OPTIMIZATION OF GAS LIFT SYSTEM

By

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CERTIFICATION OF APPROVAL

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in partial fulfillment of the requirement for the

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CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

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JAHANZEB ALI BUGTI

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ABSTRACT

The intent behind this study was to optimize the Gas Lift System in order to achieve the target of maximizing the oil production from the four oil wells. To accomplish the optimization process, hurdles or constraints associated were addressed efficiently which resulted in effective outcome. Initial gas injection rates and oil production rates were analyzed by using Well Flo3.8.7 and maximum economic waters cuts were calculated for each well. Increasing water cuts is one of the major constraint that limits the injection gas volume which needs to be optimized and this constraint was addressed by calculating the optimum gas injection rates for all wells using Well Flo3.8.7. The overall comparison between the initial conditions and optimized conditions for all wells were presented in order to provide a clear picture of optimization in terms of oil production and maximum economic water cut. The results for total increase in all production were found to be 25954stb/day and initially it was 19099stb/day. The maximum economic water cut has been improved from 52% to 78%. The second major constraint is the ability of compressor to handle the optimized gas lift volumes and to deliver these gas volumes at sufficient discharge pressure for effective gas lift process, which were addressed by making use of HYSIS simulator. A model of three stage compression system is run in HYSIS simulator by using the designed capacity of compressor in terms of volume and discharge pressure to validate the design ratings and the load of compressor was also calculated at these conditions which includes power consumption by each compression stage and respective inter stage coolers. Another model is run in HYSIS simulator for compression train and the results for the optimum injection gas lift rates (23.8 MMSCFD) were used as an input in this model and hence an optimized model of compression train was obtained which could handle the optimized gas lift volumes at sufficient discharge pressure (3100 psig). In the end the total power consumption for both models was compared together and small increase of 253 KWH were observed which is acceptable in terms of increase in oil production.

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CHAPTER 1

INTRODUCTION

1.1 Background of Project

Gas lift is a type of artificial method that is currently being used in most of the oil field across the world and the reason behind that is its wide range of applications and particular characteristics which includes flexibility in the production rates of oil and depth which makes it superior over other artificial lift methods, gas lift method is applicable and suitable for the highly deviated wells in which dog leg severity is extremely high and it can handle sand production unlike ESP because of the absence of any moving mechanical equipment. The effective designing of gas lift system is very important so that the gas lift system should adhere and cop up with the changing conditions of reservoir. Pressure depletion can cause reservoir compaction and water injection is used as a remedial action for maintaining the reservoir pressure but with the passage of time problems occurs such as increased water cuts which will increase the hydrostatic head pressure in the tubing resulting in decreased production rates and in efficient gas lift operation. To address these problems, compression unit of the gas lift system should be capable of delivering an increased volumetric capacity of gas at sufficient discharge pressures. A multi stage compression unit can deliver the discharge pressures that are sufficient for well kick off if required as well as for normal continuous gas lit operations. Use of electrical motors as prime movers provides a great amount of flexibility to the compressors in terms of the operating parameters that are flow rate and discharge pressure by using variable speed drive (VSD) motors. Optimization of current units to achieve the targets is an effective tool that saves cost and time both and this technique enables to use the current asset potentials and it also plays a vital role and help exploration & production companies for making correct procurement decisions for new equipments.

1.2 Problem Statements

With the passage of time, it is the advent phenomenon that the water cut in production tubing will increase due to the injection of water for pressure maintenance of the reservoir and a completion using an aid of gas lift process will surely face problem in this scenario. These problems will result in the lower flow rates of oil which will make the gas lift process ineffective. The problems that need to be addressed and solved include:

- Increased injection rates of lift gas required because of the increasing hydrostatic head of the column of the fluids present in the tubing that consists of oil and water so more volume of lift gas is required in order to achieve maximum production. This lift gas injected rate should be optimum because injection more from an optimum rate will cause decrease in production due to gas slippage effect. Therefore for the lift gas requirements need to be recalculated in order to achieve maximum production by choosing the accurate and optimum injection rates.

- How to optimize the compressor unit in order to accommodate the increased injection rates of lift gas that is essential to lift the fluid from the well at economically optimum rates and at the same time maintains the pressure of the lift gas which should be sufficient for effective gas lift process. Optimization of gas lift operation must be acceptable which implies that the difference between the total power requirements at design capacity and at optimized conditions should be in acceptable ranges.

1.3 Objectives

1. To analyze the initial gas injection rates and oil production rates, To Calculate maximum economic water cuts by using Well Flo 3.8.7.

2. To calculate the optimum lift gas injection rates, Optimized oil production rates and improved maximum economic water cuts by using Well Flo 3.8.7.

3. To optimize the compression system which enables the existing compression unit to accommodate the increased gas lift injection volumes (13.8 MMSCFD) and sufficient discharge pressure (3100 psig) for continuous gas lift operation by using HYSIS simulator. The approach that was followed, relates to Charles Law that is reduction in pressure causes increasing in volume. Power calculation and comparison for the optimization of compression system is mandatory to establish by using HYSIS simulator.

1.4 Scope of Study

Optimization is the key for achieving efficiency by making use of available resources. Optimization of gas lift system in terms of increase oil production has accepted a wide range of significance in oil and gas industry. Optimum gas injection rates are calculated to insure maximum oil production and sensitivity analysis of water cuts is conducted which yields the maximum economic water cut for enhancing the cumulative oil production. The optimized gas injection volumes at sufficient pressure are provided by compression unit. The need to optimize the available compression unit is to obtain lift gas which will eliminate the need to add another compression unit which is more costly than the whole gas lift system. Simulation of compression unit involves the feed properties input and required discharge pressure, based on the available margin of the machine molar flow rate of lift gas (23.8 MMSCFD) has been handled at a discharge pressure of 3100 psig. The required power to handle increased gas volumes calculation gave a clear picture for the acceptability of optimizing the system, as small increment in power has been observed. The whole work conducted not only removed the need for capital investment but also, enhanced and increased the total output of all wells.

CHAPTER 2

LITERATURE REVIEW

2.1 Artificial Lift

Artificial lift systems are particularly used when the well cannot flow naturally and reservoir pressure is not sufficient for the flow of hydrocarbons to the surface and when the required throughput of production is not achieved. For any production facility the natural drive is very important because it includes the energy provided by reservoir and formation gas. Initially well will flow under natural drive specially oil well, this shows that the bottom hole pressure is sufficient and can cater the pressure loss in the tubing and at surface facilities but when the bottom hole pressure decreases up to an extent that it is not capable of accommodating the flow and pressure losses at various points of the flow path.

There are number of artificial lift techniques that are being used in oil wells and some are given.

- Gas Lift
- Electrical Submersible Pumps (ESP)
- Sucker Rod Pumps
- Progressive Cavity Pumps (PCP)
- Hydraulic Pumps

The selection of techniques is based on several factors, but the most important factors are listed below.

- Selection based on advantages and disadvantages
- Selection based on the consideration of depth
- Selection on the basis of net present value

2.1.1 Selection by Advantages and Disadvantages

Gas lift technique has been used and advantages and disadvantages for the gas lift and for other artificial lift techniques are briefly given in Tables 2.1 and 2.2.

Table 2.1: Advantage of Artificial Lift Systems (James F. Lea et al, 2004)

Gas Lift	**ESP**	**Rod Pump**	**PCP**	**Hydraulic Pump**
Can handle solid production	It can handle high volumes	Simple system design	They have moderate cost	Can be easily retrieved
In high PI wells it can handle big volumes	Unobtrusive in urban locations	Can be used for other wells with minimum removal and installation cost	Low profile	Simple and easy to operate
Technically and operationally more flexible	Operation is very simple	Very simple and easy to operate	Electrical efficiency is high	Adaptable to deviated and crooked holes
Unobtrusive in urban locations	Easy to install down hole pressure sensors for monitoring pressure at surface	Applicable to slim hole and wells having multiple completion	Adaptable to deviated and horizontal wells	Unobtrusive in urban locations
Power source can be remotely located	No problems for crooked holes	Can lift highly viscous hydrocarbons	Can handle viscous hydrocarbons	Can use gas and electricity as a source of power
Adaptable to highly deviated wells	Applicable in off shore facilities	Easy to perform corrosion and scale treatment	Production rates can be controlled by variable speed controller	Emulsion, scale and corrosion treatment is easy to perform

Applicable in off shore facilities	Easy to perform corrosion and scale treatment	Can pump a well up to very low draw down		Can pump a well down to a low draw down
Corrosion is not severe	Lifting cost is very low for high volumes	Can handle high temperature fluids		Power source can be remotely located
Can achieve good draw down at greater depths by changing valve position near perforations	Flexibility of different sizes of pumps to be used depending upon requirement	Can use both gas or electricity as a prime mover		

Table 2.2: Disadvantages of Artificial Lift Systems (James F. Lea et al, 2004)

Gas Lift	**ESP**	**Rod Pump**	**PCP**	**Hydraulic Pump**
Constraints of the availability of lift gas	Not applicable for multiple completion wells	Not applicable for crooked holes	Efficiency reduces with depth	Complex system design
Cannot handle viscous fluids	Prime mover is only electricity	Cannot handle high production of solids	Unit is not heat tolerant due to softening of stator material	Cavitations of pump is a problem
With the requirement of compression it	Not applicable in wells with lesser volume	It is depth limited due the rod capability	Presence of gas decreases pumps	Relatively inefficient lift technique

is not good for very small fields			efficiency	
Gas hydrates problem	Cable is damaged under high temperatures	Not applicable to offshore	Failure of gas separation can damage stator	Production of gas through pump creates problems
Not effective in producing deep wells to abandonment	Cannot handle solids and gas production	Low volumetric efficiency In gassy wells	Gearbox is damaged when well bore solids or fluids leak inside	Fire hazard exists with power oil system
Casing should bear lift gas pressure	Production rates control is not flexible without VSD	liable to paraffin problems		High pressure requirements for power fluid
Handling of high pressure gas in terms of safety	Casing size selection is limited	Tubing is liable to corrosion		Requires more submergence to attain good lift efficiency
	More time required for maintenance because entire unit is present down hole	Obtrusive in urban locations		

2.1.2 Selection by Consideration of Depth/Rate System

One simple selection or elimination method is the use of charts that show the range of depth and rate in which particular lift types can function. Charts like this are approximate for initial selection possibilities along with advantage/disadvantage lists.

Particular well conditions, such as high viscosity or sand production, may lead to the selection of a lift method not initially indicated by the charts. Specific designs are recommended for specific well conditions to more accurately determine the rates possible from given depths.

2.1.3 Selection by Net Present Value Comparison

A more thorough selection technique depends on the lifetime economics of the available artificial lift methods. The economics, in turn, depend on the failure rates of the system components, fuel costs, maintenance costs, inflation rates, anticipated revenue from produced oil and gas, and other factors that may vary from system to system.

A typical NPV formula

$$NPV = \sum_{i=1}^{n} \frac{WI(Q_{HC} \times P_{HC} - Cost - Tax)_i}{(1+k)^i} \qquad \text{Eq(1)}$$

Where: WI = Work Interest

Q = Oil rate

P = Oil price

Cost = All costs, operational (Opex) and capital (Capex)

Tax = Governmental taxes

k = depreciation rate of the project (percent)

To use the NPV comparison method, the user must have a good idea of the associated costs for each system. This requires that the user evaluate each system carefully for the particular well and be aware of the advantages and disadvantages of each method and any additional equipment that may be required. Because energy costs are part of the NPV analysis, a design for each feasible method must be determined before running the economic analysis to better determine the efficiency of a particular installation.

2.2 Gas Lift

Gas lift is a form of artificial lift in which the lift gas is first compressed and then injected into the production tubing via casing tubing annulus and when this lift gas enters into production tubing then due to expansion it pushes the oil up to the surface thereby reducing the bottom hole pressure due to reduction in density because lighter components of gas will mix with heavy oil (Brown, 1980)**.**

In most of the oil fields gas lift technology is being practised because it is highly recommended for deviated wells having crooked holes, oil with sand production and gassy oil wells. The other important merit of gas lift system is that the operational cost for lifting relatively larger number of well is low provided that lift gas supply is within the vicinity of oil field (Guo et al, 2007).

2.2.1 Principle of Gas Lift

When the BHP lowers than hydrostatic head inside well bore, the liquid will not move up to the surface but it will stop at depth and in this situation zero production rates occur. In order to overcome this problem, the hydrostatic head in the well bore needs to be decreased by injecting gas. When gas is injected through the annulus to gas lift mandrels and valves into the production string at depth; the total density of fluid above injection point is decreased. Injection gas is then expanded so that it pushes the liquids ahead of it which further reduces the fluid column weight. Displacement of liquid slugs by large bubbles of gas act as pistons to push the produced fluids to the surface thus causes liquid to flow to the surface (Guo et al, 2007).

2.2.2Classification of Gas Lift

Operationally gas lift is classified into two concepts and this classification is based upon the lift gas injection.

1. Continuous Gas Lift

This includes the continuous injection of gas into production tubing via casing tubing annulus. This technique for gas injection in order to produce oil at the surface is being used mostly in the oil fields and it is also effective, safe and flexible resulting excessive production rates of oil in both large diameter tubing and small diameter tubing (Brown, 1980).

2. Intermittent Gas Lift

This includes the periodic injection of gas into production tubing via casing tubing annulus. This technique is suitable and useful for very low reservoir pressures so intermittent lift design emphasizes on producing the well at actual rates that is the rate with which the fluid enters the borehole so the oil will be accumulated at the bottom of the production tubing and periodically recovered to the surface through injection of high pressure gas (Baker oil Tools, 2003).

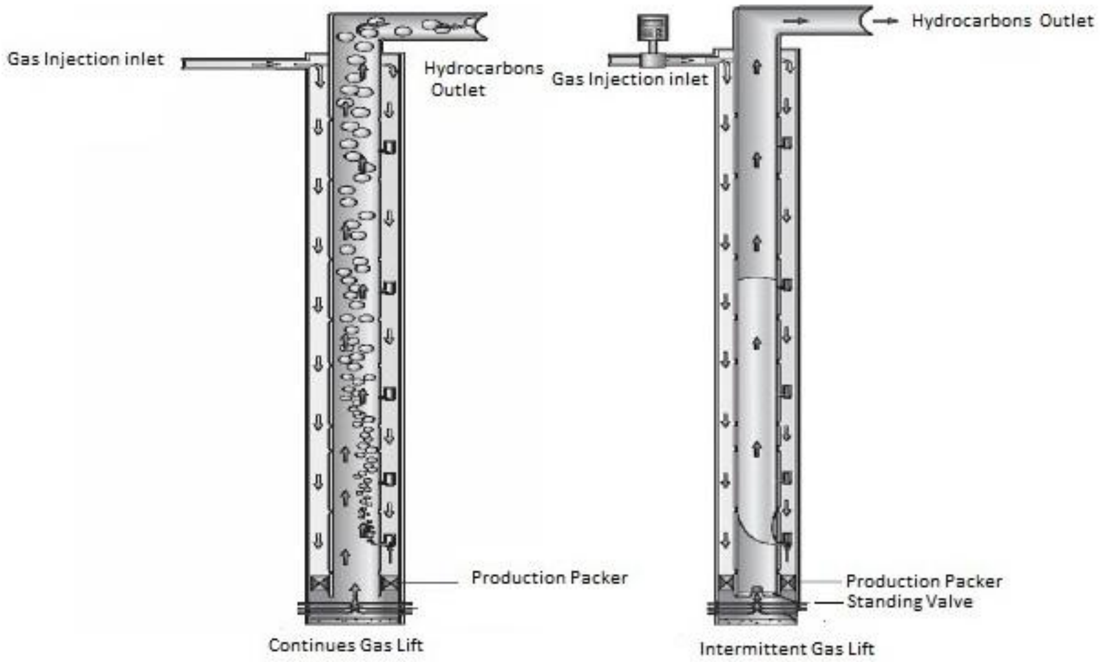


Figure 2.1: Continuous Gas Lift and Intermittent Gas Lift (Baker Oil Tool, 2003)

2.2.3 Gas Lift System

Gas lift method is one form of the artificial lift system which uses a high pressure gas in order to reduce the bottom hole pressure to lift the well fluids to the surface. The applicability and suitability of using gas lift operation involves number of considerations including the availability of gas, compression systems requires and the cost of compression (Forero et al, 1993).

Figure 2.2 shows a schematic of gas lift well with unloading valves and use of multiple gas lift valves in the gas lift design will lead to number of advantages in order to make the gas lift process more accurate and flexible. Some of the main advantages are listed below.

- Increasing the number of valves for lift gas enables to achieve increased depths for gas injection as the greater number of valves provides a flexibility of installation at different and at greater depths.
- Flexibility of changing the productivity index of the well by gas injection at different depths.
- Valves allow the metering of total volume of the gas being injected into the well.
- Useful for intermittent gas injection because of increased depth flexibility.

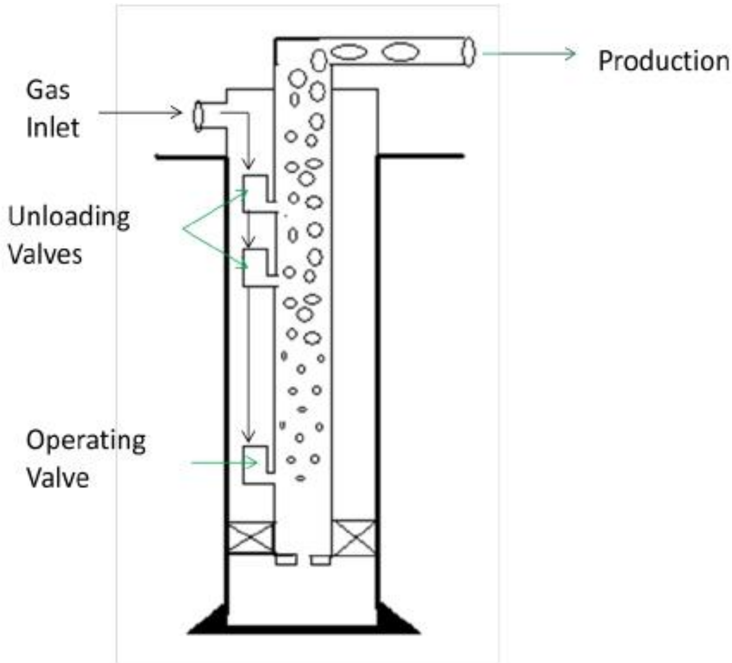


Figure 2.2: schematic of a gas lift well (Guo et al, 2007).

2.2.3.1 The Well Unloading Process

1-First stage and Second Stage

As shown in the Figure 2.3 (a) the first stage of well unloading process, here the gas injection has been commenced into casing tubing annulus and fluid is entering into the tubing from all valves because all four valves are open. The pressure of injected gas at perforation depth is greater than the pressure of reservoir. Process of well unloading is a high pressure process so gas injection rates are controlled through injection gas chokes in order to avoid any damage to gas lift valves.

(a) (b)

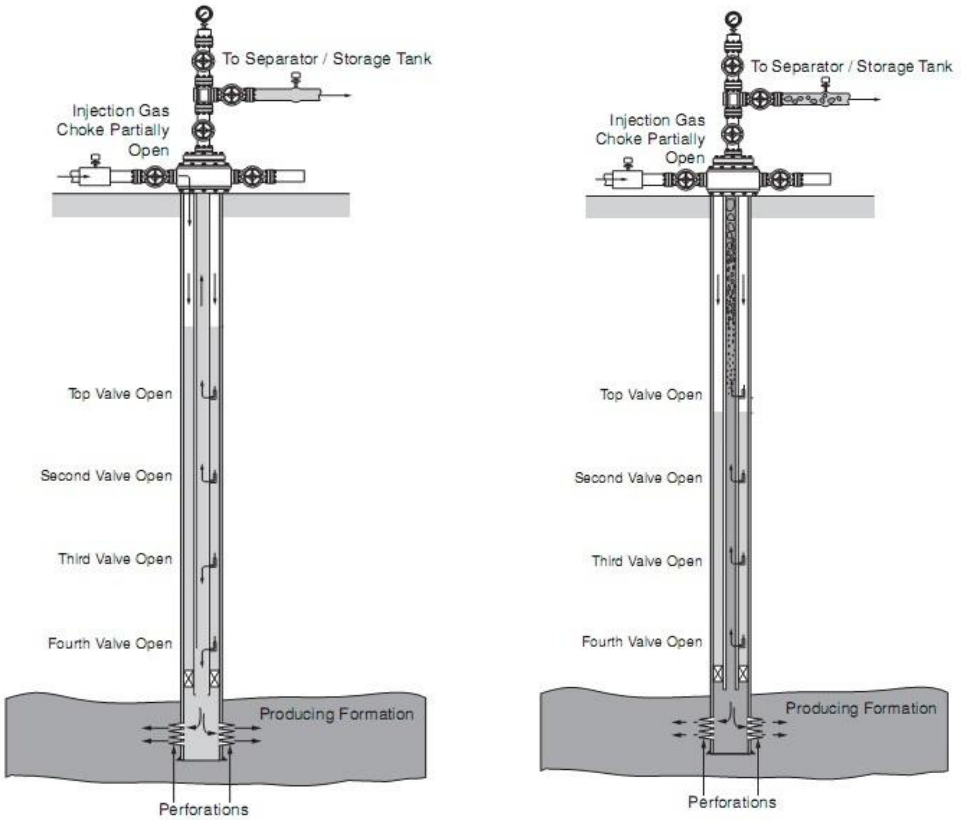


Figure 2.3: (a) Stage1 **(**HW manual 2012) (b) Stage 2 **(**HW manual 2012).

Figure 2.3(b) shows the second stage of well unloading process here fluid level is decreased in the annulus until top gas lift valve due to decrease in density and gas injection is started in to the tubing. The liquid present in the tubing above the top valve is partly evacuated by injected gas, this will result in reduction of density of the fluid which results in more unloading of casing fluid through the other remaining valves due to reduction of pressure in the tubing and if this reduction of pressure is sufficient enough to create a drawdown then formation fluids will enter into the well bore through perforations**.** (HW manual, 2012).

2-Third and Fourth Stage

Figure 2.4(a) shows the third stage of well unloading in this stage the level of casing fluid has been decreased adequately below the second gas lift valve and now both top and second gas lift valves are opened allowing the gas injection. The fluid in the tubing is unloaded enough to lessen the bottom hole pressure below reservoir pressure and this is because of the reduction of pressure in the tubing which creates a draw down hence enabling the formation fluids from reservoir to enter in the wellbore and will start producing.

(a) (b)

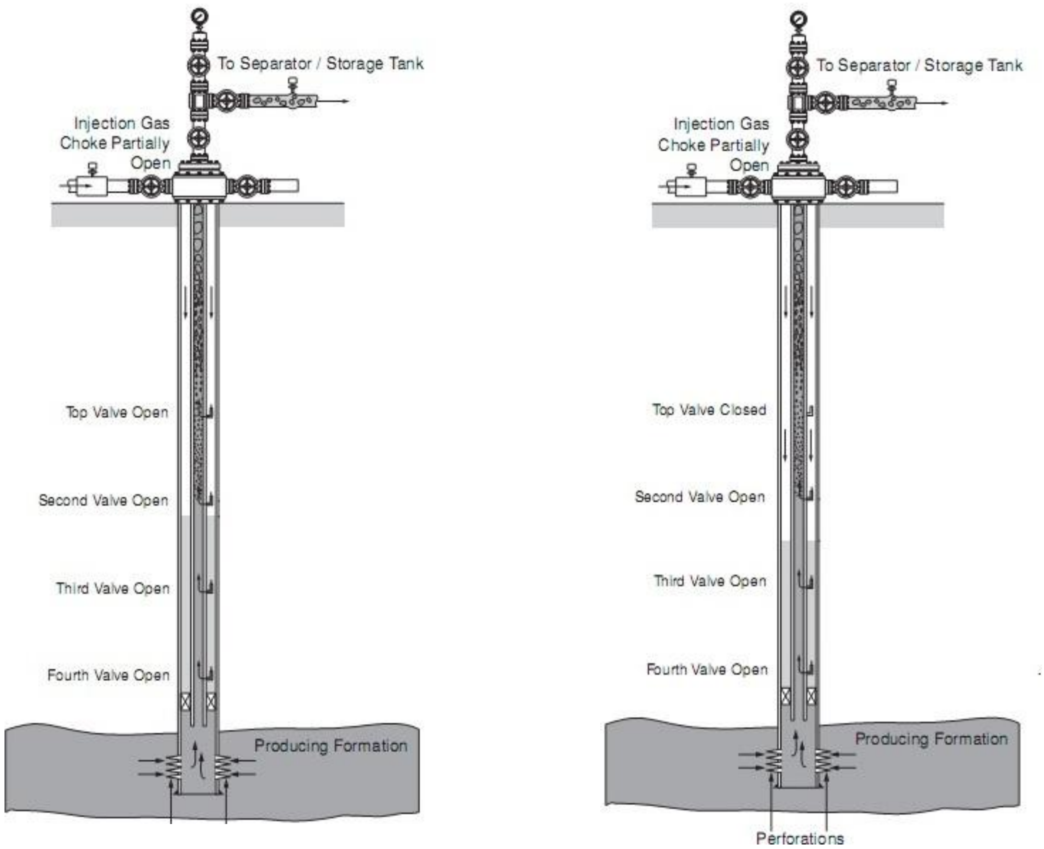


Figure 2.4: (a) Stage 3 (HW Manual, 2012) (b) Stage 4 (HW Manual, 2012)

Figure 2.4(b) above shows the fourth stage of well unloading process in which the gas lift valve at the top is now closed due to reduction in the casing pressure. In this stage gas is being injected through second valve and all valves that are open except top valve will participate in unloading the well while the liquid present in casing will flow into the tubing through third and fourth valves (HW manual, 2012).

3-Fifth and Sixth stage

Figure 2.5(a) shows the fifth stage of gas unloading process in which level of casing fluid is reduced below the third valve and now both second and third valves are passing gas and the fourth valve which is still open allows the flow of casing liquid into the tubing.

(a) (b) (c)

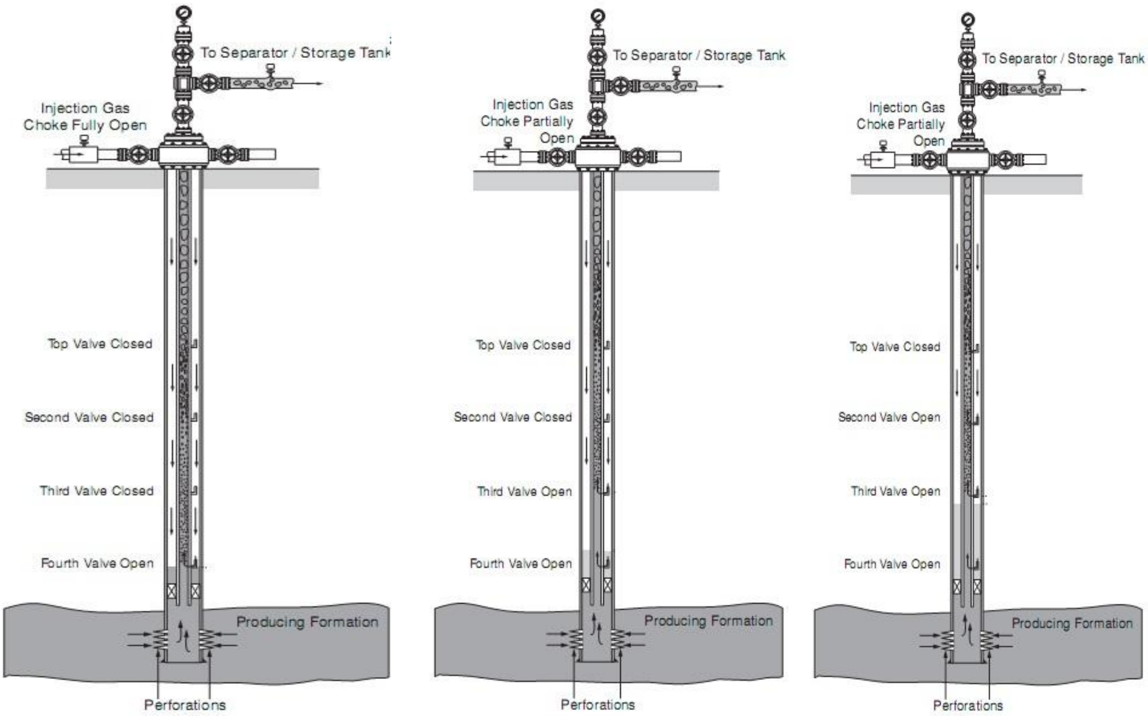


Figure 2.5: (a) Stage 5 (b) Stage 6 (c) Completion (HW Manual 2012)

Figure 2.5(b) above shows that in this stage second valve is closed due to the reduction in pressure at this point and all the gas will be injected through third valve and the similar events will repeat as in the case when first valve were closed as discussed above.

Figure 2.5(c) above shows the completion of the process where fourth valve is open and allowing gas and third valve is closed. Here all gas is being injected via operating valve that is fourth valve or bottom valve (HW manual, 2012)

2.2.4 Gas Lift Design Objectives

Design of any gas lift system that is used for lifting oil wells must fulfill the following objectives.

1. Maximize the net value of produced oil

Operating valve should be installed as deep as possible in the well and gas injection rate should be economically optimum so that a balance should prevail between amount of gas injected and amount of oil produced in terms of cost**,** (Schlumberger, 2000).

2. Maximize the flexibility of design

Gas lift design should be adaptable to changing conditions of the well as production progresses. These changes includes change in the reservoir properties which decreases the productivity of the well yielding low reservoir performance either by decreased production rates or increase in water cut (Schlumberger, 2000).

3. Minimized the well intervention

This is very important in design considerations because of the well intervention constraints especially in offshore wells wire line operations are relatively difficult to perform. The well completion having dog leg severity that is less than 60 degree provides the flexibility to replace the gas lift valves by use of wire line operations. The performance of these valves can easily be regulated at any time which shows that the production conduit can respond to the changes in the reservoir conditions and ultimately the well over all performance (Schlumberger, 2000).

4. Stability of well operation

Variations in the pressures of tubing head or casing head should be avoided. Stability of operation is linked with the stable value for the tubing and casing head pressures in order to achieve increased oil production. An unstable gas lift operation in practice can be stabilized by reducing the lift gas volume (Schlumberger, 2000).

2.2.5 Design Constraint for Gas Lift System

It includes three different conditions in which a lift gas design should be made which satisfies and achieve the design objectives.

- The valves are installed being an important part of the tubing which implies that side pocket mandrels are excluded. Here the spacing between the valves is fixed and the initial operating parameters are not changed until the tubing is replaced through work over operation. These completions are used in shallow wells (HW manual, 2012).

- This scenario includes side pocket mandrels in completion design. For the initial period of natural flow these mandrels are equipped with dummy valves and when the production declines after some time than gas lift valves are installed to achieve the desired production rates. The information collected during the natural drive period will help to eradicate the uncertainties associated with well and reservoir and this experience can be used to decide the valve settings for the real valves when dummy valves are replaced with real valves (HW manual, 2012).

- In this case a gas lift design is made in order to modify the gas lift completion which was previously installed. The need for the new design is to achieve the adaptability to the changed well condition which includes change in water cuts, reservoir pressure and well productivity. The design consideration includes the valves that need to be run in the existing side pocket mandrel. (HW manual, 2012).

2.2.6 Gas Lift Optimization

The goal of gas lift is to deliver the fluid to the top of the wellhead while keeping the bottom hole pressure low enough to provide high pressure drop between the reservoir and the bottom hole. Reduction of bottom hole pressure due to gas injection will normally increase liquid (oil) production rate, because gas injection lighten the fluid column, therefore larger amount of fluid flow along the tubing. However, injecting too much amount of gas increases the bottom hole pressure which decreases the oil production rate. This is happened because high gas injection rate causes slippage, where gas phase moves faster than liquid, leaving the liquid phase behind. In this condition, less amount of liquid will flow along the tubing. Hence, there should be an optimum gas injection rate (HW manual, 2012).

2.2.7 Nodal Analysis

Nodal analysis is a very good and effective tool for the forecasting of the production systems performance. By using this tool we can optimize the completion design so that it should adhere to the reservoir conditions and identify the reservoir constraints in order to get efficient output. Node is the point which can be selected at any point in the flow system and at that point flow in will be equal to flow out and normally the point near well head is taken as node and from that point which is selected as node the upstream part is known as inflow section and the downstream part is called as out flow section, for the nodal analysis we have two performance curves one for inflow and one for out flow and the point at which both of these performance curves intersects is called as operating point as shown in Figure 2.6 below and this operating point gives the best possible flow rate which is operationally optimum to go with (Economides, 1994).

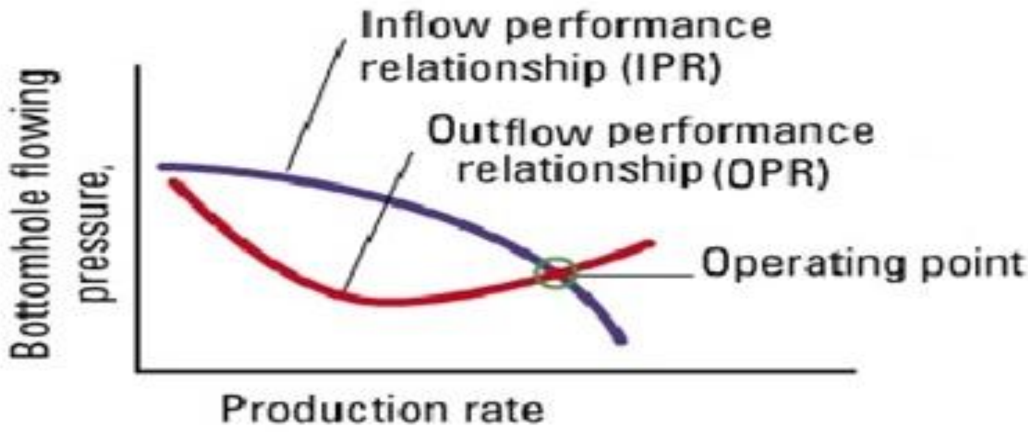


Figure 2.6: IPR and OPR (Economides, 1994)

2.2.7.1 Inflow Performance Relationship

The inflow performance of a well represents its ability to deliver fluids (Economides, 1994); an accurate prediction of the behavior of the production rate will allow an efficient Gas Lift design. The inflow performance of a well depends greatly on the type of reservoir, drive mechanism reservoir pressure, permeability, etc. When taking into account the type of drive mechanism three different types of curves can be observed (Schlumberger, 2000).

- Straight line for water drive reservoirs, and/or reservoirs with pressure above the bubble point,
- Straight line with a small curvature at the end for gas cap drive reservoirs and,
- A clear curved line for solution gas drive reservoirs and/or reservoirs with pressure below the bubble point.

It is also important to have in mind that the inflow performance behavior will not remain the same in time, but it will change with cumulative production and aging therefore a continuous update of this parameter is crucial for artificial lift operations.
Since Gas Lift operations produce two-phase flow, and also the expansion of the gas is a driving mechanism for oil production, it is possible to compare this operation with the inflow performance associated to solution gas drive when the

pressure is under the bubble point. The solution of the curved inflow performance is challenging and yet they are not completely understood. In 1968 Vogel proposed a solution to determine the inflow performance curve for solution gas drive for reservoirs below the bubble point. Vogel developed an empirical solution that covers a wide range of oil PVT properties and relative permeability, at the same time to simplify the solution assumptions like circular, radial uniform flow with constant water saturation were made, also he neglected gravity segregation (Vogel, 1968).

Besides Vogel there are other models that can predict two-phase inflow performance relationships, like the work presented by Fetkovich (Fetkovich, 1973) or Jones, Blount and Glaze (Jones et al, 1976) these are also empirical models and the accuracy of each model can change from well to well. For this particular work Vogel dimensionless equation will be used in further calculations (Vogel, 1968).

$$\frac{q_o}{q_{o,\max}} = 1 - 0.2\left(\frac{P_{wf}}{P_r}\right) - 0.8\left(\frac{P_{wf}}{P_r}\right)^2 \qquad \text{Eq (2)}$$

2.2.7.2 Tubing Performance Relationship

Tubing Performance Relationship (TPR) involves the analysis of those factors which affects the oil flow rate from bottom hole up to the surface primarily caused by pressure drop in the tubing. To analyze the effect of water cut, reservoir pressure, gas oil ratio (GOR) and inner tubing diameter and well head pressure sensitivity analysis is done. When the sensitivity analysis has been completed then we will be able to forecast the behavior of reservoir and well for example we can get a forecast according to which we may find that production is sensitive in changing the water cut or possibly when the well reaches a certain amount of GOR it will not produce. As gas lift operations yields two phase flow so the pressure calculations of the fluids at a given point is not easy and without which the design of gas lift will not be effective. To solve this difficulty there are different correlation models for multiphase flow which are being practiced frequently in industry (HW manual, 2012 &Economides, 1994).

- Hagedorn and Brown
- Duns and Ros
- Beggs and Brills

Pressure losses in tubing:

- Effect of liquid flow rate on pressure loss

From the friction equation we can see that friction losses increase as liquid rate increases (v increases). Hydrostatic gradient also increases with increased liquid production.

- Effect of gas-to-liquid ratio on pressure loss

Increase in gas-to-liquid ratio (GLR) results in reduction of hydrostatic gradient. On the other hand, increased GLR increases friction forces and has a counter effect on the bottom hole pressure. When contribution of the friction becomes higher than that of hydrostatic forces, the actual bottom hole pressure starts to increase. From a gas lift point of view this means that there is a limit of how much gas that beneficially can be injected.

- Effect of water cut on pressure loss

Increased water cuts results in increased liquid density, which in turn, increases hydrostatic forces and the bottom hole pressure

- Effect of tubing size on pressure loss

The increased diameter of tubing reduces the pressure gradient due to friction. However, there is a limit to which diameter of tubing can be increased. If the diameter is too big the velocity of the mixture ($v=q/A$, A: pipe cross section) is not enough to lift the liquid and the well starts to load up with liquid, resulting in increase of hydrostatic pressure (Economides, 1994).

2.3 Compression System

Compressor is a device that is used to increase the pressure of gas stream, and this increase in pressure is achieved by reduction of volume of gas. A compressor increases the pressure and transports the fluid via pipe line. Figure 2.7 shows a typical compression stage in which the path of gas is shown that is fed into a scrubber which removes condensate and mist from gas that can be corrosive for the compressor vanes. Scrubber usually contains deflecting plate for the momentum loss of the gas stream and condensate settles down under gravity and it also contains a demister pad which removes the remaining mist from gas stream through coalescence phenomenon. Gas then enters into compressor and then into coolers usually fin fan coolers are used in the industry to decrease the temperature that increases as a result of compression (Perry, 2007).

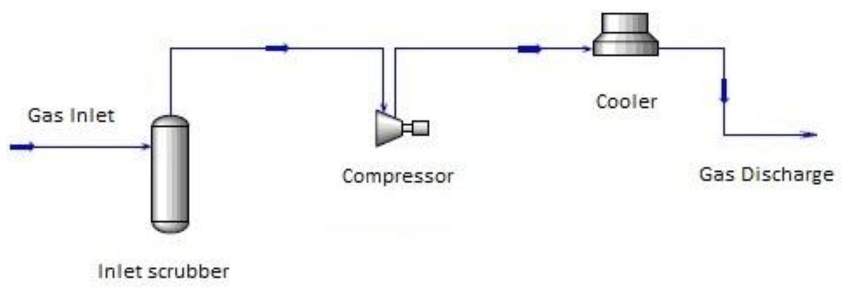


Figure 2.7: A Compression stage, (HYSIS, 2009)

Compressors that are used for the gas lift operations are subjected to one problem that is the difference between the normal operating pressure for continuous injection of lift gas and the pressure required to make the well flow in the beginning that is called as kick off pressure. This pressure difference should be less which allows the effective and efficient operation of the compressor at both conditions (Forero et al, 1993).

2.3.1 Classification of Compressors

Compressors are classified into two main types that are being widely used in oil and gas industries and these main types are

- Centrifugal Compressors
- Reciprocating Compressors

Reciprocating compressors traps the gas in the chamber and reduces the volume through a piston or plunger and discharges the gas at higher pressure from discharge out let (Perry, 2007).
Centrifugal compressors consists of the vanes or impellers and diffusers, Impellers are the moving part which rotates following a centrifugal action usually at a very high speed and convey a velocity energy to the gas stream and this energy is converted into pressure energy by both impellers and diffusers (Aungier, 2000).

2.3.1.1 Comparison of Centrifugal & Reciprocating Compressors

Comparison for both types is given in the Table 2.3.

Table 2.3: comparison of compressor types, (Hanlon, 2001).

Characteristics	**Centrifugal**	**Reciprocating**
Size	Small	Big
Noise	High	Low
Over Hauling	Frequent	Less
Design Capacities	Medium to High	Low to High
Discharge Pressure Max	70 Mpa	175 Mpa
Full Load Efficiency	High	High

2.3.2 Prime Movers for Compressors

There are two main prime movers for compressors which are

- Electric Motors
- Gas Turbines

2.3.2.1 Electric Motors

The electric motor uses electrical energy as a source for driving the compressor assembly and recent drastic improvements enables an efficient operation of the overall compressor unit for example variable speed derive (VSD) and Variable frequency drive (VFD) motors which allows flexibility to change the RPMs and automatic control of set points (flow rates /discharge pressure) due to efficient and flexible design of electric motors, (Hanlon, 2001&GPSA, 1998).

2.3.2.2 Gas Turbines

Gas turbines use combustion power of natural gas as a source for driving the compressor assembly. It contains combustion liners inside combustion chambers where a controlled ratio (1:3) of oxygen and fuel (Natural Gas) is allowed and combustion is initiated through spark plugs. Unit also uses induction gears to enhance the speed of the compressor and effectively use the power generated by gas turbines. The package also includes a compressor for combustion air having filters at intake to avoid moisture, (H.P et all, 1996 &GPSA, 1998).

2.3.3 Main Operating Parameters

There are two main operating parameters which will decide the RPMs on which compressor should operate and those parameters are the required discharge pressure and required volumetric flow as shown in Figure 2.8. These parameters have certain limits which are governed by the design of individual compressor and its performance. Every compressor has a range to deliver these operating parameters which lays within the minimum and maximum values such as minimum/maximum flow capacity and minimum/maximum discharge pressures. Surging is very important factor and in the design of every compressor it needs consideration because it is the severe vibration in compressor which can damage the compressor resulting from a reversal flow and flow that less than the minimum flow that a compressor can handle (Devold, 2006).

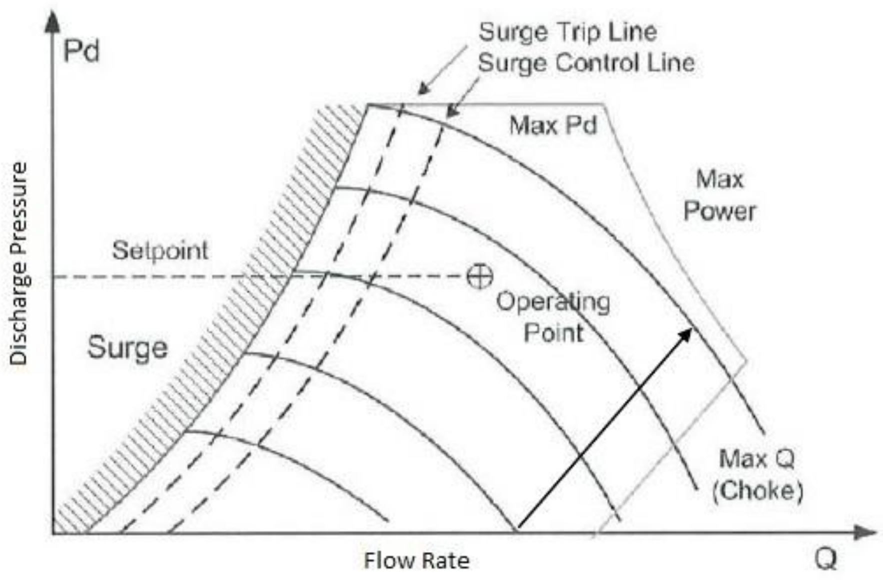


Figure 2.8: Operating Curves of Compressors, (Devold, 2006)

2.3.1 Design Criteria

1.This Section of Standard covers information necessary to select centrifugal compressors and to determine whether the selected machine should be considered for a specific job.

2.An approximate idea of the flow range that a centrifugal compressor will handle is shown in Table 2.4. A multistage centrifugal compressor is normally considered for inlet volumes between 850 and 340,000 Im^3/h. A single stage compressor would normally have applications between 170 and 255,000 Im^3/h. A multi-stage compressor can be thought of as series of single stage compressors contained in a single casing.

Table 2.4: Centrifugal Compressor Flow Range (Hanlon, 2001).

Speed to develop 3048 m head/wheel	Average isentropic efficiency	Average polytropic efficiency	Nominal flow range (inlet m^3/h)
170 – 850	0.63	0.60	20,500
850 - 12,743	0.74	0.70	10,500
12,743 - 34,000	0.77	0.73	8,200
34,000 - 56,000	0.77	0.73	6,500

56,000 - 93,400	0.77	0.73	4,900
93,400 - 135,900	0.77	0.73	4,300
135,900 - 195,400	0.77	0.73	3,600
195,400 - 246,400	0.77	0.73	2,800
246,400 - 340,000	0.77	0.73	2,500

3. Effect of speed

a) With variable speed, the centrifugal compressor can deliver constant capacity at variable pressure, variable capacity at constant pressure, or a combination of variable capacity and variable pressure.

b) Basically, the performance of the centrifugal compressor, at speeds other than design, follows the affinity (or fan) laws.

c) By varying speed, the centrifugal compressor will meet any load and pressure condition demanded by the process system within the operating limits of the compressor and the driver.

d) If speed is constant then Characteristic operating curve will be also constant. The following factors will increase suction pressure resulting in change of discharge pressure:

- Molecular weight of gas increases
- Suction pressure increases
- Inlet temperature decreases
- Compressibility factor decreases
- Ratio of specific heats, k decreases

4. Performance calculation

a. Determination of properties pertaining to compression

Compressibility factor (Z factor), ratio of specific heats (Cp/Cv or k value) and molecular mass are three major physical properties for compressor which must be clarified.

b. Determination of suction conditions

The following conditions at the suction flange should be determined:

- Temperature
- Pressure

  In case of air taken from atmosphere, corrections should be made for elevation. Air humidity should also be considered.

- Flow rate

  All centrifugal compressors are based on flows that are converted to inlet or actual conditions (Im^3/h or inlet cubic meters per hour). This is done because centrifugal compressor is sensitive to inlet volume, compression ratio (i.e., head) and specific speed.

- Fluctuation in conditions

  Since fluctuations in inlet conditions will have large effects on the centrifugal compressor performance, owing to the compressibility of the fluid, all conceivable condition fluctuations must be taken into consideration in determination of design conditions.

c. Determination of discharge conditions

- Calculation method

  Discharge conditions of a centrifugal compressor can be calculated by the following procedure.

  - Calculate the polytropic exponent "n":

- Using the equation:

$$\frac{n}{n-1} = \frac{k}{k-1} \times \eta_p \qquad \text{Eq (3)}$$

if η_p (polytropic efficiency) is known from the manufacturer data. ηp can also be estimated from Table 2.4 (k is the ratio of specific heats), (Hanlon, 2001).

2.3.2 Anti Surge Systems

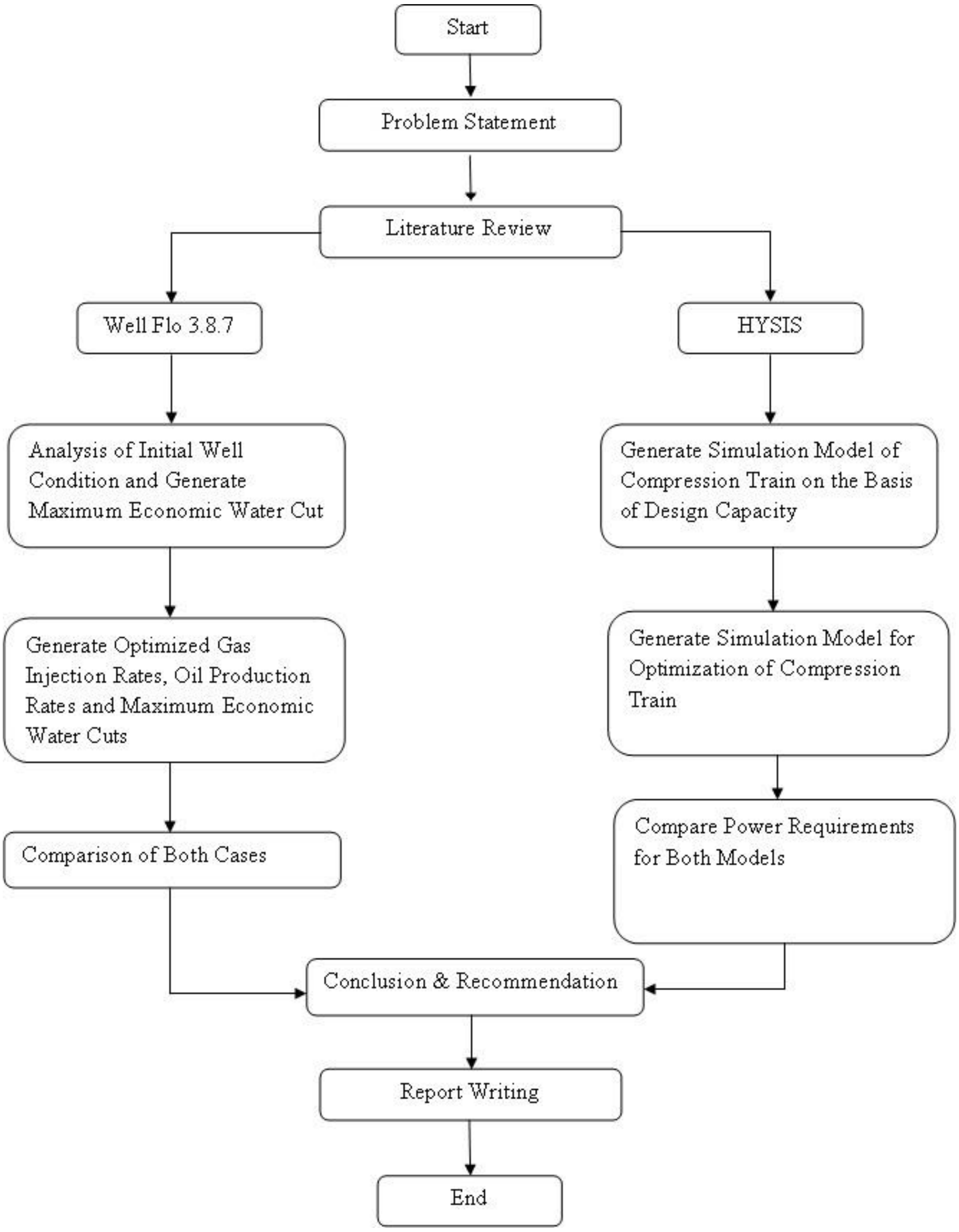
Instabilities in the compressor unit results into mechanical damage of the compressors due to extreme vibrations which are caused by low flow rates, In order to avoid such instabilities all compressors are equipped with Anti Surge systems. This system comprises of a flow control valve (FCV) which connects compressors discharge line to the inlet and this FCV is equipped with a control system which follows a set point that is the compressors surge point. When this surge point due to low flow conditions occurs the anti surge valves installed at every stage of compressor opens and the compressor will switch to recycle mode thereby preventing the unit from surging. Anti surge valves follows the set point which is usually controlled from the control panel and surge point for every compressor is also checked frequently and set pint is changed accordingly. During shut down and start up of the compressor unit these valves are used for gradual loading and unloading of the machine (Hanlon, 2001).

CHAPTER 3

METHODOLOGY

3.1 Project Flowchart

In this Chapter a methods are defined in order to achieve the project objective



The methodology is defined and discussed in detail step by step.

3.2 Steps for Gas Lift Optimization using WellFlo3.8.7

1. Designing of gas lift to analyze the existing lift gas injection rates and production rates of individual well by generating IPR & OPR plots, there intersection will give the operating point which gives the optimum production rates. Calculating the maximum economic water cut for individual well by using water cut sensitivity analysis from 1% to 99% and comparing them with the given economic production rate that is 1500 stb/day. The water cut which will be near to the economic production rate will be the maximum economic water cut.

2. Generation of the new optimum injection rates for individual well by using sensitivity analysis of lift gas injection rates from 1 to 10 MMSCF/day and plotting performance curve (oil rates vs. lift gas injection rates) to observe and select the injection rate which produces maximum oil rate on the plot that is generated by well flow because injecting more will end up with the gas slippage and due to gas slippage the oil production will reduce. Obtain the results for increased oil production rates for individual well by generating IPR & OPR plots, there intersection will give the increased operating production rates by using optimum injection rates for gas lift and extracting maximum economic water cut for individual well again by using the water cut sensitivity analysis and comparison with the economic production rate.

3. In the last step of the methodology for well Flo 3.8.7 initial and optimized conditions for all four wells were compared which includes the increase in oil production rate and improvements in maximum economic water cut. Increase in the oil production is one of the main goals and improvement in water cuts will prolong the production which will lead to maximize the total cumulative oil production of all four wells.

3.3 Gas Lift Optimization using HYSIS simulation

1. Construct and run a Simulation model to design a compression train that is required for gas lift process by using given design data/rating of compressor that is volumetric capacity and maximum design discharge pressure. Developing a simulation model includes certain steps which are, the selection of property package which includes different equations of state normally Peng Robinson is used, input of all process conditions that are given for existing compressor. Inlet and discharge pressures are defined and feed inlet conditions are also defined in the simulator in order to run simulation. The property package that is selected is a set of equation of states which helps the simulator to simulate accurately

2. Optimization of the compressor train again by simulating the model by defining the feed inlet conditions and selecting a property package that is Peng Robinson which solves different equation of states for simulation and in this case we will specify the discharge pressure at every stage and also the temperature at inter stage coolers, only the molar flow is not specified because that is the result for simulation to check that weather the simulation model of the compressor can handle the increased gas injection volumes. The approach that is followed by the simulator is to use the existing margin in the machine which is the margin in the pressure and by reducing the pressure the volumetric flow rate of gas will be increased up to the desired quantity

3. Power requirements are essential to calculate because it is necessary to check the performance of optimization process. Power or duty was calculated for the individual compressor stage for both design and optimized case; it was calculated based on the operating parameters that are volumetric flow rate and the discharge pressures. Operating parameters are responsible for the operating RPMs of compressor which is directly related to the consumption of power so simulator calculates the power utilization on the basis of increase or decrease in these operating parameters. Then power required for both cases are compared to know the economic feasibility and suitability of the project.

CHAPTER 4

RESULTS AND DISCUSSIONS

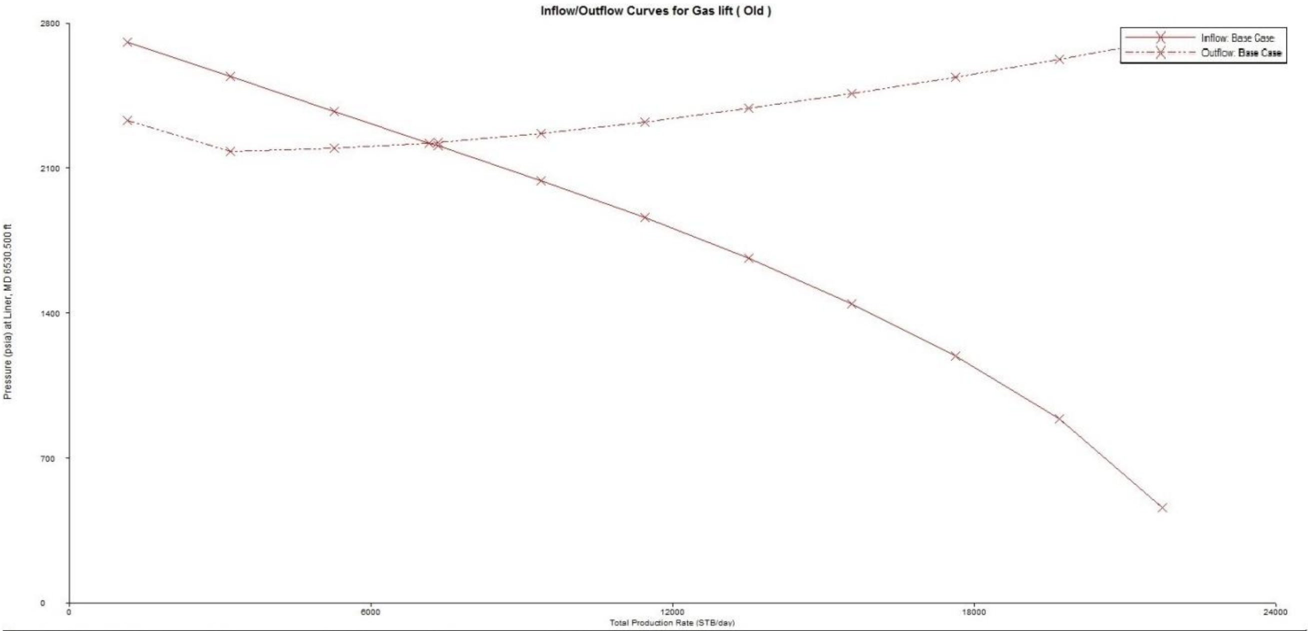
4.1 Gas Lift Volume

Due increased water cuts the hydrostatic pressure within the tubing rises and as a result of which increased injection volumes and adequate discharge pressures are required in order to produce more oil as discussed before. This requires the need to find out new optimum injection rates by using well Flo3.8.7 software which will be sufficient for lifting the well and achieving the improved oil rates. The initial injection rates are also important to validate by using the software in order to find out max economic water cuts for all four wells and compare them with the increased injection rates for gas lift, new oil production rates and more importantly the maximum economic water cut which specifies that at what values of water cuts the oil production will be economically feasible and acceptable. The results below includes the WellFlo3.8.7generated plots first for the given data which includes the oil production rates and the injection rate, by using this data the maximum economic water cut for each well is evaluated and after that the new increased optimum gas lift injection rates, the increased oil rates and the maximum economic water cuts are evaluated for all four wells, then the results are summarized for both cases and compared to see the total increase in the oil production and improvement in the range of maximum economic water cuts. By using the initial given data that is given below in table 4.1 for all wells at initial conditions to design the gas lift by using WellFlo3.8.7.

Table 4.1: Data for well 1-2-3-4

Parameters	**Well 1**	**Well 2**	**Well 3**	**Well 4**
Oil Production Rate	5000 STB/d	4814 STB/d	4480 STB/d	4804 STB/d
Water Cut	30%	30%	30%	30%
Well Head flowing Temperature	65 F°	65 F°	65 F°	65 F°
Pressure at X-tree	445 psia	440 psia	438 psia	443 psia
Skin	2.92	2.92	2.92	2.92
Permeability	100Md	100Md	100Md	100Md
Reservoir Pressure	2800 psia	2800 psia	2800 psia	2800 psia
Economic oil rate	1500 STB/d	1500 STB/d	1500 STB/d	1500 STB/d
Current gas injection rate	1.5 MMSCFD	2 MMSCFD	1.8 MMSCFD	1.6 MMSCFD

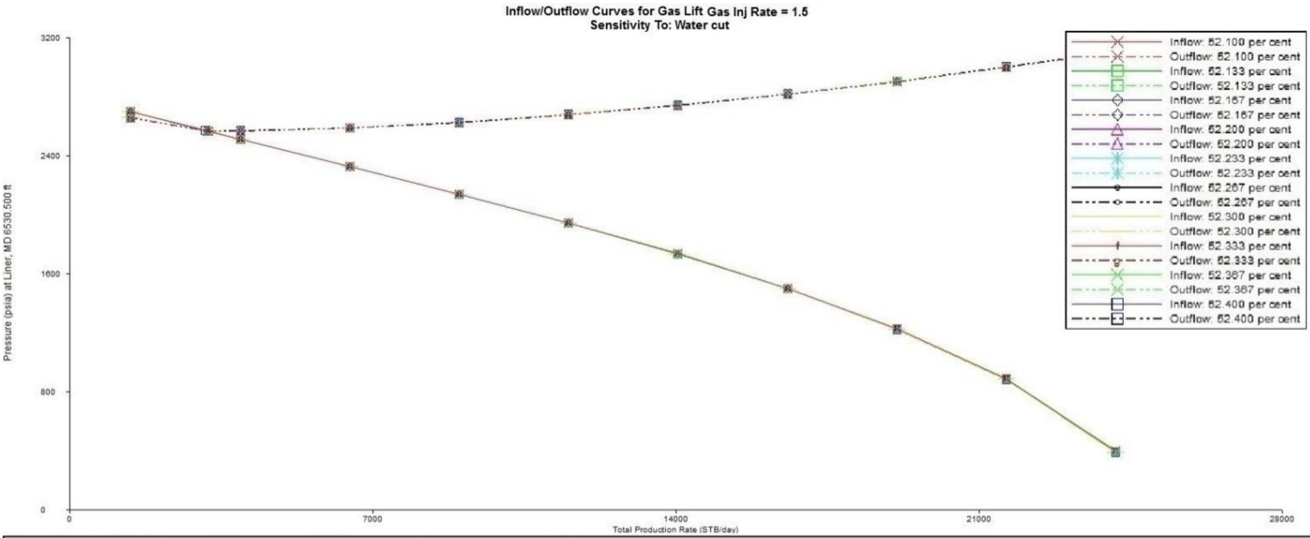
4.1.1 Well 1 Well Flo Results



Operating Pressure (psia)	Liquid Rate (STB/day)	Oil Rate (STB/day)	Water Rate (STB/day)	Gas Rate (MMSCF/day)	Water Cut (per cent)	GOR (SCF/STB)	
2221.830	7142.938	5000.056	2142.881	2.750	30.000	550.000	Stable

Figure 4.1: IPR Vs. OPR Plot Well 1

Inflow/out flow curves for well 1 was checked to validate it with the data that is given and this shows that the oil production rate at 30% water cut 5000STB/d with an gas lift injection rate of 1.5MMSCFD as shown in figure 4.1. The procedure for generating this plot in the software involves the input of all reservoir conditions that are required such as permeability, reservoir pressure etc and the injection rate that is being used for this case. These data which is given to the software will calculate and construct the two performance curves and also calculate its point of intersection as shown in the plot, which will indicate the operating point for the production rate at reservoir condition and the flow involves oil, gas and water which is clearly mentioned at the surface or separator conditions. The plot also includes the calculation of GOR which also supports the suitability of gas lift method as it is high. This whole process is repeated until the results obtained are fully screened for finding out the accurate results.

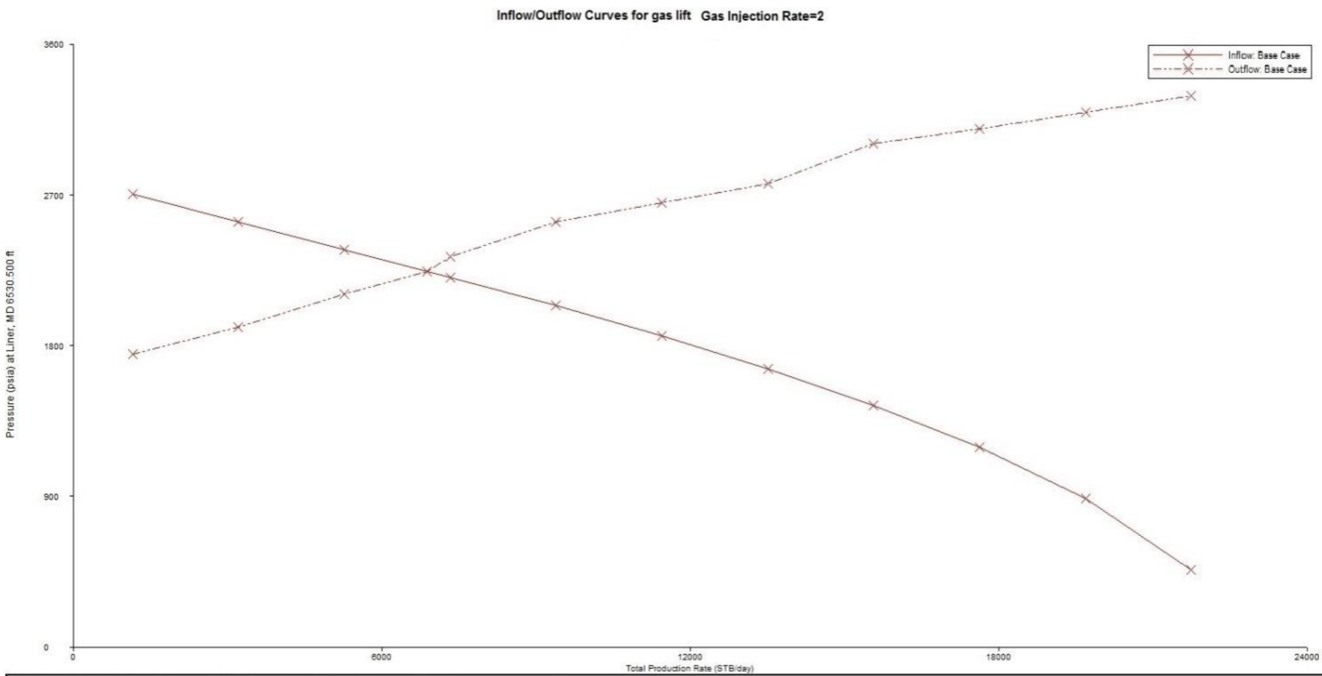


Operating Pressure (psia)	Liquid Rate (STB/day)	Oil Rate (STB/day)	Water Rate (STB/day)	Gas Rate (MMSCF/day)	Water Cut (per cent)	GOR (SCF/STB)	
2564.411	3199.785	1532.697	1667.088	0.843	52.100	550.000	Stable
2564.999	3191.316	1527.587	1663.729	0.840	52.133	550.000	Stable
2565.604	3182.588	1522.327	1660.261	0.837	52.167	550.000	Stable
2566.192	3174.110	1517.224	1656.885	0.834	52.200	550.000	Stable
2566.778	3165.667	1512.144	1653.523	0.832	52.233	550.000	Stable
2567.382	3156.955	1506.909	1650.046	0.829	52.267	550.000	Stable
2567.970	3148.487	1501.828	1646.659	0.826	52.300	550.000	Stable
2568.557	3140.027	1496.757	1643.270	0.823	52.333	550.000	Stable
2569.165	3131.292	1491.528	1639.764	0.820	52.367	550.000	Stable
2569.752	3122.835	1486.469	1636.365	0.818	52.400	550.000	Stable

Figure 4.2: Maximum Economic Water Cut Well 1

The maximum economic water for well 1 with a gas injection of 1.5MMSCFD is found to be 52.30% as shown in the figure 4.2, which shows that the when the water cut will exceed this value then the oil production rates will be less than the economic production rates that is 1500 STB/day. The process of generating this plot involves number of steps and calculation, in order to generate the plot which is pressure at liner vs total production rate including oil, gas, and water at surface conditions an input data is required which involves the designing of the tubing and gas lift valves and this is accomplished by putting the depth data for all installation equipments of completion. After depth data is given then reservoir required properties are defined into the software and after that water cut sensitivity analysis is done which includes the sensitivity analysis at all ranges to find out the water cut accurately at economic oil production rate. Usually the range that is used for sensitivity analysis is from 1% to 99% which covers the whole range from possible water cuts and after we found the economic water cut then screening criteria is followed in order to achieve the accurate maximum economic water cut.

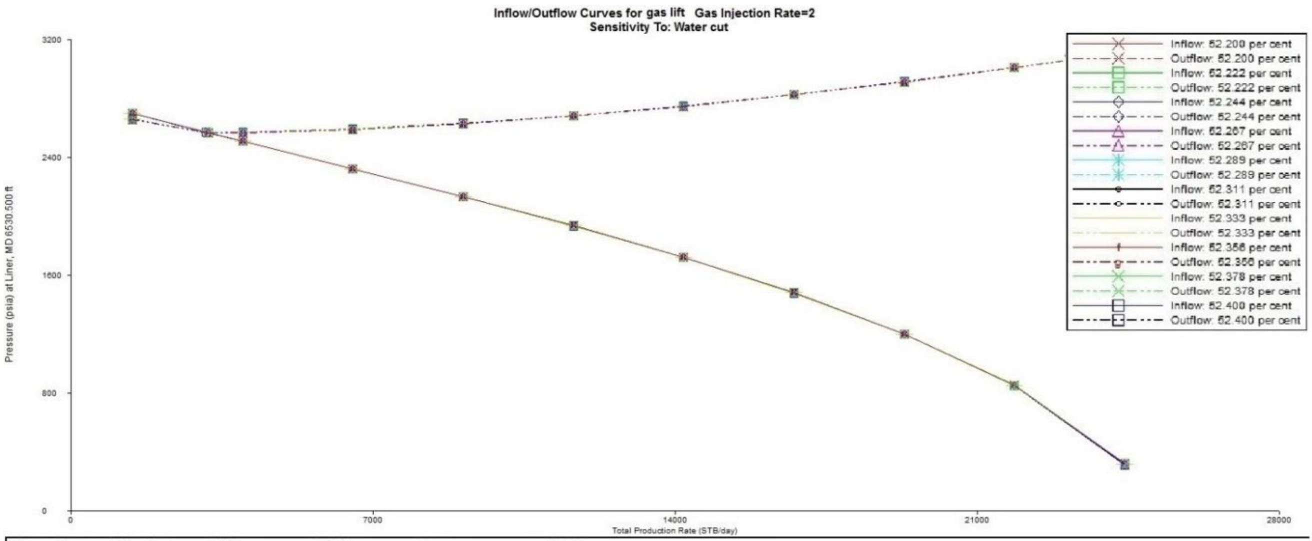
4.1.2 Well 2 Well Flo Results



Operating Pressure (psia)	Liquid Rate (STB/day)	Oil Rate (STB/day)	Water Rate (STB/day)	Gas Rate (MMSCF/day)	Water Cut (per cent)	GOR (SCF/STB)	
2243.329	6877.333	4814.132	2063.200	2.648	30.000	550.000	Stable

Figure 4.3: IPR Vs. OPR Well 2

The IPR Vs OPR intersection in the figure 4.3 shows that for well 2 the oil production rate matches with the given data that is 4814 STB/day. The procedure for generating this plot in the software involves the input of all reservoir conditions that are required such as permeability, reservoir pressure etc and the injection rate that is being used for this case. These data which is given to the software will calculate and construct the two performance curves and also calculate its point of intersection as shown in the plot, which will indicate the operating point for the production rate at reservoir condition and the flow involves oil, gas and water which is clearly mentioned at the surface or separator conditions. The plot also includes the calculation of GOR which also supports the suitability of gas lift method as it is high. This whole process is repeated until the results obtained are fully screened for finding out the accurate results.

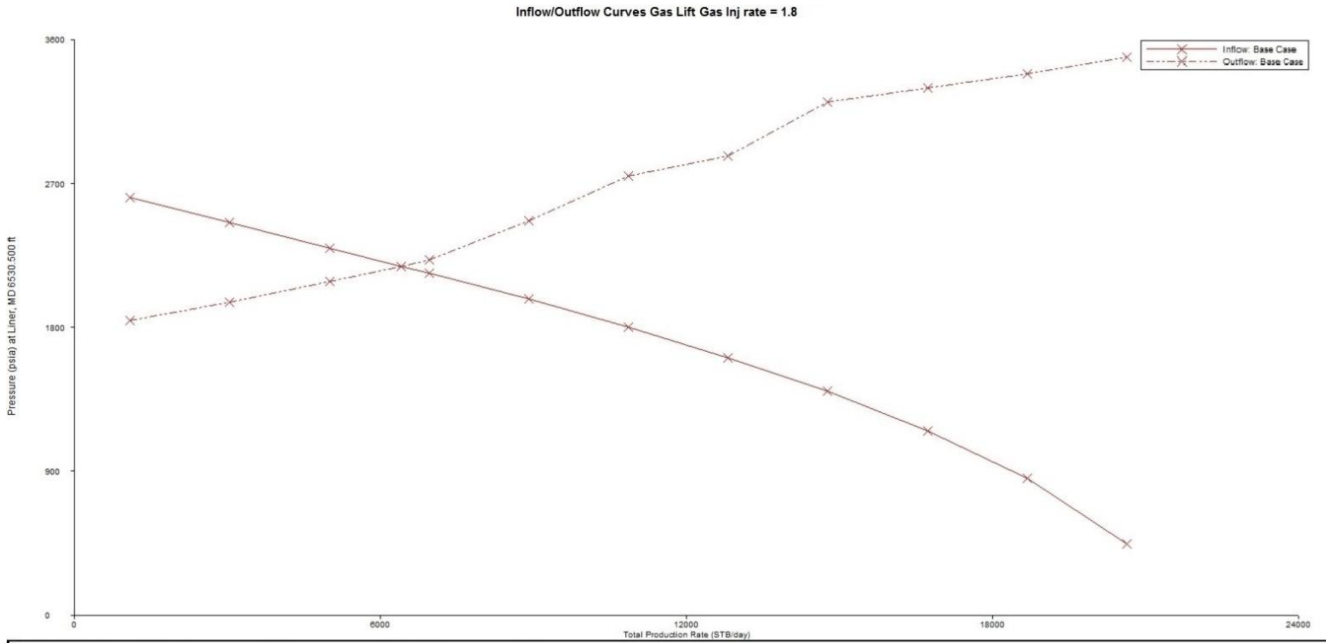


Operating Pressure (psia)	Liquid Rate (STB/day)	Oil Rate (STB/day)	Water Rate (STB/day)	Gas Rate (MMSCF/day)	Water Cut (per cent)	GOR (SCF/STB)	
2566.198	3174.027	1517.185	1656.842	0.834	52.200	550.000	Stable
2566.590	3168.379	1513.788	1654.591	0.833	52.222	550.000	Stable
2566.980	3162.754	1510.405	1652.349	0.831	52.244	550.000	Stable
2567.389	3156.862	1506.865	1649.997	0.829	52.267	550.000	Stable
2567.781	3151.219	1503.478	1647.741	0.827	52.289	550.000	Stable
2568.173	3145.565	1500.089	1645.477	0.825	52.311	550.000	Stable
2568.564	3139.940	1496.715	1643.225	0.823	52.333	550.000	Stable
2568.975	3134.022	1493.173	1640.849	0.821	52.356	550.000	Stable
2569.367	3128.377	1489.795	1638.581	0.819	52.378	550.000	Stable
2569.760	3122.735	1486.422	1636.313	0.818	52.400	550.000	Stable

Figure 4.4: Maximum Economic Water Cut Well 2

As shown in figure 4.4 the maximum economic water cut for well 2 under 2 MMSCFD is found to be 52.31%. The result has been obtained by using well Flo 3.8.7 and here sensitivity analysis is conducted and the input gas injection is used for this particular well and achieved result of maximum economic water cut for economic oil rate that is 1500 stb/day which is found to be 52.31% and this result shows that economic oil production can be achieved till we reach a water cut of 53.31%. Using this result we can also calculate the cumulative oil production for this well till depletion which will give a clear idea for economic analysis which includes the investments and outcomes comparison.

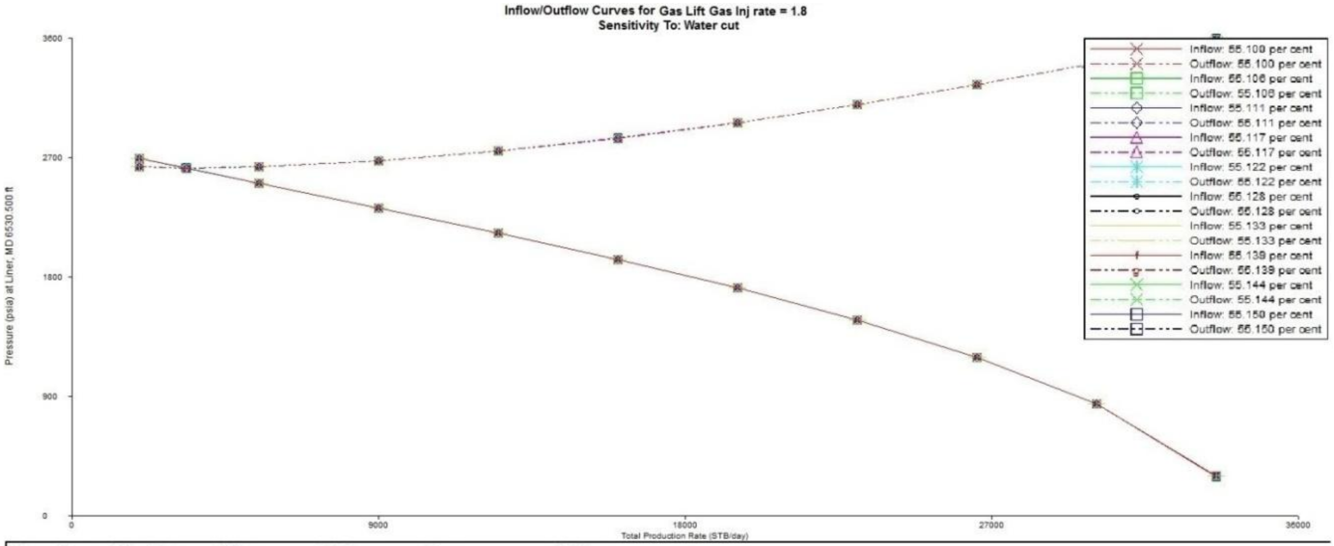
4.1.3 Well 3 Well Flo Results



Operating Pressure (psia)	Liquid Rate (STB/day)	Oil Rate (STB/day)	Water Rate (STB/day)	Gas Rate (MMSCF/day)	Water Cut (per cent)	GOR (SCF/STB)	
2183.383	6402.084	4481.459	1920.625	2.465	30.000	550.000	Stable

Figure 4.5: IPR Vs. OPR Well 3

Figure 4.5 shows the results for the oil production rate for well 3 which by using Well flo 3.8.7 are achieved. In the figure 4.5 inflow and out flow curves were generated and there intersection gives the oil production rate that is 4481STB of oil per day. This result is generated by specifying the inlet conditions to software which includes the required reservoir properties and the current gas injection rate that is being applied which will allow the software to make an efficient estimation of production rate which will affect the estimation or cumulative oil production for this well. For the overall comparison and economic analysis it is necessary to calculate the ability or productivity analysis of the well which gives a direction to invest efficiently considering the fact of total life and output of well.



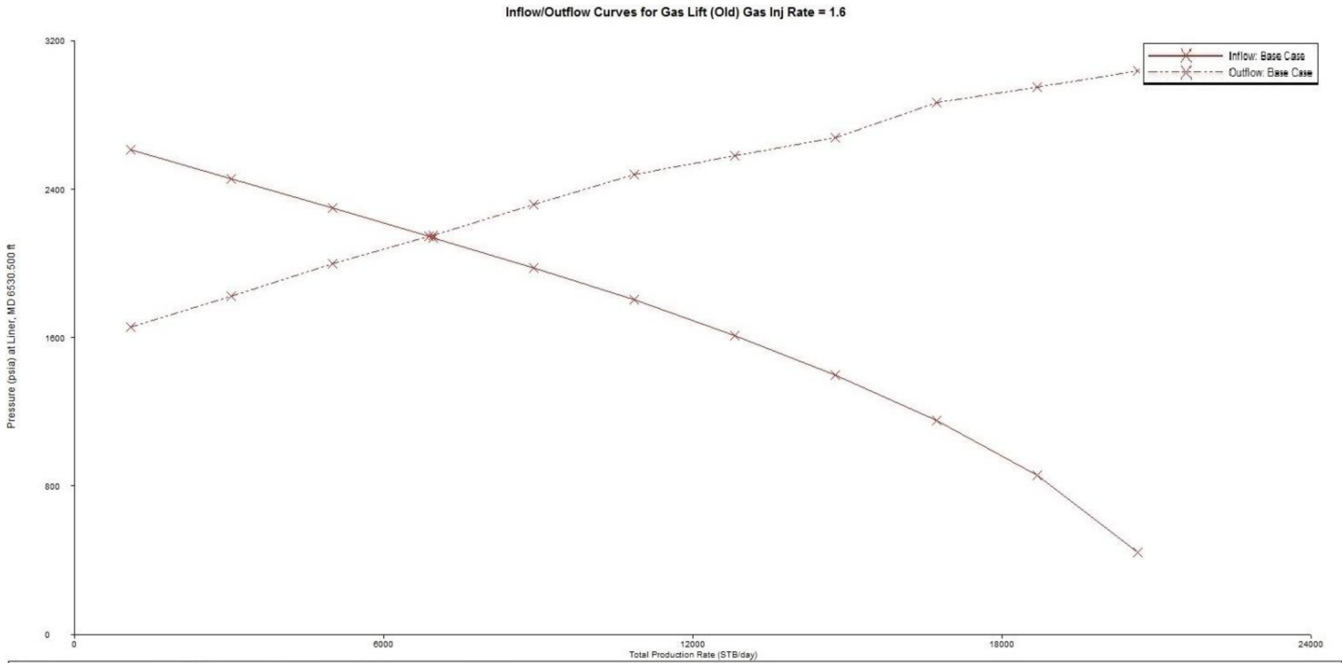
Operating Pressure (psia)	Liquid Rate (STB/day)	Oil Rate (STB/day)	Water Rate (STB/day)	Gas Rate (MMSCF/day)	Water Cut (per cent)	GOR (SCF/STB)	
2620.098	3350.626	1504.431	1846.195	0.827	55.100	550.000	Stable
2620.205	3348.533	1503.290	1845.243	0.827	55.106	550.000	Stable
2620.294	3346.793	1502.342	1844.451	0.826	55.111	550.000	Stable
2620.402	3344.705	1501.204	1843.501	0.826	55.117	550.000	Stable
2620.491	3342.967	1500.256	1842.710	0.825	55.122	550.000	Stable
2620.597	3340.886	1499.123	1841.764	0.825	55.128	550.000	Stable
2620.686	3339.167	1498.184	1840.983	0.824	55.133	550.000	Stable
2620.794	3337.058	1497.037	1840.020	0.823	55.139	550.000	Stable
2620.883	3335.330	1496.095	1839.234	0.823	55.144	550.000	Stable
2620.990	3333.240	1494.958	1838.282	0.822	55.150	550.000	Stable

Figure 4.6: Maximum Economic Water Cut Well 3

The maximum economic water cut for well 3 as shown in the figure 4.6 is found to be 55.12% with 1.8 MMSCFD; the result is achieved by using well flo 3.8.7.

The process of generating this plot involves number of steps and calculation, in order to generate the plot which is pressure at liner vs total production rate including oil, gas, and water at surface conditions an input data is required which involves the designing of the tubing and gas lift valves and this is accomplished by putting the depth data for all installation equipments of completion. After depth data is given then reservoir required properties are defined into the software and after that water cut sensitivity analysis is done which includes the sensitivity analysis at all ranges to find out the water cut accurately at economic oil production rate. Usually the range that is used for sensitivity analysis is from 1% to 99% which covers the whole range from possible water cuts and after we found the economic water cut then screening criteria is followed in order to achieve the accurate maximum economic water cut.

4.1.4 Well 4 Well Flo Results

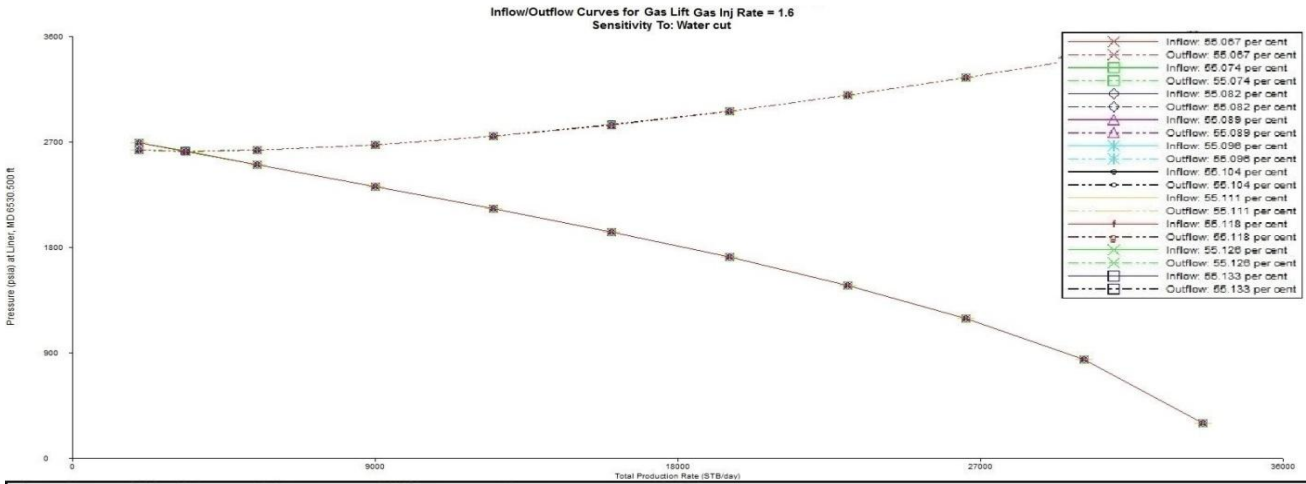


Operating Pressure (psia)	Liquid Rate (STB/day)	Oil Rate (STB/day)	Water Rate (STB/day)	Gas Rate (MMSCF/day)	Water Cut (per cent)	GOR (SCF/STB)	
2146.176	6863.071	4804.149	2058.921	2.642	30.000	550.000	Stable

Figure 4.7: IPR Vs. OPR Well 4

For well 4 the oil production rate from IPR&OPR curves as shown in the figure 4.7 is 4804 STB/day which is defined by the operating point of the plot shown in figure.

As the results for maximum economic water cuts are shown in the figure 4.8 which is found to be 55.1 %. For finding out the results for operating point and the maximum economic water cut all the data for reservoir is defined and lift gas injection rate is also taken into consideration and after these all data are specified accurately then sensitivity analysis is carried out in order to get a clear picture for water cuts till useful production life. The water cut has to be chose corresponding to the economic oil production rate in order to know about the cumulative oil production for the whole life time of well which is crucial for the economic analysis of the well to take suitable investment.



Operating Pressure (psia)	Liquid Rate (STB/day)	Oil Rate (STB/day)	Water Rate (STB/day)	Gas Rate (MMSCF/day)	Water Cut (per cent)	GOR (SCF/STB)	
2619.511	3363.289	1511.227	1852.063	0.831	55.067	550.000	Stable
2619.635	3360.859	1509.900	1850.960	0.830	55.074	550.000	Stable
2619.778	3358.089	1508.386	1849.702	0.830	55.082	550.000	Stable
2619.903	3355.649	1507.055	1848.594	0.829	55.089	550.000	Stable
2620.027	3353.222	1505.731	1847.491	0.828	55.096	550.000	Stable
2620.170	3350.440	1504.213	1846.226	0.827	55.104	550.000	Stable
2620.294	3348.019	1502.892	1845.127	0.827	55.111	550.000	Stable
2620.418	3345.592	1501.568	1844.024	0.826	55.118	550.000	Stable
2620.562	3342.799	1500.048	1842.751	0.825	55.126	550.000	Stable
2620.686	3340.379	1498.728	1841.651	0.824	55.133	550.000	Stable

Figure 4.8: Maximum Economic Water Cut Well 4

The results that are discussed below are for increased gas lift volumes for every well and the plots generated by using well Flo3.8.7 includes the increased optimum injection rates for gas lift, the optimum oil production rates and the maximum economic water cuts. . The process of generating this plot involves number of steps and calculation, in order to generate the plot which is pressure at liner vs total production rate including oil, gas, and water at surface conditions an input data is required which involves the designing of the tubing and gas lift valves and this is accomplished by putting the depth data for all installation equipments of completion. After depth data is given then reservoir required properties are defined into the software and after that water cut sensitivity analysis is done which includes the sensitivity analysis at all ranges to find out the water cut accurately at economic oil production rate. Usually the range that is used for sensitivity analysis is from 1% to 99% which covers the whole range from possible water cuts and after we found the economic water cut then screening criteria is followed in order to achieve the accurate maximum economic water cut.

4.1.5 Optimized Gas Injection Rates For Well 1

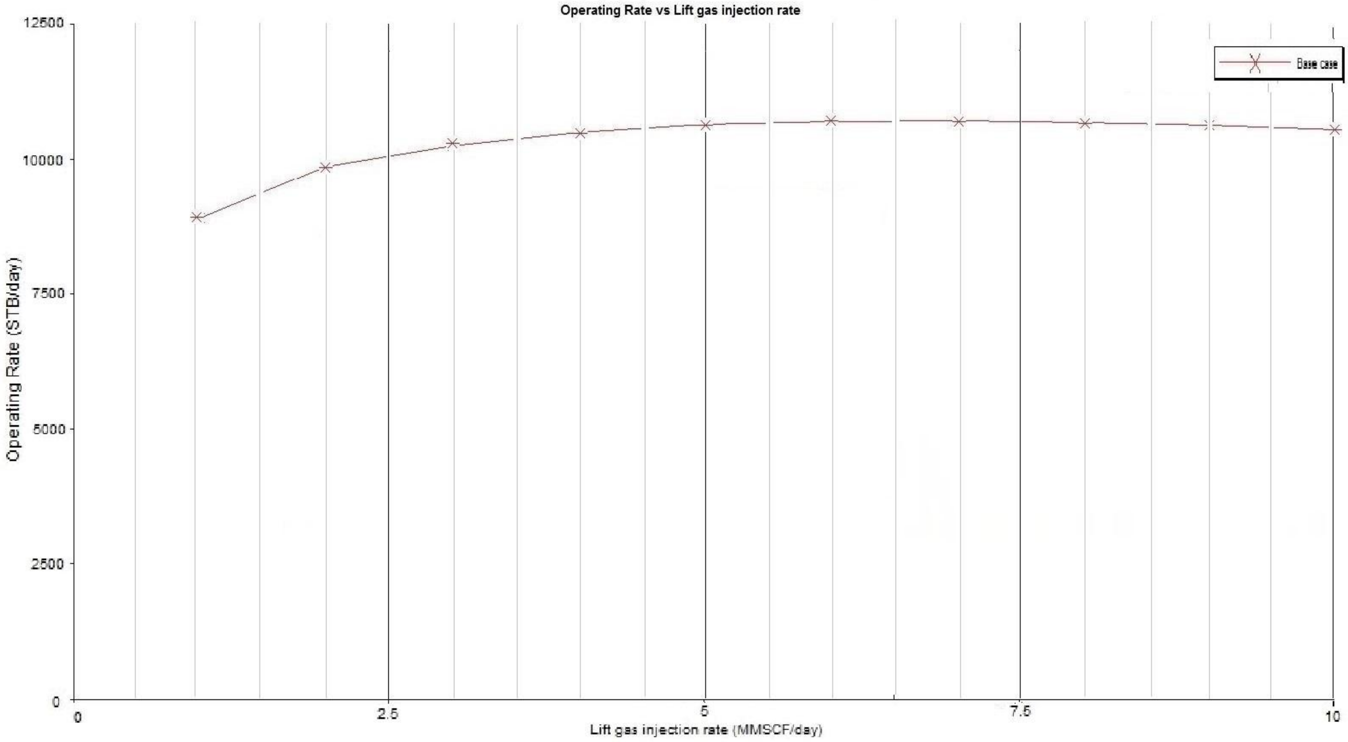
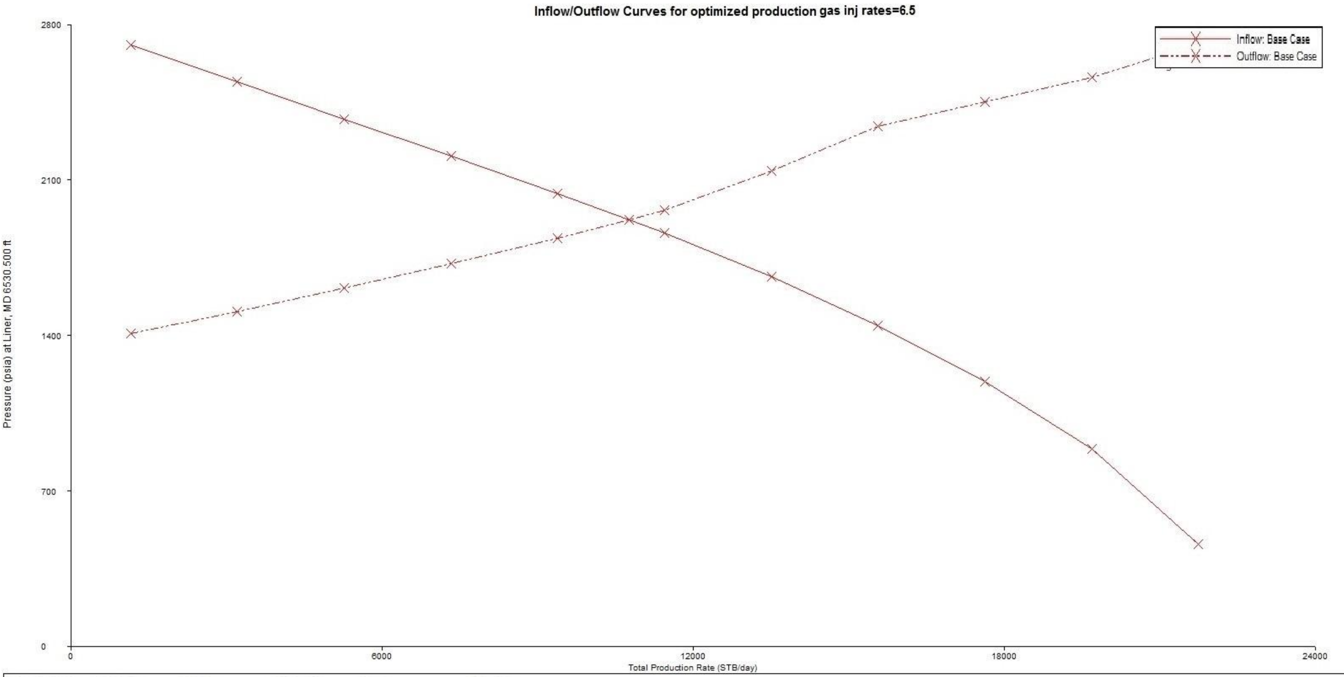


Figure 4.9: Optimum Gas Injection Rates Well 1

Figure 4.9 shows the plot of operating rates vs. gas injection rates and the injection rate that is optimum is 6.5 MMSCFD which yields maximum oil production. By using the well flo the plot is generated between operating rate and lift gas injection rate and the procedure of generating this plot is to specify the required data to the soft ware which includes the reservoir properties and the sensitivity analysis of gas lift injection rates from 0 to 10 MMSCFD in order to generate a plot which will give a trend of different oil rates at different injection rates with an increment of 0.5 MMSCFD. The observed results were analyzed to check that which injection rates yield maximum production rates as in this case it is 6.5 MMSCFD. To be more accurate the software provides exact production rates at every single point on the trend and it makes the jog very easy to select the accurate injection rate by checking and selecting the maximum production rate. As it can be seen from the lot that production is decreasing at the end of the trend which clearly shows the gas slippage effect which means injecting more than optimum will result in decrease in oil production.

4.1.6 Optimum Oil Production Rate For Well 1

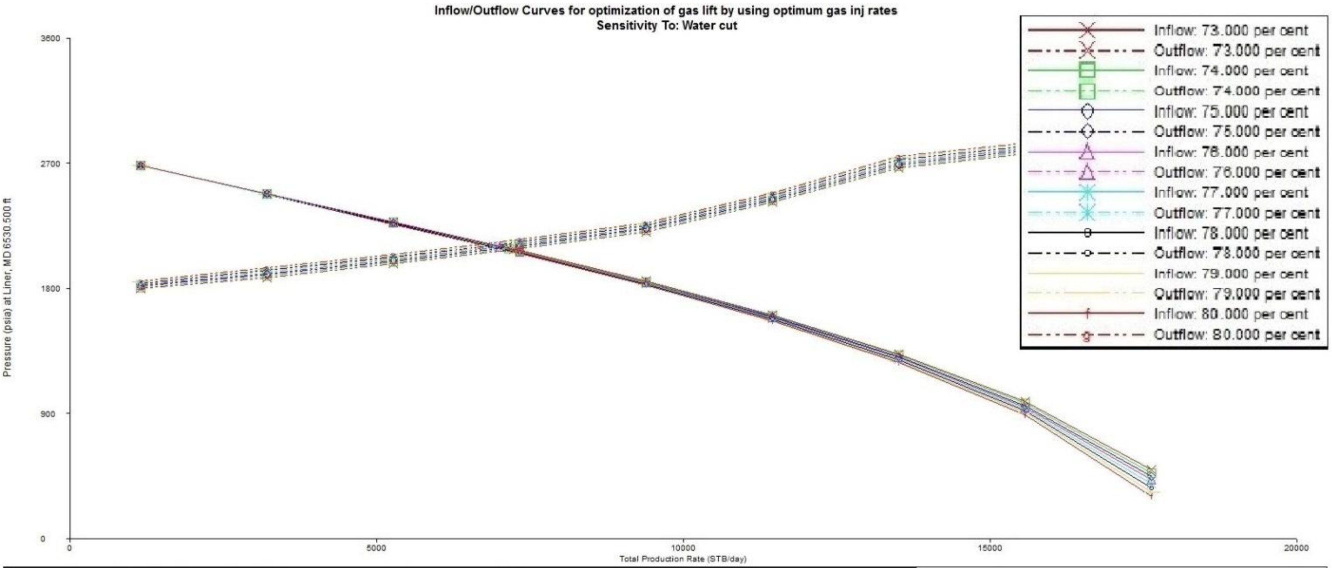


Operating Pressure (psia)	Liquid Rate (STB/day)	Oil Rate (STB/day)	Water Rate (STB/day)	Gas Rate (MMSCF/day)	Water Cut (per cent)	GOR (SCF/STB)	
1921.842	10749.476	7524.632	3224.843	4.139	30.000	550.000	Stable

Figure 4.10: IPR Vs. OPR Well 1

Figure 4.10 shows the plots of inflow and out flow curves and their intersection gives the operating point which shows the optimum production rates for well 1 and that rate is found to be 7524 STB/day. The criteria for generating this plot in the software involves the input of all reservoir conditions that are required such as permeability, reservoir pressure etc and the injection rate that is being used for this case. These data which is given to the software will calculate and construct the two performance curves and also calculate its point of intersection as shown in the plot, which will indicate the operating point for the production rate at reservoir condition and the flow involves oil, gas and water which is clearly mentioned at the surface or separator conditions. The plot also includes the calculation of GOR which also supports the suitability of gas lift method as it is high. This whole process is repeated until the results obtained are fully screened for finding out the accurate results.

4.1.7 Maximum Economic water cut for well 1



Operating Pressure (psia)	Liquid Rate (STB/day)	Oil Rate (STB/day)	Water Rate (STB/day)	Gas Rate (MMSCF/day)	Water Cut (per cent)	GOR (SCF/STB)	
2082.383	7227.519	1951.430	5276.089	1.073	73.000	550.000	Stable
2087.018	7150.670	1859.174	5291.496	1.023	74.000	550.000	Stable
2091.707	7073.944	1768.486	5305.458	0.973	75.000	550.000	Stable
2096.450	6997.330	1679.359	5317.970	0.924	76.000	550.000	Stable
2102.442	6909.125	1589.099	5320.026	0.874	77.000	550.000	Stable
2107.260	6833.126	1503.288	5329.837	0.827	78.000	550.000	Stable
2112.885	6749.913	1417.481	5332.431	0.780	79.000	550.000	Stable
2117.774	6674.504	1334.900	5339.603	0.734	80.000	550.000	Stable

Figure 4.11: Maximum Economic Water Cut Well 1

The figure 4.11 shows the maximum economic water cut is 78%. Above which oil production will be not economical. The steps generating this plot involves number of steps and calculation, in order to generate the plot which is pressure at liner vs total production rate including oil, gas, and water at surface conditions an input data is required which involves the designing of the tubing and gas lift valves and this is accomplished by putting the depth data for all installation equipments of completion. After depth data is given then reservoir required properties are defined into the software and after that water cut sensitivity analysis is done which includes the sensitivity analysis at all ranges to find out the water cut accurately at economic oil production rate.

4.1.8 Optimized gas injection rates for well 2

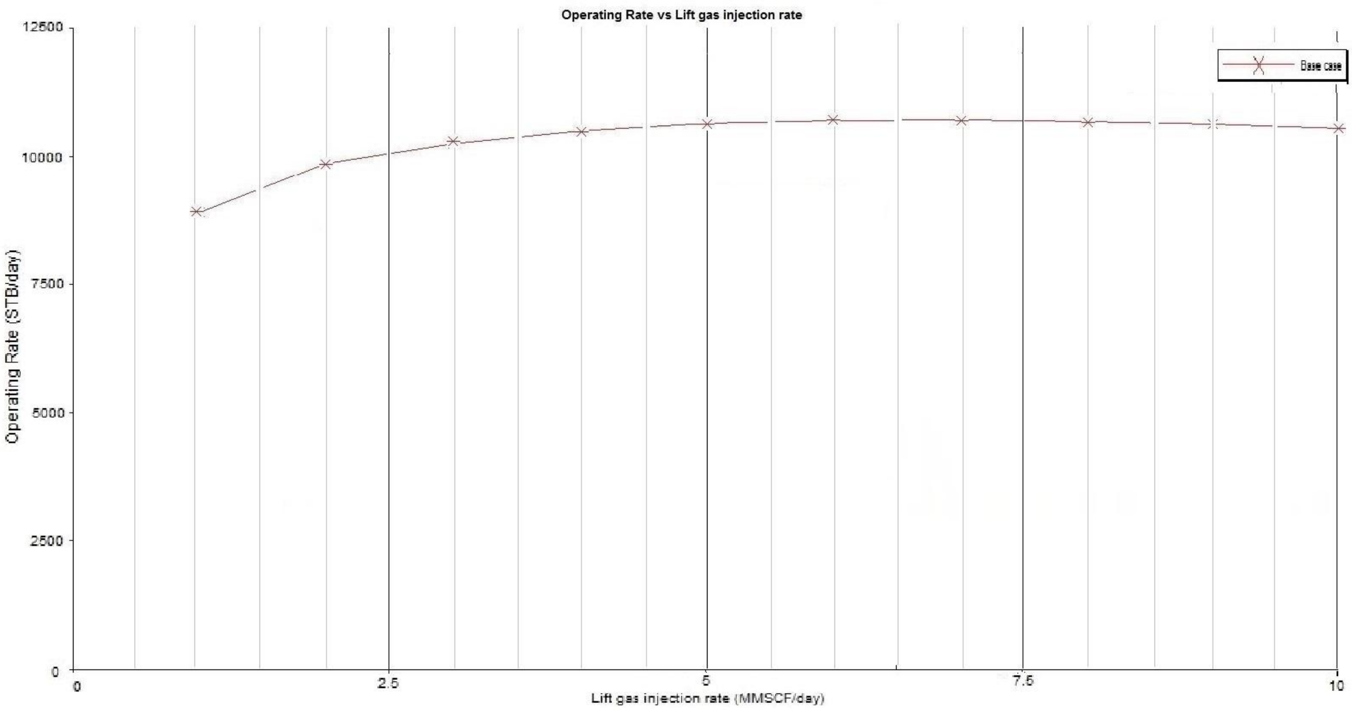
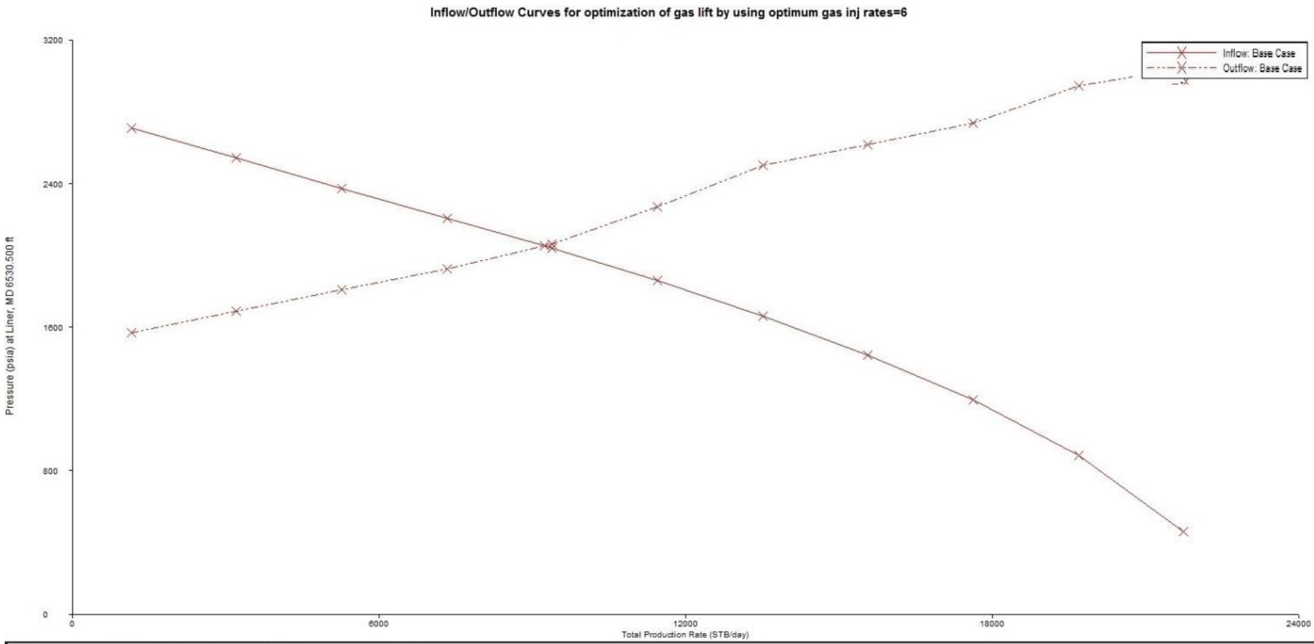


Figure 4.12: Optimum Gas Injection Rates Well 2

The optimum gas injection rate for well 2 founded is 6 MMSCFD as it's shown in figure 4.12. The results show that this injection rate suggests an optimum oil production. . By using the well flo the plot is generated between operating rate and lift gas injection rate and the procedure of generating this plot is to specify the required data to the soft ware which includes the reservoir properties and the sensitivity analysis of gas lift injection rates from 0 to 10 MMSCFD in order to generate a plot which will give a trend of different oil rates at different injection rates with an increment of 0.5 MMSCFD. The observed results were analyzed to check that which injection rates yield maximum production rates as in this case it is 6.0 MMSCFD. To be more accurate the software provides exact production rates at every single point on the trend and it makes the jog very easy to select the accurate injection rate by checking and selecting the maximum production rate. As it can be seen from the lot that production is decreasing at the end of the trend which clearly shows the gas slippage effect which means injecting more than optimum will result in decrease in oil production.

4.1.9 Optimum Oil Production rate for well 2

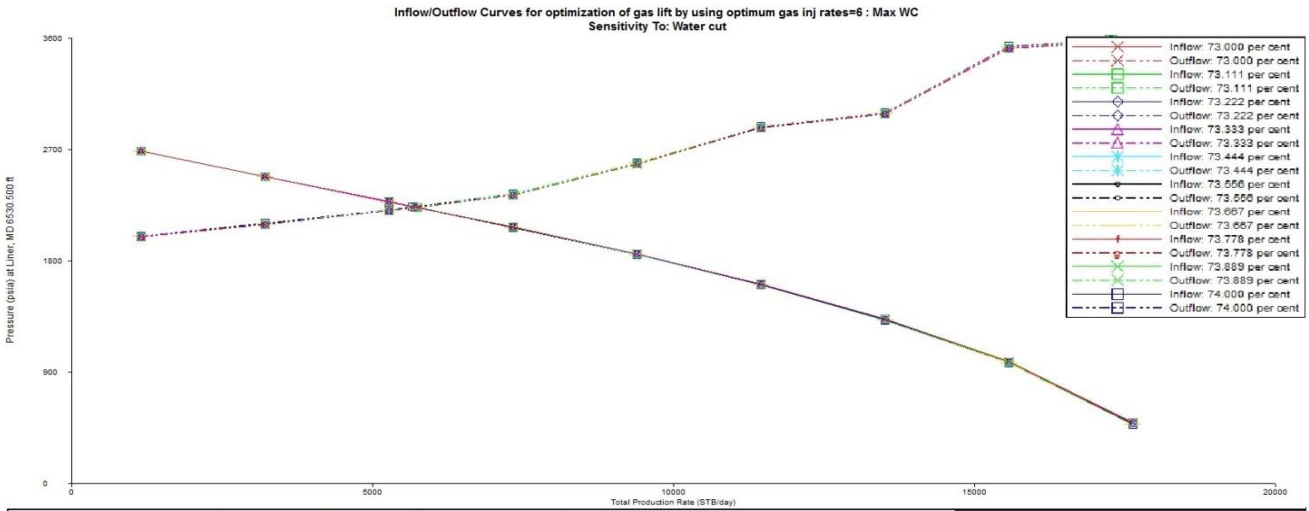


Operating Pressure (psia)	Liquid Rate (STB/day)	Oil Rate (STB/day)	Water Rate (STB/day)	Gas Rate (MMSCF/day)	Water Cut (per cent)	GOR (SCF/STB)	
2052.779	9220.286	6454.200	2766.086	3.550	30.000	550.000	Stable

Figure 4.13: IPR Vs. OPR Well 2

Figure 4.13 generated from well Flo 3.8.7 ,shows the inflow out flow plots which determines the optimum production rates for well 2 that is 6454 STB/day as a result of injection of 6.0 MMSCFD gas injection. This plot in the software involves the input of all reservoir conditions that are required such as permeability, reservoir pressure etc and the injection rate that is being used for this case. These data which is given to the software will calculate and construct the two performance curves and also calculate its point of intersection as shown in the plot, which will indicate the operating point for the production rate at reservoir condition and the flow involves oil, gas and water which is clearly mentioned at the surface or separator conditions. The plot also includes the calculation of GOR which also supports the suitability of gas lift method as it is high. This whole process is repeated until the results obtained are fully screened for finding out the accurate results.

4.1.10 Maximum Economic Water Cut For Well 2



Operating Pressure (psia)	Liquid Rate (STB/day)	Oil Rate (STB/day)	Water Rate (STB/day)	Gas Rate (MMSCF/day)	Water Cut (per cent)	GOR (SCF/STB)	
2230.887	5734.927	1548.430	4186.497	0.852	73.000	550.000	Stable
2231.456	5726.471	1539.791	4186.680	0.847	73.111	550.000	Stable
2232.025	5718.017	1531.170	4186.846	0.842	73.222	550.000	Stable
2232.595	5709.570	1522.571	4186.999	0.837	73.333	550.000	Stable
2233.165	5701.126	1513.991	4187.135	0.833	73.444	550.000	Stable
2233.741	5692.604	1505.352	4187.252	0.828	73.556	550.000	Stable
2234.312	5684.169	1496.812	4187.356	0.823	73.667	550.000	Stable
2234.884	5675.725	1488.288	4187.435	0.819	73.778	550.000	Stable
2235.456	5667.295	1479.787	4187.507	0.814	73.889	550.000	Stable
2236.030	5658.854	1471.302	4187.552	0.809	74.000	550.000	Stable

Figure 4.14: Maximum Economic Water Cut Well 2

Figure 4.14 shows the results of maximum economic water cut for well 2 that is found to be 73.60%. This result show that economic production rates for well 2 are possible to achieve until this amount of water cuts observed. The process of generating this plot involves number of steps and calculation, in order to generate the plot which is pressure at liner vs total production rate including oil, gas, and water at surface conditions an input data is required which involves the designing of the tubing and gas lift valves and this is accomplished by putting the depth data for all installation equipments of completion. After depth data is given then reservoir required properties are defined into the software and after that water cut sensitivity analysis is done which includes the sensitivity analysis at all ranges to find out the water cut accurately at economic oil production rate.

4.1.11 Well 3 Optimized Injection Rates

The figure 4.15 shows the optimum gas injection rate for well 3 that is 5.8 MMSCFD which yields that by using this injection rate the oil production will be optimum.

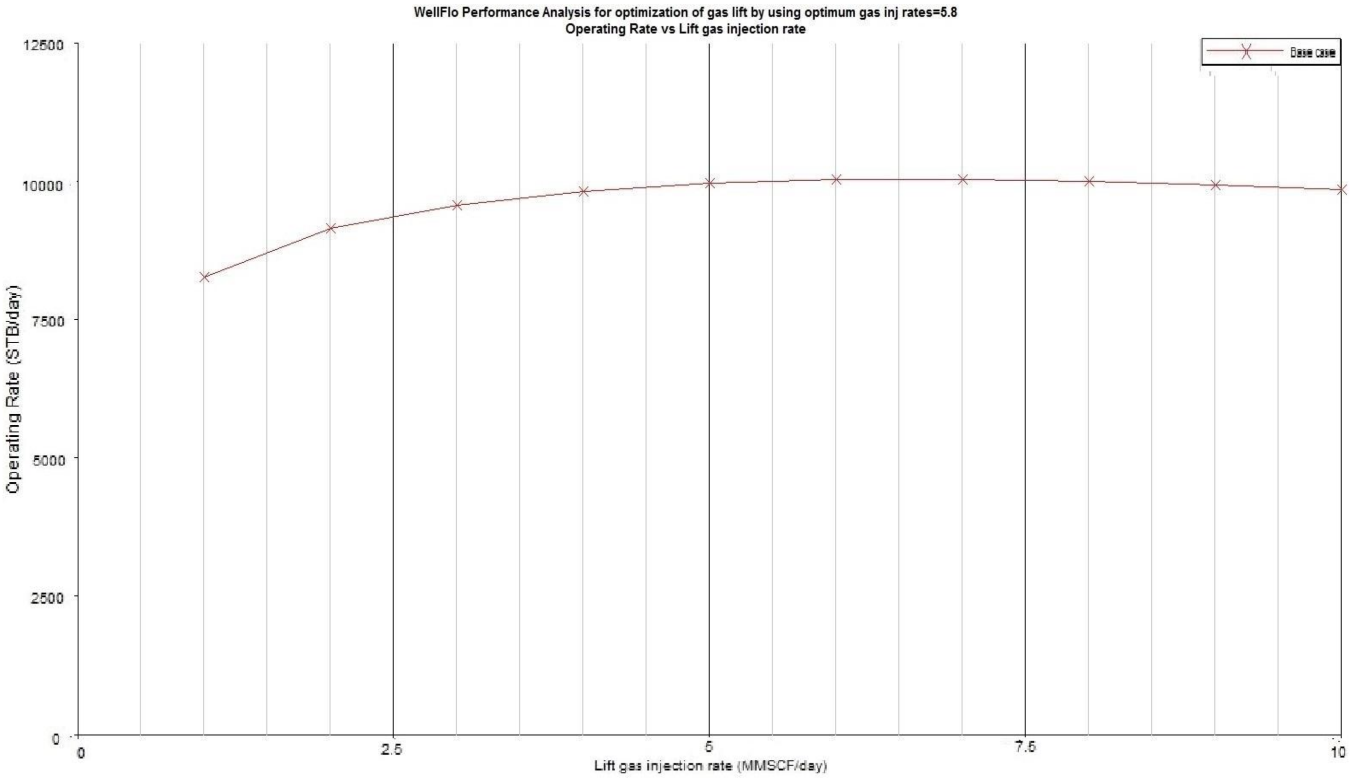
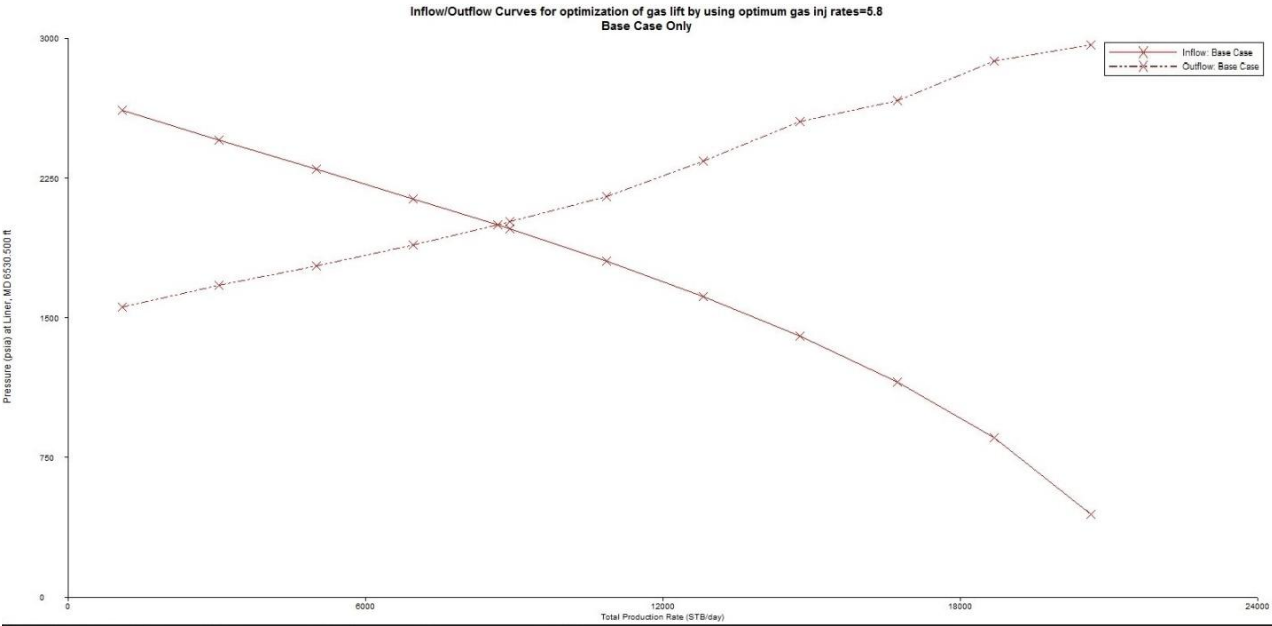


Figure 4.15: Optimum Gas Injection Rates Well 3

By using the well flo the plot is generated between operating rate and lift gas injection rate and the procedure of generating this plot is to specify the required data to the soft ware which includes the reservoir properties and the sensitivity analysis of gas lift injection rates from 0 to 10 MMSCFD in order to generate a plot which will give a trend of different oil rates at different injection rates with an increment of 0.5 MMSCFD. The observed results were analyzed to check that which injection rates yield maximum production rates as in this case it is 5.8MMSCFD. To be more accurate the software provides exact production rates at every single point on the trend and it makes the jog very easy to select the accurate injection rate by checking and selecting the maximum production rate.

4.1.12 Optimum Oil Production Rate For Well 3

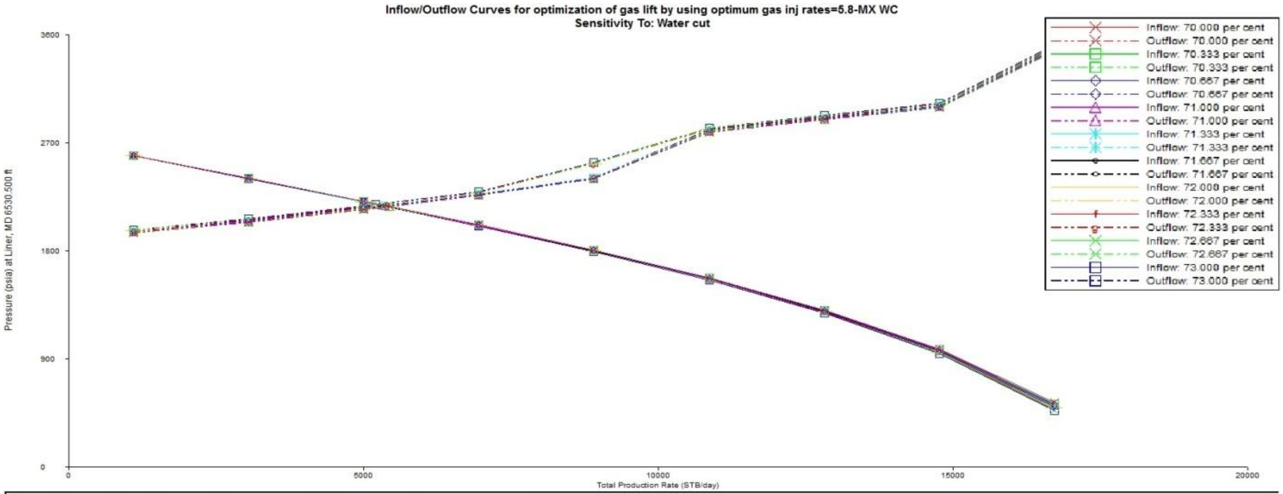


Operating Pressure (psia)	Liquid Rate (STB/day)	Oil Rate (STB/day)	Water Rate (STB/day)	Gas Rate (MMSCF/day)	Water Cut (per cent)	GOR (SCF/STB)	
1998.689	8654.119	6057.883	2596.236	3.332	30.000	550.000	Stable

Figure 4.16: IPR Vs. OPR Well 3

The figure 4.16 shows the plots generated by using well Flo3.8.7 which gives the optimum production rates for well 3 and this value is 6057 STB/day. The method for generating this plot in the software involves the input of all reservoir conditions that are required such as permeability, reservoir pressure etc and the injection rate that is being used for this case. These data which is given to the software will calculate and construct the two performance curves and also calculate its point of intersection as shown in the plot, which will indicate the operating point for the production rate at reservoir condition and the flow involves oil, gas and water which is clearly mentioned at the surface or separator conditions.

4.1.13 Maximum Economic Water Cut For Well 3



Operating Pressure (psia)	Liquid Rate (STB/day)	Oil Rate (STB/day)	Water Rate (STB/day)	Gas Rate (MMSCF/day)	Water Cut (per cent)	GOR (SCF/STB)	
2168.021	5436.226	1630.868	3805.358	0.897	70.000	550.000	Stable
2169.728	5410.893	1605.249	3805.643	0.883	70.333	550.000	Stable
2171.444	5385.505	1579.730	3805.775	0.869	70.667	550.000	Stable
2173.158	5360.239	1554.469	3805.770	0.855	71.000	550.000	Stable
2174.875	5335.014	1529.388	3805.625	0.841	71.333	550.000	Stable
2176.603	5309.738	1504.408	3805.330	0.827	71.667	550.000	Stable
2178.334	5284.519	1479.665	3804.854	0.814	72.000	550.000	Stable
2180.074	5259.280	1455.084	3804.195	0.800	72.333	550.000	Stable
2181.823	5233.999	1430.608	3803.390	0.787	72.667	550.000	Stable
2185.066	5193.747	1402.311	3791.435	0.771	73.000	550.000	Stable

Figure 4.17: Maximum Economic Water Cut Well 3

Figure 4.17 shows the result for maximum economic water cut for well 3 which is found to be 71.70 % for the economic oil production rate that is 1500 STB/day.

4.1.14 Well 4 Optimized Injection Rates

The figure 4.18 gives the result for optimum gas injection rate for well 4 and the value for optimized injection rate for this well is 5.5 MMSCFD.

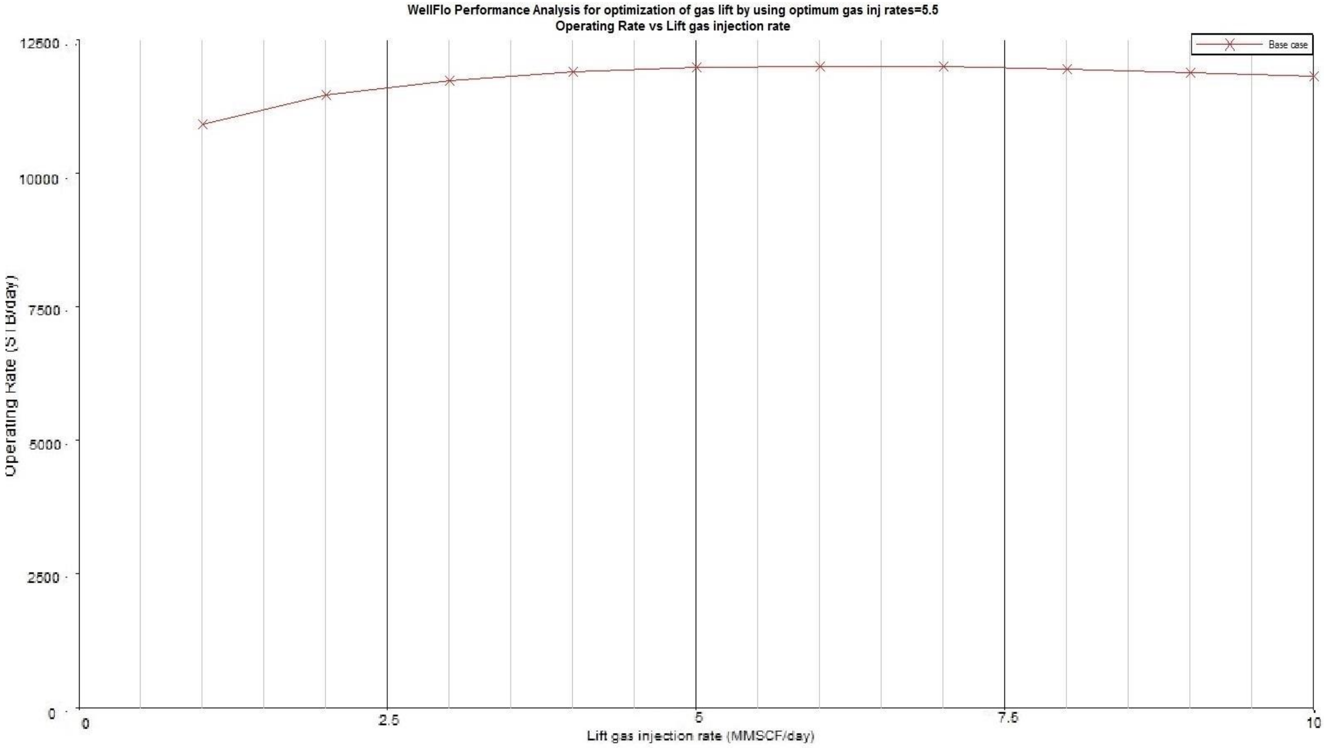
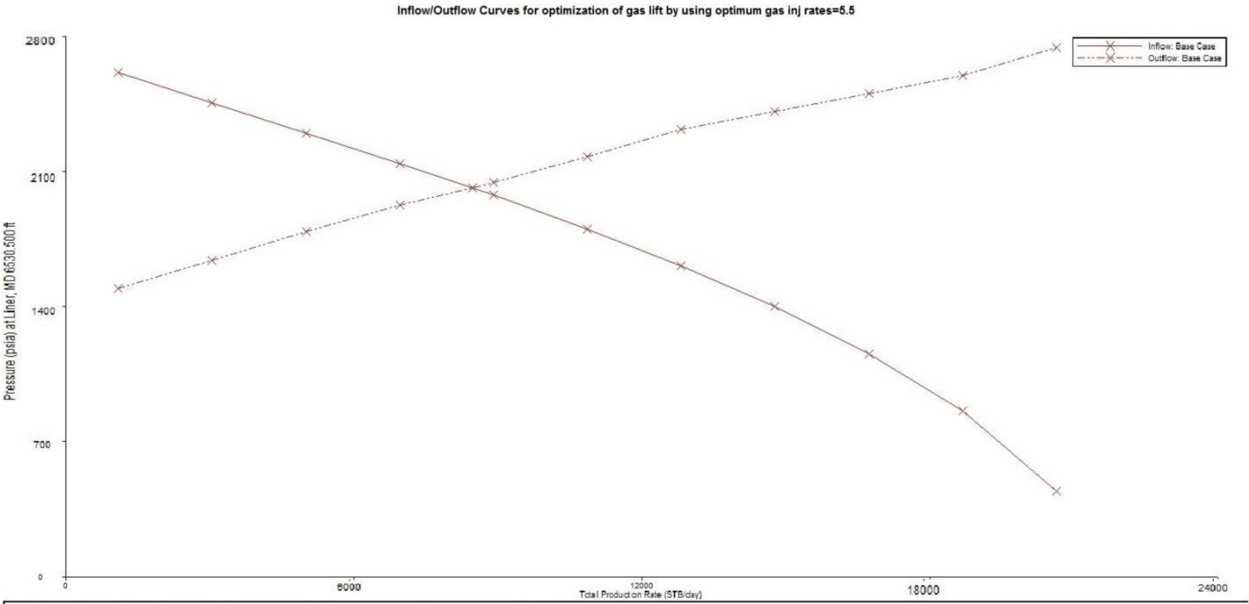


Figure 4.18: Optimum Gas Injection Rates Well 4

4.1.15 Optimum Oil Production Rate For Well 4

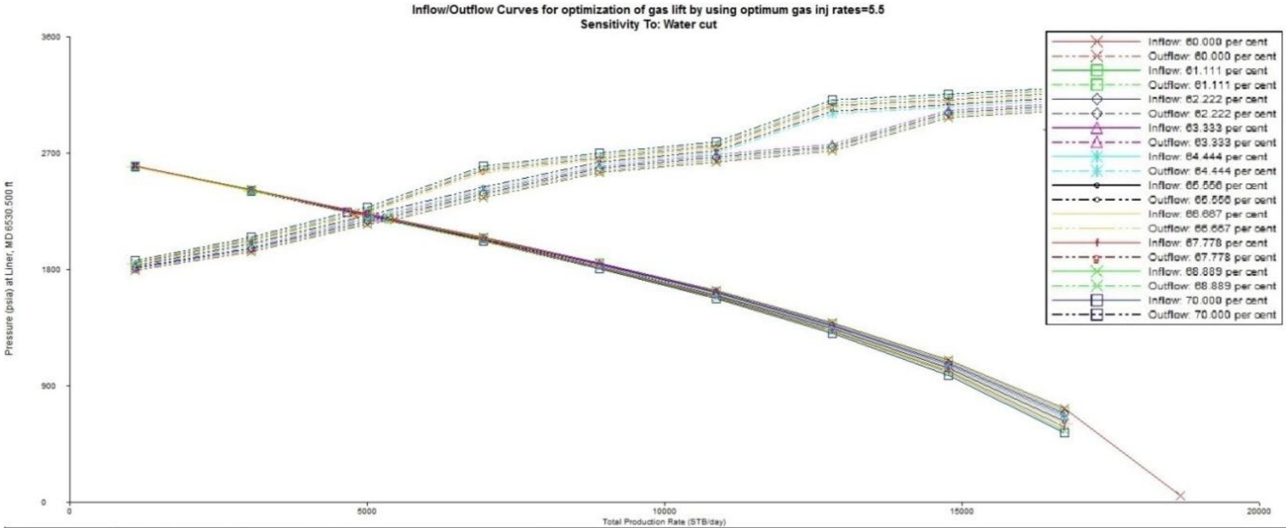


Operating Pressure (psia)	Liquid Rate (STB/day)	Oil Rate (STB/day)	Water Rate (STB/day)	Gas Rate (MMSCF/day)	Water Cut (per cent)	GOR (SCF/STB)	
2015.385	8455.962	5919.172	2536.789	3.256	30.000	550.000	Stable

Figure 4.19: IPR Vs. OPR Well 4

Figure 4.19 shows the plots of inflow and outflow curves which determines the optimum oil production rate that is 5919 stb/day.

4.1.16 Maximum Economic Water Cut For Well 4



Operating Pressure (psia)	Liquid Rate (STB/day)	Oil Rate (STB/day)	Water Rate (STB/day)	Gas Rate (MMSCF/day)	Water Cut (per cent)	GOR (SCF/STB)	
2189.310	5457.955	2183.182	3274.773	1.201	60.000	550.000	Stable
2195.439	5365.119	2086.441	3278.677	1.148	61.111	550.000	Stable
2201.536	5273.571	1992.249	3281.321	1.096	62.222	550.000	Stable
2208.573	5173.037	1896.797	3276.239	1.043	63.333	550.000	Stable
2214.567	5084.422	1807.817	3276.605	0.994	64.444	550.000	Stable
2220.527	4997.037	1721.179	3275.857	0.947	65.556	550.000	Stable
2226.438	4911.035	1636.995	3274.040	0.900	66.667	550.000	Stable
2233.315	4815.909	1551.782	3264.127	0.853	67.778	550.000	Stable
2239.108	4732.853	1472.438	3260.415	0.810	68.889	550.000	Stable
2244.859	4651.029	1395.309	3255.720	0.767	70.000	550.000	Stable

Figure 4.20: Maximum Economic Water Cut Well 4

For well 4 maximum economic water is given by the figure 4.20 which is selected as 68 % for the economic production rate suggesting the maximum value of water cut for well 4 until economic range of oil production. The procedure involves the sensitivity analysis of water cut and for that different ranges are tried in order to achive the water cut at 1500 stb/day which is the economic oil production rate. The results can be screened more upto three decimal places in order to find the most accurate value of maximum economic water cut.

4.2 Gas Lift Optimization and Comparison

All the results for initial case that is oil production rates, maximum economic water cuts and the optimized case including injection gas lift volumes, increased oil production rates and improved maximum economic water cuts for all 4 wells are summarized in the table below and discussed and further discussed.

Table 4.2: Summary of all results achieved by using well Flo 3.8.7

Well no	Initial injection rates MMSCFD	Initial production rates STB/d	Initial maximum economic water cut %	Optimized gas injection rates MMSCFD	Increased production rates STB/d	Improved maximum economic water cut %
Well 1	1.5	5000	52.30	6.5	7524	78.00
Well 2	2	4814	52.31	6.0	6454	73.60
Well 3	1.8	4481	55.13	5.8	6057	71.70
Well 4	1.6	4804	55.10	5.5	5919	68.00

Initial given data is used to find out the initial oil production rates for all four wells and hence maximum economic water cuts are evaluated by using well Flo3.8.7 for comparison with the optimized condition. The optimized gas injection volumes were calculated followed by increased production rates and improved maximum economic water cuts. As we compare the results of initial conditions and optimized conditions for well 1 which implies that after evaluating the optimized gas lift injection rate the oil production rate increased from 5000stb/day to 7524stb/day which is a considerable amount but most importantly the evaluation of maximum economic water cut improvement is remarkable initially it was 52.30% and in the second case it is optimized up to 78% which shows that the cumulative oil produced will be also high in terms of total recovery. For well 2 the initial oil production rates also improved from 4814stb/day to 6454stb/day which is again a good improvement and also the maximum economic water cut improved from 52.31% to 73.66%. In well 3 oil rates improved from 4481stb/day to 6057 stb/day and water cut is now 71.66% and finally well 4 in which production daily rates increased from 4804 stb/day to 5919stb/day and maximum economic water was 55.10 % for the initial case and 68% for the optimized case.

Total production rate for all wells at initial conditions is 19099stb/day and for the optimized case the total daily production rate is around 25954 stb/day, so the total increase of 6856 std/day and the considerable amount of improvements in the values of maximum economic water cuts which will surely increase the overall production of oil hence representing the optimized and efficient gat lift process.

4.2.1 Optimization of Compression Train

The train includes three different stages of centrifugal compressor, each stage comprises of a scrubber, Compressor and Cooler. To accommodate increased injection volumes with sufficient discharge pressures to lift the well efficiently the compression train is optimized because as the compression equipment cost is higher than the capital cost of down hole gas lift equipments so therefore the plan was to achieve the compression targets for increased flow by using the available compression unit. Power requirements were also calculated through HYSIS simulation for initial design conditions and for the optimized conditions to

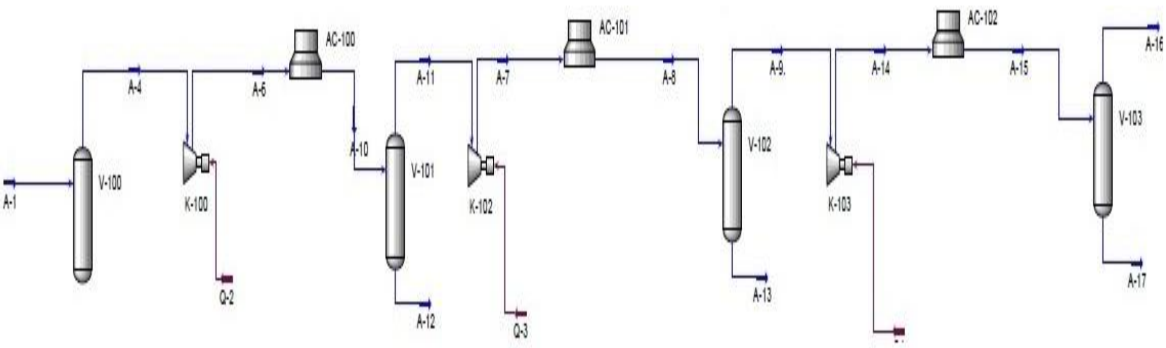


Figure 4.21: Three stage compression train system, (HYSIS).

Compare and check the feasibility for the optimized case. HYSIS model indicating the three stage compression system over view is shown in the Figure 4.21.

4.2.2 Compression simulation Design for initial conditions

This includes the simulation model of the three stages of the centrifugal compression train on the basis of operating design capacity that is how much gas a compressor can handle at the design discharge pressure. The initial design parameters are given below in the Table 4.3.

Table 4.3: Design Capacities of three stage compressor

Type	**Operating design volumetric capacity (MMSCFD)**	**Operating design discharge pressure (Psig)**
Multi stage Centrifugal Compressor	20	3500

1st Stage of Compression

The simulation model generated for the first stage compression is shown in the figure 4.22.

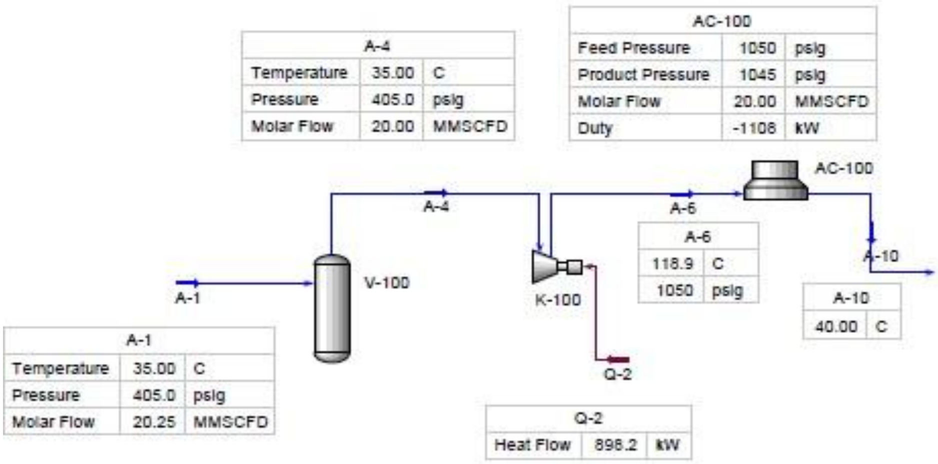


Figure 4.22: Schematic of 1st Compression stage, (HYSIS)

Inlet feed conditions and the temperatures were specified and the discharge pressure was defined for input simulation and these details are given in appendix A and appendix B.

The inlet or feeding pressure of the gas stream that is coming from the gas supply source is 405 psig with a temperature of 35 degree centigrade and as we know that operating design is 20 MMSCFD which is entering into the scrubber V-100 where gas condensate and mist is recovered, then the gas stream enters the first stage compressor K-100 and discharged at the pressure of 1050 psig. As the compression is high temperature and pressure phenomenon so the gas stream is fed to the cooler AC-100 to decrease the temperature from 119 to 40 degree centigrade.

2nd Stage of Compression

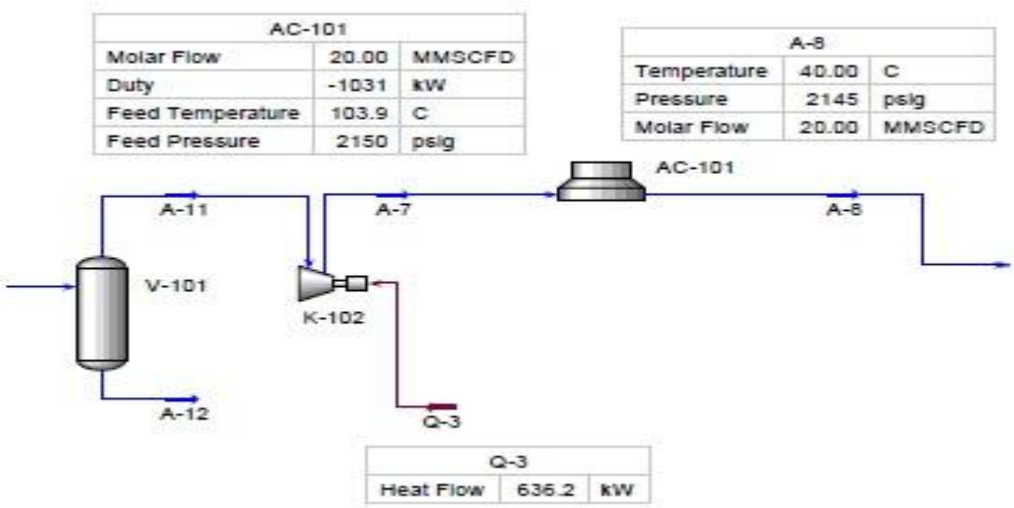


Figure 4.23: Schematic of 2nd Compression stage, (HYSIS)

Figure 4.23 shows the 2nd stage of compression, in this stage gas stream from the first stage enters in to the scrubber V-101 and then enters into the 2nd stage compressor K-102 with same molar flow and the discharge pressure of the gas stream is raised to 2150 psig. Gas stream then enters into cooler AC-101 where temperature is reduced from 104 to 20 degree centigrade with a pressure drop of 5 psig across the cooler.

3rd Stage of Compression

The figure of HYSIS simulation model above shows the 3rd stage

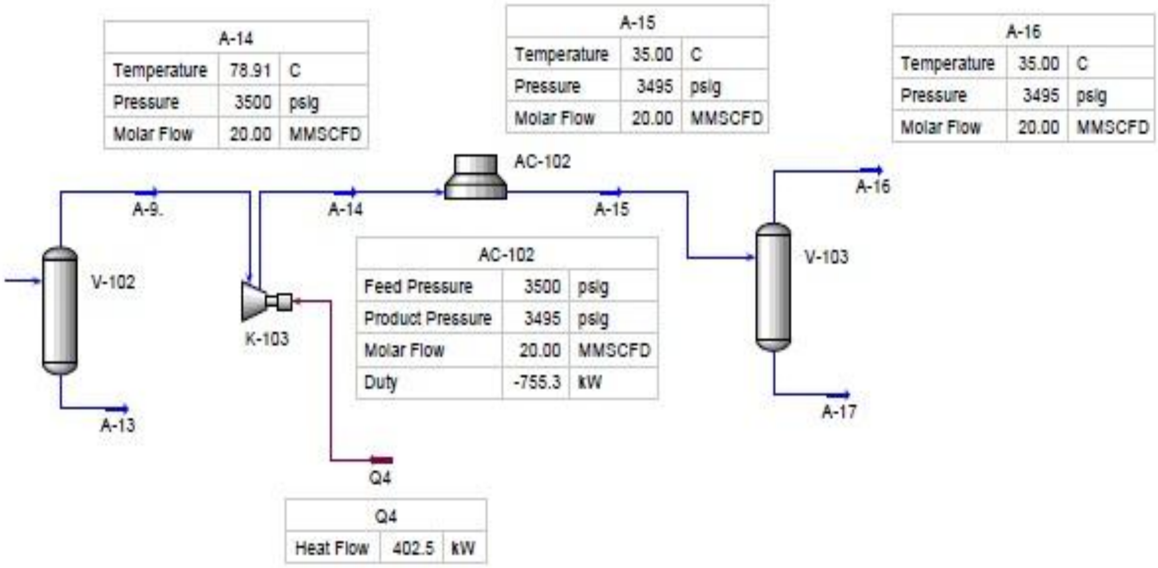


Figure 4.24: Schematic of 3rd Compression stage, (HYSIS)

stage of compression with the discharge flow of 20 MMSCFD and discharge pressure of 3495 psig this stage also has an additional scrubber V-103 for the removal of any condensate lift before injection in the all four wells

4.2.3 Compression Simulation Design for Optimized conditions

HYSIS simulation model is run for the compression design of three stage centrifugal compressor, this simulation model is run for optimized condition in order to simulate a model which can accommodate the increase in the gas lift injection volumes as these volumes exceeds the operating design volumetric capacity of 20 MMSCFD. The increased optimum gas injection rates calculated for all four wells by using well Flo is 23.8 MMSCFD and these volumes of gas were achieved at the discharge pressure of 3100 psig through optimizing the existing machine which excludes the need for adding a new compressor to the gas lift system. The fundamental phenomenon used to optimize the volumetric capacity of the compressor is involves the molar flow rates alteration by changing the compressors discharge pressure as we know that when pressure is decreased volume increases and both have inverse proportionality together as it can be understood from the study of Charles law that is P1V1=P2V2. Individual compression stages simulation is discussed below that validates this phenomenon through HYSIS simulation.

1stStage of Compression

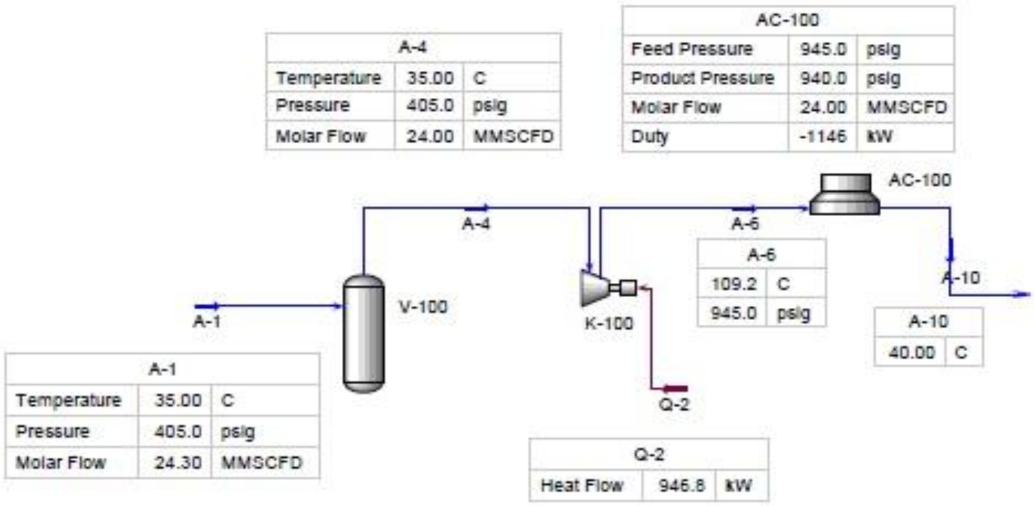


Figure 4.25: Schematic of optimized 1st Compression stage, (HYSIS)

Inlet feed conditions and the temperatures were specified and the discharge pressure was defined for input simulation and these details are given in appendix A and appendix B.

In this stage 24 MMSCFD gas at the pressure of 405 psig is fed to the scrubber V-100 and after that gas stream enters the 2nd stage compressor which discharges the gas at the pressure of 945 psig. The gas stream enters then into cooler and finally the cooled gas discharges at the pressure of 940 psig.

2nd Stage of Compression

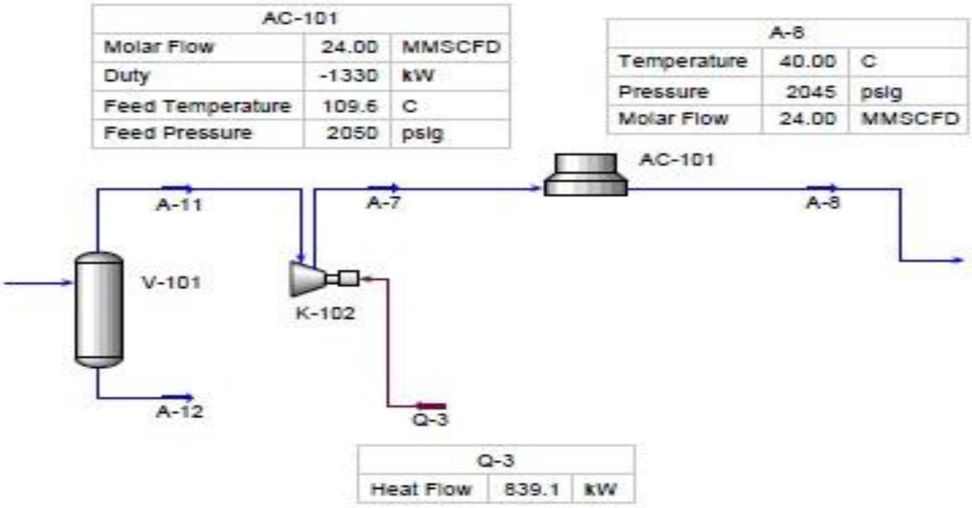


Figure 4.26 : Schematic of optimized 2nd Compression stage, (HYSIS)

The Figure 4.26 shows the simulation of 2nd stage compressor, the gas stream coming from the first stage enters into in to the scrubber V-101 for mist removal, after that it enters in the 2nd stage compressor and discharges out at 2050 psig and with the pressure drop of 5 psig in the cooler AC-101finally enters into third stage at the pressure of 2045 psig.

3rd Stage of Compression

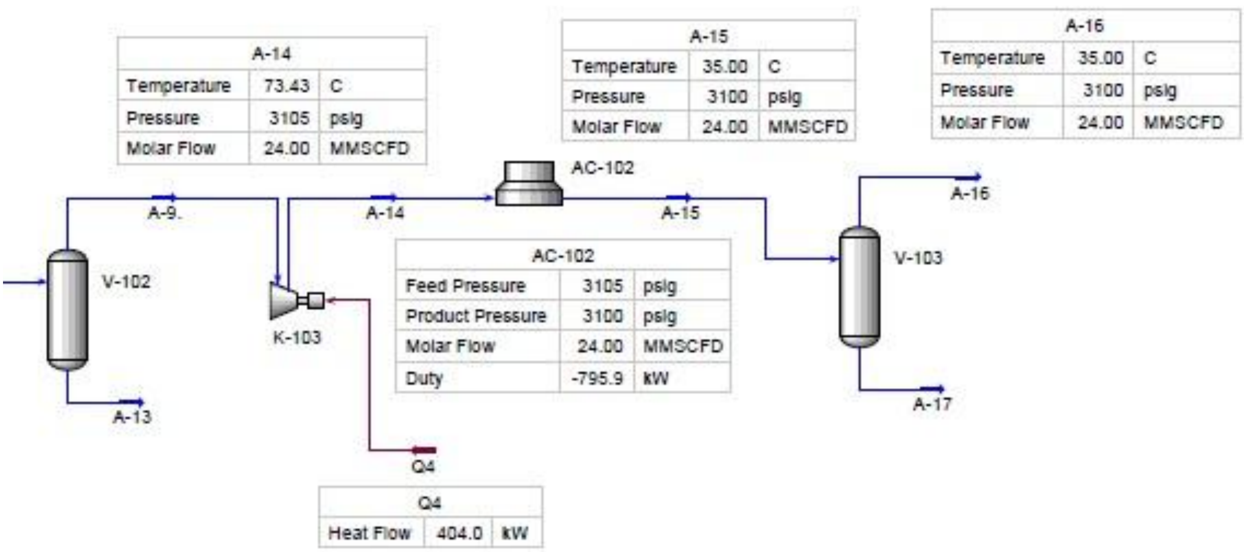


Figure 4.26 Schematic of optimized 3rd Compression stage, (HYSIS)

The Figure 4.27 shows the simulation model of the 3rd and final stage of compression where the gas stream again enters into the scrubber V-102 where the condensate is drained and recovered into the bottom. This removal of condensate is accomplished through deflection momentum loss by a deflecting plate at the entry point of gas stream and coalescence phenomenon by a demister pad. Gas then enters into the 3rd stage compressor and after compression exit the compressor having a discharge pressure of 3105 psig with the molar flow of gas of 24 MMSCFD. Hence the existing machine is successfully optimized which can provide the increased volume of gas for gas injection process and also the discharge pressure that is 3100 psig after the third stage cooler AC-102 and ultimately after the final scrubber V-103 is sufficient for gas lift process because the reservoir pressure is 2800 psia so there is a margin for 300 psig in order to kick off the well if requires and pressure requirements for continuous gas lift operation is also sufficient, in order to further decrease the pressure, throttling valves can be used either at in let of 1st stage compressor or at the discharge of 3rd stage compressor before injection into the wells.

4.2.4 Comparison for power/load requirements

Table 4.4: Power comparison required for both cases

Cases	1st Stage Power (KWh)	2nd Stage Power (KWh)	3RD Stage Power (KWh)	Total
Initial Operating condition	898	636.2	402.5	**1936.7**
Optimized Compression	946.8	839.1	404	**2189.9**

As shown in the Table 4.4 total that there is not much difference in the power requirement for both cases, the difference is 253 KW which can be neglected if the optimizations outcome in terms of increased oil rates is analyzed. Power requirements are essential to calculate because it is necessary to check the performance of optimization process. Power or duty was calculated for the individual compressor stage for both design and optimized case; it was calculated based on the operating parameters that are volumetric flow rate and the discharge pressures. Operating parameters are responsible for the operating RPMs of compressor which is directly related to the consumption of power so simulator calculates the power utilization on the basis of increase or decrease in these operating parameters. Then power required for both cases are compared to know the economic feasibility and suitability of the project. As it is also clear from the results of required power, for first stage the power requirement is higher the other stages of compression and the reason behind that is the lower suction pressure that is just 405 psig so the running RPM are comparatively higher. The increment on hourly basis for power requirement for optimized case is just 253 KW which is quite small as compared to the daily increase in oil production so this can be concluded as a good and an efficient optimization of the whole compression train with an adiabatic efficiency of 75% for all stages.

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CHAPTER 5

CONCLUSION AND RECOMENDATIONS

5.1 Conclusion

1. Optimized gas injection rates were evaluated and the total volume for gas lift was found to be 23.8 MMSCFD for all four wells. Results of optimized oil production rates and the maximum economic water cuts were compared and it was observed that gas lift system were optimized efficiently through increased oil production rates from 19099stb/day 25954stb/day and improved maximum economic water cuts from minimum 52.30% to maximum 78%.
2. Optimization of compression train was carried out to handle the increased gas lift injection volumes and also provide sufficient pressure to lift the fluids. By using HYSIS simulation software, a simulation model was developed for operating design conditions and results were found that are 20 MMSCFD molar flow and 3500 psig discharge pressure. After optimization of the compressor train results found were 24 MMSCFD molar flow at the discharge pressure of 3100 psig which is greater than reservoir pressure (2800 psig). Total power required by optimized compressor was found to be 2190 KW which was economically acceptable.

5.2 Recommendations

Following points that listed below are highly recommended for future precautions and improvements.

1. Future works should be done to address the changes occurring in the reservoir conditions as production continues, to make the gas lift process should be adaptable to these changes.
2. Steps should be taken for effective monitoring of gas lift process for example the maintenance of gas lift valves if they are passing even when they are closed will affect the performance of gas lift operation.

3. Reliability of down hole temperature and pressure gauges is crucial in terms of well monitoring; major concern should be paid regarding the selectivity of these gauges.
4. Other technical aspects such as choke size and casing pressure should be maintained according to the operational requirements.

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APENDIX A

HYSIS Simulation Data Worksheet for Design Capacity of Compression Train

LEGENDS
Burlington, MA
USA

Case Name: HYSYS (BASE CASE).HSC
Unit Set: NewUser1a
Date/Time: Sun Jun 01 07:51:50 2014

Material Stream: A-1

Fluid Package: Basis-1
Property Package: Peng-Robinson

CONDITIONS

		Overall	Vapour Phase	Liquid Phase
Vapour / Phase Fraction		0.9878	0.9878	0.0122
Temperature:	(C)	35.00 *	35.00	35.00
Pressure:	(psig)	405.0 *	405.0	405.0
Molar Flow	(MMSCFD)	20.25 *	20.00	0.2478
Mass Flow	(kg/h)	2.027e+004	1.931e+004	964.2
Std Ideal Liq Vol Flow	(USGPM)	255.9	249.3	6.646
Molar Enthalpy	(kJ/kgmole)	-7.837e+004	-7.706e+004	-1.842e+005
Molar Entropy	(kJ/kgmole-C)	156.4	157.0	109.4
Heat Flow	(kW)	-2.196e+004	-2.133e+004	-631.2
Liq Vol Flow @Std Cond	(USGPM)	---	---	6.554

PROPERTIES

		Overall	Vapour Phase	Liquid Phase
Molecular Weight		20.10	19.38	78.14
Molar Density	(kgmole/m3)	1.234	1.221	8.023
Mass Density	(kg/m3)	24.81	23.67	626.9
Act. Volume Flow	(m3/h)	817.3	815.7	1.538
Mass Enthalpy	(kJ/kg)	-3899	-3976	-2357
Mass Entropy	(kJ/kg-C)	7.782	8.101	1.400
Heat Capacity	(kJ/kgmole-C)	46.21	44.58	177.8
Mass Heat Capacity	(kJ/kg-C)	2.299	2.300	2.275
LHV Vol Basis (Std)	(kJ/kgmole)	9.483e+005	9.163e+005	3.532e+006
LHV Mass Basis (Std)	(kJ/kg)	4.717e+004	4.727e+004	4.520e+004
Phase Fraction [Vol. Basis]		0.9740	0.9740	2.597e-002
Phase Fraction [Mass Basis]		0.9524	0.9524	4.756e-002
Partial Pressure of CO2	(psig)	-14.70	---	---
Cost Based on Flow	(Cost/s)	0.0000	0.0000	0.0000
Act. Gas Flow	(ACT_m3/h)	815.7	815.7	---
Avg. Liq. Density	(kgmole/m3)	17.35	17.60	8.175
Specific Heat	(kJ/kgmole-C)	46.21	44.58	177.8
Std. Gas Flow	(STD_m3/h)	2.385e+004	2.356e+004	291.8
Std. Ideal Liq. Mass Density	(kg/m3)	348.8	341.1	638.8
Act. Liq. Flow	(m3/s)	4.272e-004	---	4.272e-004
Z Factor		---	0.9248	0.1408
Watson K		17.52	17.77	12.97
User Property		---	---	---
Partial Pressure of H2S	(psig)	-14.70	---	---
Cp/(Cp - R)		1.219	1.229	1.049
Cp/Cv		1.335	1.357	1.049
Heat of Vap.	(kJ/kgmole)	1.403e+004	---	---
Kinematic Viscosity	(cSt)	---	0.5213	0.3985
Liq. Mass Density (Std. Cond)	(kg/m3)	---	---	647.7
Liq. Vol. Flow (Std. Cond)	(m3/h)	---	---	1.489
Liquid Fraction		1.223e-002	0.0000	1.000
Molar Volume	(m3/kgmole)	0.8103	0.8188	0.1246
Mass Heat of Vap.	(kJ/kg)	697.8	---	---
Phase Fraction [Molar Basis]		0.9878	0.9878	0.0122
Surface Tension	(dyne/cm)	13.64	---	13.64
Thermal Conductivity	(W/m-K)	---	3.537e-002	0.1018
Viscosity	(cP)	---	1.234e-002	0.2499
Cv (Semi-Ideal)	(kJ/kgmole-C)	37.90	36.27	169.5

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Material Stream: A-1 (continued)

Fluid Package: Basis-1

Property Package: Peng-Robinson

PROPERTIES

		Overall	Vapour Phase	Liquid Phase		
Mass Cv (Semi-Ideal)	(kJ/kg-C)	1.885	1.871	2.169		
Cv	(kJ/kgmole-C)	34.60	32.85	169.5		
Mass Cv	(kJ/kg-C)	1.721	1.695	2.169		
Cv (Ent. Method)	(kJ/kgmole-C)	---	---	---		
Mass Cv (Ent. Method)	(kJ/kg-C)	---	---	---		
Cp/Cv (Ent. Method)		---	---	---		
Reid VP at 37.8 C	(psig)	---	---	89.56		
True VP at 37.8 C	(psig)	---	---	412.0		
Liq. Vol. Flow - Sum(Std. Cond)	(m3/h)	1.489	0.0000	1.489		
Viscosity Index		---	-7.600	-13.86		

COMPOSITION

Overall Phase

Vapour Fraction 0.9878

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Methane	893.4567 *	0.8858 *	14333.6365 *	0.7070 *	47.8755 *	0.8237 *
Ethane	20.4868 *	0.0203 *	616.0348 *	0.0304 *	1.7320 *	0.0298 *
Propane	10.0920 *	0.0100 *	445.0269 *	0.0220 *	0.8783 *	0.0151 *
i-Butane	12.1104 *	0.0120 *	703.9049 *	0.0347 *	1.2526 *	0.0215 *
n-Butane	16.2447 *	0.0161 *	944.2050 *	0.0466 *	1.6189 *	0.0279 *
i-Pentane	15.2294 *	0.0151 *	1098.8147 *	0.0542 *	1.7625 *	0.0303 *
n-Pentane	5.0460 *	0.0050 *	364.0739 *	0.0180 *	0.5781 *	0.0099 *
n-Hexane	6.0552 *	0.0060 *	521.8244 *	0.0257 *	0.7875 *	0.0135 *
n-Heptane	1.2110 *	0.0012 *	121.3523 *	0.0060 *	0.1767 *	0.0030 *
n-Octane	1.5138 *	0.0015 *	172.9244 *	0.0085 *	0.2452 *	0.0042 *
n-Nonane	1.9175 *	0.0019 *	245.9341 *	0.0121 *	0.3415 *	0.0059 *
Nitrogen	25.2300 *	0.0250 *	706.7680 *	0.0349 *	0.8765 *	0.0151 *
Total	1008.5934	1.0000	20274.4998	1.0000	58.1252	1.0000

Vapour Phase

Phase Fraction 0.9878

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Methane	891.9066	0.8953	14308.7683	0.7410	47.7924	0.8442
Ethane	20.3294	0.0204	611.3044	0.0317	1.7187	0.0304
Propane	9.8606	0.0099	434.8232	0.0225	0.8582	0.0152
i-Butane	11.5089	0.0116	668.9428	0.0346	1.1904	0.0210
n-Butane	15.1730	0.0152	881.9152	0.0457	1.5121	0.0267
i-Pentane	13.1660	0.0132	949.9428	0.0492	1.5237	0.0269
n-Pentane	4.2013	0.0042	303.1285	0.0157	0.4814	0.0085
n-Hexane	3.9028	0.0039	336.3318	0.0174	0.5075	0.0090
n-Heptane	0.4934	0.0005	49.4391	0.0026	0.0720	0.0013
n-Octane	0.3152	0.0003	36.0042	0.0019	0.0510	0.0009
n-Nonane	0.1819	0.0002	23.3362	0.0012	0.0324	0.0006
Nitrogen	25.2145	0.0253	706.3343	0.0366	0.8759	0.0155
Total	996.2537	1.0000	19310.2707	1.0000	56.6158	1.0000

Liquid Phase

Phase Fraction 1.223e-002

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Methane	1.5501	0.1256	24.8682	0.0258	0.0831	0.0550

* Specified by user.

Material Stream: A-1 (continued)

Fluid Package: Basis-1
Property Package: Peng-Robinson

COMPOSITION

Liquid Phase (continued)

Phase Fraction 1.223e-002

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Ethane	0.1573	0.0127	4.7304	0.0049	0.0133	0.0088
Propane	0.2314	0.0188	10.2037	0.0106	0.0201	0.0133
i-Butane	0.6015	0.0487	34.9621	0.0363	0.0622	0.0412
n-Butane	1.0717	0.0868	62.2898	0.0646	0.1068	0.0708
i-Pentane	2.0633	0.1672	148.8719	0.1544	0.2388	0.1582
n-Pentane	0.8447	0.0685	60.9455	0.0632	0.0968	0.0641
n-Hexane	2.1524	0.1744	185.4926	0.1924	0.2799	0.1854
n-Heptane	0.7177	0.0582	71.9132	0.0746	0.1047	0.0694
n-Octane	1.1986	0.0971	136.9202	0.1420	0.1941	0.1286
n-Nonane	1.7355	0.1406	222.5979	0.2309	0.3091	0.2048
Nitrogen	0.0155	0.0013	0.4336	0.0004	0.0005	0.0004
Total	12.3397	1.0000	964.2291	1.0000	1.5094	1.0000

K VALUE

COMPONENTS	MIXED	LIGHT	HEAVY
Methane	7.127	7.127	---
Ethane	1.601	1.601	---
Propane	0.5278	0.5278	---
i-Butane	0.2370	0.2370	---
n-Butane	0.1754	0.1754	---
i-Pentane	7.904e-002	7.904e-002	---
n-Pentane	6.161e-002	6.161e-002	---
n-Hexane	2.246e-002	2.246e-002	---
n-Heptane	8.515e-003	8.515e-003	---
n-Octane	3.257e-003	3.257e-003	---
n-Nonane	1.299e-003	1.299e-003	---
Nitrogen	20.18	20.18	---

UNIT OPERATIONS

FEED TO	PRODUCT FROM	LOGICAL CONNECTION
Separator: V-100		

UTILITIES

(No utilities reference this stream)

PROCESS UTILITY

DYNAMICS

Pressure Specification	(Active):	405.0 psig *			
Flow Specification	(Active)	Molar: 20.25 MMSCFD *	Mass: 2.027e+004 kg/h	Std Ideal Liq Volume: 255.9 USGPM	

User Variables

NOTES

Description

* Specified by user.

Material Stream: A-1 (continued)

Fluid Package: Basis-1
Property Package: Peng-Robinson

Energy Stream: Q-2

Fluid Package: Basis-1
Property Package: Peng-Robinson

CONDITIONS

Duty Type:	Direct Q	Duty Calculation Operation:	K-100		
Duty SP:	893.2 kW	Minimum Available Duty:	---	Maximum Available Duty:	---

COMPOSITION

(Not a material stream - No compositions exist)

UNIT OPERATIONS

FEED TO		PRODUCT FROM	LOGICAL CONNECTION
Compressor:	K-100		

UTILITIES

(No utilities reference this stream)

PROCESS UTILITY

DYNAMICS

Pressure Specification	(Inactive)	---					
Flow Specification	(Inactive)	Molar:	---	Mass:	---	Std Ideal Liq Volume:	---

User Variables

NOTES

Description

Energy Stream: Q-3

Fluid Package: Basis-1
Property Package: Peng-Robinson

CONDITIONS

Duty Type:	Direct Q	Duty Calculation Operation:	K-102		
Duty SP:	641.1 kW	Minimum Available Duty:	---	Maximum Available Duty:	---

COMPOSITION

(Not a material stream - No compositions exist)

UNIT OPERATIONS

FEED TO		PRODUCT FROM	LOGICAL CONNECTION
Compressor:	K-102		

UTILITIES

(No utilities reference this stream)

PROCESS UTILITY

* Specified by user.

APENDIX B

HYSIS Simulation Data Worksheet for Optimized Compression Train

aspentech	LEGENDS Burlington, MA USA	Case Name: HYSYS (REVISED CASE.).HSC Unit Set: NewUser1a Date/Time: Sun Jun 01 07:54:37 2014

Material Stream: A-1

Fluid Package: Basis-1
Property Package: Peng-Robinson

CONDITIONS

		Overall	Vapour Phase	Liquid Phase
Vapour / Phase Fraction		0.9878	0.9878	0.0122
Temperature:	(C)	35.00 *	35.00	35.00
Pressure:	(psig)	405.0 *	405.0	405.0
Molar Flow	(MMSCFD)	24.30 *	24.00	0.2973
Mass Flow	(kg/h)	2.433e+004	2.317e+004	1157
Std Ideal Liq Vol Flow	(USGPM)	307.1	299.1	7.975
Molar Enthalpy	(kJ/kgmole)	-7.837e+004	-7.706e+004	-1.842e+005
Molar Entropy	(kJ/kgmole-C)	156.4	157.0	109.4
Heat Flow	(kW)	-2.635e+004	-2.559e+004	-757.5
Liq Vol Flow @Std Cond	(USGPM)	---	---	7.865

PROPERTIES

		Overall	Vapour Phase	Liquid Phase
Molecular Weight		20.10	19.38	78.14
Molar Density	(kgmole/m3)	1.234	1.221	8.023
Mass Density	(kg/m3)	24.81	23.67	626.9
Act. Volume Flow	(m3/h)	980.7	978.9	1.846
Mass Enthalpy	(kJ/kg)	-3899	-3976	-2357
Mass Entropy	(kJ/kg-C)	7.782	8.101	1.400
Heat Capacity	(kJ/kgmole-C)	46.21	44.58	177.8
Mass Heat Capacity	(kJ/kg-C)	2.299	2.300	2.275
LHV Vol Basis (Std)	(kJ/kgmole)	9.483e+005	9.163e+005	3.532e+006
LHV Mass Basis (Std)	(kJ/kg)	4.717e+004	4.727e+004	4.520e+004
Phase Fraction [Vol. Basis]		0.9740	0.9740	2.597e-002
Phase Fraction [Mass Basis]		0.9524	0.9524	4.756e-002
Partial Pressure of CO2	(psig)	-14.70	---	---
Cost Based on Flow	(Cost/s)	0.0000	0.0000	0.0000
Act. Gas Flow	(ACT_m3/h)	978.9	978.9	---
Avg. Liq. Density	(kgmole/m3)	17.35	17.60	8.175
Specific Heat	(kJ/kgmole-C)	46.21	44.58	177.8
Std. Gas Flow	(STD_m3/h)	2.862e+004	2.827e+004	350.1
Std. Ideal Liq. Mass Density	(kg/m3)	348.8	341.1	638.8
Act. Liq. Flow	(m3/s)	5.127e-004	---	5.127e-004
Z Factor		---	0.9248	0.1408
Watson K		17.52	17.77	12.97
User Property		---	---	---
Partial Pressure of H2S	(psig)	-14.70	---	---
Cp/(Cp - R)		1.219	1.229	1.049
Cp/Cv		1.335	1.357	1.049
Heat of Vap.	(kJ/kgmole)	1.403e+004	---	---
Kinematic Viscosity	(cSt)	---	0.5213	0.3985
Liq. Mass Density (Std. Cond)	(kg/m3)	---	---	647.7
Liq. Vol. Flow (Std. Cond)	(m3/h)	---	---	1.786
Liquid Fraction		1.223e-002	0.0000	1.000
Molar Volume	(m3/kgmole)	0.8103	0.8188	0.1246
Mass Heat of Vap.	(kJ/kg)	697.8	---	---
Phase Fraction [Molar Basis]		0.9878	0.9878	0.0122
Surface Tension	(dyne/cm)	13.64	---	13.64
Thermal Conductivity	(W/m-K)	---	3.537e-002	0.1018
Viscosity	(cP)	---	1.234e-002	0.2499
Cv (Semi-Ideal)	(kJ/kgmole-C)	37.90	36.27	169.5

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Material Stream: A-1 (continued)

Fluid Package: Basis-1

Property Package: Peng-Robinson

PROPERTIES

	Overall	Vapour Phase	Liquid Phase		
Mass Cv (Semi-Ideal) (kJ/kg-C)	1.885	1.871	2.169		
Cv (kJ/kgmole-C)	34.60	32.85	169.5		
Mass Cv (kJ/kg-C)	1.721	1.695	2.169		
Cv (Ent. Method) (kJ/kgmole-C)	---	---	---		
Mass Cv (Ent. Method) (kJ/kg-C)	---	---	---		
Cp/Cv (Ent. Method)	---	---	---		
Reid VP at 37.8 C (psig)	---	---	89.56		
True VP at 37.8 C (psig)	---	---	412.0		
Liq. Vol. Flow - Sum(Std. Cond) (m3/h)	1.786	0.0000	1.786		
Viscosity Index	---	-7.600	-13.86		

COMPOSITION

Overall Phase

Vapour Fraction 0.9878

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Methane	1072.1480 *	0.8858 *	17200.3638 *	0.7070 *	57.4506 *	0.8237 *
Ethane	24.5841 *	0.0203 *	739.2418 *	0.0304 *	2.0784 *	0.0298 *
Propane	12.1104 *	0.0100 *	534.0323 *	0.0220 *	1.0540 *	0.0151 *
i-Butane	14.5325 *	0.0120 *	844.6858 *	0.0347 *	1.5031 *	0.0215 *
n-Butane	19.4936 *	0.0161 *	1133.0461 *	0.0466 *	1.9427 *	0.0279 *
i-Pentane	18.2753 *	0.0151 *	1318.5776 *	0.0542 *	2.1150 *	0.0303 *
n-Pentane	6.0552 *	0.0050 *	436.8887 *	0.0180 *	0.6938 *	0.0099 *
n-Hexane	7.2662 *	0.0060 *	626.1893 *	0.0257 *	0.9450 *	0.0135 *
n-Heptane	1.4532 *	0.0012 *	145.6227 *	0.0060 *	0.2120 *	0.0030 *
n-Octane	1.8166 *	0.0015 *	207.5093 *	0.0085 *	0.2942 *	0.0042 *
n-Nonane	2.3010 *	0.0019 *	295.1209 *	0.0121 *	0.4097 *	0.0059 *
Nitrogen	30.2760 *	0.0250 *	848.1216 *	0.0349 *	1.0518 *	0.0151 *
Total	1210.3121	1.0000	24329.3998	1.0000	69.7502	1.0000

Vapour Phase

Phase Fraction 0.9878

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Methane	1070.2879	0.8953	17170.5220	0.7410	57.3509	0.8442
Ethane	24.3953	0.0204	733.5653	0.0317	2.0624	0.0304
Propane	11.8327	0.0099	521.7879	0.0225	1.0298	0.0152
i-Butane	13.8107	0.0116	802.7313	0.0346	1.4284	0.0210
n-Butane	18.2076	0.0152	1058.2982	0.0457	1.8146	0.0267
i-Pentane	15.7992	0.0132	1139.9313	0.0492	1.8284	0.0269
n-Pentane	5.0416	0.0042	363.7542	0.0157	0.5776	0.0085
n-Hexane	4.6833	0.0039	403.5981	0.0174	0.6091	0.0090
n-Heptane	0.5921	0.0005	59.3269	0.0026	0.0864	0.0013
n-Octane	0.3782	0.0003	43.2051	0.0019	0.0613	0.0009
n-Nonane	0.2183	0.0002	28.0034	0.0012	0.0389	0.0006
Nitrogen	30.2574	0.0253	847.6012	0.0366	1.0511	0.0155
Total	1195.5044	1.0000	23172.3249	1.0000	67.9389	1.0000

Liquid Phase

Phase Fraction 1.223e-002

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Methane	1.8601	0.1256	29.8418	0.0258	0.0997	0.0550

LEGENDS
Burlington, MA
USA

Case Name:	HYSYS (REVISED CASE.).HSC
Unit Set:	NewUser1a
Date/Time:	Sun Jun 01 07:54:37 2014

Material Stream: A-1 (continued)

Fluid Package: Basis-1

Property Package: Peng-Robinson

COMPOSITION

Liquid Phase (continued)

Phase Fraction 1.223e-002

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Ethane	0.1888	0.0127	5.6765	0.0049	0.0160	0.0088
Propane	0.2777	0.0188	12.2444	0.0106	0.0242	0.0133
i-Butane	0.7218	0.0487	41.9545	0.0363	0.0747	0.0412
n-Butane	1.2860	0.0868	74.7478	0.0646	0.1282	0.0708
i-Pentane	2.4760	0.1672	178.6463	0.1544	0.2865	0.1582
n-Pentane	1.0136	0.0685	73.1346	0.0632	0.1161	0.0641
n-Hexane	2.5829	0.1744	222.5911	0.1924	0.3359	0.1854
n-Heptane	0.8612	0.0582	86.2958	0.0746	0.1256	0.0694
n-Octane	1.4383	0.0971	164.3042	0.1420	0.2329	0.1286
n-Nonane	2.0826	0.1406	267.1175	0.2309	0.3709	0.2048
Nitrogen	0.0186	0.0013	0.5203	0.0004	0.0006	0.0004
Total	14.8077	1.0000	1157.0749	1.0000	1.8113	1.0000

K VALUE

COMPONENTS	MIXED	LIGHT	HEAVY
Methane	7.127	7.127	---
Ethane	1.601	1.601	---
Propane	0.5278	0.5278	---
i-Butane	0.2370	0.2370	---
n-Butane	0.1754	0.1754	---
i-Pentane	7.904e-002	7.904e-002	---
n-Pentane	6.161e-002	6.161e-002	---
n-Hexane	2.246e-002	2.246e-002	---
n-Heptane	8.515e-003	8.515e-003	---
n-Octane	3.257e-003	3.257e-003	---
n-Nonane	1.299e-003	1.299e-003	---
Nitrogen	20.18	20.18	---

UNIT OPERATIONS

FEED TO	PRODUCT FROM	LOGICAL CONNECTION
Separator: V-100		

UTILITIES

(No utilities reference this stream)

PROCESS UTILITY

DYNAMICS

Pressure Specification (Active): 405.0 psig *

Flow Specification (Active) Molar: 24.30 MMSCFD * Mass: 2.433e+004 kg/h Std Ideal Liq Volume: 307.1 USGPM

User Variables

NOTES

Description

Material Stream: A-1 (continued)

Fluid Package: Basis-1

Property Package: Peng-Robinson

Energy Stream: Q-2

Fluid Package: Basis-1

Property Package: Peng-Robinson

CONDITIONS

Duty Type:	Direct Q	Duty Calculation Operation:	K-100		
Duty SP:	946.8 kW	Minimum Available Duty:	---	Maximum Available Duty:	---

COMPOSITION

(Not a material stream - No compositions exist)

UNIT OPERATIONS

FEED TO		PRODUCT FROM	LOGICAL CONNECTION
Compressor:	K-100		

UTILITIES

(No utilities reference this stream)

PROCESS UTILITY

DYNAMICS

Pressure Specification	(Inactive)	---						
Flow Specification	(Inactive)	Molar:	---	Mass:	---	Std Ideal Liq Volume:	---	

User Variables

NOTES

Description

Energy Stream: Q-3

Fluid Package: Basis-1

Property Package: Peng-Robinson

CONDITIONS

Duty Type:	Direct Q	Duty Calculation Operation:	K-102		
Duty SP:	839.1 kW	Minimum Available Duty:	---	Maximum Available Duty:	---

COMPOSITION

(Not a material stream - No compositions exist)

UNIT OPERATIONS

FEED TO		PRODUCT FROM	LOGICAL CONNECTION
Compressor:	K-102		

UTILITIES

(No utilities reference this stream)

PROCESS UTILITY