# COMPARATIVE ANALYSIS OF IPR MODELS FOR OIL &GAS WELL OPTIMIZATION USING PRODUCTION PERFORMANCE SOFTWARE (PERFORM) FOR STEADY STATE HORIZONTAL WELLS

**BY**

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## CERTIFICATION

This is to certify that this work "Comparative Analysis of IPR Models for Oil and Gas Well" was carried out by NWUDE, AFAM ANTHONY, with the Registration Number: 20144940038 in Partial fulfillment of the requirement for the award of Degree M.Eng in Department of Petroleum Engineering of the Federal University of Technology, Owerri.

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# DEDICATION

This project work is dedicated to the Almighty God, His beloved Son and the Blessed Holy Spirit and to my wonderful family.

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## ABSTRACT

In this work an investigation of the formulations and solution methods for the following optimization problem was done. Determination of the optimal production rates, lift gas rates, and well connections to maximize daily operational objectives subject to multiple flow rates and pressure constraints.The main materials used in this research are presented as software platforms. IHS PERFORM Ver 500 simulator was used to generate PI, determine Inflow and Vertical Lift Performance of the case study well at varying well pressure and flow rates (first on natural flow without artificial lift installed). Microsoft Excel package was used for Economic Analysis to determine the profitability of PERFORM when compared with other software tool such as Petex-Prosper, or with no software tool used. All of the optimization problems are solved using derivative-free optimization based on a constrained well Performance Analysis, PERFORM. General descriptions of the software simulations were provided in the work. Results of the sensitivity analysis on the hypothetical case using the IPR Models for horizontal gas wells provided the effect on pressure and liquid drop out.This method is very efficient. However, it may lead to bad solutions when the flow interactions among wells are significant.

**Key Words:** Analysis, IPR (Inflow Performance Relationship), PERFORM, Optimization, Horizontal Well.

# CHAPTER ONE

# INTRODUCTION

## 1.1 Background of the Study

In production optimization the goal is to maximise ultimate recovery at minimum operating expenditure. To achieve this, pressure losses encountered in the flow process are minimized between the well bore and the separator. Nodal analysis is the solution technique used to optimize the objective flow rate in order to produce wells, identify constraints and design remedial solution. In obtaining production optimization in the industry, production system analysis software is largely utilized in various aspects of production operations.

Production Performance Modelling uses the acronym, PERFORM, is among the petroleum software available for production optimization. PERFORM is a graphical tool used to analyze the performance of an oil or gas well. PERFORM can help us to; improve completion design, increase well performance as well as optimize production.

Production Performance Modelling, PERFORM could be applied in the following areas:

1. Both for oil and gas wells, although this discuss is limited only to gas wells.
2. In New wells that is Green fields or Old wells also known as brown fields

For new wells, the software can be used to simulate anticipated conditions in order to plan in advance the optimum completion and design. While, for existing wells this software is used first to model existing condition and thereafter, to evaluate areas of potential improvements.

In the design and implementation of an efficient producing well system, many of the variables that directly affect the producing capacity of the well can be altered and this flexibility is the basis of the well optimization through system analysis.

To analyze multi-layer and/or multilateral reservoirs, production and injection wells could be modelled with both empirical and mechanistic pressure drop correlations, Golan, et al (1986). This can perform the following types of analyses using the model; System Analysis, Gradient Analysis and Gas Lift Analysis.

*For System Analysis;* this involves complete conventional nodal analysis calculating the Inflow and Outflow curves for a given well using different nodes; bottom-hole, wellhead and separator for onshore wells and bottom-hole, wellhead and separator for onshore wells and bottom-hole, top of tubing, riser outlet and flow line outlet for offshore wells, William, (1996).

Additional features can be incorporated such as calculation of total skin and coning/cresting are available when using *System Analysis*.

*In Gradient Analysis:* Well or flow line pressure, temperature and velocity gradients are computed. Additional features incorporated are Flow Assurance and Auto-calibration (selection of best pressure drop correlation)

*Gas Lift Analysis:* For gas lift wells, the program has the following options;

System analysis: nodal analysis for a well under gas lift. Gas injection is modelled by changing the gas liquid ratio (GLR) of the well at fixed injection depth.

Gradient: both production and gas injection gradients can be calculated. Gas injection is also modelled with the variable GLR in the well.

Optimization: nodal analysis is performed. Gas lift input data includes injection pressure, injection rate and differential pressure at valve. Injection depth can be either fixed or evaluated, according to Brown, (1978).

## 1.2 Statement of Problem

Traditionally, during the production process, ample time is wasted in the application of various IPR models for both oil and gas wells.

Cost is always high as a result of this trail method of selecting solutions for optimal production for both conditions, deliverability of the pipeline network, fluid handling capacity of facilities, safety and economic considerations, or a combination of these considerations. The task of field operators is to devise optimal operating strategies to achieve certain operational goals.

Traditionally also materials are wasted due to many none effective runs down-hole. Another, problem that may arise from this during gas production is that the occurrence of liquid-loading, especially for unconventional (low-permeability) gas reservoirs, has a huge impact on gas production. Liquid-loading occurs as a result of the gas velocity is not high enough to carry the liquid or water to the surface. Lea and Nickens (2004) summarized several technologies to solve the liquid-loading problem that are commonly used by industry: (i) sizing production strings (a properly designed smaller tubing or velocity string), (ii) installing a compressor, (iii) plunger lift, (iv) pumping (beam pumping and hydraulic pumping), (v) foaming, and (vi) gas lift. All of the currently available technologies to solve liquid-loading use external or additional sources and therefore add to operating cost.

## 1.3 Objectives of the Study

The main objective of this work is a Comparative analysis of IPR Models for Oil and Gas Well Optimization using Production Performance Software (PERFORM) for Horizontal wells. Other specific objectives that will contribute to the overall objective include:

i. To examine and choose the most appropriate IPR Model for horizontal well optimization using PERFORM Software.
ii. Carry out sensitivity analysis on the well using the various IPR Models, on PERFORM and save time and cost of several runs into the wellbore trying variety of IPR solutions this is the usual practise traditionally in the industry.
iii. To maximises horizontal well productivity and cuts down production time delay in making uneducated guesses and eventually eliminate liquid-loading attributed to unconventional (low permeability) gas reservoirs that can have huge impact on gas production.
iv. Carry out economic evaluation using various Economic parameters of Net Cash Flow, Profit-per-dollar, Payout and Internal Rate of Return for cases with PERFORM and compare with PROSPER software case.
v. To create awareness in the industry and institutional research about the capability of the software to optimize wells using Nodal analysis approach.

## 1.4 Scope of the Study

This work shall be limited to Production control variables which include: the lift gas rates, the production rates, and the well connections to flow lines.

The scope shall also be limited to the following four IPR Models for optimizing wells under steady state condition, such as: Giger correlation, Economides et al correlation, Modified Joshi and Benard & Dupuy correlation.

Limitation of horizontal wells is also considered in this study. Drilling costs are typically two or four time higher than conventional vertical wells. Additional techniques are needed for work-overs, logging, and tools because, normal wire line operations are inadequate.

## 1.5 Significance of the Study

This research work will be very useful to the Petroleum Production Engineer, whose primary responsibility is to produce wells optimally. The study will help him identify and remove constraints in the Production system. Selection of operating conditions of production facilities, that will, guarantee optimal production of both oil and gas wells.

Furthermore, this study finds its use in the aspect of production and well surveillance, in not just identifying constraints but, implementing remedial treatments to enhance production.

Production performance modelling is critical in the design of both oil and gas wells, as well as production facilities. In this research work, simple but reliable methods are introduced to forecast future inflow performance for gas wells and plan changes required to maintain and keep production capacity at optimal, William, (1996).

A new idea is introduced in this study to increase gas velocity immediately after the onset of liquid-loading by using the reservoir capability (reservoir pressure) that does not require external technology that would add economic cost.

# CHAPTER TWO

## 2.0 LITERATURE REVIEW

In oil and gas fields, production of hydrocarbon is often limited to the conditions of the reservoir, networks of pipeline, treatment plants for the fluids, economic and safety considerations, or a blend of these considerations. The field operators are faced with the charge to develop optimum operational approaches to accomplish definite operational goals. The ultimate goal of almost all efforts to form an oil and gas field is to develop an optimal strategy for the development, management and operation of the field. Optimizing production operations for certain fields can be an important factor if the production volumes are to be increased which will reduce production costs. Though it may be useful for individual wells to perform nodal analysis for prediction, but large systems require a more complex method to accurately predict reaction of a complex system for production (Wind et al., 1981). The interaction of the flow between the wells can play a significant part in some problems of rate distribution. In most cases, the problem of distribution of rates is expressed as a general nonlinear limited optimization and solved by the method of sequential quadratic programming. Various compositions have been investigated by different researchers' (Wind et al., 1981).

Applications of optimization techniques in the petroleum upstream industry began in the early1950s and have been flourishing since then. Applications have been reported for recovery processes, planning, history matching, well placement and operation, drilling, facility design and operation and so on. Optimization techniques employed in these applications cover almost all subfields in mathematical programming, such as linear programming, integer programming, and nonlinear programming. In this chapter, we first introduce salient concepts, solution algorithms, and applications of some major subfields in mathematical programming. Then we review their applications in areas that are pertinent to this study.

It is common knowledge that in some petroleum fields, a well or a flow line can have several potential output connections that join that well or flow-line to different flow-lines and facilities. Redirecting the well connections is an effective way to debottleneck the production system. The problem of well connection optimization is to identify the best set of well connections that maximizes an operational objective. To achieve the best results, well connections often need to be optimized simultaneously with production rates and lift gas rates (and potentially other production operations). Thus, the production optimization problem addressed in this section involves maximizing a certain operational objective (such as to maximize the daily oil rate) by optimally allocating the production and lift gas rates and well connections subject to multiple flow rate and pressure constraints. To differentiate this problem from the rate allocation problem mentioned previously, the optimization problem addressed in this chapter is referred to as the *global problem*.

The global problem is a nonlinearly constrained optimization problem with both continuous (production and lift gas rates) and integer (well connections) variables. No existing formal optimization methods can be easily adapted to solve such a complicated problem. Litvak et al. (1997) presented a heuristic optimization procedure to allocate the production rates, lift gas rates, and well connections for the Prudhoe Bay oil field in Alaska.

Although the physical decision variables for the global problem are the well connections, lift gas rates, and well chokes, it was shown that optimizing on well chokes is computationally inconvenient for the rate allocation problem. Because the rate allocation problem is a part of the global problem, production rates instead of well chokes are selected as decision variables for the global problem.

The optimization problem is solved by the following methods:

1. *Choose a realistic flowing pressure at the platform*. Suppose wells are producing with a set of lift-gas rate (not optimized) we simulate the multiphase flow in the gathering system and obtained the flowing pressure at the platform

2. *Construct gas-lift performance curves*. First we fixed the platform pressure and fix its gas-lift rate, we could determine its flow rate by solving the multiphase flow problem for the flow path connecting well *j* and the platform. For each well, we computed the oil flow rate for different gas-lift rates, namely, 0, 200, 500, 1000, 2000, 3000, 4000, 5000, 6000, and 7000 MSCF/d, and obtain its gas-lift performance curve.

3. *Allocate lift-gas*. First we approximated each gas-lift performance curve using a piece-wise linear curve.

## 2.1 System Analysis Overview

Oil well performance studies carried out by Fang, and Lo, (1996), as well as, Guyaguler and Byer, (2001) modelled each component within system using equations or correlations. Equations or correlations are used to determine pressure loss through the components as a function of flow rate.

Total pressure loss is the summation of pressure losses through all components.

Mathematically expressed as:

$$P_{\textbf{Total}} = P_{\textbf{r}} - P_{\textbf{outlet (wellhead/top of tubing or flow lin outlet)}} \qquad \textbf{(2-1)}$$

Entire system is analyzed by focusing on one point, called a NODE, hence nodal analysis. At the node producing system is divided into two segments:

Upstream or Inflow (components between node & reservoir boundary)

Downstream or outflow (components between node and separator boundary)

The schematic diagram presented by Brown, (1978) showing the locations of the nodes below:

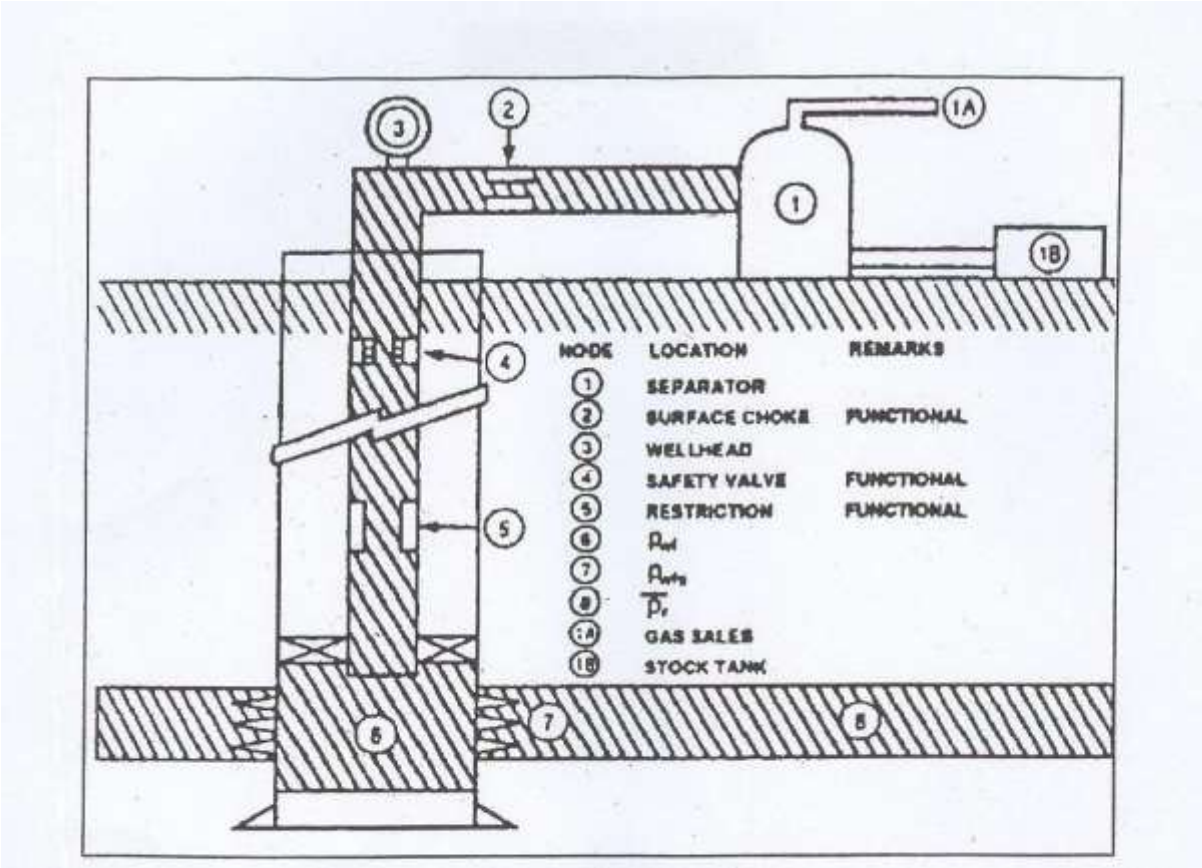


*Fig 2.1: Location of Various Nodes in Production System*

From the diagram, at the various nodes the following occurs:

i. Only one pressure exist ($P_{inflow} = P_{outflow}$)

ii. Only one flow rate exists ($Q_{inflow} = Q_{outflow}$)

Aziz, and Petalas, (1994) provided a general analysis procedure in their methodology for multiphase flow calculation. The step by step General Analysis Procedure includes:

1. Make a specific objective for the case such as, determining the size of tubing to use in the well

2. Determine the type of analysis needed to solve the problem, such as a systems analysis

3. Determine the components needed (reservoir, wellbore, completion and flow-line) and correlations desired.

4. Find all required data; make educated guesses for unknown values and enter the data for each component.

5. Calculate the case and check the output graphically

6. Interpret the output based on the type of case. Test the result for confidence by comparing the results within the data you have found.

7. Adjust the input and calculate again to improve the output results as needed

8. Repeat from step 1 for the next objective of the case.

To optimize the gas well case, we used a general system analysis approach that is comparative enough to provide solution data that will inform the right production engineering decisions on well deliverability, pressure maintenance technique and production enhancement.

The specific objective of the General Analysis Procedure is that it can be used for the following:

**A.** To determine the producing capacity of a well system for a set of well conditions

**B.** To determine the quantitative effect and importance of each variable within the system on the overall system performance.

James, et al (2008), in his work gives his clue on how to calculate for IPR. His IPR model solution can be applied using assumptions below:

- By using know quantities = the characteristics of the reservoir
- By using theoretical models for flows in porous media, E.g. the Darcy's law
- By using measurements = different well tests

Lea, et al (2008), applied system analysis with multiple inflow curves at different reservoir pressure and multiple outflow curves using various tubing sizes to solve gas well liquid-loading problems. The schematic diagram below shows the system analysis with multiple plots:

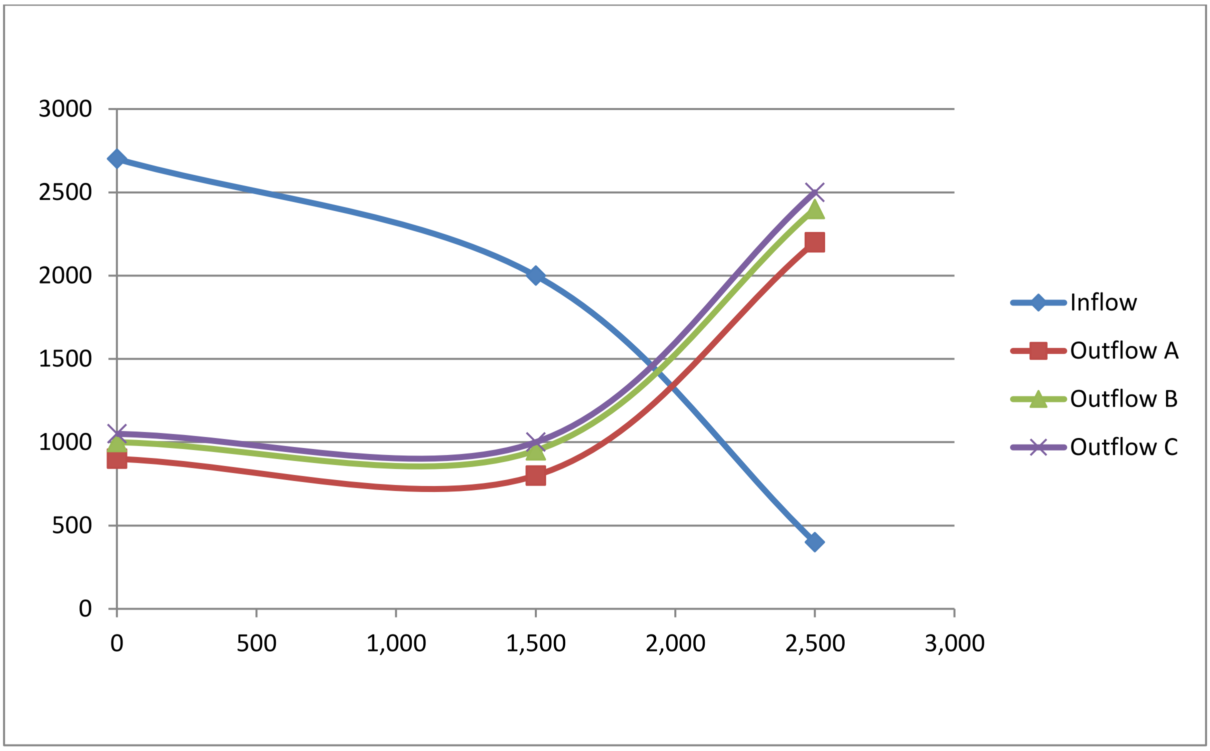


Fig 2.2: System Analysis with Multiple plots (Lea, et al, 2008).

### 2.1.1 Optimization for Horizontally Completed Wells

Emmanuel and Raney (1981) dealt on optimization for Horizontal wells. Horizontal wells, strikes the reservoir at 90° from vertical and extends a tunnel in the wellbore. According to the study, it was observed that not all reservoirs are good candidates for horizontal technology. Therefore, they are suitable for: thin reservoirs (less than 500ft thick); Reservoirs that have lower productivity than vertical wells; tight formations with horizontal as well as vertical permeability;

reservoirs that may have fractures; reservoirs with water-coning or gas-coning problems.

Stating the purpose why optimizing for horizontal Wells. Mainly to increase the surface of contact between the well and the reservoir and also to enhance productivity, the diagram is shown below:

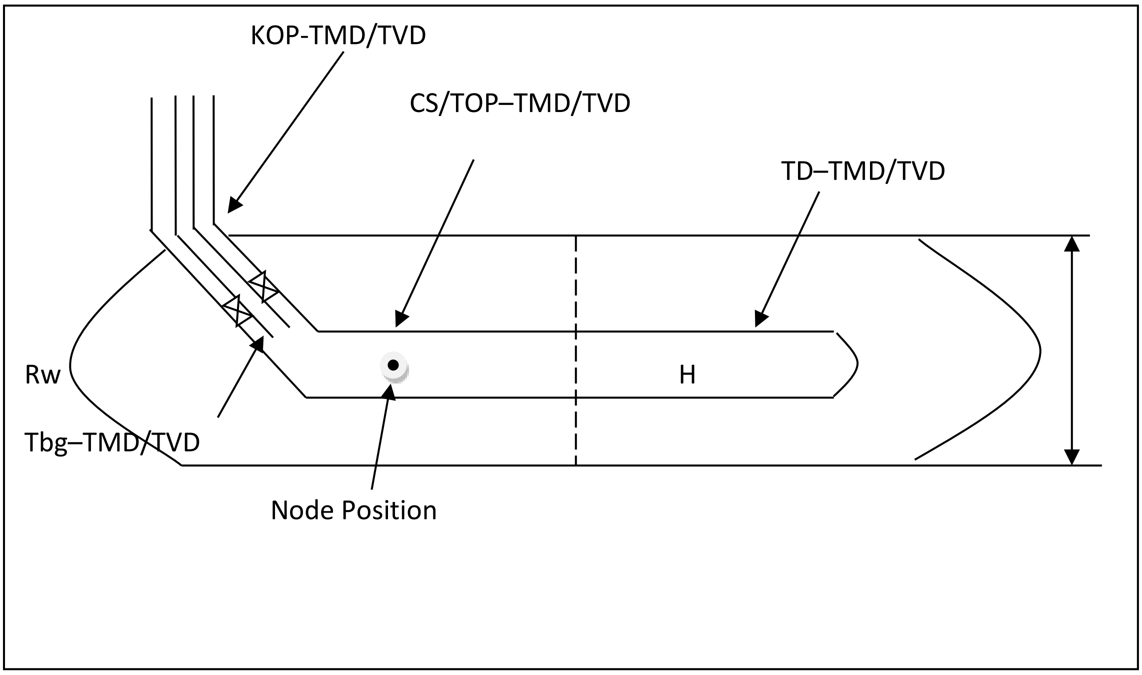


Fig 2.3: Typical horizontal well configuration by Emmanuel and Raney (1981)

### 2.1.2 Horizontal IPR Types

Horizontal reservoirs are modelled using a rectangular reservoir with a horizontal wellbore. Some of the IPR types require that the wellbore be in the centre of the reservoir. Other types specify the location of the wellbore. Both vertical and horizontal permeability is required for calculations.

### 2.1.3 Steady State Flow

At a constant flow rate for steady state flow, the pressure at every point in the reservoir will remain constant with time.

Steady state flow may be approached in reservoir with strong water drives or in cases where reservoir pressure is maintained by gas injection or water flooding.

## 2.2 Correlations Available In PERFORM To Determine Vertical IPR for Gas Wells

Correlation abound but here are some relevant ones used by PERFORM for the purpose of characterizing the inflow performance of Vertical wells. These correlations include the following:

(1) Darcy IPR for Gas wells;

(2) Back Pressure 4 Pt. Test;

(3) Jones et al (1976);

(4) Transient Flow Equation;

(5) Fractured Well IPR;

(6) Fractured Well – Chase et al (1993)

### 2.2.1 Darcy IPR Model:

Golan, (1986) and Aziz and Petalas, (1994) in their various work both used the Darcy IPR Model to apply for both oil and gas wells and developed the following assumptions: that only single phase exists; Flow is Laminar; Fluid is incompressible. From their work they recommended Darcy's IPR Model application for reservoirs above bubble point. However, below Bubble point, Vogel's correlation is necessary. Mathematical Expression is given as:

$$Qg = (0.000703)kgh(\varphi r - \varphi ws)/\,T[In(x) - \frac{3}{4} + S + DQg \qquad \text{(2-2)}$$

Where;

Qg = Gas flow rate (Mscf/d);

kg = Effective gas permeability (md);

H = Net formation thickness (ft);

φr = Average reservoir pseudo-pressure ($psi^2/cp$);

$\varphi ws$ = Flowing sand-face pseudo-pressure ($psi^2/cp$);

S = skin effect;

D = Non-Darcy turbulence factor (1/Mscf/d);

$r_e$ = Reservoir radius (ft); and $r_w$ = Wellbore radius (ft)

Darcy's Productivity Index (Darcy PI) can be calculated with the equation:

$$PI = (0.00708)Kh/\mu B[In(x) - \frac{3}{4} + S] \qquad (2\text{-}3)$$

*Where;*

PI = Productivity index (stb/d/psi);

k= Effective gas permeability (md);

h = Net formation thickness (ft);

μ = Average liquid viscosity (cp);

x = Drainage area factor $r_e/r_w$ or from area and shape factor;

S = skin effect;

D = Non-Darcy turbulence factor (1/Mscf/d);

$r_e$ = Reservoir radius (ft);

$r_w$ = Wellbore radius (ft).

### 2.2.2 Non-Darcy Turbulence Term (D):

D in the Darcy equation is used to account for inflow turbulence. It is sometimes referred to as Ramey turbulence or Ramey D-Term. It is a form of skin induced by two-phase fluid behaviour at or near the well bore. It is determined through multi-rate testing of well with the equation:

$$S' = S + S(q,t) + DQ \qquad (2\text{-}4)$$

*Where:*

*S' = Total skin;*

*S = Physical skin caused by damages near the wellbore or enhancement through stimulation;*

*S (q, t) = Rate and time dependent skin, generally caused by permeability alteration due to changing gas saturation near the wellbore;*

*DQ = Rate dependent skin described as the non - Darcy flow term.*

### 2.2.3 Drainage Area and Shape Factors

The In $r_e/r_w$ value in equation (Darcy PI) is applicable only for wells producing in the centre of a circular drainage area. For cases where the well is located in an irregular shape drainage area, is replaced with In x. Mathematically, x is defined as:

$$X = \frac{S_{factor} * S_{area}^{0.5}}{r_W} \qquad (2\text{-}5)$$

*Where:*

*$x$ = Reservoir drainage factor;*

*$S_{factor}$ = Reservoir shape factor from table;*

*$S_{area}$ = Reservoir area ($ft^2$);*

*$r_w$ = wellbore radius (ft)*

### 2.2.4 Jones et Al (1976) IPR:

This model is used to account for turbulence in a producing gas well, mostly applied to gas wells. Jones et al (1976) can also be used in oil wells with high GOR. Therefore, this model is suitable for reservoir above bubble point. Vogel equation can be used to adjust Jones equation below bubble point pressure for solution gas drive reservoirs.

Jones, Blout and Glaze equation is to account for turbulence in a producing oil or gas well. The equation is referred to as Jones equation and it is written in the following forms for gas wells:

$$\Psi r - \Psi ws = aQ2g + bQg \qquad (2\text{-}6)$$

$$a = (3.16 * 10 - 12)\beta\gamma\ g\ T/h2p\ rw\ \mu g \quad \text{: Turbulent term} \qquad (2\text{-}7)$$

$$b = \frac{(1424)T[In\ (0.472\ x) + S]}{kg\ h} \quad \text{: Laminar term} \qquad (2\text{-}8)$$

The variables **a** and **b,** can also be obtained by plotting graphically:

(Pr2-Pwf2)/Qg versus Qg

*Where:*

Ψr = average reservoir pressure (psi2/cp);

Ψws = flowing sandface pressure (psi2/cp);

Qg = Gas flow rate (Mscf/d);

β = Turbulence coefficient (1/ft);

$\gamma_g$ = Gas specific gravity;

T = Average reservoir temperature (°R);

$h_p$ = Perforation thickness (ft);

$\mu g$ = Gas viscosity (cp);

X = Drainage area factor re/rw or from area and shape factor;

S = Skin effect

Jones turbulent coefficient (β) can be defined as:

$$\beta = \frac{2.33 * 10^{10}}{K * 1.201} \tag{2-9}$$

Where:

B = turbulent coefficient (1/ft);

K = effective permeability (md)

Note: Jones equation is recommended in wells in which turbulence is assumed to be a critical factor. In gas wells, turbulence is prevalent hence Jones equation is suggested. Vogel equation can be used to adjust Jones equation below bubble point for solution gas drive reservoirs.

### 2.2.5 Back Pressure – 4-point Test for (Gas wells only):

The IPR type calculates the equation constants n and c. Usually, the model is measured with completion effects included in test data. Hence, recommended completion type is open-hole completion type. Pseudo pressure is used to calculate for gas wells to improve accuracy. This equation is given as:

$$Q = C * (\Psi r - \Psi ws) * n \qquad (2\text{-}10)$$

*Where:*

Q = flow rate (stb/d or Mscf/d);

C = Backpressure coefficient;

Ψr = Reservoir pseudo pressure (psi2/cp);

Ψws = Sand face pseudo pressure (psi2/cp);

n = Turbulence coefficient

Note: Do not use resulting n and C values from this equation in the user-entered Back Pressure equation.

### 2.2.6 Transient Flow Equation:

This can be used for a new well that has not reached pseudo steady state. Applies to wells still producing in a transient condition and therefore, suitable for both oil and gas wells. For a gas well we have the following equation;

$$Qg = \frac{kg\,h\,(\psi_r - \psi_{ws})}{\qquad} \qquad (2\text{-}11)$$

$$162\mu B\,[\log(k_g\, t \,/\, ø\, \mu\, C_t\, r_w^2) - 3.2275 + 0.87\, S]$$

Time to reach pseudo-steady state:

$$Time\ (hrs) = \frac{ø\, \mu\, C_t\, r_e^2}{(0.001005)\, k} \qquad (2\text{-}12)$$

Where :

$Q_g$ = Gas flow rate (stb/d or Mscf/d);

$K_g$ = effective permeability (md);

$\Psi_r$ = Average Resrvoir permeability (md);

$\Psi_{ws}$ = Flowing Sand face pseudo pressure (psi)

h = Net formation thickness (ft);

$C_t$ = Total system compressibility (1/psi)

### 2.2.7 Fractured well – Chase et al (1993):

This IPR equation is valid for gas wells and uses dimensionless IPR curves for predicting the performance of fractured gas wells from build up and drawdown data. The model assumes a uniform flux fracture.

Again, this is applicable for gas wells producing under pseudo steady state if the external boundary is known. If the radius is not available, then the radius of investigation can be approximated provided that producing time is available. The absolute open flow rate, $q_{max}$ is calculated as follows:

Where: $$qmax = \frac{-A \pm\sqrt{A^2-4B\,[m(Pr)]}}{2B} \qquad (2\text{-}13)$$

And:

$$A = \left(\frac{T}{0.703}\right)\{In[re - 0.37Xfe\ x - 0.75 + S]\} \qquad (2\text{-}14)$$

$$B = \frac{T\ \ D}{0.703\ kh} \qquad (2\text{-}15)$$

$$D = 3.375 * 10^{-18}\ \frac{\gamma_g\, h}{\mu_g r_w\, h^2{}_p} \qquad (2\text{-}16)$$

## 2.3 Software Simulation Overview

The main tools used in this research are presented as software platforms. Reservoir simulations are conducted using SENSOR®, surface process simulation using HYSYS®, and pressure drop calculation using PROSPER®. All simulations are run through the software platform, Pipe-It®. All of the optimization problems are solved using derivative-free optimization based on a constrained Nelder-Mead Simplex algorithm Pipe-It's default solver. General descriptions of the software simulations are given below.

### 2.3.1 SENSOR Reservoir Simulator®

The SENSOR reservoir simulator was developed by Coats Engineering, Inc., and is applicable for compositional and black oil fluid types (Sensor Reference Manual (2009)). Compositional and black oil reservoir simulations were presented in this thesis. The compositional simulations were conducted in two chapters; an integrated model and optimization (Chapter 3) and optimal injection strategy for oil reservoirs (Chapter 4). A black oil fluid type simulation was presented in the liquid-loading gas wells. The SENSOR reservoir simulator was the preferable choice to perform those simulations because it provides benefits in terms of speed, accuracy, stability, and reliability.

### 2.3.2 Aspen HYSYS®

The HYSYS simulator, developed by Aspen Technology, Inc., was used to simulate the surface facilities (Aspen HYSYS User Guide (2004)). HYSYS is considered to be one of the leading software packages of integrated simulation environments available to the downstream process industries. HYSYS supports several integration techniques and is completely Object Linking and Embedding (OLE) compliant.

### 2.3.3 The Mellanox Solution

To accelerate reservoir and seismic simulations, and to perform more complex simulations, engineering simulations are essential in order to reduce costs and speed time to production. For example, reservoir simulation models are being used in the development of new fields, and in developed fields where production forecasts are needed to help make investment decisions, to identify the number of wells required, to improve oil recovery, to identify opportunities to increase oil production in heavy oil deposits, and much more. Oil and gas companies must invest in the required infrastructure to empower their engineers with the most advanced high-performance computing (HPC) resources Mellanox's 56Gb/s InfiniBand and 10/40/56Gb/s Ethernet interconnect solutions are designed for multi-core cluster environments and can efficiently handle multiple data streams simultaneously while guaranteeing fast and reliable data transfers for each of the streams. With latency as low as 700 nanoseconds, throughput as high as 56Gb/s, extreme message rate, and low CPU overhead, Mellanox solutions enable fast and highly scalable communication among server processing units and storage systems, and therefore maximize the HPC system utilization into the 95th percentile range, on average 50% higher than other networking solutions.

### 2.3.4 Petex - PROSPER®

The PROSPER simulator, developed by Petroleum Experts, is a well performance design program for modelling tubing and pipeline in oil and gas fields (Petroleum Experts (IPM Tutorials) (2004)). PROSPER provides the ability to predict tubing and pipeline hydraulics and temperatures with accuracy and speed; types can be simulated using PROSPER: (i) gas, oil, water, and condensate production wells, (ii) water and steam injection wells, (iii) naturally flowing, (iv) artificial lifted, (iv) multi-layer and multi-lateral, and (v) deviated and horizontal wells.

### 2.3.5 Petrostreamz Pipe-It®

Petrostreamz Pipe-It is used as a software platform and optimizer for all issues addressed in this thesis. Manual data transfer between simulators, as conventionally practiced, was avoided. Pipe-it has the ability to maintain a detailed, quantitative upstream-to-downstream accounting of the individual models that constitute petroleum resources information. This software bridges the work of reservoir engineers, who speak in terms of volumetric rates, with process engineers, who often speak in terms of component molar rates, and ultimately with managers, who speak in terms of currency, revenue, net present value (NPV) and profit (Pipe-It Online Documentation, 2006). Pipe-It allows access to measured data provided by online metering and spot testing stored in databases. Pipe-it includes the **Streamz "**engine", which allows translation of measured and calculated streams from one characterization to others, as needed by downstream model in an integrated system. Streamz can also be used as a surface separation process simulation similar to HYSYS, but without heat and energy balance. Pipe-It is linked to an optimization routine based on the constrained Nelder-Mead Simplex algorithm.

### 2.3.6 Nelder-Mead Simplex Algorithm

Because of the nonlinearity of the system, petroleum production optimization problems are characterized by a non-convex objective function. Derivative information may be expensive to obtain or nonexistent. The suitable optimization method for this type of problem is therefore a derivative-free method. Among the derivative-free optimization methods, Nelder-Mead Simplex (Nelder and Mead (1965) and Lagarias et al. (1998)) is chosen to search for the optimum solution in the optimization problems discussed in this study because the application of this method in the three topics is still new and because its performance in handling problems is acceptable.

Nocedal and Wright (2006) explain how this algorithm seeks to remove the vertex in the decision space with the worst objective function value and replace it with another point with a better value. The new point is obtained by reflecting, expanding or contracting the simplex along the line that joins the worst vertex with the centroid of the remaining vertices. If the algorithm cannot find a better point in this manner, the algorithm retains only the vertex with the best function evaluation, and the algorithm then shrinks the simplex by moving all other vertices toward this value. The convergence criteria used in the optimization method are related to the improvement of the objective function and the change in the decision variable from one iteration point to the next.

### 2.3.7 IHS Energy Group - PERFORM®

PERFORM VER 500 is the well performance analysis software used for this thesis to optimize the Gas well cases. PERFORM VER 500 as a graphical tool is designed with an interface that is both users friendly and easy to navigate.

From the IHS Energy group Manual (2006), the User's Guide to various Elements and Function is described and highlighted below:

Title bar – Displays the program name of the open case (Example, Well PERFORMance Analysis C:\PSG\PERFORM VER 500\EXAMPLES\GAS.pts)

Menu bar – Display the menu names (E.g. File, Edit, Input, View, Options, Windows and Help)

Tool bar – This provides quick access to the main commands. To turn off the tool bar on the View menu, cancel the Tool bar command.

Report Window – Displays a tabular report that shows the Calculation results.

Easy Interface Window – Displays a graphical representation of a well system for data input and verification.

Graph Window – Displays a graph or plot illustrating the results of a calculation. After calculating a case, a set of plots updates that you can view or print.

Status bar – Displays applicable hints and minimum values for the current entry. To turn off the Status bar, on the View Menu, cancel the Status Bar command.

Furthermore, on the PERFORM Toolbar we can navigate with ease to perform functions as stated in the IHS Energy group manual (2006). The step process of operation allows the simulator to navigate the software tools using the following process which includes:

1. Create a new case;
2. Open an existing case;
3. Save the active case;
4. Print a document;

5. Open the Well Description dialogue box;
6. Open the Analysis Setting Dialogue box;
7. Open the Down-hole Network dialogue box
8. Open the Fluid Properties dialogue box
9. Open the Reservoir Data dialogue box
10. Open the Pressure/Temperature Calculation for wellbore and Flow line dialogue box.
11. Open the Wellbore Data dialogue box

## 2.4 Reservoir Segment (Inflow)

The reservoir component is composed of the flow between the reservoir boundary and the surface, Nind, (1981). The component is always upstream of the node. The flow through the reservoir is referred to as the inflow performance relationship (IPR) of a well. IPR is a measure of the reservoirs ability to produce fluid as a result of pressure differential. Reservoirs ability to produce fluid depends on: Reservoir type; Producing drive mechanism; Reservoir pressure; Formation permeability and Fluid properties, [Mohammad, April, 2008].

### 2.4.1 Productivity Index (PI):

Productivity Index (PI) is the rate of production per pressure drawdown.

$$PI = J = \frac{q}{P_{rm} - P_{wf}} = \frac{q}{\Delta P_1} \quad (bbls/day/Psi) \tag{2-17}$$

Where,

q = Production Rate in bbls/day

$P_{rm}$ = Static Reservoir Pressure (Psi) calculated at the middle point of the reservoir

$P_{wf}$ = Flowing Bottom hole Pressure (Psi)

### 2.3.2 Inflow Performance Relationship

$$Pwf = \left\{-\frac{1q}{j}\right\} + Prm \tag{2-18}$$

This is derived from the Plot of $P_{wf}(psi)$ against $q(bbls/day)$ we can produce a real curve and theoretical curve that does not show the actual. Also two flow rates exist: the real curve, $q^i$ = ideal case of production, where $P_{wf} = 0$, *while*; $q_{th}$ = theoretical maximum of production rate, which is impossible to realize.

For Two phase flow – use generalization IPR curve:

Physically, the transition from pure liquid Flow to the presence of some free gas in the flowing stream is a continuous one → continuity of the curves.

### 2.4.3 Prediction of the future IPR

In the previous part of the study, we have idealized the behaviour of the flow in the reservoir today.

But what will happen in the next 3, 4 or 10 years? This should be a priority to us in this study. The prediction of the wells deliverability in the future is a very important task for the engineer in order to achieve the following: Optimize the well design; evaluate artificial lift needs and abandonment conditions; maximise future financial returns.

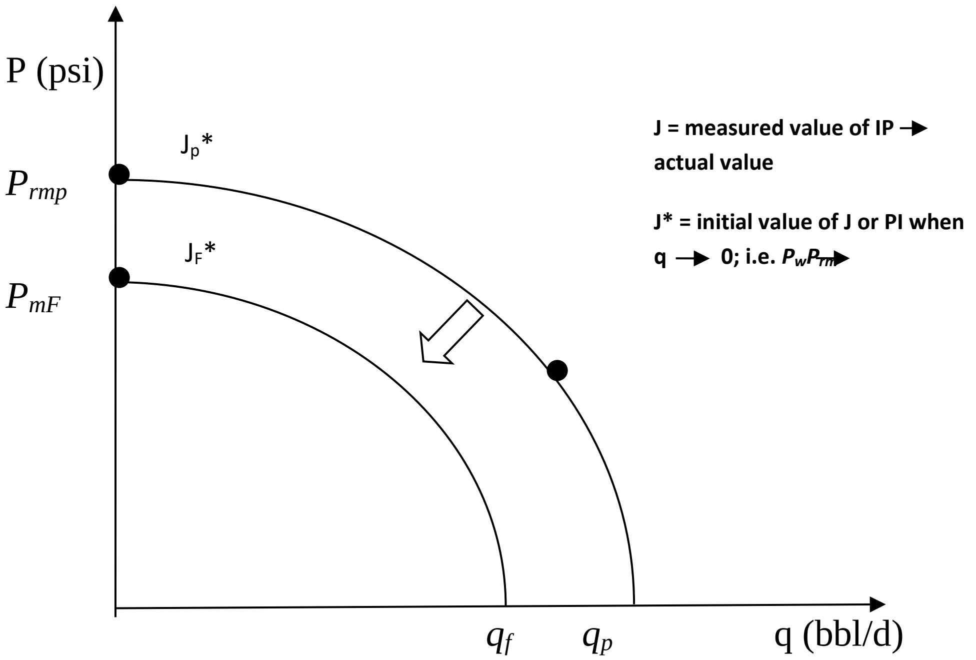


Fig 2.3: Prediction of the future IPR (Beggs, 2003)

## 2.4 Deliverability of Gas Well

Well deliverability is designed from the inflow performance relationship (IPR) and from the curve intersection of the vertical lifting performance (VLP). The

IPR includes the environments and constraints of the reservoirs while the VLP reflects on wells that are producing. In order to optimize the production of gas, pressure drop occurs when the reservoir fluid moves from the reservoir to the surface through the well, the production tubing and processing facilities (Shah and Hossain, 2015). This concept combines the flow of the reservoir, as shown by most wells IPR, with the tubing performance capacity curve that embodies substantially all of the pressure drop connected with well tubing connections. This combination brings the components of the oil production system together and can also be applied during the diagnosis, analysis and identification of incorrect or defective parts of the well system.

Well performance analysis is useful not only for determining a specific well IPR and performance of tubing; but can also be used to test a number of different options for modification. These options include; the diameter of the tubing, the pressure at the well head, the type and size of choke, the density of perforations, horizontal and complex wells and hydraulic fracturing. If all options are properly taken into account, it can lead to economic optimization: the additional cost among design can be balanced with the increase in well productivity or performance.

# CHAPTER THREE

# MATERIALS AND METHODS

## 3.1 Materials used for the study

(i) IHS PERFORM Ver 500 simulator was used to generate PI, determine Inflow and Vertical Lift Performance of the case study well at varying well pressure and flow rates (first on natural flow without artificial lift installed)

(ii) Microsoft Excel package was used for Economic Analysis to determine the profitability of PERFORM when compared with another software tool (PROSPER), as well as, case three optimization process with no software tool used.

## 3.2 Methods

The methods employed in this study are outlined below:

(i) Data gathering process (Well, Reservoir data, Flow-line and Pressure loss data)

(ii) Reservoir Model description

(iii) Parameters available for the analysis

(iv) Summary of results for all cases considered

(v) Sensitivity Analysis

(vi) Economic Analysis

(vii) Discussion of Results

**Table 3.1:** Reservoir Data for X-Field

| IPR Type | Giger et al (1985) | Symbol |
|---|---|---|
| Reservoir Pressure | 2900.0 | Psia |
| Reservoir Temp | 165 | °f |
| Wellbore Radius | 5.000 | In |
| Reservoir Radius | 1000 | Ft |
| Reservoir Thickness | 21 | Ft |
| Reservoir Skin | 0.000 | |
| Turbulence Factor | 0.00000 | 1/bpd |
| Horizontal Tunnel Length | 2000 | Ft |
| Avg. Vertical Perm | 1.000 | Md |
| Avg. Horizontal Perm | 5.000 | Md |

*Where:* $K_{avg}$ = Equivalent horizontal/ vertical permeability

$K_{horz}$ = Horizontal reservoir permeability

X-Field is an offshore gas condensate field that has been completed. Seismic studies and Well tests suggest a very large anticline structure, with possible reserves of 7.8 TCF of gas and 400 million barrels of condensate liquids.

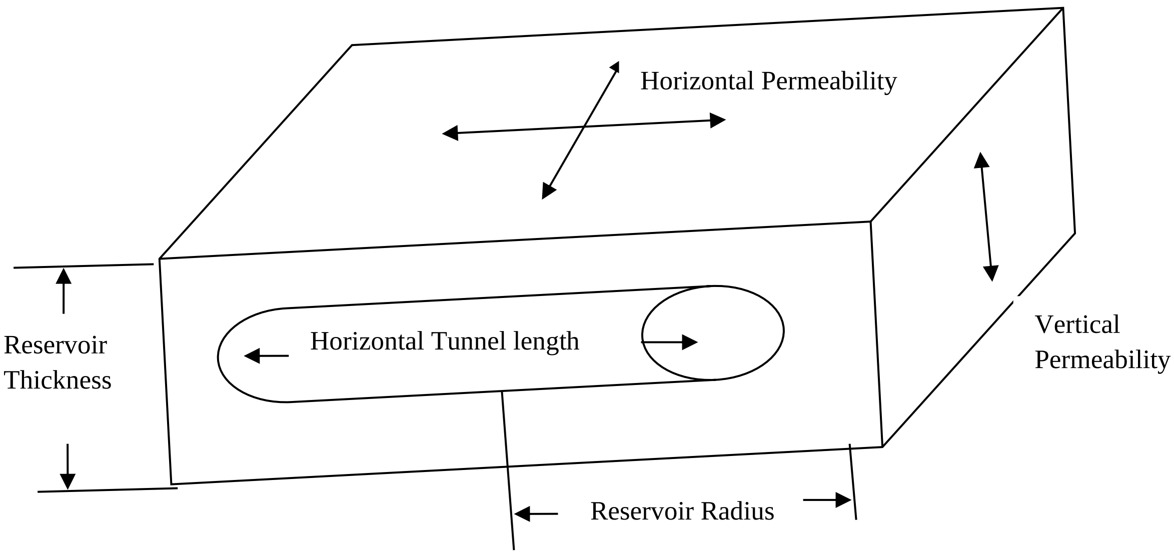


*Fig 3.1: Horizontal well geometry of the Simulation case*

## 3.2 Parameters for Optimizing Oil and Gas Wells

The parameters necessary for optimizing operation in oil and gas wells include: Reservoir skin; Completion effects; Tubing size; Well head or Separator pressure. These factors can be manipulated during sensitivity analysis process to simulate the optimal conditions required.

### 3.2.1 Parameter of Wellhead Pressure

This is the well head or top of tubing pressure (if no flow-line is used or flow-line outlet pressure if a flow-line is included) is the outlet pressure of the total system.

Lowering this outlet pressure, results in increased well capacity. Increased well performance can be achieved by installing larger chokes in the well head or installing a compressor to reduce the well head pressure.

### 3.2.2 Optimization Parameter of Reservoir Skin

The effect of altering reservoir skin is generally associated with the effect of removing damage through simulation . This can be determined from the inflow sensitivity on skin.

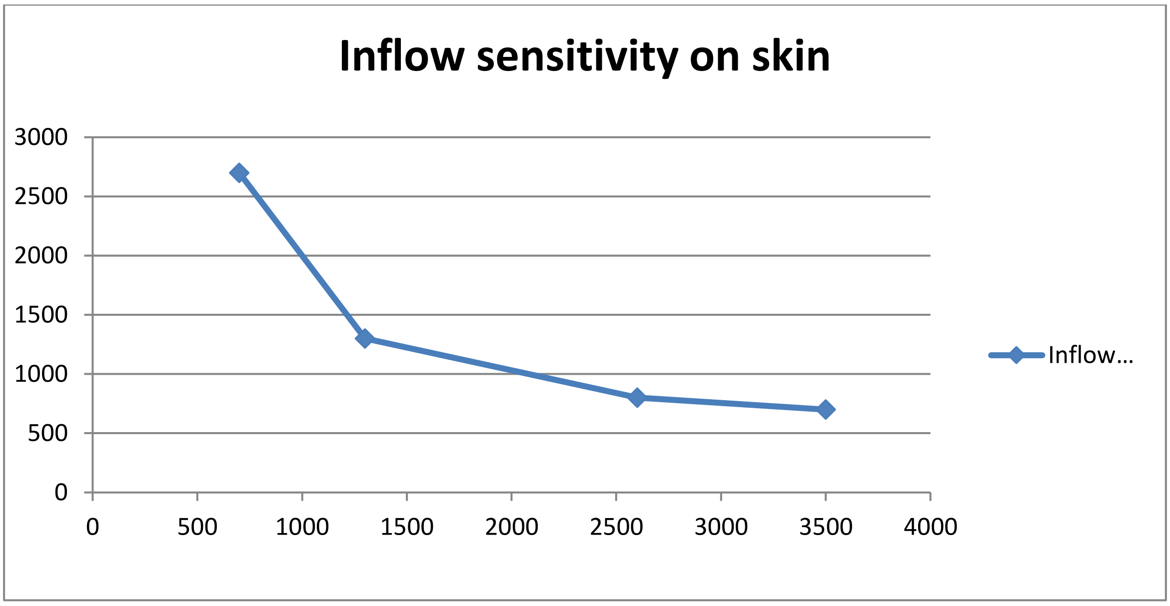


*Fig 3.2:* Inflow sensitivity on skin

From the figure above, therefore, the presence or removal of skin from the reservoir boundary, determines greatly the inflow performance. When skin = 0, implies that there is no skin. Skin = 1; indicates the formation is damaged and hence that reservoir cannot achieve optimal deliverability.  Negative Skin (-s);

shows that the well is stimulated and no impairment to flow between the reservoir boundary and the surface.

### 3.3.3 Optimization Parameter of Completion Effects

Variables in the completion design that are subject to change and optimize are: Perforation Shot density; Perforation size; Perforation length; Perforation interval; Gravel Pack size; Gravel Pack permeability; Damage zone radius and permeability; Perforation Crushed zone effect.

### 3.3.4 Differential Graph:

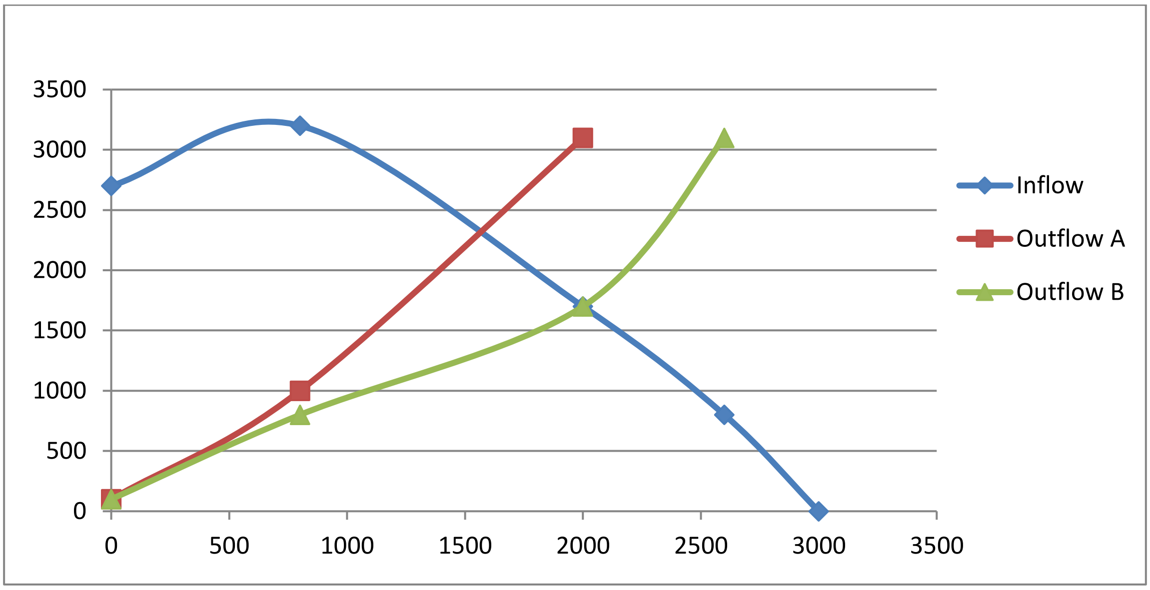


Fig 3.3: Differential graph

Differential graph helps in emphasizing the completion effect of a well. The differential graph again has two main curves namely:

One bending downwards; representing the difference between the pressure remaining after flowing through the reservoir ($P_{ws}$) and the pressure needed to flow through the out flow segment. The difference is the pressure available to produce through the completion.

The other bending upwards to the left are the actual pressure losses through the completion as a function of rate.

### 3.3.5 Perforation Interval:

This means the measured length of the formation that is actually perforated. Perforation interval is somewhat less than formation thickness due to:

- Well problems that result in the inability to completely penetrate the producing formation.
- Reduced perforation interval aimed at lowering completion cost.
- Altered perforation intervals to accommodate subsequent stimulation treatments.

### 3.3.6 Effects of Perforation Interval

Reduced perforation interval affects the inflow segment in two ways:

1. Increases the pressure loss encountered as the flow converges.
2. Reduces the number of actual perforations available for flow into the wellbore.

Both effects results in less productivity from the wells and can be interpreted on a differential graph.

### 3.3.7 Open Hole Completion Effects:

Open Hole completion has minimal effect on the system. In system analysis, the open hole is generally regarded with no pressure loss between the sand-face and the wellbore. There are no calculations performed for an open-hole completion. Hence, no input data is required when using any software (PERFORM, SAM or PROSPER simulators).

This completion type is recommended if completion effects are considered in the reservoir IPR. For instance;

On a differential graph, when a solution point flow rate of 873 (Bbl/D) is produced at a solution point Pressure of 1159.6 (Psig) we observe a completion pressure drop at a solution point of 0.00 Psi (IHS Energy Group (2006) Well PERFORMance Analysis, Version 5).

Mathematical model for Open Perforated completion: For oil well is,

$$P_{ws} - P_{wf} = aQ^2 p + bQ_p \tag{3.1}$$

Where:

$$a = \frac{(2.30 \times 10^{-14})\, \beta_p B^2 \rho\, (1/r_p - 1/r_c)}{L^2_P} \tag{3.2}$$

$$b = \frac{\mu B\, [\mathrm{In}\, (r_c / r_p)]}{\quad} \tag{3.3}$$

$(0.00708)\ L_P\ K_c$

Where:

$P_{ws}$ = Flowing Sandface pressure (psi);

$P_{wf}$ = Bottom hole flowing pressure (psi);

$Q_P$ = Liquid flow rate per perforation (stb/d/perf);

$\beta_p$ = Perforation turbulence factor ($ft^{-1}$);

B = Average formation volume factor (rb/stb);

ρ = Fluid density;

$L_p$ = Perforated tunnel length (ft);

$r_p$ = Radius of perforated tunnel (ft);

$r_c$ = Radius of compacted zone (ft).

Mathematical model for Open Perforated completion Gas well:

$$P^2_{ws} - P^2_{wf} = aQ^2\ p + bQ_{\ p} \tag{3.4}$$

Where:

$$a = \frac{(3.16 \times 10^{-12})\ \gamma_g\ \beta_p\ TZ\ (1/r_p - 1/r_c)}{L^2_P} \tag{3.5}$$

$$b = \frac{(1424)\mu_P\ TZ\ [In\ (r_c\ /\ r_p)]}{} \tag{3.6}$$

$$L_P K_c$$

### 3.3.8 Effect of Stable Perforated Completion:

This is obtained by modifying open perforation models to account for additional damage near the well bore due to drilling or completion fluid incompatible with the formation.

Mathematical model for Stable Perforated completion:

For oil well is,

$$P_{ws} - P_{wf} = \frac{141.4\ \mu\ B\ (S_{or}\ Q_p + DQ^2_p)}{K_r\ h_P} \qquad (3.7)$$

Where:

$$D = \frac{(1.63 \times 10^{-16})\ \beta_p\ B\rho\ K_r\ h_P}{N^2\ r_p\ L^2_P} \qquad (3.8)$$

And:

$$S_{tot} = S_p + S_d + S_{dp}$$

$$S_{dp} = [h_p / (L_p \times N)]\ [\text{In } r_c / r_p]\ [K_r / K_c - K_r / K_d]$$

$$S_d = \text{In } (r_d / r_w)\ [k_r / K_d - 1]$$

Equations for Gas well we have;

$$P^2_{ws} - P^2_{wf} = \frac{1424\ \mu_g\ ZT\ (S_{tot}\ Q_p + DQ^2_p)}{K_r\ h_P} \qquad (3.9)$$

Where:

$$D = \frac{(2.22 \times 10^{-15})\ \beta_p\ \gamma_g\ K_r\ h_P}{N^2\ r_p\ \mu_g\ L^2_P} \qquad (3.10)$$

Example of the effect of stable perforation, if solution point flow rate of 376 (Bbl/D) is flowing at a pressure of 1146.2 (Psig) will produce a pressure a completion pressure drop of 514.2 (psi).

### 3.3.9 Effects of Collapsed Perforation Completion:

This method is used to predict the completion based on assumption that the fluid is flowing spherically into such perforation. Equations to account for collapsed perforation completion include:

For Oil wells:

$$P_{ws} - P_{wf} = \frac{141.4\ \mu\ B\ (S_{tot}\ Q_p + DQ^2)}{K_r\ h_P} \qquad (3.11)$$

Where:

$$D = \frac{(5.42 \times 10^{-17})\, \beta_p\, B_p\, K_r\, h_P}{N^2\, r_p\, \mu} \qquad (3.12)$$

And:

$S_{tot} = S_s + S_{sd}$

$S_s = 45\, [h_p / N]^{1.1} + [h_P / N]\, [1 / r_p]\, [1 - 48\, r_p]$

$S_{dp} = [h_p /N]\, [I /r_p]\, [1- r_p/r_c]\, [K_t / K_c - K_c /K_d]$

$$\beta_p = \frac{2.60 \times 10^{10}}{K_d^{1.2}} \qquad (3.13)$$

### 3.3.10 Effects of Gravel Pack Completion:

In other to eliminate sand control problems, the GRAVEL PACK technique was developed. A slotted liner or gravel pack screen is run a tubing and set across the perforation to provide a barrier between the formation sand and well-bore.

High permeability gravel is then pumped down hole and placed between the screen and the perforations.

In system analysis, the technique used to predict completion effects through a gravel pack is simply pressure loss due to linear flow through the gravel.

### 3.3.11 Parameter of Tubing Size

Improperly sizing tubing affects an efficiently designed well system in two ways, they include:

1. If the tubing is too small, friction loss will be excessive
2. If the tubing size is too large, additional pressure loss will be encountered due to liquid loading.

As stated, the size of the tubing is one of the important parameters affecting gradients. For low velocity the slippage of gas by the liquid contributes to the pressure losses. For high velocities friction becomes the controlling factor. Between these two extremes there is a range of velocities giving the optimum gradient at the inlet of tubing in the bottom of the well. If the future range of expected rates and the oil/gas ratios can be estimated, selection of the tubing size can be made, which would assure operation within the efficient range of gradients, with the resulting increase in the flow life of the well.

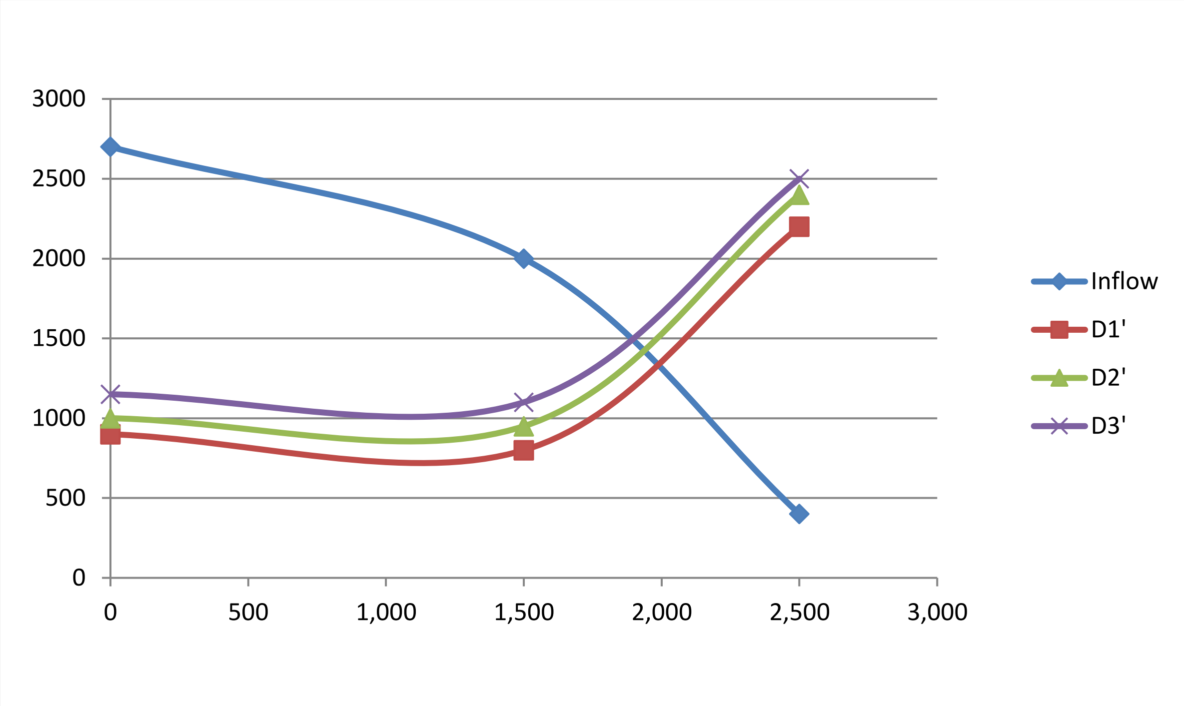


Fig 3.4: Effect of tubing size on oil well deliverability

## 3.3 Categories of Horizontal IPR Types

Horizontal IPR's are classified based on flow regimes, and can be disaggregated thus:

Table 3.2: Categories of Horizontal IPR Types

| Steady State Flow | Pseudo-Steady State Flow | Transient State Flow |
|---|---|---|

| | | |
|---|---|---|
| ***Giger et al (1984)***<br><br>***Economides et al (1991)***<br><br>***Joshi (1988)***<br><br>***Benard and Dupuy (1991)*** | ***Kuchuk (1988)***<br><br>***Bubu and Odeh (1989)*** | ***Goode and Thambynaya (1987)*** |

### 3.4.1. Well performance using Giger et al IPR model (1984)

Applied to a reservoir in steady state and used to calculate the sand-face pressure and flow rate pairs for isotropic and anisotropic reservoirs. For anisotropic reservoirs, Muskat method was used to calculate equivalent reservoir permeability and adjusted the rest of the parameters. The method can be applied to both oil and gas wells.

Isotropic equivalent parameters are given as:

$$Kavg = \sqrt{\ } Khorz * Kvert \qquad (3\text{-}14)$$

$$N\ \ horz = \frac{\sqrt{K}avg}{} Khorz:$$

$$N\ vert = \frac{\sqrt{Kavg}}{} K\ vert$$

$$Leq = L * N\ horz: \qquad Heq = h * N\ vert: \qquad req = re * N\ horz$$

Horizontal drainage component – horizontal plane:

$$Dhorz = In1 + \frac{\frac{\sqrt{1}-\left(\frac{Leq}{2req}\right)^2 * Leq}{}}{\frac{Leq}{2reqheq}} \qquad (3\text{-}15)$$

Horizontal drainage component – vertical plane:

$$Dvert = In\left[\frac{heq}{2\pi rw}\right] \qquad (3\text{-}16)$$

The reservoir storage term:

$$W\ s = D_{horz} + D_{vert} + S \qquad (3\text{-}17)$$

Reservoir rate calculation without Ramey D turbulent flow is included. For Gas well, we have that:

$$Q_g = \frac{0.000703\, K_{avg}\, L_{eq}\, (\Psi_r - \Psi_{wf})}{(T + 460)\, W_s} \qquad (3\text{-}18)$$

Reservoir rate calculation with Ramey D turbulent flow included. For Gas well, we have that:

$$Q_g = \frac{0.000703\, K_{avg}\, L_{eq}\, (\Psi_r - \Psi_{wf})}{(T + 460)\,(W_s + DQ_g)} \qquad (3\text{-}19)$$

**3.5 Economic Model:** To determine the viability or feasibility of the simulation case and show the relative economic advantage of optimally

producing with PERFORM compared with other similar Production simulators available like PROSPER we use Profit indicators, such as;
(i) NPV

(ii) Payout Period

(iii) Profit per dollar invested

(iv) DCF – ROR

Decision rule: To embark on any capital intensive project in the petroleum industry, it is necessary to proceed with such project if the profitability calculations are in line with the following decision rules Obah, (1999).

(i) NPV (Accept the highest and NPV greater than zero)
(ii) Payout period (the shorter the better)
(iii) Profit per Dollar invested (the highest the better)
(iv) DCF – ROR (Accept if > 10%)

Economic analysis of the simulation cases considered for X-field reservoir investment cost, operating cost, royalties and taxes payable are derived and used for this analysis. The best scenario must be able to optimize gas production at a relatively safe profit margin.

Table 3.3: Showing Costs, Values and assumptions for the economic analysis

| Cost | Value | References |
|---|---|---|
| **Investment Cost** | | |
| Well licensing to site clean up | $ 200,000 | SPDC |
| Cost of drilling and completing a well | $ 1,800/ft | |
| Cost of drilling and completing a well to total depth of 6,000 ft | $ 10,800,000 | Drilling Contractor |
| Installation of well head and equipments | $ 200,000 | |
| Total Cost of Well | $ 11,200,000 | |
| PERFORM installation, tech support & license | $47,000 | IHS Energy |
| PROSPER installation & technical support | $75,000 | Petex |
| Analyst Desk office, IT and fittings | $ 560,000 | |
| Miscellaneous | $ 1,200,000 | |
| Total Capital Cost for PERFORM simulated well | $ 12,740,700 | |
| Total Capital Cost for PROSPER simulated well | $ 12,870,000 | |
| Total cost without production optimization | $ 11, 200,000 | |
| **Operating Cost** | | |

| | | |
|---|---|---|
| Customized training & technical support | $ 100,000 | |
| Labour cost | $2,000/month | |
| Annual Labour cost for 20 workers | $ 480,000 | |
| Total maintenance cost | $ 250,000 | |
| Management | $ 200,000 | |
| Annual operating cost | $ 1,330,000 | |
| **<u>Tax and Royalties</u>** | | |
| Royalties | 15% of Net Revenue | |
| Tax | 25% of Net Revenue | |
| Oil Price | $30 / Bbl | |
| Gross Income (GR) | Oil price x Cum oil | |
| NCR | Gross income – <br>(CAPEX+OPEX+Tax+Royalty) | |

# CHAPTER FOUR

## RESULT ANALYSIS AND DISCUSSIONS

### 4.1 RESULTS

The offshore well data was utilized to analyze solution methods in determining optimal production rates. Decline curve analysis was applied to identify the natural gas production optimization in horizontal well.

#### 4.1.1 Effect of Pressure in horizontal wells using Giger et al IPR Model

Table 4.1: Sensitivity Analysis using Giger et al IPR

| Liquid rate Bbl/d | Inflow 1 | Inflow 2 | Inflow 3 | Outflow A |
|---|---|---|---|---|
| 0 | 2900 | 3508 | 2486.3 | 76.7 |
| 2000 | 2850 | 3401 | 2449 | 74.3 |
| 3000 | 2800 | 3293 | 2411 | 71.9 |
| 3500 | 2750 | 3185 | 2374.4 | 69.5 |
| 24000 | 200 | 300 | 100 | 3300 |
| 25000 | 0 | 0 | 0 | 3500 |

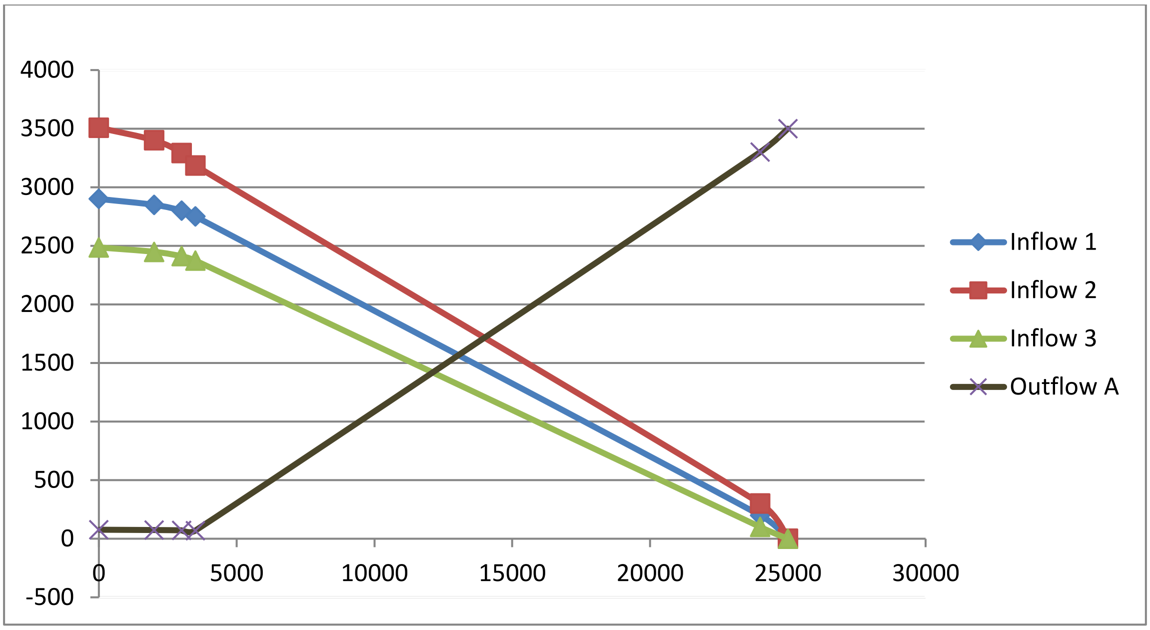


*Fig 4.1: Plot of Differential Graph for Giger et al model*

Solution Points Flow Rates [Bbl/D]

| | | |
|---|---|---|
| **(A)** | **Reservoir Pressure [psig]** | |
| **(1)** | **2900.0** | **3508** |
| **(2)** | **2850.0** | **3401** |
| **(3)** | **2800.0** | **3293** |
| **(4)** | **2750.0** | **3185** |

Solution Point Pressures [psig]

| | | |
|---|---|---|
| **(A)** | **Reservoir Pressure [psia]** | |
| **(1)** | **2900.0** | **2486.3** |

| | | |
|---|---|---|
| **(2)** | **2850.0** | **2449.0** |
| **(3)** | **2800.0** | **2411.7** |
| **(4)** | **2750.0** | **2374.4** |

Completion Pressure Drop at Solution Points [psia]

| **(A)** | **Reservoir Pressure [psig]** | |
|---|---|---|
| **(1)** | **2900.0** | **76.7** |
| **(2)** | **2850.0** | **74.3** |
| **(3)** | **2800.0** | **71.9** |
| **(4)** | **2750.0** | **69.5** |

At the recommended solution point, using Giger et Al IPR model, we observed very high flow rate of 3508 bbl/D and an equally excessively high pressure drop of 74.8 psig, which further increases at the completion intervals, with a higher pressure drop of 76.7psig. However, a recommended pressure drop of 71.9 is required to maintain an optimal production rate. Based on the system analysis, further reduction in pressure, only leads to lower liquid drop out and reduced flow rates.

### 4.1.2 Effects of pressure in horizontal wells using Economides et al IPR

Table 4.2: Sensitivity Analysis using ECONOMIDES IPR model

| Liquid rate Bbl/d | Inflow 1 | Inflow 2 | Inflow 3 | Outflow A |
|---|---|---|---|---|
| 0 | 2900 | 1165 | 1881.6 | 26.5 |
| 2000 | 2850 | 1122 | 1868.8 | 25.6 |
| 3000 | 2800 | 1079 | 1856.0 | 24.7 |
| 3500 | 2750 | 1036 | 1843.2 | 23.8 |
| 24000 | 200 | 300 | 100 | 3300 |
| 25000 | 0 | 0 | 0 | 3500 |

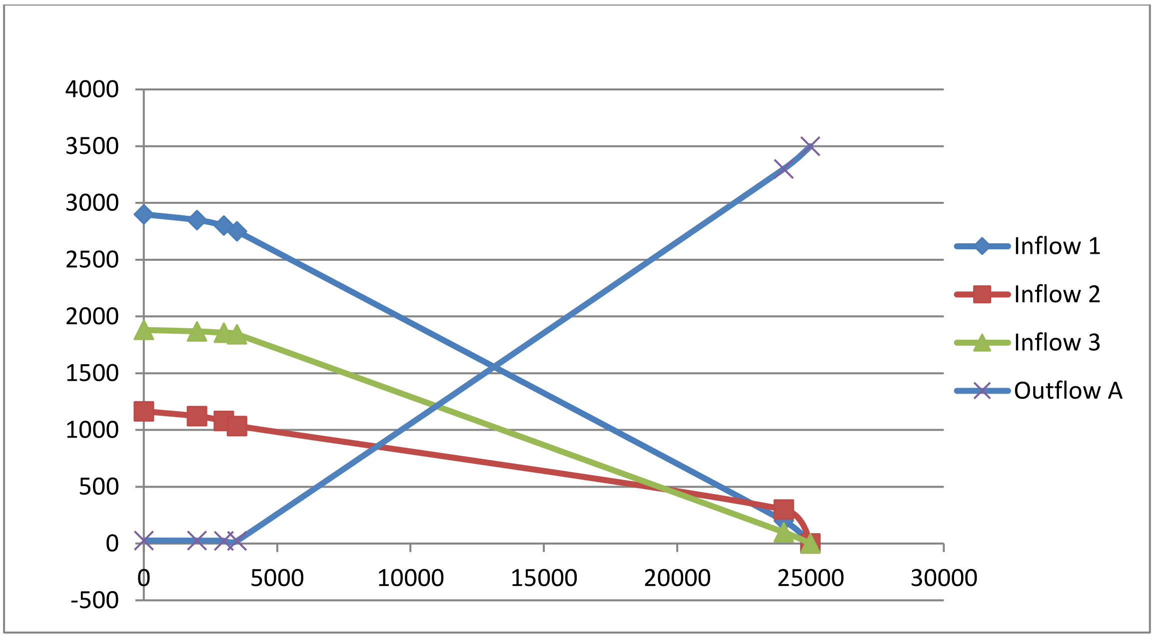


Fig 4.2: Sensitivity Analysis Plot for ECONOMIDES et al model

Solution Points Flow Rates [Bbl/D]

| (B) | Reservoir Pressure [psig] | |
|---|---|---|
| (1) | 2900.0 | 1165 |
| (2) | 2850.0 | 1122 |
| (3) | 2800.0 | 1079 |
| (4) | 2750.0 | 1036 |

Solution Point Pressures [psig]

| (B) | Reservoir Pressure [psia] | |
|---|---|---|
| (1) | 2900.0 | 1881.6 |
| (2) | 2850.0 | 1868.8 |
| (3) | 2800.0 | 1856.0 |
| (4) | 2750.0 | 1843.2 |

Completion Pressure Drop at Solution Points [psia]

| (B) | Reservoir Pressure [psig] | |
|---|---|---|
| (1) | 2900.0 | 26.5 |
| (2) | 2850.0 | 25.6 |
| (3) | 2800.0 | 24.7 |

**(4) 2750.0 23.8**

A critical system analysis of the results from ECONOMIDES et Al IPR model, shows very low flow rate of 1165 bbl/D and an equally low pressure drop of 25.6 psig, which slightly increases at the completion intervals to 26.5psig. However, a recommended pressure drop of 24.7 is required to maintain an optimal production rate.

### 4.1.3 Effect of Reservoir pressure in horizontal wells Using Joshi IPR Model

Table 4.3: Sensitivity Analysis using Joshi IPR

| Liquid rate Bbl/d | Inflow 1 | Inflow 2 | Inflow 3 | Outflow A |
|---|---|---|---|---|
| 0 | 2900 | 1151 | 1880.6 | 26.2 |
| 2000 | 2850 | 1108 | 1867.8 | 25.3 |
| 3000 | 2800 | 1066 | 1854.9 | 24.4 |
| 3500 | 2750 | 1024 | 1842.5 | 23.5 |
| 24000 | 200 | 300 | 100 | 3300 |
| 25000 | 0 | 0 | 0 | 3500 |

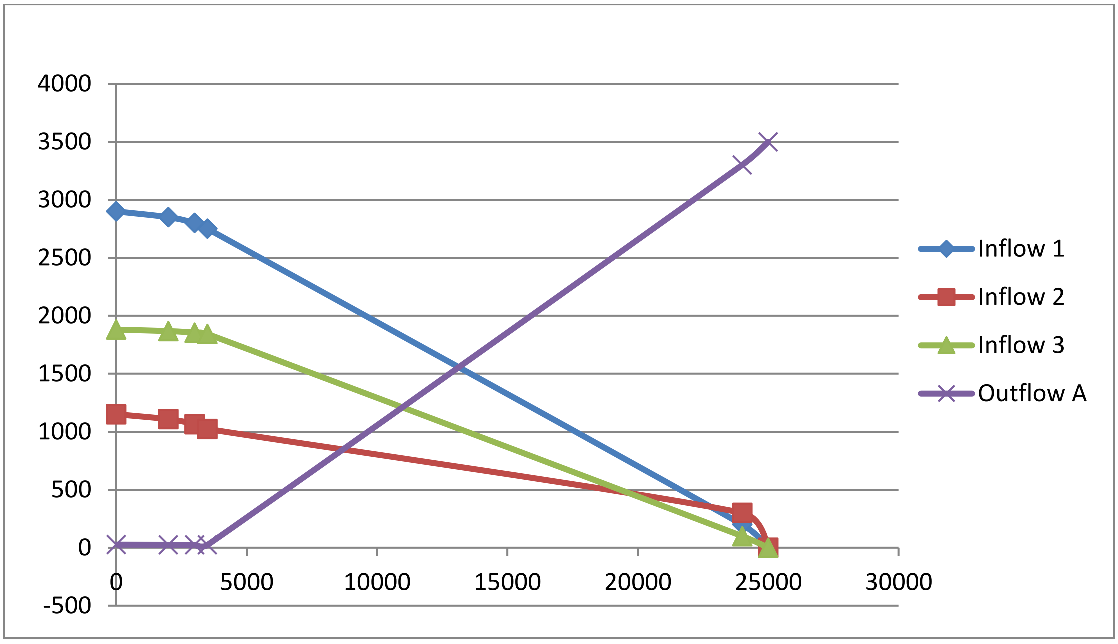


Fig 4.3: Sensitivity Analysis Plot for Joshi IPR model

Solution Points Flow Rates [Bbl/D]

| | | |
|---|---|---|
| **(C)** | **Reservoir Pressure [psig]** | |
| **(1)** | **2900.0** | **1151** |
| **(2)** | **2850.0** | **1108** |
| **(3)** | **2800.0** | **1066** |
| **(4)** | **2750.0** | **1024** |

Solution Point Pressures [psig]

| | | |
|---|---|---|
| **(C)** | **Reservoir Pressure [psia]** | |
| **(1)** | **2900.0** | **1880.1** |

| | | |
|---|---|---|
| **(2)** | **2850.0** | **1867.5** |
| **(3)** | **2800.0** | **1854.9** |
| **(4)** | **2750.0** | **1842.3** |

Completion Pressure Drop at Solution Points [psia]

| **(C)** | **Reservoir Pressure [psig]** | |
|---|---|---|
| **(1)** | **2900.0** | **26.2** |
| **(2)** | **2850.0** | **25.3** |
| **(3)** | **2800.0** | **24.4** |
| **(4)** | **2750.0** | **23.5** |

From the solution point result using Joshi IPR model, we observed the least flow rate of 1161 bbl/D and an equally lower pressure drop of 26.3 psig, which further increases at the completion intervals to 28.2 psig.

However, Joshi IPR model is not recommended to model for the well case under consideration, since we obtained even lower production rates of 1066 Bbl/D at the solution  pressure drop of 24.4 Psig.

### 4.1.4 Sensitivity Analysis Using Benard&Dupuy IPR Model

Table 4.4: Sensitivity Analysis for Renard&Dupey IPR

| Liquid rate<br><br>Bbl/d | Inflow 1 | Inflow 2 | Inflow 3 | Outflow A |
|---|---|---|---|---|
| 0 | 2900 | 1193 | 1891.6 | 27.0 |
| 2000 | 2850 | 1149 | 1878.5 | 26.1 |
| 3000 | 2800 | 10661105 | 1865.2 | 25.4 |
| 3500 | 2750 | 1061 | 1852.0 | 24.3 |
| 24000 | 200 | 300 | 100 | 3300 |
| 25000 | 0 | 0 | 0 | 3500 |

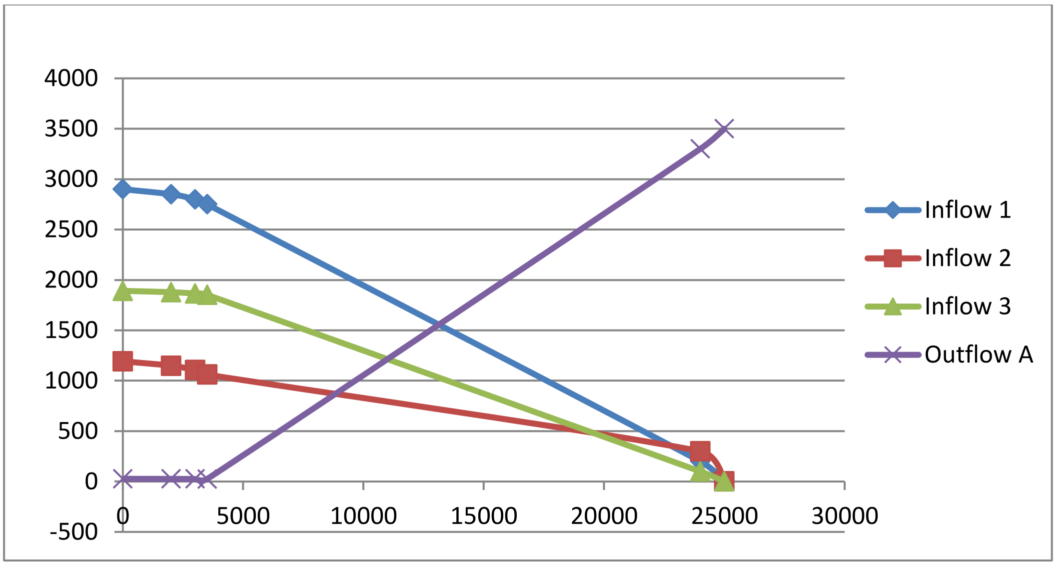


Fig 4.4: Sensitivity Analysis for Renard&Dupey IPR

Solution Points Flow Rates [Bbl/D]

**(D) Reservoir Pressure [psig]**

**(1) 2900.0 1193**

**(2) 2850.0 1149**

**(3) 2800.0 1105**

| | | |
|---|---|---|
| **(4)** | **2750.0** | **1061** |

Solution Point Pressures [psig]

| **(D)** | **Reservoir Pressure [psia]** | |
|---|---|---|
| **(1)** | **2900.0** | **1891.2** |
| **(2)** | **2850.0** | **1878.1** |
| **(3)** | **2800.0** | **1865.0** |
| **(4)** | **2750.0** | **1851.9** |

Completion Pressure Drop at Solution Points [psia]

| **(D)** | **Reservoir Pressure [psig]** | |
|---|---|---|
| **(1)** | **2900.0** | **27.0** |
| **(2)** | **2850.0** | **26.1** |
| **(3)** | **2800.0** | **25.2** |
| **(4)** | **2750.0** | **24.3** |

The solution point result using Benard&Dupuy is not too far off from Joshi IPR model, as we observed low flow rate of 1193bbl/D and equally low pressure drop of 27.0 psig.

**Table 4.5:** Comparative Evaluation of Horizontal Wells Steady State Models

| **CORRELATION(IPR)** | **JOSHI** | **ECONOMIDES** | **GIGER ET AL** | **BENARD & DUPUY** |
|---|---|---|---|---|
| | PSIG BBL/D | BBL/D | BBL/D | BBL/D |
| SOLUTION POINT | 2900 1161 | 1186 | 3508 | 1193 |
| FLOW RATE | 2850 1108 | 1122 | 3401 | 1149 |
| | 2800 1066 | 1079 | 3293 | 1105 |
| | 2750 1024 | 1036 | 3185 | 1061 |
| | PSIG PSIG | PSIG | PSIG | PSIG |
| SOLUTION POINT | 29001880.1 | 1881.8 | 2486.3 | 1891.2 |
| PRESSURE | 28501887.6 | 1868.8 | 2449.0 | 1878.1 |
| | 28001864.9 | 1856.0 | 2411.7 | 1865.0 |
| | 27501842.2 | 1843.2 | 2374.4 | 1851.9 |
| | PSIG | PSIG | PSIG | PSIG |
| COMPLETION | 2900 28.2 | 26.5 | 76.7 | 27.0 |
| PRESSURE DROP | 285026.3 | 25.6 | 74.8 | 26.1 |
| AT SOLUTION POINT | 280024.4 | 24.7 | 71.9 | 25.2 |
| | 275023.6 | 23.8 | 69.6 | 24.3 |

## 4.3. Economic Analysis

**Table 4.6:** Economic Analysis for Production Case without Software application

| Time /Yr | NP MMscf | CAPEX ($MM) | OPEX ($MM) | Gross Revenue ($MM) | NCR ($MM) before Tax | Royalty & Tax | NCR ($MM) After Tax | Cumm. NCR | PV@ 10% |
|---|---|---|---|---|---|---|---|---|---|
| 0 | 0 | -11.2 | 0.0 | 0.0 | -11.2 | 0.0 | -11.2 | -11.2 | -11.2 |
| 1 | 2.5 | 0.0 | 1.3 | 75 | 73.7 | 29.48 | 44.2 | 33.0 | 29.7 |
| 2 | 2.5 | 0.0 | 1.3 | 75 | 73.7 | 29.48 | 44.2 | 77.2 | 62.5 |
| 3 | 2.0 | 0.0 | 1.3 | 60 | 58.7 | 73.9 | 35.3 | 112.5 | 82.0 |
| 4 | 1.5 | 0.0 | 1.3 | 45 | 43.7 | 17.36 | 25.9 | 138.4 | 90.8 |
| 5 | 1.2 | 0.0 | 1.3 | 36 | 34.7 | 13.88 | 208 | 159.2 | 94.0 |
| | | | | 291 | | | 159.2 | | 253.8 |

Payout = 33.0/ 44.2 +1 = 1.8 years

Profit per Dollar invested: The total Net Cash Recovery MM$159.2 and capital investment MM$11.2.

P/$ = 159.2/11.2 = $14.21

**Table 4.7:** Economic Analysis for Production Case with PERFORM

| Time /Yr | NP mmscf | CAPEX ($MM) | OPEX ($MM) | Gross Revenue ($MM) | NCR ($MM) before Tax | Royalty & Tax | NCR ($MM) After Tax | Cumm. NCR | PV@ 10% |
|---|---|---|---|---|---|---|---|---|---|
| 0 | 0 | -12.7 | 0 | 0 | -12.7 | 0 | -12.7 | -12.7 | -12.7 |
| 1 | 3.0 | 0.0 | 1.3 | 90 | 88.7 | 35.48 | 53.5 | 40.8 | 36.7 |
| 2 | 3.2 | 0.0 | 1.3 | 96 | 94.7 | 37.88 | 60.58 | 101.4 | 82.1 |
| 3 | 3.1 | 0.0 | 1.3 | 93 | 91.7 | 36.68 | 56.8 | 158.2 | 115.3 |
| 4 | 2.8 | 0,0 | 1.3 | 78 | 65 | 26 | 39 | 197.2 | 136.3 |
| | | | | 357 | | | 197.2 | | 357.7 |

Payout = 40.8/ 53.5 +1 = 1.76 years

Profit per Dollar invested: The total Net Cash Recovery $197.2 and capital investment 12.7

P/$ = 197.2 /12.7 = $ 15.5

**Table 4.8:** Economic Analysis for PROSPER Software application

| Time /Yr | NP MMscf | CAPEX ($MM) | OPEX ($MM) | Gross Revenue ($MM) | NCR ($MM) before Tax | Royalty & Tax | NCR ($MM) After Tax | Cumm. NCR | PV@ 10% |
|---|---|---|---|---|---|---|---|---|---|
| 0 | 0 | -12.8 | 0.0 | 0.0 | -12.8 | 0.0 | -12.8 | -12.8 | -12.8 |
| 1 | 3.0 | 0.0 | 1.3 | 90 | 88.7 | 35.5 | 53.2 | 40.4 | 36.8 |
| 2 | 3.0 | 0.0 | 1.3 | 90 | 88.7 | 35.5 | 53.2 | 93.6 | 75.8 |
| 3 | 2.9 | 0.0 | 1.3 | 87 | 85.7 | 34.2 | 51.5 | 145.1 | 102.6 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 4 | 2.8 | 0.0 | 1.3 | 84 | 82.3 | 32.9 | 49.4 | 194.5 | 127.6 |
| 5 | | | | 351 | | | 194.5 | | 392.6 |

Payout = 40.4/53.2 +1 = 1.6 = 2 years

Profit per Dollar invested: The total Net Cash Recovery MM$194.5 and capital investment MM$12.8.

P/$ = 159.2/12.8 = $15.2

## 4.2 DISCUSSIONS OF RESULTS

Discussing the case study results: reveals that Giger model will give consistently highest flow rate from 3,508 Bbl/day at Pressure of 2900 PSIG to 3185 Bbl/day at 2750 PSIG with an equivalently very high pressure drop of 76.7 Psi/ Bbl/day at the completions and 71.9 Psi/ Bbl/day at the solution point.

Whereas, Joshi IPR model will produce the lowest inflow of 1024 Bbl/day at a pressure of 2750 PSIG with a rather insignificant pressure drop of 23.6.

The gas lift method is more economically beneficial as it produces up to a maximum economic water cut of 80% with gas injection rate of 2 – 4 MM scf/d producing gas rates of 1800 – 2000 STB/d

Also, Simulate Base Case Forecast under Various Operating Conditions. Since the PVT, VLP and IPR were matched to measured data, it was possible to move on and use the model to perform a system analysis.

Table 4.6 Production case without using production performance simulator will give the least profit per dollar investment of $14.21 Million, when compared with the highest profit per dollar investment of $15.5 Million for Case B, from the profit indicator calculation shown in Table 4.8.

Payout for Case A: Without Simulator or Software is 1.8 years;

Payout for Case B: Using PERFORM Software is 1.7 years;

While for Case C: Using PROSPER Software gave a payout of 1.6 years.

Furthermore, NCR for Case A: Without Simulator or Software is 159.2;

NCR for Case B: Using PERFORM Software is 197.2;

While for Case C: Using PROSPER Software had an NCR of 194.5.

# CHAPTER FIVE

# CONCLUSION AND RECOMMENDATIONS

## 5.1 CONCLUSION

With the invention of PERFORM Software for Horizontal Well optimization we recommend that oil and gas industries especially Production companies should adopt the use of PERFORM as a Software for production performance enhancement.

Robust technique to analyze and optimize the production systems are widely used in the industries, but with our study on software like Perform it makes it more efficient for this analytical technique.

## 5.2 RECOMMENDATION

More research can be done on PERFORM to discover if it can be effective for vertical wells and on unsteady state flow. Further research work can also incorporate more decision variables into the optimization problem, such as pumps and subsurface chokes for multilateral and multi-segment wells. It is also necessary to investigate the performance of the linear optimization methods and the nonlinear optimization method under different conditions.

## 5.3 CONTRIBUTION TO KNOWLEDGE

The results from the study shows that applying optimization simulation technique using PERFORM is cost effective and will enhance reservoir productivity and well deliverability rather than the traditional direct application of IPR equation based on educated guesses.

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# APPENDIX 1: Data Capturing Tools

## Table : PVT Data

| | |
|---|---|
| Reservoir Temperature | |
| Oil API Gravity | |
| Gas Relative Density | |
| GOR | |
| $P_b$ | |
| $B_o$ | |
| Gas Viscosity | |
| $B_w$ | |
| Gas Z Factor | |
| Water Salinity | |
| Water Viscosity | |

## Table : Pressure Survey

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Depth.**<br>**(ft) TVD** | | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Pressure, (psia) | | | | | | | |

**Table : Well Data**

| | |
|---|---|
| Oil Production rate, (STB/day) | |
| Water Cut, (%) | |
| WH Flowing Temperature, (°F) | |
| Pressure at Christmas tree, (psia) | |
| Skin (Well Test) | |
| PI or J (Well Test), (STB/d/psi) | |
| Damaged Zone Relative Permeability, (%) | |
| Damaged Zone Thickness, (In) | |
| Crushed Zone Skin | |
| Damaged radius | |

| | |
|---|---|
| Water Viscosity | |

**Table : Well Equipment Data**

| Node No. | Component Name | Measured Depth (ft) |
|---|---|---|
| 1 | Outlet node/ Christmas tree | 0 |
| 2 | Riser | 350 |
| 3 | Wellhead | 350 |
| 4 | 5.5’’ Tubing | 850 |
| 5 | S.C.S.S.S.V | 850 |
| 6 | 5.5’’ Tubing | 4000 |
| 7 | 5’’ Tubing | 5600 |
| 8 | 7’’ Liner | 6590.5 |

**Table : Reservoir pressure & water cut ranges**

| Parameter | Range |
|---|---|
| Water cut | |
| Reservoir Pressure | |

**Table : Economic base case conditions**

| Scenario | Maximum Economic Water Cut | Production Rate @ 30 (%) |
|---|---|---|
| Base Case | 45 (%) | 4703 (STB/day) |