

**DESIGNING OPTIMAL PRODUCTION STRATEGIES FOR MAXIMUM EFFICIENT
RECOVERY IN MATURE OIL FIELDS: CASE STUDY, A NIGER DELTA FIELD**



BY

AKASAN GABRIEL KUGBA

ENG2002596

**DISSERTATION SUBMITTED IN PARTIAL FULFILMENT OF
THE REQUIREMENTS FOR THE BACHELOR OF PETROLEUM ENGINEERING
(B.ENG.) DEGREE.**

IN

**THE DEPARTMENT OF PETROLEUM ENGINEERING,
FACULTY OF ENGINEERING,
UNIVERSITY OF BENIN, BENIN CITY, NIGERIA.**

NOVEMBER, 2025

PLAGIARISM

This work **DESIGNING OPTIMAL PRODUCTION STRATEGIES FOR MAXIMUM EFFICIENT RECOVERY IN MATURE OIL FIELDS: CASE STUDY A NIGER DELTA FIELD, USING PROSPER SOFTWARE** by Akasan Gabriel with Matriculation number ENG2002596 of the Department of Petroleum Engineering, Faculty of Engineering, University of Benin City, Edo State, Nigeria, has PASSED the PLAGIARISM TEST.

Engr. Dr. Oluwaseun. A. Taiwo

Date

PROJECT COORDINATOR

CERTIFICATION

This is to certify that this work is carried out by AKASAN GABRIEL KUGBA, Mat. No. ENG2002596, of the Department of Petroleum Engineering, Faculty of Engineering, University of Benin City, Edo State, Nigeria and is deemed adequate in quality and scope as part of requirements for the award of Bachelor of Engineering (B.Eng.).

PROJECT SUPERVISOR:

Engr. Dr. Ikponmwosa Ohenhen

Signature

Date

HEAD OF DEPARTMENT:

Engr. Dr. Ikponmwosa Ohenhen

Signature

Date

PROJECT COORDINATOR:

Engr. Dr. Oluwaseun. A. Taiwo

Signature

Date

DEDICATION

This work is dedicated to my parents, my father MR. AKASAN PETER KEFEREFE who has been constantly supporting and encouraging me in this my academic pursuit, am dedicating this to him as part of the promise I made to him in completing my degree in petroleum engineering. Also, to my lovely and ever supporting mum who would want to go any length even till the end of the world to see that am fine wherever I am. Mummy your prayers are answered, MRS MARY AKASAN.

ACKNOWLEDGEMENTS

I appreciate God almighty for his kindness and goodness because we all cannot do nothing without Him. He is my source and help through periods when I travailed. The special thanks go to my project supervisor and also the H.O.D of Petroleum Engineering Department Engr. Dr. IKPONMWOSA OHENHEN. The supervision and support He gave me truly help the progression and smoothness of this final year project. The co-operation is much indeed appreciated. A big contribution from you during the twelve weeks is very great. This final year project would be nothing without the enthusiasm and imagination from you. Lastly, I would like to thank all friends and everyone who in one way or the other has contributed directly or indirectly in making this final year project a success. Also, I want to also use this opportunity to verily appreciate my friend and course mate, Abdulkareem for his contribution to my project work God bless you my dear friend.

ABSTRACT

The production optimization of oil and gas wells using computerized well model has become a successful technique contributing towards the better efficiency and higher production of many wells. This study focuses on designing optimum production strategies in mature oil field, well modelling using prosper, one of the components of the integrated production modelling (IPM) was implemented in field X which is located in peninsular Malaysia. The model carries all the properties of the well with detailed description of the reservoir and vertical lift performance. The process includes four phases: first phase was building well model using PVT, IPR, surface and equipment data. Second phase was constructing well matching based on the monthly well test data. This helps to ensure that the model is well calibrated. Third phase was performing well analysis based on the well matching results. Well analysis can be performed by evaluating each component of the producing well. Often this procedure will identify possible problems occurred in the production components which restrict flow and cause the well to produce in a manner that the maximum potential rate is not achieved. From the results and findings achieved from the IPR-VLP curves/trend, the optimum operating point takes place at a flow rate of 900STB/D at Bottom hole pressure of 2500psia, so increasing tubing size beyond 3.96-inches offers minimal benefits and can lead to liquid loading issues. Also, maintaining a moderate wellhead pressure of 350psig achieves a stable production and prevents drawdown. Also, from my findings, the IPR-VLP intersection in the graphical trend above shows the natural equilibrium of the system, satisfying the certainty and accuracy of prosper modeling software tool. Overall, this production technique permits engineer to come with some modification which is expected to increase the production.

TABLE OF CONTENT

TITLE PAGE	i
CERTIFICATION	iii
DEDICATION	iv
ACKNOWLEDGEMENTS	v
ABSTRACT	vi
TABLE OF CONTENT	vi
LIST OF TABLES	ix
LIST OF FIGURES	x
ACRONYMS	xi
CHAPTER ONE	1

INTRODUCTION	1
1.1 BACKGROUND TO THE STUDY	1
1.2 PROBLEM STATEMENT	2
1.3 AIM/OBJECTIVES OF THE STUDY	2
1.4 SCOPE OF STUDY:	3
CHAPTER TWO	4
LITERATURE REVIEW	4
2.1 ELECTRIC SUBMERSIBLE PUMPS (ESP)	4
2.2 ENHANCED OIL RECOVERY:	5
2.3 OVERVIEW OF MATURE OIL FIELDS:	5
2.4 CHARACTERISTICS OF MATURE OIL FIELDS:	6
2.5 DEVELOPING THE OPTIMUM FIELD DEVELOPMENT PLAN FOR MATURE OIL FIELDS:	6
1. Comprehensive Reservoir Management	6
2. Enhanced Oil Recovery (EOR) and Improved Oil Recovery (IOR)	7
2.6 CHALLENGES ASSOCIATED WITH MATURE FIELD DEVELOPMENT:	10
2.7 KEY CHALLENGES ASSOCIATED WITH MATURE FIELD DEVELOPMENT INCLUDE:	10
2.8 PRODUCTION OPTIMIZATION OF A MATURE OIL FIELD ASSET:	14
2.9 PRODUCTION OPTIMIZATION STRATEGIES:	20
CHAPTER THREE	29
METHODOLOGY:	29
3.1 Research Design:	29
3.2 sampling /case selection:	30
3.3 Data Collection	30

3.3.1 Data Sources	30
3.4 Data Types:	30
3.5 Model Development Using PROSPER	31
3.5.2 Model Calibration:	32
3.5.3 Sensitivity Analysis:	32
3.6 Optimization of Production Strategy:	33
3.7 Model Validation:	33
3.8 Data Analysis and Interpretation:	33
3.9 OTOROGU FIELD:	34
3.9.1 WELL 05 SIMULATION DATA	34
CHAPTER FOUR	36
RESULTS AND DISCUSSION	36
4.1 PRESENTATION OF DATA:	36
4.1.1 Inflow-performance relationship (IPR) curve plot:	36
4.1.2 Inflow IPR V.S Outflow VLP Plot:	37
4.1.3 Well Model System:	38
4.1.4 IPR Calculation ResultsT:	39
4.1.5 VLP (Tubing) calculation results:	41
4.1.6 Choke performance plot:	42
4.2 DATA ANALYSIS:	43
4.3 DISCUSSION OF FINDINGS:	44
CHAPTER FIVE	45
CONCLUSIONS AND RECOMMENDATIONS:	45
5.1 CONCLUSION	45
5.2 RECOMMENDATIONS	45

5.3 CONTRIBUTION TO KNOWLEDGE	46
REFERENCES	47

LIST OF TABLES

Table	3.9.1	WELL	05	SIMULATION	DATA
36					

LIST OF FIGURES

Fig. 4.1	Reservoir Pressure (psia) vs. Well Flow Rate (STB/D) Plot ...	
38		
Fig. 4.2	Inflow Performance Relationship (IPR) vs. Vertical Lift Performance (VLP) Plot	39
Fig. 4.3	Simulated Well Model System (X-mas Tree, Tubing, and Casing) ...	
40		
Fig. 4.4	IPR Calculation Results Table (Graphical Output) ...	
41		
Fig. 4.5	VLP (Tubing) Calculation Results Table ...	42
Fig. 4.6	Choke Performance	Plot
43		

ACRONYMS

API	American Petroleum Institute
AOF	Absolute Open Flow
BOPD	Barrels of Oil per Day
EOR	Enhanced Oil Recovery
ESP	Electric Submersible Pump
GOR	Gas–Oil Ratio
IPM	Integrated Production Modelling
IPR	Inflow Performance Relationship
OIP	Original Oil in Place
PI	Productivity Index
PVT	Pressure–Volume–Temperature
TVD	True Vertical Depth
VLP	Vertical Lift Performance
WAG	Water Alternating Gas
WCT	Water- Cut
MD	Measured Depth
NPV	Net Present Value
ROI	Return on Investment

MEOR

Microbial Enhanced Oil Recovery

CHAPTER ONE

INTRODUCTION

1.1 Background To The Study

There are many oil and gas wells around the world that have not been optimized to achieve an objective rate in efficient manner Sylvester, (2015). In fact, many may have been routinely completed in a manner such that their maximum potential rate cannot be achieved. Mature oil fields are oil and gas reservoirs that have gone past their peak production rates and are in a state of decline, meaning they contain less easily accessible hydrocarbons and have low production due to low pressure drive Francis and Wukoma, (2017). Despite this natural decline, these fields remain important resources due to their large remaining volumes. This research is based on the optimization strategies like improve oil recovery (IOR) secondary recovery and enhanced oil recovery (EOR) strategies. Mature field strategies in Nigeria focus on technologies to boost remaining reserves, including enhanced oil recovery (EOR) techniques like CO₂ injection and chemical flooding etc. Examples of mature oil fields in Nigeria include Oloibiri (the first commercial discovery) 1956, Obagi 1966, Bonga 2008 and Agbami field 2008. The Niger delta region is one of the most prolific oil-producing areas in the world, yet it faces significant challenges in maximizing oil recovery from mature fields. As oil field sage, the efficiency of production declines, necessitating the development of optimal production strategies to enhance recovery rates.

1.2 Problem Statement

Nowadays, many oil and gas wells maybe producing at rates which appear to be optimum but actually contains unnecessary conditions to flow Zain and Abdin, (2000). These well conditions can be modelling techniques to evaluate all components of producing well systems. Often this procedure will identify possible modifications in the well which if made will result in larger flow rates Brown and Lea, (1985). All components starting at the static reservoir pressure and ending at the separator are evaluated if present. This may include inflow performance, flow across the completion, flow up the tubing string including any downhole restrictions, flow across the surface choke if applicable, safety valves, flow through horizontal flow lines and into the separation facilities. By performing well analysis using well model, each Components of the well system can be determined if it is restricting the flow rates unnecessarily when compared to the flow capacity of other system components. This optimization technique permits quick recognition by the Operators management and engineering staff of ways and means to increase production rates. Overall, optimization techniques can serve as an excellent tool to verify that a problem exists and indicate that additional testing is in order.

1.3 Aim/Objectives Of The Study

Aim:

The aim of this study is to design optimal production strategies in mature oil field, case study: Niger delta field, using prosper software.

Objectives Of The Study:

1. To design optimal production strategy in mature oil field
2. To build a reservoir well model
3. To generate the well IPR-VLP Performance relationship which shows the well flow performance between the IPR and VLP
4. To create a sample well production system model

1.4 Scope Of Study:

This project is about constructing well model using simulation followed with some analysis.

Basically, this project consists of few phases which include:

Stage 1: Build up well model

Stage 2: perform well matching

Stage 3: simulate base case scenario

Stage 4: well analysis

Stage 5: Recommendation and modification

CHAPTER TWO

LITERATURE REVIEW

The continuous need to maximize hydrocarbon recovery from mature oil fields drives ongoing innovations and optimization across primary, secondary and tertiary recovery methods Karimov and Tortarbay, (2023), Babadagli, (2005). Technologies like ESPs, EOR techniques (thermal, chemical, miscible, microbial, nano fluid). Optimal production strategies in mature typically involve a multi-disciplinary approach, integrating expertise from various engineering and scientific fields, from geophysics to economics. Methods like Electric submersible pumps, gas lift and enhanced oil recovery methods are best for recovering oil optimally from mature field Reservoirs.

2.1 Electric Submersible Pumps (ESP)

Electric submersible pumps are crucial for marginal fields where reservoir pressure is depleted, making it difficult to lift hydrocarbons to the surface, Economides, M.J, and K.G. (2000). They have demonstrated superior oil production, increasing output by an average of 400% of natural flow capacity and life significantly. Hussam Ali Khalaf (2021) studied the effect of rotational speed on ESP performance, emphasizing the importance of speed control. Khalaf's emphasis were based on the challenges ESPs encounter when handling gas -Liquid mixtures, the degradation of pump performance with increasing GVF underscores the need for enhanced modelling and design to mitigate these effects. GAS LIFT: This method involves injecting compressed gas into the well's annulus to lighten the fluid column and reduce bottom -hole pressure, yielding allowance off liquids to flow to the surface. Optimizing gas involves managing the point of injection, injection rate, and injection pressure Abdullahi, M.B,

Abdulkadir, Aliyu, (2020). A study from 2015 highlighted the potential for gas lift optimization in a large, mature golf of Mexico to reduce gas lift requirement by 50%. M. Khamechi et al. (2009) Applied genetic algorithms to optimize continuous gas lift injection rate distribution. Need for more efficient and effective gas lift optimization should be developed to enable improve in gas lift efficiency and reduce costs.

2.2 Enhanced Oil Recovery:

EOR involves injecting substances like steam, Carbon dioxide, or chemicals into the reservoir to increase the pressure drop and decrease oil viscosity, making it possible to recover appreciable fluids Lake, L.W. (1989). There are three main types of EORs.

Thermal recovery

Gas injection

Chemical injection

Rajneesh Kashyap, Mohit Kalra, and arti Rashyap (2009) provided a comprehensive review of nanoparticles for enhanced oil recovery. Further research is needed to understand how nanoparticles interact with reservoir rocks and fluids.

2.3 Overview Of Mature Oil Fields:

Mature oil fields are fields in a state of declining production, having passed their peak output, and are characterized by aging infrastructure and increasing operational challenges like higher water and gas production Francis and Wokoma (2017). Despite this, they remain critical global resources, holding significant recoverable hydrocarbons. Revitalization efforts focus on technologies such as enhanced oil recovery (EOR), well intervention, infill drilling, and upgrades

to existing infrastructure to maximize remaining reserves and minimize costs Bhattacharya and Rao (2011).

2.4 Characteristics Of Mature Oil Fields:

i. Declining production: Production levels fall below maximum rates, this is an indication that the field is in a decline phase with notable pressure drops.

ii. Aging infrastructure: Existing surface and subsurface facilities become older and may require upgrade or changing them to maintain operations.

iii. Increased water and gas production: pressure depletion in the reservoir can lead to subsequent water and gas production due to coning effect in the reservoir which can complicate operations.

2.5 Developing The Optimum Field Development Plan For Mature Oil Fields:

Developing an optimum field development plan for mature oil fields is a complex, multidisciplinary undertaking focused on maximizing hydrocarbon recovery, extending field life, and ensuring economic viability Shyamal Bhattacharya and N.S. Rao (2011). Mature fields, often characterized by low production rates, limited reserves, depleted pressure, and highwater-cut, frequently become uneconomical to produce using conventional methods. Therefore, advanced strategies and technologies are essential for their rejuvenation. Key methods and technologies involved in optimizing mature field development plans include:

1. Comprehensive Reservoir Management

Effective reservoir management is crucial, beginning from exploration and continuing through appraisal, development, and eventually to abandonment Steve R. Jones. It necessitates a

multidisciplinary approach, integrating expertise from geophysicists, geologists, petrophysics, reservoir, production, drilling, and completions engineers, as well as facilities specialists and economists. This integrated approach is vital for describing reservoir heterogeneity, hydrocarbon storage, and flow units, and for effective field development planning.

2. Enhanced Oil Recovery (EOR) and Improved Oil Recovery (IOR)

EOR techniques are pivotal for optimizing hydrocarbon production from mature oil reservoirs Damir Karimov and Zhexenbek Toktarbay (2023). They are employed when primary and secondary recovery methods are no longer sufficient, aiming to extract immobile oil and can yield recoveries ranging from 40% to 60% of the remaining oil. EOR strategies modify the physical and chemical properties of reservoir fluids and rock to enhance oil mobility and recovery by improving oil displacement and sweep efficiency. EOR techniques are broadly categorized into:

Thermal EOR Techniques: These methods introduce heat into the reservoir to reduce high crude oil viscosity, making it flow more easily. They are particularly suitable for heavy oil reservoirs.

Steam Injection (Steam Flooding / SAGD): involves injecting high-pressure, high-temperature steam to heat oil, reduce its viscosity, and drive it to production wells, George F. Boberg and C.A Craft. SAGD uses two horizontal wells (injector and producer) for extensive contact. Advancements include Fast-SAGD and Thermally Assisted Gas Oil Gravity Drainage (TA-GOGD), which involves steam injection in fractured reservoirs to heat crude oil and reduce viscosity, facilitating gravity drainage. Solar thermal power generation systems, such as the Enclosed Trough once-through steam generator (OTSG), are also emerging for steam generation.

In-situ Combustion (ISC): Injects air or oxygen into the reservoir to facilitate a controlled combustion front, generating heat that heats and displaces oil. It is suitable for light and medium oil reservoirs. Toe-to-Heel Air Injection (THAI) is an innovative ISC method utilizing a horizontal producer to mobilize heavy oil. High- Pressure Air Injection (HPAI) creates a pushing force, eliminating the need for steam and water cycling.

Electric Heating: involves downhole electrical heaters to elevate reservoir temperature, lowering oil viscosity and increasing mobility. This includes Electrical Resistive Heating (ERH), Electromagnetic Heating (EMH), and the Electro-Thermal Dynamic Stripping Process (ETDSP™), which also addresses environmental concerns by recycling CO₂ emissions and freshwater consumption.

Underground Refinery: an emerging concept focused on in-situ processing and enhancement of heavy oil directly within the reservoir.

Chemical EOR Techniques: These introduce chemicals to alter properties of oil and reservoir rock, enhancing oil recovery.

Polymer Flooding: injects high-molecular-weight polymers to increase water viscosity, improving sweep efficiency and reducing water production. Commonly used polymers include partially hydrolyzed polyacrylamide (HPAM) and xanthangum, along with biopolymers. Polymer flooding can recover over 20% additional oil from Original Oil in Place (OOIP).

Surfactant Flooding: introduces surfactants and co-surfactants to create microemulsions that significantly reduce interfacial tension (IFT) between oil and water, facilitating residual oil release. Eco-friendly natural surfactants are being developed.

Alkaline Flooding: involves injecting alkaline solutions (e.g., sodium hydroxide, sodium carbonate, ammonia) to produce in-situ surfactants that reduce IFT, promote emulsification, and alter wettability.

Low Salinity and Smart Water Flooding: Injects water with decreased salinity or modified ionic composition to enhance cumulative oil recovery. "Smart Water " technology reduces project costs and environmental footprint by not relying on traditional chemical additives.

Microbial EOR (MEOR): utilizes microorganisms and their byproducts (biosurfactants, polymers, acids, gases, enzymes) to transform reservoir and oil properties. It is ecologically safe and thrives on low-cost raw materials.

Miscible EOR Techniques: involve injecting fluids that mix with reservoir oil, reducing viscosity and increasing oil mobility. These are effective in medium and light oil reservoirs.

Carbon Dioxide (CO₂) Injection: Injected CO₂ dissolves in oil, reducing viscosity and causing oil swelling, leading to improved oil displacement. It also serves as an eco-friendly strategy by keeping CO₂ inside the reservoir. Water Alternating Gas (WAG) involves cyclic injection of water and gas.

Hydrocarbon Injection: uses hydrocarbon gases (e.g., methane, natural gas) to lower oil viscosity and enhance recovery.

Nitrogen Injection: reduces oil viscosity and increases reservoir pressure, contributing to enhanced oil recovery. Nitrogen is inert, non-corrosive, and cost-effective if extraction facilities are near oil recovery sites.

Advanced Drilling and Completion Technologies

Modern drilling and completion technologies are critical for accessing bypassed oil and optimizing production in mature fields. Horizontal Sidetracks and Multilateral Wells: used to reach bypassed oil, increase reservoir contact, and improve productivity. Short/medium radius drain-hole completions

2.6 Challenges Associated With Mature Field Development:

Mature oil fields are characterized by declining production rates, increased production costs, and the need for enhanced oil recovery (EOR) techniques. According to Alhassan et al. (2020), the decline production is often attributed to reservoir depletion, water encroachment, and the complexities of reservoir management. These challenges and problems necessitate innovative approaches to optimize production and extending the life of mature fields. Developing and sustaining production from mature oil fields present several significant challenges for operators. These fields are often considered the terminal points in the life of producing oil fields before they are abandoned as uneconomical.

2.7 Key Challenges Associated With Mature Field Development Include:

1. Declining Reservoir Energy And Production: As Reservoirs mature and age, their natural pressure declines, making it difficult to lift fluids from the bottomhole to the surface. This can lead to a decrease in the production rate or even a complete cessation of flow. This depletion of reservoir pressure significantly reduces the magnitude of inflow performance relationship (IPR) curves and absolute open flow (IOF) values. Low production rates and limited reserves are characteristics of marginal fields, which are often mature fields. More than 70% marginal field operators struggle to achieve initial oil and sustain it for more than a year.

2. Fluid Properties And Flow Dynamics: The viscous nature of the fluid can lead to decreased production or an inability to flow.

a. Increased water -cut: increased water cut is a common problem, often due to preferential movement of water through high permeability streams. High water cut can reduce oil production or even lead to well shutdown due to higher bottom- hole pressure Raunnak Aryan and Bhavinay Shelly, (2023).

b. Low oil mobility: Low oil mobility and challenging reservoir conditions often make primary and secondary recovery methods inefficient Karimov and Tortarbay, (2023).

3. Technical And Operational Complexities

a. Finding reliable and available equipment and services is a major challenge for marginal field development.

b. Obtaining export capacity in oil pipelines operated by international oil companies (IOCs) can be difficult for marginal field operators with less negotiating strength.

4. Completion Design

a. Oversized tubing: oversized tubing can cause excessive liquid phase loss due to slippage or extreme downhole liquid loading.

b. Undersized tubing: undersized tubing can limit the production rate due to increased friction resistance from high flow velocity.

5. Artificial lift systems

- a. Gas lift optimization: Gas lift optimization faces challenges such as inefficient operation, pressure surges in production facilities, and difficult production control if gas injection rates are not optimal.
- b. Inlet issues (Inhibiting gas injection) and outlet issues (Excessive back pressure from production chokes, undersized flow lines or high separator) can impair well performance.
- c. Down hole issues: Down hole issues include challenges in reservoir fluid conditions, injection rate, and valve port size.
- d. Over injection of gas: Over injection of gas can increase bottom- hole pressure and reduce production except controlled through soaking, it can as well lead to increased well head pressure, which decreases the production rate.
- e. Selecting an appropriate gas -lift pressure: Too high or too low can lead to needless investment or loss of production potential. Designing an optimal gas - lift systems involve considering factors like solid/sand handling, corrosion/scale handling, well stability, Depth, production rate flexibility, Gas-oil ratio (GOR), Electrical power space, and economics N. Okereke, L. Oloyede, and Onifade, (2020). Allocating the optimal lift gas injection rate for each well in a network is a daunting task due to these limitations/gaps

1. Economic viability and investment

- a. Bold investment decisions and the induction of new technologies are needed to boost recovery from mature fields.
- b. High capital costs are associated with some Enhanced Oil Recovery (EOR) techniques like thermal methods.

c. High operating costs: High operating costs can make marginal fields uneconomical for major operators.

2. Costs Associated with EOR techniques

a. High cost of eco-friendly steam generation due to demand for water and natural gas.

b. High cost and potential toxicity of some surfactants.

c. Substantial volumes and infrastructure (pipelines) needed for CO₂ injection contribute to cost challenges.

d. Cost of effective biocides for biopolymers and logistical difficulties in their supply.

3. Environmental concerns

a. Thermal EOR techniques, such as in-situ combustion (ISC), are considered environmentally unfriendly due to substantial carbon emissions from steam generation and combustion.

b. Direct in-situ combustion generates vast and uncontrollable quantities of CO₂ emissions, conflicting with global carbon footprint reduction goals.

4. Integration and optimization challenges

a. Seamless integration of skill sets from various disciplines (geophysicists, geologists, and economists) and their corresponding data sets can be a complex affair, but crucial for optimal field development.

b. Bottlenecks and constraints imposed by Existing infrastructure, such as available locations versus target locations or existing capacity versus new required capacity, necessitates optimal redevelopment proposals N.S Rao, (2011).

2.8 Production Optimization Of a Mature Oil Field Asset:

Production optimization of a mature field asset is a critical endeavor in the oil and gas industry, focused on maximizing hydrocarbon recovery, ensuring economic viability, and extending the operational life of existing fields Adamu and Okafor, (2021), Sylvester, (2015). Mature fields are characterized by low production rates, limited reserves, and often reach a point where conventional production becomes uneconomical, leading to potential abandonment by operators.

Challenges in Mature Field Production:

Mature fields present several significant challenges that necessitate optimization efforts:

- a. Declining Reservoir Pressure and Energy: Natural reservoir pressure diminishes overtime, leading to insufficient energy to lift fluids to the surface. This decline is often accompanied by an increase in water-cut Ndukuba and Akpabio, (2021), Faseemo et al., (2009).
- b. Economic Viability: The economics of developing and producing these fields using conventional methods become challenging due to low production rates and high operating costs.
- c. Technical and Operational Hurdles: These include finding reliable equipment and services, securing export capacity in pipelines, managing pipeline losses, and dealing with local community issues. Harsh production environments and technological limitations also impede indigenous companies.

d. Water Breakthrough: An increase in water cut can severely hamper natural flow and profitability, leading to field abandonment. Strategies for Production Optimization:

To overcome these challenges, a range of advanced technologies and integrated strategies are employed:

1. Integrated Reservoir Management:

This approach is paramount for rejuvenating mature fields and involves a multidisciplinary team (MDT) comprising geophysicists, geologists, paraphysicists, reservoir, production, drilling, completions, facilities, and economists. Reservoir management covers the entire field life, from exploration and appraisal through development (primary, secondary, IOR, and EOR) to abandonment. Key activities include:

a. Identifying Bypassed Oil: detailed geology, geophysics, and reservoir simulation studies are conducted to pinpoint undrained oil saturation areas.

b. Optimizing Well Placement: Utilizing time-lapse seismic, facies modeling (e.g., with PETREL), and dynamic models ensures accurate placement of new and re-entered wells. Downhole Fluid Analysis (DFA) and permeability profiling further aid in optimal drain-hole placement.

c. Water Injection Management: Strategies like waterflooding are optimized to maintain reservoir pressure and improve recovery.

2. Enhanced Oil Recovery (EOR) Techniques

EOR methods are critical for maximizing hydrocarbon production from mature oil reservoirs by extracting oil that remains immobile after primary and secondary recovery. EOR techniques

modify the physical and chemical properties of reservoir fluids and rock to enhance oil mobility and recovery. They are broadly categorized as:

i. Thermal EOR: Introduces heat to the reservoir to reduce crude oil viscosity, making it flow more easily. Techniques include steam injection (e.g., steam flooding), in-situ combustion, and electric heating. Advanced thermal methods are emerging, such as Toe-to-Heel Air Injection (THAI).

ii. Chemical EOR: This involves the injection of various chemicals to alter the properties of oil and reservoir rock. This includes polymer flooding (increasing water viscosity to improve sweep efficiency), surfactant flooding (reducing interfacial tension between oil and water), and alkaline flooding (producing in-situ surfactants). Low salinity and Smart Water Flooding are also gaining traction, relying on altered ionic composition rather than chemical additives.

iii. Miscible EOR: Involves injecting fluids that mix with reservoir oil, reducing its viscosity and promoting mobility. Common methods are CO₂ injection, hydrocarbon gas injection, and nitrogen injection. Techniques like Water Alternating Gas (WAG) and Polymer Water Alternate Gas (PWAG) combine gas injection with water and polymers for enhanced sweep efficiency.

iv. Emerging EOR Technologies: These include nanofluids (nanoparticles to reduce interfacial tension and modify wettability) and Microbial EOR (MEOR), which uses microorganisms and their byproducts to transform reservoir and oil properties.

3. Artificial Lift Technologies

When natural reservoir energy is insufficient, artificial lift methods are applied to add energy to the produced fluids.

a. Electric Submersible Pumps (ESPs): Research shows ESPs provide superior oil production, increasing output at an average rate of 400% of natural flow capacity and a cumulative production increase of 392% over a simulated period of 5023 days in the Niger Delta. ESPs are economically profitable (positive Net Present Value, Profitability Index greater than 1, and Internal Rate of Return between 20.1% and 45.83%). They also extend the productive life of wells significantly, often by several thousand days compared to natural flow. Moreover, ESP implementation can eliminate the need for infill drilling, reducing costs and environmental impact Kalu-ulu, Okon, and Appah, (2023).

b. Gas Lift: Involves injecting compressed gas into the annulus to lighten the fluid column, reducing its density and pressure losses, which helps lift fluid to the surface API, (1994). Gas lift optimization is crucial for maximizing output, reducing operating costs, and increasing Net Present Value (NPV). This involves optimizing parameters such as the point of injection, injection rate, and injection pressure. Excessive or insufficient gas injection can lead to inefficiency or reduced production rates due to factors like slippage.

4. Well Completion and Drilling Technologies:

Modern drilling and completion techniques are vital for accessing bypassed oil and optimizing production:

a. Horizontal Sidetracks and Multilateral Wells: Used to reach unexploited area sand increase reservoir contact, thereby enhancing productivity.

b. Intelligent Completions: Technologies like Level-3 completions and segmented completions (using packers and Internal Control Valves or sliding sleeves) allow for independent monitoring,

control of individual reservoir performance, and management of water production from the surface.

5. Modeling, Simulation, and Analysis Tools Sophisticated software and analytical methods are indispensable for design and optimization:

a. Industry Simulators: Tools like PIPESIM (for artificial lift design), INTERSECT (for reservoir description and integration), and PETREL (for system integration and reservoir-dynamic behavior modeling) are used to design and simulate well performance.

b. PROSPER Software: Widely utilized for well performance, design, and optimization, PROSPER can model and optimize various well completions and artificial lift methods.

c. Nodal Analysis: A systems approach that assesses fluid flow and pressure drops from the reservoir to the wellhead, used to optimize completion parameters, tubing sizes, and chokes. For instance, optimizing tubing size in a Niger Delta field using PROSPER resulted in a 61% increase in oil production.

d. Production Decline Curve Analysis (DCA): An important method for production forecasting and estimating recoverable hydrocarbons, although it requires a solid understanding of reservoir, production, and drilling engineering.

Benefits of Optimization:

The implementation of these strategies yields substantial benefits:

i. Increased Production and Recovery: Significant increases in oil and gas production rates are observed, sometimes by hundreds of percentage points. Field A in the Niger Delta saw production increase from 43,000 Bopd to 57,000 Bopd through a rejuvenation program.

ii. Extended Field Life: Technologies like ESPs can extend the productive lifespan of wells and the overall field asset for many years beyond their natural flow limits.

iii. Enhanced Economic Viability: Optimization makes projects profitable, as evidenced by positive NPVs, Profitability Indices greater than 1, and IRRs surpassing capital costs. This ensures a higher return on investment and helps transform abandoned or uneconomical fields into productive and sustainable assets.

iv. Operational Efficiency: Improvements in reservoir drainage, reduction in water cut, and streamlined operations contribute to overall efficiency and profitability.

V. Environmental Benefits: Some methods, such as ESPs, can reduce the need for infill drilling, thereby lessening environmental impact. CO₂ flooding can also contribute to carbon emission reduction by sequestering CO₂ in the reservoir.

Challenges and Limitations of Optimization Techniques:

Despite the significant benefits, the widespread adoption and successful implementation of these techniques face several hurdles:

a) **High Capital and Operating Costs:** Many EOR techniques, especially thermal and chemical methods, require substantial energy inputs, complex chemical formulations, or costly infrastructure development for gas supply, impacting economic feasibility.

b) **Environmental Concerns:** Thermal EOR can lead to significant carbon emissions, while some chemical EOR agents may have toxicity concerns. MEOR also presents challenges related to potential corrosion and heavy metal ion carriage to groundwater.

c). **Technical Complexities:** Challenges include chemical incompatibility of injected fluids, managing unwanted fluid interactions, injectivity issues (e.g., polymer blockages), and the sensitivity of biological agents (in MEOR) to reservoir conditions like temperature.

d). **Modeling Accuracy:** Discrepancies between simulated and actual field results can occur, necessitating rigorous calibration and validation of models. Optimizing large, multi-well network systems requires advanced, computationally intensive algorithms.

e). **Gas Lift Specific Challenges:** Excessive gas injection can cause slippage, reducing liquid production, and high-water cuts can make gas lift less effective. Optimal gas allocation across multiple wells in a network remains a complex task.

2.9 Production Optimization Strategies:

Production optimization strategies aim to maximize production rates and minimize operating costs under various technical and economic constraints. These strategies are crucial for efficiently exploiting oil and gas fields, especially in mature or marginal fields, and involve a combination of well, reservoir, and surface facility management. These are some key production optimization strategies:

a). **Artificial Lift System Optimization:** Artificial lift methods are essential for enhancing oil recovery, particularly when natural reservoir pressure is insufficient to bring fluids to the surface.

b). **Electric Submersible Pump (ESP) Systems:**

i. Increased Production and Extended Life: ESPs can significantly increase oil production and extend the productive lifespan of wells and the entire field. In one case study, ESP-assisted wells increased production at an average rate of 400% of the natural flow capacity, leading to a

cumulative production increase of approximately 392% over a simulated period of 5023 days before significant decline.

ii. Overcoming Constraints: ESP systems help overcome limitations to natural flow caused by declining reservoir pressure, increasing wellhead pressure, and increasing water-cut. They are particularly effective in fields where depletion with significantly lower reservoir pressure makes hydrocarbon production difficult.

iii. Optimal Operating Conditions: Optimal production is achieved when the ESP operates at an efficiency of 70 Hz and a wellhead pressure of 400 psi for a 4-1/2-inch tubular completion.

iv. Tubing Size Optimization: In ESP-assisted wells, 3-inch and 4-inch tubing generally perform better, with 4-1/2-inch tubing producing about 2% more than 1-inch to 3-inch tubing and 4% more than 5-inch to 6-inch tubing.

v. Deployment Strategy: ESP deployment should be timed based on well performance. For instance, in a Niger Delta case study, ESPs were recommended for installation in Well-3 after 800 days of production, Well-2 after 850 days, Well-5 and Well-1 after 1260 and 1320 days, respectively, and Well-4 after 1370 days.

vi. Installation Depth: ESPs should be installed deeper during completion design to prevent gas breakout caused by reservoir pressure decline.

vii. Reduced Infill Drilling: Implementing ESP systems can eliminate the need for infill drilling, thereby reducing costs and environmental impact, and contributing to the economic sustainability and operational lifespan of the field asset.

viii. Economic Viability: ESP-assisted wells are generally profitable, with positive Net Present Values (NPVs) and Profitability Indexes (PIs) greater than 1 at discounted rates of 12%, 15%, and 20%. Internal Rate of Return (IRR) values for ESP wells range between 20.1% and 45.83%, which are higher than typical discounted rates (Dagogo et al. (2018), Ndubuka and Akpabio, (2021)).

Gas Lift Systems: Mechanism: Gas lift involves injecting compressed gas at high pressure into the annulus, which then lightens the fluid column in the production tubing, reducing its density and pressure losses, and allowing fluids to flow from the reservoir to the surface.

Optimization Goals: Gas lift optimization aims to obtain maximum output under unspecified operating conditions, reduce operating costs, increase Net Present Value (NPV), and maximize recovery.

Well-Level Optimization: This can be achieved by optimizing parameters such as the point of injection, injection rate, and injection pressure.

Optimum Gas Injection Rate: Obtaining the optimum gas injection rate is critical because excessive gas injection can reduce the production rate and increase operation costs due to slippage (gas moving faster than liquid, leaving liquid behind).

Wellhead Pressure Management: Wellhead pressure significantly influences gas lift performance. Lower wellhead pressure typically leads to lower bottom-hole pressure required for a given production rate, improving performance. Conversely, high well head pressure due to excessive gas injection can decrease the production rate.

Smart Gas Lift Valves: Smart gas lift valves can be used to control gas injection from downhole, improving gas lift performance.

Allocation Models: For multiple wells, global optimization techniques and allocation models are used to determine the optimum gas injection rate for a group of wells, maximizing total oil production for a given total amount of gas.

Factors Affecting Performance:

a). Gas lift performance is affected by high water cuts, which can lead to reduced oil production or well shutdown due to higher bottom-hole pressure. Optimization requires considering gas injection rate, injection pressure, lift gas availability, compressor capabilities, and water handling facilities.

b). Enhanced Oil Recovery (EOR) Techniques; EOR techniques, also known as tertiary recovery, are advanced methods designed to increase oil recovery beyond what is achievable through primary and secondary methods, especially in challenging reservoir conditions or when oil is immobile. EOR strategies operate by modifying the physical and chemical properties of reservoir fluids and rock to enhance the mobility and recovery of oil.

c.) Thermal EOR Techniques: Introduce heat into the reservoir to reduce oil viscosity, making it flow more easily. Suitable for heavy oil reservoirs.

d.) Steam Injection (Steam Flooding, SAGD): High-pressure steam is injected to heat the oil, reducing its viscosity and driving it to production wells. It can increase oil production rates and ultimate oil recovery, but requires substantial energy inputs and may raise environmental concerns. SAGD (Steam-Assisted Gravity Drainage) is particularly efficient due to the expansive contact area of horizontal wells.

e.) In-situ Combustion (ISC): Air or oxygen is injected to create a controlled combustion front, generating heat that displaces oil. It is economically attractive and suitable for light and medium oil reservoirs, but has technological complexities and unpredictable combustion events.

f.) Electric Heating: Downhole electrical heaters raise reservoir temperature, lowering oil viscosity and increasing mobility. It is efficient for moderate viscosity oil and can be

economically viable for increasing recovery in a short timeframe. g. Chemical EOR Techniques: Introduce chemicals to alter properties of oil and reservoir rock, enhancing recovery.

h.) Polymer Flooding: High-molecular-weight polymers increase water viscosity, improving sweep efficiency and reducing water production. Effective for reservoirs with oil viscosities below 100cp, high oil content, and good permeability. Polymers like HPAM and Xanthan gum are commonly used.

i.) Surfactant Flooding: Surfactants reduce the interfacial tension (IFT) between oil and water to extremely low levels, facilitating the release of residual oil. Eco-friendly and cost-effective natural surfactants are being developed.

J.) Alkaline Flooding: Alkaline solutions react with organic acids in the oil to produce in- situ surfactants, reducing interfacial tension and forming oil-in-water emulsions that enhance sweep efficiency and mobilize residual oil. Can achieve up to 18%oil recovery factor.

k.) Low Salinity / Smart Water Flooding: Involves injecting water with reduced or modified salinity. The reduction in salinity mobilizes trapped oil, and adding activations (e.g., calcium, magnesium) creates "Smart Water," which can surpass conventional waterflooding performance, reduce costs, and minimize environmental footprint.

L. Miscible EOR Techniques: Involve injecting fluids that mix with the reservoir oil, reducing viscosity and promoting increased oil mobility. Effective in medium and light oil reservoirs.

m. CO₂ Injection: CO₂ dissolves in oil, reducing its viscosity and causing swelling, leading to improved oil displacement and recovery. It also serves as an eco-friendly strategy by sequestering CO₂ in the reservoir.

n. Nitrogen Injection: Reduces oil viscosity and increases reservoir pressure, enhancing oil recovery. Nitrogen is inert, non-corrosive, and requires lower injection volume than CO₂ due to lower compressibility.

o. Hydrocarbon Injection: Hydrocarbon gases (e.g., methane, natural gas) lower oil viscosity and enhance recovery, particularly in light oil reservoirs.

Emerging EOR Techniques:

i). **Nanofluids:** Liquids containing nanoparticles that exhibit specific characteristics. They can reduce interfacial tension, increase injected fluid viscosity, decrease oil viscosity, and promote slug-like displacement, leading to increased recovery rates Wasan, (2011), Hendraningrat and Torsater, (2013).

ii.) **Microbial EOR (MEOR):** Uses microorganisms and their byproducts (biosurfactants, biopolymers, acids, gases, enzymes) to enhance oil production Niu, (2010), Dietrich, (1996). MEOR is ecological, thrives on low-cost raw materials, and can alter rock wettability, reduce interfacial tension, and increase permeability Dong, (2012), Karimi, (2012), Patel, (2015).

iii.) Well Completion and Tubing Sizing Optimization

a.) Nodal Analysis: This is a systems approach for production optimization that assesses the production of the system from the reservoir to the wellhead. It can be used to optimize completion parameters and tubing size by analyzing sensitivities of various tubing sizes on the optimum rate, Brown and Lea, (1985).

b.) Tubing Size Selection: The rational tubing size is determined by analyzing its sensitivity to the optimum production rate, Tan Liu et al., (2021), Wan Renpu, (2011). An oversized tubing can

lead to excessive liquid phase loss due to slippage or extreme downhole liquid loading, while an undersized tubing limits production due to increased friction resistance. In a Niger Delta case study, a 5.5-inch tubing size yielded the highest associated gas and oil production rates, significantly increasing production by 59% and 61% respectively, compared to an initial 2.875-inch size. This enhances operational efficiency and profitability.

c.) **Multilateral and Segmented Completions:** New drilling technologies like horizontal sidetracks and multilateral wells are used to reach bypassed oil N.S Rao (2011). Level-3 multilateral completion allows for independent monitoring and intervention. Segmented or "intelligent" completions divide horizontal open holes into segments using packers, allowing for selective production or stimulation, and can be remotely controlled to enhance reservoir control and production performance.

iv.) Reservoir Management: This involves a comprehensive approach to maximize hydrocarbon recovery over the field's life.

a.) **Multi-Disciplinary Team (MDT) Approach:** Seamless integration of skills from geophysicists, geologists, petrophysics, reservoir, production, drilling, completions, facilities, and economists is essential for optimal field development planning.

b.) **Identification of Bypassed Oil:** Detailed geology and geophysics work, along with reservoir simulation studies, are carried out to identify undrained oil saturation areas. Exploiting this bypassed oil can arrest field decline and stabilize production, Juan Carlos Hernandez (2007).

c.) **alter- Injection Management:** This is a key component, especially for mature fields, to maintain reservoir pressure and improve recovery. Optimization models can maximize oil recovery and minimize water production.

d.) Infill Drilling and Well Trajectory Optimization: Redevelopment plans for mature fields often include selective infill drilling and optimization of well trajectories to reach better oil saturation areas, convert poor performing wells, or drill horizontal drain holes Adams and Cinco-ley (1994).

e.) Reservoir Characterization: Efforts to derive correlations for permeability by correlating multiple well logs with core permeability and scaling up with build-up permeability are crucial for accurate reservoir description.

f.) Well Placement with Advanced Data: Time-lapse seismic, facies modeling (using software like Petrel), and dynamic models are extensively used for accurate well placement. Down Hole Fluid Analysis (DFA) and permeability profiling, added to conventional Wireline Formation Tester (WFT) pressure surveys, help determine contact locations and optimize drain hole placement N.S Rao (2011).

V.) Production Forecasting and Analysis Tools:

a.) Decline Curve Analysis (DCA): A key method for production forecasting and estimating recoverable hydrocarbons, categorizing decline into exponential, hyperbolic, and harmonic. It requires a solid background in reservoir, production, and drilling engineering, and in-depth knowledge of the reservoir, surface facilities, and drive mechanism Kayang ling, Xingru Wu, He Zhang, and Jun he (2013).

b.) Maximum Efficiency Rate (MER) Estimation: Determines the production rate above which reservoir recovery is endangered, thereby eroding lifecycle economic value Ibianga sukubo and Peter obi (2018). A robust methodology is proposed to address inconsistencies in current practices, by modeling the relationship between changing tubing head pressure (THP) and production rate at varying choke sizes.

c.) Simulation Software: Industry-based simulators such as Pipesim, intersect, petrel, and PROSPER are used to design well completions, simulate ESP and gas lift performance, describe reservoirs, integrate systems for production optimization, and conduct nodal analysis ben Mahmud and aman (2017).

CHAPTER THREE

METHODOLOGY:

3.1 Research Design:

The research design adopts a quantitative, simulation-based, and case study research design. The approach integrates field data analysis, well modeling, and production optimization using **PROSPER** software, part of the Petroleum Experts Integrated Production Modelling (IPM) suite. The quantitative aspect focuses on measurable production parameters such as flow rates, tubing pressure, and gas–oil ratio, while the simulation approach enables predictive modeling and optimization of production strategies in mature fields (Petroleum Experts, 2021).

The case study design focuses on a specific mature oil field in the Niger Delta, which provides real operational data necessary for model calibration and validation. This design is ideal for in-depth technical analysis and practical recommendations for optimizing recovery (Yin, 2018).

Study Stages:

1. Data gathering
2. Static/dynamic characterization and baseline
3. Prosper model building and calibration
4. Scenario definition and simulation
5. Sensitivity and uncertainty assessment
6. Validation and recommendations.

3.2 sampling /case selection:

- Choose representative sample wells: e.g high water -cut, low GOR, gas coning candidates, and wells suspected to be constrained by surface facilities.
- If a field has many wells, use cluster sampling: 4-6 representative well types (by production behavior) and model one or two wells per type.

3.3 Data Collection

3.3.1 Data Sources

Data were obtained from:

Field production and well test records from the Niger Delta field (provided by the operating company).

Published technical papers and journals to supplement missing data.

PROSPER user manuals and petroleum engineering handbooks for correlations and modeling principles.

3.4 Data Types:

The following datasets were collected and used:

- a. Reservoir data:** Pressure, temperature, permeability, and fluid saturation.
- b. Well data:** Completion details, tubing dimensions, deviation survey, and choke settings.
- c. Production data:** Oil, gas, and water production rates; water cut; gas–oil ratio (GOR).

d. Fluid properties: Oil API gravity, viscosity, formation volume factor (B_o), and solution GOR.

e. Lift system data: Gas lift rate, valve depth, or pump specifications.

Where gaps existed, standard empirical correlations such as Standing's correlation for solution GOR and Beggs and Brill correlation for multiphase flow were employed (Beggs & Brill, 1973).

3.5 Model Development Using PROSPER

3.5.1 Model Setup:

The collected data were input into PROSPER to build a comprehensive well model. The setup included:

1. Defining fluid properties using PVT data (GOR, viscosity, API).
2. Inputting well geometry (tubing, casing, completion intervals).
3. Specifying reservoir and surface conditions (pressure, temperature, separator pressure).
4. Selecting appropriate flow correlations, e.g., Beggs and Brill, Hagedorn and Brown, or Duns and Ros correlation, depending on flow regime suitability.

3.5.2 Model Calibration:

Model calibration (history matching) was carried out by comparing simulated results with actual field data. Parameters such as skin factor, productivity index, and flow correlations were adjusted iteratively until the simulated production rate and flowing bottomhole pressure matched the observed field data within acceptable tolerance (Ahmed, 2017).

3.5.3 Sensitivity Analysis:

Sensitivity analysis was performed to determine the influence of key operating parameters on production performance. The following parameters were varied systematically within practical limits:

- a. Tubing diameter
- b. Wellhead pressure
- c. Gas lift injection rate
- d. Reservoir pressure
- e. Water cut percentage

This helped to identify the most significant parameters affecting production and recovery efficiency (Ikoku,1992).

3.6 Optimization of Production Strategy:

PROSPER's Optimization Module was employed to design and simulate different production strategies aimed at improving recovery. The optimization scenarios included:

1. Natural flow optimization – evaluating choke size and tubing diameter for maximum rate.
2. Artificial lift optimization – simulating different gas lift rates and injection depths to enhance oil production.
3. Well performance improvement – analyzing the impact of skin reduction, stimulation, and reduced drawdown.

The objective function of the optimization was to maximize oil production rate and cumulative recovery while maintaining safe operating limits (Petroleum Experts, 2021).

3.7 Model Validation:

The optimized results were validated by comparing simulated outputs with historical production data. Validation ensured that the model accurately represented the actual performance of the well and could be reliably used for production forecasting and decision-making. Deviations within $\pm 10\%$ of observed data were considered acceptable (Ahmed, 2017).

3.8 Data Analysis And Interpretation:

Results from the optimization process were analyzed through:

Graphical representation of production trends (oil rate vs. time).

Comparison charts for different scenarios (e.g., tubing sizes, gas lift rates).

Economic evaluation (optional) by estimating incremental oil gain and cost implications.

The results were then interpreted to identify the optimal production strategy that yields maximum efficiency and recovery for the studied Niger Delta field.

3.9 Otorogu Field:

3.9.1 Well - 05 Simulation Data

Some of the following data were used and inputted during the Otorogu well (Oto-05) simulation.

PARAMETER	SYMBOL	UNIT	VALUE
Reservoir pressure	Pres.	psia	3500
Reservoir temperature gradient	Tg	Deg. Fahrenheit	190
Gas-oil-Ratio	GOR	SCF/STB	620
Water- cut	Wc	%	45
Absolute open Flow	AOF	STB/DAY	2100
Oil API Gravity	API	Deg. API	33
Formation productivity index	PI	STB/D/PSI	15.89
Water salinity	W. S	PPM	2500
Well measured depth	MD	FT	9200
True vertical depth	TVD	FT	9200

Well head pressure	Pwh	Psig	350
Flowing bottom-hole pressure	Pwf	Psia	1600
Well flow rate	Q	STB/D	900
Tubing diameter	Dt	In.	3.96
Casing diameter	Dc	In.	8.3
Tubing measured depth	TMD	-	8000
Casing measured depth	CMD	-	9000

Table. 3.1 Well Simulation Data

CHAPTER FOUR

RESULTS AND DISCUSSION

4.1 Presentation Of Data:

Data presentations were obtained from the simulation of IPR plots which shows the plot of Reservoir pressure(psig) V.S flow rate Q(Stb/D), Inflow IPR V.S Outflow VLP Plot, Downhole equipment showing the well model system which includes the X-mas Tree, tubing and the casing at their various measured and true depths in feet., IPR Calculation Results table, VLP (tubing curve) calculation Results table and choke performance.

4.1.1 Inflow-Performance Relationship (IPR) Curve Plot:

The IPR plot Darcy (OTO-05) shows the plot of Reservoir pressure(psia) V.S The well flow rate (Stb/D) as shown in the figure below;

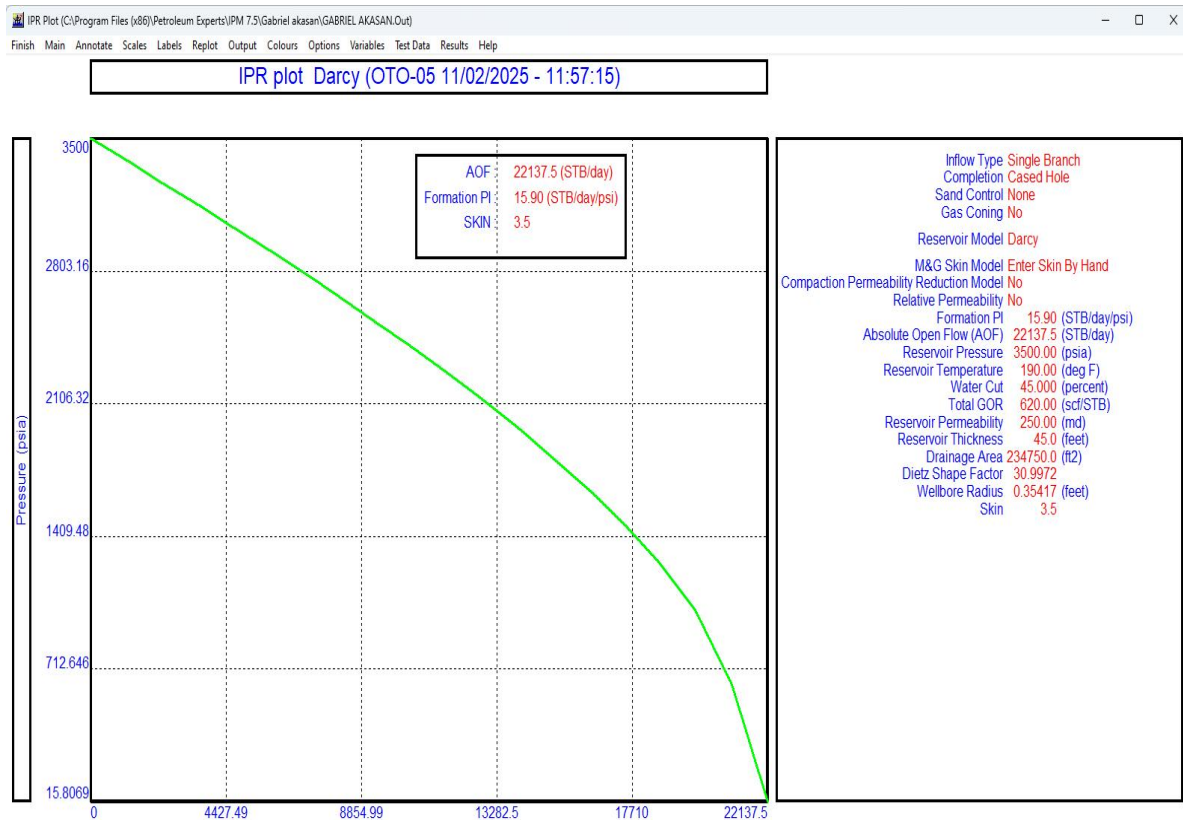


Fig. 4.1 The Plot Of Reservoir Pressure (psia) V.S The Well Flow Rate (Stb/D)

4.1.2 Inflow IPR V.S Outflow VLP Plot:

This shows the relationship between the IPR curve and VLP curve; the green curve represents the well inflow performance, while the red curve line represents the vertical lift performance of the well.

The point where they intersect gives the production operating point.

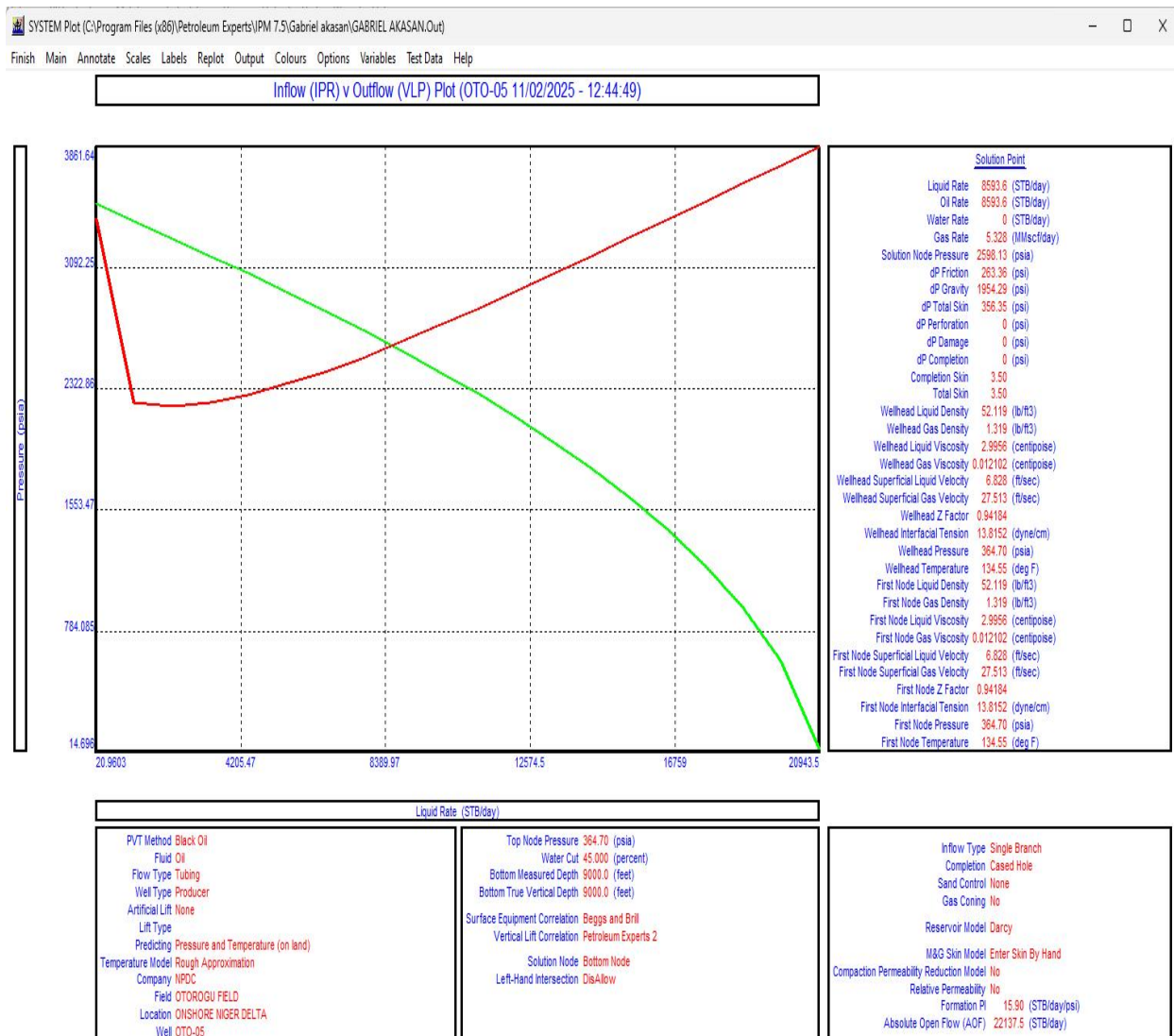


Fig. 4.2 Inflow IPR V.S Outflow VLP Plot.

4.1.3 Well Model System:

The producing well model system obtained from simulation of the downhole equipment data, is presented below, the modelled system consist of, X-mas Tree, Tubing, and casing string configuration, The tubing diameter is a 3.96-inches in the casing diameter is 8.30- inches. The modelled well system is configured below;

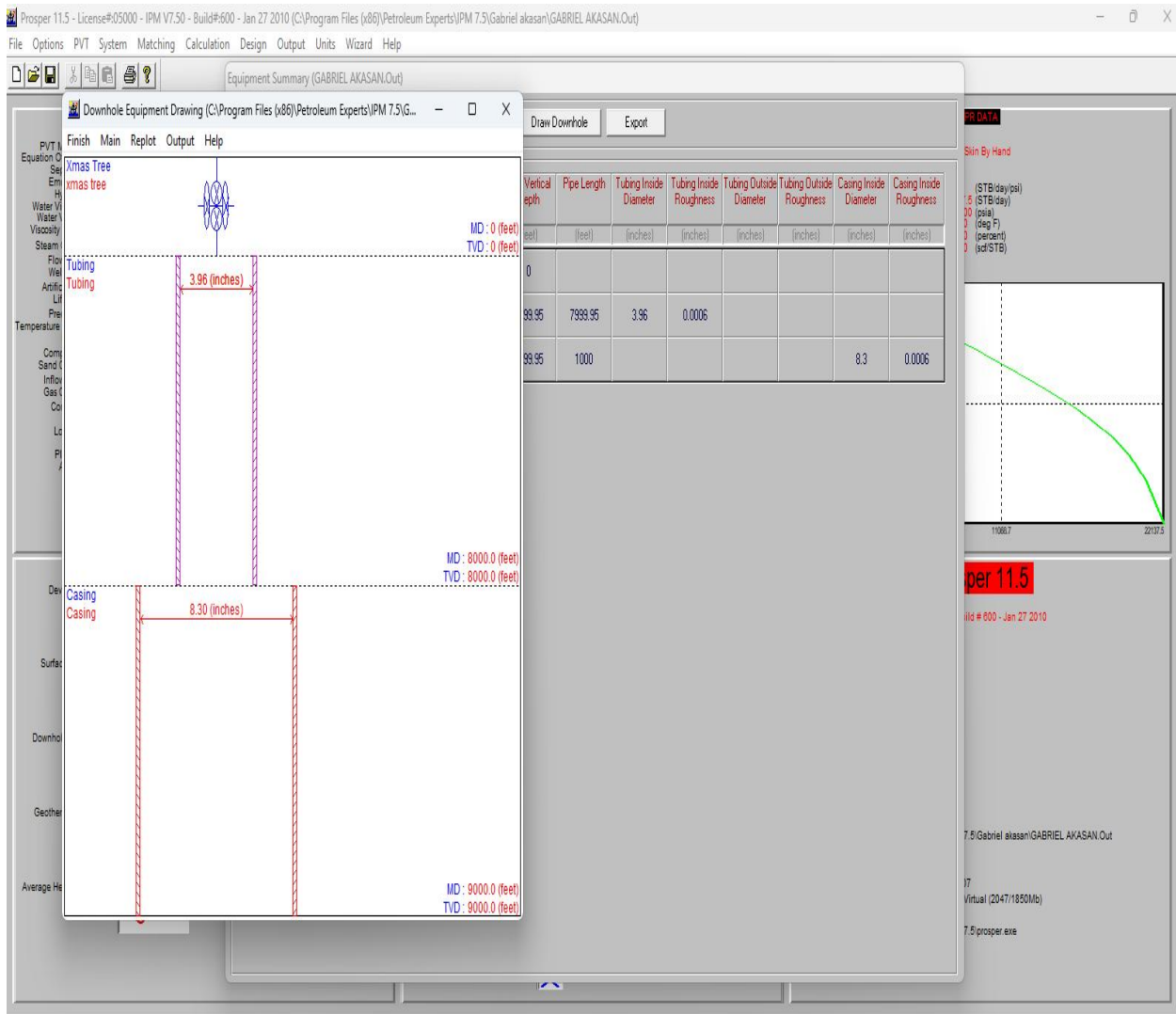


Fig. 4.3 Well Model System

4.1.4 IPR Calculation Results Table:

The IPR calculation results are shown below; the table shows the data representation of flow rate and its pressure in rows and column down to zero deviation skin factor of the well.

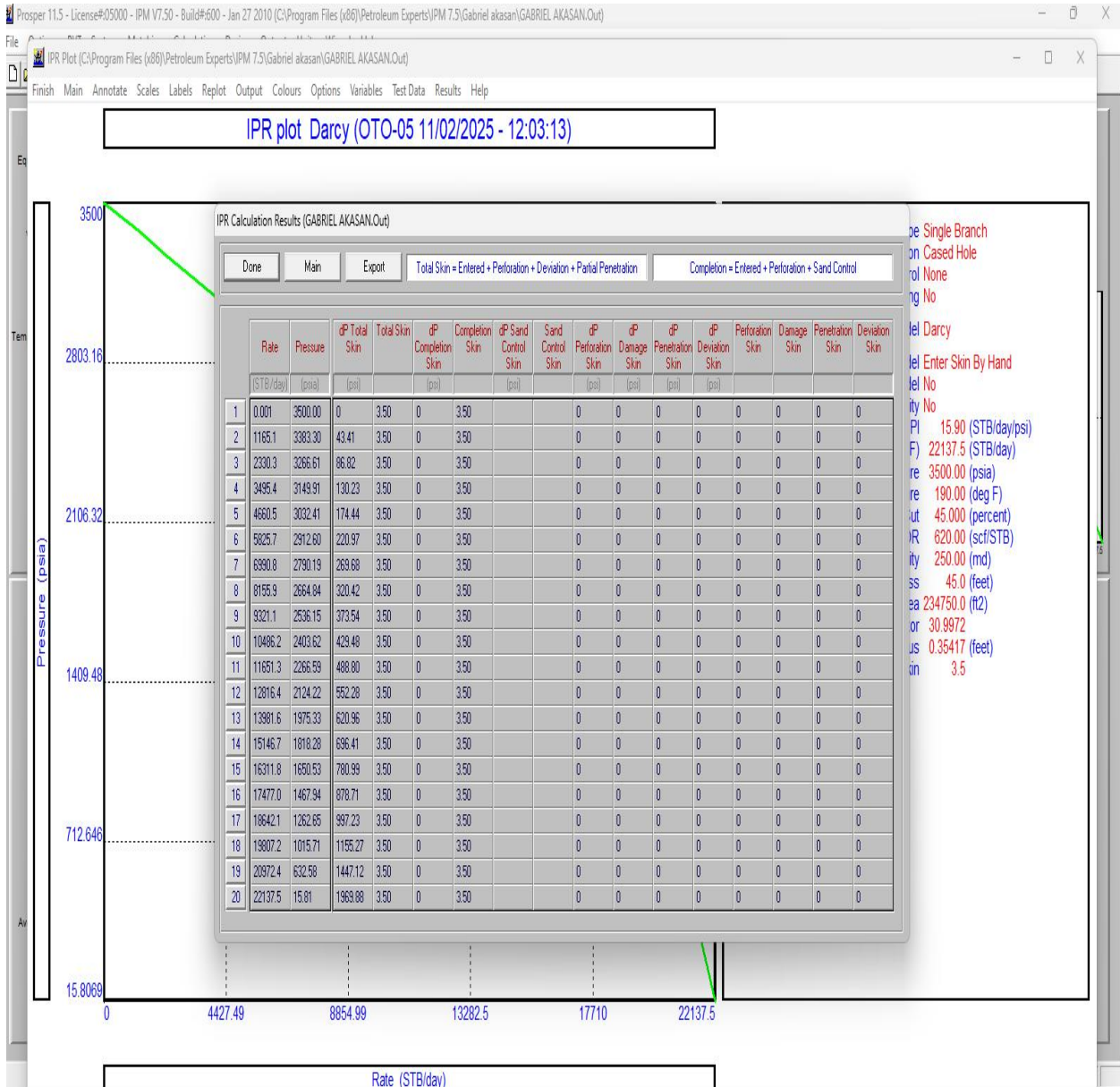


Fig. 4.4 IPR Calculation Results Table.

4.1.5 VLP (Tubing) Calculation Results:

The VLP (Tubing curve) calculation results table shows the columns of Liquid rate (stb/d), oil rate (stb/d), VLP pressure (psig), well head pressure (psig) wellhead temperature (degree Fahrenheit)

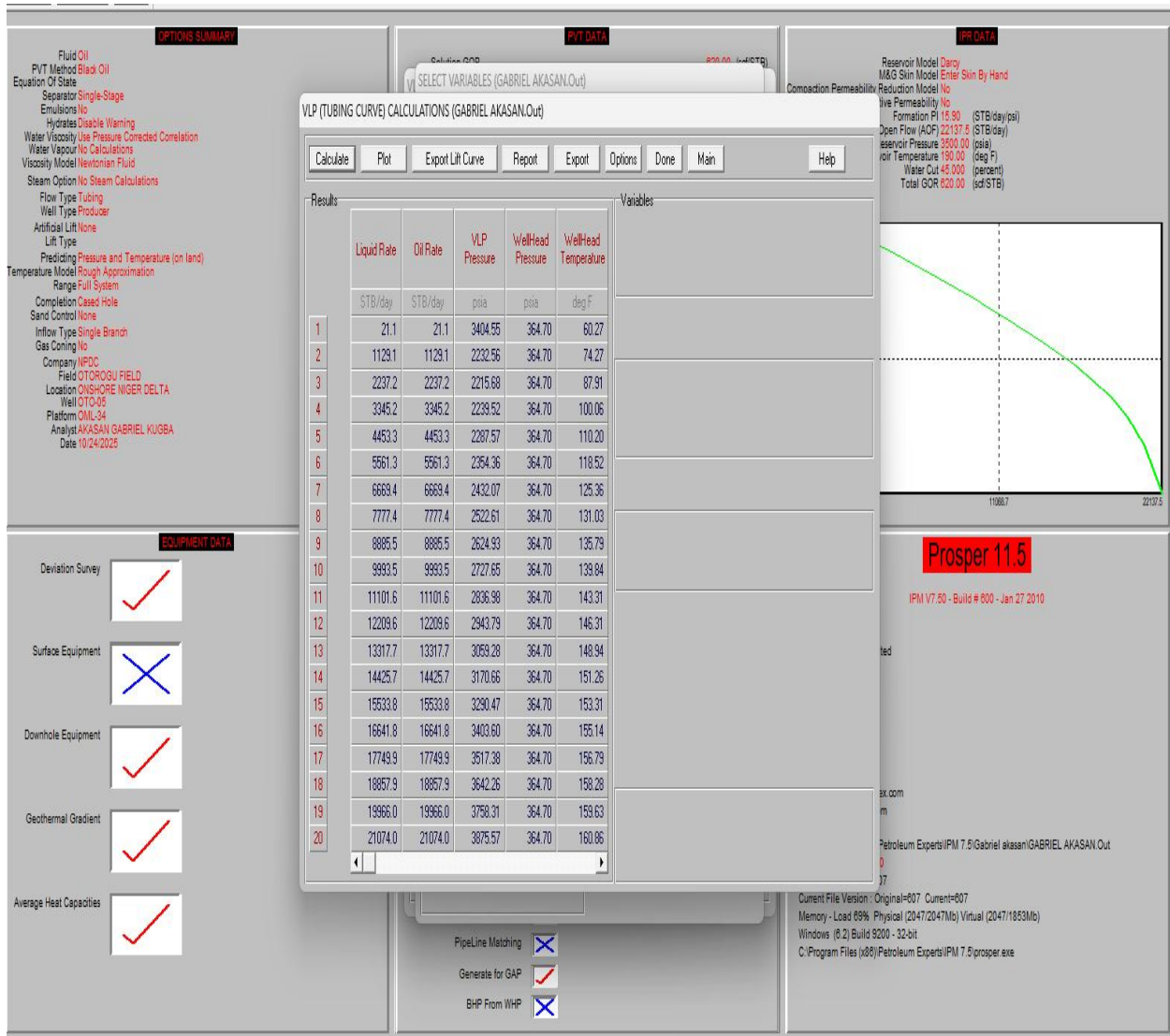


Fig. 4.5 VLP (Tubing) Calculation Results

4.1.6 Choke Performance Plot:

Choke performance plot shows the liquid rate (stb/d) profile of the fluid (oil/water) with respective corresponding outlet pressure (psig).

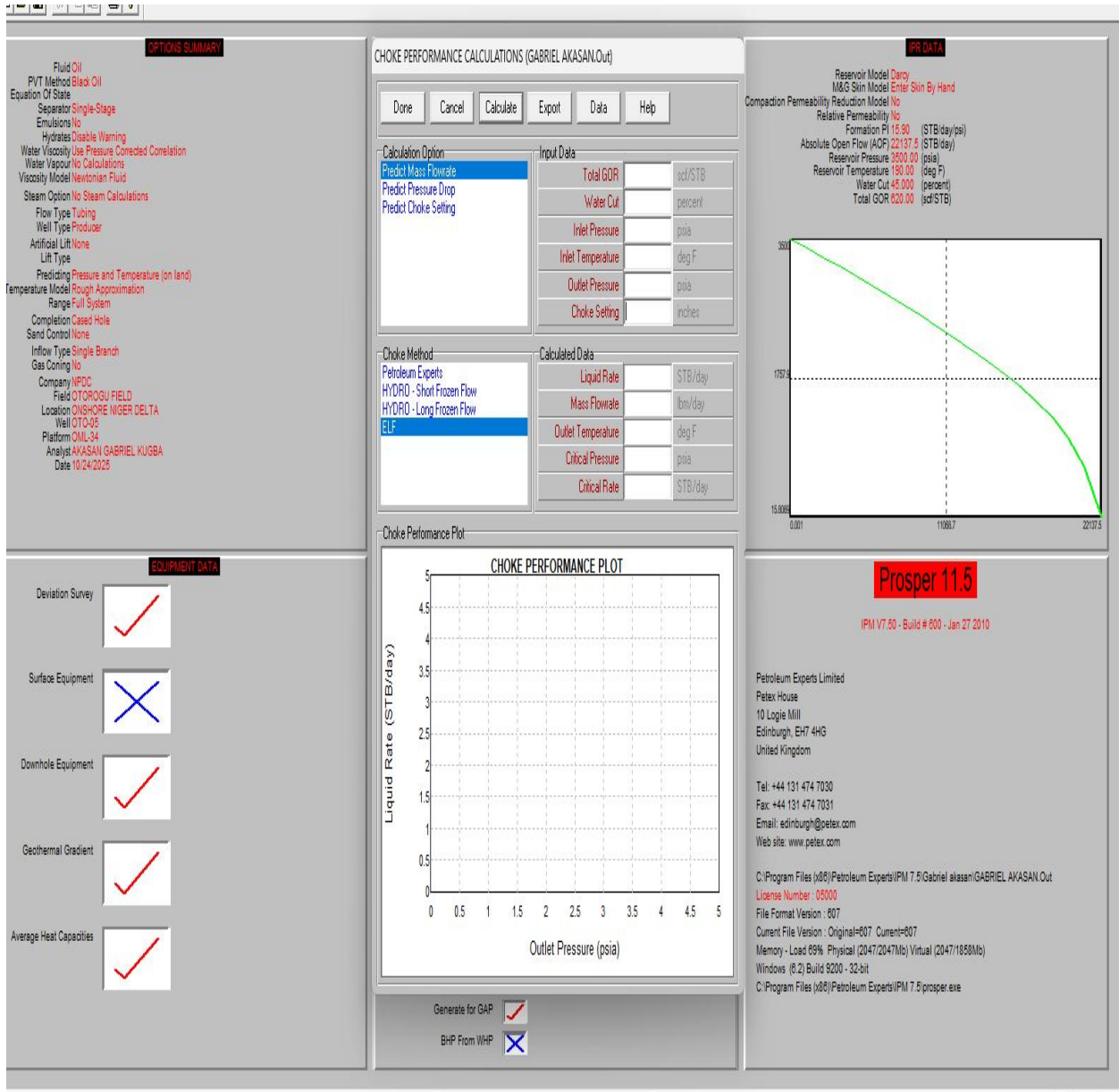


Fig 4.6 Choke Performance Plot

4.2 Data Analysis:

Data analysis is the interpretation of the above data presented above, in the IPR-VLP PLOT above, the intersection of point of the two curves (IPR-VLP) at a flow rate of about 900STB/D, the optimal operating point corresponds to a bottomhole flowing pressure of 2500psia. Increasing tubing diameter beyond 3.96-inches yields negligible rate improvement, indicating that current configuration is near optimal.

In the IPR-VLP curves above, the red curve line represents the VLP (Vertical lift performance) and the green curve represents the inflow performance relationship, the point where both curves intersect is called the production operating point where production is maximum, at this point, the IPR Equals the VLP.

From the results presented by VLP (tubing curve) calculation table, the oil production rate is maximum at rate of about 21074.0STB/D which indicates that at a vertical lift performance pressure of 3860 psig, production is maximum, so increasing the reservoir pressure beyond 3500psig yields negligible rate improvement, indicating that the current operating reservoir pressure is near optimal.

Also, the well model system presented above, shows the first configured equipment and others obtained from simulation of equipment data, the first equipment called the x-mas tree is responsible for production and flow control, the tubing having a diameter of 3.96-inches all configured above and casing with diameter of 8.30-inches, the shaded annulus shows that the casing is cemented in place for stability of operations.

4.3 Discussion Of Findings:

The analysis shows that well maximum deliverability strongly depends on tubing diameter and surface pressure.

In the IPR-VLP curves/trend, the optimum operating point takes place at a flow rate of 900STB/D at Bottom hole pressure of 2500psia, so increasing tubing size beyond 3.96-inches offers minimal benefits and can lead to liquid loading issues. Also, maintaining a moderate wellhead pressure of 350psig achieves a stable production and prevents drawdown. Also, from my findings as shown above, the IPR-VLP intersection in the graphical trend above shows the natural equilibrium of the system, satisfying the certainty and accuracy of prosper modeling software tool.

CHAPTER FIVE

CONCLUSIONS AND RECOMMENDATIONS:

5.1 Conclusion

From the results and analysis obtained, it is showed that PROSPER software is a reliable and powerful tool for well performance modeling and production optimization. The case study; Niger delta field Confirmed that:

- Production decline in mature fields can be minimized by applying nodal analysis and gas lift optimization techniques.
- Increasing tubing diameter and adjusting wellhead pressure within safe limits increases production rates.
- The maximum efficient recovery is certain when the reservoir inflow performance and out flow performance balance at the operating point predicted by the simulation software (prosper).

5.2 Recommendations

Considering the findings and conclusions of this work, the following recommendations are outlined:

I. continuous production optimization:

Regular monitoring and optimization of well performance should be implemented to adjust to changing reservoir and production conditions.

ii. integration of software tools:

future optimization studies should integrate prosper, Mbal and Gap software to achieve full-field optimization.

iii. data quality and monitoring:

accurate field data should be acquired consistently to improve simulation accuracy and ensure reliable prediction of future performance

5.3 Contribution To Knowledge

The study contributes to knowledge by demonstrating the effectiveness of using PROSPER software for designing optimal production strategies in mature oil fields. It provides a practical workflow that includes nodal analysis and sensitivity studies to determine the most efficient production parameters for enhanced oil recovery in the Niger delta field. The work through simulation performance also yields more knowledge to the simulation engineer for accuracies of future well performance prediction.

REFERENCES

- Ahmed, T. (2017). *Reservoir Engineering Handbook*. 5th ed. Gulf Professional Publishing.
- Adamu, A., & Okafor, C. (2021). *Optimization of Mature Oil Field Production Using Artificial Lift Methods in the Niger Delta*. *Journal of Petroleum Exploration and Production Technology*.
- API (1994). *Gas Lift Manual*. American Petroleum Institute, Washington, D.C.
- Babadağlı, T. (2005). *Mature Field Development Strategies and Enhanced Oil Recovery Techniques*. *Journal of Petroleum Science and Engineering*, 48(3–4), 127–141.
- Beggs, H. D., & Brill, J. P. (1973). *A Study of Two-Phase Flow in Inclined Pipes*. *Journal of Petroleum Technology*, 25(5), 607–617.
- Bertomeu, C., Osatemple, F., Adeniyi, O., & Giwa, S. (2021). *Improving Production Efficiency in Mature Niger Delta Fields*. SPE Nigeria Annual Conference Paper.
- Brown, K., & Lea, J. F. (1985). *Nodal Analysis of Oil and Gas Wells*. SPE Production Engineering.
- Economides, M. J., & Nolte, K. G. (2000). *Reservoir Stimulation*. 3rd ed., Wiley.
- Francis, I., & Wokoma, A. (2017). *Decline Trends and Production Optimization in Mature Oil Fields of the Niger Delta*. *Nigerian Journal of Engineering*, 23(1), 45–58.

- Ikoku, C. U. (1992). *Natural Gas Production Engineering*. Wiley-Interscience.
- Kalu-Ulu, E., Okon, U., & Appah, J. (2023). *Economic Assessment of ESP-Assisted Wells in the Niger Delta*. SPE Nigeria Conference Proceedings.
- Kayang Ling, X., Wu, H., Zhang, H., & He, J. (2013). *Integrated Reservoir and Production Optimization Techniques*. SPE Paper 168234.
- Lake, L. W. (1989). *Enhanced Oil Recovery*. Prentice Hall.
- M. Khamechi, R., et al. (2009). *Gas Lift Optimization Using Genetic Algorithms*. Journal of Petroleum Science and Technology, 27(12), 1363–1375.
- Ndukuba, J., & Akpabio, E. (2021). *Production Forecasting and Optimization Using ESP Systems in the Niger Delta*. Petroleum Exploration Journal, 8(2), 102–110.
- Petroleum Experts (2021). *PROSPER User Manual: Well Performance and Optimization Software*. Petroleum Experts Ltd., Edinburgh, UK.
- Sylvester, D. (2015). *Production Optimization Strategies for Mature Oil Fields*. SPE Paper 173489-MS.
- Yin, R. K. (2018). *Case Study Research and Applications: Design and Methods*. Sage Publications.