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An analysis of the Ghanaian power generation sector using an optimization model

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Abstract

The Ghana power sector has faced several challenges in the area of supply-demand balances alongside electricity tariff regulations, in particular during the past decade. This has had direct consequences on its ability to meet increasing demand. Other issues are expected to arise in the future, such as the introduction of carbon tax and a move to renewables to reduce atmospheric emissions. This paper addresses these issues through creating scenarios and making comparisons, which provide ideas on how these situations might affect the generation mix and the cost of generation. To this end a short-run computable model of the Ghana power generation system was developed to analyze those scenarios. The model is developed in the General Algebraic Modelling System (GAMS) as a Linear Programming problem.

Keywords: Ghana Power Sector, Linear Programming, Generation Cost, Emissions, Supply-Demand Forecast & Generation Mix

1. Introduction

The Ghanaian power sector, until 1997, was highly regulated, with all the various sections such as generation, transmission and distribution networks being run by a state-owned company [1]. The integrated monopolistic structure featured poor performance and managerial decisions. For example, due to the bad political situation, the government thwarted any tenable decision to adjust the electricity tariff to at least ensure long-run marginal cost recovery, because it felt it would be unpopular with consumers. This ultimately destroyed the balance sheet of the utility company and thus it could not attract the required capital from development partners, such as the World Bank (WB), to expand the infrastructural architecture and replace obsolete plant to boost system reliability. The government, recognizing the need to invest heavily in the power sector and its inability to inject the required capital to construct new power plants, resolved to structurally reform the sector. This was aimed at attracting private sector investment in the sector to promote effective competition [2]. The issue of investment in high-risk ventures was recently considered by [3] and [4]. The reform process has formally been introduced, but the sector is still undergoing transition in terms of achieving the desired structure. At present the state-owned company accounts for 88% of all grid-connected generation, while the remaining 12% comes from Independent Power Producers (IPPs). The Bulk Supply Tariff (BST) is still highly susceptible to government influence. Furthermore, the sector is suffering huge losses in bulk wholesale dispatch and supply, which invariably comes from the transmission and distribution networks. Even though the maximum level of transmission losses is supposed to be around 3%, Ghana's losses hovered around 4.7% as of 2011 mainly due to high power flows and limited transmission capacity, whereas distribution losses are in the region of 26.5% due to technical and commercial losses. While electricity accessibility has reached above 72% of the population, these losses have direct consequences on the cost of production, energy security, electricity reliability and estimation of consumer tariff rates [5]. With these challenges there is still a gradual inflow of IPPs although their commitment is linked to jointly partnering with the state-owned utilities through Power Purchase Agreement (PPA) arrangements with the government [1, 6]. This means that over time the electricity market will see the arrival of new generation capacities from both conventional and renewable energy sources to augment the current structure. Some papers have tried to analyze this subject in part. [7] performed an impact assessment on the influence of adding renewable energy systems to the operational dispatch technologies within the generation setup, where issues like fuel

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consumption, emission and generation cost were articulated based on capacity forecast analysis. [8] discussed issues related to transition from a monopolistic electricity market to a liberalized one in which the focus was on pricing, high generation & distribution costs, demand predictions, credit rating of consumers, political instability and consumer attitude. [9] and [10, 11] have carried out several studies on electricity demand and its impact on economic growth, while the role of policy changes is also discussed.

2. Overview of the Power System in Ghana

The Ghanaian power sector consists of three main groups: Ministry of Energy, the Regulatory bodies (Energy Commission (EC) and Public Utilities Regulatory Commission (PURC)) and the industry which comprise the utility suppliers and the consumers or buyers. The Ministry of Energy is the key government institution mandated with the responsibility for the implementation of the National Electrification Scheme (NES), which is intended to extend electricity accessibility to all communities within the country and also to formulate, monitor & evaluate policies, programs and projects in the energy sector. The generation capacity is handled by the state-owned company called Volta River Authority (VRA), while transmission services are carried out by another state-owned company called Ghana Grid Company (GRIDCo). The distribution services are carried out by the Electricity Company of Ghana (ECG) and Northern Electricity Department (NED), which are also state-owned utility companies. There is one private generation company which was an initiative between a local chief and a Chinese company: Sunon Asogli Power (Ghana) Ltd. which has an installed capacity of 200 MW. There is another power plant which is a joint partnership between a Turkish company TAQA and the state-owned generation utility company, VRA. The TAQA group owns and operates the Takoradi International Power thermal plant (TICO), which has an installed capacity of 110 MW. Now, investors interested in the power market prefer to enter into direct PPAs with the VRA to obtain the right economic tariffs for electricity. They usually require the VRA to fully off-take the plant's capacity on take-or-pay terms and request a government guarantee of the VRA's performance under the contract [8]. Ghana's imports and exports of electricity are driven primarily by two factors: the need to meet growing peak demand and the variability of the Volta River flow rates. The primary electricity trading partners are Ivory Coast and Togo, with which electricity is traded via the existing transmission interconnections. For example, Ghana has an exchange agreement with Ivory Coast for up to 200–250 MW of power import/export, as there is an increase in demand on both sides.

Table 1 and Table 2 give the statistical data of generation capacities and electrical energy imported & exported for a period of 10 years.

3. Electricity Demand in Ghana

Demand for electricity is not constant, but varies both throughout the day and throughout the year. Intra-day demand variations are driven by the underlying consumption patterns of residential, commercial, and industrial customers. Residential customers are characterized by small, highly variable demands, commercial customers are characterized by mid-sized, moderately variable demands, and industrial customers are characterized by large, consistent demands. Table 3 give some statistics of electricity demand from the various sections of the consumer profile.

Demand variations within the year are fundamentally influenced by climatic conditions (weather and the availability of sunlight). This influences the demand for three of electricity's key services: lighting, heating, and cooling. Ghana's equatorial location and tropical climate results in minimal seasonal variance in daylight and temperature relative to more polar locations such as Sweden or Finland, hence there is minimal seasonality in electricity demand. Demand for electricity in Ghana has been robust over the past decade due to economic growth, urbanization and rural electrification. Over the last decade, Ghana has experienced compound annual growth in peak power demand of about 1.4% , from a base of 1,258 MW in 2000 to 1,423 MW in 2009, and growth in cumulative energy demand of 3.3% annually from 7,539GWh in 2000 to 10,116GWh in 2009 [2] The increase has been due to these three (3) factors:

- Robust economic growth: Ghana's GDP grew at an average of 5.5% per annum between 2000 and 2009.
- Rapid urbanization: Ghana's urban population share went from 44% to 52% between 2000 and 2010.
- Volta Aluminium Company Limited (VALCO) demand curtailment: VALCO operations have been interrupted several times over the last 10 years due to power unavailability issues.

4. Strategic National Energy Plans for meeting electricity demand

The Energy Commission (EC) of Ghana identified three energy supply options for medium term implementation, intended to boost energy security while maintaining cost effectiveness [14].

These options were:

Option 1 An expansion plan based on natural gas usage and integration of about 10% of renewable energy to contribute to the total installed capacities by 2020. Some of the arrangements being made are:

- To convert the 125 MW Effasu barge into a combined cycle gas turbine plant (CCGT) which could increase its current capacity to 187 MW.
- To expand the 330 MW Tema gas thermal station to about 660 MW by the year 2020.

Table 1: Power Plants Generation Capacity

Plant	Fuel Type	Capacity, MW	
Hydropower Generation		Installed	Dependable
Akosombo	Water	1020	900
Kpong	Water	160	140
	Subtotal	1180	1040
Thermal Generation			
Takoradi Power Company (TAPCO)	LCO/Diesel/Natural Gas	330	300
Takoradi International Company (TICO)	LCO/Diesel/Natural Gas	220	200
Sunon Asogli Power (Ghana) Ltd	Natural Gas	200	180
Tema Thermal 1 Power Plant (TT1PP)	LCO/Diesel/Natural Gas	110	100
Mines reserve Plant (MRP)	Diesel/Natural Gas	80	40
Tema Thermal 2 Power Plant (TT2PP)	Diesel/Natural Gas	49.5	45
	Subtotal	989.5	865
	Current Total	2170	1905
Ongoing Generation Projects(2013-2015)			
Bui Hydro Power Project-BPA	Water	400	340
Takoradi 3 (T3)-VRA/GoG (Phase 1)	LCO/Diesel/Natural Gas	132	120
Kpone Thermal power Plant (KTPP)-VRA/GoG	Diesel/Natural Gas	230	200
Takoradi 2 (T2) Expansion-VRA/TAQA	Steam	110	110
VRA Solar Power Project (CSP)	Solar	2	
VRA Wind Power Project	Wind	150	
	Subtotal	1024	770 minus (S&W)
Planned Generation Projects(2015-2016)			
Osonor/TT1PP Expansion - VRA/IPP	Steam	110	100
Takoradi 3 (T3)—(Phase 2)	LCO/Diesel/Natural Gas	132	120
Domunli Thermal Project	Gas	450	440
Pwalugu Hydro Project	Water	48	45
	Subtotal	740	705

Source: Compiled based on [12, 13]

Table 2: Electricity Import and Export (GWh)

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Import	864	462	1146	940	878	815	629	435	275	198	106
Export	392	302	612	604	665	639	754	246	538	752	1036
Net Import	472	160	534	336	213	176	–125	189	–263	–555	–930

Source: Compiled based on [2, 5]

Table 3: Share of Electricity Consumption by Sector (GWh, %)

Sector	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Residential, GWh	1149	1612	1671	1727	1840	1956	2130	2094	2269	2420	2738
%	23.3	24.7	26.9	37.9	40.1	37.2	32.0	36.6	35.8	37.8	38.4
Commercial, GWh	551	579	602	620	661	676	789	802	927	884	966
%	8.2	8.3	9.7	12.5	14.4	12.9	11.9	14.0	14.6	13.8	13.6
Industrial, GWh	4306	4337	3904	2206	2029	2542	3593	2687	2963	2920	3156
%	68	66.4	62.8	48.5	44.2	48.3	54.0	47.0	46.8	45.6	44.3
Street Light, GWh	31	36	42	50	63	85	144	137	171	184	264
%	0.5	0.6	0.7	1.1	1.4	1.6	2.2	2.4	2.7	2.9	3.7
Total	6367	6564	6219	4603	4593	5259	6656	5720	6330	6408	7124

Source: Compiled based on [5]

- To achieve a renewables share of 10% by the year 2020.

Option 2: An expansion plan based on natural gas, the Bui hydropower dam project and increasing the share of renewables by 10%. Some of the arrangements being made are:

- To offset the high transmission losses by exploiting the natural positioning of the Bui hydropower dam project as a fulcrum for the national transmission grid between the southern and the northern part of the country.
- To construct Bui Hydropower with a capacity of 200 MW, instead of the 400 MW to reduce the likely environmental impact. (The government completed the project with 400 MW capacity in early 2014).

Option 3: An expansion plan based on natural gas, Bui Hydropower dam project, nuclear power and increasing renewables by 10% by 2020. One of the arrangements being made is:

- To construct a 335 MW nuclear light water reactor (IRIS-335) plant by 2018. This small nuclear reactor would be financially manageable compared to a 600 MW advanced light water plant, which would likely cost USUSD1.0-1.3 billion; about twice as much. The 335 MW plant could be expanded as more experience is gained.

5. Development of the model of the Ghana power generation system

A short-run cost minimization model was developed for Ghana's power generation sector. The model components consist of sets, parameters (including scenario assumptions), variables, and equations (constraints, balances and the objective function).

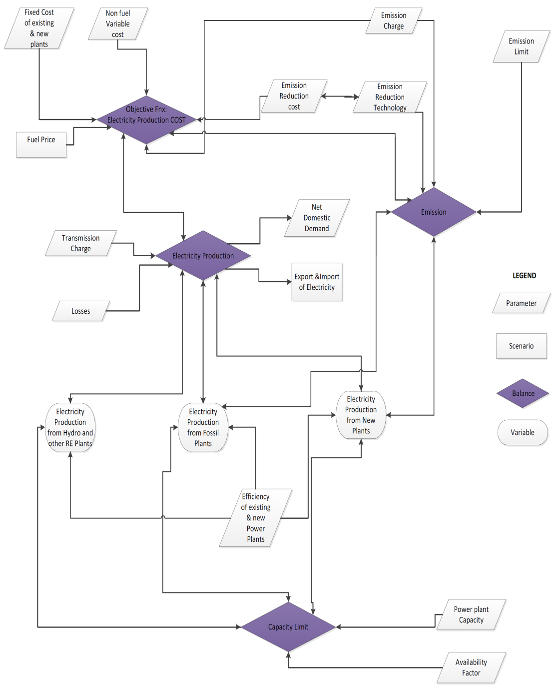

Figure 1: The structure of the model

The structure of the model is depicted in Fig. 1.

5.1. Key relations reflected in the model

Capacity Constraint: The components of this balance include the power plant capacities for both existing and new plants (thermal and renewable). The electricity generated depends on the maximum capacity of the power plant and its availability factor.

Electricity Production Balance: The power plant utilizes a primary source of energy and produces electricity as the main output, whose quantum is based on the efficiency of the power plant in utilizing the primary energy. The electricity produced plus imported electricity are to meet net domestic demand, electricity exports, transmission and distribution losses. Sometimes the local power plants are unable to meet demand and imports become necessary to maintain power supply integrity.

Emission Balance: Even though the African Union (AU) and Ghana's government have not enforced the law on CO_2 emissions reduction, the emission limit has been internalized in the model. Also an emissions-related cost factor depending on its specific CO_2 emissions was introduced for every power plant, plus an emission charge.

Objective Function-Production Cost: This integrates all the cost components with the aim of minimizing the total short-run costs of power generation. Additionally, capital costs are added to the objective function, although – as is typical in short-run models – they are not included in the optimization.

5.2. Mathematical formulae of the model

Table 4: Convention used for algebraic representation

Symbol	Specification
Sets	
p	Power plants (existing + new technologies), p ∈ P
n	New power plants, n ∈ P
f	Fossil power plants, f ∈ P
r	Renewable power plants, r ∈ P
l	Load(hour), l ∈ L
e	Emission pollutants, e ∈ E
s	Sectors (Industrial, Commercial & Residential), s ∈ S
Technological Parameters	
InstalledCapacity(p)	Installed capacity of power plant p, MW
DependableCap(p)	Dependable or maximum capacity of power plant p, MW
AvailFactor(p,l)	Availability factor of power plant p in load l
Efficiency(p)	Efficiency of power plant p
Losses(p)	Losses in the power plant p
Duration(l)	Load duration of l, h
SectoralPowerDemand(l,s)	Demand of electricity from sectors s in load l, MW
ElecImport(l)	Electricity import in load l, MW
ElecExport(l)	Electricity export in load l, MW
Economic Parameters	
FuelPrice(p)	Fuel price for primary input to power plant p, USD/MWh
FixedCost(p)	Fixed cost of power plant p, USD/MW
NonfuelVariableCost(p)	Variable O&M costs, USD/MWh
EmissionCharge	CO_2emission charge, USD/tCO_2
TransCharge	Transmission charge, USD/MWh
Environmental Parameters	
EmissionFactor(p)	Emission factor of power plant p, tCO_2/MWh
EmiLimit	CO_2emission limit, tCO_2
Variables	
Generation(p,l)	Electricity generation of power plant p in load l, MW
TotalCost	Total cost of power generation, USD

Capacity Limit

With reference to the capacity limit equations, here power generated in unit p within a certain time frame l is dependent on the maximum capacity of p and its availability factor. The maximum capacity must be less than or equal to the product of installed capacity and availability factor of p.

$$\bigvee_{p\in P, l\in L} Generation_{p,l} \leq DependableCap_{p} \times AvailFactor_{p,l}$$

Subject to:

$$\bigvee_{p\in P} InstalledCapacity_{p} \geq DependableCap_{p}$$

Electricity Production Balance

With regard to the electricity production/generation balance, net domestic demand and electricity exported should be less than or equal to the power that is generated from all p with deduction of losses mainly due to transmission and distribution congestions and the addition of imported electricity.

$$\bigvee_{l \in L} \sum_{p} \left(Generation_{p,l} \times \left(1 - Losses_{p}\right)\right) + ElecImport_{l} \geq \sum_{s} \left(SectoralPowerDemand_{l,s} \right) + ElecExport_{l}$$

Emission Constraint

Here the total emissions from all p, based on the CO_2 emission factor associated with p and electricity generation must not exceed the national CO_2 emission limit.

$$\sum_{p,l} Generation_{p,l} \times EmissionFactor_{p,l} \leq EmiLimit$$

Cost of Electricity Production/Generation

The objective function of the model seeks to minimize the total cost of power generation over the specified period of time, based on included cost components such as: non-fuel related variable cost, fuel prices, transmission charge, emission charges, and fixed costs.

$$\begin{aligned} TotalCost = & \\ & \sum_{p,l} \Bigg[Generation_{p,l} \times \Big(NonfuelVariableCost_{p} + \\ & + \frac{FuelPrice_{p}}{Efficiency_{p}} + TransCharge + \\ & + EmissionFactor_{p,l} \times EmissionCharge \Big) \Bigg] + \\ & + \sum_{p} \left(FixedCost_{p} \times InstalledCapacity_{p} \right) \end{aligned}$$

5.3. Data assumptions

The scope of the data used in this model is very broad. Therefore, only the most important parameters assumed for the calculations are presented.

Technical/Technological Data Assumptions: Parameters such as the installed capacity of power plants (MW), availability factor (%), efficiency (%) and losses (%) required for the model were acquired directly from the utility companies or they were based on respective calculations [5]. The load data that was acquired from the operators of the power plants were based on daily-hourly demand statistics. An annual hourly load demand is extrapolated based on the daily-hourly demand and the daily peak data to generate hourly load demand data for 8760 hours. The hourly net domestic demand is split into three subsectors namely: Industrial, Commercial and Residential. The Industrial data is considered to be the same throughout the whole year, thus assumes a constant shape, but the commercial and residential data varies.

Economic Data Assumptions: Data required for the economic side of the model are the Investment expenditure of the power plants (USD/MW), non-fuel variable cost (USD/MWh), transmission charges (USD/MWh) and fuel prices (USD/MWh). Most of the data acquired for these parameters were based on national statistical data [5].The fixed cost for Akosombo and Kpong hydro power plants have been assigned zero, with the assumption that they have already recovered their costs due to their long service time in operation. The thermal plants have flexible fuel firing options.

Table 5: Fuel Prices purchased for Power plants as of the year 2012

Type of Fuel	Prices, USD/MWh
Light Crude Oil(LCO)	59.5
Diesel	73.9
Natural Gas(NG)	37.2

Source: own calculations based on [5]

Since it would be cost beneficial to utilize natural gas (NG) on a long term basis due to its comparatively low cost, the prices found in Table 6 are based on NG. However, as part of the model scenarios, the price would change if other fuels are utilized and Table 5 gives the prices per fuel type.

Environmental /Emission Data Assumptions: The emission calculation for the thermal plants is based on baseline emission assumption, which uses the ex-ante assessment. Under normal circumstances, the data to be used for the model should have been empirical relative to the operation of the power plants, but due to the unavailability of data the ex-ante calculation is adopted. This is based on the initial parameters of the power plant prior to it going operational. A parameter such as emission charge (USD/tCO_2) is utilized based on the European Union Emissions Trading Scheme (EU ETS) standards [17, 18].

5.4. Computer implementation

The model was developed in GAMS (General Algebraic Modelling System) as a Linear Programming (LP) problem and the solution is found by the CPLEX solver [19]. The application of GAMS to support energy policy planning may be found in previous works, such as [20], [21], [22], and [23].

5.5. Development of scenarios

The scenarios are created based on the current situation (reference) in the Ghana power generation sector and scenarios based on this paper objective. Descriptions assigned to the scenarios are presented in Table 7.

6. Analysis of model results

The analysis presented in this section is based on GAMS model runs. The model was run with hourly resolution (8760 hours-a yearly model). For the sake of clarity the graphs are represented on a weekly basis.

Table 6: Economic and Technical Parametric Data of Power plants

Power Plant	Fuel Type	Investment Expenditure (annualised), USD/MW × 10^3	Non fuel Variable Cost, USD/MWh	Fuel Price, USD/MWh
Existing Plants				
Akosombo	Water	0	3.5	-
Kpong	Water	0	3.5	-
Takoradi Power Company(TAPCO)	LCO/Diesel/Natural Gas	400	2.3	37.2
Takoradi International Company(TICO)	LCO/Diesel/Natural Gas	275	2.3	37.2
Sunon Asogli Power(Ghana) Ltd	Natural Gas	400	1.1	37.2
Tema Thermal 1 Power Plant(TT1PP)	LCO/Diesel/Natural Gas	275	2.1	37.2
Mines reserve Plant(MRP)	Diesel/Natural Gas	400	2.3	37.2
Tema Thermal 2 Power Plant (TT2PP)	Diesel/Natural Gas	400	1.1	37.2
New Plants				
Bui Hydro Power Project-BPA	Water	1,660	2.0	-
Takoradi 3 (T3)-VRA/GoG (Phase 1)	LCO/Diesel/Natural Gas	400	2.3	37.2
Kpone Thermal power Plant(KTPP)-VRA/GoG	Diesel/Natural Gas	550	2.1	37.2
Takoradi 2 (T2) Expansion-VRA/TAQA	Steam	275	2.1	
VRA Solar Power Project (CSP)	Solar	4,000	0.5	-
VRA Wind Power Project	Wind	1,250	0.5	-
Osonor/TT1PP Expansion - VRA/IPP	Steam	275	2.1	
Takoradi 3 (T3)—(Phase 2)	LCO/Diesel/Natural Gas	400	2.3	37.2
Domunli Thermal Project	Natural Gas	400	1.1	37.2
Pwalugu Hydro Project	Water	3,600	2.0	-

Source: own calculations based on [5, 15, 16]

Table 7: Description of scenarios created

Scenario/Case	Description
Scenario 0 – Reference	The reference scenario is based on parameters and data that correspond to the existing situation especially related to 2010.
Scenario 1 – Carbon tax introduction	An emission charge of around 16.9USD/tCO_2 [17] is introduced to realize its impact on the costs of electricity generation and its corresponding emissions.
Scenario 2 – Demand sector (Residential, Commercial & Industrial)	The various sectors that form net domestic demand are varied upwards or increased by a cumulative growth rate of 3.3% [2] to realize its impact on total generation cost, average unit cost and emissions.
Scenario 3 – Change in power consumption pattern	The various sectors such as residential and commercial are kept constant while the industrial sector is increased by a cumulative growth rate of 3.3% [2] to realize its impact on total generation cost, average unit cost and emissions.
Scenario 4 – Higher Precipitation	With regard to this scenario, the precipitation level (rainfall pattern) is increased by 5% [2]. This is to realize its impact on total generation cost, unit costs and emissions.
Scenario 5 – Fuel prices	Prices arising from primary energy for electricity generation is increased by (20%) due to price instability in the global market to realize its impact on generation, unit costs and emissions.
Scenario 6 – Introduction of new generation capacities	New capacities of power plants are included to the model gradually in addition to the current existing power plants within the Ghanaian power sector according to the national schedule to realize its impact on generation, average unit cost and emissions. The introduction of new power plants has been categorized into different sub-scenarios depending on the additions.

6.1. Reference scenario

Fig. 2 shows the weekly electricity generated in meeting the demand. Generation based on demand on weekdays (Monday-Friday) are slightly higher than at the weekend (Saturday-Sunday). This could be attributed to the variance in activities carried out in those periods. The base load is supplied mainly by two (2) hydropower dams namely; Akosombo and Kpong plants. This is necessitated because it is economical to use power plants with lower variable cost to supply base loads while the thermal plants are used to supply or augment the intermediate and peak loads, possibly based on natural gas. Fig. 3 presents a graph of hourly unit cost for a week and as per the results, the cost of producing electrical power during off peak periods/hours is below 60 USD/MWh while the cost goes slightly higher than 70 USD/MWh during peak periods/hours, constituting a cost difference of around 22%. The carbon tax is considered to be zero in the reference scenario, because it does not currently exist.

6.2. Scenario 1: Carbon tax introduction

Here, the nature of Fig. 4 does not have any variance compared to the same graph under the reference situation; the only parameter that shows a comparative difference is the hourly unit cost of electricity generation. The increase is primarily due to the introduction of carbon tax in the total cost of electricity generation. Fig. 5 shows a percentage difference

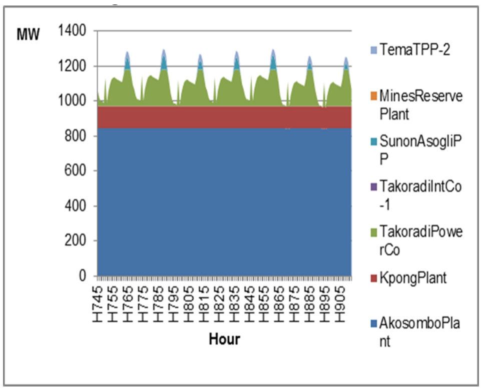

Figure 2: A graph of a weekly electricity generation duration curve

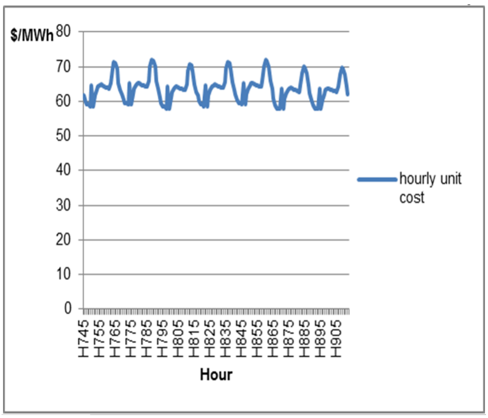

Figure 3: Weekly average unit cost for electricity generation

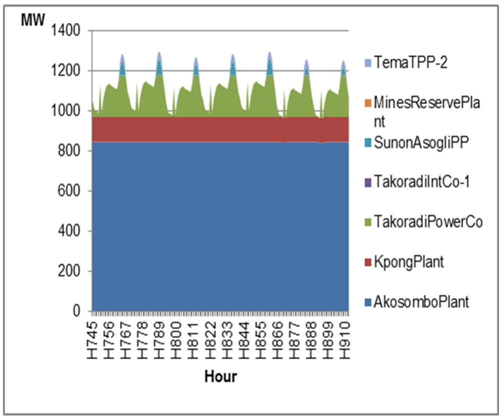

Figure 4: Graph of a weekly electricity generation duration curve-Scenario 1

of about 26% between the hourly unit cost at off peak and peak periods.

6.3. *Scenario 2: Demand sector (Residential, Commercial & Industrial)*

Fig. 6 & Fig. 7 are at complete variance with the reference situation graphs in that there is an appreciable increase in the generation level, the hourly unit cost and the hourly emission of the power plants in operation during this length

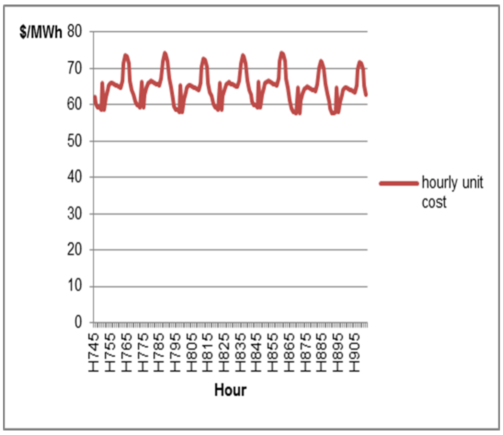

Figure 5: Weekly unit cost for electricity generation-Scenario 1

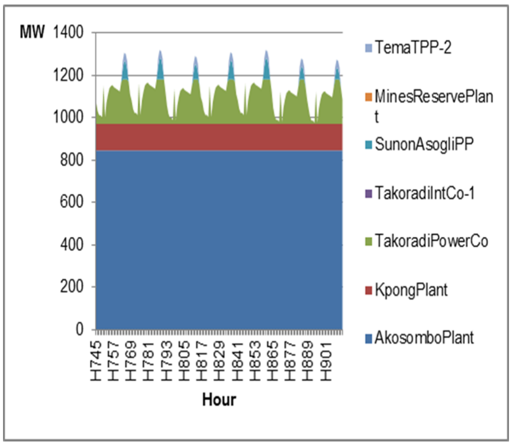

Figure 6: Graph of a weekly electricity generation duration curve-Scenario 2

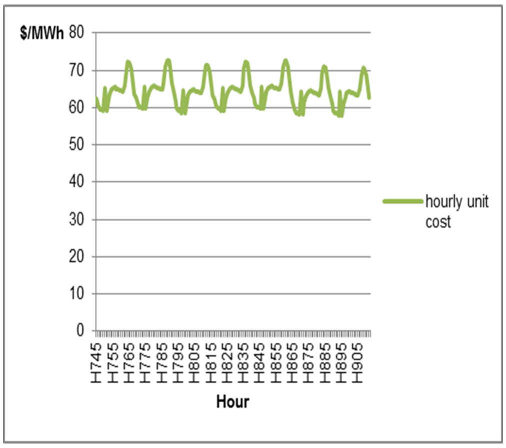

Figure 7: Weekly unit cost for electricity generation-Scenario 2

of interval. The percentage difference in the hourly unit cost between the off peak and peak period is about 24%.

6.4. *Scenario 3: Behavioral consumption pattern*

Fig. 8 & Fig. 9 are also at variance with the reference situation graphs in that there is a small increase in the genera-

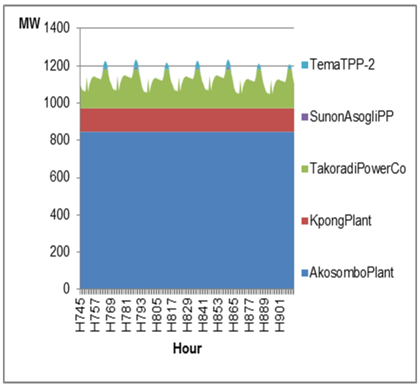

Figure 8: Graph of a weekly electricity generation duration curve-Scenario 3

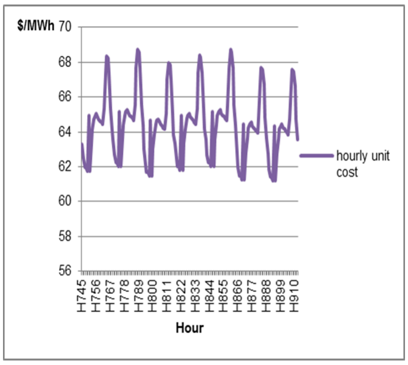

Figure 9: Weekly unit cost for electricity generation-Scenario 3

tion level, the hourly unit cost and the hourly emission of the power plants in operation during this length of interval. The percentage difference in the hourly unit cost between the off peak and peak period is about 10%.

6.5. Scenario 4: Higher precipitation

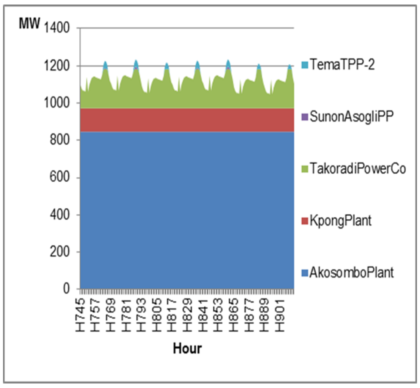

Figure 10: Graph of a weekly electricity generation duration curve-Scenario 4

Fig. 11 is at complete variance with the reference situation graph in that there is an appreciable decrease in the hourly unit cost and the hourly emission of the power plants in operation during this length of interval while the generation level in

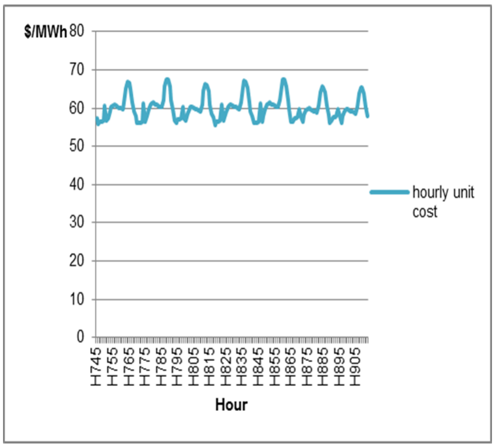

Figure 11: Weekly unit cost for electricity generation-Scenario 4

Fig. 10 shows no appreciable variance. The percentage difference in the hourly unit cost between the off peak and peak period is about 20%.

6.6. Scenario 5: Fuel prices

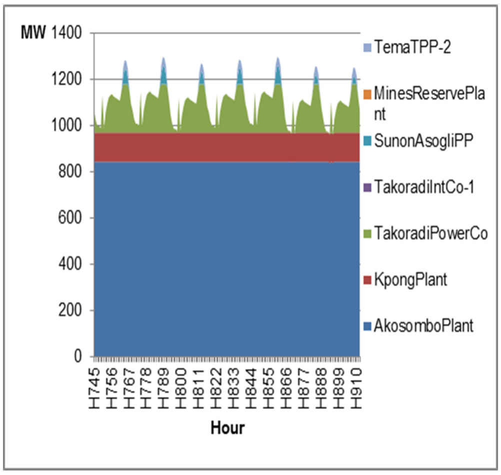

Figure 12: A graph of a weekly electricity generation duration curve-Scenario 5

Fig. 12 does not have any variance compared with the same graph represented in the reference scenario, except for the hourly unit cost of generation. This is primarily due to the increase in fuel prices in the total cost of electricity generation.

Fig. 13 shows a percentage difference of about 31% between the hourly unit cost at off peak and peak periods.

6.7. Scenario 6: Introduction of new generation capacities

In this scenario five different cases are created based on the plans of considered new investments in power generation assets:

- One renewable plant added (Hydro) planned in 2013

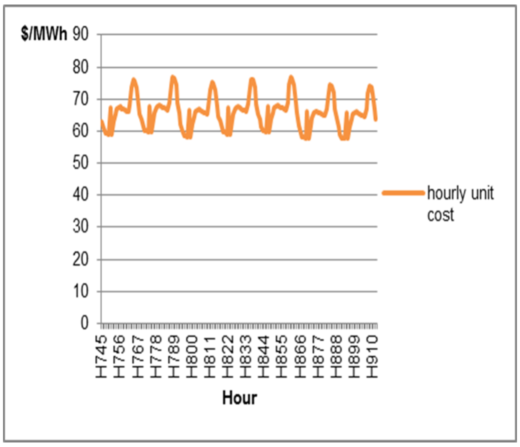

Figure 13: Weekly unit cost for electricity generation-Scenario 5

- Two renewable plants added (Hydro and Solar) planned in 2013
- Three renewable plants added (Hydro, Solar and Wind) planned in 2015
- Two renewable (Hydro & Solar) and one thermal plant (Natural Gas), planned by 2016
- One renewable (Hydro) and two thermal plants (Natural Gas) planned by 2016

6.7.1. Scenario 6a: One renewable plant added (Hydro)

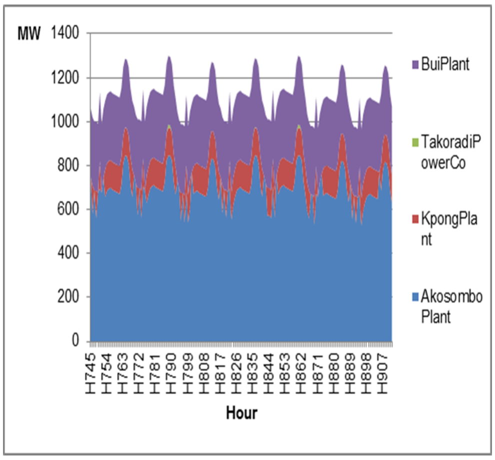

Figure 14: A graph of a weekly electricity generation duration curve-Scenario 6a

Fig. 15 is at complete variance with the reference situation graph. There is an appreciable increase in the hourly unit cost and sizeable decrease in the hourly emission of the power plants in operation during this length of interval, but

Fig. 14 has no variation except for the compositional mix in generation with the hydropower plant practically being used to meet demand. The percentage difference in the hourly unit cost between the off peak and peak period is about 23%.

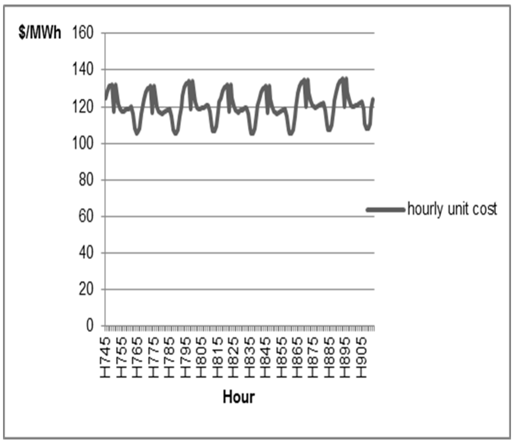

Figure 15: Weekly unit cost for electricity generation-Scenario 6a

6.7.2. Scenario 6b: Two renewable plants added (Hydro and Solar)

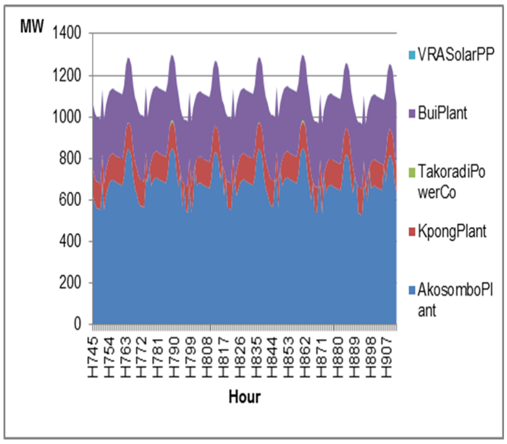

Figure 16: A graph of a weekly electricity generation duration curve-Scenario 6b

Fig. 17 is at complete variance with the reference situation graph, as there is an appreciable increase in the hourly unit cost and sizeable decrease in the hourly emission of the power plants in operation during this length of interval.

Fig. 16 has no variation except for the compositional mix in generation, with the hydropower plant practically being used to meet demand. The percentage difference in the hourly unit cost between the off peak and peak period is about 27%.

6.7.3. Scenario 6c: Three renewable plants added (Hydro, Solar and Wind)

Fig. 19 is at complete variance with the reference scenario as there is an appreciable increase in the hourly unit cost and sizeable decrease in the hourly emission of the power plants in operation during this length of interval but

Fig. 18 has no variation except for the compositional mix in generation, with hydro forming practically the base and intermediate technology being used to meet demand while wind is used mostly during peak times. The percentage difference

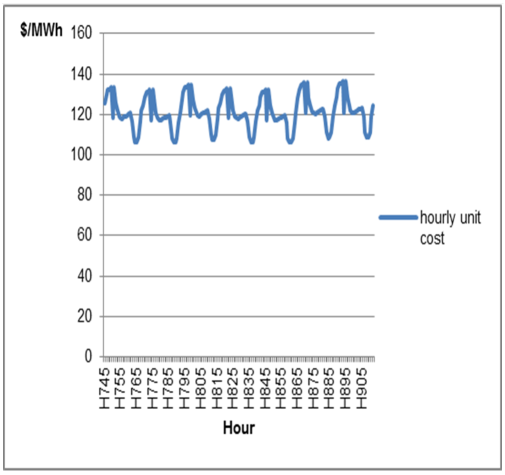

Figure 17: Weekly unit cost for electricity generation-Scenario 6b

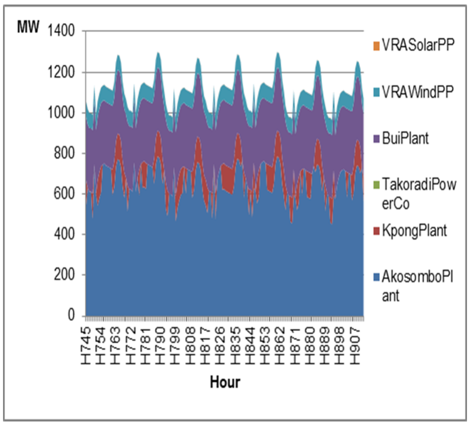

Figure 18: A graph of a weekly electricity generation duration curve-Scenario 6c

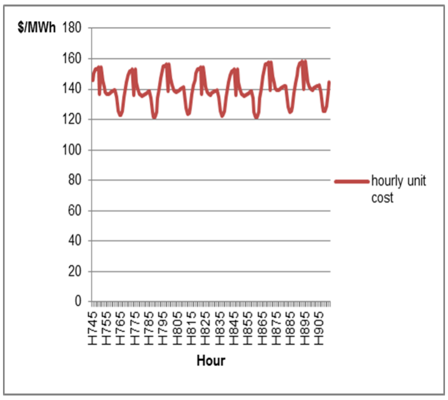

Figure 19: Weekly unit cost for electricity generation-Scenario 6c

in the hourly unit cost between the off peak and peak period is about 28%.

6.7.4. *Scenario 6d: Two renewable (Hydro & Solar) and one thermal plant (Natural Gas)*

Fig. 21 is at variance with the reference situation graph in that there is an appreciable increase in the hourly unit cost

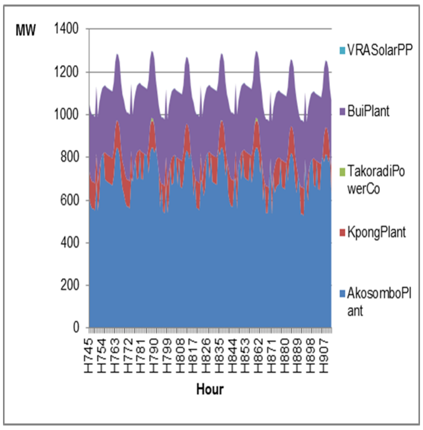

Figure 20: A graph of a weekly electricity generation duration curve-Scenario 6d

and sizeable decrease in the hourly emission of the power plants in operation during this length of interval but

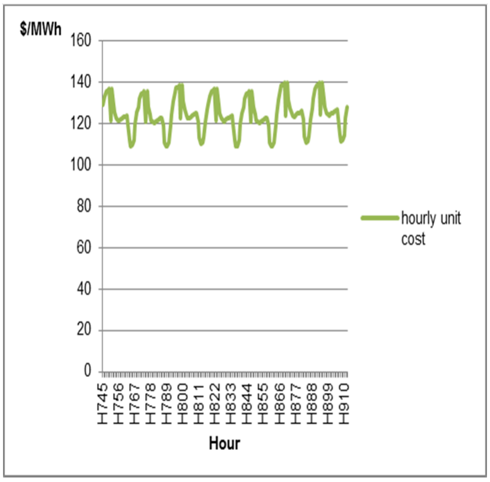

Figure 21: Weekly unit cost for electricity generation-Scenario 6d

Fig. 20 has no variation except for the compositional mix in generation, with hydropower plant practically being used to meet demand. The percentage difference in the hourly unit cost between the off peak and peak period is about 29%.

6.7.5. *Scenario 6e: One renewable (Hydro) and two thermal plants (Natural Gas)*

There exist a difference between

Fig. 23 and the reference situation graph. There is an appreciable increase in the hourly unit cost and sizeable decrease in the hourly emission of the power plants in operation during this length of interval. However,

Fig. 22 has no variation except for the compositional mix in generation with hydropower plant being used to meet the base and intermediate demand with a very small portion of the thermal plant used to meet peak demand at certain days during the week. The percentage difference in the hourly unit cost between the off peak and peak period is about 25%.

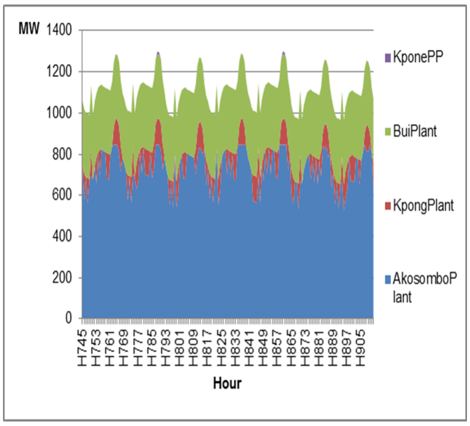

Figure 22: A graph of a weekly electricity generation duration curve-Scenario 6e

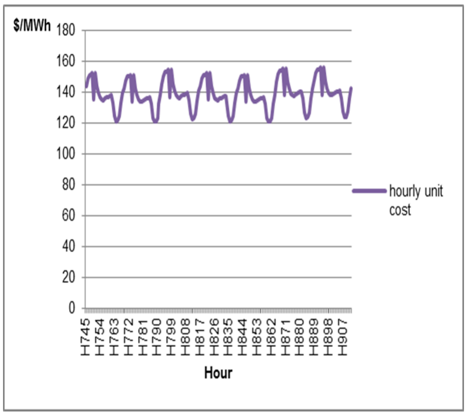

Figure 23: Weekly unit cost for electricity generation-Scenario 6e

6.8. Comparative analysis of the results

This analysis is based on some annual cumulative parameters for the reference situation, the scenarios created, and some of the comparisons are based on indicators such as the total cost of generation, average cost, total emission for all power plants and emissions from individual power plants

6.8.1. Analysis of total annual cost of generation

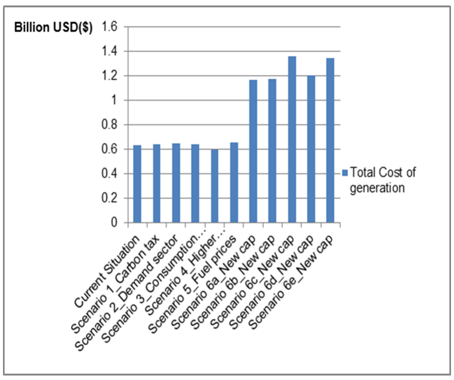

Figure 24: Total annual cost of generation for current situation vs. analyzed scenarios/cases

Fig. 24 shows that the highest cost of generation comes from case 6c, which takes account of the introduction of three new renewable plants to the existing plants thus; representing a marginal increase of 115% above the current/reference situation (see Table 8 for the percentage differences). This is basically due to the huge investment expenditures (hence fixed cost) that comes with the utilization of renewable technologies. Scenario 4, which accounts for higher precipitation, gives a fairly lower cost representing a marginal decrease of around 6% when compared to the reference scenario. In this latter situation, no additional plants are added but because of the low variable cost in operating hydro plants, thermal plants with considerable higher variable cost are shut down during certain load periods for the hydro plants and again some fixed costs are reduced as per the reduction of the thermal components.

Table 8: % cost diff. between the reference situation and the scenarios [(+) increase, (-) decrease]

Scenario	Total cost, %	Average cost %
Scenario 1_Carbon tax	1.78	1.78
Scenario 2_Demand sector	2.48	1.02
Scenario 3_Consumption pattern	1.49	0.31
Scenario 4_Higher precipitation	-5.73	-5.73
Scenario 5_Fuel prices	3.89	3.89
Scenario 6a_New cap	84.54	84.54
Scenario 6b_New cap	85.79	85.79
Scenario 6c_New cap	114.78	114.78
Scenario 6d_New cap	90.58	90.58
Scenario 6e_New cap	112.82	112.82

6.8.2. Analysis of annual average unit cost of generation

The average cost characteristics in

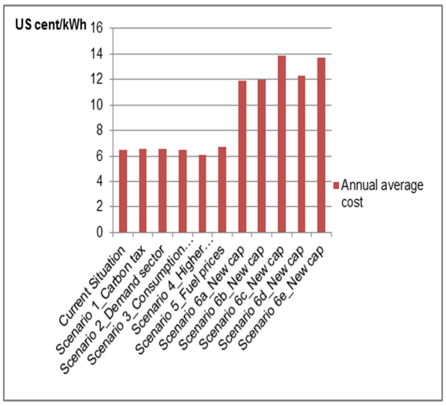

Figure 25: Annual average unit cost of generation for current situation vs. analysed scenarios/cases

Fig. 25 shows similar trends to the total annual graph represented in Fig. 24. Scenario 4, which borders on high precipitation, still maintains the least unit cost of generation. Again, the marginal cost for thermal power plants for all scenarios with the exception of scenario 5 is 3.72 US cent/kWh and the difference between this cost and the unit cost is due to the sum of the fixed costs for these plants.

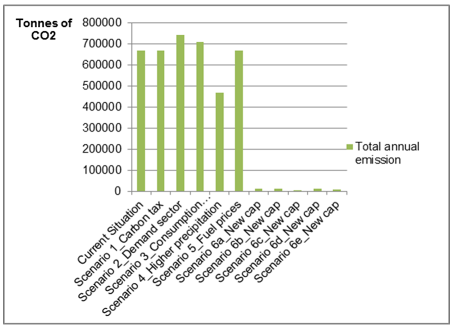

Figure 26: Total annual emission from generation for current situation vs. analyzed scenarios

6.8.3. *Analysis of total annual emissions from generation*

Fig. 26 indicates that there is no significant change or difference in the total emission generated with the current situation when the scenarios of a carbon tax and fuel price increase are introduced into the model (see Table 9 for percentage differences between reference situation and the scenarios). The introduction of the scenarios: increase in demand sector and consumption pattern shows that there is an appreciable increase in the total emissions compared to the current situation of about 11% and 6% respectively. This increase in total emissions is because of the utilization of additional thermal power to meet the cumulative increase in demand in both situations. The other scenarios (4-6a-e) show that there is an appreciable decrease in the emissions under scenario 6c, having the lowest emissions, and this is primarily due to the introduction of three new renewable power plants.

Table 9: % emission diff. between the reference situation and the scenarios [(+) increase, (-) decrease]

Scenario	Emission, %
Scenario 1_Carbon tax	0
Scenario 2_Demand sector	11.08
Scenario 3_Consumption pattern	6.21
Scenario 4_Higher precipitation	-29.93
Scenario 5_Fuel prices	0
Scenario 6a_New cap	-98.41
Scenario 6b_New cap	-98.44
Scenario 6c_New cap	-99.89
Scenario 6d_New cap	-98.44
Scenario 6e_New cap	-98.69

6.8.4. *Analysis of total annual emissions from individual power plants*

Fig. 27 shows the levels of annual emissions by the power plants in operation, which invariably come from the thermal power plants. Optimization of the cost of generation, which influences the type of power plants that should be in operation at a particular load, shows that in the case of thermal plants, Takoradi Power Company(TAPCO) was used more often, followed by Sunon Asogli Power (Ghana) Ltd, Tema Thermal 2 Power Plant (TT2PP) and then the rest. This sequence is exactly consistent with the emission levels produced by these power plants.

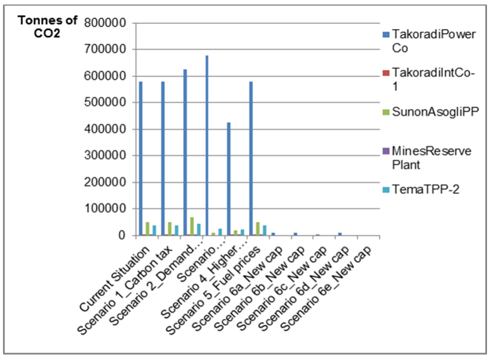

Figure 27: Total annual emission from individual power plants for current situation vs. analysed scenarios

7. Conclusion and Recommendations

Based on the results of the analysis carried out in this paper, it is clear that Ghana's power system is very sensitive and susceptible to the vagaries of situational parameters and factors, which could easily offset its current characterizations. All the scenarios with the exception of scenario 4 (increase in precipitation) show an increase in generation cost and this could be attributed to the capital cost of the generation mix, especially in the case of new thermal plants where the marginal cost is around 37.2 USD/MWh. Furthermore, the tariff rates provided by the Public Utilities Regulatory Commission (PURC) on the real situation showed that the addition of the bulk generation charge (BGC) and the transmission service charge (TSC) is around 0.07 USD/kWh while the model output for the reference situation showed around 0.065 USD/kWh, which clearly indicates that the BGC charged does not include the Capacity Charge (for dispatchable technologies) not to mention the Energy Charge to recover long-term cost. Again, the model indicated that there could be a generation capacity deficit of about 300 MW, which will straightaway put the system into a load shedding situation. It is therefore recommended that the spinning reserve margin should be looked at critically and if the system is to meet the system peak with unforced generation, there should be an average yearly addition of 220 MW for the next decade. Moreover, the utility companies need to use smart prepaid meters to retrieve most of the lost revenues, while the government could possibly commercialize the utility companies to effectively compete. Again, the tariff regime needs to be reviewed to provide fertile investment grounds for Independent Power Producers. Finally, more investment needs to be made to reduce grid losses, while investments in distributed generation (mini-hydro, PV with storage) could be utilized in sparsely populated northern districts of the country.

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We would like to acknowledge Professor Joao Santana's suggestions and comments. This work was partially supported by the statutory research program of the

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