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Performance Analysis of Gas Lifted Wells with Injection Pressure Operated Valves in the Ekofisk Field

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Abstract

Gas lift design featuring several gas lift valves in a well is common in the industry. The sequence of valves in the tubing string allows for gradual well unloading and injection through the deepest valve (operating point). Gas injection as deep as possible, in turn, results in maximized production rate. Moreover, the unloading sequence is intended to bring well back on production after shut-in periods.

There are several gas lifted wells with unloading sequences in the Ekofisk field employing injection pressure operated valves. The primary objective of this study is to investigate the performance of aforementioned wells in order to identify the under-performing wells and possible reasons for lifting issues.

To meet the aims of this study, extensive data gathering and analysis is performed. In addition, literature research is done.

The performance of ten wells is investigated. The detailed analysis of one particularly interesting well is presented. The main reason for the well's under-performance is possibly explained by valve failure. The gas lift design consideration for one particular well is presented.

The main lifting issues are associated with the changed well conditions (i.e. increased water production) when the gas lift design does not match the well's performance. In addition, the downhole crossflow results in difficulties to restart the wells after shut-in. Another possible reason for well's under-performance might be scale build-up that prevents normal gas lift operation.

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1 INTRODUCTION

1.1 Background

Artificial lift is becoming increasingly important as fields mature due to the fact that additional lift energy is required to optimize production levels. Gas lift is one of the artificial lifting techniques.

Well unloading in a gas lifted well is achieved via a series of pressure operated valves, installed in the tubing string, which reduce the fluid gradient in the tubing. Often the unloading design is required at a stage of gas lift optimization, where the injection point is moved deeper. However, a simple transfer of the injection point deeper down the well is not always possible due to various limitations (e.g. increasing hydrostatic head, well integrity constraints or compressor capacity). The sequence of unloading valves allows for a gradual reduction of hydrostatic head in the tubing and a transfer of the injection point to the operating valve. The deepest point of injection, in turn, results in maximized production rate. The idea of using unloading valves is to keep them open during the unloading process and then keep them closed while injecting through the deepest valve.

However, the unloading sequence does not always guarantee the expected well operation for several reasons. Gas lift valve failures, changing well and reservoir conditions or improper gas lift design may lead to situations where the gas lift installation may not unload or operate as designed. These aforementioned issues can therefore result in unexpected downtime and loss of production.

During the past two years, the unloading design has been implemented into several gas lifted wells in the Ekofisk field. This study sets out to assess the ConocoPhillips Norway’s experience gained from using unloading sequences for gas lift designs.

1.2 Project objectives and structure

The learning objective of this project is to become familiar with gas lift technology and understand the concept of gas lift design.

The contributing objectives are:

- To evaluate performance of wells with unloading sequences in the Ekofisk field.
- To provide recommendations for possible improvements in unloading sequence design.
- To participate in the design of the unloading sequence for one of the Ekofisk gas lifted wells (scheduled job).

This work takes the form of a case study of the Ekofisk gas lifted wells which employ unloading sequences. It also includes a design consideration of an unloading sequence with injection pressure operated valves for one particular well.

The following is a summary of the chapters present in this study.

Chapter 2 provides a general overview of the Ekofisk field.

Chapter 3 provides an overview of the theoretical aspects of gas lift technology. The operating principles of an injection pressure operated valve are discussed. This is followed by a description of the key characteristics of gas lifted wells along with some troubleshooting techniques. The chapter concludes with a description of the design principles of the unloading sequence with injection pressure operated valves.

Chapter 4 presents the methodology used in this study in order to analyze the performance of gas lifted wells.

Chapter 5 covers a case study of the wells with unloading sequences and the design consideration of an unloading sequence for one well.

Chapter 6 gives a brief summary of the findings and conclusions. It also presents the recommendations for refining future practices of using unloading sequences.

2 THE EKOFISK FIELD: GENERAL CONSIDERATION

This section is largely retrieved from the Ekofisk Reservoir Management Plan [1].

The Ekofisk field was the first field to be developed on the Norwegian Continental Shelf. The Tor, Eldfisk, Embla and Ekofisk fields are all contained within Greater Ekofisk Area (Production License 018) located in the southern part of the North Sea, *Figure 2.1*. ConocoPhillips Norway operates the license, holding a 33% interest.

Figure 2.1 – Location of the Ekofisk field in the Norwegian sector of the North Sea [1].

The field is a naturally fractured chalk reservoir producing from two horizons – Ekofisk (Paleocene) and Tor (Upper Cretaceous) – separated by a tight zone. It is an elongated anticline covering a 10.1 x 5.4 kilometer area with an estimated 7.1 billion standard barrels of oil initially in place.

The reservoir datum is defined at 10400 ft subsea with initial pressure of 7135 psia and temperature 268°F. The initial reservoir fluid was undersaturated volatile oil (38° API) with bubble point of 5550 psia. The current bubble point is about 4400 psia.

Ekofisk is characterized by high porosity in the range of 25-45% and low matrix permeability ranging from 1 to 10 mD. The average pay thickness is about 980 ft. Cross-sections across the field colored by porosity distribution are shown in *Figure 2.2*. The EE layer presents the tight zone between the Ekofisk and Tor formations.

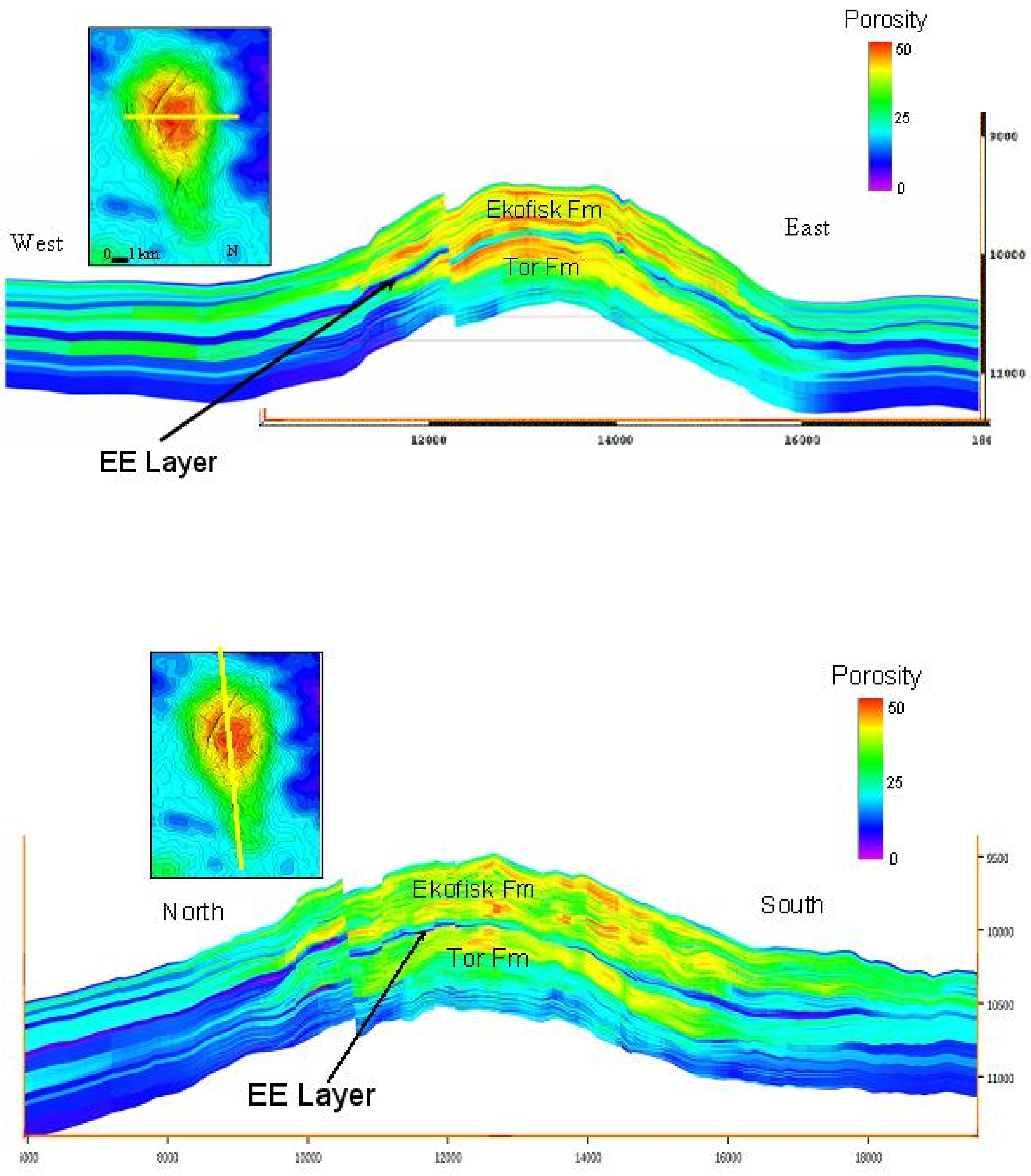


Figure 2.2 – Cross-sections across the Ekofisk field [1].

The production history of the Ekofisk field began in 1971. Since reservoir pressure started to decline due to production, water injection was initiated in 1987 in the Tor formation to maintain the reservoir pressure. Currently, the Ekofisk field goes into a mature stage of waterflood. The historical oil and water production rates and gas-oil ratio are show in *Figure 2.3.*

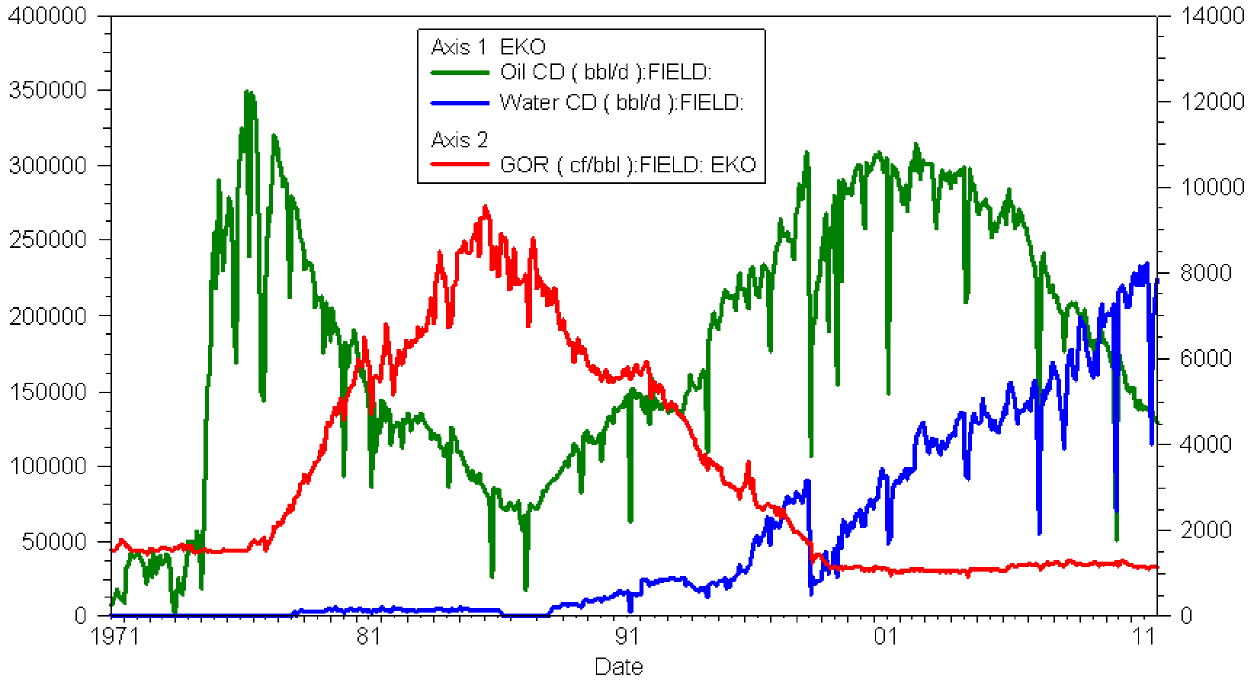


Figure 2.3 – Ekofisk historical production.

The Ekofisk field faces challenges associated with topside and downhole scale deposition. Seawater and formation water mixing results in scale buildup ($CaCO_3$, $SrCO_3$, $BaSO_4$). To prevent scale buildup, scale squeeze inhibition treatments are performed. Due to subsidence of the reservoir, casing/tubing collapses occur. Seafloor subsidence and reservoir compaction are caused by natural tendency of chalk to be deformed during hydrocarbon extraction and water weakening effects on chalk induced by waterflooding.

Acid restimulation treatments are performed to enhance oil production.

The gas lift injection was started in late 1997. Currently, around 70% of the Ekofisk producers are on continuous gas lift. The increasing water production means that more wells will be put on gas lift in the future.

3 GAS LIFT: CONCEPT, WELL PERFORMANCE, DESIGN

3.1 Gas lift technology: introduction

The general idea describing the gas lift technology is taken from several literature resources [2-5].

As the oil well is produced, the combination of reducing reservoir pressure and increasing water cut result in production rate decline and higher hydrostatic head in the tubing. When wells are no longer able to flow naturally, the artificial lift is required to bring hydrocarbons to the surface. The concept behind gas lift is to make the tubing content lighter by injecting gas through the special device integrated with the tubing – gas lift valve (GLV). This allows for reduction of bottomhole pressure and increase drawdown – the difference between reservoir pressure and bottomhole pressure – and, thereby, increase the production rate.

A typical gas lift completion is presented in *Figure 3.1*. To implement the gas lift operation, the source of high pressure gas is needed. The gas is injected down the casing-tubing annulus. Using several gas lift valves in a well (unloading valves and an operating valve), the deepest point of injection is reached.

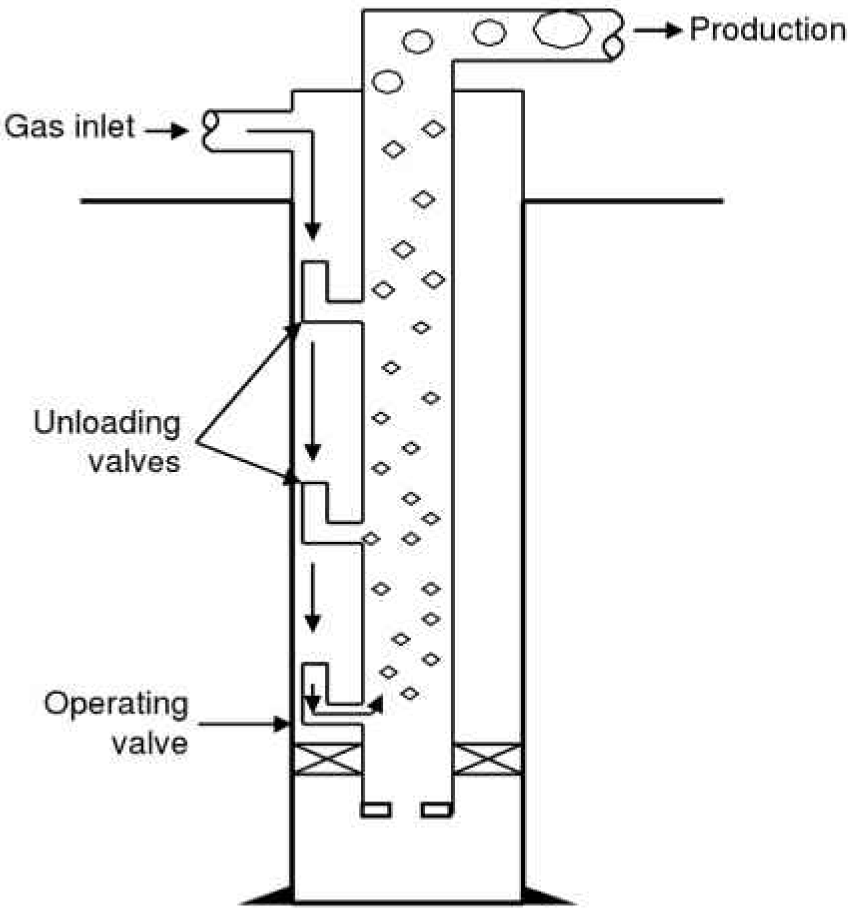


Figure 3.1 – Gas lift completion [5].

The main components of a gas lift system are:

- compression and distribution system for injection gas (compressor, dehydration unit, manifolds, gas flowlines),
- subsurface equipment (tubing equipped with mandrels and gas lift valves),
- gathering system for produced flow (pipelines, manifold, separator station).

Gas lift valves control gas entrance into the tubing. They are placed in mandrels which are integrated into the tubing string. There exist conventional and retrievable mandrels. Retrievable means that valves can be pulled out from the mandrel running into the well a kickover tool. In conventional mandrels valves are installed at the surface, and then lowered into the well.

A common way to name side pocket mandrels is as follows: starting from the deepest one A-SPM, then B-SPM, C-SPM, etc. If there are only three side pocket mandrels installed it is convenient to organize them as lower side pocket mandrel – LSPM, middle side pocket mandrel – MSPM and upper side pocket mandrel – USPM.

There are two main types of gas lift: continuous flow gas lift (constant high pressure gas injection) and intermittent gas lift (large injection rates are utilized in short time periods to lift reservoir fluid in slugs to the surface).

From a gas lift installation point of view, the gas lift can be deployed as a tubular flow (gas is injected from annulus into the tubing), annular flow (gas is injected down the tubing and then enters into the annulus), and as other alternatives.

For simplicity, in this work the term gas lift will refer to continuous gas lift with tubing flow.

The concept of the gas lift can be explained with the help of pressure gradients. Pressure versus depth profile (so-called “pressure traverse”) is shown in *Figure 3.2*. For shut-in well without gas injection the static bottomhole pressure is defined by static gas and liquid gradients. Flowing production pressure gradient and injection gas gradient determine the point of gas injection. The gas is injected into a valve located at the maximum depth where the difference between the tubing and casing pressures exists (differential pressure across the valve). The deeper injection means that the larger part of the fluid column will be lightened and the increased driving force (drawdown), in turn, will result in increased production.

The higher injection pressure, the deeper gas lift injection depth can be reached. By injecting deeper, a greater production rate with less gas lift will be achieved.

The production liquid rate plotted versus gas injection rate is a gas lift performance curve. This plot characterizes production deliverability from gas injection point of view. As can be noticed from the *Figure 3.3*, with each increase in injection rate, the corresponding increase in production rate becomes less and less, until the curve turns into flat and then turns upside down. The limit on increasing of gas lift rate is explained by increased pressure drop due to friction in the tubing and flowline.

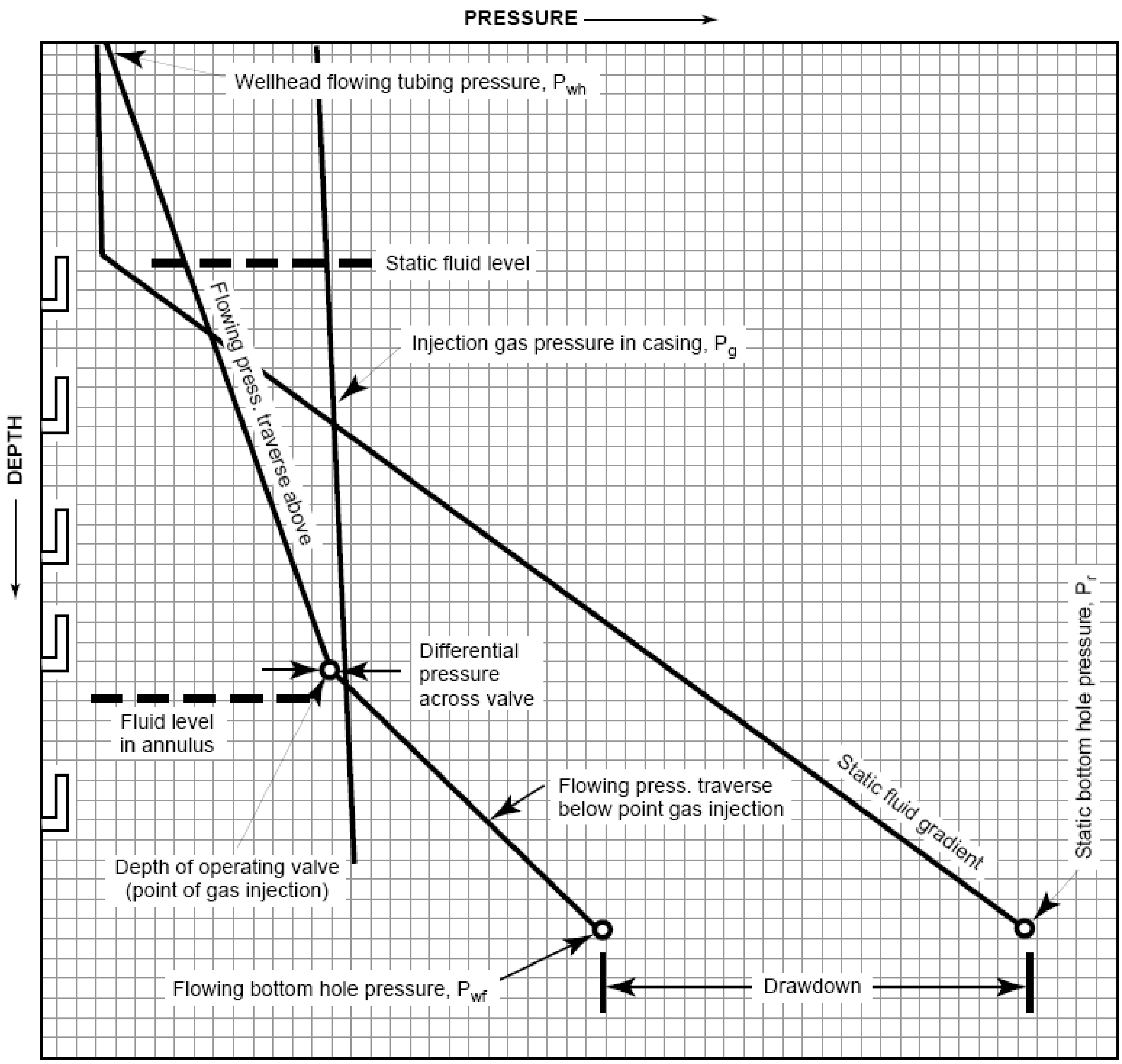


Figure 3.2 – Flowing and static pressure gradients [2].

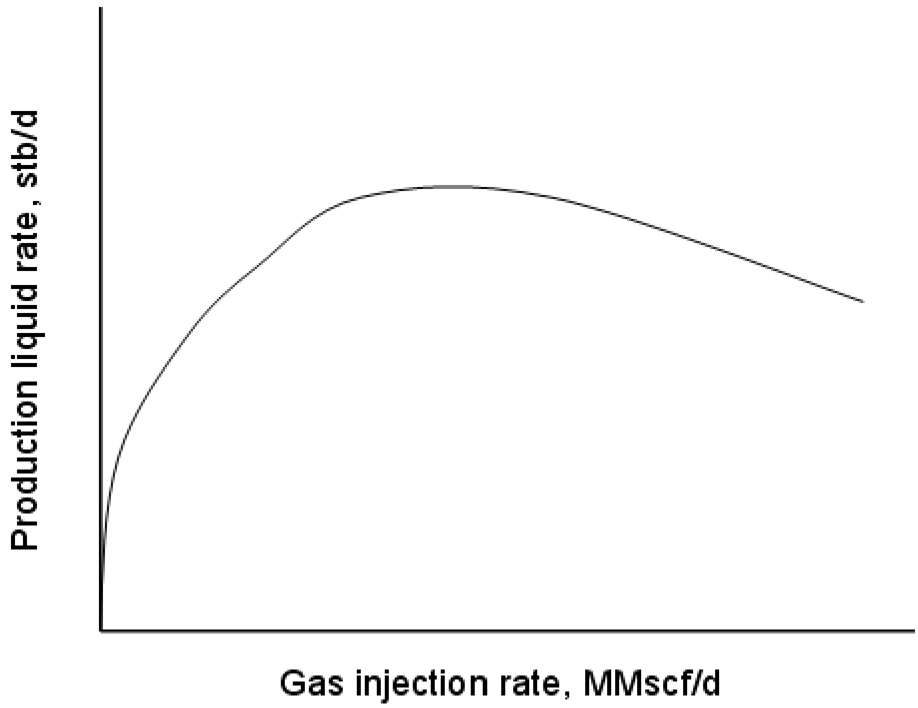


Figure 3.3 – Gas lift performance.

3.2 Well performance: inflow and outflow

The fundamental concept that describes well performance and predicts well deliverability combines ideas of inflow and outflow relationships.

3.2.1 Inflow performance

Reservoir delivery can be characterized with inflow performance relationship (IPR) - production rate plotted as a function of bottomhole pressure. The inflow performance is determined by reservoir properties (pressure, permeability, porosity, thickness, etc.), fluid properties, such as density, viscosity, and near wellbore area (which can be damaged – skin factor) [2].

The shape of IPR depends on phases produced. For undersaturated oil straight line approach is applicable. Productivity index (PI) for straight line IPR model is defined as:

$$q = PI(P_r - P_{wf})$$

q – total liquid flow rate, std/d

P_r – average reservoir pressure, psig

P_{wf} – flowing bottomhole pressure, psig

The flow rate is directly proportional to the drawdown.

When well is producing below bubble point pressure, inflow performance can be estimated with Vogel equation:

$$\frac{q}{q_{max}} = 1 - 0.2\left(\frac{P_{wf}}{P_r}\right) - 0.8\left(\frac{P_{wf}}{P_r}\right)^2$$

q_{max} – maximum liquid rate, stb/d

In this case, the productivity index decreases with increasing pressure difference between the average reservoir pressure and the flowing bottomhole pressure. The IPR curve demonstrates a non-linear behavior.

3.2.2 Outflow performance

Outflow performance, or vertical lift performance (VLP), presents the flowing bottomhole pressure as a result from flowing through the well at a specific rate by estimating pressure drops from the bottom to the surface facilities.

Total pressure drop is defined by three terms: hydrostatic losses due to altering potential energy, acceleration losses because of changes in kinetic energy and friction losses. For producing oil well, tubing elevation and friction account for most of the pressure drop, whereas acceleration is usually negligible [4].

Production delivery depends on the tubing size, wellhead pressure, water cut, gas to liquid ratio, choke size, depth.

A good and accurate multiphase flow correlation or model is essential to get representative well outflow performance. Among commonly used ones are Duns and Ros, Beggs and Brill, Hagedorn and Brown, Olga Steady State, EPS Mechanistic [2].

3.2.3 Nodal analysis concept

In nodal analysis, the intersection of the inflow and outflow curves gives an operating point – the rate at which the well can produce.

The idea of nodal analysis is to divide the production system into nodes. Flow rates or pressures are calculated downwards starting from the top node and upwards starting from the bottom node. At the solution node (generally mid-perforations depth) the production rate and corresponding bottomhole pressure give the operating point (*Figure 3.4*).

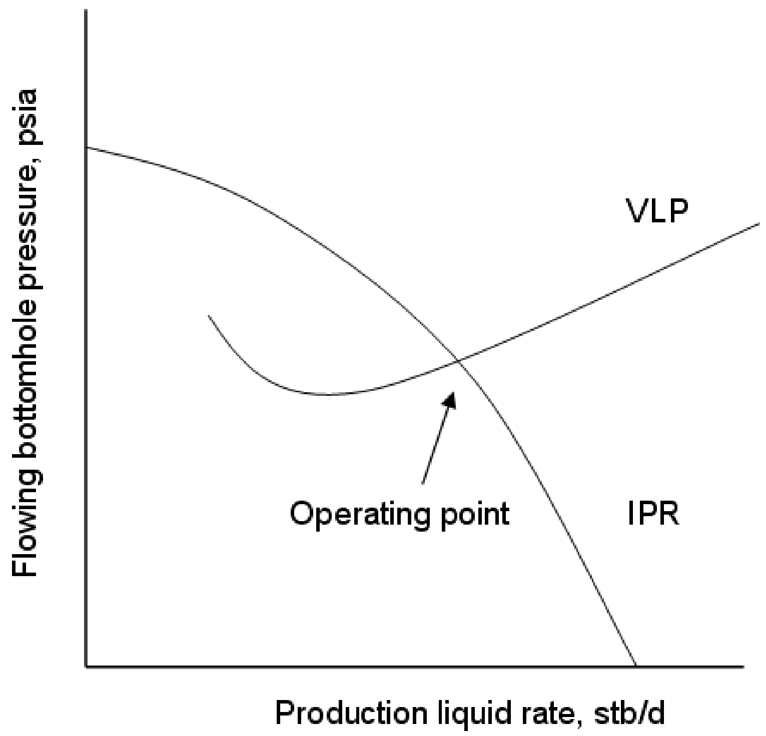


Figure 3.4 – Inflow and outflow performance.

Well performance software applications (e.g. WellFlo) are based on nodal analysis.

3.3 Gas lift valve

A gas lift valve serves as a downhole flow control device and allows gas to be injected into the tubing. Unloading valves are used to unload the well to an orifice located in the deepest possible mandrel. The idea of using unloading valves is to hold them open during unloading process and then keep them closed while injecting through the deepest valve.

An orifice and unloading pressure operated valves (so-called live valves) are considered in this section.

3.3.1 Orifice

An orifice has a port and a reverse flow check. It is a valve that is always open and only differential pressure across the valve is needed to initiate gas passage though it (often at 100 psi). It is commonly referred to as the operating valve.

Throughout this project, the term gas lift valve (GLV) is used to refer to the orifice.

The valve port size allows gas passage from annulus into the tubing. Valve performance curve in *Figure 3.5* demonstrates gas passage through the orifice. The valve is in critical (sonic) flow when gas passage through the valve does not depend upon downstream pressure (i.e. tubing pressure for a gas lift valve) [5]. The injection occurs at maximum rate so long as the downstream pressure is less then about 55% of the upstream pressure (i.e.

casing pressure for a gas lift valve). In sub-critical flow region, the amount of injected gas varies as tubing pressure changes. It is desired to operate in critical flow region, otherwise, the gas flow rate becomes sensitive to small pressure changes.

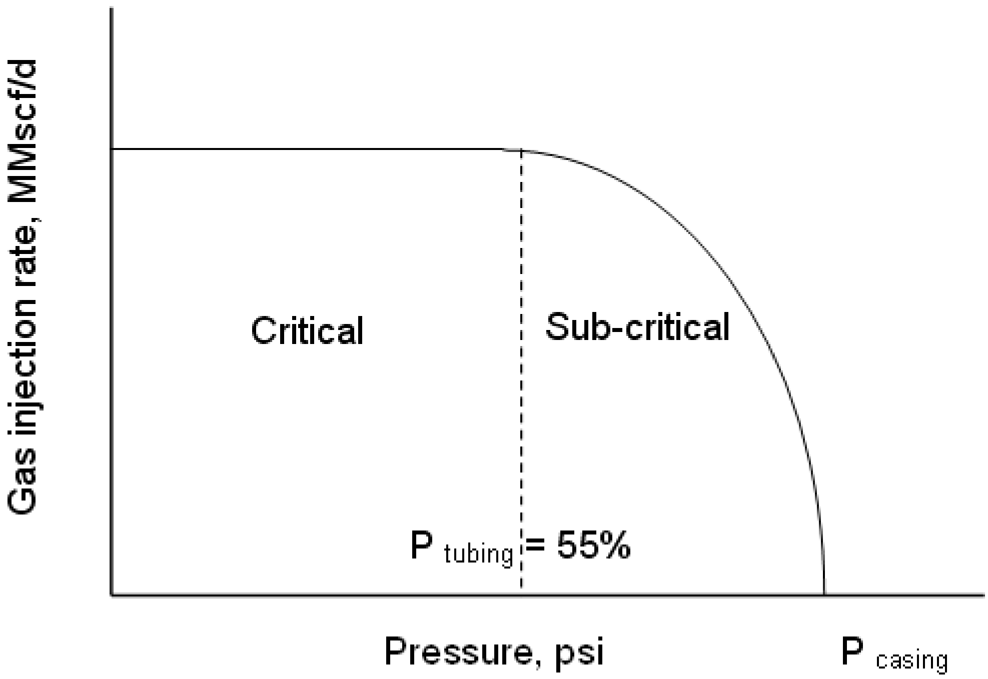


Figure 3.5 – Valve performance curve.

Gas passage prediction is important in order to size the valve (i.e. determine the port size). There are various correlations, tested valve performance data and charts available to solve this task. Thornhill-Craver correlation gives reasonable representation of gas passage through orifice valves. Gas passage charts allow for gas flow capacity evaluation for known upstream pressure, downstream pressure and orifice size [3].

3.3.2 Injection pressure operated valve

Historically, the first pressure operated valve was patented by W.R. King in 1944, and the next generation of pressure operated valves is holding the primary characteristics of the prototype [3].

This section discusses valve mechanics and performance, and is taken from several literature resources [2-3].

3.3.2.1 Valve mechanics

To understand how injection pressure operated valve performs the well unloading, the valve mechanics has to be considered. The valve is presented in *Figure 3.6*.

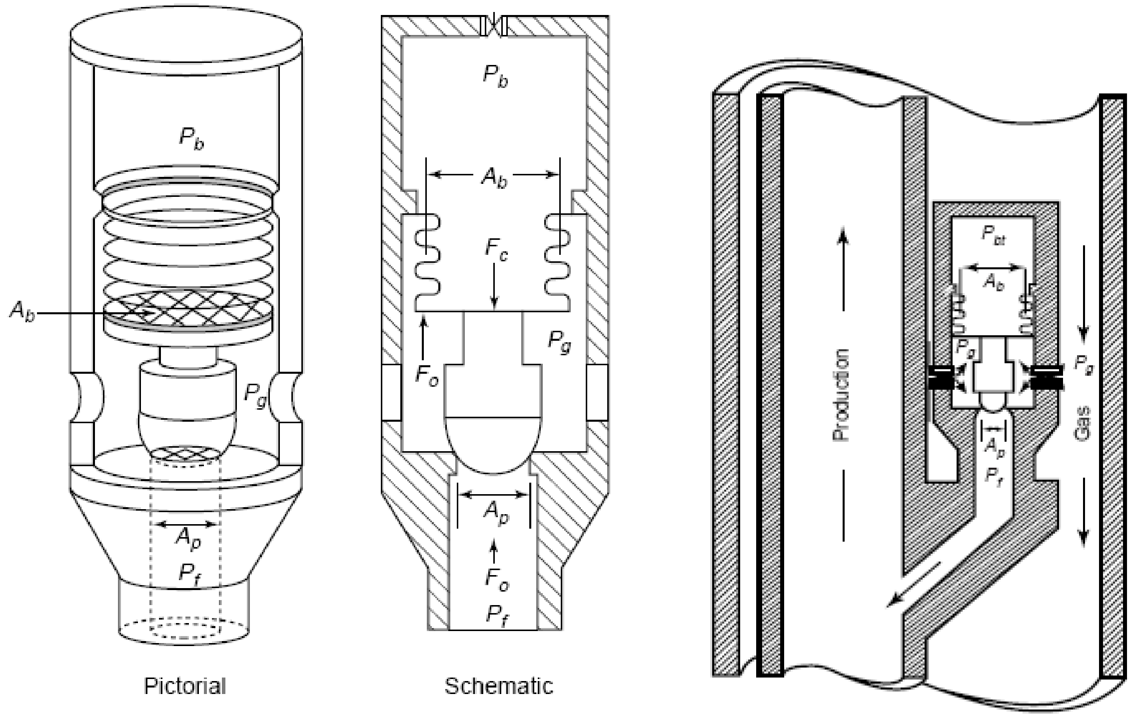


Figure 3.6 – Injection pressure operated valve [2].

Basically, forces acting on the area of the bellows and the area of the port must be considered in order to make a force balance.

When the valve is closed, the force balance can be considered mathematically as:

$$P_f A_p - P_c A_p - P_d A_b + P_c A_b = 0$$

P_f – flowing production pressure

A_p – effective port area (valve seat)

P_c – casing pressure

A_b – area of bellows

P_d – pressure in dome

Hence, the force which causes the valve to open is:

$$F_o = P_d A_b = P_c (A_b - A_p) + P_f A_p$$

The valve opening force is provided predominantly by the injection gas pressure plus there is a small contribution of production pressure in the tubing acting on the gas lift valve port.

The closing force is ensured from a pressure charged bellows (commonly with nitrogen). The dome pressure applied to the area of bellows creates a closing force which drags the stem toward the port. It can be expressed as:

$$F_c = P_d A_b = P_c^{'} A_b$$

When the injection pressure is dropped below the closing pressure, the unloading valve is closed.

Note that opening force in terms of the casing pressure is not the same as the closing pressure expressed via casing pressure. That is why this type of valves is classified as underbalanced.

The opening and closing forces are equal in situation just prior to valve opening:

$$P_c\,(A_b - A_p) + P_f\,A_p = P_d\,A_b$$

Then

$$P_c = \frac{P_d - P_f\,(A_p / A_b)}{1-(A_p / A_b)} = \frac{P_d - P_f\,R}{1-R},$$

where $A_p / A_b = R$, so-called R-factor – ratio of port area to bellows area (known from valve characteristics). One more parameter can be derived, known as production pressure effect factor PPEF, or tubing factor TEF:

$$PPEF = \frac{A_p}{\left(A_b - A_p\right)}$$

Solving equation for the dome pressure (bellows pressure):

$$P_d = P_c(1-R) + P_f\,R$$

The surface opening and closing pressures are derived by correcting P_{vo} and P_{sc} for the gas gradient.

Test rack opening pressure is the open pressure in a tester for the tubing pressure of 1 atmosphere and at reference temperature (commonly 60°F). Modifying the equation for P_c,

$$TRO = \frac{P_d \ at\ 60F}{1-R}$$

To take into account the temperature effect on a nitrogen charged bellows, a simplified equation derived from the ideal gas law can be used:

$$P_2 = P_1 \times C_t$$

P_1 – gas lift valve dome pressure at well temperature;

P_2 – gas lift valve dome pressure at reference temperature (often 60°F);

C_t – temperature correction factor.

Temperature correction factors for nitrogen based on 60°F are tabled.

Winkler et al. [6] demonstrated the algorithm for more accurately predicting the dome pressure in nitrogen charged gas lift valve. It was shown that at high pressures and temperatures the accurate nitrogen compressibility should be evaluated. The suggested equations are:

$$P_d \ at \ valve \ depth = P_d \ at \ 60F + M(T_{valve} - 60) \quad (*)$$

For $P_d \ at \ 60F$ from 1238 to 3000 psia:

$$M = -0.267 + 0.002298 \cdot \left(P_d \ at \ 60F\right) + 1.84 \cdot 10^{-7} \left(P_d \ at \ 60F\right)^2$$

For $P_d \ at \ 60F$ <1238 psia:

$$M = -0.00226 + 0.001934 \cdot \left(P_d \ at \ 60F\right) + 3.054 \cdot 10^{-7} \left(P_d \ at \ 60F\right)^2$$

Thus, based on the valve mechanics, decreasing injection pressure is the main factor which forces the unloading valves to close.

If the unloading design involves several unloading valves, the surface operating injection pressure of each valve decreases with increasing valve depths in order to avoid valve interference phenomenon (multipoint injection). The multipoint operation might lead to excessive lift gas usage and instability in the gas lift system.

Since these valves have a nitrogen-charged bellows, the valve opening and closing pressures become sensitive to temperature. This fact makes temperature the important parameter in gas lift design with injection pressure operated valves. It will be discussed further in present chapter.

The valve can be characterized by a load rate. It is a measure of an increase in pressure that will cause the movement of the valve stem. The load rate is measured in psi per inch and specified by manufactures.

In this project the term “unloading valve” will be referred to unbalanced, injection pressure operated, nitrogen-charged bellows valve.

3.3.2.2 Valve performance

The Thornhill-Craver correlation does not accurately describe the behavior of unloading valves [7]. The IPO valve flow performance is shown in *Figure 3.7*.

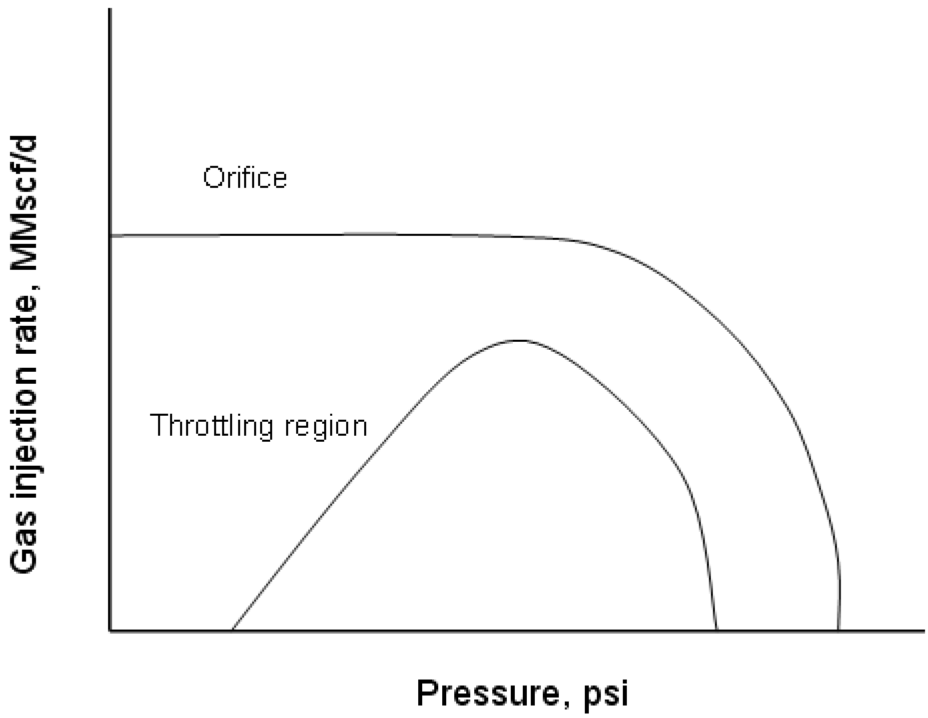


Figure 3.7 – Flow performance of the IPO valve.

Note that there is no critical flow region as it can be seen from orifice behavior. The reason for this is that as lower the downstream pressure, the stem will travel, reducing the flow area of the valve. The part of the curve that exhibits such behavior is known as the throttling region of the curve.

The dynamic tested data is available to predict the performance of unloading valves. The Valve Performance Clearinghouse program establishes experimental valve performance data and correlations [7]. Valve performance curves are generated from dynamic tests. This gives accurate gas passage predictions and allows for valve design improvement.

3.3.3 Production pressure operated valve

The other type of unloading valves is a production pressure operated valve (PPO valve) which is primarily controlled by the flowing production pressure at valve depth. This section just briefly introduces PPO valve [2, 8].

Unlike the IPO valve, PPO valve is a spring loaded (hence, no temperature effect). It has a large area of bellows that is exposed to production pressure. This makes the valve mechanics to be sensitive to changes in production pressure.

Advantages of PPO valves are that they are not temperature sensitive and the valves are not affected by fluctuations in casing pressure. They are operated at the same surface injection pressure all the way down the well allowing deeper injection.

The PPO valves are less popular choice of unloading valves due to the following reasons. As the production gradient or back pressure on the well increases, the valves will re-open. It is harder to troubleshoot issues related to using the PPO valves since these valves are controlled by the production conditions.

3.3.4 Dummy valve

It is a blank device that is set in a side pocket mandrel. It is not a real valve since the main function for a dummy valve is to prevent the tubing-casing communication. When it becomes necessary, the dummy valve is replaced by real gas lift valve.

3.4 Unloading gas lifted wells

Term “unloading” is commonly used describing two different situations. They are [8]:

- Newly completed wells. In this case annulus and tubing are filled with completion or workover (“kill”) fluid and this fluid is needed to be circulated out.
- Wells after shut-in periods. In this situation some actions should be taken to put well back on production and thereby to reduce production losses due to lifting problems.

Various restart (or kick off) options are common in the industry. These include [8]:

- Shut-in a well for pressure build-up. This allows bottomhole pressure to increase and start production by reopening the well.
- “Rock” a well (gas lift bullheading). Lift gas is applied to the top of the fluid column to reduce the height of the column and to initiate the flow.
- Nitrogen kick off. Nitrogen is injected into the casing-tubing annulus. The higher injection pressure is achievable due to higher compressor capacity of external nitrogen unit.
- Unloading sequence installation. The sequence of pressure operated valves is intended to transfer the point of injection to the operating valve and, thereby, to bring the well back on production after shut-in periods.

3.5 Advantages and problems associated with employing the IPO valves

This section observes benefits and common malfunctions of injection pressure operated valve [8]. It also reviews some articles regarding usage of IPO valve in industry and IPO valves today.

3.5.1 Advantages

The IPO valves are the most popular choice of unloading valves. High gas passage capability, predictable performance, surface control by injection pressure are the main benefits.

3.5.2 Temperature effects

The primary disadvantage of IPO valve is its sensitivity to temperature.

During the unloading process, the temperature demonstrates a transient behavior, somewhere in between the flowing and the static temperature gradients. Transient temperature changes in the gas lift unloading process were investigated at the University of Tulsa, Oklahoma [9]. A dynamic model for gas lift unloading was developed in order to demonstrate complex characteristics of this process. The results from using this transient wellbore heat transfer model demonstrated good match with measured field data.

It should be emphasized that temperature in the wellbore is actually not always defined as well known variable. This fact should be taken into account while considering performance of wells with unloading design. Moreover, it becomes difficult to account the temperature effects while various well work is performed as production choke increasing or reducing, scale squeeze treatments (cold water). However, such of temperature fluctuations might have a temporary effect on the IPO valves functionality [8].

3.5.3 Valve malfunction

There are several scenarios to be considered when unloading valves might not work as desired [2, 8]:

- The temperature at unloading valve is lower than predicted temperature in design. This may lead to situation when the unloading valve will stay open.
- The temperature at unloading valve is higher than predicted temperature in design. Then the unloading valve will close earlier than it was expected.
- The production pressure is higher than anticipated. This may cause unloading valves to reopen. However, the PPEF value for the IPO valve is usually about of 0.1, therefore, the really large increase in tubing pressure is needed to reopen the valve.
- Mechanical failures.

It should be also emphasized that multipoint injection can cause detrimental effect on unloading valve since this valve does not expected to be a point of continuous injection.

The TRO values of IPO valves installed in the Prudnoe Bay wells (Alaska) were examined [10]. It was demonstrated that the pressure settings for the valves retrieved out of the wells were not always the same as designed. The possible explanations for that might be mechanical deformations, jarring effects during installations.

The validation of real gas lift installation designs was done with the help of the unloading simulator [11]. It was demonstrated to be beneficial to revise the designs at the stage of planning based on the simulations results.

3.5.4 Injection pressure operated valves today

Companies such as Weatherford, Petroleum Technology Company (PTC) and Schlumberger suggest a new generation of gas lift valves which are designed as barrier qualified gas lift valves. These valves are equipped with a check valve to avoid fluid movement from the tubing to the casing with regards to well integrity issues.

For more than 60 years the IPO valve has evolved, resulting in changes in bellows design, check valve design, valve performance and functionality.

The PTC Safelift IPO valve has a very low load rate (i.e. long valve stem travel) due to constrained linear motion and a large bellows outer diameter (OD) that makes the valve more sensitive to injection pressure. The company claims that these IPO valves can be used as operating valves due to their reliability. The valve is designed to stay in closed position in case of dome pressure leakage or bellows failure [12].

3.6 Terminology

It is common to find the following pressure terminology associated with the gas lift operation and the unloading process [2]:

Production pressure means pressure in the tubing.

Injection gas pressure (casing pressure) is a gas pressure in casing-tubing annulus.

Flowing wellhead pressure is the observed tubing pressure at wellhead when the well is producing.

Casing head pressure is measured at casing inlet and it is often referred to as injection pressure.

Kickoff pressure is defined as the maximum allowable casing head pressure to unload the well. It is depends on gas compressor capacity.

Unloading pressure is a pressure specified for each unloading valve and is used to calculate the test rack opening pressure. As gas is injected through deeper unloading valves, this pressure decreases.

Operating pressure is commonly referred to as a surface injection pressure needed for continuous lifting operation at the point of injection.

3.7 Information required for evaluation of gas lift system performance

Production test data combined with real-time measurements at wellhead are required to recognize operational problems and take optimization actions.

3.7.1 Production well tests

Production well tests yield important information on well performance. They allow engineers to catch changes in production that signalize possible operational problems or changes in well performance [8].

During the test production rates for oil, water and gas are measured, as well as the injection gas rate. Important production characteristics of the well are calculated based on production rates:

$$Water\ cut = \frac{water\ rate}{water\ rate + oil\ rate}$$

$$Water\ to\ oil\ ratio\ (WOR) = \frac{water\ rate}{oil\ rate}$$

$$Total\ gas\ to\ oil\ ratio\ (GOR) = \frac{total\ gas}{oil\ rate}$$

$$Producing\ GOR = \frac{total\ gas - injected\ gas}{oil\ rate}$$

$$Total\ gas\ to\ liquid\ ratio\ (GLR) = \frac{total\ gas}{total\ liquid\ rate}$$

$$Producing\ GLR = \frac{total\ gas - injected\ gas}{liquid\ rate}$$

Production test data plotted as results versus time presents historical trend data.

3.7.2 Downhole pressure and temperature survey

Downhole pressure and temperature survey can be performed at static and flowing conditions. The static pressure measurements give static gradients in the well and static bottomhole pressure. The survey at flowing conditions can be used to determine the important operating parameters of the well [13].

Generally, for a gas lifted well the flowing survey is used:

- To detect the locations where the injection gas enters into the production string (these injection points can be orifice, unloading valve, hole in the tubing, leaking valves).
- To determine the flowing gradients and flowing bottomhole pressure and confirm chosen vertical flow correlation.
- To determine inflow performance (PI).

Flowing temperature records give confirmation on points of injection due to local temperature drops (Joule-Thompson effect – cooling effect when gas passes restriction). The real temperature at valve depths is important for IPO valve settings calculation.

A good flowing pressure and temperature survey is needed in order to perform gas lift design with injection pressure operated valves.

The flowing downhole survey is recognized as a good troubleshooting technique for gas lifted wells.

3.7.3 Real-time data

Pressure and temperature data at wellhead is monitored in real time, as well as gas injection rate. Downhole pressure and temperature readings are available in real time for wells with installed downhole pressure gauges.

Acquired data is meaningful to identify well operational problems at early stage.

Real-time data monitoring indicates whether the injection pressure is fluctuating or the flowing wellhead pressure and temperature are reasonable. The gas rate is controlled on the surface. However, the pressure in the annulus is also controlled by the downhole valve [8].

3.7.4 Gas lift troubleshooting techniques

Along with the downhole pressure and temperature survey and real time data monitoring, there are some other techniques that can be used for well performance evaluation and troubleshooting.

Echometer

The principal is based on use of echoes. Interpretation of acoustical recordings can be used to calculate the distance to the fluid level in annulus or tubing, and other downhole reflectors such as gas lift valves, subsurface safety valves, and possible holes [8].

Well Tracer technique

The idea of using this technique is to inject a small volume of CO_2 into the injection line and then measure the CO_2 concentration at the wellhead [14]. This non-invasive method can be used to quick determine points of injection in wells, detect tubing leaks. There is no risk of lost tools and junking of a well. The depth of injection or potential leakage is determined based on the measured travel time for the tracer CO_2.

Production logging tool (PLT)

Production log is applied to recognize types and volumes of produced fluids along the wellbore [15]. Several passes up and down are performed with various logging speed. The spinner rotation is defined by velocity of producing fluid related to the spinner. For production log interpretation the spinner rotation is positive if the fluid is recognized by the spinner as flowing from below, and negative if the fluid is recognized as flowing from above. Production logging is used to identify various downhole issues, such as formation crossflow, non-flowing perforations, gas and water coning, etc.

3.8 Unstable operation in continuous gas lifted wells

Continuous gas lift wells are prone to unstable operations – heading. Generally, it is characterized by slugging [8].

The unstable operation is marked by periodic fluctuations in casing head pressure, tubing head pressure, flow rates over time. Casing heading is also referred to as injection heading and may occur together with a varying gas injection rate. In turn, tubing heading is often referred to as production heading. Both types of unstable operation often occur in combination.

Heading is an indicator of possible downhole problems such as oversized valve, low injection gas rate, improper tubing size for the given production conditions, multi-point injection, hole in the tubing, leaking gas lift valve, and others.

Instability problems result in production losses, upsets to topside facilities, difficulties in flow rates measurements and etc.

3.9 Gas lift design with unloading valves: concept

The main goal of gas lift design is to achieve the desired operating conditions. In order to meet this requirement, it is essential to determine the positions for gas lift mandrels, select the proper valves, port sizes, and estimate the set pressures of the unloading valves.

There is no single design approach that applies to all wells. API recommended practices and various industry publications present examples of gas lift design including design with injection pressure operated valves [3, 16].

The main design methods are:

- The constant casing pressure drop method.
- The maximum producing pressure range method.

Various design bias are applied in order to put uncertainty and improve the confidence in the design. These can be wellhead pressure, flowing tubing gradient, casing pressure drop, designed gas passage, the amount of differential pressure at operating point, etc.

The final design stage is to develop different scenarios with appropriate sensitivity parameters in order to anticipate the future well performance. There are various situations that might occur in the future such as increasing water production, decreasing reservoir pressure, changes in top facilities configuration, etc.

4 METHODOLOGY

4.1 Introduction

The majority of producing wells on the Ekofisk field utilize gas lift. The gas lift compressor on a process/transport platform 2/4-J has a maximum supply pressure of 2250 psia for 2/4-X and 2/4-B platforms. It can provide 220-240 million standard cubic feet of gas per day (MMscf/d). The injection gas has a specific gravity of 0.7.

The location of wells with injection pressure operated valves is shown in *Figure 4.1*. The unloading design was implemented for 10 wells on 2/4-X and 1 well on 2/4-B production platform. The typical completion design incorporates 5½-in. tubing with three or four side pocket mandrels.

The unloading valves typically utilized in the Ekofisk field are 1½ -in. OD unbalanced nitrogen-charged bellows valves with 16/64th (¼)-in. port size. The IPO valve models are Safelift by PTC and Camco R-20 by Schlumberger. Side pocket mandrels which do not require orifice or unloading valve contain dummy valves.

The 2/4-B-17 well was historically the first well in the Ekofisk area with unloading valves installed in 2004. At the time of this report, the well is a potential candidate for new IPO gas lift design.

There are some aspects regarding 2/4-X-wells:

- Surface gas lift chokes are oversized and, therefore, not sensitive enough to adjust lift gas injection rate.
- Oversized tubing leads to excessive lift gas usage and may cause unstable production (slugging).
- Permanent pressure and temperature gauges are not installed in all wells or not working properly.

The real-time well and process information (such as well pressures, temperatures, gas injection rates, etc) is gathered and stored by the OSIsoft PI System. This information can be visualized using PI ProcessBook application.

Production test data is loaded into OilField Manager® (OFM) from the company database. This tool allows displaying and analyzing of the production data.

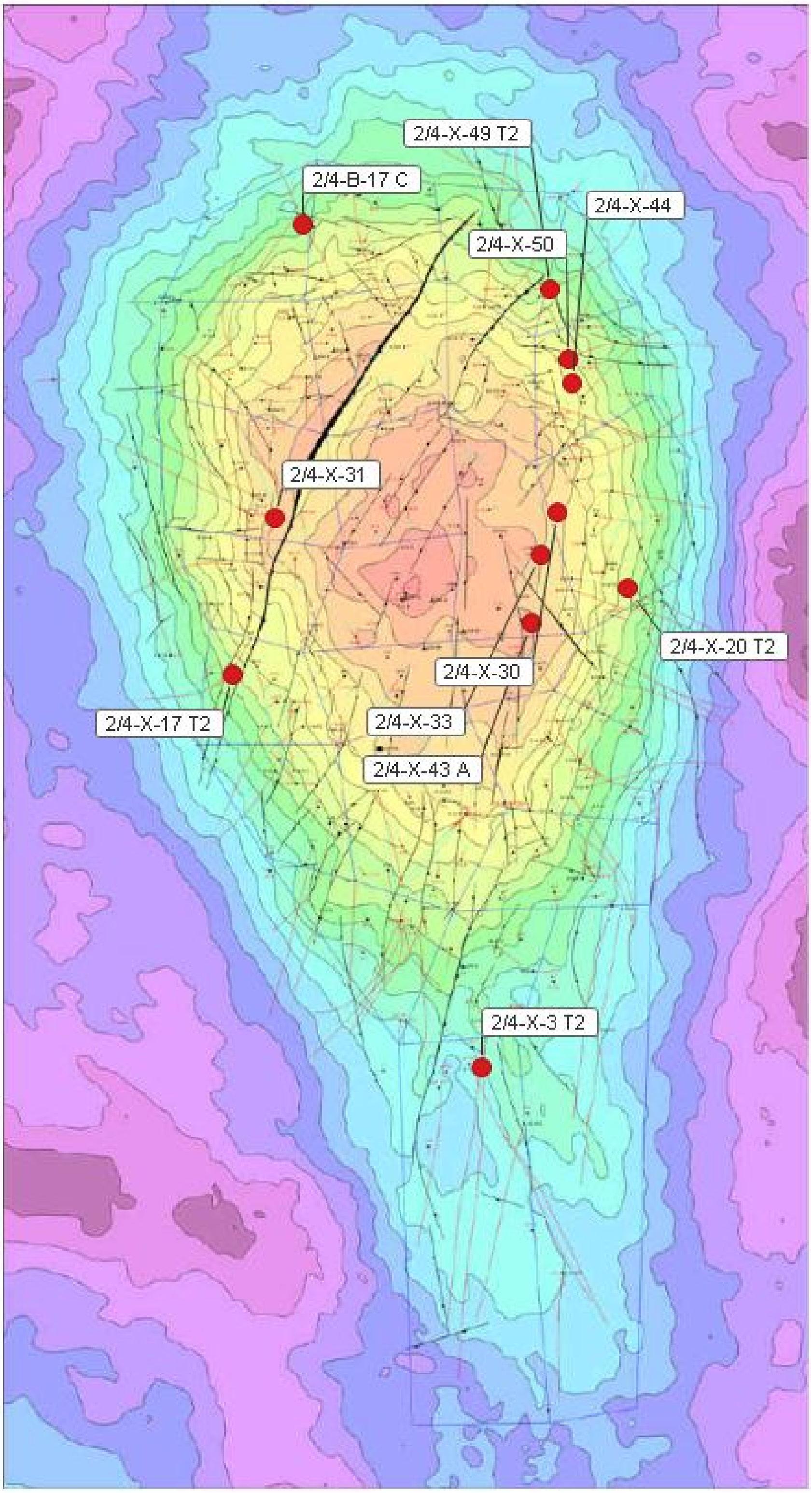


Figure 4.1 – Top Ekofisk structure map, showing the location of the wells with unloading sequences.

4.2 Data gathering

To meet the objectives of this project, the following data have been gathered and analyzed:

- Well completion data – well trajectory, tubing size, depth of side pocket mandrels, etc.
- Valve specifications – vendor, port size, setting depths, set pressures.
- Well history files. These documents contain brief summary of well intervention operations and general observations regarding well's performance.
- Production test data (i.e. oil, gas and water rates measured by test separator).
- Real time process data – wellhead and bottomhole pressure and temperature, production choke opening, gas lift rate, etc.
- Daily production loss reports. The identified daily production losses are categorized into different loss types, including losses associated with lifting issues due to liquid loading. This loss category is used to evaluate the efficiency of unloading sequence from the lifting point of view.

4.3 Well models

Well models have already been created in WellFlo software and matched to the actual well performance based on the latest production test measurements.

4.3.1 Vertical lift performance

The choice of vertical flow correlation used in well models is based on flow correlation study for Ekofisk wells performed by Weatherford [17]. The following vertical pressure profile models have been studied: Duns and Ross (modified), Beggs and Brill (modified), Hagedorn and Brown (modified), OLGA Steady State and EPS Mechanistic. OLGA Steady State correlation was found to be a good vertical multiphase correlation for outflow predictions of the gas lifted wells. It has also been demonstrated that EPS Mechanistic correlation provides the most accurate results for naturally flowing wells with GLR up to 1600 scf/stb, while OLGA Steady State correlation is the best choice for naturally flowing wells with GLR over 1600 scf/stb. Both OLGA Steady State and EPS Mechanistic correlations give good match to measured data for naturally flowing wells with GLR ranging from 900 to 1600 scf/stb. The results of the flow correlation study are illustrated in the *Figure 4. 2*.

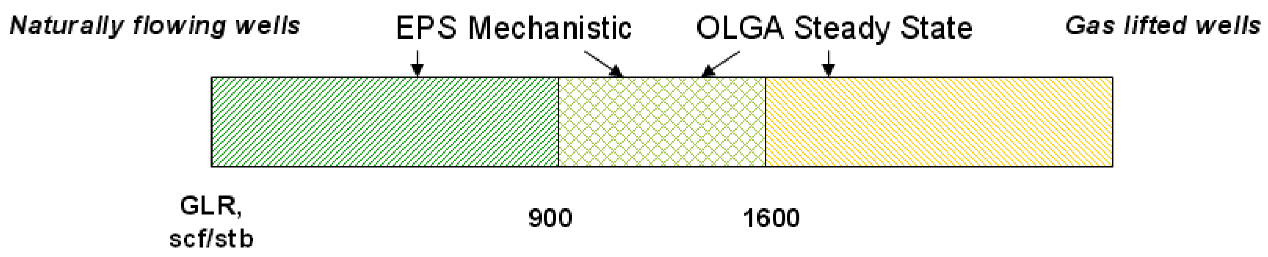


Figure 4.2 – Flow correlations for the Ekofisk wells.

4.3.2 Vertical temperature profile

The temperature profile along the wellbore is calculated using Ramey's and Willhite's heat loss correlations. The correlation is tuned to the measured wellhead temperature at a given flow rate from the latest production test [18].

From the company's experience, the temperature calculations by the tuned correlation are considered to be very accurate.

4.3.3 Inflow performance model

Combination of straight line IPR (constant PI) and non-linear Vogel approach is used for inflow performance calculations.

4.3.4 Valve performance calculations

Gas throughput for the orifice valve is calculated with the Thornhill-Craver equation.

As for the unloading valves, correlations for valve performance are based on licensed data from the Valve Performance Clearinghouse database.

Unloading valve calculations are based on the equations derived from the force-balance relationship considered earlier in Chapter 3. The evaluation of set pressures under operating conditions is needed to predict the state (open versus closed) of the unloading valve. In other words, it can be used to determine if the unloading valve is closed or open based on valve mechanics and for a given operating and tubing pressures and temperature in a well.

The rigorous method is used to determine the temperature correction factor for dome pressure. The compressibility factor for nitrogen is calculated to find out the accurate dome pressure at in situ conditions.

4.4 WellFlo

WellFlo is production software from Weatherford. The software performs steady-state multiphase flow modeling and is based on nodal analysis [18]. It is a powerful engineering tool for analysis of well performance including gas lifted wells. Well models involve information about reservoir, wellbore deviation, completion, PVT fluid properties.

“Analysis” section allows engineers to determine the operating point, run sensitivities on numerous parameters, calculate valve performance.

“Tuning” functionality enables users to import data, measured during pressure and temperature survey, to the model and tune the flow correlations.

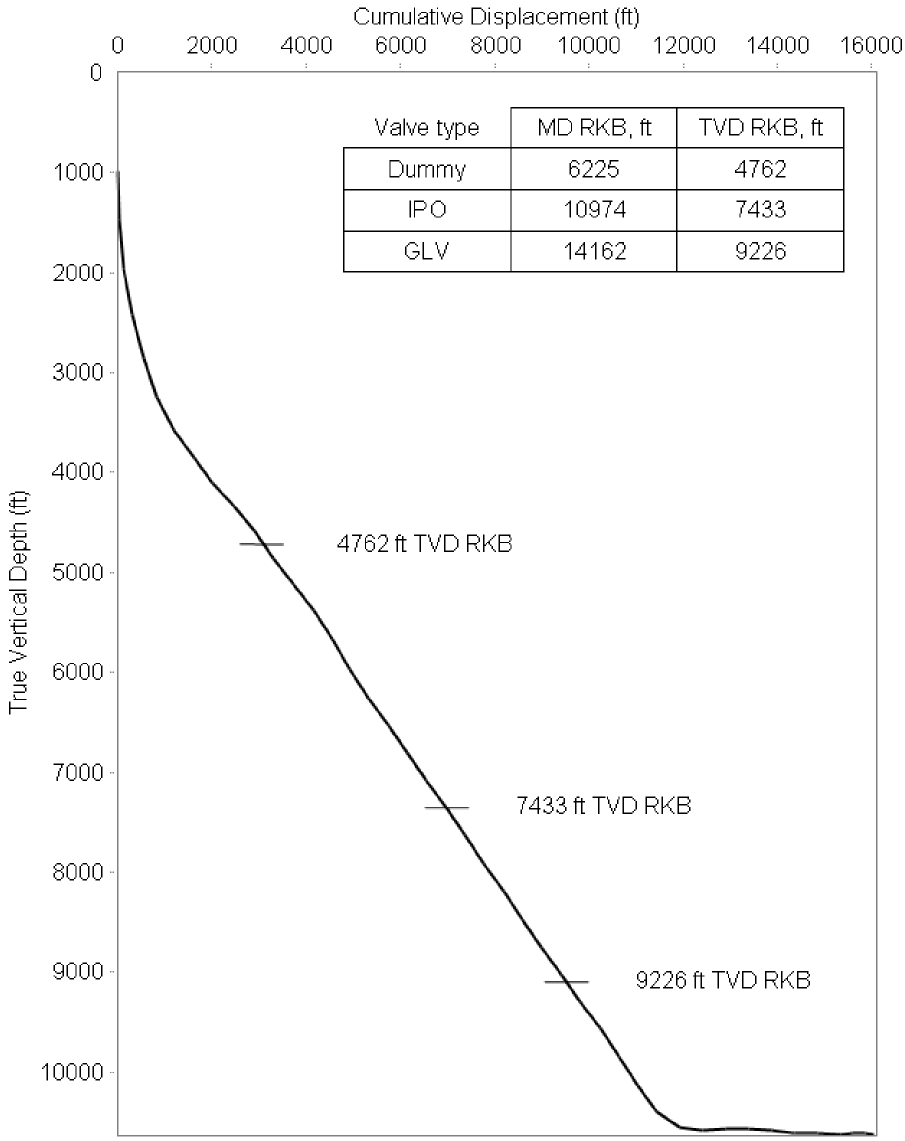
WellFlo has gas lift design option.

5 GAS LIFTED WELLS WITH INJECTION PRESSURE OPERATED VALVES IN THE EKOFISK FIELD: RESULTS AND DISCUSSION

The present chapter consists of a case study of Ekofisk producers with injection pressure operated valves installed. The last section covers the design consideration of an unloading sequence for one particular well.

5.1 Well X-03

The well is a long horizontal producer completed in the Ekofisk formation on the southern flank of the field. The well trajectory is shown in *Figure 5.1*. The locations of side pocket mandrels and the type of valves installed are also shown in this plot.



Valve type	MD RKB, ft	TVD RKB, ft
Dummy	6225	4762
IPO	10974	7433
GLV	14162	9226

Figure 5.1 – X-03 wellbore trajectory.

The gas lift was initiated in 2002. There were 2 restimulation treatments. The historical production test data is presented in *Figure 5.2*. Oil rate, liquid rate, water cut, producing GOR, total GLR and gas injection rate from good tests are plotted versus time. A good well test is the one which is representative of the actual well performance.

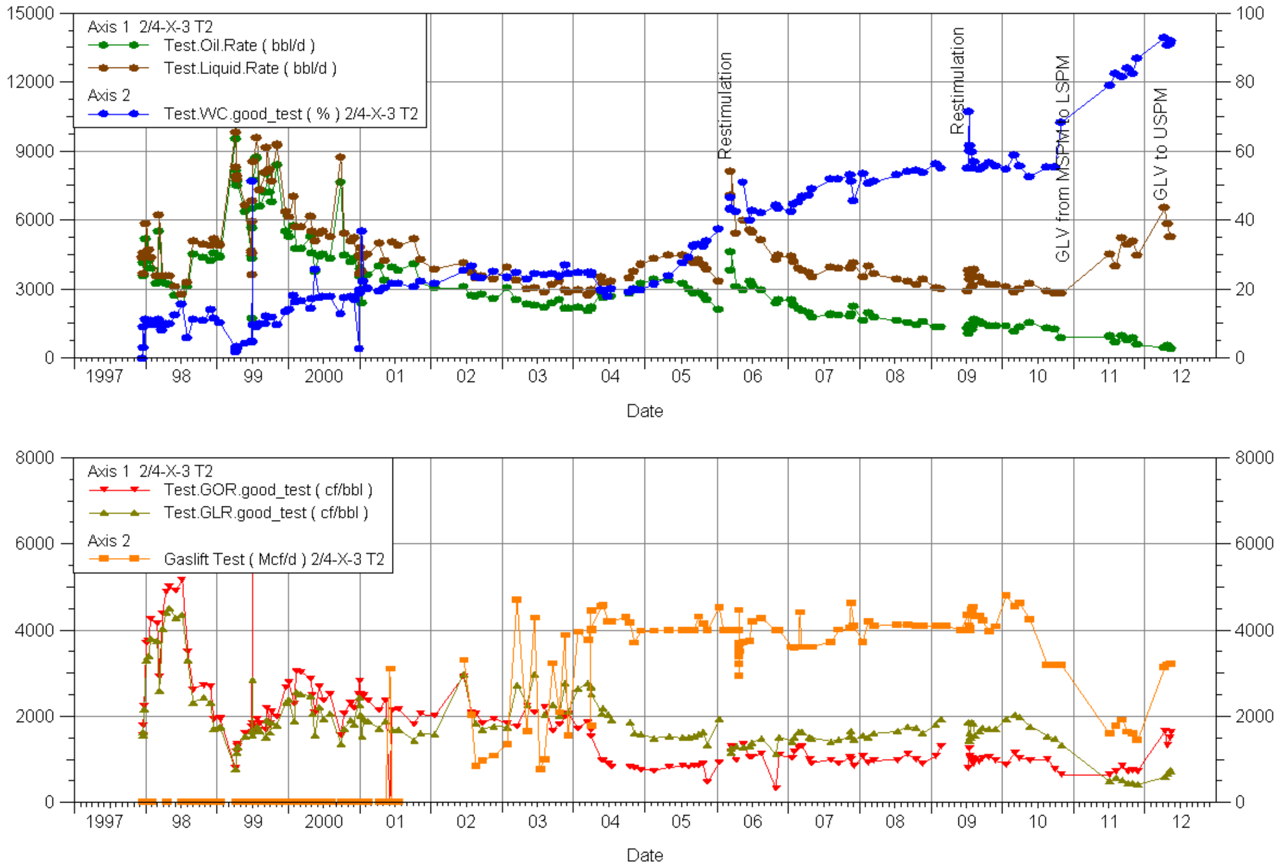


Figure 5.2 – X-03 production test data.

After water breakthrough in late 2010, a gas lift optimization was initiated in order to move the point of injection from MSPM to LSPM. The pre-job analysis has shown that an unloading valve was required in order to be able to inject gas through the LSPM. An IPO valve was installed into MSPM, and an orifice valve was set into LSPM.

In order to evaluate the well's behavior after it was put back on production, the following real-time data is analyzed. Wellhead pressure and temperature, casing head pressure, gas lift rate and choke data during initial unloading are shown in *Figure 5.3*. Initially, gas injection rate was 1.7 MMscf/d, which corresponds to the design throughput rate of the IPO valve. This suggests that gas was injected through the unloading valve in MSPM. Note that the unloading period took more than two weeks due to long shut-in period prior to the IPO installation. Following the production choke opening from 76 to 80%, the gas injection rate started to increase. Interestingly, the injection pressure decreased to about 1830 psia as the gas lift rate increased. One of the possible explanations to that could be a sudden leak development in the completion string (e.g. hole in the tubing, leaks at gas lift mandrels, etc.).

Another possible explanation for this is that gas is being injected through both IPO and orifice valves (multipoint injection). This is supported by the fact that the measured gas injection rate at that time was about 5.2 MMscf/d, which is close to the combined gas throughput capacity of the IPO and orifice valves (5.3 MMscf/d). However, according to the design, the unloading valve should be closed at casing head pressure below 1970 psia.

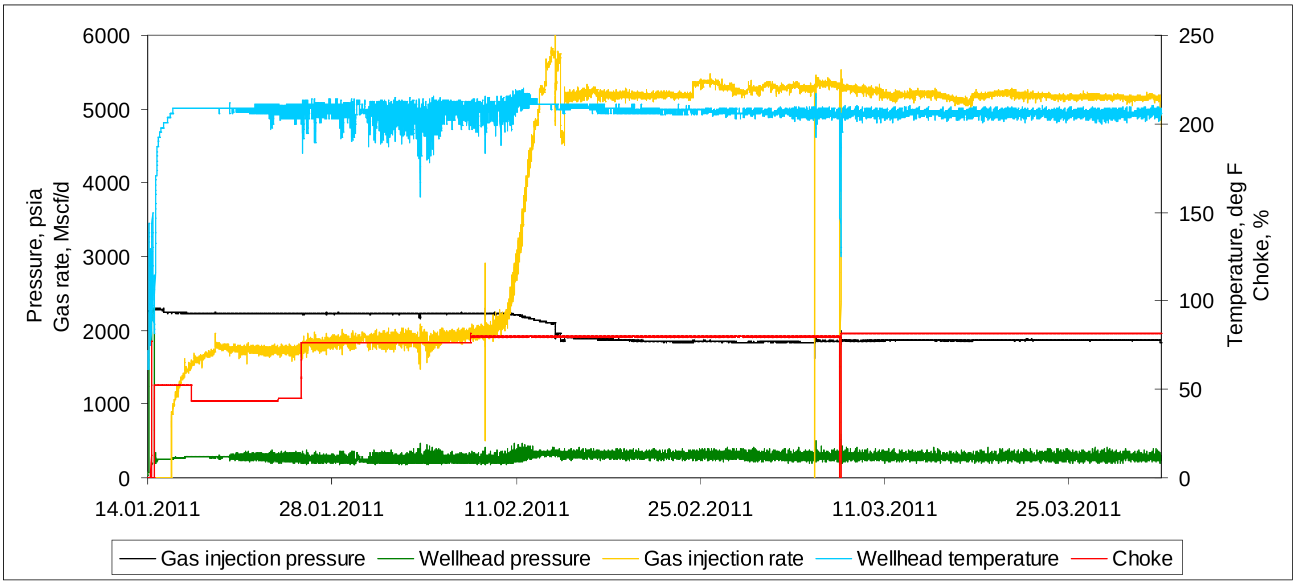


Figure 5.3 – Well X-03. Real-time pressure, temperature, gas lift rate and choke data during unloading.

From manufacture's catalog, a 1½ -in. OD Safelift-IPO valve with port size of 16/64th (¼)-in. has a port-bellows ratio of R = 0.076, therefore 1-R = 0.924.

The known test rack opening pressure for this valve:

$$TRO = \frac{P_d \ at \ 65F}{1-R} = 1753 \ psia$$

$$P_d \ at \ 65F = 1620 \ psia$$

Using the temperature correction factor of 0.989:

$$P_d \ at \ 60F = 1602 \ psia$$

Based on the well performance model, the calculated temperature at the IPO valve depth is 233°F. Therefore, dome pressure (hence the casing pressure at valve closure) at valve depth can be calculated based on equation (*) from Chapter 3:

$$M = -0.267 + 0.002298 \cdot 1602 + 1.84 \cdot 10^{-7} (1602)^2 = 3.8866$$

$$P_d \ at \ valve \ depth = 1602 + 3.8866(233 - 60) = 2274 \ psia$$

The injection pressure at valve depth from the well model is 2157 psia, which corresponds to casing head pressure of 1854 psi. Therefore, the IPO valve should be closed as the casing pressure is lower than the dome pressure. It should also be noted that the dome charging pressure was based on the static temperature survey done prior to the IPO valve installation (221°F at MSPM). Under flowing conditions, however, the temperature would be higher due to reservoir fluid flowing in the tubing. As discussed in Chapter 3, the IPO valve would then be closed at even higher injection pressure. It is therefore possible to assume that pressure in the dome has declined due to leakage after charging.

The well was producing with the gas lift rates varying between 4.4 and 5.2 MMscf/d for more than 4 months. After long shut-in in summer 2011 this well was producing with low gas lift rate of about 1.4 MMscf/day. The production profile is presented in *Figure 5.4*. Note the significant fluctuations in wellhead pressure and temperature (amplitude more than 100 psi and 25°F). As can be seen from this figure, the casing head pressure was at the maximum level (2230-2250 psia). Based on the well performance model, these conditions correspond to the situation where gas is injected through the unloading valve.

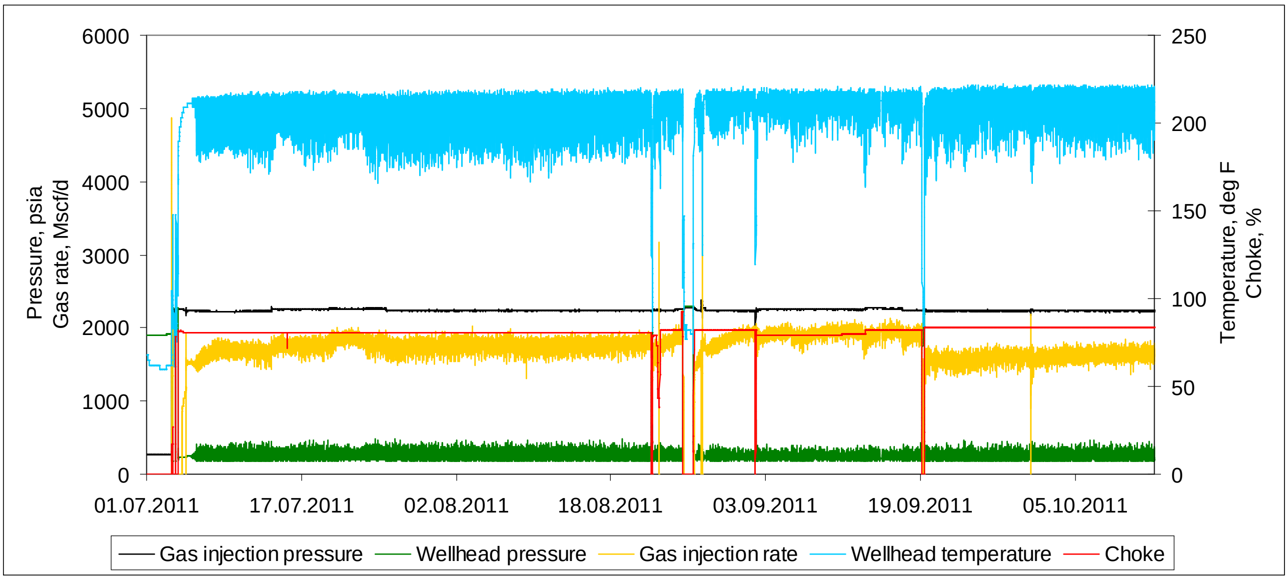


Figure 5.4 – Well X-03. Real-time pressure, temperature, gas lift rate and choke data during low gas injection rate period (well is under-lifted).

The well was producing with higher water cut (more than 10%) compared to the time of the unloading sequence design. This results in higher hydrostatic head in the tubing. It is possible to assume that the mandrel placement was not ideal for the actual production conditions, i.e. transferring the point of injection from the middle to the lowest side pocket mandrel, and therefore, full unloading of the well was not possible. The design for current conditions (87% water cut, wellhead pressure of 249 psia, injection pressure of 2250 psia, liquid rate 4495 stb/d and 1.45 MMscf/d gas injection rate) was made to evaluate if the deepest point of injection (the orifice in LSPM) can be reached. The result is presented in Figure 5.5. The operating valve is depicted by a solid blue line at 9226 ft TVD RKB. Note that at current mandrel spacing, the transfer point is on the right side of the flowing pressure gradient and the unloading gradient intersects the flowing pressure gradient curve at the depth that is shallower than the current depth of the IPO valve. This means that the current design will not unload the well properly.

Thus, the current mandrel spacing does not allow the well to be fully unloaded to the orifice depth (9226 ft TVD RKB). Mandrel respacing, however, requires tubing change-out, which is impractical.

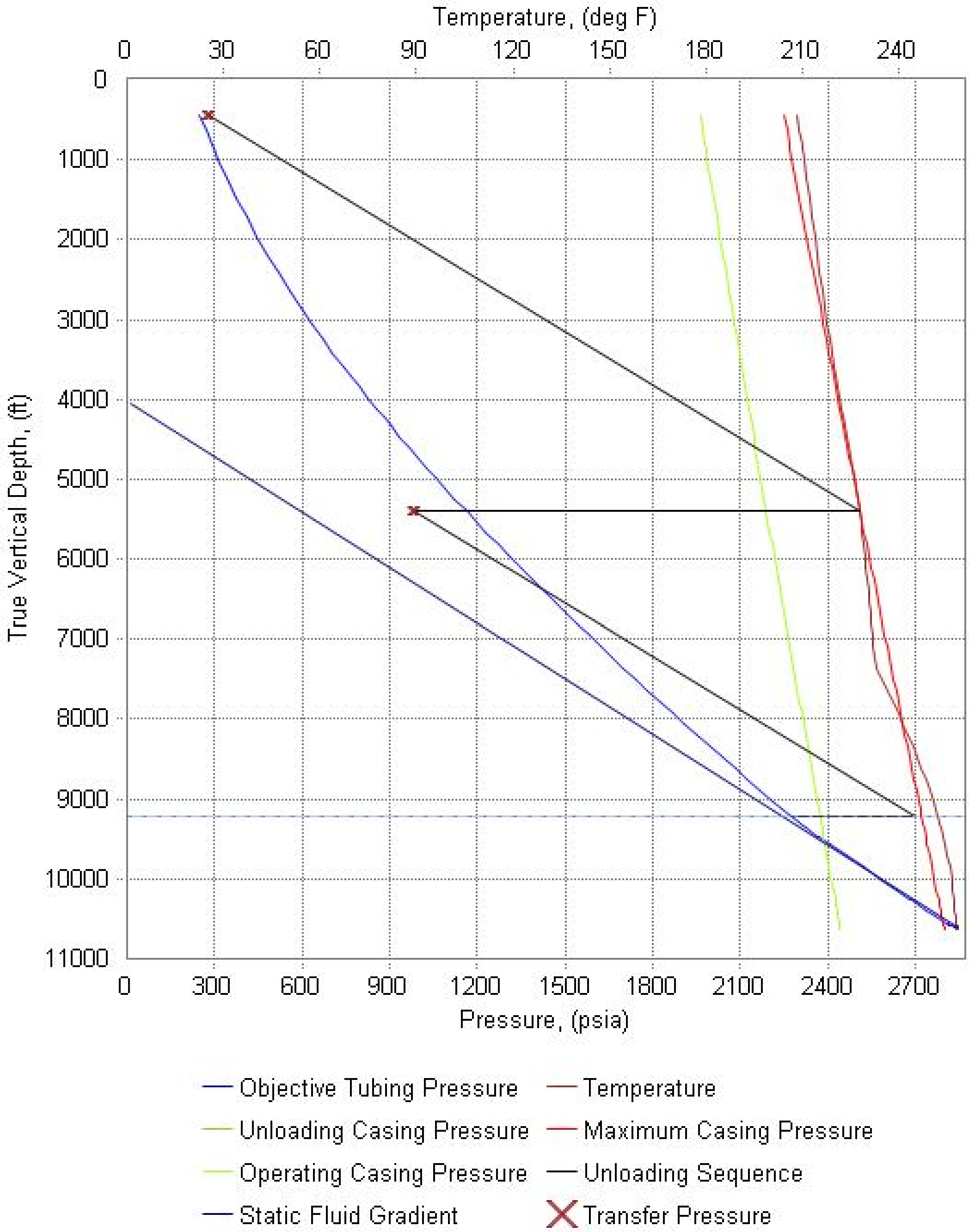


Figure 5.5 – Well X-03. Pressure versus depth graphical solution for design at changed production conditions.

Following a routine GLV test in November 2011, the well has loaded up with fluid and stopped producing. It can be assumed that the mechanical failure occurred and valve was in closed position. The well has been producing with gas injection through the IPO valve for long period of time (about 5 months). Despite of the statement about the possibility of using

Safelift IPO valve as an operating valve (as mentioned in Chapter 3), the possibility of mechanical failure can not be excluded.

To initiate the flow, the gas lift valve was installed in USPM and the well started to produce. In order to evaluate the benefit from deeper injection, i.e. to keep the orifice in LSPM and install IPO valve(s), the following analysis was done in WellFlo.

First, the well performance model was modified to reflect the current conditions. Static bottomhole pressure and temperature data recorded during the installation of the gas lift valve in USPM were used to update the reservoir pressure in the inflow model. The production test results presented in *Table 5.1* were used to calibrate the model.

Table 5.1 – Summary of the production test for well X-03.

Oil, bbl/d	371.6
Gas, Mscf/d	611.3
Water, bbl/d	7041.5
Lift gas, Mscf/d	2279.1
GOR, scf/bbl	1645

Due to high water production from the well (over 7000 stb/d, 95% water cut) and test separator constraints on water handling, the production choke opening was 21% (wellhead pressure 611 psia) during the test (while normal choke setting for this well is 84%, which corresponds to wellhead pressure of 249 psia). Based on the well performance model, the expected liquid rate at normal choke opening is about 10470 stb/d which corresponds to oil rate of 523.5 stb/d. The increase in production rate due to choke opening is demonstrated in *Figure 5.6*.

The calibrated model was then used to estimate the benefit from injecting gas through the lowest side pocket mandrel.

Table 5.2 demonstrates the benefit from gas injection through LSPM at wellhead pressure of 249 psia, 95% water cut and 3 MMscf/d gas injection rate. As can be seen from this table, the expected increase in production is about 75 stb/d.

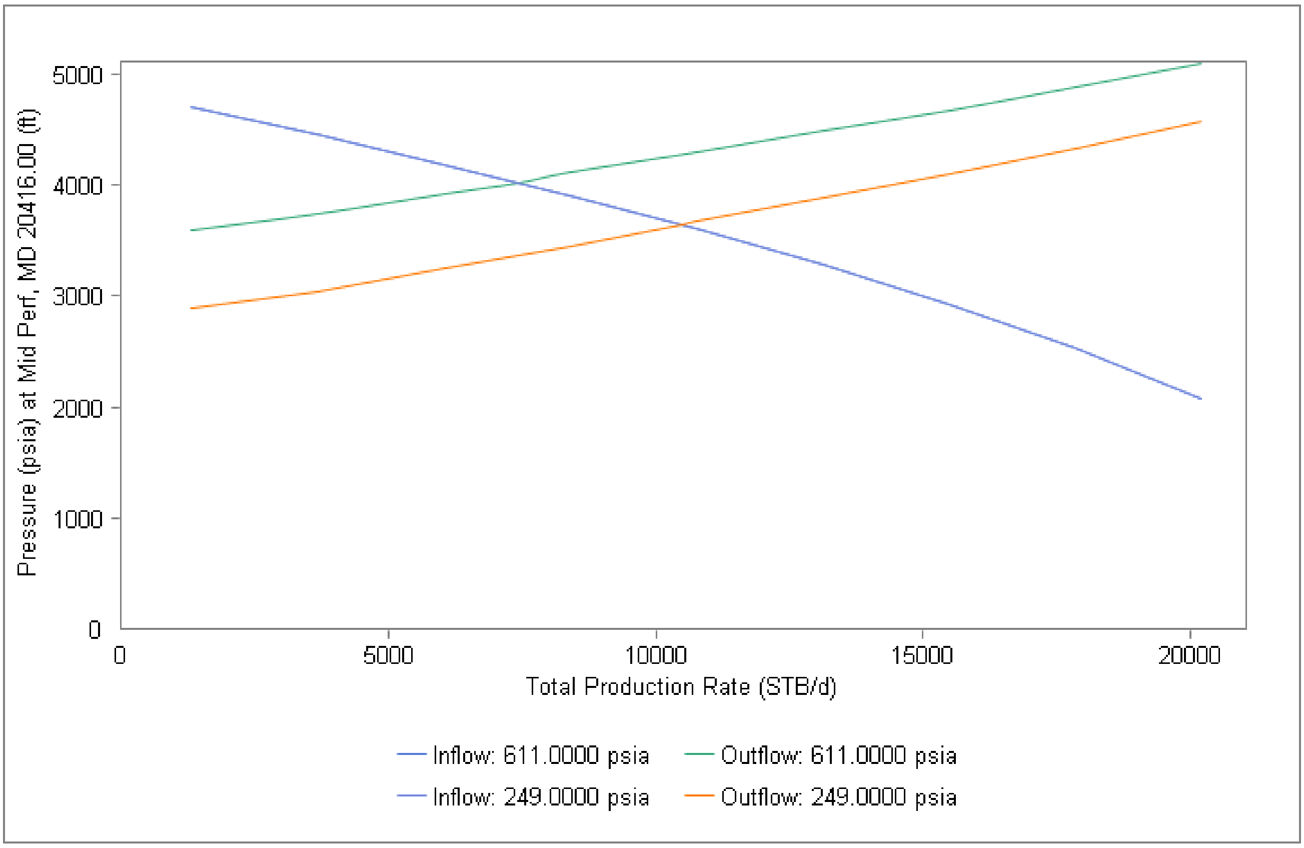


Figure 5.6 – Well X-03. Inflow performance and corresponding outflow curve for 21% and 84% production choke opening.

Table 5.2 – Well X-03 production performance.

Point of injection	*Produced liquid, stb/d*	P_{wf} *, psia*	*Total injected gas, MMscf/d*	*Incremental produced oil, stb/d*
USPM	10781.5	3063	3	75
LSPM	12284.6	3399	3	

Due to minor expected gain the unloading design was considered as not beneficial. Moreover, the flowing conditions were not representative of the normal well performance in order to run flowing pressure and temperature survey. The well is currently producing with gas injection through the orifice in USPM.

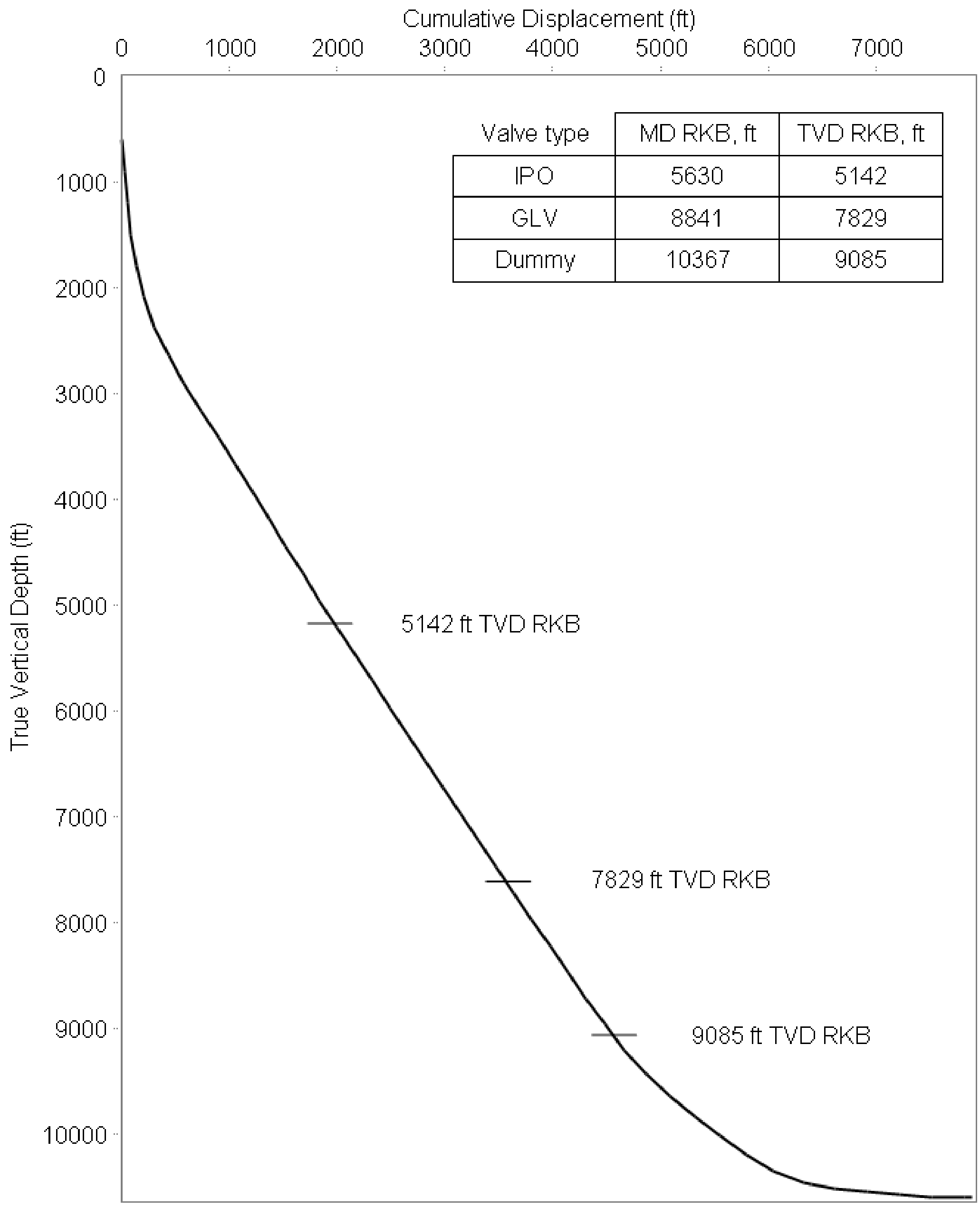
5.2 Well X-17

The well is completed in the Ekofisk formation. The well trajectory, side pocket mandrel depths and type of valves installed are shown in *Figure 5.7*. The well is equipped with downhole pressure and temperature gauges.

The well production history is presented in *Figure 5.8*. The water cut trend indicates the early water breakthrough.

Following the restimulation job, the orifice valve was moved up (from LSPM to USPM) due to increased bottomhole pressure. Then the gas lift optimization was initiated to set the orifice into MSPM. The IPO valve installation was required.

Wellhead pressure and temperature, gas lift rate, injection pressure and choke data are shown in *Figure 5.9* to demonstrate the well's behavior during the unloading period.



Valve type	MD RKB, ft	TVD RKB, ft
IPO	5630	5142
GLV	8841	7829
Dummy	10367	9085

Figure 5.7 – X-17 wellbore trajectory.

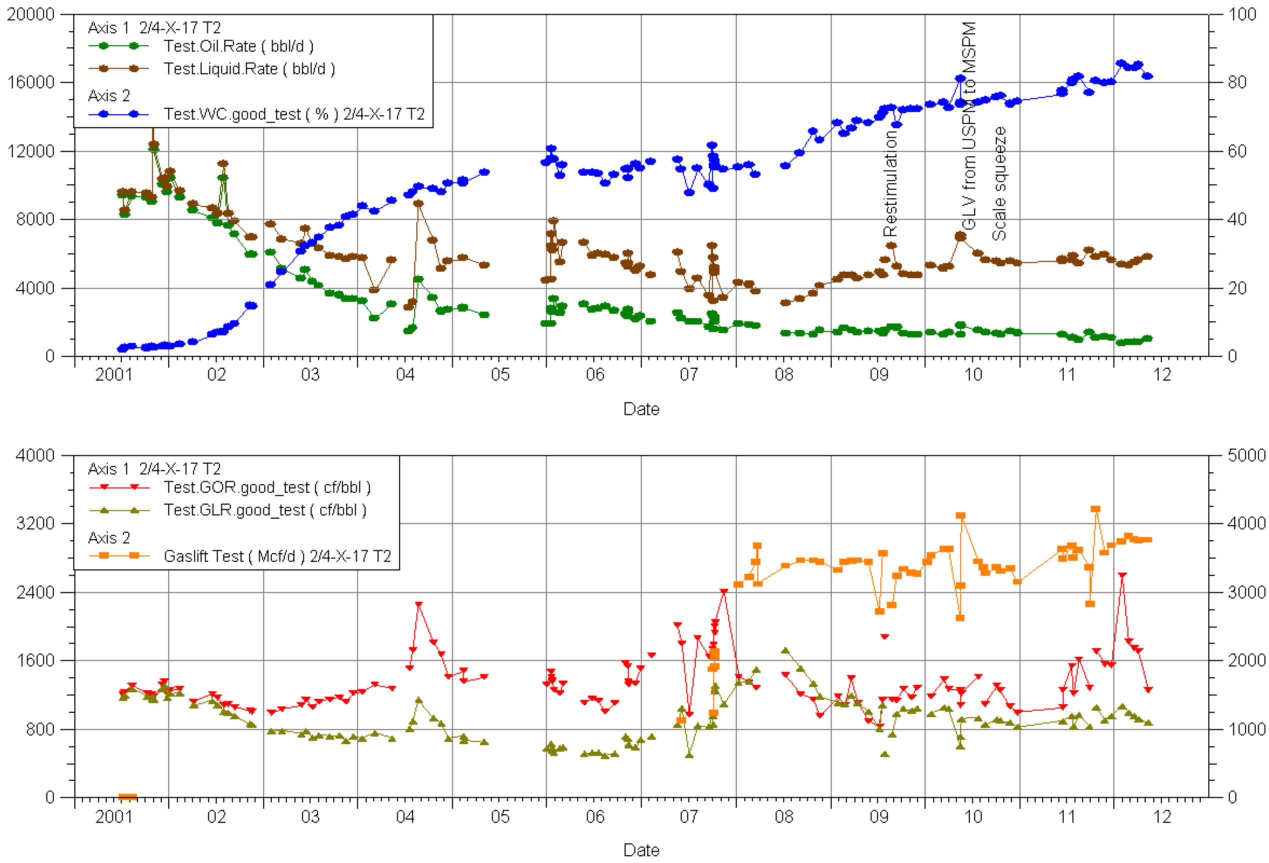


Figure 5.8 – X-17 production test data.

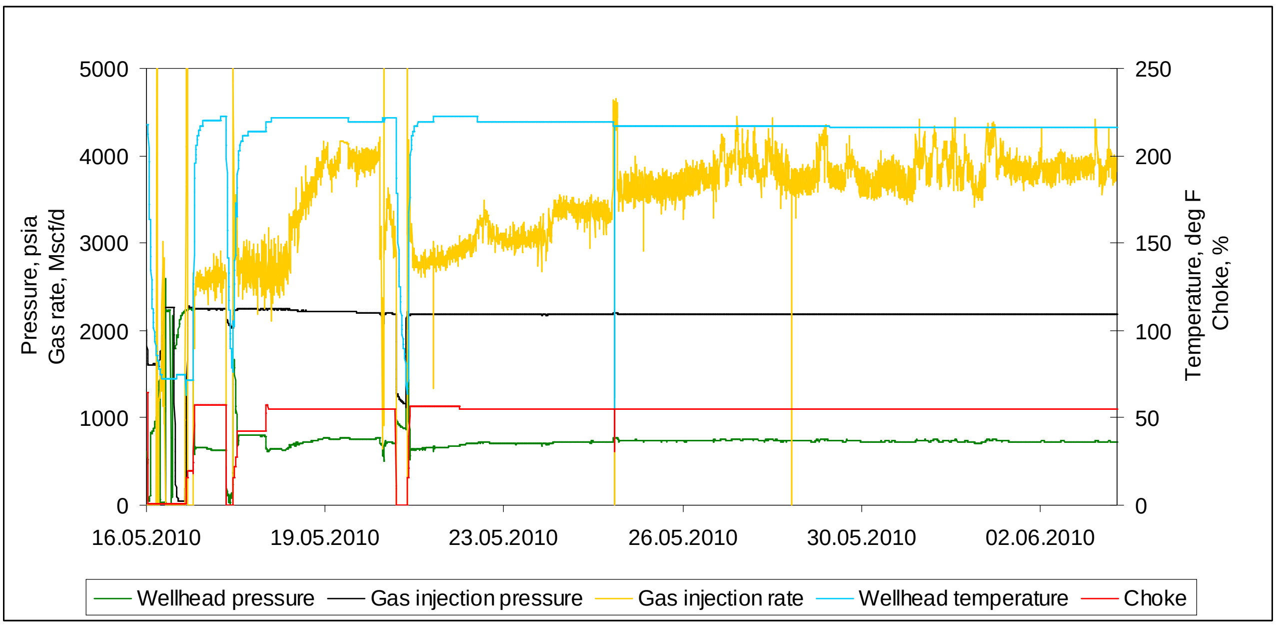


Figure 5.9 – Well X-17. Real-time pressure, temperature, gas lift rate and choke data during unloading.

During start up of the well the gas lift rate was 2.7 MMscf/d, corresponding to designed throughput capacity of the IPO valve. Further, the increase in gas rate up to 4 MMscf/d and corresponding injection pressure drop from 2248 to 2205 psia indicate that the injection goes through the orifice and the IPO valve is still open. Based on the design, the IPO valve should be closed when the injection pressure at surface drops below 2185 psia. The operating pressure was fluctuating near the designed casing closure pressure (2185 psia) that caused reopening of the IPO valve (interference from the IPO valve). This can be seen in *Figure 5.10* as spikes in gas injection rate.

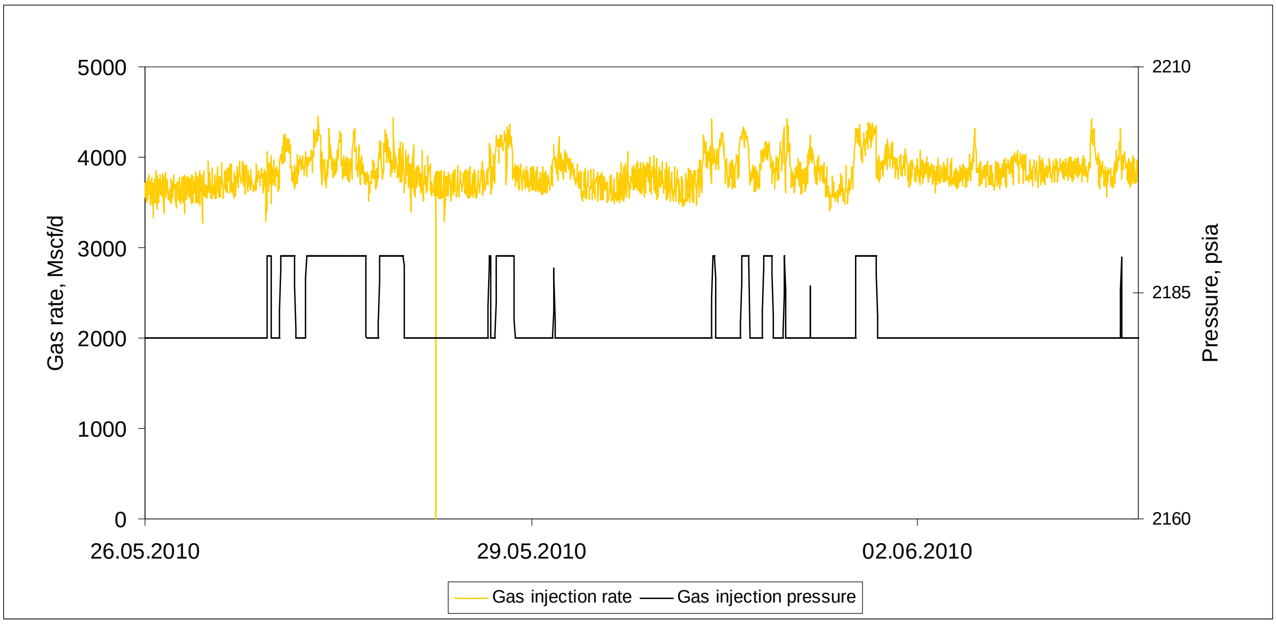
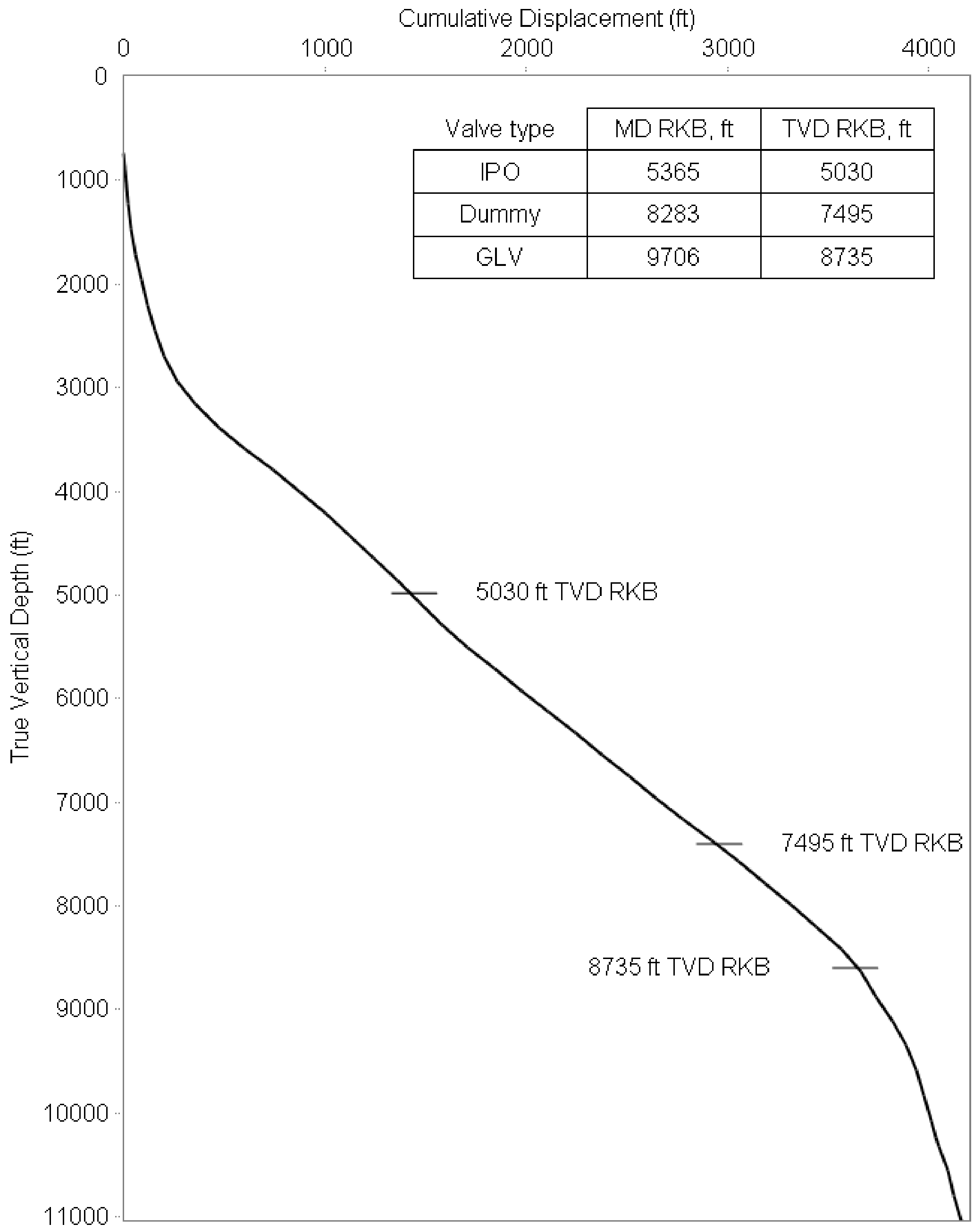


Figure 5.10 – Well X-17. Real-time gas injection pressure and gas lift rate data after unloading.

There are no production losses due to liquid loading since the IPO valve was installed. The well is an example of successful gas lift design with IPO valve and demonstrates a good continuous flow with reasonable injection gas rate through the 18/64th GLV (3.7 MMscf/d).

5.3 Well X-30

The well is completed in the Ekofisk and Tor formations. The well trajectory is shown in *Figure 5.11*. The locations of side pocket mandrels and the type of valves installed are also shown in this plot.



Valve type	MD RKB, ft	TVD RKB, ft
IPO	5365	5030
Dummy	8283	7495
GLV	9706	8735

Figure 5.11 – X-30 wellbore trajectory.

The historical production plot for the well is presented in *Figure 5.12*. Note the early water breakthrough. The well is on regular scale squeeze treatments.

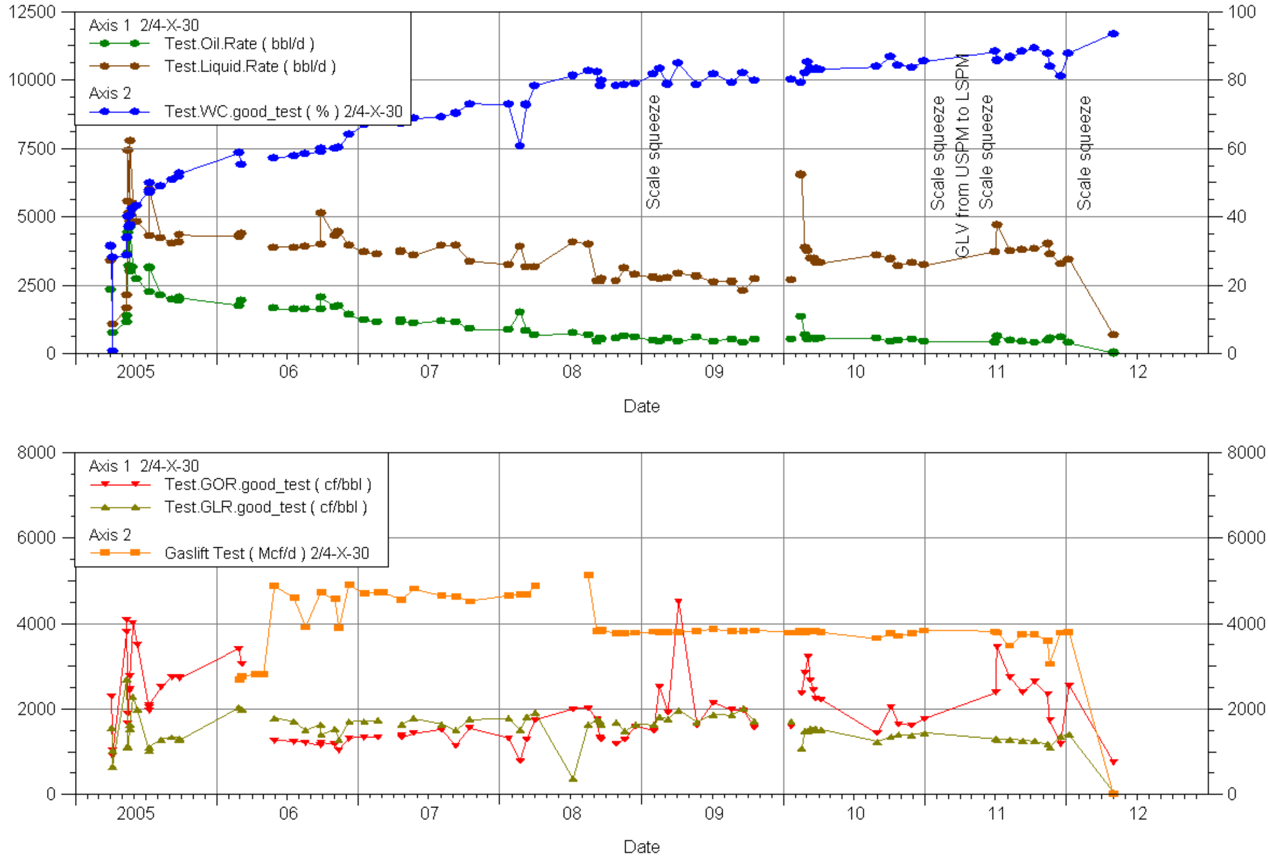


Figure 5.12 – X-30 production test data.

During the unloading process (*Figure 5.13)*, gas was injected through the unloading valve (designed maximum gas passage is 2.7 MMscf/d), and then for a short period of time through both unloading and orifice valves (the design injection rate for both valves is about the measured gas rate of 4.6 MMscf/d). Then the reduction in casing head pressure below design closure pressure (2030 psia) forced the IPO valve to close. The well was unloaded and gas was injected through the operating valve.

Later, the well was producing with high injection pressure of 2200-2250 psia (*Figure 5.14*), which might result in multipoint injection (gas injection rate was higher than designed throughput for the orifice). The fact of multiponting could be confirmed by running flowing gradient survey. The reason for high injection pressure is the oversized gas lift choke and, therefore, inability to have a good control over the pressure in the casing-tubing annulus. From the operational point of view, the decrease in casing-tubing pressure below a certain level activates the automatic alarm to shut-down all the wells.

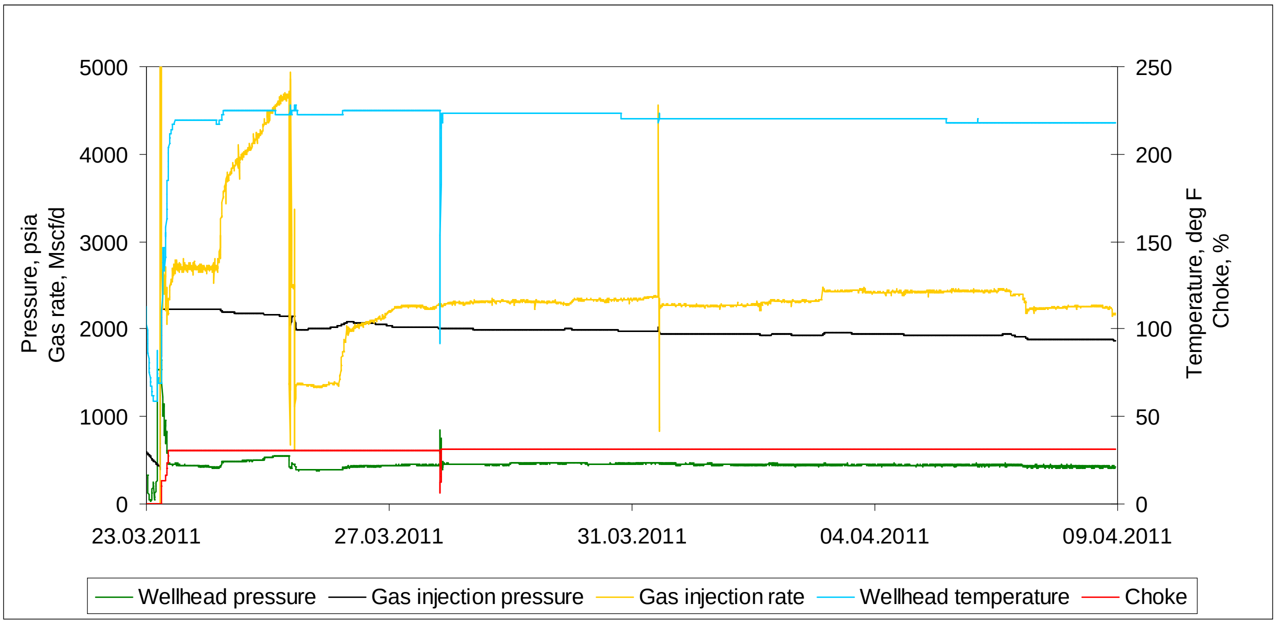


Figure 5.13 – Well X-30. Real-time pressure, temperature, gas lift rate and choke data during unloading.

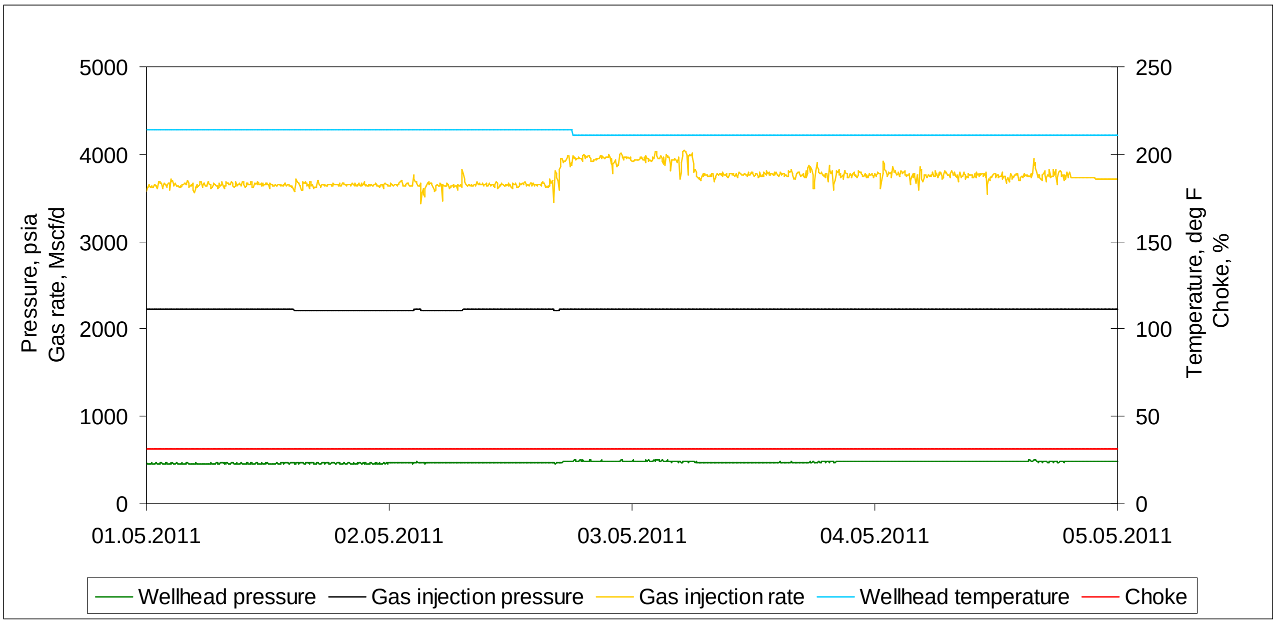


Figure 5.14 – Well X-30. Real-time pressure, temperature, gas lift rate and choke data after unloading.

Following scale squeeze treatment in February 2012, the well was not returned to production. Acoustic fluid level measurements (echometer survey) were taken one month after shut-in. The stabilized static fluid level in the tubing was found to be at 330 ft MD RKB (at wellhead pressure of 405 psia). The fluid level in the casing-tubing annulus was found to be at 9480 ft MD RKB (at casing head pressure of 2277 psia), which is significantly below the IPO valve depth (hence, the IPO valve is above the fluid level).

The detected static fluid level in the tubing is used to evaluate the tubing pressure at the IPO valve depth. The latest production test demonstrated 93% water cut. Assuming that the well is filled with 0.465 psi/ft salt water, the tubing pressure at the IPO valve depth is:

$$Tubing\ \ pressure\ at\ USPM\ = 0.465(USPM\ \ depth - \ fluid\ level) + wellhead\ \ pressure$$

$$Tubing\ \ pressure\ at\ USPM\ = 0.465(5030 - 330) + 405 = 2591\ psia$$

The estimated pressure in the tubing at the IPO valve depth should be compared to injection pressure at the same depth.

$$Casing\ pressure\ at\ USPM = 2277 + 0.048 \cdot 5030 = 2518\ psia$$

From the calculations above, it is possible to conclude that there is no differential pressure at USPM depth (5030 ft TVD RKB) to initiate the injection. The maximum available surface injection pressure of 2250 psia is not enough to kick off the well, as it corresponds to pressure less than 2500 psia at USPM depth. At the same time the possibility of the unloading valve failure can not be excluded as well.

Currently, the well is shut-in, awaiting future attempts to unload it with nitrogen (when the higher injection pressure is achievable).

5.4 Well X-31

The well is completed in the Ekofisk and Tor formations. The trajectory of the well, as well as locations of side pocket mandrels with the specified valve type are shown in *Figure 5*.15 The historical production test data is presented in *Figure 5.16.*

Following summer 2010 shut down, the unloading sequence design was performed to put the well back on production.

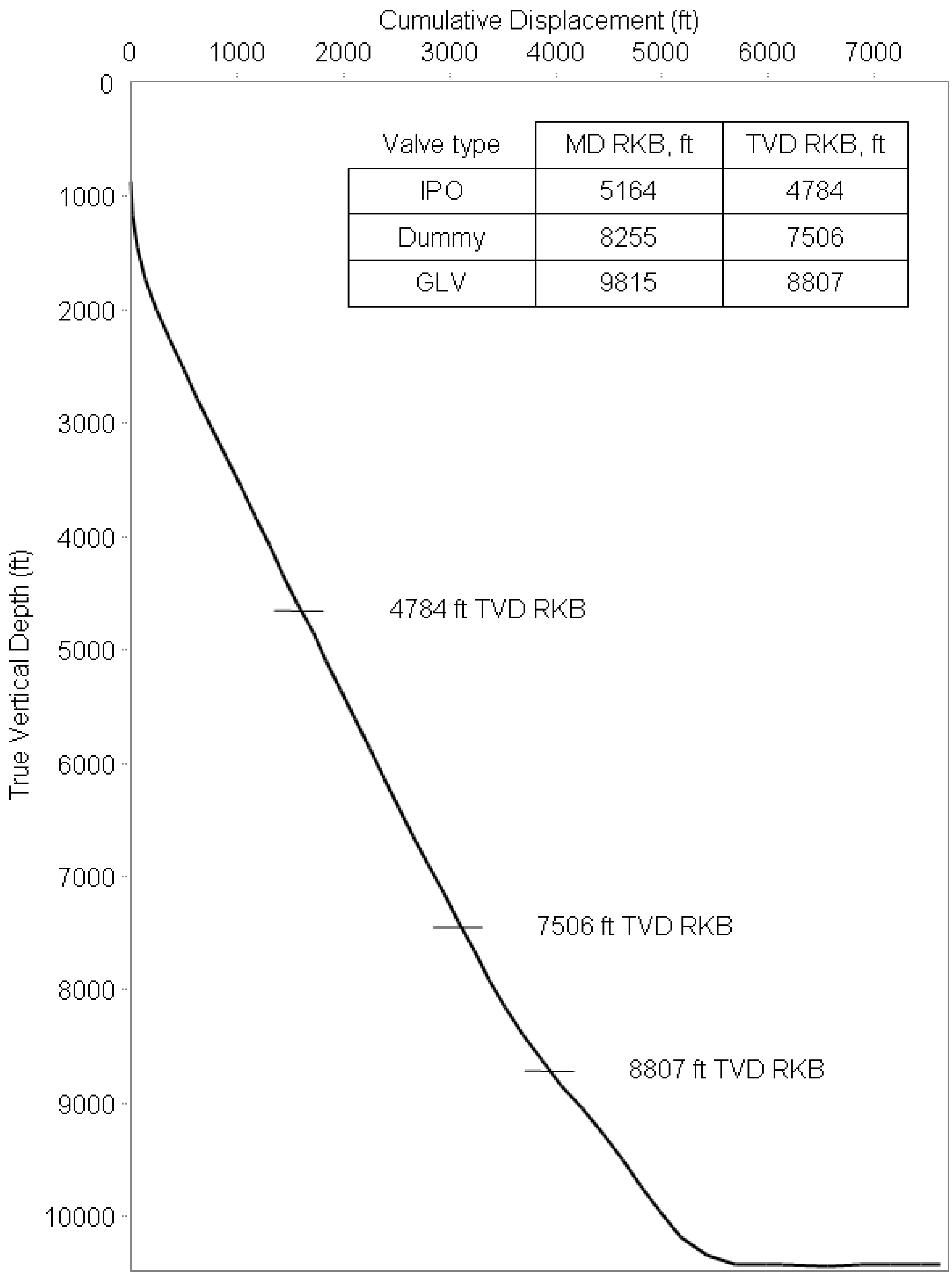


Figure 5.15 – X-31 wellbore trajectory.

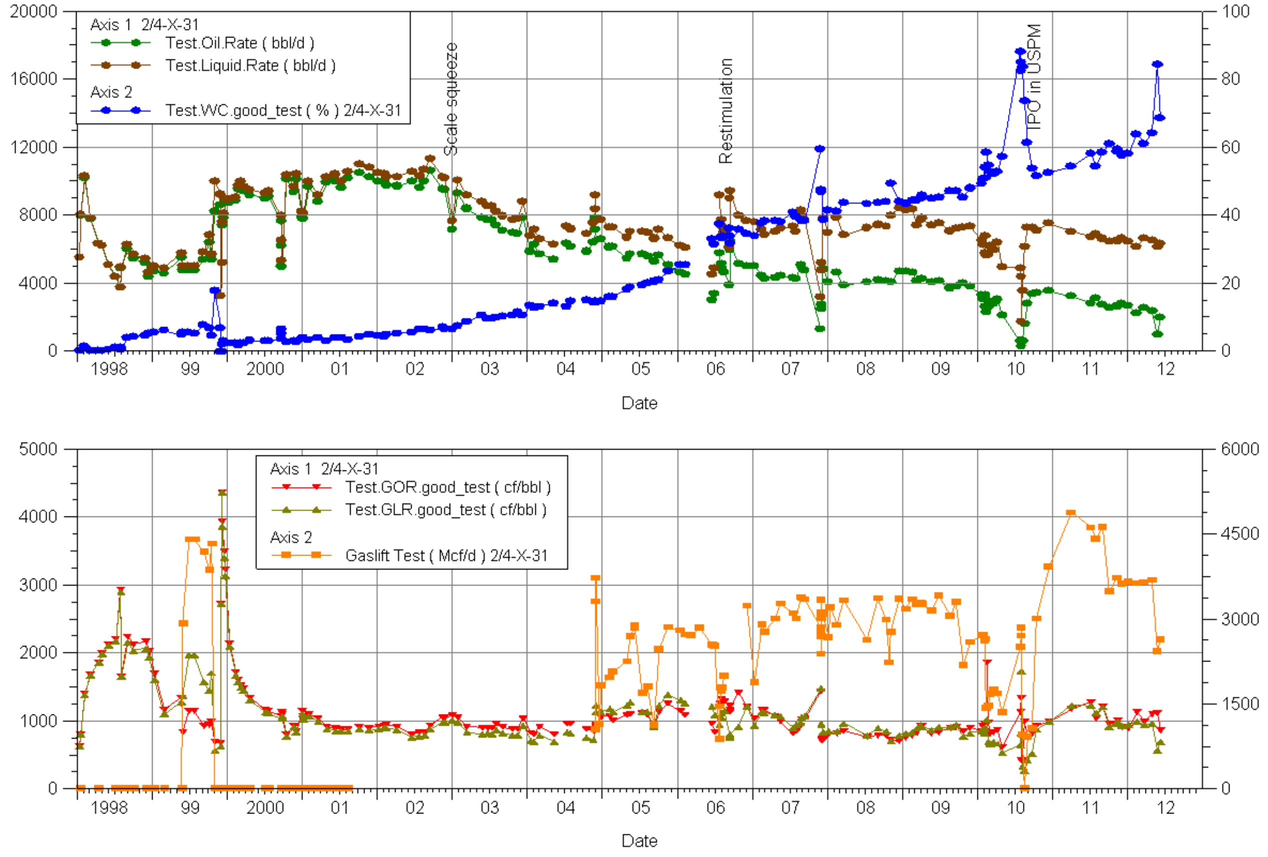


Figure 5.16 – X-31 production test data.

The well has experienced liquid loading issues after long shut-in periods. The increased water production can be noticed from WOR versus cumulative oil production plot, presented in *Figure 5.17*. The sharp peaks in WOR correlate with increases in total liquid production after long shut-in periods. Such behavior of WOR is attributed to downhole crossflow. The formation crossflow phenomenon occurs when reservoir fluid moves from high pressure zone to low pressure zone. This may lead to liquid loading in a well resulting in restart problems after shut-in periods.

Wellhead pressure and temperature, casing head pressure, gas lift rate and choke data during unloading after shut-in (ca. 3 days) are shown in *Figure 5.18*. Note the long unloading period for this well after the shut-in that supports the idea of existing crossflow between the Ekofisk and Tor formations.

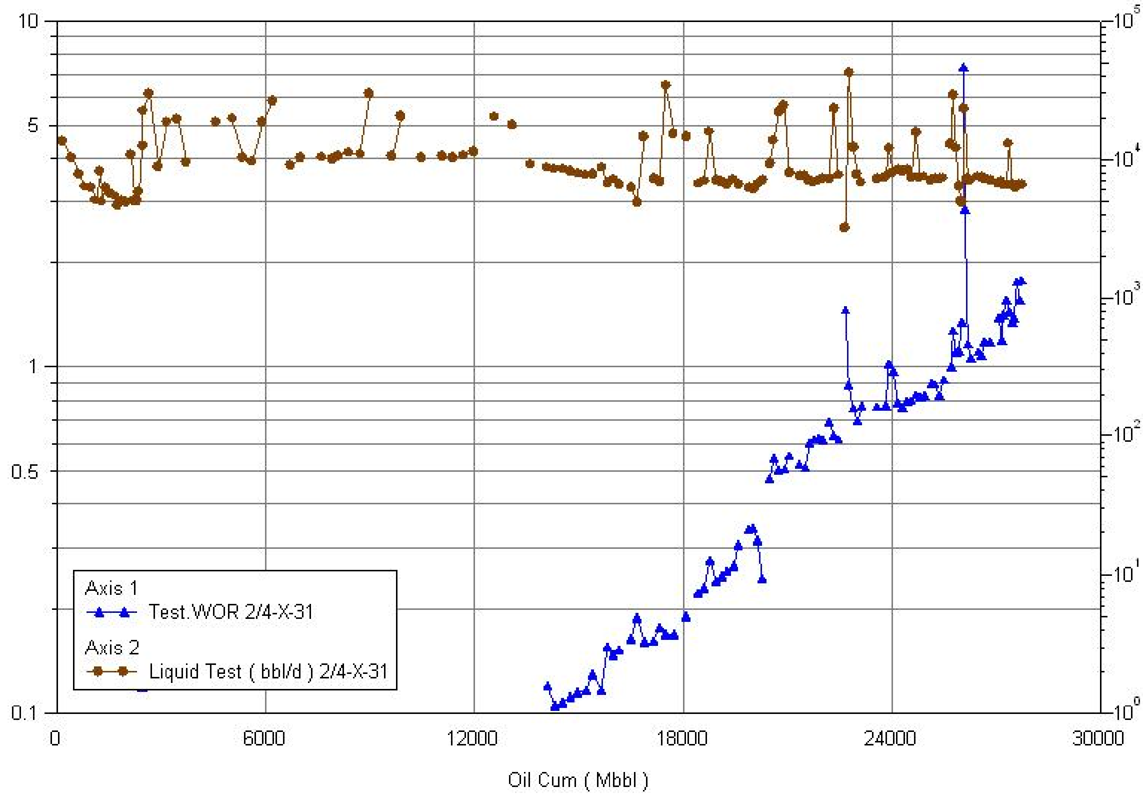


Figure 5.17– WOR and total liquid rate versus cumulative oil production for X-31.

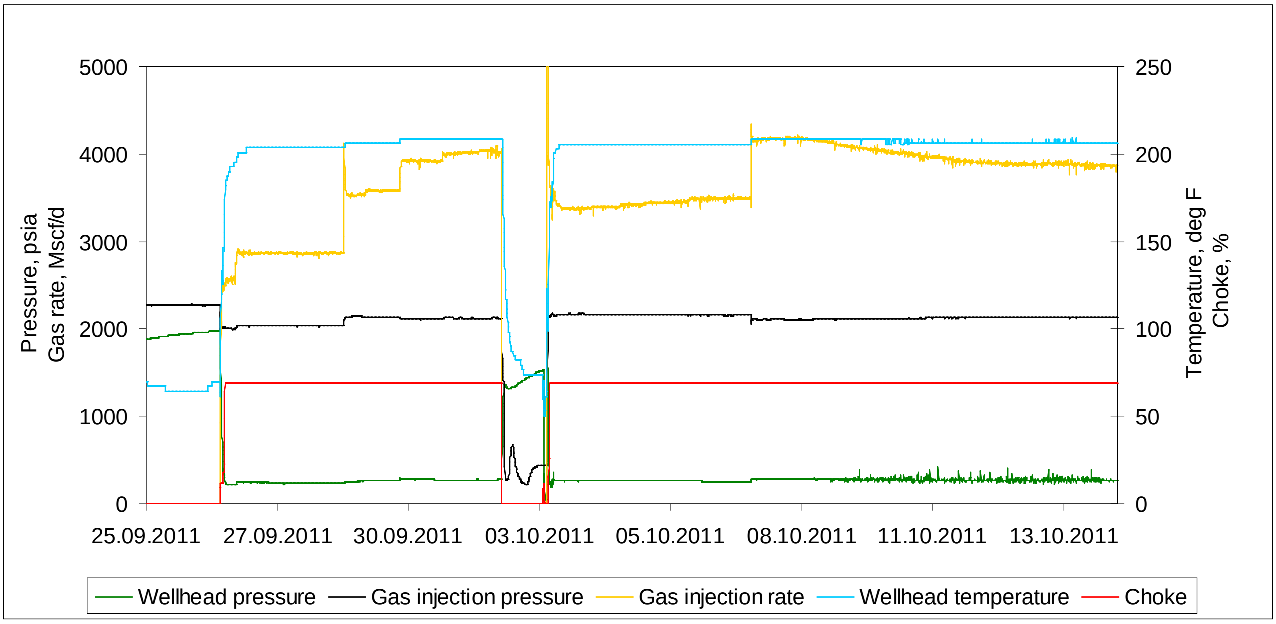


Figure 5.18 – Well X-31. Real-time pressure, temperature, gas lift rate and choke data during unloading.

Currently, the well is producing at the high injection pressure that migth remain the IPO valve open. However, the injection rate is lower than the designed throughput capacity for the 18/64th GLV. A possible explanation for that may be scaling or some other restrictions in the valves. The point(s) of injection could be determined with the help of flowing gradient survey.

5.5 Well X-33

The well is completed in both the Ekofisk and Tor formations. The well production history is shown in *Figure 5.19*. There were two restimulation treatments.

Following the sharp increase in water production in late 2010 and the installation of the sequence of two unloading valves, the well stopped production due to heavy fluid loading.

The water-oil ratio and total liquid rate are plotted against cumulative oil production in *Figure 5.20*. Similar to well X-31, sharp peaks in WOR correlate with increases in total liquid production following long shut-in periods.

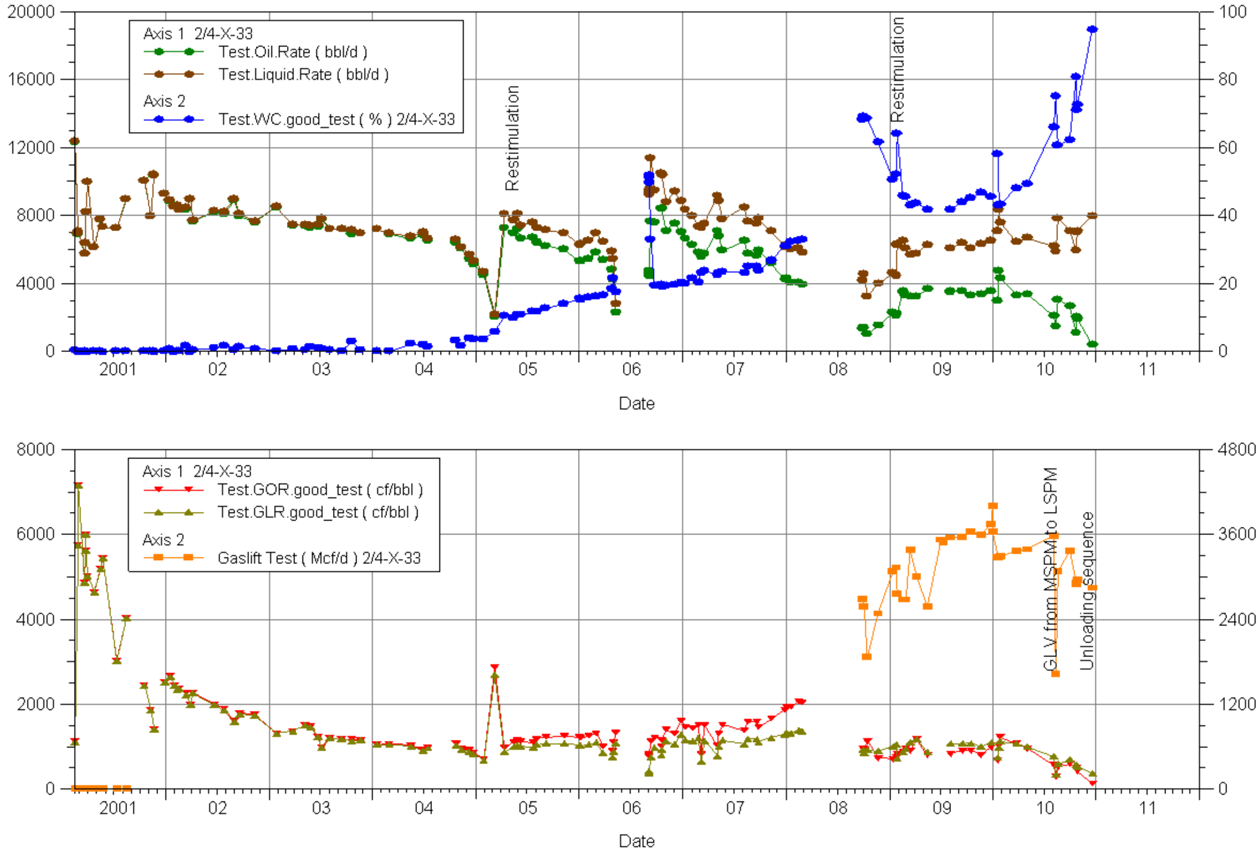


Figure 5.19 – X-33 production test data.

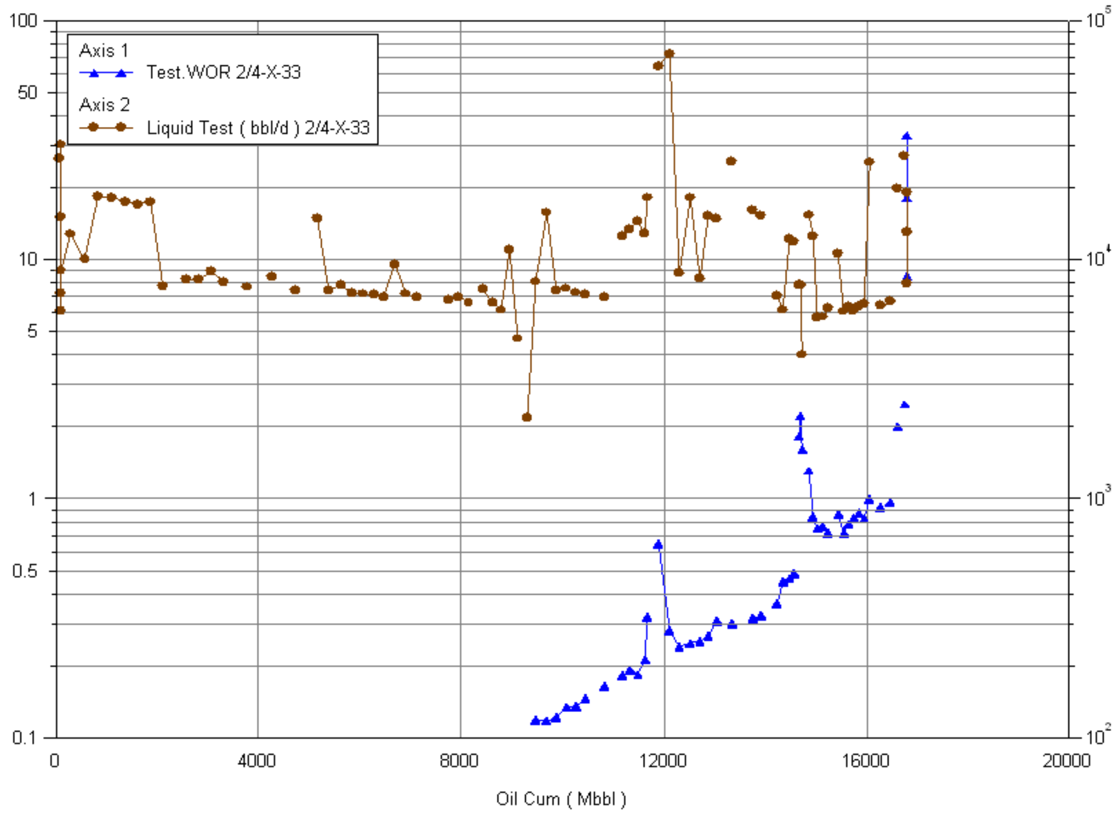


Figure 5.20 – WOR and total liquid rate versus cumulative oil production for well X-33.

The strong crossflow resulting in liquid loading during shut-in periods made it difficult to restore production from the well. Moreover, the water production rate reached the level of about 12000 bbl/d (water cut 99%), which made it impractical to produce.

Currently, the well is permanently shut-in.

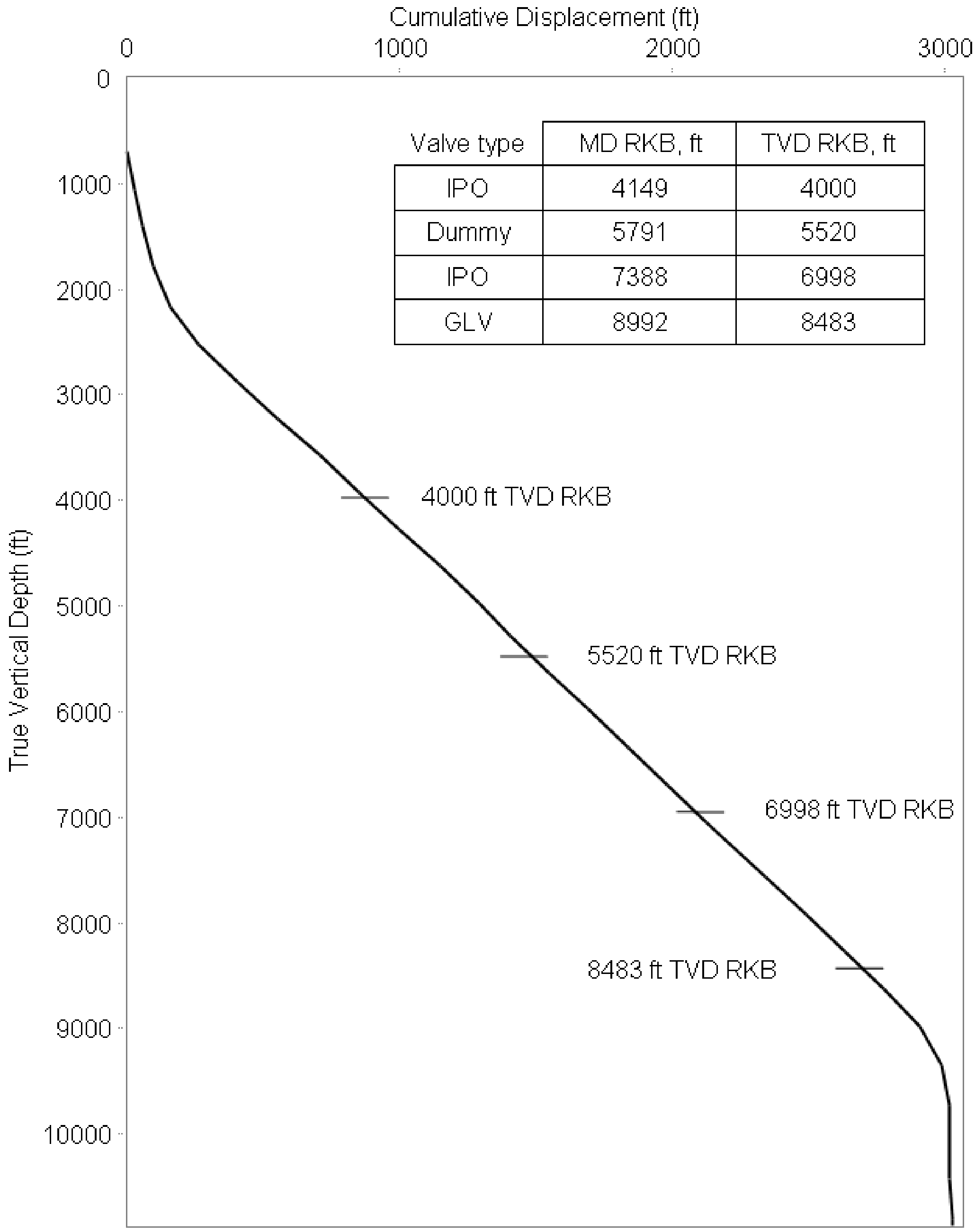
5.6 Well X-43

The well is completed in the Ekofisk and Tor formations and equipped with downhole pressure and temperature gauges. The well trajectory, side pocket mandrel depths and type of valves installed are shown in *Figure 5.21*.

The well production data in *Figure 5.22* indicates quite high water production from the production start.

Two unloading valves were installed to keep the operating valve in the lowest side pocket mandrel.

The well is suffering from severe scale build up and therefore is on regular scale squeeze treatments. Scaling on gas lift valves is observed when retrieved from the well.



Valve type	MD RKB, ft	TVD RKB, ft
IPO	4149	4000
Dummy	5791	5520
IPO	7388	6998
GLV	8992	8483

Figure 5.21 – X-43 wellbore trajectory.

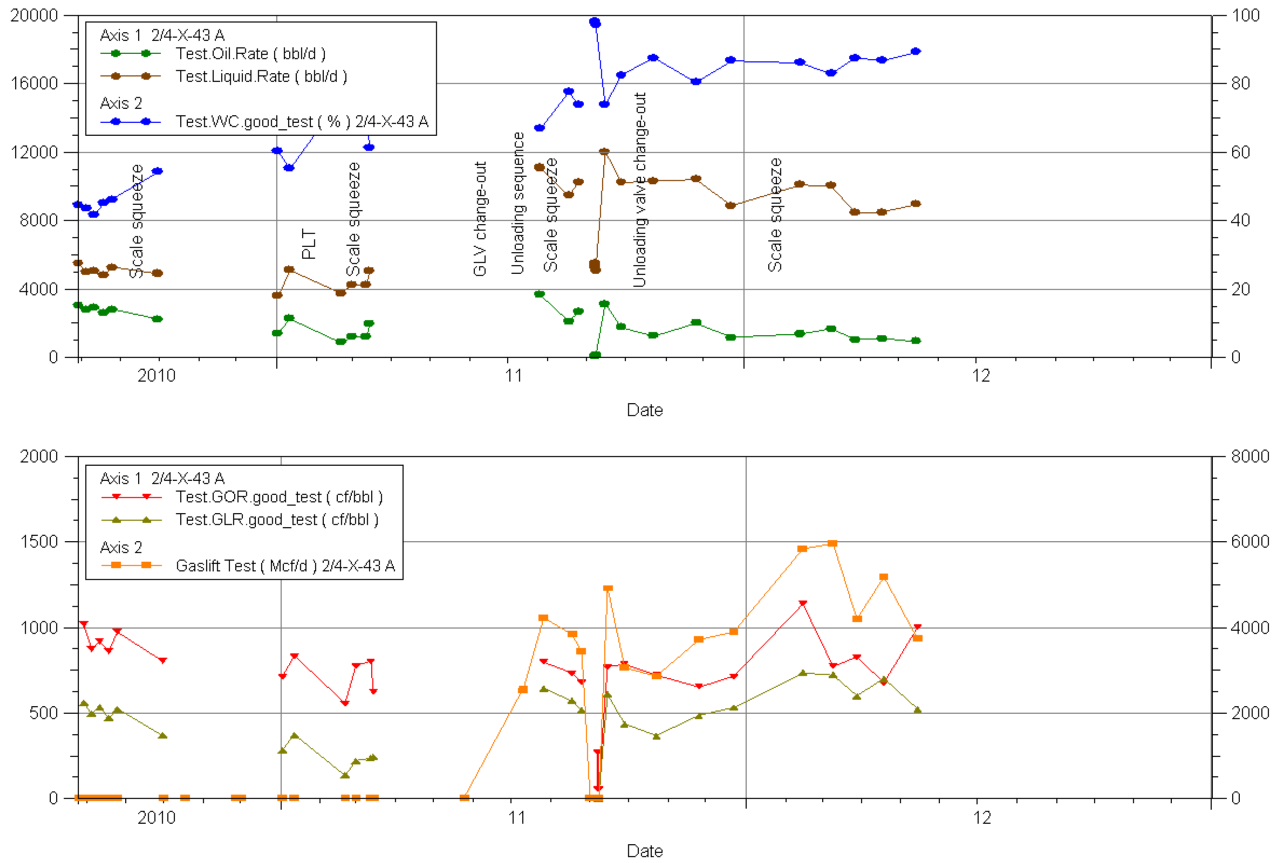


Figure 5.22 – X-43 production test data.

Due to oversized gas lift choke the injection pressure is higher than the closure pressure for both of IPO valves. Since the unloading sequence was installed, the gas lift rate is in range of 3.5-6 MMscf/d, while the design gas capacity for the orifice is 2.5 MMscf/d. The scaling build up can act as a mechanical obstruction and prevent expected well operation.

In addition, crossflow occurs in the well during shut-ins. The production logging tool (PLT) was run into the well in January 2011. The crossflow was detected between perforations at flowing pass. The production log interpretation is shown in *Figure 5.23*. Perforation intervals are marked in red in the middle sections. Spinner data indicates that water is flowing from the upper perforation interval (the Ekofisk formation) down to the well to zone with lower pressure (the Tor formation). The water holdup (i.e. the relative content) is high.

Shut-in pass interpretation (right plot) demonstrates that the oil column is covered by water coming from the upper perforation interval (the Ekofisk formation). The crossflow results in severe liquid loading issues and, therefore, difficulties to restart this well even after short periods of shut-in. The water flowing from the high pressure zone (the Ekofisk formation) should be produced first in order to be able to produce oil coming from the perforations in the Tor formation.

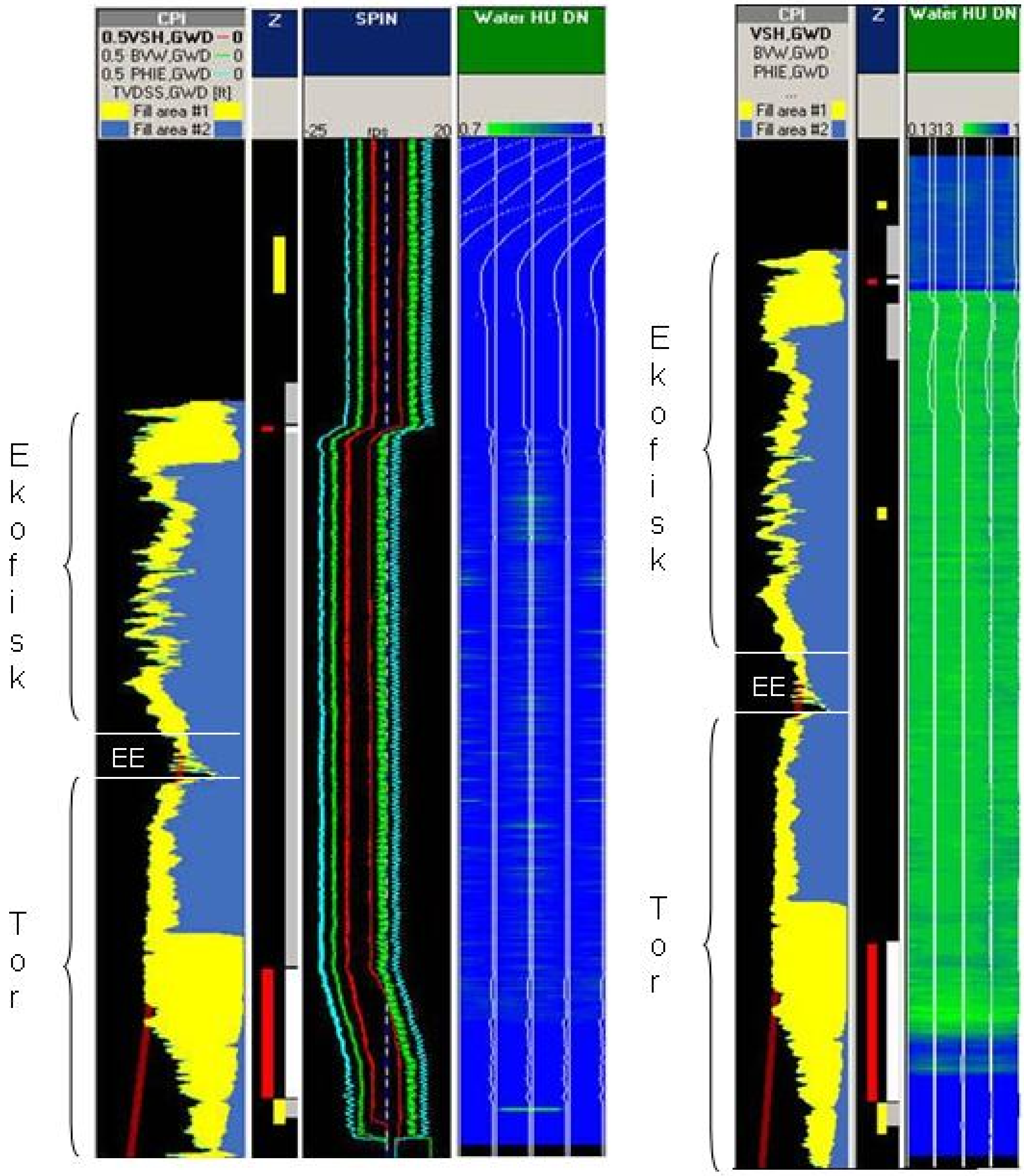


Figure 5.23 – X-43 production log interpretation results (flowing pass, to the left, shut-in pass, to the rigth).

The well is a candidate for water shut-off operation in order to plug the perforations in the Ekofisk formation which contributes only with water production resulting in the strong crossflow during shut-ins.

5.7 Well X-44

The well is completed in the Ekofisk formation. The well trajectory, side pocket mandrel depths and type of valves installed are shown in *Figure 5.24*.

The historical production test data is presented in *Figure 5.25*. Note that after restimulations in 2005 and 2008 the water cut increased sharply.

Following summer 2010 shut down the well has experienced a heavy fluid load. Gas lift optimization with unloading design was required to restart the production. An IPO valve was installed into USPM, and an orifice valve was set into MSPM.

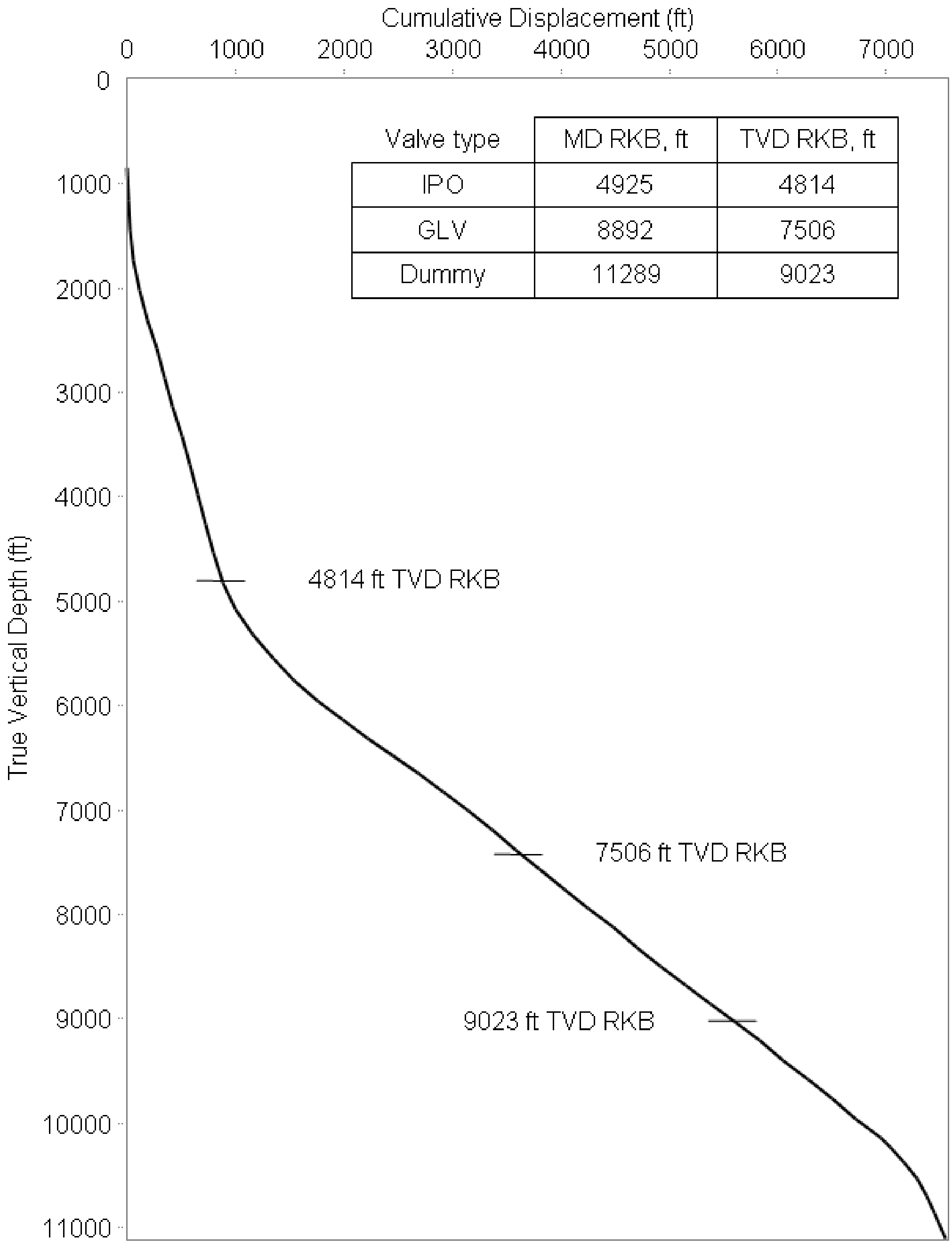


Figure 5.24 – X-44 wellbore trajectory.

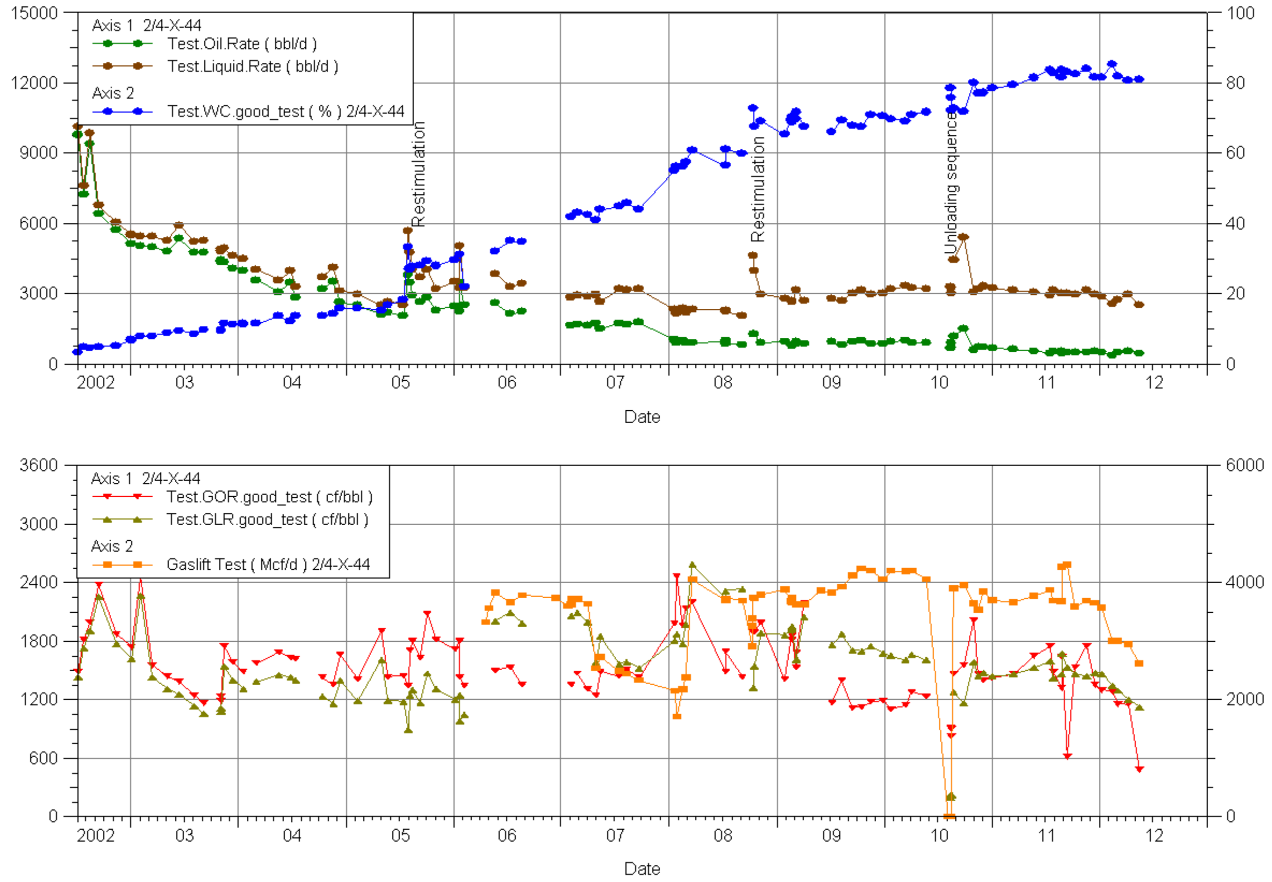


Figure 5.25 – X-44 production test data.

Since the unloading sequence was installed, the well is producing with high injection pressure of 2200-2250 psia, which may result in multipoint injection (gas injection rate is higher than designed throughput for the orifice). The fact of multiponting could be confirmed by running the flowing gradient survey.

Interestingly, during several months the gas lift rate was about 3 MMscf/d while the injection pressure was at the maximum level. During the GLV test the fluid level in the annulus was detected to be at the GLV depth. It is most likely that the gas was injected through the orifice. A possible explanation for the reduced capacity of the lift gas may be that the valves are partially scaled. Again, the point(s) of injection should be confirmed by the flowing gradient survey.

5.8 Well X-49 and well X-50

Following the same methodology, the conditions for well X-49 and well X-50 were analyzed. These wells are completed in the Ekofisk formation. Based on the production losses reports, there are no production losses due to lifting issues for these wells.

Similar to the previous well, the IPO valves most likely remain open due to high injection pressure (oversized gas lift chokes). However, the multipoint injection should be confirmed by the running flowing gradient survey.

As illustrated in Figure *5.26*, the well X-49 is unstable demonstrating tubing heading (wellhead pressure and temperature fluctuations with amplitude more than 100 psi and 10°F).The unstable production might be explained by the oversized tubing along with the multipoint injection.

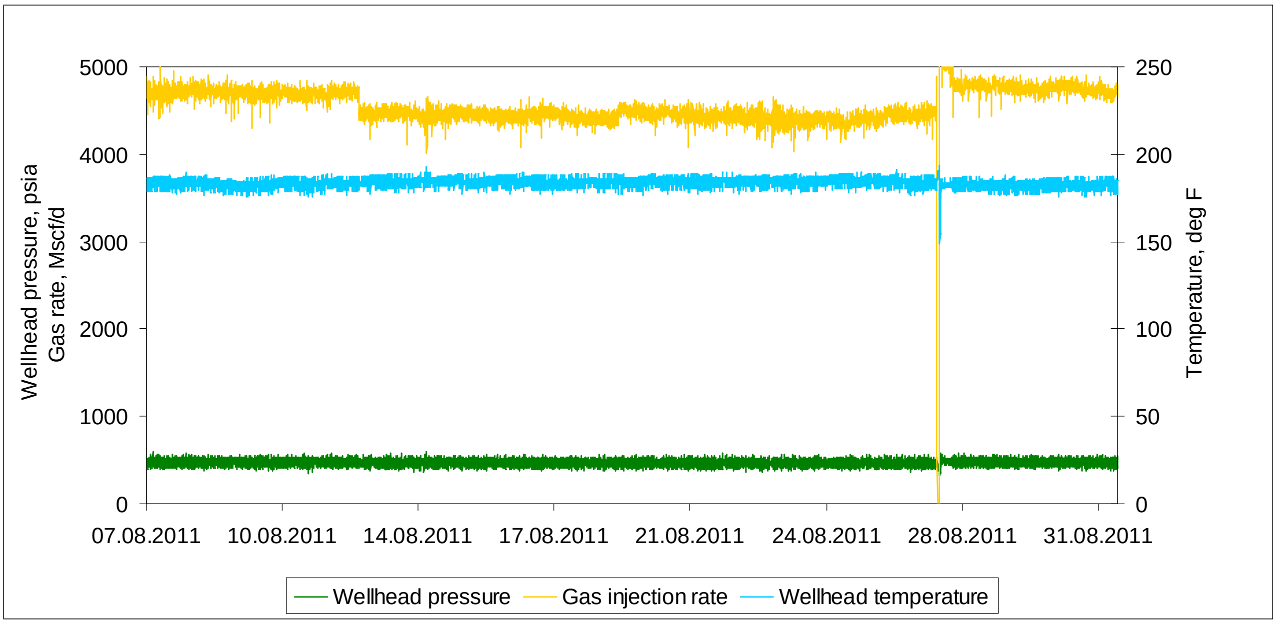


Figure 5.26 – Well X-49. Real-time wellhead pressure and temperature, and gas lift rate during slugging period.

5.9 Production losses due to liquid loading

To evaluate the efficiency of unloading sequence from the lifting point of view, a ratio of lost production due to liquid loading to well's deliverability was plotted in *Figure 5.27* for those wells that employ unloading sequence. The unloading sequence is intended to address lifting issues related to liquid loading. Therefore, in case of successful design and implementation of the unloading sequence, production loss due to liquid loading should equal zero. Hence, the ratio of lost production to well's deliverability is seen as an indicator of good operation of the unloading sequence. Note however, that the ratio does not represent the absolute volume of lost production due to liquid loading, as deliverability varies significantly from well to well. For example, although the loss ratio for well X-43 due to liquid loading is about 0.3, the absolute volume of lost production per day is higher than for X-30 well, where this ratio is 0.98. The reason for that is that well X-43 has higher deliverability (1570 bbl/d) than well X-30 (400 bbl/d).

Note that the plotted ratio is in agreement with the well-by-well analysis performed in the previous sections of this study – i.e. wells with lower loss ratio have less lifting issues.

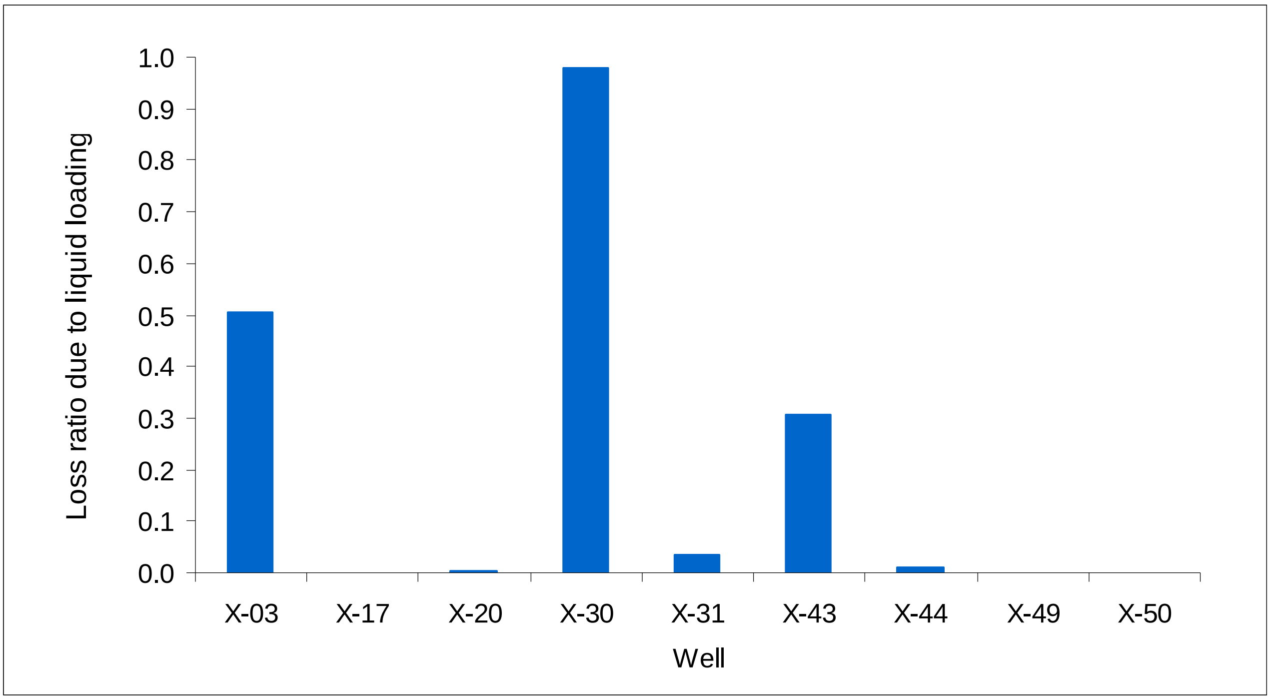


Figure 5.27 – Lost production due to liquid loading for the Ekofisk wells with unloading sequences.

5.10 Gas lift installation design for well B-17

A gas lift design consideration using WellFlo for the Ekofisk well B-17 is described in this section.

This is a well with good production data available and the gas lift mandrels are already spaced. The well trajectory and side pocket mandrel depths are shown in *Figure 5.28*.

While being on continuous gas lift, the well has stopped taking lift gas. At the time of pre-design it was flowing naturally. This means that the recorded flowing pressure and temperature survey is not representative of the well performance at normal operational conditions (i.e. when the well is on gas lift). Moreover, a restriction in the tubing did not allow running the survey deeper than 6257 ft (between the upper and middle side pocket mandrels).

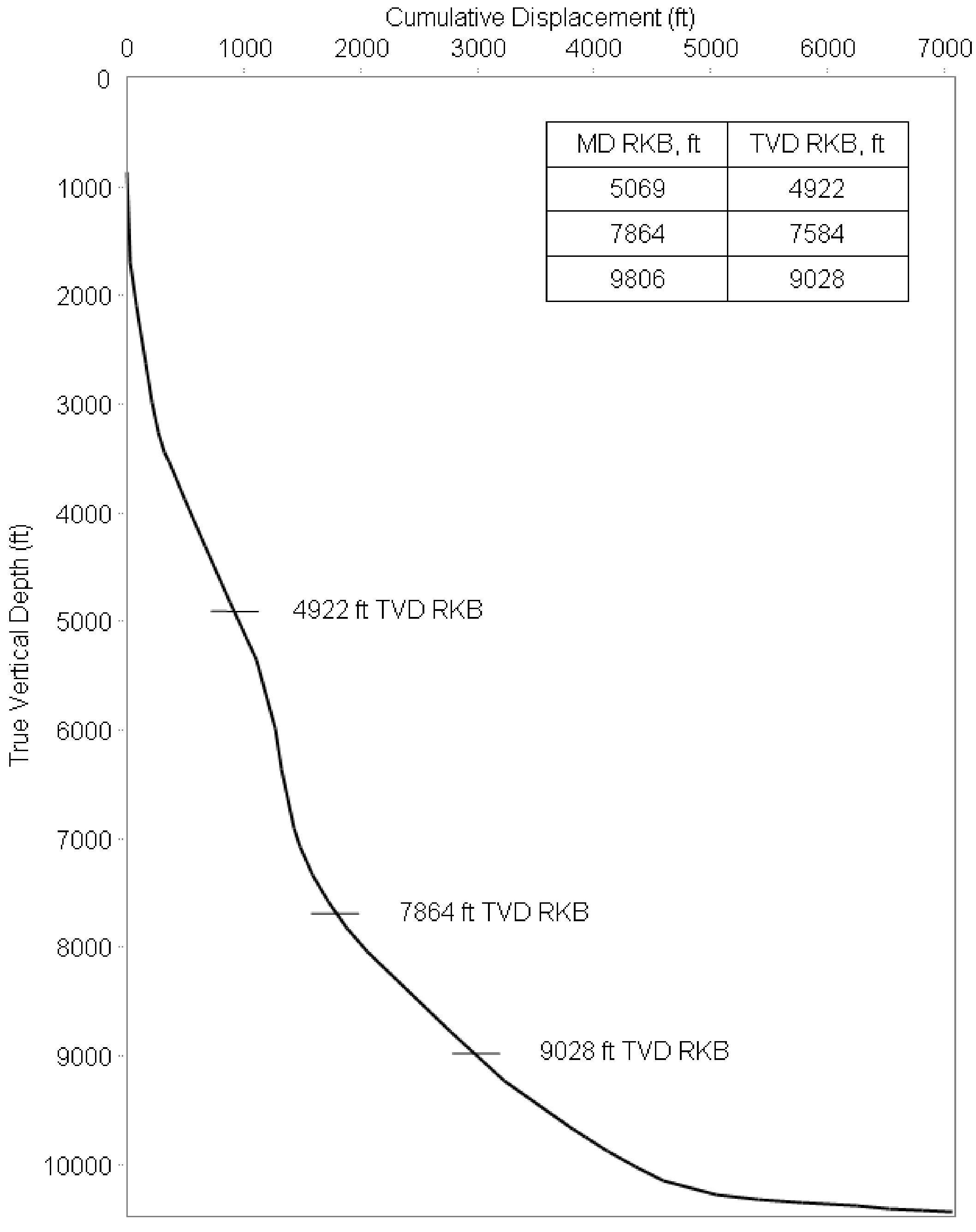


Figure 5.28– B-17 wellbore trajectory.

5.10.1 Flowing pressure and temperature survey

The well was on test separator during the survey. The *Table 5.3* below illustrates test information obtained during the survey.

Table 5.3 – B-17 production test results.

Oil rate, stb/d	746
Gas rate, MMscf/d	0.668
Water rate, stb/d	2960
Gas injection rate, MMscf/d	0
Total GOR, scf/stb	896
Water cut, %	80
Wellhead pressure, psia	912
Wellhead temperature, deg F	229
Gas injection pressure, psia	2048

As can be seen from *Figure 5.29*, the well conditions were stable throughout the survey.

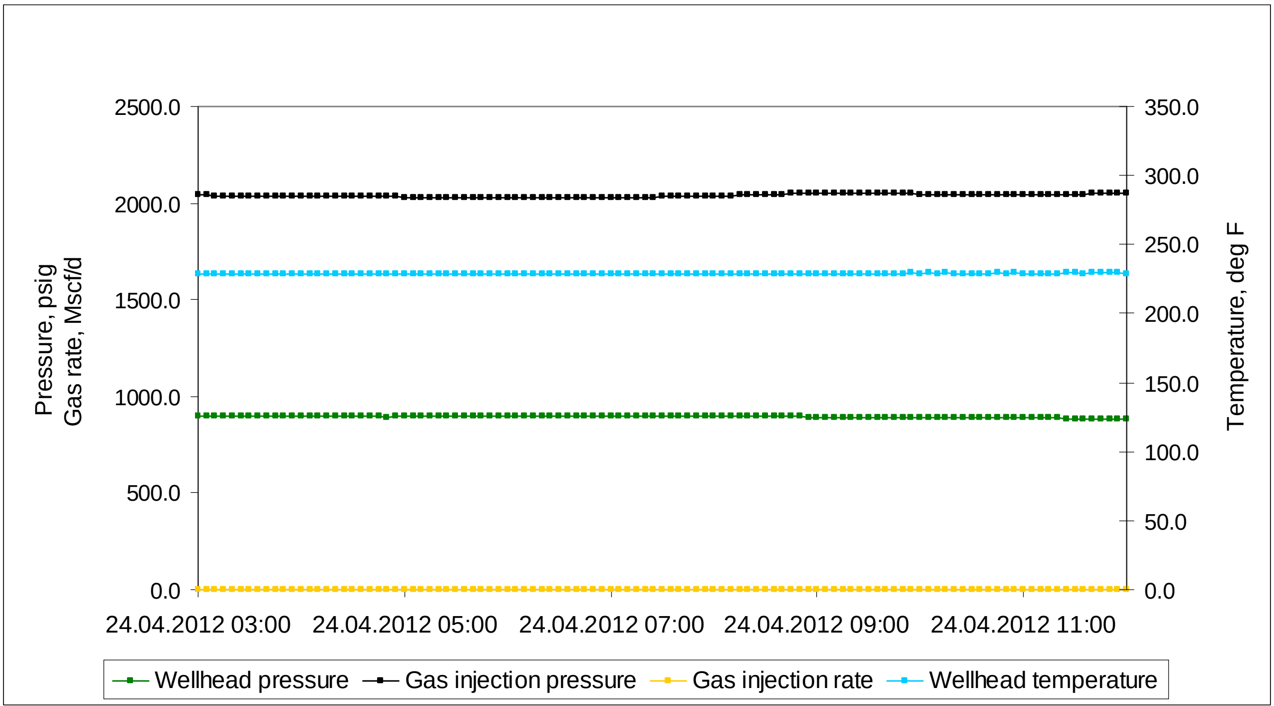


Figure 5.29 – Well B-17. Well conditions during the flowing pressure and temperature survey.

Two passes (up and down) with wireline speed of 30 ft/min were run. The frequency of pressure and temperature readings was high and had to be reduced before loading into the well performance model. Naturally producing fluid pressure profile is loaded into WellFlo and presented as readings versus measured depth.

The model pressure profile along the well was tuned to the recorded pressure survey using EPS Mechanistic flow correlation. As discussed in section 4.3.1, this flow correlation gives the best match for naturally flowing wells. The correlation is tuned to the real data by adjusting L-factor. This factor is a parameter that presents adjustment required to match the calculated and measured pressure distribution along the wellbore. The best match is achieved with L-factor of 0.9714, which confirms that EPS Mechanistic correlation provides a good match of measured data. Well and riser L-factor has been replaced by the tuned value 0.9714 in the model.

Figure 5.30 shows the results of tuning of the vertical flow correlation to the recorded flowing survey (pass down).

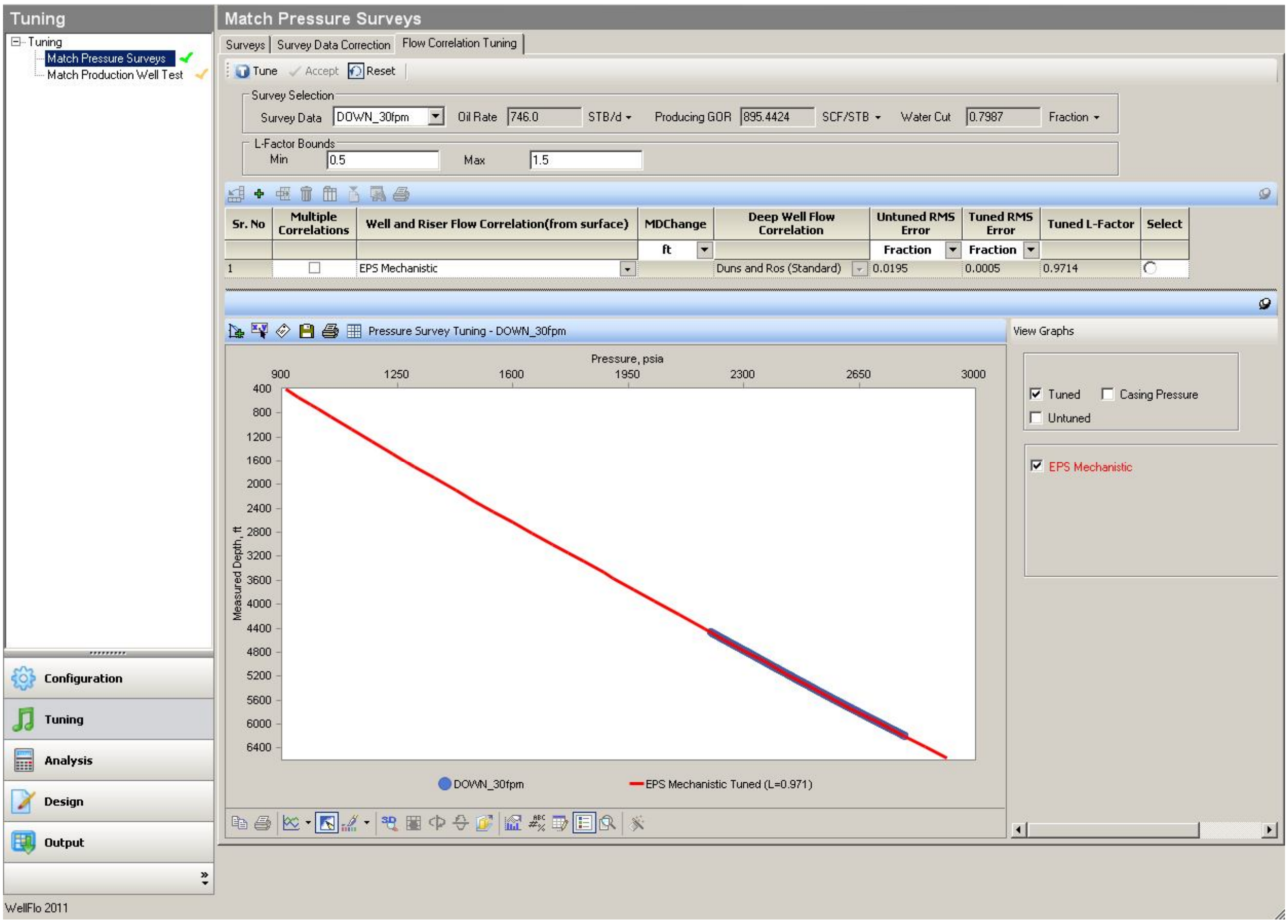


Figure 5.30 – EPS Mechanistic correlation is tuned to the recorded pressure survey (pass down).

5.10.2 Analysis

The well test data from *Table 5.3* was used to calibrate the well performance model to flowing conditions during the survey. The model parameters are shown in *Table 5.4*.

Table 5.4 – Model parameters for naturally flowing well model.

Well and riser correlation	EPS Mechanistic
Reservoir pressure, psia	4900
IPR model	Vogel (coefficient 0.2)
Test pressure, psia	4390
Test rate, stb/d	3705.8
PI, stb/d/psi	7.3

The value of productivity index (PI), obtained from the model with EPS Mechanistic flow correlation was used to model well performance with gas lift. OLGA Steady State correlation was used for this model, as discussed earlier. The gas lifted well model parameters are shown in *Table 5.5*.

Table 5.5 – Model parameters for gas lifted well model.

Well and riser correlation	OLGA Steady State (L-factor is assumed to be 1)
Reservoir pressure, psia	4900
IPR model	Vogel (coefficient 0.2)
PI, stb/d/psi	7.3

The gas lift design is based on the assumption that the lowest wellhead pressure is 550 psia. This constraint is defined by the topside facilities.

The deepest point of injection determined from the calculated pressure traverse (*Figure 5.31*) is about 6000 ft TVD RKB, whereas the lowest side pocket mandrel is at 9000 ft TVD RKB. Therefore, at least one unloading valve is required to reach the lowest side pocket mandrel.

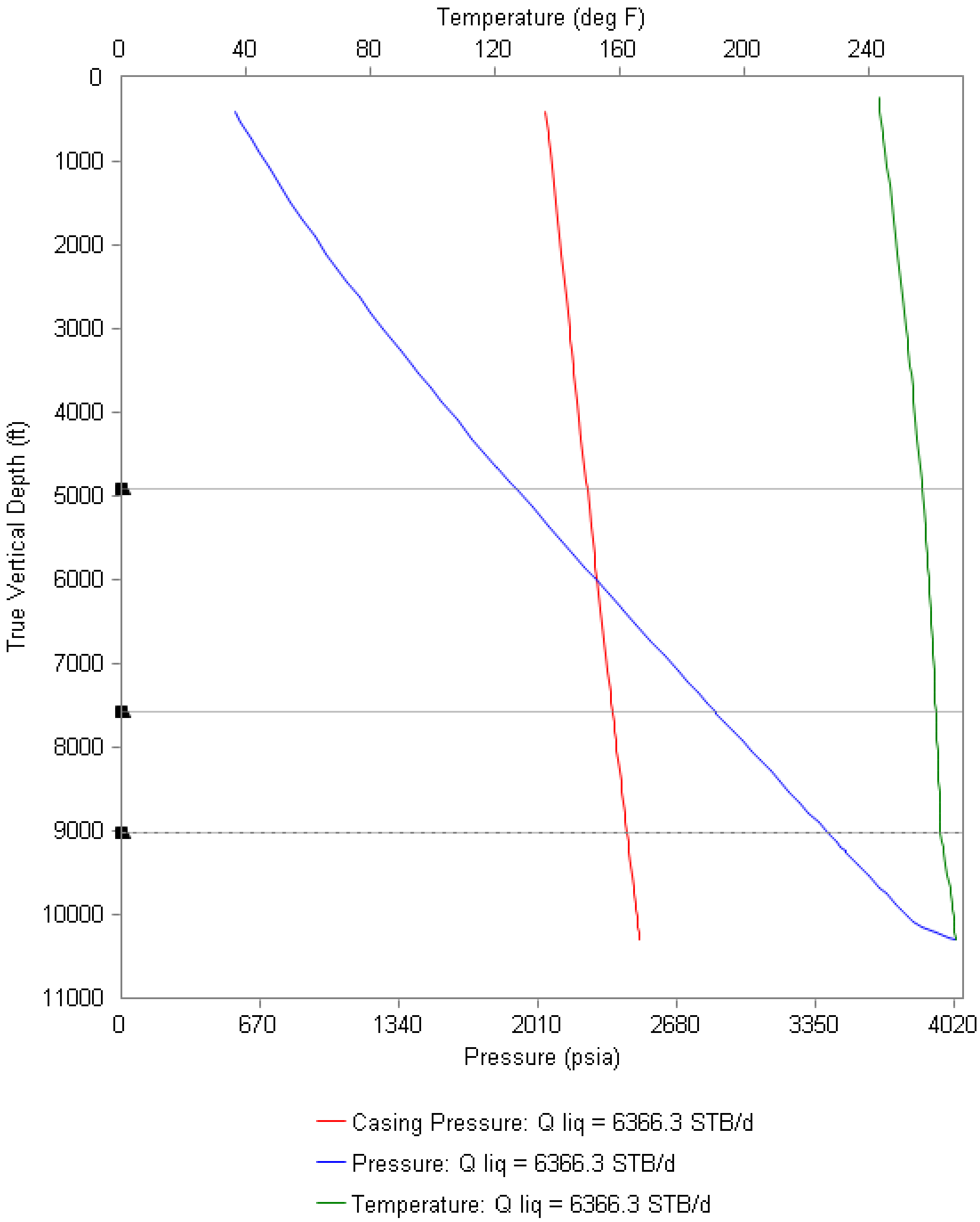


Figure 5.31 – The plot of tubing and casing pressures and temperature versus TVD for the well performance based on OLGA Steady State correlation when there is no gas injection.

Next step is to run the sensitivity on gas lift injection rate ranging from 1 to 6 MMscf/day. The gas lift rates versus total liquid production are plotted in *Figure 5.32*.

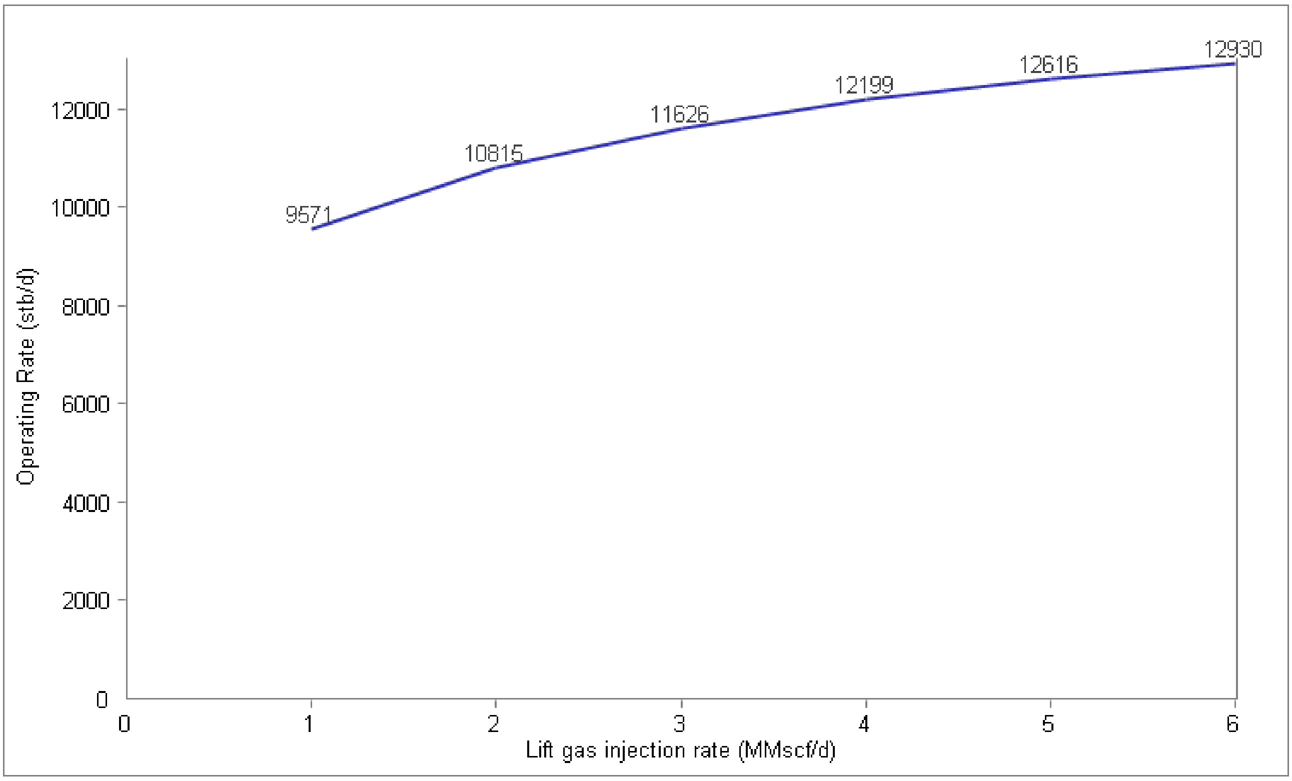


Figure 5.32 – Gas injection rate versus liquid production with the orifice in the lower side pocket mandrel.

Based on company's experience, the desired and practically achievable gas injection rate is 3 MMscf/d, which determines the design throughput capacity for the gas lift valve (orifice). This gas injection rate corresponds to 11626 bbl/d liquid rate and flowing bottomhole pressure of 3263 psia (*Figure 5.32*).

5.10.3 Gas lift design: results

The gas lift design was based on the analysis above. The maximum injection pressure was assumed to be 2150 psia.

The case with the sequence of two unloading valves and the operating valve in the lower side pocket mandrel was considered. The graphical result after running of calculations is presented in *Figure 5.33*.

As can be seen from this figure, the orifice in LSPM (9028 ft TVD RKB) can not be reached.

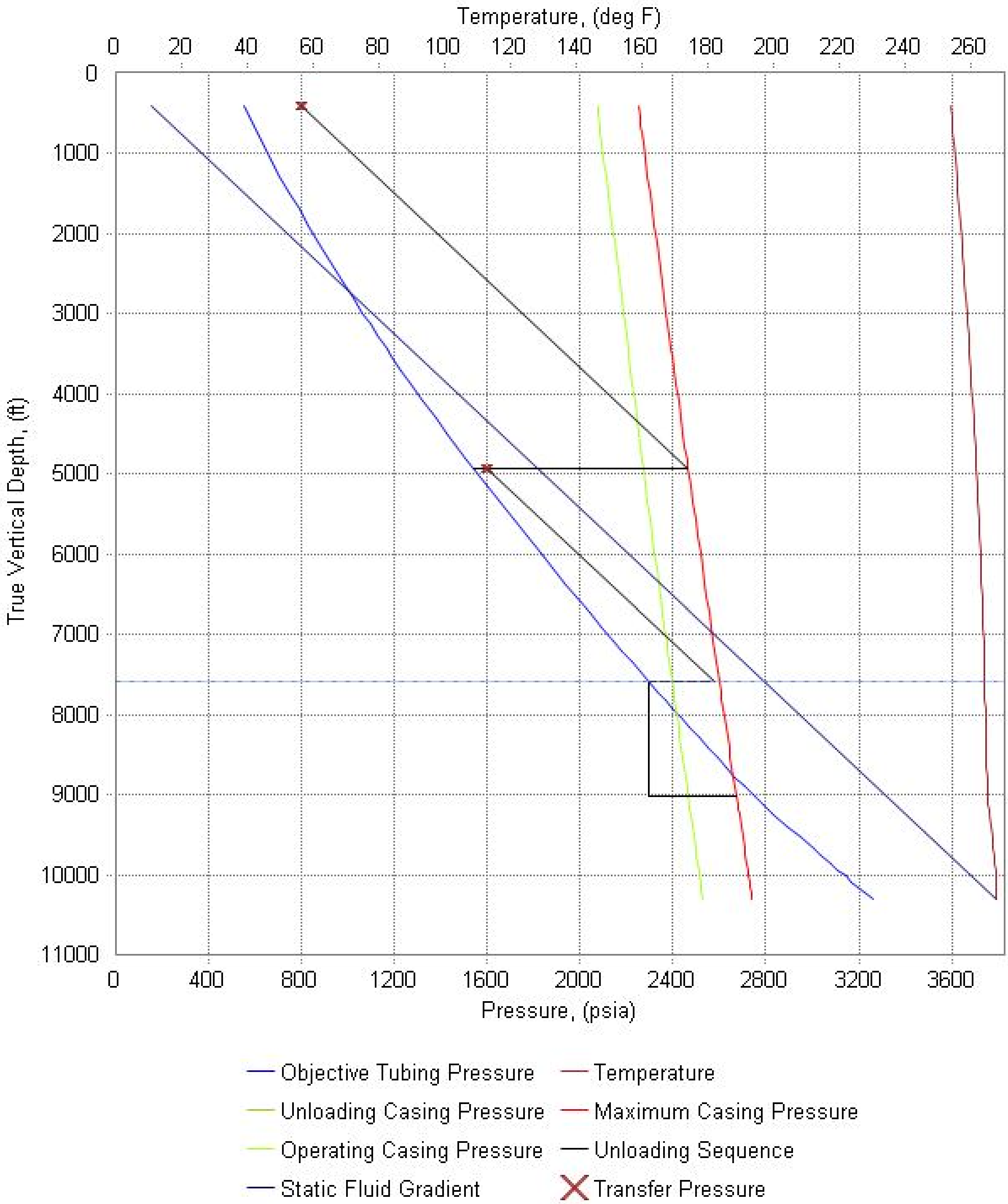


Figure 5.33 – Well B-17. Pressure versus depth graphical solution for design with the operating valve in the lower side pocket mandrel.

The design parameters were revised for the case with the unloading valve in USPM and the operating valve in MSPM. From the sensitivity run with injection through MSPM, the gas injection rate of 3 MMscf/d corresponds to the liquid rate of 11268 bbl/d. The graphical solution for design with injection point in MSPM is presented in *Figure 5.34*. Interestingly, in this case the orifice can not be reached as well. It can thus be concluded that with existing constraints (i.e. gas compressor capacity, minimum allowable wellhead pressure, well completion) the unloading sequence can not be utilized for this well.

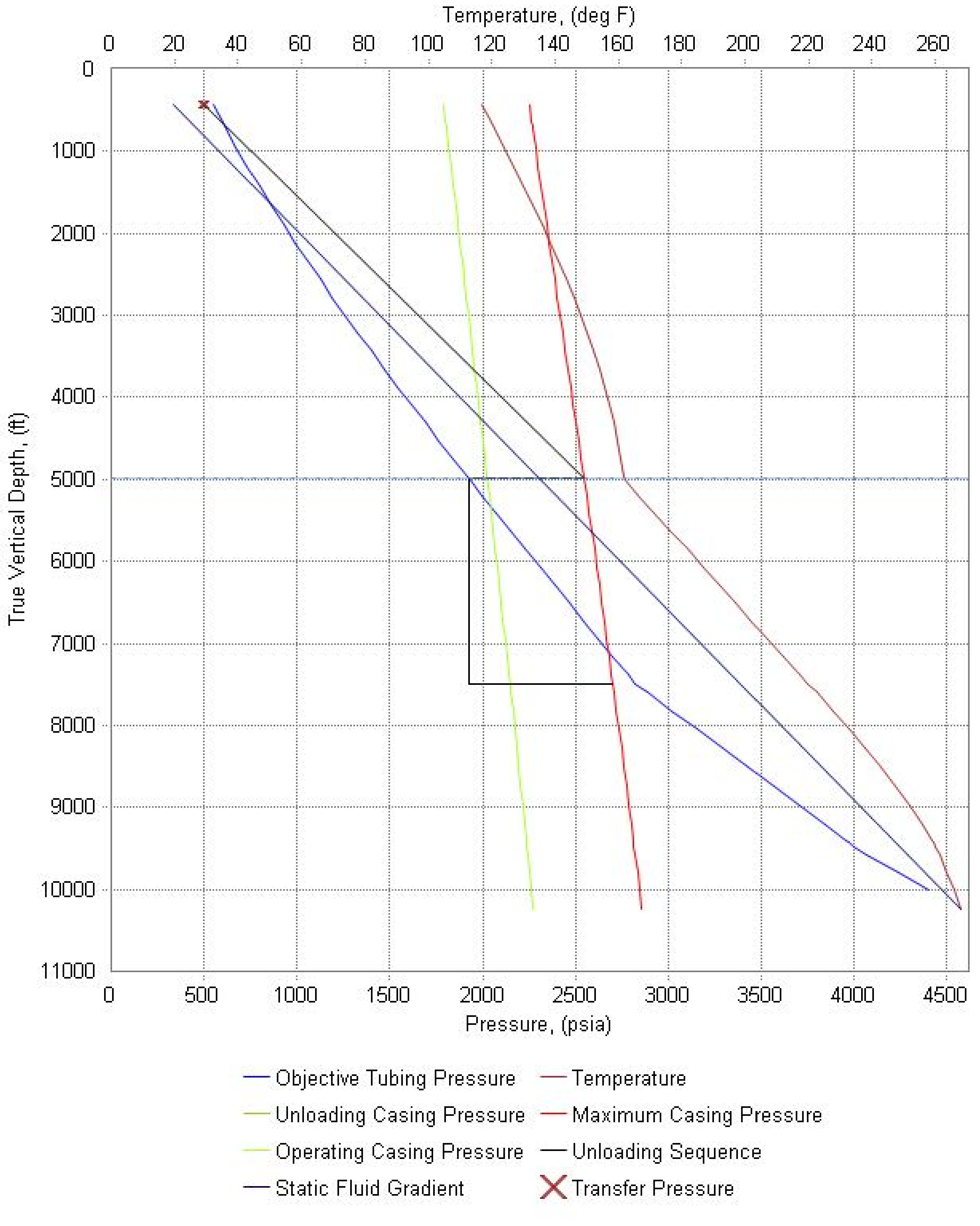


Figure 5.34 – Well B-17. Pressure versus depth graphical solution for design with the operating valve in the middle side pocket mandrel.

5.10.4 Conclusion

With current mandrel spacing it was considered to install the orifice valve in USPM and put the well on gas lift.

Besides, the gas lift design with several valves could not be implemented for this well. Due to detected restriction in the tubing, the middle and lowest side pocket mandrels are inaccessible. Moreover, producing the well at higher rates (and, hence, higher drawdown) with injection through orifice in either MSPM or LSPM may worsen the collapse.

6 CONCLUSION

The objectives of this study were to evaluate performance of wells with unloading sequences in the Ekofisk field and to participate in the unloading sequence design for one well (B-17). The learning objective was to enhance knowledge and understanding of the gas lift technology. The main question addressed in this study was to identify the possible reasons of lifting problems for wells with unloading sequences.

The performance of ten gas lifted well employing injection pressure operated valves was investigated. The main investigation was focused on one particularly interesting well (X-03). The performance analysis of this well is presented in detail.

A lot of effort was done to address the objectives with the help of the relevant literature research, communication with the engineers within the company and extensive data gathering and analysis. As a result, the following conclusions can be drawn.

The under-performing wells were identified along with those that unload and operate as designed.

In most cases the installation of unloading valves was required at the stage of moving the orifice valve deeper to gain production. However, an increase in oil production did not last long due to increase in water rate with a consequent decline in oil production rate. The changed well conditions might lead to such a situation when the well will not unload as intended. This means that the gas lift design was not appropriate for new conditions. Moreover, the downhole crossflow in the wells with perforations in the Tor and Ekofisk formations affects the unloading performance resulting in either long unloading time or inability to unload the well (wells X-31, X-43 and X-33 respectively).

The results of this study also indicate that although in some wells the unloading sequence operates as designed, i.e. it is possible to unload the well after shut-in (X-44, X-49 and X-50), topside facilities constraints result in multipoint injection. Due to oversized gas lift chokes injection pressure in casing-tubing annulus is high. As a result, the unloading valves remain open. This, in turn, leads to unstable production. It is necessary to have a proper control over gas injection rate (hence, pressure in casing-tubing annulus) in order to employ the injection pressure operated valves in the designs.

The design calculations were done for one well (B-17). It was shown that with existing constraints (i.e. gas compressor capacity, minimum allowable wellhead pressure, well completion) the unloading sequence can not be utilized in this well. This result emphasizes the importance of mandrel spacing and indicates the need for an appropriate mandrel spacing for the production conditions over the life of the wells.

The main limitation of the study was the lack of information that could be obtained from adequate troubleshooting surveys. The results therefore have to be viewed as one of the possible interpretations of the well's performance.

It is recommended to retrieve failed unloading valves and investigate for mechanical failure and valve performance testing (X-03). This could explain the observed well performance and could be used for further improvements in practices of using unloading sequences.

Due to transient nature of the unloading process, it would be beneficial to model the real cases in dynamic simulators to get a detailed insight into this complex process and, therefore, get a better understanding of such operation.

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SYMBOLS AND ABBREVIATIONS

Abbreviations

GLR – gas-to-liquid ratio

GOR – gas-to-oil ratio

IPO – injection pressure operated

IPR – inflow performance relationship

LSPM – lower side pocket mandrel

MMscf/d – million of standard cubic feet per day

MSPM – middle side pocket mandrel

mD – millidarcy

OD – outer diameter

OFM – OilField Manager

PPO – production pressure operated

PPEF – production pressure effect factor

PTC – Petroleum Technology Company

RKB – rotary kelly bushing

sm^3/d – standard cubic meter per day

SPM – side pocket mandrel

stb/d – standard barrel per day

TEF – tubing effect factor

TRO – test rack opening pressure

USPM – upper side pocket mandrel

VLP – vertical lift performance

WOR – water-to-oil ratio

Symbols

A_b – area of bellows

A_p – effective port area (valve seat)

P_c – casing pressure

P_d – pressure in dome

P_f – flowing production pressure

P_r – average reservoir pressure

P_{wf} – flowing bottomhole pressure

q – total liquid flow rate

$q_{\max}$ – maximum liquid rate

R – ratio of port area to bellows area

P_{sc} – surface opening pressure

P_{vo} – surface closing pressure