Improve Oil Production in Amal Field by gas lift Optimization

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الملخص:

إن آبار النفط التي لا يكون فيها ضغط المكمن كافياً لرفع النفط إلى السطح تحتاج إلى تطبيق إحدى تقنيات الرفع الصناعي لإتمام عملية الإنتاج. وفي بعض الأحيان يكون التدخل ضروري من بداية الإنتاج بينما في أغلب الأحيان يكون التدخل بتطبيق إحدى طرق الرفع الصناعي بعدد فترة من بداية الإنتاج. ومن أشهر طرق الرفع الصناعي التي تهدف لزيادة الإنتاجية هي طريقة الرفع بالغاز، و التي تعتمد أساساً على حقن الغاز داخل البئر لتقليل متوسط الكثافة للسائل داخل البئر، وبالتالي تقليل وزن عمود السائل داخل البئر مما يمكن ضغط المكمن من إيصال السائل للسطح.

في هذا البحث تم تحديد ثلاثة آبار في حقل آمال هي (N-36, N-18, N-53) والتي تعاني من انخفاض معدل إنتاج النفط بسبب ازدياد نسبة المياه واختيارها لإعداد تصميم مناسب لتقنية الرفع بالغاز باستخدام برنامج (Prosper).

تم توضيح خطوات التصميم باستخدام (Prosper Software) بالتفصيل، و تم الحصول على عدد الصمامات المطلوبة لرفع النفط وأعماقها و المسافة بينها. بالإضافة إلى ذلك، تم تحديد كمية الغاز اليومية المطلوب حقنها من خلال هذه الصمامات من البئر إلى داخل أنبوب الإنتاج.

أخيراً، تم استنتاج ورسم منحنيات علاقة أدائية التدفق الداخل مع أدائية الرفع العمودي، قبل وبعد عملية تصميم الرفع بالغاز وتبين وجود زيادة في الإنتاجية.

Abstract:

Wells that cannot produce liquids to the surface under their own pressure requires lift technologies to enable production. Some liquid wells need lift assistance from the beginning and almost all require it sooner or later.

One of the most popular artificial lift methods applied in the oil industry, in order to increase productivity, is the gas lift method. Its main principal is the injection of gas in the well to reduce the average density of the fluids produced from the reservoir, hence the weight of the fluid column. As a result, the declined reservoir pressure is sufficient to lift the fluids up to the surface.

In this project three wells, (N-36, N-18 and N-53), located in Amal field are selected for the study. The production for all wells is dropping due to increasing water production. Therefore, the main task in this study is to design a gas lift system for these wells by using Prosper software. The procedure of designing an optimized gas lift system in PROSPER is thoroughly described in this study.

In the design performed by Prosper, the main points obtained and determined are number of gas lift valves needed to lift the wells up, also the depth of these valves distributed through the tubing and space between valves. In addition to this, the amount of gas injected daily through these valves from casing to tubing.

Finally, Inflow performance relationship versus vertical lift performance curves for these wells are determined before and after gas lift design as indication of increasing productivity.

1. Introduction:

In the petroleum industry one of the major objectives is to maximize and/or prolong the oil production within the technical and financial limits existent. To ensure that the aim is reached many technologies such as artificial lift has been developed.

Production of well fluids is a function of natural driving mechanisms in the reservoir; however as well fluid production increases over time, natural driving mechanisms decrease which consequently impedes the natural economic production rate of hydrocarbon and profitability of the asset (Abdalsadig et al., 2016; Yakoot et al., 2014). As a result, there is a need to assist the primary production of hydrocarbons from the reservoir using artificial lift mechanisms or pressure maintenance systems to prolong the life of the well and economic value of the asset. These artificial lift mechanisms induce a pressure differential in fluid column in the well and production tubings, increase production pressure drawdown, reduce bottomhole pressure and ultimately facilitate improved production of well fluids; this is achievable by addition of external energy to the fluid that aids its production at the surface (Ghazali et al., 2014).

Gas lift is one of the most common artificial lift methods which used widely in oil production process, during the lift process; gas is injected into the tubing. Gas injection will lighten the fluid column along the tubing, so it will increase oil production. Normally oil production increases as gas injection increases. However, the gas injection has an optimum limit because too much gas injection will cause slippage, where gas phase moves faster than liquid, so that it reduces oil production.

About 98% of artificial lift mechanisms for improved production of crude oil are driven by gas-lift mechanism (Silverwell, 2016; Shokir et al., 2017). The mechanism behind gas lift entails two modes of operations – continuous-flow and intermittent flow (Vol et al., 2015; Shedid and Yakoot, 2013; Hamshary et al., 2015). Continuous-flow gas lift involves the injection of small volumes of highpressure gas into wells with high Productivity Index (PI) of > 0.5BD/psi, high basic static pressure and Gas-Liquid Ratio (GLR) of up to 2000 scf/bbl while intermittent gas lift involves the injection of large volumes of gas into an accumulated slug for a short time to move the liquid slug to the surface (Abdalsadig et al., 2016). Regarded as the only artificial lift mechanism that utilizes primary energy in the reservoir, continuous-flow gas lift mechanism supplements the primary flow of well fluids to the surface by addition of high-pressure gas at a maximum depth from an external source (Shedid and Yakoot, 2013; Hamshary et al., 2015). Successful implementation of the gas lift mechanism is influenced by different parameters such as injection depth, injection rate, valves spacing, wellhead pressure, reservoir pressure, water cut, PI, Gas-Oil Ratio (GOR), the performance of gas lift valve, gas gravity, and production tubing size (Abdalsadig et al., 2016). Amongst these parameters, the optimum injection rate has been identified to be highly critical in optimizing continuous-flow gas lift mechanism for improved well fluid production; this is because the over-injection of gas results in a decrease in well fluid production as slippage between liquid and gas phase is facilitated (Ebrahimi, 2010). Therefore, it becomes imperative to determine an optimum gas injection rate as the volume of gas injected is not directly.

Proportional to recovered well fluids. Also, gas gravity, water cut, injection rate, and wellhead pressure have been highlighted as critical parameters that affect the efficiency of continuous-flow gas lift mechanism for improved well fluid productivity (Blann and Williams, 1984). Gas lift optimization is a complex process that involves establishing an optimal distribution of gas to a network of wells and pipelines for improved well fluid production. This process entails an uninterrupted process of improvement that generates the need to optimize scenarios of production with recent production data (Shedid and Yakoot, 2013). Different methods such as Sequential Quadratic

Programming (SQP), Augment Lagrangian Models (ALM), stochastic solvers such as Genetic Algorithm (GA), etc. exist for optimization of gas lift mechanism; however, nodal analysis is the technique used in the study. Nodal analysis is a systematic method of improving well fluid production by evaluating each section of the production system to optimize process parameters such as flow rates, production tubing string, horizontal flow lines, well completion, and separation facilities (Kisson et al., 2012). Integrated simulation models have been reported suitable for production field management; computer applications have proved highly useful in using these models for production optimization processes (Shedid and Yakoot, 2013)

The main task of this study is to design a gas lift system in an oil well when the reservoir pressure will be insufficient to support economically viable production.

2. Method

The data of three wells is collected from the company. The data consists of reservoir data, surface data, and Prosper is utilized to perform IPR and VLP graph drawing and analysis. Then, gas lift valves depth is calculated by Prosper. Prosper is utilized to design gas lift valves by iteration calculation to find optimum oil production rate, gas injection rate, gas injection pressure, and valves depth,

3. Objective of Study

The aim of the study is to conduct gas lift design using Prosper software on three of Amal field belongs to Harouge Oil Operation. The names of these wells, selected for this study, are N-36, N-53 and N-18, and the main objectives are:

- Reducing the weight of the column of fluid in the tubing so that the bottomhole pressure of the well is adequate to lift the column and to overcome the resistance of the tubing, pipes and connections. Hence, increase production rates in flowing wells.
- To determine the best amount of gas to be injected to give the best result of oil production.
- Determine the number of gas lift valves to unload the wells selected for this study, and depth of theses valves plus their port sizes.

4. Reservoir – Amal “N”

The northern-and the northeastern part of Amal Field are designated as Amal "N" reservoir, which encloses an area of 48,000 acres.

Oil recovery mechanism of Amal "N" reservoir is edge and bottom water drive. The average reservoir pressure is being maintained at around 3180 psi by active edge-bottom water drive. Pressure sink has developed in the high productive low water influx northwestern part of the reservoir and water injection in this area may improve recovery and production rates.

Table (1) Reservoir Amal "N" Parameters

Reservoir Parameters:	
Area	48,000 (acres)
Net thickness	37 (feet)
Current oil saturation	56.1 (percent)
Porosity	18 (percent)
Permeability	31 (md)
Original formation volume factor	1.393 (rb/stb)
Original gas in solution	588 (bcf/stb)
Oil viscosity	0.635 (cp)
Oil gravity	37 (deg. API)
Reservoir temperature	240 (deg. f.)
Initial	4690 psia
Latest Ps	3139 psia
Bubble point Pb	2180 psia

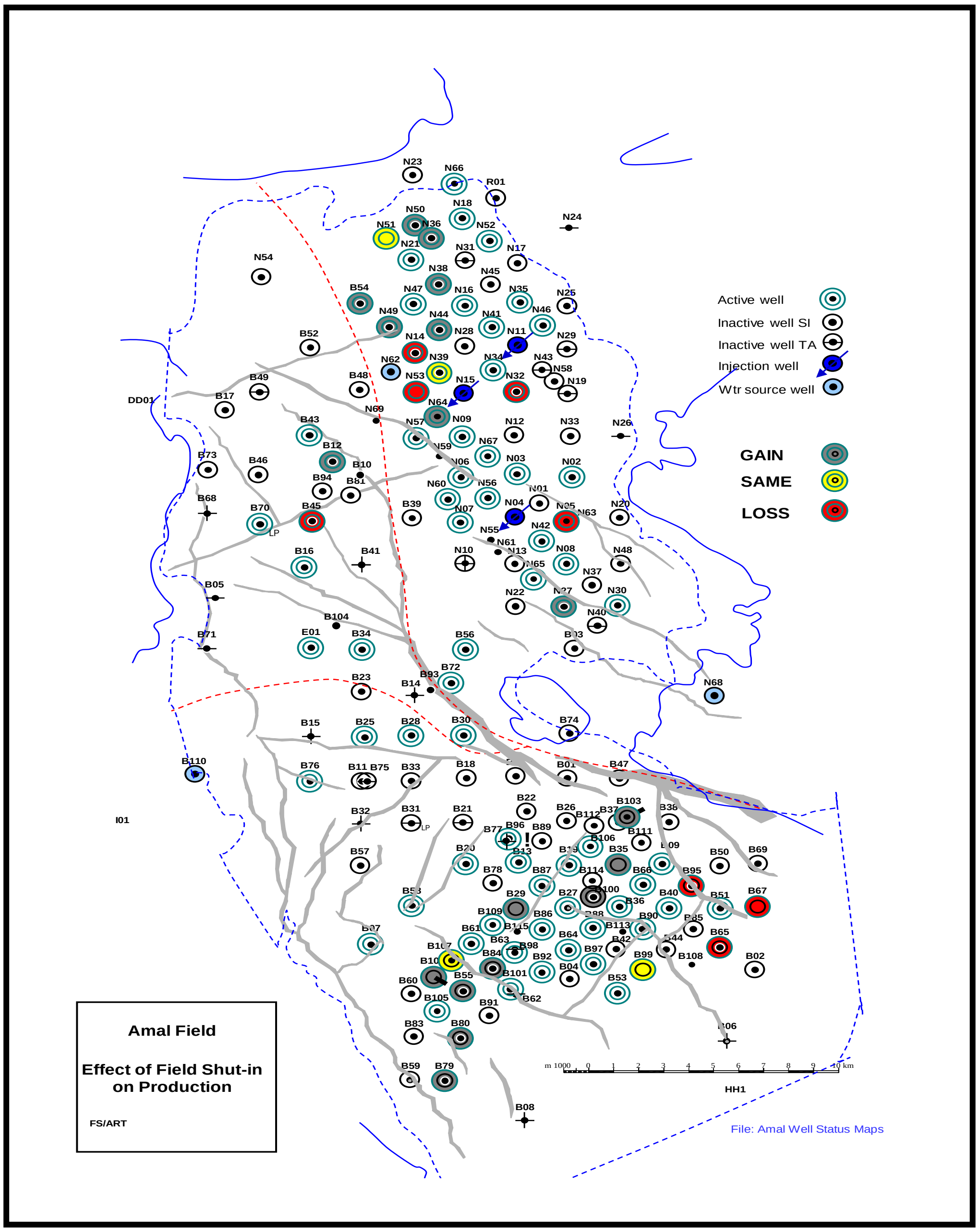
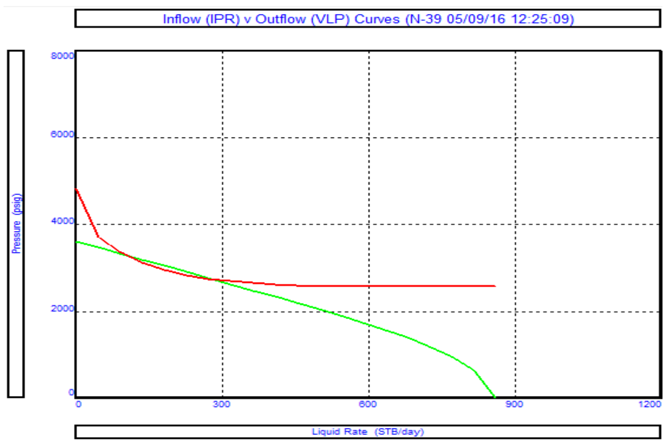

Active well
Inactive well SI
Inactive well TA
Injection well
Wtr source well
GAIN
SAME
LOSS
Amal Field
Effect of Field Shut-in on Production
FS/ART
File: Amal Well Status Maps

Figure (1) IPR curve for N-39 before applying Prosper

5.1 Inflow (IPR) vs out flow (VLP) curves for N-39 well:

Below figure (1) indicate the Inflow Performance curve vs out flow Relationship for well N39 which describes pressure drawdown as a function of production rate,



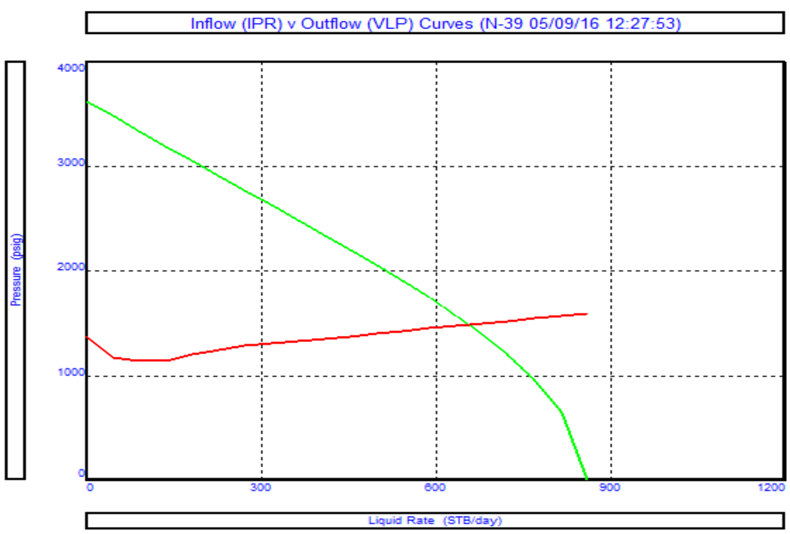


Figure (2) Inflow vs. Outflow Curves by Prosper Software gas lift for N-39

Input parameters in PROSPER gives a production profile, with no artificial lift in illustrated in fig (1). This well N-39 still have some production, which reflect that there is minimum pressure support from drive mechanism allow it to produce. However, the well must be considered as dead because any further production increase. After implementing Prosper softer and have noticeable increase in oil production and lifting the well point in May 2010, which can be seen by intersection between the VLP and IPR curve.

5.2 Inflow (IPR) vs out flow (VLP) curves for N-53 & N-18 wells:

Figure (3& 5) indicate IPR vs VLP for well N-53 & N-18, and these wells are not produce naturally as shown because VLP does not intersect with IPR. By introducing gas lift design using Prosper, optimum rate is obtained as in fig (4 & 6)

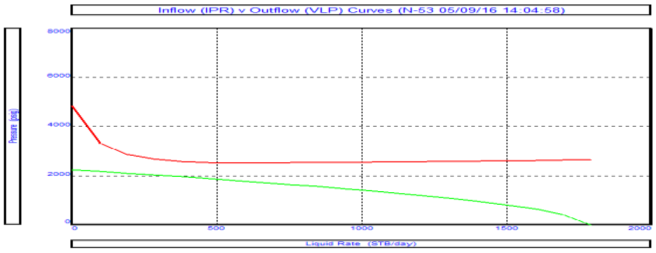


Figure (3) IPR curve for N-53 before applying Prosper

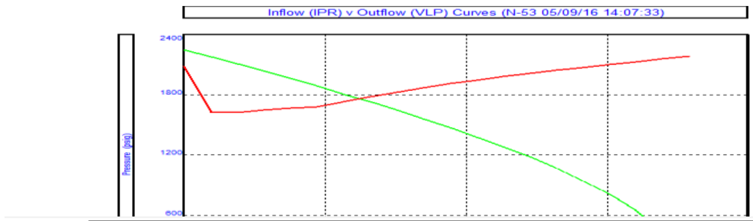


Figure (4) IPR curve for N-53 After applying Prosper

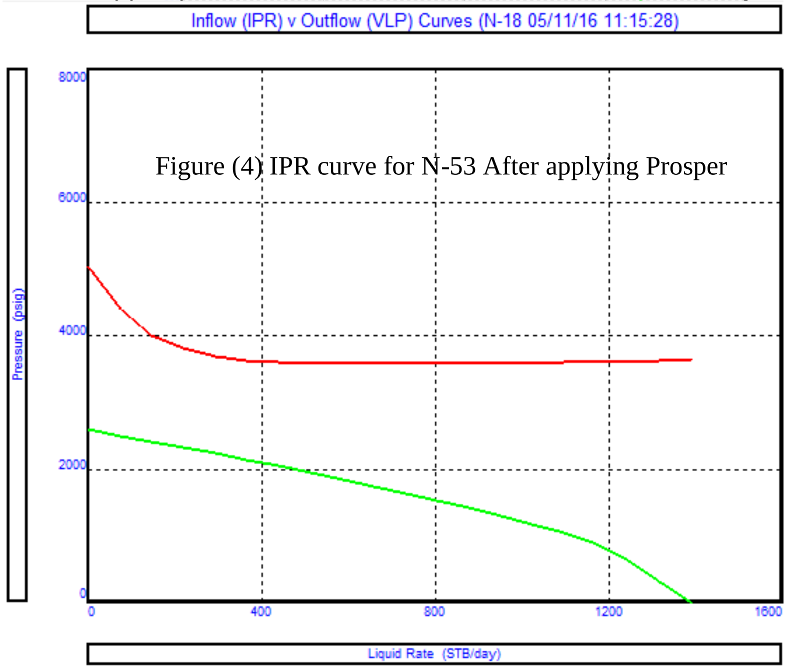


Figure (5) IPR curve for N-53 before applying Prosper

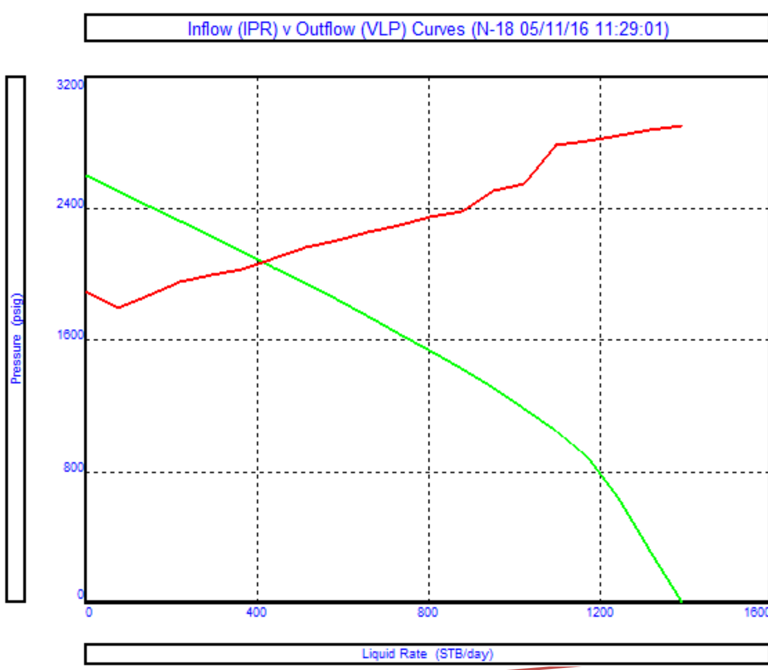


Figure (6) IPR curve for N-53 After applying Prosper

6. Gas Lift Performance Curve for N-39, N-53 and N-18

Through using PROSPER simulator different injection rate of the lifting gas can be analyzed in fig (7 &8). By looking at figure 7, the trend of the line is remaining constant when gas is injected at a rate higher than 0.5 MMscf/day, thus 0.9 MMscf/day is the maximum sensitivity of the well. However, this rate should be avoided, because only pressure will increase and probably more gas will be produced than liquid.

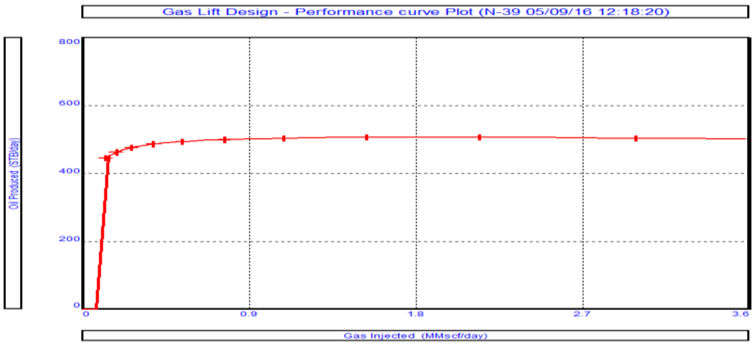


Figure (7) Gas Lift Performance for N-39

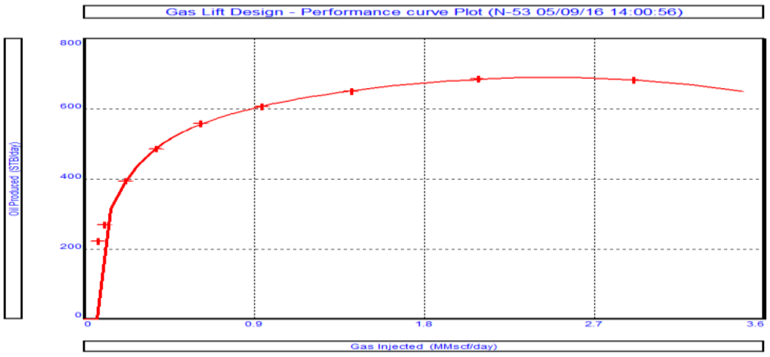


Figure (8) Gas Lift Performance for N-53

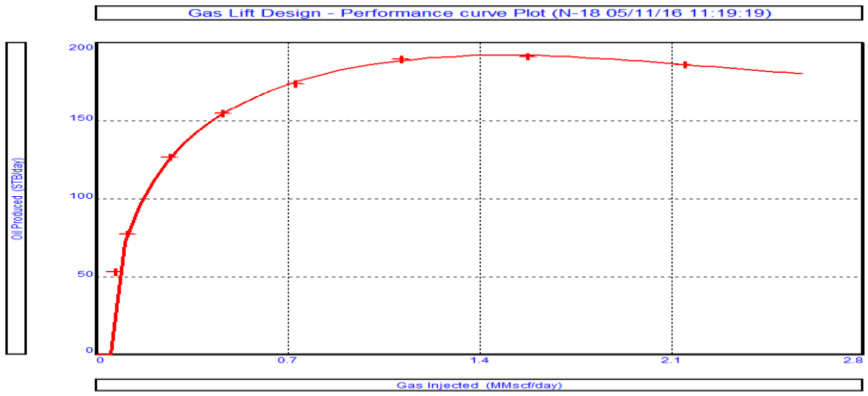


Figure (9) Gas Lift Performance for N-18

In figure 8, for well N-53, injection rate applied for this well shown clearly that any injection rate more than 1.9 MMscf/day will not change the liquid rate (oil rate specifically) rather than increasing the pressure.

By amount of 1.9 MMcf/day Gas injection, oil production from well N-53 will be increased up to 600 STB/day. When the amount of injected gas reaches 2.0 MMscf/day, oil production reaches its peak at 750 STB/day. By increasing amount of gas injection, it has small effect on oil production that it's the characteristic point called Economical Optimum Point. This optimum rate is renowned as over injection.

Maximum amount of production rate should be avoided to reduce the probability of killing the well. Nevertheless, the economical amount of injection rate can be indicated in fig (8) at 1.9 MMscf/day approx touched sustainable production system.

As the rate of injection gas increases, friction force has more predominant effect than hydrostatic pressure reduction. At this point, the maximum amount of well production rate can be achieved. By increasing gas pressure, effect of gas injection on production decreases until in a special injection rate, that is if the gas injection rate increases, the effect on production will be inversed.

The figure (9) indicates that at low injection rate at well N-18, any increase in the gas volume increases the well's liquid output. As injection rates increase, the rate of liquid volume increase falls off and the maximum possible liquid rate is reached. After this maximum any additional gas injection decreases the liquid production. In this region of high gas injection rates, multiphase flow in the tubing is dominated by frictional effects. Consequently, bottom-hole pressure starts to increase and liquid inflow to the well diminishes

7. Positioning of valves for wells N-39, N-18 and N-53:

The Pressure versus Depth plot is given in the following figure (10). Positioning of the valves, valves opening and closing pressures and the flowing pressure gradient in the tubing are visible. Gas injection pressure is now sufficient to displace all annular fluids down to 10,000’. Depth of gas lift valves is determined by design gas lift using Prosper software, and depth of each valve is shown in figures below.

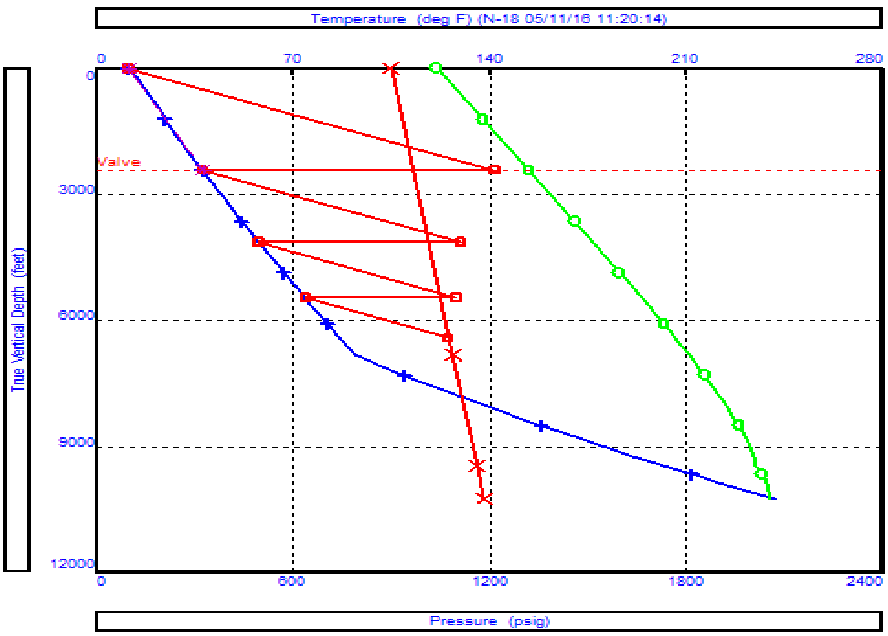


Figure (10) Valves positioning for N-18

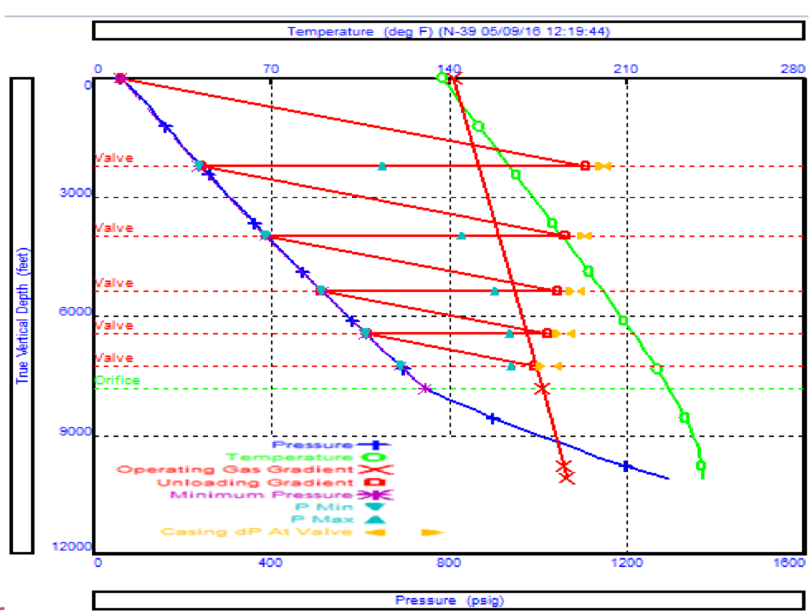


Figure (11) Valves positioning for N-39

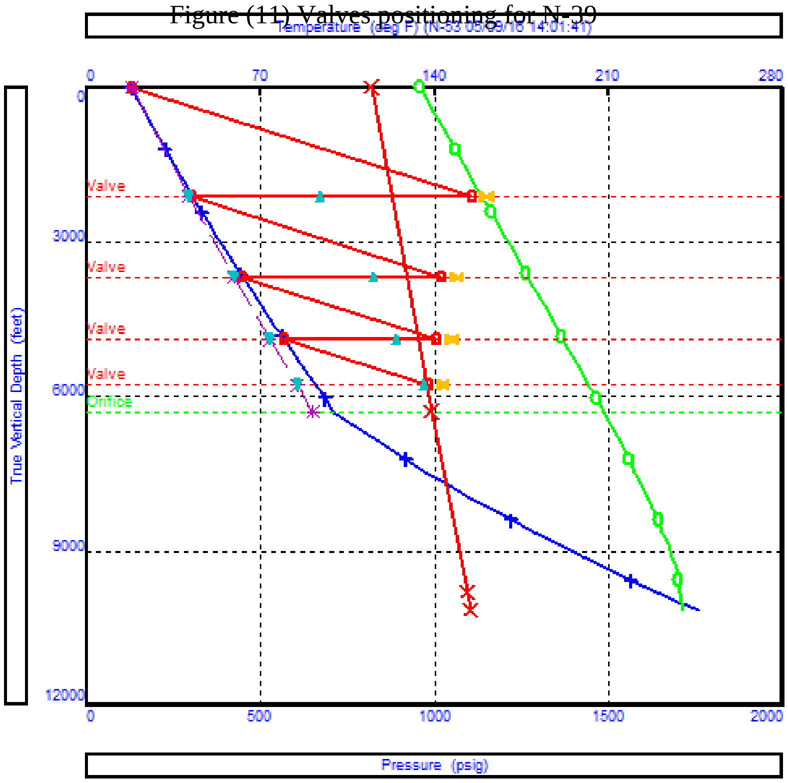


Figure (12) Valves positioning for N-53

Conclusions:

- Continuous gas lift installation is proper solution to lift the well N-18 due to higher water cut in this well at 69% which in turn increasing Pwf to approach nearly reservoir pressure.
- At N-39 well, any gas injection rate higher than 0.5 MMscf/day, will have no effect on increase production rate.
- 0.9 MMscf/day is the maximum sensitivity of the N-39 Well.
- For N-53 well, any injection rate more than 1.9 MMscf/day will not change the liquid rate (oil rate specifically) rather than increasing the pressure.
- For N-53 well, by amount of 1.9 MMcf/day Gas injection, oil production will be increased up to 600 STB/day.
- Optimum gas injection rate for well N-18 is 1 MMscf/day, and any further gas injection will reduce oil production rate due to increasing frictional force and mobility of gas faster than oil in tubing.
- Only five valves, as result of gas lift design by Prosper, are needed to unloading wells selected for this study (N-39, N-18 and N-53) with injection depth close in value for all wells.

Recommendations:

- Avoid exceeding economic optimum gas injection rate, because it has only negative impact on production.
- It is highly recommended to conduct sensitivity study for these wells to observe the optimum flow rate when GLR, injection depth and water cut are changed.

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APPENDIX

Table 1: PVT Data of the Reservoir Fluid

Parameters	Quantity	Units
Solution GOR	212	scf/stb
Oil Gravity (API)°	34	API
Gas Gravity	0	-
Water Salinity	0	ppm
Gas Impurities	0	%
Bubble Point Pressure at MD temperature	950	psig
Oil FVF at MD Temperature and Pressure	1.138	stb/bbl
Oil Viscosity	1.34	cp

Table 2: IPR Data

Parameters	Quantity	Units
Reservoir Pressure	1200	psig
Reservoir Temperature	160	°F
Water Cut	15	%
Total GOR	237	scf/stb

Table 3: Downhole Data

Measured Depth (MD)	True vertical Depth (TVD)
ft	ft
0	0
1670	1670

Table4: Downhole Equipment

Well Name	Tubing Dimensions		Casing Dimensions		Total Depth
	ID (inches)	Depth (ft RTKB)	ID (inches)	Depth (ft RTKB)	(ft RTKB)
JAF	3.5	950	7.00	990	1670

Table5: Well Test Data

Test Type	BHCIP	BHFP	Pressure Differential	Rate	Productivity Index (PI)	Water Cut
	pisg	pisg	pisg	bopd	stb/day/psi	percent
Production	1169	1010	159	1700	9	15

Table (6) production and well data for well N-36

Liquid flow rate	600 stb/day
Water cut	28 %
Total GOR	588 scf/stb
PI	0.32 stb/day/psi
Gas Specific Gravity	0.83 scf/stb
Water salinity	190000 ppm
Casing (OD)	7" @ 10110'
Tubing (OD)	3.5" @ 9972'

Mid perforation	10065'
Tubing head pressure	60 psig
Flowing head temperature	110 ºF
Bottom hole flowing temperature	240 ºF
Bottom hole flowing pressure	1745 psig
Static bottom hole pressure	3620 psig
Operating or Casing injection pressure	1060 psig
Kick off injection pressure	1100 psig
Kill fluid gradient	0.47 psi/ft
Available gas	5 MMscf/day

Table (7) design results N-36

Valve number	Valve type	Measured depth *(feet)*	Tubing pressure *(psig)*	Casing pressure *(psig)*	Tempe. *(ºF)*	Port size *(64ths")*	Valve opening pressure *(psig)*	Valve closing pressure *(psig)*
1	RD	2226.5	242.71	1156.45	163.69	8	1156.45	1140.91
2	RMI-2	3966.6	389.24	1110.56	184.26	8	1110.56	1098.30
3	RMI-2	5363.6	513.61	1095.99	200.50	12	1095.99	1073.86
4	RMI-2	6448.8	614.12	1073.49	212.66	16	1073.49	1043.17
5	RMI-2	7257.0	691.20	1043.98	221.22	20	1043.98	1007.65
6	RDO	7818.5	746.52	1007.49	226.58	21		

General Information

Country	Libya
Company	**Harouge Oil Operations**
Basin	**Sirte**
Field	**Amal**
Reservoir	**Maragh**
Well Name	**N-53**

Well Type	**Oil Producer (Vertical)**

Table (8) production and well data for well N-53

Liquid flow rate	1400stb/day
Water cut	32%
Total GOR	588 scf/stb
PI	1.35stb/day/psi
Gas Specific Gravity	0.83 scf/stb
Water salinity	190000 ppm
Casing (OD)	7"@ 10152'
Tubing (OD)	3.5"@ 9800'
Mid perforation	10090'
Tubing head pressure	130 psig
Flowing head temperature	120 ºF
Bottom hole flowing temperature	240 ºF
Bottom hole flowing pressure	1211psig
Static bottom hole pressure	2248 psig
Operating or Casing injection pressure	1020 psig
Kick off injection pressure	1100 psig
Kill fluid gradient	0.46 psi/ft
Available gas	5 MMscf/day

Table (9) Valve spacing, opening and closing pressure for well N-53

Valve number	Valve type	Measured depth *(feet)*	Tubing pressure *(psig)*	Casing pressure *(psig)*	Tempe. *(ºF)*	Port size *(64ths")*	Valve opening pressure *(psig)*	Valve closing pressure *(psig)*
1	RD	2128.1	306.91	1158.91	159.37	8	1158.91	1144.42
2	RMI-2	3682.4	449.88	1071.93	177.69	8	1071.93	1061.36

3	RMI-2	4890.0	568.15	1055.36	191.85	8	1055.36	1047.08
4	RMI-2	5785.6	659.18	1030.15	202.22	8	1030.15	1023.85
5	RDO	6286.5	711.19	1044.02	207.94	14		

General Information

Country	Libya
Company	**Harouge Oil Operations**
Basin	**Sirte**
Field	**Amal**
Reservoir	**Maragh**
Well Name	**N-18**
Well Type	**Oil Producer (Vertical)**

Table (10) production and well data for well N-18

Liquid flow rate	900 stb/day
Water cut	69 %
Total GOR	588 scf/stb
PI	0.8 stb/day/psi
Gas Specific Gravity	0.83 scf/stb
Water salinity	190000 ppm
Casing (OD)	7" @ 10314'
Tubing (OD)	2.75" @ 9461'
Mid perforation	10235'
Tubing head pressure	100 psig
Flowing head temperature	102 ºF
Bottom hole flowing temperature	240 ºF
Bottom hole flowing pressure	1475 psig
Static bottom hole pressure	2600psig
Operating or Casing injection pressure	1100 psig

Kick off injection pressure	1200 psig
Kill fluid gradient	0.46 psi/ft
Available gas	5 MMscf/day

Table (11) design results N-39

Valve number	Valve type	Measured depth (feet)	Tubing pressure (psig)	Casing pressure (psig)	Tempe. (ºF)	Port size (64ths")	Valve opening pressure (psig)	Valve closing pressure (psig)
1	RD	2428.2	324.65	1266.97	154.10	8	1266.97	1250.95
2	RMI-2	4144.9	496.68	1164.32	177.00	8	1164.32	1152.97
3	RMI-2	5457.6	636.44	1150.52	194.18	8	1150.52	1141.78
4	RMI-2	6415.1	742.88	1126.93	206.27	8	1126.93	1120.4
05	RDO	6816.3	788.00	1038.00	203.71	18		