

Digital Petroleum and Economic Evaluation under Nigeria's Petroleum Industry Act: Development and Validation of an Integrated Economic Evaluation and Investment Support Tool

Kalagbor, Christian¹; Aleruchi, B. Orij²; Asianuba B. Ifeoma³

¹New Brunswick Power Corporation

^{2,3}Emerald Energy Institute, University of Port Harcourt

DOI: <https://doi.org/10.51244/IJRSI.2026.1309000076>

Received: 07 September 2026; Accepted: 12 September 2026; Published: 04 October 2026

ABSTRACT

The Petroleum Industry Act (PIA) 2021 introduced a new fiscal framework for Nigeria's upstream petroleum sector, creating a need for reliable and efficient tools capable of evaluating petroleum investment opportunities under the evolving fiscal regime. However, conventional spreadsheet-based economic evaluation methods are often characterized by extensive manual computations, limited automation, and inadequate integration of risk and uncertainty analysis. This study developed and validated a Python-based Economic Evaluation and Investment Decision Support Tool (EEIDST) to provide an integrated digital framework for petroleum fiscal and economic evaluation under the PIA 2021. The study adopted a design, development, and validation methodology. The EEIDST integrates petroleum fiscal modelling, discounted cash flow analysis, economic evaluation, and sensitivity analysis within a unified analytical environment. The tool was designed to evaluate key economic indicators, including Net Present Value (NPV), Internal Rate of Return (IRR), Profitability Index (PI), Payback Period, Unit Capital Cost, Unit Operating Cost, Unit Technical Cost, and Government Take. Verification of the computational accuracy of the EEIDST framework was done using representative onshore petroleum project data with an independently developed Excel-based discounted cash flow model. Results showed a high level of agreement between the two model, with percentage errors for key economic indicators ranging from 0.01% to 3.73%, confirming the computational accuracy of the EEIDST model. Then validation of the reliability of the model was done through oil price and CAPEX sensitivity analysis and scenario-based analysis to determine if results from the model are logical and consistent with petroleum economic principles. The response of the EEIDST solution was consistent with established petroleum economic principles, where higher oil prices improved project profitability, higher capital costs reduced investment performance. The study concludes that the EEIDST provides a reliable, transparent, and automated platform for petroleum economic evaluation and investment decision support under Nigeria's PIA fiscal regime. The tool offers practical value to investors, petroleum operators, regulators, financial institutions, and policymakers.

Keywords: Petroleum Fiscal Regime; Investment Decision Support Tool; Petroleum Economics; Fiscal Modelling; Discounted Cash Flow

INTRODUCTION

The upstream petroleum industry remains a capital-intensive and high-risk investment environment in which project viability depends on the interaction of geological conditions, production profiles, capital expenditure (CAPEX), operating expenditure (OPEX), hydrocarbon prices, fiscal obligations, and the timing of project cash flows. Unlike conventional investments, petroleum projects typically require substantial upfront capital, have long development and production periods, and are exposed to significant uncertainty in commodity prices and production performance. Consequently, investment decisions in exploration and production (E&P) require rigorous economic evaluation capable of translating technical, commercial, and fiscal assumptions into measurable investment outcomes [1]. Financial indicators such as Net Present Value (NPV), Internal Rate of Return (IRR), Profitability Index (PI), and Payback Period are therefore important in determining project

attractiveness, while indicators such as Government Take, economic rent, effective tax rate, and cost-recovery measures provide insight into the distribution of petroleum value between investors and the host government [2]. Together, these financial and economic indicators provides insights on investment profitability, and risk exposure reason why it is important for upstream oil and gas stakeholders to assess these indicators for any petroleum economic project.

The key indicators assessed in this study are described below.

Government Take: This refers to the share of revenues (royalties, taxes, bonuses) accruing to the government. Its value for any project depends of the design of the Fiscal regime. Very often, Onshore projects typically carry higher government take due to lower risk and costs compared to Offshore projects. On the other hand, Offshore projects offer lower upfront take to attract investment with progressive structures adjusting take based on project profitability [2].

Net Present Value (NPV): The NPV represents the present value of future cash flows minus initial investment costs. It is heavily influenced by cost recovery limits, royalty rates, and corporate tax rates. Lower governments take or more generous cost recovery improve NPV. Offshore projects are particularly sensitive to NPV fluctuations due to high CAPEX and long payback periods. The NPV is obtained by subtracting the present value of periodic cash outflows from the present value of periodic cash inflows [3].

Internal Rate of Return (IRR): The IRR is the discount rate at which NPV equals zero, indicating project profitability. It is sensitive to timing, scale of cash inflows, and government take mechanisms IRR. Delays in production, higher upfront capital expenditures, or increased government fiscal obligations can reduce the project's IRR. A project is generally considered financially attractive when its IRR exceeds the investor's required rate of return or hurdle rate, which in this study is assumed as 12% [3].

Payback Period: This measures the time needed to recover initial investment costs. Particularly critical in offshore settings due to large, front-loaded capital expenditure. Shorter payback periods are preferred to reduce exposure to long-term market and political risks. Favorable fiscal regimes may include early-stage cost recovery provisions to shorten this period [3].

Profitability Index (PI): The PI shows the relative profitability of an investment, or the present value of benefits per the present worth of every dollar invested (i.e., higher net return for each dollar invested). The profitability index helps investors to understand how much in present value benefits is created per dollar of investment. When comparing two projects, the project with the largest PI value generates the largest cumulative NPV that can be accumulated from the available present worth investment dollars, and it is safe to say that the higher the PI, the better the investment [3].

Unit Technical Cost: The unit technical cost is defined as the ratio of the total cost (CAPEX and OPEX) over the economic life of a project to the total expected reserves from the project. The indicator is thus reported in \$/barrel. If other products such as gas, NGLs or condensate are also recovered along with oil, then the indicator is reported in dollar per barrel of oil equivalent (\$/BOE) [3].

Unit Operating Cost: The Unit Operating Cost is the annual operating cost divided by the annual production rate. It helps stakeholders to understand how much operating expenditure is required to produce one unit of output, and its unit is in dollar per barrel (\$/BBL) or dollar per million standard cubic fit (\$/MSCF) [3].

Unit Capital Cost: The Unit Capital Cost is the total capital investment divided by the total recoverable reserves or production capacity. With this financial indicator stakeholders can understand how much capital investment is required per unit of recoverable resource [3].

A critical determinant of petroleum project economics is the petroleum fiscal regime. A fiscal regime establishes the mechanisms through which petroleum revenues and economic rents are distributed between the investor and the resource-owning government through instruments such as royalties, taxes, levies, allowances, bonuses, and production-sharing arrangements [4]. The design of these fiscal terms must balance two potentially competing

objectives: maximizing government revenue from finite petroleum resources while maintaining sufficient investment attractiveness to encourage exploration, field development, and sustained production. This balance is particularly important in petroleum-producing jurisdictions because changes in fiscal parameters can materially affect project cash flows, investor returns, government revenue, and investment thresholds [5]. Investors therefore require analytical tools capable of evaluating not only expected project profitability but also the sensitivity of investment outcomes to changes in fiscal and economic assumptions.

In Nigeria, the need for robust petroleum economic evaluation is particularly significant because of the strategic importance of the petroleum sector to government revenue, foreign exchange earnings, and investment. Historically, Nigeria's upstream petroleum industry operated under a fragmented fiscal and regulatory framework comprising instruments such as the Petroleum Act, the Petroleum Profits Tax Act, joint-venture arrangements, and production-sharing contracts. Over time, concerns relating to fiscal uncertainty, regulatory fragmentation, investment attractiveness, and revenue optimization contributed to the demand for comprehensive sector reform [6]. The Petroleum Industry Act (PIA) 2021 was subsequently enacted as a major reform of Nigeria's petroleum industry, establishing a more integrated framework for governance, administration, host-community development, and petroleum industry fiscal management [7].

The PIA 2021 introduced significant changes to the fiscal environment within which upstream petroleum projects are evaluated. Its fiscal framework seeks to establish a progressive and transparent structure that encourages petroleum investment while providing a fair return to the Federal Government of Nigeria [8]. Among other provisions, the framework incorporates hydrocarbon taxation, Companies Income Tax, production- and price-based royalty mechanisms, cost-recovery provisions, and incentives relating to frontier exploration and gas development. The Act therefore creates a multidimensional fiscal environment in which the economic performance of a petroleum project cannot be adequately assessed from a single tax or royalty parameter. Rather, the combined effects of fiscal instruments must be incorporated into project cash-flow models to determine their implications for investor profitability and government revenue. The PIA's royalty framework, for example, varies according to terrain, production characteristics, and petroleum prices, while its tax provisions distinguish between different categories of petroleum operations [9].

Although the PIA represents a significant reform, the quantitative assessment of its fiscal implications remains an important research and analytical requirement. Existing studies on Nigeria's petroleum fiscal framework have predominantly examined the legal, institutional, comparative, and policy dimensions of the PIA and earlier fiscal regimes [9]. Comparative studies have examined differences between Nigeria and other petroleum-producing jurisdictions, while legal and policy studies have considered issues such as fiscal attractiveness, governance, implementation, and progressivity [11]. Other studies have applied quantitative approaches, including economic modelling, scenario analysis, stochastic simulation, and Monte Carlo techniques, to investigate petroleum project profitability and the effects of fiscal parameters on investment outcomes [12,13]. However, the literature reviewed in this study indicates a limited availability of integrated, localized digital applications specifically designed to translate Nigeria's PIA fiscal provisions into project-level economic evaluation and investment-support outputs.

This gap is important because conventional petroleum economic evaluation can become increasingly complex when numerous fiscal rules, production assumptions, economic variables, and uncertainty parameters must be evaluated simultaneously. Existing petroleum economic and fiscal modelling platforms may provide sophisticated analytical capabilities, but access, flexibility, localization, and adaptability to specific fiscal regimes can present practical limitations. The research underpinning this paper therefore identifies two related gaps: first, the lack of a localized quantitative framework for evaluating the effect of Nigeria's PIA 2021 fiscal provisions on petroleum project economics; and second, the absence of an accessible, digitally driven platform that integrates fiscal computation, economic evaluation, scenario analysis, sensitivity analysis, and uncertainty assessment within a single analytical environment.

Digital decision-support systems provide an opportunity to address these limitations by integrating data, computational models, fiscal rules, economic evaluation, and analytical outputs into a unified environment. In petroleum investment analysis, such systems can transform complex fiscal and project data into decision-relevant information, enabling investors, regulators, financial institutions, and other stakeholders to evaluate

alternative investment scenarios and assess risk more systematically. The theoretical foundation of the present study consequently combines petroleum fiscal regime theory, petroleum investment theory, investment-under-uncertainty theory, and decision-support systems theory. Within this framework, fiscal parameters influence project cash flows and economic performance; uncertainty in oil and gas prices, production, CAPEX, and OPEX influences the distribution of investment outcomes; and digital decision-support capabilities integrate these relationships into an analytical platform for investment evaluation.

Against this background, this study developed a Python-based Economic Evaluation and Investment Decision Support Tool (EEIDST) for upstream petroleum investment analysis under Nigeria's PIA 2021 fiscal framework. The application integrates the principal stages of petroleum economic evaluation, including production and revenue estimation, royalty computation, tax and fiscal calculations, project cash-flow modelling, and economic evaluation. It is designed to generate key project and fiscal indicators, including NPV, IRR, PI, Payback Period, breakeven price, and Government Take. The integration of these functions is consistent with the study's conceptual framework, in which changes in petroleum project and fiscal variables are translated through an integrated computational environment into project economic and investment-support outputs.

A further contribution of the study is the validation of the developed EEIDST against an independently developed Excel spreadsheet-based discounted cash flow (DCF) model. Model validation is important because a digital economic evaluation tool is only useful for investment decision support when its computational outputs can be demonstrated to be consistent with an independently developed analytical benchmark. The research design therefore treats validation as a central component of the tool-development process rather than merely as an application outcome.

Accordingly, the objective of this paper is to develop and validate a Python-based Economic Evaluation and Investment Decision Support Tool (EEIDST) for upstream petroleum investment analysis under Nigeria's Petroleum Industry Act 2021. The study specifically focuses on translating the PIA fiscal provisions into an integrated computational framework for petroleum project economic evaluation and demonstrating the capability of the developed application to support investment analysis through automated economic indicators, fiscal calculations, and uncertainty assessment. The paper contributes to petroleum economics and digital decision-support research by linking Nigeria's post-PIA fiscal framework with an integrated, programmable economic evaluation environment and by demonstrating a validation approach based on comparison with an independently developed DCF model. The resulting framework is intended to provide a transparent, adaptable, and scalable basis for quantitative upstream petroleum investment evaluation and can potentially be extended to other petroleum fiscal regimes through modification of its modular fiscal components.

LITERATURE REVIEW

The literature on petroleum investment evaluation in Nigeria has increasingly focused on the effectiveness of fiscal and regulatory reforms, particularly following the enactment of the Petroleum Industry Act (PIA) 2021. The reviewed studies can be broadly grouped into four areas: PIA and petroleum-sector reforms, petroleum fiscal regimes and investment attractiveness, quantitative economic and fiscal modelling, and uncertainty-based investment analysis. These studies provide the foundation for understanding the development of an integrated digital tool for upstream petroleum investment decision support.

A. Petroleum Industry Act and Fiscal Reform

Several studies have examined the PIA 2021 from legal, regulatory, governance, and fiscal perspectives. Iwok and Daniel [10] examined whether the PIA improved petroleum taxation, governance, and government revenue mobilization through a desk review of the Act, previous petroleum legislation, academic literature, and policy documents. The study concluded that the PIA provides a more comprehensive fiscal and governance framework with potential to improve investment and government revenue, although implementation, enforcement, transparency, institutional capacity, and some fiscal provisions remain challenges to investor attractiveness. Similarly, Sunday and Kelechukwu [14] examined the legal, regulatory, fiscal, governance, and host-community provisions of the PIA and found that the Act provides a stronger framework for governance across the petroleum

value chain, although significant gaps remain in areas including gas flaring, host-community funding, and frontier exploration.

Other studies have assessed the PIA in relation to investment attractiveness and sustainable development. Nwosi-Anele and Iledare [11] assessed the attractiveness and progressiveness of Nigeria's fiscal framework under the PIA within a zero-carbon-emission strategy and concluded that fiscal incentives and policies require further alignment with Nigeria's energy-transition objectives. Nwankwo and Ringim [15] similarly concluded that implementation of the PIA could improve transparency, investment confidence, governance, and host-community development. However, Nwankwo and Atebe [16] found that although the PIA incorporates several features of international best-practice regulatory frameworks, Nigeria continues to face challenges relating to regulatory efficiency, investor competitiveness, and institutional capacity. Paul [17] and Nnaemeka and Nnaemeka [18] also identified governance and institutional weaknesses as potential constraints to achieving the expected economic benefits of the PIA.

The literature further indicates that the effects of the PIA vary according to petroleum asset characteristics and contractual arrangements. Adedamola et al. [19] examined the economics of small and stranded gas fields and concluded that the PIA improves their commercial prospects through more competitive fiscal provisions, clearer regulatory arrangements, and investment incentives. Clement et al. [12] investigated PSC cost-recovery provisions and found that changes introduced by the PIA affect contractor returns, Government Take, and investment attractiveness. Obakhume et al. [20] used scenario-based fiscal modelling across onshore, shallow-water, and deepwater projects and reported improved contractor economics under the post-PIA fiscal regime. These studies demonstrate the need to evaluate the PIA through quantitative project-level analysis rather than relying exclusively on legal and qualitative assessments.

B. Petroleum Fiscal Regime and Investment Attractiveness

The relationship between petroleum fiscal terms and investment attractiveness has also received considerable attention. Adeyemo [21] conducted a comparative assessment of the petroleum fiscal systems of Nigeria and Angola using royalty, state participation, local content, cost recovery, income tax, profit-oil sharing, and Government Take as key variables. The study concluded that Angola's fiscal regime was relatively more stable and progressive, while Nigeria's fiscal system had advantages in its income-tax structure. Abdulsalam [22], examining Malaysia's petroleum fiscal regime, found that changes in fiscal terms produced different investment outcomes under low, medium, and high oil-price scenarios, demonstrating the importance of considering commodity-price conditions when evaluating fiscal attractiveness.

At the project level, Adeogun et al. [23] applied stochastic economic modelling to evaluate the profitability of Nigerian marginal oil fields under different reserve sizes and oil-price conditions. The study found that profitability was highly sensitive to reserve size and oil price and recommended targeted fiscal incentives and cost-minimization strategies for smaller fields. Petter and Anders [24] similarly demonstrated that development-concept selection and fiscal terms jointly influence petroleum project profitability and recovery performance. Dongkun and Yan [24] further showed that royalties, taxes, cost-recovery limits, and profit-oil splits significantly influence the distribution of petroleum economic rent between investors and governments.

The findings from these studies establish that petroleum investment decisions are strongly dependent on the interaction between fiscal terms, project characteristics, production performance, costs, and commodity prices. However, most of the studies focus on evaluating specific fiscal regimes, projects, or scenarios rather than developing a reusable digital environment capable of integrating these variables within a single investment-support platform.

C. Quantitative Economic and Fiscal Modelling

Quantitative modelling provides an important methodological basis for petroleum fiscal and investment analysis. Fubara et al. [26] employed a deterministic royalty/tax cash-flow model to evaluate the dual petroleum tax system proposed under Nigeria's 2017 fiscal reform framework. The study compared fiscal systems proposed under different petroleum reform bills and found that a dual-tax structure could increase Government Take while

maintaining investor viability for economically robust projects. However, the study emphasized the importance of appropriately calibrating tax rates, allowances, and cost-recovery provisions to avoid discouraging marginal investments.

Joseph et al. [27] similarly applied comparative fiscal-simulation modelling to examine the replacement of Petroleum Profit Tax with a dual Hydrocarbon Tax and Companies Income Tax system. The model evaluated project cash flows, NPV, IRR, and Government Take under alternative fiscal structures and demonstrated that fiscal design materially affects rent distribution and investor returns. Coddou et al. [28] developed a *Fiscal System Modeling Framework* incorporating royalties, taxes, cost-recovery rules, and profit-oil splits into a unified cash-flow model. The study demonstrated that relatively small changes in fiscal parameters could significantly affect government revenue and investor profitability.

More directly relevant to the PIA, Amina et al. [29] developed an Excel-based economic model incorporating PIA 2021 fiscal provisions to evaluate marginal-field investment using Net Cash Flow, NPV, IRR, and Government Take. The study concluded that the PIA fiscal provisions were attractive for marginal-field investment. While this study demonstrates the applicability of computational modelling to PIA-based investment analysis, its spreadsheet-based implementation is primarily designed for the specific economic evaluation undertaken by the researchers.

D. Uncertainty and Investment Decision Analysis

Petroleum investment decisions are characterized by substantial uncertainty in oil prices, reserves, production, costs, and other economic variables. Begg and Smith [30] investigated the sensitivity of petroleum project economics to uncertainty in oil-price models and parameters. Using Monte Carlo simulation and scenario analysis, the study demonstrated that alternative oil-price models and parameter assumptions can produce substantially different NPV, IRR, and expected monetary value outcomes. The authors consequently emphasized that investment evaluation based on a single deterministic price assumption may produce misleading conclusions.

Adeogun et al. [13] similarly demonstrated the importance of stochastic analysis by showing the sensitivity of marginal-field profitability to oil price and reserve size. Asuquo [31] further examined investment decisions under oil-price volatility using a game-theoretic model and demonstrated that price uncertainty can influence investment timing and strategic behaviour. Prince et al. [32], although focused on gas-utilization investments, developed a techno-economic framework integrating engineering, cost, policy, and investment criteria to support investment decisions under different price, policy, and infrastructure conditions.

E. Research Gap

The reviewed literature demonstrates considerable progress in understanding Nigeria's PIA 2021, petroleum fiscal regimes, project profitability, and investment uncertainty. Nevertheless, important gaps remain. First, a substantial proportion of PIA-related research is focused on legal, policy, regulatory, and qualitative assessments, with comparatively limited integration of the Act's fiscal provisions into comprehensive project-level computational applications [10,14]. Second, quantitative studies have demonstrated the effectiveness of economic and fiscal modelling but have largely relied on deterministic, spreadsheet-based, or study-specific models [26,27]. Third, although stochastic simulation, sensitivity analysis, and scenario modelling have been applied to petroleum investment problems [13, 30], these techniques have generally not been integrated with a comprehensive PIA-based fiscal evaluation platform.

The identified gap is therefore the absence of an integrated, programmable, and PIA-specific digital decision-support application that combines petroleum production and revenue estimation, royalty and fiscal calculations, project cash-flow modelling, economic evaluation, sensitivity analysis, and Monte Carlo simulation within a unified environment. This study addresses this gap through the development of the Python-based Economic Evaluation and Investment Decision Support Tool (EEIDST). The application integrates the principal components of upstream petroleum economic evaluation and provides investment indicators including NPV, IRR, Profitability Index, Payback Period, and Government Take. The developed tool is further validated against

an independently developed discounted cash-flow model, thereby extending existing petroleum fiscal modelling research from individual analytical models toward an integrated digital platform for upstream petroleum investment decision support.

METHODOLOGY

The study adopted a design-and-development methodology to develop and validate a Python-based Economic Evaluation and Investment Decision Support Tool (EEIDST) for upstream petroleum investment analysis under Nigeria's Petroleum Industry Act (PIA) 2021. The methodology comprised five main stages:

1. Requirements and fiscal framework analysis: Relevant PIA 2021 fiscal provisions applicable to upstream petroleum projects were identified and translated into computational rules, including royalties, taxes, allowable costs, fiscal allowances, and other applicable government levies. The relevant provisions of the Act that were relevant to this study are;

A. Royalty

The PIA 2021 provided for production-based and price-based royalties across all terrain types (which includes Onshore, Offshore, Shallow-waters, Deep Offshore) in the Seventh Schedule. Paragraphs 10(2)-(6) of the Act provides that under this framework, the royalty rate is linked directly to prices of crude oil in the international market, thereby allowing the fiscal system to capture a greater share of economic rent when the prices of oil are high while imposing no additional burden at low oil prices. Specifically, this section stipulates that no royalty-by-price is payable when the oil price is below USD \$50 per barrel, reflecting a policy intention to support project economics during low-price environments. When the oil price is at USD \$100 per barrel, the royalty-by-price increases to 5 percent, and at prices above USD \$150 per barrel, it rises further to 10 percent, ensuring that the government take increases progressively with price. For intermediate price ranges, between USD \$50 and USD \$100, and between US\$100 and US\$150. The royalty rate is calculated through linear interpolation, which provides a predictable progression of fiscal burden without a spike in the royalty rate. This fiscal system enhances the responsiveness of Nigeria's fiscal regime to global oil market conditions. The total royalty based on this fiscal provision is calculated as;

$$R_{oil} = PBR_{oil} + PrBR_{oil}(1)$$

$$R_{gas} = PrBR_{gas}(2)$$

$$RT = R_{oil} + R_{gas}(3)$$

R_{oil} and R_{gas} are the oil and gas royalties respectively, while RT is the total royalty.

PBR_{oil} , $PrBR_{oil}$, and $PrBR_{gas}$ are the oil price-based royalty, oil production-based royalty, and gas production-based royalties.

B. Host Community Development Fund (HCDF)

This is a mandatory financial contribution made by oil and gas companies operating in the Niger Delta region. The contribution is intended to support economic and infrastructure development, social welfare, and sustainability projects in the host communities. The Host Community Development Fund (HCDF) function Calculates the annual Host Communities Development Fund contribution based on the previous actual OPEX made by the operating company. Consequently, there is no contribution in Year 0. This function aligns with PIA 2021 - Sections 240, as highlighted below;

"240.(1) The constitution of each host community's development trust shall establish a fund comprising of one or more accounts ("host communities development trust fund") to be funded under this section.

(2) Each settlor, where applicable through the operator, shall make an annual contribution to the applicable host communities development trust fund of an amount equal to 3% of its actual annual operating expenditure of the preceding financial year in the upstream petroleum operations affecting the host communities for which the applicable host community's development trust fund was established".

The HCDF is calculated using the model below,

$$\text{Host Comm. Fund } [0] = 0 \quad (4)$$

$$\text{Host Comm. Fund } [i] = \text{Actual OPEX } [I - 1] \times \text{Host Comm. Fund Rate } (3\%)(i > 0)(5)$$

C. Tertiary Education Trust Fund Tax (TetFund Tax)

This is the mandatory contribution imposed in companies registered in Nigeria, including the oil and gas companies. The proceeds from the tax is intended for research, academy training, public tertiary education, and infrastructural development. The TetFund Tax is a statutory levy under TetFund Act 2011 at a rate 2% assessable profit. This function calculates the tax that applies to possible assessable income. The education tax is provided for in the Tertiary Education Trust Fund (Establishment, etc.) Act 2011 - Section 1. The Tertiary Education Trust Fund Act 2011 provides;

$$\text{IF Assessable Profit} < 0: \text{TetFund Tax} = 0(6)$$

$$\text{Else: TetFund Tax} = \text{Assessable Profit} \times \text{Education Rate } (3\%)(7)$$

D. Niger Delta Development Commission (NDDC) Levy

This levy is established under the Niger-Delta Development Commission (Establishment etc) Act 2000 Act No 6 Laws of the Federation of Nigeria. The function calculates the mandatory financial contribution imposed on Oil and gas producing companies operating in Nigeria. This levy is used by NDDC for environmental remediation, infrastructural development, as well as social and economic development in the Niger delta region. The function is coded in alignment with the provision of the Act which states as follows;

The NDDC Levy is calculated thus;

$$\text{NDDC Levy} = \text{Budget} \times \text{NDDC Rate } (3\%)(8)$$

E. Adjusted Profits

The Adjusted Profit represents the petroleum project profit after accounting for allowable operating and relevant fiscal adjustments before applying the applicable tax provisions. Under the PIA, as provided for in Section 265 (1) – (3) of the Act, the adjusted profit represents the profit derived after deducting allowable expenses from assessable revenue while excluding specifically disallowed expenditures such as penalties, litigation costs, bad debts, and certain financial charges. This fiscal term is calculated as follows:

$$\text{Adjusted Profit (AP)} = \text{Gross Revenue (GR)} - \text{Allowable Deductions } (9)$$

F. Cost Ratio Limit

The Cost Ratio Limit is applied to restrict the proportion of production revenue that can be offset by recoverable costs in accordance with the applicable fiscal regime, thereby preventing excessive cost deductions from reducing taxable income. In the Sixth Schedule of PIA 2021 Section 2(1) – (2) the Act restricts the total deductible costs for Hydrocarbon Tax purposes to 65% of gross revenue at the measurement point, with any excess qualifying costs carried forward to subsequent accounting periods. This mechanism was introduced to prevent excessive cost deductions and ensure a minimum taxable base. The Cost Ratio Limit is calculated for a petroleum project as;

$$\text{Deduction Limit} = 0.65 \times \text{Gross Revenue} \quad (10)$$

G. Chargeable Profit

The Chargeable Profit is determined after applying the allowable deductions and the cost ratio limitation to adjusted profit and constitutes the final profit upon which Hydrocarbon Tax is assessed. The provision of the Act governing the computation of chargeable profit is provided under Section 266, with the detailed application of the cost ratio limit prescribed in the Sixth Schedule of the Act. Together, these fiscal provisions form the basis for determining the hydrocarbon tax liability of upstream petroleum companies and were therefore employed as critical variables in the analytical framework of this research. The Chargeable Profit is calculated using this model;

$$\begin{aligned} \text{Chargeable Profit} \\ = \text{Adjusted Profit (AP)} - \text{Capital Allowance (CA)} \\ - \text{HT Loss brought forward.} \quad (11) \end{aligned}$$

Where *HT* is the Hydrocarbon Tax.

H. Hydrocarbon Tax (HT)

The Hydrocarbon Tax is a fiscal levy imposed on the chargeable profit derived from crude-oil operations, after deducting allowable costs, losses carried forward, and fiscal allowances. The tax applies only to crude oil, condensates, and natural gas liquids derived from associated gas, but it does not apply to non-associated gas, LNG, domestic gas, and gas processing and transportation revenue. Section 60 of the Petroleum Industry Act (PIA) 2021 provides the statutory basis for the imposition of Hydrocarbon Tax, which serves as a key fiscal instrument for assessing government revenue generation and the tax burden associated with upstream petroleum operations. The Hydrocarbon Tax is calculated as;

$$\text{HT} = \text{Chargeable Profit (CP)} \times \text{Hydrocarbon Tax Rate} \quad (12)$$

I. Company Income Tax (CIT)

The Company Income Tax is a key part of governments take under the Petroleum Fiscal Regime as established in the PIA 2021. It is a tax that is imposed on the overall taxable income of petroleum companies after deducting allowable expenses, capital allowances and losses carried forward. This CIT is applied to the profits of oil companies, and it is an important way for governments to get revenue from the oil industry. Unlike the Hydrocarbon tax (which applies only to crude oil related profits), the Company Income Tax applies to all upstream, midstream, and downstream petroleum operations, including non-associated gas, associated gas beyond the measurement point, Liquefied Natural Gas (LNG), gas processing, and transportation activities. This ensures that even where Hydrocarbon Tax does not apply as in the case of deep offshore crude oil operations or gas-focused projects, the government maintains a stable and predictable tax base. The statutory basis for the application of the Company Income Tax is provided for in Section 302 of the Petroleum Industry Act 2021. The CIT is calculated as;

$$\text{CIT} = \text{CIT Rate} \times \text{Texable Profit for CIT} \quad (13)$$

Where;

$$\text{Texable Profit for CIT} = \text{AP} - \text{CA} - \text{HT} - \text{HT Loses brought forward} \quad (14)$$

$$\text{AP} = \text{Allowable Profit}; \text{CA} = \text{Capital Allowance}$$

2. Model and application development

The Python-based EEIDST application was developed using the python modular programming approach. The different modules that were integrated into the EEIDST framework includes, the production and revenue function

(Module 1), royalty function (Module 2), fiscal computation function (Module 3), Tax calculation (Module 4), OPEX Classification function (Module 5), Profitability Matrix and Project Analysis Integration (Module 6), Monte Carlo Sensitivity Analysis (Module 7), and AI Bot Function (Module 8). These modules and their functions are highlighted in Table 1 below.

Production and Revenue Function: This is the first module of the EEIDST framework, it takes input from external hydrocarbon production forecast to calculate annual and cumulative oil and gas production volume from daily production rates. It also calculates the combined oil and gas revenue streams with adjusted inflation.

Royalty Function: This module is the second in the EEIDST architecture, it implements the PIA 2021 Seventh Schedule royalty framework for production-based and price-based royalties across all terrain types. The coding of the royalty function is governed by PIA 2021 - Seventh Schedule. The Oil Production Based Royalty is provided for in the Seventh Schedule, P10(1) -(4)(a)-(b), the Natural Gas production base royalty is provided for in the Seventh Schedule, P10(6), while the Oil Price Based Royalty is provided for in the Seventh Schedule, P11(1)(a)-(d)

Fiscal Computation Function: This is the third module that is integrated into the EEIDST framework. This module calculates the Host Community Development Fund (HCDF) which is provided for in Section 240 of PIA 2021. It also calculates the Tertiary Education Trust Fund which is provided for in Section 1 of the Tertiary Education Trust Fund Act 2011. Furthermore, this function calculates the Niger Delta Development Commission (NDDC) Levy. This is a levy that was established under the Niger-Delta Development Commission Act 2000 Act No 6 Laws of the Federation of Nigeria. Also integrated in this module was the Adjusted Profit, which was provided for in the PIA 2021 in Section 265, P(1)-(3), Cost Ratio Limit (PIA 2021 Sixth Schedule Section 2(1) – (2)), Chargeable profit (PIA 2021 Section 266(1) – (2)). Also integrated in this module is the function to calculate the Hydrocarbon tax, whose statutory basis for application is provided for in Section 260 of the PIA 2021, and lastly is the Company Income Tax (CIT), which was provided in Section 302 of the Petroleum Industry Act 2021 which provides as follows.

Tax Calculation Integration: This is the fourth module of the EEIDST framework. In this study, it is the top-level tax function which orchestrates the full fiscal workflow, combining Hydrocarbon Tax and Company Income Tax into a single callable interface. In alignment with the PIA 2021, the deductible tax which forms the government take are Hydrocarbon Tax (provided for in PIA 2021 Section 260) and Company Income Tax (provided for in PIA 2021 Section 302). So, the Total Tax was coded as the sum of the Hydrocarbon Tax and Company Income Tax in this module.

OPEX Classification Function: This is the fifth module in the EEIDST framework. This function classifies upstream operating expenses into those allowed and those not allowed as deductions for Hydrocarbon Tax under PIA 2021. This function calculates gas flare penalty payments (provided for in Section 1018 of the PIA 2021), non-allowed deductions (provided for in Section 264 of the PIA 2021), and allowed deductions (provided for in Section 263 of the PIA 2021).

Profitability Metrics and Project Analysis Integration: This is the sixth module in the EEIDST framework. In the EEIDST architecture, this function provides the project analysis master function which calls up all upstream modules into a single comprehensive project evaluation, then returns 20 different output metrics including the profitability metrics. Among other metrics returned in this modules are the NPV, IRR, PI, Payback period, Government take, Unit Technical Cost, Unit Operating Cost, and the Unit Capital Cost.

Monte Carlo Simulation Feature: This is the sixth module in the architecture of the EEIDST framework. It evaluates the impact of uncertainty and risk on hydrocarbon project profitability under varying technical, economic, and fiscal conditions. The module applies probabilistic simulation techniques by repeatedly generating random values for key uncertain input parameters such as oil price, gas price, production rate, capital expenditure (CAPEX), operating expenditure (OPEX), and fiscal variables within predefined probability distributions. The module allows users to specify between 1000 to 50000 iterative runs. Each iterative runs are randomly sampled for selected stochastic variables such as oil production, gas production, oil price, gas price, CAPEX, and OPEX. These sampled values are computed through the EEIDST fiscal and economic module to

generate a range of possible Present Values for the project. The simulation outputs are presented through probability distribution histograms with key percentile outcome reported as P10, P50, and P90, and Tornado charts used to rank the sensitivity ranking of the NPV to critical input variables. For oil and gas price variables, either a triangular or lognormal probability distribution is used. Additionally, while the lognormal probability distribution is used for oil and gas production variables, the triangular distribution is used for CAPEX and OPEX variable. This approach enables assessment of investment risk, uncertainty exposure, and project robustness under fluctuating market and operational conditions.

Artificial Intelligent (AI) Bot Response Module: This is the last module of the EEIDST framework. It powers a conversational AI assistant that is specialized in Petroleum Economics reporting. It integrates with the Groq inference API via the LangChain abstraction layer and maintains short-term conversation memory. It enforces a structured system prompt that constrains the model to produce formal petroleum economics reports. This AI response is integrated into the Python-based Economic Evaluation and Investment Decision Support Tool (EEIDST) framework to enhance user interaction, automate interpretation of economic results, and to support intelligent decision-making within the petroleum project evaluation framework. The module utilizes rule-based logic and intelligent response algorithms to analyze outputs generated from the economic, fiscal, sensitivity, and Monte Carlo simulation models and provide automated interpretations of project performance indicators.

The workflow of the Python-based EEIDST solution is shown as follows;

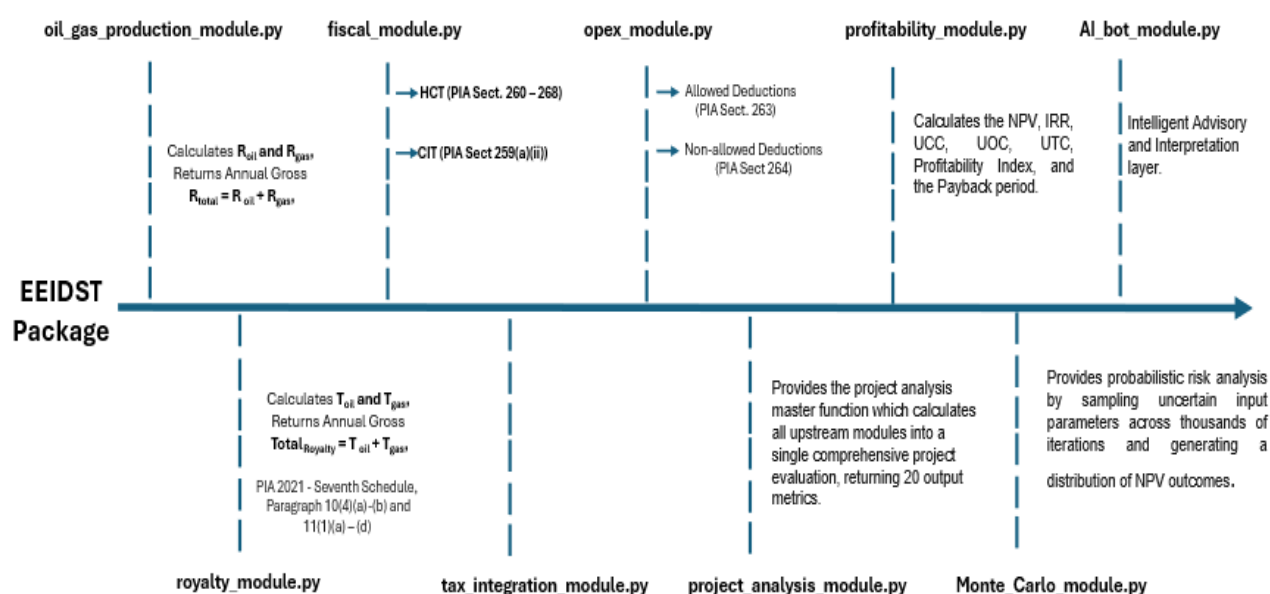


Figure 1: Python-Based EEIDST Architecture (PIA 2021 Aligned)

3. Computational Verification of the Python-Based EEIDST Using an Independent Excel-Based DCF Model

To verify the computational accuracy of the EEIDST, data for this study were collected primarily from Onshore development and production data. Key fiscal and economic parameters were obtained from the Nigeria Petroleum Industry Act (PIA) 2021 and other relevant publications of the Nigerian Upstream Regulatory Commission (NUPRC) and industry sources. Data relating to production profiles, crude oil and gas prices, capital expenditure (CAPEX), operating expenditure (OPEX), reserves, and other project parameters were cleaned, processed, and analysed then used as inputs for the testing the Economic Evaluation and Investment Decision Support Tool (EEIDST) and the independently developed Excel-based discounted cash flow (DCF) model (Figure 1 shows the Excel-based Model Workflow Diagram), to assess the accuracy and reliability of the EEIDST outputs. The outputs generated by the EEIDST were validated against the independently developed

Excel-based discounted cash-flow (DCF). The corresponding economic indicators were compared to establish the accuracy and consistency of the generated results from the Python-based application.

The study established acceptance criteria for comparing the economic and financial indicators generated by the EEIDST application with those obtained from the Excel-based discounted cash flow (DCF) model. The percentage error between the corresponding indicators was used as the basis for assessing the level of agreement. A percentage error of less than 1% was classified as excellent agreement, and the corresponding value was predetermined to be acceptable. A percentage error between 1% and 5% was classified as acceptable agreement, and the value was established as been in the acceptable range. However, where the percentage error exceeded 5%, it was pre-established that that value should be rejected, indicating that the calculated indicator requires further investigation.

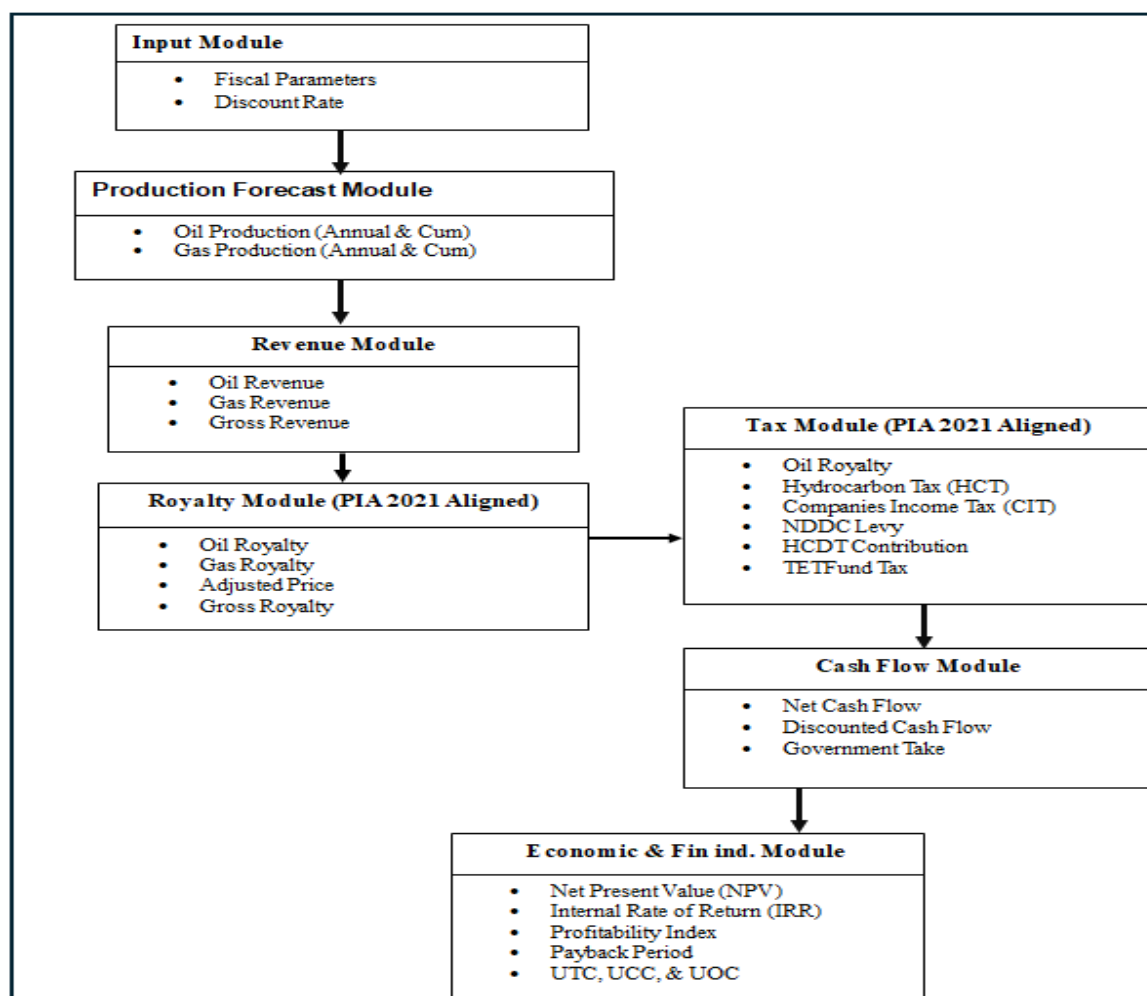


Figure 2: Excel Discounted Cash Flow Workflow Model

RESULTS

Table 2 below presents a comparative verification results of the EEIDST model against the independently developed Excel-based economic evaluation model. The results indicate a high level of agreement between the two approaches across key economic indicators, including Net Present Value (NPV), Internal Rate of Return (IRR), Productivity Index (PI), Payback Period, Unit Technical Cost, Unit Operating Cost, Unit Capital Cost, and Government Take. The calculated percentage error for all the economic indicators ranges from 0.01% to 3.73%, this demonstrates the accuracy and reliability of the EEIDST model as compared to the Excel model. The NPV, IRR, Payback period, Government Take, UCC, UOC and UTC achieved an excellent agreement, except for the Productivity Index that showed an acceptable agreement. Overall, the findings confirm that the EEIDST model closely reproduces the results of the benchmarked Excel model and is suitable for economic evaluation of onshore oil and gas field development projects.

Table 1: Verification of the EEIDST Results Through Comparison with the Excel-Based DCF Model

Economic Indicators	EEIDST	Excel Model	Percentage Error	Validation Status
Net Present Value (NPV)	\$ 137,679,518.00	\$ 136,680,566.55	0.73	Excellent Agreement
Int. Rate of Return (IRR)	15.90%	15.85%	0.32	Excellent Agreement
Profitability Index (PI)	1.670	1.610	3.73	Acceptable Agreement
Payback Period	6.900	6.901	0.01	Excellent Agreement
Unit Technical Cost	8.201	8.204	0.04	Excellent Agreement
Unit Operating Cost	3.360	3.392	0.95	Excellent Agreement
Unit Capital Cost	4.810	4.812	0.04	Excellent Agreement
Government Take	\$3,445,533,656	\$3,447,384,810	0.05	Excellent Agreement

Additionally, the EEIDST was validated to ascertain if its respond is logical and consistent with petroleum economic principles - which dictates that increases in revenue drivers, such as production or commodity prices, should improve economic indicators like Net Present Value (NPV) and Internal Rate of Return (IRR), while increases in costs or government take should reduce project profitability. To demonstrate this, a sensitivity analysis was conducted on oil price by varying the assumed oil price while keeping other key economic parameters, including CAPEX, OPEX, gas price, and production profile, constant. Table 3 presents the results of this analysis. The sensitivity analysis shows that project economics improve significantly with increasing oil prices. NPV increased from \$19.66 million at \$60/bbl to \$229.03 million at \$100/bbl, while IRR increased from 10.92% to 19.17%. At the same time, the payback period decreased from 8.0 years to 6.4 years, indicating faster recovery of the initial investment. The project was not considered economically viable at \$60/bbl but became viable from \$70/bbl onwards. These results indicate that oil price is a major driver of project profitability, with higher oil prices substantially enhancing investment attractiveness and reducing financial risk. The results showed that the response of the EEIDST is consistent with petroleum economic principles and the tool could be relied on for investment appraisal under varying oil prices.

Table 2: EEIDST Validation Results Based on Oil Price Sensitivity Analysis

Oil Price (\$/bbl)	Oil Price Assumptions	NPV (\$)	IRR (%)	Payback Period (Years)	Investment Decision
60	Moderate Low	19,661,297.41	10.92	8	Reject (Do not Invest)
70	Medium	82,071,682.96	13.62	7.4	Economically Viable
80	Base Case	137,679,518.00	15.89	6.9	Economically Viable
90	High	177,465,092.90	17.43	6.6	Economically Viable
100	Very High	229,033,345.21	19.17	6.4	Economically Viable

Furthermore, a second sensitivity analysis was conducted on the CAPEX by considering scenarios of cost overruns and cost savings while maintaining OPEX, oil price, gas price, and production profile at constant values. Table 4 presents the validation results of the EEIDST under different CAPEX scenarios. The results

demonstrate that project economics are sensitive to variations in capital expenditure (CAPEX). A 10% and 20% reduction in CAPEX increased the NPV from \$137.68 million in the base case to \$167.47 million and \$202.26 million, respectively, while the IRR improved from 15.89% (base case) to 17.72% and 20.15%. Similarly, the payback period decreased from 6.9 years in the base case to 6.6 years and 6.2 years, respectively, indicating faster capital recovery. Conversely, CAPEX overruns of 10% and 20% reduced the NPV to \$106.10 million and \$74.53 million, respectively, with corresponding decreases in IRR to 14.25% and 12.81%. The payback period also increased from 6.9 years in the base case to 7.6 years under the 20% CAPEX overrun scenario, indicating slower capital recovery. These results, generated by the EEIDST through systematic variations in project CAPEX, are consistent with established petroleum economic principles. The findings further support the reliability and computational validity of the EEIDST as a decision-support tool for upstream oil and gas investment evaluation.

Table 3: EEIDST Validation Results Based on CAPEX Sensitivity Analysis

CAPEX (\$)	Cost Assumptions	NPV (\$)	IRR (%)	Payback Period (Years)	Investment Decision
331365384	20% Cost Savings	202,263,223.47	20.15	6.2	Economically Viable
372786057	10% Cost Savings	167,469,944.69	17.72	6.6	Economically Viable
414206730	Base Case	137,679,518.00	15.89	6.9	Economically Viable
455627403	10% Cost Overrun	106,102,712.81	14.25	7.2	Economically Viable
497048076	20% Cost Overrun	74,525,906.51	12.81	7.6	Economically Viable

CONCLUSION

This study developed and validated a Python-based Economic Evaluation and Investment Decision Support Tool (EEIDST) for upstream petroleum project evaluation under the fiscal provisions of Nigeria's Petroleum Industry Act (PIA) 2021. The tool integrates petroleum fiscal modelling, discounted cash flow analysis, economic evaluation, sensitivity analysis, and Monte Carlo simulation within a single digital platform, providing a comprehensive framework for investment appraisal and decision support.

The validation results demonstrated a high degree of agreement between the EEIDST and an independently developed Excel-based DCF model, with percentage errors ranging from 0.01% to 3.73% across the evaluated economic indicators. This confirms the computational accuracy and reliability of the developed tool. Furthermore, sensitivity analyses on oil price and CAPEX produced responses that were consistent with established petroleum economic principles, showing that increases in oil prices improved project profitability while increases in capital costs reduced economic performance. These logical and predictable responses further validate the robustness of the EEIDST as an investment evaluation tool.

The study therefore concludes that the Developed Python-based EEIDST provides an efficient, transparent, and reliable digital solution for petroleum economic evaluation under Nigeria's PIA fiscal framework. By automating complex fiscal calculations and integrating uncertainty analysis, the tool enhances the quality of investment decision-making for petroleum operators, investors, regulators, financial institutions, and policymakers. The framework also offers a scalable foundation for future enhancements and adaptation to other petroleum fiscal regimes, thereby contributing to the advancement of digital decision-support systems in petroleum economics.

REFERENCES

1. Daniel, P., Keen, M., & McPherson, C. (Eds.). (2010). The taxation of petroleum and minerals: Principles, problems and practice. Routledge.

2. Johnston, D. (2003). International petroleum fiscal systems and production sharing contracts. PennWell Books.
3. Mian, M. A. (2011). Project Economics and Decision Analysis: Volume 1 – Deterministic Models (2nd ed.). PennWell Corporation, Chapter 6, pp. 251–298.
4. Tordo, S. (2007). Fiscal systems for hydrocarbons: Design issues (World Bank Working Paper No. 123). World Bank.
5. Tordo, S., Johnston, D., & Johnston, D. (2010). Petroleum exploration and production rights: Allocation strategies and design issues (World Bank Working Paper No. 179). World Bank.
6. Tordo, S., Warner, M., Manzano, O., & Anouti, Y. (2013). Local content policies in the oil and gas sector. World Bank.
7. Dike, S. C., & Okparaibea, N. (2023). An appraisal of the fiscal laws of oil and gas industry operation in Nigeria. *AJIEEL*, 7(01), 1-13.
8. Echendu, J. C., Iledare, O. O., & Onwuka, E. I. (2015). Comparative Economic-Performance Analysis of Production-Sharing Contracts in Angola, Equatorial Guinea, Gabon, and Nigeria. *SPE Economics & Management*, 7(04), 157-166.
9. Adedayo, A. V. (2014). A comparative study of the petroleum fiscal systems of Nigeria and Angola. Available from the Department of Oil and Gas Management, South America University.
10. Iwok, U., & Daniel, U. (2026). The Petroleum Industry Act (2021) and Nigeria's fiscal regime: A desk review of taxation, governance, and revenue mobilization.
11. Nwosi-Anele, A., & Iledare, O. (2024). Assessing the attractiveness and progressiveness of the fiscal framework in the 2021 Nigeria Petroleum Industry Act under a zero-carbon emission strategy.
12. Clement U., Eze, B. U., & Kingsley, I. (2025). Impact of Petroleum Industry Act (PIA) on Production Sharing Contract (PSC) cost recovery analysis in oil and gas management budgeting in Niger Delta, Nigeria.
13. Adeogun, O., Iledare, O. O., & Adekunle, J. I. (2018). Profitability of marginal oilfields in a low oil price regime: A stochastic modelling analysis.
14. Sunday, A. A., & Kelechukwu, N. E. (2023). Analysis of the Petroleum Industry Act and its impact on the Nigerian oil and gas sector.
15. Nwankwo, O. K., & Ringim, A. U. (2024). Implementation of Petroleum Industry Act 2021: A pathway for economic prosperity and sustainable development in Nigeria.
16. Nwankwo, O. K., & Atebe, O. J. (2024). Comparative analysis of best-in-class regulatory frameworks implemented in the petroleum industry vis-à-vis the Petroleum Industry Act, 2021.
17. Paul, I. O. (2021). An analysis of the Petroleum Industry Act 2021 as a panacea to achieving the economic objectives in Chapter Two of Nigeria's Constitution.
18. Nnaemeka, U., & Eke, N. P. (2025). Petroleum legislation and the economic impact of the Petroleum Industry Act (PIA) in Nigeria.
19. Adedamola, A., Mdondo, J., Agbo, C., & Samuel, P. (2022). The impact of the Petroleum Industry Act on the economics of small and stranded gas fields in Nigeria.
20. Obakhume, K. A., Igwe, E. R., Olugbeje, O. T., & Adeyemi, O. V. (2026). Shifting the balance: Fiscal attractiveness of Nigeria's petroleum regimes before and after the Petroleum Industry Act.
21. Adeyemo, V. A. (2014). A comparative study of the petroleum fiscal systems of Nigeria and Angola.
22. Abdulsalam, M. (2016). Effect of petroleum fiscal regime and tax instruments on the investment climate of marginal oil field in Malaysia.
23. Adeogun, O., Iledare, O. O., & Adekunle, J. I. (2018). Profitability of marginal oilfields in a low oil price regime: A stochastic modelling analysis.
24. Petter, O., & Anders, W. (2024). Petroleum development projects: Concept selection, taxation and recovery rate.
25. Dongkun, L., & Yan, N. (2010). Assessment of fiscal terms of international petroleum contracts.
26. Fubara, S. A., Iledare, O. O., & Akinlawon, A. J. (2018). Economic evaluation of the dual petroleum tax system proposed in the 2017 Nigeria fiscal reform framework.
27. Joseph, C. E., Iledare, O. O., Adeyemi, J. A., & Adekunle, J. I. (2018). Replacing Petroleum Profit Tax with a dual petroleum tax system: Implication on petroleum project economics in Nigeria.
28. Coddou, G., Hammond, R., Laaveg, M., Ogunyomi, B., Raeder, A., Svensson, M., & Xu, P. (2012). Fiscal System Modeling Framework. Society of Petroleum Engineers. <https://doi.org/10.2118/162893-MS>

-
29. Amina, D., Ibiye, I., Gbenga, O., Oghenerume, O., & Jesse, A. (2023). Evaluation of the profitability of marginal field investment using the fiscal provisions in the Petroleum Industry Act (PIA) 2021.
 30. Begg, S. H., & Smith, N. (2007). Sensitivity of project economics to uncertainty in type and parameters of oil price models.
 31. Asuquo, C. K. (2026). Strategic planning under price volatility: A game-theoretic model of investment decisions by Nigerian upstream operators.
 32. Prince, I., Yakubu, W., & Russien, M. (2026). Gas utilisation investment decisions supporting Nigeria's energy transition: A techno-economic framework for the Niger Delta region.