Government of the Cooperative Republic of Guyana

Update of the study on system Expansion of the Generation System

Final Report - Confidential

Prepared by: Brugman SAS

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Client	Government of the Cooperative Republic of Guyana
Subject	Guyana's Power Generation System Expansion Study Final Report
Contract	HECI/IBD/S/01/2018
Notes	• This document is the Final Report. It includes comments from the client and its stakeholders. • This report selects the most favorable generation expansion programme. It covers all activities of the Term of Reference: Power demand growth (with energy efficiency and distributed generation), large scale generation alternatives, fuel price forecasts, selection of the most favorable generation mix, Policy and Regulatory analysis with recommendations, power sector tariff analysis, a preliminary social and environmental analysis and an action plan to develop the expansion programme.

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Prepared by:

Alberto Brugman, Andres Brugman, Jose Manuel Mejia, Humberto Rodriguez and David Vargas.

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Glossary of Terms

A	A rated refrigerator or other appliance
A+	A+ rated refrigerator or other appliance
A++	A++ rated refrigerator or other appliance
A+++	A+++ rated refrigerator or other appliance (most efficient)
AC	Alternating current
AC	Air-conditioning
AES	AES Corporation
ARA	Amsterdam-Rotterdam-Antwerp
ARIMA	Auto Regressive Integrated Moving Average
ARL	Average Rated Life
B	B rated refrigerator or other appliance
BAR	Metric measurement unit of pressure
BC	Cost Benefit
BCFG	Billion cubic feet of gas
BfL	Building for Life
BIS	Berbice Interconnected System
BOEB	Billion Oil Equivalent Barrels
BOOT	Build, Own, Operate, Transfer
BOS	Balance of System
BREEAM	Building Research Establishment Environmental Assessment Methodology
BTU	British Thermal Unit
CABE	Commission for Architecture and the Built Environment
CAGR	Compounded annual growth rate
CAPEX	Capital Expenditure
CARICOM	Caribbean Community Secretariat
CASTALIA	Castalia Strategic Advisors
CCGT	Combined Cycles Gas Turbines
CDC	Commonwealth Development Corporation
CEO	Chief Executive Officer
CF	Capacity Factor
CFB	Circulating Fluidized Bed
CFB	Circulating Fluidized Bed boiler
CFL	Compact Fluorescent Light
CIF	Cost, Insurance and Freight
CNG	Compressed natural gas
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COP	Coefficient of Performance
CSC-TERI	Commonwealth Science Council, London & TERI
C-SERMS	Caribbean Sustainable Energy Roadmap and Strategy
D&E	Development & Expansion programme in GPL

DBIS	Demerara Berbice Interconnected System
DC	Direct current
DCEO	Deputy Chief Executive Officer
DG	Distributed Generation
DIS	Demerara Interconnected System
DO	Dissolved Oxygen
EBITDA	Earnings Before Interest, Taxes, Depreciations and Amortization
ECELP	East Caribbean Energy Labelling Project
EE	Energy Efficiency
EEI	European Union Energy Efficiency Index
EEO	Energy Efficiency Obligation
EEPS	End-User Economic Potential Scenario
EIA	Energy Information Administration
ENS	Energy not served
EPE	Brazilian Research Energy Company
ESBI	Electricity Supply Board International
ESCo	Energy Services Company
ESIA	Amaila Hydropower Environmental and Social Impact Assessment
FOB	Free on Board
FSRU	Floating Store and Regasification Unit
FSRU	Floating storage and regasification unit
G$	Guyana dollars
GDP	Gross Domestic Product
GEA	Guyana Energy Agency
GEPS	Generator Economic Potential Scenario
GFC	Guyana Forestry Commission
GGGI	Global Green Growth Institute
GGMC	Guyana Geology and Mines Commission
GHG	Greenhouse gases
GHI	Global Horizontal Irradiation
GIS	Geographic information systems
GoG	Government of Guyana
GOI	Guyana Office for Investment
GPL	Guyana Power and Light Inc.
GRDB	Guyana Rice Development Board
GT	Gas Turbine
GTM	Greentech Media
GUYSUCO	Guyana Sugar Corporation Inc.
GW	Gigawatt
GWh	Gigawatt-hour
GWp	Giga Watts peak
HC	Hydrocarbon
HECI	Hinterland Electrification Company Inc
HEPS	Hydroelectric Power Survey of Guyana (Montreal Engineering Company)

HFO	Heavy Fuel Oil
HHV	heat rate
HOMER	Hybrid Optimization of Multiple Energy Resources
HPS	High Pressure Sodium Lamp
HV	High Voltage
HVDC	High Voltage Direct Current
Hz	Hertz
IADB	Inter-American Development Bank
IBRD	International Bank for Reconstruction and Development
ICT	Information and Communications Technology
IDA	International Development Association
IE1	Standard Efficiency Class for Motors
IE2	High Efficiency Class for Motors
IE3	Premium Efficiency Class for Motors
IEA	International Energy Agency
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IMF	International Monetary Fund
IPP	Independent Power Producer
IRR	Internal Rate of Return
ITCZ	Inter Tropical Convergence Zone
KUI	Kwakwani Utility Company
kV	Kilo volt
kVA	Kilovolt amp
KW	Kilowatt
KWh	Kilowatt-hour
KWp	Kilo Watts peak
LAC	Latin American and Caribbean countries
LCOE	Levelized cost of electricity
LCOES	Levelized cost of electricity saving
LECI	Linden Electricity Company
LECI	Linden Electric Company Inc.
LED	Light Emitting Diode
LEED	Leadership in Energy and Environmental Design
LFO	Light Fuel Oil
lm	Lumen
LMPCI	Lethem Power Company Inc.
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MBTU	Million British Thermal Units
MMCFD	Million cubic feet gas per day
MMBNGL	Million barrels of natural gas liquids
MMBO	Million barrels of oil
MMTPA	Million metric tonnes per annum

MOGAS	Abbreviation for motor gasoline
MOU	Memorandum of Understanding
MPL	Mahdia Power and Light
MPP	Maximum Power Point
MRPL	Matthew's Ridge Power & Light Inc.
MSM	Medium Speed Motors
MW	Megawatt
MWh	Megawatt-hour
NAMA	Nationally Appropriate Mitigation Action
NASA	National Aeronautics and Space Administration
NETWWT	North East Trade Winds
NG	Natural Gas
NGL	Natural Gas Liquids
NGV	Natural gas vehicles
NICIL	National Industrial And Commercial Investments Limited
NOx	Nitrogen oxide
NREL	National Renewable Energy Laboratory
O&M	Operation & maintenance
O_2	Oxygen
OBMI	Omai Bauxite Mining Inc
OECD	Organization for Economic Co-operation and Development
OLS	Ordinary Least Squares
OPEX	Operational expenditures
OPM	Office of the Prime Minister in Guyana
ORV	open rack vaporizers
PANMAX	One of the terms for the size limits for ships traveling through the Panama Canal
PKPL	Port Kaituma Power and Light Inc.
PM	Particulate matter
PPA	Power Purchase Agreement
PSI	Pounds per square inch
PUC	Public Utilities Commission
PUCA	Public Utilities Commission Act
PV	Photovoltaic
PVPP	PV power plant
PWC	PricerwaterhouseCoopers
R^2	Coefficient of determination
RE	Renewable Energy
REETA	Renewable Energy and Energy Efficiency Technical Assistance
ROW	Right of way
SDDP	Stochastic Dual Dynamic Programming model developed by PSR Inc.
SEER	Seasonal Energy Efficiency Ratio
SEIA	Solar Energy Industries Association
SHW	Solar Hot Water
SiO_2	Silica contents

SME	Small to Medium Sized Enterprise
SO_2	Sulfur Dioxide
T12	Tubular Light fitting with diameter of 12 eighths of an inch
T5	Tubular Light fitting with diameter of 5 eighths of an inch
T8	Tubular Light fitting with diameter of 8 eighths of an inch
TED	Technology, Entertainment and Design
TERI	The Energy and Resources Institute
TPS	Technical Potential Scenario
UNFCC	United Nations Framework Convention on Climate Change
UPME	Unidad de Planeacion Minero Energetica (Colombia)
US$	United States dollars
VDC	Voltage in Direct Current (DC)
VHS	Video Home System
VPN	Virtual Private Network
VSD	Variable Speed Drive
W	Watt
WACC	Weighted Average Cost of Capital
WB	World Bank
Wdc	DC Watt
Wp	Watt peak
WTI	West Texas Intermediate, also known as Texas light sweet

Weights and measures

ºC	Degree Celsius
ºF	Degree Fahrenheit
g	gram
GW	Gigawatt
GWh	Gigawatt-hour
J	Joule
kV	Kilo volt
kVA	Kilovolt amp
KW	Kilowatt
KWh	Kilowatt-hour
ha	Hectare
hr	Hour
kg	Kilogram
km	Kilometer
km^2	Square kilometer
l	Liter
l/hr	Liter per hour
m	Meter
m^2	Square meter
m^3	Cubic meter
m^3/sec	Cubic meter per second
MJ	Mega Joule
MBTU	Million British Thermal Units
mg	milligram
mm	millimeter
mps	meter per second
MW	Megawatt
MWh	Megawatt-hour
sec	Second
ton	Metric ton

NOTE

In this study, "US$" refers to United States dollars and "G$" to Guyana dollars

1 INTRODUCTION

In order to identify guidelines for the development of the most adequate electrical infrastructure for generation and transmission expansion in the country, the Inter-American Development Bank ("IADB") conducted in 2014 an Initial Study on System Expansion of the Generation and Transmission System of Guyana ("Initial Study").

An update of the Initial Study ("2016 Expansion Study") was commissioned by IADB in October 2015 to: (i) reflect changes resulting from the variation in the prices of fossil fuels; (ii) refine the findings from the Initial Study by updating the analysis with recent information from GPL's power system and the expected investments from the utility in the coming years; (iii) explore alternatives for the development of renewable energy ("RE") generation technologies; (iv) analyze and propose the potential of Energy Efficiency ("EE") measures in amongst others, public buildings, industry, residential sector and Small and Medium Enterprises ("SME"); and (v) select the most favorable generation project and develop an action plan for its execution. The final report of the Guyana Power Generation Expansion Study was completed in June 2016.

Despite that the 2016 expansion program provided by the 2016 Expansion Study was built considering the development of thermal power plants, it was planned to do so with the use of imported Natural Gas. Currently, this has changed with the recent discovery of indigenous natural gas reserves[1]. In addition to this, the expansion program provided in the 2016 Expansion Study needed to be updated in order to present a realistic and robust consideration for the future development of renewable energy generation technologies ("RETs") in sustainable manner and eventually with the participation of the private sector. This will provide clarity on the future National RE strategy.

This study ("2018 Update Study") is based on the 2016 Expansion Study, focusing on GPL's power network with emphasis on the power expansion of the Demerara – Berbice interconnection system (DBIS)[2]. It includes in-depth revision and analysis of RE technologies and natural gas fired generation options. It also includes a preliminary socio-environmental impact and risk analysis of the issues associated with the candidate generation technologies and an analysis of the current regulation in order to reach regulatory policy recommendations to foster RE generation technologies.

Objectives of this study

The objective of this study is to update the 2016 Expansion Study in order to: (i) reflect changes in demand assumptions resulting from the expected oil revenues; (ii) reflect changes resulting from the use of domestic natural gas in electricity generation; (iii) further refine the findings with any recent information from GPL's power system, and the expected investments from the utility in the coming years in transmission and distribution; (iii) refine alternatives for the development of renewable energy generation (RE) technologies (when possible per project) within the context of Government's Green State

[1] Following the recent oil discoveries by Exxon Mobil, of approximately 2.75 billion oil-equivalent barrels offshore Guyana, the country is poised to become a major oil producer in the Region by mid-2020. Moreover, the availability of indigenous natural gas resources associated to future oil production is estimated at between 30 to 50 million cubic feet per day, a sufficient volume to alter the predominantly fuel-oil based electricity generation matrix.

[2] This study is focused in the Demerara-Berbice interconnected system (DBIS). Therefore, this study does not analyze the overall non-interconnected regions of Guyana with the exception of Linden and Mining Industries regions that are located in the area of influence of the optional hydroelectric projects.

Development Strategy (GSDS); and (iv) select the most favorable generation program and develop an action plan for its execution up to 2035.

The study develops an updated optimal generation matrix per project with a timeline up to 2035.

Structure of the report

This report contains findings, approaches and advances in the different topics needed to analyze, in a comprehensive manner, the development of generation infrastructure in Guyana, specifically in its main grid (DBIS) with consideration of the potential inclusion of the Linden network; it includes the results obtained in the following activities:

Updated Projections of Electricity Demand. This activity considered available projections of electricity demand and the basis of their formation. Both economic and population growth forecast for the country were considered, as well as the increase in electricity service coverage, rates and prices of alternative energy, and other variables or parameters that constitute "drivers" of future electricity consumption in Guyana. The update uses the new available forecasts for the economic growth of Guyana considering the significant new future Oil production in the country. Also, in consideration of the GSDS, the electricity demand forecast includes an estimation of the potential demand for electricity transportation in Guyana, which is included in the high demand growth scenario.

System Identification of Existing Generation - Transmission system. This activity entailed research and inventory of the basic technical characteristics such as capacity, availability, heat rates, type of fuel used, among others, including the remaining service life and current state of existing power plants in DBIS and GPL’s transmission infrastructure.

Price Scenarios and Conditions for the Supply of Fuel for Electricity Generation. Fuel price scenarios were evaluated in order to set prices and conditions that would apply to the fuels used to generate electricity in Guyana. Information was obtained for current fuels used for power generation by GPL including indigenous natural gas available from the offshore oil production. Price forecasts for liquid fuels (Heavy Fuel Oil - HFO and Light Fuel Oil - LFO) were based on international fuel prices scenarios recently published by the Energy Information Administration (EIA, Annual Energy Outlook 2018). Natural gas prices were estimated using the experience on wellhead prices of other natural gas producing countries and available estimations on its offshore levelized transportation costs.

Analysis and Costs of Options for New Power Plants. This task identified the power generation plants that may be considered as candidates for system expansion and their investment costs in generation and transmission infrastructure and Operation & Maintenance (O&M) costs, namely: i) hydroelectric power plants (the same five representative hydroelectric projects identified in the 2016 Expansion Study); ii) thermal power plants using liquid fossil fuels and natural gas; iii) power plants using non-conventional renewable energy sources (wind, solar, bagasse, rice husk and wood residues). Levelized costs of electricity (LCOE in US$/MWh) associated to the conventional and non-conventional options were estimated.

Methodology: Models, Expansion Criteria, Operating Criteria. This section describes the model applied in the study to establish the most economical expansion of the power system of Guyana. This includes its mathematical formulation.

Definition and Selection of Scenarios: Demand / Supply / Fuel Prices. This activity presents the scenarios of interest to study demand forecasts, supply options and fuel price levels, for which the least-cost of power expansion was established.

Modelling and Analysis of the Optimal System Expansion. This activity calibrated and applied the models in order to establish the system expansion with least Investment, Fuel, O&M and non-served demand costs associated with the scenarios of interest. The results obtained are presented in graphical and numerical form in order to facilitate the generation expansion analysis.

Verification of the Technical and Economic Robustness of the Results Obtained. With the results obtained for the optimal generation expansion for each of the scenarios of interest, and additional sensitivities that analyses the results to variations in the main parameters involved in the evaluation, this activity verified the technical and economic robustness of the results.

Energy policy and regulation. Analyze and make recommendations on energy related regulatory and policy issues including the analysis of: composition of electricity tariffs. Analyze the capacity of existing regulatory and policy entities to deal with the transmission, distribution and utilization of power generated by domestic natural gas, together with the promotion of RETs as part of a Green State development strategy. Here we prepare a thorough analysis of the current regulatory framework that includes an assessment (with recommendations) of the adequacy of the country's energy laws and regulations in supporting and regulating the development of RE, distributed generation, natural gas generation and EE with private sector participation.

Preliminary socio-environmental impact and risk analysis of the issues associated with natural gas power generation technologies, as well as an estimation of carbon emissions reduction as consequence of the proposed generation technologies.

Action Plan. Taking into account the results obtained from all previous activities select the most favorable power generation mix and propose an action plan (including recommendations) for its execution.

The results of these activities are covered in this report in the following chapters:

- Existing Generation - Transmission system (Chapter 3)
- Update of the electricity demand forecasts (Chapter 4)
- Fuel prices (Chapter 5)
- Options for new power plants (Chapter 6)
- Generation expansion optimization model (Chapter 7)
- Optimal expansion of DBIS (Chapter 8)
- Analysis of Guyana's power sector Policy and regulation (Chapter 9)
- Preliminary socio-environmental impact and risk analysis (Chapter 10)
- Action plan for the most favorable power generation mix (Chapter 11)

2 SCOPE OF CONSULTANCY

The objective of this study is to update the 2016 Expansion Study in order to: (i) reflect changes in demand assumptions resulting from the expected oil revenues; (ii) reflect changes resulting from the use of domestic natural gas in electricity generation; (iii) further refine the findings with any recent information from GPL's power system, and the expected investments from the utility in the coming years in transmission and distribution; (iii) refine alternatives for the development of renewable energy generation (RE) technologies (when possible per project) within the context of Government's Green State Development Strategy; and (iv) select the most favorable generation expansion programme and develop an action plan for its execution up to 2035.

The terms of reference of the study are provided in Appendix Q .

3 BACKGROUND OF THE POWER SECTOR IN GUYANA

This section of the report briefly describes the current situation of the power generation and transmission systems in Guyana, as well as a general overview of the current distribution system.

As previously stated, the focus of this study is in the Demerara - Berbice Interconnected System (DBIS) system[3]. The Consultant also considered Linden interconnected to DBIS in case that mid-size hydro plants are built in the interior of Guyana and/or Arco Norte project (interconnection of Guyana, Northern Brazil, Suriname, and French Guyana power systems) is developed, as a new transmission line (which would pass near Linden) would be needed to supply power from such plant(s) to DBIS. Also, in the case of the Kumarau hydroelectric power plant it was included the regional market associated to this project, consisting mainly in the mining industries of Aurora and Toparu.

3.1 Legal and Institutional framework

The power sector in Guyana has the following main policy and regulatory institutions: The Ministry of Public Infrastructure (MPI), the Guyana Energy Agency (GEA) and the Public Utility Commission (PUC).

3.1.1 The Ministry of Public Infrastructure (MPI)

The Ministry of Public Infrastructure is in charge of the following matters: energy, hydropower, utilities, hinterland electrification and electrical inspection. The following Ministry's Departments (or Agencies) regarding the power sector are under its direction: GEA, GPL, PUC, the Hinterland Electrification Company Inc (HECI) and the Electrical Inspectorate.

Its key responsibilities, among others, include the planning, creation and maintenance of major public civil works infrastructure throughout Guyana.

3.1.2 Guyana Energy Agency (GEA)

The Guyana Energy Agency Act of 1997 (amended in several opportunities), established the GEA with the following functions: i) advise and make recommendations to the Minister regarding efficient use of energy resources; ii) upon the request of the Minister, develop a national energy policy and secure its implementation, directly or through other persons; iii) secure the efficient use of energy.

GEA is directed by a Chief Executive Officer (CEO) and a Deputy Chief Executive Officer (DCEO) appointed by the Minister responsible for the energy sector. There is an Energy Agency Board formed by CEO and DCEO and other three members appointed as well by the Minister "from among governmental and private sector organizations or institutions with a particular interest or expertise in matters of energy policy" which serves as Board of Directors. The Minister is the maximum GEA's authority as he shall give to the Agency directions about the policy to be followed.

3.1.3 Public Utilities Commission (PUC)

The Public Utilities Commission (PUC) is a corporate body with members appointed by the Minister for a three-year period. It covers a wide range of public services like electricity, telecommunications, water

[3] Later on in this chapter, the Consultant defines DBIS and explains the difference between GPL's whole system.

supply, transportation, etc. In relation to the electricity sector, the PUC shall be bound by, and shall give effect to, the GEA Act and the ESRA. This body is ruled by the PUC Act (PUCA).

Chapter 9 includes a detailed presentation of the legal and institutional framework of the energy sector in Guyana.

3.2 Regulatory Framework

The main regulatory elements for the power sector are defined in the four Acts: i) the GEA Act, which defines the scope of energy policy; ii) the Electricity Sector Reform Act, which defines the scope of the electricity public services, the licenses for Independent Power Producers and the scope of its annual, five year and long term plans; iii) the Hydro Electric Power Act, which defines the scope of licenses for hydro generation; and finally, iv) the PUC Act, which defines the procedures for approval of plans and tariffs.

GPL's license, granted in 1999, includes power generation, except hydropower generation. Among the governing Acts already mentioned, the License includes the Environmental Protection Act (1996). GPL's License includes several rules related power acquisition prices and rates.

Chapter 9 provides more details on the regulatory framework of the power sector in Guyana.

3.3 Companies related to the power sector in Guyana

The **Guyana Power and Light Inc.** (**GPL**) is the main official supplier of electricity in Guyana, with its franchise area encompassing all three counties of Demerara, Berbice, and Essequibo. GPL's operations comprise generation, transmission, and distribution activities and it is authorized to purchase power from Independent Power Producers (IPPs). GPL is a state owned company, which generates most of the electricity in Guyana with its own power plants, and also buys wholesale electricity from Guyana Sugar Company (Guysuco) in order to supply electricity to DBIS system (and Essequibo region, which is isolated from DBIS).

Hinterland Electrification Company Inc. (HECI) is a company wholly owned by the Government of Guyana. Its mission is to maintain the steady extension and upgrade of electricity supply systems across the hinterland, progressively improving operations and merging isolated services as appropriate. HECI owns several small minigrids/microgrids that serve isolated communities. It currently manages the Government's Hinterland Electrification Programme and the Global Environment Facility (GEF) – Sustainable Energy Programme for Guyana with loan support through the Inter-American Development Bank (IDB), to promote renewable energy development in Guyana.

Other power companies that operate in the power sector in Guyana located in the hinterland areas and which receive subsidies from the GoG are:

- **Linden Electric Company Inc. (LECI)**: Generation and distribution of electricity to Linden. This company is fully owned by the National Industrial and Commercial Investments Limited (NICIL) which in turn is a fully owned company of the GoG[4] and purchases all its electricity from Omai Bauxite Company (owned 70% China Bosai Minerals Inc and 30% Government of Guyana).

[4] Financials and subsidiaries of NICIL found at: http://www.privatisation.gov.gy/nicil/financials.

- **Kwakwani Utility Company (KUI)**: Incorporated in January 2005 to supply of electricity and water to Kwakwani and surrounding areas and is owned by NICIL [5].
- **Lethem Power Company Inc. (LMPCI):** A wholly owned subsidiary of National Industrial and Commercial Investments Limited with license (expiring in December 2014) to supply, generate, distribute and supply electricity in Quarrie Creek in the South, Manari Creek in the North, Kanuku Mountain Range in the East and Takatu River in the West of Region 9[6].
- **Matthew's Ridge Power & Light Inc. (MRPL):** This Company is fully owned by NICIL and operates in Matthew's Ridge, a small community within the Barima-Waini region of Guyana (Region 1) with manganese mining potential. Information about size and infrastructure of the company is non-available on NICIL nor on public sources. Most power in the region is supplied by self-generators.
- **Mahdia Power and Light (MPL)**: Supplies of electricity to the Mahdia community and surrounding communities in Region 8 with around 500 customers. The company is owned by NICIL. Installed capacity of about 750 kVA in one generating set.
- **Port Kaituma Power and Light Inc. (PKPL)**: Supply of electricity to the Port Kaituma community and is owned by NICIL.

3.4 Guyana Power & Light Inc. (GPL)

As mentioned, GPL is the main official supplier of electricity in Guyana with its franchise area encompassing all three counties of Demerara, Berbice and Essequibo. GPL supplies all its domestic customers with voltage ranging from 110 to 220 volts depending on the area. Prior to 1st October 1999, the Company, then named the Guyana Electricity Corporation was wholly owned by the Government of Guyana. A 50/50% equity partnership was established between the Government of Guyana and a consortium comprising the Commonwealth Development Corporation (CDC) of the United Kingdom and the Electricity Supply Board International (ESBI) of Ireland which brought into being the new Company, GPL. This partnership dissolved in April 2003 and GPL reverted to 100 percent ownership by the government and people of Guyana. This arrangement still stands at present.

GPL is the owner of the Demerara Berbice Interconnected System (DBIS), a 60 Hz interconnected system that connected Demerara region with Berbice Region at 69 kV in June 2014. Essequibo region, served also by GPL, is not connected to DBIS.

GPL has a regulated monopoly in the transmission, distribution and sale of electricity on the Coast of Guyana where about 90% of its population resides. GPL's customer base starts from Charity in Region 2 up to Moleson Creek in Region 6. The islands of Leguan & Wakenaam, in the Essequibo River, are powered by GPL as well.

As of December 2017, GPL has 188,664 customers (90.9% residential, 8.57% commercial and 0.4% industrial) and gross sales of G$32,743 million (US$ 158.2 million). Such sales are equivalent to 555.3 GWh (47% residential, 18% commercial and 35% industrial). The installed capacity in DBIS is 172.2 MW and available capacity is 135.9 MW. GPL´s gross generation was 809,411 GWh in 2017 (Essequibo

[5] http://www.privatisation.gov.gy/documents/financials/KUI/KUI%202011.pdf.

[6] Electricity to LMPCI used to be provided by Moco-Moco 0.5MW (located in Region 9) hydro plant before 2003, when it was destroyed by a landslide in July 2003. The Ministry of Public Infrastructure in January 2016 started to seek proposals to rehabilitate and operate the Moco-Moco Hydropower, to be operated under a Build, Own, Operate, Transfer (BOOT) arrangement in order to supply power to Lethem Power Plant under a negotiated and agreed Power Purchase Agreement.(http://www.electricity.gov.gy/index.php/request-for-expressions-of-interest-moco-moco-hydro).

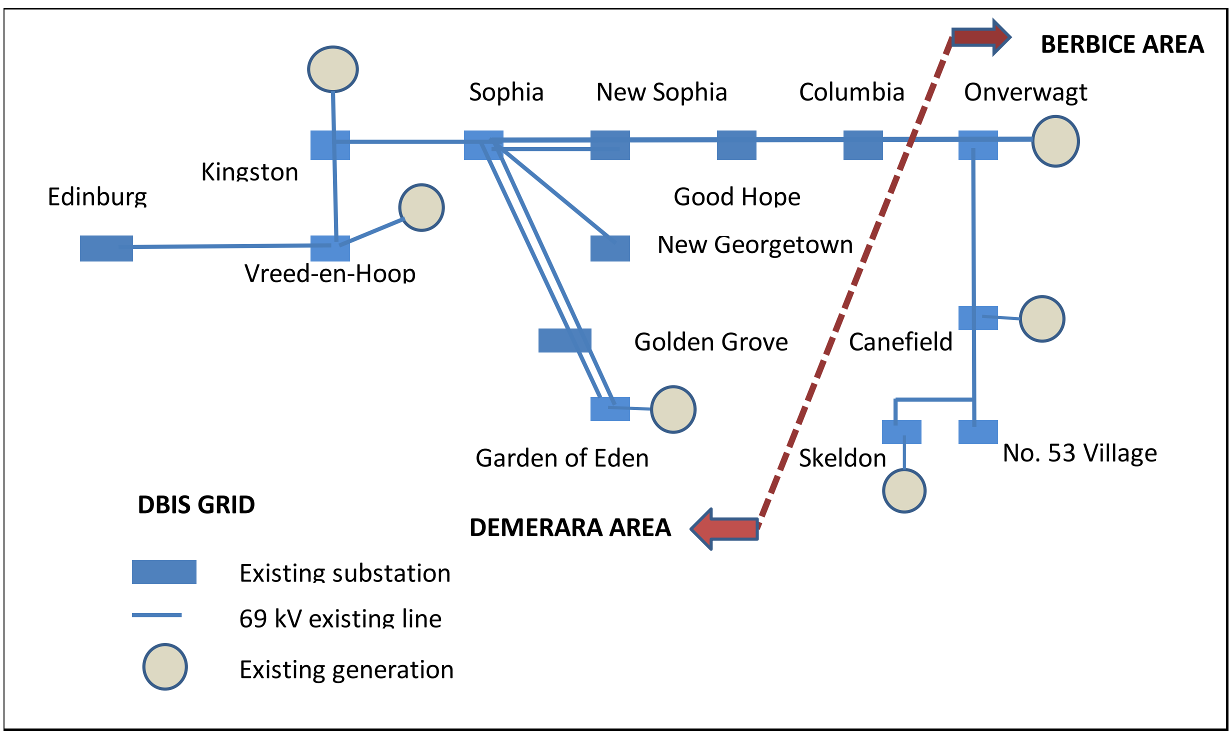
region 41,683 GWh). GPL had a high level of transmission and distribution losses of 29.6% in comparison to other utilities in the region. In 2017, 90% of GPL's gross generation came from Heavy Fuel Oil (HFO) fired reciprocating engines and 10% from Light Fuel Oil (LFO) fired in reciprocating engines, being the bagasse generation participation null in this year given the unavailability of the Guysuco cogeneration power plant. GPL has a 40 MW PPA to purchase energy generated by sugar cane bagasse and HFO from Guysuco (which owns a 30 MW bagasse cogeneration plant and also has 10 MW reciprocating engines fueled by HFO), although historical availability of such PPA has been low.

3.5 Areas of electricity service and system topology

GPL's electricity system is concentrated on the Guyana's coast, where 90% of the population is concentrated having electricity service coverage of over 90%, where it covers three different areas: Demerara, Berbice and Essequibo. The company has four main subsystems (i.) Demerara Interconnected System (DIS), (ii) Berbice Interconnected System (BIS), (iii) Essequibo Coast and (iv) Essequibo Islands. The Demerara Interconnected System (DIS) and Berbice Interconnected System (BIS) were interconnected in 2014 with the completion of the Sophia–Onverwagt transmission link 73.8 km of 69 kV which also linked substations Columbia and Good Hope. Such system is nowadays known as the DBIS (Demerara – Berbice Interconnected System).

Main power plants connected to DBIS are the diesel generating units located at the Kingston, Vreed-en-Hoop and Garden of Eden substations, which supply the Demerara area and the generating units of the Skeldon, Canefield and Onverwagt substations in Berbice area. Figure 1 provides an overview of the existing DBIS Generation - Transmission (G-T) system.

Figure 1. Existing DBIS generation and transmission system



Source: Consultant with GPL information

Essequibo region is not connected to DBIS and has generation capacity owned by GPL of 15.8 MW (Leguan, Ana Regina, and Wakenaam). There is a power plant of about 18 MW connected at Linden owned by Bosai Bauxite Company from which LECI purchases power apart from supplying power for Bosai's mining operations. Leonora is also a small isolated system.

3.6 Generation capacity

3.6.1 DBIS system

As of December 2017, DBIS's generating installed capacity was 172.2 MW (135.9 MW effective & operative) distributed in 117.8 MW (114.5 MW effective & operative) in Demerara and 54.4 MW (21.40 MW effective & operative) in Berbice. GPL's generation system is a mix of relatively old high-speed diesel units fueled by LFO, and relatively new medium-speed diesel units fueled by HFO. However, within very recent years the proportion of relatively new HFO units has increased significantly and their capacity now constitutes a majority of the GPL system installed capacity. Also, in the Skeldon substation there are 2x15 MW steam turbines (included in the tables) owned and operated by the Guyana Sugar Corporation (Guysuco), a state owned company, which uses sugar cane bagasse as main fuel, that today are not in operation due to technical difficulties. Guysuco as well owns 10 MW in reciprocating engines supporting a Power Purchase Agreement (PPA) with GPL (capacity included in the tables) fueled by HFO.

Table 1 summarizes the generation capacity of DBIS as of 2017.

Table 1. Summary of generation capacity per region on DBIS system (MW)

LOCATION & POWER PLANT	Installed Capacity (MW)	Efective & Operative (MW)	Fuel Type
DEMERARA			
PPDI Garden of Eden Station	22.0	22.0	HFO
Garden of Eden Power Station	11.0	8.0	LFO
PPDI Kingston 1 Station	22.0	22.0	HFO
PPDI Kingston 2 Station	36.6	36.3	HFO
PPDI Vreedenhoop Station	26.2	26.2	HFO
SUBTOTAL	**117.8**	**114.5**	
BERBICE			
Skeldon Energy Inc (SEI)12	10.0	10.0	HFO
Skeldon Biommass Cogen	30.0	0.0	Baggasse
Onverwagt Power Station	4.1	3.7	LFO
Canefield Power Station #3	5.5	4.2	HFO
Canefield Power Station # 10,11,13	4.8	3.5	LFO
SUBTOTAL	**54.4**	**21.4**	
TOTAL DBIS	**172.2**	**135.9**	

Source: GPL, data aggregated by the consultants

GPL recently installed a 3x8.7 MW HFO-fueled Wartsila reciprocating engines at Vreed en Hoop (DP4), in West Bank Demerara, and is developing a short term expansion in Garden of Eden in East Bank.

GPL currently operates to a deterministic capacity margin criteria. GPL's criterion to define its reserve capacity requirements (difference between peak demand and installed capacity in MW) is the sum of the sizes (in MW) of its two largest units. According to this criteria, with the completion of Wartsila units at Kingston in 2011 and West Bank Demerara in 2014 the required reserve margin is 17.4 MW. This criteria is being subject to further analysis considering probabilistic indicators, as the Loss of Load Probability and economic cost of non-served electricity, as typically analyzed and applied in other systems[7].

Power Purchase Agreement between GPL and Guysuco

GPL has just one Power Purchase Agreement (PPA) at present, with the state-owned sugar producer, Guysuco. GPL is purchasing surplus power, and Guysuco is not an IPP per se. GPL is purchasing 6.2 GWh per month from Guysuco; partly from the bagasse-fired cogeneration plant, and partly from Guysuco's Wartsila diesel generators. The rates are as follows: a) from the cogeneration plant – 4 US cents/kWh; b) from the Wartsila diesels – 2 US cents/kWh, with GPL supplying the HFO. The agreement is expected to continue indefinitely. From 2012, a minimum of 50% of Guysuco's commitment has to come from the cogeneration plant, and the remainder from the diesel units. In the recent past there has been an operational problem at the cogeneration plant, which has meant that all the power exported to GPL has come from the diesel units. Guysuco guarantee to deliver 8.0 MW continuously. From GPL's License, a maximum of 10.0 MW can come from an IPP without having to hold a tender. Guysuco is committed to delivering 70,000 MWh per year, with provision to supply extra energy but at half the rates. In December 2017 the bagasse cogeneration plant included in the sugar plant was closed due that it did not worked as originally planned and the GoG is planning to divest from Guysuco and privatize the Skeldon plant (including the bagasse cogeneration plant). The PPA is served nowadays with the 10 MW gensets which were divested to another GoG independent company.

3.6.2 Generation Capacity in other regions not connected to DBIS

3.6.2.1 Linden

None of the thermal units in Linden system are owned or operated by LECI, power is purchased from the owner – BOSAI Bauxite Company (which owns about 18 MW of power generation capacity). BOSAI Bauxite Company has an extraction capacity of 1.2 million tons of bauxite ore a year, and an annual output of 350,000 tons of bauxite processed.

3.6.2.2 Essequibo

Table 2 shows the generation installed capacity in Essequibo Region (owned and/or operated by GPL) which is not interconnected to DBIS system but does require capital expenditures and operational expenditures in GPL annual plans.

[7] For example it would be convenient to evaluate these indicators in 2016 for which the reserve margin over annual peak demand was 27.0 MW, in comparison of the reserve margin of 13.3 MW corresponding to year 2017.

Table 2. Summary of generation capacity in Essequibo region (MW)

LOCATION	Installed Capacity (MW)
Bartica	6.4
Leguan	1.2
Wakenaam	1.0
Anna Regina	7.2
Total	15.8

Source: GPL 2018

3.6.3 Generation Expansion Program

GPL is considering to install additional 8.7 MW HFO gensets in Garden of Eden and for this study it was assumed that the Skeldon bagasse cogeneration power plant (2x15 MW) will be refurbished by a new investor, as well its connection capacity will be expanded by GPL, in order to supply to DBIS 13.5 MW from this cogeneration plant after 2021 (in addition to the 10 MW existing diesel generation operated by a separated GoG company).

Unit Mirrlees # 4 in Canefield has been considered already decommissioned. And the rest of old units: Nigata # 5 and # 6 in Garden of Eden, Mobile # 1, # 2, # 6 and # 8 and GM # 7 in Onverwagt and Mirrlees # 3 and Mobile Cat Set # 10, # 11 and # 12 in Canefield are considered to be decommissioned by 2020, before the commissioning of a high capacity new power plant using or Liquid Fuel after 2020 (and Natural Gas/Liquid Fuel after 2022).

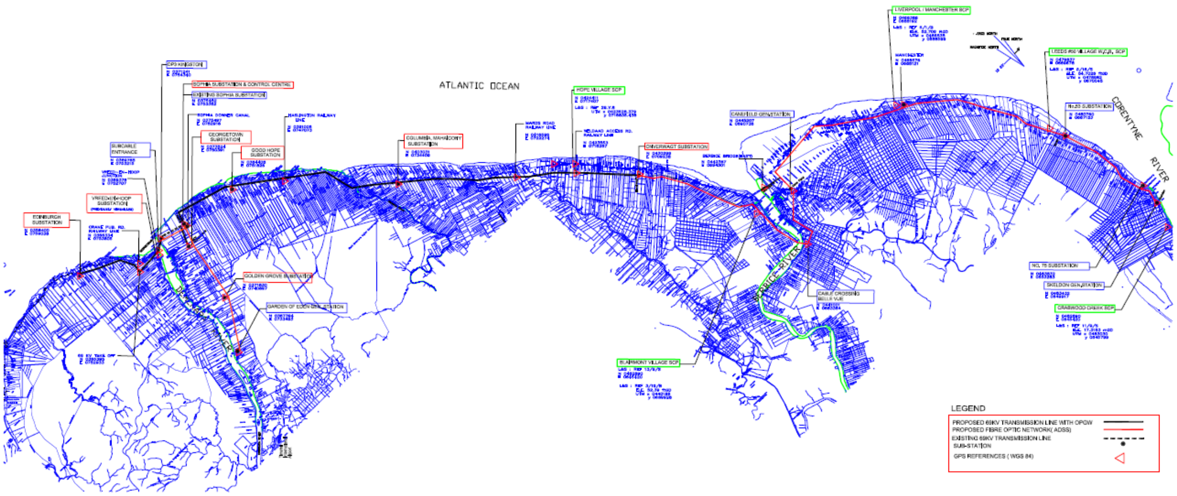
3.7 Transmission system

3.7.1 Actual Transmission system

The transmission system in Guyana is constituted of 69 kV lines for a total length of 276 km, interconnecting the substations of Skeldon (Demerara region) to Edinburgh Cannes (Demerara region) in a radial structure along the coastal area. The frequency of the electrical system in Guyana is 60 Hz. The whole transmission infrastructure belongs to the public utility GPL.

Figure 2 shows the transmission and distribution network of DBIS (note: No Essequibo, nor Linden, nor rural areas shown).

Figure 2. Coastal map showing transmission and distribution system of DBIS



SOURCE: GPL

The 69 kV transmission grid interconnects the Substations as described in Table 3 and Table 4.

Table 3. GPL transmission sub-stations[8]

Region	Substations	Capacity (MVA)
West Coast Demerara	Edinburgh	1 x 10
West Coast Demerara	Vreed-en-Hoop	1 x 20
East Bank Demerara	Golden Grove	2 x 10
East Bank Demerara	Garden of Eden	2 x 16.7
GeorgeTown	Kingston	2 x 26/35
GeorgeTown	New GeorgeTown	2 x 16.7
GeorgeTown	Sophia (Upgraded)	3 x 16.7
GeorgeTown	New Sophia	Nil
GeorgeTown	Sophia Converter	Nil
East Coast Demerara	GoodHope	1 x 26/35
East Coast Demerara	Columbia	1 x 16.7
Berbice	Onverwagt	1 x 16.7
Berbice	Canefield	1 x 16.7
Berbice	No. 53 Village, Corentyne	1 x 16.7
Berbice	Skeldon (Guysuco)	1 x 16.0

Source: GPL

[8] Source: GPL April 2015 Transmission System Diagram.

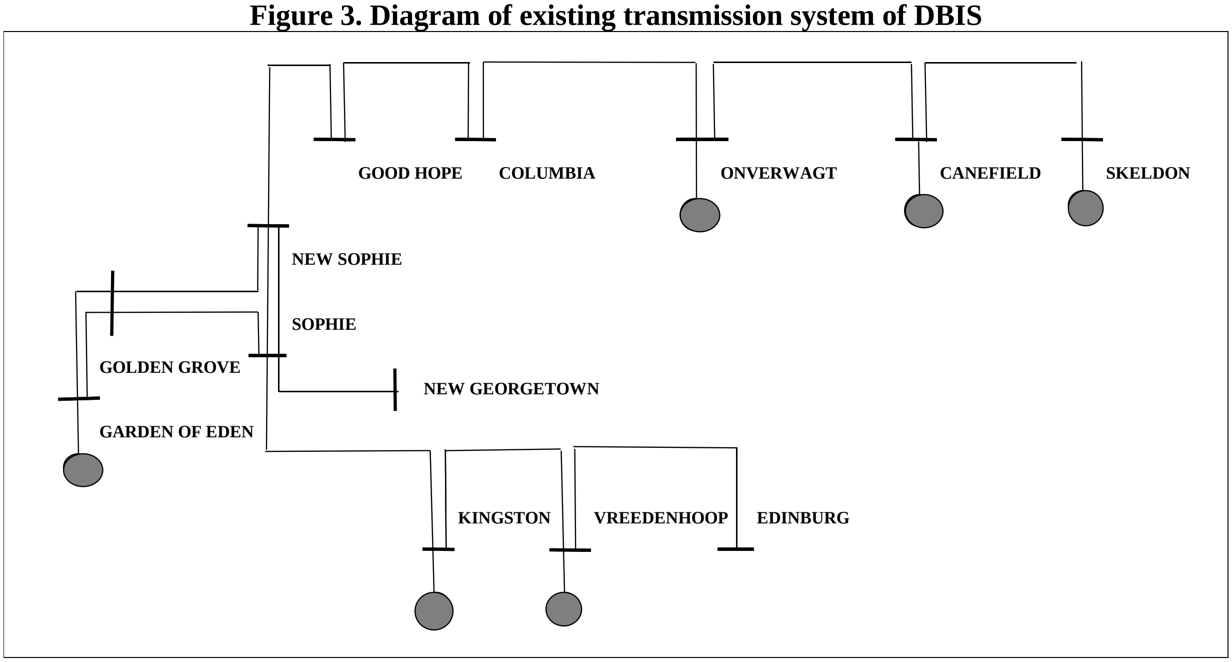
Table 4. GPL transmission network length[9]

Transmission Line	Length (kms)
Skeldon - No. 53 Village	21.1
No. 53 – Canefield	55.9
Canefield – Onverwagt	41.3
Onverwagt - Columbia	37.2
Columbia - GoodHope	26.6
GoodHope - New Sophia	10.0
New Sophia - Sophia (Upgraded)	0.3
Sophia (Upgraded) - Golden Grove	20.0
New Sophia - Golden Grove	20.0
Golden Grove - Garden of Eden	18.0
Sophia – New GeorgeTown	4.4
Sophia – Kingston	5.0
Submarine cable from Kingstown to Vreed-en-Hoop	2.4
Vreed-en-Hoop to Edinburgh	13.8
Total	**276.1**

Source: GPL

Figure 3 shows the one line schematic diagram of existing DBIS grid.

Figure 3. Diagram of existing transmission system of DBIS

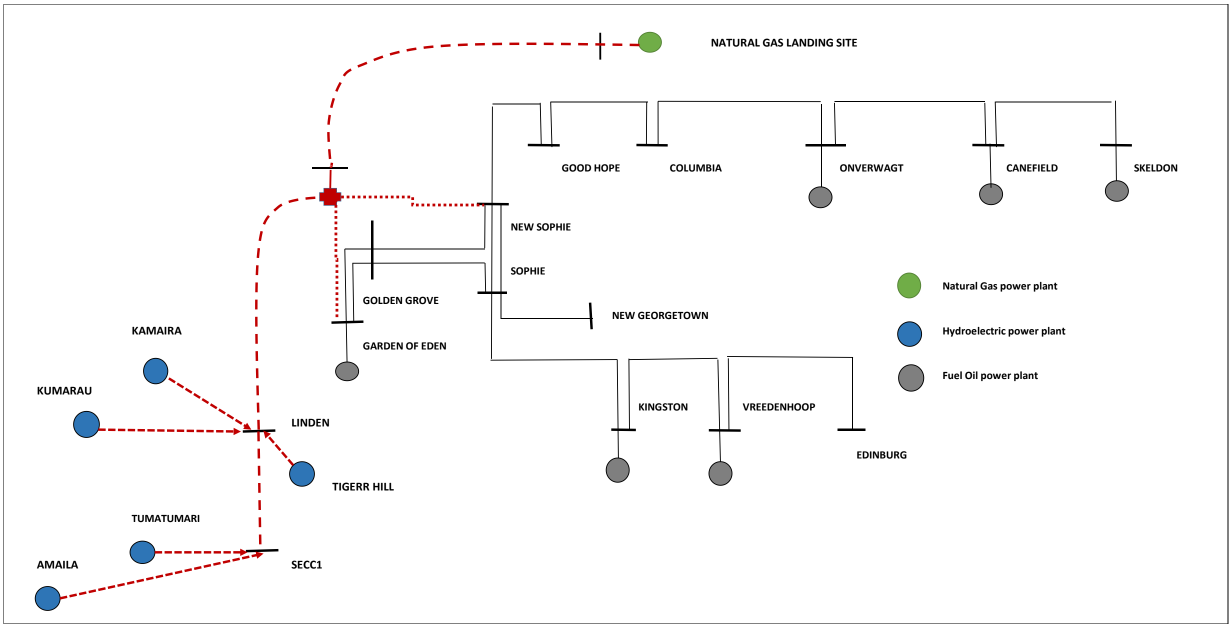


Source: Consultant

Figure 4 illustrates the expected future interconnection of the DBIS with main future hydro and natural gas candidate power plants.

[9] Source: GPL April 2015 Transmission System Diagram.

Figure 4. DBIS: Future generation and transmission system



Source: Consultant with GPL information

3.7.2 Transmission expansion program

The D&E Programme 2015-2019 of GPL[10] projects an investment of US$12.13M in transmission lines in order to construct 95 km of 69 kV lines to:

- Power new substations at Linden Highway / Soesdyke junction (12.5 km), Canal No. 2 (10.5 km), Parika (16.5 km) and Linden (6 km) from Garden-of-Eden, Vreed-En-Hoop, Edingburg and Bamia respectively.
- Construct parallel lines from Sophia to Kingston (10 km total) and from Sophia to Good Hope to Columbia (39.5 km).

In addition, the provided draft D&E Programme 2015-2019 of GPL projects an investment of US$29.63M in substations to:

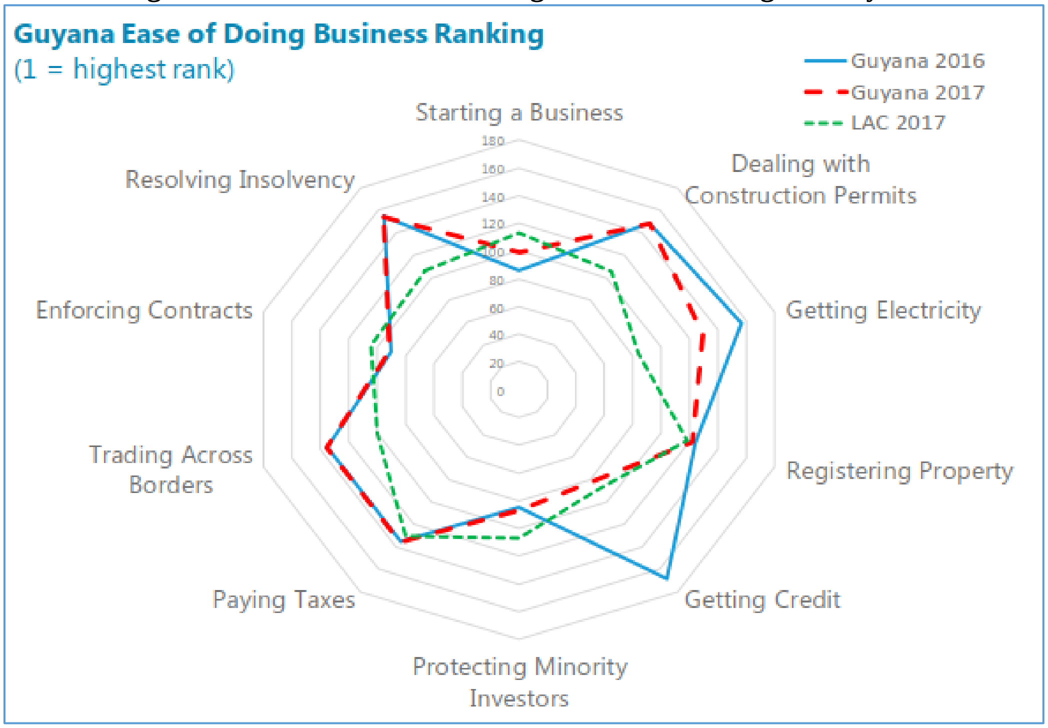
- Construct five (5) new substations with a total capacity of 118 MVA at Soesdyke, Canal No.2, Parika, Williamsburg, and Linden.
- Extend nine (9) existing substations to accommodate new transmission lines.
- Replace five (5) old 69/13.8 kV power transformers.
- Provide twenty- four (24) new feeders at the five new substations.

3.8 Service quality

The electricity sector is one of the main difficulties in doing business in Guyana. Figure 5 shows the World Bank's 2017 Doing Business Report chart for Guyana, where getting electricity has a high rank, and is well above the Latin American and Caribbean's average.

[10] At the moment of this study, GPL indicated that this programme is being revised. However, no further information from GPL was provided for this study about the the update of the D&E Programme.

Figure 5. World Bank 2017 Doing Business Ranking for Guyana



Source: IMF (2017c). Page 15.

According to PUC's yearly operating standards & performance targets, system's average interruption frequency index (SAIFI) of GPL increased to 118 in 2016 (last available data) which compares to 48 in 2012, reflecting frequent power service interruptions.

4 ELECTRICITY DEMAND FORECASTS

According to recent demand forecasts analyzed in Brugman (2016) and market analysis commissioned by the Government of Guyana (GoG), Guyana is expected to experience a significant growth in electricity demand in the coming years, with predictions of electricity consumption more than doubling in the next decade. This growth would be even more pronounced due to the recent discovery of oil in offshore Guyana and its associated natural gas, which in part is being considered to be transported to inland Guyana for power generation and other purposes. This chapter presents different scenarios of electricity demand forecast for DBIS system. Such scenarios were built in order to reflect different prospects of Guyana's economy and particularities of DBIS system and constitute an important part of the evaluation of the long term generation expansion of DBIS done in Section 8 of this report.

4.1 Methodology

Academic research has shown that GDP is the main independent variable that explains variations of power demand in a given country (Payne 2010). Other research has included additional variables such as GDP per capita and electricity prices, mainly.

Different methods to forecast power demand in Guyana were reviewed in Appendix A in Brugman (2016). After careful consideration of the strengths and weaknesses of each approach, and after reviewing the availability and confidence of available historical data, this study opted to forecast DBIS electricity demand in two steps: (i) Forecast GPL's electricity sales using a multivariate regression approach to understand how GDP and population explain GPL's electricity sales; (ii) To the results obtained in i), add some variables which reflect additional (and fewer) loads, which cannot be captured by the econometric model obtained in i).

When forecasting GPL's electricity sales in step i), for instance, it was tested whether or not population should be another variable to be included when forecasting electricity sales of GPL. After identifying which are the variables that explain most of the power sales, the coefficients were estimated and tests for statistical validity and error behavior were made. Once a valid model that explains GPL's electricity sales was obtained, the independent variable (specifically, GDP) was forecasted under three scenarios accordingly to apply those estimates to the model and obtain fitted values for electricity sales of GPL.

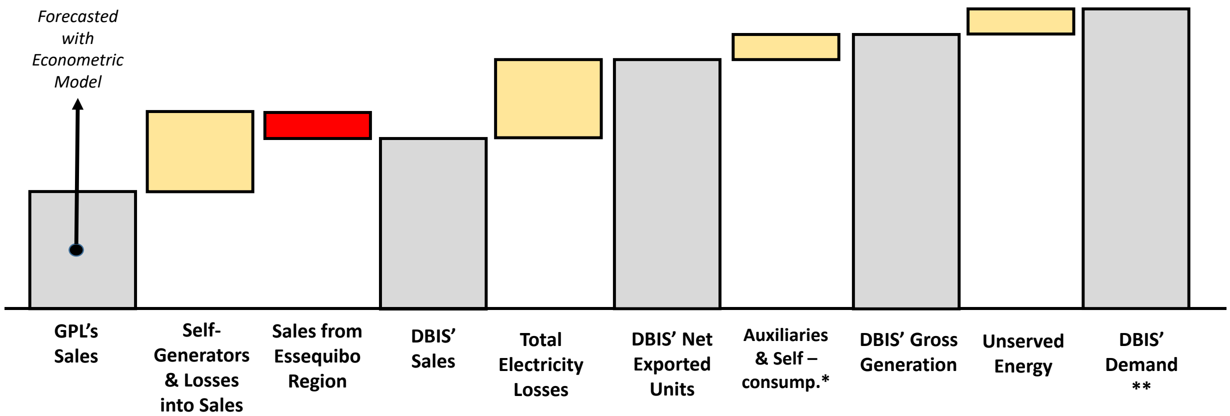
Once obtained GPL's electricity sales forecast, the following variables were included:

- Sales to Self-Generators switching to DBIS
- Losses converted into sales
- Sales from Essequibo Region
- New residential connections
- Electricity losses (technical and non-technical)
- Sales from Linden (after 2024, year assumed the interconnection of Linden to DBIS, see 4.7.2)
- Auxiliaries and Self-consumption
- Non-served demand
- Distributed generation and Energy Efficiency

Base, High and Low cases reflecting different GDP's growth rates were built.

Demand of electricity is defined as the Gross Generation of GPL per year plus unserved energy. Figure 6 summarizes the steps that the Consultant followed to estimate DBIS' electricity demand in this study. After estimating GPL's sales using the Consultant's econometric model and adjusting for self-generators switching into the grid, losses converted into sales and taking out Essequibo Sales[11], DBIS' sales are obtained. Total electricity losses are added to DBIS' sales to obtain DBIS' "Net Exported Units". Next, auxiliaries' consumption are added to reach DBIS' gross generation. Finally, non-served demand is added to reflect the demand that was not served but potentially would be served to some extent.

Figure 6. Steps to estimate DBIS' demand from GPL's sales



* Station Auxiliaries + Sophia Converter Losses + GPL's Own use consumption
** Sales from Linden are added to DBIS' Demand in case Linden is interconnected to DBIS

Source: Consultant

Once DBIS demand is obtained as shown in Figure 6, distributed generation and energy efficiency measures are included.

4.2 Database

GDP figures in Guyana need to be considered carefully since in 2009 historical growth figures, which were calculated with base year 1998 and were discontinued by the Guyana Bureau of Statistics, were rebated using year 2006 as a base. Therefore in this study, the Consultant used data obtained from the World Bank (IBRD IDA) national accounts database[12], which provides Guyana's historical GDP in real terms since 1981 until 2014 (using 2006 as a base, in accordance to latest available data from Guyana Bureau of Statistics).

It is important to take into consideration that since 2006, Guyana's economy has enjoyed high growth rates in relation to its history. Therefore, any econometric model that takes only recent history arguing lack of historical data could result in biased estimates. However, historical data of power sales and GDP in Guyana are scarce, as the Consultant has 37 annual data points from year 1981 until year 2017 to estimate statistical parameters (of which 5 years have incomplete information). Although this continues to be a small relative number to perform statistical analysis, it is the only data available which matches GPL sales and GPL gross generation available data per year. On the other hand, Guyana's population from 1996 onwards was obtained from the Guyana Bureau of Statistics which was available from 1996

[11] As of 2018, electricity sales from the Essequibo region, which is not connected to DBIS, are included in GPL's sales. Therefore a downward adjustment needs to be done to estimate DBIS sales. If Essequibo should become connected in the future, such sales should be added again.

[12] https://data.worldbank.org/indicator/NY.GDP.MKTP.KN?end=2016&locations=GY&start=1960&view=chart (last access on March 12, 2018)

until 2016 at the time of this study on their website[13]. Population from 1981 until 1995 was obtained from Klass (2010) study. Table 5 shows the data used for estimating the parameters of our statistical model.

Table 5. GPL's generation, GPL's sales, Guyana's GDP and Guyana's population

Year	Generation (GWh)	GPL Sales (GWh)	GDP (G$ million)	Population (000)
1981	213.0		238,160	758.0
1982	188.9		206,747	757.6
1983	205.1		192,704	757.3
1984	205.8	162.7	183,013	756.9
1985	213.2	169.5	187,405	756.5
1986	204.7	160.9	185,717	756.1
1987	209.9	178.9	187,387	755.7
1988	202.4	161.6	180,466	757.2
1989	159.1	121.6	171,543	756.8
1990	212.4	150.4	166,332	750.7
1991	219.1	171.0	176,286	719.1
1992	237.5	167.0	190,092	739.0
1993	252.2	169.0	205,705	747.0
1994	290.6	217.0	223,238	763.7
1995	333.7	217.0	234,370	773.4
1996	347.3	262.0	252,846	777.6
1997	390.4	262.0	268,591	778.8
1998	431.2	285.0	264,002	777.1
1999	443.2		271,842	781.2
2000	476.9	287.2	268,100	743.1
2001	504.6	289.9	274,132	744.2
2002	512.7	288.1	277,013	751.2
2003	488.9	268.1	274,228	753.8
2004	514.9	292.2	283,261	756.3
2005	528.4	300.8	277,718	758.9
2006	534.6	312.1	291,965	761.5
2007	559.2	349.8	312,461	763.7
2008	566.0	355.6	318,638	766.2
2009	586.0	370.3	329,955	753.2
2010	626.0	413.5	343,610	752.1
2011	653.4	430.5	361,465	750.7
2012	690.2	455.1	380,537	748.9
2013	710.7	475.9	399,631	746.9
2014	717.1	493.6	415,210	744.6
2015	751.0	518.9	427,894	742.0
2016	798.8	550.9	442,254	743.5
2017	809.4	555.3		

Source: GDP growth from World Bank and Bureau of Statistics of Guyana (G$ million) in constant 2006 prices. Population from Bureau of Statistics of Guyana and Klass (2010); Power Generation and GPL's Sales from Klass (2010), Guyana Power Sector Policy and Investment Strategy & GPL for 2011 until 2017. 1999 non-available as this year GPL was formed as a merge of three electricity companies.

The last real observation of electricity sales and generation from GPL that the consultant obtained was 2017. However, GDP and population for 2017 was not available at the time of this report.

[13] http://www.statisticsguyana.gov.gy/demo.html (last access on March 14, 2018).

4.3 Econometric Model

This study uses an ordinary least squares (OLS) regression model to explain the variance of total electricity sales (GWh/year) of GPL as a function of GDP in constant terms (in Guyanese dollars) and Population (in thousands). Although the multivariate regression model performs well (coefficient of determination, R^2, of 0.991), the simple linear regression model using only GDP as unique dependent variable performs similarly well (R^2 of 0.990). In favor of statistical efficiency, Population was discarded as a dependent variable[14] and the Consultant worked with a simple linear regression model in the following form:

$$\boldsymbol{Y = \beta_0 + \beta_1 * \mathrm{X} + \epsilon}$$

Where:

$\boldsymbol{Y}$ = Electricity Sales of GPL (GWh/year)

$\boldsymbol{X}$ = Gross Domestic Product ("GDP") (in million Guyanese dollars constant terms 2006)

$\boldsymbol{\epsilon}$ = Residual term

The obtained model using the data shown in Table 5 is:

$$\boldsymbol{\hat{Y} = -113 + 0.001476 * \mathrm{X}}$$

More detail of the regression results of the models can be viewed in Appendix B , as well as the residual plots, which are normally distributed with constant variance. Since residuals behave with mean near to zero and constant variance, and the obtained coefficient for GDP and F-statistic are statistically significant, as well as the overall model (coefficient of determination, R^2, of 0.990) the model performs well when forecasting electricity sales in the future.

4.4 GDP Forecast

GDP forecasts were obtained from public sources of the World Bank (IBRD IDA) and International Monetary Fund (World Economic Outlook Database, March 2018)[15]. For instance, IMF forecasts matches those of another important document used in this section of the study, which is the IMF´s Country report No 17/175 called "Guyana: 2017 article iv consultation—press release; Staff report; and Statement by the executive director for Guyana", which was published in June 2017 (IMF 2017a, now on). World Bank estimates are available until 2020 while IMF estimates are available until 2022[16], as shown in Table 6, which also shows GoG's growth estimate of 3.8% for 2018 and a 2.2% growth for 2017 equal to the first semester 2017 real growth. At the time of this report, 2017 actual GDP growth was not yet published.

[14]This is because population is not statistically significant to explain GPL's Sales at a 95% confidence level (t value of Population is 0.06 in the regression model).

[15] Appendix A shows such data obtained in March 2018.

[16] More strictly, IMF (2017a) also provides estimates for GDP growth in 2027 of 2.3%, 2.8% in 2037, and an average 2023-37 of 1.4%.

Table 6. GDP growth forecast in Guyana

Year	WB	IMF	Gov
2017	2.9%	3.5%	2.2%
2018	3.8%	3.6%	3.8%
2019	3.7%	3.7%	
2020	3.7%	38.5%	
2021		28.5%	
2022		2.8%	

Source: IMF (2017a), World Bank, GoG (Gov 2017 of 2.2% is the real growth for the first semester 2017).

4.4.1 Oil discovery effect in GDP

In 2015, Exxon Mobil made a significant oil discovery offshore. In May 2017 reserves were conservatively estimated to hold between 800 and 1,400 million barrels (IMF 2017c). Commercial production is planned to commence by mid-2020, with an output of 100,000 barrels/day. This expanding oil production and increased public investment are expected to increase GDP growth.

At time of this study the only public estimate of the effect of oil discoveries in offshore Guyana in Guyana's Gross Domestic Product (GPD) growth in the medium term was done by IMF (2017c) in May 2017. As shown in Table 6, GDP is expected to grow 38.5% in 2020 and 28.5% in 2021. IMF said that such estimate is conservative as it has a "conservative ad hoc inclusion of oil production from 2020 onwards". The following were assumptions:

- Guyana starts oil-production by mid-2020 with 100,000 barrels/day for up to 8 years, before gradually declining to 80,000 barrels from 2029-32 and 60,000 barrels from 2033-37. 2021 is the first year with full oil production.
- Oil price equal to WEO projections, rising from US$43 /barrel in 2016 to US$57/barrel in 2022 and converting to a long term value of US$60 /barrel.
- Government spends all its oil revenues during 2021-24, saves one third of it during 2025-29 and 50 percent afterwards.
- Based on experience from other countries, IMF assumed that the value-added of the oil sector becomes relevant as a share of gross production. For instance, the oil sector's share of GDP is projected to peak at about 40 percent during 2021-22

The authorities' data and projections on the national accounts and balance of payments currently do not reflect the foreign companies' investments in developing Guyana's offshore oil resources during the preparatory phase. This causes GDP, imports and FDI to be underestimated. For consistency and because of the lack of reliable information, FDI was not covered in IMF's projections.

As of May 2017, the prospects of others fields (Liza-2, Payara and Snoek) were still in the exploration stage and IMF noted that they could substantially increase oil production and proven reserves. Note that since then, Exxon Mobil has announced that production could reach eventually 310,000-340,000 barrels/day according to Esso (2017) and that reserves of 3.2 BOEB according to ExxonMobil (2018).

At present, oil exploration and drilling is not included in the national accounts and balance of payment statistics. Thus, official statistics underestimate GDP, the imports of goods and services, and FDI[17].

[17] The IMF staff recommended GoG's authorities to include oil exploration and production when they rebase the national accounts to 2018 and also include it in the BOP statistics (IMF 2017c).

The oil sector is fairly isolated from the rest of the economy, with no significant spillovers at this time. IMF's expects that oil will have a large impact on GDP[18], but a much smaller impact on GNP[19]. The main direct effect on the domestic economy will be through fiscal revenue. The revenue-sharing agreement sets the government's share at 50 percent of "profit oil." With 75 percent of total oil revenues initially allocated for "cost recovery," the government's share is only 12.5 percent, but will increase significantly after Exxon Mobil and partners recover their initial upfront investment. [IMF (2017c)].

The development of oil resources and public investment will support medium-term growth. The long-term outlook hinges on the government's ability to improve the business climate and use the oil windfall to increase potential growth through productivity-enhancing reforms and economic diversification. [IMF (2017c)]

These are other effects that Guyana's macroeconomics is expected to have from its oil discovery:

- As Guyana grows richer, it could lose access to grants and concessional financing, which are projected to taper off with the start of oil production. [IMF (2017c)]
- The increased dependence on natural resources exacerbates the economy's vulnerability to external shocks and could reduce the competitiveness of the non-oil economy due to the potential appreciation of the exchange rate. Several countries experienced competitiveness problems in other sectors after they became oil producers. [IADB (2017a)]
- Ultimately, the conversion of medium-term oil wealth into long-term growth and well-being hinges on the Government's capacity (through its institutions) to enact productivity-enhancing reforms. International evidence shows that natural resource wealth has the potential to become a real development asset when coupled with strong institutions (both public and private), smart investments in skills and technological capacities, and solid macroeconomic fundamentals. [IADB (2017)]

4.4.2 GDP growth scenarios

We developed four GDP growth scenarios. The intention is to reflect IMF´s estimates in one scenario and three deviations from such estimate in other scenarios. We did not develop a macroeconomic model to forecast each national account but rather produced overall variations to reflect broad deviations. The following sections show the rationale of each scenario.

4.4.2.1 Base Case

The Base Case reflects IMF (2017a) baseline forecasts with a minor adjustment in 2017, due to lower than expected growth in 2017 (2017 IMF estimate of 3.5% was lowered to 2.6% after the real growth in the first six months of 2017 was 2.2%). After 2023, a 1.3% annual growth rate estimate was used but maintaining the 2027 IMF estimate of 2.3%. Such annual growth rate was estimated by equating the 2023-37 growth estimate of IMF (1.4%). As noted before, this scenario is conservative due to the fact that oil production will be higher than 100,000 barrels per day after post-May-2017 discoveries results.

[18] Gross Domestic Product (GDP) is the total income earned **domestically**. It includes income earned domestically by foreigners, but it does not include income earned by domestic residents on foreign ground. (Mankiw 1997).
[19] Gross National Product (GNP) is the total income earned by **nationals** (that is, by residents of a nation).It includes the income that nationals earn abroad, but does not include the income earned within a country by foreigners. (Mankiw 1997).

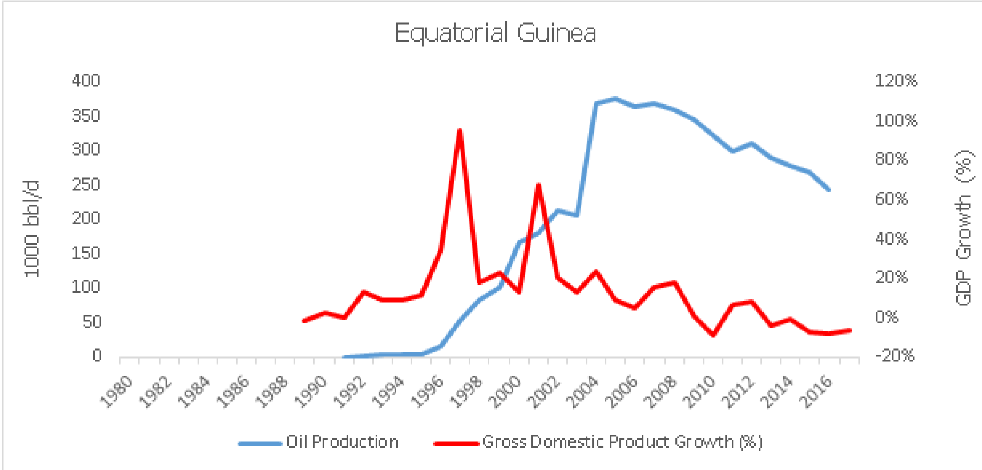
4.4.2.2 High Case

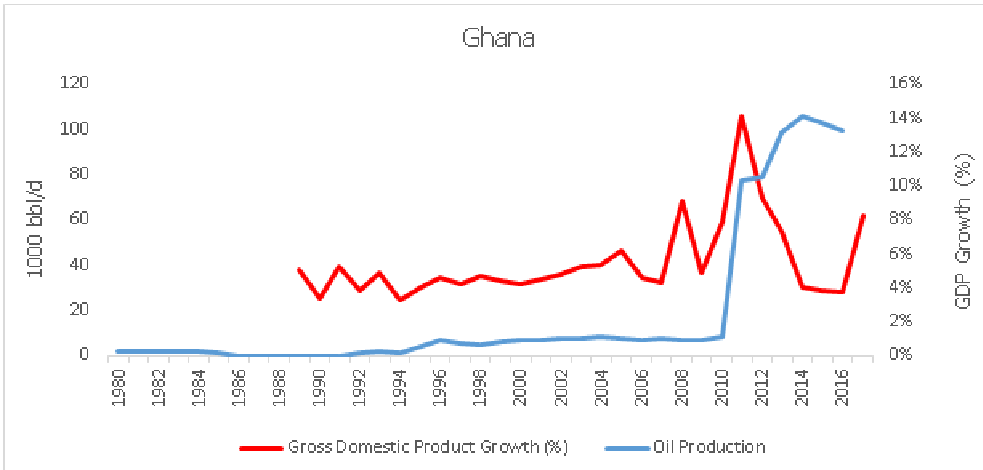
As noted before, IMF forecasted Guyana's real GDP based on US$60 dollars per barrel price and the assumption that total oil production amounts to 100,000 barrels per day from mid-2020 to 2028, 80,000 barrels per day during 2029-32, and 60,000 barrels per day during 2033-37. As of time of such forecast (May 2017), Exxon Mobil's discovery was <u>conservatively</u> estimated to hold between 800 and 1,400 million barrels (IMF 2017b, 2017c). Nowadays, the size of such discovery has increased in another 1,600 to 2,000 million barrels, depending on select hull, due to Liza Phase 2 drilling results. (Esso 2017). Oil production estimates have also increased an additional 190,000 to 220,000 barrels per day commencing mid-2022. As a result, Guyana's total oil production is now estimated roughly to about 300,000 barrels per day[20] (which gives roughly 30 years of continuous production). Due to such increase in oil production, this study proposes a High Case scenario were GDP increases more than IMF estimates.

Our exercise does not forecast GDP from a technical macroeconomic perspective and is without detail on value-added sectors nor national accounts. On the contrary, we made a simplified upward adjustment of IMF's forecasts on a proportional basis in relation to the growth in oil production. This results in high GDP growth rates similar to those experienced to other countries which experienced relevant oil discoveries, as shown in Figure 7.

[20] Economist (2017) estimates that oil production in Guyana could be more than 400,000 barrels per day in mid-2020s.

Figure 7. GDP growth and oil production in Equatorial Guinea and Ghana





Source: International Energy Statistics. EIA. 2018

The upward adjustment made to GDP growth forecast in our High Case is shown in Figure 8. In such exercise, IMF’s estimates from 2023-26 and 2028-2036 were not directly available. They were estimated using an equal value for all those years but targeting to obtain the same averages of IMF’s estimates. The consultant’s adjustment is derived from the oil production ratio.

Figure 8. GDP growth forecast in High Case

	IMF GDP growth (% year)	IMF Average Oil Production (barrels/day)	Consultant Average Oil Production (barrels/day)	Production Ratio (x)	Consultant GDP growth (% year)
2017	3.5%	0	0	1	2.9%
2018	3.6%	0	0	1	3.8%
2019	3.7%	0	0	1	3.7%
2020	38.5%	50,000	50,000	1	38.5%
2021	28.5%	100,000	100,000	1	28.5%
2022	2.8%	100,000	200,000	2	5.6%
2027	2.3%	100,000	300,000	3	6.9%
2037	2.8%	60,000	180,000	3	8.4%
AVG. 2017-22	13.4%				13.8%
AVG. 2023-37	1.4%	----> IMF = 1.4%			4.3%
AVG. 2017-37	4.9%	----> IMF = 4.9%			7.0%

Source: Consultant. IMF's oil production obtained from IMF (2017c). Consultant's oil production obtained from interpretation of oil production guidelines from Esso (2017).

4.4.2.3 Low Case

The Low Case builds from [IMF (2017c). DBA. Page 3] comment that "… the oil sector's share of GDP is projected to peak at about 40 percent during 2021-22" and uses IMF´s non-oil GDP growth. This case could in some way reflect the risk that lower international energy prices delays the development of its oil fields and that the GoG does not spend most of its oil revenues (say keeps them in a Sovereign Fund). Although this scenario has a lower probability of occurrence in our view, it provides great benefit in the evaluation of the long term generation expansion in Section 8 as it is an actual "Business as Usual" scenario. To obtain GDP growth rates we built a GDP series that reflects 60% of Base Case's GDP from 2021-20235 to reflect that the oil sector's share of GDP would reach 40% of the economy.

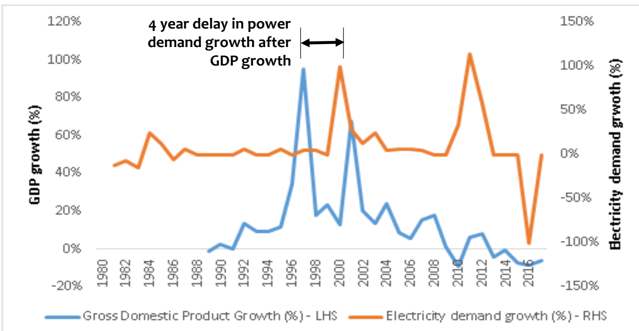
4.4.2.4 Base Case Delayed

In Section 4.3 of this report we showed that power demand in Guyana is highly correlated and therefore explained by its GDP. However, this link might get partially lost in the presence of a strong alteration of GDP and if no additional power capacity is installed on time. This scenario reflects the possibility that power demand might not grow at the same phase as GDP growth when a country experiences a strong economic shock (as it is expected that Guyana will experience in 2021 when oil production revenues' will start entering the economy through public investment).

The necessity of working with this scenario came after reviewing the case of Equatorial Guinea, which has some similarities to what may experience Guyana going forward (for instance, Equatorial Guinea is quoted by IMF 2017a as an example of effects on GDP of sudden oil production as would happen in Guyana). Figure 7 on page 38 shows how the Equatorial Guinea's economy grew as oil production started in 1996. However, Figure 9 shows that power demand growth did not grow at the same phase as GDP did, even more, power demand grew with 4 years of delay.

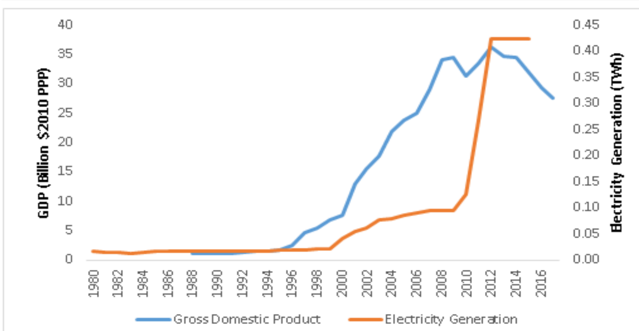
From Figure 9 one also notices that power capacity increased in line with generation, which could imply that lack of generation capacity in Equatorial Guinea deterred electricity generation growth (i.e. demand existed and was not supplied). This bring us to the point to solve a "chicken and egg" situation. Should Guyana install surplus capacity before oil production starts (and assume the risk of having excess capacity at large economic cost if demand does not increased as forecasted) or start increasing capacity as Equatorial Guinea did, after demand picked up?. A possible solution for this is to install power technologies with high flexibility and modularity since DBIS system should have modular capacity that could expand in short periods of time as soon as GPL notice demand increases and new loads from new/actual clients. In addition, the connection to DBIS of self-generators forecasted in Section 4.7.1 on page 45 could be delayed. Finally, as noted in Section 8.3, new generation expansion would replace HFO/LFO generation; however, such engines would remain as backup that could be used to supply increasing demand if necessary. As a result of this fact, power demand in Guyana is expected to behave somewhere between the Base Case and the base Case Delayed.

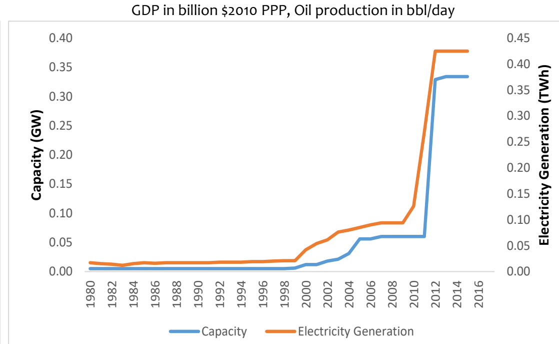
Figure 9. GDP and power demand in Equatorial Guinea



Year	GDP	Δ%	GWh	Δ%	Oil	Δ%
1988	1.2		17.0		0.0	
1989	1.1	-1%	17.0	0.0%	0.0	
1990	1.2	3%	17.0	0.0%	0.0	
1991	1.2	0%	17.0	0.0%	0.1	
1992	1.3	13%	18.0	5.9%	1.6	
1993	1.5	9%	18.0	0.0%	4.5	
1994	1.6	9%	18.0	0.0%	5.0	
1995	1.8	12%	19.0	5.6%	5.0	0%
1996	2.4	35%	19.0	0.0%	17.0	240%
1997	4.7	95%	20.0	5.3%	52.0	206%
1998	5.5	18%	21.0	5.0%	83.0	60%
1999	6.8	23%	21.0	0.0%	102.0	23%
2000	7.7	13%	42.0	100.0%	167.5	64%
2001	12.9	68%	54.0	28.6%	181.4	8%
2002	15.5	20%	61.0	13.0%	212.6	17%
2003	17.6	14%	76.0	24.6%	206.5	-3%
2004	21.9	24%	80.0	5.3%	368.2	78%
2005	23.8	9%	85.0	6.3%	375.5	2%
2006	25.1	5%	90.0	5.9%	362.9	-3%
2007	28.9	15%	94.0	4.4%	368.5	2%
2008	34.0	18%	94.0	0.0%	359.2	-3%
2009	34.5	1%	94.0	0.0%	346.0	-4%
2010	31.4	-9%	126.0	34.0%	322.7	-7%
2011	33.5	7%	269.0	113.5%	298.9	-7%
2012	36.3	8%	425.0	58.0%	310.4	4%

GDP in billion $2010 PPP, Oil production in bbl/day





Source: International Energy Statistics. EIA. 2018

Since our model links power demand with GDP growth, we need to reduce GDP growth estimates to lower the power demand growth. As well, this case could be seen as what would happen if the GDP of Guyana does grow to the same long term estimate of IMF (2017a) but with a lower phase over the years. We do so by keeping 2021-22 growth rates equal to Low Case Scenario (reflecting non-oil GDP growth) and by changing 2023-2025 growth estimates to 15% (2023), 10% (2024-27) and 5.7% (2028). Long term 2028+ growth equals to Base Case. We note that GDP in 2028 becomes that same as in the Base Case.

4.4.3 Scenario results

Table 7 shows GDP growth rates of each scenario used in this study and Table 8 summarizes the assumptions previously explained on each case.

Table 7. GDP growth estimates: Base, Base Delayed, High and Low cases

	High Case	Base Case	Low Case	Base Case Delayed
2010A	4.1%	4.1%	4.1%	4.1%
2011A	5.2%	5.2%	5.2%	5.2%
2012A	5.3%	5.3%	5.3%	5.3%
2013A	5.0%	5.0%	5.0%	5.0%
2014A	3.9%	3.9%	3.9%	3.9%
2015A	3.1%	3.1%	3.1%	3.1%
2016A	3.4%	3.4%	3.4%	3.4%
2017E	2.9%	2.6%	2.2%	2.6%
2018E	3.8%	3.7%	3.6%	3.7%
2019E	3.7%	3.7%	3.7%	3.7%
2020E	38.5%	38.5%	3.7%	3.7%
2021E	28.5%	28.5%	3.9%	3.9%
2022E	5.6%	2.8%	3.9%	3.9%
2023E	3.8%	1.3%	1.3%	15.0%
2024E	3.8%	1.3%	1.3%	10.0%
2025E	3.8%	1.3%	1.3%	10.0%
2026E	3.8%	1.3%	1.3%	10.0%
2027E	6.9%	2.3%	2.3%	10.0%
2028E	3.8%	1.3%	1.3%	5.7%
2029E	3.8%	1.3%	1.3%	1.3%
2030E	3.8%	1.3%	1.3%	1.3%
2031E	3.8%	1.3%	1.3%	1.3%
2032E	3.8%	1.3%	1.3%	1.3%
2033E	3.8%	1.3%	1.3%	1.3%
2034E	3.8%	1.3%	1.3%	1.3%
2035E	3.8%	1.3%	1.3%	1.3%

A= Actual Value; E= Estimated Value.

Source: Consultant

Table 8. Summary of GDP growth assumptions in demand growth scenarios

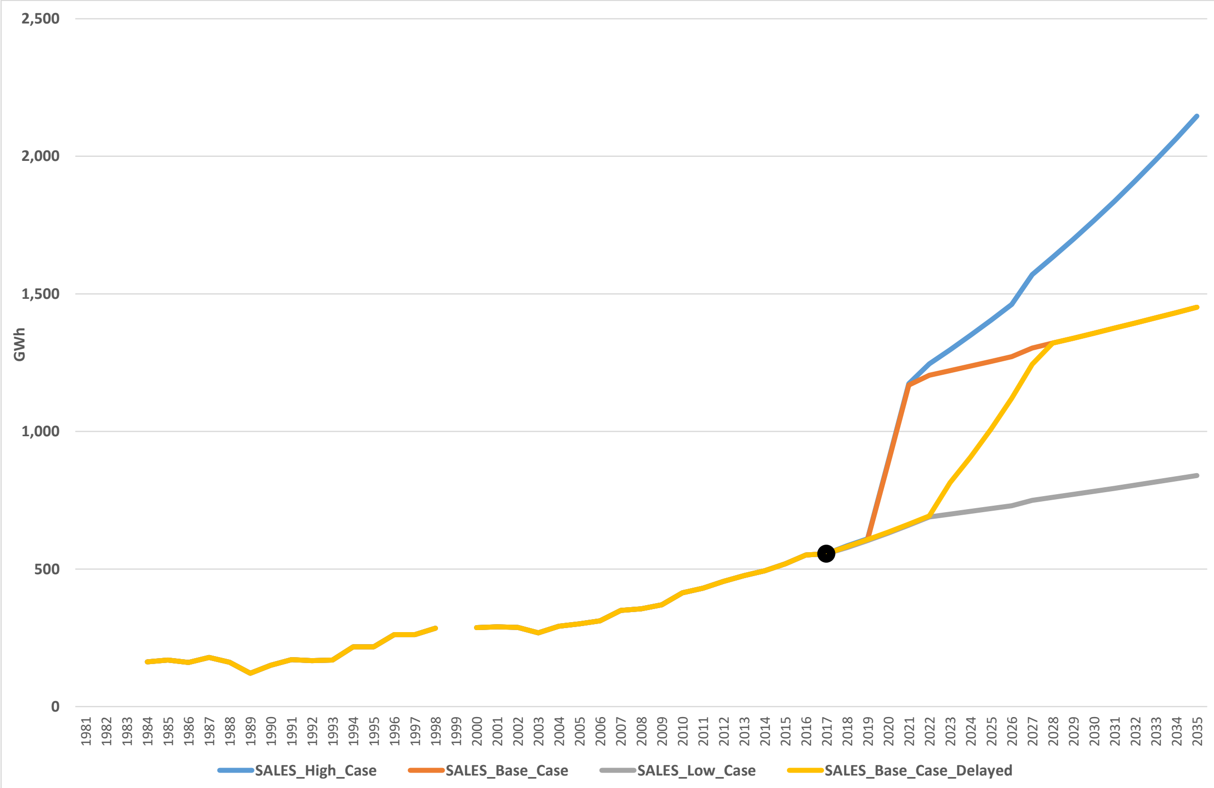
	Base	**Base delayed**	**High**	**Low**
2017	2.6% growth is mid-point of WB and 1S2017 actual	Equal to Base Case	WB estimate of 2.9%	1S2017 actual growth of 2.2%
2018	3.7% is the average WB, IMF, real growth1S2017.	Equal to Base Case	WB estimate of 3.8%	IMF (2017a) non-oil GDP growth estimate of 3.6%
2019-22	IMF (2017a)	IMF (2017a) non-oil GDP growth estimates	IMF, except 2022 that is 2 x IMF	IMF (2017a) non-oil GDP growth estimates
2023-35	IMF (1.3% to reflect 1.4% average growth 2023-37)	Consultant adjustment to reflect delay of power demand growth	3 x Base	Equal to Base Case

Source: Consultant

4.5 GPL's electricity sales forecast results

Figure 10 shows the three forecasts (Base, High, Low and Base delayed) of GPL's Electricity Sales obtained with the econometric model and GDP forecasts estimates for the four cases of GDP growth.

Figure 10. GPL's electricity sales forecast: Base, High, Low and Base delayed Cases



Source: Consultant

The obtained forecasts were desegregated into residential, commercial and industrial sectors according to the historical patterns.

4.6 Evolution of customers

4.6.1 Residential customers

The evolution of residential customers of DBIS is shown in Table 9 and was obtained by adding each year 4160 new residential customers to DBIS, which corresponds to the average number of new residential customers from 2012 to 2017. To estimate residential sector's energy share, the consultant used an average consumption of 127 kWh/month[21] per residential household which was provided GPL's as of 2017 with a 1.8% long term growth (which corresponds to the historical average growth per year of household consumption from 2011 until 2017) to reach 176 kWh-month in 2035. This reflects an intensification in the consumption of electricity by households (increased use of appliances) as income rises and labor force participation improves. Such long term consumption of 176 kWh-month per household is slightly above (2014 data)[22] Latin American and African averages (171 kWh-month and 172

[21] Appendix C shows general statistics from GPL's customers from 2004 until September 2017, which shows that residential consumption per household has a CAGR of 1.8% since 2004.

[22] The Consultant forecasted Latin American and African electricity residential consumption per household in 2035 using the 14-year historical trend of enerdata's dataset (which shows that Latin America has a CAGR of 0.7% and

kWh-month, respectively, but well below actual North American and European averages (1,016 kWh-month and 309 kWh-month, respectively)[23], and compares to world average of 283 kWh-month per household.

Given that GPL's sales vary on each scenario, this implies that the residential sector sales' share varies from 47.3% in 2017 to 36.0% in 2035 (Base Case and Base Case Delayed), 24.3% in High Case and 62.1% in the Low Case. The new residential customers from 2017 until 2021 in the forecasts are 22,085 and compare to 30,900 new residential customers on GPL´s D&E 2016-2020. The forecasts implies that 74,871 new residential connections would be made from 2018 until 2035 in all cases.

Table 9. Electricity demand from residential customers

Base Case	Metric	2011A	2012A	2013A	2014A	2015A	2016A	2017A	2018F	2019F	2020F	2025F	2030F	2035F
GPL Electricity Sales	**GWh**	**430.5**	**455.1**	**475.9**	**493.6**	**518.9**	**550.9**	**555.3**	**581.4**	**607.1**	**884.3**	**1,254.4**	**1,357.1**	**1,451.3**
Residential Sector	GWh	195.1	205.9	218.1	231.2	244.2	259.0	262.4	268.7	275.1	281.7	316.0	352.0	389.3
Residential Sector	%	45.3%	45.3%	45.8%	46.8%	47.1%	47.0%	47.3%	46.2%	45.3%	31.9%	25.2%	25.9%	26.8%
Residential Customers	Number	146,620	151,480	157,064	162,028	166,504	166,130	171,577	172,540	173,485	174,428	178,777	181,971	183,848
Average Consumption	KWh-month	111	113	116	119	122	130	127	130	132	135	147	161	176
New Residential Customers	Number		4,860	5,584	4,964	4,476	-374	5,447	963	945	943	791	536	255

High Case	Metric	2011A	2012A	2013A	2014A	2015A	2016A	2017A	2018F	2019F	2020F	2025F	2030F	2035F
GPL Electricity Sales	**GWh**	**430.5**	**455.1**	**475.9**	**493.6**	**518.9**	**550.9**	**555.3**	**584.2**	**609.9**	**888.3**	**1,404.3**	**1,766.3**	**2,146.2**
Residential Sector	GWh	195.1	205.9	218.1	231.2	244.2	259.0	262.4	268.7	275.1	281.7	316.0	352.0	389.3
Residential Sector	%	45.3%	45.3%	45.8%	46.8%	47.1%	47.0%	47.3%	46.0%	45.1%	31.7%	22.5%	19.9%	18.1%
Residential Customers	Number	146,620	151,480	157,064	162,028	166,504	166,130	171,577	172,540	173,485	174,428	178,777	181,971	183,848
Average Consumption	KWh-month	111	113	116	119	122	130	127	130	132	135	147	161	176
New Residential Customers	Number		4,860	5,584	4,964	4,476	-374	5,447	963	945	943	791	536	255

Low Case	Metric	2011A	2012A	2013A	2014A	2015A	2016A	2017A	2018F	2019F	2020F	2025F	2030F	2035F
GPL Electricity Sales	**GWh**	**430.5**	**455.1**	**475.9**	**493.6**	**518.9**	**550.9**	**555.3**	**578.1**	**603.7**	**630.2**	**719.8**	**782.4**	**839.7**
Residential Sector	GWh	195.1	205.9	218.1	231.2	244.2	259.0	262.4	268.7	275.1	281.7	316.0	352.0	389.3
Residential Sector	%	45.3%	45.3%	45.8%	46.8%	47.1%	47.0%	47.3%	46.5%	45.6%	44.7%	43.9%	45.0%	46.4%
Residential Customers	Number	146,620	151,480	157,064	162,028	166,504	166,130	171,577	172,540	173,485	174,428	178,777	181,971	183,848
Average Consumption	KWh-month	111	113	116	119	122	130	127	130	132	135	147	161	176
New Residential Customers	Number		4,860	5,584	4,964	4,476	-374	5,447	963	945	943	791	536	255

Base Case Delayed	Metric	2011A	2012A	2013A	2014A	2015A	2016A	2017A	2018F	2019F	2020F	2025F	2030F	2035F
GPL Electricity Sales	**GWh**	**430.5**	**455.1**	**475.9**	**493.6**	**518.9**	**550.9**	**555.3**	**581.4**	**607.1**	**633.7**	**1,008.6**	**1,357.1**	**1,451.3**
Residential Sector	GWh	195.1	205.9	218.1	231.2	244.2	259.0	262.4	268.7	275.1	281.7	316.0	352.0	389.3
Residential Sector	%	45.3%	45.3%	45.8%	46.8%	47.1%	47.0%	47.3%	46.2%	45.3%	44.4%	31.3%	25.9%	26.8%
Residential Customers	Number	146,620	151,480	157,064	162,028	166,504	166,130	171,577	172,540	173,485	174,428	178,777	181,971	183,848
Average Consumption	KWh-month	111	113	116	119	122	130	127	130	132	135	147	161	176
New Residential Customers	Number		4,860	5,584	4,964	4,476	-374	5,447	963	945	943	791	536	255

Source: Consultant using GPL's data

4.6.2 Industrial and commercial customers

An inquiry was made in January 2018 to GPL's management about recent and upcoming major new loads. As a result, no major significant new loads for connection to the DBIS networks were identified nor provided. Therefore, it was not incorporated any new major load (except new loads of Guyana's road links with Brazil near Linden as shown in Section 3.6.2.1). This implies that all major DBIS loads in the future would be incorporated into power demand forecasts by the econometric model according to GDP growth.

As reference, Table 10 shows forecasted electricity sales for GPL and the share of each sector. This numbers do not include the effect of self-generators switching to DBIS, which is covered in Section 4.7.1.

Africa a CAGR of 1.3% since 2000); Under this consideration, Latin American electricity residential consumption per household in 2035 would be 197 KWh-month and that of Africa would be 223 KWh-month.

[23] Electricity household consumption per month in 2014 was obtained from World Energy Council enerdata database (https://www.worldenergy.org); such dataset has a large sample of electricity consumption per household. Unfortunately, no similar LAC country such as Guyana is available in such dataset for a better comparison.

Table 10. Total GPL's forecasted sales and share per sector

BASE CASE		2011A	2012A	2013A	2014A	2015A	2016A	2017A	2018F	2019F	2020F	2021F	2022F	2023F	2024F	2025F	2030F	2035F
Residential Customers	Number	146,620	151,480	157,064	162,028	166,504	166,130	171,577	175,737	179,896	184,056	188,215	192,375	196,534	200,694	204,853	225,651	246,448
Comercial Customers	Number	14,241	14,817	15,176	15,047	15,457	16,136	16,361	17,110	17,809	32,343	47,107	48,159	48,127	48,085	48,033	48,417	47,763
Industrial Customers	Number	561	581	633	705	743	747	726	761	795	1,448	2,114	2,168	2,172	2,177	2,181	2,230	2,231
Residential Customers	GWh	195.1	205.9	218.1	231.2	244.2	259.0	262.4	273.7	285.3	297.2	309.5	322.1	335.0	348.4	362.1	436.5	521.8
Comercial Customers	GWh	74.3	79.8	82.0	84.8	87.3	95.5	97.3	102.2	106.9	195.0	285.4	293.1	294.3	295.4	296.4	305.8	308.8
Industrial Customers	GWh	161.0	169.4	175.8	177.5	187.5	196.4	195.6	205.5	214.9	392.0	573.7	589.2	591.5	593.8	595.9	614.8	620.7
Residential Customers	% share / Total	45.3%	45.3%	45.8%	46.8%	47.1%	47.0%	47.3%	47.1%	47.0%	33.6%	26.5%	26.7%	27.4%	28.1%	28.9%	32.2%	36.0%
Comercial Customers	% share / Total	17.3%	17.5%	17.2%	17.2%	16.8%	17.3%	17.5%	17.6%	17.6%	22.1%	24.4%	24.3%	24.1%	23.9%	23.6%	22.5%	21.3%
Industrial Customers	% share / Total	37.4%	37.2%	36.9%	36.0%	36.1%	35.7%	35.2%	35.3%	35.4%	44.3%	49.1%	48.9%	48.5%	48.0%	47.5%	45.3%	42.8%
Residential Customers	KWh/Client - Month	111	113	116	119	122	130	127	130	132	135	137	140	142	145	147	161	176
Comercial Customers	KWh/Client - Month	435	449	450	470	470	493	496	498	500	502	505	507	510	512	514	526	539
Industrial Customers	KWh/Client - Month	23,920	24,292	23,141	20,987	21,024	21,910	22,449	22,489	22,529	22,570	22,610	22,651	22,691	22,732	22,773	22,978	23,185
Residential Customers	% growth - year		2.2%	2.1%	2.8%	2.7%	6.3%	-1.9%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%
Comercial Customers	% growth - year		3.2%	0.4%	4.3%	0.2%	4.8%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
Industrial Customers	% growth - year		1.6%	-4.7%	-9.3%	0.2%	4.2%	2.5%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%

HIGH CASE		2011A	2012A	2013A	2014A	2015A	2016A	2017A	2018F	2019F	2020F	2021F	2022F	2023F	2024F	2025F	2030F	2035F
Residential Customers	Number	146,620	151,480	157,064	162,028	166,504	166,130	171,577	175,737	179,896	184,056	188,215	192,375	196,534	200,694	204,853	225,651	246,448
Comercial Customers	Number	14,241	14,817	15,176	15,047	15,457	16,136	16,361	17,267	17,968	32,562	47,388	50,413	52,243	54,139	56,103	69,939	83,468
Industrial Customers	Number	561	581	633	705	743	747	726	768	802	1,457	2,127	2,269	2,358	2,451	2,547	3,221	3,899
Residential Customers	GWh	195.1	205.9	218.1	231.2	244.2	259.0	262.4	273.7	285.3	297.2	309.5	322.1	335.0	348.4	362.1	436.5	521.8
Comercial Customers	GWh	74.3	79.8	82.0	84.8	87.3	95.5	97.3	103.2	107.8	196.3	287.1	306.8	319.4	332.6	346.2	441.8	539.6
Industrial Customers	GWh	161.0	169.4	175.8	177.5	187.5	196.4	195.6	207.4	216.8	394.7	577.1	616.8	642.1	668.5	696.0	888.1	1084.7
Residential Customers	% share / Total	45.3%	45.3%	45.8%	46.8%	47.1%	47.0%	47.3%	46.8%	46.8%	33.5%	26.4%	25.9%	25.8%	25.8%	25.8%	24.7%	24.3%
Comercial Customers	% share / Total	17.3%	17.5%	17.2%	17.2%	16.8%	17.3%	17.5%	17.7%	17.7%	22.1%	24.5%	24.6%	24.6%	24.6%	24.7%	25.0%	25.1%
Industrial Customers	% share / Total	37.4%	37.2%	36.9%	36.0%	36.1%	35.7%	35.2%	35.5%	35.5%	44.4%	49.2%	49.5%	49.5%	49.5%	49.6%	50.3%	50.5%
Residential Customers	KWh/Client - Month	111	113	116	119	122	130	127	130	132	135	137	140	142	145	147	161	176
Comercial Customers	KWh/Client - Month	435	449	450	470	470	493	496	498	500	502	505	507	510	512	514	526	539
Industrial Customers	KWh/Client - Month	23,920	24,292	23,141	20,987	21,024	21,910	22,449	22,489	22,529	22,570	22,610	22,651	22,691	22,732	22,773	22,978	23,185
Residential Customers	% growth - year		2.2%	2.1%	2.8%	2.7%	6.3%	-1.9%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%
Comercial Customers	% growth - year		3.2%	0.4%	4.3%	0.2%	4.8%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
Industrial Customers	% growth - year		1.6%	-4.7%	-9.3%	0.2%	4.2%	2.5%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%

LOW CASE		2011A	2012A	2013A	2014A	2015A	2016A	2017A	2018F	2019F	2020F	2021F	2022F	2023F	2024F	2025F	2030F	2035F
Residential Customers	Number	146,620	151,480	157,064	162,028	166,504	166,130	171,577	175,737	179,896	184,056	188,215	192,375	196,534	200,694	204,853	225,651	246,448
Comercial Customers	Number	14,241	14,817	15,176	15,047	15,457	16,136	16,361	16,929	17,625	18,347	19,180	20,047	19,795	19,531	19,257	18,189	16,337
Industrial Customers	Number	561	581	633	705	743	747	726	753	787	821	861	902	894	884	874	838	763
Residential Customers	GWh	195.1	205.9	218.1	231.2	244.2	259.0	262.4	273.7	285.3	297.2	309.5	322.1	335.0	348.4	362.1	436.5	521.8
Comercial Customers	GWh	74.3	79.8	82.0	84.8	87.3	95.5	97.3	101.1	105.8	110.6	116.2	122.0	121.0	120.0	118.8	114.9	105.6
Industrial Customers	GWh	161.0	169.4	175.8	177.5	187.5	196.4	195.6	203.3	212.6	222.4	233.6	245.3	243.3	241.2	238.9	231.0	212.3
Residential Customers	% share / Total	45.3%	45.3%	45.8%	46.8%	47.1%	47.0%	47.3%	47.3%	47.3%	47.2%	46.9%	46.7%	47.9%	49.1%	50.3%	55.8%	62.1%
Comercial Customers	% share / Total	17.3%	17.5%	17.2%	17.2%	16.8%	17.3%	17.5%	17.5%	17.5%	17.6%	17.6%	17.7%	17.3%	16.9%	16.5%	14.7%	12.6%
Industrial Customers	% share / Total	37.4%	37.2%	36.9%	36.0%	36.1%	35.7%	35.2%	35.2%	35.2%	35.3%	35.4%	35.6%	34.8%	34.0%	33.2%	29.5%	25.3%
Residential Customers	KWh/Client - Month	111	113	116	119	122	130	127	130	132	135	137	140	142	145	147	161	176
Comercial Customers	KWh/Client - Month	435	449	450	470	470	493	496	498	500	502	505	507	510	512	514	526	539
Industrial Customers	KWh/Client - Month	23,920	24,292	23,141	20,987	21,024	21,910	22,449	22,489	22,529	22,570	22,610	22,651	22,691	22,732	22,773	22,978	23,185
Residential Customers	% growth - year		2.2%	2.1%	2.8%	2.7%	6.3%	-1.9%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%
Comercial Customers	% growth - year		3.2%	0.4%	4.3%	0.2%	4.8%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
Industrial Customers	% growth - year		1.6%	-4.7%	-9.3%	0.2%	4.2%	2.5%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%

BASE CASE DELAYED		2011A	2012A	2013A	2014A	2015A	2016A	2017A	2018F	2019F	2020F	2021F	2022F	2023F	2024F	2025F	2030F	2035F
Residential Customers	Number	146,620	151,480	157,064	162,028	166,504	166,130	171,577	175,737	179,896	184,056	188,215	192,375	196,534	200,694	204,853	225,651	246,448
Comercial Customers	Number	14,241	14,817	15,176	15,047	15,457	16,136	16,361	17,110	17,809	18,538	19,377	20,251	26,022	30,193	34,805	48,417	47,763
Industrial Customers	Number	561	581	633	705	743	747	726	761	795	830	870	912	1,175	1,367	1,580	2,230	2,231
Residential Customers	GWh	195.1	205.9	218.1	231.2	244.2	259.0	262.4	273.7	285.3	297.2	309.5	322.1	335.0	348.4	362.1	436.5	521.8
Comercial Customers	GWh	74.3	79.8	82.0	84.8	87.3	95.5	97.3	102.2	106.9	111.8	117.4	123.2	159.1	185.5	214.8	305.8	308.8
Industrial Customers	GWh	161.0	169.4	175.8	177.5	187.5	196.4	195.6	205.5	214.9	224.7	236.0	247.8	319.8	372.8	431.8	614.8	620.7
Residential Customers	% share / Total	45.3%	45.3%	45.8%	46.8%	47.1%	47.0%	47.3%	47.1%	47.0%	46.9%	46.7%	46.5%	41.2%	38.4%	35.9%	32.2%	36.0%
Comercial Customers	% share / Total	17.3%	17.5%	17.2%	17.2%	16.8%	17.3%	17.5%	17.6%	17.6%	17.6%	17.7%	17.8%	19.5%	20.5%	21.3%	22.5%	21.3%
Industrial Customers	% share / Total	37.4%	37.2%	36.9%	36.0%	36.1%	35.7%	35.2%	35.3%	35.4%	35.5%	35.6%	35.7%	39.3%	41.1%	42.8%	45.3%	42.8%
Residential Customers	KWh/Client - Month	111	113	116	119	122	130	127	130	132	135	137	140	142	145	147	161	176
Comercial Customers	KWh/Client - Month	435	449	450	470	470	493	496	498	500	502	505	507	510	512	514	526	539
Industrial Customers	KWh/Client - Month	23,920	24,292	23,141	20,987	21,024	21,910	22,449	22,489	22,529	22,570	22,610	22,651	22,691	22,732	22,773	22,978	23,185
Residential Customers	% growth - year		2.2%	2.1%	2.8%	2.7%	6.3%	-1.9%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%
Comercial Customers	% growth - year		3.2%	0.4%	4.3%	0.2%	4.8%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
Industrial Customers	% growth - year		1.6%	-4.7%	-9.3%	0.2%	4.2%	2.5%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%

Source: Consultant

4.7 Additional variables considered to forecast power demand

An analysis of the following variables was made in order to arrive at a "total system demand" of DBIS system:

- Self-generators switching into national grid
- Electricity losses (including loss reduction estimates)
- Essequibo sales
- Auxiliaries and self-consumption
- Linden demand
- Non-served demand
- Distributed generation and Energy Efficiency measures

4.7.1 Self-Generators switching into the DBIS interconnected System

The Consultant queried GPL and officials with latest available self-generation data in Guyana and were advised to use an updated information as of 2016 of the survey performed in 2010 by John Cush. This information estimated that in 2010 the installed capacity of self-generation in Guyana was about 47 MW (58.4 kVA with 0.8 power factor), and that 10.94 GWh/month is generated by the self-generators (0.32 plant factor), equivalent to an annual consumption of about 131.3 GWh/year.

The new updated information (presented in Appendix C) shows that in 2016 the installed capacity of self-generation in Guyana is 61 MW (76.6 kVA with 0.8 power factor). Such updated information does not provide the load factor of such clients; therefore we applied the same load factor of 2010 survey, which yields that annual consumption of self-generators is about 171.2 GWh/year (0.32 plant factor).

61 MW is equivalent to about 35% of DBIS's actual available capacity. In 2010 most companies reported using LFO with only one enterprise using HFO, and that self-generation is mostly being used to secure reliable supply and, in some cases, to reduce the cost of power during peak consumption hours.

We note that Cush (2010) survey estimated that 31 MW of self-generators capacity (i.e. 66% of self-generators) would switch to GPL's interconnected grid within 2 years of Amaila Falls commissioning (or other economic power generation alternative expansion). As Guyana enters into non-conventional renewable energy generation capacity that would reduce electricity costs to final consumers, self-generators would find it rational to switch back to GPL's supply as electricity tariffs would be cheaper than the cost of self-generation and adequate quality of service is offered.

In this study, the assumptions made in PPA Energy Consultants (2013) about self-generation switching to DBIS interconnected system were applied. Therefore the Consultant assumed that all self-generators will switch to the Grid in a linear way in 4 years, according to Table 11, starting in 2025. In such table, average demand of self-generators grows at an annual rate slightly above Low Case scenario (non-oil economy). We did not increased self-generators power demand with the growth rates of Base Case in order to reflect that some of this self-generating capacity would be replaced either with solar PV panels and/or natural gas or Liquefied Petroleum Gas (LPG) power generation.

Table 11. New electricity demand from self-generators switching to DBIS

Self Generation Migration		BASE	2016	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035
Self Generation migration to DBIS	%	0%	0%	0%	0%	0%	0%	0%	25%	50%	75%	100%	100%	100%	100%
Self Generation	MW	61.3	64.6	76.6	79.6	82.6	85.7	88.9	92.1	95.6	99.1	102.7	106.4	110.3	131.5
Growth per year	%		5.4%	3.8%	3.8%	3.8%	3.8%	3.7%	3.7%	3.7%	3.7%	3.7%	3.6%	3.6%	3.6%
Average Generation	GWh	171.2	180.5	214.1	222.2	230.6	239.3	248.2	257.4	266.9	276.7	286.8	297.3	308.0	367.3
Self Generation migrated to DBIS	MW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	23.0	47.8	74.3	102.7	106.4	110.3	131.5
Additional Demand	***GWh***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***64.3***	***133.4***	***207.5***	***286.8***	***297.3***	***308.0***	***367.3***
Load Factor	%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%

Source: Consultant using GPL updated information and PPA (2013), ME (2010) and Cush (2010)

4.7.2 Linden Demand

Power demand forecasts for the DBIS was estimated considering its interconnection with Linden in 2024[24]. Specifically, it was assumed that Linden Electricity Company (LECI) and Omai Bauxite Mining Inc. (OBMI) would become major customers of electricity. It will occur either (i) when a transmission line that interconnects Linden with GPL's grid becomes operational in 2024, if a new hydroelectric power plant would be installed to supply DBIS, with its transmission connection (two circuits at 230 kV) crossing near Linden; or (ii) if the hydroelectric power plant is not selected in the expansion plan, such transmission line would be built and Linden would be connected to DBIS at 69 kV[25].

Linden is the second largest city in Guyana after Georgetown, and capital of the Demerara - Berbice region. It is located 107 km from Georgetown and has a population of around 60,000 citizens. It is primarily a bauxite mining region as OBMI, which is located near Linden, is the main source of economic activity in the locality. Total electricity consumption of Linden has varied since 2007 between 65 and 71 GWh per year, depending on the activity of the mining company as shown in Table 12 that summarizes historical data of Linden energy consumption.

[24] However it execution may be delayed taking into account that one major aspect still to be solved to support its eventual financial sustainability is that tariffs charged by Linden Electricity Company have been at well below cost recovery levels (being subsidized by the Government) and a key issue is the increase rate at which they will be brought into line with tariffs in the rest of the country. Civil disturbances in Linden have led to the postponement of tariff increases.

[25]As shown in Appendix H of Brugman (2016), from the point of view of the overall economy of Guyana, a 69 kV DBIS-Linden transmission system would be atractive to supply Linden demand, The development of mid size hydroelectric power plants to supply DBIS demand would require the installation of a 230 kV transmission connection (2 circuits) crossing near Linden (as well as the potential future Arco Norte transmission system). In this way if the optimal generation expansion of DBIS would include such hydros, the Linden – DBIS transmission system could be built at 230 kV and advanced to 2024. Under this situation and depending of the commissioning dates, this system could be initially energized at 69 kV and then energized to 230 kV (a decision at this respect, however, sould take into consideration the costs and requirements of the new 69 or 230 kV substations).

Table 12. Linden electricity sales

Linden Electricity Sales (GWh)	2006	2007	2008	2009	2010	2011	2012	2013	2014
Bauxite Sales	21.2	26.1	28.6	21.0	21.3	25.3	25.3	25.7	24.9
Linden Community	43.2	42.7	42.4	44.7	46.9	46.5	44.8	45.3	46.4
Total	**64.3**	**68.8**	**71.0**	**65.7**	**68.2**	**71.8**	**70.1**	**71.0**	**71.3**
Growth Bauxite Sales		23.3%	9.7%	-26.5%	1.3%	18.7%	0.0%	1.4%	-3.0%
Growth Linden Community		-1.0%	-0.8%	5.4%	4.9%	-0.9%	-3.6%	1.1%	2.4%
Growth Total Linden		**7.0%**	**3.2%**	**-7.5%**	**3.8%**	**5.2%**	**-2.3%**	**1.2%**	**0.4%**

Source: GPL - LECI 2015. The consultant queried in February 2018 data from Linden sales but such data was not available at the date of this report.

To forecast Linden's electricity sales the latest real data of 71.3 GWh-year were increased with the average annual growth rate equal to GPL's forecasted annual growth rate of our Base Case but penalized by a 0.23 factor (such factor was estimated by the Consultant and is used to reflect that Linden's annual power sales growth rate from 2007 until 2014 of 1.4% compares to 6.0% for the DBIS system in the same period of time).

Additionally, Guyana and Brazil would develop road links crossing near Linden; therefore, incremental loads of 1.0 MW have been added in each year from 2018 to 2022 and additional 0.5 MW in each year from 2023 onwards; such new loads were obtained from PPA Energy Consultants (2013) study[26].

A 0.742 load factor was used to convert new loads into energy demand which was based on our historical analysis of DBIS demand. This load factor is similar to the one used by PPA Energy Consultants (2013) of 0.7829 who took a different approach by measuring the hourly load data from each of the power stations that will eventually comprise the DBIS system. The following table shows Linden Demand forecast before and after losses. Losses were obtained from averaging 2007 until 2011 Linden losses (from LECI annual reports) and assumed constant until 2021, when Linden would be connected to DBIS system (and OBMI electricity supply substituted for a GPL direct supply under existing GLP market conditions, i.e. losses & Tariffs applied to OBMI and Linden users). After 2021, when Linden is interconnected to DBIS, losses are assumed equal to the forecasted losses of DBIS. Table 13 shows Linden's demand forecasts.

[26] This load estimate correspond to new communities and commercial activities relocated near Linden as attracted by the new transportation infrastructure and commercial activity and in such conditions is considered as an additional load in the area.

Table 13. Linden electricity sales and demand forecast[27]

Linden Electricity Sales (GWh)	2014A	2015	2016	2017	2018	2019	2020	2021	2025	2030	2035
Total Linden Sales	71.3	72.1	73.1	73.3	74.1	74.8	82.7	88.8	90.3	91.9	93.4
Annual Growth Rate	0.4%	1.2%	1.4%	0.2%	1.1%	1.0%	10.5%	7.4%	0.3%	0.3%	0.3%
Adjustment Factor	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
GPL's sales growth Base Case		5.1%	6.2%	0.8%	4.7%	4.4%	45.7%	32.1%	1.4%	1.4%	1.3%
New loads per year											
Capacity (MW)	0.0	0.0	0.0	0.0	1.0	1.0	1.0	1.0	0.5	0.5	0.5
Cummulated Capacity (MW)	0.0	0.0	0.0	0.0	1.0	2.0	3.0	4.0	6.5	9.0	11.5
Load Factor	0.742	0.742	0.742	0.742	0.742	0.742	0.742	0.742	0.742	0.742	0.742
Energy (GWh)	0.0	0.0	0.0	0.0	6.5	6.5	6.5	6.5	3.2	3.2	3.2
Cummulated Energy (GWh)	0.0	0.0	0.0	0.0	6.5	13.0	19.5	26.0	42.2	58.5	74.7
Total Linden											
Total Linden Sales (GWh)	71.3	72.1	73.1	73.3	74.1	74.8	82.7	88.8	90.3	91.9	93.4
New Load (GWh)	0.0	0.0	0.0	0.0	6.5	13.0	19.5	26.0	42.2	58.5	74.7
Total Linden Demand (GWh)	**71.3**	**72.1**	**73.1**	**73.3**	**80.6**	**87.8**	**102.2**	**114.8**	**132.5**	**150.4**	**168.1**
Total Losses Linden	NA	NA	18.0%	18.0%	18.0%	18.0%	18.0%	25.4%	23.0%	20.1%	17.1%
Technical Losses Linden	NA	NA	4.8%	4.8%	4.8%	4.8%	4.8%	13.7%	12.4%	10.7%	9.0%
Non-Technical Losses Linden	NA	NA	13.3%	13.3%	13.3%	13.3%	13.3%	11.7%	10.7%	9.4%	8.1%
Total Linden Demand final (GWh)	**71.3**	**72.1**	**73.1**	**89.4**	**98.3**	**107.1**	**124.6**	**153.9**	**172.2**	**188.2**	**202.8**

Source: Consultant.

In modelling Linden into DBIS, it was assumed that Linden is connected to the DBIS system around year 2024, when it is assumed that a new hydroelectric power plant would be installed to supply DBIS, with its transmission connection (two circuits at 230 kV) crossing near Linden (or, alternatively, a 69 kV DBIS-Linden would be constructed).

4.7.3 Essequibo Sales

As shown in the "Existing generation and transmission system" section of this study, DBIS is the major interconnected system of GPL; however, GPL also serves other non-interconnected rural systems, the main being Essequibo region. Essequibo region had 11,982 clients in 2014 which consumed a total of 25.9 GWh in 2014, representing 5.3% of total GPL's energy sales in 2014. In 2017, Essequibo demand was 41.7 GWh.

Therefore, in order to estimate DBIS demand, we took-out from GPL's sales the portion of such sales which correspond to Essequibo, which we forecasted using the same annual growth rate of the forecasted sales of GPL, as shown in Table 14.

Table 14. Essequibo's region energy sales subtracted from GPL's sales forecast

Essequibo Sales	Metric	2011A	2012A	2013A	2014A	2015A	2016A	2017A	2018F	2019F	2020F	2021F	2025F	2030F	2035F
Essequibo - Base Case	GWh	22.6	23.5	24.8	25.9	39.5	41.6	41.7	43.6	45.6	66.4	87.7	94.2	101.9	108.9
Essequibo - High Case	GWh	22.6	23.5	24.8	25.9	39.5	41.6	41.7	43.9	45.8	66.7	88.1	105.4	132.6	161.1
Essequibo - Low Case	GWh	22.6	23.5	24.8	25.9	39.5	41.6	41.7	43.4	45.3	47.3	49.5	54.0	58.7	63.0
Essequibo - Base Case Delayed	GWh	22.6	23.5	24.8	25.9	39.5	41.6	41.7	43.6	45.6	47.6	49.8	75.7	101.9	108.9

Source: Consultant

4.7.4 Energy not served in DBIS system

An estimate of energy not served in DBIS was obtained from energy not served by the entire GPL Company. Table 15 shows the energy not served (ENS) for the entire GPL system[28], which on average, represents about 2.0% of total GPL's sales per year (3.6% since 2011) and 1.4% of GPL's Generation (2.3% since 2011).

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[27] Linden electricity demand forecasts were estimated including electricity losses and the DBIS-Linden interconnection in 2021. After this year it includes DBIS technical electricity losses as exporter system. Also, after 2021 non-technical electricity losses in Linden are assumed to be progressively reduced with similar trend of DBIS non-technical electricity losses.

[28] ENS refers to non supplied electricty demand.

Table 15. Energy not served in GPL's system

ENERGY NOT SERVED - GPL (MWh-year)								
Year	**Generation**	**Network**	**Converter**	**Total**	**GPL Sales**	**GPL Generation**	**As % Sales**	**As % Generation**
2008	7,938	4,951	0	12,888	355.6	566.0	3.6%	2.3%
2009	14,813	7,155	5,680	27,648	370.3	586.0	7.5%	4.7%
2010	6,469	6,994	5,214	18,678	413.5	626.0	4.5%	3.0%
2011	5,308	5,968	5,481	16,757	430.5	653.4	3.9%	2.6%
2012	5,648	6,533	4,210	16,390	455.1	690.2	3.6%	2.4%
2013	3,181	9,832	3,925	16,937	475.9	710.7	3.6%	2.4%
2014	4,135	7,145	2,630	13,910	493.6	717.1	2.8%	1.9%
2015	2,479	5,706	2,448	10,634	518.9	751.0	2.0%	1.4%
2016				11,180	550.9	798.8	2.0%	1.4%
2017				11,256	555.3	809.4	2.0%	1.4%

Source: GPL Note: GPL's sales 2015 estimated

This study assumed that energy not served is about 1.4% of gross generation for forecasting purposes; such level is the not-served energy as a percentage of gross generation in 2017.

4.7.5 Losses Reductions

The reduction of total DBIS system's losses (technical and non-technical) are incorporated in two ways into the demand forecasts. Firstly, the obtained DBIS's sales are increased by the total losses' factor in order to arrive to DBIS's "Net Exported Units"; the technical and commercial losses factors were forecasted from 2015 until 2035 shown in Table 16. Secondly, a fraction of the yearly reduction of non-technical losses was converted into paid electricity (i.e. sales), in line with other demand studies. For instance, the Consultant assumed that not all future reductions of non-technical losses are converted into paid-electricity, as such reductions imply today non-paid electricity consumed by some users. The Consultant assumed that 50% of the nontechnical loss reductions, as in PPA Energy Consultants (2013), are converted into effective power sales.

Table 16. GPL technical and non-technical losses forecast

Additional demand from Losses Reduction		**2015A**	**2016A**	**2017A**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Sales GPL Base Case	GWh	519	551	555	581	607	884	1,254	1,357	1,451
Sales GPL High Case	GWh	519	551	555	584	610	888	1,404	1,766	2,146
Sales GPL Low Case	GWh	519	551	555	578	604	630	720	782	840
Sales GPL Base Case Delayed	GWh	519	551	555	581	607	634	1,009	1,357	1,451
Technical Losses	%	14.9%	14.5%	14.5%	14.1%	14.1%	14.1%	12.4%	10.7%	9.0%
Commercial Losses	%	14.3%	14.7%	15.1%	14.7%	14.0%	14.0%	12.0%	10.1%	8.1%
Total Losses	%	29.2%	29.2%	29.6%	28.7%	28.1%	28.1%	24.4%	20.8%	17.1%
Reduction in Commercial Losses	%				0.4%	1.1%	1.1%	3.1%	5.0%	7.0%
Reductions (Energy) - Base Case	GWh		0.0	0.0	2.4	6.6	9.6	38.3	68.1	101.4
Reductions (Energy) - High Case	GWh		0.0	0.0	2.4	6.6	9.7	42.9	88.7	149.9
Reductions (Energy) - Low Case	GWh		0.0	0.0	2.3	6.6	6.8	22.0	39.3	58.7
Reductions (Energy) - Base Case Delayed	GWh		0.0	0.0	2.4	6.6	6.9	30.8	68.1	101.4
Conversion Factor	%		50%	50%	50%	50%	50%	50%	50%	50%
Additional demand from Losses Reduction	**GWh**				**1.2**	**3.3**	**4.8**	**19.1**	**34.1**	**50.7**
Additional demand from Losses Reduction	**GWh**				**1.2**	**3.3**	**4.8**	**21.4**	**44.3**	**75.0**
Additional demand from Losses Reduction	**GWh**				**1.2**	**3.3**	**3.4**	**11.0**	**19.6**	**29.3**
Additional demand from Losses Reduction	**GWh**				**1.2**	**3.3**	**3.4**	**15.4**	**34.1**	**50.7**

Source: Consultant using GPL (2013a). GPL D&E Programme Draft inquires

4.7.6 Auxiliaries and Self Consumption

Auxiliaries are forecasted in this study in absolute terms using a 2-year historical average, which implies a reduction on a relative reduction against gross generation. Such reduction in relative auxiliaries and self-consumption reflects the use of new generation plants (and the replacement of old motor units) for base-load operation that would reduce the dependency on older plants that were using up to 5% of their generation for auxiliaries, as stated in GPL's D&E programme. Table 17 shows the historical auxiliaries and self-consumption patterns applied in the forecasts.

Table 17. Auxiliaries and self-consumption

Year	Gross Generation	Auxillaries	Station Auxillaries	Sophia Converter Losses and Auxilliary	GPL Own Use Consumption	Auxiliaries / Gross Generation
2011	653,375	24,161	18,091	6,070	893	3.7%
2012	690,214	22,880	17,690	4,777	934	3.3%
2013	710,692	21,664	16,152	4,559	953	3.0%
2014	717,107	20,776	16,498	3,249	1,029	2.9%
2015	751,014	20,030	16,010	3,006	1,014	2.7%
2016	798,796	21,817	18,045	3,150	623	2.7%
2017	809,410	21,054	18,276	2,287	491	2.6%

Source: GPL and Consultant estimate for 2015

4.7.7 Energy Saved from Energy Efficiency and Distributed Generation

4.7.7.1 Energy Efficiency measures

Table 18 shows the estimate of Guyana's electricity end-uses and reveals that six end-uses contribute 77% of the total electricity use in Guyana.

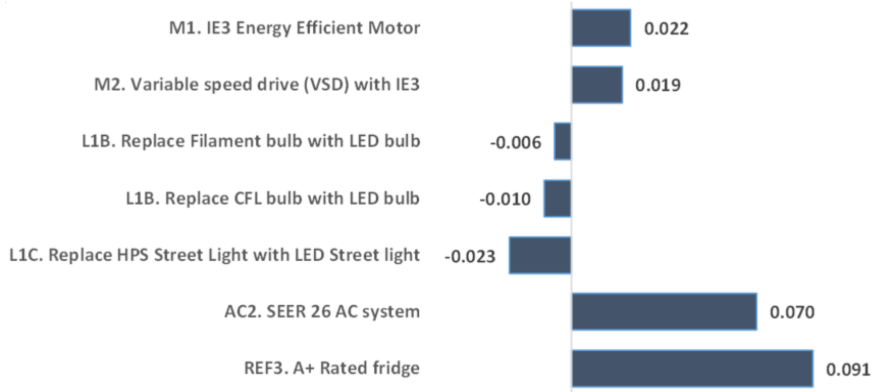
Table 18. End uses of electricity in DBIS in 2015

End-Use	*%*	*Cumulated*
Motors	26.6%	26.6%
Lighting	22.9%	49.5%
All air conditioning	15.1%	64.6%
All refrigeration	6.3%	70.9%
All mechanical ventilation	4.1%	74.9%
Standalone fridges and freezers*	2.6%	77.6%

*Although this category is the tenth highest in terms of electricity use it is included in the list as it is combined with Refrigeration into one category for the purposes of analysis. Source: Brugman (2016)

EE measures for Guyana in Brugman (2016) were designed on such six main end uses and are described in Appendix E of this report. Such EE measures were ranked using their Levelized Cost of Electricity Saved (LCOES) which is shown in Appendix F of this report. Only such EE measures that had LCOES´s lower than the average power generation cost of DBIS, had the largest electricity savings and rationale of implementation[29] were chosen. This reduced the number of EE measures to implement in Guyana to seven, which are listed in Figure 11.

Figure 11. LCOES of the 10 EE measures (US$/KWh)



Source: Brugman (2016)

In 2035 these EE measures would reduce electricity demand in DBIS in around 99 GWh.

4.7.7.2 Distributed Generation

Distributed generation occurs when an end-user install their own electricity generating device in order to meet some or all of their demand. Distributed displacement occurs when users install a device which provides the energy needed for a particular end-use which would have normally used electricity. The consultant believes that the two most hopeful technologies in Guyana for displacing electricity demand in this way are photovoltaic cells (solar-electric) and solar hot water (solar thermal) technologies. Both are based on panels which are placed on a roof or other available surface and provide either electricity or solar hot water for the end-user. With distributed generation systems sizes are much smaller than systems used at the utility scale with for instance a domestic system being typically sized to 1kW and a commercial system to 8kW. Industrial PV systems are very site specific but can typically be of the order of 20kW and upwards. This compares to a utility scale PV project which are larger than 1,000kW.

This study evaluates two technologies in Guyana for displacing electricity demand on a distributed (end-user) basis: (i) Photovoltaic cells (solar-electric) for commercial, industrial and community users and (ii) residential solar water heaters (solar thermal) technologies. We note that although distributed wind competitiveness (from 1kW to 100 kW) has improved and is now comparable to photovoltaics[30], they are more suitable for rural areas or low density rural areas because of safety reasons, relatively large size (rotor-diameters of about 7-9 meters of competitive distributed wind technologies), sound levels and larger initial capital costs[31]. As a result, distributed wind is another feasible technology for some DBIS'

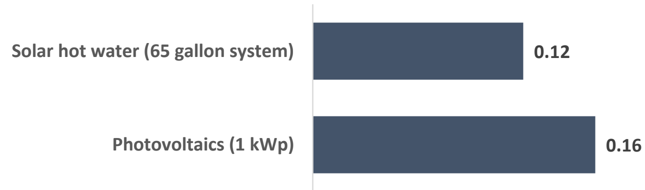
[29] The consultant made a cost benefit analysis of EE measures for IADB in 2016 until 2026, were applicability for Guyana was discussed. This report uses the same EE measures selected in such study but with different targets for year 2035. For instance, 40% of Brugman 2016 target are used in this study.

[30] For instance, NREL estimates LCEOS of distributed wind between 0.13-0.25 US$/KWh (https://www.energy.gov/sites/prod/files/2018/02/f49/Distributed-Wind-Competitiveness-Improvement-Project-02-27.pdf) .

[31] Capital costs (at least US$4,000/kW according to NREL from https://www.energy.gov/sites/prod/files/2017/08/f35/2016-Distributed-Wind-Market-Report.pdf)

areas[32]. Figure 12 shows the two (2) distributed generation measures selected with their LCOES (Appendix H shows assumptions used).

Figure 12. LCOES of the two (2) distributed generation measures (US$/KWh)



Source: Consultant

Photovoltaics. About 3.1 MW of distributed Solar PV systems are installed in Guyana as of 2017[33]. High penetrations of distributed generation can push the electricity grid to the limits of its operational capacity by affecting both frequency and voltage. A commonly used rule of thumb in the U.S. allows distributed PV systems with peak powers up to 15% of the peak load on a feeder[34]. However, some recent more detailed work by NREL suggests that in many cases a maximum penetration of 30% of peak power may be possible[35]. Maximum demand in Guyana is expected to reach 251 MW by 2035 in the Low Case Scenario and 360 MW in the Base Case Scenario. If a maximum penetration of PV of 20% of Low Case Scenario´s demand is assumed then the maximum penetration of PV on the system would be approximately 50 MW in 2035 representing around 77 GWh of total demand reduction in that year (with estimated capacity factor of 17.5%). Prices of PV systems are reducing in Guyana. For example GEA installed an 8.46kW system in 2012 at a price of 3,886 US$/kW whereas in 2016 they have installed a 10kW system at a price of 2,280 US$/kW[36]. In 2017 Guyana installed 813 kW solar systems in public buildings and schools at an average cost of 1,686 US$/kW[37]. If suitable community-based PV projects could be constructed then the residential sector could also be included in these projects, but the technical details of these projects would need to be worked through with appropriate sub-metering and billing arrangements.

Solar hot water. There is no direct data on how much electricity is used to produce hot water for ablutions (showers, baths and hand-washing) in Guyana. On the basis of imports of electricity using equipment it has been assessed that the number of electric heating resistors purchased in Guyana by 2035 would be 29,298 with an assumed average power usage of 1,500W and average operating hours of 1,640 hours per year (4.5 hours per day). It has further been assumed that around 40% of the electric resistors in use would be used for water heating which gives a total number of units in use of 11,538 in 2035. This gives an overall electricity use of about 28 GWh/year for electrically heated hot water for ablutions in 2035. It should also be noted that these estimates are based on units that would displace hot water heating based on electrical filaments. The actual number of solar thermal units which could be installed however is

[32] However, because of the aformentioned reasons, its potential penetration in DBIS is included in the photovoltaics demand as a substitute of photovoltaic solutions when communities' residential users or commercial/industrial clients find them attractive.

[33] GEA (2017)

[34] "IEEE Application Guide for IEEE Std 1547, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems," IEEE Std 1547.2-2008 , pp. 1-207, April 15 2009.

[35] Maximum Photovoltaic Penetration levels on Typical Distribution Feeders, p1, available at http://www.nrel.gov/docs/fy12osti/55094.pdf, sourced on March 20, 2018.

[36] Source: Personal communication from Leon DeSouza of GEA, recieved on April 19th 2016.

[37] GEA (2017)

likely to be much higher than this as other fuels such as oil and gas could also be displaced with this measure.

4.7.7.3 Electricity savings from EE and Distributed Generation measures

The forecasts of electricity savings, marginal investment and number of interventions (i.e. replacement of old appliances by new EE appliances) are shown in Appendix F for EE measures and for distributed generation measures are shown in Appendix H . In summary, the following bullets explain such results.

- **EE measures.** Total number of interventions of the EE measures until year 2035 evaluated in this study is estimated at 3.078 million. A significant proportion of these interventions are in the form of lighting replacements with LEDs. The additional capex (i.e. additional capex against the baseline of not implementing the EE measure) required for all the EE measures up to 2035 is estimated to be US$ 24.37 million. Through implementation of these EE measures it is estimated that by 2035 the electricity consumption would be reduced by 99 GWh in that year. This is equivalent to a reduction of about 4.2% percent of the total demand in the Base Case which would exist without EE measures.
- **RE photovoltaics projects.** Photovoltaics systems installed on non-residential (i.e. industrial and commercial users) and suitable residential community projects, and evaluated in this study, have the potential to reduce electricity imports from the grid by 77 GWh by 2035, or 4.6% of the total DBIS demand in 2035 (Low Case Scenario). Installing 11,538 solar water heaters (65 gallon) systems has the potential to reduce electricity import from the grid by 28 GWh by 2035, or 1.7% of the total DBIS demand in 2035.
- **Total (RE photovoltaics projects and EE measures).** The cumulative total number of interventions in the country of both RE photovoltaics and EE measures up to 2035 was estimated at approximately 3.1 million. The additional capex (i.e. additional capex against the baseline of not implementing EE and RE photovoltaics) required for all the EE measures over the baseline up to 2035 is estimated to be US$ 137.9 million. Through implementation of both RE photovoltaics and EE measures it is estimated that by 2035 the demand would be reduced by 204 GWh from the baseline estimate of 1656 GWh in 2035 (Low Case Scenario).

Table 19 summarizes the main aspects of each EE measure and distributed generation forecasted in this study.

Table 19. Main values of the selected RE projects and EE measures (cumulative 2018-2035)

		LCOES USD/KWh	Marginal Capex USD/unit	Total Capex USD/unit	Electricity Savings MWh	Marginal Capex USD k	Total Capex USD k	Total Number Interventions Cummulative
M1	IE3 Energy Efficient Motor	0.022	380	1,120	47,452	937	2,763	2,467
M2	Variable speed drive (VSD) with IE3	0.019	1,300	2,420	328,169	3,207	5,969	2,467
M3	IE3+VSD+67mm pipe	0.108	38,300	86,824	0	0	0	0
L1B	Replace Filament bulb with LED bulb	-0.006	7	8	129,370	2,940	3,392	452,265
L1B	Replace CFL bulb with LED bulb	-0.010	3	8	130,032	6,973	19,320	2,575,947
L1C	Replace HPS Street Light with LED Street light	-0.023	250	400	134,565	5,251	8,402	21,006
AC1A	Cool-roof paint on roof	0.021	10	40	0	0	0	0
AC1B	Natural ventilation	0.047	100	100	0	0	0	0
AC2	SEER 26 AC system	0.070	387	762	43,920	2,531	4,984	6,541
REF3	A+ Rated fridge	0.091	140	260	33,926	2,531	4,703	18,097
	Sub-Total EE				**847,434**	**24,371**	**49,533**	**3,078,790**
DG1	Photovoltaics (1 kWp)	0.160	1,800	1,800	680,910	90,372	90,372	50,206
DG2	Solar hot water (65 gallon system)	0.119	2,015	2,015	236,202	23,249	23,249	11,538
	Sub-Total Distributed Generation				**917,112**	**113,620**	**113,620**	**61,744**
	TOTAL				**1,764,546**	**137,992**	**163,153**	**3,140,534**

SOURCE: Consultant

Table 20. Demand before and after Energy savings of EE and RE measures per scenario

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2030	2035
Base Case (DBIS with Linden 2024)	MWh/year	762,170	788,273	817,237	1,180,835	1,541,273	1,575,649	1,584,643	1,762,745	1,861,687	1,965,416	2,253,196	2,377,086
Base Case + Distributed Gx + EE Measures	MWh/year	762,170	775,513	799,629	1,157,941	1,509,815	1,535,858	1,536,100	1,700,984	1,786,750	1,878,718	2,116,014	2,173,383
EE Measures electricity Savings	%		1.6%	2.2%	1.9%	2.0%	2.5%	3.1%	3.5%	4.0%	4.4%	6.1%	8.6%
Demand Growth after EE	%		1.8%	3.1%	44.8%	30.4%	1.7%	0.0%	10.7%	5.0%	5.1%	0.5%	0.5%
High Case (DBIS with Linden 2024)	MWh/year	762,170	792,287	821,304	1,186,356	1,548,229	1,629,230	1,681,967	1,905,307	2,051,040	2,203,174	2,750,916	3,193,101
Base Case + Distributed Gx + EE Measures	MWh/year	762,170	779,528	803,697	1,163,462	1,516,770	1,589,439	1,633,424	1,843,546	1,976,104	2,116,476	2,613,735	2,989,398
EE Measures electricity Savings	%		1.6%	2.1%	1.9%	2.0%	2.4%	2.9%	3.2%	3.7%	3.9%	5.0%	6.4%
Demand Growth after EE	%		2.3%	3.1%	44.8%	30.4%	4.8%	2.8%	12.9%	7.2%	7.1%	2.7%	2.7%
Low Case (DBIS with Linden 2024)	MWh/year	762,170	784,272	813,160	848,029	879,106	911,253	917,169	1,092,116	1,187,827	1,288,250	1,554,878	1,659,405
Base Case + Distributed Gx + EE Measures	MWh/year	762,170	771,512	795,552	825,135	847,648	871,462	868,626	1,030,355	1,112,890	1,201,552	1,417,696	1,455,702
EE Measures electricity Savings	%		1.6%	2.2%	2.7%	3.6%	4.4%	5.3%	5.7%	6.3%	6.7%	8.8%	12.3%
Demand Growth after EE	%		1.2%	3.1%	3.7%	2.7%	2.8%	-0.3%	18.6%	8.0%	8.0%	0.6%	0.5%
Base Case Delayed (DBIS with Linden 2024)	MWh/year	762,170	788,273	817,237	852,267	883,484	915,774	1,063,642	1,342,350	1,551,782	1,776,829	2,253,196	2,377,086
Base Case + Distributed Gx + EE Measures	MWh/year	762,170	775,513	799,629	829,373	852,026	875,983	1,015,099	1,280,589	1,476,845	1,690,131	2,116,014	2,173,383
EE Measures electricity Savings	%		1.6%	2.2%	2.7%	3.6%	4.3%	4.6%	4.6%	4.8%	4.9%	6.1%	8.6%
Demand Growth after EE	%		1.8%	3.1%	3.7%	2.7%	2.8%	15.9%	26.2%	15.3%	14.4%	0.5%	0.5%

SOURCE: Consultant.

4.8 Electric vehicles

Table 21 shows the electricity demand (GWh) forecasted from Electric Vehicles (EV) utilization in Guyana (see Appendix R for explanation of these forecasts).

Table 21. Electric Vehicles: Electricity Demand per scenario

Demand from EV	Unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Low Case	GWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Base Case	GWh	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.6	2.4	3.3	4.2	5.0	6.0	6.9	7.8	8.8	9.8	10.8
Base Case Delayed	GWh	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.6	2.4	3.3	4.2	5.0	6.0	6.9	7.8	8.8	9.8	10.8
High Case	GWh	0.0	0.0	0.0	0.0	0.0	0.0	2.5	5.1	7.7	10.4	13.1	15.9	18.8	21.7	24.7	27.8	30.9	34.2

Source: Consultant

Using as a guideline 280,000 registered vehicles in Guyana in 2018, we are forecasting the utilization of 5,100 EV in 2035 in Base Case and 16,000 EV in the High Case. Table 22 shows the total number of EV vehicles and its comparison to total registered vehicles and its share.

Table 22. Electric Vehicles and total registered vehicles forecast

Number EV	Unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Low Case	GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Base Case	GWh	0	0	0	0	0	0	374	757	1,148	1,550	1,960	2,381	2,811	3,251	3,701	4,161	4,632	5,114
Base Case Delayed	GWh	0	0	0	0	0	0	374	757	1,148	1,550	1,960	2,381	2,811	3,251	3,701	4,161	4,632	5,114
High Case	GWh	0	0	0	0	0	0	1,178	2,383	3,618	4,881	6,175	7,499	8,853	10,239	11,657	13,107	14,591	16,108
Total Cars	**Unit**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Low Case	GWh	280,000	283,354	286,749	290,184	293,660	297,178	300,738	304,341	307,987	311,677	315,410	319,189	323,013	326,882	330,798	334,761	338,771	342,830
Base Case	GWh	280,000	283,354	286,749	290,184	293,660	297,178	300,738	304,341	307,987	311,677	315,410	319,189	323,013	326,882	330,798	334,761	338,771	342,830
Base Case Delayed	GWh	280,000	283,354	286,749	290,184	293,660	297,178	300,738	304,341	307,987	311,677	315,410	319,189	323,013	326,882	330,798	334,761	338,771	342,830
High Case	GWh	280,000	283,354	286,749	290,184	293,660	297,178	300,738	304,341	307,987	311,677	315,410	319,189	323,013	326,882	330,798	334,761	338,771	342,830
EV share	**Unit**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Low Case	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Base Case	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.2%	0.4%	0.5%	0.6%	0.7%	0.9%	1.0%	1.1%	1.2%	1.4%	1.5%
Base Case Delayed	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.2%	0.4%	0.5%	0.6%	0.7%	0.9%	1.0%	1.1%	1.2%	1.4%	1.5%
High Case	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%	0.8%	1.2%	1.6%	2.0%	2.3%	2.7%	3.1%	3.5%	3.9%	4.3%	4.7%

Source: Consultant

These estimates assume that EV in Guyana would start to become available in 2024 after end-user electricity tariffs decrease as a result of natural gas availability (and hydro availability later on) for power generation becomes available and its distribution grid becomes more reliable. EV share in 2035 of 1.5% of registered vehicles in Base Case and 4.7% in High Case in Guyana compares to other Latam peers 2030 EV goals such as Chile (3.8%), Colombia (3.2%) and Costa Rica (5%). We note that such targets are much lower than global forecasts since they reflect lower GDP per capita levels in Latam than developed countries and also lower potential levels of tax subsidies to EV from governments. As well, Base Case scenarios also assume a Compressed Natural Gas Vehicles (CNGV) penetration of 3% in 2035 due that such transport technology is more economically viable than EV as shown in Appendix R .

4.9 Results of DBIS' Electricity Demand Forecast

The following tables (Table 23 until Table 26) show, in detail, the above calculations for each of the four scenarios.

Gross Generation in DBIS in 2017 was 809.4 GWh (including Essequibo). After taking out 41.7 GWh from Essequibo's generation, Gross Generation in 2017 in the previous demand tables becomes 810 GWh which matches real DBIs generation.

Notice that to obtain system peak demand, in MW, from the Annual Demand, in GWh, this study applied a constant value of 0.755 (obtained from DBIS Electricity demand after EE of 762.2 GWh and DBIS peak demand in 2017 of 115.3 MW) for the system load factor for all forecasted years. Real load factor of DBIS was 76.0% in 2017.

Table 23. Base case DBIS demand forecast with Linden

Base Case	Metric	2014A	2015A	2016A	2017A	2018F	2019F	2020F	2021F	2022F	2023F	2024F	2025F	2030F	2035F
Electricity Sales	**GWh**	**493.6**	**518.9**	**550.9**	**555.3**	**581.4**	**607.1**	**884.3**	**1168.5**	**1204.4**	**1220.8**	**1237.5**	**1254.4**	**1357.1**	**1451.3**
Rate of Growth	%	*3.7%*	*5.1%*	*6.2%*	*0.8%*	*4.7%*	*4.4%*	*45.7%*	*32.1%*	*3.1%*	*1.4%*	*1.4%*	*1.4%*	*1.4%*	*1.3%*
Residential	GWh	231.2	244.2	259.0	262.4	273.7	285.3	297.2	309.5	322.1	335.0	348.4	362.1	436.5	521.8
Commercial	GWh	84.8	87.3	95.5	97.3	102.2	106.9	195.0	285.4	293.1	294.3	295.4	296.4	305.8	308.8
Industrial	GWh	177.5	187.5	196.4	195.6	205.5	214.9	392.0	573.7	589.2	591.5	593.8	595.9	614.8	620.7
Residential	%	46.8%	47.1%	47.0%	47.3%	47.1%	47.0%	33.6%	26.5%	26.7%	27.4%	28.1%	28.9%	32.2%	36.0%
Commercial	%	17.2%	16.8%	17.3%	17.5%	17.6%	17.6%	22.1%	24.4%	24.3%	24.1%	23.9%	23.6%	22.5%	21.3%
Industrial	%	36.0%	36.1%	35.7%	35.2%	35.3%	35.4%	44.3%	49.1%	48.9%	48.5%	48.0%	47.5%	45.3%	42.8%
New loads from Self Generation	GWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	64.3	308.0	367.3
Losses converted into sales	GWh	0.0	0.0	0.0	0.0	1.2	3.3	4.8	8.6	11.3	13.8	16.5	19.1	34.1	50.7
Sales from Essequibo region	GWh	-25.9	-39.5	-41.6	-41.7	-43.6	-45.6	-66.4	-87.7	-90.4	-91.6	-92.9	-94.2	-101.9	-108.9
Total Sales DBIS	**GWh**	**467.6**	**479.4**	**509.3**	**513.6**	**538.9**	**564.8**	**822.7**	**1089.4**	**1125.3**	**1143.0**	**1161.1**	**1243.7**	**1597.3**	**1760.3**
Rate of Growth	%	3.7%	2.5%	6.2%	0.9%	4.9%	4.8%	45.7%	32.4%	3.3%	1.6%	1.6%	7.1%	2.0%	2.0%
Residential	GWh	231.2	244.2	259.0	262.4	253.8	265.5	277.3	290.6	303.5	316.8	330.4	344.5	420.8	508.0
Commercial	GWh	84.8	87.3	95.5	97.3	95.1	100.5	182.8	268.3	276.7	279.1	281.4	283.8	299.9	311.0
Industrial	GWh	177.5	187.5	196.4	195.6	190.1	198.7	362.6	530.6	545.0	547.1	549.2	615.5	876.7	941.4
Residential	%	46.8%	47.1%	47.0%	47.3%	47.1%	47.0%	33.7%	26.7%	27.0%	27.7%	28.5%	27.7%	26.3%	28.9%
Commercial	%	17.2%	16.8%	17.3%	17.5%	17.7%	17.8%	22.2%	24.6%	24.6%	24.4%	24.2%	22.8%	18.8%	17.7%
Industrial	%	36.0%	36.1%	35.7%	35.2%	35.3%	35.2%	44.1%	48.7%	48.4%	47.9%	47.3%	49.5%	54.9%	53.5%
Total Losses	**%**	**29.6%**	**29.2%**	**29.2%**	**29.6%**	**28.7%**	**28.1%**	**28.1%**	**27.3%**	**26.6%**	**25.9%**	**25.1%**	**24.4%**	**20.8%**	**17.1%**
Technical Losses	%	14.0%	14.9%	14.5%	14.5%	14.1%	14.1%	14.1%	13.7%	13.4%	13.0%	12.7%	12.4%	10.7%	9.0%
NonTechnical Losses	%	15.6%	14.3%	14.7%	15.1%	14.7%	14.0%	14.0%	13.6%	13.2%	12.8%	12.4%	12.0%	10.1%	8.1%
Net Exported Units	**GWh**	**663.9**	**676.7**	**719.1**	**729.9**	**756.3**	**785.1**	**1143.6**	**1499.1**	**1533.0**	**1541.9**	**1551.0**	**1645.3**	**2015.7**	**2123.5**
Rate of Growth	%	1.7%	1.9%	6.3%	1.5%	3.6%	3.8%	45.7%	31.1%	2.3%	0.6%	0.6%	6.1%	1.0%	1.1%
Auxiliaries & Self-Consumption	GWh	20.8	20.0	21.8	21.1	21.4	21.2	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3
Gross Generation	**GWh**	**684.7**	**696.7**	**740.9**	**750.9**	**777.8**	**806.3**	**1164.9**	**1520.4**	**1554.3**	**1563.2**	**1572.3**	**1666.6**	**2037.0**	**2144.8**
Rate of Growth	%	1.5%	1.8%	6.3%	1.3%	3.6%	3.7%	44.5%	30.5%	2.2%	0.6%	0.6%	6.0%	1.0%	1.1%
Unserved Energy	GWh	13.9	10.6	11.2	11.3	10.5	10.9	15.9	20.8	21.3	21.4	21.6	22.9	28.0	29.5
Unserved Energy	%	1.9%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%
Electricity Demand before Linden	**GWh**	**698.6**	**707.4**	**752.1**	**762.2**	**788.3**	**817.2**	**1180.8**	**1541.3**	**1575.6**	**1584.6**	**1593.8**	**1689.5**	**2065.0**	**2174.3**
Linden Interconnection	GWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	168.9	172.2	188.2	202.8
DBIS Electricity Demand before EE	**GWh**	**698.6**	**707.4**	**752.1**	**762.2**	**788.3**	**817.2**	**1180.8**	**1541.3**	**1575.6**	**1584.6**	**1762.7**	**1861.7**	**2253.2**	**2377.1**
Rate of Growth	%	1.0%	1.3%	6.3%	1.3%	3.4%	3.7%	44.5%	30.5%	2.2%	0.6%	11.2%	5.6%	1.1%	1.1%
EE measures	GWh					12.8	17.6	22.9	31.5	39.8	48.5	61.8	74.9	137.2	203.7
DBIS Electricity Demand after EE	**GWh**	**698.6**	**707.4**	**752.1**	**762.2**	**775.5**	**799.6**	**1157.9**	**1509.8**	**1535.9**	**1536.1**	**1701.0**	**1786.7**	**2116.0**	**2173.4**
Electric Vehicles						0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.6	6.0	10.8
DBIS Electricity Demand	**GWh**	**698.6**	**707.4**	**752.1**	**762.2**	**775.5**	**799.6**	**1157.9**	**1509.8**	**1535.9**	**1536.1**	**1701.8**	**1788.4**	**2122.0**	**2184.2**
Rate of Growth	%	1.0%	1.3%	6.3%	1.3%	1.8%	3.1%	44.8%	30.4%	1.7%	0.0%	10.7%	5.0%	0.5%	0.5%
Load Factor			0.732	0.740	0.755	0.755	0.755	0.755	0.755	0.755	0.755	0.755	0.755	0.755	0.755
Maximum Demand	**MW**		**110.3**	**116.1**	**115.3**	**117.3**	**121.0**	**175.2**	**228.4**	**232.3**	**232.4**	**257.4**	**270.5**	**321.0**	**330.4**

Source: Consultant

Table 24. High case DBIS demand forecast with Linden

High Case	Metric	2014A	2015A	2016A	2017A	2018F	2019F	2020F	2021F	2022F	2023F	2024F	2025F	2030F	2035F
Electricity Sales	**GWh**	**493.6**	**518.9**	**550.9**	**555.3**	**584.2**	**609.9**	**888.3**	**1173.6**	**1245.7**	**1296.6**	**1349.5**	**1404.3**	**1766.3**	**2146.2**
Rate of Growth	%	*3.7%*	*5.1%*	*6.2%*	*0.8%*	*5.2%*	*4.4%*	*45.6%*	*32.1%*	*6.1%*	*4.1%*	*4.1%*	*4.1%*	*4.0%*	*4.0%*
Residential	GWh	231.2	244.2	259.0	262.4	273.7	285.3	297.2	309.5	322.1	335.0	348.4	362.1	436.5	521.8
Commercial	GWh	84.8	87.3	95.5	97.3	103.2	107.8	196.3	287.1	306.8	319.4	332.6	346.2	441.8	539.6
Industrial	GWh	177.5	187.5	196.4	195.6	207.4	216.8	394.7	577.1	616.8	642.1	668.5	696.0	888.1	1084.7
Residential	%	46.8%	47.1%	47.0%	47.3%	46.8%	46.8%	33.5%	26.4%	25.9%	25.8%	25.8%	25.8%	24.7%	24.3%
Commercial	%	17.2%	16.8%	17.3%	17.5%	17.7%	17.7%	22.1%	24.5%	24.6%	24.6%	24.6%	24.7%	25.0%	25.1%
Industrial	%	36.0%	36.1%	35.7%	35.2%	35.5%	35.5%	44.4%	49.2%	49.5%	49.5%	49.5%	49.6%	50.3%	50.5%
New loads from Self Generation	GWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	64.3	308.0	367.3
Losses converted into sales	GWh	0.0	0.0	0.0	0.0	1.2	3.3	4.8	8.7	11.7	14.7	17.9	21.4	44.3	75.0
Sales from Essequibo region	GWh	-25.9	-39.5	-41.6	-41.7	-43.9	-45.8	-66.7	-88.1	-93.5	-97.3	-101.3	-105.4	-132.6	-161.1
Total Sales DBIS	**GWh**	**467.6**	**479.4**	**509.3**	**513.6**	**541.6**	**567.5**	**826.4**	**1094.2**	**1163.8**	**1214.0**	**1266.1**	**1384.7**	**1986.1**	**2427.3**
Rate of Growth	%	3.7%	2.5%	6.2%	0.9%	5.4%	4.8%	45.6%	32.4%	6.4%	4.3%	4.3%	9.4%	4.1%	4.1%
Residential	GWh	231.2	244.2	259.0	262.4	253.8	265.5	277.3	290.6	303.7	317.2	331.2	345.6	425.9	520.1
Commercial	GWh	84.8	87.3	95.5	97.3	96.0	101.4	184.0	269.9	289.6	302.8	316.6	331.0	430.8	536.6
Industrial	GWh	177.5	187.5	196.4	195.6	191.8	200.5	365.1	533.8	570.5	593.9	618.4	708.1	1129.4	1370.6
Residential	%	46.8%	47.1%	47.0%	47.3%	46.9%	46.8%	33.6%	26.6%	26.1%	26.1%	26.2%	25.0%	21.4%	21.4%
Commercial	%	17.2%	16.8%	17.3%	17.5%	17.7%	17.9%	22.3%	24.7%	24.9%	24.9%	25.0%	23.9%	21.7%	22.1%
Industrial	%	36.0%	36.1%	35.7%	35.2%	35.4%	35.3%	44.2%	48.8%	49.0%	48.9%	48.8%	51.1%	56.9%	56.5%
Total Losses	**%**	**29.6%**	**29.2%**	**29.2%**	**29.6%**	**28.7%**	**28.1%**	**28.1%**	**27.3%**	**26.6%**	**25.9%**	**25.1%**	**24.4%**	**20.8%**	**17.1%**
Technical Losses	%	14.0%	14.9%	14.5%	14.5%	14.1%	14.1%	14.1%	13.7%	13.4%	13.0%	12.7%	12.4%	10.7%	9.0%
NonTechnical Losses	%	15.6%	14.3%	14.7%	15.1%	14.7%	14.0%	14.0%	13.6%	13.2%	12.8%	12.4%	12.0%	10.1%	8.1%
Net Exported Units	**GWh**	**663.9**	**676.7**	**719.1**	**729.9**	**760.0**	**788.8**	**1148.7**	**1505.7**	**1585.6**	**1637.6**	**1691.3**	**1831.8**	**2506.3**	**2928.0**
Rate of Growth	%	1.7%	1.9%	6.3%	1.5%	4.1%	3.8%	45.6%	31.1%	5.3%	3.3%	3.3%	8.3%	3.2%	3.2%
Auxiliaries & Self-Consumption	GWh	20.8	20.0	21.8	21.1	21.4	21.2	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3
Gross Generation	**GWh**	**684.7**	**696.7**	**740.9**	**750.9**	**781.4**	**810.0**	**1170.1**	**1527.0**	**1606.9**	**1658.9**	**1712.6**	**1853.1**	**2527.6**	**2949.3**
Rate of Growth	%	1.5%	1.8%	6.3%	1.3%	4.1%	3.7%	44.4%	30.5%	5.2%	3.2%	3.2%	8.2%	3.1%	3.1%
Unserved Energy	GWh	13.9	10.6	11.2	11.3	10.9	11.3	16.3	21.2	22.3	23.1	23.8	25.8	35.1	41.0
Unserved Energy	%	1.9%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%
Electricity Demand before Linden	**GWh**	**698.6**	**707.4**	**752.1**	**762.2**	**792.3**	**821.3**	**1186.4**	**1548.2**	**1629.2**	**1682.0**	**1736.4**	**1878.8**	**2562.7**	**2990.3**
Linden Interconnection	GWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	168.9	172.2	188.2	202.8
DBIS Electricity Demand	**GWh**	**698.6**	**707.4**	**752.1**	**762.2**	**792.3**	**821.3**	**1186.4**	**1548.2**	**1629.2**	**1682.0**	**1905.3**	**2051.0**	**2750.9**	**3193.1**
Rate of Growth	%	1.0%	1.3%	6.3%	1.3%	4.0%	3.7%	44.4%	30.5%	5.2%	3.2%	13.3%	7.6%	3.0%	3.0%
EE measures	GWh					12.8	17.6	22.9	31.5	39.8	48.5	61.8	74.9	137.2	203.7
DBIS Electricity Demand after EE	**GWh**	**698.6**	**707.4**	**752.1**	**762.2**	**779.5**	**803.7**	**1163.5**	**1516.8**	**1589.4**	**1633.4**	**1843.5**	**1976.1**	**2613.7**	**2989.4**
Electric Vehicles						0.0	0.0	0.0	0.0	0.0	0.0	2.5	5.1	18.8	34.2
DBIS Electricity Demand	**GWh**	**698.6**	**707.4**	**752.1**	**762.2**	**779.5**	**803.7**	**1163.5**	**1516.8**	**1589.4**	**1633.4**	**1846.0**	**1981.2**	**2632.5**	**3023.6**
Rate of Growth	%	1.0%	1.3%	6.3%	1.3%	2.3%	3.1%	44.8%	30.4%	4.8%	2.8%	12.9%	7.2%	2.7%	2.7%
Load Factor			0.732	0.740	0.755	0.755	0.755	0.755	0.755	0.755	0.755	0.755	0.755	0.755	0.755
Maximum Demand	**MW**		**110.3**	**116.1**	**115.3**	**117.9**	**121.6**	**176.0**	**229.5**	**240.4**	**247.1**	**279.3**	**299.7**	**398.2**	**457.4**

Source: Consultant

Table 25. Low case DBIS demand forecast with Linden

Low Case	Metric	2014A	2015A	2016A	2017A	2018F	2019F	2020F	2021F	2022F	2023F	2024F	2025F	2030F	2035F
Electricity Sales	**GWh**	**493.6**	**518.9**	**550.9**	**555.3**	**578.1**	**603.7**	**630.2**	**659.2**	**689.3**	**699.4**	**709.5**	**719.8**	**782.4**	**839.7**
Rate of Growth	%	*3.7%*	*5.1%*	*6.2%*	*0.8%*	*4.1%*	*4.4%*	*4.4%*	*4.6%*	*4.6%*	*1.5%*	*1.5%*	*1.4%*	*1.4%*	*1.4%*
Residential	GWh	231.2	244.2	259.0	262.4	273.7	285.3	297.2	309.5	322.1	335.0	348.4	362.1	436.5	521.8
Commercial	GWh	84.8	87.3	95.5	97.3	101.1	105.8	110.6	116.2	122.0	121.0	120.0	118.8	114.9	105.6
Industrial	GWh	177.5	187.5	196.4	195.6	203.3	212.6	222.4	233.6	245.3	243.3	241.2	238.9	231.0	212.3
Residential	%	46.8%	47.1%	47.0%	47.3%	47.3%	47.3%	47.2%	46.9%	46.7%	47.9%	49.1%	50.3%	55.8%	62.1%
Commercial	%	17.2%	16.8%	17.3%	17.5%	17.5%	17.5%	17.6%	17.6%	17.7%	17.3%	16.9%	16.5%	14.7%	12.6%
Industrial	%	36.0%	36.1%	35.7%	35.2%	35.2%	35.2%	35.3%	35.4%	35.6%	34.8%	34.0%	33.2%	29.5%	25.3%
New loads from Self Generation	GWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	64.3	308.0	367.3
Losses converted into sales	GWh	0.0	0.0	0.0	0.0	1.2	3.3	3.4	4.9	6.5	7.9	9.4	11.0	19.6	29.3
Sales from Essequibo region	GWh	-25.9	-39.5	-41.6	-41.7	-43.4	-45.3	-47.3	-49.5	-51.7	-52.5	-53.3	-54.0	-58.7	-63.0
Total Sales DBIS	**GWh**	**467.6**	**479.4**	**509.3**	**513.6**	**535.9**	**561.7**	**586.4**	**614.6**	**644.1**	**654.8**	**665.7**	**741.1**	**1051.3**	**1173.3**
Rate of Growth	%	3.7%	2.5%	6.2%	0.9%	4.3%	4.8%	4.4%	4.8%	4.8%	1.7%	1.7%	11.3%	2.2%	2.2%
Residential	GWh	231.2	244.2	259.0	262.4	253.7	265.5	276.6	288.7	301.1	313.8	326.9	340.4	413.6	497.3
Commercial	GWh	84.8	87.3	95.5	97.3	94.1	99.5	104.0	109.9	116.1	115.9	115.7	115.4	116.1	112.4
Industrial	GWh	177.5	187.5	196.4	195.6	188.0	196.7	205.7	216.0	226.9	225.0	223.1	285.3	521.7	563.6
Residential	%	46.8%	47.1%	47.0%	47.3%	47.3%	47.3%	47.2%	47.0%	46.8%	47.9%	49.1%	45.9%	39.3%	42.4%
Commercial	%	17.2%	16.8%	17.3%	17.5%	17.6%	17.7%	17.7%	17.9%	18.0%	17.7%	17.4%	15.6%	11.0%	9.6%
Industrial	%	36.0%	36.1%	35.7%	35.2%	35.1%	35.0%	35.1%	35.1%	35.2%	34.4%	33.5%	38.5%	49.6%	48.0%
Total Losses	**%**	**29.6%**	**29.2%**	**29.2%**	**29.6%**	**28.7%**	**28.1%**	**28.1%**	**27.3%**	**26.6%**	**25.9%**	**25.1%**	**24.4%**	**20.8%**	**17.1%**
Technical Losses	%	14.0%	14.9%	14.5%	14.5%	14.1%	14.1%	14.1%	13.7%	13.4%	13.0%	12.7%	12.4%	10.7%	9.0%
NonTechnical Losses	%	15.6%	14.3%	14.7%	15.1%	14.7%	14.0%	14.0%	13.6%	13.2%	12.8%	12.4%	12.0%	10.1%	8.1%
Net Exported Units	**GWh**	**663.9**	**676.7**	**719.1**	**729.9**	**752.1**	**780.8**	**815.1**	**845.8**	**877.4**	**883.3**	**889.2**	**980.4**	**1326.6**	**1415.3**
Rate of Growth	%	1.7%	1.9%	6.3%	1.5%	3.0%	3.8%	4.4%	3.8%	3.7%	0.7%	0.7%	10.3%	1.3%	1.3%
Auxiliaries & Self-Consumption	GWh	20.8	20.0	21.8	21.1	21.4	21.2	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3
Gross Generation	**GWh**	**684.7**	**696.7**	**740.9**	**750.9**	**773.5**	**802.0**	**836.4**	**867.0**	**898.8**	**904.6**	**910.5**	**1001.7**	**1347.9**	**1436.6**
Rate of Growth	%	1.5%	1.8%	6.3%	1.3%	3.0%	3.7%	4.3%	3.7%	3.7%	0.6%	0.7%	10.0%	1.3%	1.3%
Unserved Energy	GWh	13.9	10.6	11.2	11.3	10.8	11.2	11.6	12.1	12.5	12.6	12.7	13.9	18.7	20.0
Unserved Energy	%	1.9%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%
Electricity Demand before Linden	**GWh**	**698.6**	**707.4**	**752.1**	**762.2**	**784.3**	**813.2**	**848.0**	**879.1**	**911.3**	**917.2**	**923.2**	**1015.6**	**1366.7**	**1456.6**
Linden Interconnection	GWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	168.9	172.2	188.2	202.8
DBIS Electricity Demand	**GWh**	**698.6**	**707.4**	**752.1**	**762.2**	**784.3**	**813.2**	**848.0**	**879.1**	**911.3**	**917.2**	**1092.1**	**1187.8**	**1554.9**	**1659.4**
Rate of Growth	%	1.0%	1.3%	6.3%	1.3%	2.9%	3.7%	4.3%	3.7%	3.7%	0.6%	19.1%	8.8%	1.3%	1.3%
EE measures	GWh					12.8	17.6	22.9	31.5	39.8	48.5	61.8	74.9	137.2	203.7
DBIS Electricity Demand after EE	**GWh**	**698.6**	**707.4**	**752.1**	**762.2**	**771.5**	**795.6**	**825.1**	**847.6**	**871.5**	**868.6**	**1030.4**	**1112.9**	**1417.7**	**1455.7**
Electric Vehicles						0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DBIS Electricity Demand	**GWh**	**698.6**	**707.4**	**752.1**	**762.2**	**771.5**	**795.6**	**825.1**	**847.6**	**871.5**	**868.6**	**1030.4**	**1112.9**	**1417.7**	**1455.7**
Rate of Growth	%	1.0%	1.3%	6.3%	1.3%	1.2%	3.1%	3.7%	2.7%	2.8%	-0.3%	18.6%	8.0%	0.6%	0.5%
Load Factor			0.732	0.740	0.755	0.755	0.755	0.755	0.755	0.755	0.755	0.755	0.755	0.755	0.755
Maximum Demand	**MW**		**110.3**	**116.1**	**115.3**	**116.7**	**120.3**	**124.8**	**128.2**	**131.8**	**131.4**	**155.9**	**168.4**	**214.5**	**220.2**

Source: Consultant

Table 26. Base case delayed DBIS demand forecast with Linden

Base Case Delayed	Metric	2014A	2015A	2016A	2017A	2018F	2019F	2020F	2021F	2022F	2023F	2024F	2025F	2030F	2035F
Electricity Sales	**GWh**	**493.6**	**518.9**	**550.9**	**555.3**	**581.4**	**607.1**	**633.7**	**662.8**	**693.1**	**814.0**	**906.7**	**1008.6**	**1357.1**	**1451.3**
Rate of Growth	%	*3.7%*	*5.1%*	*6.2%*	*0.8%*	*4.7%*	*4.4%*	*4.4%*	*4.6%*	*4.6%*	*17.4%*	*11.4%*	*11.2%*	*1.4%*	*1.3%*
Residential	GWh	231.2	244.2	259.0	262.4	273.7	285.3	297.2	309.5	322.1	335.0	348.4	362.1	436.5	521.8
Commercial	GWh	84.8	87.3	95.5	97.3	102.2	106.9	111.8	117.4	123.2	159.1	185.5	214.8	305.8	308.8
Industrial	GWh	177.5	187.5	196.4	195.6	205.5	214.9	224.7	236.0	247.8	319.8	372.8	431.8	614.8	620.7
Residential	%	46.8%	47.1%	47.0%	47.3%	47.1%	47.0%	46.9%	46.7%	46.5%	41.2%	38.4%	35.9%	32.2%	36.0%
Commercial	%	17.2%	16.8%	17.3%	17.5%	17.6%	17.6%	17.6%	17.7%	17.8%	19.5%	20.5%	21.3%	22.5%	21.3%
Industrial	%	36.0%	36.1%	35.7%	35.2%	35.3%	35.4%	35.5%	35.6%	35.7%	39.3%	41.1%	42.8%	45.3%	42.8%
New loads from Self Generation	GWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	64.3	308.0	367.3
Losses converted into sales	GWh	0.0	0.0	0.0	0.0	1.2	3.3	3.4	4.9	6.5	9.2	12.1	15.4	34.1	50.7
Sales from Essequibo region	GWh	-25.9	-39.5	-41.6	-41.7	-43.6	-45.6	-47.6	-49.8	-52.0	-61.1	-68.1	-75.7	-101.9	-108.9
Total Sales DBIS	**GWh**	**467.6**	**479.4**	**509.3**	**513.6**	**538.9**	**564.8**	**589.6**	**618.0**	**647.5**	**762.1**	**850.7**	**1012.7**	**1597.3**	**1760.3**
Rate of Growth	%	3.7%	2.5%	6.2%	0.9%	4.9%	4.8%	4.4%	4.8%	4.8%	17.7%	11.6%	19.0%	2.0%	2.0%
Residential	GWh	231.2	244.2	259.0	262.4	253.8	265.5	276.6	288.7	301.1	314.5	328.2	342.6	420.8	508.0
Commercial	GWh	84.8	87.3	95.5	97.3	95.1	100.5	105.1	111.0	117.2	151.8	177.6	206.4	299.9	311.0
Industrial	GWh	177.5	187.5	196.4	195.6	190.1	198.7	207.8	218.3	229.2	295.8	344.9	463.7	876.7	941.4
Residential	%	46.8%	47.1%	47.0%	47.3%	47.1%	47.0%	46.9%	46.7%	46.5%	41.3%	38.6%	33.8%	26.3%	28.9%
Commercial	%	17.2%	16.8%	17.3%	17.5%	17.7%	17.8%	17.8%	18.0%	18.1%	19.9%	20.9%	20.4%	18.8%	17.7%
Industrial	%	36.0%	36.1%	35.7%	35.2%	35.3%	35.2%	35.3%	35.3%	35.4%	38.8%	40.5%	45.8%	54.9%	53.5%
Total Losses	**%**	**29.6%**	**29.2%**	**29.2%**	**29.6%**	**28.7%**	**28.1%**	**28.1%**	**27.3%**	**26.6%**	**25.9%**	**25.1%**	**24.4%**	**20.8%**	**17.1%**
Technical Losses	%	14.0%	14.9%	14.5%	14.5%	14.1%	14.1%	14.1%	13.7%	13.4%	13.0%	12.7%	12.4%	10.7%	9.0%
NonTechnical Losses	%	15.6%	14.3%	14.7%	15.1%	14.7%	14.0%	14.0%	13.6%	13.2%	12.8%	12.4%	12.0%	10.1%	8.1%
Net Exported Units	**GWh**	**663.9**	**676.7**	**719.1**	**729.9**	**756.3**	**785.1**	**819.5**	**850.4**	**882.2**	**1028.0**	**1136.3**	**1339.6**	**2015.7**	**2123.5**
Rate of Growth	%	1.7%	1.9%	6.3%	1.5%	3.6%	3.8%	4.4%	3.8%	3.7%	16.5%	10.5%	17.9%	1.0%	1.1%
Auxiliaries & Self-Consumption	GWh	20.8	20.0	21.8	21.1	21.4	21.2	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3
Gross Generation	**GWh**	**684.7**	**696.7**	**740.9**	**750.9**	**777.8**	**806.3**	**840.9**	**871.7**	**903.5**	**1049.3**	**1157.6**	**1361.0**	**2037.0**	**2144.8**
Rate of Growth	%	1.5%	1.8%	6.3%	1.3%	3.6%	3.7%	4.3%	3.7%	3.7%	16.1%	10.3%	17.6%	1.0%	1.1%
Unserved Energy	GWh	13.9	10.6	11.2	11.3	10.5	10.9	11.4	11.8	12.3	14.3	15.8	18.6	28.0	29.5
Unserved Energy	%	1.9%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%
Electricity Demand before Linden	**GWh**	**698.6**	**707.4**	**752.1**	**762.2**	**788.3**	**817.2**	**852.3**	**883.5**	**915.8**	**1063.6**	**1173.4**	**1379.6**	**2065.0**	**2174.3**
Linden Interconnection	GWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	168.9	172.2	188.2	202.8
DBIS Electricity Demand	**GWh**	**698.6**	**707.4**	**752.1**	**762.2**	**788.3**	**817.2**	**852.3**	**883.5**	**915.8**	**1063.6**	**1342.4**	**1551.8**	**2253.2**	**2377.1**
Rate of Growth	%	1.0%	1.3%	6.3%	1.3%	3.4%	3.7%	4.3%	3.7%	3.7%	16.1%	26.2%	15.6%	1.1%	1.1%
EE measures	GWh					12.8	17.6	22.9	31.5	39.8	48.5	61.8	74.9	137.2	203.7
DBIS Electricity Demand after EE	**GWh**	**698.6**	**707.4**	**752.1**	**762.2**	**775.5**	**799.6**	**829.4**	**852.0**	**876.0**	**1015.1**	**1280.6**	**1476.8**	**2116.0**	**2173.4**
Electric Vehicles						0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.6	6.0	10.8
DBIS Electricity Demand	**GWh**	**698.6**	**707.4**	**752.1**	**762.2**	**775.5**	**799.6**	**829.4**	**852.0**	**876.0**	**1015.1**	**1281.4**	**1478.4**	**2122.0**	**2184.2**
Rate of Growth	%	1.0%	1.3%	6.3%	1.3%	1.8%	3.1%	3.7%	2.7%	2.8%	15.9%	26.2%	15.3%	0.5%	0.5%
Load Factor		0.000	0.732	0.740	0.755	0.755	0.755	0.755	0.755	0.755	0.755	0.755	0.755	0.755	0.755
Maximum Demand	**MW**	**0.0**	**110.3**	**116.1**	**115.3**	**117.3**	**121.0**	**125.5**	**128.9**	**132.5**	**153.6**	**193.8**	**223.7**	**321.0**	**330.4**

Source: Consultant

5 FUEL PRICES FORECASTS

5.1 International fossil fuel prices

In Guyana, electricity costs have been driven significantly by prices of Heavy Fuel Oil (HFO) and Light Fuel Oil (LFO) used for power generation, representing high volatility in recent years and implying high tariffs for final users and significant levels of CO2 emissions. Future DBIS power generation expansion has options to reduce the costs of future electricity supply and the CO2 emissions. Those options are based on hydro and several non-conventional energy renewable sources (mainly Wind, Biomass and Solar), or using cheaper indigenous Natural Gas, that could reduce the future use of liquid fuels for power generation, It is expected that indigenous Natural Gas produced from the offshore Oil and Gas developments now under execution in Stabroek Block (120 miles offshore Guyana) will be available through pipeline after 2022, permitting to reduce power generation costs and tariffs for final users. This fuel would be used as a transitional cleaner fuel toward the fulfilment of the environmental policy adopted in the country to reach a goal of zero CO2 emissions from the power generation in the long term. Coal, a traditional cheap fuel available in the international market is not considered today as a potential fuel that could be used in Guyana for power generation given its high CO2 emission level.

The analysis of DBIS optimal generation expansion required the application of fuel prices forecasts for all fuels that could be used for power generation in Guyana and these are related to the international fuel prices. Table 27 presents the scenarios foreseen by the U.S. Energy Information Administration (EIA) in February 2018 for the future oil prices. They were used in this study to estimate fuel prices for power generation in Guyana.

Table 27. Oil prices' forecast

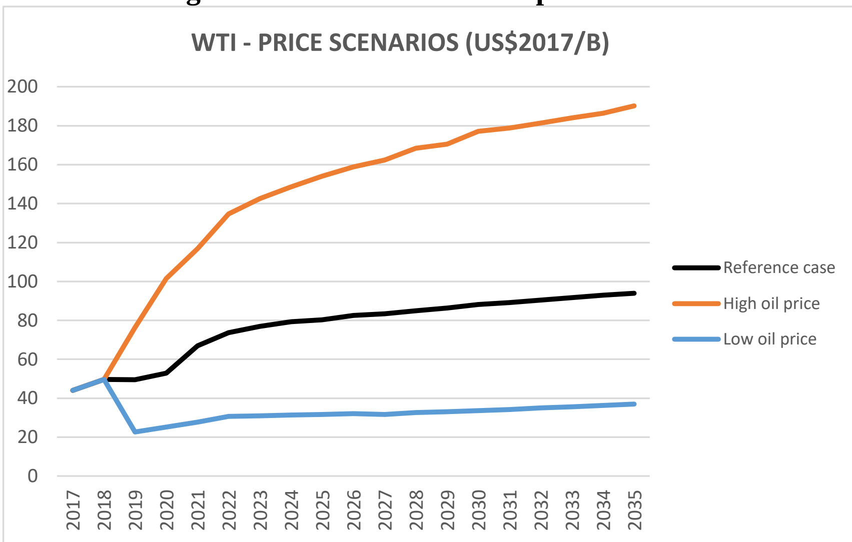
SCENARIOS	2017	2018	2019	2020	2025	2030	2035
WTI (USD/B)							
Reference case	44.1	49.7	49.5	52.8	80.3	88.1	94.0
High oil price	44.1	49.7	76.3	101.5	154.1	177.1	190.2
Low oil price	44.1	49.7	22.6	25.2	31.6	33.6	37.0
High O&G res. and tech.	44.1	49.7	47.8	50.6	68.1	73.5	79.3
Low O&G res. and tech.	44.1	49.7	49.8	54.7	88.2	96.9	105.6

Source: EIA, February 2018 (at 2017 price level)

For the update of the generation expansion program the following three fuel prices scenarios were selected among the scenarios published in 2018 by the EIA: 1) Reference Case[38], 2) Low Case (consisting in the Low oil price), 3) High Case (consisting in the High oil price). Figure 13 illustrates the selected international oil price scenarios.

[38] The "Reference Case" of fuel prices corresponds to the EIA's Reference Case for fuel prices. We leave "Reference Case" for fuel prices to maintain coherence with EIA's case convention. On the other hand, the "Base Scenario" for the expansion analysis, was built using the "Reference Case" of fuel prices, the "Base Case" of demand growth and a 10% for discount rate.

Figure 13. International WTI price forecast



Source: Consultant

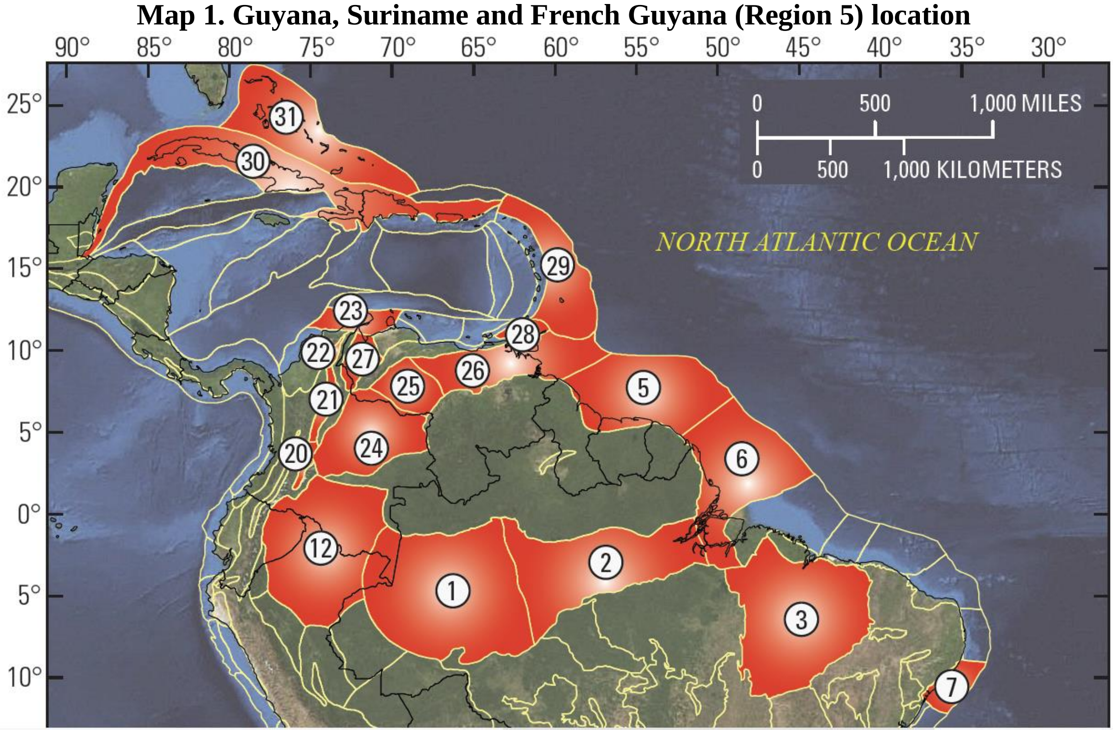
5.2 Fuels prices forecasts for Guyana

5.2.1 Liquid fuels and natural gas

5.2.1.1 Oil and Natural Gas resources

Guyana's oil reserves were obtained from US Department of Energy 2012 survey. They are located in the so-called Region 5 covering Guyana, Suriname and French Guyana, as presented in Map 1.

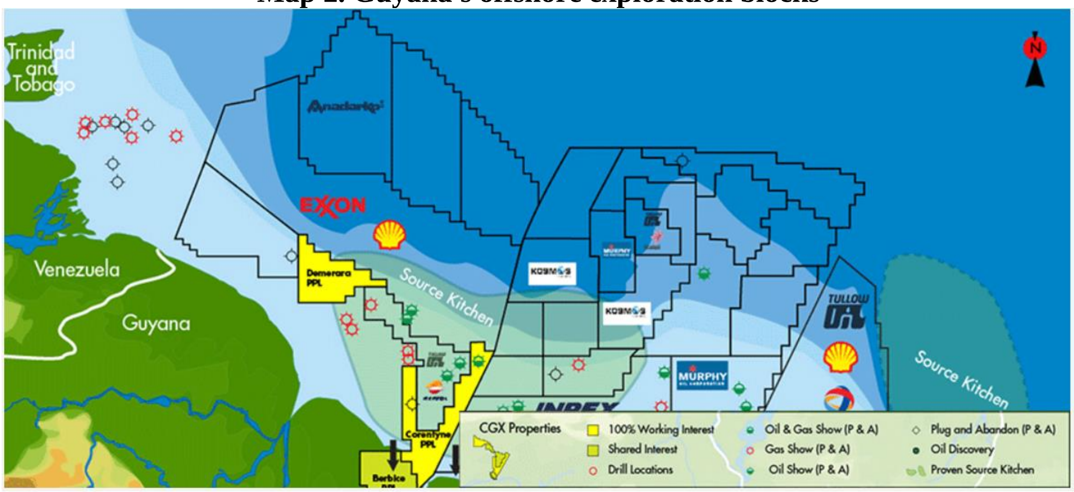
Map 1. Guyana, Suriname and French Guyana (Region 5) location



SOURCE: U.S. Geological Survey World Energy Assessment Team, 2000. Internet address: http://pubs.usgs.gov/dds/dds-060/

Such survey states that all Region 5 have reserves (mean estimates) of about 13,608 million of undiscovered oil barrels and 32,032 billion of undiscovered cubic feet of gas. The survey estimated that Guyana undiscovered mean reserves of oil are 2,205 million barrels of oil and 6,021 billion of cubic feet of natural gas, most of them offshore.

Map 2. Guyana's offshore exploration blocks



Source: GOI

In addition, the Guyana Office for Investment (GOI) in its website (as of March 2018) states that oil and gas deposits in Guyana's offshore reserves are estimated at 2.2 billion barrels and 6 trillion cubic feet respectively. GOI explains that these deposits occur in the Guyana Basin which covers the entire coastal region and extends 150 km out into the Atlantic Ocean. According to Guyana Geology and Mines Commission (GGMC)[39], Guyana is divided into two Petroleum Basins named Guyana and Takutu, respectively. The Guyana Basin is further divided into two basins, Onshore and Offshore. The following paragraphs describe the Basins and the historical exploration activity.

- **Onshore Guyana Basin.** The deepest part of the southern "boundary" is about 150 miles from the Guyanese Coastline. NABI Oil And Gas, Inc. and ON Energy Inc. companies have concessions within this part of the Basin. Within the Onshore Guyana Basin, there was a chance of these blocks being subjected to competitive bidding, however this does not take away any one's prerogative to apply for concessions within this area. There were 13 wells drilled within this part of the Basin from 1916 to present day. Only Rose Hall-1 drilled in 1941 and Drill-1 in 1967 had oil shows. The eastern part of the Onshore Guyana Basin has the largest thickness of sediments reaching some 2,500 m. It should also be noted that the gas found on the coast is nearly all biogenic, with a very small area yielding thermogenic gas.
- **Offshore Guyana Basin.** Repsol, Anadarko, Esso/Hess/Nexen, Mid-Atlantic Oil and Gas, Inc., Ratio Energy/Guyana Ltd and CGX Resources Inc. have petroleum concessions in this part of the basin. Presently, a number of companies are negotiating for concessions in the offshore Guyana Area. One of the aspects of the Offshore Guyana Basin, is that from the near shore to around 80 miles to the north, the seabed is generally on the continental shelf, then it moves to the slope and as one gets further it reaches the deep-water area. From the northwest (where the Anadarko concession is) to the North-eastern area depths can be from 1,000 feet to more than 10,000 feet. This area is known as the "ultra-deep waters". In May 2015, ExxonMobil made a significant discovery of petroleum while drilling in Stabroek Block (120 miles offshore Guyana) which have provided important reserves that

[39] http://www.ggmc.gov.gy/main/?q=divisions/petroleum (last accessed in March 20, 2018).

today are in development stage with the primary objective to produce oil directly for the international markets.

- **Takutu Basin.** Located in the southwestern area of Guyana lies the Karanambo-1 well, this was drilled in 1982 by Home Oil Company. This was the best prospect drilled within this Basin. A small amount of light crude was accrued. Tests conducted on samples from Karanambo-1 found that the oil is of good quality (420API) and is of a "sweet" variety, that is, it contains less than 0.5% hydrogen sulphide. However, its geological characteristics are mainly naturally fractured reservoirs, thus proving more difficult to find commercial petroleum than regular reservoirs. The other wells drilled in the Takutu are Lethem-1 (1980), Turantsink-1 (1992) and Apoteri K2 well (2011).

Table 28 compares undiscovered oil and gas reserves of Guyana with other countries in Latin America and the Caribbean using the data from the same survey (Mean Reserves estimated by 2012, part of which today are classified as discovered reserves, as in the case of Guyana).

Table 28. Assessment of undiscovered reserves in some Latin American & Caribbean countries

		Argentina	Brazil	Chile	Colombia	Ecuador	Guyana	Suriname	FrenchGuy	Peru	Trin.&Tob	Venezuela
Oil Onshore	MMBO	1,951	61	253	5,120	807	23	63	0	1,833	37	15,608
Oil Offshore	MMBO	1,267	46,685	84	0	163	2,182	12,966	12	1,483	721	4,056
Oil Total	**MMBO**	**3,218**	**46,746**	**337**	**5,120**	**970**	**2,205**	**13,029**	**12**	**3,316**	**758**	**19,664**
Gas Onshore	BCFG	21,821	200	4,804	10,101	331	65	176	0	1,901	1,116	60,255
Gas Offshore	BCFG	14,874	194,208	1,601	0	221	5,956	35,827	34	4,436	30,675	40,985
Gas Total	**BCFG**	**36,695**	**194,408**	**6,405**	**10,101**	**552**	**6,021**	**36,003**	**34**	**6,337**	**31,791**	**101,240**
NGL Onshore	MMBNGL	430	6	107	491	11	3	8	0	83	50	3,057
NGL Offshore	MMBNGL	437	8,121	36	0	11	330	1,988	1	233	1,128	1,522
NGL Total	**MMBNGL**	**867**	**8,127**	**143**	**491**	**22**	**333**	**1,996**	**1**	**316**	**1,178**	**4,579**

SOURCE: U.S. Geological Survey World Energy Assessment Team, 2000 [MMBO, million barrels of oil; BCFG, billion cubic feet of gas; MMBNGL, million barrels of natural gas liquids. Countries' data in: http://pubs.usgs.gov/dds/dds-060/R6.html#TOP

By 2012, Guyana had similar levels of undiscovered natural gas reserves as Chile or Peru, and more undiscovered oil reserves than Chile and Ecuador together. As well, Guyana has close geographical proximity to important undiscovered oil and gas reserves in Venezuela, Suriname, and Trinidad and Tobago.

The UN International Tribunal ruling in September 2007, which is binding on both Guyana and Suriname, settled the maritime boundary dispute between the two countries paving the way for full exploitation of the hydrocarbon resources within Guyana's Exclusive Economic Zone and Continental Shelf. GOI states that there are four companies doing exploration work in Guyana Exxon Mobil, Repsol, Century Guyana Ltd. and CGX Energy Inc[40].

5.2.1.2 Guyana's petroleum products imports

In 2016, Guyana imported 5.55 million barrels of oil refined products such as gasoil/diesel, fuel oil, and unleaded mogas. Table 29 shows imported petroleum products.

[40] http://goinvest.gov.gy/sectors/energy/ (last accessed in March, 2018).

Table 29. Guyana's petroleum products imports

TOTAL IMPORTS OF PETROLEUM PRODUCTS FOR PERIOD 1994 TO 2016			
	VOLUME		CIF VALUE
	BBLS	LTRS	US$
1994	3,095,728	492,181,436	72,067,912
1995	3,624,053	576,178,402	85,161,130
1996	3,711,893	590,143,846	100,696,609
1997	4,093,677	650,842,653	107,727,233
1998	4,125,765	655,944,238	78,539,499
1999	4,137,266	657,772,751	99,704,391
2000	3,924,614	623,963,783	143,277,974
2001	3,834,651	609,660,809	123,373,521
2002	3,865,505	614,566,203	122,643,684
2003	3,980,199	632,801,092	153,193,966
2004	3,901,760	620,330,288	185,702,255
2005	3,546,069	563,779,936	240,663,147
2006	3,179,925	505,567,690	251,594,083
2007	3,910,234	621,677,546	319,122,554
2008	3,660,583	581,986,208	405,960,936
2009	3,924,723	623,981,072	282,909,993
2010	4,137,931	657,878,518	375,951,700
2011	4,341,345	690,218,765	534,982,446
2012	4,867,748	773,910,151	604,000,602
2013 (revised)	4,726,150	751,397,875	582,281,795
2014	4,938,855	785,215,261	561,633,697
2015	5,001,497	795,174,539	355,201,732
2016	5,547,048	881,279,689	333,248,345
TOTAL	**94,077,221**	**14,956,452,750**	**6,119,639,204**

Source: GEA, Annual Report 2016.

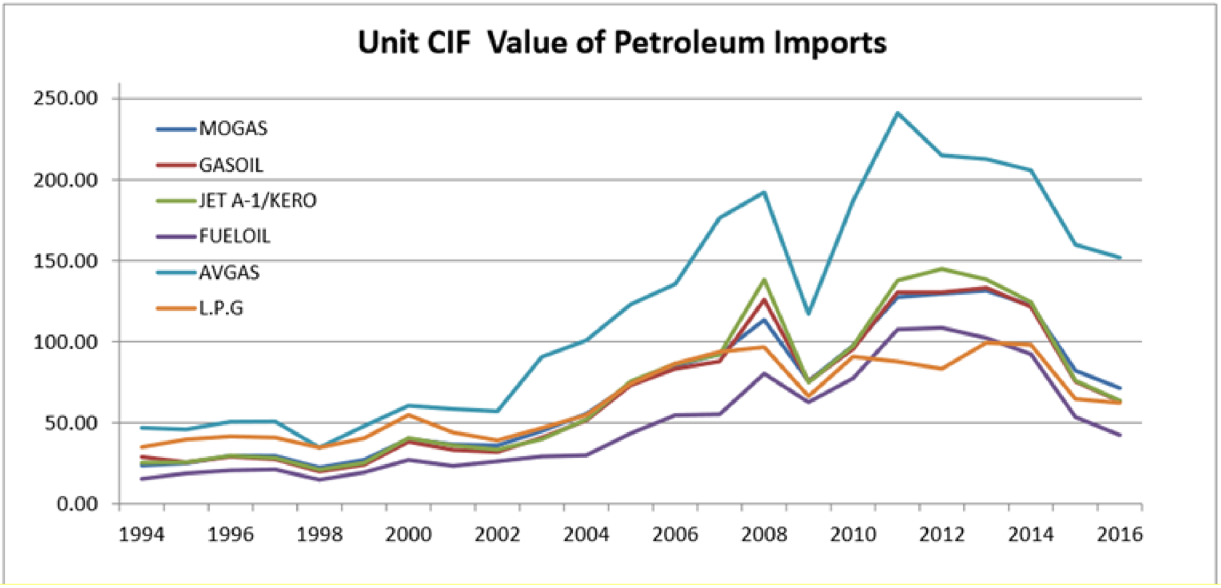
Table 30. Guyana's petroleum products imports in 2016

TOTAL IMPORTS BY PRODUCTS FOR THE YEAR 2016			
PRODUCTS	VOLUME		C.I.F VALUE
	LTRS	BBLS	US$
MOGAS: UNLEADED	206,345,483	1,297,874	92,769,769
GASOIL (0.5S)/DIESEL	380,120,687	2,390,887	151,501,925
KERO	13,815,996	86,900	5,468,739
AVJET	25,020,301	157,373	10,104,870
FUELOIL	223,741,237	1,407,290	59,717,413
AVGAS	31,440,375	8,970	1,362,612
L.P.G	1,426,154	197,754	12,323,018
TOTAL	**881,910,233**	**5,547,048**	**333,248,345**

Source: GEA

Prices have varied according to international oil price variation as shown in Table 31.

Table 31. Guyana: Import prices of petroleum products



Source: GEA. Annual Report 2016

5.2.1.3 GPL historical purchases of liquid fuels

Table 32 shows GPL's fuel volumes and prices of liquid fuels purchases and their high correlation to the international WTI price. It also shows how the participation of HFO has incremented to 94% in 2015 given the commissioning of new power plants using HFO as the most economical fuel for power generation.

Table 32. GPL's fuel purchases data and weighted average prices of HFO & LFO

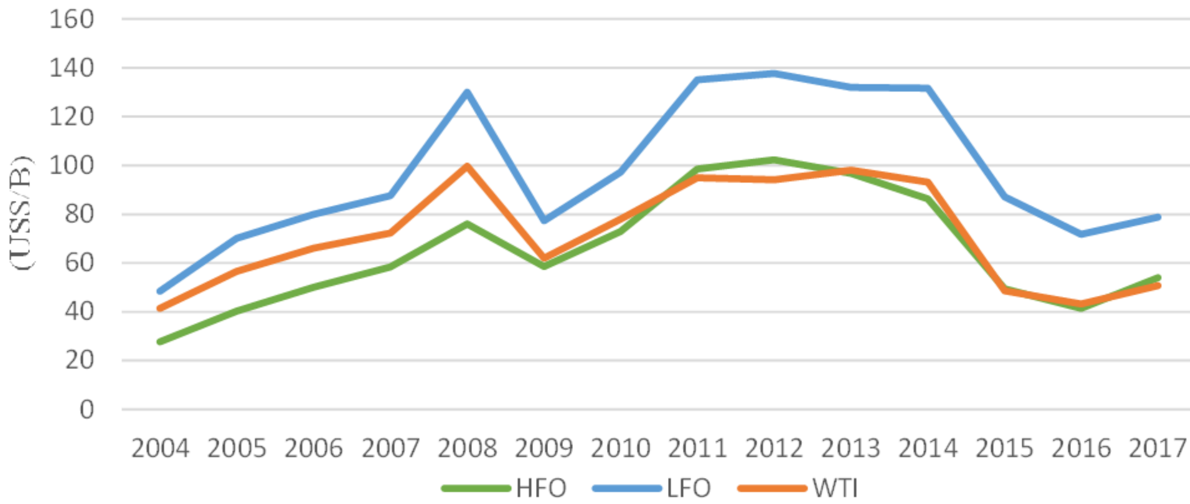
YEAR	Volume - Barrels			Fuel Mix %		Annual Cost - US$000		
	HFO	LFO	TOTAL	HFO	LFO	HFO	LFO	TOTAL
2004	546,449	336,833	883,282	62	38	15,166	16,336	31,502
2005	499,274	370,302	869,576	57	43	20,124	25,951	46,075
2006	462,177	407,296	869,473	53	47	23,170	32,557	55,727
2007	471,955	428,983	900,938	52	48	27,561	37,563	65,124
2008	581,375	305,805	887,180	66	34	44,212	39,763	83,975
2009	607,584	301,057	908,641	67	33	35,552	23,276	58,828
2010	761,245	189,587	950,832	80	20	55,502	18,429	73,931
2011	716,978	252,663	969,641	74	26	70,576	34,116	104,692
2012	838,420	174,188	1,012,608	83	17	85,693	23,991	109,684
2013	908,538	115,298	1,023,836	89	11	87,865	15,221	103,086
2014	903,557	135,914	1,039,470	87	13	79,287	18,117	97,405
2015	970,830	59,457	1,030,287	94	6	48,017	5,295	53,312
2016	963,525	102,828	1,066,353	90	10	44,472	7,412	51,884
2017	980,962	110,822	1,091,785	90	10	58,012	8,920	66,932

WEIGHTED AVERAGE PRICES (US$/B)			
YEAR	Crude Oil	HFO	LFO
2004	34.70	27.75	48.50
2005	50.13	40.31	70.08
2006	61.47	50.13	79.93
2007	69.47	58.40	87.56
2008	95.41	76.05	130.03
2009	60.52	58.51	77.31
2010	78.01	72.91	97.21
2011	94.87	98.44	135.03
2012	94.11	102.21	137.73
2013	97.98	96.71	132.01
2014	93.17	86.26	131.60
2015	48.66	49.46	87.10
2016	43.29	41.51	71.83
2017	50.80	54.00	78.74

Source: GPL

Figure 14 illustrates the evolution of WTI, HFO and LFO prices during 2004-2017.

Figure 14. HFO, LFO & WTI historical prices



Source: Consultant (processed with GPL historical data)

Currently power generation relies mainly on imported liquid fuels (HFO and LFO) purchased from Suriname and Trinidad & Tobago and in the future significant hydrocarbon indigenous offshore reserves would be developed in the Stabroek Block to produce indigenous Oil and Natural Gas.

5.2.1.4 HFO and LFO price forecasts in Guyana

Guyana is developing its offshore Oil resources to be traded directly to the international markets from Floating Production Storage and Offloading (FPSO) vessels anchored near the oil fields (located around 190 km offshore). Until today, available studies indicate that the installation of onshore refinery facilities to refine oil products would not be economically competitive in the case of Guyana. This would imply that the economic value of HFO and LFO required for power generation would remain linked to its international prices as it has been in the past. According to this criteria, Reference, High and Low price scenarios for HFO and LFO dedicated to power generation have been forecasted using WTI price as price index and applying a regression obtained from the historical statistics of WTI, HFO and LFO annual average prices for power generation in Guyana during 2009-2017, which was considered by the consultant as the most representative historical period to reflect to the future the price relationships of the HFO and LFO with WTI (i.e. before 2009 the historical data shows a significant difference between HFO and WTI prices that has not been observed during 2009-2017 and the LFO price margin increased significantly).

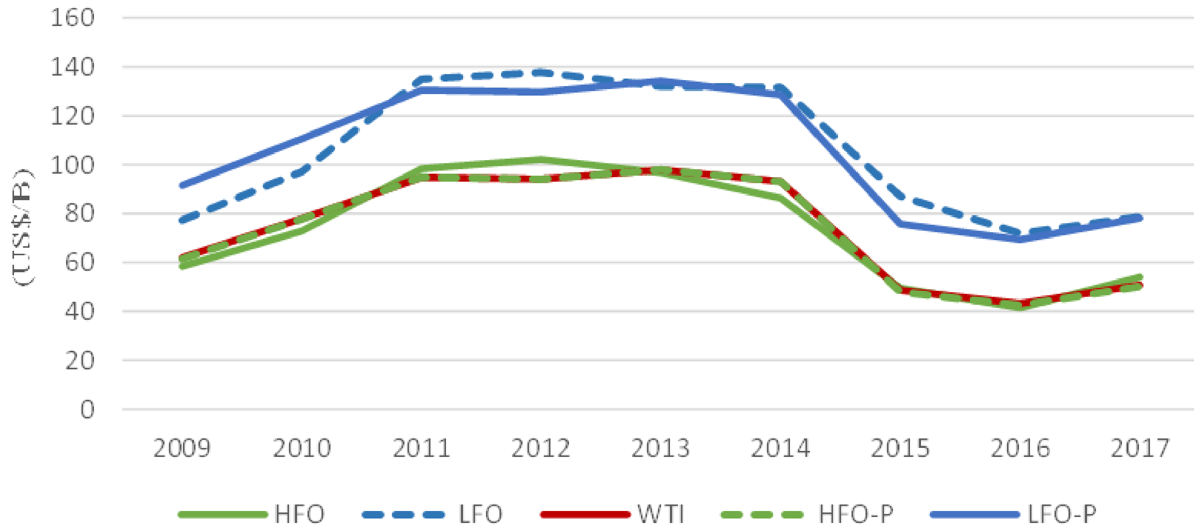
Through this analysis, the following price relationships were obtained and applied for the construction of the fuel price scenarios.

HFO price (Guyana) = -1.318 + 1.0136 x WTI price

LFO price (Guyana) = 17.948 + 1.1873 x WTI price

Figure 15 illustrates the application of these price relationships during 2009 – 2017.

Figure 15. HFO & LFO prices as a function of WTI price



Source: Consultant

5.2.2 Natural gas price forecast for Guyana

5.2.2.1 Option to import LNG

In 2014 opportunities were preliminary considered to substitute HFO and LFO for Natural Gas in Guyana through LNG imports aiming at a reduction in the electricity costs. A version of the 'Natural Gas in the Caribbean-Feasibility Studies' (the Natural Gas Study)[41] was submitted by Castalia Strategic Advisors to IADB on October 2014. This study assumed prices forecasts for natural gas and oil from August 2014, and the results obtained indicated potential natural gas economic attractiveness for Guyana. Subsequently, the price of oil dropped significantly. Over the same period, natural gas prices have also fallen, but not by as much as oil. With this new oil price scenario Castalia Strategic Advisors updated the study and the new scenarios suggest that if the price of oil remains below US$55/Barrel for the next 10 years, it will not be feasible for countries of the Caribbean to switch from HFO to imported natural gas.

5.2.2.2 Indigenous Natural Gas availability

As many other Caribbean countries, Guyana has been relying on oil products at volatile prices to generate electricity and meet other energy needs. In the future replacing oil products with indigenous natural gas in Guyana, and installing new power plants operated with natural gas, could be an option to reduce electricity prices. As mentioned previously, future offshore Oil production in Guyana is being developed in the Stabroek block located offshore Guyana. It will be accompanied by Natural Gas production which will be separated and partially re-injected in order to optimize Oil production. Also, part of this Natural Gas production would be available around 2023 to be transported via pipelines (of around 190 km offshore length) to inland Guyana to support power generation and other uses[42].

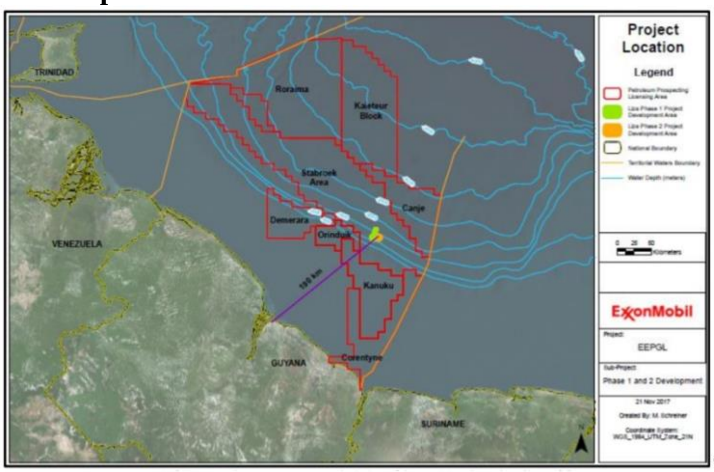
[41] "Natural Gas in the Caribbean—Feasibility Studies. Castalia". IADB. 2014 and 2015 update.

[42] Other maritime gas transportation systems, as CNG (compressed natural gas) or LNG (liquified natural gas) would represent higher transportation costs, as concluded in available studies (see for example: "Desk Study of the Options, Cost, Economics, Impacts, and Key Considerations of Transporting and Utilizing Natural Gas from Offshore Guyana for the Generation of Electricity", GoG, Energy Narrative, June 2017).

Esso Exploration and Production Guyana Limited (EEPGL) is the designated Operator under a Petroleum Agreement signed by EEPGL, Hess Guyana Exploration Limited (Hess) and CNOOC Nexen Petroleum Guyana (Nexen) with the Government of the Cooperative Republic of Guyana. The Petroleum Agreement covers approximately 26,806 km2 (10,350 square miles) and was executed together with a Petroleum Prospecting License for the Stabroek block. In 2014, Hess (30%) and Nexen (25%) acquired a commercial interest to the block. In May 2015, EEPGL announced a significant discovery of high-quality oil-bearing sands with the Liza-1 well (approximately 190 km [120 miles] offshore Guyana). In July 2017, EEPGL announced gross recoverable resources for the Stabroek block were estimated at 2.25-2.75 billion oil-equivalent barrels, which included Liza and other successful exploration wells associated with the Liza Deep, Payara, and Snoek discoveries. More recently, EEPGL is considering initiating the second phase of the Stabroek Block Liza discovery, the Liza Phase 2 Development, which would serve as the second oil and gas development project in Guyana.

Map 3 illustrates the location and main characteristics of the Liza Phase 1 and Liza Phase 2 Developments within the territorial waters of Guyana, approximately 190 km (120 miles) northeast of Georgetown, Guyana in the Stabroek Block.

Map 3. Location and main characteristics of the Liza 1 and Liza 2 Project Developments



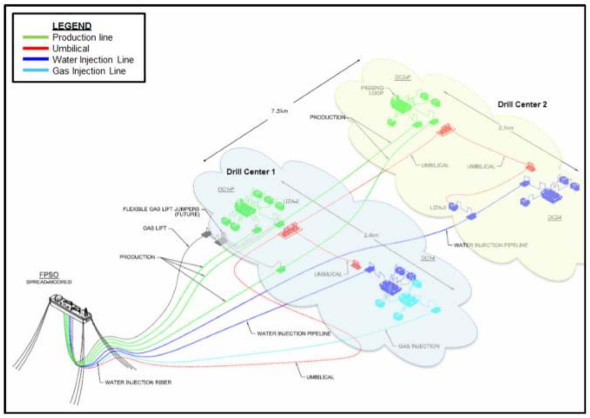
Major Component	Phase 2 Development	Phase 1 Development
Surface Production Facility Design Concept	A single Floating Production, Storage, and Offloading (FPSO) vessel is used for each development	
Distance from Shore	Each FPSO is approx 190km from Georgetown	
FPSO Mooring System	Each FPSO uses a spread mooring system with mooring lines connected to anchor piles embedded in seafloor	
Oil Production Capacity (barrels per day)	Approx 190,000 to 220,000	100,000, capable of sustained peaks up to 120,000
FPSO Oil Storage Capacity	Approx 1.6 to 2 million barrels, depending on selected hull	1.6 million barrels
Offloading Frequency by Export Tankers	Every 4-6 days	Every 5-10 days
Subsea Production Facility Design Concept	Each development uses subsea production trees, and gas/water injection trees clustered around subsea manifolds	
Wells	Approx 35-40 wells	17 wells
Drill Ships	Each development may use up to two dynamically-positioned drill ships	
Onshore Support including Shorebase	Onshore infrastructure includes shorebase, pipe yards, fabrication facilities, fuel supply facilities, and waste management facilities; potential sharing between developments	
Logistics Support	Marine vessels and helicopters throughout all stages; potential sharing between developments	

Source: Esso (2017)

5.2.2.3 Liza 1 & 2 Development Projects

Liza Phase 1 Development is currently in execution and includes 17 subsea development wells and a Floating Production Storage and Offloading (FPSO) vessel to process, store, and offload the recovered oil. The FPSO will be connected to the wells via associated equipment, collectively referred to as subsea umbilicals, risers, and flowlines (SURF), to transmit produced fluids (i.e., oil, gas, produced water) from production wells to the FPSO, as well as treated gas and water from the FPSO to the injection wells.

Map 4. Preliminary Liza Phase 1 Field Layout

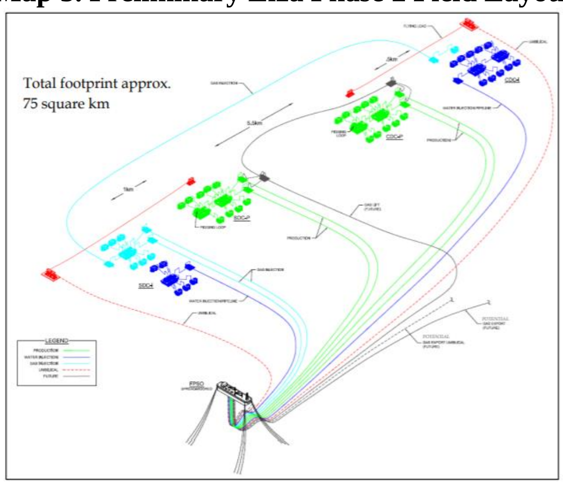


Source: Esso (2017)

5.2.2.4 Liza Phase 2 Development Project

EEPGL is considering initiating the second phase of the Stabroek Block Liza discovery, the Liza Phase 2 Development, which would serve as the second oil and gas development project in Guyana. The development plan for the Liza Phase 2 Development will also use an FPSO and SURF production system similar to Liza Phase 1. Although the developments will be similar, they are independent development projects. The Liza Phase 2 Development will also be located in the eastern area of the Stabroek Block.

Map 5. Preliminary Liza Phase 2 Field Layout



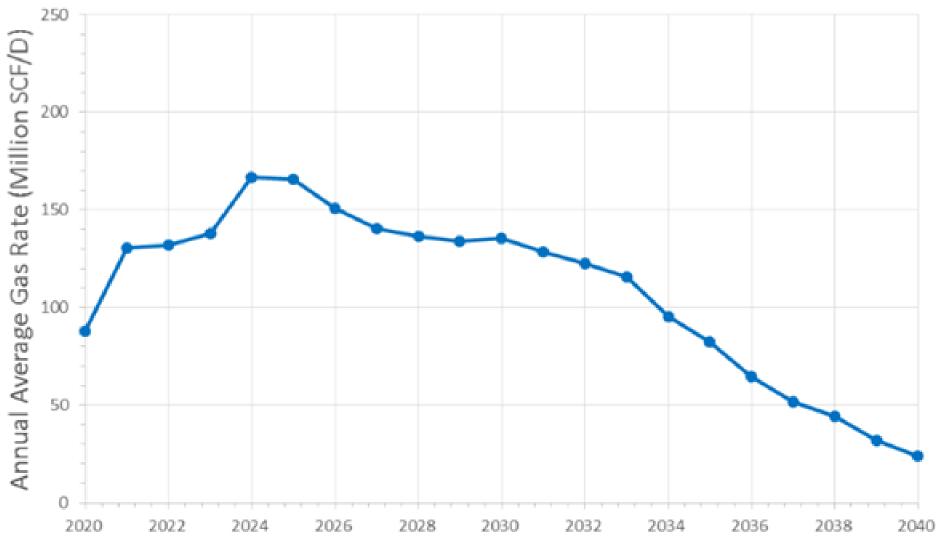
Source: Esso (2017)

5.2.2.5 Natural Gas Disposition

Natural gas will be produced in association with the produced oil. EEPGL will use some of the recovered gas as fuel on the FPSO, and proposes to re-inject the remaining gas back into the Liza reservoirs, which will assist in optimizing management of the reservoir. Three primary alternatives were considered for addressing associated gas produced in Liza fields: gas re-injection, continuous flaring and gas export. Gas re-injection was determined to be feasible and it provides benefits in reservoir management. As such, produced gas not used as fuel gas on the FPSO will be re-injected under normal operations. Continuous flaring of gas on a routine basis is not preferred, primarily due to the associated air emissions.

According to the available information, 0.1 Tcf of produced gas would be required as fuel for FPSO operations, at a rate of ~20 mmcfd, 0.5 Tcf of produced gas would re-injected for reservoir pressure maintenance requirements and 0.2 Tcf would be available for sales at ~30 mmcfd per day. In addition, it is being studied the evaluation of feasibility for up to 50 mmcfd for additional supply. Natural gas production profile with 30 mmcfd sales is illustrated in Figure 16.

Figure 16. Liza Phase 1 Total gas production profile with ~30 mmcfd sales



Source: GoG

Quantities and Quality. It is estimated that natural gas available inland Guyana for power generation from Liza fields would be in the range of 30 mmcfd at the lower bound (as broadly required for the DBIS generating system) and potentially as much as 145 mmcfd at the upper bound (if required for additional uses). EEPGL proposed these two volumes for the possible sizes for the natural gas pipeline to shore. It is estimated that this volume of natural gas would be available for power generation by January 1, 2023

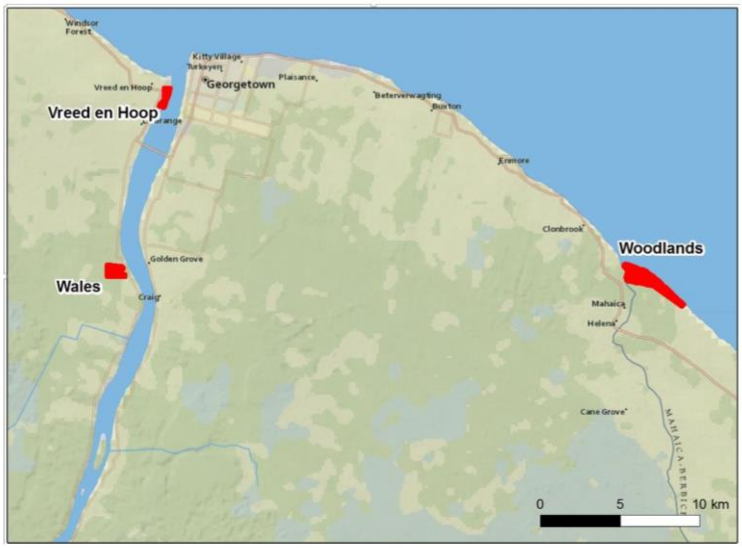
The assessment of the natural gas composition included in the Energy Narrative study shows that natural gas liquids (mainly propane and butane) account for 12.3% of the natural gas produced. Separating these liquids from the 30 mmcfd of natural gas supply would provide nearly 890,000 barrels per year of LPG, more than four times Guyana's current LPG consumption. This abundant supply could open new opportunities to promote LPG use for transportation, home cooking and water heating, or as a chemical feedstock for new industries. After removing the LPG, 26.3 mmcfd of dry gas would be available for electricity generation and other uses.

5.2.2.6 Natural Gas transportation

Offshore transportation technology: Analysis of alternative transportation media done for the gas supply shows that a natural gas pipeline is the preferred transportation technology from offshore to Guyana given the high capital costs and higher technical risk of floating LNG and seaborne CNG.

Landing site: Today it is considered Woodlands as the most promising landing site of the proposed pipeline, even though Georgetown (specifically near the Vreed-en-Hoop existing power plant) is an alternative option. Next map illustrates these two options. The assessments of the Woodlands, Vreed-en-Hoop and its associated Wales Estate industrial area indicates that both sites have constraints but the original screening assessment that Woodlands offers fewer overall constraints than Vreed-en-Hoop has been confirmed, including loss of its elevation advantage. According information provided by the GoG, additional technical analysis has assessed Vreed-en-Hoop to have ~$72M US incremental development cost versus Woodlands, due to the requirement to connect power and gas supplies to the Wales Estate in case to select this area for the installation of an industrial park in the future.

Map 6. Possible landing sites of natural gas pipeline



Source: Power Plant Location Assessment Update, ExxonMobil

Potential industrial gas supply for petrochemical industries. ExxonMobil has progressed feasibility studies for the potential commercialization of gas volumes in the event future discoveries identify suitable gas supplies above gas-to-power requirements. Methanol and urea (fertilizer) producing large-scale industrial facilities appear to be the more likely viable foundation industries for investors per facility, requiring large investments (around 1-2 US$ billion). However, pipeline-landing analysis has not been based on suitability for these industry's needs but focused of the supply for power generation and other local uses.

5.2.2.7 Offshore pipeline costs

For this study is has been available preliminary estimations of the investment cost of the offshore pipeline that could be applied to Woodlands (initially considered in Clonbrook) and Georgetown landing sites. The cost to install and 8-in pipeline (30 mmcfd) and a 12-in pipeline (145 mmcfd) was estimated for each proposed route by using industry practices[43].

Table 33 summarizes such investment cost estimates.

[43] This estimations are included in the Energy Narrative study using the following methodology: 1) the cross sectional area of the pipeline was calculated, 2) the weight of the pipeline in kg/m was calculated, 3) the cost of the pipeline in $/ m was calculated in 2013 prices, 4) the 2013 prices were adjusted to process today using a market index for steel, 5) the coating cost of 15% of the uncoated pipe was calculated, 6) the installed cost was calculated as 2.5 times the total pipe cost per m, and 7) the final cost for the pipeline segment was calculated.

Table 33. Estimated pipeline cost for offshore natural gas pipeline options

Landing	Length (km)	Installed Cost (8-in)	Installed Cost (12-in)
Georgetown	185	$170MM	$235MM
Clonbrook	180	$165MM	$230MM

Source: Energy Narrative

It is estimated that the compressor station cost will be $27.5MM for the 8-in pipeline and $37.5MM for the 12-in pipeline. In addition to compression, the natural gas liquids present in the wet gas that is transported in the pipeline can be separated and sold as LPG. Also a cost of US$15.75 million for a separator plant for 30 mmcfd and US$76.125 for a 145 mmcfd capacity separator are estimated.

Table 34. Estimated cost for natural gas compressors

Item	8-in Pipeline	12-in Pipeline
Compressor Station	$25.0MM	$25.0MM
Compression	$2.5MM	$12.5MM
Total Compressor Station Cost	$27.5MM	$37.5MM
Gas Separation Plant	$16MM	$76MM
Total Cost	**$43.5MM**	**$114MM**

Source: Energy Narrative

Table 35 shows the total estimated cost for the pipeline after adding in the cost of compression and liquids separation to the estimated cost for each variation in pipeline size and length.

Table 35. Estimated all-in cost for offshore natural gas pipeline options

Landing	Length (km)	Installed Cost (8-in)	Installed Cost (12-in)
Georgetown	185	$213.5MM	$349MM
Clonbrook	180	$208.5MM	$344MM
New Amsterdam	205	$233.5MM	$374MM

Source: Energy Narrative

Based on the above cost analysis, Energy Narrative estimated the transportation tariff for each potential route based on 30 mmcfd average volumes for the 8-in pipeline, and 145 mmcfd average volumes for the 12-in pipeline[44].

[44] . The analysis assumes that the cost of the natural gas separation plant is borne by the LPG stream separated for other uses, and so is not included in the estimated costs for natural gas transportation for power generation.

Table 36. Levelized natural gas transportation tariffs, offshore pipeline options

	Landing Point		
	Georgetown	Clonbrook	New Amsterdam
	8-in (30 MMcfd)		
Without Compression	2.72	2.64	3.05
With Compression	3.17	3.09	3.49
	12-in (145 MMcfd)		
Without Compression	0.78	0.76	0.86
With Compression	0.9	0.89	0.99

Source: Energy Narrative

5.2.2.8 Referential indigenous natural gas price in inland site

For the purposes of this study, it was estimated a Natural Gas referential price for power generation in Guyana at the landing site (Woodlands) for the indigenous natural gas. It was considered that it would be composed by a wellhead price plus a levelized offshore transportation tariff, including compression costs (and excluding the costs of the LPG separation) [45].

Wellhead price: it is understood that this price will be established through negotiations between the Government of Guyana and the oil Producer, and it is not known today. For the study the consultant applied a referential range of US$ 1.6-2.5/MBTU, similar as the applicable in other natural gas producing countries. For example: a) in 2017 wellhead price for purchases of indigenous natural gas for power generation in Peru was US$ 1.58/MBTU (according the application of a formula included in the production contract), b) Trinidad & Tobago wellhead gas price is not a published figure, however available publications indicate that in 2016 two major upstream producers reported average gas prices of US$1.72 and US$1.88 per mmcf, and c) last wellhead prices published by EIA (US$ 2.66/MBTU in 2012) and the current level of the Henry Hub price (around US$ 2.8/MBTU) suggest that the average wellhead natural gas price in United States would be very low. Appendix L includes a documentation of these figures.

Price at landing site: as a referential level, and for comparison purposes with HFO and LFO prices and guidance for the potential development of a future Natural Gas market in Guyana, it was estimated a range of US$ 2.5 - 5.6/MBTU for the economic price of natural gas for power generation in landing site (US$ 4.7/MBTU for the Base Case)[46].

For the purpose of the DBIS generation expansion study that price range has been considered as the pertinent price for the gas used for power generation. However it is clear that the cost of the gas for the supplier would be mainly a fixed cost composed by the investment in the offshore gas pipeline and its complementary infrastructure (compression station and others), so that its development requires securing a market for the gas.

[45] The levelized offshore transportation tariff for gas was estimated in the Energy Narrative study assuming that the project is financed with 20% equity (at a real cost of capital of 12%) and 80% debt (at a real interest rate of 8%). Annual O&M costs were estimated to be 2% of the project's capital cost. The project was assumed to have a 20 year depreciation life and taxes were not included in the cost assessment.

[46] Such estimation takes into account a range of US$ 1.6 – 2.5/MBTU for the wellhead price plus a range of US$ 0.9 - 3.1/MBTU estimated for the levelized tariff of the offshore natural gas transportation estimated in the Energy Narrative study.

As indicated by the GoG, it is currently being considered to install this infrastructure with a capacity of 145 mmcfd. Under this situation, for the supply of gas for electricity generation (30-50 mmcfd) the following two options could be had to cover the fixed cost of this infrastructure:

I. that 20.7-34.5% (corresponding to 30-50 mmcfd) of the capacity of the offshore transport infrastructure would be considered dedicated to the plant, in which case the plant would participate in its execution assuming the corresponding fixed transportation cost and the gas price for power generation would be the wellhead price (around US$ 1.6/MBTU in the base case scenario)[47]; or

II. the producer, or other agent, would develop the offshore gas transportation system (including its required compression station) providing or purchasing the natural gas at its wellhead price, then transporting it to the power plant, delivering the gas at a price that would reflect the wellhead price plus the levelized tariff of offshore transportation (around US$ 4.7/MBTU in the base case scenario)

We believe that the first option could imply the incentive to reflect in the power generation cost only the wellhead price for the gas (i.e. not reflecting its full economic value in inland Guyana), situation that could provide a distorted wholesale electricity price in the energy market that could create a barrier for the future economic development of the renewal energy sources for power generation in Guyana.

So, for this study it was assumed the second option, which it would be required a contract that distributes the risks associated with the volume dedicated to electricity generation, for which a natural gas sales contract with payment of availability premium or a take or pay contract with payment obligation of a percentage could be agreed among the parties.

Typically, a take or pay stipulation requires the buyer to purchase a minimum quantity of the product or service in each period, usually annually or, alternatively, to pay that minimum amount even if he has not taken it or accepted to receive it. In the natural gas market, historically that minimum amount has been between 70% and 90%.

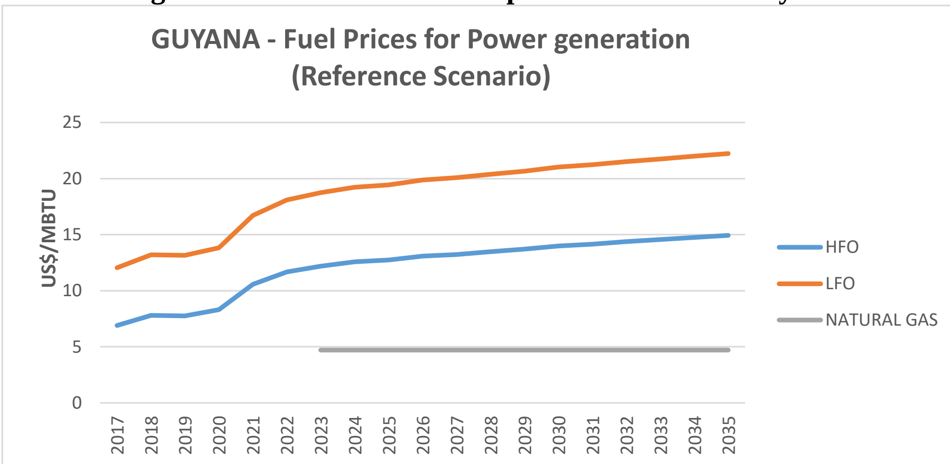
For purposes of the study of the expansion plan, it has been considered a take or pay contract for the natural gas supply to the new power plant with payment obligation of 70% of the total contracted, similar to the practice that some countries have used to initiate the development of the natural gas market.

5.2.3 Summary of fuel prices' forecasts for Guyana

Figure 17, Figure 18 and Figure 19 summarize the three scenarios for fuel prices (Reference, High and Low) for HFO, LFO and NG. They are expressed in terms of US$ dollars (2017 level) per MBTU.

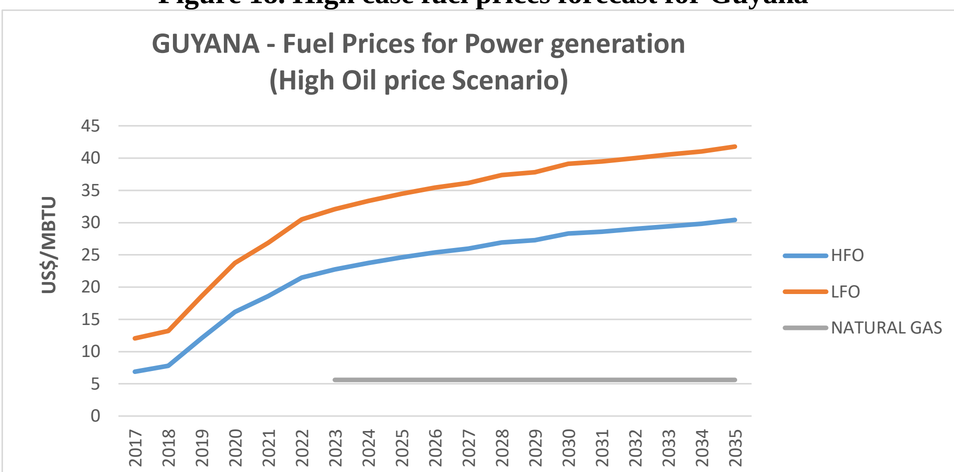
[47] This financial schemme, however could not be much convenient. In order to guarantee open access to the natural gas transport system and the formation of an efficient natural gas market, most of the countries' energy markets regulate that natural gas transport activity is independent of production, commercialization and distribution of natural gas, including the activity of generating electricity. In the case of offshore deposits, similar to other countries (as, for example, the case of offshore gas production in Guajira, Colombia), the gas producer assume the costs of offshore transport infrastructure to the connection site with the transport network on the mainland. However, in the case of Guyana, the investment in in the ofshore gas transport infrastructure is substantial, so that its development, whether by the producer or by another agent, requires securing a market for the gas.

Figure 17. Reference case fuel prices forecast for Guyana



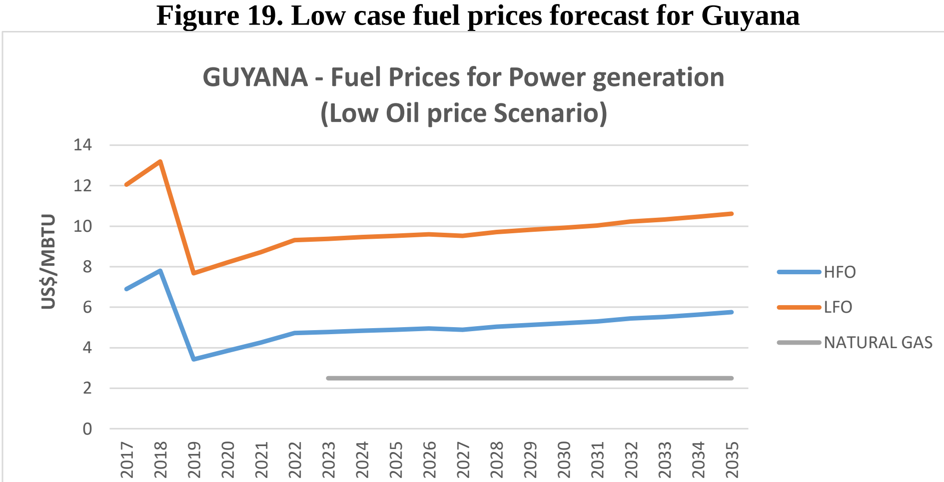
Source: Consultant

Figure 18. High case fuel prices forecast for Guyana



Source: Consultant

Figure 19. Low case fuel prices forecast for Guyana



Source: Consultant

6 OPTIONS OF NEW POWER PLANTS

6.1 Background

An electrical system must have a sufficient amount of generating units available to meet the changes in demand from base load to peak load. The most efficient units designed to operate for long periods of time work most of the year; others only act as backup and their annual operation will be greatly reduced. To meet the changes in demand, conventional generation plants are classified in the following groups[48] in Table 37.

Table 37. Groups and types of conventional power plants

Load	Type of power plant
Peak	Gas turbine
	Internal combustion engine
	Hydroelectric with pumped reservoir
Intermediate	Steam turbine (low efficiency)
	Combined cycle (low Efficiency)
	Hydroelectric
Base	Nuclear plant
	Steam turbine (high efficiency)
	Combined cycle (high efficinecy)

Source: Kam (1985)

Peak load units should be operating in and out several times a day. Some of these units are mobile and for ease in starting, are used in backup or emergency situations. Furthermore, they are characterized by a low investment cost, but a high cost of generation.

Intermediate load units generally operate Monday to Friday and are out of operation during evenings or weekends. Its efficiency is higher than the peak units, but less than the base units

Base load units operate at full capacity most of the year; their investment costs are high, while generation costs are low. Due to their complexity, thermoelectric plants of this type take longer to respond to changes in demand.

According to its geographical location, natural resources (including its indigenous natural gas availability to be provided from the offshore Oil & Gas fields that are being developed today), access to international fuel markets and electricity demand characteristics, Guyana will require different types of conventional power technologies (thermal and hydroelectric) to generate electricity in the most economical and reliable way, considering the "dispatchable characteristic" of power generation associated to this type of power plants (i.e. they are able to provide power generation to supply the electricity demand varying during the day and season). In the case of hydroelectricity with high capacity power plants, it should be also taken into account the inherent characteristics of seasonality and stochasticity associated to the hydraulic inflows and the reservoir operation permitting hourly regulation to dispatch total plant capacity during peak hours and, according reservoir size, seasonal or even annual hydro regulation.

[48] Kam W. Li & Paul Priddy, *Power Plant System Design*, John Wiley & Sons,1985, p.1.

In addition, Guyana has the option to develop new non-traditional power generation based on renewable energy sources, as mini & micro hydroelectricity, biomass, wind and solar (as the existing Skeldon generation capacity that uses bagasse as a by-product from the sugar industry). In general terms, the electricity generation that could be obtained from this type of power plants should consider the hourly energy availability (intermittent associated mainly to wind and solar generation). Also, the daily energy availability (in the case of mini & micro hydros without significant reservoirs) and the seasonal energy availability should be considered (which is associated to several resources, being of most relevance in the case of sugar cane bagasse and the hydro inflows). This implies inherent characteristics of "non dispatchable power" for most of these power plants and its generation variability does not permit to consider its installed generation capacity as "firm capacity" that would be available to supply demand during peak hours in all days in the year.

The generation – transmission expansion analysis of DBIS required, first, its characterization in terms of the operation of its existing generation system (which provided elements to define the reserve margin requirements) and, second, the status of its transmission grid (which provided elements to define the connection systems of new power plants), as presented next[49].

6.1.1 Operation of the existing generation system

The planning and operation of the Guyana power system is based on National Grid Code (NGC) and in particular, the operation shall comply with the requirements of Operational Code. The Operational Code includes the criteria, procedures and information requirements necessary to execute the operational planning, the generation dispatch and coordination supervision and control of integrated operation of the GPL System. The following are the main considerations applied to stablish the operation of the generating system

- When available, the cogeneration units at Skeldon power plant using bagasse as fuel, operate at full power during the "sugar cane crop periods" for 22 weeks/year supplying the main grid, and at a lower power level during the "out of crop period" for 30 weeks/year. During crop periods, the excess generated power is injected into the grid but the value is limited to 12.8MW as a result of the limitation imposed by the rating of the substation transformer (16MVA). During the second period, 9.5MW of the three units of Wartsila plant is delivered to the transmission grid. Under this situation, the capacity of the biggest unit is 15 MW (one unit of the Skeldon cogeneration power plant) or 12.6% of the peak load and 23.5% during minimum load. An emergency trip of this unit, especially during the "In crop period" at full power and during the minimum load condition, can lead the system to a dangerous situation with low frequency and low voltages.
- The Merit Order list of generators gives priority to DP1 to DP4 and Skeldon. The DP4 power plant was commissioned in 2015 and are the most efficient units (app 7.92 MMBTU/MWh), so during normal operation, the DP4 operates as the base load.
- The units at Kingston power plants, four units at DP2 and five units at DP3, are dispatched for load following throughout the day. The total installed power is 58 MW, but the amount of power that can be dispatched from these power plants can be limited by the permissible power transfer capabilities of L5 a 69 kV line with rated capacity of 63.6 MVA, limited to 46 MW during evening peak and limited to 40 MW during the hottest part of the day.

[49] Sections 6.1.1 and 6.1.2 were taken from the following document provided by the GoG: Pre-Feasibility Study for the "Arco Norte" Interconnection Project, Bilateral Electric Interconnection Guyana – Suriname, DRAFT n. 3. CESI. IADB

- The generators of DP1 are the last set of generators to be dispatched mainly during peak period or as emergency, due to the age of the generating units and relatively high energy consumption of the auxiliary units for heating of the heavy fuel oil. These units are in operation for over 20 years.
- The unit No.3 Mirrlees of Canefield Power Plant is normally dispatched during some evening peaks, mainly for voltage support. The unit is also dispatched during maintenance periods of units at DP1 to DP4 and depending on load conditions and voltage at Canefield.
- The Canefield thermal units are used as back up.

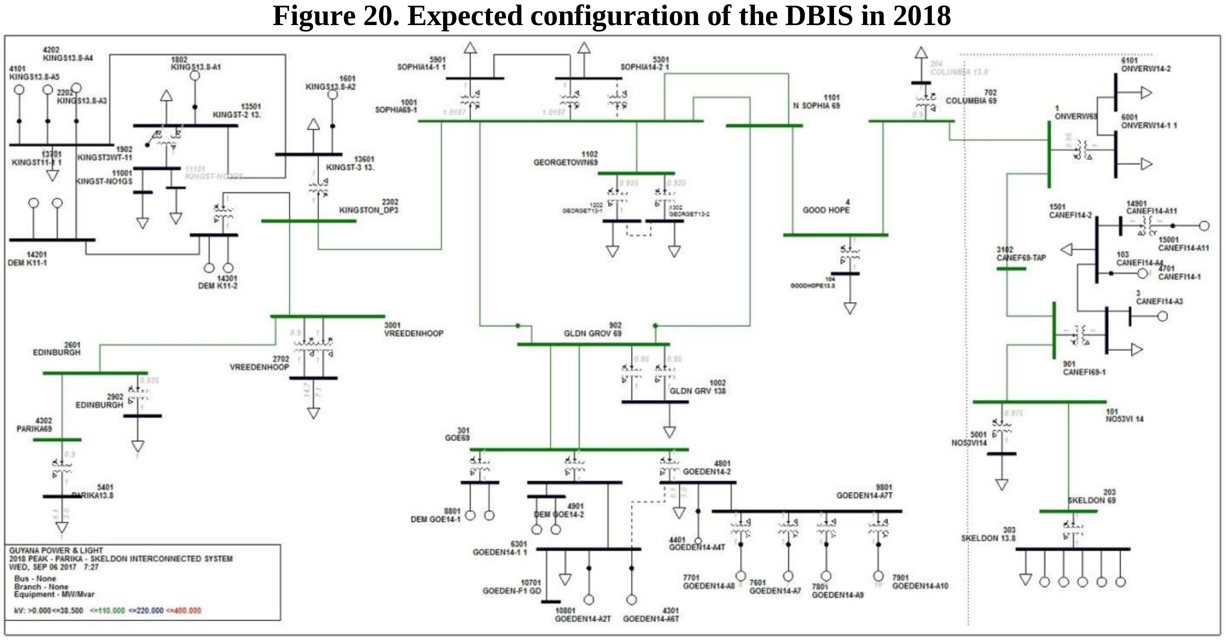
6.1.2 Operation of the 69 kV transmission system & connection criteria of new large power plants

DBIS grid consists of ten - 69/13.8kV step-down substations connected by double or single circuit overhead lines. The substations are equipped with one transformer 69/13.8 kV with nominal power of 16.7 MVA supplying loads that are within a range from 2 MW to 8 MW. The loading level of substations is relatively low also compared with the capacity of the lines.

Two double circuits compose the transmission grid (Garden of Eden to Golden Grove and Golden Grove to New Georgetown and Sophia-Upgraded), and several single circuit OH lines at 69 kV with ratings from 46.6 MVA up to 52.6 MVA. Part of the system is a 2.4 km submarine cable at 69 kV connecting Vreed-en-Hoop substation with Kingston-DP3 substation. The central part of the network is developed within the area of the triangle Edinburgh - Good Hope- Garden of Eden with lengths from 5 to 20 km. On the eastern part of the country are located the substations of Columbia, Onverwagt, Canefield, No. 53 Village and Skeldon. The substations along the eastern transmission corridor are connected through long single circuit lines with lengths from 27 to 56 km. The total length of the eastern grid is 182 km. The longest line is Line 22 Canefield to No. 53 Village at 55.9 km. This longitudinal and not meshed grid with relatively low load makes difficult the voltage control on the remote stations and is a source of possible stability problems. For the 69 kV transmission lines, the target loading in normal conditions is 75% of the normal rating. The estimated length of all MV 13.8 kV feeders is 783.28 kms.

The single line diagram of the expected configuration of the DBIS in 2018 is shown in Figure 20.

Figure 20. Expected configuration of the DBIS in 2018



DBIS Grid – Source: Bilateral Electric Interconnection Guyana - Suriname (DRAFT 3). CESI. IADB

According to the National Grid Code, the opening of the faulted transmission element (N1) shall allow no greater than 5 MW of consequential load shed. The remaining load shall have loop service and not be affected by the fault, *but currently the present network does not fully comply with the N-1 criterion.* The management of overload situations is performed automatically by protections and manually by operators at dispatching center. Operators monitor the performance of all system components at the transmission level though SCADA. In the event a component becomes overloaded, SCADA would flag this to the operators who undertake the corrective actions. The known bottlenecks on the transmission network are: The single circuit OH line with a length of 5 km from Kingston power plant to Sophia – This line has a limited capacity,42.1MW at 75°C (Normal) and 56.5 MW at 100°C (Emergency) and prevents the full power dispatching from DP2 and DP3 power plants. Thus, the capacity of this line shall be upgraded. Furthermore, the outage of this line is considered as the most critical contingency of the grid. According to provided information, this line will be doubled by GPL by the end of 2018.

The capacity of the substation transformer at Skeldon TPP (16.7MVA) prevents the maximum power injection into the grid from the power plant especially during the in-crop period. This occurs twice per year when the total available production reaches 40 MW totally, out of which 30 MW net are to be injected into the grid.

6.1.3 Reserve margin requirement for DBIS

Background: The criterion for reserve capacity historically applied by GPL to identify the generation expansion requirements in DBIS is the size of the two largest conventional units (excluding the 2x15 MW Skeldon cogeneration units which are not available during “out of crop” periods), resulting in a reserve of 17.4 MW for 2018. This reserve margin should be increased according to the size of new units to be installed in the new Gas fired generating capacity. With the installation of new hydropower with large capacity foreseen for the mid-term, it would be required to determine the reserve requirement according to the “firm” capacity determined for this type of power plants by the hydro inflows during dry periods.

Reserve margin applied in the study: Considering the long term planning period stablished for this study (18 years covering 2018 through 2035) for the purposes of the DBIS generation expansion analysis it was selected a reserve margin criteria of 15% of the peak demand (providing an initial reserve margin similar to the size of the two largest units) and an economic cost of US$ 3,000/MWh for the non-served energy. In this way, the expansion model (which applies least cost optimization) selects the capacity expansions, initially without hydroelectric power plants operating in the system, when 115% of peak demand reaches total effective available peaking capacity, non-including RET capacity not available for peaking, or when it would be economical the substitution of power generation in existing plants with high variable cost; in the last case implying reserve margins higher that 15% off peak demand. In the long term, with new hydroelectric power plants operating in the system, through the modeling of the generation expansion considering the occurrence of “dry” hydrological scenarios, the least cost generation expansion is selected to prevent energy shortages, or to obtain economical fuel costs substitutions, also implying reserve margins higher than 15% of peak demand.

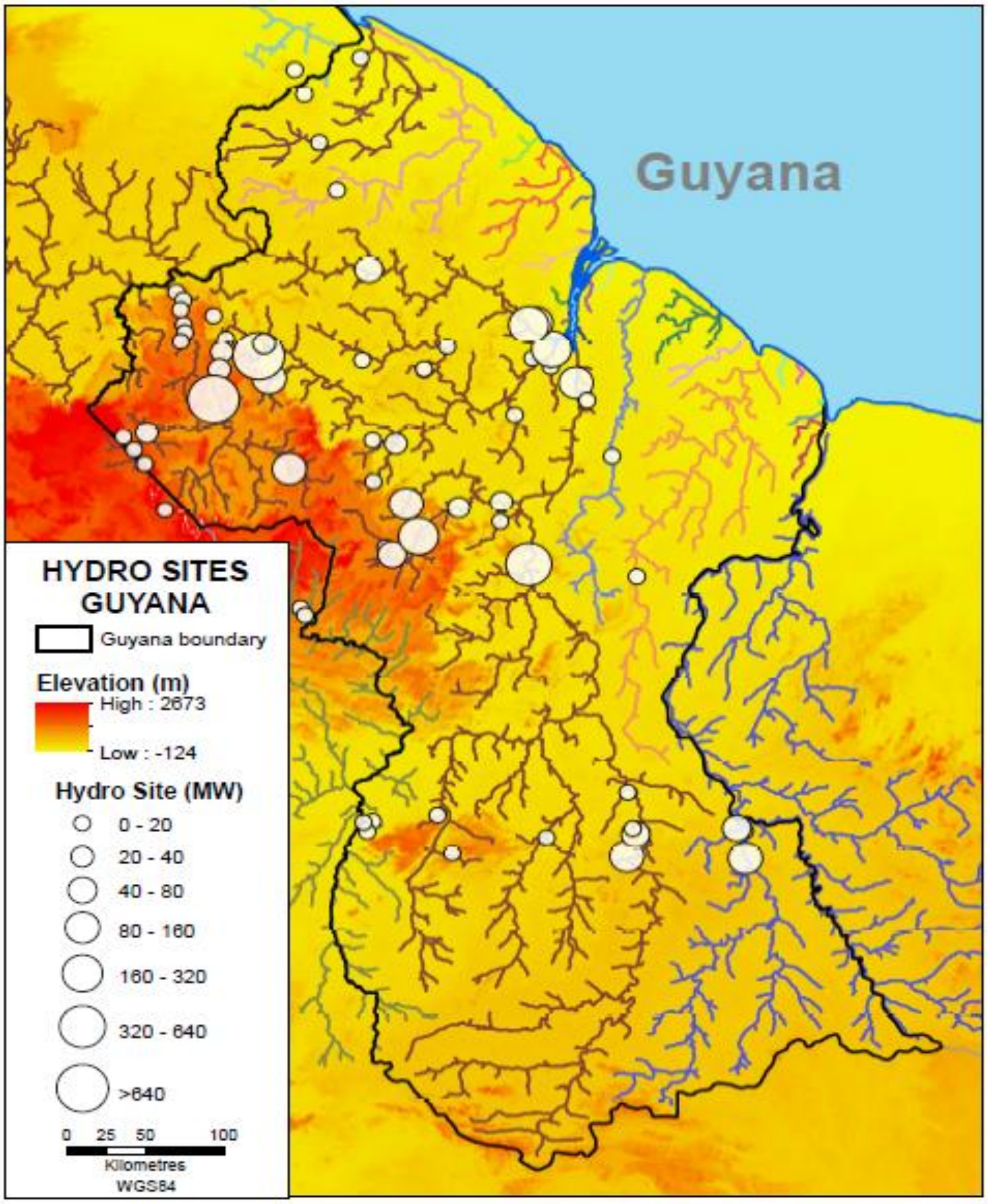
This chapter is dedicated to the presentation of the basic characteristics and costs associated to the candidate power technologies that were considered in this study. A summary of the basic characteristics and costs of the candidate power plants considered in the study is presented in Section 7.2.5.

6.2 Hydroelectric options

6.2.1 Projects selected for the study

Location and basic capacity of the potential hydroelectric developments in Guyana are summarized in Map 7.

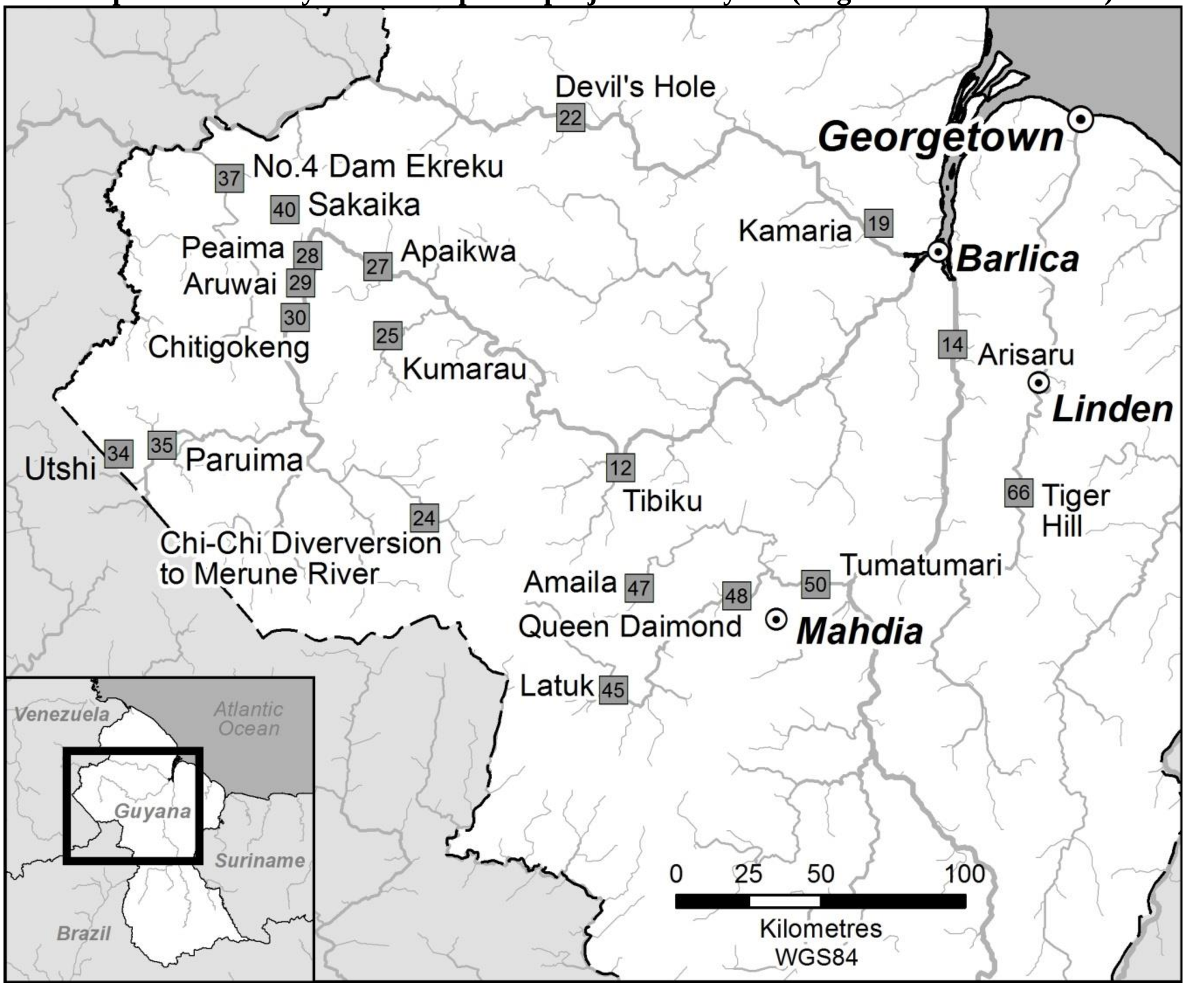
Map 7. Guyana hydroelectric resources



Source: Map processed for the study by consultant

Map 8 shows the location of 19 hydroelectric projects in Guyana with capacity between 15 and 120 MW of average continuous power generation with sites relatively close to DBIS. They are all located between latitudes 5.0 and 6.5.

Map 8. Potential hydroelectric power projects in Guyana (Avg Cont 15 to 120 MW)



Source: Map processed for the study

Table 38 was prepared with the available information and preliminary estimates related to basic technical characteristics and costs, including its transmission connection and access roads, for the 19 candidate projects as applied in Arco Norte studies. Such candidate projects were selected from the list received from the GoG for the 2016 Expansion Study and considering the following selection criteria: (a) geographical proximity to DBIS; (b) sizes between 15 and 120 avg-cont-MW.

Table 38. Basic Characteristics of potential hydroelectric power projects for DBIS

Ref No. 3/	Region 3/	Names of Sites 3/	Status 3/	Rivers 3/	Capacity (MW) 2/	Ave. cont. (MW) 3/	MW/m3/s 2/	Max m3/s 2/	Investment Cost $/kW 4/	Construction period Years 2/
14	7	Arisaru 1/		Essequibo	522	120	0.16	2,406	2,253	4
47	8	Amaila 5/	Sites to Pre - Construction Level	Kuribrong	165	103	3.02	54	3,400	3
19	7	Kamaria 5/	Sites to Pre-Feasibility Level	Cuyuni	180	103	0.15	1,175	3,413	4
24	7	Chi-Chi Div Merume	Sites to Pre- Feasibility Level	Mazaruni	605	96	5.40	112	2,555	4
25	7	Kumarau 5/	Site with studies private sector	Kurupung	149	86	2.71	52	4,708	3
45	8	Iatuk		Potaro	160	77	1.12	117	3,970	3
22	7	Devil's Hole		Cuyuni	175	62	0.17	762	3,928	3
12	7	Tiboku 1/	Sites to Feasibilty Level	Mazaruni	408	40	0.27	1,522	2,660	4
29	7	Aruwai		Mazaruni	888	38	1.00	892	1,490	5
27	7	Apaikwa		Mazaruni	128	34	0.12	912	3,517	3
50	8	Tumatumari 5/	Tender Document and Final Design	Potaro	152	34	0.26	596	2,594	3
30	7	Chitigokeng		Mazaruni	658	31	0.75	874	1,713	4
48	8	QueenDaimond		Potaro	67	29	0.20	263	5,990	3
35	7	Paruima		Kamarang	60	26	0.57	78	5,991	3
37	7	Dam Ekreku 4		Ekreku	47	20	0.68	61	11,880	3
28	7	Peaima		Mazaruni	105	19	0.11	914	3,523	3
40	7	Sakaika		Ekreku	91	17	1.82	48	2,569	3
34	7	Utshi		Utshi	31	17	2.36	12	9,794	3
66	10	Tiger Hill 5/	Sites to Feasibilty Level	Demerara	28	15	0.28	94	7,603	3

1/ Not considered as a candidate project because of "hard" environmental constraints.
2/ Source: Arco Norte study
3/ Source: Information obtained in the first mission
4/ Source: Arco Norte study (interest during construction not included)
5/ Project selected as candidate in the expansion study

Source: Consultant using data from Arco Norte study and other studies

The Government of Guyana selected the following five projects[50] to be considered in the study: 1-Kamaria, 2-Tiger Hill, 3-Tumatumari, 4-Kumarau, and 5-Amaila. The following comments and graphs illustrate the current situation of these projects which were originally identified in the Hydroelectric Power Survey of Guyana ("HEPS") done by Montreal Engineering Company in 1976. This study considered this five high capacity hydroelectric projects representative of the "dispatchable" hydroelectric technology that could be potentially developed in Guyana to start the commissioning by 2025 or later to supply DBIS power demand[51].

Table 39. Selected potential hydroelectric power plants

Site	Nominal Capacity (MW)	Latitude	Longitude
Kamaria	180	6.48917	-58.8125
Kumarau	149	6.138899	-60.34334
Amaila	165	5.35139	-59.55806
Tumatumari	152	5.36278	-59.00889
Tiger Hill	28	5.64917	-58.37389

Source: HEPS

[50] The Consultant understood that such five projects were selected from a list of 15 candidate projects, mainly with criteria based on close proximity to DBIS and investment costs, amongst others factors.
[51] The Government of Guyana, during a workshop held in Georgetown on October 28th, 2015, selected five high capacity hydroelectric projects based on previous studies owned by the Government of Guyana and from the list received from the energy authorities during the consultancy finished in 2016 to build a Guyana's Power Generation System Expansion Program.

6.2.2 Basic description

A basic description of Kamaria, Tumatumari and Amaila hydroelectric projects considered in this study is presented next as considered in in the 2016 Generation Expansion Study. Also Kumarau and Tiger Hill hydroelectric projects are presented according new updated information provided for this study[52].

6.2.2.1 Kamaria Project

Kamaria would be a low head run-of-river hydroelectric power plant in Cuyuni River with 180 MW installed capacity and with a very small reservoir. It was conceived as a second downstream power development after Oko Blue project (388 MW), also a low head power plant but with a large reservoir covering an area of 1,429 km^2 and representing a density index of 0.27 MW/km^2 which is well below the required standards of around 4 MW/km^2 that are usually considered today for this type of project under current environmental considerations (the project was conceived in 1976 when the environmental standards and electromechanical equipment were very different from nowadays). Because of this in the Arco Norte study Oko Blue was not considered as candidate plant for the expansion and most probably its eventual future development would require a complete redesign, even considering the possibility to use the new technology of low head bulb turbines that has been used recently in countries as Russia and Brazil for this type of projects. The Kamaria project, as a second potential hydroelectric development downstream Oko Blue[53] project, would be involved in this type of technical redesign increasing from 4 to 6 years its potential development. The earliest year considered for its potential commissioning in this study was 2027.

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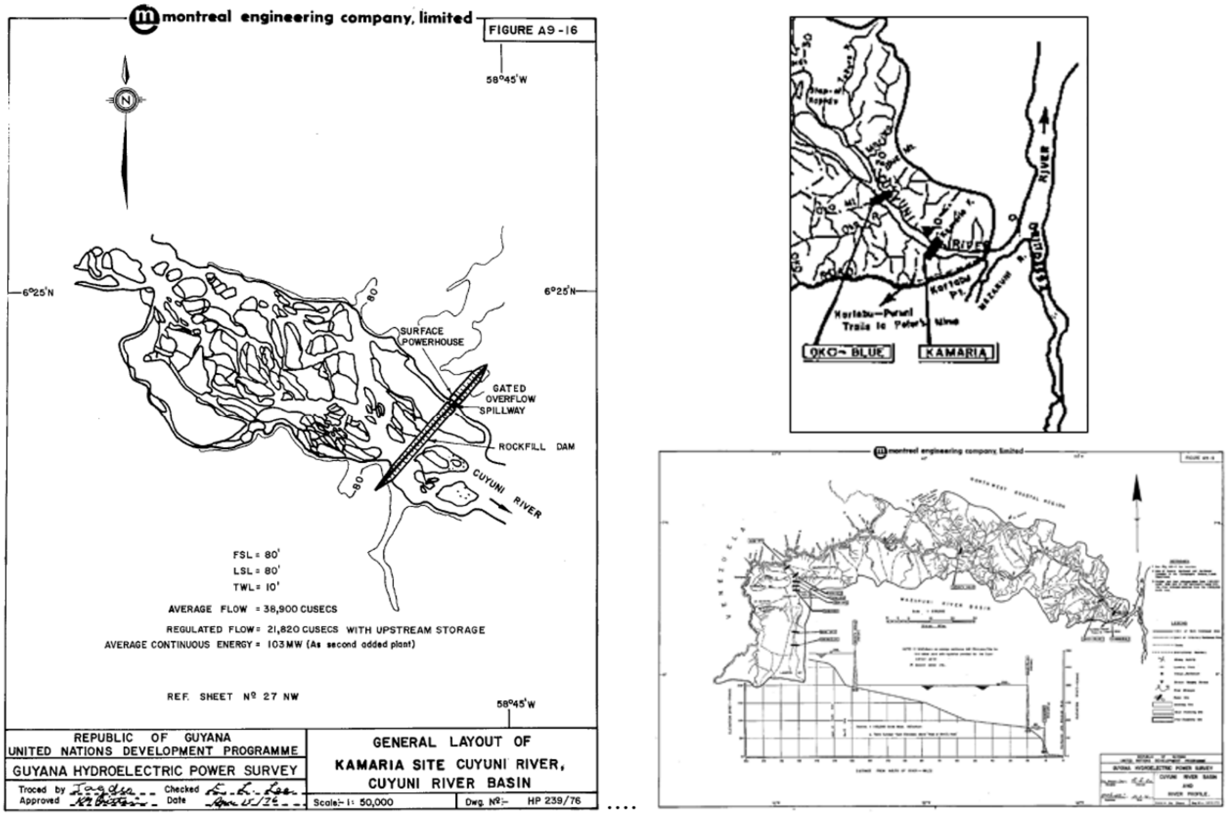
[52] Tiger Hill, 12 MW Hydropower Plant. Prefeasibility Study, 2017, GEA & Kurupung River Hydroelectric Project, Progress Report, February 2018, Sands Spring

[53] The Montreal (1976) study considers Kamaria project as a scond potential hydro development downstream from Oko Blue, and not as a stand alone project. Studies should be made to evaluate if Kamaria could be a stand alone project.

Map 9. Hydroelectric Project Kamaria

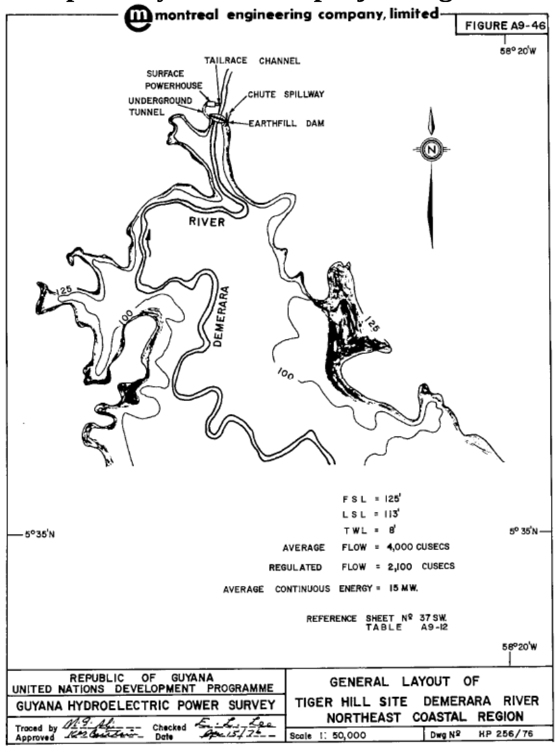


Source: Montreal Engineering Company (1976)

6.2.2.2 Tiger Hill Project

Tiger Hill shown in Map 10 is the smallest of the five hydroelectric projects considered in the study and the nearest to DBIS grid. It is also a low head run-of-river power plant (12 MW) with a very small reservoir. Its updated prefeasibility study available in 2017 evaluated its technical and economic feasibility. With a head of 10 m the power plant will operate as run-of-river system with no systemically relevant storage volume.

Map 10. Hydroelectric project Tiger Hill



Source: Montreal Engineering Company (1976)

Social and environmental impacts will be relatively low, due to the assumed small flooded area. Flooding will be the biggest social and environmental impact of the project. The assumed flooding will be 7 km². A social and environmental impact assessment process must be performed to predict and asses the type of scale of potential biodiversity impacts, and opportunities to benefit conservations.

The benefits of the power plant, like cheap rural electrification around the location, infrastructural development like the new access roads and creation of local jobs will outweigh the negative effects for the local residence. From the power plant a low 13.8 kV subnet can be implemented to supply the surrounding households. Also, the nearby village of “Ituni” within a 12-km distance could be supplied over a 13.8 kV transmission line. Together with the new access road, any kind of small or medium industry or agriculture production could settle to profit from cheap electricity prices and new build infrastructure. The power plant itself will create new jobs during the construction and operation.

The two generators feed into a common 13.8 kV busbar. The busbar is equipped with a circuit breaker and is connected to the two main transformers (13.8kV/69kV). For reasons of redundancy and power loss reduction, a two-transmission 69 kV line system (on one power pylon, 51 km) was designed. Two step-down transformers will be located at Linden to feed into the local lower voltage grid.

The yearly generated energy would be 60 GWh. From an economical perspective the operation of the power plant would reduce significantly the current subsidies of 15.2 million US$/year that the Government assumes for the electricity supply to Linden. In this analysis it also would have to be considered if more economical power generation could be provided to Linden from other hydroelectric power plants taking into account future connecting 230 kV transmission lines crossing near Linden.

Table 40. Tiger Hill specifications

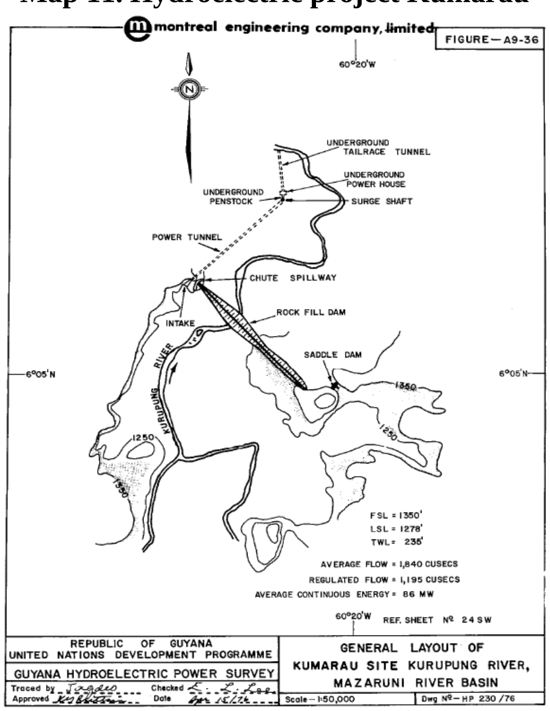
Location	Region 10, Guyana
Name of River:	Demerara River
Mean River Discharge:	Q_{mean} = 123 m^3/s
Rated Turbine Discharge	$Q_{Turbine\_Net}$ = 143 m^3/s (2 x 72,5 m^3/s)
Rated Head:	H_r = 10 m
Annual Plant Output:	60,231 MWh / year
Rated Capacity:	12 MW (2 x 6 MW)
Load Factor:	56 %
Total Power Plant Efficiency:	85,7 %
Elevation of Weir Crest:	24 m ASL (without liability, GPS data)
Width of Weir Crest	127 m
Dam Height:	15 m_{max}
Type of Plant:	Run-of-River System with a Gravity Concrete Dam and integrated Power Station
Type of Hydro Turbines:	Kaplan
Length of Transmission Line:	51 km
Voltage Level:	69 kV, 2 systems
Distribution Network:	Linden Power Grid
CO_2 Savings:	40.4 million kg/year
Levelized Cost of Electricity:	8,71 Cent/kWh (including transmission line)
Specific Cost:	5,217 USD/kW

Source: Tiger Hill, 12 mw hydropower plant, pre-feasibility study 2017, GEA

6.2.2.3 Kamarau Project

Kamarau is a medium size high head hydroelectric project that has been studied by the private sector to be developed to supply local demand for the mining industry. With 100 MW installed capacity could export power to DBIS grid (requiring a relative long 138 kV transmission connection of 286 km to Linden). It would use Kurupurug river inflows for power generation (41.2 m3/s net average being required a minimum non-generable ecological inflow of 4.5 m3/s).

Map 11. Hydroelectric project Kumarau



Source: Montreal Engineering Company (1976)

The project is scalable with opportunity for long term expansion. As a local project could be built with 35 MW installed capacity and 241 GWh annual generation to supply Toroparu mines through a 68 km of 138 kV transmission lines, as a regional project could be built with 50 MW installed capacity and 321 GWh annual generation, appropriate for electricity supply to the regional mining industry (Aurora Gold Mines and others through 120 km of 138 kV transmission lines) and as a national project could be built with 100 MW installed capacity and 515 GWh annual generation requiring 286 km of transmission lines connecting with Linden, Puruni, Itaballi and Bartica. Considering its connection to the proposed 230 kV transmission system CECC1 – Linden – Georgetown it would also require a new 230/138 kV substation in Linden at a cost estimated in US$ 8 M.

Map 12 illustrates plant location and its optional interconnections.

Map 12. Hydroelectric project Kumarau Location

Source: Kurupung River Hydroelectric Project at Kumurau Falls, Progress Report, February 2018

Main project characteristics of these options are summarized in Table 41.

Table 41. Kumarau specifications

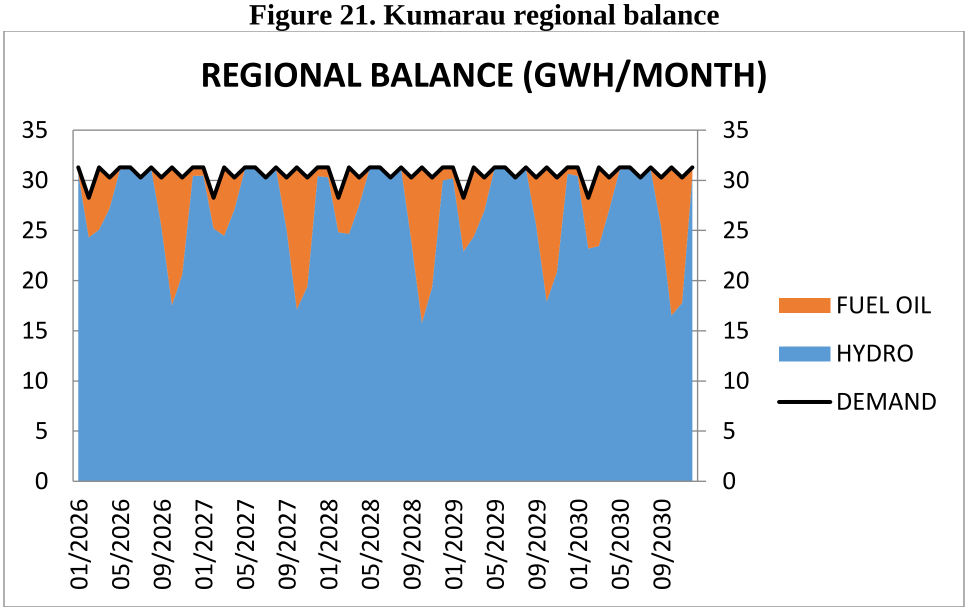
Description	Project	Regional Expansion	National Expansion
Net Annual Flow (m^3/s) [1]	41.22	41.22	41.22
Power Capacity (MW)	35	50	100
% of available Flow	36%	52%	100%
Capacity Factor	79%	73%	59%
Reservoir Area (Km^2)	~0	~0	~0
Line Distance to Linden (km)	N/A	N/A	286
EPC Capex (incl. Transmission- US$m)	122	168	338
Unit Capacity Cost (US$/KW)	3,478	3,352	3,380
Timeline to Construction	~2 yrs	~3 yrs	~4 yrs

Source: Kurupung River Hydroelectric Project at Kumarau Falls, Progress Report, February 2018

Based on the information supplied for this study, the electricity demand of the Toparu mine would be 35 MW (258 GWh/year, implying 0.84 load factor) and for the Aurora mine 15 MW (around 110 GWh/year if estimated with the same 0.84 load factor). To supply those loads it would be required to maintain backup installed capacity in gensets and associated facilities. For Toparu mine it estimated it would be required 5 x 7.4 = 37 MW in gensets that would use fuel oil IFO180 and in Aurora mine 5 x 3.5 = 17.5 MW in gensets that would use fuel oil No. 4.

If the project is developed with 50 MW to supply regional demand it would be required temporary fuel oil power generation to supply demand, as presented in Figure 21 (the figure illustrates the seasonality of the required fuel oil generation given the lack of reservoir and the variability of the inflows).

Figure 21. Kumarau regional balance

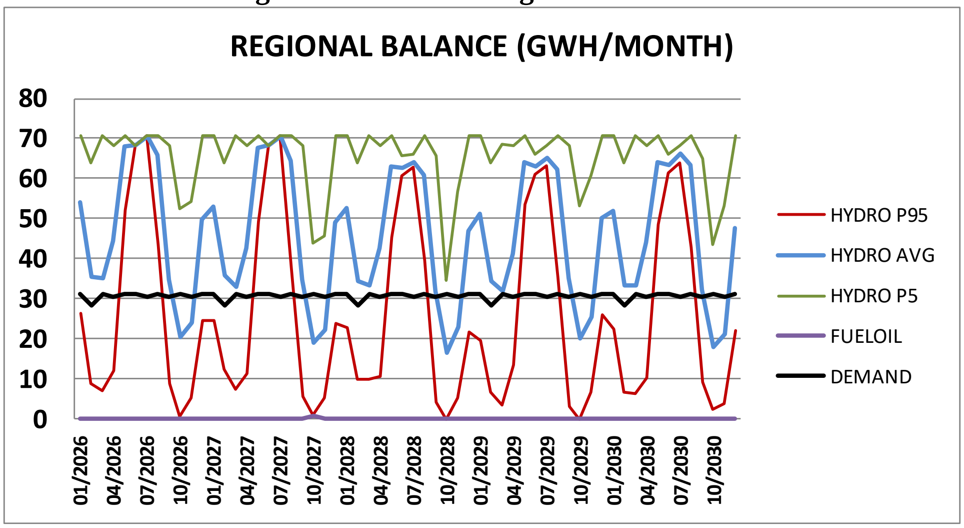


Source: consultant

If equipped with 100 MW, the small reservoir associated to this project and the low hydro inflows during dry seasons indicate that it could not provide firm capacity to DBIS after supplying the regional mining peak demand (50 MW). This imply that its potential benefits for DBIS are related only to: i) available non-firm power during wet seasons that could be used to reduce fuel costs, and ii) temporary electricity exports to the mining regions to avoid fuel oil generation during dry seasons.

Figure 22 illustrates the regional power exchanges under this option (the graph illustrates the volatility of the monthly Kamarau power generation, levels P95, Average and P5[54], and its difference with the regional demand would be the DBIS regional power exports or imports).

Figure 22. Kumarau regional balance 2



Source: Consultant

Appendix P contains the results obtained in a preliminary economic evaluation of this project under the assumption of 40 years for its useful life, US$ 25/MW-year for its O&M costs and for the regional option to install 50 MW (US$ 168 million) and national option (US$ 338 million), both operating with gensets and liquid fuels for backup the power generation required to supply the regional demand.

The regional option would have significant benefits related to liquid fuels substitution and would provide around US$ 460 million of net benefits (NPV at 10%) and an internal rate of return of 37.5%. This development would be dedicated mainly to the regional mining industry.

The national option with 100 MW was evaluated from the point of view of its global national incremental benefits and costs (US$ 170 = 338-168 million investment to obtain additional "non-firm" 50 MW and 194 GWh/year that could be dedicated to DBIS cost reductions).

Costs and benefits were estimated associated to the increment from 50 MW to 100 MW of the size of the project. For this purpose it were estimated the power sales of DBIS to supply part of regional demand under dry conditions to avoid liquid fuel regional generation as well as the Kumarau hydroelectric generation available for DBIS during wet seasons, after supplying regional demand.

[54] Px indicates the monthly generation level (GWh/month) that would be exceded with a Probability of x%, considering only the volatility of the hydro inflows..

This evaluation was done considering the following assumptions:

- The project would not provide to DBIS of firm capacity (due lack of reservoir and very low inflows during dry seasons).
- Two scenarios of gas price were considered: US$ 4.7/MBTU (the estimated gas landed price) and US$ 1.6/MBTU (the estimated wellhead price and considering that the offshore gas transportation system would be a fixed cost for DBIS).
- Total O&M and fuel costs in the two systems (DBIS and Regional mining system) where estimated (i) with and (ii) without the project[55]. The cost difference (ii)-(i) constitutes the total benefits of the project, which were separated for DBIS and for the Regional mining system as follows:
  - Benefits for DBIS would be mainly originated by O&M and fuel costs savings in DBIS.
  - Additional benefits for DBIS were estimated due additional electricity sales that could make to the regional mining industry, which were estimated at a price of 50% of liquid fuels variable costs in the backup units.
  - Additional benefits for the mining industry would be the cost reductions for its backup generation during dry hydrological occurrences less payments to DBIS for the electricity purchases, also valued at the mentioned price.
  - DBIS would assume all incremental costs (Investment and O&M) of the new power plant.

The results obtained in the preliminary economic analysis indicate that with a natural gas price of US$ 4.7/MBTU for DBIS the incremental investment in the power plant (US$ 170 million) would provide a global NPV for the country (at 10%) of US$ 93 million and an IRR of 15.8%,

With such gas price and the adopted assumptions, this project would provide to the mining industry of US$ 22 million of net benefits without additional investment and to DBIS another US$ 71 million with an IRR of 14.6%.

However, with US$ 1.6/MBTU for the gas price (the indicative level applied in this study for the wellhead gas price in Guyana and the relevant gas price for DBIS if the power sector assumes the fixed cost of the offshore gas transportation system) the net benefits for the project would be negative for DBIS.

The execution of this project would require of several agreements between GPL and the private mining industries in the region for its development. Such agreements would include, among others: i) Connection agreement, ii) Operation agreement, ii) Share of the participating companies in project costs and benefits, and iii) Price agreement for power interchanges.

Significant risks could be foreseen of costs increases due to the project's location and long transmission lines, implying a significant technical and financial effort for project construction and operation.

Even though it could constitute a source of economic energy, for the purpose of the DBIS generation expansion this project sized at 100 MW has not been included in its expansion program, given that this project would not provide firm capacity for DBIS demand supply and the gas price and gas supply conditions (i.e. take or pay or availability premium payments) for DBIS is still undefined, implying a high risk that project benefits for DBIS could be negative.

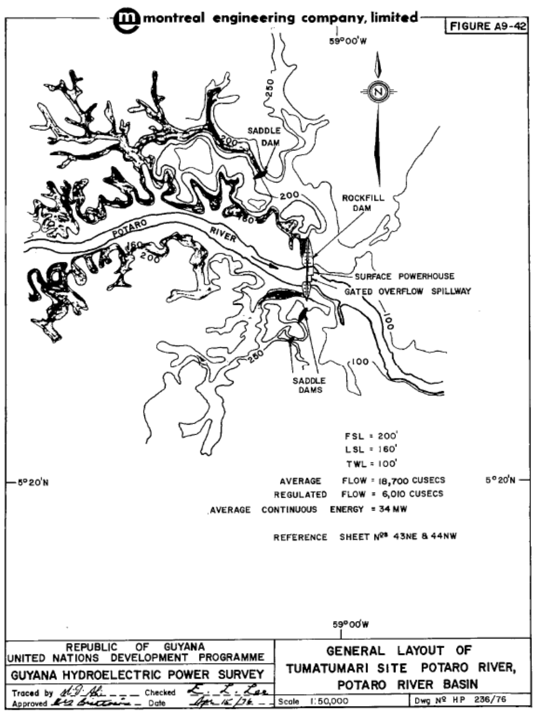
[55] This estimation was done applying the SDDP model at monthly level during 2018-2035 and the annual results obtaned for 2035 were extended untils the end of the economic life of 40 years estimated for the project.

6.2.2.4 Tumatumari project

Tumatumari shown in Map 13 is also a low head run-of-river power plant (152 MW) located in the Potaro River. As it is presented in Arco Norte study: "…its reservoir would flood an area of 54 km², and there is no influence with protected areas. However, two Indigenous Lands (Campbelltown and Maicobe) would be directly affected. The number of people living in those villages is unknown, but due to the existence of these Indigenous Lands, the need for human resettlement is expected. The reservoir also affects an area of gold mining. While the cumulative environmental and socio-economic impacts should be analyzed in a sector-level environmental analysis, the possibility of reservoir water contamination by mining wastes and its consequences should be studied in an environmental impact assessment. The reservoir would also affect at least three roads in the area. Development at Tumatumari could start quickly because there is an existing truck road".

In addition, there are available studies with reduced capacity installed in this project that could reduce its environmental impacts. In fact, today it is considered the rehabilitation of a small capacity power plant which was installed and operated in this site many years ago and a definition would have to be taken if this site is selected for the installation of a high capacity power plant. Also, 2027 is considered as its earliest commissioning year of this large power plant.

Map 13. Hydroelectric project Tumatumari



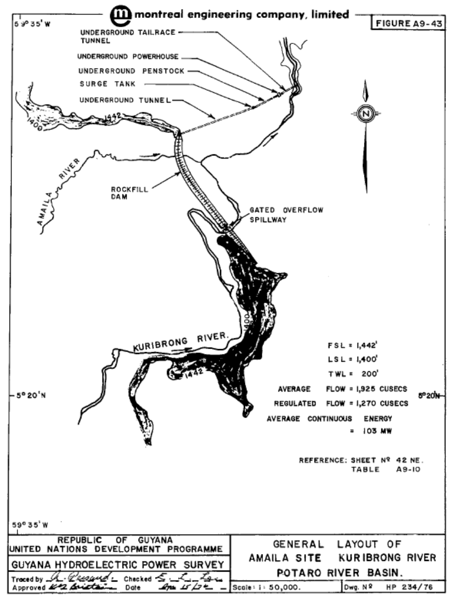
Source: Montreal Engineering Company (1976)

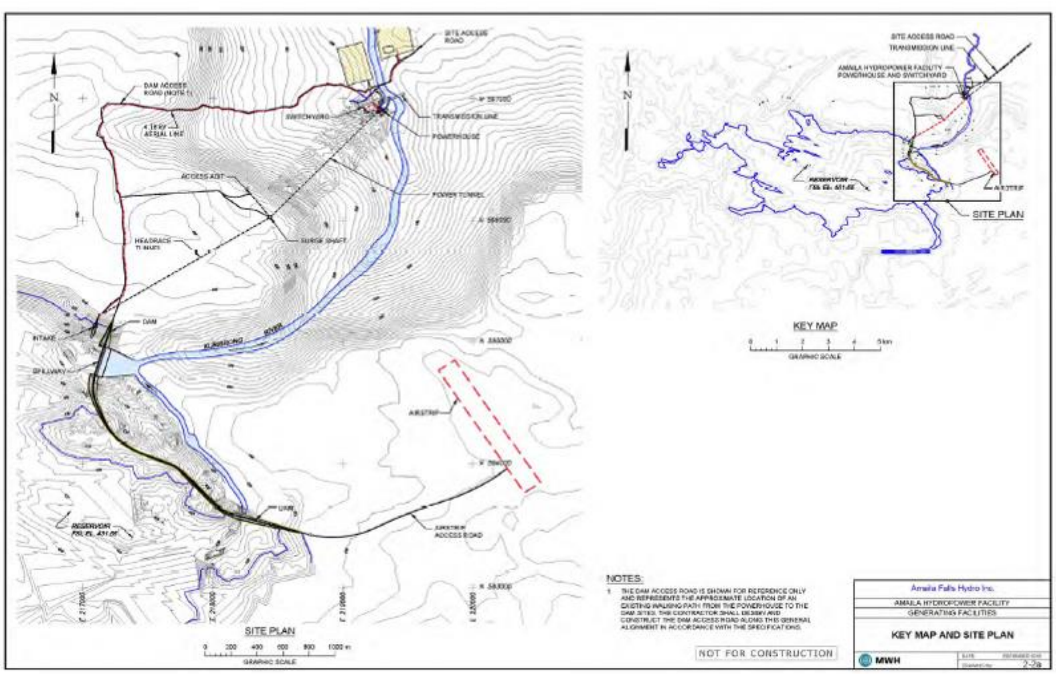
6.2.2.5 Amaila Project

Amaila shown in Map 14 is a medium size (165 MW) high head hydroelectric project with a small size reservoir. According Arco Norte studies: "…. The site is located at the confluence of the Amaila and Kuribrong Rivers. The construction of the hydro facility and electrical interconnection was anticipated to begin in late 2013 and would take approximately four years to complete. However, since in August 2013 the works have been stalled. According to the Amaila Hydropower Environmental and Social Impact

Assessment (ESIA) Update (2011), the reservoir would have a surface area of 23.3 km² (implying a density index of 7.1 MW/km2). The Hydropower Facility area consists of natural forests with no human occupation, mining or forestry concessions, or Amerindian designated lands. The powerhouse would be located at the bottom of the Amaila Falls escarpment, approximately 3 km from the water intake. To provide sufficient access to the transmission line and Hydropower Facility, the construction of approximately 85 km of new roads, and upgrading 122 km of existing roads are necessary. ". For this study 20214 is considered as its earliest commissioning year.

Map 14. Hydroelectric project Amaila





Source: Montreal Engineering Company (1976)

6.2.3 Summary of hydroelectric projects' characteristics

A summary of the main characteristics of the five projects is presented in Table 42.

Table 42. Main characteristics of the five hydroelectric projects

PROJECT	CONSTR. PERIOD. (YEARS)	INVESTMENT COSTS 1/ US$/KW	TRANSMISSION CONNECTION INCLUDED	CAPACITY (MW)	FIRM CAPACITY (%) 2/	AVERAGE GENERATION (GWH/YEAR)	FACTOR (MW/m3/s)	MINIMUM ECOL. (m3/s)	MAXIMUM (m3/s)	RESERVOIR (mm3)	
										MIN	MAX
Kamaria	3	3960	To Linden, 102 km, 230 kV/2c	180	55%	1081	0.150	NA	1200	246.7	246.7
Tiger Hill	3	5217	To Linden, 51km, 69kV/2c	12	55%	66	0.084	NA	143		
Kumarau National	4	3380	To Linden, 286km, 138 kV/2c	100	26%	515	2.100	4.5	48		
Kumarau Regional	3	3352	Without connection to DBIS	50		321	2.100	4.5	24		
Tumatumari	3	3010	To SECC1, 39km, 230 kV/2c	152	42%	751	0.260	NA	585	699	699
Amaila	3	3945	To SECC1, 100km, 230 kV/2c	165	63%	1094	3.020	1.0	55	34.3	135.6

1/ Includes transmission connection and accesss road not includes interest during construction
2/ Estimated with P95 monthly generations and 0.25 plant factor

Source: Consultant using data from Arco Norte (2016) and others

The estimation of reference investment costs for the five proposed hydro plants included in this study was based on existing data related to Guyana's hydroelectric potential, including MONENCO's HEPS and the Arco Norte study in the case of Kamaria and Tumatumari and considering updated estimations included in recent studies for Tiger Hill (Tiger Hill, 12 MW Hydropower Plant. Prefeasibility Study, 2017, GEA), Kumarau (Kurupung River Hydroelectric Project, Progress Report, February 2018, Sands Spring) and Amaila (Norconsult, 2016). This was done as follows:

– First, we reviewed the investment cost for Amaila considering the budget included in the Norconsult-2017 study (US$ 800.7 million which includes interest during construction (IDC) and transmission connection to Georgetown). From this budget we deducted IDC (71.3 US$M) and the investment cost of the section of the transmission system that could be shared with other hydros (78.4 US$M of the transmission system SECC1 - Georgetown, as estimated in Arco Norte Study). This provided an adjusted estimation of US$ 651 million for Amaila (US$ 3,945/kW) including its transmission connection to SECC1 substation and without IDC.

– Similar as the criteria applied in Arco Norte study, Kamaria and Tumatumari investment costs were escalated using the same cost increase as Amaila (1.16 = 3,945/3,400) obtaining US$ 3,960/kW for Kamaira and US$ 3,010/kW for Tumatumari (not including IDC and including transmission connection of Kamaira to Linden and Tumatumari to SECC1).

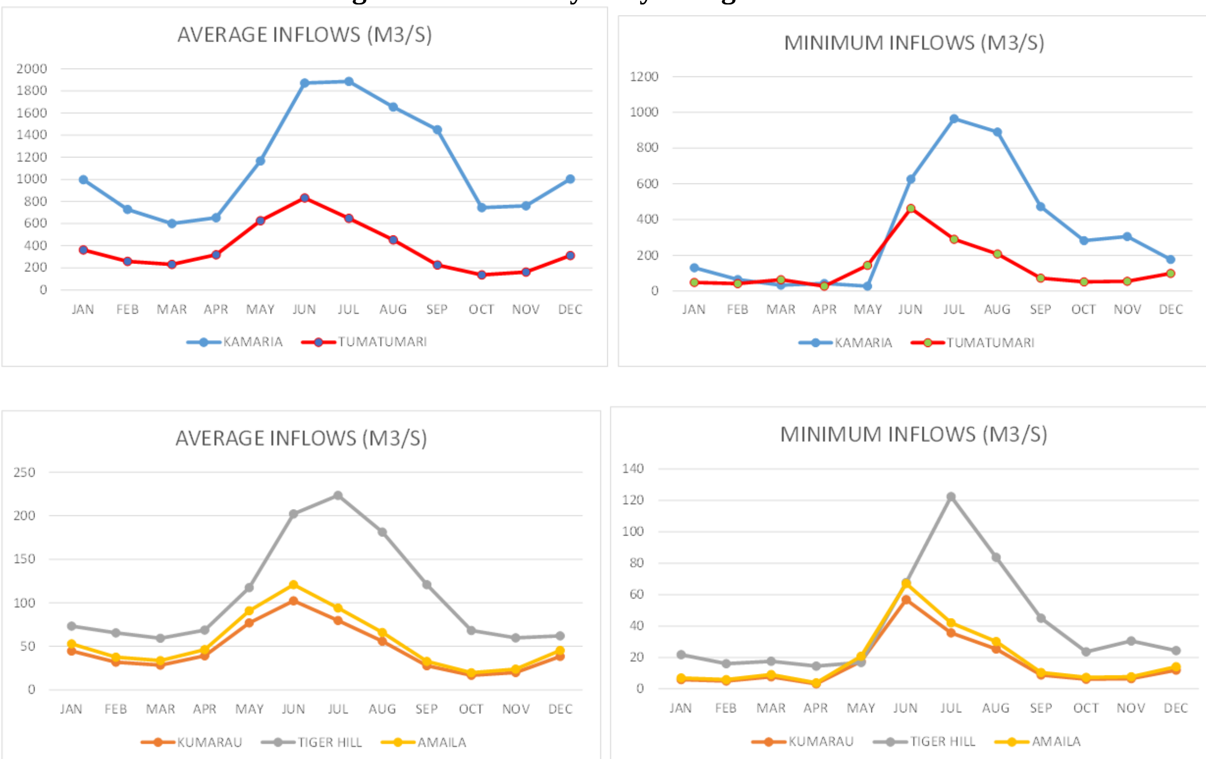
– From available recent studies provided by the GoG we obtained the investment costs estimates for Tiger Hill (12 MW at US$ 5,217/kW) without IDC and including transmission connection to Linden, and Kumarau (100 MW at US$ 3,380/kW) without IDC and including transmission connection to Linden.

Considering that the available information for most of the hydropower potential sites in Guyana is subject to update with enhanced cartography, topographical surveys, as well as hydrological and environmental studies, the lack of more recent cost estimates and detailed engineering surveys makes it difficult to estimate with certainty the current costs to develop Guyana's hydro potential, for which the costs included in this study should be considered as a reference only.

6.2.4 Hydrological statistics

The available statistical series of inflow records at the potential hydro sites were obtained from Arco Norte (2015). Figure 23 summarizes average and minimum inflows monthly variability.

Figure 23. Summary of hydrological statistics



Source: Consultant using Arco Norte (2015)

River discharges were analyzed using the Stochastic Dual Dynamic Programming (SDDP) model, a hydrothermal dispatch model developed by PSR Inc., which finds optimal (minimum cost) reservoir operation of complex systems and then simulates its operation in a stochastic environment. Initially, the SDDP model fits an autoregressive time series model to the historical data. An autoregressive model up to order 6 was fitted to the data (order is chosen based on statistical hypothesis testing). Fitted model preserves a series of historical statistical parameters such as the monthly mean, standard deviation and skewness coefficient, as well as the temporal correlation structure. The model works in a multivariate context preserving also the spatial correlation structure when the model is used to represent several hydrologic stations. Next, a simulation of the operation of each power plant was done for 100 synthetically generated hydrologic occurrences based on statistical parameters identified as described above. The results of the simulation gave 100 equally likely cases each one of them representing the energy dispatches of the five hydro power plants of interest. The results obtained for each of the five hydroelectric projects were analyzed using statistical methodology to find energy dispatch by months and quarters and by probability level (P10, P30. P50, P70 and P90), the quarterly results are presented in Table 43.

Table 43. Hydroelectric projects generation (GWh/quarter)

KAMAIRA

	P10	P30	P50	P70	P90		AVERAGE
1	116	175	208	257	316		214
2	180	245	279	309	344		271
3	309	336	360	360	360		345
4	143	201	251	299	330		245
						TOTAI	**1076**

TIGER HILL

	P10	P30	P50	P70	P90		AVERAGE
1	6	9	12	14	20		12
2	13	16	18	21	24		18
3	20	23	24	25	25		23
4	7	10	11	13	16		11
						TOTAI	**65**

KUMARAU

	P10	P30	P50	P70	P90		AVERAGE
1	70	101	126	149	177		125
2	148	165	180	198	200		178
3	140	158	166	177	187		165
4	50	71	85	99	123		86
						TOTAI	**554**

TUMATUMARI

	P10	P30	P50	P70	P90		AVERAGE
1	91	125	149	182	230		155
2	200	239	255	278	309		256
3	183	208	225	245	266		225
4	72	94	108	122	155		110
						TOTAI	**747**

AMAILA

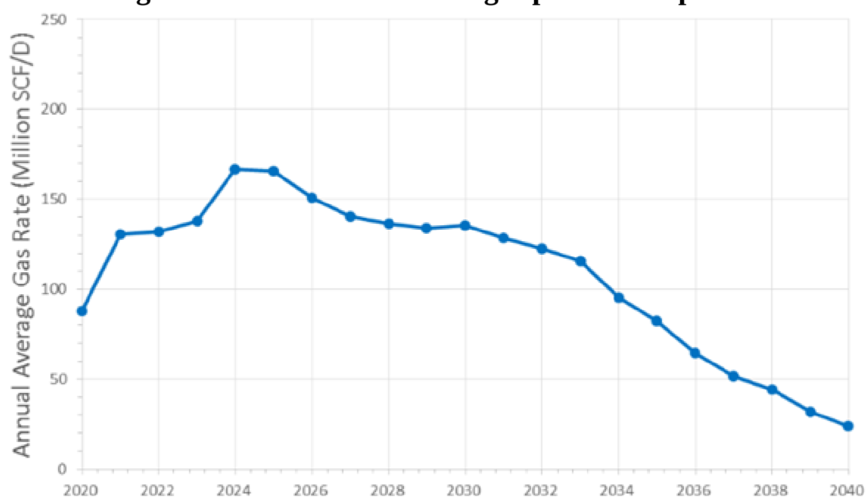
	P10	P30	P50	P70	P90		AVERAGE
1	153	214	250	295	323		247
2	257	284	319	327	327		303
3	330	330	330	330	330		330
4	132	179	209	252	298		214
						TOTAI	**1094**

Source: Consultant using Arco Norte (2015)

6.3 Natural gas options

As presented before, Natural Gas will be produced in association with the produced oil. EEPGL will use some of the recovered gas as fuel on the FPSO, and proposes to re-inject gas back into the Liza reservoirs, which will assist in optimizing management of the reservoir leaving gas availability to be supplied for power generation through a gas pipeline from the FPSO to the landing site (Woodlands being today the most promised site) in volumes of around 30-50 mmcfd (millions of square foot per day), during at least around 15 years.

Figure 24. Liza Phase 1 Total gas production profile



Source: Liza Phase 1 Gas Production Profile, ExxonMobil, January 2018.

6.3.1 Offshore gas transportation for power generation

The most promising exploitation for power generation of the landed natural gas is to build a new large natural gas fired / dual fuel power plant in the landing site. Size of this plant has been estimated in the order of 100-250 MW. This option would not require building additional onshore pipelines but it would require a reliable transmission connection (a 230 kV, two-circuit transmission connection to New Sophie or to Garden of Eden substations, as presented in Section 6.7.1). Under this option the existing power plants would remain using HFO / LFO for power generation and being operated mostly as backup power plants[56].

Energy Narrative considered three hypothetical locations where the pipeline may be routed: 1) Georgetown, 2) Clonbrook, and 3) New Amsterdam. The cost to install and 8-in pipeline (30 mmcfd) and a 12-in pipeline (145 mmcfd) was estimated for each proposed route. The cost of the offshore pipeline was estimated by using industry practices in estimating, the methodology was as follows: 1) the cross

[56] A second option, not evaluated in this study due considerations by the GoG of construction difficulties, consists in the transportation the natural gas through pipelines to the existing power plants in order to substitute the current uses of HFO / LFO and to expand the generation system in those sites. New natural gas-fired generation capacity would also be dual fuel. This option would imply that a new power plant should be located at the natural gas landing point (with smaller installed capacity), but additional power generation capacity should also be located at the existing generation sites where feasible natural gas pipelines could be connected. (Appendix O includes this estimations obtained from Energy Narratives Study).

sectional area of the pipeline was calculated, 2) the weight of the pipeline in kg/m was calculated, 3) the cost of the pipeline in $/ m was calculated in 2013 prices, 4) the 2013 prices were adjusted to process today using a market index for steel, 5) the coating cost of 15% of the uncoated pipe was calculated, 6) the installed cost was calculated as 2.5 times the total pipe cost per m, and 7) the final cost for the pipeline segment was calculated.

Table 44. Estimated pipeline cost for offshore natural gas pipeline options

Landing	Length (km)	Installed Cost (8-in)	Installed Cost (12-in)
Georgetown	185	$170MM	$235MM
Clonbrook	180	$165MM	$230MM
New Amsterdam	205	$190MM	$260MM

Source: Energy Narrative estimates

It is estimated that the compressor station cost will be $27.5MM for the 8-in pipeline and $37.5MM for the 12-in pipeline. In addition to compression, the natural gas liquids present in the wet gas that is transported in the pipeline can be separated and sold as LPG. Also a cost of US$15.75 million for a separator plant for 30 mmcfd and US$76.125 for a 145 mmcfd capacity separator are estimated.

Table 45. Estimated cost for natural gas compressors

Item	8-in Pipeline	12-in Pipeline
Compressor Station	$25.0MM	$25.0MM
Compression	$2.5MM	$12.5MM
Total Compressor Station Cost	$27.5MM	$37.5MM
Gas Separation Plant	$16MM	$76MM
Total Cost	**$43.5MM**	**$114MM**

Source: Energy Narrative estimates

Table 46 shows the total estimated cost for the pipeline after adding in the cost of compression and liquids separation to the estimated cost for each variation in pipeline size and length.

Table 46. Estimated all-in cost for offshore natural gas pipeline options

Landing	Length (km)	Installed Cost (8-in)	Installed Cost (12-in)
Georgetown	185	$213.5MM	$349MM
Clonbrook	180	$208.5MM	$344MM
New Amsterdam	205	$233.5MM	$374MM

Based on the above cost analysis, Energy Narrative estimated an indicative transportation tariff for each potential route based on 30 mmcfd average volumes for the 8-in pipeline, and 145 mmcfd average volumes for the 12-in pipeline.

The estimated tariff assumed the project was financed with 20% equity (at a real cost of capital of 12%) and 80% debt (at a real interest rate of 8%). Annual O&M costs were estimated to be 2% of the project's capital cost. The project was assumed to have a 20 year depreciation life and taxes were not included in the cost assessment. This analysis resulted in the levelized tariffs for the various pipeline route options shown in Table below. Note that the analysis below assumes that the cost of the natural gas separation plant is borne by the LPG stream that is generated by the plant, and so is not included in the estimated costs for natural gas transportation.

Table 47. Levelized natural gas transportation indicative tariffs, offshore pipeline options

	Landing Point		
	Georgetown	Clonbrook	New Amsterdam
	8-in (30 MMcfd)		
Without Compression	2.72	2.64	3.05
With Compression	3.17	3.09	3.49
	12-in (145 MMcfd)		
Without Compression	0.78	0.76	0.86
With Compression	0.9	0.89	0.99

Source: Energy Narrative calculations

For a transported volume of 30 mmcfd the levelized transportation tariffs resulted in US$3.17 per MMBtu in Georgetown, US$3.09 per MMBtu in Clonbrook, and US$3.49 per MMBtu in New Amsterdam. From these three sites, Clonbrook resulted in the vicinity of Woodlands, the most promising site at the moment of this study.

6.3.2 Natural Gas power plants

Three candidate technologies based on Natural Gas (and liquid fuels as alternate fuel) are considered as potential generation plants to be developed in Guyana for a new large power plant located near landing site of natural gas[57]: GT-gas turbines (20-33-50 MW units), CCGT-combined cycles (100-150 MW power plants) and RICE-reciprocating internal combustion engines (17 MW units).

6.3.2.1 Gas Turbines and Combined Cycles (GT & CCGT)

Table 48 summarizes typical investments costs estimated in other countries in the Caribbean region.

[57] According the scope of work and indications received for this study, generation expansions using natural gas and located in sites of existing power plants (i.e. Vreed-en-Hoop or Garden of Eden) were not considered given the expected costs and difficulties for the natural gas transportation.

Table 48. Typical investment cost of gas fired power plants (GT & CCGT)

Source	GT - USD/kW	CCGT – USD/kW
ETESA (Panama, “Revisión del plan de Expansión 2013”)	1,200	2,100 – 2,240
ICE (Costa Rica, “Plan de Expansión de la generación Eléctrica 2012-2024”)	1,000	
ENEL (Honduras, “Plan de Expansión de Generación 2013-207”)	847 – 751	1,384
CEAC (Centro América, “Plan Indicativo Regional de Expansión de la Generación 2012-2027”)	922 – 1,162	1,923
CFE (Mexico, COPAR “Costos y Parámetros de Referencia, 2012”)	700	1,240

Source: Consultant using different studies

For this study total investment cost for GT units of 20, 33 and 50 MW was estimated in 1,100, 1,000 and 900 US$/kW, respectively. The heat rate of the plants (HHV) was estimated in 10,200, 10,100 and 10,000 BTU/kWh, respectively. Its operation and maintenance costs in US$16-18/kW-year (fixed) plus US$3.5/MWh (variable) using LFO and US$14-16/kW-year and US$3.0/kWh using natural gas. Total investment cost for a 1x150 MW and 1x100 MW CCGT was estimated in 1,950 and 2,000 US$/kW, respectively. Its heat rate (HHV) in 8,000 and 8,160 BTU/kWh, respectively, and its fixed operation and maintenance costs in 25 and 23 US$ kW-year, respectively plus 3.5 US$/MWh (variable). CO2 emissions of this type of technology using natural gas was estimated using 688 TonCO2/GWh for GT and 421 TonCO2/GWh for CCGT and using LFO 928 and 568 TonCO2, respectively. The investment costs estimated for the new projects include the gas connection infrastructure to the gas supply system. The GT and CCGT technologies could also use LFO as fuel in which case O&M fixed costs would increase by US$ 2/kW-year and O&M variable costs would increase by US$ 0.5/MWh.

6.3.2.2 Reciprocating Internal Combustion Engines (RICE)

Reciprocating engines using HFO or LFO are widely used in Guyana by GPL, and by small and large industries. In Guyana, these units are sized from a few kW in small industries up to 8.7 MW at GPL, and in the future it is estimated that 11.4 or 17 MW engines using LFO or HFO could be introduced to reduce fuel and investment costs. Also, according to the Natural Gas Study, the conversion of the existing plants owned by GPL to use natural gas will require an investment cost of US$ 100/kW, estimated for the installation of the local gas infrastructure and equipment required for the natural gas combustion for power generation.

For this study total investment cost for 11.4 MW engines using Natural Gas/LFO was estimated in US$1,495/kW and US$1,755/kW using Natural Gas/HFO (as considered in Arco Norte study), the heat rate of the plant (High Heating Value, HHV) is estimated in 8,500 and 10,300 BTU/kWh, for HFO and LFO respectively, and its operation and maintenance costs in US$ 45/kW-year (fixed) plus US$ 9.8/MWh (variable) for the HFO units and 12/kW-year (fixed) plus US$ 8.9 US$ 9/MWh (variable) for the LFO units. CO2 emissions of this type of technology could be estimated using 700 TonCO2/GWh with HFO/LFO and 451 TonCO2/GWh with gas.

The option to install 17 MW of reciprocating engines using Natural Gas/HFO in the existing power plants (Vreed-en-Hoop and Garden of Eden) was not considered in the medium term given constraints indicated by GPL, mainly related to limited transportation capacity for equipment. However it is an option for the large power plant considered to be installed in the gas landing site.

Costs for this RICE electric generating facility is based on five engines, each with a net rated output capacity of 17 MW. The total design capacity is 85 MW and could be reduced or extended in 17 MW modules according required capacity. This generating facility is comprised of the engine generating sets which are fired on natural gas; medium voltage generators coupled to each engine; the engine auxiliary systems; and the electrical and control system. The engine auxiliary systems include fuel gas, lubricating oil, compressed air, cooling water, air intake, and exhaust gas systems. Each engine is a four-stroke, spark-ignited gas engine that operates on the Otto cycle. Table 49 contains the basic characteristics and costs estimated in 2017 by the Energy Information Administration of USA for this type of power plant.

Table 49. Basic characteristics and costs of RICE

Technology:	RICE	
Nominal Capacity (ISO):	85,000 kW	
Nominal Heat Rate (ISO):	8,500 Btu/kWh-HHV	
Capital Cost Category		(000s) (January 1, 2016$)
Civil Structural Material and Installation		9,473
Mechanical Equipment Supply and Installation		49,716
Electrical / I&C Supply and Installation		10,827
Project Indirects (1)		16,070
EPC Cost before Contingency and Fee		86,086
Fee and Contingency		9,000
Total Project EPC		95,086
Owner Costs (excluding project finance)		19,017
Total Project Cost (excluding finance)		114,103
Total Project EPC	/ kW	1,119
Owner Costs 20% (excluding project finance)	/ kW	224
Total Project Cost (excluding project finance)	/ kW	1,342

(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.

Source: EIA, 2017

Major areas for O&M for the RICE Facility include engine and generator minor and major maintenance which are based on hours of operation. The maintenance range is from 3,500 hours of operation for typical maintenance items, 12,000 hours of operation for a minor overhaul, and 16,000 hours of operation for a major overhaul. Additionally O&M maintenance and repair includes balance of plant systems such as the compressed air system, fire water system, lube oil system, and the emission control system. Table 50 presents the O&M expenses for the RICE Facility.

Table 50. O&M expenses for RICE

Technology:	RICE
Fixed O&M Expense	$6.90/kW-year
Variable O&M Expense	$5.85/MWh

Source: EIA

Table 51 presents environmental emissions for the RICE Facility using natural gas.

Table 51. Environmental emissions for RICE

Technology:	RICE
NO_x	0.07 g/bhp-hr
SO_2	0.001 lb/MMBtu
CO_2	117 lb/MMBtu

Source: EIA

Costs were adjusted from price level of Jan 2016 to the price level adopted for this study (2017) by applying the producer price index for industry data for Electric power generation (implying 5.3% increase). In this way investment costs are estimated in US$ 1,413/kW, fixed O&M costs in US$ 7.3/kW-year and variable O&M costs in US$ 6.2/MWh.

For this study, CO2 emissions of RICE technology were assumed in 700 or 451 TonCO2/GWh, using HFO or Natural Gas, respectively.

6.4 Wind options

6.4.1 Wind Potential

For the assessment of the wind energy in the expansion of Guyana's power capacity, it is necessary to consider the wind potential on the coast because of the vicinity to the grid line and the largest consumption centers, as well as being the region that exhibits the largest wind potential in the country. One of the fundamental sources of information is the Persaud's Paper. Other sources are also analyzed in the following sections.

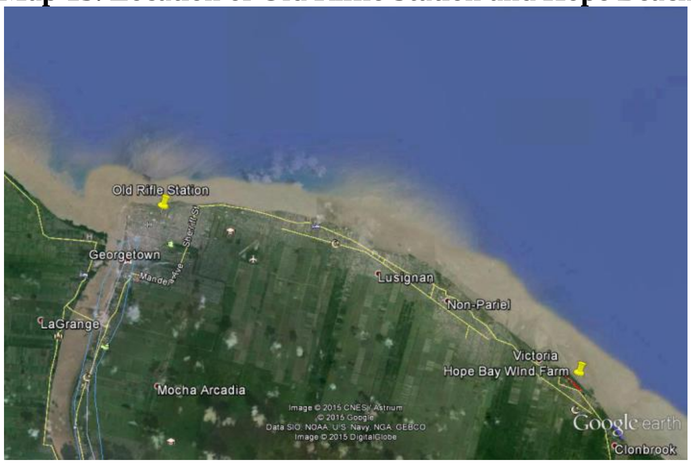
6.4.1.1 Persaud's Paper

Guyana is located on the north eastern edge of South American mainland between latitude 1-9o N. These latitudes lie within the range of two predominant weather zones, the North East Trade Winds (NETW) and the Inter Tropical Convergence Zone (ITCZ). The NETW are steady winds with good all-year energy potential, whilst ITCZ is an equatorial belt of calm winds resulting from the convergence of the northern and southern trade winds. The annual north-south movement of the ITCZ is responsible for the variation of the weather and winds patterns over Guyana.

The NETW predominates across the coastlands with greatest influence on the coast lands and reducing as they progress inland. The impacts of ITCZ are greatest in the northwest region and generally only experienced for few months in the year. Map 15 shows the seasonal behavior of the monthly mean wind velocity recorded in the period 1968-1974 at the Old Rifle Range station[58], in Georgetown and close to the coast[59] (Map 14 indicates its location).

[58] This station was in the city of Georgetown, with coordinates 6o 30'N, -58o -09'W.
[59] Persaud, S., D. Flynn, and B. Box. Potential for wind generation on the Guyana Coastlands. Renewable Energy 18 (1999) 175-189

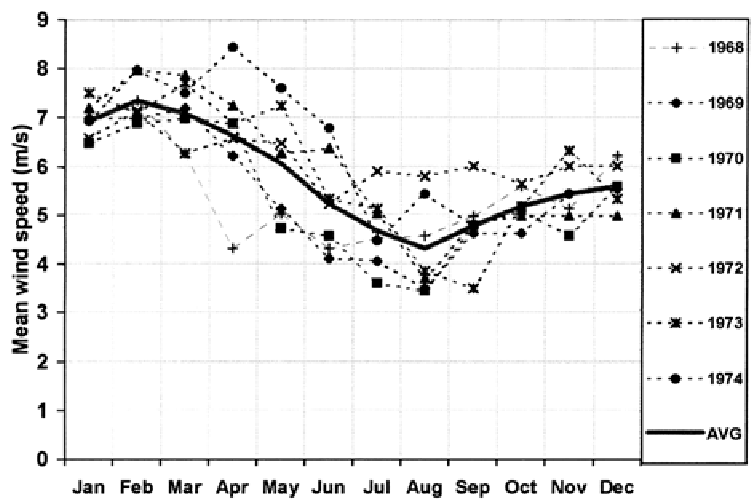
Map 15. Location of Old Riffle Station and Hope Beach



Note: Distance between Old Riffle Station and Hope Beach: 24 km

The average shows high wind speeds during the winter period January –March and low values in the summer period July-September. It was found that a hybrid Weibull probability density function best described the annual wind speed probability distribution at the reference height of 10.7 m. With an annual mean wind speed of 5.79 m/s, and an annual average power density (PD) of 159 W/m², this distribution represents a class-3 wind resource in the Bagatelle wind power scale, suitable for most wind turbine applications. The available resource exhibits a significant seasonal variation from power densities in the range 250-300 W/m2 during the winter to 1-100 W/m2 during the summer. Therefore, energy availability during the period July-September would be minimal, convenient period for wind turbine maintenance.

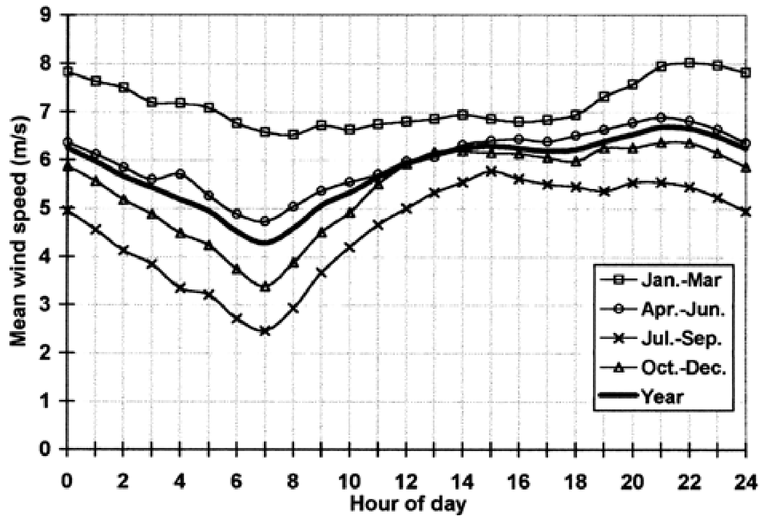
Figure 25. Monthly mean wind speeds. Old Rifle Range, Georgetown, 1968-1974.



Note: Anemometer Height: 10.67 m. Source: Persaud, S., D. Flynn, and B. Box. Potential for wind generation on the Guyana Coastlands. Renewable Energy 18 (1999) 175-189.

The behavior of the daily mean wind speed shows an increasing pattern from 6.5 m/s at 6 am to 8 m/s at 21 pm and then the average decreases to 6.5 m/s at 6 am. This behavior is more pronounced during the summer period, from 2.5 m/s at 6 am up to 15 pm 5.5 m/s, and the decreasing to 2.5 m/s at 6 am of the next day.

Figure 26. Daily wind velocity pattern

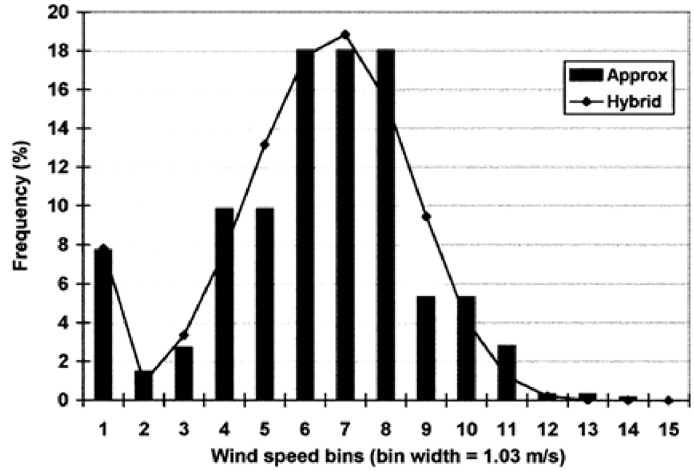


Note: Anemometer Height: 10.67 m. Source: Persaud, S., D. Flynn, and B. Box. Potential for wind generation on the Guyana Coastlands. Renewable Energy 18 (1999) 175-189.

Figure 27 shows the annual frequency distribution of hourly wind speeds for the period 1971-1973. Examination of the figure indicates a Weibull distribution except for the frequencies at low wind velocities in the range 0-1.03 m/s. In the analysis presented by Persaud et.al., frequencies in this range were removed and the remaining data scaled to represent 100% of useful data, and the Weibull parameter determined were: k=3.8, c=6.88 m/s, vm = 5.79 m/s, PD =158.6 W/m2, and the cumulative probability of observing very low wind speeds, Fo=7.71%, all at 10.67 m[60].

[60] The consultant received for this study several statistics of the hourly wind speeds in other sites of interest for the installation of wind plants, as Port Mourant. However the analysis of such statistics indicated that the wind velocities and wiebull distribution would be surprisingly high which suggest that the basic informations on such measurements need to be reviewed. In consequence, due to consistent data and confusing reports for Port Mourant, with the available information colected for this study it was not possible to estimate the hourly output for typical week as well as for the week with the lowest wind speed, for the potential sites of interest for the installation of wind plants in Guyana.

Figure 27. Hybrid and approximate annual frequency distributions (1971-1973)

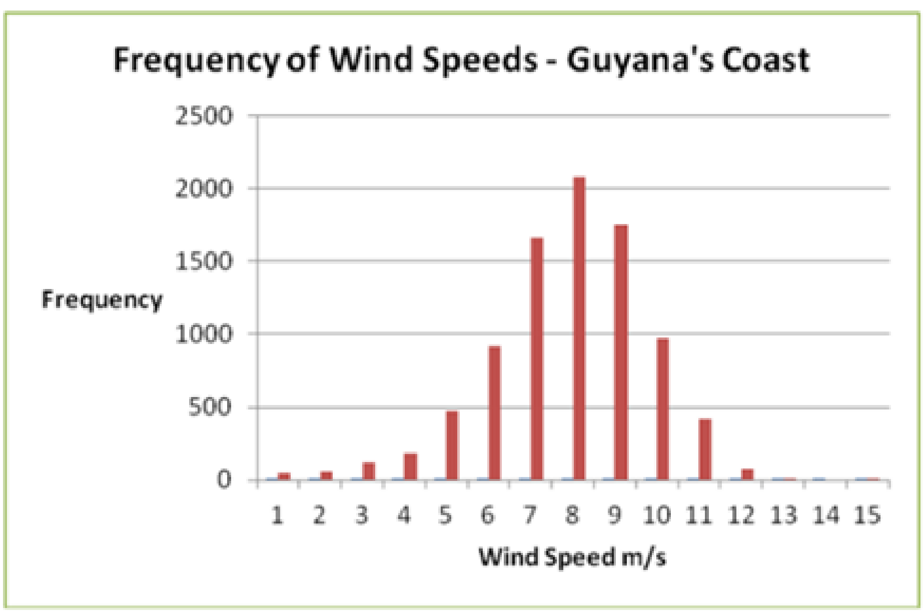


Note: Anemometer Height: 10.67 m. Source: Persaud, S., D. Flynn, and B. Box. Potential for wind generation on the Guyana Coastlands. Renewable Energy 18 (1999) 175-189.

6.4.1.2 2003 Hope Beach Measurements

During the period 2002/3 a wind power feasibility study, sponsored by the Dutch Government with Delta Caribbean, NEG-Micon and Rheden Steel as co-sponsors, was carried out for the Guyana government. Wind speed data was recorded at Hope Beach, an area on Guyana's coastline 20 km to the east from Georgetown, and the results were favorable for the installation of wind turbines. Figure 28 shows a plot of frequency of occurrence against hourly speeds.

Figure 28. Frequency of wind speeds at Hope Beach



Source: ArcoNorte – December 2, 2015.

The analysis of this data at 40 m height gave the following results

- Hourly average wind speeds were between 6.5 and 8.5 m/s
- Wind speeds showed little variation during the day and were the highest in the evenings

- Wind turbines would only be inoperable for a maximum of 100 hours during the year due to lack of wind
- Shape factor k = 5.2
- Scale factor c = 8.45
- Wind turbulence was estimated at about 8%

As noted, the wind velocity measurements were taken at 40 m. For verifying the shape and c factors above mentioned, Figure 29 was digitalized, and the Weibull distribution was fitted to the graph, with the result shown in Figure 29. The Root Mean Square Error is 2.58% and can be considered acceptable considering that the original report is not available. Table 52 shows the corresponding frequency table and the values to be employed for the calculation of the energy output of the wind turbine.

Figure 29. Frequency of wind speeds for Guyana's Coast and Weibull fitting

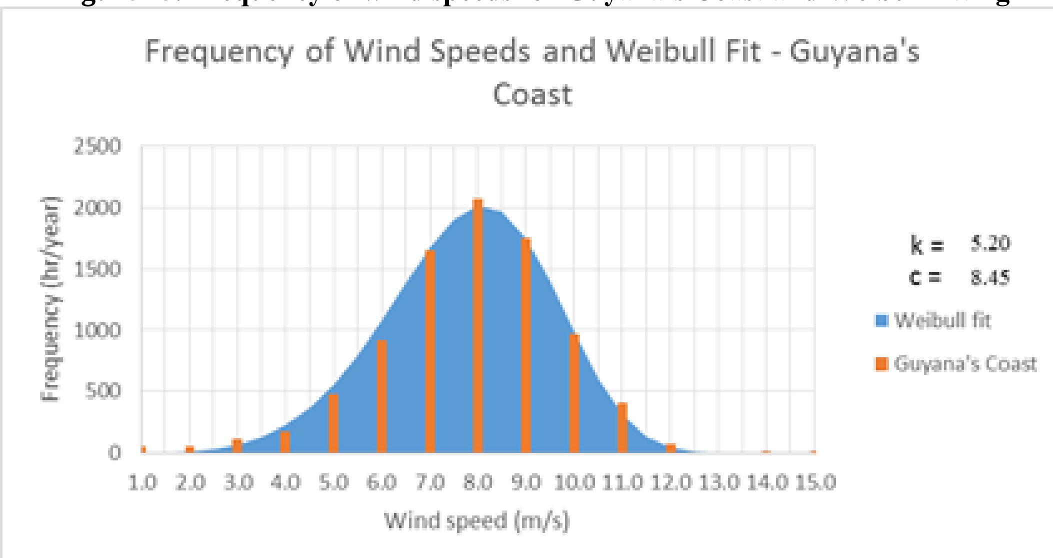


Table 52. Wind speeds frequency for Guyana's Coast

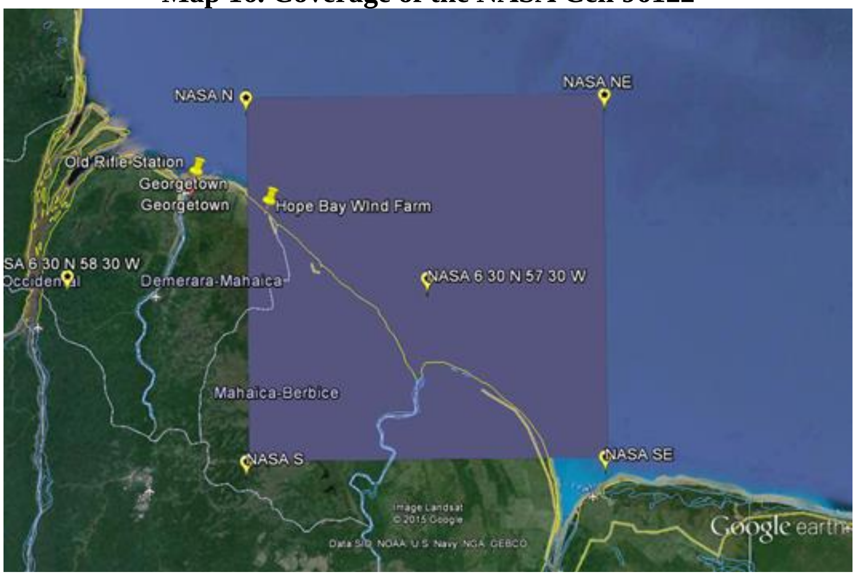
Velocity (m/s)	Frequency (hr/year)
1	50.9
2	55.6
3	115.7
4	180.6
5	476.9
6	916.7
7	1657.4
8	2074.1
9	1750.0
10	967.6
11	412.0
12	74.1
13	12.1
14	10.5
15	5.9
Total (hr/year)	**8760**

Height: 40 m (to be confirmed). Source: Digitized from graph.

6.4.1.3 NASA Surface Meteorology

Another source for information on wind power is the NASA Surface Meteorology and Solar Energy web site. This source provides averaged solar and wind information for cells of size 1o x 1o (approximately 110 km * 110 km). For the 20 MW Wind Power Plant, located near Hope Beach, the information that applies corresponds to the cell 96122 centered at Latitude 6.5o N and Longitude -57.5o W. Map 16 shows the coverage of this cell, which includes Hope Beach and surroundings, and a vast region to south.

Map 16. Coverage of the NASA Cell 96122



Cell Midpoint Latitude: 6.5, Cell Midpoint Longitude: 57.5. Source: Adapted from Google Earth

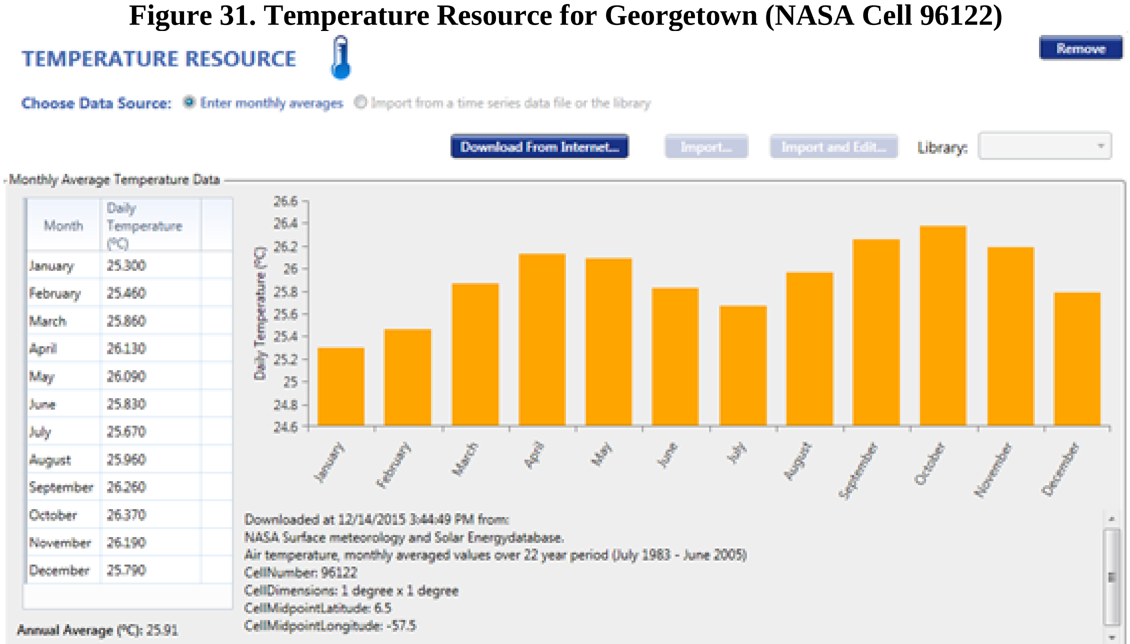
Figure 30 shows Wind Resource for Hope Beach and the area covered by NASA Cell 96122. The annual average is 3.51 m/s, with a maximum of 4.29 m/s during January and a minimum of 2.92 m/s during August at 50 m anemometer height.

Figure 30. Wind Resource for Hope Beach area (NASA Cell 96122) at 50 m

Source: NASA Surface meteorology and Solar Energy database. Downloaded by HOMER Pro

Figure 31 shows the air temperature for NASA Cell 96122, showing a maximum of 26.13oC for the month of April, and a minimum of 25.3oC for the month of January.

Figure 31. Temperature Resource for Georgetown (NASA Cell 96122)



Source: NASA Surface meteorology and Solar Energy database. Downloaded by HOMER Pro

It is important to note that the mean monthly velocities at 50 m are lower than the monthly wind velocities measures at 10.43 m at the Old Riffle Station. This difference can only be explained considering that NASA value is an average on a square of 1ox1o (equivalent to 111 km*111 km) and because of the low velocities in the hinterland the average is reduced. That's the reason why this information is not considered.

6.4.1.4 Wind data assessment reports for four locations

For the development of this 2018 report update, GEA supplied Wind Data Assessment Reports (May 25, 2018) for the locations of Port Mourant, on the coast close to New Amsterdam, and for Jawalla, Orealla and Yupukari in the hinterland.

In Port Mourant, the wind vane and anemometer were installed on a Water Tank Tower for a very preliminary survey of the site. A new tower and new instrumentation will be placed during 2018.

Map 17. Location of meteor stations in Jawalla, Orealla and Yupukari

The instrumentation in Port Mourant were installed on a Water Tower Tank and not on an appropriate wind measurement tower. The very preliminary results show that this is a promising site. During year 2018, new measurement and data logging equipment will be installed on a proper wind measurement tower.

The conclusion of the Wind Data Assessment Reports for Jawalla, Orealla and Yupukari is that their Wind Power Densities at 50 m are *Poor* (Wind Power Class Classification). The average annual wind speed on current economically feasible projects must be a minimum of 7.0 m/s. This velocity can be achieved at 80 m or higher in these locations, according to the wind shear coefficients, but this height becomes impractical for small wind projects[61].

6.4.1.5 WES Report

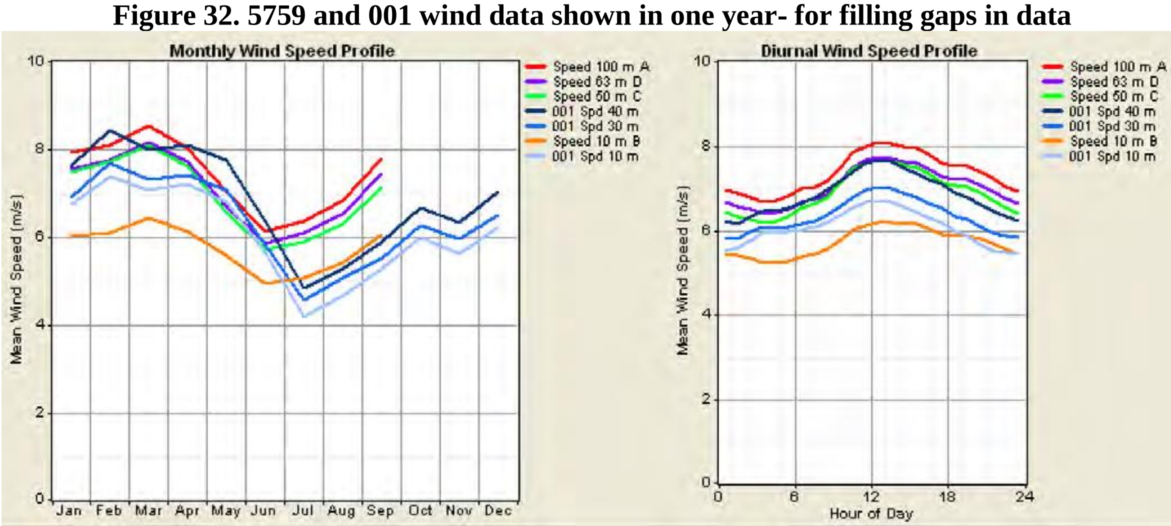
This report is based on wind measurements from a met tower, corrected for long term wind speed average and modeled over the project area using WASP software[62].

The met tower (#5759) was a 100 m tall guyed met tower placed at Hope Beach for measuring speeds for the project. The tower had instruments at six heights: 100 m vane and anemometer, 63 m anemometer, 50 m anemometer and 10 m vane and anemometer. The 30 m and 71 m instruments connections were not correct, so this data was not used. All instruments heights are approximate from ground level.

The measurement data set is from Jan 1, 2015 till Dec 31, 2015. Due to a failure in the power system of the data logger, there was a loss of data after September 16, 2015. The missing data was "synthetized" using the data from September 17 to December 31 of 2003, using information of a 40 m tall wind measurement tower (#001) installed at same place years before.

Figure 32 shows the monthly wind speed profiles for the 100 m, 63 m, 50 m and 10 m anemometers of the tower #5759 and the 40 m, 30 m and 10 m anemometers of the tower #001, and their diurnal wind profiles.

Figure 32. 5759 and 001 wind data shown in one year- for filling gaps in data



Source: Guyana Hope Beach, Wind Energy and Energy Assessment Report, WES Engineering (May 2016), Wisconsin, USA, page 10.

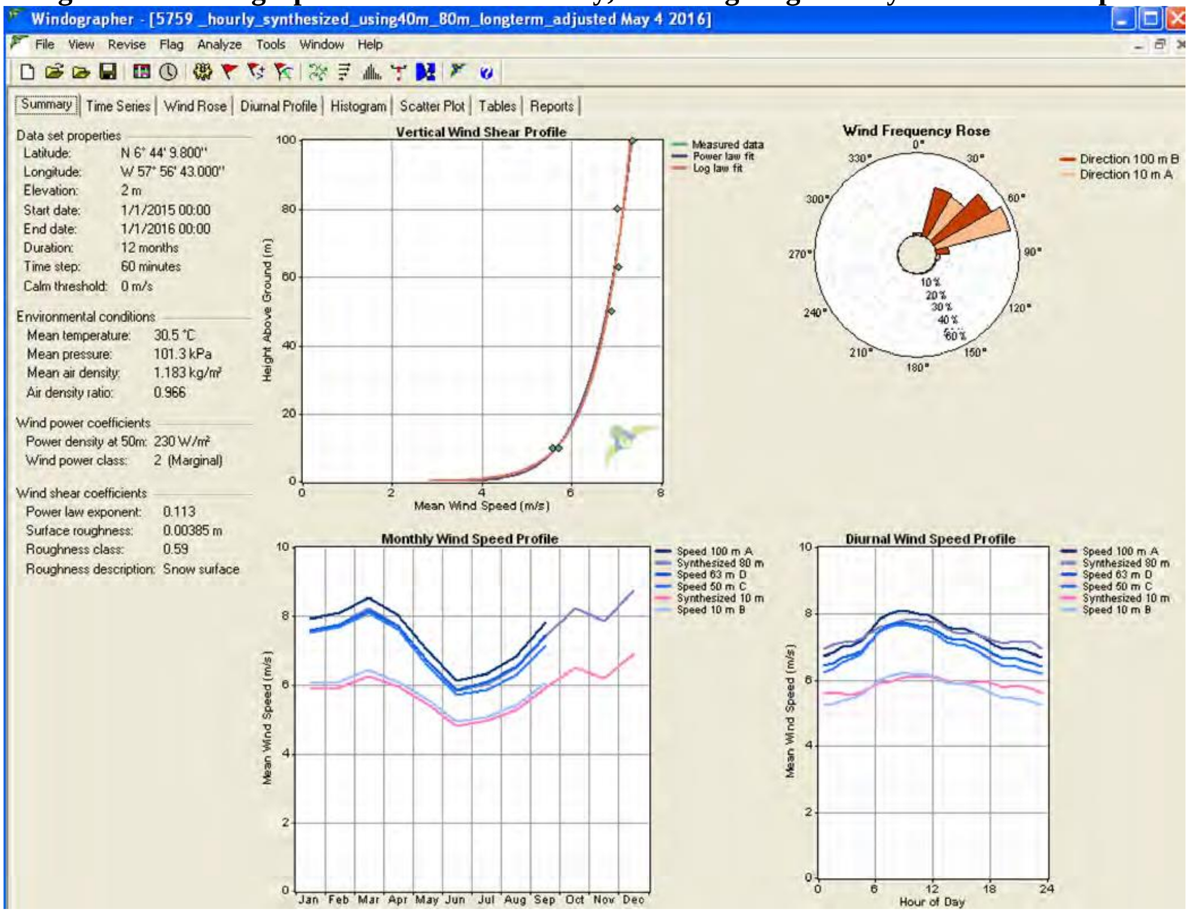
Windographer software has a fill gaps process to create lost values for data gaps. The synthesized data was compared to the other long-term data sources for accuracy of scale and hourly variability of winds. Figure 33 shows the synthetized 80 m (turbine hub height) monthly wind profile, the diurnal wind speed Profile, the vertical wind shear and the wind frequency rose. From the wind rose, the prevailing wind directions are 30° to 60° East from North at 100 m height. The vertical wind shear profile, employed for

[61] See Appendix Appendix J .

[62] Guyana Hope Beach, Wind Energy and Energy Assessment Report, WES Engineering (May 2016), Wisconsin, USA.

extrapolating velocities at other heights, has a power law exponent of 0.113. The power density at 50 m is 230 W/m2 (Wind Power Class 2 – Marginal).

Figure 33. Windographer 5759 data summary, including long term synthesized 80m speed



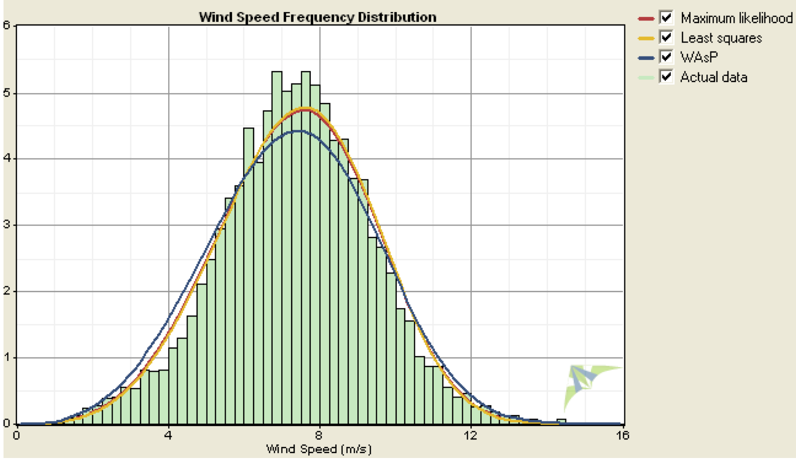
Source: Guyana Hope Beach, Wind Energy and Energy Assessment Report, WES Engineering (May 2016), Wisconsin, USA.

The below image from the Windographer software gives the Turbulence Intensity(TI) summary for the 100 m instrument, the Representative TI is low, with value below 0.1 at 13 m/s. There is not data to provide a 15 m/s bin. This site is in an IEC Category C turbulence, the lowest category, due to the seashore location.

Figure 34 has the probability distribution of the wind data used for analysis- 100 m height. Weibull parameter k and c have been estimated with three different methods.

Figure 34. Probability Distribution Function – 100 m height

Algorithm	Weibull k	Weibull c (m/s)	Mean (m/s)	Proportion Above Mean	Power Density (W/m2)	R Squared
Maximum likelihood	4.038	8.113	7.358	0.510	300.1	0.98321
Least squares	4.087	8.127	7.375	0.510	301.0	0.98395
WAsP	3.727	8.066	7.283	0.505	299.8	0.97081
Actual data	(8,760 time steps)		7.371	0.505	299.8	



Source: Guyana Hope Beach, Wind Energy and Energy Assessment Report, WES Engineering (May 2016), Wisconsin, USA, page 10.

For 80 m, the best-fit Weibull parameters are: k=4.30 and c=8.07 m/s.

Long term average wind speed at site modeled in the range 6.8 m/s to 7.0 m/s for a turbine hub height of 80 m. The Net Capacity Factor (NCF) for the wind turbine HZ 2 MW 111 m rotor turbine was 36% for the long term annualized average.

6.4.1.6 Jargstorf Report

B. Jargstorf of the German company Factor 4 Energy Projects GmbH conducted an evaluation of the proposed wind farm in Hope Beach. This project has been discussed since the last decade and has suffer various wind park configuration changes.

Following Jargstorf report[63], "In the PINs from March 2014 and November 2015 the estimated annual energy production is given as 82 and 80 GWh, respectively. In the first case it was based on a 25 MW wind park with 10 Goldwind 2.5 MW units (gearless, direct drive), in the latter on a 26 MW configuration with 13 units of the Haizhuang Windpower Equipment Co. with 2 MW each. Details about the wind turbine were not given - it is assumed, however, that the developer calculated the annual output for the HZ-102-2MW model with 102 m rotor diameter. In the final proposal of the developer, it is proposed a 2 MW machine with an enlarged rotor diameter of 111 m". Therefore, the projected wind park at Hope Beach will increase its surprisingly high capacity factor from 35.1% to 41.0%.

Later in the analysis of the financial proposal, and as consequence of the other technical points on the Hope Beach Project reported by Jargstorf, he suggest a "more realistic capacity factor, say, of 27% instead of 37%".

[63] B. Jargstorf. Hope Beach Wind Park Project – Inception Mission Report. Factor 4 (July 2016) Wismar. Germany.

The major reasons for the criticism of Jargstorf on the project are: the wind energy assessment carried out by WES (previous section) have missing wind velocity periods completed with measurements of other station, the technical information on the proposed wind turbine has to be measured by an independent party, the wind turbine is not appropriate according to the IEC wind class classification, the configuration of the park is not appropriate for safety and health reasons for the inhabitants close to the wind park location, and a higher estimate of the wind losses instead of the proposed 23% because of a higher estimate for the wake losses for the whole park, among others gaps in the project reported.

6.4.2 Capacity Factor

For the analysis of wind energy generated by a wind turbine, an essential parameter is the Capacity factor. In the 2016 report, employing a turbine that exceeded the specs of a 1.8 MW wind turbine for Hope Beach (where the Annual Average Wind Speed is 7.6 m/s), and a loss factor of 17.7%, the Capacity Factor for a single turbine was 38.5%. When considering other losses of the wind park (wake losses and other), NCF was rounded to 36%.

The final question concerning this study is, what is an appropriate Net Capacity Factor not only for Hope Beach but for the coastal line of Guyana, where the most promising places seems to be the coastal line from Hope Beach to Port Mourant.

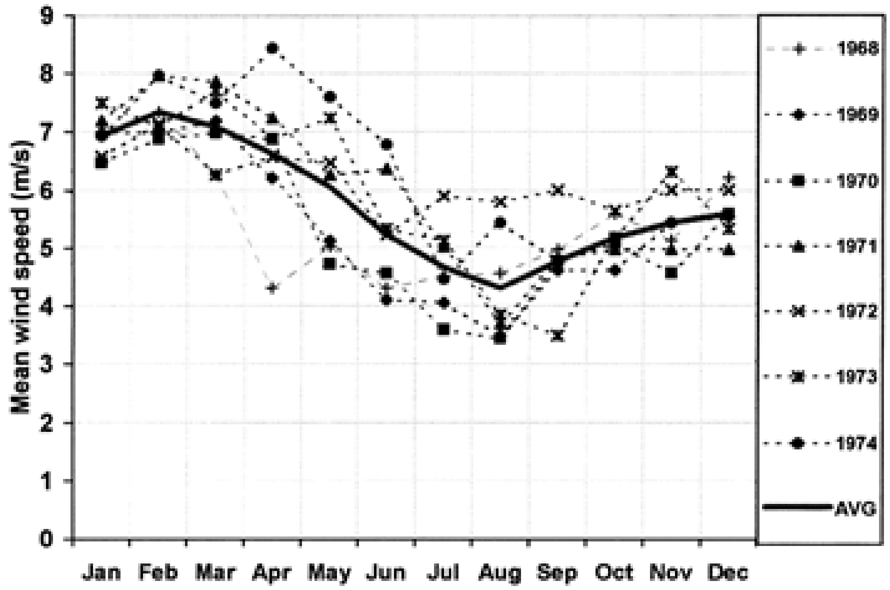
In the previous 2015 report, using limited wind information for Hope Beach, Brugman SAS proposed a capacity factor de 36% for individual turbines. The WES Engineering Report of 2016, one year later of the Brugman suggest, with better wind velocity measurements, calculated a Net Capacity Factor for the HZ 2 MW 111 m rotor turbine at 36% for the long term annualized average. This last figure is the one criticized by Jargstorf.

In virtue of the WES wind evaluation and the very preliminary wind evaluation of Port Mourant, it seems convenient to maintain the capacity factor in the range 36% - 33% for the coastal line from Hope Beach to Port Mourant.

6.4.2.1 Monthly behavior of mean wind speeds and energy generation

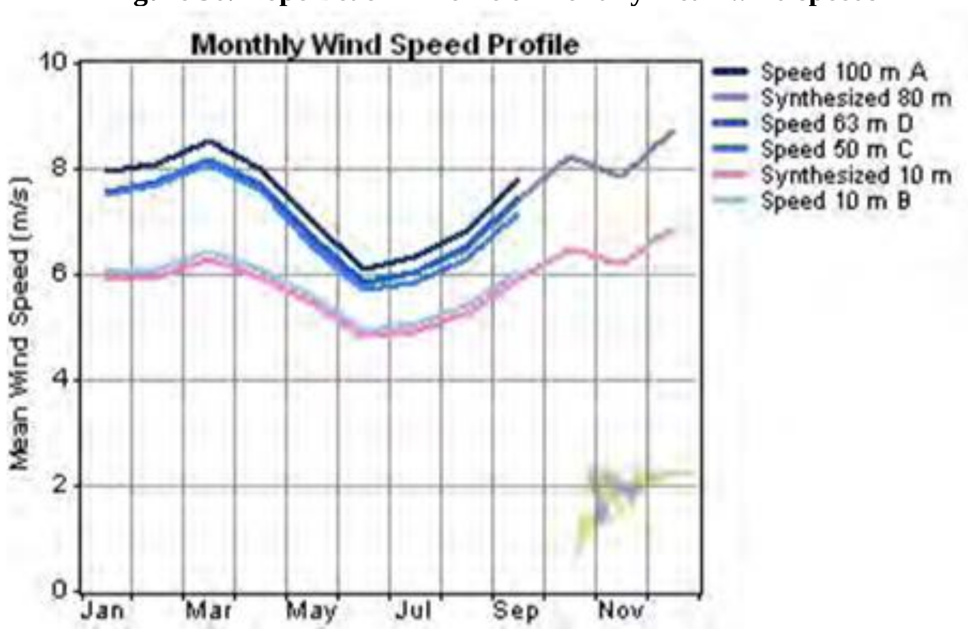
Monthly profiles of wind speeds for Old Rifle Range and Hope Beach on the Caribbean shore are shown in next figures.

Figure 35. Monthly mean wind speeds. Old Rifle Range, Georgetown, 1968-1974



Note: Anemometer Height: 10.67 m.

Figure 36. Hope Beach - Profile of monthly mean wind speeds



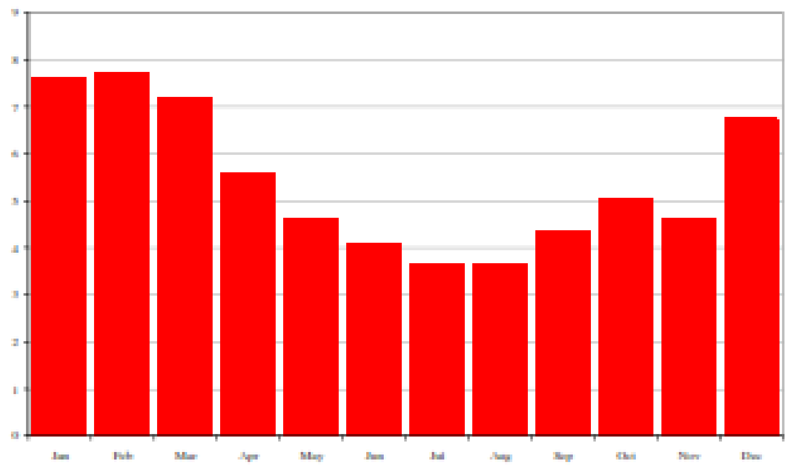
The figures show a maximum moving from March to April, a minimum in the period June- August, and a recovery of the monthly mean wind velocities in the last months of the year.

The available information does not give the monthly profiles of the expected energy generation in anyone of these locations.

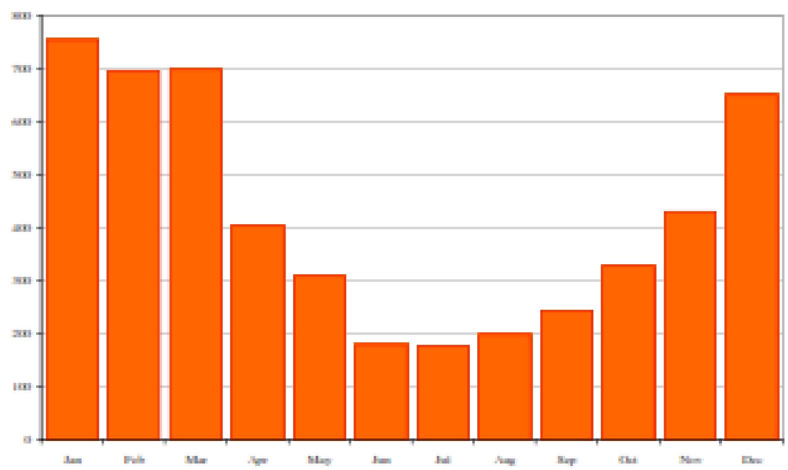
Figure 37 shows the profile of the monthly wind speeds and the monthly production for a 2 MW wind turbine wind class III at Nieuw Nickerie in Surinam. It shows the influence of the velocity profile on the generation profile. A similar behavior could be expected for the locations in the Guyanese shore.

Figure 37. Suriname – Nieuw Nickerie –winds speeds & generation (monthly)- 2 MW wind turbine Class III

Nieuw Nickerie, Suriname - Monthly Wind Speed in m/s



Nieuw Nickerie, Suriname - Monthly Production in MWh - Wind Class III Turbine - 2 MW



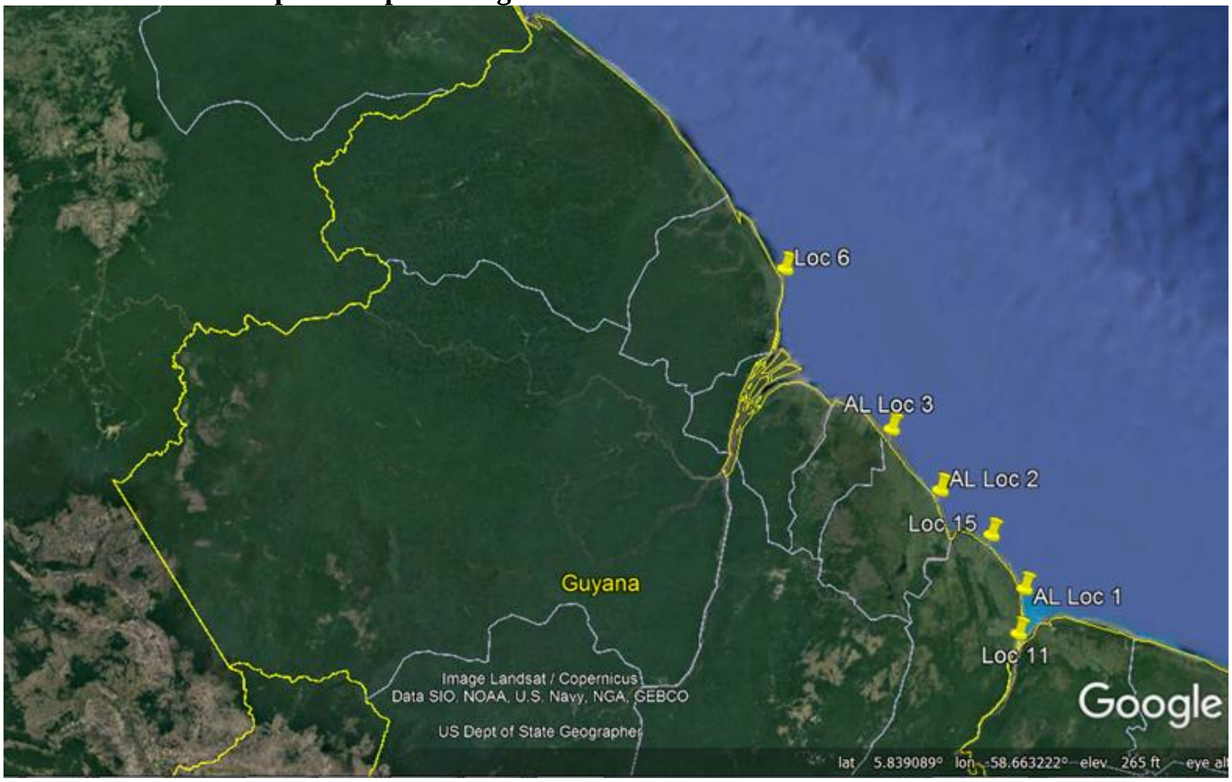
Source: own calculation, based on measured wind data from 2006 - 2009 at 30 m above ground (raw data) by Anton de Kom Universiteit von Suriname, Faculteit der Technologische Wetenschappen (Mr. C. Wijngaarde, MSc.)

To verify the promissory wind conditions of the Guyanese Atlantic shore, in fully agreement with information received from the GoG, this report considers recommendable wind measurements of the highest quality in the next places on the shore.

Table 53. Summary of recommended wind measurement sites.

Rank	Site #	Location	Lat	Long
1	AL_Loc 1	Corentyne, Leeds to Number Sixty one	6.035594	-57.1615
2	15	Port Mourant	6.259866	-57.3519
3	AL_Loc 2	Onverwagt	6.429864	-57.6185
4	11	Crabwood Creek	5.826004	-57.1587
5	AL_Loc 3	Essex to De Kinderen	6.675216	-57.8840
6	6	North Anna Regina	7.337393	-58.4824

Map 18. Map showing the locations of the recommended sites



Source: GoG

6.4.3 Investment and O&M costs

For this study a representative investment cost of US$ 1,657/kW was considered for DBIS onshore wind plants and US$ 47.8/kW/year as operating and maintenance costs. These costs correspond to estimates prepared in 2017 by the Energy Information Administration (USA) and are very similar to the estimations for a reference project obtained prepared with NREL (USA) statistics. Appendix K includes a detailed presentation of these estimates. The useful life of this type of projects was assumed in 20 years.

6.5 Solar options

The main driver for development of solar photovoltaic energy in Guyana has been until today the improvement of the quality of life of isolated communities where grid power is unavailable. The total estimated existing solar PV installed capacity in Guyana is about 5.3 MW, of which 3 MW are on-grid (mostly distributed PV Solar systems in public buildings and schools) and 2.3 MW off-grid (in remote hinterland communities). These includes projects to be completed in 2018 and Guyana's first 400 kW Solar PV Farm. Now, the capacity of Solar PV Projects in the pipeline (financing not secured but being pursued) is 34.2 MW (20 MW from GGGI initiatives with self-generators + 9MW GPL + 5.2 MW IRENA). An estimate of Potential Solar PV capacity is about 85.3MW (inclusive of 5.3 MW installed as at 2018 + the 34.2 MW in the pipeline + additional 20MW on GPL grid + 20 MW off-grid + 5 MW Linden + 0.8 MW Ituni).[64]

This examined opportunities for additional projects to increase supply to the Demerara – Berbice interconnection system (DBIS), including the potential impacts of Distributed Generation (DG) considered in the power demand forecast evaluation.

The solar irradiation in Guyana has been considered satisfactory for the exploitation of solar energy and has been estimated at a mean radiation level of 1700 kWh/m²/year.

For the development of solar photovoltaic projects, the basic information depends on the type of technology considered. For electricity generation with flat PV modules, Global Horizontal Irradiation (GHI) and ambient temperature are required.

In Brugman (2016), the source of information was the NASA Surface Meteorology and Solar Energy web site. This source provides averaged solar, wind and temperature information for 1o x 1o cells (110 km x110 km). For a plant located near Georgetown, the information corresponds to the cell 96121 centered at Latitude 6.5o N and Longitude -58.5o W. Map 19 shows the coverage of this cell, which includes Georgetown and surroundings, and a vast region to the south.

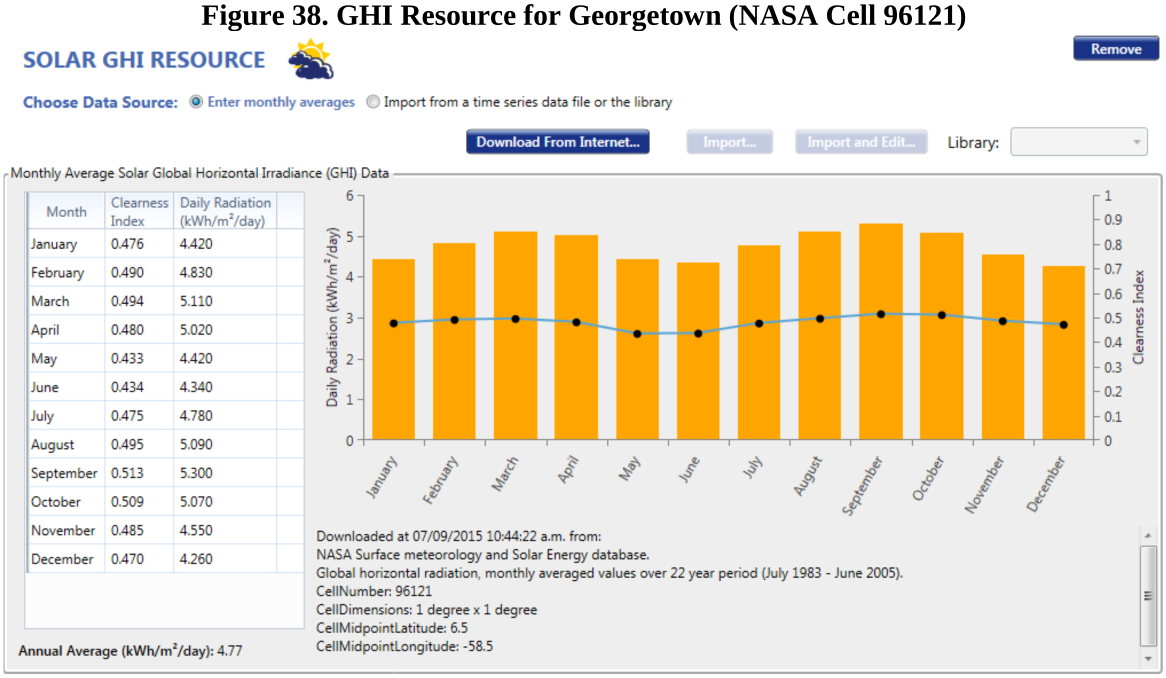
[64] Solar RoadMap Guyana. International Solar Alliance (2018). Note. Mini-grids are treated as off-grid.

Map 19. Coverage of the NASA Cell 96121

Source: Adapted from Google Earth. Cell Midpoint Latitude: 6.5, Cell Midpoint Longitude: 58.5

Figure 38 shows GHI for Georgetown and the area covered by NASA Cell 96121. The annual average is 4.77 kWh/m2/day, with a maximum of 5.3 kWh/m2/day during September and a minimum of 4.34 kWh/m2/day during June.

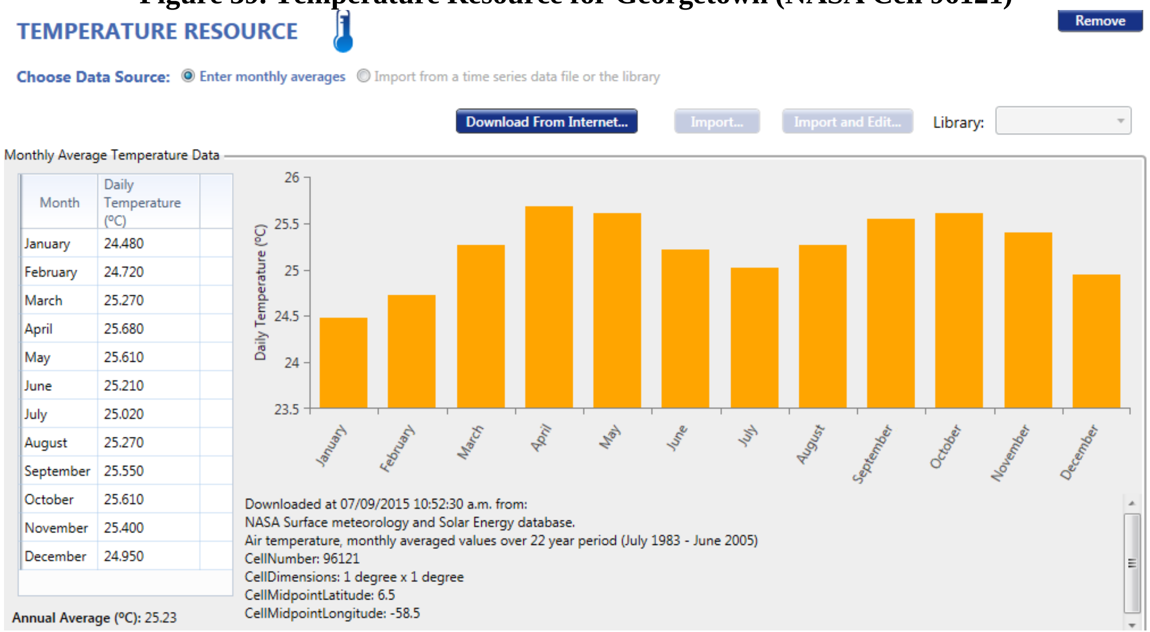
Figure 38. GHI Resource for Georgetown (NASA Cell 96121)



Source: NASA Surface meteorology and Solar Energy database. Downloaded by HOMER Pro

Figure 39 shows the air temperature for NASA Cell 96121, showing a maximum of 25.68oC for the month of April and October, and a minimum of 24.48oC for the month of January.

Figure 39. Temperature Resource for Georgetown (NASA Cell 96121)



Source: NASA Surface meteorology and Solar Energy database. Downloaded by HOMER Pro

The spatial resolution of one degree by one degree employed in the 2016 report is very low (averages for an area of app. 110 km x 110 km). Recent free available web site information provides higher spatial resolution and long-term average of critical parameters from satellite information[65]. The source is the Global Solar Atlas developed by SOLARGIS for the World Bank Group founded by ESMAP[66].

The main advantages and superiority of this information over the one in the previous report are:

- Higher spatial resolution of solar radiation and other parameters is 1 km x 1 km
- Effects of terrain have been considered (shading from buildings, structures and vegetation is not considered)
- The solar resource and PV Power potential represent a period of 1994/1999/2007 till December 2015, depending on the satellite data coverage (see Figure below).
- Temporal resolution (time step) of solar resource depends on the satellite region, and this ranges between 10/15/30 minutes.
- Air temperature data are derived from CFSR and CFSv2 meteorological models and they are available at the time step of 1 hour.
- Solar resource, PV power potential, and air temperature data is aggregated long-term into yearly averages.

[65] Presently Solargis processes data from three satellite data providers (EUMETSAT, Japanese Meteorological Agency and National Oceanic and Atmospheric Administration) with geostationary satellites operating at five key positions, to cover the entire world (except polar and subpolar regions).

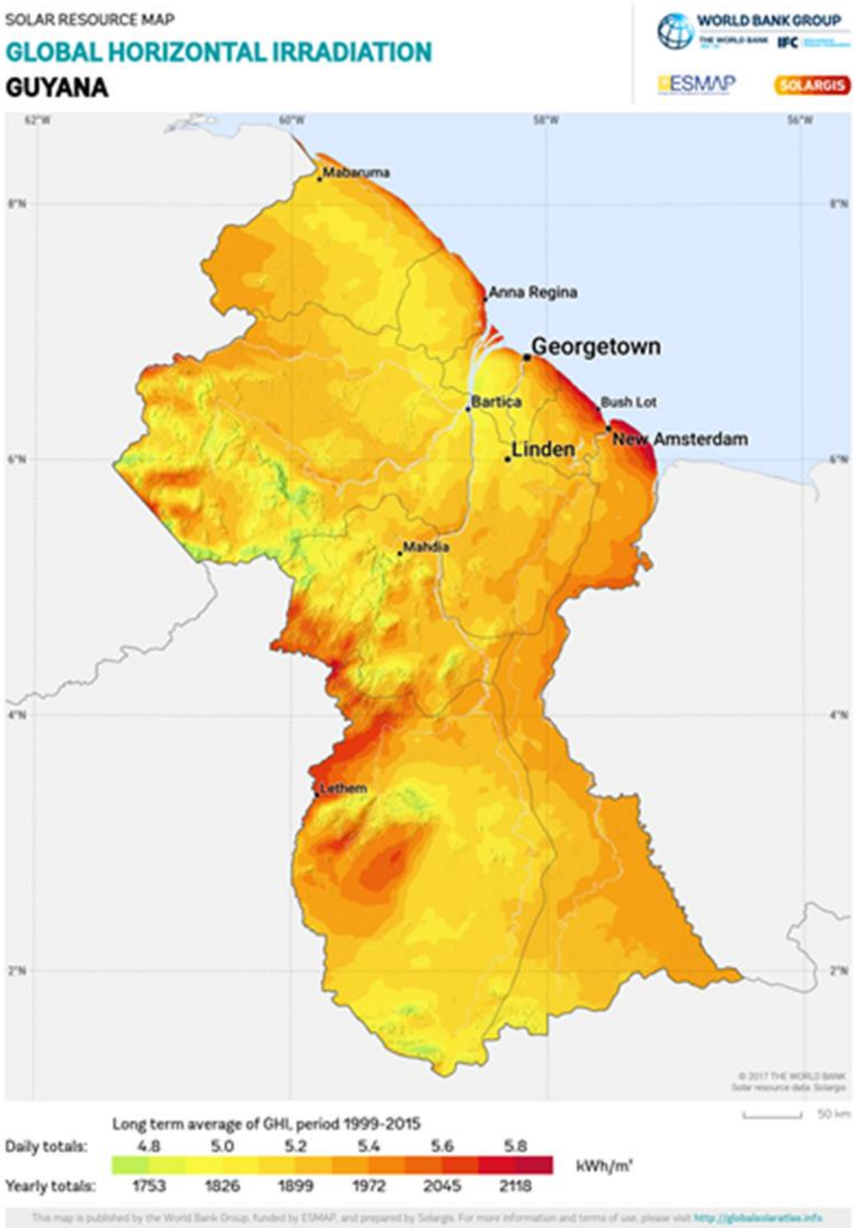
[66] http://globalsolaratlas.info/downloads/guyana

6.5.1 Global Horizontal Irradiation (GHI)

GHI (Global Horizontal Irradiation) is the sum of direct and diffuse components of solar radiation [kWh/m2]. It is considered as a climate reference as it enables comparing individual sites or regions.

Map 20 shows the long-term 1999-2015 Global Horizontal Irradiation (GHI) for Guyana. The long term average ranges between with 4.7 – 4.8 kWh/m2/year for few spots in the south west and, 5.8-5.9 kWh/m2/year for the sea border region to close to New Amsterdam and the south-west region of south west close to Lethem.

Map 20. Global Horizontal Irradiation – Guyana



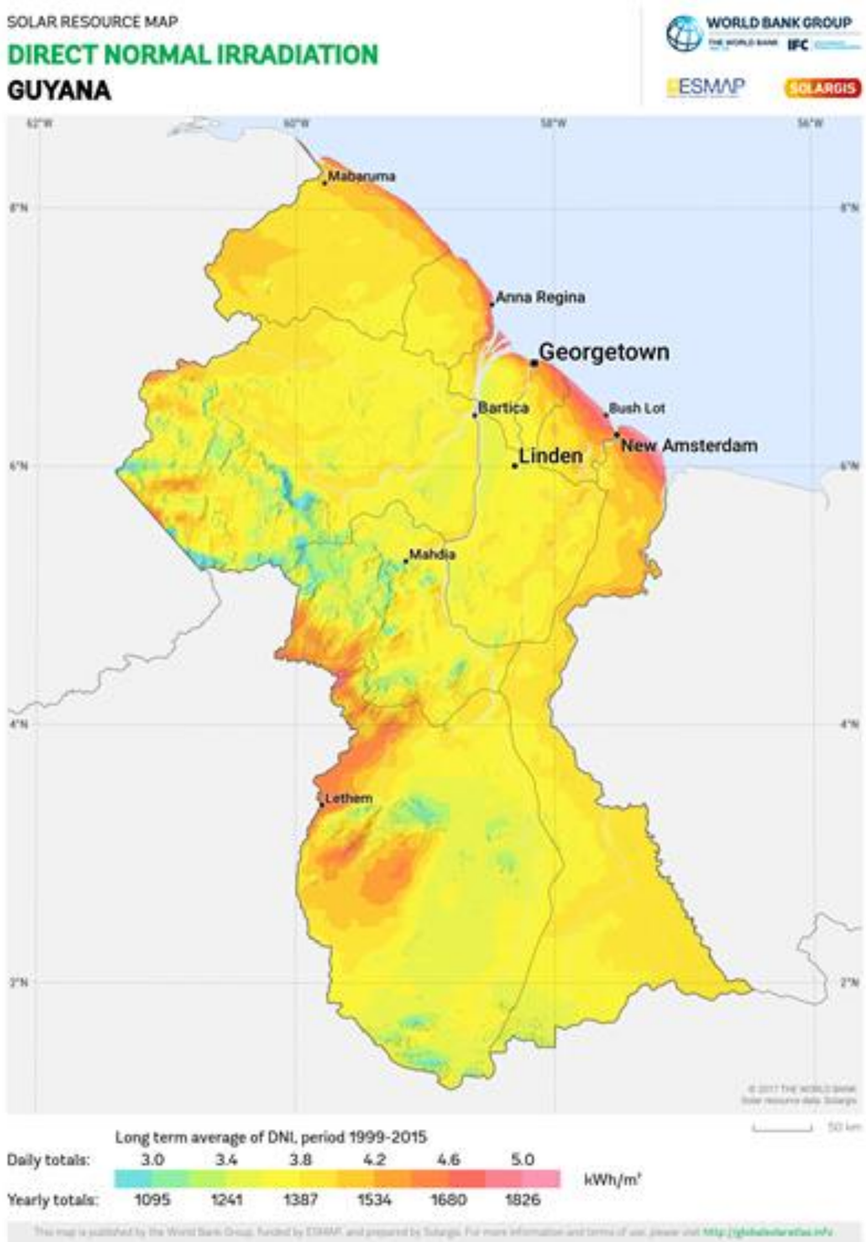
Source: http://globalsolaratlas.info/downloads/guyana

6.5.2 Direct Normal Irradiation

DNI (Direct Normal Irradiation) is the solar radiation component that directly reaches the surface [kWh/m2]. It is relevant for concentrating solar thermal power plants (CSP) and photovoltaic concentrating technologies (CPV).

Map 21 shows the long-term 1999-2015 DNI for Guyana. The long term average ranges between 3.0 for few spots in the south-west and, 5.0 kWh/m2/year for the sea border region to close to New Amsterdam and 4.6 in the south-west region of south west close to Lethem.

Map 21. Direct Normal Irradiation – Guyana



Source: http://globalsolaratlas.info/downloads/guyana

6.5.3 PVOUT

Another very important output the Global Atlas provide is PVOUT (PV Electricity output). This is the amount of energy, converted by a PV system into electricity [kWh/kWp] that is expected to be generated according to the geographical conditions of a site and a configuration of the PV system. PVOUT is also known as Specific Yield (SY) of a PV System, that is, the total amount of energy generated per kWp installed.

$$PVOUT\,(year) = SY = \frac{Total\ Annual\ Energy\ Generated\ (kWh)}{Installed\ PV\ Peak\ Power\ (kWp)}$$

Table 54 shows the configuration of the PV system employed for the computation of PVOUT.

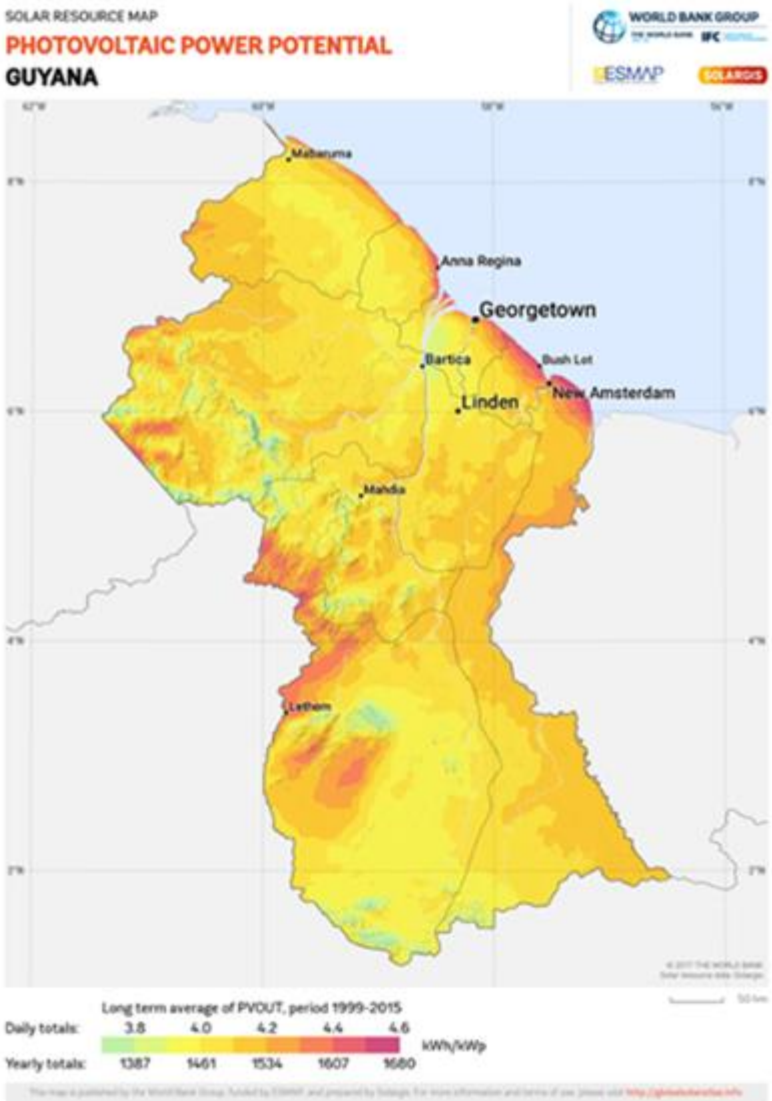
Table 54. PV Configuration

PV Configuration	
Installed Power:	1 kWp
Modules:	CSI modules, NOCT = 46 °C temperature coeff. of the Pmax = -0.45 %/K
Inverters:	Central Inverters with Euro Efficiency 97.5 %
Mounting of PV modules:	Fixed mounting structures North or South oriented with optimum tilt angle and with typical row spacing
Other DC losses:	Dirt, dust, soiling, frost, snow, DC cabling losses, electrical mismatch, electrical losses of 7.5 %
Transformer:	Standard high efficiency transformer, AC cabling losses of 1.5 %

Source: Consultant

Map 22 shows the long-term average 1999-2015 of PVOUT for a 1 kWp PV System with the previous configuration. The region with the highest potential is the shore, with a potential between 4.5-4.6 kWh/kWp, maximum at Port Mourant, Bush Lot, Mahaica and Anna Regina, between 4.2 – 4.3 for Georgetown. Also, between 4.2 - 4.3 kWh/kWp, Lethem and Kato. In the rest of the country around 4.0 kWh/kWp are expected.

Map 22. PVOUT for a 1 kWp PV System– Guyana



Source: http://globalsolaratlas.info/downloads/guyana

6.5.4 Capacity Factor

The Capacity Factor (CF) is the ratio of the actual output over a period of a year and its output if it had operated at nominal power the entire year:

$$CF = \frac{Energy\ generated\ per\ annum\ (kWh)}{8760\ \left(\frac{hours}{annum}\right) x\ Installed\ Capacity\ (kWp)}$$

Comparing this equation and the previous one, the values reported in the PVOUT map on a year basis, divided by 8760 hours are the Capacity Factors of the PV Plant in the different regions of the country.

Table 55 shows the Daily PVOUT, Specific Yield, and Capacity Factor for 1 kWp PV Plant in different Cities and Towns from direct reading of the bands in the map. More accurate values can be obtained for each town using directly the web application.

Table 55. Daily PVOUT, Specific Yield, and Capacity Factor for 1 kWp PV Plant in different Cities and Towns

PVOUT (kWh/kWp-day)			Specific Yield (kWh/kWp)			Capacity Factor (%)			Cities, Municipalities
3.8	to	3.9	1388	to	1424	15.84%	to	16.26%	
3.9	to	4	1424	to	1461	16.26%	to	16.68%	Bartica
4	to	4.1	1461	to	1498	16.68%	to	17.10%	Aishalton, Mabaruma, Akwero, Linden, Kwakwani, Land of Canaan
4.1	to	4.2	1498	to	1534	17.10%	to	17.51%	Parika
4.2	to	4.3	1534	to	1571	17.51%	to	17.93%	Crabwood Creek, Charity, Corriverton, Georgetown
4.3	to	4.4	1571	to	1607	17.93%	to	18.35%	Lethem, Kurukabaru, Paramakatoi, Kato, San Martin, New Amsterdam
4.4	to	4.5	1607	to	1644	18.35%	to	18.76%	Mibikuri, Mahaicny, Mahaica, Anna Regina
4.5	to	4.6	1644	to	1680	18.76%	to	19.18%	Port Mourant, Bush Lot

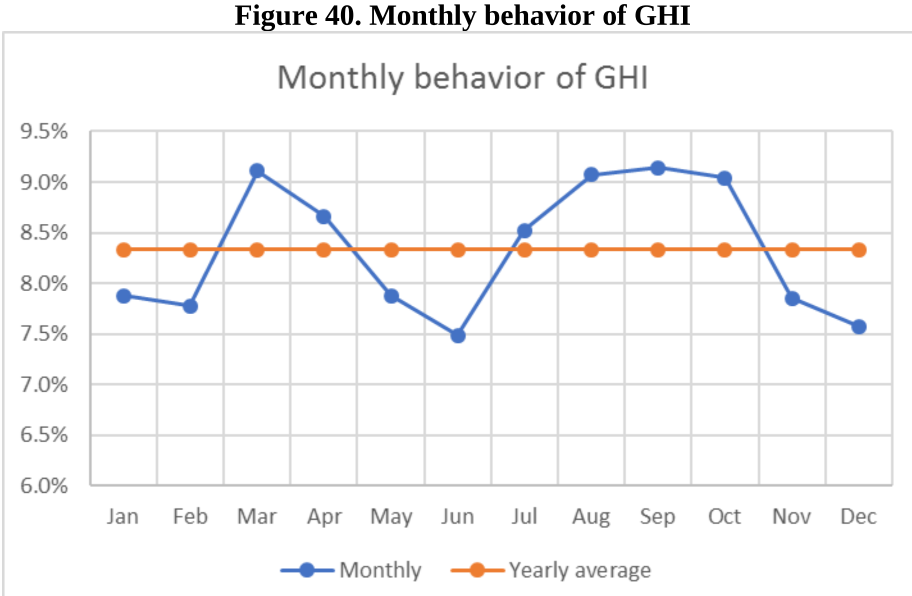
Source: Consultant

The PVOUT map and the table show that the best locations for PV plants are along the shore with capacity factors between 17 and 19%.

6.5.5 Monthly behavior of GHI and Temperature

If the monthly behavior of GHI follows the pattern of the information given in Map 19 and Figure 38 of page 115, Figure 40 shows their behavior referred to the year average of solar radiation computed as the monthly percentage of the total annual irradiation[67].

Figure 40. Monthly behavior of GHI



Source: Consultant

[67] There is no web access to the monthly behavior of GHI and Temperature.

6.5.6 Investment, O&M costs and plant factor

For the update of the DBIS generation expansion it is considered in the short term two grid connected solar plants (3 MW each, including battery storage capacity) located in Naarstigheid, West Coast Berbice and Sam's Ville Kuru Kururu.

For new PV power plants, the study includes 4x12 MW plant candidates with investment costs of US$ 3,500/MW with battery storage capacity and US$ 1,370/MW without it[68]. O&M costs were taken as US$ 24/MW-year and plant factor in 19%. Appendix I includes a detailed presentation of these cost parameters.

6.6 Biomass options

As noted by IMF (2017c), Guysuco's business model is unsustainable given low competitiveness, depressed sugar prices and the expected dismantling of the EU sugar quota system in 2017 (see Figure 41). Given the liberalization of the EU sugar market in 2017, the IMF encouraged the GoG's authorities to press ahead with the overhaul of the sugar industry by scaling down and privatizing inefficient units (while providing a safety net to those affected) and diversifying the revenue stream.

According to the State paper on the Future of the Sugar Industry[69] which was presented to the National Assembly by the Honorable Minister of Agriculture, the Special Purpose Unit of the National Industrial and Commercial Investments Limited was established as a corporate vehicle to manage the divestment and diversification of the sugar industry in Guyana. The divestment and diversification of the sugar industry was recommended because the Guyana Sugar Corporation Inc. (Guysuco) was in financial turmoil since it was heavily indebted. As the Honorable Minister of Agriculture explained in the State paper, "the future of the sugar industry is considered to lie in a smaller sugar sector with reduced losses and cash deficits . . . coupled with a separate and profitable diversified enterprise which would ensure a viable future."

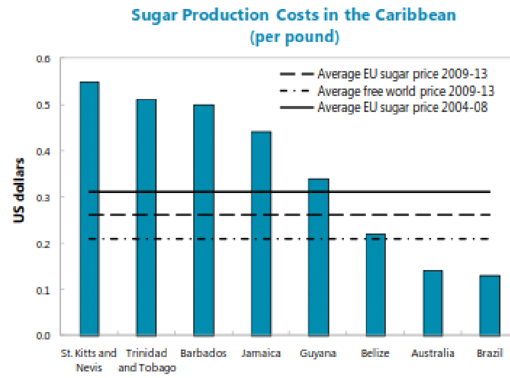
[68] Investment costs for solar PV grid connected (with and without battery storage) verified in LAZARD'S LEVELIZED COST OF ENERGY ANALYSIS—VERSION 11.0, November 2017.

[69] State paper on the Future of the Sugar Industry. http://agriculture.gov.gy/2017/05/08/state-paper-on-the-future-of-the-sugar-industry/ . Queried March 20, 2018.

Figure 41. Reform of EU regime

For several decades, Guyana and other Caribbean sugar exporters have enjoyed tariff-free access to the EU market. However, since 2005, the EU has embarked on a liberalizing reform of its sugar regime and intends to dismantle EU production quotas on September 30, 2017.

The reform is expected to further compress the already small EU sugar market premium due to increased competition from EU beet sugar producers. Some Caribbean countries have already closed their structurally uncompetitive sugar industries upon the announcement of the EU reform. Trinidad and Tobago and St. Kitts and Nevis phased out sugar production in mid/late-2000s given their significant cost disadvantage relative to large-scale producers like Brazil and Australia. Guyana mainly exports sugar to the United Kingdom (UK), which will still be affected by the new EU sugar regime until the UK's formal separation (and it is unclear what sugar regime the UK will have afterwards).



Sources: Bulte and Ruben (2007); various articles on sugar in the Caribbean; WEO, and Fund staff estimates.

Refined sugar could be sold at a premium in the CARICOM market if there was a refinery in the region, which would boost demand for Guyanese raw sugar.

Source: IMF (2017c). Page 10.

Skeldon and Enmore sugar plants were closed in December 31, 2017. At the time of this study, such facilities are not in operation and are subject to a privatization process.

Power exports to DBIS could become a diversification opportunity for Guysuco after the current re-organization process ends. We are including in this study Albion (9.8 MW) and Uitvlugt (6 MW)[70] as advised discussed by PUC and Guysuco´s management, after querying them about our findings in our previous study (Brugman (2016)).

The same Rice (2 MW) and Wood (0.7 MW) candidates of Brugman (2016) are being considered as candidates for power expansion. Table 56 summarizes the Biomass plants evaluated in this study.

Table 56. Biomass cogeneration alternatives

Plant	Capacity (MW)	Internal Consumption (MW)	Export Capacity to DBIS (MW)	Capex (US$/kW)	Load factor (%)
Albion	13.6	3.8	9.8	2,150	66%
Uitvlugt	8.6	2.6	6.0	2,250	69%
Georgetown Wood	0.66	NA	0.66	2,600	43%
Rice - 5 Region	2.3	NA	2.3	3,500	47%
Rice – 6 Region	2.0	NA	2.0	3,500	47%

Source: Consultant.

[70] An assumption is made that Uitvlugt could offer the same power export to DBIs as of Enmore in Brugman (2016)

Our analysis assumes that Skeldon, which has an installed capacity of 30MW[71] (Biomass, although it did not work properly since its beginning) plus 10 MW gensets, with internal consumption of 8.75MW. The update of the generation expansion study assumes that 10 MW gensets continues to serve GPL's PPA and that the bagasse power plant would be refurbished and the substation capacity increased to provide to DBIS 13.75 MW of biomass seasonal generation (16% annual plant factor average) after 2020.

6.7 Transmission connections of high capacity power plants

6.7.1 High capacity power plant located in Woodlands

For the connection to DBIS's 69 kV grid of new gas fired power plant of large capacity (100-250 MW) located in Woodlands, it would be required a two circuits "deep connection" from the power plant substation up to Sophia or New Sophia substations through. Given this location and the Rights of Way (ROW) and tension level estimated for the Arco Norte interconnection system it is considered that such transmission system would consist of a two circuit 230 kV transmission system including its required 230/69/13.8 kV substations. Total length estimated for this this line is 37 km. This line will run east from Sophia, or the Garden of Eden substation just south of Georgetown, parallel to the coast, reaching the Colombia-Mahaicony located near the Woodlands site. Total investment cost of this system is estimated in US$ 25.1 million (see Appendix M).

6.7.2 Five large capacity hydroelectric power plants

Transmission connection of the five hydroelectric projects considers that a double circuit 230 kV transmission line would be installed in Guyana as a backbone of the Arco Norte Interconnection System, connecting SECC1 substation (future) with Linden (future) and New Sophie substations (or Garden of Eden substation if preferred as DBIS connection site). This system would be required to connect Amaila and Tumatumari hydroelectric projects and partially, Linden – New Sophie, in the case of Kumarau and Kamaira hydroelectric projects, while Tiger Hill could also eventually supply only Linden, with or without being interconnected to DBIS.

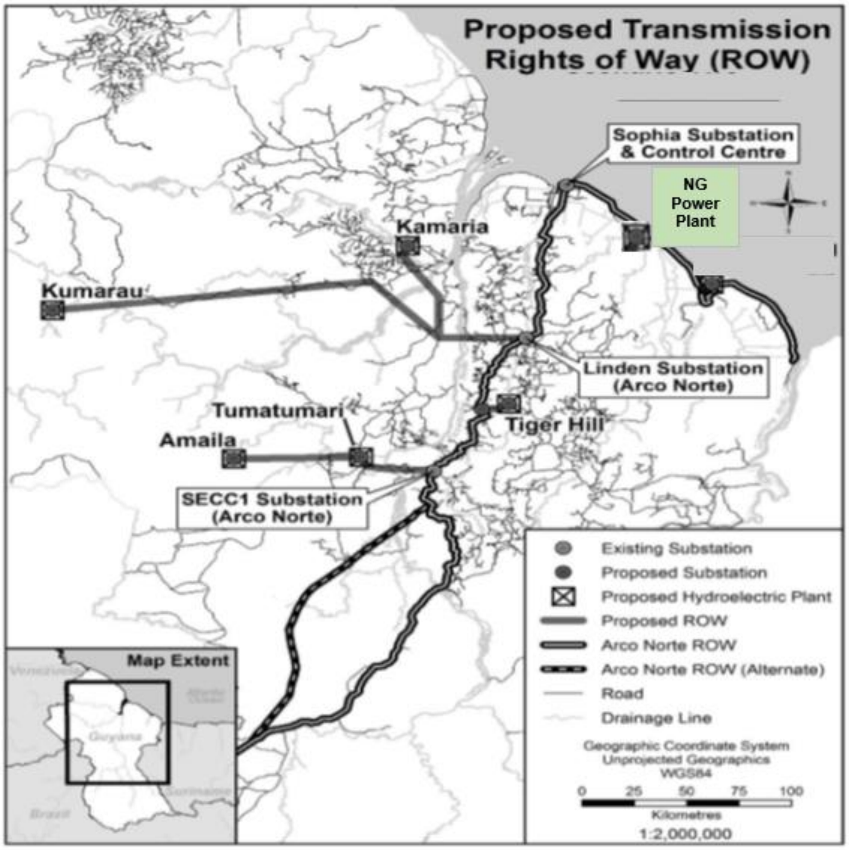
This connection line runs from future Arco Norte substation SECC1 located approximately 90 km south of Linden (near Tumatumari site) and then through Linden and finally reaching DBIS grid. The proposed Rights of Way (ROW) follows the road from Brazil to Linden, crossing the Demerara River, the Soesdyke Linden Highway, and the East Bank Public Road through to Garden of Eden.

For the purposes of the expansion study this line is separated in two main tranches: a) SECC1-Linden, which would be required for the connection to DBIS Tumatumari and Amalia power plants, and b) Linden – Garden of Eden, which would be required for the connection of all five power plants. The investment cost of the first tranche (including transmission lines and substations is estimated in US$ 31.2 million and the investment in the second tranche in US$ 62.8 million. Basic characteristics and investment cost estimates of this "backbone" transmission line are presented in Appendix M .

The basic transmission line and substation costs used were taken from the Arco Norte study. The ROW for each plant are illustrated in the figure. All ROW use the same route from Linden to Sophia following the Soesdyke - Linden Highway north of Linden before entering Georgetown via existing canal easements south of the airport.

[71] Restricted today by a grid transmission capacity of Skeldon of 13.5 MW.

Map 23. Proposed transmission Rights of Way



Source: Consultant

The ROW considered for the new power plants connections are described next.

Kamaria ROW begins by heading south-west from the plant crossing Cuyuni River (min. span width 370m) before turning south-east crossing the Mazaruni River before heading south parallel to the Bartica Potaro Road until parallel with the Rockstone Road where it turns and heads due east crossing the Essequibo River at Rockstone before following the Rockstone Road through to Linden.

Kumarau ROW begins by heading north-east from the plant crossing the Mazaruni River then parallel to ETK Road crossing the Puruni River before following the Peters Mine Road and passing Peters Mine before turning to the south-east, crossing the Mazaruni River continuing on until parallel with the Rockstone Road where it turns and heads due east crossing the Essequibo River at Rockstone before following the Rockstone Road through to Linden.

Tiger Hill ROW heads due north to Linden parallel to the Demerara River approximately 40km, the connection line is included in the project estimation as a 69 kV line with 2 circuits.

Tumatumari ROW heads in a southerly direction following the Tumatumari Konawaruk Road before turning east and following an All Weather Unsealed Road crossing the Essequibo River at BenhoriBumoko Island and then further east to SECC1.

Amaila ROW head in an easterly direction to Tumatumari dropping down the escarpment and crossing the Potaro River. They then follow the rights of way described for Tumatumari.

6.8 Levelized cost of electricity (LCOE) comparison

The power plant candidates considered for the evaluation of generation expansion in Guyana were preliminarily evaluated through a calculation of the Levelized Cost of Electricity (LCOE) associated to each candidate plant. LCOE is a convenient summary measure of the overall cost competitiveness of different generating technologies, and therefore useful for the purposes of comparing technologies with different operating and investment characteristics. It represents the constant per-megawatt hour cost (in real US dollars) of building and operating a generating plant over an assumed financial life. In other words, the LCOE is the constant unit cost of a constant payment stream that has the same present value as the total cost of building and operating a plant over its life[72].

The key inputs to calculate LCOE include investments costs (updated at its commissioning date), fuel costs, fixed and variable operations and maintenance (O&M) costs, utilization factor and operating life for each plant type, as well as the discount rate, which represents in this case the value of money over time.

The importance of the factors varies among the technologies. For instance, for technologies such hydroelectricity that have no fuel costs and relatively small O&M costs, the LCOE cost changes in rough proportion to the estimated overnight capital cost of generation capacity. For technologies with significant fuel cost, both fuel cost and overnight cost estimates significantly affect the LCOE cost. The availability of various incentives, including government subsidies or tax credits for a given technology, can also impact the calculation of LCOE. In this study it was assumed that there is no government benefit directed toward any given technology and equal treatment of corporate tax rates across all technologies.

LCOE represents the minimum price at which energy must be sold for a given plant to break even (in other words, to have net present value of zero). It is relevant to note that this approach does not take into account tax incentives (as stated above) and the effects of depreciation or tax shields of interest payments over the life of the project. In order to incorporate complex financing assumptions one should build a complete financial model for each plant over time. Equal financing levels and tax incentives for each plant was assumed, as well as equal depreciation accounting policies of each project. The following simplified criteria to calculate the LCOE of a plant in constant dollars of year 2018 was used:

$$LC = \frac{IC * \Psi + O\&M_{FIXED}}{8760 * LF} + \Phi * FC + O\&M_{VARIABLE} + \beta * \Omega$$

$$\Psi = \frac{i(1+i)^n}{(1+i)^n - 1}$$

[72] The approach followed in this study is aproppiated to estimate LCOE indicators for candidate power plants operating in mainly thermal power systems, for which the generation expansion requirements are basically driven by requirements of “firm” capacity, as it is the DBIS situation today. This permited the comparison of LCOE indicators associated to thermal plants used to supply peak loads (i.e. motors or gas turbines operating with low plant factors).The methodology applied is different from the one utilized in the Arco Norte study where LCOE indicators were estimated for “firm” energies associated to thermal power plants (by estimating maximum energy quantities considering available capacity of this power plants). The Arco Norte study approach is useful to compare LCOE indicators for power plants operating in mainly hydro power systems, for which generation expansion requirements are basically driven by requirements of “firm” energy, as it would be in the long term expected Arco Norte interconnected system.

Where,

IC =	Total Capital Investment Cost including interest during construction (Dollars/MW)
Ψ =	Conversion rate to represent the IC (ie. a Present Value) into a stream of n periods of constant payments with discount rate i, as stated below
i =	Yearly discount rate in real (constant) terms after taxes calculated as the Weighted Average Cost of Capital (WACC) without adjustments for uncertainty
n =	Operating Life (number of years) of the plant
O&M fixed =	Fixed Operation and Maintenance Costs per year (Dollars/MW)
O&M variable =	Variable Operation and Maintenance Costs (Dollars/MWh)
LF =	Plant Factor (%)
Φ =	Heat rate (MBTU/MWh)
FC =	Fuel Cost (Dollars/MBTU)
B =	CO_2 Cost per ton in US$ (US$/Ton)
Ω =	CO_2 emission per ton (Ton/MWh)

As with any projection, there is uncertainty about all of these factors and their values can vary across time as technologies evolve and fuel prices change. In this section, a discount rate of 10% (in dollar real terms) was considered. No effect of inflation was considered in discount rate, nor in fuel price projections. A US$30/ton CO_2 cost was considered in real 2018 prices.

The LCOE shown for each utility-scale generation technology in the tables that are presented at the end of this section were calculated based on a different life periods in which each plant should recover its total investment and operating costs. Different levels of load factors were used according to each technology considered as explained in Table 57. Hydro projects' capex includes transmission losses. Other assumptions for fixed and variable O&M costs were used according to each technology, as shown in Table 57.

Table 57. Levelized cost of electricity: Assumptions

Name	Technology	Fuel Type	Installed Capacity	Operational Life	Investment Costs	O&M Fixed Cost	O&M variable Cost	Heat Rate	Load Factor	Min. Load Factor	Max. Load Factor
Hydro_Kamaira	Hydro	Water	180	40	4,610	20.0	0.0	0	68.6%	65.0%	70.0%
Hydro_Amaila	Hydro	Water	165	40	4,593	20.0	0.0	0	75.7%	75.0%	80.0%
Hydro_Tiger Hill	Hydro	Water	12	40	6,074	20.0	0.0	0	62.8%	60.0%	65.0%
Hydro_Tumatumari	Hydro	Water	152	40	3,504	20.0	0.0	0	56.4%	55.0%	60.0%
Hydro_Kumarau_Natio	Hydro	Water	100	40	4,238	20.0	0.0	0	58.8%	55.0%	60.0%
Hydro_Kumarau_Regio	Hydro	Water	50	40	3,902	20.0	0.0	0	73.3%	70.0%	75.0%
Engine_LFO_11	Engine	LFO	11.4	20	1,495	15.0	8.9	9.72		70.0%	90.0%
Engine_Gas_17	Engine	Natural Gas	17	20	1,413	7.3	6.2	8.50		70.0%	90.0%
Engine_HFO_11	Engine	HFO	11.4	20	1,755	45.0	9.8	9.72		70.0%	90.0%
Bagasse_Albion	Biomass	Sugar	9.8	20	2,150	20.0	0.0	10.80	66.0%	65.0%	70.0%
Bagasse_Uitvlug	Biomass	Sugar	5.7	20	2,250	20.0	0.0	10.80	69.0%	65.0%	70.0%
Rice	Biomass	Rice	4.3	25	3,500	45.0	0.0	10.80	47.0%	45.0%	50.0%
Wood	Biomass	Wood	0.7	25	2,600	25.0	0.0	10.80	43.0%	40.0%	45.0%
Wind_8	Wind	Wind	8	20	1,657	47.5	0.0	0	35.0%	35.0%	40.0%
Wind_20	Wind	Wind	20	20	1,657	47.5	0.0	0	35.0%	35.0%	40.0%
Solar_12	Solar	Solar	12	25	1,370	23.0	0.0	0	18.0%	20.0%	25.0%
Solar_Storage_12	Solar_Storage	Solar	12	25	3,500	23.0	0.0	0	18.0%	20.0%	25.0%
Solar_Thermal_Tower	Solar_Storage	Solar	120	35	6,900	77.5	0.0	0.00	47.0%	45.0%	50.0%
Natural_Gas_GT_50	Gas Turbine	Natural Gas	50	20	900	14.0	3.0	10.00		70.0%	90.0%
Comb_Cycle_100	Combined Cycle	Natural Gas	100	25	2,000	25.0	3.5	8.16		70.0%	90.0%
Comb_Cycle_150	Combined Cycle	Natural Gas	150	25	1,950	23.0	3.5	8.00		70.0%	90.0%
Natural_Gas_GT_20	Gas Turbine	Natural Gas	20	20	1,100	16.0	3.0	10.20		70.0%	90.0%
Natural_Gas_GT_33	Gas Turbine	Natural Gas	33	20	1,000	15.0	3.0	10.10		70.0%	90.0%

Source: Consultant. Hydro Investment Costs ($/kW) from 10% discount rate scenario as shown in Table 58.

To take into account the time value of money in hydroelectric plants (as most are built in 3 years except Kumarau National which is built in 4 years), Table 58 shows the capital costs that were used for each discount rate.

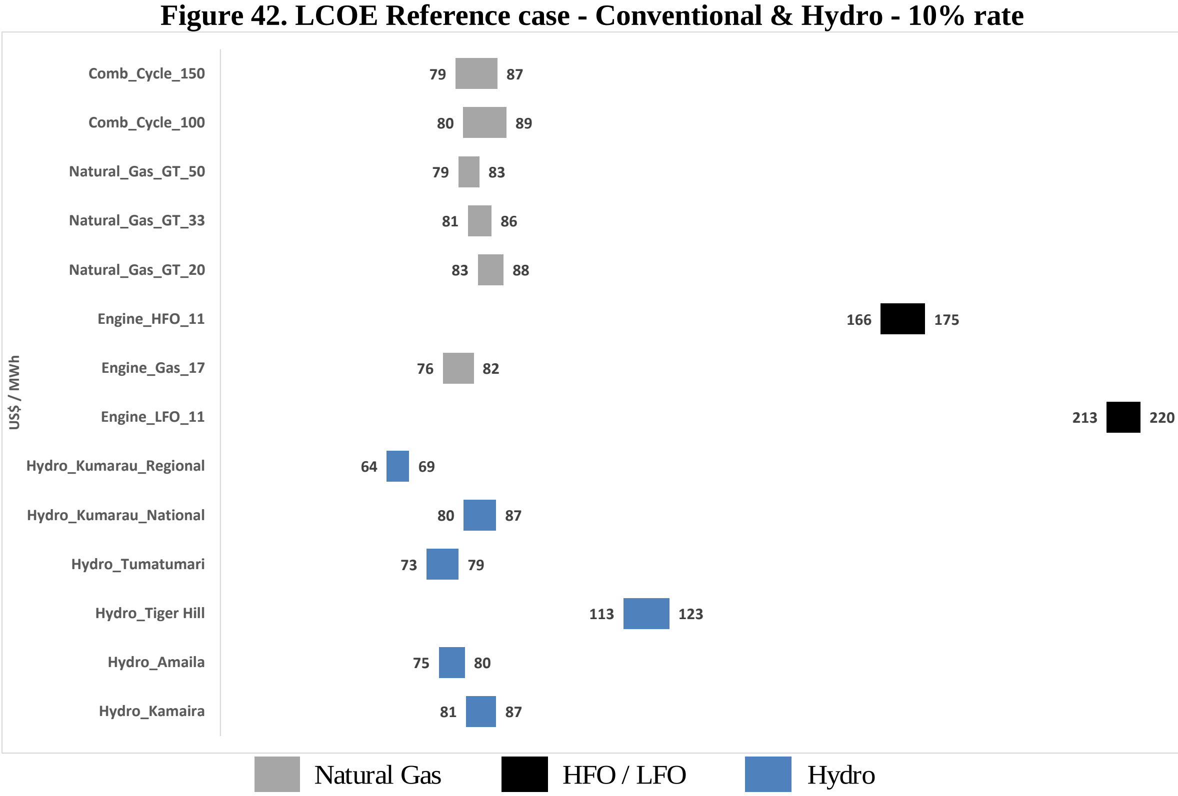
Table 58. Hydroelectric projects' capital cost (US$/kW) per each discount rate

Name	8%	10%	12%
Hydro_Kamaira	4,474	4,610	4,749
Hydro_Amaila	4,457	4,593	4,731
Hydro_Tiger Hill	5,895	6,074	6,256
Hydro_Tumatumari	3,401	3,504	3,609
Hydro_Kumarau_National	4,055	4,238	4,427
Hydro_Kumarau_Regional	3,787	3,902	4,020

Source: Consultant

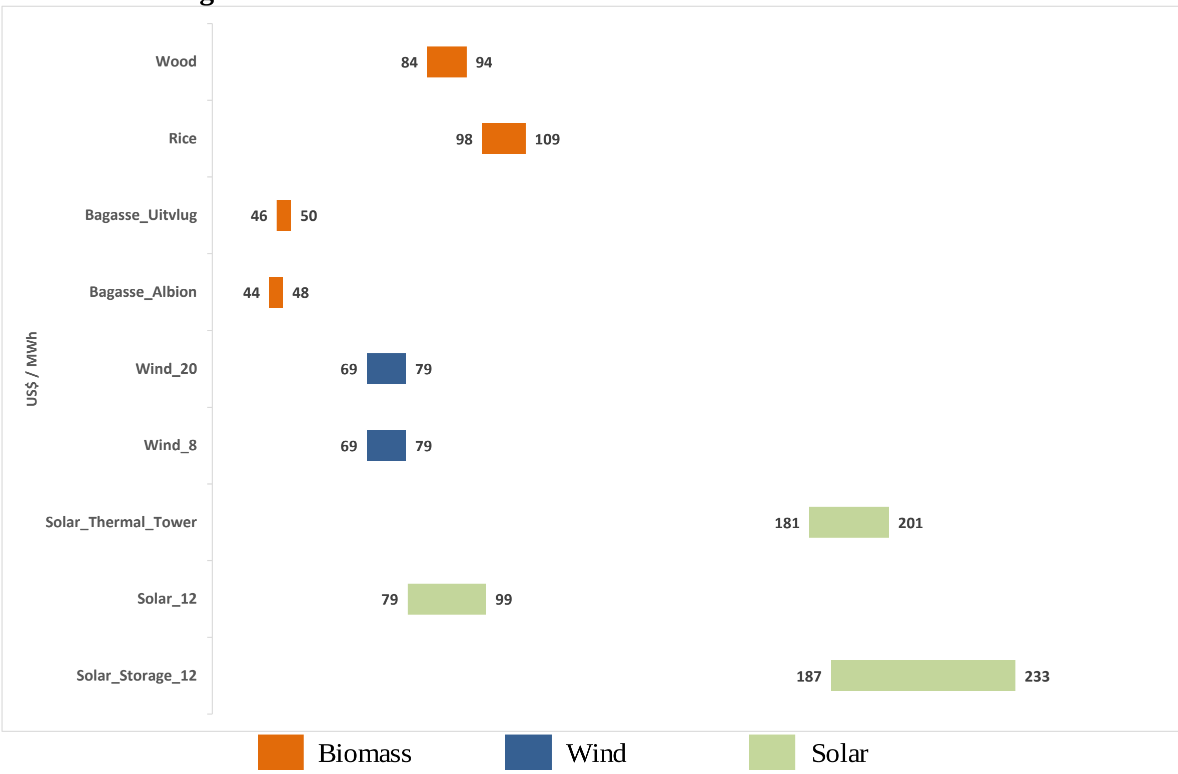
Figure 42 and Figure 43 show the LCOE plotted against load factors (x-axis) obtained for the plant candidates for the Reference Case scenario of fuel prices and 10% discount rate. In order to obtain a comparable comparison, the consultant split the comparison between power plants using non-conventional renewable energy sources (such as wind, biomass and solar, which do not have firm energy) and power plants using conventional technologies (hydro, thermal plants and liquid-fueled motors) which have firm energy and/or capacity for peak hours.

Figure 42. LCOE Reference case - Conventional & Hydro - 10% rate



Source: Consultant

Figure 43. LCOE Reference Case - Renewables - 10% discount rate



Source: Consultant

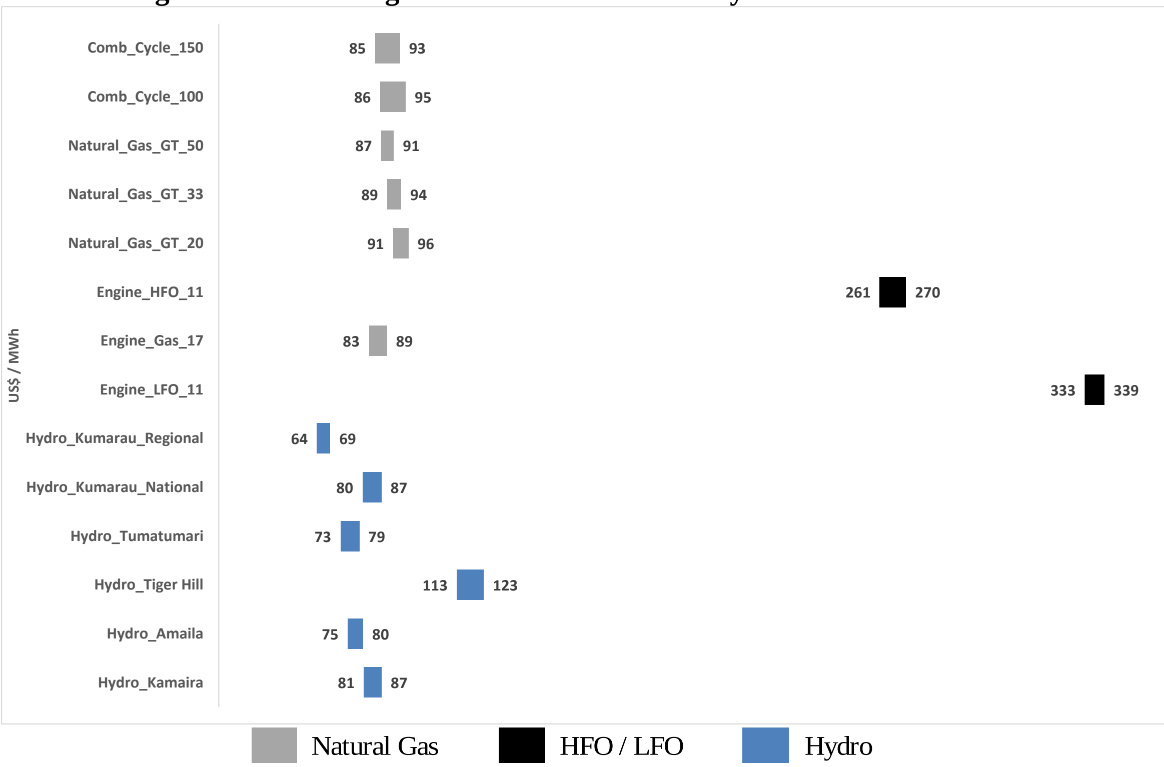
The results obtained indicate that the liquid fuel options have the highest levelized costs while the hydro plants Kumarau Regional, Tumatumari, Amalia and Kumarau national offer the best levelized costs amongst conventional power generation technologies with firm energy. The Hydro option with the higher LCOE (plant factor between 60% and 70%) is Tiger Hill while the lowest is Kumarau Regional (which has a higher load factor). The natural gas engines (17 MW) and Gas Turbine (50 MW) offer the lowest LCOE of all fuel-fired options, natural gas engines having lower LCOE when plant factors are above 70%.

On the other hand, of those technologies which do not offer a firm energy, the Sugar Cane Bagasse options have the lowest levelized costs as shown in Figure 43 (Albion has the lowest LCOE of the Biomass options). An 8 MW wind plant with expected 35%-40% capacity factor has a middle LCOE while Solar, Rice and Wood have the largest LCOE (solar battery storage technologies having the highest, however this technology could provide peaking power supply).

The results suggest that Biomass, Wind and a High Capacity Hydro (either Kumarau Regional, Tumatumari Amaila and Kumarau national) could most probably form part of the minimum cost generation expansion strategy for Guyana, probably followed by 17 MW engines using natural gas or 50 MW natural gas turbine. However, this has to be confirmed through more detailed power expansion economic analysis, taking into account, if feasible, the substitution of the use of liquid fuels for natural gas in the existing power plants and the hydrological uncertainty. The model applied later on in this study, represents the hydrological uncertainty using historical information and therefore improves the robustness of the results, as LCOE are complex to estimate in hydrothermal systems.

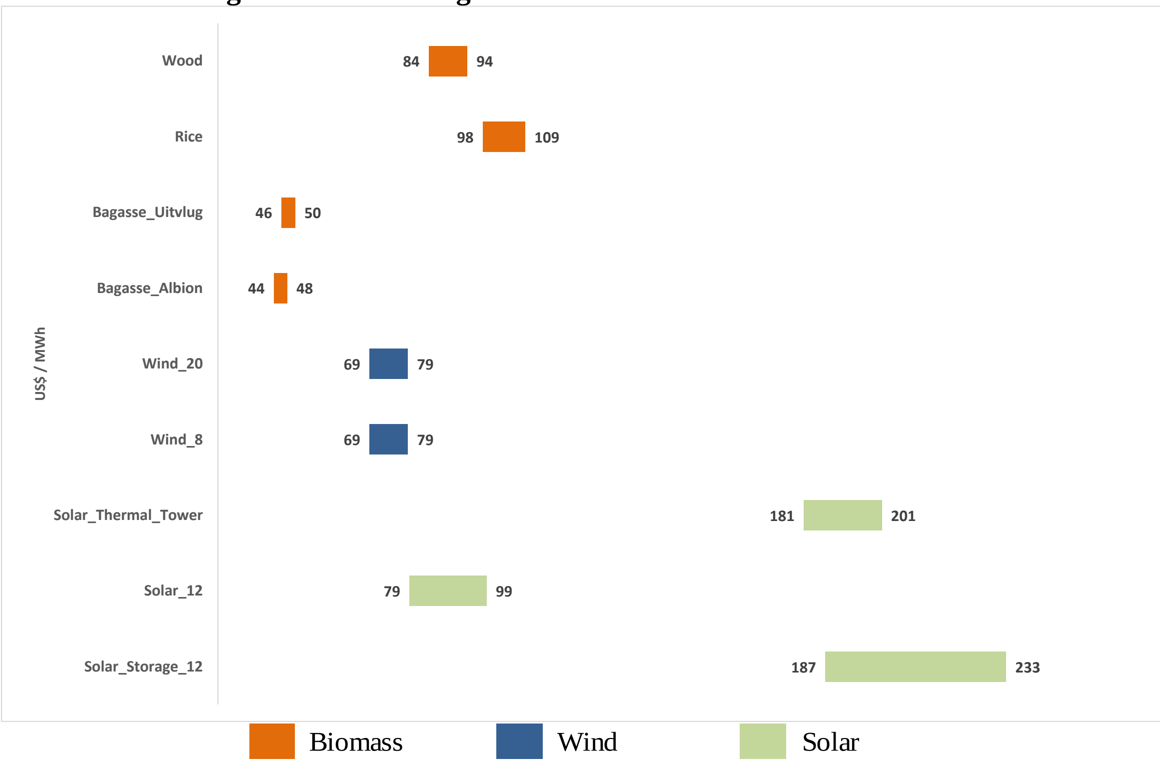
Figure 44 and Figure 45 illustrate the High fuel prices scenario, where the results do not vary considerably from the Reference Case. Hydro technologies continue to offer lower LCOE than natural gas options, except Tiger Hill.

Figure 44. LCOE High case - Conventional & Hydro - 10 % discount rate



Source: Consultant

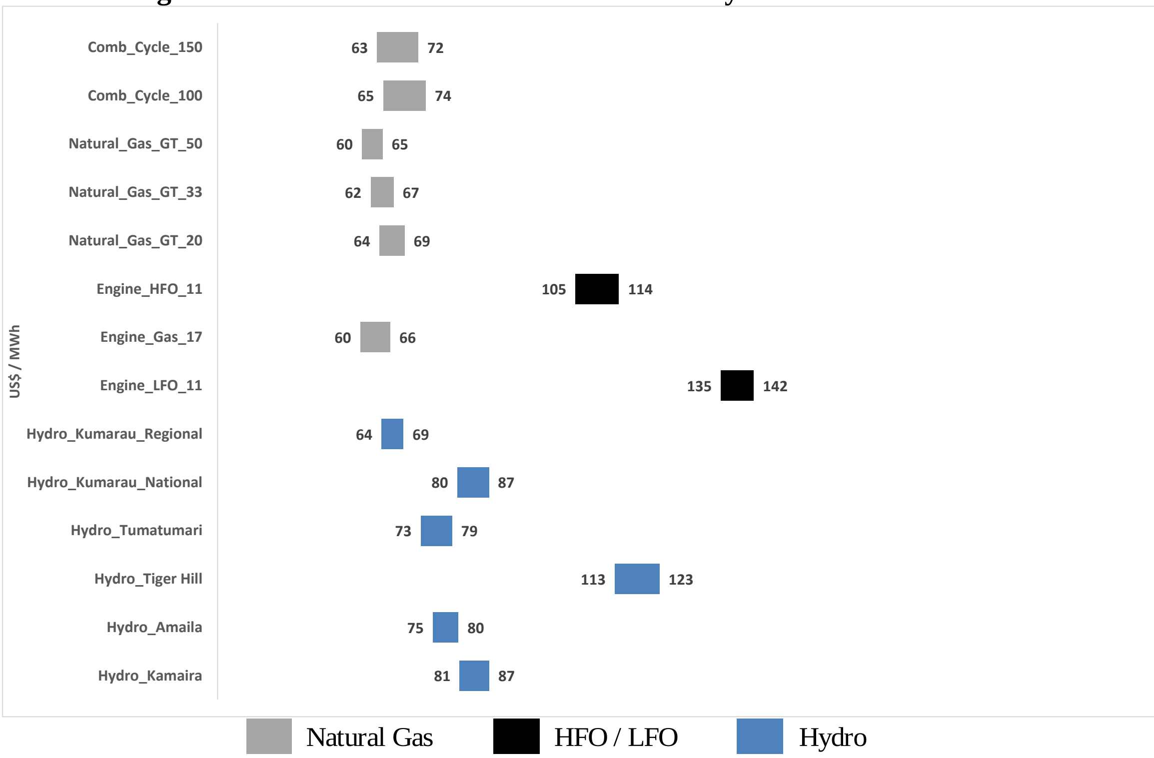
Figure 45. LCOE High case - Renewables - 10% discount rate



Source: Consultant

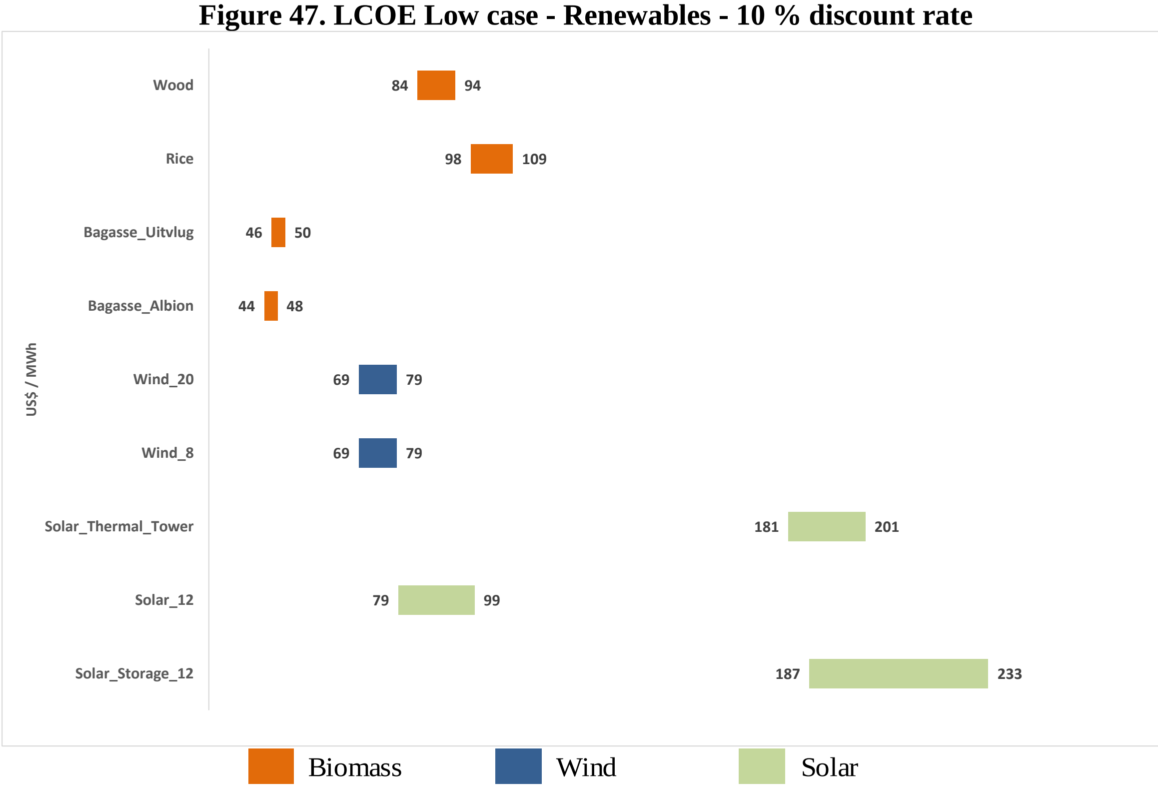
Figure 46 and Figure 46 illustrate the Low Fuel prices scenario; natural gas open cycle turbines (50 MW followed by 33 MW) become the most attractive options; even more, they now offer lower LCOE levels of hydro options, due to lower natural gas prices. Biomass continues to remain favorable technologies.

Figure 46. LCOE Low case - Conventional & Hydro - 10% discount rate



Source: Consultant

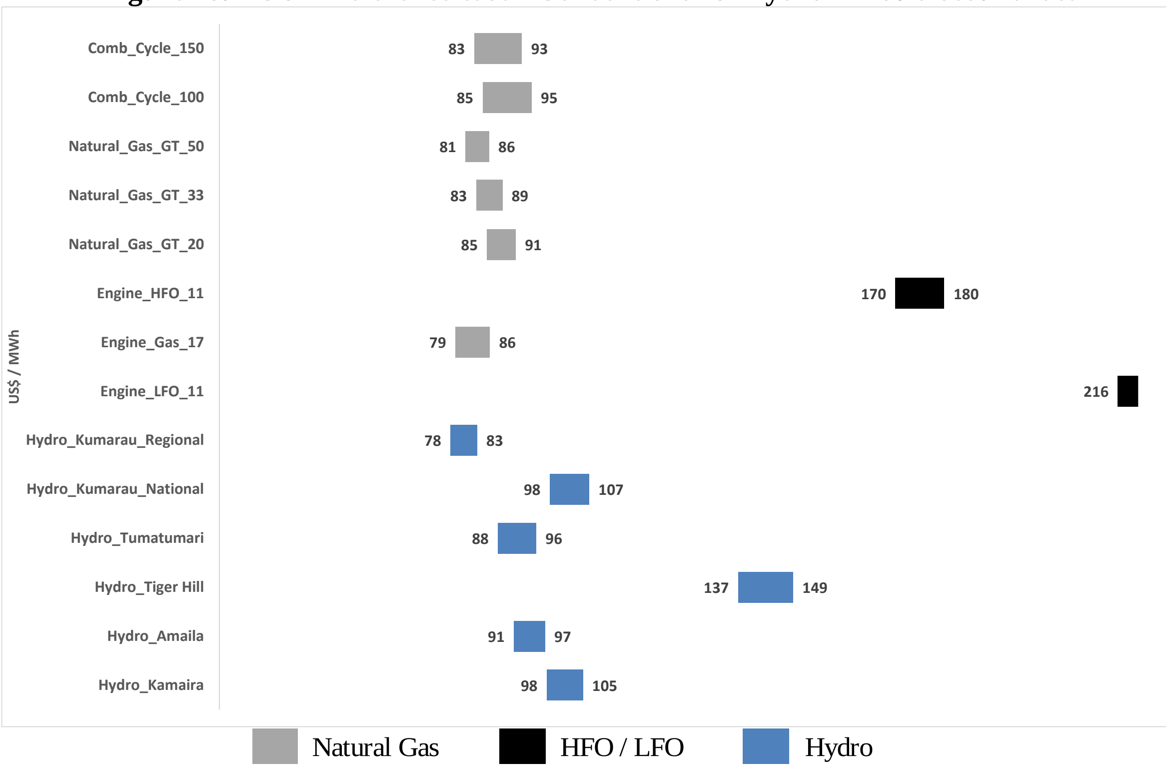
Figure 47. LCOE Low case - Renewables - 10 % discount rate



Source: Consultant

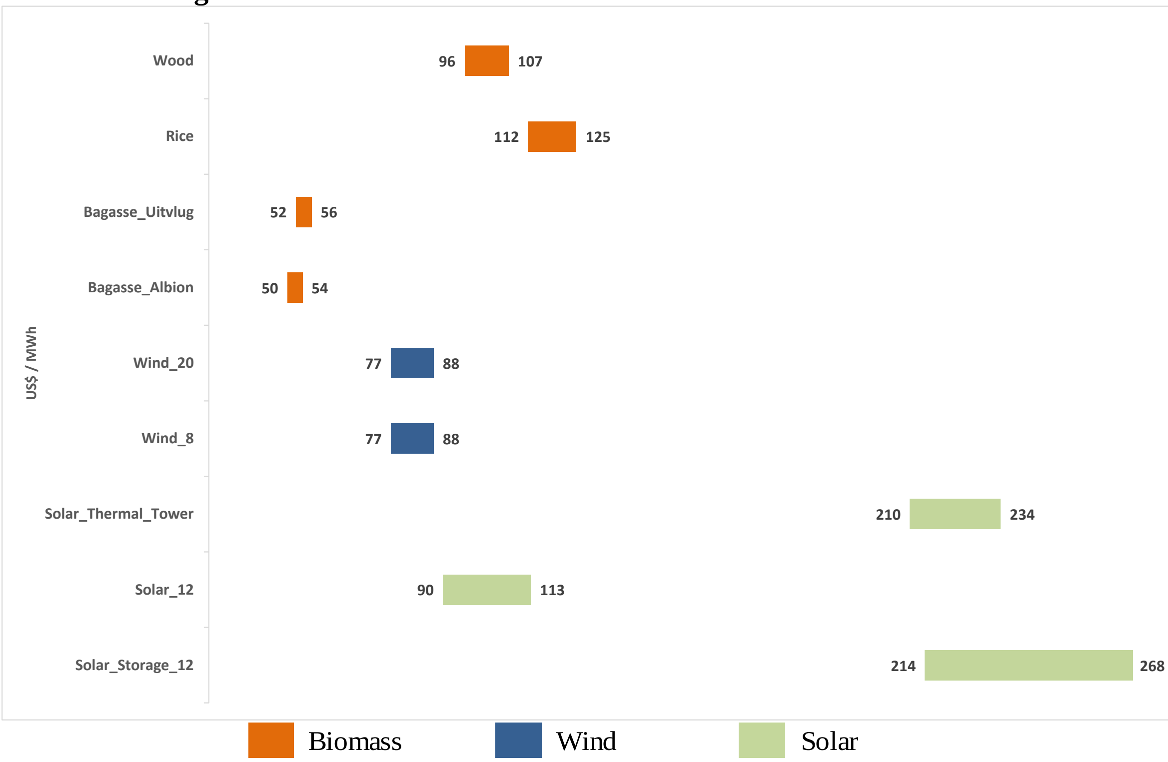
Figure 48 until Figure 51 illustrate the Reference price scenario evaluated with 12% and 8% discount rates where sugar bagasse Biomass options remain the most favorable options in terms of LCOE. The Hydro options remains unchanged, as the higher LCOE (plant factor between 60% and 70%) is Tiger Hill while the lowest is Kumarau Regional, followed by Tumatumari.

Figure 48. LCOE Reference case - Conventional & Hydro - 12% discount rate



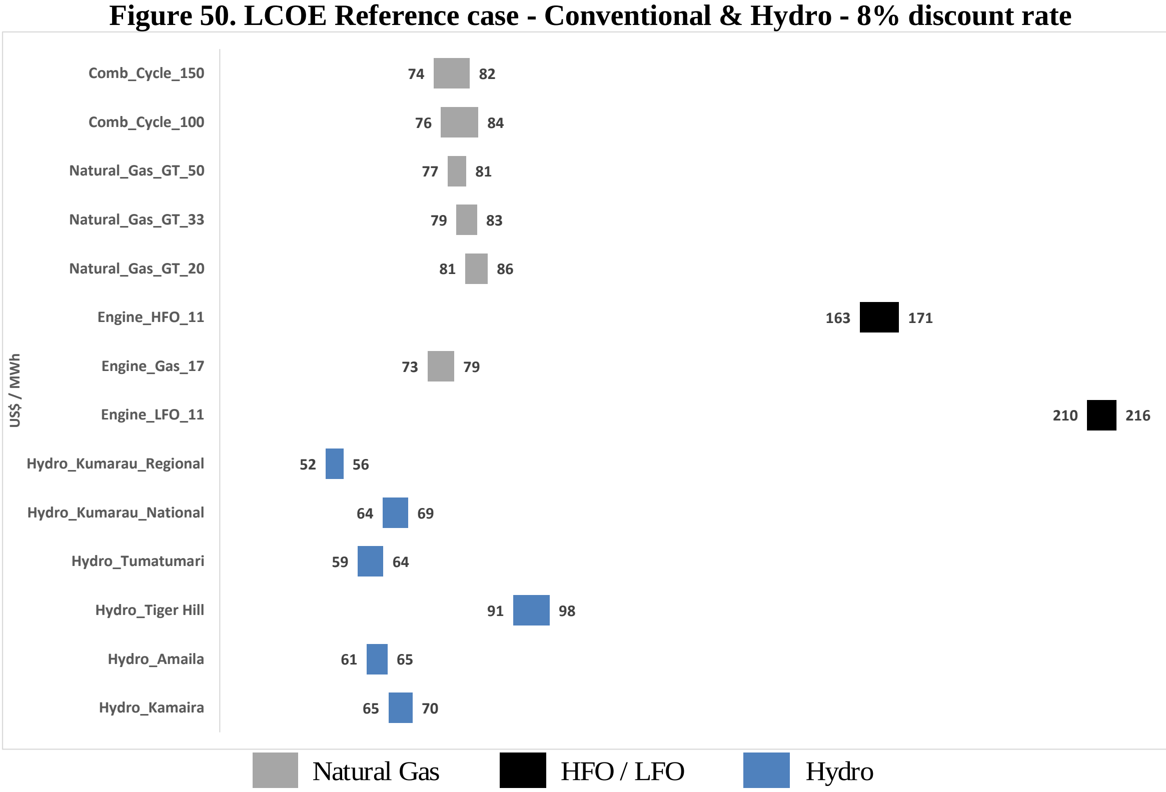
Source: Consultant

Figure 49. LCOE Reference case - Renewables - 12% discount rate



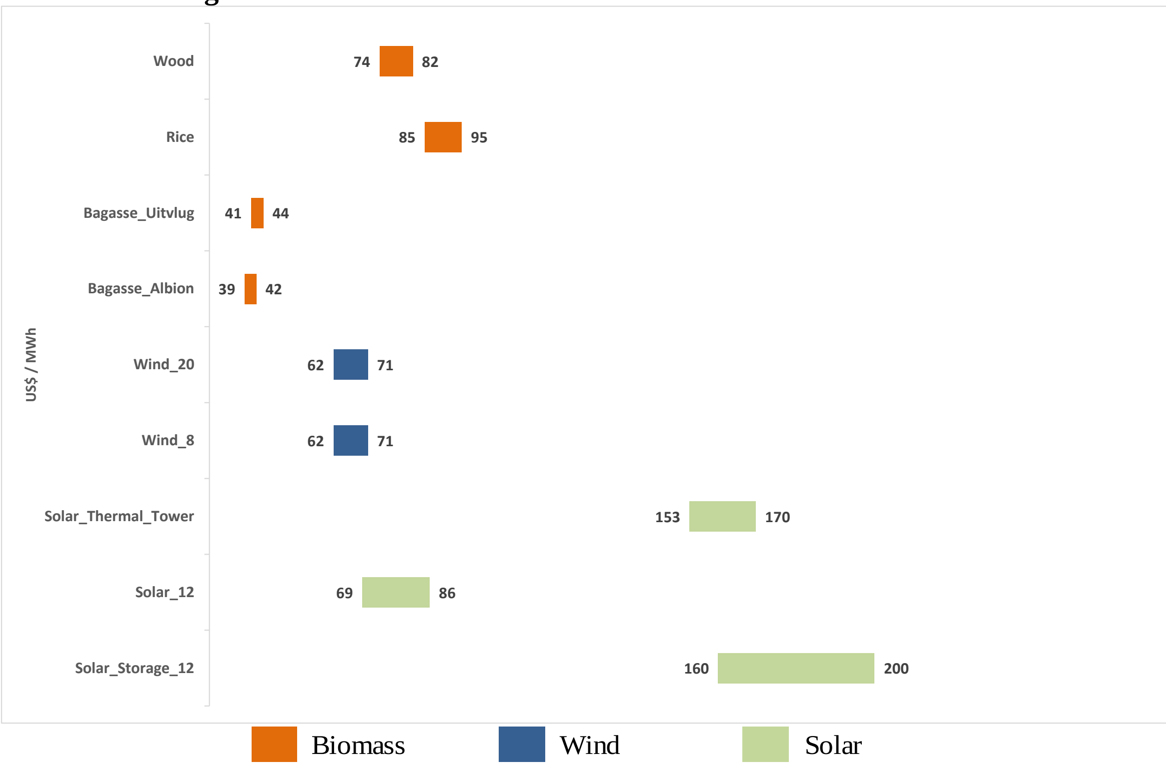
Source: Consultant

Figure 50. LCOE Reference case - Conventional & Hydro - 8% discount rate



Source: Consultant

Figure 51. LCOE Reference case - Renewables - 8% discount rate



Source: Consultant

7 GENERATION EXPANSION OPTIMIZATION MODEL

The 18-year Guyana's generation system optimal expansion updated in this study was performed with a computational model built by the Consultant, which develops the temporal sequence of new power plants that minimize the present value of future investment costs in new equipment (new generation plants and their associated transmission) plus operational cost (fuels and operation and maintenance) plus Carbon Dioxide (CO2) emission costs of new and existing plants. In order to adapt this model to DBIS, different scenarios are defined (each built with different assumptions of demand growth and fuel prices), and afterwards, the Consultant defines different power generation expansion alternatives that are evaluated with the model, until an optimal solution is established.

The mathematical model was used to find, in an integrated way, investment decisions in new plants as well as the optimal (i.e. cost minimization subject to certain constraints) operation of the system. In particular, the model minimizes present value of total cost of these two components using a mixed integer programming technique allowing to include continuous variables representing plant dispatch and integer variables representing decision investment in new plants.

This chapter is organized in the following way: Section 7.1 describes the model applied and Section 7.2 presents the data used: Energy and Power demand forecasts, existing plants and expansion projects characteristics, fuel prices and other information required for the optimization.

7.1 Expansion model

7.1.1 System representation

a. Temporal step

The model was applied using monthly temporal steps in such a way that seasonal variations in hydroelectric generation can be captured. Investment decisions in new projects were represented annually.

b. Demand

Power demand was modelled by one annual value representing the maximum load of the system during such period. α represents the reserve margin over the power demand required in the system expansion in order to have a reliable supply.

Energy demand was modelled using monthly steps; for each month demand was modelled by $\boldsymbol{NB}$ blocks representing the system load duration curve. Thus, the first block corresponds to energy demand during peak hours and, in this way, power demand of the system (maximum load). Each one of the following blocks corresponds to decreasing load; last block corresponds to minimum load. The sum of the energy of the $\boldsymbol{NB}$ blocks corresponds to the energy demand of the system.

$\boldsymbol{P_i}$ denotes peak power demand during year $\boldsymbol{i}$.

$\boldsymbol{D_{i,j,k}}$ denotes energy demand for year $\boldsymbol{i}$, month (or other time step) $\boldsymbol{j}$, block $\boldsymbol{k}$.

$\boldsymbol{H_{i,j,k}}$ denotes duration in hours of block $\boldsymbol{k}$, for year $\boldsymbol{i}$, month $\boldsymbol{j}$.

c. Hydroelectric Projects

Hydrologic uncertainty of this type of projects was represented by S series or scenarios (different generation possibilities) for each time period, each one of them equally likely. Generation of the plant associated to each one of the scenarios was denoted by $\boldsymbol{GA_{i,j,s}}$ for year $\boldsymbol{i}$, month $\boldsymbol{j}$, scenario $\boldsymbol{s}$. Available power for the plant (taking out forced and planned outages) was denoted by $\boldsymbol{PA_{i,j}}$. Installed capacity of the plant was denoted by $\boldsymbol{PA_i^*}$. Minimum power dispatched by the plant was denoted by $\boldsymbol{PA_{min}}$. Previous values were obtained from an initial analysis of the operation of each power plant reservoir; finding generation of the plant for synthetic hydrology. This was accomplished using SDDP model.

d. Existing thermal plants

$\boldsymbol{NPE}$ existing thermal plants were considered. Each one of them was characterized by the following values:

- Each existing plant $\boldsymbol{pe}$ has an available power for each period of time denoted by $\boldsymbol{PPE_{i,j,pe}}$.
- Installed capacity of each plant was denoted by $\boldsymbol{PPE^*_{i,pe}}$.
- Operating costs (fuels, operation and maintenance and CO_2 emission costs) were expressed by unit of generation as $\boldsymbol{CPE_{i,j,pe}}$. This value is the result of fuel prices forecasts, heat content of the fuel, the efficiency of the generation plants considered, CO_2 emission factors expressed by unit of generation and the forecasted unitary cost for such emissions.
- Minimum power dispatched by the plant was denoted by the value $\boldsymbol{PPE_{pe,min}}$.

e. Future thermal plants

$\boldsymbol{NPC}$ technologies were considered as candidates to the thermal expansion of the system. Each individual technology was denoted by $\boldsymbol{pc}$ and was represented by a given number of modules with identical characteristics in terms of power, costs, etc. Gas turbines are identified by the subscript gt. Each candidate project was characterized by its cost, expressed as an annuity of the total investment in generation and transmission required to commit the project, considering a discount rate equal $\boldsymbol{r}$. The annuity for plant $\boldsymbol{pc}$ was denoted by A_{pc} and its useful life by $\boldsymbol{VU_{pc}}$. As in the case of existing plants, available power was denoted by $\boldsymbol{PPC_{i,j,pc}}$ and installed capacity by $\boldsymbol{PPC^*_{i,pc}}$. Operation of the plant requires a minimum power equal to $\boldsymbol{PPC_{pc,min}}$. Operation costs (fuel and operation and maintenance) were expressed per unit of generation as $\boldsymbol{CPC_{pc}}$.

f. Non-served demand

The option of non-serving or supplying part of the demand was considered. Non-served energy demand in year $\boldsymbol{i}$, month $\boldsymbol{j}$, block $\boldsymbol{k}$ and series $\boldsymbol{s}$ was denoted by $\boldsymbol{dr_{i,j,k,s}}$ and has an unitary cost of $\boldsymbol{CR}$.

7.1.2 Problem formulation

The problem was formulated as a mixed integer programming problem seeking to minimize the present value of investment and operation (fuel and operation and maintenance) costs during a planning horizon of $\boldsymbol{NP}$ years.

a. Decision variables

Decision variables of the problem are:

a1. $\boldsymbol{x_{i,pc}}$ is an integer variable representing the number of modules in operation for plant $\boldsymbol{pc}$ during year $\boldsymbol{i}$.

There is one variable associated to each one of the candidate plants considered for the expansion of the system, for each year of the planning horizon,

a2. $\boldsymbol{cp_{i,j,k,s,pc}}$ is the power dispatched by the candidate plant $\boldsymbol{pc}$ during month $\boldsymbol{j}$, year $\boldsymbol{i}$, block $\boldsymbol{k}$ and series $\boldsymbol{s}$. This variable is bounded by the following values:

$$\boldsymbol{PPC_{pc,min} * x_{i,pc} \leq cp_{i,j,k,s,pc} \leq PPC_{i,j,pc} * x_{i,pc}}$$

for all possible values of $\boldsymbol{i, j, k, s}$ *and* $\boldsymbol{pc}$, except gas turbines. Some of this type of plants can be part of a combined cycle. Therefore, the effective capacity of gas turbines operating in an isolated way will be equal to the number of turbine modules minus twice the number of combined cycles, since two gas turbines are required to conform a combined cycle module. If gt denotes gas turbines and cc denotes combined cycles, the bounds for the dispatch variable of such plants are given by:

$$\boldsymbol{PPC_{gt,min} * \left(x_{i,gt} - 2 * x_{i,cc}\right) \leq cp_{i,j,k,s,gt} \leq PPC_{i,j,gt} * (x_{i,gt} - 2 * x_{i,cc})}.$$

a3. $\boldsymbol{ep_{i,j,k,s,pc}}$ is the power dispatched by the candidate plant $\boldsymbol{pc}$ during month $\boldsymbol{j}$, year $\boldsymbol{i}$, block $\boldsymbol{k}$ and series $\boldsymbol{s}$. This variable is bounded by the following values:

$$\boldsymbol{PPE_{pe,min} \leq ep_{i,j,k,s,pe} \leq PPE_{i,j,pe}}$$

a4. $\boldsymbol{ap_{i,j,k,s}}$ is the power dispatched by Amaila Falls Project during month $\boldsymbol{j}$, year $\boldsymbol{i}$, block $\boldsymbol{k}$ and series $\boldsymbol{s}$.

$$\boldsymbol{PA_{min\leq} ap_{i,j,k,s} \leq PA_{i,j}}$$

a5. $\boldsymbol{rp_{i,j,k,s}}$ denotes the power corresponding to the non attended demand for block $\boldsymbol{k}$, year $\boldsymbol{i}$, month $\boldsymbol{j}$ and series $\boldsymbol{s}$.

$$\boldsymbol{0 \leq rp_{i,j,k,s} \leq \infty}$$

b. Objective function

b1. Investment cost in candidate plants

$$\boldsymbol{A = \sum_{pc=1}^{NPC} \sum_{i=1}^{NP} \left\{ \frac{A_{pc} * x_{i,pc}}{(1+r)^{i-1}} \right\}}$$

For planning purposes the relevant investment costs associated to the construction of each new potential power plant (and transmission line) was evaluated deducting from its total investment cost the restitution cost during its remaining useful life after the planning horizon (i.e. 2036 until the end year of its useful life). In other words, the investment cost used for the optimization of the generation expansion was the one associated to the period in which the projects were available for operation within the planning period (2015-2035). Investment costs in combined cycles correspond to the incremental cost of them, which is the total costs minus the investment costs in the two gas turbines conforming the combined cycle.

b2. Operating costs associated to candidate plants

$$\boldsymbol{B} = \sum_{pc=1}^{NPC}\sum_{i=1}^{NP}\left[\frac{1}{(1+r)^{i-1}}\sum_{j=1}^{12}\sum_{k=1}^{NB}\left\{\frac{1}{NS}\left\{\sum_{s=1}^{NS} ce_{i,j,k,s,pc} * CPE_{i,j,pc} * H_{i,j,k}\right\}\right\}\right]$$

b3. Operating costs associated to existing plants

$$\boldsymbol{C} = \sum_{pe=1}^{NPE}\sum_{i=1}^{NP}\left[\frac{1}{(1+r)^{i-1}}\sum_{j=1}^{12}\sum_{k=1}^{NB}\left\{\frac{1}{NS}\left\{\sum_{s=1}^{NS} cp_{i,j,k,s,pc} * CPC_{i,j,pc} * H_{i,j,k}\right\}\right\}\right]$$

b4. Cost of non-served demand

$$\boldsymbol{D} = \sum_{i=1}^{NP}\left[\frac{1}{(1+r)^{i-1}}\sum_{j=1}^{12}\sum_{k=1}^{NB}\left\{\frac{1}{NS}\left\{\sum_{s=1}^{NS} dr_{i,j,k,s} * CR\right\}\right\}\right]$$

The objective function will be the minimization of total cost

$$z = Min\{A + B + C + D\}$$

c. Constraints

c.1 Meeting power demand

This constraint expresses the fulfilment of the annual power demand of the system, including a reserve margin, by existing and future plants.

$$PA_i^* + \sum_{pe=1}^{NPE} PPE_{i,pe}^* + \sum_{pc=1}^{NPC}\left\{PPC_{i,pc}^* * x_{i,pc}\right\} = P_i * \alpha$$

There is an equation for each one of the years.

c.2 Meeting energy demand

This constraint establishes the fulfilment of the energy demand in each year, month, block and hydrological series.

$$\left\{ap_{i,j,k,s+} \sum_{pe=1}^{NPE} ep_{i,j,k,s,pe} + \sum_{pc=1}^{NPC} cp_{i,j,k,s,pc} + rp_{i,j,k,s}\right\} * H_{i,j,k} = D_{i,j,k}$$

There is an equation for each one of the years, months, blocks and hydrological series.

c.3 Hydroelectric generation

The addition of the hydroelectric dispatched power for each one of the blocks multiplied by its duration corresponds to the plant generation obtained from the previously mentioned dispatch of the plant.

$$\sum_{k=1}^{NB} \{ap_{i,j,k,s} * H_{i,j,k,s}\} = GA_{i,j,s}$$

There is an equation for each year, month and hydrological series.

c4. Candidate's continuity.

This equation establishes that the number of existing modules in each plant must be non-decreasing along the planning period. Let's consider two consecutive periods, this is the first period (month j year i) is related to the following period $i1$, $j1$ by:

$$i1 = \begin{cases} i & j < 12 \\ i+1 & j = 12 \end{cases} \qquad \text{and} \qquad j1 = \begin{cases} j+1 & j < 12 \\ 1 & j = 12 \end{cases}$$

$$x_{i,j,pc} \leq x_{i1,j1,pc}$$

There is a number of constraints equal to de number of periods in the planning horizon minus one for each one of the candidate plants.

c.5 Turbines and combined cycles

The model allows the consideration of expansion based on gas turbines that can be converted to combined cycles once the cycle is closed. Two gas turbines are required to close the cycle and be converted to a combined cycle. Therefore, the number of gas turbines in the expansion must be at least twice the number of combined cycles. This is expressed as:

$$x_{i,gt} \geq 2 * x_{i,cc}$$

Where:

gt denotes gas turbines and cc denotes combined cycles. Thus, $2 * x_{i,cc}$ gas turbines will be operating as part of the combined cycles and $x_{i,gt} - 2 * x_{i,cc}$ as conventional gas turbines.

The solution to the above mixed integer programming problem found the minimum cost expansion of the system for each case analyzed. For the cases without hydroelectricity is a simpler problem since in this case it is not necessary to consider neither the uncertainty associated with hydrology nor variables nor constraints associated with such plant.

7.2 Database

This section explains the data used in the optimization analysis for the Base Scenario. Time horizon covers from year 2018 until year 2035. Currency is US$ in real terms using December 2017 as base.

7.2.1 Electricity Demand

Table 59 shows electricity demand forecasts (energy and power) for DBIS used in the optimization program for the Base Scenario. The support of these figures can be found in the electricity demand forecast chapter of this report and its related appendices.

Table 59. DBIS electricity demand forecast

YEAR	Base	
	Energy GWh	Power MW
2015	707.4	110.3
2016	752.1	116.1
2017	762.2	115.3
2018	775.5	117.3
2019	799.6	121.0
2020	829.4	125.5
2021	852.0	128.9
2022	876.0	132.5
2023	1,015.1	153.6
2024	1,280.6	193.8
2025	1,476.8	223.7
2026	1,690.1	256.0
2027	1,919.3	290.8
2028	2,092.9	317.2
2029	2,104.5	319.1
2030	2,116.0	321.0
2031	2,127.6	322.9
2032	2,139.1	324.8
2033	2,150.7	326.7
2034	2,162.1	328.6
2035	2,173.4	330.4

Source: Consultant

Annual energy forecasts were disaggregated by month and by block[73] in such a way that main characteristics of the load duration curve are preserved. Five (5) blocks were used in order to represent

[73] By block it is meant a discretization of the load duration curve. Each block has a given number of hours in the period, and each one corresponds to decreasing levels of load. For example, block one has a duration of 3.5% of the time an corresponds to the peak hours of the period. Blocks 2 to 5 have a duration of 24.25% of the time.

the demand characteristics of the Guyana Power System. Table 60 shows the duration of the blocks used in the optimization model.

Table 60. Duration of energy blocks

Block	Percent of time
1	3.5%
2	24.1%
3	24.1%
4	24.1%
5	24.1%

Source: Consultant estimate using GPL's data

7.2.2 Hydrology and hydro generations

Section 6.2 on this report discussed the hydrologic aspects related to river discharges of the five hydroelectric projects studied.

Table 42 presents the plant characteristics used in the optimization analysis for each of the five hydro projects. Table 43 summarizes the energy generation probability distributions associated to each hydro project (this table summarizes by quarters the monthly energy generations used by the model).

7.2.3 Fuel costs

Fuel cost estimates were explained and developed in Section 4 of this report. Base case of fuel price forecasts used in the study is presented in Table 61.

Table 61. Fuel prices forecast (Base Case)

Year	HFO US$/MBTU	LFO US$/MBTU	NATURAL GAS US$/MBTU
2018	7.8	13.2	NA
2019	7.8	13.2	NA
2020	8.3	13.8	NA
2021	10.6	16.7	NA
2022	11.7	18.1	NA
2023	12.2	18.7	4.7
2024	12.6	19.2	4.7
2025	12.7	19.4	4.7
2026	13.1	19.9	4.7
2027	13.2	20.1	4.7
2028	13.5	20.4	4.7
2029	13.7	20.7	4.7
2030	14.0	21.0	4.7
2031	14.2	21.2	4.7
2032	14.4	21.5	4.7
2033	14.6	21.7	4.7
2034	14.8	22.0	4.7
2035	14.9	22.2	4.7

Note: Natural gas assumed with 70% take or pay supply conditions and NA implies no availability of fuel in such year in Guyana. Source: Consultant

7.2.4 Existing plant technical characteristics

Table 62 presents technical and cost characteristics of existing plants. At the moment, these plants are fired on liquid fuels and the study considers that they would remain using HFO or LFO as a backup plants of new RE or Natural Gas power plants. .

Table 62. Technical characteristics of existing power plants

Name	Effective Capacity (MW)	Unavailability (%) 1/	Fuel	Year of Retirement	O&M Fixed Cost ($/KW-year)	O&M variable Cost ($/MWh)	Heat Rate (BTU/kWh)	CO2 Emissions (Ton/GWh)	Peaking Capacity Factor (%)
Demerara Power HFO I-1-4	22.00	6.3%	HFO		47.10	9.8	10.14	700	100%
Demerara Power HFO II-1-4	22.00	6.1%	HFO		47.10	9.8	9.57	700	100%
Demerara Power HFO III-1-5	36.30	4.0%	HFO		47.10	9.8	7.78	700	100%
Vreed en Hoop HFO IV-1-3	26.20	6.1%	HFO		47.10	9.8	8.38	700	100%
Garden of Eden	8.00	3.7%	LFO	2020	47.10	8.9	10.12	700	100%
Onverwagt	3.70	3.7%	LFO	2020	47.10	8.90	10.22	700	100%
Canefield HFO M3	4.20	27.8%	HFO	2020	47.10	9.80	10.86	700	100%
Canefield LFO Mobile	3.50	7.5%	LFO	2020	47.10	8.9	10.54	700	100%
Skeldon DG 1-3	10.00	33.0%	HFO		47.10	9.8	10.18	700	100%
Skeldon TG 1-2 (2x15 MW)	0.00	100.0%	BAGGASSE		47.10	9.8	10.18	700	0%

1/ Expected average unavailability as informed in the 2016 Expansion Study. Skeldon TG 1-2/Baggasse is considered being refurbished and recomissioned by 2021

Source: Consultant

7.2.5 Candidate plants

Table 63 summarizes the basic characteristics and reference costs of all candidate plants to the expansion: hydroelectric power plants (Kamaria, Tiger Hill, Kumarau, Tumatumari and Amaila), gas turbines & combined cycles (natural gas/LFO), reciprocating internal combustion engines (natural gas/HFO or LFO), biomass (bagasse, rice husk and wood chips), wind and solar.

Table 63. Technical and cost characteristics of candidate plants for expansion

Thermal & Non-conventional Renewable Energy power plants

UNITS & PLANTS	CAPACITY (MW)	FUEL	USEFUL LIFE (YEARS)	HEAT RATE (BTU/KWH)	O&M FIXED COST (US$/KW/Y)	O&M VARIABLE COST (US$/MWH)	INVESTMENT COST (US$/KW)	TRANSM. COST (%)	OUTAGE RATE (%)	CO2 EMISSIONS (TON/GWH)	PEAKING CAPACITY FACTOR (%)
GasTurbine20	20	LFO	20	10.20	18	3.5	1,100	0%	10%	800	100%
		Gas		10.20	16	3.0				688	
GasTurbine33	33	LFO	20	10.10	17	3.5	1,000	0%	10%	800	100%
		Gas		10.10	15	3.0				688	
GasTurbine50	50	LFO	20	10.00	16	3.5	900	0%	10%	800	100%
		Gas		10.00	14	3.0				688	
CombCycle100	100	LFO	25	8.16	27	4.0	2,000	0%	10%	568	100%
		Gas		8.16	25	3.5				421	
CombCycle150	150	LFO	25	8.00	25	4.0	1,950	0%	10%	568	100%
		Gas		8.00	23	3.5				421	
Engine GAS-17MW	17.0	HFO	20	9.00	45	9.8	1,413	0%	10%	700	100%
		Gas		8.50	7.3	6.2				451	
Engine HFO-11MW	11.4	HFO	20	9.72	45	9.8	1,755	0%	10%	700	100%
		Gas		8.50	12	8.8				451	
Engine LFO-11MW	11.4	LFO	20	9.72	15	8.9	1,495	0%	10%	700	100%
		Gas		8.50	12	7.9				451	
Demerara Exp-GoE	17.4	HFO	20	9.72	45	10	0	0%	10%	700	100%
		Gas		8.50	12	9				451	
Bagasse-Albion	9.8	Bagasse	20	10.80	20	0	2,200	30%	15%	0	0%
Bagasse-Uitvlugt	5.7	Bagasse	20	10.80	20	0	2,200	30%	15%	0	0%
Wind	6x20		20		47.5	0	1,657	10%	10%	0	0%
Solar PV	4x12		30		24	0	1,370	10%	10%	0	0%
Solar PV storage	2x12		30		24	0	3,500	10%	10%	0	100%
Rice Husk	4.34	Rice Husk	25	10.80	45	0	3,500	30%	15%	0	100%
Wood Residues	0.66	Wood	25	10.80	25	0	2,600	30%	15%	0	100%

Hydroelectric power plants

PROJECT	CONSTR. PERIOD. (YEARS)	INVESTMENT COSTS 1/ US$/KW	TRANSMISSION CONNECTION INCLUDED	CAPACITY (MW)	FIRM CAPACITY (%) 2/	AVERAGE GENERATION (GWH/YEAR)	FACTOR (MW/m3/s)	MINIMUM ECOL. (m3/s)	MAXIMUM (m3/s)	RESERVOIR (mm3)	
										MIN	MAX
Kamaria	3	3960	To Linden, 102 km, 230 kV/2c	180	55%	1081	0.150	NA	1200	246.7	246.7
Tiger Hill	3	5217	To Linden, 51km, 69kV/2c	12	55%	66	0.084	NA	143		
Kumarau National	4	3380	To Linden, 286km, 138 kV/2c	100	26%	515	2.100	4.5	48		
Kumarau Regional	3	3352	Without connection to DBIS	50		321	2.100	4.5	24		
Tumatumari	3	3010	To SECC1, 39km, 230 kV/2c	152	42%	751	0.260	NA	585	699	699
Amaila	3	3945	To SECC1, 100km, 230 kV/2c	165	63%	1094	3.020	1.0	55	34.3	135.6

1/ Includes transmission connection and accesss road not includes interest during construction
2/ Estimated with P95 monthly generations and 0.25 plant factor

Source: Consultant

7.2.6 CO_2 emissions costs

The optimization model works with a harmonized carbon price over the lifetime of all technologies. According to the practice applied by the International Energy Agency, US$ 30/ton (metric) was taken to be the shadow price of carbon emissions, not being a cost that would be borne by investors[74].

[74] Projected Costs of Generating Electricity, IEA, 2015 (p. 33).

7.2.7 Discount rate

The optimization of DBIS generation expansion was made using a discount rate of 10% in real terms, rate usually considered by the Consultant in similar studies. Low (8%) and high (12%) sensitivities were done.

7.2.8 Cost of non-served energy

The optimization model uses the economic cost of non-served energy which was selected at a level of US$ 3,000/MWh

8 DBIS OPTIMAL GENERATION EXPANSION

This section discusses the evaluation of DBIS optimal generation expansion during short (up to 2022), mid (2023-2025) and long term (2026-2035) considering the following new generation options:

a) Power plants using alternative fossil fuels (liquid fuels and natural gas)

b) Power plants using non-conventional renewable energy sources (wind, solar and biomass)

c) Five representative hydroelectric power plants of mid-size capacity[75]

To support the search of the optimal DBIS generation expansion program, three complementary partial optimizations were conducted in the 18-year planning horizon 2018-2035. Present values of total comparative costs of DBIS generation-transmission expansion and operation during this period were estimated (present value in 2017 of investment[76], fuel, operation, maintenance, CO2 emissions and non-served demand costs) under each of these three optimizations in order to obtain conclusions about DBIS optimal expansion strategy.

i) *Optimization I (BAU: Identification of a base line expansion)*: It consists in the identification of the optimal Business as Usual generation expansion during short, mid and long terms using reciprocating engines, fueled with HFO and LFO, or gas turbines and combined cycles fueled with LFO.

ii) *Optimization II (Selection of the optimal technology for a gas fired generation expansion):* It consists in the identification of the optimal technology for a new gas fired generation expansion using around 30 mmcfd of indigenous natural gas located in its landing site. This optimization considers the BAU and renewable energy generation optimal expansion during short-term, different technological options for the gas fired generation during mid-term and the expected hydroelectric & renewable energy expansion during long-term.

iii) *Optimization III (Selection of optimal long term generation expansion):* This optimization considers BAU and optimal gas fired and renewable energy generation expansion during mid-term and options of renewable energy expansions, including five potential high capacity hydroelectric power plants, during long-term.

The results of these three optimizations are presented in the next sections for the Reference Scenario, which corresponds to Base demand, Reference fuel prices and a 10% discount rate.

[75] Kumarau (50 MW or 100 MW), Kamaria (180 MW), Tumatumari (152 MW), Tiger Hill (12 MW) or Amaila (165 MW).

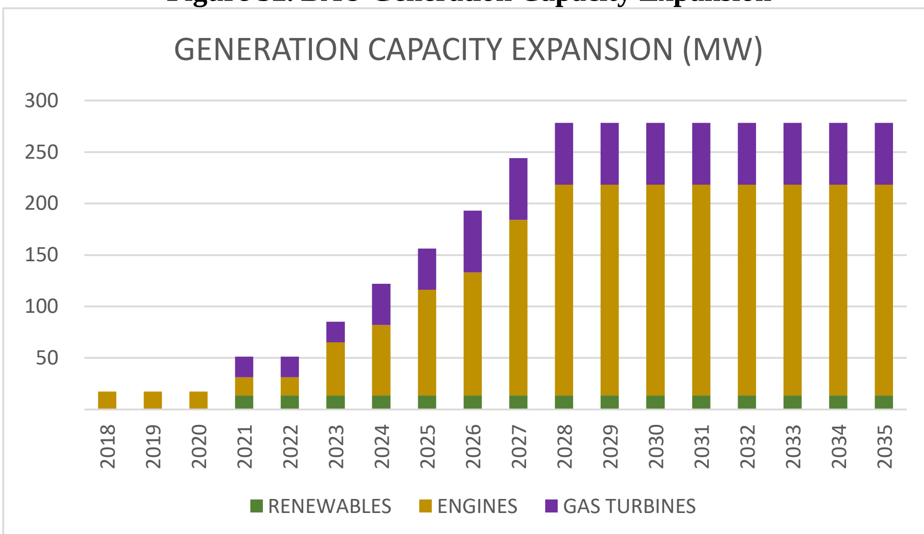
[76] As presented in Section 7.1.2 (section b1), for planning purposes the relevant investment costs associated to the construction of each new potential power plant (and transmission line) were evaluated deducting from their total investment cost their residual value during their remaining useful life after the planning horizon (i.e. 2036 until the end year of their useful life). In other words, the investment cost used for the optimization of the generation expansion was the “equivalent annual cost” in each of the years in which the projects are considered available for operation within the planning period (2018-2035). This explains why the present values of the investment costs of the power plants (and transmission lines) included in the tables presented in this section are lower than their total investment costs.

8.1 Optimization I: BAU Case

The optimal "Business as Usual" generation expansion Case could be considered as a referential base line Case in which DBIS generation capacity continues being expanded with power plants using only liquid fossil fuels[77].

Figure 52 illustrates the optimal BAU expansion strategy obtained with the Optimization Model under the Base Scenario (Base case of demand growth, Reference case of fuel prices and 10% discount rate).

Figure 52. BAU Generation Capacity Expansion

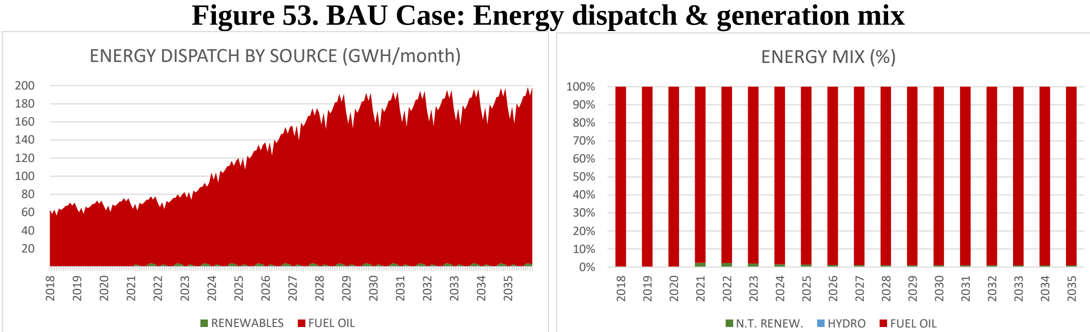


Source: Consultant

In this Case, the optimal generation expansion would be a progressive installation of HFO and LFO reciprocating engines and gas turbines, as follows: a) 17.4=2x8.7 MW in gensets using HFO during 2018-19 (project being developed by GPL), b) 60=3x20 MW in gas turbines using LFO during 2021-2026, and c) 187=11x17 MW in gensets using HFO during 2023-2028.

Figure 53 illustrates future generation dispatch in DBIS under this Case, implying an energy mix using almost 100% liquid fuels during 2018-2035.

Figure 53. BAU Case: Energy dispatch & generation mix

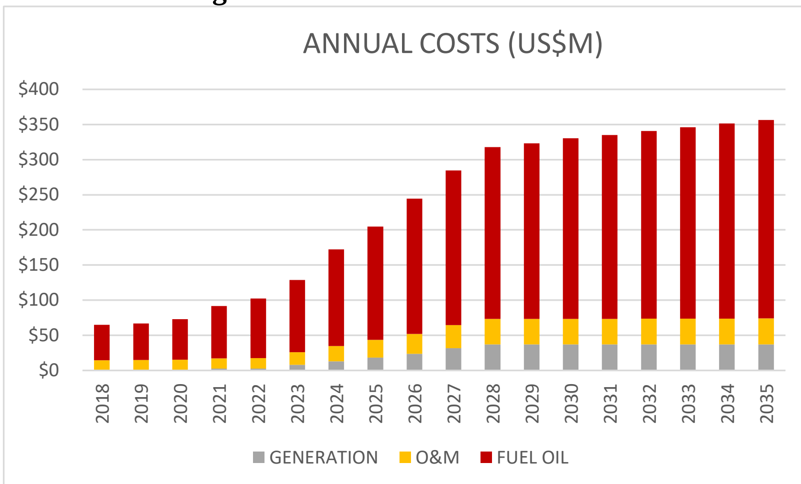


Source: Consultant

[77] In addition to the installation of the following power plants: a) 2 x 8.7 MW HFO units in Garden of Eden, already included in the GPL's D&E Program, and b) Refurbishment of the cogeneration facilities (15 MW) in Skeldon to be comissioned in 2022, including the installation of a second 16.7 MVA transformer in Skeldon substation.

The following graph illustrates the evolution of future annual generation costs in BAU case.

Figure 54. BAU Case: Annual costs

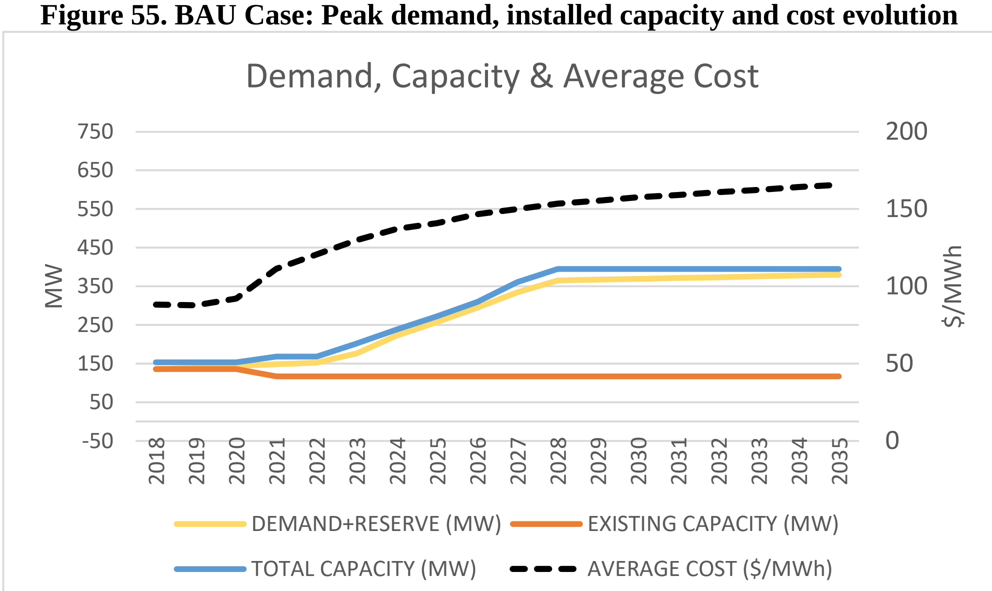


Source: Consultant

Annual generation expansion costs increases from US$ 65 M in 2018 to US$ 357 M in 2035. Total generation expansion cost (Present Value in 2017 at 10%) of this Case is US$ 1,525 million (79% consisting in fuel costs) without considering costs of CO2 emissions.

Figure 55 illustrates the peak demand and total installed capacity evolution under this case, as well as the evolution of average generation costs that increases from US$ 85/MWh in 2018 to US$ 164/MWh in 2035, without considering any CO2 emissions costs.

Figure 55. BAU Case: Peak demand, installed capacity and cost evolution



Source: Consultant

8.2 Optimization II (Selection of optimal technology for the gas fired generation expansion)

As presented in the fuel section, Guyana will have the availability of around 30 mmcfd of indigenous natural gas that would supply fuel for electricity generation in a new power plant of around 170 MW to be commissioned after 2022. For the installation of this plant we have considered several technological options consisting in Combined Cycles (CC), Gas Turbines (GT) and Reciprocating Internal Combustion Engines (RICE) using natural gas. Table 64 summarizes main characteristics and unitary costs of the different technologies and unit sizes evaluated to select the optimal option for this natural gas fired power plant, under the assumption that it would be installed near Woodlands, the most promising landing site of the offshore produced gas known at the time of this study.

Table 64. Main parameters of alternative technologies of power plants using gas

CONCEPT	CC 150MW	CC 100MW	TG 50MW	TG 33MW	TG 20MW	RICE 17MW
INVESTMENT COST ($/KW)	1,950	2,000	900	1,000	1,100	1,413
O&M VARIABLE COST ($/MWH)	3.5	3.5	3.0	3.0	3.0	6.2
O&M FIXED COST ($/KW/Y)	23.0	25.0	14.0	15.0	16.0	7.3
HEAT RATE (BTU/KWH)	8,000	8,160	10,000	10,100	10,200	8,500
CO2 WITH NG (TON/GWH)	421	421	688	688	688	451

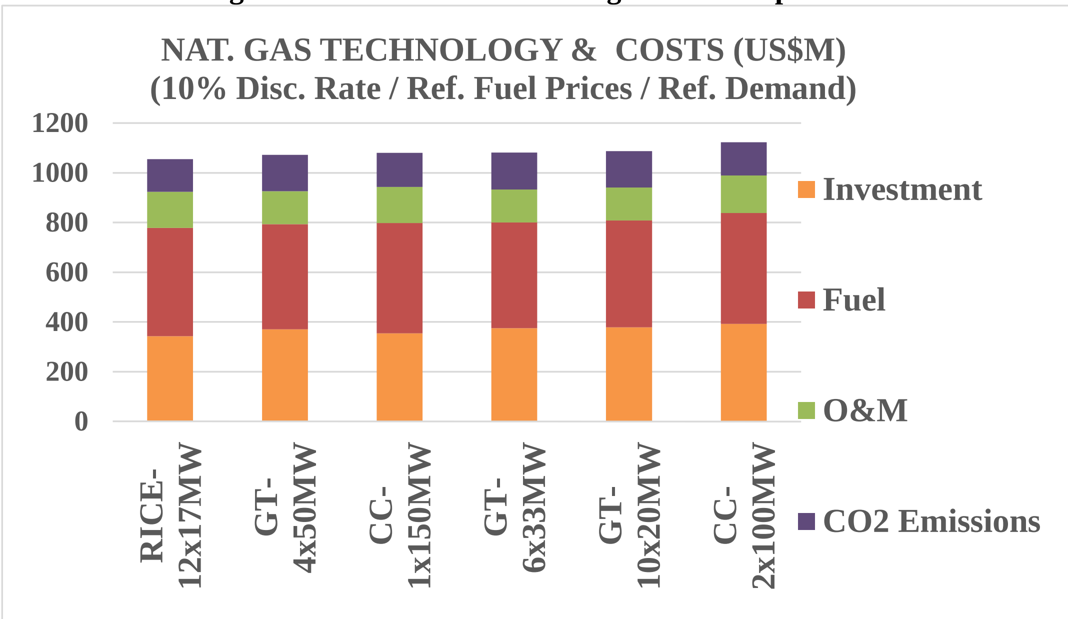
Source: Processed data obtained mainly from ETESA, CEAC and EIA

The optimization model was applied to select individually (and by steps) for each technology the optimal capacity itinerary of the new power plant to be installed after 2022[78]. This optimization included the consideration of all candidates of renewal energy power plants during all planning period and the five high capacity hydroelectric candidates for DBIS generation expansion in the long term.

Figure 56 summarizes total generation expansion costs obtained under the Base Scenario disaggregated by main components (present values of investment, fuel, O&M and CO2 emissions costs) that could be associated to the different optional technologies for this power plant.

[78] The optimization process considers that the HFO/LFO power generation of the existing power plants in Garden of Eden, Kingston and VreedenHoop would be substituted by NG generation in the new power plant and that the existing power plants would remin operating providing backup to DBIS based on HFO/LFO generation.

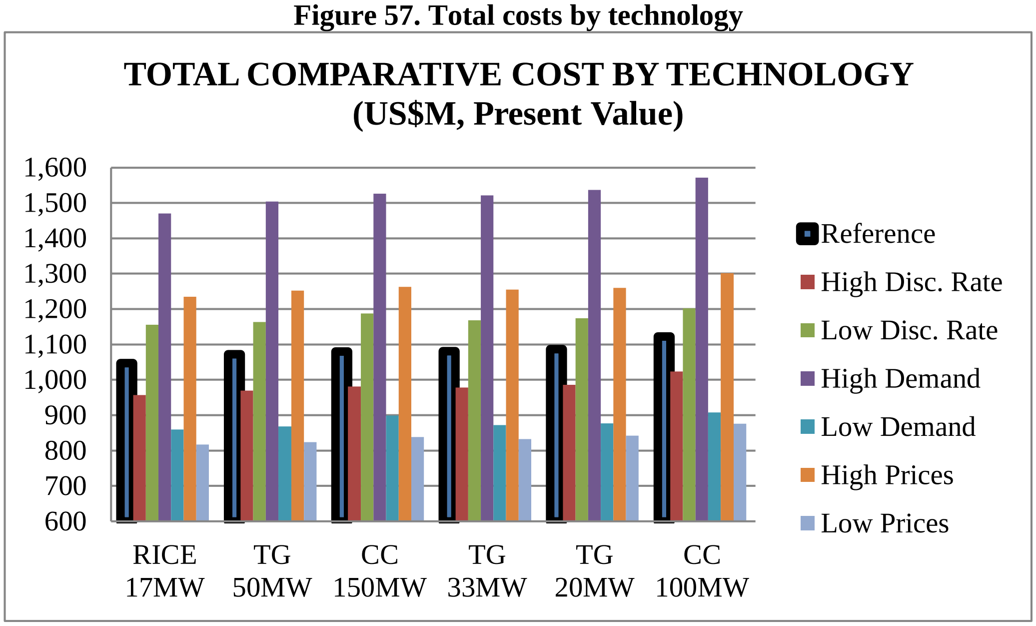
Figure 56. Costs of Natural Gas generation expansion



Source: Consultant

Figure 57 summarizes total present value of comparative costs by technology obtained from the optimizations performed with the model for the Base and Sensitivity scenarios (on demand growth, fuel prices and discount rates). They indicate that the minimum cost technology for the installation of this new power plant would be Reciprocating Internal Combustion Engines with 17 MW units.

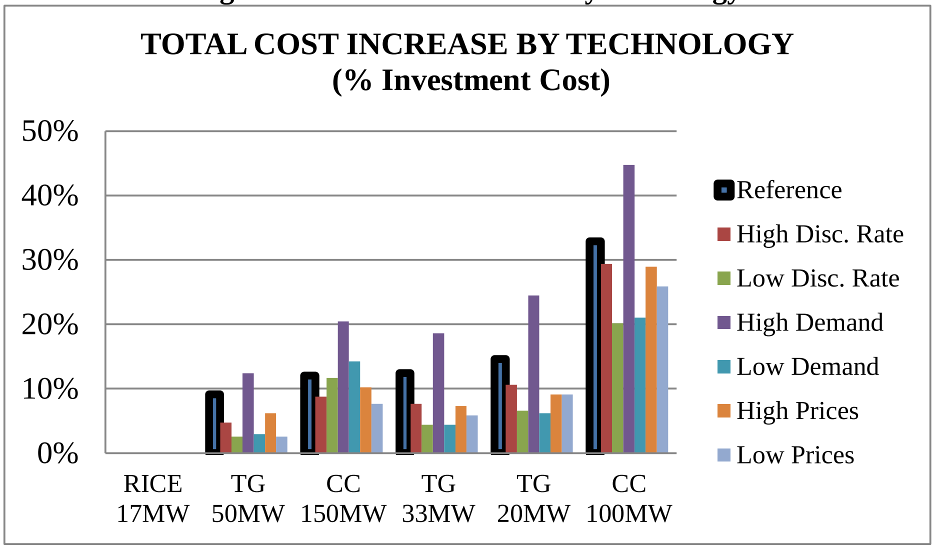
Figure 57. Total costs by technology



Source: Consultant

Figure 58 illustrates the magnitude of total comparative cost differences of the optional technologies with the most economical in terms of percentage of the investment cost estimated for a new RICE power plant (around US$ 240 million for a 10 x 17 MW power plant operated with dual fuel: Natural Gas or Liquid Fuel).

Figure 58. Total cost increase by technology



Source: Consultant

8.3 Optimization III (long term generation expansion optimization)

This optimization was focused to evaluate DBIS generation expansion during the long term horizon (up to 2035) with and without Natural Gas usage. The case with Natural Gas assumes the certified Natural Gas availability of 30 mmcfd (NG 30 Case), for which a sensitivity case with 50 mmcfd (NG 50 Sensitivity Case) is also evaluated. The case without Natural Gas availability was built to accomplish the objective to supply DBIS electricity demand with near 100% Renewable Energy generation after 2025 (GREEN Case).

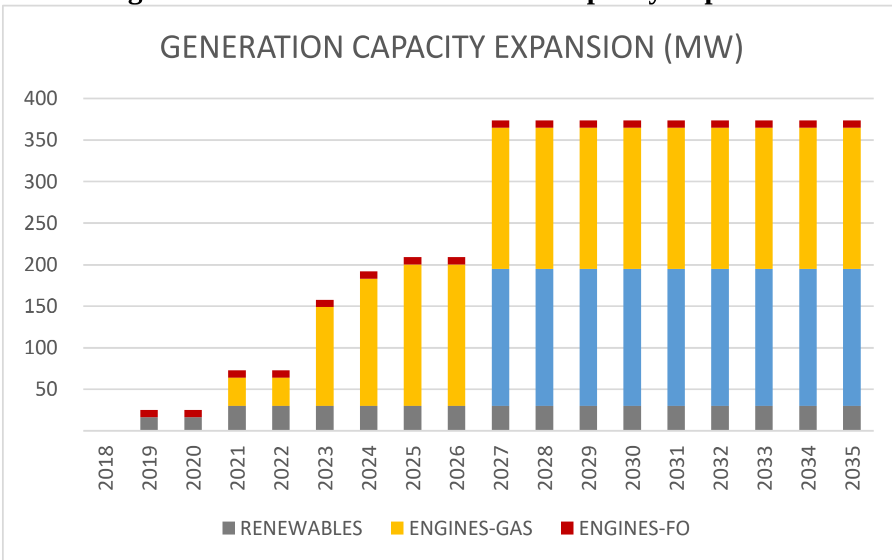
For purposes of the study of the expansion plan and in order to consider the financial requirements of the offshore transportation activity, it has been considered a take or pay contract for the natural gas supply to the new power plant with payment obligation of 70% of the total contracted, similar to the practice that some countries have used to initiate the development of the natural gas market.

The objective of this evaluation was to confirm the economic attractiveness of the optimal DBIS generation expansion based on Natural Gas and to identify the alternative second best generation expansions meeting the GSDS goal of almost full power generation with renewable energy after 2025, without natural gas availability. The results of these optimizations permitted also to obtain conclusions about: i) the power generation cost for DBIS under each scenario and how it would be reflected in the average tariff for the final users, ii) the financial feasibility of the new gas fired power plant.

8.3.1 Optimal expansion with 30 mmcfd (NG 30 Case)

Figure 59 illustrates the optimal NG30 expansion strategy obtained with the Optimization Model under the Base Scenario (Reference fuel prices, Base demand growth and 10% discount rate).

Figure 59. NG 30 Case: Generation Capacity Expansion

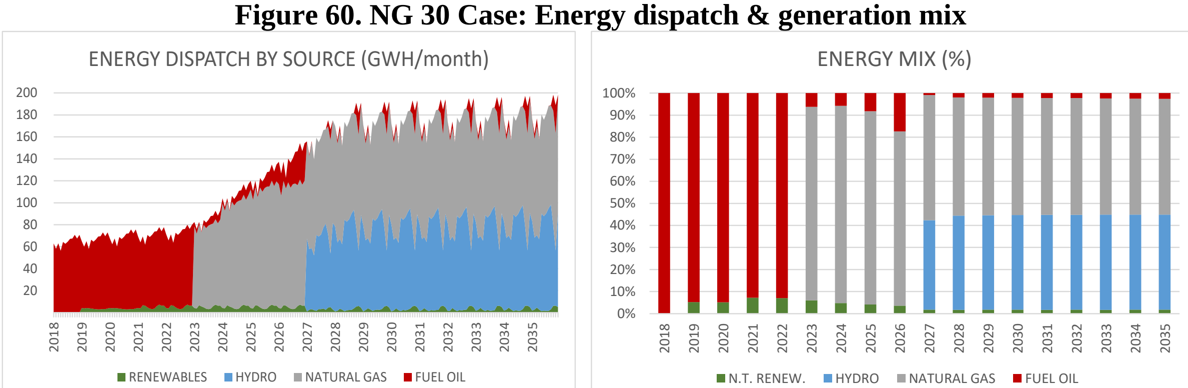


Source: Consultant

In this Case, the optimal generation expansion would also start in 2019 with the commissioning of 8.7 MW in HFO/NG reciprocating engines (located in Garden of Eden but to be translated to the new Natural Gas power plant site in 2023), 6 MW solar and 10 MW wind. Then it would be followed by a progressive installation of 170 MW NG (dual fuel) reciprocating engines with 10x17 MW units, with the first one in 2021 (initially operated with liquid fuel). The generation expansion would also include 165 MW hydro in 2027 (Amaila) if the Natural Gas availability would be limited to 30 mmcfd but this project could be delayed if this availability is increased, being required the installation of additional capacity operated with natural gas (as presented for the sensitivity case).

Figure 60 illustrates future generation dispatch in DBIS under this scenario, implying an energy mix using 88% of natural gas and 4% of RET during 2025 which would change to 57-53% of natural gas and 43-45% RET+Hydro after 2027.

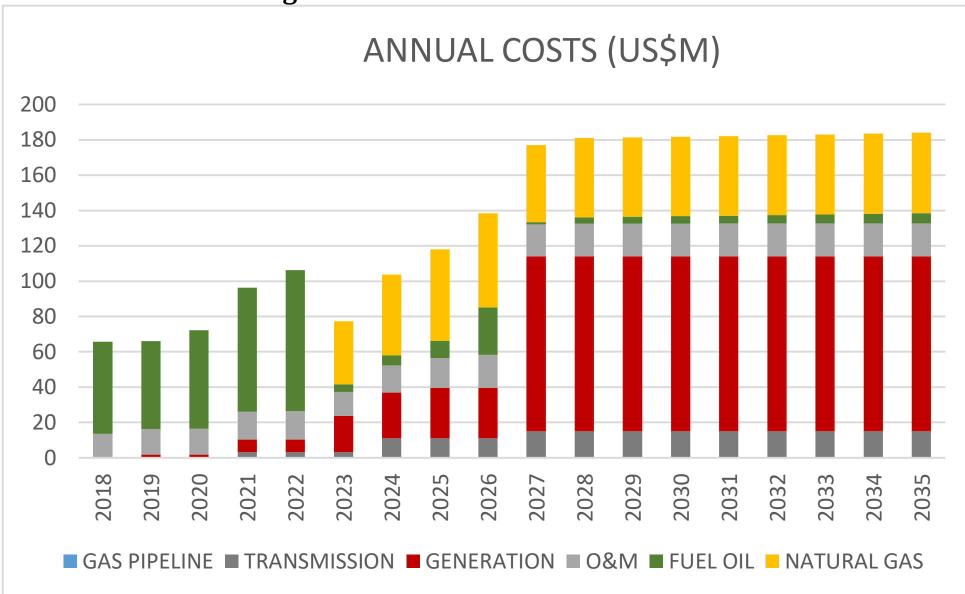
Figure 60. NG 30 Case: Energy dispatch & generation mix



Source: Consultant

Figure 61 illustrates the annual costs forecasts for this case. The Present Value at 10% of total costs represent US$ 1,000 million, significantly lower than the BAU Case but higher than the corresponding to the NG 50 Case.

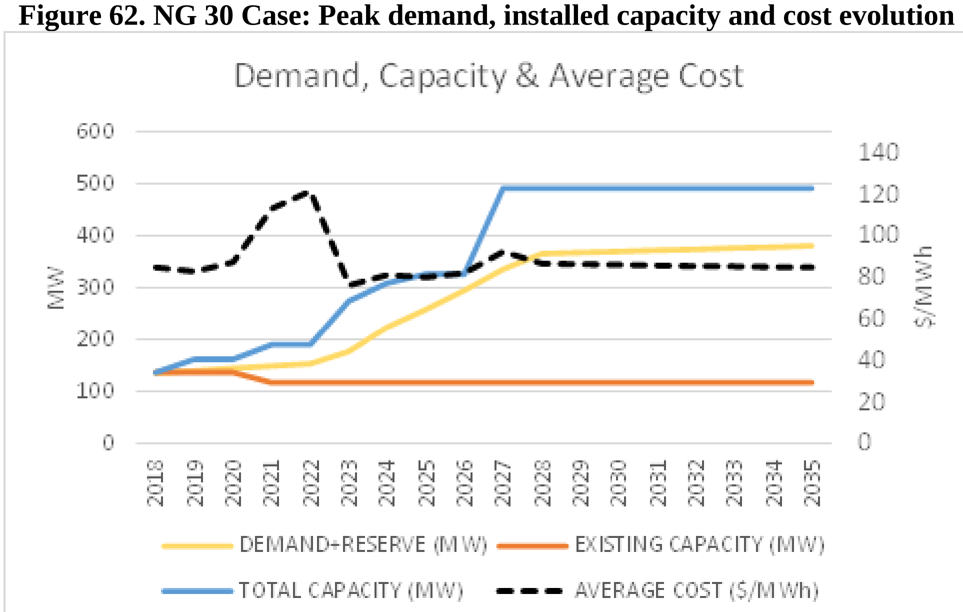
Figure 61. NG 30 Case: Annual costs



Source: Consultant

Figure 62 illustrates the peak demand and total installed capacity evolution under this scenario, as well as the evolution of average generation costs that increases from US$ 85/MWh to US$ 121/MWh in 2022 and then decreases to around US$ 86/MWh after 2027, without considering CO2 emissions costs.

Figure 62. NG 30 Case: Peak demand, installed capacity and cost evolution

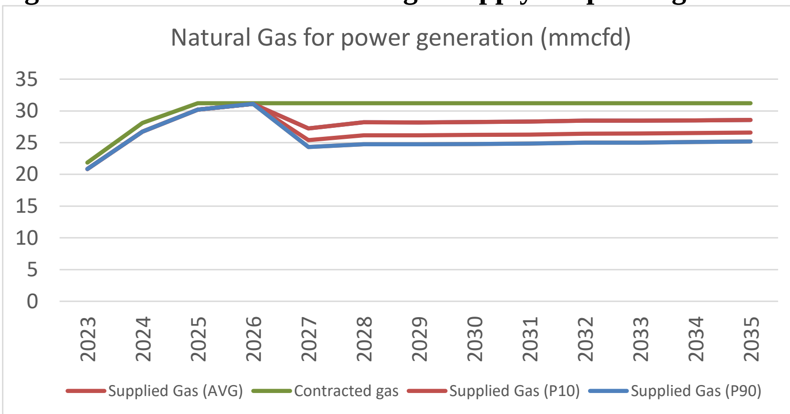


Source: Consultant

A preliminary indicative financial analysis of the commercial operations of the new Natural Gas Power Plant, considering a gas price of US$ 4.7/MBTU for the gas supplied with a 70% take or pay contract, suggest that it could be developed with an average selling price of US$ 89/MWh during 2023-2035 providing a financial Return of 10% to the developers (in real terms and before taxes). Appendix N includes the details of this estimation.

In this case, with hydroelectric power plants included in DBIS generation expansion, the future profile of the contracted and the expected gas usage for power generation indicates that the 70% take or pay commitment of the gas supply contract would be satisfied, as it is presented in Figure 63.

Figure 63. NG 50 Case: Natural gas supply for power generation

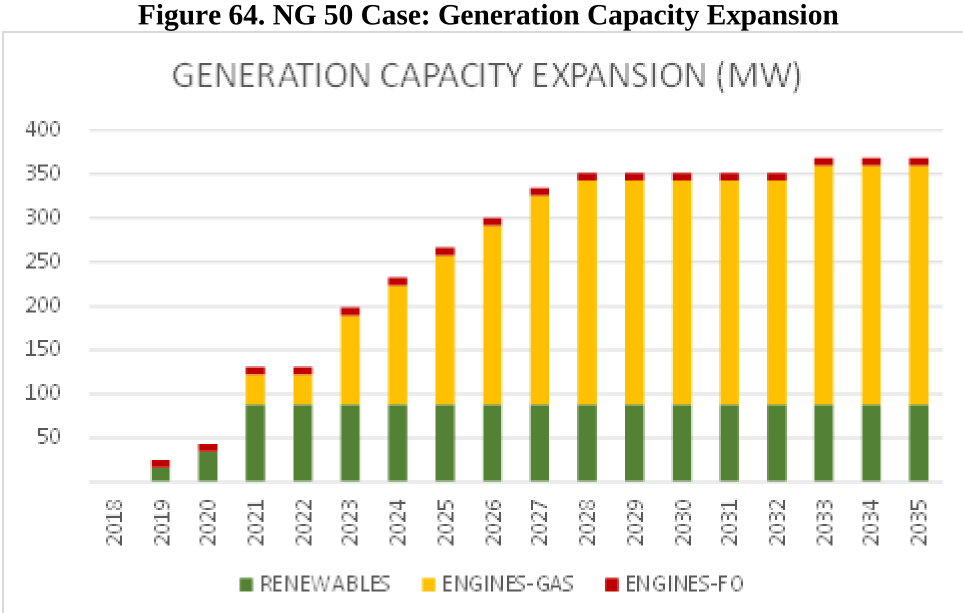


Source: Consultant

8.3.2 Optimal expansion with 50 mmcfd (NG 50 Case)

Figure 64 illustrates the optimal NG50 expansion strategy obtained with the Optimization Model under the Base Scenario (Reference fuel prices, Base demand growth and 10% discount rate).

Figure 64. NG 50 Case: Generation Capacity Expansion



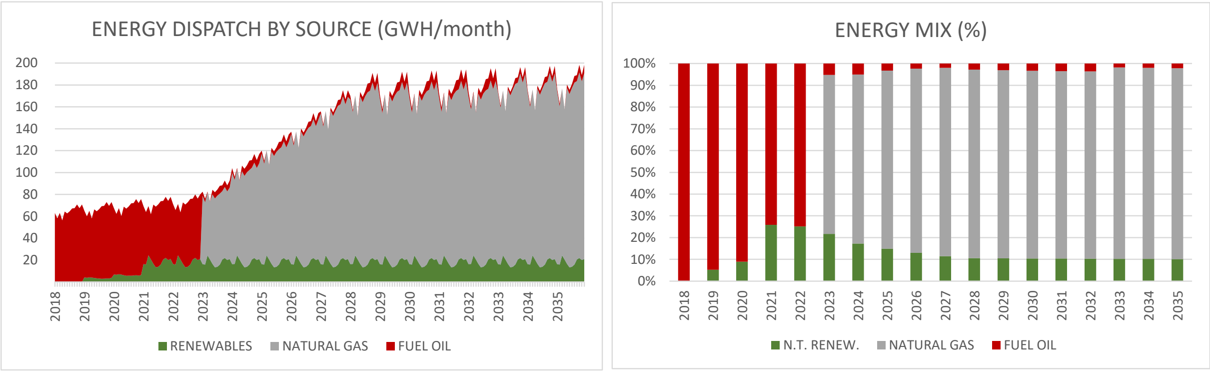
Source: Consultant

In this Case, the optimal generation expansion would start in 2019 with the commissioning of 8.7 MW in HFO/NG reciprocating engines (located in Garden of Eden but to be translated to the new Natural Gas power plant site in 2023), 6 MW solar and 10 MW wind, followed by 18 MW in solar plants in 2020. In 2021 it would include 30 MW in wind plants, the recuperation of Skeldon biomass power plant (13.8

MW) and the installation of Albion biomass power plant (with 9.8 MW). In this year it would be also required the commissioning of 34 MW in dual fuel reciprocating engines (2x17 MW) located in the new landing site of the Natural Gas but operated initially with liquid fuels until 2023. After this year this plant would be operated with Natural gas and its capacity would be progressively increased with 17 MW units up to 272 MW in 2032 (according demand increase). In this case it would be required the confirmation of 20 mmcfd of additional Natural Gas availability (50 mmcfd total).

Figure 65 illustrates future generation dispatch in DBIS under this scenario, implying an energy mix using 82-88% of natural gas and 14-10% of RET during 2025-2035.

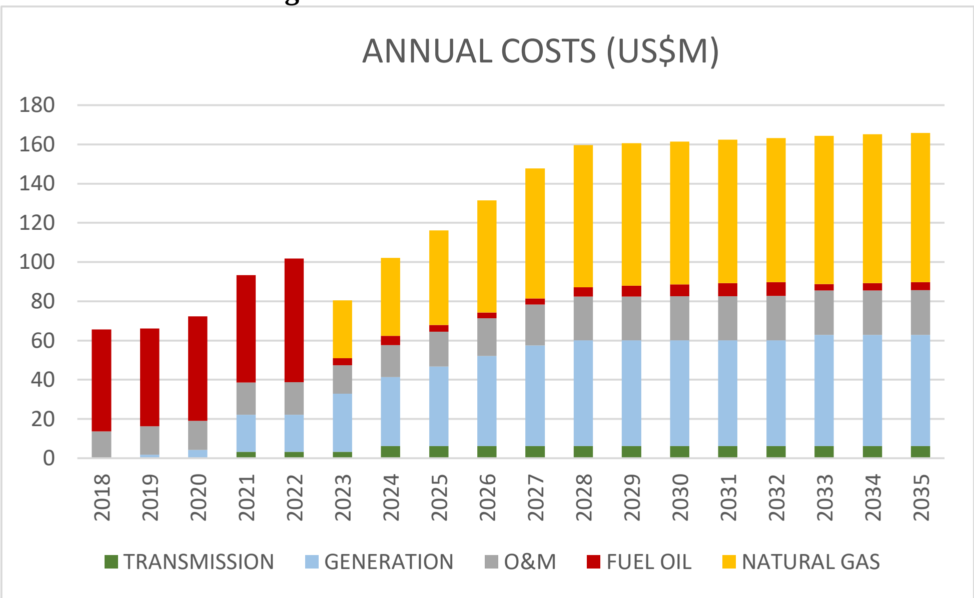
Figure 65. NG 50 Case: Energy dispatch & generation mix



Source: Consultant

Figure 66 illustrates the annual costs forecasts for this case. The Present Value at 10% of total costs represent US$ 938 million, significantly lower than the BAU Case.

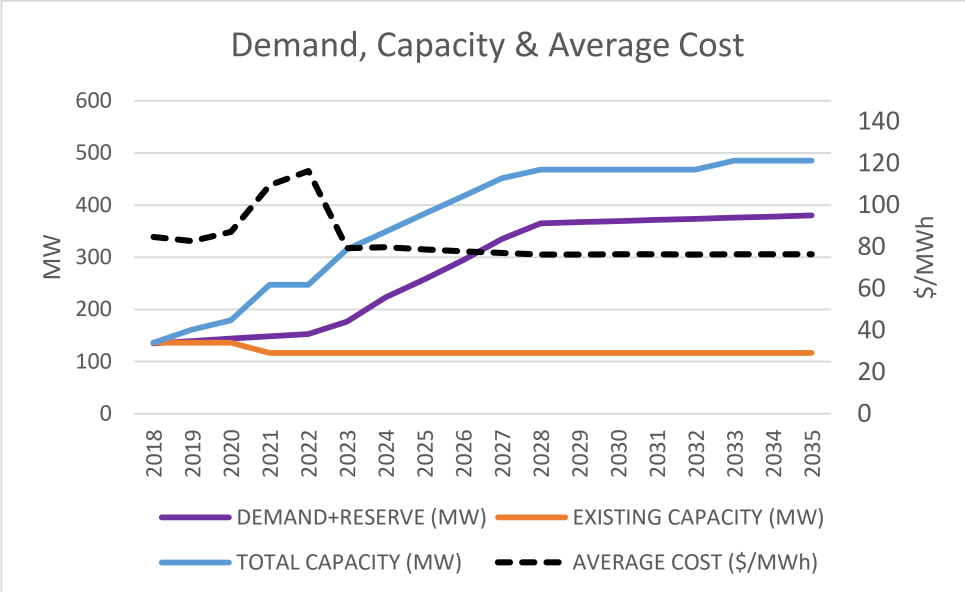
Figure 66. NG 50 Case: Annual costs



Source: Consultant

Figure 67 illustrates the peak demand and total installed capacity evolution under this scenario, as well as the evolution of average generation costs that increases from US$ 85/MWh to US$ 116/MWh in 2022 and then decreases to around US$ 76/MWh after 2026, without considering CO2 emissions costs.

Figure 67. NG 50 Case: Peak demand, installed capacity and cost evolution

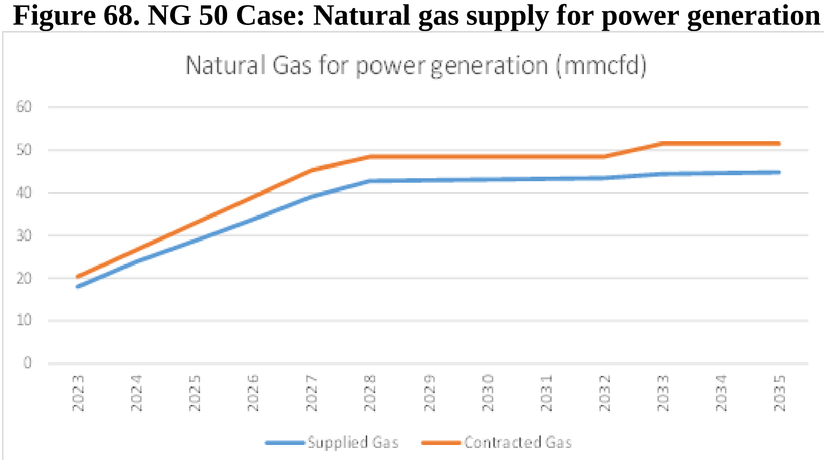


Source: Consultant

A preliminary indicative financial analysis of the commercial operations of the new Natural Gas Power Plant, considering a gas price of US$ 4.7/MBTU for the gas supplied with a 70% take or pay contract, suggests that it could be developed with an average selling price of US$ 72/MWh during 2023-2035 providing a financial Return of 10% to the developers (in real terms and before taxes). Appendix N includes the details of this estimation.

In this case, without hydroelectric power plants included in DBIS generation expansion, the future profile of the contracted and the expected gas usage for power generation indicates that the 70% take or pay commitment of the gas supply contract would be more than satisfied, as it is presented in Figure 68

Figure 68. NG 50 Case: Natural gas supply for power generation

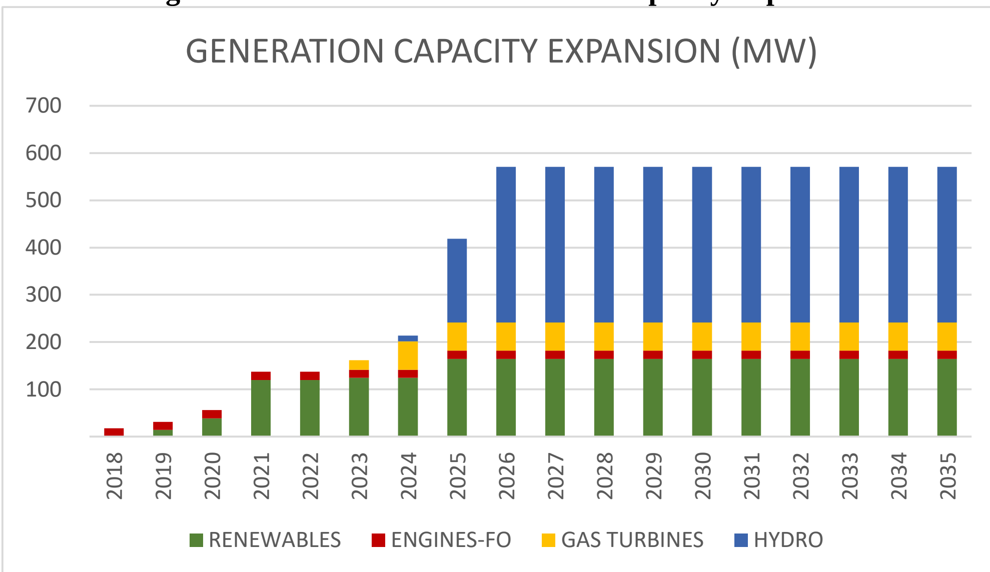


Source: Consultant

8.3.3 Optimal expansion without gas and Green goals in 2025 (GREEN Case)

Figure 69 illustrates the optimal GREEN expansion strategy obtained with the Optimization Model under the Base Scenario.

Figure 69. GREEN Case: Generation Capacity Expansion

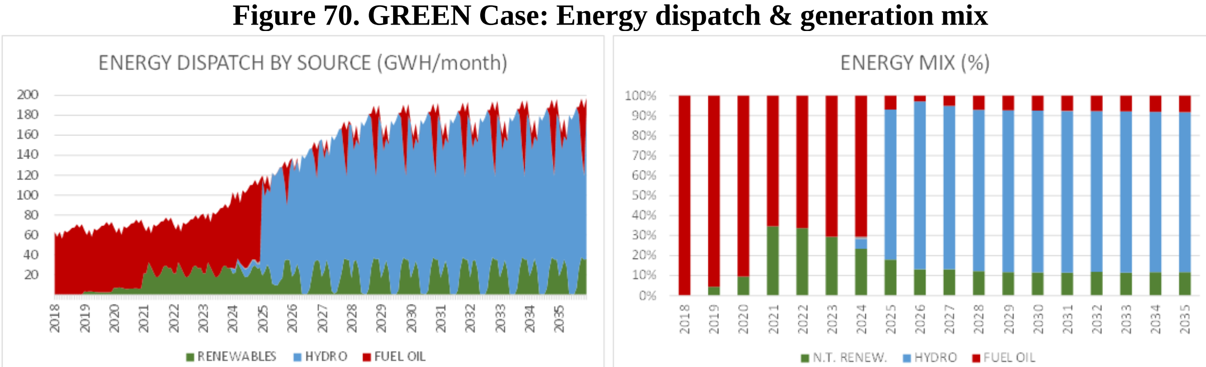


Source: Consultant

In this case, during 2018-2019 DBIS generation expansion would include 17.6 MW in HFO gensets, 6 MW in solar and 8 MW in wind, during 2019-2020 it would include additional 36 MW solar, 30 MW in biomass (including 13.75 MW of the recuperation of the existing Skeldon bagasse power plant) and 40 MW in wind. Later, during 2023-2024 it would be commissioned 60=3x20 MW in gas turbines, 12 MW in hydro (Tiger Hill) and 4 MW in biomass. In 2025 it will commissioned 165 MW hydro (Amaila) and 40 MW in wind and in 2027 it would be included 152 MW in hydro (Tumatumari).

Figure 70 illustrates future generation dispatch in DBIS under this scenario, implying an energy mix using 92-97% of Renewable Energy sources for power generation during 2025-2035. This would imply that the 60 MW installed in gas turbines fueled with LFO would be used to provide backup and temporary power generation compensation to the intermittent and seasonal RE generation.

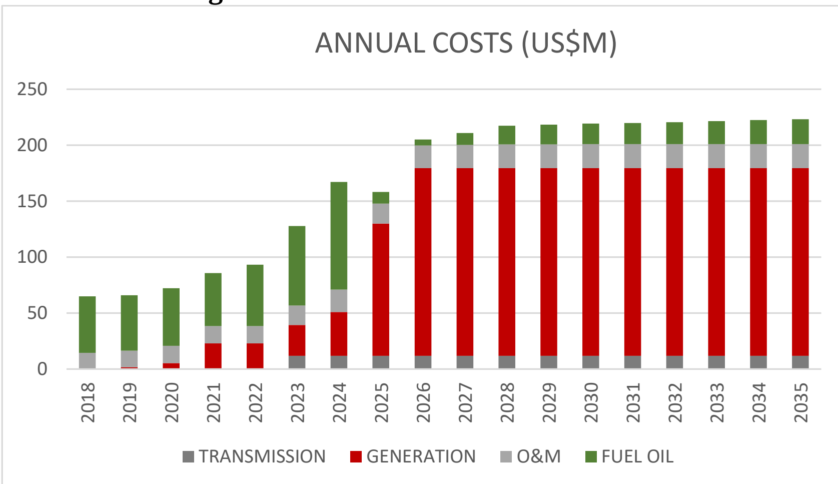
Figure 70. GREEN Case: Energy dispatch & generation mix



Source: Consultant

Figure 71 illustrates the annual costs forecasts for this case. The Present Value at 10% of total costs represent US$ 1,192 million, higher than the GAS 30 case. [79]

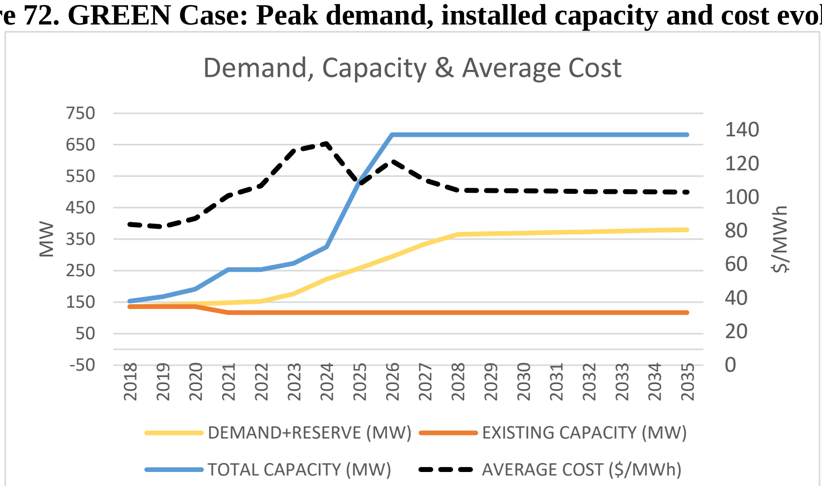
Figure 71. GREEN Case: Annual costs



Source: Consultant

Figure 72 illustrates the peak demand and total installed capacity evolution under this scenario, as well as the evolution of average generation costs that increases from US$ 85/MWh to US$ 122/MWh in 2022 and then decreases to around US$ 103/MWh after 2030, without considering CO2 emissions costs.

Figure 72. GREEN Case: Peak demand, installed capacity and cost evolution



Source: Consultant

[79] With 20 mmcf flexible natural gas availability at a price of US$ 4.7/MBTU the optimal expansion of DBIS generating capacity would include around 100 MW of new thermoelectric capacity by 2025 that would provide backup for the new Renewal Energy power plants required to acomplish the Green Goals by 2025. Total cost of this strategy for the power sector would be similar and of around US$ 1,200 million, including a payment to maintain a reserve capacity of around 20 mmcfd in the offshore gas transportation system. However the intrisic relative inflexibility of the natural gas production activity and the plausible absence of a significant market for the natural gas in Guyana in the study horizon indicates that for the acomplishment of the GREEN goals, backup power plants using liquid fuels would be more economical and appropiated than using natural gas.

8.3.4 Summary

Table 65 summarizes the results obtained in the four alternative cases evaluated for DBIS optimal generation expansion in the long term under the Base Scenario (Base case of demand growth, Reference case of fuel prices and 10% discount rate). They consist in: i) the BAU case, using liquid fuels for power generation, ii) the GAS 30 case with 30 mmcfd of indigenous gas available for power generation (including also a sensitivity case 50 mmcfd of gas availability), and iii) the GREEN case, meeting the "green goal" of near 100% DBIS generation with renewable energy sources in 2025 without gas availability. Such results provide indicators about the cost reductions in DBIS generation expansion that could provide the consideration within the GSDS "green goals" the use of natural gas as a new clean fuel for power generation in DBIS during 2023 – 2035.

Table 65. Summary of results

CASE	BAU	GAS 30	GAS 50	GREEN
CAPACITY EXPANSIONS IN 2035 (MW)				
Renewables	14	30	88	164
Hydro	0	165	0	329
Gas	0	170	272	0
Fuel Oil	264	9	9	77
TOTAL	**278**	**374**	**369**	**571**
RENEWABLE ENERGY AND NATURAL GAS PARTICIPATIONS (%)				
2025 RET & hydro	1%	4%	15%	95%
2025 NG		88%	82%	
2030 RET & hydro	1%	45%	10%	93%
2030 NG		53%	88%	
2035 RET & hydro	1%	45%	10%	92%
3035 NG		53%	88%	
PRESENT VALUE OF TOTAL DBIS COSTS (2018-2035)				
Generation				
Investment	127	319	246	636
O&M	198	139	151	154
Fuel Oil	1,200	272	235	348
Natural Gas	0	210	274	0
Subtotal	**1,525**	**939**	**907**	**1,137**
Transmission	0	61	31	55
TOTAL	**1,525**	**1,000**	**938**	**1,192**
AVERAGE GENERATION COST (USD/MWh) 1/				
2018	85	85	85	85
2022	117	121	116	128
2025	139	80	79	107
2030	156	86	76	104
2035	164	85	76	103

Source: Consultant

The exploitation during 2023-2025 of indigenous natural gas for power generation in Guyana would reduce total generation expansion costs from US$ 1,525 million (associated to a Business as Usual expansion strategy based on 257 MW HFO gensets) to US$ 1,000 million with a volume of 30 mmcfd (based on 170 MW NG gensets, 165 MW Hydro – Amaila and 30 MW RET). The adoption of this natural gas based generation expansions for DBIS would require the consideration of natural gas within the SGDG green goal for 2025 allowing the use this clean fuel for power generation during 2025 – 2035. If this would not be the case, the optimal expansion to meet such goal would not include natural gas as fuel for power generation (but 329 MW Hydro – Amaila & Tiger Hill & Tumatumari, 60 MW LFO gas turbines, 17 MW HFO gensets and 164 MW RET) and its total cost would be US 1,192 million.

8.4 Sensitivity analysis

In order to assess the robustness of the results obtained for the most economical system expansion of DBIS, we prepare a sensitivity analysis to variations in main drivers used in the evaluation. Table 66 summarizes the results obtained of total DBIS generation – transmission expansion costs under each of the cases considered (BAU, GAS 30 & 50 and GREEN) for the different scenarios considered for demand forecast, fuel prices and discount rate.

Table 66. Costs of DBIS generation – transmission expansion (All cases)
(Present value of total costs during 2018 – 2035, US$ million)

SCENARIO	DRIVER VARIABLE			CASE			
	DEMAND	FUEL PRICES	DISC. RATE	BAU	GAS 30	GAS 50	GREEN
BASE	BASE	BASE	10%	1525	1000	938	1194
HIGH DISC. R.	BASE	BASE	12%	1304	914	836	1109
LOW DISC. R.	BASE	BASE	8%	1800	1098	1055	1280
HIGH PRICES	BASE	HIGH	10%	2607	1208	1129	1470
LOW PRICES	BASE	LOW	10%	818	772	818	976
HIGH DEMAND	HIGH	BASE	10%	2103	1402	2103	1698
LOW DEMAND	LOW	BASE	10%	1127	862	765	923

Source: Consultant

As presented in Table 66, the GAS cases shows the lower present value of total DBIS generation – transmission expansion costs in all scenarios, situation that indicates the robustness of the economic attractiveness for the use of natural gas to support the generation expansion in Guyana during 2023-2035.

Table 67 indicates the influence that the driver variables had in the selection of the participation of the different technologies in optimal DBIS generation expansion during 2018-2035 for GAS 30 case.

Table 67. DBIS generation expansion (30 mmcfd natural gas availability) - (MW)

SCENARIO	DRIVER VARIABLE			ADDITIONAL CAPACITY (2035)			
	DEMAND	FUEL PRICES	DISC. RATE	RET	HYDRO	GAS / DUAL	HFO / GAS
BASE	BASE	BASE	10%	30	165	170	9
HIGH DISC. R.	BASE	BASE	12%	30	165	170	9
LOW DISC. R.	BASE	BASE	8%	30	165	170	9
HIGH PRICES	BASE	HIGH	10%	88	165	170	9
LOW PRICES	BASE	LOW	10%	30	165	179	9
HIGH DEMAND	HIGH	BASE	10%	152	165	187	40
LOW DEMAND	LOW	BASE	10%	30	165	85	17

Source: Consultant

Table 68 indicates how the consideration of a high and low discount rates and low prices would not change the optimal expansion when limited the gas availability to 30 mmcfd. High prices would increase in 58 MW the RET participation (30 MW in wind, 18 solar and 10 MW biomass), high demand in 122 MW and also in 57 MW Gas and HFO/dual, while low demand will reduce in 85 MW gas , increasing in 9 MW HFO/dual.

Table 68 summarizes the participation of the different technologies in optimal DBIS generation expansion during 2018-2035 for GAS 50 sensitivity case, which correspond to the exploitation 50 mmcfd of natural gas for power generation.

Table 68. DBIS generation expansion (50 mmcfd natural gas availability) - (MW)

SCENARIO	DRIVER VARIABLE			ADDITIONAL CAPACITY (2035)			
	DEMAND	FUEL PRICES	DISC. RATE	RET	HYDRO	GAS / DUAL	HFO / GAS
BASE	BASE	BASE	10%	88	0	272	9
HIGH DISC. R.	BASE	BASE	12%	60	0	272	9
LOW DISC. R.	BASE	BASE	8%	124	0	255	9
HIGH PRICES	BASE	HIGH	10%	124	0	275	9
LOW PRICES	BASE	LOW	10%	30	0	255	9
HIGH DEMAND	HIGH	BASE	10%	97	0	312	9
LOW DEMAND	LOW	BASE	10%	78	0	170	9

Source: Consultant

Table 67 indicates how the consideration of high discount rate will reduce it in 18 MW solar expansion while low discount rate would imply the economic attractiveness to increase in 36 MW the RET participation in the expansion (from which 30 MW would be wind and 6 MW biomass), reducing in 17 MW the gas expansion. High prices would increase in 36 MW RET participation, in similar way as the low discount rate. However, low fuel prices will reduce in 17 MW the economic expansion in gas and in 58 MW the RET expansion a high discount rate (12%) and low fuel prices in 58 MW (30 MW in wind, 18 solar and 10 MW biomass). Also, a high demand would imply the additional installation of 40 MW in gas and 9 MW in solar, while a low demand would reduce in 102 MW the required expansion in gas and 10 MW in biomass.

These results confirm the importance of the selection of the natural gas expansion composed by relatively small size units (17 MW) in order to have the flexibility of adjust the generation expansion according to the real demand growth and also to the evolution of fuel prices and economic parameters. If selected RICE technology for the new power plant it should be noted also its relative advantages of power generation flexibility to compensate the variability and intermittency of RET generations.

8.5 Conclusions about the expansion program

Oil production in Guyana, expected to start in mid-2021, will have large positive externalities in Guyana's economy. Power demand forecast under this new economic environment becomes a critical and difficult task, as although there is a wide literature on the impact of large oil discoveries (and subsequent production) on Gross Domestic Product (GDP) in a country, there is few empirical evidence on the impact on power demand growth in such country. In other words, how fast growth in GDP is translated into new power demand after an oil shock.

In this study we continued modelling power demand in terms of GDP, which is expected to have annual double-digit growth after oil production starts in 2021 but in the long term to have a small growth rate. As a result, power demand is expected to increase considerably from 2021-24 but growth to become moderate in the long term. The only source of GDP growth with long term estimates was IMF estimates produced in May 2017, which are considered conservative. The consultant modelled four different scenarios of power demand growth to reflect this uncertainty. One of those scenarios takes the Base Case but “delayed” the power sector demand growth in order to reflect the actual transmission and distribution infrastructure of the power sector, which has caused power service deterioration along the country, and high rates, one of the highest in Latin America. Advances in such fronts would produce that power demand growth would be more similar to the Base Case instead to such Delayed Base Case. On the other hand, the High Case reflects a higher long term growth rate while the Low Case reflects a Business as Usual case.

Under the Reference Scenario selected for this study, the expected peak demand in DBIS would increase from 115 MW in 2017 to 330 MW in 2035, requiring the installation of significant additional “firm” capacity in the system to supply 215 MW of additional peak demand. Given the expected high demand increase with the new oil economy of Guyana, this would be required within the next 10-12 years.

An optimal "Business as Usual (BAU)" expansion strategy to attend the required generation capacity expansion in DBIS would lead to the installation of new generating capacity composed by gensets for base generation (around 204 MW in several units operating with HFO/LFO) and peaking gas turbines (around 60 MW in several units operating with LFO). This would represent a total generation cost of US$ 1,525 million during 2018-2035, present value at 10% (without considering transmission and distribution costs) from which 76% would be fuel costs. In addition, such generation expansion strategy would imply high CO2 emissions, not compatible with the Government’s Green State Development Strategy adopted for Guyana.

The indigenous natural gas produced in association to the offshore oil development at the Starbroek block, at wellhead prices and levelized offshore transportation tariffs reflecting its economic cost in Guyana´s landing site, will constitute an economical new fuel that could complement future generating "firm" capacity requirements for DBIS. In addition, given its CO2 moderate emission level, natural gas could be considered as a transitional cleaner fuel toward the objective to reach a Green Economy for Guyana.

The results of the study suggest that the most appropriated technology for the gas to power conversion would be the installation of several reciprocating internal combustion engines (RICE) sized at around 17 MW per unit. Its costs, operational flexibility and moderate size in comparison to the combined cycle (CC) technology of around 100-150 MW offer advantages to expand DBIS generation by modules according future real demand growth, even though RICE technology is less efficient in terms of BTU/Kwh fuel consumptions than CC technology. Also, in comparison to gas turbines (GT) of around 20-30-50 MW per unit, RICE power generators offer higher BTU/kWh efficiency that compensates its higher investment costs. In addition alternate fuel for RICE power plants (HFO/LFO mix) could be less costly than the alternate fuel for CC and TG (LFO). Also, the intermittent nature of renewable generation, low-priced natural gas and advancements in engine technology and flexibility gave also to RICE technology advantages for reliable generation in the case of DBIS.

To reduce fuel costs and CO2 emissions, DBIS future generation expansion could include Renewal Energy Technologies for new power generation (using wind, solar and biomass) in the short and midterm. However, given that these technologies do not provide "firm" capacity, after the installation of the natural gas expansion using the natural gas availability for power generation, currently estimated in 30-50 mmcfd, the most promising technology for DBIS power generating development would be the installation of hydroelectric power plants, once the natural gas availability for power generation has been fully exploited. In addition, this strategy will foster the achievement of the green energy goals stablished for the future development of Guyana.

The evaluation of these matters constitutes a challenge and this study contributes with the application of a generation – transmission planning procedure that has permitted to stablish the following conclusions about the plausible optimal generation expansion for DBIS under a Reference Demand/Supply scenario and two levels in the natural gas availability for power generation during 2023-2035:

With 30 mmcfd natural gas availability (NG 30 Case), the optimal generation expansion would start with 8.7 MW in HFO/Natural engines, 6 MW solar and 10.3 MW wind in 2019 followed by a progressive installation of 170 MW NG (dual fuel) reciprocating engines with 10x17 MW units, with the first one in 2021 (initially operated with liquid fuel). The generation expansion would also include 165 MW hydro in 2027 (Amaila). Given the commissioning of this hydro capacity, and the requirements of the firm natural gas usage, the 72 MW Renewal Energy capacity in wind, solar and biomass would not be required. Encompassing such generation expansion it will be required the construction of the trunk transmission line (2 circuits at 230 kV) and associated substations in the following three tranches: SECC1 – Linden, Linden - New Sophie (or Garden of Eden) and New Sophie (or Garden of Eden) - Woodlands (substation of the new gas fired thermal power plant near Columbia substation).

With 50 mmcfd natural gas availability (NG 50 Case), the optimal generation expansion would start with 8.7 MW in HFO/Natural Gas engines, 6 MW solar and 10.3 MW wind in 2019, followed by a progressive installation of 272 MW NG (dual fuel) reciprocating engines with 16x17 MW units, with the first one in 2021 (initially operated with liquid fuel). For the consideration of this case it would be required the confirmation of 20 mmcfd of natural gas availability for power generation. The generation expansion would also include additional 72 MW in Renewal Energy capacity in 2021, including wind (30 MW), solar (18 MW) and biomass (24 MW, including the recuperation of 13.8 MW of the existing Skeldon bagasse power plant). Encompassing such generation expansion it will be required the construction of the trunk transmission line (2 circuits at 230 kV) New Sophie (or Garden of Eden) - Woodlands (substation of the new 272 MW gas fired thermal power plant near Columbia substation). Also, in this program it would be economical the 69 kV Linden interconnection in 2024.

With these expansion strategies (for 30-50 mmcfd gas availability) total DBIS generation costs would be reduced from the US$ 1,525 million, if BAU strategy would be developed, to US$ 938 - 1,000 million, and average unitary generation costs would be reduced from the US$ 85/MWh estimated for 2018, to US$ 76-85/MWh for the long term (after being increased to US$ 115 -121/MWh in 2022 due increases in HFO prices before the commissioning date of the new natural gas facilities), instead of being increased to US$ 164/MWh in the case of the BAU expansion.

A preliminary indicative financial analysis of the commercial operations of the new Natural Gas Power Plant of 272 MW using 50 mmcfd in the long term (with a gas price of US$ 4.7/MBTU and the gas supplied with a 70% take or pay contract), suggests that it could be developed with an average selling price of US$ 72/MWh during 2023-2035 providing a financial return of 10% to the developers (in real terms and before taxes). For the 170 MW power plant using 30 mmcfd and similar terms for the natural gas supply contract, the selling price required to obtain 10% financial return would be US$ 89/MWh.

With these expansion DBIS generation mix would evolve from almost 100% liquids fuels in 2018 to around 4-8% in 2025 and 2% in 2035. Natural gas participation would represent 82-88% in 2025 and 88-53% in 2035. Renewable energy sources (RET & Hydro) would participate with 15-4% in 2025 and with 10-45% in 2035. The two figures corresponding to generation expansion using 50-30 mmcfd, respectively).

Even though the national option of Kamarau hydro (100 MW) could constitute a source of economic electricity for DBIS, it has not been included in DBIS expansion in the cases using natural gas given that this project would not provide firm capacity for DBIS and also because the gas price and gas supply conditions (i.e. take or pay contract) for DBIS are still undefined, implying a potential risk that project benefits for DBIS could not be realized (if gas supply for power generation would be provided reflecting a gas price near wellhead price or if take or pay commitments for gas supply incentive the new natural gas power generation in the electricity market). Independently of the above, on a regional scale, Kamarau hydro Regional (50 MW) continues to be beneficial to build as it would supply electricity to the regional mining industry and therefore replacing costly liquid fuel power generation.

The evaluation of the DBIS optimal generation expansion with the objective to achieve in 2025 a generation mix with near 100% renewable energy sources, indicates that natural gas would not be the appropriate fuel to support the additional 60 MW thermoelectric backup generation required during 2024-2035 to compensate the variability and intermittency of the renewal energy generation at relative large scale, as required in this case. The significant fixed investment costs associated to its offshore transportation to inland Guyana, and its probable inflexibility for its production, suggests that liquid fuels instead would be more economical and financeable fuel.

The optimal generation expansion for this case *(GREEN Case)* would include 17.6 MW in HFO gensets, 6 MW in solar and 8 MW in wind, during 2019-2020 it would include additional 36 MW solar, 30 MW in biomass (including 13.75 MW of the recuperation of the existing Skeldon bagasse power plant) and 40 MW in wind. Later, during 2023-2024 it would be commissioned 60=3x20 MW in gas turbines, 12 MW in hydro (Tiger Hill) and 4 MW in biomass. In 2025 it will commissioned 165 MW hydro (Amaila) and 40 MW in wind and in 2027 it would be included 152 MW in hydro (Tumatumari).

Total costs associated to this case would amount US$ 1,192 million and the long term average generation costs would represent US$ 103/MWh. All these figures lower than BAU case but higher than GN 50 and GN 30 cases.

The consolidation of the generation expansion strategy for DBIS would require a significant support in negotiations and agreements with different stakeholders about its main components, such as: a) natural supply conditions and prices, b) Arco Norte development (inclusive considering the option of a bilateral interconnection with Suriname), and c) hydroelectric developments and power interchanges with regional markets, amongst others.

9 ANALYSIS OF GUYANA'S POWER SECTOR POLICY AND REGULATIONS

9.1 Introduction

The objectives of this chapter are:

- Analyze and make recommendations on energy related regulatory and policy issues including the analysis of composition of electricity tariffs. Also, analyze the capacity of existing regulatory and policy entities to deal with the transmission, distribution and utilization of power generated by domestic natural gas, together with the promotion of RETs as part of a Green State development strategy.
- Prepare a thorough analysis of the current regulatory framework that includes an assessment (with recommendations) of the adequacy of the country's energy laws and regulations in supporting and regulating the development of RE, distributed generation, natural gas generation and EE with private sector participation.

In this chapter we review the main elements of the policy and regulatory frameworks of the electricity sector in Guyana in order to identify the consistency between these elements and the need for adjustments taking into account the proposed optimal generation expansion program. Main elements examined are: a) consistency between objectives and diagnosis of energy resources and electricity needs, b) consistency and degree of specification of objectives, goals, policy and regulatory instruments, programs and projects, c) consistency between all the elements of the energy policy and budget feasibility, d) consistency between the energy policies for each energy resource and the policies and goals of the electricity sector, if any. Finally, based on the previous analysis, the consultant draws recommendations to improve the national energy policy and its regulatory framework.

The development of this chapter was done within the context of Guyana's Power Generation System Expansion. In this sense, the policy and regulatory analysis, and proposals that stem from such analysis, are linked to the main findings of the present Study and also taking into account the analysis and included in other studies provided by the GoG[80] . Under this context, this chapter approaches the functionality of existing energy policy and regulatory bodies to identify their capacity to deal with the promotion and implementation of a power generation expansion plan, including Renewable Energy developments and Energy Efficiency programs. In the same way, main barriers and incentives for the promotion of a sustainable energy path in the country are identified. Recommendations for a regulatory framework that includes sustainable energy sources, reduces fossil fuel dependence as well as carbon emissions and at the same time provide affordable power without creating a financial burden for the utility and final users are provided. The tariff system is analyzed from the standpoint of incentives for efficient energy generation, oriented to facilitate the development of the expansion plan, and also indicating the potential benefits of lower tariffs for the final users that the availability of indigenous natural gas could represent if used as clean fuel for power generation in Guyana in a transitional path toward the full use of renewable energy sources for power generation in the long term.

[80] Main reports prepared by other consultants used to complete and support this task are: i) REPORT 2 - DRAFT NATIONAL ENERGY POLICY OF GUYANA - GREEN PAPER, Roland Clarke PhD, IDB Consultant. 23 December 2016, ii) ENERGY TRANSITION ROADMAP FOR GUYANA , Roland Clarke PhD, Consultant – Government of Guyana. 10 March 2017, and iii) Desk Study of the Options, Cost, Economics, Impacts, and Key Considerations of Transporting and Utilizing Natural Gas from Offshore Guyana for the Generation of Electricity . Revised Final Report. Report to the Government of Guyana. Energy Narrative. June 8, 2017

This chapter is divided in four sections, being the first one, this introduction. The second part presents a description of the energy policy and regulatory framework, and presents some considerations about them. The third and fourth sections contain conclusions and recommendations, respectively.

9.2 Description of Energy Policies and Regulatory Framework

This section describes the current energy policies focused in the power sector, in five parts: the policy background, the energy policy and strategies, the institutional framework, the legal framework and the regulatory framework

9.2.1 Policy Background

Since 1994, Guyana has outlined energy policies and strategies oriented to reduce dependence on imported fuels and to promote the utilization of domestic resources. However, these policies seem not being adopted in a law or Act[81]. As it can be seen in Table 1, the goals were clear and ambitious, expecting for 2004, that 61.5% of Guyana´s energy supply to be provided with indigenous resources like hydro power and bagasse. It is important to emphasize, as it will be recalled later on, that more ambitious goals have been adopted recently in the Guyana Green Development Strategy (total power generation near 100% with renewal resources by 2025). However this goal was adopted before more recent commercial definitions to initiate the development of the Oil and Gas reserves located offshore Guyana, with Oil dedicated to the international market and with its associated Gas used to foster Oil production and also providing the opportunity to use indigenous natural gas, as clean fuel, in the national energy matrix, and more specifically for power generation. This matter offer a new energy prospective that would have to be taken into account to foster in the mid-term the economic power generation expansion in Guyana exploiting this new energy source.

Table 69. Background: The National Energy Policy Committee (July 1994)

POLICY OBJECTIVES	STRATEGIES	GOALS
• To provide stable, reliable and economic supply of energy • To reduce dependency on imported fuels • To promote where possible the increased utilization of domestic resources	• Promotion, where feasible, the increased utilization of indigenous energy resources (bagasse, wood waste, rice-husk, hydropower) • More efficient utilization of energy • Continued oil exploration activities and the establishment of energy farms to provide fuelwood. • Formation of the Energy Agency is absolutely necessary for the successful implementation of the Policy	• By 1998, 53.7% of energy supply will be provided by indigenous resources (bagasse, wood waste, rice-husk, and hydropower) and 46.3% by imported petroleum products. • By 2004, 61.5% and 38.5%, respectively. • More efficient utilization of bagasse will increase the contribution from this energy source. Hydro-energy (49%) will be the major source of electricity generation by this time.

[81] "ENERGY POLICY OF GUYANA - PREPARED BY THE NATIONAL ENERGY POLICY COMMITTEE - July 1994". This document constitutes a good approach to a national energy strategy. However, it was only a draft document, without legal force and lacks of enough financial instruments in order to achieve the proposed goals.

Source: Consultant

Since 1994 until present, there have been several initiatives and studies that represent evolving thoughts about the ways to diversify energy supply away from imported oil products and set Guyana on a more sustainable path to national development and poverty reduction.

9.2.2 Existing energy policies and strategies

The policy objectives for energy supply in Guyana are guided today by the Guyana Green Development Strategy (CGDS) that for the electricity sector intend to move Guyana towards a goal of 100 percent renewable power for power generation by the year 2025[82]. It is also guided by the original 1994 Guyana Energy Policy, and a number of national, regional and international initiatives aimed at sustainable energy and climate change. The most pertinent policy objectives for the electricity service are:

- The Guyana Green Development Strategy, which today is under development taken into account the new prospective availability of indigenous natural gas.
- The 1994 Energy Policy of Guyana state policy objectives that are intended to: a. Provide stable, reliable and economic supply of energy; b. Reduce dependency on imported fuels; c. Promote where possible the increased utilization of domestic resources; and d. Ensure energy is used in an environmentally sound and sustainable manner.
- A Low Carbon Development Strategy (2010) with the goal “to help reduce global deforestation and forest degradation by 25% by 2015”. The rationale behind this goal is: “Guyana will be able to invest in creating a low deforestation, low carbon, climate resilient economy”
- Guyana’s Intended Nationally Determined Contribution as subsequently revised and submitted to the United Nations Framework Convention on Climate Change (UNFCCC) for publication on their web site states that Guyana will have a 100 percent renewable power supply in the power sector by the year 2025.
- An Assessment of Fiscal and Regulatory Barriers to Deployment of Energy Efficiency and Renewable Energy Technologies in Guyana (2014). This document seeks to identify these barriers and propose strategies that may be utilized to remove them. It was found that “an increasing demand for reliable, cost effective, accurately priced energy supplies is a major challenge to sustainable economic development in Guyana and the country experiences difficulties in accessing capital especially for smaller firms and lower to middle income households. The limited knowledge of the technical risks associated with renewable energy and energy efficiency projects limit local investments and opportunities for foreign capital and are affected by high transaction costs. Furthermore, the lack of a strategic removal of energy subsidies continue to undermine the economic case for improved energy efficiency and increased renewable energy use.
- The CARICOM Energy Policy (2013) shows an overall goal/vision of “Fundamental transformation of the energy sectors of the Member States of the Community through the provision of secure and sustainable supplies of energy in a manner which minimizes energy waste in all sectors, to ensure that all CARICOM citizens have access to modern, clean and reliable energy supplies at affordable and stable prices, and to facilitate the growth of internationally competitive Regional industries towards achieving sustainable development of the Community”. The rationale of this goal/vision was

[82] It states that “Guyana policy goals set at the Paris Agreement, 2016 are: a. “We will move towards a 100% renewable power supply by 2025, conditioned [on] appropriate support and adequate resources”; b. “Our proposed commitments, through avoided emissions, can contribute the equivalent of up to 48.7 million metric tons of carbon dioxide to the global mitigation effort”; c. Guyana in the short term up to 2020 will – ‘invest in solar power, wind power and hydropower to transition more rapidly to renewable sources of energy and reduce our dependence on fossil fuels’.

to assure access to affordable, adequate, safe and clean energy products necessary for the development of Member States.

- The Caribbean Sustainable Energy Road Map and Strategy, CSERMS (2015) suggests a regional target of 48% of installed power capacity by the year 2027. Regional renewable energy capacity share targets are: in the short term (20% by 2017), medium term (28% by 2022), and long term (47% by 2027)". Lastly "CSERMS recommends a 33% reduction in energy intensity, to be applied evenly across all member states."
- Finally, there are two very important initiatives that would impact national energy policy and the achievements of its objectives, goals and targets in a very positive way. These are: a) The Guyana Generation Expansion Study and Annexes (2016) which was done for the GoG. This study shows that GPL's least cost pathway is dominated by renewable energy including a medium scale hydroelectric power plant which would do the bulk of the generation, plus wind energy, grid scale solar photovoltaics and biomass. There is also some thermal generation using diesel or natural gas. Hence, there is a realistic potential to reach the 100% renewable power target in the power sector by replacing the thermal generators with distributed generation from renewable energy. Additional generation expansion planning analyses would have to be conducted to see if the 100 percent scenario remains the least cost, or how significantly does it depart from the least cost scenario. b) The Brazilian led Arco Norte project that connects the State of Roraima in northern Brazil to the three Guianas and the Caribbean Sea. This poses potential for Guyana to participate in cross border electric grids and the development of large scale hydro power resources. It also involves the roadways, high speed communication systems and a port of harbor in Guyana or one of its neighbors.

The Draft National Energy Policy of Guyana – Report 2 – Green Paper (DNEP), completed on February 20, 2017, presents the suggested national policy objectives for Guyana as well as the specific policies for energy supply, energy demand, and the attendant cross cutting issues. For the special case of electricity, the policies are intended to move Guyana towards a goal of 100 percent renewable energy by the year 2025. The document draws upon the Guyana Power Generation Expansion Study, 2016; the Green Development Strategy (GDS), 2016; the Assessment of Fiscal and Regulatory Barriers to Deployment of Energy Efficiency and Renewable Energy Technologies in Guyana, 2014; the Low Carbon Development Strategy (LCDS), 2009 and revised in 2010 and 2013; and the National Development Strategy, 2001 to 2010.

Today it is clear that it would be necessary to adapt the current energy policies and strategies to the new scenario created by the prospective availability of indigenous natural gas in Guyana. As the Energy Narrative study[83] indicates: "*Each of these studies were completed before the potential supply of offshore natural gas was known, and so do not incorporate the use of natural gas in the suggested policy guidelines. Even so, the potential for using natural gas in Guyana's energy sector is explicitly mentioned in the draft policy document. Although the draft policy notes that the goal is to transition toward 100% renewable energy in the electricity sector by 2025, Section 3.1.1 notes that GPL's capacity expansion will include thermal power plants fueled with Light fuel oil (LFO) and Heavy Fuel Oil (HFO) in the short term and thermal reciprocating plants fired with natural gas in the long term. It also notes that GPL will investigate the feasibility of establishing a liquefied natural gas re-gasification plant at a suitable location for supply to power stations, industrial users, and residential users. Natural gas is intended to serve as the bridge fuel to a full 100 percent renewable energy scenario should this prove to be necessary. While the discovery of natural gas resources in Guyana will remove the necessity to import natural gas via*

[83] Desk Study of the Options, Cost, Economics, Impacts, and Key Considerations of Transporting and Utilizing Natural Gas from Offshore Guyana for the Generation of Electricity . Revised Final Report. Report to the Government of Guyana. Energy Narrative. June 8, 2017

LNG, the inclusion of natural gas as a potential transition fuel opens room in the national energy policy to use the domestic resource for electricity generation".

GEA has issued a Strategic Plan that incorporates the same general energy objectives and policies considered since 1994. So, it would be convenient to update it to the incorporation of natural gas in the energy matrix of the country.

The GEA Strategic Plan 2014 – 2018 includes guidelines for power generation. This plan includes as well the Arco Norte Study **-** (Guyana, Suriname, French Guyana and Northern Brazil). The details of this plan are included in Appendix T .

9.2.3 Institutional framework

The legal and institutional framework for the energy sector of Guyana comprises of the following institutions: The Ministry of Public Infrastructure, the Guyana Energy Agency (GEA), the Public Utility Commission (PUC) and the National Industrial and Commercial Investment Limited (NICIL). Its departments include: Guyana Energy Agency (GEA), Guyana Power and Light (GPL), the Hinterland Electrification Company Inc. (HECI) and the Electrical Inspectorate. The Public Utilities Commission (PUC) is an autonomous regulatory agency acting under its own Act. The regulations direct the GEA's authority and actions to license and oversee the activities related to the oil and gas products that are imported today.

The structure of the electricity sector is comprised mainly by GPL utility a state owned company, which generates most of the electricity in Guyana with its own power plants and buys wholesale electricity to Guyana Sugar Company (GUYSUCO, which today is being divested to separate its power generation business from the sugar industry by creating a new power generation company) in order to supply electricity to DBIS system. There are several other smaller minigrids/microgrids that serve isolated communities which are owned by the Hinterland Electricity Company Inc. (HECI) which in turn is a wholly owned by the Government of Guyana[84],

9.2.3.1 The Ministry of Public Infrastructure

The Ministry of Public Infrastructure is responsible for: energy, hydropower, utilities, hinterland electrification and electrical inspection. The following Ministry Department are under its direction: GEA, GPL, PUC, HECI and Electrical Inspectorate[85].

9.2.3.2 The Guyana Energy Agency (GEA)

The Guyana Energy Agency Act of 1997 (amended in several opportunities), established the Guyana Energy Agency (GEA) with the following functions: i) advise and make recommendations to the Minister regarding efficient use of energy resources; ii) upon the request of the Minister, develop a national energy policy and secure its implementation, directly or through other persons; iii) secure the efficient use of energy.

[84] This chapter focuses on GPL and DBIS system; however, as stated previously in this study, there are other state-owned power companies in Guyana such as Linden Electricity Company (LECI), Kwakwani Utility Company (KUI), Lethem Power Company Inc. (LMPCI), Matthew's Ridge Power & Light Inc. (MRPL), Mahdia Power and Light (MPL) and Port Kaituma Power and Light Inc. (PKPL); all such companies provide electricity in other regions.
[85] This structure is according to the Official Gazette, 6th June, 2015, Legal Supplement – B.

The GEA is directed by a Chief Executive Officer (CEO) and a Deputy Chief Executive Officer (DCEO) appointed by the Minister responsible for the energy sector. There is an Energy Agency Board formed by CEO and DCEO and other three members appointed as well by the Minister "from among governmental and private sector organizations or institutions with a particular interest or expertise in matters of energy policy"[86] which serve as Board of Directors. The Minister is the maximum GEA authority as it is his office that shall give to the Agency directions about the policy to be followed.

9.2.3.3 The Public Utilities Commission (PUC)

The Public Utilities Commission (PUC) is a corporate body with members appointed by the Minister for a three-year period. It covers a wide range of public services like electricity, telecommunications, water supply, transportation, etc. In relation to the electricity sector, the PUC shall be bound by, and shall give effect to, the GEA Act and the ESRA. This body is ruled by the PUC Act (PUCA).

9.2.3.4 Guyana Power and Light Inc (GPL)

Guyana Power Light and Inc. (GPL) is the main national electric grid infrastructure service provider in Guyana. GPL is a state owned vertically integrated utility. GPL generates most of the electricity in Guyana with its own power plants. It operates three girds, the Demerara/Berbice Interconnected System (DBIS), the Essequibo system and the Bartica system. It also buys wholesale electricity from a bagasse fired cogeneration plant collocated with a diesel plant at the Skeldon Sugar Factory to assist in the supply of electricity to the DBIS system. GPL also operates a mini grid in the Essequibo region that utilizes diesel generation. Under its license GPL is permitted to purchase electricity from hydro facilities under the terms of a power purchase agreement (PPA). The license also requires that GPL undertakes a tendering process for the acquisition of all new non-hydro generating plant.

9.2.3.5 Hinterland Electricity Company Inc (HECI)

Hinterland Electrification Company Inc. (HECI) is a company wholly owned by the Government of Guyana. Its mission is to maintain the steady extension and upgrade of electricity supply systems across the hinterland, progressively improving operations and merging isolated services as appropriate. HECI owns several small minigrids/microgrids that serve isolated communities. It currently manages the Government's Hinterland Electrification Programme and the Global Environment Facility (GEF) – Sustainable Energy Programme for Guyana with loan support through the Inter-American Development Bank (IDB), to promote renewable energy development in Guyana.

9.2.4 Legal framework

The main Acts relevant to the electricity sector are the GEA Act, the Public Utilities Commission Act (PUCA), the Electricity Sector Reform Act of 1999 (ESRA) and the Hydro Electric Power Act of 1953[87].

9.2.4.1 The Guyana Energy Agency Act

GEA Act gives to the Guyana Energy Agency some powers in the petroleum sector like the issuance and regulation of licenses for importing, storing and distributing petroleum products. It is important to point

[86] The organizations or intitutions shall be consulted by the Minister prior to making such appointments.

[87] Amended in 1973, followed by the Hydroelectric Power (Amendment) Act of 1988 and the Hydro-Electric Power (Amendment) Act in 2013. Many of the ammendments are related to enviromental issues, prohibitions and penalties.

out that the Agency can, as well, with the approval of the Minister, regulate: i) the uses of specific sources of energy; ii) the technical standards of plant, equipment and appliances, and the restrictions, or prohibition, of such kind of elements; iii) the financial incentives, or otherwise, the utilization and development of alternative sources of energy. Regarding to the electricity sector, the GEA Act gives to the Agency the functions assigned under the Hydro-Electric Power Act to the President and the Minister.

It is worthwhile to note that most of the GEA Act is devoted to the regulation of petroleum products and no mention is done to the power sector as a whole. This fact could explain, in part, why there is no a power system generation plan. The other reason, as it is noted forward, is that the Public Utilities Commission Act requires GPL to adopt a development and expansion program. In this sense, it is possible that the power expansion plan has been left in GPL's hands considering that this state owned utility is an integrated monopoly[88].

9.2.4.2 The Electricity Sector Reform Act (ESRA)

The ESRA created GPL and developed the requirements, among others, for a license (includes "public supplier" definition that means any person who supplies electricity for public purposes, which includes the Independent Power Producers), contract for supply a consumer, and establish rates for supply. The ESRA develops the following relevant elements:

9.2.4.2.1 The Annual, Five-Year and Long Term Plans and the D&E Programme

The ESRA defines the "sustainability programme" which means that every public supplier shall have and maintain both an annual and a rolling five year plan. These programs shall be coordinated under a license granted to such public suppliers. The ESRA also defines a "development and expansion programme", which sets out the manner through which the public supplier will develop and expand its facilities and services to be provided to consumers "and which, subject to the provisions of this Act and the terms of a license or exemption, shall be deemed to be a development and expansion programme under the Public Utilities Commission Act". The public supplier shall have as well a rolling 15-year demand forecasts and long term plans to address it.

Section 38 of ESRA develops in detail the different aspects and information that shall be included in the plans, like technical data, costs, benefits, equity, debt, etc. The plans shall consider the extent to which alternative generation can be facilitated and its commercial feasibility.

It is important to point out that one of the specific components is to have a "development and expansion programme" consistent with the plans, through which the public supplier will develop and expand its facilities. Every year the public supplier shall submit, for approval to the PUC, the annual and five-year development and expansion program. The PUC may approve after receiving the Minister and GEA views. Under GPL's license, the D&E Plan is submitted to the Minister for approval (the Minister in reviewing the plan receives the considerations of the PUC and the GEA).

It is relevant to note that ESRA does not specifically mandate a National Power Expansion Plan.

[88] GEA´s Chief Executive Officer is member of the Board of Directors of GPL.

9.2.4.2.2 License to an IPP

Independent power producer (IPP) projects may be developed, only if the governing bodies of Guyana Power & Light, Inc. and the IPP have first agreed the terms and conditions upon which such electricity will be purchased by GPL, and such terms and conditions insofar as they relate to rates that have further been approved by the Commission, and the Minister is satisfied that the criteria of 4 (1) (c) (ii)[89] will be met by the proposed IPP project.

Prior to granting a license to an IPP for the generation of electricity for sale to a public supplier, the Minister shall be satisfied that the rates have been approved by the PUC.

9.2.4.2.3 Access to Renewable Energy (RE)

Section 20th of the ESRA establishes that it is a duty of a public supplier to develop and maintain an efficient, coordinated and economical systems of electricity supply, and to facilitate the use of alternative forms of electricity generation using renewable resources wherever commercially feasible, as well, to facilitate competition in the generation of electricity. In this matter the main agencies involved in the promotion of the RE in Guyana are GEA (focused, among others, in the promotion of solar and other sources of distributed electricity generation in public, commercial, industrial and residential sectors, and development of small and medium hydroelectric projects), GPL (which is developing grid tie power plants using solar and wind resources) and HECI (which has promoted extensive penetration of mini-solar power generation in the hinterlands and currently manages the Government's Hinterland Electrification Programme and the Global Environment Facility –GEF- Sustainable Energy Programme for Guyana).

9.2.4.2.4 Rate Schedules

The Second Schedule of ESRA includes a tariff structure comprises by a fix charge and a charge for kWh that change according to a range of monthly consumption in the case of residential sector. The tariff topic is elaborated in section 9.2.5.

9.2.4.3 The Public Utilities Commission Act (PUCA)

Part VII of the PUCA includes the requirement for the already mentioned "development and expansion programs".

The Part VIII of the PUCA develops the general rates elements like principles and tariffs filing. For generation, the PUC has the power to investigate the costs of an IPP (section 35).

9.2.4.4 The Hydro-Electric Power Act of 1956

Given the importance of the Hydro-Electric Power Act (HEPA) for the development of hydro generation, in line with one of the findings of this Study, the following paragraphs analyze some relevant issues of this Act.

[89] The criteria of 4 (1) (c) (ii) is: "(ii) that the terms and conditions so approved are commercially prudent and viable, will not adversely affect or will enhance the system-wide capacity, reliability and efficiency of the public supplier, and are compatible with national energy policy".

The HEPA gives the Minister the following powers[90]: i) grant licenses to use water for power generation; ii) specify the price at which the energy may be sold and that these prices are subject to review during the currency of the license every five years; iii) grant up until 50 years, at the discretion of the Minister, and provide a royalty payment; iv) acquire by expropriation the lands; and iv) regulate the construction, maintenance, operation, purchase and taking over of all works which may be deemed necessary for the purposes of the Act.

Prior to grant the license, the parties shall approved the conditions upon which electricity shall be purchased by the public supplier, and such terms and conditions insofar they relate to rates have further been approved by the PUC, and the terms are commercially prudent and viable and not adversely affect the system wide capacity.

The HEPA includes a "Subsidiary Legislation - Hydro-Electric Power Regulations" section which develops in detail different aspects related with the license like application, general lay out plans, reports, amendments, terms of interim and final license, among others.

In our view, there appears to exist a barrier to perform a bidding process in order to grant a license for construction, operation and exploitation of a hydro project, in the sense that in order to grant the license, one of its requirements is to review the price each five years. At this respect it would be worthwhile to evaluate in some detail the economic and legal implications of this matter considering the potential uncertainties that it could imply to private investors, as in a hydro project variable costs are very low, the investment is high and sunk and there is no a relation with oil prices (as Guyana doesn't have a marginal electricity pricing system neither a wholesale electricity market). However, as the Minister has wide powers for regulatory and granting license, it could be enough to issue, for example by Decree, a policy to grant the license for the hydro project selected in the power generation expansion plan, such that the Decree defines the main elements of the license and the criteria to select the best Independent Power Producer (IPP)[91] proposal[92]. Anyway, this appreciation needs a further legal assessment. There is also the view that (1) the power of the Minister under the HEPA (section 13) to expropriate investments in hydropower development and the measure of compensation acts as a barrier to such development. (2) the time for granting of interim license does not provide sufficient security for the level of Investment to be made in the development phase of the Project. It is argued that the interim license should be granted to secure the Investment in the development phase of the Project.

9.2.5 Regulatory Framework

As it can be seen, the main regulatory elements for the power sector are defined in the following four Acts: i) the GEA Act, which defines the scope of energy policy; ii) the Electricity Sector Reform Act, which defines the scope of the electricity public services, the licenses for Independent Power Producers, the scope of annual plan, and the five year plan and long term plans; iii) the Hydro Electric Power Act, which defines the scope of licenses for hydro generation; and finally, iv) the PUC Act, which defines the procedures for approval of plans and tariffs.

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[90] Buy virtue of section 7 of the GEA Act.

[91] ESRA definition: "independent power producer means any person who generates electricity for the purpose of selling it to another public supplier for trnamission, distribution or sale to consumers, but shall not include any person for whom the generation of electricity is not its principal business and not more than 10 MW of electricity would be supply by the person to a public supplier for transmisssion, distribution or sale to consumers."

[92] Clearly, there are other barriers to private investment like uncertainties about environmental license, revenue payments for energy delivered, etc. Policies are proposed in order to mitigate these risks in section 10.

GPL was granted a license to supply electricity to the coastal regions of Guyana in 1999, concurrent with the ESRA which created it. This License, as amended in 2010, limits GPLs activities to: i) power generation, except hydropower generation, ii) the transmission, distribution, storage, furnishing and sale of electricity, iii) the purchase of electricity through PPAs with IPPs, and iv) the installation, operation, and maintenance of meters, electric lines and other electric apparatuses, installations, and facilities necessary to carry out its activities[93].

This License also establishes that GPL may only purchase power from IPP´s which has to be from RE source. It is understood that according to this regulation GPL could promote and purchase power from hydroelectric power plants developed by IPP´s. At this respect, the GPL´s License includes several rules related power acquisition prices and rates, which are described below.

9.2.5.1 Power acquisition – Prices for PPA[94]

Section 14th of the GPL´s License refers to power acquisition from other suppliers under the ESRA and the conditions have been approved by the PUC.

Section 15 of the License establishes that the replacement and additions of generation capacity over 10 MW shall be done through an international bidding process[95]. The tender process shall be developed and carried out by GPL.

The same Section 15 establishes that in case a license is granted to the Amaila Falls and/or the Tumatumari hydro-power projects, GPL must sign the PPA. For these projects, the License provided by that time (1999), that the development of the projects shall not be subject to the competitive bidding procedures[96].

In all PPA cases, GPL may purchase energy from an IPP when the PUC has approved the tariff and when the price is not higher than the marginal cost of GPL´s electrical energy production.

Given that GPL´s power generation is based on oil products like HFO and LFO, this requisite can constitute a barrier for GPL´s generation expansions in RE because of volatility of fuel prices.

One alternative to overcome this barrier is to modify the GPL´s License to allow the purchase of energy coming from PPAs based on developments of renewable energy projects that are the result of a bidding process under the mandate of a national policy suggested in this study.

[93] The provision of fuels for electricity generation is not listed among the authorized activities, although section 28 does provide authorization for GPL to "act and to perform such other activities and services as may be necessary for the purposes of exercising its rights, fulfilling its obligations and performing the activities and services authorized under this License." This broad language could provide sufficient authorization for GPL to build and operate natural gas pipelines and other delivery services if they were deemed necessary. Amending GPL's License or enacting separate legislation that explicitly grants or prohibits GPL from owning and operating natural gas distribution facilities would remove any ambiguity.

[94] In this document the PPA concept (power purchase agreement) is used in general terms to indicate a contract to purchase electricity.

[95] However, for capacities below 10 MW transparency should be maintained through appropiate competitive selection of such investments.

[96] The GPL License mentions letters of intend dated 1998 with two different companies.

9.2.5.2 GPL's Rates or Tariffs[97]

According to the License's conditions, the tariffs are governed by First and Second Schedules of the ESRA and the first Schedule of the License. The calculation of the rates and their approval are under PUC Act.

The Second Schedule of ESRA includes a tariff structure comprises by a fix charge and a charge for kWh that change according to a range of monthly consumption in the case of residential sector. For commercial sector there is only one range. For industrial sector, there is a demand charge by kVA per month with two ranges for energy consumption. The first Schedule establishes that these basic rates shall be increased or decreased according to the allowed GPL´s revenue which is calculated under a rate of return or cost of service approach. The tariff structure is currently the same one. In April, 2016, GPL has announced rates shown in Table 70, which includes a fuel rebate of 15% (originated at that time by the reduction of oil prices as it was also established in April 1, 2015 when a 10% rebate was implemented).

Table 70. GPL Rates from April 1, 2016 (applied in March, 2018)

Category	Tariffs	Current Fixed Rate / Demand Charge	Fixed Rate / Demand Charge effective April 1, 2016	Current Energy Rate	Energy Rate effective April 1, 2016	15 % Fuel Rebate G$	Net Energy Rate GY$ effective April 1, 2016
Non-Government							
Residential: Lifeline	A >75 kWh	359.52	**341.54**	48.42	**46.00**	6.90	**39.10**
Residential	A <75 kWh	369.52	**351.04**	53.78	**51.09**	7.66	**43.43**
Commercial	B	2596.84	**2467.00**	69.82	**66.33**	9.95	**56.38**
Industrial	C	1852.86	**1760.22**	63.07	**59.92**	8.99	**50.93**
Industrial	D	1852.86	**1760.22**	60.41	**57.39**	8.61	**48.78**
Street Lights	E			53.35	**50.68**	7.60	**43.08**
Government							
Residential	GA >75 kWh	406.81	**386.47**	58.42	**55.50**	8.32	**47.17**
Residential	GA <75 kWh	406.81	**386.47**	59.21	**56.25**	8.44	**47.81**
Commercial	GB	2709.74	**2574.25**	72.85	**69.21**	10.38	**58.83**
Industrial	GC	1933.42	**1836.75**	65.81	**62.52**	9.38	**53.14**
Industrial	GD	1933.42	**1836.75**	63.04	**59.89**	8.98	**50.90**
Industrial	GE			55.67	**52.89**	7.93	**44.95**

Source: GPL

The rules of the Schedules of ESRA and GPL´s License, and the rate structure, specify the formulas and procedures to obtain the different rates. It should be noted that 14% VAT is now applicable to electricity charges.

The First Schedule of GPL´s License defines the rules for allowed revenue like the formulas for the calculation of the rate of return, the assets rate base, fuel surcharge/rebate to each customer´s billing and foreign exchange surcharge/rebate. The Rate Base is comprised by the allowable fixed assets (property, plant and equipment), allowable inventory (including fuel) and working capital.

Finally, according to Section 26 of the ESRA, the Tariff may include different charges like a charge in respect of availability of a supply of electricity and may vary to the extent that the supply is taken up; unsatisfactory power factor of the consumer's electric load; a charge in respect of cost of fuel and variations in the foreign exchange rates.

[97] ESRA definition: "rates" means any tariff charged by the Company for the supply of electricity or services".

9.2.5.3 Tariffs under different the generation expansion programs

The expected evolution of the average power generation cost of DBIS is shown in Table 71 on each of the modelled scenarios.

Table 71. Average generation cost per generation expansion program

AVERAGE GENERATION COST (USD/MWh)				
	BAU	**GAS 50**	**GAS 30**	**GREEN**
2018	85	85	85	85
2022	117	116	121	128
2025	139	79	80	107
2030	156	76	86	104
2035	164	76	85	103

Source: Consultant

In order to estimate the average generation cost on each expansion program, distribution losses reductions were obtained from same estimates when forecasting power demand (24% in 2025, 21% in 2030 and 17% in 2035). Assuming a constant cost in US$/MWh for the transmission and distribution component of the tariff, the expected final tariff to end users (energy component only) in DBIS on each of the modelled case is shown in Table 72.

Table 72. Average final tariff (energy component) per generation expansion program

AVG. FINAL TARIFF - ENERGY COMPONENT(USD/MWh)				
	BAU	**GAS 50**	**GAS 30**	**GREEN**
2018	227	227	227	227
2022	266	265	272	280
2025	289	215	216	250
2030	305	208	220	242
2035	309	205	216	237

Source: Consultant

The forecasts of Table 72 suggest that in the BAU case the average tariff would have to be progressively increased, due to the expected increase of oil prices, reaching 309 US$/MWh in 2035 (a significant increase of the order of 40% in real terms). It also indicates that from 2018 until 2022 average energy tariffs would increase in all cases (under the EIA WTI reference price scenario). However, in the long term, the utilization of natural gas for power generation suggests that the average generation costs in Table 71 would not increase, or even could decrease, implying moderate tariffs reductions after 2023. The most notable reduction on final tariffs is experienced in the GAS 50 scenario (8% reduction in 2035 against 2018 levels) followed by the GAS 30 scenario (4% reduction in 2035 against 2018 levels). The green scenario does not result in final tariff reduction but in a minor increase. The reduction could be higher on the GAS 50 and GAS 30 scenarios if the natural gas price of 4.7 US$/MBTU is reduced. However, this reduction would further promote more natural gas expansion and reduce RE technologies participation such as wind, solar, biomass and hydro.

9.2.6 Environmental Framework (Green State Development Strategy)

The third central theme of the Framework for the Green State Development Strategy ("GSDS") is "Energy – Transition towards renewable energy and greater energy independence". Box 3 of such document "Framework of the Guyana Green State Development Strategy and Financing Mechanisms" is shown in Figure 73.

Figure 73. Guyana's Green State Development Strategy (GSDS): Goals related to energy

- *Unconditional Nationally Determined Contributions*
  - Remove import duty and tax barriers on the importation of renewable energy equipment, compact fluorescent lamps and LED lamps to incentivise and motivate energy efficient behaviour
  - Conduct energy audits and replace inefficient lighting at public, residential and commercial buildings to reduce energy consumption
  - Public education and awareness programmes to provide consumers with information and tools to reduce energy consumption and expenditure
  - Implement building codes and net-metering of residential renewable power
  - Seek to construct and/or promote the construction of small hydro systems at suitable locations such as MocoMoco, Kato and Tumatumari
  - Power all of the six newly established townships, starting with Bartica, using renewable energy sources.
  - Work closely with farmers in agricultural areas across Guyana to encourage the use of bio-digesters to reduce waste, produce biogas and provide affordable, healthy and efficient cooking means in the household.
- *Conditional Nationally Determined Contributions*
  - Reducing dependence on fossil fuels for energy generation, achieving close to 100% renewables by 2025 through a diversified renewable energy infrastructure including biomass, solar, wind and hydropower
- Additional national goals of relevance:
  - Commitment to providing energy access to all the populations, and acceleration of the development of distributed energy to the hinterland communities.
- *SDGs*. **SDG 7** (7.1, 7.2, 7.3, 7.b), **SDG 8** (8.4), **SDG 13** (13.2)

Source: Framework of the Guyana Green State Development Strategy and Financing Mechanisms. UN Environment. April 4, 2017.[98]. SDG = Sustainable development Goal.

The GSDS goals related to energy would require the consideration of the prospective availability of indigenous natural gas in Guyana as a clean fuel appropriated for power generation.

9.3 Policy and Regulatory considerations

The policy, institutional and regulatory framework constitutes an arrangement of different elements that should be consistent among them. The analysis seeks to assess how all the elements are defined, how they interact and if there are some aspects that were left aside and that must be included, specially, in terms of the findings of the present Study related to the power generation capacity expansion.

[98] Queried on January 29, 2018 at http://www.motp.gov.gy/index.php/notices/policies/2016-framework-for-guyana-green-state-development-strategy

As elsewhere, the supply of electricity and its policy, planning and regulatory framework are immersed in the country's general energy policy and its legal and institutional structure. The following sections present some considerations about Guyana's energy policy and institutional structure.

9.3.1 General Policy Considerations

Some considerations can be done about the energy and electricity policy explicit in the GEA´s Strategic plan.

The Strategic Plan (SP) shows consistency between objectives and diagnosis of energy resources and electricity needs.

However, the degree of specification of objectives, strategies, goals, policy and regulatory instruments, programs and projects, responsibilities and financing is not enough to guarantee the development of the strategies and, in consequence, the achievement of the objectives.

This situation suggest the convenience to adopt a formal and flexible national plan of expansion of the electricity sector with the level of detail required and properly articulate all strategies and activities with different institutions and GPL

An important aspect would be the proper articulation of such plan with the agents involved in the development and future exploitation of the offshore natural gas for power generation. In this respect, in this report assumes that power sector companies (manly GPL and IPP´s) will not participate directly in the development of the offshore infrastructure required to supply natural gas for power generation implying a power generation activity unbundled from the natural gas production and transportation activities.

A matter of vital significance would be the conception of the natural gas supply, conditions and prices to be agreed by gas producers and transporters with the owners of the new natural gas fired power plant, taking into account the convenience to establish and eventually regulate the inland gas price in Guyana and the promotion of a national natural gas market. This matter is expanded later in the recommendations section.

9.3.2 Considerations about Renewable Energy and Distributed Energy Policy and Regulation

As it may be seen, the GEA´s Plan includes guidelines for renewable energy in the same way it was foreseen in 1994. In this Plan, as it was pointed out above, the main actions are some memorandums about different studies. Although these studies are quite important to advance on a solid path for generation expansion, it is required to define the final power projects that permit the achievement of the final goals.

In the biomass field, the real possibilities have been in the sugar cane industry. However, as shown in the present Study, the generation of energy surpluses to the grid coming from generation with bagasse haven't been a source of reliable supply. However, the consideration of this type of power plants as non-dispatched units in the expansion program guaranty future reliability in DBIS power supply by maintaining generation reserve margins composed only by dispatched generating units. An efficient generation with bagasse of cane requires an efficient sugar industry and the right incentives on the price side. Neither of both requisites seems to have contributed to the goals of the Strategic Plan of GEA.

In relation to distributed generation (mainly small PV systems), although GEA has some guidelines for solar generation, GPL's D&E Program visualizes that "While Guyana has both wind and PV potential and ongoing interest is being shown by various parties from time to time, it is not expected that any such development will significantly impact the generation mix in the future." This situation shows that at present stage, distributed generation seems to be a general intention in Guyana´s energy policies for DBIS system (even though, there have been some rural programs in non-interconnected regions which include pilot programs of PV systems). This landscape is consistent with the general situation of GPL related to the grid infrastructure. In order to advance to distributed generation, it is a requisite to have a solid grid, with a clear grid code.

Even though, the government of Guyana should reinforce the following aspects required to develop distributed generation in Guyana:

- Set policy guidelines for Public Utilities Commission to require the GPL to develop and publish a feed-in tariff mechanism for grid tied distributed renewable energy technologies;
- Set policy guidelines for Public Utilities Commission to require the GPL to develop and publish connection policy for small scale and commercial scale distributed renewable energy systems;
- Set policy guidelines to determine an appropriate market share for distributed generation versus IPP's versus GPL in respect to the generation of renewable energy.

These aspects are extended later in the recommendations sections.

9.3.3 Considerations for Energy Efficiency Policy and Regulation

The Energy Efficiency (EE) field is possibly the one that has less attention in the present policy and regulatory framework. For instance, the Development and Expansion Program of GPL addresses EE mainly in the education field and recognizes GEA´s leadership in this front. However, today GEA is considering the promotion of the EE programs in other residential, commercial and public sectors.

EE is a field where there is room for the International Monetary Fund (IMF)[99] recommendations for Caribbean countries for "setting national energy efficiency standards (e.g. energy labeling and energy efficient building codes) and providing appropriate incentives will help encourage the adoption of energy efficient technologies by businesses, particularly hotels, as well as households." All this in the framework an energy updated policy.

The following are some relevant issues which need to be addressed to implement EE in Guyana (further actions in Section 11.2.9):

- **Institutional arrangements** – Better coordination between GPL and GEA on issues and projects related to electrical energy efficiency. Consideration of whether a specialized group or organization needs to be set up to oversee energy efficiency programmes.
- **Market Capacity** – Enough trained professionals and organizations that are knowledgeable about energy efficiency. Consideration of the development of the Energy Services Company (Esco) model for delivery of energy efficiency measures.
- **Technology** – This needs to be the right technology and made available in the market and at an affordable price with the right financing package.

[99] IMF working paper "CARIBBEAN ENERGY: MACRO-RELATED CHALLENGES", March 2016.

- **Information and Communication** – Better coordination and sharing of information, better measurement of electricity end-use, better communication of this information to a wide base of stakeholders.
- **Legal and Regulatory Frameworks**– Energy efficiency is not seen as a priority in the market. Energy Efficient Standards need to be introduced and compliance to these energy efficiency standards needs to be enforced. These standards could be delivered through a number of mechanisms: Voluntary Agreements negotiated between government and businesses; Energy efficiency obligations approved by the government; Energy efficiency certificates; energy efficiency or carbon taxes.
- **Financing and Pricing**– Appropriate financing of energy efficiency projects needs to be developed using low interest rates. Consideration of directing subsidies towards energy efficiency rather than price reduction of tariffs. Better coordination of resources within the finance sector to simplify and innovate finance.
- **Program execution -** After quantifying energy efficiency goals, the energy efficiency program should be executed by a team (either as new group as part of GEA, PUC or a newly independent created company) that would be responsible with day to day operations of the energy efficiency program without leaving apart the long term objectives of such plan. Guyana’s authorities should learn from international experience and adopt an energy efficiency program with international best practices and adapt it to Guyana intrinsic characteristics. Such model should target funds from different stakeholders such as Governments, donors, investors and financial markets (say multilateral banks) and be self-sustainable in order to adequately provide the signals to retailers, consumers and power companies that would reduce electricity demand in a gradual form according to the energy efficiency targets established by authorities.

9.3.4 Considerations about the D&E Plan of GPL

Given that GPL only may purchase energy from an IPP when the provided price is not higher than the marginal cost of GPL´s electrical energy production, GPL can find difficult to promote new generation with RE, like wind and solar generation, mainly under current oil prices.

9.4 Conclusions

In our opinion, taking into account both plans, that is, the GEA Strategic Plan and the GPL Plan, Guyana seems to have an energy policy and an expansion plan properly integrated and structured for the power system. However, those have not been effective, as evidenced by the results of such plans, where several goals established for the power sector have been not been achieved yet.

A plan properly integrated and structured means that the policies, the strategies, the goals, the instruments, the responsibilities, the source of the financial resources and the time table, are very well defined and integrated.

Although some of the previous elements appears in the GEA and GPL plans, the fact that the goals have been not achieved during more than 20 years, it means that there exist different kind of problems and/or barriers.

Having stated the above, the main conclusions of the analysis of policy and regulatory framework are presented below.

9.4.1 Conclusions about the Power Sector Policy

There are different policy instruments to develop a strategy based on market approaches. Those instruments are different in nature depending on each market context (for instance, market size, energy resource endowment). One approach is to develop a competition in the market framework[100] which includes mechanism as a wholesale market with open access, net metering and feed-in tariffs for distributed generation, organization period bidding processes for energy supply, etc. A second approach is competition for the market in which economic efficiency is ensured through mechanisms like international bidding processes for the projects defined in a Centralized Plan for power expansion.

Guyana, as in other CARICOM countries, has a relatively small electricity market in comparison to other electricity markets in Latin America and the world. The Consultant believes that such size represents a barrier to create a scheme based on a wholesale market that fosters the power generation expansion according to a spot or contracts market pricing mechanism. So, the alternative is to promote competition to install and operate the new power plants.

- Under this last context, it is clear that the key factor that explains the few advances towards an electricity sector based on indigenous resources, and in general towards an efficient electricity sector despite the energy resources used, is the lack of a national power system expansion plan, with clearly assigned responsibilities to each governmental agency, including GPL like the main Utility in the Country.
- Guyana does not have a long-term National Power Expansion Plan which establishes concrete objectives and goals, neither the strategies nor instruments in order to implement it. This study seeks to contribute in this field.
- Although GEA has a Strategic Plan, the strategies outlined in such plan lacks instruments (for instance financing instruments for each strategy, institutional and human resources allocated, incentives to attract investors, etc.), does not allocate responsibilities and does not have defined schedules.
- For instance, in the GEA´s Plan there is not a clear definition of GPL´s role in the development of the different strategies.

9.4.2 Conclusions about Renewable Energy and Energy Efficiency

- One barrier to promote and implement RE and EE technologies, which hasn't been assessed in the present study, but that has been addressed in 2016 by the IMF for Caribbean Countries, is the investment capacity of Guyana, as well as other Caribbean countries, in infrastructure[101].
- The EE field requires developing and reinforcing concrete objectives and strategies as had been developed recently, mainly by GEA.
- Updated information about the power sector and access to such information is another barrier for investment which should be mitigated by creating a long term planning team which capacity to lead

[100] Competition in the market refers to a market structure where comptition is feasble among the already stablished agents and the potential entrants. Competition for the markets refers to competitions for a License or a concession.
[101] IMF Working Paper WP/16/53 CARIBBEAN ENERGY: MACRO-RELATED CHALLENGES. March 2016: "V. TRANSFORMING THE ENERGY SECTOR: HOW EXPENSIVE AND HOW FEASIBLE? Energy sector transformation may require significant upfront investments to make necessary upgrades and introduce renewable energy and energy-efficient technologies. With the IADB's support, staff estimated the investment envelope needed to implement the energy strategies already specified by Caribbean countries. However, public sector financing of large scale investments is often constrained by the limited fiscal space and the high debt burden faced by many Caribbean economies…", pg 29.

(internally and externally) planning studies in relation to the power sector (e.g. official demand forecasts, generation expansion studies, self-generation surveys, energy usage surveys, etc.).

- EE mixed with distributed generation has the potential to decrease electricity usage in DBIS in different levels according to the level of efficiency that the authorities want to pursue for Guyana. EE measures would indirectly create a Sustainable Energy Industry in Guyana that will be complementary to the steps which Guyana is already taking to protect its virgin rain forest and put Guyana in a good place to meet its climate change commitments under the recently agreed Paris Agreement[102]. The energy efficiency programme could effectively act as a Nationally Appropriate Mitigation Action under the Paris Agreement and should help to lever in carbon financing if this is deemed to be necessary.
- RE and EE developments within the new indigenous Natural Gas availability expected in Guyana requires further analysis and the development of a technical, policy, legal and regulatory framework. It would include the creation of a new Oil and Gas Directorate and the strengthening of the existing institutions (GPL, GEA, MPI and PUC) in this area.
- To implement these measures will need a stepping-up in the rate of activity in Guyana and progress to be made on several fronts including: (i) The introduction of energy efficiency minimum standards into a legal framework; (ii) Carefully worked incentive schemes to promote energy efficiency products over others; (iii) A skilled and trained workforce able to run and implement energy efficiency programmes; (iv) Appropriate structured finance to help implement the programme.

With the implementation of such a programme there is the potential for long term benefits for the consumer, the utility and the country.

9.5 Recommendations

The previous conclusions lead to the following policy and regulatory recommendations.

9.5.1 Policy recommendations

- The first and main recommendation is to create a National Policy for the Power System, including Energy Efficiency. This means to construct and to adopt at the highest governmental level a Power System Expansion Plan, based on technical and economic studies, the environmental principles and the financial possibilities of the country.
- The Plan shall define clear and precise strategies that best fit the special context of Guyana, that is, its relative small size of its electricity market and local endowment of energy resources. In this sense, it is recommended that the process of policy decision making takes into account the stake holder of the energy sector.
- The Plan shall define feasible and concrete goals according to Guyana´s budget and financial possibilities.
- Additionally, the policy shall define clear criteria for the selection of generation projects in order to avoid discretionary investments that do not fulfill the Plan objectives.
- Given the importance of getting competition as much as possible in the future, the Plan shall provide general guidelines of requisites for a sound process to select the investors in the required infrastructure expansions to supply future electricity demand.

[102] UNFCCUNFCCC Paris Agreement, available here: https://unfccc.int/documentation/documents/advanced_search/items/6911.php?priref=600008831

9.5.2 Recommendations for Future Engine Generator Capacity Expansion

The DBIS generation expansion update applied an optimization model during the 18-year planning horizon 2018-2035 to find the optimal DBIS generation expansion program. Total comparative costs of DBIS generation-transmission expansion and operation during this period were estimated (present value in 2017 of investment[103], fuel, operation, maintenance, CO2 emissions and non-served demand costs) under such optimization process in order to obtain conclusions about DBIS optimal expansion strategy.

Main conclusion obtained is that the electricity generation expansion in the DBIS should no longer be carried out using petroleum products after 2023 and the needs for new capacity with natural gas engine generators sum up 170-270 MW between 2021 and 2035 (total capacity to be determined by natural gas availability for power generation) the existing generating units using HFO/LFO will remain as reserve capacity for peaking hours and backup in the DBIS system.

For the optimization analysis of DBIS generation expansion the natural gas supply and the power generation activities were considered unbundled and related through a natural gas supply contract with a 70% take or pay clause. With this type of contractual arrangement and with the assumed inland natural gas price in the base case (US$ 4.7/MBTU) it was preliminarily verified that selling electricity prices from the new gas fired power plant, at site plant, in the order of US$ 72 or 86/MWh (for natural gas availabilities of 50 or 30 mmcfd, respectively) would provide a financial return or around 10% to investment. This verification avoid the consideration of management of stranded costs for the power sector but imposes also gas to power generation inflexibility that implies that, in general, RE projects would be less economical attractive for DBIS.

There are three main alternatives to power generation supply that have different incentives for economic and operational efficiency and private participation. The analysis for the case of GPL as state owned company is summarized in Table 73.

Table 73. Alternatives on GPL's engines

ALTERNATIVE	ADVANTAGES	DISADVANTAGES
1. GPL owns, operate, maintain and expand the engine generation capacity. Expansion for plant acquisition is done by a bidding process.	• Lesser transaction costs (as there is no a PPA). • Direct control over engine generators.	• This alternative reduces the room for private participation therefore its benefits related to capital investment and implementation of efficient standards. • When there is a reduced space for private participation, the benchmarking the investment and operating costs among IPPs is very limited.
2. GPL owns and expand the engine generation capacity. The operation and maintenance is contracted with a third party by	• Lesser transaction costs (as there is no a PPA). • Direct control over engine generators.	• This alternative reduces the room for private participation therefore its benefits related to capital investment and implementation of efficient standards.

[103] As presented in Section 7.1.2 (section b1), for planning purposes the relevant investment costs associated to the construction of each new potential power plant (and transmission line and gas transportation system) were evaluated deducting from their total investment cost their residual value during their remaining useful life after the planning horizon (i.e. 2036 until the end year of their useful life). In other words, the investment cost used for the optimization of the generation expansion was the "equivalent annual cost" in each of the years in which the projects are considered available for operation within the planning period (2018-2035). This explains why the present values of the investment costs of the power plants (and transmission lines and gas pipeline) included in the tables presented in this section are lower than their total investment costs.

competition. Expansion for plant acquisition is done by a bidding process.		• When there is a reduced space for private participation, the benchmarking the investment and operating costs among IPPs is very limited.
3. IPPs own, operate and maintain the engine generation capacity and the energy is sold to GPL.	• Reduces GPL´s needs for capital. • The incentives for economic and operational efficiency are more powerful than in the other two alternatives regarding the contractual conditions and a good risks allocation between the parties.	• It has the transaction costs related to the PPA. • Although there is no direct control over engine generators, this can be overcome with standards and maintenance monitoring.

Source: Consultant

According to the above analysis, and in order to look forward for efficiency and private engagement, it is important GPL promotes private participation taking into account the characteristics of future power plant replacements and expansions.

9.5.3 Recommendations for the exploitation of natural gas in power generation and other uses[104]

This section contains main recommendations obtained by the consultant for the future development of the natural gas sector in Guyana, including gas supply for power generation.

Identification of the Natural Gas and regulation of related activities

Current regulations define "petroleum and petroleum products" as "petrol, diesel, bunker-C, and any other heavy oils, liquefied natural gas, liquefied petroleum gas, aviation fuel, kerosene, and any other hydrocarbon-based fuel source or product of the petroleum refining process, whether in liquid or gaseous form". In addition, "gas" is defined as "liquid of non-liquid gas which can be used as fuel for the operation of a spark ignition engine or flame or heat generating appliance". Both definitions clearly cover natural gas.

In general, the Regulations are appropriate for natural gas as they provide broad guidelines for overseeing the technical, operational, health, safety, and environmental parameters for related infrastructure and installations. While the broad requirements are sufficient, the specific parameters referenced in the regulations would need to be developed for natural gas installations and businesses. One gap in the Regulations is the lack of any mention of pipelines. The regulations for storage and bulk transportation both touch on aspects of the regulations that would be required to oversee natural gas pipelines and distribution systems, but as currently written both are inadequate. The storage regulations assume a contained facility held entirely within land that the operator either owns or has permission to use – this would not necessarily be true for pipelines built under public or private lands along rights-of-way easements. The bulk carrier regulations touch on many requirements for transporting natural gas safely, but "bulk transportation carrier" is clearly defined as "a vehicle capable of transporting 2000 liters or more of petroleum and petroleum products." This covers both land and water based transportation, but excludes pipelines.

Institutional framework

[104] Part of this section is presented in the Energy Narratives study provided by the GoG.

It has been recommended to establish an institutional and regulatory framework for the oil and gas sector that includes the Ministry of Infrastructure, the Guyana Energy Agency, the Audit Office of Guyana (AOG), Guyana Revenue Authority (GRA), and the Ministry of Finance. Also it would be recommended to establish a new body to regulate the oil and gas sector and a new directorate for petroleum in the Ministry of Public Infrastructure to provide policy guidance and licensing for the upstream, midstream and downstream aspects of the Oil & Gas chain.

The Draft National Energy Policy (DNEP) of Guyana states that a new regulatory oversight body will be established "to balance multiple competing interests of public and private entities, and enable growth of the sector while supporting the efficient, safe and orderly development of energy resources while minimizing the environmental footprint of the sector. This agency will be established after it has been demonstrated that significant long term exploitable oil and gas reserves have been verified. This will serve as the single credible body to monitor and regulate all aspects of the sector"

GEA role for the Natural Gas regulation

The Petroleum and Petroleum Products Regulations 2014 direct the GEA's authority and actions to license and oversee the transportation, storage, wholesale and retail sale, import, and export of petroleum and petroleum products. As written, the regulations clearly give the GEA the authority to regulate and oversee natural gas activities and infrastructure. This role would have to be matched in the future with the functions to be assigned to the proposed regulatory body.

GPL roles within the Natural Gas activity

Electricity Sector Reform Act of 1999 and the Electricity Sector Reform (Amendment) Act of 2010 The ESRA, as amended in 2010, created the Guyana Power and Light Company and established the conditions for its license, its duties to supply electricity, parameters for purchasing power from IPPs, the mechanism used to set retail electricity tariff rates, and penalties for non-compliance. The ESRA does not describe specific technologies for the generation of electricity, with the exception of promoting sustainable technologies where appropriate. The tariff setting mechanism does include provisions for adjustments related to fuel prices and foreign exchange rates, allowing GPL to pass through reductions in the cost of fuel to the consumer, as it would be expected with the future DBIS generation expansion using indigenous natural gas. The ESRA does not directly address fuel supply for electricity generation, or proscribe any manner in which the fuel should be purchased or stored. As such, there is no restriction within the law from GPL acquiring fuel directly from importers or domestic producers, or maintaining its own fuel supplies. The ESRA does state that GPL is only allowed to break up streets and otherwise affect public or private lands for works related to electricity lines. This would prohibit GPL from breaking up roads for the purpose of installing natural gas pipelines without special approval.

GPL was granted a license to supply electricity to the coastal regions of Guyana in 1999, concurrent with the ESRA which created it. This License, as amended in 2010, limits GPLs activities to: i) the generation of electricity (except hydropower); ii) the transmission, distribution, storage, furnishing and sale of electricity; iii) the purchase of electricity through PPAs with IPPs iv) the installation, operation, and maintenance of meters, electric lines and other electric apparatuses, installations, and facilities necessary to carry out its activities.

The provision of fuels for electricity generation is not listed among the authorized activities, although section 28 does provide authorization for GPL to "act and to perform such other activities and services as may be necessary for the purposes of exercising its rights, fulfilling its obligations and performing the activities and services authorized under this License." *This broad language could provide sufficient* *authorization for GPL to build and operate natural gas pipelines and other delivery services if they were deemed necessary. Amending GPL's License or enacting separate legislation that explicitly grants or prohibits GPL from owning and operating natural gas transportation and distribution facilities would remove any ambiguity.*

Formation of a Natural Gas market

In order to guarantee open access to the natural gas transport system and the formation of an efficient natural gas market, most of the countries' energy markets regulate that natural gas transport activity is independent of production, commercialization and distribution of natural gas, including in them the activity of generating electricity. According to this, the natural gas transporter may not directly carry out production, commercialization, or distribution activities, or have economic interest in companies whose purpose is to carry out these activities. The transporter may not have economic interest in power generation companies either.

In the case of offshore deposits, similar to other countries (as, for example, the case of offshore gas production in Guajira, Colombia), the gas producer would assume the development of offshore transport infrastructure to the connection site with the transport network on the mainland. However, in the case of Guyana, investment in transport infrastructure is substantial, so that its realization, whether by the producer or by another agent, requires securing a market for the gas.

As indicated by the GoG, it is currently being programmed to install this infrastructure with a capacity of 145 mmcfd. Under this situation, for the supply of gas for electricity generation (30-50 mmcfd) the following two options could be had: i) part of the capacity of the offshore transport infrastructure (30-50 mmcfd) would be considered dedicated to the plant, in which case the plant would participate in its execution assuming the corresponding fixed transportation cost and the gas price would be the wellhead price; or ii) the producer or other agent would develop the offshore gas transportation system (including its required compression station) providing or purchasing the natural gas at its wellhead Price, then transporting it to the power plant, delivering that gas at a price that would reflect the wellhead price plus the levelized cost of transportation.

The second option would require a contract that distributes the risks associated with the volume dedicated to electricity generation, for which a sales contract with payment of availability premium or a take or pay contract with payment obligation of a percentage could be agreed among the parties.

Typically, a take or pay stipulation requires the buyer to purchase a minimum quantity of the product or service in each period, usually annually or, alternatively, to pay that minimum amount even if he has not taken it or accepted to receive it. In the natural gas market, historically that minimum amount has been between 70% and 90% of the total contracted. This type of contract could be adopted in Guyana, or other, similar to the practice that some countries have used to initiate the development of the natural gas market.

9.5.4 Recommendations for future Wind Plants

Guyana has advanced in defining its power wind potential and had identified several possible locations of wind farms to install around 40 MW (in the 50 mmcfd case) according to the generation expansion plan proposed in this study. The following guidelines are proposed to promote such projects (when applicable):

- The wind projects should be part of the National Power Expansion Plan.
- The construction and operation of the future projects shall be assigned to an IPP developer through a bidding process in order to promote economic efficiency.

- The design and conduction of the bidding process for future projects shall be under the Minister directions, with the support of international expertise in order to obtain best practices in this process. There is already a great experience in the Latin American countries to be taken advantage of.
- The technical standards of equipment, the quality of products and the respective factory guarantees shall be clearly defined in the terms of reference.
- The design of the Power Purchase Agreement (PPA) shall be part of the terms of reference and shall take advantage of international experience as much as possible.
- To reduce energy output uncertainty of future projects, GEA shall undertake wind measurements in the area where the wind farm will be located.

9.5.5 Recommendations for a Hydroelectric Power Development Policy

A hydro project requires the License under the Hydro Electric Development Act and the Environment Protection Act and GPL doesn´t have such authorization to develop hydroelectric power plants within its license.

Therefore, the strategic objective of building a high capacity hydroelectric plant, requires a special strategy. The following recommendations are proposed in this direction:

- The specific hydroelectric project to be developed must be identified in the National Power Expansion Plan adopted by the GEA and the Minister.
- Definition of its financial structure with clear allocation of responsibilities in the Government Agencies.
- The creation of a Project Management team with the oversight of the Minister and multilateral agencies that support the project. This team shall have the following functions:

    - Structuration and development of the international bidding process to select the IPP investor that would build the project and sell its capacity to GPL under the power purchase agreement.
    - Draft the final License as a key component of the terms of reference of the bidding process.
    - The risks allocation (like construction risks, demand risks, environmental risks, etc.) shall be a key factor of success for all the projects developed as a result of bidding process for construction and operation.
    - Obtain from authorities the environmental license as a pre-requisite for the bidding process.
    - Direction of the PPA closure, with the respective PUC approval and GPL participation.
    - Oversight the construction and finance flows to guarantee its completion on time.

9.5.6 Recommendations for a Biomass Power Development

The energy surplus into the grid coming from cogeneration with bagasse has gain little progress during the last years in Guyana, despite the objectives of GEA Strategic Plan. On the contrary, it has been noticed before, that there have been operational problems at the cogeneration plant Guysuco, which has meant that, in some instances, all the power exported to GPL has come from the diesel units.

One of the main constraints is cane supply to the sugar industry. On the other hand, the current price does not incentivizes the efficient expansion of cogeneration with the objective to produce surpluses.

One suggestion to solve such problem is that GEA's Power Strategic Plan instructs GPL to study the level of a feed-in tariff for biomass generation. This study shall be done under an expansion plan of least cost, in order to avoid increase in tariffs to final consumers. The GEA Plan shall instruct the PUC to assess and to approve the feed-in tariff if it is feasible.

9.5.7 Recommendations for a Distributed Generation

In this sense, the main recommendation for the short and medium term related to Renewal Energy (RE) power generation and Distributed Generation (DG) is that GPL should develop and adopt a grid code with clear rules for potential distributed generation in DBIS system (Appendix T contains the specific recommendations at this respect).

In general, distributed generation, like Photovoltaic (PV) generation, is introduced in a systematic way in those electric systems with a robust grid and control distribution management. This is not the case of Guyana in the short and medium term. For instance, the state and capacity of the grid requires deep studies with the respective investments for upgrades. The grid conditions required to enable DG shall be identified in GPL's grid code specifications, mainly focused to rule the connection and operation of photovoltaic systems, when feasible, in the existing residential sector (with emphasis in the new houses and communities), as well as for large commercial and industrial clients.

Guyana shall continue working in the creation of conditions for future distributed generations, say for example, apart from the sectors explained above, in new residential units where capital investments in photovoltaic technology could be smaller than the cost of in actual residences. The following strategies and guidelines are oriented in that direction:

- The GEA Strategic Power Plan shall instruct GPL to update a Grid Code to take into account the conditions for distributed generation with focus on large industrial and commercial clients, and for new residences toward the long term. For this task, the Guyana Government should adopt best practices in this front from recent international experiences and assistance from distributed generation experts.
- As a second medium term step, GEA Strategic Power Plan shall include the design and structure of pilot projects to promote net metering PV systems in a specific area of Georgetown or the Coast in large commercial and industrial clients, where this kind of systems can be feasible as stated in the EE chapter of this study. The design of the pilot projects shall include the legal[105], technical[106] and economic assessment of net metering and feed-in tariffs mechanisms to be used by GPL. There is a wide variety of alternatives that must be evaluated under a specific project (GEA has informed in the Strategic Plan 2013 – 2017 the development of a pilot project which results are unknown).
- Once the feasibility is confirmed (including the PUC assessment of impacts on final consumer tariffs), the GEA Strategic Plan and the PUC shall order GPL to promote and allow the connection of PV systems using net metering or feed in tariffs.

Appendix 1 includes the considerations for policy and regulation of distributed generation that have been obtained in this study and specific recommendations to foster this activity in Guyana.

9.5.8 Recommendations Energy Efficiency

Policy action to promote EE in Guyana has focused on the provision of fiscal incentives, like tax exemptions that have been used to encourage efficient lighting. GPL's. D&E Plan emphasizes, as well, in education programs.

[105] As the current tariff structure is definen in the Energy Sector Reform Act, it is important to evaluate if this Act shall be ammended to allow net metring or feed-in tariffs.
[106] One technical and economic issue to be evaluated is the impact of distributed generation under a context of high energy losses.

In the "Summary of Existing and Proposed Energy Policies in CARICOM States" the FMI informs that Guyana has suggested the incorporation of national EE standards, appliances' labelling standards, "tax reductions" and "public demonstration"[107].

This is a field where there is room for the IMF recommendations for Caribbean countries for "setting national energy efficiency standards (e.g. energy labeling and energy efficient building codes) and providing appropriate incentives will help encourage the adoption of energy efficient technologies by businesses, particularly hotels, as well as households."

In this context, and taking into account the results of the EE analysis in this study, including the critical issues pointed out in such section, the policy and regulatory guidelines proposed for EE are:

- **Minimum energy efficiency standards and energy labeling-** The GEA Strategic Plan shall define clear responsibilities for the development and adoption of appliance labelling standards. Minimum standards of energy efficiency implemented through a legal and regulatory framework provide a good stick for progressing energy efficiency across the entire Guyana economy. These standards could be promoted through the East Caribbean Energy Libeling Project (ECELP). The imports of appliance that do not fulfill the standards shall be prohibited.
- **Demonstrator Projects -** Demonstrator Projects are an effective means of raising the profile of electrical energy efficiency. These projects are often best developed initially through the public sector. Guyana already has some good examples: The new wing of Georgetown Hospital, Energy efficiency work which GEA has done in schools and other sectors, and in the private sector STARR Computers initiative to implement 7kW of photovoltaic capacity on their roofs. However, these projects need promoting and extending with appropriate interpretation materials so that all stakeholders including the general public are aware of them and able to learn from them.
- **Shared value and innovative financing-** Shared value models can help promote energy efficiency measures by for example offering cash-back on energy efficient devices or working with retailers and manufacturers to reduce the cost of energy efficient devices. Some energy efficient technologies are already tax exempt, but this list should be reviewed on a regular basis to ensure that all appropriate technologies are captured. This is particularly important in Guyana and the Caribbean and Latin America in general where there is little access to cheap finance. Structured finance is critical. The ideal would be to take the financial question outside of the hands of the consumer so that the energy efficiency option is not only the best option but also the cheapest, but this is best done through a large programme so that the risks of measures under-delivering predicted savings can be mitigated. Programmes are also a good way for the burgeoning Guyana energy efficiency industry to learn by doing. A programmatic approach also offers the possibility of cheaper finance or levering in carbon funds. The shared value model often is best delivered through a service model approach which focuses on delivering the services which electricity can provide rather than selling units of electricity.
- **Building codes -** A large percentage (typically two-thirds) of electrical energy use is in buildings. Extending buildings codes to cover energy efficiency and looking at opportunities to develop retrofit building codes is a very positive step towards reducing electricity and other energy use in buildings.
- **Training and networking-** Training energy professionals is an essential part of progressing an energy efficiency programme. This can be done on a regular basis utilizing existing networks such as REETA, but also more formal training promoted through bursaries can help to build capacity within Guyana to deliver energy efficiency projects.

[107] IMF Working Paper "CARIBBEAN ENERGY: MACRO-RELATED CHALLENGES", March 2016, page 22. The Paper doesn´t explain the scope of "tax reductions" neither "public demonstration".

- **Partnering-** Guyana already has a burgeoning relationship with The Energy and Resources Institute of India (TERI) but it should also look to foster relationships further afield. It should work more closely through REETA with other CARICOM nations to promote energy efficiency, a relationship which could be particularly useful when it comes to procuring energy efficient goods and services in a CARICOM level programme. It should also look to foster relationships with developed countries both from a financing, training, technology and delivery perspective.
- **Large scale programmes-** Programmes can be of principally two types: programmes geared towards the few large energy users in Guyana which have specific electricity challenges for which specific professional expertise is needed; More general programmes for small energy users who share similar issues but for whom investment in an energy efficiency programme needs to be made relatively simple in order to be able to participate. These programmes need to be resourced, managed and monitored and with specific goals in mind in terms of energy efficiency savings in order to be effective.
- **A technology hub-** Technologies do have an important role to play in electrical energy efficiency. Technologies are developing rapidly. For example energy storage can be an important part of any future energy system and there are new storage technologies being developed for solar and wind: at both the small scale and utility scale. At small scale, companies like SMA and TESLA are offering integrated grid-tied inverters with battery storage included. Technology innovation is important not just for delivering energy efficiency but also distributed generation and facilitative technologies such as smart grids. Care should also be given to how energy using devices are recovered since there is the possibility that some energy-inefficient devices could be re-utilized by secondary users who cannot afford to buy a new device.
- **Bring in the private and not-for profit sectors-** The public sector cannot deliver an energy efficiency programme alone. It is important to work with the private sector so that they can help to innovate new business models. The not-for-profit sector also has its role to play because often they can identify end-user needs that would not usually be attractive to the private sector or seen by the public sector. The best projects are often delivered through a combination of public, private and not-for-profit sectors working in collaboration.
- Perform official surveys to obtain detailed electricity end-use data in Guyana, which is not present and is a pre-requisite to measure and design any EE strategy. After enough and reliable data has been collected, perform an EE consultancy to design and quantify EE strategies in the short and medium term.
- GEA shall implement a monitoring program to assess the EE gains through the implementation of the above strategies.

9.5.9 Recommendations for electricity tariffs structure to final consumers

Under the scope of the present Study, which is oriented to the development of a Power System Expansion Plan, what is really relevant is if the efficient cost of generation to be charge in the consumer bills is identified by GPL in a proper manner.

According to the review of GPL´s License, the tariff structure and some bills, it is not clear how the energy costs are passed through to final consumers. More specifically, although it defines the rules for allowed revenue like the formulas for the calculation of the rate of return, the assets rate base, fuel surcharge/rebate to each customer´s billing and foreign exchange surcharge/rebate, it does not define specific formulas for the distribution component, neither for the transmission component and generation component.

The main recommendation of policy and regulation is transparent costs of the different components of the value chain, total supply costs and cross-subsidization (subsidy received by each consumer and the additional cost charged to other consumers). This will help to promote EE and the comparison of energy costs with other similar countries.

9.5.10 Recommendations on Tariffs' unification under the Integration of DBIS and Linden Systems

According to the Base Scenario used in this study, in 2024 DBIS and Linden would be interconnected. Due to the fact that Linden has lower (subsidized) end user electricity rates compared with those of DBIS' consumers, this could lead to a strong political pressure over the Government.

In order to prevent potential economic and political problems, it would be convenient to design a transition policy consisting of a path of rates increases in Linden, before and during the interconnection, up to a level considered as reasonable for the society.

9.5.11 Recommendations on Electric transportation

The Green State Development requires the consideration of the use of electricity in the transportation sector, and the following aspects are considered in the Guyana Energy Policy.

- Investigate the infrastructure needs to support customer ownership of electric vehicles (EVs), as well as the grid integration requirements and standards. This will include investigations into the EV charging infrastructure, installation standards, and electric vehicle building codes. Investigations will also be undertaken of the training requirement of technical personnel;
- Demonstrate the feasibility of electric vehicles. The Government will facilitate the private sector in the procurement of a number of electric vehicles and charging station to demonstrate the feasibility of these vehicles to the general public. The demonstration will comprise of cars, light commercial vehicles and trucks; and
- Encourage the adoption of electric vehicles through education and awareness.

10 PRELIMINARY SOCIO-ENVIRONMENTAL IMPACT AND RISK ANALYSIS

In this chapter we present a preliminary socio-environmental impact and risk analysis of the issues associated with the identified power generation technologies of the optimal generation expansion program proposed in this study.

The Consultant notes that this is not a complete and exhaustive Socio-Environmental Impact Analysis on each technology analyzed in this study for Guyana, as this would imply to perform exhaustive studies within Guyana's social and environmental context, site visits to individual generation projects being studied, demographic inspection on near sites communities, local environmental studies and other related matters. On the contrary, this analysis summarizes overall impacts per generation technology which may or not apply to a given project, as some of the impacts depend also on size and location of power generation plants; the Consultant enters into detail when information is available on a per project basis (e.g. Amaila Falls) considered in the optimization plan.

The Consultant developed calculations per proposed generation technology (using the optimization model of this study) that quantify the main environmental impacts (CO_2 emissions) that the implementation of such technology would have in Guyana. As well, the Consultant made a qualitative analysis of the risks that such proposed generation technologies have in the social and environmental aspects.

This chapter contains two sections. The first section shows and quantifies the environmental impact and risks of each generation and the second section shows the social impact and risks of each generation and EE technology. After each analysis, conclusions are presented.

10.1 Environmental Impact and risks of each generation and EE technology

This study uses the greenhouse emission factors shown in Table 74 as parameters in the optimization model.

Table 74. Emission Factors (Ton CO2/GWh)

FUEL	HFO	LFO	GAS
Gas Turbines		808	688
Combined Cycle		568	421
Reciprocating Engines	700	700	590
Wind Plant			
Solar Plant			
Biomass Plant			

Source: Central America Generation Expansion Indicative Regional Plan, GTPIR, 2012

Introducing natural gas and renewables like wind, solar and hydro in Guyana would have relatively low negative environmental impacts than continuing generating power with liquids. There are environmental risks associated with such infrastructure development and with operating renewable power plants or motors with natural gas, but they are lower than the risks to importing and using fuel oil for electricity generation.

Table 75 shows the estimated impact on CO_2 emissions associated to the combustion of fuels in the updated expansion programmes that were considered in the optimization analysis made in this study for the following three cases: i) Business as Usual (BAU Case), ii) Availability of 50 mmcfd of natural gas for power generation (NG 50 Case), and iii) Availability of 30 mmcfd of natural gas for power generation (NG 30 Case). Please see Appendix S for explanation of economic cost of CO2.

Table 75. Estimated CO2 emissions associated to fuel consumption per generation expansion case

CONCEPT	BAU CASE	GAS 50 CASE	GAS 30 CASE	GREEN CASE
	ONLY FUEL OIL	FUEL OIL, RENEWABLES & NATURAL GAS	FUEL OIL, RENEWABLES, HYDRO & NATURAL GAS	FUEL OIL, RENEWABLES & HYDRO
Average Emission Factor (Ton CO2/GWh)				
2018 - 2024	692	522	583	551
2025 - 2035	693	406	283	50
Present Value of CO2 Emissions (USD million) 1/	237	158	143	81

Note: 1/ Present value at 10% of CO2 emissions during 2016-2035 valued at US$ 30/ton. Source: Consultant

Table 75 confirms that a DBIS generation expansion using only fuel oil (BAU CASE) would have the highest CO2 emissions followed by the full expansion with gas (GAS 50 CASE, associated to 50 mmcfd availability), then the partial expansion with gas and considering hydro in the long term (GAS 30 CASE, associated to 30 mmcfd availability) and finally the use of almost full renewable energy sources for power generation after 2025 (GREEN CASE) would have the lowest CO2 emissions.

Table 76 summarizes the main environmental impacts and risks of each technology analyzed in this study.

Table 76. Overall Environmental Impact Analysis

Technology	Positive Environmental Impacts	Negative Environmental Impacts
Engines	• No absolute environmental benefit was found for constructing and/or operating HFO/LFO fueled power plants in Guyana. From a relative point of view, engines burning HFO/LFO produce lower greenhouse emissions (mainly CO_2) than coal based power generation but higher greenhouse emissions than other technologies. • Some liquid fuel engines have low carbon monoxide (CO) and hydrocarbon (HC) emissions thanks to their high thermal efficiency.	• Significant air pollution due to greenhouse gases (GHG) mainly in the form of Carbon Dioxide (CO_2), other emissions such as Carbon Monoxide (CO), hydrocarbon (HC), sulphur dioxide (SO2), Nitrogen oxides (NOx), and particulate matter (PM) emissions due to burning HFO and/or LFO to generate electricity and due to HFO and/or LFO transportation to the plant. NOx, SO2 and PM are the main emissions of interest regarding stationary HFO/LFO fuel engines. SO2 and PM emissions are mainly related to the quality of the liquid fuel. • During construction, the potential impacts on air quality will be (i) dust generation from on-site activities, and (ii) vehicle exhaust emissions. Dust generation has a nuisance value and may present a health risk for near communities. On the other hand, during the operation of the plant, the environmental impact is associated with emissions from burning HFO / LFO. • Land erosion can increase due to vegetation clearance and loss, as land needs to be prepared for plant construction. • Air and land pollution from stockpiling of materials during plan construction. • Oil and metal pollution to soil and water during construction and operation is likely. • Noise disturbance and nuisance to onsite and offsite during construction and operation. • Potential impacts on waste arising from vegetation waste from site clearance, spoil from groundworks (including site levelling, landscaping, backfilling), construction waste (including excess materials, temporary structures and staff wastes), operational waste and waste arising from oily water treatment, water from the site

		drainage system, sewage waste, and decommissioning wastes. Waste water may contaminate soil and water channels.
Wind	• In contrast to power generation that burn fossil fuels to generate electricity, wind turbines do not pollute our atmosphere with greenhouse gases. • There is no water impact associated with the operation of wind turbines (however, as in all manufacturing processes, some water is used to manufacture steel and cement for wind turbines).	• The visual effect caused by operating onshore wind turbines can be major annoyance in people's lives and could damage local tourism [Dennis (2012)]. • The noise caused by operating onshore wind turbines is a major annoyance in people's lives [Lee (2011)]. Wind turbines cause noise in two main ways: mechanical noise and aerodynamic noise. The latter, although still lacking factual evidence of its impact, is considered to be a critical issue. Its low frequency may cause annoyance in people's lives. Some researchers found that the low-frequency aerodynamic noise of wind turbines can bother people by causing sleep disturbances and hearing loss, and can also hurt the vestibular system. • The danger of wind turbines on wildlife (mostly birds and bats) is a concern. Although some studies suggest that local birds can learn to avoid obstacles (including wind turbines), birds will still be killed by the wind park [Hau E. (2000)]. • The primary health and safety considerations are related to blade movement and the presence of industrial equipment in areas potentially accessible to the public. An additional concern associated with wind turbines is potential interference with radar and telecommunication facilities. And like all electrical generating facilities, wind generators produce electric and magnetic fields. • Wind farm's complementary infrastructure such as transmission line and access roads need to be built with their associated environmental problems to reach the wind park location. • Large land areas required for this type of technology • There is a risk that erosion of seaside could eventually affect the wind park and therefore care need to be taken when selecting the location.

Solar	• No greenhouse emissions are expected to be released to air, due to the fact that solar PV power plants do not release greenhouse gases or any toxic pollutants during operation. It is worth mentioning that solar PV power plants have very low emissions of air pollutants such as sulfur dioxide, nitrogen oxides, carbon monoxide and volatile organic compounds during operations compared to fossil fuel power generation facilities, since solar power plants do not involve combustion processes. • While there are no global warming emissions associated with generating electricity from solar energy, there are emissions associated with other stages of the solar life-cycle, including manufacturing, materials transportation, installation, maintenance, and decommissioning and dismantlement. Most estimates of life-cycle emissions for photovoltaic systems are between 0.07 and 0.18 pounds of carbon dioxide equivalent per kilowatt-hour. However, this is far less than the lifecycle emission rates for natural gas (0.6-2 lbs of CO_2/kWh) and coal (1.4-3.6 lbs of CO_2/kWh). • During its operation, the solar power plant is not considered to exhibit any significant noisy operations, although the facility's inverters and transformers may produce noise, but this is not considered a serious issue, since they will not generate any significant noise.	• Unlike wind parks, there is less opportunity for solar PV projects to share land with agricultural uses. However, land impacts from utility-scale solar systems can be minimized by siting them at lower-quality locations such as brownfields, abandoned mining land, or existing transportation and transmission corridors. Smaller scale solar PV arrays, which can be built on homes or commercial buildings, also have minimal land use impact. • Thin-film PV cells contain a number of more toxic materials than those used in traditional silicon photovoltaic cells, including gallium arsenide, copper-indium-gallium-diselenide, and cadmium-telluride. If not handled and disposed of properly, these materials could pose serious environmental or public health threats. However, manufacturers have a strong financial incentive to ensure that these highly valuable and often rare materials are recycled rather than thrown away. However, such recycle procedures, due to lack of scale, are not economical and therefore care should be taken proper decommissioning or disposal of PV cells. • Photovoltaic panels may contain hazardous materials, and although they are sealed under normal operating conditions, there is the potential for environmental contamination if they were damaged or improperly disposed upon decommissioning. Concentrating solar power systems may employ materials such as oils or molten salts, hydraulic fluids, coolants, and lubricants, which may be hazardous and present spill risks. Proper planning and good maintenance practices can be used to minimize impacts from hazardous materials. • Construction activities are not expected to result in significant soil loss; however clearing, grading, excavation, levelling and other earthworks like soil compaction, may disturb the soil due to the removal of top soil, which could trigger soil erosion process. It is relevant to note that the clearing and use of land for solar power facilities during construction can adversely affect native vegetation and wildlife in many ways, including loss of habitat; interference with rainfall and drainage; or direct contact causing injury or death.

		The impacts are exacerbated when the species affected are classified as sensitive, rare, or threatened and endangered. • Construction activities can alter the drainage of water channels, of particular importance in Guyana, and therefore careful consideration of this impact should be taken. Studies should be conducted to identify how water resources are impacted (ground and surface) during construction phase • A major motivation for deploying solar power is to reduce emissions of carbon dioxide from traditional power generation. When installing solar power in forested regions, this motivation needs further research because trees and brush must be removed to prevent shading of solar panels. [Turney (2011)] • The other source of impact to soil is waste generation from construction material or accidental leakage of chemicals can cause direct contamination to soil which may degrade lower layers of soil depending on the amount of spills. Improper management of non-hazardous and hazardous waste generated during construction may lead to impacts on soil, water, visual environment, in addition to health and safety of workers. • During construction, dust generation may result from earthworks such as levelling, grading, excavation works and movement of vehicles across dirt/unpaved roads, especially during windy conditions. • During construction and plant decommissioning, exhaust emissions of SO2, NOx, CO, CO_2, and PM10 will be attributed predominantly to the operation of the construction plant and road vehicles such as movement of trucks and vehicles during construction works. These emissions will be limited to the project area and are anticipated to be generated in small concentrations and dispersed rapidly within the area leading to an impact of low significance. • Noise will be produced during construction and decommissioning activities of solar PV cells. As well, there are several noise

		generating activities such as opening access roads to construction personnel camp and facilities (if needed), earthworks, haulage activities, excavation, backfilling, and installation of PV panels, and other equipment within the facility in addition to noise sources generated from machinery and equipment on site. • The construction and decommissioning activities are likely to create a visual intrusion and a disruption to aesthetics like materials lay down, excavation, backfilling, and spoil. • Construction activities can pose risks on the terrestrial ecology within or in the vicinity of the project site. Also, it may cause temporary disturbance to resident birds with ground nests due to noise, dust and particulate emissions, and possible illegal hunting by construction workers. Reptiles and other fauna present within the project site may temporarily move to adjacent locations during construction activities, however are expected to return back as construction is completed. • Soil impacts during operation phase are limited to accidental spillage of lubricant, fuel and other chemicals that may potentially cause soil degradation. • During the decommissioning phase, the decommissioning activities are anticipated to have an impact of medium significance to soil. This is due to possible accidental leakage of fuel, oil, or chemicals during demolition activities. • Solar panels have risk of glare and therefore should be built far from airports and residential dwellings; moreover, potential visual disturbance to birds are expected, and as a result, migratory bird flyway could be impacted. Intensity of light reflected from a PV module surface depends on factors such as the amount of sunlight reaching the surface and will therefore vary based on, among others, geographic location, time of year, cloud cover, and PV module orientation.

		• Waste generated during operation phase will be limited to wastewater from maintenance and cleaning activities in addition to domestic waste (due to workers domestic activities). • Large land areas required for this type of technology.
Hydro (This section of Hydro social impacts have been extracted from Amaila Falls EISA Update in January 2011)	• Clean fuel source that is renewable yearly by rainfall • Do not emit pollutants into the air because they burn no fossil fuel • Hydropower is readily available as the flow of water is controlled • Hydro project will displace energy generation from existing thermal power plants, which use oil, eliminating their greenhouse gas emissions and other air quality pollutant emissions. The hydro project can also reduce the need for local businesses to use inefficient diesel-fueled self-generators, which emit greenhouse gases. • For Amaila Falls, presence of the reservoir can cause local groundwater levels to rise; thus, a possible positive impact would be greater availability of water in some areas, possibly resulting in (lowland forest) vegetation growth, and new wetlands are expected to be created along the former alluvial plains in the Kuribrong and Amaila River watersheds.	• Any mid-size hydro project has several negative environmental effects in construction activities that will have ecological and geological effects. This could result in loss of wild lands, wetlands and wildlife habitat, can stop the flow of nutrients downstream, will reduce biological activity downstream, and could result in anaerobic decomposition of vegetation and production of greenhouse gasses. Also, this may cause migration of animals to new areas, where new equilibrium may favor some species over others and also block fish migration. • Water-loss due to evaporation • The project Amaila Falls will produce a reduction in the water flow over Amaila Falls. Though this is a negative impact on a scenic resource, there is no present access to the falls. • The reservoir and the construction of access roads will have significant loss of forest, trees and vegetal ecosystem • Changes in water quality due to the lack of dissolved oxygen near the bottom of the reservoir. This is toxic to fish and can lead to the death of aquatic life. As well, this is corrosive to turbines. • Accommodation of amphibians, riparian fauna and birds to a new environment • Inappropriate reservoir operation with large variations in water levels could threaten fish by drying up shallow breeding and flood producing areas. • The most significant potential impacts on surface water resources relate to changes in flow and water quality due to the presence of the reservoir (i.e., operation phase), changes in flow and water quality downstream of the power house during operations, changes

		in flow between the dam and powerhouse during operations, and changes in water quality downstream of the dam during construction. • The potential impacts on ground water resources are considered to be of low magnitude and Importance. These will consist of locally lowering of the water table during construction, increasing it around the reservoir during operations and changing it locally in the downstream Kunbrong during operations (sometimes higher and sometimes lower). The lowering of any water table should not be extensive and there are no uses of the ground water in the Hydropower Facility DA_I, therefore this impact will not Interfere with any of the region's water supply After filling, the reservoir can cause a rise in the groundwater levels, which could result m an Impact on surrounding land. This change can cause the formation of wetland areas, along a strip of varying width along the reservoir margin Given that there are no human land uses m the immediate or nearby area to the reservoir the results of this impact, should it occur, are not expected to be significant, though some alternation of forest structure and species may be induced. The raising of the water table may also initiate processes that cause instability of the reservoir margin due to subsurface water flows, particularly in areas of sandy soils. • The principal impact on topography and soils relates to the extensive earth works necessary. For the dam construction, and to a lesser degree the transmission line tower foundations and Access Road. While the portions of the directly affected area have sandy soils prone to erosion, most of the area has gentle slopes covered by forest formations, which decrease the potential for erosion. The Project ESMPs include various erosion prevention and run-off control measures. This Impact is a medium magnitude impact, reversible, and relatively short duration. • The risk of instability and erosion of reservoir margins during operation may occur in shallower areas due to fluctuating water levels. At its minimum operating level the reservoir surface area will be reduced to approximately 8 lan2 from its fill supply surface

		area of about 23.3 km2 leaving approximately 1 5 lan2 of exposed areas. In spite of this, the probability of significant erosion is considered to be low as most of the exposed areas are relatively flat and exposure will occur during dry months when there is less rainfall to cause erosion. If erosion occurs, it would be limited to specific areas where soil type and slope favor its occurrence. Erosion of the reservoir margins will be monitored by the Reservoir Margin Stability Monitoring and Erosion Control Plan. • The risk of soil contamination is relatively low assuming implementation of the hazardous material and petroleum product management procedures and solid and hazardous waste management plans. Given the limited volumes of hazardous materials and petroleum products, the result of a spill would be relatively small in terms of affected area unless the spill is directly into a water body. Potential impacts are filter decreased with the implementation of spill prevention and control procedures and emergency/contingency plans, which are part of the Project ESMP. • The reservoir may result in the creation of some new wetlands, which may be a positive impact m terms of enhancing overall biodiversity but may also result in creation of areas with stagnant or semi-stagnant water that could affect some of the vegetation and enhance the proliferation of disease vectors. The magnitude or size of the created wetlands will be a function primarily of the surface topography in and outside the reservoir boundary, and the permeability of the soils immediately outside the reservoir. • Whi1e some riverbank erosion of the Kuribrong immediately downstream of the powerhouse is possible, the affected area will be relatively small and basic construction measures can control this Impact. • Impacts due to construction work within floodplains are mainly related to construction of the transmission line tower foundations and portions of the Access Roads which may result in sediment transport and/or instability of riverbanks. Construction

		environmental management procedures proposed for the Project should effectively mitigate and control this impact. • The risk of induced seismic events is very unlikely due to a low probability of occurrence given the absence of seismic events in the region and considering the size and volume of the Project reservoir. • The net emissions from the clearing of the reservoir, transmission line corridor and road corridor are approximately 1.1 million tons C02e over twenty years (average 55,000 tons CO_2/year). The avoided GHG emissions from oil fired thermal power plants due to project operations is estimated to be 670,000 tons of CO_2 per year or about 13.4 million tons over twenty years. Therefore, the net GHG emissions from the vegetation clearing associated with the Project are approximately 8% of the estimated avoided GHG emissions from decreased usage of oil fired thermal power plants over a 20-yr period. • The net GHG emissions from reservoir operation is the difference in the GHG emissions from the river at and downstream of the falls under the present, pre-project conditions compared to estimates of GHG emissions from the reservoir and the same downstream reach under operating conditions. The high concentrations of carbon and low pH of upstream water suggests that a large amount of C02 is emitted as and after the water goes over Amaila Falls and travels downstream. This is expected to be similar to the amount emitted by the reservoir. • Other potential Impacts on climate and air quality include changes in air quality during construction and changes in micro-climate around the reservoir. During the construction phase, impacts on air quality will be generally concentrated m areas near earth moving activity, around unpaved roads used by vehicles and equipment, and in the vicinity of temporary industrial and power generation facilities. Fugitive emissions of particulate materials will also be generated by construction of the Electrical Interconnection and Access Road, though with less intensity and duration as construction progresses. The potential magnitude of these impacts

		is low, and can be effectively mitigated through the relatively standard environmental control procedures to be implemented at the Project. • No significant alterations m local climate are expected given the relatively small reservoir dimensions. If any effect is exerted on micro-climate, it would likely affect only a very limited area. This effect could consist of some alterations m the heat and humidity transfer rates in the reservoir DAI and immediate surrounding areas. There are no anticipated impacts on rainfall. • The primary source of vegetation reduction is due to land clearing for the reservoir area and along the alignment of the transmission line. The transmission line is 100 meters wide along an entire length of about 270 kms. The total area of preserved and disturbed forestland to be cleared by Amaila Falls project is about 45.4 km2 (or 4,540 ha), which represents 0.043% of total forested area in Guyana. • The clearing of the transmission line and access road will cause forest fragmentation which could have two general effects on the surrounding landscape (1) fragmentation per se will not occur in areas of primary and secondary forest, rather new continuous forest edges will be created; and (2) there will be an incremental increase in habitat fragmentation in areas already disturbed by humans. • An increase in the exploitation of timber resources may occur or expand in areas of primary forest due to the establishment of new access roads. In addition, the transmission line easement itself may Increase access to primary forest areas. • There is a risk of floristic changes in most areas around Amaila Falls since the majority of the water will be diverted to the powerhouse resulting in a long-term reduction m flow and a consequent reduction m the spray area. The plant community at the mist zone will be affected by the change in annual flow variation, which will tend to affect the spatial distribution of the plant community, with the expected result that a more stable community

		will become established in response to the more stable flow conditions. • The physical works in the Kuribrong and Amaila rivers during the construction period will affect the aquatic habitat, thus resulting in changes in the composition of these communities and abundance of organisms. Possible impacts include increased amounts of sediments transported as a result of earthwork activities and the consequent decreased water transparency may also alter habitat quality. Changes in habitat quality downstream of the dam and reservoir are also expected in the reservoir-filling phase in response to alterations in water discharge. • During operations, the change from a lotic to a lentic environment will produce habitat changes and cause changes to aquatic organism populations due to the loss of habitat for riverine and rheophllic ("current-loving") species and the establishment of populations of species adapted to lentic environments. At present, it is difficult to filly infer the extent to which habitat changes resulting from the conversion of the rivers into a reservoir will affect the ichthyofauna from the upper Kuribrong and Amaila Rivers. The complementary results of the field inventories to be conducted during the dry season will be important in providing data, especially from the future reservoir area, to adequately assess the local fish diversity. • The Kuribrong River stretch between the dam and the confluence with Amaila River (about 1.5 km) will be lost as aquatic habitat because of the dam. The only flows in this segment will be the contribution from a small tributary on the right margin and direct rainfall runoff • The construction activities and formation of the reservoir will significantly impact terrestrial fauna populations in an irreversible way. As well fauna populations during construction will be disturbed and increased hunting pressure by local communities and construction workers will occur.

Biomass	• The mechanical collection of raw cane generates a quarter of greenhouse emissions (CO_2) compared to the pre-burning cane before manual collection. The manual collection of raw cane leaves straws and leaves in the field, abducting 50 times more carbon in the soil that bio-char produced when burning. [Galdos (2010)]. The surplus biomass that comes with raw cane can be used as fuel by the bagasse boiler and ashes can be arranged in the soil. • The proposed conversion of a boiler operating at low pressure (17 bar) to a high pressure boiler (85 bar) has a potential reduction of 1,680 tons of CO_2 per MW installed. • Power generation using biomass contributes to the environment as it burns bagasse, husk, or wood waste, which otherwise represents an environmental problem (storage and disposal problems). • The use of crops for biomass production (reforested wood, sugar cane crops and rice) destined for energy production in cogeneration processes represents a potential reduction of 1,680 tons of CO_2 per MW installed. • Construction times of cogeneration plants with biomass are lower than those of most generation technologies considered in this study.	• Forest biomass and productive land are limited resources, and part of Guyana's natural capital. So it is essential to consider how to use existing biomass resources efficiently before imposing additional demands on land for energy production, which would considerably impact the ecosystem.
Natural Gas	• Greenhouse emissions (CO_2 Carbon dioxide) from thermal electricity generation using natural gas would be reduced compared to generating power using reciprocating engines fueled by HFO and LFO. • Sulphur dioxide (SO2) and particulate matter (PM) emissions are low for power plants running on natural gas. Nitrogen oxide (NOX) emissions are also low. • The construction of natural gas infrastructure brings additional taxes, fees, royalties, or revenues to implement National Environmental Plans or Strategies, to effectively manage existing	• Although greenhouse gas (GHG) emissions in the form of carbon dioxide (CO_2) and methane (CH4) from natural gas are reduced compared to fuel oil, power generation using natural gas still releases pollutants, including nitrous oxides (NOx), carbon monoxide (CO), particulate matter (PM), volatile organic compounds (VOCs), sulfur dioxide (SO2) and lead (Pb). • Land resources will be negatively impacted to accommodate natural gas generation plant facilities and transportation pipeline facilities

	protected areas, and to establish and effectively manage new protected areas. • Infrastructure development to transport and distribute natural gas has the potential to reduce poverty-related environmental problems and support sustainability and development plans in Guyana. Poverty reduction through natural gas industry job creation and increased revenues for governments, regional and local businesses can reduce the negative impacts associated with poverty. Negative environmental impacts associated with poverty include improper sanitation that pollutes water resources, habitat degradation for sub-standard housing construction, and overexploitation of forestry and fishery resources using unsustainable practices. • Reduced fuel transportation risks. Some accidents have occurred at on-shore facilities, though they have been rare.	• Natural gas generation and transport facilities could be established on or near critical habitat including protected areas, therefore affecting such habitats. • The construction of natural gas pipelines can impact marine habitats, such as seagrass beds, as well as coastal habitats, such as beach dunes and mangroves. • The construction of natural gas infrastructure can impact protected areas, sensitive habitats, natural resources and protected areas or ecosystems, and endangered or threatened species. • LPG leaks can present substantial risks as the liquid spreads and evaporates, since natural gas is highly flammable once it returns to its gaseous state. • Natural gas has the highest hazard ranking for flammability, while diesel is ranked as moderately flammable. • Natural gas generation facilities and transport compressors produce noise pollution

The following are the main conclusions of the environmental impact obtained from the previous table and analysis done in this study:

- Natural Gas could economically substitute the use of HFO and LFO for power generation in Guyana and this substitution would also imply significant CO2 emissions being possible to qualify Natural Gas as a clean fuel that could be used as a transitional fuel toward the achievement of a 100% goal of renewable energy power generation in DBIS in the long term.
- Mid-size hydro projects such as Amaila Falls has strong environmental impacts during construction. However, such impact is partially compensated by displacing power generation that burn fossil fuels, which produce high quantities of air pollutants. The total area of preserved and disturbed forestland to be cleared for Amaila project development is about 45.4 km2 (or 4,540 ha), which represents 0.043% of total forested area in Guyana.
- In general, solar power plants and wind parks are sustainable and safe, given that they do not cause the release of air pollutants or global warming emissions. Although solar PV energy is a clean alternative to fossil fuels, making the panels themselves (and therefore decommissioning them) have a negative environmental impact.
- Disposal of solar PV cells should be carefully planned as cells contain pollutants. There aren't enough places to recycle old solar panels, and there aren't enough defunct solar panels to make recycling them economically attractive. GoG authorities should be cautious and PV disposal by the IPP in charge of solar plants.
- The potential environmental impacts associated with solar power can vary greatly depending on the technology, which includes two broad categories: photovoltaic (PV) solar cells or concentrating solar thermal plants (CSP)[108]. The solar analysis shown here corresponds to PV solar cells, which are the resulting technology in the optimal generation plan in this study. As well, the scale of the plant — ranging from small, distributed rooftop PV arrays to large utility-scale PV and CSP projects — also plays a significant role in the level of environmental impact. Here we analyze small PV solar plants of 3 MW. Estimates for utility-scale PV systems range from 3.5 to 10 acres (14,164 m2 to 40,468 m2) per megawatt. This implies a size of 37.6x37.6m to 201x201m. CSP facilities.
- Although not related to a particular generation technology, the proposed reduction in overall energy transmission and distribution losses in DBIS grid will contribute with less impact on the environment (via power demand reduction) and promote sustainability of Guyana’s energy sector.

10.2 Social Impact and risks of each generation and EE technology

Table 77 summarizes the main social impacts and risks of each technology analyzed in this study.

[108] For example, solar PV cells do not use water for generating electricity while Concentrating solar thermal plants (CSP), like all thermal electric plants, require water for cooling.

Table 77. Socio-Economic Impact Analysis

Technology	Positive Socioeconomic Impacts	Negative Socioeconomic Impacts
Engines	• The infrastructure development needed to construct and operate reciprocating engines would create jobs for residents directly involved in construction and operations, and lead to increased revenues near the areas of development.	• Reciprocating engines fueled by liquid fossil fuels (HFO and/or LFO) have high power generation costs which are transferred to the final consumer with high end-user electricity tariffs, which affect the competitiveness of industrial and commercial sectors in the economy and affect the income of households. • Security hazards for workers from stockpiling of materials during construction. • Landscape aesthetic will be lost due to installation or addition of new equipment and machinery. • Traffic accidents during construction and operation (e.g. transportation of machinery and equipment for plant) affects safety of workers and community. Potential traffic impacts from the power project include increased road traffic and increased safety risks. During the construction phase traffic will be generated from a series of activities including, site clearance, construction of access road, installation of plant and equipment, and construction of the transmission line. • As with other power plants of any technology, social disruption by immigration likely due to job seekers from neighboring communities in search of employment, business or life opportunities coming up from the Project • Land vibration is likely impact due to engine combustions and when suspension and machine alignment is poor • Dust generated in construction and operation (e.g. traffic and other equipment on the site and along the unpaved roads.) may disturb communities and affect air quality to onsite and offsite receptors. • Potential noise impacts from the Power Plant will be from traffic and site activity during the construction phase and the small increase in traffic volumes, corona discharge (the noise generated

		by high voltage lines), and from the power transformers and reciprocating engines during the operational phase. • Significant risk of fire outbreaks due to the presence of large quantity of HFO or LFO at the power plant and during transportation
Wind	• Power generation using wind would result in a reduction in the cost of electricity generation compared to reciprocating engines fueled by HFO and LFO, which would have a large direct benefit for residents and benefit the economy of Guyana. • The infrastructure development needed to construct and operate a wind farm would create jobs for residents directly involved in construction and operations, and lead to increased revenues near the areas of development. • Because the private sector would play a key role in wind park infrastructure development, this would contribute to foster development through the private sector. • During the construction phase and operation, the wind park infrastructure would have a positive economic impact in the areas where they are built due to increased revenues for governments and local businesses. For example, there would be increased revenue for local and regional businesses for provision of direct and indirect services. Depending on the project site location, there could also be increased revenue from rental and purchase of housing units for workers during construction and operations.	• Wind turbines placed in flat areas typically use more land than those located in hilly areas, therefore surrounding communities near flat onshore seaside in Guyana will be more affected by a wind park. • Some people living close to wind facilities have complained about vibration issues which may deteriorate relationship with close communities. • Under certain lighting conditions, wind turbines can create an effect known as “shadow flicker”. This annoyance can be minimized with careful siting, planting trees or installing window awnings, or curtailing wind turbine operations when certain lighting conditions exist [NREL (2012)]. • Wind turbines may produce accidents. For instance, some government’s authorities require that large wing turbines have white or red lights for aviation safety. Daytime lightning is unnecessary in some countries as long as the turbines are painted white. • These impacts may be disproportionately experienced by minority or low-income populations, thus resulting in environmental justice issues.
Solar	• During the operation, health and safety risks on workers are limited due to nature of operation activities; the activities will be limited to guarding and on call and\or onsite technical support (Maintenance and cleaning).	• Solar facilities may interfere with existing land uses, such as agricultural uses, cultural uses, military uses, and minerals production. Solar facilities could impact the use of nearby specially designated areas such as wilderness areas, areas of critical environmental concern, or special recreation management areas.

	• Vehicle traffic is not expected to occur during the operation phase due to minimal number of personnel present within the project site. • Positive benefits of the project may arise either from short-term job opportunities during construction, or long-term job opportunities during operation (direct and indirect employment). It is important that construction and operation jobs to be targeted to the local people. Construction and operation of solar facilities, by creating both direct and indirect employment creates income in the regions where the development occurs. • Solar plants have benefits to society since they will provide a clean and pollution free energy, as sun provides a tremendous resource for generating clean and sustainable electricity without large toxic pollution or global warming emissions.	Proper siting decisions can help to avoid land disturbance and land use impacts. • During construction and decommissioning, there will be potential impacts on workers' health and safety due to exposure to risks through construction activities that lead to accidents causing injuries and death. • During the Construction Phase traffic is expected to increase to a certain degree due to the nature of activities that will take place such as the transport of equipment and materials to and from the site through the surrounding road network. • Construction of a solar plant can affect archaeological and cultural resources, therefore studies to avoid building plants on such sites should be done. • These impacts may be disproportionately experienced by minority or low-income populations, thus resulting in environmental justice issues.
Hydro (This section of Hydro social impacts have been extracted from Amaila Falls EISA Update in January 2011)	• Lower Energy Costs. The Project will lower the long-term average cost of wholesale electricity, especially after the initial debt term, by replacing energy from expensive thermal generation units that use imported fuels. Even more, Amaila Falls will help provide the energy necessary for the growth of the country's industrial production and provide a source of reliable, Cle-au and renewable energy that will support the sustainable long-term growth of the national economy. New commercial activities may emerge due to the higher quality and lower cost of energy, increasing the number of available jobs and consequently the national gross domestic product. • Energy Supply for the Future. The Project will be the foundation for meeting Guyana' s future energy needs through the creation of a double- circuit 230-kV transmission network that will form the backbone of a new high voltage transmission system Twenty years after the staff of operations the Hydropower Facility and Electrical Interconnection will be transferred to the Government of Guyana	• Migration into Forested Areas. The potential impact on demographics relates to the opening of a new access road and Improvement of existing roads, which contribute to increased risk of migration into forested areas where income may be generated from extraction activities. • Conflicts with Local Population. The Project may cause tension between out-of-region construction workers and local population. Since most of the employed workers, whether immigrant or local, will be lodged at Project construction camps, with the principal one at the Hydropower Facility, the Project will not create a significant direct demand for housing or urban infrastructure in any nearby communities or cities. However indirect demand from Project suppliers and from any induced population influx may affect living conditions of the existing nearby communities and cause social conflicts.

	at zero additional cost; thereby bequeathing an asset that provides long-term energy Independence, national competitiveness and environmental sustainability to Kiture generations. • Communications Network. The Project transmission line will provide the opportunity to expand Guyana's high-speed communications network using fiber optic technology built into the transmission interconnection. • Economic Stimulus .The Project will help stimulate the economy during construction and beyond, because it provides opportunity for jobs and service providers during construction and a more reliable source of affordable electricity for Guyana's economy. This direct stimulation also provides the basis for creation of secondary and tertiary jobs and economic activity during both construction and operation. • National Economy and Finances. The Project impacts on national economy and finances are all of a positive nature and include: Balance of payments Improvement due to the expected reduction of public expenditures on fuel Imports for thermal power plants, Increased tax revenues due either directly or indirectly to the Project Enhancement of national industry competitiveness, Reduction of long-term energy cost to GPL and consumers, Alleviation of demand for government investment in infrastructure, and enhanced potential for attraction of industrial and other private sector investment. • Reservoir may offer new recreational opportunities and therefore bring income opportunities to communities. • Hydropower produces power cheaply and therefore end-user tariffs will decrease at a higher rate against other power generation technologies. • Hydro power plants are dependable and long-lived, and their maintenance costs are low compared to other power generation technologies.	• Due to the new access road, there is a risk of induced development, especially illegal mining and forestry activities. • The construction of the hydro project will increase the risks to worker health and safety and to accidents in the construction zone, work fronts and service routes.

	• Benefit Local Communities. The Project will include community development programs that include, among other things, assisting communities to prepare for obtaining employment from and providing goods and services to the Project. • Improvements in the national balance of payments will result from reductions in public expenditures for imported fuel for thermoelectric plants, and in imports of components for new thermoelectric plants • Tax revenues for the public sector from taxes on services rendered and goods consumed • Enhancement of national industry competitiveness by more reliable energy because of increased supply, possible tariff reductions, and increased capacity of the public sector to invest m infrastructure • Enhanced potential for attraction of industrial and other private-sector Investment • The new access roads can induce changes in land-use patterns due to increased accessibility.	
Biomass	• Increased productivity of mechanical collection of sugar cane brings increased production (sugar and cogeneration under bagasse) without requiring increased cultivated land, which favors Guysuco's profitability and long term sustainability. • Small cogeneration plants that sell excess energy to DBIS, on average, have better availability factors (about 90% to 95%) than other power generation plants. • Power generation with biomass would result in a substantial reduction in the cost of electricity generation, which would have a large direct benefit for residents and benefit the economy of Guyana. • The infrastructure development needed to build (or expand/connect actual) cogeneration plants using biomass would	• Security hazards for workers from stockpiling of materials during construction. • Landscape aesthetic will be lost due to installation or addition of new equipment and machinery. • Traffic accidents during construction and operation (e.g. transportation of machinery and equipment for plant) affects safety of workers and community. • As with other power plants of any technology, social disruption by immigration likely due to job seekers from neighboring communities in search of employment, business or life opportunities coming up from the Project

	create jobs for residents directly involved in construction and operations, and lead to increased revenues near the areas of development. • Because Guysuco would play a key role in providing energy to DBIS by power generation using biomass, this would contribute to Guysuco's operations. • Efficient combustion systems and gas cleaning in the boiler reduce the impact of unburned particulate matter and health of workers and the surrounding community influence. • Improved productivity through biomass cogeneration of sugar industry and a potential growth of the bioenergy industry, would lead to an increase in revenue and foreign exchange for Guyana that are transformed into better conditions in public services in communities across the country.	• Land vibration is likely impact due to engine combustions and when suspension and machine alignment is poor. • Dust generated in construction and operation (e.g. traffic and other equipment on the site and along the unpaved roads.) may disturb communities and affect air quality to onsite and offsite receptors.
Natural Gas	• Power generation with natural gas would result in a substantial reduction in the cost of electricity generation, which would have a large direct benefit for residents and benefit the economy of Guyana. • The infrastructure development needed for the natural gas industry would create jobs for residents directly involved in construction and operations, and lead to increased revenues near the areas of development. • Because the private sector would play a key role in natural gas infrastructure development, this would contribute to foster development through the private sector. • During the construction phase of operating facilities to generate power with natural gas would have a positive economic impact in the areas where they are built due to increased revenues for governments and local businesses. For example, there would be increased revenue for local and regional businesses for provision of services, such as shipping, barging of construction materials, architects, surveyors, lawyers, real estate agents, engineers, and	• Dangers from the construction of natural gas infrastructure are similar to other large infrastructure projects in the energy sector. Construction hazards for workers include working at heights, in confined spaces, and with heavy equipment. • New development can result in the loss of access to land resources by local populations, and for other economic purposes, even when local land-use policies are followed. Further, there can be loss of aesthetic values that are important to residents and tourists alike. • Social risks from operating the supply chain and power plants for natural gas consist of risks to on-site personnel and risks to the public. Risks to on-site personnel include exposure to oxygen depletion and extreme low-temperature materials. Natural gas leaks could endanger on-site personnel and the public as well as the environment. • Spills of hazardous chemicals that impact groundwater resources and human health

	other professionals. Depending on the project site location, there could also be increased revenue from rental and purchase of housing units for workers during operations. • Over the medium to long term, natural gas will also likely be used to meet other energy needs, such as in transportation and industrial uses. This will also result in cost savings for businesses and residents.	• Fires or explosions from flammable and combustible materials stored on the project site • Loss of habitats or species • Loss of fishery resources which are important as protein and income sources for local populations • Noise pollution • Destruction of cultural and historical resources, such as shipwrecks.

The following are the main conclusions on the social impact obtained from the previous table:

- DBIS generation expansion with Natural Gas, Solar and Wind in the short-medium terms and Hydro in the long term power plants will lower the average electricity generation cost, especially after the initial debt term, by replacing energy from expensive thermal generation units that use imported fuels. On the other hand, reciprocating engines fueled by liquid fossil fuels (HFO and/or LFO) have high power generation costs which are transferred to the final consumer with high end-user electricity tariffs, which affect the competitiveness of industrial and commercial sectors in the economy and affect the income of households.
- Compared to other conventional thermal power plants, coal-fueled power stations have a particularly long supply chain, and thus substantial socioeconomic benefits. The transportation of coal generates substantial economic activity, and leads to ancillary benefits as portions of this infrastructure can serve multiple purposes. However due to its high CO2 emissions and costs this technology has not being considered appropriate for DBIS generation expansion.
- During the construction phase of operating facilities use natural gas would have a positive economic impact in the areas where they are built due to increased revenues for governments and local businesses.
- Mid-size hydro projects, natural gas power plants, wind parks and solar power plants may cause tension between out-of-region construction workers and local population because of noise, landscape, environmental impacts.
- The infrastructure development needed to construct and operate a power plant would create jobs for residents directly involved in construction and operations, and lead to increased revenues near the areas of development.
- Because the private sector would play a key role in wind parks and solar infrastructure development, this would contribute to foster development through the private sector.

11 ACTION PLAN

This chapter presents an Action Plan (including recommendations) for implementing the most favorable power generation expansion program in Guyana obtained in this study. The Action Plan summarizes the main activities that will need to be completed by the Government of Guyana in several areas required for the completion of the optimal expansion program for DBIS.

More specifically, the first section of this chapter summarizes the structure of the Action Plan, which is composed by different areas and tasks, and present a general timeline for its execution. The second section describes each of the Action Plan's areas through their main activities, and proposes which stakeholders should be involved.

This Action Plan is built under the assumption of having availability of 30 mmcfd of natural gas.

11.1 Structure of Action Plan

The Action Plan is divided in twelve (7) areas—Area 1 to Area 7 — and three (3) Actions – Action A to Action C. The 3 Actions are a continuous and evolutionary process in all Stages of the Action Plan due to its regulatory and energy policy nature. In total, there are fourteen (14) tasks, each task representing the development of certain infrastructure (e.g. generation project, transmission line, gas infrastructure) or an action to be taken (e.g. energy efficiency program, regulatory reform). The completion of the 7 areas and 3 actions will result in the development of the recommended generation expansion program in Guyana and therefore commencement of electricity generation using new technologies such as hydro, wind, natural gas and solar, as well as to maintain the existing biomass generation. Existing HFO/LFO power plants would remain as a backup capacity and to provide temporary generation to supply electricity demand. It is important to note that this Action Plan might vary over time, as demand and supply conditions change in Guyana; therefore, continuous updates to such plan should be made internally by an institution selected by the GoG as proposed in Action C. Each phase includes a series of tasks, which in turn each one is explained by some activities that need to be correctly executed in order to complete the task.

The areas and tasks contained in the Action Plan are listed in Table 78 and outlined below, were the column year shows the year at which the project should be completed.

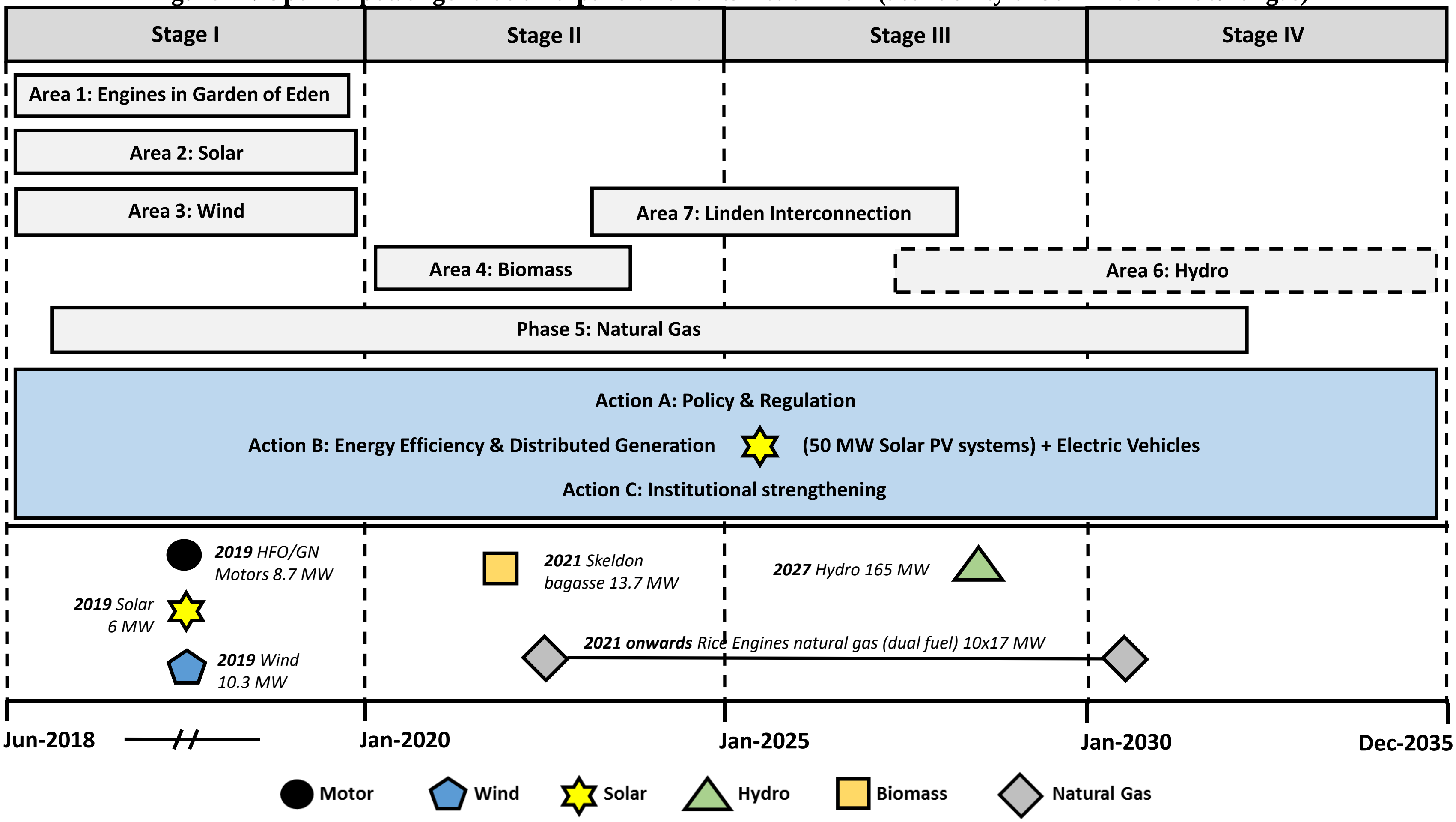
Table 78. Action plan's Areas, Actions and Tasks (availability of 30 mmcfd natural gas)

	Area / Action		Year	Task	Project
1	Engines (Garden of Eden)		2019	Engines HFO	Dual HFO/NG 8.7 MW
2	Solar		2019	Solar project	Solar 6 MW (2x3 MW)
3	Wind		2019	Wind Park	Wind 10.3 MW Hope Beach
4	Biomass		2021	Bagasse	Skeldon 13.7 MW (Plant Refurbishment)
5	Natural Gas	**A**		Natural Gas infrastructure	Natural Gas infrastructure
		B	2021	Natural Gas Rice	NG Rice 170 MW (10x17 MW)
6	Hydro		2027	Mid-size Hydro	Mid-size Hydro 165 MW
7	Linden interconnection		2024	Linden	Linden interconnection to DBIS
A	Policy & Regulation			Regulatory Reforms	Energy policy & Power sector regulation reforms
B	EE, EV & Distributed Generation			EE, EV & Distributed Generation	Energy Efficiency measures, Distributed Generation (50 MW) and Electric Vehicles
C	Institutional strenghtening	**A**		Institutional strengthening	Strengthen GPL
		B		Institutional strengthening	Strengthen GEA

Source: Consultant

For visualization purposes, we split the Action plan into four (4) Stages, the first with a 2 year duration and the remaining with a 5-year duration period – Stage I to Stage IV, starting in year 2018 and ending in year 2035. The Figure 74 shows the optimal power generation expansion plan obtained in this study, the fourteen (14) proposed tasks and its timing. This Action Plan is built under the assumption of having availability of 30 mmcfd of natural gas.

Figure 74. Optimal power generation expansion and its Action Plan (availability of 30 mmcfd of natural gas)



Source: Consultant

As noted in Figure 74, the Action Plan is built around four (4) stages – Stage I to Stage IV, each with different areas to develop. It is important note that there is a great concentration of activities to develop during Stage I (i.e. from 2018 until 2020). For instance, in the next first two years, GPL should build new generation capacity with engines in Garden of Eden and also (mostly via IPPs) with solar and wind. As well, during such Stage, GPL must advance in the expansion of the transmission substations to import electricity from biomass from Skeldon[109], and implement the Energy Efficiency activities and distributed generation to be promoted by GEA (as noted in Action B). Also, during the Stage I, the GoG needs to perform the policy and regulatory recommendation (Action A) and continue with the implementation of Energy Efficiency activities and distributed generation (Action B). Also, in Action B the Government should start the promotion and massive introduction of Electric Vehicles (and CNG Vehicles) in Guyana.

During Stage I of the Action Plan, which goes from 2018 until 2020, the GoG should promote the development of required natural gas infrastructure (natural gas offshore pipeline, compression and LPG separation plants, regulation and institutional arrangements) for power generation and development of the natural gas industry in Guyana.

11.2 Action Plan timeline and activities per Area

As noted above, the Action Plan has 7 Areas and 3 Actions. In this section, the Consultant presents a timeline of each Area. This timeline also describes the main activities for each Task in the Action Plan. Also, the general responsibilities that each of the stakeholders would have are listed, as well as the required interactions and coordination amongst them.

11.2.1 Area 1: Reciprocating Engines

The objective of this Area is to expand GPL's actual generation capacity for DBIS in 8.7 MW with dual fuel reciprocating engines fueled with HFO/Natural Gas in Garden of Eden, as such site has been selected by GPL, which would commence commercial operation in 2019. This unit would be translated in 2023 to the Natural Gas inland site that would be selected for the new gas fired (also dual) power plant. The following subsections describe the main activities to perform in this Area. This task is broken down in four (4) main activities, as follows.

- Create project committee. A Project Committee (PC) is created within GPL with internal employees of different units. The PC manages, coordinates and asks for approval regarding all related matters of the development of the projects.
- Secure funding for, and perform any feasibility study. In this activity, GPL carry out any feasibility study for the new HFO and LFO engines. Specifically it should prepare a technical-economic feasibility study for the selection of the site of the new plant. Securing the resources for the consultants on time is important for allowing a smooth construction of the new capacity.
- Define the capacity and technical specifications. In this activity GPL defines all the final technical details and requirements of the engines to be installed and its connection system to DBIS grid.
- Choose form to build new generation capacity (directly or through an IPP). In this activity GPL chooses how the new power generation capacity will be built, either directly or through an IPP.
- Project structuring. In this activity GPL negotiates and signs all required contractual arrangements such as financial, legal, insurance, environmental, social, commercial, fuel supply, O&M and others in relation to each project.

[109] Provided that at such time Skeldon sugar production has been normalized, which implies that the Government should continue its current efforts to solve the actual circumstances of the sugar industry in Guyana.

- Project construction. In this activity the project is built.

11.2.2 Area 2: Solar

The objective of this Area is to expand GPL's actual generation capacity for DBIS in 6 MW with two utility-scale solar plants, each of 3 MW, to commence commercial operation in 2019[110]. GPL should note that on average, the development of a solar plant takes between 12 and 26 months, therefore this task becomes a priority[111]. For the development of the solar plants, the following are the main activities that should be performed by GPL.

- **Create project committee**. A Project Committee (PC) is created within GPL with internal employees of different units. The PC manages, coordinates and asks for approval regarding all related matters of the development of the project.
- **Secure funding for, and perform any feasibility study**. In this activity, GPL should carry out any pre-feasibility study for the new power plant.
- **Define the exact capacity, locations and technical specifications**. In this activity GPL defines all the final technical details and requirements of the project to be installed and drafts the specifications of the PPA to be signed according to GPL's necessity. At least the following technical specifications should be defined after this activity:
    - Solar resource assessment
    - Evaluation of infrastructure requirements (site location, geotechnical data, environmental issues, water supply etc.)
    - Selection of high potential sites for Solar Power plants (preparation of a list of sites)
    - PV technology inputs
    - PV site selection matrix
    - Plant layout
    - O&M philosophy
    - Investment and O&M cost estimate
    - Grid access studies and costs
    - Environmental assessment considering flora and fauna.
    - Yield estimate (MWh/year)
    - Capacity and availability of the Wind Park
    - Factors affecting yield estimate (module performance depreciation, temperature and climate impacts, soiling)
    - Technical standards that the plant should adopt
- **Obtain environmental licenses**.
- **Preparation of Request of Expressions of Interest (EOIs) and Pre-selection of Bidders**. In this activity, the PC holds conference and meetings, prepare Draft Request for Expressions of Interest, finalize and issue to possible bidders Request for Expressions of Interest for bidders to prepare their EOIs. Finally, PC evaluates EOIs and pre-qualify bidders.
- **Preparation of Request of Proposals (RFPs) and Selection of Preferred Bidder**. In this activity, the PC prepare a Data Room that contains all relevant and available documentation for the bidders.

[110] Note that GPL will also install 3 MW of additional power generation in Essequibo system, not interconnected to DBIS.
[111] Some of the activities may already be done by GPL as there are 3x3 MW of solar plants being studied by GPL (2x3 MW connected to DBIS and 1x3 MW connected to Essequibo area) to commence in 2018, as stated in International Solar Alliance (2018).

Also, in this activity the PC and its advisor prepare and release Draft RFP and term sheets, Release Draft RFP, hold pre-bid meetings and conduct site visits, revise RFP Documents and Issue Final RFP; after bidders submit their bids, the PC evaluates bids and GPL selects preferred bidder that will build the plant.

- **Negotiation of Project Agreements with Preferred Bidder**. Once the preferred bidder (IPP) has been selected, the PC must negotiate any changes in the proposal received by the preferred bidder, award the PPA contract, and oversee the construction of the Project. In this activity, the PC helps to obtain Environmental and Construction permits, develops Draft Project Agreements, and prepares revised agreements. Also, the preferred bidder submits best and final offer, the GPL awards the PPA contract.
- **Power Plant construction**. In this activity the power plant is built and PC oversees the construction of the plant.

11.2.3 Area 3: Wind

The objective of this Area is to expand GPL's actual generation capacity for DBIS in 10.3 MW (possibly Hope Beach) with a wind park to commence commercial operation in 2019. GPL should note that on average, the development of a wind park takes between 20 and 30 months depending on the quality and quantity of the studies performed. The following subsections describe the main activities to perform in this Area.

For the development of the Hope Beach, following main activities should be performed by GPL:

- **Create project committee**. A Project Committee (PC) is created within GPL with internal employees of different units. The PC manages, coordinates and asks for approval regarding all related matters of the development of the project.
- **Secure funding for, and perform any feasibility study**. In this activity, GPL carry out any pre-feasibility study for the new wind power plant.
- **Define the exact capacity and technical specifications**. In this activity GPL defines all the final technical details and requirements of the wind farm to be installed and drafts the specifications of the PPA to be signed according to GPL's necessity. At least the following technical specifications should be defined after this activity:
    - Wind resource assessment (wind resource data and validation, land availability, grid proximity)
    - Wind data analysis and long term correlation
    - Evaluation of infrastructure requirements (site location, access roads, land ownership, geotechnical data, topographic situation, environmental issues, etc.)
    - Environmental studies considering Flora and Fauna (birds, bats, among others), visual impacts and noise
    - Wind Turbine technology inputs
    - Site selection matrix
    - Wind farm layout and optimization, micro-sitting
    - Grid access studies and costs
    - Yield estimate (MWh/year)
    - Capacity and availability of the Wind Park
    - Factors affecting yield estimate (module performance depreciation, temperature and climate impacts, soiling)
    - Technical standards that the plant should adopt

- **Preparation of Request of Expressions of Interest (EOIs) and Pre-selection of Bidders**. In this activity, the PC holds conference and meetings, prepare Draft Request for Expressions of Interest, finalize and issue to possible bidders Request for Expressions of Interest for bidders to prepare their EOIs. Finally, PC evaluates EOIs and pre-qualify bidders.

- **Preparation of Request of Proposals (RFPs) and Selection of Preferred Bidder**. In this activity, the PC prepare a Data Room that contains all relevant and available documentation for the bidders. Also, in this activity the PC and its advisor prepare and release Draft RFP and term sheets, Release Draft RFP, hold pre-bid meetings and conduct site visits, revise RFP Documents and Issue Final RFP; after bidders submit their bids, the PC evaluates bids and GPL selects preferred bidder that will build the plant.
- **Negotiation of Project Agreements with Preferred Bidder**. Once the preferred bidder (IPP) has been selected, the PC must negotiate any changes in the proposal received by the preferred bidder, award the Power Purchase Agreement (PPA) and oversee the construction of the Project. In this activity, the PC helps to obtain Environmental and Construction permits, contributes with grid connection studies, contribute with social arrangements with communities in the vicinity, develops Draft Project Agreements, and prepares revised agreements. Also, the preferred bidder submits best and final offer, the GPL awards the PPA contract.
- **Power Plant construction**. In this activity the power plant is built and PC oversees the construction of the plant.

11.2.4 Area 4: Biomass

The objective of this Area is to expand GPL’s actual generation capacity for DBIS in 13.7 MW with the imports of electricity generated from sugar cane bagasse from Skeldon (13.75 MW to start operation in 2021). At least the following activities should be done in this Area.

- **Expand transmission capacity of Skeldon**. The actual 13 MW capacity of the substation that connects Skeldon with DBIS should be increased to allow additional 13.75 MW of electricity production from biomass (sugar cane bagasse).
- **Perform overhaul of Skeldon production facility**. Skeldon plant should be overhauled and investment should be made in order to allow the production of electricity to DBIS from sugar cane bagasse in excess of its internal consumption.
- **Revise PPA between GPL and the new owner of Skeldon**: The new owner of Skeldon after privatization occurs should agree (ideally before closing the transaction) on exporting electricity from biomass to DBIS according to a revised PPA (which should increase in the capacity to be supplied with the bagasse power plant).

11.2.5 Area 5: Natural gas

11.2.5.1 Task 5A: Natural Gas Infrastructure

During this Area of the Action Plan, it would be required to build the natural gas infrastructure. This includes the selection of the natural gas landing site and the construction of the offshore transportation pipelines and the onshore compression and LPG separation plants. This should be coordinated with the selection of the site for the new natural gas power plant and the onshore connection facility to allow the supply of 30 mmcfd of natural gas for power generation in DBIS by January 2023, including the gas supply contract. This Action Plan is built under the assumption of having availability of 30 mmcfd of natural gas.

The specific activities are still under definition according the agreements being defined by GoG with the oil and gas producer at the moment of this study.

11.2.5.2 Task 5B: Natural Gas reciprocating engines and Connection system

The objective of this Area is to *gradually* (according prospective real demand increase evaluated periodically) expand GPL's actual generation capacity for DBIS in 170 MW with reciprocating (dual fuel) engines fueled with natural gas – dual fuel (10x17 MW) in landing site of the natural gas including its 230 kV (2 circuits) interconnection system to DBIS, which would commence commercial operation in 2021.

According to the optimal expansion required for supplying demand forecasted for the base case, the 230 kV connection would be required in 2021 and the following commissioning itinerary for the new gas fired power units: 2x17 MW in 2021 (operated initially with liquid fuel), 5x17 MW in 2023 (including the gas connection), 2x17 MW in 2024, 1x17 MW in 2025.

This capacity correspond to the exploitation of 30 mmcfd of natural gas for power generation and could be revised according final selection of natural gas availability for power generation. The following are the main activities to perform in this task.

- **Create project committee.** A Project Committee (PC) is created within GPL with internal employees of different units. The PC manages, coordinates and asks for approval regarding all related matters of the development of the projects.
- **Secure funding for, and perform any feasibility study.** In this activity, GPL carry out any feasibility study for the new natural gas (dual fuel) engines. Specifically it should prepare a technical-economic feasibility study for the selection of the site of the new plant. Securing the resources for the consultants on time is important for allowing a smooth construction of the new capacity.
- **Define the exact capacity and technical specifications.** In this activity GPL defines all the final technical details and requirements of the engines to be installed.
- **Choose form to build new generation capacity (directly or through an IPP).** In this activity GPL chooses how the new power generation capacity will be built, either directly or through an IPP.
- **Project structuring.** In this activity GPL negotiates and signs all required contractual arrangements such as financial, legal, insurance, environmental, social, commercial, fuel supply, O&M and others in relation to each project.
- **Project construction.** In this activity the project is built.

11.2.6 Area 6: Mid-size Hydro

The generation expansion also includes 165 MW hydro to commence operation in 2027 (Amaila) with its 230 kV interconnection system to the future SECC1 substation. Given GLP´s current objectives and role related to the future power generation developments in Guyana, which do not includes hydroelectric developments, and its financial limitations, and considering the lessons learned related to the intended development of the Amaila hydroelectric Project in the past, it is foreseen that the development of a hydroelectric project in Guyana would require a Private Sector participation.

A Private Sector Project Preparation of a financeable mid-size hydroelectric project will require striking a balance among the following three components of the project structure:

- **Ownership structure**. The shareholding of the project interest could be purely private, purely public or some combination of both. It should be suited to the nature of the project and also to the ability of various shareholders to contribute to the successful implementation and operation of the corresponding facilities.
- **Financial structure**. The first decision in structuring the financial package is the portion of the project cost that should be funded in the form of equity; the rest will be project debt. For energy

projects, equity varies between 20 and 40% of the project cost. The acceptable equity ratio depends on the creditworthiness of the sponsors, the risks and the location of the project, and

- **Security Package**. Identification, analysis, allocation and mitigation of project risks are essential to structuring a project finance package. These risks are related to events that could endanger the project during development, construction and operation.

The preparation of the project structure may go through several iterations before one can get the right sponsors who will be willing and able to bring in financial resources while providing a comparative advantage in construction and operation.

The Option of Public-Private Partnership (PPP) for Financing Power Projects is a concept that could be applied in this case. It would cover the required long-term contracts between the public and private sectors for construction and operation of the hydroelectric power plant. The required PPP could include the following contractual arrangements:

- Project implementation agreement (concession given by the government to the Project Company and its constitution).
- Project environmental agreement (environmental impact analysis and gestation of the environmental license required for the construction of the project)
- Power purchase agreement (PPA) between the Project Company and GPL.
- Government guarantee of the utility obligations under the PPA.
- Obtain from the Multilateral Investment Guarantee Agency (MIGA) a guarantee for the private investors.
- Equity contribution agreement among the public and private sector.
- Obtain from the International Development Association (IDA- World Bank) of a Partial Risk Guarantee of loan repayment to the commercial lenders.
- Government counter-guarantee of the IDA guarantee
- Individual loan agreements and common terms agreement.
- Obtain through a competitive process of an Engineering Procurement and Construction (EPC) contract to mitigate the risks of construction delay and cost overruns.
- Obtain through a competitive process of an Operation and Maintenance (O&M) contract to mitigate the operational risks

11.2.7 Area 7: Interconnection System

During this Area of the Action Plan, the following activities should be executed in order to build the 230 kV (2 circuits) SECC1-Linden-Georgetown with its first section (Linden-Georgetown) to be commissioned by 2024 in order to connect Linden area to DBIS and the second section (SECC1-Linden) to connect the future Amaila hydro in 2027. This is particular important and its first section should be planned ahead as this implies a change in end-user tariffs due high subsidies that Linden has in relation to DBIS.

- **Sign a Memorandum of Understanding (MOU) between GPL and LECI**. In this activity, the main stakeholders involved in the interconnection of Linden to DBIS, which are GPL and LECI, should sign a MOU in order to agree and state each of their individual actions, and their timing, that need to be implemented in relation with Linden’s interconnection to DBIS. The MOUs will give comfort to the GoG, GEA, GPL and LECI in advancing with all activities in this Area. Further agreement of how LECI and GPL would operate after the interconnection is done need to be set in the MOU.

- **Hire a technical, regulatory and commercial study for end-user tariffs**. In this activity the GoG, GPL and LECI will hire a technical study on how to integrate the different end-user tariffs of LECI and DBIS. As well, the study will define final tariff levels for each end-user in the residential, commercial and industrial sector. As well, a timing and strategy to unify such tariffs will be defined in the study. Finally, the study will propose an implementation plan with DBIS and Linden related communities. All stakeholders (GoG, GEA, GPL and LECI) give feedback and approve the implementation plan and its timing.
- **Execute tariff implementation plan**. In this activity, GPL and LECI execute the different actions that were proposed and approved in the implementation plan.
- **Design the Transmission line**. In this activity, GPL contracts the required environmental and technical studies related to the transmission line that will connect Linden to DBIS. Consideration of the prefeasibility studies of Arco Norte system includes this line and it would be convenient to maintain the basic characteristics as a part of such system.
- **Built the Transmission line by sections (first section to be commissioned in 2024 and second section in 2027).** In this activity, GPL contracts the supply and installation of the transmission line and associated substations to be commissioned by sections in 2024 and 2027.

11.2.8 Action A: Policy and regulatory reforms

This Action is broken down in the following activities that will result in the improvement of the functionality of existing energy policy and regulatory bodies to promote the implementation of renewable energy and energy efficiency, as explained in the regulatory chapter of this study.

- **Energy Policy Update**. Policy review and development of a baseline report and draft policy paper for a revised National Energy Policy for Guyana, taking into account the recommendations of the policy and regulatory chapter of the present study.
- **Elaboration and adoption of an Energy Efficiency Plan framed in the Updated Energy Policy**. GEA shall structure and adopt an Energy Efficiency Plan that defines objectives, goals, responsibilities, resources and schedule in order to promote the EE objectives outlined in the GEA's Strategic Plan.
- **Institutional organization of natural gas sector**. Propose and develop the legal reforms required to establish an institutional and regulatory framework for the oil and gas sector that includes the Ministry of Infrastructure, the Guyana Energy Agency, the Audit Office of Guyana (AOG), Guyana Revenue Authority (GRA), and the Ministry of Finance. This reform should also establish a new body to regulate the oil and gas sector and a new directorate for petroleum in the Ministry of Public Infrastructure to provide policy guidance and licensing for the upstream, midstream and downstream aspects of the Oil & Gas chain. A match with current role and functions of GEA related to the Oil & Gas sector should also considered in this reform.
- **Regulation of natural gas market.** This activity would require the support of appropriate consultancy to develop a regulatory framework for the natural gas market in Guyana considering the activities of natural gas production, transportation, distribution and consumption (in power generation and other uses) for Guyana. Standards contracts for natural gas supply and transportation should be included in this regulatory framework as well as natural gas prices formation for gas supply and charges for natural gas transportation and distribution.

11.2.9 Action B: Energy Efficiency, Distributed Generation and Electric Vehicles

11.2.9.1 Energy Efficiency Measures

Guyana has advanced in Energy Efficiency measures and has gained through GEA a considerable understanding of the benefits and importance of implementing appropriate EE measures; however, Energy Efficiency measures is a continuous process in which constantly the Government should provide incentives for the demand side to reduce its power consumption.

This Action is broken down in the following activities that will result in the continuous implementation of EE practices, standards and technologies in Guyana in order to obtain the energy and financial savings quantified in the EE chapter of this study.

- **Electricity consumption surveys.** Perform complete and adequate electricity consumption surveys to gain exact understanding of electricity consumption patterns in Guyana (Residential, Commercial, Industrial clients in DBIS). The findings of these results would become a valuable resource to design and prioritize EE measures.
- **Develop minimum energy efficiency standards and energy labelling**. Minimum standards of energy efficiency implemented through a legal and regulatory framework provide a good stick for progressing energy efficiency across the entire Guyana economy. These standards could be promoted through the East Caribbean Energy Labelling Project (ECELP).
- **Perform demonstrator Projects**. Demonstrator Projects are an effective means of raising the profile of electrical energy efficiency. These projects are often best developed initially through the public sector. Guyana already has some good examples: The new wing of Georgetown Hospital, Energy efficiency work which GEA has done in schools and other sectors, and in the private sector STARR Computers initiative to implement 7 kW of photovoltaic cells on their roofs. However, these projects need promoting and extending with appropriate interpretation materials so that all stakeholders including the general public are aware of them and able to learn from them.
- **Execute adequate EE training**. Training energy professionals is an essential part of progressing an energy efficiency programme. This can be done on a regular basis utilizing existing networks such as REETA, but also more formal training promoted through bursaries can help to build capacity within Guyana to deliver energy efficiency projects.
- **Promote shared value and innovative financing**. Shared value models can help promote energy efficiency measures by for example offering cash-back on energy efficient devices or working with retailers and manufacturers to reduce the cost of energy efficient devices. Some energy efficient technologies are already tax exempt, but this list should be reviewed on a regular basis to ensure that all appropriate technologies are captured. This is particularly important in Guyana and the Caribbean and Latin America in general where there is little access to cheap finance. Structured finance is critical. The ideal would be to take the financial question outside of the hands of the consumer so that the energy efficiency option is not only the best option but also the cheapest, but this is best done through a large programme so that the risks of measures under-delivering predicted savings can be mitigated. Programmes are also a good way for the burgeoning Guyana energy efficiency industry to learn by doing. A programmatic approach also offers the possibility of cheaper finance or levering in carbon funds. The shared value model often is best delivered through a service model approach which focuses on delivering the services which electricity can provide rather than selling units of electricity.
- **Bring in the private and not-for profit sectors**. The public sector cannot deliver an energy efficiency programme alone. It is important to work with the private sector so that they can help to innovate new business models. The not-for-profit sector also has its role to play because often they can identify end-user needs that would not usually be attractive to the private sector or seen by the

public sector. The best projects are often delivered through a combination of public, private and not-for-profit sectors working in collaboration.

- **Develop building codes.** A large percentage (typically two-thirds) of electrical energy use is in buildings. Extending buildings codes to cover energy efficiency and looking at opportunities to develop retrofit building codes is a very positive step towards reducing electricity and other energy use in buildings.
- **Perform partnering with international EE institutions**. Guyana already has a burgeoning relationship with The Energy and Resources Institute of India (TERI) but it should also look to foster relationships further afield. It should work more closely through REETA with other CARICOM nations to promote energy efficiency, a relationship which could be particularly useful when it comes to procuring energy efficient goods and services in a CARICOM level programme. It should also look to foster relationships with developed countries both from a financing, training, technology and delivery perspective.
- **Execute large scale EE programmes** can be of principally two types: programmes geared towards the few large energy users in Guyana which have specific electricity challenges for which specific professional expertise is needed; More general programmes for small energy users who share similar issues but for whom investment in an energy efficiency programme needs to be made relatively simple in order to be able to participate. These programmes need to be resourced, managed and monitored and with specific goals in mind in terms of energy efficiency savings in order to be effective.
- **Create a technology hub**. Technologies do have an important role to play in electrical energy efficiency. Technologies are developing rapidly. For example energy storage can be an important part of any future energy system and there are new storage technologies being developed for solar and wind: at both the small scale and utility scale. At small scale, companies like SMA and TESLA are offering integrated grid-tied inverters with battery storage included. Technology innovation is important not just for delivering energy efficiency but also distributed generation and facilitative technologies such as smart grids. Care should also be given to how energy using devices are recovered since there is the possibility that some energy-inefficient devices could be re-utilized by secondary users who cannot afford to buy a new device.
- **Create fiscal incentives for EE friendly technology**. Technologies that comply with Energy Efficiency standards are appropriate to reduce import tariffs and VAT to motivate their usage. It is appropriate that communication and coordination between GoG institutions (e.g. Ministry, GEA and IRA) is established to coordinate.

11.2.10 Distributed Generation

The objective of this Action is to gradually reach 50 MW of distributed generation penetration (mostly Solar PV systems, but also distributed wind, from commercial and industrial clients as well as large communities) by 2035. As well, another objective of this Action is to gradually reach more than 10,000 solar hot water systems by 2035. Appendix B includes our recommendations on policy and regulations for distributed generation. At this respect it would be convenient to update the existing regulations and grid code and provide promotion and implementation of distributed generation. It would be recommended to develop initiatives that cover technical aspects related to the connection to the grid, legal and contractual issues for the relation distributor-customer and distributed generation operator, and economic /tributary incentives for its promotion, Also the regulation of technical aspects, as limits required for maximum power of injection to the grid and maximum contracted power with the local distributor are required. In this area feed in and backup tariffs should be also regulated.

11.2.11 Electric and CNG Vehicles

The objective of this Action is to gradually reach 5,100 Electric Vehicles (and also another 10,800 CNG vehicles) in Guyana by 2035 and starting in 2024, when electricity tariffs to end users would decrease as a result of lower cost power generation. The following activities should be performed in this Action.

- **Technology introduction and testing.** The Government of Guyana through GEA should promote EV technology via information dissemination nationwide as well as public tests. Encourage the adoption of electric vehicles through education and awareness. Demonstration should include cars, light commercial vehicles and trucks.
- **Infrastructure requirements**. Investigate the infrastructure needs to support customer ownership of electric vehicles (EVs), as well as the grid integration requirements and standards. This will include investigations into the EV charging infrastructure, installation standards, and EV building codes. Investigations will also be undertaken of the training requirement of technical personnel;
- **Design the necessary Government incentives to promote the introduction of EVs.** This activity includes the reduction of import tariffs and VAT charges for EVs and its related equipment, promote private investment in the construction of charging stations, design of community and commercial building codes to include EV charging stations, amongst others.
- **Build public infrastructure to support the charging of EV.** The Government will facilitate the private sector in the procurement of a number of electric vehicles and charging station to demonstrate the feasibility of these vehicles to the general public. and
- **EV charging stations**. Promote and build the private infrastructure for residential, industrial and commercial EV charging.
- **Financial incentives**. Design financial incentives (e.g. private financing) for final users to migrate to EV.
- **Grid requirements**. GPL should build a connection guide in order to correctly install private charges in residences.

For CNG Vehicles the following activities should be done.

- **Technology introduction and testing.** The Government of Guyana through GEA should promote EV technology via information dissemination nationwide as well as public tests.
- Analyze and regulate the natural gas price of CNG vehicles.
- Build the public / private infrastructure to transport natural gas to CNG stations.
- Design the necessary Government incentives to promote the introduction of CNG vehicles.
- Build public infrastructure to support the operation of CNG vehicles. Public charges
- Design financial incentives for final users to migrate to CNG vehicles. The private sector should be incentivized to participate in the conversion toward CNG of the actual vehicle fleet. Special attention should be done in public transportation, industries and public in general.

11.2.12 Action C: Institutional strengthening

The objective of this Action is to build new capabilities and functions, or strengthen some of their existing ones, on GPL and GEA. The result institutions after correctly implementing the activities proposed in this Action will prepare such institutions to correctly execute the proposed optimal generation expansion program, which demands internal experience and expertise from such institutions. The following subsections describe the main activities to perform in this Action.

11.2.12.1 Task C.A: Strengthen GPL

Action C.A is broken down in different activities that will result in the strengthening the operations, procedures, administrative infrastructure and expertise of GPL. The following are the main activities to perform in this task.

- **Strengthen power generation personnel**. The optimal generation expansion program involves a high degree of complexity as it recommends the construction of different power generation technologies to the one GPL has worked with; therefore, internal expertise capable to manage such expansion program in an efficient and cost effective way should be correctly formed, promoted, and compensated by GPL. Such personnel would be responsible of all related matters of power generation within the company, including the structuring and contracting of IPPs that would built the expansion of the power system in Guyana. GPL should provide all facilities and tools for such team to make the correct decisions in the right timing in order to reach successful completion of the Action Plan.
- **Invest on IT to guarantee data readiness**. Fast access to updated and reliable detailed data about all GPL's operations in an electronic way is a requirement for correct decision making and correct execution of day to day operations. In this activity GPL should design and execute an improvement on its databases, IT system and models in order to gathering historical and actual data in an efficient way sustainable in the long term. This would benefit not only the power generation units of GPL, but will benefit the entire company.
- **Creation of an internal planning unit to improve energy planning capabilities**. GPL should acquire and develop models, tools and procedures to generate a credible D&E program in which GPL's administration performance will be evaluated. The planning unit, formed with technical and financial personnel, would not participate on day-to-day operations, but rather would focus on medium and long term planning of the company. Such unit would be responsible to maintain financial models for correct decision making, evaluate capital and operational expenditures on a value creation way, develop and measure the D&E program, perform all forecasting exercises required by the company, and other related matters.
- **Acquire best practices on transmission losses reduction activities**. Reduction of total losses is particular relevant for GPL to generate internal cash resources and to eventually reach a sustainable break-even and profit in its balance sheet. As well, reduction of losses at the level forecasted in this study (17% in 2035) is imperative for the correct execution of energy efficiency measures in Guyana. In this activity, GPL's personnel, institutional procedures, IT, and related matters are strengthened by acquiring and maintaining the best practices available in the market to reach long term losses' reduction targets.

11.2.12.2 Task C.B: Strengthen GEA

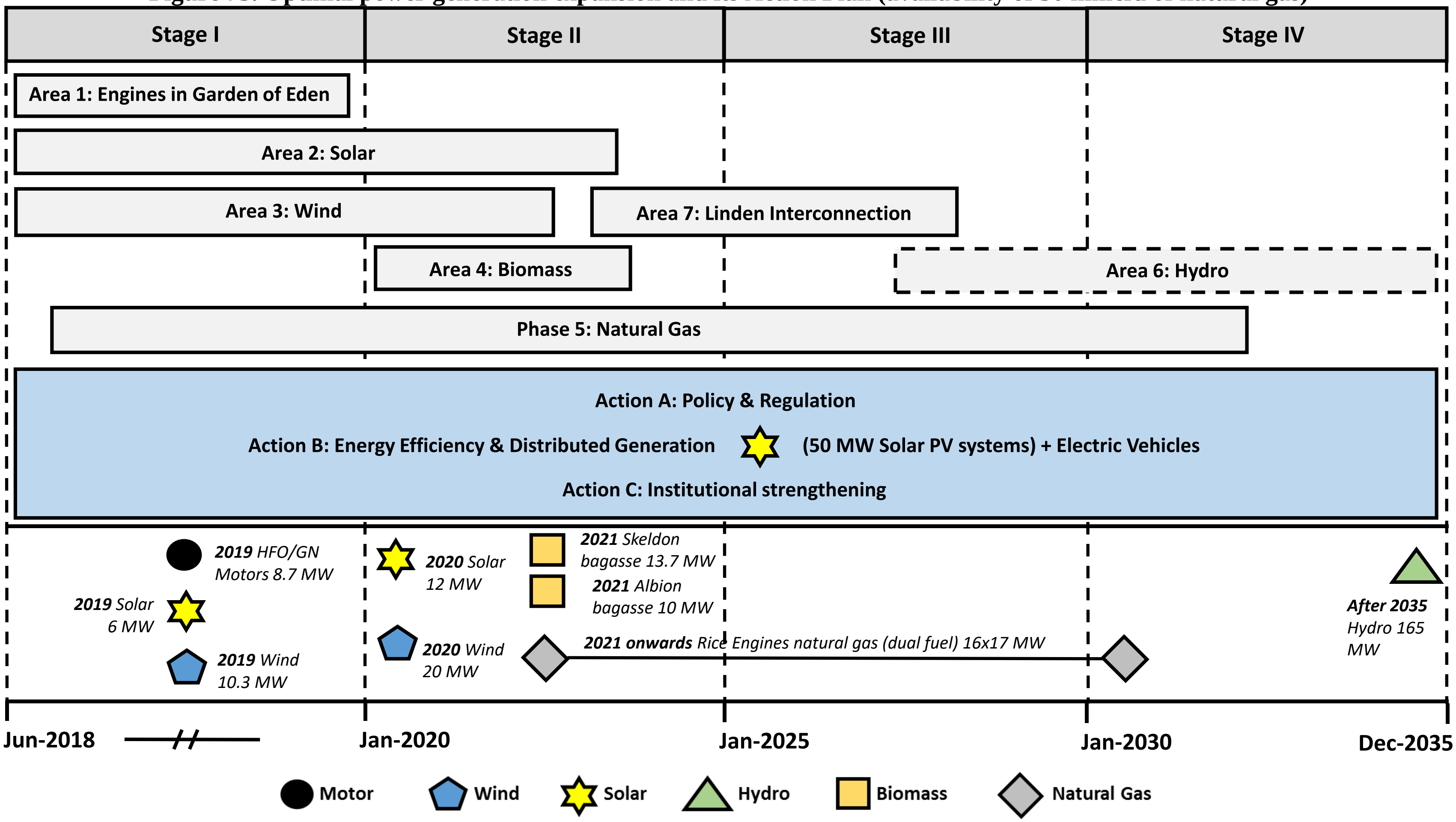
Action C.B is broken down in activities that will result in the strengthening the operations, procedures, administrative infrastructure and expertise of GEA The following are the main activities to perform in this task.

- **Create energy planning unit with adequate IT models**. In this activity an energy planning unit (EPU) within GEA would be created. The EPU main responsibilities would be to make the long term planning of the electricity sector with supply diagnostics and evaluations, demand forecasting, annual generation and transmission expansion plans built using simulation packages for this purposes, and other related matters in order to adequately guide Guyana's power sector expansion.
- **Create Energy Efficiency unit to promote and develop EE practices in Guyana**. This unit main responsibilities would be to implement the activities stated above of Action 9.

11.3 Sensitivity: Natural gas availability of 50 mmcfd

As a sensitivity, Figure 75 shows the optimal power generation expansion plan with its fourteen (14) proposed tasks if natural gas availability for power generation is increased from 30 mmcfd to 50 mmcfd.

Figure 75. Optimal power generation expansion and its Action Plan (availability of 50 mmcfd of natural gas)



Source: Consultant

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Appendix A . World Bank & IMF GDP growth forecasts for Guyana

Appendix Figure A-1 shows the available GDP growth forecast for Guyana published the World Bank (IBRD/IDA) until 2020.

Appendix Figure A-1. World Bank GDP growth forecast of Guyana

THE WORLD BANK IBRD • IDA | Global Economic Prospects | OVERVIEW | GLOBAL OUTLOOK | REGIONAL OUTLOOKS | TOPICAL ISSUES | DATA | DOWNLOADS

Latin America and the Caribbean

(Real GDP growth at market prices in percent, unless indicated otherwise)

REGIONAL FORECASTS | COUNTRY FORECASTS

GDP growth[1]	2015	2016	2017e	2018f	2019f	2020f
Guyana	3.1	3.4	2.9	3.8	3.7	3.7

Source: World Bank IBRD IDA data available at http://www.worldbank.org/en/publication/global-economic-prospects#data (last access in March 14, 2018)

Appendix Figure A-2 shows the GDP forecasts of Guyana published by the International Monetary Fund ("IMF") until 2022.

Appendix Figure A-2.IMF GDP forecast of Guyana

INTERNATIONAL MONETARY FUND

IMF Country Report No. 17/175

GUYANA

June 2017

2017 ARTICLE IV CONSULTATION—PRESS RELEASE; STAFF REPORT; AND STATEMENT BY THE EXECUTIVE DIRECTOR FOR GUYANA

Table 7. Guyana: Medium-Term Macroeconomic Framework

				Est.	Projections					
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	(Annual percent change)									
Production and prices										
Real GDP	5.2	3.8	3.1	3.3	3.5	3.6	3.7	38.5	28.5	2.8
Non-oil real GDP	5.2	3.8	3.1	3.3	3.5	3.6	3.7	3.7	3.9	3.9
Consumer prices (average)	1.9	0.7	-0.9	0.8	2.3	2.7	2.9	3.1	3.1	3.1
Consumer prices (end of period)	0.9	1.2	-1.8	1.5	2.6	2.7	3.0	3.1	3.1	3.1
Terms of trade	-4.5	-3.0	22.6	7.5	-7.8	-0.2	1.5	0.8	0.2	0.2

Source: International Monetary Fund, IMF Country report No. 17/175, June 2017, https://www.imf.org/en/Publications/CR/Issues/2017/06/28/Guyana-2017-Article-IV-Consultation-Press-Release-Staff-Report-and-Statement-by-the-45010 (last access in March 14, 2018)

Appendix B . GPL's sales regression models output

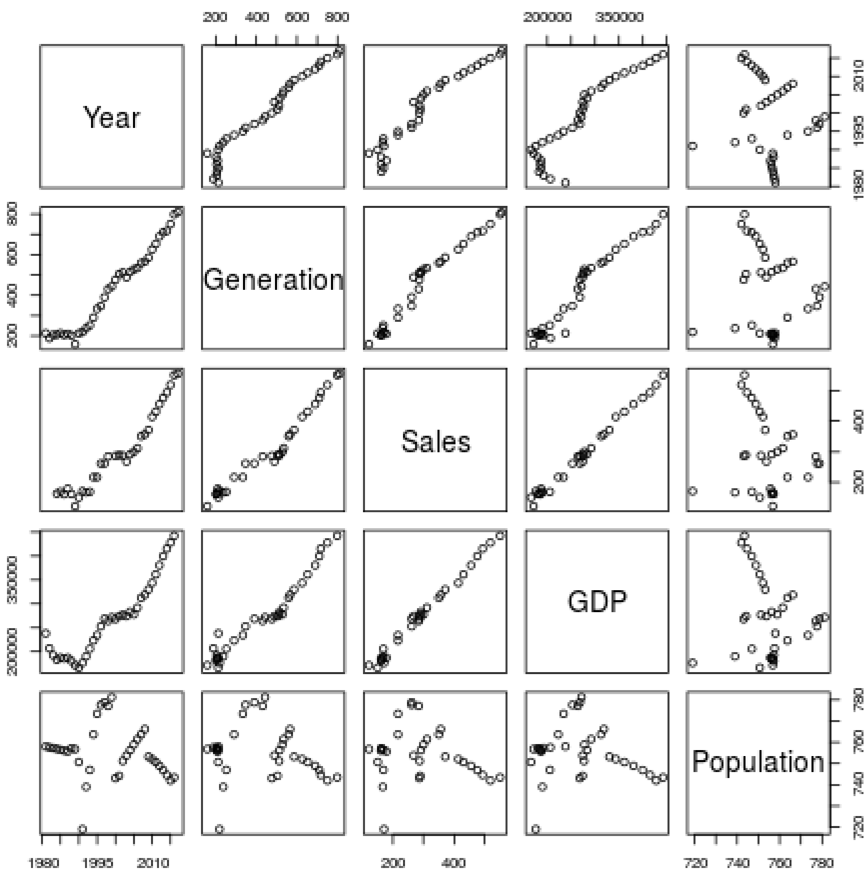
This appendix shows the results of different statistical models which were obtained using the R statistical package.

Appendix Figure B-1. Summary Statistics of data

```
      Year        Generation        Sales            GDP
 Min.   :1981   Min.   :159.1   Min.   :121.6   Min.   :166332
 1st Qu.:1990   1st Qu.:213.2   1st Qu.:171.0   1st Qu.:192051
 Median :1999   Median :443.2   Median :287.2   Median :268346
 Mean   :1999   Mean   :432.1   Mean   :298.9   Mean   :268459
 3rd Qu.:2008   3rd Qu.:566.0   3rd Qu.:370.3   3rd Qu.:314005
 Max.   :2017   Max.   :809.4   Max.   :555.3   Max.   :442254
                                NA's   :4       NA's   :1
```

Source: Consultant

Appendix Figure B-2. Data series plot



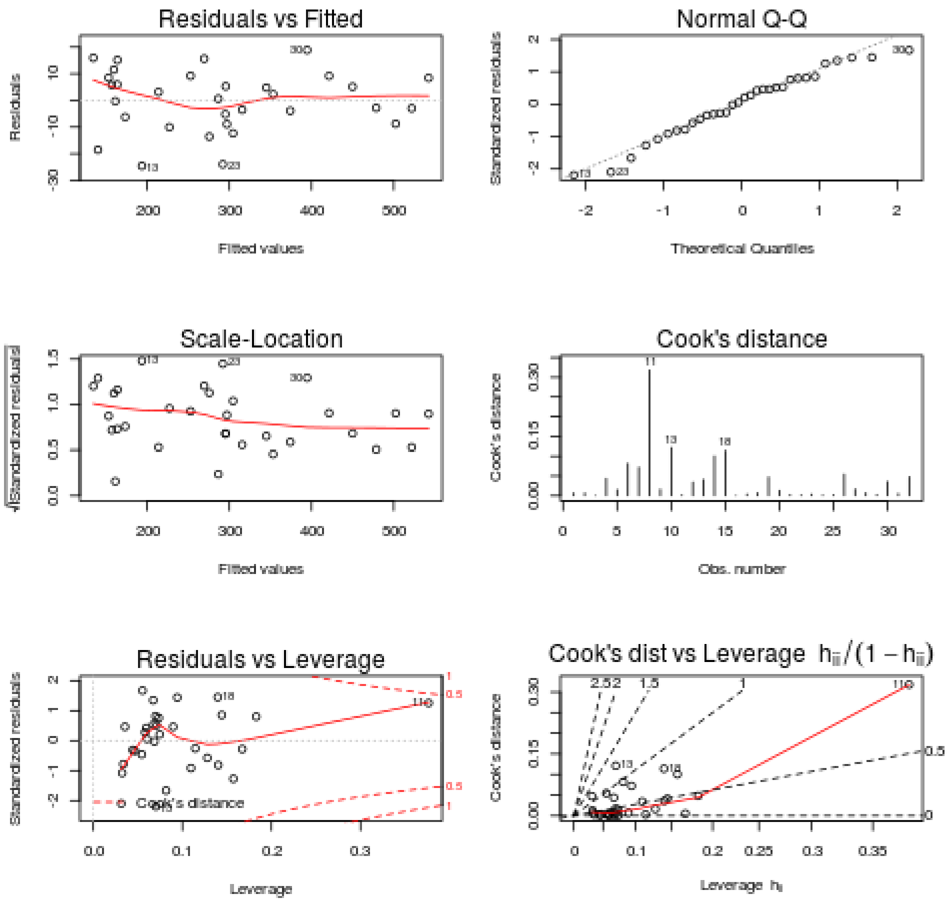
Source: Consultant

Appendix Figure B-3. Results of model: Sales ~ (GDP, Population)

```
Call:
lm(formula = Sales ~ GDP + Population, data = mdata)

Residuals:
    Min      1Q  Median      3Q     Max
-24.554  -6.861   1.476   8.442  18.874

Coefficients:
              Estimate Std. Error t value Pr(>|t|)
(Intercept)  1.366e+02  1.299e+02   1.052   0.3016
GDP          1.470e-03  2.574e-05  57.115   <2e-16 ***
Population  -3.286e-01  1.707e-01  -1.925   0.0641 .
---
Signif. codes:  0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1

Residual standard error: 11.61 on 29 degrees of freedom
  (5 observations deleted due to missingness)
Multiple R-squared:  0.9914,     Adjusted R-squared:  0.9908
F-statistic:  1670 on 2 and 29 DF,  p-value: < 2.2e-16
```

Source: Consultant

Appendix Figure B-4. Residual's plots for model: Sales ~ (GDP, Population)



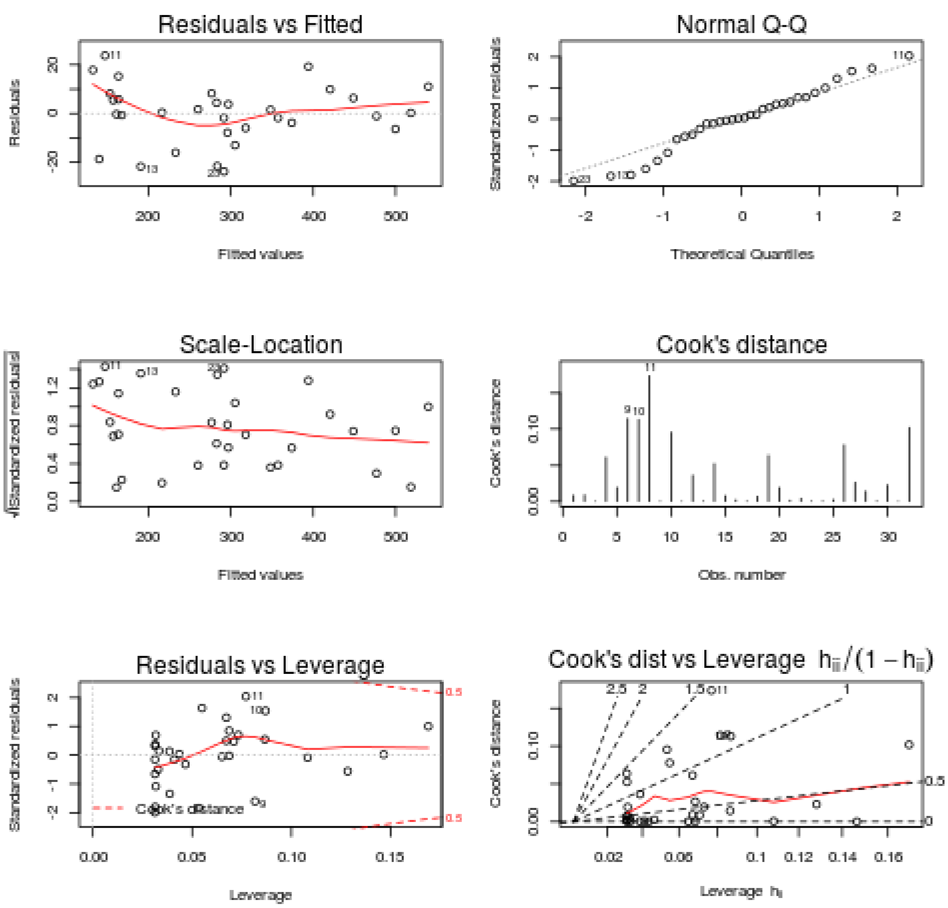
Source: Consultant

Appendix Figure B-5. Results of model: Sales ~ GDP

```
Call:
lm(formula = Sales ~ GDP, data = mdata)

Residuals:
     Min       1Q   Median       3Q      Max
-23.7113  -5.9986   0.3585   6.8220  23.7611

Coefficients:
              Estimate Std. Error t value Pr(>|t|)
(Intercept) -1.130e+02  7.609e+00  -14.85  2.3e-15 ***
GDP          1.476e-03  2.668e-05   55.32  < 2e-16 ***
---
Signif. codes:  0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1

Residual standard error: 12.13 on 30 degrees of freedom
  (5 observations deleted due to missingness)
Multiple R-squared:  0.9903,    Adjusted R-squared:   0.99
F-statistic:  3060 on 1 and 30 DF,  p-value: < 2.2e-16
```

Source: Consultant

Appendix Figure B-6. Residuals' plots of model: Sales ~ GDP



Source: Consultant

Appendix Table B-1. Sales historical data and forecast (GWh/year)

	SALES_High_Case	SALES_Base_Case	SALES_Low_Case	SALES_Base_Case_Delayed
1981				
1982				
1983				
1984	162.7	162.7	162.7	162.7
1985	169.5	169.5	169.5	169.5
1986	160.9	160.9	160.9	160.9
1987	178.9	178.9	178.9	178.9
1988	161.6	161.6	161.6	161.6
1989	121.6	121.6	121.6	121.6
1990	150.4	150.4	150.4	150.4
1991	171.0	171.0	171.0	171.0
1992	167.0	167.0	167.0	167.0
1993	169.0	169.0	169.0	169.0
1994	217.0	217.0	217.0	217.0
1995	217.0	217.0	217.0	217.0
1996	262.0	262.0	262.0	262.0
1997	262.0	262.0	262.0	262.0
1998	285.0	285.0	285.0	285.0
1999				
2000	287.2	287.2	287.2	287.2
2001	289.9	289.9	289.9	289.9
2002	288.1	288.1	288.1	288.1
2003	268.1	268.1	268.1	268.1
2004	292.2	292.2	292.2	292.2
2005	300.8	300.8	300.8	300.8
2006	312.1	312.1	312.1	312.1
2007	349.8	349.8	349.8	349.8
2008	355.6	355.6	355.6	355.6
2009	370.3	370.3	370.3	370.3
2010	413.5	413.5	413.5	413.5
2011	430.5	430.5	430.5	430.5
2012	455.1	455.1	455.1	455.1
2013	475.9	475.9	475.9	475.9
2014	493.6	493.6	493.6	493.6
2015	518.9	518.9	518.9	518.9
2016	550.9	550.9	550.9	550.9
2017	555.3	555.3	555.3	555.3
2018	584.2	581.4	578.1	581.4
2019	609.9	607.1	603.7	607.1
2020	888.3	884.3	630.2	633.7
2021	1,173.6	1,168.5	659.2	662.8
2022	1,245.7	1,204.4	689.3	693.1
2023	1,296.6	1,220.8	699.4	814.0
2024	1,349.5	1,237.5	709.5	906.7
2025	1,404.3	1,254.4	719.8	1,008.6
2026	1,461.2	1,271.5	730.2	1,120.8
2027	1,569.8	1,303.3	749.6	1,244.2
2028	1,632.9	1,321.0	760.4	1,321.0
2029	1,698.4	1,339.0	771.3	1,339.0
2030	1,766.3	1,357.1	782.4	1,357.1
2031	1,836.8	1,375.5	793.6	1,375.5
2032	1,909.9	1,394.1	804.9	1,394.1
2033	1,985.8	1,412.9	816.4	1,412.9
2034	2,064.5	1,432.0	828.0	1,432.0
2035	2,146.2	1,451.3	839.7	1,451.3

Source: Consultant

Appendix C . Sales, energy and customers of GPL (2004-2017)

Appendix Table B-1. Sales historical data and forecast (GWh/year)Sales, energy and customers of GPL (2004-2017)

Details	Units	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Customers Total (No.)	**No.**	**126,858**	**127,076**	**129,888**	**137,721**	**142,439**	**147,035**	**151,288**	**161,396**	**166,878**	**172,873**	**177,780**	**182,704**	**183,013**	**188,664**
Residential	No.	115,611	116,039	118,082	125,805	130,399	133,397	137,513	146,620	151,480	157,064	162,028	166,504	166,130	171,577
Commercial	No.	10,863	10,628	11,357	11,344	11,439	13,041	13,166	14,241	14,817	15,176	15,047	15,457	16,136	16,361
Industrial	No.	384	409	449	572	601	597	609	561	581	633	705	743	747	726
Net Sales-Total (G$000)	**G $000**	**14,883,450**	**16,458,737**	**17,741,546**	**19,860,645**	**22,978,176**	**23,972,759**	**26,567,288**	**27,532,838**	**29,028,087**	**30,639,951**	**31,790,878**	**30,042,915**	**28,969,490**	**28,569,162**
Residential	G $000	6,438,535	7,262,867	7,309,160	8,040,737	8,785,358	9,383,848	10,422,944	10,963,968	11,520,441	12,436,945	13,302,239	12,281,238	11,865,789	11,698,222
Commercial	G $000	3,236,292	3,640,619	4,144,604	4,528,330	4,989,806	5,135,778	5,661,059	5,605,065	5,991,806	6,225,817	6,295,427	5,981,371	5,913,226	5,933,953
Industrial	G $000	5,208,623	5,555,251	6,287,782	7,291,578	9,203,012	9,453,133	10,463,284	10,963,805	11,515,839	11,977,188	12,193,211	11,780,305	11,190,475	10,936,987
Sales Total (MWh)	**MWh**	**292,160**	**301,139**	**314,102**	**350,922**	**355,882**	**370,310**	**413,545**	**430,457**	**455,092**	**475,875**	**493,592**	**518,878**	**550,894**	**555,308**
Residential	MWh	139,830	145,788	142,459	155,581	160,364	166,335	185,067	195,085	205,934	218,074	231,242	244,163	258,984	262,446
Commercial	MWh	55,205	59,024	64,371	70,345	64,827	66,800	75,083	74,344	79,797	82,024	84,802	87,262	95,505	97,288
Industrial	MWh	97,125	96,327	107,272	124,996	130,691	137,175	153,394	161,028	169,361	175,778	177,548	187,454	196,404	195,574

Residential	KWh/No - month	101	105	101	103	102	104	112	111	113	116	119	122	130	127
Commercial	KWh/No - month	423	463	472	517	472	427	475	435	449	450	470	470	493	496
Industrial	KWh/No - month	21,077	19,627	19,909	18,210	18,121	19,148	20,990	23,920	24,292	23,141	20,987	21,024	21,910	22,449

Source: GPL

CAGR (2017/2004) Residential = (127/101)^(1/13)-1 = 1. 8%

Appendix D . Information of self-generators' installed capacity in Guyana

Name of Company	Installed Capacity (kVA) 2010	Percentage (%) of Installed Capacity	Installed Capacity (kVA) 2016	Percentage (%) of Installed Capacity
Demerara Distilleries Ltd.	8,150	13.95	5,625	7.34
Prittipaul Investments	5,010	8.57	5,010	6.54
Noble House	4,625	7.91	6,125	7.99
Banks DIH	4,194	7.18	13,250	17.29
Caribbean Containers Ltd	4,050	6.93	2,860	3.73
Guyana Stockfeeds Ltd.	3,920	6.71	3,920	5.12
BEV Enterprise	3,100	5.31	3,100	4.05
Guyana Quality Sea Foods	3,000	5.13	3,000	3.92
Sterling Products Ltd	2,956	5.06	2,956	3.86
Barama	2,588	4.43	2,588	3.38
Pegasus Hotel	2,013	3.44	2,013	2.63
Edward Beharry & Co Ltd	1,890	3.23	1,890	2.47
Buddy's Princess Hotel	1,876	3.21	1,876	2.45
Continental Industries	1,300	2.22	1,375	1.79
E.C. Viera Investments	1,290	2.21	1,290	1.68
BM Enterprise	1,025	1.75	1,025	1.34
Demerara Oxygen	1,000	1.71	1,000	1.31
Guyana Furniture Manufacturing	965	1.65	965	1.26
Precision Woodworking	890	1.52	-	0.00
John Fernandes Ltd.	750	1.28	750	0.98
Trinidad Cement Ltd. (TCL)	622	1.06	622	0.81
Industrial Fabrication Ltd.	500	0.86	500	0.65
Giftland Office Max	464	0.79	8,375	10.93
Triple Star Enterprises	360	0.62	360	0.47
Parika Sawmills	313	0.54	313	0.41
Popeyes Restaurant	300	0.51	600	0.78
Caribbean Aviation Maintenance Services	169	0.29	-	0.00
BASIF	165	0.28	165	0.22
ECI	160	0.27	250	0.33
Marlin Inc.	160	0.27	160	0.21
Technical Services Inc.	150	0.26	150	0.20
Supra International Inc.	150	0.26	150	0.20
Single Seafood	140	0.24	150	0.20
Loring Laboratories	75	0.13	-	0.00
Namilco	60	0.1	2,590	3.38
khemharshan Babulal			350	0.46
Germans Restaurant	55	0.09	55	0.07
Burma Mahaicony E.C.D			900	1.17
Don Robin Rice Mill			305	0.40
TOTALS: KVA	**58,434**	**100**	**76,612**	**100**
Total : MW	**47**		**61**	

Source: GPL

Appendix E . EE technologies and measures

E.1 Motors

GPGSEP estimated that 27% of all electricity used on the DBIS system between 2015 and 2035 will be used to power motor-driven motors. For the analysis of motors three key electrical energy savings measures were examined:

- **M1: Energy efficient motors.** Motors come in a range of efficiencies. These efficiencies have been standardized around three standards: IE1 (low efficiency), IE2 (better efficient), IE3 (best efficiency). The analysis examined the benefits and costs of choosing IE1, IE2 and IE3. IE1 (the least efficient) was chosen as the baseline assumption.
- **M2: Variable speed drives.** Variable speed drives are drives which are able to vary their speed by altering the voltage and frequency applied to their motors. This means that the motors do not always operate at their nominal power rating but may operate on average at a much lower power rating. The variable speed drives draw a little power themselves and so should only be used in situations where the mechanical power output of the motor varies during operation. For examining variable speed drives the baseline assumption is that an IE3 (most efficient) motor has already been implemented. This is because it is assumed that an IE3 motor would normally be implemented first before a variable speed drive. For the purposes of modelling the impact of implementing a variable speed drive is seen as a reduction in the number of hours of usage of a motor each year at the nominal power rating of the motor although in reality the motor may run continuously but at different power consumptions due to running at different speeds.
- **M3: Cost optimization of pumped systems.** Motors at the industrial scale are often used in pumped systems where their function is to pump fluids from one location to another around an industrial plant. The pumping energy required is primarily used to overcome the friction in the pipes. This friction can be reduced by increasing the size of the pipes for two reasons: larger pipes will convey the same volume of fluid at a lower velocity; larger pipes have a smaller area of pipe compared to the volume of fluid they convey. There is a Capex penalty to pay with larger pipes, but this is offset to some extent by the need for a smaller motor and lower maintenance costs. The analysis uses a baseline assumption that IE3 (most efficient) motors are already installed with variable speed drives (VSDs).

E.2 Air-Conditioning and Mechanical Ventilation

Between 2015 and 2035 GPGSEP estimated that air-conditioning could make up 15% of the electrical load on the DBIS system and that mechanical ventilation could make up a further 4%, meaning that all equipment used for space-conditioning could make up about 19% of total electricity use. For air-conditioning and mechanical ventilation four different energy efficiency measures are examined.

- **AC1A: Cool Reflective Roofs.** Cool roofs work through the implementation of specialist paints which reflect the rays of the sun away from the roof of a building and stop the sunlight from being absorbed by the roof. Cool roofs may also incorporate insulation and thermal mass in order to reduce the heat load within a building. For the purposes of calculation it has been assumed that specialist paints only are used to reduce the heat load.
- **AC1B: Natural ventilation.** Natural ventilation is a means of cooling buildings using natural air flows. A very good example of natural ventilation has already been implemented in Guyana in the form of the new wing at Georgetown Hospital which uses no air-conditioning at all but induces cross-flow ventilation through central columns (stacks). This means that the new wing of the hospital has no roof furniture (condensers, compressors etcetera) like the old wing of the hospital and no electricity burden in terms of additional operating costs. This so called "Stack" ventilation is possible because of the height of the building which is able to take advantage of higher wind speeds but also because

of the induced draft from the hot roof space. Because not all buildings have these inherent advantages, for the purposes of modelling it has been assumed that natural ventilation in most circumstances would primarily be induced due to natural cross-ventilation through louvers or other openings in the fabric of buildings. It has been assumed that there would be a small uplift in Capex in order to design or refurbish a building to natural-ventilation standards.

- **AC2: Energy efficient AC systems.** If air-conditioning needs to be deployed then it is a good idea to install the most efficient systems which can be afforded. Air conditioning efficiencies are expressed in terms of a Seasonal Energy Efficiency Rating (SEER). SEERs describe the amount of cooling expressed in BTU/hr divided by the electricity usage in kW for a system in operation over a typical cooling season in the USA. It has been assumed that if air-conditioning equipment is installed it will be of the mini-split type. Mini-split air conditioners typically have a cooling effect of between 5,000 and 9,000 BTU/hr. For the purposes of calculation it has been assumed that an average unit with a cooling capacity of 9,000 BTU/hr to account for larger cooling loads which might be better served by larger units. The minimum SEER for a mini-split air-conditioner sold in the USA is 13.5, but there may be many other less efficient units in the Guyana market which may have been displaced from the USA or manufactured in other countries. For this reason the baseline assumption is that a unit would have a SEER of 10. In future work it will be very important to check the above sizing assumptions against current practice in Guyana. There seems to be a trend for technicians to oversize units to deliver between 12,000 and 24,000 BTU of cooling. Therefore an important aspect of this measure is to train technicians in the appropriate sizing of units to fit the particular building characteristics.
- **MV1: Energy efficient mechanical ventilation.** Mechanical ventilation fans come in different shapes and sizes. Fans can be optimized with more efficient blades, more efficient motors or indeed by reducing their use through natural ventilation methods described above. For the purposes of calculation it has been assumed that the fan's motor would be upgraded from an IE1 (low efficiency) to an IE3 (best efficiency) motor.

E.3 Lighting

GPGSEP estimated that between 2015 and 2035 lighting will consume 23% of the electricity on the DBIS system. There are a variety of lighting fixtures and technologies used in Guyana but for the purposes of calculation the following four were considered in GPGSEP:

- **Strip lighting (tube lighting).** Strip lighting, also called tube lighting, uses fluorescent tube lights, usually to light large spaces in commercial or industrial settings. There are different forms of tube light each designated with the letter "T" followed by a number. The number represents the diameter of the tube in eighths of an inch (an eighth of an inch is about 3mm). T12 and T8 strip lights have been around since the 1930´s but T8 became more common in the 1980´s due to their higher efficiency compared to T12s. T5 strip lights had a limited range from the 1950´s but then more powerful and energy efficient T5s were introduced in the 1990´s.
- **Incandescent general purpose filament lamps.** Filament lamps have been around since the beginning of the 19th century, but were only commercialized in the 1870´s. They were the main type of light used in early street lighting and were the basis for the first commercialization of electricity in the 1880´s and became the standard type of light bulb right up to the 1980´s when compact fluorescent bulbs began to be introduced.
- **Compact fluorescent ("energy efficient") bulbs.** Compact Fluorescent light bulbs (CFLs) are fluorescent lamps that were designed to replace the incandescent lamps. CFLs use a tube which is curved or folded to fit into the space of an incandescent bulb, and a compact electronic ballast in the base of the lamp.

- **Street lighting.** Street lighting may typically be provided by metal halide or high pressure sodium lights. The costs of these different options are similar and so for calculation purposes high pressure sodium (HPS) street lights have been used as the baseline assumption.

The following figure shows the baseline lightning technologies used in GPGSEP.

Baseline lightning technologies used in GPGSEP

SOURCE: Consultant with photos from wikipedia

The different EE measures in lightning are briefly discussed. As part of the analysis the role that light or motion sensors and natural lighting may play in reducing electricity use for lighting is also considered.

- **L1A:** replacing T12 strip lights with T8, T5 or LED. Light Emitting Diode (LED) tube lights are an emerging technology which integrate highly efficient LED technology into existing T8 or T5 fittings but are a very different type of technology. LED lights have extremely long lives and very high light outputs per unit of electricity used.
- **L1B:** Replacing filament lamps with LEDs. Since 2000 LED bulbs have been introduced. LED lights are solid-state electronic devices originally used in the computer industry as indicator lights. They are now main-stream replacements for filament lamps. Their Capex continues to decrease while efficiencies continue to increase.
- **L1B:** Replacing CFLs with LEDs. Compact Fluorescent light bulbs (CFLs) were once considered to be the best available technology for energy efficiency lighting, but they are fast being overtaken by LED technology which is set to become even more efficient in the future. The relative power consumption of LEDs compared to CFLs varies greatly from brand but can be fifty percent or less, and it is for this reason that LEDs can offer significant electricity savings over CFLs.
- **L1C:** Replacing Sodium street lights with LED street lights. LED lights have extremely long lives and very high light outputs per unit of electricity used.
- **L2:** Install motion (occupancy) or light sensors with LED. With this measure it is assumed that LED lighting has already been implemented as the baseline measure. The measure looks at the impact of implementing LED bulbs with integrated motion (occupancy) or light sensors. The impact of this would be to turn individual luminaires off either when natural light levels are above a certain level or when areas are unoccupied.
- **L3:** Enhanced natural lighting and LEDs. With the introduction of enhanced natural lighting into a building the costs of using electric light would be reduced. This measure requires a consideration of the architectural form of a building. It has been assumed that a standard measure which could be

implemented would be the introduction of light shelves into a building, although other measures such as roof lights would also have a similar effect. Light shelves are strategically located reflective shelves placed by a window below the ceiling and are able to reflect light deeper into a building than would otherwise be the case. It has been assumed that light shelves would be the more common implementation because not all spaces within a building have access to a roof for a roof light. In Guyana, common practice is to completely close windows and to draw the curtains in order to stop the heat from the sun entering a building. Light shelves can be integrated with closed windows but would not work with drawn curtains. Therefore it is very important to consider the use of natural lighting in the context of the building design strategy in order to minimize thermal gains while maximizing the penetration of light. In practical terms to implement natural lighting in Guyana will require the rigorous testing of different technologies and the development of design advice on the back of this testing.

E.4 Refrigeration and Freezing

GPGSEP estimated that between them self-contained refrigerator and freezer devices of the type used in houses and in commercial food-retail establishments could make up around 9% of electricity use in Guyana in 2015. For refrigerators and freezing the very successful energy efficiency labelling scheme promoted in the European Union was used to assess the potential impact of different efficiencies on energy use. A baseline assumption of a B rated appliance was used in GPGSEP. Electricity for appliances rated at A, A+, A++ and A+++ are examined against this baseline assumption.

Appendix F . LCOES calculations of Energy Efficiency Measures

The details of the LCOES calculations from Brugman (2016) for the measures described in Appendix E are shown in the following two pages.

Key Features of Energy Efficiency Measure Calculations

(A)* REF CODE	(B) END-USE/MEASURE NAME	(C) Nominal Power Rating W	(D) Lifetime years	(E) Hours of use per year Hours/year	(F) Efficiency** %	(G) Unit electricity usage per year kWh/year	(H) Electricity Saved vs baseline kWh/year	(I) Percent saving vs baseline %	(J) Unit Capex US$	(K) Annual Capex*** US$	(L) Annual Capex vs baseline US$/year	(M) Capex recovery factor per kWh US$/kWh	(N) Opex US$/year	(O) Opex vs baseline US$/year
Motors														
M1	**Energy efficient motors**													
M1	IE1 (baseline)	11,000	20	4380	88%	55,000			740	99			128.5	0
M1	IE2 Energy Efficient Motor	11,000	20	4380	90%	53,653	1,347	2%	920	123	24	0.02	128.5	0
M1	IE3 Energy Efficient Motor	11,000	20	4380	91%	52,713	2,287	4%	1,120	150	51	0.02	128.5	0
M2	**Variable Speed Drives**													
M2	IE3 (baseline)	11,000	20	4380	91%	52,713			1,120	150			128.5	0
M2	Variable speed drive (VSD) with IE3*****	11,000	20	3066	91%	36,899	15,814	30%	2,420	324	174	0.01	257	128.5
M3	**Cost optimisation of pumped systems**													
M3	IE3+VSD+42mm pipe (baseline)	11,000	20	3066	91%	36,899			48,524	6,496			257	0
M3	IE3+VSD+54mm pipe	3,158	20	3066	91%	10,594	26,306	71%	62,075	8,311	1,814	0.07	257	0
M3	IE3+VSD+67mm pipe	1,095	20	3066	91%	3,672	33,227	90%	86,824	11,624	5,128	0.15	257	0
M3	IE3+VSD+76mm pipe	592	20	3066	91%	1,986	34,913	95%	123,406	16,521	10,025	0.29	257	0
M3	IE3+VSD+108mm pipe	108	20	3066	91%	361	36,538	99%	175,066	23,438	16,941	0.46	257	0
Lighting														
L1A	**Replacing T12 strip lights with T8 or LED**													
L1A	T12 Strip light (baseline)	40	15	1000	100%	40			4	1			0	0
L1A	Replace T12 Strip light with T8	32	20	1000	100%	32	8	20%	17	2	2	0.21	0	0
L1A	Replace T12 Strip light with T5	28	24	1000	100%	28	12	30%	17	2	2	0.13	0	0
L1A	Replace T12 Strip light with LED	20	50	1000	100%	20	20	50%	34	4	3	0.17	0	0
L1B	**Replacing filament lamps with LEDs**													
L1B	Filament bulb (baseline)	40	1	1000	100%	40			1	1			0	0
L1B	Replace Filament bulb with LED bulb	6	50	1000	100%	6	34	85%	8	1	0	-0.01	0	0
L1B	**Replacing CFLs with LEDs**													
L1B	CFL Bulb (baseline)	12	8	1000	100%	12			5	1			0	0
L1B	Replace CFL bulb with LED bulb	6	50	1000	100%	6	6	50%	8	1	0	-0.01	0	0
L1C	**Replacing HPS with LED street lights**													
L1C	High pressure sodium (HPS) street light (baseline)	250	4	4380	100%	1,095			150	49			50	
L1C	Replace HPS Street Light with LED Street light	70	15	4380	100%	307	788	72%	400	59	9	0.01	25	-25
L2	**Install motion or light sensors with LED**													
L2	LED Bulb (baseline)	6	10	1000	100%	6			8	1			0	
L2	Motion/light sensor with LED	6	10	500	100%	3	3	50%	18	3	2	0.59	0	0
L3	**Enhanced natural lighting**													
L3	LED Bulb (baseline)	12	20	1000	100%	12			0	0				
L3	Light Shelf+LED	12	20	360	100%	4	8	64%	100	13	13	1.74	0	0

Notes:

* Column letter headings are referred to in the detailed descriptions in the appendix

** Only used for pumps and drives and mechanical ventilation. In other measures energy saved through reduced nominal power, or hours of use (see appendix for more detail)

*** Calculated by annualising the capital cost using a discount rate of 12%

**** This is calculated from the sum of the Capex and Opex recovery factors per kWh

***** The impact of the variable speed drive has been modeled as a reduction in usage hours although in reality the motor would run for the same number of hours but at a lower power rating.

Source: Consultant

Key Features of Energy Efficiency Measure Calculations (continued)

(A)*	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
REF CODE	END-USE/MEASURE NAME	Nominal Power Rating W	Lifetime years	Hours of use per year Hours/year	Efficiency** %	Unit electricity usage per year kWh/year	Electricity Saved vs baseline kWh/year	Percent saving vs baseline %	Unit Capex US$	Annual Capex*** US$	Annual Capex vs baseline US$/year	Capex recovery factor per kWh US$/kWh	Ope US$/y
Air-conditioning													
AC1A	**Cool Reflective Roofs**												
AC1A	Non-cool-roof paint on roof	900	5	1460	100%	1,314			30	8			0
AC1A	Cool-roof paint on roof	810	5	1460	100%	1,183	131	10%	40	11	3	0.02	0
AC1B	**Natural ventilation**												
AC1B	No natural ventilation	900	30	1460	100%	1,314			0	0			0
AC1B	Natural ventilation	720	30	1460	100%	1,051	263	20%	100	12	12	0.05	0
AC2	**Energy efficient AC systems**												
AC2	SEER 10 (baseline)	900	17	1460	100%	1,314			375	53			0
AC2	SEER 13	692	17	1460	100%	1,011	303	23%	458	64	12	0.04	0
AC2	SEER 16	563	17	1460	100%	821	493	38%	574	81	28	0.06	0
AC2	SEER 26	346	17	1460	100%	505	809	62%	762	107	54	0.07	0
Refrigeration													
REF1	**Energy efficient refrigerators**												
REF1	B Rated fridge (baseline)	64	12	8760	100%	557			120	19			0
REF2	A Rated fridge	48	12	8760	100%	420	137	25%	140	23	3	0.02	0
REF3	A+ Rated fridge	35	12	8760	100%	309	249	45%	280	42	23	0.09	0
REF4	A++ rated fridge	25	12	8760	100%	223	334	60%	587	95	75	0.23	0
REF5	A+++ rated fridge	20	12	8760	100%	171	386	69%	593	96	76	0.20	0
Mechanical Ventilation													
MV1	**Energy efficient mechanical ventilation**												
MV1	Fan with IE1 motor (baseline)	65	6	800	88%	59			20	5			0
MV1	Fan with IE3 motor	65	6	800	91%	57	2	4%	22	5	0	0.20	0

Notes:

* Column letter headings are referred to in the detailed descriptions in the appendix

** Only used for pumps and drives and mechanical ventilation. In other measures energy saved through reduced nominal power, or hours of use (see appendix for more detail)

*** Calculated by annualising the capital cost using a discount rate of 12%

**** This is calculated from the sum of the Capex and Opex recovery factors per kWh

Source: Consultant

Appendix G . Estimates of the number of units and electricity savings of selected EE measures

Detail of electricity savings, marginal investment and number of interventions (i.e. replacement of old appliances by new EE appliances) are shown in the following table.

Estimates of the number of units in use for different end-uses up to 2035

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	TOTAL
	Electricity Savings (MWh/year)													
M1	IE3 Energy Efficient Motor	98	203	317	437	568	836	1,086	1,370	1,693	2,059	3,622	5,640	**47,452**
M2	Variable speed drive (VSD) with IE3	674	1,405	2,195	3,025	3,926	5,778	7,512	9,474	11,710	14,242	25,050	39,006	**328,169**
L1B	Replace Filament bulb with LED bulb	266	554	865	1,193	1,548	2,278	2,962	3,735	4,616	5,614	9,875	15,377	**129,370**
L1B	Replace CFL bulb with LED bulb	267	557	870	1,199	1,556	2,290	2,977	3,754	4,640	5,643	9,926	15,456	**130,032**
L1C	Replace HPS Street Light with LED Street light	286	597	932	1,284	1,667	2,453	3,190	4,022	4,972	6,047	10,635	14,894	**134,565**
AC2	SEER 26 AC system	91	191	298	410	532	784	1,019	1,285	1,588	1,931	3,397	4,992	**43,920**
REF3	A+ Rated fridge	78	162	253	349	453	666	866	1,093	1,351	1,642	2,636	3,406	**33,926**
	Total	**1,760**	**3,668**	**5,731**	**7,898**	**10,249**	**15,084**	**19,612**	**24,732**	**30,570**	**37,179**	**65,140**	**98,771**	**847,434**

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	TOTAL
	Marginal Capex (USD k)													
M1	IE3 Energy Efficient Motor	16	18	19	20	22	45	42	47	54	61	58	74	**937**
M2	Variable speed drive (VSD) with IE3	55	60	65	68	74	152	143	161	184	208	197	253	**3,207**
L1B	Replace Filament bulb with LED bulb	51	55	60	63	68	140	131	148	169	191	180	232	**2,940**
L1B	Replace CFL bulb with LED bulb	121	131	141	148	161	331	310	351	400	453	428	549	**6,973**
L1C	Replace HPS Street Light with LED Street light	91	98	106	112	121	249	233	264	301	341	322	414	**5,251**
AC2	SEER 26 AC system	44	47	51	54	58	120	113	127	145	164	155	199	**2,531**
REF3	A+ Rated fridge	44	47	51	54	58	120	113	127	145	164	155	199	**2,531**
	Total	**421**	**457**	**494**	**519**	**563**	**1,157**	**1,084**	**1,226**	**1,397**	**1,582**	**1,496**	**1,920**	**24,371**

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
	Cummulative number of Interventions												
M1	IE3 Energy Efficient Motor	43	89	139	191	248	365	475	599	741	901	1,584	2,467
M2	Variable speed drive (VSD) with IE3	43	89	139	191	248	365	475	599	741	901	1,584	2,467
L1B	Replace Filament bulb with LED bulb	7,819	16,291	25,453	35,078	45,519	66,997	87,105	109,848	135,777	165,127	290,443	452,265
L1B	Replace CFL bulb with LED bulb	44,532	92,786	144,973	199,792	259,263	381,591	496,118	625,653	773,341	940,505	1,654,263	2,575,947
L1C	Replace HPS Street Light with LED Street light	363	757	1,182	1,629	2,114	3,112	4,046	5,102	6,306	7,669	13,490	21,006
AC2	SEER 26 AC system	113	236	368	507	658	969	1,260	1,589	1,964	2,388	4,201	6,541
REF3	A+ Rated fridge	313	652	1,019	1,404	1,821	2,681	3,485	4,396	5,433	6,608	11,622	18,097
	Total	**53,225**	**110,898**	**173,273**	**238,793**	**309,873**	**456,080**	**592,963**	**747,785**	**924,303**	**1,124,098**	**1,977,187**	**3,078,790**

Source: Consultant. Number of Street Light Customers estimated at 91 (obtained from billing data provided by GPL) and held constant until 2035.

Appendix H . Distributed generation summary

The study evaluated two technologies in Guyana for displacing electricity demand on a distributed (end-user) basis: (i) Photovoltaic cells (solar-electric) and (ii) solar hot water (solar thermal) technologies. Both are based on panels which are placed on a roof or other available surface and provide either electricity or solar hot water for the end-user. The Levelized Cost of Electricity (LCOE) for photovoltaic and solar hot water systems were assessed and with these results an estimate of implementation for Guyana was done. The LCOE results are shown in the Table below and the penetrations of non-residential photovoltaics (i.e. industrial and commercial sector) and solar hot water in Guyana are presented in Table below. Main findings were:

- Solar hot water systems (65 gallon system) with nominal power rating of 1,5kW could be implemented with an LCOE of US$0.12/kWh assuming a capital cost of 2,015 US$/kW.
- Photovoltaic systems would have a LCOE of around US$0.23/kWh for the residential case (similar to the current average residential tariff) assuming a capital cost of 2,500 US$/kW.
- For non-residential photovoltaic systems it was assumed that a lower capital cost of 1,800 US$/kW installed would be possible due to economies of scale from its larger size. Under this price scenario, the LCOE of non-residential systems would be US$0.16/kWh.
- The solar hot water systems have the potential to displace up to 28 GWh of electricity or about 1.7% of the total electricity used in Guyana in 2035 (Low Case Scenario).
- Photovoltaics systems installed on non-residential and community projects have the potential to reduce electricity import form the grid by 76 GWh by 2035, or 4.6% of the total electricity demand in 2035 (Low Case Scenario).

Key Features of Distributed and Displaced Generation Measure Calculations

(A) REF CODE	(B) END-USE/MEASURE NAME	(C) Nominal Power Rating W	(D) Lifetime years	(E) Hours of generation or displacement per year Hours/year	(F) Efficiency %	(G) Unit electricity generation or displacement per yearU kWh/year	(H) Electricity generated or displaced vs baseline kWh/year	(I) Percent saving vs baseline %	(J) Unit Capex US$	(K) Annual Capex*** US$	(L) Annual Capex vs baseline US$/year	(M) Capex recovery factor per kWh US$/kWh	(N) Opex US$/year	(O) Opex vs baseline US$/year	(P) Opex recovery factor per kWh US$/kWh	(Q) Levelised cost of electricity **** US$/kWh
Distributed Generation and Displacement																
DG1	**Solar Electric (PV) (residential)**															
DG1	No photovoltaics															
DG1	Photovoltaics (1 kWp)	-1,000	20	1531	100%	-1,531	1,531	100%	2,500	335	335	0.22	20	20	0.01	0.23
DG1	**Solar Electric (PV) (commercial & industrial + community)**															
DG1	No photovoltaics															
DG1	Photovoltaics (1 kWp)	-1,000	25	1531	100%	-1,531	1,531	100%	1,800	229	229	0.15	15	15	0.01	0.16
DG2	**Solar Hot Water (SHW)**															
DG2	No solar hot water	1,500		1460	90%	2,433										
DG2	Solar hot water (65 gallon system)	0	20	1460	100%	0	2,433	100%	2,015	270	270	0.11	20	20	0.01	0.12

Notes:

** Efficiency losses from PV are due to inverter and other losses between the solar panel and the consumer unit.
*** Calculated by annualising the capital cost using a discount rate of 12%
**** This is calculated from the sum of the Capex and Opex recovery factors per kWh
Negative number indicates installed generating power (W) or energy generation (kWh/year)

Source: Consultant

Forecasts for the implementation of distributed generation measures up to 2035

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	TOTAL
	Electricity Savings (MWh/year)													
DG1	Photovoltaics (1 kWp)	1,590	3,530	5,449	7,532	9,819	12,215	14,772	16,992	22,762	27,508	54,012	76,857	**680,910**
DG2	Solar hot water (65 gallon system)	485	1,011	1,580	2,178	2,826	4,159	5,407	6,819	8,429	10,251	18,030	28,075	**236,202**
	Total	**2,075**	**4,541**	**7,029**	**9,710**	**12,645**	**16,374**	**20,179**	**23,811**	**31,191**	**37,758**	**72,041**	**104,932**	**917,112**
	Marginal Capex (USD k)													
DG1	Photovoltaics (1 kWp)	1,869	2,281	2,256	2,450	2,689	2,817	3,007	2,610	6,785	5,580	4,995	5,634	**90,372**
DG2	Solar hot water (65 gallon system)	402	436	471	495	537	1,104	1,034	1,169	1,333	1,509	1,427	1,832	**23,249**
	Total	**2,271**	**2,717**	**2,727**	**2,945**	**3,226**	**3,921**	**4,040**	**3,779**	**8,118**	**7,089**	**6,422**	**7,466**	**113,620**
	Cummulative number of Interventions													
DG1	Photovoltaics (1 kWp)	1,039	2,306	3,559	4,921	6,414	7,979	9,650	11,100	14,869	17,969	35,283	50,206	
DG2	Solar hot water (65 gallon system)	199	416	649	895	1,161	1,709	2,222	2,802	3,464	4,213	7,410	11,538	
	Total	**1,238**	**2,722**	**4,209**	**5,815**	**7,576**	**9,689**	**11,872**	**13,902**	**18,333**	**22,182**	**42,692**	**61,744**	

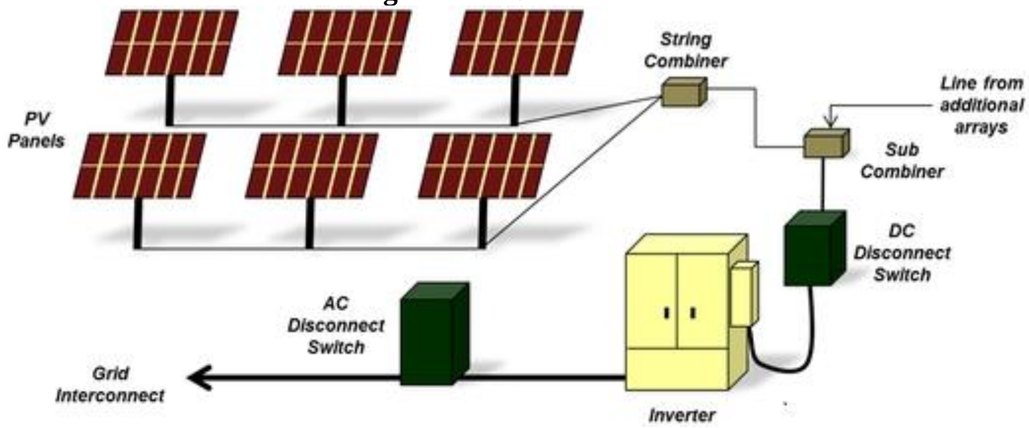
Source: Consultant

Appendix I . PV Power Plant Basics

The main components of a PV power plant (PVPP) are indicated in Figure 76:

- PV generator, composed of PV modules arranged in panels,
- Inverter(s),
- Connection to the grid

Figure 76. PV Power Plant Basics



Source: Consultant

The PV generator is composed of modules converting solar irradiation into DC power. The inverters convert the DC power of the PV generator to AC grid compatible electricity. The inverters may simply fix the voltage at which the array operates, or (more commonly) use a Maximum Power Point (MPP) tracking function to identify the best operating voltage for the array. The inverter operates in phase with the grid (unity power factor), and generally delivers as much power as it can to the electric power grid given the sunlight and temperature. The inverter acts as a current source; it produces a sinusoidal output current but does not act to regulate its terminal voltage in any way.

The connection to the grid may include transformer, switchgear and protection devices so that the PV plant can be disconnected from the grid in case of failures or maintenance works on the grid.

Besides the main components shown above, other Balance of System (BOS) components are required. This includes: module mounting and support structure, cabling, junction boxes, DC switches, protection devices, and other auxiliary components.

I.1 Modules

There are different modules technologies and can be classified according to the type of semiconductor they use. Essentially there are two classes: crystalline and thin film, as shown in Table 79.

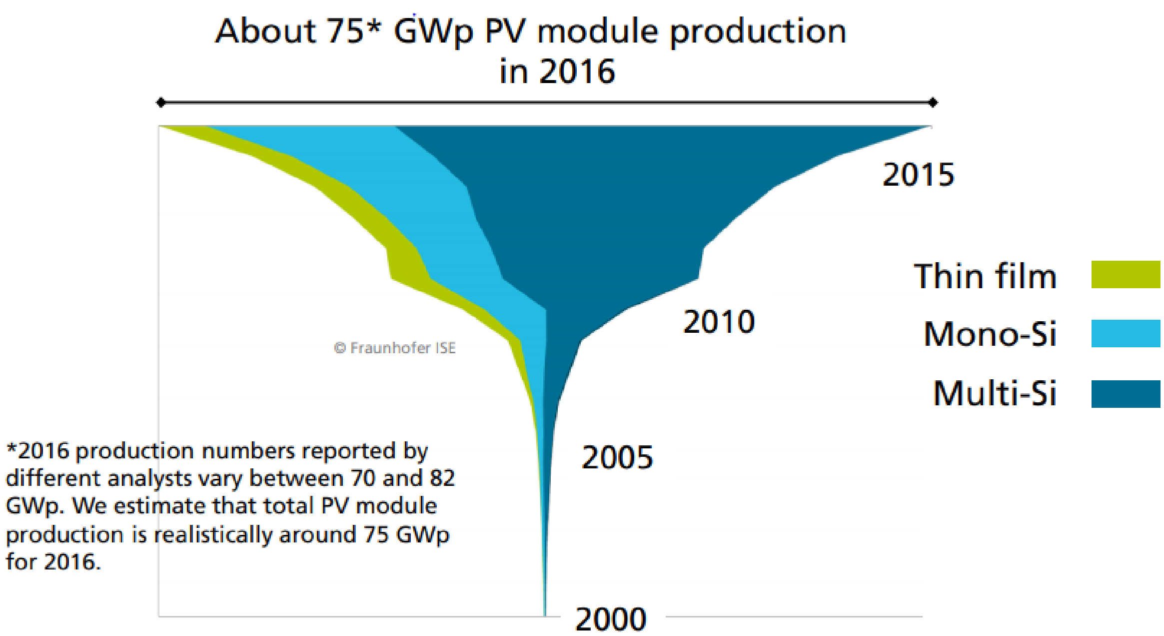
Table 79. Module technology classes

Class	Semiconductor	Technology	Efficiency
Crystalline	Silicon (Si)	Mono-crystalline	15-20 %
	Silicon (Si)	Poly (or multi) crystalline	13-16 %
Thin Film	Silicon (Si)	Amorphous silicon (single layer)	6 - 8%
	Cadmium Telluride (CdTe)		9-11%
	Copper Indium Diselenide (CIS)		10-12%

Source: Consultant

The world market is dominated by the silicon cells, accounting for almost 95% of the world market (production in the range 70 to 82 GWp in 2016)[112]. They have a long record of reliability in small, medium and large scale (utility scale) applications. The market share for Thin Film modules is currently small but reached around 5% of the world market in 2016.

Figure 77. Annual PV Module Production by Technology in 2016



Source: Photovoltaics Report. Fraunhofer Institute for Solar Energy, ISE

Mono and poly silicon modules have many references in hundreds of projects, mono have high efficiency and poly medium, both use direct and diffuse irradiation, both have high drop of efficiency at high temperatures and mono show higher expenses per kWp.

Modules are manufactured in the range of few tens of Watts Peak (Wp) up to 300 – 400 Wp and to be series interconnected at levels of 600, 1000 and 1500 VDC. This issue is important because

[112] Photovoltaics Report. Fraunhofer Institute for Solar Energy, ISE. (2018) Freiburg, Germany

interconnecting modules in series at higher voltages reduce the cost of wiring and wiring related components of the BOS.

I.2 PV Inverters

There are three classes of inverters: central and string inverters for power plants, and micro-inverters for power in the module power range. String inverters are employed for sub-sets of string connected modules with capacities in the range of few tents of kWp up to 100 kWp. Central inverters use large subsets of module strings (it can reach more than 100) and have capacities over 100 kW.

For PV power plants the total power of the plant can be reached assembling many small capacity inverters or a small number of inverters of large capacities. To determine the capacity of the inverter several factors must be taken into account, and although there is in the world market a wide variety of brands and models, here the reliability criteria comes into play for the total supply of the plant, i.e. in case of failure of one inverter, the design of the plant as a whole should consider what percentage of the plant operation should be left out of power and the way of how to minimize generation losses also should consider making use of a single model inverter to streamline maintenance and staff training. Plus, the parts and repairs for inverters should become standard and for that a single capacity and inverter model are proposed.

It is also important to consider whether the inverter has an integrated transformer, or this must be installed separately. If the inverter has not an integrated transformer, civil works would increase and thus the environmental impact and design complexity of power plant would have to include maintenance plans for such extra equipment. The galvanic isolation has the advantage of providing some filtering and reduction of common mode noise.

It is noteworthy that there is to date in Guyana no experience with photovoltaic power plants of medium and large scale, therefore, the issue of training and development of staff capable of servicing these systems should be a priority, accompanied with proper preventive maintenance capability and storage of spare parts for a prompt and expeditious response in the event of the failure of one inverter.

Therefore, it is important to make the decision of whether to use inverters of small capacity (of few tens of kW) or large capacity (about megawatts), as in this case has already been mentioned, different considerations come into play and assessments, including, system reliability, maintenance, spare parts, training requirements, system size and cost.

Both concepts have pros and cons. Central inverters use to have good part load and long-life time but requires yearly maintenance and should have high energy losses during malfunction of a single inverter, and have because of its capacity, no stock of spare inverter. String inverters exhibits often maintenance free, high efficiency, less energy losses during malfunction of a single inverter, spare inverters can be stored near the plant, ease replacement and are mass produced. On the contrary, the use to have a higher initial cost for smaller plants and time consuming during installation.

Micro-inverters are appropriate for capacities in the module range capacities or by adding many module – micro-inverters systems typical up to 10 kWp.

I.3 Mounting systems

Modules can be mounted on two different types of mounting systems: fixed modules and tracking systems. Tracking systems are structures that follow the sun during its daily movement and allows the incidence of more solar radiation on the modules, increasing its yield (between 25 and 35%, depending on the tracking system and latitude). There are three types of tracking systems: one-axis tracking (horizontal axis), one-axis tracking (tilted axis) and two-axis tracking.

Fixed modules or modules on tracking systems offer pros and cons. Fixed modules are easy to maintain, requires low land per MW (2.5 to 3 hectare/MWp), low system price and can withstand higher winds. On the contrary, they present lower yield than tracking systems. Tracking systems have a higher yield but are sensible to the wind, have higher maintenance costs, higher area requirements (4 to 5 hectares/MWp), self-consumption of energy and higher system price.

I.4 Components selection

To minimize technology and engineering risks, this document focuses on proven technologies already holding a good track record. It adopts robust design methods which allow also the use of free simulation tools. Furthermore, and to benefit from economy of scale a minimum plant capacity of 1 MW has been adopted. Hence the selected characteristics are shown in Table 80.

Table 80. Components Selection for the 1 MW PV Plant

Component	Technology	Comment
PV Modules	Polycrystalline modules	This technology has a long, proven and robust record
Inverters	String Inverters	Proven mass-product, widely available in different capacities, flexible
Mounting system	Fixed mounting	This technology has a long, proven, robust, maintenance free, durable record
Power plant capacity	1 MWp	Capacity with good economy of scale, design, readily available, replicable

Source: Consultant

I.5 Costs (utility scale PV plants)

For the computation of the LCOE (Levelized Cost of Energy), two types of costs need to be considered: Capital costs, and Operation and Maintenance Costs (O&M).

I.5.1 Capital Cost

Information on the costs and performance of PV plants installed in Latin American is very scarce, and non-systematically recorded and analyzed by institutions in the region. Table 81 shows the installed cost of 9 PV Power Plants in operation in Chile since 2012. These plants are connected to the Central Interconnected Systems and to the North Interconnected System of the country. The average cost is 3.28 MUS$/MW[113], with a minimum of 1.59 MUS$/MW and a maximum of 5.33 MUS$/MW. It is important to note that the projects do not benefited of the modules price decrease of the last five years.

[113] There is no information whether the figures are for MWAC or MWDC

Table 81. Utility scale PV plants - Costs and capacities of grid-tie PV Plants in Chile

PV PLANT NAME	MW	MUS$	MUS$/MW	OPERATION
Pozo Almonte	16	71	4.44	07-jun-14
Diego de Almagro	36	130	3.61	26-may-14
Pozo Almonte - Solar 2	7.5	40	5.33	29-mar-14
San Andrés	50.33	120	2.38	12-feb-14
Amanecer	100	241	2.41	13-ene-14
Andacollo	1.26	2	1.59	01-jul-13
Esperanza	2.88	7	2.43	20-dic-12
Tambo Real	1.2	3	2.50	12-dic-12
La Huayca I	1.4	6.5	4.64	01-oct-12
Calama Solar 3	1	3.5	3.50	13-jun-12

Source: Román, R. et al. Experiencias de plantas solares en Chile en operación y conectadas a la red. Ministerio de Energía and GIZ. (2014) Santiago de Chile

In Colombia, the Yumbo PV Power plant, owned and operated by the Colombian company CELSIA in September 2017, the cost was 1 MUS$/MWp.

Panama PV Plant Costs

In the "Indicative Expansion Plan of Panamá (2017-2031), the developers have register a total 53 PV projects, for a total capacity of 17.56 MW, a capacity average of 14.87 MW (maximum 130 MW, minimum 3.0 MW). The average investment cost is 1398 US$/kW (maximum 3000 US$/kW, minimum 825 US$/kW).

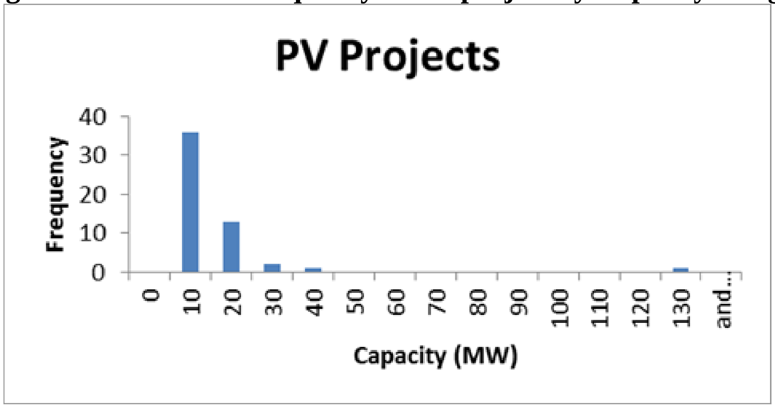
Table 82. Panama - Characteristics of the PV plants in the expansion plan of Panama

Project	Capacity (MW)	Investment Cost (US$/kW)	Fixed O&M (US$/kW-year)	Useful life (Years)	Annual Energy (GWh)	Capacity Factor
Count	53	53	50	53	53	53
Summ	787.88		1452.22		1470.32	
Average	14.87	1398.11	29.04	31.04	27.74	20.84%
Max	130	3000	80	40	246.66	26.20%
Min	3	825	5.11	20	5	16.48%
Std Deviation	17.562	401.922	16.837	7.095	33.639	0.030

Source: Own calculations, based on Indicative Expansion Plan of Panamá (2017-2031), Vol. II, ETESA (2017) Panama

68% of the projects (36) have a capacity in the range 0-10 MW, 26% of the projects (13) have a capacity in the range 10-20 MW, 3.4 % of the projects (2) have a capacity in the range 20-30 MW, 1.9 % of the projects (1) have a capacity in the range 30-40 MW and only 1 a capacity of 130 MW.

Figure 78. Panama - Frequency of PV project by Capacity Range



Source: Own calculations, based on Indicative Expansion Plan of Panamá (2017-2031), Vol. II, ETESA (2017) Panama

Most of the projects are in the capacity range 0-10 MW (36). The average capacity is 8.94 MW, average investment cost of US$1370/kW, average O&M of US$24.0/kW-year, average useful life of 30.0 years and average capacity factor of 20.33%. This is the range of capacity of the power plants envisaged for Guyana.

Table 83 shows the same averages for the other capacity ranges and for the 130 MW PV Plant.

Table 83. Panama - Characteristically averages of the PV plants by capacity range

		Averages					
Capacity Range (MW)	Projects	Capacity (MW)	Investment Cost (US$/kW)	Fixed O&M (US$/kW-year)	Capacity Factor	Useful life (Years)	Annual Energy (GWh)
0-10	36	8.94	1370.4	24.00	20.33%	30.00	16.05
10-20	13	18.15	1394.6	39.84	22.12%	33.08	35.60
20-40	3	33.33	1211.7	20.80	21.18%	31.67	61.00
130	1	130.00	3000.0	80.00	21.66%	40.00	246.66
Total	53						

Source: Own calculations, based on Indicative Expansion Plan of Panamá (2017-2031), Vol. II, ETESA (2017) Panama

Other references

Due to the lack of information from of LA projects, this section employs information from different sources, most of them from projects carried out in other regions, principally from in the U.S.

For the analysis of U.S. reports, it is important to note differences in the approaches of different institutions involved in the tracking of the cost of PV systems:

- Some institutions consider the costs of the system and other the price.
- Some institutions consider WDC and other WAC
- Some institutions consider as Utility scale, PV plants with capacities larger than 2 MW, or even larger than 1 MW, and other considers Utility scale the PV plants with capacities larger than 5 MW (for instance, LBNL[114]).

[114] LBNL: Lawrence Berkeley National Lab., USA.

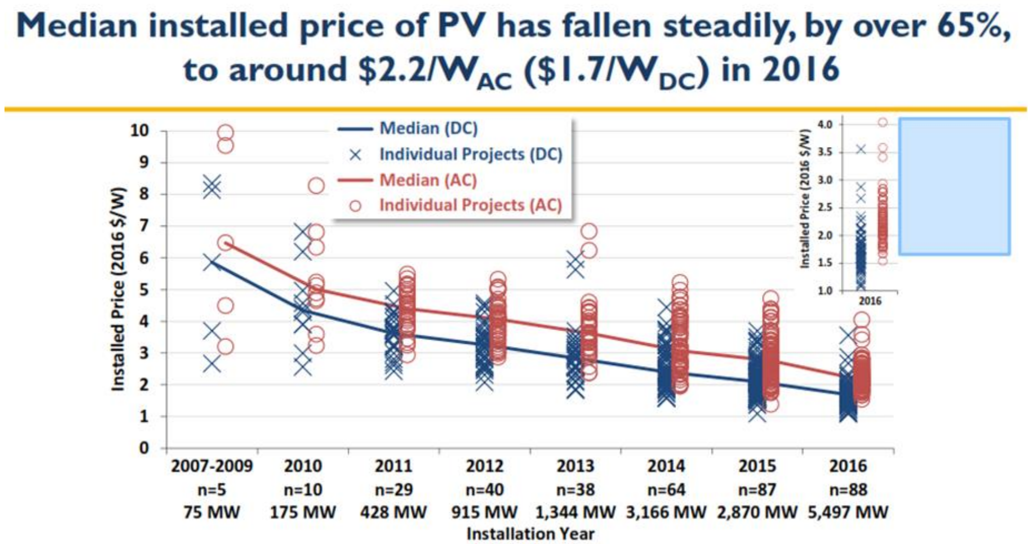
- For estimating the cost, some institutions employ the Bottom-Up methodology in which the cost of the components is considered and added up to obtain the cost in US$/kW. Other, the Top-Down methodology to assert the final cost of the system and obtain the cost in US$/kW.

In the past, the cost of modules amounted for a large share in the cost of the PV projects. Nowadays the cost of solar modules has decreased significantly and represent one third to one half of the total cost of the plants. Module prices are in the US 53 to 64 cUS$/Wp for suppliers from South and Southeast Asia, Korea and Japan, including also German and Chinese suppliers.

Utility scale solar is defined by LBNL to include any ground-mounted photovoltaic (PV), or concentrating photovoltaics (CPV), or concentrating solar thermal power that is larger than 5 MWAC. Utility-scale solar PV plants include any ground-mounted PV with fixed modules or tracking system.

Evaluating 88 PV projects totaling 5497 MWAC, the median installed price for 2016 was $ 2.2/WAC (or $1.7 / WDC) and the price for the lowest 20th percentile of projects of the sample were priced at or below $2.0 /WAC, with the lowest price around $1.5 /WAC.

Figure 79. Median installed price of PV projects (2007-2016)



Source: Bolinger, M. et. al. Utility-Scale Solar 2016. Lawrence Berkeley National Lab (September 2017) USA

In Figure 79, the installed prices are shown here in both DC and AC terms, but because AC is more relevant to the utility sector, all metrics used in the rest of this slide deck are expressed solely in AC terms. The lowest 20th percentile fell from $2.2/WAC ($1.6/W DC) in 2015 to $2.0/WAC ($1.5/W DC) in 2016. The minimum price among our 88 projects in 2016 was $1.5/WAC ($1.1/WDC). This sample is backward-looking and may not reflect the price of projects built in 2017/2018.

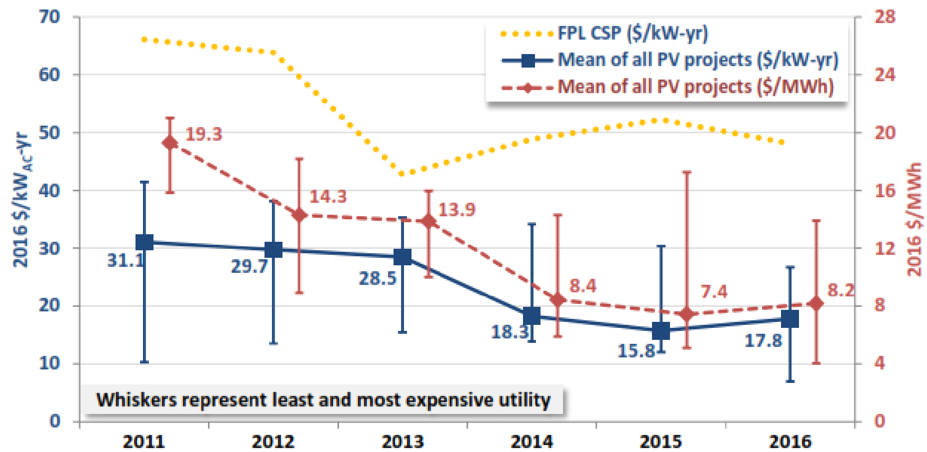
Projects using single tracking system were 0.15 $/WAC more costly than fixed-tilt projects in 2016.

Modest economies of scale evident in the sample, from $2.3/WAC for projects smaller than 20 MWAC to $2.1/WAC for projects between 50 and 100 MWAC.

I.5.2 Operation and Maintenance

Data on O&M cost was also limited in the LBL report, but with publicly available information the O&M cost ranges between $18/kWAc-year or $8/MWh.

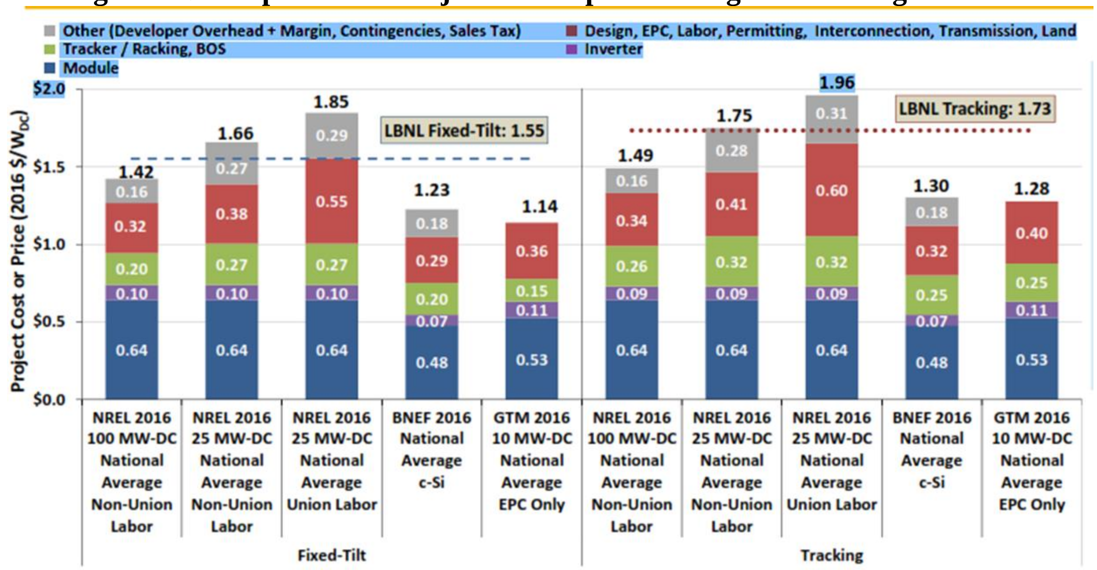
Figure 80. Empirical O&M Cost over time



Source: Bolinger, M. et. al. Utility-Scale Solar 2016. Lawrence Berkeley National Lab (September 2017) USA

When approaching the cost of utility scale PV plants, applying the bottom-down methodology and comparing with the results of other institutions that employ the bottom-up methodology, Figure 81 shows that LBNL's top-down empirical prices are close to modelled bottom-up prices.

Figure 81. Comparison of Project cost or price among different organizations



Prices are presented in $/WDC for consistency with NREL, BNEF and GTM. GTM project represents only turn-key EPC costs and excludes permitting, interconnection, transmission, developer overhead, fees, and profit margins. BNEF: Bloomberg New Energy Finance. Source: Bolinger, M. et. al. Utility-Scale Solar 2016. Lawrence Berkeley National Lab (September 2017) USA

Table 84 presents the aggregation of the different cost items for each one of the reports listed in Figure 81. The low cost of PV Systems has been reached through cost reductions in the module and inverters to the level shown in the table.

Table 84. Comparison of costs of LBNL and other sources

	LBNL Fixed-Tilt: 1.55 US$/WDC					LBNL Tracking: 1.73 US$./WDC				
Item	**1**	**2**	**3**	**4**	**5**	6	7	8	9	10
Module	0.64	0.64	0.64	0.48	0.53	0.64	0.64	0.64	0.48	0.53
Inverter	0.1	0.1	0.1	0.07	0.11	0.09	0.09	0.09	0.07	0.11
Tracker / Racking, BOS Inverter	0.2	0.27	0.27	0.2	0.15	0.26	0.32	0.32	0.25	0.25
Design, EPC, Labor, Permitting, Interconnection, Transmission, Land	0.32	0.38	0.55	0.29	0.36	0.34	0.41	0.6	0.32	0.4
Other (Developer Overhead + Margin, Contingencies, Sales Tax)	0.16	0.27	0.29	0.18		0.16	0.28	0.31	0.18	
Total	1.42	1.66	1.85	1.22	1.15	1.49	1.74	1.96	1.3	1.29

Processed from: Bolinger, M. et. al. Utility-Scale Solar 2016. Lawrence Berkeley National Lab (September 2017) USA

I.5.3 Costs summary

Table 85 shows a summary of cost data from different sources for PV plants, in various scales and for different applications.

Table 85. Cost summary for Utility-Scale PV Plants

Source	Scale	Technology Type	Scale/ Application	Year	Mean installed cost ($/kW)	Fixed O&M ($/kW-yr)	Economic Lifetime (yr)	Source
EIA / Cost and Perfomace of New Generating Tehcnologies	Utility	PV 150 MW	Utility scale - Tracking 150 MW	2019	$ 2,004	$ 22		Energy Information Administration. Annual Energy Outlook 2018. ht
EIA / Cost and Perfomace of New Generating Technologies	Utility	PV 150 MW	Utility scale - Fixed 150 MW	2019	$ 1,763	$ 22		Energy Information Administration. Annual Energy Outlook 2018. ht
NREL ATB	Utility	PV Land Based - 100 MW	Utility Scale - L	2018	$ 1,054	$ 11	20	NREL (National Renewable Energy Laboratory). 2017. *2017 Annual* CO: National Renewable Energy Laboratory. http://www.nrel.gov/an
NREL ATB	Utility	PV Land Based - 100 MW	Utility Scale -M	2018	$ 1,148	$ 12	20	NREL (National Renewable Energy Laboratory). 2017. *2017 Annual* CO: National Renewable Energy Laboratory. http://www.nrel.gov/an
NREL ATB	Utility	PV Land Based - 100 MW	Utility Scale - H	2018	$ 1,513	$ 13	20	NREL (National Renewable Energy Laboratory). 2017. *2017 Annual* CO: National Renewable Energy Laboratory. http://www.nrel.gov/an
NREL	Utility	PV, >2 MW	Utility, ground-mounted, fixed tilt	2017	$ 1,340	$ 21		U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017. Fu.R. et al
NREL	Utility	PV, >2 MW	Utility, ground-mounted, one-axis tracking	2017	$ 1,440	$ 21		U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017. Fu.R. et al
Panama - Indicative Expansion Plan (2017-2031)	Utility	PV 0-10 MW	Utility Scale	2017	$ 1,370	$ 24	30	Indicative Expansion Plan 2017-2031. ETESA. (June 2017) Ciudad de
Panama - Indicative Expansion Plan (2017-2031)	Utility	PV 10-20 MW	Utility Scale	2017	$ 1,395	$ 40	33	Indicative Expansion Plan 2017-2031. ETESA. (June 2017) Ciudad de
Panama - Indicative Expansion Plan (2017-2031)	Utility	PV 20-40 MW	Utility Scale	2017	$ 1,212	$ 21	32	Indicative Expansion Plan 2017-2031. ETESA. (June 2017) Ciudad de
Panama - Indicative Expansion Plan (2017-2031)	Utility	PV 130 MW	Utility Scale	2017	$ 3,000	$ 80	40	Indicative Expansion Plan 2017-2031. ETESA. (June 2017) Ciudad de
LBL Utility PV	Utility	Utility scale - Fixed Axis > 5 MW AC	Utility Scale	2016	$ 2,200	$ 18	20	Utility-Scale Solar 2016 - An Empirical Analysis of Project Cost, Perf the United States Mark Bolinger, Joachim Seel, Kristina Hamachi LaC
LBL Utility PV	Utility	Utility scale - Tracking > 5 MW AC	Utility Scale	2016	$ 2,350	$ 18	20	Utility-Scale Solar 2016 - An Empirical Analysis of Project Cost, Perf the United States Mark Bolinger, Joachim Seel, Kristina Hamachi LaC

Source: Consultant. LBL: Lawrence Berkeley Lab, USA. NREL: National Renewable Energy Lab, USA

Appendix J . Wind measurements in four locations

GEA provided WDA (Wind Data Assesment) for four locations.

Location of other wind measuring station.

Location	Longitude (°) W	Latitude (°) N	Anemometer height (m)	Wind vane height (m)
Port Mourant	-57.351821	6.259848	132	132
Jawalla	-60.484167	5.675283	30	30
Orealla	-57.342033	5.317983	30	30
Yupukari	-59.353383	3.664933	30	30

J.1 Port Mourant

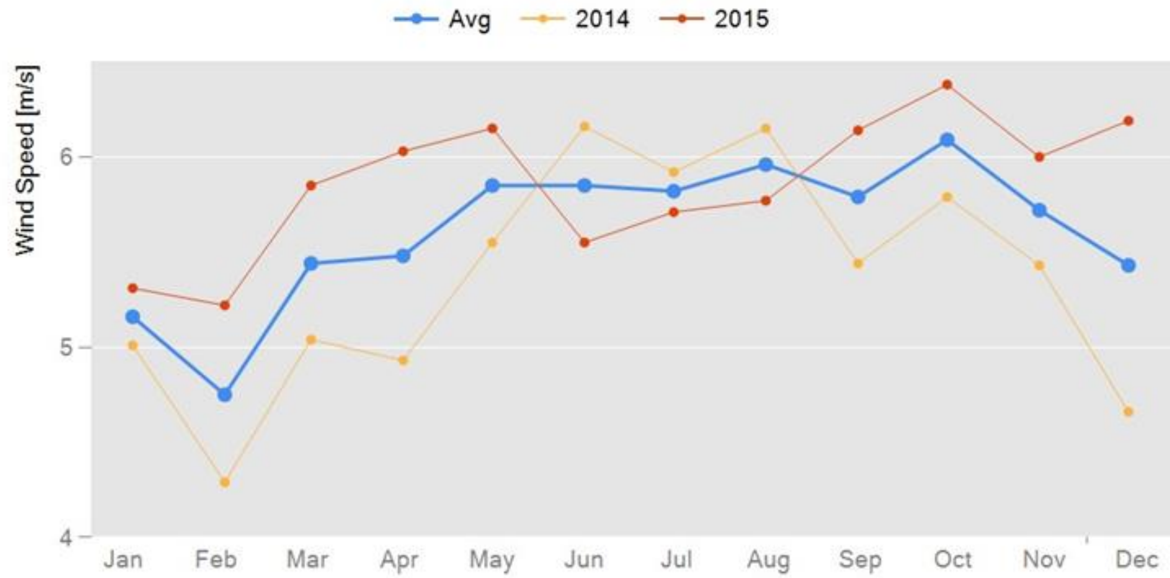
The following Figure shows the location of the wind measurement station in port Mourant.

Port Mourant -Station Location

The report presents the monthly mean of the wind speed at 40 m anemmometer height starting starting January 2014 and ending December 2015 (24 months)[115]. Next figure shows the monthly average wind speeds. It is important to note that the wind speed and direction equipment was installed in a water tower tank and indeed not as appropriate as a meteor tower. For this reason, the results are considered very preliminary.

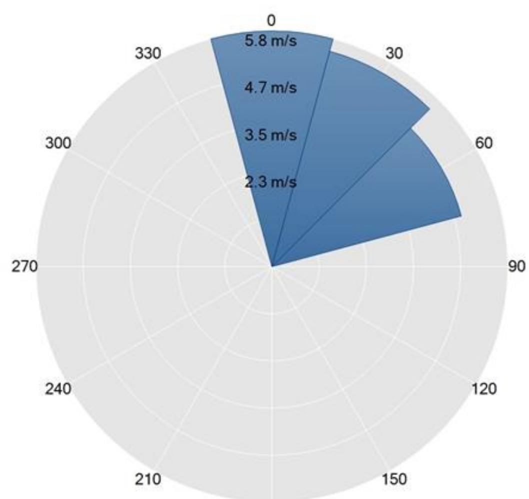
[115] Port Mourant. Wind Data Assessment Report. Supplied by GEA (May 25, 2018)

Port Mourant – Average monthly wind speeds at 132 meters anemometer height.



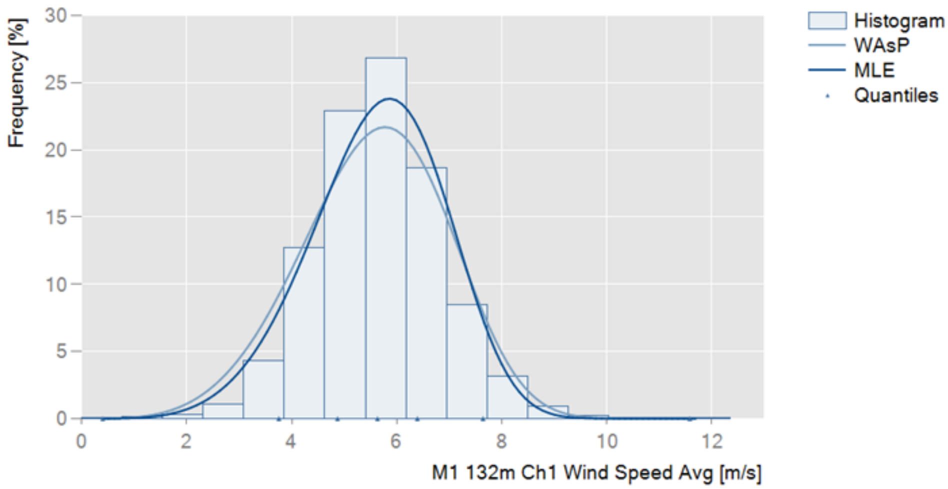
Next figure shows the wind rose displaying the sector wise wind speed. The prevailing wind directions are North, North Northeast.

Port Mourant– Wind speeds and frequency



Next figure shows the wind speed distribution and the fittings using Wasp (Wind Assessment Program) and MLE (Maximum Likelihood Estimation). The frequency graph show that the most frequent wind speed is around 6 m/s and the maximum average wind speed is 10 m/s.

Port Mourant. Wind speed distribution at 132 m.



Next figure shows the Weibull parameters A and k calculated with two methods and the data. But the number observations is very low (15342) corresponding only to a coverage of only 15.3% of the data.

Port Mourant -Weibull A and k parameters estimated by MLE and Wasp

Type	Weibull A [m/s]	Weibull k	Mean [m/s]	St.D. [m/s]	> Mean [%]	Observations [#]
MLE	6.1	5.03	5.6	1.3	51.4	-
WAsP	6.1	4.54	5.6	1.4	49.4	-
Data	-	-	5.6	1.2	49.4	15342

The estimated wind power density at 50 m is 24.4 W/m^2 which is *Wind Power Class Category Poor*.

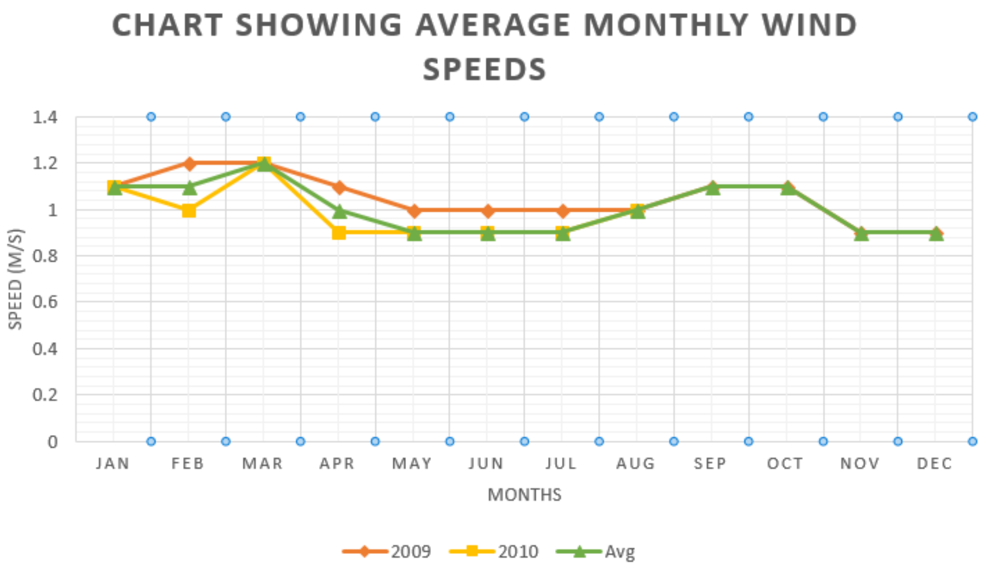
Employing the wind shear coefficient of 0.508 and the Power Law, the extrapolated wind velocity at the hub height of 80 m is 4.38 m/s. The site is a promising site due to two facts: the wind instruments were installed in an inappropriate tower and the data coverage is of only 15.3 %. With the new tower and instruments data of higher confidence are going to be collected.

J.2 Jawalla

The report presents the monthly mean of the wind speed at 30 m anemometer height starting January 2009 and ending August 2010 (20 months)[116]. Next figure shows the monthly average wind speeds.

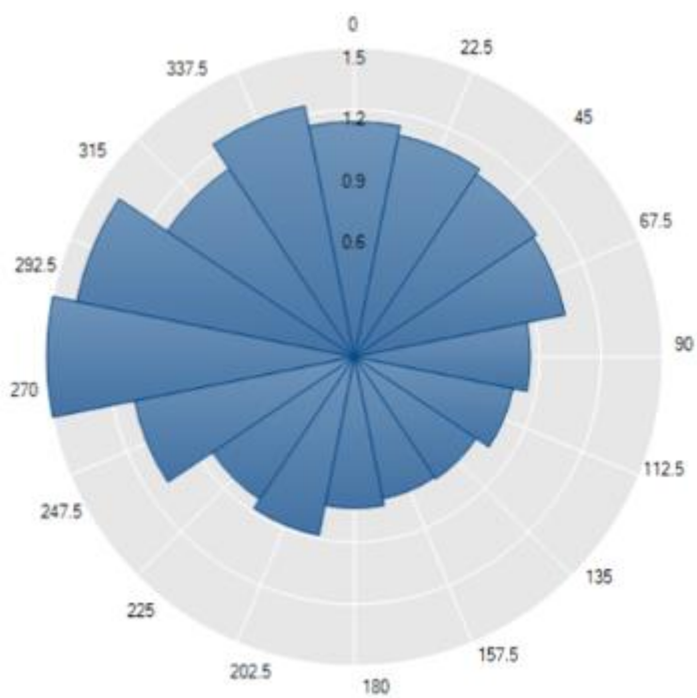
[116] Jawalla. Wind Data Assessment Report. Supplied by GEA (May 25, 2018)

Jawalla – Average monthly wind speeds at 30 meters anemometer height.



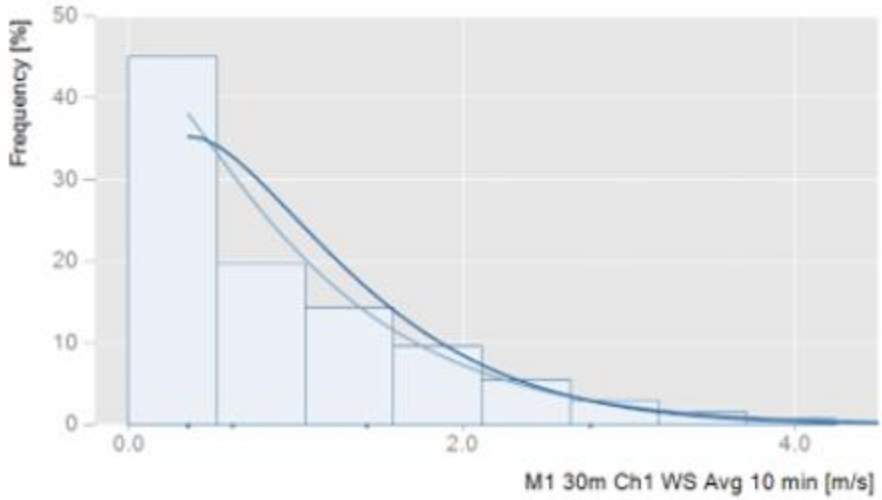
Next figure show the wind rose displaying the sector wise wind speed. The prevailing wind directions are West, West Northwest and North Northwest.

Jawalla – Wind speeds and frequency



Next figure shows the wind speed distribution. The frequency graph show that the most frequent wind speed is close to calm, and the maximum average wind speed is 4 m/s.

Jawalla. Wind speed distribution at 30 m.

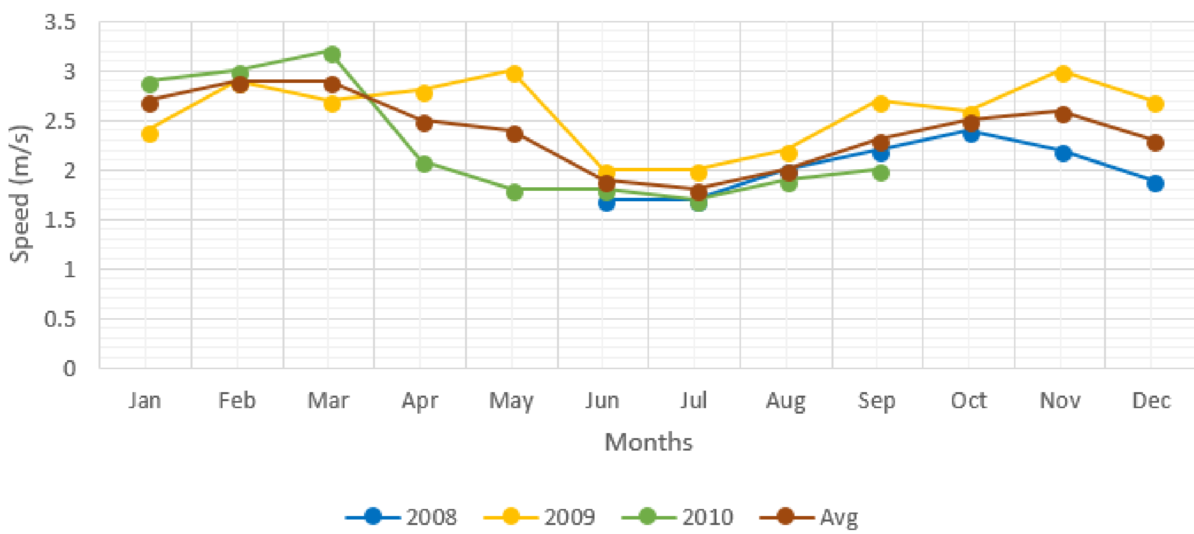


The estimated wind power density at 50 m is 2.9 W/m^2 which is in the *Wind Power Class Category Poor*.

J.3 Orealla

The report presents the monthly mean of the wind speed at 30 m anemometer height starting June 2008 and ending September 2010 (40 months)[117]. Next figure shows the monthly average wind speeds.

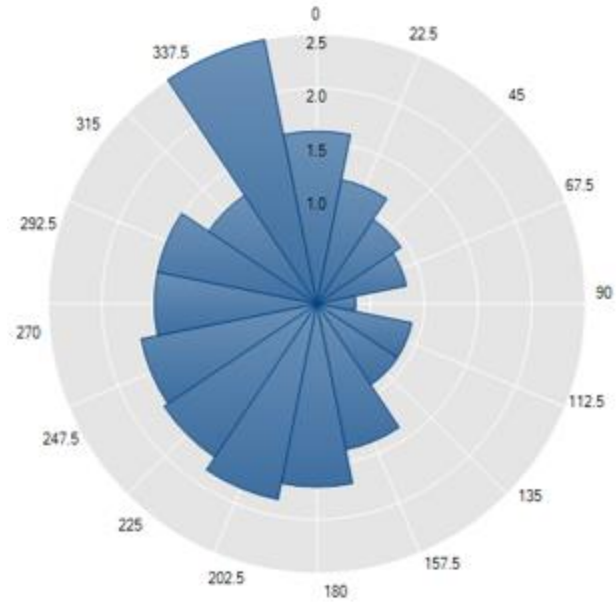
Orealla – Average monthly wind speeds at 30 meters anemometer height



Next figure show the wind rose displaying the sector wise wind speed.

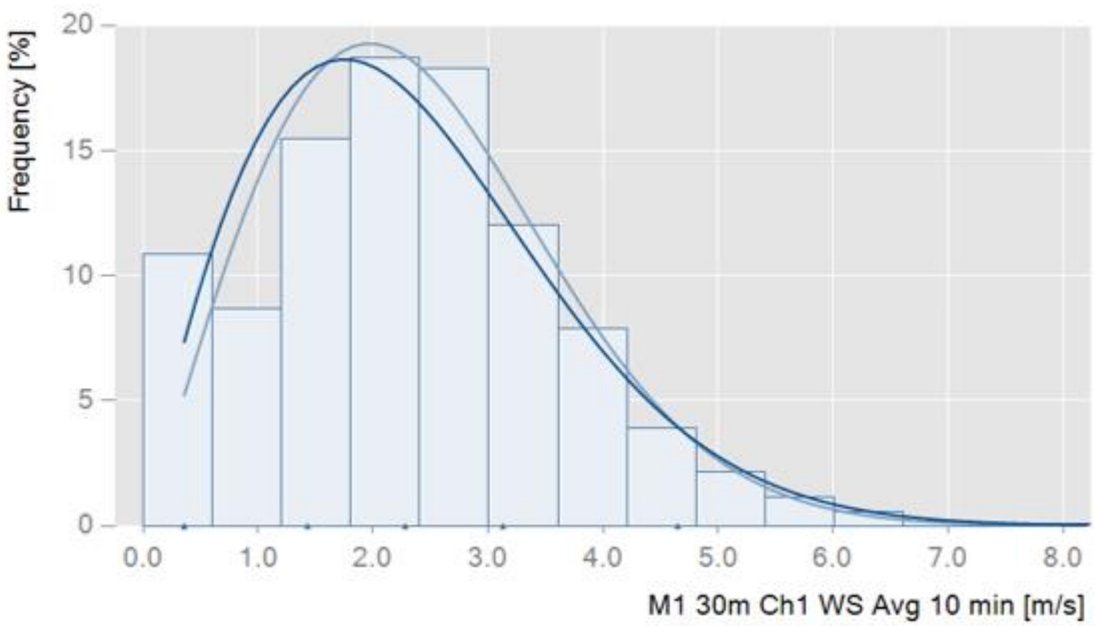
[117] Orealla. Wind Data Assessment Report. Supplied by GEA (May 25, 2018)

Orealla – Wind speeds and frequency



Next figure shows the wind speed distribution. The frequency graph show that the most frequent wind speed is between 2 and 3 m/s, and a low percentage of 10.5% of winds higher than 4 m/s.

Orealla - Wind speed distribution at 30 m.

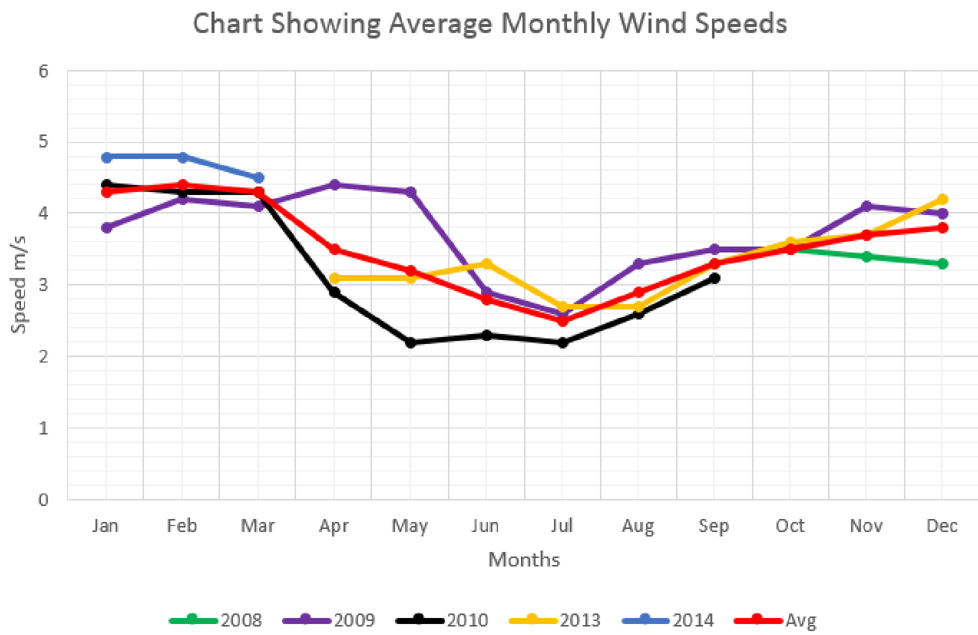


The estimated wind power density at 50 m is 23.8 W/m^2 which is in *Wind Power Class Category Poor*.

J.4 Yuparakari

The report presents the monthly mean of the wind speed at 30 m anemometer height starting October 2008 and ending December 2014 (51 months), with missing information during 15 months[118]. Next figure shows the monthly average wind speeds.

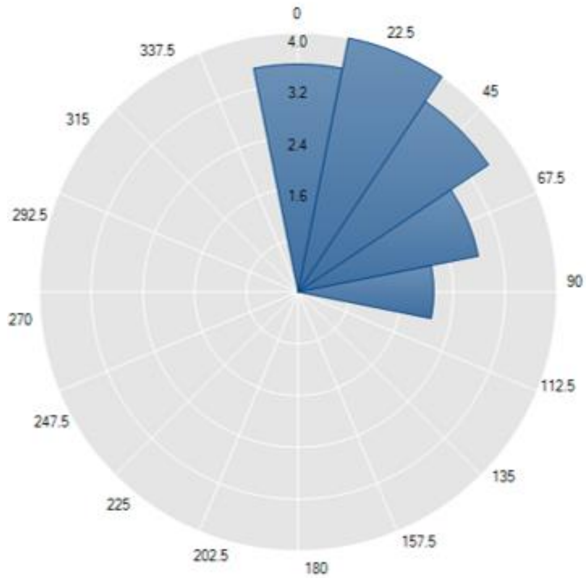
Yupukari – Average monthly wind speeds at 30 meters anemometer height



Next figure show the wind rose displaying the sector wise wind speed. The prevailing wind directions are North Northeast, Northeast and North.

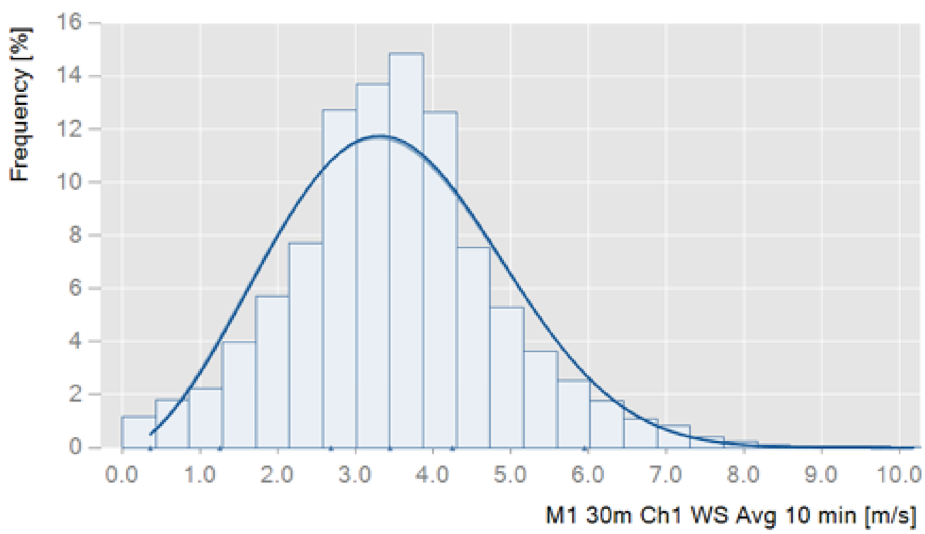
[118] Yupukari. Wind Data Assessment Report. Supplied by GEA (May 25, 2018)

Yupukari – Wind speeds and frequency



Next figure shows the wind speed distribution. The frequency graph show that the most frequent wind speed is between 3 and 4 m/s, and a low percentage of 3% of wind with the required operational velocity of 6 – 7 m/s .

Yupukari - Wind speed distribution at 30 m.

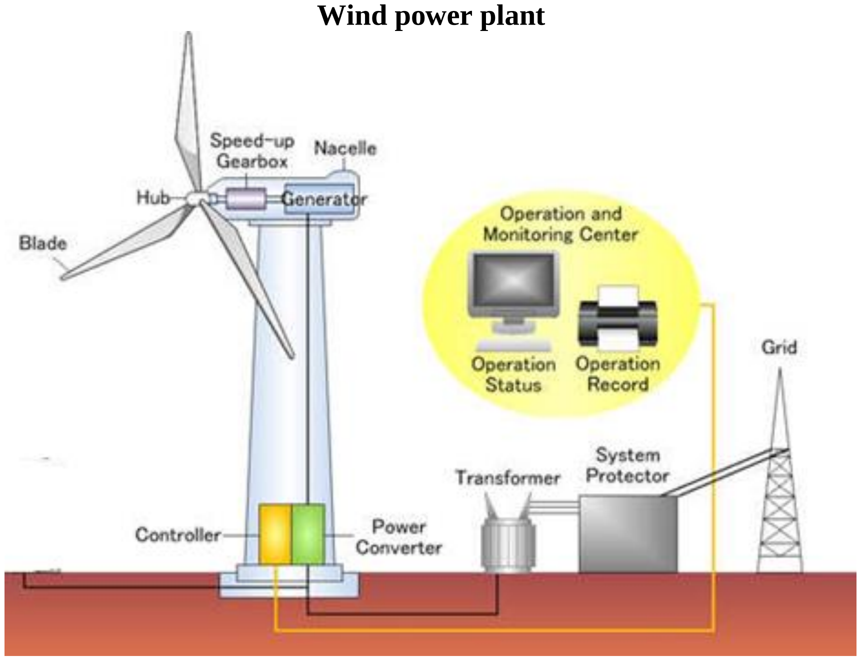


The estimated wind power density at 50 m is 61.2 W/m^2 which is in the *Wind Power Class Category Poor.*

Appendix K . Wind Power Plant Basics

The turbine's long rotor blades catch the wind's energy. In the nacelle at the top of the tower, the rotor driven gear box increases the speed of the drive shaft that turns the generator to produce electricity. A transformer boosts the voltage and feeds it to the power system.

Wind power plant



A wind power plant consists essentially of several turbines interconnected to the grid. Each wind turbine has its own generator, controller and power converter connected to the transformer that feeds the grid.

The wind turbines are properly distributed on a terrain to take advantage of the dominant wind direction, to reduce the losses of the wake effect produced by each turbine on the output of the other turbines of the farm and the interconnection of the wind turbines to the grid.

K.1 Costs

For the computation of the LCOE (Levelized Cost of Energy), two types of costs need to be considered: Capital costs, and Operation and Maintenance Costs (O&M).

K.1.1 Panama Costs

In the "Indicative Expansion Plan of Panamá (2017-2031), the developers have register a total 13 Wind Projects, for a total capacity of 1097 MW, a capacity average of 84 MW (maximum 136 MW, minimum 19.8 MW). The average investment cost is 2044 US$/kW (maximum 3030 US$/kW, minimum 1500 US$/kW).

Panama – Characteristics of the Wind Power Plants included in the Indicative Expansion Plan (2017-203)

Panama Wind Projects Portfolio Characterics	Capacity (MW)	Investment Cost (US$/kW)	Fixed O&M (US$/kW-year)	Useful life (Years)	Annual Energy (GWh)	Capacity Factor
Summ	1097				3160.45	
Average	84.38	2044.19	52.36	25.00	243.11	32.70%
Max	136	3030.3	130.43	30	383.71	44.09%
Min	19.8	1500	14.58	20	48.73	22.25%
Std Deviation	38.500	453.533	29.139	4.082	116.836	0.058
Count	13	13	13	13	13	13

Source: Plan Indicativo de Expansión de Panamá (2017-2030). ETESA. Panama

For WPP in the capacity range 19.8-32 MW, there are 3 projects, with an average capacity of 25.6 MW, average investment cost of US$2210/kW, average O&M of US$38.40/kW-year, average useful life of 21.7 years and average capacity factor of 30.34%.

For WPP in the capacity range 69-136 MW, there are 10 projects, with an average capacity of 102.02 MW, average investment cost of US$1994/kW, average O&M of US$56.54/kW-year, average useful life of 26 years and average capacity factor of 33.41%.

Panama – Characteristics by capacity ranges of the Wind Power Plants included in the Indicative Expansion Plan (2017-203)

		Averages					
Capacity Range (MW)	Projects	Capacity (MW)	Investment Cost (US$/kW)	Fixed O&M (US$/kW-year)	Capacity Factor	Useful life (Years)	Annual Energy (GWh)
19.8-32.0	3	25.6	2210	38.40	30.34%	21.7	67.4
69-136	10	102.02	1994	56.54	33.41%	26.0	295.83
Total	13						

Source: Plan Indicativo de Expansión de Panamá (2017-2030). ETESA. Panama

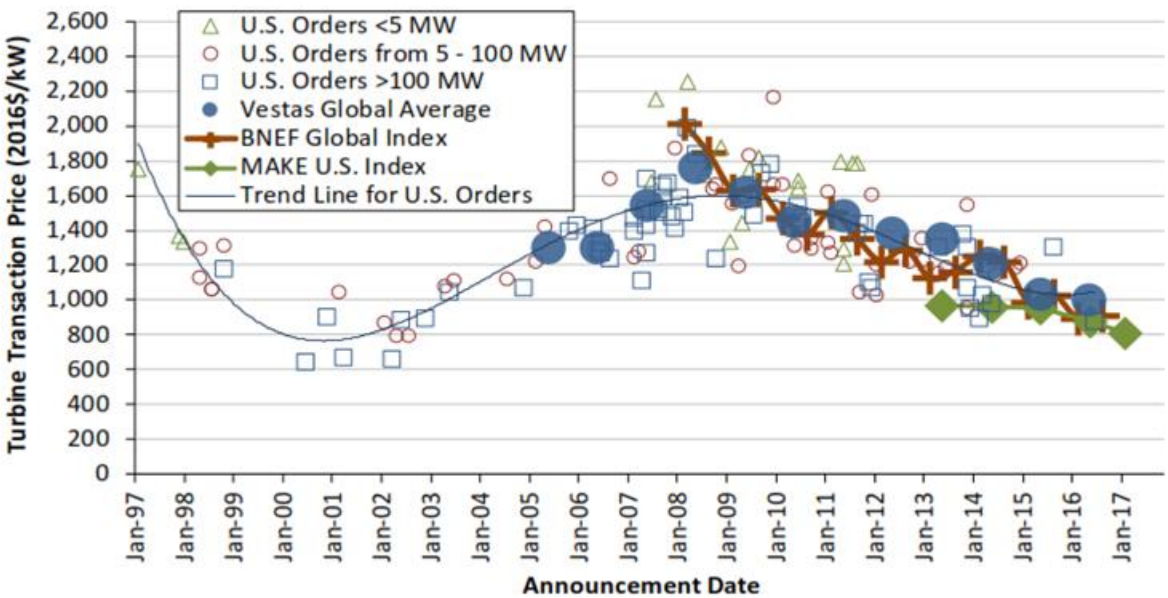
K.1.2 US DOE - LBL Information

A more detailed cost information can be found in the series of reports of the National Renewable Laboratory, and US Department of Energy and Lawrence Berkeley Lab, all from USA.

Turbine prices

Wind turbine prices have dropped substantially since 2008, despite continued technological advancements that have yielded increases in hub heights and especially rotor diameters. Further decreases occurred in 2016, with wind turbines sold at price points like the early 2000s. Next figure shows the evolution of turbine prices since 1997 up to January 2017, with and end value of turbines in 2017 of US$800/kW. Major drivers of this decrease have been increases in hub height, larger rotor diameters.

Reported wind turbine transaction prices over time

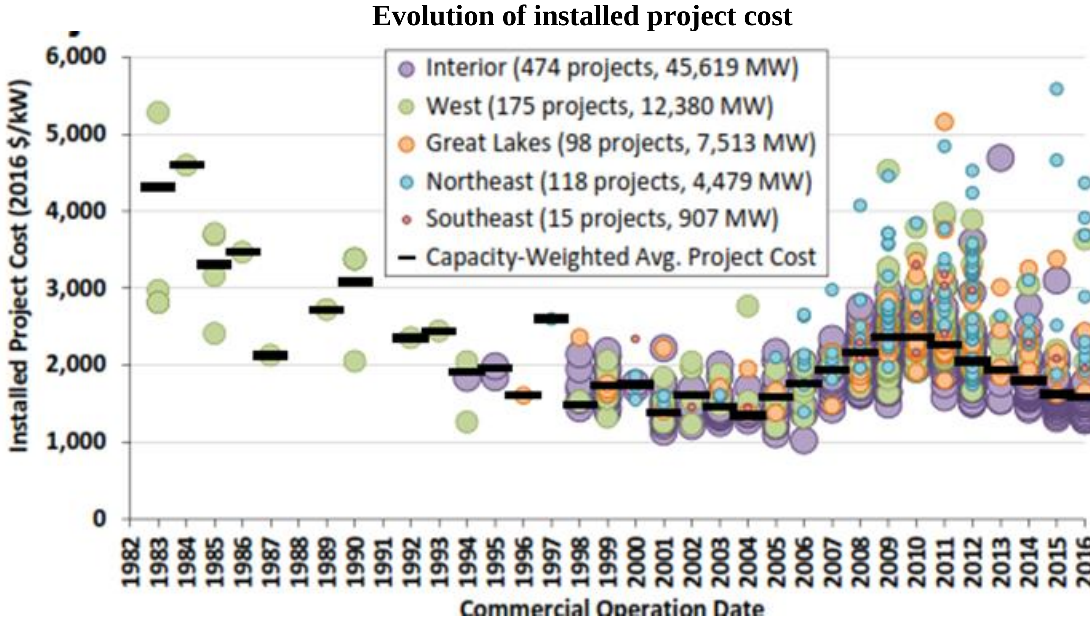


Source: Wiser, R. and M. Bolinger. 2016 Wind Technology Market Report. US Department of Energy and LBL (2017) Washington, D.C.

Project costs

Next figure shows the evolution of the installed cost of projects and how its declined from the eighties to the early two thousand, an increase around 2010 and since then, until today, a decline below US$2000/kW driven mainly by lower turbine prices.

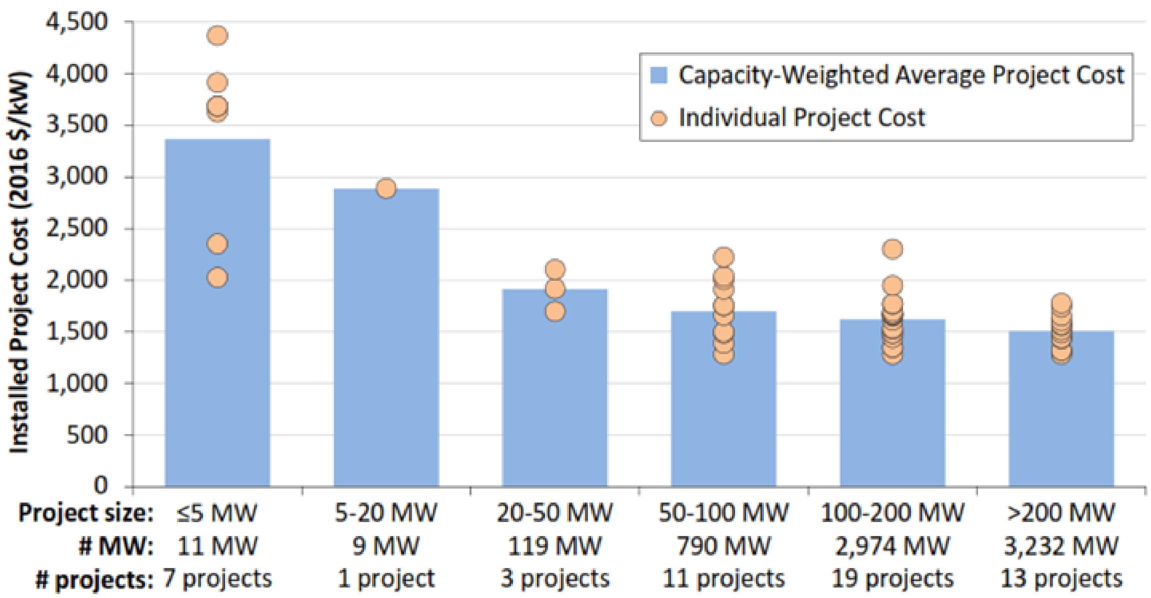
Evolution of installed project cost



Source: Wiser, R. and M. Bolinger. 2016 Wind Technology Market Report. US Department of Energy and LBL (2017) Washington, D.C.

Average installed project costs exhibit economies of scale, especially at the lower end of the project size range. Next figure shows that among the sample of projects installed in 2016, there is a substantial drop in per-kW average installed costs when moving from projects of 5 MW or less to projects in the 20–50 MW range. Economies of scale continue, though to a lesser degree, as project size increases beyond 50 MW. For 7 projects of capacity lesser than 5 MW, the installed cost was around US$3400/kWp whereas for projects between 5-20 MW around US$2900/kW and US$1900 for projects in the range 20-50 MW, with a continued decline in the installed project cost to US$1500/kW for projects with a capacity large than 200 MW.

Installed wind power project cost by project size: 2016 projects

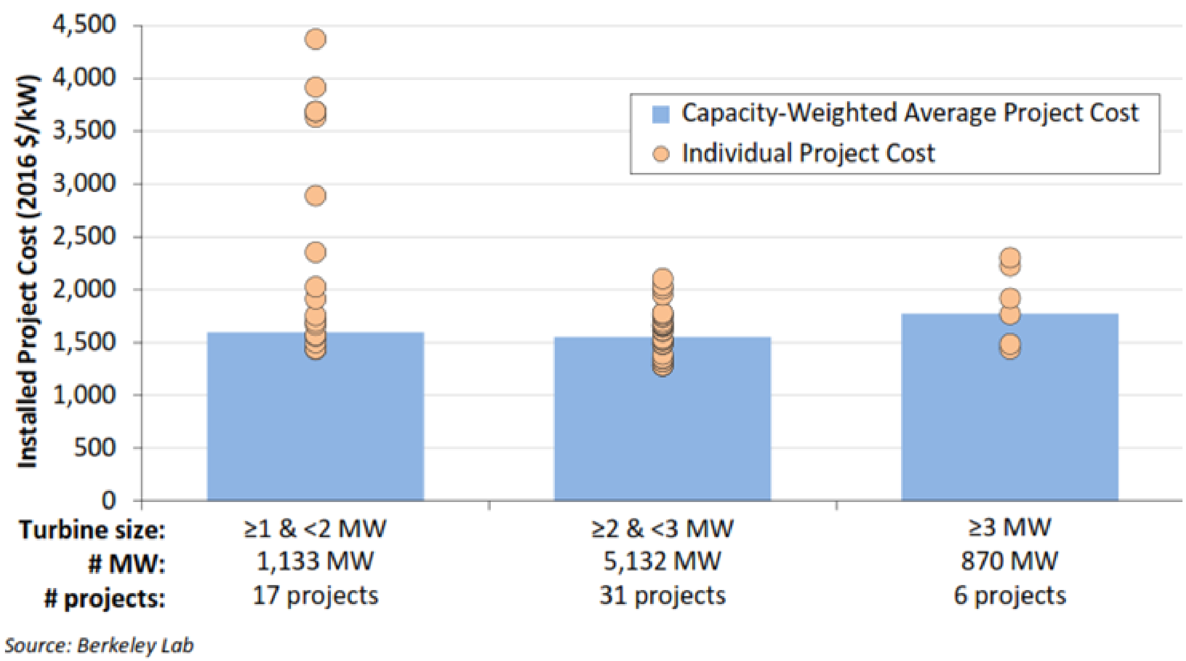


Source: Berkeley Lab

Source: Wiser, R. and M. Bolinger. 2016 Wind Technology Market Report. US Department of Energy and LBL (2017) Washington, D.C.

Next figure shows the installed project cost by turbine size. For turbines in the range 1-2 MW, there is a wide range for the project costs, but the capacity weighted average project cost is around US$1600/kW, also for the turbine capacity range 2-3 MW.

Installed wind power project cost by turbine size: 2016 projects



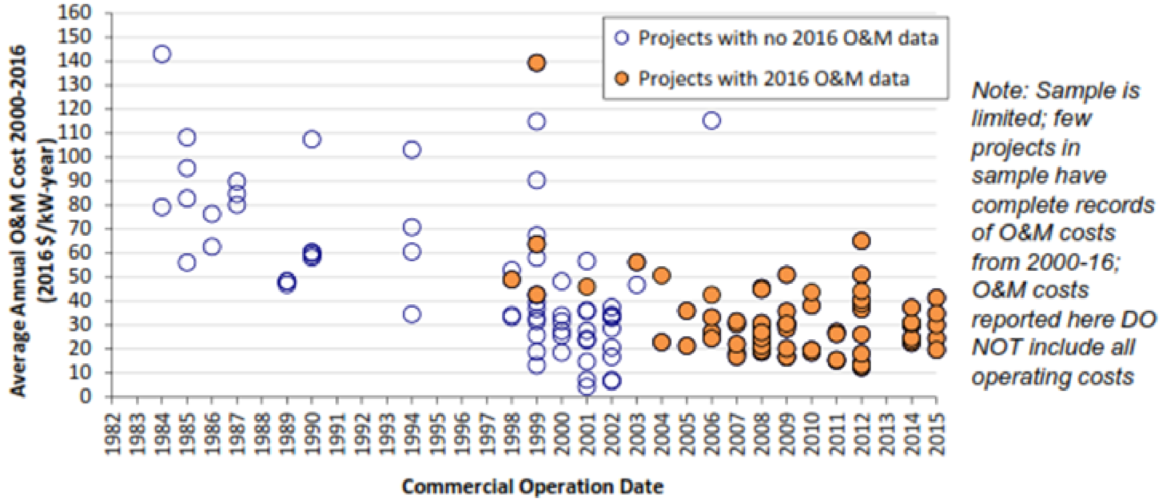
Source: Wiser, R. and M. Bolinger. 2016 Wind Technology Market Report. US Department of Energy and LBL (2017) Washington, D.C.

From the two previous figures the major impact is from the project capacity.

K.2 O&M

O&M costs are important component of the overall costs of wind energy and can vary substantially among projects. Publicly available information on O&M is very limited. Increase in the of O&M are expected as turbines age (component failures become more common) and warranties expires. But more recently installed turbines, with larger turbines, benefit of sophisticated designs and the overall O&M costs may experience a lower cost on a $/kW-year basis. Next figure shows the wide range of annual costs of O&M.

O&M Cost by project age and commercial operations date



Source: Wiser, R. and M. Bolinger. 2016 Wind Technology Market Report. US Department of Energy and LBL (2017) Washington, D.C.

Capacity-weighted average 2000-16 O&M costs for projects built in the 1980s equal $69/kW-year, dropping to $57/kW-year for projects built in 1990s, to $28/kW-year for projects built in the 2000s, and to $27/kW-year for projects built since 2010

K.3 NREL Information

A further analysis performed by NREL considers a Utility Scale Wind Farm of 200 MW, employing 93 wind turbines each one rated at 2.16 MW. The importance of the analysis lies in the disaggregation of the components in terms of technology and costs.

For a 2.16 MW turbine, next table shows de disaggregation of CapEx in three major items: Turbine capital cost (US$1071/kW), BOS (Balance of System) US$364/kW and Financial Costs (US$155/kW) for a total CapEx of US$1590/kW. This figure is in accordance with the scale of the projects showed in the previous figure. With respect to the previous 2016 report, there is a decrease in CapEx of 100 US$/kW.

Reference project- Turbine CapEx

	2.16-MW Land-Based Turbine ($/kilowatt [kW]) Market
Rotor module	**303**
Blades	193
Pitch assembly	64
Hub assembly	46
Nacelle module	**527**
Nacelle structural assembly	105
Drivetrain assembly	205
Nacelle electrical assembly	185
Yaw assembly	32
Tower module	**240**
Turbine capital cost	1,071
Development cost	18
Engineering management	20
Foundation	65
Site access and staging	50
Assembly and installation	48
Electrical infrastructure	163
Balance of system	364
Construction financing cost	60
Contingency fund	95
Financial costs	155
Total capital expenditures	1,590

Source: Stehly, T, D. Heimiller and G. Scott. 2016 Cost of Wind Energy Review. National Renewable Energy Laboratory (December 2017) Golden, Co. USA. Page 47

For the computation of the annual energy production of the reference project analyzed in NREL's report, turbine parameters, wind resources characteristics and losses are given in the next tables.

Reference project- Turbine parameters

Turbine Parameters	
Turbine rated power (MW)	2.16
Turbine rotor diameter (m)	108
Turbine hub height (m)	84
Maximum rotor tip speed (meters per second [m/s])	80
Tip-speed ratio (TSR) at maximum coefficient of power (C_p)	8
Drivetrain design	Geared
Cut-in wind speed (m/s)	3
Cut-out wind speed (m/s)	25
Maximum coefficient of power	0.47

Source: Stehly, T, D. Heimiller and G. Scott. 2016 Cost of Wind Energy Review. National Renewable Energy Laboratory (December 2017) Golden, Co. USA. Page 9

Reference project- Wind Resource Characteristics

Wind Resource Characteristics	
Annual average wind speed at 50-m height (m/s)	7.25
Annual average wind speed at 84-m hub height (m/s)	7.81
Weibull k	2.0
Shear exponent	0.143
Turbine elevation (meters above sea level)	450

Source: Stehly, T, D. Heimiller and G. Scott. 2016 Cost of Wind Energy Review. National Renewable Energy Laboratory (December 2017) Golden, Co. USA. Page 9

Reference project- Wind Losses and Availability Assumptions

Losses	
Losses (i.e., array, energy conversion, and line)	15%
Availability	98%

Source: Stehly, T, D. Heimiller and G. Scott. 2016 Cost of Wind Energy Review. National Renewable Energy Laboratory (December 2017) Golden, Co. USA. Page 10

The AEP (Annual Energy Production) is the net energy generated by the Wind Plant.

Next table shows the AEP and the Net Capacity Factor of 41% for the Reference Project.

Reference project- Wind Plant AEP and Capacity Factor Summary

AEP and Capacity Factors	7.25 m/s at 50 m
Net energy capture (MWh/MW/year)	3,588
Net capacity factor (%)	41%

Source: Stehly, T, D. Heimiller and G. Scott. 2016 Cost of Wind Energy Review. National Renewable Energy Laboratory (December 2017) Golden, Co. USA. Page 10

OpEx costs are generally expressed in two categories: 1) fixed O&M costs (e.g., scheduled plant maintenance or land lease costs) and 2) variable O&M costs (e.g., unscheduled plant maintenance). For simplicity, annual OpEx can be converted to a single term and expressed as either dollars per kilowatt per year ($/kW/yr) or dollars per megawatt-hour ($/MWh). NREL analysis uses the dollars-per-kilowatt-per-year convention. The figure of the DOE-LBL analysis is US$27/kW/year for Fixed O&M.

Reference project- OpEx

	2.16-MW Land-Based Turbine ($/kW/yr)
Operations	15.2
Land lease cost	8.1
Maintenance	28.4
OpEx	**51.7**

Source: Stehly, T, D. Heimiller and G. Scott. 2016 Cost of Wind Energy Review. National Renewable Energy Laboratory (December 2017) Golden, Co. USA. Page 11

The LCOE has been computed employing the CRF (Capital Recovery Factor). The CRF is defined as the uniform periodic payment, as a fraction of the original investment cost that will fully repay a loan including all interest, over the term of the loan. T. he CRF can be thought of as the recurring fixed payment over the life of a loan common to most types of mortgages. For example, a $100 loan at 8% interest amortized over 20 years requires a constant annual payment of $10.18 (equivalent to the CRF). Notably, the CRF ignores the impact of corporate income taxes, thus is applicable to a no-tax investment scenario, such as from a government investment.

Reference project - Inputs and LCOE

	2.16-MW Land-Based Turbine ($/kW)	2.16-MW Land-Based Turbine ($/MWh) Market
Turbine capital cost	1,071	23.5
Balance of system	364	8.0
Financial costs	155	3.4
CapEx	**1,590**	**34.9**
OpEx ($/kW/yr)	**52**	**14.4**
Fixed charge rate (real) [%]	7.9%	
Net annual energy production (MWh/MW/yr)	3,588	
Net capacity factor (%)	41%	
TOTAL LCOE ($/MWh)	**49**	

Source: Stehly, T, D. Heimiller and G. Scott. 2016 Cost of Wind Energy Review. National Renewable Energy Laboratory (December 2017) Golden, Co. USA. Page 9

With respect of the 2016 report, the LCOE decreased to 49 US$/MWh, instead of 61 US$/MWh two years before. For the near future, it is expected a decrease in the LCOE due to taller towers, larger rotors, both taller tower and larger rotor, higher wind speeds and the combination of all these improvements. If both technological advancements can be implemented with a concurrent increase in either CapEx and OpEx, the net effect would be the decrease of the LCOE from 66 US$/MWh to 52 US$/MWh.

K4. EIA Information

The agency Energy Information Administration from USA also provide cost indicators for wind power plants in its publication “Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2018”. The tables presented below represents EIA’s assessment of the cost to develop and install various generating technologies used in the electric power sector. The costs shown represent costs for a typical facility for each generating technology before adjusting for regional cost factors. Overnight costs exclude interest accrued during plant construction and development. Wind technologies demonstrate some degree of variability in cost based on project size, location, and access to key infrastructure (such as grid interconnections, fuel supply, and transportation).

Technology	First available year[1]	Size (MW)	Lead time (years)	Base overnight cost (2017 $/kW)	Project Contin-gency Factor[2]	Techno-logical Optimism Factor[3]	Total overnight cost[4,10] (2017 $/kW)	Variable O&M[5] (2017 $/MWh)	Fixed O&M (2017$/ kW/yr)
Wind[10]	2020	100	3	1,548	1.07	1.00	1,657	0.00	47.47
Wind Offshore[8]	2021	400	4	4,694	1.10	1.25	6,454	0.00	78.56

10/ Total overnight cost shown in the table represents the average input value across all 22 electricity market regions, as weighted by the respective capacity of that type installed during 2016 in each region to account for the substantial regional variation in wind

For onshore wind power plants, EIA cost estimates are similar as the costs parameters for the reference project estimated with NREL information (Capex US$ 1,657/kW IEA vs US$ 1,590/kW NREL and Opex US$ 47.47/kW-year vs US$ 51/kW-year NREL.

K.4 Costs Summary

Next table shows a summary of cost data from different sources for wind plants, in various scales and for different applications. These figures provide an indication of the variability of the Capex and Opex costs for wind power plants.

Cost summary for Utility-Scale Wind Power Plants

Source	Scale	Technology Type	Scale/ Application	Year	($/kW) Mean installed cost	($/kW-yr) Fixed O&M	(yr) Economic Lifetime	Source
NREL ATB	Utility	Land Based Wind - 100 GW	Utility Scale - TRG - L	2018	$ 1,375	$ 49	20	NREL (National Renewable Energy Laboratory). 2017. *2017 An* Golden, CO: National Renewable Energy Laboratory. http://www.nrel.gov/analysis/data_tech_baseline.html
NREL ATB	Utility	Land Based Wind - 100 GW	Utility Scale - TRG - M	2018	$ 1,474	$ 50	20	NREL (National Renewable Energy Laboratory). 2017. *2017 An* Golden, CO: National Renewable Energy Laboratory. http://www.nrel.gov/analysis/data_tech_baseline.html
NREL ATB	Utility	Land Based Wind - 100 GW	Utility Scale - TRG - H	2018	$ 1,573	$ 51	20	NREL (National Renewable Energy Laboratory). 2017. *2017 An* Golden, CO: National Renewable Energy Laboratory. http://www.nrel.gov/analysis/data_tech_baseline.html
Panama - Indicative Expansion Plan (2017-2031)	Utility	WP 19.8-32.0 MW	Utility Scale	2017	$ 2,210	$ 38	22	Indicative Expansion Plan 2017-2031. ETESA. (June 2017) Ciudad
Panama - Indicative Expansion Plan (2017-2031)	Utility	WP 69-136 MW	Utility Scale	2017	$ 1,994	$ 57	26	Indicative Expansion Plan 2017-2031. ETESA. (June 2017) Ciudad
NREL	DG	Wind <10 kW	Distributed Generation	2016	$ 7,645	$ 40		NREL (National Renewable Energy Laboratory). Upda Generation Renewable Energy Estimate of Costs. Go Energy Laboratory. https://www.nrel.gov/analysis/tech
NREL	DG	Wind 10–100 kW	Distributed Generation	2016	$ 6,118	$ 35		NREL (National Renewable Energy Laboratory). Upda Generation Renewable Energy Estimate of Costs. Go Energy Laboratory. https://www.nrel.gov/analysis/tech
NREL	DG	Wind 100–1000 kW	Distributed Generation	2016	$ 3,751	$ 31		NREL (National Renewable Energy Laboratory). Upda Generation Renewable Energy Estimate of Costs. Go Energy Laboratory. https://www.nrel.gov/analysis/tech
NREL	DG	Wind 1–10 MW	Distributed Generation	2016	$ 2,346	$ 33		NREL (National Renewable Energy Laboratory). Upda Generation Renewable Energy Estimate of Costs. Go Energy Laboratory. https://www.nrel.gov/analysis/tech

Source	Scale	Technology Type	Scale/ Application	Year	Mean installed cost	Fixed O& M	Economic Lifetime	Source
Department of Energy - LBL	Utility	WP ≤5 MW	Utility Scale	2016	$ 3,369	$ 27	25	Wiser, R. and M. Bolinger. 2016 Wind Technology Market Report. US Department of Energy and LBL (2017) Washington, D.C.
Department of Energy - LBL	Utility	WP >5 MW & ≤20 MW	Utility Scale	2016	$ 2,889	$ 27	25	Wiser, R. and M. Bolinger. 2016 Wind Technology Market Report. US Department of Energy and LBL (2017) Washington, D.C.
Department of Energy - LBL	Utility	WP >20 MW & ≤50 MW	Utility Scale	2016	$ 1,915	$ 27	25	Wiser, R. and M. Bolinger. 2016 Wind Technology Market Report. US Department of Energy and LBL (2017) Washington, D.C.
Department of Energy - LBL	Utility	WP >50 MW & ≤100 MW	Utility Scale	2016	$ 1,700	$ 27	25	Wiser, R. and M. Bolinger. 2016 Wind Technology Market Report. US Department of Energy and LBL (2017) Washington, D.C.
Department of Energy - LBL	Utility	WP >100 MW & ≤200 MW	Utility Scale	2016	$ 1,623	$ 27	25	Wiser, R. and M. Bolinger. 2016 Wind Technology Market Report. US Department of Energy and LBL (2017) Washington, D.C.
Department of Energy - LBL	Utility	WP >200 MW	Utility Scale	2016	$ 1,505	$ 27	25	Wiser, R. and M. Bolinger. 2016 Wind Technology Market Report. US Department of Energy and LBL (2017) Washington, D.C.
NREL 2015 Wind Cost Review	Utility	Land based, 2 MW wind generator	Utility scale	2015	$ 1,690	$ 51	20	Moné, C. et. al. 2015 Cost of Wind Energy Review. National Renewable Energy Laboratory (March 2017) Golden, Co. USA. https://emp.lbl.gov/publications/2015-cost-wind-energy-review

DG: Distributed Generation. LBL: Lawrence Berkeley Lab, USA. NREL: National Renewable Energy Lab, USA

Appendix L . Natural gas prices

L.1 Natural gas prices in Trinidad & Tobago

Source: http://energynow.tt/blog/trinidad-tobago-natural-gas-prices-down-35-in-2016

The average gas selling prices of two major upstream producers in Trinidad & Tobago declined by approximately 35% between 2015 and 2016, with BP reporting average prices of US$1.72 in 2016 and EOG Resources reporting average prices of US$1.88 per mmscf. These figures are taken from the company's Annual Reports and SEC filings; in the case of BP, the figure quoted is for their South American region, but as Trinidad & Tobago, is their only gas producing asset in the region, the price can be assumed to be the Trinidad & Tobago price.

Both companies reported prices that were below the benchmark Henry Hub price, which averaged US$ 2.52 per mmbtu in 2016 (see box for explanation of units).

The prices obtained by these two major upstream gas producers in Trinidad & Tobago are significantly lower than the prices that they were able to secure in many other markets where they operate. For BP in 2016, Trinidad & Tobago represented their lowest gas prices out of all their global locations, with their gas fetching averaging as much as US$ 5.71 per mmscf in the Australasia region. For EOG Resources, their Trinidad & Tobago operations were able to sell gas at a higher price than their US operations, where they only average US$1.60 per mmcf, though significantly lower than their other international operations, which obtained prices of US$3.64 per mmcf.

This is the first time that BP's Trinidad & Tobago selling prices have dipped below the Henry Hub price since 2011, when they averaged US$ 4 per mmbtu. The average selling price for bp reflects a combination of gas sold to LNG through the various marketing arrangements for the four different trains and gas sold to the National Gas Company (NGC) under long-term contracts. EOG Resources on the other hand sells all of its gas to the NGC.

The details of these contracts are all subject to commercial confidentiality and not in the public domain, but it is public knowledge that the newer vintage EOG contract prices are linked with final commodity prices, while BP's prices from NGC are at fixed prices, with a gentle price escalation over time. NGC and BP have been involved in intense negotiations for a new gas supply contract to come into effect in January 2019, which the Prime Minister and both companies have recently reported is very close to finalization.

In most years, BP has secured higher prices for its natural gas in Trinidad & Tobago than EOG Resources, because of its access to international LNG markets through Atlantic. Since the advent of US shale gas, most of this gas would have been sold to South American markets. The higher LNG prices that BP was able to access through LNG sales partially offset the lower prices under the long-term NGC contracts. The fact that BP was unable to secure higher prices than EOG in 2015 and 2016 reflects the weakness of LNG prices in both global and South American markets. Lower gas production from bpTT also meant that the company was unable to sell as much gas as LNG, also acting as a dampener on their average selling price even when LNG prices were higher than the selling price to NGC.

The weakness in Trinidad and Tobago gas prices in 2016 underlines both the challenge to the government in collecting taxation from a sector whose profitability would have been severely challenged and the challenge for the respective companies to commit much needed capital to increase production.

L.2 Wellhead natural gas price in Peru

2017

Factor de Actualización del Precio del Gas Natural en Boca de Pozo - Lote 88

FACTOR DE ACTUALIZACIÓN DEL PRECIO DE GAS EN BOCA DE POZO

$$\boxed{FA = 0,60 * \frac{Ind1_i}{Ind1_0} + 0,40 * \frac{Ind2_i}{Ind2_0}} \quad (1)$$

Donde:

Ind1 = Promedio aritmetico del indice Oil Field and Gas Field Machinery (WPU1191), publicado por el Department of Labor - USA
Ind2 = Promedio aritmetico del indice Fuel and related products and power (WPU 05), publicado por el Department of Labor - USA

Periodo Base (0)	Indices	
	$Ind1_0$	$Ind2_0$
Dic 1999 - Nov 2000	128,00	101,08

Periodo Móvil (i)	Indices	
	$Ind1_i$	$Ind2_i$
Dic 2015 - Nov 2016	215,24	144,86

Calculado al	Factor de Ajuste del Año Anterior (2)	Factor de Ajuste Calculado (3)
01-ene-17	1,6647	1,5822

(1) Fórmula establecida en el literal b) del subacápite 8.4.4.1 de la Cláusula Octava del Contrato de Licencia del Lote 88, modificado por adenda suscrita el 06 de agosto de 2014. En dicha Adenda se reemplazó el Índice WPS1191 por el Índice WPU1191.

(2) Factor de Ajuste aplicado desde enero de 2016.

(3) Según la quinta modificacion al contrato de licencia literal c) párrafo 2 durante los 5 años subsiguientes a partir del 01.01.2013, la aplicación del factor de ajuste determinado en el literal b) no representará un incremento acumulado anual en el Precio máximo realizado superior al 7%.

Source. http://www.osinergmin.gob.pe/seccion/centro_documental/gart/PliegosTarifarios/FBP01012017.pdf

PRECIO DEL GAS NATURAL ACTUALIZADO - 2017 (US$/MMBTU)

CASO : GENERADORES ELECTRICOS

Precio Actualizado el	Precio Base Actualizado el 01-ene-17	Precio Aplicado en el 2016	Variación %	Precio Aplicable para el 2017 (4)
01-ene-17	1,5822	1,6647	-4,96%	1,5822

(4) La aplicación del factor de ajuste no representó un incremento acumulado anual superior a (7%).

CASO : OTROS CONSUMIDORES DE CALIDDA

Precio Actualizado el	Precio Base Actualizado el 01-ene-17	Precio Aplicado en el 2016	Variación %	Precio Aplicable para el 2017 (5)
01-ene-17	2,8480	2,9965	-4,96%	2,8480

(5) La aplicación del factor de ajuste no representó un incremento acumulado anual superior a (7%).

Nota: Valores calculados en base a la información disponible a la fecha.
Nuestos cálculos deben ser tomados únicamente como referencia.

Appendix M . Transmission connection specifications

230 kV TRANSMISSION SYSTEM SECC1-LINDEN & LINDEN - GARDEN OF EDEN

Line SECC1-LINDEN-GOE	161	km	Arco Norte Study		
	280	US$k/km	Implicit Arco Norte Study		
	45.1	US$M	Arco Norte Study (Prices 2015)		
	1.071		Indexation to 2017		
	48.3	US$M	Prices 2017		
Section SECC1 - LINDEN (52%)	25.1	US$M	Aprox	314	US$k/km
Section LINDEN - GOE (48%)	23.2	US$M	Aprox	290	US$k/km

Swithching Substation SECC1

Bays at 230 kV	2	Pair of 2 bays
Unitary Cost	3500	US$/2 Bays (ETESA, Panamá)
Total	7.0	US$M

Linden Substation

Bays at 230 kV	2	Pair of 2 bays
Unitary Cost	3500	US$/2 Bays (ETESA, Panamá)
Subtotal	7.0	US$M
Transformer cost (230/169/13.8 kV)	4.0	US$M
Total	11.0	US$M

Garden of Eden Substation

Total cost	33.3	US$M	Arco Norte Study (Prices 2015)
	1.071		Indexation to 2017
	35.7	US$M	Prices 2017

Line & Substations by sections

SECC1 - LINDEN	32.1	US$M
LINDEN - GARDEN OF EDEN	69.8	US$M
Useful life	40	years
O&M costs	*2.5*	*% Investm/year*

TRANSMISSION CONNECTION OF THE NEW POWER PLANT

Planta to Columbia	5.0	km
Columbia - Good Hope	26.6	km
Good Hope - New Sophie	10.0	km
Total	41.6	km
Transmission Line (2c-230kV)	290.0	US$k/km (ETESA, Panamá, Conductor 636 ACSR, Includes IDC)
Total Line	12.1	US$M
Bays at 230 kV	2	Pair of 2 bays
Unitary Cost	3500	US$/2 Bays (ETESA, Panamá)
Total bays	7.0	US$M
Transformer & Others	6.0	US$M
Total Transmission System	***25.1***	***US$M***
Useful life	*40*	*years*
O&M cost	*2.5*	*% Investm/year*

Appendix N . Natural gas availability cases

N.1 Case with 50 mmcfd of natural gas

DEVELOPMENT OF THE NEW NATURAL GAS POWER PLANT
Preliminary Financial Analysis

	2020	2021	2022	2023	2024	2025	2030	2035
INSTALLED CAPACITY (MW)		34	34	102	136	170	255	272
GENERATION - HFO (GWH)		116	92					
GENERATION - NG (GWH)				741	994	1,209	1,826	1,906
TOTAL GENERATION (GWH)		116	92	741	994	1,209	1,826	1,906
Plant Factor		0.39	0.31	0.83	0.83	0.81	0.82	0.80
Heat Rate (BTU/kWh)		8.5	8.5	8.5	8.5	8.5	8.5	8.5
MBTU HFO		989	782					
MBTU NG				6,302	8,453	10,277	15,517	16,204
Price HFO (US$/MBTU)		10.6	11.7					
Price NG (US$/MBTU, wellhead)				4.7	4.7	4.7	4.7	4.7
Transm. Losses (%)		2%	2%	2%	2%	2%	2%	2%
SALES (GWH)		114	90	727	975	1,185	1,789	1,868
Price (US$/MWh)		72.0	72.0	72.0	72.0	72.0	72.0	72.0
COSTS (US$M)								
Investment	48.0	0.0	96.1	48.0				
O&M Fixed		0.2	0.2	0.7	1.0	1.2	1.9	2.0
O&M Variable		0.7	0.6	4.6	6.1	7.4	11.2	11.7
Fuel		10.5	9.1	29.6	39.7	48.3	72.9	76.2
NG transportation				0.0	0.0	0.0	0.0	0.0
Transmission		3.2	3.2	3.2	6.2	6.2	6.2	6.2
Total	***48.0***	***14.6***	***109.2***	***86.2***	***53.0***	***63.2***	***92.2***	***96.1***
SALES (US$M)		***8.2***	***6.5***	***52.3***	***70.2***	***85.3***	***128.8***	***134.5***
NET REVENUES (US$M)	***-48.0***	***-6.4***	***-102.7***	***-33.9***	***17.1***	***22.1***	***36.6***	***38.4***
SALE PRICE	**72**							
IRR (before taxes)	10%							

N.2 Case with 30 mmcfd of natural gas

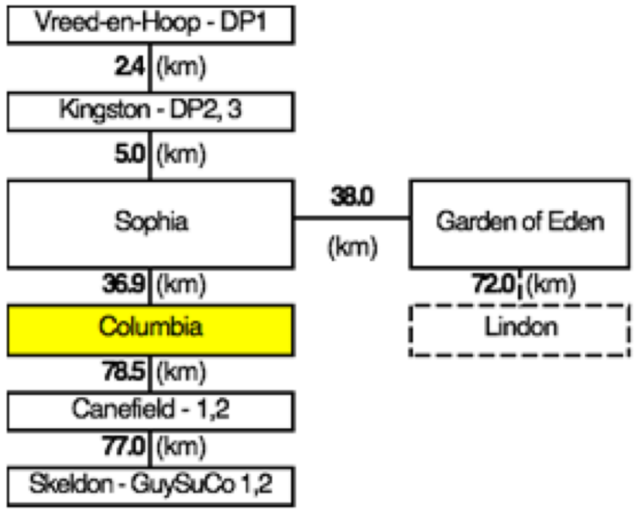
DEVELOPMENT OF THE NEW NATURAL GAS POWER PLANT
Preliminary Financial Analysis

	2020	2021	2022	2023	2024	2025	2030	2035
INSTALLED CAPACITY (MW)		34	34	119	153	170	170	170
GENERATION - HFO (GWH)		241	245					
GENERATION - NG (GWH)				891	1,145	1,294	1,124	1,140
TOTAL GENERATION (GWH)		241	245	891	1,145	1,294	1,124	1,140
Plant Factor		0.81	0.82	0.85	0.85	0.87	0.75	0.77
Heat Rate (BTU/kWh)		8.5	8.5	8.5	8.5	8.5	8.5	8.5
MBTU HFO		2,051	2,085					
MBTU NG				7,573	9,732	10,998	9,556	9,690
Price HFO (US$/MBTU)		10.6	11.7					
Price NG (US$/MBTU, wellhead)				4.7	4.7	4.7	4.7	4.7
Transm. Losses (%)		2%	2%	2%	2%	2%	2%	2%
SALES (GWH)		236	240	873	1,122	1,268	1,102	1,117
Price (US$/MWh)		89.0	89.0	89.0	89.0	89.0	89.0	89.0
COSTS (US$M)								
Investment	48.0	0.0	120.1	48.0				
O&M Fixed		0.2	0.2	0.9	1.1	1.2	1.2	1.2
O&M Variable		1.5	1.5	5.5	7.1	8.0	6.9	7.0
Fuel		21.7	24.3	35.6	45.7	51.7	44.9	45.5
NG transportation				0.0	0.0	0.0	0.0	0.0
Transmission		3.2	3.2	3.2	11.0	11.0	15.1	15.1
Total	***48.0***	***26.6***	***149.4***	***93.2***	***64.9***	***71.9***	***68.1***	***68.9***
SALES (US$M)		***21.0***	***21.4***	***77.7***	***99.9***	***112.9***	***98.1***	***99.4***
NET REVENUES (US$M)	***(48.0)***	***(5.6)***	***(128.0)***	***(15.5)***	***35.0***	***41.0***	***29.9***	***30.6***
SALE PRICE	89							
IRR (before taxes)	10%							

Appendix O . Onshore natural gas transportation costs

A preliminary pipeline identification and costs estimate for natural gas onshore transportation was done in the Energy Narrative study based on the length of the exiting 69 kV lines Columbia – Sophia (39.6 km), Sophie – Kingston (5.0 km), Kingston – Vreed en Hoop (2.4 km), Sophie – Garden of Eden (36.0 km) and Columbia - Canefield (78.5 km). In such study, the gas pipeline connections to Skeldon and to Linden where considered not economically feasible. Figure 82 below highlights where the pipeline would land relative to the main generation facilities and substations in the GPL system.

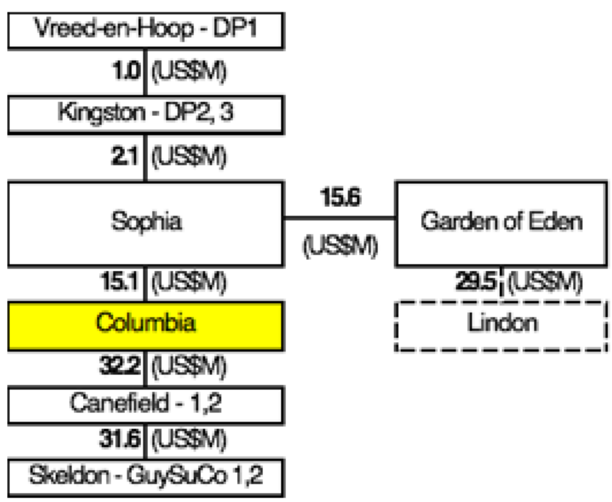
Figure 82. Columbia landing site distance from other GPL generation units



Source: Energy Narrative calculations

Investment costs estimates for main natural pipeline trenches are presented in Figure 83.

Figure 83. Columbia landing site pipeline development cost



Source: Energy Narrative calculations

Based on the generation outlook, such study assumed that natural gas pipelines would be built between the offshore natural gas landing site near Columbia and the generation units at Vreed-en-Hoop, Kingston, Garden of Eden, and Canefield. Total investment cost of these gas pipeline extensions is estimated in US$ 66.0 M. The pipeline extensions to Linden or Skeldon were considered uneconomical under this Option given the long distance and limited natural gas demand expected at each of these two locations.

This Energy Narrative analysis resulted in the levelized tariffs for the various pipeline route options shown in Table 86 below[119].

Table 86. Estimated natural gas onshore transportation charge by segment

NG Pipeline Segment	Volume (MMcfd) Average	Peak	(US$) Cost	(US$/MMBtu) Unit Cost
Columbia - Sophia	19.3	33.1	15.129	0.377
Sophia - Kingston	12.6	21.7	2.05	0.075
Kingston - Vreed-en-Hoop	5.1	8.7	0.984	0.093
Sophia - Garden of Eden	6.6	11.4	15.58	1.135
Columbia - Canefield	4.3	7.4	32.185	3.599

Source: Energy Narrative calculations

The onshore transportation cost analysis assumed that a 30 mmcfd pipeline would be built and compression would be needed to ensure pipeline pressure and flow was maintained. For this volume resulted in an estimated total (offshore + onshore) average gas transportation charge of US$3.09 per MMBtu for a gas landing site located near Woodlands. Table 87 summarizes the charges by segment corresponding to this option.

Table 87. Estimated natural gas total onshore + offshore charge by segment

Total NG Trans $	Transportation (US$/MMBtu) Undersea	Compression	On shore	Total
Vreed-en-Hoop	2.64	0.45	0.55	3.64
Kingston	2.64	0.45	0.45	3.54
Columbia	2.64	0.45	0.00	3.09
Garden of Eden	2.64	0.45	1.14	4.23
Canefield	2.64	0.45	3.60	6.69

Source: Energy Narrative calculations

[119] The tariffs for the onshore gas transportation were estimated in the Energy Narrative study and assumes that the project was financed with 20% equity (at a real cost of capital of 12%) and 80% debt (at a real interest rate of 8%). Annual O&M costs were estimated to be 2% of the project's capital cost. The project was assumed to have a 20 year depreciation life and taxes were not included in the cost assessment.

Appendix P . Preliminary economic evaluation of Kamarau hydroelectric project

P.1 Evaluation with gas price US$ 4.7/MBTU

NATIONAL ECONOMIC EVALUATION OF THE REGIONAL PROJECT (50 MW)

	COSTS O&M&Fuel W/O PROJECT		COSTS WITH THE DEVELOPMENT OF THE 50 MW REGIONAL PROJECT				
YEAR	REGION US$M	TOTAL US$M	INVESTMENT US$M	O&M HYDRO US$M	BACKUP COST US$M	TOTAL COST US$M	NET BENEFITS US$M
2022		0	0.0			0.0	0.0
2023		0	55.4			55.4	-55.4
2024		0	55.4			55.4	-55.4
2025		0	55.4			55.4	-55.4
2026	96.5	96.5		1.25	5.9	7.2	89.3
2027	96.5	96.5		1.25	6.3	7.5	88.9
2028	96.5	96.5		1.25	6.8	8.0	88.4
2029	96.5	96.5		1.25	6.4	7.7	88.8
2030	96.5	96.5		1.25	7.4	8.6	87.9
2035	96.5	96.5		1.25	6.6	7.8	88.6
2050	96.5	96.5		1.25	6.6	7.8	88.6
2061	96.5	96.5		1.25	6.6	7.8	88.6
	NPV (10%)	$ 637				NPV(10%)	$ 460.4
						IRR	37.5%

NATIONAL ECONOMIC EVALUATION OF THE 100 MW PROJECT

	NATIONAL COSTS WITH THE DEVOLOPMENT OF 50 MW PROJECT					NATIONAL COSTS AND NET BENEFITS WITH THE DEVELOPMENT OF 100 MW PROJECT					
YEAR	INVESTMENT US$M	O&M HYDRO US$M	BACKUP COST US$M	DBIS O&M&Fuel US$M	TOTAL COST US$M	INVESTMENT US$M	O&M HYDRO US$M	BACKUP COST US$M	DBIS O&M&Fuel US$M	TOTAL COST US$M	NET BENEFITS US$M
2022	0.0				0.0	84.5				84.5	-84.5
2023	55.4				55.4	84.5				84.5	-29.1
2024	55.4				55.4	84.5				84.5	-29.1
2025	55.4				55.4	84.5				84.5	-29.1
2026		1.25	5.9	87.9	95.0		2.5	0.0	41.0	43.5	51.5
2027		1.25	6.3	115.2	122.7		2.5	0.0	62.3	64.8	57.8
2028		1.25	6.8	40.5	48.6		2.5	0.0	17.6	20.1	28.5
2029		1.25	6.4	40.0	47.7		2.5	0.0	15.8	18.3	29.4
2030		1.25	7.4	42.6	51.2		2.5	0.0	18.0	20.5	30.7
2035		1.25	6.6	45.5	53.3		2.5	0.0	17.9	20.4	33.0
2050		1.25	6.6	45.5	53.3		2.5	0.0	17.9	20.4	33.0
2061		1.25	6.6	45.5	53.3		2.5	0.0	17.9	20.4	33.0
										PV (10%)	$ 92.7
										IRR	15.8%

ECONOMIC EVALUATION OF THE 100 MW PROJECT FOR THE MINING INDUSTRY

	REGIONAL COSTS WITH THE 50 MW PROJECT				REGIONAL COSTS AND NETS BENEFITS WITH THE 100 MW PROJECT					
YEAR	INVESTMENT US$M	O&M HYDRO US$M	BACKUP COST US$M	TOTAL REGION US$M	INVESTMENT US$M	O&M HYDRO US$M	BACKUP COST US$M	ELEC. PURCH. 1/ US$M	TOTAL REGION US$M	NET BENEFITS US$M
2022	0.0			0.0	0.0				0.0	0.0
2023	55.4			55.4	55.4				55.4	0.0
2024	55.4			55.4	55.4				55.4	0.0
2025	55.4			55.4	55.4				55.4	0.0
2026		1.3	5.9	7.2		1.3	0.0	3.0	4.2	3.0
2027		1.3	6.3	7.5		1.3	0.0	3.1	4.4	3.1
2028		1.3	6.8	8.0		1.3	0.0	3.4	4.6	3.4
2029		1.3	6.4	7.7		1.3	0.0	3.2	4.5	3.2
2030		1.3	7.4	8.6		1.3	0.0	3.7	4.9	3.7
2035		1.3	6.6	7.8		1.3	0.0	3.3	4.5	3.3
2050		1.3	6.6	7.8		1.3	0.0	3.3	4.5	3.3
2061		1.3	6.6	7.8		1.3	0.0	3.3	4.5	3.3

NPV (10%) $ 21.7

ECONOMIC EVALUATION OF THE 100 MW PROJECT FOR DBIS

	WITHOUT PROJECT	COSTS AND NET BENEFITS FOR DBIS WITH THE 100 MW PROJECT					
YEAR	DBIS O&M&Fuel US$M	INVESTMENT 2/ US$M	O&M HYDRO 2/ US$M	DBIS O&M&Fuel US$M	COSTS US$M	REG. SALES US$M	NET BENEFITS US$M
2022		84.5			84.5		-84.5
2023		29.1			29.1		-29.1
2024		29.1			29.1		-29.1
2025		29.1			29.1		-29.1
2026	87.9		1.3	41.0	42.3	3.0	48.5
2027	115.2		1.3	62.3	63.6	3.1	54.7
2028	40.5		1.3	17.6	18.8	3.4	25.1
2029	40.0		1.3	15.8	17.1	3.2	26.2
2030	42.6		1.3	18.0	19.2	3.7	27.1
2035	45.5		1.3	17.9	19.1	3.3	29.7
2050	45.5		1.3	17.9	19.1	3.3	29.7
2061	45.5		1.3	17.9	19.1	3.3	29.7

NPV (10%) $ 71.0

IRR 14.6%

P.2 Evaluation with gas price US$ 1.6/MBTU

ECONOMIC EVALUATION OF THE 100 MW PROJECT FOR DBIS

WITHOUT PROJECT		COSTS AND NET BENEFITS FOR DBIS WITH THE 100 MW PROJECT					
YEAR	DBIS O&M&Fuel US$M	INVESTMENT 2/ US$M	O&M HYDRO 2/ US$M	DBIS O&M&Fuel US$M	COSTS US$M	REG. SALES US$M	NET BENEFITS US$M
2022		84.5			84.5		-84.5
2023		29.1			29.1		-29.1
2024		29.1			29.1		-29.1
2025		29.1			29.1		-29.1
2026	53.1		1.3	41.0	42.3	3.0	13.8
2027	79.9		1.3	62.3	63.6	3.1	19.4
2028	19.5		1.3	17.6	18.8	3.4	4.1
2029	18.5		1.3	15.8	17.1	3.2	4.6
2030	20.0		1.3	18.0	19.2	3.7	4.5
2035	20.6		1.3	17.9	19.1	3.3	4.8
2050	20.6		1.3	17.9	19.1	3.3	4.8
2061	20.6		1.3	17.9	19.1	3.3	4.8

NPV (10%)	-$ 97.5
IRR	0.7%

Appendix Q . Terms of Reference

GUYANA
Update of the Study on System Expansion of the Generation System
TERMS OF REFERENCE

I. BACKGROUND

1. Guyana is expected to experience a significant growth in electricity demand. The Government of Guyana (GOG), as well as private developers, has recently commissioned demand forecasts and market analyses which predict that electricity consumption in the main power grid is likely to more than double in the next ten years. Guyana Power and Light (GPL) is therefore faced with the challenge to produce, distribute and commercialize the necessary energy to supply that demand under adequate quality standards and economic conditions.

2. Additionally, recent reports describe that reliability of electricity supply has been low, and characterized by frequent and long outages, load discharges and voltage variations. Poor reliability has been linked to dependence on old and obsolete equipment for power generation, underinvestment in the distribution grid, and lack of incentives for efficient provision of service.

3. Electricity prices in Guyana are the third highest in the Caribbean due in large part to the country's reliance on expensive imported fuel oil for electricity generation. At present, the cost of fuel accounts for up to 52% of the total cost of electricity generation. Although the effects of oil price hikes on the final cost of electricity have historically been cushioned by government subsidies, such increases in production inputs continue to negatively impact GPL's overall financial position. Nonetheless, over the last two years GPL has benefited from the decline in international fuel prices and has recorded improvements in its financial performance. Concomitant with GPL's reduced fuel costs, the Public Utilities Commission (PUC) approved the introduction of a ten percent (10%) fuel rebate in March 2015 and a further ten percent (10%) net rate reduction effective April 1, 2016.Despite these reductions, electricity rates in Guyana remain among the highest in the Region, with an average tariff of US$0.24/kWh.

4. Following the recent oil discoveries by Exxon Mobil, of approximately 2.75 billion oil-equivalent barrels offshore Guyana, the country is poised to become a major oil producer in the Region by mid-2020. Moreover, the availability of indigenous natural gas resources is estimated at between 30 to 50 million cubic feet per day, a sufficient volume to alter the predominantly fuel-oil based electricity generation matrix.

5. Major economic and infrastructural transformation is expected over the long term, stemming from increased foreign direct investment, increased demand for goods and services and increased foreign exchange earnings. As a consequence, real GDP growth is expected to be 38.5 percent and 28.5 percent in 2020 and 2021 respectively[1]. Such growth scenarios within the context of an emerging oil and gas sector will alter recent electricity demand forecasts.

6. GPL has considered demand growth scenarios in the development of its successive Development and Expansion Plans (D&E) which identifies numerous investments in infrastructure to expand and upgrade the network, as well as the utility´s generation capacity. Within these D&E Plans, the GOG has identified a strategy to have access to new electricity generation capacity and to

[1] IMF Country Report No. 17/175

improve the economic result of its energy mix.

7. In order to identify guidelines for the development of the most adequate electrical infrastructure for generation and transmission expansion in the country, the Inter-American Development Bank (IADB) conducted in 2014 an Initial Study on System Expansion of the Generation and Transmission System of Guyana (Initial Study).

8. An update of the Initial Study was commissioned in October 2015 to: (i) reflect changes resulting from the variation in the prices of fossil fuels; (ii) refine the findings from the Initial Study by updating the analysis with recent information from GPL's power system and the expected investments from the utility in the coming years; (iii) explore alternatives for the development of renewable energy generation (RE) technologies; and (iv) analyze and propose the potential of Energy Efficiency (EE) measures in amongst others, public buildings, industry, residential sector and Small and Medium Enterprises (SME); and (v) select the most favorable generation project and develop an action plan for its execution. The final report of the Guyana Power Generation Expansion Study was completed in June 2016.

9. In 2013 a GEF program, called Sustainable Energy Program for Guyana (GY-G1004) was approved for Guyana with the objective to increase energy access in Guyana, and contribute to sector sustainability and reduction of Greenhouse Gas emissions.

10. In 2016, based on mentioned expansion study commissioned in 2015 and finalized in 2016, the same program under its component 1: Strengthening of the policy and institutional framework to implement RETs in Guyana, has supported the development of a Road map study for the development of the optimal expansion plan that identified the realization of hydro, solar and biomass as Renewable Energy sources.

11. Despite that the 2016 expansion plan was considering the development of thermal power plants, it was planned to do so with the use of imported Natural Gas. Currently, this has changed with the resent discovery of indigenous natural gas reserves. The expansion plan needs to be updated in order to present a realistic and robust plan for the future development of RETs in sustainable manner and eventually with the participation of the private sector. This will provide clarity on the future National RE strategy.

II. CONSULTANCY OBJECTIVES

1. Following the recent discovery of indigenous natural gas resources, it has become necessary to conduct a review of the 2016 Expansion Study, as part of a least cost electricity generation matrix. Given the volume of associated natural gas that will be available locally, an updated analysis of the natural gas generation option under the mentioned study is therefore required within the context of a least cost generation optimization model. The consultant shall develop an optimal generation matrix per project with a timeline up to 2035.

2. The emergence of an oil and gas sector will also significantly impact the economic outlook of the country and consequently the demand projections, thus this demand impact needs to be considered.

3. Therefore, the current study will be commissioned to: (i) reflect changes in demand assumptions resulting from the expected oil revenues; (ii) reflect changes resulting from the use of domestic natural gas in electricity generation; (iii) further refine the findings with any recent information from GPL's power system, and the expected investments from the utility in the coming years in transmission and distribution; (iii) refine alternatives for the development of renewable energy generation (RE) technologies (when possible per project) within the context of Government's Green State Development Strategy; and (iv) select the most favorable generation project and develop an action plan for its execution up to 2035.

III MAIN ACTIVITIES

In order to achieve the consultancy objective, the Consultant firm will develop at least the following activities:

a. Update the 2016 Guyana Power Generation Expansion Study considering: (i) the availability of indigenous natural gas, estimated volumes, current prices and projections; (ii) updated electricity demand for Guyana; (iii) the latest information from GPL's power system and its Development and Expansion plan; and (iv) updated information regarding technical and non-technical transmission upgrades and substation installation.

b. The consultant will include the pertinent information and the conclusions of the studies and analyses on the feasibility of establishing a supply for Natural Gas for electricity generation and potential implication in tariffs.

c. In addition, the consultancy will: (i) update the LCOE analysis considering the other RE sources included in the previous expansion study; (ii) add an upfront cost analysis of all possible technologies for Natural Gas.

d. The consultant will analyze options for natural gas and update and prioritize the options for hydropower, a source of baseload generation, as an integral part of a generation mix that also includes intermittent RE and conventional fuel-oil based generation. Consideration will be given to utility scale solar PV projects that have already been announced by GPL. (This activity will include an estimation of the generation cost (US$/MWh of energy delivered and US$/MW of installed capacity) by source identified (when possible by project), and how it compares with current generation. RE projects will be identified and prioritized by size and costs.

e. Analyze and make recommendations on energy related regulatory and policy issues including the analysis of: composition of electricity tariffs. Analyze the capacity of existing regulatory and policy entities to deal with the transmission, distribution and utilization of power generated by domestic natural gas, together with the promotion of RETs as part of a Green State development strategy.

f. Prepare a thorough analysis of the current regulatory framework that includes an assessment (with recommendations) of the adequacy of the country's energy laws and regulations in supporting and regulating the development of RE, distributed generation, natural gas generation and EE with private sector participation.

g. The final report will include a preliminary socio-environmental impact and risk analysis of the issues associated with natural gas power generation technologies, as well as an estimation of carbon emissions reduction as consequence of the proposed generation technologies.

h. Prepare an executive summary of the study;

i. Prepare a presentation in PowerPoint identifying the main findings and conclusions from the updated study;

j. Taking into account the results obtained from all previous activities select the most favorable power generation mix and propose an action plan (including recommendations) for its execution; and

k. Prepare and carry out a workshop in Georgetown, Guyana, to present the main findings and conclusions of the study. The workshop will be organized in coordination with the IDB.

Appendix R . Electric Vehicles in Guyana

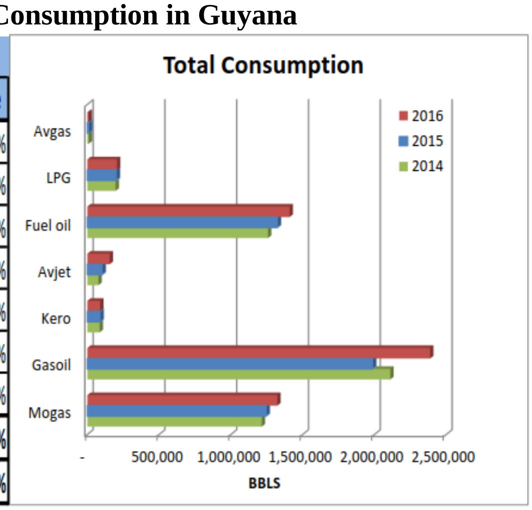
In order to forecast the long term electricity demand from electric vehicles (EV) in Guyana, we adopted a general approach to forecast different levels of penetration of such technology on the transport sector. We should note, however, that this exercise was accompanied by forecasting as well the number of compressed natural gas vehicles (CNGV) that Guyana could have if the Government promotes such technology as well. This takes more importance due to the fact that CNG vehicles are more economically viable for Guyana due to lower initial investment as actual motorcars in Guyana can migrate to dual gas/diesel + CNG fuels when such technology is available. Instead, electric vehicles need to be purchased by final users, which imply a significant investment from end-users. From an environmental point of view, EV offer no CO2 emissions (on a wheel-road level) whole CNG offer on average a 20% reduction on CO2 emissions compared with mogas/gasoil motor vehicles (from 122 g/km of gasoline vehicle to 98 g/km from CNG vehicle). Although CNG continues to produce CO2, it does contribute toward the migration toward a Green State at a lesser cost than EV vehicles.

The following methodology was used to forecast the electricity demand from electric vehicles: From historical mogas and gasoil consumption in Guyana from the transport sector, fuel consumption from such sector was forecasted in the long term using historical trends. From such forecast, different levels of EV and CNGV were forecasted to replace mogas and gasoil consumption; such replacement levels were based on regional countries experience and long term goals for each scenario. Once targets were found, and based on the fuel consumption per km of each fuel using real data from vehicles, electricity and natural gas demand was obtained for each scenario. Finally, average yearly mileage was used to convert distance data into number of vehicles in order to check the soundness of the exercise. The following paragraphs explain the main assumptions and results.

From Table 30 we obtain that Guyana imported 1.29 million barrels of gasoline (mogas) and 2.39 million barrels of diesel (gasoil) in 2016. Additionally, the following Figure shows Guyana's consumption of oil products (which considers inventory variations, apart from imports).

Oil products: Consumption in Guyana

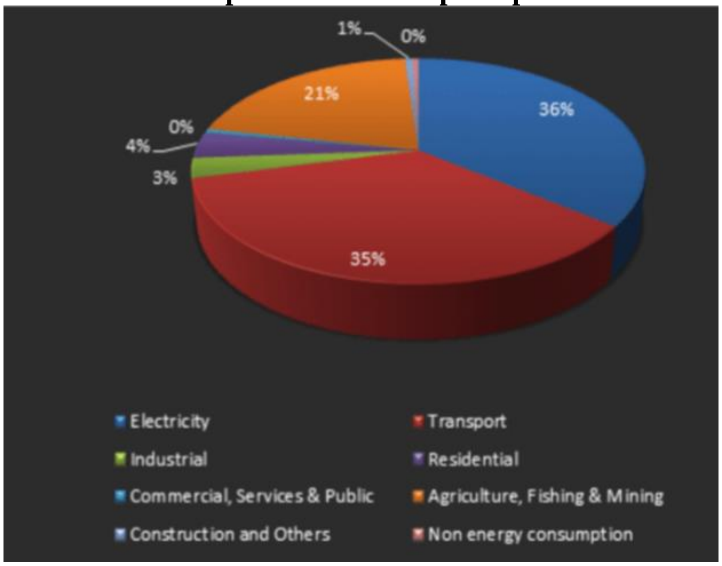
TOTAL CONSUMPTION (BBLS)					
January - December		2014	2015	2016	% change
	Mogas	1,214,868	1,244,943	1,322,842	6.26%
	Gasoil	2,110,143	1,986,647	2,387,793	20.19%
	Kero	86,023	88,031	89,746	1.95%
	Avjet	77,309	102,498	155,678	51.88%
	Fuel oil	1,258,669	1,323,033	1,408,915	6.49%
	LPG	197,121	201,454	206,648	2.58%
	Avgas	9,813	8,407	9,074	7.92%
	Total	**4,953,944**	**4,955,013**	**5,580,696**	**12.63%**
	Bpd	**13,572**	**13,575**	**15,248**	**12.32%**



Source: GEA. Annual report 2016

The transport sector in Guyana consumes about 35% of total petroleum products (GEA 2014, latest data available) as shown in the following Figure.

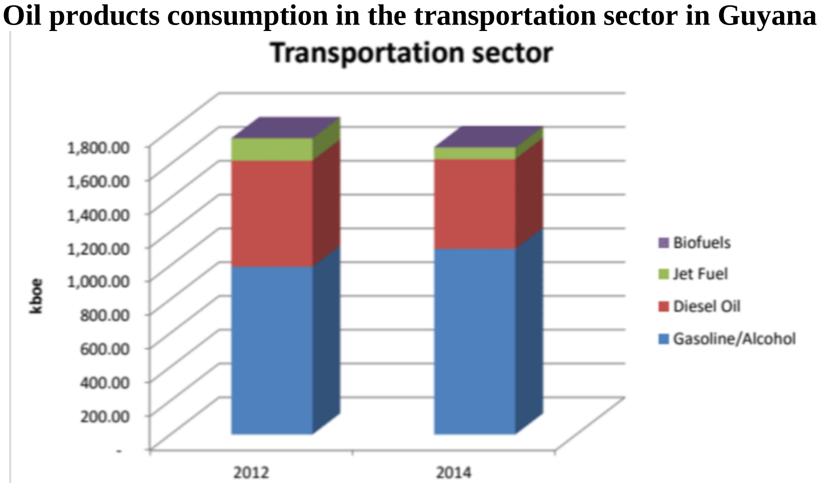
Petroleum products consumption per sector



Source: GEA. Annual report 2015

Transport sector oil consumption in Guyana is driven mainly by the need for gasoline (mogas) with 1.0 million barrels consumed in 2014 and diesel (gasoil) with about 0.55 million barrels consumed in 2014 due to the vehicle fleet in the country as shown in the following Figure.

Oil products consumption in the transportation sector in Guyana



Source: GEA

The fuel consumption for the transport sector (assuming a BAU scenario where no EV nor CNGV are incorporated in Guyana) was forecasted with a 1.2% annual growth rate until 2035 (which corresponds to the arithmetical average of annual growth rate in mogas and gasoil fuel consumption in Guyana since year 2000). Once obtained such fuel level usage (using same mix of 62% gasoline and 38% diesel), and using the information provided in the following table, electricity demand from EV and natural gas demand from CNG where obtained for three scenarios as described below.

Main assumptions used in EV and CNGV forecasts

Assumption	Unit	Value	Source
Gasoline consumption	Liters / kms (100)	7.78	SpritMonitor (https://www.spritmonitor.de) - All vehicles
Diesel consumption	Liters / kms (100)	6.96	SpritMonitor (https://www.spritmonitor.de) - All vehicles
Electricity consumption	kWh / kms (100)	16.12	SpritMonitor (https://www.spritmonitor.de) - All vehicles
CNG consumption	kg / kms (100)	5.15	SpritMonitor (https://www.spritmonitor.de) - All vehicles
Retail Price Gasoline	G$/LTR (year 2014)	226.9	GEA website statistics
Retail Price Diesel	G$/LTR (year 2014)	219.9	GEA website statistics
Retail Price CNG	USD / MBTU	4.7	Consultant
CO2g emissions Gasoline	g / km	122.5	European Environment Agency (https://www.eea.europa.eu)
CO2g emissions Diesel	g / km	119.2	European Environment Agency (https://www.eea.europa.eu)
CO2g emissions EV	g / km	0	
CO2g emissions CNGV	g / km	98	NGVA Europe Catalogue June 2017 - Volkswagen Variant GNC (http://www.ngva.eu)
Conversion factor CNG BTU/kg	BTU/Kg	50020	Energy Content Factsheet (http://www.gowithnaturalgas.ca)
Average kms per year EV	miles / year	7336	Idaho National laboratory. Electric Vehicle Mile traveled on-road results (https://www.energy.gov)
Average kms per year EV	kms / year	11807	Idaho National laboratory. Electric Vehicle Mile traveled on-road results (https://www.energy.gov)
Average kms per year EV	kms / year	14500	Institute Trasnport Economics Norway. https://www.toi.no/

Source. Consultant using different sources as shown in table

For each demand scenario the following main assumptions were used to forecast EV usage in Guyana.

Scenario	Main Assumptions	Reference
Base & Base Case Delayed	Long term transport fuel mix: EV: 2%; CNGV:3%; Diesel: 35%, Gasoline: 60%. EV penetration start in 2024 (after natural gas onshore available)	**Costa Rica EV goal:** 100,000 vehicles ~ 5% of actual registered vehicles. **Colombia EV goal 2030:** 400,000 vehicles ~ 3.2% of actual registered vehicles. **Chile EV forecast 2030:** 156,000 vehicles ~ 3.8% of actual registered vehicles. **Colombia CNGV goal 2030:** 3.2% of actual registered vehicles. Colombia actual CNGV penetration since introduction in 1986: 211,000 vehicles ~ 2,.5% of actual registered vehicles.
Low	Long term transport fuel mix: EV: 0%; CNGV:3%; Diesel: 37%, Gasoline: 60%. No EV, CNG instead	
High	Long term transport fuel mix: EV: 5%; CNGV:0%; Diesel: 36%, Gasoline: 59%. EV penetration start in 2024 (after natural gas onshore available), no CNG	

Source: Consultant using UPME (Colombia): http://www1.upme.gov.co/SalaPrensa/ComunicadosPrensa/Comunicado_UPME_10_2017.pdf, Generadores de Chile (Chile): http://www.capital.cl/wp-content/uploads/2017/08/170822-presentacion-estudio-usos-futuros-de-la-electricidad-generadoras-de-chile-1.pdf, Costa Rica : http://ndci.global/compelling-stats-facts-electric-vehicles/

The following is the electricity demand forecasted from EV.

Electric Vehicles: Electricity Demand per scenario

Demand from EV	Unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Low Case	GWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Base Case	GWh	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.6	2.4	3.3	4.2	5.0	6.0	6.9	7.8	8.8	9.8	10.8
Base Case Delayed	GWh	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.6	2.4	3.3	4.2	5.0	6.0	6.9	7.8	8.8	9.8	10.8
High Case	GWh	0.0	0.0	0.0	0.0	0.0	0.0	2.5	5.1	7.7	10.4	13.1	15.9	18.8	21.7	24.7	27.8	30.9	34.2

Source: Consultant

Updated vehicle statistics in Guyana were not available for this study and public statistics are scarce. Nowadays there are about 280,000 registered vehicles in Guyana[120]. Such number compares with 81,473

[120] Registered vehicles from Guyana Revenue Authority (GRA) were not available for this study. This estimate was obtained from a conference held in January 2018 by Guyana´s Tax Chief (link: https://newsroom.gy/2018/01/25/vehicle-smuggling-remains-rampant-secured-license-plates-for-2018/).

registered vehicles[121] in March 2009 and 127,825 registered vehicles in 2008.Vehicle breakdown in year 2008 (only breakdown available at the time of this study[122]) was 35% motorcars, 29% motorized 2&3 wheelers, 15% minibuses, 7% trucks and 14% other type of vehicles. In 2015, total public bus fleer in Guyana was about 3513 minibuses[123]. With these references, the following are the total number of EV vehicles and its comparison to total registered vehicles and its share.

Electric Vehicles and total registered vehicles forecast

Number EV	Unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Low Case	GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Base Case	GWh	0	0	0	0	0	0	374	757	1,148	1,550	1,960	2,381	2,811	3,251	3,701	4,161	4,632	5,114
Base Case Delayed	GWh	0	0	0	0	0	0	374	757	1,148	1,550	1,960	2,381	2,811	3,251	3,701	4,161	4,632	5,114
High Case	GWh	0	0	0	0	0	0	1,178	2,383	3,618	4,881	6,175	7,499	8,853	10,239	11,657	13,107	14,591	16,108
Total Cars	**Unit**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Low Case	GWh	282,124	285,503	288,924	292,385	295,888	299,432	303,019	306,649	310,323	314,040	317,803	321,610	325,463	329,361	333,307	337,300	341,341	345,430
Base Case	GWh	282,124	285,503	288,924	292,385	295,888	299,432	303,019	306,649	310,323	314,040	317,803	321,610	325,463	329,361	333,307	337,300	341,341	345,430
Base Case Delayed	GWh	282,124	285,503	288,924	292,385	295,888	299,432	303,019	306,649	310,323	314,040	317,803	321,610	325,463	329,361	333,307	337,300	341,341	345,430
High Case	GWh	282,124	285,503	288,924	292,385	295,888	299,432	303,019	306,649	310,323	314,040	317,803	321,610	325,463	329,361	333,307	337,300	341,341	345,430
EV share	**Unit**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Low Case	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Base Case	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.2%	0.4%	0.5%	0.6%	0.7%	0.9%	1.0%	1.1%	1.2%	1.4%	1.5%
Base Case Delayed	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.2%	0.4%	0.5%	0.6%	0.7%	0.9%	1.0%	1.1%	1.2%	1.4%	1.5%
High Case	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%	0.8%	1.2%	1.6%	1.9%	2.3%	2.7%	3.1%	3.5%	3.9%	4.3%	4.7%

Source: Consultant

Such estimates assume that EV in Guyana would start to become available in 2024 after end-user electricity tariffs decrease as a result of natural gas availability (and hydro availability later on) for power generation becomes available. EV share in 2035 of 1.5% of registered vehicles in Base Case and 4.7% in High Case compares to Latam peers with EV goals such as Chile (3.8%) , Colombia (3.2%) and Costa Rica (5%). We note that such targets are lower than global forecasts but reflect lower GDP per capita levels in Latam.

As well, Base Case scenarios also have CNGV penetration due that such transport technology is more economically viable than EV. It is important to keep in mind the cost advantage of CNGV over fuel and EV. For instance, taking the information from 2014 transport consumption, the following table shows how the cost of transportation was US$289 million (including CO2 emissions @ US$30/Ton). If such consumption was totally replaced by EV, the cost (excluding capex of vehicles and related infrastructure) would have been US$106 million. If totally replaced by CNGV, the cost (excluding capex of converting to dual fuel vehicles and related infrastructure) would have been US$50 million.

[121] https://www.stabroeknews.com/2010/news/stories/03/22/over-80000-vehicles-registered-in-14-months/
[122] http://www.who.int/violence_injury_prevention/road_safety_status/country_profiles/guyana.pdf
[123] http://www.pressreader.com/guyana/stabroek-news/20150209/281698318171869

Oil products

Barrels (BBLS)	Transportation
Gasoline	1,000,000
Diesel	550,000
	1,550,000

Liters	Transportation
Gasoline	158,987,567
Diesel	87,443,162
	246,430,729

G$ million	Transportation
Gasoline	36,067
Diesel	19,224
	55,291

USD million	Transportation	CO2 Emission	Total
Gasoline	180	7.5	188
Diesel	96	4.6	101
	276	**12**	**289**

kms (100)
20,435,420
12,563,673
32,999,093

MJ	Transportation
Gasoline	5,322,903,749
Diesel	3,257,694,998
	8,580,598,747

EV

kWh	Transportation
Gasoline	329,418,970
Diesel	202,526,404
	531,945,373

G$ million	Transportation
Gasoline	13,177
Diesel	8,101
	21,278

USD million	Transportation	CO2 Emission	Total
Gasoline	66	0	66
Diesel	41	0	41
	106	**0**	**106**

kms (100)
20,435,420
12,563,673
32,999,093

MJ	Transportation
Gasoline	1,185,908,290
Diesel	729,095,054
	1,915,003,344

NGV

MBTU	Transportation
Gasoline	5,264,225
Diesel	3,236,440
	8,500,665

G$ million	Transportation
Gasoline	4,948
Diesel	3,042
	7,991

USD million	Transportation	CO2 Emission	Total
Gasoline	25	6	31
Diesel	15	4	19
	40	**10**	**50**

kms (100)
20,435,420
12,563,673
32,999,093

Kg	Transportation
Gasoline	105,242,413
Diesel	64,702,914
	169,945,327

MJ	Transportation
Gasoline	5,553,273,363
Diesel	3,414,146,080

Appendix S . Economic costs of CO2 emissions[124]

All generation projects have environmental costs of different types inherent to its technology, not normally included in their estimates of direct costs because it constitutes external effects to the project, or externalities. Of these effects, the international community is gradually recognizing in particular the social and environmental costs of emissions of greenhouse gases. Already today, inside and outside the Kyoto Protocol, many countries have established mechanisms to assess the cost of reducing emissions of greenhouse gases. In the present study a first assessment of the emissions associated with the thermoelectric power plants studied was made, based on the following indicators shown in Appendix Table 88.

Table 88. CO2 emissions by power plant type

Tipo de Planta	Emisiones ($TonCO_2/GWh$)	
	Rango	Valor Usado
Hidroelectrica con embalse	10 a 30	20
hidroelectrica filo de agua	1 a 18	12
Planta eolica	7 a 124	50
Solar fotovoltaica	13 a 731	300
Turbina de Diesel	555 a 883	808
CC diesel		568
Planta de carbon	790 a 1182	1071
Motor de media velocidad	686 a 726	700
TG gas natual		688
CC gas natural	389 a 511	421
CC GNL		473

Source: CEAC-GTPIR. Indicative Regional Generation Expansion Plan 2012-2027 (Central America)

It is important to clarify that the equivalent emissions given in the table take into account what is known as the project life cycle. This concept can be defined as the evaluation of all the steps required to obtain a product. Extraction, processing, and transportation of the fuel, the construction of the plant, the actual production of electricity, waste disposal and removal is included in the case of electricity generation, over its lifetime. That's why even renewable energy projects such as hydropower, present emissions, although of a lower order than those using fossil fuels magnitude. It is noted that although CO2 emissions are one of the most important environmental impacts of fossil fuel generation, there are others such as SO2, NOx, volatile organic compounds and particulate emissions, among others, but they involve social costs, are more difficult to assess in this context, so have not been considered in economic evaluations of the expansion plans.

A wide literature is available for the assessment of CO2 emissions, or its economical evaluation for a power system, it is clear that the initial reductions can be achieved at low cost, through measures such as demand management, more use of natural gas in relation to coal, some reforestation programs, etc. However, as these cheap solutions are achieved more expensive actions could be economically justified. Some studies indicate for example:

[124] Extracted from: CEAC-GTPIR. Indicative Regional Generation Expansion Plan 2012-2027 (Central America) and complemented by the consultants

- A Dutch study indicated a cost of between 23 and 27 US$/ton of CO2 to achieve a 50% reduction of their emissions by 2020.
- A German study estimated the cost of fuel switching and energy conservation by about US$ 5/ton, to an upper value of US$ 53/ton in the case of capture by "CO2 scrubbing" in coal plants.
- In five countries they have set emissions taxes, ranging between 42 and 115 US$/ton.
- The United States Department of Agriculture has estimated a cost of between 12 and 18 US$/ton to achieve reductions of between 10 and 30% of CO2 through reforestation and forest management.
- A very recent study by EPRI, estimated the cost of CO2 avoided by using generation plants with new technologies that make removal of CO2. Costs range between 17.5 and 60.7 US$/ton.
- For Guyana it has been considered US$ 20/ton in another study "Forest carbon stock in Guyana: Projected emissions and REDD reference scenarios". Denis Alder and Marijke van Kuijk Prepared for Guyana Forestry Commission. 2009

Financial assessments for some projects have considered that could achieve registration with the voluntary emission reduction market, which represented in 2015r a financial compensation of about US$ 0.5/ton CO2 reduced. And experiences from the Prototype Carbon Fund of the World Bank and various experiences of carbon credits market bids indicate prices to a level that begins approximately US$ 2/ton CO2. International tenders held by the Netherlands within the context of CDM (clean development mechanism) have yielded values in the order of US$ 5/ton.

However, *from an economic point of view*, it is generally recognized higher values for the economic cost of CO2 emissions, in the order of US$ 20-25/tonCO2, based on estimates suggested by the International Monetary Fund. Similar values have been estimated by the International Energy Agency for the period 2013 - 2040 (in which projects an initial value of US$ 10/ton CO2 progressively increased to US$ 40 / ton CO2 for this parameter).

Recently, the International Energy Agency published the report: "Projected Costs of Generating Electricity", 2015 Edition. In this document it is published a methodology to calculate the levelized average lifetime costs of electricity produced in a power plant by technology and country. This methodology works with a harmonized carbon price common to all countries over the lifetime of all technologies. Many countries do not have an explicit carbon price. In these cases, US$ 30/tonCO2 is taken as the shadow price of carbon (not being a cost that would be borne by investors).

In this order of ideas, for the study update of the optimal DBIS generation expansion a value of US$ 30/tonCO2 was applied for the estimation of the economic cost of CO2 emissions from fuel combustion in the thermoelectric plants.

Appendix T . GEA's strategic Plan Summary

The GEA Strategic Plan 2014 – 2018 includes guidelines for power generation. This plan includes as well the Arco Norte Study - (Guyana, Suriname, French Guyana and Northern Brazil). The following tables in this Appendix present a summary of such plan.

Table 89. Guyana Energy Policy: GEA strategic Plan 2014 – 2018 (1/3)

POLICY OBJECTIVE	STRATEGIES

• Provide stable, reliable and economic supply of energy;
• Reduce dependency on imported fuels;
• Promote where possible the increased utilization of domestic resources;
• Ensure energy is used in an environmentally sound and sustainable manner.
	• The development of the Amaila Falls Hydro-Electric Project as a key strategic component towards ensuring the sustainability of Guyana's energy supply.
	  • Memorandum of Understanding between ELETROBRAS and Government of Guyana (Dec 09, 2010) to perform the hydrological inventory of two of Guyana's hydrological basins, the Potaro and the Mazaruni
	  • Memorandum of Understanding to Establish a Working Group on Infrastructure Projects (December, 2012) to produce proposals for concrete actions for the construction of hydroelectric plants and lines;
	  • Party to a Memorandum of Understanding on the Northern Arc Interconnection Project

• The Guyana Power Sector Policy and Implementation Strategy of 2010 was developed primarily to ensure its viability. This Policy links renewable energy and energy efficiency.	• Assess and keep under review the opportunities for mini and micro hydropower applications where feasible. • Continue to pursue options for higher pressure bagasse-fueled cogeneration to increase power cogeneration capacity. • Power generation options from rice husk and wood waste will also be reviewed. • Over the next 5 years, Guyana is expected to install more than 1 MW of PV. • Support the implementation of wind farms, provided that pricing mechanisms are competitive and sustainable. Wind energy at the residential and commercial levels for off-grid applications will also be encouraged. • Options for interconnecting renewable energy generators to the grid will be reviewed and explored towards the implementation of grid-tied systems and net-metering platform. Once proven beneficial to all parties, grid-tie options can be encouraged as a means of reducing investment in fossil-based generators and meeting incremental demand from renewable energy sources. • Importation and installation of solar water heaters will be encouraged for both residential and commercial use. The tourism and hospitality sector, still at an early stage of development, will be engaged with the objective.

Source: Consultant based on GEA´s Strategic Plan 2014- 2018

Table 90. Guyana Energy Policy: GEA strategic Plan 2014 – 2018 (2/3)

HYDRO STRATEGIES	ACTIONS
• Develop and encourage the development and utilization of sources of energy other than those sources presently in use. • Conduct research into all sources of energy including those sources presently used will be conducted with the objective of generating energy. • Review hydro-electric power projects to determine the suitability of design and conduct inspections during construction to ensure compliance with the plans in keeping with its mandate under the Hydroelectric Power Act.	• Asses the list of hydropower sites. • Development of a feasibility study for Kumu Falls, however, stream data is not available and as such the Agency is seeking to install a water level recorder to gather data for the design of the hydropower scheme. • From the success of this event a total of two locations per year will be identified for the installation of these devices to help determine stream flow patterns. • Amaila Falls is expected to have an installed a capacity of 165MW. Construction was anticipated to begin in 2014. • In general, a list of other studies • IRENA: The substantive Hydroelectric Power Act and Regulations of 1956 were amended in 1973, followed by the Hydroelectric Power (Amendment) Act of 1988 and the Hydro-Electric Power (Amendment) Act was passed in 2013. These laws are likely to be updated and revised within the next five years.

SOLAR STRATEGIES	ACTIONS
• Develop and encourage the development and utilization of sources of energy other than those sources presently in use. • Demonstrate, research and utilize solar photovoltaic technology as a source of renewable energy to meet energy needs where appropriate.	• There is also great interest within the private sector for large solar photovoltaic systems tied into the national grid under a power purchase agreement (PPA) and for offsetting energy costs at their place of business. • Options for interconnecting renewable energy generators to the grid will be reviewed and explored. • Once proven beneficial to all parties, grid-tied options can be encouraged as a means of reducing investment in fossil-based generators and meeting incremental demand from renewable energy sources. • GEA will therefore seek to promote the use of solar photovoltaic grid-tied technologies by using the current pilot installation as a working example of the benefits of grid-tied technology.

Source: Consultant based on GEA´s Strategic Plan 2014- 2018

Table 91. Guyana Energy Policy: GEA strategic Plan 2014 – 2018 (3/3)

WIND STRATEGIES	ACTIONS
• GEA will continue to develop and encourage the development and utilization of sources of energy other than those sources presently in use. • Research into all sources of energy including those sources presently used will be conducted with the objective of generating energy.	• GEA will support the implementation of wind farms to supply energy to the national grid, provided that pricing mechanisms are competitive and sustainable. • Wind energy at the residential and commercial levels for off-grid applications will also be encouraged. • GEA will conduct wind measurements at suitable sites with the objective of determining wind energy potential and continue to monitor installed wind generators across the country.
BIOENERGY STRATEGIES	**ACTIONS**
• Develop and encourage the development and utilization of sources of energy other than those sources presently in use by promoting local examples. • - Conduct research into all sources of energy including those sources presently used.	• Bagasse: The employment of high pressure boilers for cogeneration may provide an opportunity for improving the electricity output of existing sugar factories and creating an additional source of income from a renewable energy source. GEA will work with GUYSUCO to explore the feasibility of generating additional energy from bagasse at the various sugar estates for sale to the national grid. • Rice Husk: GEA has assessed the potential of rice husk biomass for the generation of electricity. A list of locations, potential biomass quantities from rice mills and a map with the listing of all potential sources of rice husk energy sources have been completed. This will help in guiding the installation of a rice husk to energy plant by 2017. • Rice millers will be encouraged to investigate the opportunities for generating energy from rice husk. GEA will seek to establish a 20 to 30kW demonstration unit.

Source: Consultant based on GEA´s Strategic Plan 2014- 2018

Appendix U . Recommendations on Policy and Regulation of Distributed Generation

Distributed Generation (DG) can be defined loosely as small-scale generation. DG is a relatively new concept in the electricity economics literature but the idea behind it is not new at all. The first power plants generated close to the consumers and then demand growth and scale economies foster the electricity generation development to large power plants located far from the consumers. But rapidly changing generation technologies, and regulatory environments and policies have resulted in a renewed interest in DG. International Energy Agency (IEA) listed five major factors that contribute to this evolution i.e. developments in DG technologies, constraints on the construction of new transmission lines, increased customer demand for highly reliable electricity, the electricity market liberalization and concerns about climate change. It possible summarize these factors in two: electricity market liberalization and environmental concerns.

U.1 DG Definitions

There are various DG definitions. According to National Renewable Energy Lab (NREL): DG is any source of electricity that is at or near the point of load. It can be connected to the utility's distribution lines, or just provide power to a stand-alone load. According to IEA, DG is the generation plant that serves a customer on the site or that provides support to a distribution network, connected to the network at distribution voltage levels. According to CONAE (Mexico), DG is the generation or storage of small-scale electric power, close to the load center, with the option of interaction (buy or sell) with the electrical network, and in some cases, considering the maximum energy efficiency. And according to the Department of Energy (DOE, USA), DG is the use of generation technologies of small scale located near the load, cost efficient, with capacity to improve the reliability of supply, reduce emissions and increase generation options diversifying the supply portions.

All definitions have in common the following points: small scale generation, close to the load, interaction with the grid at voltage distribution levels and with benefit to the grid like improvement of the reliability of the supply.

DG can be owned and operated by utilities or their customers and can provide a variety of benefits to their owners and the broader power system. The reason for connecting DG systems to the grid are the DG benefits. Next table shows the benefits (theoretically) of DG. They are of different nature: Reliability and security benefits, economic benefits, emissions benefits and power quality benefits.

Nevertheless, when connecting a DG system to the grid, the fundamental issue is the preservation (when no the improvement) of the quality, reliability and safety of the electricity provided by the grid. This fundamental issue is the focus of concern when promoting and implementing DG.

Table 92. Theoretical Benefits of Distributed Generation

Reliability and Security Benefits	Economic Benefits	Emission Benefits	Power Quality Benefits
• Increased security for critical loads • Relieved transmission and distribution congestion • Reduced impacts from physical or cyber-attacks • Increased generation diversity	• Reduced costs associated with power loss • Deferred investments for generation, transmission, or distribution upgrades • Lower operation costs due to peak shaving • Reduced fuel costs due to increased overall efficiency • Reduced land use for generation	• Reduced line loss • Reduced pollutant emissions	• Voltage profile improvement • Reduced flicker Reduced harmonic distortion

Source: Wang, J. A Planning Scheme for Penetrating Embedded Generation in Power Distribution Grids. MIT (2013) Boston, US

U.2 Lines of action

For the promotion and implementation of DG, keeping in mind the fundamental issue above mentioned, it is recommended to develop initiatives that cover technical aspects related to the connection of DG to the grid, legal and contractual issues for the relation distributor-customer/DG operator, and economic /tributary incentives for its promotion.

U.3 Technical Considerations

U.3.1 Interconnection to the Grid

DG connected to the distribution network will affect the operation mode and performance of distribution network. To ensure the safe operation of distribution network and the power supply quality of users, the interconnection[125] of distributed generation to grid must meet the following basic requirements:

1) It must ensure the distribution network qualified that the voltage deviation caused by the connection of distributed generation to grid does not exceed the allowed range;

2) The normal operation current of distribution equipment does not exceed the rated value and the thermal stability current does not exceed the allowable value [5];

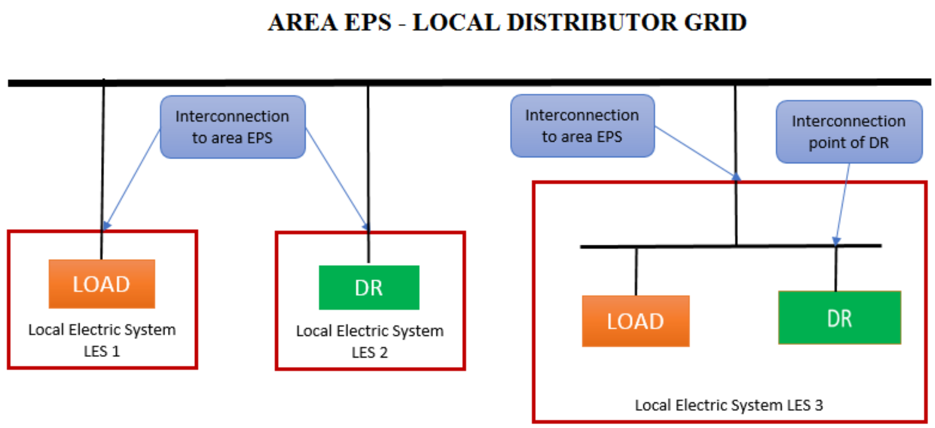
3) Short circuit capacity does not exceed the allowable value of the distribution, such as circuit breaker, cables, etc.;

[125] Interconnection: The result of the process of adding a DR unit to an existing EPS (Electric Power System)

4) The quality of the power produced by distributed generation is qualified. The voltage sag, swell, flicker and harmonic caused by it do not exceed the specified value.

To an Area Electric Power System (EPS), Local Electric Systems (LES) are connected to the distributor grid. Standard interconnection is in next figure, LES 1 represents the standard loads. But also, a Distributed Resource like LES 2 can be tied to the grid where energy is injected to the grid or exchanged with the grid when the DR includes a storage system. The option LES 3 considers the interconnection of Load and DR in the premises of the consumer where electricity generated by DR goes to the load.

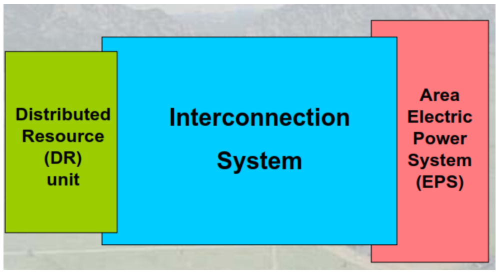
Figure 84. Interconnection of Local Electric Systems to the Distributor Grid



Source: Adapted from "Requisitos Técnicos para la Interconexión", Diario Oficial, 8 abril 2010, México

Next figure shows schematically the interconnection of a Distributed Resource (DR) to an existing Area Electric Power System (EPS).

Figure 85. Connection scheme of DG to the grid IEEE Std. 1547



Source: Adapted from IEEE Std. 1547[126]

The three elements are the existing EPS, the new DR unit and the Interconnection System[127] .

[126] IEEE Std. 1547-2003. IEEE Application Guide for IEEE Std 1547™, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems. IEEE Std 1547.2-2008, pp. 1-207, April 15, 2009

[127] Following the definitions of the IEEE1547 Std / Interconnection equipment: Individual or multiple devise used in an interconnection system; Interconnection System: The collection of all interconnection equipment and functions, taken as a group, used to interconnect a DR unit (s) to an area EPS.

Authors categorized DR in into two types of generators:

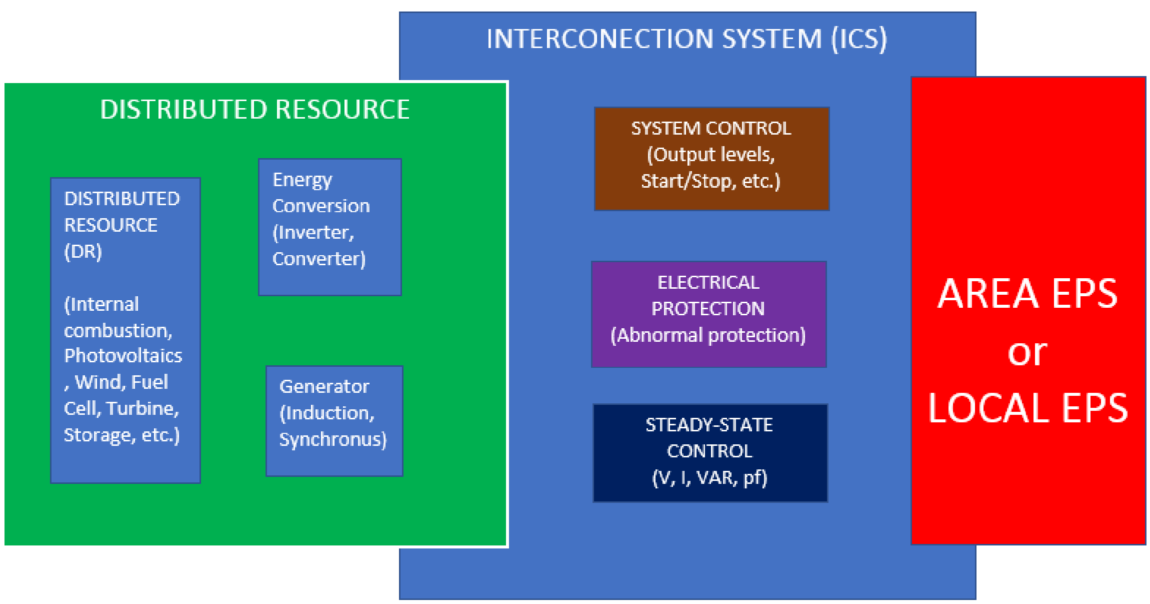
- Rotating machine-based systems
- Static power converter-based systems

DR systems may include the following technologies:

- Combined heat power (CHP)
- Fuel cells
- Micro combined heat and power (Micro CHP)
- Micro turbines
- Photovoltaic Systems
- Reciprocating engines
- Small Wind power system
- Storage systems (batteries, flywheels).

Following the IEEE Std. 1547, a high-quality standard, very well-known and extensively adopted or adapted Standard for DG in the USA and in other countries, next figure shows for the DR both type of generators. Important to note is that some generators are DC generators like photovoltaics and fuel cells, and for this reason the use of an inverter (transform DC power into AC power) is a must. The Interconnection System (ICS) must consider the system control, the electrical protection and the steady-state control.

Figure 86. Definition of the installation and its content



The Interconnection Systems (ICS) has three aspects to deal with: System Control, Electrical Protection and Steady-State Control.

A major issue related to interconnection of distributed resources onto the power grid is the potential impacts on the quality of power provided to other customers connected to the grid. These issues are:

- **Voltage Regulation:**-Over-voltages due to reverse power flow: If the downstream DG output exceeds the downstream feeder load, there is an increase in feeder voltage with increasing distance. If the substation end voltage is held to near the maximum allowable value, voltages downstream on the feeder can exceed the acceptable range.
- **DG Grounding Issue: -**A grid-connected DG, whether directly or through a transformer, should provide an effective ground to prevent un-faulted areas from over-voltage during a single-phase to ground fault. Proper grounding analysis of DG will ensure compatibility with grounding for both the primary and secondary power systems.
- **Harmonic Distortion:** -Voltage harmonics are virtually always present on the utility grid. Nonlinear loads, power electronic loads effects of the harmonics include overheating and equipment failure, faulty operation of protective devices, nuisance tripping of a sensitive load and interference with communication circuits.
- **Islanding: -** "Islanding" occurs when a small region of the power grid is isolated by broken lines, etc., and yet local sources provide enough power to keep the voltages up. In case the DG in the distribution system is capable to meet the load demand, DG can be operated in the island mode and continue to energize the distribution system. This is a source of concern for the grid operators in case of repairs and maneuvers due to the fact they can find a supposed de-energized grid with energy.

Because these systems interact with the grid, is the grid operator is the institution that must supervises the quality of the DG installation, operational and safety, the compliance of the infrastructures and operational with its own requirements.

When there is a High PV Penetration, utility become concerned on different issues. As can be seen in next table, not only technical issues like voltage control or protection are of high priority, also equipment specifications and clarification of responsibilities between DG and grid operators are necessary.

Table 93. Issues and priorities in DG

Identified Issues	Relative Priority	Identified Issues	Relative Priority
Voltage Control	High	Equipment Specs	High
Protection	High	Interconnection Handbook	Medium
System Operations	High	Rule 21 and WDAT	Medium
Power Quality	High	IEEE 1547/ UL 1741	Medium
Monitoring and Control	Medium	Application Review	High
Feeder Loading Criteria	High	Clarification of Responsibilities	High
Transmission Impact	Medium	Integration with Tariffs	Medium
Feeder Design	Medium	Coordination with Other Initiatives	Medium
Planning Models	Medium		Source: Russell Neal, Southern California Edison

Source: R. Neal, Southern California Edison.

U.3.2 Components Standards

To assure the quality and safety of the electrical interaction with the grid it is advisable to adopt /adapt Standards for the components of de DR. For PV systems, International Electrotechnical Commission (IEC) has established standards for the safety of modules (for silicon cells, thin film cells) (IEC62109-1:2010, IEC62109-2-2011), concentrator PV and mounting assemblies (IEC62108), wiring, among others. Most of the well renowned companies of PV modules complies with IEC Standards.

For Grid Protection, IEC 61727 Ed. 2.0, 2004 and IEC62116 Ed. 1, 2008.

And for Inverters, the IEC Standard 62116 applies for utility interconnected inverters. Underwriter Laboratories (UL) Standard UL1547 is a standard widely adopted.

In the case of other DER technologies, there also IEC standards for water turbines, wind turbines, thermal solar power plants, gas / fuel engines and batteries.

Other countries and institutions have also developed and adopted standards. For instance, Germany has Verein Deutsche Ingenieure (VDE) Standards, Australia AS/NZS, United Kingdom G Standards.

In conclusion, the development/adoption/adaptation of standards is also very valuable when considering the safety, performance and durability of the systems, the last one very important for preserving the investment of the project developers.

U.3.3 Connection Requirements

The development of a DG project (engineering, procurement, mounting, installation and commissioning) connected to an Area EPS must be carried out by qualified personnel and certified by an independent certification body, assuring the principles of independence and lack of interest conflicts.

The power injected to a grid by a group of DG systems must consider the nature of the power and the location of the point of injection to the grid. In the case of a high variable PV generator, IEEE1547 recommends injecting a maximum of 15% of the peak power of a feeder[128]. This figure has reached 30% in certain grids in the USA[129]. That means, that the total capacity injected by a PV system or PV systems has a limit and this is posed by the grid operator.

There is also the need to develop/adapt/adopt a *DG Interconnection Code* for the Interconnection of DG to the grid, in full agreement and concordance with the current grid code.

U.3.4 Legal Framework, Economic /Tributary Incentives

Various countries have developed own regulatory frameworks for DG. At the highest level in the electricity authorities, they have developed a legal framework for DG and enforcing legal instruments to the electricity authorities for developing technical standards and other regulations, tax and incentives of different nature for the developers of DG projects.

[128] Reference 1.

[129] Maximum Photovoltaic Penetration levels on Typical Distribution Feeders, p1, available at http://www.nrel.gov/docs/fy12osti/55094.pdf, sourced on April 1st 2018

At the level of Grid Operator – DG developer, in some countries like in Mexico, there is a contract model for the interconnection of renewable energy or cogeneration system, and imposing limits like the maximum power injected to the grid depending on the scale and type of user (low scale: <10 kW for residential users, < 30 kW for general service; <500 kW medium scale) and additionally, to a maximum of the contracted power with the Local Distributor.

The important consideration is that DG penetration must be a controlled development hand by hand with the Local Distributor. Technologies like PV Systems, nowadays a cheap and easy to install "**plug and flow**" technology, could develop in an uncontrolled and unsupervised way putting in risk the safety, quality and reliability of the current electrical service.