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# Economic Evaluation of Gas Power Plant Project for the First Gas Industrial Park in Nigeria

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***Authors' contributions***

*This work was carried out in collaboration between both authors. Author OAF designed the study and wrote the protocol. Author AOL carried out the analyses and wrote the first draft of the manuscript. Author OAF reviewed the first draft and wrote the final draft. Both authors read and approved the final manuscript.*

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## ABSTRACT

In this paper, discounted cash flow analysis and Monte Carlo simulation were used to evaluate the Gas Power Plant Project for the first Gas Industrial Park in Nigeria. These methods gave maximum insight into the basis for investment decision and show the profitability of gas fired generation. A Net Present Value of $10.8 million at a discount rate of 15% and an Internal Rate of Return (IRR) of 16% with a payback period of 9 years was realized. Probabilistic result gave a 62.8% certainty of having a positive NPV and IRR values above the hurdle rate for investment. The capacity factor, capital cost and debt capital were uncertain parameters that will have huge effect on the power project. The study concludes that the gas fired power plant project in the industrial park is economically viable.

*Keywords: Gas power plant; industrial park; simulation; profitability; investment; sensitivity analysis.*

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## ABBREVIATIONS

| | | | |
|---|---|---|---|
| *CCGT* | *: Combined-Cycle Gas Turbine* | *DCF* | *: Discounted Cash Flow* |
| *DSCR* | *: Debt Service Cover Ratio* | *DSO* | *: Domestic Supply Obligation* |
| *EPZ* | *: Export Processing Zone* | *ELPS* | *: Escravos-Lagos Pipeline System* |
| *ESPR* | *: Electricity Sector Power Reform* | *G&P* | *: Gas and Power* |
| *GRIP* | *: Gas Revolution Industrial Park* | *GWh* | *: Gigawatt Hour* |
| *IPP* | *: Independent Power Producer* | *ITA* | *: Investment Tax Allowance* |
| *kWh* | *: Kilowatt Hour* | *LFN* | *: Law of the Federation of Nigeria* |
| *LRMC* | *: Long Run Marginal Cost* | *MBtu* | *: Thousand British thermal unit* |
| *MScf* | *: Thousand Standard Cubic Feet* | *MWh* | *: Megawatt Hour* |
| *MYTO* | *: Multi Year Tariff Order* | *NERC* | *: Nigerian Electricity Regulatory Commission* |
| *OCGT* | *: Open-Cycle Gas Turbine* | *NNPC* | *: Nigerian National Petroleum Corporation* |
| *PHCN* | *: Power Holding Company of Nigeria* | *PRG* | *: Partial Risk Guarantee* |
| *TCN* | *: Transmission Company of Nigeria* | *VOM* | *: Variable Operation and Maintenance* |
| *WACC* | *: Weighted Average Cost of Capital* | *WAGP* | *: West Africa Gas Pipeline* |

## 1. INTRODUCTION

Nigeria is the largest natural gas reserve holder in Africa and the ninth-largest in the world with an estimated proved reserve of 180 trillion cubic feet [1]. However, natural gas production has been constrained by the lack of infrastructure to monetize it. As part of Nigeria's resolve to become a major international player in the international gas market as well as to lay a solid framework gas infrastructure expansion within the domestic market, the Nigerian Gas Master Plan was approved. The development of this master plan is aimed at promoting investment in pipeline infrastructure and new gas-fired power plants to help curtail gas flaring and provide more gas to fuel much-needed electricity generation within the country.

In line with this, Nigerian National Petroleum Corporation (NNPC) which is the country's national oil company provided guidelines for a robust infrastructure programme that would attract investments to the tune of $16 billion to develop associated gas within four years. This project is known as the Gas Revolution Industrial Park (GRIP) and is located in Delta State, Nigeria. The park will be a dedicated gas based industrial park with Free Trade Zone (FTZ) & Port Status [2]. It is expected to house world class Infrastructures which include: Gas Supply and Processing facilities; Power Supply Unit; Deep Sea Port; Urban facilities; Industries; Centralized utilities provision and Integrated fibre optic network. The industrial park project will be executed in phases and the first construction work will be with the gas-fired power plant, the water treatment plant and the gas processing facility [2].

Seeing this as a means of gas utilisation and power generation within the country, this project aims to evaluate the economic viability of the power project in the park. This is due to the fact that previous investments in gas power plant projects within the country have not yielded the desired results. Huge investments were made on various gas-fired power plant projects in the last decade some of which are Geregu (414MW), Omotosho (335MW) and Alaoji (346MW), but the country has failed to exceed 5000 MW of generation capacity over the years. Recently, generation fell to as low as 2800 MW as only 5 gas power plants of the supposed 23 plants in the country was functioning. Different reasons (Maintenance of gas pipelines, Low gas pressure, Pipeline and power towers vandalisation, Political reasons, Network problems etc. and most frequently, shortage of gas) have been given as the cause of the lack of commensurate increase in generation as more capital is invested into the power sector [3-6]. It is therefore imperative to evaluate the power project in the industrial park as power generation will be a major factor in the success of the broad industrial park project.

The objectives of this study therefore include (i) analyze the economic viability of the power project under existing fiscal regime and regulatory framework in Nigeria and (ii) evaluate this investment opportunity taking into consideration risks and uncertainties involved in a gas power plant project. This study will therefore give some more insight to gas power plant projects as well as enrich existing literature in this area.

### 1.1 Gas Revolution Industrial Park (GRIP)

The Ogidigben Integrated Industrial Gas Park is located on a land mass of about 2800 Hectares situated between Ogidigben and Ajudaibo communities in Delta state. The park was designed after the Nagarjuna Fertiliser Plant in India and the Xenel Petrochemical Plant in Saudi Arabia. The park is an intrinsic part and parcel of the Nigerian Gas Master Plan. This park will be a prototype for subsequent development in other states in Nigeria. The Federal government of Nigeria represented by the Nigerian National Petroleum Corporation (NNPC) oversees the development of the Green Industrial city which is strategically located near a major central gas processing facility (CPF).

Industries sited in the park would produce petrochemicals, fertilizers, methanol and other related products (Fig. 1). This is expected to replace the nation's dependency on crude oil. The park which is proposed to be the largest Gas City in Sub-Saharan Africa has free trade zone (FTZ) and port status and will comprise these industries, power plant, other support offices and residential facilities. It is strategically located on the east bank of the Escravos River, opposite NNPC/Chevron Nigeria's Escravos facilities and one advantage of this location is its close proximity to the ELPS (which delivers pipeline gas to consumers in western and central Nigeria) which enables relatively easy gas access with less pipeline infrastructure development cost.

Phase one is to establish the backbone of the project which is the power plant with gas supply agreement with Exxon Mobil, the water treatment plant, the port, the residential houses that will support the project and the gas processing facility. After that, phase two constitutes the petrochemicals, fertilizer, methanol plants etc. and from there on, the execution of the project will continue organically [2]. On completion, the industrial park will consolidate Nigeria's position and market share in high value export markets, maintain 10 per cent market share in global LNG trade and dominate regional gas pipelines supplies [2]. The project will be jointly handled by the Ministry of Transport, Petroleum, Power as well as Trade and Investment.

Power generation in Nigeria is currently via three ways: grid generation, embedded generation and captive generation. Grid power generation refers to the evacuation of power on the national grid and requires an off-taker which could be the transitional bulk trader, an eligible customer declared as such by the Minister of Power or an industrial customer. Currently, 56 licenses have been issued for grid power generation by NERC [8]. Embedded generation on the other hand is an off grid power where power generated is evacuated through the distribution system of a distribution company. 3 licenses have been issues by NERC for embedded power generation in Nigeria [8]. Captive generation is also an off-grid power but no distribution infrastructure is required as the power is consumed by the


**Fig. 1. A Model of the GRIP [7]**

generator and is usually not sold to a third party. Captive generation requires only a permit from NERC but generation exceeding 1MW will require a license [8]. The power project in the industrial park is considered a captive power since distribution will be within the park and not through distribution system of a distribution company but will require a license since generation will exceed 1MW [7].

## 2. INVESTMENTS IN GAS TO POWER PROJECTS IN NIGERIA

The economic development and growth of a country are inextricably linked to its electric power sector. Until recently, the Nigerian electricity generation, transmission, and distribution was entrusted to a state-owned monopoly entity NEPA (later known as PHCN). This monopolistic business model has led to capacity shortage, poor performance, and inefficiencies. Part of the country's plans to rehabilitate the electrical power sector has been to increase power production facilities. In order to achieve this, the government of Nigeria signed a contract of $800 million with ENRON, an American Energy Company and its Nigerian partners to build a 560 MW gas turbine power plant. Also, a subsidiary of AES Corporation invested $225 million to secure majority share in a 290MW plant, Agip constructed a 450 MW plant in the town of Kwale at a cost of $240 million and Exxon Mobil was permitted to construct a 350 MW plant in Rivers State.

Subsequently, the construction of open cycle gas turbine plants was approved The Federal Government of Nigeria. The project consists of Geregu (414MW), Omotosho (335MW), Papalanto (335MW) and Alaoji (346MW) pow*er plants and will be* co-financed by the Chinese Government. Also, a $110 million contract was awarded by the Federal Government of Nigeria *to* Siemens Limited, a German company headquartered in Berlin and Munich, for the design and construction of a 279MW combustion *turbine power plant* in Afam to augment the power generation in Nigeria. Also the NNPC awarded a $312 million gas-fired power plant project with capacity of 450 MW which is expected to be *added to the national grid.*

All this was done to boost power generation within the country but that was not the case. With this in mind, the government's aspirations for the country to be among the world's top 20 economies by 2020 with an ambitious target to generate 40,000 MW of electricity by that year, faced an enormous challenge considering current power generation was only about 4,000 MW [9]. A decision was then made to privatize the power sector.

As the first phase of privatization began, some financial institutions pledged their support to finance some of the projects that will increase electricity generation in the country including gas supply. For example, the African Development Bank (AfDB) approved $184.2 million loan (₦29.4 billion) to encourage private investments into the Nigerian power sector. The World Bank also provided its first Partial Risk Guarantee (PRG) for US$145 million to support Nigeria's gas sector and bring more electricity to Nigerian consumers (World Bank, 2013). The first phase of the privatisation was concluded in November 2013. This was a $2.5 billion transaction that saw PHCN unbundled into six generation companies (GENCOS) (with four for thermal power and two for hydro) and eleven distribution companies (DISCOS), and sold to new private owners [9].

After the privatisation two years ago, more power projects have been put in place by private investors. Since 2014, fifteen gas power plants have been under construction to meet domestic electricity needs[10] while Nigeria's Geometric Power plans to build a 1,080 MW power plant jointly with General Electric, with the first phase of the project generating 500 MW expected to be completed in 2019 at a cost of $800 million.

### 2.1 Gas Fired Power Plants

Approximately 23% of the world's electricity generation is based on natural gas [10]. The global gas-fired generation capacity amounts to 1168 GWe. In Europe, the total electricity generation capacity is about 804 GWe, of which 22% is based on natural gas. In the United States, the total capacity is about 1039 GWe, with 400 GWe based on natural gas.

In Nigeria, a very high percentage (Fig. 2) of new generation power plants built in recent years has been natural gas fired plants. Though issues of tripped circuits, gas constraints, pipeline vandalism and plant outages according to TCN have prevented a full-fledged increase in the Country's generation capacity with an average capacity of about 4000 MW currently, current market preference for gas-fired power generation for base load generation in Nigeria and many other countries can be explained mainly by the perceived lower cost of gas-fired generation.

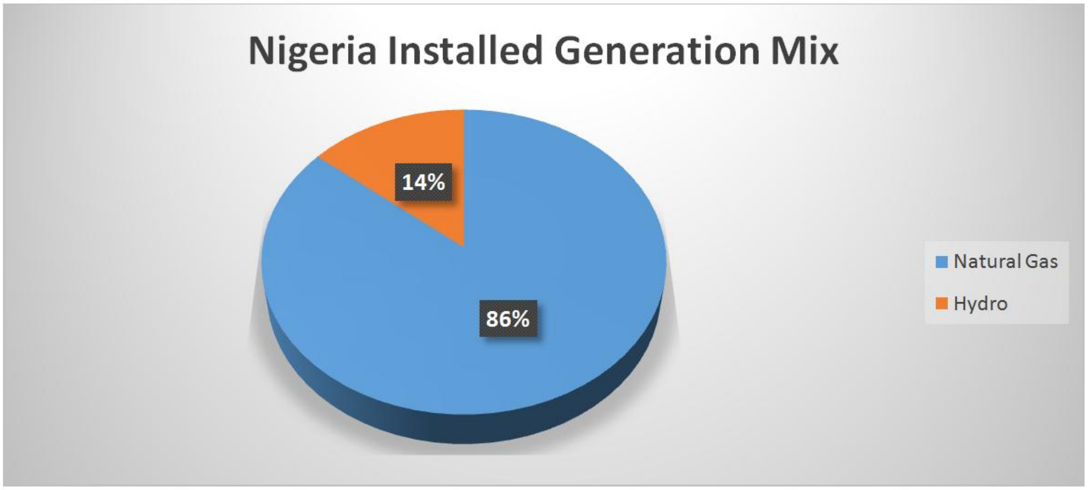



**Fig. 2. Electricity generation in Nigeria by Energy Source [11]**

Natural gas has distinct advantages over other fossil fuels with carbon content lower than that of crude oil, a heating value greater than that of either crude oil or coal, and a carbon intensity lower than oil or coal (Fig. 3). Similarly, power plants fired with natural gas have glaring economic advantages due to their excellent dynamic response in operation, short construction period and low capital investment [12].

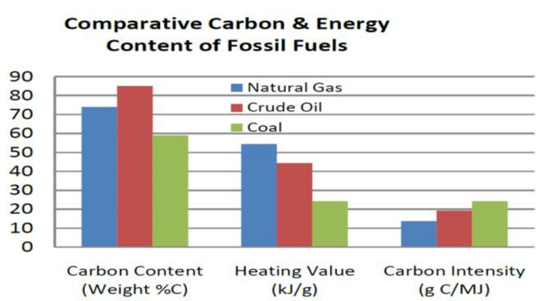



**Fig. 3. Comparative carbon and energy content of fossil fuels**
*Source: Ref. [10]*

Gas fired power plants exist in two main types; the combined-cycle gas turbine (CCGT) plants and the open-cycle gas turbine (OCGT) plants. OCGT plants were introduced decades ago for peak-load electricity generation services [13]. It is a combustion turbine plant fired by natural gas to turn a generator rotor that produces electricity and the residual heat is then exhausted to the atmosphere. OCGT plants offer moderate electrical efficiency which ranges between 35% and 42% LHV (Lower Heating Value) and can be built within a period of three to four years [14]. CCGT plants on the other hand consist of compressor/gas-turbine groups, the same as the OCGT plants, but the main improvement is that the hot gas-turbine exhaust is not discharged into the atmosphere as in the case of OCGT, rather, it is re-used in a heat recovery steam generator (HRSG). Its use in the HRSG is to generate steam which drives a steam turbine and consequently, produces additional power. The electrical efficiency of CCGT plants is expected to increase from the range of 52–60% (LHV) which is currently in place to about 64% by 2020 [13].

Above all, a CCGT plant is only attractive than an OCGT if it is fiscally reasonable. This means that the saving resulting from fuel costs due to higher efficiency in CCGT plants must be greater than the sum of the initial capital and Operating and Maintenance (O&M) costs of the plant [15].

## 3. BRIEF LITERATURE ON VALUATION METHODS

The traditional way of valuing projects before deciding on an on investment comprise of five basic methods. These are: profitability index, payback period, internal rate of return, net present value and decision tree analysis. These methods have been adjudged by its proponents to produce satisfactory results that make economic sense. They are simple, robust inexpensive and widely available in comparison to others. These methods offer the same results despite an *investors* relative *risk aversion. In these methods, the discount rate which* does not take into account the market risk is utilised to discount *future cash flows by converting* them into *cash flows* in present *value* [16]. The main drawback of these methods is the inability to correctly predict costs and benefits in the future. The methods are briefly discussed here.

### 3.1 Net Present Value

The Net Present Value (NPV) which is also called the net present worth is the most popular valuation method prior to deciding on an investment. It evaluates the worth of a project whether there is a surplus or shortage of cash flows, in present *value terms. The approach used in this method is to apply a discount rate to convert* future cash inflow and outflows to present value and find the difference between them. The formula for calculating the NPV is given below.

NPV = PV – Cost

$$PV = \frac{C_1}{1+r}$$

Where

$C_1$ = cash flow at date 1
r = discount rate

### 3.2 Payback Period (PB)

*Payback period* also called pay-off period is one of the simplest investment valuation methods. It is defined as the time it will take to recover the cash outflow of an investment from the cash inflow generated by the investment. It can be obtained from the following formula.

$$PB = \frac{Cost\ of\ Investment}{Annual\ net\ cash\ flow}$$

### 3.3 Internal Rate of Return (IRR)

The internal rate of return is defined as the discount rate needed to cause the net present value (NPV) to become zero. Simply mean that the interest rate at which the present value of the cash outflows equates that of cash inflow. It can be calculated by the following formula.

$$NPV = \sum_{n=0}^{N} \frac{C_n}{(1+r)^n}$$

Where r = internal rate of return.

Using a numerical approach, r can be found. For example, using the secant method.

$$r_{n+1} = r_n - NPV_n\left(\frac{r_n - r_{n-1}}{NPV_n - NPV_{n-1}}\right)$$

### 3.4 Profitability index (Benefit-cost Ratio)

The profitability index also known as benefit-cost ratio is obtained by finding the ratio of the present value of future cash flows of a project to the initial cash outlay required for the project.

$$Profitability\ Index = \frac{Present\ Value\ of\ Cash\ Inflows}{Initial\ Cost\ of\ Investment}$$

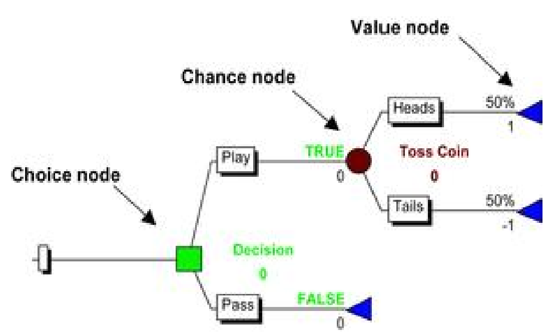
### 3.5 Decision Tree Analysis

Decision tree analysis uses a probability tree to determine the best trajectory to take when there are many sources of uncertainty and a string of decisions to make. The decision tree is made up of decision (choice), chance and end (value) nodes depicted by squares, circles and triangles respectively as shown in figure below. In this analysis, the expected *values (EV)* of competing alternatives are calculated using the formula below and the alternative with the highest EV is selected to be the best.

$$E\ V(j) = \sum_{i=1}^{N} X_{ij} P_i$$

Where

EV(j) = expected value of action j
$X_{ij}$ = payoff when action j is selected and event I occurs
Pi = probability of occurrence of event i
N = number of events




**Simple decision tree with one choice node and one chance node**

## 4. THEORETICAL FRAMEWORK

A market where a single firm can produce total business output at a lower unit cost, and thus more efficiently than two or more firms is known as a natural monopoly according to Sherer [17]. Baumol [18] stated a natural monopoly as an industry in which multiform production is more costly than production by a monopoly.

The cost structure of natural monopoly is assumed to have a constant Marginal Cost (MC) and a declining Long Run Average Total Cost (LRAC). An electric company is a classic example of a natural monopoly, where competition may lead to an inefficient market outcome. Once the huge fixed cost involved with power generation are paid, each additional unit of electricity costs very little. Having two electric companies split electricity production, each with its own power source and power lines, would lead to a near doubling of price, because of low marginal costs, high sunk costs and declining average costs.

Pricing of a natural monopoly is best if the price is equal to the average total cost (P = ATC). At this point, such firm remains in business without making supernormal profit which is normally associated with natural monopolies [19]. Since power generation in the industrial park will be from a single firm in the form of a captive generation, it is therefore seen as a natural monopoly and will therefore look to charge a price that is not less than its average total cost.

### 4.1 Regulatory and Fiscal Framework

NERC has determined that the lowest-cost new entrant generator is an open cycle gas turbine (OCGT) using natural gas. It was selected because it was considered among the most efficient power plant, in addition to availability of natural gas in Nigeria. Therefore all new entrants are expected to use an efficient technology benchmark for project evaluation and analysis. Also, NERC requires each new entrant IPP that requires a tariff beyond the MYTO benchmark to apply to the NERC for approval. In such case, the IPP will open its plans, accounts and financial model to scrutiny by the NERC, which will then apply prudence and relevance tests to determine whether such plant and site-specific costs should be allowed in the tariff [8].

The fiscal regime that the power project falls under is the Corporate Income Tax Act (CITA). Its provision [20] with regards to power plant is stated as follows: a tax free period of 3 years with an additional 2 years subject to satisfactory performance, annual capital allowance of 90% plus an additional investment allowance of 15% or 35% (for companies without the initial tax holiday period) after the tax free period, deduction limit of 66-2/3 percent of assessable profits, company income tax (CIT) of 30% and education tax of 2% of assessable profit which is not deductible for the purpose of computing CIT.

### 4.2 Technical and Financial Framework

Recent Studies revealed that the energy demand for the major industries in the industrial park is estimated at 150MW [7]. Other minor allied industries with energy demand of 50MW are also expected to be sited in the future. This then means that a total generation capacity of about 200MW will be needed to meet the demand. Gas power plant from Alstom known as GT13E2 (2012 configuration) is seen as a realistic solution to the required demand since it meets NERC benchmark of an efficient technology [7]. Also, the product meets three key business imperatives of global power producers: the need to reduce the cost of electricity; the desire to minimise plants environmental footprint and; the need for superior reliability and flexibility.

Financing is an important aspect of a power project and it can take two main forms; Corporate and project financing. Project financing is assumed for the power project in the industrial park so as to meet the objectives of this study. The project finance will include 30% of the capital costs by the shareholders (with equity rate of 15%) and the remaining 70% from international agencies with 10% interest rate by a loan which takes ten years to repay; after the construction period of 3 years, the repayments will start and continue for 10 years. Other financial terms assumed according to international financing terms include; a commitment fee of 0.1%, upfront fee of 0.1% and a minimum Debt Service Cover Ratio (DSCR) of 1.5x.

### 4.3 Methodology

This research work adopted the Discounted Cash Flow (DCF) methodology after review of literature done in the previous part. This is to enable proper evaluation of the economic viability of the gas-fired power plant by considering the time value of money. Probabilistic approach of economic evaluation using Monte Carlo simulation was employed to incorporate risks and uncertainties that is usually involved in a power project as well as to determine the influential factors that will affect the viability of the power project.

#### 4.3.1 Model

The model for evaluating the economic viability of the gas-fired power plant project adopted here was the one given according to Mian [21] for cash flow analysis. The deterministic approach in this study made use of the assessment model designed for Microsoft excels. The model includes the Net cash flow (NCF), Net Present Value (NPV), Internal Rate of Return (IRR), Payback period (PO), Profitability Index (PI), Present Value Ratio (PVR), and Maximum Cash in Red (MCR). The main equations are listed in Table 1. The model is based on one workbook with several sheets, one for each component. It also corresponds to excel inbuilt formulas with corrections made by Charnes [22] for NPV.

A stochastic model is needed to incorporate uncertainty in this analysis because the models listed above are not able to capture the effect of the interdependent relationship among several variables that are attributes of the power plant. Incorporating uncertainty is advantageous because it allows for multi-point rather than single point solution that expresses how optimistic or pessimistic the results are as shown by Charnes [22]. In the probabilistic approach, The algorithms that were chosen and used in the economic analysis conformed with all the processes involved in the simulation exercise starting from building a model, incorporating assumptions, running @RISK software, running sensitivity analysis, running Tornado chart and finally analyzing the results [21].

#### 4.3.2 Data sources

The data used in this study were according to the different framework as explained previously and were mostly gotten from the Nigerian Electricity Regulatory Commission (NERC) Library, ALSTOM, the Nigerian National Petroleum Corporation (NNPC) and studies based on international best practices particularly California Energy Commission (CEC) report.

#### 4.3.3 Model assumptions

In the evaluation of the power plant, various factors were considered. Assumptions made were based on NERC regulatory framework and downstream fiscal terms. Main factors considered include: capital expenditures ($1,044 per kW based on NERC benchmark), operational expenditures (FOM - ₦2,496,000 per MW per year and VOM - ₦920 per MWh based on NERC benchmark), feed gas price ($3.80 per Mscf based on upstream gas price to commercial sector in Nigeria (NNPC)), CITA rate (30% based on CITA), [20] plant heat rate (8.98mBtu/kWh based on technical data from ALSTOM), capacity factor (80% based on NERC benchmark), gearing ratio (Debt/Equity) (70:30 based on NERC benchmark), capacity degradation rate (0.2% per annum based on international best practices) and availability rate (98% of available capacity based on NERC benchmark). Table 2 shows a summary of the deterministic assumptions. Given these information, a base case scenario was designed for the deterministic model.

**Table 1. Model equations of profitability indicators**

| S/N | Profitability indicators | Models/Equations |
|---|---|---|
| 1. | Net Cash Flow (NCF), | Net Cash Flow= Cash Inflow - Cash Outflow |
| 2. | Net Present Value (NPV), | $NPV = \sum_{t=1}^{n} \frac{NCF_t}{(1+i_d)^t} - I_o$ |
| 3. | Internal Rate of Return (IRR), | $\sum_{t=1}^{n} \frac{NCF_t}{(1+IRR)^t} = 0$ |
| 4. | Payback period (PO), | Cash Inflow = Cash Outflow |
| 5. | Profitability Index (PI), | $PI = 1 + \frac{NPV}{PV\ of\ Capital\ Investment}$ |
| 6. | Present Value Ratio (PVR), | $PVR = \frac{NPV}{PV\ of\ Capital\ Investment}$ |

**Table 2. Deterministic model assumptions**

| Name | Value |
|---|---|
| **Technical details** | |
| Plant Spec | Open Cycle (Alstom- GT13E2) |
| Contracted Power | 200 MW |
| Plant Heat conversion rate | 8.980MBtu/KWh |
| Gas Energy content | 1.015MMBtu/Mscf |
| Capacity Degradation | 0.20% per annum |
| Heat rate Degradation | 0.16% per annum |
| Internal Losses | 0.01% |
| Average Power Availability factor | 98% |
| Dispatch Rate | 100% |
| Capacity factor | 80% |
| Sent out Efficiency | 38% |
| Auxiliary requirement | 2% |
| **Financial details** | |
| CAPEX | $208.8 Million |
| CAPEX Profile/construction years | 20%: 40%: 40% (3 years) |
| Gearing Ratio (Debt/Equity) | 70:30 |
| Cost of Debt (Interest rate) | 10% per annum |
| Upfront fee | 0.1% flat |
| Commitment fee | 0.1% flat |
| Loan term | 10 years |
| Return on Equity | 15% |
| Pre-tax WACC | 11.5% |
| Post Tax WACC | 9.4% |
| **Fiscal parameters** | |
| CITA Rate | 30% |
| Education Tax | 2% |
| Tax Holidays | 3 or 5 years |
| Capital Allowances (Plant & Equipment) | Initial: 90%<br>ITA with Tax holiday: 15%<br>ITA without Tax holiday: 35% |
| Inflation rate | 2% (US$) |
| Exchange rate | N198 / $1 |
| **NERC terms** | |
| NERC Fees | License fee: $75,000;<br>Processing fee (New): N300,000 ($1515.2) and;<br>Processing fee (Renewal): N150,000 ($757.6) |
| Capital Cost | $1,044 per kW |
| Fixed Operating and Maintenance Cost | ₦2,496,000(or $12,606) per MW per year |
| Variable Operating and Maintenance Cost | ₦920 (or $4.65) per MWh |
| NERC Annual Operating Fees | 1.5% of Turnover or kwh generated |
| **Gas price** | |
| Feed gas cost including transmission cost | $3.80/Mscf |
| **Timing** | |
| Reference Year | 2015 |
| Contract Period | 20 years |

The probability distribution assumption made for each key variable used in the evaluation of the power plant shows the probability distribution fitting of the observed value of the random variable. In some cases, triangular distribution was utilized to obtain the best estimate while in other cases, uniform distribution was employed by using equal probability between the minimum and maximum values. Also, normal distribution was used for one variable because it has values clustered around the mean value.

Table 3 shows a summary of the probabilistic assumptions used in the evaluation of the power plant using @RISK software with 10,000 iterations.

**Table 3. Monte Carlo distribution assumptions**

| Input parameters | Minimum | Likeliest | Maximum | Distribution type |
|---|---|---|---|---|
| Capital cost ($/kW) | 979 | 1044 | 1200 | Triangular distribution |
| FOM (₦/MW/yr) | 1,362,240 | 2,496,000 | 2,807,661 | Triangular distribution |
| VOM (₦/MWh) | 904 | 920 | 1188 | Triangular distribution |
| Feed gas cost ($/Mscf) | 3.30 | 3.80 | 7.00 | Uniform distribution |
| Heat rate (mBtu/kWh) | 8.877 | 8.98 | 10.588 | Triangular distribution |
| Capacity factor (%) | 65 | 80 | 92 | Uniform distribution |
| Availability rate (%) | 95 | 98 | 98 | Uniform distribution |
| Debt capital (%) | 0 | 70 | 80 | Triangular distribution |
| Capacity degradation factor (%) | 0.1 | 0.2 | 1.0 | Uniform distribution |
| CITA (%) | | 30 | | Normal distribution |

## 5. PRESENTATION AND DISCUSSION OF EMPIRICAL RESULTS

### 5.1 Deterministic Result

A spreadsheet-based deterministic economic model was utilized in the evaluation of the power plant project to analyse the investment opportunity through single point analysis. Cash flow, profitability and scenario analysis was carried out.

#### 5.1.1 Cash flow analysis

Fig. 4 shows the project net cash flow which is forecasted to be positive for most years. There was a negative cash flow before 2019 because those years are the construction period of the power plant and where capital is mostly invested, but after that period, net cash flow will be positive throughout the power generation period. This is illustrated in Fig. 5.

#### 5.1.2 Profitability analysis

The cash flow spreadsheet model result for the gas power plant as presented in Table 2 is the result for the key profitability indicators. The outcome of the cash flow analysis of the power plant project using the base case scenario is excellent because at a discount value of 15%, it yielded a positive NPV of $10.8 million after tax.

According to investment theory, projects that have positive NPV values are implementable. It is assumed that the discount factor will handle inflation and some uncertainty in the time value of money. However, to quantify the size of the investment, another profitability indicator, the PVR is used. Projects with positive PVR are doable as can be seen in Table 1 where PVR is 0.1 at a discount factor of 15%.

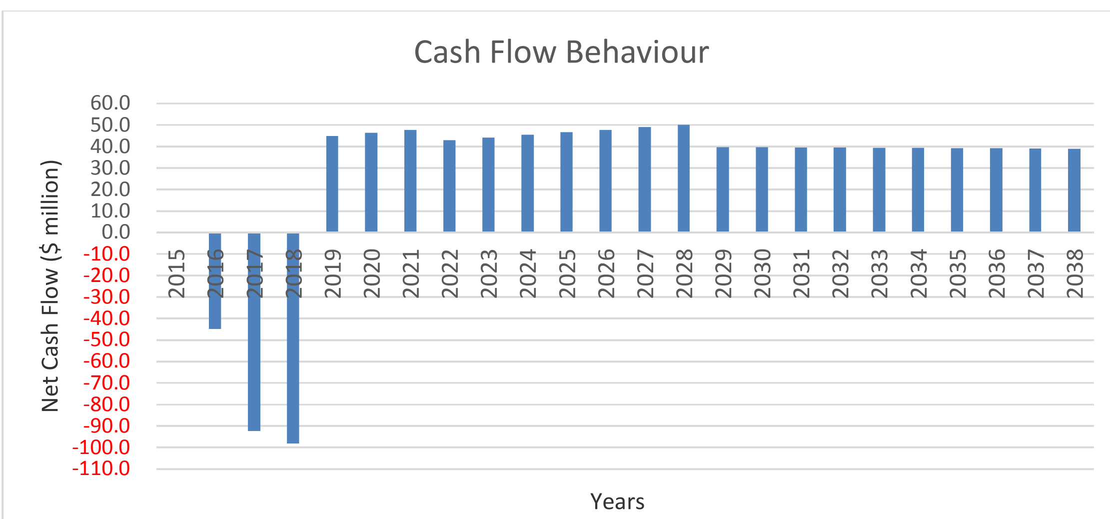



**Fig. 4. Cash flow chart**

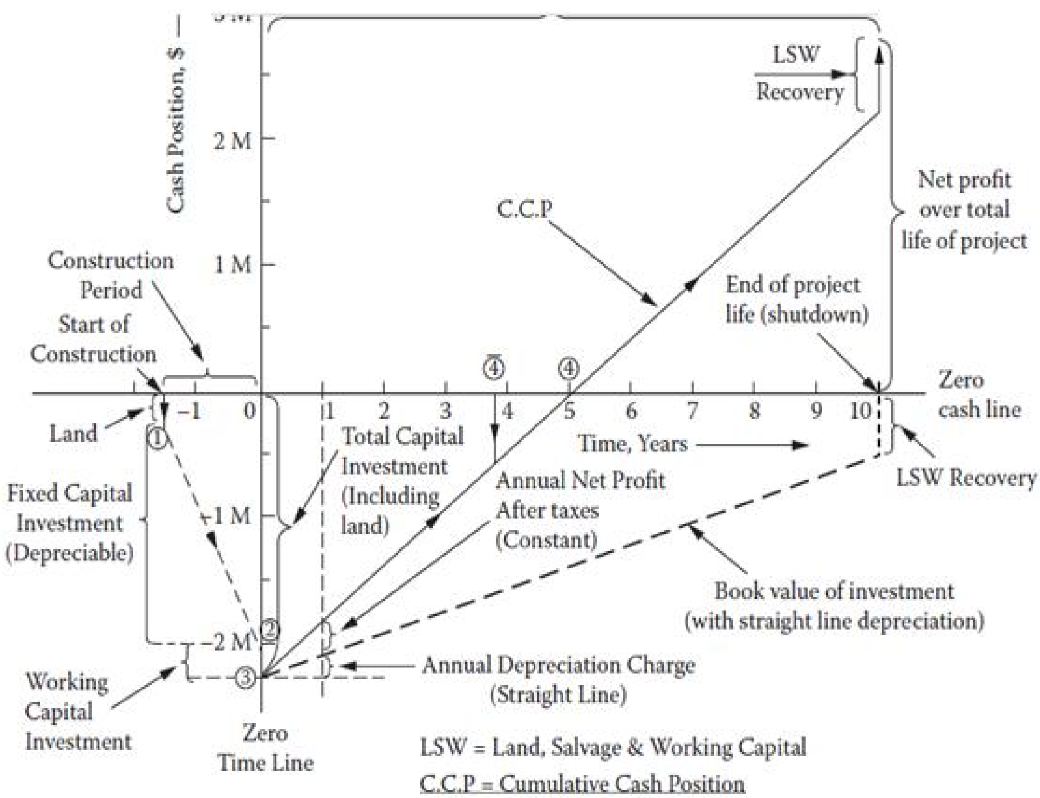



**Fig. 5. Cumulative cash from project inception to end of low at year end of project**

*Source: Petroleum Economics and Engineering, Third Edition, Hussein K. Abdel-Aal, Mohammed A. Alsahlawi, December 14, 2013 by CRC Press Reference - 478 Pages - 16 Color & 114 B/W Illustrations ISBN 9781466506664 - CAT# K14628*

Also, Profitability Index which measures the efficiency of the investment was obtained as 1.1. This indicates that the total return on the investment dollar is $1.1. The undiscounted unit technical cost of $73.29 per MWh shows how much it costs to generate a megawatt hour of electricity. This amount is lower than the power tariff which is $85.52 per MW (as shown in Table 5) and the decision rule is to accept a project when the power tariff is higher than the unit technical cost. This simply indicates that what the project will cost in the long run will be lower than the revenue it generates, hence, making it economically justified. In addition, an Internal Rate of Return of 16% was obtained which is above the hurdle rate for power plant investors in Nigeria [6].

Furthermore as depicted in Table 4, the maximum cash in red is $235.6 million which is equivalent to the total direct investment of the project. This amount is the maximum cash flow exposure or maximum cumulative cash outlay in the project life cycle. The project also pays back in the 9$^{th}$ year (2023) which is after 5 years of power generation. From Fig. 6, it can be seen that at 2023 the investment break even because cumulative cash flow is negative at the end of 2022 and positive at the end of 2023. However, the precise the breakeven point in year 2023 can be seen roughly on a graph, showing pay back (PB) as the point in time when cumulative cash flow crosses from negative to positive. In Fig. 6, break even may occur any time in year 2023 at the moment when the cumulative cash flow becomes 0. Since we have only annual cash flow data, we assume the year's cash flows are spread evenly through the year i.e. it is represented by the straight line between 2023 end data points and payback period is estimated by interpolation.

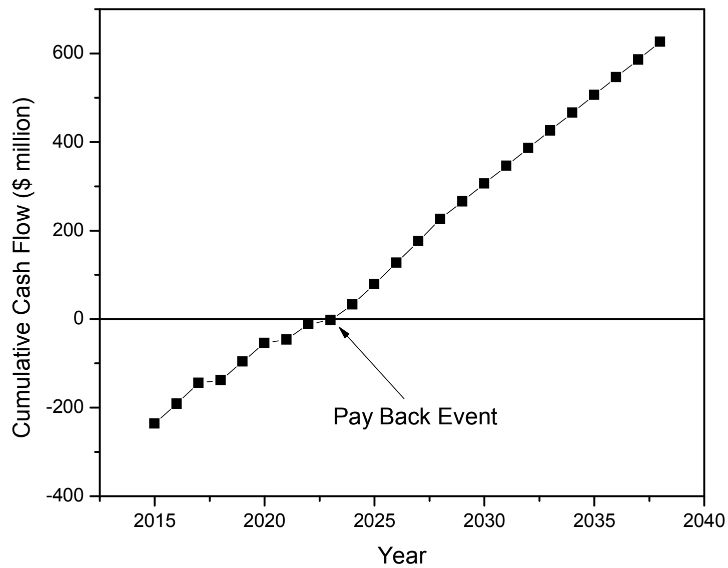



**Fig. 6. Cumulative cash flow at year end**

**Table 4. Key profitability indicators**

| Indicator | Unit | Value |
|---|---|---|
| NCF | $mm | 624.1 |
| NPV@ 15.0% | $mm | 10.8 |
| IRR | $mm | 16.0% |
| PVR@ 15.0% | | 0.1 |
| PI@ 15.0% | | 1.1 |
| Max. Cash Flow Exposure | $mm | -235.6 |
| Payout Year | | 2024 |
| Payout Period | | 9 |
| Unit Technical Cost | $/MWh | 73.29 |
| Direct Investment | $mm | 235.6 |

Overall, the power project is profitable and economical under the base case scenario analysed but the power tariff which has generated the cash flow would also be carefully analysed and compared to the NERC benchmark tariff so as to determine if power users in the industrial park will be willing to buy electricity at that price or find other alternatives if possible.

### 5.1.3 Power tariff analysis

The power tariff used for the base case scenario is presented in the table below (Table 3) with capacity and energy charge taking a large percentage of the total tariff. The high energy charge is as a result of the feed gas price assumed in the base case and since it is a pass through cost, the cost of gas is passed to the power consumers. The capacity charge covers all other cost of the investor and also provides reasonable returns to investors.

**Table 5. Power tariff at power generation start year**

| Power Tariff @ Prod Start | Unit | Charge |
|---|---|---|
| Capacity charge | $/MWh | 44.85 |
| FOM charge | $/MWh | 2.03 |
| VOM charge | $/MWh | 5.03 |
| Energy charge | $/MWh | 33.62 |
| Total charge | $/MWh | 85.52 |

It is important to note that the power tariff at power generation start year (Table 5) is a reasonable tariff that should be accepted by NERC in granting license according to the regulatory framework explained in the previous chapter of this project. Also, power users in the industrial park should be willing to pay this tariff since it is close to NERC's MYTO benchmark tariff of $84 per MWh for grid power generation. The slight increase is as a result of a much higher availability rate of 98% (compared to MYTO model of 95%) that will be enjoyed in the industrial park.

### 5.1.4 Financial analysis

Since 70% of the investment will be debt capital, it is important to determine if the debt service cover ratio forecasted will make banks willing to invest in the power project or not.

The total debt generated for the project is $146.2 million which will be repaid for ten years starting from 2019 which is the year the project starts making revenue. The average DSCR and minimum DSCR is forecasted to be 2.7 and 2.04 respectively (Fig. 5). The Debt Service Cover Ratio is a measure of a company or project's ability to cover or pay off debt. It refers to the amount of cash or cash flow required to pay off a debt and how much total debt actually is. The higher the debt service cover ratio, the easier it is to borrow money for the investment.

Fig. 7 shows that after the construction period where the DSCR remains zero, the power project has a DSCR over 2.0 from the power generation start year which is above the minimum of 1.5 stated in the financial framework of this project. This value indicates that this project will be able to pay off bank debt when borrowed.

#### 5.1.5 Scenario analysis

Analysis of the impact of fiscal terms on the profitability of the power plant is important to enable investors pick the most optimal incentive when taking investment decision. Table 6 shows the impact of Tax Holiday on the Power Project Profitability.

Table 6 shows that the power project is more profitable and economical when a tax holiday of 3 years is granted compared to choosing an option without tax holiday. It generated a NPV of \$10.8 million (compared to \$0.15 million without tax holiday) and an IRR of 16.0% (compared to 15.01% without tax holiday). Also, the PVR and PI is 0.06 greater with the tax holiday than without it.

The best case however is found with the option that provides a tax holiday of three years plus an additional two years based on merit which then gives a total of 5 years tax holiday. This generated a NPV of \$17.6 million, IRR of 16.61% and also a shorter payback period of 8 years (compared to other options with 9 years payback).

### 5.2 Probabilistic Results

Probabilistic plots of acceptable ranges of key profitability indicators including the available energy and payback period is shown in table 7 to enhance the evaluation of the plant. Thereafter, the results of sensitivity analysis using Tornado and Spider charts in order to see the effect of different cost parameters on NPV, IRR, PI and DSCR is illustrated as a barometer for economic evaluation.

The range of values allowable for best economic outcome is shown in Table 7 based on the probabilistic approach starting with a 90% certainty that available energy will range between 1098 GWh and 1503 GWh once power generation begins. The NPV distribution (Table 7 and Fig. 8) shows that a NPV breakeven occurs when the project NPV is zero and rises to a maximum of \$83,900,000 where an intrinsic probability of 62.8%; a high confidence interval is obtained for the feed gas price and other variables. Positive values of the mean, median and mode also indicates that the project has a great chance of being profitable as shown in Fig. 6.

Similarly, the distribution for the IRR, PVR and PI shows a 62.8% certainty of having an Internal Rate of Return above 15% (can be up to 23.91%) hurdle rate for investments in Nigeria, PI above 1.0 (can be as high as 1.568) and PVR above zero (can be as high as 0.568) as shown in table 7. The Payback period distribution shows a 97.8% certainty of recovering the initial investment between 7 and 10 years (Table 7). This is a reasonable payback period since investors always look to recover their investments as quick as possible.

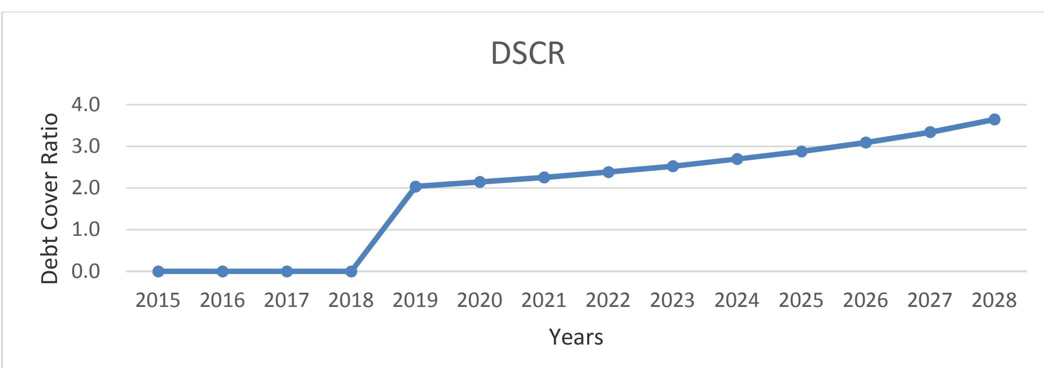



**Fig. 7. Forecast of the Debt Service Cover Ratio (DSCR)**

**Table 6. Impact of tax holiday on the power project profitability**

| Indicator | Unit | Option 1 Without tax holiday (CA of 90% and ITA of 35%) | Option 2 With tax holiday of 3 years (CA of 90% and ITA of 15%) | Option 3 With tax holiday of 5 years (CA of 90% and ITA of 15%) |
|---|---|---|---|---|
| NCF | \$mm | 593.7 | 624.1 | 655.9 |
| NPV@ 15.0% | \$mm | 0.15 | 10.8 | 17.6 |
| IRR | \$mm | 15.01% | 16.00% | 16.61% |
| PVR@ 15.0% | | 0.00 | 0.06 | 0.10 |
| PI@ 11.5% | | 1.00 | 1.06 | 1.10 |
| Payout year | | 2024 | 2024 | 2023 |
| Payout period | | 9 | 9 | 8 |

**Table 7. Probabilistic output forecast based on the desired output**

| Indicator | Certainty (%) | Lower range | Upper range | Desired output |
|---|---|---|---|---|
| Available energy | 90 | 1098 GWh | 1503 GWh | At least constant |
| NPV | 62.8 | \$0 | \$83,900,000 | NPV ≥ 0 is attractive |
| IRR | 62.8 | 15% | 23.91% | IRR>15% hurdle rate is attractive |
| PI | 62.8 | 1 | 1.568 | PI>1 is attractive |
| PVR | 62.8 | 0 | 0.568 | PVR >0 is attractive |
| Payback period | 97.8 | 7 years | 10 years | Payback period<10 years is fine. |

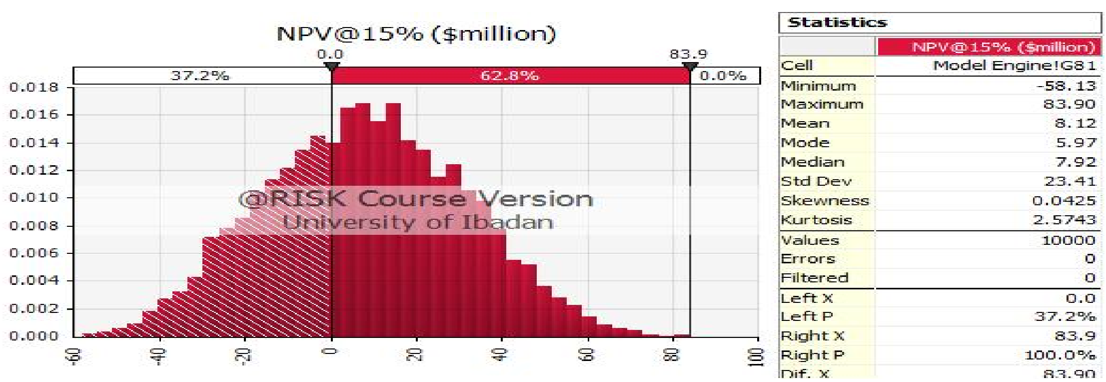



**Fig. 8. Desirable range of NPV (NPV of zero and above)**

Generally, the probabilistic approach shows that the power project has nothing less than a 62.8% certainty of being profitable and economical considering various uncertainties that will be involved in the course of the project. To drive home the analysis further, it is important to know the key variables that investors should look out for which really can affect the profitability of the project. This is carried out using sensitivity analysis with tornado and spider charts.

### 5.2.1 Sensitivity analysis

Figs. 9 to 11 shows the sensitivity analysis of uncertain variables on the key profitability indicators, available energy and the minimum Debt Service Cover Ratio (DSCR). The sensitivity analysis shows the various effects of changes in the value of key input parameters (like costs, capacity factor, Heat rate, Debt Capital, CITA etc.) on the economic indices.

Fig. 9 shows capacity factor and availability rate as the only two variables that affect the available energy from the power plant with the capacity factor being the most sensitive variable. The variables have a positive relationship with the available energy, therefore, increase in the capacity factor or availability rate leads to increase in the available energy from the plant.

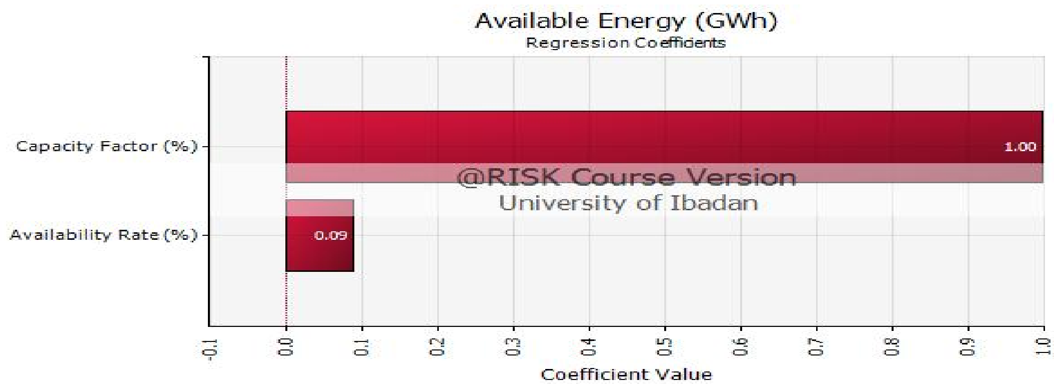



**Fig. 9. Available energy sensitivity chart**

In contrast, all input variables affected the NPV as shown in Fig. 10. The capacity factor was the most sensitive variable with an impact as high as 76% followed by the Debt Capital and capital cost down to the variable operating and maintenance cost (VOM) which had the least impact.

In the case of IRR as shown in Fig. 11, the capacity factor remains the most sensitive variable with 74% impact level while the least sensitive variable was the heat rate which has negative impact on the IRR. This implies that a higher heat rate makes the project less profitable.

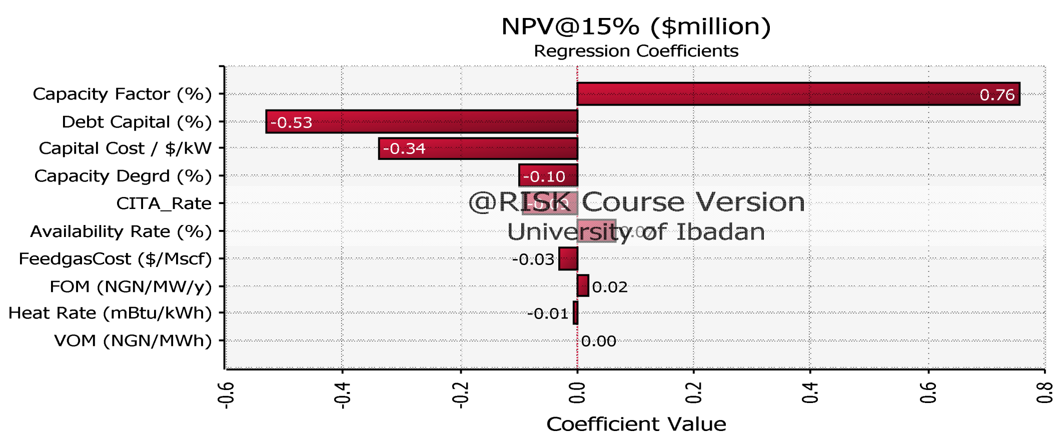



**Fig. 10. NPV sensitivity chart**

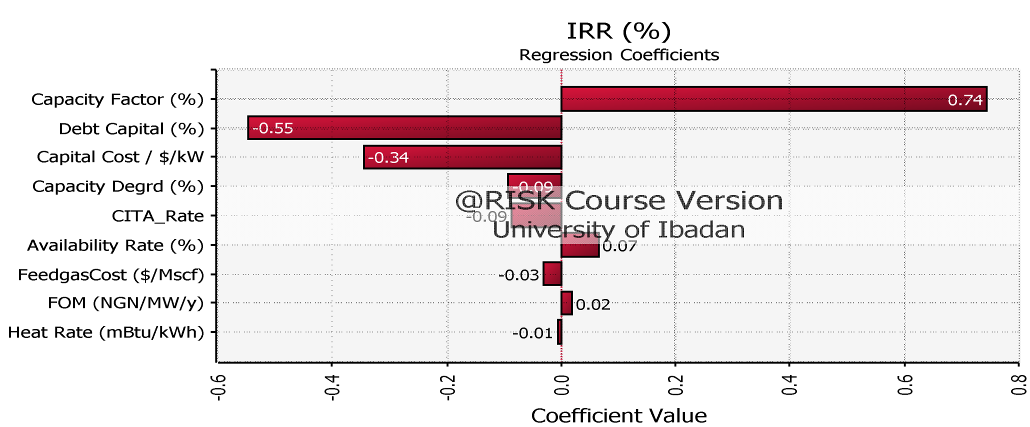



**Fig. 11. IRR sensitivity chart**

It was equally observed that the sensitivity analysis of Profitability Index (PI) and the Present Value Rate (PVR) followed the same trend with the IRR.

However, the payback period followed a slightly different trend with the capacity factor still remaining the most sensitive parameter followed by the debt capital and capital cost but the impact of capacity degradation rate and CITA rate was reduced as the availability rate had a higher impact while the fixed operating and maintenance cost was the least sensitive. This shows that higher plant availability leads to a reduction in payback period.

In general, capacity factor is the most sensitive parameter in that minimal perturbations of it can greatly affect the profit earning of the project. Also, it is seen from figures presented that, increase in the capacity factor reduces the payback period but increases the value of NPV, IRR, PI and PVR.

Sensitivity analysis of one other important output parameter (Minimum Debt Service Cover Ratio) is shown in Fig. 12. The figure indicates debt capital as the most sensitive parameter followed by the capacity factor and the capital cost being the least sensitive. The figure also shows that the more the percentage of debt used to finance the project, the more difficult it will be to achieve the required DSCR as increase in debt capital leads to a decrease in DSCR. Similarly, increase in capital cost leads to a decrease in the DSCR while increase in the capacity factor leads to an increase in the DSCR.

**5.2.2 Tornado chart**

Tornado charts (Figs. 13 and 14) are used to measure the effect of changes in any variable on selected forecasts (NPV, Payback period and DSCR). It helps to know the extent to which input parameters can affect the selected forecasts.

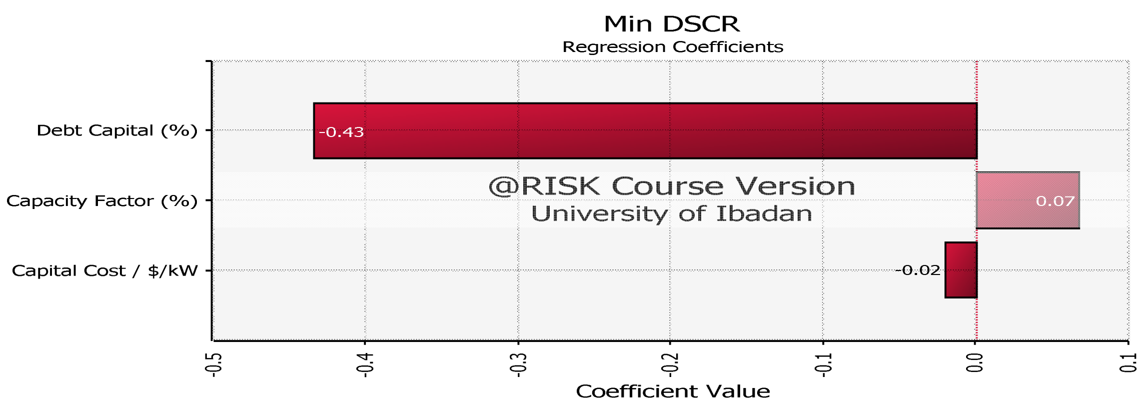



**Fig. 12. Minimum debt service cover ratio sensitivity chart**

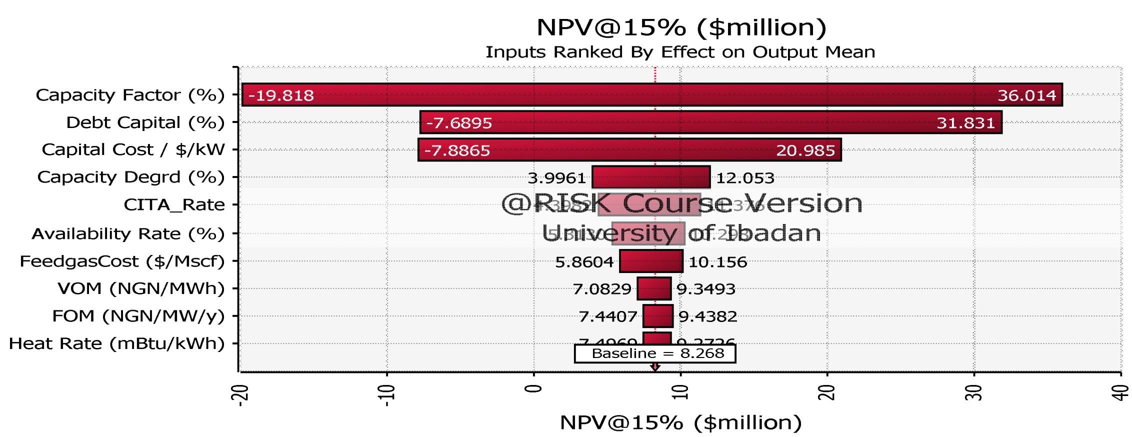



**Fig. 13. NPV tornado chart**

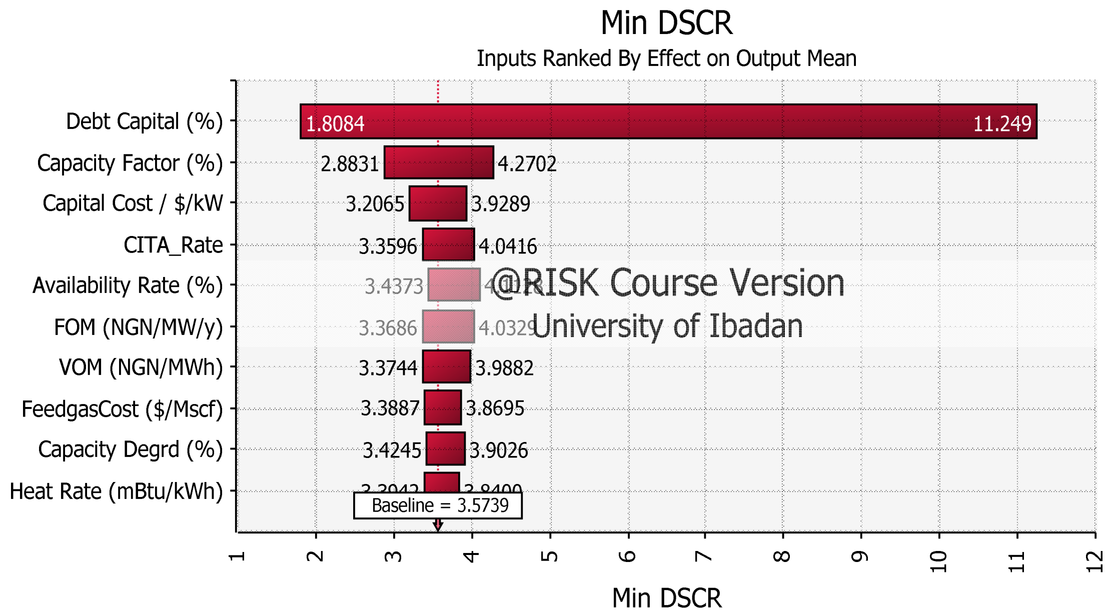



**Fig. 14. DSCR tornado chart**

Fig. 13 shows the extreme values of NPV with respect to the effect of the changes made to the variable parameters. These figure shows that three parameters (Capacity factor, Debt Capital and capital cost) have very high impact on the NPV and can make the NPV negative thereby altering the profitability of the plant if not properly monitored. Similarly, these parameters can make the project payback period to be over 9 years (figure not included) which means capital will be tied down for a longer period of time which is undesirable.

Fig. 14 show that debt capital has the highest impact on the Debt Service Cover Ratio with a baseline of 3.57. This shows that borrowing above 70% of capital required will make the project less profitable and more difficult to service debt.

Summarily, the probabilistic approach has enhanced the evaluation of the power plant by determining the degree of certainty with which desired output can be measured. In addition, sensitivity of output to changes in input parameters was also determined alongside the effect of increase or decrease in the input variables on the economic indices.

Overall, the profitability of the power plant project is highly dependent on having a capacity factor not less than 80%, capital cost not more than $1,044 per kW and a gearing ratio of not more than 70% debt as shown by the sensitivity analysis and also confirmed by the Tornado chart.

## 6. CONCLUSION

This study has shown that the gas fired power project in the industrial park is economically viable and will give good returns on investment under existing fiscal and regulatory framework in Nigeria. With the help of the range of the economic indices shown in the results obtained, it is a project that investors will be willing to undertake. However, the capital cost of the project, capacity factor of the plant and the debt used in financing the project will be key to making final investment decision on the project.

Based on the findings from these analyses, the following recommendations were made: the power project at the industrial park should be carried out based on existing fiscal terms and regulatory framework in Nigeria as results have shown that gas fired generation is profitable and economical. However, capacity factor of 80%, gearing ratio with 70% debt and capital cost of $1,044 per kW should be properly monitored as their effect will alter the tariff which then affects the profitability of the power project.

Also, government should encourage and provide incentives for captive power generataion as results from these analysis shows that there is just little difference between the tariff charged by grid power generators and an efficient captive power generator. This will encourage a decentralised power generation system where different regions will be able to generate their own power and reduce the load on the national grid.

## COMPETING INTERESTS

Authors have declared that no competing interests exist.

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