Optimization of the production schedule of an oil field

José Cristian Arturo Otárola Lagos

Presented to

The Faculty of the Department of Mineral Resources Engineering

Technical University of Crete

In partial Fulfillment of the Requirements for the Degree

MASTER OF SCIENCE IN PETROLEUM ENGINEERING

August 2017

TECHNICAL UNIVERSITY OF CRETE

DEPARTMENT OF MINERAL RESOURCES ENGINEERING

The undersigned hereby certify that they have read and recommend to the Faculty of Mineral Resources Engineering for acceptance a thesis entitled “**Production Wells and Gas Lift Design on Case Study Scenario"** by **José Cristian Arturo Otárola Lagos** in partial fulfillment of the requirements for the degree of **Master of Science**.

Date: ___________.

Chair of Committee,

____

Dr. Varotsis

Committee Members,

____

Dr. Gaganis

____

Dr. Kalogerakis

Head of Department,

____

Dr. Pasadakis

Contents

List of Figures

List of Tables

Acknowledgements

In first place, I would like to thank my thesis advisor, Dr. Vasileios Gaganis of the Mineral Resources Engineering Department at the Technical University of Crete. Throughout the process of preparation of this work, he always showed great disposition to discuss any inquiry I might have, providing better than the answers, the conversation that would lead to generally find the answers to my doubts by myself, helping me to see that many times the solutions can be simpler than what you think.

I would also like to acknowledge Professor Nikolaos Pasadakis, coordinator of the program, whose efforts to bring the MSc Course, Petroleum Engineering to existence have given to the students of already three generations the opportunity to reach for new areas of knowledge, being also a wonderful person and providing support to all those who need it.

To my parents and sisters, my gratitude for believing in me and supporting me when I took the decision of putting everything aside and come to the other side of the world to continue studying.

Finally, I want to express my gratitude and much more than that to Dimitra Dalamagka, my girlfriend, who has been the strongest support during the program and during the process of making this thesis. Being able to be in this stage wouldn't have been at all possible without you by my side. May our future projects continue proving that we are an amazing team, I love you.

Thank you all.

José Otárola Lagos

Abstract

The oil and gas industry constantly evolves by the hand of technology. The available software, with the input provided by mathematical correlations, provide a great tool for modeling, simulating and predicting the behavior of reservoirs and wells, provided of course with the proper information. The MSc course provided the opportunity to work with some of the software used in the oil and gas industry.

In the present work, and with the assistance of two packages from the IPM Suite (REVEAL and PROSPER), the process of designing a group of wells that must meet a target production for a given reservoir model will be faced. An initial overview for oil recovery methods will be provided, together with the problem statement and a brief description of the software packages to be used.

After this, a quick examination of the provided reservoir model will be performed, with the objective of assessing any difficulties that the operation could face.

After the presentation of the production problems that need to be solved, the procedure starts with the design of the wells, starting with their geometrical design as well as the downhole equipment to be used. Once the initial design is completed, an evaluation of the results obtained with the design proposed will be performed with the objective of determining if there is need for artificial lift systems to be implemented (For this study, Gas Lift).

With the initial designs completed and evaluated, the design of a Gas Lift System will be done with the use of the software package PROSPER, leading this to a proposed artificial lift design.

Finally, an evaluation of the results obtained and the influence of the design in the production expected for the reservoir model will be done, along with some comments on the relevance of the effort invested on satisfying the production requirements and the proposal of future work to be done on the same study case.

1. Introduction

1.1. Oil recovery mechanisms

The target of oil and gas exploitation is the financial profit which relates to the production increment. The oil seeps are almost eliminated and the natural drive mechanisms cannot meet the production requirements. Consequently, the invention and implementation of the new techniques that may allow the full exploitation of the oil reserves has become a necessity. For this reason the oil recovery is not only based on the natural drive mechanisms, but the most of the oil initially in place in a reservoir can be produced through artificial methods. By these methods the engineers interfere with the physics of the reservoir and change the pressure regimes in the wellbore and/or the reservoir, so that to enable the production from depleted or close to depletion wells and from liquid loaded wells.

The oil recovery methods are categorized, as it is presented in *Figure 1*, in three categories:

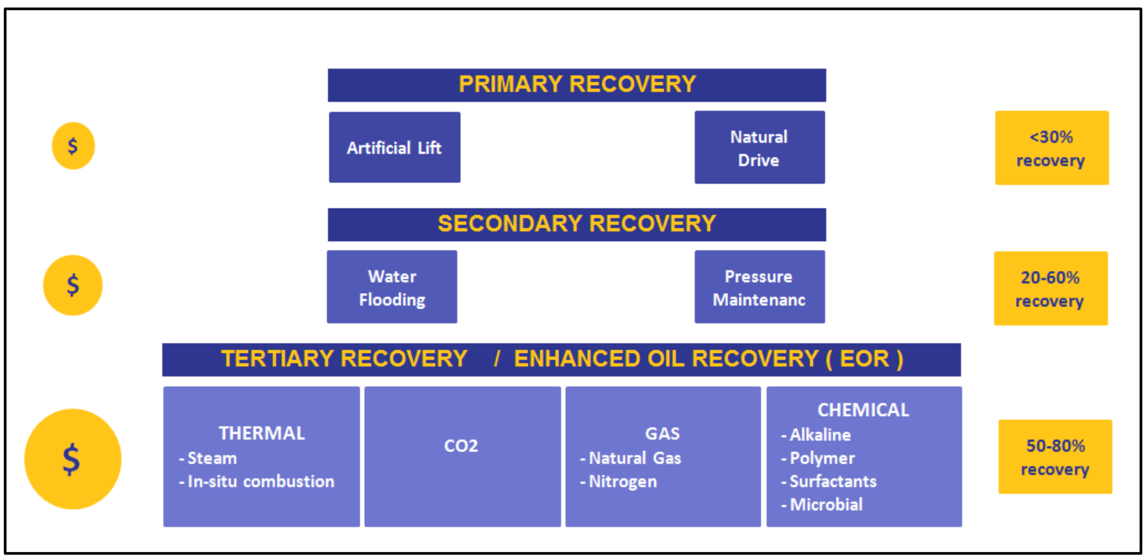


Figure 1: *Categories of oil recovery techniques [1].*

<u>Primary oil recovery</u>

This category includes the natural drive mechanisms and the submersible pumping equipment that may be used, which can be considered as artificial lift. The natural drive mechanisms (segregation, gas cap and/or solution gas expansion, water influx, rock compression) are playing the major role in the natural flow production. Only around 20-25% of the oil initial in place (OIIP) may be delivered by primary recovery methods [2].

Secondary oil recovery

The methods that are included in this category are dealing with the pressure maintenance in the reservoir or in the midstream facilities. The techniques that are considered as secondary oil recovery methods are the water flooding and the surface pump boosting.

Artificial lift techniques are applicable when the reservoir production declines due to depletion.

With the implementation of any of the secondary recovery methods it can be recovered up to 40% of the well's potential production, meaning that an additional 20% of the amount produced with primary recovery methods can be produced [2].

Enhanced Oil Recovery (EOR)

The production that belong in this category are increasing as different experimental studies try to optimize the existing techniques and to find new ways to interfere with the reservoir. The major EOR techniques are steam injection, in situ combustion, gas lift, CO_2 injection and chemical substances (as polymers, alkalines, surfactants and microbes) injection that act as catalysts.

Enhanced oil recovery methods are applied to reservoirs after the main drive mechanisms (primary recovery) and the secondary recovery techniques are applied. For this reason, they are usually applied on mature and close to depletion reservoirs. The application of the EOR techniques can lead to the recovery of up to 60-65% of the well's potential production [3]. The importance of the EOR methods in exploitation domain is that they enable the production of residual oil that cannot be produced with the other methods. However, EOR techniques are of special interest, they are not of often use, because of high costs, but they are long-term technically and financially beneficial.

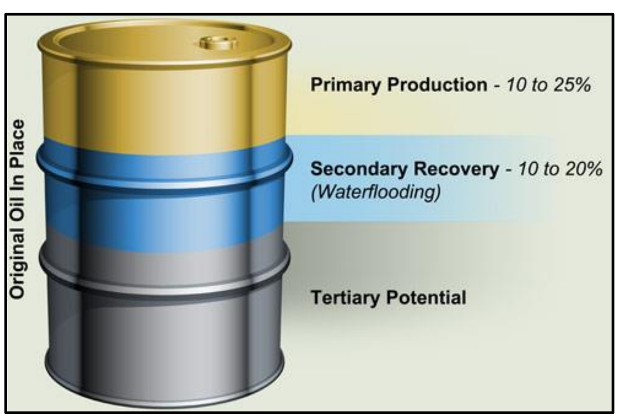


Figure 2: *Contribution of each recovery technique in oil production (in %) [3].*

1.2. Gas Lift

Gas lift is one of the most often used artificial lift methods. More than 94% of the currently oil producing wells globally will require artificial lift after some years of production, according to recent market news [4]. Some real data from the market, about the gas lift contribution in production [5]:

- The 46.5% of the oil production from the fields operated by BP in 2001 was obtained through gas lift application.
- The 25% of the oil production from the fields operated by Exxon in 2004 was obtained through gas lift application.
- The 25% of the oil production from the fields operated by Shell in 2001 was obtained through gas lift application.

Gas lift is a very commonly used Artificial Lift Method, because it requires less cost and less implementation risk since it is widely known and there are many applications worldwide. The main goals of this technique are the restoration of the reservoir pressure and the increase of oil production, while keeping the operating cost low [6].

The production by gas lift technique is enhanced by two ways [6]:

1) By injecting a low-density fluid (gas) which is getting mixed with the effluents, the total mixture density decreases. Consequently, the hydrostatic pressure drop in the tubing will decrease, enabling the production of the dense effluents.

2) The injected gas implies a pressure drive to the effluents in the tubing and “pushes” them upwards.

Typical gases used for injection are: carbon dioxide (CO_2), nitrogen or air (N_2), natural gas.

1.3. Identifying a gas injection candidate

When the production results after the application of primary and secondary recovery techniques are not satisfying, it’s time for the EOR to be chosen. Mature oilfields are in general good candidates for artificial lift application. The characterization of a field as “mature” differs in the Oil & Gas industry. For the purposes of this study the definition followed by Halliburton Company will be considered as valid; “a mature field is one where production has reached its peak and has started to decline” [7].

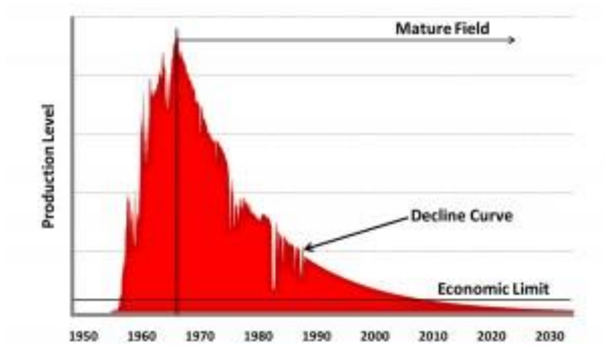


Figure 3: *Mature fields production curve [7].*

In Halliburton Company, they believe in the rule of the "5 P's" about the handling of the production from mature fields; "Proper Planning Prevents Poor Performance" [8]. The selection of the appropriate artificial lift method is a procedure with many aspects.

The question that must be answered when the decision about the selection of artificial lift method is not about the installation and operation cost but it is about which one is the most suitable for each well. Some parameters that are taken into consideration for the initial selection of recovery method that will be applied are the following [9]:

1. Reservoir Pressure and Well Productivity.
2. Reservoir fluid characteristics (Gas Liquid Ratio, solids content, etc.).
3. Surface facilities constraints about the quantities of gas, water and oil that are designed to handle.
4. Depth ranges that are possible candidates for gas injection.
5. Financial evaluation (OPEX and CAPEX).
6. Feasibility of application and implementation (time schedule, availability of equipment, expertise of personnel).

Gas lift technique is more suitable for oilfields with low oil saturation and reservoirs with high permeability [10]. Also, reservoirs characterized by high GOR values are suitable candidates for gas lift application. The effluents are light, so the injected gas will be able to increase their recovery due to segregation.

In terms of well characteristics, the different types of gas lift (Continuous and Intermittent) in combination with the Valve Systems are suitable for most of the production wells, depending this on the parameters that characterize them and the task to be performed [6]:

1) High PI, High BHP: Continuous Open and Semi-open, system to be used in our case.
2) High PI, Low BHP: Continuous/Intermittent Closed.
3) Low PI, High BHP: Continuous/Intermittent, Semi-open and Closed.
4) Low PI, Low BHP: Intermittent Closed.

There are two different types of gas lift, depending on whether the injection will be intermittent or continuous [11].

• ***Intermittent Gas Lift*** is characterized by the periodic opening and closing of one or more injection valves, which is regulated by a timing device or depending on the pressure. It is suitable for wells with high Productivity index and low reservoir pressure and for wells with Low Productivity Index and high reservoir pressure or inversely [6, 9]. With this type of gas lift a specific volume of gas is injected at a high flow rate, giving a push to the flow [12]. Its main purpose is the **slug removal** from the wells.

• ***Continuous Gas Lift*** is referred to the continuous injection from one or more valves. It is suitable for wells with high Productivity Index (≥0.5sbbl/day/psi) and high bottomhole pressure [6, 9]. With this type of gas lift the gas is injected at a given pressure and flow rate and its main influence in the flow is the reduction of its density. Its main purpose is the increase of the **oil production**.

1.4. Problem statement

A Reservoir Model for an oil field has been provided. Taking in consideration the characteristics of this reservoir, it has been requested the design of 4 production wells that will provide a total production of ten thousand and five hundred barrels of liquid per day. The Reservoir Model provides the information for the location of the four production wells, as well as the data corresponding to each one of these wells for the simulation between the years 2009 and 2025.

As specific request for the work to be done the wells must be designed as S-shaped, i.e. vertical down to the kick-off point, build up section with a maximum rate of three degrees every one hundred feet, no hold section, and a drop-down section with the same rate, ending with a vertical section to the target of one thousand feet. The design of the wells must guarantee the target production during the whole simulation and artificial lift methods must be applied in case of being necessary.

1.5. Software overview

The software to be used in the elaboration of this thesis correspond to two packages from the Integrated Production Modelling (IPM) of Petroleum Experts: REVEAL and PROSPER.

- **REVEAL:** It is a specialized reservoir simulator modeling near well bore effects including mobility and injectivity issues. Capable of modelling rigorously thermal and chemical effects which may arise from the injection of non-reservoir fluids at non-reservoir temperatures. For the development of this thesis, a Reservoir Model will be provided and be available as source of data for the design of the wells, which will be done using the other package available.

- **PROSPER:** Well performance, design and optimization program. Considered the standard well modelling tool of the industry, it is designed to allow the building of reliable and consistent well models, with the ability of address each aspect of well bore modelling viz, PVT, VLP correlations and IPR. Since this package also contains the tools for the design of Artificial Lift Systems, it is also considered a unique diagnostic tool to identify gas lift valves failure, points of gas injection and other operational problems.

From the two packages, the one that will be mostly used is PROSPER. REVEAL will be used as a source of data for the design of the Production Wells and the Artificial Lift System.

2. Field description

The field corresponds to a Database provided by PetEx for training and practice on different topics with the assistance of the packages of the IPM suite.

The PVT properties of reservoir fluid are the following:

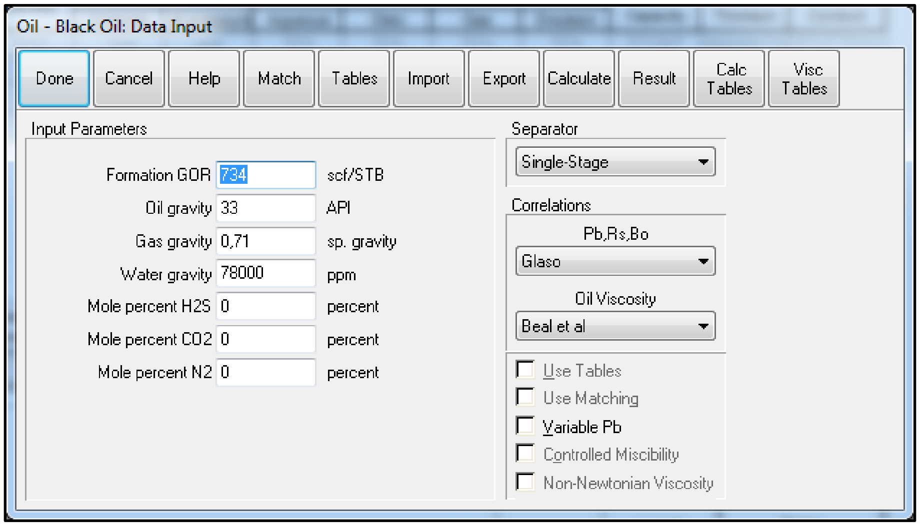


Figure 4: *Effluents PVT properties.*

As it is possible to see in the PVT properties, the reservoir contains a Light Oil with a relatively low gas concentration (Light Oils, according to the classification of the Environmental Protection Agency, may show GOR's between 300 and 100.000 scf/bbl).

Another characteristic that may raise inquiries is the fact that for this reservoir, the Critical Water Saturation has a value of 45 percent. Since this is an artificially generated reservoir, this high value for the critical saturation is more a way to emulate the influence of a water drive source than a true characteristic of the reservoir itself.

The Reservoir Model also considers the installation of four production wells, which must be designed to satisfy specific production rates. However, during the time contemplated in the simulation of the reservoir, it is possible to observe a sudden increase of the Water Cut in the four wells, two of them occurring in early stages of the simulation and reaching values of water cut between the 40 and 60 percent. The two other wells, even when it takes longer for them to have a water breakthrough, have an almost violent increase in the percentage of water present in the liquid, reaching values above the ninety percent which may present difficulties for the late stages of the simulation.

The field has been generated in a Corner Point Grid, for a total of 700 x 700 x 4 blocks. The blocks that are not used are declared as void (No value has been input). For effects of calculation of distances, the Oil Rig is directly above the cell [65, 62] and the target blocks for the production wells are also provided. Although the reservoir is not "parallel" to the surface, the reservoir model includes the reference system that allows to obtain the direct view from axis X, Y and Z, making in this way possible to estimate the horizontal distances that need to be covered (Table 1).

Block	Well	Hz Distance to Rig [65,62] (ft)	Approx. Depth Top Block (ft)	Available Depth (TBD - 1000) (ft)
[61,66]	W1	1900	10170	9170
[67,49]	W2	4100	10400	9400
[61,79]	W3	5600	9658	8658
[65,55]	W4	2150	10265	9265

***Table 1:** Wells' blocks location.*

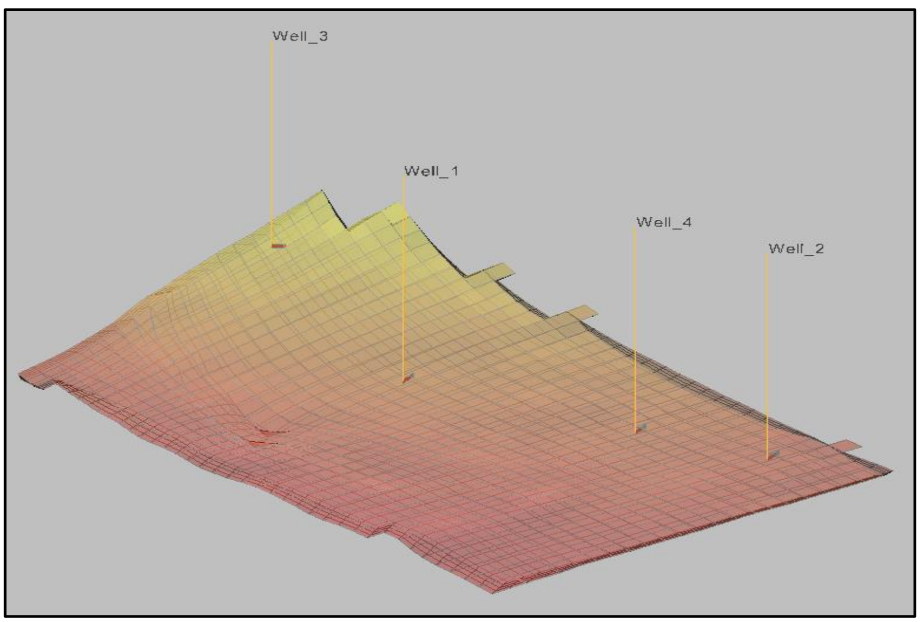


***Figure 5:** 3D visualization of the oil field*

2.1. Oil production

The results for the prediction of the production from each well indicate that Well 3 can reach the plateau until the first half of 2013 and is the one between the four wells with the longest production before depletion to start. On the other hand, the depletion of Well 2 starts very soon, at the second half of 2009. Under natural flow drives Well 1 is almost fully drained after 2010 and it seems that the production is eliminated. Well 4 has also a short plateau period until 2010 and then depletion starts.

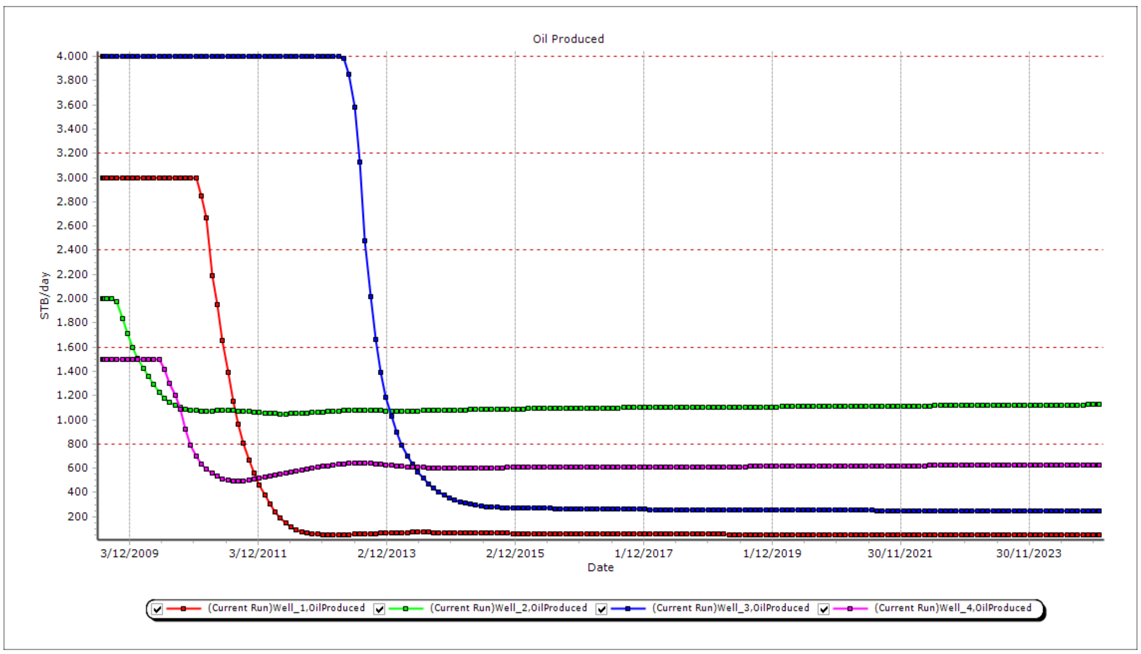


Figure 6: *Oil production prediction until 2025 for each well in Reservoir Model.*

2.2. Gas production

The gas production under natural flow drives and before gas lift implementation, follows the oil production trends as above described.

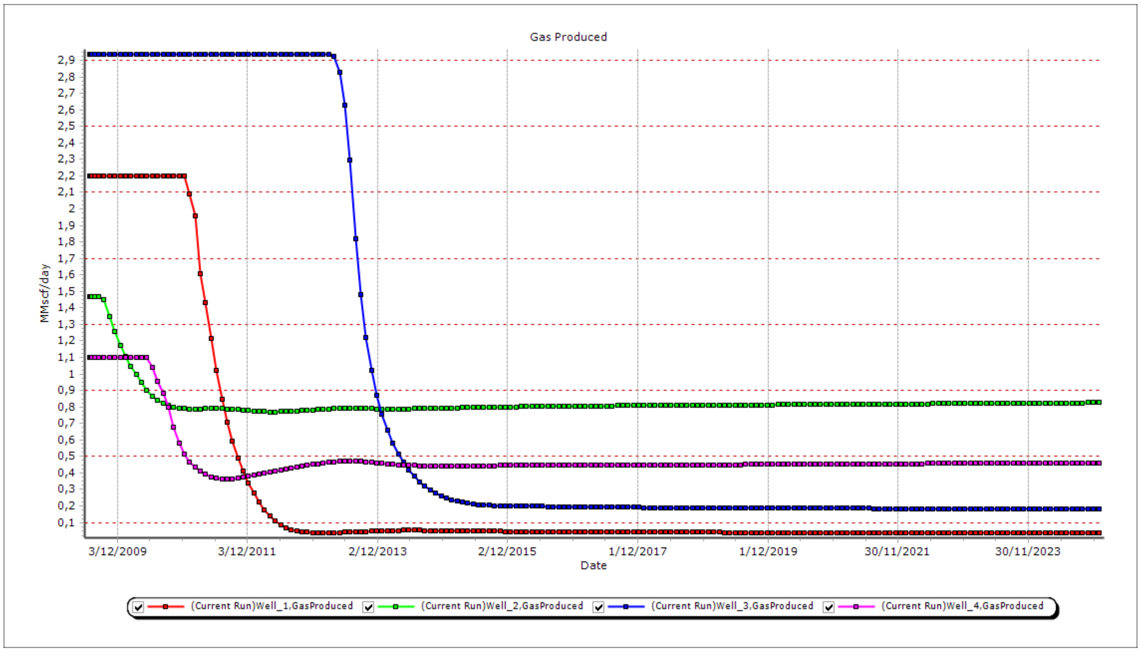


Figure 7: *Gas production prediction until 2025 for each well.*

2.3. Water Cut

The water production percentage is supplementary of the oil and gas production. The decrease of oil production corresponds to the increase of water cut. The oil production of Well 1 is starts to decrease at 2010 and reaches almost zero values at2011 and now the reservoir fills up with water, as the water cut becomes more than 95%. The same situation occurs for Well 3, with water cut reaches 90% at 2014, when the oil production becomes very low.

The situation differs for Wells 2 and 4. Both are not reaching full depletion with time, but they keep having a constant low production. They are producing a multiphase mixture of water and oil, in which water is almost 50-60%.

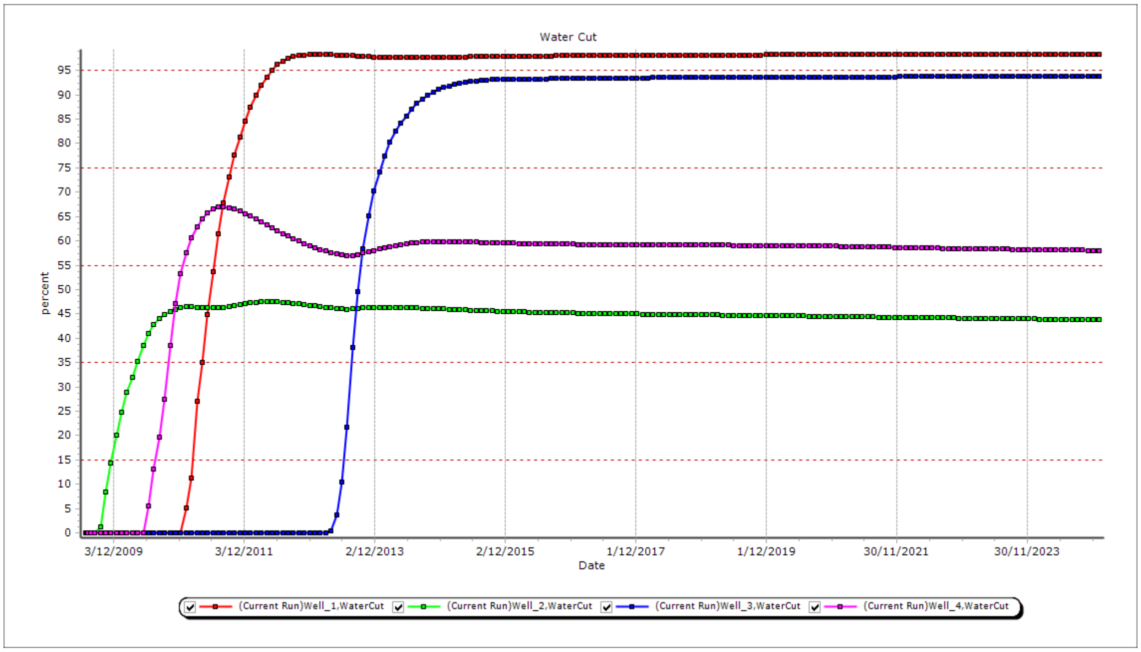


Figure 8: *Water cut prediction until 2025 for each well.*

.

3. Designing the Path of the Wells

Assumptions:

- ✓ Production casing from top to bottom.
- ✓ Liners are not used.
- ✓ S-shaped wells

The wells are S-shaped with the following design characteristics:

- ➢ Build up section up to a rate of 3°/100ft,
- ➢ No hold section,
- ➢ Drop up section at a rate of 3°/100ft,
- ➢ Final vertical section of 1,000ft length up to Target Depth (TD).

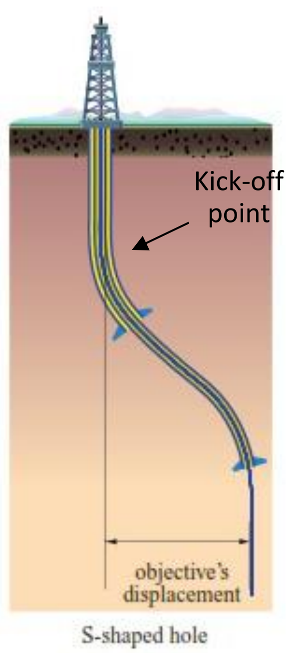


Figure 9: *General configuration of an S-shaped well [13].*

3.1. Geometrical Design

The first step to be taken for the design of the production wells is the Geometrical Design, which is the path the well will follow from the oil rig in the surface, until it reaches the target blocks in the reservoir. To accomplish this, it is necessary to first identify in space the location of the reservoir, as well as the location of the target blocks that will host the production wells, together with the Vertical Depth and the Horizontal Distance that needs to be covered by the well.

According to the information provided, the oil rig is located above the cell (65, 62) of the reservoir, and from the Reservoir Model is possible to obtain the target block where the wells will be placed (Table 2).

Well	Block
W1	[61,66]
W2	[67,49]
W3	[61,79]
W4	[65,55]

Table 2: *Target block of each well.*

With this information available, we resort to the Z-axis projection of the 3-D plot of the reservoir. Once the target blocks have been identified on the grid, the distance tool of REVEAL can be used to obtain the Horizontal Distance to be covered. According to the information provided, the Horizontal Distance from the oil rig to the target blocks are as shown in (Table 5).

Well	Block	Hz Distance to Rig [65,62] (ft)
W1	[61,66]	1900
W2	[67,49]	4100
W3	[61,79]	5600
W4	[65,55]	2150

Table 3: *Horizontal distance between the oil rig and the target blocks.*

To value corresponding to the depth of each one of the target blocks must be estimated from the section where the grid and coordinates of the top layer are stored. The information provided for each one of the blocks consists on the depth for the top 4 corners in the Z axis. With this information, the depth estimation for the middle point of the target blocks gives the following results (Table 4):

Well	Block	Approx. Depth Top Block (ft)
W1	[61,66]	10170
W2	[67,49]	10400
W3	[61,79]	9658
W4	[65,55]	10265

Table 4: *Estimated depths of each target block from the top block of each well.*

Since the design requires leaving a vertical section of one thousand feet before reaching target, the available depth to work in the design is reduced (Table 5).

Well	Block	Available Depth (TBD - 1000)
W1	[61,66]	9170
W2	[67,49]	9400
W3	[61,79]	8658
W4	[65,55]	9265

Table 5: *Available depth for the design of each well.*

With this information now available, it is possible to design the S-Shaped section of the well. According to the requirements stablished for the design of the wells, the maximum turning rate corresponds to an angle of three degrees every one hundred feet (3^{o}/100ft). Since the turning rate can be described as a circumference arc with:

$$L = R * a$$

Where:

- L = Length of the circumference arc [ft]
- R = Radius of the circumference [ft]
- a = angle that supports the arc, in radians.

Then, setting the circumference arc in a fixed value of one hundred feet, it is possible to calculate different turning radiuses (Table 6) with the objective of choosing a trajectory for the production wells.

With Arc = 100 ft.	
Angle (S°)	T. Radius (ft)
1	5730
1,5	3820
2	2865
2,5	2292
3	1910

Table 6: *Turning radiuses for different angles of the arcs.*

After verifying results obtained with these radiuses, it has been decided that the production wells 1 and 4 will be built with a turning radius of 5.730 feet, while wells 2 and 3 will be built with a turning radius of 2.865 feet. To achieve the necessary horizontal displacement the build-up total angle for each well must be as shown in (Table 7).

Well	Build Up Angle
W1	33,47
W2	73,47
W3	88,70
W4	35,67

Table 7: *Build up angle for each well.*

The same angle must be applied in the drop-down section to reach again to a vertical section. With this new information, it is possible to provide a first look at the design of the wells (Table 8).

Well	Depth to KOP (ft)	Length of Curved Section (ft)	Hz Depth, Curved Section (ft)	Accumulated Vertical Depth (ft)	Target Depth (ft)
W1	2850,3	6694	6320,2	9170,5	10170
W2	3906,7	7347	5493,2	9399,9	10400
W3	2929,5	8870	5728,5	8658,0	9658
W4	2582,5	7134	6682,5	9265,0	10265

Table 8: *Design length and depths of each well.*

The (Table 9) shows the progression and comparison between Measured Depth and True Vertical Depth for the four Production Wells.

Well 1		Well 2		Well 3		Well 4	
MD	TVD	MD	TVD	MD	TVD	MD	TVD
0	0	0	0	0	0	0	0
2850,3	2850,3	3906,7	3906,7	2929,5	2929,5	2582,5	2582,5
3350,3	3349,7	4406,7	4404,2	3429,5	3427,0	3082,5	3081,9
3850,3	3845,3	4906,7	4886,6	3929,5	3909,4	3582,5	3577,5
4350,3	4333,3	5406,7	5339,2	4429,5	4362,0	4082,5	4065,5
4850,3	4810,1	5906,7	5748,3	4929,5	4771,1	4582,5	4542,3
5350,3	5271,9	6406,7	6101,4	5429,5	5124,2	5082,5	5004,1
5850,3	5715,3	6906,7	6387,9	5929,5	5410,7	5582,5	5447,5
6197,3	6010,4	7406,7	6598,9	6429,5	5621,7	6082,5	5869,1
6544,3	6305,5	7580,2	6653,3	6929,5	5751,0	6149,5	5923,8
7044,3	6748,9	7753,7	6707,7	7364,5	5793,8	6216,5	5978,4
7544,3	7210,7	8253,7	6918,7	7799,5	5836,6	6716,5	6400,0
8044,3	7687,5	8753,7	7205,2	8299,5	5965,8	7216,5	6843,4
8544,3	8175,5	9253,7	7558,3	8799,5	6176,9	7716,5	7305,2
9044,3	8671,1	9753,7	7967,4	9299,5	6463,3	8216,5	7782,0
9544,3	9170,5	10253,7	8420,0	9799,5	6816,4	8716,5	8270,0
10544,3	10170,5	10753,7	8902,4	10299,5	7225,5	9216,5	8765,6
		11253,7	9399,9	10799,5	7678,1	9716,5	9265,0
		12253,7	10399,9	11299,5	8160,5	10716,5	10265,0
				11799,5	8658,0		
				12799,5	9658,0		

Table 9: *Measured Depth (MD) and True Vertical Depth (TVD) estimation progress for each well.*

3.2. Downhole equipment

For this stage, it is necessary to specify the equipment that will form the path through which the fluid will travel to the surface. For this case, and with a geometrical design already prepared, it has been chosen to apply a standard configuration, specifically the one proposed in the examples provided when working with PROSPER, which is an accepted downhole configuration for production wells. This configuration uses the following elements:

Element	ID (in)	Inside Roughness (in)
X-Mas Tree	-	-
Tubing	4,052	0,0006
SSSV	3,72	-
Casing	6,4	0,0006

Table 10: *Geometrical characteristics of the downhole equipment.*

- The Christmas Tree, located in surface.
- Tubing from the Christmas Tree to the wellbore.
- Sub Surface Safety Valve, located just before the KOP.
- Casing, in the Pay zone.

These will be the Downhole Equipment and Geometric Designs that will be used as input in PROSPER to perform the simulation and proceed with the work.

3.3. Evaluation of initial design

Since an initial design has been developed for the production wells, it is necessary to test and evaluate them against the data provided by the Reservoir Model. The information of interest consists of the PVT data of the model (Figure 4), as well as the evolution of the Bottom Hole Pressure and Water Cut in each one of the blocks where the Production Wells will be located.

From the Reservoir Model, we obtain the plots for Bottom Hole Pressure and Water Cut for each one of the wells during the period of interest, with the idea of evaluating the performance of the initially proposed designs.

Well N°1

The Well N°1 (3000 stbl/day) shows no presence of water almost until the end of the year 2010, showing after this point a quick increase of the Water Cut, reaching a 45% in May of 2011 and setting at a 98 – 99% from the beginning of October of 2012. The BHP of the well shows a fast drop from its initial value of 5890 psi at t=0, to a value of 5207 psi around the middle of November 2010. Once the Water Cut has reached a value of almost 99%, the BHP value shows an almost constantly decreasing behavior, until it reaches a value of 4528 psi at the end of the simulation (Figure 10).

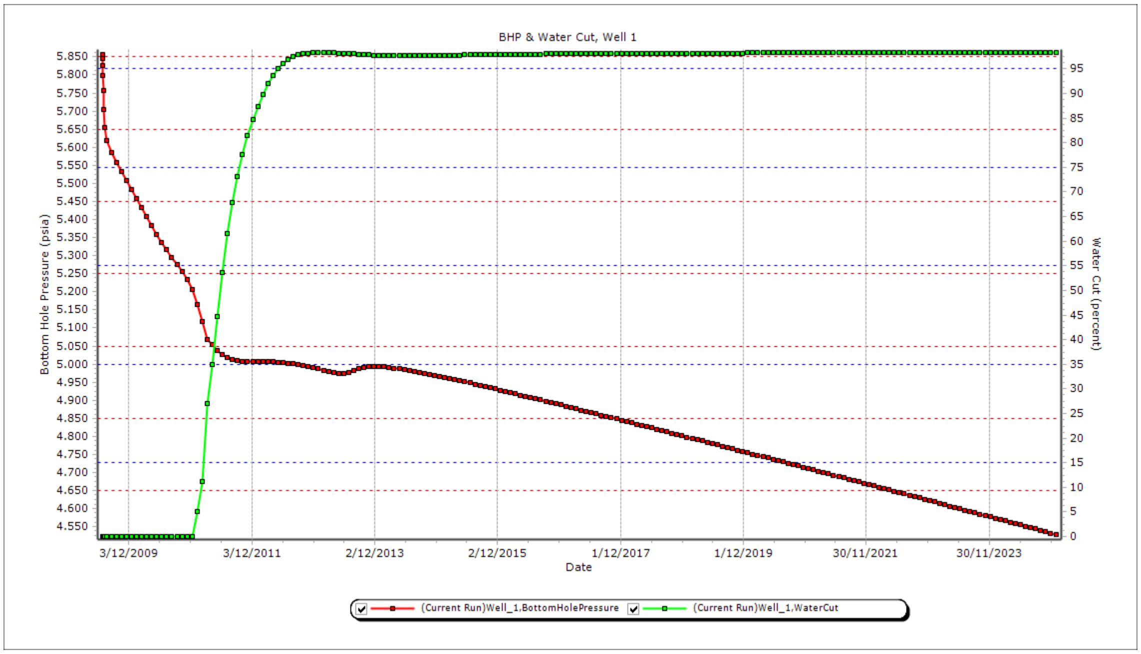


Figure 10: *Bottomhole pressure and water cut progress during production for well 1.*

Well N°2

The Well N°2 (2000 stbl/day), shows presence of water in a very early stage of the production (August 2009), but unlike the situation observed in Well N°1, the Water Cut reaches a maximum of a 48% in April 2012 to finally go down to a 44% at the end of the simulation. The BHP that starts at 5970 psi, shows a fast decline until January 2011 (5475 psi), after which it drops at a slow rate until the end of simulation, where it reaches a final value of 4969 psi (Figure 11).

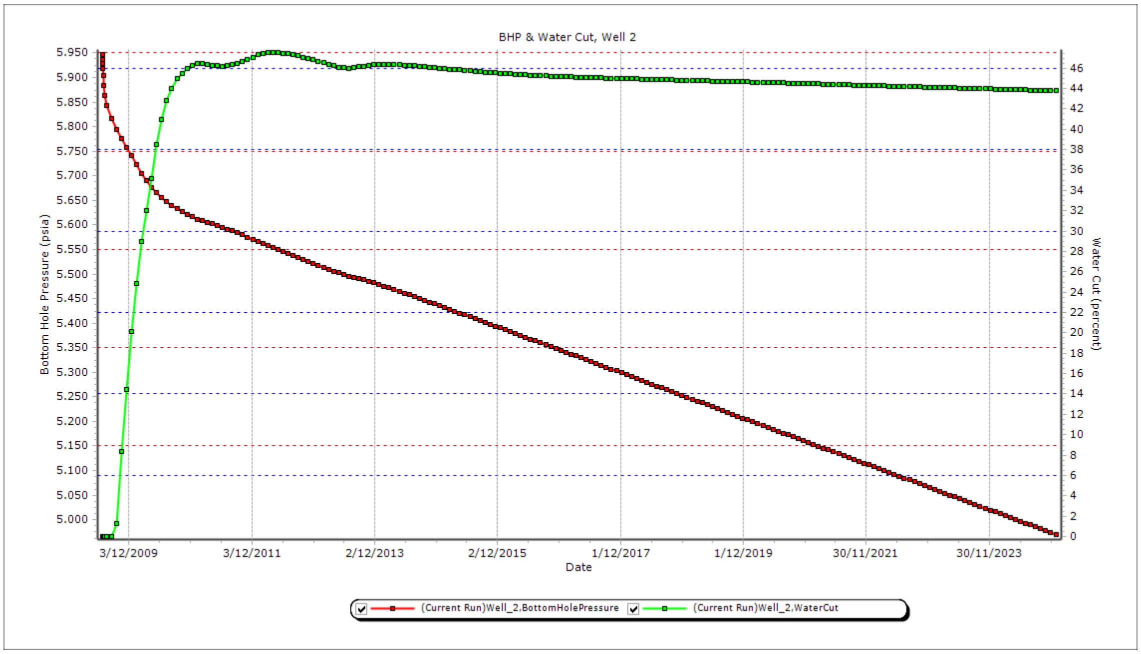


Figure 11: *Bottomhole pressure and water cut progress during production for well 2.*

<u>Well N°3</u>

From the four production wells, the Well N°3 (4000 stbl/day) is the one that shows the longest period without presence of water (Until the start of March 2013). After this, however, the percentage of water present in the liquid produced increases quickly, going through a 38% at the end of July 2013, rising above the 90% in October 2014 and finally settling just below the 94% by the end of the simulation. When it comes to the values for the BHP, we have a starting value of 5750 psi, that drops steadily until it reaches a value of 4717 psi when the water breakthrough occurs. After this, the BHP value drops slowly until it reaches the 4104 psi at the end of the simulation (Figure 12).

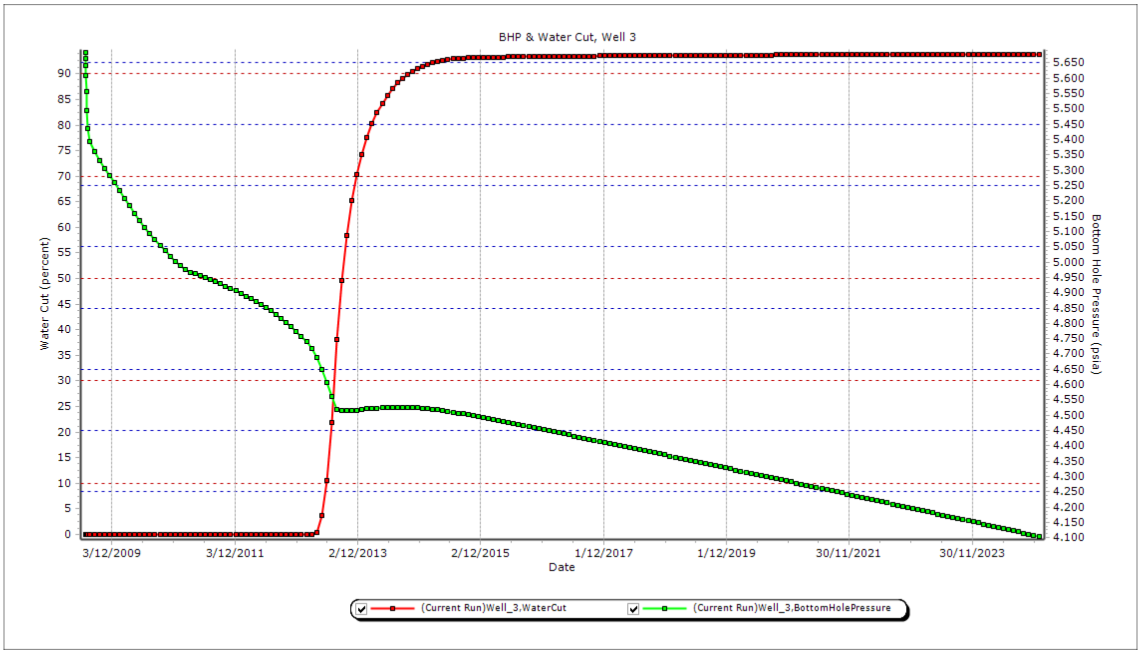


Figure 12: *Bottomhole pressure and water cut progress during production for well 3.*

<u>Well N°4</u>

The fourth and final well is the one with the lowest production rate (1500 stbl/day). It shows an early presence of water (May 2010) with a quick increase, reaching a value of 67% in August 2011 and surprisingly decreasing after this to a 60% by the end of the simulation. The pressure in the Bottom Hole starts at a value of 5925 psi, dropping to 5485 psi when water shows up in the production and then slowly decreasing, to reach a final value of 4716 psi at the end of the simulation (Figure 13).

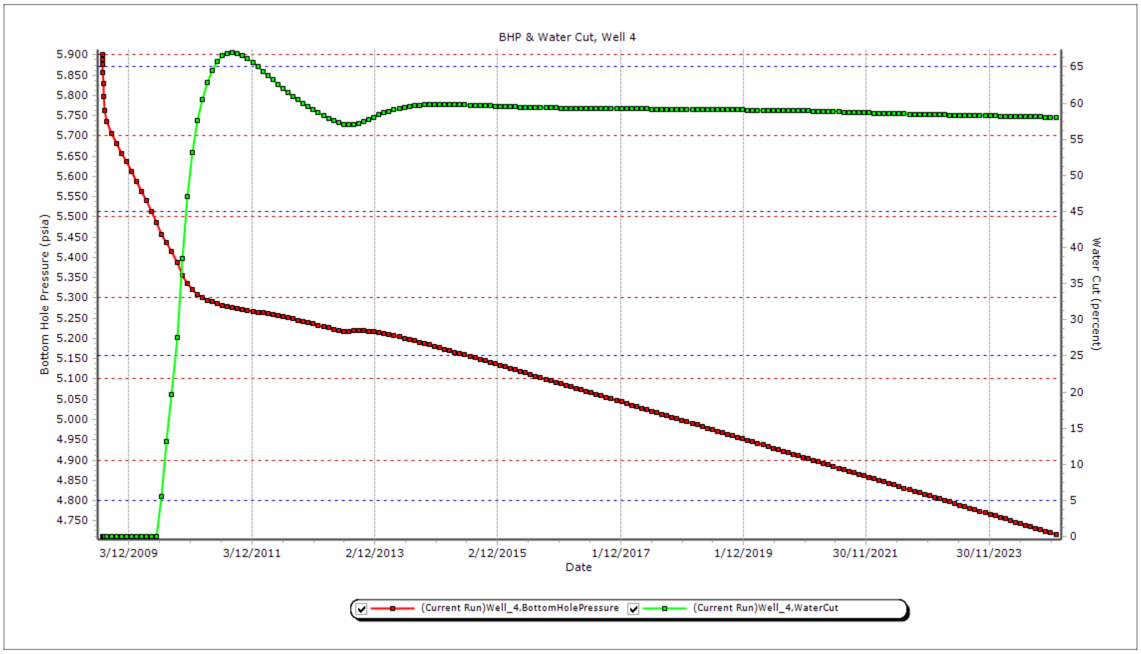


Figure 13: *Bottomhole pressure and water cut progress during production for well 4.*

With this general information and with the objective of evaluating the performance of the designed wells, some key values for Water Cut and BHP are collected (Table 11).

W1		
Water Cut	Period	Lowest BHP for period
0	Until 14/11/2010	5207
45	Around 13/05/2011	5038
98	04/10/2012 and after	4528

W2		
Water Cut	WC Date	Lowest BHP for period
0	Until 21/08/2009	5816
46	13/01/2011 and 27/04/2014	5475
48	07-04-2012	5553
44	End of simulation	4969

W3		
Water Cut	WC Date	Lowest BHP for period
0	Until 03/03/2013	4717
38	Around 31/07/2013	4520
90	Around 24/10/2014	4525
94	End of simulation	4104

W4		
Water Cut	WC Date	Lowest BHP for period
0	Until 18/05/2010	5485
39	Around 15/10/2010	5355
60	End of simulation	4716
67	Around 11/08/2011	5276

Table 11: *Water cut and Lowest Bottomhole pressure for each well and for different time periods.*

With the tool of Traverse Pressure Gradient provided by PROSPER, it is possible now to verify if the current design for the production wells can bring the production to the surface. For this, we simulate the calculation of Pressure Traverse with the different Water Cuts we have chosen for each Well. For the designed wells to be able to bring the production to the surface, the pressure value at the end of the Traverse Pressure Gradient must be lower than the BHP for the corresponding Water Cut.

Well N°1

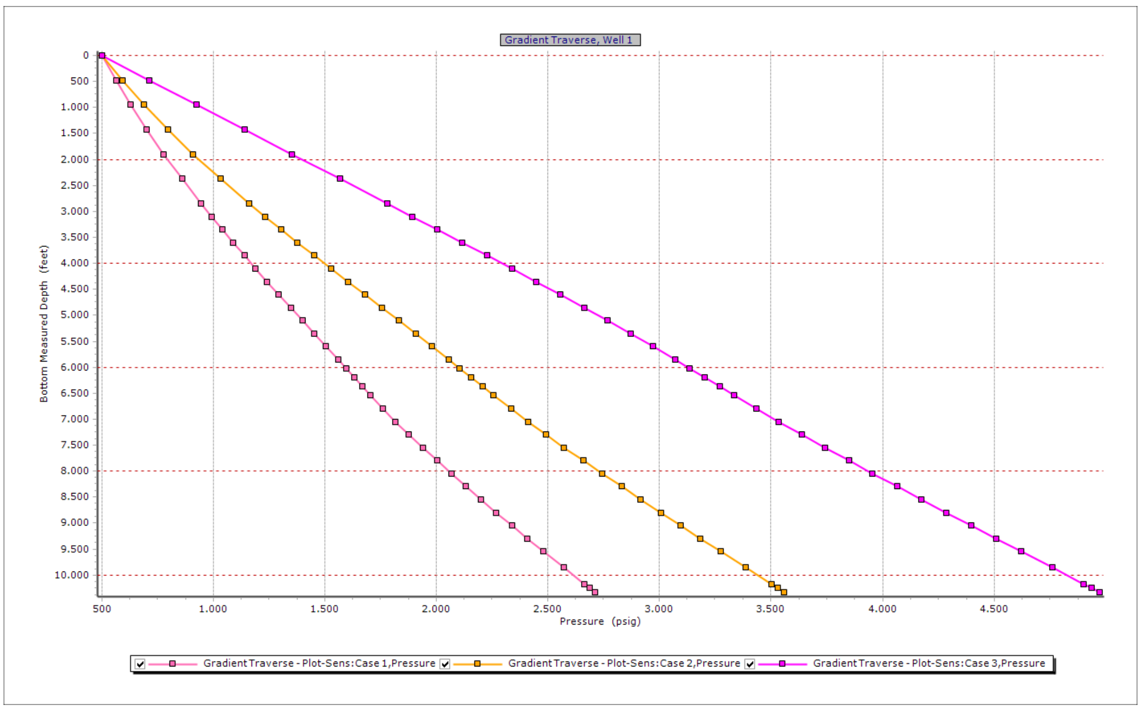


Figure 14: *Pressure Traverse for Well 1 for different cases of water cut.*

.

Water Cut	Pressure at End of Traverse	BHP around period
0	2710	5207
45	3559	5038
98	4973	4528

Table 12: *Pressure Traverse main points of the plot for Well 1.*

After comparing the pressure value at the end of the Pressure Traverse for each Water Cut value with the corresponding BHP values, it is possible to observe that upon reaching a water cut of a ninety eight percent, the well loses the capability of bringing liquid to the surface. Since the water breakthrough occurs in an early stage of the production, it will be necessary to apply an artificial lifting method to allow this well to produce during the whole projected time.

__Well N°2__

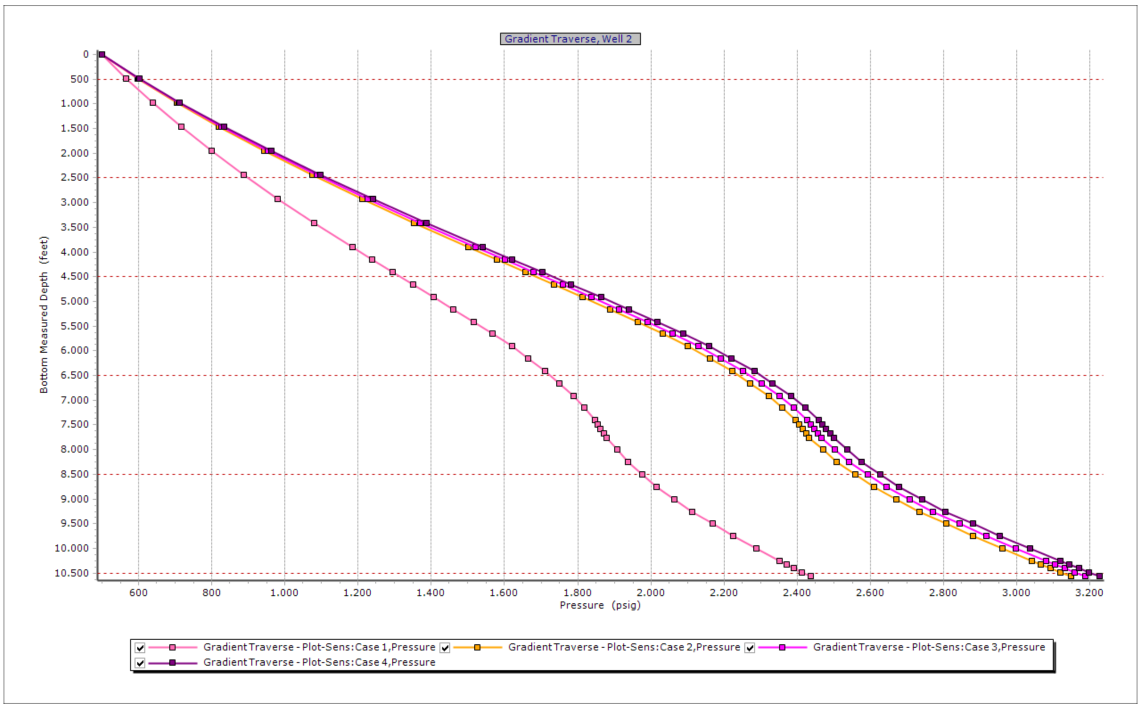


Figure 15: *Pressure Traverse for Well 2 for different cases of water cut.*

Water Cut	Pressure at End of Traverse	BHP around period
0	2436	5816
46	3186	5475
48	3226	5553
44	3147	4969

Table 13: *Pressure Traverse main points of the plot for Well 2.*

Well N°2 shows a good behavior during all the stages of production. As it is possible to see, the final value for pressure in the Traverse for the four selected Water Cut values stays below the BHP value. Therefore, the design of this well is expected to deliver its production to surface without any artificial method of support during the life of the project.

__Well N°3__

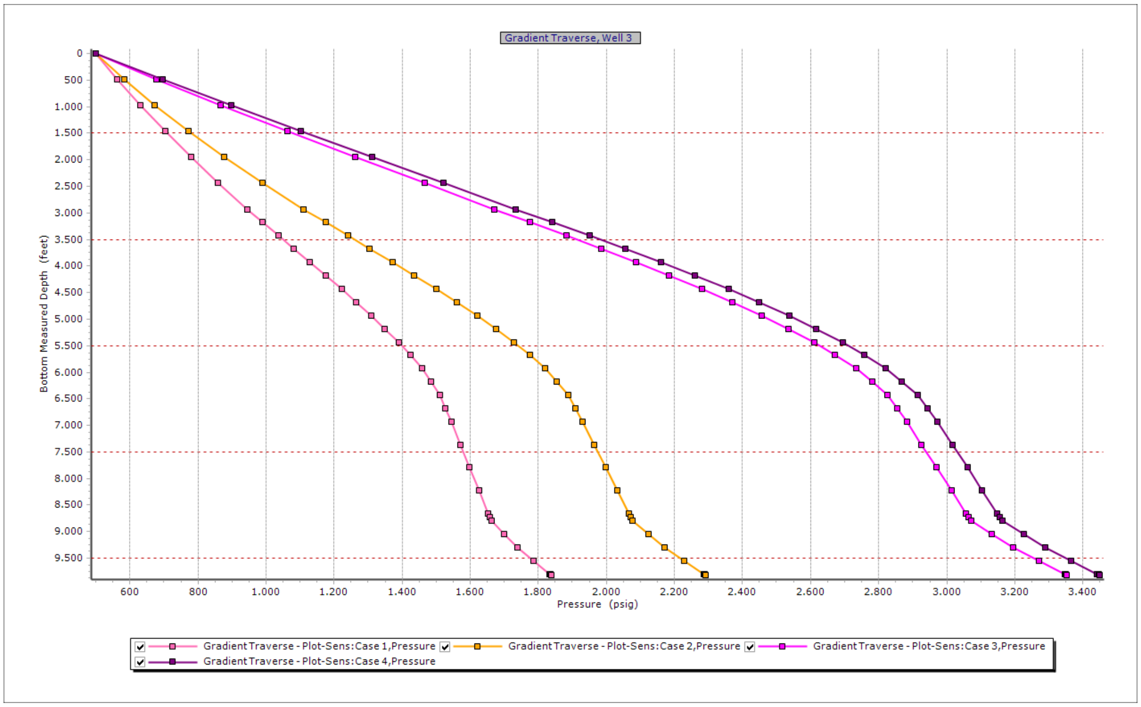


Figure 16: *Pressure Traverse for Well 3 for different cases of water cut.*

Water Cut	Pressure at End of Traverse	BHP around period
0	1837	4717
38	2291	4520
90	3352	4525
94	3449	4104

Table 14: *Pressure Traverse main points of the plot for Well 2.*

The third well on the reservoir, as the previous well did, shows final values for its Pressure Traverses that are all below the pressure in the Bottom Hole, which means that the well should be successful in providing the requested production during the execution of the project. Important is to notice, though, that by the end of the simulation the pressure difference provided by the Traverse and the expected value for the BHP is not significant and variations from the expected values could lead to the requirement of an artificial lifting method.

Well N°4

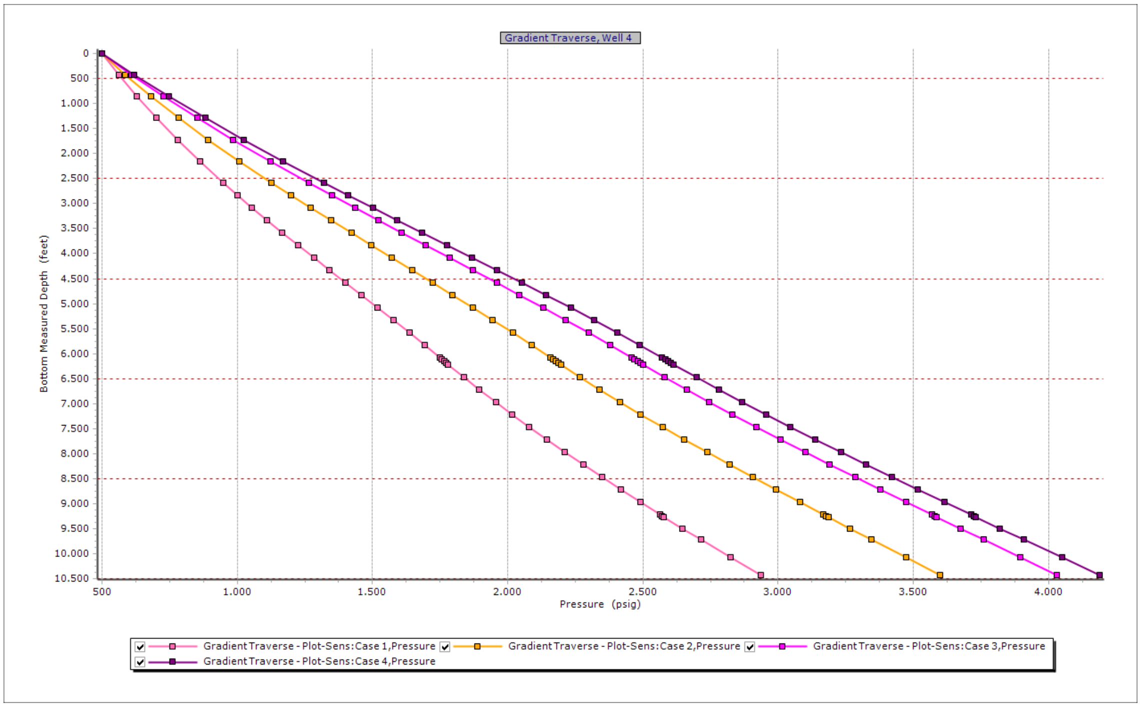


Figure 17: *Pressure Traverse for Well 4 for different cases of water cut.*

Water Cut	Pressure at End of Traverse	BHP around period
0	2934	5485
39	3597	5355
60	4031	4716
67	4189	5276

Table 15: *Pressure Traverse main points of the plot for Well 2.*

The same situation observed in the wells N°2 and N°3 is seen in the behavior of Well N°4: the pressure value expected at the target depth, shown by the Pressure Travers, is in all Water Cut cases below the BHP value expected, allowing us to believe that the well design proposed is correct and will provide the expected production during all the project.

3.4. Summary, Well Design evaluation.

The information gathered from the Reservoir Model, combined with the Pressure Traverse Gradient from PROSPER, shows that the proposed design for the Production Wells is satisfactory. Three of the four wells meet the requirements of production whilst the Well N°1, that shows itself unable to deliver its production once it has reached a 98% Water Cut, shows a small difference in pressure that needs to be supplied to ensure the capability of this well to meet its target production. , we proceed to design for this well an artificial lift system which in this case, will correspond to a Gas Lift System.

4. Gas lift preliminary design

Main purpose of the gas lift technique is to enable the production of effluents while dealing with the flow assurance in the tubing and in the midstream flowlines. So the main parameters that restrict the gas lift design are the maintenance of the bottom-hole pressure at values which will create the appropriate pressure drive for the flow in the tubing and the maintenance of the wellhead pressure in ranges which will provide the appropriate flow to the midstream facilities.
Prior to the gas lift operation design some basic restrictions are taken into consideration [11]:

- The injected gas is restricted by the surface separation facilities.
- The injected gas is restricted by the friction pressure losses in the tubing.
- Avoid water or gas coning effects.

4.1. Pressure traverse

The design of a gas lift operation contains the estimation of the required pressure of the injected gas at the injection depth and the estimation of the volume of the injected gas [14].
All the above considerations of pressure change restrictions when gas lift technique is applied can be quantified by the pressure traverse [11]:

$$\boxed{p_{whf} + \Delta p_{trav} = p_{wf}}$$

Where:
p_{wf} is the bottomhole flowing pressure [psia],
p_{whf} is the wellhead flowing pressure [psia] and
Δp_{trav} is the pressure traverse [psi]
The pressure traverse indicates the pressure change in the well and it is a function of the flow rate, the GLR, the depth, the properties and the composition of the fluid and is expressed:

$$\Delta P_{trav} = \frac{dp}{dz} * H$$

Where:

H is the depth [ft],

dp is the pressure difference between two different points of the well [psi] and

dz is the vertical difference between two different points of the well [ft]

When no enhanced oil recovery techniques are applied, the natural flow can overcome only a certain amount of pressure drop in the well as moving upwards, so the effluents can reach up to a specific depth, which is indicated with the dotted lines in Figure 18. The gas injection is decided to occur at the Injection Point H_{inj}. The pressure gradient of the natural flow (before the injection) is presented as $(\frac{dp}{dz})_b$ and the pressure gradient after the injection is presented as $(\frac{dp}{dz})_a$.

The Balance Point is the depth at which the downhole pressure of the injected gas is equal to the pressure in the tubing and is the theoretical injection point. The actual Injection Point differs some hundreds of feet from the Balance point, because the injection pressure has to count also the overcoming of the pressure drop in the gas valve (Δp_{valve}). For this reason, the injection is applied at a depth about 150 feet closer to the surface than the theoretical [11].

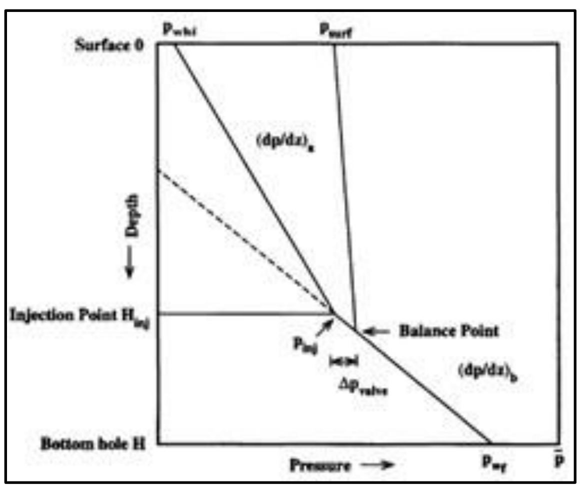


Figure 18: *Pressure traverse in the well [11].*

4.2. Unloading process

The gas is injected in the casing annulus. The initiation of the process is implemented by the gas lift valves that are placed in different depths. The valves are necessary because the pressure of the static fluid column at the desired injection depth in higher than the available gas pressure at the injection depth [14]. The selection of their placement depth is an optimization process.

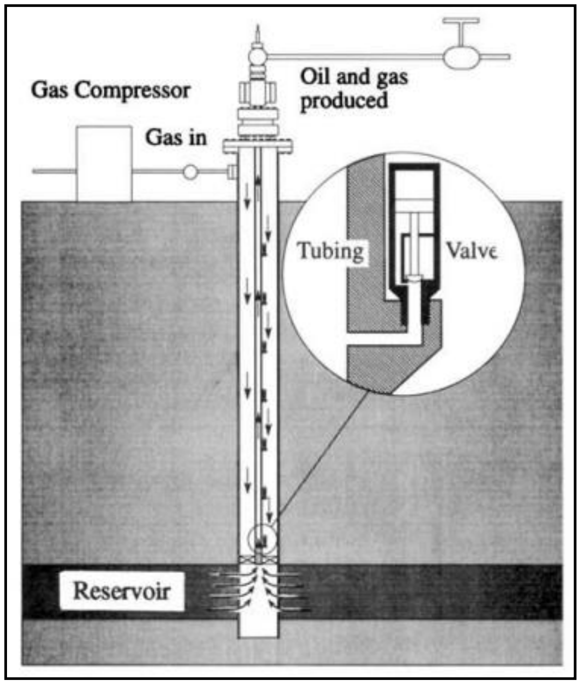


Figure 19: *Gas lift configuration and details of gas lift valves [11].*

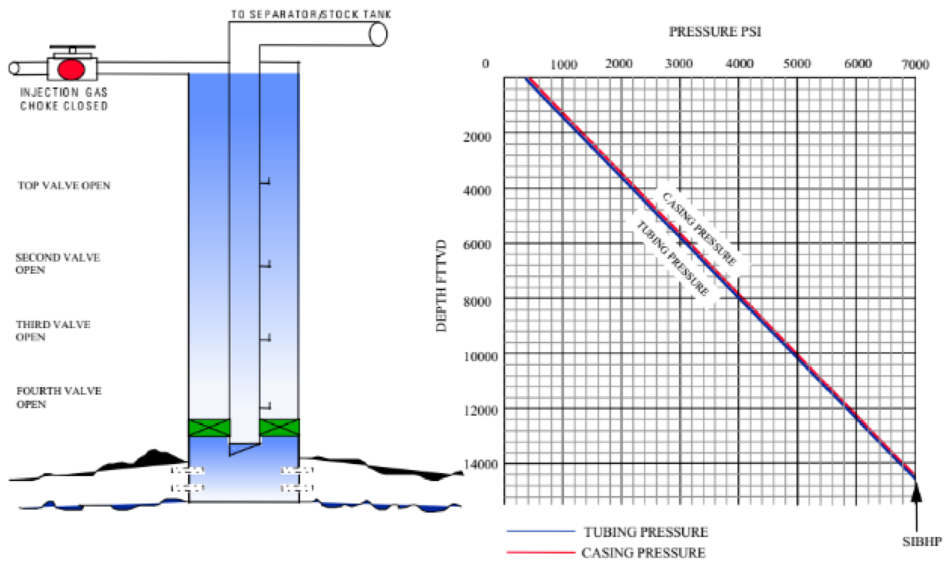
The interpretation of the pressure traverse may be done either from the top to bottom or inversely. The unloading sequence in a continuous gas lift well is briefly presented in Figure 20.

Before the initiation of the process, when all the gas lift valves are open, the casing and tubing pressure gradients in the static loading condition are equal, as presented schematically in Figure 20a [14]. The bottom hole pressure in this stage is the so called Shut-In Bottom Hole Pressure (SIBHP).

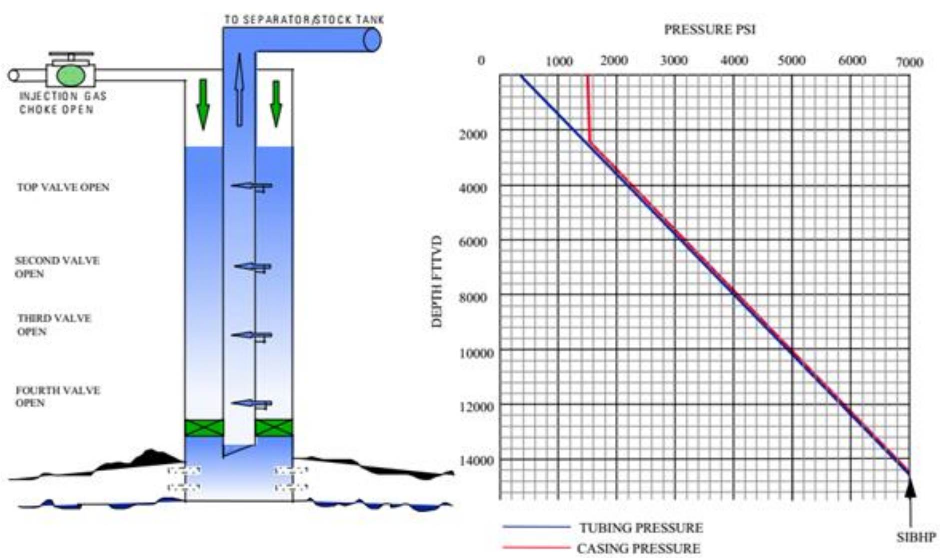
When the gas valves open, gas starts to be injected in the casing annulus. Physically this action forces the kill fluid (the high-density fluid that cannot be produced and creates obstacles in the flow and possible loading of the well) to move to the tubing string and towards the wellhead. This is presented in Figure 20b, where no formation fluid is produced yet. Still no drawdown has be notified, because the reservoir pressure is still less than the pressure in perforations level [14].

As it continues to displace the unloaded fluid to the annulus, the pressure to the casing continues to increase. When the annulus fluid reaches the first valve depth the pressure in the casing becomes equal to the design kick off pressure as presented in Figure 20c. In this part the gas gets into the casing annulus and decreases the fluid’s density above the gas lift valve and so the hydrostatic column above the gas lift valve becomes lighter. A pressure drive is created that enables the flow towards the surface because of the positive pressure difference between the lower and the upper side of the valve.

As the gas injection continues the unloading process continues to the deeper valves and the upper valves close when the fluid level reaches the next deeper valve. The production of formation fluid begins when the bottom hole pressure reaches the so called Flowing Bottom Hole Pressure (FBHP), as presented in Figure 20d. The positive differential of the shut-in minus the flowing bottomhole pressure is the so called “drawdown”, that indicates the initiation of the flow of the reservoir fluids into the wellbore. Then the unloading process has been completed when the injected gas reaches the orifice valve.



(a)



(b)

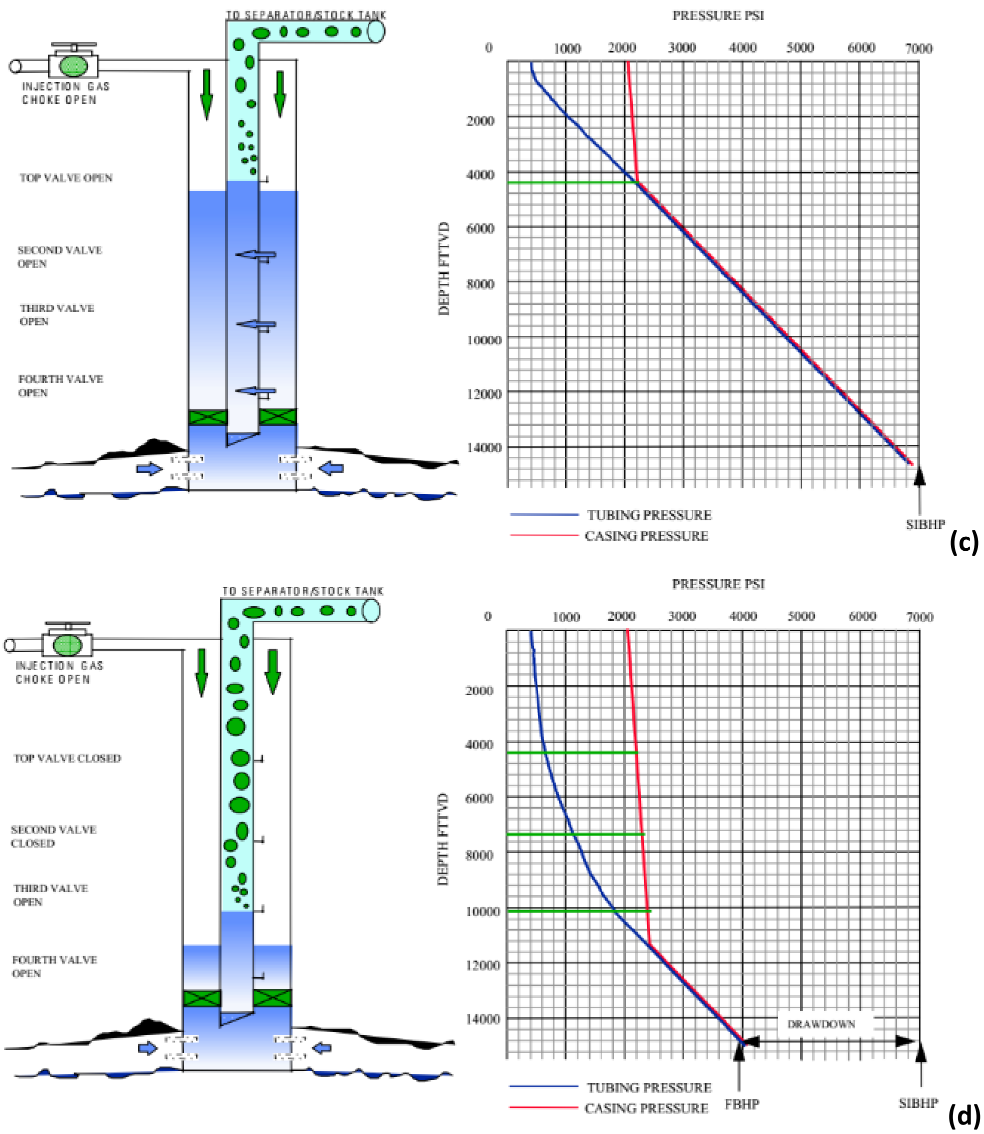


Figure 20 a, b, c & d: *Well unloading process in continuous gas lift [14].*

4.3. Optimum injection point estimation

There are two different approaches for the estimation of the optimum injection point:

<u>*Graphical Method*</u>

This method uses the pressure-depth plot. For this the static and flowing gradient lines must be plotted and according to them the balance and injection points will be estimated graphically.

Static gradient line: is the p-h plot made by using the static pressure gradient starting from the bottom.

Flowing gradient line: is the p-h plot made by using the productivity index for the estimation of the slope, parallel to the static gradient line.

Balance point: is the intersection of the flow gradient line and the projection of the pressure at the middle depth of the well.

Injection depth: is the balance depth and the additional depth difference which corresponds to a pressure loss in the injection valve about 100psi.

Volumetric Balance Method

It is based on the calculations of injection pressure, volume and depth according to the procedure that is described in the following paragraphs.

4.3.1. Injection-point pressure and depth

The pressure of the injected gas derives from the mechanical energy balance, assuming zero kinetic energy and friction pressure drop in the casing:

$$\int_{surf}^{inj} \frac{dp}{\rho} + \frac{1}{144} * \int_{0}^{H} dH = 0$$

Where:

ρ is the gas density and is calculated from the real gas law:

$$\rho = \frac{28.97 * \gamma * p}{Z * R * T}$$

Where:

γ is the gas specific gravity,

Z is the real gas compressibility factor,

R is the gas global constant (R=10.73psi ft^3/lbmole/R)

T is the temperature [R]

Molecular weight of air=28.97

The pressure of the injected gas can be calculated from the formula:

$$p_{inj} = p_{surf} * \frac{e^{0.01875 * \gamma * D_{inj}}}{Z * T}$$

Where:

D_{inj} is the injection depth (TVD) [ft]

p_{inj} is the pressure of the gas at the injection point [psia],

$\bar{Z}$ is the average compressibility factor of the injected gas,

p_{surf} is the desired pressure at the surface facilities [psia]

The calculation follows a trial and error procedure: an initial assumption for the p_{inj} will help to estimate the $\bar{Z}$, through the graphs of p_{pr} and T_{pr} and the procedure continues with some iterations for different assumed p_{inj} values up to the one that will verify the above equation with best proximity.

For simplicity reasons if the above equation is extended as a Taylor series and for γ=0.7, $\bar{Z} = 0.9$ and $\bar{T} = 600R$, it can be expressed as:

$$p_{inj} = p_{surf}\left(1 + \frac{D_{inj}}{40.000}\right)$$

4.3.2. Volume of injected gas

The volume of the gas that can be injected is calculated by the following formula [15]:

$$V = V_{annulus} * \frac{\bar{P} * T}{Z * P * \bar{T}}$$

Where:

V is the volume of the injected gas at standard conditions [ft^3],

$V_{annulus}$ is the total annulus volume [ft^3],

T is the temperature at standard conditions [R],

$\bar{T}$ is the average temperature in the annulus [R],

P is the pressure at standard conditions [psia],

$\bar{P}$ is the average gas pressure in the annulus [psia]

Where $\bar{P} = \frac{P_{inj}+P_{surf}}{2}$

5. Gas lift conceptual design

Black oil data

The oil viscosity is calculated by the software, using the Beal et al correlation. The Bubble point pressure (P_b), Solution gas ratio (R_s) and Oil volume factor (B_o) and calculated by the software using the Glaso correlations.

n/n	Property	Value
1	Formation GOR	734 scf/sbbl
2	Oil specific gravity	33 API
3	Gas specific gravity	0.71
4	Water specific gravity	78,000 ppm

Table 16: *Oil properties.*

For simplicity purposes of the surface facilities, a single stage separator has been assumed for the separation facilities.

Gas lift candidate well determination

As previously stated, from the four designed wells only the Production Well N°1 requires an artificial lift system to operate appropriately until the end of the schedule. Under normal circumstances, the process of calculating and designing the system would take time, with different aspects to take in consideration, such as the depth on which the valves will be placed and the number of valves necessary, the amount of gas to be injected, as well as the pressure to be used in the injection. All these calculations can be performed by PROSPER, if we give an appropriate input.
As a first step, it is necessary to define the Well N°1 as a Gas Lifted Well. This is accomplished in the Options Menu of PROSPER in the section "Artificial Lift" (Figure 21).

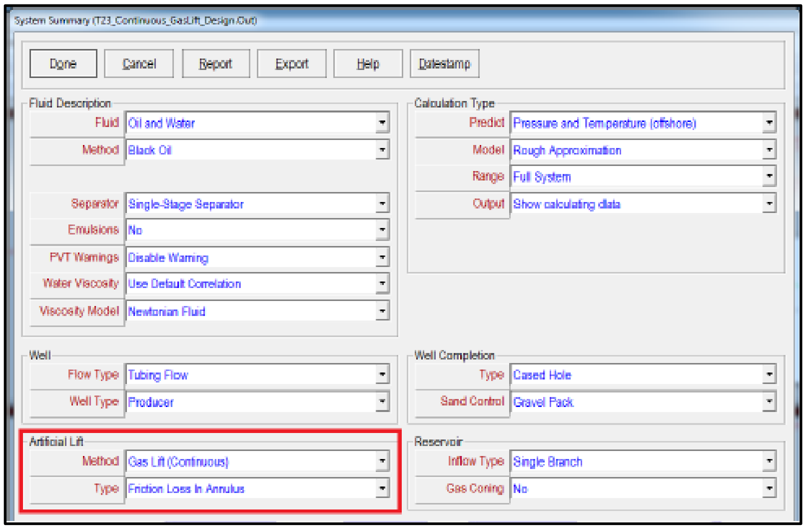


Figure 21: *Command window in PROSPER software about the declaration of Well 1 as a candidate for gas lift implementation.*

Once the Well has been redefined, it is necessary to add complementary information to the Downhole Equipment, such as the Outside Diameter of the Tubing, the Inside Diameter of the Casing, the Inside Roughness of the Casing and the Outside Roughness of the Tubing. These factors allow us to define the Annulus through where the gas will be injected. Following the same criteria used for the initial design, the default values proposed in the Tutorial of PROSPER for design of Continuous Gas Lift Systems will be used (Table 17).

Parameter	Value (in)
Tubing Outside Diameter	4,8
Tubing Outside Roughness	0,0006
Casing Inside Diameter	6,4
Casing Inside Roughness	0,0006

Table 17: *Geometrical properties of the tubing and the casing of the well where gas lift will be implemented.*

According to the PROSPER Tutorial, the next step in the design of the Gas Lift System would be to update the Reservoir Conditions, this to re-calculate the IPR curves. However, since we already have established production that must be met (3,000 stbl/day), a different course of action will be used. The menu for design of the Gas Lift System has various options from which, we will focus initially in two of them:

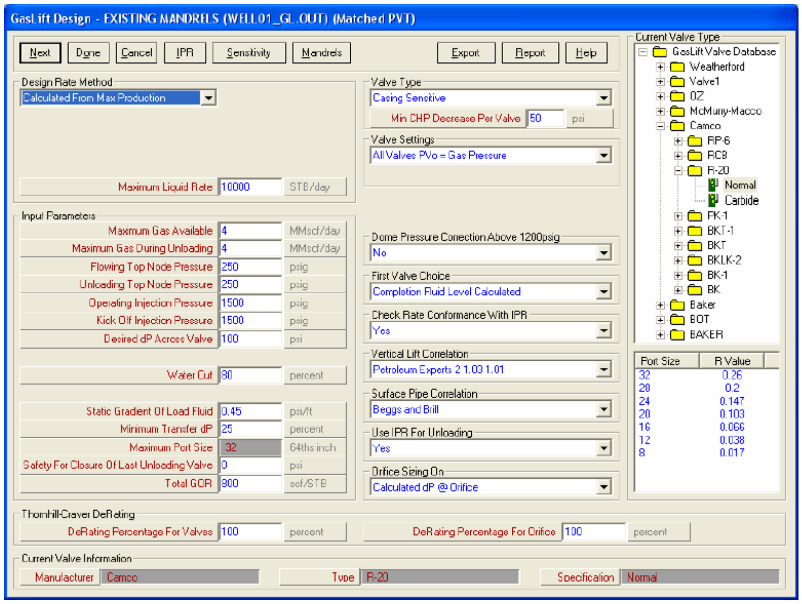


Figure 22: *Command window in PROSPER software where gas lift design parameters are set.*

<u>Design Rate Method</u>

On this section, there are three available options:

- Calculated from Maximum Production: If this option is selected, PROSPER will find the maximum possible oil production rate by determining the optimum gas injection rate and depth.
- Calculated from Maximum Revenue: Using economic parameters entered by the user, the program will find the gas lift design that maximizes the total revenue.
- Entered by User: This option is used when there is a given production rate or when modelling for an existing installation.

Since the purpose of this work is to satisfy the Liquid Production Rate of the well until the end of validity of the Reservoir Model the option "Entered by the User" is selected, while the production is indicated to be in terms of "Liquid Production".

<u>Maximum Gas Available</u>

The gas that will be injected is the one coming from the other three production wells (2, 3 & 4), taking in consideration that the GOR of corresponds to 734 scf/stb and the strong increase of the Water Cut in all wells, it is possible to observe an important decrease of the Gas Production (Figure 23) that must be taken in consideration when making the design of the Lift System.

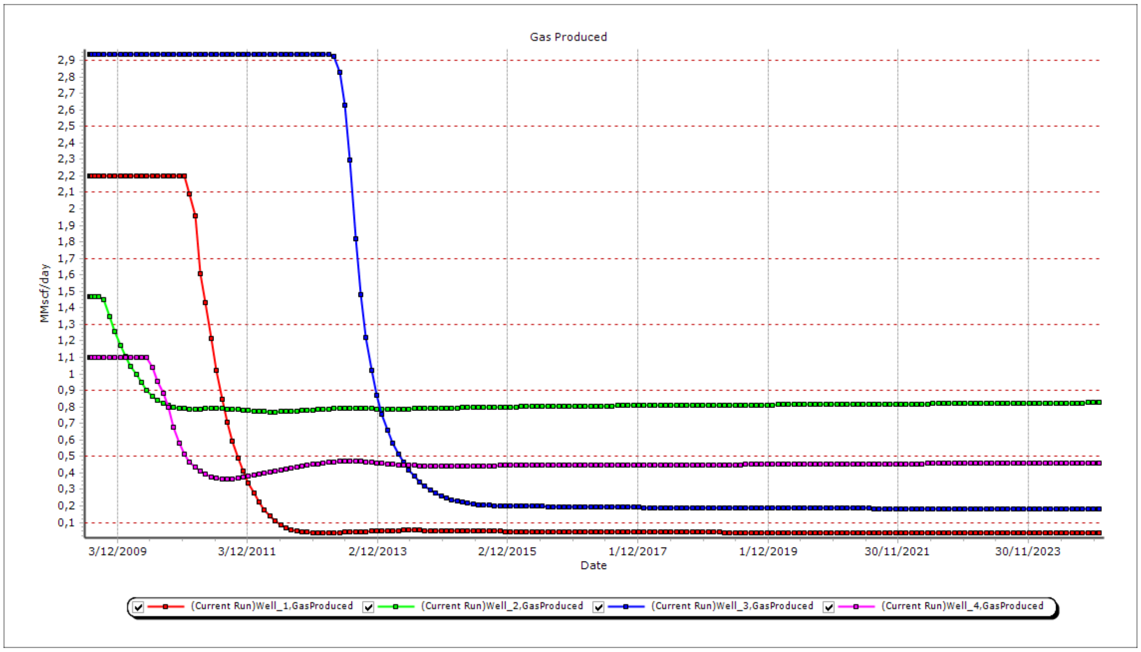


Figure 23: *Gas production of all the four wells before gas lift implementation.*

Since the gas injected will come from the combined production of well 2, 3 and 4, it is necessary to obtain numeric values for this production. Exporting the Gas Production data from the Reservoir Model in REVEAL, it is possible to observe that from the 197 steps of the simulation, the lowest combined production is registered in November of 2015 (1,44404 MMscf).

Well 2		Well 3		Well 4		Total
Date	Production	Date	Production	Date	Production	
18-11-2015	0,79965	18-11-2015	0,19943	18-11-2015	0,44496	1,44404

Table 18: *Minimum achieved gas production from all the wells.*

This information allows to set the “Maximum Gas Available” in 1,4 MMscf, since is guaranteed that in any other time step the available gas will be more than the value for the 18 of November of 2015.

Input Parameters:

- Flowing Top Node Pressure & Unloading Top Node Pressure: As described in the well design, it will be set at 500 psig.
- Operating Injection Pressure & Kick Off Injection Pressure: 2500 psig. PROSPER may modify this value during the process of design to optimize the model.
- Desired dP Across Valve: 150 psi.
- Maximum Depth of Injection: 9,000 feet.
- Water Cut: 99 percent.

- Minimum Spacing: 200 feet.
- Static Gradient of Load Fluid: 0.45 psi/ft. The Water Cut of the fluid has reached a value of 98%, the well is basically producing water.
- Minimum Transfer dP: 25 percent.
- Safety for Closure of Last Unloading Valve: 0 psi.
- Total GOR: 734 scf/STB.
- Valve Settings: All Valves PVo = Gas Pressure.
- Dome Pressure Correction Above 1,200 psig: Yes.
- Valve Spacing Method: Normal.
- Check Rate Conformance with IPR: No.
- Surface Pipe Correlation: Beggs and Brill.
- Use IPR for Unloading: No.
- Orifice Sizing On: Calculated dP @ Orifice.

For the Valve Type, the same one selected in the Tutorials will be selected (Camco R-20 Normal). With the input data already provided, we move to the Design Menu (Button "Next") and click on "Design". PROSPER at this point will proceed to perform calculations according to the data provided, to determine the necessary gas injection, as well as the number of valves and depth for these valves. Is possible that the program will suggest modifications in some of the parameters, this to meet in a better way with the requirements. Fortunately, the data provided to PROSPER for the calculations has provided satisfactory results, obtaining a design for the Gas Lift System on the first attempt (Figure 24).

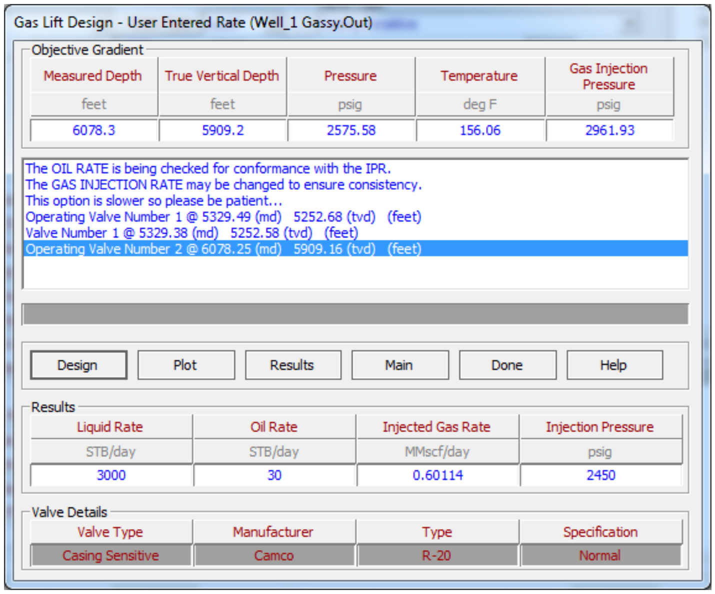


Figure 24: *Command window in PROSPER software with gas lift design results.*

<u>*GOR influence*</u>

By inserting gas through the valves, the flow density gets lower. Since the mixture becomes lighter, the hydrostatic pressure will decrease and therefore the liquid becomes easier to bring to surface. It is possible to make a quick evaluation of how much gas it is required to inject by "playing" with different values of GOR until a favorable Traverse Pressure Gradient is found.

Also, the amount of gas that can be produced per amount of oil that can be produced (GOR) increase through gas lift injection. The influence of gas lift on GOR values and pressure distribution for different depths is presented in Figure 25.

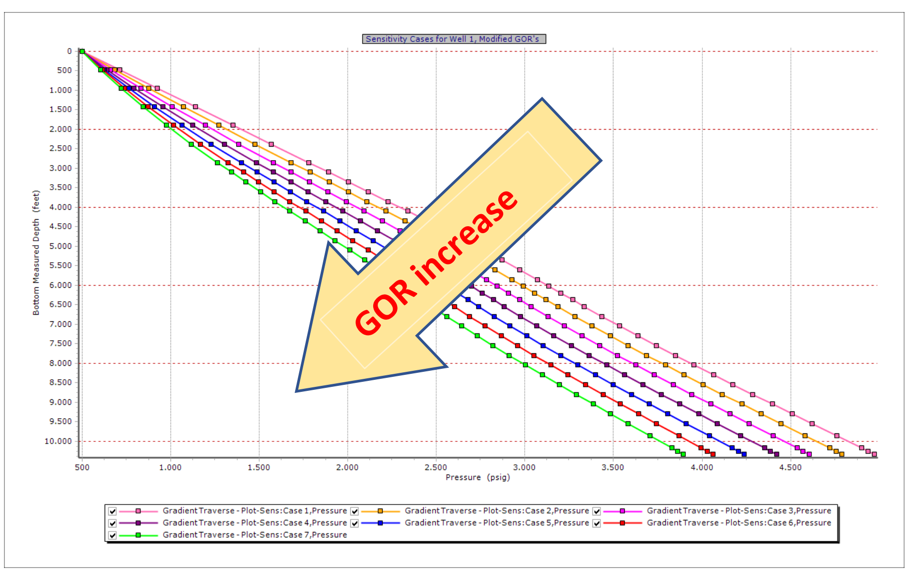


Figure 25: *Sensitivity analysis of GOR and gas lift implementation on Well 1.*

Oil Saturation progress

The gas injection is draining the oil from the reservoir and this can be expressed with the reduction of the oil saturation in time, during the production.

It can be observed that small change of the oil saturation occurs after the middle of production. The reservoir reaches depletion from the left frontiers gradually to the right. After 2,460 days approximately the "active" productive layers of the reservoir are concentrated to the right side of the reservoir, close to the wells 2, 3 and 4.

In Figure 26 is represented the oil saturation progressive change (decrease) at different stages of production.

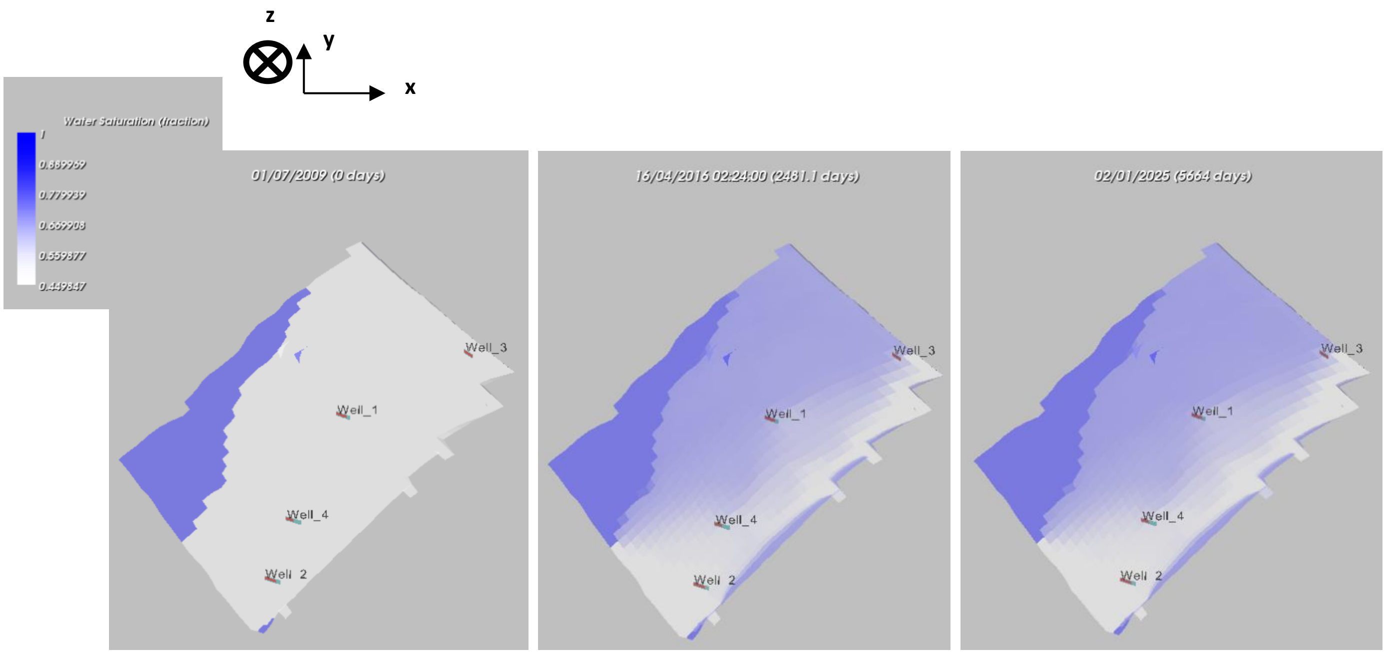
1st day of production | Middle of production | Last day of production

Figure 26: *Oil saturation during production when gas lift is applied.*

Water Saturation progress

The water saturation during production is also an indicator of the gas injection impact. The indications are the opposite of the oil saturation, meaning that the water presence dominates of the oil's one, as the production continues. The water saturation increase in the spots of oil saturation decrease is a desirable result, because it means that the existed oil has been replaced and produced.

In Figure 27 is represented the water saturation progressive change (increase) at different stages of production.



1st day of production *Middle of production* *Last day of production*

Figure 27: Water saturation during production when gas lift is applied.

6. Results of gas lift implementation

The Pressure vs Depth (PvD) plot represents the gas lift influence on the flow. More specifically it shows the change in pressure gradient for all the depths from the bottom hole up to the wellhead. Gas injection is responsible for the change of the mixture's density and so for the pressure gradient and the slope of the plot. For depths between the injection point and the bottom-hole, the pressure-depth plot is sharper and the slope is smaller. Small slope indicates that larger pressure difference occurs for a specific depth difference. Physically this is related to the increased mixture's density for depths greater than the injection point. However, the small slope means that the flow must overcome greater pressure difference to

reach shallower depths, so that to enable the flow to reach the surface in case of very small slope. The theoretical interpretation meets the actual conditions. In Figure 28, the blue line represents the pressure distribution for different depths up to the bottom-hole. At the injection point the slope changes because for depths greater than the injection point the mixture is denser, since no gas is added. Consequently, the pressure gradient will be smaller and the slope will be sharper, indicating that large pressure drive is needed to avoid liquid loading.

For points closer to the surface than the injection point, the oil is mixed with the injected gas, resulting in reduced mixture's density and this enables the flow towards the surface.

The total number of stages for the Gas Lift System is two, and even when the it was given the option of placing them up to a depth of 9000 feet, the valves are suggested to be installed at measured depths of 5329 and 6078 feet. Since figure 28 is built with the True Vertical Depths as input parameter, it shows the location of the valves at shallower depths.

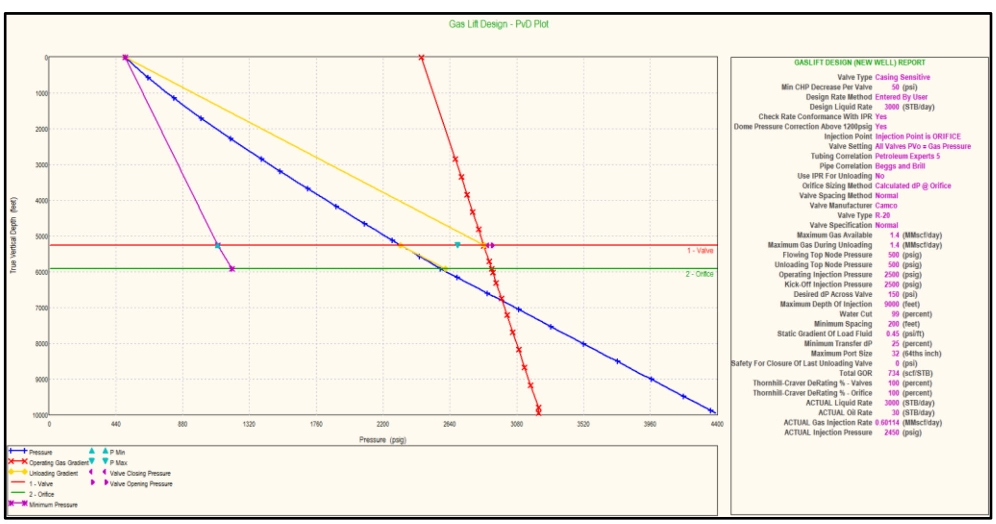


Figure 28: *Gas lift design PvD plot.*

7. Conclusions

After doing the design of the wells, evaluating them and designing an Artificial Lift System for one of the wells, it is important to evaluate how useful are the efforts applied, especially when we take in consideration the fact that the implementation of an Artificial Lift System involves an important investment.

The design of wells and the Gas Lift System have the purpose of delivering to the surface the requested production, no evaluation or optimization has been performed on them and it is necessary to look to the expected production of the field (Table 19).

Well	End of Plateau (EoP)	Oil Production until EoP (bbl)	O.P. from EoP until End of Simulation (bbl)	Total Production (bbl)	Percentage of Production
3	mar-12	3.960.000	1.377.000	5.337.000	31%
1	dic-10	1.710.000	151.200	1.861.200	11%
2	sept-09	120.000	6.039.000	6.159.000	36%
4	jun-10	540.000	3.132.000	3.672.000	22%

Table 19: Estimated Oil Production for the field. Self-elaborated.

As we can see, the efforts of applying an Artificial Lift System have been directed to a Well that during the production life that follows the plateau will produce less than a 10% percent of what it produced during the plateau stage. Even more, the total production of Well N°1 represents only an 11% of the total production of the field. More surprising is the fact that Well N°2, which has been designed with one of the 2 lower Production Rates, is the one that at the end of the production time has contributed the most to the total (36 percent). Extending this even more, the Total Production expected is 17.029.200 bbl, from which the production of Well N°1 after the Plateau represents less than a 1%.

Apart from the evaluation process of the work done, it is important to mention the usefulness of the software employed in the process of designing wells and artificial lift systems. However, it is worth to mention that the process of designing, even with the help provided by the software packages it is not possible without the background knowledge. Both PROSPER and REVEAL, prove to be amazing tools, with a variety of options which allow to perform work that goes far beyond the extension of the one done here.

8. Recommendations for further study

Beyond the extent of the specific study but in its radius of interest, the following further subjects are proposed for further investigation:

- Performance analysis between gas and steam injection.
- Sensitivity analysis by artificial networks for the different flow parameters that influence the gas lift design (flow velocity, shear rates, tubing diameter, etc.).
- Design of the compressor that is acting as an energy source for the gas lift procedure. A compressor is used to increase (compress) the pressure of the injected gas and its operation is energy consuming and has a significant cost. Consequently, an important aspect of its design is the optimization of its design to achieve efficient and profitable operation [9].
- Impacts of injection gas fluid properties.
- Implementation of Enhanced Oil Recovery Mechanisms to improve the production from the reservoir.

9. Bibliography

[1] "Enhanced Oil Recovery (EOR) Summary," [Online]. Available: http://www.scmdaleel.com/category/enhanced-oil-recovery-eor-summary/164. [Accessed 01 04 2017].

[2] A. H. T. N. A. G. Z. M. E. A. Saleem Qadir Tunio, "Comparison of Different Enhanced Oil Recovery Techniques for Better Oil Productivity," *International Journal of Applied Science and Technology,* vol. 1, no. 5, pp. 143-153, September 2011.

[3] "Oil Recovery Overview," MidCon Energy, [Online]. Available: http://www.midconenergypartners.com/oil-recovery-overview.php. [Accessed 10 5 2017].

[4] "Frost & Sullivan," 17 7 2016. [Online]. Available: https://ww2.frost.com/frost-perspectives/global-artificial-lifts-market-can-it-survive-through-global-oil-price-slump/. [Accessed 17 04 2017].

[5] 2. 3. A. I. G.-L. Workshop, "2016 39th Annual International Gas-Lift Workshop," 19-20 05 2016. [Online]. Available: http://alrdc.org/workshops/2016_2016gasliftworkshop/. [Accessed 17 04 2017].

[6] W. C. L. A. G. Boyun Guo, Petroleum Production Engineering: A Computer-Assisted Approach, Elsevier, 2007.

[7] "What is a Mature Field?," Halliburton, [Online]. Available: http://halliburtonblog.com/what-is-a-mature-field/. [Accessed 2 5 2017].

[8] "Artificial Lift Systems and The 5 P's," Halliburton, [Online]. Available: http://halliburtonblog.com/artificial-lift-and-the-5-ps/. [Accessed 2 5 2017].

[9] James F. Lea and Henry V. Nickens-Amoco EPTG/RPM, "Selection of Artificial Lift," in *SPE Mid-Continent Operations*, Oklahoma, 1999.

[10] Prof. Tom Aage Jelmert, Nan Chang, Lars Høier. Sultan Pwaga, Collins Iluore, Øystein Hundseth, Federico Juárez Perales, Muhammad Usman Idrees, "Comparative Study of Different EOR Methods," Trondheim, 2010.

[11] A. D. H. C. E.-E. Michael J. Economides, Petroleum Production Systems, Prentice Hall PTR, 2009.

[12] Henri Cholet, Technip, Well Production Practical Handbook, Paris: Institute Francais du Petrole, 2000.

[13] "Directional Drilling," Vailant Energy Services, [Online]. Available: http://www.valiantenergy.ca/services-2/. [Accessed 6 5 2017].

[14] Schlumberger, Gas Lift Design and Technology, 2000.

[15] H. W. University, Production Technology, Heriot Watt University , 2011.