad enclosed switchgear 2025;
- Reconductoring of the F3-28 km feeder backbone using Cosmos conductor type and concrete poles structures by the end of 2023;
- Construction of two new feeder circuits utilizing cosmos conductor type and concrete poles structures each with an approximate length of 8 km by the end of 2025;

No. 53 Village 13.8/69kV Upgraded Substation- 2024

- Construction of one new AIS 13.8/69 kV substation by installing:
  (1) Three breaker and ½ 69 kV switchgear;
  (2) 13 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component.
  (3) Two- 25 MVA 13.8/69 kV Transformers.
  (4) Three new feeder circuits utilizing cosmos conductor type on concrete structures with an approximate length of 3 km.

- Reconductoring of the F2 & F3-15 km feeder backbone using Cosmos conductor type and concrete poles structures by the end of 2025;

Skeldon 69kV Upgraded Substation- 2024

- Installation of two AIS 69 kV double bus single breaker bay to accommodate one new transmission line (L23P);
- Installation of 69 kV 2-busbars with bus-tie circuit breaker to accommodate one new transmission line (L23P);

14.8.4 New Substation

Crab Island 13.8/69 kV Substation-New 2025

- Construction of one new AIS 13.8/69 kV substation by installing:
    (1) Three breaker and ½ 69 kV switchgear;
    (2) 15 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component.
    (3) Two- 35 MVA 13.8/69 kV Transformers.
    (4) Six new feeder circuits utilizing cosmos conductor type on concrete structures with an approximate length of 5 km each;

Williamsburg 13.8/69 kV Substation-New 2024

- Construction of one new AIS 13.8/69 kV substation by installing:
    (1) Five breaker and ½ 69 kV switchgear;
    (2) 15 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component.
    (3) Two- 25 MVA 13.8/69 kV Transformers.
    (4) Six new feeder circuits utilizing cosmos conductor type on concrete structures with an approximate length of 5 km each;

Williamsburg 69/230 kV Substation- New-2026

- Construction of one new AIS 230 kV substation that consists of six double bus single breaker 230 kV switchgear;
- Installation of two- 2 winding 100 MVA 69/230 kV Transformers.
- Expansion of the 69 kV substation by installing one breaker and ½ 69 kV switchgear.

14.9 Essequibo Coast and Essequibo Islands

Bartica, Leguan Island, Wakenaam Island, Essequibo Coast

14.9.1 Generation Conventional & Renewable

Bartica Power Plant/ RE Projects/ Distribution Feeders

- Installation of one- 1.5 MWp Solar Photovoltaic Plant by the end of 2022;
- Installation of one- 0.75 MWh BESS by the end of 2022;
- Installation of one- 1.2 MW additional LFO generation unit by the end of 2023;
- Installation of one-2 MW new LFO generation unit by the end of 2025;

Anna Regina Power Plant/ RE Projects/ Distribution Feeders

- Installation of one- 8 MWp Solar Photovoltaic Plant by the end of 2024;
- Installation of one- 8 MWh BESS by the end of 2024;
- Installation of two- 5.5 MW additional HFO generation unit by the end of 2024;
- Construction of new 13.8 kV distribution network 10 km –express from Anna Regina Power Plant to Onderneeming by the end of 2023;
- Reconductoring of the South feeder- 32.5 km using Cosmos conductor type and concrete poles structures by the end of 2025;

Leguan Power Plant/ RE Projects/ Distribution Feeders

- Installation of one- 0.6 MWp Solar Photovoltaic Plant by the end of 2023;
- Installation of one- 0.8 MWh BESS by the end of 2023;
- Installation of one- 0.41 MW additional Cat- LFO generation unit by the end of 2023;
- Installation of one- 0.41 MW additional Cat- LFO generation unit by the end of 2025;
- Installation of 450 kVAr APFC in the distribution network, the end of 2024;

Wakenaam Power Plant/ RE Projects/ Distribution Feeders

- Installation of one- 0.75 MWp Solar Photovoltaic Plant by the end of 2022;
- Installation of one- 1.151 MWh BESS by the end of 2022;
- Installation of one- 0.41 MW additional Cat- LFO generation unit by the end of 2023;
- Installation of one- 0.41 MW additional Cat- LFO generation unit by the end of 2025;
- Installation of 450 kVAr APFC in the distribution network the end of 2024;

Interconnection of the Island-13.8 kV Networks-2024

- Construction of new 13.8 kV distribution network 10 km –express from Leguan Power Plant to interconnection OHL Crossing to Hogg Island.
- Construction of new 13.8 kV distribution network 6 km –express from Wakenaam Power Plant to interconnection OHL Crossing to Hogg Island.

- Construction of new 13.8 kV distribution network 7 km to distribute power to new customers on Hogg Island.
- Construction of new 13.8 kV distribution network 0.92 km of OHL Crossing between Hogg Island and Leguan utilizing OH river crossing Towers.
- Construction of new 13.8 kV distribution network 0.84 km of OHL Crossing between Hogg Island and Wakenaam utilizing OH river crossing Towers.

14.9.2 Transmission

- Construction of 7.3 km of new transmission line (L40) between Leguan and Wakenaam Substation by the end of 2026;
- Construction of 38 km of new transmission line (L41) between Wakenaam and Suddie Substation by the end of 2026;
- Construction of 39 km of new transmission line (L42) between Suddie and Devonshire Castle Substation by the end of 2026;

14.9.3 New Substation

Leguan 13.8/69 kV Substation-New 2026

- Construction of one new AIS 13.8/69 kV substation by installing:
    (1) Two breaker and ½ 69 kV switchgear;
    (2) 11 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component.
    (3) Two- 10 MVA 13.8/69 kV Transformers.
    (4) Two new feeder circuits utilizing cosmos conductor type on concrete structures with an approximate length of 4 km each;

Wakenaam 13.8/69 kV Substation-New 2026

- Construction of one new AIS 13.8/69 kV substation by installing:
    (1) Two breaker and ½ 69 kV switchgear;
    (2) 11 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component.
    (3) Two- 10 MVA 13.8/69 kV Transformers.
    (4) Two new feeder circuits utilizing cosmos conductor type on concrete structures with an approximate length of 5 km each;

Suddie 13.8/69 kV Substation-New 2026

- Construction of one new AIS 13.8/69 kV substation by installing:
    (1) Two breaker and ½ 69 kV switchgear.

(2) 11 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component.

(3) Two- 10 MVA 13.8/69 kV Transformers.

(4) Three new feeder circuits utilizing cosmos conductor type on concrete structures with an approximate length of 6 km each.

Devonshire Castle 13.8/69 kV Substation-New 2026

- Construction of one new AIS 13.8/69 kV substation by installing:
    (1) Two breaker and ½ 69 kV switchgear.

    (2) 11 cubicle 15 kV class metal-clad enclosed switchgear with all relevant ancillary component.

    (3) Two- 10 MVA 13.8/69 kV Transformers.

    (4) Three new feeder circuits utilizing cosmos conductor type on concrete structures with an approximate length of 6 km each.
- Installation of 10 MVAr of Fix Capacitor Banks-Detuned Compensation Systems by the end of 2026.

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End

of

Development and Expansion Programme

2022-2026