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ARTIFICIAL LIFT OPTIMIZATION FOR CHEROUQ FIELD, TUNISIA

A Thesis
By

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AFFIDAVIT

I declare in lieu of oath, that I wrote this thesis and performed the associated research myself, using only literature cited in this volume.

Adel Mohammed Elhooni

Leoben, June 2012

ABSTRACT

Cherouq concession is located in the Southern Tunisia desert in the Tunisian portion of Ghadames basin and was taken over by OMV in the mid of 2011. Production in Cheroug concession started in mid 2008 and the field currently is producing approximately 6,000 bopd from approximately 13 wells from different eight fields. Most of the wells are producing in natural flow, and a gas lift system is currently installed. First wells were converted to gas lift production in the end of May 2011.

In my study I am doing an artificial lift optimization for Cherouq field, to shift the wells, which need to be artificially lifted, to a suitable lifting method and investigate other artificial lift alternatives to gas lift. Moreover to investigate the future scenarios in case of some of the production parameters has been changed.

To achieve the ultimate gaols a PROSPER software was used to perform nodal analysis, and modelling each individual well, ESP (Electrical Submersible Pump) designs and Gas lift designs were performed to the wells by PROSPER as well. Water cut, gas oil ratio, productivity index and reservoir pressure sensitivity was analysed for each well to contain the whole image of how the field well perform in the future, the thing which is very essential for any developing plan.

Sucker rod pumps were designed for three wells only (Angham-1, Methaq-2 and Waha-1), those wells are low producers and for the other wells sucker rod is not a comparable to ESP or gas lift, as the production achieved by ESP and GL is much higher than what we can get with sucker rod and this is due to the limitation of the great lifting depth in addition to the amount of fluid that should be lifted to achieve a higher production rate comparing to the other lifting methods.

To see if the study is applicable an economic study was performed, the thing, which judges if the project is worth to be executed.

ABSTRAKT

Die Cherouq Konzession liegt im südlichen Tunesien, in der tunesischen Wüste, ist Teil des Ghadames Beckens und wurde von der OMV Mitte 2011 übernommen. Die Produktion in der Cherouq Konzession begann Mitte 2008 und liefert derzeit aus 13 Bohrungen in 8 Feldern rund 6.000 Barrel Öl pro Tag, zumeist aus natürlichem Fluss. Seit Mai 2011 wird zur Verbesserung der Ausbeute ein Gas-Lift-System bei einzelnen Bohrungen installiert.

In meiner Arbeit untersuche ich, welche Artificial Lift Methode(Auftriebsystem)für das Cherouq Feld am besten geeignet ist. Dazu werden diese unterschiedlichen Methoden alternativ zur Gas-Lift Methode untersucht und Zukunftsszenarien für die wahrscheinlichen Veränderungen der Produktionsparameter erstellt.

Unter Verwendung der PROSPER Software von Schlumberger wurden die einzelnen Bohrungen im Rahmen einer 'Node Analysis'(Knotenanalyse) modelliert, wobei besonderes Augenmerk auf Design der ESPs, bzw. des Gas-Lift Systems unter den Parametern Water Cut, Gas-Öl-Verhältnis, Produktivitäts Index und Reservoirdruckempfindlichkeit gelegt wurde. Anhand dieser Untersuchungen wurden die Szenarien für die zukünftige Entwicklung der Produktion des gesamten Cherouq Feldes entwickelt, welche die Grundlage für den Feldentwicklunsplan liefern.

Ein Gestängepumpenszenario (Sucker rod pumps) wurde nur für 3 Bohrungen entwickelt (Angham-1, Methaq-2 und Waha-1), da diese als niedrige Erzeuger eingestuft werden. Für alle anderen Bohrungen kam aufgrund der Tiefe nur ESP oder Gas Lift in Frage.

Abschließend wurde unter Berücksichtigung der einzelnen Szenarien eine Wirtschaftlichkeitsstudie durchgeführt, um die vorgeschlagenen Artificial Lift Maßnahmen auf ihre Effizienz zu überprüfen.

DEDICATION

In the name of ALLAH most gracious most merciful

This dissertation is humbly dedicated to my parents, my brothers, and all of my friends.
I am grateful to my parents for providing me education, inspiration and confidence, as they were the candle the burns to lighten me my way through life.

To my friends who where always there to support me and to help.

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Chapter 1 Introduction

When an oil well is first discovered, it can flow naturally because of the sufficient reservoir energy, this energy is the reservoir pressure, with continuing the production reservoir pressure decreases until it is not possible for a natural production and the well is dead. In order to resume production a form of an artificial lift system should be installed.

Gas lift, Electrical Submersible Pump, Progressive Cavity pump, Sucker Rod and Hydraulic Pump are all forms of artificial lift method, each is suitable under a certain environment, see chapter three, as there are more details about artificial lift systems, where equipment, working principles, advantages and disadvantages is discussed.

In this book I will discuss the performance and the possibilities to improve the production from Cherouq concession, currently in Cherouq fields the only artificial lift system used is gas lift, and to reach the optimum production an alternative artificial systems should be considered, as some wells have a production environment, e.g. high water cut or remote location from the gas injection compressor, which are dose not suit gas lift installations.

To produce optimally means the economic factors should be taken in considerations, CAPEX and OPEX should be carefully considered together with mean time between failures. These three factors are one of those, which limit the selection of the artificial lift system.

Objectives

The aim of this study is to perform a production engineering study at Cheroug oil field in Tunisia. The main objective is to optimize the production for the whole field (13 wells), seven of which are completed with gas lift, and the rest is on natural flow. This study is summarized as flowing:

- Analyzing and reviewing the current situations.
- Selecting, or changing to, the suitable artificial lift for each well and then for the whole field.
- Investigating future scenarios.

Executive summary

For a better understanding of the field and the production behavior, different relations where plotted versus time, in instance; daily oil, water and gas productions, studying and analyzing theses information for each individual well gives the firs impression on which artificial suits a certain well.

Fluid properties are one of the very important factors that play a basic role in designing any artificial lift method, the reason why a sufficient time was devoted to analyze the available PVT data and extract the information needed for containing the complete image of the reservoir.

For the sake of achieving the ultimate aims, a Prosper software was used to set different scenarios models for the wells, existing gas lift were optimized and other lifting methods were investigated. Natural flow wells; both the flowing and the shut in once were analyzed as well with several lifting possibilities. Upon these analyses the suitable artificial lift method will be selected for the whole field.

Further more, with Prosper several future scenarios were run for each individual well, the sensitivity was run for the change of; water cut, GOR, reservoir pressure etc. this of course gives a good support for selecting the suitable artificial lift method.

All wells in Cherouq field are producing in a ***comingle way***, which means that several layers are produced together through the same tubing and from a several sliding sleeves (in Cherouq wells each several layers are produced from each individual sliding sleeves). This type of completion allows the operating company to pay its investment in a shorter time. On the other hand, technically it makes some complicating in getting a representative data for each individual layer, such as; reservoir pressure, and the contribution of each layer to the total production.

To estimate the ***life of field (LOF)*** it is very crucial to know how much was produced from the reservoirs (from each individual layer), in the case of commingled completion this task is not an easy one, as the production comes from several reservoirs at the same time.

All wells in Cherouq field are completed with a 7 inch casing, and in the case of installing ESP ***the accessibility of the downhole*** it is only possible with Y-tool (see chapter three), but in Cherouq field it is not possible to install a Y-tool as the minimum casing diameter should be 9 inch for Y-tool to be installed.

Chapter 2 Field Background

Field history

Cherouq concession locates in the Jenein Nord Exploration Permit, which is located within the Ghadames basin of southern Tunisia and is comprised of 4 blocks designated Jenein Nord "A" (904Km^2), "B" (48 Km^2), "C" (8 Km^2) and "D"(280 Km^2) for a total area of 1240 Km^2.

Pioneer Natural Resources Tunisia Ltd. ("Pioneer") originally entered the Jenein Nord exploration permit on July 1, 2004 by acquiring 22.5% of Anadarko Jenein Nord LTD's 50% interest. On January 1, 2006 Pioneer acquired Anadarko Jenein Nord LTD's remaining interest thus becoming operator and a 50/50 participant with ETAP. (1)

In an effort to reduce uncertainty, maximize cost efficiencies and accelerate the exploration process, 341.5 km^2 of 3D seismic was acquired over portions of the Jenein Nord Permit during June-July 2006, and fast track processing of the data was concluded in October 2006.

Exploration drilling began in October 2006 and 3 successful discoveries capable of commercial development have been drilled within the Jenein Nord "A" Permit area. Table 1 summarizes these drilling results:

	Spud date	TD; FM @ TD	Reservoir	Net Pay meters	Cost D+C+T $MM	1P-2P-3P STOOIP (MMBO)
Waha-1	22-09-06	4170 m Ord. Sanrhar	Acacus "A"	4.42	$14.3	4.4-6.5-9.5
Cherouq-1	15-12-06	4090 m Ord. Sanrhar	Acacus "A-B"	24.13	$13.0	3.5-5-6.6
El Badr-1	22-02-07	3650 m Sil. Tannezuft	Acacus "A-B"	22.49	$9.0	24-40-69

Table 1 Exploration drilling in Jenein Nord (1)

In June 2011 OMV took over the concession from Pioneer Natural resources, production in Cherouq concession started in mid of 2007 and the fields are currently producing approx. 6,000 boe/d from approx. fourteen wells in eight fields, currently most of the wells are producing on gas lift. The gas lift system is currently installed and the first wells are being converted to gas lift since the end of May 2011. (1)

The main producing reservoirs are in the Acacus with some also in Taghi and Tanezzuft formations. All wells are producing commingled from up to eight formations; water cut ranges from 0 to approx. 80%. Figure, 1 shows the distribution of the fields and the wells in Cherouq concession. (1)

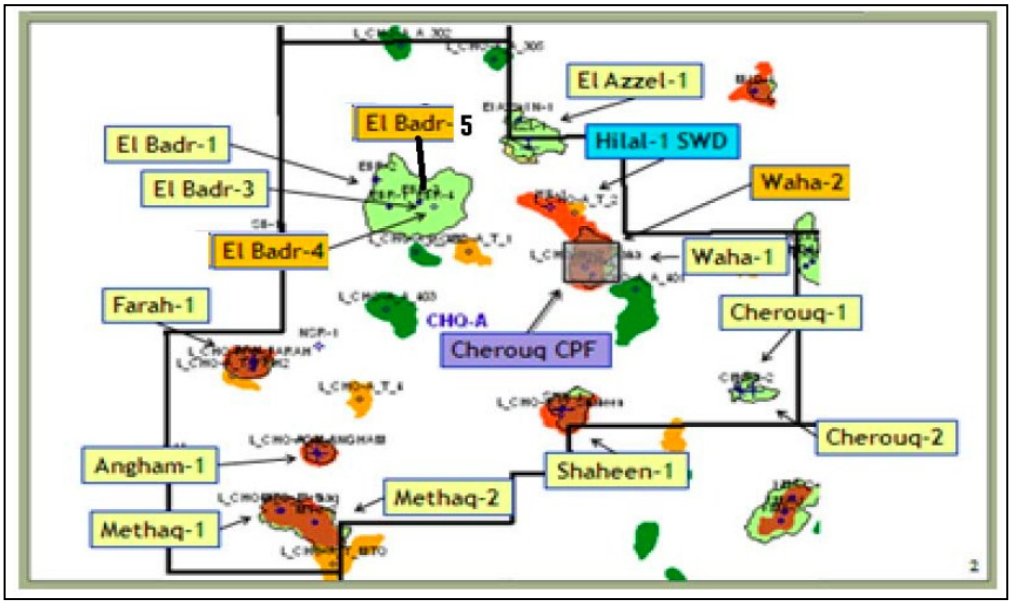


Figure 1 Distribution of the reservoirs in Cherouq field (1)

The structural evolution of the basin is long and complex but can be summarized as follows:

Pre-Cambrian-Cambrian: The Pan African Orogeny represents the initial tectonic phase within the region and plays a major role in creating zones of weakness which would be reactivated throughout geologic time. The major lineaments were oriented in NE-SW direction with possible E-W transfer zones. Development of NW-SE and N-S shear zones is also associated with this phase. (1)

Ordovician-Permian: 3 major events are noted during this period:

- Taconic (mid–late Ordovician)
- Caladonian (early-mid Devonian)
- Hercynian (late Carboniferous to Early Permian)

The Hercynian event considerably affected the basin by intensely reactivating the pre-existing NE-SW and E-W structural grain. The sediments deposited during this Era show a SW regional dip and progressive erosion towards the NE. (1)

Mesozoic-Tertiary: the opening of Tethys and the Atlantic influenced the Ghadames basin by reactivating previously created structural trends. The inversion of pre-existing N-S and NE-SW faults trends took place during the Austrian compressional event (Barremian-Aptian). The Tertiary Apline compression induced further inversions along NE-SW fault systems. (1)

Stratigraphic Chart

Figure, 2 details the Tunisian stratigraphic sequence

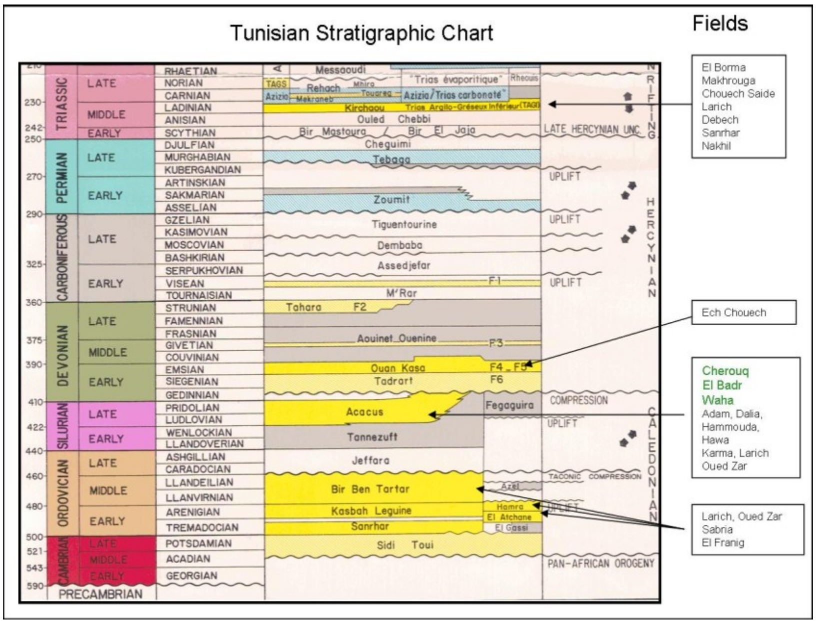


Figure 2 Tunisia stratigraphy chart (1)

Reservoir Characterizations

In general the Ghadames Silurian system can be characterized by a S-N progradational geometry. The marine shales of the Silurian Tannezuft are rich in organic matter. In particular, the "Hot Shale" unit at the base of the Silurian constitutes one of the main source rocks for the basin and is believed to have sourced the reservoirs discovered in Jenein Nord.

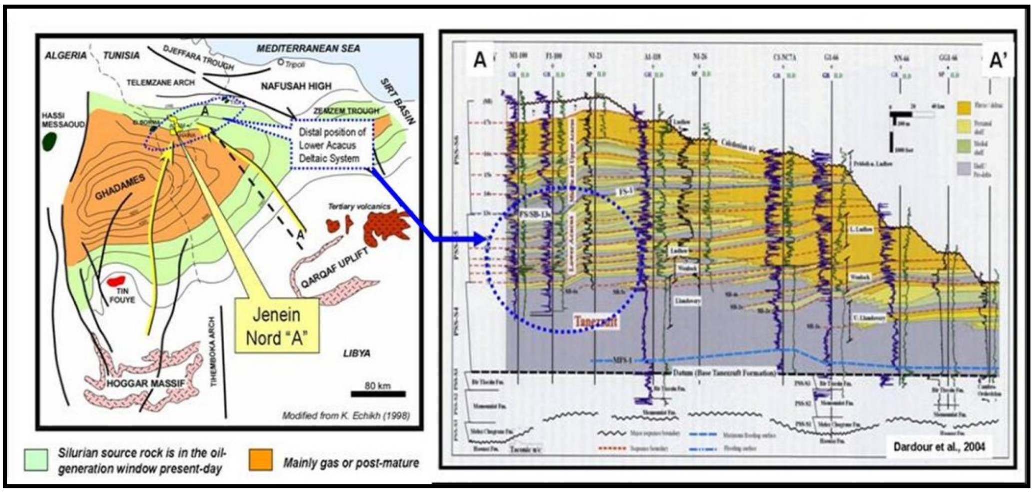


Figure 3 the structure (1)

Prograding conditions during the Silurian resulted in a gradual increase in terrigenous input to the basin and deposition of intercalations of thin sandy layers at the top of the Tannezuft. These "T-sands" have been found to be hydrocarbon bearing within the wells drilled to date in the Jenein Nord permit area. These sands precede the incoming Acacus marine depositional system and may in fact be more representative of initial Acacus deposition (i.e. basal Acacus).

The Acacus represents the evolution of a major SSE-NNW prograding Silurian deltaic system, the distal portions of which extend across those portions of southern Tunisia in which the Jenein Nord permit is located (figure 3).

Fluid Properties

To approach the optimum design for an artificial system a representative reservoir fluid properties should be available, a PVT analysis is required to take place to obtain the necessary data. Cherouq reservoirs consist of a several thin multilayer sands, and PVT data are available for only 5 wells (out of 14 wells), the maximum number of layers that were tested is two for each well, and to solve this issue the following was done:

- For the wells which have a PVT data for some layers, the data was united for the highest GOR and bubble point pressure as a worst scenario.
- For other wells, which do not have any PVT data, the production histories were analysed and they were matched to production histories of the wells with PVT data, and the ones with the same behaviours shared the same PVT data.The Average API gravity is about 41 APIº and water salinity is about 120,000 ppm. among all reservoirs, table 2 shows the summary of the PVT data that was run in Cherouq concession:

	Pr (psig)	Pb (psig)	visc @ Pb (cp)	Rs scf/bbl	Tr (f)	oil density @ Pb gm/cm³	Oil FVF @ Pb (stb/bbl)
Cherouq-1							
B2-2 (3184.4 - 3188.0 m)	4659.00	1341.00	0.538	467.00	184.00	0.70	1.322
A7(3393 - 3398 m)	5024.00	4095.00	0.182	1577.00	197.00	0.59	1.870
Waha-1							
T1 (3541.4 - 3543.5 m)	5305.00	1159.00	0.673	327.00	200.00	0.73	1.223
A9 (3514.5 - 3517.0 m)	5225.00	1297.00	0.510	432.00	199.00	0.70	1.302
Elbader-1							
T2 (3548.0 - 3553.0 m)	5322.00	1969.00	0.388	647.00	212.00	0.68	1.427
Angham-1							
A9-b (3675.5 - 3677.5m)	5545.00	2643.00	0.273	999.00	205.00	0.63	1.602
Elazzel-1							
Tagi-g (2338.5 - 2243 m)	3163.00	203.00	0.62	64.80	154.00	0.72	1.098

Table 2 PVT data available (1)

Field performances

Production history was plotted as well as the IPR curves for all wells, in order to help in diagnosing the performance for each well. From the production history we can clearly conclude that as soon the water break occurs a fast increase in the water cut is followed, this increase is always companied with increase of the hydrostatic pressure until the well is not able to flow. In appendix A. a description of each well performance is detailed.

Looking to the production history in figure 4, in the very early stage of the field life the production increased from about 1260 bbl/day in November 2007 to 9450 bbl/day in July 2008, this change is due to the additional wells drilled with this period, those wells are; Cherouq-1, El Badr-1, Shaheen-1, and Methaq-1.

Production from the field stayed constant for about half a year and then, this is before having drilled two other wells, which are Angham-1 (drilled in the first quarter of 2009) and Methaq-2 (drilled in the end of the second quarter of 2009), and of course they contributed to cause a slight increase in production.

During the year 2010 other two wells were added Cherouq-2 (put on production on November11, 2010) and El Badr-3 (put on production on July 23,2010), but it also can be seen that the field production decreased to around 4100 bbl/day by the mid of 2010. This decrease in production is because of the increase of WC%, which led to many well to be killed. In the first quarter of 2011 four wells were added, and as it is showed in the figure below the production jumped again to 10,000 bbl/day. The production stayed constant around this level for about 2 months, and then a dramatic fall occur and this again because of shutting in some wells. In June 2011 gas lift system installed and the first well put on gas lift production and this cause an increase in production and as more wells put on GL we have this jump in the production.

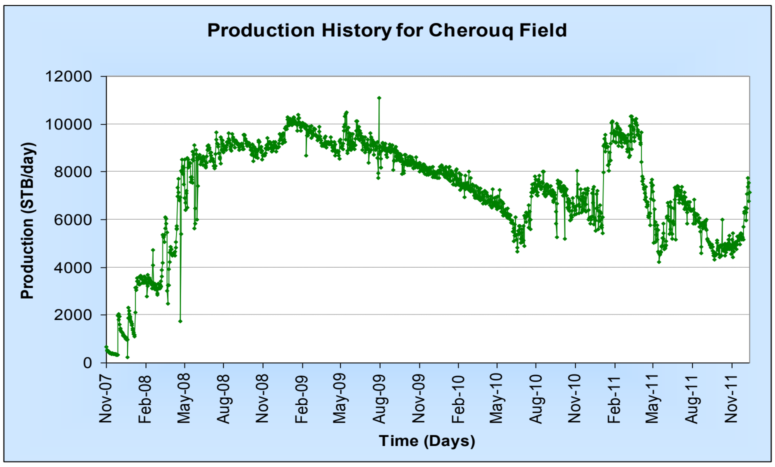


Figure 4 Production history of Cherouq field (1)

Chapter 3 Over view on Electrical Submersible Pump and Gas Lift

Wells will produce under natural flow conditions when reservoir pressure will support sustainable flow by meeting the entire pressure loss requirements between the reservoir and separator. In cases where reservoir pressure is insufficient to lift fluid to surface or at an economic rate, it may be necessary to assist in the lift process by either:

- Reducing flowing pressure gradients in the tubing e.g. reducing the hydrostatic head by injecting gas into the stream of produced fluids. This process is known as gaslift.
- Providing additional power using a pump, to provide the energy to provide part or all of the pressure loss that will occur in the tubing.

In the case of gas lift, the pressure gradients will be reduced because of the change in fluid composition in the tubing above the point of injection.

When pumps are used, apart from fluid recompression and the associated fluid properties, there is no change in fluid composition. There are many specific mechanisms for providing pump power and the lift mechanism. e.g.

- Electrical powered centrifugal pumps
- Hydraulic powered centrifugal/turbine, jet and reciprocating pumps
- Sucker rod and screw pumps

Each artificial lift system has a preferred operating and economic envelope influenced by factors such as fluid gravity, G.O.R., production rate as well as development factors such as well type, location and availability of power. (2)

Advantages and disadvantages comparison of different artificial lift

Table 3 summarizes the advantages and disadvantages of different artificial lift systems.

SRP		*ESP*		*GL*		*JP*	
Advantages	Limitations	Advantages	Limitations	Advantages	Limitations	Advantages	Limitations
Simple system design and analysis	Low to medium volume handling (depth depending)	Extremely high volumes lifting	Only with electric power application	Large volume handling with solids - minor problems	Energy source not always available	High volumes handling	Relatively inefficient lift method
Staff operability simple	Friction problems in crooked holes	Crooked hole present no problem	High voltages necessary	Crooked holes present no problem	System general low efficiency	Crooked hole present no problem	Requires at least 20% submergence to approach best lift efficiency
Slim-hole & multiple completions applicable	High solids production is troublesome	Simple to operate	Impractical and difficult to operate in low-volume wells	Flexible-conversion continuous-intermittent GL as well declines	Difficult to lift emulsions and viscous crudes	Possible Power source being remotely located	Design of system is more complex
A well pump-off conditions application	Lower volumetric efficiency gassy wells	Down-hole pressure sensor by cable telemetering data to surface	Difficult (and expensive) a well decline capability follow	Trouble less lifting gassy wells	Not efficient for small fields or one-well leases if compression equipment is required	Can use water as a power source	Pump may cavitate under certain conditions
Flexible-Can match displacement rate to well performance as well declines	Down-hole pump design limitations in small casing	Availability in different size	Lack of production rate flexibility	Easy obtaining down-hole pressures and gradients	Gas freezing and hydrate problems	Has no moving parts	Very sensitive to any change in back pressure
Viscous oils and high-temperature lifting	Obtrusive in urban locations	Unobtrusive in urban locations	Cable problems in tubular handling & high temperature wells	Unobtrusive in urban locations	Problems with dirty surface lines	Unobtrusive in urban locations	Free gas production through the pump reduces ability to handle liquids
Gas or electricity as power source	Non-offshore operations	Applicable offshore	Depth limited system (3500.0 m), due to cable cost and power consumption	Applicable offshore	System properly analysis difficulty without good engineering	Applicable offshore	Power oil systems are fire hazard

Easy to perform corrosion and scale treatments	Susceptible to paraffin problems	Easy to perform corrosion and scale treatments	Gas and solids production are troublesome	Corrosion is not usually as adverse	Safety problem with high pressure gas	Easy to perform corrosion and scale treatments	High surface power fluid pressures are required
Availability of different sizes	Tubing cannot be internally coated for corrosion	Lifting cost for high volumes generally low	Difficult analysis unless good engineering know-how	Mostly serviceable with Wireline unit	Requires makeup gas in rotative systems	Retrievable without pulling tubing	
			Casing size limitation				
			Cannot be set below fluid entry without a shroud				

Table 3 Advantages and disadvantages of different artificial lift methods (2) (4) (7) (11)

The limitations of SRP, ESP and GL are summarized in table 4.

Form of lift	***SRP***	***ESP***	***GL***
Maximum Operating depth	5,000m	4,500m	5,500m
Maximum Operating Volume	3,000 BPD	60,000 BPD	60,000 BPD
Maximum Operating Temp.	280^0C	200^0C	230^0C
Corrosion Handling	Good to Excellent	Good	Good to Excellent
Gas Handling	Fair to Good	Fair	Excellent
Solids Handling	Fair to Good	Fair	Good
Fluid Gravity	> 8 API	> 10 API	> 20 API
Prime Mover	Gas or Electric motor	Electric motor	Compressor
Servicing	WO rig	WO rig	WO rig or Wireline Unit
Efficiency	50 – 70%	35 – 60%	10 – 30%

Table 4 The limitation of some artificial lift methods (1) (4) (7)

Electrical Submersible Pumps

In the oil and gas industry, electric submersible pump (ESP) systems are probably best known as an effective artificial lift method of pumping production fluids to the surface. ESPs are especially effective in wells with low bottom-hole pressure, low gas/oil ratio, low bubble-point, high water cut or low API gravity fluids.

Over the last several years, ESP technology has developed a reputation as a low-maintenance, cost-effective alternative to vertical turbine, split case and positive displacement pumps in various fluid-movement surface applications in the petroleum industry.

About 15 to 20 percent of almost one million wells worldwide are pumped with some form of artificial lift employing electric submersible pumps. In addition, ESP systems are the fastest growing form of artificial lift pumping technology. They are often considered high volume and depth champions among oil field lift systems.

Found in operating environments all over the world, ESPs are very versatile. They can handle a wide range of flow rates from 70 bpd to 64,000 bpd or more and lift requirements from virtually zero to as much as 15,000 ft of lift. As a rule, ESPs have lower efficiencies with significant fractions of gas, typically greater than about 10 percent volume at the pump intake. Given their high rotational speed of up to 4000-rpm and tight clearances, they are also only moderately tolerant of solids like sand. If solid-laden production flows are expected, special running procedures and pump placement techniques are usually employed. When very large amounts of free gas are present, downhole gas separators and/or gas compressors may be required in lieu of a standard pump intake.

ESP systems can be used in casing as small as 4.5 in outside diameter and can be engineered to handle contaminants commonly found in oil-aggressive corrosive fluids such as H2S and CO2, abrasive contaminants such as sand, exceptionally high downhole temperatures and high levels of gas production. Increasing water cut has been shown to have no significant detrimental effect on ESP performance. ESPs have been deployed in vertical, deviated and horizontal wells, but they should be located in a straight section of casing for optimum run life performance.

On a cost-per-barrel basis, ESPs are considered economical and efficient. With only the wellhead and fixed or variable-speed controller visible at the surface, ESP systems offer a small footprint and low-profile option for virtually all applications, including offshore installations. (3) (4)

Electrical submersible pump equipment

The Submersible pump

The heart of the ESP unit is the submersible pump and the design and analysis of the whole ESP system cannot be understood without a basic comprehension of the operation of the pump. This is the reason why the description operation of the centrifugal pumps. The submersible pumps used in ESP installations are multistage centrifugal pumps operating in a vertical position. Although their constructional and operational features underwent a continuous evolution over the years, their basic operational principle remained the same. Produced liquids, after being subjected to great centrifugal forces caused by the high rotational speed of the impeller, lose their kinetic energy in the diffuser where a conversion of kinetic to pressure energy takes place. This is the main operational mechanism of radial and mixed flow pumps.

Figure 5 illustrates the main parts of an ESP pump containing mixed flow stages. The pump shaft is connected to the gas separator or the protector by a mechanical coupling at the bottom of the pump. Well fluids enter the pump through an intake screen and are lifted by the pump stages.

Other parts include the radial bearings (bushings) distributed along the length of the shaft providing radial support to the pump shaft turning at high rotational speeds. An optional thrust bearing takes up part of the axial forces arising in the pump but most of those forces are absorbed by the protector's thrust bearing.

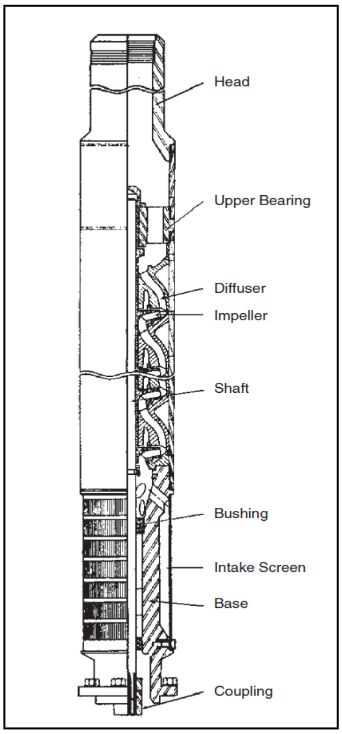


Figure 5 Electrical Submersible Pump (4)

The liquid producing capacity of an ESP pump depends on the following factors:

- the rotational speed provided by the electric motor,
- the diameter of the impeller,
- the design of the impeller (characterized by its specific speed),
- the actual head against which the pump is operating, and
- the thermodynamic properties (density, viscosity, etc.) of the produced fluid.

Conventional ESP installations run on AC power with a constant frequency of 60 Hz or 50 Hz. ESP motors in 60 Hz electrical systems rotate at a speed of about 3,500 RPM, whereas in the case of a 50 Hz power supply the motor speed is about 2,900 RPM. For constant speed applications the most important factor is impeller size which, of course, is limited by the ID of the well casing. Pumps of bigger sizes can produce greater rates although impeller design also has a great impact on pump capacity.

The length of individual ESP pumps is limited to about 20–25 ft, for ensuring proper assembly and ease of handling. Tandem pumps are made up of several pump sections (up to three) and are used to achieve higher operational heads usually required in deeper wells. This way several hundreds of stages can be run, the maximum number of stages being limited by one or more of the following factors:

- the mechanical strength of the pump shaft, usually represented by the shaft's horsepower rating,
- the maximum burst-pressure rating of the pump housing, and
- the maximum allowed axial load on the unit's main thrust bearing (usually situated in the protector section).

Individual stages in ESP pumps, provided they are of the same impeller design, handle the same liquid volume and develop the same amount of head. The heads in subsequent stages are additive so a pump with a given number of stages develops a total head calculated as the product of the total number of stages and the head per stage. This rule allows one to find the number of stages required to develop the total head to overcome the total hydraulic losses, valid at the desired liquid production rate in a well. Since the size of well casing limits the outside diameter of the ESP, which can be run, pump selection is heavily restricted by the actual casing size. Appendix B lists the main dimensional data of common API tubulars. For comparison, Appendix C contains the most important parameters (diameters, recommended liquid rate ranges) of submersible pumps available from a leading manufacturer. (4)

Pump stages

The centrifugal pump consist of a number of stages to provide the required energy to lift the fluid to the surface, each stages consists of an impeller and diffuser as it is shown in figure 6

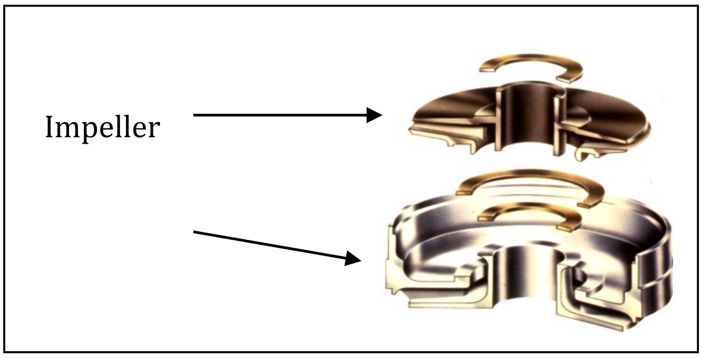


Figure 6 Pump stages (9)

Impeller and diffuser functions

The function of the impeller is to transfer the energy by rotation to the fluid when it passes through it therefore increases the kinetic energy of the fluid; the rotation of the high speed impeller guides the fluid into the stationary diffuser, the diffuser then converts the kinetic energy to a potential energy in a form of pressure as it passes through stages. (4) (9)

Redial and mixed flow pumps

The difference between these two types of designs is described by the pump impeller vane angles and the size and shape of the internal flow passages, the redial one has a radial flow impeller which has a vane angles at close to 90 degree, and therefore, is usually found in pumps designed for low flow rates, whereas the mixed one has a vane angels at close to 45 degree, and therefore, are usually found in pumps designed for higher flow rates. See figure 7. (7) (9)

Figure 7 Type of flows (radial and mixed flow) (7)

Pump performance curves

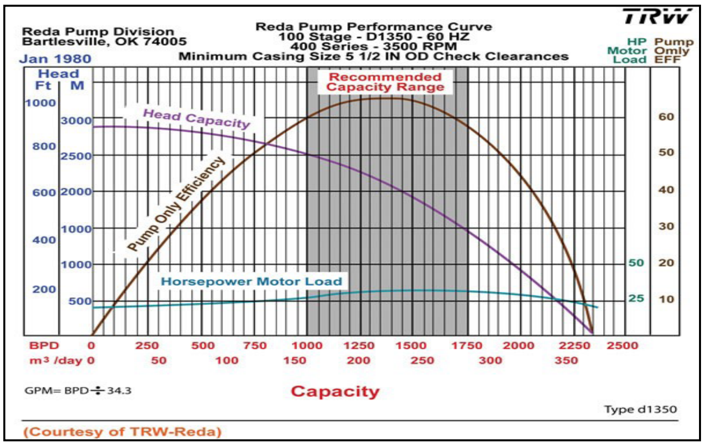


Figure 8 Pump performance curve (7)

The performance of ESP pumps is characterized by the pump performance curves. These are plotted in the function of the pumping rate and represent:

- the head developed by the pump,

• the efficiency of the pump, and

• the mechanical power (brake horsepower) required to drive the pump when pumping water.

Each curve represents an certain individual pump, and each pump manufacture issued his own curves for his own pumps. They are obtained by running a pump in fresh water at a constant speed, while varying its throughput by throttling the discharge side of the pump. During the test, the pressure difference across the pump, the brake horsepower, and the pump efficiency are measured at different pump throughput rates. The resulting pressure increase is then converted to its equivalent head. With this data, the above-mentioned three points are obtained. Although these curves are generated using fresh water (with a specific gravity of 1.0), the same values of head are usually used when selecting a pump for a fluid with a different specific gravity provided the viscosity of the fluid is similar to the viscosity of water. Brake horsepower, on the other hand, does require a specific gravity correction. (4)

Pump intakes

A standard intake can be used when the well is producing above the fluid bubble point pressure, or if a maximum of 10% free gas is being produced, if not the free gas would enter the pump causing significant problems, such as gas locking, lower bearing lubrication, decreased efficiency, reduced flow rates etc. to avoid all this a Gas Separator intake must be installed.

The rotary gas separator is based on the principle of the separation of particles of different densities under the action of centrifugal forces. In this design, a rotating field of centrifugal force is created. The separated gas is vented to the annulus, while the remaining fluid enters the pump. (6)

Figure 9 Pump intake (6)

Electrical submersible motor

ESP motors are three-phase, two-pole, squirrel cage induction-type electric motors, ESP motors are three-phase, two-pole, squirrel cage induction-type electric motors. (4)

As you can see in figure 10 the main parts of the motor are:

- Motor shaft.
- Rotor.
- Lamination (with the Copper Bars).
- Stator (Laminations and the stator windings).
- Housing.

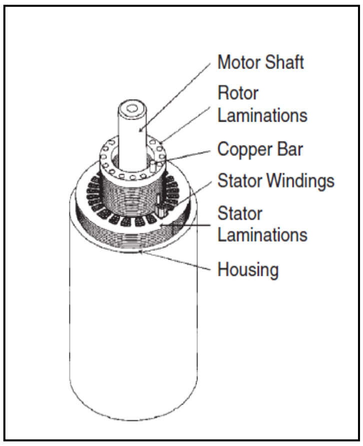


Figure 10 Electrical submersible motor (4)

The motor stator is located inside the motor housing; the stator is a hollow cylinder made up of a great number of tightly packed steel disc sheets called "Laminations", the laminations have a several holes (slots) and to prevent an electrical connection between the windings, which are installed inside the slots, and the stator these slots are highly insulated. (4)

Inside the stator and separated from it by annular air gab located the rotor, the rotor just like the stator made up of the laminations, the slots in the rotor laminations accommodate a cobber bar joined from their two ends into what is so called " end rings", making up the squirrel cage. The rotor lamination has a keyway, which accommodates the key, which fixed into the motor shaft in order to transmit the torque to the shaft. (4)

To prevent the undesirable redial movements of the rotor, the ESP's motors are manufactured with a number of rotors with a length interval of (1 ft long), and a redial bearing is mounted between them.(4)

The rotating magnetic field developed by the AC current flowing in the stator windings induces a current in the rotor. Due to this induced current a magnetic field develops in the rotor, too. The interaction of the two magnetic fields turns the rotor and drives the motor shaft firmly attached to the rotor. (4)

To compensate for the axial load "movement" due to shaft and rotor weight, a thrust bearing of the proper capacity is installed at the top, Figure 11 shows both the redial and the thrust bearings. (4)

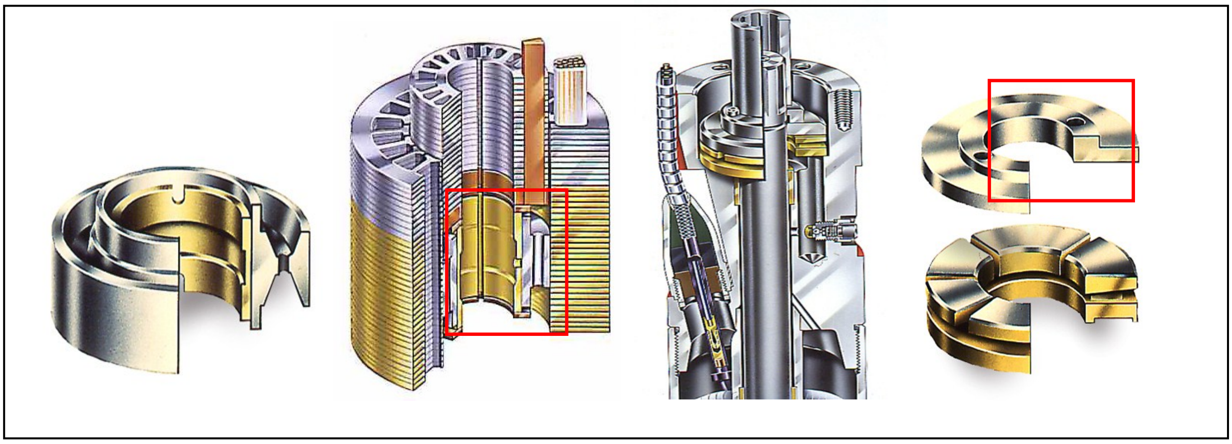


Figure 11 Radial and thrust bearing (9)

The motor is a very crucial part of the ESP as any failure in the motor will lead to a failure of the whole system, these motors run at a relatively constant speed of 3500 rpm on 60-Hertz frequency and 2,915 rpm on 50 Hertz frequency. The motors are filled with nonconductive refined oil to lubricate the motor bearings and transfer the heat, which generated inside the motor to the motor housing; heat from the motor housing then is carried away by the produced fluid, to achieve an accepted cooling efficiency the velocity of the well fluid around the motor must be around 1 ft./sec. (10)

Sealing section

The seal section is located between the motor and the intake and performs the following functions (3):

- Houses the thrust bearing that carries the axial thrust developed by the pump
- Isolates and protects the motor from well fluids
- Equalizes the pressure in the wellbore with the pressure inside the motor
- Compensates for the expansion and contraction of motor oil due to internal temperature changes

Seal sections can be used in tandem configurations for increased motor protection. They are available in bag type and labyrinth-style designs to meet specific applications; the selection of the type of the seal section depends on many factors (3):

- Well fluid gravity,
- type of well (vertical, horizontal or highly deviated),
- and the motor size.

Electrical cable

Over half of ESP failures worldwide occur in the cable string, which comprises of the main cable, motor lead extensions, splices, penetrators, etc. If extending runlife is the most effective means of reducing operating costs, then this primary failure mode needs specific attention.

The cable provides power to the motor and the gauge. If the cable is damaged prior to or during installation, runlife will be reduced. The cable is made up of conductors, insulations, barriers, jackets and armor. Plus there are difference configurations, different types of armor and different armor construction. However, if the best cable for a particular operation is used and proper handling procedures are followed, but correct installation practices are not adheared to, the runlife will be compromised. (5)

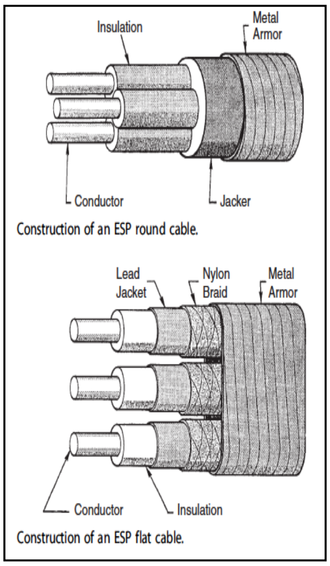


Figure 12 Elictrical cable (4)

Surface equipment

Wellhead

Due to the weight of the subsurface equipment and the need to maintain an annulus control the ESP installation has a special wellhead, which not only has a positive sealing around the tubing but also around the ESP electrical cable. There are several wellhead installations; in the Hercules wellhead the downhole power cable is fed through the wellhead, this type installation is illustrated in figure 13. (4)

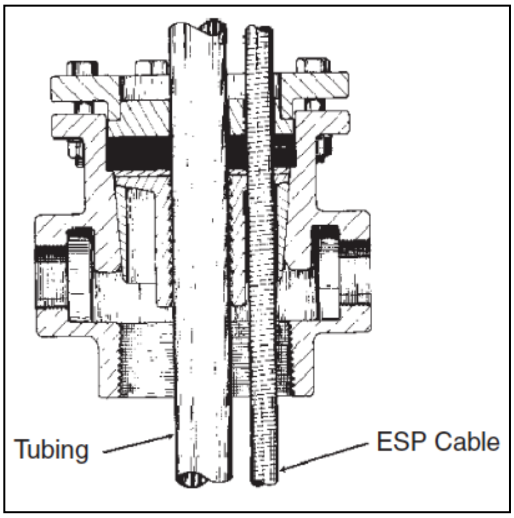


Figure 13 Hercules wellhead (4)

In other wellheads the power cable is cut at the wellhead and it is equipped with a power connector from its end, and the surface cable which comes from the switch board also has a connector in his end, and both ends are united at the wellhead, the advantages of this type of wellhead to the previous type, that they allow a higher wellhead pressure rating and they are easier to use, see figure 14. (4) (3)

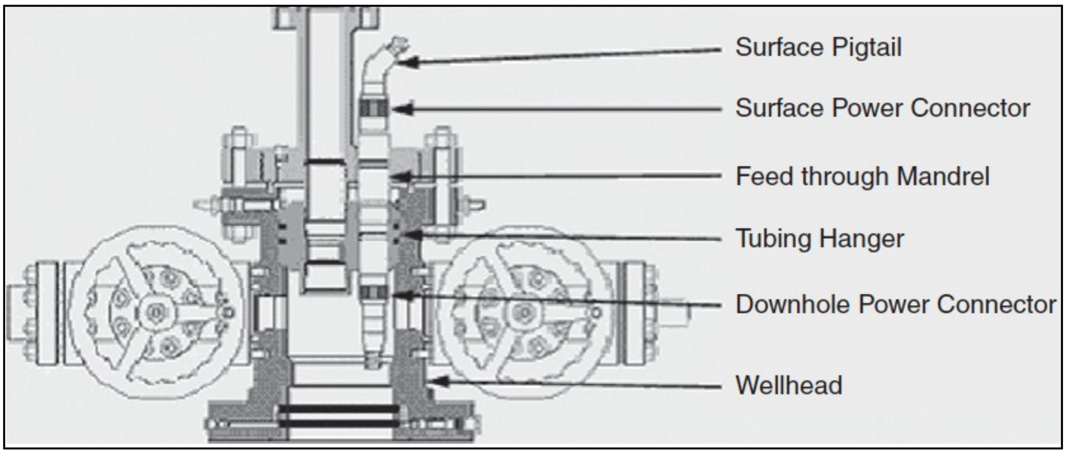


Figure 14 ESP wellhead (4)

Junction Box

The junction box is the point where the surface power cable that comes from the wellhead is connected to the power cable comes from the switchboard; it is also called a “vent box”, and it provides the following important functions (4):

- It provides the electrical connection between the downhole and the surface electric cables.
- It vents any gas to the atmosphere, which might reach this point due to migration of well gases up the ESP power cable. The venting of gas eliminates the danger of fire or explosion because gas is not allowed to travel in the cable to the switchboard.
- It acts as an easily accessible test point for electrically checking the downhole equipment.

Switchboard

Switchboard is the brain of the conventional ESP installations, it control the electrical motor, and consequently, controls the operation of the whole installation. It has also the following functions (3) (4) (5) (7):

- Provides a controlled on/off switching of the ESP equipment to the power supply using high capacity switch disconnectors or vacuum contactors.
- Protects the surface and downhole equipment from a wide variety of problems.
- Monitors and records the most important operating parameters; line current, voltages and power factor, and so on.

The switchboard is basically an on/off switch with fuses and a disconnect. Everything else in a switchboard is extra equipment. The are many extra instruments that are often included in a switch board, such as:

- Motor controller
- Amp charts
- Back Spin Shunts
- Surface Panel for Downhole Gauge
- Instrument Transformers
- SCADA
- Surge Protection
- Status beacons

The switchboard will provide a hard start to the ESP; as a result in shallow applications it is common to include a softstarter to reduce the inrush current.

Transformer

Rarely does the power supplied at a wellsite match with the power required by the ESP. Normally the ESP requires a medium voltage (250-4000 volts), while the site power is high voltage line power(6000 volts). In order to adjust the available voltage to the required voltage, transformers are used. Transformers are selected on the basis of voltage levels and power ratings. The required surface voltage heavily depends on the setting depth of the ESP equipment since the voltage drop in the power cable increases with cable length. This voltage drop plus the selected motor voltage give the necessary surface voltage. (4) (5) (7)

Miscellaneous equipment

Variable speed drive (VSD)

The variable speed drive (VSD) changes the frequency of the electric current driving the ESP motor and thus considerably modifies the head performance of the submersible pump. By properly setting the driving frequency, a very basic limitation of ESP units can be eliminated and the lifting capacity of the submersible pump can easily be modified to match the inflow performance of the well. Without a VSD unit, in wells with unknown liquid production capacities the ESP unit has to be exchanged with a unit better fitting the inflow to the well, which usually involves a costly workover operation. (4)

Check valve

A one way valve which set two or three joints above the ESP pump to prevent the revers motion due to the revers flow of the produced fluid in the cases of pump shut down. Revers motion within the pump parts should highly be avoided due to the following sever problem it causes (4) (5):

- Motor and cable can be burned
- Damage to the shaft due to high torque

State of art switch boards are not possible to start then as long a revers motion is occurring with in the pump.

Bleed valve

It uses whenever a Check valve is used, it is set above the check valve in order to bleed out the tubing above the check, so in case of pump failure the tubing can be pulled dry. The drain valve contains a break-off plug that, after being sheared, opens a hole in the tubing through which liquid can flow back to the well bottom. Shearing of the plug is best accomplished by using a sinker bar on a wireline, but dropping a short bar in the tubing may also be used. (5) (7)

Centralizers

Centralizers used to keep the motor and the pump in the center to guarantee a proper calling efficiency for the system, also protects the cable from being damaged because of it get rubbed against the casing wall, keeps the pump located in the center in deviated wells where the pump is tend to stick in one side of the casing, more over by applying the centralizers we avoid any damages can happen to outer coating applied to the pump in the corrosive environments. (4) (5)

Y-tool

Is a special crossover assembly installed in the bottom of the tubing, where the pump is set in the offset section, and the other section (the straight part which is in line with the tubing string) is plugged. This application gives the opportunity to reach the section of well below the ESP unit and the flowing measurement can be done (4):

- formation treatment: acidizing, fracturing, and so on,
- well completion: perforation of new pays, and so on,
- running of pressure surveys using wireline or coiled tubing, and
- other well logging tasks.

ELECTRICAL SUBMERSIBLE PUMP DESIGHN

Selecting the right ESP is important to provide the most efficient and reliable operation. Complete and accurate well should be carefully evaluated to arrive at the most economical and efficient installation. The guide and the checklist for the design are detailed below (7):

Required data

- Physical description
  - Casing size and weight.
  - Tubing size, type and thread.
  - Total depth.
  - Depth of perforation.

- Production data
  - Static fluid level and/or static bottom hole pressure.
  - Pumping fluid level and/or flowing bottom hole pressure.
  - Desired production rate.
  - Bottom hole temperature.
  - GOR.

    - Surface backpressure.

- Well fluid data
    - API gravity of oil.
    - Specific gravity of brine.

- Power supply
    - Surface voltage, phase and cycle.
    - Line capacity.

- Unusual conditions
    - Abrasives.
    - Corrosions.
    - Paraffin.
    - Emulsion.
    - Scaled forming tendencies.

Gas Lift

Gas lift is one of a number of processes used to artificially lift oil or water from wells where there is insufficient reservoir pressure to produce the well. The process involves injecting gas through the tubing-casing annulus. Injected gas aerates the fluid to reduce its density; the formation pressure is then able to lift the oil column and forces the fluid out of the wellbore. Gas may be injected continuously or intermittently, depending on the producing characteristics of the well and the arrangement of the gas-lift equipment. (8)

Gas lift is a form of artificial lift where gas bubbles lift the oil from the well. The amount of gas to be injected to maximize oil production varies based on well conditions and geometries. Too much or too little injected gas will result in less than maximum production. Generally, the optimal amount of injected gas is determined by well tests, where the rate of injection is varied and liquid production (oil and perhaps water) is measured. (8)

Although the gas is recovered from the oil at a later separation stage, the process requires energy to drive a compressor in order to raise the pressure of the gas to a level where it can be re-injected. (8)

Operational mechanism

The two broad categories of gas lifting (continuous flow and intermittent lift) both utilize high-pressure natural gas injected from the surface to lift well fluids but work in different principles.

In continuous flow operation, lift gas is continuously injected at the proper depth to into the well stream from the casing-tubing annulus or the tubing string annulus. This injected gas joins the formation gas to lift the fluid to the surface by one or more of the following processes (11):

- Reduction of the fluid density and the column weight so that the pressure differential between reservoir and wellbore will be increased.
- Expansion of the injection gas so that it pushes liquid ahead of it which a further reduces the column weight.
- Displacement of liquid slugs by large bubbles of gas acting as pistons.

If a well has a low reservoir pressure or a very low producing rate an intermittent gas lift is preferable to use.

Intermittent gas lift, although also using compressed gas injected from the surface, works on a completely different operational mechanism. The well is produced in periodically repeated cycles, with accumulated liquid columns being physically displaced to the surface by the high-pressure lift gas injected below them.
During the intermittent cycle fluids are first allowed to accumulate above the operating gas lift valve, then lift gas is injected through the valve and below the liquid column, if a proper gas lift volume and pressure are used, lift gas propels the liquid slug to the surface (wellhead) and into the flow line. (11)
Advantages and Limitations of gas lift

Gas lift suits almost every type of well that needs to be artificially lifted, it can be used to artificially lift oil wells to depletion, to kick off wells that will flow naturally, to back flow water injection wells, and to unload water from gas well.
General advantages of using any version of gas lift can be summed up as follows (11):

- Initial cost of downhole gas lift equipment is usually low.
- Comparing with the other artificial lift methods, gas lift is the most flexible method, which means that any gas lift installation can be modified to accommodate extremely great changed in liquid production rate.
- Wells can be produced to depletion by applying gas lift only.
- Suitable in vertical and deviated wells.
- Corrosion control in wells is easily accomplished.
- Accessibility to downhole, so any downhole measurement can be conducted.
- Is not effected by the sand produced with fluid.
- Comparing with the other methods gas lift has a longer service life, this because gas lift system has a few moving parts.
- Low operating cost.
- When the wells produce a substantial amount of gas, gas lift system is the only choice.
- Gas lift valve can be removed and changed by wire line, so there is no need to kill the well or to any production intervention unlike any other artificial lift method.
- The major item of gas lift (compressor) is installed on the surface, which makes it easy to Maintain and inspect.

On the other hand gas lift also has some limitations, which can be summarized as following (11):

- Availability of injection gas.
- Wide well spacing my limit the use of centrally located source of high-pressure gas.
- If a sour gases or water exist in the gas, treatment and drying process are needed to avoid

corrosion.

- Installation of gas lift system including compressors usually requires a longer lead-time and greater preparations than does single well pumping system.
- Gas lift surface equipment is very expensive.
- Conversion of old wells to gas lift require a higher level of casing integrity than would be required for pumping system.

GAS LIFT EQUIPMENT

Basically gas lift dose not have many equipment, the reason why gas lift is considered as a flexible lifting method.

Downhole equipment:

- ***Gas lift mandrel***: it is a pipe connected to the tubing having and it is the part where the gas lift valves installed. (7)
- ***Gas lift valves***: it is the heart of the gas lift, it is installed to control the injection of gas into the produced fluid to assist their travel to the surface the valve is opens and closes in response to the pressure change into the casing or the tubing.

Practically all gas lift vales use the effect of pressure acting on the area of a valve element, bellows, to cause the desire valve action. (7)

- ***Check valve***: installed in the bottom of the tubing to prevent the production fluid to flow inversely, specially in wells whose reservoir pressure is weak then we might face the risk of fracturing the reservoir. (7)
- ***Packer***: the reason to use a packer is economically; all gas lift installation nowadays is installed with packers to avoid using a huge quantity of gas. (7)

SURFACE EQUIPMENT:

- ***Compressor***: provides the required pressure to the injected gas, it is the heaviest part of the gas lift system and the most expensive. (7)
- ***Gas volume gauge***: an orifice meter and square root chart is the typical field method od determining gas volume, for good gas lift operations and gas conservation reasonable accuracy in measurement are required. (7)

GAS LIFT MECHANISM

Before gas lift injection begins, the fluid levels in both the tubing and casing are at the surface. The pressure of the weight of this fluid holds the valves open. (12)

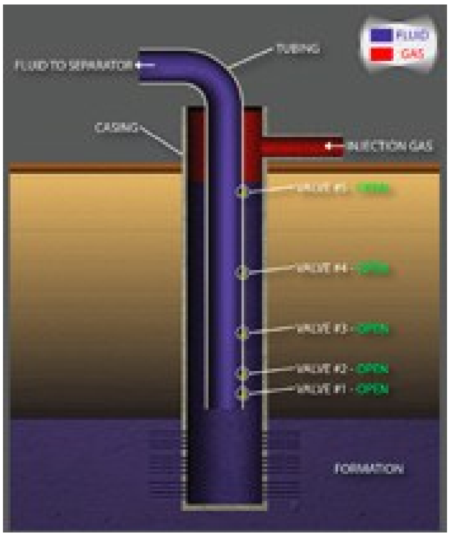


Figure 15 Gas lift working principals (a) (12)

- Gas injection into the casing has begun
- Fluid is u-tubed through all open valves
- No formation fluids being produced; all fluids are from the tubing and casing

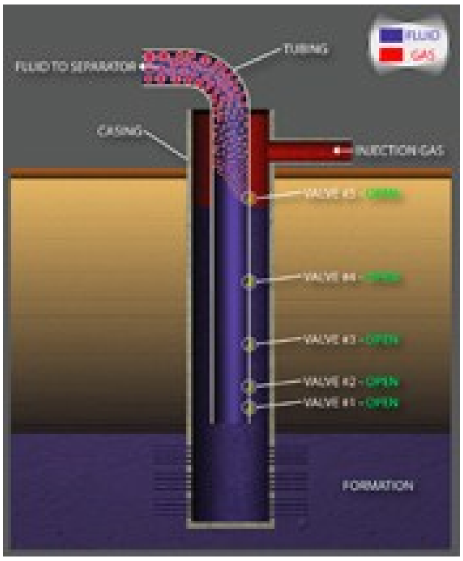


Figure 16 Gas lift working principals (b) (12)

- The fluid has been unloaded to top 5 valve
- The fluid is aerated above this point in the tubing and fluid density decreases.
- Pressure is reduced at top valve, as well as all lower valves.
- Unloading continues through lower valves.

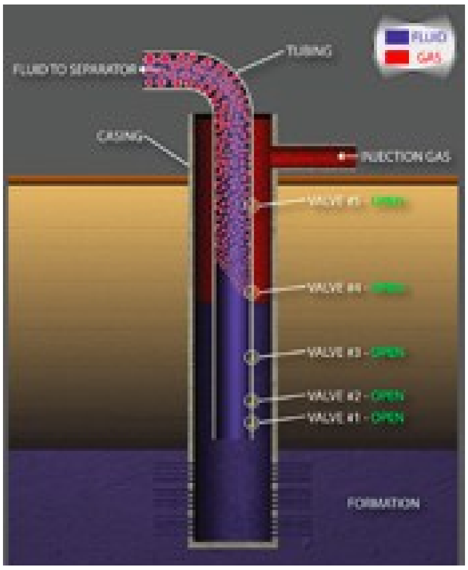


Figure 17 Gas lift working principles (c) (12)

- Fluid level is now below valve 4
- Injection transfers to valve 4 and pressure is lowered
- Casing pressure drops and valve 5 closes
- Unloading continues through lower valves

- All gas is being injected through valve 4
- Lower valves remain open
- A reduction in casing pressure causes upper valves to close in sequence

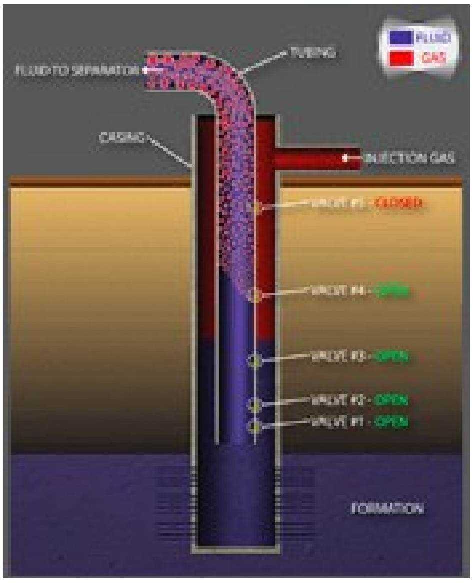


Figure 18 Gas lift working principals (d) (12)

- All gas is being injected through valve 3
- Lower valves remain open
- A reduction in casing pressure causes upper valves to close in sequence

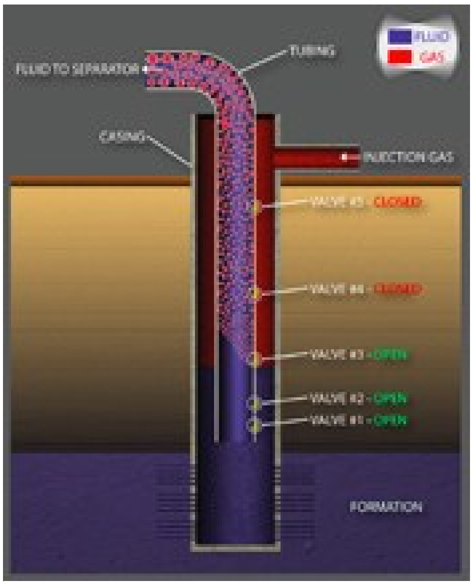


Figure 19 Gas lift working principals (e) (12)

- Valve 2 open; this is the Point of Injection

(ability of reservoir to produce fluid matches the ability of the tubing to remove fluids)

- Casing pressure is dictated by operating valve set pressure
- Upper valves are closed
- Valve 1 remains submerged unless operating conditions change in the reservoir (i.e. formation drawdown)

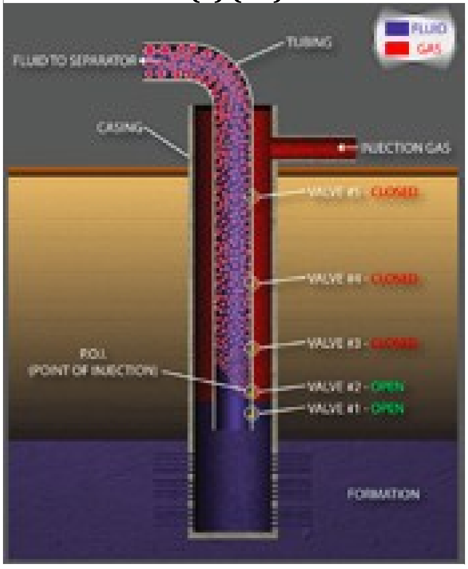


Figure 20 Gas lift working principals (f) (12)

GAS LIFT DESIGN:

Two cases of gas lift design (11):

1. Spacing and pressure setting for new wells.
2. Pressure setting for new wells, which already provided with gas lift mandrels but not produced on gas lift.

   Spacing is the act of determination the depths of gas lift valves.

THE REQUIRED DATA FOR GAS LIFT DESIGN

Reservoir Data:

- Flow rate (BPD).
- Productivity index.
- Water cut (%).
- Formation GOR.
- Bubble point pressure.
- Specific gravity of (oil, water, gas produced and the injected gas).
- Oil viscosity.
- API gravity.

OTHER DATA

- Injection gas pressure available.
- Static bottom hole pressure.
- Casing size.
- Tubing size.
- Tubing end.
- Perforation depth and thickness.

Sucker Rod Pump

The Sucker Rod Pump brings underground oil to the earth's surface by a reciprocating motion. It is driven by a motor, which turns a flywheel with a crank arm, attached to the crank arm is a Pitman Arm, which in turn, attaches to the Walking Beam. At the other end of the walking beam is the Horsehead. The Hanger Cable hangs off the Horse-head, and is attached with a clamp to a Polished Rod, which goes through a Stuffing Box and is attached to the Rod String.
At the bottom of the well a Traveling Valve, often just a ball in a cage, is attached to the Plunger (shown in green) at the end of the Rod String. Below that is another ball in a cage, called a Standing Valve. (7) (13)

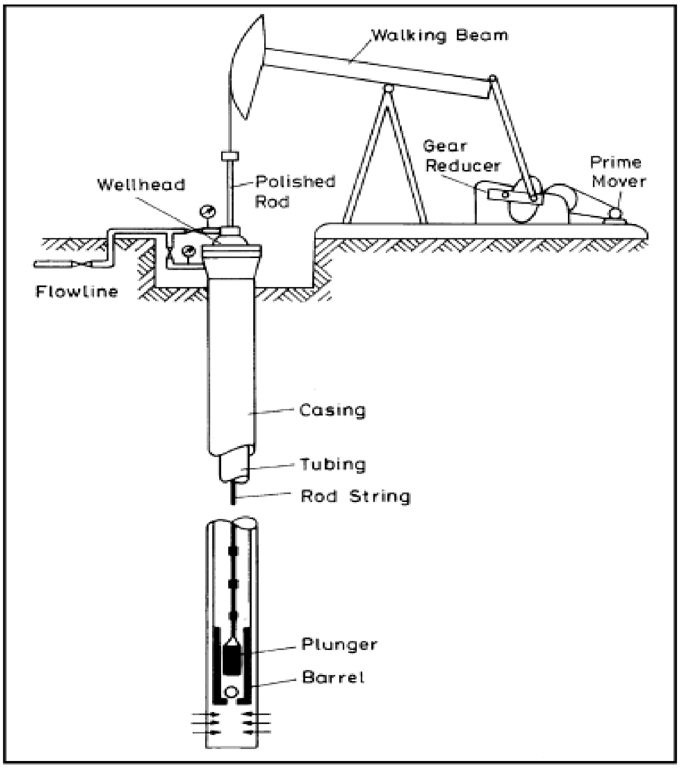


Figure 21 Sucker Rod Pump (7)

There are many parameters that the engineer should know to make a pump design. One of these parameters is the PI, to get the PI could not be a problem if there is an access to the data that required for calculating PI, but if it is not, an alternative solution should be found to obtain the PI. Swabbing process is that the engineers rely on in such situation.

Sucker rod sub surface pump types:

Rod (insert) pump

The entire pump is lowered inside the tubing by the sucker rod, and the barrel is set in its working position by the setting assembly. (7)(13)

- Stationary barrel (top anchor): the pump is suspended from the top of the barrel, while the plunger is the part, which travels along the pump.
- Stationary barrel (bottom anchor): the pump is suspended from the bottom of the barrel.
- Travelling barrel (bottom anchor): it is also called an inverted pump, where the plunger is the stationary and the barrel is the travelling part. Here the anchoring is not optional; it must be at the bottom.

Tubing pumps

The barrel of the pump is run as unit with the tubing, then the plunger is lowered by the plunger is lowered by the sucker rod. In addition in this type of pumps there is no setting assembly. This pump is suitable for high production rates where the inside diameter of the barrel is larger than what is it in the rod pump. (7) (13)

Sucker rod pump subsurface Description

Barrel: is a cylindrical vessel into which the fluid enters and transmitted by the plunger. (13)

Plunger: is responsible on displacing the fluid from above the standing valve up to the cage and the tubing. The plunger is provided with cups, rings or other soft backing to prevent leakage. (13)

Standing valve: is a ball-and-seat valve type (check valve), which is mounted in the barrel for (stationary barrel rod pump) and in the plunger for (travelling barrel rod pump) and its purpose is allowing the fluid to enter into the barrel or (the plunger). (13)

Travelling valve: it is similar to the standing valve and it is also could be mounted with barrel or the plunger depends on the type of the pump. Its function is permit the fluid entering to the plunger and prevents it from going back in to the barrel. (13)

Setting assembly: it is the main function is to suspend the pump in its working position, and it is equipped with seals in order to prevent the leakage of the fluid back to the bottom of the tubing after replacing it. (13)

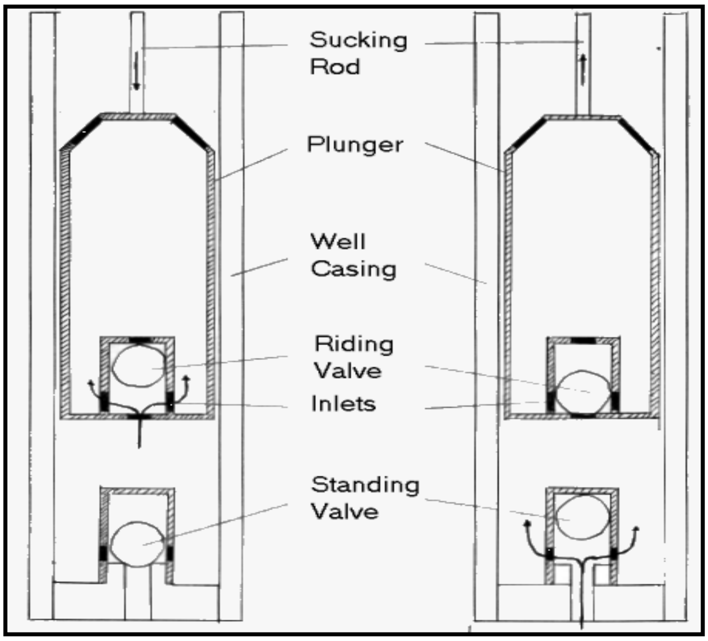


Figure 22 Sub-surface pump (7)

The Sucker Rod String Rod: It's responsible of transmitting the movement from the horse beam down to the subsurface pump. (13)

Sucker rods string types

Grade C Sucker Rod

This type can be used with low and medium loads it can't be used if we have corrosive fluids.

Grade K Sucker Rod

This type is used in low to medium loaads as well, however its suitable if corrosive fluids are existed.

D Carbon Sucker Rod Grade

This type is used if we have moderate loads wells and noncorrosive fluids.

KD Special Grade Sucker Rod

This type is designed to tolerate heavy load and can work effectively in the presence of corrosive fluids.

D Alloy Grade Sucker Rod

This type can be run only if we don't produce corrosive fluids, and it can handle heavy loads.

Sinker bar: It's necessary in order to maintain the swinging process of the sucker rod. In addition it prevents buckling of the last strings.

Pony rods: It helps us to reach the exact depth that we need, where it is available in different length; 2,4,6,8 and 10 feet.

The Couplings:

- Sucker rod coupling: its purpose is to connect two rods of the same size to each other.
- Sub- coupling is used to connect different sizes, or to connect the polished rod to the rod string (polished rod coupling).

The polished rod: It's the part of the rod which we can see on the surface, it's thicker than the other rods so it will be able tolerate the load of the subsurface equipments.

Rod guide: It's working as a centralizer in order to prevent buckling and wearing.

Tubing anchor: it is run with the tubing in order to prevent the tubing to move with the plunger, which leads to the phenomena of buckling.

Surface equipment

Pumping Unit main component (7) (13)***:***

1. Gear box
2. Cranks
3. Horse-head
4. Bearing
5. Breaks
6. Weight counter
7. Walking beam
8. Pitman arm
9. Electrical motor

Pumping unit types:

1. Air balance
2. Beam balance
3. Conventional (the most preferable)
4. Low profile
5. Reveres profile
6. Conventional portable

The sucker rod failures

The most common stresses that sucker rod subsurface equipment expose to, are the following.

Tensile failure

It happens when the applied load exceeds the tensile strength of the rod, which causes a reduction in the cross sectional area of the infected sections.

Fatigue failure

This type of failure begins as small cracks, these cracks have a tensile strength far smaller than the tensile strength of the rod strength so these fractures will be the weakest points in the rod

Corrosion failure

It is mainly caused as a result of the reaction between the rod steel and the operating environment. The corrosion might be caused by the corrosive fluids such as CO2 and H2S dissolved in water reducing its PH making it more acidic.

Coupling failure

Power tongue is a necessary tool to make sure that the rods are connected properly otherwise the rods and the couplings will be damaged. Using the displacement card provided by the manufacturing company helps us to adjust the power tongue with the suitable pressure.

Pump Off

This happened when gas exists in the pump, where a back pressure is accrued when the plunger contact the liquid surface, which causes tubing buckling. In addition the liquid is forced against the barrel wall and it is damaged by the phenomena of burst.

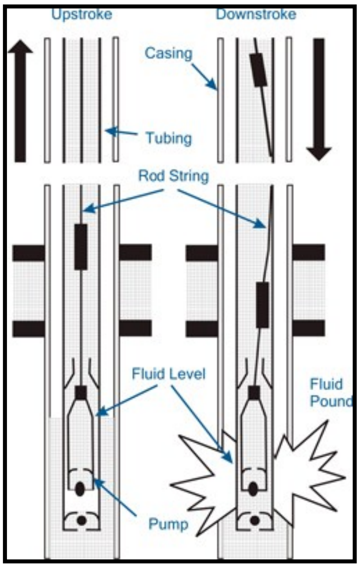


Figure 23 Pump off failure (7)

Sand failure

The existing of sand in the producing fluid could harm badly the standing valve, which leads to a pump leak problem.

Handling Sucker rods

i. The rods should be examined during the delivery process to make sure that they aren't damaged.
ii. The rods must handle with care, two men to carry each rod and mustn't contact with ground.
iii. The protector shouldn't be removed until we are about to start rod installation.
iv. Avoided storing rods on each other where that could damage them.
v. It's crucial to make sure that the work over rig responsible on rod installation is located on the center of the well to prevent the friction between the rods and the sides of the walls.
vi. The rods pins must lubricated by threat-lubricant which contains corrosion inhibiters (don't use engine oil)
vii. The elevators must be inspected regularly where using damaged elevator could harm the rods.
viii. To avoid pump off the pump should be set below the bubble point pressure level.
ix. Installing a screen at the bottom of the well will reduce sand production.

The pumping cycle:

The pumping cycle is described in its simplest form in fig. the standing valve is located at the bottom of the tubing and the traveling valve is located at the bottom of the rods. Because the plunger is an integral part of the rod system, all fluids that pass from a point in the working barrel below the traveling valve to a point above it must pass through the traveling valve. Let's start the description of the pumping action at a point in the pumping cycle where the plunger reaches the bottom of the stroke and begins the upstroke. The traveling valve closes as the plunger lifts weight of the fluid above it in the tubing. As soon as the pressure in space between the standing and traveling valves falls to a level below that exerted by the fluids flowing into the well from the formation, the standing valve opens and formation fluids flow upward through it.

Well bore fluids are lifted one full stroke during the upward movement of the plunger. Once the plunger reaches its stroke, its movement is reversed, the traveling valve opens, the standing valve closes, and down stroke begins. Fluid above the standing valve is moving upward through the traveling valve, which is open. The standing valve itself is closed because it carries the weight of the fluid column above in the tubing.

This cycle continues with the alternating movement of the rods and the opening and closing of the two valves. Stroke by stroke the fluid is moved up the tubing to the surface. The valves do not necessarily open and close at the exact top and bottom of the stroke. The point in the up stroke at which the standing valve opens depend upon the spacing, that is, the volume that exists at the bottom of the stroke, between the traveling and standing valves, and on the amount of free gas percent in this volume. On the stroke, the traveling valve remains closed until the pressure below the plunger exceeds that above it. The traveling valve then opens and fluid passes through it into the tubing.

The exact point in the down stroke at which the traveling valve opens depends on the free gas volume in the fluid below the valve.

It is clear from this elementary description of the pumping cycle that the higher volume of free gas, the greater proportion of the stroke that is taken up in gas expansion and compression, without any pumping action taking place.

For wells producing a reasonable volume of gas, a natural gas anchor is normally installed on the tubing below the pump. This allows the separated gas to be produced up to the annulus before it would otherwise enter the pump. (13)

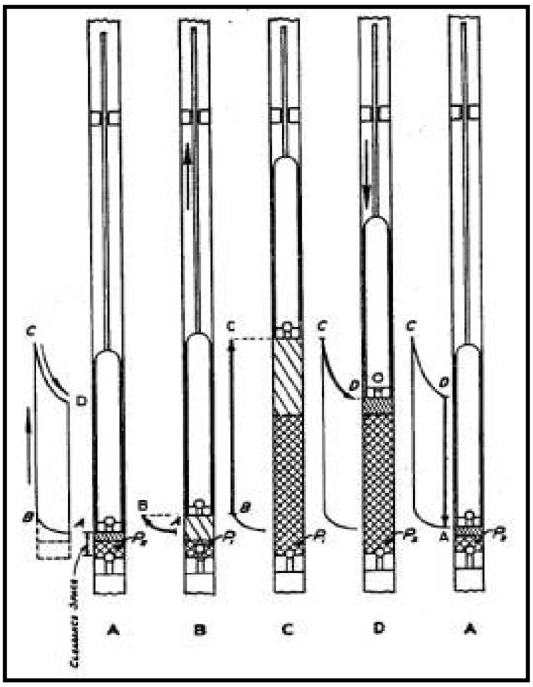


Figure 24 Pump cycle

Sucker rods Buckling

Oil pressure and of the forces resulting from pump action cause the comprehensive force acting on the rods at the bottom of the well. Often this compressive force causes the rods to buckle.

The buckling can effect negatively on the pump performance, as it reduces the stroke length of the plunger, and it also causes a great wear of the rods, the coupling, the pump and the tubing, and as a result of the above damages a leaking point can occur, which results in a loss of production. It is there for very important to determine buckling and eliminate it. (13)

Lateral Buckling

The rods are subjected to a pressure and a force from the plunger, and it is known that if the compressive force exceeds the buckling critical force the rod deforms laterally in one plane. It can be assumed that it takes the form of a sinusoidal curve.(13)

Helical Buckling

If the compressive load exceeds the lateral buckling limit the helical buckling occurs, and the rods takes the shape of a helix.(13)

Factors that can trigger buckling

There are many measurements that we can do to avoid buckling from happening or to reduce it; some of those measurements are listed below: (13)

- Pump speed: the higher the speed the higher the tendency of having buckling, bigger pumps with a slower pump speed is preferred than a smaller pump with a higher pump speed. Depending on the rod length there is certain pump speed must be selected.
- Traveling valve diameter: as the fluid pumped through the traveling valve a pressure drop thought the valve occurs which lead to an additional buckling force, there for the bigger the traveling valve the smaller the buckling force caused by it.
- Clearance between plunger and Barrel: the bigger the clearance the lower the buckling force, anyway the clearance can not be so high as the fluid would leak to the bottom of the plunger instead of flowing through the traveling valve.
- Protectors: are made from polyamide and they are installed along the rods to keep the rods in the center od the tubing in order to reduce the erosion between the tubing and the rods, and they also have a positive effect on the lateral buckling as the length of the wave is limited, the distance between the protectors are very important usually it is equal to the pump surface stroke length.
- Sinker bars: sinker bars provide concentrated weight above the pump to help keep the rod string straight and in tension, which reduces buckling of the sucker rods.

Chapter 4 Artificial Lift System Selection in Cherouq Field

General

To select the suitable artificial lift for a field, different lifting method should be investigated, and each individual well should be analyzed and studied separately. And of course selection the right method will depend on the limitation of each method regarding to the conditions of the interested field, See chapter three, also the economic factor must be taken in considerations.

Prior to any step further to the design the current well status should be reviewed, see table 5 for Cherouq field status as on August 25, 2011 (when working on this report was started).

Well	Status	Avg Oil Production bopd	Avg water Production bwpd	Avg Gas Poroduction Mscfpd
Methaq 1	Producing to Separator MBD 220.	850	11.5	1450
Methaq 2	Producing to tanks on location, pumped to separator MBD 220.	95	1.1	82.7
Angham1	Shut-in	/	/	/
Waha 1	Shut-in	/	/	/
Waha 2	Gas lifting to test separator.	990	636	409
Shaheen1	Producing to tanks on location, pumped to inlet separator	300	240	250
ElAzzel 1	Shut-in	/	/	/
Farah 1	Producing to tanks on location, pumped to 3rd Stage	400	460	97.4
ElBadr 1	Swabbing operations on going	/	/	/
ElBadr 3	Gas lifting to the inlet separator	1335.9	83.3	576.8
ElBadr 4	Gas lifting to the inlet separator	995.9	31	961.5
ElBadr 5	Gas lifting to the inlet separator	1010.0	487.9	10.5
Cherouq 1	Shut-in	/	/	/
Cherouq 2	Producing to tanks on location, pumped to inlet separator	500	650	580
		6476.507212	2601.02058	4418.247837

Table 5 Field status

Approaching the designs

Having a gas lift facilities installed in a field makes the selection of more often to go towards gas lift, but again it is always depends on how much we can produce with other artificial lift methods, and how economical will be to convert to them. To approach the optimum design for GL and ESPs the main focusing was on how to achieve a higher production with minimum cost, so for ESP the number of stages was highly considered as it controls the pump cost, also choosing the pump with the best operating conditions (operation point) and best efficiency was one of the selection criteria. Where as for gas lift the gas volume injected to each well was selected carefully as extra gas injection leads to a lower production and of course more gas means more money.

Angham-1

As it is shown Appendix A, the well is shut in as it is not capable to flow naturally, for more details about the well performance see chapter 2. Three artificial systems are investigated; gas lift, ESP and rod pump.

Figure 15 compares the free flow and the flow with GL at different gas injection rates.

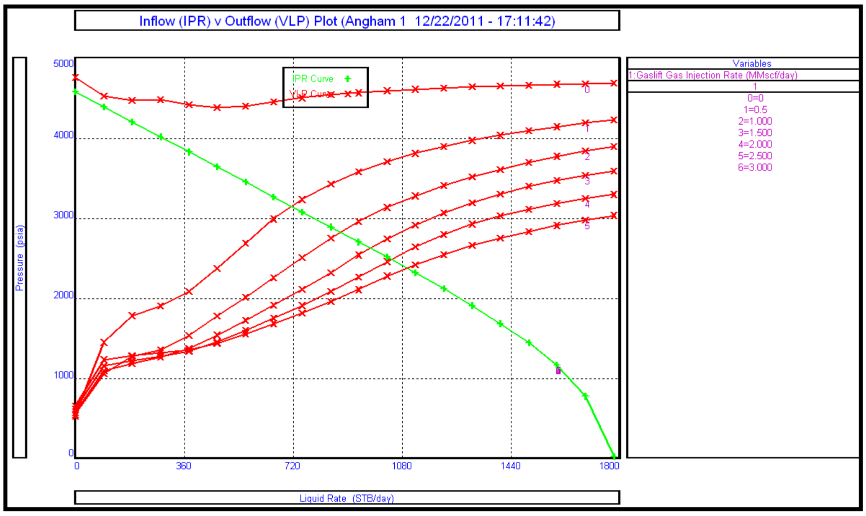


Figure 25 Gas lift performance at different injection rates

Table 6 below shows the possible fluid rate at different rates of the injection gas, and a one can see that at two 2.00 MMcf/day is the rate after which the increase in the fluid rate is not considerably high, so 2.00 MMcf/day has been considered as the optimum gas injection rate, at which 1045.2 bpd can be produced.

Injected Gas MMcf/day	0.5	1.00	1.5	2.00	2.5	3.00
Oil rate STB/day	286	350	390	418	438	463

Table 6 Oil production vs. Gas injected

Figure 16 shows the gas lift design drawing. On which is indicated the number and the spacing of the valves.

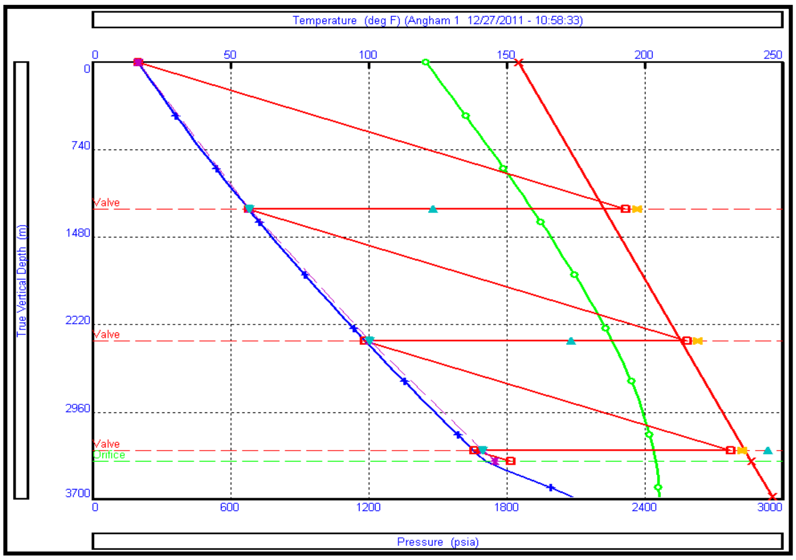


Figure 26 Gas lift design sketch

Figure 17 shows the relation between the injection depth and flow rate, where we can see clearly that flow rate is not highly affected by changing the injection depth.

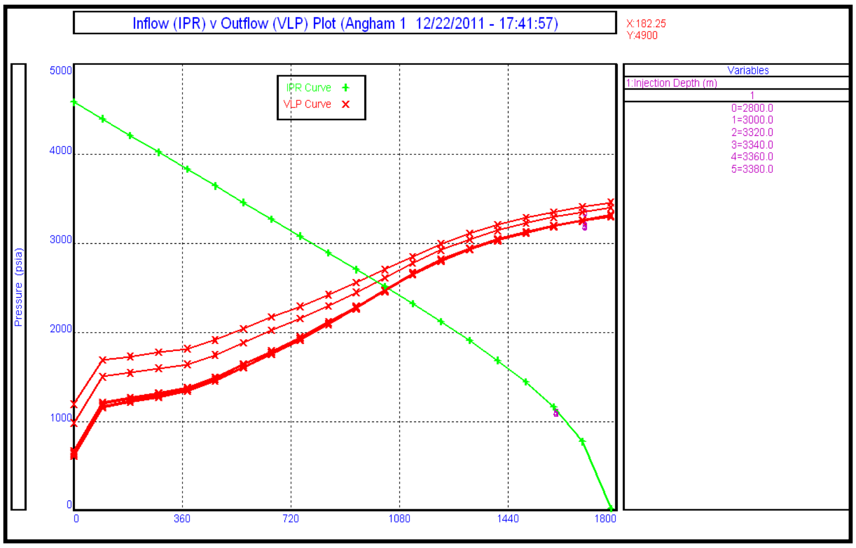


Figure 27 the effect of injection depth

Angham-1 has moderate GOR and a high WC, as it mentioned in the well performance (chapter 2) the well died because of the increase of WC, this environment could be very suitable for an ESP installation to achieve a higher production rate, table 7 shows the ESP design summary, the production, which can be achieved with this pump under the current well situation is 1412.6 FBPD (565.06 BOPD).

ANGHAM-1	
INPUT DATA	
Reservoir Pressure, P_r (psig)	4564
Water Cut (%)	60
Wellhead flowing pressure (psia)	200
Gas separator efficiency (%)	70
Pump depth (m)	3414
Operating Frequency (Hz)	50
Length of cable (m)	3414
CALCULATED DATA	
Pump Intake Pressure (psi)	858.6
Pump Intake Rate (RBPD)	2222.5
Pump discharge pressure (psi)	3943
Pump discharge rate (RBPD)	1800.55
Head required (m)	2304
SELECTED EQUIPMENT	
Pump Name	REDA GN2100 5.13 inch
Motor Name	CENTERLIFT 450
Motor Name-Plate power (HP)	240
Motor Name-Plate Volts (Volts)	1941.6
Motor Name-Plate Amps (Amps)	58
Cable name	# 1 COPER 0.26 (V/1000ft) 123 A Max.
RESULTS	
Number of Pump stages	263
Power required (HP)	153
Pump Efficiency (%)	63.2
Current used (A)	55
Motor efficiency (%)	82.7
Power generated (HP)	153
Motor Speed (rpm)	2894

Table 7 ESP design summary

Figure 18 shows the selected pump performance curve, the main aspect of the ESP design was to accommodate and run the maximum pump size down concerning the minimum inside casing diameter, in order to construct the pump which will have the minimum number of stages. This could reduce the surface power requirements and provide longer pump run-life.

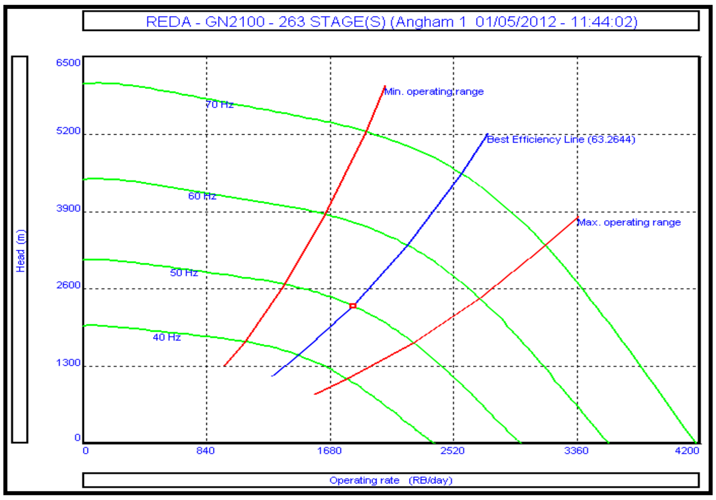


Figure 28 Pump performance curve

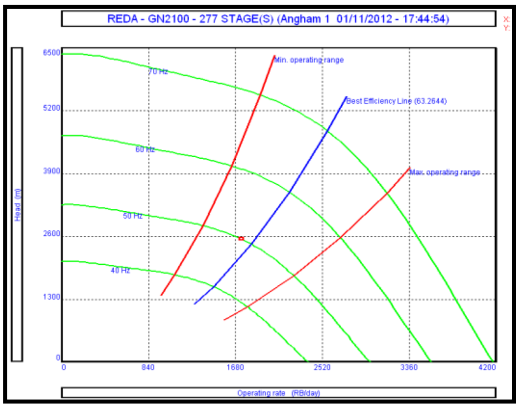


Figure 29 Pump performance curve at 95% WC

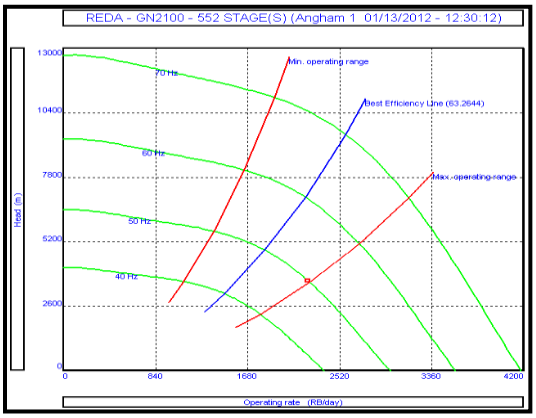


Figure 30 pump performance curve at 1420 scf/stb

In figure 21 is shown a comparison between GL and ESP production at different tubing size, and it also shows that ESP can achieve higher rates in all sizes, for 3 ½ tubing which is already run it Angham-1 the difference between the both method is 367.4 BFPD (147 BOPD). One can see that for ESP tubing size does not have a big affect on the production (all most production is the same), and for gas lift the increment does not worth tubing size to be replaced when a water cut is constantly increasing.

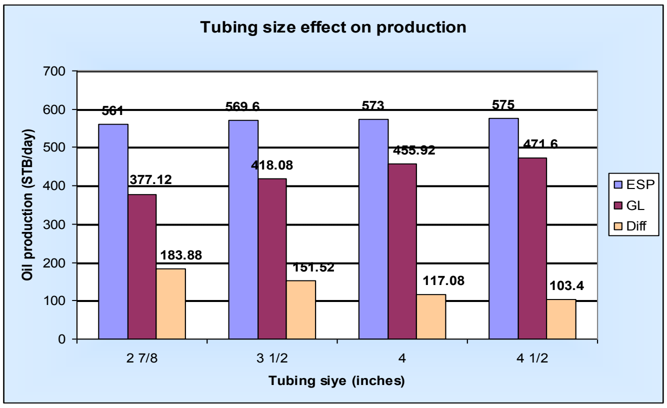


Figure 31 Tubing size effect on Production

Figure 22 shows the affect of WC on the production for natural flow, ESP and GL (tubing size 3 ½ inch), looking at the natural flow curve it is clear that the well can not produce with the current WC (60%) the reason why an artificial lift method must be installed, to make a good comparison between GL and ESP lets take points where WC is 60% and 90%, at the first point the different in production is 147 BOPD, where as in the second point the increment is 39 BOPD, looking to the production history of Angham-1 water cut is rising constantly.

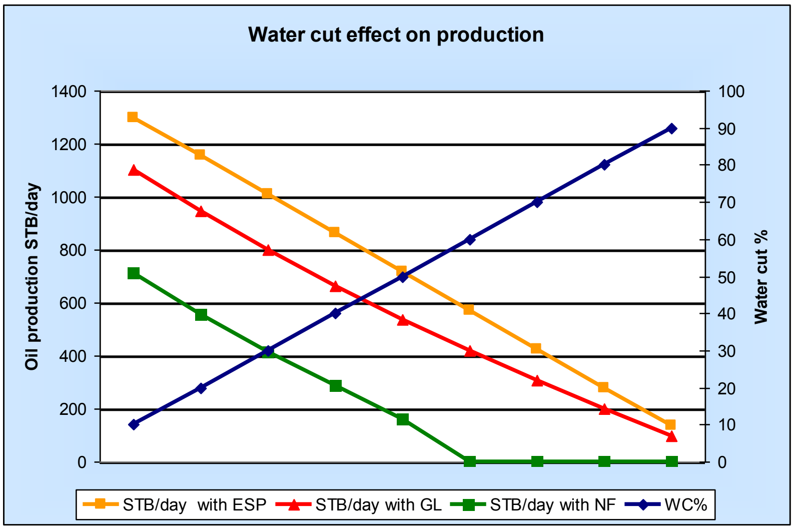


Figure 32 Water cut effect on production

Figure 23 shows the effect of GOR on both artificial lift methods, ESP is affected with in the first three points as production dropped from around 1400 to 1200 BFPD, while GL is not affected by increasing GOR.

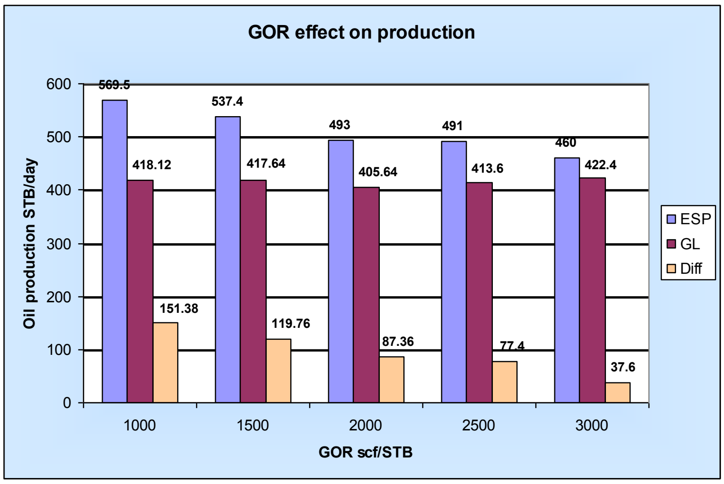


Figure 33 GOR effect on production

Sucker rod pump design was studied for Angham-1, but it is not a competitor to GL or ESP, Angham-1 has a high WC and a high lifting depth, which makes it difficult to achieve rates similar to the rates from GL and ESP, only 206 bpd can be produced using sucker rod.

Figure 24 shows the potential production for Angham-1 from Sucker Rod pump in comparison with GL and ESP.

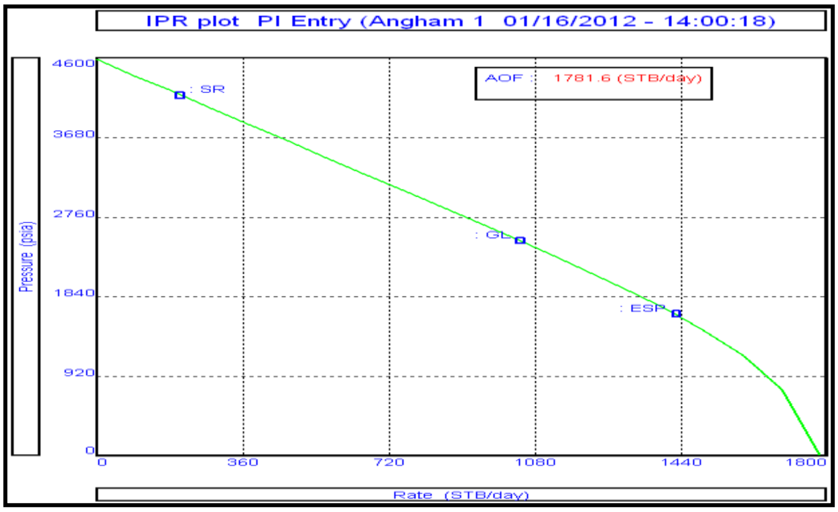


Figure 34 comparison of production potential from ESP GL and sucker rod

Table 8 summarizes the design of the sucker rod. See Appendix E for RODSTAR design.

Pump Unit Name		Lufkin C-912-365-468
Pump unit type		Conventional clockwise
Pump stroke length		102
Pump Max. stroke length		168
Pump speed		7 strokes/min
Pump diameter		1.87”
Plunger diameter		1.75”
Rods	1 inch	29.4 %
	0.875 inch	30 %
	0.75 inch	40.6 %

Table 8 Sucker rod pump design summary

Cherouq-1

For Cherouq-1 GL and ESP were studied, for sucker rod it is not possible to be installed for this well, as we have a very high WC and also a high GOR, for more details about the advantages and disadvantages see the table 3, again because of the depth limitation and the high desired rate sucker rod pump can not operate efficiently, and this due to the high load applied on the rods and unit.

Figure 25 shows the possible rates at different gas injection rates.

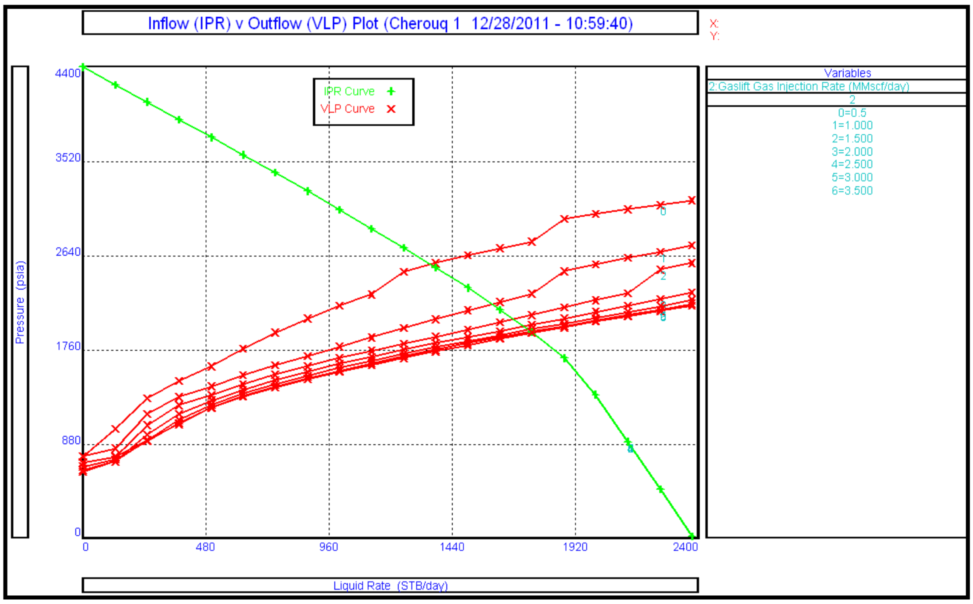


Figure 35 Gas lift performance at different injection rates

Table 9 below illustrates the quantities of liquid, which can be covered at each injection rate, 1.00 MMcf/day was selected as the optimum injection rate, after which no high increment on oil production is possible.

Injected Gas MMcf/day	0.5	1.00	1.5	2.00	2.5	3.00
Oil rate STB/day	298	350	369	378	382	384.5

Table 9 Oil production at different gas injection rates

Figure 26 shows the gas lift design drawing. On which is indicated the number and the spacing of the valves.

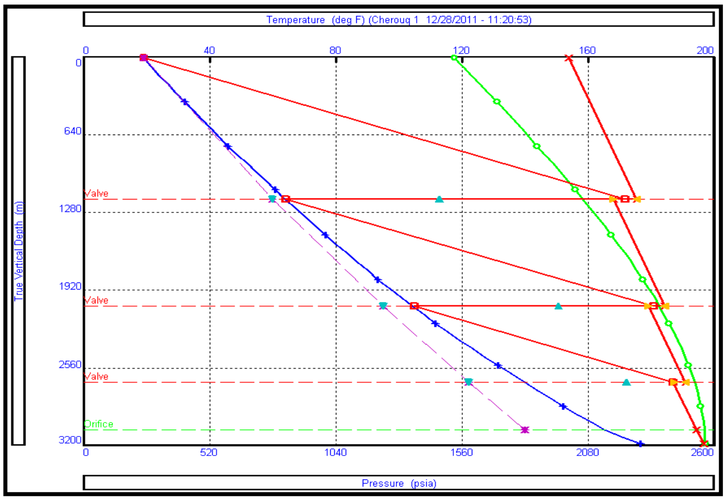


Figure 36 Gas lift design skitch

ESP design showed a high production capability, taking in consideration the high GOR in Cherouq-1, and all results which were achieved by the ESP design was based on 80% separation efficiency of the downhole separator, table 10 shows the ESP design summary for Cherouq-1, the production rate which can be achieved by the selected pump and under the current conditions is

CHEROUQ-1	
INPUT DATA	
Reservoir Pressure, P_r (psig)	4400
Water Cut (%)	80
Wellhead flowing pressure (psia)	186
Gas separator efficiency (%)	80
Pump depth (m)	3000
Operating Frequency (Hz)	50
Length of cable (m)	3100
CALCULATED DATA	
Pump Intake Pressure (psia)	1118
Pump Intake Rate (RBPD)	3519
Free GOR entering pump (scf/stbo)	
Pump discharge pressure (psi)	3276
Pump discharge rate (RBPD)	2472
Head required (m)	1780
SELECTED EQUIPMENT	
Pump Name	REDA SN3600 5.38 inch
Motor Name	CENTERLIFT 450

Motor Name-Plate power (HP)	240
Motor Name-Plate Volts (Volts)	1941.6
Motor Name-Plate Amps (Amps)	58
Cable name	# 1 COPER 0.26 (V/1000ft) 123 A Max.
RESULTS	
Number of Pump stages	162
Power required (HP)	146
Pump Efficiency (%)	69
Current used (A)	53.6
Motor efficiency (%)	82.4
Power generated (HP)	146
Motor Speed (rpm)	2899.01

Table 10 ESP design summary

Figure 27 shows the selected pump performance curve, operating point shows that the pump is operating a slightly below the best efficiency.

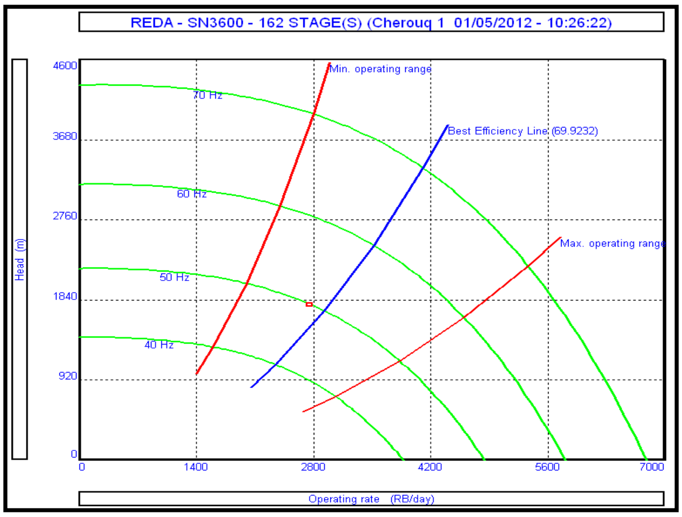


Figure 37 Pump performance curve

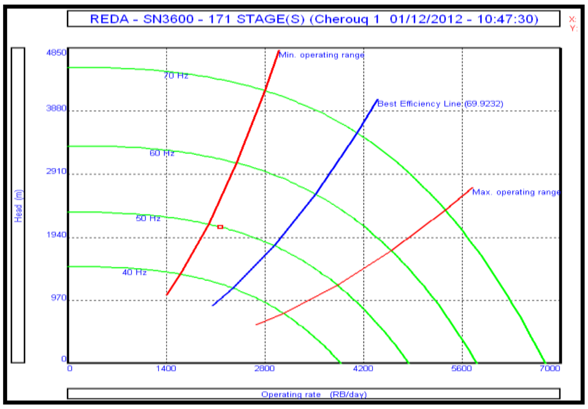


Figure 38 Pump performance curve at 95% WC

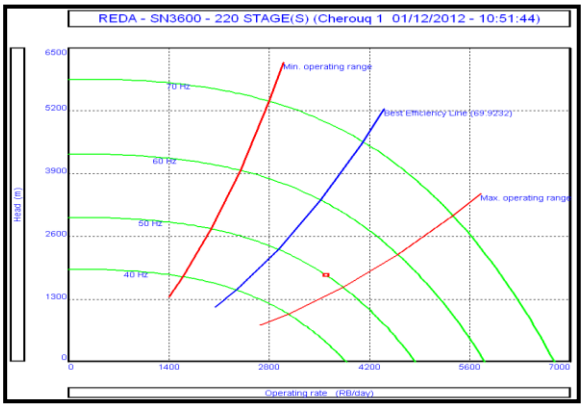


Figure 39 Pump performance curve at 2500 scf/stb

In figure 30 is shown a comparison between GL and ESP production at different tubing size, and it also shows that ESP can achieve higher rates in all sizes, for 3 ½ tubing which is already run in Angham-1 the difference between both methods is 330.9 BFPD (66.18 BOPD). Again ESP is not affected by changing tubing size, as all most the production was achieved by all tubing sizes, for gas lift if tubing size was changed from 31/2 to 4 inch, the increment would be only by 21 barrels.

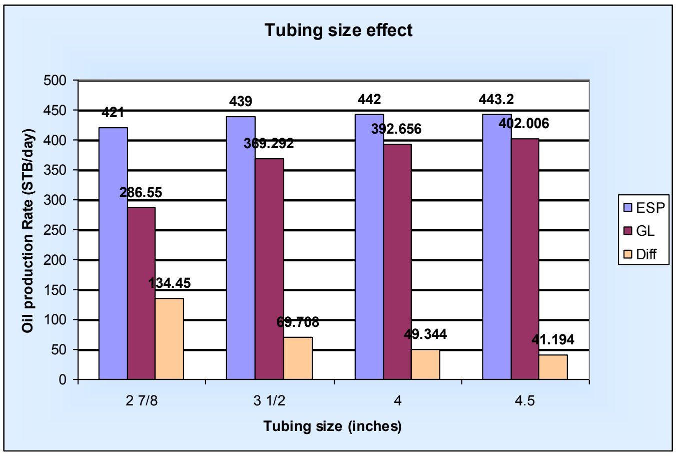


Figure 40 Tubing size effect on Production

Figure 31 shows the affect of WC on the production by GL and ESP, as it illustrated water cut dose not have a big effect on production, for natural flow it is obvious that the well is not able to flow naturally when the WC is around 80%.

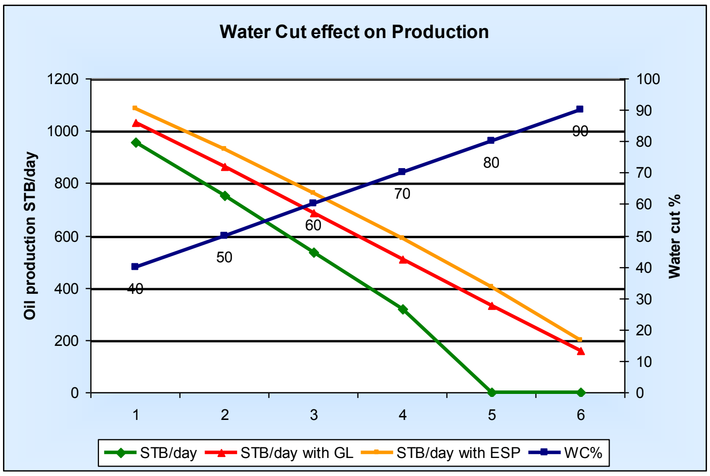


Figure 41 Water cut effect on production

Figure 32 illustrates how production behaves with the change of GOR, for the ESP production is almost constant at 2000 bpd considering a downhole separation efficiency of 80%. GL production behaves the same; production is also constant at around 1650 bpd.

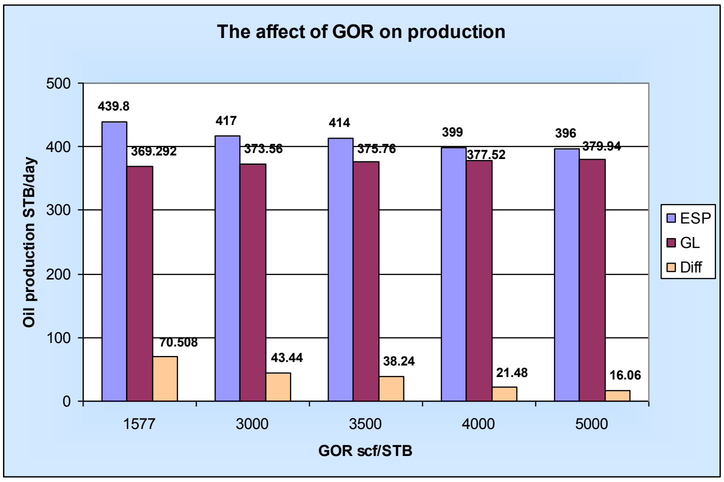


Figure 42 GOR effect on production

Cherouq-2

Well is been producing for about one year, (since November 2010) see well performance for more details, the well is producing to a tank on location as the reservoir energy is not enough to deliver the fluid (829.8 bfpd-331 bopd) to the station the reason why this well is a candidate for an artificial lift system installation.

Figure 33 shows the production rate at different gas injection rates, and it shows a higher production than the natural flow does.

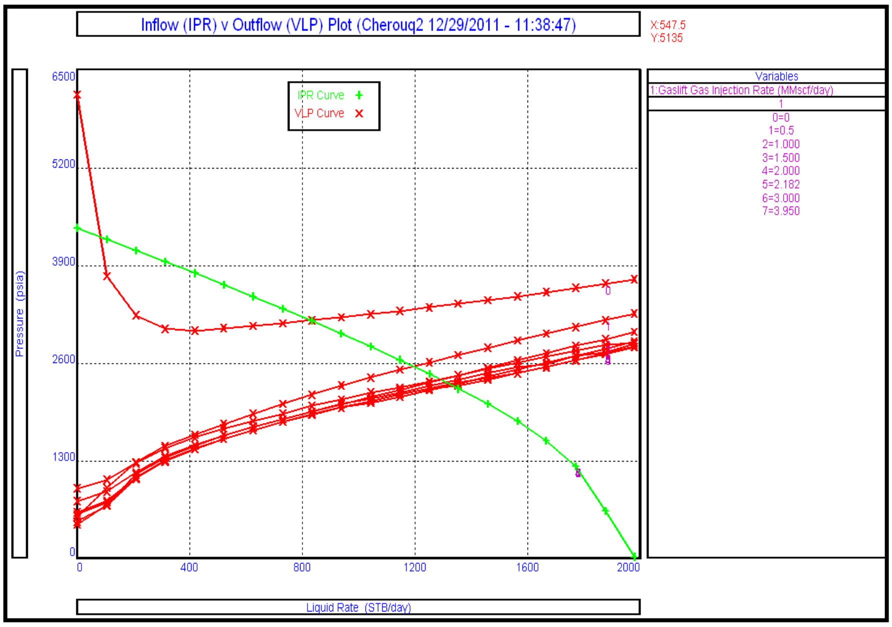


Figure 43 Gas lift performance at different injection rates

A comparison between the gas injection rates and the amount of oil each can produced is shown in table 11. It is clear that at 0.5 cf/day is the optimum for well cheouq-1.

Injected Gas MMcf/day	0.5	1.00	1.5	2.00	2.5	3.00
Oil rate STB/day	477.9	517.1	532.2	534.7	526.9	524

Table 11 Oil production vs gas injection

Number of valves and their spacing is shown on figure 34.

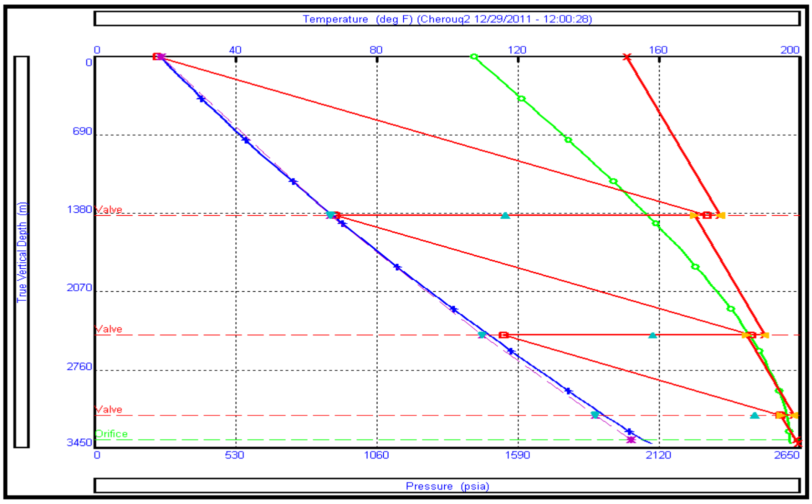


Figure 44 Gas lift design sketch

Seeking for a higher production an ESP module has been set for Cherouq-2, and as expected ESP showed a higher production potential, gas separation sensitivity chart shows that there is no need for a downhole gas separator under the current situation. ESP design summarize is illustrated in table 12.

CHEROUQ-2	
INPUT DATA	
Reservoir Pressure, P_r (psi)	4400
Water Cut (%)	65
Wellhead flowing pressure (psi)	110
Gas separator efficiency (%)	0
Pump depth (m)	3407
Operating Frequency (Hz)	50
Length of cable (m)	3500
CALCULATED DATA	
Pump Intake Pressure (psi)	1743.27
Pump Intake Rate (RBPD)	2667
Free GOR entering pump (scf/stbo)	
Pump discharge pressure (psi)	3512.61
Pump discharge rate (RBPD)	1940.33
Head required (m)	1474.24
SELECTED EQUIPMENT	
Pump Name	REDA SN2600 5.38 inch
Motor Name	CENTRILIFT 450

Motor Name-Plate power (HP)	120
Motor Name-Plate Volts (Volts)	1100
Motor Name-Plate Amps (Amps)	58
Cable name	1 # COPPER 0.26 V/1000 ft 123 A
RESULTS	
Number of Pump stages	153
Power required (HP)	98.3
Pump Efficiency (%)	67
Current used (A)	58.1
Motor efficiency (%)	83
Power generated (HP)	98.3
Motor Speed (rpm)	2883

Table 12 ESP design summary

Figure 35 below shows the selected pump performance curve, where you can see that the pump is operating at its best efficiency.

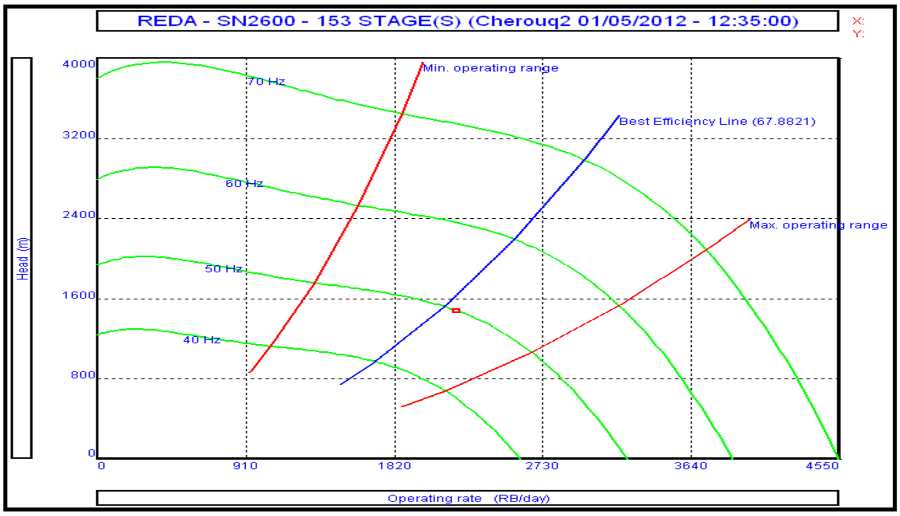


Figure 45 pump performance curve

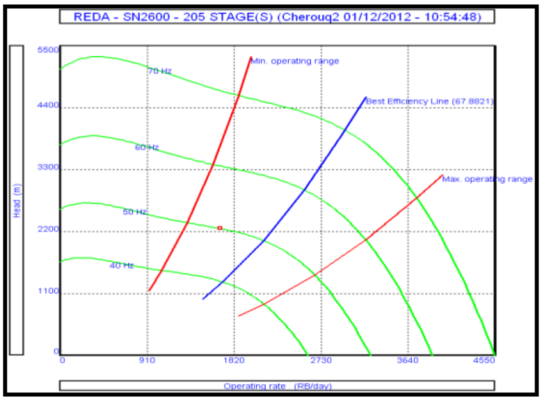


Figure 46 Pump performance curve at 95% WC

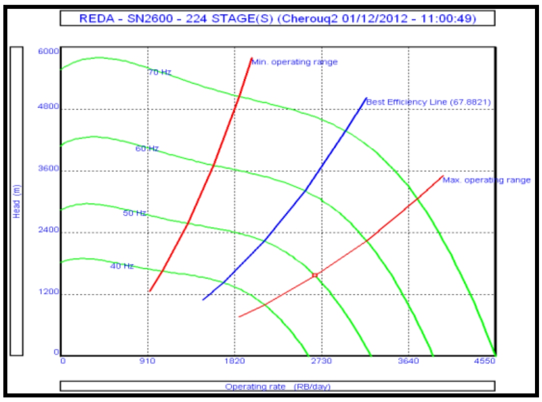


Figure 47 Pump performance curve at 1950 scf/stb

The chart on the right shows how much oil can be produced from GL and ESP at different tubing sizes, it is easy to find that 27/8 is the optimum tubing size for the both lifting methods.

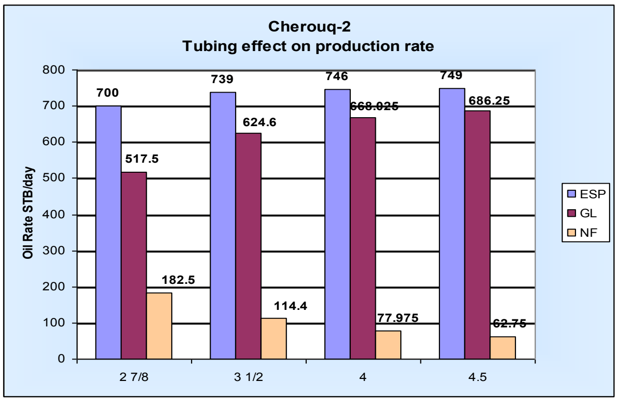


Figure 48 tubing size effect on production

Where as in figure 39 both methods shows a dramatic drop in production, ESP is producing more than GL at all values, the difference between both method decreases with the increasing of WC, at 90% ESP can produce about 47 bbl/day more than GL.

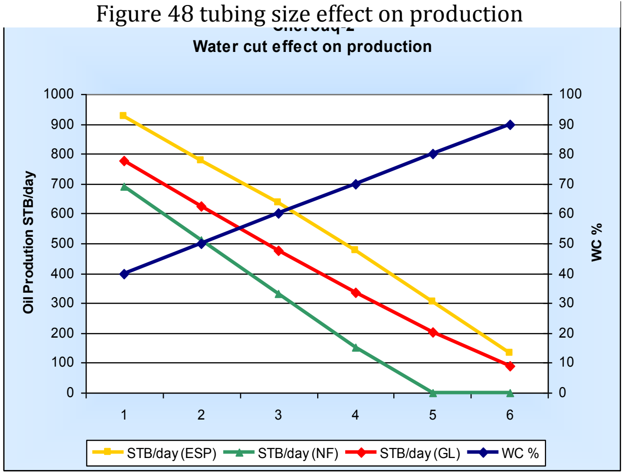


Figure 49 Water cut effect on production

Looking to the chart 40 one can see the effect of GOR on the production, as GOR is one of ESP handling problems it is obvious that production by ESP decreases with the increase of the GOR see chapter 3 for more details), the ESP design for cherouq-2 considers no downhole gas separator.

While production from GL is increasing with the higher GOR values, and looking to the chart at 3000 scf/day the difference between the two methods is about 50 bbls/day.

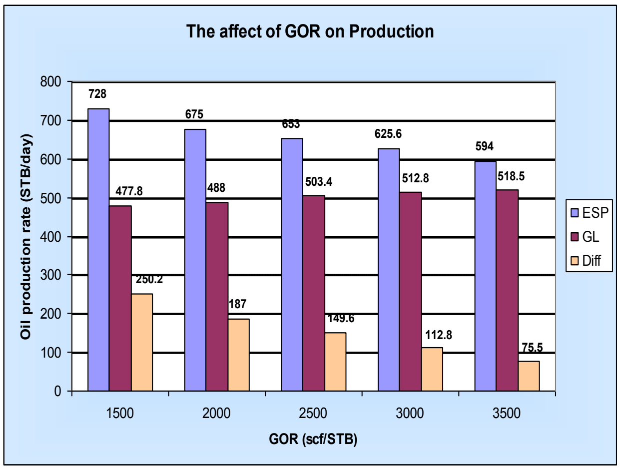


Figure 50 GOR effect on production

El Badr-1

The well died in May 2011, and a GL system was installed to it. With the gas lift the well is capable to produce around 1100 BOPD, as the GOR is not high in well El Badr-1 ESP also could be a good alternative to GL, Sucker Rod pump can not provide the same rate which can be produced by the other two methods.

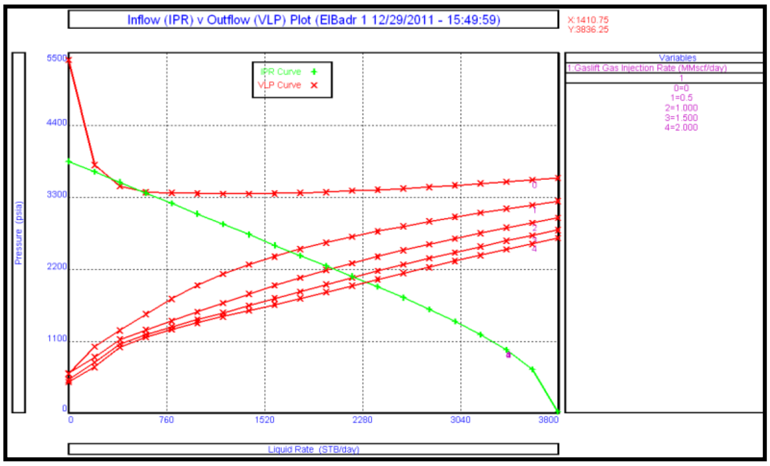


Figure 51 Gas lift performance at different injection rates

As it with all GL lift designs which had done a different injection gas rates were run in the module to be able to choose the optimum injection rate, in this case the optimum rate is 1.00 MMscf/day which provides an oil rate around 1125 BOPD.

Injected Gas MMcf/day	0.5	1.00	1.5	2.00	2.5	3.00
Oil rate STB/day	949	1125	1217	1270	1301	1318

Table 13 Oil production vs gas injection

Figure 42 shows the GL design sketch, illustrating the number of valves needed and the spacing of the valves.

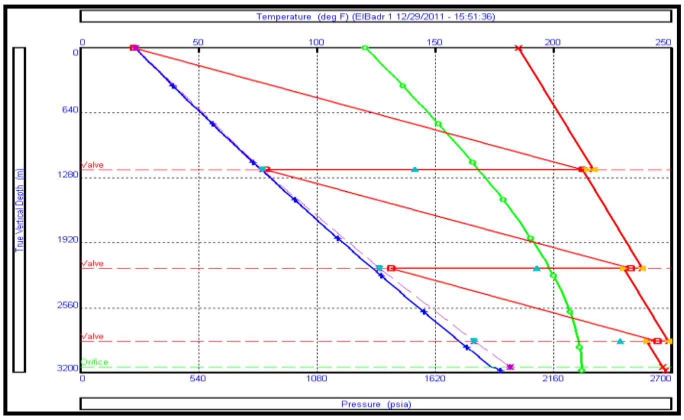


Figure 52 Gas lift design sketch

El Badr-1 is a good candidate for an ESP system, it has a low GOR and a good productivity index, and with ESP a higher production rate can be achieved than with GL. ESP design was done and the following table lists all design features.

With the selected pump the well is capable to produce around 1660 BOPD around 535 BOPD higher than GL potential.

El Badr-1	
INPUT DATA	
Reservoir Pressure, P_r (psi)	3850
Water Cut (%)	45
Wellhead flowing pressure (psi)	
Gas separator efficiency (%)	0
Pump depth (m)	3140
Operating Frequency (Hz)	50
Length of cable (m)	3240
CALCULATED DATA	
Pump Intake Pressure (psi)	1158
Pump Intake Rate (RBPD)	4940
Free GOR entering pump (scf/stbo)	
Pump discharge pressure (psi)	3108
Pump discharge rate (RBPD)	3960
Head required (m)	1659
SELECTED EQUIPMENT	
Pump Name	CENTURION P47 5.38 inch
Motor Name	CENTRILIFT 562
Motor Name-Plate power (HP)	255
Motor Name-Plate Volts (Volts)	1170

Motor Name-Plate Amps (Amps)	105
Cable name	1 # COPPER 0.26 V/1000 ft 123 A
RESULTS	
Number of Pump stages	155
Power required (HP)	209.3
Pump Efficiency (%)	65
Current used (A)	103.8
Motor efficiency (%)	87
Power generated (HP)	209.3
Motor Speed (rpm)	2916.5

Table 14 ESP design summary

The selected pump performance curve is shown in figure 43, on which it is illustrated that the pump is operating a slightly higher than its BEP.

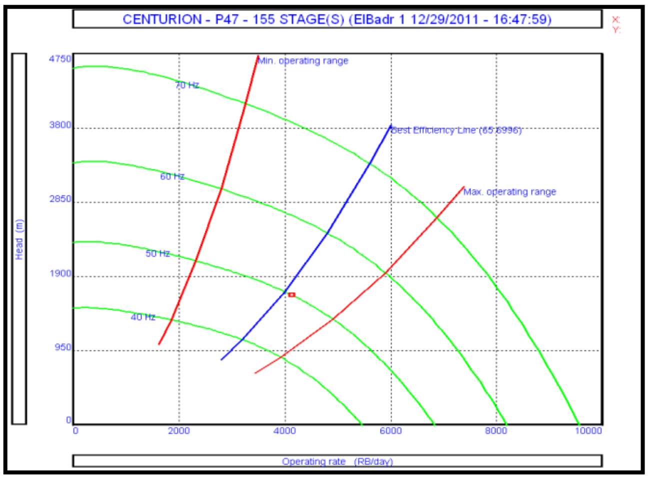


Figure 53 Pump performance curve

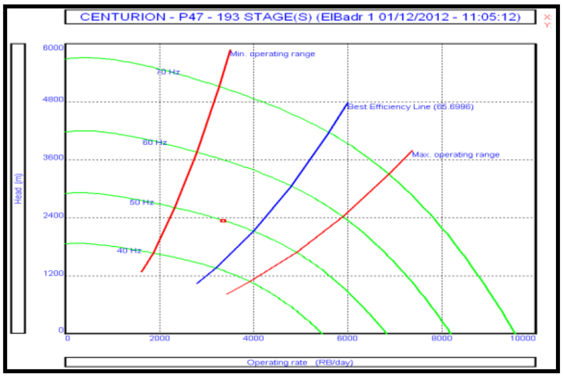


Figure 54 Pump performance curve at 95% WC

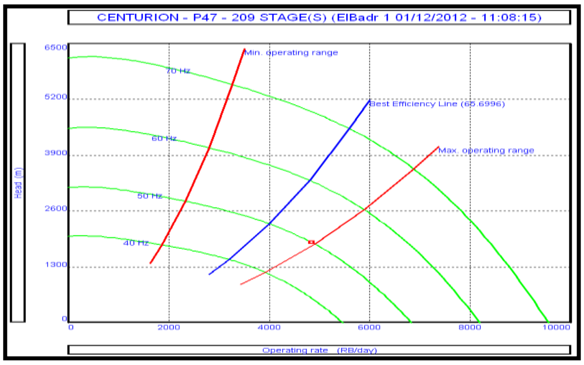


Figure 55 pump performance cure at 870 scf/STB

Tubing size used in El Badr-1 is 3 ½ inch tubing, looking at bars which presents the production from GL system, one can see that production increases as the tubing size increase, but the increment is decreases as the tubing size increases, for ESP pump there is no a big change, only tens of barrels are added to the production each time the tubing size increased. Comparing the figures in the chart one can say that 3 ½ tubing size is the best of this well. See figure 46.

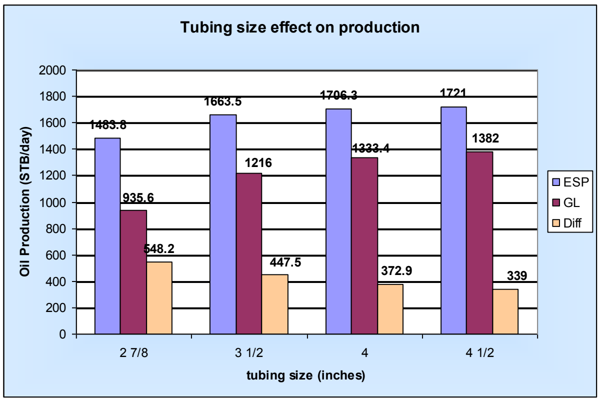


Figure 56 Tubing size effect on production

Water cut is one of the parameter, which has a hug effect on production especially for some artificial lift methods such as GL system (see the chapter 3). For El Badr-1 the comparison between GL and ESP regarding to the change in WC% is shown in Figure 47, where it shows that ESP can always provide a higher production, under the current condition ESP can provide 353 BOPD more than GL, this difference is increases with increasing the WC%, but even in the worst case ESP can deliver 65 BOPD higher than GL.

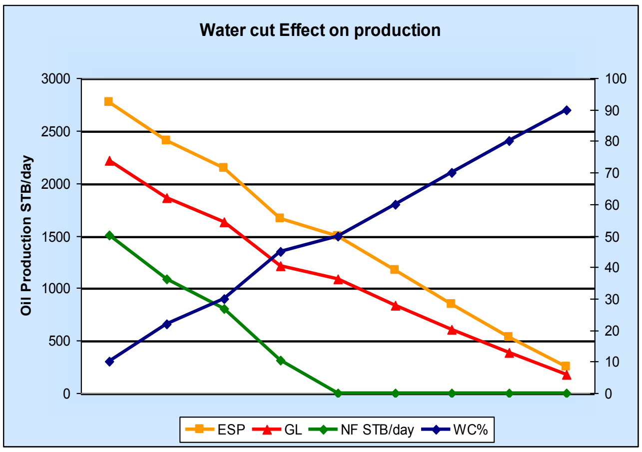


Figure 57 Water cut effect on production

GOR in El Badr-1 is at an average of 500 scf/day, and it has been in this range for more than 3 years, but considering the increasing of GOR must take place to have a complete idea about how artificial lift systems behave with the change of GOR. See figure 48 for comparison.

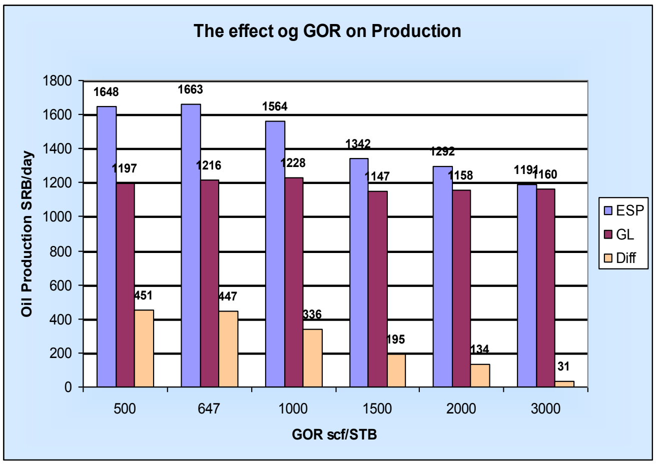


Figure 58 GOR effect on production

El Badr-3

The well is already gas lifted since May 2011, from the production history (see chapter 2) the well was producing around 1000 BOPD after GL the average production was around 1500 BOPD but this figure decreased to 1000 BOPD by December 2011. Figure 49 shows the rates which can be achieved by GL system.

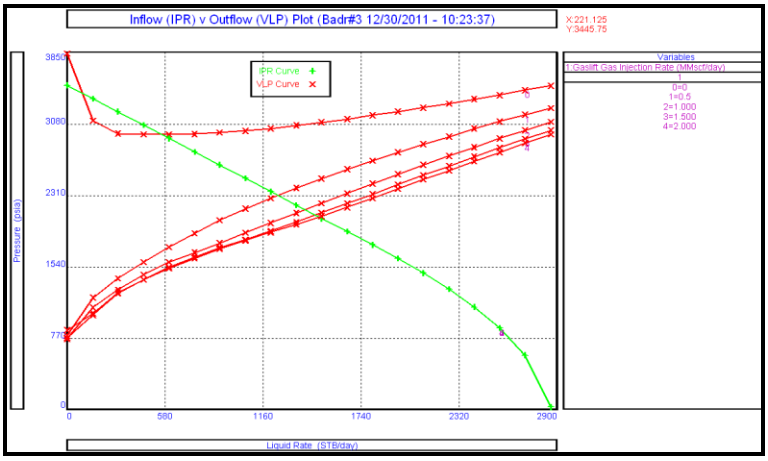


Figure 59 Gas lift performance at different injection rates

Table 15 shows how Oil rate changes with the increase of the injection gas, 1.00 MMcf/day is the optimum rate of injection.

Injected Gas MMcf/day	0.5	1.00	1.5	2.00	2.5	3.00
Oil rate STB/day	1148	1296	1353	1372	1370	1357

Table 15 Oil production vs. gas injection

Figure 50 shows the design sketch of the GL system and number of valves needed and their spacing.

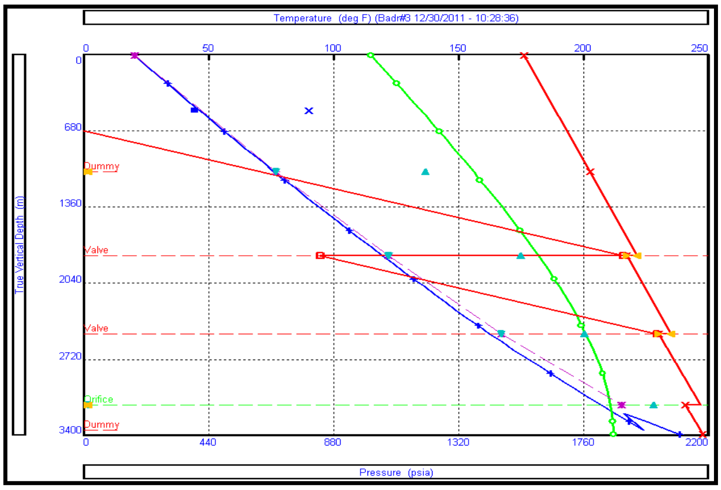


Figure 60 Gas lift design sketch

Just like Elbadr-1, El Badr-3 is a good candidate for ESP pump; GOR is constant at around 500 scf/day. ESP potential is Approx. 1070 BOPD which are 780 BOPD higher that what GL can deliver.

Table 16 summarized the ESP design.

El Badr-3	
INPUT DATA	
Reservoir Pressure, P_r (psi)	3500
Water Cut (%)	8
Wellhead flowing pressure (psi)	
Gas separator efficiency (%)	0
Pump depth (m)	3000
Operating Frequency (Hz)	50
Length of cable (m)	3100
CALCULATED DATA	
Pump Intake Pressure (psi)	710
Pump Intake Rate (RBPD)	4377
Free GOR entering pump (scf/stbo)	
Pump discharge pressure (psi)	3162
Pump discharge rate (RBPD)	2989
Head required (m)	2209
SELECTED EQUIPMENT	
Pump Name	CENTRILIFT K34 5.38 INCH
Motor Name	CENTRILIFT 450
Motor Name-Plate power (HP)	240
Motor Name-Plate Volts (Volts)	2200

Motor Name-Plate Amps (Amps)	58
Cable name	1 # COPPER 0.26 V/1000 ft 123 A
RESULTS	
Number of Pump stages	228
Power required (HP)	198
Pump Efficiency (%)	66
Current used (A)	58
Motor efficiency (%)	83
Power generated (HP)	198
Motor Speed (rpm)	2882.4

Table 16 ESP design summary

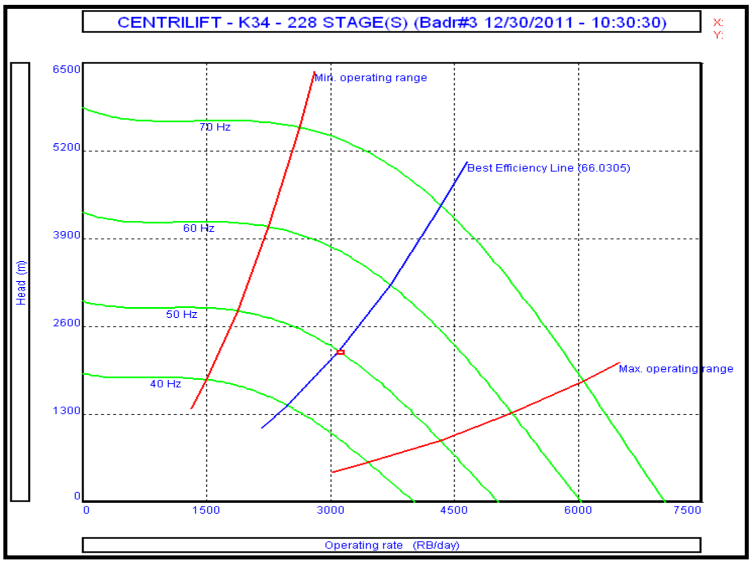


Figure 61 Pump performance curve

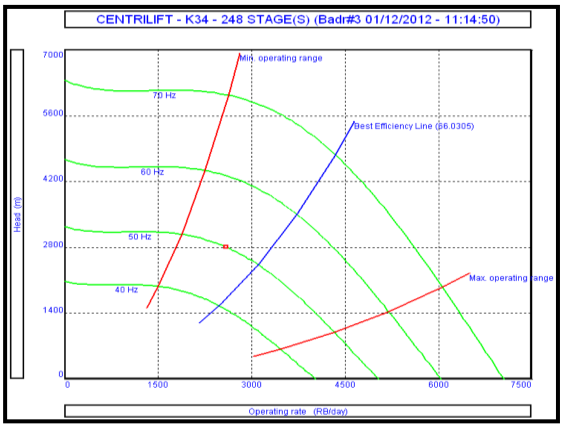


Figure 62 Pump performance curve at 95% WC

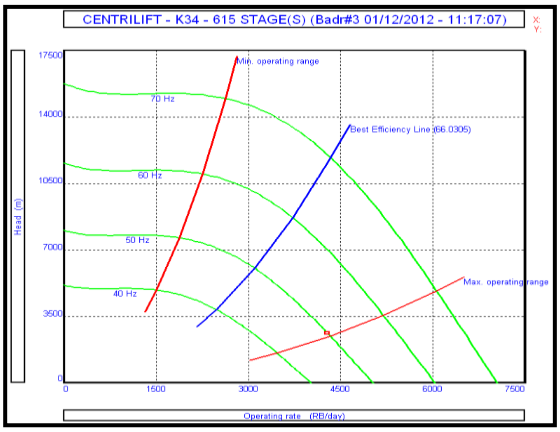


Figure 63 Pump performance curve at 715 scf/stb

WC% affect is shown in figure 54, where a comparison between NF, GL and ESP is illustrated, it is obvious that NF is not possible as the WA% increase at 20% the will is dead, for the artificial lift ESP showed again that more oil can be produced by installing it.

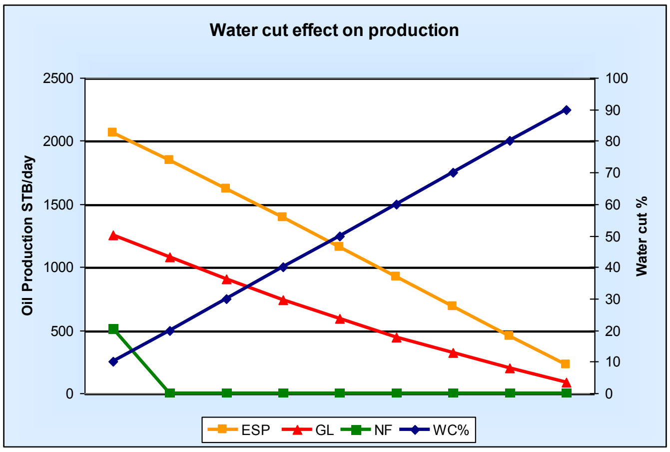


Figure 64 Water cut effect on production

Figure 55 shows the production from both GL and ESP at different tubing sizes.

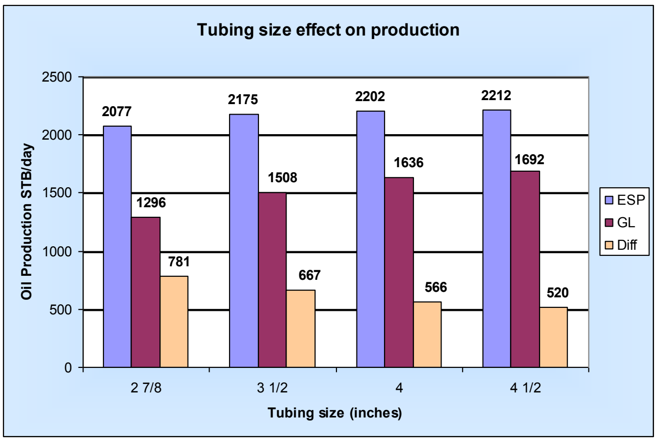


Figure 65 Tubing size effect on production

Figure 56 shows how Oil production behaves with the change of the GOR, ESP performance is declining with the increase of GOR.

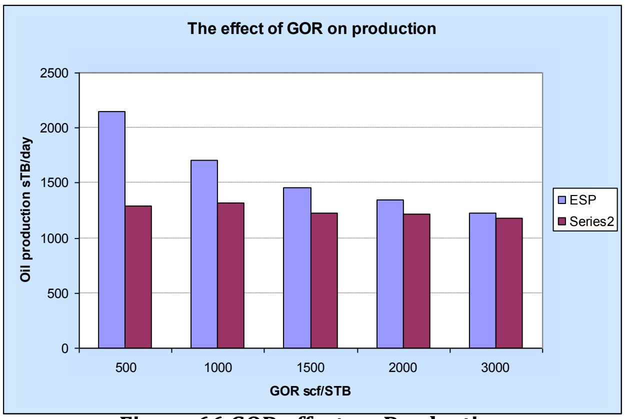


Figure 66 GOR effect on Production

El Badr-4

The well production dropped to less than the half since the first day of production, El Badr-3 is already on GL production, production before gas lift was around 400 BOPD and after GL 1500 BOPD (May 2011). Figure 57 shows the production potential by GL at different rates of the injection gas (as in August 2011).

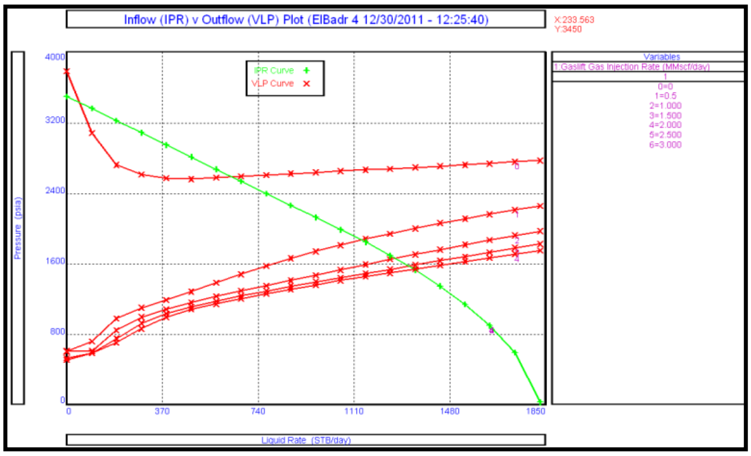


Figure 67 Gas lift performance at different injection rates

The table below shows the possible production at different injection rates, at the 1.00 MMcf/day is the optimum value, after which no profitable increment is occurred.

Injected Gas MMcf/day	0.5	1.00	1.5	2.00	2.5	3.00
Oil rate STB/day	1116	1244	1294	1315	1322	1325

Table 17 Oil production vs. gas injecton

Figure 58 shows the GL design, also illustrating the number of valves required and their spacing.

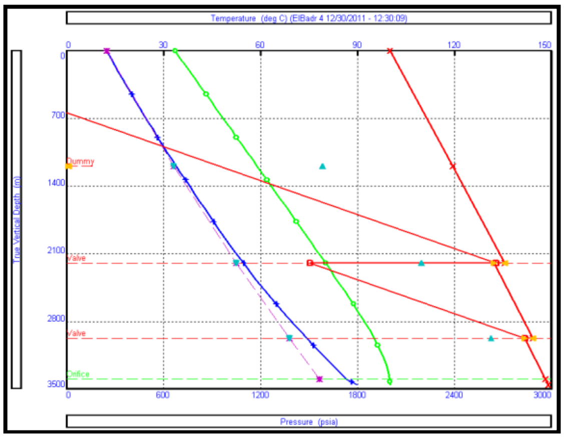


Figure 68 Gas lift design sketch

ESP showed a higher production in this well as well; El Badr-4 has even less GOR than El Badr-3 and El Badr-1, Table 18 summarized the ESP design for El Badr-4.

El Badr-4	
INPUT DATA	
Reservoir Pressure, P_r (psi)	3500
Water Cut (%)	2
Wellhead flowing pressure (psi)	
Gas separator efficiency (%)	0
Pump depth (m)	3400
Operating Frequency (Hz)	50
Length of cable (m)	3500
CALCULATED DATA	
Pump Intake Pressure (psi)	1295
Pump Intake Rate (RBPD)	1913
Free GOR entering pump (scf/stbo)	
Pump discharge pressure (psi)	3250
Pump discharge rate (RBPD)	1871
Head required (m)	1894
SELECTED EQUIPMENT	
Pump Name	REDA GN2100 5.13 inch
Motor Name	CENTRILIFT 450
Motor Name-Plate power (HP)	120
Motor Name-Plate Volts (Volts)	1100
Motor Name-Plate Amps (Amps)	58
Cable name	1 # COPPER 0.26 V/1000 ft 123 A
RESULTS	
Number of Pump stages	221
Power required (HP)	99.3
Pump Efficiency (%)	63
Current used (A)	58.5
Motor efficiency (%)	83
Power generated (HP)	99.3
Motor Speed (rpm)	2882

Table 18 SPE design summary

Figure 59 shows the performance curve of the selected pump, indication that the pumps operated at the BEP.

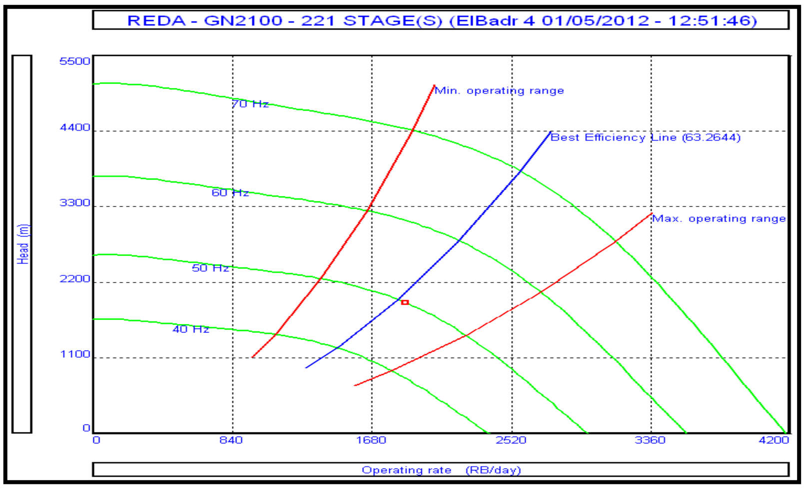


Figure 69 Pump performance curve

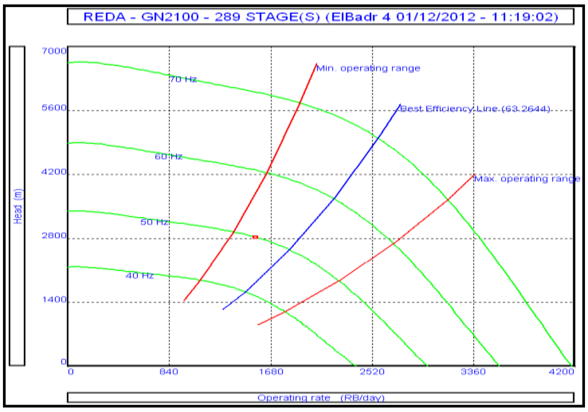


Figure 71 pump performance curve at 95% WC

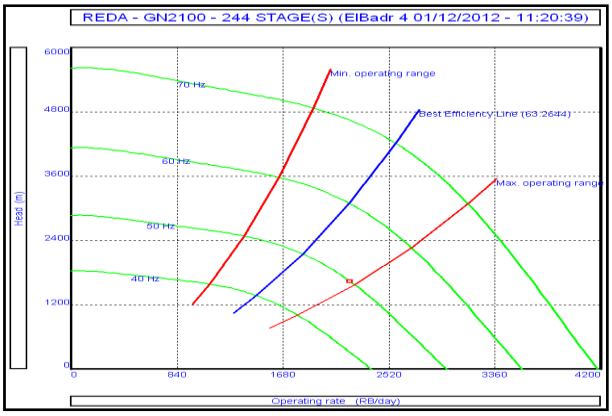


Figure 70 Pump performance curve at 620 scf/stb

As you can see in figure 62 ESP pump is not highly affected by the tubing size, where as GL does and this because as tubing size increases the friction introduced by the high velocity of gas is decreased, of course the rate will continue in increasing until the gravity of the fluid become higher that gas ability to lift it.

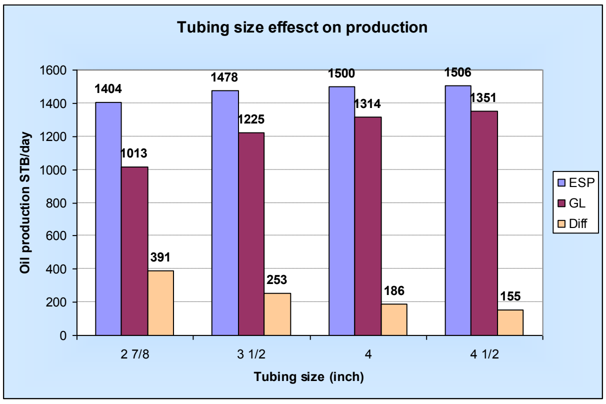


Figure 72 Tubing size effect on production

Figure 63 shows how production effected by the increase of WC%, starting from 10% water cut the well is not able to flow naturally, for artificial lifts ESP shows a higher production potential, the current WC% is around 5% and ESP provides a high difference than GL until water cut reaches 70%, in this case changing to ESP depends on when the well will be producing with a 70% WC.

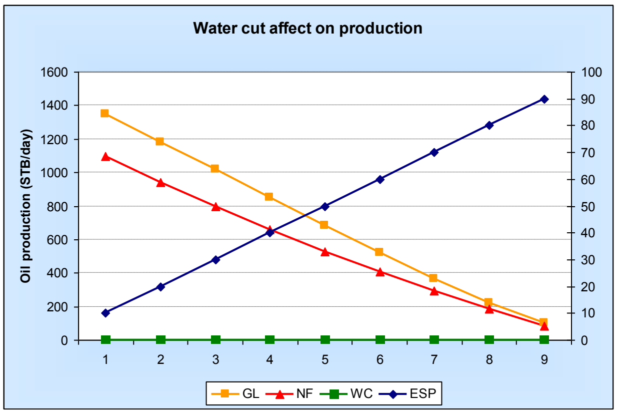


Figure 73 Water cut effect on production

Figure 64 shows the affect of GOR on production, and it indicates that at high GOR GL is better to be used as an artificial lift fort his well. The current GOR is around 15 scf/day (as in August 2011).

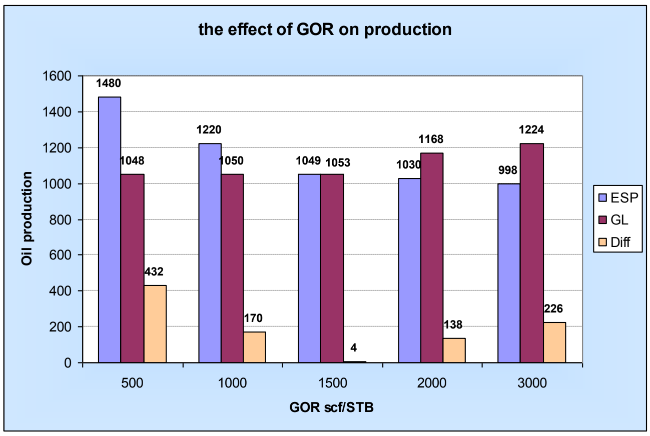


Figure 74 GOR effect on production

El Badr-5

The Well is on production for about 9 months, GL started 3 moths since the first day of production as production started to decline. GOR is an average of 500 (scf/day), which makes it a suitable environment for ESP installation as we do not have any other limitation such as sand production or sour gases.

Figure 65 shows the potential oil production with GL at different gas injection rates.

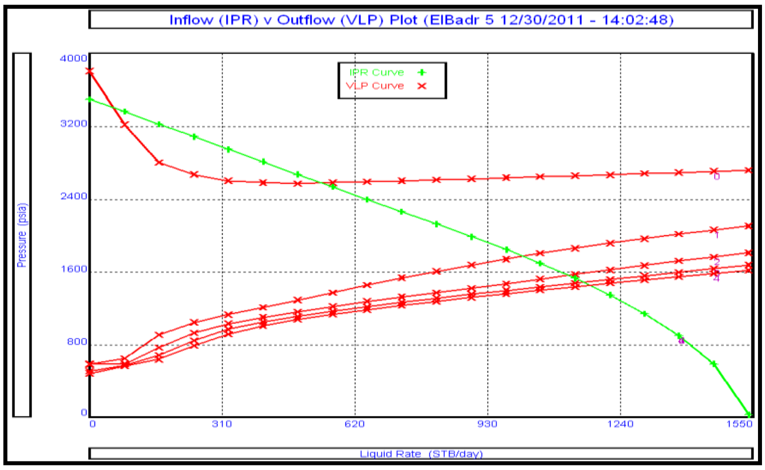


Figure 75 Gas lift performance at different injection rates

Table 19 illustrates the oil rate at each injection rate, and one can note that after 1.00 MMcf/day there is no attractive increment in oil production.

Injected Gas MMcf/day	0.5	1.00	1.5	2.00	2.5	3.00
Oil rate STB/day	1001.7	1106	1143	1156	1163	1166

Table 19 Oil production vs. gas injection

Figure 66 shows GL design for El Badr-5, and showing the required valve Number and their spacing.

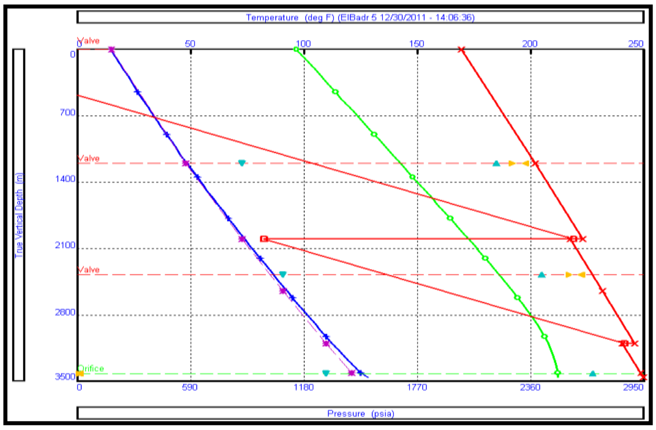


Figure 76 Gas lift design sketch

Table 20 summarizes the ESP design.

El Badr-5	
INPUT DATA	
Reservoir Pressure, P_r (psi)	3500
Water Cut (%)	1
Wellhead flowing pressure (psi)	
Gas separator efficiency (%)	70
Pump depth (m)	3400
Operating Frequency (Hz)	50
Length of cable (m)	3500
CALCULATED DATA	
Pump Intake Pressure (psi)	826
Pump Intake Rate (RBPD)	2264
Free GOR entering pump (scf/stbo)	
Pump discharge pressure (psi)	3412
Pump discharge rate (RBPD)	1719
Head required (m)	2546
SELECTED EQUIPMENT	
Pump Name	REDA GN 2000 5.13 inch
Motor Name	CENTERILIFT 544
Motor Name-Plate power (HP)	300
Motor Name-Plate Volts (Volts)	1395
Motor Name-Plate Amps (Amps)	105
Cable name	1 # COPPER 0.26 V/1000 ft 123 A
RESULTS	
Number of Pump stages	325

Power required (HP)	235
Pump Efficiency (%)	59.5
Current used (A)	100
Motor efficiency (%)	83.9
Power generated (HP)	235
Motor Speed (rpm)	2879

Table 20 ESP design summary

Figures 67 shows the selected pump performance curve indicating that the pump is operating at it BEP

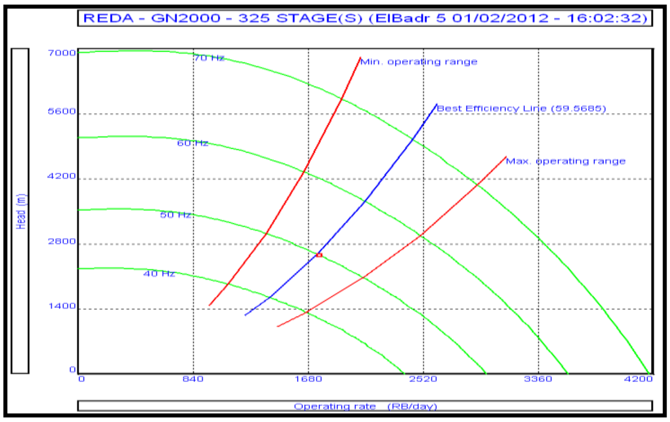


Figure 77 Pump performance curve

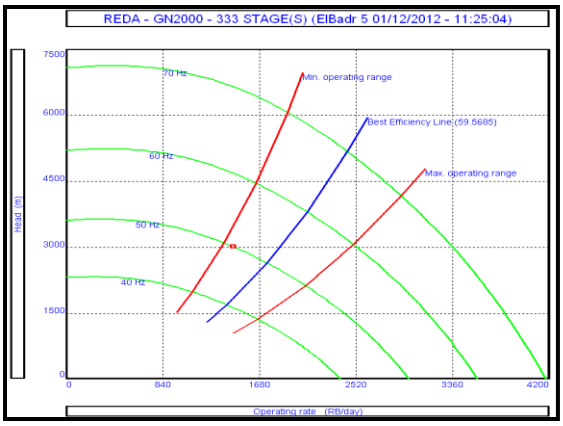


Figure 78 Pump performance curve at 98% WC

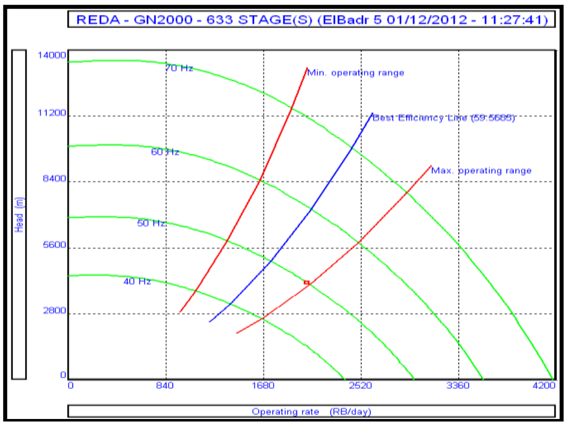


Figure 79 Pump performance curve at

Figure 70 shows the change on production as the tubing size changes as well, again ESP not affected by the tubing size but for GL one can see an increase in the production as the tubing size is increases, the tubing size which is used in El Badr-5 is 3 ½ and it is suitable for this well.

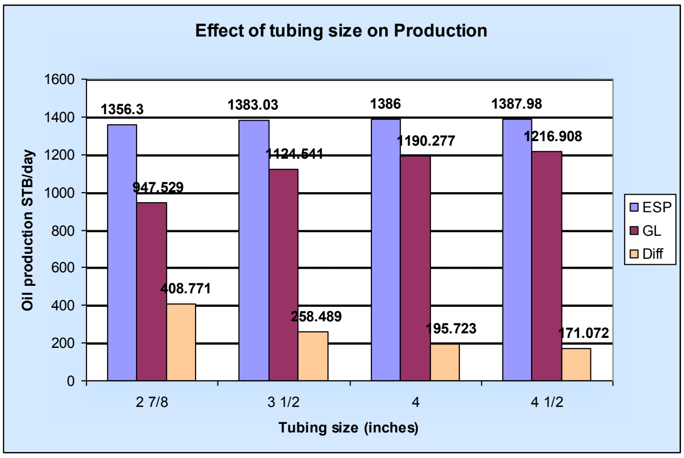


Figure 80 Tubing size effect on production

Figure 71 shows the affect of WC% on production, ESP showed a higher production at all values and at 90% WC the difference between two methods is around 84 BOPD.

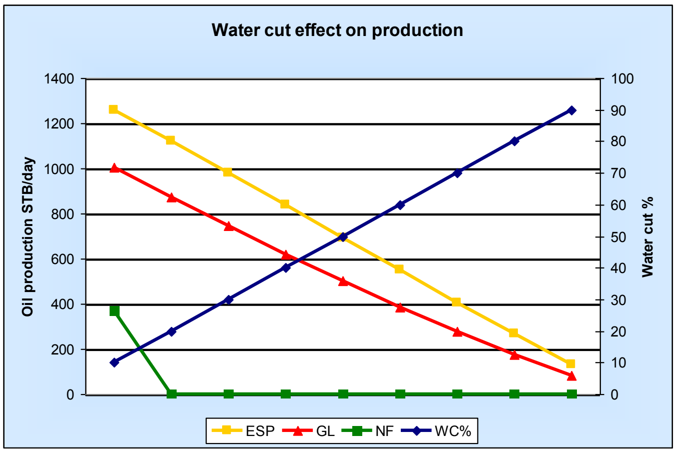


Figure 81 Water cut effect on production

Figure 72 shows how GOR can affect the production.

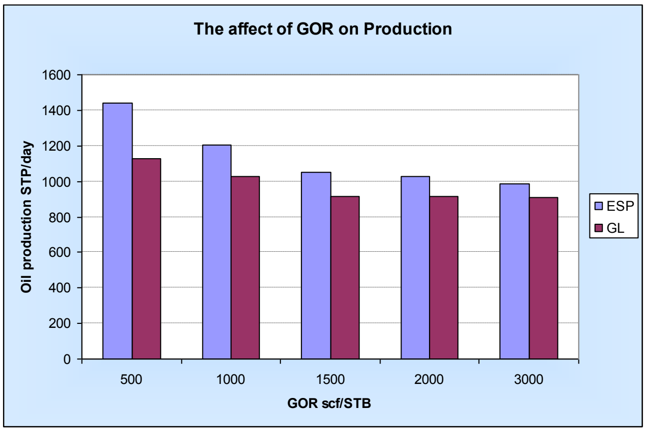


Figure 82 GOR effect on production

Farah-1

A well with a low productivity index, water broke through in October 2010 and production decreased due to that, before gas lift the well was flowing to thank on location, GL design has been done and several injection rates where investigated. See figure 73

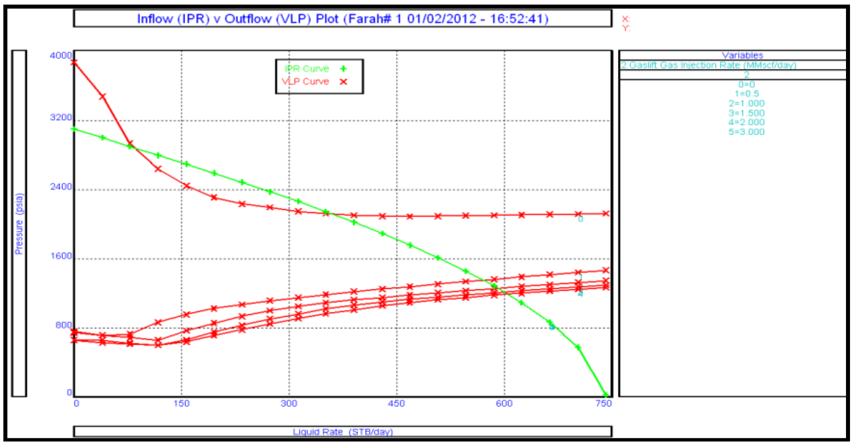


Figure 83 Gas lift performance at different injection rates

Table 21 below shows the amount of oil which can be produced at different gas injection rates.

Injected Gas MMcf/day	0.5	1.00	1.5	2.00	2.5	3.00
Oil rate STB/day	473	490	497	501	502	501

Table 21 Oil production vs. gas injection

ESP also has been studied for well Farah-1, see the design summary in table 22

Farah-1	
INPUT DATA	
Reservoir Pressure, P_r (psi)	3100
Water Cut (%)	20
Gas separator efficiency (%)	80
Pump depth (m)	3400
Operating Frequency (Hz)	50
Length of cable (m)	3500
CALCULATED DATA	
Pump Intake Pressure (psi)	842
Pump Intake Rate (RBPD)	1073.5

Free GOR entering pump (scf/stbo)	
Pump discharge pressure (psi)	2886.6
Pump discharge rate (RBPD)	834
Head required (m)	1883
SELECTED EQUIPMENT	
Pump Name	CENTERILIFT R9 4 inch
Motor Name	REDA 456-91-std
Motor Name-Plate power (HP)	60
Motor Name-Plate Volts (Volts)	729
Motor Name-Plate Amps (Amps)	45.5
Cable name	1 # COPPER 0.26 V/1000 ft 123 A
RESULTS	
Number of Pump stages	336
Power required (HP)	50
Pump Efficiency (%)	60
Current used (A)	45.5
Motor efficiency (%)	82.5
Power generated (HP)	50
Motor Speed (rpm)	2876

Table 22 ESP design summary

Figures 74,75,76 show the performance curve of the pump:

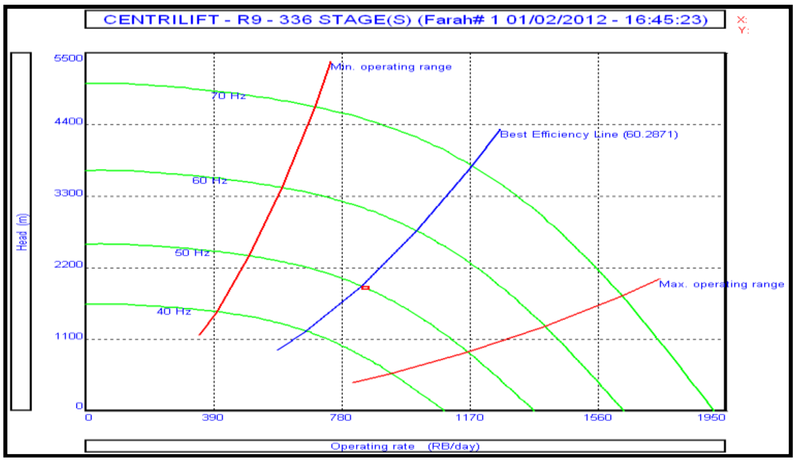
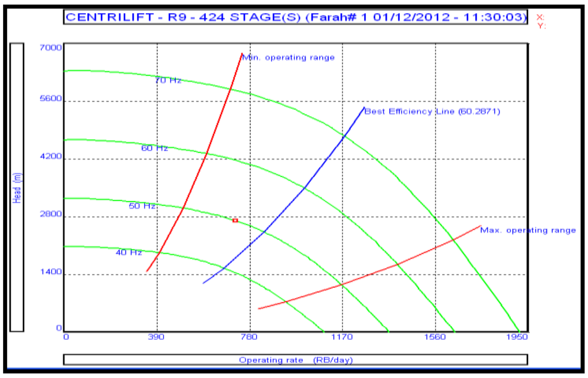


Figure 84 Pump performance curve



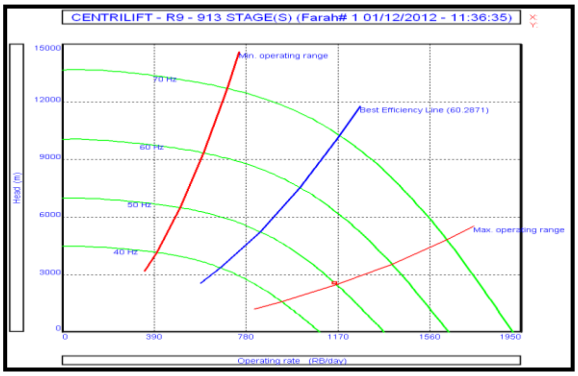


Figure 85 Pump performance curve at 98% WC **Figure 86 Pump performance curve at**

Figure 77 compares between productions from ESP and GL at different WC% values, as it is illustrated there is no makeable difference between them especially at high WC%.

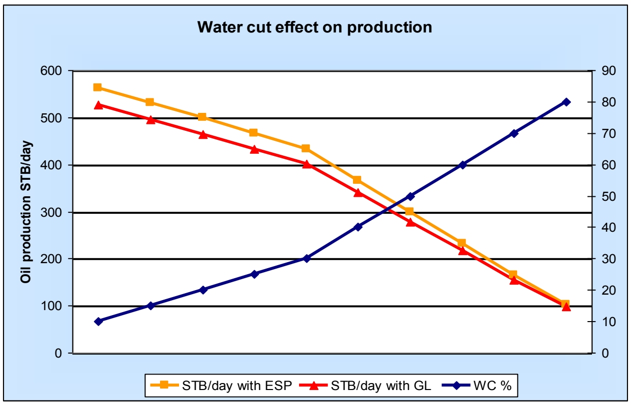


Figure 87 water cut effect on production

The tubing size used in Farah-1 is 3 ½ inch tubing, and comparing it with the other tubing size one can clearly decide that 3 ½ inch tubing is the optimum size for Farah-1, see figure 78 below

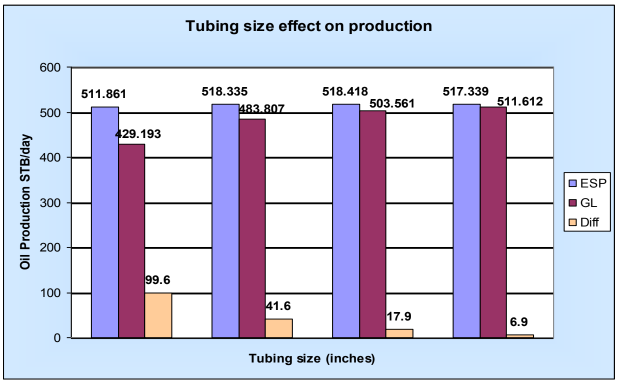


Figure 88 Tubing size effect on production

The figure below shows how production is effected by the increase of the GOR at 3000 scf/STB both method have almost the same production.

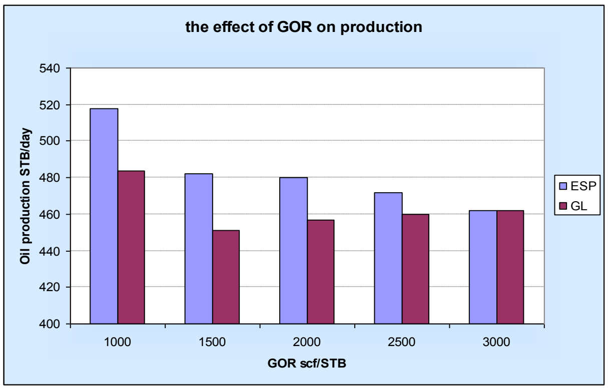


Figure 89 GOR effect on production

Methaq-1

Figure 80 shows performance of the GL system at different injection rates, the well is producing naturally an amount of oil that does not differ a lot than what it can deliver with GL.

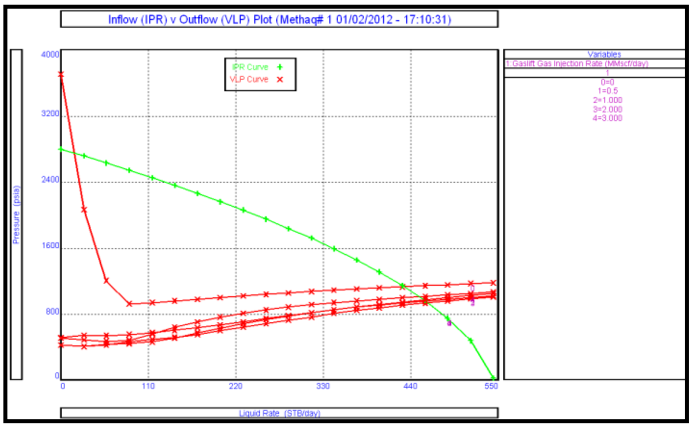


Figure 90 Gas lift performance at different injection rates

The table below illustrates the amount of oil that can be produced at different injection rates.

Injected Gas MMcf/day	0.5	1	1.5	2	2.5	3
Oil rate STB/day	427	436	438.3	438.4	436	433

Table 23 Oil production vs. gas injection

Methaq-1 is not a good candidate for an ESP installation the design showed that ESP potential is less that what can be produced with GL, the table below shows the ESP design summary.

Methaq-1	
INPUT DATA	
Reservoir Pressure, P_r (psi)	2800
Water Cut (%)	1
Gas separator efficiency (%)	80
Pump depth (m)	2900
Operating Frequency (Hz)	50
Length of cable (m)	3000
CALCULATED DATA	
Pump Intake Pressure (psi)	1067.5
Pump Intake Rate (RBPD)	1582.5
Pump discharge pressure (psi)	1573.7
Pump discharge rate (RBPD)	1180

Head required (m)	708.5
SELECTED EQUIPMENT	
Pump Name	CENTERLIFT F35 5.13 inch
Motor Name	CENTERILIFT 450
Motor Name-Plate power (HP)	36
Motor Name-Plate Volts (Volts)	391.6
Motor Name-Plate Amps (Amps)	50
Cable name	1 # COPPER 0.26 V/1000 ft 123 A
RESULTS	
Number of Pump stages	155
Power required (HP)	26.7
Pump Efficiency (%)	43
Current used (A)	74.2
Motor efficiency (%)	82.7
Power generated (HP)	26.7
Motor Speed (rpm)	2895

Table 24 ESP design summary

The figures below shows the performance curves of the selected pump.

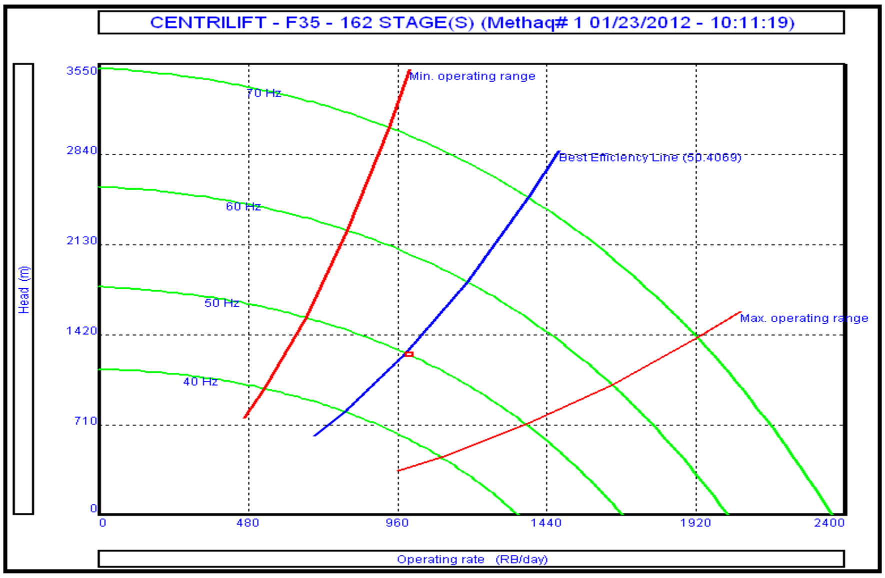


Figure 91 Pump performance curve

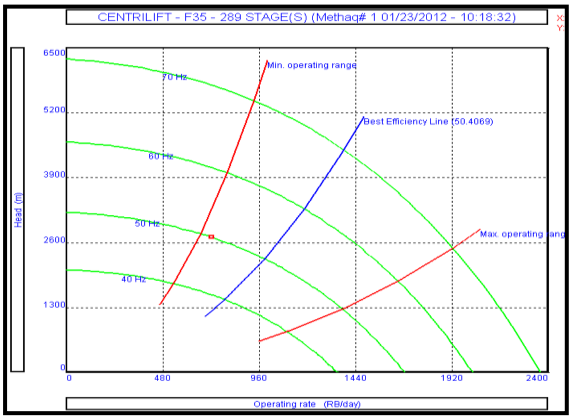


Figure 92 Pump performance curve at 98% WC

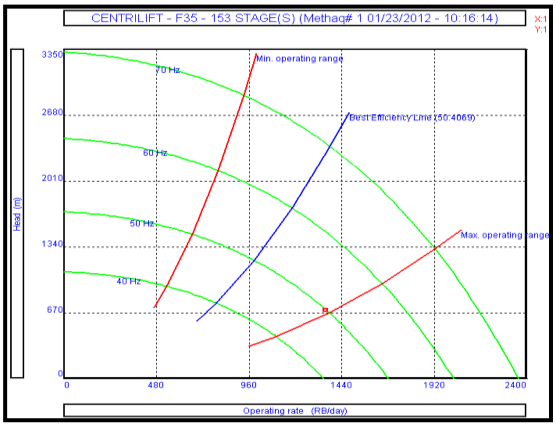


Figure 93 Pump performance curve at 2560 scf/stb

Tubing size effect on production is shown in figure 84, by analyzing the values in the chart tubing size 3 ½ is considered to be the optimum tubing size for this well.

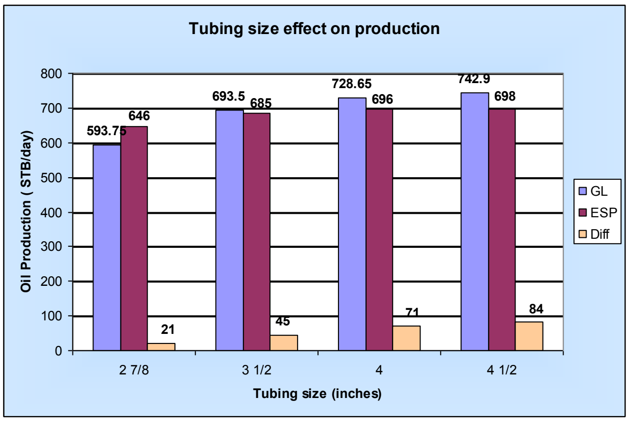


Figure 94 Tubing size effect on Production

Figure 85 shows the production behavior with the change of water cut, while chart 86 shows how GOR affects the production.

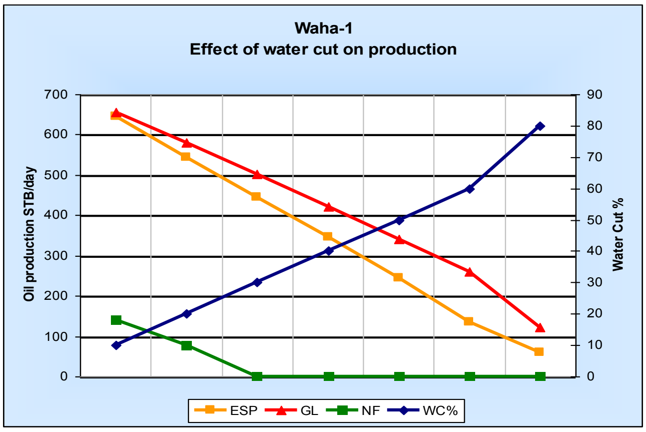


Figure 95 Water cut effect on production

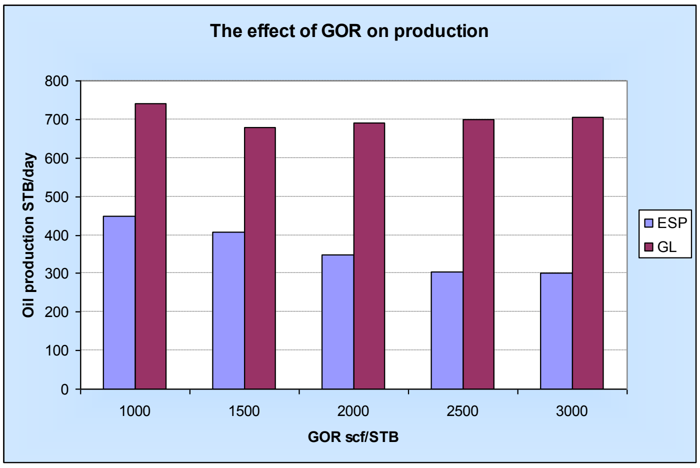


Figure 96 GOR effect on production

Methaq-2

As you can see in the well performance (chapter 2) the well is not able to flow naturally, Methaq-2 has a very low productivity index, the thing which makes it not a good candidate for an ESP system, where as a GL design has been done and the well could deliver around 71 BOPD. The chart below shows the performance of GL at different injection rates versus natural flow. Sucker rod showed a very good performance with 121 bpd, for sucker rod design see Appendix E.

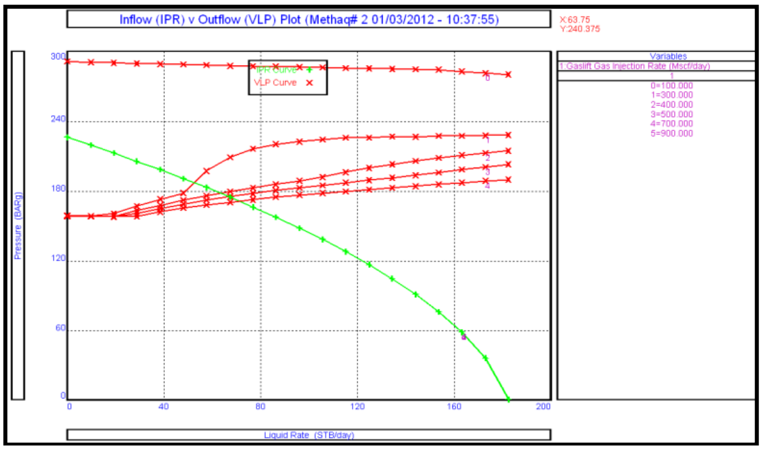


Figure 97 Gas lift performance at different injection rates

The table blow illustrates the potential oil production at different injection rates.

Injected Gas Mcf/day	100	300	500	700	900	100
Oil rate STB/day	0	52.6	67	71	73	0

Table 25 Oil production vs. gas injection

The effect of water cut on production is illustrated in chart 88, current 2% and at a value of 90% oil production will be around 5 BOPD.

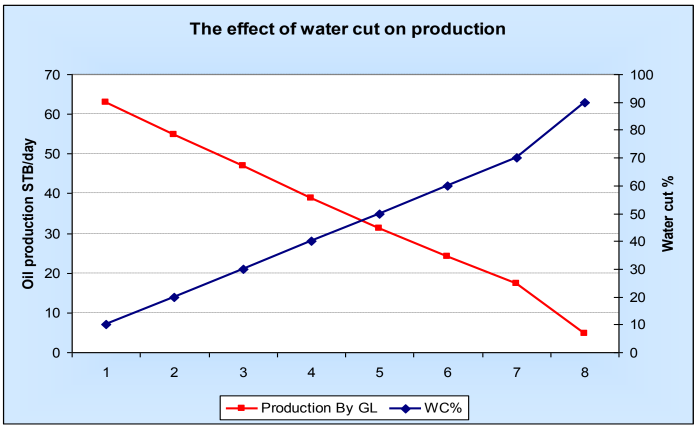


Figure 98 Water cut effect on production

Tubing size as well as GOR have no a big effect on production, the tubing size which is used is 3 ½ and it is suitable for the well capability, there is a slight increase in production is the GOR increase, average production is always around 72 BOPD (under the current situation).

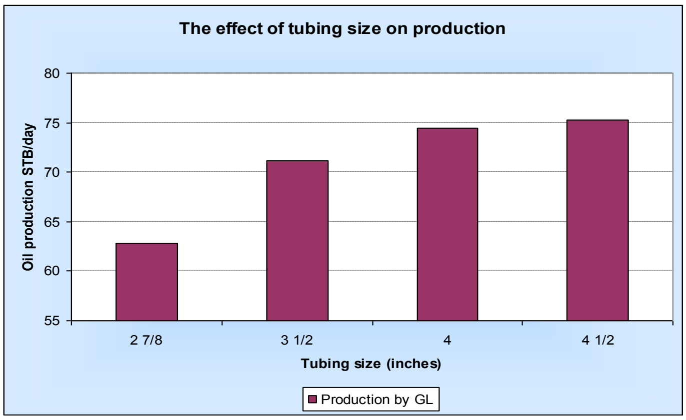


Figure 99 Tubing size effect on production

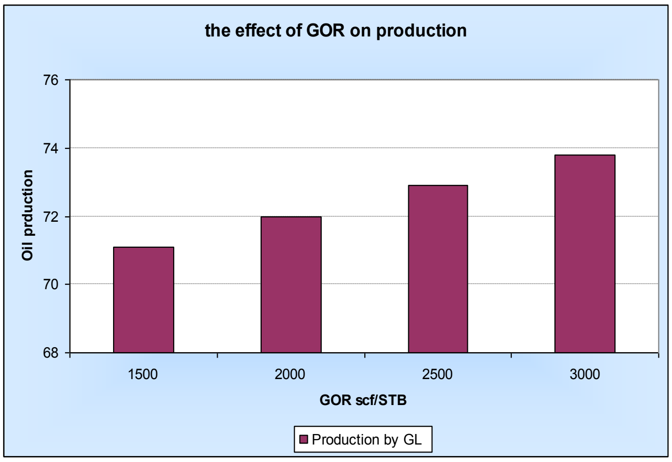


Figure 100 GOR effect on production

Shaheen-1

The well is flowing naturally but the fluid can not be delivered to the station (see chapter two), a GL design has been done, and it showed a good production potential, the chart below is showing the performance of GL system at different injection rates.

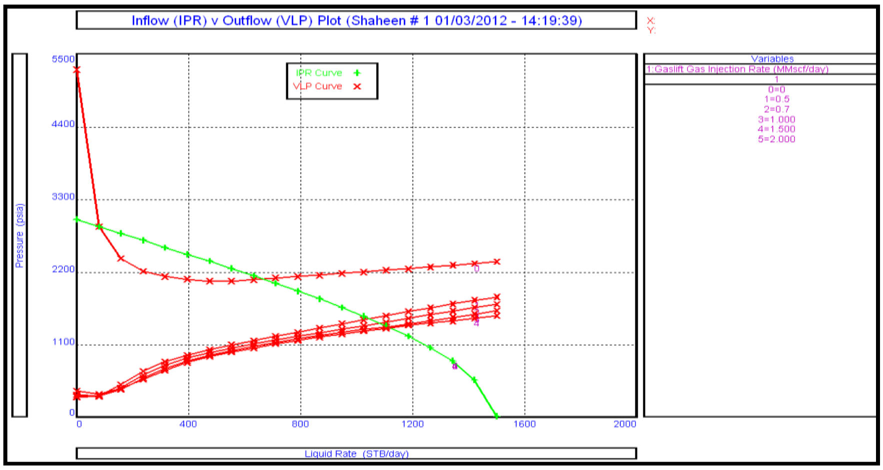


Figure 101 Gas lift performance at different injection rates

Table 26 provides the amounts of oil that can be produced at different injection rates, the rate at the yellow square found to be the optimum injection rate. Figure XX shows the GL design sketch.

Injected Gas Mcf/day	0.5	0.7	1	1.5	2
Oil rate STB/day	596.6	618	634	639	641

Table 26 Oil production vs. injection rate

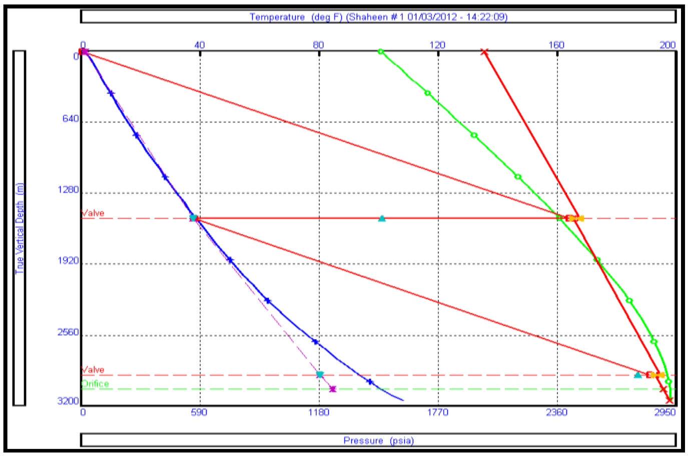


Figure 102 Gas lift design sketch

Shaheen-1	
INPUT DATA	
Reservoir Pressure, P_r (psi)	3000
Water Cut (%)	43
Wellhead flowing pressure (psi)	
Gas separator efficiency (%)	0
Pump depth (m)	3000
Operating Frequency (Hz)	50
Length of cable (m)	310
CALCULATED DATA	
Pump Intake Pressure (psi)	1105
Pump Intake Rate (RBPD)	2168
Free GOR entering pump (scf/stbo)	
Pump discharge pressure (psi)	2651
Pump discharge rate (RBPD)	1549
Head required (m)	1399
SELECTED EQUIPMENT	
Pump Name	REDA GN 2000 5.13 inch
Motor Name	CENTERILIFT 450
Motor Name-Plate power (HP)	102
Motor Name-Plate Volts (Volts)	970
Motor Name-Plate Amps (Amps)	58
Cable name	1 # COPPER 0.26 V/1000 ft 123 A
RESULTS	
Number of Pump stages	173
Power required (HP)	75
Pump Efficiency (%)	59
Current used (A)	54.5
Motor efficiency (%)	82.66
Power generated (HP)	75
Motor Speed (rpm)	2895.2

Table 27 ESP design summary

Figure 93 shows the performance curve of the selected pump. Also you can see in chart 96 how production changes with the change of water cut among the two artificial lift systems, one can easily note that there is no big different between the two method especially at high water cut values. Looking at chart 95 the moat suitable tubing size that could be used is 3 ½ inch tubing, which is the one already is used in Shaheen-1.

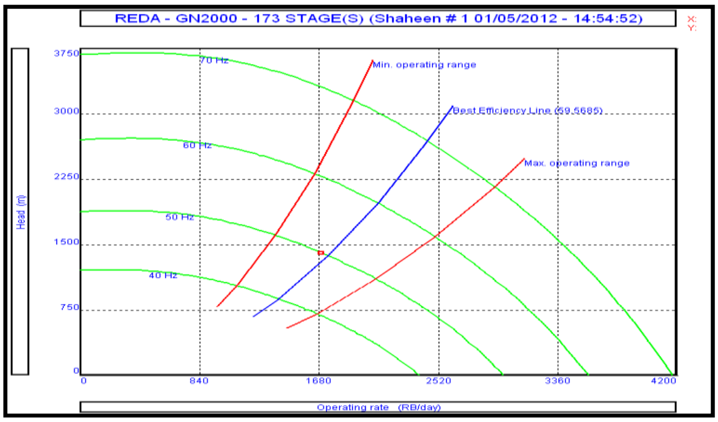
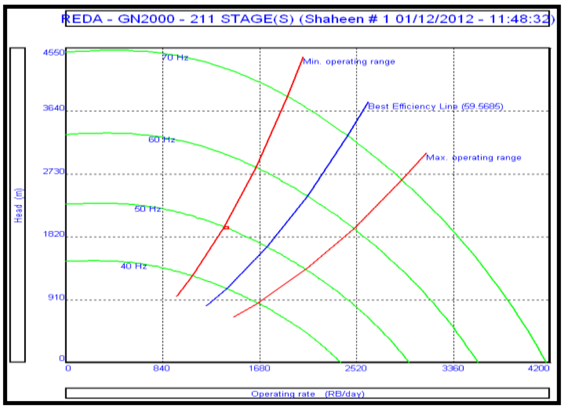


Figure 103 Pump performance curve



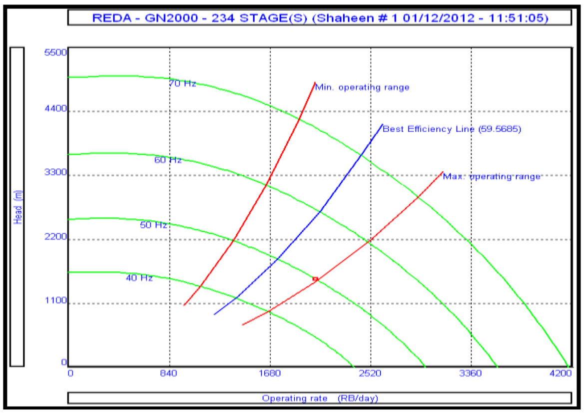


Figure 104 Pump performance curve at 75% WC

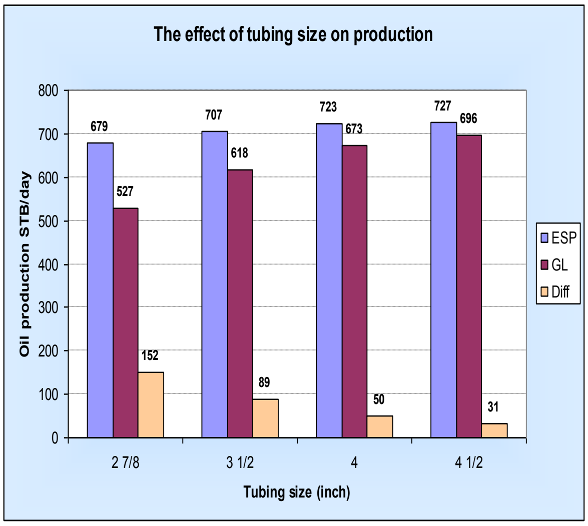


Figure 105 tubing size effect on production

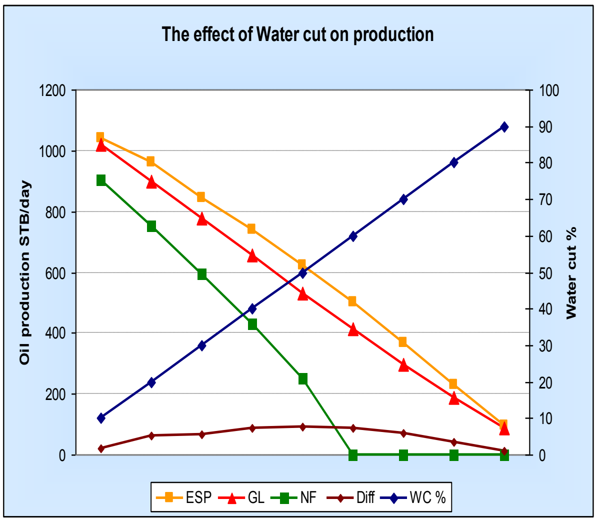


Figure 106 Water cut effect on production

Figure 97 shows the effect of GOR on production, the effect is quite obvious on ESP, where as for GL there is no remarkable change when the increment is small, at 2000 scf/STB GL exceeded the potential of the ESP, while at 3000 scf/STB the production from GL has dropped by 100 scf/STB and this could be due to the friction introduced from the high gas velocity. Considering zero percent-downhole separation- efficiency in the case of ESP.

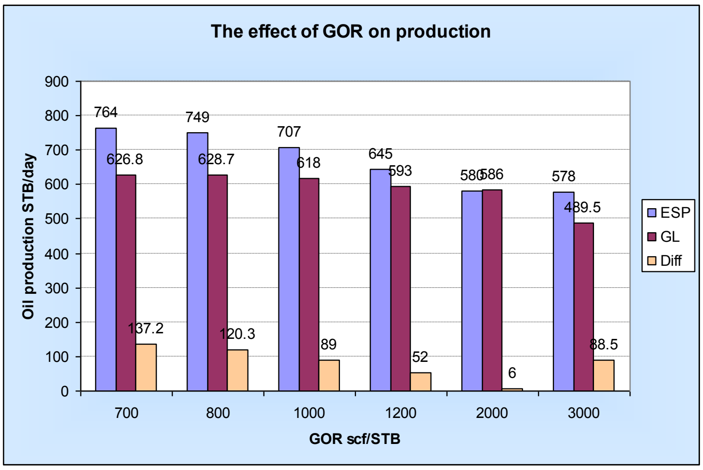


Figure 107 GOR effect on production

Waha-1

As the well is producing intermittently, it was challenging to estimate WC%, the reason why two scenarios was discussed for this well, the first with WC% equal to 6%, and the other with 50 water cut.

Figure 98 shows the performance of GL at both water cut values.

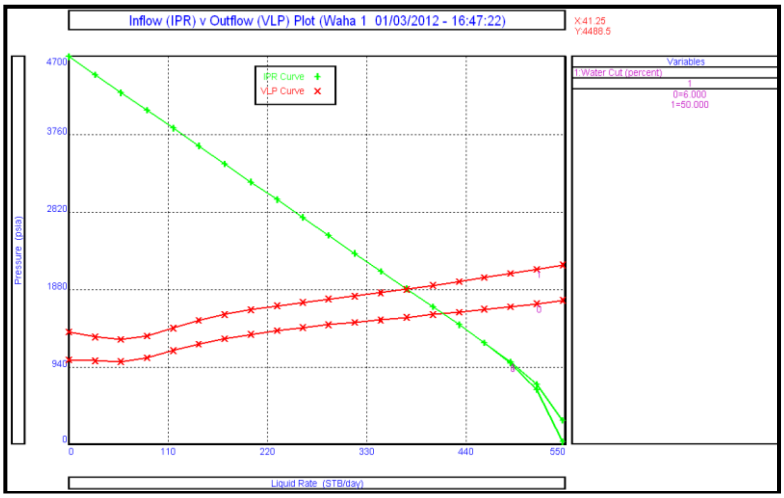


Figure 108 Gas lift performance at different injection rates

Table 28 shows the oil that can be produced at different injection rates.

Injected Gas MMcf/day	WC% = 6	0.5	0.7	1	1.5	2
Oil rate STB/day		390	396	400	403	401
Injected Gas MMcf/day	WC% = 50	0.5	0.7	1	1.5	2
Oil rate STB/day		188.4	192.5	195	198	197

Table 28 Oil production vs. gas injection

Valve number needed and their spacing are showed on the sketch of the GL design. See figure 99.

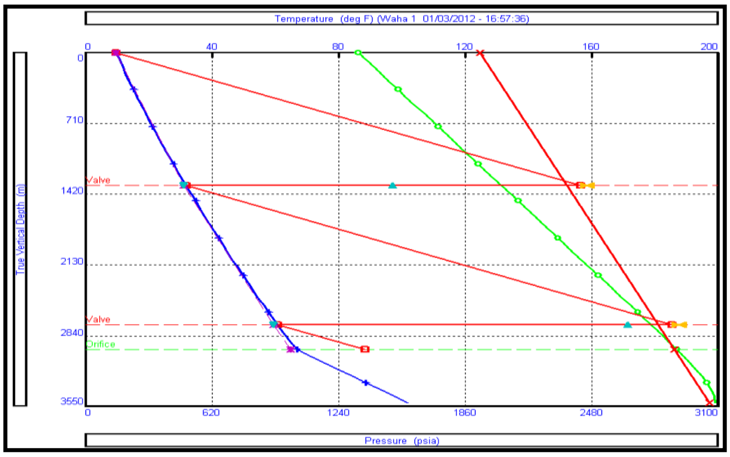


Figure 109 Gas lift design sketch

Waha-1		
INPUT DATA		
Reservoir Pressure, P_r (psi)	4700	
Water Cut (%)	Scenario one	6
	Scenario two	50
Wellhead flowing pressure (psi)		
Gas separator efficiency (%)	70	
Pump depth (m)	3200	
Operating Frequency (Hz)	50	
Length of cable (m)	3300	
CALCULATED DATA		
Pump Intake Pressure (psi)	573	
Pump Intake Rate (RBPD)	728.5	
Free GOR entering pump (scf/stbo)		
Pump discharge pressure (psi)	3205	
Pump discharge rate (RBPD)	577	
Head required (m)	2389	
SELECTED EQUIPMENT		
Pump Name	REDA DN 800 4 inch	
Motor Name	ESP_Inc 375_50	
Motor Name-Plate power (HP)	76.5	
Motor Name-Plate Volts (Volts)	1100	
Motor Name-Plate Amps (Amps)	38.5	
Cable name	1 # COPPER 0.26 V/1000 ft 123 A	
RESULTS		

Number of Pump stages	450
Power required (HP)	44
Pump Efficiency (%)	59
Current used (A)	31
Motor efficiency (%)	77
Power generated (HP)	44
Motor Speed (rpm)	2905

Table 29 ESP design summary

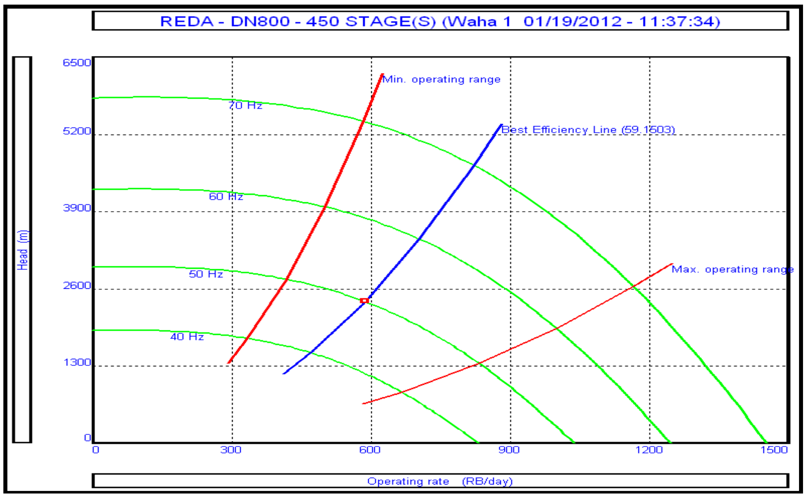


Figure 110 pump performance curve

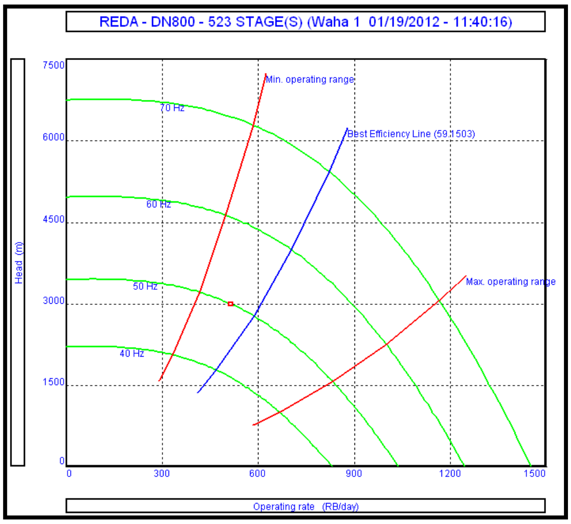


Figure 111 pump performance curve at 95% WC

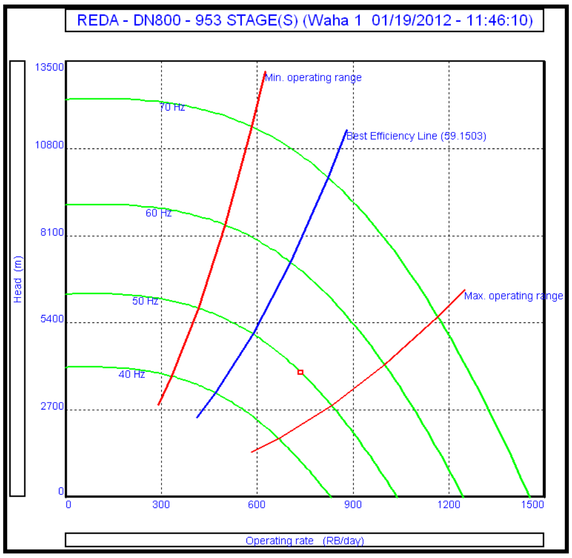


Figure 112 Pump performance curve at 722 scf/stb

Looking to the right chart one can conclude that ESP dose not provide much more oil than GL, and with increasing the WC GL is even performing better than ESP.

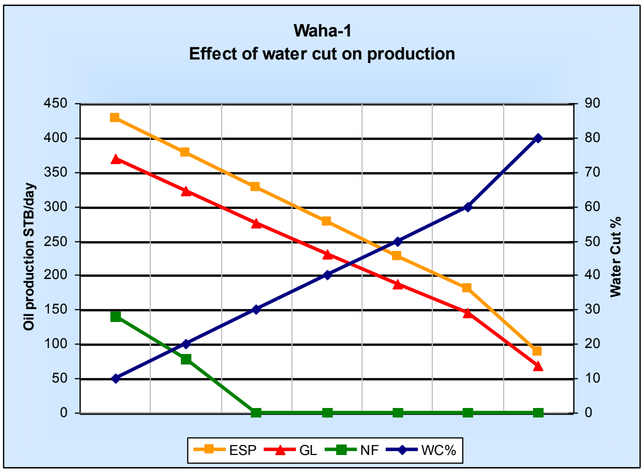


Figure 113 Water cut effect on production

Comparing the production from different tubing sizes showed that 3 ½ inch is the optimum size for this Waha-1.

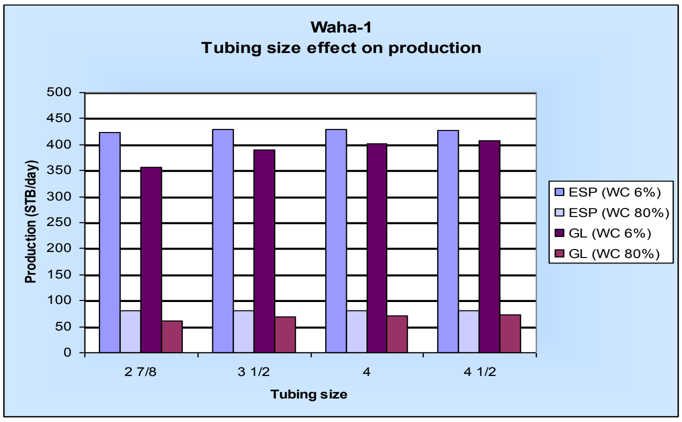


Figure 114 Tubing size effect on production

At high GOR almost there is no difference between both method ESP productions Dropped from 420 BOPD at 500 scf/day to 300 BOPD at 3000 scf/day. See figure 105.

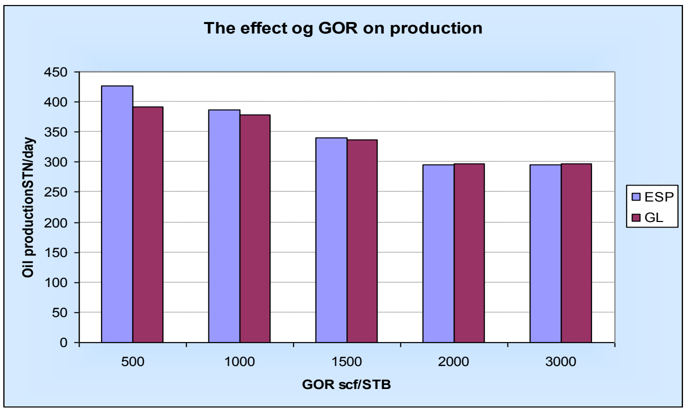


Figure 115 GOR effect on production

Waha-1 is a low producer as it shown in the figures above there is no difference between the productions from GL and ESP, and as sucker rod pumps suit more in wells with a low production a Sucker Rod design was done for Waha-1. See figure 106 for the comparison between GL, ESP and sucker rod, almost the same amount of liquid can be produced with sucker rod pump (416 bpd). For RODSTAR design see App. E.

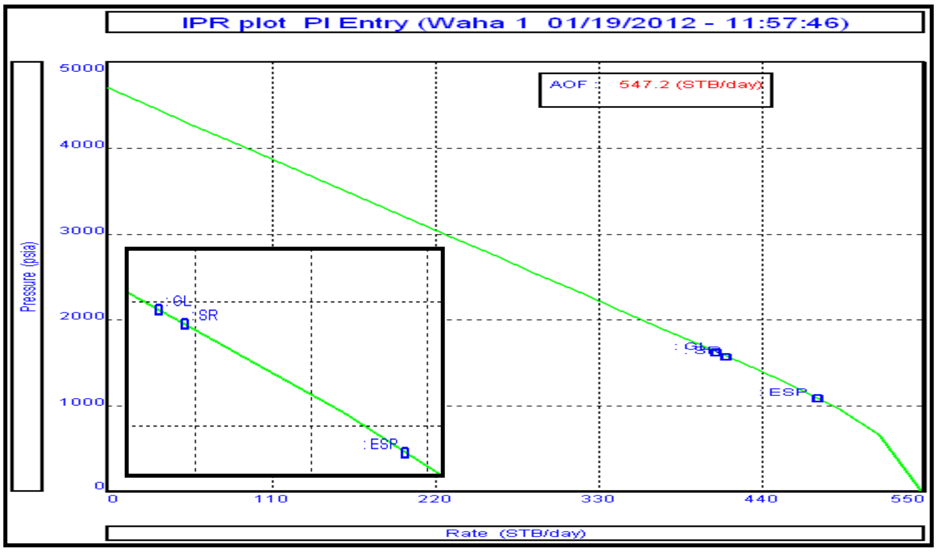


Figure 116 Comparison between the production potential from ESP, GL and sucker rod

The table below summarizes the sucker rod design for Waha-1:

Pump Unit Name		Lufkin C-640-365-168
Pump unit type		Conventional clockwise
Pump stroke length		102
Pump Max. stroke length		168
Pump speed		8 strokes/min
Pump diameter		2.5"
Plunger diameter		2.25"
Rods	1.125 inch	32.5 %
	1 inch	33.1 %
	0.875 inch	34.4 %

Table 30 Sucker rod design summary

Waha-2

The drawing below shows the performance of GL system the well is already on GL June 2011.

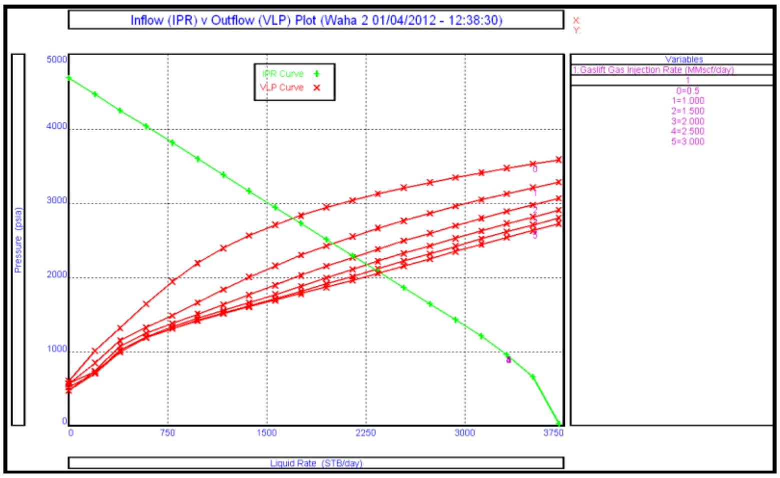


Figure 117 Gas lift performance at different injection rates

Table 31 shows the production potential at several injection rates.

Injected Gas MMcf/day	0.5	1	1.5	2	2.5	3
Oil rate STB/day	1189	1401	1515	1583	1624	1650

Table 31 Oil production vs. gas injection

Figure 108 shows the GL design sketch on which the number of valves needed and their spacing is illustrated.

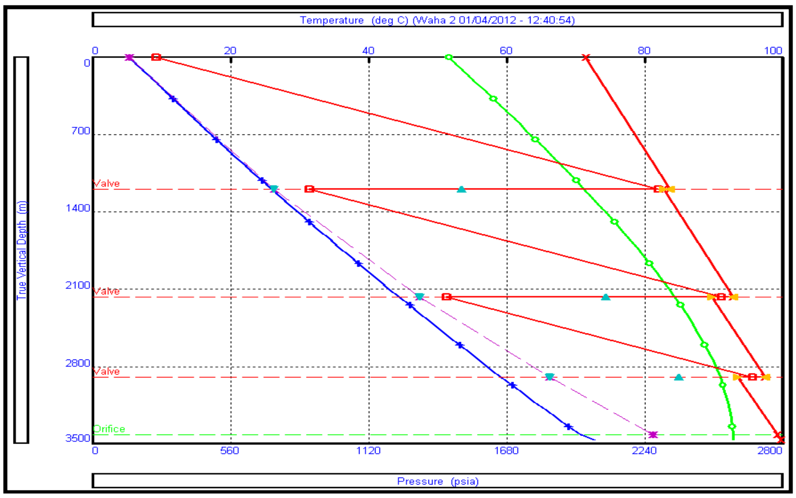


Figure 118 Gas lift design sketch

Waha-2	
INPUT DATA	
Reservoir Pressure, P_r (psi)	4686
Water Cut (%)	30
Wellhead flowing pressure (psi)	
Gas separator efficiency (%)	0
Pump depth (m)	3450
Operating Frequency (Hz)	50
Length of cable (m)	3550
CALCULATED DATA	
Pump Intake Pressure (psi)	1352
Pump Intake Rate (RBPD)	3659
Pump discharge pressure (psi)	3915
Pump discharge rate (RBPD)	3598
Head required (m)	2153
SELECTED EQUIPMENT	
Pump Name	CENTRILIFT GC4100 5.13 inch
Motor Name	CENTERILIFT 562 KMH
Motor Name-Plate power (HP)	340
Motor Name-Plate Volts (Volts)	1964
Motor Name-Plate Amps (Amps)	81
Cable name	
RESULTS	
Number of Pump stages	241
Power required (HP)	240
Pump Efficiency (%)	66
Current used (A)	75.3
Motor efficiency (%)	90.4
Power generated (HP)	240
Motor Speed (rpm)	3006

Figure 109 below shows the pump performance curve; whereas figure 111 illustrates the effect of Tubing size on production again 3 ½ inch suits Waha-2, as there is no high increment with a bigger tubing size. Figure 112 shows the effect of water cut in production, one can easily see that the difference in production between both methods is decreasing as the water cut increases, but even in high values (90%) ESP can provide at least 90 BOPD more than GL.

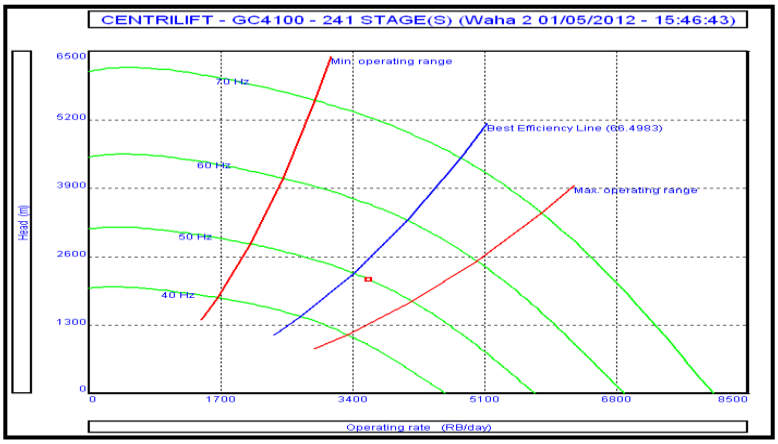


Figure 119 Pump performance curve

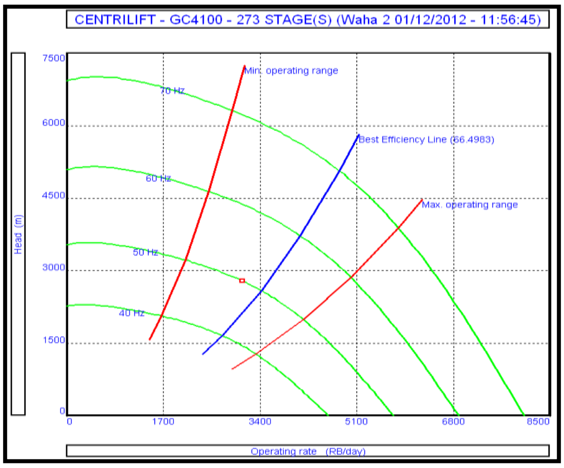


Figure 120 Pump performance curve at 98% WC

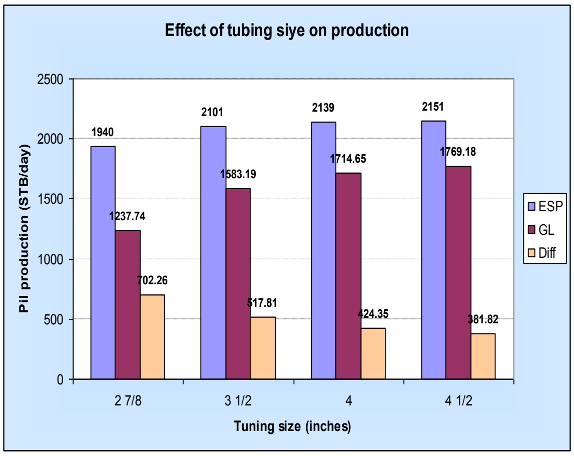


Figure 121 Tubing size effect on production

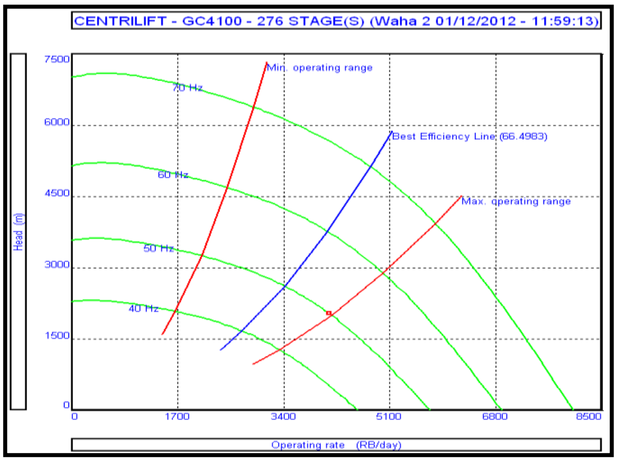


Figure 123 pump performance curve at 710 scf/stb

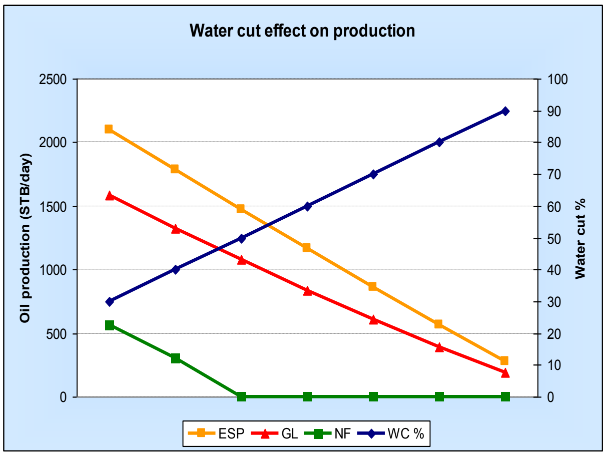


Figure 122 Water cut effect on production

The chart below show how production from both artificial lift can be affected by GOR; also shows that as the GOR increases the difference between the two methods is decreasing.

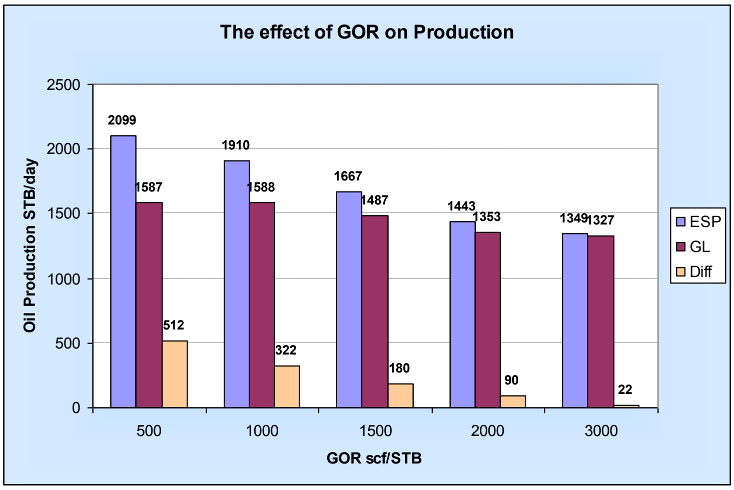


Figure 124 GOR effect on production

Chapter 5 Analyzing and summarizing of Cherouq field

Life of Field

Knowing the amount of oil that can be produced in a reservoir is very essential for any field development plan in the first place. Changing to an artificial lift production or from one method of artificial lift to another means investing a huge amount of money, and as it is very important for a company to make sure that all expenditures can be paid out in a short time and to make profits from this investment predicting the remaining oil in place is very crucial.

One of the challenges of Cherouq field is how to predict how much oil has been already produced and how much of it remained, all reservoirs in Cherouq field are producing from several thin layers, and all wells completed be produced in a commingled way, which make it kind of difficult to estimate the life of field. For more information about commingled flow see chapter two.

To be close enough to predict the future potential of the field, the reservoir pressure and the productivity index were reduced by 20% and then 40 % to see what GL and ESP can provide, this task was done for all wells, but in this chapter only Angam-1 is presented the results from the other wells is viewed in table 32.

Figure 115 shows how IPR curve changes with changing the reservoir pressures at constant PI, and the productions potential from GL and ESP presented on the IPR curve.

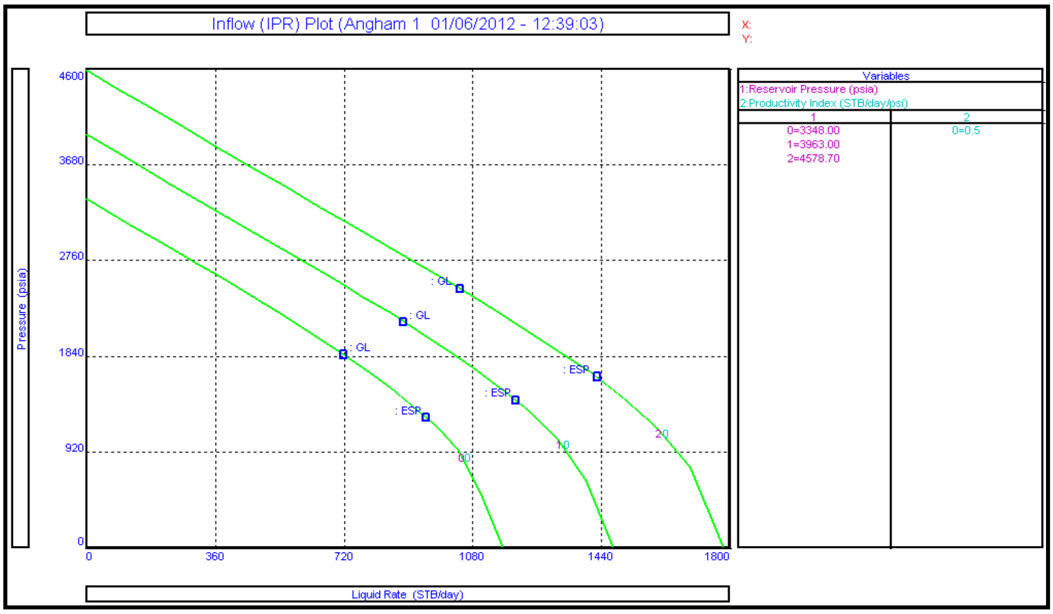


Figure 125 Comparisons between ESP and GL production potential at different Reservoir pressures

Figure 116 shows how IPR curve changes with the change of the productivity index at constant reservoir pressure.

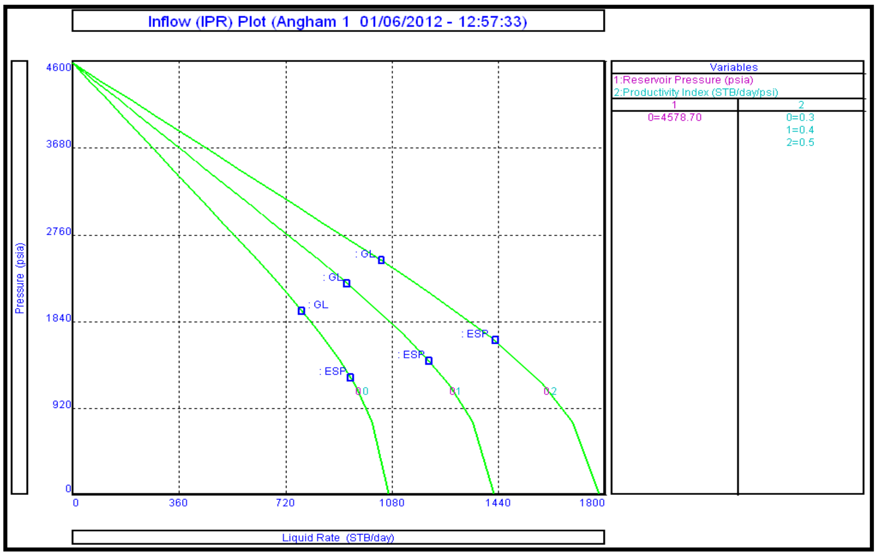


Figure 126 Comparison between ESP and GL production at different PI

Figure 117 summarizes the effects of the reservoir pressure and productivity index on oil production at different reservoir pressures and productivity index, at all values ESP showed a higher production potential than GL.

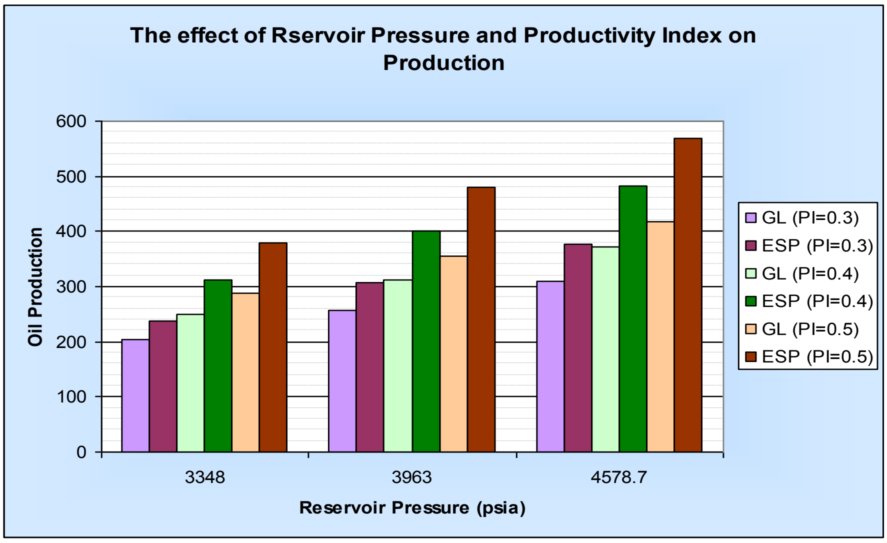


Figure 127 the effect of productivity index and reservoir pressure on production

Well Name	PI STB/d/psi		ESP Oil Rate (STB/d)			GL Oil Rate (STB/d)		
Angham-1		**Pr (psi)**	3348	3963	4578.7	3348	3963	4578.7
	0.3		237.8	306.5	376	204	258	309
	0.4		312	400	482	250	312	371
	0.5		380	480	570	287	355	418
Cherouq-1		Pr (psi)	2640	3520	4400	2640	3520	4400
	0.462		140	202	273	118.5	177.5	243.5
	0.616		189.5	270	359	147.5	225	310
	0.77		234	334	439	173	268	369
Cherouq-2		Pr (psi)	2640	3520	4400	2640	3520	4400
	0.448		255	370	493	187	288.5	400
	0.56		314	451	601	217	338	472
	0.7		380	546	713	249	391	517
El Badr-1		Pr (psi)	2464	3080	3850	2464	3080	3850
	0.8		604	866	1195	463	664	907
	1		756	1055	1409	545.5	777	1057
	1.25		920	1272	1363	633	896	1216
El Badr-3		Pr (psi)	2240	2800	3500	2240	2800	3500
	0.672		811	1124	1530	452.5	686.5	980.5
	0.84		984.5	1394.5	1812	521.5	795.5	1134
	1.05		1247.5	1669	2077	595.5	909.5	1296
El Badr-4		Pr (psi)	2240	2800	3500	2240	2800	3500
	0.448		544.5	748.5	1057.5	446	643	886.5
	0.56		683	958	1274	532	765.5	1047.5
	0.7		835	1155	1478	628.5	900	1225.4
El Badr-5		Pr (psi)	2240	2800	3500	2240	2800	3500
	0.3776		0	0	928	368.8	548	774
	0.472		532	757	0	410	608.5	861
	0.59		0	0	1383	534	797	1124
Farah-1		Pr (psi)	1984	2480	3100	1984	2480	3100
	0.24512		167	235	347	167	222	324
	0.3064		213	296	428.5	199	269	396.5
	0.383		268	366.5	518	236	228	484
Methaq-1		Pr (psi)	1792	2240	2800	1792	2240	2800
	0.224		133	207	282	168	218	283
	0.28		178	261	349	201.5	265.5	348.5
	0.35		230	323.7	422	241.6	323	427
Methaq-2		Pr (psi)	2112	2640	3300	2112	2640	3300
	0.064		/	/	/	0	20	49
	0.08		/	/	/	0	24,8	59
	0.1		/	/	/	0	30	71
Shaheen-1		Pr (psi)	1920	2400	3000	1920	2400	3000
	0.48		264	339	494	229	302	435
	0.6		322	415	592	270	361	522
	0.75		399	508	707	317	428.5	618
Waha-1	WC = 6%	Pr (psi)	3008	3760	4700	3008	3760	4700
	0.08512		144	209.5	283	141	193	261
	0.1064		186	262	349	170.3	235	319
	0.133		234	323	420	205	286	389
Waha-2		Pr (psi)	2999.04	3748.8	4686	2999.04	3748.8	4686
	0.576		869	1172	0	630.5	858	1141
	0.72		0	1464	1829.5	752	1024.7	1359
	0.9		1378	1744	2101	880	1194	1583

Table 32 Production from ESP and gas lift at different Productivity index

Comparing the production from ESP and GL in different conditions

Well	Current Status	WC%	GOR	Tubing Size	Pr	ESP							GL		
						Pump Name	Motor Name	Cable Name	Nummber of Stages	Pump Depth	Oil rate	Downhole separator	Injection Rate MMcf/d	Injection Depth	Oil rate
Angham-1	Shut in	10	999	31/2	4564	REDA GN2100 5.13 inch	CENTERLIFT 450	# 1 COPER 0.26 (V/1000ft) 123 A Max.	263	3300	1300	70%	2	3380	1104.1
		50	999	31/2							716				537.8
		90	999	31/2							136				97.84
		60	999	31/2							569.5				418.12
		60	2000	31/2							493				405.64
		60	3000	31/2							460				422.4
		60	999	2 7/8							561				377.12
		60	999	4							573				455.92
		60	999	4 ½							575				471.6
Cherouq-1	Shut in	70	1577	3 ½	4400	REDA SN3600 5.38 inch	CENTERLIFT 450	# 1 COPER 0.26 (V/1000ft) 123 A Max.	162	3000	587	0%	1	3072	511.17
		80	1577	3 ½							400.8				333.98
		90	1577	3 ½							199				160.58
		78	1577	3 ½							439.8				369.29
		78	3000	3 ½							417				373.56
		78	4000	3 ½							399				377.52
		78	1577	2 7/8							421				286.55
		78	1577	4							442				392.66
		78	1577	4 ½							443.2				402.01
Cherouq-2	Production to a tank on location	60	1577	2 7/8	4400	REDA SN2600 5.38 inch	CENTRILIFT 450	1 # COPPER 0.26 (V/1000ft) 123 A	153	3300	638	0%	0.5	3380	477.84
		80	1577	2 7/8							304				205
		90	1577	2 7/8							132				91.15
		78	1577	2 7/8							700				517.5
		78	2000	2 7/8							675				488
		78	3000	2 7/8							625.6				512.8
		78	1577	3 ½							739				624.6
		78	1577	4							746				668.03
		78	1577	4 ½							749				686.25

El Badr-1	Swabbing operation on going	30	647	3 ½	3850	CENTURION P47 5.38 inch	CENTRILIFT 562	1 # COPPER 0.26 V/1000 ft 123 A	155	3140	1628	0%	1.5	3140	1628
		60	647	3 ½							1170				837
		80	647	3 ½							533				383.6
		22	647	3 ½							1663.5				1216
		22	1500	3 ½							1342				1147
		22	3000	3 ½							1191				1160
		22	647	2 7/8							1483.8				935.6
		22	647	4							1706.3				1333.4
		22	647	4 ½							1721				1382
El Badr-3	Gas lifted to inlet separator	30	550	2 7/8	3500	CENTRILIFT K34 5.38 inch	CENTRILIFT 450	1 # COPPER 0.26 V/1000 ft 123 A	228	3000	1621	0%	1	3130	903
		60	550	2 7/8							924				448
		90	550	2 7/8							223				91
		8	550	2 7/8							2077				1296
		8	1000	2 7/8							1711				1315
		8	2000	2 7/8							1347				1220
		8	550	3 ½							2175				1508
		8	550	4							2202				1636
		8	550	4 ½							2212				1692
El Badr-4	Gas lifted to inlet separator	30	550	3 ½	3500	REDA GN2100 5.13 inch	CENTRILIFT 450	1 # COPPER 0.26 V/1000 ft 123 A	221	3400	1017	0%	1	3396	798
		60	550	3 ½							519				407
		90	550	3 ½							103				86
		2	550	3 ½							1478				1225
		2	1000	3 ½							1220				1050
		2	2000	3 ½							1030				1168
		2	550	2 7/8							1404				1404
		2	550	4							1500				1314
		2	550	4 ½							1506				1351
El Badr-5	Gas lifted to inlet separator	30	647	3 ½	3500	REDA GN 2000 5.13 inch	CENTERILIFT 544	1 # COPPER 0.26 V/1000 ft 123 A	325	3400	979.37	70%	1	3417.4	744.8
		60	647	3 ½							549.88				387.8
		90	647	3 ½							131.16				83.19
		1	647	3 ½							1383				1124.5
		1	1000	3 ½							1207				1027
		1	2000	3 ½							1029				913
		1	647	2 7/8							1356.3				1370
		1	647	4							1386				1400

		1	647	4 ½							1388				1402
Farah-1	Production to a tank on location	30	999	3 1/2	3100	CENTERILIFT R9 4 inch	REDA 456-91-std	1 # COPPER 0.26 V/1000 ft 123 A	336	3400	433.65	80%	0.75	3200	402.43
		60	999	3 1/2							231.92				216.44
		80	999	3 1/2							102.46				98.3
		17	999	3 1/2							518.34				483.81
		17	2000	3 1/2							480				457
		17	3000	3 1/2							462				462
		17	999	2 7/8							511.86				429.19
		17	999	4							518.42				503.56
		17	999	4 1/2							517.34				511.61
Methaq-1	Producing to serparator MBD 220	30	1577	3 1/2	2800	CENTERLIFT F35 5.13 inch	CENTERILIFT 450	1 # COPPER 0.26 V/1000 ft 123 A	155	2900	302	80%	0.5	3530	315
		50	1577	3 1/2							197				222
		70	1577	3 1/2							86				127
		5	1577	3 1/2							685				693.5
		5	2500	3 1/2							413				435
		5	3000	3 1/2							396				437
		5	1577	2 7/8							412				384
		5	1577	4							423				4
		5	1577	4 1/2							422				450
Methaq-2	Production to a tank on location	30	1577	3 1/2	3300	#	#	#	#	#	/	#	0.7	2900	46.8
		60	1577	3 1/2							/				24.1
		90	1577	3 1/2							/				4.8
		2	1577	3 1/2							/				71.2
		2	2500	3 1/2							/				72.9
		2	3000	3 1/2							/				73.8
		2	1577	2 7/8							/				62.8
		2	1577	4							/				74.4
		2	1577	4 1/2							/				75.3
Shaheen-1	Production to a tank on location	50	1000	3 1/2	3000	REDA GN 2000 5.13 inch	CENTERILIFT 450	1 # COPPER 0.26 V/1000 ft 123 A	173	3000	625	0%	0.7	3050	533
		70	1000	3 1/2							367				298
		90	1000	3 1/2							98				87
		43	1000	3 1/2							707				618
		43	2000	3 1/2							580				586
		43	3000	3 1/2							578				489.5
		43	1000	2 7/8							679				527

		43	1000	4							723				673
		43	1000	4 1/2							727				696
Waha-1	Shut in	20	432	3 1/2	4686	REDA DN 800 4 inch	ESP_Inc 375_50	1 # COPPER 0.26 V/1000 ft 123 A	450	3500	377.6	70%	0.5	2890	322.32
		50	432	3 1/2							228.25				187.25
		80	432	3 1/2							88.78				68.46
		6	432	3 1/2							449				389.25
		6	1000	3 1/2							406				378
		6	2000	3 1/2							304				298
		6	432	2 7/8							442				355.79
		6	432	4							448				402.32
		6	432	4 1/2							447				407.68
Waha-2	Gas lifted to inlet separator	50	432	3 1/2	4686	CENTRILIFT GC4100 5.13 inch	CENTERILIFT 562 KMH	1 # COPPER 0.26 V/1000 ft 123 A	241	3450	1475	0%	2	3417	1077.5
		70	432	3 1/2							861.5				611.79
		90	432	3 1/2							276				189.09
		30	432	3 1/2							2101				1583.2
		30	1500	3 1/2							1667				1487
		30	3000	3 1/2							1349				1327
		30	432	2 7/8							1940				1237.7
		30	432	4							2139				1714.7
		30	432	4 1/2							2151				1769.2

Table 33 Field Production summary

Production versus Cost

Well Name	status as 25 of August 2011			Design Cost summary								
	Description	Natural Oil production stb/day	Gaslift Oil production stb/day	Gaslift Oil production stb/day	ESP Oil production stb/day	ESP additional oil Pro. to gaslift stb/day	ESP cost $1000	ESP oil revenue / $1000 (30 days) at Avg oil price ($ 100)	SR Oil production stb day	SR additional oil Prod. to gas lift stb/day	SR cost $1000	SR oil revenue / (30 days) at Avg oil price ($ 100)
Angham-1	**Shut-in**	/	/	418	569.5	151.5	400	4545	336	-82	220	/
Cherouq-1	**Shut-in**	/	/	369	440	71	300	2130	/	/	/	/
Cherouq-2	**Producing to tanks on location,**	/	/	517	700	183	300	5490	/	/	/	/
El Badr-1	**Swabbing operations on going**	/	/	1216	1663.5	447.5	300	13425	/	/	/	/
El Badr-3	**Gas lifting to the inlet separator**	/	1336	1296	2077	781	400	23430	/	/	/	/
El Badr-4	**Gas lifting to the inlet separator**	/	996	1225	1478	253	400	7590	/	/	/	/
El Badr-5	**Gas lifting to the inlet separator**	/	1010	1124.54	1383.03	258.489	450	7755	/	/	/	/
Farah-1	**Producing to tanks on location,**	400	/	483.807	518.335	34.528	450	1036	/	/	/	/
Methaq-1	**Producing to Separator MBD 220.**	850	/	694	514	-180	/	/	/	/	/	/
Methaq-2	**Producing to tanks on location,**	95	/	71.2	/	/	/	/	122	50.8	210	1524
Shaheen-1	**Producing to tanks on location,**	300	/	618	707	89	300	2670	/	/	/	/
Waha-1	**Shut-in**	/	/	389.254	449	59.746	475	1792	475	85.746	210	2572
Waha-2	**Gas lifting to test separator.**	/	990	1583.19	2101	517.81	400	15534	/	/	/	/

Looking to figure 128 one can easily compare the different in production that can be achieved from ESP, GL and Sucker rod (for only three wells). For Elbadr1, Elbadr3, Waha2, the increment is considerably big between the two lifting method, however we still need to consider the cost of installing the artificial lift to be able to decide the suitable AL for each well, the reason why chart 129 was plotted, where you can see the cost of ESPs and SRs, as gas lift is surface facilities are already in place the only cost we consider is the operating injection cost and this is negligible comparing to the installation cost of ESP, and SRs.

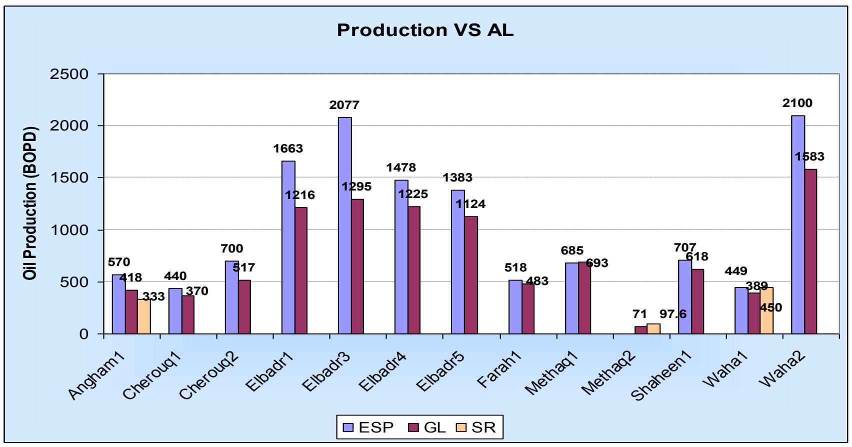


Figure 128 Oil production from different artificial lift methodes for each well

The cost of the sucker rods is around 210 M USD, and for the ESPs it varies from as minimum as 300 M USD to a maximum of 475 M USD, from comparing figures 128 and 129 I could come out with table where I calculated the pay out time (POT) for each well, and it was figured out that some of the wells whose a high ESPs installation cost can pay out the investment in a shorter time than the low cost one or at least having a similar POT.

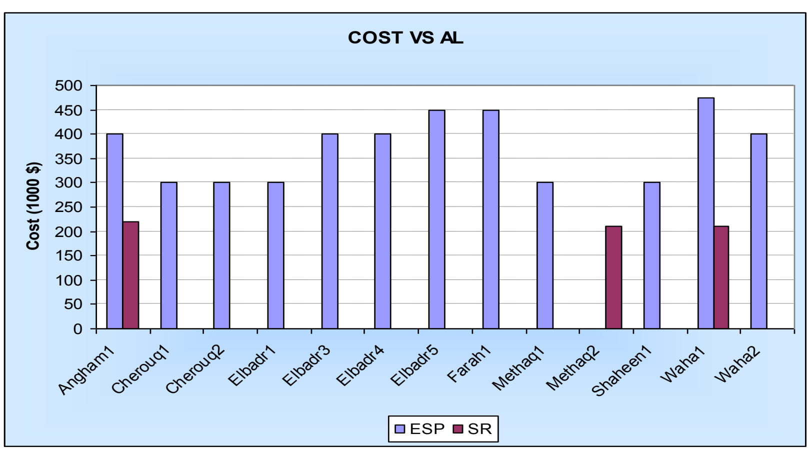


Figure 129 Wells vs Artificial cost

WELL NAME	RECOMMENDED (AL) (POT: Pay Out Time.)
Angham-1	ESP (POT @ 100 $/bbl = 26 days)
Cherouq-1	ESP (POT @ 100 $/bbl = 42 days)
Cherouq-2	ESP (POT @ 100 $/bbl = 16 days)
Elbadr-1	ESP (POT @ 100 $/bbl = 6 days)
Elbadr-3	ESP (POT @ 100 $/bbl = 5 days)
Elbadr-4	ESP (POT @ 100 $/bbl = 15 days)
Elbadr-5	ESP (POT @ 100 $/bbl = 18 days)
Farah-1	If WC increases start GL
Methaq-1	If well died start GL
Methaq-2	If well died start GL
Shaheen-1	If well died start GL
Waha-1	Stay on GL
Waha-2	ESP (POT @ 100 $/bbl = 8 days)
Angham-1	ESP (POT @ 100 $/bbl = 26 days)

Table 34 selected artificial lift method vs POT

Conclusion

Cherouq field in August 2011 when I started working in this thesis was producing around 6000 BOPD from approx. 8 wells four of which were on gas lift, by applying the artificial lift study on the field (optimizing injection from GL wells, converting some wells to other AL method, designing AL for the shut in wells) production could be doubled to an approx. 12000 BOPD. See figure 130. The PVT data and reservoir pressure are not representative; as for PVT data are available only for four wells and optimized for the other wells, as it has been mentioned before all wells are producing in commingled way, which makes it more challenging to measure the reservoir pressure. As gas lift is already installed in place completing all wells with gas lift will be the most economic.

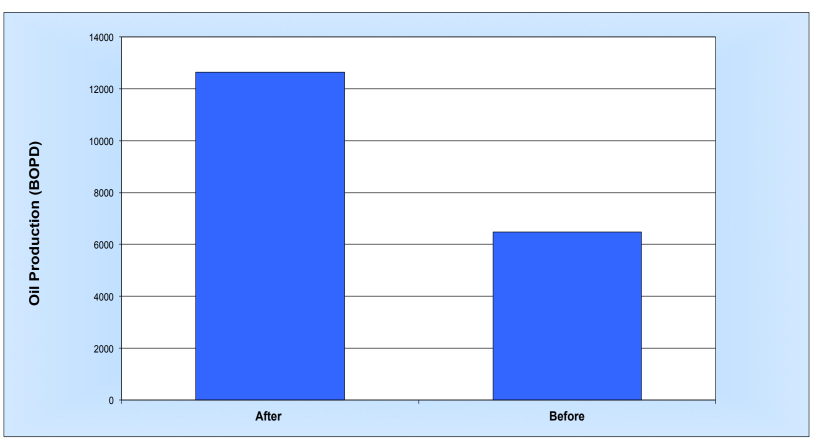


Figure 130 oil production differences by applying AL

References

1. Company Reports and Presentations

2. Department of petroleum Engineering (Heriot Watt University)

3. WWW.Pumpzone.com

4. Electrical submersible pump manual Design, Operations, and Maintenance, Gabor Takacs. 2009.

5. Electrical pumping system, www.espexpert.com.

6. Weatherford website

7. Libyan National Oil Company training courses.

8. Wikipedia

9. Schlumberger presentations and website.

10. Production Optimization of Electrical Submersible Pumps (Esps) in SARIR field, LIBYA,Waleed Moftah Emtair Mohammed, October 2010.

11. Gas Lift Manual, Gabor Takacs,2005.

12. PCS (Production Control Service) Opti- flow Gas Lift system.

13. On lateral and Helical Buckling of a rod in a tubing, S.A. Lukasiewicz, C. Knight, the University of Calgary.

14. *Appendix A: Well by well performance*

<table>
<tr><td>Well Name</td><td></td></tr>
<tr><td rowspan="3">Angham 1</td><td>

- January 2009, first production.
- Will died in March 2010, needs ALS.
- Low productivity index 0.5 STB/day/psi.
- Water cut is around 65%.
- Moderate GOR 1000 scf/bbl
- Figure xxx shows the production history of Angham 1, as shown an early water break occurred after about four months from starting the production, the increasing of water cut lead to a higher hydrostatic pressure and well could not flow. The Figure below illustrated the inflow and outflow performance of Angham-1, and is obviously showing that there is no intersect between the two curves, which indicates that this well needs an ALS to be installed. The reason of this water cut jumps can be concluded as it is due to opening and closing different sliding sleeves.

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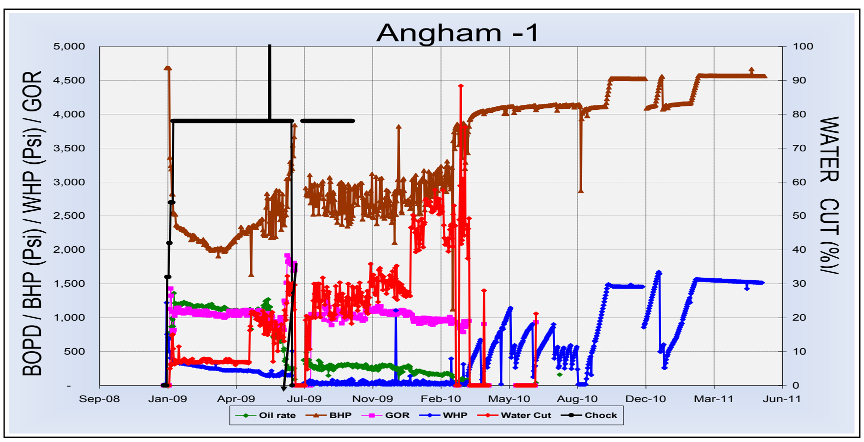

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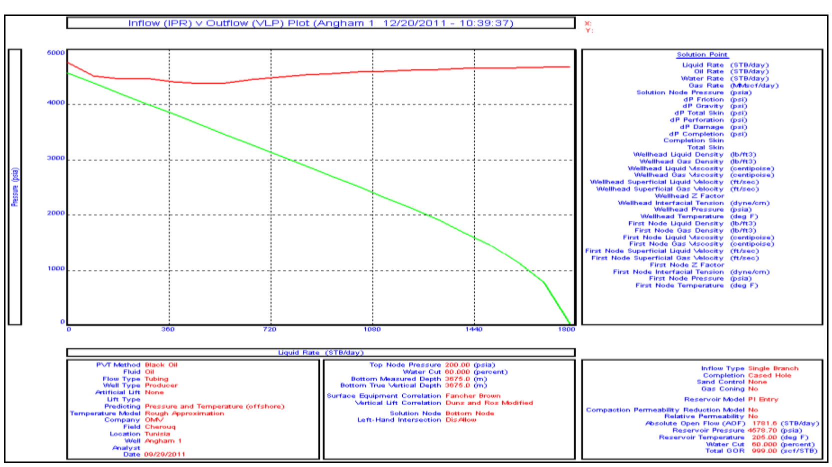

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<table>
<tr><td>Well Name</td><td></td></tr>
<tr><td rowspan="3">Cherouq 1</td><td>

- On December 17th, 2007 first production
- No gas lift mandrel
- PI about 0.77 STB/day/psi.
- High water cut around 80%
- High GOR
- Production history is shown in figure below, well died in August 201, due to water accumulation, PLT shows a tubing leak from 3358.6 to 3360.9 m. figure xxx shows the inflow and out flow performance, from those two charts one can conclude that Cherouq-1 is an artificial lifting candidate.

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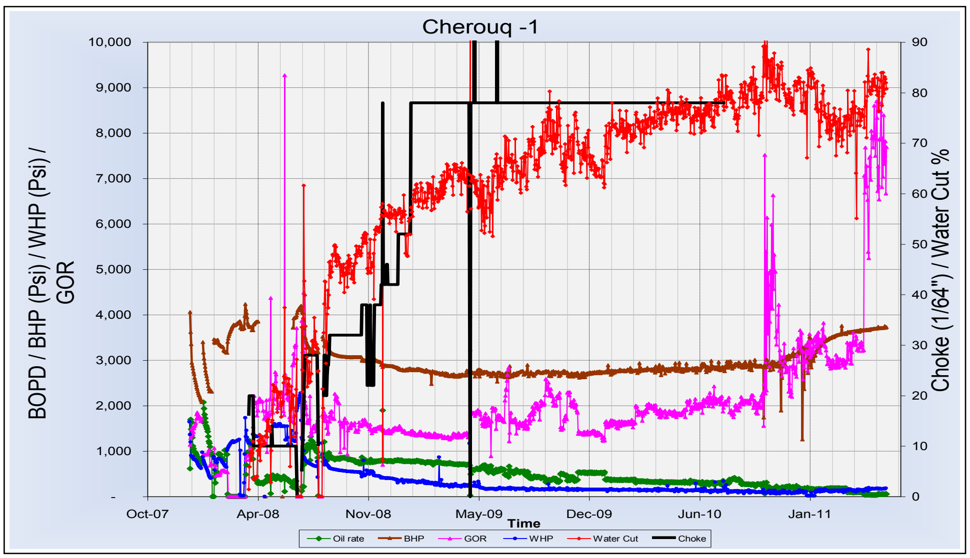

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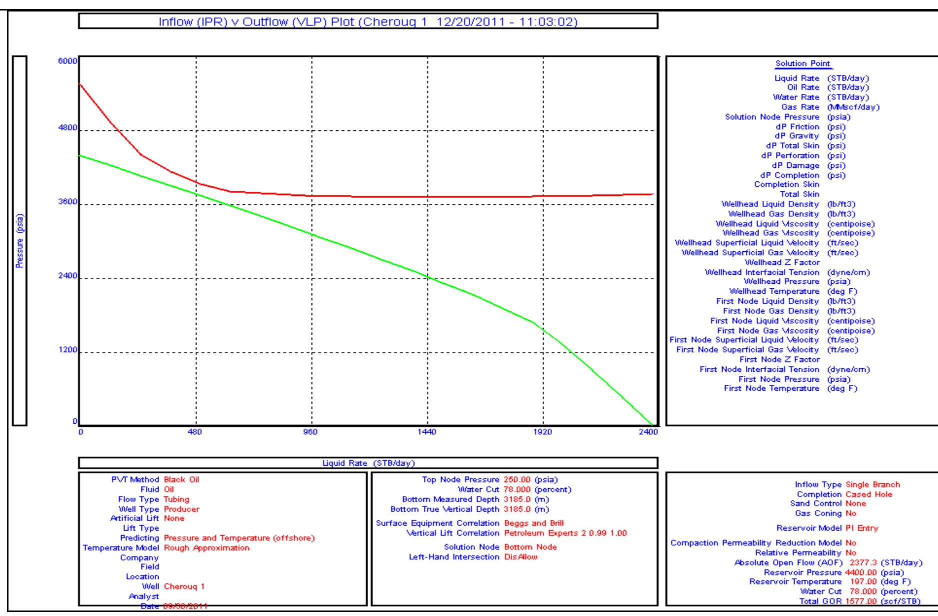

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<table>
<tr><td>Well Name</td><td></td></tr>
<tr><td rowspan="3">Cherouq 2</td><td>

- November 19th, 2010 firs production (CT N2 lift)
- Gas lifted.
- Water cut 65%.
- High GOR
- Some sand production.
- See the production history in the figure below, average production is around 800 STB/day; a higher production can be achieved with ALS.

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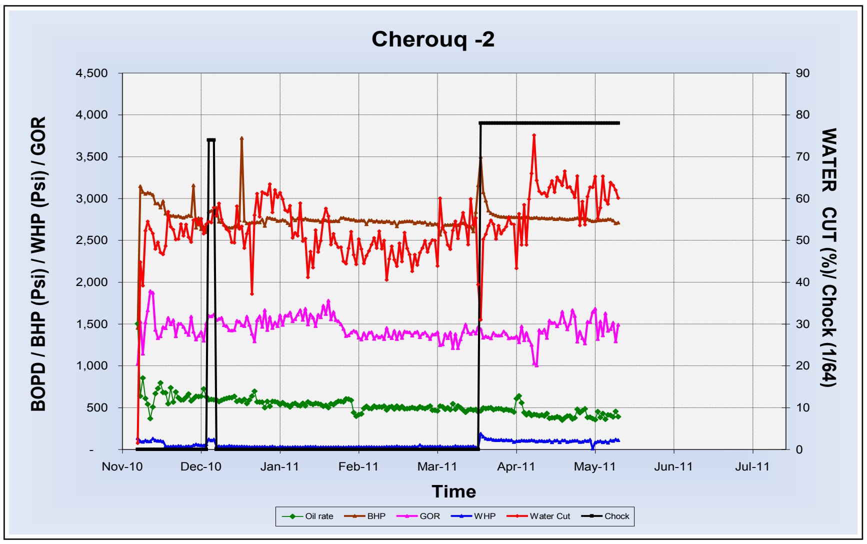

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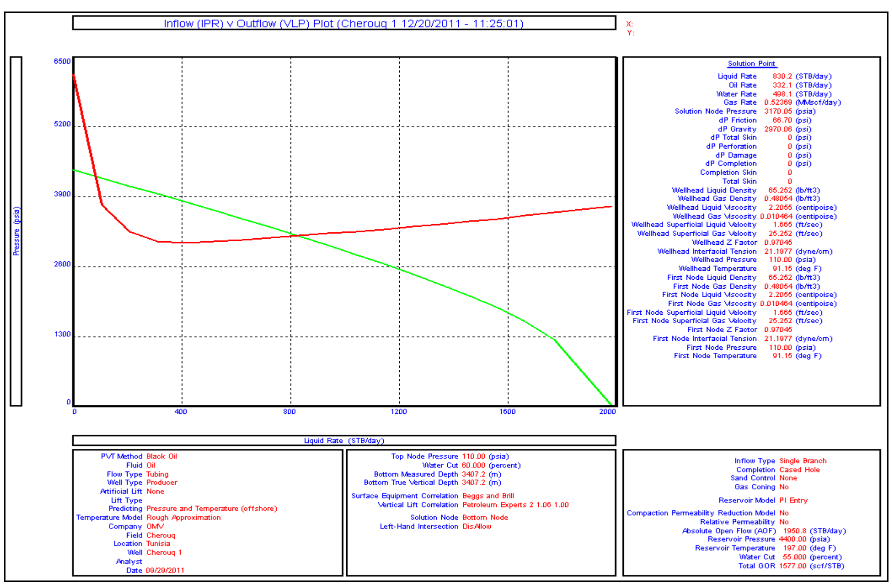

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<table>
<tr><td>Well Name</td><td></td></tr>
<tr><td rowspan="3">El Azzel 1</td><td>

- May 3rd first production.
- Producing with gas lift.
- PI around 0.4 STB/day/psi.
- Low Productivity index and low GOR.
- Water cut around 60%.
- The figure below shows the production history, well is able to flow, IPR curve is shown that an artificial lift is needed.

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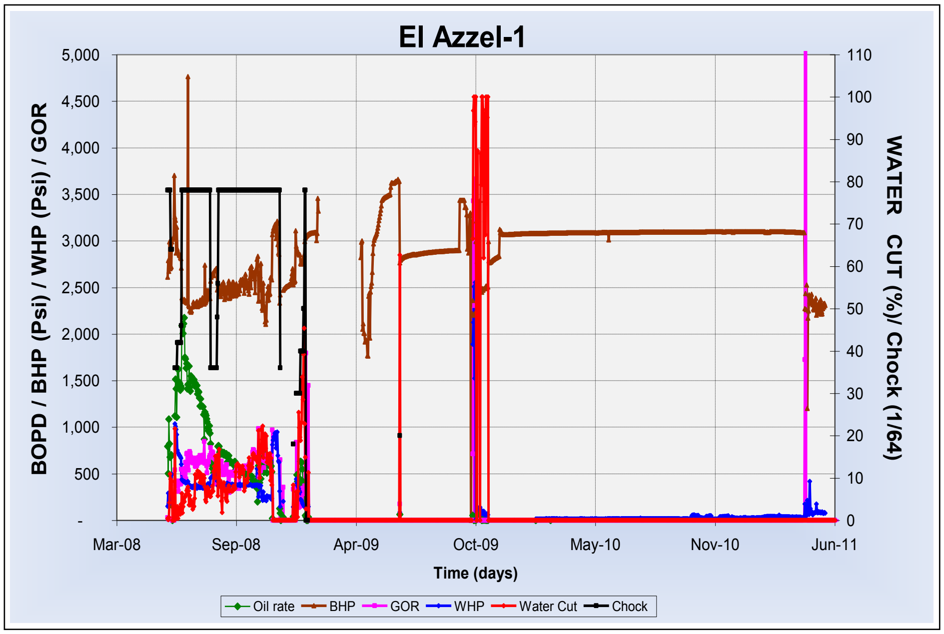

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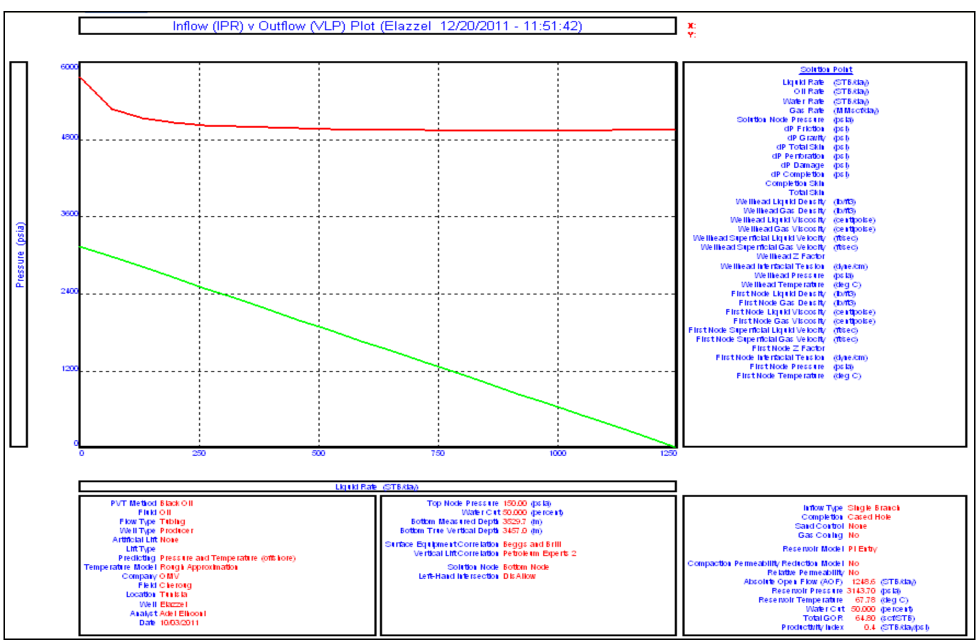

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<table>
<tr><th>Well Name</th><th></th></tr>
<tr><td rowspan="3">El Badr 1</td><td>

- On January 25th, 2008 first production.
- Recently converted on GL, as you can see from IPR curve natual flow not possible due to the increase of water cut.
- Low GOR.
- Water cut around 45%.
- The figure shows the production history water was

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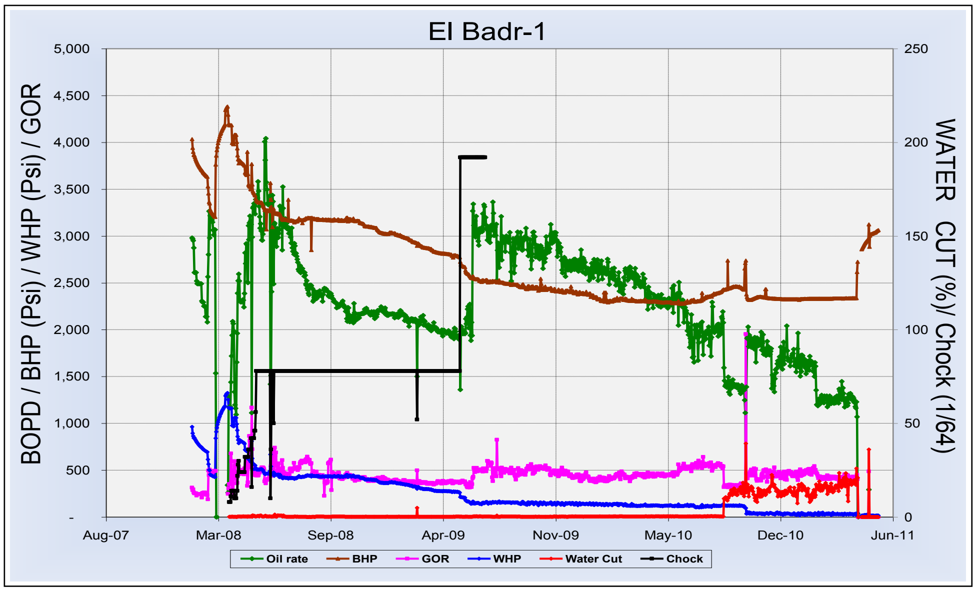

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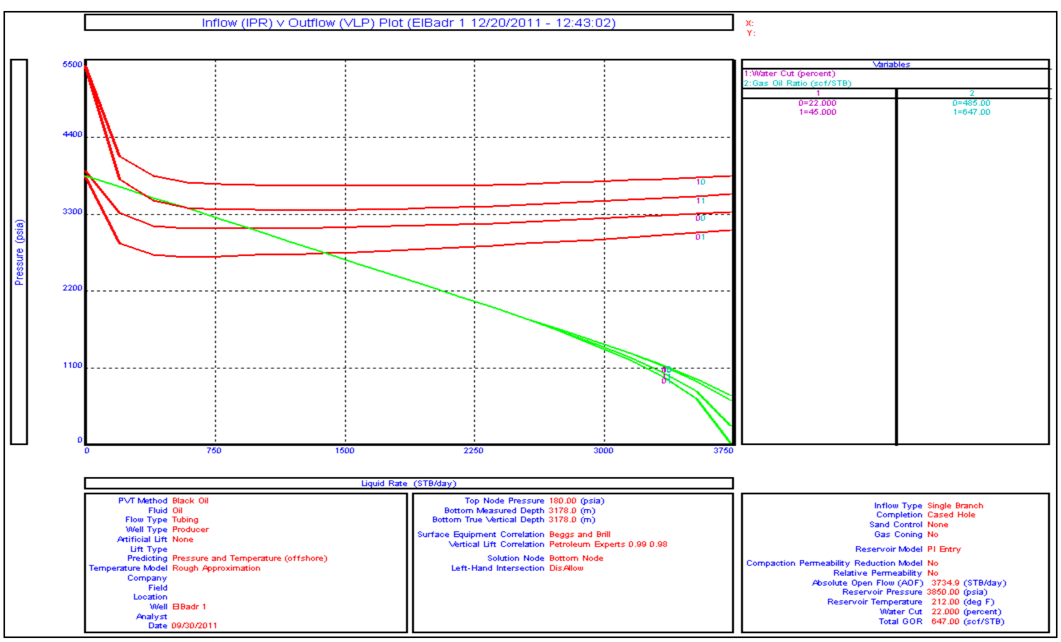

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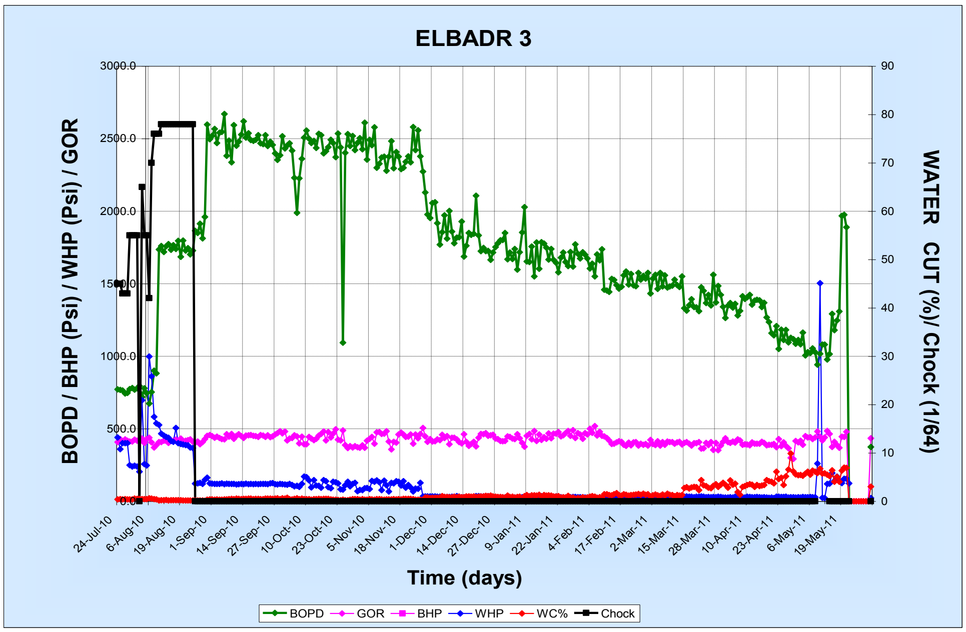
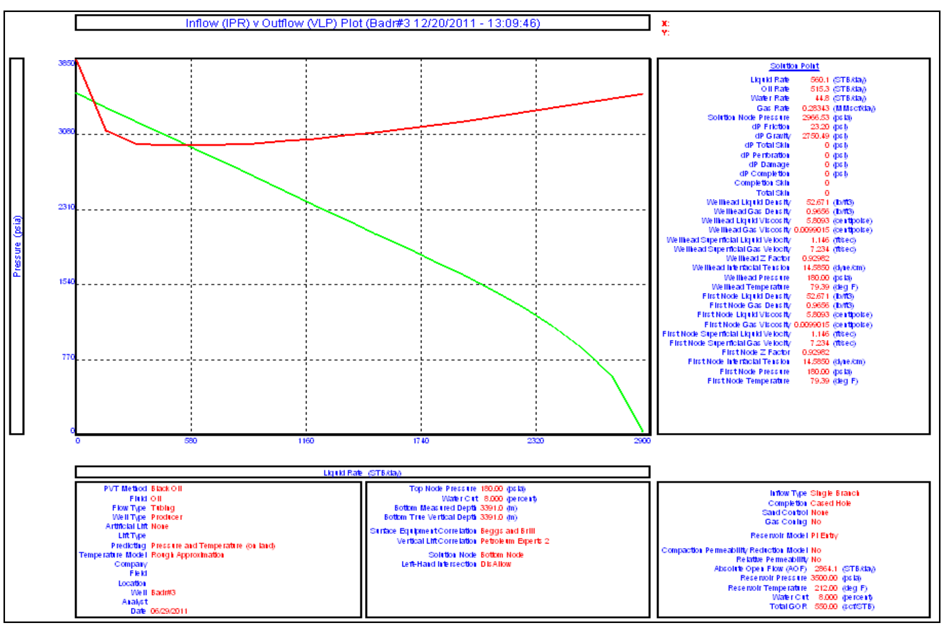
Well Name	
El Badr 3	• On July 23th, 2010 first production • Gas lifted since May 12th, 2010. • Water cut around 5%. • Low GOR • Permanent down hole gauge is not working • The Figure shows the production history





<table>
<tr><td>Well Name</td><td></td></tr>
<tr><td rowspan="3">El Badr 4</td><td>

February 11th, 2011 first production
Gas lifted since May 9th, 2011
Water cut around 5%
Low GOR
The figure below shows the production history, average free flow production was around 500 STB/day, where as after GL production rose up to around 1100 STB/day.

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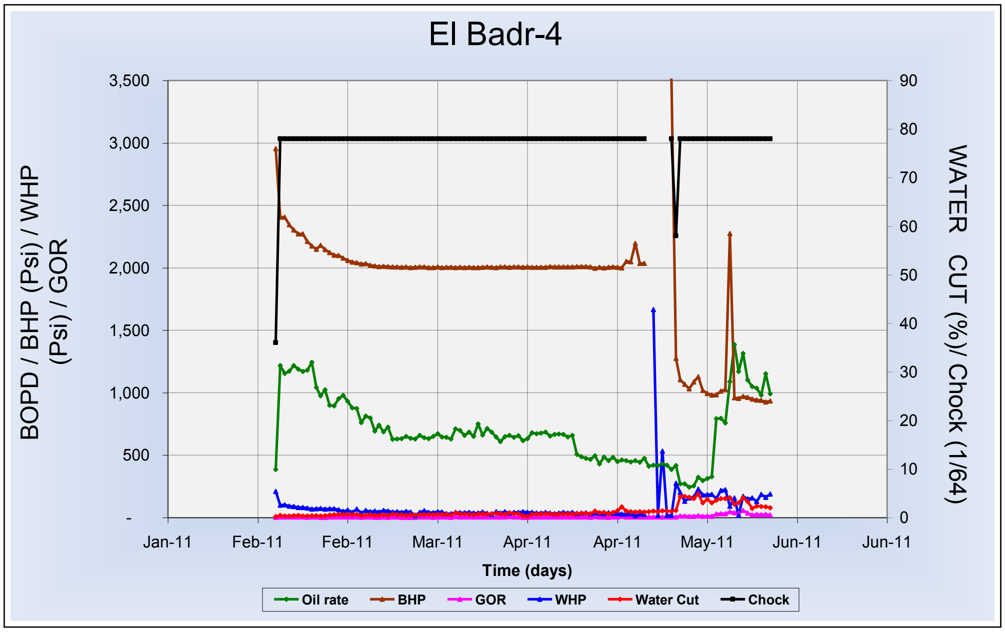

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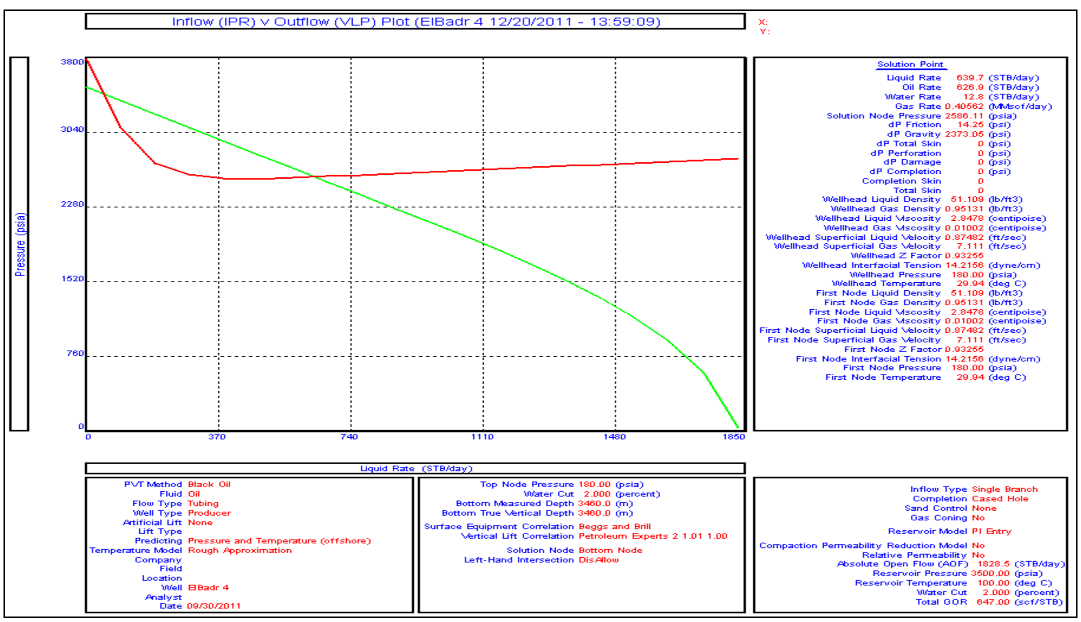

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<table>
<tr><td>Well Name</td><td></td></tr>
<tr><td rowspan="3">El Badr 5</td><td>

- March 28th, 2011 first production
- Gas Lifted, since July 3rd, 2011.
- Water cut around 5%
- Low GOR
- Production history is shown in the figure below, before GL well was producing to tank on location, after GL production all most at the same range.

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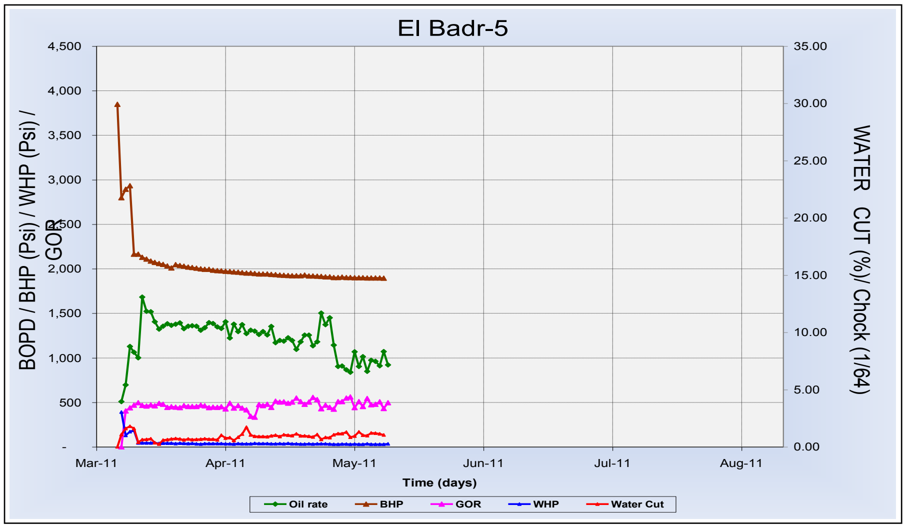

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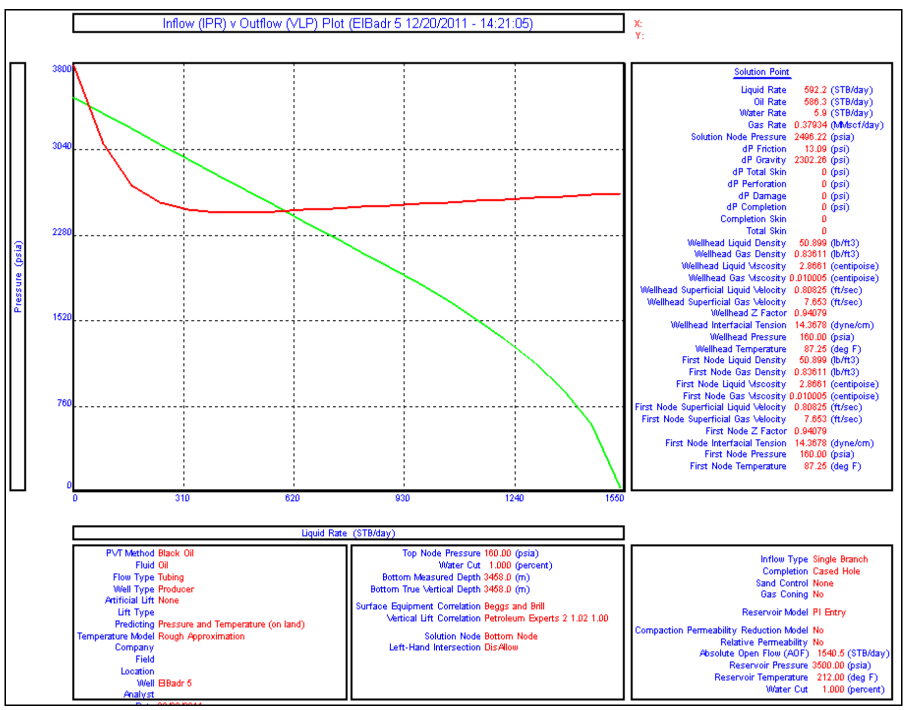

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<table>
<tr><td>Well Name</td><td></td></tr>
<tr><td rowspan="3">Farah 1</td><td>

- April 11th, first production.
- Water cut around 20%.
- Medium GOR.
- Currently converted on GL.
- The figure shows the production history, again as the water cut increased a dramatic drop in the production is accompanied, and it is obvious that any further increase in water cut will kill the well, IPR curve shows the possible production, which is almost half of the amount that was produced before the water break in.

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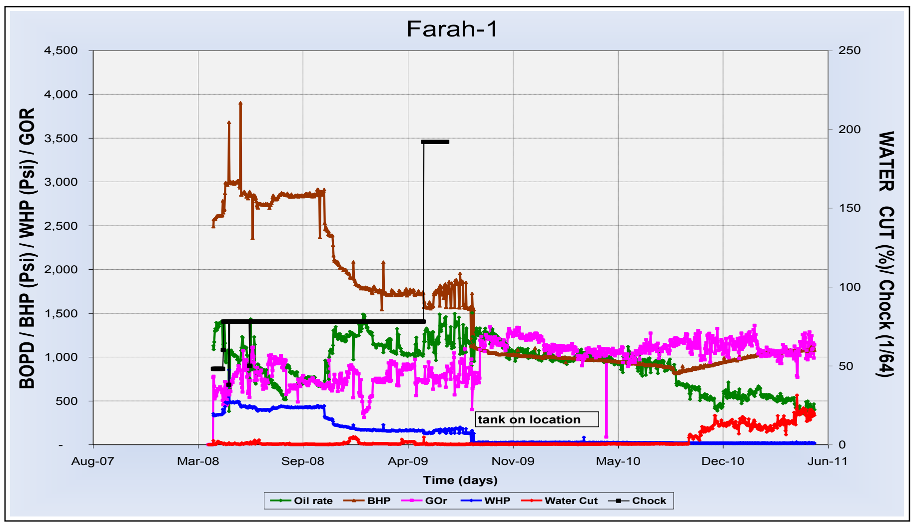

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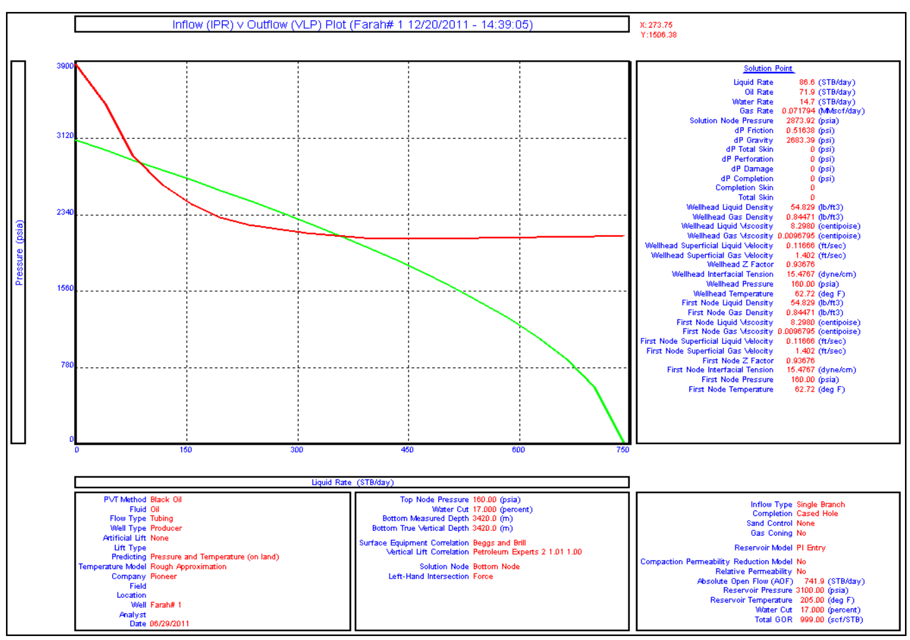

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<tr><td>Well Name</td><td></td></tr>
<tr><td rowspan="3">Methaq 1</td><td>

- July 30th, 2008 first production.
- Water cut around 2%.
- High GOR
- No gas well mandrels.
- The production history see the figure below, a dramatic pressure drop at the early stage of production and then we have less and less decline rate, well is producing to a tank on location, current status of the well is shut in .

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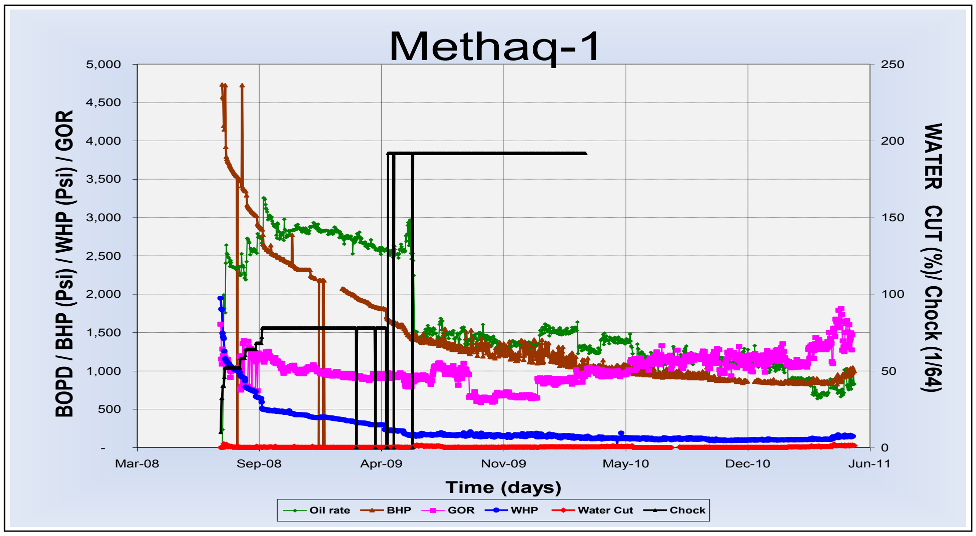

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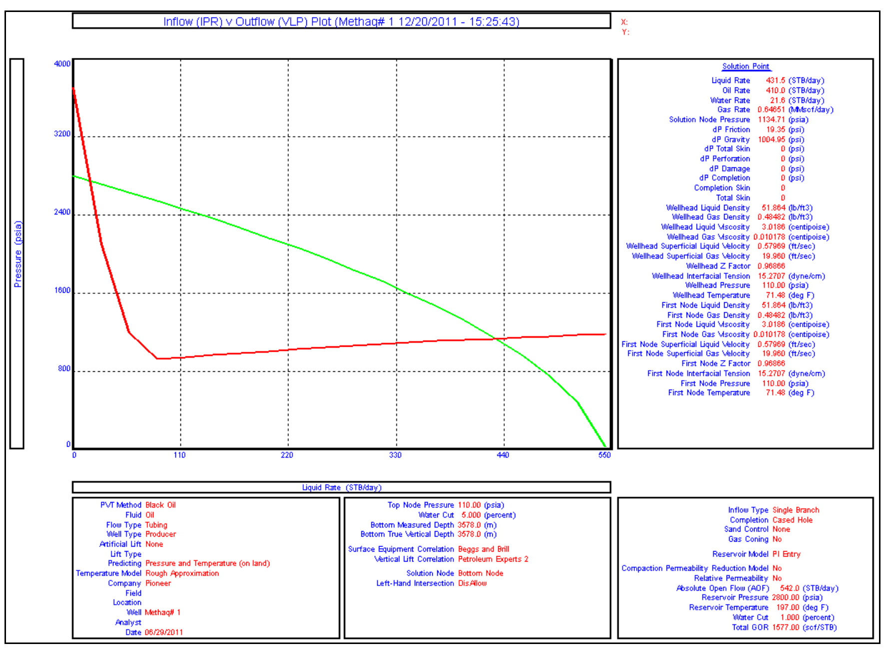

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<table>
<tr><td>Well Name</td><td></td></tr>
<tr><td rowspan="3">Methaq 2</td><td>

- First production on June 24th, 2009.
- Currently was convertd to GL.
- Water cut around 2%.
- High GOR
- The figure below shows production history, may 2010 BUT was applied, BHFP is flocculating dramatically, before GL well was producing to a tank on location, IPR curve indicates that an ALS installation was necessary.

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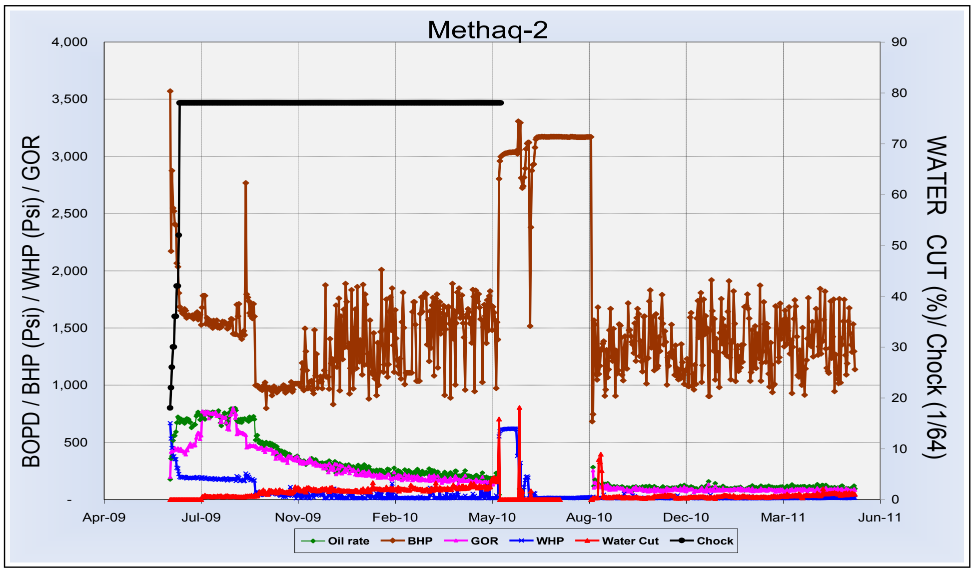

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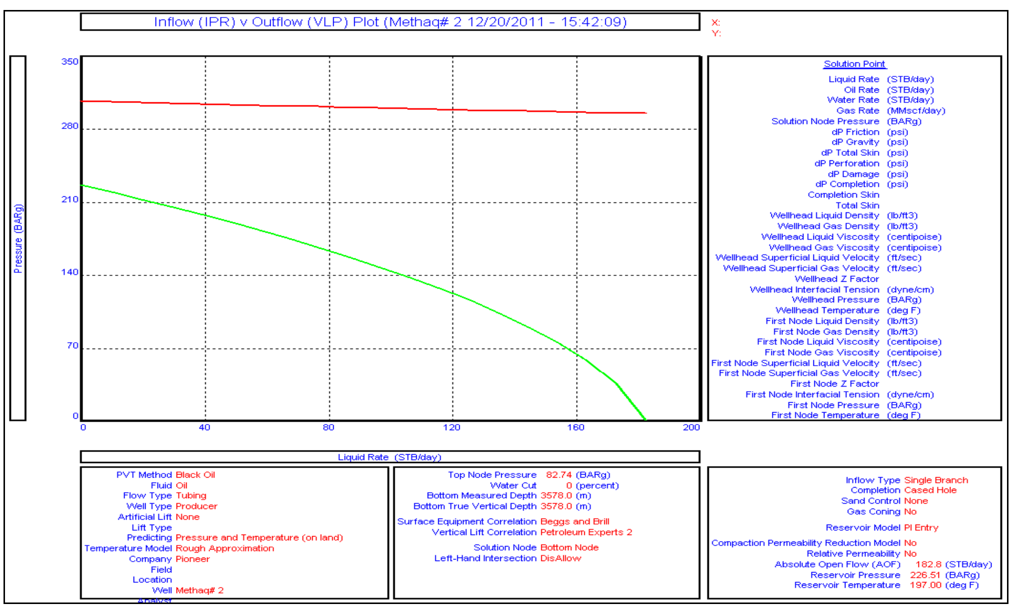

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<table>
<tr><td>Well Name</td><td></td></tr>
<tr><td rowspan="3">Shaheen 1</td><td>

- Om March 6th, 2008 the first production.
- No gas lift mandrels.
- Water cut around 50%.
- Medium GOR
- Production history is shown below, well is producing to tank on location, water cut increased dramatically during the last stage of production, which caused a decrease in the production, the thing that makes Shaheen-1 is an ALS candidate.

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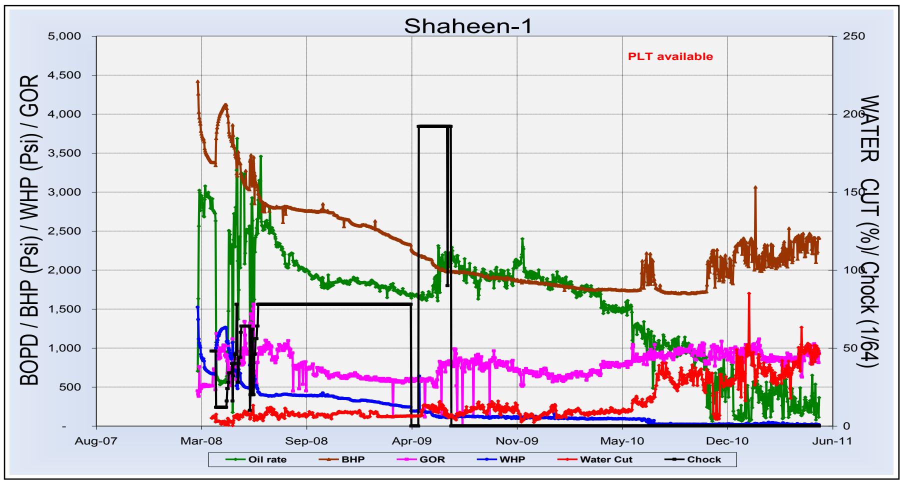

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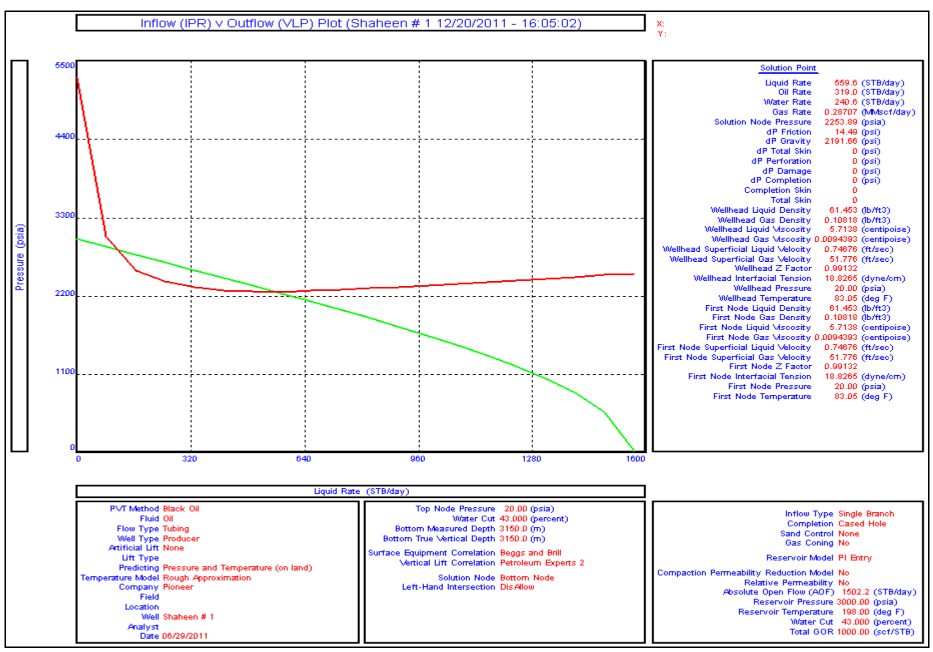

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<table>
<tr><td>Well Name</td><td></td></tr>
<tr><td rowspan="3">Waha 1</td><td>

- Production started on November 20th, 2001.
- No gas lift mandrels.
- Low GOR.
- Production history is shown below. This well is producing intermittently, tubing size could be an issue (later on this report a tubing size analysis will be conducted), and water cut can not be confirmed because of the production behavior.

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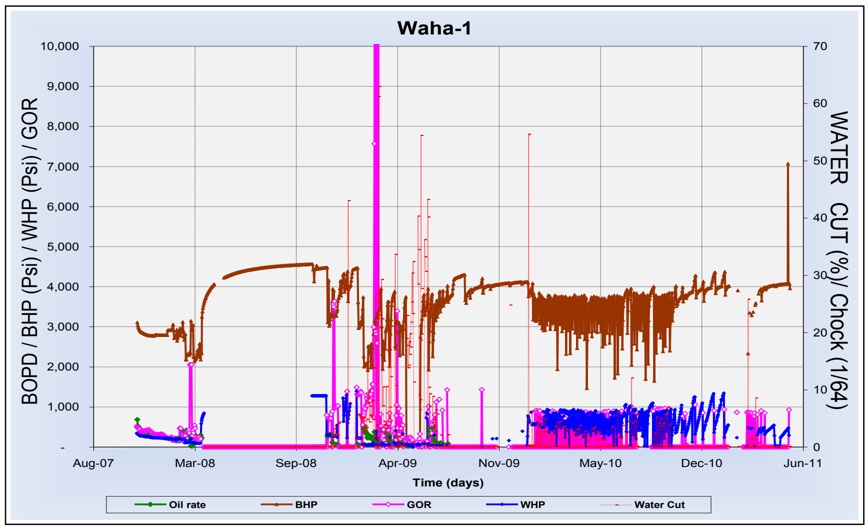

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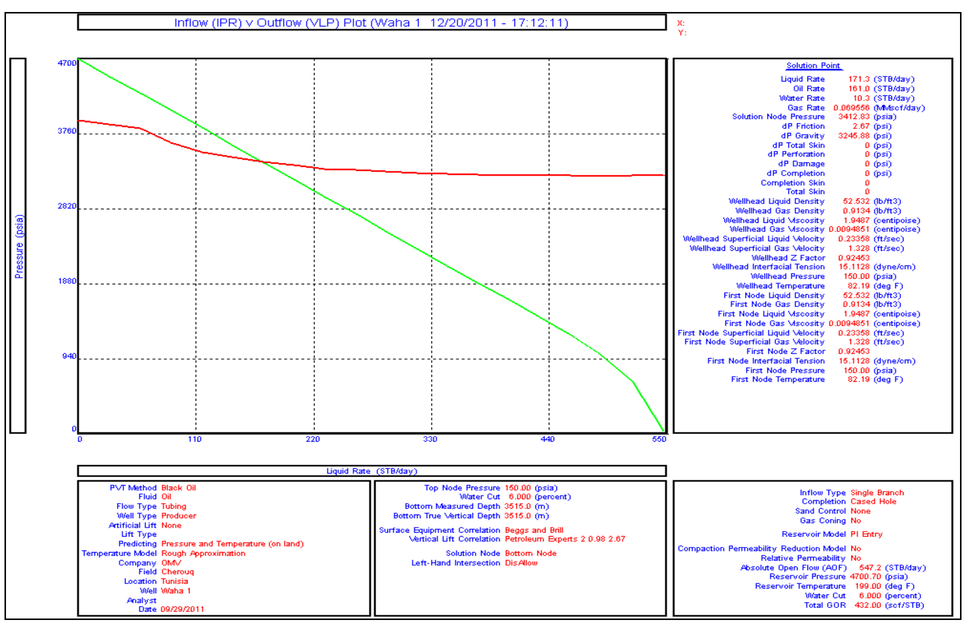

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<tr><td>Well Name</td><td></td></tr>
<tr><td rowspan="3">Waha 2</td><td>

- Production started on January 4th, 2011.
- Currently was converted to gas lifte.
- Water cut around 45%.
- Low GOR.
- Production history is shown below, well was capable to produce around 560 bopd. But as it is illustrates in the production data Water cut is continuously increasing, which will lead to a zero production, the reason why a GL system was installed.

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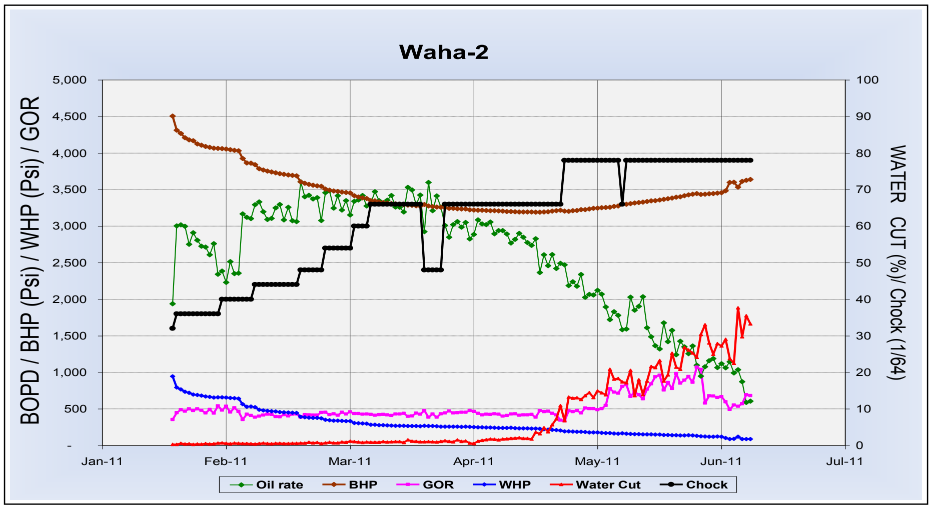

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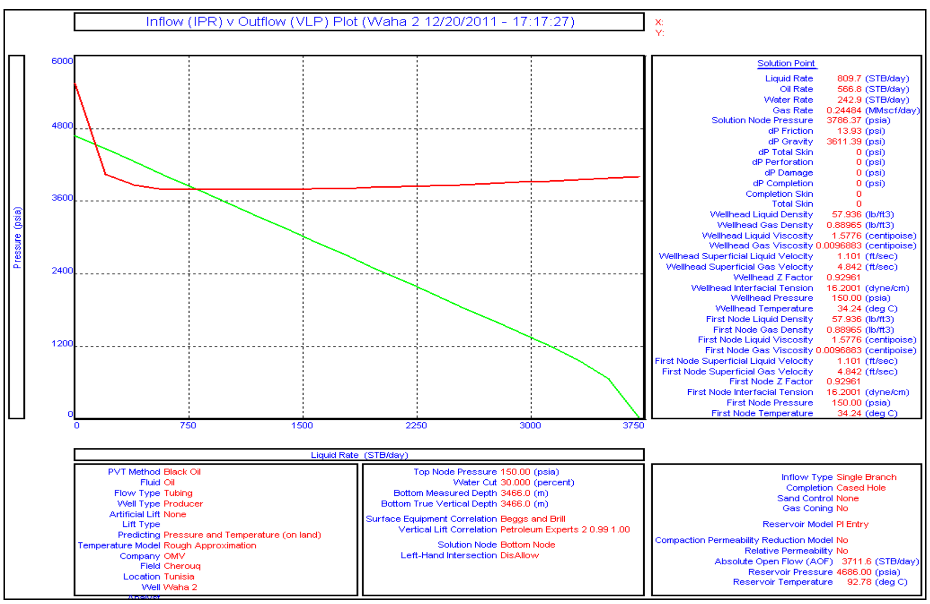

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Appendix B Friction head losses vs pumping rate chart

DESCRIPTION

Figure A-1 contains a diagram to estimate frictional head losses vs. pumping rate in standard API tubing and casing.

The heavy line displays values for new pipes, the other for used ones.

EXAMPLE PROBLEM

Find the frictional head loss in a 4,500 ft deep well with an old tubing of 1.995 in ID at a liquid flow rate of 1,000 bpd.

SOLUTION

At a 1,000 bpd rate, the specific head loss is read from the diagram as:

Dhfr . 41 psi=1**;** 000 ft

The total head loss in the tubing string is thus:

DHfr . 41 4**;** 500=1**;** 000 . 185 psi

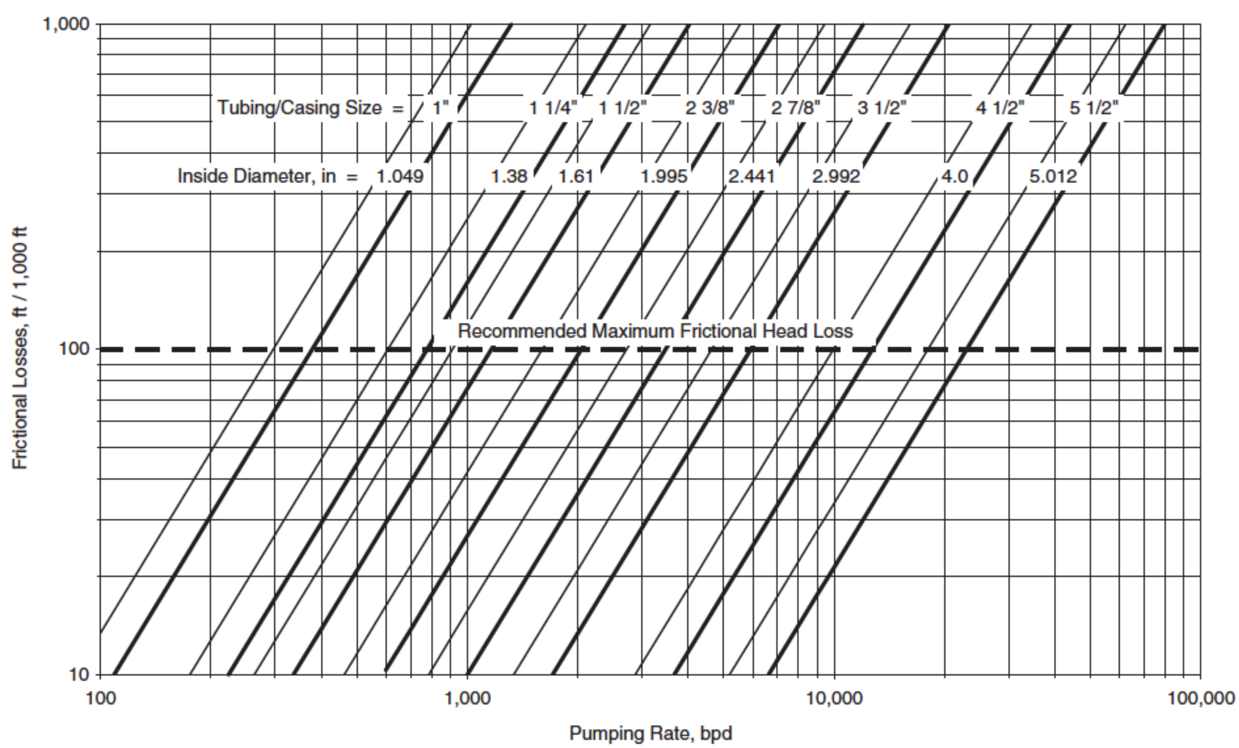


Fig. A.1 Diagram to estimate frictional head losses versus pumping rate in standard API tubing and casing

Appendix C API tubing and casing dimensions

Table B.1 Main dimensions of API tubing and casing

Size (in.) Nominal	OD	Weight lb/ft	OD	Diameter (in.) ID	Drift	Coupling OD (in.)
API NUE tubing						
1½		2.75	1.900	1.610	1.516	2.200
2	2⅜	4.00	2.375	2.041	1.947	2.875
2½	2⅞	6.40	2.875	2.441	2.347	3.500
3	3½	7.70	3.500	3.068	2.943	4.250
3½	4	9.50	4.000	3.548	3.423	4.750
4	4½	12.60	4.500	3.958	3.833	5.200
API EUE tubing						
1½		2.90	1.900	1.610	1.516	2.500
2	2⅜	4.70	2.375	1.995	1.901	3.063
2½	2⅞	6.50	2.875	2.441	2.347	3.668
3	3½	9.30	3.500	2.992	2.867	4.500
3 ½	4	11.00	4.000	3.476	3.351	5.000
4	4½	12.75	4.500	3.958	3.833	5.563

Continued

Size (in.) Nominal	OD	Weight lb/ft	OD	Diameter (in.) ID	Drift	Coupling OD (in.)
Regular API casing						
	4½	9.50	4.500	4.090	3.965	5.000
		11.60	4.500	4.000	3.875	5.000
		13.50	4.500	3.920	3.795	5.000
	5½	14.00	5.500	5.012	4.887	6.050
		15.50	5.500	4.940	4.825	6.050
		17.00	5.500	4.892	4.767	6.050
		20.00	5.500	4.778	4.653	6.050
		23.00	5.500	4.670	4.545	6.050
	6⅝	17.00	6.625	6.135	6.010	7.390
		24.00	6.625	5.921	5.796	7.390
	7	20.00	7.000	6.456	6.331	7.656
		23.00	7.000	6.366	6.241	7.656
		26.00	7.000	6.276	6.151	7.656
		29.00	7.000	6.184	6.059	7.656
		32.00	7.000	6.094	5.969	7.656
	8⅝	28.00	8.625	8.017	7.892	9.625
		36.00	8.625	7.825	7.700	9.625
		40.00	8.625	7.725	7.600	9.625
		44.00	8.625	7.625	7.500	9.625
	9⅝	36.00	9.625	8.921	8.765	10.625
		40.00	9.625	8.835	8.679	10.625
		13.50	9.625	8.755	8.599	10.625
		47.00	9.625	8.681	8.525	10.625

Continueued

Size (in.) Nominal	OD	Weight lb/ft	OD	Diameter (in.) ID	Drift	Coupling OD (in.)
	10	40.50	10.750	10.050	9.894	11.750
		55.50	10.750	9.760	9.604	11.750
	13	48.00	13.375	12.715	12.559	14.375
		68.00	13.375	12.415	12.259	14.375

Voltage drop chart in copper conductor

DESCRIPTION

Figure E.1 presents a widely used correlation to calculate the voltage drop in usual ESP cables.

EXAMPLE PROBLEM

Find the three phase voltage drop in a 5,000 ft long AWG #2 size submersible cable with copper conductors if the motor current is 80 amps, and the average cable temperature is 200 F.

SOLUTION

At a current of 80 amps and AWG #2 cable size the specific voltage drop is read from the chart as:

DV=1**;** 000 ft . 23 V=1**;** 000 ft

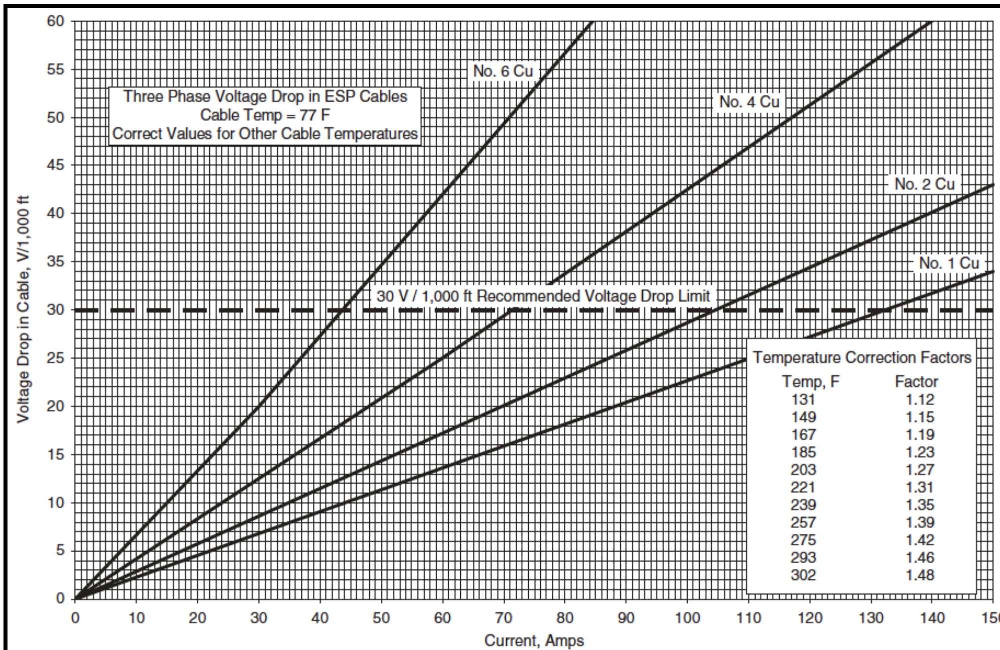
The total voltage drop at 77 F is found next:

DV . 23 5**;** 000=1**;** 000 . 115 volts

The correction factor for the actual cable temperature of 200 F is found from the table on the chart as: Correction . 1**:**27

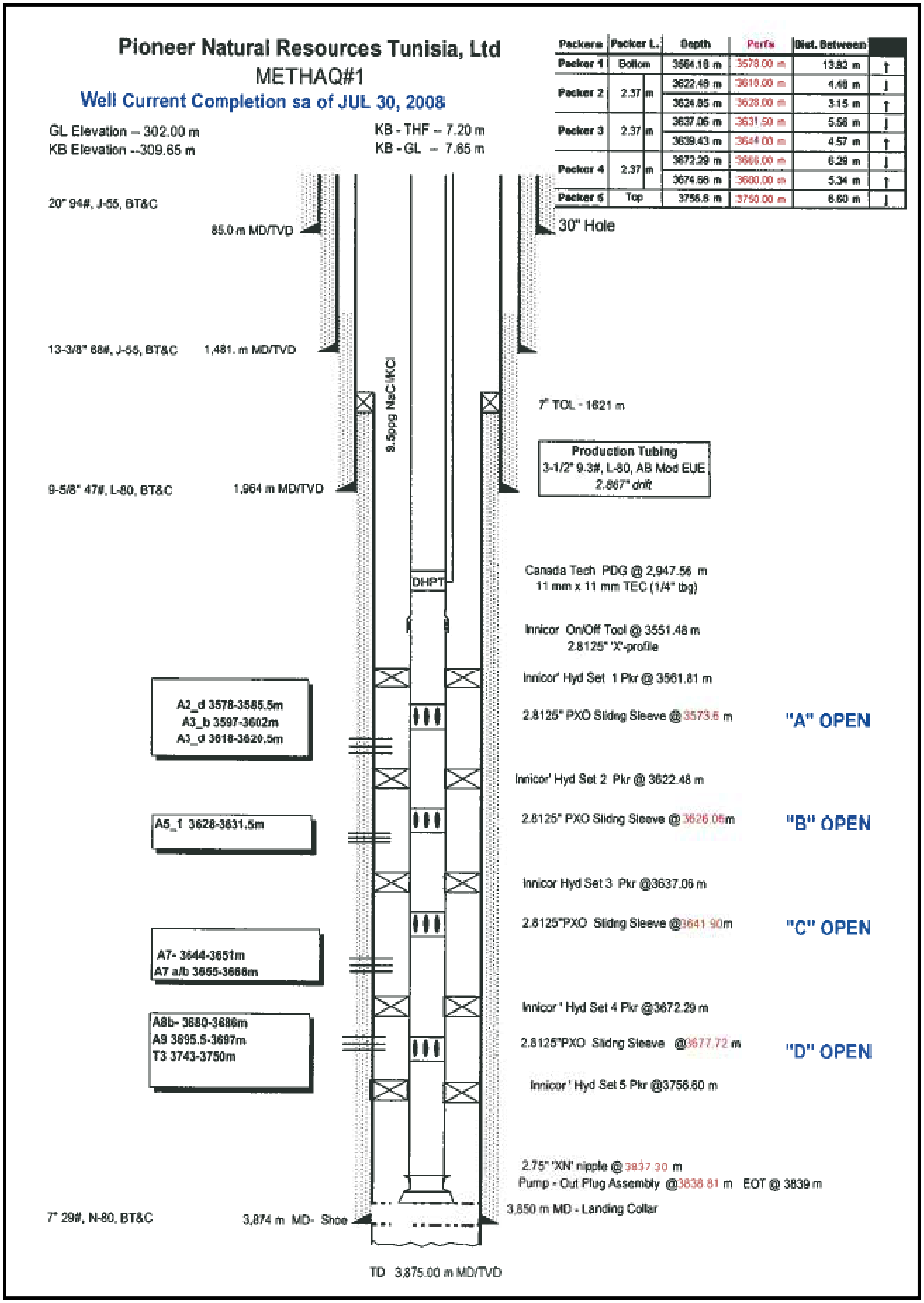
The total voltage drop across the cable at the operating temperature is calculated as given in the following:

DVcorr . 1**:**27 115. 146 amps

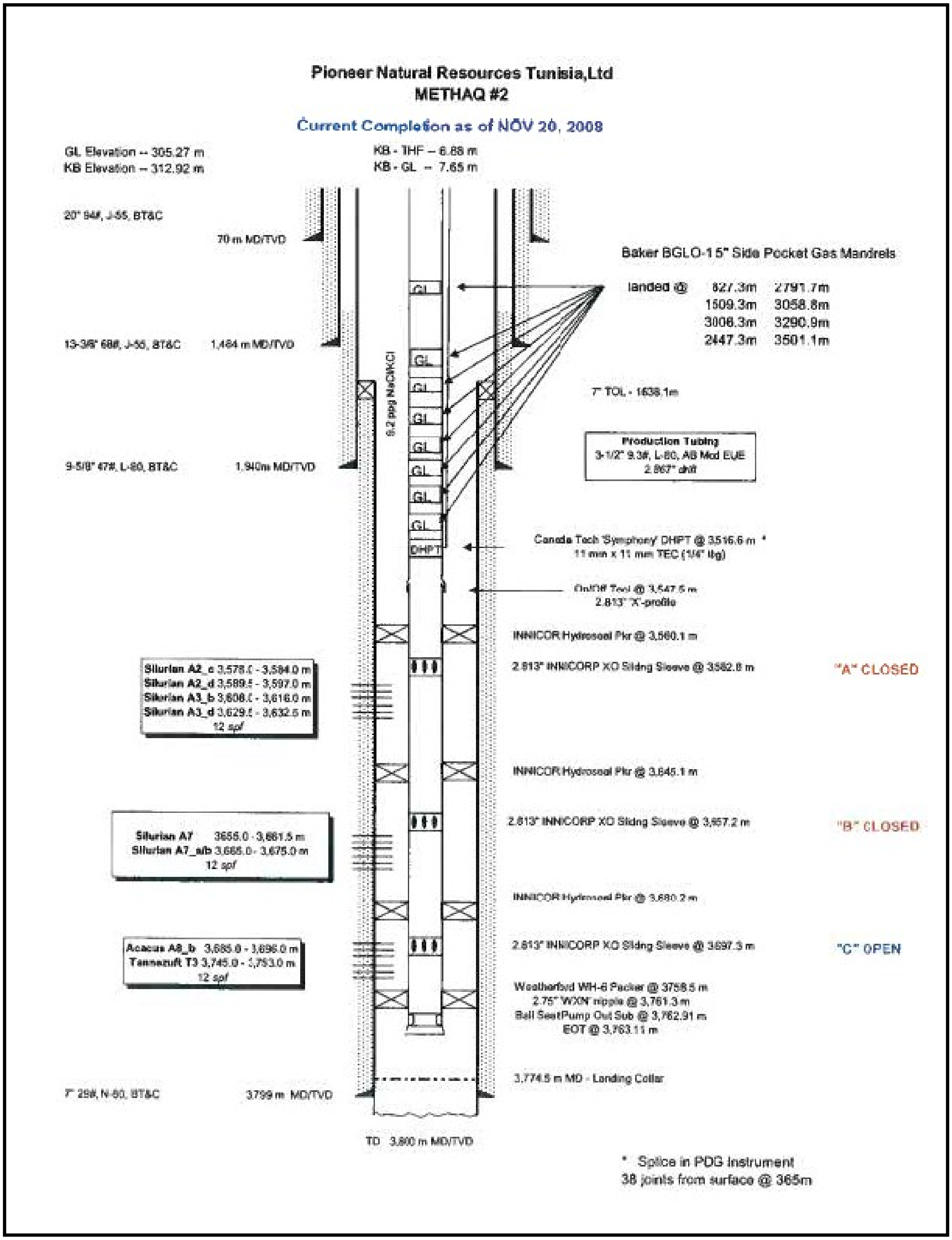


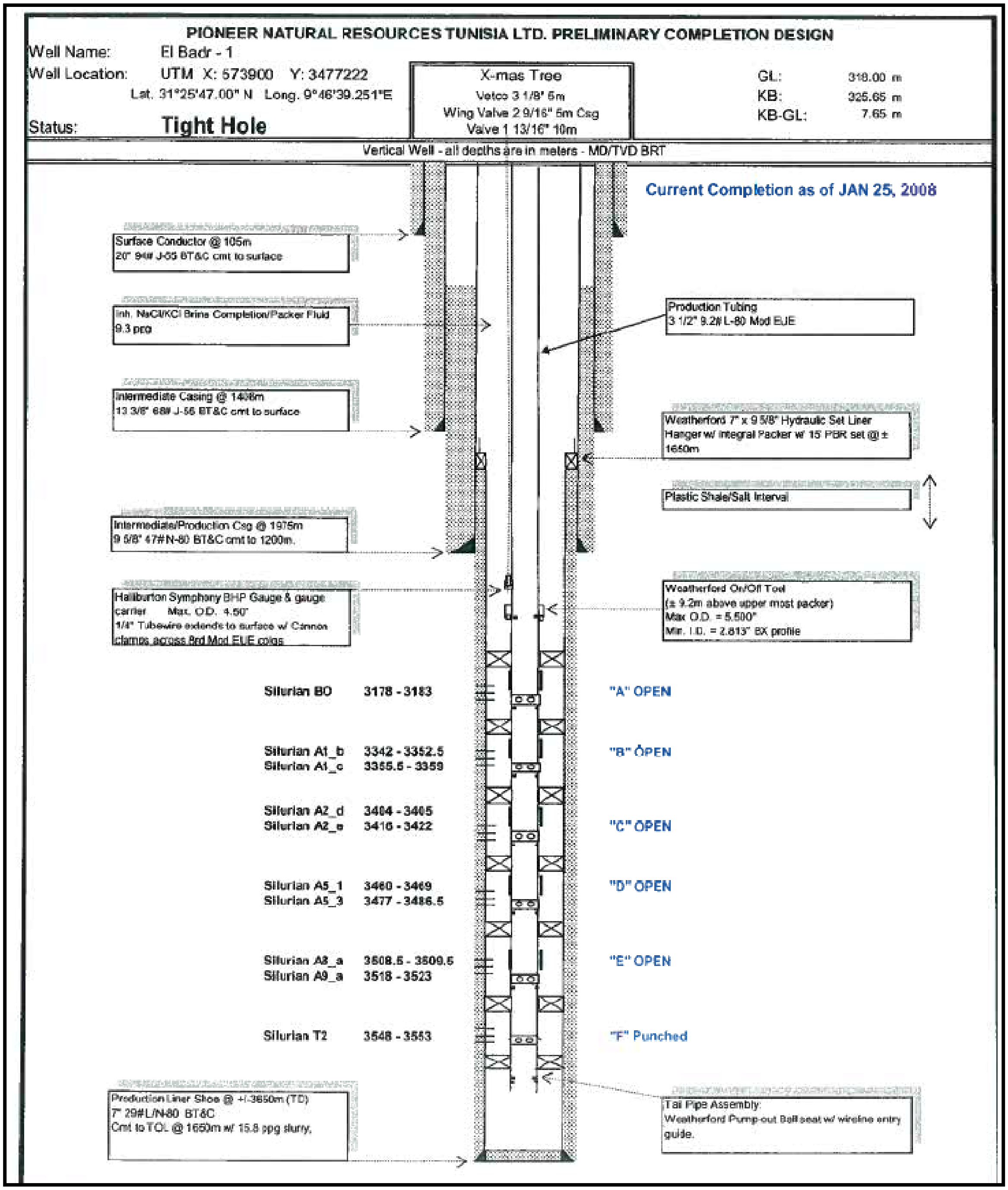
ig. E.1 Typical values of voltage drops in copper conductors

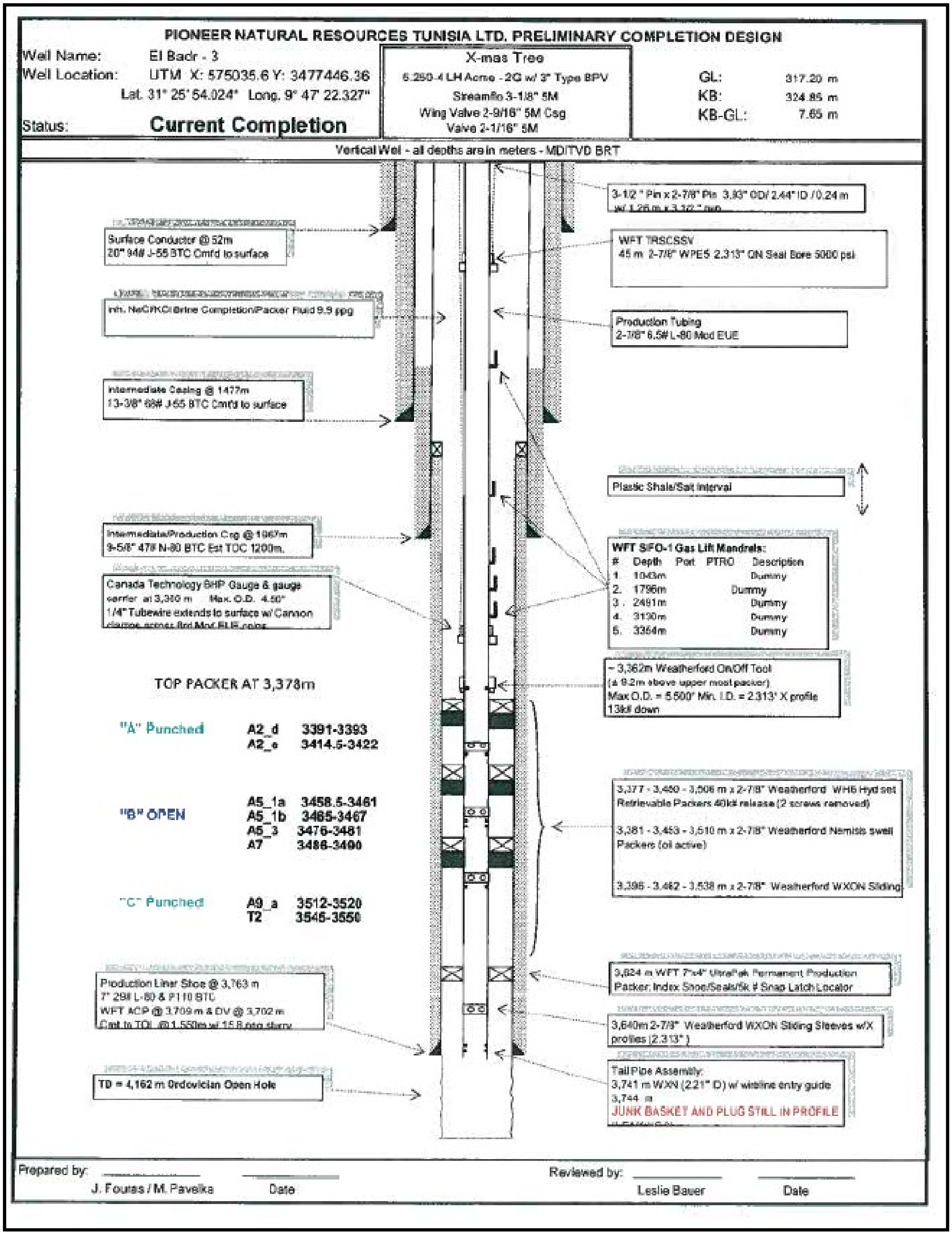
Appendix D Wells completion schematic



Packers	Packer L.		Depth	Perfs	Dist. Between	
Packer 1	Bottom		3564.18 m	3578.00 m	13.82 m	↑
Packer 2	2.37	m	3622.48 m	3618.00 m	4.48 m	↓
			3624.85 m	3628.00 m	3.15 m	↑
Packer 3	2.37	m	3637.06 m	3631.50 m	5.56 m	↓
			3639.43 m	3644.00 m	4.57 m	↑
Packer 4	2.37	m	3672.29 m	3666.00 m	6.29 m	↓
			3674.66 m	3680.00 m	5.34 m	↑
Packer 6	Top		3756.6 m	3750.00 m	6.60 m	↓


Pioneer Natural Resources Tunisia,Ltd
METHAQ #2
Current Completion as of NOV 20, 2008
GL Elevation -- 305.27 m
KB Elevation -- 312.92 m
KB - THF -- 6.88 m
KB - GL -- 7.65 m
20" 94#, J-55, BT&C
70 m MD/TVD
Baker BGLO-1.5" Side Pocket Gas Mandrels
landed @ 827.3m 2791.7m
1509.3m 3058.8m
3006.3m 3290.9m
2447.3m 3501.1m
13-3/8" 68#, J-55, BT&C
1,484 m MD/TVD
9.2 ppg NaCl/KCl
7" TOL - 1638.1m
Production Tubing
3-1/2" 9.3#, L-80, AB Mod EUE
2.867" drift
9-5/8" 47#, L-80, BT&C
1,940m MD/TVD
GL
DHPT
Canada Tech 'Symphony' DHPT @ 3,516.6 m *
11 mm x 11 mm TEC (1/4" tbg)
On/Off Tool @ 3,547.5 m
2.813" 'X'-profile
INNICOR Hydroseal Pkr @ 3,560.1 m
Silurian A2_c 3,578.0 - 3,584.0 m
Silurian A2_d 3,589.5 - 3,597.0 m
Silurian A3_b 3,608.0 - 3,616.0 m
Silurian A3_d 3,629.5 - 3,632.5 m
12 spf
2.813" INNICORP XO Sliding Sleeve @ 3582.8 m
"A" CLOSED
INNICOR Hydroseal Pkr @ 3,645.1 m
Silurian A7 3655.0 - 3,661.5 m
Silurian A7_a/b 3,665.0 - 3,675.0 m
12 spf
2.813" INNICORP XO Sliding Sleeve @ 3,657.2 m
"B" CLOSED
INNICOR Hydroseal Pkr @ 3,680.2 m
Acacus A8_b 3,685.0 - 3,696.0 m
Tannezuft T3 3,745.0 - 3,753.0 m
12 spf
2.813" INNICORP XO Sliding Sleeve @ 3697.3 m
"C" OPEN
Weatherford WH-6 Packer @ 3758.5 m
2.75" 'WXN' nipple @ 3,761.3 m
Ball Seat/Pump Out Sub @ 3,762.91 m
EOT @ 3,763.11 m
3,774.5 m MD - Landing Collar
7" 29#, N-80, BT&C
3799 m MD/TVD
TD 3,800 m MD/TVD
* Splice in PDG Instrument
38 joints from surface @ 365m

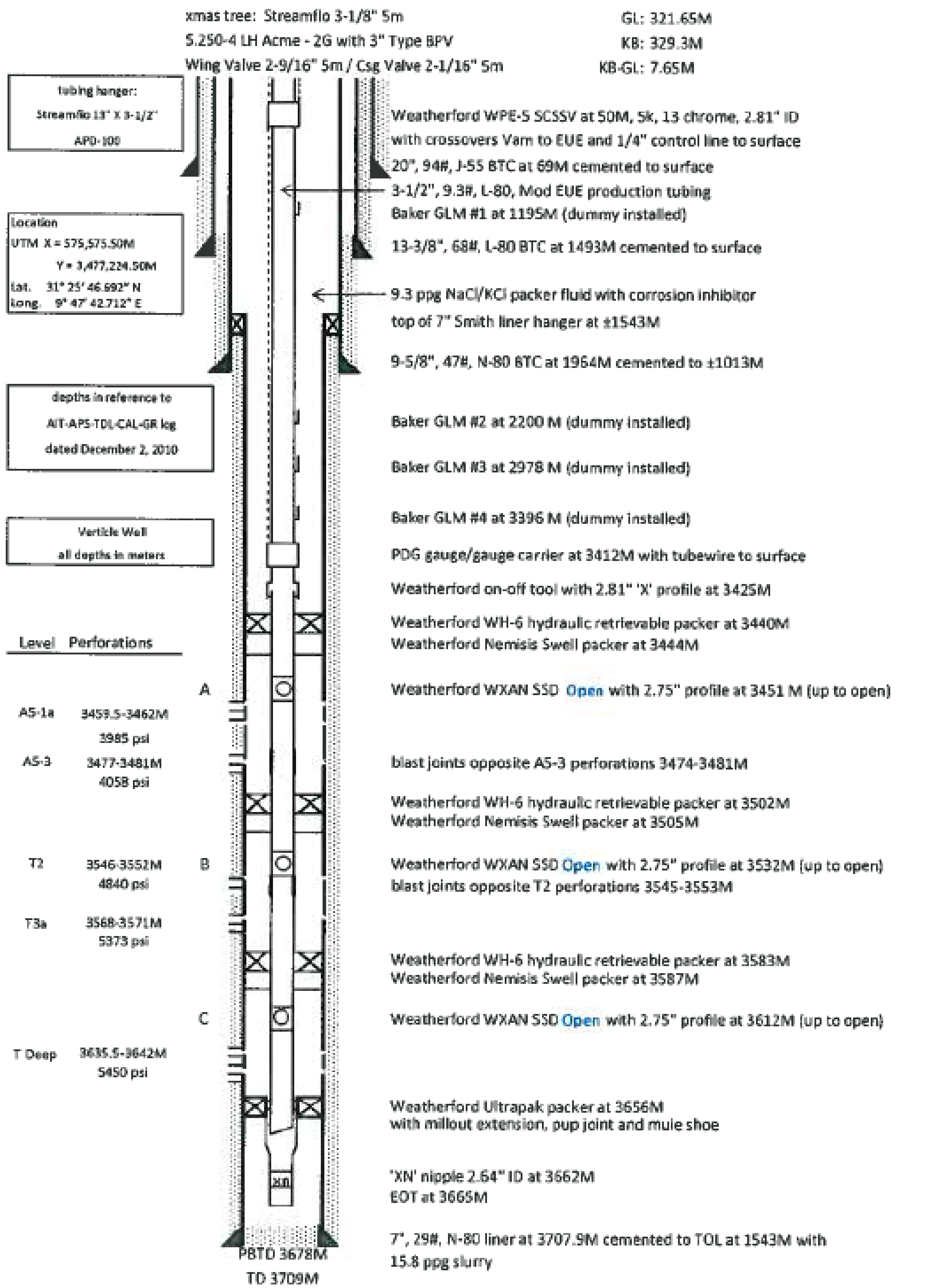

PIONEER NATURAL RESOURCES TUNISIA LTD. PRELIMINARY COMPLETION DESIGN
Well Name: El Badr - 1
Well Location: UTM X: 573900 Y: 3477222
Lat. 31°25'47.00" N Long. 9°46'39.251"E
Status: Tight Hole
X-mas Tree
Vetco 3 1/8" 5m
Wing Valve 2 9/16" 5m Csg
Valve 1 13/16" 10m
GL: 318.00 m
KB: 325.65 m
KB-GL: 7.65 m
Vertical Well - all depths are in meters - MD/TVD BRT
Current Completion as of JAN 25, 2008
Surface Conductor @ 105m
20" 94# J-55 BT&C cmt to surface
Inh. NaCl/KCl Brine Completion/Packer Fluid
9.3 ppg
Production Tubing
3 1/2" 9.2# L-80 Mod EUE
Intermediate Casing @ 1408m
13 3/8" 68# J-55 BT&C cmt to surface
Weatherford 7" x 9 5/8" Hydraulic Set Liner Hanger w/ integral Packer w/ 15' PBR set @ ± 1650m
Plastic Shale/Salt Interval
Intermediate/Production Csg @ 1975m
9 5/8" 47# N-80 BT&C cmt to 1200m.
Halliburton Symphony BHP Gauge & gauge carrier Max. O.D. 4.50"
1/4" Tubewire extends to surface w/ Cannon clamps across 8rd Mod EUE cplgs
Weatherford On/Off Tool
(± 9.2m above upper most packer)
Max O.D. = 5.500"
Min. I.D. = 2.813" BX profile
Silurian BO 3178 - 3183 "A" OPEN
Silurian A1_b 3342 - 3352.5
Silurian A1_c 3355.5 - 3359 "B" OPEN
Silurian A2_d 3404 - 3405
Silurian A2_e 3416 - 3422 "C" OPEN
Silurian A5_1 3460 - 3469
Silurian A5_3 3477 - 3486.5 "D" OPEN
Silurian A8_a 3508.5 - 3509.5
Silurian A9_a 3518 - 3523 "E" OPEN
Silurian T2 3548 - 3553 "F" Punched
Production Liner Shoe @ +/-3650m (TD)
7" 29# L/N-80 BT&C
Cmt to TOL @ 1650m w/ 15.8 ppg slurry.
Tail Pipe Assembly:
Weatherford Pump-out Ball seat w/ wireline entry guide.



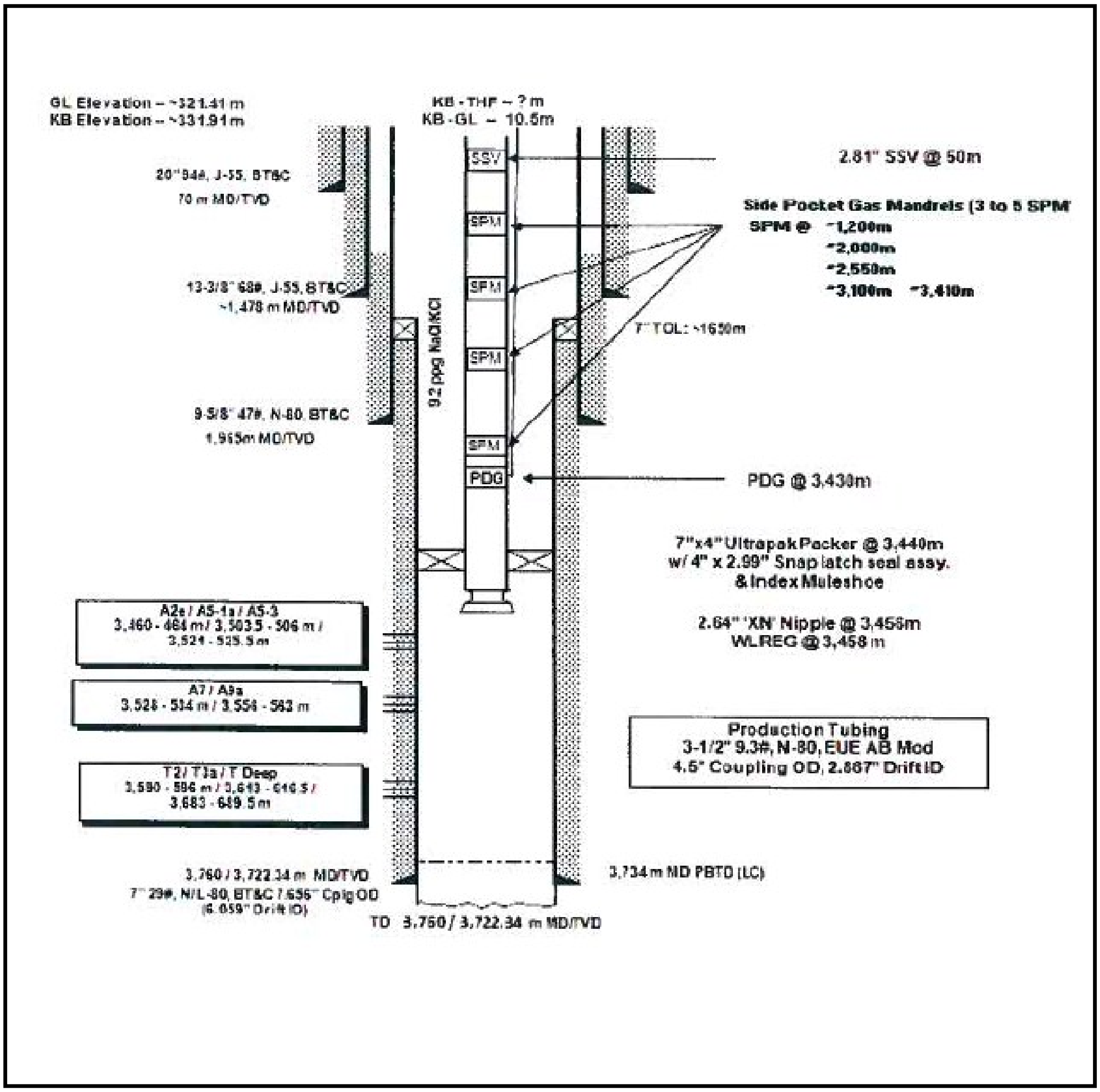
PIONEER NATURAL RESOURCES TUNISIA LTD. PRELIMINARY COMPLETION DESIGN
Well Name: El Badr - 3
Well Location: UTM X: 575035.6 Y: 3477446.36
Lat. 31° 25' 54.024" Long. 9° 47' 22.327"
Status: Current Completion
X-mas Tree
6.250-4 LH Acme - 2G w/ 3" Type BPV
Streamflo 3-1/8" 5M
Wing Valve 2-9/16" 5M Csg
Valve 2-1/16" 5M
GL: 317.20 m
KB: 324.85 m
KB-GL: 7.65 m
Vertical Wel - all depths are in meters - MD/TVD BRT
3-1/2 " Pin x 2-7/8" Pin 3.93" OD/ 2.44" ID / 0.24 m
Surface Conductor @ 52m
20" 94# J-55 BTC Cmt'd to surface
WFT TRSCSSV
45 m 2-7/8" WPE5 2.313" QN Seal Bore 5000 psi
inh. NaCl/KCl Brine Completion/Packer Fluid 9.9 ppg
Production Tubing
2-7/8" 6.5# L-80 Mod EUE
Intermediate Casing @ 1477m
13-3/8" 68# J-55 BTC Cmt'd to surface
Plastic Shale/Salt Interval
Intermediate/Production Csg @ 1967m
9-5/8" 47# N-80 BTC Est TOC 1200m.
WFT SFO-1 Gas Lift Mandrels:
Depth Port PTRO Description
1. 1043m Dummy
2. 1796m Dummy
3. 2491m Dummy
4. 3130m Dummy
5. 3354m Dummy
Canada Technology BHP Gauge & gauge
carrier at 3,360 m Max. O.D. 4.50"
1/4" Tubewire extends to surface w/ Cannon
~ 3,362m Weatherford On/Off Tool
(± 9.2m above upper most packer)
Max O.D. = 5.500" Min. I.D. = 2.313" X profile
13k# down
TOP PACKER AT 3,378m
"A" Punched
A2_d 3391-3393
A2_e 3414.5-3422
"B" OPEN
A5_1a 3458.5-3461
A5_1b 3465-3467
A5_3 3476-3481
A7 3486-3490
"C" Punched
A9_a 3512-3520
T2 3545-3550
3,377 - 3,450 - 3,506 m x 2-7/8" Weatherford WH6 Hyd set
Retrievable Packers 40k# release (2 screws removed)
3,381 - 3,453 - 3,510 m x 2-7/8" Weatherford Nemisis swell
Packers (oil active)
3,396 - 3,462 - 3,538 m x 2-7/8" Weatherford WXON Sliding
Production Liner Shoe @ 3,763 m
7" 29# L-80 & P110 BTC
WFT ACP @ 3,709 m & DV @ 3,702 m
3,624 m WFT 7"x4" UltraPak Permanent Production
Packer: Index Shoe/Seals/5k # Snap Latch Locator
3,640m 2-7/8" Weatherford WXON Sliding Sleeves w/X
profiles (2.313")
TD = 4,162 m Ordovician Open Hole
Tail Pipe Assembly:
3,741 m WXN (2.21" D) w/ wireline entry guide
3,744 m
JUNK BASKET AND PLUG STILL IN PROFILE
Prepared by:
J. Fouras / M. Pavelka
Date
Reviewed by:
Leslie Bauer
Date

PIONEER NATURAL RESOURCES TUNISIA LTD.

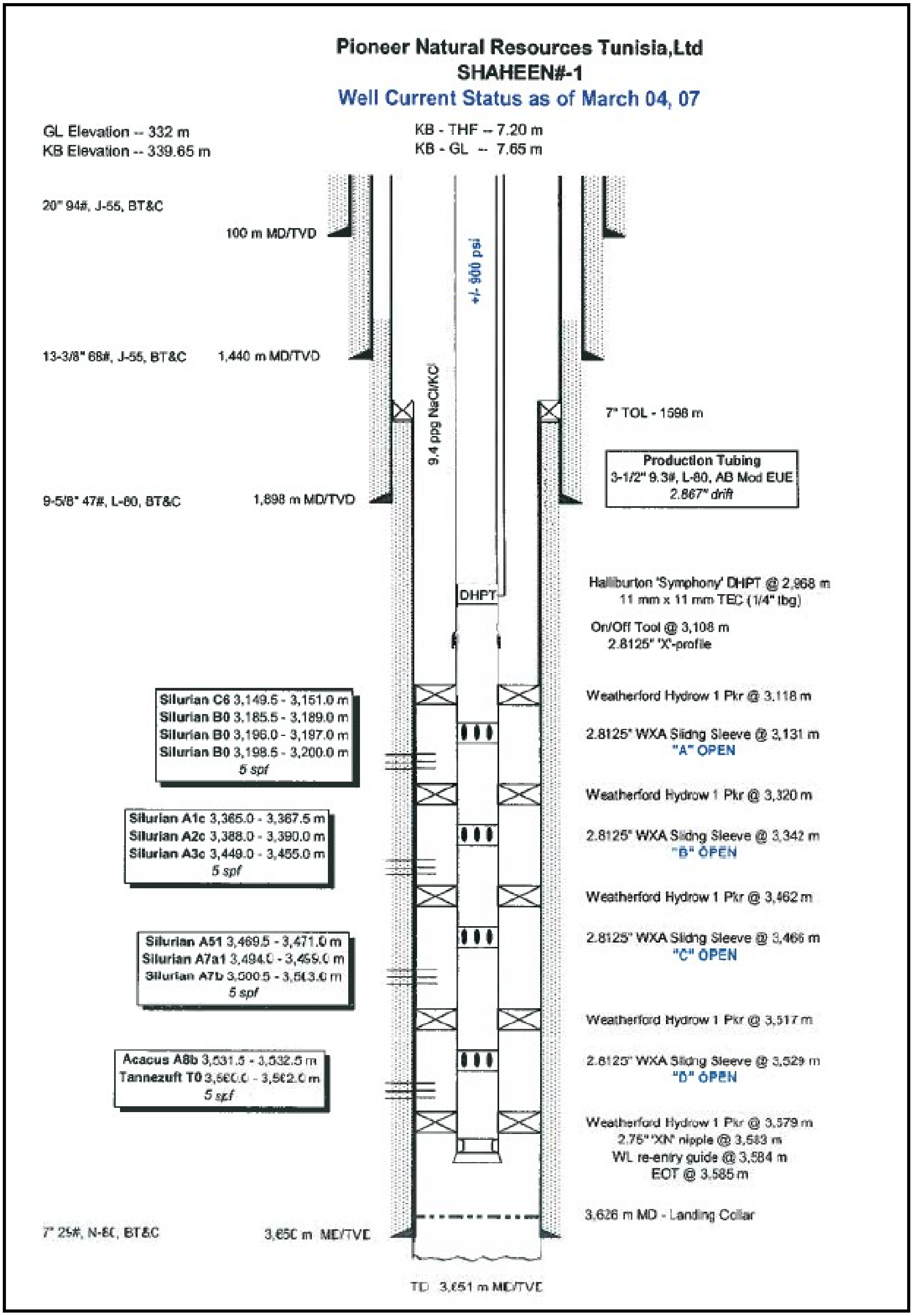
El Badr 4 Final Completion - December 13, 2010

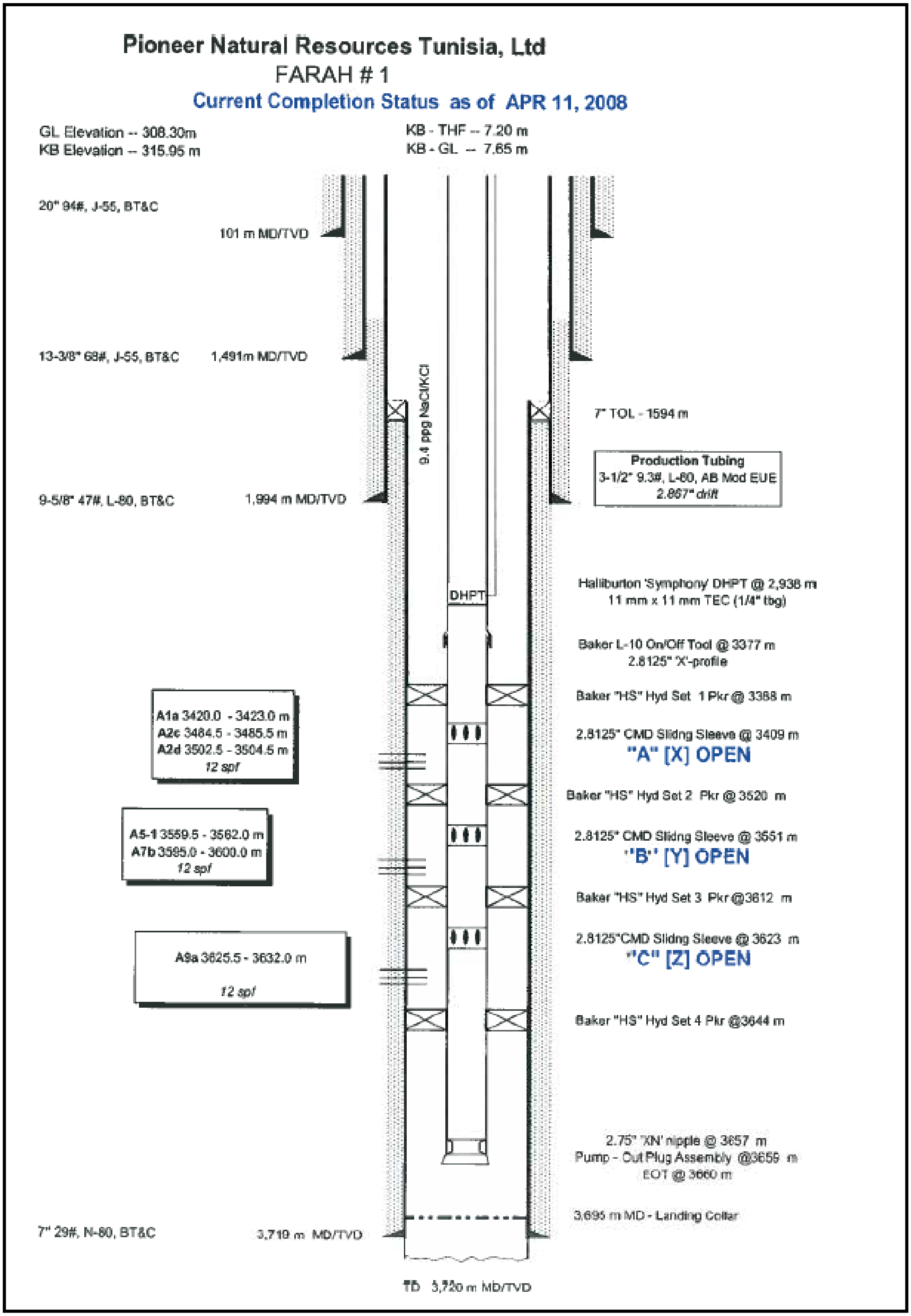


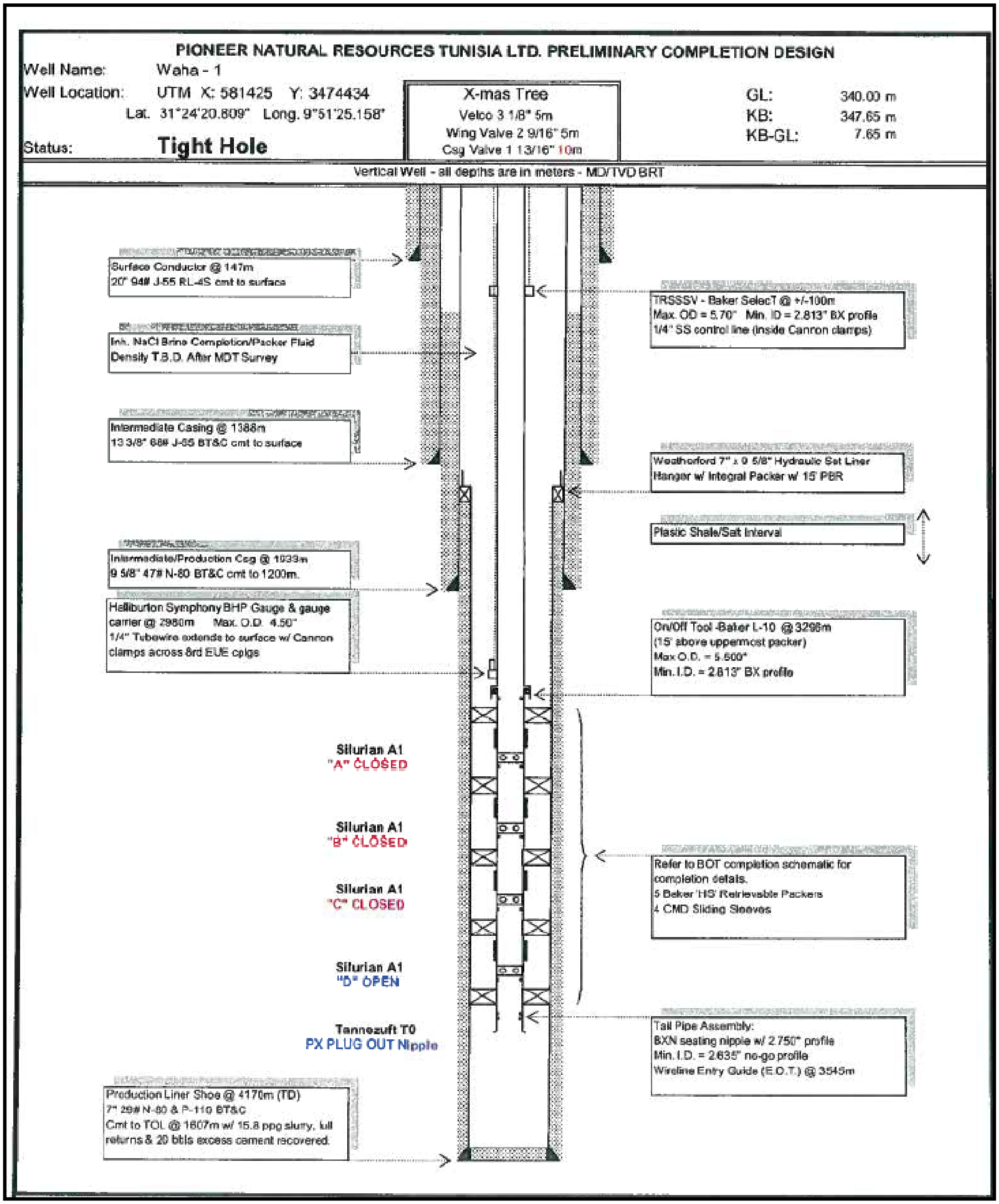
EL Badr-5

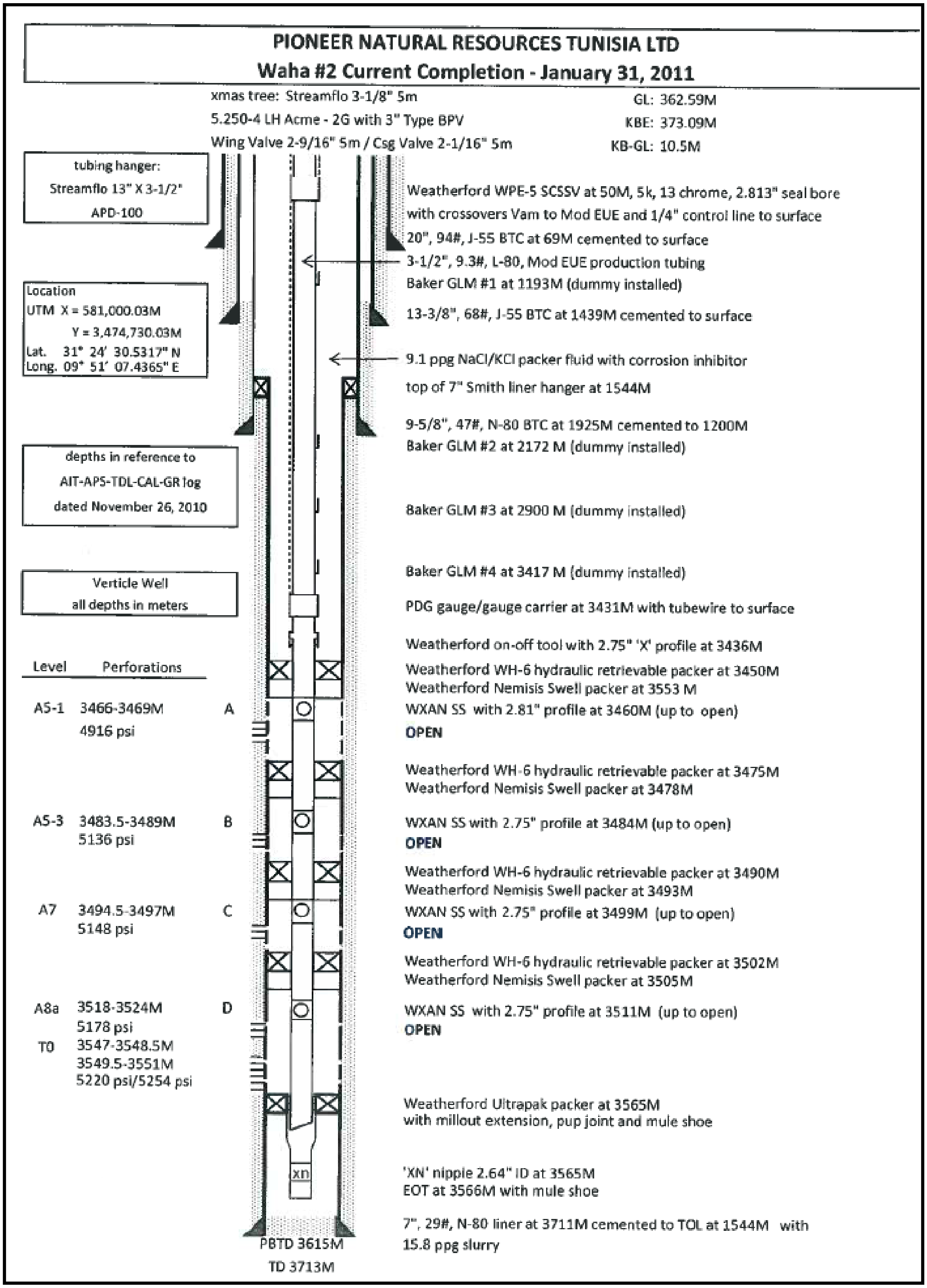


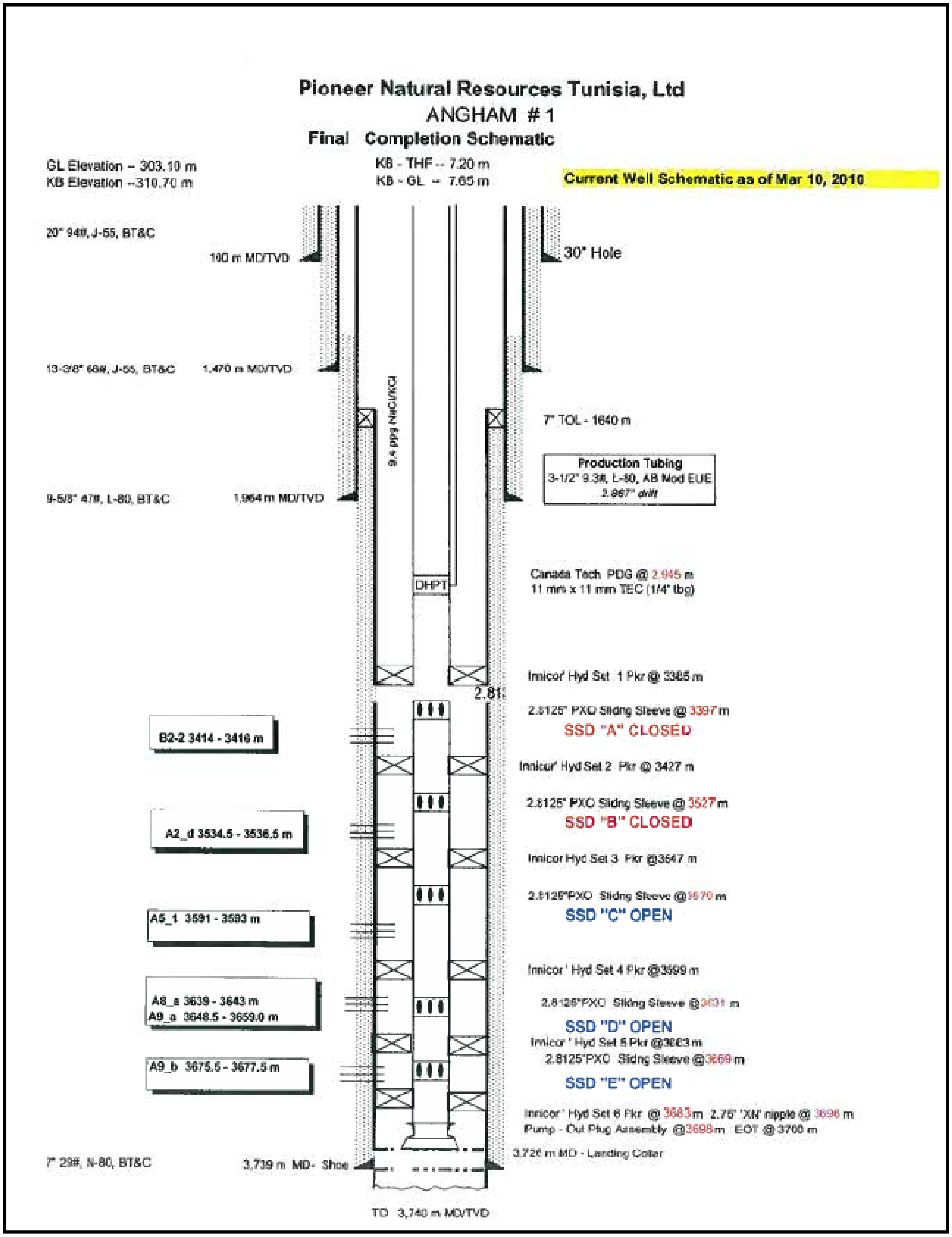
GL Elevation – ~321.41 m
KB Elevation – ~331.91 m
KB - THF – ? m
KB - GL – 10.5m
SSV
SPM
SPM
SPM
SPM
PDG
2.81" SSV @ 50m
Side Pocket Gas Mandrels (3 to 5 SPM
SPM @ ~1,200m
~2,000m
~2,550m
~3,100m ~3,410m
20" 94#, J-55, BT&C
70 m MD/TVD
13-3/8" 68#, J-55, BT&C
~1,478 m MD/TVD
7" TOL: ~1650m
9.2 ppg NaCl/KCl
9-5/8" 47#, N-80, BT&C
1,965m MD/TVD
PDG @ 3,430m
7"x4" Ultrapak Packer @ 3,440m
w/ 4" x 2.99" Snap latch seal assy.
& Index Muleshoe
A2e / A5-1a / A5-3
3,460 - 464 m / 3,503.5 - 506 m /
3,524 - 525.5 m
2.64" 'XN' Nipple @ 3,456m
WLREG @ 3,458 m
A7 / A9a
3,528 - 534 m / 3,556 - 563 m
Production Tubing
3-1/2" 9.3#, N-80, EUE AB Mod
4.5" Coupling OD, 2.867" Drift ID
T2 / T3a / T Deep
3,590 - 596 m / 3,643 - 646.5 /
3,683 - 689.5 m
3,760 / 3,722.34 m MD/TVD
7" 29#, N/L-80, BT&C 7.656" Cplg OD
(6.059" Drift ID)
3,734 m MD PBTD (LC)
TD 3,760 / 3,722.34 m MD/TVD

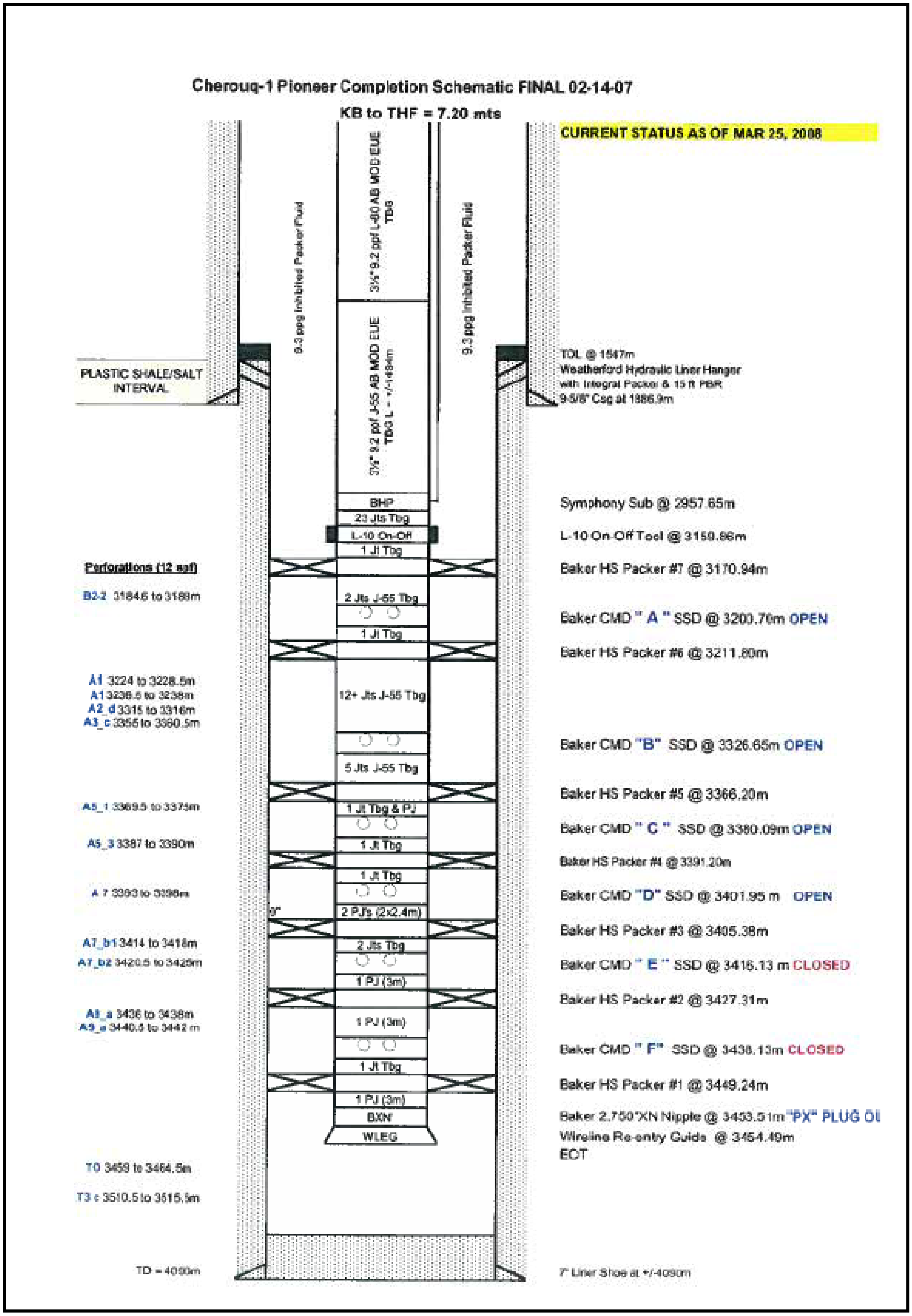

Pioneer Natural Resources Tunisia,Ltd
SHAHEEN#-1
Well Current Status as of March 04, 07
GL Elevation -- 332 m
KB Elevation -- 339.65 m
KB - THF -- 7.20 m
KB - GL -- 7.65 m
20" 94#, J-55, BT&C
100 m MD/TVD
+/- 900 psi
13-3/8" 68#, J-55, BT&C
1,440 m MD/TVD
9.4 ppg NaCl/KCl
7" TOL - 1598 m
Production Tubing
3-1/2" 9.3#, L-80, AB Mod EUE
2.867" drift
9-5/8" 47#, L-80, BT&C
1,898 m MD/TVD
DHPT
Halliburton 'Symphony' DHPT @ 2,968 m
11 mm x 11 mm TEC (1/4" tbg)
On/Off Tool @ 3,108 m
2.8125" 'X'-profile
Silurian C6 3,149.5 - 3,151.0 m
Silurian B0 3,185.5 - 3,189.0 m
Silurian B0 3,196.0 - 3,197.0 m
Silurian B0 3,198.5 - 3,200.0 m
5 spf
Weatherford Hydrow 1 Pkr @ 3,118 m
2.8125" WXA Slidng Sleeve @ 3,131 m
"A" OPEN
Silurian A1c 3,365.0 - 3,367.5 m
Silurian A2c 3,388.0 - 3,390.0 m
Silurian A3c 3,449.0 - 3,455.0 m
5 spf
Weatherford Hydrow 1 Pkr @ 3,320 m
2.8125" WXA Slidng Sleeve @ 3,342 m
"B" OPEN
Weatherford Hydrow 1 Pkr @ 3,462 m
Silurian A51 3,469.5 - 3,471.0 m
Silurian A7a1 3,494.0 - 3,499.0 m
Silurian A7b 3,500.5 - 3,503.0 m
5 spf
2.8125" WXA Slidng Sleeve @ 3,466 m
"C" OPEN
Weatherford Hydrow 1 Pkr @ 3,517 m
Acacus A8b 3,531.5 - 3,532.5 m
Tannezuft T0 3,560.0 - 3,562.0 m
5 spf
2.8125" WXA Slidng Sleeve @ 3,529 m
"D" OPEN
Weatherford Hydrow 1 Pkr @ 3,579 m
2.75" 'XN' nipple @ 3,583 m
WL re-entry guide @ 3,584 m
EOT @ 3,585 m
3,626 m MD - Landing Collar
7" 29#, N-80, BT&C
3,650 m MD/TVD
TD 3,651 m MD/TVD


Pioneer Natural Resources Tunisia, Ltd
FARAH # 1
Current Completion Status as of APR 11, 2008
GL Elevation -- 308.30m
KB Elevation -- 315.95 m
KB - THF -- 7.20 m
KB - GL -- 7.65 m
20" 94#, J-55, BT&C
101 m MD/TVD
13-3/8" 68#, J-55, BT&C
1,491m MD/TVD
9.4 ppg NaCl/KCl
7" TOL - 1594 m
Production Tubing
3-1/2" 9.3#, L-80, AB Mod EUE
2.867" drift
9-5/8" 47#, L-80, BT&C
1,994 m MD/TVD
DHPT
Halliburton 'Symphony' DHPT @ 2,938 m
11 mm x 11 mm TEC (1/4" tbg)
Baker L-10 On/Off Tool @ 3377 m
2.8125" 'X'-profile
Baker "HS" Hyd Set 1 Pkr @ 3388 m
A1a 3420.0 - 3423.0 m
A2c 3484.5 - 3485.5 m
A2d 3502.5 - 3504.5 m
12 spf
2.8125" CMD Slidng Sleeve @ 3409 m
"A" [X] OPEN
Baker "HS" Hyd Set 2 Pkr @ 3520 m
A5-1 3559.5 - 3562.0 m
A7b 3595.0 - 3600.0 m
12 spf
2.8125" CMD Slidng Sleeve @ 3551 m
"B" [Y] OPEN
Baker "HS" Hyd Set 3 Pkr @3612 m
A9a 3625.5 - 3632.0 m
12 spf
2.8125"CMD Slidng Sleeve @ 3623 m
"C" [Z] OPEN
Baker "HS" Hyd Set 4 Pkr @3644 m
2.75" 'XN' nipple @ 3657 m
Pump - Out Plug Assembly @3659 m
EOT @ 3660 m
3,695 m MD - Landing Collar
7" 29#, N-80, BT&C
3,719 m MD/TVD
TD 3,720 m MD/TVD

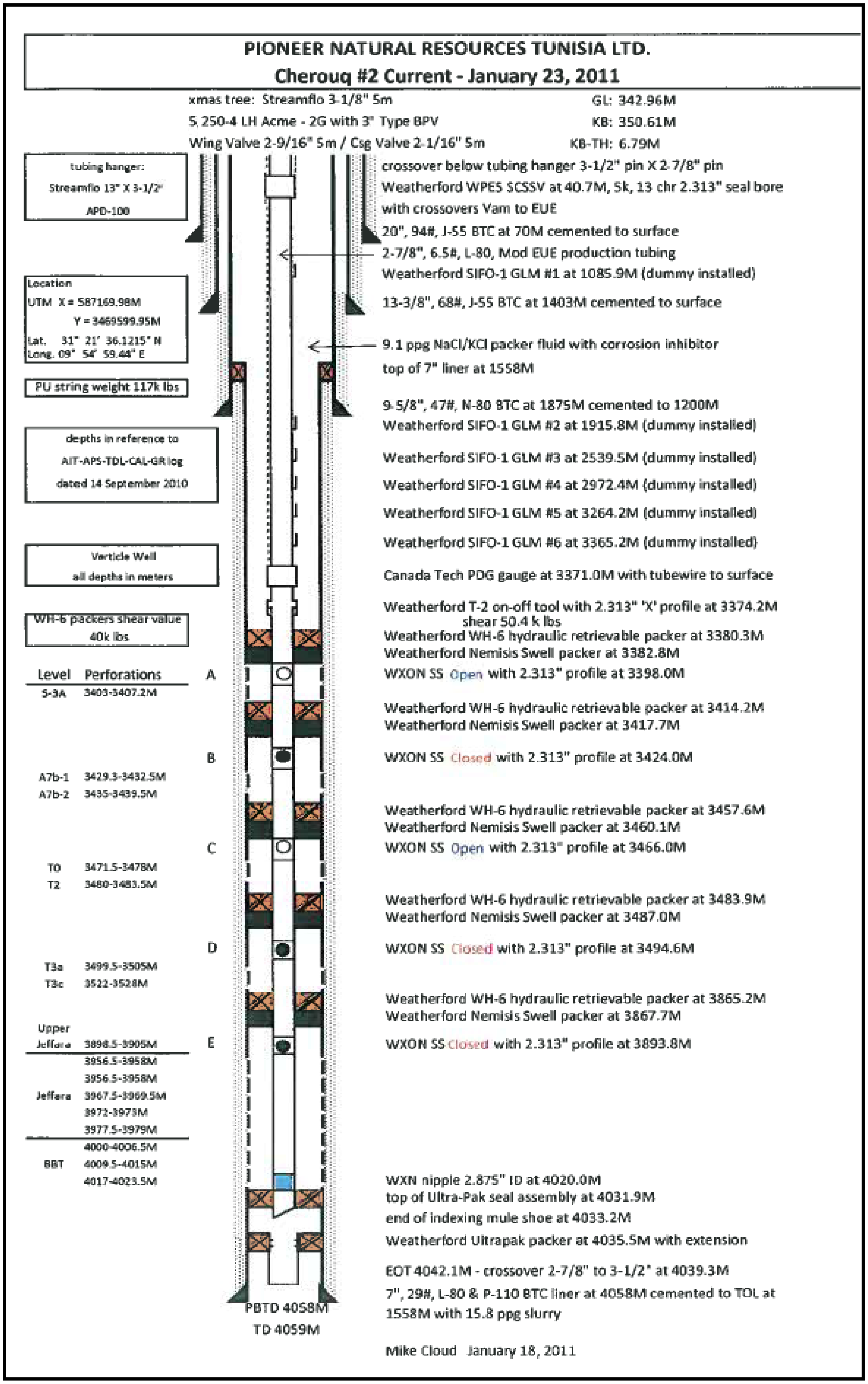

PIONEER NATURAL RESOURCES TUNISIA LTD. PRELIMINARY COMPLETION DESIGN
Well Name: Waha - 1
Well Location: UTM X: 581425 Y: 3474434
Lat. 31°24'20.809" Long. 9°51'25.158"
Status: Tight Hole
X-mas Tree
Velco 3 1/8" 5m
Wing Valve 2 9/16" 5m
Csg Valve 1 13/16" 10m
GL: 340.00 m
KB: 347.65 m
KB-GL: 7.65 m
Vertical Well - all depths are in meters - MD/TVD BRT
Surface Conductor @ 147m
20" 94# J-55 RL-4S cmt to surface
TRSSSV - Baker SelecT @ +/-100m
Max. OD = 5.70" Min. ID = 2.813" BX profile
1/4" SS control line (inside Cannon clamps)
Inh. NaCl Brine Completion/Packer Fluid
Density T.B.D. After MDT Survey
Intermediate Casing @ 1388m
13 3/8" 68# J-55 BT&C cmt to surface
Weatherford 7" x 9 5/8" Hydraulic Set Liner
Hanger w/ Integral Packer w/ 15' PBR
Plastic Shale/Salt Interval
Intermediate/Production Csg @ 1933m
9 5/8" 47# N-80 BT&C cmt to 1200m.
Halliburton Symphony BHP Gauge & gauge
carrier @ 2980m Max. O.D. 4.50"
1/4" Tubewire extends to surface w/ Cannon
clamps across 8rd EUE cplgs
On/Off Tool -Baker L-10 @ 3298m
(15' above uppermost packer)
Max O.D. = 5.600"
Min. I.D. = 2.813" BX profile
Silurian A1
"A" CLOSED
Silurian A1
"B" CLOSED
Silurian A1
"C" CLOSED
Silurian A1
"D" OPEN
Refer to BOT completion schematic for
completion details.
5 Baker 'HS' Retrievable Packers
4 CMD Sliding Sleeves
Tannezuft T0
PX PLUG OUT Nipple
Tail Pipe Assembly:
BXN seating nipple w/ 2.750" profile
Min. I.D. = 2.635" no-go profile
Wireline Entry Guide (E.O.T.) @ 3545m
Production Liner Shoe @ 4170m (TD)
7" 29# N-80 & P-110 BT&C
Cmt to TOL @ 1807m w/ 15.8 ppg slurry, full
returns & 20 bbls excess cement recovered.


PIONEER NATURAL RESOURCES TUNISIA LTD
Waha #2 Current Completion - January 31, 2011
xmas tree: Streamflo 3-1/8" 5m
5.250-4 LH Acme - 2G with 3" Type BPV
Wing Valve 2-9/16" 5m / Csg Valve 2-1/16" 5m
GL: 362.59M
KBE: 373.09M
KB-GL: 10.5M
tubing hanger:
Streamflo 13" X 3-1/2"
APD-100
Location
UTM X = 581,000.03M
Y = 3,474,730.03M
Lat. 31° 24' 30.5317" N
Long. 09° 51' 07.4365" E
depths in reference to
AIT-APS-TDL-CAL-GR log
dated November 26, 2010
Verticle Well
all depths in meters
Level Perforations
A5-1 3466-3469M
4916 psi
A
A5-3 3483.5-3489M
5136 psi
B
A7 3494.5-3497M
5148 psi
C
A8a 3518-3524M
5178 psi
D
T0 3547-3548.5M
3549.5-3551M
5220 psi/5254 psi
Weatherford WPE-5 SCSSV at 50M, 5k, 13 chrome, 2.813" seal bore
with crossovers Vam to Mod EUE and 1/4" control line to surface
20", 94#, J-55 BTC at 69M cemented to surface
3-1/2", 9.3#, L-80, Mod EUE production tubing
Baker GLM #1 at 1193M (dummy installed)
13-3/8", 68#, J-55 BTC at 1439M cemented to surface
9.1 ppg NaCl/KCl packer fluid with corrosion inhibitor
top of 7" Smith liner hanger at 1544M
9-5/8", 47#, N-80 BTC at 1925M cemented to 1200M
Baker GLM #2 at 2172 M (dummy installed)
Baker GLM #3 at 2900 M (dummy installed)
Baker GLM #4 at 3417 M (dummy installed)
PDG gauge/gauge carrier at 3431M with tubewire to surface
Weatherford on-off tool with 2.75" 'X' profile at 3436M
Weatherford WH-6 hydraulic retrievable packer at 3450M
Weatherford Nemisis Swell packer at 3553 M
WXAN SS with 2.81" profile at 3460M (up to open)
OPEN
Weatherford WH-6 hydraulic retrievable packer at 3475M
Weatherford Nemisis Swell packer at 3478M
WXAN SS with 2.75" profile at 3484M (up to open)
OPEN
Weatherford WH-6 hydraulic retrievable packer at 3490M
Weatherford Nemisis Swell packer at 3493M
WXAN SS with 2.75" profile at 3499M (up to open)
OPEN
Weatherford WH-6 hydraulic retrievable packer at 3502M
Weatherford Nemisis Swell packer at 3505M
WXAN SS with 2.75" profile at 3511M (up to open)
OPEN
Weatherford Ultrapak packer at 3565M
with millout extension, pup joint and mule shoe
xn
'XN' nipple 2.64" ID at 3565M
EOT at 3566M with mule shoe
7", 29#, N-80 liner at 3711M cemented to TOL at 1544M with
15.8 ppg slurry
PBTD 3615M
TD 3713M


Pioneer Natural Resources Tunisia, Ltd
ANGHAM # 1
Final Completion Schematic
GL Elevation -- 303.10 m
KB Elevation --310.70 m
KB - THF -- 7.20 m
KB - GL -- 7.65 m
Current Well Schematic as of Mar 10, 2010
20" 94#, J-55, BT&C
100 m MD/TVD
30" Hole
13-3/8" 68#, J-55, BT&C
1,470 m MD/TVD
9.4 ppg NaCl/KCl
7" TOL - 1640 m
Production Tubing
3-1/2" 9.3#, L-80, AB Mod EUE
2.867" drift
9-5/8" 47#, L-80, BT&C
1,964 m MD/TVD
DHPT
Canada Tech PDG @ 2,945 m
11 mm x 11 mm TEC (1/4" tbg)
Innicor Hyd Set 1 Pkr @ 3385 m
2.81
2.8125" PXO Sliding Sleeve @ 3397 m
SSD "A" CLOSED
B2-2 3414 - 3416 m
Innicor Hyd Set 2 Pkr @ 3427 m
2.8125" PXO Sliding Sleeve @ 3527 m
SSD "B" CLOSED
A2_d 3534.5 - 3536.5 m
Innicor Hyd Set 3 Pkr @3547 m
2.8125"PXO Sliding Sleeve @3570 m
SSD "C" OPEN
A5_1 3591 - 3593 m
Innicor ' Hyd Set 4 Pkr @3599 m
2.8125"PXO Sliding Sleeve @3631 m
SSD "D" OPEN
A8_a 3639 - 3643 m
A9_a 3648.5 - 3659.0 m
Innicor ' Hyd Set 5 Pkr @3663 m
2.8125"PXO Sliding Sleeve @3669 m
SSD "E" OPEN
A9_b 3675.5 - 3677.5 m
Innicor ' Hyd Set 6 Pkr @ 3683 m 2.75" 'XN' nipple @ 3696 m
Pump - Out Plug Assembly @3698 m EOT @ 3700 m
3,726 m MD - Landing Collar
7" 29#, N-80, BT&C
3,739 m MD- Shoe
TD 3,740 m MD/TVD



Cherouq-1 Pioneer Completion Schematic FINAL 02-14-07
KB to THF = 7.20 mts
CURRENT STATUS AS OF MAR 25, 2008
3½" 9.2 ppf L-80 AB MOD EUE TBG
3½" 9.2 ppf J-55 AB MOD EUE TBG
9.3 ppg Inhibited Packer Fluid
9.3 ppg Inhibited Packer Fluid
PLASTIC SHALE/SALT INTERVAL
TOL @ 1547m
Weatherford Hydraulic Liner Hanger
with Integral Packer & 15 ft PBR
9-5/8" Csg at 1886.9m
BHP
23 Jts Tbg
L-10 On-Off
1 Jt Tbg
2 Jts J-55 Tbg
1 Jt Tbg
12+ Jts J-55 Tbg
5 Jts J-55 Tbg
1 Jt Tbg & PJ
1 Jt Tbg
1 Jt Tbg
2 PJ's (2x2.4m)
2 Jts Tbg
1 PJ (3m)
1 PJ (3m)
1 Jt Tbg
1 PJ (3m)
BXN
WLEG
Symphony Sub @ 2957.65m
L-10 On-Off Tool @ 3159.86m
Baker HS Packer #7 @ 3170.94m
Baker CMD " A " SSD @ 3200.70m OPEN
Baker HS Packer #6 @ 3211.80m
Baker CMD "B" SSD @ 3326.65m OPEN
Baker HS Packer #5 @ 3366.20m
Baker CMD " C " SSD @ 3380.09m OPEN
Baker HS Packer #4 @ 3391.20m
Baker CMD "D" SSD @ 3401.95 m OPEN
Baker HS Packer #3 @ 3405.38m
Baker CMD " E " SSD @ 3416.13 m CLOSED
Baker HS Packer #2 @ 3427.31m
Baker CMD " F" SSD @ 3438.13m CLOSED
Baker HS Packer #1 @ 3449.24m
Baker 2.750"XN Nipple @ 3453.51m "PX" PLUG ON
Wireline Re-entry Guide @ 3454.49m
EOT
Perforations (12 spf)
B2-2 3184.6 to 3188m
A1 3224 to 3228.5m
A1 3236.5 to 3238m
A2_d 3315 to 3316m
A3_c 3356 to 3360.5m
A5_1 3369.5 to 3375m
A5_3 3387 to 3390m
A 7 3393 to 3398m
A7_b1 3414 to 3418m
A7_b2 3420.5 to 3425m
A8_a 3436 to 3438m
A9_a 3440.5 to 3442 m
T0 3459 to 3464.5m
T3 c 3510.5 to 3515.5m
TD = 4090m
7" Liner Shoe at +/-4090m


PIONEER NATURAL RESOURCES TUNISIA LTD.
Cherouq #2 Current - January 23, 2011
xmas tree: Streamflo 3-1/8" 5m
5 250-4 LH Acme - 2G with 3" Type BPV
Wing Valve 2-9/16" 5m / Csg Valve 2-1/16" 5m
GL: 342.96M
KB: 350.61M
KB-TH: 6.79M
tubing hanger:
Streamflo 13" X 3-1/2"
APD-100
Location
UTM X = 587169.98M
Y = 3469599.95M
Lat. 31° 21' 36.1215" N
Long. 09° 54' 59.44" E
PU string weight 117k lbs
depths in reference to
AIT-APS-TDL-CAL-GR log
dated 14 September 2010
Verticle Well
all depths in meters
WH-6 packers shear value
40k lbs
Level Perforations
S-3A 3403-3407.2M
A7b-1 3429.3-3432.5M
A7b-2 3435-3439.5M
T0 3471.5-3478M
T2 3480-3483.5M
T3a 3499.5-3505M
T3c 3522-3528M
Upper Jeffara 3898.5-3905M
Jeffara 3956.5-3958M
3956.5-3958M
3967.5-3969.5M
3972-3973M
3977.5-3979M
BBT 4000-4006.5M
4009.5-4015M
4017-4023.5M
A
B
C
D
E
crossover below tubing hanger 3-1/2" pin X 2-7/8" pin
Weatherford WPE5 SCSSV at 40.7M, 5k, 13 chr 2.313" seal bore
with crossovers Vam to EUE
20", 94#, J-55 BTC at 70M cemented to surface
2-7/8", 6.5#, L-80, Mod EUE production tubing
Weatherford SIFO-1 GLM #1 at 1085.9M (dummy installed)
13-3/8", 68#, J-55 BTC at 1403M cemented to surface
9.1 ppg NaCl/KCl packer fluid with corrosion inhibitor
top of 7" liner at 1558M
9-5/8", 47#, N-80 BTC at 1875M cemented to 1200M
Weatherford SIFO-1 GLM #2 at 1915.8M (dummy installed)
Weatherford SIFO-1 GLM #3 at 2539.5M (dummy installed)
Weatherford SIFO-1 GLM #4 at 2972.4M (dummy installed)
Weatherford SIFO-1 GLM #5 at 3264.2M (dummy installed)
Weatherford SIFO-1 GLM #6 at 3365.2M (dummy installed)
Canada Tech PDG gauge at 3371.0M with tubewire to surface
Weatherford T-2 on-off tool with 2.313" 'X' profile at 3374.2M
shear 50.4 k lbs
Weatherford WH-6 hydraulic retrievable packer at 3380.3M
Weatherford Nemisis Swell packer at 3382.8M
WXON SS Open with 2.313" profile at 3398.0M
Weatherford WH-6 hydraulic retrievable packer at 3414.2M
Weatherford Nemisis Swell packer at 3417.7M
WXON SS Closed with 2.313" profile at 3424.0M
Weatherford WH-6 hydraulic retrievable packer at 3457.6M
Weatherford Nemisis Swell packer at 3460.1M
WXON SS Open with 2.313" profile at 3466.0M
Weatherford WH-6 hydraulic retrievable packer at 3483.9M
Weatherford Nemisis Swell packer at 3487.0M
WXON SS Closed with 2.313" profile at 3494.6M
Weatherford WH-6 hydraulic retrievable packer at 3865.2M
Weatherford Nemisis Swell packer at 3867.7M
WXON SS Closed with 2.313" profile at 3893.8M
WXN nipple 2.875" ID at 4020.0M
top of Ultra-Pak seal assembly at 4031.9M
end of indexing mule shoe at 4033.2M
Weatherford Ultrapak packer at 4035.5M with extension
EOT 4042.1M - crossover 2-7/8" to 3-1/2" at 4039.3M
7", 29#, L-80 & P-110 BTC liner at 4058M cemented to TOL at
1558M with 15.8 ppg slurry
PBTD 4058M
TD 4059M
Mike Cloud January 18, 2011

Appendix E Rod Star designs

All RODSTAR designs were done By

RODSTAR-D 3.3.1

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Company: OMV
Well: Ang1
Disk file: ANG1.rsvx
Comment:

Page 1 of 4
User:
Date: 1/10/2012

INPUT DATA

Target prod. (m³/D):	131.2	Pump int. pr. (kPa):	14132
Run time (hrs/day):	24.0	Fluid level	
Tubing pres. (kPa):	344.7	(m over pump):	1715.2
Casing pres. (kPa):	344.7	Stuf.box fr. (lbs):	100
		Pol. Rod Diam:	1.5" (38.1 mm)

Fluid properties

Water cut:	60%
Water sp. gravity:	1.2
Oil API gravity:	42.2
Fluid sp. gravity:	1.0458

Motor & power meter

Power Meter	Detent
Electr. cost:	$.06/KWH
Type:	NEMA D

Pumping Unit: Lufkin Air-Balanced (A-2560D-470-240*)

API size: A-2560-470-240 (unit ID: AL1)

Crank hole number	#1 (out of 2)
Calculated stroke length (in):	239.9
Crank Rotation with well to right:	CCW
Air tank pressure at bottom-of-stroke (psig):	Unknown

Tubing and pump information

Tubing O.D. (mm	88.900	Upstr. rod-fl. damp. coeff:	0.100
Tubing I.D. (mm):	75.997	Dnstr. rod-fl. damp. coeff:	0.100
Pump depth (m):	2900	Tub.anch.depth (m):	2900
Pump condition:	Full		
Pump type:	Tubing	Pump vol. efficiency :	80%
Plunger size (ins)	2.75	Pump friction (lbs):	200.0

CALCULATED RESULTS

Production rate (m³/D):	133.4	Peak pol. rod load (lbs):	46340
Oil production (m³/D):	53.4	Min. pol. rod load (lbs):	15362
Strokes per minute:	6.03	MPRL/PPRL	0.332
System eff. (Motor->Pump):	37%	Unit struct. loading:	99%
Permissible load HP:	154.7	PRHP / PLHP	0.33
Fluid load on pump (lbs):	13801	Buoyant rod weight (lbs):	23225
Fluid level TVD (m from surface):	1184.8	N/No: .21 ,	Fo/SKr: .296
Polished rod HP:	51.2		

Required prime mover size (speed var. not included)	BALANCED (Min Torq)
NEMA D motor:	100 HP
Single/double cyl. engine:	100 HP
Multicylinder engine:	100 HP

Torque analysis and electricity consumption	BALANCED (Min Torq)
Peak g'box torq.(M in-lbs):	1701
Gearbox loading:	66%
Cyclic load factor:	1.5
Max. air tank pres. (psig):	482
Daily electr.use (KWH/day):	1220
Monthly electric bill:	$2233
Electr.cost per m³ fluid:	$0.549
Electr.cost per m³ oil:	$1.372

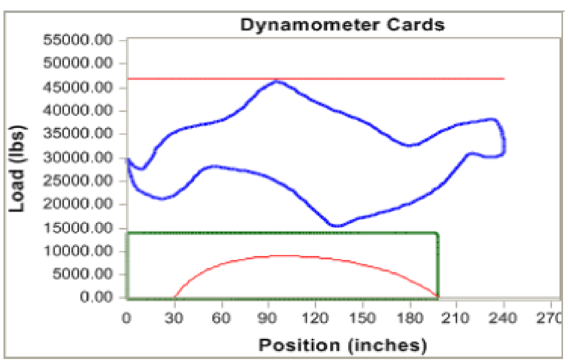
Tubing, pump and plunger calculations

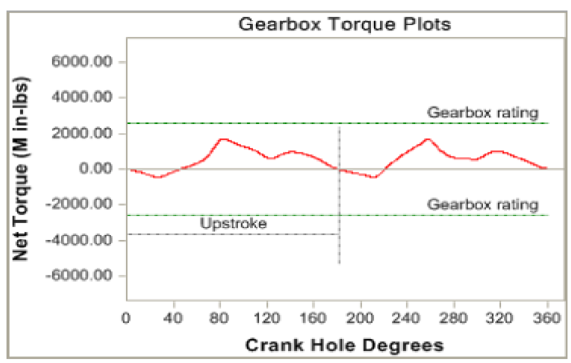
Tubing stretch (ins):	.0
Prod. loss due to tubing stretch (m³/D):	.0
Gross pump stroke (ins):	197.4
Pump spacing (in. from bottom):	28.5
Minimum pump length (ft):	32.0
Recommended plunger length (ft):	6.0

Rod string design / Rod string stress analysis (service factor: 0.9)

Diameter (inches)	Rod Grade	Length (m)	Min. Tensile Strength (psi)	Fric. Coeff	Stress Load %	Top Maximum Stress (psi)	Top Minimum Stress (psi)	Bot. Minimum Stress (psi)	Stress Calc. Method
1.125	WFT T66/XD	800	140000	0.2	88%	46006	15104	8460	API MG T/2.8
1	WFT T66/XD	800	140000	0.2	87%	43629	10219	4352	API MG T/2.8
0.875	WFT T66/XD	1300	140000	0.2	89%	41900	4998	-333	API MG T/2.8

NOTE Stress calculations do not include buoyancy effects.





RODSTAR-D 3.3.1

© Theta Oilfield Services, Inc. (www.gotheta.com)

Company: OMV
Well: methaq 2
Disk file: METHAQ 2.rsvx
Comment:

User:
Date: 1/18/2012

INPUT DATA

Target prod. (m³/D):	19.5	Pump int. pr. (kPa):	1384
Run time (hrs/day):	24.0	Fluid level	
Tubing pres. (kPa):	344.7	(m over pump):	117.4
Casing pres. (kPa):	344.7	Stuf.box fr. (lbs):	100
		Pol. Rod Diam:	1.5" (38.1 mm)

Fluid properties

Water cut:	2%
Water sp. gravity:	1.2
Oil API gravity:	42.0
Fluid sp. gravity:	0.8233

Motor & power meter

Power Meter	Detent
Electr. cost:	$.06/KWH
Type:	NEMA D

Pumping Unit: Lufkin Conventional - New (C-912D-36*)

API size: C-912-365-192 (unit ID: CL159)

Crank hole number	#1 (out of 4)
Calculated stroke length (in):	193.3
Crank Rotation with well to right:	CCW
Max. CB moment (M in-lbs):	Unknown
Structural unbalance (lbs):	-1800
Crank offset angle (deg):	0.0

Tubing and pump information

Tubing O.D. (mm	88.900	Upstr. rod-fl. damp. coeff:	0.100
Tubing I.D. (mm):	75.997	Dnstr. rod-fl. damp. coeff:	0.100
Pump depth (m):	3550	Tub.anch.depth (m):	3500
Pump condition:	Full		
Pump type:	Insert	Pump vol. efficiency :	80%
Plunger size (ins)	1.5	Pump friction (lbs):	200.0

CALCULATED RESULTS

Production rate (m³/D):	19.5	Peak pol. rod load (lbs):	34573
Oil production (m³/D):	19.1	Min. pol. rod load (lbs):	20167
Strokes per minute:	3.89	MPRL/PPRL	0.583
System eff. (Motor->Pump):	39%	Unit struct. loading:	95%
Permissible load HP:	41.9	PRHP / PLHP	0.31
Fluid load on pump (lbs):	7097	Buoyant rod weight (lbs):	23385
Fluid level TVD (m from surface):	3432.6	N/No: .166 ,	Fo/SKr: .291
Polished rod HP:	12.8		

Required prime mover size (speed var. not included)	BALANCED (Min Torq)
NEMA D motor:	40 HP
Single/double cyl. engine:	30 HP
Multicylinder engine:	40 HP

Torque analysis and electricity consumption	BALANCED (Min Torq)
Peak g'box torq.(M in-lbs):	865
Gearbox loading:	95%
Cyclic load factor:	2
Max. CB moment (M in-lbs):	2764.19
Counterbalance effect (lbs):	28740
Daily electr.use (KWH/day):	385
Monthly electric bill:	$704
Electr.cost per m³ fluid:	$1.183
Electr.cost per m³ oil:	$1.207

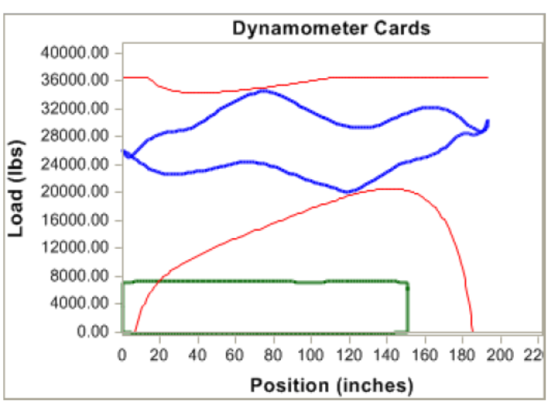
Tubing, pump and plunger calculations

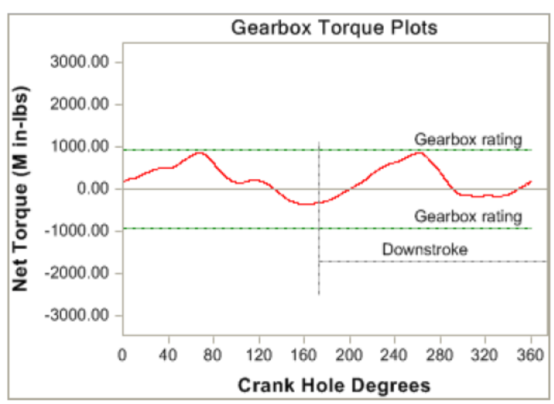
Tubing stretch (ins):	.2
Prod. loss due to tubing stretch (m³/D):	.0
Gross pump stroke (ins):	150.8
Pump spacing (in. from bottom):	34.9
Minimum pump length (ft):	27.0
Recommended plunger length (ft):	6.0

Rod string design / Rod string stress analysis (service factor: 0.9)

Diameter (inches)	Rod Grade	Length (m)	Min. Tensile Strength (psi)	Fric. Coeff	Stress Load %	Top Maximum Stress (psi)	Top Minimum Stress (psi)	Bot. Minimum Stress (psi)	Stress Calc. Method
1	WFT T66/XD	1000	140000	0.2	64%	43256	25211	15668	API MG T/2.8
0.875	WFT T66/XD	1500	140000	0.2	65%	40479	19801	6218	API MG T/2.8
0.75	WFT T66/XD	1050	140000	0.2	53%	28639	7416	-453	API MG T/2.8

NOTE Stress calculations do not include buoyancy effects.





RODSTAR-D 3.3.1

Company: OMV
Well: waha 1
Disk file: WAHA1.rsvx
Comment:

© Theta Oilfield Services, Inc. (www.gotheta.com)

User:
Date: 1/13/2012

INPUT DATA

Target prod. (m³/D):	75.5	Pump int. pr. (kPa):	3277
Run time (hrs/day):	24.0	Fluid level	
Tubing pres. (kPa):	344.7	(m over pump):	350.4
Casing pres. (kPa):	344.7	Stuf.box fr. (lbs):	100
		Pol. Rod Diam:	1.5" (38.1 mm)

Fluid properties

Water cut:	6%
Water sp. gravity:	1.2
Oil API gravity:	40.0
Fluid sp. gravity:	0.8476

Motor & power meter

Power Meter	Detent
Electr. cost:	$.06/KWH
Type:	NEMA D

Pumping Unit: Lufkin Air-Balanced (A-2560D-470-240*)

API size: A-2560-470-240 (unit ID: AL1)	
Crank hole number	#1 (out of 2)
Calculated stroke length (in):	239.9
Crank Rotation with well to right:	CCW
Air tank pressure at bottom-of-stroke (psig):	Unknown

Tubing and pump information

Tubing O.D. (mm	88.900	Upstr. rod-fl. damp. coeff:	0.100
Tubing I.D. (mm):	75.997	Dnstr. rod-fl. damp. coeff:	0.100
Pump depth (m):	2980	Tub.anch.depth (m):	2900
Pump condition:	Full		
Pump type:	Tubing	Pump vol. efficiency :	80%
Plunger size (ins)	2.25	Pump friction (lbs):	200.0

CALCULATED RESULTS

Production rate (m³/D):	76.6	Peak pol. rod load (lbs):	44718
Oil production (m³/D):	72	Min. pol. rod load (lbs):	16986
Strokes per minute:	5.2	MPRL/PPRL	0.38
System eff. (Motor->Pump):	48%	Unit struct. loading:	95%
Permissible load HP:	131.9	PRHP / PLHP	0.30
Fluid load on pump (lbs):	12634	Buoyant rod weight (lbs):	24411
Fluid level TVD (m from surface):	2629.6	N/No: .186 ,	Fo/SKr: .28
Polished rod HP:	39.9		

Required prime mover size (speed var. not included)	BALANCED (Min Torq)
NEMA D motor:	100 HP
Single/double cyl. engine:	75 HP
Multicylinder engine:	100 HP

Torque analysis and electricity consumption	BALANCED (Min Torq)
Peak g'box torq.(M in-lbs):	1464
Gearbox loading:	57%
Cyclic load factor:	1.5
Max. air tank pres. (psig):	489
Daily electr.use (KWH/day):	962
Monthly electric bill:	$1760
Electr.cost per m³ fluid:	$0.753
Electr.cost per m³ oil:	$0.801

Tubing, pump and plunger calculations

Tubing stretch (ins):	.5
Prod. loss due to tubing stretch (m³/D):	.2
Gross pump stroke (ins):	196.9
Pump spacing (in. from bottom):	29.3
Minimum pump length (ft):	33.0
Recommended plunger length (ft):	6.0

Rod string design / Rod string stress analysis (service factor: 0.9)

Diameter (inches)	Rod Grade	Length (m)	Min. Tensile Strength (psi)	Fric. Coeff	Stress Load %	Top Maximum Stress (psi)	Top Minimum Stress (psi)	Bot. Minimum Stress (psi)	Stress Calc. Method
1.125	WFT T66/XD	800	140000	0.2	81%	44324	16687	10383	API MG T/2.8
1	WFT T66/XD	800	140000	0.2	82%	42809	12693	6963	API MG T/2.8
0.875	WFT T66/XD	1380	140000	0.2	83%	41244	8421	-333	API MG T/2.8

NOTE Stress calculations do not include buoyancy effects.