MAJOR PROJECT

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PRODUCTION OPTIMIZATION USING NODAL ANALYSIS

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PRODUCTION OPTIMIZATION USING NODAL ANALYSIS

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(ISO 9001:2000 Certified)

CERTIFICATE

This is to certify that the work contained in this dissertation titled "**Production Optimisation using Nodal Analysis**" has been carried out by **Preeti Godiyal** (R040208029) and **Sandesh Bhardwaj** (R040208034) under my supervision and has not been submitted elsewhere for a degree.

Date 12/04/12

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ABSTRACT

The upstream of the petroleum industry involves itself in the business of oil and gas exploration and production (E & P) activities. While the exploration activities find oil and gas reserves, the production activities performs the important task of delivering oil and gas to the downstream industry (i.e. processing plants, refineries). Thus, Petroleum production can be called as the heart of the Petroleum Industry. The basic aim is to maximize oil and gas production in a cost-effective manner. Familiarization and understanding of oil and gas production systems and fluid properties are essential for overcoming hurdles and achieving this task. The most important parameters that are used to evaluate performance or behavior of petroleum fluids flowing from an upstream point (in reservoir) to a downstream point (at surface) are pressure and flow rate. According to basic fluid flow through reservoir, production rate is a function of flowing pressure at the bottom hole of the well for a specified reservoir pressure and the fluid and reservoir properties. The flowing bottom hole pressure required to lift the fluids up to the surface may be influenced by size of the tubing string, choke installed at down hole or surface and pressure loss along the pipeline. Nodal analysis is the application of systems analysis to the complete well system from the outer boundary of the reservoir to the sand face, across the perforations and completion section to the tubing intake, up the tubing string including any restrictions and down hole safety valves, the surface choke, the flow line and separator. In this project effort is to show how efficiently the bottlenecks in the Petroleum Production Systems can be resolved using nodal analysis and the subsequent improvement in the oil/gas production.

CONTENTS

Chapter I

Introduction

Background

Any production well drilled and completed to move oil and gas from its original location in the reservoir to the stock tank or sales line. Movement or transport of these fluids requires energy to overcome friction losses in the system and delver the fluids to separator . The fluids must travel through the reservoir and the piping system and ultimately into the separator for gas-liquid separation. The production system can be relatively simpler or can include many components in which energy or pressure losses occur. The pressure drop in the total system at any time will be the initial pressure minus the final pressure .This pressure drop is the sum of the pressure drops occurring in all the components of the system. Since the pressure drop through any component varies with producing rate, the producing rate will be controlled by the components selected. The selection and sizing of the individual components is very important, because of the interaction among the components, a change in the pressure drop in one component may change the pressure drop behavior in all the others. This occurs because flowing fluid is compressible. Therefore the pressure drop in a particular component depends not only the now rate through the component, but also on the average pressure that exists in the component. The final design of a production system cannot be separated into reservoir performance and piping system performance and handled independently. The amount of oil and gas flowing into the well from the reservoir depends on the pressure drop in the piping system and the pressure drop in the piping system depends on the amount of fluid flowing through it. Therefore, the entire production system must be analyzed as one unit.

3 types of pressure losses are expected to occur in the system while the fluid moves from the bottom of the tubing to the surface:

1. Frictional losses
2. Gravity losses or head losses
3. Acceleration losses

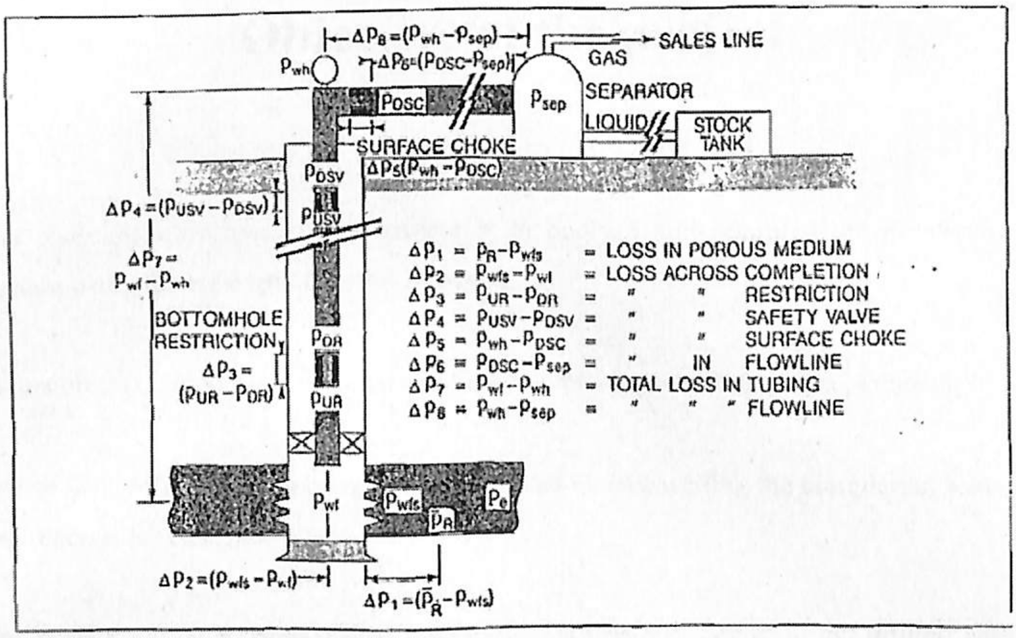


Fig 1. Various pressure drops in a system

The systems analysis approach, often called "Nodal Analysis, "' has been applied for many years to analyze the performance of systems composed of interacting components. Electrical circuits, complex pipeline networks and centrifugal Pumping systems are all analyzed using this method. Its applications to well producing systems was first proposed by Gilbert (1954) and discussed by Nind (1964) and Brown (1978).Nodal Analysis approach is a trademark of Flopetrol Johnston, a division of Schlumberger Technology Corporation, and is protected by U.S. Patent #4,442,710.

Objective of the project

- The foremost objective of this project is to analyze and optimize the Petroleum Production System using the concept of **Nodal Analysis.**

- In this project, emphasis will be on Production Optimization through proper sizing of **Tubing.**

- The project will also focus on understanding and recommending the completion schematic for the well chosen for case study.

- The project will attempt to identify the problems that may occur during drilling and completing the well and also suggestions for their mitigation.

- The project will also identify various stimulation techniques that may be used for the better and efficient flow of well throughout its life.

Scope of the project

The nodal analysis approach may be used to analyze many producing oil and gas well problems and finds several applications . The procedure can be applied to both flowing and artificial lift wells and it can also be applied to the analysis of injection well performance by appropriate modification of the inflow and outflow expressions . A partial list of possible applications include:

- Selecting tubing size
- Selecting flow line size
- Gravel pack design
- Surface choke design
- Subsurface safety valve design
- Analyzing an existing system for abnormal flow restriction
- Artificial lift design
- Well stimulation evaluation
- Determining the effect of compression on gas well performance
- Analyzing effects of perforation density

In the project we have tried to find the optimum size of the tubing .

METHODOLOGY

In order to analyze the application of Nodal Analysis approach in Production Optimization, a detailed study and sound knowledge about the topic was necessary. Book authored by H.Dale Beggs titled "Production Optimization using Nodal Analysis" was the primary source of reference. The case study taken is of BLACKFRIARS FIELD. The case study required for the Project and other concerned data was obtained with the assistance of our Mentor, Mr.Arun S. Chandel, Asst. Professor, UPES.

Initially for determining the optimum tubing size IPR was constructed using Vogel's Inflow Performance Method for the upper sandstone zone(ZONE A) and lower fractured limestone zone(ZONE B) respectively.

VLP construction was then done with assumed THP for zone A and ZONE B respectively using Gilbert charts. Various tubing size were taken into account. The best tubing size will then be chosen according to flow capacity of the two zones.

A schematic along with a diagram for a production well with all the completion jewelery in place will then be made to represent actual completed well. Also problems anticipated while drilling and completing the well associated with the zones available will be identified and measures taken for their mitigation will be decided.

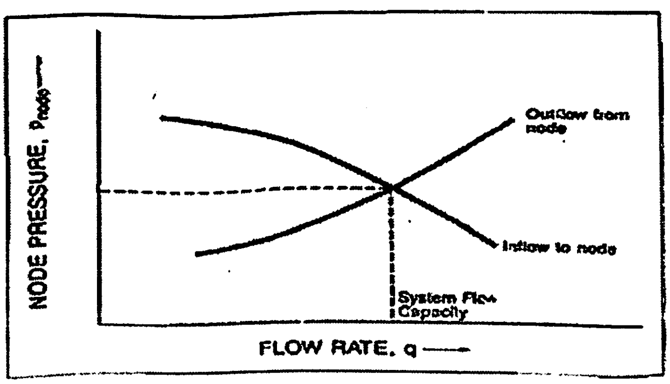
Stimulation strategy for the problems encountered will also be taken into account and recommended accordingly for the purpose of mitigating problems during the life of the well.

Chapter II

LITRATURE REVIEW

Nodal Analysis

Nodal Analysis divides the total well system into two subsystems at a specific location called the nodal point. One subsystem considers the inflow from the reservoir, through possible pressure drop components and to the nodal point. The other subsystem considers the outflow system from some pressure on the surface down to the nodal point. For each subsystem, the pressure at the nodal point is calculated and plotted as two separate, independent pressure-rate curves. The curve from the reservoir to the nodal point is called the inflow Curve, and the curve from the separator to the nodal point is



called the outflow curve

The intersection of the inflow and outflow curves is the predicted operating point where the flow rate and pressure from the two independent curves are equal. Although the nodal point may be located at any point in the system, the most common position is at the mid-perforation depth inside the tubing. With this nodal point, the inflow curve represents the flow from the reservoir through the completions into the tubing, and the outflow curve represents the flow from the node to a surface pressure reference point (e.g., separator); summing pressure drops from the surface to the node at the mid-perforations depth.

The Nodal Analysis method employs single or multiphase flow correlations, as well as correlations developed for the various components of reservoir, well completion, and surface equipment systems to calculate the pressure loss associated with each component in the system. This information then is used to evaluate well performance under a wide variety of conditions that will lead to optimum single well completion and production practices. It follows that nodal analysis is useful for the analysis of the effects of liquid loading on gas wells.

First, Nodal Analysis will be used to analyze the effects of various tubing sizes on the ability of wells to produce reservoir liquids. Second, Nodal Analysis is used to clarify the detrimental effects of excessive surface production tubing pressure. Increased surface pressure adds backpressure on the reservoir at the sand face. The added backpressure reduces gas production and lowers the gas velocity in the tubing that again reduces the efficiency with which the liquids are transported to the surface

The Nodal Concept

Figure 3 are schematics of a simple producing system. This system consists of three phases:

1. Flow through porous medium.

2. Flow through vertical or directional conduit.

3. Flow through horizontal pipe.

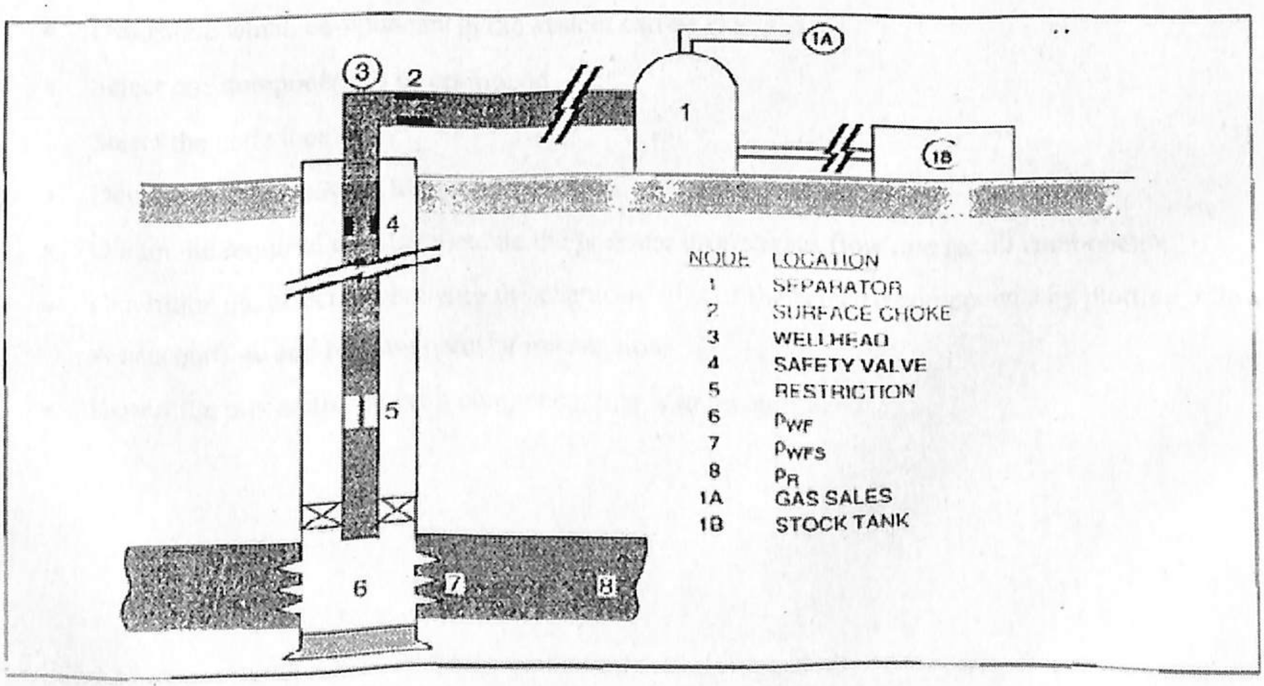


Fig .3

The node is classified as a functional node when a pressure differential exists across it and the pressure or flow rate response can be represented by some mathematical or physical function.

Node 1 represents the separator pressure, which is usually regulated at a constant value. The pressure at node 1A (see fig.3) is usually constant at either gas sales lines pressure or gas compressor suction pressure. The pressure at node 1B is usually constant at 0 psig. Therefore, the separator pressure will be held constant at the higher of the two pressures needed to flow single phase gas from node 1 to node 1A or to flow single phase liquid from node 1 to node 1B. It will be assumed that the separator pressure is constant for any flow rate, and it will be designated as node 1.

Notice that in the system there are two pressures that are not a function of flow rate. They are Pressure at node 8 and PSEP at node 1. For this reason any trial and error solution to the total system problem must be started at node 1 (PSEP), or at node 8 (Pr) or both nodes 1 and 8 if and intermediate node such as 3 or 6 is selected as the solution node. Once the solution node is selected, the pressure drops or gains from the starting point and are added until the solution node is reached.

Procedure for Nodal Analysis

- Determine which components in the system can be changed.
- Select one component to be optimized.
- Select the node location.
- Develop expressions for inflow and outflow
- Obtain the required data to calculate the pressure drop versus flow rate for all components.
- Determine the effect of changing the characteristics of the selected components by plotting inflow versus outflow and reading point of intersection.
- Repeat the procedure for each component that is to be optimized.

Nodal analysis is the application of systems analysis to the complete well system from the outer boundary of the reservoir to the sand face, across the perforations and completion section to the tubing intake, up the tubing string including any restrictions and downhole safety valves, the surface choke, the flow line and separator.

It uses a combination of;

1. Well inflow performance.

2. Downhole multipurpose flow conduit performance (vertical or directional conduit performance).

3. Surface performance (including choke, horizontal or inclined flow performance and separator).

In this section, the performance of either a naturally flowing or artificial lift well will be determined.

The effect of various changes in one component of the system has an over-all effect on the entire system. Typical wells are selected in order to show the effect of various changes, such as;

1. Separator pressure.

2. Flowline size.

3. Surface choke size.

4. Tubing size.

Analysis shows whether or not the particular well is limited in its production rate by the reservoir's ability to give up fluids or by the producing system. The selection of various parameters, such as separator pressure or size of flowline is related to economics. For example, the selection of the separator pressure in a gas lift system is extremely important in determining compressor horse-power. Separator pressures from 40 to 120 psi may have very little effect on the flow rate from a low productivity well (perhaps 10 B/D), but may have a very decisive effect on the flow rate of high productivity wells (perhaps 500 B/D). A complete systems analysis shows the effect of varying the separator pressure on compressor horse power and, hence, the economic feasibility of buying more or less horse power. The various profit indicators such as pay-out, rate of return, net present value; etc., can be used to make the decision.
In other cases, the changing out of the flowline may permit the same separator pressure but reduce the wellhead flowing pressure and, hence, increase production considerably.
It may be that the downhole and horizontal conduits have not been properly sized. Too small a tubing size may retard the production rate as well as too large a tubing size. Also, low flow rates can be inefficient in large tubing sizes and undesirable heading conditions may exist.

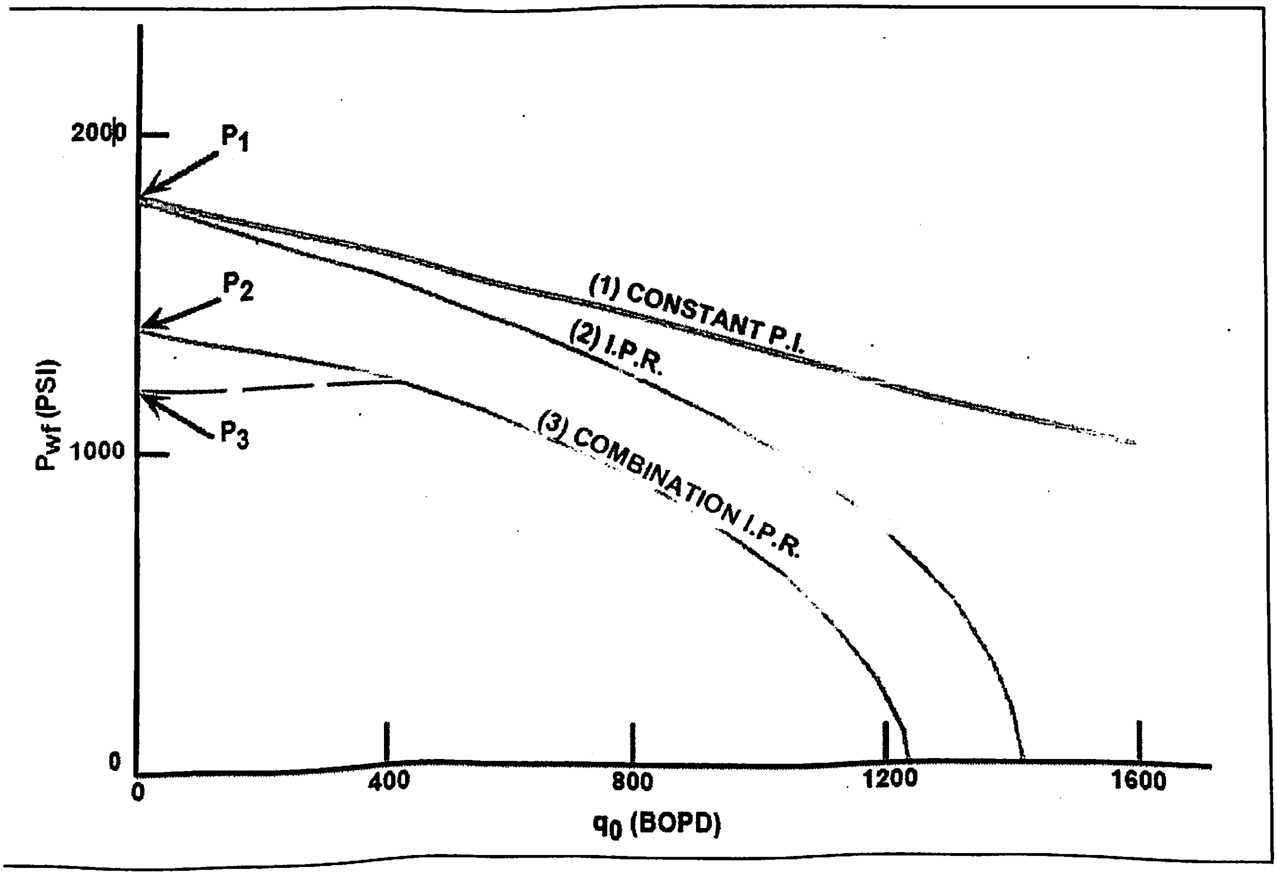
Inflow Performance Curves

In performing a system analysis on a well, it is necessary to have good test data on the well so that the reservoir capability can be predicted.

IPR (Inflow Performance Relationship) curve may beshown as;

1. A straight line (constant PI - Productivity Index denoted "J").
2. A curve which shows that the PI is decreasing with rate (as in gas wells).
3. A combination of 1 and 2.

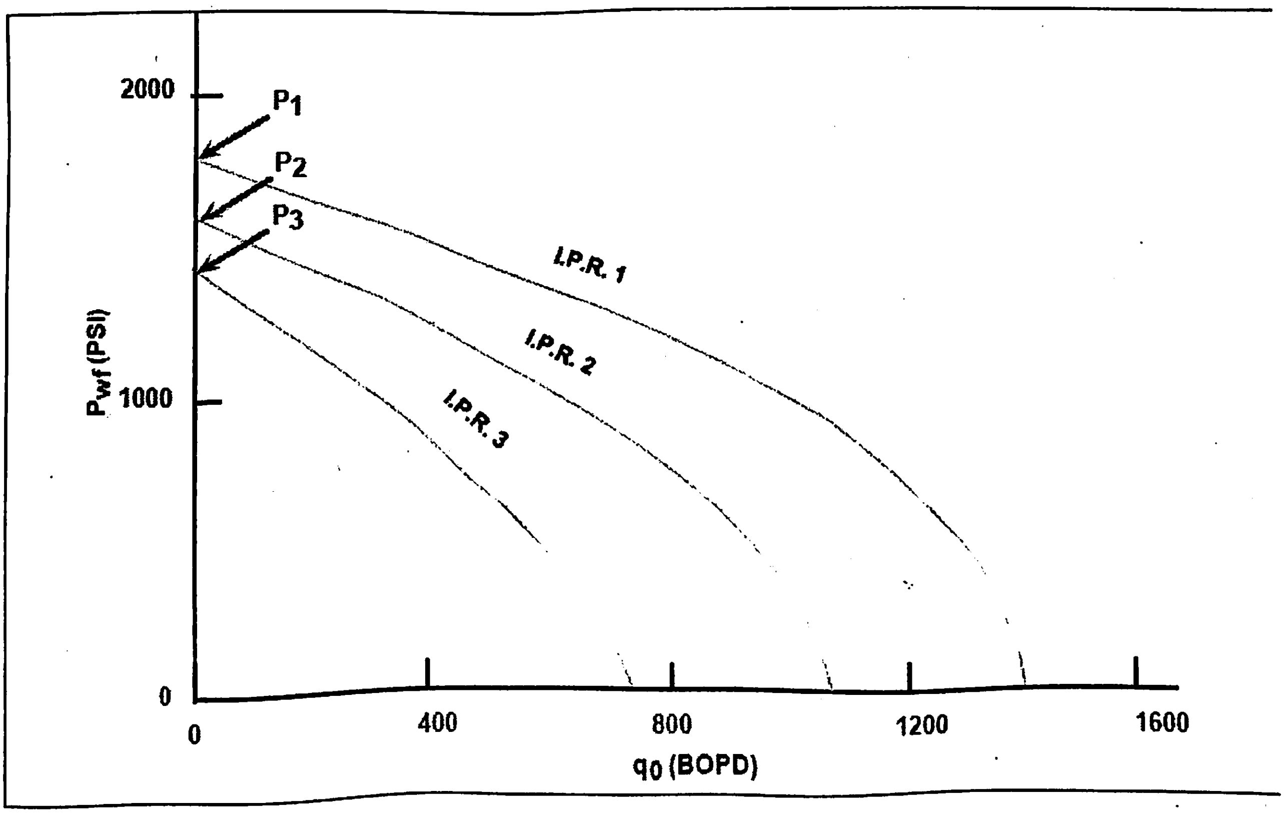
The constant PI normally occurs for single phase liquid flow above the bubble point pressure, and the curved line shows the PI to be decreasing below the bubble point pressure because of two phase flow conditions in the reservoir (liquid plus gas).



Inflow Performance Curves.

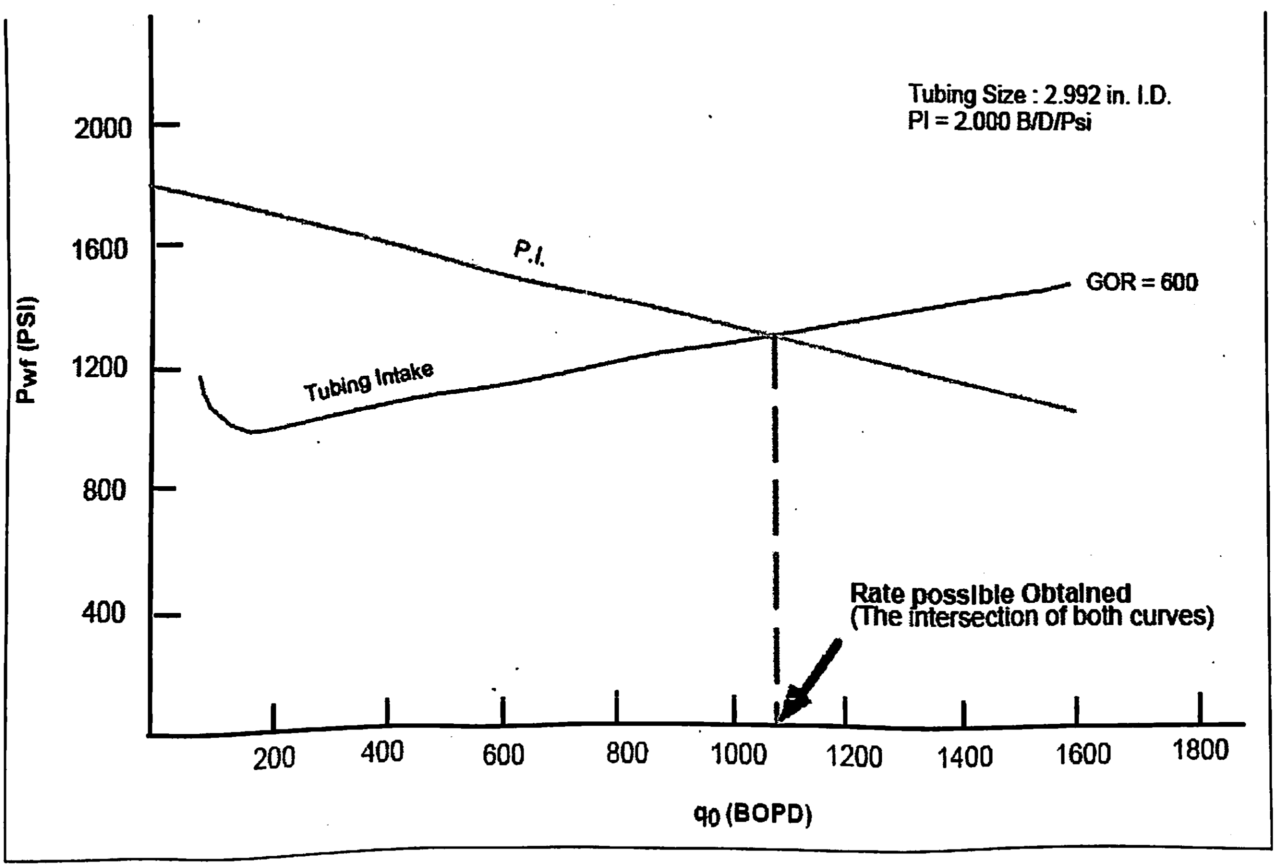
Tubing Intake Curves

Figure shows a tubing intake or vertical multiphase flow curve being added to the inflow performance curve in order to determine the flow rate. If the simplest case of a constant wellhead pressure is assumed, then this curve is easily constructed by assuming flow rates and determining the corresponding flowing bottomhole intake pressure for a set tubing size, GOR, wellhead pressure, depth and fluid properties. Any number of vertical multiphase flow correlations may be used with the most popular being those of Hagedorn and Brown5, Orkiszewski6, Duns and Ros7 and Beggs and Brill8. Modern software allow these individual curves to be generated directly with the computer as opposed to referring to the thick volumes of pre-generated curves



Future Inflow Performance Curves.

The following figure shows the concept of intersection of Tubing Intake Curves with IPR



Tubing Intake Curve in Combination with IPR Curve.

Chapter III

Equations and methods used

Inflow performance relationship (IPR)

The relationship between pressure drawdown and flow rate has been expressed in the form of a productivity index PI or J.

Where $J= q/ p_e-p_{wf}$

Where P_e= reservoir pressure

P_{wf}= bottom hole flowing pressure

And q = flow rate (bopd)

J= productivity index

As shown below the IPR of the well can be shown as a straight line.

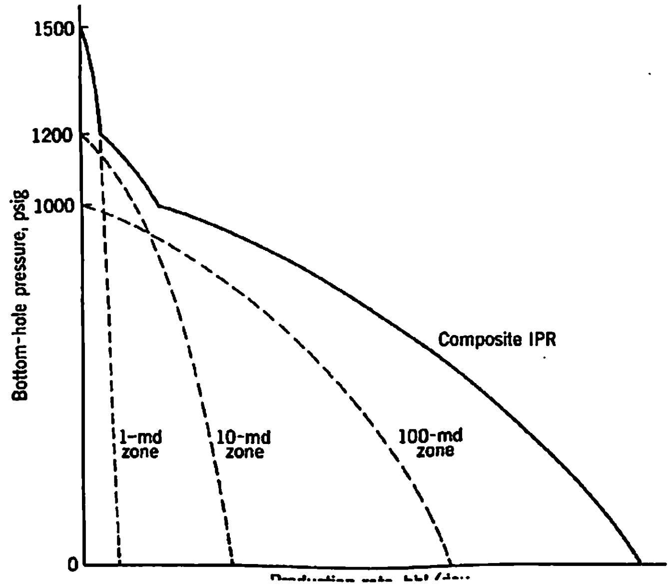
A curve which shows that PI decreases with rate.

In single phase flow this is a straight line but when gas is moving in the reservoir, at a pressure below the bubble point, this in not a linear relationship.

Factors influencing the shape of the IPR

1. **Stratified formation**

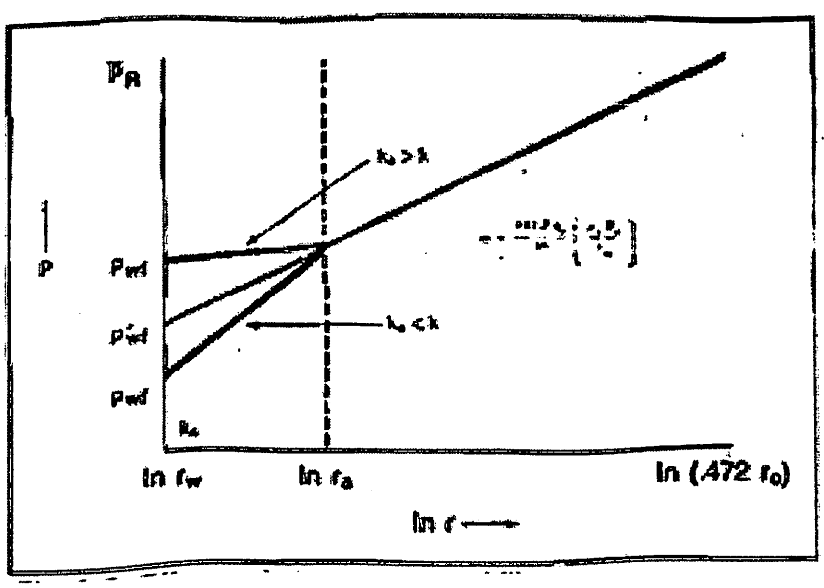
When zones of varying kh are opened in a well, the one with the highest kh well contribute more to the production of the well, then the lower kh zones will contribute, thus the average reservoir pressure of the high kh zones drops faster than the other zones in the well. This causes the zones to start flowing at different flowing bottom hole pressures. At the lower rates or higher flowing pressures it is the zone with the lowest kh that have the highest average pressure so that it produces first and then as the flowing pressure drops below the average pressure of the other zones that start to contribute to the flow. The PI of the well improves as more of the zones contribute, so the PI improves with the lowering of the flowing



pressure.

2. **Effect of skin**

The permeability of the formation near the well bore is altered during the drilling and completion of the well, operations that are performed with the well pressure overbalancing the formation pressure . flux of solids and fluids from the well bore tends to damage permeability near the wellbore. The permeability is altered again by cleanup and simulation treatments meant to remove to remove formation damage or increase the productivity of the well. Other deviations from the ideal well are caused by flow restrictions in the formation and convergence to the perforated interval, which is often only a fraction of the net pay zone .



Effect of altered permeability near the wellbore

Pressure drop associated with these near well bore phenomena is termed a skin and is generally defined as a dimensionless skin factor , S.

$S= \Delta Pskin/(q_s uB/2\pi kh)$

$\Delta P_{wf(actual)}= \Delta P_{wf(ideal)}+\Delta P_{skin}$

The actual drawdown across the reservoir when a skin exists ΔP_{actual} is given by the equation above.

3. **A decrease in k_0 as the gas saturation increases.**
4. **An increase in oil viscosity as pressure decreases and gas is evolved**
5. **Shrinkage of the oil as gas is evolved.**
6. **Formation damage or stimulation around the wellbore**
7. **Increase in turbulence as Q_0 increases.**

Methods for generating IPR curve for a well

1. **Darcy's method for single phase flow**

When the bottom-hole pressure is higher than the bubble-point pressure, single-phase liquid flow results, since all of the gas dissolves in the oil. The production can be calculated using Darcy's
equation from a vertical well with closed outer boundary (Brown, 1984).
where:

$$PI = \frac{0.007082\, koh}{uo\, BO\, (In\frac{re}{rw} - 0.75 + S + a'q)}$$

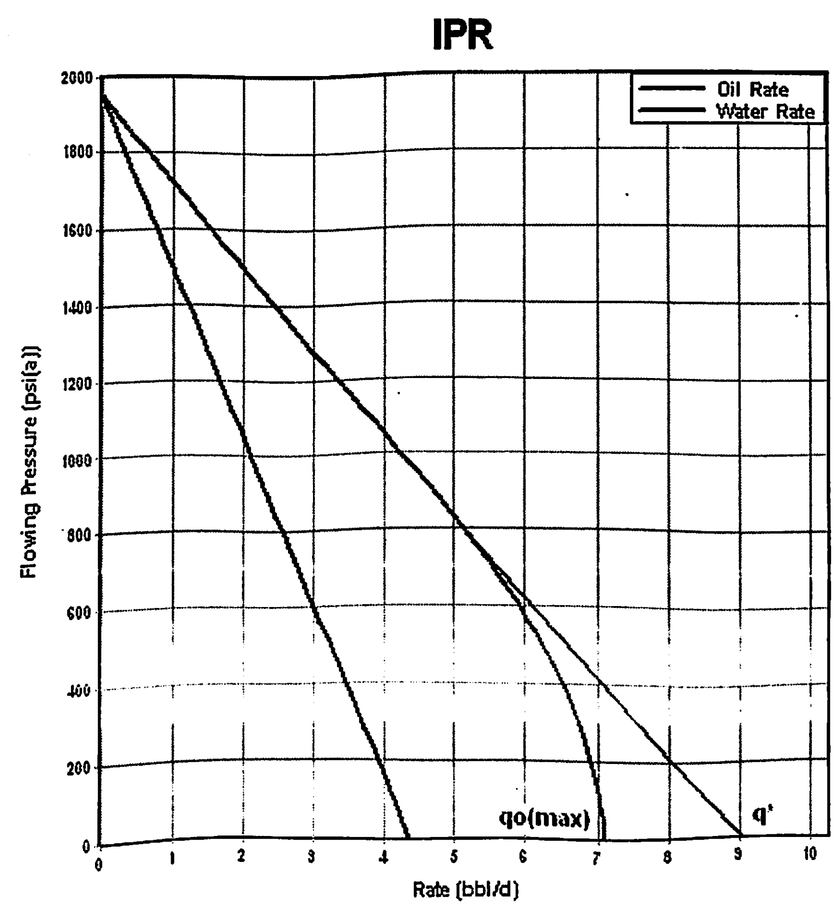
PI= productivity index stb/d/psi
Ko=effective permeability (md)
h=effective feet of oil pay (ft)
pr=average reservoir pressure (psia)
pwf= wellbore sandface flowing pressure at center of perforations (psia)
q=oil flow rate (stb/d)
re=radius of drainage (ft)
rw=radius of wellbore (ft)
S=total skin

low flow rates)
u = viscosity (cp) at average pressure of (Pr + Pwf)/2
Bo = formation volume factor at average pressure

2. Vogel's method

gave the following general equation to account for two-phase flow in the reservoir (saturation effects):

He arrived at this equation from a computer solution to several solution-gas drive reservoirs and for different fluid properties. His solution has been found to be very good and is widely phase flow exists (liquid and gas). It appears to



3. **Fetkovich s E uation**

-pressure equation,

which takes the form of the following:

Qg=

where:

Q

Pr = average reservoir pressure, psi
Pwf = bottom-hole pressure, psi
c = coefficient from well data
n = exponent obtained from well tests

on the well testing data, which may not be practical from an economic viewpoint. Economic practicality is hampered by the fact that the well is probably already in the loaded condition

4. **Standings method (modification of vogel's method)**

for either damage or

Standing proposed simulation around the wellbore. The degree of permeability alteration can be expressed in terms of a Productivity or

FE Ideal drawdown Actual Drawdown

FE

FE $\frac{Pr-Pwf-\Delta Pskin}{Pr-Pwf}$

Using the previous definition of flow efficiency the Vogel's equation becomes:

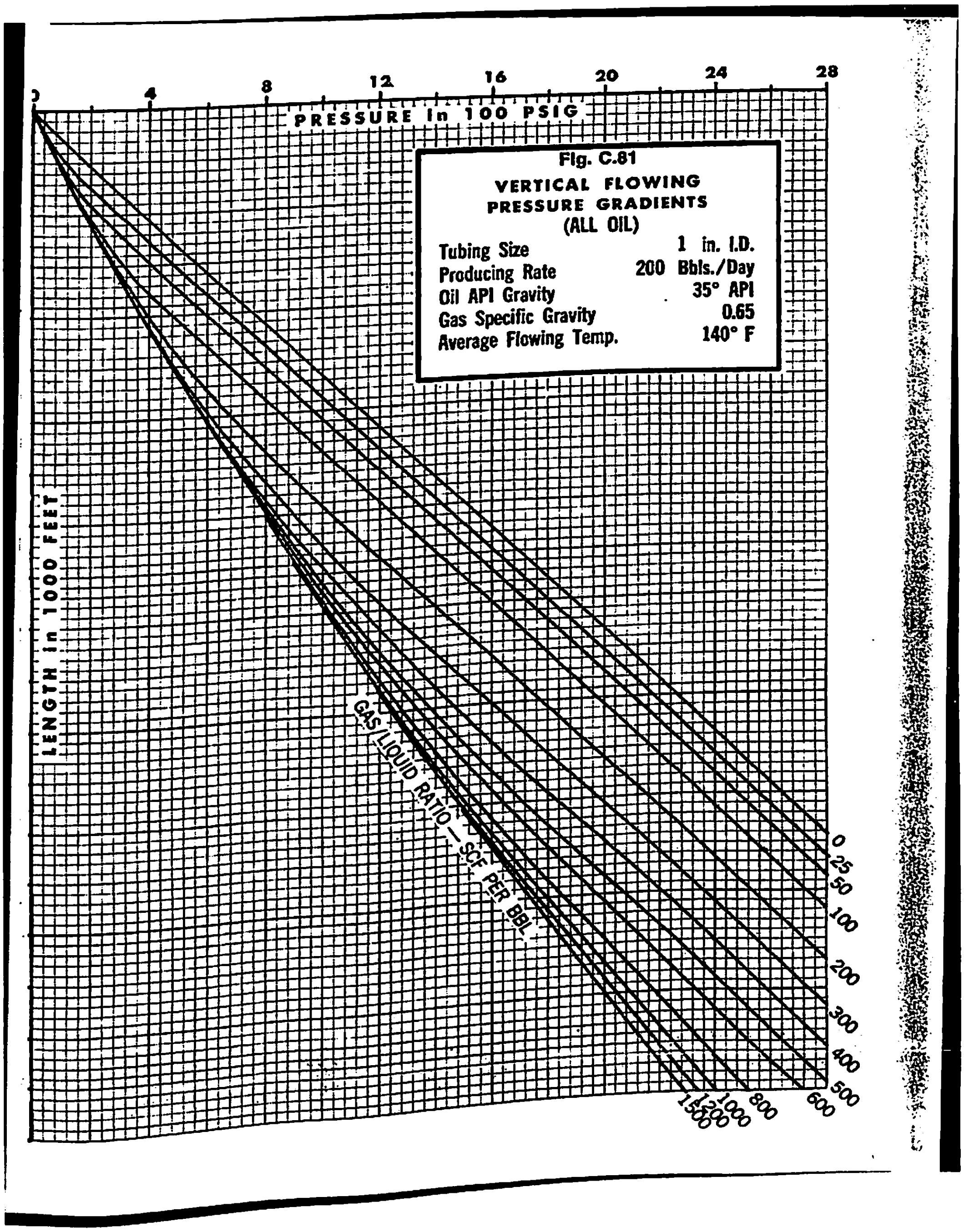
o max(FE=1) 1 0.2 p'wf p 0.8 p'wf p)

Where Pwf' can be calculated from the above equation in terms of flow efficiency or FE. This method involves the modification of Vogel's method as damage and simulation effects are tken into account by using the flow efficiency term in the Vogel's equation.

In our project Vogel's e uation has been used to generate the IPR for pressures below bubble point.

Vertical lift performance :Gilbert

Gilbert family of curves (one of them is shown below)use GLR as a parameter , and there is one family for each tubing size and liquid rate. In referring to these figures , note that pressures are given in psi, depths in thousands of feet , production rate in bbl/ day , GLRs in mcf/bbl, and tubing sizes in inches. It will also be noted that two depth scales are shown on each; the graphs covers the cases of 1.66in, 1.9in, 2.375in, 2.875in and 3.5 in tubing; gross production rates of 50, 100,200,400 and 600 bpd; GLRs of upto 7 mcf/bbl (the actual values varies with the tubing size and production rates).


0
4
8
12
16
20
24
28
PRESSURE in 100 PSIG
Fig. C.81
VERTICAL FLOWING
PRESSURE GRADIENTS
(ALL OIL)
Tubing Size 1 in. I.D.
Producing Rate 200 Bbls./Day
Oil API Gravity 35° API
Gas Specific Gravity 0.65
Average Flowing Temp. 140° F
LENGTH in 1000 FEET
GAS/LIQUID RATIO — SCF PER BBL.
0
25
50
100
200
300
400
500
600
800
1000
1200
1500

Flow Regimes inside a tubing

As the oil travels up the tubing different types of flow can occur as the gas is liberated from the liquid phase.

If the well is producing above the bubble point pressure the flow is single phase but as it rises up the tubing the pressure will drop below this pressure and the multiphase regimes will start to form.

Bubble Flow

The gas starts to come out of solution and form in the liquid medium in an even dispersion.

Slug or Plug Flow

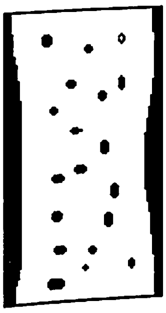
As the fluid moves upward the gas bubbles move faster than the liquid, because of the buoyancy effect, and collect in large bubbles. These bubbles grow to a size where extend across the diameter of the tubing separating slugs of liquid containing the smaller bubbles

Churn Flow

With increasing gas velocity, the larger bubbles become unstable and collapse, resulting in a highly turbulent flow pattern. Churn flow is characterized by oscillatory, up and down motions of the liquid.

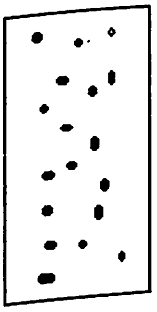
Annular Flow

As the pressure is lowered these large pockets of case break through the slugs and form a continuos phase in the center of the tubing carrying droplets of the liquid with a film of oil flowing along the walls of the tubing.



Mist Flow

Eventually the gas volume is so large that the film of liquid on the wall of the tubing disappears and the only liquid moving is the droplets or mist in the gas phase.



Single Phase Flow

Single-phase liquid flow exists in.an oil well only when the wellhead pressure is. above the bubble-point pressure of the oil, which is usually not a reality. However, it is. convenient to start from single-phase liquid for establishing the concept of fluid flow in oil wells where multiphase flow usually dominates. Consider a fluid flowing from point 1 to point 2 in a tubing string of .length L and height Δz (Fig.10). The first law of thermodynamics yields the following equation for pressure drop:

$$\Delta P = P_1 - P_2 = \frac{g}{g_c}\rho\Delta z + \frac{\rho}{2g_c}\Delta u^2 + \frac{2f_F\rho u^2 L}{g_c D} \quad (14)$$

Where,

ΔP = pressure drop, lbf/ft2

P1 = pressure at point 1, lbf/ft2

P2 = pressure at point 2, lbf/ft2

g = gravitational acceleration, 32.17 ft/s2

gc = unit conversion factor, 32:17 lbm-ft/lbf –s2

ρ = fluid density lbm/ft3

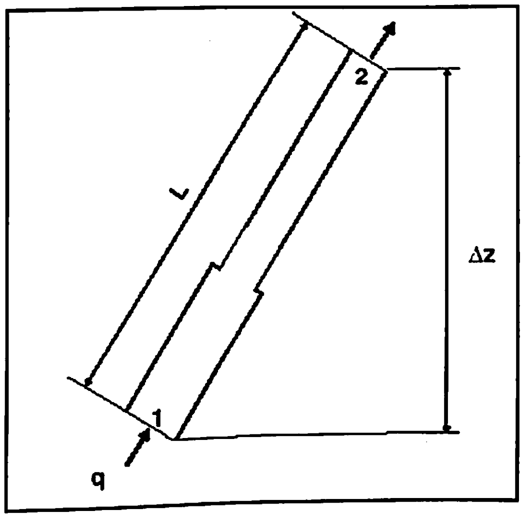
Δz = elevation increase, ft

u = fluid velocity, ft/s

fF = Fanning friction factor

L = tubing length, ft

D = tubing inner diameter, ft



Flow along a tubing string

The Fanning friction factor (fF) can be evaluated based on Reynolds number and relative roughness. Reynolds number is. defined as the ratio of inertial force to viscous force. The Reynolds number is expressed in consistent units as

$$N_{Re} = \frac{Du\rho}{\mu} \qquad (15)$$

For laminar flow where NRe < 2,000, the Fanning friction factor is inversely proportional to the Reynolds number, or

$$f_F = \frac{16}{N_{Re}} \qquad (16)$$

For turbulent flow where NRe > 2,100, the Fanning friction factor can be estimated using empirical correlations.

$$\frac{1}{\sqrt{f_F}} = -4 \times \log\left\{\frac{\varepsilon}{3.7065} - \frac{5.0452}{N_{Re}} \log\left[\frac{\varepsilon^{1.1098}}{2.8257} + \left(\frac{7.149}{N_{Re}}\right)^{0.8981}\right]\right\} \tag{17}$$

Where,

The relative roughness is defined as ε = δ/d, and δ is the absolute roughness of pipe wall.

3.3 Single-Phase Gas Flow

The first law of thermodynamics (conservation of energy) governs gas flow in tubing. The effect of kinetic energy change is .negligible because the variation in tubing diameter

is .insignificant in most of the gas wells. With no shaft work device installed along the tubing string, the first law of thermodynamics yields the following mechanical balance

Equation:

$$\frac{dP}{\rho} + \frac{g}{g_c} dZ + \frac{f_M v^2 dL}{2 g_c D_i} = 0 \tag{18}$$

Because

$$dZ = \cos\theta dL, \ \rho = \frac{29\gamma_g P}{ZRT}, \ \text{and} \ v = \frac{4 q_{sc} z P_{sc} T}{\pi D_i^2 T_{sc} P} \tag{19}$$

Can be rewritten as

$$\frac{zRT}{29\gamma_g} \frac{dP}{P} + \left\{\frac{g}{g_c} \cos\theta + \frac{8 f_M Q_{sc}^2 P_{sc}^2}{\pi^2 g_c D_i^5 T_{sc}^2} \left[\frac{zT}{P}\right]^2\right\} dL = 0, \tag{20}$$

Which is an ordinary differential equation governing gas flow in tubing. Although the temperature T can be approximately expressed as a linear function of length L through geothermal gradient, the compressibility factor z is. a function of pressure P and temperature T. This makes it difficult to solve the equation analytically. Fortunately, the pressure P at length L is. not a strong function of temperature and compressibility factor. Approximate solutions to Eq. (20) have been sought and used in the natural gas industry.

Multiphase Flow in Oil Wells

In addition to oil, almost all oil wells produce a certain amount of water, gas, and sometimes sand. These wells are called multiphase-oil wells. The TPR equation for single. phase flow is. not valid for multiphase oil wells. To analyze TPR of multiphase oil wells rigorously, a multiphase flow model is required.

Flow Regimes

As shown in least four flow regimes have been identified in gas-liquid two-phase flow. They are:-

- Bubble Flow
- Slug Flow
- Churn Flow
- Annular Flow

These flow regimes occur as a progression with increasing gas flow rate for a given liquid flow rate. In bubble flow, gas phase is.dispersed in the form of small bubbles in a continuous liquid phase. In slug flow, gas bubbles coalesce into larger bubbles that eventually fill the entire pipe cross-section. Between the large bubbles are slugs of liquid that contain smaller bubbles of entrained gas. In churn flow, the larger gas bubbles become unstable and collapse, resulting in. a highly turbulent flow pattern with both phases dispersed. In annular flow, gas becomes the continuous phase, with liquid flowing in an annulus, coating the surface of the pipe and with droplets entrained in the gas phase.

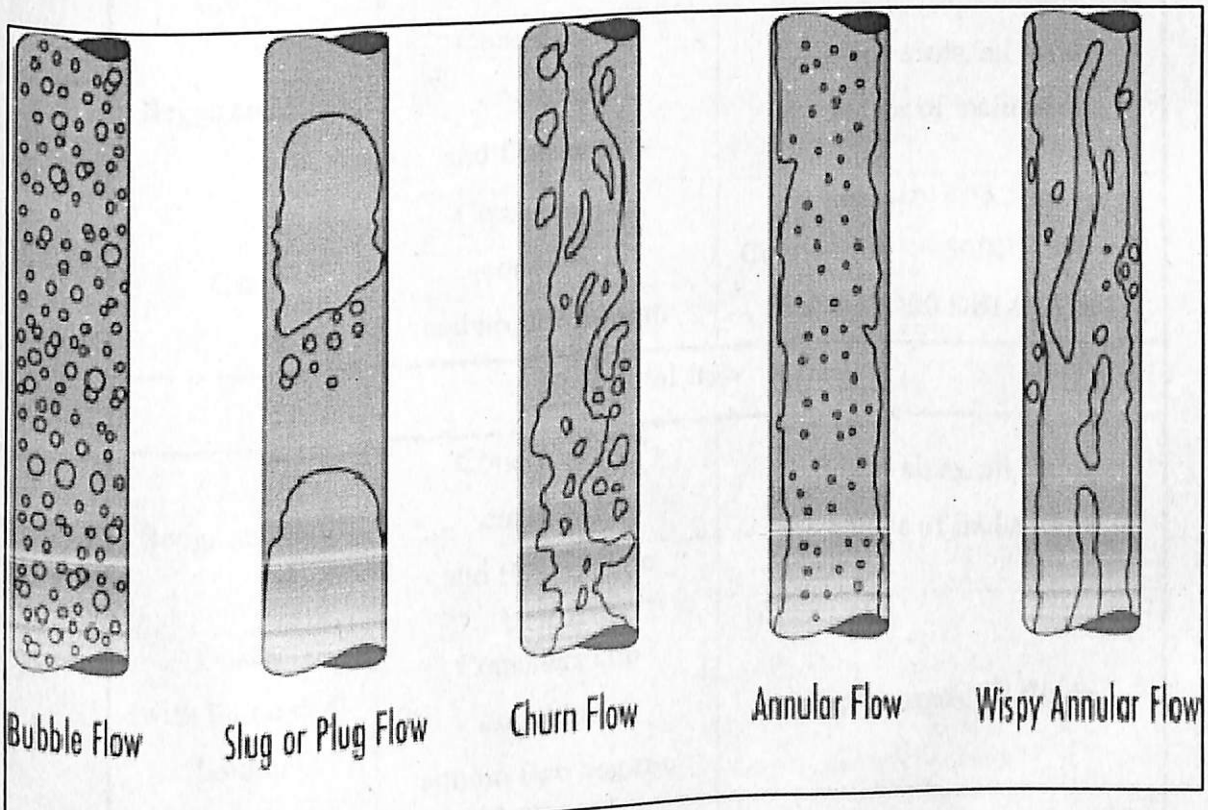


Fig .13 Flow Regimes

Well Flow Correlations

Correlation	Considerations of slip conditions and flow regime	Recommended ranges
Vertical flow		
Hagedorn and Brown	Considers slip conditions and no flow regime	All pipe sizes, all fluids
Beggs and Brill	Considers slip conditions and flow regime	All pipe sizes, all fluids All angles of inclinations
Gray	Considers slip conditions and no flow regime	Pipe size <=3.5 in. Condensate <= 50BBL/MMscf Water <=350 BBL/MMscf
Horizontal flow		
Beggs and Brill	Considers slip conditions and flow regime	All pipe sizes, all fluids All angles of inclinations
Dukler (with Eaton et al. holdup correlation)	Considers slip conditions and no flow regime	All pipe sizes, all fluids
Inclined flow		
Beggs and Brill	Considers slip conditions and flow regime	All pipe sizes, all fluids All angles of inclinations

Beggs and Brill Correlation is been used in this project to determine the flow regime in the tubing and the flowline.

<u>**Beggs and Brill Correlation**</u>

For multiphase flow, many of the published correlations are applicable for "vertical flow" only, while others apply for "horizontal flow" only. Few correlations apply to the whole spectrum of flow situations .that may be encountered in oil and gas operations, namely uphill, downhill, horizontal, inclined and vertical flow. The Beggs and Brill (1973) correlation, is one of the few published correlations capable of handling all these flow directions.

3.6.2 Flow Pattern Map

The Beggs and Brill correlation helps in determining the flow pattern. Since the original flow pattern map was created, it has been modified. This modified flow pattern map is .used for the calculations. The transition lines for the modified correlation are defined as follows:

$$L_1^* = 316\, C_L^{0.302}$$
$$L_2^* = 0.0009252\, C_L^{-2.4684}$$
$$L_3^* = 0.1\, C_L^{-1.4516}$$
$$L_4^* = 0.5\, C_L^{-6.738}$$

The flow type can then be readily determined either from a representative flow pattern map or according to the following conditions. Where,

$$Fr_m = \frac{V_m^2}{gD}$$

Segregated flow

If:-

$$C_L < 0.01 \quad \text{and} \quad Fr_m < L_1^*$$

Or

$$C_L \geq 0.01 \quad \text{and} \quad Fr_m < L_2^*$$

Intermittent flow

If:-

$$0.01 \le C_L < 0.4 \quad \text{and} \quad L_3^* < Fr_m \le L_1^*$$

Or

$$C_L \ge 0.4 \quad \text{and} \quad L_3^* < Fr_m \le L_4^*$$

Distributed flow

If

$$C_L < 0.4 \quad \text{and} \quad Fr_m \ge L_4^*$$

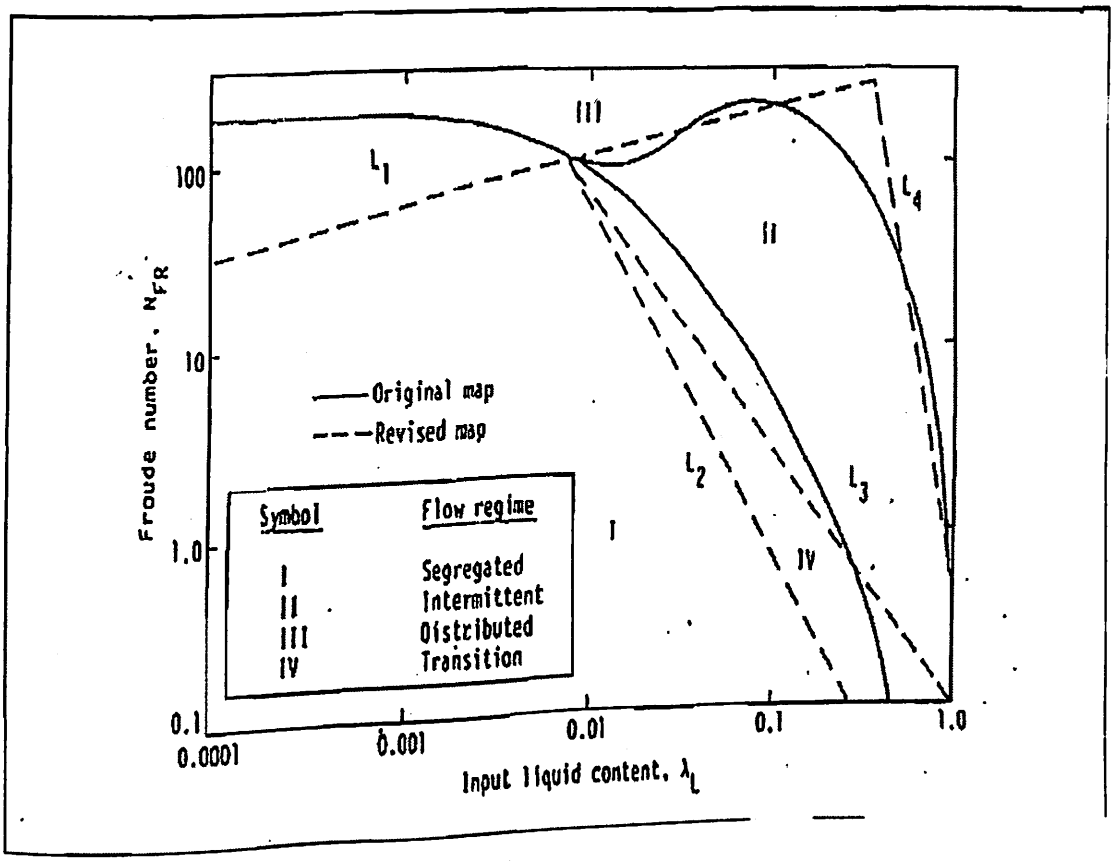
Or

$$C_L \ge 0.4 \quad \text{and} \quad Fr_m > L_4^*$$

Transition flow

If and

$$L_2^* < Fr_m < L_3^*$$



Beggs and Brills flow regime map

CASE STUDY

BLACKFRIARS FIELD DEVELOPMENT

Blackfriars field is located offshore in approximately 250ft of water. Initial exploration and appraisal drilling confirmed the presence of two oil reservoirs with the following characteristics:

ZONE A: UPPER ZONE

Depth Interval	Depth 7125ft - 7189ft TVDSS
Lithology	Partially consolidated sandstone, fine grained, 500mD but with 7% mixed layer sensitive clays
Oil type	30° API gravity oil
GOR	700SCF/BBl
Reservoir PI	8 stb/day/psi
Reservoir pressure	3000psi at 7125ft

ZONE B: LOWER ZONE

Depth Interval	7411ft - 7483ft TVDSS
Lithology	Massively fractured limestone reservoir [Matrix Permeability = 0.5mD]
Oil Type	35° API
GOR	420SCF/Bbl
Reservoir PI	10stb/day/psi
Reservoir pressure	3860psi @ 7411ft

Between the upper and lower zones, there are a series of mud/siltstones sequences with a shale layer on top of the lower zone as shown in FigQ1. A strong aquifer underlies the lower zone.

Assume the following:

1. 9-5/8″ Casing set at 7050ft
2. Below the casing wells are planned to be drilled as **vertical wells**
3. Tubing sizes available to choose from are: 3-1/2″ , 4″ and 4-1/2″ ID
4. Bit sizes available: 8-1/2″; 6″

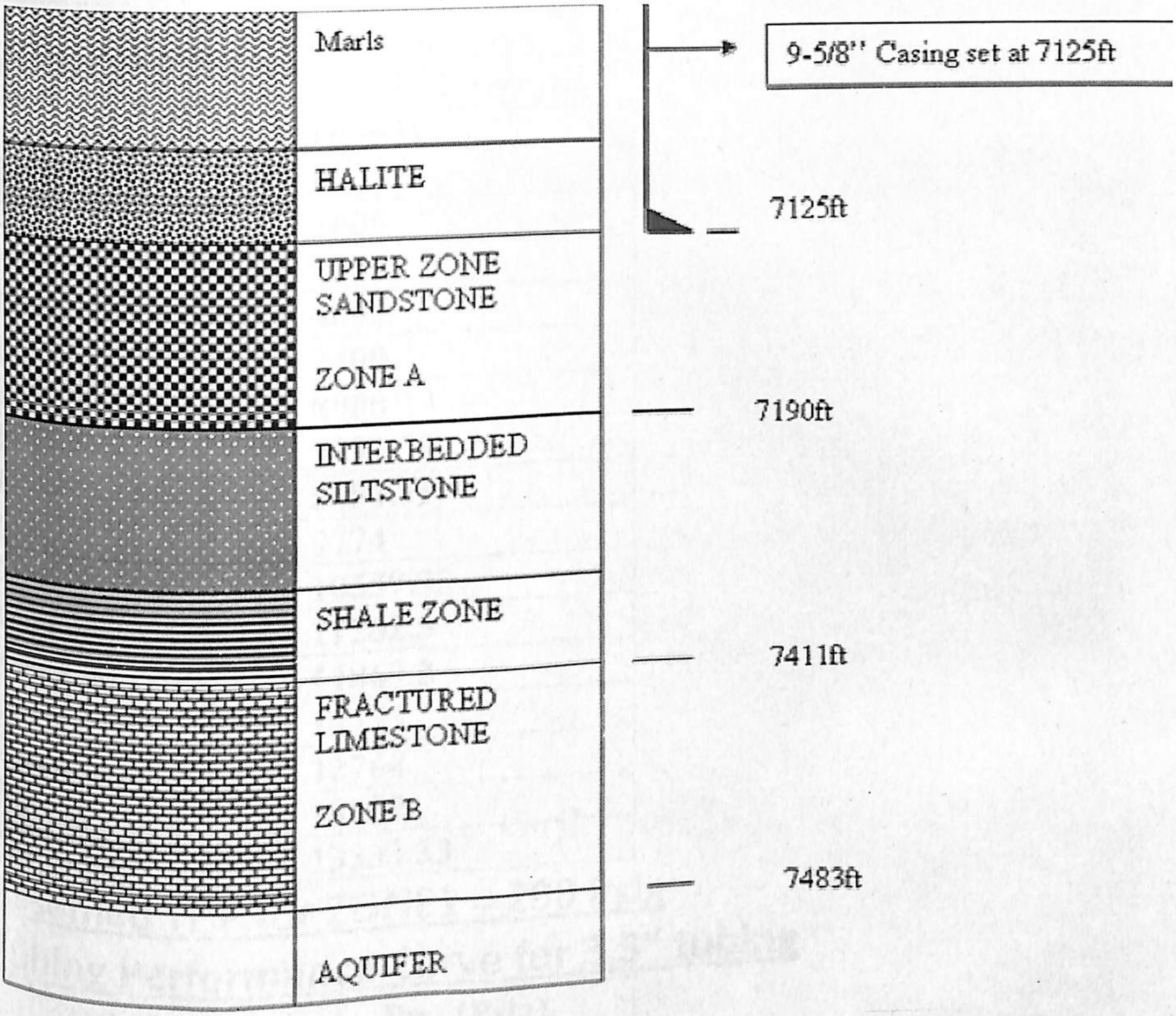
A. Discuss and make recommendations on the following:

1. Identify and review your concerns plus the anticipated problems with respect to drilling and completing the wells
2. Your bottom hole completion strategy. Justify your strategy
3. Your Completion string design for the above scenario limited to completion jewels type, functions, sizes, depth, vendor and economic risk assessment required for AFE[Authorization for Expenditure]
4. Provide a detailed schematic diagram of your completion design showing components and depths.

HINT: It is important you plot the IPR & VLP curves for nodal analysis. Source the appropriate Gilbert curves [Pressure profile curves based on your stated assumed Tubing Head Pressure]. **CLEARLY STATE ALL ASSUMPTIONS MADE and Justify.**

B. In order to boost productivity it is desired to stimulate both the upper and lower zones, briefly discuss the appropriate stimulation technique you would recommend for the reservoirs.

Fig Q1: LITHOLOGY COLUMN



SOLUTION

ZONE 1

IPR for ZONE 1

Pwf(Psig)	Q(bbls)
3000	0
2800	1600
2600	3200
2400	4800
2200	6400
2000	8000
1800	7893.33
1600	8881.71
1400	9774
1200	10559.33
1000	11262.5
800	11869.2
600	12373
400	12768
200	13108
0	13333.33

Assumed THP for ZONE1 = 200 Psig

Tubing Performance Curve for 3.5” tubing

Q(bbls)	Pwf (Psig)
50	1866
100	1566
200	1500
400	1416
600	1433
970	1484
2970	1722
4050	1858
5030	1971
6010	2096
7990	2334

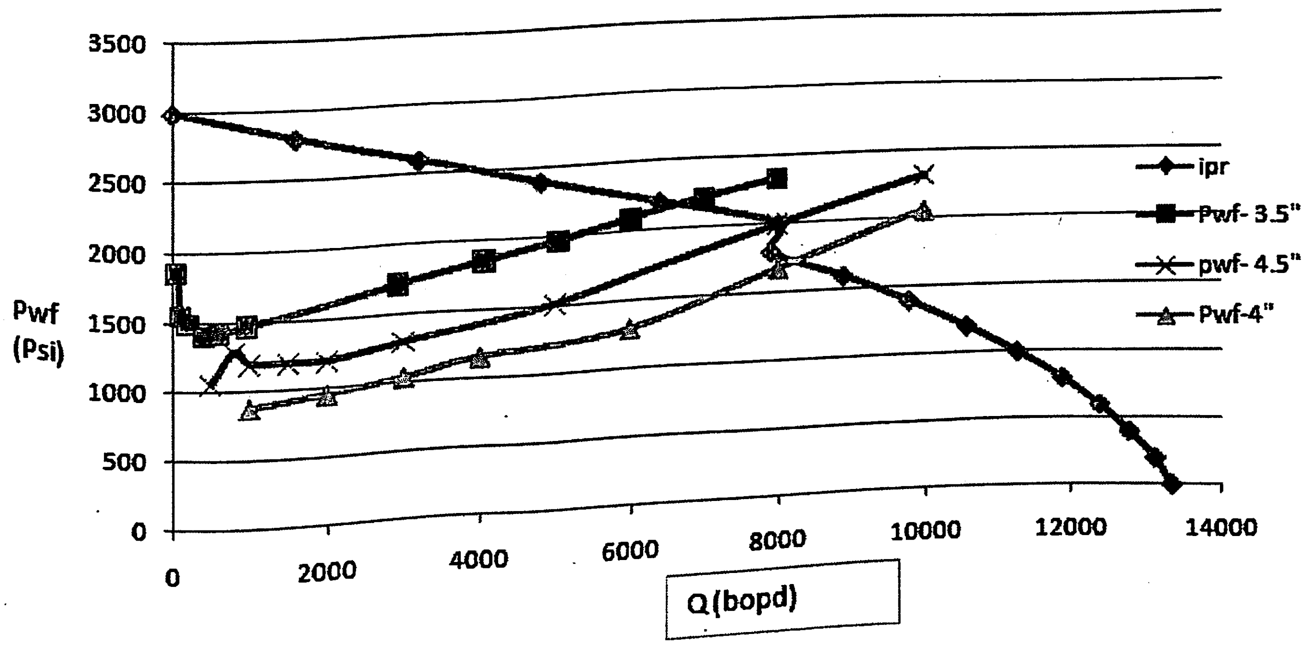
Tubing Performance Curve for 4” tubing

Q(bbls)	Pwf(Psig)
1000	880
2000	960
3000	1040
4000	1160
6000	1300
8000	1680
10000	2000

Tubing Performance Curve for 4.5” tubing

Q(bbls)	Pwf(Psig)
500	1060
800	1290
1000	1200
1500	1200
2000	1200
3000	1300
5000	1520
8000	2000
10000	2320

VLP Curve for ZONE 1



ZONE 2

IPR for ZONE 2

Pwf	Q
3860	0
3758	1000
3655	2000
3439	4000
3211	6000
2968	8000
2706	10000
2421	12000
2105	14000
1744	16000
1313	18000
0	21444

Assumed THP for ZONE 2 = 400 Psig

Tubing Performance Curve for 3.5" tubing

Q	Pwf
1000	2401
3000	3170
5000	3994

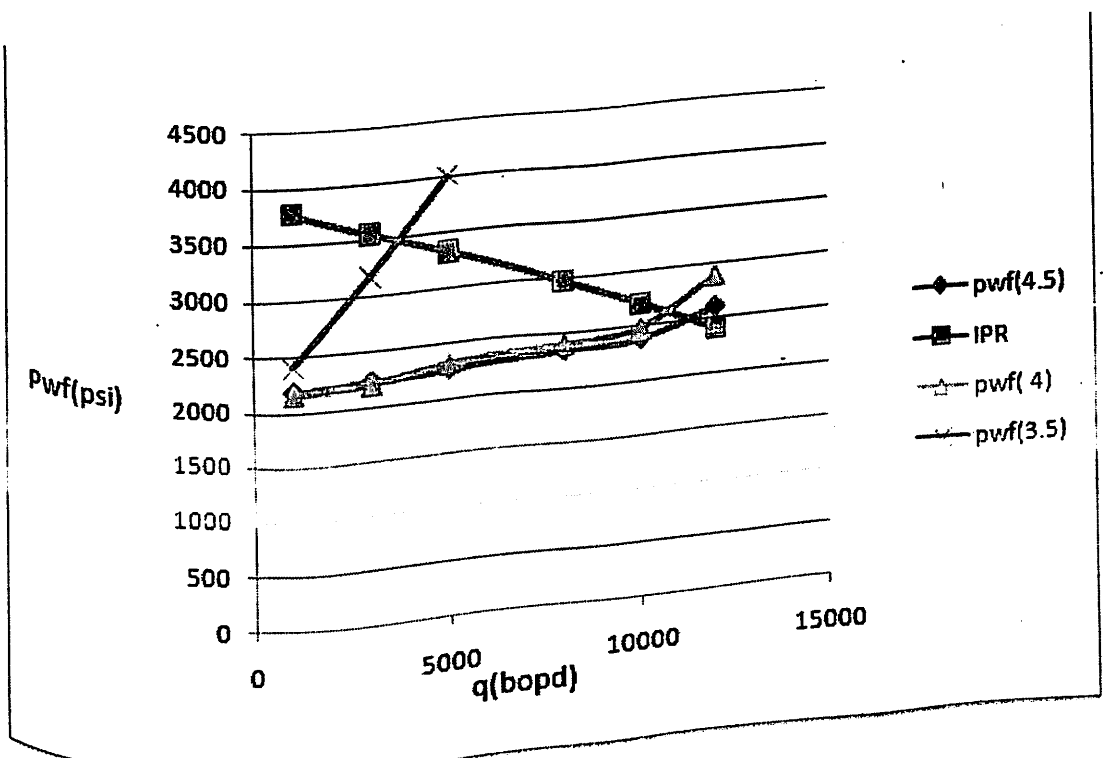
Tubing Performance Curve for 4" tubing

Q	Pwf
1000	2160
3000	2200
5000	2320
8000	2400
10000	2480
12000	2880

Tubing Performance Curve for 4.5" tubing

Q	Pwf
1000	2180
3000	2220
5000	2260
8000	2340
10000	2380
12000	2600

VLP Curve for Zone 2



SELECTION OF TUBING

- Too small a tubing size may retard the production rate as well as too large a tubing size. Also, low flow rates can be inefficient in large tubing sizes and undesirable heading conditions may exist.

- Since the tubing size of 4” intersects the IPR at rate Q 8000 bbls for upper zone and 11500 bbls in lower zone which is largest for upper zone and comparable to 4.5” in lower zone.

- So pick 4” tubing so that we can even save the cost, larger tubing size can even cause problems in well completions.

- Even production with larger tubing at low flow rates is difficult

CALCULATIONS OF FLOW REGIMES

ZONE 1

Tubing Size = 4"

Q_l = 8000 bpd

Convert this bpd into ft^3/ sec

Conversion factor 6.5035 * 10^{-5} ft ^{3}/sec = 1 bbl/day

Q_l =0.52028 ft^3 / sec

Q_g = 0.3641 ft^3 / sec

I.D = 4 inch= 0.333 ft

Area= 3.14 * d^2 / 4 = 0.08709

V_{sl} = Q_l/ A= 0.52028/0.08709 = 5.97 ft/sec

V_{sg} = Q_g/ A= 0.3641/0.08709 = 4.1807 ft/sec

$V_m = V_{sl} + V_{sg}$ = 5.97+4.18= 10.15 ft/sec

$C_l = V_{sl}/V_m$ = 0.58881

Nfr = V_m^2/ gD = 103.02/ 32.2* 0.333= 9.670774

$L_1^* = 316\ C_l^{0.302} = 269.19$

$L_2^* = 0.0009252\ C_l^{-2.4684} = 3.43022 * 10^{-3}$

$L_3^* = 0.1\ C_l^{-1.4516} = 0.2161$

$L_4^* = 0.5\ C_l^{-6.738} = 17.88$

Since $C_l \geq 0.4$ & $L_3 < N_{fr} \leq L_4$

So Flow regime is Intermittent in upper Zone

ZONE 2

Tubing Size = 4"

Q_l = 11500 bpd

Q_l =0.747 ft^3 / sec

Q_g = 0.314 ft^3 / sec

I.D = 4 inch= 0.333 ft

Area= 3.14 * d^2 / 4 = 0.08709

V_{sl} = Q_l/ A= 0.747/0.08709 = 8.5773 ft/sec

V_{sg} = Q_g/ A= 0.314/0.08709 = 3.6054 ft/sec

$V_m = V_{sl} + V_{sg} = 8.5773+3.6054= 12.18$ ft/sec

$C_l = V_{sl}/V_m = 8.5773/ 12.18 = 0.7042$

$Nfr = V_m^2/ gD = 12.18^2/ 32.2* 0.333= 13.835$

$L_1* = 316\ C_l^{0.302} = 284.24$

$L_2* = 0.0009252\ C_l^{-2.4684} = 2.19 * 10^{-3}$

$L_3* = 0.1\ C_l^{-1.4516} = 0.1663$

$L_4* = 0.5\ C_l^{-6.738} = 5.3112$

Since $C_l \geq 0.4$ & $N_{fr} > L_4$

Flow is Distributed in lower Zone

Concerns and anticipated problems in Drilling and Completion of these zones

There will be a number of problems in drilling and completion of wells since the formation contains a number of formations of Halite, Sandstone, Siltstone etc. The possible encountered problems are discussed according to respective zones which will be drilled from top to bottom

HALITE

- Halite formation is basically a salt containing formation
- It poses serious problems in **Cementing** of well
- **Salt Dissolution** during drilling is a serious threat
- Washing away of formation salt
- Compressive strength developed is critical
- Plastic salt flow can cause **Casing collapse**
- To minimize problems use cement slurries with shorter gel strength periods and rapid compressive strength development

SANDSTONE

- The given formation is partially consolidated Sandstone which will cause serious problems of **Lost Circulation**
- Due to consolidation problems, **circulating and washing** of zone will be difficult
- Since it contains clays, which will in turn cause problems of **fine migration**
- **Consolidation problems** have to be managed by using **wire wrapped screens**
- Use **Lost circulating pills** to avoid lost circulation

SHALES

- Shales have the property to split in direction of bedding, which is the major cause of problems
- Shales causes **Key Seating problems**
- **Sticking pipe** may also be encountered
- **Bore Hole instability** is also possible
- Generation of Hydrocarbons is also possible which may lead to production of gas from organic matter, which results in formation of **Over Pressured Zones**
- **Hydration of shales** can be avoided by OBM/SBM

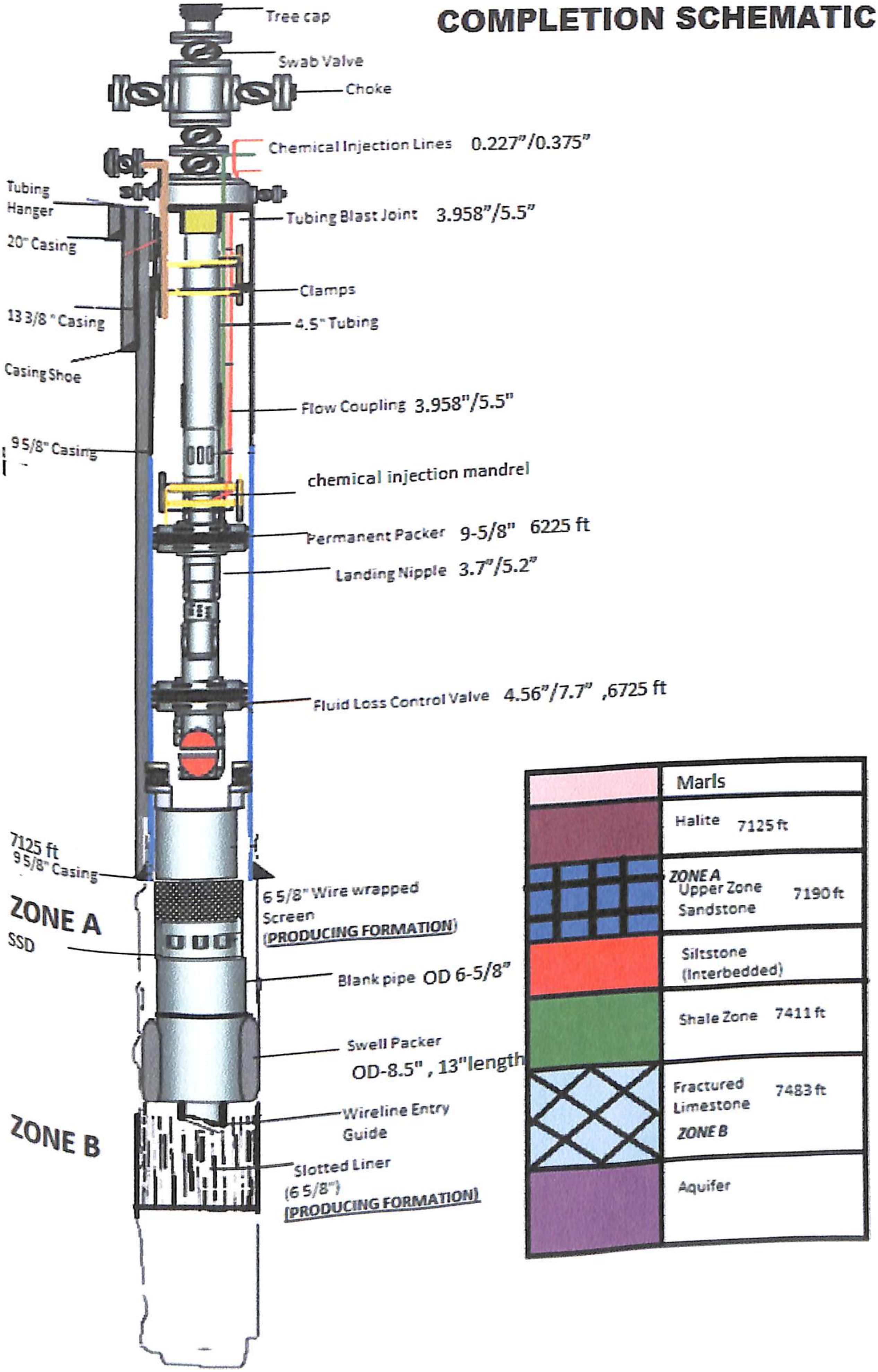
LIMESTONE

- **Hole stability** problems may occur
- Fractured limestone, so **Lost Circulation** may be encountered
- Occurrence of **Doglegs** is possible
- Limestone is major cause of **scaling** problems, which may lead to development of scales in tubing and other installations
- To avoid completions problems **slotted liners** are used

AQUIFER

- Presence of Aquifer leads to **coning problems** in early life of the well
- **Channeling** ie Flow behind the casing due to excess water production
- **2 D coning** in fractured limestone formation

COMPLETION SCHEMATIC



Name of equipment	vendor	Size ID/OD	Use
Wireline entry guide	Schlumberger, Halliburton, Baker Oil Tool, Weather ford	3.7	it is used for directing the e- line or wireline string when retrieving so that it comes out easily without being stuck.
Nipple profile	Schlumberger, Baker Oil Tool, Halliburton, Weatherford	3.7"/5.2"	it is for setting the hydraulic packer also for hanging PDG, jet pumps etc. It may also be utilized for setting deep set plug for long term well isolation.
Permanent packer	Weatherford, Baker Oil Tool, Schlumberger, Halliburton	9-5/8"	hydraulically set permanent drillable packer which is able to withstand the loads as determined in tubing stress analysis.
Chemical injection lines and mandrels	Schlumberger, Baker Oil Tool	0.227"/0.375"	chemical injection lines for injecting demulsifiers, scale inhibitor etc .
Tubing clamps	Weatherford, Baker Oil Tool, Schlumberger, Halliburton		to clamp production tubing , chemical injection lines
Fluid loss control valve-	Baker Oil Tools, Schlumberger	4.56"/7.7"	It is a tubing-mounted check valve that has been designed to isolate the lower section of a wellbore from the upper section.
Wire-wrapped screens (WWS)	Baker Oil Tool, Schlumberger , Halliburton	6-5/8" OD	they comprise a base pipe with holes, longitudinal rods and a single wedge-shaped wire wrapped and spot-welded to the rods. Some designs omit the longitudinal rods, but they do help offset the wire wrap from the pre-drilled base pipe holes. The wire is either welded or gripped by a connector at the ends of the screen.
Blank pipe	Schlumberger, Halliburton,	OD 6-5/8"	it is used against problematic and non

	Baker Oil Tool, Weather ford		producing formations like shale to seal off the zone completely.
Screen hanger or packer	Schlumberger, Halliburton, Baker Oil Tool, Weather ford	9-5/8"	this is used to bear the load of the screens and the bottom hole completion jewelery.
Flow coupling	Schlumberger, Baker Oil Tool	3.958"/5.5"	a relatively , short thick walled completion component installed in areas where turbulence is anticipated. The additional wall thickness prevent any failure due to erosion in turbulent flow.
Swell packer	Baker Oil tools, Schlumber, Halliburton	OD-8.5" Length-13"	they are used for zonal isolation , here used to isolate the shale and other problematic zones.
Blast joint	Schlumberger,Baker Oil Tool	3.958"/5.5"	they are constructed with thick walls and is placed in places where there may be a possibility of erosion due to solids laden fluid or against perforations
SSD(sliding sleeve door)	Schlumberger,Baker Oil Tool		This is installed below the sand screen to from zone 2 zone 1 will be opened and allowed to produce.
Bridge plug	Schlumberger		This is installed against the limestone zone to seal and plug the zone when it has stopped producing.

Completion jewels of the well

- **Nipple profile-**It is for setting the hydraulic packer also for hanging PDG, jet pumps etc. It may also be utilized for setting deep set plug for long term well isolation.

- **Permanent packer-** hydraulically set permanent drillable packer which is able to withstand the loads as determined in tubing stress analysis.

- **Chemical injection lines-** chemical injection lines for injecting demulsifiers, scale inhibitor etc .

- **Tubing clamps-** to clamp production tubing , chemical injection lines .

- **Fluid loss control valve-**It is a tubing-mounted check valve that has been designed to isolate the lower section of a wellbore from the upper section.

- **Wire-wrapped screens (WWS)-** they comprise a base pipe with holes, longitudinal rods and a single wedge-shaped wire wrapped and spot-welded to the rods. Some designs omit the longitudinal rods, but they do help offset the wire wrap from the pre-drilled base pipe holes. The wire is either welded or gripped by a connector at the ends of the screen.

- **Blank pipe-** it is used against problematic and non producing formations like shale to seal off the zone completely.

- **Screen hanger or packer-**this is used to bear the load of the screens and the bottom hole completion jewelery.

- **Flow coupling-** a relatively , short thick walled completion component installed in areas where turbulence is anticipated. The additional wall thickness prevent any failure due to erosion in turbulent flow.

- **Swell packer-** they are used for zonal isolation , here used to isolate the shale and other problematic zones.

- **Blast joint-** they are constructed with thick walls and is placed in places where there may be a possibility of erosion due to solids laden fluid or against perforations.

- **Mule shoe-** it is used for directing the e- line or wireline string when retrieving so that it comes out easily without being stuck.

Stimulation strategy

Zone A

Lithology :Partially consolidated sandstone, fine grained, 500mD but with 7% mixed layer sensitive clays

The sandstone in the upper zone is partially consolidated for which sandscreens are used in completion jewellery. It also consists of intermixed clay which can be of the following types:

a) **Fines Migration** : In these conditions the gravel pack or the fracturing with TSO (tip screen out) properties may be helpful. In the sandstones, blocking due to migrated fines can be treated with acidizing with the deep penetrating acid which can dissolve the fines. The conventional mud acid (HF + HCl) and hydrofluoric acid etc. are generally used as the treatment fluid. In limestone or carbonate reservoirs the HCl is mostly used to remove the fines and clear the near wellbore damage zone. Because the fines are not dissolved, but are dispersed in natural fractures or the wormholes that are created, N2 is usually recommended to aid fines removal when the well has a low bottomhole pressure.

b) **Swelling clay** : the salinity of the external injected water or liquid should be kept high enough to prevent the swelling. The removal of smectite is usually accomplished with HF or fluoboric acid, depending on the depth of penetration. The fluoboric acid is suitable for deeper penetration. In the event of very deep clay-swelling problems (more than 2 ft), the best treatment is usually a fracture to bypass the damage, as the matrix treatments will not be able to remove the damage to that deep penetration.

Zone B

Lithology: Massively fractured limestone reservoir

Problems associated include :

1. Discrete fragments particles of either organic or inorganic origin
2. Microcrystalline material formed from carbonate
3. Coarsely finely crystalline cementing material
4. Problems of scaling may also occur in the tubing in later stages

At present it looks as if there is no need for Stimulations as its producing around 11000 bopd and its already fractured. But if problems aggravate during the later stages of production, Stimulation can be carried out by Acid Frac Job by using 15% HCl

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CONCLUSION

- The Nodal Analysis method employs single or multiphase flow correlations, as well as correlations developed for the various components of reservoir system
- This information then is used to evaluate well performance under a wide variety of conditions that will lead to optimum single well completion and production practices.
- **Through Nodal Analysis one can predict that the under performance of the well is due to reservoirs inability or problem in production equipments**
- To determine overall well performance, system Nodal Analysis is a useful tool.
- First, Nodal Analysis will be used to analyze the effects of various tubing sizes on the ability of gas wells to produce reservoir liquids.
- The Nodal analysis done on the case study indicates that 4" tubing is best suitable for the zones. A single string dual zone completion is undertaken
- Wire meshed screens are used for Zone A and Slotted liner for Zone B