Production Optimization for Natural Flow and ESP Well
A Case Study on Well NS-5 Mishrif Formation-Nasriya Oil Field

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1- Abstract:

As the reservoir conditions are in continuous changing during its life, well production rate and its performance will change and it needs to re-model according to the current situations and to keep the production rate as high as possible.

Well productivity is affected by changing in reservoir pressure, water cut, tubing size and wellhead pressure. For electrical submersible pump (ESP), it will also affected by number of stages and operating frequency.

In general, the production rate increases when reservoir pressure increases and/or water cut decreases. Also the flow rate increase when tubing size increases and/or wellhead pressure decreases. For ESP well, production rate increases when number of stages is increased and/or pump frequency is increased.

In this study, a nodal analysis software was used to design one well with natural flow and other with ESP. Reservoir, fluid and well information are taken from actual data of Mishrif formation-Nasriya oil field/ NS-5 well. Well design steps and data required in the model will be displayed and the optimization sensitivity keys will be applied on the model to determine the effect of each individual parameter or when it combined with another one.

الانتاج الأمثل لبئر ينتج بالجريان الطبيعي و بواسطة المضخة الغاطسة
دراسة على بئر NS-5 ينتج من مكمن المشرف حقل الناصرية النفطي

الخلاصة:

ان ظروف المكمن تتغير باستمرار خلال فترة الانتاج لذلك فان انتاجية الابار تتغيرتبعا لهذه الظروف. بسبب ما سبق فان الابار تحتاج الى اعادة تصميم من ناحية الاكمال او تغير ظروف التشغيل للحصول على اعلى انتاج ممكن في الظروف الحالية.

ان انتاجية الابار تتأثر بشكل اساسي بضغط المكمن و نسبة الماء الى النفط و حجم انابيب الانتاج و ضغط راس البئر. اما الابار التي تعمل بواسطة المضخات الغاطسة فانها تتاثر ايضا بعدد مراحل المضخة و سرعة الدوران.

بصورة عامة، فان معدل الانتاج يزداد بازدياد ضغط المكمن و نقصان كمية الماء الى النفط. كما ان الانتاجية تزداد ايضا بزيادة قطر انبوب الانتاج و نقصان ضغط راس البئر. اما بالنسبة للمضخات الغاطسة، فان معدل الانتاج يزداد بزيادة مراحل المضخة و سرعة دورانها.

في هذة الدراسة، سيتم تصميم بئرين احدهم ينتج بالدفع الطبيعي و الاخر بواسطة المضخة الغاطسة. تم استخدام بيانات حقلية حقيقية في عملية التصمبم بالاعتماد على بئر NS-5 الذي ينتج من مكمن المشرف في حقل الناصرية النفطي جنوب العراق. ان عملية التصميم و ايجاد الحالة الانتاجية للابار خلال تغير الظروف التشغيلية و المكمنية سيتم توضيحها بالاعتماد على برنامج تحليل عقدي.

2- Introduction:

There are two parameters controlling the well performance which are inflow performance relationship (IPR) and Vertical Lift Performance (VLP). IPR is known as the relationship between well flowing bottom-hole pressure (Pwf) and production rate so it represent the flow from reservoir to inside wellbore.

There are many correlations and methods can be used to describe the reservoir performance. Each correlation has its own conditions to be applied according to reservoir and flow type. The most important methods which could be used for black oil reservoir are Vogle, Darcy and Fetkovich. In this work, the productivity index (PI) is already calculated from PLT data of well NS-5, therefore it can be used directly in nodal analysis.

The VLP depends on many parameters such as fluid PVT properties, tubing inside diameter, surface pressure, well depth, water cut and gas oil ratio. The total pressure loss from well bottom to surface is the magnitude of the three terms, gravity, friction and acceleration. In oil well completion design, the gravity component should be comprised around 75% of the total pressure gradient [1].

Electrical Submersible Pump (ESP) components are key parameters in ESP design and any change in one or more of it will affect overall ESP performance. ESP components are; motor which is the system prime mover and electric motor with different type and size of ESP motors that give a different amount horsepower required. Gas separator, the presence of free gas in produced fluid decreases the ESP efficiency, so that a gas separator is used to remove the gas from produced fluid to the annulus. Pump, used to lift the fluid from down hole. To improve ESP capacity several pump stages could be used. Power Cable: used to supply the electric power to the motor down hole [2].

The objectives of well modeling & analysis are as follows [3]:

1. To calculate the optimum flow rate at which the well will flow with a known wellbore conditions and completion.
2. To evaluate the well and when it might be ceased to produce. This could be due to time when the reservoir pressure depletes.
3. To determine the best economical time to install artificial lift and helping in chosen the suitable artificial lift plan according to well conditions.
4. To evaluate well conditions and completion system in order to planning for the best and economically method which improving flow rate.
5. To evaluate each part in the well completion to determine if there is any restriction to flow unnecessarily.

3- Well Modeling and Optimization Sensitivities (Natural Flow) for well (NS-5):

3.1- IPR Generation:

The inflow performance relationship is modeled based on production log data for this well. The PLT data for well NS-5 are listed in Table (1) [4].

Table (1) PLT data of well NS-5

Well name	NS-5
Reservoir pressure **psi**	3365.9
Reservoir temperature **°F**	163.11
Productivity index **STB/Day.psi**	7.4
Well head pressure **psi**	975
Well head temperature **°F**	124
Flow rate **STB/Day**	2697.43
Gauge depth **m**	2011.5
Gauge pressure **psi**	3001.4
Gauge temperature **°F**	163.82

the IPR results are generated using PLT as shown in Figure (1).

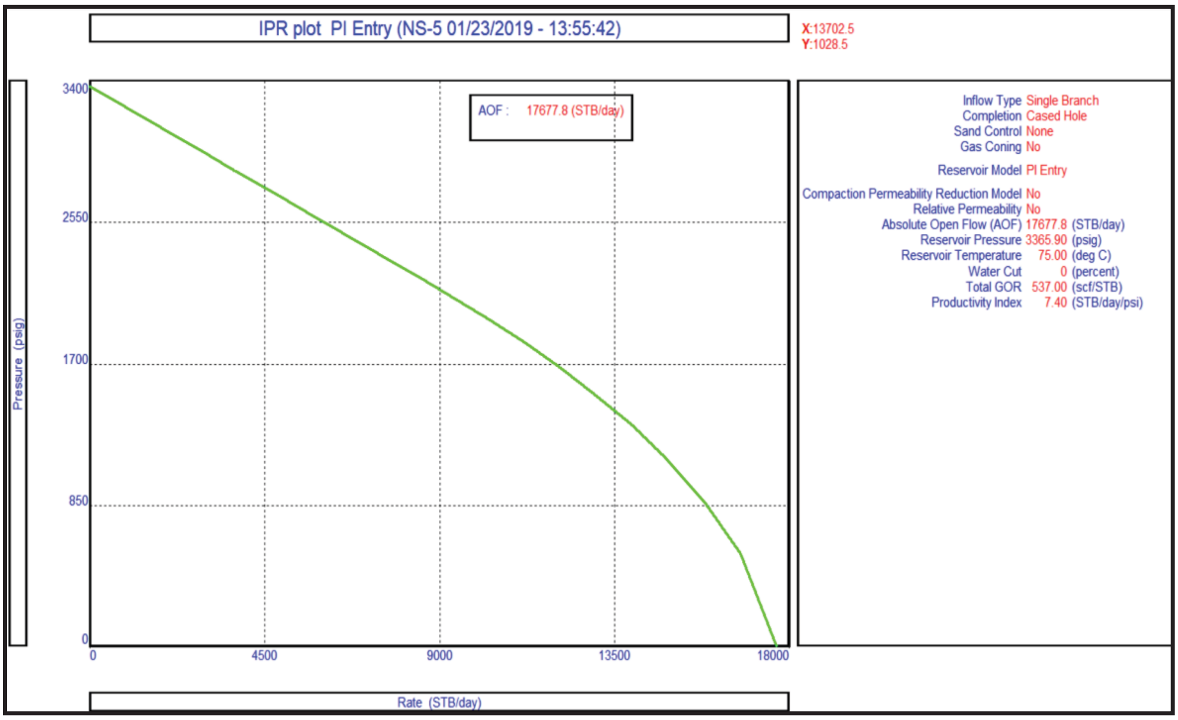

Fig. (1) Inflow Performance Relationship for well NS-5

3.2- Matching Pressure Gradient:

The actual measured data of PLT test is used to obtain the best fit vertical flow correlation which described the test rate, well head pressure, well head temperature and flowing bottom hole pressure. As shown in Figure (2), Hegedorn and Brown correlation line was the closest one to the measured point from all used correlations, so that may use after making this correlation fully matches with measured point.

In spite of being Hegedron & Brown correlation didn't distinguish between flow regime, but it gives the nearest calculated results to the measured results also the liquid hold up starts to decrease at a value very close to bubble point which indicate gas liberation and changing in flow regime from one phase liquid to two phase bubble, so it will be used to describe the well lifting performance.

Hagedron & Brown correlation is considered as most widely applied of oil wells as VLP correlation. It works well for bubble flow regime and slug flow regime in many applications. It could be used in wells for slug flow at moderate to high production rates also it use pipe roughness to describe two phase friction factor [5].

Ansari et al (1994a & 1994b) prepared eight different two-phase flow correlations and its relative errors, the smaller the relative performance factor, the more accurate correlation. According to Ansari's result, Hegdorn and Brown was found best correlation for current case [6].

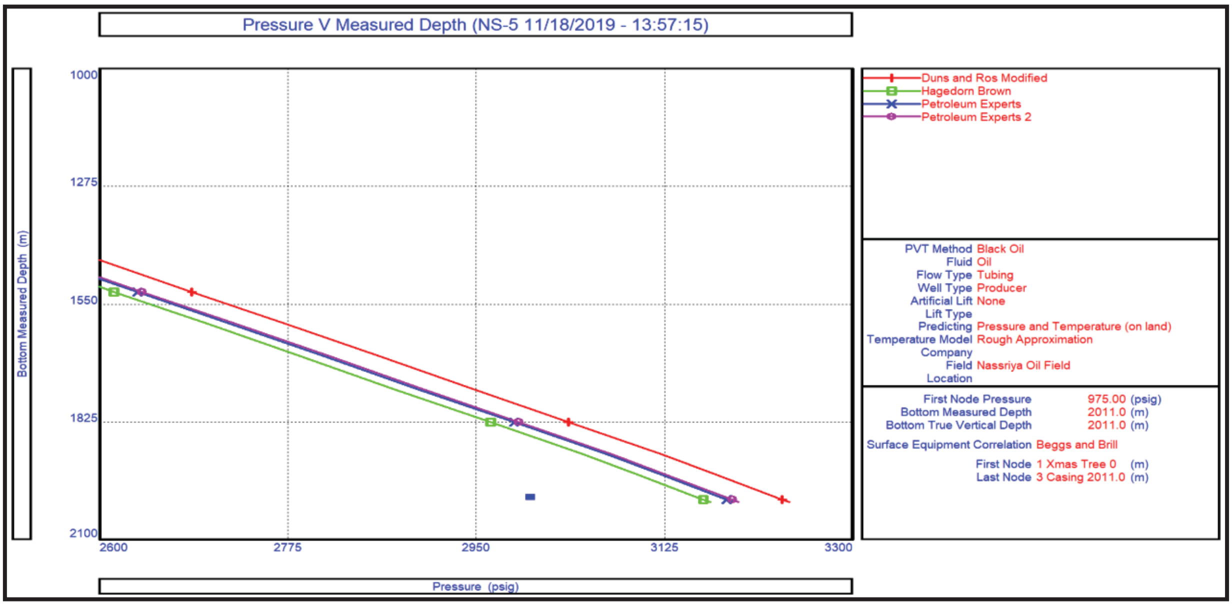

Fig. (2) Matching VLP Correlations with PLT

To fully match Hagedorn & Brown correlation with the test point, it should be multiply be parameter 1 & 2 which will be define later. Table (2) shows that Hagedorn & Brown correlation had the minimum standard deviation value after multiplying by parameter 1 & 2 which is zero while other correlation still have some deviation values.

Parameter 1: is the multiplier for the gravity term in the pressure drop correlation. Parameter 2: is the multiplier for the friction term.

Table (2) Correlations fitting Parameters & Standard Deviation

Correlation	Parameter 1 value	Parameter 2 value	Standard Deviation
Duns & Ros Modified	0.94657	0.35876	0.00024414
Hagedorn Brown	0.96438	0.57842	0
Petroleum Experts	0.95892	0.54137	0.00048828
Petroleum Experts 2	0.95768	0.53745	0.00024414

3.3- Matching VLP/IPR with Measured Data:

Match VLP correlation and IPR with test point to obtain the difference in liquid rate and bottom hole pressure for measured and calculated data as shown in the Figure (3) below:

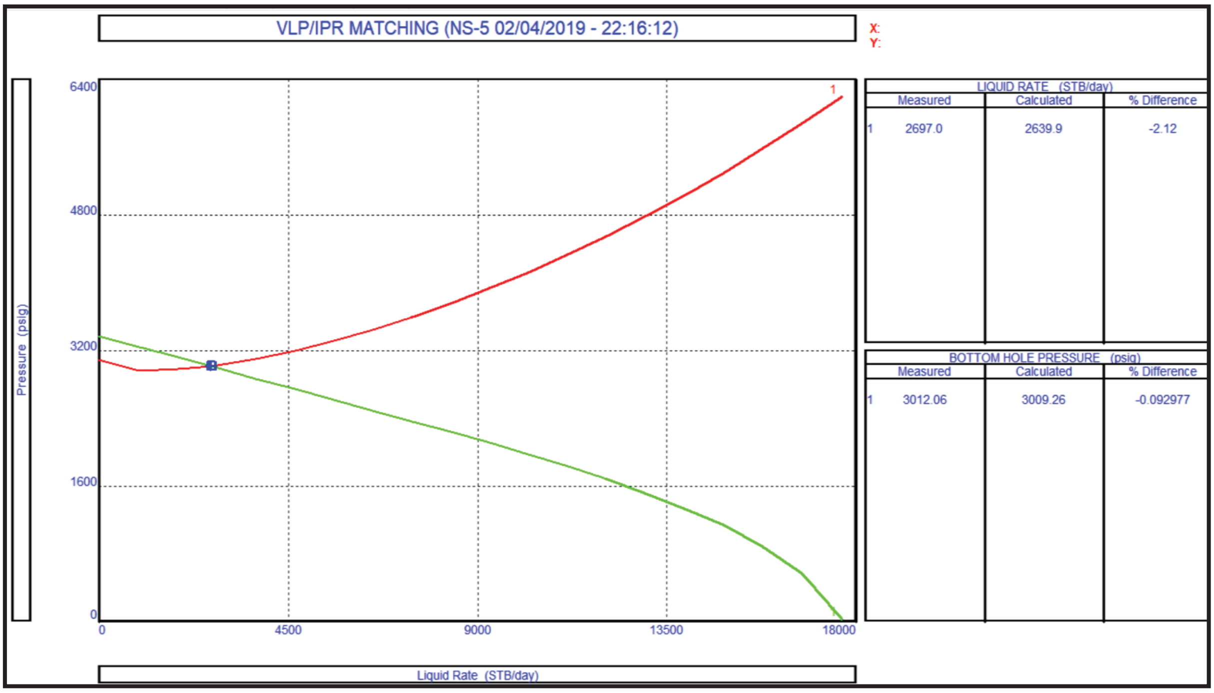

Fig. (3) VLP/IPR Matching

3.4- Well design sensitivity:

The most important part of building a well physical model is to evaluate well performance under different reservoir and operation conditions such as: decline in reservoir pressure, increase in water cut, changing in well head pressure according to De-Gas Station circumstances and changing in production tubing size due to design requirements.

The production sensitivities will be applied to the designed well to determine well state under different situations. Liquid flow rate and bottom hole pressure will be calculated as they are the main production parameters.

Table (3) and Figure (4) show the effect of reservoir pressure decline and water cut increase on production rate (Assumed WHP= 975 psi which is the same wellhead pressure as PLT data).

Table (3) Well production results as reservoir pressure decreasing and WC increasing.

	Pr= 3365.9 psi		Pr= 3250 psi		Pr= 3150 psi	
WC	Liquid Rate STB/D	BHP psi	Liquid Rate STB/D	BHP psi	Liquid Rate STB/D	BHP psi
0	2633	3010	2009	2978.5	1394	2961.6
10	2151	3075	1454	3053	NO Flow	
20	1589	3151	NO Flow		NO Flow	
30	852	3250	NO Flow		NO Flow	
40	NO Flow		NO Flow		NO Flow	
50	NO Flow		NO Flow		NO Flow	
60	NO Flow		NO Flow		NO Flow	
	Pr= 3050 psi		Pr= 2950 psi			
WC	Liquid Rate STB/D	FBHP psi	Liquid Rate STB/D	FBHP psi		
0	NO Flow		NO Flow			
10	NO Flow		NO Flow			
20	NO Flow		NO Flow			
30	NO Flow		NO Flow			
40	NO Flow		NO Flow			
50	NO Flow		NO Flow			
60	NO Flow		NO Flow			
	Pr= 2850 psi		Pr= 2750 psi			
WC	Liquid Rate STB/D	FBHP psi	Liquid Rate STB/D	FBHP psi		
0	NO Flow		NO Flow			
10	NO Flow		NO Flow			
20	NO Flow		NO Flow			
30	NO Flow		NO Flow			
40	NO Flow		NO Flow			
50	NO Flow		NO Flow			
60	NO Flow		NO Flow			

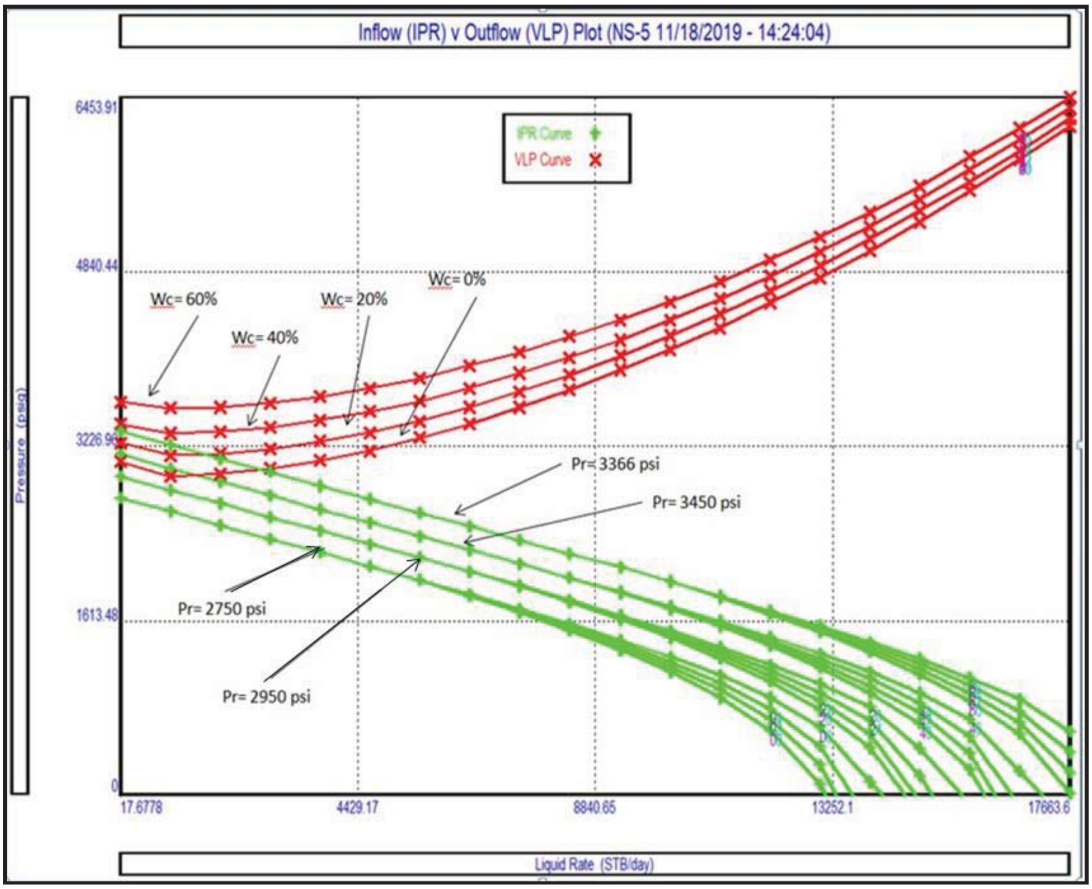

Fig. (4) VLP/IPR relationship for different Pr & WC

From Table (3) and Figure (4), it is clear that the liquid rate is decreasing when the reservoir pressure decline as the pressure drop between reservoir pressure and Pwf decreased. For example, the well was producing about 3633 STB/Day when reservoir pressure is 3366 psi (Δp=365 psi), then when the reservoir pressure decreased to 3150 psi (Δp=189 psi) the well was produce 1394 STB/Day. At the end, the well ceased if reservoir pressure decreasing less than 3050 psi. All above results for WHP=975 psi and zero water cut.

As shown in Table (3) and Figure (4) that the increasing in water cut can cause the reduction in the production rate. When reservoir pressure and WHP are 3366 psi and 975 psi respectively, the well produced 2633 STB/Day and 1589 STB/Day for WC equal to 0% and 20% respectively. The well was ceased when water cut equal and more than 40%.

Table (4) and Figure (5) show the effect of changing the WHP and TBG size on the production rate at Reservoir pressure= 3365.9 psi and WC= 0%.

Table (4) Well production results as WHP and TBG size changed.

	WHP= 300		WHP= 600		WHP= 975	
TBG ID in	Liquid Rate STB/D	FBHP psi	Liquid Rate STB/D	FBHP psi	Liquid Rate STB/D	FBHP psi
2.44	6226	2524	4851	2710	2633	3010
2.99	8383	2233	6279	2517	3015	2958
3.83	10713	1899	7499	2352	3204	2932

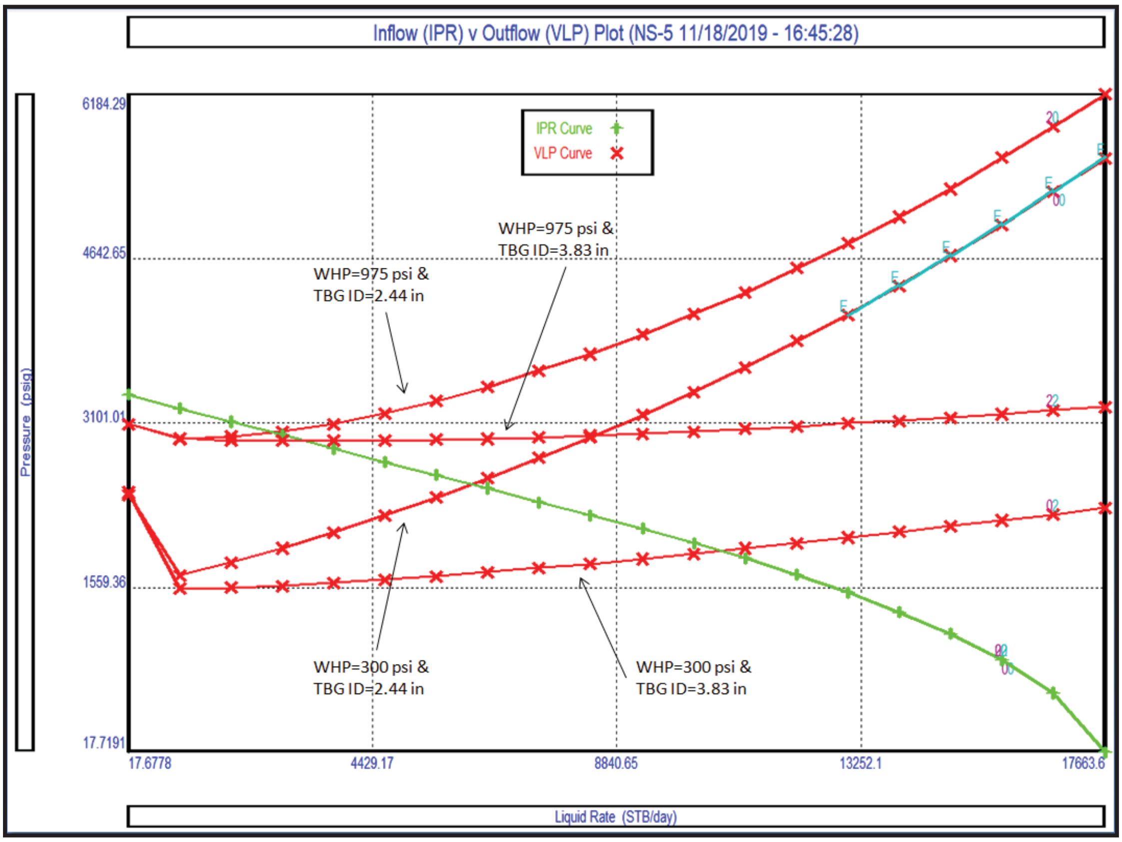

Fig. (5) VLP/IPR relationship for different WHP and Tubing size.

As shown in Table (4) and Figure (5), the production rate decreased when wellhead pressure increases and this is due to more WHP, leading to more Pwf and less pressure drop cross the reservoir causes low production rate. The well produced 2633 STB/Day when WHP equal to 975 psi then the production rate increased to 6226 STB/Day when WHP decreased to 300 psi for same tubing size (ID=2.44 inch).

From Table (4) and Figure (5), the production rate increased when tubing inside diameter increase, and this is due to reduction in fraction term lead to less pressure loss. For 2.44

inch ID, the well produce d 2633 STB/Day, while the production rate increase to 3204 STB/Day when tubing ID increase to 3.83 inch for same wellhead pressure.

4- ESP Well Design and performance sensitivity:

The electrical submersible pump is consider as one of the most important artificial lift method used in the oil industry because it required very little surface space, can be installed in vertical or highly deviated well either onshore or offshore. Also, it can be used in casing size (4.5 inch) and larger. ESP can be used in wells up to +13,000 ft in depth and it can handle fluid rate reach to 60,000 BPD depending on its size, design and operation conditions. If the ESP not operated at recommended operation parameters, the ESP efficiency will decrease and it may get failure [7]. Figure (6) shows the common ESP components.

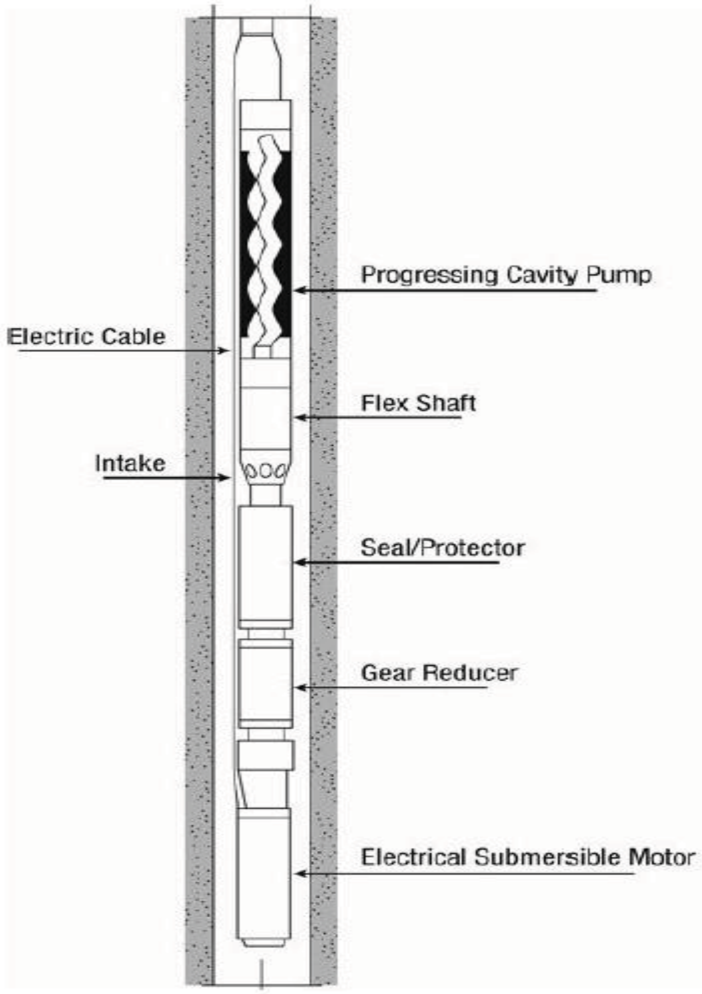

Fig. (6) Schematic plot of ESP component [8].

4.3- ESP Design Parameters:

The main parameters were used in ESP design are:

1- **Pump depth:** this depth is the depth at which the pump of ESP set and it is represent the depth of intake pressure. Pump depth should be above the perforation interval and far enough from ESP erosion factors such as sand production and also should be below the depth at which the bubble point pressure is reached.

2- **Design rate:** is the rate need to be attained when installing ESP. In this study, the minimum rate of natural flowing well was 2600 BPD @ 2.875'' TBG size, 0% WC, 975 psi WHP and 3365 psi reservoir pressure while The maximum rate was 10700 BPD @ 4.5'' TBG size, 0% WC, 300 psi WHP and 3365 psi reservoir pressure as presented in Table (4). So that the design rate will be consider as the midpoint between minimum and maximum rate which is about 6000 BPD.

3- **Gas separator:** if free gas enters the pump, ESP efficiency can be decreased because gas separator is needed to take the free gas out from ESP pump and direct it to the annulus. The decision of putting gas separator depending on Dunbar plot which is a relationship between the intake pressure, gas liquid ratio and the intercept with gas separator efficiency curves. If the test point above the red line, then no need for gas separator as shown in Figure (7).

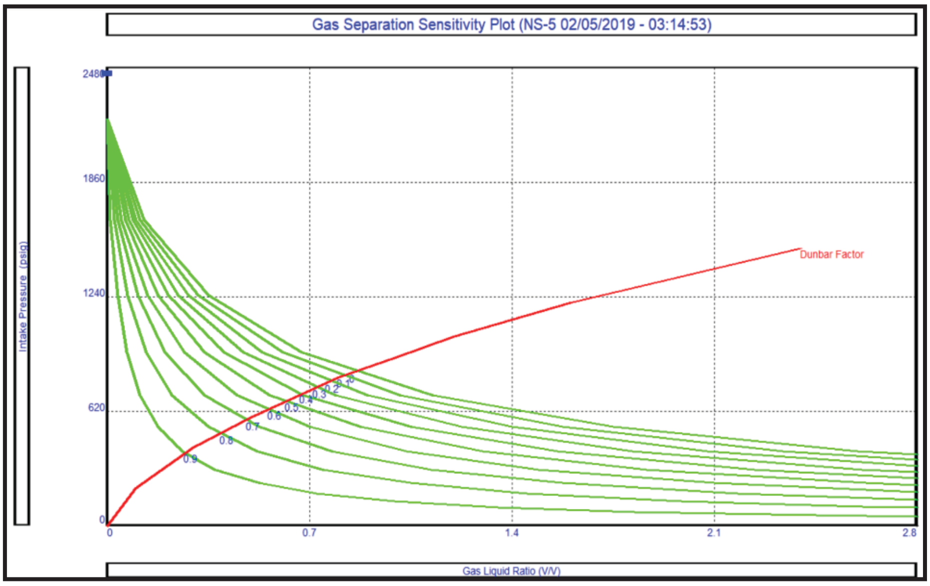

Fig. (7) Gas Separator Sensitivity Plot

The final ESP design parameters chosen to design the ESP are listed in Table (5).

Table (5) ESP design parameters

Parameter	Value
WHP psi	975
Reservoir pressure psi	3365
Reservoir Temp. °C	72.838
GOR scf/stb	537
WC %	0
Design rate BPD	6000
Pump depth m	1902
Design frequency Hz	60

ESP design Data/Result which is suitable and fit to operation requirements are shown in the following Table (6):

Table (6) ESP Design Result

Pump Intake Pressure	**2443 psig**
Pump Intake Rate	7926 bbl/day
Pump Discharge Pressure	3254.5 psig
Pump Discharge Rate	7843 bbl/day
Selected Pump	Centrilift GC8200 5.13 inches
Selected Motor	Centrilift 450 175HP, 2285V, 50A
Selected Cable	Copper 0.26Volts/1000ft 115amp Max
Number of Stages	82
Power Required	153.4 HP
Pump Efficiency	71.5 %
Motor Efficiency	82.5 %
Current Used	46.8 amps

The efficiency of designed ESP for different operation conditions according to design parameters very close to the best efficiency line and this improve the suitability of designed ESP for studied well as shown in Figure (8).

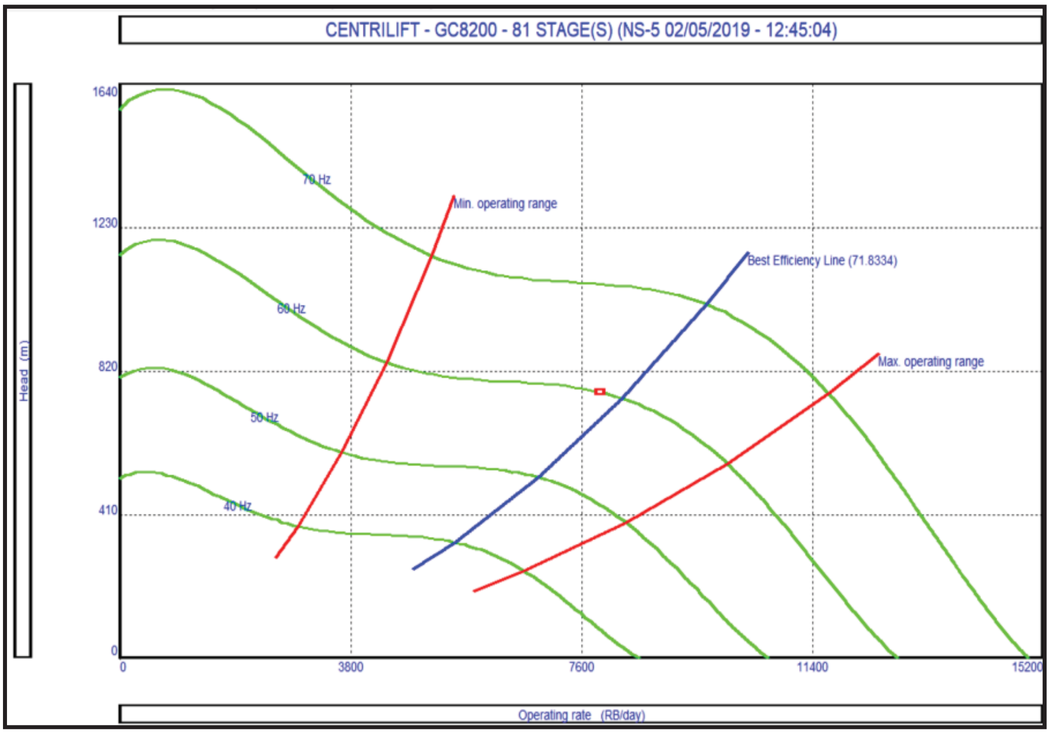

Figure (8) ESP Efficiency at different operation conditions

4.4- ESP Well Performance Evaluation Under different Operation Conditions:

Same as natural flow well; the reservoir and operation conditions have great impact on well productivity. Consequently, the designed ESP tested under different conditions such as decline in reservoir pressure, increase in water cut, changing in well head pressure, change in tubing size, change ESP operating frequency and stages number of ESP pump.

Table (7) and Figure (9) show the effect of changing in well head pressure and tubing size on well production rate (Reservoir pressure= 3365 psi and 0 % water cut).

Table (7) ESP production results at different WHP and TBG size

	WHP= 300 psi		WHP= 600 psi		WHP= 975 psi	
TBG ID in	Liquid Rate STB/D	FBHP psi	Liquid Rate STB/D	FBHP psi	Liquid Rate STB/D	FBHP psi
2.44	7770	2315	7099	2406	5978	2557
2.99	8988	2150	8186	2259	6978	2422
3.83	10714	1898	8806	2175	7461	2357

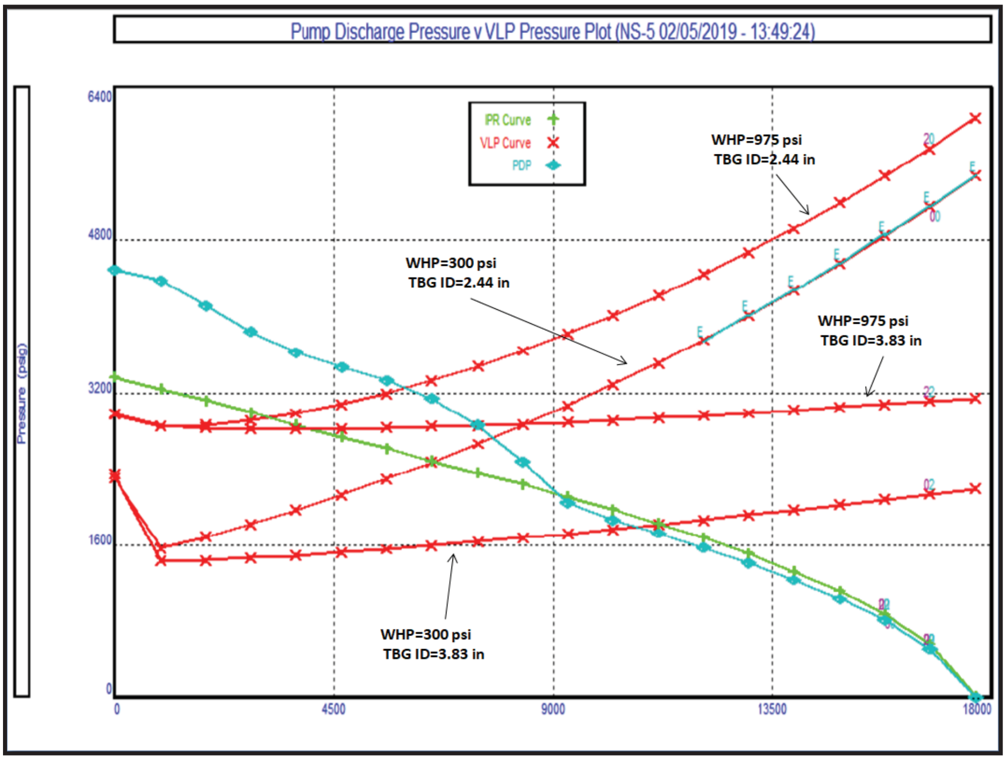

Fig. (9) Shows VLP/Discharge pressure relationship for different WHP and TBG size.

As shown in Table (7) and Figure (9), that the production rate increase when wellhead pressure decrease for the same reason effecting on natural well previously. The only different between natural flow and ESP well, is that the using of ESP increased the flow rate. For natural flow well, flow rate is 2633 STB/Day while ESP well produced 5978 STB/Day under same conditions (WHP=975 psi, TBG ID=2.44 inch). For the ESP only, the well produced 7770 STB/Day with 300psi WHP, then produced 5978 STB/Day with 975 psi WHP.

As presented in Table (7) and Figure (9), the increasing on tubing size will increase flow rate. The ESP well produced 5978 STB/Day with 2.44 inch ID, then produced 7461 STB/Day with 3.83 inch ID while natural flow well produced 2633 STB/Day with 2.44 inch ID under same operation conditions (WHP=975).

Table (8) show and Figure (10) show the effect of frequency and number of stages on production rate (Reservoir pressure= 3365 psi, 975 psi WHP and 0 % water cut).

Table (8) Production result for different Hz and No. of stage

	Frequency Hz = 40		Frequency Hz = 50	
No. of Stages	Liquid Rate STB/D	FBHP psi	Liquid Rate STB/D	FBHP psi
80	4183	2800	5022	2687
100	4456	2763	5431	2631
120	4690	2731	5736	2590

	Frequency Hz = 60		Frequency Hz = 70	
No. of Stages	Liquid Rate STB/D	FBHP psi	Liquid Rate STB/D	FBHP psi
80	5949	2561	6956	2425
100	6508	2486	7617	2336
120	6868	2437	8087	2272

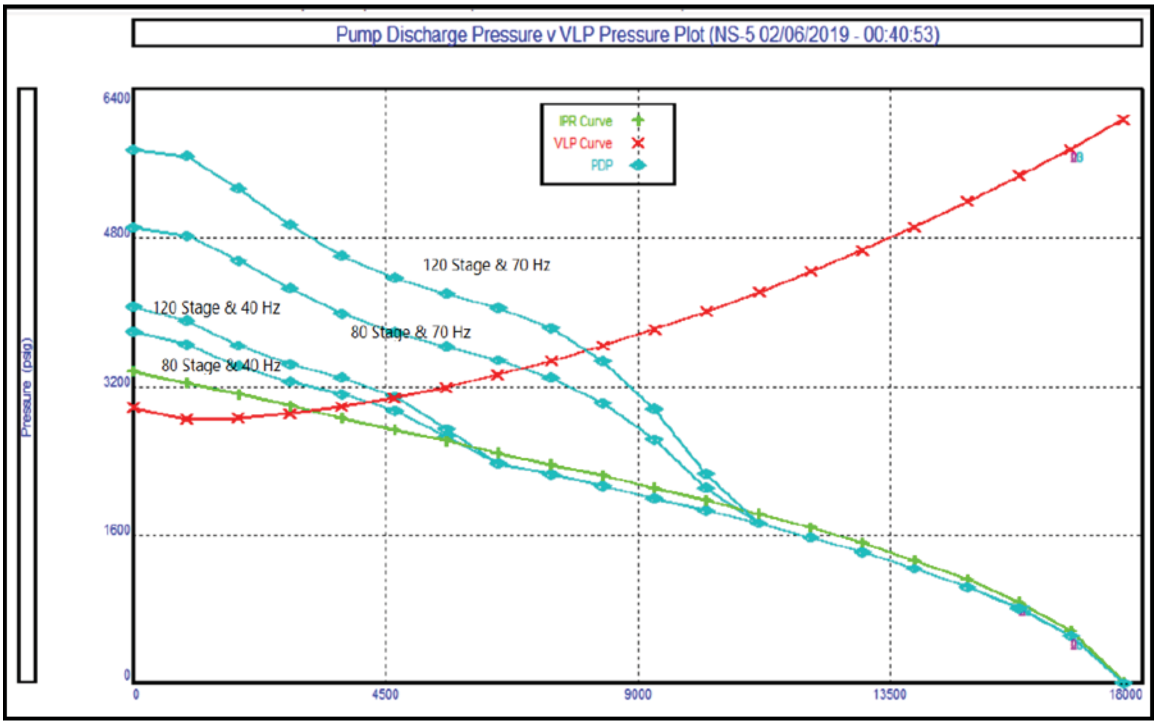

Fig. (10) Shows the VLP/Discharge pressure relationship for different number of stages and operating frequency.

As shown in Table (8) and Figure (10), for the same number of stages, the ESP well production rate increase when frequency increase as the pump will rotate more with high frequency. For example, the well produced 4183 STB/Day with 40 Hz then flow rate increased to 6956 STB/Day with 70 Hz (number of stages equal to 80 stages).

As presented in Table (8) and Figure (10), for the same frequency, the ESP well produces more fluid when number of stages increased. For the same frequency equal to 40 Hz, the well produced 4183 STB/Day with 80 stages then production rate increased to 4690 STB/Day with 120 stages.

Table (9) and Figure (11) show the effect of reducing the reservoir pressure (Pr) and increasing the water cut (WC) to well production rate (975 psi WHP and 60 Hz).

Table (9) production results for different reservoir pressure and water cut

	Pr=3365.9 psi		Pr=3250 psi		Pr=3150 psi	
WC %	Liquid Rate STB/D	BHP psi	Liquid Rate STB/D	BHP psi	Liquid Rate STB/D	BHP psi
0	5978	2557	5636	2488	5283	2436
10	5879	2571	5508	2505	5135	2456
20	5748	2589	5338	2528	4959	2479
30	5584	2611	5140	2555	4756	2507
40	5370	2640	4924	2584	4547	2535
50	5140	2671	4692	2615	4337	2563
60	4896	2704	4472	2645	4128	2592

	Pr=3050 psi		Pr=2950 psi	
WC %	Liquid Rate STB/D	FBHP psi	Liquid Rate STB/D	FBHP psi
0	4919	2385	4553	2334
10	4762	2406	4389	2356
20	4582	2430	4210	2381
30	4386	2457	4020	2406
40	4187	2484	3827	2432
50	3984	2511	3645	2457
60	3782	2538	3477	2480

	Pr=2850 psi		Pr=2750 psi	
WC %	Liquid Rate STB/D	FBHP psi	Liquid Rate STB/D	FBHP psi
0	4179	2285	3805	2235
10	4015	2307	3653	2256
20	3837	2331	3501	2276
30	3664	2354	3348	2297
40	3504	2376	3194	2318
50	3341	2398	3037	2339
60	3178	2420	2879	2360

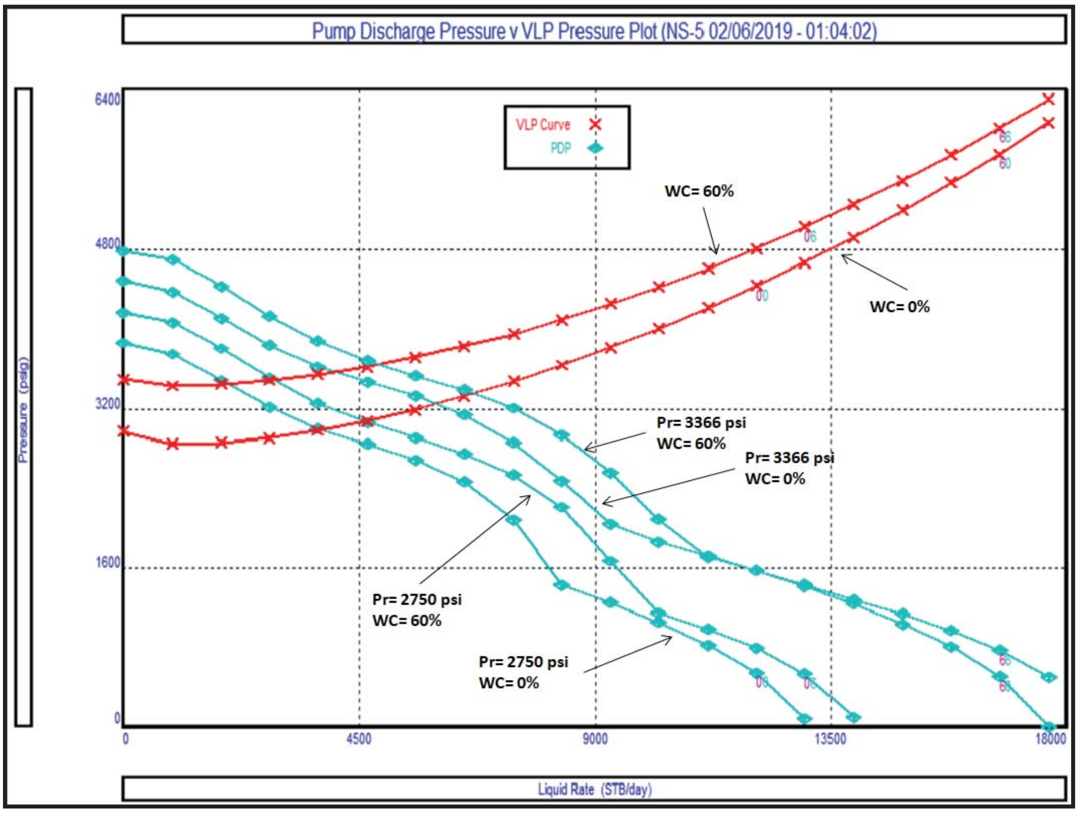

Fig. (11) Shows VLP/Discharge pressure relationship for different Pr and WC.

From Table (9) and Figure (11), the production rate increases when reservoir pressure increase and water cut decreases. For example, the ESP well produced 3805 STB/Day (Pr= 2750 psi &WC=0%) then production rate increased to 5978 STB/Day (Pr=3366 psi & WC=0%) while the natural flow well was ceased when reservoir pressure equal to 2750 psi under same operation condition (WHP=975 psi). For different water cut, the ESP well produced 5978 STB/Day with zero water cut then production rate decreased to 4896 STB/Day with 60% water cut, while the natural flow well was ceased when water cut equal to 60% under same operation conditions.

Conclusions:

1- The production rate increases when tubing size increases and/or wellhead pressure decreases for both of natural flow well and ESP well.
2- For ESP well, the production rate increases when ESP frequency increases and/or number of stages increases.
3- As the production conditions are changing during reservoir life, thus it is very important to re-design the well from time to time according to new situations.
4- ESPs are very useful to increase well productivity when the well is not able to produce under natural flow condition or the production rate is low.
5- Some well ceased while production under natural flow, but it could be putted again in production by using ESP.
6- As ESP design is restricted to initial well completion (casing size and down hole restrictions), the reservoir management team should take this into account for future reservoir development plans.

Nomenclature:

Symbol	Definition	Symbol	Definition
IPR	Inflow performance relationship	AOF	Absolute Open Flow
VLP	Vertical Lift Performance	DGS	De-Gas Station
Pwf	Flowing Bottomhole Pressure	WHP	Well Head Pressure
P.I	Productivity Index	WC	Water Cut
PLT	Production Log Tool	Pr	Reservoir Pressure
PVT	Pressure-Volume-Temperature	TBG	Tubing
GOR	Gas Oil Ratio	ESP	Electrical Submersible Pump

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