**Optimization of Big-Bore High Pressure High Temperature (HPHT)**

**Wells in Low Pressure Reservoir**

by

Alif Aiman Bin Adnan

Dissertation submitted in partial fulfillment of

the requirements for the

Bachelor of Engineering (Hons)

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Bandar Seri Iskandar

31750 Tronoh

Perak Darul Ridzuan

## CERTIFICATION OF APPROVAL

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Approved by,

Dr. Sonny Irawan
Senior Lecturer
Geoscience & Petroleum Engineering Department
Universiti Teknologi PETRONAS
Bandar Seri Iskandar, 31750 Tronoh
Perak Darul Ridzuan, MALAYSIA

Dr. Sonny Irawan 28/04/2011
Project Supervisor

UNIVERSITI TEKNOLOGI PETRONAS
TRONOH, PERAK
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**ABSTRACT**

Since initial production in early 1990s, the Alpha gas field has been experiencing significant pressure decline. The pressure decline had started to affect the performance of the field; reduced in overall gas production. Subsequently, the extensive pressure decline had caused several wells to collapse due to formation subsidence. The project focused to determine the suitable completion design and casing program for optimum gas recovery from the low pressure environment. The project utilized WellFlo simulation program to compare and analyze the results. Among the identified designs to be simulated are; (1) 10 inch Tubingless Completion (2) Conventional 9-5/8 inch Tubing and (3) Tapered 9-5/8 × 7-5/8 inch Tubing design. The selected design must be able to yield significant increase in gas recovery, extending the producing life of the field and adequate Zonal Isolation to prevent well failure. The 10 inch Tubingless Completion had met the required parameters and was selected as the suitable design for the project. The 10 inch Tubingless Completion increased gas recovery by 23.15 Percent (%) and extended the producing life of the field up to 16.8 years. In addition, the 7 inch Drill-in Liner provided improved Zonal Isolation between the producing Limestone layer and overlaying Shale structure.

## ACKNOWLEDGEMENTS

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## NOMENCLATURE

| Quantity | Symbol | Dimensions |
|---|---|---|
| Average Flow Rate | $Q_{Avg}$ | (Mscf / day) |
| Difference in Elevation from $P_{wf}$ to $P_{wh}$ | H | inch |
| Flowing Bottom Hole Pressure | $P_{wf}$ | (lbm/inch$^2$) |
| Flowing Wellhead Pressure | $P_{wh}$ | (lbm/inch$^2$) |
| Gas Deviation Factor | Z | - |
| Gas flow rate at Standard Condition | $Q_{sc}$, $q_{sc}$ | (Mscf / day) |
| Gas Specific Gravity | G | - |
| Moody Friction Factor | F | - |
| Temperature | T | ($^0$R) |
| Tubing Diameter | D,d | inch |

| Subscript | Symbol | Dimensions |
|---|---|---|
| Gas Specific Gravity | $\gamma_g$ | - |
| Gas Viscosity | $\mu$ | Cp |
| Inner Wall Roughness | $\varepsilon$ | inch |

# CHAPTER 1

# INTRODUCTION

## 1.1 Project Background

The title of the project is 'Optimization of Big Bore HTHP Wells in Low Pressure Reservoir'. The project will be using the completion technology implemented in the Alpha Gas Field in Indonesia. The published paper on the field includes history, applied drilling program, casing plan and the production string configuration used during the development and optimization of the gas field.

The Alpha Gas field was initially developed during the 1970s with the reservoir having High Temperature and High Pressure (HTHP) environment. The first big-bore wells were designed and commissioned in early 1990s to further enhance the field development. The big-bore wells enabled maximum gas-flow rate per well and reduced overall development investments by cutting the number of required wells. Eleven wells were drilled and completed, with flow rates up to 217 MM Scf/Day for each well. The project was considered highly successful [1].

As the field continued to be developed, the reservoir pressure in the Alpha field has declined from 7,100 Psi to less than 600 Psi. As a result, 31 wells were lost due to formation subsidence and wellbore collapse. Additional wells were required to meet volume requirements. The new wells were executed under more difficult and challenging environment due to the severe drawdown completion interval [1].

The following campaigns were conducted to further exploit the Alpha Gas Field:

- Conversion from 9-5/8 inch conventional production tubing to 10 inch tubingless completions [1]
- Installation of 7 inch Drill-in Liners across shale collapse zone
- High temperature Underbalanced Drilling (UBD) of the sour gas reservoir
- Rotary drilling through tree components enabling an undamaged completion

## 1.2 Problem Statement

Continuous production will further reduce the existing reservoir pressure. As reservoir pressure declines, conventional completion string could not provide adequate flow capacity for the gas to flow. This will result in declining gas production rate. To overcome the problem, new completion technology will have to be implemented to continue producing gas from the low pressured reservoir.

## 1.3 Objectives

- To determine the completion design for optimum gas production
- To determine the casing program for gas production in low pressure reservoir
- To compare the Production Vs. Time curves for each completion designs

## 1.4 Scope of Study

The scope of study is related to conducting production simulations using WellFlo®. The project is divided into three parts: (1) Gather information on Big-Bore completions and conduct theoretical calculations, (2) Construct simulation models using WellFlo® and design the casing program to accommodate production conduit, (3) Generate the Production vs. Time Curves and decide on the completion design which gives the optimum production.

The simulation models are divided into two segments; Static Reservoir Model and Production Conduit Model. Firstly, the Static Reservoir Model is constructed using WellFlo®. The reservoir and fluid properties are entered into the simulation block. The reservoir model will be a constant parameter for the different completion designs. Secondly, the Production Conduit Model will be developed. The model will consist of three different configurations:

i. 9-5/8 inch Tubing Completion
ii. 10 inch Tubingless Completion
iii. Tapered 9-5/8 x 7-5/8 inch Tubing Design

Later, casing program will be designed to accommodate the selected production conduit. The casing design must be able to withstand the force coming from the reservoir matrix and fluid contained within the pore spaces.

Simulations will be conducted on the integrated models which consist of the Static Reservoir Model and Production Conduit Model. A production profile will be generated on each completion designs. The production profile will be illustrated by the Production vs. Time curves which will be used to determine the completion design that generates an optimum gas production.

### 1.5 Significance of the Project

The project is highly significant for producing gas from low pressure environment. Optimized production techniques are required to optimally drain the reservoir fluid without causing further damages to the reservoir. In addition, implemented optimized production technology could extend the producing time of the reservoir and delay the investment of well stimulation programs.

### 1.6 Feasibility of the Project

The project is based on computer simulations to predict the performance of the reservoir depending on the completion program. The project is expected to be completed within 4 months of research period. Positive and implemented outputs are expected to be produced from the project.

# CHAPTER 2

# THEORY AND LITERATURE REVIEW

## 2.1 Wellbore Completion Design

In addition to the simulation model conducted by WellFlo, theoretical calculations will be conducted to compare the actual results from the simulation with the results from initial findings. Among the required calculations are:

- Tubular Design and Capacity
- Tubing Performance Relation (TPR)
- Gas Production vs. Time Prediction

### 2.1.1 Tubular Design and Capacity

The production tubing design and capacity will be the governing variable for the system. The suitable tubing capacity is required to produce the gas at optimum rate while at the same time extending the production plateau of the field.

The equation for **Tubing Capacity** calculation is the R.V Smith Equation [9][10]. The equation is used to measure the compatibility of the production tubing to the fluid flow from the reservoir. The Smith Equation is for vertical flow of gas which is similar to Weymouth Equation for horizontal flow [9][10].

$$Q = 200{,}000\left[\frac{D^5({P_{wf}}^2 - e^s {P_{wh}}^2)s}{G\,T\,Z\,f\,H\,(e^s - 1)}\right]^{0.5} \quad \text{.........................................} \quad (1)$$

Where,

$$S = 0.375\left(\frac{GH}{TZ}\right)$$

The **Reynolds Number** ($N_{Re}$) is a ratio of fluid momentum force to viscous shear force. The parameter is used to determine the type of flow presence in the tubing and to calculate the Friction Factor production tubing [9][10]. The Reynolds Number equation for natural gas flow is shown below:

$$N_{Re} = \frac{20q\gamma_g}{\mu D} \quad \text{.........} \quad (2)$$

**Relative Roughness** ($e_D$) is used to measure the ratio of roughness on the tubing inner wall [9][10]. The equation is given by:

$$e_D = \frac{\varepsilon}{D} \quad \text{.........} \quad (3)$$

**Friction Factor** (*f*) is used for calculating the gas flow rate. We assume the fluid is a Single Phase Gas Flow [9][10]. The equation is given by:

For smooth wall tubing in turbulent flow regime,

$$f = 0.0056 + \frac{0.5}{{N_{Re}}^{0.32}} \quad \text{.........} \quad (4)$$

**valid if* $3 \times 10^3 < N_{Re} < 3 \times 10^6$

For rough wall tubing with fully developed turbulent flow regime,

$$\frac{1}{\sqrt{f}} = 1.14 - 2\log\left[e_D + \frac{21.25}{{N_{Re}}^{0.9}}\right] \quad \text{.........} \quad (5)$$

### 2.1.2 Tubing Performance Relation (TPR)

In normal practices, the Tubing Performance Relation (TPR) is calculated using Nodal Analysis. For convenience is using the Nodal Analysis technique, the calculations are usually conducted using Bottom Hole ($P_{wf}$) as the solution node [13].

When the Bottom Hole is used as the solution node, the inflow performance is the Well Inflow Performance (IPR) and the outflow performance is the Tubing Performance Relation (TPR); given the end-of-tubing is located above the production zone. The intersection between IPR and TPR curve represents the optimum operating point of the system [13].

Consider the Bottom Hole as the solution node; the TPR is described as below [13].

$$P_{wf}^{\ 2} = e^{s} + \frac{6.67 \times 10^{-4}\ [e^{s}-1] f q^{2} z^{2} T^{2}}{d^{5} \cos \alpha} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \ (6)$$

Shown below is an example of typical IPR and TPR plot:

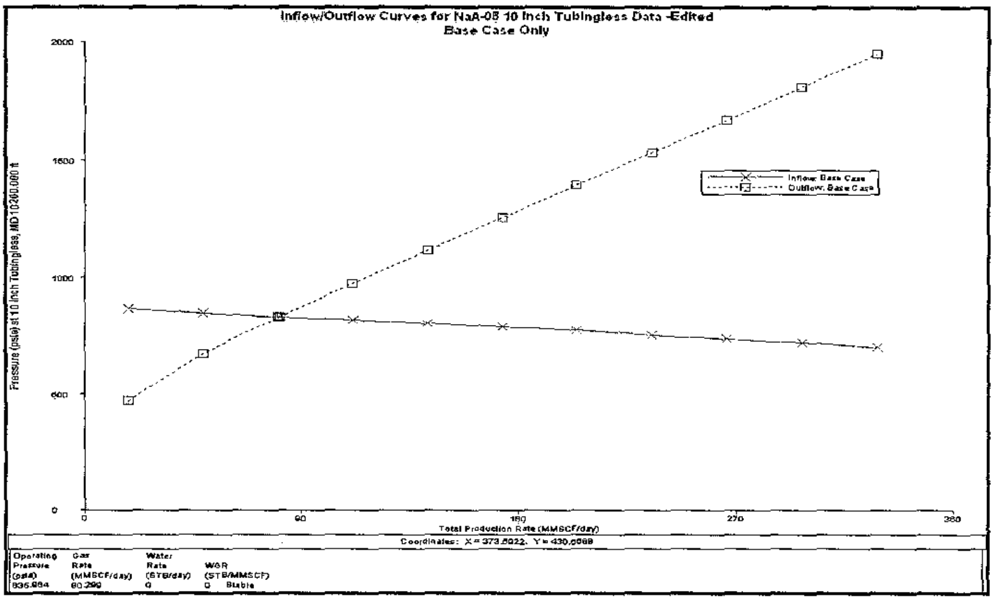



*Figure 1: IPR and TPR Plot* [1]

### 2.1.3 Gas Production vs. Time Prediction

The **Production Rate – Time Prediction** is used to show the production profile of the producing field. The calculation for the estimation is complex and usually conducted by simulation software for accurate results. Shown below is the general equation used for future production estimations [9]:

$$Time = \frac{Gas\ Produced\ During\ Interval}{Q_{Avg}} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (7)$$

$$P_{wf}^{\,2} = P_i^{\,2} - \frac{1637 Q_G T Z \mu}{kh}\left[\log \frac{kt}{\phi \mu c_{ti} r_w^{\,2}} - 3.23 + 0.87(s)\right] \ldots\ldots (8)$$

Attached below is a sample of production cycle curve generated by using theoretical calculations:

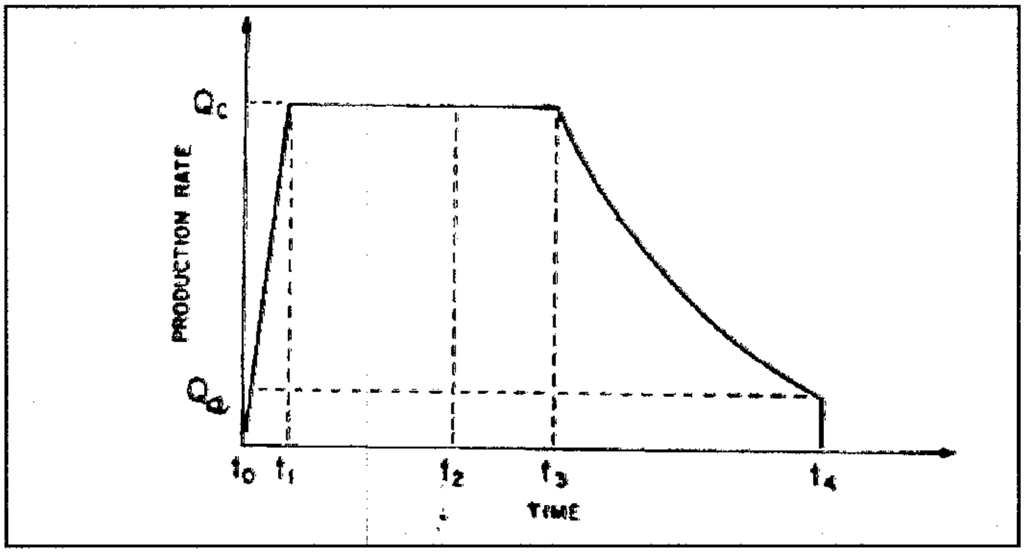



*Figure 2: Typical Production Cycle* [9]

The Production Cycle diagram illustrates the life of the reservoir from initial production to abandonment. It is desirable to have an elongated production plateau before production starts to decline. As production declines, pressure maintenance or artificial lift techniques may be introduced to meet the desired production rate.

## 2.2 Gas Field Development

Gas reservoir development always directly linked to the market by pipeline; therefore the physical characteristics of the reservoir could not predict the best depletion pattern because the market must be able to accept the gas [9]. The design of an optimum development plan for natural gas field depends on the typical characteristics of the producing field as well as the markets to be served by the field [9].

However, basic field parameters; *(1) total natural gas reserves (2) well productivity (3) dependence of production rate on pipeline pressure (4) depletion of natural gas reserves*, are required prior to designing the development scheme of the field [9].

Key elements that affect the total gas production system are stated below [13]:

i. Flow through the Reservoir
ii. Flow through the Production String
iii. Flow through the Field Gathering System and Processing Equipment
iv. The Compressing of the Gas
v. Flow through the Auxiliary Pipeline to the point of sale

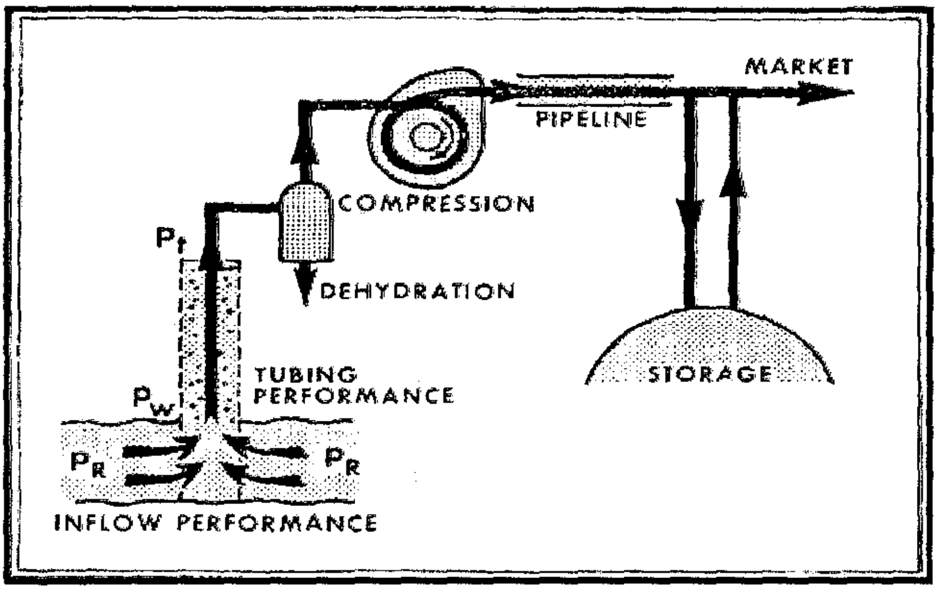



*Figure 3: Total Gas Production System* [13]

### 2.2.1Pipeline Flow Calculation

The calculation uses Panhandle equation to determine the pressure required at the discharge point of the compressor [13].

$$Q = 435.87\,(E)\left(\frac{T_b}{P_b}\right)^{1.07881}\left(\frac{P_1{}^2 - P_2{}^2}{T.L.Z}\right)^{0.5394}\left(\frac{1}{G}\right)^{0.4606}(D)^{2.6182} \;\ldots\ldots\; (9)$$

### 2.2.2 Compressor Station Calculation

The calculation utilizes adiabatic compression equation to determine the Suction Pressure ($P_{suc}$) at the intake of the compressor [13].

$$\frac{HP}{MMscfd} = 0.08578\left(\frac{k}{k-1}\right)(T_{suc})(Z_{suc})\left[\left(\frac{P_{dis}}{P_{suc}}\right)^{\frac{k-1}{k}} - 1\right] \;\ldots\ldots\; (10)$$

$$BHP = \frac{(HP/MMscfd)(Q)}{E} \;\ldots\ldots\; (11)$$

### 2.2.3 Gathering System Calculation

The gathering system consists of multiple pipelines that linked to a single gathering station from different producing wells. The calculation uses Weymouth to find the Wellhead Pressure ($P_{tf}$) of a single well [13].

$$Q = K\sqrt{P_{tf}{}^2 - P_{suc}{}^2} \;\ldots\ldots\; (12)$$

### 2.2.4 Tubing Flow Calculation

The calculation uses correlations for vertical flow such as Hagedorn and Brown method to find the Flowing Bottom-Hole Pressure ($P_{wf}$) [13].

$$Q = 200{,}000\left[\frac{D^5\left(P_{wf}^{\ 2} - e^s.P_{tf}^{\ 2}\right)s}{\gamma_g.T.Z.f.L(e^s - 1)}\right]^{0.5} \quad \ldots\ldots (13)$$

$$S = \frac{0.0375(\gamma_g)(L)}{T.Z} \quad \ldots\ldots (14)$$

### 2.2.5 Reservoir Calculation

The calculation uses the Well Spacing Coefficient ($C_{avg}$) from the well test analysis. The Flowing Bottom-Hole Pressure ($P_{wf}$) from the reservoir side is matched to the pressure from surface back-calculations. The difference is the value should not exceed 3 Psia [13].

$$Q = C_{avg}\left(P_R^{\ 2} - P_{wf}^{\ 2}\right)^n \quad \ldots\ldots (15)$$

The pressure drop must be considered in each of the components in the production system. The restrictions presence in the components must be within the tolerance limit to allow gas to flow to the point of sale. Excess pressure drop will cause gas to accumulate and cause pressure build up at the bottom of the well. Other problems related to hydrates formation may occurred as the pressure increases in the well [13].

## 2.3 Big-Bore Completions

The objective of Big-Bore completions is to reduce the life cycle costs of developing prolific, high profile gas reservoirs. Completions that use 6-5/8 inch or bigger tubular design are considered as Big-Bore completions. The design can significantly reduce both operating and capital expenses and increase the net present value of hydrocarbon assets. [14].

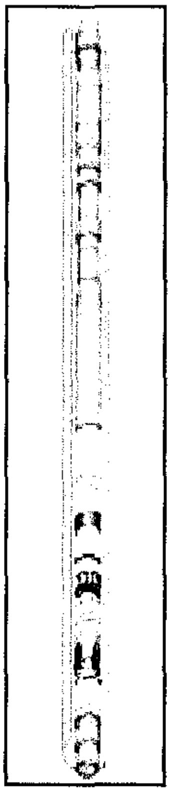


*Figure 4: Typical Monobore Big-Bore Completion* [14]

The larger production conduit provides increased flow area, while the monobore scheme reduces flow restrictions. Other benefits include [16]:

- Eliminate gas turbulence areas and restrictions on production
- Earlier Return of Investment (ROI)
- Exploitation of the reservoir through fewer wells
- Lower long-term operating expenses from quicker depletion of the reservoir
- Lower topsides and maintenance expenses

## 2.4 High Pressure High Temperature (HPHT) Well Condition

A High Pressure High Temperature (HPHT) wells are hotter and more pressurized than typical wells. In HPHT wells, the bottomhole temperature or temperature at Total Depth (TD) is higher than 300 degree Fahrenheit (149 degree Celsius) and pore pressure reaching at least 0.08 Psi per foot [17].

Typical HPHT reservoirs are found in the North Sea, deepwater of the Gulf of Mexico and China. Currently the number of well drilled and completed with HPHT characteristics are still low but the number is increasing [17].

By nature, high pressure fields contain more hydrocarbons than those with normal conditions. As long as the fields boast enough reservoirs, the development of HPHT wells is economical. In addition, operating at HPHT conditions is extremely dangerous and increase risks to drilling, completion and work-over activities. Strict operating procedures are implemented to ensure the safety of HPHT operations [17].

## 2.5 Low Pressure Reservoir

Low pressure reservoir is considered as reservoir having pressure less than 1000 Psi. Low pressure environment usually occurred when the reservoir's natural drive or energy rapidly declines after several years of production [1]. The reservoir's energy usually originated from:

- Strong aquifer support from bottom shale formation or water-bearing zone
- Energy from dissolved Free Gas or dissolved Solution Gas
- Energy from the compressed rock matrix and formation fluid
- Energy from gravity drainage

After producing for several years under its own natural drive, pressure maintenance scheme such as gas or water injection is usually implemented to sustain production. Significant enhancement on the completion design would made production more feasible rather than having pressure maintenance techniques.

## 2.6 Literature Review

The objectives of the project are: (1) to determine completion design for optimum gas production, (2) to determine the casing design for producing in low pressure reservoir, (3) to compare the Production vs. Time curves for each completion designs.

The completion technologies applied in the project were based on the gas development projects performed in the Arun field in Indonesia and the North Field in Qatar. Both of the fields were producing for several years and major re-development programs were implemented to further exploit the two fields. The Arun gas field in Indonesia had adopted the *10-inch Tubingless Completions* on the re-development campaign to construct seven new wells in 2002. The implementation of the completion design had increased the initial production up to 29% [1].

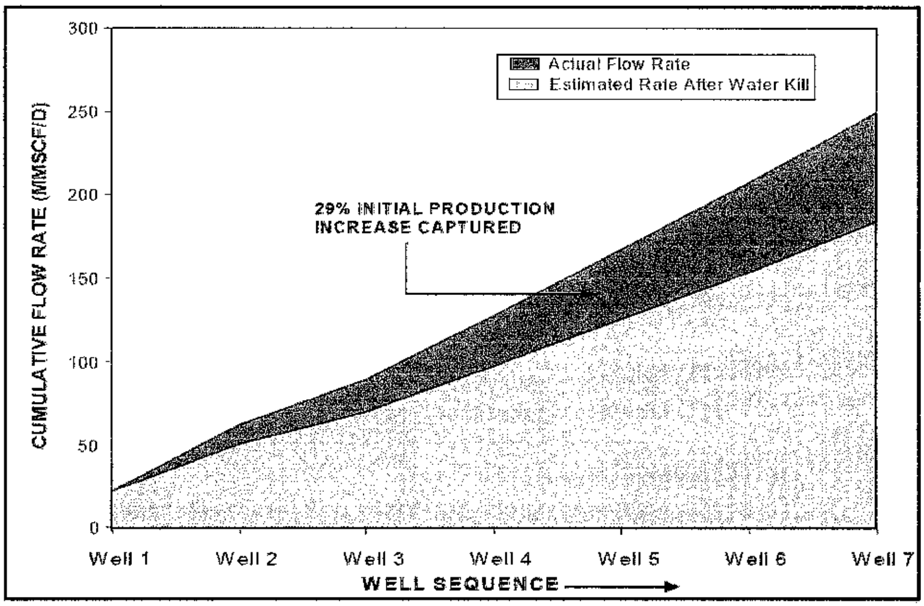



*Figure 5: Arun Big-Bore Initial Rate Enhancement* [1]

The North Field in Qatar had adopted the *Tapered 9-5/8 x 7-5/8 Tubing x 7-inch Liner* design on eight new wells to produce gas at 200 MM scfd. The design had resulted: (1) minimizing the overall development cost by reducing the number of wells to be drilled, (2) enable production plateau to be extended by having higher flowing wellhead pressure, $P_{wh}$ [2].

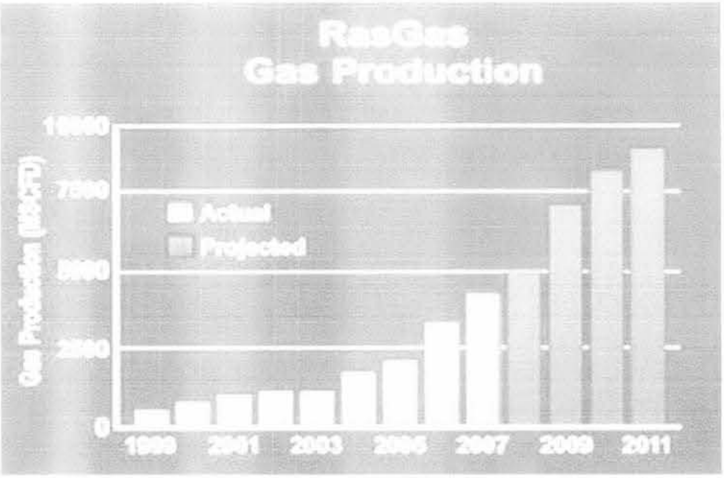



*Figure 6: North Qatar Field Performance* [2]

The implementation of the two designs in respective locations had proven significant increase in production volume as well as reducing the overall development cost and time.

The completion designs to be simulated in the projects are taken from the projects in Indonesia and Qatar. The three types of completions are explained in the following parts:

### 2.6.1 Conventional 9-5/8 inch Tubing Completion

The design incorporates the use of 9-5/8 inch Production Tubing from the surface (0 ft) to the top of the 10 inch Liner. The productive zones will be completed Open-Hole with the hole having 8-1/2 inch Diameter. This enables the well to have total production conduit of 9-5/8 x 10 x 8-1/2 inch in Diameter. The casing program uses 30 inch Driven Conductor followed by 20 inch and 13-3/8 inch Steel Casing to isolate the formation. Below the 13-3/8 inch Steel Casing is the 10 inch Liner followed by Open-Hole completion with 8-1/2 inch Diameter into the productive zones [1].

Attached below is the completion schematic to further describe the design:

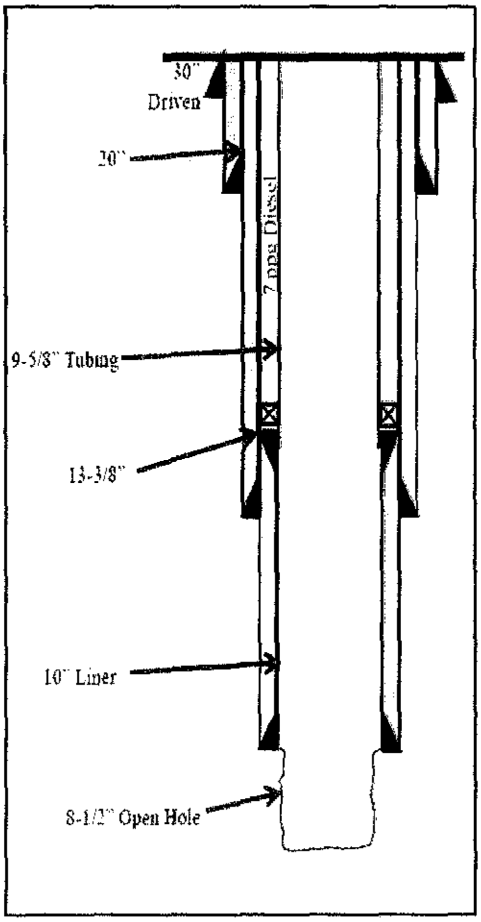



*Figure 7: Conventional 9-5/8 inch Tubing Completion* [1]

### 2.6.2 10 inch Tubingless Completion

The design uses 10 inch Tubingless conduit from the surface (0 ft) to the top of productive layer. 7 inch Drill-in Liner will be installed at the bottom of the Tubingless conduit to enable drilling operations into the productive carbonate reservoir. The production zone will be completed Open-Hole with the hole having 5-5/8 inch Diameter. This enables the production conduit to have total volume of 5-5/8 x 7 x 10 inches in Diameter. The Casing Program is similar to the Conventional 9-5/8 inch Tubing Completion with the addition of the Drill-in Liner and smaller Open-Hole completion [1].

Attached below is the 10 inch Tubingless Completion diagram:

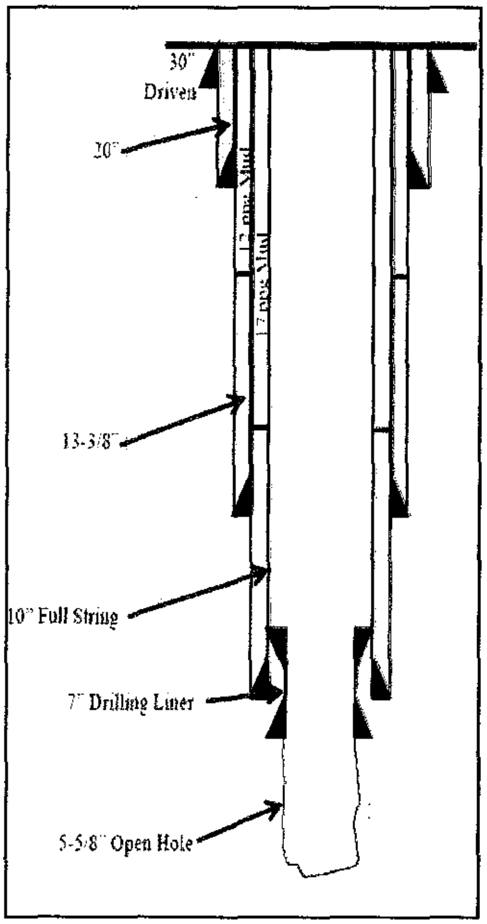



*Figure 8: 10 inch Tubingless Completion* [1]

### 2.6.3 Tapered 9-5/8 x 7-5/8 inch Tubing x 7 inch Liner Completion

The design uses Tapered 9-5/8 x 7-5/8 inch Tubing. The Production Tubing connects to the 7 inch Liner which penetrates through the productive rock layer. The design is different compared to the Conventional 9-5/8" Completion and 10" Tubingless Completion. The Tapered Completion design has a cased productive zone rather than having Open-Hole completion. The tapered design allows gas expansion along the production conduit as the gas pressure is reduced. The Casing Program for the Tapered Completion also differs with the previous two completions. The casing program uses 30 inch Drive Conductor followed by 18-5/8 inch and 13-3/8 inch Steel Casing. The lower section of the 13-3/8 inch Casing is completed with 9-5/8 inch Liner and 7 inch Liner will penetrates the producing zone [2].

Attached is the diagram for the Tapered 9-5/8 x 7-5/8 inch Tubing Completion:

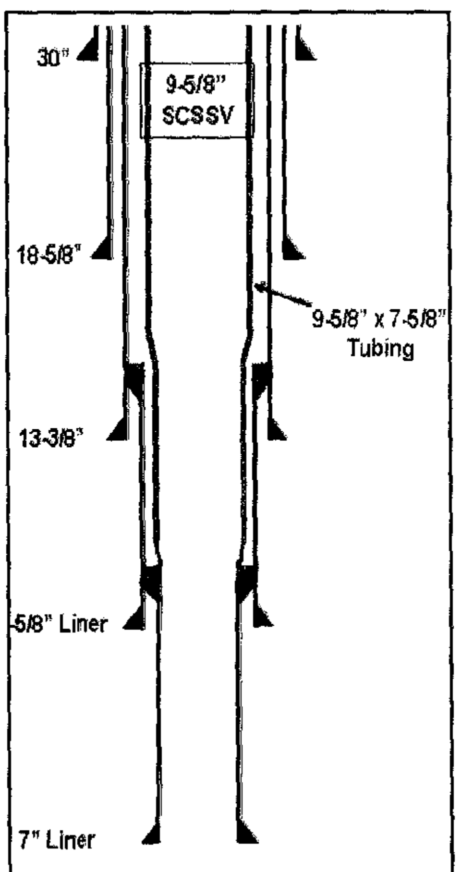



*Figure 9: Tapered 9-5/8 x 7-5/8 inch Tubing Completion* [2]

The Production Conduit Model will be based on the three completion designs. The Production Conduit Model will be integrated with the Static Reservoir Model to initiate simulation. Simulation will be conducted on the integrated model to determine the design which results the optimum gas production. The optimum production can be described as:

- Having extended production plateau
- Having longer production time
- Having low differential pressure ($\Delta P$) between the bottom of the well and wellhead node

The second objective is to design the casing program to accommodate the production conduit. Different completion design would have different casing configuration due to the size of the production conduit. For example, the Conventional 9-5/8 inches Tubing would have the 30 inch Driven Conductor followed by 20 inch Conductor Casing, 13-3/8 inch Surface Casing and 10 inch Liner [1]. The casing design will determine the size of hole to be drilled. The function of the casing program includes:

- To protect the inner production tubing from compressive force from the formation
- To prevent formation collapse or subsidence
- To prevent crossflows between water bearing zone and productive hydrocarbon zone
- To isolate different formation layers (shale, limestone, sandstone)

The casing used will have to bear the external compressive force and the internal burst energy acting on the casing wall. Materials such as 129#X-52 Steel and L-80 Steel will be used extensively in manufacturing the casing. Each casing connections would have a gas tight premium connection to avoid gas from escaping through the casing's micro-annulus gaps [1].

In field practices, the annulus between the casing and the formation will be cemented. The cement will provide better Zonal Isolation in addition to the casing program. Zonal Isolation is important to prevent fluid escaping to the surface, mixing of unwanted fluids and formation collapse or subsidence [2].

The third objective is to compare the Production vs. Time curves for each completion designs. The curve will be generated using WellFlo®. The curve should be achieved after simulation is conducted on the integrated model. The curve will illustrate which design yields the optimum rate. The curve will be analyzed based on two main parameters: (1) total production years, (2) extension of production plateau before decline. Attached below is a sample of optimized production cycle [3]:

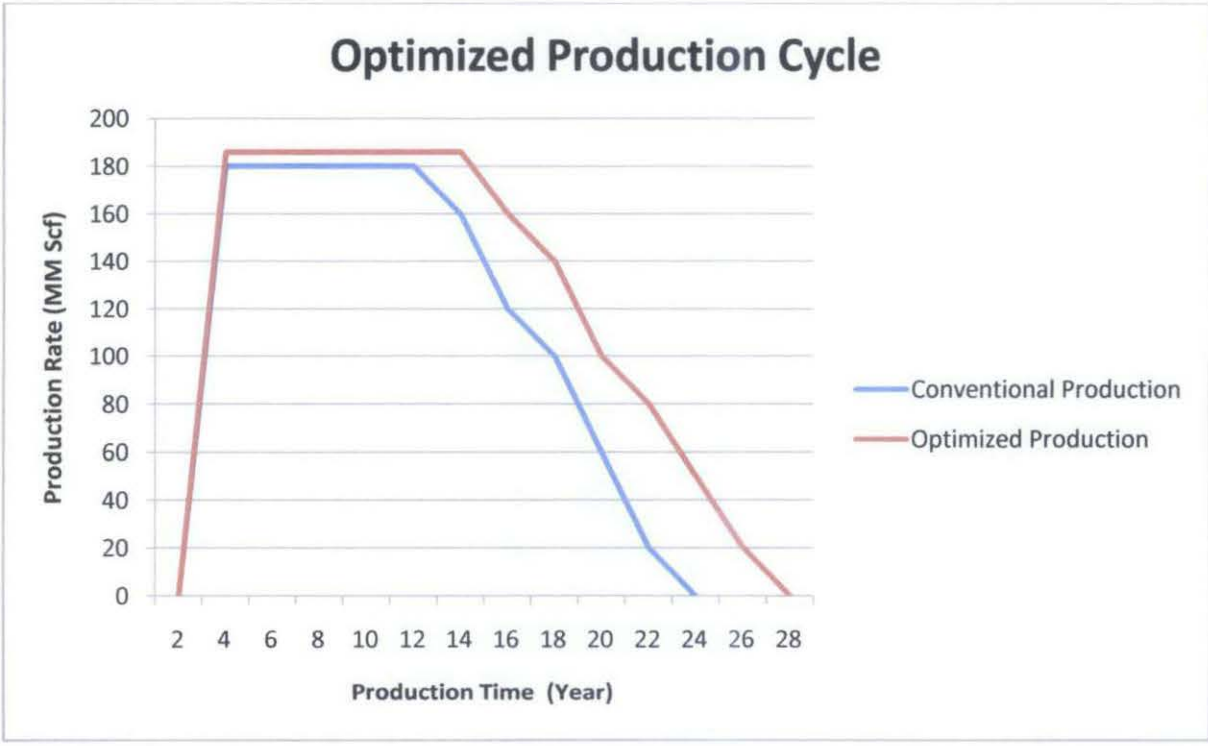



*Figure 10: Optimized Production Cycle* [3]

# CHAPTER 3

# METHODOLOGY

## 3.1 Research Methodology

Construct Static Reservoir Model with constant parameters; *Reservoir Pressure, Porosity, Permeability, Gas Density, Skin Factor, Temperature*

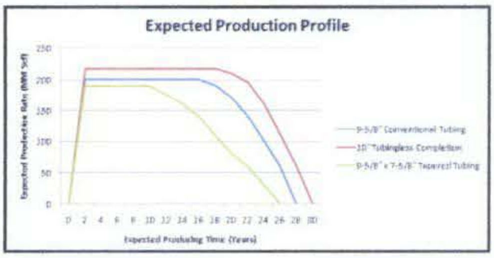
Construct Production Conduit Model with different configurations:

- Conventional 9-5/8" Tubing
- 10" Tubingless Completion
- Tapered 9-5/8" x 7-5/8" Tubing

Integrate Static Reservoir Model with Production Conduit Model.

Commence simulation on the integrated model to determine the design which yields optimum production

Generate Production Cycle graph; Production Rate vs. Time




Decide on design which yields optimum production

Pipeline Calculation

$$Q = 435.87\,(E)\left(\frac{T_b}{P_b}\right)^{1.07881}\left(\frac{P_1^{\,2}-P_2^{\,2}}{T.L.Z}\right)^{0.5394}\left(\frac{1}{G}\right)^{0.4606}(D)^{2.6182}$$

Compressor Calculation

$$\frac{HP}{MMscfd} = 0.08578\left(\frac{k}{k-1}\right)(T_{suc})(Z_{suc})\left[\left(\frac{P_{dis}}{P_{suc}}\right)^{\frac{k-1}{k}} - 1\right]$$

$$BHP = \frac{(HP/MMscfd)(Q)}{E}$$

Gathering System Calculation

$$Q = K\sqrt{P_{tf}^{\,2} - P_{suc}^{\,2}}$$

Tubing Flow Calculation

$$Q = 200{,}000\left[\frac{D^5\,(P_{wf}^{\,2} - e^s.P_{tf}^{\,2})\,s}{\gamma_g.T.Z.f.L(e^s - 1)}\right]^{0.5}$$

$$S = \frac{0.0375(\gamma_g)(L)}{T.Z}$$

Reservoir Calculation

$$Q = C_{avg}(P_R^{\,2} - P_{wf}^{\,2})^n$$

Design and integrate the Casing program with the Tubing design

*Figure 11: Methodology*

Reservoir Data

| | |
|---|---|
| Average Reservoir Pressure, $P_r$ | 875 psia |
| Average Reservoir Temperature, $T_r$ | $350^0F$ / $810^0R$ |
| Average Reservoir Depth, Z | 10,200 ft (TVD) |
| Average Net Payzone Thickness | 180 ft |
| Average Porosity, Ø | 18% |
| Average Permeability, k | 320 mD |
| Wellbore Radius, $r_w$ | 5.625 inch |
| External Radius, $r_e$ | 1500 ft |
| Drainage Area, $A_d$ | $7.069 \times 10^6$ $ft^2$ |
| Darcy Flow Coefficient, B | 146509.8 MMscfd |
| Fetkovich Coefficient | 0.0005 |
| Average Water Saturation | 10.7% |
| Formation Volume Factor, $B_o$ | 1.32 |
| Gas API Gravity | 86 $^0$API |
| Gas Specific Gravity, $\gamma_g$ | 0.65 |
| Gas Viscosity, $\mu_g$ | 0.25 cp |
| Number of Wells, N | 5 |
| Well Spacing Coefficient, $C_{avg}$ | 0.00742 MMscfd/psia |
| n-coefficient | 0.75 |
| Pseodo-Critical Pressure, $P_{pc}$ | 671 psia |
| Pseodo-Critical Temperature, $T_{pc}$ | $370^0R$ |

*Table 1: Reservoir Data* [1][2]

Tubing Data

| | |
|---|---|
| Tubing Length, $L_{tubing}$ | 10,000 ft (TVD) |
| Average Tubing Temperature, T | $100^0F$ / $560^0R$ |
| Compressibility factor, z | 0.90 |
| Tubing Diameter, D | *Depends on types of completion* |
| Friction factor, $f$ | 0.0144 |

*Table 2: Tubing Data* [1][2]

Surface Facilities Data

| | |
|---|---|
| Ratio of flowrate and pressure, K | 0.763 x $10^6$ scfd/psia |

*Table 3: Surface Facilities Data* [1][2]

Compressor Data

| | |
|---|---|
| Operating Limit, BHP | 20,000 HP |
| Efficiency, E | 0.80 |
| k-factor | 1.25 |
| Suction Temperature, $T_{suc}$ | $60^0$F / $520^0$R |
| Compressibility factor, $z_{suc}$ | 1.0 |

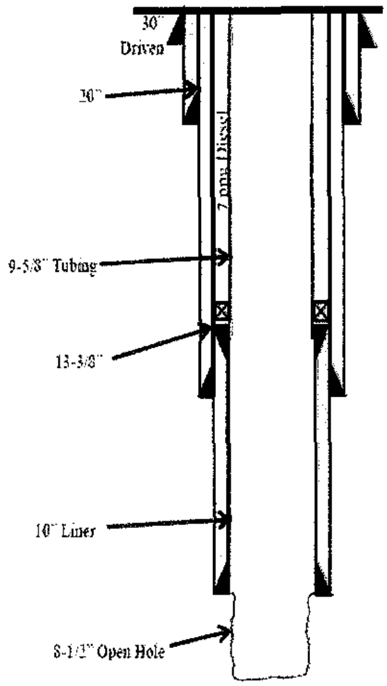
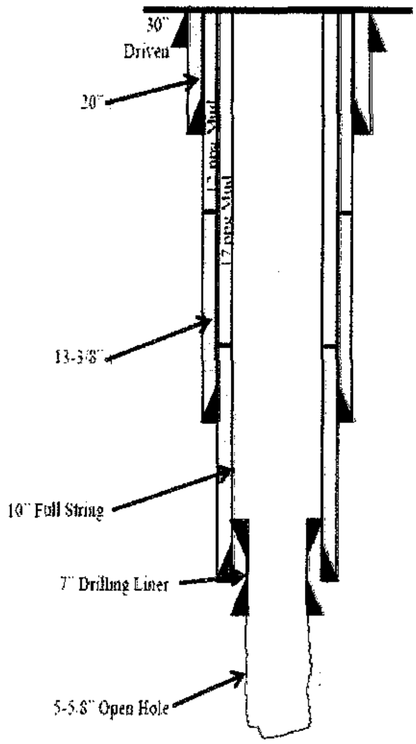
*Table 4: Compressor Data* [1][2]

Pipeline Data

| | |
|---|---|
| Pipe Length, $L_{pipe}$ | 120 miles |
| Pipe Diameter, D | 13 inch |
| Output Pressure, $P_L$ | 200 psia |
| Average Temperature, T | $70^0$F / $530^0$R |
| Efficiency, E | 0.92 |
| Base Pressure, $P_b$ | 14.73 psia |
| Base Temperature, $T_b$ | $60^0$F / $520^0$R |

*Table 5: Pipeline Data* [1][2]

Production Conduit Model Data

| | | |
|---|---|---|
| **Conventional 9-5/8 Inch Completion Tubing** | • Productive layer is completed Open-Hole with 8-1/2" hole diameter<br>• Production conduit is completed with 10" Liner connected to 9-5/8" Tubing to surface | <br> |
| **10 Inch Tubingless Completion** | • Productive layer is completed Open-Hole with 5-5/8" hole diameter<br>• Production conduit uses 10" Full String Tubing from top of production zone to surface<br>• Incorporates the use of 7" Drill-In Liner to penetrate 30 ft into production zone | <br> |

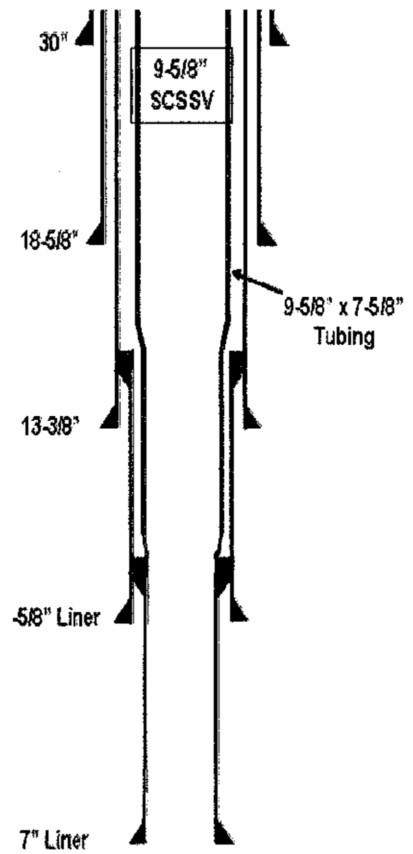
| | | |
|---|---|---|
| **Tapered 9-5/8 Inch × 7-5/8 Inch Tubing** | • The productive zone is completed with 7” Liner with perforations<br>• The production conduit uses tapered 9-5/8” x 7-5/8” Tubing connected to the top of 7” Liner |  |

*Table 6: Production Conduit Data* [1][2][3]

### 3.2 Tools and Equipments

In the project, WellFlo® software will be used to conduct the gas production simulation with different completion configuration.

WellFlo® is a Nodal Analysis program. Its function is to analyse the behaviour of petroleum fluids in wells. The behaviour is modelled in terms of the pressure and temperature of the fluids, as a function of flowrate and fluid properties. The program takes as its input a description of the *reservoir*, *well completion* and the *surface equipment*. This is combined with *fluid properties* data. The program then performs calculations to determine the pressure and temperature of the fluids. Different modes of operation can be employed to either solve the flowrate given controlling pressures (typically done for deliverability calculations) or solving for pressure drops given measured flowrates (typically done for diagnostic calculations) [12].

WellFlo® calculations are based on Nodal Analysis. There are two main types of Nodal Analysis; (1) determination of flowrates from pressures [12], (2) determination of pressures from flowrates [12]. Determination of flowrates is concerned with *deliverability* applications while the determination of pressures is concerned with *monitoring* or *diagnostic* applications [12].

<u>Deliverability Applications</u>

1. Calculating the flow potential (deliverability) of a well

   Uses techniques to determine operating point – whereby pressures at the node in the system are calculated from a range of flowrates. Only one flowrate will give the same pressure at the solution node calculated in both directions (intersection of IPR and TPR curves) [12].

2. Designing the completion of a well

   Enabled the calculations of deliverability as a function of different sizes of tubing or different perforations. This allows the optimum completion is chosen. Design facilities also include valve positioning, valve settings and ESP selections [12].

3. Modelling the sensitivity of a well design

   Reflects the different factors which may affect the production system such as water encroachment or decreasing reservoir pressure. This may refine the design of well completion components. Such sensitivities may pertain to the reservoir, well, surface facilities or operating conditions [12].

<u>Diagnostic Applications</u>

1. Comparison of measured data with calculated data

   It can be used for different purposes such as evaluating the best flow correlation within WellFlo®, evaluating match parameters (pipe roughness) or determining if the well is behaving as expected performance [12].

2. Monitoring well performance

   To predict reservoir pressure from measured surface pressure and flowrate. This would enable users to see if the system is behaving as predicted even if all parameters are not measured at the same time [12].

3. For designing production system

   Mainly used to calculate the pressure drop or drawdown in a system. This will determine whether fluids are able to flow in the system. Optional facilities are also available to select ESPs and motors for the production system [12].

The following part will describe the required information to be entered into WellFlo®.

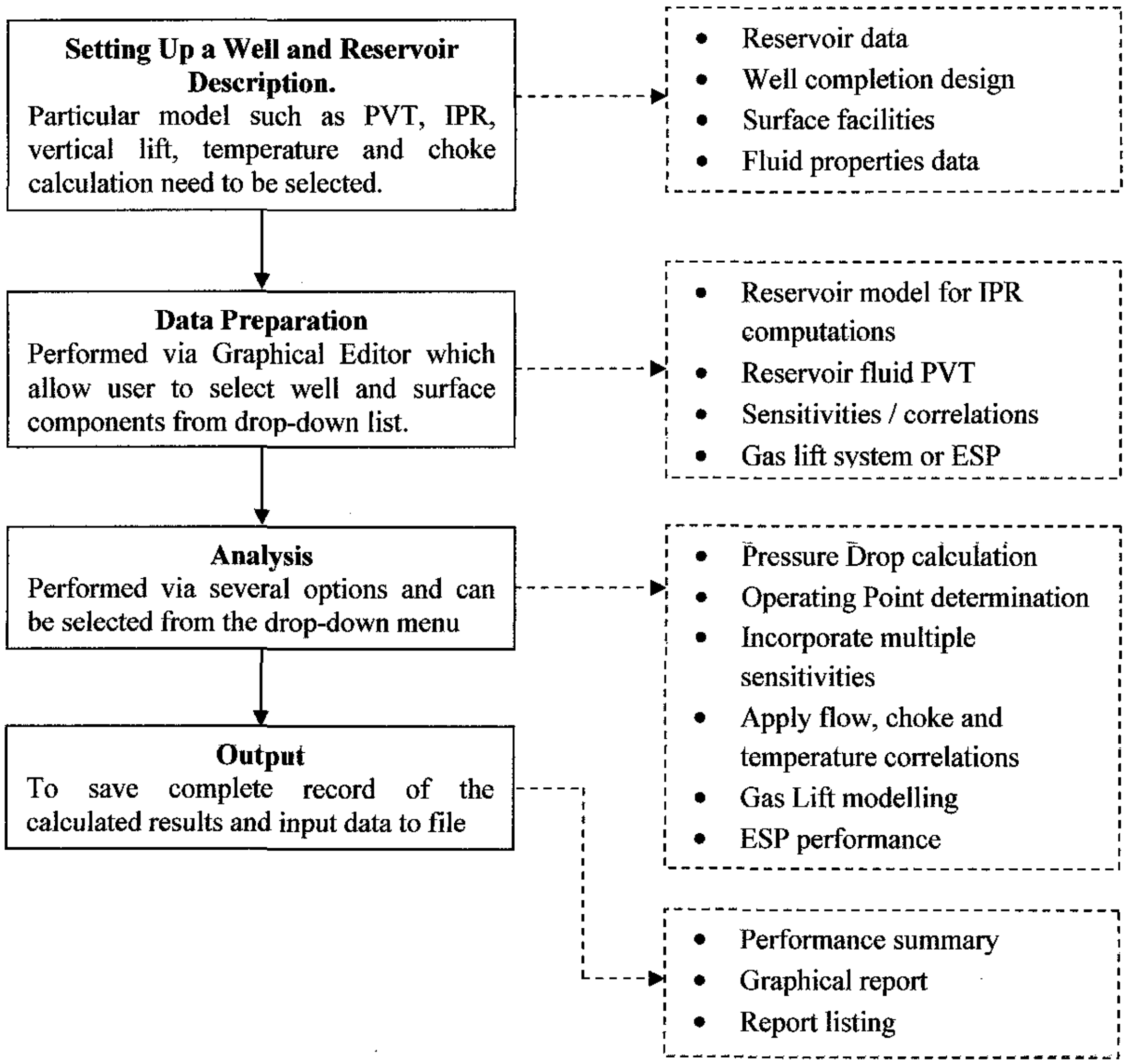



*Figure 12: WellFlo® General Operation Method* [12]

### 3.3 Project Planning – Gantt chart and Key Milestones

| | Final Year Project (FYP-1) | | | | | | | | | | | | | | Final Year Project (FYP-2) | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Activity / Week** | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 |
| Gather information regarding Big-Bore Wells optimization | | | ■ | ■ | | | | | | | | | | | | | | | | | | | | | | | | |
| Conduct initial theoretical calculation regarding gas production and tubing design using Deliverability Analysis | | | | | ■ | ■ | ■ | | | | | | | | | | | | | | | | | | | | | |
| Construct Static Reservoir Model with constant formation and fluid properties | | | | | | | | ■ | ■ | ■ | ■ | | | | | | | | | | | | | | | | | |
| Construct Production Conduit Model with 3 different completions | | | | | | | | | | | | ■ | ■ | ■ | ■ | | | | | | | | | | | | | |
| Integrate both Models and commence simulation | | | | | | | | | | | | | | | | ■ | ■ | ■ | ■ | | | | | | | | | |
| Generate Production Cycle Curve; Produced Rate vs. Time for each completion designs | | | | | | | | | | | | | | | | | | | | ■ | ■ | | | | | | | |
| Decide which design yields optimum production over time | | | | | | | | | | | | | | | | | | | | | | ■ | ■ | ■ | | | | |
| Design Casing Progam to accommodate selected design | | | | | | | | | | | | | | | | | | | | | | | | | ■ | ■ | | |
| Integrate Production Conduit with Casing Program | | | | | | | | | | | | | | | | | | | | | | | | | | | ■ | ■ |

| | Final Year Project (FYP-1) | | | | | | | | | | | | | | Final Year Project (FYP-2) | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Milestones / Week** | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 |
| Completion of Static Reservoir Model | | | | | | | | | | | ■ | | | | | | | | | | | | | | | | | |
| Completion of Production Conduit Model | | | | | | | | | | | | | | | ■ | | | | | | | | | | | | | |
| Completion of dynamic simulation | | | | | | | | | | | | | | | | | | | ■ | | | | | | | | | |
| Completion of Production Cycle profile | | | | | | | | | | | | | | | | | | | | | ■ | | | | | | | |
| Completion of Casing Program | | | | | | | | | | | | | | | | | | | | | | | | | | ■ | | |

*Figure 13: Gantt chart and Key Milestones*

## CHAPTER 4

## RESULTS AND DISCUSSIONS

### 4.1 Reservoir Formation and Structure

The gas production zone is from the K-30 Limestone formation at average depth approximately 10,200 feet (TVD). The Limestone reservoir consists of consolidated matrix structure which prevents any sand or carbonate material production during the depletion of the dry gas reserves. Good porosity and permeability is obtained from the reservoir with average porosity and permeability at 18% and 320 mD, respectively. The critical aspect of the Limestone reservoir is that the payzone is overlaid by over-pressured water bearing formation and highly compacted shale structure [1].

The presence of these two elements had resulted abnormally pressured condition which continues to compress the Limestone reservoir. The pressure gradient across the Shale structure is around 0.039 Psi/ft. The Limestone reservoir is expected to experience deformation or damage when the reservoir pressure depletes to 400 Psia. The overburden stress from the water bearing zone and Shale structure will cause the Limestone reservoir to compacts and collapses [1].

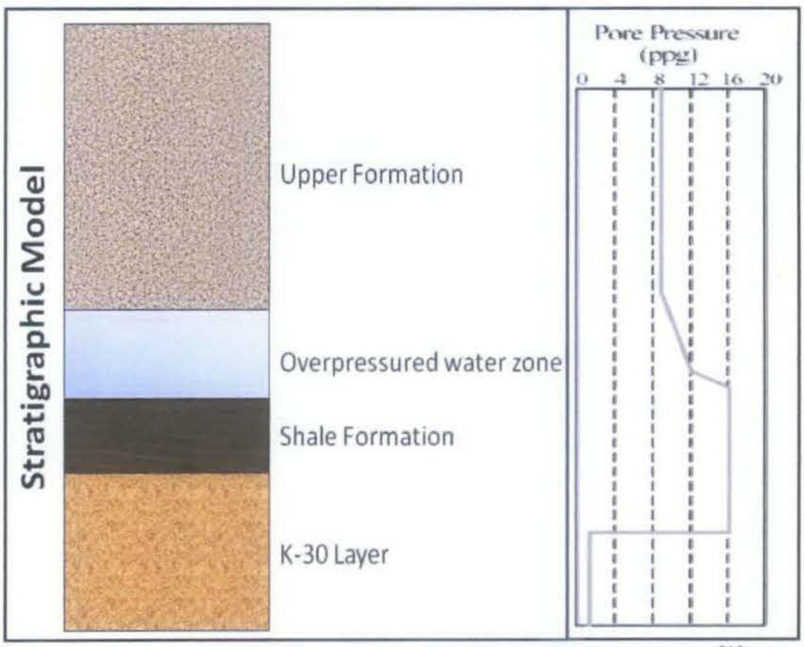



*Figure 14: Stratigraphic Model of the reservoir* [1]

## 4.2 Assumptions and Limitations

The simulation only focuses on the types of completion to optimize gas recovery. Other parameters such as gathering lines, compressor stations and transmission lines will not be discussed in the paper. Hence, several assumptions and limitations are set to meet the focus of the project. Among the matters are:

1. Reservoir pressure is simulated only to 450 Psia to avoid the effects of reservoir damage to the total production system.
2. Any change is reservoir rock and fluid properties are neglected.
3. Water-cut is not present in the system.
4. No heat loss is considered in the total production system (adiabatic operations).
5. The gathering lines at the surface are represented by the K-coefficient which is at 0.763 x $10^6$ Scfd/Psia.
6. The compressor station is assumed as a single unit having 20,000 HP.
7. Change in flow regime within the transmission lines is neglected.
8. Pressure at end of transmission lines are set at 200 Psia

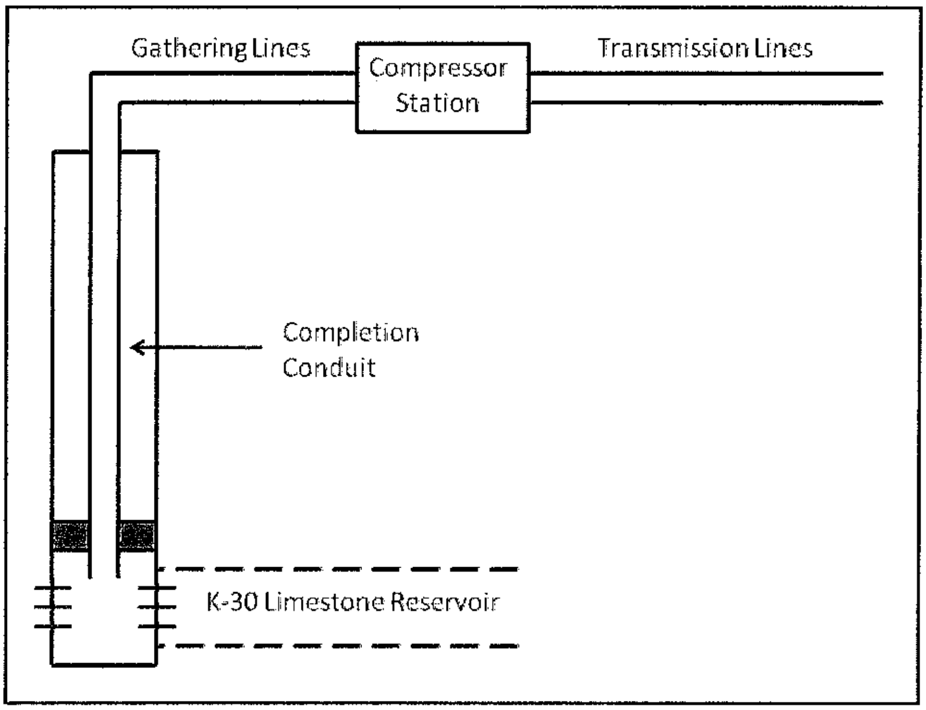



*Figure 15: WellFlo Simulation model*

## 4.3 Reservoir Flow Performance

The reservoir performance is defined as the Inflow Performance Relation (IPR). The IPR measures the potential of the reservoir at given average reservoir pressure. Shown below are the IPR curves for each of the completion designs; *10 inch Tubingless Completion*, *9-5/8 inch Tubing* and *Tapered 9-5/8 × 7-5/8 inch Production Tubing.*

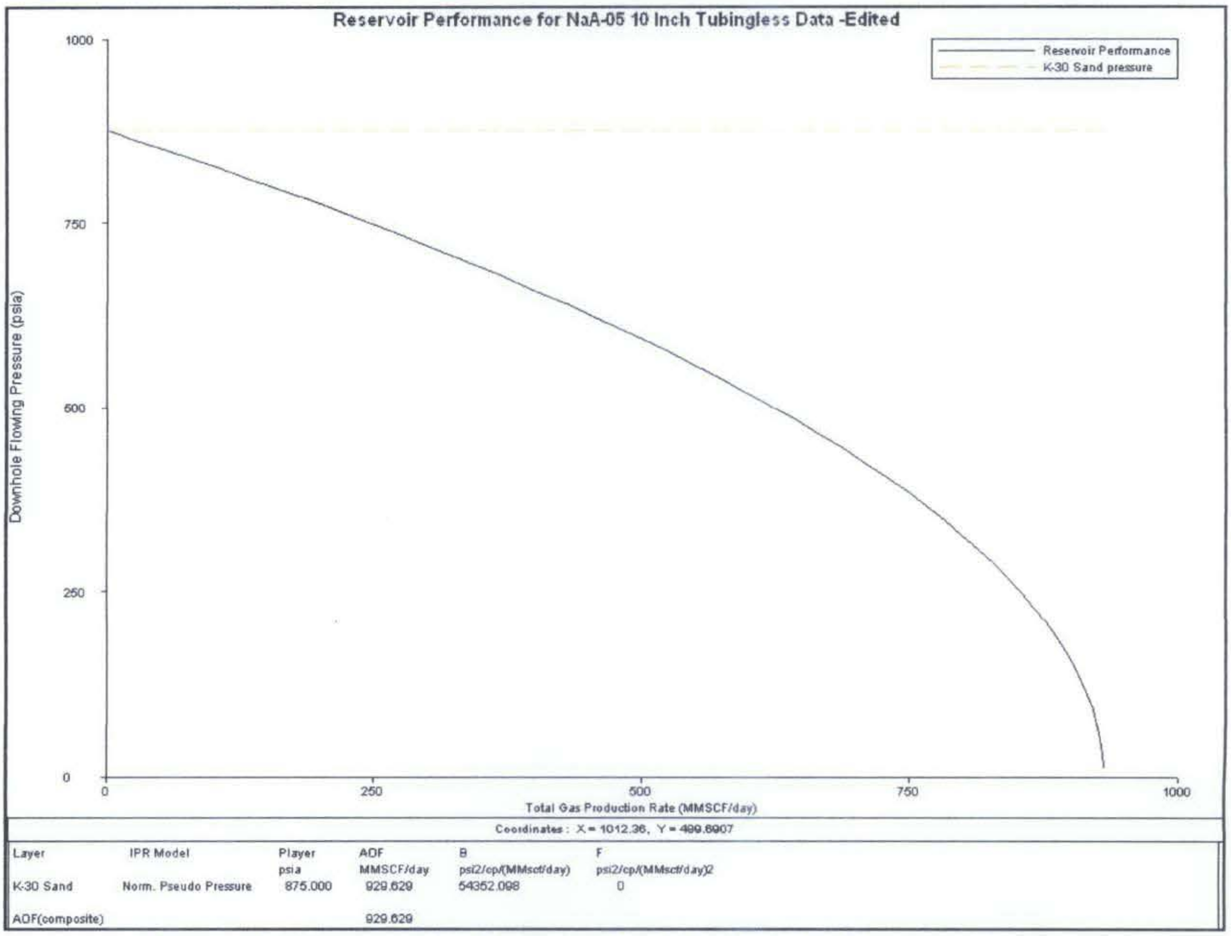



*Figure 16: Reservoir Performance for 10 inch Tubingless completion*

| 10 inch Tubingless Completion | |
|---|---|
| Wellbore Diameter | 5.625 inch (Open Hole) |
| Absolute Open Flow (AOF) | 929.629 MMscfd |
| Initial Reservoir Pressure | 875 Psia |

*Table 7: IPR properties of 10 inch Tubingless completion*

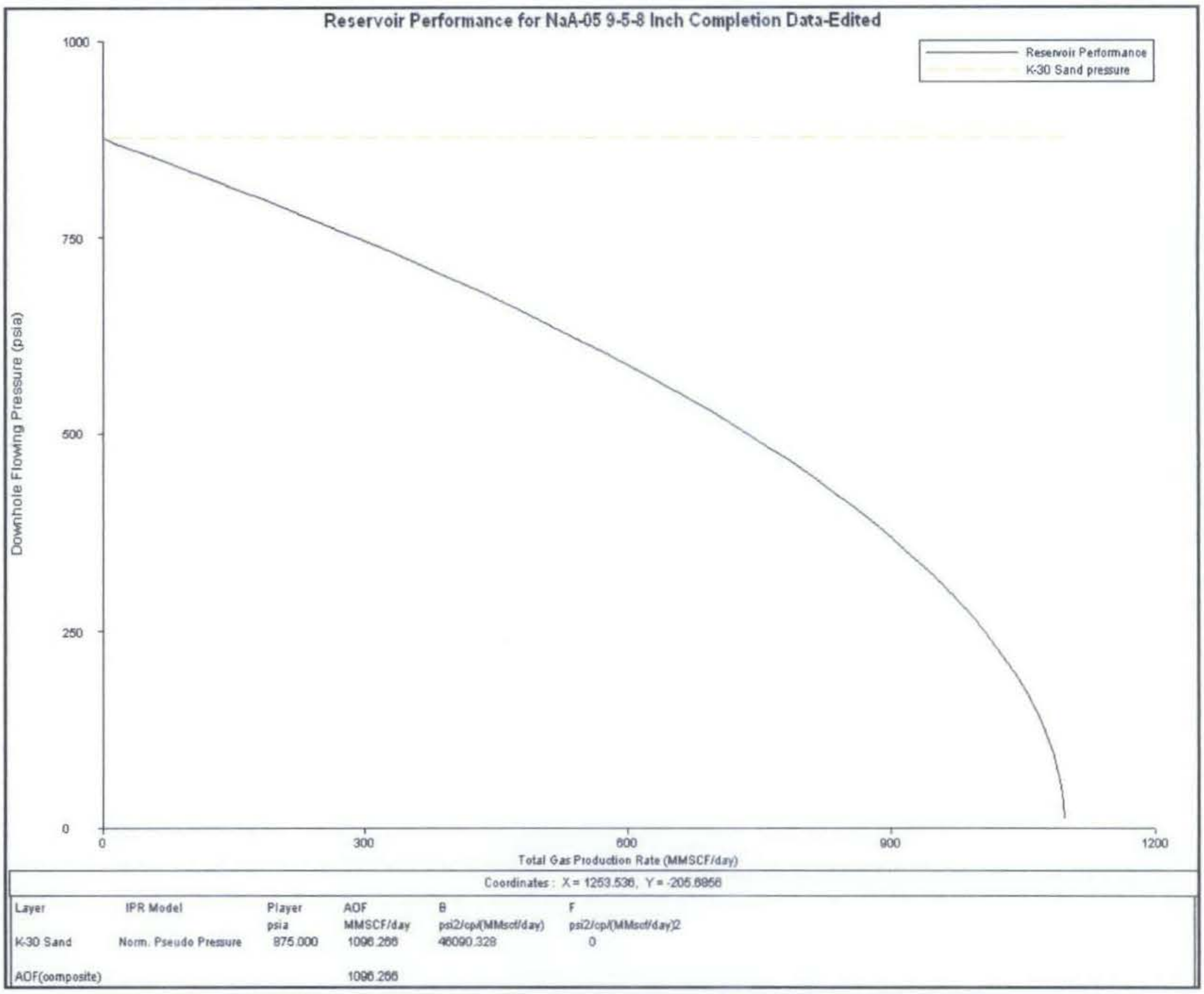



*Figure 17: Reservoir Performance curve for 9-5/8 inch Tubing*

| Conventional 9-5/8 inch Tubing Completion | |
|---|---|
| Wellbore Diameter | 8.5 inch (Open Hole) |
| Absolute Open Flow (AOF) | 1096.266 MMscfd |
| Initial Reservoir Pressure | 875 Psia |

*Table 8: IPR properties of 9-5/8 inch Tubing*

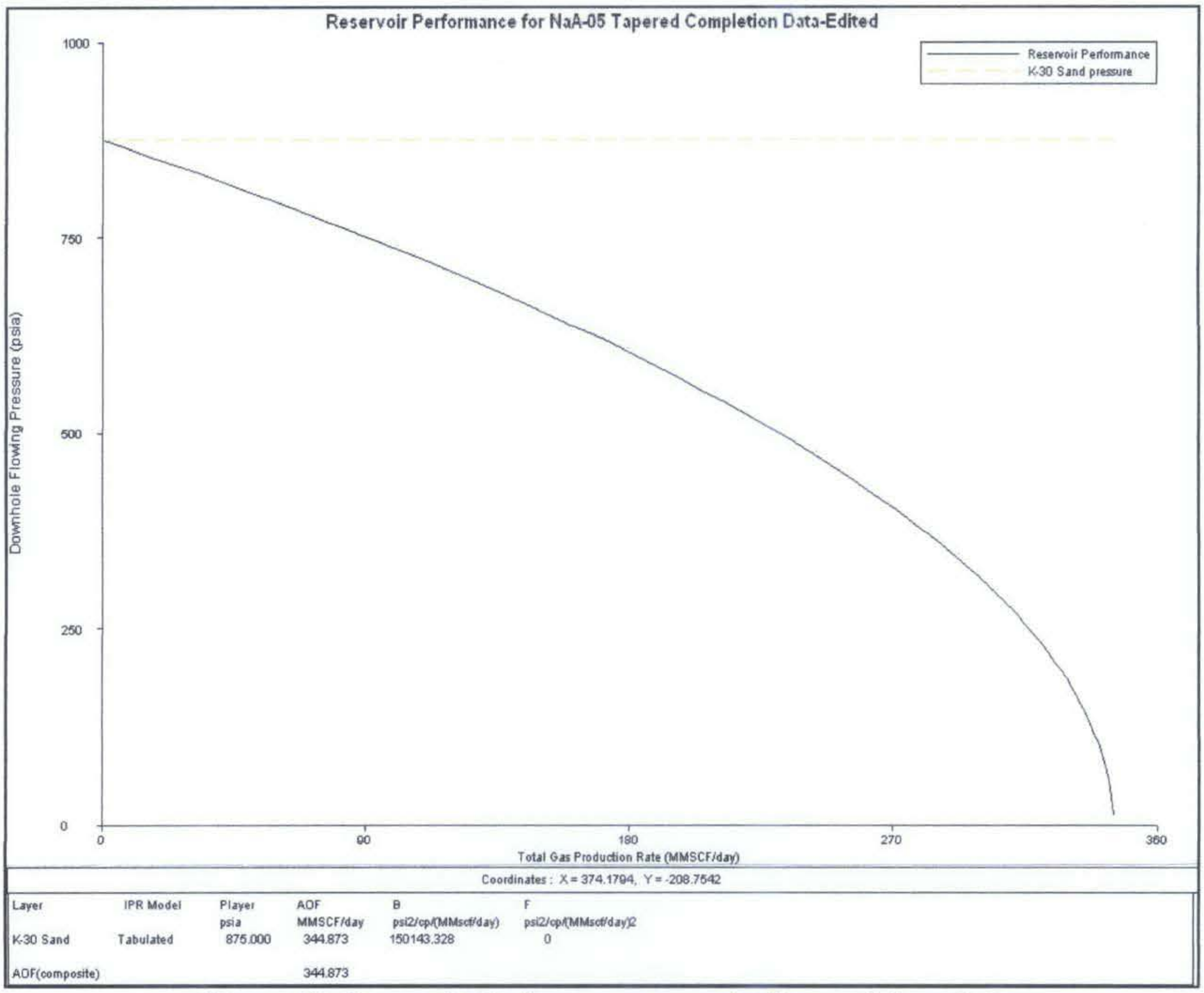



*Figure 18: Reservoir Performance curve for Tapered Completion*

| Tapered 9-5/8 × 7-5/8 inch Production Tubing | |
|---|---|
| Wellbore Diameter | 7 inch (Cased Hole) |
| Absolute Open Flow (AOF) | 344.873 MMscfd |
| Initial Reservoir Pressure | 875 Psia |

*Table 9: IPR properties Tapered Completion*

In general, having larger wellbore diameter would increase the flow potential of the reservoir. The increase in flow potential is described in the Absolute Open Flow (AOF) value. The AOF value is obtained when the reservoir pressure is equal to zero or at atmospheric condition; 14.73 Psia. This condition is only achievable theoretically and not in real operating environment [9][10].

Larger wellbore diameter would increase the effective drainage contact area, which permits higher flow potential. In addition, the flow potential is also affected by the productive zone completion method whether completed Open Hole or Cased Hole.

As shown above, when the productive zone is completed Open Hole, the flow potential of the reservoir increases by 62.6%. This is because the Open Hole completion allows greater exposed drainage area [1]. Cased Hole completion has rather restricted exposed drainage area which only achievable when perforated [2]. For gas production, Open Hole completion is preferred for greater flow potential from the reservoir's perspective.

The flow potential increases by 15.2% when the Open Hole completion is increased from 5.625 inch to 8.5 inch. Larger diameter would increase the exposed area thus increasing flow potential. The performance of the three completions is illustrated below:

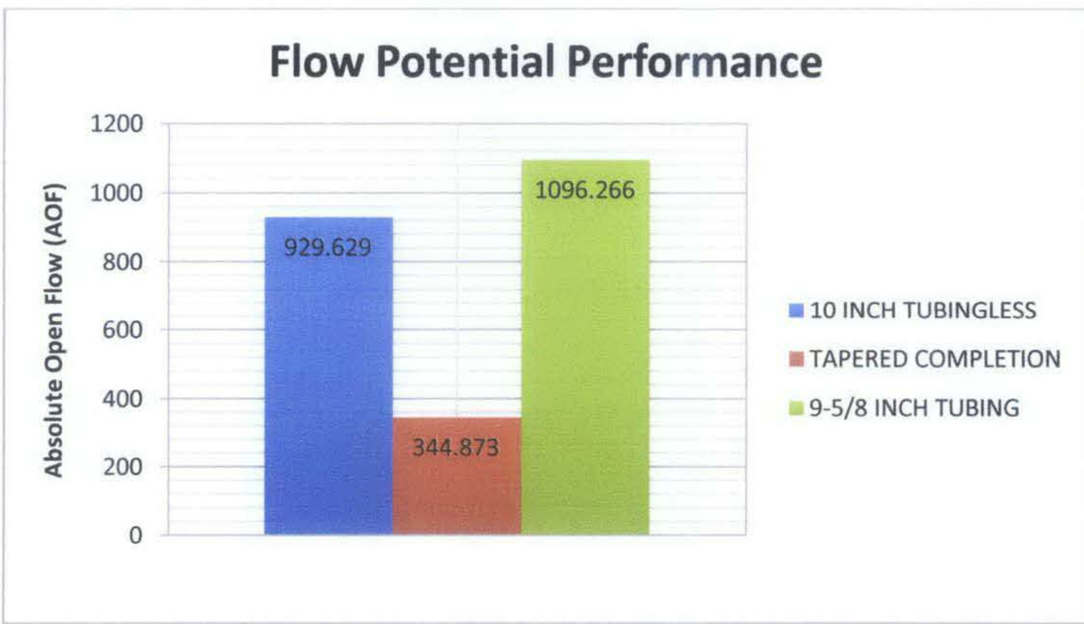



*Figure 19: Flow Potential Performance*

## 4.4 Completion Design Potential

The tubular performance of the system is shown in the Tubular Performance Relation (TPR) curve. The intersection between the IPR and TPR curve will be the optimum operating point of the system. Results for the three completions are shown below:

<u>10 inch Tubingless Completion</u>

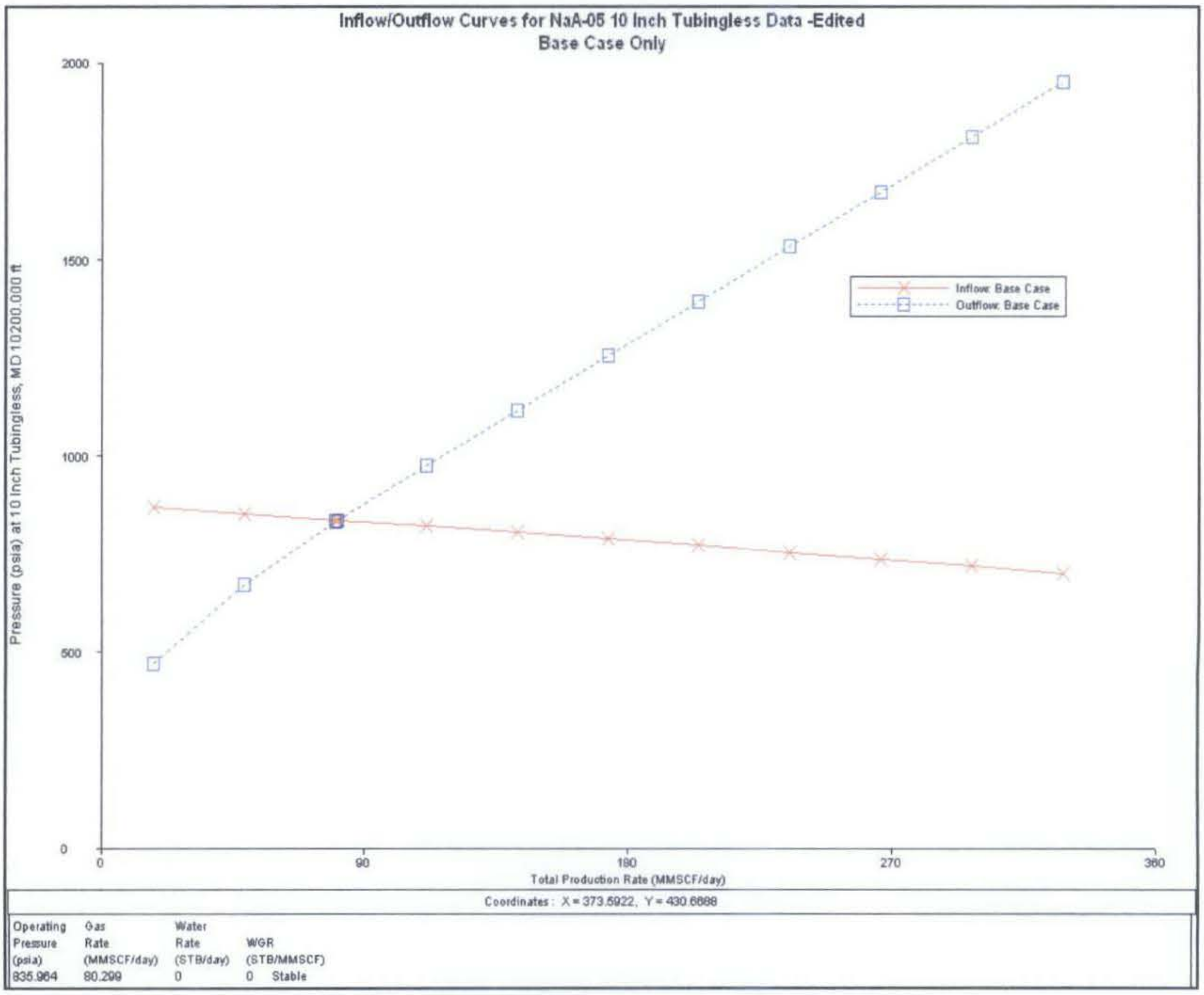



*Figure 20: Operating Point for 10 inch Tubingless Completion*

At Reservoir Pressure, $P_R$ is equal to 875 Psia, the 10 inch Tubingless Completion yields 80.229 MMScfd of gas at Bottom-Hole Flowing Pressure, $P_{wf}$ of 835.964 Psia. At respective operating point, the Wellhead Pressure, $P_{wh}$ is equal to 633.596 Psia. The NODAL analysis is performed up to 450 Psia with stable operating points.

9-5/8 inch Tubing Completion

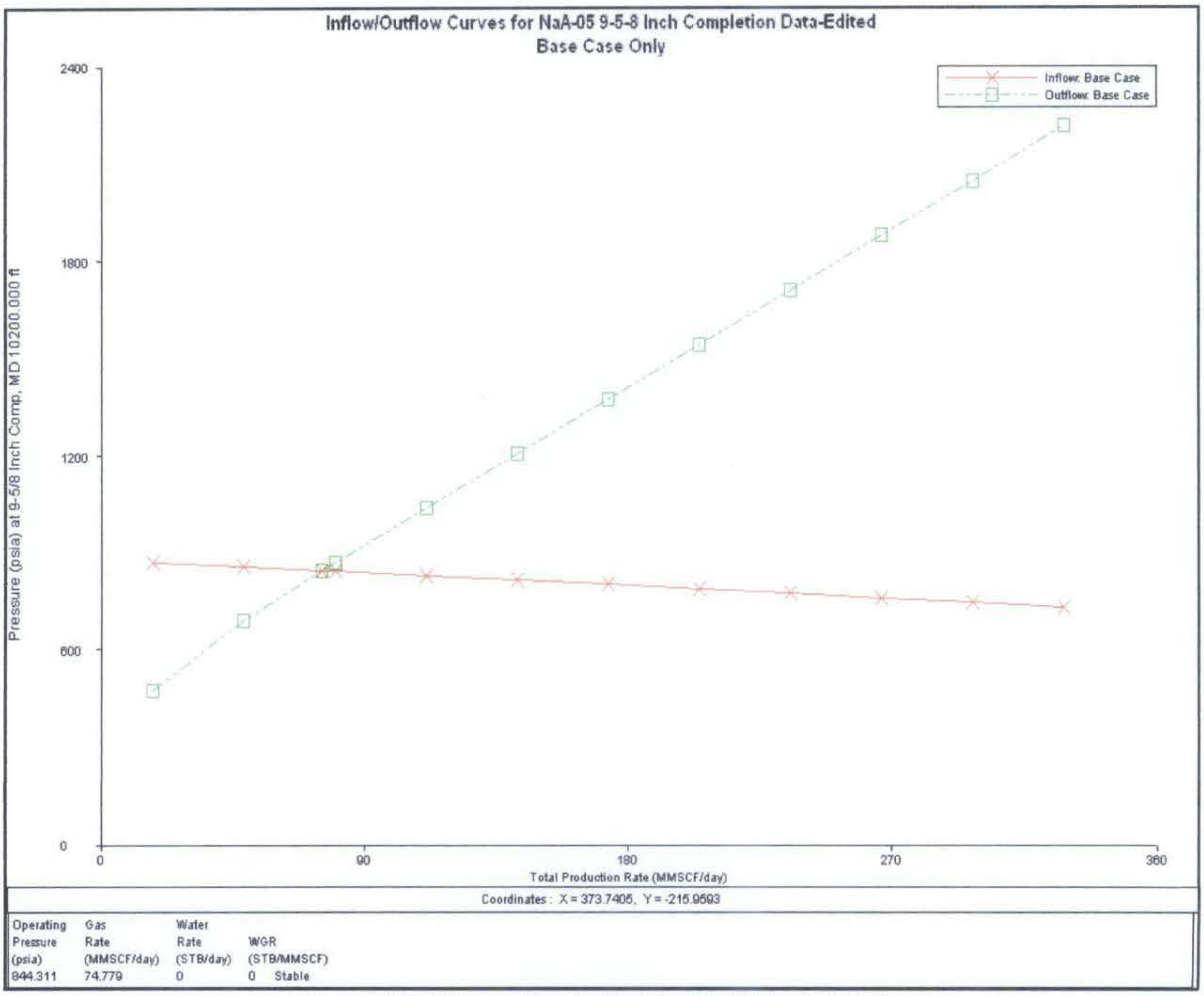



*Figure 21: Operating Point for 9-5/8 inch Tubing*

For 9-5/8 inch Tubing, the operating point is lower than 10 inch Tubingless. At equivalent Reservoir Pressure, $P_R$ the produced gas rate is at 74.779 MMScfd with Bottom-Hole Flowing Pressure, $P_{wf}$ of 844.311 Psia. The Wellhead Pressure, $P_{wh}$ is at 619.296 Psia.

The gas production from the 9-5/8 inch Tubing design dropped almost 6.8% from the 10 inch Tubingless completion. This is because the 9-5/8 inch Tubing has more restrictions due to the smaller tubing diameter. Smaller tubing produces greater frictional losses and more energy is required for the gas to overcome the pressure drop [9][10]. More energy is required for the gas to flow to the surface, hence reducing the amount of gas produced in the system [13].

Tapered 9-5/8 × 7-5/8 inch Tubing

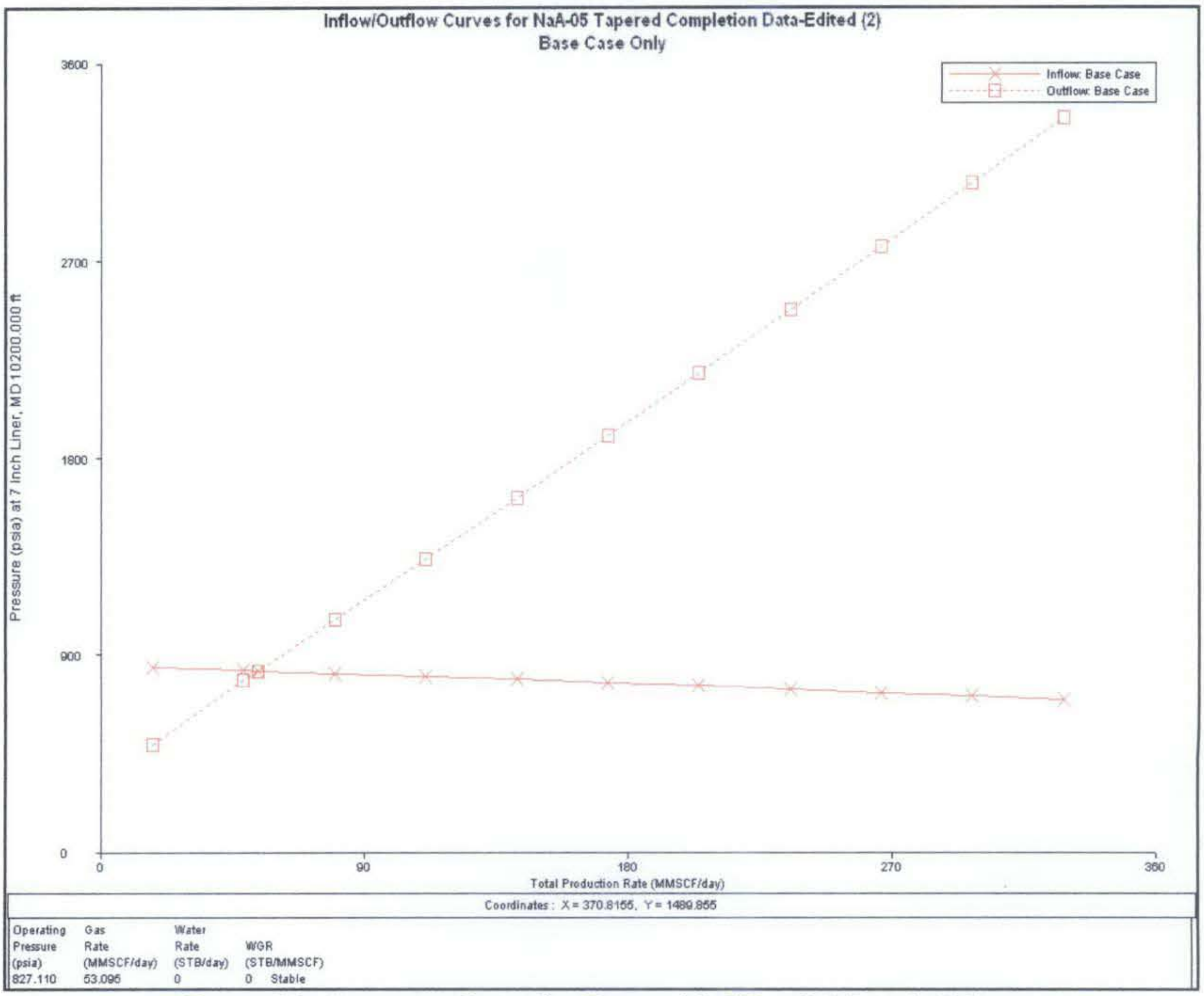



*Figure 22: Operating Point for Tapered 9-5/8 × 7-5/8 inch Tubing*

Among the three completion designs, the Tapered 9-5/8 × 7-5/8 inch Tubing yields the least producing capacity, which is at 55.841 MMScfd, 30.4% less than the 10 inch Tubingless completion. At the respective flow rate, the Bottom-Hole Flowing Pressure, $P_{wf}$ is at 851.591 Psia while the Wellhead Pressure, $P_{wh}$ is at 564.174 Psia.

The reason for such large decline is due to the design of the Tapered system. The Tapered system is more stable to be implemented in high pressure reservoirs [4]. Higher reservoir pressure allows the gas to overcome the pressure losses occurred at each expansion joint.

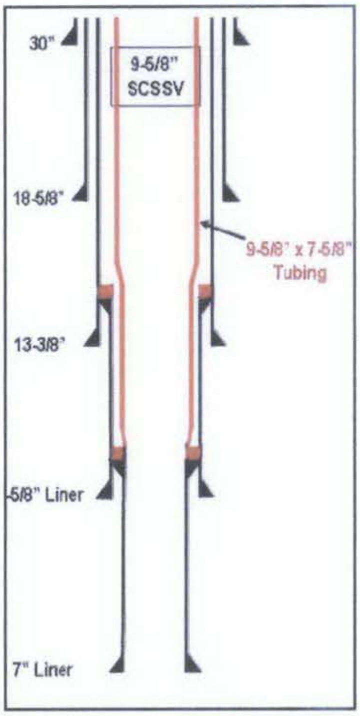



*Figure 23: Tapered 9-5/8 × 7-5/8 inch Tubing* [2]

At each expansion joints, the gas flow changes from steady, laminar flow to a less stable turbulent flow. The change in flow regimes had resulted greater frictional losses in the conduit, thus resulted more pressure drop [13]. As are result, more energy from the reservoir is required to flow the gas to the surface. The depleting reservoir could not provide adequate energy to overcome the restrictions in the system.

The Tapered design is not suitable to be used in low pressure reservoir as the energy to drive the gas up to the surface is not adequate to overcome the losses at the expansion joints [13]. Artificial lift methods; Gas Lift or Electrical Submersible Pump (ESP) are recommended to be used if the Tapered design is selected for producing in low pressure gas reservoirs.

### 4.5 Final Design Selection

The simulation is conducted at various Reservoir Pressure, $P_R$ to determine various operating points as it depletes. The operating point and producing capacity of each design is simulated to determine the suitable design to be implemented. The results from the simulation are analyzed and presented in terms of Gas Flow Rate Depletion Profile and Cumulative Production Chart:

<u>Gas Flow Rate Depletion Profile</u>

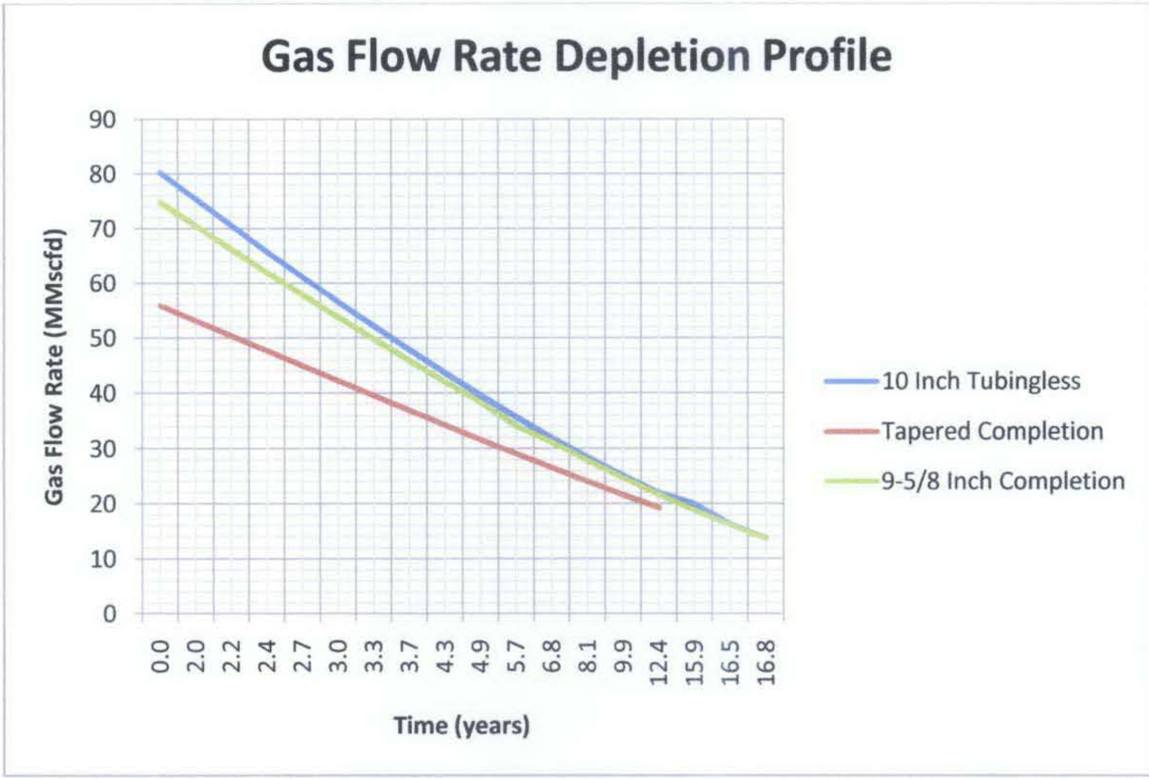



*Figure 24: Gas Flow Rate Depletion Profile*

Figure 24 illustrates the depletion profile for each of the completion designs; 10 inch Tubingless, 9-5/8 inch Tubing and Tapered Tubing completion. Both the 10 inch Tubingless and 9-5/8 inch Tubing completions capable of extending the producing life of the field up to 16.8 years. The Tapered Tubing Completion could only sustain production up to 12.4 years. Beyond the period, the Tapered Tubing design could not achieve a stable operating condition for optimum gas production.

The 10 inch Tubingless completion provided significant increase in gas production during the early stage of production period; up to 5.7 years when compared to the 9-5/8 inch Tubing design. Beyond the 5.7 year period, the 10 inch Tubingless design only provided slight increase in gas production. However, the increment was sufficient to improve overall recovery of the field up 23.15 Percent (%).

Beyond the 16.8 years of production, other means of artificial lift techniques are required to continue producing from the gas field. Pressure Maintenance scheme or Enhanced Gas Recovery technique may be proposed to resume production. However, the stimulation package must meet the current economic and market to ensure the proposal is financially feasible.

Cumulative Production Chart

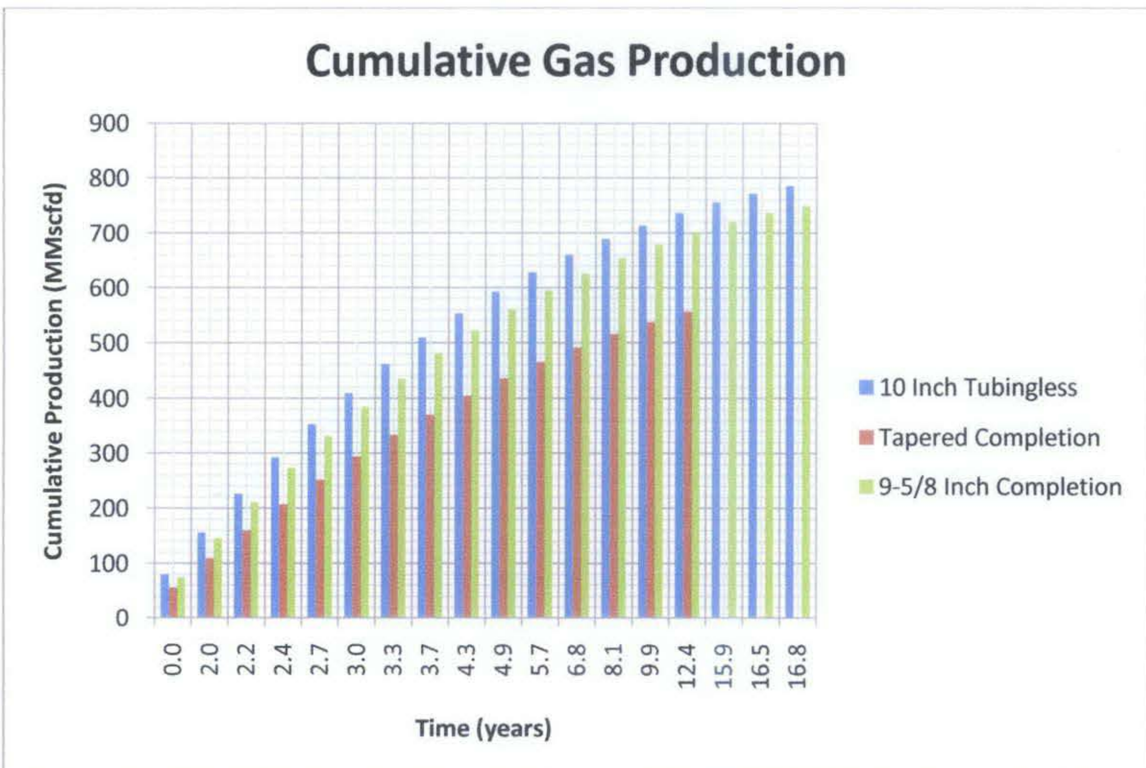



*Figure 25: Cumulative Gas Production chart*

Figure 25 illustrates the cumulative gas production over the producing period of the field. The development plan consists of five (5) wells to retain minimum daily production of 217 MMScfd. The 10 inch Tubingless completion produced up to 785.724 MMScfd of cumulative production for a single well, and increase of 4.63 Percent (%) when compared to the 9-5/8 inch Tubing design. The 9-5/8 inch Tubing design only generated 749.369 MMScfd of gas throughout the 16.8 years of production.

When compared to the Tapered 9-5/8 × 7-5/8 inch Tubing, the 10 inch Tubingless design generated an increase of 29.19 Percent (%) in cumulative gas production. The Tapered Tubing design only churned out 556.335 MMScfd of gas for 12.4 years of production. Beyond the production limit, the design failed to achieve an optimum operating condition.

In overall production from the gas field, the 10 inch Tubingless design managed to provide an additional increase in gas recovery up to 23.15 Percent (%), approximately 908.875 MMScfd of gas production. The project is considered economically feasible with the current market for gas as well as in the future.

In addition to the successes of increasing gas recovery and extending the producing life of the field, the 10 inch Tubingless design also provided improvements in preventing formation subsidence and well failure.

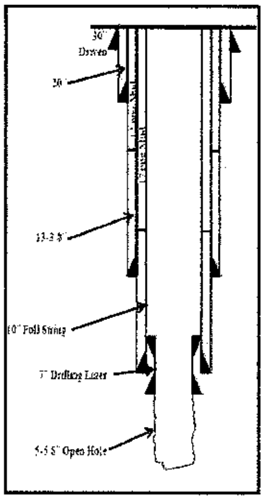



*Figure 26: 10 inch Tubingless Completion Design* [1]

The introduction of 7 inch Drill-in Liner as part of the casing programme had managed to provide excellent Zonal Isolation between the producing K-30 Limestone reservoir and the overlaying Shale structure. The Drill-in Line penetrated 20 to 30 feet into the Limestone reservoir preventing further formation subsidence as the reservoir continue to be depleted under low pressure environment.

The 7 inch Drill-in Liner was then cemented to increase the strength of the well especially near the Shale-Limestone contact layer. The vertical and lateral stresses from the highly-pressured Shale structure posed little danger to the well.

As a conclusion, the 10 inch Tubingless completion was selected as the suitable design for producing in low pressure reservoir condition. The design managed to provide three key elements to continue production:

- Increased gas recovery up to 23.15 Percent (%)
- Extended the producing life of the field to 16.8 years
- Prevented well failure from formation subsidence and structural collapse

# CHAPTER 5

# CONCLUSIONS AND RECOMMENDATIONS

## 5.1 Conclusion

As a conclusion, the 10 inch Tubingless completion will be implemented for gas production in low pressure reservoir. The selected design was able to improve overall gas recovery by 23.15 Percent (%). In addition, the selected design was able to extend the producing life of the reservoir up to 16.8 years under natural depletion energy. The casing design includes the implementation of 7 inch Drill-in Liners to properly isolate the overlaying Shale formation as well as penetrating deep into the productive K-30 Limestone formation.

## 5.2 Future Recommendations

In the future, the project could be improved by implementing the following matters:

i. The use of WellFlo 4.0 with extended sensitivities options to simulate alterations in matrix and fluid properties.
ii. The use of refined simulation model with accurate PVT data, completion data, surface facilities data and production history.
iii. The use of dynamic reservoir model variables such as water-cut effect, formation damage and drainage area to further refine the limitations of the reservoir.
iv. The integration of other simulation software such as Eclipse or Prosper to simulate the effect of pressure/temperature gradient changes, flow regimes and reservoir depletion profile over time.

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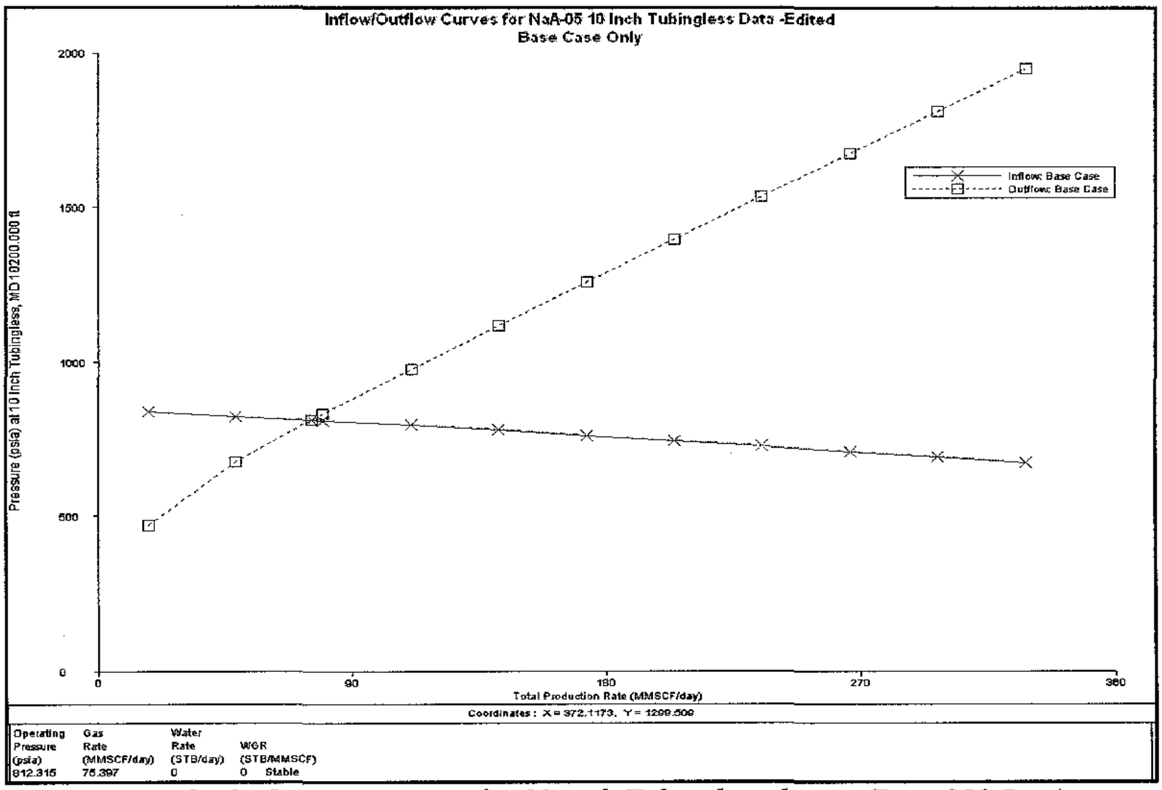
# APPENDIX

| | | 10 Inch Tubingless | | | | | 9-5/8 Inch Completion | | | | | Tapered Completion | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Outlet Pressure (Psia) | Reservoir Pressure (Psia) | Time (years) | $P_{wf}$ (Psia) | $P_{wh}$ (Psia) | Gas Flow Rate (MMscfd) | Cumulative Production Rate (MMscfd) | Time (years) | $P_{wf}$ (Psia) | $P_{wh}$ (Psia) | Gas Flow Rate (MMscfd) | Cumulative Production Rate (MMscfd) | Time (years) | $P_{wf}$ (Psia) | $P_{wh}$ (Psia) | Gas Flow Rate (MMscfd) | Cumulative Production Rate (MMscfd) |
| 120 | 875 | 0.0 | 835.964 | 633.596 | 80.229 | 80.229 | 0.0 | 844.311 | 619.296 | 74.799 | 74.799 | 0.0 | 851.591 | 564.174 | 55.841 | 55.841 |
| 120 | 850 | 2.0 | 812.315 | 620.926 | 75.397 | 155.626 | 2.0 | 820.255 | 607.684 | 70.486 | 145.285 | 2.0 | 827.11 | 555.21 | 53.095 | 108.936 |
| 120 | 825 | 2.2 | 788.699 | 607.906 | 70.568 | 226.194 | 2.2 | 796.23 | 595.725 | 66.236 | 211.521 | 2.2 | 802.654 | 545.961 | 50.357 | 159.293 |
| 120 | 800 | 2.4 | 765.104 | 594.514 | 65.816 | 292.01 | 2.4 | 772.226 | 583.396 | 62.033 | 273.554 | 2.4 | 778.214 | 536.405 | 47.626 | 206.919 |
| 120 | 775 | 2.7 | 741.541 | 580.754 | 61.155 | 353.165 | 2.7 | 748.251 | 570.682 | 57.887 | 331.441 | 2.7 | 753.796 | 526.522 | 44.905 | 251.824 |
| 120 | 750 | 3.0 | 718.017 | 556.591 | 56.594 | 409.759 | 3.0 | 724.313 | 557.57 | 53.805 | 385.246 | 3.0 | 729.41 | 516.292 | 42.199 | 294.023 |
| 120 | 725 | 3.3 | 694.525 | 552.039 | 52.143 | 461.902 | 3.3 | 700.412 | 544.044 | 49.797 | 435.043 | 3.3 | 705.058 | 505.691 | 39.509 | 333.532 |
| 120 | 700 | 3.7 | 671.065 | 537.082 | 47.814 | 509.716 | 3.7 | 676.547 | 530.087 | 45.871 | 480.914 | 3.7 | 680.742 | 494.693 | 36.839 | 370.371 |
| 120 | 675 | 4.3 | 647.656 | 521.726 | 43.62 | 553.336 | 4.3 | 652.73 | 515.692 | 42.04 | 522.954 | 4.3 | 656.471 | 483.275 | 34.192 | 404.563 |
| 120 | 650 | 4.9 | 624.297 | 505.967 | 39.575 | 592.911 | 4.9 | 628.971 | 500.853 | 38.316 | 561.27 | 4.9 | 632.264 | 471.414 | 31.581 | 436.144 |
| 120 | 625 | 5.7 | 600.955 | 489.784 | 35.684 | 628.595 | 5.7 | 605.238 | 485.54 | 34.076 | 595.346 | 5.7 | 608.095 | 459.067 | 29.003 | 465.147 |
| 120 | 600 | 6.8 | 577.624 | 473.177 | 31.96 | 660.555 | 6.8 | 581.528 | 469.745 | 31.222 | 626.568 | 6.8 | 583.966 | 446.203 | 26.467 | 491.614 |
| 120 | 575 | 8.1 | 554.298 | 456.145 | 28.412 | 688.967 | 8.1 | 557.834 | 453.46 | 27.877 | 654.445 | 8.1 | 559.875 | 432.79 | 23.98 | 515.594 |
| 120 | 550 | 9.9 | 530.968 | 438.692 | 25.053 | 714.02 | 9.9 | 534.149 | 436.679 | 24.683 | 679.128 | 9.9 | 535.822 | 418.793 | 21.551 | 537.145 |
| 120 | 525 | 12.4 | 507.621 | 420.822 | 21.891 | 735.911 | 12.4 | 510.652 | 419.402 | 21.652 | 700.78 | 12.4 | 511.799 | 404.18 | 19.19 | 556.335 |
| 120 | 500 | 15.9 | 484.253 | 402.55 | 19.937 | 755.848 | 15.9 | 486.776 | 401.641 | 18.797 | 719.577 | N/A | N/A | N/A | N/A | N/A |
| 120 | 475 | 16.5 | 460.856 | 383.889 | 16.198 | 772.046 | 16.5 | 463.078 | 383.408 | 16.131 | 735.708 | N/A | N/A | N/A | N/A | N/A |
| 120 | 450 | 16.8 | 437.406 | 364.849 | 13.678 | 785.724 | 16.8 | 439.354 | 364.718 | 13.661 | 749.369 | N/A | N/A | N/A | N/A | N/A |

*Appendix 1: Results from Wellflo Simulation for each of completion designs*




*Appendix 2: Operating point for 10 inch Tubingless design ($P_R$ = 850 Psia)*

## WellFlo Nodal Analysis Results

Solution node is "10 Inch Tubingless" at a measured depth of 10200.000 ft

Stability check: on

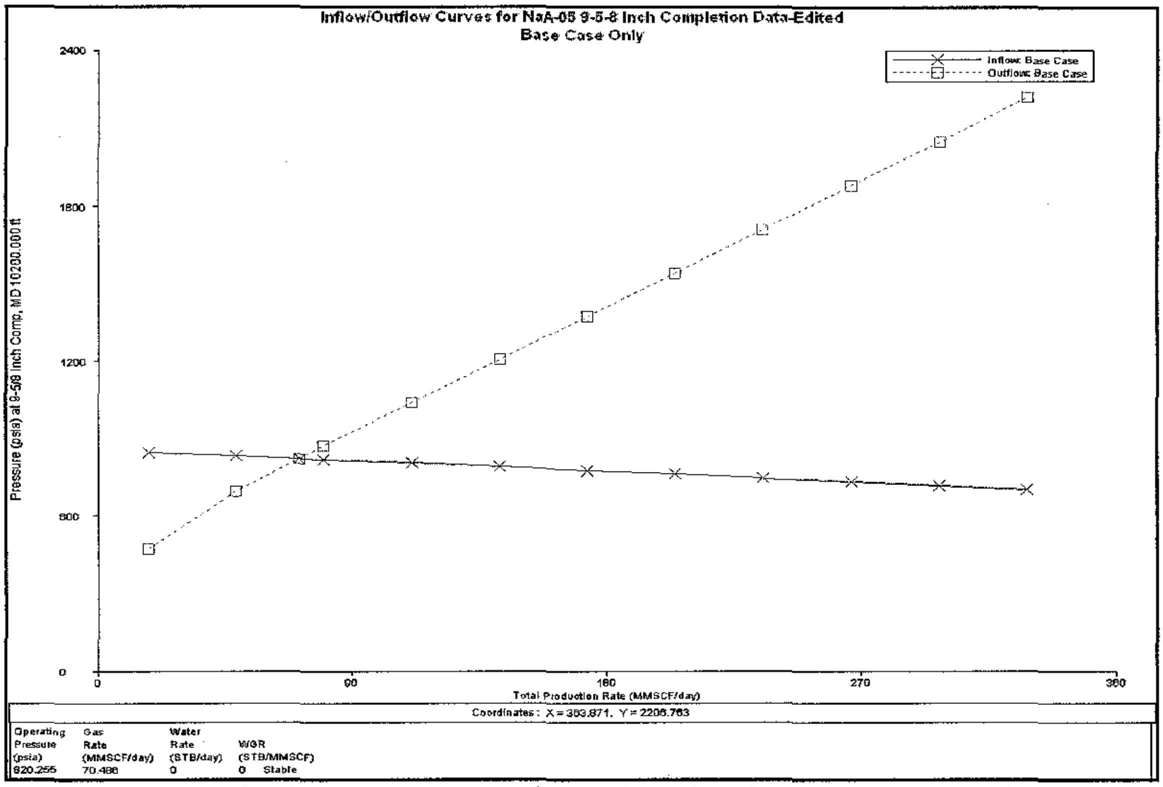
### Case 1

| | | |
|---|---|---|
| Sens 1: | Unused. | |
| Sens 2: | Unused. | |
| Flow Rate | Inflow Pressure | Outflow Pressure |
| 17.244 | 841.523 | 469.985 |
| 48.282 | 826.057 | 673.635 |
| 79.321 | 810.299 | 831.266 |
| 110.359 | 794.236 | 976.248 |
| 141.398 | 777.850 | 1116.619 |
| 172.437 | 761.108 | 1255.261 |
| 203.475 | 743.986 | 1393.392 |
| 234.514 | 726.473 | 1531.585 |
| 265.552 | 708.530 | 1670.097 |
| 296.591 | 690.120 | 1809.069 |
| 327.629 | 671.209 | 1948.548 |
| 75.397 | 812.315 | 812.315 |

The operating point is stable, was determined
by interpolation, and was refined by iteration.

| | |
|---|---|
| Operating Pressure: | 812.315 psia |
| Operating Temperature: | 350.000 degrees F |
| Operating Rate: | 75.397 MMSCF/day |
| K-30 Sand layer flow rate: | 75.397 MMSCF/day gas at 812.315 psia |
| Critical unloading rate: | 12.045 MMSCF/day |

*Appendix 3: 10 inch Tubingless design analysis result ($P_R$ = 850 Psia)*




*Appendix 4: Operating point for 9-5/8 inch Tubing ($P_R$ = 850 Psia)*

## WellFlo Nodal Analysis Results

Solution node is "9-5/8 Inch Comp" at a measured depth of 10200.000 ft

Stability check: on

### Case 1

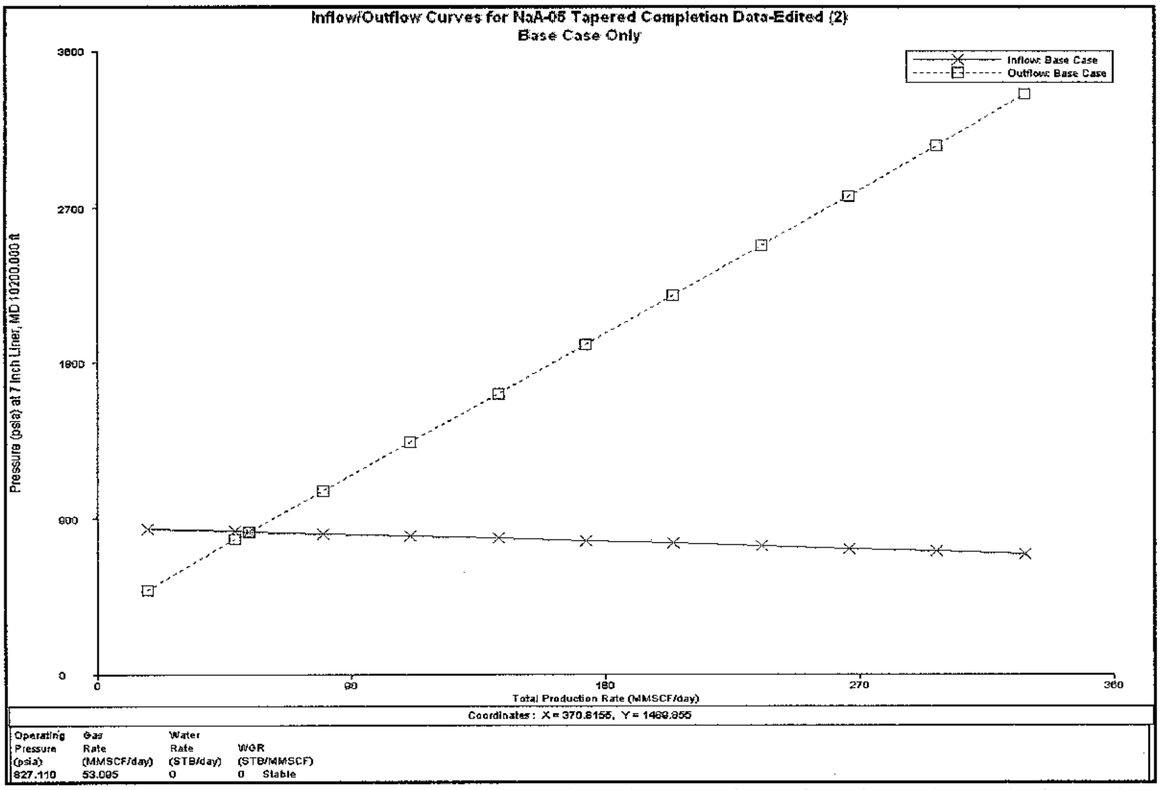
Sens 1: Unused.
Sens 2: Unused.

| Flow Rate | Inflow Pressure | Outflow Pressure |
|---|---|---|
| 17.244 | 842.816 | 473.154 |
| 48.282 | 829.736 | 691.261 |
| 79.321 | 816.457 | 869.558 |
| 110.359 | 802.972 | 1038.825 |
| 141.398 | 789.253 | 1205.708 |
| 172.437 | 775.282 | 1372.285 |
| 203.475 | 761.049 | 1539.293 |
| 234.514 | 746.550 | 1707.016 |
| 265.552 | 731.797 | 1875.530 |
| 296.591 | 716.762 | 2044.867 |
| 327.629 | 701.334 | 2215.017 |
| 70.486 | 820.255 | 820.255 |

The operating point is stable, was determined by interpolation, and was refined by iteration.

Operating Pressure: 820.255 psia
Operating Temperature: 350.000 degrees F
Operating Rate: 70.486 MMSCF/day
K-30 Sand layer flow rate: 70.486 MMSCF/day gas at 820.255 psia
Critical unloading rate: 10.330 MMSCF/day

*Appendix 5: 9-5/8 inch Tubing analysis result ($P_R$ = 850 Psia)*




*Appendix 6: Operating point for Tapered 9-5/8 × 7-5/8 inch Tubing ($P_R$ = 850 Psia)*

## WellFlo Nodal Analysis Results

Solution node is "7 Inch Liner" at a measured depth of 10200.000 ft

Stability check: on

### Case 1

Sens 1: Unused.
Sens 2: Unused.

| Flow Rate | Inflow Pressure | Outflow Pressure |
|---|---|---|
| 17.244 | 842.631 | 491.343 |
| 48.282 | 829.209 | 784.094 |
| 79.321 | 815.581 | 1060.510 |
| 110.359 | 801.738 | 1338.138 |
| 141.398 | 787.643 | 1618.412 |
| 172.437 | 773.286 | 1901.186 |
| 203.475 | 758.643 | 2186.247 |
| 234.514 | 743.710 | 2473.523 |
| 265.552 | 728.497 | 2763.018 |
| 296.591 | 712.977 | 3054.837 |
| 327.629 | 697.126 | 3349.090 |
| 53.095 | 827.110 | 827.110 |

The operating point is stable, was determined by interpolation, and was refined by iteration.

Operating Pressure: 827.110 psia
Operating Temperature: 350.000 degrees F
Operating Rate: 53.095 MMSCF/day
K-30 Sand layer flow rate: 53.095 MMSCF/day gas at 827.110 psia
Critical unloading rate: 20.339 MMSCF/day
Completion P/drop at Operating Rate: 0.578 psia

*Appendix 7: Tapered Tubing design analysis result ($P_R$ = 850 Psia)*