© 2015 Oladipupo A. Ogunnubi
AN ECONOMIC VALUATION OF SOLAR ENERGY POTENTIAL IN NIGERIA

BY

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THESIS

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ABSTRACT

Nigeria has a population of over 160 million, and just over 50% have electricity access. Many initiatives promote solar energy development to mitigate Nigeria’s power challenges. This work shows an economic valuation of the solar photovoltaic (PV) potential in Nigeria. Assuming a 100 megawatts (MW) capacity upgrade, this paper compares distributed residential-scale and centralized utility-scale PV configurations under lower 2013 and higher 2016 PV project cost assumptions. Metrics such as levelized cost of energy (LCOE), benefit-cost ratio (BCR), net present value (NPV), and payback period, are assessed. A sensitivity analysis is performed to consider the effects of inflation.

Our results show that all expected LCOE values under 2013 cost assumptions are above $0.30 per kilowatt-hour (kWh) while expected LCOE values for the 2016 cases are less than $0.30 per kWh. Expected BCR values for residential PV at 2013 PV costs increased from 1.01 to 3.37 before and after inflation effects, respectively. Expected BCR values for the utility PV case increased from 1.36 to 3.93 before and after inflation effects. Results show that expected NPV results for all 2016 cost scenarios are greater than those for 2013 scenarios. In addition, two scenarios show no possibilities of payback while the two other scenarios break-even as early as 6 and 6.5 years at best.

In light of the major effect that PV project costs have on overall LCOE, it is recommended that government provide incentives that directly tackle initial project costs. These incentives should be founded and enforced on solid renewable energy policy, framework, and infrastructure.

In terms of future work, we look to include reliability benefits and transmission expansion economics into the economic model as solar capacity upgrades may require transmission system upgrades. There is also an opportunity to apply optimization theory to obtain the conditions for which LCOE, BCR, NPV, and payback are optimized under specific economic and power system constraints.
To my dear mother and family for their constant love and faithful prayers.  
To my good friends and colleagues for their great support and encouragement.  
To God Almighty for His amazing grace, divine favor, and beautiful blessings.
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Chapter 1

INTRODUCTION

1.1 Overview of Energy Development in Africa

Key issues in Africa’s energy sector are insufficient generation capacity and poor system reliability [1]. Scholars, experts, entrepreneurs, corporations, and international development agencies are leveraging their resources to support Africa’s energy development efforts. A noteworthy initiative is Power Africa by the US Agency for International Development (USAID). Power Africa has kindled interest in, mobilized financial support for, and incentivized technical assistance toward Africa’s energy situation [2], [3]. Power Africa promotes renewable energy. This thesis focuses on the economics of solar photovoltaic (PV) applications in Nigeria.

1.2 Nigeria Overview

Nigeria has a power capacity of under five gigawatts, a population of over 160 million, and just over 50% have electricity access [2], [4]. The inadequate state of electricity in Nigeria both in terms of transmission and generation capacity are noted in [1], [2], [4], [5], [6]. More than 40% of its citizenry is under 15 years and it has a high population growth rate [6]. Thus, the energy demand is high. With a strong solar radiation profile [6] and a thermal-based generation mix [7], Nigeria could include solar in its power portfolio. In light of these factors, we are evaluating the potential for solar power in Nigeria. A Pan-African study focused on rural electrification, residential PV, and diesel generation was conducted in [8]. Our past work involved a similar study with a focus on solar energy potential in Nigeria [9]. Herein, we build upon [9] by performing a sensitivity analysis on our past results to consider inflation rate effects.
1.3 Research Motivation

The first motivating factor for this work is to support the energy development efforts in Africa. In parallel with Power Africa [2], this work is an effort to support Nigeria with technical assistance as the country strives to improve its power sector.

Another motivating factor is the global demand for cleaner fuels due to excess greenhouse gas (GHG) emissions. According to Energy Information Administration (EIA), China and the United States account for over a third of global GHG emissions. China, the United States, Russia, and India account for over 50% of global carbon emissions. The main reason for this is that these economies are highly industrialized. These countries have sizable power generation capacities with a significant portion fueled by conventional thermal resources, such as coal and petroleum, which have high carbon content.

With respect to Nigeria, the country emits very little carbon in comparison with the United States and other leading economies in the Americas, Europe and Asia. This is in correlation with the power capacity in Nigeria, which is much lower relative to other major economies. Some evidence of this is seen in Table 1.1.

Nigeria also looks to diversify its current generation mix and integrate renewable resources like solar, which leads to a third motivating factor for this research. Nigeria’s generation mix mainly comprises of petroleum and some hydro resources. As a result, Nigeria’s power sector is extremely sensitive to economic fluctuations affecting crude oil. Thus, Nigeria looks to include renewable sources to diversify the country’s generation portfolio and reduce overall sensitivity to and dependence on petroleum.

Yet another motivation for this work is related Nigeria’s solar profile. As shown in Figures 1.1, 1.2, and 1.3, there is a significant solar profile in Nigeria compared to the United States and Germany. Germany leads the world in solar capacity with over 30 gigawatts (GW) installed and the country experiences a solar intensity of about 1300 kilowatt-hours per squared-meter (kWh per m\(^2\)) at maximum (see Figure 1.2). Contrarily, Nigeria has no significant solar capacity but has a solar profile in the range of 1600 to 2400 kWh per m\(^2\) as seen in Figure 1.3. Thus, it is deemed relevant to economically value the solar resource and any potential benefits it may serve Nigeria.
Table 1.1: An economic comparison between Nigeria and USA

<table>
<thead>
<tr>
<th>Economic Term</th>
<th>USA</th>
<th>Nigeria</th>
<th>Data Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013 GDP ($)</td>
<td>16,800 billion</td>
<td>522 billion</td>
<td><a href="http://www.worldbank.org">www.worldbank.org</a></td>
</tr>
<tr>
<td>Population</td>
<td>340 million</td>
<td>170 million</td>
<td><a href="http://www.prb.org">www.prb.org</a></td>
</tr>
<tr>
<td>Power Capacity (GW)</td>
<td>1000</td>
<td>4 to 5</td>
<td><a href="http://www.eia.gov">www.eia.gov</a></td>
</tr>
<tr>
<td>Solar Capacity (GW)</td>
<td>15</td>
<td>0</td>
<td><a href="http://www.eia.gov">www.eia.gov</a></td>
</tr>
<tr>
<td>Electricity Production (Total kWh)</td>
<td>4200 billion</td>
<td>27 billion</td>
<td><a href="http://www.worldbank.org">www.worldbank.org</a></td>
</tr>
<tr>
<td>Electricity Consumption (kWh per Capita)</td>
<td>12461</td>
<td>140</td>
<td>Power Africa</td>
</tr>
<tr>
<td>CO2 Emissions (kg per Capita)</td>
<td>17,500</td>
<td>490</td>
<td><a href="http://www.worldbank.org">www.worldbank.org</a></td>
</tr>
<tr>
<td>Education System</td>
<td>Very Strong</td>
<td>Needs Improvement</td>
<td>-</td>
</tr>
<tr>
<td>Research Capabilities</td>
<td>Very Strong</td>
<td>Needs Improvement</td>
<td>-</td>
</tr>
</tbody>
</table>

Figure 1.1: Contour showing the solar radiation profile for USA (Source: SolarGIS)
Figure 1.2: Contour showing the solar radiation profile for Germany (Source: SolarGIS)
1.4 Thesis Overview

Our study approach was to gather and enter input key economic data on both Nigeria and solar PV systems. Solar PV performance was estimated based on the data. Energy revenue and costs were projected using an economic model. Additional factors including incentives, and credits were also considered. Key valuation metrics, such as net present value and benefit-cost ratio, were then calculated and evaluated for both distributed and centralized PV cases. Figure 1.4 shows key steps in our technical approach.
In Chapter 2, there are four key sections. Section 2.1 describes methods for estimating PV performance. Section 2.2 contains details about the economic model employed in this thesis. Section 2.3 defines the valuation metrics of interest, such as payback period, and levelized cost of energy. In Section 2.4, we demonstrate the application of Monte Carlo to our analysis.

Chapter 3 pertains to simulation details. In Section 3.1, we give details about annual solar PV performance estimates for Nigeria. In Section 3.2, we state the details of economic inputs and assumptions made. In Section 3.3, we test the economic model developed for our simulations.

In Chapter 4, simulation results are shown. Results specific to distributed and centralized PV configurations are discussed in Sections 4.1 and 4.2, respectively. Sensitivity of results to inflation are stated in Section 4.3. A comparison and summary of all key output metrics (such as net present value and benefit-cost ratio) are detailed in Sections 4.4 and 4.5.

Chapter 5 contains our conclusions and future work, which are in Sections 5.1 and 5.2, respectively.

Figure 1.4: Diagram showing key steps in the study approach
Chapter 2

LITERATURE REVIEW

2.1 PV Performance Estimation

Forecasting the performance of solar photovoltaic systems poses a challenge due to the stochastic nature of factors, such as climate, that affect expected solar insolation at any given point in time. Various tools and approaches have been developed by scholars and industry experts to solve this challenge. Two of these PV estimation methods are described in Sections 2.1.1 and 2.1.2.

2.1.1 PVWatts Calculator

As described in [10], PVWatts Calculator is an online calculator that estimates the energy production and cost of energy of a grid-connected photovoltaic (PV) systems using solar resource data for locations throughout the world. It allows homeowners, small building owners, installers and manufacturers to develop preliminary estimates of the cost and performance of potential PV installations. PVWatts Calculator was created by the National Renewable Energy Laboratory (NREL), a federal laboratory that is overseen by the US Department of Energy (USDOE).

2.1.2 Peak-Hours Approach

As illustrated in [11], the peak-hours approach estimates PV performance based on two key assumptions:

1. Maximum power point trackers (MPPTs) ensure that solar PV panels operate at the knee of the I-V curve in order to keep daily system efficiency constant.
2. The average system efficiency per day is the same as the efficiency of the system at 1 unit of sun intensity.

A more detailed formulation for this approach is shown in (2.1) to (2.7). Consider the following terms:

- \(1SUN\) = 1 unit of sun intensity (in kW per m\(^2\))
- \(E_D\) = Daily solar energy (in kWh per day)
- \(E_Y\) = Yearly solar energy (in kWh per day)
- \(P_{AC}\) = AC power (in kW)
- \(A\) = Geographic area covered by solar PVs (in m\(^2\))
- \(\eta_{sys}\) = System efficiency
- \(\eta_{1SUN}\) = Efficiency at \(1SUN\)
- \(INS_D\) = Daily solar insolation (in kWh per m\(^2\) per day OR kW per m\(^2\))
- \(INS_{D-1SUN}\) = Daily solar insolation relative to \(1SUN\) (in hours per day)
- \(DGR\) = Solar module degradation factor

AC Power at 1 unit of sun intensity is given by:

\[
P_{AC} = 1SUN \times \eta_{1SUN} \times A
\]  \hspace{1cm} (2.1)

Making \(A\) the subject of the formula, we get:

\[
A = \frac{P_{AC}}{1SUN \times \eta_{1SUN}}
\]  \hspace{1cm} (2.2)

The daily energy produced by a solar PV system is a function of system efficiency and insolation data in the following manner:

\[
E_D = INS_D \times A \times \eta_{sys}
\]  \hspace{1cm} (2.3)

And from (2.2):

\[
E_D = INS_D \times \frac{P_{AC}}{1SUN \times \eta_{1SUN}} \times \eta_{sys}
\]
\[ E_D = P_{AC} \times \frac{INS_D}{1SUN} \times \frac{\eta_{sys}}{\eta_{1SUN}} \]

On an annual basis, assuming each month has 30 days, the formula for solar energy estimation becomes:

\[ E_Y = \sum_{i=1}^{12} [P_{AC} \times 30 \times INS_{D-1SUN}(i)] \]  

(2.6)

where \( INS_{D-1SUN}(i) \) is the average daily insolation at 1SUN in month \( i \). Now, considering the degradation of PV modules:

\[ E_Y = \sum_{i=1}^{12} [(1 - DGR)^i \times P_{AC} \times 30 \times INS_{D-1SUN}(i)] \]  

(2.7)

In this thesis, the peak hours approach was used.

2.2 Economic Model

The economic model for this study was based on cash flow and valuation frameworks in [11] and [12]. There are three main aspects of the economic model. The first is the present time or year zero analysis. Next are the projections from year 1 to project end, which is taken to be 30 years. The third aspect is an analysis of additional project cash flows at year end perhaps due to salvage value expected at project life. The itemized list shows key terms used in the model formulation.

- \( t \) = Index of time (typically per year)
- \( T \) = Total life/duration of project/investment opportunity (in years)
- \( PVC_t \) = PV project cost (in $ per W)
- \( MP_t \) = Market price for energy at year \( t \) (in $ per kWh)
• $DA_t =$ Depreciation and amortization at year $t$ (in $)
• $IC_t =$ Investment costs at year $t$ (in $)
• $FC_t =$ Fixed costs at year $t$ (in $)
• $VC_t =$ Variable costs at year $t$ (in $)
• $PT_t =$ Property taxes/costs in year $t$ (in $)
• $TC_t =$ Total costs at year $t$ (in $)
• $R_t =$ Revenue at year $t$ (in $)
• $EBITDA_t =$ Earnings before interest, taxes, depreciation, and amortization in year $t$ (in $)
• $EBIT_t =$ Earnings before interest and taxes at year $t$ (in $)
• $Int_t =$ Interest expense at year $t$ (in $)
• $Tax_t =$ Taxes at year $t$ (in $)
• $EBT_t =$ Earnings before taxes at year $t$ (in $)
• $NI_t =$ Earnings or net income at year $t$ (in $)
• $SV_T =$ Salvage value at project life (in $)
• $BV_T =$ Book value at project life (in $)
• $ANI_T =$ Additional net income at project life (in $)
• $ACF_T =$ Additional cash flow at project life (in $)

2.2.1 Year Zero Analysis

The aim of each stage of the model is to obtain the year-end cash flows over the project life. Through (2.8), $CF_0$ is obtained. Generally, due to start-up capital costs, $CF_0 < 0$:

\[
IC_0 = PVC_0 \times DCPowerRating
\]

\[
NI_0 = -IC_0
\]

\[
CF_0 = NI_0
\]
2.2.2 Analysis from Year One to Project End

By year 1, project is assumed to be operational and actively generating revenue. For each year \( t \) (where \( 1 \leq t \leq T \)), (2.9) is used:

\[
R_t = E_t \times MP_t \\
EBITDA_t = R_t - TC_t \\
EBIT_t = EBITDA_t - DA_t \\
EBT_t = EBIT_t - Int_t \\
NI_t = EBT_t - Tax_t \\
CF_t = R_t - TC_t - Tax_t
\]  \hspace{1cm} (2.9)

2.2.3 Project End Analysis

At project life, the new \( CF_T \) is the sum of the previous \( CF_T \) obtained during the second analysis stage and \( ACF_T \) obtained from (2.10):

\[
ANI_T = SV_T - BV_T - Tax_T \\
ACF_T = ANI_T
\]  \hspace{1cm} (2.10)

2.3 Valuation Metrics and Terms

2.3.1 Payback Period

From [11], [12], [13], payback period is a measure of the time (typically in years) that it takes for a project to "break even" or recover its initial investment funds.

2.3.2 Time Value of Money (TVM) and Net Present Value (NPV)

As described in [12], [13], TVM theory emphasizes that money today (in the present) is worth more than money tomorrow (in the future) because of the uncertainty of the future. Also, present money can be invested ahead of future money at some positive rate of return. Consequently, all future money or "cash flows" are subject to a market-based "discount rate" that is used to obtain the corresponding "present value" of monies expected in the future. The mathematical formulation
for present value is shown in (2.11):

\[ PV_{\text{cashflows}} = \sum_{t=0}^{T} \frac{CF_t}{(1 + r)^t} \] (2.11)

where,

- \( PV_{\text{cashflows}} \) = Present value of cash flows
- \( CF_t \) = Cash flow (positive or negative) in year \( t \)
- \( r \) = Discount rate

A cash flow can either be positive (i.e., an inflow) or negative (i.e., an outflow) at any point in time. Cash flows generally relate to the net value of project benefits less costs. In essence, \( CF_t = B_t - C_t \) where \( B_t \) and \( C_t \) are magnitudes for benefits and costs, respectively, at a time \( t \). Thus, \( NPV \) is defined as the present value of future cash flows less initial project costs (2.12). Alternatively, \( NPV \) can be defined as the present value of benefits less the present value of costs (2.13):

\[ NPV = -C_0 + \sum_{t=1}^{T} \frac{CF_t}{(1 + r)^t} \] (2.12)

\[ PV_{\text{benefits}} = \sum_{t=0}^{T} \frac{B_t}{(1+r)^t} \quad PV_{\text{costs}} = \sum_{t=0}^{T} \frac{C_t}{(1+r)^t} \]

\[ NPV = -PV_{\text{costs}} + PV_{\text{benefits}} \] (2.13)

where,

- \( C_0 \) = Magnitude of initial project costs
- \( PV_{\text{benefits}} \) = Present value of project benefits
- \( PV_{\text{costs}} \) = Present value of project costs

Where as all projects with \( NPV > 0 \) are valuable, it is recommended to consider other valuation metrics and factors when comparing multiple projects.
2.3.3 Internal Rate of Return (IRR)

From [11], [12], [13], IRR is the value of \( r \), in (2.12) or (2.13), for which \( NPV \) equals zero (et Ceteris Paribus). A project is preferable if its internal rate of return is greater than the economic discount rate. The internal rate of return is obtained by solving for IRR in (2.14) or (2.15):

\[
0 = -C_0 + \sum_{t=1}^{T} \frac{CF_t}{(1 + IRR)^t} \tag{2.14}
\]

\[
0 = -\sum_{t=0}^{T} \frac{C_t}{(1 + IRR)^t} + \sum_{t=0}^{T} \frac{B_t}{(1 + IRR)^t} \tag{2.15}
\]

2.3.4 Benefit-Cost Ratio (BCR)

As shown in (2.16), BCR is a ratio of \( PV_{benefits} \) to \( PV_{costs} \). Costs include setup and operational and maintenance (O&M) costs realized throughout the project life cycle:

\[
BCR = \frac{PV_{benefits}}{PV_{costs}} \tag{2.16}
\]

2.3.5 Levelized Cost of Energy (LCOE)

According to [11], [13], [14], LCOE represents the unit energy costs of building and managing a power plant over its entire life. All costs factors such as fuel, financing, and operational costs are considered in levelized cost calculations. Project incentives as well as system characteristics like degradation are also factored in. Variations in LCOE values for different generation technologies vary for divergent reasons [14], [15]. For instance, since renewable sources like wind and solar have no fuel costs and small variable costs, their LCOE values are primarily affected by capital costs. Contrarily, the levelized costs for controllable thermal sources are mostly affected by fuel and variable operational costs. LCOE serves a standardized metric for comparing energy costs of diverse generation sources. The mathematical formulation for LCOE is shown in (2.17) and (2.18):

\[
PV_{costs} = \sum_{t=1}^{T} \frac{E_t \times LCOE}{(1 + r)^t} \tag{2.17}
\]
\[ LCOE = PV_{\text{costs}} \div \sum_{t=1}^{T} \frac{E_t}{(1 + r)^t} \]  

(2.18)

where \( E_t = \) magnitude of energy produced or saved at year \( t \).

### 2.4 Random Sampling and Monte-Carlo Simulation

A random variable (RV) is a function that is defined by a collection or set of probabilistic occurrences [16], [17]. A discrete RV has a finite set of probabilistic events while a continuous RV has an infinite set [16], [17].

#### 2.4.1 Uniform Distribution

As shown in [16], [17], for two real values, \( a \) and \( b \) where \( a < b \), the uniform distribution function, denoted as \( U(a, b) \), is defined as:

\[ f(x) = U(a, b) = \begin{cases} \frac{1}{b-a}, & \text{if } a \leq x \leq b \\ 0, & \text{otherwise} \end{cases} \]  

(2.19)

*Standard uniform distribution* is a special case where \( a = 0 \) and \( b = 1 \) (2.20):

\[ f(x) = U(0, 1) = \begin{cases} 1, & \text{if } 0 \leq x \leq 1 \\ 0, & \text{otherwise} \end{cases} \]  

(2.20)

Per the above, let \( \tilde{A} \) represent an RV. Assuming \( \tilde{A} \) is uniformly distributed over the interval \([a, b]\), \( f_{\tilde{A}}(x) \) represents the probability density function (PDF) defined by exact probabilities at all values of \( x \) [16], [17]:

\[ f_{\tilde{A}}(x) = P\{\tilde{A} = x\} = U(a, b) = \begin{cases} \frac{1}{b-a}, & \text{if } a \leq x \leq b \\ 0, & \text{otherwise} \end{cases} \]  

(2.21)

From [16], [17], \( F_{\tilde{A}}(x) \) represents the cumulative distribution function (CDF) defined in (2.22) and (2.23):

\[ F_{\tilde{A}}(x) = P\{\tilde{A} \leq x\} = \int_{-\infty}^{x} f_{\tilde{A}}(w)dw \]  

(2.22)
\[
F_A(x) = \begin{cases} 
  0, & \text{if } x < a \\
  \frac{x-a}{b-a}, & \text{if } a \leq x < b \\
  1, & \text{otherwise}
\end{cases} 
\] (2.23)

Equation (2.22) is a general relationship between the CDF and PDF for any RV. See [16], [17] for more detail on other types of distribution functions, such as Gaussian, and Weibull distributions.

2.4.2 Normal Distribution

Normal distribution function, denoted as \( \mathcal{N}(\mu, \sigma^2) \), is defined as follows:

\[
f(x) = \mathcal{N}(\mu, \sigma^2) = \phi(x, \mu, \sigma) = \frac{1}{\sigma\sqrt{2\pi}} \exp \left( -\frac{(x - \mu)^2}{2\sigma^2} \right) \] (2.24)

where,

- \( \mu = \) mean or expected value of the distribution
- \( \sigma = \) standard deviation of the distribution
- \( \sigma^2 = \) variance of the distribution

When \((\mu, \sigma) = (0, 1)\), this is a special case called standard normal distribution (2.25):

\[
f(x) = \mathcal{N}(0, 1) = \phi(x, 0, 1) = \frac{1}{\sqrt{2\pi}} \exp \left( -\frac{x^2}{2} \right) \] (2.25)

Similar to the case of a uniform distribution, PDF and CDF for a normally distributed random variable, \( \tilde{A} \), are given by (2.26) and (2.27), respectively:

\[
f_{\tilde{A}}(x) = \phi(x, \mu_{\tilde{A}}, \sigma_{\tilde{A}}) = \mathcal{N}(\mu_{\tilde{A}}, \sigma_{\tilde{A}}) \] (2.26)

\[
F_{\tilde{A}}(x) = \Phi(x, \mu_{\tilde{A}}, \sigma_{\tilde{A}}) = \int_{-\infty}^{x} \phi(w, \mu_{\tilde{A}}, \sigma_{\tilde{A}})dw \] (2.27)

2.4.3 Realizations, Sample Vectors, and Monte Carlo (MC) Simulation

Monte Carlo simulation uses random sampling to solve large-scale multidimensional systems [18]. For any particular system, inputs are sampled at random
according to a given distribution function and then processed to generate corresponding output results. In this study, system inputs were distributed uniformly.

Let \( \tilde{X} \) represent an RV. The first three randomly generated samples or "realizations" of \( \tilde{X} \) are denoted by \( \tilde{x}^{(1)} \), \( \tilde{x}^{(2)} \), and \( \tilde{x}^{(3)} \) respectively. Assuming a system with \( N_X \) total input RVs and \( N_Y \) total output RVs, the vectors of all input RVs, \( \tilde{X} \), and output RVs, \( \tilde{Y} \), are shown in (2.28):

\[
\tilde{X} = (\tilde{X}_1, \tilde{X}_2, ..., \tilde{X}_{N_X}) \quad \tilde{Y} = (\tilde{Y}_1, \tilde{Y}_2, ..., \tilde{Y}_{N_Y})
\]  (2.28)

Assuming \( S(\cdot) \) is a deterministic function or system being analyzed, (2.29) shows the relation between inputs and outputs:

\[
\tilde{Y} = S(\tilde{X})
\]  (2.29)

\( \tilde{x}^{(1)} \) represents the first "input sample vector" of all the first realizations for each system input. Correspondingly, \( \tilde{y}^{(1)} \) denotes the "output sample vector" that is generated from processing \( \tilde{x}^{(1)} \) through \( S(\cdot) \). Repetition of this random sampling process over a sufficient number of iterations is the essence of MC:

\[
\tilde{x}^{(1)} = (\tilde{x}_1^{(1)}, \tilde{x}_2^{(1)}, ..., \tilde{x}_{N_X}^{(1)}) \quad \tilde{y}^{(1)} = (\tilde{y}_1^{(1)}, \tilde{y}_2^{(1)}, ..., \tilde{y}_{N_Y}^{(1)})
\]  (2.30)

\[
\tilde{y}^{(1)} = S(\tilde{x}^{(1)})
\]

\[
(\tilde{y}_1^{(1)}, \tilde{y}_2^{(1)}, ..., \tilde{y}_{N_Y}^{(1)}) = S(\tilde{x}_1^{(1)}, \tilde{x}_2^{(1)}, ..., \tilde{x}_{N_X}^{(1)})
\]  (2.31)

Assuming \( J \) is the total number of MC simulation runs, (2.32) is deduced:

\[
\begin{bmatrix}
\tilde{y}_1^{(1)} & \cdots & \tilde{y}_{N_Y}^{(1)} \\
\tilde{y}_1^{(2)} & \cdots & \tilde{y}_{N_Y}^{(2)} \\
\vdots & \ddots & \vdots \\
\tilde{y}_1^{(J)} & \cdots & \tilde{y}_{N_Y}^{(J)}
\end{bmatrix}
= S
\begin{bmatrix}
\tilde{x}_1^{(1)} & \cdots & \tilde{x}_{N_X}^{(1)} \\
\tilde{x}_1^{(2)} & \cdots & \tilde{x}_{N_X}^{(2)} \\
\vdots & \ddots & \vdots \\
\tilde{x}_1^{(J)} & \cdots & \tilde{x}_{N_X}^{(J)}
\end{bmatrix}
\]  (2.32)
Equation (2.33) is the MC simulation model for this study:

$$
\begin{bmatrix}
(LCOE^{(1)} & BCR^{(1)} & NPV^{(1)} & Payback^{(1)}) \\
(LCOE^{(2)} & BCR^{(2)} & NPV^{(2)} & Payback^{(2)}) \\
\vdots & \vdots & \vdots & \vdots \\
(LCOE^{(J)} & BCR^{(J)} & NPV^{(J)} & Payback^{(J)})
\end{bmatrix}
= \text{EconomicModel} \left( \begin{bmatrix}
(\bar{\tau}^{(1)} & E^{(1)} & \bar{B}^{(1)} & \bar{C}^{(1)} & \ldots) \\
(\bar{\tau}^{(2)} & E^{(2)} & \bar{B}^{(2)} & \bar{C}^{(2)} & \ldots) \\
\vdots & \vdots & \vdots & \vdots \\
(\bar{\tau}^{(J)} & E^{(J)} & \bar{B}^{(J)} & \bar{C}^{(J)} & \ldots)
\end{bmatrix} \right) \quad (2.33)
$$

From (2.33), key input RVs in this study are discount rate, energy production, and costs. Our deterministic system is the economic model described in Section 2.2. Valuation metrics, such as $LCOE$, $NPV$, and $BCR$, are the output RVs.
3.1 PV Performance Estimation for Nigeria

In terms of residential PV, solar irradiation data was obtained from [19]. The peak-hours approach described in Section 2.1.2 was used to estimate annual residential PV performance expected in Nigeria. Solar capacity was assumed to be distributed across 12 major cities in Nigeria based on gross domestic product (GDP), population size, and geographic location. The total estimated residential PV output was 133,600,000 kWh annually. Figure 3.1 shows the energy distribution by city. Centralized PV performance was assumed to be the same as the distributed case.

Figure 3.1: % Distribution of residential PV annual energy projections by city
3.2 Inputs and Assumptions

Assuming a 100 MW capacity upgrade, two solar PV cases are simulated: distributed-residential and centralized-utility PV. Each considers scenarios of lower (2013) and higher (2016) PV project costs using US prices in [20]. For all scenarios in both cases, 1000 MC iterations were run. It is assumed that all solar panels are equity-financed and that system degradation compounds at 1% annually for both residential and utility cases. Annual fixed costs are 1% of initial project costs with annual variable costs ranging between 0% and 30% of fixed costs. The ranges for derate factor and discount rate are assumed to be (70%,76%) and (7%,13%), respectively, and all input RVs are uniformly distributed. See Table 3.1.

Table 3.1: Table of all input factors and respective distribution types

<table>
<thead>
<tr>
<th>Input Factor</th>
<th>Value/Range</th>
<th>Distribution Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>Discount Rate</td>
<td>7% to 13%</td>
<td>Uniform</td>
</tr>
<tr>
<td>2013 PV Project Costs ($/W)</td>
<td>Case 1: 4.19 to 5.19</td>
<td>Uniform</td>
</tr>
<tr>
<td></td>
<td>Case 2: 2.50 to 3.50</td>
<td>Uniform</td>
</tr>
<tr>
<td>2016 PV Project Costs ($/W)</td>
<td>Case 1: 1.50 to 3.00</td>
<td>Uniform</td>
</tr>
<tr>
<td></td>
<td>Case 2: 1.30 to 1.95</td>
<td>Uniform</td>
</tr>
<tr>
<td>Power Rating (MW)</td>
<td>100</td>
<td>None (Fixed)</td>
</tr>
<tr>
<td>Derate Factor</td>
<td>70% to 76%</td>
<td>Uniform</td>
</tr>
<tr>
<td>Energy Market Price ($/kWh)</td>
<td>0.10 to 0.20</td>
<td>Uniform</td>
</tr>
<tr>
<td></td>
<td>24% - Income</td>
<td>None (Fixed)</td>
</tr>
<tr>
<td>Tax Rate</td>
<td>30% - Corporate</td>
<td>None (Fixed)</td>
</tr>
<tr>
<td>Project Life (years)</td>
<td>30</td>
<td>None (Fixed)</td>
</tr>
<tr>
<td>Fixed Costs</td>
<td>1% of Initial Project Costs</td>
<td>None (Fixed)</td>
</tr>
<tr>
<td>Variable Costs</td>
<td>0% to 30% of Fixed Costs</td>
<td>Uniform</td>
</tr>
<tr>
<td>System Degradation</td>
<td>1% Annually</td>
<td>None (Fixed)</td>
</tr>
<tr>
<td>Salvage Value</td>
<td>5% of Initial Project Costs</td>
<td>None (Fixed)</td>
</tr>
<tr>
<td>Inflation Rate</td>
<td>6% to 10%</td>
<td>Uniform</td>
</tr>
</tbody>
</table>
3.3 Economic Model Test

Our economic model and study approach were tested using 2011 economic data. Monte Carlo was performed over 1000 iterations for the residential PV case. Results are shown in Table 3.2. Although our residential PV \(LCOE\) results appear comparable to those in [8], much cannot be inferred about the similarity between our model and theirs. The reason is that both models were developed at different time points, based on different data sets, and under different assumptions. For instance in [8], 2011 discount factor was assumed to be fixed at 5% whereas in this study, the discount rate uniformly ranged between 7% and 13%.

Table 3.2: A comparison between simulated and reference \(LCOE\) values for Nigeria based on 2011 market data

<table>
<thead>
<tr>
<th>2011 Market Data</th>
<th>(LCOE) from [8]</th>
<th>(LCOE) from This Study</th>
</tr>
</thead>
<tbody>
<tr>
<td>(\text{Panel Costs in Dollars})</td>
<td>(\text{Exchange Rate in Dollars per Euro})</td>
<td>(\text{Euro per KWh})</td>
</tr>
<tr>
<td>Min $5.00</td>
<td>1.3921</td>
<td>0.2500</td>
</tr>
<tr>
<td>Max $6.00</td>
<td>1.3921</td>
<td>0.5000</td>
</tr>
</tbody>
</table>
4.1 Case 1: Distributed PV in Nigeria

From a residential standpoint, it is important to note that solar PV is complementary to more controllable thermal generation sources such as petrol and diesel. Solar energy revenues and succeeding benefits are therefore realized in the form of savings. Hence, the effect of taxes on energy revenues and income is ignored. Property insurance costs are also ignored, as residential panels are assumed to have coverage through warranty programs. Salvage value is also assumed to be negligible at life. Furthermore, with no identifiable government incentives in place, residential PV owners were assumed to bare all associated costs.

Two scenarios involving different project cost assumptions were evaluated. Both are shown in Table 4.1. PV project cost values were obtained from [20].

Table 4.1: Distributed PV simulation cases

<table>
<thead>
<tr>
<th>Residential PV Project Costs</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Case Year</td>
<td>Minimum</td>
<td>Maximum</td>
</tr>
<tr>
<td>2013</td>
<td>$4.19</td>
<td>$5.19</td>
</tr>
<tr>
<td>2016</td>
<td>$1.50</td>
<td>$3.00</td>
</tr>
</tbody>
</table>

Figures 4.1 and 4.2 show cumulative payback projections for scenarios of 2013 and 2016 costs, respectively, per Table 4.1. In Figure 4.1, each blue shaded bar is an expected value projection for cumulative payback at a particular year. There are 30 bars since our simulations were discretized annually over 30 years. Each bar shows the expected net value between total project costs and cumulative sum of benefits realized up to a given year. Ideally, it is preferred that cumulative payback projects become (and stay) positive at (and beyond) a time point within the project life cycle. The point at which the cumulative payback becomes positive is the payback period for that scenario.
The green line above the tip of the shaded pillars are the maximum or best possible cumulative payback projections over the project life. For each year, there are 1000 cumulative payback realizations from 1000 Monte Carlo iterations. The average of all those realizations gives the expected cumulative payback for that year, which is the shaded bar. The maximum of those realizations represents the green point above the bar tip in each year.

The red line below the tip of the bars is the minimum possible set of cumulative payback projections over the project life. In other words, the worst-case projections. Similar to explanations in the preceding paragraph, the minimum of the generated cumulative payback samples represents red point below the pillar tip for any given project year.

As seen in Figure 4.1, results show no possibility of payback under assumptions made. The concave characteristic seen in the curve(s) is attributable to the discount rate effect on future payback in accordance with TVM theory. As time progresses, the there is a compounding discount rate effect on income projections and, in turn, on payback.

In Figure 4.2, mean cumulative payback projections stay negative over the en-
tire project life. However, best-case projections cross year-axis between year 8 and year 10 (i.e., at year 9 approximately). This shows that there are possibilities of payback for the residential case under 2016 project cost assumptions. This is largely attributable to the reduction of initial project costs. As seen in Figures 4.1 and 4.2, expected value for initial projects costs (i.e., the height of the year zero bar) is more than halved from about -$466 million under 2013 cost assumptions to -$225 million under 2016 assumptions.

Figure 4.2: Cumulative payback plot for residential PV case under 2016 panel cost assumptions

4.2 Case 2: Centralized PV in Nigeria

Contrary to the distributed case, all solar energy produced in the centralized PV case actually generates receivable income and is subject to Nigeria’s corporate tax rate of 30%. Tax incentives are also considered here, particularly the "local value added" and "labor-intensive production" incentives as described in [21]. Furthermore salvage value, property insurance, and property taxes are each factored in at 5%, 1%, and 1% of initial capital costs, respectively. As in the residential PV case, 2013 and 2016 cost scenarios are studied (see Table 4.2).
Table 4.2: Centralized PV simulation cases

<table>
<thead>
<tr>
<th>Case Year</th>
<th>Minimum</th>
<th>Maximum</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>$2.50</td>
<td>$3.50</td>
</tr>
<tr>
<td>2016</td>
<td>$1.30</td>
<td>$1.95</td>
</tr>
</tbody>
</table>

Figure 4.3: Cumulative payback plot for utility PV case under 2013 panel cost assumptions

Results in Figures 4.3 and 4.4 appear similar to those in residential PV case. In Figure 4.3, results show no possibility of payback under assumptions made. In Figure 4.4, while mean cumulative payback projections stay negative over the entire project life, payback opportunities arise as best-case projections cross the year-axis between year 8 and year 10. Similar to Figure 4.2, this is attributable to the reduction of expected year zero costs by about $130 million moving from 2013 to 2016 PV cost assumptions.
4.3 Sensitivity Analysis: Inflation Rate Effects

Previous results in Sections 4.1 and 4.2 did not consider effects of inflation. In this section, we attempt to capture the sensitivity of our results to inflation. In essence, inflation served as a new input random variable that was uniformly distributed between 6% and 10% as shown in Table 3.1. Inflation effects were then incorporated into each of the four previous scenarios depicted by Figures 4.1, 4.2, 4.3, and 4.4 and birthed results shown in Figures 4.5, 4.6, 4.7, and 4.8, respectively.

In general, the effect of inflation makes the new results appear more favorable than inflation-free results by all means. In relation to the residential PV case under 2013 costs assumptions, Figure 4.5 shows that expected cumulative payback projections stay negative all through year 30. However, payback opportunities do arise as best-case projections cross the year-axis between year 19 and year 20. This is much better compared to Figure 4.1, which shows no possibility of payback at best.

Inflation-embedded results for residential PV at 2016 PV costs in Figure 4.6...
show an expected payback payback period of 16 years approximately. Best-case projections cross the year-axis at about 6 years and 6 months. Again, this is much better compared to Figure 4.1.

In terms of centralized PV case, results for the 2013 case shown in Figure 4.7 are more prominent due to inflation compared to inflation-free correspondent, Figure 4.3. As seen in Figure 4.6, results just fall short of breaking even at project life. Nevertheless, a payback period of about 13 years is attainable as a best-case scenario.

Figure 4.8 pertains to centralized PV at 2016 prices and inflation effects are also salient. Expected cumulative payback projections cross the year-axis at about year 13. Best-case projections cross the year-axis at about year 6. Worst-case projections do stay negative over the entire project.

Figure 4.5: Cumulative payback plot for residential PV case under 2013 project cost assumptions and inflation rate effects
Figure 4.6: Cumulative payback plot for residential PV case under 2016 project cost and inflation rate factors

Figure 4.7: Cumulative payback plot for utility PV case under 2013 project cost assumptions and inflation rate effects
4.4 Comparison of Results

In this section, we perform a comparison of the output metrics obtained from all simulated scenarios. There are a total of eight scenarios. Each scenario is abbreviated using the nomenclature shown below:

- ResiPV-2013-No-Infl = Residential PV case under 2013 project cost assumptions and no inflation effects.
- UtilPV-2013-No-Infl = Utility PV case under 2013 project cost assumptions and no inflation effects.
- ResiPV-2013-With-Infl = Residential PV case under 2013 project cost assumptions with inflation effects considered.
- UtilPV-2013-With-Infl = Utility PV case under 2013 project cost assumptions with inflation effects considered.
• ResiPV-2016-No-Infl = Residential PV case under 2016 project cost assumptions and no inflation effects.

• UtilPV-2016-No-Infl = Utility PV case under 2016 project cost assumptions and no inflation effects.

• ResiPV-2016-With-Infl = Residential PV case under 2016 project cost assumptions with inflation effects considered.

• UtilPV-2016-With-Infl = Utility PV case under 2016 project cost assumptions with inflation effects considered.

4.4.1 LCOE Comparison

Figure 4.9 shows a comparison of LCOE results from all scenarios, including those with and without inflation effects. Following are some key observations made:

• All expected LCOE values under 2013 project cost assumptions are above 30 cents while expected values for the 2016 cases are less than 30 cents.

• For 2013 PV cost scenarios, residential mean LCOE values increased from about $0.44 before inflation to about $0.52 after inflation while the expected utility LCOE values increased from $0.33 before inflation to about $0.44 after inflation.

• For 2016 PV cost scenarios, residential mean LCOE values increased from about $0.21 before inflation to about $0.25 after inflation while the expected utility LCOE values increased from $0.19 before inflation to about $0.27 after inflation.

• The three scenarios with lowest LCOE values are ResiPV-2016-No-Infl, ResiPV-2016-With-Infl, and UtilPV-2016-No-Infl at $0.1151, $0.1282, and $0.1318 per kilowatt-hour, respectively.
4.4.2 BCR Comparison

Similar to Figure 4.9, Figure 4.10, shows a comparison of $BCR$ results from all scenarios, including those with and without inflation effects. Following are some key observations made:

- For 2013 PV cost scenarios, residential mean $BCR$ values increased from 1.01 to 3.37 before and after inflation effects. Expected $BCR$ values for the utility PV case increased from 1.36 before inflation is considered to 3.93 after effects of inflation.

- For 2016 PV cost scenarios, residential mean $BCR$ values increased from 2.16 before inflation to about 7.08 after inflation while the expected utility $BCR$ values increased from 2.35 before inflation to about 6.36 after inflation.

- The three scenarios with highest possible $BCR$ values are ResiPV-2016-With-Infl, UtilPV-2016-With-Infl, and UtilPV-2013-With-Infl at 16.59, 11.87, and 7.41, respectively.
4.4.3 NPV Comparison

Figure 4.11 is a comparison of $NPV$ results from all scenarios. Following are some observations from the results:

- All mean $NPV$ results for 2016 scenarios are greater than all values from 2013 scenarios.

- All scenarios except ResiPV-2016-With-Infl and UtilPV-2016-With-Infl have negative expected $NPV$ values with ResiPV-2016-With-Infl at $124$ million and UtilPV-2016-With-Infl at $98.4$ million.

- All expected values for scenarios with inflation effects are greater than expected values from all corresponding scenarios without inflation effects.
4.4.4 Payback Period Comparison

During our simulation, some Monte Carlo iterations resulted in realizations with no payback possibilities. Such realizations affect numerical calculations for mean payback period. In other words, an expected value for payback period cannot be obtained over all the iterations. As a result, Figure 4.12 does not include mean values for any scenarios unlike previous Figures (4.9, 4.10, and 4.11).

For any particular scenario in Figure 4.12, the minimum payback period represents the time point when the maximum cumulative payback line crosses the year-axis. For example, looking at Figures 4.7 and 4.8, the best case cumulative payback lines cross the year-axis at about 13.0 and 6.0 years, respectively. Thus, in Figure 4.12, UtilPV-2013-With-Infl and UtilPV-2016-With-Infl scenarios have minimum payback periods of 13.0 and 6.0 years, respectively.

Similar to minimum values, for any given scenario, the maximum payback period is the time point where the minimum cumulative payback lines crosses the year-axis. Since there is no scenario in which the worst-case cumulative payback gives an x-intercept, maximum payback period is the maximum value of feasible payback periods obtained during all iterations of the simulation. In essence, if a
minimum value exists and is less than 30, maximum payback is 30.0 years approximately. Scenarios with no possibility of payback are assigned minimum and maximum payback periods of zero. Such is the situation seen in scenarios ResiPV-2013-No-Infl and UtilPV-2013-No-Infl of Figure 4.12. Following are some observations from the comparison of payback period results:

- ResiPV-2013-No-Infl and UtilPV-2013-No-Infl scenarios show no possibilities of payback.

- The three scenarios with the best (i.e. shortest) payback period possibilities are UtilPV-2016-With-Infl at about 6.0 years, ResiPV-2016-With-Infl at 6.5 years, and UtilPV-2016-No-Infl at 9.0 years.

![Payback Period Comparison](image)

**Figure 4.12:** Comparison of all payback period results for all scenarios
4.5 Summary of Results

Statistical results for all eight simulated scenarios are compiled in Tables 4.3 to 4.10. The Mean, Min, and Max metrics given in the tables represent the average, minimum, maximum values, respectively, of a particular set of output realizations. StdDev and StdError represent the standard deviation and standard error, respectively, of the realized samples. RelError is relative error and is equal to standard error over the mean. Lbound95% and Ubound95% are the lower and upper bounds of the 95% confidence interval associated with the mean. For any particular output variable, the probability that its Mean lies between its Lbound95% and Ubound95% values is 95%. Further detail on all these metrics can be found in [18].

Tables 4.3, 4.4, 4.5, and 4.6 contain data for 2013 cost scenarios with and without inflation effects. Similarly, Tables 4.7, 4.8, 4.9, and 4.10 contain data for all 2016 scenarios. Looking at inflation-free results (i.e., Tables 4.3, 4.4, 4.7, and 4.8), 2016-ResiPV-No-Infl and 2016-Util-PV-No-Infl are stronger scenarios as they have lower mean LCOE, higher mean NPV, and higher mean BCR values. There is very little difference between the expected values of output metrics for 2016-ResiPV-No-Infl and 2016-Util-PV-No-Infl scenarios.

The aforementioned observations are as expected. Given that 2016 project cost assumptions are lower than those for 2013, initial projects costs for 2016 scenarios are therefore expected to be lower than those for 2013 scenarios. In turn, this leads to lower LCOE, higher BCR, higher NPV, and the potential for lower payback periods.

Comparing inflation-affected results (i.e., Tables 4.5, 4.6, 4.9, and 4.10), 2016-ResiPV-With-Infl and 2016-Util-PV-With-Infl are stronger scenarios with better expected values for LCOE, NPV, and BCR. As previously observed in Section 4.4.3, 2016-ResiPV-With-Infl and 2016-Util-PV-With-Infl are the only two scenarios with positive expected values for NPV. There is also little difference between the expected values of output metrics for both scenarios. This is also expected per the rationale stated in the previous paragraph.

While 2016 distributed and centralized results are relative comparable in both inflation-free and inflation-affected cases, it should be duly noted that distributed PV simulations did not include incentives unlike the utility case. If residential PV incentives were available, results for residential PV configuration will be more favorable as expected residual benefits will increase and expected payback peri-
ods will reduce. And in accordance with economics, improved payback periods increases the residential PV feasibility as consumers generally prefer earlier payback schedules.

Table 4.3: Statistical summary of results for 2013-ResiPV-No-Infl scenario

<table>
<thead>
<tr>
<th>Case_Scenario</th>
<th>Output</th>
<th>LCOE</th>
<th>BCR</th>
<th>NPV</th>
<th>Payback Period</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013_Resi_PV_NoInfl</td>
<td>Mean</td>
<td>0.4397</td>
<td>1.011</td>
<td>-$333,300,000</td>
<td>NA</td>
</tr>
<tr>
<td></td>
<td>Min</td>
<td>0.3114</td>
<td>0.6110</td>
<td>-$446,500,000</td>
<td>NA</td>
</tr>
<tr>
<td></td>
<td>Max</td>
<td>0.6130</td>
<td>1.482</td>
<td>-$171,200,000</td>
<td>NA</td>
</tr>
<tr>
<td></td>
<td>StdDev</td>
<td>0.0589</td>
<td>0.2069</td>
<td>$47,370,000</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>StdError</td>
<td>0.0019</td>
<td>0.0065</td>
<td>$1,498,000</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>RelError</td>
<td>0.4239%</td>
<td>0.6475%</td>
<td>-0.4494%</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>Lbound95%</td>
<td>0.4360</td>
<td>0.9978</td>
<td>-$336,200,000</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>Ubound95%</td>
<td>0.4433</td>
<td>1.023</td>
<td>-$330,400,000</td>
<td>-</td>
</tr>
</tbody>
</table>

Table 4.4: Statistical summary of results for 2013-UtilPV-No-Infl scenario

<table>
<thead>
<tr>
<th>Case_Scenario</th>
<th>Output</th>
<th>LCOE</th>
<th>BCR</th>
<th>NPV</th>
<th>Payback Period</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013_Util_PV_NoInfl</td>
<td>Mean</td>
<td>0.3250</td>
<td>1.3639</td>
<td>-$201,000,000</td>
<td>NA</td>
</tr>
<tr>
<td></td>
<td>Min</td>
<td>0.2276</td>
<td>0.8326</td>
<td>-$302,500,000</td>
<td>NA</td>
</tr>
<tr>
<td></td>
<td>Max</td>
<td>0.4596</td>
<td>2.064</td>
<td>-$62,250,000</td>
<td>NA</td>
</tr>
<tr>
<td></td>
<td>StdDev</td>
<td>0.0421</td>
<td>0.2678</td>
<td>$41,040,000</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>StdError</td>
<td>0.0013</td>
<td>0.0085</td>
<td>$1,298,000</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>RelError</td>
<td>0.4099%</td>
<td>0.6210%</td>
<td>-0.6456%</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>Lbound95%</td>
<td>0.3224</td>
<td>1.347</td>
<td>-$203,600,000</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>Ubound95%</td>
<td>0.3276</td>
<td>1.381</td>
<td>-$198,500,000</td>
<td>-</td>
</tr>
</tbody>
</table>

Table 4.5: Statistical summary of results for 2013-ResiPV-With-Infl scenario

<table>
<thead>
<tr>
<th>Case_Scenario</th>
<th>Output</th>
<th>LCOE</th>
<th>BCR</th>
<th>NPV</th>
<th>Payback Period</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013_Resi_PV_Infl</td>
<td>Mean</td>
<td>0.5231</td>
<td>3.374</td>
<td>-$189,700,000</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>Min</td>
<td>0.3627</td>
<td>1.582</td>
<td>-$435,300,000</td>
<td>19.50</td>
</tr>
<tr>
<td></td>
<td>Max</td>
<td>0.7378</td>
<td>6.823</td>
<td>$214,300,000</td>
<td>29.99</td>
</tr>
<tr>
<td></td>
<td>StdDev</td>
<td>0.0651</td>
<td>0.9200</td>
<td>$110,700,000</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>StdError</td>
<td>0.0021</td>
<td>0.0291</td>
<td>$3,501,000</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>RelError</td>
<td>0.3932%</td>
<td>0.8623%</td>
<td>-1.847%</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>Lbound95%</td>
<td>0.5191</td>
<td>3.317</td>
<td>-$196,500,000</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>Ubound95%</td>
<td>0.5272</td>
<td>3.431</td>
<td>-$182,800,000</td>
<td>-</td>
</tr>
</tbody>
</table>
Table 4.6: Statistical summary of results for 2013-UtilPV-With-Infl scenario

<table>
<thead>
<tr>
<th>Case_Scenario</th>
<th>Output</th>
<th>LCOE</th>
<th>BCR</th>
<th>NPV</th>
<th>Payback Period</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013_Util_PV_Infl</td>
<td>Mean</td>
<td>0.4382</td>
<td>3.932</td>
<td>-$96,330,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Min</td>
<td>0.3170</td>
<td>1.842</td>
<td>-$276,900,000</td>
<td>13.00</td>
</tr>
<tr>
<td></td>
<td>Max</td>
<td>0.6060</td>
<td>7.410</td>
<td>$188,300,000</td>
<td>29.96</td>
</tr>
<tr>
<td></td>
<td>StdDev</td>
<td>0.0509</td>
<td>0.9769</td>
<td>$86,200,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>StdError</td>
<td>0.0016</td>
<td>0.0309</td>
<td>$2,726,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>RelError</td>
<td>0.3670%</td>
<td>0.7857%</td>
<td>-2.830%</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Lbound95%</td>
<td>0.4351</td>
<td>3.871</td>
<td>-$101,700,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Ubound95%</td>
<td>0.4414</td>
<td>3.992</td>
<td>-$90,990,000</td>
<td></td>
</tr>
</tbody>
</table>

Table 4.7: Statistical summary of results for 2016-ResiPV-No-Infl

<table>
<thead>
<tr>
<th>Case_Scenario</th>
<th>Output</th>
<th>LCOE</th>
<th>BCR</th>
<th>NPV</th>
<th>Payback Period</th>
</tr>
</thead>
<tbody>
<tr>
<td>2016_Resi_PV_NoInfl</td>
<td>Mean</td>
<td>0.2109</td>
<td>2.164</td>
<td>-$69,190,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Min</td>
<td>0.1151</td>
<td>1.109</td>
<td>-$209,500,000</td>
<td>9.00</td>
</tr>
<tr>
<td></td>
<td>Max</td>
<td>0.3519</td>
<td>3.984</td>
<td>$119,800,000</td>
<td>29.86</td>
</tr>
<tr>
<td></td>
<td>StdDev</td>
<td>0.0447</td>
<td>0.5713</td>
<td>$57,200,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>StdError</td>
<td>0.0014</td>
<td>0.0181</td>
<td>$1,808,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>RelError</td>
<td>0.6697%</td>
<td>0.8350%</td>
<td>-2.615%</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Lbound95%</td>
<td>0.2082</td>
<td>2.128</td>
<td>-$72,730,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Ubound95%</td>
<td>0.2137</td>
<td>2.199</td>
<td>-$65,640,000</td>
<td></td>
</tr>
</tbody>
</table>

Table 4.8: Statistical summary of results for 2016-UtilPV-No-Infl

<table>
<thead>
<tr>
<th>Case_Scenario</th>
<th>Output</th>
<th>LCOE</th>
<th>BCR</th>
<th>NPV</th>
<th>Payback Period</th>
</tr>
</thead>
<tbody>
<tr>
<td>2016_Util_PV_NoInfl</td>
<td>Mean</td>
<td>0.1888</td>
<td>2.345</td>
<td>-$43,830,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Min</td>
<td>0.1318</td>
<td>1.445</td>
<td>-$131,300,00</td>
<td>9.00</td>
</tr>
<tr>
<td></td>
<td>Max</td>
<td>0.2688</td>
<td>3.606</td>
<td>$79,620,000</td>
<td>29.96</td>
</tr>
<tr>
<td></td>
<td>StdDev</td>
<td>0.0248</td>
<td>0.4469</td>
<td>$36,300,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>StdError</td>
<td>0.0008</td>
<td>0.0141</td>
<td>$1,148,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>RelError</td>
<td>0.4147%</td>
<td>0.6026%</td>
<td>-2.619%</td>
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</tr>
<tr>
<td></td>
<td>Lbound95%</td>
<td>0.1873</td>
<td>2.318</td>
<td>-$46,080,000</td>
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</tr>
<tr>
<td></td>
<td>Ubound95%</td>
<td>0.1904</td>
<td>2.373</td>
<td>-$41,580,000</td>
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</tr>
</tbody>
</table>

Table 4.9: Statistical summary of results for 2016-ResiPV-With-Infl

<table>
<thead>
<tr>
<th>Case_Scenario</th>
<th>Output</th>
<th>LCOE</th>
<th>BCR</th>
<th>NPV</th>
<th>Payback Period</th>
</tr>
</thead>
<tbody>
<tr>
<td>2016_Resi_PV_Infl</td>
<td>Mean</td>
<td>0.2501</td>
<td>7.085</td>
<td>$124,000,000</td>
<td>13.22</td>
</tr>
<tr>
<td></td>
<td>Min</td>
<td>0.1282</td>
<td>2.915</td>
<td>-$147,700,000</td>
<td>6.50</td>
</tr>
<tr>
<td></td>
<td>Max</td>
<td>0.4204</td>
<td>16.60</td>
<td>$552,800,000</td>
<td>29.99</td>
</tr>
<tr>
<td></td>
<td>StdDev</td>
<td>0.0470</td>
<td>2.208</td>
<td>$125,300,000</td>
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</tr>
<tr>
<td></td>
<td>StdError</td>
<td>0.0015</td>
<td>0.0698</td>
<td>$3,962,000</td>
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</tr>
<tr>
<td></td>
<td>RelError</td>
<td>0.5942%</td>
<td>0.9857%</td>
<td>3.195%</td>
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<tr>
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<td>Lbound95%</td>
<td>0.2472</td>
<td>6.948</td>
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<td>Ubound95%</td>
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<td>7.222</td>
<td>$131,800,000</td>
<td></td>
</tr>
<tr>
<td>Case_Scenario</td>
<td>Output</td>
<td>LCOE</td>
<td>BCR</td>
<td>NPV</td>
<td>Payback Period</td>
</tr>
<tr>
<td>---------------</td>
<td>--------</td>
<td>----------</td>
<td>---------</td>
<td>-------------</td>
<td>----------------</td>
</tr>
<tr>
<td>2016_Util_PV_Infl</td>
<td>Mean</td>
<td>0.2706</td>
<td>6.358</td>
<td>$98,410,000</td>
<td>13.43</td>
</tr>
<tr>
<td></td>
<td>Min</td>
<td>0.1943</td>
<td>3.061</td>
<td>-$87,960,000</td>
<td>6.00</td>
</tr>
<tr>
<td></td>
<td>Max</td>
<td>0.3741</td>
<td>11.87</td>
<td>$419,200,000</td>
<td>29.91</td>
</tr>
<tr>
<td></td>
<td>StdDev</td>
<td>0.0342</td>
<td>1.511</td>
<td>$92,470,000</td>
<td>-</td>
</tr>
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<td></td>
<td>StdError</td>
<td>0.0011</td>
<td>0.0478</td>
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</tr>
<tr>
<td></td>
<td>RelError</td>
<td>0.3998%</td>
<td>0.7514%</td>
<td>2.971%</td>
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<tr>
<td></td>
<td>Lbound95%</td>
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<td>6.264</td>
<td>$92,680,000</td>
<td>-</td>
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<td>Ubound95%</td>
<td>0.2727</td>
<td>6.451</td>
<td>$104,100,000</td>
<td>-</td>
</tr>
</tbody>
</table>
5.1 Conclusive Remarks and Recommendations

In this thesis, an economic valuation of solar energy potential in Nigeria was performed. Valuation metrics, such as $LCOE$, $BCR$, $NPV$, and payback period, were evaluated. Two implementation cases were considered: distributed-residential PV and centralized-utility PV. Under each case, scenarios of higher 2013 and lower 2016 project cost assumptions were analyzed. Furthermore, all scenarios were analyzed with and without inflation effects.

Under the assumption of 100 MW solar implementation, results from Monte Carlo simulations and our economic model showed that there is indeed a favorable case for solar PV implementation in Nigeria, both in residential-distributed and centralized-utility configurations. Solar PV becomes significantly more favorable and feasible as implementation costs reduce from year 2013 to year 2016. This is especially true for the distributed PV case.

In light of the major effect that PV project costs have on overall $LCOE$, it is recommended that government provide incentives that directly tackle initial project costs. These incentives should be founded and enforced on solid renewable energy policy, framework, and infrastructure. Transformational initiatives, such as the US Department of Energy SunShot Initiative [20] and Germany Energiewende [22], [23] have led (and are leading) to major technological advancements, improved design efficiencies, and favorable price trends in solar [20], [23]. Through similar initiatives, Nigeria can potentially realize the same aforementioned benefits and capture immense economic value from its notable solar irradiation profile [19].
5.2 Future Work

In terms of future work, there is an opportunity to improve our economic model by including reliability benefits and capacity value in payback calculations. Also, our efforts can be enhanced by considering transmission expansion economics since solar capacity upgrades may require transmission system upgrades.

Another way that this study can be more comprehensive is by performing an economic comparison between solar and other energy resources, such as diesel, hydro, and wind. There is also an opportunity to conduct similar studies for other African countries, such as Ghana and Tanzania, that are undergoing substantial energy development.

Furthermore, our simulation results could be improved by increasing the number of Monte Carlo iterations but as a tradeoff to computational time. Optimization theory can also be employed here to obtain the conditions for which \( LCOE \), \( BCR \), \( NPV \), and payback are optimized under specific economic and power system constraints.
REFERENCES


