DANMADAMI, A.M. 2024. *Hybrid analytical hierarchy process model for the optimisation of marginal field development in Nigeria*. Robert Gordon University, PhD thesis. Hosted on OpenAIR [online]. Available from: https://doi.org/10.48526/rgu-wt-2795516

Hybrid analytical hierarchy process model for the optimisation of marginal field development in Nigeria.

DANMADAMI, A.M.

2024

Hybrid Analytical Hierarchy Process Model for the Optimisation of Marginal Field Development in Nigeria

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PhD 2024

Hybrid Analytical Hierarchy Process Model for the Optimisation of Marginal Field Development in Nigeria

AMINA MOHAMMED DANMADAMI

A thesis submitted in partial fulfilment of the requirements of

Robert Gordon University for the degree of Doctor of Philosophy

November 2024

Acknowledgements

I extend my deepest appreciation to Dr. Ibiye Iyalla, my Principal Supervisor, and Dr. Gbenga Oluremi for their unwavering support throughout my PhD journey. I am also immensely grateful to Dr. Ruissein Mohan, Dr Rosslyn Shanks and Dr. Jesse Andrawus for their guidance, encouragement, and for continually pushing me to excel. My sincere thanks go to the Graduate School and the School of Computing, Engineering, and Technology at Robert Gordon University for their invaluable support. Special appreciation to the Petroleum Technology Development Fund (PTDF) for funding this research.

I would also like to express my gratitude to my employer, the Nigeria Midstream and Downstream Petroleum Regulatory Authority, for granting me the opportunity and support to undertake this study. I am committed to ensuring that my research adds value to both the organization and the industry. To my colleagues, I say a heartfelt thank you! A special mention to Okechukwu Nwachukwu, Dr. Sani Hassan, and Najib Adamu for their encouragement and contributions.

My sincere gratitude goes to the management and staff of the Nigeria Upstream Petroleum Regulatory Commission (NUPRC) for their assistance in providing the necessary data for this research. In particular, I wish to acknowledge Mr. Amadasu, Mr. Salihu Garba, Mr. Ewuga, Vivian Akpagher, Seun Mumini, Mfon, Mr. Boma, Fati Bisayo, Celestine Letoski, Umar Hassan, Abdurrahman Idris, Faruq Shuaib, Dr Yusuf Bashir, Mohammed Malah and Barnabas for their invaluable support.

I deeply appreciate my study participants for their time and contributions. The interviews were extensive, and I am truly grateful for their patience and insights. A special thank you to Mr A. M. Abba and Mr. Chikezie Nwosu for going the extra mile. My profound appreciation also goes to my Professorial team, Prof. Wumi Iledare and Prof. Godwin Chukwu, for their constructive feedback and guidance.

Finally, to my family—words cannot fully express my gratitude for your love and support. You all stood by me, proofreading, sourcing research materials, caring for the children, making me laugh, and ensuring I stayed motivated. Usman, all I can say is that you are the best. May Allah reward you for your love, patience, and sacrifice.

Dedication

This thesis is dedicated to the memory of my late father Alhaji Muhammad Danmadami. Baba was a dedicated father who touched our lives and that of many others in profound ways. He was a pillar of strength whose prayers, wisdom, guidance and unwavering support made me the person I am today. Baba your memory continues to live on in our hearts. May Jannatul Firdaus be your final abode. Thank you for being the best father in the world. Your legacy of love, kindness and integrity remains my inspiration, daily. Allah ya jikanka da rahama.

Abstract

The slow pace of marginal field development in Nigeria poses a critical challenge to the nation's energy security and economic stability, given the reliance on oil and gas revenues. This stagnation stems from the lack of a systematic decision-making framework to address uncertainties in planning and evaluate strategic options against multifaceted objectives. Traditional approaches, focused primarily on financial metrics, fail to capture the complexity of marginal field development, resulting in suboptimal decisions and missed opportunities.

To address this gap, this research introduces a hybrid Analytical Hierarchy Process (AHP) model integrated with the Weighted Sum Method (WSM), screening, and economic modelling. The model prioritizes key criteria—Cost, Health, Safety, and Environment (HSE), Regulation, Security, Stakeholders, and Technology—while screening ensures feasibility and WSM evaluates alternatives against benchmarks. This comprehensive approach enhances the model's robustness and adaptability to Nigeria's unique challenges.

A case study of a shallow offshore field highlights the effectiveness of the hybrid AHP model in optimizing marginal field development. The analysis identified tieback development as the most cost-effective, regulatory-compliant, and reliable option. In comparison, cluster development emerged as the second-best choice, with a 9.6% increase in cost relative to the tieback option. Partial standalone development showed a 17.8% increase in cost compared to tieback. Full standalone development was identified as the least cost-effective option, with a 24.4% increase in cost compared to tieback. Validation through analysis of producing fields showed an 88% accuracy rate, confirming the model's practicality and alignment with industry requirements.

The research underscores the strategic potential of marginal fields to add 200,000 barrels of oil per day to Nigeria's output, bolstering economic growth and energy security. By providing a structured and reliable framework, this study equips stakeholders with the tools to make informed, sustainable, and efficient decisions for the optimisation marginal field development.

Keywords: Marginal Field Development Optimisation, Analytical Hierarchy Process, Decision Support Model, Option selection, Decision Criteria

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List of Acronyms

AICD	Autonomous Inflow Control Devices
API	American Petroleum Institute, unit of oil gravity
BAT	Best available techniques
BOE	Barrels of oil equivalent
BSCF	Billion standard cubic feet
CAPEX	Capital expenditure
DRILLEX	Drilling Expenditure
EIA	Energy Information Agency
EPS	Early Production System
FFD	Full Field Development
FID	Final Investment Decision
FLNG	Floating liquified natural gas
FPSO	Floating, Production, Storage, and Offloading
GIIP	Gas initially in place
GOM	Gulf of Mexico
GOR	Gas oil ratio
HSE	Health safety environment
IEA	International Energy Agency
IOC	International Oil Company
mD	Milli Darcies, unit of permeability
MD	Measured depth
MF	Marginal field
MMBBL	Million Barrels
MMBOE	Millions of barrels of oil equivalent
MMSCFD	million standard cubic feet per day (gas rate units)
MMSTB	Million stock tank barrels (oil volume units)
NDMI	Niger Delta Militants Insurgencies
NGL	Natural gas liquids
NMDPRA	Nigerian Midstream and Downstream Petroleum Regulatory Authority
NPV	Net Present Value
NUPRC	Nigerian Upstream Petroleum Regulatory Commission
OPEX	Operational expenditure

PFD	Phased Field Development
Psia	Pounds per square inch absolute, unit of pressure
PSMs	Problem structuring methods
RB	Reservoir barrels, at reservoir conditions
SCF	Standard cubic feet
STB	Stock tank barrels
STOOIP	Stock tank oil originally in place
SURF	Subsea, Umbilicals, Risers and Flowlines
Swc	Connate water saturation
TVDSS	True vertical depth subsea
UR	Ultimate Recovery
USD	US dollar, the currency of the United States
WI	Water Injection

Chapter 1 Introduction

1.1 Background

The progressive increase in global reliance on energy for social and economic development, driven by rising population, especially in developing countries, like Nigeria creates a critical need to secure additional energy sources for safe and sustainable growth and energy security. Despite the increasing emphasis on renewable energy, oil and gas will continue to play a vital role in the global energy mix for the foreseeable future (Figure 1.1).

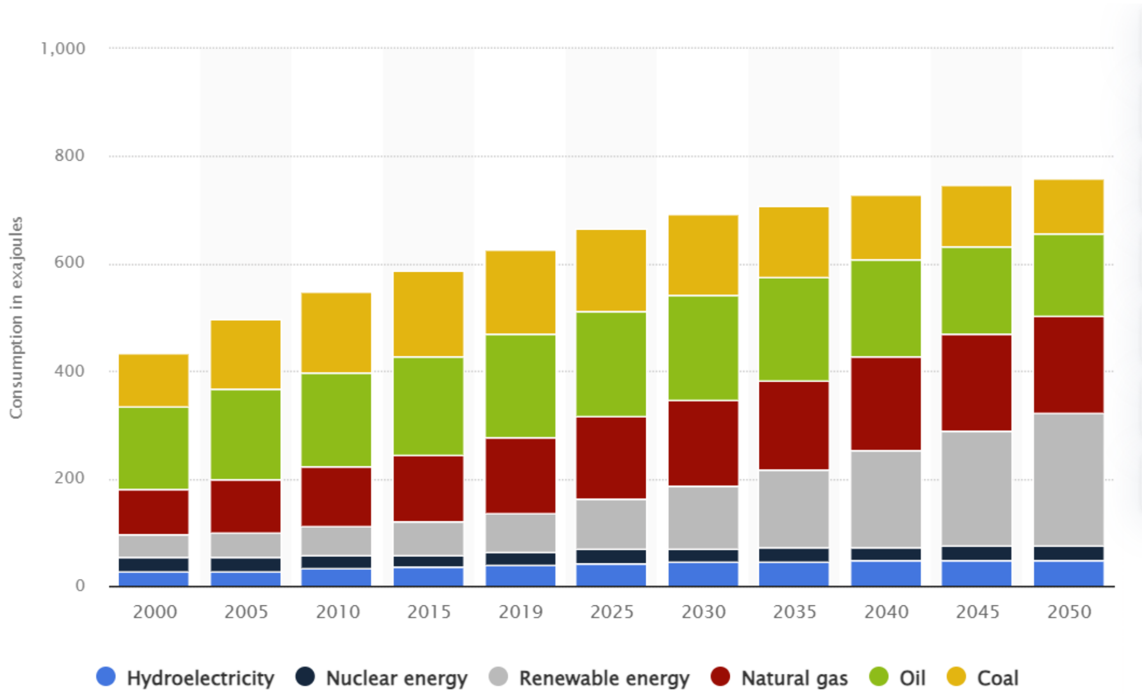

Figure 1.1: Energy Sources and Consumption (Source: Statistica 2023)

As shown in Figure 1.1, crude oil remains a significant contributor to global energy consumption, highlighting its critical importance (IEA, 2023). Owing to its abundance, low cost of production and high density enabling easy transport and storage, oil and gas account for 34% of global energy usage. While this makes oil and gas a competitive energy option for global usage, it must be stated that large oil and gas fields that justified substantial upfront investments are in decline. New discoveries consist of smaller, dispersed accumulations, usually referred to as marginal fields, and often uneconomical to develop under current technical and economic conditions. Consequently, meeting the increased demand for oil and gas requires increased production, may involve discovering new fields and/or reexploring previously producing fields or developing those considered marginal.

A marginal field is defined as "a field that may not produce enough net income to make it worth developing at a given time; should technical or economic conditions change; such a field may become commercial" (Josephs et al., 2022; Svalheim, 2004). Marginal fields are characterised by their smaller reserves and challenging operating conditions representing a significant component of global oil and gas landscape (Pan et al., 2022). Over 95% of the global known recoverable oil reserves are contained in less than 5% of major fields, while the rest are contained in small fields. Figure 1.2 shows Marginal offshore fields less than 50 MMboe recoverable reserves and approximately 75% of these pools are classed as small pools (Figure 1.2). The increasing economic needs for energy and improved technological development necessitate the development of marginal field, especially in developing countries plagued with energy poverty, poor energy accessibility and affordability.

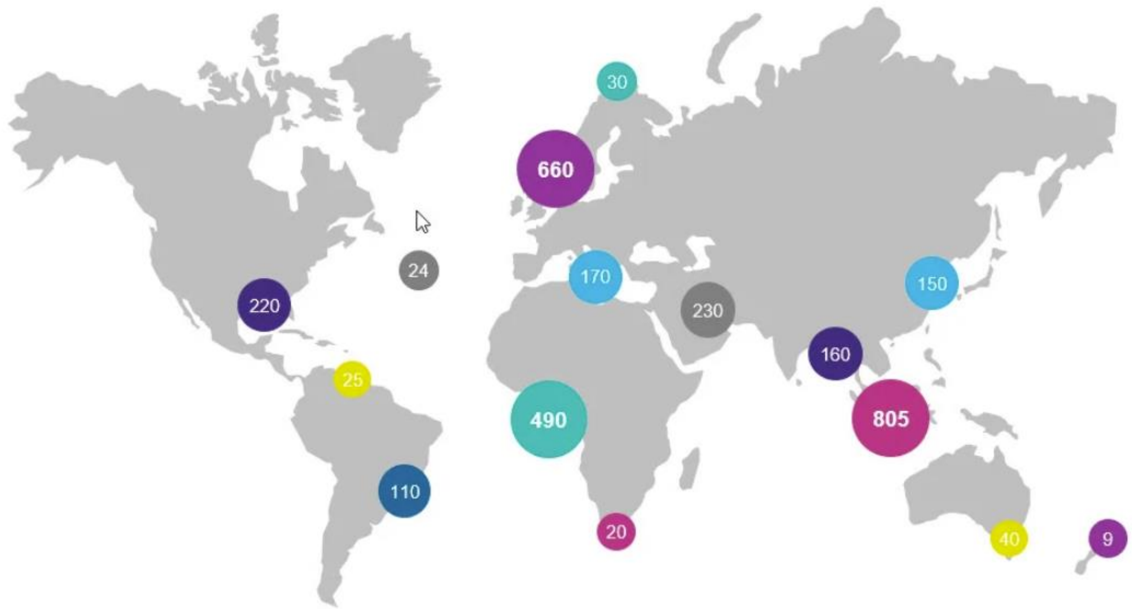

Figure 1.2: Global Overview of Marginal Fields (Source: ioconsulting.com)

Marginal field development offers a promising strategy to address global energy challenges. If properly harnessed, the enormous economic potentials of these fields can be beneficial to the country in many ways, including increasing domestic hydrocarbon production, enhancing energy security, fostering economic growth, and creating employment opportunities. The need to embrace marginal field development is further emphasised by the evolving global energy landscape, marked by fluctuating oil prices, increasing demand for cleaner energy sources, and the necessity to transition towards sustainable energy solutions. While these challenges are real and pressing, it also offers opportunity that allows countries to strategically position themselves to navigate the complexities of the energy transition, leverage technology and their natural resources to drive socio-economic development.

Many oil and gas producing countries including Nigeria have therefore embarked on Marginal Fields Program, with necessary incentives that allow marginal fields to be economically viable, and to encourage investments in marginal field development to meet their national objectives. In Norway, the Government embarked on the Marginal Fields Program to address the problem of existing (large) fields entering a tail-end production phase, large portfolio of small discoveries not yet developed, low exploration activity and increased international competition by giving incentives to encourage investors (Svalheim, 2004). Angola started the marginal field program to stem the decline in production. The Angolan Oil and Gas legislation was revised to spur growth in the sector by reducing taxes to encourage exploration and improved operation efficiency (Silva and Frazao, 2015). The Indonesian Government also encouraged development of its sixty marginal fields by offering incentives to investors on a case-by-case basis (Abdul Gani, et al., 2016). The incentives are to be in the form of reducing its stake in the oil production contract to allow marginal fields to be economically viable.

The Federal Government of Nigeria commenced marginal fields program in 2001 as part of her policy to improve the nation's strategic oil and gas reserves and promote indigenous participation in the upstream sector. This program was carried out through her regulatory agency the Department of Petroleum Resources (now Nigeria Upstream Petroleum Regulatory Commission. The legal and regulatory framework for the marginal fields' project is the Petroleum (Amendment) decree No. 23 of 1996 and the DPR marginal fields guideline. According to the amended Petroleum Act, the holder of an Oil Mining Lease (OML) could farm out marginal fields with the consent of the President, provided that the fields had been left unattended for at least ten years. The President's consent was contingent upon it being in the public interest, the field being left unattended for an unreasonable time, and the parties involved being acceptable to the Federal Government. This policy granted participatory rights to indigenous companies, allowing them to conduct petroleum operations under OMLs held by International Oil Companies (IOCs). Consequently, one hundred and eighty-three marginal fields with oil reserve of about 2.3 billion barrels have been identified (DPR 2020).

With the passage of the petroleum industry bill into law in August 2021, the petroleum industry act (PIA 2021) which has now repealed The Petroleum Act, vests the regulation of upstream activities in Nigeria Upstream Petroleum Regulatory Commission (NUPRC). To this end, the Petroleum Industry Act (PIA 2021) defines a marginal field as a field or discovery which has been declared a marginal field prior to 1st January 2021 or which has been lying fallow without activity for seven years after its discovery prior to the effective date. All Oil Mining Lease (OMLs) are now converted to Petroleum Mining Lease (PML) and all producing marginal fields are now Petroleum Prospecting Lease (PPL).

Marginal fields development in Nigeria holds a lot of potentials and advantages as enumerated by industry observers and analysts (Orimobi, 2020 and Duru, 2020):

- The offer price of Nigeria marginal field assets is almost a giveaway. Africa assets are on the average about 5% cheaper than global assets, Nigeria assets are sold at up to 45% discount compared to global assets making them the most attractive options.
- Some of the marginal fields are near existing infrastructure, this relieves operators of the cost and burden of constructing production and processing facilities, laying pipelines and flow stations as well as production operation infrastructure.
- Marginal field operators are allowed by the legal and regulatory framework to own assets at sole risk independent of the Government. An unusual practice considering OPEC’s membership policy that mandates host government to have participatory interest in all mineral licenses. However, they can enter a partnership with local or foreign companies to develop the assets.
- The long-awaited Petroleum Industry Act 2021 ensures Marginal Field operators are issued separate licenses for each field of production which allows them to use as collateral to source funds.

- The law also allows marginal field owners to partner with foreign companies with the requisite finance and technical expertise to develop their assets.
- PIA provides for improved fiscals which is expected to attract investment. Part of this is graduated royalty which is an incentive for fields with low production.

Within the Nigeria context, there are two ways through which indigenous companies can acquire fields - through award (bidding process or discretionary) and divestments from IOCs. Those obtained through bidding and discretionary award are those fields that have been discovered but never produced, usually fields within the IOCs acreage. The operators of the fields are designated marginal field operators. Those obtained through divestments are usually blocks and have been in production but divested by IOCs, and therefore have existing structures in place. The operators of divested assets are designated as indigenous operators. These divested assets being developed by indigenous companies have been very successful and produced operators such as AMNI Petroleum, Shoreline Energy, Aiteo, Neconde Energy, Waltersmith Petroman, Yinka Folawiyo Petroleum Company, Eroton, Amni International, Seplat Petroleum, Atlas Petroleum, FIRST E&P, Sahara, Belema Oil, and many others. They have added significant volumes to national production and created employment and empowerment opportunities for Nigerians (Eze et al, 2017). According to data from Nigerian Upstream Petroleum Regulatory Commission (NUPRC), eighty-seven (87) marginal fields have been awarded to indigenous companies through supervised bid rounds and discretionary award. In 2021, fifty-seven (57) fields were awarded to 161 indigenous companies (Figure 1.3). Twenty-four (24) fields were awarded to 31 indigenous companies in a three phased bidding process in 2003 while six (6) fields were awarded on discretionary allocations between 2006 and 2010 to four companies (Figure 1.4).

Figure 1.3: Nigeria Marginal Fields awarded (Source: NUPRC, 2021)

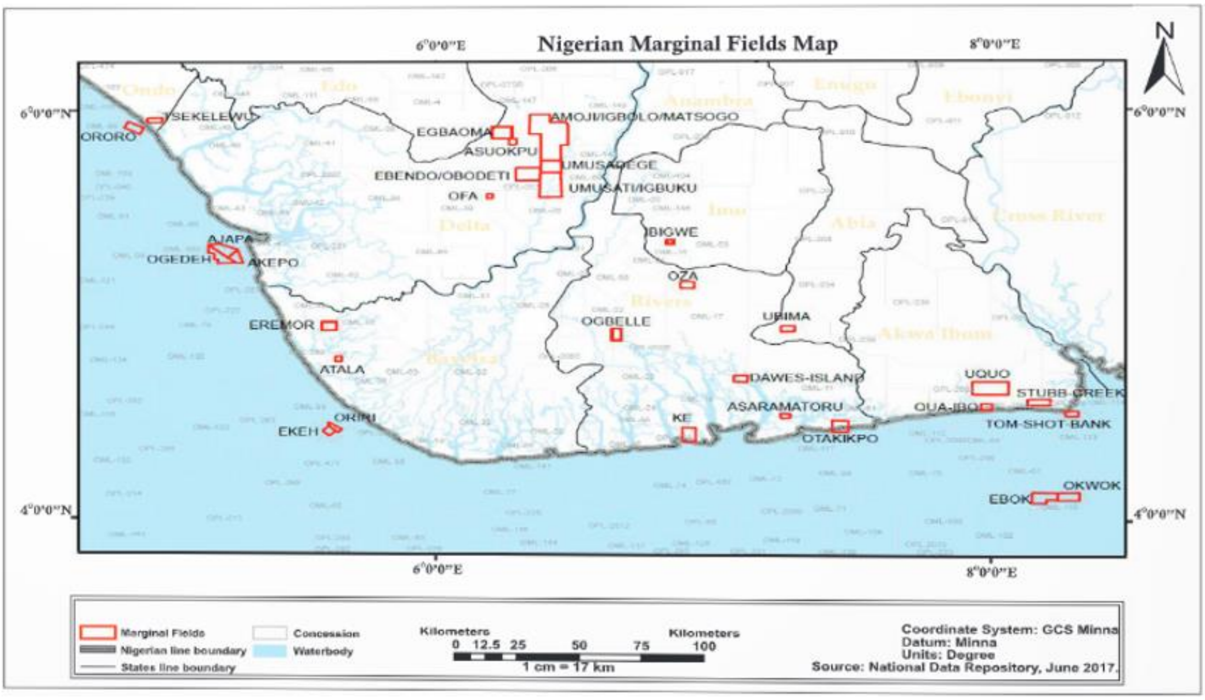

Figure 1.4: Nigeria Marginal Fields awarded between 2003 to 2010 (Source: NUPRC, 2018)

This study will focus on the marginal fields acquired through bidding and discretionary awards between 2003 to 2010. As shown in Figure 1.4, twelve (12) fields are located onshore, nine (9) fields offshore while the remaining eight (8) are in swamp. Ogbelle field was awarded to the Niger Delta Petroleum Resources, Okwok and Ebok fields awarded to Oriental Energy was to compensate the company for losing part of its OML 115 to Equatorial Guinea due to boundary adjustment. Otakikpo and Ubima fields were awarded to Green Energy Ltd and All Grace Energy Ltd respectively based on their commitments to fund three pilot projects, using the Public Private Partnership mechanism (Osahon 2013, Sarki 2020).

The Oil and Gas sector in Nigeria plays a very important role in the economic development of the country, providing 90% of Nigeria's export revenues, 70% of Government revenue and over 95 % of foreign exchange earnings as reported by the Central Bank of Nigeria (CBN). Marginal field activities (from 2003 to 2020) have resulted in the growth of marginal reserves from 110 MMbbls to 528 MMbbls. This upward increase of 2.8% was observed because of reserves addition from two marginal fields in 2019 (Sarki, 2020), with a potential for further increase, if the marginal fields properly developed.

In a country that currently produces crude oil below its OPEC quota by about 300,000 barrels per day due to operators not meeting their technical allowable rate (TAR) as a result of crude oil theft and insecurity (NUPRC 2023). Production from marginal fields could easily close this shortfall and boost indigenous entrepreneurial, managerial, and fund raising capabilities in Nigeria oil sector as the international oil companies carry out major divestments. While marginal fields have been contributing about 2.5% of total daily production in Nigeria, this is a deviation from the intended objective of the Federal Government initiative. This is because over 70 percent of awarded marginal fields remain undeveloped. Even though the legal framework allows marginal fields to operate and contribute immensely to the countries oil quota, challenges still exist and prevents their development to an optimum level. In this vein, Ashore et al. 2015; Oyakhire and Omeke 2017 identified insecurity, inadequate funding, multiple taxation, ineffective regulation, lack of technology and technical know-how as the major constraints to marginal field development in Nigeria. It was also stated that stakeholders' engagement, corporate social responsibility, collaborations and partnerships are enabling factors that have contributed to the success of the developed marginal fields (Otomboshoba and Dosunmu 2017).

1.2 Research Rationale

Marginal oil and gas fields, despite their smaller reserves and operational challenges, hold significant potential to enhance energy security, economic growth, and local development in resource-rich nations like Nigeria. With the potential to increase their contribution to national production from 2.5% to 10%, these fields represent a crucial opportunity for the sustainability of the energy sector. However, their development is complicated by challenges such as limited data, uncertain reservoir characteristics, environmental and social concerns, regulatory hurdles, and market volatility, necessitating a robust and structured approach to field development planning (Eyankware and Esaenwi, 2019; Josephs et al., 2022; Kalu-Ulu, 2023).

The planning of marginal field development is an intricate process involving the evaluation of multiple development options under uncertainty and across various disciplines. Selecting the most appropriate development option for marginal field development is a multi-criteria decision making problem. It requires assessing a combination of technical, economic, and non-technical parameters to determine the optimal hydrocarbon recovery strategy (Back, 2016; Ciccarelli et al., 2018). Traditional decision-making methodologies employed involve Net Present Value (NPV) evaluation, comparative risk assessments, cost-benefit analysis, and other financial based techniques. These approaches usually based on a single financial metric which convert non-monetary decision-making criteria to a monetary equivalent (Virine and Murphy, 2007). Final selection of the appropriate marginal field development option is typically by a score card approach. While these traditional decision making approaches work well, they have the following shortcomings (Rodriguez-Sanchez et al., 2012; Passalacqua et al., 2017; McLachlan et al., 2017);

- They fail to address the complex and interdisciplinary nature of the decision-making process.
- Reliance on a single financial metric does not capture the multifaceted considerations required, such as technical, social, and environmental factors.

- Difficulty in quantifying qualitative variables, including security, stakeholder engagement, ethical considerations, and regulatory impacts.
- Significant subjectivity in evaluating and prioritizing alternatives.
- Lack of mechanisms for integrating group decision-making, essential in stakeholder-driven industries.
- Inability to adapt to uncertainty in strategic objectives or evolving circumstances, limiting re-evaluation flexibility.

To address these challenges, the study develops a decision support tool based on a hybrid AHP model, which evaluates multiple development alternatives. This model considers key factors such as cost, safety, regulatory frameworks, and stakeholder engagement to prioritize development options that maximize both technical feasibility and economic return. A significant strength of AHP lies in its ability to derive priority scales, which quantify intangible factors in relative terms. It integrates both quantitative and qualitative data, making it particularly suitable for industries like oil and gas exploration and production, where decisions hinge on both rigorous data analysis and the subjective judgment of experts.

By addressing the limitations of traditional methods, this study provides a structured framework to optimize marginal field development strategies, ensuring technical feasibility, economic return, and sustainable resource utilization.

1.3 Research Aim and Objectives

The aim of this study is to develop a decision support tool using the hybrid analytical hierarchy process model for the optimisation of marginal field development in Nigeria. To achieve the aim of this research work, the following are the objectives of the study:

1. To develop a Decision-Making Model for Marginal Field Development by;
    a. Identifying criteria for evaluating marginal field development options in Nigeria
    b. Identifying possible field development options based on reserves, terrain and available infrastructure
2. To investigate the applicability of the decision model through case study of representative marginal field

a. To establish the relative importance of criteria for selecting marginal field development option
b. To examine the performance of the decision model by using it to evaluate and rank development alternatives for selected case study fields.
c. To investigate the robustness of the developed decision model and results obtained from its application in the case study fields.

3. To develop a Software Application for Model Implementation

1.4 Overview of Methodology

This study employs a hybrid Analytical Hierarchy Process (AHP) model to develop a decision-making framework for selecting optimal development options for marginal oil and gas field projects in Nigeria. The AHP framework, based on Thomas L. Saaty's multi-criteria decision analysis, systematically prioritizes and ranks alternatives using financial, technical, and operational criteria (Saaty, 2007). By integrating AHP with complementary quantitative techniques, the model addresses the complexities and uncertainties inherent in marginal field development, offering a robust and adaptable approach (Marttunen et al., 2017).

AHP is particularly appealing due to its hierarchical structure, which facilitates the logical and natural organization of complex decision problems (Mu and Pereyra-Rojas 2018; Ramanathan, 2001; Saaty, 2008). This hierarchical feature enhances stakeholders' understanding of the issue, fostering engagement and informed participation in the decision-making process (Taherdoost, 2017). While AHP may risk over-simplification, it effectively condenses complex realities into a structured framework suitable for assessment, even in situations with scarce or unreliable data (Rodriguez-Sanchez et al. 2012). This capability is invaluable in developing countries like Nigeria, where reliable quantitative data is often unavailable (Otombosoba, 2018). Furthermore, AHP is systematic and time-efficient, making it a practical tool for decision-making (Zediri et al., 2021).

The AHP framework prioritizes and ranks alternatives through pairwise comparisons of criteria, such as financial performance, technical feasibility, and operational considerations. Expert judgments are quantified using Saaty's 9-point scale, ensuring consistency and reliability through consistency checks and sensitivity analyses. This systematic evaluation is complemented by additional methodologies to enhance the decision-making process (Fairuz et al., 2023).

The hybrid approach integrates AHP with:

1. Field Development Screening: Assessing the feasibility of various development options.
2. Weighted Sum Model: Evaluating and ranking the viable options based on their performance across decision criteria

By combining these methodologies, the framework provides a comprehensive evaluation of both qualitative and quantitative factors, enabling decision-makers to navigate the multifaceted challenges of marginal field development effectively.

Validation of the model is conducted using historical data from active marginal fields, ensuring its reliability and accuracy. This hybrid framework offers actionable insights tailored to the Nigerian oil and gas context, addressing critical challenges such as regulatory compliance, environmental sustainability, stakeholder engagement, and financial viability.

This practical, data-driven decision-making tool is designed to support industry stakeholders, policymakers, and investors in optimizing marginal field development strategies. The detailed methodology underlying this framework is elaborated in Chapter 4.

1.5 Thesis Outline

This thesis report has seven (7) chapters in which all aspects of the research conducted towards achieving the research objectives is outlined.

Chapter 1: Introduction has provided an overview of marginal field development, marginal field development in Nigeria, overview of the Nigeria oil and gas industry outlining peculiarities with regards marginal fields in Nigeria and justification for the research. It also highlights the research aim and objectives and further outlines its scope and limitations.

Chapter 2: Literature Review presents a literature review of marginal field development – global, Africa and Nigeria. The chapter presents a detailed discussion of the current approaches and practices in marginal field development. It outlines the technical and commercial considerations for developing marginal fields as well as review of existing works in the evaluation of marginal field development. Decision making in marginal fields developed is discussed highlighting critical factors in marginal field development. Lastly, Multicriteria decision making is reviewed with emphasis on Analytical Hierarchy Process and its application in decision making.

Chapter 3: Development of Marginal Fields Decision Model details the assessment of Niger Delta marginal fields, development of a well-structured decision-making process by carefully considering project cost, health, safety and environmental impact, legal regulations, security, stakeholder (social feasibility), and technology criteria in line with subject matter experts' preference to select optimal marginal field development option.

Chapter 4: Methodology provides a description of research methodology employed in this study to achieve the research objectives, plans, procedures, data analysis is outlined in this chapter. It presents details of AHP Modelling outlining each step of the process.

Chapter 5: Application of Marginal Field Decision Model, outlines the application of the model to the prioritisation of criteria for evaluating marginal field, generating and selecting optimal development option for a representative marginal field.

Chapter 6: Implementation of Decision Model into a Digital Tool and Validation details the design of an intuitive and user-friendly interface for the decision support tool considering the needs and preferences of end users. The chapter gives details of testing and validation of the decision support tool to ensure that it functions correctly and produces accurate results using developed marginal fields in production.

Chapter 7: Conclusions and Recommendations outlines the research study's conclusions are outlined, and suggestions for future work based upon the research framework directed toward the application of AHP in selecting marginal field development option.

Chapter 2 Literature Review

This chapter reviews key literature underpinning the research, starting with an overview of marginal field development, its challenges, and the technologies used to address them. It also examines the economic and financial considerations essential for decision-making. Finally, the chapter introduces the Analytic Hierarchy Process (AHP), a Multicriteria Decision Analysis (MCDA) tool, highlighting its relevance for optimizing marginal field development strategies. This chapter thus sets the stage for the research by synthesizing insights from existing studies and identifying gaps addressed by this study.

2.1 Marginal Field Development

The development of oil fields presents unique challenges and opportunities depending on whether the field is classified as a commercial or marginal field. While both types require significant investment and careful planning, their economic viability, development timelines, and operational strategies differ considerably. Commercial fields typically offer long-term profitability and extensive development windows, whereas marginal fields necessitate rapid monetisation and efficient use of limited resources due to their shorter productive life and constrained profit margins (Oyakhire and Omeke, 2017; Felappi et al., 2021, Yusuf et al., 2020). Table 2.1 provides a detailed comparison of the key differences between commercial and marginal fields, highlighting their distinct characteristics and the implications for field development strategies.

Table 2.1: Comparison of Commercial and Marginal Oil Field Development Characteristics

Element	Commercial Fields	Marginal Fields
Productive Life	20 to 35 years	3 to 7 years
Planning Timeline	5 to 7 years for appraisal and development planning	Minimal time for planning; rapid development is required
Profit Margins	High	Limited
Capital Mobilization	Gradual, reducing cost of capital	Requires upfront capital expenditure
Economic Impact of Delays	Minor, as long-term cash flows compensate	Significant, as delays reduce the economic value

Element	Commercial Fields	Marginal Fields
		of reserves (Giannessi et al., 1994)
Data Availability	Comprehensive appraisal programs ensure high data availability	Limited due to high costs of appraisal drilling and long-duration tests
Data Uncertainty	Manageable, as financial gains offset costs of flawed reserve estimates	Critical, with decisions made based on limited information (Oyakhire and Omeke, 2017)
Development Costs	High but spread over long production periods	High upfront costs must be quickly recovered
Reservoir Management	Extensive, allowing for long-term planning and risk mitigation	Focused on minimizing losses and ensuring profitability in a short timeframe
Use of Analogues	Limited reliance on analogues due to available data	Heavy reliance on analogues and expert knowledge to compensate for data gaps
Financial Risks	Absorbed over time due to substantial cash flow and long productive life	Higher risks due to limited margins and shorter economic viability
Field Development Strategy	Designed for maximum recovery with flexibility in timing and cost	Prioritizes rapid monetization, cost efficiency, and minimal risk

Table 2.1 highlights the fundamental differences in development strategies, economic considerations, and operational approaches between commercial and marginal fields. Based on the dilemma associated with marginal fields, some innovation is required to optimise their development to improve their profitability.

Marginal fields are located across many terrains, onshore, swamp, offshore. The development for each terrain varies because of the peculiarities of each terrain. Each of these terrains presents unique challenges and opportunities, requiring tailored development approaches to ensure economic viability and sustainable resource extraction. The development of these fields requires innovative and cost-effective solutions that take into account the specific characteristics and constraints of the terrain in which they are located. Easier accessibility and lower initial costs characterize onshore fields. Swamp fields face accessibility issues, unstable terrain, and ecological sensitivity. Development demands specialized equipment and techniques to navigate wetlands while minimizing environmental disruption. Offshore fields are the most complex and expensive to develop, requiring advanced technology, substantial infrastructure, and strict regulatory compliance. Harsh marine conditions and logistical challenges in remote areas add to the costs (Valkenier, 2016; Onwuka et al. 2020). Across all field types, remote locations often lack critical infrastructure, adding logistical challenges and significant costs. The experience from fields like Prudhoe Bay highlights issues in logistics, production facility installation, and worker health, emphasizing the need for careful planning and investment (Heimer et al., 1978; Aalund, 1996., Shrimpton and Storey, 1996).

There are no standard methods for development of marginal field projects because they are all unique in their challenges, small of reserves, proximity to facilities, environmental. However, examination of 35 marginal fields' that have been developed across different basins reveal that the development system should incorporate all the following shared features (Giannessi et al. 1994, Otomboshoba 2018); good planning, proper application and/or technological innovation and technology selection, have positively changed the economics of the development (Hassan et al. 2000; Wilkins et al. 2016; Abdul Gani et al. 2016; Valkenier 2016; Udofia et al. 2017; Shaipullah et al. 2018). Technology is not restricted to technical issues such as drilling, completion, surface facilities, export facilities but also all the required professional skills, as procurement, risk evaluation, production monitoring, safety engineering, reservoir management, financial engineering etc. Also, fiscal incentives have resulted in a positive change in the economics of the fields (Iyua et al. 2016; Toluse et al. 2016; Kakayor et al. 2016; Udofia et al. 2017; Otomboshoba 2018). One common issue that has been raised by numerous studies is financial reforms for both developed and developing countries (Svalheim 2004; Iledare and Suberu 2010; Abdul Gani et al. 2016) to improve the economics of MFs.

2.1.1 Challenges of Marginal Field Development

There are a number of factors which may contribute to the situation where so many petroleum discoveries remain undeveloped. Marginal fields in general share one or more of the following characteristics that can result in high risk of returns on capital investment, escalation in CAPEX and OPEX during field development (Ahmed, 2008):

2.1.1.1 Size of Reserves

Uncertainty on the quantity of reserves or a field that may have low exploitable reserves is considered a marginal field. They usually has a few years of plateau oil production. international Oil Companies consider them too small for economically viable production. Development of fields with small reserves is often challenging, as they need the same expensive infrastructure as large fields, while the expected revenue streams are smaller due to the smaller reserve sizes. However, the definition of what considered small reserves varies, for example in Egypt, fields with recoverable reserves of about 5 MMbbls are considered marginal (Agiza et al.1986). In the United Kingdom, a field is regarded as marginal if it has reserves of 20 MMbbls while Malaysia defines 30 MMbbls or less as marginal Norway 75 MMbbls (Etemaddar 2016). In the U.S. basin 48, very small fields with an Estimated Ultimate Recovery (EUR) of only 1 million barrels are defined by the American Association of Petroleum Geologists as significant fields, but such discoveries would be abandoned as non-commercial or left undrilled in many foreign countries (Ivanhoe and George, 1993). In Nigeria, definition of marginal fields remains the prerogative of the Government. Adeogun and Iledare (2015), however, defined a marginal field in terms of field size threshold for an onshore terrain in Nigeria as an oilfield with less than fifteen million barrels of recoverable reserves under favourable fiscal regime and available technology. Also, What is considered a small reserve by one oil company may not be considered small by another company depending on the capacity of the company and the availability or nonavailability of bigger reserves.

2.1.1.2 Geological Constraints

Fields located in areas with challenging geological formations such as unconventional reservoirs, tight formations or structurally complex regions. These conditions can pose technical challenges for exploration and production activities. Inconclusive seismic results, presence of faults or other geological anomalies likely to considerably influence the recoverable reserves. Project economics is sensitive to the performance of individual wells. If producing intervals are thin or have low permeabilities, well productivities will be low, implying slower build up rate and increased number of wells. If the reservoir is faulted or discontinuous, individual wells may require to be side-tracked, may not be worth completing or may have limited life, again implying an increased number of wells.

2.1.1.3 Inadequate Data

Usually have minimal data from one or two discovery wells and initial test information. The uncertainty surrounding data is not exclusive to marginal fields; rather, it is a pervasive issue in the oil field development sector, requiring extensive years of appraisal to ascertain reserves within a given field. The acquisition and analysis of geological, geophysical, and reservoir data play a pivotal role in evaluating the hydrocarbon production potential of a designated area (Dike et al., 2019). Appraisal activities commonly employ tools such as appraisal drilling, long-duration tests, and 2D or 3D seismic surveys. Due to the high and sometimes unbearable cost involved in using conventional appraisal tools such as appraisal drilling, long duration tests, it is impossible for marginal field operators to conduct heavy data acquisition. This limited information introduces uncertainty into the concept selection phase which is then propagated through to the field development plan (Volz, 2008). This uncertainty can have a significant impact on the economic performance of the project because decisions made at the concept selection phase have a large impact on the ultimate value derived from the project (Vasantharajan, 2006; Walkup and Ligon, 2006).

2.1.1.4 Remote Location

Oil fields located in very remote areas often lack infrastructure such as roads, power, communication, and others in the immediate environment. Operators prefer fields with some level of existing infrastructure. Based on the huge financial and time investments required to put the necessary infrastructures in place, owners of these fields often put them out as marginal fields. The logistics problems of supporting exploration and exploratory drilling in remote locations of the world have been well publicized recently.

From the experience gained from the development of the Prudhoe Bay field, Heimer et al., (1978) noted that a problem being recognized more frequently and requiring particular attention is that remote-location logistics do not end with exploration and drilling. Installation of production facilities poses problems just as production facilities pose problems that are intricate, potentially expensive, and difficult to solve. The health of workers stationed in remote locations, where access to health care is limited is of special interest (Aalund, 1996., Shrimpton and Storey, 1996).

2.1.1.5 Technological Constraints

An oil field that requires unconventional technological requirements for exploitation is considered not economically viable. Such an oil field may be termed marginal but new technological innovations may alter the situation. The Buchan oil field in the central North Sea was considered a very risky field operationally and was expected to be abandoned after five years (Mieras, 1984). However, the development of new technology made it possible for the field's recoverable reserves to be explored for a longer time. In India, 67 small oil field blocks were discovered but were not developed due to their technological and geological constraints.

2.1.1.6 High Environmental Concerns

Oil field operations often raise significant environmental concerns, particularly in regions with high environmental risks, which can render some fields marginal due to their impact on return on investment (Simmonset al., 2013; Vasudeva et al., 2013). Offshore operations, extreme weather conditions, and high-security zones require robust risk mitigation to safeguard personnel, equipment, and the environment, inevitably driving up production costs. Temporary halts in production, caused by natural disasters such as hurricanes, cyclones, or wildfires, result in revenue losses discounted by the time value of money.

Historical examples illustrate these challenges. In 1992, Hurricane Andrew destroyed or severely damaged offshore platforms in the Gulf of Mexico, disrupting 5% of the U.S. natural gas supply. Similarly, Hurricane Katrina in 2005 destroyed 50 offshore oil platforms and significantly impacted the Mars platform, incurring billions in losses. Events like the Alberta wildfire in 2016 halted a quarter of Canada’s oil production, costing the economy millions daily. Additionally, severe weather events, such as EF-5 tornadoes, have caused extensive damage to oil production infrastructure.

Loss of personnel, environmental spills, structural damage, and frequent evacuations make operations in these regions costly and, for smaller fields, economically unviable. In such cases, these fields are often abandoned and classified as marginal (Robinne et al., 2016).

To develop marginal fields in environmentally sensitive areas, operators must carefully evaluate technical, environmental, and economic feasibility. Effective development strategies require selecting suitable technologies and implementing sound management plans that balance environmental protection with operational and financial sustainability.

2.1.1.7 Price Instability

The low price and price instability of the produced oil makes the cost of production from these small fields expensive and economically less viable. A field that is not regarded as marginal at a given oil price may become marginal at a lower oil price. No company will continue to produce without profit. The only option left for the oil and gas industry in the event of a price fall is to increase production; where this is not possible, given the small size of oil reserves the industry resort to shutting down producing wells and the fields may be finally classified as marginal. In the 1980s oil prices collapsed, and many marginal wells were shut down, especially in the United States of America, and when the price was revived majority of these wells were again put into production. In 2015, low oil prices brought an abrupt halt to the wild pace of drilling globally. Most oil companies came under pressure to stop production and consequently abandon their oil wells due to a fall in oil prices.

2.1.2 Other Challenges Peculiar to Nigeria

Even though the legal framework allows marginal fields to operate, and they are contributing immensely the following challenges still exist and prevents their development to an optimum level. The identified challenges unique to Nigeria's operating environment were itemised and organised into four themes viz: funding, technical, regulatory and community.

2.1.2.1 Funding Constraints

Access to funding is a significant challenge for marginal field development in Nigeria. Many local banks are hesitant to provide funding for oil and gas projects, and international financing can be difficult to secure due to Nigeria's reputation for corruption and political instability. Most marginal field owners in Nigeria face challenges in securing the necessary funds to support their operations, despite the government's efforts to provide incentives for the success of the marginal fields program. These owners struggle to attract funding, even with the available incentives. To access offshore funds, which are typically more affordable, it has become necessary to seek foreign technical partners (Adetoba, 2012; Nwaozuzu, 2014). However, one of the conditions stipulated in the marginal fields program is that foreign partners can only hold a maximum stake of 49% in the fields, to promote indigenous participation. This condition, combined with the relative marginality of the fields, has deterred many potential investors. Nevertheless, it is crucial to ensure the indigenization of marginal field development (Cherwayko, 2012). Most of the marginal fields currently in operation in Nigeria were funded by local banks after the field owners had established production and sold their stock or raised private equity. Among the field operators, Brittania-U was the only company that received funding from a bank prior to achieving first oil, while others relied on shareholder contributions for their initial funding (Ekeh and Ashekomeh, 2015; Ezeani and Nwuke, 2016; Otombosoba, 2017; Nwaozuzu, 2018).

2.1.2.2 Technical, Infrastructure and Operational Challenges

Marginal fields currently in operation in Nigeria continue to encounter a range of operational and technical challenges. Operational challenges encompass issues such as difficulty in agreeing operational synergies with original lease owners (mainly IOCs), late signing of JOA due to lack of co-operation among equity holders within a field, inadequately trained and incompetent staff, excessive staffing levels, poor information management, and suboptimal project contracting practices (Oruwari, 2020). On the other hand, one of the major technical hurdles stems from insufficient data, which has resulted in inaccurate reservoir assessments and consequently poor field development strategies (Iyua et al., 2016; Toluse et al., 2016; Kakayor et al., 2016; Udofia et al., 2017; Otomboshoba, 2018; Onwuka et al., 2020).

Furthermore, marginal field operators face limitations in accessing essential oilfield equipment such as service rigs, drill rigs, and other specialised machinery, primarily due to the dominance of International Oil Companies (IOCs) in this sector (Cherwayko, 2012; Iyua et al., 2016; Toluse et al., 2016). Additionally, there is a deficiency in necessary technology and infrastructure, including pipelines, power supply, terminals, export facilities, refineries, and storage. Crude exports from Nigeria heavily rely on export pipelines owned and operated by IOCs, who allocate volumes to small operators in clusters of 3 to 5 operators. Marginal field operators often struggle to obtain the required export capacity to fully realise the production potential of their fields, as they lack strong negotiating power with the IOCs for managing export capacities and allocations. Metering is carried out by the IOCs, and pipeline losses, which can be a significant volume of the exported oil, are allocated at their discretion to the marginal field operators. Also, equipment for oil exports is entirely operated by the IOCs, and equipment failures and repair time can result in complete shutdowns and downtime in oil export operations.

2.1.2.3 Regulatory Environment

The regulatory environment in Nigeria is characterised by complex and sometimes conflicting regulations, policies, and laws (i.e., permitting procedures, regulations, and enforcement) that governs the planning and permitting of oil and gas projects is built of interdependent conditions that create bottlenecks in projects. This can create challenges for marginal field development, including delays in the approval process, uncertainty regarding regulatory requirements, and issues with compliance. According to Deloitte report (2014) there is: "Delay in obtaining approvals from the government for field development: The time lag in obtaining approval for field development which typically ranges between 2 to 3 years, usually delays commencement and execution of projects. This poses investor-relation issues as the oil companies would have to manage the expectations of investors during the period of approval delay (Mart 2010). The Ministry of Environment is responsible for conducting and approving EIAs, but often lacks the technical competency to evaluate complex oil and gas operations. This leads to delays and potential inaccuracies in the EIA process, affecting project timelines and compliance.

Adetoba, 2012; Otombosoba, 2017; Nwaozuzu, 2018; Otombosoba & Dosunmu, 2018 have indicated that the bidding process for marginal fields in Nigeria was plagued by irregularities and lacked transparency in awarding contracts, leading to the non-development of many marginal fields. Furthermore, the inconsistency in government policies regarding the marginal fields program has been a major hindrance. While the program was intended to be continuous, there have been no bids awarded since the 2001 round until 2020, despite attempts in 2010 and 2013 that did not materialize. Additionally, the absence of policies promoting collaboration, facility sharing, and the adoption of new technology has led to stringent requirements imposed by International Oil Companies (IOCs) on indigenous companies during farmout agreements, resulting in high production costs for operators and potential conflicts among partners (references). Insufficient collaboration and communication further contribute to project delays and inefficiencies (Otombosoba & Dosunmu, 2017; Oruwari, 2019). The underutilization of new technology, known to enhance the economics of field development, compounds these challenges.

2.1.2.4 Community Challenges

Community relations are a critical aspect of marginal field development in Nigeria. Many marginal fields are in areas where local communities are marginalised and have historically experienced limited benefits from oil and gas production. This can create tensions between communities and operators and require significant efforts to build trust and establish positive relationships. This has led to security challenges, including incidents of theft, vandalism, and kidnapping, are a significant concern for marginal field operators in Nigeria. These challenges can disrupt operations, lead to production losses, and increase costs.

The security of personnel and facilities poses a significant challenge to the oil and gas industry in Nigeria, and this issue has yet to be effectively addressed. Nigeria has one of the highest production costs per barrel, and a significant portion of this cost is attributed to security measures. Incidents of pipeline breakages and vandalism have led to substantial revenue losses for the country (DPR, NNPC, 2019). Pipelines are frequently targeted for vandalism, resulting in significant resource losses (Johnson et al. 2022). These acts of sabotage originated in the 1990s due to various factors, including demands for full control of resources, perceived injustice in the Niger Delta region, and outright theft of crude oil and refined petroleum products by criminals. In 2019 alone, there were 1,406 reported cases of pipeline vandalism, leading to environmental degradation and pollution. These incidents have had a detrimental impact on refineries and associated facilities for product and crude oil transportation. Environmental concerns, such as oil spills, gas flaring, and other forms of pollution, also pose significant challenges in Nigeria. Marginal field operators must adopt measures to minimise the environmental impact of their operations and adhere to increasingly stringent environmental regulations.

The local community is a crucial stakeholder for the success of oil and gas projects in Nigeria. About 20% of the projects faced community issues, which were more common for onshore projects than offshore ones. Projects with community issues had higher cost overruns and longer schedule delays, indicating a significant impact on project performance. Environmental issues, insufficient project assistance, and inadequate government reaction to community requests were identified as the common reasons for community issues. These issues can lead to project shutdowns, facility damage, and decreased productivity. The consequences of community crises can be significant and may force companies to drop projects. Therefore, addressing community issues is crucial for the successful implementation of oil and gas projects in Nigeria.

2.1.2.5 Insecurity

Security has become a major concern for the oil and gas industry in Nigeria, with all projects facing different degrees of security challenges in production and transportation operations as well as safety challenges for their employees. These security issues significantly impact project performance, with cost overruns 10% higher and schedule delays more than 15% higher for projects with significant security issues. The causes of security issues in Nigeria include environmental destruction, lack of infrastructure, poor human development, limited economic opportunities, and conflicts among different groups. The negative consequences of security issues can be huge, with 30% of total production in Nigeria lost due to security issues, and incidents of attacks on oil and gas production facilities leading to high-cost overruns, schedule delays, and safety concerns. Overall, security issues are confirmed as a major factor in degrading Nigerian oil and gas project performance and causing huge revenue losses. Security is another factor that determines the marginality of an oil well. The attack on oil facilities and crew members has increased by the day in Nigeria. Support vessels have been severally attacked and crew members kidnapped for ransom. Shut-in of crude oil production is a common feature due to insecurity. Production is lost, facilities damaged, workers attacked (both offshore and onshore), oil companies shut down wells and the economic viability of the oil fields in this area is drastically ebbing away. Pirates and militants have attacked drilling rigs, such that some multinational oil companies operating in the country have suspended their activities on land, swamp and shallow offshore and have moved deeper offshore where they perceive that the risks are very minimal.

This is made possible by the government's introduction of deep offshore block allocation in 1993. If the abandoned oil fields remain without development activities for ten years, they would have technically become marginal fields. According to NNPC 2014 report, pipeline vandalism increased by 4.54% during the 2013 production year. In the report, a total of 3,700 lines were vandalized, resulting in a loss of about 355.69 thousand metric tons of petroleum products worth about 44.75 billion Naira. Between 2014 and 2015 about 4,000 oil theft and vandalism attempts were reported at the various product pipelines across the country (Njoku, 2016).

Understanding these unique challenges is crucial for successful marginal field development in Nigeria. Operators must navigate these complexities while implementing effective strategies to mitigate security risks and address environmental concerns. These shape the development strategies and decision-making processes associated with marginal field development.

2.2 Marginal Field Development Technologies

Marginal field development poses significant technical challenges, requiring innovative engineering practices to achieve profitability. Marginal field development involves specialized technologies designed to address the unique challenges posed by fields with smaller reserves, uncertain reservoir characteristics, and often difficult operating environments. Key principles for addressing these challenges include fast-track development, simplicity, mobility, and reusability. These marginal field technologies are tailored to ensure cost-effectiveness, operational efficiency, and environmental sustainability, making marginal fields economically viable for development. These technologies are essential for maximizing recovery while ensuring economic viability, particularly for small and indigenous operators especially for countries like Nigeria where funding is a big challenge. The utilization of advanced techniques enabled by emerging technologies has significantly transformed small oilfields, previously deemed uneconomical, into endeavours that are both technically viable and economically attractive (Rashid et al., 2017). Hassan et al. (2000), Wilkins et al.

(2016), Abdul Gani et al. (2016), Valkenier (2016), Udofia et al. (2017), and Shaipullah et al. (2018) have demonstrated that meticulous planning, proper application of innovative technologies, and effective technology selection have positively influenced the economics of marginal field development.

2.2.1 Reservoir Modelling

Reservoir flow modelling represents one of the most advanced methodologies for predicting production profiles, providing a detailed depiction of fluid production over time. These profiles can be presented as flow rates or cumulative production and are integral to generating reliable cash flow forecasts when combined with hydrocarbon price projections. The integration of production profiles from flow modelling with economic evaluations enables the comparison of various reservoir management concepts, forming the basis for assessing economic viability (Hassan et al., 2000). Such insights are crucial for effective reservoir management, including the accurate determination of reserves (Adagunodo et al., 2022; Jeong et al., 2017).

Reservoir models rely on field measurements such as well logs, seismic surveys, and production history, offering a comprehensive understanding of reservoir characteristics. These models are vital for optimizing reservoir depletion strategies, thereby enhancing the economic feasibility of marginal fields (Hassan et al., 2000). However, one of the primary challenges in marginal field development is the limited availability of high-quality data (Uwaga, 2008; Alaneme & Igboanugo, 2012; El Gazar et al., 2015; Wilkins et al., 2016; Jeong et al., 2017). For instance, Uwaga (2008) analyzed three fundamental PVT parameters using a database from producing fields in the Niger Delta. Through dynamic simulation, the study demonstrated that earlier PVT estimates were overly conservative, suggesting that marginal fields could be more profitable than previously anticipated.

Recent technological advancements, particularly in Information and Communications Technology (ICT), have introduced computer-aided optimization techniques that enable comprehensive reservoir evaluation. These techniques have proven effective in supporting field development and production plans to maximize hydrocarbon recovery and profitability. For example, Jun et al. (2017) applied a Monte Carlo simulation integrated with a Genetic Algorithm to optimize a gas condensate field in Vietnam with contractual gas sales obligations. Similarly, studies by Alaneme and Igboanugo (2012), El Gazar et al. (2015), Cao et al. (2016), Jeong et al. (2017), and Aremu (2019) have shown that machine learning approaches can significantly improve data representation compared to conventional methods, even with limited datasets.

Jeong et al. (2017) investigated the economics of a development project for a basement fracture reservoir in Vietnam characterized by geological uncertainties and reserve size variability. By employing proxy models combined with history matching and artificial neural networks, the study quantified the uncertainties in ultimate recovery and assessed project economics. The analysis revealed that connectivity between domains in the reservoir significantly impacts ultimate recovery and, consequently, project viability. Incorporating Net Present Value (NPV) as an objective function in development optimization was found to be critical. Additionally, sensitivity analyses across multiple development strategies were deemed necessary for robust decision-making.

While individual processes such as well development, production optimization, and export strategies have been refined, a holistic approach to optimizing the entire field development strategy remains elusive. Such an approach would integrate well planning, production, and export options, ensuring comprehensive alignment with economic and technical objectives.

2.2.2 Re-entry Drilling

Re-entry drilling has emerged as a transformative technique for revitalizing declining oil fields. This method optimizes existing resources, including surface facilities and well infrastructure, thereby reducing costs. For example, the incorporation of advanced directional drilling and LWD technologies has enabled 100% directional control, favourable rates of penetration (ROP), and high-quality logs, optimizing execution time and reducing project timelines. Sanchez et al. (2015) documented that re-entry drilling with hybrid rotary steerable systems (RSS) achieved deeper re-entries with greater cost efficiency.

Re-entry drilling offers a cost-effective and efficient approach to oil production, particularly in the context of marginal field development. This technique involves re-accessing a previously drilled wellbore to enhance production, target untapped reserves, or perform repairs and maintenance. By leveraging existing well infrastructure, re-entry campaigns significantly reduce the costs and time associated with drilling entirely new wells (Sanchez et al., 2015; Haryasukma et al., 2022).

The process capitalises on detailed knowledge of the reservoir, such as logs and production history from the original well, enabling precise borehole trajectories that optimise resource recovery. On average, re-entry operations require less than half the time and cost of new well drilling, making them an attractive solution for revitalising declining fields. Successful execution depends on early collaboration among operators' geological and drilling teams, as well as service providers.

Recent technological advancements have further enhanced the efficiency of re-entry campaigns. The integration of advanced directional drilling and Logging While Drilling (LWD) technologies ensures 100% directional control, favourable Rate of Penetration (ROP), and high-quality real-time logging, contributing to reduced execution times. For instance, a campaign involving eight re-entries achieved a combined saving of 39.46 days from the total planned execution time.

Innovations such as hybrid Rotary Steerable Systems (RSS), including the push-and-point-the-bit RSS, have revolutionised re-entry drilling. These tools enable increased Dogleg Severity (DLS), facilitating deeper well trajectories while minimising costs. Re-entry drilling is particularly advantageous for marginal fields, where maximising existing resources—such as surface facilities, wellheads, and casing infrastructure—is critical to economic viability.

Re-entry drilling presents a practical and cost-efficient strategy for enhancing production, reducing downtime, and optimising resource utilisation in marginal field development. By incorporating cutting-edge technologies and adopting collaborative planning, operators can unlock the potential of declining fields and achieve sustainable production growth.

2.2.3 Multilateral Drilling

Multilateral wells are a popular choice for fields where maximum fixed asset utilization is required. Multilateral wells represent a significant advancement in well construction, featuring multiple "branch" wellbores drilled from a single "trunk" wellbore. This innovative approach provides operators with the flexibility to:

1. Access multiple reservoirs from a single wellbore.
2. Enhance production rates within a single reservoir.
3. Minimise surface infrastructure by reducing the number of required well slots (Saeed et al. 2020).

Multilateral wells establish an interconnected network of horizontal or high-angle wellbores surrounding a primary wellbore. These wellbores are pressure-isolated and reentry-accessible, enabling effective drainage of multiple target zones. Compared to traditional horizontal wells, this design is often more effective in boosting productivity and increasing recoverable reserves. Moreover, multilateral wells can extend the economic life of mature fields while reducing both drilling and waste disposal costs.

This technique has proven highly successful in diverse drilling environments worldwide, including onshore and offshore operations in regions such as the Middle East, North Sea, North Slope, and Austin Chalk. Such technology was developed and used in more than 40 wells in Middle East (Saeed et al. 2020). The dramatic returns provided by multilateral completions make them an attractive option for operators in complex reservoirs (Coss et al., 2017).

Multilateral drilling is particularly valuable in reservoirs with the following characteristics:

1. Small or isolated hydrocarbon accumulations in multiple zones.
2. Oil accumulations above existing perforations.
3. Lens-shaped pay zones.
4. Strongly directional formations.
5. Distinct sets of natural fractures.
6. Vertically segregated zones with low transmissibility.

By enabling operators to efficiently target and drain complex reservoirs, multilateral wells offer a transformative solution for marginal field development, combining cost-effectiveness with enhanced resource recovery.

2.2.4 Early Production Systems

Early Production Systems are pivotal for marginal field development due to their cost-effectiveness and ability to accelerate time-to-first-oil. By enabling production during the appraisal phase, EPS generate early cash flow, reduce economic uncertainties, and inform critical development decisions. For instance, data obtained through EPS help optimize field strategies, such as well placement, facility sizing, and enhanced recovery methods, thus improving decision metrics like IRR and payback period (Singh, 1992; Mastrangelo et al., 2003; Valenchon et al., 2000).

2.2.4.1 Tie-Back to Existing Facilities

The tie-back marginal field development strategy, is a cost-effective and efficient method for integrating satellite fields with existing infrastructure to optimize hydrocarbon extraction. It defines the approach, emphasizing its economic and operational benefits in minimizing capital investment and accelerating production timelines. Implementation involves integrating satellite fields, adapting technology, and ensuring effective project management. The strategy enhances cost efficiency, maximizes resource recovery, and extends field lifespan.

Tie-back systems leverage existing infrastructure to reduce upfront capital costs and accelerate production timelines. However, their viability depends on reservoir properties, flow assurance challenges, and distance from existing facilities (Husy, 2011). For instance, small-diameter pipelines or tie-back systems connected to existing pipeline networks reduce capital expenditure and optimize transport costs, making marginal fields more economically viable (Manan et al., 2019). Reeled pipes—whether flexible or rigid—are advantageous, as they can be reused, ensuring their economic viability across multiple projects. However, flow assurance issues, such as wax deposition and hydrate formation, can limit the maximum tie-back distance to approximately 50 km for oil fields, with longer distances possible for gas fields (Acheampong et al., 2021).

To address these challenges, technologies like subsea pumping and electrical heating are critical. Subsea pumping extends tie-back distances by boosting production rates and mitigating slugging issues, making it particularly effective when applied with tailored flow assurance strategies. according to Grinning et al., (2009) and Abili et al., (2012) for shallow marginal fields, multiphase pumps enhance operational efficiency by maintaining even production profiles, which support economic criteria such as NPV and Unit Technical Cost (UTC). Conversely, for deepwater marginal fields, these pumps are less advantageous without additional flow assurance measures due to severe slugging challenges. High risk environments like such as Grand Banks region, offshore Eastern Canada require mitigation techniques such as trenching to protect flowlines against iceberg keel interactions (Vasudeva et al., 2013).

Existing infrastructure, such as pipelines or processing facilities, may have limited capacity and may not be able to handle the additional production from the new tie-back field. This constraint can limit the volume of hydrocarbons that can be produced and processed. Also, if the existing infrastructure is owned or operated by a third party, there is a risk of conflicting priorities or operational issues that could impact the tie-back development. Economically, tie-back systems also influence fiscal considerations, such as pipeline tariffs and cost-sharing arrangements. Studies (Acheampong et al., 2021) have shown that infrastructure unbundling and progressive fiscal regimes can significantly improve NPV and extend the productive life of marginal fields. Decision-makers must balance the long-term cost benefits of pipeline installation against the upfront investment and regulatory compliance challenges (Johnson et al., 2022).

While tie-back developments offer a cost-effective and efficient means of bringing marginal fields into production, there are significant disadvantages and risks that need to be carefully evaluated. These include capacity and operational constraints, increased environmental and safety risks, regulatory challenges, and technical limitations. A thorough analysis of these factors is essential to determine whether a tie-back development is the optimal strategy for a given marginal field.

2.2.4.2 Early Production Facilities

The economic constraints associated with marginal field development necessitate technical solutions emphasizing mobility and reusability. Given that most production surface structures will serve multiple developments, these systems are designed to be versatile and adaptable. EPFs are temporary, modular systems designed to enable rapid commencement of production, allowing operators to generate revenue while gathering critical reservoir performance data to inform full-field development. The modular nature of these facilities enhances flexibility and reduces deployment time, which is essential for marginal fields where swift monetization of resources is a priority.

For offshore operations, floating structures or reusable subsea installations are optimal, offering the flexibility to be redeployed across different fields. Floating Production Storage and Offloading (FPSO) units and Floating Storage and Offloading (FSO) units provide adaptable storage and processing solutions for offshore marginal fields. FPSOs, in particular, integrate production, storage, and transportation capabilities, reducing the need for extensive offshore infrastructure (Radhakrishnan et al., 2020; Oginni et al., 2019). Their leasing flexibility aligns with the economic constraints of marginal fields, enabling faster deployment and cost savings. Decision-makers must evaluate FPSO or FSO adoption based on field size, production timeline, and expected revenue streams, as these systems significantly influence the economic threshold of marginal field viability.

Similarly, for onshore fields, skid-mounted systems are preferred due to their ease of installation, mobility, and cost-effectiveness. The modular design of EPS allows rapid deployment, flexibility, and scalability, making it suitable for dynamic production scenarios (Figure 2.2). For example, EPS can be adapted to test compartmentalization or reservoir drive mechanisms, which influence investment decisions regarding injection strategies and facility requirements. This ensures that EPS not only address immediate production needs but also provide actionable insights for long-term development strategies (Coopersmith et al., 2014).

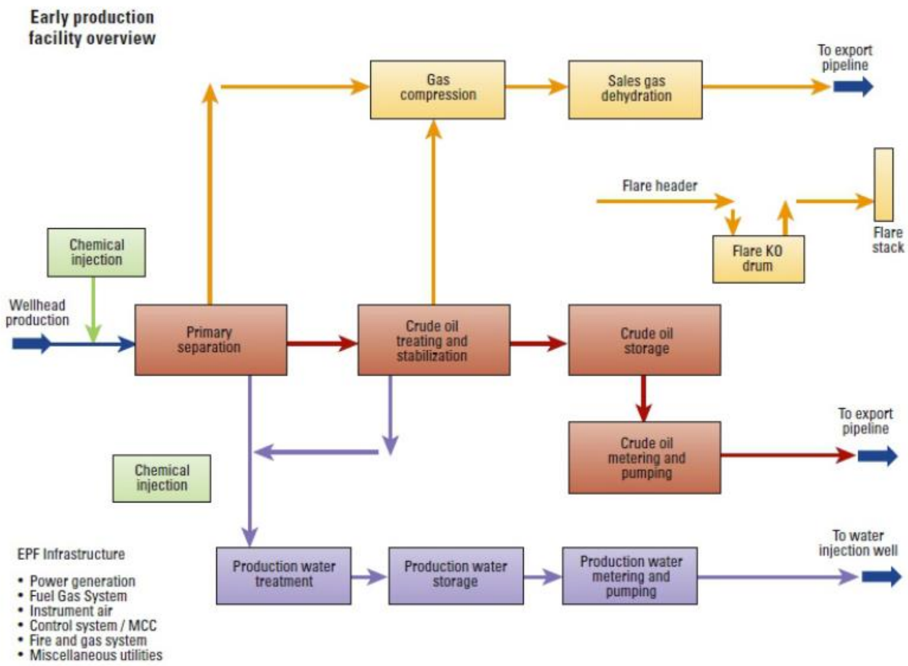

Figure 2.1: Early Production Facility - GMS Interneer, oil and gas equipment provider (Source: gmsthailand.com)

As shown in Figure 2.2 EPS are modular technology that are flexible, and enables production to start early, accelerating the time to first oil and gas. The modules are designed for transportability, connectability, operability, upgradeability and to meet all international standards and regulatory requirements. EPS standard designs enables fast-track production schedules, providing available production capacity when and where it is needed for early cashflow.

2.2.4.3 Central Processing Facilities

Central Processing Facilities (CPF) play a strategic role in consolidating production from multiple marginal fields, thereby optimizing operations and reducing costs (Ahmed et al., 2019). This shared infrastructure enhances economies of scale and supports decision-making by improving production efficiency and operational coordination (Yusuf et al., 2019; Ashok et al., 2018). For example, integrating enhanced oil recovery (EOR) techniques, such as water or gas injection, into CPFs can maximize recovery rates, improving project feasibility under economic metrics like NPV and breakeven costs. CPFs are particularly relevant for marginal fields with fluctuating production rates. Their modular and scalable designs allow adaptation to evolving production profiles, ensuring sustainable development (Sobamowo et al., 2020). By incorporating advanced technologies such as remote monitoring and digitalization, CPFs also reduce operational risks and improve decision-making through real-time data analytics.

2.2.5 Subsea Processing and Boosting

Subsea processing technology is a transformative solution for marginal fields, particularly offshore, where traditional surface-based processing may be uneconomical. By addressing flow assurance challenges such as hydrate formation and solids management at the seabed, SPT minimizes operational costs and enhances recovery rates (Ohanyere and Abili 2015; Tsimplis et al. 2019).

SPT is integral to decision-making as it directly impacts project economics. For example, its ability to reduce production costs per barrel can improve NPV and make projects viable under lower oil price scenarios. Additionally, by enabling the development of remote or deepwater fields, SPT expands the range of viable investment opportunities, offering operators greater flexibility in marginal field portfolios. However, its application requires careful consideration of economic and fiscal factors. Governments may incentivize the use of SPT through favourable tax policies to support marginal field development during periods of low oil prices (Tsimplis et al., 2019). This highlights SPT’s role as a key enabler in unlocking the potential of offshore marginal fields while maintaining economic sustainability.

Multiphase pumps are an innovative technology for marginal field development, addressing key technical challenges such as flow assurance, hydrate and wax management, and the need for artificial lift to boost production. These pumps enable the transportation of unprocessed well fluids—oil, gas, and water—through pipelines without separation, offering numerous advantages for marginal field tie-backs.

Multiphase pumping is particularly effective for shallow marginal fields, providing a consistent production profile and mitigating slug formation, which is a major flow assurance issue. This results in prolonged field productivity and extends the lifespan of production facilities. The technology is best implemented during the later stages of a field's life, especially when the water cut exceeds 70%, to maximize efficiency and cost-effectiveness. Placement of multiphase pumps close to the wellhead minimizes fluid phase separation, further aiding in slug management.

With a maximum step-out distance of approximately 30 km, multiphase pumps can be combined with multiple boosting stations to extend tie-back distances while reducing the need for extensive seabed infrastructure. This approach, as described by Abili et al. (2012), lowers costs and simplifies operational complexity. Additionally, multiphase pumping is environmentally friendly, eliminating the need for flaring, produced water re-injection, or seabed disposal, thus reducing environmental pollution.

For deepwater marginal fields, the benefits of multiphase pumping are somewhat limited due to severe slugging challenges. However, combining this technology with tailored flow assurance strategies can significantly enhance production rates. Advances in pump reliability, particularly in seal technology, and their successful application in various fields globally underscore their viability as a cost-effective and sustainable solution for remote marginal fields.

Multiphase pumps represent a transformative technology in marginal field development, offering enhanced production, reduced costs, and environmental benefits, especially when applied strategically in alignment with field-specific challenges.

2.2.6 Digital Technologies and Intelligent Oilfields

The oil and gas industry has increasingly embraced digital technologies, transitioning towards intelligent oilfields that leverage real-time data, advanced analytics, and automated workflows. These innovations are reshaping field operations, enhancing efficiency, and optimizing asset performance. For instance, a Middle Eastern operator implemented smart automated workflows integrated with real-time surveillance and advanced analytics to improve asset management and operational decision-making (Al-Jasmi et al., 2013).

Intelligent or smart well completions utilize downhole monitoring and control systems to optimise production and manage reservoir dynamics. These systems can help control flow rates, manage water, or gas breakthrough, and improve overall field performance. It is important to note that the selection of specific well, drilling, and completion techniques for marginal fields depends on various factors, including reservoir characteristics, economic viability, and available technologies. Engineering studies, economic evaluations, and site-specific assessments are typically conducted to determine the most suitable approach for each marginal field (Dike et al., 2019 and Abd Rahim et al 2022).

In Nigeria, notable advancements in digital technology have been applied in marginal fields such as Orogho, Sapele, and Opkurhurhu. Technologies like geosteering for precise horizontal well placement, dynamic underbalance perforation, and smart well completions have significantly enhanced safety, efficiency, and productivity (Iyua et al., 2016). These initiatives demonstrate the potential of digitalization to address challenges associated with marginal field development.

Studies by Adelana et al. (2020) and Shittu et al. (2019) highlight the growing adoption of digitalization and data analytics technologies in marginal field operations. These technologies include advanced data acquisition systems, real-time monitoring tools, predictive analytics, and machine learning (ML) algorithms. Such tools enable operators to optimize well performance, identify production bottlenecks, and make data-driven decisions to improve reservoir management and enhance production performance.

Artificial Intelligence (AI) and Machine Learning (ML) have further revolutionized marginal field development. According to Obande et al. (2020), these technologies excel in analysing vast datasets, identifying patterns, and providing predictive insights for reservoir characterization, production optimization, and equipment maintenance. AI and ML algorithms support well performance analysis, predictive maintenance, and real-time decision-making, thereby improving operational efficiency and reducing costs (Oyewole et al., 2019). For example, predictive analytics powered by AI can anticipate equipment failures, minimizing downtime and ensuring uninterrupted production.

The integration of digital technologies, AI, and ML into marginal field development demonstrates a transformative shift in the industry. These tools not only improve technical and economic outcomes but also enhance the sustainability and long-term viability of marginal oilfields.

Technology has been a game changer in the oil and gas industry, opportunities for applying technologies that minimize costs, advance hydrocarbon recovery and boost productivity while reducing environmental impact at the surface and in the subsurface are vast (Hassan et al. 2000; Wilkins et al. 2016; Abdul Gani et al.

2016; Valkenier 2016; Udofia et al. 2017; Shaipullah et al. 2018). The development of marginal fields across the globe has been enhanced through the combined application of cutting-edge technologies and strategic planning. Examples include:

- Gulf of Suez (Younis Field): The use of 3D seismic, gravel packs, and overbalance techniques resulted in profitable development (Hassan et al., 2000).
- Gulf of Thailand (Nong Yao Field): Sequential drilling and technology application minimized risk and maximized resource appraisal (Wilkins et al., 2016). The field also featured extended-reach drilling (ERD) to develop a 14ft oil rim beneath a thick gas cap, incorporating Autonomous Inflow Control Devices (AICDs) to balance production and reduce unwanted fluid extraction (Yusuf et al., 2020).
- Offshore North West Java (ONWJ): Grouping fields and using floating structures sustained production economically (Abdul Gani et al., 2016).
- North Sea (Wintershall Operations): The reuse of existing platforms and pipelines, combined with smart engineering and new technologies, extended platform lifespans and improved marginal field economics (Valkenier, 2016).

The use of innovative versus proven technology may yield significant additional benefits to a company given potential application across the portfolio of its projects. The potentially higher costs and additional risks for a "pilot" project may be sub-optimal from the government's perspective if there is limited future application within the country. The use of innovative technologies has been cited by various scholars as one the key determinants of marginal oil field development (Lai et al., 2022; Hari et al., 2022; Yamanaka et al., 2022).

For effective oil field development, the deployment of appropriate technology is essential. Marginal fields, in particular, require specialized and unconventional technologies to enhance operational efficiency and maximize return on investment. Although these technologies exist, their accessibility for operators in Nigeria is significantly constrained by high costs (Offia, 2011). However, marginal field technologies are not widely available across the oil industry, further complicating their adoption. Additionally, because these tools and equipment are unconventional and highly specialized, their costs are significantly higher than those of conventional oil field development. Consequently, the high operational costs associated with marginal field technologies can sometimes offset the economic benefits of production, making the venture financially unviable. This underscores the need for innovative financing models, strategic partnerships, and cost-effective technological solutions to support marginal field operators in overcoming these challenges.

2.3 Commercial Considerations

Developing marginal oil and gas fields presents unique economic and financial challenges due to their limited reserves, high development costs, and often uncertain profitability. Operators must adopt a strategic approach to evaluate economic feasibility, secure funding, and optimize field development to ensure returns on investment. For these fields, commercial considerations revolve around optimizing costs, leveraging innovative technologies, mitigating risks, and ensuring regulatory and stakeholder alignment to achieve profitability.

2.3.1 Early and Increased Cash Flow in Marginal Field Development

The economic viability of marginal field development is highly dependent on strategies that ensure early and increased cash flow, given the unique challenges these fields present. Marginal fields are often characterized by smaller reserves, limited production lifespans, and higher unit costs, which necessitate innovative approaches to accelerate revenue generation while minimizing both capital expenditure (CAPEX) and operational expenditure (OPEX). Achieving early cash flow is critical not only for sustaining field operations but also for attracting investment and mitigating financial risks associated with field development.

2.3.1.1 Modular and Reusable Low-Cost Facilities

One of the primary strategies employed to achieve early cash flow is the deployment of Early Production Facilities (EPFs). As explained in section 2.2.4 these are modular and reusable low-cost facilities, such as skid-mounted systems, which are easily transportable and adaptable to different field conditions. Operators have employed these facilities to minimize both capital and operational costs while offering the flexibility to be redeployed to other projects once a field reaches the end of its economic life (Hauwert et al., 2016; (Valkenier, 2016).

These systems are particularly effective in onshore and shallow offshore environments, where infrastructure can be easily redeployed.

2.3.1.2 Use of Tankers for Storage and Export

The use of tankers for storage and export presents a viable alternative to extensive pipeline infrastructure, particularly in offshore environments. This approach is instrumental in minimizing capital expenditure (CAPEX) and accelerating time to market, especially during the early stages of field development. Floating Storage Units (FSUs) or tankers provide an effective means of storage and transportation, reducing the dependency on fixed pipeline infrastructure and enhancing operational flexibility. The ability of tankers and shuttle vessels to transport hydrocarbons in smaller volumes makes them particularly suitable for marginal fields with lower production rates. Early Production Systems (EPS) frequently incorporate shuttle transportation as a means of rapidly monetizing reserves. However, the selection of tanker size and frequency must be carefully aligned with the production profile and market logistics to optimize transportation costs and minimize potential delays (Radhakrishnan et al., 2020).

For marginal fields located in regions with limited or underdeveloped pipeline infrastructure, alternative transportation methods such as rail and truck transport can serve as feasible options for moving hydrocarbons to storage or distribution hubs (Onwuka et al., 2020). These alternatives are particularly useful for short-distance transportation or niche-market supply chains. However, decision-makers must balance the higher operational costs associated with truck and rail transport against the lower initial investment, considering critical factors such as market accessibility, production volume, and regulatory constraints (Manan et al., 2019).

In addition to offshore storage solutions, both onshore and floating storage facilities play a crucial role in managing production schedules and inventory efficiently. Tank farms and dedicated terminals provide a buffer against market fluctuations, ensuring a stable and consistent supply chain. The integration of onshore storage represents a strategic decision aimed at aligning production with demand, thereby improving cash flow management and enhancing market competitiveness (Nwoba et al., 2020). Ultimately, the choice of storage and transportation method must be guided by economic, logistical, and operational considerations, ensuring that marginal field developments remain commercially viable while optimizing hydrocarbon recovery.

2.3.1.3 Phased Development

Phased development is also a critical approach, where field development is executed in stages. This method allows operators to spread capital investments over time, aligning expenditures with production milestones and reducing upfront financial risks. Early revenues generated from initial development phases can be reinvested into subsequent phases, creating a self-sustaining development model. Therefore, companies have adopted strategies such as phasing of the operations, flexible field development plan which can accommodate changes, effective sharing of facilities with nearby fields (Alwady, 2001, Udofia et al., 2017).

Phased development approaches allow operators to minimize upfront investments and generate early cash flow by achieving first oil quickly. This incremental investment model enables operators to defer large-scale capital expenditures, assess reservoir performance, and adapt development plans over time , aligning expenditures with production milestones. The approach also reduces financial risk and ensures that early cash flow from initial phases can fund subsequent development stages. Modular and scalable infrastructure supports future upgrades, ensuring the field remains economically sustainable.

Recent advancements in technology have reshaped the phased development strategy. Skowronek et al. (2019) highlight how integrated field development and planning solutions have enabled more efficient decision-making processes. These cloud-based tools allow operators and suppliers to collaboratively evaluate various development scenarios, costs, and schedules in real-time, enhancing planning precision and adaptability.

2.3.1.4 Standardization and Use of Off-the-Shelf Equipment

The adoption of off-the-shelf equipment is generally preferred over tailor-made solutions in marginal field development due to its significant cost and operational advantages. Standardization not only reduces procurement costs but also shortens delivery times, facilitating quicker project execution. Additionally, the use of standardized equipment enhances reusability across multiple projects, thereby promoting efficiency in asset utilization. This approach simplifies maintenance procedures, minimizes spare parts inventory requirements, and reduces the need for specialized training, all of which contribute to improved operational efficiency. Furthermore, the implementation of standardized solutions has proven to be particularly effective in lowering the overall cost of marginal field development, making projects more economically viable in resource-constrained environments (Valkenier, 2016).

The viability of marginal fields has been significantly enhanced through technological advancements and the re-evaluation of traditional approaches to shallow water field development. Given that economic feasibility is the primary driver for marginal field projects, it is crucial to identify and implement the right subsystems to ensure sustained production over a period of 7 to 10 years. In this context, the use of the IOS (Integrated Offshore Solutions) platform, which features a minimal unmanned wellhead platform (WHP), has facilitated the sanctioning of marginal field developments by adhering to a minimalist design philosophy. This approach enables operators to reassess their requirements for unmanned platforms while maintaining industry compliance, ultimately achieving a faster time to first oil and improving the economic viability of projects. Moreover, the IOS case study demonstrates how leveraging proven technology, standardization, and innovative design and installation methods can make marginal fields commercially attractive, particularly in the context of brownfield developments (Arora, 2022).

Marginal fields are becoming more viable through new technologies and challenging traditional approach to developing shallow water fields. The main driver for marginal field is economics. It is therefore important to ensure that right sub systems can be identified so these fields can produce for 7-10 years. The IOS platform which is a minimum unmanned WHP has enabled marginal field to be sanctioned due to its minimalist design philosophy. It is allowing operators to re-consider their requirements for an unmanned platform whilst still being industry complaint and enabling them to achieve quicker first time to oil, be more economically viable while supporting their brownfield field developments. The IOS case study was able to enable operator to make their marginal fields viable as it leveraged proven technology, standardization, innovation in design and installation (Arora 2022).

2.3.2 Innovative Financing

The unique economic challenges of marginal field development necessitate innovative financial engineering strategies to enhance project feasibility and sustainability. Key approaches include:

2.3.2.1 Leasing of Equipment and Facilities

To enhance cost efficiency, leasing of equipment and facilities is increasingly preferred over outright purchases. Leasing helps shift financial burdens from CAPEX to OPEX, offering greater financial flexibility, especially in the early stages of field development. This approach is particularly advantageous unless economic conditions support rapid depreciation of purchased assets, typically no more than half the forecast production period (approximately two to three years). Leasing also ensures that equipment remains versatile and can be redeployed across multiple projects, maximizing asset utilization and minimizing the risks associated with asset obsolescence. Leasing enables operators to shift financial burdens from Capex to Opex, allowing for more flexible cost management and reducing financial risks, especially during early project phases.

2.3.2.2 Collaboration and Partnerships

Collaboration among operators, service providers, and regulatory bodies is essential for marginal field development. Shared infrastructure, joint ventures, and integrated field development planning allow operators to pool resources and expertise. Building partnerships with contractors and suppliers to distribute project risks and align incentives. Partnerships with suppliers can also reduce costs by fostering early engagement and customized technology deployment. Collaborative financial models, such as production-sharing agreements or performance-based contracts, foster shared accountability and mutual benefits.

Partnerships and collaboration play critical roles in the success of marginal fields. Joint ventures and social investments have consistently fostered cooperation and removed barriers to project implementation (Humphrey and Dosunmu, 2016, 2018). Social investments, such as infrastructure development and education programs, enhance goodwill with host communities, mitigating risks of disruptions. Conversely, inadequate community engagement often results in protests, sabotage, and delays (Otombosoba and Dosunmu, 2017).

These new financial concepts redefine traditional funding and risk management models, enabling marginal field operators to achieve economic viability while adapting to the unique challenges of these fields. By combining innovative financial strategies with technical ingenuity, operators can optimize resource utilization and enhance project sustainability.

Ensuring early and increased cash flow is vital for the success of marginal field development projects. Through strategic approaches such as early production systems, modular facilities, phased development, and innovative financial models like leasing, operators can accelerate revenue generation while minimizing costs and risks. Furthermore, fostering collaborative relationships within the industry and adopting flexible operational frameworks are key to sustaining profitability in the dynamic landscape of marginal field development.

2.3.3 Risk Mitigation

Marginal field projects inherently carry higher risks due to inherent uncertainties associated small reserve volumes, technical complexities, fluctuating market dynamics, and regulatory challenges. Identifying and mitigating these risks is crucial for ensuring project viability and long-term sustainability. Strategies such as thorough feasibility studies, hedging against price fluctuations, and implementing robust risk management frameworks help mitigate these uncertainties. Diversification through clustering multiple marginal fields also reduces exposure to individual field risks.

2.3.3.1 Development whilst Appraising

Risk minimization is a critical component of marginal field development due to the inherent uncertainties associated with small reserves, complex geological conditions, fluctuating market dynamics, and regulatory challenges. One of the most effective strategies for mitigating these risks is the implementation of continuous appraisal throughout the lifecycle of the field. Continuous appraisal involves the systematic and ongoing evaluation of geological, technical, operational, and economic parameters to inform decision-making, reduce uncertainties, and optimize field performance.

The strategy of simultaneous development and appraisal has been widely adopted by marginal field operators to accelerate time to first production while mitigating financial and technical risks (Kakayor, 2016). Marginal fields are inherently more vulnerable to uncertainties due to limited subsurface data, unpredictable reservoir characteristics, and constrained financial resources (Offia, 2011). To address these challenges, operators employ a phased development approach, in which development wells in relatively well-understood reservoirs are also utilized for appraisal purposes in less-defined areas. This concurrent strategy significantly reduces the number of dedicated appraisal wells required, optimizing costs and improving decision-making efficiency (Eyankware and Esaenwi, 2019).

Continuous appraisal plays a crucial role in phased development, allowing subsequent investment decisions to be informed by the performance of earlier phases. This approach minimizes financial exposure by deferring major capital expenditures until initial production results validate reservoir potential. Ongoing monitoring of reservoir pressure, fluid composition, production rates, and well performance is essential for detecting anomalies such as water breakthrough, pressure declines, and unexpected changes in production trends (Poedjono et al., 2018).

To enhance reservoir characterization over time, operators deploy advanced reservoir monitoring techniques such as 4D seismic surveys, production logging, and pressure transient analysis (Satter and Iqbal, 2016). These methods provide valuable insights into reservoir behaviour, facilitating data-driven adjustments to the development strategy. Additionally, geological models are periodically updated based on new seismic interpretations, well logs, and core sample analyses, reducing subsurface uncertainties and improving overall field management (Oyakhire and Omeke 2017). This iterative and adaptive approach ensures that field development remains aligned with real-time reservoir performance, maximizing hydrocarbon recovery while optimizing investment efficiency.

2.3.3.2 Fiscal and Regulatory Incentives

Supportive fiscal and regulatory frameworks play a crucial role in attracting investment to marginal fields (Ayodele and Frimpong 2005). Governments may provide incentives such as reduced royalties, tax reliefs, or streamlined approval processes to encourage development. Clear and stable regulations ensure predictability and build investor confidence, which is vital for long-term planning.

The fiscal regime in operation in any specific country can have a significantly greater impact on the profitability of marginal fields than technology alone

(Ayodele and Frimpong 2003). One common issue that has been raised by numerous studies has been the issue of financial reforms both for developed and developing countries (Svalheim 2004; Iledare and Suberu 2010; Abdul Gani et al. 2016) to improve the economics of marginal fields.

The primary responsibility for ensuring the safety and integrity of an oil and gas asset lies with the operating company, which must implement robust health, safety, and environmental (HSE) management systems to mitigate risks. However, regulatory authorities also play a critical role in overseeing industry operations, balancing economic interests, public safety, and environmental protection.

Regulators enforce compliance with industry standards and legislation to ensure that risks associated with oil and gas operations are kept "as low as reasonably practicable" (ALARP). This approach seeks to minimize hazards to acceptable levels by requiring operators to adopt best practices, technological innovations, and risk management frameworks. Ultimately, effective collaboration between operators and regulators is essential to achieving sustainable and responsible field development while safeguarding both industry and public interests.

2.3.3.3 Environmental and Social Considerations

Sustainable development practices are becoming increasingly critical in marginal field projects, as operators must balance economic viability with environmental and social responsibility. Minimizing the environmental footprint is essential and can be achieved through strategies such as shared infrastructure, reduction of gas flaring, and effective waste management (Cao et al., 2016; Kumar, 2019). These measures not only enhance environmental sustainability but also improve operational efficiency and cost-effectiveness. Additionally, community engagement and local capacity building are fundamental to securing a social license to operate. Given that marginal fields often contribute to regional economic development, fostering positive relationships with host communities through employment opportunities, infrastructure development, and corporate social responsibility (CSR) initiatives is crucial. Proactively addressing social and environmental concerns ensures long-term project sustainability while aligning with global Environmental, Social, and Governance (ESG) standards.

The successful commercialization of marginal fields demands a multi-faceted strategy that integrates cost efficiency, technological innovation, collaboration, and effective risk management. By addressing these factors, operators can transform marginal fields into economically viable assets, contributing to energy supply and regional development. This approach is particularly crucial for Nigerian marginal field operators, who often face significant funding challenges for field development.

2.4 Decision Criteria

Based on the foregoing, this study identified cost, HSE (Health, Safety, and Environment), regulation, security, stakeholders, and technology as the most critical criteria for optimal marginal field development. These were selected based on their relevance to the challenges associated with marginal fields, alignment with industry standards, regulatory frameworks for approving Field Development Plans (FDPs) and their representation of strategic pillars commonly adopted by petroleum companies. These strategic pillars emphasize maximizing economic value, ensuring operational safety, complying with regulations, fostering positive stakeholder relationships, and leveraging appropriate technologies to optimize production.

2.4.1 Project cost

Cost is a critical criterion in marginal field development due to its direct impact on the economic feasibility of such projects. Marginal fields, characterized by their limited profitability margins, demand cost-effective strategies to ensure financial viability. The primary cost considerations include capital expenditure (CAPEX) and operational expenditure (OPEX), both of which must be carefully managed to optimize project outcomes.

CAPEX refers to one-time expenditures on equipment and facilities incurred during the project's initiation phase. These costs include seismic surveys, exploration and appraisal drilling, development planning, procurement, and installation of production infrastructure. CAPEX does not indicate project profitability but reflects its affordability (Adamu et al., 2013). Minimizing CAPEX is crucial for reducing financial risks. Operators often employ strategies like partnerships, phased development, and leasing production facilities to mitigate upfront costs (Gupta &

Gupta, 2012). This enables companies to allocate resources efficiently while maintaining the affordability of marginal field projects.

OPEX encompasses recurring costs during the production phase, including personnel, maintenance, logistics, and supplies. While CAPEX represents initial investments, OPEX reflects the ongoing financial burden of sustaining operations. Companies face a strategic choice between higher initial CAPEX to minimize OPEX or lower upfront costs with potentially higher OPEX as the project progresses. Studies (Hauwert et al., 2016; Oruwari, 2018) suggest a preference for low initial CAPEX while ensuring OPEX remains manageable to maintain long-term project viability.

Numerous studies highlight strategies for reducing both CAPEX and OPEX in marginal field development. These include adopting modular and reusable facilities, leveraging existing infrastructure, sharing facilities, and innovative financing methods (Rahim, 2022). In Nigeria, Eromosele and Okoro (2015) emphasized early production facilities and partnerships as effective cost-reduction approaches. Similarly, Kue and Orodu (2016) identified cost drivers and proposed optimization strategies tailored to the Nigerian context.

Net Present Value (NPV) is a key metric in decision-making, offering a simplified yet powerful assessment of project profitability. While NPV is vital, it may overlook efficiency in capital utilization, making complementary metrics like Unit Technical Cost (UTC) essential. UTC measures the cost per barrel of development and production, enabling regional and technical comparisons. For example, UTC varies significantly by geography, ranging from \$2-5/bbl in the Middle East to \$10-20/bbl in the North Sea (Jahn et al., 2011). Ensuring UTC aligns with global standards (~\$28/bbl) supports cost-effective project execution.

In Nigeria, studies by Adisa and Adeleke (2018) and Oluyemi et al. (2019) have explored the challenges of cost management in marginal fields, proposing strategies to enhance cost-efficiency. Acheampong et al. (2021) highlighted the significance of cost-sharing and progressive fiscal regimes in maintaining profitability in low-margin projects.

Effective cost management in marginal field development is pivotal to ensuring economic viability and project success. By optimizing CAPEX and OPEX, employing innovative cost-reduction strategies, and leveraging economic indicators like NPV and UTC, operators can enhance profitability and mitigate risks. These approaches, when tailored to regional and project-specific contexts, provide a robust foundation for the sustainable development of marginal oil fields.

2.4.2 Health, Safety and Environment

Health, Safety, and Environment (HSE) considerations are important in marginal field development, ensuring regulatory compliance, operational safety, environmental sustainability, and social acceptance. Given the environmental sensitivity and stakeholder expectations surrounding oil and gas projects, integrating robust HSE practices is non-negotiable for achieving successful and sustainable outcomes.

Health and safety measures are essential to safeguarding personnel and minimizing operational risks. Proper implementation of safety protocols helps prevent accidents and equipment failures, thereby reducing project downtime and associated costs (Van Dijk, 2013). While the oil and gas industry has a well-established safety philosophy embedded in equipment design and operations, unplanned events such as oil spills, explosions, and facility damage can still occur. In Nigeria, oil spills remain a significant risk, negatively impacting the economic viability of marginal fields due to cleanup costs, damage to assets, and reputational harm (Eze et al., 2017). Thus, projects must include robust safety frameworks and contingency plans to mitigate these risks.

Environmental protection is a critical aspect of HSE, focusing on minimizing the ecological footprint of oil and gas operations. Key considerations include:

- Pollution Management: Preventing air and water contamination through proper waste management, reduced flaring, and venting of associated gas (Ya'u et al., 2021).
- Climate Change Mitigation: Addressing greenhouse gas (GHG) emissions is imperative, given that the oil and gas sector contributes approximately one-third of global energy-related GHG emissions (Nwankwo et al., 2020). Operators are increasingly adopting decarbonization strategies, including integrating renewables into upstream projects, reducing methane emissions, and deploying carbon capture, utilization, and storage (CCUS) technologies.

- Ecosystem Preservation: Maintaining biodiversity and preventing habitat degradation, especially in areas sensitive to environmental changes.

Projects that demonstrate reduced environmental impact are more likely to secure regulatory approval and community support, reducing opposition and delays.

CSR is increasingly recognized as a key component of sustainable field development. Oil and gas companies are expected to demonstrate commitment to local communities through initiatives that improve living standards, enhance infrastructure, and create shared value. CSR practices not only foster goodwill but also enhance social license to operate, reducing risks of disruptions from host communities (Humphrey and Dosunmu, 2018).

The oil and gas sector faces mounting pressures from investors, activists, and governments to align operations with global climate policies and emission reduction goals (Eze et al., 2017). Disclosure of environmental data, implementation of sustainable practices, and adoption of low-carbon technologies are becoming prerequisites for continued operation in the industry. While these challenges pose financial and operational constraints, they also present opportunities to innovate and enhance sustainability. For instance:

- Reducing flaring and venting can yield economic benefits by capturing valuable hydrocarbons.
- Developing LNG infrastructure and incorporating renewables into upstream projects can diversify energy portfolios and reduce reliance on fossil fuels.
- Supporting large-scale clean energy technologies such as offshore wind and biofuels aligns industry competencies with global decarbonization goals.

The financial implications of HSE are significant, especially in marginal fields with tight profit margins. Environmental risks, including oil spills and extreme weather events, can escalate costs due to cleanup, repair, and legal penalties. Frequent evacuations and remobilizations caused by safety concerns or natural disasters further diminish economic viability. Projects with robust HSE measures, however, are more likely to succeed in such challenging environments, as they minimize risks and align with global best practices (Oyekan et al., 2020).

HSE considerations are integral to marginal field development, balancing regulatory compliance, operational efficiency, and environmental sustainability.

By addressing health and safety risks, mitigating environmental impacts, and incorporating CSR practices, operators can ensure long-term project success. Moreover, aligning with global climate policies and stakeholder expectations positions the industry as a proactive contributor to sustainable development, even in a resource-constrained and environmentally sensitive context.

2.4.3 Regulation

The regulation plays a significant role in governing the exploration, development, and production of marginal fields. Clear and supportive regulations that address licensing, taxation, environmental requirements, and local content policies provide the necessary framework for investment and operations Tsimplis et al., 2019. A transparent and stable regulatory environment encourages investment and facilitates the development of marginal fields (Ovadia, 2014; Udo et al., 2020). At the Concept selection stage when all feasible development concepts are determined it is necessary to analyse the compliance of engineering solutions with technical regulations. The FDP will be subject to a nation's policy and legal framework. These instruments should incorporate the country's strategy for development of the sector and associated conditions and obligations which can influence the FDP e.g. domestic utilisation of oil or gas, contract/license duration, when the FDP needs to be submitted, its contents etc (Asiogo, 2017).

The unique characteristics of marginal field development, as discussed in previous sections, necessitate a new regulatory approach. Traditionally, regulatory approval for field development is granted post-appraisal drilling; however, Kakayor et al. demonstrated the feasibility of a field development strategy in which a development concept is finalized before full field appraisal. This was made possible through regulatory support, allowing operators to streamline project timelines while ensuring compliance with industry standards.

While the primary responsibility for asset safety rests with the operating company, regulators play a crucial role in balancing economic activities, public interest, and environmental protection. Regulatory bodies strive to keep risks "as low as reasonably practicable" (ALARP) while addressing objectives such as economic efficiency, operational viability, consumer protection, and environmental safety. Given the rapidly evolving oil and gas landscape, regulators must continuously adapt their frameworks, integrating best practices to enhance governance and oversight (Ekhator, 2016; Nwankwo and Iyeke, 2022).

A key aspect of modern regulatory strategy is the adoption of common guidelines and benchmarking protocols to identify and implement best industrial practices (Araujo and Leoneti 2019). In recent years, regulators have increasingly relied on benchmarking processes to evaluate performance across the industry. However, the perspective of performance measurement, auditing, and benchmarking differs between regulatory agencies and operating companies. While companies focus on productivity enhancement within the constraints of cost-effectiveness and regulatory compliance, regulators aim to identify and promote companies that not only meet but exceed regulatory requirements.

Benchmarking relies on data submitted by operating companies, including licensing documents, incident reports, and verification audits. Performance benchmarks may be established based on minimum acceptable regulatory compliance levels or, alternatively, the performance standards of industry-leading operators (ISO 9001:2015). By implementing structured benchmarking frameworks, regulators can enhance accountability, safety, and operational efficiency, ensuring that marginal field developments adhere to the highest industry standards while remaining economically viable and environmentally responsible (Schneider et al. 2015).

Thus, it is very important to ensure that the Development Concept is incompliance with industry standards. If the development concept does not fulfil standardized requirements, it could not be considered for further studies. When feasibility of the Development Concept is approved, local authority requirements for each stage of project execution should be considered (OGA, 2018). Another example is the USA which states by the Jones Act that crews on vessels must be citizens of the USA, the tankers must have at least 75% American ownership, and tankers for transporting hydrocarbons must be built in the USA. This state makes the FPSO concept for USA fields' exploitation significantly more expensive than in other regions. Thus, it is important to consider the local authority requirements compliance for each feasible Development Concept. The optimal development concept meets all requirements from the local government without additional expenditures (Khalidov et al., 2023; Ovadia, 2014; Husy, 2011).

By understanding and complying with regulatory requirements, obtaining the necessary licenses and permits, adhering to environmental and safety regulations, engaging with regulatory authorities, and maintaining open communication, you can navigate the approval process effectively and ensure compliance throughout the marginal field development project. Regularly review and update your knowledge of regulatory changes to adapt your practices accordingly.

2.4.4 Security

Security is a major concern in the Niger Delta region, Nigeria compared to other regions and countries due to issues like vandalism, theft, and militancy (Rui et al., 2018). A focus on security helps in mitigating these risks and ensuring the safety of assets and personnel. Security of personnel and facilities is also a big challenge to the operations of the industry in Nigeria that has not been tackled (Eze et al., 2017; Nwaozuzu, 2014;). More need to be done to tackle this problem, Nigeria has one of the highest costs of production per barrel and one of the main reasons is that a large portion of the production cost is for security. There have been incessant attacks on oil and gas facilities, support vessels, drilling rigs and workers resulting in shut down of wells with the economic implications. Workers are kidnapped on land, swamp and shallow offshore for huge ransom. Consequently, IOCs operating in the country have moved most of their production activities to deep offshore to minimize the security risks suspending their land and swamp activities. There have been incidences of pipeline breakages, averaging 5 breakages per day between 2005 to 2019 (figure 4) which have resulted in colossal loss of revenue to the country (NNPC ASB 2019).

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2.4.5 Stakeholders

The stakeholder criterion is essential for ensuring the social feasibility and success of marginal field development projects. Social feasibility involves assessing the project's social impact and securing support from local communities, regulators, and other stakeholders (Mbelwa, 2018). Projects with robust stakeholder engagement are less likely to face opposition and have higher success rates (Akaranta et al., 2021). This is particularly crucial in marginal fields, where socio-political and economic complexities can present significant challenges. Research supports the importance of stakeholder engagement in petroleum projects. For instance, Otombosoba and Dosunmu (2017) demonstrated that effective communication strategies foster trust even in challenging environments, while Humphrey and Dosunmu (2018) highlighted the role of partnerships and social investments in Nigerian marginal fields. These findings align with global best practices, underscoring the need for holistic stakeholder management.

Governments often have high expectations regarding revenue generation, job creation, and business opportunities, which can complicate the approval of Field Development Plans (FDPs) if unmet (Ogeer, 2022). Key stakeholders—government institutions, politicians, local communities, NGOs, and the media—significantly influence project outcomes (Oruwari and Dagogo, 2019). Managing these diverse interests requires effective coordination, transparency, and preparation by operators and lead agencies (Otombosoba and Dosunmu, 2017). Managing external stakeholders—including regulators, financial institutions, and suppliers—also improves project outcomes. Transparent communication and trust-building mitigate conflicts and foster long-term cooperation (Akaranta et al., 2021). For example, the Younis field's development succeeded due to the effective involvement of multidisciplinary teams and service companies, ensuring seamless coordination (Hassan et al., 2000).

Community engagement plays a fundamental role in the successful development of marginal fields. Operators that prioritize local involvement, social investments, and infrastructure development not only contribute to regional economic growth but also secure a stronger social license to operate (Humphrey and Dosunmu, 2016). Establishing positive relationships with host communities fosters cooperation, reduces conflicts, and enhances long-term project sustainability.

Beyond external stakeholder engagement, effective people management and interdisciplinary collaboration within operational teams are critical to improving efficiency and stakeholder relations (Valkenier, 2016). Many challenges associated with marginal field development stem from limited subsurface and production data, which introduce technical uncertainties and investment risks. However, assembling a highly skilled and competent team can significantly mitigate these uncertainties, enabling better decision-making and optimizing field performance. Technical expertise is particularly vital in marginal field operations, where resource constraints necessitate innovative problem-solving and adaptive management strategies. Therefore, ensuring the presence of technically competent personnel is paramount to achieving sustainable oil production and long-term operational success (Oyakhire and Omeke, 2017).

Incorporating stakeholder engagement as a criterion ensures that marginal field projects are socially feasible, politically acceptable, and economically viable. By addressing stakeholder expectations and fostering collaboration, operators can mitigate risks and promote sustainable development, contributing to the long-term success of the petroleum industry.

2.4.6 Technology

The technology criterion is an important consideration in optimizing the development of marginal fields. It encompasses technical feasibility (a measure of technical viability of the development options), the availability of the required technology, efficiency of the technology used, the ability of the technology used in the development option to scale up or down. Technical viability refers to the extent to which a technology option is capable of meeting the technical requirements necessary for the development of marginal fields in Nigeria. Technical requirements may include factors such as drilling equipment, pipelines, processing facilities, and other infrastructure. Technology has been extensively discussed in section 2.2.

By incorporating cost, HSE, regulation, security, stakeholders, and technology as evaluation criteria, this study provides a holistic framework tailored to the specific challenges of marginal field development. These criteria ensure that decision-making processes are robust, comprehensive, and aligned with both industry best practices and regulatory requirements. This approach facilitates the selection of optimal development strategies that balance economic, technical, social, and environmental considerations.

2.5 Decision Making Frameworks

Developing marginal fields requires comprehensive decision-making frameworks to address technical, economic, and operational challenges while ensuring optimal resource utilization and financial viability. Decision frameworks help operators evaluate alternatives, prioritize investments, and mitigate risks.

2.5.1 Traditional DCF Methods

Decision-makers can utilize several methods to evaluate uncertainty, mitigate risks, and select viable solutions. Ayodele and Frimpong (2003), Akinpelu and Omole (2009), Adamu et al. (2013), Ezemonye and Clement (2013), Idigbe and Bello (2013) Adeogun and Illedare (2015), Ashore (2015), Ekeh and Asekomeh (2015) and Akinwale and Akinbanmi (2016) have analysed the investment decision in the Nigeria marginal oil fields through economic evaluation using traditional models the net present value (NPV), internal rate of return (IRR), profitability index (PIR), payback period and probabilistic approach via Monte Carlo simulation. Adenikinuju et al (2016), acknowledges that NPV solely considers likely outcomes required for development, lacking consideration for changing conditions, new information, and the flexibility available to the operator post the initial go or no-go project decision. Field development concept selection based on NPV calculated from a basic economic model could lead to the exclusion of important aspects such as safety and environment. This can lead to selection of non-optimal option. The NPV is static, and if initial evaluations yield a negative NPV, the implication is that the field development should not proceed (MacLean, 2005). However, real-world scenarios often require flexibility—managers may need to scale up production in response to unexpected demand or scale down funding for a research project lacking marketable products. Traditional DCF approaches, despite their merits, fail to capture the value of such flexibility (Damodaran, 2003; Kodukula, 2006; Abisoye, 2007; Bowman and Moskowitz, 2011; Acheampong, 2010; Pire et al., 2012).

2.5.2 Real Options Analysis

Real Options Analysis (ROA) which serves as a step beyond traditional economic approach because of its ability to incorporate flexibility and option value has also been used by different researchers like Lund (1999), Abisoye (2007), Acheampong, (2010) to evaluate investment analysis in the oil and gas sector in United Kingdom, Norway and many more countries. Results showed that investment shows higher return on investment when analysed with ROA compared to when analysed with traditional approach. However, the study already done on marginal fields have failed to consider investment in oil and gas project in the analysis of investment decision in the marginal fields" development in Nigeria. The researchers also failed to take into account all the uncertainties that might arise as a result of Niger Delta Militants Insurgencies (NDMI) resulting in huge crude oil losses and the consequent financial implication.

2.5.3 Decision Theory Valuation

Alaneme and Igboanugo (2015) identified Decision theory valuation methodology as an effective tool in the analysis and management of risks for decision making in marginal oilfield exploitation. The study yielded corresponding payoff values for different reserve expectations of low, medium, and high cases in barrels of crude oil. This approach provides a cost effective first-pass appraisal mechanism needful for decision making process open to investment capitalists engaged in marginal oilfield exploitation. It successfully predicted the risk ratios of fundamental decision alternatives guided by basic assumptions on state of nature. However, it has a constraint in inadequately quantifying risks with precision. These approaches did not consider important factors such as safety and environment, community issues which are critical to investment decision in the marginal fields' development.

2.5.4 Multicriteria Decision-Making (MCDM)

Multi-Criteria Decision Making (MCDM) encompasses a range of mathematical modelling techniques designed to solve complex decision problems involving multiple criteria. It enables decision-makers to systematically evaluate and select the best alternative or course of action. MCDM has been successfully applied across various industries, including engineering, resource management, and healthcare (Hamurcu and Eren, 2019; Stojčić et al., 2019). Extensive literature reviews have examined the methodologies, merits, and limitations of MCDM, underscoring its adaptability and value in diverse contexts (Velasquez and Hester, 2013; Kumar et al., 2017; Mardani et al., 2017; Sriram et al., 2022). As a result, MCDA enjoys widespread acceptance and continues to play a vital role in decision-making across numerous industries.

Multi-Criteria Decision Analysis (MCDA) is well-suited for addressing the decision-making challenge of selecting the optimal option for marginal field development. The concept selection process in this context can be framed as a multicriteria problem, where the objective is to identify the most suitable marginal field development option from a range of alternatives. By systematically evaluating multiple conflicting criteria, MCDA provides a structured framework for making informed and balanced decisions in this complex scenario. MCDA addresses the human factor problem of reliance on intuition and experience in making decisions involving multi objectives and trade-offs. This is often subjective and polluted by human bias (Virine and Murphy, 2007; Virine, 2008).

In Table 2.2 a comparison of three widely used multi-criteria decision-making (MCDM) methods is provided: Analytic Hierarchy Process (AHP), Technique for Order of Preference by Similarity to Ideal Solution (TOPSIS), and Preference Ranking Organization Method for Enrichment Evaluation (PROMETHEE) (Wu and Abdul-Nour, 2020). Each of these methods is designed to help decision-makers evaluate and select the most optimal solution from a set of alternatives based on multiple criteria (Jozaghi et al., 2018). The table highlights the key features, advantages, and disadvantages of each method, offering a clear understanding of their applicability, strengths, and limitations. This comparison aids in selecting the most suitable approach depending on the complexity of the problem, the nature of the decision criteria, and the decision-making environment.

Table 2.2: Comparison of AHP, TOPSIS, and PROMETHEE Decision-Making Methods

Method	**Description**	**Advantages**	**Disadvantages**
AHP	A structured decision-making method that uses pairwise comparisons and a hierarchy of criteria to determine	- Provides a clear and logical framework for complex decision-making. - Incorporates qualitative and quantitative	- Can become cumbersome with a large number of criteria or alternatives. - Subjective judgments may introduce bias.

Method	Description	Advantages	Disadvantages
	priorities and select the best option	criteria. - Allows consistency checks in pairwise comparisons. - Suitable for group decision-making.	- Inconsistencies in comparisons can affect results. - Requires expertise for implementation.
TOPSIS	A ranking method based on the concept that the chosen alternative should have the shortest distance from the ideal solution and the farthest from the negative ideal solution.	- Easy to understand and implement. - Works well with quantitative data. - Considers both the best and worst-case scenarios. - Suitable for problems with multiple criteria. - Efficient for large datasets.	- Requires normalization of data. - Sensitive to weights assigned to criteria. - Assumes criteria are independent. - Does not provide explicit justification for rankings.
PROMETHEE	A multi-criteria decision-making method based on pairwise comparisons and preference functions to rank alternatives.	- Flexible and user-friendly. - Handles both qualitative and quantitative criteria. - Can be tailored with different preference functions. - Provides a detailed ranking and outranking analysis. - Suitable for complex problems.	- Requires subjective selection of preference functions and thresholds. - Computationally intensive for large datasets. - May not handle trade-offs between criteria as explicitly as AHP.

AHP stands out among the various Multi-Criteria Decision Analysis (MCDA) methods, particularly for concept selection in marginal field development. Unlike TOPSIS and PROMETHEE, AHP provides a systematic approach that facilitates the ranking of alternatives based on multiple criteria. One of its key advantages is the incorporation of a consistency ratio, which helps assess the reliability of the decision-maker's judgments. This feature ensures that the decision-making process is not only structured and transparent but also robust against inconsistencies that may arise from subjective evaluations. Given the complexity and the need for careful judgment in selecting the best development concept for marginal fields, AHP's ability to handle both qualitative and quantitative criteria and evaluate the consistency of judgments makes it particularly well-suited for this task. It enables decision-makers to confidently navigate the complexities of marginal field development by providing a clear, reliable, and transparent decision-making framework.

2.5.5 Analytical Hierarchical Process (AHP)

The Analytic Hierarchy Process (AHP) is a general theory of measurement. It is used to derive ratio scales from both discrete and continuous paired comparisons. These comparisons may be taken from actual measurements or from a fundamental scale which reflects the relative strength of preferences and feelings. The AHP has a special concern with departure from consistency, its measurement and on dependence within and between the groups of elements of its structure. It has found its widest applications in multicriteria decision-making, planning and resource allocation and conflict resolution (Saaty, 1987).

AHP is a structured decision support tool widely recognized for its robustness in group decision-making contexts (Sharfiee 2019). It facilitates clear and quantitative evaluation of alternatives by establishing an appropriate framework and offering a basis for assessing values and trade-offs. AHP operates through pairwise comparisons, decomposing complex problems into a hierarchy of sub-problems, which are then evaluated relative to one another.

A hierarchy is a structured system that organizes the components of a multi-criteria decision-making problem into levels, where each component, except the topmost, is subordinate to one or more higher-level components. AHP simplifies complex decision-making by breaking it down into basic pairwise comparisons and using these comparisons to establish overall priorities, enabling the ranking of alternatives. Developed by Saaty (1977), AHP employs relative measurement, making it particularly suitable for situations where absolute measurements are unavailable. This approach is highly effective for handling multi-criteria decision analysis (MCDA) involving both qualitative and quantitative criteria (Ishizaka, 2019).

Islam and Saaty (2010) identified several key applications of the Analytical Hierarchy Process (AHP) technique, highlighting its versatility and effectiveness in decision-making. These applications include;

I. Simplified representation of a complex problem

II. Measurement and allocation of criteria weights
III. Determination of optimal choice among alternatives
IV. Measurement of consistency in human judgement
V. Prediction of future outcomes
VI. Resolution of conflicts by clear analysis
VII. Framework for forward/backward planning
VIII. Supporting tool for other decision-making techniques such as Cost Benefit Analysis and MAUT

These diverse uses underscore AHP's robustness and adaptability, making it a critical tool for tackling complex, multi-criteria decision-making challenges.

A significant strength of AHP lies in its ability to derive priority scales, which quantify intangible factors in relative terms. It integrates both quantitative and qualitative data, making it particularly suitable for industries like oil and gas exploration and production, where decisions hinge on both rigorous data analysis and the subjective judgment of experts.

With the aid of the Analytical Hierarchy Process (AHP), a decision-maker can visually structure the decision-making problem as a hierarchy of attributes, facilitating clarity and systematic evaluation. This hierarchical representation typically includes three levels:

I. Decision Aim 1: At the top of the hierarchy, the decision aim represents the overarching objective or goal of the decision-making process. This is the main target that guides the evaluation.
II. Criteria: The second level consists of criteria or factors that are considered critical to achieving the decision aim. These criteria represent the aspects or attributes against which the available options are evaluated. Each criterion may also have sub-criteria, further refining the assessment process.
III. Options: At the bottom level of the hierarchy are the decision alternatives or options available to the decision-maker. These represent the potential courses of action or choices to be ranked and selected based on their relative performance against the criteria.

The visual representation of the hierarchy, such as in Figure 2.12, provides an intuitive framework for understanding the relationships between the decision goal, the criteria, and the available options, enhancing the transparency and reliability of the process.

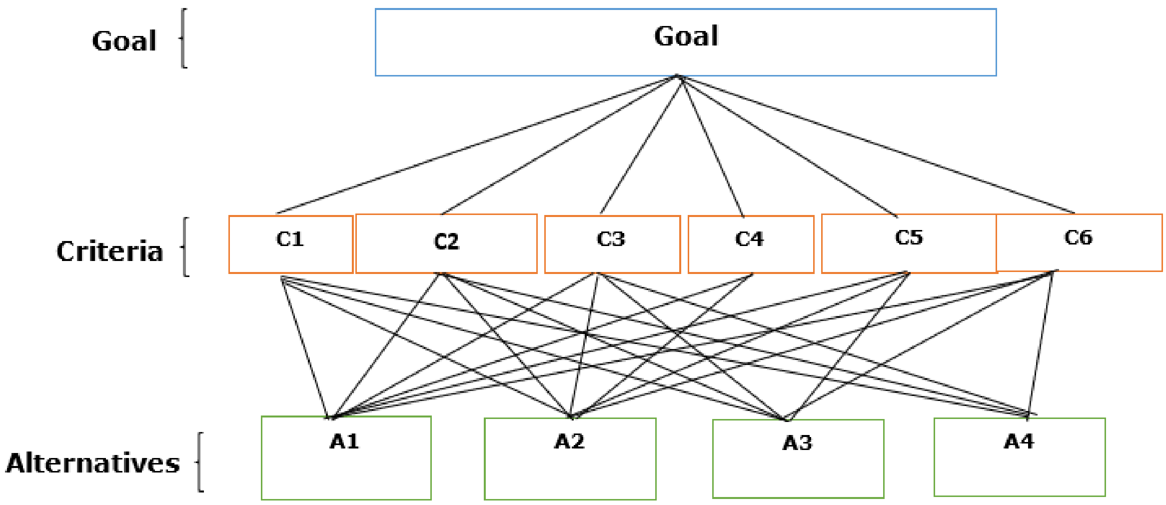


Figure 2.2: AHP Decision Hierarchy Structure

To ensure consistency and standardization in the AHP process for paired comparison judgments, Saaty (1977) developed a numerical scale for translating qualitative descriptions of relative importance into quantitative values. This scale, illustrated in Table 2.3, facilitates the hierarchical ranking of decision elements by their relative importance, thereby supporting structured and objective decision-making.

Table 2.3: AHP Relative Importance Scale

Intensity of importance	**Definition**	**Explanation**
1	Equal importance	Criteria a and b contribute equally to the objective
3	Moderate importance of one over another	Experience and judgment slightly favor criteria a over b
5	Strong importance	Experience and judgement strongly favor element a over b
7	Demonstrated importance	Element a is favored very strongly over b its dominance is demonstrated in practice
9	Absolute importance	The evidence favoring element a over b is of the highest possible order of affirmation
2, 4, 6, 8	Intermediate values between the two adjacent judgments	When compromise is needed. For example 4 can be used for the intermediate between 3 and 5
Reciprocals of above non zero	If a has one of the above numbers assigned to it when compared with b. then b has the reciprocal value when compared with a	

Rationals	Ratios arising from the scale	If consistency were to be forced by obtaining n numerical values to span the matrix

Saaty's scale is not only straightforward to use but also highly effective, as its validity has been supported by theoretical foundations and numerous successful applications across diverse fields (Saaty and Vargas, 2012).

However, AHP's reliance on subjective judgment introduces a potential drawback: the accuracy of results can be influenced by decision-makers' preferences, particularly when weighting qualitative criteria (Sabaei et al., 2015). This subjectivity is mitigated by the Saaty numerical scale (0–9), which transforms qualitative assessments into quantitative data, ensuring more consistent and reliable evaluations (Saaty, 1987). By combining systematic rigor with flexibility for subjective insights, AHP remains a valuable tool for decision-making in complex, multi-criteria environments like marginal field development in the oil and gas industry.

The Analytic Hierarchy Process (AHP) is a powerful decision-making method that combines systematic analysis with flexibility and ease of use. Its ability to address both quantitative and qualitative factors makes it an indispensable tool for tackling complex multi-criteria decision problems. By breaking down problems into manageable components and synthesizing judgments, AHP enables decision-makers to arrive at well-informed, consistent, and transparent conclusions.

2.5.6 Decision Support Tools

The AHP process involves numerous iterations and can be time-consuming and tedious. One way to mitigate this challenge is by automating the workflow. Software support can significantly reduce the barriers to applying Multi-Criteria Decision-Making (MCDM) procedures, making the process more efficient and user-friendly. This is particularly relevant in the selection of marginal field development options, where numerous criteria and alternatives must be evaluated, making automation essential for streamlining the decision-making process. The adoption of the AHP technique is further facilitated by the availability of user-friendly software such as Expert Choice, Decision Lens, and Super Decisions, which assist decision-makers in handling the mathematical aspects of the method (Mu and

Pereyra-Rojas, 2018). Other AHP tools, such as Criterium, Expert Choice, and HIPRE 3+ (Ossadnik and Lange 1999), are also available. However, these tools are generic and do not specifically address the unique requirements of selecting marginal field development options. This limitation underscores the need to develop specialized software tailored to the specific demands of marginal field development.

2.5.7 AHP in Field Development

AHP has been widely applied in field development planning, where decisions are often made under uncertainty and involve various technical, economic, and environmental factors. Several studies have demonstrated its effectiveness in the oil and gas sector, particularly in selecting optimal development strategies, investment options, and technology choices.

One of the primary applications of AHP in field development is selecting the optimal development strategy. For instance, Passalacqua et al., (2017) applied AHP to rank efficiently various alternatives of development such as EOR options, well types options, facilities options, transport options,. They considered criteria such as operability and reliability, subsurface conditions, as well as economical quantitative parameters, such as Life Cycle Costing (LCC). The results showed that AHP provided a comprehensive approach to prioritize the most suitable development strategy based on the specific objectives and constraints of the project.

The Analytical Hierarchy Process (AHP) has also been effectively utilized in the selection of appropriate subsea technologies for offshore oil field development. Ysseri (2012) demonstrated that while financial viability is the primary driver of concept selection, the most critical decision variables include technology readiness, reliability and availability, constructability, maintainability, operability, and costs. These variables collectively influence both the cost and the overall benefits of the selected technology, highlighting the need for a balanced evaluation of multiple factors. Technology selection in offshore oil field development requires integrating these decision variables to ensure the chosen solution meets the operational and financial objectives of the project. Ysseri's study introduced an integrated analytic framework employing AHP for selecting subsea technologies that best satisfy the diverse requirements of decision-makers. By structuring the selection process hierarchically, the framework allows for the systematic evaluation and prioritization of options based on the identified variables. The study also included a detailed survey of factors influencing decision-making and provided a practical case study. In the case study, AHP was used to compare two subsea trees produced by different suppliers, demonstrating the selection process and decision-making methodology. The research emphasized the practicality and accessibility of AHP as a decision-support tool, offering a transparent and systematic approach for selecting subsea technologies in complex offshore development scenarios.

AHP has also been applied in selecting suppliers of oil and gas companies oil field development, particularly in marginal and low-recovery fields. For example, Zediri et al. (2021) used AHP to select the best supplier for oil and gas companies in Algeria. They considered criteria such as Price and Costs, Financial status, Logistics, Supplier quality system, Technical capability. The study demonstrated that AHP allowed for a systematic comparison of different suppliers, and could contribute to improving the supply chain, developing the decision-making process and increasing performance efficiency in oil and gas companies

In marginal field development, AHP has proven effective in optimizing project decisions. Gani et al. (2016) used AHP in conjunction with Value Improving Practices (VIPs) to select floating production technologies for an ONWJ Indonesia field, demonstrating its value in enhancing project profitability. Passalacqua et al. (2017) employed AHP to prioritize Enhanced Oil Recovery (EOR) techniques for heavy oil fields, emphasizing the tool's ability to incorporate multidisciplinary insights for complex evaluations.

The Analytic Hierarchy Process (AHP) is a widely adopted multi-criteria decision-making (MCDM) tool in the oil and gas industry in Nigeria. It aids in prioritizing alternatives based on a structured evaluation of criteria. Applications of AHP in the Nigerian oil and gas sector include refinery site selection (Okokpujie et al., 2019), life cycle cost analysis of refineries (Okafor, 2013), and assessment of vulnerable infrastructure to climate impacts (Usie et al., 2020). AHP has also been utilized in selecting gas monetization projects (Omoleomo et al., 2020) and evaluating petroleum product costs using statistical models (Nikkeh et al., 2022). These studies highlight its importance in addressing complex decision-making challenges.

In Nigeria, Aweh et al. (2021) applied AHP to assess environmental criteria for siting petroleum refineries, demonstrating its utility in evaluating multiple factors systematically. Usie et al. (2020) showcased AHP's potential in prioritizing infrastructure criticality under climate change impacts, providing a framework for adaptation planning in the Niger Delta.

The integration of AHP with other MCDM methods, such as PROMETHEE and TOPSIS, as demonstrated by Qaradaghi (2016), further enhances its application in resource allocation and portfolio optimization. These techniques have been applied to compare completion designs for high-rate gas wells, balancing capital costs, productivity, and operational risks.

AHP has proven to be a valuable tool in field development, providing decision-makers with a structured, transparent, and systematic approach to select the optimal development strategies. Its ability to integrate multiple criteria, evaluate the consistency of judgments, and support complex decision-making processes makes it particularly well-suited for the oil and gas sector. However, its reliance on subjective judgments and potential scalability issues should be considered when applying it to large, complex field development projects. Despite these limitations, AHP remains an important method for concept selection, technology evaluation, and risk assessment in field development.

In marginal field development, AHP offers a structured framework to evaluate development options by incorporating screening and economic analysis. Its ability to accommodate diverse decision-maker judgments and dynamic criteria makes it an indispensable tool for optimizing development strategies in complex and resource-constrained contexts. Further it can be automated into a software to provide a user-friendly interface, automate the calculations involved in AHP, and generate results efficiently.

These studies demonstrate the potential benefits of using the AHP technique in the Nigerian oil and gas industry. However, there is still a need for further research to investigate the application of AHP specifically in the context of marginal field development and to develop a comprehensive framework for selecting an optimal marginal field development strategy in Nigeria.

2.6 Summary

This chapter has provided a comprehensive review of existing literature on marginal field development, highlighting the unique challenges and complexities inherent in these projects. The lack of requisite funds is a significant challenge for marginal field owners in Nigeria. Despite government incentives, attracting funding remains difficult. The involvement of foreign technical partners is seen to access offshore funds, but limitations on foreign ownership stakes and the marginal nature of the fields deter potential investors. Local banks have played a vital role in funding operational marginal fields, often after production has commenced and through the sale of stock or private equity. Nigeria's infrastructure, encompassing roads, power supply, water supply, and other amenities, is generally inadequate and demands substantial investment. This poses a challenge for the development of marginal fields, as significant infrastructure investments are necessary to support exploration, production, and transportation activities. Irregularities in the bidding process, policy inconsistencies, the inadequacy of the current fiscal regime, the lack of collaboration and communication, and the limited adoption of new technology collectively hamper the development and optimal utilisation of marginal fields in Nigeria.

The literature also highlights the transformative role of advanced technologies in turning marginal fields into economically viable projects. Key criteria identified for successful marginal field development include cost, health, safety, and environment (HSE) considerations, regulatory requirements, security concerns, stakeholder involvement, and the adoption of appropriate technology. These criteria encompass both quantitative and qualitative factors, necessitating a decision-making framework that can effectively address these often conflicting variables. Through this critical analysis, the Analytic Hierarchy Process (AHP) emerged as the most suitable Multi-Criteria Decision Method (MCDM) technique for developing a robust decision-making model for marginal field development. The application of AHP will allow for a structured and transparent evaluation of different development alternatives, ensuring that all relevant criteria are adequately considered.

Chapter 3 Case Study of Niger Delta Marginal Fields

Marginal field development in Nigeria, particularly in the Niger Delta, presents unique opportunities and challenges due to the region's complex geology, historical context, and regulatory landscape. In this chapter, a critical analysis of marginal field development in Nigeria was carried out to identify the crucial factors for optimal development and to explore feasible options, considering the unique characteristics of the Nigerian oil and gas sector. All of the gathered data informed the selection and identification of Niger Delta marginal fields development options with corresponding technology.

3.1 Niger Delta Basin

One advantage of marginal field development is that these fields are located in known basins. Familiarity with the basin and operating environment aids in identifying critical variables required for developing an effective model. A thorough understanding of the basin is essential for constructing a model that supports the selection of the optimal field development option.

There are six basins in Nigeria, and they are Benue, Bida, Borno, Gongola, Niger Delta and Yola basins as shown in the geological map of the basins in Nigeria (Figure 3.1). However, all Oil and Gas activity in Nigeria is domiciled in the Niger Delta Basin. There are plans by the Government to develop other basins as part of its objective to increase Nigeria oil and gas reserves base through rigorous exploration. This reinforces the importance of this work.

An important aspect of marginal field development is that these fields are located within known basins, which provides valuable insights into their operating environment. A comprehensive understanding of the Niger Delta Basin is critical for identifying key variables essential for developing a model to optimize field development decisions. Such knowledge enables the creation of robust models for selecting the most suitable development options.

Nigeria has six sedimentary basins: Benue, Bida, Borno, Gongola, Niger Delta, and Yola Basins, as illustrated in the geological map of Nigeria (Figure 3.1). However, all current oil and gas activities are concentrated in the Niger Delta Basin. The

Nigerian government has outlined plans to develop other basins as part of its strategy to expand the nation's oil and gas reserves through extensive exploration. These efforts highlight the relevance and importance of this study, particularly in optimizing marginal field development within the Niger Delta Basin.

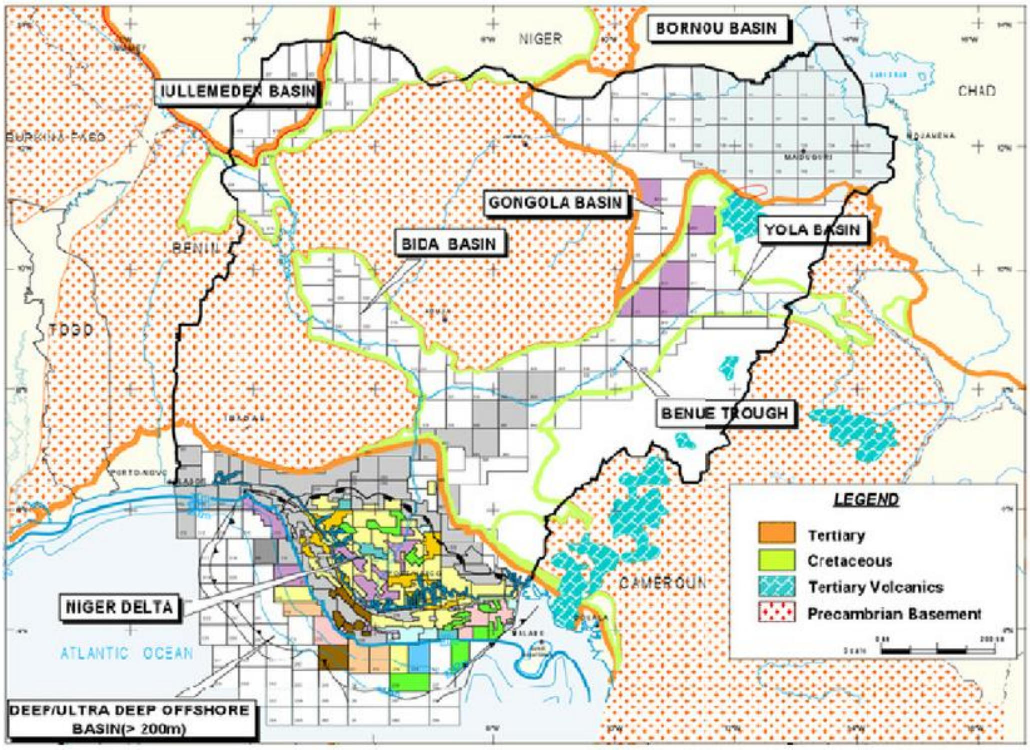


Figure 3.1: Geological Map and Sedimentary Basins in Nigeria (Source: DPR 2018).

A wide range of research has been conducted on the Niger Delta Basin to understand its stratigraphy, structural framework, and reservoir distribution. It is one of the largest delta systems in the world underlying an area of about 256,000 km2 (Doust 1990; Adegoke et al. 2017) located at the top of the Gulf of Guinea on the West African continental margin which formed the site of a triple junction during continental break-up in the Cretaceous. Delta structure and stratigraphy are closely associated, the evolution of each is dependent on the interaction between amount of sediment and subsidence rates. The main subsurface structures are syn- and post- sedimentary listric normal faults which mark the main delta sequence. They perish out upwards into the alluvial sands and single out at depth near the top of the marine claystones (Doust 1990). Major growth-fault trends cross the delta from northwest to southeast, dividing it into several structural and stratigraphic belts, called depobelts. There are five most important depobelts documented each with its own sedimentation, deformation, and petroleum history specifically, Northern Delta, Greater Ughelli, Central Swamp, Coastal Swamp, Offshore depobelts. Each depobelt is a discrete unit that links to a break in regional dip of the delta, and is confined landward by growth faults, and seaward by large counter-regional faults or the growth fault of the next seaward belt (Dim et al. 2020). The deltaic sequence in each of these depobelts is distinct in age, so that they represent successive phases in the delta's history.

Delta construction proceeded in discrete minibasins ranging in tectonic configuration from extensional, through translational to compressional toe-thrust regions. Outcropping units of the Niger Delta consist of the Imo Formation and the Ameki Group comprising the Ameki, Nanka, Nsugbe, and Ogwashi-Asaba formations (Dim et al. 2016; Adegoke et al. 2017; Dim et al. 2020). The subsurface lithostratigraphic units are the major transgressive marine Akata Shales, the petroliferous paralic Agbada Formation, and the continental Benin Sands. The Benin formation is continental in nature and consists late Eocene to Holocene porous fresh water bearing sandstones and overlies the Agbada formation. Agbada formation consists of a paralic sequence of sandstone, siltstone and fluvio-marine sands with shale intercalations and overlies the Akata formation. The Akata formation is made up chiefly of prodeltaic shales and silts with minimum sands. Channel and basin-floor fan deposits in the Agbada Formation form the primary reservoirs in the Niger Delta (Doust 1990; Dim et al. 2020). The marine shales of Akata and the Benin sands form the main source rock of the Niger Delta petroleum system and overburden rock units respectively.

Traps are mainly dip closures (rollover anticlines in growth faults) and relatively rare stratigraphic traps (Ibe and Ezekiel 2018). Hydrocarbons have been sourced from marine shales with land plant material transforming mainly into Types III and II/III organic matter within the oil window between 9,000 and 14,000 ft. depth. The Niger Delta is very prolific with the reservoirs being largely shoreface, beach, channel sands, and sometimes turbidites containing oil reserves of about 37 billion barrels and 203 TCF of gas reserves (DPR 2018). The Niger Delta crude is low-sulphur, nickel bearing, light waxy, and nondegraded. Hydrocarbons have been found in all the depobelts of the Niger Delta. Most of the larger accumulations occur in roll-over anticlines in the hanging-walls of growth faults, where they may be trapped in either dip or fault closures. The hydrocarbons are found in multiple pay sands with relatively short columns, and adjacent fault blocks usually have independent accumulations. Generally, studies on the Niger Delta Basin have shown the existence of hydrocarbon prospective zones that cut across fields and deeper depths not yet drilled (Dim et al. 2016; Aigbogun and Mujakperuo 2018; Dim et al. 2020). However, the reserves tend to accumulate in traps or small pockets which seems to make them marginal because of the compartmentalisation. Table 3.1 shows the typical characteristics of fields in the Niger Delta. Reservoirs are not complex therefore no complexities in developing them.

Table 3.1: Summary of characteristics of Niger Delta Fields

Parameter	**Attributes in Niger Delta**
Geology	Tropical delta at passive continental margin of south Atlantic. Early tertiary to recent age. Mostly shallow ramp depositional model, shelf break locally mappable.
Traps	Dip closures (rollover anticlines in growth fault). Fault bound traps. Stratigraphic traps (truncation traps, tidal deltas, channels, etc.).
Source Rocks	Marine shales with land plant material (high potential). Marine-deltaic shales (low potential). Lower coastal plain shales (low potential). Types III/II, II, III, vitrinite, liptinite. Within penetrations measured < 0.7. Top oil window variable 9000 to 14000 ft.
Reservoirs	Deltaic sandstones (shoreface, beach, channels, etc.). Stacked sand/shale alternations. Multi-reservoir fields. Reservoir depth 5000 to 18000 ft.
Hydrocarbons	Oil/condensate/gas. Gravity 25 to 45 API, non-biodegraded. Low-sulphur/nickel. Pristine/phytane ratios 0.5 to 1.6. Rich in waxes/resins, other land plant material, SOM.

3.1.1 Niger Delta Reservoir Characteristics

The Niger Delta is a complex geological region with a variety of reservoir types, so the metrics for a typical Niger Delta reservoir can vary depending on the specific reservoir. However, some common metrics for the Niger Delta reservoirs are shown in Table 3.2 compared to industry metrics.

Table 3.2: Metric for Niger Delta Reservoirs compared to Industry Metrics (Rui et al. 2021)

Characteristics	Nigerian Reservoir	Grade Group	Industry Criteria
Porosity	25% to 40%	Very good and up	0 to 5% negligible; 5 to 10% poor; 10 to 15% fair; 15 to 20% good; 20 to 25% very good
Permeability	>200 mD up to 2 darcy	Very good and up	1 to 10 mD fair; 10 to 100 mD good; 100 to 1000 mD very good
API	23 to 35 API	Light crude or middle crude	Extra heavy oil (API <10°); Heavy crude oil (API <22.3°); Medium (API.>22.3 and API<31.1°); Light crude (API>31.1°)
Hydrocarbon Saturation	70% to 90%	Higher than average	Typical hydrocarbon saturation range between 60% and 80%
Reservoir Rock Thickness	Primary reservoirs sandstone reservoir with thickness of 100 m	Much higher than average	Average sandstone thickness 25 m

Well Success Rate	70%	Much higher than average	New areas (no previous exploration) success rate: 10% to 20%; Geologically known areas: 20% to 30%; Areas next to existing production zones: around 60%; Average success rate < 40%

From Table 3.2 it can be seen that Niger Delta reservoirs are graded much higher than global average. The typical crude type in the Niger Delta is a light, sweet crude oil. This type of crude oil has a low density, low sulfur content of around 0.5% nickel bearing, light waxy, and nondegraded making them easy to produce and transport. The gas is typically composed mainly of methane, with smaller amounts of ethane, propane, and heavier hydrocarbons. The gas is also considered to be of good quality, and it is typically dry, with low levels of impurities, such as sulfur and water (NUPRC). The most prominent crude oil found in the Niger Delta is the Qua Iboe crude oil, which is produced from the Qua Iboe field, and is considered to be one of the highest quality crude oils in Nigeria. Other crude oils found in the Niger Delta include the Bonny Light crude oil, the Forcados crude oil, and the Brass River crude oil. Niger Delta crude is considered as a high-quality crude oil, as it is relatively easy to refine and produces a high yield of gasoline and diesel fuel (NUPRC). These characteristics are important to evaluate as they can affect the feasibility of the field development and the production potential (Yu et al. 2011).

3.1.2 Existing Infrastructure in the Niger Delta

According to data from NUPRC, Hydrocarbon is currently extracted from 323 developed fields located in both onshore and offshore terrains. These fields, which either contain Crude Oil, Condensates or Natural Gas reservoirs, are connected to 265 production processing stations, after which the stabilised Oil and Gas are exported via 31 export terminals. The onshore processing infrastructures are linked to 8 crude oil/condensates and NGLs export terminals through pipelines that span 5,284 km. Some of these delivery pipelines connected to the five onshore export terminals are utilised by both the asset operators and third-party oil producers, for transportation, storage and lifting of Crude Oil blends through export or delivery to domestic refineries (NUPRC 2023). The Niger Delta region in Nigeria has a significant infrastructure network to support the oil and gas industry and the overall development of the region. This infrastructure includes transportation systems, pipelines, ports, refineries, and power generation facilities as listed in Table 3.3. Below is a detailed discussion of the existing infrastructure in the Niger Delta:

Table 3.3: Existing infrastructure in the Niger Delta (NUPRC).

Facility	Name
Terminals	Pennington – CNL, Bonny – SPDC, Bonny – MPNU, Qua Iboe – MPNU, Brass – NAOC, Ukpokiti – Express Petroleum
FPSO	Knock Adoon (Antan) – Addax, Sendje, Berge (Okwori) – Addax, EA - sea eagle – SPDC, Okono – NPDC, Abo – NAE, Agbami – Star Deep, Akpo – Tupni, Bonga – SNEPCO, Erha – ESSO, Usan – ESSO, Ailsa Craig – AMNI, Armanda perkasa – AMNI, Armanda Perdana(Oyo) – Allied Energy, Trinity Spirit – Atlas petroleum, Jamestown – Cavendish, Front puffin – Yinka Folawiyo, Abigail-Joseph – First E&P, Ajapa – Brittania-U
MOPU	Ima Langley – AMNI, Auntie Julie – Continental Oil and Gas, Mr P – Conoil Producing, Ebok – Oriental
FSO	Okono-Okpoho – NPDC, FSO Tulja – Seepco, FSO Unity – TEPNG
Gas Plant	Ebendo – Energia, Ogbele – NDEP
Processing Facility	EPF 2,500 bopd processing capacity – Universal, Uquo Gas – Frontier, Oil processing facility – Frontier, Umusadege – Midwestern
EPF	EPF – Orient Petroleum, EPF 2500bopd processing capacity – Universal, EPF Qua Ibo early – Network, Assaramatoru EPF – Prime
Flow station	Ibigwe, Ebendo, Umuseti, Egboama, Ogbele

While pipelines are often considered the most efficient, safe, and environmentally friendly method of transporting petroleum products over long distances in many countries, this is not the case in Nigeria, where vandalism and pipeline sabotage have led to catastrophic disasters. As a result, there is a significantly higher reliance on road haulage for petroleum product transportation (NUPRC). This is as a result of the collapse of rail infrastructure and the lack of inland water transportation.

3.2 Assessment of Marginal Fields in Niger Delta

In order to critically appraise marginal field development in Nigeria, the marginal field operators were categorised into three key groups. Group one consists operating companies whose marginal fields have been fully developed and are in production. Group two are companies whose marginal fields are at various stages of development. Group three are companies whose marginal fields are inactive, and their licenses have been revoked by the regulatory agency Department of Petroleum Resources (DPR) now Nigeria Upstream Petroleum Regulatory Commission (NUPRC). Group one consists of the seventeen (17) marginal field operators whose fields are in production as shown in Table 3.4. Their fields of operation were then evaluated based on reserves and production to identify successful marginal field operators for further engagement to understand their developmental progression and operational challenges.

Table 3.4: Group 1 Marginal Fields in Production

S/N	Operator	Operator Initials	Field Name	Block	Location
1	All Grace Energy Limited	AGEL	Ubima	OML 17	Land
2	Brittania U Nigeria Limited	BUNL	Ajapa	OML 90	Offshore
3	Chorus Energy Limited	CEL	Amoji/Matsogo/Igholo	OML 56	Land
4	Energia Limited (Operator)/Oando Production and Development Limited	EL	Ebendo / Obodeti (Ex Obodugwa / Obodeti)	OML 56	Land

S/N	Operator	Operator Initials	Field Name	Block	Location
5	Excel Exploration and Production Limited	EEPL	Eremor	OML 46	Swamp
6	Frontier Oil Limited	FOL	Uquo	OML 13	Swamp
7	Green Energy International Limited	GEIL	Otakikpo	OML 11	Land
8	Midwestern Oil and Gas Limited/Suntrust Oil Company Limited	MDOGL	Umusadege	OML 56	Land
9	Millennium Oil and Gas Limited	MIOGL	Oza	OML 11	Land
10	Niger Delta Petroleum Resources Limited	NDPRL	Ogbele	OML 54	Swamp
11	Network E&P Limited	NEPL	Qua Ibo	OML 13	Land
12	Prime Exploration & Production (Operator)/Suffolk Petroleum Limited	PEPL	Asamatoru	OML 11	Swamp
13	Pillar Oil Limited	POL	Umusati/Igbuku	OML 56	Land
14	Platform Petroleum Limited	PPL	Egbaoma (Ex Asuokpu / Umutu)	OML 38	Land
15	Oriental Energy Resources Limited	OERL	Ebok	OML 67	Offshore
16	Universal Energy Limited	UEL	Stubb Creek	OMLs 13/14	Swamp
17	Waltersmith Petroman Limited (Operator)/Morris Petroleum Limited	WPL	Ibigwe	OML 16	Land

Thirteen (13) of the awarded fields are situated onshore, nine (9) offshore, and the remaining eight (8) in swamp areas. Notably, nearly all onshore fields, accounting for 85%, are in production, while 70% of swamp fields are in production; in contrast, only 20% of offshore fields are currently in production.

3.2.1 Reserves Performance and Replacement Trends in Marginal Fields

Reserves are a critical factor in determining the appropriate development option for oil and gas fields. Based on data obtained from regulators, the reserves position of marginal fields as of January 1, 2006, ranged from 1.1 MMbbls to 84 MMbbls. Among the 22 fields analysed, 9 had reserves below 10 MMbbls, 5 had reserves between 10–20 MMbbls, 7 fields had reserves between 20–30 MMbbls, and only one field recorded 84 MMbbls. Marginal field operators achieved a net addition of +27.09 MMbbls to 2P oil and condensate reserves, representing a 5% positive net increase. Most operators show a significant increase in reserves from 2006 to 2021.

Of the 17 fields in production, 7 exhibited reserve growth, while the others either remained constant or showed declines (Figure 3.2). The top five contributors to reserve growth were NDPRL, FOL, CEL, MDOGGL, and BUNL, with substantial reserve increases of 213%, 206%, 130%, 112%, and 98%, respectively. BUNL, MDOGGL, and POL stand out as having the highest reserves in 2021. CEL and UEL consistently remain among the lowest in both periods. This underscores the varying degrees of success in resource exploration and development strategies over time.

However, when analysed by reserves replacement ratio (RRR), the leading performers were Oriental, All Grace, Pillar, Waltersmith, and Niger Delta, as shown in Figure 3.3. Only three fields achieved an RRR above the critical 100% threshold, with ratios of 123%, 142%, and 218%, indicating their ability to sustain current production levels while allowing room for future growth. In contrast, one field had an RRR of 56%, five fields had ratios between 1–20%, seven fields recorded 0%, and one field posted a negative RRR of -9.8%.

The fields with 0% RRR generally face significant production challenges, primarily related to pipeline availability issues. This underscores a recurring challenge for many marginal fields, where reserve growth is not prioritized due to operational and infrastructural constraints. This highlights the need for targeted strategies to address production bottlenecks and enhance reserve replacement to ensure the long-term sustainability of marginal field operations.

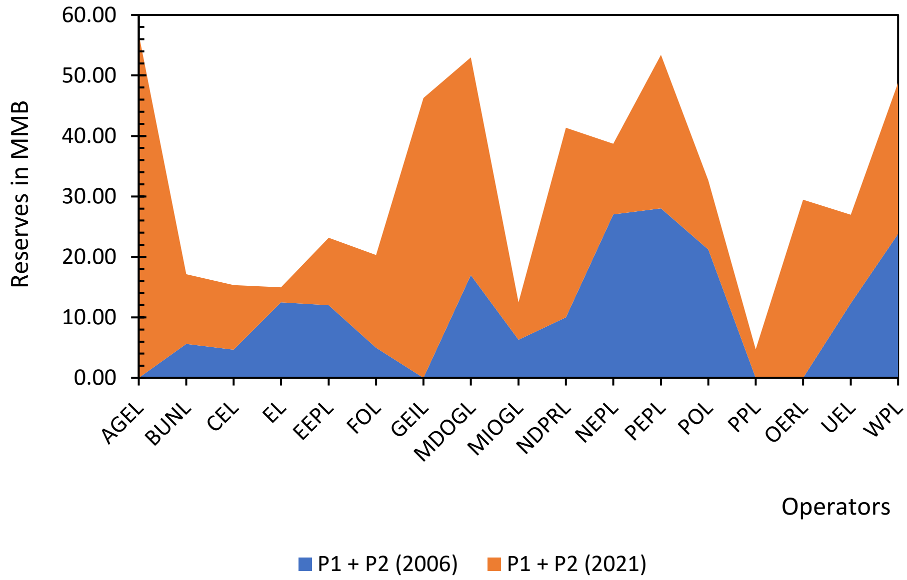


Figure 3.2: Reserves Trend in Group 1 Marginal Fields.

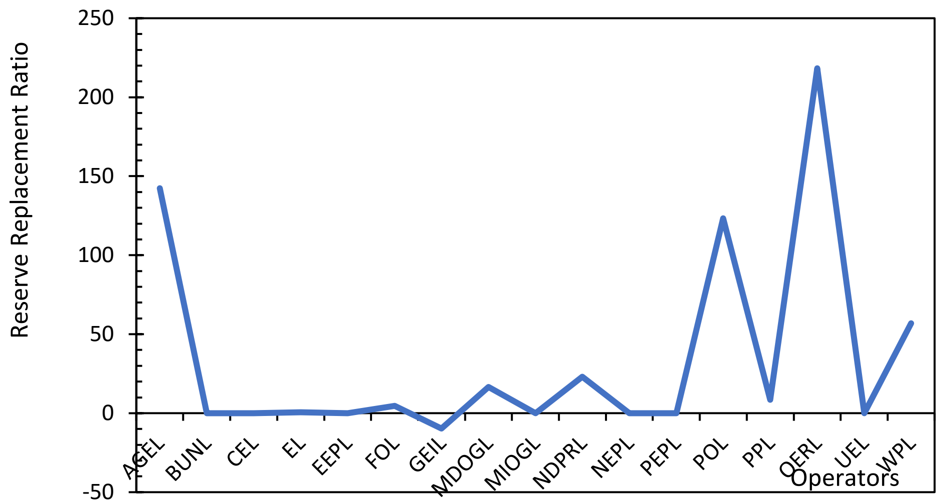


Figure 3.3: Reserves Replacement Ratio in Group 1 Marginal Fields.

3.2.2 Production trend

Marginal fields in production under Group One have generally sustained steady production once operations began. Niger Delta (NDPRL) was the first field to come onstream and maintain consistent production, followed by fields such as Walter Smith (WPL) and Pillar Oil (POL), listed chronologically by year of first production in Table 3.6. Cumulative production from all marginal fields since inception to the end of 2021 totalled 232,851,154 barrels (bbl), contributing approximately 10% of Nigeria’s national production.

Table 3.5: Annual Production for Group 1 Marginal Fields (NUPRC).

Marginal Fields Cumulative Production '000																		
Operator	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**TOTAL**
NDPRL	130	657	426	1,383	1,559	1,238	682	502	434	927	1,423	1,645	1,732	1,749	2,663	2,469	3,207	22,826
WPL	-	-	-	171	386	607	634	667	959	1,282	1,409	1,057	1,633	1,793	1,967	1,317	892	14,774
POL	-	-	-	-	163	74	0	409	524	555	1,016	565	915	927	1,073	891	838	7,949
MDOGL	-	-	-	427	1,185	1,076	2,663	3,138	2,978	3,647	6,207	652	5,367	5,691	5,237	3,830	2,985	45,083
PPL	-	-	-	847	590	329	487	614	470	646	664	446	967	996	1,052	986	813	9,907
BUNL	-	-	-	-	-	347	331	492	426	501	665	748	445	433	289	586	499	5,762
EL	-	-	-	-	23	340	523	446	732	955	1,665	8,098	1,231	1,584	1,834	1,667	1,387	20,487
OERL	-	-	-	-	-	-	3,056	11,122	12,845	10,395	10,761	7,869	6,656	6,382	6,074	4,750	4,235	84,145
FOL	-	-	-	-	-	-	-	-	-	-	160	560	121	42	50	313	450	1,696
UEL	-	-	-	-	-	-	-	-	-	-	483	596	932	761	865	852	949	5,437
NEPL	-	-	-	-	-	-	-	-	-	-	480	244	806	656	674	556	576	3,992
GEIL	-	-	-	-	-	-	-	-	-	-	-	-	1,560	1,924	1,892	1,682	1,598	8,655
MIOGL	-	-	-	-	-	-	-	-	-	-	-	-	70	127	51	-	-	248
EEPL	-	-	-	-	-	-	-	-	-	-	-	-	21	63	68	267	235	654
PEPL	-	-	-	-	-	-	-	-	-	-	261	285	-	69	-	-	-	615
CEL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	166	183	271	621
AGEL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	294	294
	130	**657**	**426**	**2,828**	**3,906**	**4,012**	**8,377**	**17,390**	**19,369**	**18,908**	**25,193**	**22,764**	**22,455**	**23,197**	**23,956**	**20,349**	**18,936**	**232,851**

Despite a history of steady production, a noticeable drop in production levels occurred in 2021, attributed to the following factors:

1. Crude Oil Theft:
    - 2021 witnessed an unprecedented surge in crude oil theft, accounting for an estimated 12% of the nation's daily average production.
    - The severity of theft led to the declaration of force majeure at the Bonny Oil & Gas Terminal (BOGT) and the shutdown of fields connected to critical infrastructure such as the Nembe Creek Trunk Line (NCTL) and the Trans Niger Pipeline (TNP).
    - This trend persisted into 2022, prompting calls for government intervention and enhanced security measures.
2. Security Challenges:
    - Security issues in oil-producing regions, including pipeline vandalism, community unrest, sabotage, and third-party interference, have significantly affected production.
    - Operators are often unable to execute development or intervention activities essential for sustaining or optimizing production.
    - In many cases, operators were forced to shut in production, exacerbating the drop in output.

These challenges highlight the need for robust interventions to address theft and security issues, ensuring the sustainability and optimization of production in marginal fields.

Figure 3.4 illustrates a comparison between the 2021 Technical Allowable Rate (TAR) and 2021 Actual Production for various operators of marginal fields in Nigeria. For most operators, actual production is consistently lower than the TAR, indicating that these operators are producing below their technical capacity.

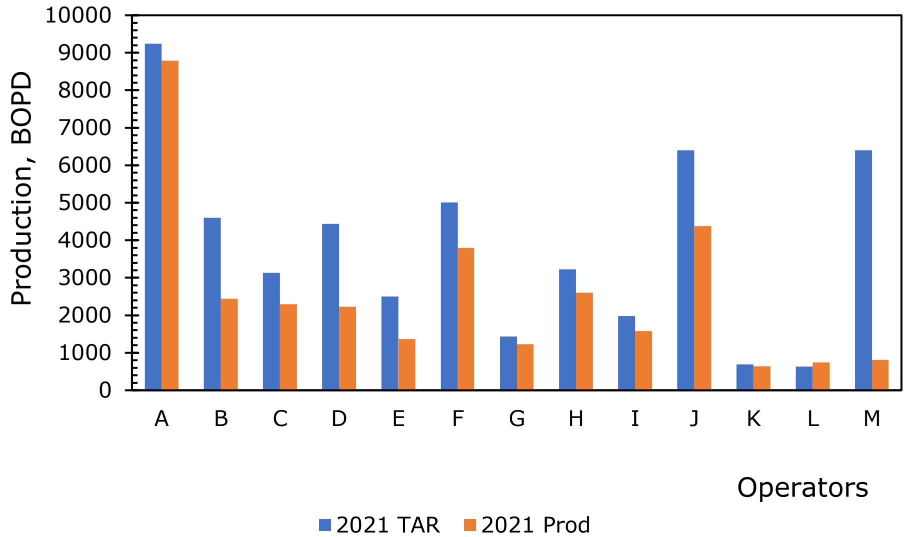


Figure 3.4: Production Trend for Group 1 Marginal Fields

For most of the operators as shown in Figure 3.4, actual production is consistently lower than the TAR, indicating that these operators are producing below their technical capacity. Operator M has the highest discrepancy, with TAR close to 7,000 BOPD and actual production significantly below this threshold. Operator J and Operator M exhibit the largest gaps between TAR and actual production, suggesting underutilization of potential production capacity. This trend may reflect broader challenges in Nigeria's marginal field operations, including security concerns, infrastructure limitations, or regulatory compliance issues. These highlights the need for targeted interventions to optimize production, bridge the gap between TAR and actual output, and improve the economic viability of marginal fields.

The Average Daily Production (BOPD) for various operators of marginal fields is shown in Figure 3.5. Each operator, labelled from A to P, shows differing production capacities, measured in barrels of oil per day.

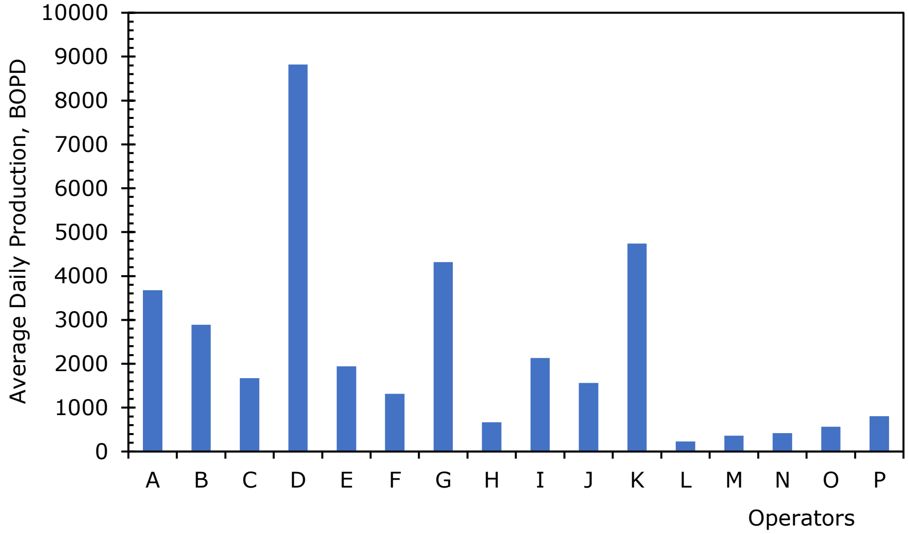


Figure 3.5: Production Trend for Group 1 Marginal Fields

As shown in Figure 3.5 Operator D achieves the highest average daily production, nearing 9,000 BOPD. This suggests robust operational capacity and possibly efficient field development and management practices. Operators A, J, and K also exhibit relatively high average daily production levels, though significantly lower than Operator D. 30 % of the operators have very low average daily production, barely exceeding 1,000 BOPD. These operators may be dealing with smaller field sizes, operational inefficiencies, funding constraints, or other limiting factors. There is a noticeable disparity between the operators, with production ranging from less than 1,000 BOPD to almost 9,000 BOPD. This suggests varying levels of field productivity, infrastructure, and operational capabilities across operators. For low-production fields, strategic efforts such as collaborative partnerships, government support, or regulatory adjustments might be required to overcome challenges and boost production.

3.3 Application of Decision Criteria to Case Study Fields

This section analyses Group 1 field development strategies to identify key development concepts for model formulation. By evaluating the influence of cost, HSE, regulation, security, stakeholders, and technology, common development variables were identified and structured into a concept matrix. This matrix serves as the foundation for an optimized decision-making model, ensuring alignment with real-world industry practices and balancing technical and economic feasibility in marginal field development.

3.3.1 Analysis of effect of Cost Criteria on Group 1 MFs

All the marginal fields in group 1, producing fields adopted a phased development strategy, allowing the operators to reduce initial upfront capital expenditure and additionally de-risk the investment. All of the developments were carried out mainly in two phases with some few doing more. Phase 1 involved re-entry of existing wells, building of the production facilities and pipeline to export production. While phase 2 involved conducting 3D seismic surveys, drilling more wells and installing gas processing facilities. All developments involved parallel continued appraisal. Phase 3 involved building modular refineries and drilling more wells.

Well re-entry is less expensive than drilling a new well, the borehole trajectory to the production zone is known, there is information about the reservoir from the logs and production history. Re-entry drilling provided operators the opportunity for cost savings by optimising resources such as surface facilities, well head, conductor, surface and intermediate casing if they are still in good condition. Wells were drilled at $6m constituting a 50% savings in cost of drilling.

All the marginal fields reviewed re-entered the existing wells in the fields making a huge cost saving on drilling of wells. Several of them 71.4% had dual-zone completion thereby draining from multiple reservoirs with the attendant cost savings with more revenue.

All seventeen fields utilised early production facilities which enabled them save cost and earn some early revenue. Some of the EPFs were existing facility converted for production operations. To make cost savings on capital expenditure, operators made collaboration and strategic alliances enabling the utilization of the benefit of economies of scale. They went into collaboration with major oil companies and oil service companies to develop their marginal oil fields.

Marginal field development starts from the development phase because wells have already been drilled. All the field developments were phased, allowing the companies to reduce initial upfront capital expenditure and additionally de-risk the investment. All the fields utilised early production facilities which enabled them save cost and earn some revenue.

The most pragmatic path is to clean and re-enter already existing wells. It is less expensive than drilling a new well, the borehole trajectory to the production zone is known, there is information about the reservoir from the logs and production history. Success of re-entry drilling is improved by synergy between the drilling and geological department with the service provider. Also, the employment of latest directional drilling LWD technologies guarantee good results such as perfect directional control, good (rate of penetration) ROP and good quality logs. re-entry drilling provides the opportunity for cost savings by optimising resources such as surface facilities, well head, conductor, surface, and intermediate casing if they are still in good condition.

To make cost savings on capital expenditure, operators made collaboration and strategic alliances enabling the utilization of the benefit of economies of scale. They went into collaboration with major oil companies and oil service companies to develop their marginal oil fields. Collaboration was observed in the following areas: sharing of infrastructure, development through Joint venture partnership (discussed further under stakeholders), data management, knowledge sharing and research, development, and innovation, entering production sharing contracts with service providers with attractive terms and so on.

3.3.2 Analysis of effect of Health, Safety and Environment Criteria

All the marginal fields in group 1 demonstrated commitment to HSE because bringing marginal fields to production requires the safe and efficient execution of extremely complex, technical multi-million dollar projects. These projects have significant risks and, if poorly executed, can result in environmental disasters, severe financial repercussions and reputational difficulties for the companies involved. The management team of the successful fields shows leadership and commitment in all HSE issues as part of their responsibilities which include but not limited to co-ordinating the development, implementation and ensuring compliance with all HSE Policies, guidelines and statutory rules and regulations. For example, where necessary, wells were equipped with downhole sand control mechanism as required to safeguard asset integrity, reduce production deferment, reduce/eliminate high cost associated with frequent facilities de-sanding. However, as they all employ Early Production Facilities (EPFs), certain operators fail to generate a sufficient volume of gas to warrant gas processing; consequently, they resort to gas flaring and incur associated penalties. Furthermore, these operators are penalized for inadequate compliance with regulatory water disposal requirements. Only those who had gas utilisation plans were not paying the penalty.

Existing data from previous operations can be leveraged to conduct desktop EIAs, reducing the need for extensive fieldwork leading to early EIA approvals. Operators can use these baseline studies to create more accurate and comprehensive EIAs. However, many MFs were previously operated without comprehensive environmental evaluation studies. There is a lack of historical environmental data for these fields, complicating current environmental assessments and management plans. A significant percentage of divested assets lack prior environmental evaluation studies, transferring environmental liabilities to new owners. If environmental evaluation studies had been conducted, laboratory results would likely indicate the need for environmental restitution. New operators must address these legacy issues, often without prior baseline data.

3.3.3 Analysis of effect of Regulation Criteria on Group 1 MF

Approval for Field Development Plans (FDPs) was granted to 85% of the operators of group 1 marginal fields, while the remaining 15% faced disapproval due to non-compliance with statutory prerequisites and failure to provide requested supplementary information within the specified timeframe. Some of the marginal field operators were granted waivers to be able to obtain an approval to develop. Some fields were granted were allowed to latch on earlier developed plans by the farmors. Most of the fields were granted waivers to start field development with data from one well whilst the requirement is three wells. These led to delays for some fields in obtaining the necessary approvals, permits and licenses. Operators also do not know the regulatory requirements and some of them make late applications for licenses resulting in delays in their projects.

3.3.4 Analysis of effect of Security Criteria on Group 1 MFs

Fifty six percent (56%) of group 1 marginal field operators were seriously impacted by the unprecedented level of theft was reached in 2021 estimated at 12% of the daily average production of the Nation. The consequence of this level of theft is the declaration of force majeure at Bonny Oil & Gas Terminal (BOGT) and shut down of fields evacuating through the Nembe Creek Trunk Line (NCTL) and the Trans Niger Pipeline (TNP). Marginal field operators strategically mitigated the operational challenges posed by insecurity, primarily by implementing alternative strategies for crude oil export in response to pipeline vandalism. Notably, this issue significantly impacted on group 1 operators who relied on Forcados and Brass terminals for production transportation. Case studies have demonstrated the effectiveness of successful alternatives, including barging, trucking, and in-situ processing of their production using modular refineries. Figure 3.6 shows the number of breakages between 2005 to 2019 resulting in huge losses to operators.

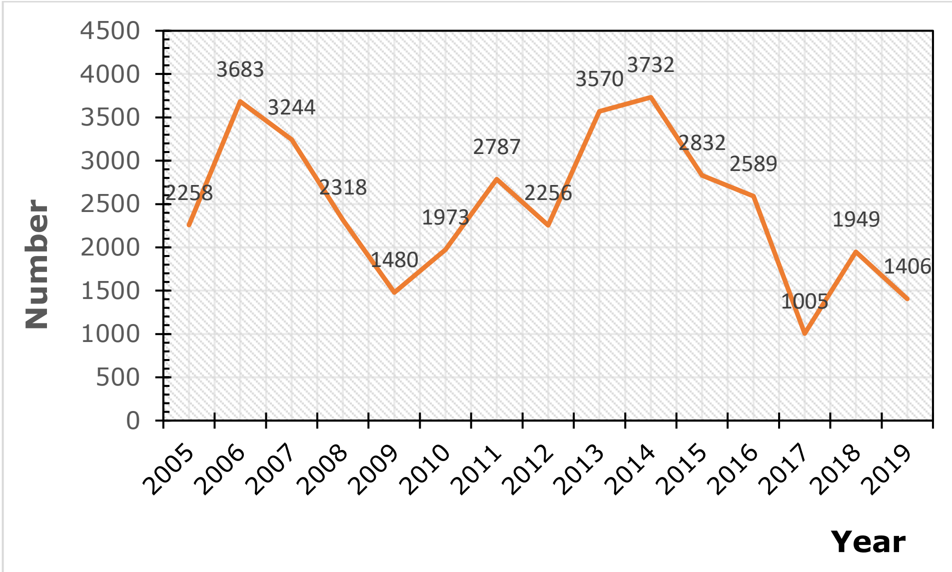


Figure 3.6: Pipeline Breakages between 2005 to 2019 (NNPC Ltd 2019).

The producing marginal fields and pipeline networks connected Bonny Oil Terminal (BOT), Brass Terminal (BRT) and Forcados Oil Terminal (FOT) are the worst hit by crude oil theft because they are located in the inner and most hostile part of the Niger Delta. That is why Chorus, Platform, Pillar, Midwestern, Energia who grouped to share cost of transportation experience crude theft. They configured to export through two networks Brass and Forcados. In both scenarios they are still affected by theft. Other producing fields affected by theft include; Excel evacuates Forcados, Millenium exports through pipeline to Bonny but has recently joined the Pillar cluster, Niger Delta and Waltersmith evacuate through Bonny and they both have modular refinery so reduce theft of volume that goes to refineries. The other fields Frontier, Universal, Network do not experience crude theft because they evacuate through Quo Iboe terminal. All Grace barges to Green Energy and Green Energy exports the combined production to Ima terminal therefore not affected by theft. The other two oil terminals located offshore (Escravos and Qua Iboe) do not report regular oil theft and sabotage because majority of the producing fields are situated offshore, while others situated in the upper part of the region. (Johnson et al. 2022).

Insecurity increases cost of borrowing and production insurance. Relationship between direct foreign investment and insecurity

3.3.5 Analysis of effect of Stakeholders Criteria on Group 1 MFs

Examination of group 1 marginal fields revealed they had the following features; good governance structure, formidable world class management team and shareholders, reliable and well-known contractors and suppliers, a lean team of cross functional employees (unicorns) who have industry experience, host community engagement through corporate social responsibility which translated their asset to bankable value. They were able to attract the necessary funding and overcome the inadequate data hurdle based on their industry knowledge.

The successful operators leveraged on stakeholders of the oil and gas industry through joint cooperation. They collaborated in terms of infrastructure sharing, knowledge sharing, and strategic partnership improve the performance of marginal oil field development. The overall result revealed that collaboration in form of strategic alliance and partnership is a driver or development support strategy for marginal oil field development.

The study established that marginal field operators may apply different strategies in responses to social demands in their operating environment. It is observed that the dynamic response or interactive strategy have produced beneficial result by sustaining peace in their operating environment in the long run compared to reactive or adaptive strategy which might gain temporary benefits in the short run.

3.3.6 Analysis of effect of Technology Criteria on Group 1 MFs

In terms of technology, assessment of group 1 fields was done by critical analysis of Wells, drilling, completion technology, Production facilities options, Export and transportation options employed by marginal field operators.

3.3.6.1 Well Development

It was found that reasonable but not cutting-edge technology was employed for drilling and completion. The operators mostly employed vertical wells, some horizontal wells, few multilaterals, use of 3D and 4D seismic, measuring while drilling (MWD), logging while drilling (LWD), wireline formation testing and dual completions because co-mingling is allowed for marginal fields. There were no smart wells. Although some of the fields demonstrate use of some innovation.

All the group 1 fields were discovered in the 60s, 70s and 80s, by one or two wells and some fields were appraised by further two to three wells. Therefore, the available well data is of mixed quality and vintage. All the wells are vertical. The well data consists of limited log data. Some fields like Ubima and Otatikpo had full 3D seismic coverage acquired in 1997 and 1989 respectively and the fields have been well defined by three to four drilled wells thereby minimizing structural and Petrophysical uncertainties. Most of the other fields had only 2D seismic and had to shoot 3D seismic to get better definition of their reservoirs being a cheaper way. Also, at the time of farm out by IOCs no production has taken place hence no historical production and pressure data were available for the fields. Data gaps were filled in by regional knowledge of the Niger Delta basin and simulations.

As shown in Table 3.6 the majority of group 1 fields are characterised by 1 to 4-well production, three (3) of the fields have one well each, another three (3) have two wells each, and two (2) fields have 3 wells producing. Seven (7) fields are producing with 4 to 7 wells two out of the seven are producing from 6 wells each. Oriental and Midwestern stand out with a substantial number of wells, 26 and 17, respectively. These companies operate at a different scale, producing over 10,000 barrels of oil per day (bopd), which is the maximum production threshold for qualification as a marginal field, as outlined in the guidelines. Oriental was already an established player in the industry and was awarded these fields as compensation for boundary adjustments. All the fields had the initial wells as vertical and later on drilled deviated wells.

Seven (7) of the seventeen (17) group 1 fields have single completion while the rest have some of the wells on dual completion. To optimise project economics, operators focus has been on maximizing well production rates. This objective is achieved by completing as many zones as possible within the wells. The rationale behind this approach is that leaving reservoirs untapped as behind-casing opportunities is less attractive, as revenue from these zones only materializes in later production years. Consequently, the completion strategy has predominantly been limited to dual completions rather than multizone.

All the fields benefit from robust aquifer support resulting in high recovery rates. All the fields experienced natural depletion as their primary drive mechanism but later incorporated gas lift mandrels in wells to facilitate artificial lift during the latter stages of well life. Oriental's Ebok field stands as a unique example, as it is currently maintained using Electrical Submersible Pumps (ESPs). ESPs offer advantages over gas lift systems as they can operate efficiently at lower flowing bottom-hole pressures (FBHP). However, it's important to acknowledge that ESP systems and installations come with significant capital costs and are sensitive to gas and sand production, resulting in substantial ongoing maintenance expense. Tables 3.6 and 3.7 provides a summary of development methods for Group 1 marginal fields

Table 3.6: Development Process for Group 1 Marginal Fields (NUPRC).

S/N	Operator	Block	Field Name	Terrain	Reserves (oil + condensate) BBLs	Number of Wells Drilled	Seismic Data Acquired	Year of Production	Production Volume BOPD	Remarks
1	AGEL	OML 17	Ubima	Onshore	56.84	4	3D Seismic	2021	370 TAR 578	
2	BUNL	OML 90	Ajapa	Offshore	11.53	5	2D & 3D seismic	2010	1,179	
3	CEL	OPL 283	Amoji	Onshore	-	3	-	-	Nil	HGOR Crude Oil Theft
			Igbolo		-	1	-	-	Nil	
			Matsogo		10.71 + 5.93	2	-	2019	754 TAR 980	
4	EL	OPL 283	Ebendo & Obodeti	Onshore	2.47 + 15.72	7	-	2009	3,850 TAR 4390	
5	EEPL	OML 46	Eremor	Swamp	11.14	4	3D seismic	2017	650 TAR 3182	
6	FOL	OPL 2003	Uquo	Onshore	15.30 + 0.63	9	2D & 3D Seismic	2015	1,248 TAR 1,523	

S/N	Operator	Block	Field Name	Terrain	Reserves (oil + condensate) BBLs	Number of Wells Drilled	Seismic Data Acquired	Year of Production	Production Volume BOPD	Remarks
7	GEIL	OML 11	Otakikpo	Swamp	46.26	3	2D & 3D seismic	2017	5,224 TAR 7560	
8	MDOGL	OPL 283	Umusadege	Onshore	36.01	18	3D seismic	2008	16,374 TAR 12093	
9	MIOGL	OML 11	Oza	Onshore	6.16	4	-	2017	338	
10	NEPL	OML 13	Qua Ibo	Swamp	11.71	5	3D seismic	2015	1,798 TAR 1916	
11	NDPRL	OML 54	Ogbele	Onshore	31.35 + 15.84	11	-	2005	8,910 TAR 11586	
12	OERL	OML 67	Ebok	Offshore	29.45	45	3D seismic	2011	11,764 TAR 18320	
		OML 67	Okwok	Offshore		9	3D seismic		Nil	
13	POL	OPL 283	Umuseti & Igbuku	Onshore	11.43 + 14.51	9	-	2009	2,512 TAR 5285	

S/N	Operator	Block	Field Name	Terrain	Reserves (oil + condensate) BBLs	Number of Wells Drilled	Seismic Data Acquired	Year of Production	Production Volume BOPD	Remarks
14	PPL	OML 38	Egbaoma	Onshore	4.73 + 5.20		-	2008	3,032 TAR 4004	
15	PEPL	OML 11	Asaramatoru	Swamp	25.40	2	2D & 3D seismic	2015	191	Crude Handling Issues
16	UEL	OMLs 13/14	Stubb Creek	Swamp	14.69	9	-	2015	2,254 TAR 3171	
17	WPL	OML 16	Ibigwe	Onshore	25.03	11	-	2008	4,916 TAR 3787	

Table 3.7: Summary of Wells and Completion Types in group 1 Marginal Fields (NUPRC).

Company	Field	Reservoir	Well	String (total)	String Active)	NF	GL	ESP	Fluid Type
AGEL	Ubima	1	1	1	1	1	0	0	Oil
BUNL	Ajapa	2	2	2	2	2	0	0	Condensate
CEL	Amoji	1	1	1	1	1	0	0	Condensate
EEPL	Eremor	1	3	3	3	3	0	0	Oil
EL	Ebendo	4	5	7	7	7	0	0	Oil/Condensate
FOL	Uquo	1	1	1	1	1	0	0	Oil
GEIL	Otatikpo	5	4	8	8	8	0	0	Oil
MDOGL	Umusadege	17	16	21	21	12	9	0	Oil
MIOGL	Oza	1	2	2	2	2	0	0	Oil
NDPRL	Ogbele	6	6	7	7	3	4	0	Oil
NEPL	Quo Iboe	3	2	3	3	3	0	0	Oil
OERL	Ebok	12	22	23	21	6	9	7	Oil
PEPL	Asaramatoru	0	0	0	0	0	0	0	Oil
POL	Umuseti	5	3	6	6	6	0	0	Oil
PPL	Egboama	8	6	11	11	11	0	0	Oil/Condensate
UEL	Stubb Creek	1	3	3	3	3	0	0	Oil
WPL	Ibigwe	7	7	10	10	3	7	0	Oil

Key:

NF: Natural Flow, GL: Gas Lift, ESP: Electric Semisubmersible Pump

3.3.6.2 Production Facilities

A phased approach was adopted by most of the marginal fields in production. All the marginal fields under consideration were developed using an Early Production System (EPS) for the first phase of production. EPS involves producing oil through a temporary processing system and exporting the processed crude to a storage vessel for subsequent transport to market. The benefits of an EPS include acquisition of better reservoir data, field development planning, investment optimisation and cashflow generation. The companies were able to generate cash flow from their assets as well as collect real-time production data, allowing them to appraise reservoir performance ahead of permanent development. Some of the EPSs were later upgraded to crude oil processing facilities. Pillar Energy constructed a 10,000 bopd flow station, a 30 MMscfd gas plant and 20,000 bopd storage. Oriental installed a production processing platform tied back to Ebok Floating storage offloading vessel (FSO). Some of the marginal fields have vertical integrated development, Niger Delta and Waltersmith constructed refineries to reduce the bottleneck with export.

The Niger Delta, being a mature basin with existing facilities and infrastructure, prompts the consideration of nearby facilities for processing as a viable option. In situations where no facility is in close proximity, economic constraints necessitate technical solutions characterised by mobility and reusability. Given that the expenses for most production surface structures will be borne not by a singular development but by at least two, the imperative arises for them to be mobile and reusable. Consequently, skid-mounted systems are deemed more suitable for onshore and swamp environments, while offshore scenarios favour the utilization of mobile offshore production units (MOPUs) or reusable subsea installations and central processing facilities for clustering. Furthermore, these facilities are anticipated to be leased rather than outright purchased, with a stipulation allowing the option for outright purchase if deemed necessary.

3.3.6.3 Transportation Options

There were a lot of collaboration in export and transportation options for marginal field development. A JV partnership constructed a 53 km, 12” export line from Umusadege field to Erienu manifold to serve as an alternative export line for the cluster group to removes export the bottleneck. The 10” Kwale-Akri oil delivery pipeline that is operated by NAOC is also used by marginal field operators to convey their crude to terminals. Crude transportation methods involve tiebacks to trunk lines, trucking, barging, shuttle services, and/or storage tankers.

Floating structures are particularly effective in remote locations where seabed pipelines are not cost effective. Floating structures eliminate the need to lay expensive long-distance pipelines from the oil well to an offshore terminal. They can also be used economically in smaller oil fields which can be exhausted in a few years. Once the field is depleted, the floating structures can be moved to a new location. For most of the fields initial means of transporting produced crude is by trucking or barging because of the high cost of building pipelines. Later on, when production stabilises they build pipelines to join the trunk line to terminal. However, TNP, reports high cases of crude oil theft and or losses. These leads to the use of trucks for transportation of produced crude.

Each individual marginal field development is unique and may have some aspect of technology which is quite unique or novel, but the producing marginal fields adapted technologies already proven in larger fields.

Additionally, the assessment of marginal field operators based on reserves addition, reserves replacement ratio, and production trends identified the following companies as the most successful: Niger Delta, Oriental, Waltersmith, Midwestern, Pillar Oil, and Green Energy. These operators demonstrated strong performance in sustaining and growing production through effective field development strategies. To further understand the key factors behind their success, a detailed evaluation of their fields was conducted using the previously identified criteria summarized in Table 3.8.

Table 3.8: Effect of Criteria on Successful Marginal Fields

Field	Year of Prod.	Effect of each criteria					
		Stakeholders	Technology	Regulation	HSE	Security	Cost
Ogbelle (NDEP)	2005	Integrated publicly-owned company Shareholders interested in the business Management consisting of top notch industry experts. Skilled team and efficient operations Employed use of historical knowledge from former staff of Chevron, Employees from host committee 5% of their profit is dedicated to host committee	EPF 3D seismic Multi zone completion Multilateral wells Modular refinery Gas processing	Local content Gas utilization utilizing not just local capital, but also deploying indigenous oil production services from local contractors	Gas development plan Operations Geared Towards Zero Incidents	In-situ production processing	Phased development 2 Well reentries Equity from shareholders Bank loan for workover of Ogbele 1 Sale of diesel and gas

		Strategic Partnership with the State National Oil Company of South Sudan					
Ibigwe (WS)	2008	Waltersmith Petroman Oil Limited (70%) and Morris Petroleum Limited (30%) Management consisting of top notch industry experts with industry knowledge Partnership with host committee/ MOU Lean team of Multi-disciplinary staff Employees from host committee Maintain high standards of corporate governance Access To SEPLAT Facility where gas can be tapped	EPF, 3D seismic, Work over, Dual completion, Vertical and Horizontal Wells, Modular Refinery, Wireline reentry, Ibigwe flow station	Compliance with the industry standards and best practices	Operate to the highest international social, environmental and safety standards	5,000bopd storage capacity tank installed to minimise deferment in the event of disruption in export schedules caused by pipeline outage.	Turnkey contracts Phased development Crude evacuation will be handled through existing TNP to Bonny for export Modular expandable facilities Sale of refined products

Umusadege	2008	Midwestern Oil and Gas Company 70% Sun Trust Oil Coy 30% interest Partnership with Mart Resources Maintaining good relationship with all stakeholders through consistent communication Formation of subsidiary companies Board consists of highly experienced professionals and business experts	EPF, Central Processing Facility, Multiphase Metering, Group Gathering Facility	Increasing Local Content by using local service companies, laboratory services, and personnel	9 Million Man-Hours lost-time-injury-free (LTI-free) operations in 2019 HSE awards and recognitions by international bodies		Subsidiary companies – risk service provider, drilling, pipeline
Umuseti	2009	Pillar Oil JV with Newton Energy Debt Free	EPF, Tie into NAOC pipeline, Coiled Tubing operations, internal gravel pack	Compliance with stipulated regulations	Compliance with No flare guidelines 800m spacing met in all three wells	Joint export with 2 other MFs	Phased development Farm into existing rig contract Phased incremental

							scale-up of existing facilities
Otatikpo	2017	Green Energy 60% Lekoil 40% interest	EPF, 3D Seismic, PROSPER tool, Modular Flow Station, Shuttle tanker, Workover, DST/TCP, Horizontal Wells, Sand Control	Zero routine gas flare facility	Small scale gas utilization projects	Alternate crude evacuation strategy	2 Phased development, Reenter existing wells Evacuation via shuttle tanker to nearby terminal

After assessing the fields, it was found that all the successful developments followed similar strategies as shown in Figure 3.7. This pattern was used to generate field development options for marginal fields in Nigeria.

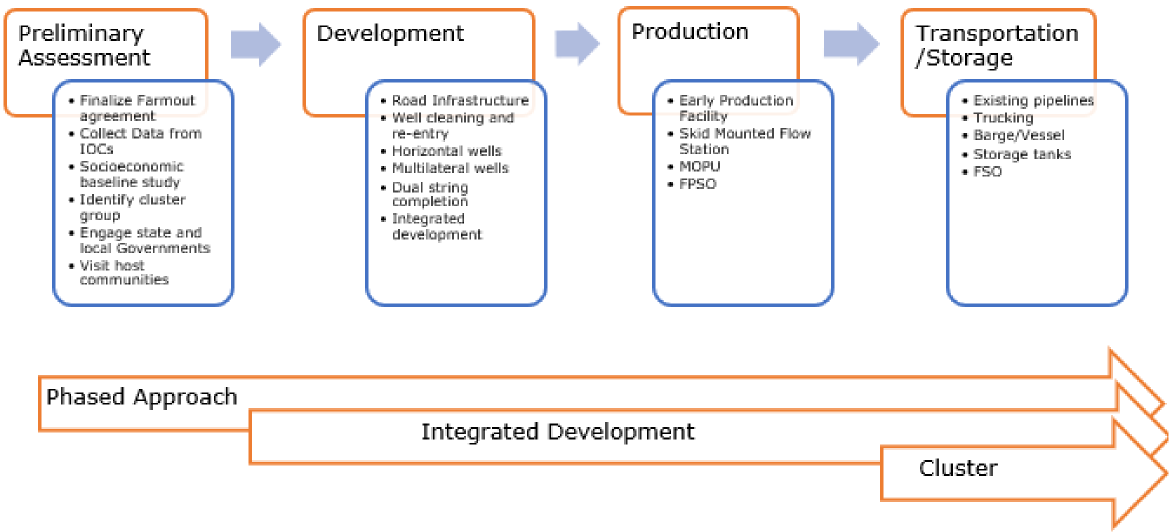


Figure 3.7: Development Strategies for Group 1 Marginal Fields.

Figure 3.7 reflects a comprehensive strategy for marginal field development, balancing technical, economic, and social considerations. This framework serves as a model for generating effective field development options and ensuring the success of Nigeria's marginal fields.

The marginal field development framework follows a phased, integrated, and cluster-based approach to optimize costs and efficiency. It begins with a preliminary assessment, including farmout agreements, data collection, stakeholder engagement, and socioeconomic studies. The development phase focuses on well re-entry, horizontal/multilateral wells, and infrastructure setup. In production, early production facilities (EPFs), skid-mounted flow stations, MOPUs, and FPSOs are utilized for efficient hydrocarbon extraction. Transportation and storage options include pipelines, trucking, barges, storage tanks, and FSOs. The phased approach minimizes financial risks, integrated development ensures holistic planning, and clustering enables shared infrastructure, reducing CAPEX and OPEX. This strategy aligns with best practices from successful operators like Waltersmith, Midwestern, and Green Energy.

3.3.7 Consideration of Alternatives for Marginal Field Development in Nigeria

The assessment of Group 1 marginal fields provided critical insights into the key challenges and success factors influencing marginal field development. The primary challenge identified was funding, which remains a significant constraint for operators. This finding informed the decision to incorporate additional cost-saving measures, such as leveraging nearby facilities and adopting Central Processing Facilities (CPF), to enhance financial viability. The analysis also identified a set of critical success factors that form the foundation of the marginal field development concept matrix. These factors are essential for optimizing development strategies and ensuring project success.

One of the most crucial elements for marginal field development is industry expertise and commitment. The involvement of experienced proponents with deep industry knowledge enhances decision-making and technical execution. Additionally, the adoption of lean, cross-functional teams facilitates efficient resource utilization and improves operational efficiency.

Partnerships and collaborations also play a fundamental role in optimizing field development. Strategic alliances allow operators to pool resources, share infrastructure, and access specialized expertise, thereby reducing operational costs and mitigating risks. Similarly, the use of innovative financing and contracting models is necessary to address funding constraints. Creative financial arrangements, such as leasing equipment, performance-based contracts, and joint ventures, provide operators with more flexible and cost-effective development options.

To further improve economic feasibility, various cost-saving measures were identified. Phased development strategies allow operators to stagger investments over time, aligning expenditures with production milestones. The use of Early Production Facilities (EPFs) accelerates revenue generation while minimizing initial capital outlay. Sharing production facilities and infrastructure also reduces overall costs and enhances operational synergies. Furthermore, leasing equipment instead of outright purchases minimizes upfront financial commitments while ensuring flexibility in resource utilization.

Another key success factor is the application of proven and simple technologies. The use of 3D seismic imaging, well workover operations, and deviated wells enables cost-effective and efficient field development. By prioritizing reliable and readily available technologies, operators can optimize production without incurring excessive technical and financial risks.

Security risks were also identified as a major concern, necessitating the implementation of alternative export strategies to minimize disruptions. Developing secure export routes and contingency plans ensures operational continuity and protects revenue streams from external threats such as vandalism and crude oil theft.

Additionally, gas utilization strategies were recognized as a crucial component of marginal field development. The effective utilization of associated gas aligns with environmental regulations, reduces flaring, and maximizes resource efficiency by supporting gas-to-power initiatives, reinjection for enhanced oil recovery, or gas monetization projects.

Finally, corporate social responsibility (CSR) emerged as a key determinant of long-term project sustainability. Engaging host communities through employment opportunities, infrastructure development, and social services fosters positive stakeholder relationships and reduces conflicts. Implementing targeted CSR initiatives strengthens community ties, enhances social acceptance, and mitigates operational disruptions.

Collectively, these critical success factors provide a structured roadmap for optimizing marginal field development in Nigeria. By balancing technical feasibility, economic efficiency, and social responsibility, operators can enhance the viability of their projects while contributing to the sustainable growth of the oil and gas industry. The findings from this assessment form the basis for the marginal field development concept matrix, ensuring that future development strategies are data-driven, adaptable, and aligned with industry best practices.

3.4 Marginal Field Development Concept Matrix

The patterns derived from successful developments offer a practical foundation for generating field development options tailored to the unique conditions of marginal fields in Nigeria. Building on these findings, and through a review of global field development practices, a set of strategic variables has been identified to enhance the development of Nigeria's marginal fields. These strategies address critical challenges in cost management, health and safety, environmental sustainability, and operational efficiency. These insights have been organized into a Marginal Field Development Concepts Matrix, which serves as a guiding framework for future field development efforts. A high level presentation of the concept selection matrix is shown in Table 3.9.

Table 3.9: Challenges of Marginal Field Development.

	Development Options				Transportation options	Alternatives
	Base Case Wells	Well Type	Completion Technology	Production Facilities		
MF Attributes Terrain Reserves Distance	1+	Re-entry	Single Dual zone	Nearby Facility Skid Mounted Flow Station MOPU Central Processing Facility	Pipeline Trucking Barge Shuttle Tanker	A1 A2 A3 A4 A5 A6 A7 A8 A9 A10 A11 A12 A13 A14 A15 A16 A17 A18 A19 A20 Etc

The Marginal Field Development Concept Matrix presented in the Table 3.9 is a structured framework developed as an outcome of the rigorous assessment of Group 1 marginal fields. It provides a systematic approach to selecting appropriate development options based on key marginal field (MF) attributes, including terrain, reserves, and distance. The matrix integrates well type, completion technology, production facilities, and transportation options to determine viable field development alternatives.

Key Components of the Matrix

Base Case Wells

The matrix assumes that at least one or more wells (1+) are available for development, highlighting that marginal fields often require re-entry of existing wells rather than drilling new ones.

Well Type

The predominant well type considered is re-entry, which aligns with cost-saving strategies by utilizing existing wellbores rather than drilling new wells from scratch.

Completion Technology

Two primary completion approaches are identified: Single-zone completions are typically simpler and more cost-effective, suitable for fields with well-defined reservoirs. Dual-zone completions provide the advantage of enhanced recovery, especially in fields where multiple productive layers exist.

Production Facilities

Various production facility options are considered to ensure economic viability.

Nearby Facilities: Connecting marginal fields to existing infrastructure to reduce capital investment.

Skid-Mounted Flow Stations: A cost-effective and modular solution for early production and smaller reserves.

Mobile Offshore Production Unit (MOPU): A flexible option for offshore fields, enabling production without the need for permanent structures.

Central Processing Facility (CPF): Used in a cluster development approach to process production from multiple fields in a shared facility, optimizing costs.

Transportation Options

Pipeline: The most cost-effective transportation method when infrastructure is available.

Trucking: Used for fields where pipeline connectivity is not feasible, particularly for onshore or nearshore developments.

Barge: Suitable for fields located near inland waterways or swamp terrains.

Shuttle Tanker: Applied in offshore marginal fields where pipelines are not an option, allowing oil transport via sea routes.

Development Alternatives

The matrix offers a range of development alternatives, the total number of alternatives is calculated as $2 \times 5 \times 4 \times 2 = 80$. Each development alternative representing a specific combination of well type, completion method, production facility, and transportation mode. These alternatives provide flexibility in decision-making, enabling operators to optimize costs, mitigate risks, and maximize production efficiency. However, given the extensive number of scenarios, it is essential to validate the technical feasibility of each concept. A decision variable may be individually feasible, but when combined with others, the outcome may not align with project objectives. Therefore, the application of screening criteria becomes imperative, guiding the selection of plausible scenarios for further analysis and consideration. The screening will be based on key marginal field (MF) attributes, including terrain, reserves, and distance. A screening model was developed and incorporated into the AHP model. Screening the scenarios ensures that only technically and economically viable combinations proceed to further analysis, enhancing the robustness of the decision-making process.

Chapter 4 Research Methodology

This chapter outlines the research methodology employed within this study to achieve the research aim and objectives outlined in Chapter 1. Specifically the chapter describes the process in developing and applying a hybrid Analytical Hierarchy Process (AHP) model for optimizing marginal field development in Nigeria. The methodology integrates a systematic decision-making framework with industry-relevant criteria to ensure robust, data-driven recommendations. It describes the research design, data collection methods, and the analytical framework applied.

4.1 Research Design

This study adopts a mixed-methods approach, combining qualitative and quantitative methods to develop an AHP-based optimization model for marginal field development. The mixed-methods design ensures a comprehensive evaluation of both subjective expert judgments and objective performance metrics. The research programme is characterised by a series of distinct yet inter-related research stages and elements that address the study's aim, and three research objectives outlined in Chapter 1 (Figure 4.1).

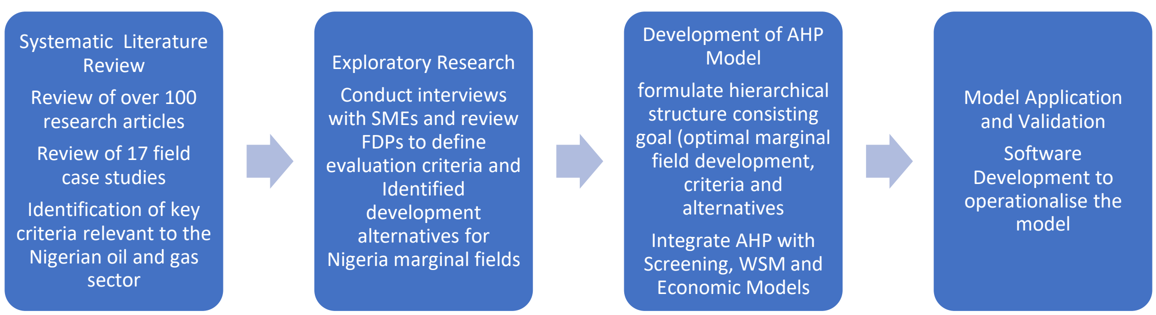


Figure 4.1: Stages and Elements of Research Program

4.2 Data Collection and Sources

A multiple-method approach to data collection was adopted to ensure the comprehensiveness and validity of this study. This approach integrated both qualitative and quantitative techniques, enabling the triangulation of data and ensuring robust findings. By employing a combination of structured questionnaires, expert interviews, and secondary data analysis, the study captured diverse perspectives and comprehensive insights into marginal field development. This multi-faceted strategy not only enhanced the depth and breadth of the data but also mitigated potential biases associated with relying on a single source of information. Consequently, it provided a solid foundation for developing and validating the decision-making model proposed in this research.

4.2.1 Case Study

A case study approach was employed to carry out critical analysis of the financial, legal and technical requirements for Investment and challenges of Marginal Fields Development in Nigeria. This study utilized primary data obtained from the Nigerian Upstream Petroleum Regulatory Commission (NUPRC), the regulatory agency responsible for overseeing upstream oil and gas activities in Nigeria. As the custodian of upstream data for the oil and gas industry, NUPRC provided reliable and verified information critical for this research. The dataset collected was comprehensive and offered valuable insights into the development of marginal fields in Nigeria. The data covered multiple aspects of marginal field development, with parameters selected to capture key factors influencing operational and economic outcomes. These include:

- Field Reserves Data: Information on marginal fields awarded between 2003 and 2010 for the years 2006, 2021, and 2022 to enable comparisons and trend analysis. Reserves Data was also used to estimate reserves per well through decline curve analysis (DCA) and determine the total number of wells required for optimal field development
- Reservoir and Operational Properties: Reservoir characteristics, such as pressure, temperature, and permeability. Estimated recoverable volumes and production potential.
- Infrastructure Data: Availability and distribution of infrastructure within the Niger Delta region, including: pipelines, flow stations, terminals, floating production and storage facilities, storage facilities. These data

points highlighted logistical and operational challenges specific to marginal field development.

- Field Development Plans: 10 Field development plans from selected marginal and commercial fields. Detailed insights into well design, drilling schedules, and cost estimates. This was used to collect data on production history applied in forecasting future production trends, validating reserves estimates, and evaluating the technical feasibility of development options. Economic data was also collected to calculate UTC and other metrics.

This comprehensive analysis provided a robust foundation for developing and validating the decision-making model for marginal field development. The detailed and multi-faceted dataset provided a robust foundation for analysing marginal field development strategies. It ensured that the research outcomes were firmly grounded in industry practices and aligned with both technical and economic considerations.

4.2.2 Expert Consultations

To refine the criteria identified through the literature review, consultations were conducted with fifteen Subject Matter Experts (SMEs) from the oil and gas industry, specifically those experienced in marginal field development. This number is consistent with industry standard (De Oliveira Neto et al., 2017; Gandhare & Akarte, 2019). The researcher leveraged the Society of Petroleum Engineers (SPE) network to identify these SMEs, ensuring that participants represented a wide range of relevant disciplines, including reservoir engineering, geoscience, petroleum economics, environmental management, and regulatory expertise. Semi-structured interviews were conducted via WhatsApp and Teams to gather insights on the most critical criteria for marginal field development. This process aimed to build on existing knowledge and incorporate practical, field-specific expertise.

In addition to the interviews, structured questionnaires were designed to collect pairwise comparisons of criteria and alternatives from SMEs. The questionnaires followed the Analytical Hierarchy Process (AHP)-specific framework, utilizing

Saaty's 9-point scale to evaluate the relative importance of the criteria and alternatives. As explained in Chapter 2, the AHP framework requires a specific number of judgments to populate the comparison matrix fully. For this study, six criteria were identified, necessitating 15 judgments, calculated using Equation 4.1:

$$\text{Number of judgements required} = \frac{n(n-1)}{2} \ldots\ldots\ldots\ldots \text{Equation 4.1}$$

Substituting n = 6

Number of judgements required = $\frac{6(6-1)}{2} = 15$

A sample questionnaire, provided in Appendix 1, illustrates the format used to capture expert inputs systematically. This structured approach ensured the collection of consistent and comprehensive data, facilitating accurate computation of priority weights for the identified criteria and alternatives.

To complement the questionnaires, structured interviews were also conducted, where SMEs systematically evaluated each criterion through pairwise comparisons to determine their relative importance in marginal field development. The criteria considered included cost, regulation, technology, stakeholder engagement, HSE (Health, Safety, and Environment), and security. The pairwise comparison exercise, as justified by its ability to systematically capture and quantify the complex interrelationships among diverse criteria (Zuraidi et al., 2018), provided a nuanced understanding of stakeholder priorities. By adopting this method, the research ensured a robust and transparent framework for assessing multiple factors critical to decision-making (Floridi and Lauderdale, 2020).

The information gathered through expert consultations was instrumental in calculating the relative importance of each criterion, forming the foundation of the AHP model used to optimize marginal field development. This systematic, data-driven approach ensured alignment with stakeholder priorities, thereby enhancing the granularity, rigor, and reliability of the decision-making process.

4.2.3 Limitations of Data Collection

Several notable limitations were encountered during the interview phase, including the time-intensive process of participant recruitment, the extensive time required for conducting interviews, translating and transcribing recorded data, the allocation of resources for travel to Nigeria, and the potential risk of data overload resulting from comprehensive data gathering efforts. Nevertheless, despite the existence of alternative data collection methods, the utilization of semi-structured and structured interviews was preferred due to their capacity to elicit more individualized and detailed accounts. This approach afforded respondents the opportunity to articulate and clarify their thoughts on the issues under exploration (King, 2004). The reliance on decision-makers' preferences for weighting criteria can introduce subjectivity and potential biases. Additionally, ensuring consistency in pairwise comparisons can be challenging, especially in problems with numerous criteria and alternatives.

4.2.4 Selection of Case Study Marginal Fields

Among the 183 officially recognized marginal fields in Nigeria, 30 fields were specifically awarded during the marginal field bid round, forming the pool from which case study selections were made. The fields chosen for this study are those categorized as fully developed and currently in production, referred to as Group 1 Marginal Fields.

The selected fields represent a diverse range of terrain types, including onshore, swamp, and offshore environments. This deliberate selection strategy was adopted to ensure a comprehensive analysis that captures the unique characteristics and challenges associated with each terrain. By including fields from across these categories, the study provides a balanced and logical coverage of the spectrum of marginal fields, thereby enhancing the robustness and applicability of the developed decision-making model.

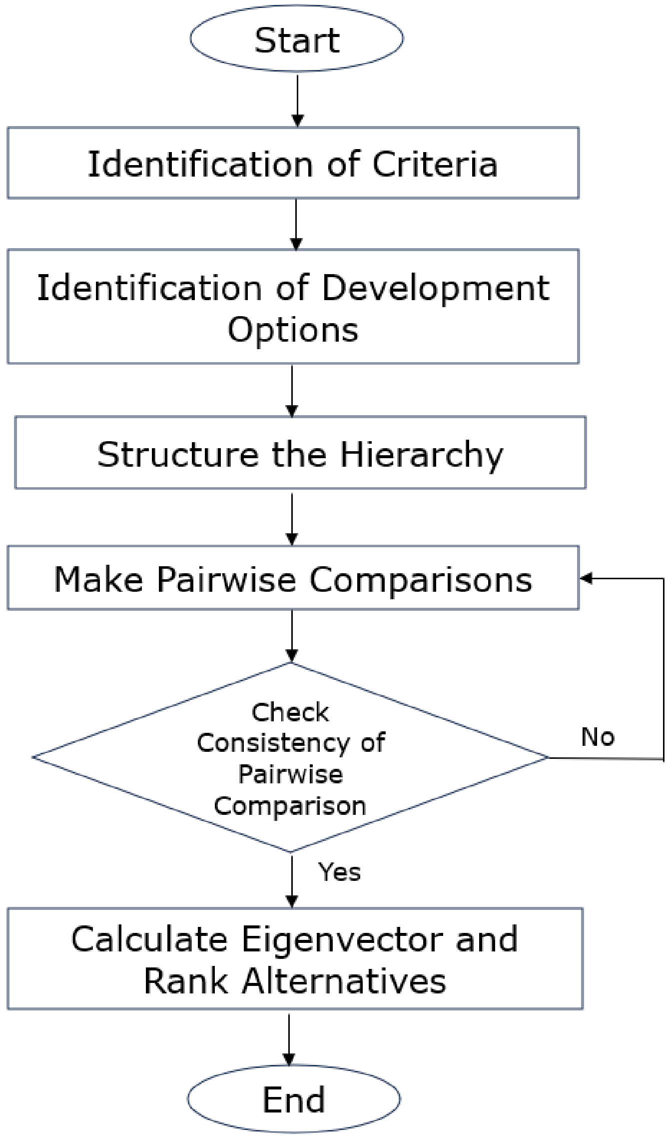


Figure 4.2: Flowchart for Model Development

4.3 Decision Model Development

This phase of the study focuses on designing a decision-making model tailored to the unique challenges and opportunities associated with marginal field development in Nigeria. This model is developed to integrate key criteria such as cost, HSE, regulation, security, stakeholders and technology ensuring a holistic approach to decision-making. This section describes the process of identifying developments options and criteria for the selection of marginal field development options.

4.3.1 Identification of Criteria

The selection of criteria for evaluating optimal marginal field development options was guided by the need to align with corporate objectives and comply with regulatory frameworks for approving Field Development Plans (FDPs). This comprehensive approach ensures that economic viability, technical soundness, social responsibility, and environmental sustainability are fully integrated into the decision-making process. Marginal fields, often characterized by lower reserves and higher operational costs, present unique challenges that demand carefully defined criteria to ensure their development is technically feasible and economically viable.

A comprehensive literature review was conducted to identify the criteria for selecting optimal marginal field development options. This involved examining academic journals, industry reports, technical papers, and case studies on marginal field development in Nigeria (17) and other regions (35 developments). These data were systematically gathered from institution archives, online databases. Through the literature review, common criteria which were mainly financial metrics used in past studies and industry practice for evaluating marginal field development options were identified. Additionally, key factors influencing the success or failure of marginal field developments, such as economic viability, technical feasibility, environmental impact, regulatory compliance and social considerations were identified. Emerging trends and best practices in the industry that could influence the selection criteria were also identified. This step ensures a robust theoretical foundation for developing the criteria and provides insights into the current state of knowledge in the field.

The identified criteria are cost, health, safety, and environment (HSE), regulation, security, stakeholders and technology. These six criteria formed the foundation for the development of the Analytic Hierarchy Process (AHP) model to evaluate and compare development concepts for marginal fields.

4.3.2 Identification of Development Options

In considering the development of marginal fields in Nigeria, a comprehensive review of field developments both globally and within Nigeria was undertaken to identify all potential solutions. A broad range of possible field development strategies, alternative facility concepts, and export options were explored. This analysis focused on understanding the characteristics of different marginal fields, evaluating key metrics such as reserves, production potential, economic viability, environmental impact, and existing infrastructure, and comparing these against various development options. Throughout the evaluation process, it has been crucial to consider the impact on the entire value chain, from reservoir to market. By identifying and studying the shared characteristics of successful developments, it becomes feasible to derive patterns that can serve as a blueprint for optimizing marginal field development in Nigeria.

4.3.2.1 Generate Development Concepts

To identify suitable development options for marginal field development in Nigeria, case studies of 17 successful marginal field developments within the Niger Delta Basin of Nigeria was conducted. These fields, categorized as Group 1, include those currently in production and awarded through competitive bidding processes or discretionary allocations. Concepts previously applied in these marginal field development were systematically examined to create variables tailored to the specific peculiarities of Nigerian marginal fields. A detailed explanation of the main criteria—cost, Health, Safety & Environment (HSE), regulation, security, stakeholders, and technology—was provided, demonstrating how they influence marginal field concept development decision-making. This ensured that the decision-making framework reflects both theoretical insights and practical realities, making the methodology both theoretically sound and practically applicable.

The overarching goal of marginal field development is to bring into production fields that would otherwise remain undeveloped due to economic, technical, or operational constraints. To achieve this, the assessment process was guided by the following key objectives:

- Maximizing economic oil and gas recovery through best in class reservoir management practices and application of appropriate technology
- Minimization of environmental damage through flare elimination, gas venting, spills etc
- Minimization of host community disruptions and discontent through proactive and continuous engagement
- Minimizing the impact of insecurity on operations.
- Optimize use of third-party facilities, engagement, and collaboration with stakeholders
- Ensuring regulatory compliance
- Minimising both CAPEX and OPEX

This examination laid the foundation for identifying critical factors influencing development strategies. A comprehensive field development matrix was developed, categorizing individual challenges for each field and highlighting both commonalities and unique issues. This facilitated comparative analyses across different field groups, including performing and underperforming marginal fields. The achievement of successful marginal field development necessitates the incorporation of the following fundamental elements: Early production, reduced capital investment, implementing phased development, risk mitigation through ongoing appraisal, maximum flexibility tailored for offshore development, scalability pertinent to onshore scenarios, proven technology integration, employing modular and reusable low-cost facilities, use minimal number of wells and facilities/platforms and minimum abandonment costs.

I. Well Development

Objective: Design wells to achieve maximum recovery with minimal complexity and cost while ensuring safe and successful completions.

Standard Practice: The majority of wells in marginal fields have been developed successfully without HSE incidents, exceeding geological objectives, and tripling production. Deviated wells are preferred due to reservoir heterogeneity, with horizontal sections limited to effective inflow zones (<1,000 ft) based on field observations. Multilateral wells, while theoretically advantageous as expounded in section 2.2.3, were excluded due to increased complexity and lack of cost-efficiency. Multilateral wells can allow access of multiple reservoir sections within the same well, which reduces the required well count and the construction costs of the upper hole sections. However, the disadvantage is that the multilateral design itself can introduce extra complications and risks for a successful completion. There were no significant data to demonstrate that multilateral wells in the development would be cost efficient. Furthermore, multilateral wells did not meet the simple well design objective.

Re-entry Wells: Leveraging existing wells when feasible reduces cost, infrastructure needs, and development timelines. This can help expedite the production timeline and generate revenue more quickly.

II. Completion Strategy

Approach: Initial completions will use field-proven technology with provision for future advancements. Strategies include:

- Gas lift mandrels for natural and artificial lift as required.
- Dual-string completions for reservoirs with multiple zones, maximizing early production and economic viability.
- Compliance with NUPRC regulatory policies, including safety valves and hydraulic packers.

Exclusions: Intelligent completions and multi-zone commingling were deemed technically complex and are not considered.

III. Production Facilities

Existing Infrastructure: The Niger Delta, being a mature basin with existing facilities and infrastructure. Where available, nearby processing facilities will be utilized to reduce costs.

Mobility and Reusability: Facilities will prioritize mobility, such as skid-mounted systems for onshore/swamp fields and Mobile Offshore Production Units (MOPUs) or reusable subsea installations for offshore fields. Leasing is preferred, with an option for purchase if economically justified.

IV. Transportation Options

Methods: Crude will be transported via tiebacks to trunk lines, trucking, barging, or floating storage systems.

Floating Solutions: Floating structures are ideal for remote or short-lifespan fields, avoiding high pipeline costs and allowing redeployment post-depletion.

The identified feasible concepts to exploit Niger Delta marginal field, especially for undeveloped fields, to assure that any possible concepts that provide value is not discarded were formed into the concepts matrix. The matrix has a decision variable as heading in each column. This matrix provides a comprehensive framework for evaluating and comparing development options by organizing key decision-making elements into a structured format. By systematically categorizing these variables, the matrix facilitates the assessment of multiple scenarios, enabling stakeholders to identify the most feasible and cost-effective strategies for marginal field development.

4.3.2.2 Develop Technical Screening Model

A technical screening is conducted, the objective of concept screening phase is to mature the reservoir understanding and carry out a wide screening of possible options in all areas of the project from reservoir to market and identify a shorter list of alternatives that are environmentally, technically and economically feasible for Niger Delta fields. This validation process involves screening the scenarios against key marginal field attributes such as terrain, reserves, and distance to existing facilities.

Terrain

The terrain of a marginal field—whether onshore, swamp, or offshore—plays a critical role in determining its feasibility and development strategy. Different terrains present unique operational challenges, infrastructure requirements, and cost implications. Onshore fields typically allow for easier access, lower operational costs, and more straightforward logistics, whereas swamp and offshore fields demand specialized infrastructure such as floating production units, modular flow stations, or shuttle tankers. The terrain also influences transportation options, well design, and facility installation, ultimately shaping the overall economic viability of the field. Properly aligning development strategies with terrain-specific constraints is essential for optimizing marginal field operations.

Reserves

Reserves are a critical factor in determining the appropriate development option for oil and gas fields. The minimum volume of reserves required for the economically viable development of a field depends significantly on the terrain. Reserves data, sourced from the Nigerian Upstream Petroleum Regulatory Commission (NUPRC), were analysed and categorized based on the terrain—onshore, swamp, and offshore. The size and quality of recoverable hydrocarbon reserves influenced the economic viability of development. To identify feasible development options, this study utilized reserves thresholds for standalone development as established by the analysis of Group 1 fields. These thresholds are 5 MMbbls for onshore fields, 7 MMbbls for swamp fields, and 15 MMbbls for offshore fields (Nwaozuzu 2018, Adeogun and Iledare 2016). These values serve as the minimum reserve requirements to justify standalone development under current economic conditions.

Distance to Existing Facilities

The proximity of marginal fields to existing facilities is another critical factor influencing development strategy. Fields located near existing processing facilities, pipelines, or export terminals may be more suitable for tie-back development, which involves connecting the marginal field to these facilities. This approach can significantly reduce CAPEX and OPEX, thereby enhancing economic viability. Fields located too far from existing facilities were deemed less viable due to high capital expenditure requirements. For tie-back options, the profitable distance was calculated to ensure that the Unit Technical Cost (UTC) remains below or equal to $52 per barrel, which represents 65% of the current crude oil price used in the study to fulfil the Cost Petroleum Recovery (CPR) expectation outlined in the Petroleum Industry Act (PIA). This criterion ensures the economic viability of tie-back strategies by balancing transportation costs and overall development expenses.

The analysis also considers the condition and capacity of existing infrastructure, including processing facilities, pipelines, and transportation networks. This assessment helps determine whether existing infrastructure can accommodate additional production from new marginal fields or if upgrades are required. Table 4.1 summarises the data collected, further details in Appendix. This formed input into the decision support tool.

Table 4.1: Data on Available Facilities in the Niger Delta

Facilities	**Facilities Data**
Oil Fields	Location coordinates, Production status, Proximity to Pipeline, Terrain, OML/OPL block
Oil Terminals	Location coordinates, OML/OPL block, Terrain
FPSO	Location coordinates, OML/OPL block, Terrain

The proximity of a marginal field to existing infrastructure (e.g., pipelines, processing plants) significantly affects development costs. Fields located too far from existing facilities were deemed less viable due to high capital expenditure requirements. For tie-back options, the profitable distance was calculated to ensure that the Unit Technical Cost (UTC) remains below or equal to $52 per barrel, which represents 65% of the current crude oil price used in the study to fulfil the Cost Petroleum Recovery (CPR) expectation outlined in the Petroleum Industry Act (PIA). This criterion ensures the economic viability of tie-back strategies by balancing transportation costs and overall development expenses.

Where necessary, assumptions were incorporated to account for data gaps and standardize the evaluation criteria. These assumptions were based on industry best practices and historical data from similar projects. By incorporating these attributes into the screening model, potential incompatibilities between decision variables are identified and excluded. A screening model was developed from this process to serve as the initial stage of the decision-making framework, generating viable options that will subsequently be evaluated using the Analytical Hierarchy Process (AHP) model. The screening model was designed to systematically assess key technical and economic factors influencing marginal field development, ensuring that only feasible options are considered in the decision-making process.

A structured flowchart was developed to visually represent the screening process. Microsoft PowerPoint was selected as the tool for designing the flowchart due to its ease of use, broad compatibility, and widespread availability. Standard flowchart symbols were utilized, including:

- Start/End points: Indicating the beginning and conclusion of the process.
- Process/Task symbols: Representing actions taken at various stages.
- Decision symbols: Used to introduce conditional steps where choices are made.
- Connectors: Ensuring logical flow between steps.

- Input/Output symbols: Representing data requirements and results at different stages of the screening process.

After the technical screening, UTC for each option is estimated by using commercial data bases and operators experience; it is important to estimate costs during the full service life of the field from planning studies up to abandonment. Well costs are the major expenditure thus, well type selection is usually done following the same approach presented in this work and is performed simultaneously to the field development planning activities. On the other hand, the production profile associated to each development option has to be calculated to estimate the income due to hydrocarbons sale. Production profiles can be calculated from simple models like exponential declination or using more complex ones based on energy balance where reservoir, wells and pipe systems are coupled in a model to estimate the production versus time, this later process can be cumbersome and usually consumes several hours depending on the model complexity and computer process speed.

4.3.2.3 Estimating Unit Technical Costs

After the technical screening, UTC for each option is estimated by using commercial data bases and operators experience using equation 4.2. It is important to estimate costs during the full service life of the field from planning studies up to abandonment. However, no costs were obtained for abandonment for it was not included.

$$UTC = \frac{CAPEX+OPEX}{Production} \text{.........................} \quad \textit{Equation 4.2}$$

Where UTC is the unit technical cost.

It is often more useful to use the discounted values to allow for the time effect of money, hence;

$$UTC\ PV\ cost = \frac{PV\ CAPEX+PV\ OPEX}{PV\ Production} \text{...............} \textit{Equation 4.3}$$

The production profile associated to each development option has to be calculated to estimate the income due to hydrocarbons sale. Production profiles were calculated from simple exponential declination model. For Niger Delta marginal field development, production assumptions were made based on terrain based on data from NUPRC. Onshore fields were assumed to have reserves of 5 MMbbls, with an initial daily oil production rate of 500 bopd, peaking at 1,500 bopd. Swamp fields had higher reserves of 7 MMbbls, an initial production rate of 700 bopd, and a peak of 5,500 bopd. Offshore fields had the largest reserves at 20 MMbbls, an initial production rate of 900 bopd, and a peak of 9,500 bopd. A field life of 15 years was assumed for all cases, and decline curve analysis was utilized to forecast oil production trends, providing insights into long-term viability and depletion rates.

Decline Curve Analysis

Having defined and gathered adequate data for initial reserves estimation, the next step is to look at various options to develop the field. The production forecasting for marginal fields in this study employed Decline Curve Analysis (DCA) based on the Arps equation. DCA is a well-established method widely used for analysing declining production rates and predicting future performance of oil and gas wells (Mannon, 1965; Felkovich, 1996; Elahi, 2019). Notably, financial institutions exhibit greater acceptance of DCA estimates compared to other more technically oriented methodologies. DCA, being a graphical procedure, offers simplicity in plotting, facilitates timely results, and is easily analysable. The production forecast derived from DCA served as the foundation for optimising production operations and planning for the marginal fields. Adeogun and Iledare 2015 employed it for production forecast in their study to define marginal fields in clear terms.

Decline was exponential according to the Arp/s equation given as follow;

$$q_t = q_i e^{-at} \text{ ....} \textit{Equation 4.4}$$

Cumulative oil production, N_p

$$N_p = \frac{(q_i - q_t)*365}{a} \text{ ....} \textit{Equation 4.5}$$

Time required to produce cumulative N_p

$$t = \frac{ln\left(\frac{q_i}{q_t}\right)}{a} \quad \text{.........} \textit{Equation 4.6}$$

q_t = production rate at any time t, BOPD

q_i = initial rate of production, BOPD

t = time period between q_t and q_i years

a = nominal decline rate, fraction per year

N_p = cumulative oil production during the time period, barrels

Total productive life of the oilfield was taken to be 15 years

Figure 4.3 and 4.4 show the production profile for a typical shallow offshore marginal field in the Niger Delta.

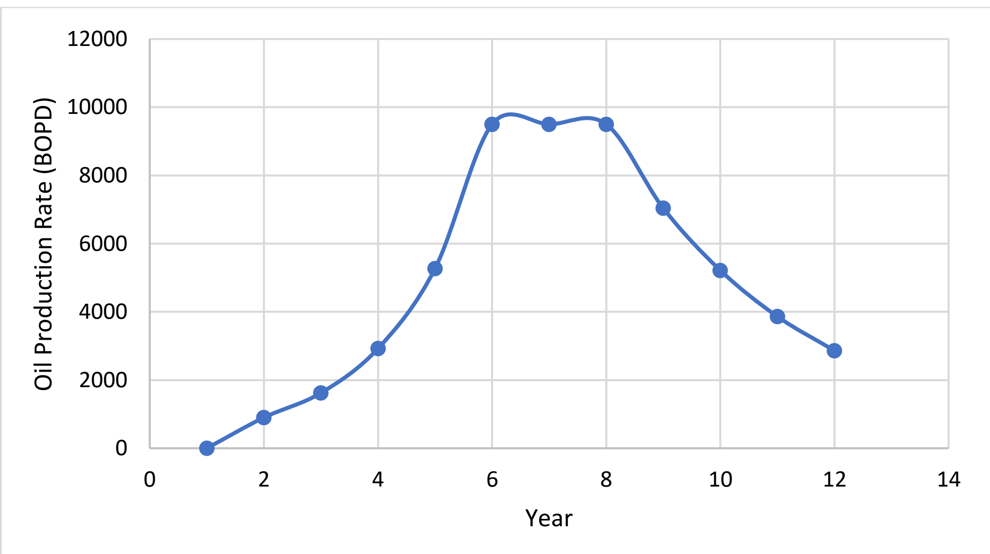


Figure 4.3: Oil Rate of Production for a typical Offshore Niger Delta Marginal Field

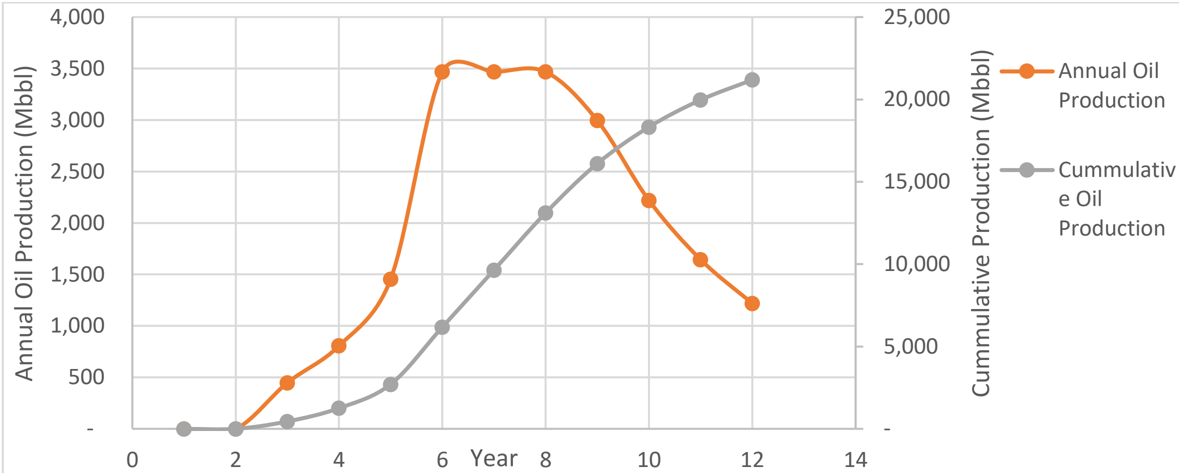


Figure 4.4: Annual Oil Rate of Production for a typical Offshore Niger Delta Marginal Field

4.3.3 Construction of the Decision Hierarchy

A hierarchical structure that reflects the decision making criteria and their relationship to the overall objective was developed. The concept selection problem was systematically decomposed and modelled into a hierarchical structure. The identified criteria for the selection of optimal marginal field development and generated options are used to construct the hierarchy structure. The hierarchy structure was constructed in an inverted manner reflecting the decision making process. In the structure, generated option are at the top level A1, A2, A3 and A4. The second level has the criteria cost, HSE, regulation, security, stakeholders, and technology. And the goal is to select an optimal development option for marginal fields in Nigeria at the bottom level. Structuring the problem in this way makes it possible to better understand the decisions to be achieved, the criteria to be used and the alternatives to be evaluated. This hierarchy also assisted the subject matter experts in assessing whether the elements at each level are of similar magnitude, enabling accurate comparisons between them. The complexities of the Nigeria environment were considered seriously in construction of the hierarchy which guided the decision to limit the structuring to criteria and not to consider sub-criteria. Specific issues that contribute to the solution, as well as all the individuals involved in the problem were identified. Note that not all fields will be eligible for all four development options.

4.3.4 Construct Pairwise Comparison Matrices to obtain Criteria Weights

Once the hierarchy has been constructed, the importance weight of the criteria was calculated. In order to obtain the weight (priority scores) of the criteria, pairwise comparison matrices were constructed which is a decision matrix (Table 4.2). To select the optimal field development option, it is necessary to determine the relative importance of the criteria that influence the decision-making process. In this study, six criteria namely cost, HSE, regulation, security, stakeholders and technology are required to be ranked in the decision making across onshore, swamp, and offshore terrain. A 6 x 6 matrices was constructed for each terrain to compare the identified criteria that affect marginal field development (Table 4.2).

Table 4.2: Sample Decision Matrix of Criteria for marginal Field Development.

Criteria	Cost	HSE	Regulation	Security	Stakeholders	Technology
Cost						
HSE						
Regulation						
Security						
Stakeholders						
Technology						

Experts in the field, recognized as Subject Matter Experts (SMEs), conveyed their preferences by indicating the criteria they deemed more crucial or accorded higher priority within the domain of marginal field development. To allow basis for the analysis of the data gathered, a non-parametric scale will be used as the basis for the interpretation and evaluation. The data gathered will be scored using the following categorical responses. For each pair of criteria for example Cost vs HSE, the SME responded to the question "How important is Cost relative to HSE and by how much?" The Saaty scale (Table 4.3) was used to reflect these preferences. Rating the relative “priority” of the criteria is done by assigning a weight between 1 (equal importance) and 9 (extreme importance) to the more important criterion, whereas the reciprocal of this value is assigned to the other criterion in the pair.

In each of these comparisons, the judgments of the SMEs are used to calculate the relative importance or priority of one criterion over the other across the terrains under consideration. For instance, if more SMEs believe that cost is more important than HSE, the priority score for cost will be higher in that comparison. These priority scores can then be used in decision-making processes to determine the most suitable course of action or alternative in marginal field development based on the specific criteria and their relative importance.

These preferences were documented in the Upper Triangular Matrix (green part) of the decision matrix (Table 4.2), facilitated through Microsoft Excel. The Lower Triangular Matrix was subsequently derived as the inverse of the Upper Triangular Matrix (blue part). These selections were grounded in their professional discernment, knowledge, and experience pertaining to the intricacies of marginal field development. Where it is difficult to decide or if the criteria is perceived to be equally important, the option indicating that the criteria are equally important is selected or the appropriate even number.

Table 4.3: The Saaty Fundamental Scale for Pairwise Comparison (Saatay 2007).

Intensity of importance	**Definition**	**Explanation**
1	Equal importance	Criteria a and b contribute equally to the objective
3	Moderate importance of one over another	Experience and judgment slightly favor criteria a over b
5	Strong importance	Experience and judgement strongly favor element a over b

7	Demonstrated importance	Element a is favored very strongly over b its dominance is demonstrated in practice
9	Absolute importance	The evidence favoring element a over b is of the highest possible order of affirmation
2, 4, 6, 8	Intermediate values between the two adjacent judgments	When compromise is needed. For example, 4 can be used for the intermediate between 3 and 5
Reciprocals of above non- zero	If a has one of the above numbers assigned to it when compared with b. then b has the reciprocal value when compared with a	
Rationals	Ratios arising from the scale	If consistency were to be forced by obtaining n numerical values to span the matrix

The provided pairwise comparison results represent the judgments of subject matter experts (SMEs) regarding the importance of various criteria in the context of onshore, swamp and offshore marginal field development. The SMEs' individual assessments are consolidated using the geometric mean Equation 4.7. Fifteen judgments were collected from each subject matter expert and geometric mean of the judgments of the fifteen subject matter experts was used for the eigenvector analysis.

$$\textit{Geometric Mean} = G = \sqrt[n]{x_1 x_{2\ldots\ldots}} x_n \ldots\ldots\ldots\ldots\ldots \textit{ Equation 4.7}$$

These judgments are used to establish the relative priority or significance of one criterion compared to another. The geometric mean of all judgements and explanations for onshore, swamp and offshore terrain respectively are summarized in Appendix 2.

4.3.5 Eigenvector Analysis to Create Priorities for Criteria

The Analytical Hierarchy Process (AHP) involves a series of calculations to determine the relative weights of criteria and the preferences for alternatives based on pairwise comparisons. The fundamental equation used in AHP is the calculation of the priority vector for each level of the hierarchy. Eigenvector analysis is used to analyse the properties of matrices, particularly square matrices. It involves finding the eigenvectors and eigenvalues of a given matrix.

Given a matrix of pairwise comparison judgments A, where a_{ij} represents the preference of criterion i over criterion j, the priority vector w is calculated as follows:

$$w_i = \frac{1}{n}\sum_{j=1}^{n} a_{ij} \qquad \text{..................}\textit{Equation 4.8}$$

Where:

w_i is the weight of criterion i

n is the number of criteria

The priority vector w is then normalized to ensure that the sum of its components is equal to 1, which is achieved by dividing each element by the sum of all elements:

$$w_{normalized} = \frac{w}{\sum_{i=1}^{n} w_i} \qquad \text{............................}\textit{Equation 4.9}$$

This normalized priority vector $w_{normalized}$ represents the relative weights of the criteria based on the pairwise comparisons.

Keep in mind that AHP involves multiple levels of the hierarchy, including criteria, sub-criteria, and alternatives. The above equation was used at each level to calculate the relative weights. Additionally, eigenvalue methods are often used to find the principal eigenvector of the matrix A, which corresponds to the normalized priority vector $w_{normalized}$.

The Eigenvector analysis is a by-product of pairwise comparison that shows the determinants in their ranking values either expressed as ratios or decimals. The most important thing to look out for as in the AHP process is the Eigenvector values as it points us in the direction of the best decision to take. However, it must be checked that the right decisions are validated for the best investment in our case for marginal field development.

Using the pairwise comparison matrix, the weights of the criteria can be calculated using mathematical formulas. The weights represent the relative importance of each criterion in achieving the goal of optimising marginal field development.

$$A = \begin{bmatrix} a_{11} & a_{12} & \cdots & a_{1n} \\ a_{21} & a_{22} & \cdots & a_{2n} \\ \cdots & \cdots & \ldots & \cdots \\ a_{n1} & a_{n2} & \cdots & a_{nn} \end{bmatrix} = \begin{bmatrix} \frac{w_1}{w_1} & \frac{w_1}{w_2} & \cdots & \frac{w_1}{w_n} \\ \frac{w_2}{w_1} & \frac{w_2}{w_2} & \cdots & \frac{w_2}{w_n} \\ \vdots & \vdots & \ldots & \vdots \\ \frac{w_n}{w_1} & \frac{w_n}{w_2} & \cdots & \frac{w_n}{w_n} \end{bmatrix} \text{.................}\textit{Equation 4.10}$$

Where vector of priorities is $\overline{w}$

$$\overline{w} = \begin{bmatrix} w_1 \\ w_2 \\ \vdots \\ w_n \end{bmatrix} \text{.........................}\textit{Equation 4.11}$$

The priorities are calculated from the pair-wise comparison matrices using eigenvector analysis by solving the following eigenvalue problem (Saaty 2008):

$$A.\underline{w} = \begin{bmatrix} \frac{w_1}{w_1} & \frac{w_1}{w_2} & \cdots & \frac{w_1}{w_n} \\ \frac{w_2}{w_1} & \frac{w_2}{w_2} & \cdots & \frac{w_2}{w_n} \\ \vdots & \vdots & \ldots & \vdots \\ \frac{w_n}{w_1} & \frac{w_n}{w_2} & \cdots & \frac{w_n}{w_n} \end{bmatrix} . \begin{bmatrix} w_1 \\ w_2 \\ \vdots \\ w_n \end{bmatrix} = n. \begin{bmatrix} w_1 \\ w_2 \\ \vdots \\ w_n \end{bmatrix} = n.\underline{w} \text{.............................}\textit{Equation 4.12}$$

For this study, six criteria: Cost (c), Security (s), Stakeholders (st), Regulation (r), Technology (t), HSE (h) were considered therefore a 6x6 matrix was set up as shown in equation 4.12.

$$A = \begin{bmatrix} \frac{w_c}{w_c} & \frac{w_c}{w_h} & \frac{w_c}{w_r} & \frac{w_c}{w_s} & \frac{w_c}{w_{st}} & \frac{w_c}{w_t} \\ \frac{w_h}{w_c} & \frac{w_h}{w_h} & \frac{w_h}{w_r} & \frac{w_h}{w_s} & \frac{w_h}{w_{st}} & \frac{w_h}{w_t} \\ \frac{w_r}{w_c} & \frac{w_r}{w_h} & \frac{w_r}{w_r} & \frac{w_r}{w_s} & \frac{w_r}{w_{st}} & \frac{w_r}{w_t} \\ \frac{w_s}{w_c} & \frac{w_s}{w_h} & \frac{w_s}{w_r} & \frac{w_s}{w_s} & \frac{w_s}{w_{st}} & \frac{w_s}{w_t} \\ \frac{w_{st}}{w_c} & \frac{w_{st}}{w_h} & \frac{w_{st}}{w_r} & \frac{w_{st}}{w_s} & \frac{w_{st}}{w_{st}} & \frac{w_{st}}{w_t} \\ \frac{w_t}{w_c} & \frac{w_t}{w_h} & \frac{w_t}{w_r} & \frac{w_t}{w_s} & \frac{w_t}{w_{st}} & \frac{w_t}{w_t} \end{bmatrix}$$ ....*Equation 4.13*

The geometric mean of all the judgements was inputted into the matrices by terrain; matrix *Ons* for onshore, matrix *Swp* for swamp and matrix *Off* for offshore

$$Ons = \begin{bmatrix} 1 & 1 & 1 & 1 & 2 & 2 \\ 1 & 1 & 1 & 1 & 2 & 2 \\ 1 & 1 & 1 & 1 & 3 & 3 \\ 1 & 1 & 1 & 1 & 2 & 2 \\ \frac{1}{2} & \frac{1}{2} & \frac{1}{3} & \frac{1}{3} & 1 & 2 \\ \frac{1}{2} & \frac{1}{2} & \frac{1}{3} & \frac{1}{2} & \frac{1}{2} & 1 \end{bmatrix}$$ ....*Equation 4.14*

$$Swp = \begin{bmatrix} 1 & \frac{1}{3} & \frac{1}{3} & 1 & 1 & 2 \\ 2 & 1 & 1 & 1 & 2 & 2 \\ 3 & 1 & 1 & 1 & 2 & 3 \\ 1 & 1 & 1 & 1 & 2 & 2 \\ 1 & \frac{1}{2} & \frac{1}{2} & \frac{1}{2} & 1 & 2 \\ \frac{1}{2} & \frac{1}{2} & \frac{1}{3} & \frac{1}{2} & \frac{1}{2} & 1 \end{bmatrix}$$ ....*Equation 4.15*

$$Ofs = \begin{bmatrix} 1 & 1 & 1 & 2 & 2 & 1 \\ 1 & 1 & 1 & 3 & 4 & 1 \\ 1 & 1 & 1 & 2 & 4 & 2 \\ \frac{1}{2} & \frac{1}{3} & \frac{1}{2} & 1 & 1 & 1 \\ \frac{1}{2} & \frac{1}{4} & \frac{1}{4} & 1 & 1 & 1 \\ 1 & 1 & \frac{1}{2} & 1 & 1 & 1 \end{bmatrix} \text{.............................} \textit{Equation 4.16}$$

All the calculations were done in Excel and a sample is presented in Appendix 3. The final solutions by terrain are;

$$Ons = 0.195 + 0.195 + 0.225 + 0.195 + 0.106 + 0.084$$

$$Swp = 0.114 + 0.215 + 0.245 + 0.215 + 0.133 + 0.079$$

$$Off = 0.193 + 0.223 + 0.242 + 0.115 + 0.084 + 0.143$$

4.3.6 Consistency Check

In the AHP method, the priorities make sense only if derived from consistent or nearly consistent matrices. The consistency ratio (CR) was used to check the consistency of the pairwise comparisons for each SME. The CR values are less than 0.1 which means it matches the consistency test. If it is not yet consistent, the comparison has to be repeated again. Saaty (1977) proposed a consistency index (CI), which is related to the eigenvalue method:

Where CI = Consistency index = $\frac{\lambda max-n}{n-1}$..........*Equation 4.17*

Consistency ratio = $CR = \frac{CI}{RI}$.....................*Equation 4.18*

where RI is the random index (the average CI of 500 randomly filled matrices) which can be found in Table 4.4 (Saaty 1977; Ishizaka and Labib 2009; Jandova and Talasova 2013).

Table 4.4 Random index table

N	1	2	3	4	5	6	7	8	9	10	11	12
RI	0.00	0.00	0.58	0.90	1.12	1.24	1.32	1.41	1.45	1.49	1.52	

If CR is less than 10% (0.1), then the matrix can be considered as having an acceptable consistency.

It is important to emphasize that throughout the course of the interviews, the researcher took great care to clarify each element of the discussion, effectively mitigating the potential for discrepancies arising from issues of comprehension or interpretation. Nevertheless, it is imperative to acknowledge that instances of inconsistent judgments did arise, primarily from respondents who independently completed the questionnaires without direct researcher guidance. Importantly, it is noteworthy that these isolated inconsistencies did not exert any discernible influence on the overall consistency of the study. However, to ensure and enhance the coherence of the collected data, an iterative feedback mechanism was employed. This iterative process was designed to attain an acceptable level of consistency while also accommodating, to some extent, the preferences of the experts involved.

Improving the Inconsistency in AHP: For the SMEs that were interviewed, we kept iterating until we reached an acceptable consistency. However, the three who sent in their responses were all inconsistent.

To avoid inconsistency in the tool, The Bolton and Gear (1983) approach was imbedded into the eigenvector analysis to avoid rank reversal in the event of criteria or alternatives change.

$$\overline{w}_i = \frac{w_i}{max[w_k]}, i = 1, 2, 3, 4, 5, 6 \ and \ k = 1, 2, 3, 4, 5, 6 \text{.........} \textit{Equation 4.19}$$

Where $w = (w_c, w_h, w_r, w_s, w_{st}, w_t)^T$ is eigenvector weight vector and

$w_i = (\overline{w}_c, \overline{w}_h, \overline{w}_r, \overline{w}_s, \overline{w}_{st}\ \overline{w}_t)^T$ is the B-G normalized weight vector.

4.3.7 Rating the Criteria

The next step is to determine the weights and priorities of the development options with respect to each criterion. Based on a detailed analysis of marginal field development in Nigeria and expert judgment, scores were assigned on a three-point scale to represent performance against the qualitative criteria; HSE, regulation, security, stakeholders and technology. They reflect the perceived performance of each alternative against the specified criteria and serve as inputs for the AHP model, which calculates weighted scores and facilitates decision-making. A score of 1 signifies best performance, 2 signifies moderate performance, while 3 signifies worst performance. The performance of each criterion was assessed using the three-point scale and incorporated into a matrix. The method involved normalizing the criteria values, assigning weights to each criterion based on their relative importance, and then calculating a weighted sum for each alternative.

4.3.8 Ranking of Alternatives by Deriving Overall Priority

The final step is to synthesise the results and identify the preferred development option. This involves aggregating the weights and priorities of each development option and selecting the option with the highest overall score. This involved combining the products of each criterion weight with the score of an alternative when evaluated with reference to the criterion to obtain the weighted score for that alternative as shown in Equation 4.19 (Na et al. 2017; Nnaji and Banigo 2018). The procedure is repeated for all considered alternatives and their obtained weighted scores are used for comparatively ranking the alternatives.

$$w_i = \frac{1}{n}\sum_{j=1}^{n} a_{ij} * S_{ij} \ldots \quad \text{..............................} \textit{Equation 4.20}$$

$$A_i^{WSMScore} = \sum_{j=1}^{n} w_j\, a_{ij}\,, \quad for\ i = 1,2,3, \ldots, m \quad \text{....... Equation 4.21}$$

Where i=1,2,3…,m is the value of the best alternative, n is the number of criteria, an alternative value I the criteria j, are value criteria j and max used to sort the alternative decision where alternatives have the greatest value will be placed on top.

$$A_i^{WSMScore} = \sum_{j=1}^{6} w_j \, a_{ij} \, , \quad for \; i = 1,2,3,4$$

Where w_i is the weighted score for alternative i, a_{ij} is the weight of importance of criterion j and S_{ij} is the score of alternative i with respect to criterion j. final synthesis and ranking of is as shown in Table 4.5.

Table 4.5: Final Synthesis and Ranking of Alternatives

Synthesis	Cost	Stakeholders	Security	HSE	Technology	Regulation	Total weights	Overall Priorities
Alternative A	R_1*A_1	R_2*A_1	R_3*A_1	R_4*A_1	R_5*A_1	R_6*A_1	$\sum R_1A_1 \ldots . R_6A_1$	
Alternative B	R_1*A_2	R_2*A_2	R_3*A_2	R_4*A_2	R_5*A_2	R_6*A_2	$\sum R_2A_2 \ldots . R_6A_2$	
Alternative C	R_1*A_3	R_2*A_3	R_3*A_3	R_4*A_3	R_5*A_3	R_6*A_3	$\sum R_1A_1 \ldots . R_6A_1$	
Alternative D	R_1*A_4	R_2*A_4	R_3*A_4	R_4*A_4	R_5*A_4	R_6*A_4		

Table 4.6 Sample Matrix for assigning weights and aggregation

Criteria	Cost	HSE	Regulation	Security	Stakeholders	Technology
Alternative						
A1						
A2						
A3						
A4						

The results of the AHP analysis can provide insights into the most optimal development option for marginal fields in Nigeria based on the selected criteria.

$$B_c = \begin{bmatrix} 1 & 4 & 8 & 2 \\ \frac{1}{4} & 1 & 4 & 1 \\ \frac{1}{8} & \frac{1}{4} & 1 & \frac{1}{3} \\ \frac{1}{2} & 1 & 3 & 1 \end{bmatrix} \text{..........................} \textit{Equation 4.22}$$

These were then summed up with the scores of the criteria to obtain the overall priorities.

4.4 Sensitivity Analysis

Sensitivity analysis is a mathematical approach used to assess how variations in input data can influence results or decisions (Goepel, 2017). It serves as a reliable tool for validating model inputs and evaluating the robustness of results obtained from model applications (Smith et al., 2008). According to Abu-Shabeen (2008), relying on current inputs of a decision model becomes questionable if a sensitivity analysis reveals that a change of 5% or less in any input parameter alters the most-preferred alternative. Such outcomes necessitate further review and validation of the initial parameter weights.

In this research, sensitivity analysis was employed in Chapter Five to validate the input data and to implement the decision model for the case study (Objective 2). Sensitivity scenarios were designed to reflect shifts in strategic priorities, providing a comprehensive view of how varying emphases impact decision outcomes. These scenarios encompass a range of operational strategies and stakeholder concerns, ensuring the model’s robustness across diverse conditions. The Numerical Incremental Analysis (NIA) method was adopted, being the most prevalent approach in the literature for sensitivity analysis in cases where the Analytical Hierarchy Process (AHP) is used for Multi-Criteria Decision Analysis (MCDA) (IJzerman, Groothuis-Oudshoorn, and Hummel, 2011; Chen and Kocaoglu, 2008; Siraj et al., 2013). Commonly referred to as "one-at-a-time analysis," this method involves incrementally adjusting the numerical values of a single parameter while holding others constant to observe the resulting impact on model outcomes. (Mu and Pereyra-Rojas 2018).

The implementation of NIA for the developed decision model followed established methodologies (Barker and Zabinsky, 2011; SHELL, 2017; Mu and Pereyra-Rojas 2018; Rahman and Szabó, 2021; Haag et al., 2022; Enyinda et al., 2022). In this procedure:

1. The weight of one decision criterion was set to 50%, while the remaining five criteria equally shared the remaining 50% (Table 4.7).
2. The AHP model was reapplied using the adjusted weights for each scenario.
3. New priority scores and rankings of the development options were calculated using the Weighted Sum Method or eigenvector-based computations.
4. Sensitivity results for each decision criterion were visualized through graphical plots, illustrating the impact of weight adjustments on the model's outcomes.

This analysis enhanced the robustness of the decision-making framework, confirming the stability and reliability of the results under varied input scenarios and highlighting the critical influence of decision criteria on marginal field development options.

Table 4.7: Criteria Weight Changes for Sensitivity Analysis

Scenario	**Description**
Scenario 1	Criteria weights and priorities derived from SME inputs
Scenario 2	Cost weighted 50% and other criteria weighed equally
Scenario 3	HSE weighed 50% other criteria weighed equally
Scenario 4	Regulation weighed 50% other criteria weighed equally
Scenario 5	Security weighed 50% other criteria weighed equally
Scenario 6	Stakeholders weighed 50% other criteria weighed equally
Scenario 7	Technology weighed 50% other criteria weighed equally

4.5 Digital Tool Development

The process of selecting an optimal marginal field development strategy involves a series of steps, including data collection, stakeholder engagement, pre-assessment, economic modelling, and sensitivity analysis. These steps, as depicted in the flowchart, were previously performed manually, which was time-consuming and prone to human error. To enhance efficiency and consistency, the model was automated using Python, providing a digital tool capable of handling complex data and delivering optimal solutions systematically.

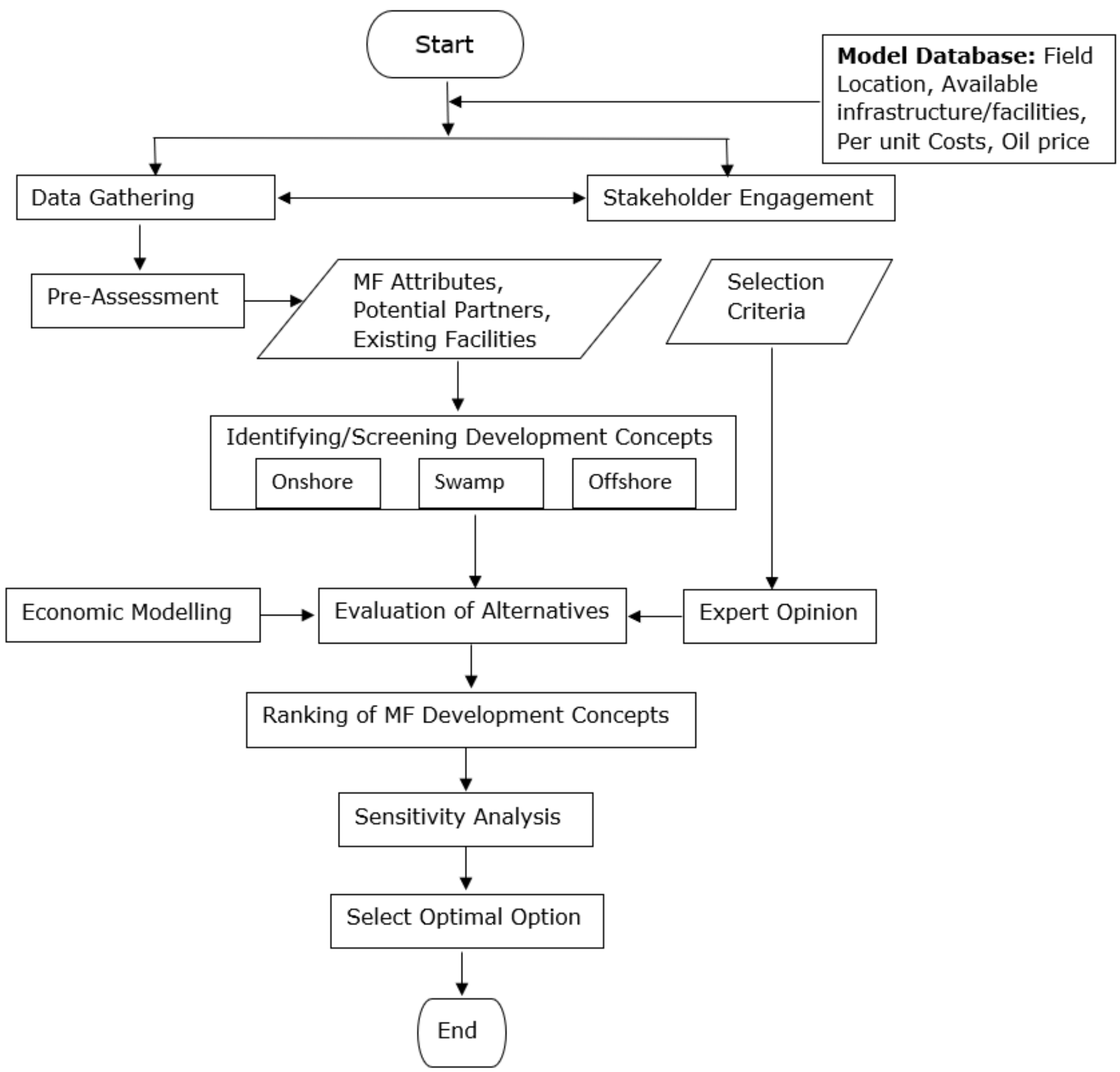


Figure 4.5: Flowchart for Marginal Field Development Decision Tool

4.5.1 Model Design and Framework

The automated model was developed to replicate and enhance the logical flow shown in Figure 4.3. The core components of the framework include:

Input Data: Field-specific attributes (e.g., location, available infrastructure, costs, and oil price) were incorporated into a centralized model database.

Processing Layers:

Data Gathering and Pre-Assessment: Automating data collection from structured datasets and external sources.

Screening Development Concepts: Classifying marginal fields into onshore, swamp, and offshore categories based on input criteria.

Economic Modelling and Evaluation of Alternatives: Automating the calculation of key economic indicators like NPV.

Ranking and Sensitivity Analysis: Developing algorithms to rank alternatives and assess the impact of parameter variations.

4.5.1.1 Programming Tool Selection

Python was chosen as the primary programming language for developing the Marginal Field Development Model due to its flexibility, extensive libraries for data analysis and visualization, and ease of integration with external tools (Sayantini, 2020). As an open-source and free-to-use language, Python is particularly suited for implementing AHP models due to its ability to support advanced functionalities such as sensitivity analysis and potential integration with machine learning for enhanced decision-making (Naveen et al 2018). It is highly customizable, making it ideal for researchers who require a significant degree of flexibility in their model development process. Moreover, Python's extensive ecosystem includes libraries such as NumPy for mathematical computation, Matplotlib and Seaborn for visualization, and Pandas for data handling, which are critical for operationalizing complex models like AHP.

While Python was selected as the optimal choice, other options such as MATLAB and Decision-Support Platforms were considered. MATLAB offers an all-in-one environment for mathematical computation and visualization and is more suitable for researchers with access to licensed software. However, its proprietary nature limits accessibility for some researchers, especially in academia. On the other hand, decision-support platforms provide quick solutions for practitioners and stakeholders with limited programming knowledge but lack the scalability and customization needed for large-scale or advanced AHP implementations.

The comparison of these tools is summarized in Table 4.8 to highlight their strengths, limitations, and suitability for various user groups. This comparative analysis underscores Python's advantages in developing a scalable, adaptable, and research-driven decision-support system for marginal field development strategies.

Table 4.8: Comparison of Programming Tools

Criteria	Python	MATLAB	Decision-Support Platforms
Customization	High	Moderate	Low
Ease of Use	Moderate	Moderate	High
Cost	Free/Open-Source	Licensed (Paid)	Paid (Some are Free Versions)
Integration with Data	High	High	Low
Visualization Quality	High	High	Moderate
Scalability	High	High	Low
Sensitivity Analysis	High	High	Limited

4.5.2 Data Gathering and Pre-Assessment

The data collection process was automated by integrating Python scripts with the model database. This step involved:

Input Data Format

Reservoir attributes: Number of reservoirs (n), reservoir volume (v), and re-enterable wells (w).

4.5.2.1 Model Database

The model would take in data on the relevant factors that can affect the feasibility of developing the marginal fields. However, it requires a database from which important additional information on nearby infrastructure and associated infrastructure costings (economics) can be extracted for analyses.

Data of facilities, oil fields, oil terminals and FPSOs in Nigeria were sourced from the NUPRC. The distances between these infrastructures are calculated using location coordinates extracted from the Nigeria oil concession map (Figure 4.2).

To input the data into a decision support tool for marginal field development, information was organized into structured datasets and used to create a database that can be queried efficiently. Below is the format of the data for Facilities, Oil Fields, Oil Terminals, FPSOs and Economics (Cost):

I. Facilities Data

This dataset includes information about various facilities (floating facilities, flow stations, terminals) involved in the decision-making process for marginal field development.

Example Entry:

- **Facility Name:** Facility A
- **Facility Type:** Oil Field
- **Location Coordinates:** (Latitude: 12.3456, Longitude: -78.9012)
- **OML/OPL Block:** PML-123
- **Terrain:** Onshore
- **Production Status:** Active
- **Proximity to Pipeline:** Yes

By structuring the data in this manner, it was easily inputted into decision support tool to perform analyses, comparisons, and decision-making related to marginal field development based on the various attributes and factors associated with these facilities and locations.

II. Field location Data

Geospatial data for identifying existing infrastructure and facilities. As received from NUPRC, there were only 30 licenced marginal fields out of which 17 were producing, 11 oil terminals and 14 FPSOs as shown in Appendix 4.

A web-based tool in mind, the facilities data was extracted, formatting it into JSON format. JSON (JavaScript Object Notation) is a widely used data format for web projects (Mozilla, 2023) and was preferred because it is accepted across any programming language, in this case JavaScript. It is readable, easy to understand, lightweight, and most importantly, makes data entries compact and rapidly portable, saving storage space and trimming storage management costs. Appendix 5 shows a sample of the facility data collected and transformed into JSON format.

Several functions were developed such as the Harvesine method to calculate the distance between two facilities, the NPV method to calculate the Net Present value of a development strategy, and the Well Completion Cost method to calculate the completion cost relative to terrain and available re-enterable wells as shown Appendix 6. Appendix 7 provides details of Python code implementations for these functions. Furthermore, Google Maps was integrated to display location coordinates in a presentable way and charts were integrated for quick visual analysis.

III. Economic (Cost) Data

This data includes information on the terrain and the associated costings for the relevant infrastructure (per unit costs of development equipment, well costs, infrastructures costs, CAPEX, OPEX). Other relevant data that are inputted include oil price, discount rate, and fiscal terms. Python scripts processed input data to extract marginal field attributes and identify potential development partners and existing facilities within proximity to the field. A geospatial analysis module using the Haversine method was employed to calculate the distance between the field and neighbouring facilities.

4.5.3 Screening of Development Concepts

The automation process involved classifying development options based on field attributes. Each marginal field was categorized as either onshore, swamp, or offshore. A rule-based system was implemented to map field attributes to the most suitable development strategy tables (as detailed in Appendices).

Economic modelling was automated to evaluate the financial viability of each development concept. NumPy Python library was used to calculate the economic metrics Unit Technical Cost (UTC) and Net Present Value (NPV). The algorithm retrieved cost data (e.g., CAPEX, OPEX) and production forecasts from the database to estimate profitability for each development option. The economic modelling module was integrated with the development strategy screening, enabling seamless data flow and evaluation.

4.5.4 Ranking of Development Concepts

A ranking system was implemented to prioritize marginal field development concepts based on their performance to decision criteria. Development concepts were ranked using AHP-derived weights for cost, HSE, regulation, security, stakeholders, and technology. The rankings were generated dynamically based on field-specific input data. Matplotlib Python library were used to create bar charts and heatmaps for visual representation of rankings.

4.5.5 Sensitivity Analysis

Sensitivity analysis was incorporated to evaluate the impact of variations in criteria on the rankings of development concepts. The Python tool adjusted parameters and observed real-time changes in rankings. Sensitivity analysis results were visualized using charts and plots, aiding stakeholders in understanding the influence of key parameters.

4.5.6 User Interface Development

A user-friendly interface was designed to enable field operators and decision-makers to interact with the digital tool. The interface was implemented using Dash, a Python-based framework, to ensure accessibility and ease of use. For a seamless user experience, field operators are expected to provide specific data relevant to their field, including the number of reservoirs ('n'), reservoir volume ('v'), and the number of re-enterable wells ('w'). These inputs are critical for generating the most suitable development options using the Marginal Field Development Strategy Selection Algorithm, as detailed in Appendix 6. The algorithm leverages these variables to select factors from each Development Strategy table (refer to Appendix 8), ultimately determining the feasible development options applicable to a facility.

Upon receiving the input data, the algorithm initiates by identifying the closest facilities within a 10 km radius. If no facilities are identified within this initial range, the search radius is expanded to 100 km. To calculate the distance between the selected field and nearby facilities, the algorithm employs the Haversine method, a well-established formula for measuring great-circle distances between points on a sphere, ensuring accuracy in spatial calculations.

Once the proximity analysis is complete, additional functions are executed to analyse various development scenarios. The algorithm proceeds to calculate the Net Present Value (NPV) for each development strategy associated with the identified facilities. This comprehensive process ensures that all feasible options are evaluated based on economic viability, operational efficiency, and alignment with field-specific characteristics.

By integrating spatial analysis, economic evaluation, and strategic decision-making, the Marginal Field Development Strategy Selection Algorithm provides operators with a robust tool for optimizing marginal field development. The inclusion of user-friendly features, such as automated calculations and clear visualization of results, further enhances its practical application in real-world scenarios.

By operationalizing the AHP-based model into a digital tool, the methodology enhances the decision-making process for selecting optimal marginal field development strategies, ensuring a systematic and transparent approach that can be easily adapted to varying contexts.

4.5.7 Validation and Testing

The automated model was validated using historical data from marginal fields in Nigeria. The results of the automated model were compared with those obtained manually to ensure accuracy and to confirm the model’s robustness.

Chapter 5 Hybrid AHP Model for the Selection of Optimal marginal Field Development Option

This chapter presents the results and discussion of the study, which developed a hybrid Analytical Hierarchy Process (AHP) model to evaluate marginal field development options in the Niger Delta. The model integrates a screening process to eliminate infeasible options based on reserve size, terrain suitability, and infrastructure proximity, ensuring focus on viable alternatives. The AHP framework prioritizes decision criteria, including cost (Unit Technical Cost, UTC), Health, Safety, and Environment (HSE), regulatory compliance, security, stakeholder engagement, and technology. The Weighted Sum Method (WSM) evaluates and ranks the viable options based on their performance across these prioritized criteria. This hybrid approach offers a structured, robust, and balanced decision-making framework to address the complexities of marginal field development, ensuring strategic and informed evaluations.

5.1 Generation of Development Options for Niger Delta Marginal Fields

The procedure for generating technically feasible potential development options for marginal oil fields based on their different attributes is laid out in attached flowchart (Figure 5.1), a decision-making support tool. The blue coloured symbols signify important steps and processes to arrive at possible development options. The red symbols are critical decision steps in the process, representing the attributes (terrain, reserves) for the generation of marginal field development options while the green signifies the options (A1, A2, A3, A4, A5) generated based on the attributes. Options A1 to A5 are composite options consisting of four possibilities from the pathways.

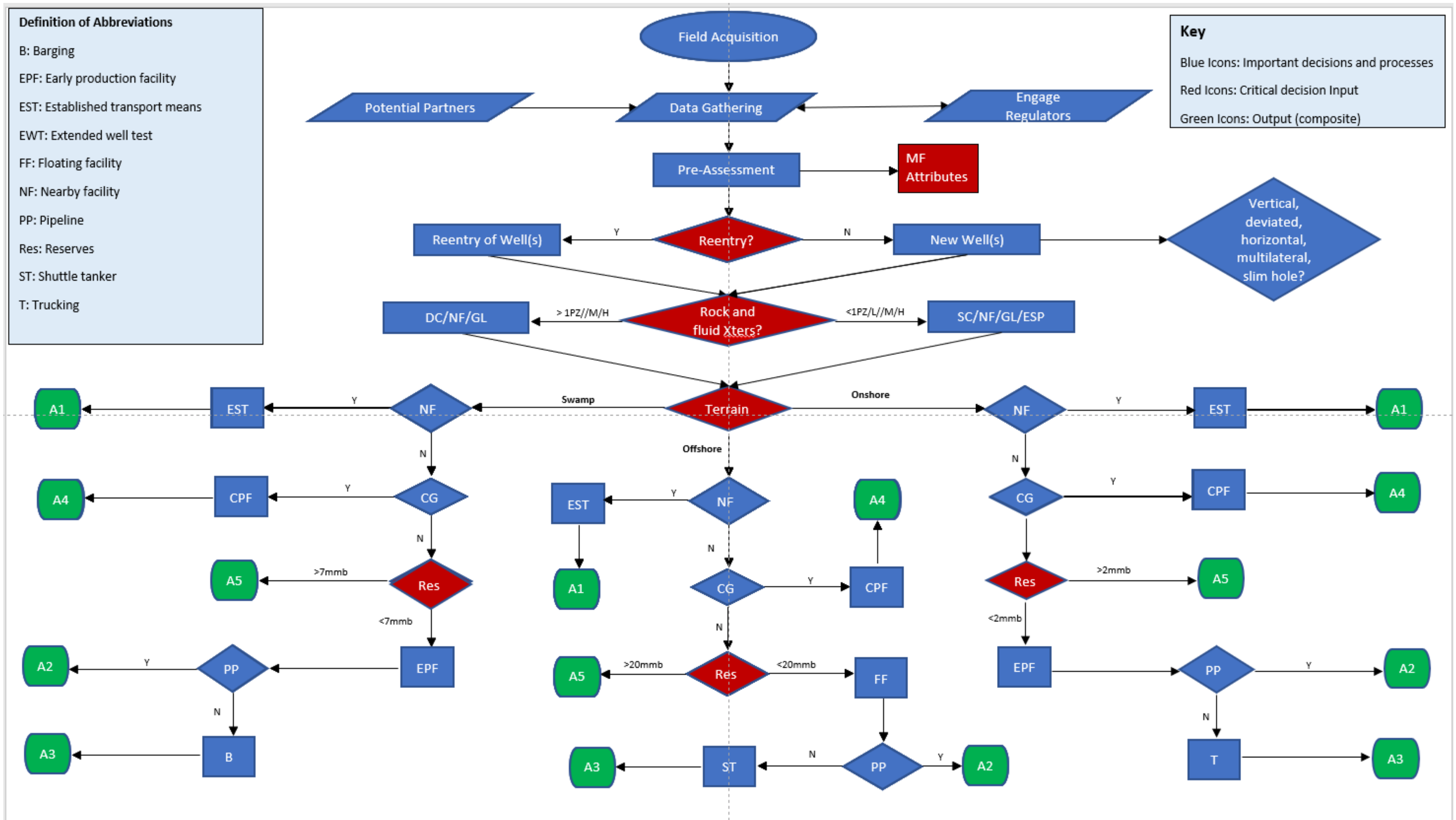


Figure 5.1: A Flowchart for screening marginal field development

Start

This is the point the development planning for the marginal field starts. The procedure starts from the point after all farm out agreements have been signed with the relevant "farmors" to the field.

Identification of other Potential partners

First thing to do is identify potential partners for the development of the field, these include other field operators nearby, financiers to secure funding, service companies, crude handling companies. Secure funding commitment from financiers.

Data Gathering

Subsequent to identification of potential partners, the next step is to start the data collection. The data include geological information, geophysical and production data, the major asset list and any mandatory investment program. This is to enable conduct of detailed integrated field study, risk assessments (community related (CSR), environmental etc.), conduct well integrity checks and audit well abandonment procedures. This phase will require a physical inspection visit to the field.

Regulatory Approvals

Visit the regulatory authorities to obtain the permits register to guide on the regulatory requirements and for ensuring timely approvals. Some of the approvals required include: field development plan, environmental impact assessment (EIA), drilling permit, completion permit, permit to survey (PTS), oil pipeline license (OPL) and many more. Early engagement of the regulators is key to attainment of timely approvals and or permits.

Pre-Assessment

Review of reservoirs in existing wells to identify completion candidates. Estimate expected recovery using recovery factor from analogue data.

Conduct a decline curve analysis to estimate the expected production and number of wells required to achieve the production. If you have enough data to work with.

Where higher accuracy in the expected production performance is required, MBE or numerical simulation is conducted. These days the software packages can be leased per use saving cost of having to purchase an expensive software.

Key Assumptions

All the fields are partially appraised, reserves have been estimated, no production from the fields, presence of aquifer therefore primary depletion, oil production, stacked reservoirs, homogenous properties, no need for water injection, rich aquifer support onshore and swamp fields will be two phased developments. Estimation of recovery factor was based on analogue and nearby contiguous fields in the Niger Delta.

Even though the algorithm has end points of one option, some fields meet the criteria and have all the options applicable to them. The foregoing is dealing with fields who have all of the options identified. Standard Niger Delta marginal fields well design will be employed for all developments.

Well Development

Based on data collected from IOC, conduct geological and geophysical (G&G) studies/review if existing well can be re-entered then re-enter existing well, otherwise drill new well. At this point engage service providers and contractors, ensure proper contracting agreement (Turnkey contract) that ensures less risk to operator or shared risk.

Re-entry

If well can be repaired, cleaned, and re-entered, then action is completion of the existing well(s) to commence field production, otherwise operators to drill a new well. The sequence of re-entry is: Prepare Well Site, Implement Rigless workover: Acquire wireline logs & Re-perforate, Carry out Maximum Efficiency Rate (MER) Test.

Extended Well Test (EWT) will be part of the development process to reduce some uncertainties. Some of these uncertainties are: structure, field production (oil and gas) profile, GOR changes with time, aquifer strength and reservoir pressure decline with time. A key assumption is that all reservoirs in Niger Delta basin have aquifers therefore water drive, this is based on findings from the literature review of developed fields in the basin.

The overall well objective will be to complete reliable, high-potential (and ultimate recovery) wells, at the lowest life-cycle cost in a timely and HSE responsible manner.

Completion Strategy

To achieve the well objectives, the following completion strategy is recommended to be utilized:

Fit for purpose field proven technology will be selected for the initial development wells with the introduction of new technology in a structured approach.

Minimise well interventions but allow for reservoir monitoring and appropriate management e.g., fluid contact movement, pressure surveys and zone changes

For light oil, wet and dry gas reservoirs that have more than one reservoir identified, select dual completion, they start on natural flow and provision of gas lift mandrels for future artificial lift of wells once a gas management plan has been implemented.

If only one reservoir has been identified for the above reservoirs, single completion with provision for gas lift.

If heavy oil reservoir or reservoirs for light oil reservoirs without potential gas supply from nearby fields, and ESP will be implemented. With ESP only a single completion can be implemented because of space constraint in the production tubing.

To achieve well objectives efficiently and economically, a completion strategy that supports early production is recommended. Complete as many zones as possible with a single well. If there are sizeable reserves available you don’t keep them behind sleeve. Behind sleeve are tiny reserves that you cannot justify drilling a well. Keep it behind sleeve so there is no cross flow.

Processing and Transportation

The terrain is critical here, it determines the type of processing facility and transport to use; If onshore or swamp the options are nearby facility and Early Production Facility (EPF), If offshore it is nearby floating facility or a leased floating facility. The reservoir fluids in Niger Delta are generally good quality, sweet crude with medium to high API gravity (16-42^{0}API). There is usually no technical complexity in the transportation of production from the reservoirs. For fields that produce condensates, it is usually spiked with the heavier crude.

Option A1: Tie-Back Development

Scenario: Applicable to fields in all terrains, within a distance of 10, 15 and 20 km onshore, swamp and offshore respectively.

Description: When a nearby processing facility is readily available, and arrangements have been established, production is directed to this facility. Subsequently, the processed product is exported via established channels.

This development strategy involves the reentry of the existing well(s) in the field or drilling of 1+ wells, tying into a nearby existing facility, and transportation of production through already established means to third party terminal. These strategy uses efficient technologies, but is limited in terms of expansion. The cost of this development strategy will be relatively low because only 1-2 wells are being drilled (re-entry), and coiled tubing drilling is less expensive than traditional drilling methods. The major cost involved will be the cost of laying the pipeline to the flow station at $700/km onshore/swamp and $1,000/km offshore. Existing facilities are typically equipped with production facilities, pipelines, and other infrastructure needed for the transportation and processing of crude oil. Therefore this development has several advantages, reduced capital expenditure required for the development, reduced the time it takes to bring the field into production, access to buyers for the oil produced from the marginal field. This helps to reduce the risk associated with finding new buyers for the oil. Cost of processing and transportation has been converted from CAPEX to OPEX which is good for the economics of the development at $1.50/bbl. Also, the existing facilities are operated by experienced personnel who are familiar with the equipment and processes. This can help to improve the operational efficiency of the project by reducing the need for training and increasing the reliability of the equipment. Generally total cost of this development option will be about $10m.

This development strategy has a moderately low regulatory requirement associated with producing, processing and transporting oil to market due to the use of existing wells (or few new wells), facilities and pipeline. Drilling new wells, building a new flow station and pipeline can require a significant amount of regulatory approval. The environmental impact of this development will also be low, as re-entering an existing well can be a more environmentally friendly option. Also, using existing flow stations helps to minimize this impact by reducing the need to clear new land and construct new infrastructure. This can help to reduce the carbon footprint of the project and minimize the impact on local ecosystems. However, this development option has a high security risk onshore, it is prone to pipeline vandalism, kidnapping of personnel, and attacks on facilities. Consequently the development involves the deployment of security personnel and surveillance equipment to monitor the project site and prevent unauthorized access. In addition, implementation of community engagement programs to foster good relations with the local population and reduce the risk of sabotage is critical. In the swamp terrain security is medium and low offshore.

Option A2: Partial Standalone Development

Scenario: Relevant when no nearby facility is accessible, and the field holds reserves of 5 MMbbl, 7 MMbbl, 20 MMbbl or more onshore, swamp and offshore respectively.

Description: In such cases, an Early Production Facility (EPF) or floating facility is leased to undertake production processing. If a proximate pipeline exists, the produced hydrocarbons are exported via a third-party pipeline. Alternatively, arrangements can be made with nearby fields for collective gathering and subsequent export via a pipeline.

This is development option consisting composite options A2, A6. Its involves development of a single marginal field as an independent project, but with connection or integration with other nearby fields and existing infrastructure for transportation of production.

This development strategy involves re-entry of existing well(s) in the field using coiled tubing drilling, or drilling of 1+ new wells depending on the field characteristics, EPF (skid mounted flow station), export via pipeline to third party terminal. These are effective technology for marginal field development have the capacity to handle the initial production from the field and facilitate the gathering, processing, and storage of the produced hydrocarbons. It also enables expansion with increase in production up to the allowable allocation by third party operators of the pipeline. It provides an opportunity to gather more data about the field's production potential and reservoir behaviour, which can help in making informed decisions for future development phases. This approach enables the operator to assess the potential of the field and optimise production before committing to a full-scale development.

This partial standalone development allows operators to directly manage regulatory compliance and meet the specific requirements of the field. By having full control over the development and operation, operators can ensure adherence to regulatory standards and reporting obligations. The regulatory requirement and environmental impact for this development strategy is more than that for Tieback development because of introduction of EPF and pipeline. However, EPFs are designed to minimize the environmental impact of production. They typically have a small footprint and are equipped with modern, efficient equipment that reduces emissions and waste. Safety protocols, emergency response plans, and environmental management practices can be implemented to mitigate risks and ensure compliance with HSE regulations.

The cost of this development strategy will be moderately low higher than that for Tieback development because of the use of EPF and pipeline to tie-in to third party pipeline. The cost of leasing EPF is approximately \$20/bbl and cost of pipeline at $700/km. This development option will have a capital expenditure of about $25m.

Stakeholders appeal for this option will be medium, there will be early production therefore early revenue, reasonable regulatory requirements and CSR for local communities. This are cost items that will add to the total development cost. CSR will alleviate the potential risks associated with onshore developments. The security risk for this development is higher because of the additional facility (EPF) and pipeline to export. Therefore, more security personnel and surveillance equipment to be deployed to monitor the project site and prevent unauthorized access.

Option A3: Full Standalone Development

Scenario: Pertinent when constructing a pipeline to a nearby facility is cost-prohibitive, when pipeline downtime is a concern, when a third-party pipeline is vulnerable to vandalism within a community, or when the crude quality does not conform to pipeline requirements.

Description: Onshore production can be transported by truck to an alternative facility or directly to the terminal, depending on the most cost-effective and practical solution.

Swamp production can be transported via barges to an alternative facility or directly to the terminal, depending on feasibility and cost considerations.

Offshore, operators in such cases lease a floating facility and direct production to a Floating Storage and Offloading (FSO) unit for storage. Transportation for export is accomplished via shuttle tankers, or, if the floating facility offers storage, direct export is facilitated.

This is development option consisting composite options A3, A7, A10. A standalone marginal field development refers to the development of a single marginal field as an independent project, without any direct connection or integration with other nearby fields or existing infrastructure.

This development strategy involves re-entry of existing well(s) in the field using coiled tubing drilling or drilling of 1-2 new wells, EPF (skid mounted flow station or floating facility), export via trucking or barging or shuttle tanker to third party terminal. These are effective technology for marginal field development and can be expanded with increase in production. This option offers operators greater control and flexibility over the design, operation, and management of the field. It allows for customized approaches and strategies specific to the field's unique characteristics. This approach enables the operator to assess the potential of the field and optimise production before committing to a full-scale development. The project requires the establishment of dedicated infrastructure and facilities tailored to the specific field's production requirements. This may involve the construction of production platforms, storage tanks, processing facilities, and export infrastructure. The cost of this development strategy will be higher than that for partial standalone option because of the use of EPF, and trucking, barging or shuttle tanker which are transport options that are more expensive than pipeline. Standalone marginal field development may have higher initial capital costs, as each field requires individual infrastructure and facilities. The absence of shared resources can lead to higher investment and operating expenses. However, there is cost flexibility because it allows for tailored cost management specific to the field's requirements. Operators have control over the design and scale of infrastructure and can optimise costs based on the field's size, production potential, and economics.

The regulatory requirement and environmental impact for this development strategy is high. Navigating the regulatory landscape for standalone projects may be more complex and time-consuming, requiring thorough assessments, permits, and approvals for various aspects of the development. Additionally, this option may face challenges in implementing robust HSE measures due to limited resources and scale. Ensuring compliance with HSE regulations and managing potential risks and environmental impacts may require additional efforts and investments. However, EPFs are designed to minimize the environmental impact of production. They typically have a small footprint and are equipped with modern, efficient equipment that reduces emissions and waste.

Stakeholders appeal for this option will be high, there will be early production therefore early revenue. Also the option can offer opportunities for direct engagement and collaboration with stakeholders. Local communities, suppliers, and service providers can be involved in the development and operation of the field, potentially leading to increased local content, employment, and economic benefits. The CSR requirements CSR for local communities will be high. These are cost items that will add to the total development cost. CSR will alleviate the potential risks associated with onshore developments. The security risk for this development is medium because there is no pipeline transportation pipeline to export only securing of the facility. Therefore reasonable number of security personnel and surveillance equipment to be required to monitor the project site and prevention of unauthorised access.

Option A4: Cluster Development

Scenario: Considered when there are possible cluster groups within proximate distance to each other

Description: In these circumstances, the operators pool resources together to install a Central Processing Facility and production is exported via pipeline, barge or shuttle tanker depending on the terrain and economics.

This is development option consisting composite options A9, A10, A11. It involves the development of fields in close proximity to each other as a group and managed as a cluster instead of individually.

This development option involves re-entry or 1-2 new wells, single/dual zone completion, CPF (central processing facility), export via pipeline, trucking or barging or shuttle tanker to third party terminal depending on the terrain. This option has the potential of huge cost savings, improved efficiency, increasing revenue, providing avenue for stakeholder engagement, and enhancing HSE compliance. Additionally, CPF can enhance security by centralizing operations and reducing the number of locations that need to be secured. This can also improve safety by reducing the risk of accidents or incidents that can occur when multiple facilities are involved. Also a CPF can provide a central location for engaging with local communities and other stakeholders. This can help to build trust and promote collaboration, leading to a more sustainable and mutually beneficial relationship between the oil company and local communities. Additionally, a CPF can create jobs and other economic benefits for the surrounding communities, contributing to local development.

Cost is medium low, by consolidating resources and infrastructure, cluster development can achieve cost savings through shared facilities, equipment, and personnel. Centralized processing and production facilities enable streamlined operations, maintenance, and logistics, leading to improved efficiency and reduced operating costs. The regulatory requirement of this development option can facilitate compliance with regulatory requirements. By consolidating operations, it becomes easier to adhere to regulations, meet reporting obligations, and demonstrate responsible field development practices. In a cluster development, HSE practices and standards can be standardized and implemented consistently across multiple fields. Sharing resources and expertise can lead to improved HSE performance, better emergency response capabilities, and reduced environmental impact. Reduced environmental footprint: By minimizing the infrastructure footprint through shared facilities, cluster development can help reduce the environmental impact and land disturbance associated with individual field developments. Regulatory and environmental impact will be medium low.

Security will be medium because by consolidating production and infrastructure in a cluster, security risks can be managed more effectively. Centralized security measures can be implemented to protect the cluster, reducing vulnerabilities associated with individual field developments. Also, cluster development can provide opportunities for collaboration and cooperation among stakeholders. Local communities, suppliers, and service providers can benefit from economies of scale, fostering local content development and enhancing social and economic benefits. Therefore stakeholder appeal for this option will be high.

Option A5: Defer Development

Scenario: Applicable to all terrain.

Description: When none of the above conditions are met, field development is deferred until conditions become favourable.

Where the marginal field does not meet any of the conditions for viable field development, the field development is deferred until conditions change. The conditions are enough reserves, availability of proximal facilities for either a tieback or cluster development. If more exploration is conducted and more reserves become available, fields could be developed on a standalone basis. If other fields within proximal distance get developed, then their might be an opportunity for sharing of facility which them makes the development viable.

5.2 Hierarchical Structure for Selection of Optimal Marginal Field Development Option

As highlighted in Chapter one, the complexity of marginal field development decision making necessitates the requirement for a decision model to aid the process. The objective of optimising marginal field development is to minimize cost, manage stakeholders i.e. regulators and host community, ensure no gas flaring and other regulatory requirements so as to bring marginal fields that would otherwise remain undeveloped into production. Figure 5.2 depicts the decision problem of selecting optimal marginal field development option. It shows the process from acquisition of field, screening to identify developments options down to the selection of optimal option based on identified criteria.

To select the most suitable development concept that simultaneously achieves these objectives, including the maximization of economic recovery, minimization of environmental impact, mitigation of community disruptions, addressing insecurity, optimizing facility usage, and ensuring regulatory compliance—all while minimizing both CAPEX and OPEX to ensure profitable oil and gas production.

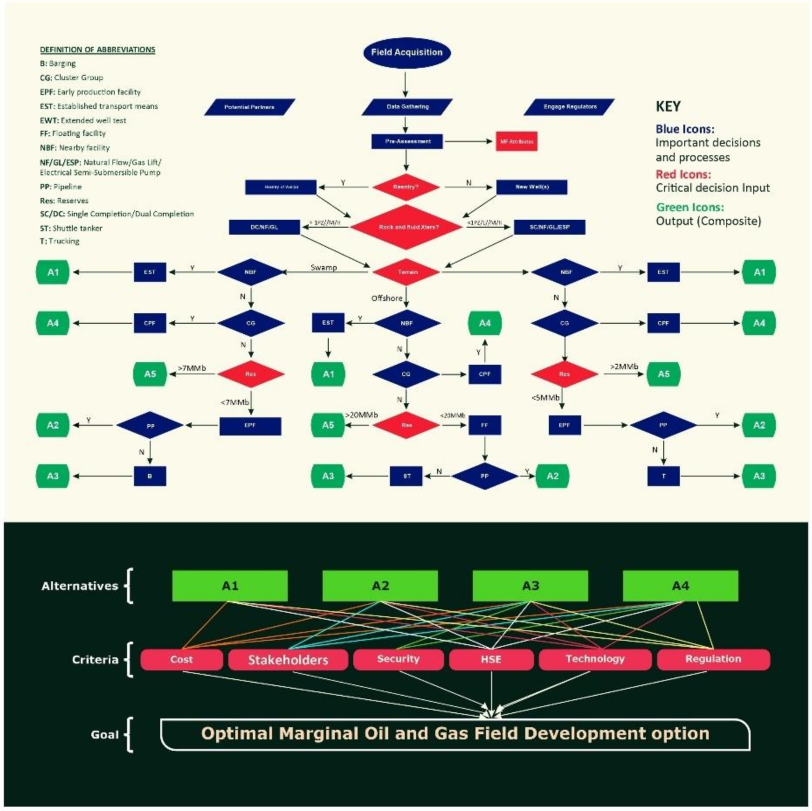


Figure 5.2: Decision Model for Selection of Optimal Marginal Field Development Option

The decision-making process for selection of optimal marginal field development option involves evaluating the generated option or options from the screening model (Figure 5.1) A1, A2, A3, and A4 against the identified criteria in section 2.6 to determine the most technically and economically viable option.

5.3 Prioritisation of Decision Criteria

To select an optimal field development option, it is essential to determine the relative importance of the criteria influencing the decision. A pairwise comparison of the criteria was conducted to evaluate their significance in the decision-making process for marginal field development across distinct terrains: onshore, swamp, and offshore. This section presents the results of the pairwise comparison and eigenvector analysis, derived from the expert judgments of 15 subject matter specialists, including both operators and regulators. The experts' assessments were refined through iterative adjustments to ensure consistency, culminating in priority scores that quantitatively reflect the relative importance of each criterion within each terrain.

5.3.1 Pairwise Comparison

SMEs articulated their preferences guided by the nine-point Saaty scale. These selections were grounded in their professional discernment, knowledge, and experience pertaining to the intricacies of marginal field development. The judgment of the experts with regards importance of criteria in onshore, swamp and offshore field development are summarized in Table 5.1 to 5.3.

The provided pairwise comparison results represent the judgments of subject matter experts (SMEs) regarding the importance of various criteria in the context of onshore, swamp and offshore marginal field development. The participants' individual assessments are consolidated using the geometric mean as explained in section 4.3.1. These consolidated judgments are used to establish the relative priority or significance of one criterion compared to another.

Table 5.1: SMEs' Judgements and Geometric Mean of the judgments Onshore Terrain

Pairwise Comparison	SME1	SME2	SME3	SME4	SME5	SME6	SME7	SME8	SME9	SME10	SME11	SME12	SME13	SME14	SME15	Geomean
Cost vs HSE	1/5	1/5	1/5	1	3	1/7	3	3	5	1/3	3	3	1	7	1/3	1.01
Cost vs Regulation	1/3	1/9	1/3	5	3	1/3	1/3	3	1	1/5	1	1/5	1	9	1/5	0.70
Cost vs Security	1/5	1/5	1/3	2	3	1/5	1	7	1/5	1	3	3	1	1/3	1/5	0.75
Cost vs Stakeholders	1/3	1/4	1/3	5	3	1/5	3	7	1	3	1/5	7	3	5	5	1.52
Cost vs Technology	5	1/3	5	2	5	5	1	9	7	1/3	1	5	3	1/3	7	2.32
HSE vs Regulation	3	1	1	1	1/3	5	1/5	3	1/3	1/3	1/3	1/5	1	1/7	1	0.68
HSE vs Security	1	1	1	1	1/3	5	1	3	1/5	1	3	1/3	1	1/9	3	0.93
HSE vs Stakeholders	3	4	1/3	9	1/5	3	3	5	1/3	3	1/5	5	5	1/7	7	1.64
HSE vs Technology	7	4	5	1	1/5	9	3	9	3	1/3	1/3	5	5	1/7	7	2.07
Regulation vs Security	1/5	1	1/5	1	1/3	1/3	5	3	1/3	5	3	3	1	1/7	3	0.95
Regulation vs Stakeholders	1	9	1	9	1/3	1/3	7	5	3	5	1	9	1	7	9	2.68
Regulation vs Technology	5	9	5	1/5	1	5	7	9	7	5	3	9	3	1/5	9	3.34
Security vs Stakeholders	3	4	1	7	1	1/3	3	5	3	1	1/3	7	3	7	3	2.24
Security vs Technology	7	4	7	1	3	6	5	5	5	1/5	1/3	5	3	1/7	7	2.38
Stakeholders vs Technology	5	4	7	1/9	3	9	1	5	3	1/3	1	1/3	3	1/7	3	1.57

Table 5.2: SMEs' Judgements and Geometric Mean of the judgments Swamp Terrain

Pairwise Comparison	SME1	SME2	SME3	SME4	SME5	SME6	SME7	SME8	SME9	SME10	SME11	SME12	SME13	SME14	SME15	Geomean
Cost vs HSE	1/5	1/7	1/5	1/2	5	1/7	1/5	1	5	1/3	1	3	1/5	1/5	1/5	0.48
Cost vs Regulation	1/3	1/9	1/3	1	3	1/3	1/3	3	1	1/5	1/3	1/3	1/5	1/3	1/7	0.42
Cost vs Security	1/5	1/5	1/3	2	3	1/5	1/5	7	1/5	1/3	3	5	1/3	1/5	1/3	0.60
Cost vs Stakeholders	1/3	1/5	1/3	4	3	1/5	1/3	7	1	3	1/3	5	1	1/3	1/5	0.81
Cost vs Technology	4	1/3	5	1/2	7	3	4	7	7	1/5	1	3	1	4	1/7	1.76
HSE vs Regulation	3	1	1	3	1/3	5	3	5	1/3	1	1/3	1/3	1	3	1/3	1.15
HSE vs Security	1	1	1	2	1/3	5	1	7	1/5	1	1	5	1	1	3	1.33
HSE vs Stakeholders	3	5	1/3	9	1/3	3	3	5	1/3	3	1/3	5	3	3	3	1.99
HSE vs Technology	7	5	5	2	1/3	9	7	7	3	1/5	1/3	3	3	7	1/5	2.19
Regulation vs Security	1/5	1	1/5	3	1/5	1/3	1/5	3	1/3	1	3	7	1	1/5	7	0.82
Regulation vs Stakeholders	1	9	1	9	1/3	1/5	1	5	3	5	3	7	1	1	7	2.08
Regulation vs Technology	5	9	5	1/6	3	5	5	7	7	1/3	3	9	3	5	3	3.28
Security vs Stakeholders	3	4	1	6	1	1	3	3	3	3	1/3	1	1	3	1/3	1.66
Security vs Technology	7	5	7	1/2	5	5	7	5	5	1/5	1/3	3	1	7	1/7	2.16
Stakeholders vs Technology	5	4	7	1/9	3	7	5	3	5	1/3	1	3	1	5	1/3	2.03

Table 5.3: SMEs' Judgements and Geometric Mean of the judgments Offshore Terrain

Pairwise Comparison	SME1	SME2	SME3	SME4	SME5	SME6	SME7	SME8	SME9	SME10	SME11	SME12	SME13	SME14	SME15	Geomean
Cost vs HSE	1/7	1/9	1/5	1/3	3	1/7	3	5	5	1/5	1/3	1/3	1/5	3	1	0.60
Cost vs Regulation	1/3	1/9	1/3	1/2	3	1/3	1	5	1	1/3	1/3	1/3	1/5	1	1	0.57
Cost vs Security	1/5	1/5	1/3	3	3	3	5	5	5	3	3	5	1	5	5	2.06
Cost vs Stakeholders	3	1/5	1/3	5	5	1/7	5	6	5	3	1	5	1	5	1	1.82
Cost vs Technology	3	0.33	5	1/5	3	1/5	3	7	1	1/5	1/3	1/3	1	3	1/3	0.92
HSE vs Regulation	3	1	1	4	1/3	9	1/3	3	1	1	1	1/3	1	1/3	3	1.18
HSE vs Security	3	1	1	3	1/5	9	5	5	5	5	3	7	5	5	7	3.20
HSE vs Stakeholders	5	7	1/3	9	3	9	5	5	1	7	3	7	3	5	3	3.79
HSE vs Technology	7	7	5	1/3	1/3	9	1	7	1/3	1/3	1	1	1	1	1/3	1.32
Regulation vs Security	1/3	1	1/5	5	1/3	7	3	3	5	3	3	9	3	3	7	2.24
Regulation vs Stakeholders	3	9	1	9	3	7	5	3	1	3	1	7	5	5	5	3.58
Regulation vs Technology	5	9	5	1/5	1/3	7	5	5	1	1/5	1	3	3	5	1	1.96
Security vs Stakeholders	5	6	1	5	5	1	3	3	1/5	5	1/3	1/3	1	3	1/7	1.47
Security vs Technology	5	5	7	1/9	3	7	1	3	1/7	1/7	1/3	1/5	3	1	1/9	0.96
Stakeholders vs Technology	3	5	7	1/9	1/3	9	1/3	3	1	1/3	1	1/3	3	1/3	1/3	1.02

5.3.2 Decision Criteria Priority Scores

The geometric mean as shown in Tables 5.1 to 5.3, representing aggregated experts judgments were used to produce a consensus pairwise comparison matrices (Table 5.4 to 5.6). These matrices represent the collective evaluation of criteria weights across terrains: onshore, swamp, and offshore. The matrices are then evaluated to calculate the priority scores of the criteria.

The judgment matrix presented in Table 5.4 is the foundational input for the Analytical Hierarchy Process (AHP) applied to onshore marginal field development. It represents pairwise comparisons of the criteria, where experts have assigned relative importance based on their professional judgment. Each entry indicates how much more important one criterion is relative to another, with values of "1" indicating equal importance, values greater than "1" showing higher importance, and fractions (e.g.,1/2, 1/3) indicating lower importance.

Table 5.4: Judgment Matrix for Criteria Weighting Onshore

Criteria	Cost	HSE	Regulation	Security	Stakeholders	Technology
Cost	1	1	1	1	2	2
HSE	1	1	1	1	2	2
Regulation	1	1	1	1	3	3
Security	1	1	1	1	2	2
Stakeholders	1/2	1/2	1/3	1/2	1	2
Technology	1/2	1/2	1/3	1/2	1/2	1

Table 5.5 provides the pairwise comparison of criteria for swamp marginal field development, showcasing the relative importance of each criterion as judged by experts. The matrix is an essential component of the Analytical Hierarchy Process (AHP), designed to quantify and prioritize factors influencing decision-making in swamp terrain.

Table 5.5: Judgment Matrix for Criteria Weighting Swamp

Criteria	Cost	HSE	Regulation	Security	Stakeholders	Technology
Cost	1	1/2	1/3	1	1	2

HSE	2	1	1	1	2	2
Regulation	3	1	1	1	2	3
Security	1	1	1	1	2	2
Stakeholders	1	1/2	1/2	1/2	1	2
Technology	1/2	1/2	1/3	1/2	1/2	1

Table 5.6 provides a pairwise comparison of criteria for offshore marginal field development, capturing expert assessments of the relative importance of factors influencing decision-making in these technically challenging and capital-intensive terrains.

Table 5.6: Judgment Matrix for Criteria Weighting Offshore

Criteria	Cost	HSE	Regulation	Security	Stakeholders	Technology
Cost	1	1	1	2	2	1
HSE	1	1	1	3	4	1
Regulation	1	1	1	2	4	2
Security	1/2	1/3	1/2	1	1	1
Stakeholders	1/2	1/4	1/4	1	1	1
Technology	1	1	1/2	1	1	1

The normalization and weight derivation steps, as outlined in Sections 4.3.1 and 4.3.2, were meticulously applied to the aggregated judgment matrices (Tables 5.4 to 5.6) to ensure both accuracy and consistency. These steps facilitated the calculation of priority scores, which represent the relative importance of each criterion for onshore, swamp, and offshore terrains. The priority scores, derived using eigenvector analysis, are summarized in Tables 5.7 to 5.9. A consistency check was conducted for each terrain-specific judgment matrix. The Consistency Ratios for the onshore, swamp, and offshore matrices—0.013, 0.022, and 0.034, respectively—were all well below the acceptable threshold of 0.1, as recommended by Alonso and Lamata (2006) and Pauer et al. (2016). These low ratios confirm the reliability and consistency of the pairwise comparisons, reinforcing the credibility of the analytical process and its suitability for guiding decision-making in the context of marginal field development.

The terrain-specific weights were subsequently integrated into the hybrid AHP model. This integration accounted for the unique operational characteristics, environmental sensitivities, and logistical challenges inherent to each terrain, providing a customized framework for marginal field development decision-making.

Table 5.7: Normalised Matrix for Criteria Weighting Onshore

Criteria	Cost	HSE	Regulation	Security	Stakeholders	Technology	Priority Score
Cost	0.200	0.200	0.214	0.200	0.190	0.167	0.195
HSE	0.200	0.200	0.214	0.200	0.190	0.167	0.195
Regulation	0.200	0.200	0.214	0.200	0.286	0.250	0.225
Security	0.200	0.200	0.214	0.200	0.190	0.167	0.195
Stakeholders	0.100	0.100	0.071	0.100	0.095	0.167	0.106
Technology	0.100	0.100	0.071	0.100	0.048	0.083	0.084
						Total	1.000
Consistency Ratio: 0.013							

Table 5.7 presents the relative importance of each criterion for onshore marginal field development, derived from the pairwise comparisons in the judgment matrix. Regulation has the highest Priority Score of 0.225, indicating its dominant role in onshore marginal field development. This suggests that compliance with legal and regulatory requirements is crucial for onshore fields, possibly due to stricter enforcement of land use policies, environmental considerations, and operational standards onshore.

Cost, HSE (Health, Safety, and Environment), and Security each have identical Priority Scores of 0.195. This parity highlights their collective importance in onshore operations: Cost reflects the financial viability of onshore development, which benefits from lower infrastructure costs but may involve additional expenses related to land acquisition or remediation. HSE underscores the need to manage risks associated with human safety and environmental impact. Security is significant due to the susceptibility of onshore operations to vandalism, theft, or sabotage, particularly in sensitive regions as noted by Humphrey and Dosunmu (2017). Ensuring the highest HSE standards, cost control and security risk mitigation measures are of critical concern in onshore marginal field development.

Stakeholders have a Priority Score of 0.106, lower than the top three criteria but still notable. This reflects the necessity of engaging with local communities, governments, and other interest groups to secure social licenses for onshore field development. Technology is assigned the lowest Priority Score of 0.084, indicating it is less critical compared to other factors in onshore operations. This aligns with the generally lower technological complexity of onshore fields relative to swamp or offshore terrains a finding supported by Rui et al. (2018).

Table 5.8: Normalised Matrix for Criteria Weighting Swamp

Criteria	Cost	HSE	Regulation	Security	Stakeholders	Technology	Priority Score
Cost	0.118	0.111	0.080	0.200	0.118	0.167	0.132
HSE	0.235	0.222	0.240	0.200	0.235	0.167	0.217
Regulation	0.353	0.222	0.240	0.200	0.235	0.250	0.250
Security	0.118	0.222	0.240	0.200	0.235	0.167	0.197
Stakeholders	0.118	0.111	0.120	0.100	0.118	0.167	0.122
Technology	0.059	0.111	0.080	0.100	0.059	0.083	0.082
						Total	1.000
Consistency Ratio: 0.022							

The Normalized Matrix for Criteria Weighting (Table 5.6) for swamp marginal fields reflects the relative importance of key criteria derived from the judgment matrix. Regulation has the highest Priority Score of 0.250, indicating its significant influence in swamp field development. This is likely due to the sensitive nature of swamp environments, which require strict regulatory oversight to minimize ecological disruption and ensure sustainable operations. HSE is ranked second with a Priority Score of 0.217, emphasizing the importance of maintaining safety standards and mitigating environmental risks. Swamp fields often pose challenges such as unstable ground conditions and proximity to delicate ecosystems, making HSE a top priority.

Security has a Priority Score of 0.197, reflecting the risks associated with operating in swamp terrains. The prevalence of kidnapping and other security risks in creeks necessitates robust security arrangements. Typically, a three-boat system—comprising a lead, main operational, and chase boat—is deployed to ensure the safety of personnel and assets. This layered security approach is indispensable for maintaining operational continuity in the face of significant risks. Cost has a Priority Score of 0.132, ranking fourth. While cost considerations remain important, the challenges posed by environmental, regulatory, and security issues may take precedence in swamp terrains.

Stakeholders rank fifth with a Priority Score of 0.122. While engaging local communities and interest groups is still important, it carries slightly less weight compared to other criteria. Technology has the lowest Priority Score of 0.082, suggesting that while advancements in technology are valuable, they are not as critical as other factors in swamp field development. The existing technological solutions may be sufficient to address the challenges specific to swamp fields, reducing its relative importance.

Table 5.9: Normalised Matrix for Criteria Weighting Offshore

Criteria	Cost	HSE	Regulation	Security	Stakeholders	Technology	Priority Score
Cost	0.200	0.218	0.235	0.200	0.154	0.143	0.192
HSE	0.200	0.218	0.235	0.300	0.308	0.143	0.234
Regulation	0.200	0.218	0.235	0.200	0.308	0.286	0.241
Security	0.100	0.073	0.118	0.100	0.077	0.143	0.102
Stakeholders	0.100	0.055	0.059	0.100	0.077	0.143	0.089
Technology	0.200	0.218	0.118	0.100	0.077	0.143	0.143
						Total	1.000
Consistency Ratio: 0.034							

The normalized matrix for offshore (Table 5.7) marginal fields represents the relative importance of six criteria based on their weighted contributions to the development of offshore fields. Regulation has the highest priority score of 0.241, reflecting the stringent regulatory requirements associated with offshore operations. The complex nature of offshore activities often demands higher compliance standards, including environmental protection and operational safety. HSE ranks second with a Priority Score of 0.234, underscoring its importance in offshore operations. Offshore fields face unique challenges such as extreme weather, deep-water conditions, and high environmental sensitivity, necessitating a strong focus on safety and environmental management.

Cost ranks third with a Priority Score of 0.192, indicating its critical role in offshore field development. Offshore fields are capital-intensive, with high exploration, drilling, and production costs. Managing costs efficiently is essential for economic viability. Technology has a Priority Score of 0.143, highlighting its role in addressing technical challenges in offshore environments. Advanced technological solutions are crucial for deep-water drilling, subsea production systems, and remote operations, although they are not the primary focus compared to HSE and Regulation. Security scores 0.102, reflecting a relatively lower priority compared to other criteria. Offshore operations are generally less prone to security threats such as vandalism and theft compared to onshore or swamp fields, though piracy and sabotage may still be concerns.

Stakeholders have the lowest Priority Score of 0.089, suggesting that stakeholder concerns are less critical in offshore operations. Offshore fields are often geographically isolated, reducing direct interactions with local communities, which diminishes stakeholder influence.

5.3.3 Comparison of Criteria across Terrain

The criteria compared across the three terrains onshore, swamp and shallow offshore is summarised in Figure 5.3. Regulation emerged as the most critical criterion across all terrain, it has the highest priority score across all terrains; onshore (0.225), swamp (0.250) and offshore (0.241) indicating the stringent compliance requirements in the Nigerian oil and gas sector. Cost was significant for onshore and offshore fields, indicating the emphasis on economic feasibility. HSE and Security were particularly important for swamp and offshore fields due to the higher environmental and operational risks associated with these environments.

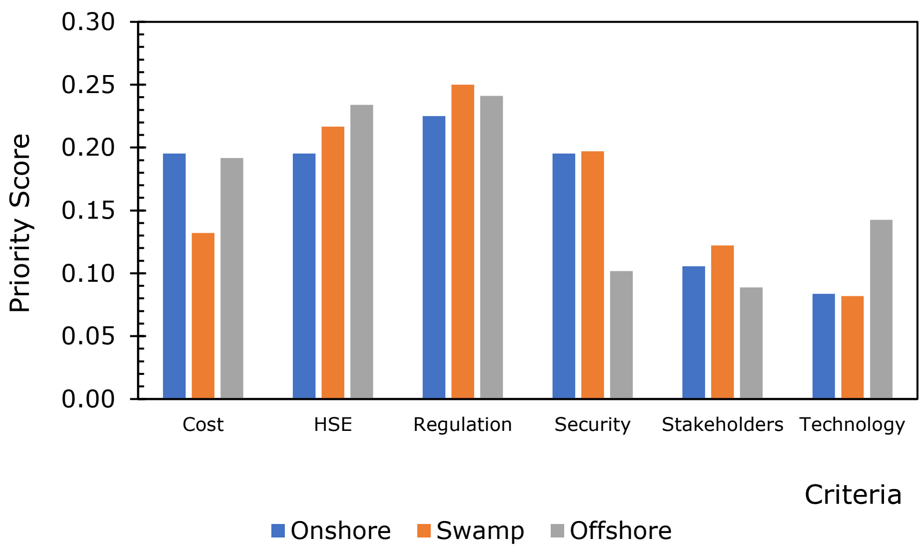


Figure 5.3: Comparison of Priority Score across onshore, swamp and offshore

Regulation emerged as the most critical criterion across all terrains, with the highest importance surprisingly observed in swamp terrains, followed by offshore. This underscores the significant role regulatory compliance plays in ensuring sustainable and efficient development, especially in sensitive swamp environments. Health, Safety, and Environmental (HSE) considerations were found to be most critical offshore, where the potential for catastrophic incidents is significantly higher, while they were least critical onshore, where HSE challenges are generally easier to manage. Moreover, meeting regulatory requirements, including local content policies, has the potential to significantly accelerate economic growth and promote sustainable development in oil-producing nations. This approach has proven successful in countries such as Norway and Algeria, where robust regulatory frameworks and sustainability-focused practices have contributed to long-term industry growth and national development as noted by Asiago (2017).

Security concerns, on the other hand, were negligible offshore but critically important in onshore and swamp terrains, which are highly vulnerable to militancy and vandalism. Onshore fields exhibit a higher priority for cost considerations compared to swamp fields, with offshore fields ranking the highest in cost significance. This trend reflects the substantial cost disparity across terrains, as offshore fields demand significant investments in advanced technology, specialized infrastructure, and complex operational setups. In contrast, onshore fields are relatively more cost-efficient due to their accessibility and less demanding technological requirements. Swamp fields, positioned as intermediate in terms of cost, highlight the unique challenges associated with wetland terrains, such as logistical constraints and environmental sensitivities, which drive up costs but not to the extent observed in offshore developments. These findings underscore the critical role of cost-efficiency strategies tailored to terrain-specific demands in optimizing marginal field development.

Swamp fields exhibit the highest priority for stakeholder involvement, primarily due to their proximity to local communities and the associated land use, environmental, and socio-economic concerns. This underscores the importance of engaging stakeholders to address potential conflicts, ensure community support, and mitigate environmental impacts. Onshore fields rank moderately in stakeholder involvement, reflecting their accessibility to communities but with fewer complexities compared to swamp terrains. Offshore fields, on the other hand, rank lowest in this criterion, as their remote location minimizes direct community interactions, reducing the immediate need for extensive stakeholder engagement. This variation highlights the terrain-specific dynamics of stakeholder priorities in marginal field development.

In the context of the technology criterion, Offshore fields rank highest, reflecting the advanced technological requirements for exploration and production in marine environments, where operations are often complicated by deep water and harsh conditions—a finding corroborated by Valkenier (2016). Swamp fields follow, requiring specialized equipment to address the unique challenges posed by wetland terrains, such as limited accessibility and environmental sensitivities. Onshore fields rank lowest, as their development is relatively straightforward and demands less sophisticated technology. This prioritization highlights the terrain-specific technological demands, with Offshore fields necessitating cutting-edge innovations, Swamp fields requiring moderate specialization, and Onshore fields benefiting from simpler development processes.

A comparison between the Hybrid AHP model and the traditional approach employed by operators of successful marginal field developments revealed that the traditional approach prioritised cost in the development strategy employed. The Hybrid AHP model systematically prioritized regulation and health, safety, and environment (HSE) as the most important criteria across all terrains, with security ranked as the third most critical factor for onshore and swamp fields, and cost ranking third for offshore fields. This reflects the operational and regulatory demands specific to each terrain. The structured pairwise comparison inherent in the AHP model ensures a mathematically consistent and unbiased evaluation of factors, offering a quantitative and objective approach to identifying terrain-specific priorities. The model's transparency and consistency are particularly valuable in balancing competing priorities and integrating both qualitative and quantitative factors.

Also, because of the involvement of subject matter experts the practical realities faced by marginal field operators, such as financial constraints, stakeholder engagement challenges, and security risks that are prevalent in Nigeria’s oil and gas sector are reflected. This method benefits from decision-makers’ field experience, which provides nuanced insights into socio-political and community-related factors that are often challenging to quantify in a structured model. These underscores the value of the Hybrid AHP model as an important tool for optimizing marginal field development. The AHP model provides an objective and systematic framework for decision-making, and also captures the experiential knowledge and contextual nuances critical to successful field development.

This prioritization indicates that marginal field development strategies must be tailored to the unique characteristics of each field type Onshore fields demand cost-effective solutions with moderate attention to HSE and stakeholder concerns. Swamp fields require balanced approaches focusing on HSE, stakeholder engagement, and regulatory compliance. Offshore fields necessitate significant investment in technology, safety measures, and regulatory adherence due to their complexity and operational risks. Understanding these priorities helps operators allocate resources effectively, mitigate risks, and select field development strategies that maximize economic and operational efficiency while addressing the unique challenges of each marginal field type.

5.3.4 Rating of Decision Criteria

Based on the detailed analysis of marginal field development in Nigeria and incorporating subject matter experts' (SMEs) judgment, a scoring system was developed to evaluate the performance of alternatives against identified criteria (Table 5.10). Scores were assigned using a three-point scale to represent performance levels:

- 1 indicates the best performance, signifying optimal alignment with the criteria.
- 2 represents moderate performance, reflecting partial alignment or average results.
- 3 signifies the worst performance, indicating significant challenges or misalignment with the criteria.

This scoring framework was designed to convert qualitative evaluations into numerical data, enabling a standardized and systematic comparison of alternatives. By quantifying subjective judgments, the scoring approach ensures that diverse factors, such as regulatory compliance, HSE considerations, and stakeholder engagement, are objectively assessed.

The scores serve as critical inputs for the Hybrid Analytical Hierarchy Process (AHP) model. Within the model, these scores are weighted based on the relative importance of each criterion, as derived from pairwise comparisons and eigenvector analysis. This weighted scoring system enables comprehensive and transparent decision-making by prioritizing alternatives that offer the best overall performance while addressing the specific challenges and opportunities of marginal field development in Nigeria.

Table 5.10: Criteria Scores for Rating Development Options

S/No	**Criteria**	**Class**	**Rating**
1.	Cost in UTC $/bbl	To be calculated	Not applicable (Quantitative)
2.	HSE	Low	1
		Medium	2
		High	3
3.	Regulation	Low Requirement - Defer approvals and permitting	1
		Medium - Meet certain requirements	2
		Full Requirement - Zero waivers	3
4.	Security	Low	1
		Medium	2
		High	3
5.	Stakeholders	Low	1
		Medium	2
		High	3

6.	Technology	Low complexity	1
		Medium complexity	2
		High complexity	3

Table 5.10 summarises the scoring of criteria to enable proper rating to evaluate the performance of development options. The descriptions of the 3-Scale rating are enumerated as follows.

Description of HSE Criteria Rating

Low (1): the development option has low HSE risks. The development option demonstrates a strong commitment to HSE, with well-implemented measures that significantly reduce risks. It aligns closely with industry best practices, ensuring a safe working environment and effective environmental protection. There is a proactive approach to continuous improvement in HSE performance. Minimal environmental impact, low risk of regulatory or community opposition.

Medium (2): the development option has medium HSE risk. The development option meets industry-standard HSE requirements, providing an acceptable level of safety and environmental protection. While there may be some areas for improvement, the HSE measures in place are generally effective in managing risks and ensuring compliance. Moderate environmental impact, manageable with mitigation measures.

High (3): the development option has high HSE risk. The development option has some basic HSE measures in place, but they are insufficient to fully mitigate risks. There are noticeable gaps in safety protocols, environmental protection practices, and regulatory adherence, leading to moderate risks to health, safety, and the environment. Significant environmental impact, potential for regulatory hurdles and community opposition.

Description of Regulation Criteria Rating

Low (1): Reflects a scenario where approvals and permitting are readily granted, and regulatory compliance does not serve as a barrier. This level of regulatory support facilitates a more flexible approach, allowing for the deferral of certain permitting processes without jeopardizing the overall development.

Medium (2): Implies adherence to specific requirements set by regulators, necessitating compliance with identified standards. While this level recognizes the need for compliance, it does not preclude the possibility of negotiating or seeking waivers for certain specified conditions.

High (3): Adherence strictly to the stipulations of the law without seeking or obtaining waivers. This level is characterized by zero waivers. It serves as a significant disincentive, as it entails a rigid adherence to all regulatory requirements without any allowances.

Description of Security Criteria

Low (1): Minimal security risk; the field is located in a stable and secure area with low crime rates. There are no significant threats of theft, sabotage, or vandalism. The local community is supportive of the project, and there is minimal need for security personnel or measures.

Medium (2): Moderate security risk; the field is in an area that experiences occasional security threats. There might be periodic community protests, theft, or vandalism, and there is a need for moderate security measures, such as hiring security personnel and deploying CCTV cameras.

High (3): High security risk; the field is in a region prone to frequent security challenges, such as militant activity, organized theft, or community unrest. Comprehensive security arrangements are necessary, including armed security personnel, barriers, and real-time monitoring.

Description of Stakeholders Criteria Rating

Low (1): High level of stakeholder support and engagement. Most stakeholders, including local communities, government agencies, and investors, are actively involved and supportive of the project. There are strong partnerships, and any concerns are quickly addressed through effective communication and collaboration.

Medium (2): Moderate level of stakeholder support and engagement. The majority of stakeholders are reasonably satisfied, but there are still some issues or concerns that need to be addressed. There is general cooperation, but there may be occasional conflicts or misunderstandings.

High (3): Minimal stakeholder support or engagement. There is significant opposition or dissatisfaction from key stakeholders, such as local communities, government authorities, or investors. The project faces potential delays, protests, or legal challenges due to unresolved stakeholder concerns.

Description of Technology Criteria Rating

Low Complexity (1): The basic technology is generally suitable for the marginal field and provides an acceptable level of performance. While there are some limitations, these can be managed without significantly impacting project outcomes. The technology meets most project needs and offers a reasonable balance between cost and effectiveness.

Medium Complexity (2): additional advanced technology, additional modules. The technology is well-suited to the specific needs of the marginal field, offering high performance, reliability, and efficiency. It enhances project outcomes, reduces operational risks, and is cost-effective. The technology is also flexible and can adapt to changes in field conditions.

High Complexity (3): digital technology. The technology is state-of-the-art and highly optimized for the marginal field, providing exceptional performance and reliability. It maximizes production, minimizes risks, and offers significant long-term benefits. The technology is highly adaptable, scalable, and future-proof, ensuring sustained success and competitiveness.

These scores reflect a comprehensive evaluation approach, where each alternative's suitability for marginal field development in Nigeria can be assessed against critical success factors. This scoring would then be used in the Analytical Hierarchy Process (AHP) model to determine the optimal development strategy.

5.4 Application of Model to Case Study Field

The practical application of the developed hybrid AHP model was validated using a representative case study. An offshore field was chosen for this purpose due to the prevalent challenges associated with offshore development. Notably, a significant number of offshore fields remain undeveloped, highlighting the need for robust decision-making tools to address their unique complexities and drive economic viability.

5.4.1 Case Study Field Description

The Ekeh field was used as a case study to demonstrate the use of the Hybrid AHP model (Figure 5.4). The Ekeh field was discovered in 1986 by Chevron with one exploratory well Ekeh-1 a second well Ekeh-2H an appraisal well has also been drilled. The Ekeh Field contains some 55 to 110 MMstbbl of oil in place plus 32 to 42 Bcf gas in place, distributed amongst a series of stacked reservoir. The data obtained from farmor comprised details of licence interests, seismic and well data, technical interpretations, reports and presentations.

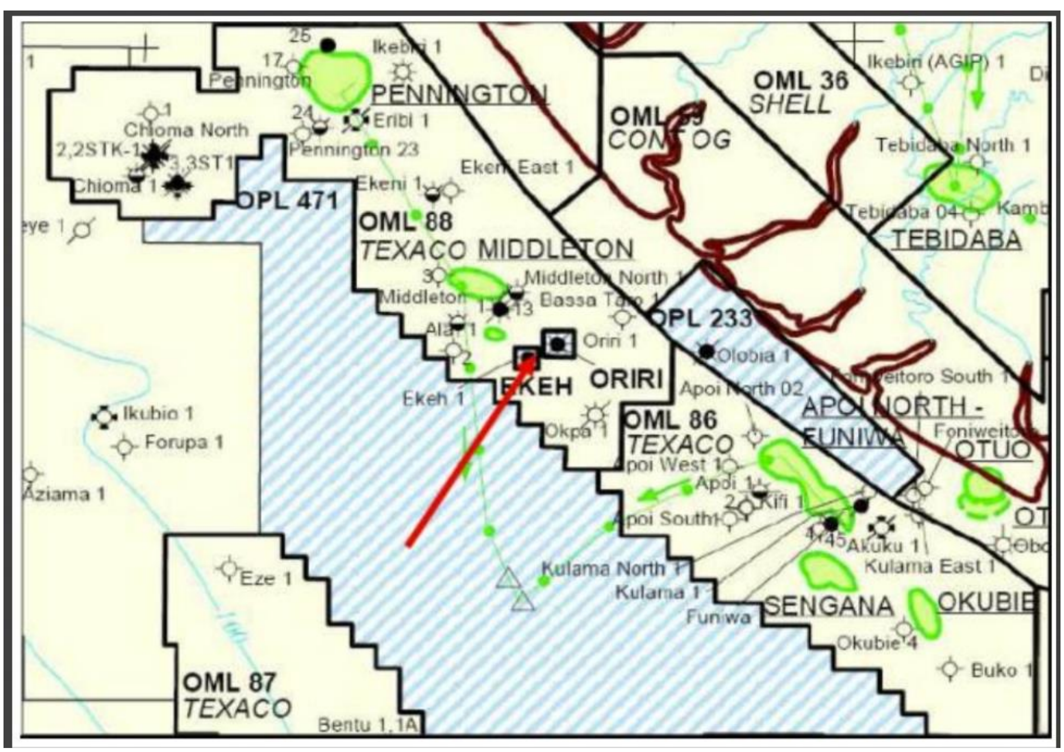


Figure 5.4: Location Map for Ekeh Field offshore Nigeria (http://www.movidoeandp.com/ekehcpr.pdf)

5.4.2 Defining the Decision Problem for Ekeh Field

The screening model developed in section 3.5 was used to identify the possible development options for the case study field. Based on field details shown in Table 5.11 all data have been gathered, based on the obtained data and their assessment the existing wells can be re-entered. More than one reservoir has been identified and analogue data suggests a strong aquifer support therefore wells will be dual completed as deviated. All identified development options for Niger Delta marginal fields apply as possible options for Ekeh field; A1, A2, A3 and A4.

Table 5.11: Outcome of Concept Screening of Ekeh Field Development

Element	**Features**
Field Acquisition	Company: Movido E&P Limited, 100% participatory interest Field/Location: Ekeh, PML 88, Shallow Offshore (Figure 5.2)
Data Gathering	Details of licence interests, seismic and well data, technical interpretations, reports and presentations, Ekeh Farm-in Agreement, Regulatory Permit Register Partners Farm- in agreement with MRI for 40% equity interest, Middleton Production Platform lease, 3rd party FSO for crude evacuation, MOU with host communities Nearby Facilities and Fields Middleton 7 Km with spare capacity, Oriri Field (2.70 MMbbls) 2 km away and Atala Field (21.30 MMbbls) 35 km
Pre-Assessment	Structure: Medium complexity based on 2D data Reserves: 23.48 MMbbls Identified Reservoirs: Iku-3, Iku-6 and Ewinti2.1. Reservoir properties: Medium complexity Porosities 25-30%, Permeability 512-1990mD, Oil viscosity/gravity ~ 0.3cp/38 API (Light crude) Aquifer support: Assumed medium to strong possibly strong aquifer support known from observing nearby analogues.

	Physical integrity and usability of the Middleton Production Platform, wells and export system for production processing, gas disposal and oil export confirmed. Field Potential Evaluation Production rate: 3,500 bopd Number of wells: 3-7 Recovery Factor: 45
Can existing wells be re-entered?	Yes. Physical integrity and usability of the wells and export system for production processing, gas disposal and oil export confirmed.
Completion option?	Based on field characteristics, wells will be dual completion on natural flow with gas mandrels installed for reservoir management.
Processing option?	Tie-back to Middleton platform Reserves enough to justify a Mobile Offshore Production Unit Available cluster groups to jointly install a Central Processing Facility
Crude Export Options?	Middleton platform established means of transporting crude. Via subsea pipeline to 17 km 18” pipeline Eremor flow station Via barge to Ima. Ekeh, Atala, Oriri blend evacuated via a barge to Ima.

5.4.3 Development Options for Ekeh Field

The outcome of the screening based on the reserves and availability of existing facility and possible cluster groups, is that all options A1, A2,A3, and A4 apply. The decision makers need to determine the best development option for the case study field.

Note:

Development Strategy: A phased development approach will be adopted for all options. This strategy allows for incremental expansion and reduces upfront financial risks while enabling continuous appraisal and production optimization.

- Initial Development: 2 oil wells re-entered in the first phase. Re-entry of wells saves up to 50% of drilling costs compared to new wells at $11m.
- Second Phase: An additional 2 oil wells will be drilled to enhance recovery and production at $22.
- All wells will have 3-1/2" dual string inside 9-5/8" production casing dual zone completion to maximize drainage from multiple reservoirs per well, increasing efficiency and cost-effectiveness. All wells will be completed with gas lift mandrel for reservoir management. All wells will be equipped with surface controlled sub-surface safety valves SCSSVs) and top permanent hydraulic set packers in line with the NUPRC regulatory completion policies.
- Pipeline cost at $3m/km, manifold etc $5m, MOPU rental at $40,000/day

Option A1

Tie-in to the Middleton existing production system, located 7 km away. Leveraging nearby infrastructure minimizes CAPEX and accelerates the production timeline.

Option 2

Deployment of an Early Production Facility (EPF) using a Mobile Offshore Production Unit (MOPU) to facilitate early production and revenue generation. Installation of a 17 km subsea pipeline for crude oil export to the nearest terminal, ensuring secure and reliable transportation.

Option A3

Deployment of an Early Production Facility (EPF) on a Mobile Offshore Production Unit (MOPU) to enable rapid production start-up and phased development.

Export of crude oil via barge transportation to the Ima FSO terminal for storage and subsequent transfer to offtake vessels.

Option A4

Combine resources with Oriri Field (2.70 MMB) located 2 km away and Atala Field (21.30 MMB) located 35 km away. Establish a Central Processing Facility (CPF) to process production from all three fields, achieving economies of scale and centralized management of operations. Crude oil will be exported via barge transportation to the designated terminal, mitigating dependency on pipelines.

5.4.4 Hierarchy Structure for Ekeh Field

The hierarchy structure Ekeh field was developed as shown in Figure 5.5. The goal at the top level is to select an optimal field development option. The criteria to guide the selection is as established in section 5.4.1.3 for offshore fields on the second level. The identified development options A1, A2, A3, and A4 at the bottom level.

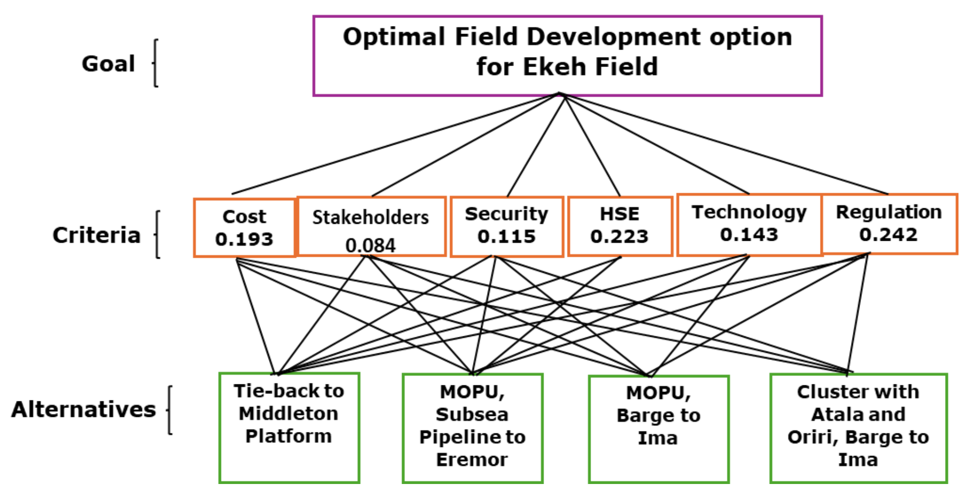


Figure 5.5: Ekeh Field Development Hierarchical Structure

5.4.5 Performance of Identified Development Options against Identified Criteria

Using the rating of criteria in section 4.4.2, the details of the assessment of the performance of the identified alternatives (A1, A2, A3, A4) against the identified criteria (Cost, HSE, Regulations, Security, Stakeholders and Technology), below is the explanation of the comparison of alternatives with respect to each criteria and summarized in Table 5.7.

Unit Technical Costs of the Alternatives

The unit technical cost of the alternatives was calculated based on equation 4.5. The UTC for the investments alternatives A1, A2, A3, and A4 for Ekeh were found to be 30.3 $/bbl, 37.7$/bbl, 35.7$/bbl, and 33.2$/bbl respectively.

The unit technical cost (UTC) for the Ekeh field investment alternatives was determined using Equation 4.5. The calculated UTC values for the investment alternatives A1, A2, A3, and A4 were 30.3 $/bbl, 37.7 $/bbl, 35.7 $/bbl, and 33.2 $/bbl, respectively. These values provide a comparative assessment of the economic feasibility of each development option, offering insights into cost efficiency and financial viability in marginal field development.

In terms of cost-effectiveness, Alternative A1 emerges as the most economically viable option. This alternative benefits from lower initial capital investment due to the sharing of existing facilities, which significantly reduces the overall development expenditure. The primary cost driver for Alternative A1 is the construction of a 7 km pipeline to Middleton, but even with this, it remains the most cost-efficient option.

In contrast, Alternatives A3 and A4 incur higher capital and operational expenditures (CAPEX and OPEX), primarily due to the utilization of Mobile Offshore Production Units (MOPU). The additional infrastructure and technological requirements associated with MOPU lead to increased costs for both construction and ongoing operations.

Alternative A2 presents the highest cost among the evaluated options, primarily due to the combined use of a MOPU and the construction of a 17 km subsea pipeline to Eremor. This dual requirement significantly raises the initial CAPEX, making it the least cost-effective choice in terms of development strategy.

Alternatives compared with respect to Health, Safety, and Environmental (HSE)

The evaluation of Health, Safety, and Environmental (HSE) risks across the development alternatives reveals significant differences in potential impacts. Alternative A1 demonstrates a lower HSE risk profile, primarily due to its reliance on fewer wells, the application of established technologies, and the utilization of existing facilities. These factors contribute to minimizing environmental disturbances and reducing the complexity of health and safety management during operations. The integration of existing infrastructure inherently limits the scope of new construction and operational activities, thereby mitigating environmental footprint and associated HSE concerns.

On the other hand, Alternatives A2, A3, and A4 exhibit higher HSE risks. These alternatives involve the deployment of Mobile Offshore Production Units (MOPU) and Central Processing Facilities (CPF), which introduce additional complexities in both operational safety and environmental management. The increased infrastructure requirements and the introduction of new technologies increases the potential for safety incidents and environmental degradation. Consequently, the risk profile for these alternatives reflects a greater need for comprehensive HSE management strategies to address the expanded operational scope.

Alternatives compared with respect to Regulation

Alternative A1 presents the lowest regulatory requirements, as it primarily involves obtaining drilling and pipeline permits. The local content requirements are minimal, with most compliance responsibilities being passed on to the host operator. This simplified regulatory process makes Alternative A1 more streamlined and less bureaucratically intensive, allowing for quicker project initiation and reduced administrative overhead. Also it promotes common usage of assets/facilities to ensure utilization of available capacities as enshrined in the marginal fields guideline (DPR 2020).

For Alternative A2, the regulatory requirements are classified as medium. In addition to the standard drilling permits, this option requires further permits and approvals for the use of the Mobile Offshore Production Unit (MOPU) and the construction of a subsea pipeline to an onshore terminal. The involvement of MOPU introduces additional regulatory layers, but they remain manageable.

Similarly, Alternative A3 involves medium regulatory requirements, as it necessitates drilling permits, approvals for the use of a MOPU, and an export permit for the Floating Storage Offloading (FSO) unit. These additional regulatory steps introduce moderate complexity but are necessary to ensure compliance with industry standards for offshore operations.

Alternative A4 also requires a medium level of regulatory compliance. In this scenario, drilling permits, approvals for the use of a Central Processing Facility (CPF), and pipeline permits are needed. Furthermore, an export permit for the FSO is required. The regulatory burden is shared among operators, which could alleviate some of the compliance workload, but the overall process still demands thorough coordination and adherence to multiple regulatory frameworks.

Alternatives compared with respect to Security

Alternative A1 presents a high security risk, primarily due to threats from militants and the risk of oil bunkering. While there are no significant issues with host community relations, the external threats from illegal activities and regional instability pose substantial risks to operations. These risks could lead to disruptions in production, potential damage to infrastructure, and increased costs for security measures.

For Alternative A2, the security risks are rated as medium. Similar to A1, there are no significant host community concerns; however, the presence of militants and risks of bunkering remain a challenge. Although these risks are lower than in A1, they still require attention and mitigation strategies, including enhanced surveillance and security patrols.

In contrast, Alternatives A3 and A4 present lower security risks. This reduced risk is attributed to the use of barges for transporting production rather than pipelines, which minimizes the vulnerability to bunkering and militant activity. The barge transportation system provides greater flexibility and reduces the infrastructure's exposure to external attacks, resulting in a more secure and controlled environment for production operations.

Alternatives compared with respect to Stakeholders

Alternative A1 may be less favourable to stakeholders because it involves fewer wells, which limits both revenue generation and employment opportunities for the local population. The smaller scale of operations may reduce the overall economic benefits, making this option less attractive from a stakeholder engagement perspective.

Alternative A2 is more favourable to stakeholders as it involves a moderate number of wells and the use of a Mobile Offshore Production Unit (MOPU), creating more employment opportunities and engagement prospects, despite fewer stakeholders to involve. However, the use of MOPU might introduce some environmental concerns, although these are offset by the operational benefits.

Alternative A3 is likely to be more favourable to stakeholders due to the increased number of wells, which can enhance revenue generation and employment prospects. The use of a MOPU and Floating Storage and Offloading (FSO) unit, however, poses potential environmental challenges, which could impact stakeholder perception negatively. Although the economic benefits are higher, the environmental risks could lead to concerns from certain stakeholder groups.

Alternative A4 may be the most favourable to stakeholders as it involves a greater number of wells, promising increased revenue and job creation. The environmental impact is minimized through the use of a central processing facility (CPF) and joint export systems, which streamline operations and reduce potential risks. This balance of economic benefits and environmental protection makes A4 highly attractive to a broad range of stakeholders.

Alternatives compared with respect to Technology

Alternative A1 involves the use of tie-back technologies, which are characterized by low complexity. These technologies are well-established and straightforward, offering an efficient solution that enhances operational performance while reducing costs. This simplicity makes A1 an attractive option from a technical perspective, as it minimizes the potential for operational challenges and delays.

Alternative A2, on the other hand, is rated as highly complex due to the combined use of a Mobile Offshore Production Unit (MOPU) and a subsea pipeline. The integration of these technologies introduces significant technical challenges, requiring specialized expertise and higher capital expenditure, making this option more complex to implement and manage.

Alternative A3 presents a medium level of complexity, largely due to the use of a MOPU in conjunction with a Floating Storage and Offloading (FSO) unit. While these technologies are more complex than tie-backs, their use is not as challenging as a subsea pipeline, positioning A3 as a moderately complex development option.

Alternative A4, although involving clustering and the use of a Central Processing Facility (CPF), is rated as medium complexity for individual operators. The CPF helps centralize operations, which reduces some operational burdens, but the overall system still requires careful coordination, especially in terms of shared infrastructure and compliance with operational standards.

Table 5.12: Decision Matrix for Ekeh Field Development

	Option A1	Option A2	Option A3	Option A4
Project Cost	$30.3/bbl	$37.7/bbl	$35.7/bbl	$33.2/bbl
HSE	The HSE risks associated with this development strategy would be low. since it involves few wells, use of established technology and existing facilities environmental impact is low.	The HSE risks associated with this development strategy would be medium since it involves few wells, use of established technology and MOPU. Environmental impact will also be low.	The HSE risks associated with this development strategy would be high because of the FSO which can have a negative environmental impact. Use of few wells, use of established technology and MOPU has less HSE risk.	The HSE risks associated with this development strategy is medium since it involves few wells, use of established technology and CPF. Environmental impact will also be low.
Legal Regulations	The regulatory requirements for this development strategy would be low, as only drilling and pipeline permits are required. Local content requirement is few with most passed on to host operator.	The regulatory requirements for this development strategy would be medium in addition to drilling permits there are also permits and approvals for use of MOPU and pipeline to onshore terminal.	The regulatory requirements for this development strategy would be medium in addition to drilling permits there are also permits and approvals for use of MOPU and export permit for FSO.	The regulatory requirements for this development strategy would be medium in addition to drilling permits there are also permits and approvals for use of CPF, pipeline and export permit for FSO. Compliance shared amongst operators
Security	The security risks associated with this development strategy would be medium, no host community issues but	The security risks associated with this development strategy would be medium, no host community issues	The security risks associated with this development strategy would be medium, no host community issues	The security risks associated with this development strategy would be medium, no host community issues

	militants and bunkering risks.	but militants and bunkering risks.	but militants and bunkering risks.	but militants and bunkering risks.
Stakeholders	This development strategy may be less favorable to stakeholders since it involves few wells, therefore less revenue and employment opportunities.	More favorable to stakeholders, slightly less stakeholders to engage, more employment opportunities because of use of MOPU	This development strategy may be more favorable to stakeholders since it involves more wells, which can increase revenue and employment opportunities. However, the use of MOPU and FSO for production can still have a negative impact on the environment.	This development strategy may be more favorable to stakeholders since it involves more wells, which can increase revenue and employment opportunities. Environmental impact is minimal due to use of a central facility and joint export.
Technology	The use tie-backs are low complexity technologies that can improve efficiency and reduce costs.	This development strategy has high complexity because of the use of MOPU and subsea pipeline	This development strategy has medium complexity because of the use of MOPU and FSO subsea pipeline	This strategy even though has clustering and CPF is rated medium complexity for individual operators.

5.4.6 Decision Matrix for Case Study Field

This performance evaluation was used to construct the decision matrix for Ekeh Field (Table 5.8) to systematically compare options and select the most suitable alternative based on their performance across identified criteria. The provided decision matrix compares four alternatives (A1, A2, A3, A4) against six decision criteria.

Table 5.13: Decision Matrix for Ekeh Field Development

	Cost	HSE	Regulation	Security	Stakeholders	Technology
A1	$30.3/bbl	2	1	3	1	2
A2	$37.7/bbl	3	3	2	2	3
A3	$35.7/bbl	3	3	1	2	3
A4	$33.2/bbl	3	2	1	3	3

To ensures that all criteria and scores are expressed on a common scale, allowing for fair comparisons across alternatives the decision matrix is normalised as shown in Table 5.9 for calculating the priority score of the decision. For example, comparing a high-cost metric against a low HSE score becomes possible.

Table 5.14: Normalised Matrix for Ekeh Decision Matrix

	Cost	HSE	Regulation	Security	Stakeholders	Technology
A1	1.000	1.000	1.000	0.333	1.000	1.000
A2	0.804	0.667	0.333	0.500	0.500	0.667
A3	0.849	0.667	0.333	1.000	0.500	0.667
A4	0.913	0.667	0.500	1.000	0.333	0.667

1. Cost: A1 has the highest cost score (1.000), indicating it is the most cost-effective option among all. A4 follows with a score of 0.913, which suggests that while A4 is competitive, A1 still outperforms in cost. A3 has a score of 0.849, making it relatively close to A4 but less cost-efficient. A2 has the lowest cost score (0.804), meaning it is the least cost-effective option. Cost is often a dominant criterion in field development decisions, and A1's top ranking in cost contributes significantly to its overall priority score.

2. HSE (Health, Safety, Environment): A1 achieves a perfect score (1.000), meaning it meets the highest standards for HSE. A2, A3, and A4 all score 0.667, indicating they are moderate performers in HSE but do not match A1's level. A1's excellent performance in HSE further strengthens its position as the top alternative. This criterion is critical, particularly in the oil and gas industry, where safety and environmental compliance are paramount.

3. Regulation: A1 again leads with a perfect score of 1.000, indicating full compliance with regulatory requirements. A4 scores 0.500, performing better than the remaining alternatives but still lagging behind A1. A2 and A3 share the lowest score (0.333), indicating these options face significant challenges in meeting regulatory standards. Regulatory compliance is a deal-breaker in marginal field development, and A1's strong performance gives it a competitive edge. A2 and A3 may require additional investments or modifications to meet regulatory standards.

4. Security: A3 and A4 both score 1.000, indicating they provide the highest security, making them favourable in this regard. A2 scores 0.500, indicating moderate security performance. A1 has the lowest score (0.333) for security, which is a noticeable drawback. Security is a critical factor in the Niger Delta region due to issues like vandalism, theft, and unrest. While A1 excels in most criteria, its security score is a weakness that decision-makers must carefully address.

5. Stakeholders: A1 again leads with a perfect score of 1.000, indicating it is the most favourable option for stakeholders. A2 and A3 share a moderate score of 0.500. A4 has the lowest score (0.333), suggesting that it may face challenges in gaining stakeholder support. Stakeholder alignment is crucial for project success. A1's high score reflects its ability to meet stakeholder expectations, while A4 might face resistance or delays due to lower stakeholder buy-in.

6. Technology: A1 achieves a perfect score of 1.000, indicating it employs the most effective and advanced technology. A2, A3, and A4 all score 0.667, meaning they offer moderate technological solutions but fall short of A1.

Technological advancements can improve efficiency, reduce operational costs, and enhance productivity. A1's superior technology reinforces its overall ranking.

5.4.7 Aggregation of Results and Ranking of Development Options for the Case Study

In this final stage of the AHP Analysis, the obtained criteria scores for offshore from section presented in Table 5.3 is combined with the normalised weights to obtain the weighted scores for each option (Table 5.10). the weighted scores were aggregated to derive overall priority scores. The overall priorities indicate the relative significance of each alternative. Furthermore, it provides the overall priorities, indicating the relative significance of each alternative. All alternative priorities obtained are combined as a weighted sum—to take into account the weight of each criterion—to establish the overall priorities of the alternatives. The alternative with the highest overall priority constitutes the best choice.

Table 5.15: Aggregation of Results and Ranking of Development Options

Criteria	**Cost**	**HSE**	**Regulation**	**Security**	**Stakeholders**	**Technology**	
Priority Score	0.193	0.223	0.242	0.115	0.084	0.143	
Options				**MMULT**			**Aggregated Scores**
A1	1.000	1.000	1.000	0.333	1.000	1.000	0.912
A2	0.804	0.667	0.333	0.500	0.500	0.667	0.579
A3	0.849	0.667	0.333	1.000	0.500	0.667	0.654
A4	0.913	0.667	0.500	1.000	0.333	0.667	0.693

$$Weighted\ Score_{ij} = Normalized\ Score_{ij} * Weight_j$$

$$Overall\ Priority\ Score_i = \sum_{j=i}^{n} \left(Normalized\ Score_{ij} * Weight_j\right)$$

Note: Overall scores are calculated based on the weighted sum of individual criteria scores.

Figure 5.6 illustrates the overall priority scores assigned to the identified development options for Ekeh Field (A1, A2, A3, and A4) based on the developed Hybrid AHP Decision Model. The "Overall Priority Score" on the y-axis represents the aggregated evaluation of each alternative considering multiple factors such as cost, HSE (Health, Safety, and Environment), regulatory requirements, security, stakeholder engagement, and technological complexity. The x-axis lists the four alternatives (A1, A2, A3, and A4).

1. **Alternative A1 (0.912)** has the highest priority score, due to strong performance in cost, HSE, Regulation, stakeholders and technology. This suggests that A1 is considered the most favourable investment option. As previously discussed, A1 involves the use of tie-back technology, which is a low-complexity, cost-effective solution with minimal environmental risks. Its low regulatory requirements and the use of established infrastructure likely contribute to its high ranking.

2. **Alternative A4 (0.693)** emerges as the second best option, with strong performance in cost and security and moderate scores in HSE and technology. Its cluster development approach provides additional scalability benefits. It could be a viable alternative if stakeholder engagement and regulatory compliance issues are addressed.

3. **Alternatives A3 (654)** exhibit relatively similar scores, both slightly below 0.7. While A3 has a medium level of complexity due to the use of MOPU and an FSO (Floating Storage and Offloading unit), it still ranks lower than A1 due to higher costs and operational risks. A4 also ranks similarly due to the use of clustering and a Central Processing Facility (CPF), offering a middle ground between complexity and flexibility for individual operators.

4. **Alternative A2 (0.579)** has the lowest priority score. This lower ranking reflects its higher complexity and cost due to the combined use of a Mobile Offshore Production Unit (MOPU) and subsea pipelines, which increase the operational risks and regulatory hurdles. Additionally, the extended pipeline construction (17 km) contributes to its lower score. While A2

employs dual-zone completion and an Early Production Facility (EPF), its higher cost (e.g., subsea pipeline installation) have negatively impacted its overall score.

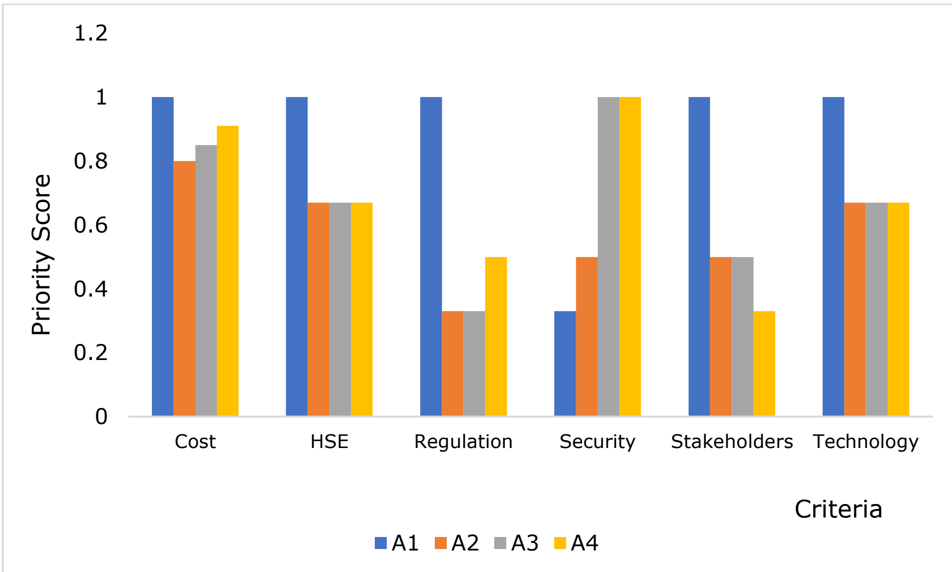


Figure 5.6: Overall priority scores of investment alternatives for Ekeh Field

The results from the priority analysis highlight that A1 stands out as the optimal choice when balancing various criteria. Its simplicity, lower costs, and minimal environmental risks make it the most suitable option for development in marginal fields. In contrast, A2's relatively low ranking demonstrates that despite its higher potential capacity, its complexity and costs make it less attractive.

The slight differences between A3 and A4 indicate that both offer moderate advantages, especially in terms of scalability and stakeholder engagement. A4, which uses a CPF and joint export strategy, could be more beneficial in the long term due to shared infrastructure, but the complexity and shared responsibilities might pose coordination challenges.

In summary, the analysis suggests that A1 should be prioritized as the preferred option for marginal field development, offering the best combination of cost-effectiveness, regulatory ease, and technical feasibility. A3 and A4 could serve as viable alternatives depending on specific field conditions and operational preferences, while A2, though technically feasible, poses significant cost and complexity challenges that may make it less appealing.

This option aligns with the development option selected in the competent persons report for the company.

5.4.8 Robustness of Investment Alternatives to changes in Criteria

Results of sensitivity analysis from applying the model to the case study is presented in this section. Figure 5.7 illustrates the sensitivity analysis of Ekeh field development options (A1, A2, A3, and A4) across seven distinct scenarios. The y-axis represents the criteria weights, while the x-axis shows the various scenarios under which the alternatives are assessed. The sensitivity analysis results in Figure 5.7 demonstrate how varying the weights assigned to different decision criteria influence the priority scores of the development options (A1, A2, A3, and A4) across seven scenarios. Each scenario reflects a shift in strategic emphasis, with one criterion given a 50% weight while the remaining criteria are equally distributed. It shows the effect of how changes in the importance of different criteria (Cost, Health, Safety, and Environment (HSE), Regulation, Security, Stakeholders, and Technology) impact the relative preference and ranking of the identified development options (A1, A2, A3, A4) for case study marginal field development. The criteria which are most influential in decision-making and how robust each development option is to changes in these criteria are identified.

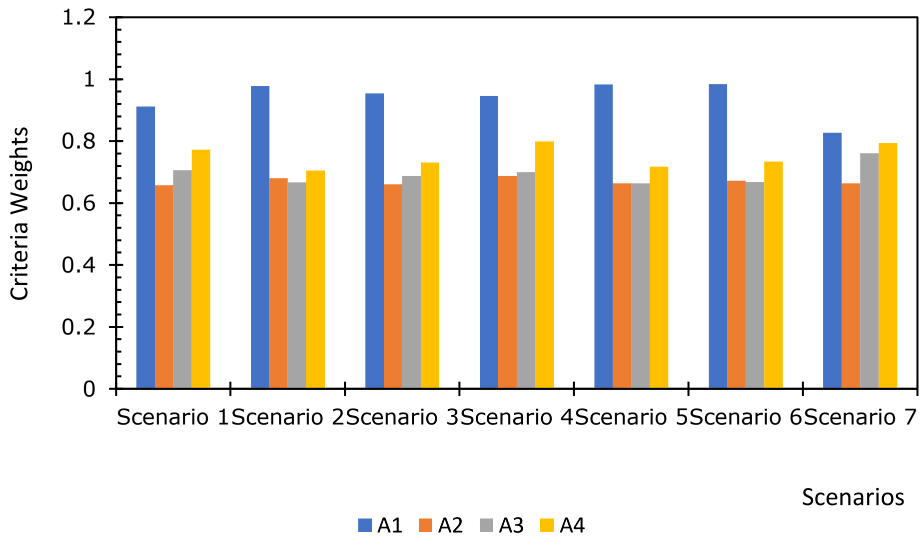


Figure 5.7: Effect of change in criteria weights on alternatives

Scenario 1 (Baseline – SME Input)

A1 achieves the highest score (0.912), indicating it is the most favourable option based on the combined judgment of subject matter experts (SMEs). A4 ranks second (0.773), reflecting moderate alignment with baseline preferences, followed by A3 (0.706). A2 scores the lowest (0.658), suggesting it is the least preferred under SME-determined priorities.

Scenario 2 (Cost Weighed 50%):

A1 shows a significant increase in its score (0.978), reinforcing its strong cost-efficiency and dominance in cost-driven scenarios. A4 drops slightly to 0.705 but remains a competitive alternative due to its balanced cost-performance. A2 and A3 exhibit marginal changes (0.680 and 0.667, respectively), indicating limited sensitivity to cost as a primary driver.

Scenario 3 (HSE Weighed 50%):

A1 maintains a strong performance (0.954), highlighting its alignment with HSE priorities. A4 improves marginally to 0.731, reflecting its compliance with HSE standards. A3 and A2 show limited sensitivity, with scores of 0.687 and 0.661, respectively, under an HSE-focused scenario.

Scenario 4 (Regulation Weighed 50%):

A1 continues to excel with a score of 0.946, underscoring its regulatory compliance. A4 sees the highest improvement in this scenario (0.799), reflecting its suitability in regulation-driven strategies. A3 and A2 remain consistent at 0.699 and 0.688, respectively, showing moderate alignment with regulatory considerations.

Scenario 5 (Security Weighed 50%):

A1 scores the highest (0.983), indicating its robustness in security-sensitive scenarios. A4 performs well (0.717), reflecting moderate suitability in managing security risks. A2 and A3 show little variation, with scores of 0.664 and 0.664, respectively.

Scenario 6 (Stakeholders Weighed 50%):

A1 remains the top-ranked option (0.984), suggesting it effectively addresses stakeholder considerations. A4 improves slightly to 0.734, demonstrating its potential to engage stakeholders effectively. A2 and A3 perform similarly, with scores of 0.672 and 0.668, indicating less sensitivity to stakeholder emphasis.

Scenario 7 (Technology Weighed 50%):

A1 experiences its largest drop (0.827), reflecting lower dominance in technology-driven scenarios compared to other criteria. A4 improves significantly to 0.793, showcasing its technological advantages and scalability. A3 improves to 0.761, indicating its relative strength in technology-intensive contexts, while A2 remains stable at 0.664.

The sensitivity analysis shows that Alternative A1 consistently ranks highest across all seven scenarios, demonstrating its robustness and reliability in various conditions. This suggests that A1 is the most resilient option when considering different sets of criteria and weights. The strong performance of A1 across all scenarios is likely due to its lower complexity, cost-effectiveness, and minimal regulatory requirements, making it the most flexible option.

Alternative A4 performs relatively well in most scenarios, coming close to A1 in certain cases. Its performance suggests that it is a viable option, particularly in scenarios where the flexibility of the Central Processing Facility (CPF) and joint export solutions are advantageous.

Alternative A3 remains steady in the middle, neither excelling nor performing poorly across most scenarios. Its moderate performance could be attributed to the balance between cost and technical complexity, with the use of MOPU and Floating Storage Offloading (FSO) units offering certain benefits but also posing some challenges.

Alternative A2, however, consistently shows the weakest performance in nearly all scenarios. The high costs associated with the construction of a subsea pipeline and the operational challenges of a MOPU seem to have a negative impact on its overall assessment. A2's lower performance indicates that it is the least favourable option when weighed against the other alternatives.

The sensitivity analysis highlights A1 as the most favourable alternative across multiple scenarios, offering strong performance and reliability. A4, while slightly less robust, presents itself as a viable second choice. A3, with moderate performance, can be considered depending on specific field conditions. A2 consistently performs poorly, making it the least desirable option for marginal field development. This analysis underscores the importance of considering multiple criteria and testing various scenarios to ensure a well-rounded and optimal decision-making process.

5.4.9 Optimal Field Development Option

The dominance of Option A1 across most decision criteria underscores its viability as the most feasible option for marginal field development, provided security risks are effectively mitigated. A1's consistent performance across cost, HSE (health, safety, and environment), regulation, and technology criteria positions it as the most technically and economically viable choice. Its capacity to align with the stringent requirements of regulatory bodies and international petroleum industry practices further validates its suitability.

Option A4 emerges as a competitive alternative, demonstrating a balanced performance in terms of cost-effectiveness and security. However, its viability is contingent on improving stakeholder support, which remains a critical factor for successful marginal field development, especially in terrains proximal to communities. Addressing stakeholder engagement challenges can enhance A4's acceptability and long-term sustainability.

Key Considerations for Marginal Field Development:

- Capital Efficiency: A1 and A4 avoid excessive capital and operating expenditures, ensuring economic feasibility while maintaining profitability in marginal fields.
- Environmental Sustainability: Both options prioritize the elimination of routine natural gas flaring, aligning with environmental regulations and the global shift toward reducing carbon emissions.
- Compliance with Standards: The identified options meet the technical standards for petroleum operations, adhering to good international petroleum industry practices, as well as the health, safety, and environmental standards established by government agencies.
- Infrastructure Optimization: These development strategies provide for the efficient and economic use of facilities and pipelines, reducing redundancies and operational inefficiencies.

Recommendations for Decision-Makers: Decision-makers must focus on the trade-offs among the key criteria, particularly security and stakeholder engagement, to maximize the feasibility and success of the selected option. While technical and economic factors are critical, integrating social and environmental considerations into the development strategy enhances the long-term sustainability of marginal field operations.

Strategic Framework for Marginal Field Development: An effective development strategy for marginal fields balances economic feasibility, technical innovation, and sustainability. This approach ensures that marginal fields contribute significantly to national energy security and economic growth. By mitigating risks, optimizing resource utilization, and fostering collaboration with stakeholders, marginal fields can transition from low-priority assets to strategic contributors within the petroleum sector.

5.5 Summary

In summary, this research presents a hybrid Analytical Hierarchy Process (AHP) model tailored for the selection and optimization of marginal field development options in Nigeria. It incorporates a screening tool to identify four primary development strategies (A1, A2, A3 and A4) based on terrain, reserves, and proximity to existing infrastructure.

The decision-making framework prioritizes six key criteria—Cost, HSE (Health, Safety, and Environment), Regulation, Security, Stakeholders, and Technology—through pairwise comparisons to calculate their respective priority scores. The results highlight Regulation and HSE as the most critical considerations, underscoring the industry's shift towards sustainable and environmentally conscious practices. This focus also aligns with the increasing significance of Environmental, Social, and Governance (ESG) criteria in attracting funding, as investors and financial institutions increasingly prioritize projects demonstrating strong ESG compliance.

The model's comprehensive evaluation of Ekeh marginal field development an offshore field yielded the following insights:

1. Option A1 emerged as the most favourable alternative for offshore marginal field development, achieving the highest overall priority score. It consistently performed well across all criteria—Cost, HSE, Regulation, Security, Stakeholders, and Technology—making it the most technically and economically viable choice. Its alignment with the Competent Persons Report (CPR) further validated its selection.

2. Option A4 ranked second, excelling in Technology and demonstrating moderate strengths in Regulation and Cost. Its cluster development approach enhances scalability, making it a competitive alternative.
3. Option A2 delivered a balanced performance across all criteria but did not dominate any specific area. This makes it a viable alternative with acceptable trade-offs for decision-makers.
4. Option A3 scored consistently lower across most criteria, particularly in Cost, Regulation, and Stakeholder alignment, rendering it the least favourable option.

The validated hybrid AHP model offers several benefits, making it an invaluable tool for marginal field development in Nigeria:

- Guidance for Decision-Makers: The model provides a systematic framework for selecting cost-effective, safe, and regulatory-compliant development strategies, enabling informed decision-making.
- Regulatory Efficiency: It supports regulators in reviewing Field Development Plans (FDPs), minimizing overlaps, and expediting approvals.
- Bias Monitoring: By monitoring the consistency of judgments, the model ensures objectivity, reduces subjectivity, and minimizes decision-making bias.

The hybrid AHP model addresses the complexities of marginal field development, offering stakeholders a reliable, transparent, and scientifically grounded tool to navigate Nigeria's unique oil and gas landscape effectively.

Chapter 6 Demonstrating use of Tool - Optifield Marginal Fields Digital Tool

6.1 Introduction

In this section, the developed marginal field development decision support tool is presented. The tool is named Optifield to convey the tool's focus on optimizing decision-making for marginal field development while suggesting efficiency, effectiveness, and innovation. The Optifield tool is a web-based application designed to assist in the evaluation and decision-making process for marginal field development options. It leverages advanced algorithms and industry expertise to streamline the process of finding, comparing, and implementing oil and gas projects specific to Nigeria. It is a comprehensive decision-support system that helps oil and gas stakeholders evaluate the financial and operational viability of different marginal field development options. By providing detailed cost and revenue analyses, as well as NPV calculations, the tool enables users to make informed decisions that maximize returns.

6.2 User Interface Design

The Optifield tool is designed with several key features and functionalities that streamline the evaluation and decision-making process for marginal field development. Its capabilities integrate advanced algorithms, comprehensive data analysis, and user-friendly interfaces to provide stakeholders with robust decision-support for optimizing field development strategies.

The user interface is designed to be intuitive and user-friendly. It includes:

1. Landing page

The OptiField landing page as shown in Figure 6.1 is designed to provide a clear and concise overview of the platform's value propositions and features, aimed at helping users make informed decisions in field development and decision-making.

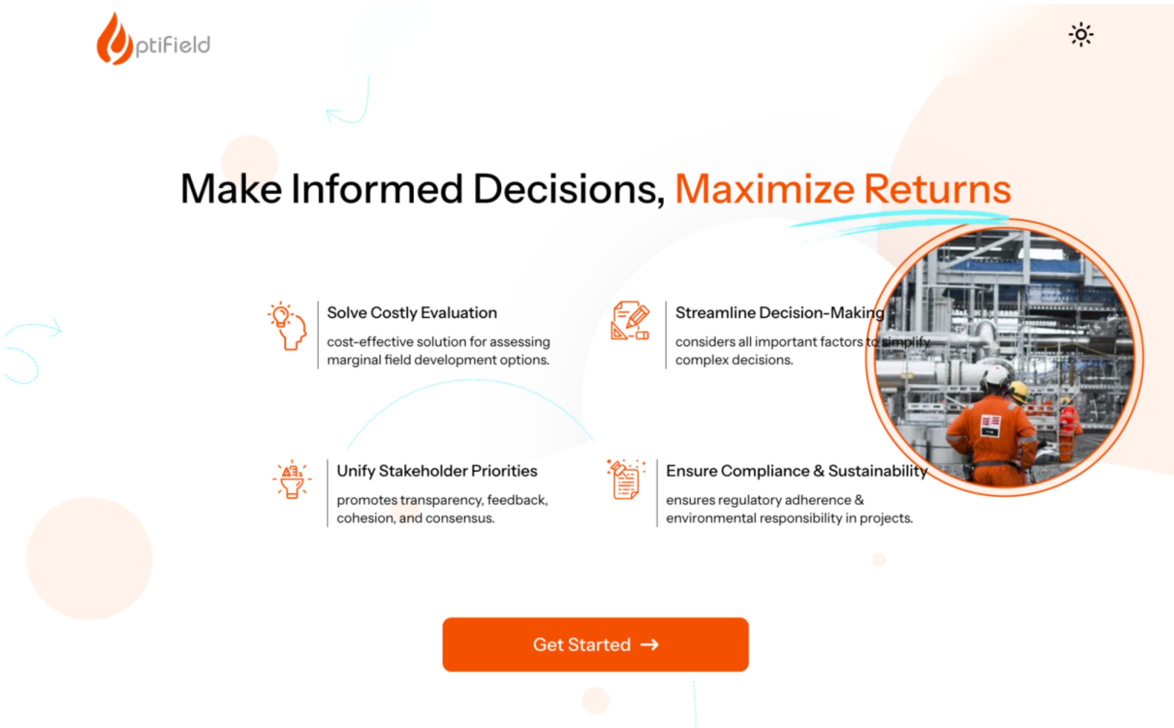


Figure 6.1: Optifield Landing page Interface

The interface is designed to be intuitive, making it easy for users to understand and engage with the tool. The clear layout and strategic placement of elements ensure that users can quickly grasp the benefits and functionalities of OptiField. Users can easily navigate through the key features without feeling overwhelmed by information.The use of icons and images makes the interface visually engaging and helps to convey information effectively. The "Get Started" button provides a clear next step for users, driving them towards deeper interaction with the tool.

2. Select Terrain

This interface appears after clicking "Get Started" on the landing page is designed to be intuitive and user-friendly, guiding users through the initial steps of using the tool which primarily is to make them select the terrain of their marginal field. It is designed for straightforward interaction, ensuring users can quickly and easily make their selections by clicking on any of the terrain options

(Onshore, Swamp, Offshore) to select their preferred terrain as shown in Figure 6.2.

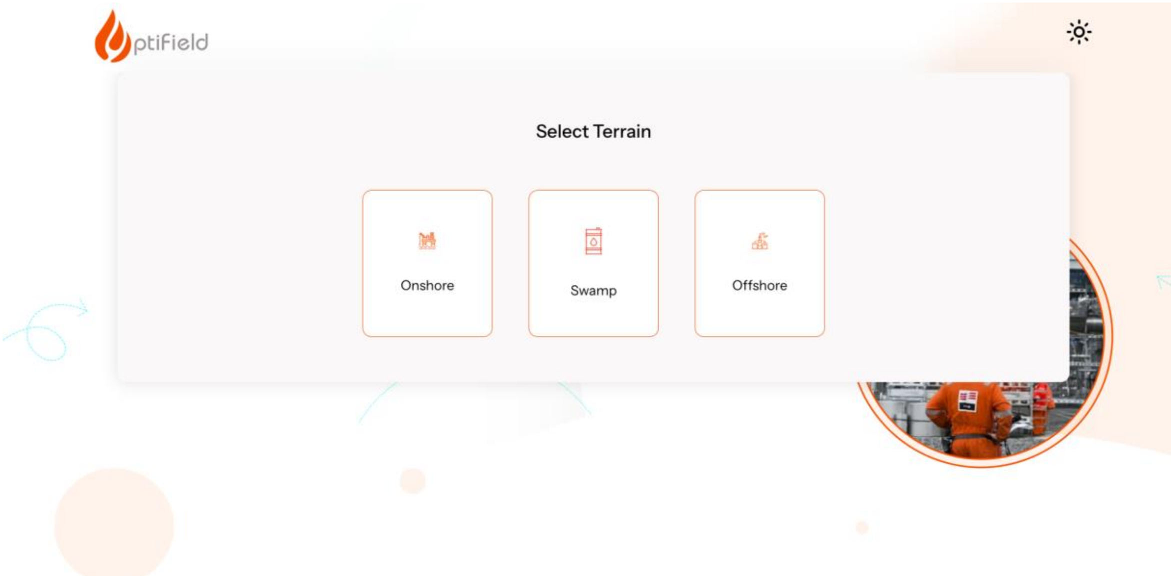


Figure 6.2: Select Terrain Interface

Upon selecting a Terrain e.g. 'onshore', a simple form to further select their marginal field is displayed as shown in Figure 6.3.

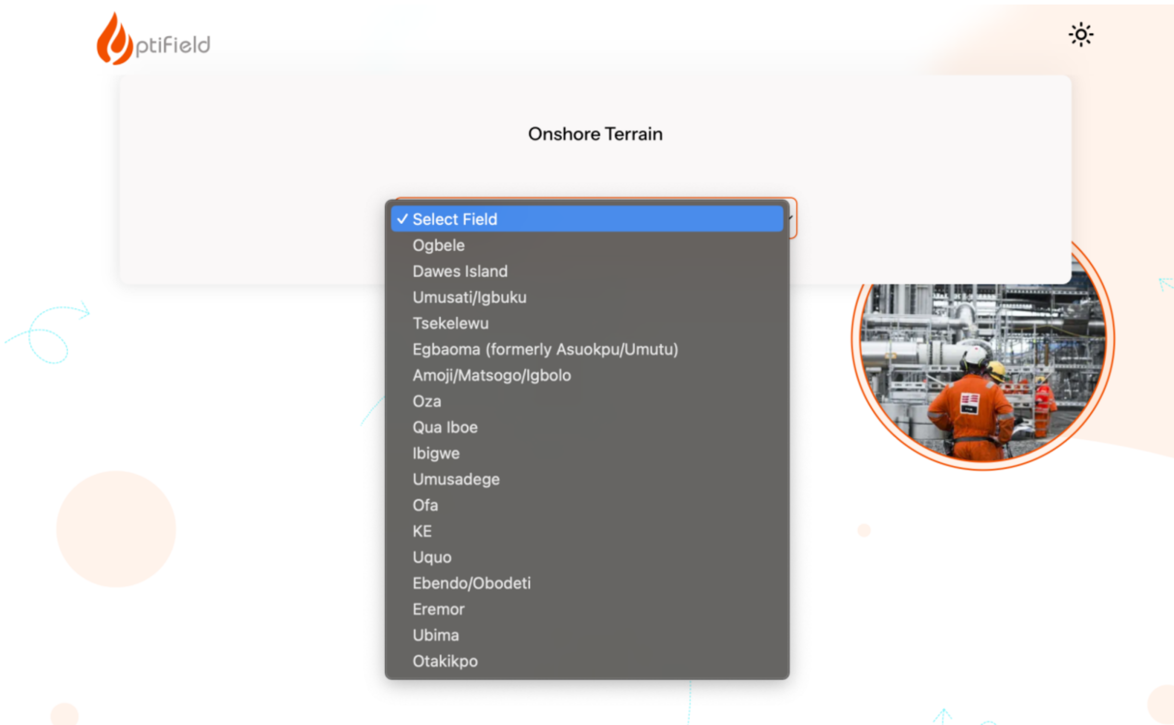


Figure 6.3: Select Field Interface

3. Data Input Interface

After selecting a marginal field, users are directed to this interface specifically designed to collect critical data about the selected field as shown in Figure 6.4. This interface is crucial for gathering the necessary inputs that will be used in further analysis and decision-making regarding field development.

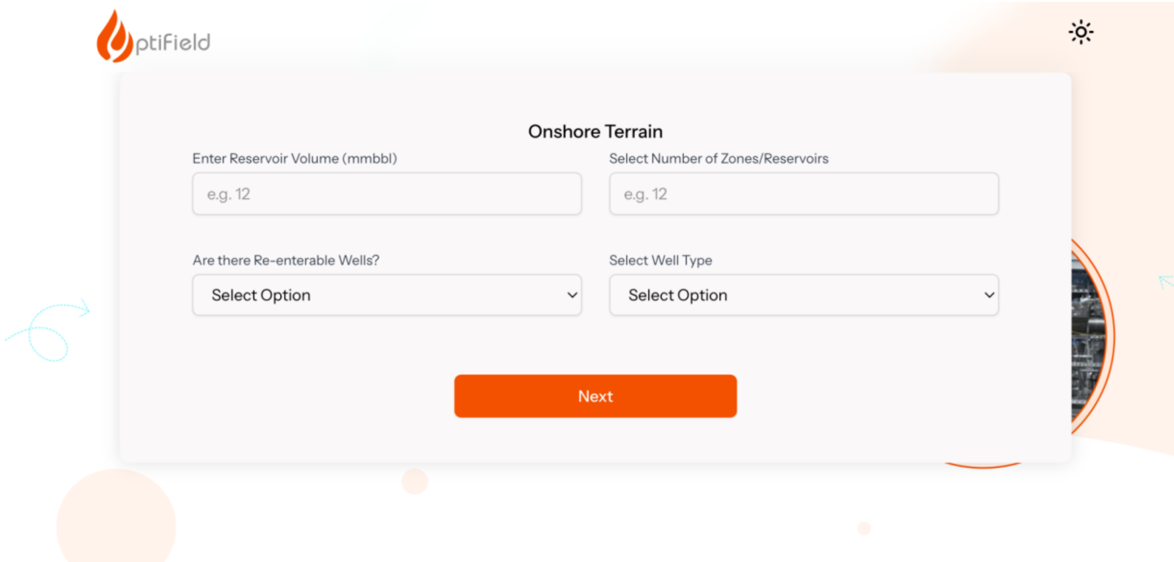


Figure 6.4: Data Input Interface

The interface is thoughtfully designed to be intuitive and user-friendly, ensuring that users can easily navigate and input the required information without confusion. This includes

- Enter Reservoir Volume (mmbbl): This text input field is designed for users to enter the reservoir volume in million barrels (mmbbl). The placeholder text "e.g. 12" provides an example format, guiding users on the expected input.
- Select Number of Zones/Reservoirs: Another text input field where users can specify the number of zones or reservoirs. The placeholder text "e.g. 12" similarly guides the user on the correct input format.
- Are there Re-enterable Wells?: This dropdown menu allows users to select an option regarding the presence of re-enterable wells. The dropdown ensures standardized input, reducing the risk of errors and variations in data entry. The options are 'yes' and 'No, calculate required number of wells'. If Yes, the user input the number of re-enterable wells else it is calculated if 'No' is selected.
- Select Well Type: Another dropdown menu for selecting the type of well, providing options tailored to different well types (vertical, Horizontal or

Deviated). This standardization helps streamline the data collection process and ensures consistency.

- Next Button: A prominent orange button labeled "Next" is located at the bottom of the form. This button is crucial for guiding users to the next step in the process, ensuring a smooth and logical flow through the interface.

Upon clicking 'Next' button, the data is collated and it changes to 'View result' as shown in Figure 6.5.

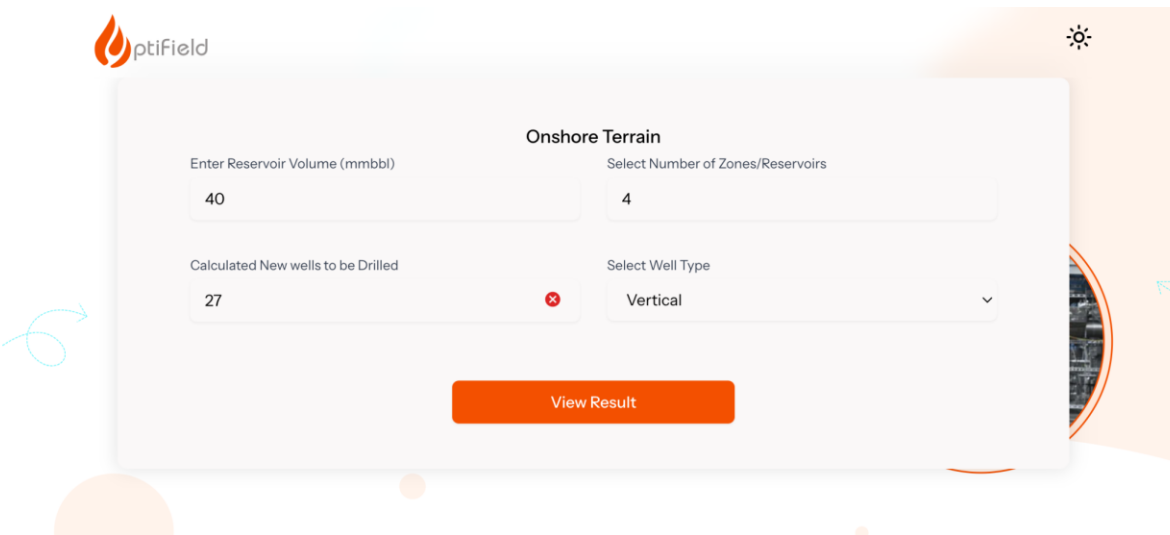


Figure 6.5: View Result

4. Result Interface

The OptiField result page is designed to provide users with a comprehensive analysis of different development options for their selected marginal field. This interface plays a crucial role in helping stakeholders make informed decisions based on detailed cost and revenue projections. It contains three main sections as shown in Figure 6.6 – 6.9.

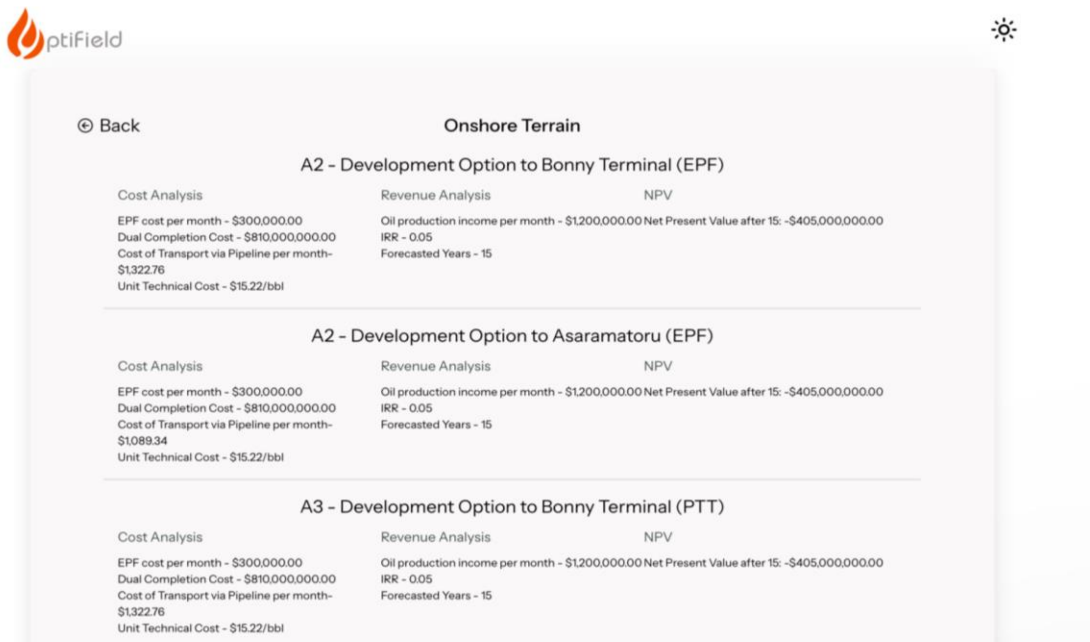
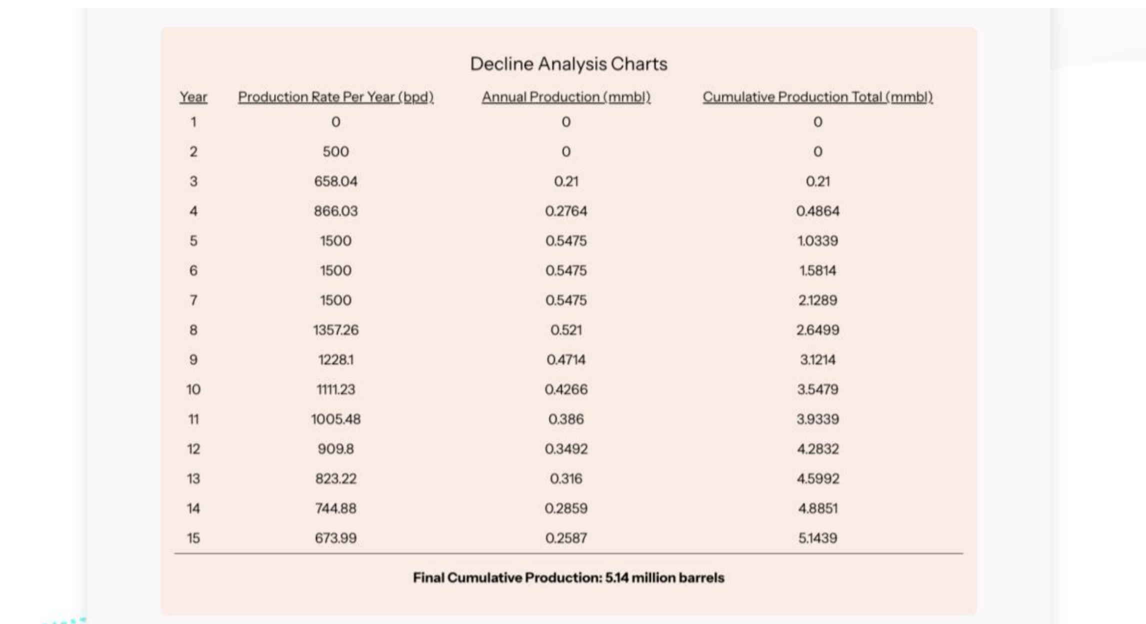


Figure 6.6: Development Options Section result



Decline Analysis Charts

Year	Production Rate Per Year (bpd)	Annual Production (mmbl)	Cumulative Production Total (mmbl)
1	0	0	0
2	500	0	0
3	658.04	0.21	0.21
4	866.03	0.2764	0.4864
5	1500	0.5475	1.0339
6	1500	0.5475	1.5814
7	1500	0.5475	2.1289
8	1357.26	0.521	2.6499
9	1228.1	0.4714	3.1214
10	1111.23	0.4266	3.5479
11	1005.48	0.386	3.9339
12	909.8	0.3492	4.2832
13	823.22	0.316	4.5992
14	744.88	0.2859	4.8851
15	673.99	0.2587	5.1439

Final Cumulative Production: 5.14 million barrels

Figure 6.7: Decline Curve Analysis Section

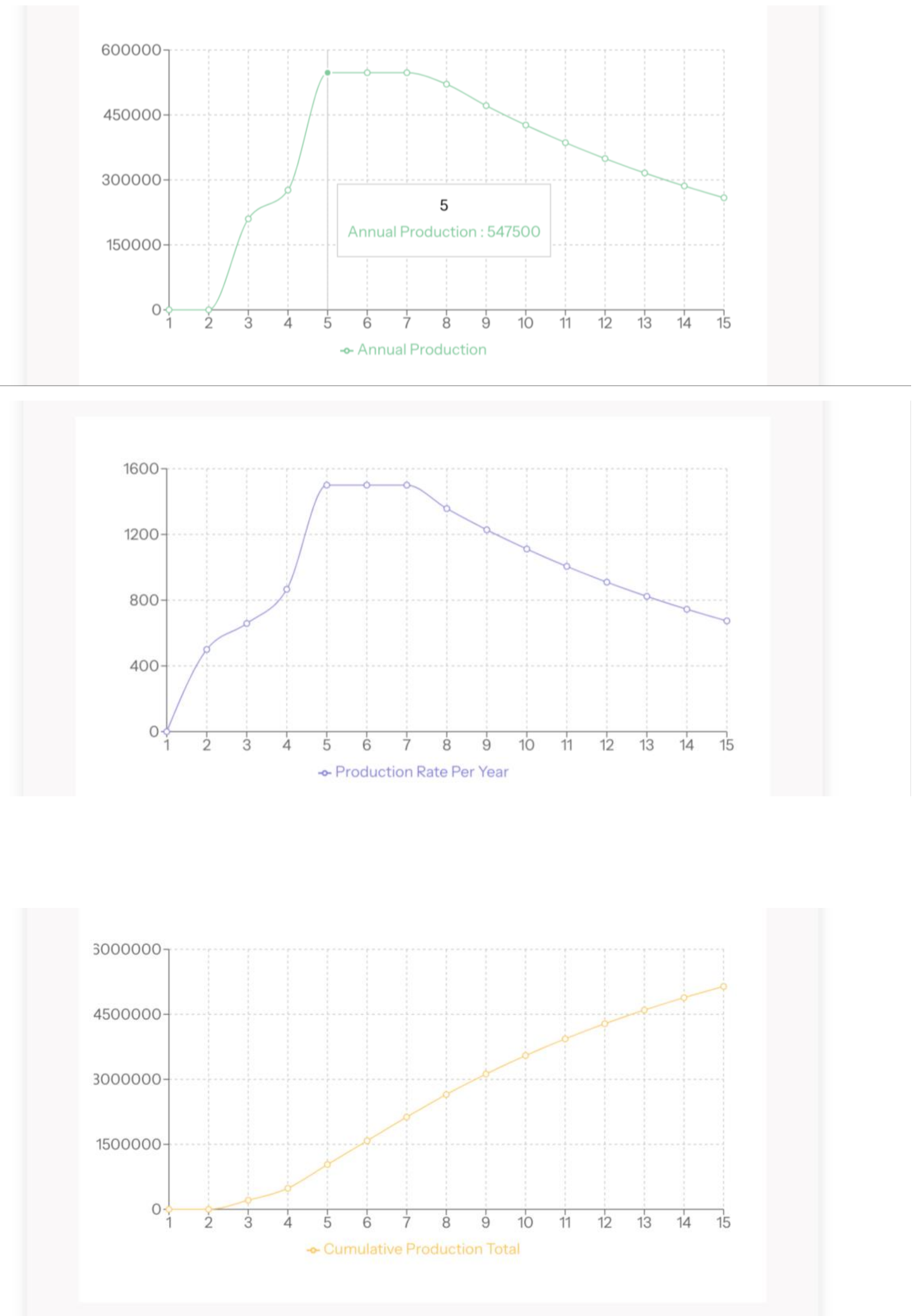


Figure 6.8: Decline Curve Analysis Charts

6.3 User Manual

This user manual provides step-by-step instructions for accessing, navigating, and utilizing the OptiField tool effectively. By following these guidelines, users can optimize their marginal field development decisions and achieve data-driven results.

1. Accessing the Tool

1. Visit the OptiField website https://optifield-tool.vercel.app/
- Click on the "Get Started" button on the landing page to initiate the process.

2. Terrain Selection

- On the initial interface, select the type of terrain for your project: Onshore, Swamp, or Offshore.
- The selected terrain will be highlighted with a darker border at the top of the screen, ensuring visibility.

3. Marginal Field Selection

- After selecting the terrain, browse the list of available marginal fields under the selected terrain.
- Click on your desired field to proceed.

4. Data Input for Marginal Fields

- Once a field is selected, provide specific input data as prompted;
  - Reservoir Volume (MMbbl): Input the volume of reserves in million barrels.
  - Number of Zones/Reservoirs: Enter the total number of productive zones or reservoirs
  - Re-enterable Wells: Use the dropdown menu to indicate the number of re-enterable wells or select 'No' to allow the tool to calculate it based on existing.

- Well Type: Choose the well type from the dropdown menu.

- Click the "Next" button to proceed.

5. Adjusting Criteria

- Modify the input fields and dropdown menus to refine various criteria (terrain-specific attributes or cost metrics).
- Use the “Back” button to return to previous sections and makes changes to your selections.

6. Run Simulation

- After all required data has been entered and adjusted, click the **"Run Simulation"** button.
- The tool will process the data and generate detailed analyses and projections tailored to your input.
- Once the simulation completes, click on **"View Results"** to access the outcome.

7. Viewing Result

The results page presents a detailed breakdown of analyses and projections for each development option:

- Development Options:
- ranked strategies with detailed insights for cost and revenue implication.
- Cost Analysis:
- EPF (Early Production Facility) Cost per Month
- Dual Completion Cost
- Transportation Cost via Pipeline per Month.
- Unit Technical Cost (UTC)
- Revenue Analysis and NPV:

Monthly Oil Production Income.

Net Present Value (NPV) after 15 Years.

Internal Rate of Return (IRR).

Projected Revenue over the forecasted period.

- Decline Curve Analysis (DCA)

Charts and tables for production rate, annual production, and cumulative production over 15 years.

8. Interpreting Results

- Order of Preference/Recommendation:

The development options are presented in descending order based on their priority scores. This ranking methodology ensures that the option with the highest score appears at the top, signifying it as the optimal choice according to the established criteria. Each subsequent option is ranked in decreasing order of priority, reflecting its relative suitability. The top-ranked option represents the development strategy with the most favourable combination of cost efficiency and projected revenue, as determined by the weighted criteria. This approach provides stakeholders with a clear and logical framework for selecting the best possible development option, ensuring that the decision-making process is guided by objective, data-driven insights.

- Cost Analysis:

Focus on the EPF cost per month, dual completion cost, cost of transport via pipeline, and unit technical cost. Lower values in these categories generally indicate more cost-effective options.

- Revenue Analysis and NPV:

Examine the oil production income, NPV, and IRR. Higher oil production income is positive, but a negative NPV indicates a net loss over the projected period. The IRR shows the rate of return on investment, with negative values indicating unprofitable options.

- Comparative Metrics:

Use the unit technical cost ($/bbl) to compare the efficiency of different options. Consistently lower costs suggest better operational efficiency.

- Decline Curve Analysis:

The Decline Analysis Charts and Table from OptiField provide a comprehensive overview of how production declines over a span of 15 years, with detailed metrics for each year. The table includes the production rate per year (in barrels per day, bpd), annual production (in million barrels, mmbl), and the cumulative production total (in million barrels, mmbl). By analyzing the decline trends, users can make informed decisions about further investments, operational adjustments, and potential enhancements to optimize production.

6.4 Comparative Analysis of Tool with Actual Field Data

The validity of the developed decision-support tool, OptiField, was assessed through a comparative analysis with actual outcomes from historical marginal field developments in Nigeria. The analysis involved evaluating the tool's predictions against existing field data to determine its accuracy and reliability. The findings of this comparative study are summarized in Table 6.1, which outlines key attributes, current development options, and corresponding tool-recommended options for various fields.

Table 6.1: Comparison of Results from Tool with Actual Field Data

Operator	**Field Name**	**MF Input Attributes**		**Curr. Option**	**Tool Option**
		Terrain	**Res in MMB**		
AGEL	Ubima	Onshore	56.84	A2	A2
BUNL	Ajapa	Offshore	11.53	A3	A1
CEL	Amoji	Onshore	10.71	A2	A2
EL	Ebendo	Onshore	2.47	A2	A4
EEPL	Eremor	Swamp	11.14	A2	A2

FOL	Uquo	Swamp	15.30	A2	A2
GEIL	Otakikpo	Onshore	46.26	A2	A2
MDOGL	Umusadege	Onshore	36.01	A2	A2
MIOGL	Oza	Onshore	6.16	A2	A2
NDPRL	Ogbele	Onshore	31.35	A2	A2
NEPL	Qua Ibo	Onshore	11.71	A2	A2
PEPL	Asamatoru	Swamp	25.40	A2	A2
POL	Umusati	Onshore	11.43	A2	A2
PPL	Egbaoma	Onshore	4.73	A2	A2
OERL	Ebok	Offshore	29.45	A2	A2
UEL	Stubb Creek	Swamp	14.69	A2	A2
WPL	Ibigwe	Onshore	25.03	A2	A2

The results indicate that the tool’s predictions were 88% accurate, with minimal deviations from actual field development strategies. The high level of agreement between the tool's recommendations and real-world outcomes underscores the reliability of the tool in accurately identifying optimal development strategies. For example, for fields such as Ubima, Amoji, and Ogbele, the tool's predictions perfectly matched the actual options (A2), reflecting its ability to align with practical decision-making.

However, deviations were observed in a few cases, such as the Ebendo field (Onshore) and Egbaoma field (Onshore). These deviations can be attributed to assumptions embedded in the model, such as a minimum reserve threshold of 5 million barrels (MMbbls) for onshore marginal fields. The analysis revealed that reserves as low as 2 MMbbls are viable for standalone development in onshore fields, highlighting the need to refine the model’s assumptions for enhanced precision.

Key Observations:

1. **High Accuracy**: The model demonstrated an 88% prediction accuracy, emphasizing its robustness and reliability in decision-making for marginal field development.

2. **Minimal Deviations**: Deviations between the tool's recommendations and actual outcomes were minimal, suggesting that the underlying assumptions and algorithms are largely valid.
3. **Insights for Refinement**: The findings highlight the need to adjust the minimum reserve threshold for onshore fields to align with practical realities, thus improving the model's predictive power.
4. **Practical Utility**: The tool's ability to closely match actual outcomes confirms its practical applicability in guiding operators, policymakers, and stakeholders in selecting development options.

In summary, this comparative analysis validates the practical applicability and accuracy of the OptiField tool in marginal field development decision-making. The findings also provide actionable insights for refining the tool to better accommodate variations in reserve thresholds and other field-specific parameters. This exercise further establishes the tool as a reliable and robust framework for optimizing marginal field development in Nigeria.

6.5 Summary

The Hybrid AHP model demonstrated excellent performance across various validation tests, consistency checks, scenario testing, and comparison with actual data. Key findings include:

- **Consistency and Reliability:** Consistent CR values across criteria confirm logical coherence in judgments.
- **Robustness:** Strong performance across various scenarios, particularly for Option A1.
- **Practical Applicability:** Minimal deviations from actual field data, confirming the model's real-world relevance.

The validated model is therefore a reliable and effective tool for optimizing the development of marginal fields in Nigeria, capable of guiding decision-makers towards cost-effective, safe, and compliant development strategies.

Chapter 7 Conclusion, Recommendation and Future Work

This chapter is divided into three main sections. The first section presents the general conclusions of the study. The conclusions are based on the research aim, objectives and strategies taken to achieve them. The primary aim of this research was to develop decision support for assisting decision-makers to determine the optimal option for marginal field development in Nigeria. The second section offers recommendations based on the findings of the study, aimed at improving decision-making and practices in marginal field development. Finally, the third section explores potential areas for improvement and further development of the current study, outlining opportunities for future research and enhancements to the methodology.

7.1 Conclusion

This research has successfully achieved its objectives, culminating in the development of a robust, hybrid AHP-based decision-making model tailored for marginal field development in Nigeria. The key outcomes of this study are as follows:

7.1.1 Objective 1: Development of a Decision-Making Model

This study has successfully achieved the development of a robust, hybrid AHP-based decision-making model tailored for marginal field development in Nigeria. Critical components such as screening, economic modelling, and the Weighted Sum Method (WSM) were integrated into the model. The model was grounded in a comprehensive set of criteria that integrate both qualitative and quantitative factors critical to marginal field development. The qualitative criteria, including regulatory compliance, Health, Safety, and Environment (HSE), security, stakeholder engagement, and technology, provide a multidimensional framework for assessing development options. Quantitative metrics such as Unit Technical Cost (UTC) further enrich the decision-making process by offering an economic lens to evaluate the feasibility of options.

The study identified four main development options—A1, A2, A3, and A4—as suitable for marginal field development in Nigeria. These options are tailored based on terrain, reserves, and proximity to existing facilities, providing flexibility to meet the diverse conditions and challenges associated with marginal fields.

- Option A1: Most suitable when a nearby processing facility is readily accessible, with distances of 50 km, 75 km, and 100 km for onshore, swamp, and offshore terrains, respectively. This option is characterized by utilizing existing facilities for production and export, ensuring cost efficiency and leveraging established infrastructure.
- Option A2: Appropriate when no nearby facility is available, but the field has substantial reserves (5 MMbbl, 7 MMbbl, or 20 MMbbl for onshore, swamp, and offshore fields, respectively). This option involves leasing an Early Production Facility (EPF) or floating facility to process and export hydrocarbons, either via a third-party pipeline or collaborative arrangements with neighbouring fields.
- Option A3: Best suited for scenarios where pipeline construction is cost-prohibitive, third-party pipelines face downtime or vandalism, or crude quality does not meet pipeline specifications. This option entails transporting onshore production by truck, swamp production by barge, and offshore production via a Floating Storage and Offloading (FSO) unit or shuttle tankers.
- Option A4: Most effective for cluster groups within a proximate distance, where operators can pool resources to establish a Central Processing Facility (CPF). Production is exported via pipeline, barge, or shuttle tanker, depending on terrain and economic considerations.

The decision-making model stands out for its systematic and comprehensive approach, offering a structured framework that integrates multiple factors influencing marginal field development. This model serves as a foundation for informed decision-making, enabling stakeholders to select development options that optimize both economic returns and sustainability.

7.1.2 Objective 2: Investigation of Model Applicability

Objective two sought to determine the relative importance of the identified criteria in marginal field development decision-making across onshore, swamp, and offshore terrains. The study's findings provide a nuanced understanding of the role that different factors play in shaping field development decisions.

The AHP methodology proved effective in establishing the relative importance of decision criteria, ensuring a systematic, transparent, and replicable process. The results revealed that regulation consistently emerged as the most critical criterion across all terrains, with the highest priority scores of 0.225, 0.245, and 0.242 for onshore, swamp, and offshore terrains, respectively. This underscores the importance of regulatory compliance in ensuring successful and sustainable marginal field development.

Other factors such as Health, Safety, and Environment (HSE), Cost, Security, Stakeholders, and Technology were ranked based on their importance in each terrain:

- In onshore terrains, HSE, Cost, and Security shared equal importance (priority score: 0.195), followed by Stakeholders (0.106) and Technology (0.084).
- In swamp terrains, HSE and Security were equally significant (priority score: 0.215), followed by Stakeholders (0.133), Cost (0.114), and Technology (0.079).
- In offshore terrains, Technology gained relatively more importance (priority score: 0.143) due to the need for advanced solutions in addressing the unique challenges posed by offshore operations.

The consistency ratios for all comparisons were within acceptable thresholds (ranging from 0.021 to 0.097), demonstrating the reliability of the results. These findings provide a solid foundation for prioritizing critical factors in marginal field development, ensuring that decisions are informed by both quantitative analysis and industry best practices.

Comparing the results obtained with results from analysis of successful fields using traditional approach (NPV) emphasized cost as the primary driver of decision-making, but it overlooked critical qualitative factors like stakeholder and environmental concerns, which are crucial in the Nigerian context. While traditional approach offers valuable insights, the Hybrid AHP model provides a more robust framework for marginal field development by integrating both quantitative and qualitative factors. This holistic approach ensures that critical dimensions such as stakeholder engagement and environmental impact are not overlooked, enabling more informed and sustainable decision-making in the oil and gas industry.

The study rigorously tested the applicability of the developed decision model using representative case studies of marginal fields in Nigeria, such as the Ekeh offshore field. The model's application demonstrated its ability to evaluate and rank development alternatives effectively, with A1 (tieback development) consistently identified as the optimal choice for fields like Ekeh. This result aligns with industry best practices, which emphasize the advantages of tieback and cluster developments in terms of cost-effectiveness, HSE performance, and operational efficiency.

A1 maintains the highest weight 0.9 in most scenarios, indicating its overall robustness across varying criteria. The sensitivity analysis demonstrates that A1 is the most robust and versatile alternative for offshore marginal field development. A4 offers a compelling alternative under specific conditions. The Hybrid AHP model, validated through this analysis, provides a reliable framework for decision-making in marginal field development, ensuring that economic, environmental, and regulatory considerations are adequately balanced.

7.1.3 Objective 3: Development of a Software Application

To ensure practical implementation of the decision-making model, this research developed a software application that automates the evaluation process. The software translates the AHP-based model into a user-friendly tool, enabling stakeholders to assess development options with efficiency, consistency, and scalability. By automating the processes of pairwise comparisons, criteria weighting, and development option ranking, the software addresses challenges inherent in manual decision-making, such as scalability and input inconsistencies.

The software's practical implications are significant, as it empowers operators, regulators, and policymakers with a systematic tool for informed decision-making. Additionally, the automation fosters transparency and reproducibility in evaluating marginal field development options, ensuring that decisions are data-driven and aligned with industry best practices.

The development of this software represents a critical step forward in operationalizing the AHP-based model, providing stakeholders with an accessible and reliable means of optimizing marginal field development strategies. It serves not only as a decision-support tool but also as an audit and benchmarking mechanism for existing marginal fields, promoting continuous optimization of their operations.

This research significantly advances the optimization of marginal field development strategies in Nigeria by integrating economic, environmental, social, and regulatory considerations into a systematic framework. The hybrid AHP-based model, combined with the developed software, offers a replicable methodology that can be adapted to other oil-producing regions facing similar challenges.

By prioritizing cost-effective and sustainable development options, the research enhances indigenous participation and economic benefits in Nigeria's oil and gas industry. Moreover, it provides a valuable benchmark for assessing and optimizing existing marginal fields, fostering continuous improvement in their operations.

The decision model and software application empower stakeholders with a robust decision-support tool, enabling transparent and informed choices for marginal field development. It addresses critical industry challenges such as scalability, consistency, and adaptability, ensuring that development strategies align with regulatory, environmental, and economic priorities.

Additionally, the model serves as an audit and benchmarking tool, facilitating the evaluation of existing fields and the identification of opportunities for optimization. By advancing industry best practices, this research contributes to the sustainable and efficient development of Nigeria's energy sector.

The comparative analysis of the developed decision-making tool with actual field data demonstrates its validity and practical applicability for marginal field development. The model achieved an 88% accuracy rate in predicting development options for marginal fields, confirming its effectiveness in guiding decision-making processes. This high level of accuracy underscores the robustness of the hybrid AHP-based model in addressing the complexities of marginal field development, particularly in Nigeria's dynamic oil and gas sector.

The minimal deviations observed between the tool's predictions and the actual development outcomes highlight the reliability of the model. The primary source of deviation was the assumption that a minimum reserve of 5 MMbbls is required for onshore standalone development. The analysis revealed that reserves as low as 2 MMbbls could suffice for standalone development in certain onshore fields. This insight provides a valuable refinement for the model, suggesting the need to account for context-specific thresholds in reserve requirements during future iterations.

Moreover, the model's ability to closely align with real-world outcomes reinforces its practical utility for operators, regulators, and other stakeholders. By integrating critical criteria such as terrain, reserves, regulatory compliance, and infrastructure availability, the tool delivers a structured framework that supports informed decision-making. This is particularly vital for optimizing field development strategies, improving resource allocation, and enhancing the economic viability of marginal field projects.

In conclusion, the results of the comparative analysis validate the tool as a reliable decision-support system for marginal field development. Its alignment with actual field data demonstrates its potential to minimize uncertainties and improve the planning and execution of development projects. Future enhancements to the tool could focus on refining reserve thresholds and incorporating additional data to further increase its accuracy and adaptability. Overall, this study contributes significantly to the development of a practical and systematic framework for optimizing marginal field operations in Nigeria and beyond.

7.2 Recommendations

The findings from this study provide actionable insights for marginal field operators, policymakers, and other stakeholders, highlighting strategic measures that can enhance the success of marginal field development projects. The following recommendations are proposed:

Operators must develop tailored strategies that address the unique priorities and challenges of each terrain. For instance, offshore terrains require advanced technology, while onshore terrains demand robust security measures.

Understanding and adhering to regulatory requirements is critical across all terrains. Operators should invest in regulatory expertise and proactive engagement with government agencies to ensure smooth project execution and avoid costly delays.

Upholding rigorous HSE standards is non-negotiable. Operators should prioritize measures to protect personnel, assets, and the environment, with particular attention to terrains like offshore, where risks are amplified.

While cost management remains crucial, it should never come at the expense of safety, compliance, or environmental integrity. Operators should adopt innovative approaches that optimize costs without compromising these critical areas.

Leveraging advanced technologies such as automation, remote monitoring, and data analytics can significantly improve operational efficiency and safety. Technologies must be selected and adapted to address terrain-specific challenges, especially in offshore and swamp environments.

Security measures are critical in swamp and onshore terrains prone to militancy and vandalism. Operators must implement robust systems to safeguard assets, personnel, and operations against potential threats.

While stakeholder engagement may carry less weight in offshore terrains, it remains a vital element in ensuring project success. Establishing positive relationships with local communities and other stakeholders can help mitigate conflicts and foster a supportive environment.

Collaboration among experts in diverse fields, such as safety, environmental management, engineering, and technology, can lead to innovative and efficient solutions. Partnerships with technology providers can also facilitate access to cutting-edge tools and expertise, driving improved exploration and production outcomes.

Operators should actively engage in technology partnerships to not only address current operational needs but also contribute to the development of new technologies. These innovations could benefit other fields in the future, strengthening the overall petroleum sector and fostering sustainable practices.

By adopting these recommendations, marginal field operators and stakeholders can optimize their development strategies, balancing economic, technical, social, and environmental considerations to maximize the long-term success and sustainability of marginal field projects.

7.3 Future Work

While this study focuses on Nigeria, the model's adaptability suggests its potential for broader application in other oil-producing regions. Future research can refine the framework to accommodate evolving regulatory, economic, and technological conditions, ensuring its ongoing relevance and utility.

Further development of the software application could include enhancements such as real-time data integration and advanced visualization tools, improving its functionality and usability. Additionally, expanding the model to include emerging considerations, such as energy transition policies and renewable integration, could extend its applicability in a rapidly changing energy landscape.

This research lays a robust foundation for future studies, contributing to the continuous improvement of marginal field development strategies and the broader advancement of the global energy industry.

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Appendix

Appendix 1: Questionnaire

An Analytical Hierarchy Process Model for the Optimization of Marginal Field Development in Nigeria

Invitation and Consent Form for Participants of Pairwise Comparison Survey

Dear Participant,

We are currently undertaking a research project in selection of optimal field development option for Marginal Field Development in Nigeria.

We would like to invite you to participate in a survey aimed at gathering your valuable insights and judgments on various criteria for decision-making in the context of marginal field development. Your expertise and opinions will contribute to optimising decision-making processes in the oil and gas industry.

The survey will involve a pairwise comparison exercise where you will be asked to compare different criteria based on their relative importance. This will help us understand the priorities and preferences associated with cost, regulation, technology, stakeholders, HSE (Health, Safety, and Environment), and security in the context of marginal field development.

Your participation in this survey is entirely voluntary. By completing the survey, you are consenting to your responses being used for research purposes and ensuring the confidentiality and anonymity of your data. Please rest assured that your individual responses will be kept strictly confidential and will only be reported in aggregate.

By participating, you will contribute to advancing knowledge and understanding in the field of marginal field development and aid decision-makers in making informed and effective choices.

Thank you in advance for your time and valuable input. Your contribution is greatly appreciated.

Sincerely,

Amina Danmadami

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Instructions

In the following sheets, we would like to elicit your opinion in order to select amongst the alternatives. The pair wise comparison scale is used to express the importance of one element over another (Table 1).

Saaty Comparison Scale

Explanation	Numeric Value
If A and B are equally important : Mark/Insert →	1
If A is moderately more important than B : Mark/Insert →	3
If A is strongly more important than B : Mark/Insert →	5
If A is very strongly more important than B : Mark/Insert →	7
If A is extremely more important than B : Mark/Insert →	9
Use even numbers for intermediate judgements	2, 4, 6, 8

Example: Given criteria A and B, you can judge their relative importance as shown below: if you think the criteria 'Cost' in column A is strongly more important than the criteria 'HSE' in column B, then you mark 5 with (X) on the left hand side. if you think the option 'Regulation' in column B is extremely more important than the option 'Cost' in column A, then you mark 9 with (X) on the right hand side.

A Criteria	9	8	7	6	5	4	3	2	1	2	3	4	5	6	7	8	9	B Criteria

Cost					x													HSE
Cost																	x	Regulation

Start survey here

With respect to Goal: Selection of Optimal Field Development Option, Using the scale from 1 to 9 (where 9 is extremely and 1 is equally important), please indicate (X) the relative importance of Criteria A (left column) to Criteria B (right column) in the context of **Onshore** Marginal Field Development. **Please use the even numbers only when compromise are needed**.

A **Criteria**	9	8	7	6	5	4	3	2	1	2	3	4	5	6	7	8	9	**B** **Criteria**
Cost																		HSE
Cost																		Regulation
Cost																		Security
Cost																		Stakeholders
Cost																		Technology
HSE																		Regulation
HSE																		Security
HSE																		Stakeholders
HSE																		Technology
Regulation																		Security
Regulation																		Stakeholders
Regulation																		Technology
Security																		Stakeholders
Security																		Technology
Stakeholders																		Technology

With respect to Goal: Selection of Optimal Field Development Option, Using the scale from 1 to 9 (where 9 is extremely and 1 is equally important), please indicate (X) the relative importance of Criteria A (left column) to Criteria B (right column) in the context of **Swamp** Marginal Field Development. **Please use the even numbers only when compromise are needed**.

A **Criteria**	9	8	7	6	5	4	3	2	1	2	3	4	5	6	7	8	9	**B** **Criteria**
Cost																		HSE

Cost																		Regulation
Cost																		Security
Cost																		Stakeholders
Cost																		Technology
HSE																		Regulation
HSE																		Security
HSE																		Stakeholders
HSE																		Technology
Regulation																		Security
Regulation																		Stakeholders
Regulation																		Technology
Security																		Stakeholders
Security																		Technology
Stakeholders																		Technology

With respect to Goal: Selection of Optimal Field Development Option, Using the scale from 1 to 9 (where 9 is extremely and 1 is equally important), please indicate (X) the relative importance of Criteria A (left column) to Criteria B (right column) in the context of **Offshore** Marginal Field Development. **Please use the even numbers only when compromise are needed**.

A **Criteria**	9	8	7	6	5	4	3	2	1	2	3	4	5	6	7	8	9	**B** **Criteria**
Cost																		HSE
Cost																		Regulation
Cost																		Security
Cost																		Stakeholders
Cost																		Technology
HSE																		Regulation
HSE																		Security
HSE																		Stakeholders
HSE																		Technology
Regulation																		Security
Regulation																		Stakeholders
Regulation																		Technology

Security																		Stakeholders
Security																		Technology
Stakeholders																		Technology

Investment Alternatives

A1: 1+ wells, re-entry/new well, single/dual zone completion, Tie-in to nearby facility, export via established means

A2: 1+ wells, re-entry/new well, single/dual zone completion, Early Production Facility - EPF (skid mounted flow station/ Mobile Offshore Production Unit - MOPU), export via pipeline to another facility/third party terminal

A3: 1+ wells, re-entry/new well, single/dual zone completion, EPF (skid mounted flow station/MOPU), export via trucking/barge/shuttle tanker to another facility/ third party terminal

A4: 1+ wells, re-entry/new well, single/dual zone completion, CPF (central processing facility), export via pipeline/barge/shuttle tanker to another facility/third party terminal

A5: Defer development

With respect to Cost, Using the scale from 1 to 9 (where 9 is extremely and 1 is equally important), please indicate (X) the relative importance of Alternative A (left column) to Alternative B (right column) in the context of **Onshore** Marginal Field Development. **Please use the even numbers only when compromise are needed**.

A Alternative	9	8	7	6	5	4	3	2	1	2	3	4	5	6	7	8	9	**B Alternative**
A1																		A2
A1																		A3
A1																		A4
A2																		A3
A2																		A4
A3																		A4

With respect to Cost, Using the scale from 1 to 9 (where 9 is extremely and 1 is equally important), please indicate (X) the relative importance of Alternative A (left column) to Alternative B (right column) in the context of **Swamp** Marginal Field Development. **Please use the even numbers only when compromise are needed**.																		
A Alternative	9	8	7	6	5	4	3	2	1	2	3	4	5	6	7	8	9	**B Alternative**
A1																		A2
A1																		A3
A1																		A4
A2																		A3
A2																		A4
A3																		A4

With respect to Cost, Using the scale from 1 to 9 (where 9 is extremely and 1 is equally important), please indicate (X) the relative importance of Alternative A (left column) to Alternative B (right column) in the context of **Offshore** Marginal Field Development. **Please use the even numbers only when compromise are needed**.																		
Alternative A	9	8	7	6	5	4	3	2	1	2	3	4	5	6	7	8	9	Alternative B
A1																		A2
A1																		A3
A1																		A4
A2																		A3
A2																		A4
A3																		A4

With respect to HSE, Using the scale from 1 to 9 (where 9 is extremely and 1 is equally important), please indicate (X) the relative importance of Alternative A (left column) to Alternative B (right column) in the context of **Onshore** Marginal Field Development. **Please use the even numbers only when compromise are needed**.

A Alternative	9	8	7	6	5	4	3	2	1	2	3	4	5	6	7	8	9	**B Alternative**
A1																		A2
A1																		A3
A1																		A4
A2																		A3
A2																		A4
A3																		A4

With respect to HSE, Using the scale from 1 to 9 (where 9 is extremely and 1 is equally important), please indicate (X) the relative importance of Alternative A (left column) to Alternative B (right column) in the context of **Swamp** Marginal Field Development. **Please use the even numbers only when compromise are needed**.

A Alternative	9	8	7	6	5	4	3	2	1	2	3	4	5	6	7	8	9	**B Alternative**
A1																		A2
A1																		A3
A1																		A4
A2																		A3
A2																		A4
A3																		A4

With respect to HSE, Using the scale from 1 to 9 (where 9 is extremely and 1 is equally important), please indicate (X) the relative importance of Alternative A (left column) to Alternative B (right column) in the context of **Offshore** Marginal Field Development. **Please use the even numbers only when compromise are needed**.

A Alternative	9	8	7	6	5	4	3	2	1	2	3	4	5	6	7	8	9	**B Alternative**
A1																		A2
A1																		A3
A1																		A4
A2																		A3
A2																		A4

A3																		A4

With respect to Regulation, Using the scale from 1 to 9 (where 9 is extremely and 1 is equally important), please indicate (X) the relative importance of Alternative A (left column) to Alternative B (right column) in the context of **Onshore** Marginal Field Development. **Please use the even numbers only when compromise are needed**.

A Alternative	9	8	7	6	5	4	3	2	1	2	3	4	5	6	7	8	9	**B Alternative**
A1																		A2
A1																		A3
A1																		A4
A2																		A3
A2																		A4
A3																		A4

With respect to Regulation, Using the scale from 1 to 9 (where 9 is extremely and 1 is equally important), please indicate (X) the relative importance of Alternative A (left column) to Alternative B (right column) in the context of **Swamp** Marginal Field Development. **Please use the even numbers only when compromise are needed**.

A Alternative	9	8	7	6	5	4	3	2	1	2	3	4	5	6	7	8	9	**B Alternative**
A1																		A2
A1																		A3
A1																		A4
A2																		A3
A2																		A4
A3																		A4

With respect to Regulation, Using the scale from 1 to 9 (where 9 is extremely and 1 is equally important), please indicate (X) the relative importance of Alternative A (left column) to Alternative B (right column) in the context of **Offshore** Marginal Field

Development. **Please use the even numbers only when compromise are needed**.																	
A Alternative	9	8	7	6	5	4	3	2	1	2	3	4	5	6	7	8	9	**B Alternative**
A1																		A2
A1																		A3
A1																		A4
A2																		A3
A2																		A4
A3																		A4

With respect to Security, Using the scale from 1 to 9 (where 9 is extremely and 1 is equally important), please indicate (X) the relative importance of Alternative A (left column) to Alternative B (right column) in the context of **Onshore** Marginal Field Development. **Please use the even numbers only when compromise are needed**.																		
A Alternative	9	8	7	6	5	4	3	2	1	2	3	4	5	6	7	8	9	**B Alternative**
A1																		A2
A1																		A3
A1																		A4
A2																		A3
A2																		A4
A3																		A4

With respect to Security, Using the scale from 1 to 9 (where 9 is extremely and 1 is equally important), please indicate (X) the relative importance of Alternative A (left column) to Alternative B (right column) in the context of **Swamp** Marginal Field Development. **Please use the even numbers only when compromise are needed**.																		
A Alternative	9	8	7	6	5	4	3	2	1	2	3	4	5	6	7	8	9	**B Alternative**
A1																		A2

A1																		A3
A1																		A4
A2																		A3
A2																		A4
A3																		A4

With respect to Security, Using the scale from 1 to 9 (where 9 is extremely and 1 is equally important), please indicate (X) the relative importance of Alternative A (left column) to Alternative B (right column) in the context of **Offshore** Marginal Field Development. **Please use the even numbers only when compromise are needed**.

A Alternative	9	8	7	6	5	4	3	2	1	2	3	4	5	6	7	8	9	**B Alternative**
A1																		A2
A1																		A3
A1																		A4
A2																		A3
A2																		A4
A3																		A4

With respect to Stakeholders, Using the scale from 1 to 9 (where 9 is extremely and 1 is equally important), please indicate (X) the relative importance of Alternative A (left column) to Alternative B (right column) in the context of **Onshore** Marginal Field Development. **Please use the even numbers only when compromise are needed**.

A Alternative	9	8	7	6	5	4	3	2	1	2	3	4	5	6	7	8	9	**B Alternative**
A1																		A2
A1																		A3
A1																		A4
A2																		A3
A2																		A4
A3																		A4

With respect to Stakeholder, Using the scale from 1 to 9 (where 9 is extremely and 1 is equally important), please indicate (X) the relative importance of Alternative A (left column) to Alternative B (right column) in the context of **Swamp** Marginal Field Development. **Please use the even numbers only when compromise are needed**.

A Alternative	9	8	7	6	5	4	3	2	1	2	3	4	5	6	7	8	9	**B Alternative**
A1																		A2
A1																		A3
A1																		A4
A2																		A3
A2																		A4
A3																		A4

With respect to Stakeholders, Using the scale from 1 to 9 (where 9 is extremely and 1 is equally important), please indicate (X) the relative importance of Alternative A (left column) to Alternative B (right column) in the context of **Offshore** Marginal Field Development. **Please use the even numbers only when compromise are needed**.

A Alternative	9	8	7	6	5	4	3	2	1	2	3	4	5	6	7	8	9	**B Alternative**
A1																		A2
A1																		A3
A1																		A4
A2																		A3
A2																		A4
A3																		A4

With respect to Technology, Using the scale from 1 to 9 (where 9 is extremely and 1 is equally important), please indicate (X) the relative importance of Alternative A (left column) to Alternative B (right column) in the context of **Onshore** Marginal Field

Development. **Please use the even numbers only when compromise are needed**.																		
A Alternative	9	8	7	6	5	4	3	2	1	2	3	4	5	6	7	8	9	**B Alternative**
A1																		A2
A1																		A3
A1																		A4
A2																		A3
A2																		A4
A3																		A4

With respect to Technology, Using the scale from 1 to 9 (where 9 is extremely and 1 is equally important), please indicate (X) the relative importance of Alternative A (left column) to Alternative B (right column) in the context of **Swamp** Marginal Field Development. **Please use the even numbers only when compromise are needed**.																		
A Alternative	9	8	7	6	5	4	3	2	1	2	3	4	5	6	7	8	9	**B Alternative**
A1																		A2
A1																		A3
A1																		A4
A2																		A3
A2																		A4
A3																		A4

With respect to Technology, Using the scale from 1 to 9 (where 9 is extremely and 1 is equally important), please indicate (X) the relative importance of Alternative A (left column) to Alternative B (right column) in the context of **Offshore** Marginal Field

Development. **Please use the even numbers only when compromise are needed**.																		
A Alternative	9	8	7	6	5	4	3	2	1	2	3	4	5	6	7	8	9	**B Alternative**
A1																		A2
A1																		A3
A1																		A4
A2																		A3
A2																		A4
A3																		A4

Appendix 2: Geometric Mean of Judgements

Onshore

Pairwise Comparison	SME1	SME2	SME3	SME4	SME5	SME6	SME7	SME8	SME9	SME10	SME11	SME12	SME13	SME14	SME15	Geomean
Cost vs HSE	1/5	1/5	1/5	1	3	1/7	3	3	5	1/3	3	3	1	7	1/3	1.01
Cost vs Regulation	1/3	1/9	1/3	5	3	1/3	1/3	3	1	1/5	1	1/5	1	9	1/5	0.70
Cost vs Security	1/5	1/5	1/3	2	3	1/5	1	7	1/5	1	3	3	1	1/3	1/5	0.75
Cost vs Stakeholders	1/3	1/4	1/3	5	3	1/5	3	7	1	3	1/5	7	3	5	5	1.52
Cost vs Technology	5	1/3	5	2	5	5	1	9	7	1/3	1	5	3	1/3	7	2.32
HSE vs Regulation	3	1	1	1	1/3	5	1/5	3	1/3	1/3	1/3	1/5	1	1/7	1	0.68
HSE vs Security	1	1	1	1	1/3	5	1	3	1/5	1	3	1/3	1	1/9	3	0.93
HSE vs Stakeholders	3	4	1/3	9	1/5	3	3	5	1/3	3	1/5	5	5	1/7	7	1.64
HSE vs Technology	7	4	5	1	1/5	9	3	9	3	1/3	1/3	5	5	1/7	7	2.07
Regulation vs Security	1/5	1	1/5	1	1/3	1/3	5	3	1/3	5	3	3	1	1/7	3	0.95
Regulation vs Stakeholders	1	9	1	9	1/3	1/3	7	5	3	5	1	9	1	7	9	2.68
Regulation vs Technology	5	9	5	1/5	1	5	7	9	7	5	3	9	3	1/5	9	3.34
Security vs Stakeholders	3	4	1	7	1	1/3	3	5	3	1	1/3	7	3	7	3	2.24
Security vs Technology	7	4	7	1	3	6	5	5	5	1/5	1/3	5	3	1/7	7	2.38
Stakeholders vs Technology	5	4	7	1/9	3	9	1	5	3	1/3	1	1/3	3	1/7	3	1.57

Swamp

Pairwise Comparison	SME1	SME2	SME3	SME4	SME5	SME6	SME7	SME8	SME9	SME10	SME11	SME12	SME13	SME14	SME15	Geomean
Cost vs HSE	1/5	1/7	1/5	1/2	5	1/7	1/5	1	5	1/3	1	3	1/5	1/5	1/5	0.48
Cost vs Regulation	1/3	1/9	1/3	1	3	1/3	1/3	3	1	1/5	1/3	1/3	1/5	1/3	1/7	0.42
Cost vs Security	1/5	1/5	1/3	2	3	1/5	1/5	7	1/5	1/3	3	5	1/3	1/5	1/3	0.60
Cost vs Stakeholders	1/3	1/5	1/3	4	3	1/5	1/3	7	1	3	1/3	5	1	1/3	1/5	0.81
Cost vs Technology	4	1/3	5	1/2	7	3	4	7	7	1/5	1	3	1	4	1/7	1.76
HSE vs Regulation	3	1	1	3	1/3	5	3	5	1/3	1	1/3	1/3	1	3	1/3	1.15
HSE vs Security	1	1	1	2	1/3	5	1	7	1/5	1	1	5	1	1	3	1.33
HSE vs Stakeholders	3	5	1/3	9	1/3	3	3	5	1/3	3	1/3	5	3	3	3	1.99
HSE vs Technology	7	5	5	2	1/3	9	7	7	3	1/5	1/3	3	3	7	1/5	2.19
Regulation vs Security	1/5	1	1/5	3	1/5	1/3	1/5	3	1/3	1	3	7	1	1/5	7	0.82
Regulation vs Stakeholders	1	9	1	9	1/3	1/5	1	5	3	5	3	7	1	1	7	2.08
Regulation vs Technology	5	9	5	1/6	3	5	5	7	7	1/3	3	9	3	5	3	3.28
Security vs Stakeholders	3	4	1	6	1	1	3	3	3	3	1/3	1	1	3	1/3	1.66
Security vs Technology	7	5	7	1/2	5	5	7	5	5	1/5	1/3	3	1	7	1/7	2.16
Stakeholders vs Technology	5	4	7	1/9	3	7	5	3	5	1/3	1	3	1	5	1/3	2.03

Offshore

Pairwise Comparison	SME1	SME2	SME3	SME4	SME5	SME6	SME7	SME8	SME9	SME10	SME11	SME12	SME13	SME14	SME15	Geomean
Cost vs HSE	1/7	1/9	1/5	1/3	3	1/7	3	5	5	1/5	1/3	1/3	1/5	3	1	0.60
Cost vs Regulation	1/3	1/9	1/3	1/2	3	1/3	1	5	1	1/3	1/3	1/3	1/5	1	1	0.57
Cost vs Security	1/5	1/5	1/3	3	3	3	5	5	5	3	3	5	1	5	5	2.06
Cost vs Stakeholders	3	1/5	1/3	5	5	1/7	5	6	5	3	1	5	1	5	1	1.82
Cost vs Technology	3	0.33	5	1/5	3	1/5	3	7	1	1/5	1/3	1/3	1	3	1/3	0.92
HSE vs Regulation	3	1	1	4	1/3	9	1/3	3	1	1	1	1/3	1	1/3	3	1.18
HSE vs Security	3	1	1	3	1/5	9	5	5	5	5	3	7	5	5	7	3.20
HSE vs Stakeholders	5	7	1/3	9	3	9	5	5	1	7	3	7	3	5	3	3.79
HSE vs Technology	7	7	5	1/3	1/3	9	1	7	1/3	1/3	1	1	1	1	1/3	1.32
Regulation vs Security	1/3	1	1/5	5	1/3	7	3	3	5	3	3	9	3	3	7	2.24
Regulation vs Stakeholders	3	9	1	9	3	7	5	3	1	3	1	7	5	5	5	3.58
Regulation vs Technology	5	9	5	1/5	1/3	7	5	5	1	1/5	1	3	3	5	1	1.96
Security vs Stakeholders	5	6	1	5	5	1	3	3	1/5	5	1/3	1/3	1	3	1/7	1.47
Security vs Technology	5	5	7	1/9	3	7	1	3	1/7	1/7	1/3	1/5	3	1	1/9	0.96
Stakeholders vs Technology	3	5	7	1/9	1/3	9	1/3	3	1	1/3	1	1/3	3	1/3	1/3	1.02

Appendix 3: Eigenvector Calculations for Priority Scores

Onshore

Criteria	Cost	HSE	Regulation	Security	Stakeholders	Technology	Priority Score
Cost	1	1	1	1	2	2	0.195
HSE	1	1	1	1	2	2	0.195
Regulation	1	1	1	1	3	3	0.225
Security	1	1	1	1	2	2	0.195
Stakeholders	1/2	1/2	1/3	1/2	1	2	0.106
Technology	1/2	1/2	1/3	1/2	1/2	1	0.084
	5	5	4 2/3	5	10 1/2	12	

Criteria	Cost	HSE	Regulation	Security	Stakeholders	Technology	Total	Average	Consistency Measure
Cost	0.200	0.200	0.214	0.200	0.190	0.167	1.171	0.20	6.091
HSE	0.200	0.200	0.214	0.200	0.190	0.167	1.171	0.20	6.091
Regulation	0.200	0.200	0.214	0.200	0.286	0.250	1.350	0.23	6.127
Security	0.200	0.200	0.214	0.200	0.190	0.167	1.171	0.20	6.091
Stakeholders	0.100	0.100	0.071	0.100	0.095	0.167	0.633	0.11	6.071
Technology	0.100	0.100	0.071	0.100	0.048	0.083	0.502	0.08	6.024
	1	1	1	1	1	1	6	1	
								CI	0.017
								RI	1.240
								CR	0.013

Appendix 4: Facilities Data

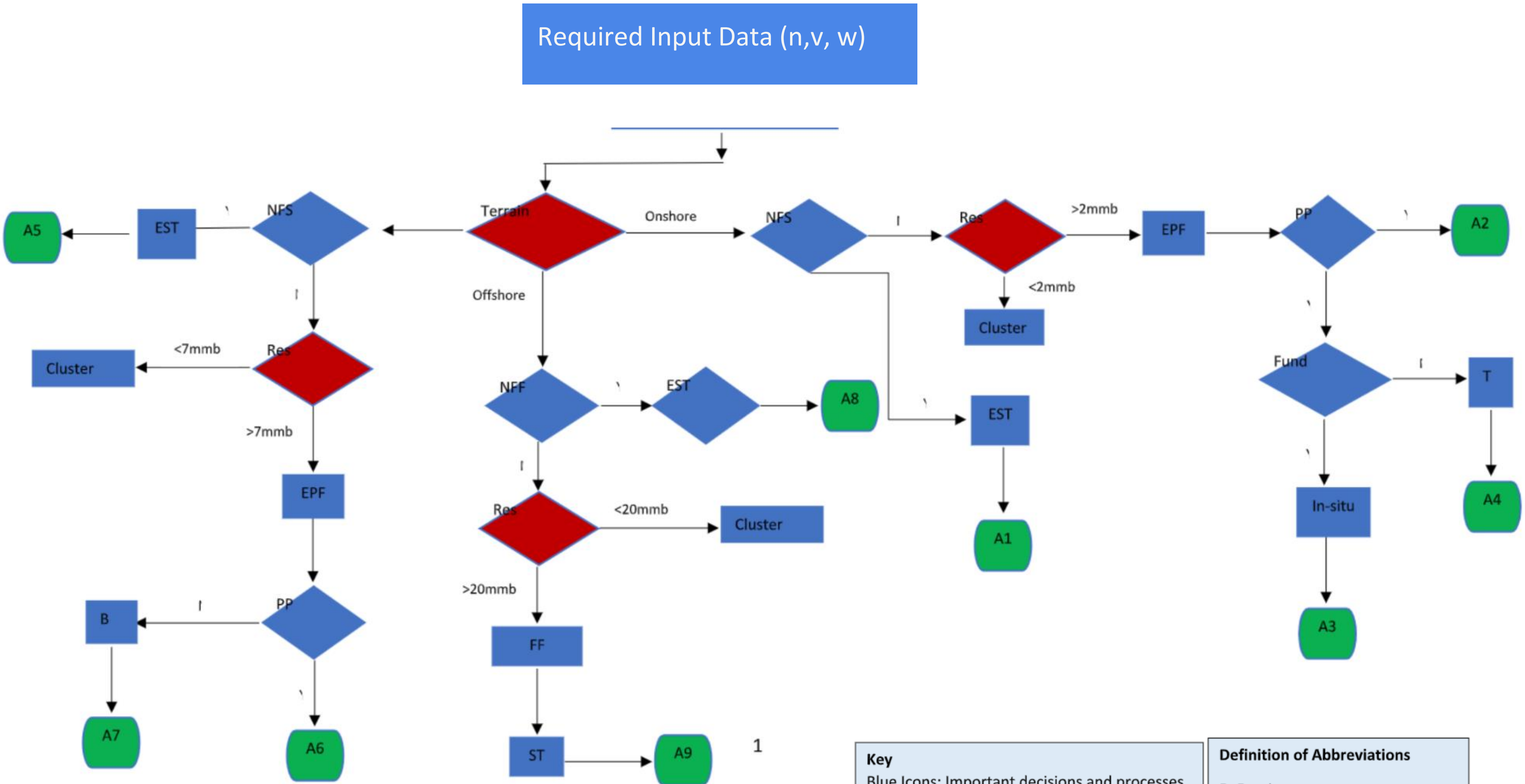
Facility Type	Name	Block	Location	Is Producing
Oil Field	Ogbele	OML 54	Swamp	Yes
	Omerelu	OML 53	Land	
	Asamatoru	OML 11	Swamp	Yes
	Okwok	OML 67	Offshore	Yes
	Ebok	OML 67	Offshore	Yes
	Stubb Creek	OMLs 13/14	Swamp	Yes
	Dawes Island	OML 54	Swamp	
	Umusati/Igbuku	OML 56	Land	Yes
	Atala	OML 46	Swamp	
	Ekeh	OML 88	Offshore	
	Ogedeh	OML 90	Offshore	
	Ororo	OML 95	Offshore	
	Egbaoma (Ex Asuokpu/Umutu)	OML 38	Land	Yes
	Amoji/Matsogo/Igholo	OML 56	Land	Yes
	Akepo	OML 90	Offshore	
	Oza	OML 11	Land	Yes
	Ajapa	OML 90	Offshore	Yes
	Qua Iboe	OML 13	Land	Yes
	Ibigwe	OML 16	Land	Yes
	Umusadege	OML 56	Land	
	Ofa	OML 30	Land	
	KE	OML 55	Swamp	
	Tom Shot Bank	OML 14	Offshore	
	Uquo	OML 13	Swamp	Yes
	Ebendo/Obodeti (Ex Obodugwa/Obodeti)	OML 56	Land	Yes
	Oriri	OML 88	Offshore	

	Eremor	OML 46	Swamp	Yes
	Tsekelewu	OML 40	Land/Swamp	
	Otakikpo	OML 11	Land	Yes
	Ubima	OML 17	Land	Yes
Terminals	Escravos	OML 43	Land	
	Escravos Offshore	OML 109	Offshore	
	Forcados	OML 45	Land	
	Forcados Offshore	OML 227	Offshore	
	Pennington Offshore	OML 86	Offshore	
	Brass	OML 141	Land	
	Brass Offshore	OML 225	Offshore	
	Bonny	OML 117	Land	
	Bonny Offshore	OML 72	Offshore	
	Qua Iboe	OML 13	Land	
	Qua Iboe Offshore	OML 67	Offshore	
FPSO	Abo	OML 125	Offshore	
	Efha	OML 133		
	Bonga	OML 118		
	EA	OML 79		
	Pennington	OML 88		
	Agbami	OML 127		
	Okwori	OML 126		
	Akpo	OML 130		
	Okono	OML 119		
	Usan	OML 138		
	Okoro	OML 112		
	Edikan	OML 100		
	Antan	OML 123		
	Ebok	OML 115		

Appendix 5: Facilities Data (Sample JSON format)


```
{
    id: 1,
    name: "Ogbele",
    oml:"95",
    isProducing:true,
    oilPipelineProximity: 0,
    oilPipeline: true,
    gasPipelineProximity: 5,
    gasPipeline: true,
    Terrain: "Land",
    type: "Oil Field",
    coords: {
        longitude: 6.658534690435712,
        latitude: 4.903797283669056,
    }
}
```

Appendix 6: Marginal Field Development Strategy Selection Algorithm



1

Key
Blue Icons: Important decisions and processes
Red Icons: Critical decision Input
Green Icons: Output

Definition of Abbreviations

B: Barging
EPF: Early production facility
EST: Established mode, pipeline or shuttle tanker
EWT: Extended well test
FF: Floating facility
NFF: Nearby floating facility
NFS: Nearby flow station

Marginal Field Attributes

Assumptions: reservoirs are water drive, DWA, PAF

Appendix 7: Fomulas

1. Harvesine

Distance between two facilities,

d = $2Ratan\sqrt{(1-\ a)/a}$

2. NVP

The Net Present Value of a Development Strategy,

NPV = $\sum_{x}^{y}\ \left(\frac{r-OPEX}{(1+i)^{x}}\right)-\ CAPEX$

3. Completion Cost

The Completion cost for a new well,

c = $z_c n_{new}\ +\ 0.5 z_c n_r$ (single completion)

c = $2(z_c n_{new}\ +\ 0.5 z_c n_r)$ (double completion)

Where:

lat_1 = Latitude of Selected Field

lat_2 = Latitude of Current Close Facility

lon_1 = Longitude of Selected Field

lon_2 = Longitude of Current Close Facility

$$a\ = sin^2\left(\frac{lat_2\ -\ lat_1}{2}\right) + cos(lat_1)cos(lat_2)sin^2(\frac{lon_2\ -\ lon_1}{2})$$

i = interest rate

y = years

r = Revenue per year

$OPEX$ varies based on the development strategy as shown in Appendix V

$CAPEX$ varies based on the development strategy as shown in Appendix V

n_r = Number of Re-enterable wells

n_c = Well Constant based on terrain

z_c = Well Cost Constant

V_o = Reservoir Volume (mmbbl)

Number of New wells, $n_{new} = \frac{V_o - n_r n_c}{n_c}$

Appendix 8: Variable Factors for Each Development Strategy

<table>
<tr><th>Strategy</th><th>Details</th><th>OPEX</th><th>CAPEX</th></tr>
<tr><td>A1</td><td>Development of exisiting and new Well(s), single/dual zone completion, Tie-in to a nearby facilty and export via established means.</td><td>OPEX land/Offshore, $O_l = p_d p_c$

OPEX Swarm, $O_s = b_c$</td><td rowspan="2">v_c = Variable Cost

CAPEX cost, C = Completion Cost + v_c</td></tr>
<tr><td>A2</td><td>Development of exisiting and new Well(s), single/dual zone completion, Early Production Facility, Export via Pipeline to another facility or Third party Terminal.</td><td>OPEX land/Offshore cost, $O_l = p_d p_c + c_{epf}$

OPEX Swarm cost, $O_s = b_c + c_{epf}$</td></tr>
</table>

A3	Development of exisiting and new Well(s), single/dual zone completion, Early Production Facility, Export via Trucking/Barge/Shuttle tanker to another facility or Third party Terminal.	OPEX land/ Offshore, For p_d > 20 km $O_l = p_d\, p_c + c_{epf}$ **For p_d < 20 km** OPEX land/ Offshore , $O_l = b_c + c_{epf}$ OPEX Swarm cost, $O_s = b_c + c_{epf}$	
A4	Development of exisiting and new Well(s), single/dual zone completion, Central Processing Facility, Export via Pipeline/Barge/Shuttle tanker to another facility or Third party Terminal.	OPEX cost, $O = c_{cpf}$	

Where

p_d = Pipeline/FPSO Distance to Facility

p_c = Pipeline/FPSO Cost

b_c = Barging/Trucking Cost

c_{epf} = Early Production Facility Cost /Terrrain

c_{cpf} = Central Processing Facility Cost /Terrrain

Appendix 9: AHP Analysis

Below are the priority scores for the criteria Table 1, and for the alternatives by terrain Tables 2, 3, 4.

Table 1: Priority scores for criteria

Criteria	Priority Scores		
	Onshore	Swamp	Offshore
Cost	0.195	0.114	0.193
HSE	0.195	0.215	0.223
Regulation	0.225	0.245	0.242
Security	0.195	0.215	0.115
Stakeholders	0.106	0.133	0.084
Technology	0.084	0.079	0.143

Table 2: Priority scores for alternatives onshore

Onshore							
Alternatives	Cost	HSE	Regulation	Security	Stakeholders	Technology	Overall Priorities
A1	0.104	0.108	0.106	0.081	0.049	0.027	0.476
A2	0.038	0.039	0.049	0.043	0.020	0.017	0.206
A3	0.012	0.015	0.022	0.022	0.010	0.012	0.092
A4	0.041	0.033	0.048	0.049	0.027	0.028	0.226

Table 3: Priority scores for alternatives swamp

Swamp							
Alternatives	Cost	HSE	Regulation	Security	Stakeholders	Technology	Overall Priorities
A1	0.057	0.120	0.137	0.085	0.061	0.025	0.484
A2	0.024	0.040	0.046	0.050	0.031	0.016	0.206
A3	0.010	0.013	0.014	0.030	0.012	0.011	0.089
A4	0.023	0.043	0.049	0.050	0.030	0.028	0.221

Table 4: Priority scores for alternatives offshore

Offshore							
Alternatives	Cost	HSE	Regulation	Security	Stakeholders	Technology	Overall Priorities
A1	0.113	0.127	0.114	0.050	0.041	0.055	0.500
A2	0.027	0.041	0.053	0.028	0.016	0.029	0.195
A3	0.015	0.012	0.024	0.011	0.007	0.014	0.084
A4	0.038	0.043	0.051	0.025	0.020	0.045	0.222

Appendix 10: Python Functions

Haversine Function

```
import math

def haversine_distance(coords1, coords2):
    """
    This function calculates the Haversine distance between two points on the earth specified by latitude/longitude.

    Parameters:
    coords1 (dict): A dictionary containing 'latitude' and 'longitude' of the first location.
    coords2 (dict): A dictionary containing 'latitude' and 'longitude' of the second location.

    Returns:
    float: The Haversine distance between the two locations in kilometers.
    """

    # Convert degrees to radians
    RADIANS_PER_DEGREE = math.pi / 180

    # Convert latitudes and longitudes to radians
    latitude1 = coords1['latitude'] * RADIANS_PER_DEGREE
    longitude1 = coords1['longitude'] * RADIANS_PER_DEGREE
    latitude2 = coords2['latitude'] * RADIANS_PER_DEGREE
    longitude2 = coords2['longitude'] * RADIANS_PER_DEGREE

    # Calculate differences in coordinates
    d_lat = latitude2 - latitude1
    d_lon = longitude2 - longitude1
```

```
    # Haversine formula to calculate distance between two points on a sphere
    a = math.sin(d_lat / 2) ** 2 + math.cos(latitude1) * math.cos(latitude2) * math.sin(d_lon / 2) ** 2
    distance = 6371.01 * 2 * math.atan2(math.sqrt(a), math.sqrt(1 - a))

    return distance
```

Net Present Value Function

```
def net_present_value(irr, years, initial_investment, average_yearly_revenue, recurrent_yearly_cost):
    """
    This function calculates the Net Present Value (NPV) of a series of cash flows.

    Parameters:
    irr (float): The discount rate or interest rate.
    years (int): The number of years for the cash flows.
    initial_investment (float): The initial investment amount.
    average_yearly_revenue (float): The average yearly revenue.
    recurrent_yearly_cost (float): The recurrent yearly cost.

    Returns:
    float: The calculated NPV.
    """

    # Initialize NPV with the negative initial investment
    npv = -initial_investment

    # Calculate NPV for each year
    for i in range(1, years + 1):
```

```
        # Calculate the net cash flow for the year
        cash_flow = average_yearly_revenue - recurrent_yearly_cost

        # Discount the cash flow and add it to the NPV
        npv += cash_flow / pow(1 + irr, i)

    return npv
```

Get Closeby/Cluster Facilities Function

```
def get_cluster_facilities(terminal_arr, facility_coords):
    """
    This function calculates the haversine distance from a facility to each terminal in a list,
    filters out terminals that are more than 150km away, sorts the remaining terminals by distance,
    and returns the five closest terminals.

    Parameters:
    terminal_arr (list): A list of dictionaries, each containing 'coords' key for a terminal.
    facility_coords (dict): A dictionary containing 'coords' key for the facility.

    Returns:
    list: A list of dictionaries for the five closest terminals within 150km, each dictionary contains 'coords' and 'distance'.
    """

    # Calculate the haversine distance from the facility to each terminal
    distances = []
```

```python
    for terminal in terminal_arr:
        distance = haversine_distance(facility_coords['coords'], terminal['coords'])
        terminal['distance'] = distance
        distances.append(terminal)

    # Filter out terminals that are more than 150km away
    filtered_distances = [terminal for terminal in distances if 0 < terminal['distance'] <= 150]

    # Sort the terminals by distance, closest first
    sorted_distances = sorted(filtered_distances, key=lambda terminal: terminal['distance'])

    # Return the five closest terminals
    return sorted_distances[:5]
```

Get Development Stratrgy per Facilty Function

```python
def get_development_type(terrain, oil_volume, is_cluster, crude_to_facility, process_to_facility, process_to_terminal):
    """
    This function determines the development type based on various parameters.

    Parameters:
    terrain (str): The type of terrain (onshore, swamp, offshore).
    oil_volume (float): The volume of oil.
    is_cluster (bool): Whether it's a cluster.
    crude_to_facility (bool): Whether crude is to be transported to the facility.
```

```
    process_to_facility (bool): Whether processed oil is to be transported to the facility.
    process_to_terminal (bool): Whether processed oil is to be transported to the terminal.

    Returns:
    list: A list containing the development type and an array of development types.
    """

    # Initialize variables
    dev_type = ""
    dev_arr = []

    # Define minimum volumes for different terrains
    cluster_min_volume_land = 5  # Minimum acceptable Rerservoir volume for Land
    cluster_min_volume_offshore = 20  # Minimum acceptable Rerservoir volume for Offshore
    cluster_min_volume_swamp = 10  # Minimum acceptable Rerservoir volume for Swamp

    # Determine development type based on terrain and other parameters
    if terrain == "onshore":
        if 0 < oil_volume < cluster_min_volume_onshore:
            dev_type = "AL4" if is_cluster else "AL5"
        else:
            if crude_to_facility:
                dev_type = "AL1"
            if process_to_facility:
                dev_type = "AL2"
```

```
      if process_to_terminal:
        dev_type = "AL3"
    dev_arr.append(dev_type)

  elif terrain == "offshore":
    if 0 < oil_volume < cluster_min_volume_offshore:
      dev_type = "AW4" if is_cluster else "AW5"
    else:
      if crude_to_facility:
        dev_type = "AW1"
      if process_to_terminal:
        dev_type = "AW3"
    dev_arr.append(dev_type)

  elif terrain == "swamp":
    if 0 < oil_volume < cluster_min_volume_swamp:
      dev_type = "AS4" if is_cluster else "AS5"
    else:
      if crude_to_facility:
        dev_type = "AS1"
      if process_to_facility:
        dev_type = "AS2"
      if process_to_terminal:
        dev_type = "AS3"
    dev_arr.append(dev_type)

  return [dev_type, dev_arr]
```

Completion Cost Function

```
def completion_cost(terrain, new_wells, enterable_wells):
```

```python
    """
    This function calculates the completion cost based on the terrain and the number of new and enterable wells.

    Parameters:
    terrain (str): The type of terrain (onshore, swamp, offshore).
    new_wells (str): The number of new wells as a string.
    enterable_wells (str): The number of enterable wells as a string.

    Returns:
    float: The calculated completion cost.
    """
    cost_onshore = 5 # Completion cost onshore
    cost_offshore = 20 # Completion cost offshore
    cost_swamp = 10 # Completion cost swamp

    # Convert the number of wells from string to integer
    new_wells = int(new_wells)
    enterable_wells = int(enterable_wells)

    # Calculate the completion cost based on the terrain
    if terrain.lower() == "onshore":
        return new_wells * cost_onshore + enterable_wells * 0.5 * cost_onshore
    elif terrain.lower() == "offshore":
        return new_wells * cost_offshore + enterable_wells * 0.5 * cost_offshore
    elif terrain.lower() == "swamp":
        return new_wells * cost_swamp + enterable_wells * 0.5 * cost_swamp
```