2019 ANNUAL REPORT

REVIEW OF THE GHANA WHOLESALE ELECTRICITY MARKET (GWEM)

ELECTRICITY MARKET OVERSIGHT PANEL
EMOP

ENERGY COMMISSION

THE ELECTRICITY MARKET OVERSIGHT PANEL (EMOP) – ITS CONSTITUTION AND FUNCTIONS

The EMOP is an 11- member panel consisting of:

(a) The Chairperson;
(b) The Executive Secretary of Energy Commission;
(c) The Executive Secretary of the Public Utilities Regulatory Commission (PURC);
(d) The Chief Executive Officer of Ghana Grid Company Limited (GRIDCo);
(e) The Head of System Operations and Control of GRIDCo;
(f) One representative nominated by;
   a. the Distribution Licensees, and
   b. the Bulk Customers
(g) Two representatives nominated by the Wholesale Suppliers;
(h) One person responsible for the administration of the Electricity Market Oversight Panel; and
(I) One other person with knowledge and experience in matters relevant to the wholesale electricity market.

The list of the current members of the EMOP is attached as Appendix 2 of this document.

The functions of EMOP are to, among others:

(a) monitor the general performance of the market administration functions of the Utility;
(b) ensure the smooth operation of the wholesale electricity market;
(c) review the operations of the wholesale electricity market and studies related to the development of the market;
(d) review procedures, manuals, and electricity market rules for the operation of the wholesale electricity market;
(e) monitor pre-dispatch schedules;
(f) resolve disputes referred to it by Market Participants in respect of transactions in the wholesale electricity market; and
(g) ensure the long-term optimization of the hydroelectric supply sources in the country.

A key responsibility of the EMOP is to make appropriate recommendations to the Energy Commission in respect of developments in the Ghana Wholesale Electricity Market.

THE EMOP MEMBERS

Michael Opam
Chairman

Oscar Amonoo-Neizer
Executive Secretary, Energy Commission

Mami Dufie Ofori
Executive Secretary, PURC

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Chief Executive Officer, GRIDCo

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Nana Osae Nyampong VI
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Representative of Wholesale Suppliers

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Administrator

FOREWORD AND ACKNOWLEDGEMENTS

The growing difficulties with traditional financing sources and the imminent appearance of Independent Power Producers (IPPs), in addition to the desire to create a dynamic institutional environment in the power sector of Ghana, led to the Power Sector Reforms (PSR). The PSR led to restructuring the monopoly of power generation, transmission, and distribution towards opening up the wholesale electricity market for new private sector entrants in power generation and an "open access" transmission system. The reforms have been institutionalized under the Electricity Regulations 2008, (L.I. 1937) which has created the Ghana Wholesale Electricity Market (GWEM) as a platform for the wholesale trading of electricity and provision of ancillary services in the National Interconnected Transmission System (NITS).

Additionally, the Electricity Market Oversight Panel (EMOP) was established to supervise the administration and operation of the GWEM. Substantial progress has, since, been made in the power sector under the oversight of the EMOP in relation to its mandate. The EMOP, since its inception, has provided valuable information on developments in the wholesale electricity market through its monthly bulletins and the publication of its mid-year report on the wholesale electricity market.

This report has been prepared in fulfilment of EMOP's responsibility to report on its activities and assessment of the governance and administration of the wholesale electricity market. The report offers a comprehensive analytical exposure of the GWEM for 2019.

This report elucidates the fact that transactions in the GWEM in respect of the Bilateral Contract Market and the Spot Market as envisaged by L.I. 1937 are already in place, though in a loose form of market trading. The transactions based on Power Purchase Agreements (PPAs) between Market Participants confirms that the Bilateral Contract Market as envisaged in L.I. 1937 is in operation.

Similarly, the exclusion of Akosombo and Kpong hydroelectric plants from bilateral contracts effectively forces these resources into the Spot Market to be traded at the System Marginal Cost. The next major step in the process of fully operationalizing the GWEM is to formally document the rules regarding the transactions in the markets and to separate market operation functions by establishing the Independent Market Operator (IMO).

The year 2019 saw considerable improvements in the supply and transmission of electricity to meet the needs in the economy. The value of electricity generated and traded in the GWEM in 2019 is estimated at about GHS 7,412 million which is equivalent to 2.1% of Ghana's Gross Domestic Product (GDP) in 2019.

A major challenge confronting the power sector is the burden of the financial obligations resulting from the costs of excess power generation capacity brought about by over-procurement in the past. The report contains an analysis of the challenges associated with excess capacity cost obligations. The report recommends to develop and implement strategies beyond the re-engineering of the management of the proceeds from the Energy Sector Levy Act (ESLA) funds. This will provide adequate funds in the Power Generation and Infrastructure Support Account which is intended to be used, among other things, to pay for power utility debts.

The report also highlights some major activities undertaken by the EMOP with regards to its mandates.

These include effectively monitoring pre-dispatch and real-time dispatch of Wholesale Suppliers in the National Interconnected Transmission System (NITS), coordinating the development of the market design and rules and enhancing transparency in the wholesale electricity market through the publication of monthly editions of GWEM bulletins. Additionally, the EMOP has developed two Market Manuals – the Market Monitoring Protocol and the Complaint and Dispute Resolution Procedure.

The EMOP has also successfully resolved disputes between GRIDCo and some Market Participants. Significantly, the EMOP has reviewed the Electricity Transmission Ancillary Services Pricing Policy and Guidelines and would wish to encourage the PURC to initiate its implementation to guide the procurement of ancillary services in the NITS.

Finally, the report contains highlights on the outlook for the power market in 2020. By all indications the outlook for 2020 is projected to be good.

I hope the contents of the report will be of benefit to policymakers as well as other stakeholders including the academia.

I would like to express my profound gratitude to the Members of the EMOP and the Secretariat for their dedication and hard work towards the fulfillment of EMOP's mandates. I would also like to take this opportunity to thank the Ministry of Finance, Ministry of Energy, Energy Commission, Public Utilities Regulatory Commission, Ghana Grid Company Limited, Market Participants and other stakeholders for their collaboration and support.

I would urge all stakeholders to continue to assist the EMOP in its desire to ensure that the Ghana Wholesale Electricity Market is fully functional and the full benefits are realized.

This report has been published under my authority as Chairman of the EMOP of Ghana.

Michael Opam
Chairman
EMOP

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ACRONYMS / ABBREVIATIONS

AGPP	–	Atuabo Gas Processing Plant
BPA	–	Bui Power Authority
BSP	–	Bulk Supply Point
CAR	–	Capital Asset Recovery
CBGC	–	Composite Bulk Generation Charge
CEB	–	Communauté Électrique du Bénin
CIE	–	Compagnie Ivoirienne d'Electricité
CUF	–	Capacity Utilization Factor
DFO	–	Diesel Fuel Oil
EC	–	Energy Commission
ECG	–	Electricity Company of Ghana
EMOP	–	Electricity Market Oversight Panel
EPC	–	Enclave Power Company
ERERA	–	ECOWAS Regional Electricity Regulatory Authority
ESI	–	Electricity Supply Industry
ESLA	–	Energy Sector Levy Act
ESP	–	Electricity Supply Plan
ESPC	–	Electricity Supply Plan Committee
GDP	–	Gross Domestic Produce
GHp	–	Ghana Pesewa
GNGC	–	Ghana National Gas Company
GRIDCo	–	Ghana Grid Company
GWEM	–	Ghana Wholesale Electricity Market
GWh	–	Gigawatt hours
HFO	–	Heavy Fuel Oil
IMO	–	Independent Market Operator
IPPs	–	Independent Power Producers
KTPP	–	Kpone Thermal Power Plant
kV	–	Kilovolts
kWh	–	Kilowatt-hour
LCO	–	Light Crude Oil
LPG	–	Liquefied Petroleum Gas
MGHS	–	Million Ghana Cedis
MW	–	Mega Watt
MMBtu	–	Million British thermal unit
MMScf	–	Million Standard Cubic Feet
NEDCo	–	Northern Electricity Distribution Company
NITS	–	National Interconnected Transmission System

PGISA	–	Power Generation and Infrastructure Support Account
PPA	–	Power Purchase Agreement
PSRP	–	Power Sector Reform Programme
PURC	–	Public Utility Regulatory Commission
SAPP	–	Sunon Asogli Power Plant
SONABEL	–	Société Nationale d'électricité du Burkina Faso
TAPCO	–	Takoradi Power Company
TICO	–	Takoradi International Company
TT1PP	–	Tema Thermal 1 Power Plant
TT2PP	–	Tema Thermal 2 Power Plant
TTIP	–	Takoradi – Tema Interconnection Project
US$	–	United States Dollar
US cents	–	United States Cent
VALCO	–	Volta Aluminum Company
VRA	–	Volta River Authority
WAGP	–	West African Gas Pipeline
WAGPCo	–	West African Gas Pipeline Company

EXECUTIVE SUMMARY

The Electricity Regulations, 2008, L.I. 1937 established the Ghana Wholesale Electricity Market (GWEM) to facilitate wholesale trading of electricity and the provision of ancillary services in the National Interconnected Transmission System (NITS). The L.I. 1937 further established the Electricity Market Oversight Panel (EMOP) to supervise the administration and operation of the GWEM.

The EMOP has made significant progress in carrying out its mandates. Specifically, the EMOP has carried out some key activities including coordination of the development of the Ghana Wholesale Electricity Market Design and Rules, sensitization of Market Participants on the GWEM, publication of the GWEM monthly bulletins and other reports relating to the electricity market. The EMOP has also established a Remote Monitoring System with GRIDCo to monitor, in real-time, the dispatch of power plants on the NITS. Additionally, the EMOP has developed a Complaint and Dispute Resolution Procedure and has, subsequently, resolved disputes between GRIDCo and some Market Participants.

In 2019, the System Peak demand was 2,803.7 MW compared to the Ghana Peak demand of 2,480 MW.

A total of 17,732.6 GWh of electricity was traded in the GWEM in 2019. Of this amount, 65.2% and rest of 34.8% were traded via Bilateral Contracts and the Spot Market respectively.

A total of 17,034.6 GWh of electricity was consumed[1] in the GWEM in 2019. Of the total electricity consumed in 2019, the Regulated Market accounted for 77.1%, the De-regulated Market 9.3% and the Export Market 13.6%. Thermal based power plants consumed a total of 97.4 trillion Btu of fuel for electricity generation in 2019. This consisted of 77.5% of natural gas, 16.3% of Heavy Fuel Oil (HFO), 5.6% of Light Crude Oil (LCO) and 0.5% of Distillate Fuel Oil (DFO).

With a combined dependable operating capacity of 4,365 MW compared to the maximum demand of 2,803.7 MW recorded in 2019, the unpleasant financial obligation in the Regulated Market requiring payment for the excess capacity procured in the Bilateral Contract Market (BCM) has posed a major challenge for the power sector in general and particularly the pricing of electricity in the country. Excess generation capacity payment obligations amounted to US$ 304.98 million in 2019.

Given the enormity of the lingering financial burden created out of liabilities from excess capacity cost obligations, there is the need to resolve the problem expeditiously. The issue can be addressed with carefully crafted interventions. This report has, in that regard, made the following recommendations:

a) The intervention with immediate result is to increase electricity tariffs to accommodate the costs of excess capacity. We have assessed possible policy interventions through the GWEM pricing mechanism which when deployed could recover the full cost of electricity supply including the excess capacity costs obligations;

b) The excess capacity regime may be re-engineered into a Firm Capacity Market

[1] Electricity consumption refers to the electricity consumed by end-use sectors (agriculture, buildings, industry and transport), while electricity demand also includes onsite electricity consumed by power plants, refineries, blast furnaces, coke ovens, oil and gas extraction, and heat and boiler transformation.

arrangement in which capacity would be procured and priced on competitive basis; and

c) In the medium to long term, with current average annual normal demand growth, the level of excess generation capacity in the power system would decline gradually to levels that are reasonable and acceptable by best utility practice.

To enhance the smooth operation of the GWEM, the report has, among others, recommended as follows:

a) Institutional Reforms – There is the need for the separation of the Market Operator functions from the transmission asset owner responsibilities. The separation will enable the implementation of a fully liberalized wholesale electricity market; and

b) Capacity Charge Pricing guidelines – In order to enhance least cost or competitive procurement of power in the BCM, the EMOP is recommending that the PURC should develop a Capacity Pricing Policy to guide Distribution Companies in future bilateral contract arrangements.

INTRODUCTION

This report on the Ghana Wholesale Electricity Market (GWEM) is presented by the EMOP in compliance with Electricity Regulations 2008 (L.I. 1937). The report has been developed to:

a) Make information on the GWEM available to stakeholders, including policymakers; and

b) Assist with planning in the Power Sector as may be necessary, by electricity industry players and other stakeholders.

The report consists of the following Five (5) Chapters:

Chapter One (1) presents an overview of the GWEM and discusses the major Power Sector Reform (PSR) milestones;

Chapter Two (2) is the main body of the Report. It contains a review of the 2019 performance of the GWEM in respect of the technical delivery, as well as issues relating to electricity demand and supply in the market. This chapter further outlines the structure and applicable pricing principles in the GWEM and provides a succint review of the commercial and financial transaction as well as the outcomes of prices in the GWEM in 2019. Additionally, it discusses the huge financial liabilities in the power sector emanating from the costs of excess generation capacity in the GWEM;

Chapter Three (3) provides an overview of the outlook for 2020 based on the projections made in the 2020 Electricity Supply Plan (ESP);

Chapter Four (4) presents additional information on the GWEM; and

Chapter Five (5) contains some key recommendations required to ensure the smooth operation of the GWEM.

CHAPTER 1

MARKET OVERVIEW

1.1 POWER SECTOR REFORMS MILESTONES

- **1997 – Energy Commission (EC) and Public Utilities Regulatory Commission (PURC)** were established as regulators for the electricity sector of Ghana as part of the Power Sector Reforms Programme (PSRP).

EC - The Energy Commission was set up in 1997 under the Energy Commission Act (Act 541) to regulate and manage the development and utilisation of energy resources in Ghana, as well as to provide the legal regulatory and supervisory framework for all operators in the power sector in the country, specifically by granting licenses for the wholesale supply, transmission, distribution and sale of electricity. Its mandate also covers the processing, transmission and distribution of natural gas. The Commission's mandate was expanded in 2011, to include the promotion and management of renewable energy resources in the country by the Renewable Energy Act, 2011, (Act 832). Again, in 2016, the Commission was further mandated, under the Energy Commission Amendment Act, 2016, (Act 993), to promote Local Content and Local Participation in the Electricity Supply Industry in Ghana.

PURC- The Public Utilities Regulatory Commission (PURC) was set up as a multi-sectorial regulator in October 1997 under the Public Utilities Regulatory Commission Act, 1997 (Act 538) to regulate the pricing of electricity in respect of the transmission, distribution and sale of electricity to final consumers. It also has the responsibility for regulating the pricing of water and the transportation of natural gas.

2008 – Ghana Grid Company (GRIDCo) was established as an independent Electricity Transmission Utility (ETU) in accordance with the Energy Commission Act, 1997 (Act 541). GRIDCo was incorporated on December 15, 2006, as a private limited liability company under the Companies Code, 1963, Act 179 and granted a certificate to commence business on December 18, 2006. The company became operational on August 1, 2008, following the transfer of the core staff and power transmission assets from the Volta River Authority (VRA) to GRIDCo.

- **2008 – Enactment of Electricity Regulations, 2008 (L.I. 1937).** These regulations provided the framework for the establishment and regulation of the Ghana Wholesale Electricity Market (GWEM). The L.I. 1937 also established the Electricity Market Oversight Panel (EMOP), independent of the ETU, to supervise the administration and operation of the GWEM.

- **2009 – The National Electricity Grid Code** was developed.

The Grid Code establishes the requirements, procedures, practices, and standards that govern the development, operation, maintenance, and use of the high voltage transmission system in Ghana. The purpose of the Grid Code is to ensure that the National Interconnected Transmission System (NITS) **provides fair, transparent, non-discriminatory, safe, reliable, secure, and cost-efficient delivery** of electrical energy. The Grid Code also describes the responsibilities and obligations associated with all the functions involved in the supply, transmission, and delivery of bulk electric power and energy over the NITS.

It specifically defines the roles of the ETU, a Wholesale Supplier, a Distribution Company, and a Bulk Customer in respect of connections, operations, and planning in the NITS.

- **2012 – Northern Electricity Distribution Company (NEDCo)** was operationalized as a wholly owned subsidiary of VRA.

The Northern Electricity Department (NED) of the Volta River Authority (VRA) was established in 1987 to distribute electricity in the Brong-Ahafo, Northern, Upper East and Upper West Regions of Ghana as part of VRA's 161kV transmission grid extension to the northern parts of Ghana. In pursuit of the PSRP, VRA Management, in 1997, registered the Northern Electricity Distribution Company (NEDCo) as a wholly owned VRA subsidiary, with a Board of Directors, to take over the operations of NED. In May 2012, VRA Management operationalized NEDCo as a wholly-owned subsidiary.

- **2017 – The Electricity Market Oversight Panel (EMOP)** was set up in accordance with the Electricity Regulations, 2008 (L.I. 1937).

The EMOP was inaugurated on 22nd December, 2017 with the responsibility of supervising the Ghana Wholesale Electricity Market and overseeing the market operation functions of the Electricity Transmission Utility.

1.2 MARKET PARTICIPANTS

In accordance with Regulation 8(1) of L.I. 1937, a person shall not participate in trading in the Ghana Wholesale Electricity Market unless that person:

(a) has an operating license or permit issued by Energy Commission;
(b) is registered with the ETU; and
(c) has entered into a contractual arrangement with the ETU.

The operating licenses or permits issued by the Energy Commission are in the following categories:

(a) Electricity Wholesale Supply License;
(b) Electricity Distribution License;
(c) Bulk Customer Permit;
(d) Electricity Brokerage License; and,
(e) Electricity Export License.

A full list of the current Market Participants as at the end of December 2019 is attached as Appendix 1 of this document.

1.3 MARKET OPERATOR

The ETU is currently the operator of the Ghana Wholesale Electricity Market. The institutional reforms being implemented in the power sector and prescribed by law, however, requires the separation of market operator functions from the transmission asset ownership as well as its operation and maintenance responsibilities. The separation is to enable the implementation of a fully liberalised wholesale electricity market. The Independent Market Operator (IMO) is yet to be established and EMOP intends to engage stakeholders, particularly policymakers, to discuss and develop timelines towards its establishment and operationalization.

1.4 MARKET GOVERNANCE

1.4.1 Electricity Market Oversight Panel

The EMOP is the entity mandated with oversight responsibility for the GWEM. Its regulatory functions are, however, intended to be exercised at "arms-length". The primary functions of EMOP are to, among others, monitor the general performance of the market administration functions of the Transmission Utility and ensure the smooth operation of the wholesale electricity market by monitoring pre-dispatch and dispatch schedules as well as resolve disputes referred to it by Market Participants in respect of transactions in the wholesale electricity market.

The EMOP, in ensuring that it performs its governance mandates effectively, has set up three Working Committees (WC) to assist it. These are:

(a) The Technical and Commercial Committee;
(b) The Legal and Regulatory Committee; and
(c) The Compliance Committee. These Committees comprise members of the EMOP, members of civil societies, and industry experts.

1.4.2 Ghana Wholesale Electricity Market Rules

The Market Rules are a set of rules to govern the operations in the wholesale electricity market including pre-dispatch, real-time dispatch, and settlements as well as the resolution of disputes between Market Participants. The EMOP is mandated, under L.I. 1937, to monitor these operational activities on a daily basis. The ETU has the responsibility to develop the Market Rules for the approval of the Energy Commission. The activity which is currently ongoing is being coordinated by EMOP.

CHAPTER 2

MARKET PERFORMANCE FOR 2019

2.1 GHANA WHOLESALE ELECTRICITY MARKET TRADING HIGHLIGHTS – 2019

Table 1 shows a summary of trading in the GWEM comprising transactions via bilateral contract and supplies to the spot market in 2019.

Table 1: **Summary of trading in the GWEM in 2019**

GWEM	
Total Traded (GWh)	17,732.6
Total Value (MGHS)	7,451.1
% of GDP[2]	2.1%
Bilateral Contract Market	
Total Traded (GWh)	11,493.2
Total Value (MGHS)	6,497.8
% of GDP	1.9%
Spot Market	
Total Traded (GWh)	6,239.4
Total Value (MGHS)	947.4
% of GDP	0.3%

2.2 ELECTRICITY SUPPLY PLAN (ESP)

The Electricity Supply Plan (ESP) is a document compiled by the Electricity Supply Plan Committee (ESPC) to highlight developments in the GWEM. It presents an outlook of power demand and supply for the ensuing year covering the following:

(a) projected demand for the year;
(b) availability of all the existing power generation sources; and
(c) power projects that are expected to come to commercial operation in the year.

Additionally, the ESP provides an indication of the fuel requirements and the associated costs for power generation. The availability of the power transmission system and associated infrastructure requirements for the year are also assessed in the ESP.

The ESPC is made up of representatives from Energy Commission, GRIDCo, Volta River Authority (VRA), Bui Power Authority (BPA), Electricity Company of Ghana (ECG), Northern Electricity Distribution Company (NEDCo), and the Ghana National Petroleum Corporation (GNPC)

[2] *The estimated GDP for 2019 is GHS 349.48 Billion.*

2.3 ELECTRICITY DEMAND

2.3.1 System Demand Overview

System peak demand, comprising both domestic and export loads, recorded in 2019 was 2,803.7 MW, amounting to an increase of 11% over the system peak demand of 2,525 MW recorded in 2018. The system peak demand recorded was also 5.2% higher than the 2,665.7 MW projected in the 2019 ESP. The Average electricity demand for 2019 of 2,041.9 MW, represented an increase of 12.1% over 2018 and 3.8% higher than the average electricity demand projected in the 2019 ESP.

In meeting the system peak demand of 2,803.7 MW recorded in 2019, the total generation by all the hydropower stations was 1,187.1 MW, thus contributing 42.3% of the total generation capacity while the thermal-based power plants accounted for the rest of 1,616.6 MW (57.7%).

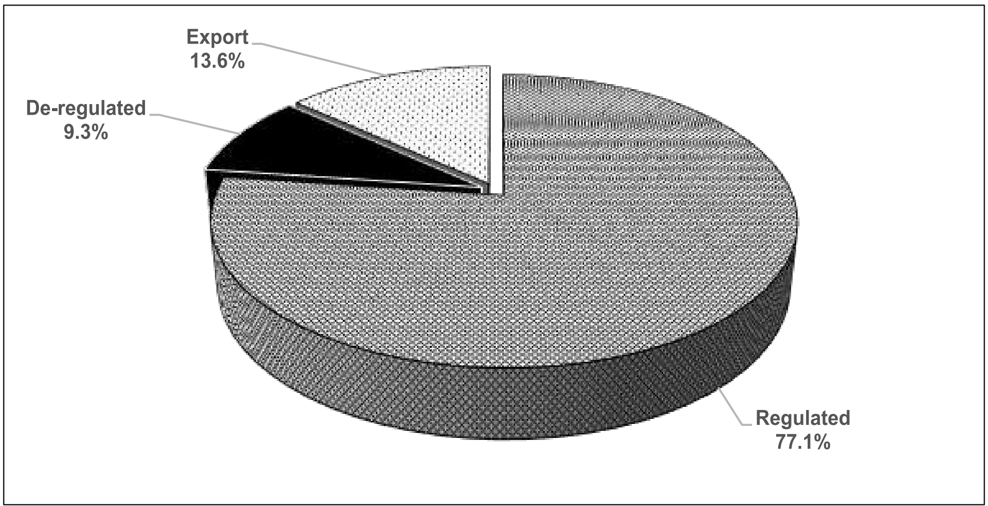
The Ghana peak demand recorded for 2019 was 2,480 MW. It represented an increase of 4.1% over the 2,382.6 MW recorded in 2018. This was, however, 1% lower than the 2,505.7 MW projected for the year 2019 in the ESP.

The total consumption of electricity in the GWEM in 2019 was 17,034.6 GWh. This represented an increase of 11.7% over 15,244.2 GWh that was recorded in 2018 and also equaling 4.3% rise on the 16,330.7 GWh projected in the 2019 ESP. Of the total electricity consumption of 17,034.6 GWh recorded in 2019, the Regulated Market accounted for 77.1%, the De-regulated Market accounted for 9.3%, and the Export Market contributed 13.6%. Figure 1 shows the shares of electricity consumed according to the type of market in 2019.

2.3.2 Regulated Market Demand

The Distribution Companies namely, Electricity Company of Ghana (ECG), NEDCo, and Enclave Power Company (EPC) are the primaryplayers in the Regulated Market. The combined average electricity demand of the Distribution Companies also increased by 11.3% to 1,569.8 MW in 2019 from 1,410.7 MW in 2018.

Figure 1: **Shares of the electricity consumed in the various market in 2019**



A total of 13,133.3 GWh of electricity was consumed in the Regulated Market in 2019. This represented a growth of 6.2% on the 12,357.6 GWh recorded in 2018 and was also 3.3% higher than the 12,719 GWh projected in the 2019 ESP. The electricity consumption recorded for ECG was 11,487.2 GWh, representing a 5.7% growth on the 10,869.9 GWh it consumed in 2018 and also equilibrated to 3.7% higher than the 11,075 GWh projected in 2019 ESP. The consumption recorded for NEDCo and EPC were 1,410.5 GWh and 235.5 GWh in 2019 respectively. These represented 6.3% and 46.5% growth over their 2018 consumption of 1,328.9 for NEDCo and 160.6 GWh for EPC respectively. However, the consumption of NEDCo was 2.3% lower than the 1,444 GWh projected in the 2019 ESP while EPC's consumption, on the other hand, was 17.8% higher than the projected 200 GWh in the 2019 ESP. Figure 2 shows the shares of electricity consumed by the Distribution Companies in 2019.

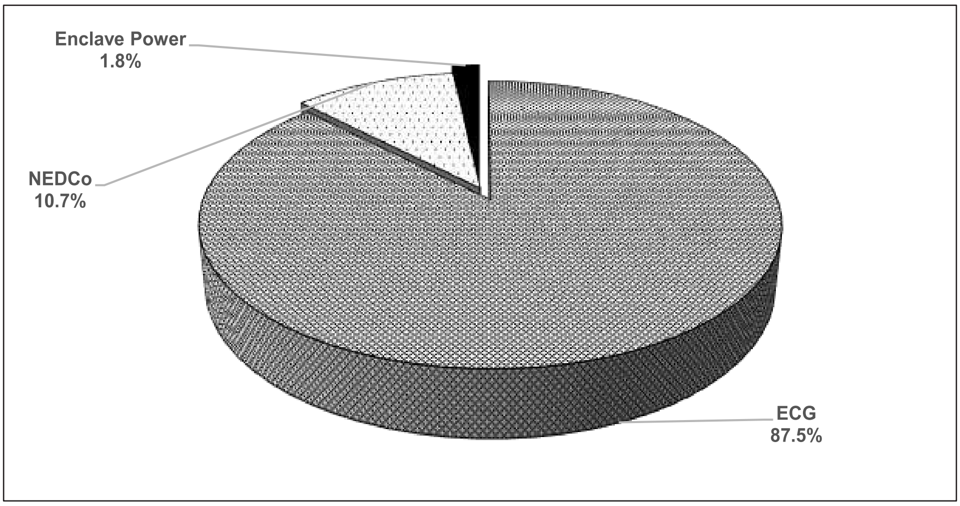
2.3.3 De-regulated Market Demand

The De-regulated Market in Ghana is made up of Bulk Customers whose consumption is above a threshold determined by the EC and also purchase electricity directly from wholesale suppliers for their own consumption and are granted permits by the Energy Commission to do so. The Bulk Customers operating in the De-regulated Market include mining companies and large industrial customers. It is important to note that some Bulk Customers embedded within the distribution networks purchase their needs from the Distribution Companies. Currently, of the fifty-one (51) registered Bulk Customers, twenty-three (23) of them operate in the De-regulated Market outside of the distribution network. The average demand of Bulk Customers grew by 18.5%, from 152.1 MW in 2018 to 180.2 MW in 2019.

Demand for the mining companies accounted for 92.9% of the total demand of the Bulk Customers in 2019 while the large industrial customers accounted for the rest of 7.1%.

Electricity consumption by Bulk Customers in the De-regulated Market increased by 19.5% in2019, from 1,332 GWh in 2018 to 1,578.4 GWh. The consumption in 2019 was 11.7% higher than the 1,412 GWh projected in the 2019 ESP. The electricity consumption recorded for the Bulk Customers constituted 9.3% of the total national electricity consumption for 2019.

Figure 2: **Shares of the electricity consumed by the Distribution Companies in 2019**



The consumption of the mining companies grew by 20.9% in 2019 from 1,090.8 GWh in 2018 to 1,318.9 GWh. The mining companies thus consumed 83.6% of the total electricity consumption in the De-regulated Market in 2019. The electricity consumption of the large industrial customers also grew by 7%, from 241.2 GWh in 2018 to 259.4 GWh in 2019 and constituted 16.4% of the total electricity consumed in the De-regulated Market. Figure 3 shows the shares of electricity consumed by customer category in the De-regulated Market.

2.3.4 Export Market Demand

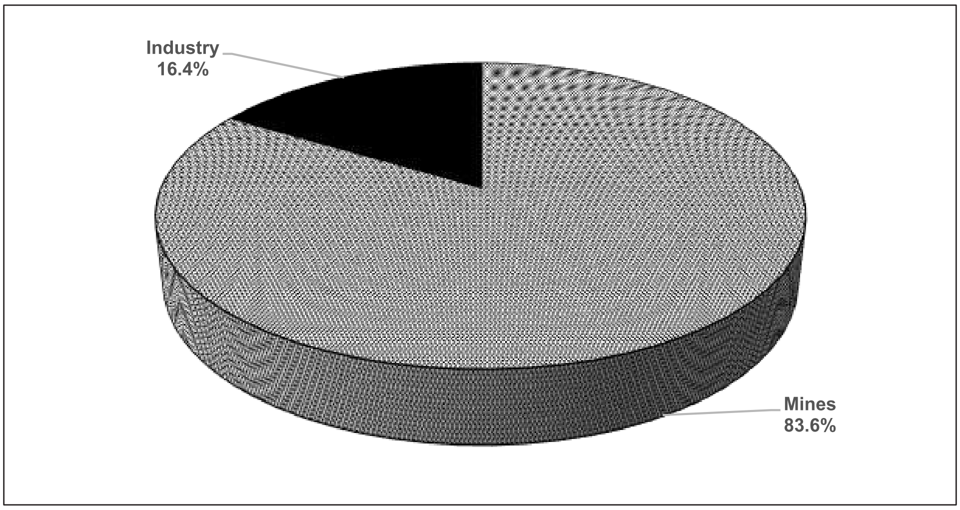
Ghana exports electricity on contractual arrangements to its neighbouring countries: Togo and Benin through Communauté Electrique du Bénin (CEB) and Burkina Faso through La Société Nationale d'Electricité du Burkina (SONABEL). In addition, there is a power exchange arrangement with Compagnie Ivoirienne d'Electricité (CIE) of La Côte d'Ivoire. The average electricity demand for the export market increased from 84.4 MW in 2018 to 163.2 MW in 2019, representing an increase of 93.3%.

Electricity supply to the VALCO aluminum smelter, located in Tema, is also considered as part of the export market[3]. VALCO's average demand increased by 9.4%, from 93.1MW in 2018 to 101.9 MW in 2019.

Electricity exported to neighbouring countries in 2019 increased significantly by 93.4%, from 739.5 GWh in 2018 to 1,430.4[4] GWh and was also 34.3% higher than the 1,065.3 GWh projected in the 2019 ESP. The total electricity exported constituted 8.2% of the total electricity consumed in the GWEM in 2019.

Electricity exported to both CEB and SONABEL saw a substantial increase in 2019 over 2018. Supply to CEB increased from 385 GWh in 2018 to 777.5 GWh in 2019 while exports to SONABEL increased from 277.1 GWh in 2018 to 576.5 GWh in 2019. The combined exports to CEB and SONABEL show an increase of over 100% between 2018 and 2019.

Figure 3 :**Shares of the electricity consumed by customer category in the De-regulated Market**



[3] *According to the PURC Act, Act 538*
[4] *The total export value of 1,430.4 GWh includes inadvertent export to CIE of 76.4 GWh.*

In 2019, the electricity consumption of VALCO increased by 9.5% from 815.2 GWh in 2018 to 892.6 GWh and it was significantly lower than the 1,283.8 GWh projected in the 2019 ESP by 30.5%.

2.4 ELECTRICITY SUPPLY

Total electricity generated and supplied in the GWEM rose by 12.1% from 15,950.8 GWh in 2018 of 17,876.5 GWh in 2019. The electricity supply was made up of 17,749.2 GWh from domestic generation and 127.4 Gwh of inadvertent imports tvia the La Cote D'Ivoire intertie.

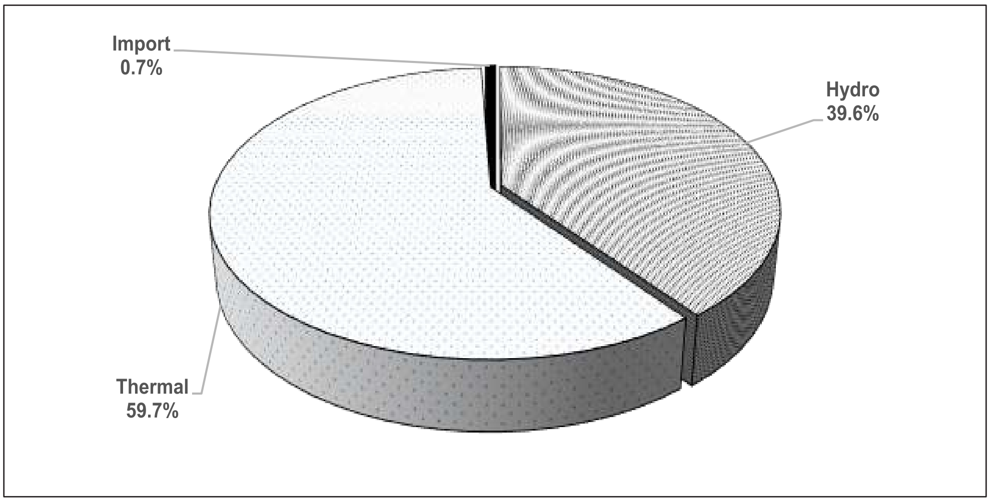
Although thermal power plants accounted for the larger share of the total electricity supplied in 2019, their contribution of 59.7% was marginally lower than the 60% recorded in 2018 and also lower than the 66.2% projected in the 2019 ESP. Hydroelectric power plants accounted for 39.6% of the total electricity supply and was higher than its share of 36.8% in 2018 as well as being higher Inadvertent imports accounted for only 0.7% of the total electricity supply in 2019.

Figures 4 shows the shares of electricity supply by sources for 2019. Electricity supplies in the GWEM are traded via the Bilateral Contract Market (BCM) and the Spot Market. The total electricity traded in the BCM was 11,668.8 GWh representing 65.3% of the total electricity traded in 2019 but was 12.7% lower than the 13,315.8 GWh projected in the 2019 ESP. On the other hand, 6,207.8 GWh of electricity, constituting 34.7% of the total electricity traded in 2019, was supplied in the Spot Market and was significantly higher than the supply of 5,070.6 GWh projected in the 2019 ESP by 22.4%.

2.4.1 Electricity Supply to the Regulated Market

In 2019, the electricity needs of the Regulated Market were met from both the Bilateral Contract Market transactions and the Spot Market supplies from Akosombo and Kpong hydropower plants.

Figure 4: **Shares of supply sources in the total electricity supplied in 2019.**



A total of 13,782.4 GWh of electricity was traded in the Regulated Market in 2019. Of this amount, 9,927.4 GWh was purchased from the BCM, constituting 72% of the total electricity supplied to the Regulated Market. The rest of the 3,855 GWh constituting 28% of the total was supplied from the Spot Market generation resources.

The ECG, being the largest player in the Regulated market, purchased a total of 8,627.9 GWh of electricity from the BCM and this represented 71.5% of all the electricity purchases of ECG supplied from the wholesale electricity market in 2019. To make up for its total electricity requirements of 12,055 GWh, ECG also purchased 3,427.1 GWh from the Spot Market in 2019 which represented 28.5% of the company's total electricity purchases from the GWEM.

NEDCo purchased a total of 1,480.2 GWh of electricity from the wholesale electricity market in 2019. Of the total electricity purchased, 1,117.8 GWh was from the BCM representing 75.5% of NEDCo's purchases from the wholesale electricity market. The Spot Market purchases of NEDCo was 362.4 GWh accounted for 24.5% of the total electricity purchased by the company in 2019.

The EPC purchased a total of 247.2 GWh of electricity in 2019. Of this amount, 193.2 GWh was purchased via the BCM representing 78.1% of the total electricity purchased by EPC. The rest of EPC's total requirements of 54 GWh in 2019 representing 21.9% of its total purchases was received from the Spot Market.

2.4.2 Electricity Supply to the De-regulated Market

Bulk Customers in the De-regulated Market purchased a total of 1,656.4 GWh of electricity in 2019. Of the amount, 1,056.9 GWh of electricity was purchased on the BCM while 599.5 GWh was received from the Spot Market. These represented 63.8% and 36.2% of their total supply from the BCM and Spot Market respectively.

2.4.3 Electricity Supply to the Export market

A total of 1,501.1 GWh of electricity was exported to Ghana's neighbouring countries with the BCM contributing 750.6 GWh which constituted 50% of the total electricity exported in 2019. In 2019, all of VALCO's needs of 936.7 GWh was served from only the Spot Market in line with GoG's policy directive regarding electricity supply to the smelter.

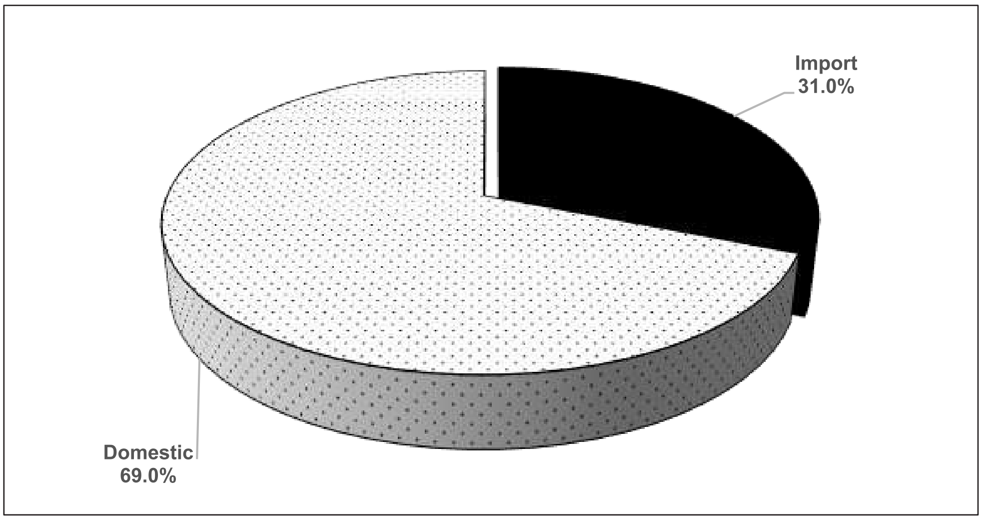
2.5 FUEL SUPPLY AND PRICES

2.5.1 Fuel Supply

The fuel for electricity generation by thermal power plants are natural gas, heavy fuel oil (HFO), Light Crude Oil (LCO), and a small amount of distillate fuel oil (DFO) used primarily for starting and stopping of the gas turbines. The sources of natural gas supply are i) domestic oil and gas fields and ii) imports from Nigeria through the West African Gas Pipeline (WAGP). All liquid fuels for power generation are imported.

In 2019, a total of 49,521.5 MMSCF of natural gas constituting 69% of the total natural gas supplied was from domestic sources and the rest of 22,226.2 MMSCF constituting 31% was imported through the WAGP. Figure 5 shows the shares of natural gas supply from various sources.

Figure 5: **shows the shares of natural gas from the various supply sources.**



A total of 97.4 trillion Btu of all fuels used by thermal power plants for electricity generation was consumed in 2019 compared to 112 trillion Btu that was projected to be consumed in the 2019 ESP.

2.5.1.1 Natural Gas Consumption

A total of 75.5 trillion Btu of natural gas was consumed in 2019 by power plants, accounting for 77.5% of the total fuel mix but this figure was 5.9% lower than was projected in the 2019 ESP. The actual natural gas consumed by thermal power plants in 2019 was 7.3% lower than the total natural gas consumption projected in the 2019 ESP. On a monthly basis, the differences between the actual consumption of natural gas and the projected ranged between 2% and 44%.

The most significant shortfalls in the natural gas consumption occurred between February 2019 and April 2019 owing to supply difficulties. Thereafter, supplies stabilized and consumption remained as projected in the 2019 ESP.

The significant shortfalls in the first half of the year resulted from some challenges with the supply of natural gas from Ghana National Gas Company (GNGC) to the Aboadze Power Enclave. In February 2019, shortages occurred owing to operational difficulties with the Floating Production Storage and Offloading (FPSO).

In March 2019, shortages occurred as a result of transmission pipeline difficulties emanating from the diversion of natural gas supply through the Schlumberger by-pass which limited total supplies to 100 Million Standard Cubic Feet per Day (MMSCFD) coupled with lower natural gasflows from the WAGP.

During the first half of April 2019, the Atuabo Gas Processing Plant (AGPP) was shut down for maintenance works which resulted in the curtailment of natural gas supplies to the Aboadze Power Enclave during the period. In addition, natural gas supply from the Sankofa Oil and Gas Fields was curtailed to enable maintenance works and tie-in at the Takoradi Regulating and Metering Station (TRMS).

In the second half of the year, however, natural gas consumption increased due to increased supply from the Sankofa Oil and Gas Fields through the reverse flow facility to Tema and Kpone for power generation. The increase in natural gas supply also enabled the Karpowership, which was moved from Tema to Sekondi, to operate fully on natural gas.

2.5.1.2 HFO Consumption

Heavy Fuel Oil (HFO) consumption in 2019 was 15.9 trillion Btu which constituted 15.6% of the total liquid fuel mix for electricity generation but it was significantly lower than the 32.1 trillion Btu projected in the 2019 ESP by over 100%. Total HFO consumed by AKSA and Karpowership was lower than projected in the 2019 ESP owing to the inability of the power plants to finance the procurement of the needed fuel for electricity generation as a result of the indebtedness of the power of-taker (ECG).

2.5.1.3 LCO Consumption

Even though it was projected that no LCO will be consumed in 2019, a total of 5.5 trillion Btu was consumed, constituting 5.7% of the fuel mix. It, however, became necessary to consume LCO as a result of insufficient natural gas supply to SAPP and TICO as well as the commissioning of the Cenpower and Amandi power plants.

2.5.1.3 DFO Consumption

A total of 0.5 trillion Btu of DFO was consumed in 2019 which constituted 0.5% of the total fuel mix. Figure 6 shows the trends in monthly fuel consumption for 2019.

2.5.2 Fuel Prices

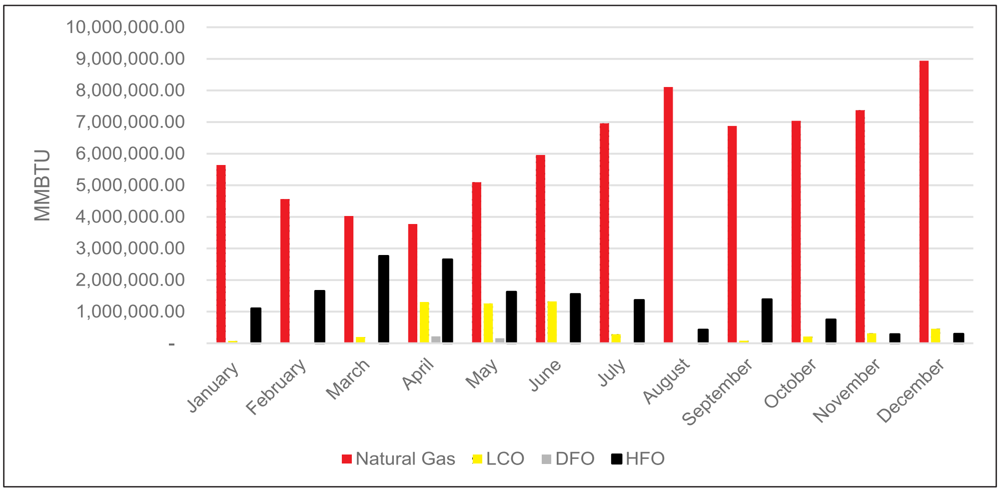
2.5.2.1 Natural gas prices

Natural gas prices from Sankofa and TEN are based on contracts while the supplies from Jubilee fields are at no cost for processing by the AGPP. Imported natural gas from Nigeria is also based on a contractual agreement between VRA and the Nigerian National Petroleum Corporation (NNPC) and the price is indexed to the price of crude oil and other ancillary services provided by both the West African Gas Pipeline Authority (WAGPA) and VRA.

2.5.2.2 Liquid Fuel Prices

The landed prices of heavy fuel oil (HFO) averaged 69.2 US$/bbl in 2019, which was 2.6%

Figure 6: **Monthly fuel consumption for 2019.**



lower than the average price of 71 US$/bbl recorded in 2018. On a monthly basis, HFO prices ranged between 64.7 US$/bbl and 75 US$/bbl in 2019 while in 2018 it ranged between 63.1 US$/bbl and 81.7 US$/bbl. Figure 7 shows the comparison between the monthly HFO prices for 2018 and 2019.

Light crude oil prices averaged 69.4 US$/bbl in 2019 compared to an average of 76.1 US$/bbl in 2018, representing a reduction of 8.8% between 2018 and 2019. Figure 8 shows the comparison between the monthly LCO prices for 2018 and 2019.

Generally, natural gas prices for electricity generation were relatively cheaper than all the other fuels. From January to June 2019, the natural gas price approved by the PURC was 7.3 US$/MMBtu but was later reduced to 6.1 US$/MMBtu for the period between July to December 2019.

Figure 7: **Trends in HFO prices in 2019 compared to the same period in 2018.**

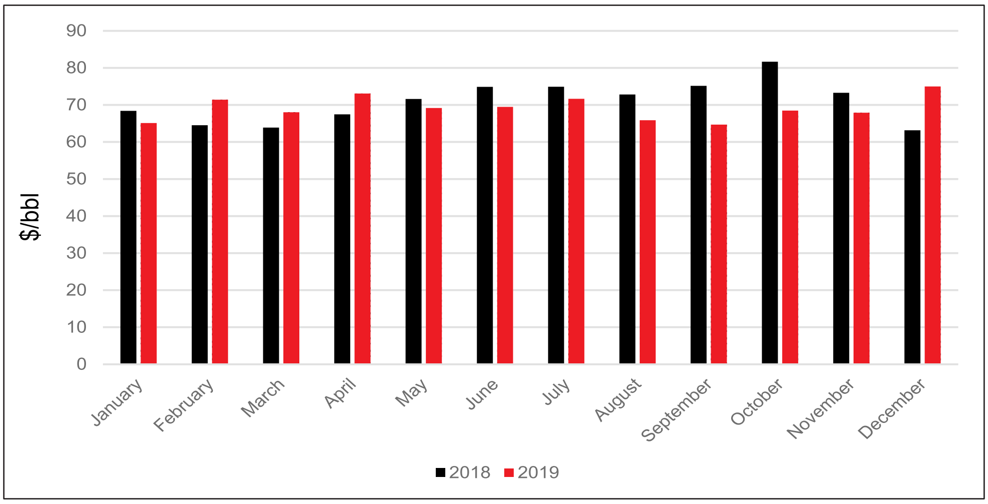
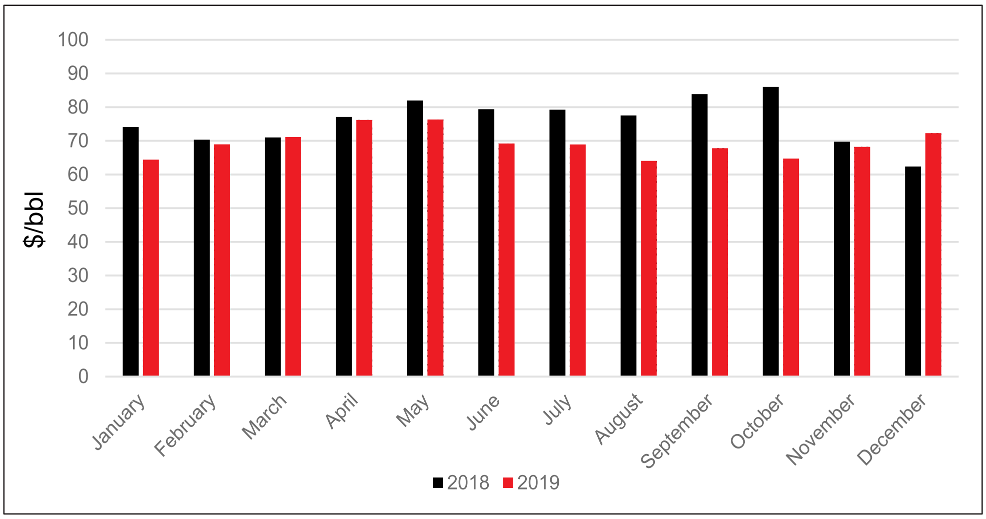


Figure 8: **Trends in LCO prices in 2019 compared to 2018.**



The average landed HFO price was 11.7 US$/MMBtu while LCO and DFO prices averaged 13.1 US$/MMBtu and 18.6 US$/MMBtu respectively. Figure 9 shows the comparison of fuel prices used by power plants in 2019.

2.6 THE ELECTRICITY TRANSMISSION SYSTEM PERFORMANCE IN 2019

2.6.1 System Overview

The national interconnected electricity transmission system is the backbone in the generation and supply of electricity. It plays a critical role in the smooth functioning of the GWEM as it provides the platform for the operation of the electricity market as it moves electricity from generators to load centres and thereby enhances access to electricity for social development and economic growth.

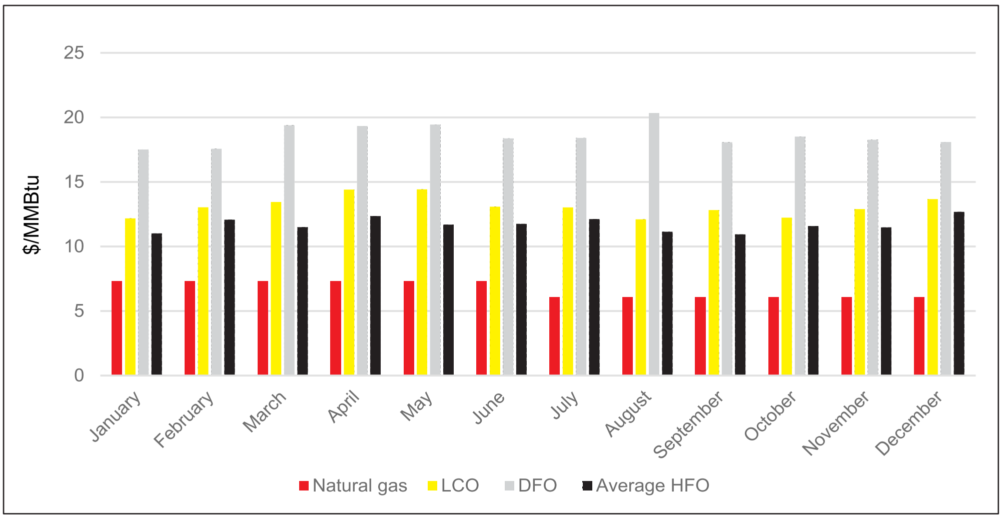
Additionally, in order to ensure that the total cost of operations in the wholesale electricity market is minimized, the operation and performance of the transmission system with respect to issues of congestion and losses have to be addressed comprehensively.

Ghana's electricity transmission infrastructure is relatively extensive and includes 6,500 circuit km of high voltage lines operated at 330kV, 161kV, and 69kV connected to 63 Bulk Supply Points (BSPs) and 141 transformers with a total capacity of 8,507 7 MVA.

2.6.2 Transmission System Reliability

The transmission system has faced voltage challenges in the past especially in the Ashanti, Western and Northern regions. A number of critical transmission infrastructure projects were commissioned in 2019 and these brought about improvements in the transmission of power in the NITS. The 330 kV Aboadze to Kumasi transmission line, 330 kV Kintampo to Bolgatanga, and the 161 kV Asawinso to Juaboso were completed and commissioned in 2019. The commissioning of the 330 kV substation at Adubiyili in Tamale also brought about an improvement in the reliability and quality of power supply in Tamale metropolis.

Figure 9: **Monthly fuel prices for 2019**



As a result of these interventions, the performance of the transmission system was generally good in 2019 as the lingering congestions problems were largely limited.

Despite these efforts to stabilize the reliability in power transmission, there were about five partial system collapses in 2019 which occurred on 12th March, 20th April, 27th June, 16th September, and 2nd December. These system disturbances occurred resulting from power supply difficulties which led to the tripping of some transmission lines.

According to data from GRIDCo, the transmission frequency was 70.7 % of the time within the prescribed band of 49.8Hz to 50.2Hz. Figure 10 shows a summary of the performance of the transmission system with respect to frequency stability.

2.6.3 Transmission System Losses

The total transmission system losses averaged 4.7% in 2019. This was 0.3% above the average losses of 4.4% recorded in 2018. The monthly transmission system losses ranged between 3.2% and 6.2% in 2019 compared to 3.8% and 5.1% in 2018.

Figure 11 shows a comparison of Transmission losses for 2018 and 2019

2.7 PRICING AND TRADING OF ELECTRICITY IN THE GWEM

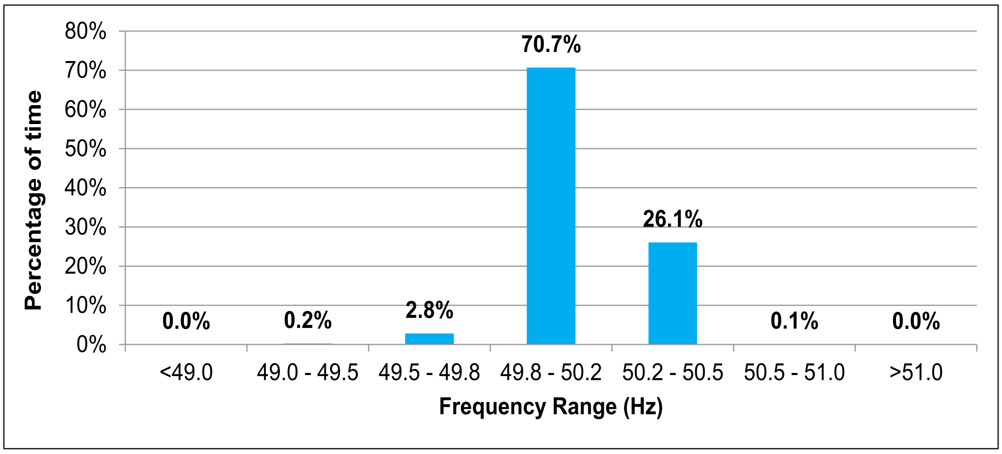
2.7.1 Pricing Framework in the GWEM

The Ghana Wholesale Electricity Market (GWEM) has a structure with well-defined trading arrangements and pricing framework prescribed in the legislation, L.I. 1937. The framework consists of clear pricing arrangements associated with bilateral contracts and with spot market trading.

2.7.1.1 BCM Pricing Mechanism

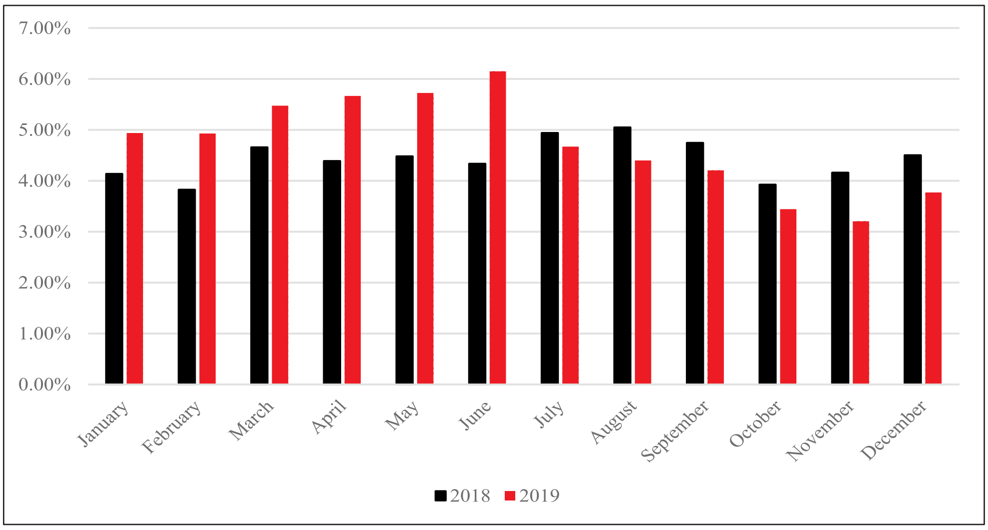
Pricing in the Bilateral Contract Market (BCM) is underpinned by long-term contracts signed between Wholesale Suppliers and other market

Figure 10: **System frequency distribution for 2019**



Source: 2020 Electricity Supply Plan

Figure 11: **Transmission losses for 2018 and 2019**



participants including Distribution Companies, Bulk Customers, and Export Market Customers.

The contracts between Wholesale Suppliers and Distribution Companies are based on prices that are negotiated between the parties but requiring the approval of the regulator, the PURC.

Currently, electricity supplied to the three (3) Distribution Companies are under Power Purchase Agreements (PPAs) signed with fourteen (14) different Wholesale Suppliers. Of the fifty-one (51) licensed Bulk Customers, twenty-three (23) of them are supplied electricity under contracts with VRA. In contrast, of the thirty-one (31) licensed Bulk Customers who buy electricity from the Distribution Companies, only one of them has a valid and operating contract.

2.7.1.2 Spot Market Pricing Mechanism

On the other hand, the pricing framework in the Currently, electricity supplied to the three (3) Distribution Companies are under Power Purchase Agreements (PPAs) signed with fourteen (14) different Wholesale Suppliers. Of the fifty-one (51) licensed Bulk Customers, twenty-three (23) of them are supplied electricity under contracts with VRA. In contrast, of the thirty-one (31) licensed Bulk Customers who buy electricity from the Distribution Companies, only one of them has a valid and operating contract.

2.7.1.2 Spot Market Pricing Mechanism

On the other hand, the pricing framework in the Spot Market is prescribed in L.I. 1937.

Additionally, in the case of Ghana, the Spot Market has been designed to provide a platform for transparent management and equitable allocation of the relatively cheap "legacy hydro" resources from Akosombo and Kpong hydro-electric power plants, as well as to mitigate the market power and dominance of generation resources of VRA.

The L.I. 1937 stipulates that Spot Market Price (SMP), would be the system marginal cost of supply at any time based on economic merit-order dispatch of generating resources available in the system. In other words, the Spot Market Price (SMP) should reflect the short-run marginal cost of the system, SSRMC, which is defined as the additional cost of producing one more unit of electricity to meet the maximum demand in the NITS at any time.

It is an established theory that pricing energy based on SSRMC produces total revenues larger than the total variable operating costs of the power plants serving the load, but it could be insufficient to pay for the additional corresponding capital costs (annuity) of the power plants.

Under optimal conditions, however, the total revenue accruing from selling all the energy at a "reference price" that is equal to the SSRMC plus the income obtained from payments for the total generation capacity provided in order to meet the system peak load would be equivalent to the total capital costs plus the total operating costs of the whole system. This postulation however assumes that (i) there is the non-existence of economies of scale, and (ii) the capacity payment[5] is equivalent to the development cost of a least cost peaking plant appropriate to the size of the NITS.

On the basis of the above conceptual discussions, the Spot Market Price (SMP) may be calculated as:

(i) a Single Tariff (US cents/kWh) reflecting the SSRMC (operating costs i.e. fuel plus non-fuel variable costs) of generation; or
(ii) a Two-Part Tariff structure consisting of (a) Firm Capacity Charge (US$/kW/month) and (b) SSRMC (US cents/kWh).

2.8 TRADING IN THE GWEM IN 2019

2.8.1 Overview

From data recorded in 2019 and discussed in earlier sections of this report, a total amount of 17,836.9 GWh of electricity was produced and traded in the GWEM within the BCM and the Spot Market.

Transactions in the BCM via bilateral contract arrangements based on Power Purchase Agreements (PPAs) accounted for 65.2% of all the electricity traded. The transaction in the BCM involved eight (8) wholesale suppliers (VRA and seven (7) Independent power producers) and 26 other market participants (3 Discos and 23 Bcs).

The Spot Market transactions accounted for 34.8% of all electricity traded and were supplied by only two (2) power plants - the Akosombo and Kpong hydropower plants.

Trading of electricity produced from these power plants, by law (LI 1937), is excluded from bilateral contracts. Electricity generation and supplies from these two (2) hydroelectric power plants are, however, regulated by the EMOP who carries out this responsibility through the Legacy Hydro Allocation Framework Mechanism. Besides approving how much "legacy" hydroelectricity is to be generated in the ensuing year, EMOP also decides on how the "legacy" hydroelectricity should be allocated among the competing markets - Regulated Market, De-regulated Market, Export Market, and then the VALCO Smelter.

The exception to EMOP's mandate, however, is the deliberate government policy that all of the electricity required by the VALCO Smelter for its operations should be supplied from the "legacy" hydroelectricity.

[5] *This equilibrates to the monthly capital cost plus the fixed operation and maintenance costs of a standard simple cycle gas turbine.*

2.8.2 Outcome of prices in the Bilateral Contract & Spot Markets in 2019

In this report, prices in the GWEM have been calculated based on the principles discussed above. Specifically, the following two (2) pricing methodologies have been used to derive the prices in the Bilateral Contract Market and the Spot Market. Using data on the actual electricity dispatched from January to December 2019 the calculated costs of electricity in the various market segments of the GWEM using the following two methods:

a) Average Total Costs (ATC) – equivalent to the total costs of electricity supplied (based on prices executed in the bilateral contracts) divided by the total electricity supplied; and

b) Spot Market Price (SMP) – using the System Short-Run Marginal Cost (SSRMC) principles and in accordance with L.I. 1937.

While the monthly ATC calculated for 2019 are based on actual electricity generated by the power plants and the applicable contract prices, the monthly SMPs corresponding to electricity supplied from Akosombo and Kpong hydropower plants have been calculated as "Reference Prices" using the SSRMC methodology prescribed in LI 1937 and noted above.

For purposes of comparative analysis, we have calculated, separately,

a) Actual Total Market Price (ATMP) – it is the average total cost of electricity supplied to the whole GWEM based on the actual contract prices for the power plants and the accounting costs[6] of the Akosombo and Kpong hydroelectric power plants as determined by PURC.

b) Actual Regulated Market Price (ARMP) – it is the average total cost of electricity supplied to the Regulated Market based on the actual contract prices for the power plants and the accounting costs of the Akosombo and Kpong hydroelectric power plants as determined by PURC.

c) PURC Gazetted Tariffs: Regulated Market – it is derived by converting the Composite Bulk Generation Charge (CBGC) contained in the PURC Gazette (denominated in GHp/kWh) into US cents/kWh using the prevailing monthly average exchange rates between the Ghana cedi and the United States Dollar.

d) System Short-Run Marginal Cost (SSRMC) – it is the variable cost of the last power plant that is used to meet the peak demand based on economic merit order dispatch of the available power plants used to meet the total demand. The variable cost is constituted by the variable operating and maintenance (O&M) cost and fuel cost.

e) Spot Market Price (SMP): Two-Part Tariff – it is the SSRMC and the capacity charge of the system marginal plant.

f) Spot Market Price (SMP): Single Part Tariff – it is the average total cost of the SSRMC and the capacity charge of the system marginal plant.

g) Spot and Bilateral Contract: L.I. 1937 – it is the average total cost of meeting the total energy requirement based on the contracted prices for the power plants and the legacy hydroelectricity priced at the SMP.

Table 2 shows the monthly prices based on the methodologies discussed above for 2019.

[6] The historic accounting cost of the electricity generated from the Akosombo and Kpong hydroelectric power plants are 2.66 US cent /kWh and 4.54 US cent /kWh respectively.

Table 2: **Monthly average prices for different scenarios for 2019.**

Month	Actual Total Market Price	Actual Regulated Market Price	PURC Gazetted Price: Regulated Market	System SRMC	Spot Market Price: Two-Part Tariff		Spot Market Price: Single Part Tariff	Spot + Bilateral Contracts: LI 1937
	Average Total Cost	Average Total Cost	Average Total Cost	Short-Run Marginal Cost	System Marginal Capacity Charge	System SRMC: Energy Charge	Average Total Short-Run Marginal Cost	Average Total Cost
	(US cents/kWh)	(US cents/kWh)	(US cents/kWh)	(US cents/kWh	(US$/kW/month)	US cents/kWh)	(US cents/kWh)	(US cents/kWh)
January	7.311	7.949	8.776	8.166	13.49	8.166	10.909	10.099
February	7.467	8.245	8.564	8.233	13.49	8.233	11.141	10.667
March	7.873	8.379	8.295	8.166	13.49	8.166	10.938	11.108
April	8.859	9.704	8.445	8.187	13.49	8.187	11.345	12.535
May	8.013	8.740	8.409	8.166	13.49	8.166	11.316	11.174
June	8.413	8.871	8.197	8.188	13.49	8.188	11.382	11.985
July	8.155	8.754	8.609	8.166	13.49	8.166	11.170	11.358
August	7.971	8.280	8.580	8.166	13.49	8.166	10.894	10.593
September	8.204	8.591	8.522	8.187	13.49	8.187	11.655	12.363
October	8.144	8.383	8.804	8.166	13.49	8.166	11.566	11.172
November	7.959	8.282	8.698	8.187	13.49	8.187	11.750	11.634
December	8.138	8.541	8.464	8.166	13.49	8.166	11.254	10.734

2.8.3 Cost of electricity Traded in the Regulated Market

The Regulated Market remains the largest segment of the GWEM accounting for 79% of all electricity traded in the GWEM. Of the total electricity of 14,124 GWh traded in the Regulated Market in 2019, about 71.9% was supplied via PPAs between the Wholesale Suppliers, including VRA, and Distribution Companies. The rest (28.1%) came from the Spot Market which the Regulated Market was allocated 62.1% of total legacy hydroelectricity generated in 2019. Based on these data the Actual Regulated Market Price (ARMP) was calculated on a monthly basis. The PURC Gazette of the average costs for bulk generation to the Regulated Market was also computed using the prevailing average monthly exchange rates.

Table 3 shows the data used and the resulting computation of the monthly ARMP and the PURC Composite Bulk Generation Charge (CBGC) for 2019.

2.8.4 Cost of electricity Traded in the De-regulated Market

The De-regulated Market is constituted by Bulk Customers (BCs) who operate outside of the Regulated Market. The participants in the De-regulated market include mining Companies and some large Industries. In 2019, the BCs purchased a total of 1,652.7 GWh, accounting for 8.5% of all electricity traded and averaging 137.7 GWh per month.

All the electricity requirements of the BCs are supplied based on agreements they have negotiated with VRA. VRA meets the needs of the BCs from a combination of the “legacy” hydroelectricity and electricity generated from VRA's thermal power plants. While the volumes of “legacy” hydroelectricity supplied are determined using the EMOP allocation framework, the electricity from the thermal power plants are pre-determined by VRA based on projections for the ensuing year. The cost of electricity supplied to the BCs is, therefore, the weighted average total cost of the “legacy” hydroelectricity and the thermal electricity supplied. Table 4 shows the electricity supplied monthly from the two (2) sources and the resulting average total costs for the De-regulated Market in 2019 and average total prices for the De-regulated Market in 2019.

Table 3: **Comparison of ARMP and PURC CBGC**

Month	Hydro (GWh)	Thermal (GWh)	Total (GWh)	Average Total Cost (US cents/kWh)	PURC Gazetted CBGC (US cents/kWh
January	388.8	762.1	1,150.90	7.9	8.8
February	381.3	755.6	1,136.80	8.3	8.6
March	418.5	779.2	1,197.60	8.4	8.3
April	386.5	847.4	1,233.90	9.7	8.5
May	386.5	1,188.8	1,575.30	8.0	8.4
June	291.4	882.8	1,174.20	8.9	8.2
July	290.8	809	1,099.80	8.8	8.6
August	267.9	739.3	1,007.30	8.3	8.6
September	293.8	727.9	1,021.70	8.6	8.5
October	263.2	818.3	1,081.50	8.4	8.8
November	315.7	864.9	1,180.50	8.3	8.7
December	290.2	974.3	1,264.50	8.5	8.5
TOTAL	**3,974.50**	**10,149.50**	**14,124.00**		

Table 4: **Monthly electricity supplies and average total cost of supply for De-regulated Market customers for 2019**

Month	Hydro (GWh)	Thermals (GWh)	Total (GWh)	Total Average Cost (US cents/kWh)
January	127.6	33.4	160.9	4.7
February	102.3	0.0	102.3	3.2
March	108.5	0.0	108.5	3.5
April	86.9	24.5	111.4	4.8
May	99.9	35.8	135.8	5.0
June	46.9	70.1	117	7.1
July	62.4	72.9	135.3	6.9
August	45.3	92.3	137.7	7.8
September	42.5	97.1	139.7	8.0
October	70.9	70.7	141.6	6.65
November	80.0	61.7	141.7	5.34
December	100.6	43	143.6	5.15
TOTAL	**973.9**	**601.6**	**1,575.40**	

2.8.5 Cost of electricity Supplied to the Export Market

The Export Market is relatively small involving only the VRA as the sole Wholesale Supplier and the three (3) national electricity companies in Togo, Benin and Burkina Faso. The Export Market accounted for 6.4% of the total electricity traded in the GWEM.

Electricity supplied to these countries, in 2019, were produced from VRA's generation portfolio – a combination of "legacy" hydroelectricity and thermal generation mainly from the TICO power plant. Although the cost of electricity sold by VRA in the Export Market are under Bilateral Contracts with the respective utility companies in the countries, the objective of VRA's pricing strategy in the Export Market is to become competitive. Consequently, the allocation of "legacy" hydroelectricity for the Export Market is done so that the average total cost of electricity does not exceed the contracted prices. Practically, the actual cost of electricity traded in the Export Market may vary from time to time depending on the proportion of legacy hydroelectricity in the total volume of electricity supplied.

The Export Market transactions comprised 904.5 GWh of thermal electricity and, using the agreed allocation formula for 2019, an amount of 473.4 GWh of legacy hydroelectricity. The legacy hydroelectricity supplied to the Export Market constituted 7.6% of the total legacy hydroelectricity generation of 6,200 GWh in 2019.

This represented a monthly average supply allocation of 36.2 GWh. On the basis of this monthly allocation amount and adjusting for actual monthly transmission system losses, the volumes of electricity supplied to the Export Market and the resulting average total costs in 2019, on a monthly basis, were derived. The resulting computations are shown in Table 5 below.

The monthly electricity supplied to the Export Market increased consistently from 90.1 GWh in January to 186.8 GWh in December 2019 representing an increase of about 100% over the period. Similarly, the average total cost of electricity increased from 6.9 US cents/kWh in January 2019 to 8.5 US cents/kWh in tandem with the increasing amount of thermal power in the total supply mix to the Export Market. The proportion of thermal power generation in the supply mix increased from 57.8% in January 2019 to 79.9% in December 2019.

To meet the demand for electricity in the Export Market in 2019, the legacy hydroelectricity allocation at the beginning of the year was equivalent to 36.2 GWh per month.

All the thermal-based electricity supplies to the Export Market was allocated from the TICO power plant. It is worth noting that supplies from legacy hydroelectricity in February 2019 of 55.9 GWh was higher than the monthly allocation amount of 36.2 GWh agreed with the PURC. The higher supplies from the legacy hydroelectricity generation in February 2019 was to make up for the very low electricity generation from the TICO power plant whose supplies are allocated for the export market only.

2.9 EXCESS CAPACITY COSTS ANALYSIS FOR 2019

2.9.1 Excess Capacity Costs Challenge

The financial burden arising out of the costs of excess electricity generation capacity continues to pose a difficult challenge in the Ghana Power Sector. Excess capacity costs arise because the available generation capacity is in excess of the needs of the entire country. While having excess generation capacity is generally a good operational outcome because it enhances supply adequacy and reliability, it, however, imposes an

Table 5: **Monthly electricity supplies and average total cost of supply for the Export Market in 2019**[7]

Month	Hydro (GWh)	Thermals (GWh)	Total (GWh)	Total Average Cost (US cents/KWh)
January	38.0	52.0	90.1	6.9
February	55.9	38.1	94.0	5.7
March	38.3	55.5	93.8	7.0
April	38.3	61.1	99.4	7.2
May	38.4	83.1	121.5	7.7
June	38.5	84.7	123.3	7.7
July	37.9	71.6	109.5	7.5
August	37.8	63.0	100.9	7.3
September	37.8	46.2	84.0	6.8
October	37.5	68.8	106.3	7.4
November	37.4	131.0	168.4	8.3
December	37.6	149.2	186.8	8.5
TOTAL	**473.4**	**904.5**	**1,377.90**	

unpleasant financial obligation on off-takers and consumers as it requires them to consume the contracted electrical energy or otherwise pay a specified amount of money (capacity charge) as a penalty.

Appropriately, however, wholesale suppliers rely on take-or-pay arrangements to ensure that they receive enough revenues to honour their debt obligations to lenders as well as recover their fixed operating and maintenance costs. On the other hand, the take-or-pay contracts compel the buyer to accept delivery of a certain minimum amount of electricity or otherwise pay for the difference between what is agreed to in the contract and what is actually dispatched or supplied.

The GWEM has currently contracted more generation capacity than is required to meet the prevailing maximum loads as well as providing for reasonable reserve requirements. As at December 2019, the 16 contracted power plants serving the GWEM (excluding embedded generation capacity) had a combined dependable operating capacity of 4,365 MW compared to the maximum demand recorded in the year of 2,803.7 MW.

This represents a dependable operating excess capacity of 1,561.3 MW. In order words, the Ghana power system had a reserve margin of about 55.7% which is well above the appropriate optimal reserve margin, typically between 10% to 20% depending on prevailing technical and economic factors.

In energy terms, the total electrical energy contracted on a take-or-pay basis from the six[8] (6) operating thermal-based IPPs is estimated at 10,544[9] GWh for the year 2019. Based on the actual[10] electrical energy dispatched by these power plants from January to December 2019, the

[7] *Total electricity export does not include the inadvertent export to CIE of 76 Gwh.*

total unsupplied electricity amounted to 6,400 GWh constituting about 60.7% of the contracted supply. In effect, the six (6) power plants supplied only 39.3% of their contracted supply in 2019 which resulted in payment obligations resulting from excess contracted energy.

The estimated total costs of excess generation capacity in 2019 amounted to US$304.98 million representing an average monthly excess capacity costs obligation of US$25.2 million. Table 6 shows the monthly average excess capacity costs obligation for 2019.

The excess capacity cost obligations from August to December 2019 were elevated owing to the coming into full commercial operation of the Cenpower Generation Co. Ltd power plant.

2.10 DEALING WITH EXCESS CAPACITY CHALLENGE

Given the enormity of the financial burden of excess capacity cost obligations, there is the need to resolve the problem expeditiously. The resolution of excess capacity costs challenge can be achieved with carefully crafted sustainable interventions over the immediate-to-short term and eventually the long-term period.

2.10.1 Immediate-to-short term interventions

The intervention with immediate results is to increase electricity tariffs to accommodate the additional costs of excess generation capacity in the revenue requirement build-up. We have assessed this possible policy intervention by evaluating the pricing mechanism which when deployed could recover the full cost of electricity supply including the excess capacity costs obligation. Specifically, we studied the two variants of the SMP as follows:

a) where all the electricity supplied in the market is sold at a “reference price” equaling the pure System Short-Run Marginal Costs with an additional Firm Capacity Charge which is equal to the capacity charge of a benchmark peaking gas turbine plant; and

b) where all the electricity supplied in the market is sold at a price which is equal to the weighted average total cost of thermal power at their bilateral contract prices and the “legacy” hydroelectricity priced at the SMP.

The prices calculated using these two methodologies are then compared with the average total costs of electricity supplied to the Regulated Market plus the excess capacity costs obligations emanating from the take-or-pay obligations.

Table 7 shows the resulting comparative figures on a monthly basis.

The analysis suggest that, enough revenue would be generated to pay for excess capacity cost obligations if all electricity in the wholesale electricity market is priced at a Single Market Clearing Price corresponding to any of the two methodologies.

While the first pricing approach is similar to a “single buyer” market model, the second approach is consistent with the pricing framework prescribed in the LI 1937. Figure 12 shows a comparison of the average monthly cost of generation based on the three pricing methodologies.

Despite being a feasible option, increasing tariffs is untenable given that the same consumers of electricity contribute to the ESLA, a large part of

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[8] These are Ameri, AKSA, Karpowership, CENIT, Cenpower, Amandi, Sunon Asogli Phase 1 and Sunon Asogli Phase 2. Note that TICO and Bui are not included. Currently the two (2) Sunon Asogli Power Plants do not exercise their take-or-pay contract agreement.

[9] As at December 2019, ECG alone has take-or-pay contracts equivalent to 11,307 GWh of power annually from six (6) thermal-based IPPs.

[10] The 6 thermal-based IPPs generated a combined total of 3,564 GWh in the year.

Table 6: **Average monthly excess capacity costs obligation in 2019**

Month	Excess Capacity Costs (US$' million)
January	21.25
February	14.71
March	11.92
April	13.24
May	21.25
June	19.14
July	19.93
August	32.1
September	40.12
October	33.31
November	39.48
December	38.53
Total	**304.98**

Table 7: **Comparative average monthly costs of generation based on various pricing methodologies**

	Actual Reg. Market Price + Excess Cap Cost	Spot Market Price: Single Part Tariff	Spot + Bilateral Contracts: LI 1937
	Average Total Cost	Average Total Short-Run Marginal Cost	Average Total Cost
Month	**(US cents/kWh)**	**(US cents/kWh)**	**(US cents/kWh)**
January	9.8	10.9	10.1
February	9.5	11.1	10.7
March	9.4	10.9	11.1
April	10.8	11.3	12.5
May	10.3	11.3	11.2
June	10.6	11.4	12.0
July	11.7	11.2	11.4
August	12.3	10.9	10.6
September	11.6	11.7	12.4
October	11.1	11.6	11.2
November	11.5	11.7	11.6
December	11.2	11.3	10.7

whose proceeds is to be lodged into the Power Generation and Infrastructure Support Account (PGISA) which is to be used to fund, among others, the debts of power utilities.

Figure 12 shows the comparison of monthly average costs of generation of the pricing methodologies.

Additionally, in the immediate term, the excess capacity cost obligations could be mitigated by scheduling dispatch of power plants in such a manner as to reduce excess capacity costs. In that regard, the "minimization of excess capacity costs" would be the primary objective in the real-time dispatch of power plants in the GWEM. For this objective to be fully met, however, the availability of all power plants contracted on take-or-pay basis must be ensured – that is ensuring the physical readiness of the take-or-pay contracted power plants to operate as well as making available fuels supplies at all times. While this objective is attainable, it is necessary that all the take-or-pay power plants are frequently monitored.

It is worth noting that there could be some inherent financial trade-offs as regards the impact on end-user tariffs when implementing the concept of "excess capacity cost minimization" in the dispatch of power plants. In this regard, the EMOP intends to undertake a detailed assessment of the "excess capacity costs-minimization" policy option and advise the EC accordingly.

2.10.2 Medium-to-long term interventions

2.10.2.1 Normal Demand Growth – "Do nothing policy option"

The demand[11] for electricity in the GWEM between 2015 and 2019 grew, on the average, by 9.7%, annually. At this rate of growth, the level of excess generation capacity would decline gradually thereby relieving the power system of the excess capacity cost obligation to levels that are reasonable and acceptable. This intervention corresponds to a "do-nothing" policy scenario.

2.10.2.2 Competitive procurement of power

In the medium to long term, competitive procurement of new power generation assets would also mitigate the excess capacity challenges. This is because the current excess capacity challenge has come about owing to the fact that the major market participants have, in the recent past, procured additional generation capacity outside the scope of an optimal system planning regime as well as disregarded laid down regulatory processes.

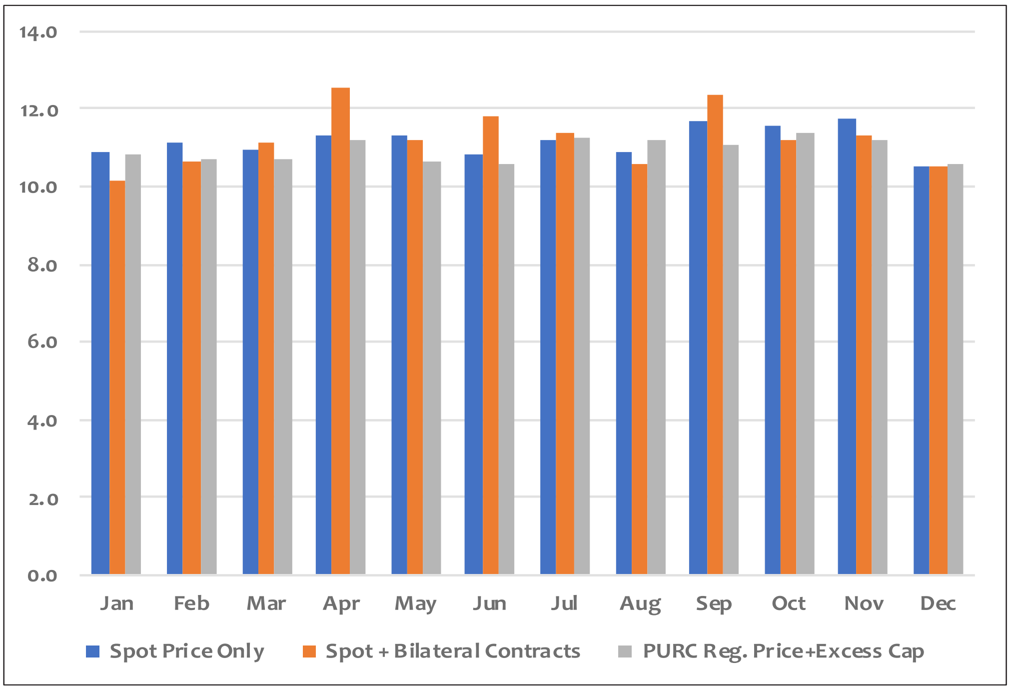
A major challenge facing the procurement of power in the Regulated Market and which has resulted in excess contracted generation capacity has been the inefficient and politically influenced procurement of power by the ECG who ironically constitute the largest customers in the market. The ECG procured over 67.4% of the electricity traded in the GWEM in 2019. The un-competitive procurement regime, in the past, coupled with the inability of the regulator to influence prices of electricity procured by the ECG have led to inefficiencies and higher costs for consumers.

These inherent weaknesses have led to excess capacity obligations, poor power sector investment signals and inefficient operations.

In that regard, future procurement of additional capacity should be conducted under the right regulatory oversight and also on a competitive basis. There is the need for the PURC to impose some discipline in the procurement of power for the Regulated Market by influencing the prices, especially the capacity charges, at which power can be procured for sale to customers in the Regulated Market.

Additionally, there is the need to transform the prevailing excess capacity regime into a firm capacity market arrangement under which capacity would be procured on a competitive basis. This transformation process, however, should be well guided to ensure that there is value-for-money as the capacity market takes shape.

Figure 12: **Comparison of monthly average costs of generation of the pricing methodologies**



2.10.2.3 Establishment of the Independent Market Operator (IMO)

The critical role of an IMO in managing operations in a wholesale electricity market cannot be overemphasized as by its mandate could schedule dispatch of power plants transparently under commonly agreed rules in order to minimize costs to consumers.

The creation of an IMO in the GWEM was a key component of the power sector reform programme in Ghana. There is the need to speed up its creation within the GRIDCo, initially, and subsequently to give it the requisite autonomy to operate under "arms-length" regulatory oversight by the EMOP as has been prescribed in the LI 1937. To enable the rapid operationalization of the IMO there is the urgent need to finalize the Ghana Electricity Market Rules in which dispatch of power plants would be done with clear objectives including the assurance of minimizing excess capacity cost obligations in the GWEM.

[11] *Demand including exports.*

CHAPTER 3

OUTLOOK FOR 2020 BASED ON THE 2020 ESP

3.1 ASSUMPTIONS BEHIND THE ELECTRICITY SUPPLY PLAN (ESP) FOR 2020

The 2020 ESP provides an outlook for electricity demand and supply for 2020 based on demand forecasts and outlook for power supply, taking into consideration the existing sources of generation as well as ongoing projects.

The 2020 ESP considered the following factors in its supply and demand outlook.

a) Demand increases attributable to ongoing distribution network expansion works intended to extend coverage and improve service quality to ECG and NEDCo customers;
b) Expected completion and commissioning of various ongoing rural electrification projects within the ECG and NEDCo distribution zones in 2020;
c) Increased VALCO demand due to the ramp-up to full operation of the second potline, increasing the Smelter's demand from the current 55 MW4 to 150 MW. Please note that since the startup of the second potline in June 2018, the Smelter has encountered a series of internal challenges such that they have not yet been able to attain full potline operation;
d) Increased exports to SONABEL (Burkina) from an average of 60 MW in 2019 to a planned maximum of 150 MW in 2020;
e) Increased exports to CEB (Togo/Benin) from an average of 120 MW in 2019 to a planned maximum of 180 MW in 2020;
f) Re-opening of the AngloGold Ashanti mine at Obuasi

3.2 ELECTRICITY DEMAND OUTLOOK FOR 2020

System Peak Load which includes exports is projected to grow from 2,803.7 MW in 2019 to 3,115 MW in 2020 representing an increase of 11.1%. Electricity Export to neighbouring countries is expected to range between 320 MW and 330 MW in 2020. The average system demand is projected to increase by 9.5% from 2,041.9 MW in 2019 to 2,236.6 MW in 2020.

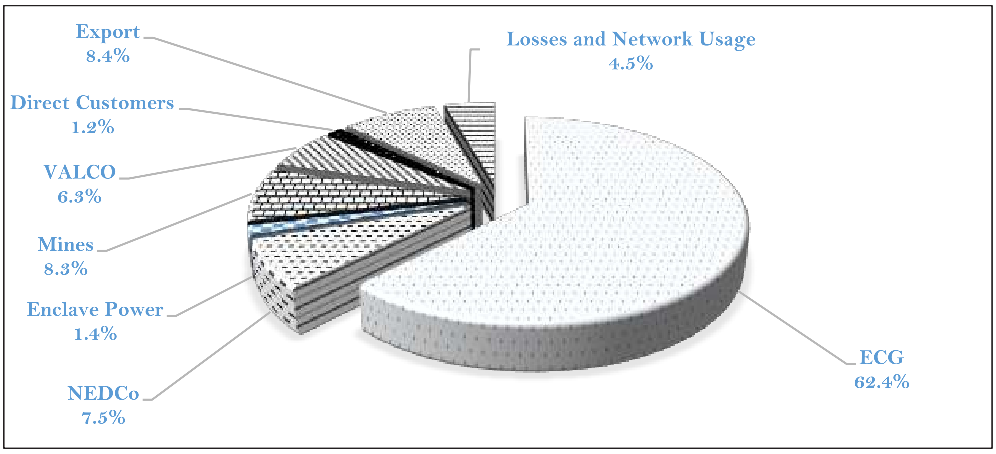
Ghana's Peak Load which represents domestic demand, excluding VALCO, is projected to increase by 12.3% from 2,480 MW in 2019 to 2,785 MW in 2020.

Peak loads for ECG and NEDCo are projected to be 1,874.7 MW and 243.3 MW in 2020 respectively. Electricity demand by the mining companies is projected to reach a peak of 246.6 MW in 2020 while Enclave Power Company is expected to record a peak demand of 57 MW. Other Bulk Customers on the NITS are projected to record a peak demand of 52.8 MW.

3.3 ELECTRICITY CONSUMPTION OUTLOOK FOR 2020

The Electricity Company of Ghana is projected to of-take 12,234.84 GWh of electricity, representing 62.4% of the total projected supply in the year 2020. The other distribution utilities, NEDCo and Enclave Power Company are projected to respectively. VALCO is projected to consume 1,229.78 GWh representing 6.3% of the total consumption supply. Ghana is projected to export a total of 1,652.06 GWh of electricity to CEB and SONABEL in 2020. Total system usage and losses are projected to be 876.22 GWh, representing 4.5% of the total electricity supply. Figure 13 shows the shares of the projected electricity consumption by the various of-takers.

Figure 13: **Shares of projected electricity consumption for 2020**



3.4 ELECTRICITY SUPPLY OUTLOOK FOR 2020

Electricity supply in 2020 is projected to grow by 6.6% from 18,307.24 GWh in 2019 to 19,593 GWh in 2020. Of the total supply in 2020, electricity generation from the hydroelectric power plants are projected to contribute 6,229 GWh, which represents 31.8% of the total projected electricity supply. Thermal generation sources are projected to account for 68% of the total projected electricity supply, whilst renewable generation sources are projected to account for the remaining 0.2%. It is also projected that 99.8% of the total electricity supply would be from power plants connected to the NITS while 0.2% would be from power plants embedded in the distribution networks and therefore outside the transactions in the GWEM.

The VRA power plants are projected to supply a total of 9,190 GWh, representing 46.9% of the total projected electricity supply. The Akosombo and Kpong hydroelectric power plants are projected to supply a total 5,465 GWh, which is 49.5% of the projected total supply of VRA and 27.9% of the projected total electricity supply in the country.

The Bui Power Plant is projected to supply 764 GWh of electricity in 2020, representing 3.9% of the total electricity supply in the country. The IPPs are projected to account for 49.2% of the projected total electricity supply of-take 1,462.7 GWh and 283.78 GWh respectively representing 7.5% and 1.4% of the total electricity supply

3.5 FUEL SUPPLY AND CONSUMPTION OUTLOOK FOR 2020

Out of the estimated 109 trillion Btu of fuel required for thermal power generation in 2020, it is projected that 107 trillion Btu of that amount, representing 98.2% of the total fuel requirements will be provided from natural gas. It is estimated in the 2020 ESP that, about 40% of the natural gas supply would be provided by ENI, with 36% from AGPP, 14% from WAGP, and 10% from LNG.

In 2020, the IPPs are projected to consume 62.6 trillion Btu of natural gas representing, 58.5% of the projected total natural gas supply while the VRA thermal power plants are projected to consume 44.4 trillion Btu of natural gas representing 41.5%. It is further projected that 76.9 trillion Btu of natural gas representing, 71.9% of the total projected natural gas supply will be consumed in the Western Power Enclave, whiles the remaining 28.1% will be consumed in the Eastern Power Enclave.

Even though Ghana is an oil-producing country, all the liquid fuels used in power generation are imported. In 2020, a total of 136,147 barrels of LCO is projected to be consumed mainly by Cenpower over the period January 2020 to the third week of March 2020 following which the power plant will be operated fully on natural gas. HFO consumption is projected to be 212,858 barrels. This will enable AKSA to operate for a very limited period in 2020.

CHAPTER 4

OTHER DEVELOPMENTS IN THE GWEM

4.1 DISPUTE RESOLUTION

The Electricity Regulations, 2008 (L.I. 1937) mandates the EMOP to resolve disputes referred to it by Market Participants in respect of transactions in the Wholesale Electricity Market.

In accordance with the regulations, the EMOP has developed a Complaint and Dispute Resolution Procedure to ensure that these disputes are resolved transparently and effectively. The procedure sets out the guidelines for making a complaint to the EMOP and also the processes employed by the EMOP to resolve disputes between Market Participants.

In 2019, GRIDCo presented three disputes it had with some Market Participants to the EMOP for resolution. The disputes and resolutions are discussed below:

a) GRIDCo's disagreement with VRA on transmission loss pricing and billing for imports from CIE. It was reported that in June 2017, VRA unilaterally changed the transmission loss tariff from 2.1 GHp/kWh to 3.6 GHp/kWh. The reference metering point on the transmission network had also been changed from Prestea in Ghana to Riviera in Cote d'Ivoire in November 2016. These had resulted in differences in the value of transmission losses in the books of both VRA and GRIDCo;

It was resolved that the transmission losses from Riviera to Prestea could not be recovered from GRIDCo since GRIDCo is only in charge of transmission losses within Ghanaian territory. The EMOP, therefore, recommended that VRA should add the transmission losses from Riviera to Prestea to their generation costs in their tarif submissions to the PURC for consideration. It was further recommended that PURC should implore VRA to write of the existing debt of GRIDCo due to the changes in the transmission loss tariff from 2.1 GHp/kWh to 3.6 GHp/kWh.

b) Bui Power Authority (BPA) Capital Asset Recovery (CAR). It was reported that BPA had been submitting bills for CAR to GRIDCo since May 2013 in respect of some investment in its transmission asset:

It was resolved that BPA should submit the transmission assets as part of its asset recovery in its power generation tariff. EMOP subsequently made a recommendation to PURC to direct the BPA to stop invoicing GRIDCo with the costs of their transmission assets.

c) Dispute on payment of regulatory levies by VALCO, Enclave Power Company (EPC), Savanna Cement, and Diamond Cement. Firstly, VALCO was disputing the payment of all levies and charges (regulatory levy, ancillary service charge, and power infrastructure charge). They explained that the Ministry of Energy had excluded them from paying all other levies apart from the transmission tariff. Secondly, EPC was disputing the payment of ancillary service charge because they are a Distribution Company and the PURC gazetted tariff indicated that Distribution Companies were exempted from paying that charge. Thirdly, Diamond Cement and Savanna Cement complained about high regulatory tarif to GRIDCo. This, they indicated was affecting their cost of business and so had not made any payment for the ancillary services and power infrastructure charges. They had petitioned the PURC and Association of Ghana Industries (AGI) but the issue had not been resolved.

indicated was affecting their cost of business and so had not made any payment for the ancillary services and power infrastructure charges. They had petitioned the PURC and Association of Ghana Industries (AGI) but the issue had not been resolved.

The EMOP resolved the dispute by proposing to PURC to cancel the debt of VALCO, EPC, Savanna Cement, and Diamond Cement so that GRIDCo can take them of their books.

4.2 DEVELOPMENT OF A REMOTE MONITORING SYSTEM

The EMOP has developed a remote Monitoring System with the Electricity Transmission Utility (GRIDCo). The System enables the EMOP to observe, in real-time, all operational information on the National Interconnected Transmission System (NITS) as well as dispatch of electricity from wholesale electricity suppliers. The information observed include system demand, system generation, electricity export, and import, plants generation, water levels of the hydro dams, available generation at peak, projected peak load, system frequency, Tema gas supply pressure, voltages at GRIDCo's bus bars and feeders, GRIDCo substation loads, reactive power generation and the power factors at which the plants are generating.

The Monitoring System enables the EMOP to, among other things:

a) ascertain whether Pre-Dispatch Schedule of electricity matches Real-Time Dispatch;
b) collate data for the preparation of the Ghana Wholesale Electricity Market Bulletin; Weekly Statistics and Power Sector Situation Report;
c) acquire first-hand information on potential load shedding;
d) acquire information about the stability of the System;
e) analyze changes in demand;
f) monitor the electricity generation mix.
g) monitor Ghana's interactions in the Regional Electricity Market (import and export); and
h) monitor the water level of the hydro dams.

The EMOP has further developed a web-based application **(http://www.emopgh.org)** to make the monitoring link accessible on all electronic devices (computer, mobile phone, tablet, and a smart TV).

4.3 PUBLICATION OF WHOLESALE ELECTRICITY MARKET MONTHLY BULLETIN

The EMOP published eleven (11) editions of the monthly Wholesale Electricity Market Bulletin in 2019. The bulletin is published to help in the dissemination of information in the GWEM. The bulletin highlights major developments on the GWEM. It analyses the performance of the key GWEM indicators against their benchmarks and also examines the implications of any discernable trends in the market.

4.4 EMOP ALLOCATION FRAMEWORK FOR LEGACY HYDRO-ELECTRICITY SUPPLY

The EMOP has the responsibility for ensuring the long-term optimization of the hydroelectricity supply sources in the country, particularly electricity generated from the Akosombo and Kpong Power Plants. This has become necessary in order, to ensure that the relatively cheaper hydroelectricity from Akosombo and Kpong power plants are not over-drafted and also to prevent VRA from using it in addition to their thermal assets to exert market power.

As a result, the electricity generation from these two hydro power plants are excluded from being used by VRA for bilateral contracts. It is for this reason that the EMOP allocates electricity generated from the cheaper hydro equitably to all classes of consumers guided by government policies.

The EMOP has consequently developed a framework which is used for the allocation of electricity generated from the Akosombo and Kpong hydropower plants each year.

4.4.1 Allocation Framework

4.4.1.1 Guiding Principles

The allocation of the legacy hydro-electricity supplies are guided by the following principles:

a) Government of Ghana (GoG) policy directives (adequate supply for VALCO and Ghana Water Company Limited);

b) Ensure that the cost of electricity supply to the export market is competitive in terms of pricing; and

c) Equitable allocation to all other consumers in the electricity market.

4.4.1.2 Allocation Timelines

Electricity generation from the legacy hydroelectric power plants are forecasted on a five-year rolling time scale by VRA and submitted to EMOP by end of October of each year. EMOP decides on the allocation of the hydro generation by the end of November of each year and submitted to the PURC for consideration in the tarif setting process.

4.4.1.3 Modelling

The model used for the allocation of electricity generated from the Akosombo and Kpong hydroelectric power plants is contained in Appendix 4. Table 8 shows the projected hydro allocation for 2019 based on the principles. It is however important to note that the actual allocations in 2019 were deferent because of higher total generation from the legacy hydro while Valco consumption dipped below the projected.

Table 8: **Legacy Hydro Allocation for 2019**

	Projected		Actual	
Consumers	**Allocation (GWh)**	**Percentage (%)**	**Allocation (GWh)**	**Percentage (%)**
VALCO	1,366.6	26.9	936.7	15.1
Export	551.4	10.9	750.6	12.1
GWCL	69.8	1.4	66.1	1.1
Sub-total	***1,987.8***	***39.2***	***1,743.6***	***28.2***
Energy to be pro-rated	***3,083.3***		***4,454.5***	
Distribution Utilities	2,621.8	51.7	3,855.0	62.1
Bulk Customers	461.5	9.1	599.5	9.8
Sub-total	***3,083.3***	***60.8***	**4,454.5**	***71.8***
Total Generation	**5,071.1**	**100.0**	**6,207.8**	**100.0**

CHAPTER 5

KEY RECOMMENDATIONS

5.1. INSTITUTIONAL REFORMS

The institutional reforms being implemented in the power sector and prescribed by law requires the separation of Market Operator functions from the transmission asset owner responsibilities. The separation is to enable the implementation of a fully liberalised wholesale electricity market. The EMOP intends to engage stakeholders, particularly policymakers, to discuss and develop timelines towards the establishment of the Independent Market Operator.

5.2. CAPACITY CHARGE PRICING GUIDELINES FOR THE REGULATED MARKET

In order to enhance least cost or competitive procurement of power in the BCM, the EMOP is recommending that the PURC should develop a Capacity Pricing Policy to guide Distribution Companies in future bilateral contract arrangements.

It is noted that the Spot Market (SM) allows for incremental electricity supplies besides the contracted capacity and also makes up for shortfalls and imbalances as well as providing critical ancillary services. Effectively, therefore, the Spot Market facilitates competition in the bilateral contract market transactions by providing an alternative source of supply of electricity outside the contracts. Additionally, in the case of Ghana, the Spot Market has been designed to manage the equitable allocation of the relatively cheap "legacy hydro" electricity produced from the Akosombo and Kpong hydropower plants, as well as to mitigate the market power and dominance of the electricity generation resources of the VRA.

Technically, the firm capacity of the marginal generation unit is required to enable it to inject and transport energy through the transmission system during the peak hours and therefore has to be priced. The spot price of this capacity (capacity price) is the capacity marginal cost which is equivalent to the development cost of a least cost peaking plant.

Even though the mandates over pricing in the GWEM are clearly defined in L.I. 1937, the PURC may be able to indirectly influence pricing in the GWEM by virtue of the fact that the PURC, under PURC Act 538, has the power to investigate the reasonableness as well as approve prices in bilateral contracts signed by Distribution Companies.

Effectively, therefore, long-term contract arrangements between wholesale suppliers and distribution utilities for the Regulated Market cannot be executed in the GWEM if the prices are not approved by the PURC. It is on the strength of this mandate that the PURC could influence the market by determining and setting "benchmark capacity charges[13]" which all bilateral contracts for the Regulated Market must conform to.

5.3. MITIGATING MARKET POWER

Market power, especially by a state-owned entity such as VRA, could lead to uncompetitive behavior that may result in a high cost of power as well as diminish investments by independent private power generators. Indeed, VRA alone

[13] *Capacity Charges must correspond to a simple cycle gas turbine power plant and also a combined cycle power plant.*

currently owns about 47% of the total available power generation capacity in the country thereby giving it absolute market power. The legal requirement to exclude the legacy hydro from bilateral contract has diminished the market power of VRA.

Beyond VRA it is important to put in place a policy that will limit the market power of any Wholesale Supplier by ensuring that no single supplier has access to generating resources with a total combined capacity of more than a certain pre-determined proportion of the total available generation capacity in the power system at any particular time. The policy, however, has to be well crafted to enhance competition in the power market at all times.

GLOSSARY

In this report, unless the context otherwise requires:

Act - means the Energy Commission Act, 1997, (Act 541);

Bilateral contract - means a contract of financial settlement between two parties for a transaction in the wholesale electricity market;

Bulk Customer - means a customer that purchases or receives electric power of an amount or level that the Commission may specify;

Bulk Supply Point - Means any point at which electricity is delivered from a transmission system to any distribution system.

Capacity Utilization Factor - means the ratio of the electricity generated by a power plant in kWh to installed plant capacity for the number of hours in a period. {CUF = plant output in kWh / (installed plant capacity in kW *30*24)}.

Commission - means the Energy Commission established under the Act;

Composite Bulk Generation Charge - is the weighted average rate at which electricity distribution companies, shall procure electricity from generation sources in respect of their operations in the regulated.

Distribution Utility - means a person licensed under the Act to distribute and sell electricity without discrimination to consumers in an area or zone designated by the Commission;

Electricity Market Rules - means the published document developed and adopted by the Utility and Market Participants and approved by the Commission to govern the operation of the market for the wholesale supply of electricity by the National Interconnected Transmission System;

Market Manual - means a published document that is created and adopted by the Utility that contains requirements to be followed, met or performed by one or more of the Market Participants and the Utility in support of the obligations contained in the electricity market rules relating to the operation of the wholesale electricity market;

Person - includes a body corporate, whether corporation aggregate or corporation sole
and an unincorporated body of persons as well as an individual;

Public Utilities Regulatory Commission (PURC) - means the Public Utilities Regulatory Commission established by Public Utilities Regulatory Commission Act, 1997 (Act 538);

Spot Market - means the real-time market that comprises an hourly auction of electricity by a generator to meet the projected demand;

Spot Market Price - means the real-time price of electricity on the spot market as determined by the Utility;

System Marginal Cost - means the additional cost of producing one more units of electricity in the National Interconnected Transmission System;

Transmission Service - means the safe and reliable operation of high voltage electrical circuits, transformers and substations to ensure the cost effective dispatch and movement of electricity from the facility of a wholesale supplier to a Bulk Customer or distribution company;

Utility - means the public utility granted a license under section 23(5) of the Energy Commission Act, 1997 (Act 541) for the transmission of electricity throughout the country;

Wholesale Electricity Market - means an electricity market established by market rules approved by the Commission for bulk trading of electricity, ancillary services or any other related electricity supply product or service;

Wholesale Supplier - means a person licensed under the Act to install and operate a facility to procure or produce electricity for sale to a Bulk Customer or to a distribution company.

Market Participants - includes a wholesale electricity supplier, a distribution utility
and a bulk customer;

National Interconnected Transmission System - means all electricity plant and equipment within the borders of the country that function or are operated at any voltage higher than 36 Kilovolts and any associated figure or supply equipment that is shared for common use.

APPENDICES

Appendix 1

The current members of the Electricity Market Oversight Panel (EMOP)

Table 9: **List of current EMOP Members**

No.	Name	Position	Contact
1	Michael Opam	Chairman	michaelopam@yahoo.com
2	Jonathan Amoako-Baah	CEO, Ghana Grid Company	ceo@gridcogh.com
3	Oscar Amonoo-Neizer	Executive Secretary, Energy Commission	amonoo-neizer@energycom.gov.gh
4	Mami Dufie Ofori	Executive Secretary, PURC	dufieofori@yahoo.com
5	Mark Baah	Head, System Operations, GRIDCo	mark.baah@gridcogh.com
6	Abubakari Obuama Addy	Representative, Wholesale Suppliers	abubakari.addy@vra.com
7	Nana Osae Nyampong VI	Representative, Wholesale Suppliers	nana.nyampong@newmont.com
8	Samuel DeSouza	Representative, Bulk Customers	ebensantos@yahoo.com
9	Ebenezer Baiden	Representative, Distribution Utilities	wamuna@gmail.com
10	William Amuna	WEM Expert	ekyem@energycom.gov.gh
11	Eric Kyem	Administrator	noble.dormenu@vra.com
12	Noble Dormenu	Co-opted member	

Table 10: **List of current EMOP Members in the various sub-committees**

	Technical and Commercial	Regulatory and Legal	Compliance
1	Michael Opam	Micheal Opam	Micheal Opam
2	Jonathan Amoako-Baah	Oscar Amonoo-Neizer	Eric Kyem
3	Eric Kyem	Eric Kyem	Jonathan Amoako-Baah
4	Mark Baah	William Amuna	Mark Baah
5	Abubakari Addy	Abubakari Addy	William Amuna
6	Samuel DeSouza	Mami Dufie Ofori	Samuel DeSouza
7	Ebenezer Baiden	Ebenezer Baiden	Mami Dufie
8	Nana Osae Nyampong VI	Nana Osae Nyampong VI	Oscar Amonoo-Neizer

List of Market Participants as at 31st December 2019

Table 11: **List of Wholesale Suppliers**

Wholesale Suppliers			
No.	**Name of Company**	**Address**	**Contact Person**
1	Volta River Authority (VRA)	ElectroVolta house, Ministies. Accra	Emmanuel Antwi-Darkwa
2	Sunon Asogli Power Plant (SAPP)	Tema	Johnson Yan
3	Takoradi International Company (TICO)	Aboadze, Takoradi	Robert Weley
4	Karpowership	Tema	Vokan Buyukbicer
5	Bui Power Authority	Airport Residential Area	Fred Oware
6	Cenpower	Accra	Seloame Baeta
7	Cenit	Tema	Victor
8	AKSA	Tema	Murat Captug
9	Rotan Power *	Airport Residential Area	Mohammed Haji
10	Amandi *	Aboadze, Takoradi	William Pyne
11	Early Power *	Accra	Kingsley Asare
12	Marinus Energy*	Atuabo	Diana Ayeetey

NB*not yet operational

Table 12: **List of Distribution Utilities**

Distribution Utilities			
No.	**Name of Company**	**Address**	**Contact Person**
1	Electricity Company of Ghana (ECG)	Accra	Kwame Agyemang-Budu
2	Enclave Power Company (EPC)	Tema	Joseph Aduhene
3	Northern Electricity Distribution Company (NEDCo)	Tamale	Osmani A. Ayuba

Table 13: **List of Bulk Customers**

Bulk Customers					
No.	**Name of Company**	**Address**	**Contact Person**		Email
1	Tema Steel Co. Ltd	Tema, Steel works road			
2	Diamond Cement, Ghana	Tema, Steel works road	K. Chiti Babu		
3	B5-Plus Ltd	Tema, Kpone barrier			
4	Savanna Diamond Company Ltd	Buipe	Y. Sriniv Asa Rao	General Manager	
5	Aluworks	Tema, Heavy industrial area	Richard S. Fianke		
6	Sentuo Steel Ltd	Tema, Heavy industrial area			
7	Ferro Fabrik	Tema, Heavy industrial area			
8	Cocoa Processing Company Ltd	Tema, Heavy industrial area	Michael Eshun		
9	Western Steel and Forging Ltd	Tema, Heavy industrial area			
10	Rider Steel Ghana Ltd	Tema, Free Zones Enclave	TP Patnaik	Managing Director	tppatnaik@ridersteelghana.com
11	Cargill Ghana Ltd	Tema, Free Zones Enclave			
12	Barry Callebaut Ghana Ltd	Tema, Free Zones Enclave			
13	CIMAF Ghana Ltd	Tema, Free Zones Enclave	William Kwabena Bessah	Head Electrical	
14	GHACEM Ltd, Tema	Tema	Samuel Oduro		samuel.oduro@ghacem.com
15	Pioneer food Cannery Ltd	Tema, Fishing harbour	Daniel Nkunda		
16	Roofing and Steel Ghana Ltd	Ningo Prampram			
17	Olam Ghana Ltd	Accra, North industrial area			
18	Fan Milk Ltd	Accra, North industrial area	Samuel Bampoe		
19	Anglogold Ashanti Ltd	Accra, Airport residential area	Eric Asubonteng		
20	Newmont Ghana	Accra, Airport residential area	Joshua Mortoti		joshua.mortoti@newmont.com
21	Keegan Resources Gh. Ltd	Accra, Airport residential area	Ben Adoo		
22	Goldfields Ghana Ltd	Accra, Airport residential area	Emmanuel Bosomtwe	Engineering Manager	
23	Black Ivy Ghana Ltd	Airport Commercial area			
24	Golden Star Ltd (Bogoso/Prestea)	Accra, Roman Ridge	Jerry Agala		
25	New Century Mines	Accra, Roman Ridge	Ernest Amo Darkoh	Energy & Power Cordinator	eamo-darkoh@asrgh.com
26	Ghana Water Company	Accra, Independence Avenue			

Bulk Customers					
No.	Name of Company	Address	Contact Person		Email
27	Perseus Mining (Ghana) Ltd	Accra, Giffard road East Cantonment	Daniel Ayim	Electrical Instrumentation Sup.	daniel.ayim@perseusmining.com.gh
28	Akosombo Textiles Ltd	Accra, Adjaben road	Francis Kwesi Villars		
29	Printex Ltd	Accra, Spintex road			
30	United Steel Company Ltd	Accra, Spintex road industrial area	Mohammed Beyrouti	Factory Manager	
31	Kasapreko Company Ltd	Accra, Spintex road			
32	Sodachlor Industrial Chem. Ltd	Takoradi	Henry Birch Freeman	Manager	
33	Western Diamond Cement Company Ltd	Takoradi	Mohammed Majeed Khan	Mgt Rep	mdmajeed49@gmail.com
34	Drillworx Ghana Ltd	Accra/Kumasi			
35	Chirano Gold Mine	Chirano	Adriano Sobreira		adriano.sobreira@kinross.com
36	Asanko Gold	Accra	Abdul Karim Mumuni		
37	Adamus Resources	Accra	Jeffrey Afaridun	Electrical Manager Engineering Manage	jaidun@adamusgh.com
38	Fujain Sentuo Ceramic Tile Company	Tema	Eric Lin	General Manager	
39	West African Forgings	Tema	Mr. HimeshnPetel		
40	Wan heng Ghana	Accra	Jack Shen		
41	AgDevCo Ghana	Accra	Pat rick Van Brakel	General Manager	pbrakel@agdevco.com
42	Dangote Cement	Tema	James Jeyakumar	General Manager	
43	Unilever Ghana	Tema	Charles Brefo Nimo	Site Engineering Manager	nimo@unilever.com
44	Nestle Ghana	Accra	Joshua Adu	Factory Electricity and Automation Manager	
45	Miniplast	Accra	Anthony K. Osei	Logistics Manager	
46	Early International Group	Accra	Samuel K. Owusu		
47	Ghana Manganese Company	Accra		General Mine Manager	
48	Mensin Gold Bibiani	Bibiani	Dean Bertram		dbertram@rml.com.au
49	Guinness Ghana Breweries PLC	Tema		Public Policy and Regulatory Affairs Manager	
50	Nixin Paper Mill Ghana Limted	Accra	Steven Qi		hoistqi@yahoo.com
51	Rider Steel Ghana Ltd	Kumasi	TP Patnaik	Managing Director	tppatnaik@ridersteelghana.com

Appendix 2:

Table 14: **Projected monthly electricity supply by Power Plants for 2019**

	Projected generation (GWh)					
Generation Sources	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**
AKOSOMBO GS	377.1	340.6	341.4	364.9	377.1	364.9
KPONG GS	67.6	61	83.7	65.4	67.6	65.4
TAPCO	86	79.4	161.5	93.5	100.1	102
TICO	173.8	182.8	67.7	195.8	202.4	129.8
TT1PP	-	36.7	-	-	-	-
KTPP	43.6	-	-	-	-	-
TT2PP						
VRA SOLAR	0.3	0.2	0.3	0.2	0.3	0.2
Imports From Cote d'Ivoire						
Total VRA Generation	**748**	**701**	**655**	**720**	**747**	**662**
BUI GS	55.2	49.9	55.2	53.4	55.2	53.4
SAPP 161	62.4	50.7	56.9	60.4	57	60.4
SAPP 330	113.8	102.8	215	208.1	215	208.1
CENIT						
AMERI POWER PLANT	154	139.1	154	83.6	86.4	77
KARPOWER BARGE	256.7	231.9	256.7	248.5	256.7	248.5
AKSA	90	56	55	89	60	72
CEN POWER						
AMANDI						
Total Supply (GWh)	**1,480.10**	**1,331.40**	**1,447.80**	**1,463.00**	**1,477.30**	**1,381.40**

Projected generation (GWh)						
Generation Sources	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
AKOSOMBO GS	297.3	377.1	299.2	377.1	364.9	377.1
KPONG GS	67.6	67.6	65.4	67.6	65.4	67.6
TAPCO	109.4	165.4	155.1	144.2	144.9	150.4
TICO	159	202.4	195.8	101.2	120.5	202.4
TT1PP	-	65	-	54.7	-	55
KTPP	-		57.3	-	57.3	-
TT2PP						
VRA SOLAR	0.3	0.3	0.2	0.3	0.2	0.3
Imports From Cote d'Ivoire						
Total VRA Generation	**634**	**878**	**773**	**745**	**753**	**853**
BUI GS	55.2	55.2	53.4	55.2	53.4	55.2
SAPP 161	62.4	62.4	60.4	62.4	60.4	59.3
SAPP 330	215	215	110	113.8	110	113.8
CENIT						
AMERI POWER PLANT	51.6	51.6	59.6	57	59.6	33.7
KARPOWER BARGE	256.7	-	248.5	265.7	248.5	256.7
AKSA	115	143	78	161	166	142
CEN POWER						
AMANDI						0
Total Supply (GWh)	**1,389.90**	**1,405.20**	**1,382.90**	**1,460.10**	**1,450.90**	**1,513.70**

Table 15: **Projected Bulk Electricity Consumption for 2019**

Projected electricity consumption 2019											
Energy Forecast (GWh)	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
ECG	860.09	941.61	954.30	958.08	883.96	876.98	889.32	878.83	935.61	937.67	985.73
NEDCo	116.14	123.58	117.85	119.55	117.66	120.16	119.37	121.10	124.80	123.46	123.74
Enclave Power Company	13.13	14.54	16.44	16.99	16.44	16.99	16.99	16.44	19.43	18.65	19.43
MINES	95.07	98.42	95.68	97.31	92.50	98.55	101.71	95.42	99.20	95.75	98.42
Other Bulk Customers	20.97	21.04	20.15	19.96	18.44	19.47	18.64	18.36	19.85	19.17	21.46
VALCO	98.30	108.90	105.60	109.70	104.60	108.60	109.20	106.10	108.60	106.10	109.20
CEB(Togo/Benin)	26.83	29.70	28.74	29.70	28.74	29.70	29.70	28.74	29.70	28.74	29.70
SONABEL(Burkina)	34.44	37.88	51.34	53.00	50.83	50.35	50.49	49.43	50.49	49.43	50.49
CIE(Ivory Coast)	-	-	-	-	-	-	-	-	-	-	-
EDM(Mali)	-	-	-	-	-	-	-	-	-	-	-
Network Usage	0.71	0.77	0.78	0.78	0.73	0.74	0.75	0.73	0.77	0.77	0.80
LOSSES	69.56	75.65	76.44	77.22	72.21	72.63	73.44	72.28	76.31	75.83	79.09
Total	**1,335.25**	**1,452.08**	**1,467.31**	**1,482.31**	**1,386.12**	**1,394.17**	**1,409.60**	**1,387.43**	**1,464.76**	**1,455.58**	**1,518.06**
Total Energy to be transmitted less network usage & losses	**1,264.98**	**1,375.66**	**1,390.09**	**1,404.31**	**1,313.18**	**1,320.80**	**1,335.41**	**1,314.42**	**1,387.68**	**1,378.98**	**1,438.17**

Table 16: **Actual and Projected Electricity Supply for 2019**

Total Supply (GWh)				Deviation (%)	Actual Contribution to total Generation (%)
VRA Power Plants	**Actual**	**Projected**	**Deviation**		
AKOSOMBO GS	5,365.77	4,258.50	1,107.27	26.00	30.00
KPONG GS	841.99	811.50	30.49	3.76	4.71
TAPCO	1,067.43	1,491.80	(424.37)	(28.45)	5.97
TICO	1,616.30	1,933.60	(317.30)	(16.41)	9.04
TT1PP	377.28	211.40	165.88	78.47	2.11
TT2PP	138.43	-	138.43	-	0.77
KTPP	392.97	158.20	234.77	148.40	2.20
Sub-total	***9,800.17***	***8,865.00***	***935.17***	***10.55***	***54.79***
BUI GS	1,043.87	650.00	393.87	60.60	5.84
IPP's					
SAPP	2,622.18	2,655.80	(33.62)	(1.27)	14.66
CENIT	183.41	-	183.41	-	1.03
KARPOWERSHIP	1,510.19	2,775.10	(1,264.91)	(45.58)	8.44
AMERI	1,483.40	1,007.20	476.20	47.28	8.29
CENPOWER	359.00	-	359.00	-	2.01
AKSA	608.38	1,227.00	(618.62)	(50.42)	3.40
AMANDI	148.83	-	148.83	-	0.83
Sub-total IPP	***6,915.39***	***7,665.10***	***(749.71)***	***(9.78)***	***38.66***
IMPORT	127.41	-	127.41	-	0.71
Total Supply	**17,886.84**	**17,180.10**	**706.74**	**4.11**	**100.00**
EXPORT	1,430.39	915.80	514.59	56.19	

Table 17: **Electricity supply from Power Plants for 2019**

	Electricity Generation (GWh)					
Power Plants	**January**	**February**	**March**	**April**	**May**	**June**
BUI GS	155.43	126.13	73.91	62.80	47.58	25.39
TAPCO	127.48	120.05	45.04	52.32	79.63	98.54
TICO	69.78	38.57	95.32	77.46	108.44	112.75
T3	-	-	-	-	-	-
SAPP	165.65	125.94	131.59	181.00	204.12	203.78
MRP	-	-	-	-	-	-
TT2PP	-	6.61	6.83	6.51	10.51	16.42
AKOSOMBO GS	549.19	537.09	581.94	497.26	546.06	364.93
KPONG GS	76.87	73.31	88.22	75.57	73.17	62.73
TT1PP	3.14	20.81	-	20.54	53.08	25.97
CENIT	-	-	-	-	2.67	-
KARPOWERSHIP	86.80	168.21	207.41	199.63	152.33	146.70
AMERI PLANT	156.43	151.55	137.23	144.48	118.15	112.97
KPONE THERMAL	41.64	-	27.63	30.85	11.83	64.19
CENPOWER	6.92	1.65	9.98	35.93	123.16	159.73
AKSA ENERGY	46.04	30.80	126.47	123.86	44.44	42.35
AMANDI	-	-	-	-	-	-
BRIDGE POWER	-	-	-	-	-	-
Sub-total	***1,485.36***	***1,400.72***	***1,531.57***	***1,508.20***	***1,575.19***	***1,436.46***
Import	9.89	10.47	13.84	12.15	9.55	9.59
Total-Grand	**1,495.25**	**1,411.19**	**1,545.41**	**1,520.35**	**1,584.73**	**1,446.05**

Electricity Generation (GWh)							
Power Plants	**July**	**August**	**September**	**October**	**November**	**December**	**Total**
BUI GS	27.64	32.08	27.95	126.29	216.87	121.81	**1,043.87**
TAPCO	66.22	77.34	72.55	107.98	106.87	113.41	**1,067.43**
TICO	135.27	222.18	198.07	213.81	[illegible]	201.10	**1,616.30**
T3	-	-	-	-	-	-	**-**
SAPP	277.48	354.49	247.96	245.46	251.77	232.94	**2,622.18**
MRP	-	-	-	-	-	-	**-**
TT2PP	19.41	17.76	12.07	12.73	12.20	17.39	**138.43**
AKOSOMBO GS	394.91	360.63	371.62	356.81	407.20	398.14	**5,365.77**
KPONG GS	71.24	69.07	60.79	64.20	60.64	66.18	**841.99**
TT1PP	8.35	75.74	40.45	53.93	8.54	66.73	**377.28**
CENIT	-	-	-	26.07	74.37	80.29	**183.41**
KARPOWERSHIP	127.24	26.73	126.77	52.87	[illegible]	167.58	**1,510.19**
AMERI PLANT	156.12	118.64	119.97	89.70	[illegible]	81.43	**1,483.40**
KPONE THERMAL	83.18	10.68	33.59	18.63	59.96	10.78	**392.97**
CENPOWER	-	-	3.33	18.30	-	-	**359.00**
AKSA ENERGY	39.37	25.56	42.53	38.40	23.35	25.20	**608.38**
AMANDI	5.87	1.14	9.99	28.71	40.28	62.85	**148.83**
BRIDGE POWER	-	-	-	-	-	0.01	**0.01**
Sub-total	***1,412.29***	***1,392.02***	***1,367.64***	***1,453.87***	***1,550.27***	***1,645.84***	***17,759.43***
Import	13.98	8.94	15.43	11.31	10.67	1.61	***127.41***
Total-Grand	**1,426.26**	**1,400.97**	**1,383.07**	**1,465.18**	**1,560.94**	**1,647.44**	**17,886.85**

Table 18: **Actual and Projected CUFs for 2019**

	Actual CUF (%)	Projected CUF (%)	Deviation (%)
BUI	29.87	18.60	11.27
TAPCO	36.93	51.61	(14.68)
TICO	54.27	64.92	(10.65)
T3	0.00	0.00	-
SAPP	53.45	54.14	(0.69)
MRP	0.00	0.00	-
TT2PP	19.75	0.00	19.75
AKOSOMBO	60.05	47.66	12.39
KPONG	60.07	57.90	2.18
TT1PP	34.18	19.15	15.03
CENIT	16.62	0.00	16.62
KARPOWERSHIP	36.68	67.40	(30.72)
AMERI PLANT	67.74	45.99	21.74
KPONE THERMAL	20.39	8.21	12.18
CENPOWER	10.98	0.00	10.98
AKSA ENERGY	18.77	37.86	(19.09)
Amandi	8.94	0.00	8.94

Table 19: **Actual Electricity Consumption for 2019**

	Electricity Consumption (GWh)						
	ECG	**NEDCo**	**Enclave Power**	**Mines**	**VALCO**	**Others**	**Export**
January	1,016.12	112.38	15.26	96.72	68.11	21.97	90.06
February	938.12	111.13	19.17	83.73	70.72	20.44	97.58
March	1,015.67	128.75	21.06	89.83	84.67	22.36	97.63
April	980.43	123.79	20.28	92.77	87.66	22.43	106.00
May	980.35	127.78	21.43	117.70	92.00	22.45	131.46
June	893.74	115.74	19.21	106.60	77.74	20.36	122.98
July	898.85	111.48	19.62	116.24	73.57	19.97	119.12
August	889.54	111.25	19.09	119.89	76.83	20.13	101.83
September	884.88	108.40	18.43	123.31	81.18	20.25	87.73
October	935.30	115.67	20.79	125.44	83.50	23.08	110.14
November	989.77	124.46	21.45	121.35	59.12	22.85	171.11
December	1,064.48	119.67	19.72	125.35	37.44	23.11	194.76
Total	**11,487.24**	**1,410.51**	**235.51**	**1,318.94**	**892.55**	**259.41**	**1,430.39**

Table 20: **Comparison of monthly electricity import and export for 2018 & 2019**

	2018 (GWh)		2019 (GWh)	
	Import	Export	Import	Export
January	2.02	27.07	9.89	90.06
February	41.27	29.25	10.47	97.58
March	12.62	34.31	13.84	97.63
April	10.54	87.99	12.15	106.00
May	7.09	59.49	9.55	131.46
June	8.24	50.63	9.59	122.98
July	10.41	64.54	13.98	119.12
August	6.24	71.53	8.94	101.83
September	9.23	60.09	15.43	87.73
October	14.56	70.79	11.31	110.14
November	12.63	87.12	10.67	171.11
December	4.99	96.70	1.61	194.76
Total	**139.84**	**739.50**	**127.41**	**1,430.39**

Table 21: **Monthly projected fuel consumption for 2019**

Summary of Annual Fuel Requirements			
	LCO (MMBTU)	Natural Gas (MMBTU)	HFO (MMBTU)
T1	-	15,668,149.00	-
T2	-	17,731,383.00	-
TT1PP	-	2,427,694.00	-
TT2PP	-	-	-
MRPP	-	-	-
KTPP	-	1,863,437.00	-
TOTAL VRA	-	**37,690,663.00**	-
CENIT	-	-	-
AMERI	-	11,360,507.00	-
CENPOWER	-	-	-
SAPP	-	22,270,931.00	-
KARPOWER	-	8,919,587.00	14,806,546.15
AKSA			17,311,252.20
TOTAL IPP	-	**42,551,025.00**	**32,117,798.35**
TOTAL (VRA&IPP)	-	**80,241,688.00**	**32,117,798.35**

Table 22: **Actual fuel consumed in 2019 in (MMBTU)**

	Natural Gas	LCO	DFO	HFO	LPG	Total
TAPCO	11,018,800.40	0.00	0.00	0.00	0.00	11,018,800.40
TICO	13,901,520.24	463,512.74	1,223.22	0.00	0.00	14,366,256.21
SAPP	20,296,536.73	1,000,444.57	2,428.44	0.00	0.00	21,299,409.74
TT2PP	1,799,916.67	0.00	0.00	0.00	0.00	1,799,916.67
TT1PP	4,562,855.50	0.00	0.00	0.00	0.00	4,562,855.50
CENIT	2,025,414.66	0.00	0.00	0.00	0.00	2,025,414.66
KARPOWERSHIP	1,599,808.05	0.00	0.00	10,924,954.01	0.00	12,524,762.06
AMERI PLANT	15,865,864.73	0.00	0.00	0.00	0.00	15,865,864.73
KPONE THERMAL	4,168,346.68	0.00	366,344.10	0.00	0.00	4,534,690.78
CENPOWER	233,869.59	3,006,424.11	25,656.68	0.00	0.00	3,265,950.38
AKSA ENERGY	0.00	0.00	0.00	4,969,495.36	0.00	4,969,495.36
Amandi	0.00	1,069,067.08	66,742.43	0.00	0.00	1,135,809.51
Total	**78,150,814.88**	**5,539,448.51**	**462,394.87**	**15,894,449.37**	**1,704,517.59**	**101,751,625.22**

Table 23: **Contributions of the power plants in meeting the System Peak Load and the Ghana Peak Load for 2019.**

	Maximum Peak Generation (MW)	Generation @ System Coincident Peak (MW)	Generation @ Ghana Coincedent Peak Load (MW)
AKOSOMBO GS	922.30	826.40	846.90
KPONG GS	110.00	98.00	93.00
BUI GS	391.70	262.70	263.70
SEAP	382.10	313.20	360.50
TAPCO	154.00	151.00	153.00
TICO	346.00	339.00	340.00
TT1PP	107.00	-	106.00
CENIT	108.00	107.00	106.00
TT2PP	24.80	24.30	24.50
AMANDI	199.50	194.00	-
KARPOWER	374.30	254.90	303.10
AMERI	213.20	117.20	-
KTPP	102.00	100.00	-
CENPOWER	-	-	-
AKSA	329.90	16.00	201.30
Import	17.00	-	-
Total Maximum Peak Generation	3,781.80	**2,803.70**	**2,798.00**
Export to CIE at peak	142.00	**142.00**	**55.00**
Export to CEB at peak	231.00	**223.00**	**182.00**
Export to Sonabel	135.00	**92.00**	**81.00**
System Coincident Peak Load		**2,803.70**	**2,798.00**
Ghana Coincedent Peak Load		**2,346.70**	**2,480.00**

Table 24: **Monthly Weighted average HFO prices (US$/bbl)**

	2019	2018
January	65.11	68.39
February	71.41	64.53
March	68.01	63.89
April	73.07	67.45
May	69.16	71.60
June	69.48	74.89
July	71.67	74.91
August	65.88	72.82
September	64.68	75.15
October	68.48	81.66
November	67.89	73.28
December	75.00	63.15

Table 25: **Monthly delivered LCO prices (US$/bbl)**

	2018	2019
January	74.08	64.41
February	70.32	68.96
March	71.02	71.14
April	77.11	76.23
May	81.98	76.32
June	79.41	69.22
July	79.25	68.92
August	77.53	64.04
September	83.89	67.83
October	86.03	64.71
November	69.75	68.21
December	62.36	72.31

Table 26: **shows the projects that were commissioned as at the end of October 2019.**

Equipment	Projects
Transmission Line	1. 161 kV Sunyani-Berekum line 2. 161 kV Mim-Juabeso line 3. 330kV Aboadze-Anwomaso 4. 330kV Kintampo- Nayagnia 5. 161 kV Buipe – Adubiliyi 6. 161 kV Adubiliyi – Tamale 7. 330 kV Kintampo-Adubiyili 8. 330 kV Adubiyili-Nayagnia 330kV Karpowership -Takoradi Thermal Power Plant
Substation/Transformers	33 MVA transformer at Berekum 2X200 MVA autotransformers at Kintampo 330 kV S/S 2x200 MVA autotransformers at t 330kV Adubiliyi S/S 330 kV Adubiliyi Substation
Generating Plants	360 MW CENPOWER 140 MW Amandi

Appendix 3:

Table 27: **Summary of demand and supply outlook for 2020**

Customer Category	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Demand												
Total System Demand (MW)	2,919.00	2,987.00	3,064.00	3,093.00	3,054.00	3,019.00	2,894.00	2,912.00	2,872.00	3,056.00	3,074.00	3,115.00
Demand for Export (MW)	330.00	330.00	330.00	330.00	330.00	320.00	320.00	320.00	320.00	320.00	330.00	330.00
Domestic Demand (MW)	2,589.00	2,657.00	2,734.00	2,763.00	2,724.00	2,699.00	2,574.00	2,592.00	2,552.00	2,736.00	2,744.00	2,785.00
Available Generation Capacity (MW)	3,394.00	3,204.00	3,879.00	4,180.00	4,180.00	4,180.00	4,208.00	3,968.00	3,848.00	4,118.00	4,238.00	4,158.00
Import (MW)	-	-	-	-	-	-	-	-	-	-	-	-
Total Generation Capacity with Import (MW)	3,394.00	3,204.00	3,879.00	4,180.00	4,180.00	4,180.00	4,208.00	3,968.00	3,848.00	4,118.00	4,238.00	4,158.00
Surplus/deficit with Import (MW)	475.00	217.00	815.00	1,087.00	1,126.00	1,161.00	1,314.00	1,056.00	976.00	1,062.00	1,164.00	1,043.00
Surplus/deficit without Import (MW)*	475.00	217.00	815.00	1,087.00	1,126.00	1,161.00	1,314.00	1,056.00	976.00	1,062.00	1,164.00	1,043.00
Reserve with Import	16%	7%	27%	35%	37%	38%	45%	36%	34%	35%	38%	33%
Reserve without Import*	16%	7%	27%	35%	37%	38%	45%	36%	34%	35%	38%	33%
Supply												
Total Electricity Supply (GWh)	1,618.00	1,566.00	1,725.00	1,675.00	1,686.00	1,573.00	1,563.00	1,558.00	1,539.00	1,651.00	1,680.00	1,759.00
Domestic Supply (GWh)	1,460.00	1,409.00	1,565.00	1,542.00	1,549.00	1,441.00	1,436.00	1,444.00	1,427.00	1,522.00	1,546.00	1,600.00
Export (GWh)	158.00	157.00	160.00	133.00	137.00	132.00	127.00	114.00	112.00	129.00	134.00	159.00
Domestic Consumption (GWh)*	1,387.72	1,339.09	1,488.22	1,467.65	1,473.42	1,371.19	1,366.24	1,374.22	1,357.81	1,448.87	1,470.33	1,521.43

Table 28: **Projected fuel consumption of the power plants for 2020**

PLANT	LCO (Barrels)	Natural Gas (MMBtu)	HFO (Barrels)
T1	-	11,569,743.00	-
T2	-	16,010,601.00	-
TT1PP	-	1,066,827.00	-
KTPP	-	2,679,931.00	-
TT2PP	-	68,655.00	-
AMERI	-	13,036,789.00	-
TOTAL VRA	-	***52,225,328.00***	-
KARPOWERSHIP	-	25,480,157.00	-
SAPP 161	-	4,744,538.00	-
SAPP 330	-	17,063,782.00	-
CENIT	-	3,968,932.00	-
AMANDI	-	10,808,570.00	-
CENPOWER	136,147.00	495,733.00	-
AKSA	-		212,858.00
TOTAL IPP	**136,147.00**	**62,561,712.00**	**212,858.00**
TOTAL (VRA&IPP)	**136,147.00**	**114,787,040.00**	**212,858.00**

Appendix 4:

Allocation Framework Model

General Allocation formula

$$T_G = T_l + \sum_{p=1}^{n} G_p + \sum_{d=1}^{m} C_d$$

Conditions for allocation

(a) The variable T_l will be considered first in the allocation, such that;

$$T_G - T_l = \sum_{p=1}^{n} G_p + \sum_{d=1}^{m} C_d$$

Let $T_G - T_l = C$

(b) The reminder of the total electricity generation C, will then be allocated to GoG priorities.

$$C - \sum_{p=1}^{n} G_p = \sum_{d=1}^{m} C_d$$

Let $C - \sum_{i=1}^{n} G_p = D$

The allocation of Y_i will be done by EMOP in consultation with GoG in the order of priorities; Y_1 beforeY_2, Y_2 before $Y_3 \ldots Y_{n-1}$ before Y_n

The respective allocation (quantities of energy) to each GoG policy in the order determined above will be based on assumptions determined every year.

(c) The remainder of the total electricity generation D, will be allocated on pro-rata basis

Let the respective total electricity demand for other customers be Z_j:

Let the total electricity demand for other consumers be

$$\sum_{j=1}^{m} Z_j = W$$

Hence,

$$\sum_{j=1}^{m} \frac{Z_j}{W} = 1$$

Therefore, $C_d = D * \frac{Z_j}{W}$

The final allocation equation of,

$$T_G = T_l + \sum_{p=1}^{n} G_p + \sum_{d=1}^{m} C_d$$

Becomes;

$$T_G = T_l + \sum_{p=1}^{n} G_p + \sum_{j=1}^{m} D * \frac{Z_j}{W}$$

Reasonable care has been taken to ensure the information contained in this report is accurate at the time of publication, nevertheless, any errors, omissions or inaccuracies therein are regretted.

The **EMOP** would very much appreciate and welcome comments from readers on this report. All comments should be sent to:

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