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Guideline of Artificial Lift Selection for Mature Field

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Abstract

Ras Fanar is located in the western part of the Gulf of Suez about 3 km east of the city of Ras Gharib, Egypt (Fig. 1). Production commened in January 1984 and a peak production rate of 20 MSTB/D was achieved in January 1988.
Due to the relatively low reservoir pressure for Ras Fanar field, some of the wells experienced lifting problems at water cuts above 20% requiring nitrogen lift to restore intermittent production. Clearly, some sort of artificial lift was needed in order to restore the production rate to the normal levels and to maximize the ultimate recovery.

The decision of which artificial lift method to use is very important to the long-term profitability of the field. An improper selection of artificial lift can reduce production and increase the operating cost substantially. Once a decision has been made on the type to install on a well, it can be rarely altered whether or not the method selected was and still is the optimal for the existing conditions.

This paper presents the screening criteria on the different artificial lift techniques and discusses why the choices were confined to ESP's and gas lift as the most suitable techniques to be applied in the field. The paper explains the two different alternatives, and studies the technical consideration behind each.

Reservoir simulation model was used to predict the performance and the ultimate recovery either naturally or using ESP and Gas Lift. An economical evaluation for both cases was then conducted taking into considerations both capital and operating costs of each opinion.

Introduction

The Ras Fanar field (Fig.1) was discovered in 1974 by Shell-BP-Deminex group. It was declared commercial and commenced production in 1984 with six wells drilled successively and distributed equally on two production platforms. By late 1984 when the six wells were completed, the field average production was around 8 MBOPD.
Since early production, the field has shown a high production potential with a conservative reservoir pressure decline. The pressure decline was in the range of 1.9 to 2.2 psi/MMSTB of oil produced.

Due to the relatively low reservoir pressure in the Ras Fanar field, some of the wells experienced lifting problems at water-cuts (~20%) which required nitrogen assistance to restore intermittent production. The reservoir fluid is a 30 – 32^O API with a high sulfur content of about 1.9% by wt. The associated gas is sour containing about 12% H_2S and 11% CO_2 by volume at separator conditions. In December 1995, the field produced at an average rate of 12,000 bopd and a water-cut of 16%. Figure (2) shows the field performance graph.

In light of the above considerations, a study has been conducted to select suitable technique to be applied for the field in order to optimize production, and to maximize field recovery.

Reservoir Description

The field comprises one uniform reservoir, namely the Nullipore. It is a carbonate build up (reefal limestone) of the Miocene age. The reservoir is hydraulically communicated, with no sharp boundaries like shales or anhydrite in between. The major and minor faults are all non-sealing, which results in having the same pressure regime in different wells throughout the field Fig. (3) illustrates Structure contour map for RF field. The structural column is approximately 730 ft between the crest at 1900 ft-TVDss and the original OWC at 2430 ft-TVDss. The field always shows increasing oil potential which resulted in upgrading the reserves several times.
Overall 24 wells have been drilled by the end of 1995 in the Ras Fanar area. Production by natural flow commenced in January 1984 from one well (RF-B1). During the same year, five further wells (RF-A1, -A2, -A3, -B2, -B3) were successively put on stream which boosted production from 8 MBOPD to over 16 MBOPD by late 1984. After an initial

start-up phase the field reached rate of more than 20,000 bopd in 1988. Water breakthrough occurred first in wells A2, A3 in 1987.

In 1992 a fourth well was drilled from the 'A' platform (RF-A4) and this was followed by a well from the 'B' platform in the following year. In 1993, a 12-inch crude evacuation pipelines were commissioned to replace the old 8-inch lines. After this installation the field reached a production rate of over 22,000 bopd. However, the water-cut developed rapidly.

Over the 12 years of production, the reservoir pressure has declined from 812 psia to some 665 psia. (@ 2200 ft-TVDss) under active water influx. Figure (4) illustrates the pressure history of the field.

Selection of Artificial Lift Methods:

An extensive study was conducted to compare different artificial lift alternatives: Beam pumping, Jet, Gas lift and Electrical submersible pumps. Table (1) represents a comparative study between the different lifting techniques. For the field especially high rate, low GOR, with no sand or scale the choice were confined to ESP's and gas lift as the most suitable techniques to be applied. The following section will illustrate the screening criteria for the suitable technique.

Beam pumping: Initially and based on poor well productivities. An air balanced Lufkin model A-912D pumping unit was chosen together with an obannon downhole pump 3.5" OD plunger, 144 inch stroke, double acting, designed to handle 1300-2000 BPD gross. The Lufkin unit is well suited for application on platforms because of: Low unit weight, Little or no horizontal impulse, Soft acceleration on rods at start of uptake. Ability to change the counter balance by regulator adjustment. In light of the higher than expected inflow capability of the producing wells, a sucker rod pumping system would not be adequate for the reservoir producing influx.

Hydraulic pumping: While a sound alternative from technical point f view, hydraulic jet pumping is excluded for reasons of insufficient plant capacity, absence of oil sweetening, and susceptibility of Ras Fanar Crude to wax deposition at temperature below 18 ^oC.

Pumping the production and power fluid up the casing is the most operational disadvantage of the jet pump. When production and power fluid are primarily oil, paraffin deposition will be a major problem at Ras Fanar conditions. Corrosion and scale are also problem when large volumes of water are handled.. Naturally, the presence of some 6% mol H_2S and 3 % mol of CO_2 in the reservoir fluid will magnify the problem.

Gas Lifting: The utility of gas lifting depends heavily on the availability of adequate volumes of good-quality lift gas. The feasibility of gas lift as an alternative means of artificial lift for Ras Fanar Field will be investigated in the following paragraphs.

ESP Pumping: One of the main advantages of ESP's is that they afford a wide flexibility with respect to offtake levels. The main concern in the operation of an ESP installation is the ability to handle free gas production. An excessive volume of gas can result in deterioration in the pressure head capacity performance, unstable flow and cavitation ultimately leading to pump/motor failure.

Ras Fanar Wells Model and History Matching

Natural flowing gradient curves were produced for each of Ras Fanar wells except well RF-A1, which had been closed in due to high gas oil ratio. Individual well models were developed, and the resultant inflow performance curves were matched to survey gradients of each well. Table (2) illustrates the results of history matching for natural flowing gradient with different correlations compared to the actual data from pressure surveys analysis. Based on the results of the matching process the Hagedorn and Brown correlation was selected as a best match for the vertical flow performance for RF wells.

Having selected a vertical flow correlation, sensitivities were then run on the water cut to predict wells performance at different water cut. Figure (5) illustrates the predicted tubing intake curves for one of the RF wells performance at different water cuts. Well inflow performance is expressed in the form of Vogel's equation. Table (3) illustrates the values of reservoir pressures, bottom hole flowing pressures and absolute open flow potential (AOFP) for the wells.

Gas Lift Design Calculations

Gas lift design calculations were performed for each well according to the following assumptions; Maximum injection pressure was 600 PSIA, 50-psi drop across P.O.I., Produced fluid is water with 0.47 psi/ft gradient. Production tubing strings with 4.5 " nominal size. The deepest point of injection for the wells was calculated. According to these calculations and the assumptions listed above, gas lift design calculations were performed in order to calculate the required gas lift mandrels spacing. Figure (6) illustrates the gas lift mandrel spacing calculations for one of RF wells. Table (4) illustrates the proposed mandrel depths for each well and the gas lift data.

Well performance predictions under gaslifted flow were developed covering a wide range of sensitivities in water cuts, well head pressure versus the gas injection rates for each well. It is assumed that the gas injection through the annulus and the production through tubing. Anticipated water cuts were covered with runs at 0, 20, 40, 60, and 80%. Sensitivity plots on gas injection volumes were illustrated in Figure (7). The well head tubing pressure sensitivities versus gas injection volumes also illustrated in Figure (8). In order to predict wells performance under gas lift system, a tubing intake curves was created under various water cuts. Figure (9) illustrates the predicted well performance on gas lift system. The vertical flow performance curves for all the wells were generated in order to simulate the pressure drop inside the production string and production facilities.

The Ras Fanar solution gas contains some 15% mol H_2 s for both safety and operational considerations a closed system would necessitate the installation of a gas sweetening plant and gas lift compressor engines fuel. This implies a large capital investiment. For these reasons the option of the open gas lift system was selected. In case of external high-pressure gas source were available, and with reference to the predicted well performance under gas lift. It was estimated that the optimum gas injection volume was 1.5 mmscf/day for each well with 12 mmscf/day for the entire field. This approach was considered to be quite attractive from the operational view.
Supply gas at pressure can be taken from Ras Shukeir – Suez trunkline and transported to offshore used for gas lift and returned onshore to General Petroleum Company at low pressure for disposal.

Electrical submersible pumps
The artificial lift through ESP system for the field has investigated. One of the main advantages of ESP's is that they afford a wide flexibility with respect to offtake levels. The main concern in the operation of an ESP installation is the ability to handle free gas production. An excessive volume of gas can result in deterioration in the pressure head capacity performance, unstable flow and cavitation ultimately leading to pump/motor failure. Most manifactures recommend that the amount of gas at the pump intake of an ESP should not exceed a maximum of about 10% by total volume. It was therefore deemed necessary to use a downhole gas separator. The ESP pumps will be set in 7-inch liner/casing; RF wells are completed with a 7 inch 29 LB/ft liner and 9 5/8 inch casing to surface. The maximum size pumps that can be run in 7 inch 29 LB/ft casing (ID=6.184 inch, drift=6.059inch) and their operating ranges illustrated in Table (5). The larger dimensions of the ODI pump (with MLE) do not allow sufficient clearance in 7" casing (0.08" compared to 0.33" for Reda & centrlift pumps/MLE) to compensate for the dogleg severity that exist in most of the Ras Fanar wells. ODI pumps were therefore not considered. The following assumptions were assumed for design; Pump depth 100 ft above the top of perforation, the desired production rate ranging 5000-7000 blpd and the Production string 3 ½ inch tubing.

Specialized computer software was utilized to select the optimum type of pump, motor, cable and the downhole equipment. Using the above assumptions wells data, PVT and reservoir parameters also the operational considerations were used as data entries. The suitable pump can be selected to give the desired production rate. For all wells Reda pump was selected as a suitable type within series GN-7000 and Centrlift with series GC 8200.
Tables 6 illustrate ESP size (stages/horsepower) required at ESP startup for both REDA and Centrlift. Figure (10) illustrates the predicted well performance under variable speed drives with the selected pumps. Figure (11) shows the pump efficiency and the Horsepower required for the well.

Equipment Selection
Potentially highly corrosive fluids exist in the Ras Fanar field. Based upon initially relatively low water cut development, in the range of 20-40%, carbon steel has been recommended for the tubular and casing, 9cr 1 mo for the completion accessories to provide better erosion /corrosion resistance and stainless steel for the wellhead equipment.

Wells Performance Evaluation under Gas Lift and ESP
In order to evaluate the performance for Ras Fanar wells under Gas lift and ESP, a comparison was made for the wells performance on both cases and the results indicated the following:
Gas lift is more efficient to lift oil on different water cuts with a limited drawdown so the water production in case of the gas lift expected to be lower than the case of ESP.
ESP is efficient to accelerate the production with a water production higher than the gas lift case.
The production rates for the Gas lift case is lower than the ESP. Figure (12) illustrates wells performance on both cases Gas Lift and ESP.

Prediction sensivities for Gas Lift and ESP
Field reservoir performance calculations were conducted using the latest reservoir simulation model for Ras Fanar field in cases of natural flowing, gas lift and ESP. The bottom hole pressure tables, generated as described before for both two cases; Natural flowing and gas lift were imported into the reservoir simulator in order to model well bore performance correctly. For ESP option, the assumptions would run against minimum pump intake pressure 250 psia. Table (7) illustrates the assumptions for both cases, ESP and gas lift. The results of the prediction sensitivities are illustrated in Figure (13). The results indicated that the Gas Lift system provides a constant production profile for 4 years and then deteriorates in addition to the recovery factor +/- 50% and incremntal oil of +/- 32 mmSTB. The field production is accelerated under ESP performance and the production profile constant for approximately 1.5 years only and the recovery factor +/- 48% and incremntal oil of +/- 26 mmSTB.

Capital cost for Gas Lift
The downhole equipment for the Gas Lift system, these include 4 ½" tubing, gas lift mandrels, valves, production packers, sliding side doors, safety valves and accessories. Table (8) illustrates the capital cost items and prices of the downhole equipment for each well.
Surface equipment cost estimates for the gas lift case was developed under the following assumptions: Maximum gas Requirements + /- 24 MMscf/d. Gas supply from EGPC main gas transmission pipeline "Ras Shukier - Suez" passing the Ras Fanar area, Gas is sweet dry, and clean. Operating pressure of +/- 70 barg. Pipeline design code for pipeline is ANSI B31.8 – Rating 600// ANSI C.S, design for Ras Fanar gas lift facility to be under the same code specification. Table (9) illustrates the capital cost items and prices for the project.

Operating cost for Gas Lift

The following assumptions were made for the gas lift "open case": Present GPC tariff for treatment, 0-5000 bopd $1.2 /bbl, 5000-10000 bopd $1.08 /bbl and +10000 bopd $0.96 /bbl. Work over string rate $1.5 mill/month. All lift gas supplied by third parties. Gas price $2000/MMSCF, Work over required are one well every year. (I.e. each well worked over every 7 years).

Artificial lift budget, these includes gas lift valves and spare parts, etc is $ 0.07 MM/year

Capital cost of ESP system

The capital cost of ESP system are illustrated in table (10), these includes onshore water treatment, electrical system and facilities, downhole and surface completion equipment and the rig installation costs.

Operating cost of ESP system

The following assumptions were made for ESP : Present GPC tariff for treatment, 0-5000 bopd $1.2 /bbl, 5000-10000 bopd $1.08 /bbl and +10000 bopd $0.96 /bbl. Two Work over/well in first year and 1 failure/well in each subsequent year with string rate $1.15 mill/month (each work over cost= $ 0.3 MM . Well service budget is $ 0.05 mm/year. According to these assumptions the operating cost calculted.

Economical analysis of Gas Lift and ESP systems

Based on the assumptions above, The cost per bbls calculted and illustrated in table (10) and it was observed that the cost per bbl in case of ESP is always higher than that by Gas Lift. The analysis of capital and operating costs for Gas Lift and ESP can be summarized as follows:

For the Gas Lift case the incremental Oil 32 MMstb requires $11.2 MM capital and $ 165 MM for the operating cost. For the ESP case the incremental Oil 26 MMstb requires $9.26 MM capital and $ 185 MM for the operating cost.

Summary & Conclusions

1. ESP's and gas lift are the most suitable techniques to be applied in the field.
2. The simulation model was used to predict the performance of the field on both cases Gas Lift and ESP.
3. The recovery factor in case of Gas lift is higher than that of ESP system but the economical evaluation indicated that the capital cost of ESP is lower than that of Gas Lift system.
4. Operating cost for ESP is higher than that on Gas Lift system.
5. Finally ESP was preferred to the Gas Lift and applied since mid of 1996 due to the ESP provides high degree of independence more than that provided by the gas lift that can be subject to any shut downs in the supplying company.

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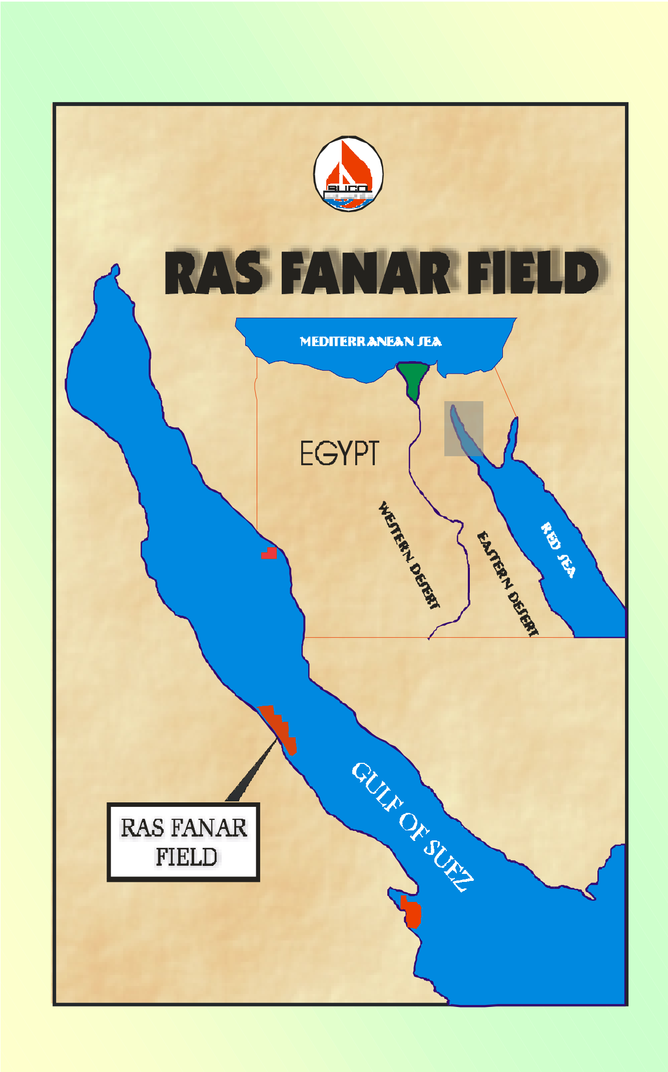

Figure (1) Ras Fanar field location map.

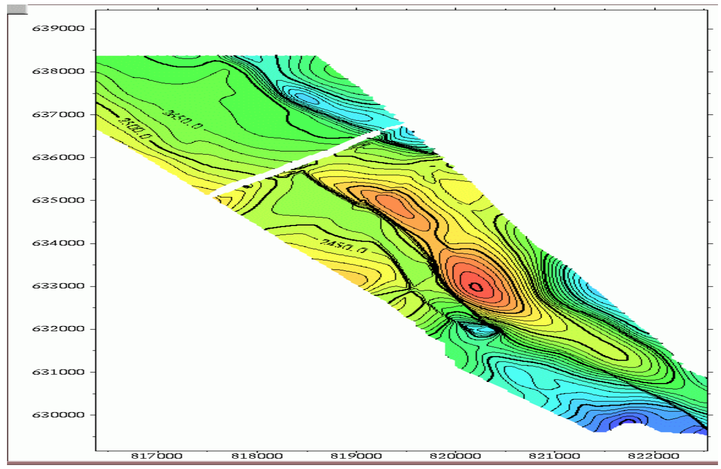

Figure (3) structure contour map for RF field.

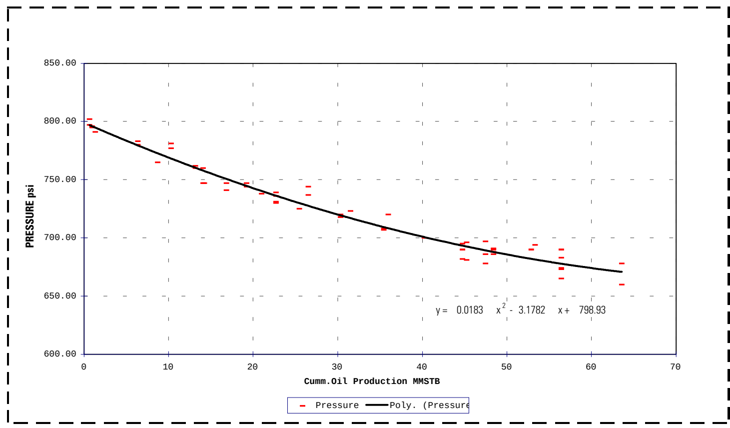

Figure (4) The pressure history of the field.

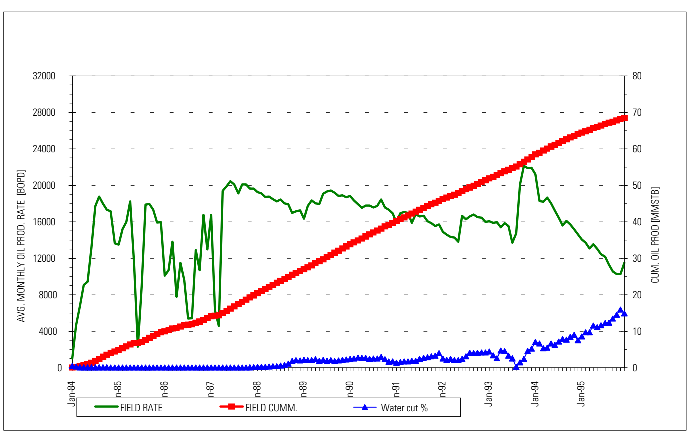

Figure (2) Production history for the field.

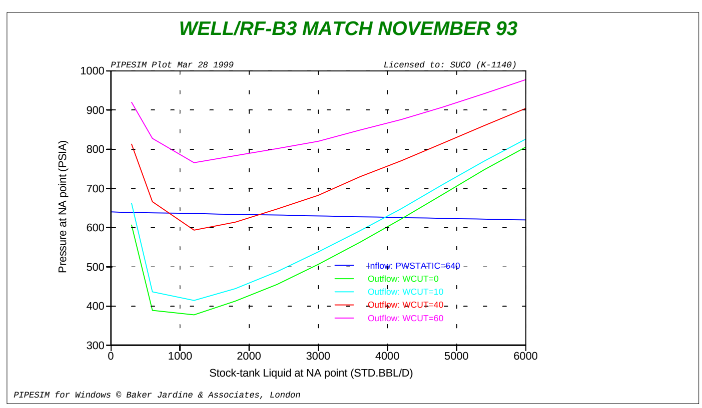

Figure (5) Predicted tubing intake curves on natural flowing.

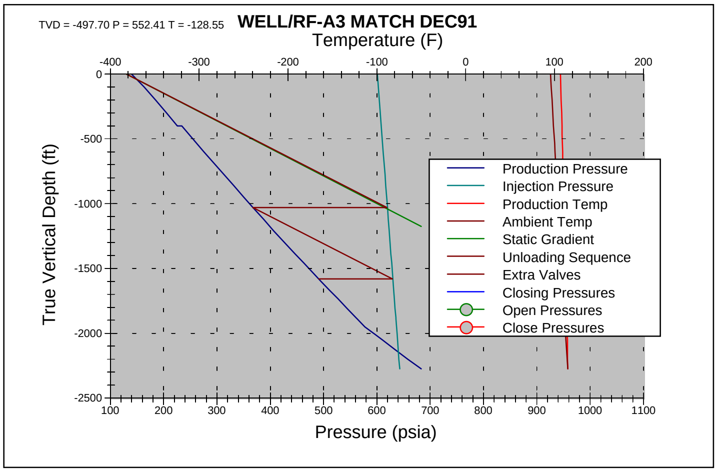

Figure (6) Gas Lift design and mandrel spacing

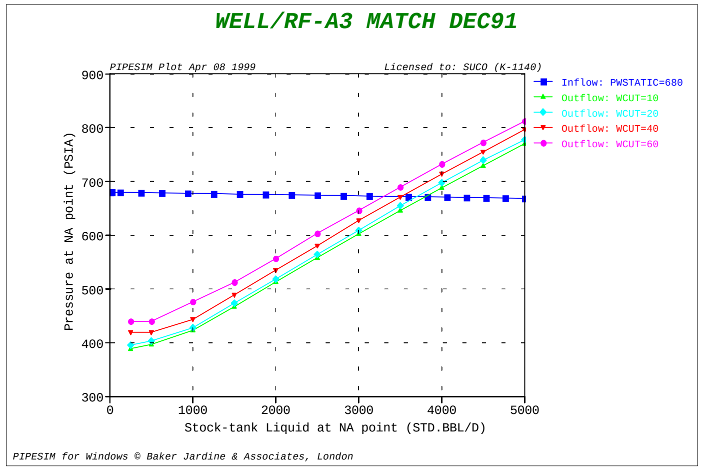

Figure (9) Predicted well performance on gas lift.

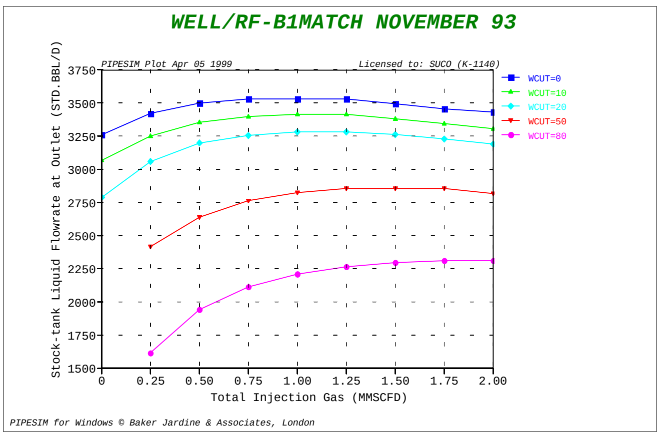

Figure (7) Sensitivity on gas lift inj. Volume with different water cuts.

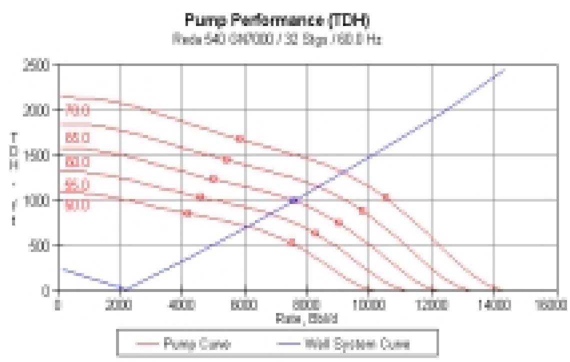

Figure (10) Predicted well performance on ESP

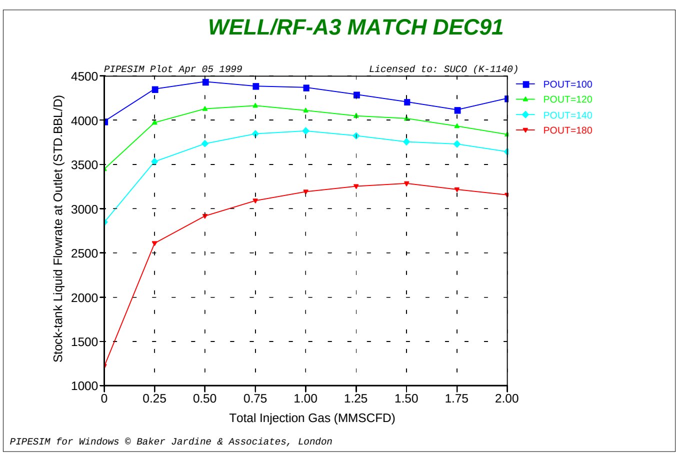

Figure (8) Sensitivity on gas lift inj. Volume with different Tubing head pressures.

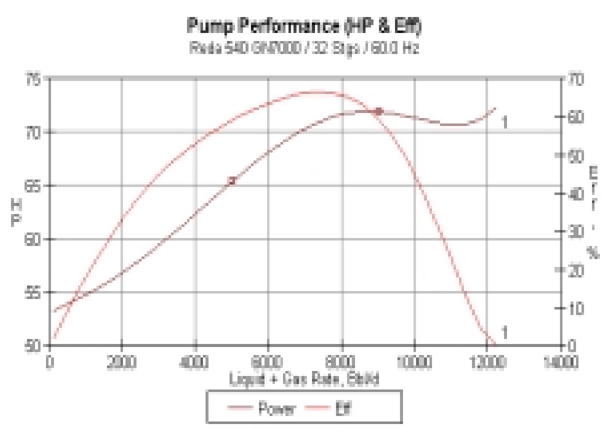

Figure (11) Pump efficiency and horsepower required.

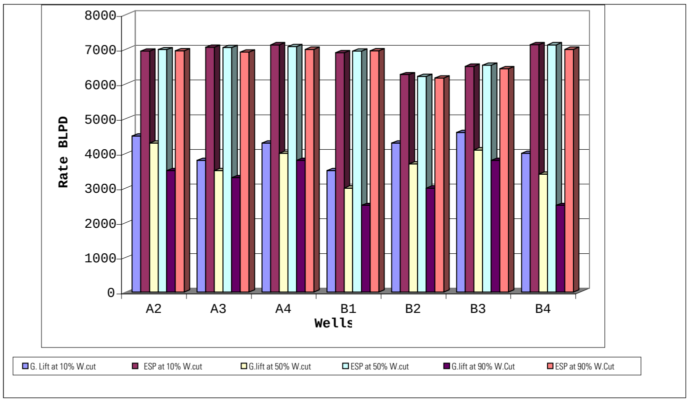

Figure (12) Wells capabilities on Gas Lift & ESP at different Water cuts.

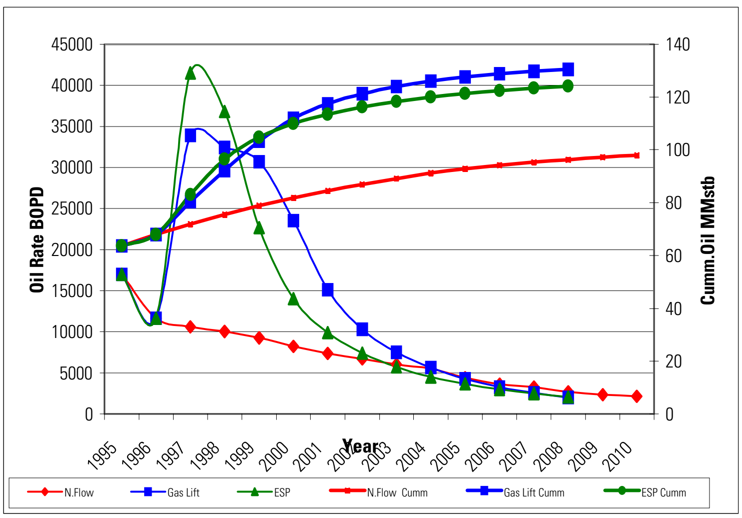

Figure (13) Results of prediction runs for Natural flowing, Gas Lift and ESP.

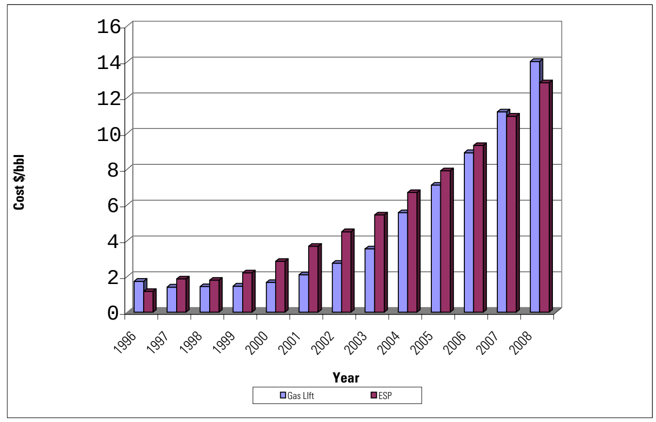

Figure (14) the cost in $/bbl for ESP and Gas Lift.

Table (1) Comparative study between different lifting techniques.

Item	Gas lift	ESP	Hydraulic	S.Rod
Workover Frq.&tool	Low rigless	High rig	Moderate rig/riglss	High rig
Shut down	low	High	Moderat	low
Run life year/well	v.good	medium	Good	v.low
Movable parts	none	exist	None	exist
Wire line operation	easy	difficult	Impossible	impossible
Capital cost	high	high	meduim	meduim
Operating cost	low	high	Moderate	high
High GOR	effective	Inefficient	Inefficient	Inefficient
High w.cut	restricted	effective	Unsuitable	Unsuitable
High rate	effective	effective	Ineffective	Inefficient

Table (2) The results of history match for natural flowing gradient with different correlations.

WELL	DEPTH TVD-ss	Pwf, PSIA meas.	Pwf Calculated, PSIA					
			H&B	% error	ORK.	% error	B&P	% error
RF-A2	-2116	638.9	621	-3.5	590	-14.9	754	22.37
RF-A3	-2181	683	666	-3.05	611	-12.9	769	15.4
RF-A4	-2077	641	655	2.71	657	3.1	803	31.4
RF-B1	-2077	581	570	-2.41	569	-2.63	670	19.5
RF-B2	-2087	628	665	7.3	689	12	802	34.25
RF-B3	-2031	618	612	-1.19	610	-1.58	771	30.3
RF-B4	-2134	654	698	8.19	710	10.4	838	34.2

Table (3) illustrates the calculated AOFP for the wells.

WELL	PS PSIA	Pwf PSIA	Rate BPD	AOFP STB/DAY
RF-A2	655	636	4600	91971
RF-A3	690	683	3000	165030
RF-A4	645	641	4500	449155
RF-B1	610	581	3500	47195
RF-B2	633	628	4600	232967
RF-B3	325	618	4500	106623
RF-B4	664	654	5000	174546

Table (4) illustrates the proposed mandrel depths for each well and the gas lift data.

Wells	Deepest Point of injection ft-TVD-ss	Mandrel Spacing ft-TVD-ss	Gas lift valves data			
			Type	Port size inches	TRO PSIA	Valve opening pressure PSIA
RF-A2	2101	1045 1585	Camco, R-20	3/8 7/16	660 675	619 629
RF-A3	2013	1030 1580	Camco, R-20	3/8 7/16	620 675	619 629
RF-A4	2016	1055 1700	Camco, R-20	3/8 7/16	615 645	619 631
RF-B1	2125	1055 1625	Camco, R-20	3/8 1/2	585 725	619 630
RF-B2	1986	1285 1825	Camco, R-20	7/16 1/2	655 735	623 633
RF-B3	2090	1055 1585	Camco, R-20	3/8 1/2	620 725	619 629
RF-B4	2017	1100 1655	Camco, BK	3/8 3/8	730 760	620 580

Table (5) illustrates the maximum size pumps and their operating ranges in 7" casing.

Vendor	Series	Pumps	Recommended operating range (BFPD @50 HZ)	Pump+MLE (diam iches)
Reda	540	GN 7000	4000-1000	5.73
Centrlift	513	GC 8200	3670-8670	5.73
ODI	70	K100	7000-9480	5.98

Table (6) shows ESP size (stages/horsepower) required at ESP startup.

At ESP start up					**ESP size**	
Well	**Free gas %**	**Water cut %**	**Well head pressure PSIA**	**Pump intake pressure PSIA**	**No of stages**	**HP**
A2	17	10	315	481	36	58
A3	17.6	10	315	434	27	68
A4	18.6	10	315	425	36	110
B1	17.5	10	315	427	35	103
B2	16.1	10	315	449	39	86
B3	17.2	10	315	431	40	99
B4	17.4	10	315	425	31	78

Table (7) the assumptions for the prediction sensitivities on Gas Lift and ESP.

	Gas lift	**ESP**
Start date	Jan.,96	Jan.,96
Work schedule	2 wells/month	2 wells/month
Min BHP constraint	controlled by lift curves	250 psia
Min WHP constraint	Controlled from slug catcher	Controlled from slug catcher
Field abondment rate	2000 bopd	2000 bopd

Table (8) Capital cost items and prices of the downhole equipment for the Gas Lift.

Item	**Cost, $well**
Packer	35000
SSD+ flow couplings	22000
Gas lift mandrels	9000
Safety valves	28000
Seating nipple	1500
	95000
7 wells at $ 95500	668500
18000 ft of new tubing $ 8/ft	144000
Total	812500

Table (9) Capital cost items and prices of Gas Lift.

Item	**Cost, $well**
Materials	1880
Construction	2320
Logistic's and marine services	250
Engineering &procurement services	500
Project team, site supervision/inspection	680
Insurance	220
Contingency	380
SubTotal	6230
Downhole equipment	812
Rig activities (7days /well)	1880
Total	8922

Table (10) Capital cost items and prices of ESP.

Item	**Cost, $ MM**
Onshore water treatment	1.1
On/Offshore electrical system & Platform facilities	1.3
Downhole comlpetion + surface equipment	2.6
Rig installation 7 wells in 10 days/well	2.65
Total	**7.65**