Montan Universität Leoben

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PRODUCTION OPTIMIZATION OF ELECTRICAL SUBMERSIBLE PUMPS (ESPs) IN SARIR FIELD, LIBYA

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.

Waleed M. E. Mohammed

Leoben, October 2010

KURZFASSUNG

Die Sarir Lagerstätte ist das größte Ölfeld in Libyen. Sie ist 56 km lang, 40km breit und bedeckt 378 m² des südöstlichen Teils der Libyschen Wüste. Durch das erste Bohrloch C-001-65 wurde am 15. Dezember 1961Öl aufgefunden. Der geologische Aufbau der Lagerstätte ist eine komplexe Zusammensetzung von Sandsteinen aus der Kreidezeit. Alle 350 Bohrlöcher werden mittels elektrischen Tauchkreiselpumpen betrieben.

Der Zweck dieser Diplomarbeit ist die Analyse des derzeitigen Aufbaus und eine Optimierung der Förderung für fünf mit ESP produzierten Bohrlöchern dieser Lagerstätte. Die Produktionsoptimierung wurde mittels “Nodal Analysis Technique” zwischen Lagerstätte und Bohrlochskopf vorgenommen, ohne Berücksichtigung der installierten Obertagedüse und des Separators. Für die Kalkulation wurden folgende Software Programme verwendet “SubPump” und “Avocet”.

Zwei Ansätze in dieser Studie wurden dabei zur Optimierung herangezogen:

- Optimierung der Förderung durch Kombination von Gas-Lift als sekundäre Methode mit einer elektrischen Tauchpumpe (z.B.: ESP/GL), und
- Größenänderung des aktuellen Designs, sowie eine optimierte Pumpenabsetzteufe.

Mehrere Vorteile ergeben sich aus der Anwendung dieser Konzepte, z.B.: Strom sparen, Produktionsverbesserung, Reduktion der Reparaturen an der Sonde.

Diese Ansätze wurden auf der Grundlage wirtschaftlicher Netto-Cash-Flow-Berechnungen für fünf Jahre ausgewertet. Darüber hinaus weist ein Vergleich der NCF Resultate für beide Ansätze auch auf ein großes Verbesserungspotenzial hin. Die Anwendung der Kombination von ESP/GL Methode und der Pumpenabsetzteufe führt zu einer Erhöhung des NCF von 40 % und 28%, jeweils bezogen auf den derzeitigen Status.

Die beiden Ansätze wurden technisch verglichen und zeigen die Vorteile höherer Produktion, niedrigeren Stromverbrauchs und weniger Reparaturen bei der ESP/GL Kombination. Auf der anderen Seite wird durch eine optimierte Dimensionierung des Steigrohres und der Pumpenabsetzteufe ein wesentlicher Vorteil erzielt.

ABSTRACT

Sarir field is the largest oil field in Libya. The Sarir field, which is 56 km long and 40 km wide, covers about 378 km2 of southern east part of Libyan Desert. Oil was discovered by the first well C-001-65 on 15th December, 1961.The geological formation of this field is a convex composition of sandstone from the cretaceous period. Currently this field has about 350 well; all of which are producing with electrical submersible pump.

The purpose of this thesis is to analysis the current design and to perform production optimization for five ESP wells in this field. Production optimization was achieved by the principles of Nodal Analysis Technique which was applied between the reservoir and the wellhead ignoring the surface choke and separator. SubPump and Avocet well surface Modeler softwares were used to perform the calculations. Two approaches in this study are considered to optimize the production:

- Production optimization by combining gas lift as a secondary method with an electrical submersible pump (i.e., ESP/GL), and then
- Resizing current design and optimizing pump setting depth.

Several benefits and advantages are achieved from applying those approaches, for instance; saving power, reducing number of stages and production improvement.

Those approaches were economically evaluated based on net cash flow (NCF) calculations for five years period. Moreover, comparing the NCF which was resulted from applying those approaches with the present status indicates higher improvement and good results. Applying the combination of ESP/GL method and optimizing the pump setting depth increase the NCF by 40% and 28%, respectively relative to the present status.

The two approaches when compared technically, advantages of higher production, lower power consumption and lower stages observed in the combination of ESP/GL. On the other hand, minimizing tubing and cable, in addition to production improvement observed in shifting the pump up and optimizing the pump setting depth.

DEDICATION

In the name of ALLAH most gracious most merciful

This dissertation is humbly dedicated to my parents, my wife, my children Mohammed, Khaled and Taqwa

I am grateful to my parents for providing me education, inspiration and confidence. I am also indebted to my wife who provided the encouragement, and extraordinary understanding which enabled me to take many hours from our family while writing this dissertation.

My friends have always been a positive influence in my life, and for this I am eternally grateful.

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My MSc. was funded by the Arabian Gulf Oil Company Libya, to whom I am grateful and greatly indebted.

I would especially like to thank my mentor and advisor Prof. Herbert Hofstaetter for his continuous support and encouragement through this research project. Under his supervision I have greatly improved my knowledge and skills in the areas of petroleum production engineering and Artificial lift system. It is an honour to have him as my supervision and to be his friend.

I wish to thank Prof. Thonhauser for the time that he took inside his very busy schedule to help me in some topics.

I would like to thank and express my deepest appreciation to all my friends and colleagues in the Production and Processing Engineering Department for all their support.

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Last but not least, special and infinite thanks to the most important people in my life, my parents, my wife and my children.

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CHAPTER 1: Introduction

1.1 Background

The great majority of the world's oil wells need some kind of artificial lifting mechanism to produce their liquid to the surface, as the natural energy from thier reservoirs is insufficint to do so . In Libya the artificial lift methods that are widely used are SRP, gas lift and ESP, which is the corner stone of this project, since the existence of mature reservoirs and quite deep wells as well as the availability of the produced gas. Historically, the first submersible pumping unit was installed in an oil well in 1928 [2] , and since then the concept has proved itself throughout the oil-producing world. Presently, it is considered as an effective and economical means of lifting large volumes of fluids from great depths under a variety of well conditions.Sarir oil field (South East Libya) produces some associated gas with the oil, which is not enough for a gas lift technique. Therefor,lifting method in Sarir field is ESPs. Analysis and optimization of pumping equipment and well performance are needed for all types of artificial lift. This seems especially true for submersible pumping systems, which on per well basis has high OPEX and intervesion costs. A submersible installations require optimum equipment design and perfectly matched with actual well performance(IPR).

It might be a challenging to obtain the most economics return on your artificial lift investment, due to increase water cut over time and lack of inflow or various underperformance issues. These issues are necessary to apply production optimization technique to analyze and optimize ESP installations. Nodal analysis is the latest tool available for production engineer and used to investigate the effects of changes in operating parameters on the well's performance.

1.2 Objective

The objective of this study is to perform a production engineering study at Sarir oil field in Libya. The main goal of the study is to optimize the production of (5 ESP wells) currently operating in this field based on three approaches as follow:

- Analysis and review of the existing ESP design
- Finding the optimum rate with the optimum pump setting depth
- Combined ESP with Gas lift (Hybrid)

1.3 Methodology

In order to accomplish the proposed objectives, two Softwares are used for designing; for diagnostic analysis for existing ESP design, and combined ESP/gas lift systems calculations SubPump software was used, and Avocet Well and Surface Modeler software was used for finding the optimum pump and pump setting depth calculations. The results of designs will allow us to select the optimum submersible pump equipment and keep them running in a proper condition which results in continue the production in a more economical and cost saving approach.

Describing the Sarir Field and Electrical submersible pumps operation conditions in this field are presented in the second chapter. The third chapter follows with an overview of the electrical submersible pump system. Submersible pump's analysis and production optimization by using two Softwares (SubPump and Avocet) are mentioned in the forth Chapter and in the fifth chapter, the results and discussion of the analysis and production optimization concerning some specific wells (C-001-65, C-046-65, C-101-65, C-105-65 and C-144-65) in the field mentioned are discussed, as well economical evaluation was performed to evaluate the two approaches (Combined ESP/Gas lift and optimizing the pump setting depth). Finally, in the last Chapter, according to the results of analysis and evaluation, conclusion and recommendations for improving ESP operations in the Sarir field are presented. It is hoped that the project will encourage discussion on the topic and assist the longevity of the ESPs in the Sarir oil field in a more consistent manner.

CHAPTER 2: Description of the Sarir Field and ESPs Operation Conditions

2.1 Sarir Field Overview

The Sarir or, more specifically, the Sarir “C” field lies on the western edge of the Calanscio sand sea in southern portion of Sirte basin and is the largest oil field in Libya. It occurs at the south-eastern margin of the Upper Cretaceous- Tertiary Sirte basin that contains all the major oil fields of Libya and is the most prolific oil-producing basin in North Africa. The Sarir “C” field, which is part of a complex of three fields, is 56 Km long and 40 Km wide covering approximately 378 Km2. To its north lies the Sarir “L” accumulation, which covers approximately between the two, a much smaller Sarir North pool. Estimated ultimate recovery from the “C” field is 3.8 billion bbl of oil and from the “L” field, 1.2 billion bbl, ranking them as the 51st and 201st largest fields in the compilation of Carmalt and St.John (1986) [24] , [25]

The Sarir field was discovered in December 1961. Commercial production commenced five years later in December 1966. More than 300 wells have been drilled in these fields, some water injection took place from 1968-1982 in the northeast area of Sarir C-main for pressure maintenance. The field produces 37API gravity, highly under saturated paraffinic oil with a maximum original oil column of 275 feet. An excellent aquifer underlies the oil column and it ranges in thickness from 230 feet in the C-main area to in excess of 800 feet off structure. The principal reservoir, called the C-main field, consists of a large, basement controlled, fault and truncated anticline. The structure is approximately 33 kilometres long and 15 kilometres wide. The C-Main reservoir is composed of thick Lower Cretaceous age sandstone of the Sarir Group which is subdivided into six geological members designated from bottom to top as Members 1, 2, 3, 4, 5AC and 5AB as shown in **Figure 2-1**. Oil production in Sarir C-Main Field is mainly from Members 3, 4 and 5 with members 1 and 2 below the field oil-water contact. In addition oil is also produced from an overlying Upper Cretaceous age Transgressive Sandstone Unit (TGS).

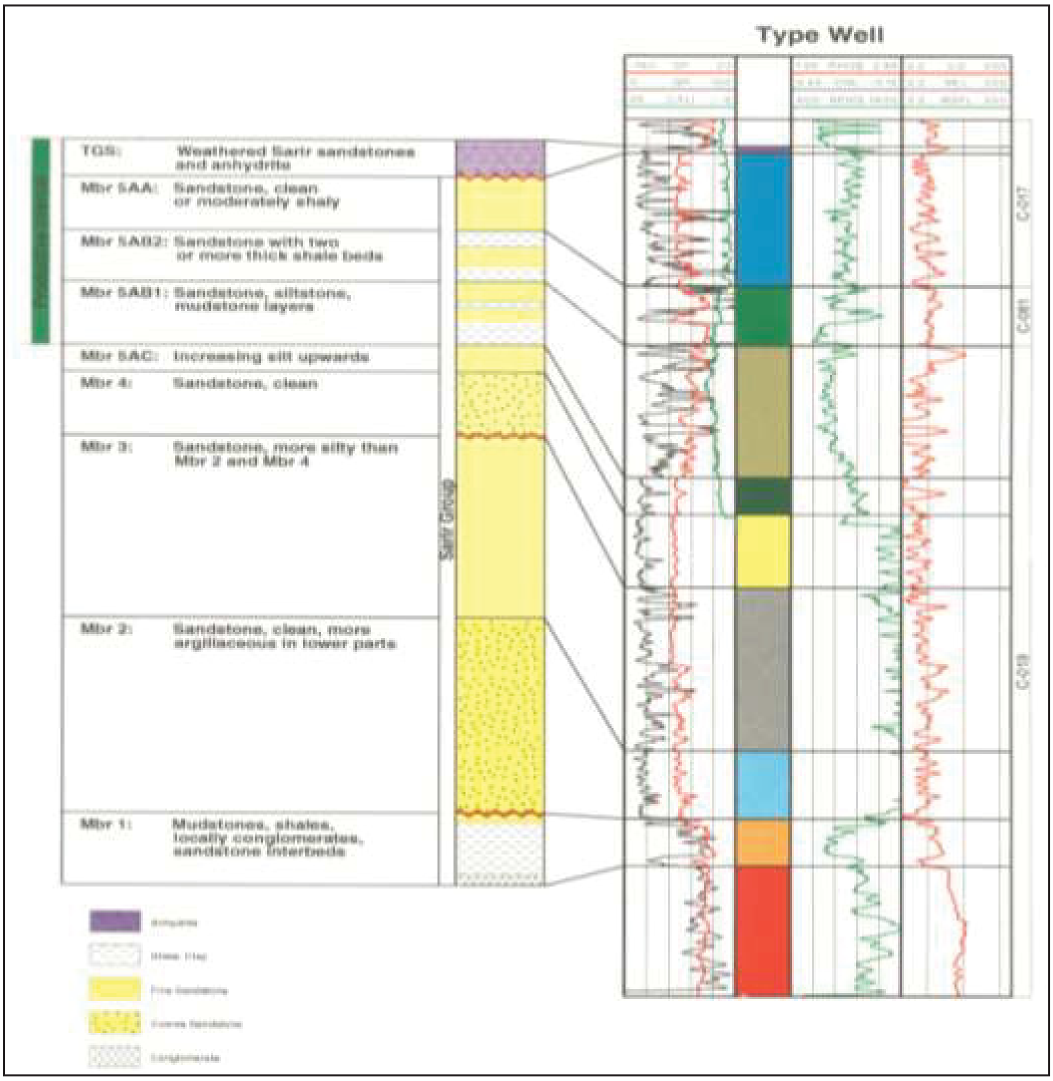


Figure 2-1: Stratigraphy of the Sarir Group and TGS [26]

The predominant oil recovery mechanism in the field is bottom water drive with a large regional aquifer directly underlying the hydrocarbon accumulation, providing good pressure support over most of the field.

Gross thickness of the Sarir sand varies from 483 feet on top of the structure to at least 2061 feet on the flank. Sarir initial reservoir pressure was 3900 Psig but has been depleted to between 2700 Psig and 2160 psig.

In 1980 as a result of this depletion some form of artificial lift was necessary in order to lift oil from the producing interval to the surface and on to stations The first candidate well for an ESP installation was C002-65 in 1983 when the static bottomhole pressure was depleted to 3200 psi, this was followed by two wells, C117-65 and C-073-65 in 1984.

Initially the installation of ESP equipment was held back due to the lack of a high voltage distribution system. The only wells connected to a distribution system were adjacent to the main crude oil processing area, GC1. The ESP candidate wells were not necessarily these wells. Consequently many of the first installations had to be powered by diesel motor generator sets producing power at around 380 volts. Since the pump setting depth was roughly 5,000 ft, step up transformers were used to increase this voltage to the 1,000 volt range. This procedure was satisfactory on a short term basis and as many as 15 wells were operated with these generator sets. Maintenance of course, is a problem and the frequent need to shut the units down for servicing greatly reduced the pump run life. In the late 1980's a main 33 KV line was run from Messla, the nearest field to the north, to Sarir and an 11 KV distribution constructed through out the field. This allowed every ESP candidate well to be scheduled for installation and consequently installations increased greatly. Slowly the start-up problems with the high line were resolved and the power supply is very steady and unit run life is currently over 700 days.

Presently about 350 wells are producing by E.S.P and this method has proven very successful. All the Sarir production comes from electrical submersible pumped wells. Many tools can be run in the hole to monitor the efficiency of pumps, temperature, motor vibration, current leakage and so on. AGOCO has established the need to run tools and equipment so that these parameters can be monitored. This includes Y-tools and pressure, temperature, vibration sensors.

2.2 Sarir Gatherings Centre GC:

The field production infrastructure comprises an extensive network of gathering network of pipes which connects each wellhead to the gathering centre (GC) which receive the crude oil. Each group of wellhead is connected to a gathering centre which determined by well distribution over specific area.

Each gathering centres (GC1, GC2, GC3, GC4, GC5, and GC6) are connected to the GC main through trunk line, **Figure 2-2, Figure 2-3** and **Table 2-1** show GCs, the number of wellhead of wells drilled, ESP operated wells and the amount of production of each GC.

Table 2-1: Sarir Gathering Centre [5]

GCs	Total wells drilled	ESP wells	Production of GCs BFPD
GC 1 (C-main)	107	77	51,000
GC 2 (C-main)	141	120	97,000
GC 3 (C-main)	70	63	39,000
GC 4 (L-Field)	79	62	37,000
GC 5 (C-main)	26	18	11,000
GC 6 (C-North)	21	14	5,000
Total	444	354	240,000 bbl/day

2.3 ESPs run life in the Sarir oil field

There are about 350 ESPs operating in the Sarir oil fields, producing from three distinct reservoirs, C-Main, L-Field, and C-North. As the field has matured and reservoir fluid composition has changed, completion practices have been improved to help increase the productivity of the wells and the longevity of the ESPs. Over the time, the number of producing wells has increased, and additional ESPs have been brought on line. The well locations are indicated in **Figure 2-2** and **Figure 2-3**. Analysis reveals that the run lives of ESPs considerably vary. In the Sarir oil field the mean time between failures is 700 days, with the age of the longest surviving pump being in excess of 18 years in Well No.C-35-65.About 95% of the ESPs installed in the Sarir oil fields have been provided by the same vendor (Reda), 5% of the ESPs installed provided by Weatherford, Al khorayef, Wood group and (Centrilift) Baker Eastern.

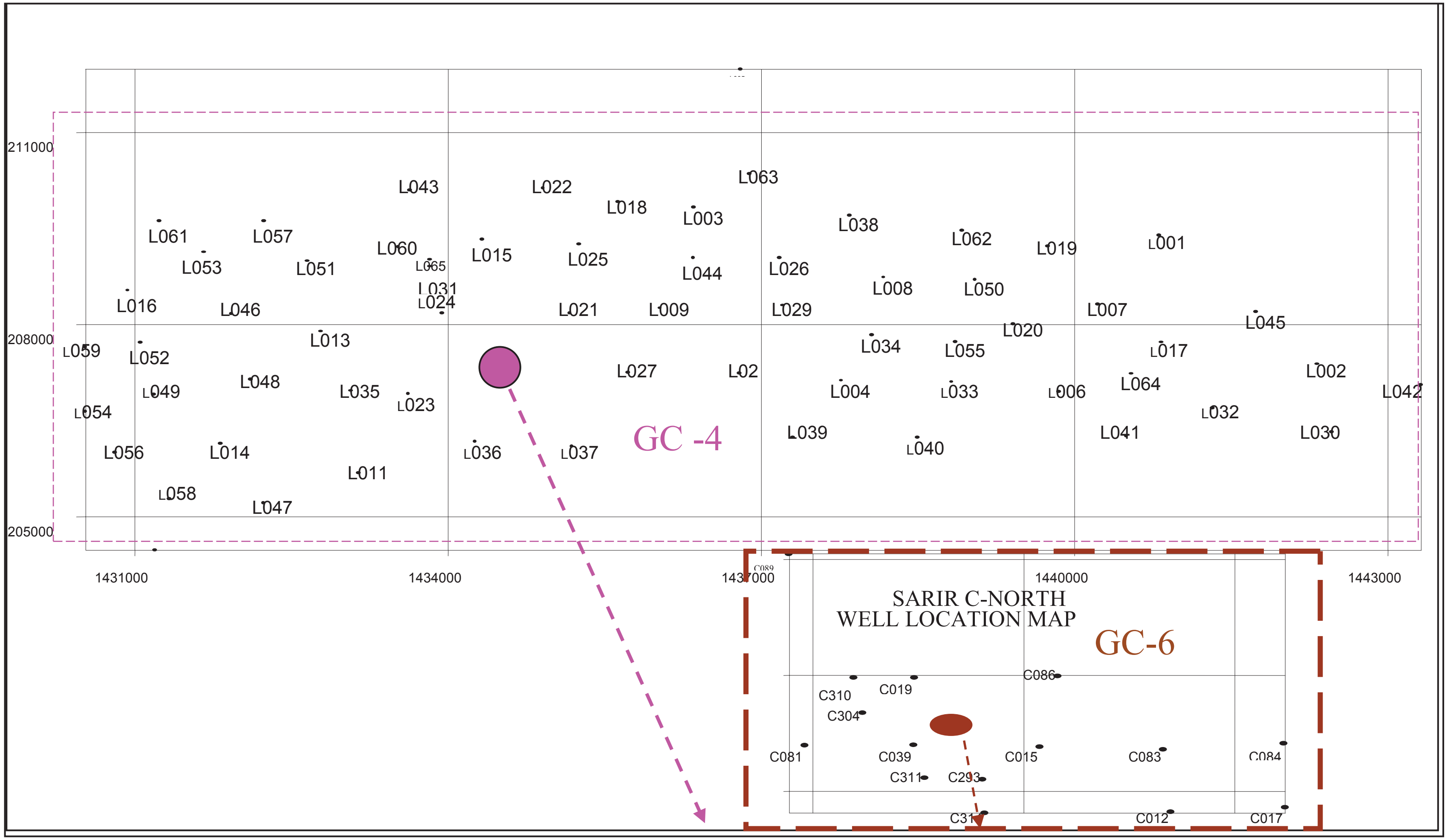


Figure 2-2: Map of GC-4 and GC-6 [26]

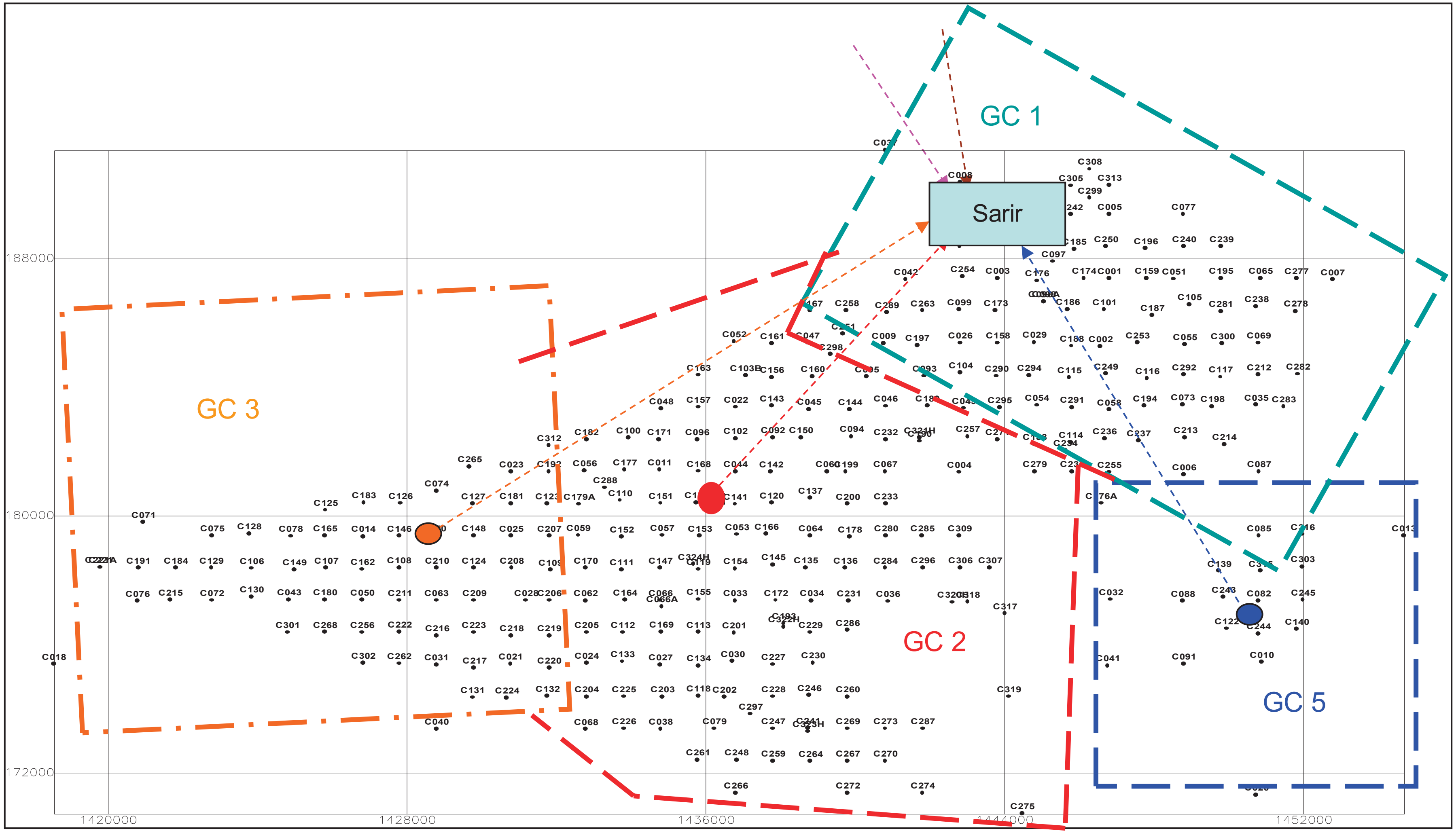


Figure 2-3: Map of GC-1, GC-2, GC-3 and GC-5[26]

2.4 Sarir Field Conditions

Sarir field is a sandstone reservoir produces light crude oil (API 37) gravity. The oil has a low GOR, and no appreciable CO2 and H2S content; therefore, ESP's are used to produce this reservoir. Original reservoir pressure was 3,900 psi and the reservoir temperature is 220-225 F°. **Table 2-2** presents the average Sarir field laboratory PVT data. The average reservoir thickness is approximately 275 ft. An excellent aquifer underlies the oil column. The sandstone reservoir is very friable and sanding problems were noted in several wells. To mitigate sanding problems, one well was gravel packed. Most oil producers in this field are cased wells. A Y-tool is installed in some wells to enable access to the reservoir section for logging or remedial operations. A hydraulically set, retrievable production packer, which allows access for power and instrument cables in some leaking wells, this equipment is employed in wells that have 7" casing and with a casing leak that is either very large or very long so that either a casing patch or cement squeeze is impractical. [26]

Table 2-2: Average Sarir Field Laboratory PVT Data [26]

Reservoir and Fluid properties	Values	Number of Measurements
Volume Formation Factor Bo (BBL/STB)	1.14	3
Gas Specific Gravity (Sp.Gr.)	0.95	2
Gas Oil Ratio (GOR) SCF/STB	150	3
Stock Tank Oil Density (gr/cc)	0.84	3
API°	37	3
Reservoir Oil Density @ 225F° and 3000 psi.	0.76	-
Bubble Point Pressure (psia)	534	13
Oil Compressibility (10^{-5}/psi)	0.724	10
Oil Viscosity (Cp)@ 3000 psia and2000 psia	1.9 & 1.74	10
Water Salinity (ppm)	198000	-

2.5 ESP Monitoring Field System

The first step taken to optimize submersible pumping system in the Sarir field was the implementation of a comprehensive monitoring system. The system included well site monitoring, control equipment, detailed failure investigation, and documentation.

Well site ESP monitoring and control, was performed by an advanced motor controller that provided more information and protection than standard motor controllers. In addition to providing protection against under voltage, voltage unbalance, phase reversal and excessive starts the controller retained the cause of last pump shutdown. For example COSCO VSB111controller logs the last 5 shut downs but not the time and the REDA K095 controller records many more than this and the time and date that they occurred. We were trying to set up the IMPAC cards so that each high line feeder could be monitored for voltage fluctuations, phase imbalance as well as the current being drawn by the motor as each high line failure was causing pump failures We usually had the recording on the IMPAC card stop on pump shut down so we could investigate if power fluctuations just before the power shut down had caused the pump failure. There is of course no point in monitoring the start-up with the IMPAC as the controllers have a time delay built in and check for power stability before allowing the ESP to start IMPAC cards can only be installed on REDA switchboards or boards that have been retrofitted with a K095 controller. This allowed the cause of the shutdown to be recorded by the field operator on the pump's amp chart so a chronological record of individual and field wide shutdowns could be made. This also allowed shutdowns to be correlated to any operating problems that were evident on the amp charts or the IMPAC card. It is very important to have the correct CT Ratio set up when starting any ESP for the first time. It should be set so that normal running amps yield a line in the middle of the chart. They are also of assistance on problem wells as the chart time can be switched to 24 hour from 7 day [26]

Pump failure investigation and documentation was carried out by a company supervisor (ESP Group) and a manufacturer technician during the Workover to change out the failed pump as well as by the pump supplier during teardown. A detailed submersible pump pull report was made in the field that documented electrical measurements and physical observations made by the company technician.

These reports were compared to pump supplier teardown reports so that the cause of the failure could be determined. The failure of one component in the system often causes another component to fail (e.g., a failed protector allows wellbore fluid flow into the motor which in turn causes the motor to burn out and possibly in severe cases the pothead to blow).

2.6 Sarir Field ESPs Failure Mode

The failure mode is the main evidence of the downhole equipment failure. It is usually a result of an abnormal operating condition identified by the operator through surface instruments, a monitoring/control system, or a well test. A failed mode can be established once the operator has determined that the downhole equipment has “failed”. Usually, a pull is required to repair or substitute the downhole equipment [27]

The information collected on the 350 ESPs in Sarir field from 2001 to 2008 yields the following data. In the screening process, some figures were prepared to show ESP failure mode during this period and also the number of failures compared to the number of installations on a yearly basis. The **Figure 2-4** and **Table 2-3** show the Sarir field ESPs failure mode during the period from 2001 to 2008, quantifying the percentage, number of failures and the failure mode. The most interesting aspect of this figure and table is the very high percentage of failures attributable to motors and cables. Also **Figure 2-5**details the number of installations in the Sarir field and shows the total number of ESPs pulled during the 8-year period [26]

Run times for ESP installations are a function of bottomhole temperatures, solid content of produced fluids, corrosion, gas/liquid ratio (GLR), power quality, and effectiveness of transient-power protection devices. An industry standard by which to compare run times is unavailable; however, in hostile ESP operating environments, a run time of 365 days can be satisfactory [28]

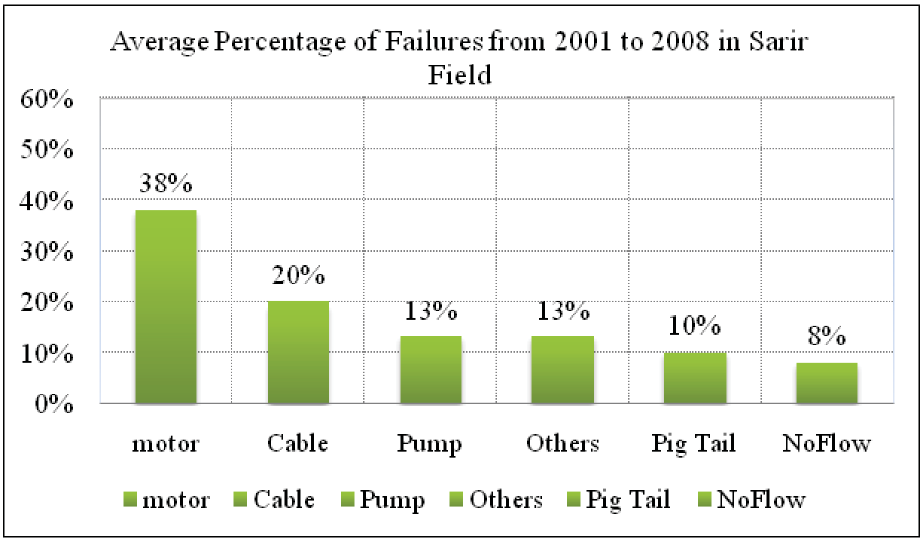
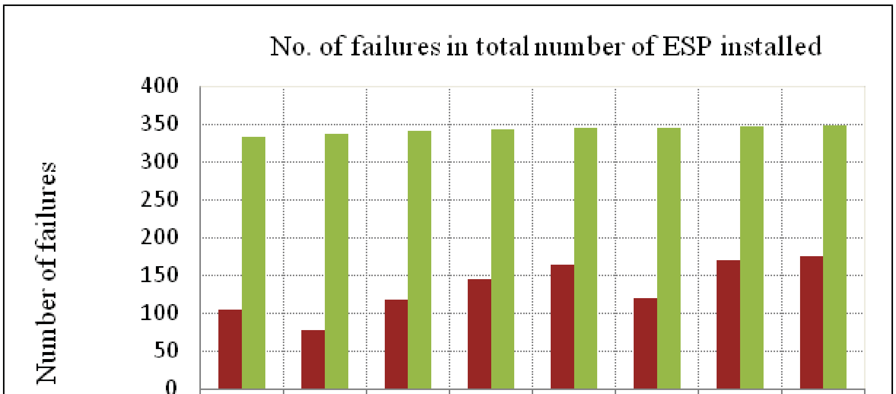


Figure 2-4: ESP –Failure by Category in Sarir Field [26]

Table 2-3: Sarir Field ESPs Failure Mode[26]

Failure Mode	2001	2002	2003	2004	2005	2006	2007	2008
Motor	40	34	42	46	78	50	50	60
Pump	7	12	18	23	17	20	22	15
Cable	20	13	17	30	41	15	38	50
Pig Tail	3	2	10	20	15	10	22	35
No Flow	11	2	10	18	4	10	15	8
Others	23	15	21	8	10	16	24	8
Total Failures/Year	104	78	118	145	165	121	171	176



	2001	2002	2003	2004	2005	2006	2007	2008
No. Failures	104	78	118	145	165	121	171	176
Cumul. No.	334	338	341	343	346	346	348	350

Figure 2-5: Number of Failures in Total Number of ESP Installed [26]

2.7 Failure Analysis

The data gathered by the Sarir ESP monitoring system showed that severe high line voltage fluctuation was the primary cause of the frequent submersible motor failures. The majority of pump failures are expected to be mechanical when operating in harsh environments (sand, scale, and H2S). However, between 2001 and 2008, 71% of the Sarir ESP failures were classified as electrical in nature. These failures were found primarily in motors (38%), cables (20%) and in pumps (13%). The cause of the electrical failures was contributed to the following:

- Careless handling of electrical cable during pulling and running operations,
- The power supply which results in electricity-consuming devices to malfunction or fail. Power supply can affect many types of equipment of the facility, especially electronic equipment. ESP down hole and surface equipment might be damaged or fail prematurely if they are not protected from harmful voltage changes and related disturbance.
- Shutdown and start-up of units due to production demand.

The following field wide changes were made to improve power quality and reduce the frequency of electrical failures in Sarir ESPs,

2.7.1 Cable Repair

On arrival of a reel of used cable at the cable shop, the cable is spooled to another reel and visually inspected. The cable is also checked electrically at this time phase to phase and phase to ground. Cable failures are located with a thumper so that they can be cut out and the section replaced with good cable. On completion of the inspection and repair, the cable is subjected to the "high pot test". If the cable satisfactory passes this test, the reel of cable is immersed in a tank of water. The cable is again subjected to the "high pot test". Ohm-meter readings are taken to determine the phase to phase and phase to ground readings. If acceptable, the cable is placed on the ready line.

2.7.2 Power Supply

Initially electric power was provided by diesel engine generating units. In the late 1980's a main 33 KV line was run from nearby field (Messla), and an 11KV distribution constructed through out the field. And current study is carrying on to install Turbines in the Sarir field to avoid the power fluctuating and the start-up problems with the high line.

2.7.3 Downhole Sensors

They are installed to improve the quality control of the ESPs.

2.8 Production Overview

Figure 2-6 and **Figure 2-7** show historical Production rates and bottomhole pressures for C-main, Sarir field recorded for the producer wells between the years 1967 and 2008.

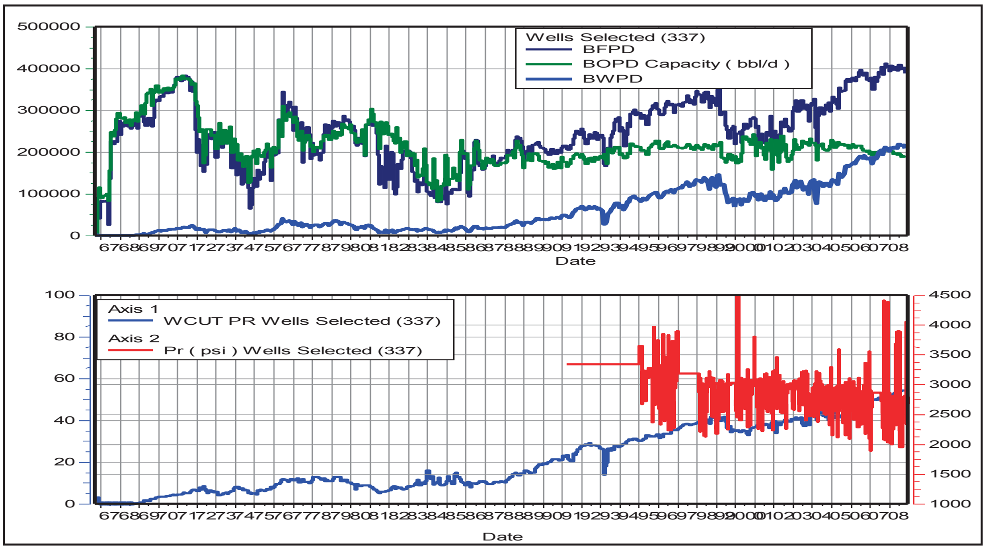


Figure 2-6: Production Performance Plot Of C-Main , Sarir Field[26]

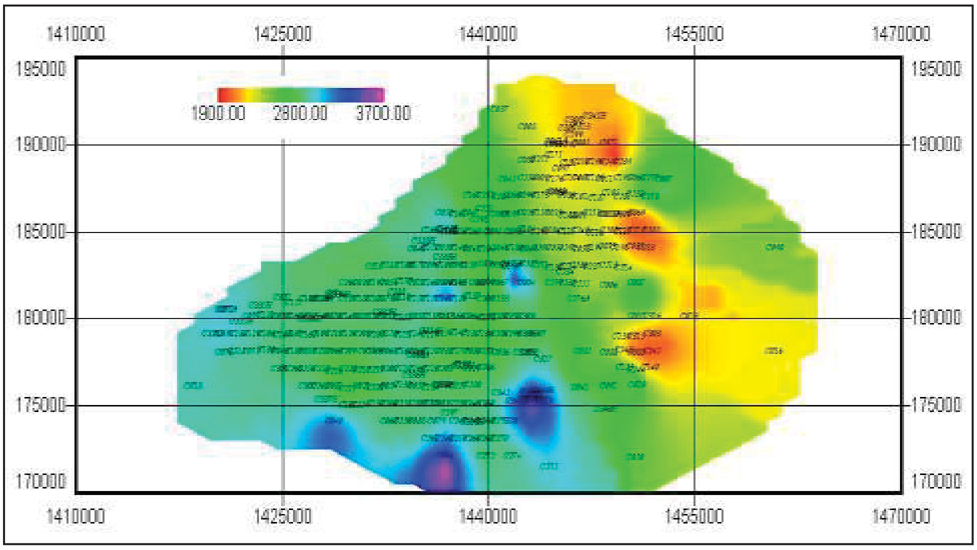


Figure 2-7: Reservoir Pressure C-main, Sarir Field, 2008[26]

CHAPTER 3: Overview of the Electrical Submersible Pump System

3.1 Introduction

The electrical submersible pumping was invented and developed by a Russian named Armais Arutunoff in the late 1990s [1] .In 1911, Arutunoff started the company Russian Electrical Dynamo of Arutunoff (its acronym REDA still being known all over the world). The electrical submersible pump is one form of artificial lift system which is heavily in use in company's oil wells, others being beam pumps, gas lift and progressive cavity pump to lift large volumes of fluids from great depths under a variety of well conditions. The typical submersible pumping unit consist of an electric motor, seal section, intake section, multistage centrifugal pump, electric cable, surface installed switchboard, junction box, and transformers. Optional equipment may include a pressure sensor for sensing bottom hole temperature and pressure as well as check, and bleeder valves. The submersible pump is also used in producing high viscosity fluids, gassy wells, and high temperature wells.

The electric motor turns at a relatively constant speed and the pump and motor are directly coupled with a protector or seal section in between. The motor and pump rotate at 3,475 to 3,500 rpm for 60 Hz power and 2,900 to 2,915 rpm for 50 Hz power. Power is transmitted to the subsurface equipment through a three-conductor electrical cable strapped to the tubing on which the unit is run into the well [1]

The system's surface equipment includes transformers, a switchboard, junction box and surface power cables. Power passes through a cable running from the transformer to the switchboard and junction box, then to the wellhead. A typical submersible pump installation is given in **Figure 3-1**

The pump performs at highest efficiency when pumping liquid only. It can and does handle free gas along with the liquid. The unit is a precision-built piece of equipment and, under normal operating conditions, can be expected to give from 1 to 3 years of good operating life with some units operating over 10 years. Electrical pumping is becoming more popular and is presently being used in a greater percentage of the wells that are need artificial lift methods. In particular it is well suited for offshore applications [1]

Continued improvements that elongate the running time will make the electrical pump more and more attractive. Practically all of the present installations are tubing retrievable to replace the pump; however, the cable suspended unit (CSPS) is being manufactured and is presently installed in some areas [1] , [2]

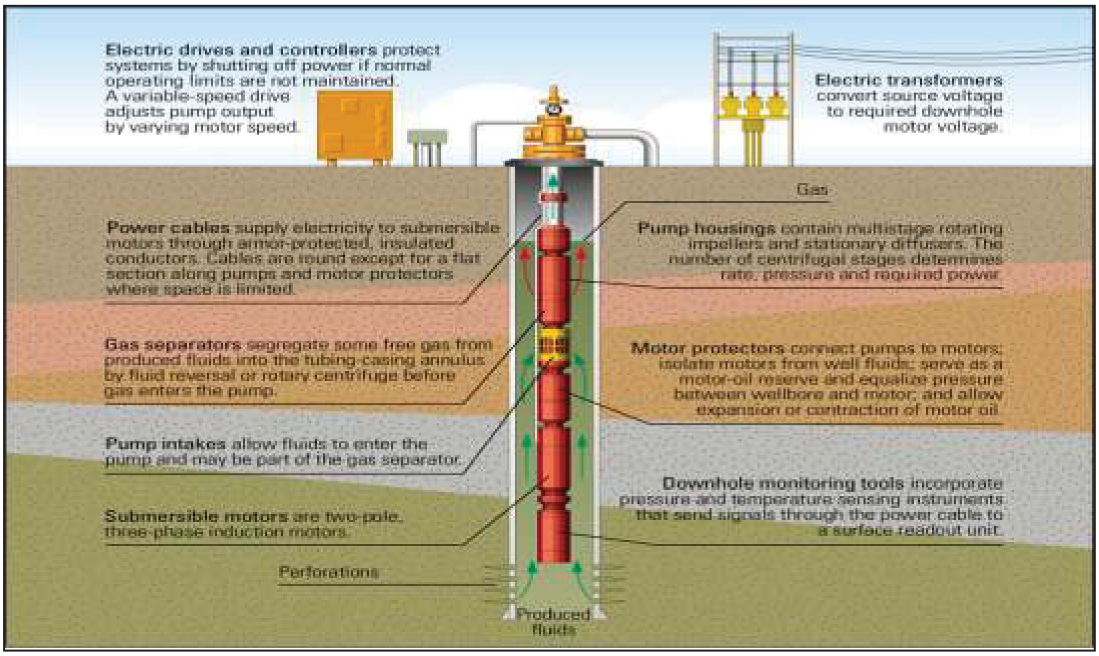


Figure 3-1: Atypical Submersible Pump Installations [3]

3.2 Components of an ESP System

3.2.1 Impeller / Diffuser

Submersible pumps are multi-staged centrifugal pumps; each stage consists of rotating impeller and stationary diffuser. Pressure- energy change is achieved as the liquid being pumped surrounds the impeller, and as the impeller rotates it gives a rotating motion to the liquid.

Smaller flow pumps are generally centrifugal flow design, as flow rates increased, design of impeller changes to mixed flow.

The energy imparted to the fluid is determined by the configuration and diameter of the pump impeller. Impeller outside diameter is limited by the internal diameter of the pump housing while well casing inside diameter effects pump housing diameter. Another limitation for the impeller internal diameter is the outside diameter of the shaft, must be strong enough to transmit power to all stages [4] , [5]

3.2.2 Electrical Submersible Motor

ESP motors are three-phase, two pole, and squirrel cage induction-type. They filled with highly refined nonconductive oil. The motor is made up of rotors mounted on a shaft and located in the electrical field within the housing electric motors.

A group of electro-magnets come together to form a hollow cylinder with one pole of each electro- magnet facing toward the centre. This group of electro-magnets is called stator. The motor is often referred to as the heart of an ESP system because if the motor stops, everything stops. Also when something goes wrong with the motor it normally changes from a state of operating correctly to completely unusable. Next to the pump, the motor is the second most important item in the ESP system. Motor selection is based on expected pump loading and possible pump loading. It involves looking into the future to changing well conditions and if a VSD is used it often needs to be oversized to handle higher frequencies. However, there is a point where installing a motor that is too large is detrimental to both the motor life and the efficiency of the ESP system.

Motors come in single, upper, centre and lower tandem sections. The diameter varies and this can have a large impact on the cooling of the motor.

The general rule of thumb is that well fluid needs to move past the motor at a speed of 1 ft/s or 0.3 m/s to ensure proper cooling occurs; however, most ESP design software calculates motor cooling [4] , [5] , [7]

These motors run at a relatively constant speed of 3500 rpm on 60-Hertz frequency and 2,915 rpm on 50 Hertz frequency. The thrust bearing of the motor carries the load of the motor’s rotors. The nonconductive oil in the motor housing lubricates the motor bearings and transfers heat generated in the motor to the motor housing. Heat from the motor housing is, in turn, carried away by the well fluids moving past the exterior surface of the motor. Motors should never be set below the point of fluid entry unless some means of directing the fluid by the motor is utilized. The motor is the driving force (prime mover), which turns the pump as illustrated in **Figure 3-2**

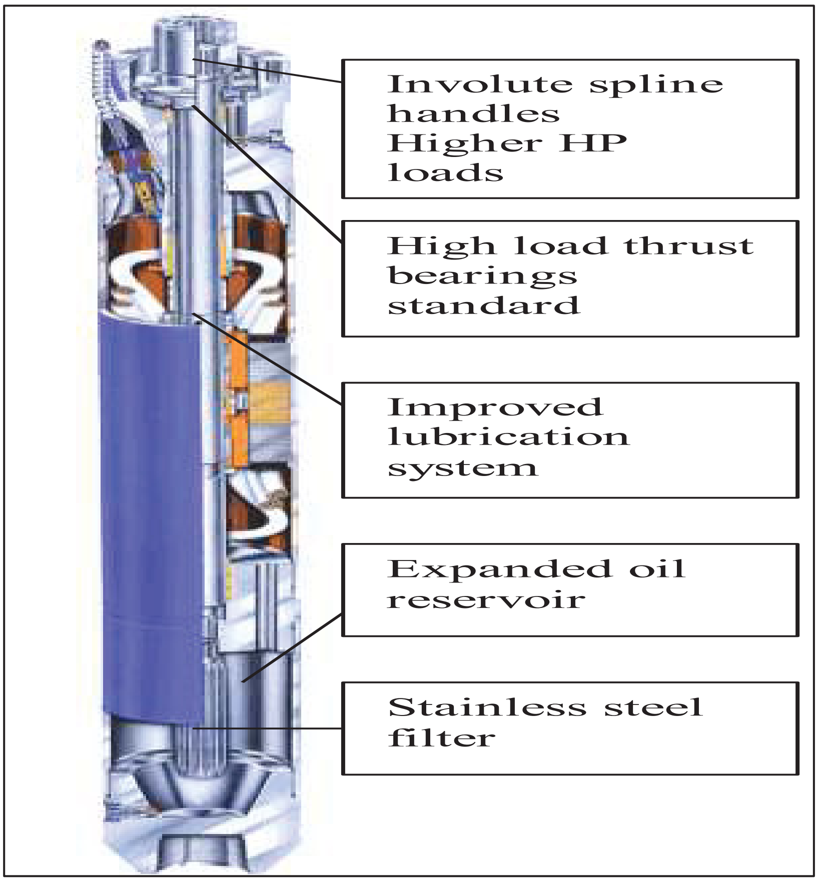


Figure 3-2: High Efficiency Motor [7]

3.2.3 Equalizer Section (Seal Assembly)

The equalizer section is placed between motor and pump's shaft or gas separator shaft as shown in **Figure 3-3**. It allows to the expansion of the dielectric oil contained in the rotor cap of the motor. The temperature rise resulting from the environment and motor will result in expanding the dielectric oil. Seal assembly takes this expansion.

The seal is sometimes referred to as a protector and has 5 main functions:

- Equalize the pressure in the motor with that of the wellbore
- Prevent well fluid from getting into the motor
- Provide a reservoir for the motor oil to expand and contract
- Provide a thrust bearing for down thrust loading
- Transmit the torque from the motor to the pump

When designing the seal the size of the pump, type of well fluid, size of motor and deviation of the well need to be taken into account. These will not only determine metallurgy, shaft size and thrust bearing size, but determine the type of the protector, which could be:

- Labyrinth Style
- Positive Seal (Bag) Type
- Metal Bellows Type

With the above designs there are elastomer considerations that will determine the type of well bore fluids and temperatures each of these can handle [1] , [5]

Figure 3-3: Modular Protector [8]

3.2.4 The Centrifugal Pump

The pump as shown in **Figure 3-4** is the most important item in the design of the ESP and should be selected based on reservoir conditions. It is from the pump that all other items in the ESP are designed. If the incorrect pump is selected, the design of the ESP can never result in the lowest over all operational cost .Submersible pump is multi-staged centrifugal pump. Each stage consists of a rotating impeller and a stationary diffuser.

The number of stages will determine the volumes of fluid to be produced, total head generated and the horsepower required .The geometry of the stage will determine the production range [1] ,[2] ,[8]

Once the stage type and number of stages has been selected the following needs to be considered:

- Stage Type (Radial, Mixed or Axial)
- Stage Material (high nickel, high chromium, heat treated, etc.)
- Bearing Selection (bronze, ceramic, tungsten carbide, silicon carbide, etc)
- Bearing Spacing (Head and Base, Every x stages, Every stage)
- Shaft Material (Monel, Inconnel, etc)
- Housing Material or Coating (Carbon Steel, Ferretic Steel, Stainless Steel)
- Pump Construction (Floater or Compression)

The pump moves the fluid to surface and if any of the above are not designed to match the reservoir the operational cost will not have been optimized.

The flow rate of a submersible centrifugal pump depends on the following operational parameters:

- Speed of rotation,
- Size of impeller,
- Impeller design,
- Number of stages,
- The total dynamic head against which the pump is operating, and
- The physical properties of the fluid being pumped.

Figure 3-4: High Efficiency Pump [8]

3.2.4.1 Pump Performance Curves

In selecting a pump for a particular application, we must look carefully at its performance or test curves, which typically chart of three different aspects of performance: head versus pump capacity, motor horsepower versus capacity and pump efficiency versus capacity (**Figure 3-5**: ESP performance curve. Courtesy Schlumberger-Reda)

These curves are published by pump manufacturers for each of their individual pump types—the ones shown in (**Figure 3-5**), for example, are for a 100 stage, Schlumberger-Reda D1350 pump. 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, performance curves are drawn showing head, pump efficiency, and brake horsepower for a specified number of pump stages, as a function of pump throughput rate.

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[1] ,[2]

Pump performance curves are normally published for either a single pump stage or, as was done in **Figure 3-5**, for 100 pump stages.

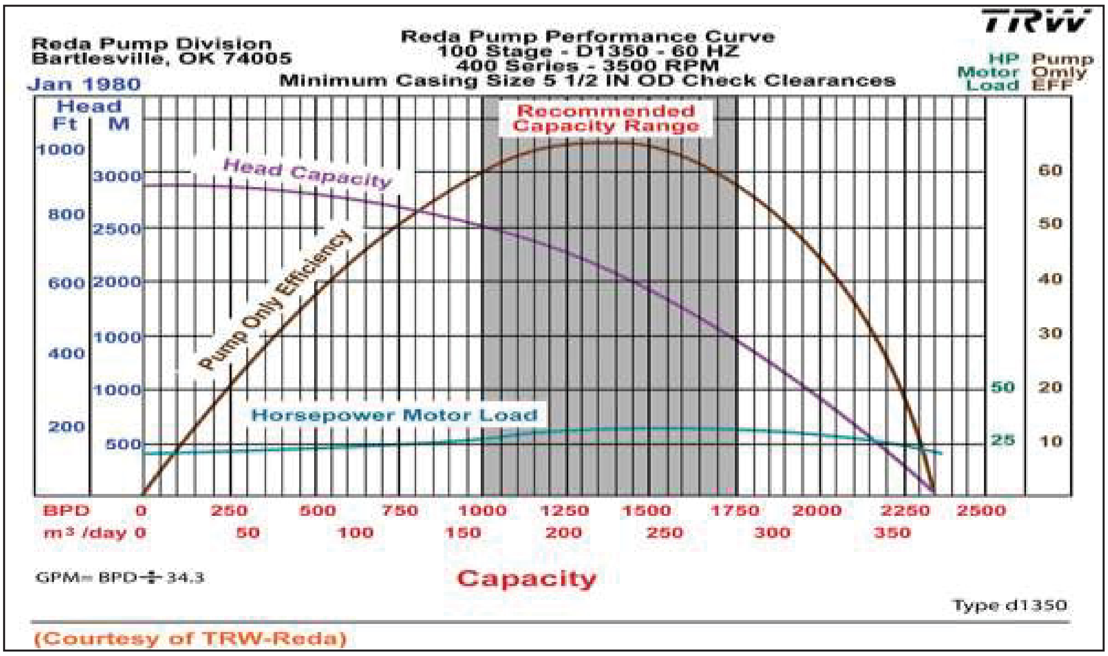


Figure 3-5: Pump Performance Curve, Courtesy Schlumberger-Reda [9]

3.2.5 Pump Intake (Gas Separator)

There are two types of pump intakes: the standard intake and the gas separator intake. When the free gas or GLR is less than 10% the standard intake is used, and the pump performs normally. As the gas increases, the pressure is reduced and the pump will eventually “gas lock”.

The construction of a standard intake only needs to consider bearing selection, shaft material and housing material. If free gas is present the design of the intake can radically change to be gas separator as show in **Figure 3-6**.

Radial impellers can handle up to 10% free gas and mixed flow impellers can handle up to 20% free gas without a special intake. However, once those levels are exceeded the possibility of gas locking exists. When gas locking occurs, the production from the ESP will drop to zero instantly and the ESP will shut down.

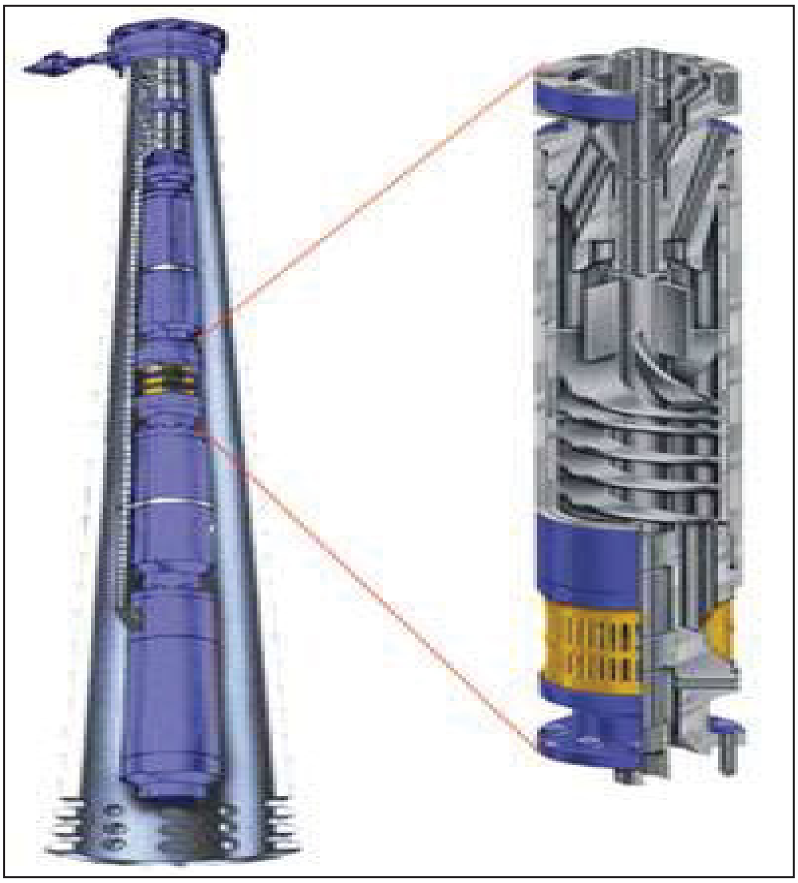


Figure 3-6: Centrifugal Gas Separator [8]

This is a situation where correct design could improve production. If production up the annulus is possible static and rotary gas separators can be considered. If flow up the annulus is not possible gas handling devices that blend the fluid to prevent gas locking can be considered. With various combinations of devices up to 70% free gas down hole can be produced with an ESP [1]

3.2.6 The ESP Power Cable

Electric power from the surface is transmitted to the submersible motor through a special three – phase electric power cable leading from the surface to the motor connection. This cable must be small in diameter but well protected from mechanical abuse. The cable provides power to the motor and the gauge. If the cable is damaged prior to or during installation, run life will be reduced. The cable is made up of conductors, insulations, barriers, jackets and armor. It can be made in round or flat profile. In addition, 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 adhered to, the run life will be compromised [1] ,[2]

3.2.7 Miscellaneous Down Hole Equipment

3.2.7.1 Cable Bands

They are used to strip the power cable to the production string to avoid the mechanical damage of the tubing during running and pulling operation. The recommended distance between cable bands is 15 ft [1] ,[2]

3.2.7.2 Flat Cable Guards

They are used along the ESP equipment to protect the flat cable from mechanical damage by firmly fixing it to outside of the ESP components. They come in 18 in. and use to cover all MLE cable [1] ,[2]

3.2.7.3 Check Valve

It is usually installed about 2 to 3 joints above the pump to maintain a full liquid column in the tubing string during equipment shutdown periods. It is used to prevent leaking of the fluid from the tubing down through the pump when the pump is not running. Fluid flowing through the pump would result in reverse rotation of the subsurface unit when motor is shutoff. If check valve is not installed a leakage of fluid down the tubing through the pump occurs, which can be resulted in a motor burn, cable burn, or broken shaft [1]

3.2.7.4 Bleeder Valve (Drain Valve)

Whenever a check valve is used in the tubing string, it is necessary to install a bleed or drain valve directly above the check valve to prevent pulling a wet tubing string [1]

3.2.7.5 Centralizer

Especially in deviated wells to eliminate damage and obtain the proper cooling of the equipment. And also it is used to place the motor and pump in the centre of the wellbore. It also uses to prevent rubbing of power cable against the casing string.

3.2.7.6 Y-Tool

The Y-tool application is designed to allow access to the reservoir with an ESP in the well by including a by-pass tube and hanging the ESP off to the side of the main tubing string. With a Y-tool perforations can be added, logs can be run – it is even possible to run a spinner survey with the ESP in operation. The standard Y-Too involves the use of plugs to prevent recirculation while the ESP is in operation, but there is also an auto Y-tool which uses a flapper to control the flow path automatically [1]

3.2.8 Surface Equipment

3.2.8.1 Electric Power Supply

For an efficient operation, it is necessary to have a dependable uniform power supply.

The three basic supplies are:

- Lease generation equipment.
- Local Power Company.
- Microturbine installation

- **Microturbine Overview**

Microturbine is the newest technology to use associated gas for generating electric power and thermal energy. For many oil- production operations, economical and high-quality Microturbine electricity can provide all the power needed onsite to run pumps, blowers, compressors, and lift systems. Excess electric generation can often be exported for profit to a nearby power consumer looking for an economical, reliable, and price-stable source of energy. And heat recovered from the Microturbine can offset energy costs in the oil/ water separation process or other field processes using heat [37] [38]

While providing power savings from associated gases, microturbine eliminates harmful venting and flaring, abates noxious odours, destroys volatile compounds, and substantially reduces greenhouse emissions to below current and proposed regulations. In some locations, the clean burning microturbine can reclaim stranded assets by making them economically productive while complying with current air-quality regulations.

And unlike ancillary emissions-clean-up equipment, microturbine with a black-start capability option continues to abate exhaust emissions if the grid goes down.

The clean-burning microturbine resolves the many problems that have prevented the use of associated gas as a fuel and prevented the utilization of stranded gas assets. Unlike a reciprocating engine generator, the microturbine is similar to a large turbine generator and is designed for continuous operation with minimal routine maintenance, high reliability, and a long service life.

The microturbine energy generated and consumed on site directly reduces the amount of electric power purchased to operate oil-producing equipment. Microturbine can power various types of pumping systems including beam pumps, progressing cavity pumps, submersible pumps, and surface transfer pumps, as well as blowers for steam generators and other electrically driven equipment. And the cogenerated thermal energy recovered from the microturbine engine can preheat the hot air and hot water used to increase recoverable oil or be used in the oil/gas separation process.

Most onsite microturbine energy systems are sized to consume all the associated gas produced or all the onsite power needed. Single or multiple microturbines can be configured to match any capacity from as little as 70 kilowatts (kW) up to several megawatts (MW).

To further combat the harmful effects of air pollution and climate change, several states are proposing to dramatically lower permitted NOx emissions for distributed generation equipment. Some improved flaring systems do reduce greenhouse-gas potency to acceptable levels, but they are both costly and waste all the energy value of the gas.

Microturbine operating on associated gas produces useful energy while emitting extremely minimal amounts of harmful NOx, CO, and CO2— well below those generated by flaring [37] [38]
And the high-temperature gas path of the microturbine effectively destroys many odours and contaminants.

Microturbine can generate power from fuel sources such as:

- Casing gas from oil production
- Condensate gas from liquid processing
- Gas too rich or too lean to meet pipeline standard

- Sour gas with H2S- up to 7%

Benefits of microturbine in oil and gas industry

- Low Installed Cost
- Short Commissioning Period
- Easy Interconnects to Local Grid
- Very Low Maintenance
- Ease of Operations
- No Lubricants or Coolants
- Small Footprint, Light Weight
- < 65dBA Acoustic Emissions
- Ultra-low NOx emissions with no post-combustion devices or chemicals
- Accepts 350-2500 Btu w/up to 7% H2S

3.2.8.2 Transformers

The available surface voltage is not compatible with the required motor voltage .Transformers must be used to provide the right voltage level on the surface. The distribution of electric power to the oil fields is usually accomplished at an intermediate voltage such as 6,000 volts or higher. Since ESP equipment operates at voltages between 250 and 4,000 volts, transformation of the distribution voltage is usually required. Oil immersed self-cooled (OISC) transformers are used in land-based applications. Dry type transformers are sometimes used in offshore applications that exclude oil-filled transformers [1]

3.2.8.3 Switchboard

The switchboard is the control centre of a conventional ESP installation and acts as a motor controller to provide overload and under load protection .Protection during under load, a condition where the pump is not displacing its design volumes, is needed because low flow rates will not allow adequate cooling of the motor. Protection against overload, a condition where excessive amperage flows through the motor, is needed to prevent the burning of the motor windings. Additionally the switchboard may be used as an adjustable time, automatic restart control [1] ,[4] The switchboard can also be used to record amperage on a continuous basis using typically a 24-hour chart or weekly chart, it is called ammeter chart. These ammeter charts can helps to determine causes of failures and give an indication of well and pump performance.

The main basic components of the switchboard are:

- Main switch
- elector switch
- Fuses
- Potential transformer
- Overload relays
- Under load relays
- Ammeter chart recorder
- Current transformer

3.2.8.4 Junction Box

A junction box or sometimes called vent box performs three functions:

- Provides a point to connect the power cable from the switchboard or controller to the power cable coming from the well.
- Provides a vent to the atmosphere for any gas that might migrate up the submersible power cable.
- Provides easily accessible test points for electrically checking the downhole equipment.

The junction box should be located at least 15 ft from the well head and should be located at all times for security reasons [1]

3.2.8.5 Wellhead Assembly

The wellhead must be equipped with a tubing head pack-off which provides a positive seal around the cable and the tubing. There are several different methods available from wellhead manufacturers for providing this pack-off.

The ESP wellhead or tubing support is used as a limited pressure seal High-pressure wellheads, up to 3,000 psi, use an electrical power feed to prevent gas migration through the cable. Wellheads are manufactured to fit standard casing sizes from 4.5 to 10 ¾ in [1] , [2]

3.2.9 Optional Equipment

3.2.9.1 Downhole Pressure and Temperature Monitor

Downhole ESP monitors are very beneficial for optimizing production and maximizing the run life of an ESP. Valuable reservoir and pump performance data is available with the use of downhole pressure and temperature monitoring system. By correlating reservoir pressure with the withdrawal rate, an operator can determine when to change pump size, change injection rate, or consider well workover.

There are different types of downhole pressure and temperature sensors available from submersible pump suppliers. This system has the capability of continuously monitoring bottom hole pressure and temperature at the pump's setting depth, and of detecting electrical failures, such as shorts to ground.

The system requires no special wires. All signals are sent to the surface instruments over the regular power cable [1] ,[4]

3.2.9.2 Variable Speed Drive (VSD)

Another option for changing the capacity of an electric submersible pump is to install a surface device that can change the voltage frequency supplied to the motor. This device is referred to as a variable frequency generator (VFG), variable frequency drive (VFD) or variable-speed drive (VSD).It is used instead of the standard 50- or 60-Hz motor controller at the surface.

As an example, a VFG may be rated at 300 KVA with a frequency range of 36 to 90 Hz. Because the motor speed is proportional to frequency, and the pump speed is equal to the motor speed, a variable speed generator allows the pump to operate at a speed above or below its rated capacity at 60 or 50 Hz. There is an upper limit, though, on pump speed variability. This limit is at the amperage overload condition of the downhole motor. Subject to this limit, a variable frequency generator can be used to increase or decrease pump rates by as much as 20% to 30%, to satisfy changing inflow performance. If greater changes are required, a resizing of the pump will be necessary.

Variable frequency generators and variable-speed drives can also provide soft-start protection. Using a VSD to control a pump motor can reduce the strain on the pump shaft and reduce pump damage by slowly "ramping-up" the motor speed. A number of operating procedures have been developed to make the electrical submersible pump more versatile in its application to a specific well or field. However, the best approach is to carefully design and select a pump for each well based on its own characteristics and assume that the pump will operate continuously[1] , [13] ,[14] ,[15]

3.2.10 ESP Application

3.2.10.1 Shroud Pumping System

Shroud allows the pump to be set below the perforations or producing formation for cooling the motor due to the heat generated by motor operation is transferred to the well fluid as it flows past the motor housing. A minimum fluid velocity of 1 ft/sec is recommended to provide adequate cooling. Because the motor relies on flow of well fluid for cooling, a standard ESP should never be set at or below the well perforations or producing zone unless the motor is shrouded [1] , [4] , [5]

A shroud as shown in **Figure 3-7** can serve two purposes:

- Direct fluid past the motor for cooling.
- Allow free gas to separate from the fluid before entering the pump intake.

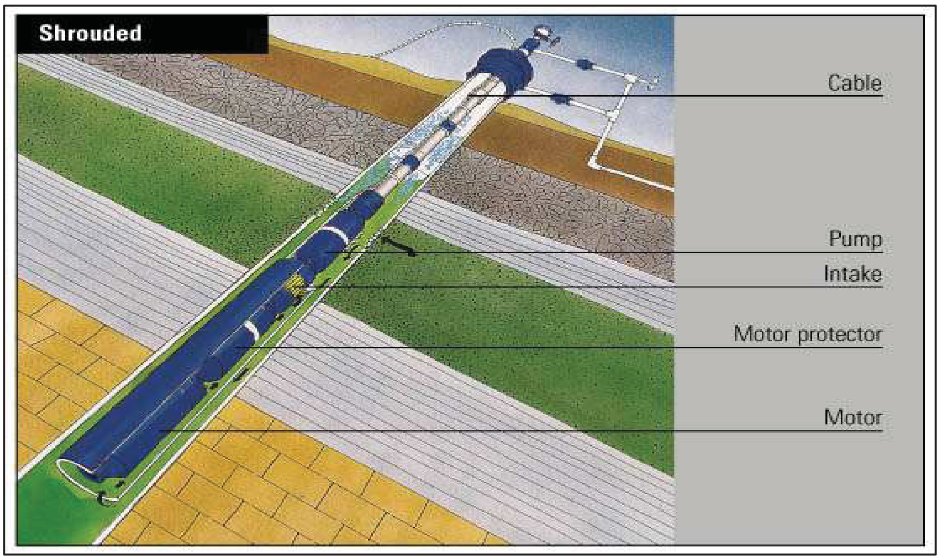


Figure 3-7: Shroud Pumping System [10]

3.2.10.2 Dual ESP Installation

Figure 3-8 represents the installing of two ESPs into one well. This may at first seem extreme, but the practice is becoming more common [1] , [8]

There are four reasons why two ESPs would be installed in one well:

- High Rate - each pump produces half the rate to allow for higher production
- High Head – the lower pump produces into the upper pump
- Redundancy – each pump could produce the well independently
- Zonal Isolation – two zone can be produced with separate ESPs

The most common of the above is achieving redundancy. When one ESP fails the second can be used to allow production to continue without delay or the need for a workover. This will only be economically attractive in situations where workover costs are high, rig delays are long or well access is periodic.

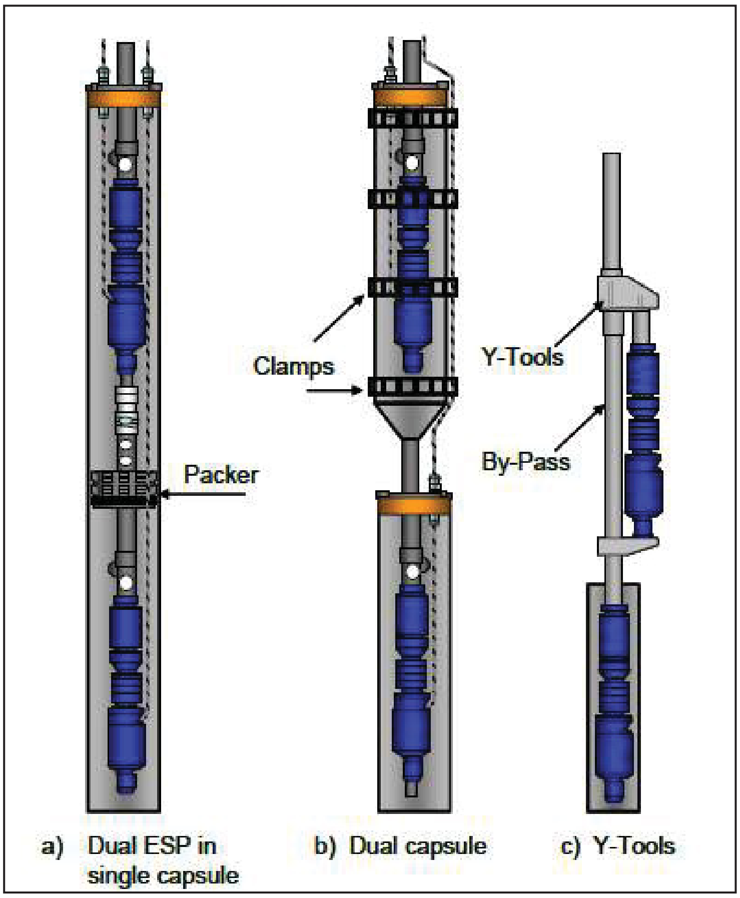


Figure 3-8: Dual ESP Installation [8]

3.2.11 Electrical Submersible Pump Problems

3.2.11.1 Pump Failures

Submersible pumps run under harsh conditions and are subjected to damaging effects of well stream. Most the pump failures are caused by these reasons [1] , [4] , [5]

- Up thrust wear occurs when the pump is operated at flow rates greater than the maximum recommended pump rate
- Down thrust wear occurs when the pump is operated at flow rates lower than the minimum recommended pump rates
- Radial wear is caused by well fluid laden with abrasive material
- Erosion in pump stages in pump stages occurs when abrasive-laden fluids are produced and can cut through the pump housing
- Scale build up can plug or even lock pump stages

3.2.11.2 Motor Failures

Excessive motor overload failure: High specific gravity of the well fluid, undersized motor from poor data, irregular voltage at the motor terminals.

Seal section leak: Allows well fluid to enter motor fluids causing a gradual contamination of the motor oil and motor burnout.

Insufficient fluid movement: Generally 1ft /sec fluid velocity by the motor recommended for cooling. Lower velocities can cause increasing internal temperature which can result in serious motor failures [1] , [4] , [5]

3.2.11.3 Protector (seal section) Failures

Protector failures are caused by the following factors [1] , [4] , [5]

- Broken or damage the mechanical seal which leads to leak the well fluid to the motor
- Vibration transmitted from the a worn pump
- Defective equipment or unsuitable installation
- The ESP unit's main thrust bearing located in the protector might fail as soon as the pump operates in great up- or down thrust mode.
- Labyrinth-type protectors might fail in deviated (more than 30 degrees from the vertical) well sections.

3.2.11.4 Rotary Gas Separator Failures

Rotary gas separators may fail because of internal abrasion due to the great centrifugal forces acting on the solid particles when sand-laden well fluids are produced. Cutting of the separator housing can happen if no special abrasion resistant materials are used [1] , [4] , [5]

3.2.11.5 Cable Failures

During the running or pulling processes mechanical damage can occur as a result of crushing, stretching or cutting. High temperature, high pressure gas or corrosion can deteriorate the cable. Excessive current results in breaking down the insulation [1] , [4] , [5]

3.2.12 Ammeter Chart Analysis

One of the most valuable tools available to the field service technician for troubleshooting is the recording ammeter. It is located in the motor controller or switchboard to monitor the input amperage to the motor by using a current transformer coupled to one of the electric cable's conductors. The current is recorded in the function of time on a circular chart with the proper scale.

The recording paper divided in to 96 sections each represents 15 minutes and there are also lines have different amperage values on them [1] , [4] , [5]

3.2.12.1 Normal Operation

Normal operations may create a curve above or below nameplate amperage but it should be a smooth symmetrical curve to be considered ideal as shown in **Figure 3-9**. A well that does not produce a smooth curve, but the amperage line is consistent from day to day is normal Operation for that well's characteristics. Any deviation from a well's normal operation is indication to possible problems or changing well conditions.

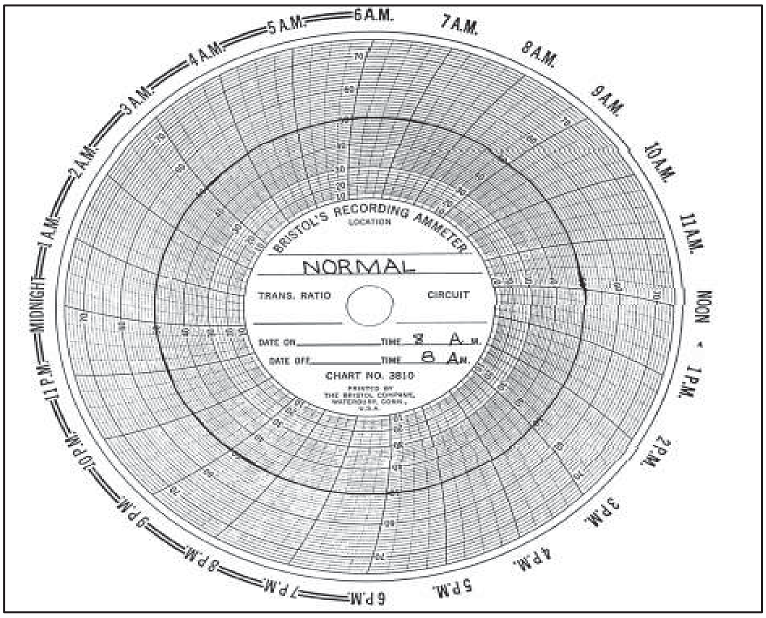


Figure 3-9: Amp Chart Indicating Normal Operation of a Submersible System [1]

3.2.12.2 Power Fluctuations

Once the primary power supply voltage fluctuates, the amperage will fluctuate in an attempt to retain constant horsepower output. The fluctuations will be reflected on the amp chart. An amp chart indicating power fluctuations in a submersible system is shown in **Figure 3-10**. But when the current spikes recorded are not too severe this type of operation is not detrimental to equipment, but corrective measurements must be taken [1] , [4] , [5]

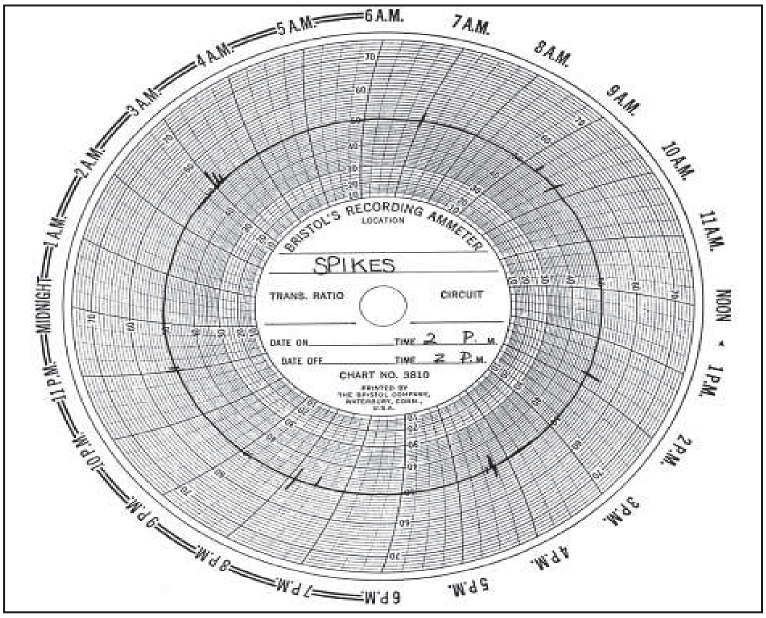


Figure 3-10: Amp Chart Indicating Power Fluctuations in a Submersible System [1]

3.2.12.3 Gas Locking

In **Figure 3-11** an example of gas locking problem was represented. In section A, the start up, because of excessive gas annular fluid level is high; therefore, the production rate and amperage are accelerated slightly due to the reduced total dynamic fluid head .As annular level drops, the pumping rate approaches the design value and motor current decreases to the nameplate value in Section B. Because the pump is oversized, as compared to well inflow rates, annular liquid level drops further in Section C. A decrease in amperage and some fluctuation is recorded when the fluid level falls below design as gas begins to break out near the pump, finally, becoming very erratic as the fluid level nears the pump intake section D.

To overcome such a problem pump can be lowered to increase the pump intake pressure and preventing gas from leave the solution [1] , [4] , [5]

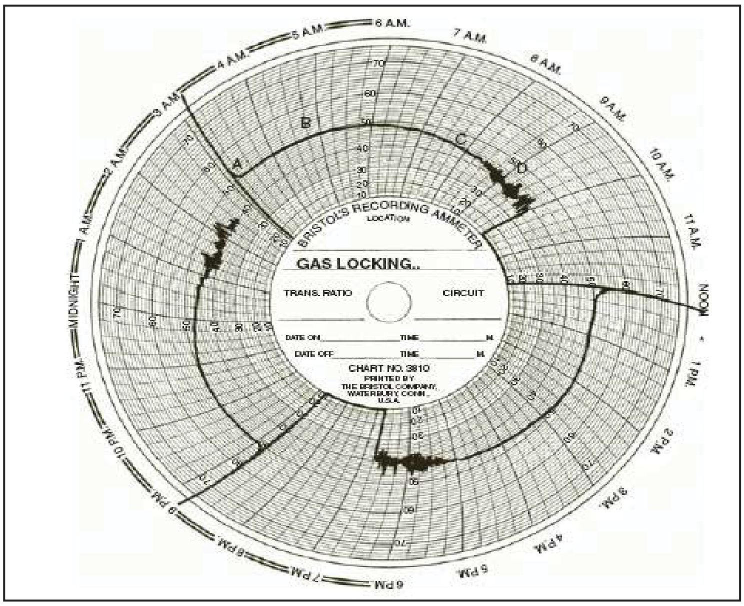


Figure 3-11: Amp Chart Indicating Gas locking in a Submersible System [1]

3.2.12.4 Fluid Pump-Off Conditions

Figure 3-12 is an ammeter chart of a unit which has shutdown due to under current and pumped off. It is automatically restarted but shutdown again periodically. Section A through C it looks like gas locking problem but no fluctuations due to gas break out present. The fluid level comes to pump intake depth and fluid production is decreased in section D. As under current point is reached the unit shuts down. This kind of problems may be the result of designing a too large unit for the well capacity or due to the change in reservoir condition like, decreasing reservoir pressure or change in fluid property [1] , [4] , [5]

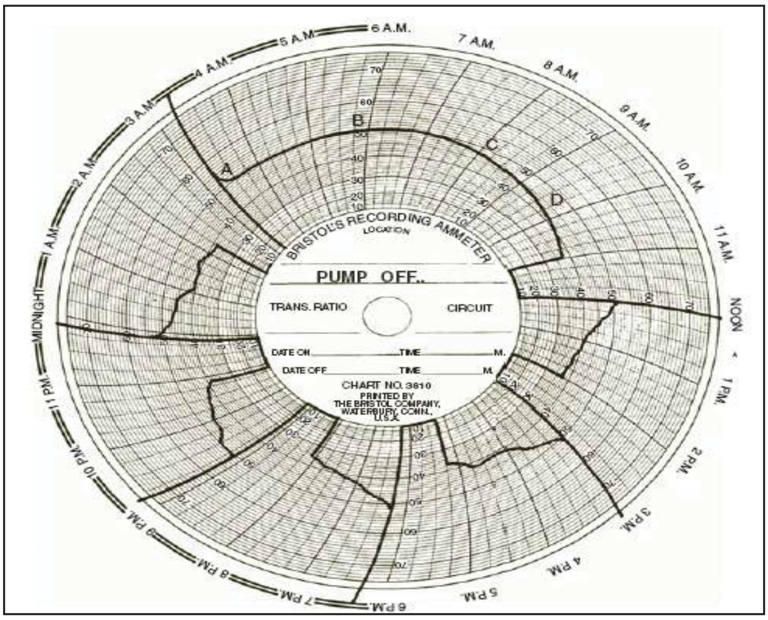


Figure 3-12: Amp Chart Indicating Fluid Pump-off in a Submersible System [1]

3.3 Design of Electrical Submersible Pump System

ESP system design is usually not so complicated if well data are reliable. While starting the design procedure it has to be known that enough well data was available. Abrasive well environment and power source information also affect the design of the equipments. The design of an ESP is to select a proper pump and calculate required pump stages for a desired liquid rate. It is important that the pump must be chosen to suit the desired rate of production. The pump must be sized to produce the increase in pressure necessary to lift the well fluid to the surface and maintain the required pressure at the wellhead. In the vertical centrifugal pump this is merely a matter of selecting the correct number of stages.

The motor must be select to suit the flow and head along with the efficiency of the selected pump stages. The required motor will need a cable capable of delivering sufficient power to start the motor and run it efficiently with minimal power losses [1] , [2]

3.3.1 Factors Affecting Pump Design

3.3.1.1 Flow configuration sizes

Casing size becomes extremely important in the design of an installation because it controls the maximum size (outside diameter) of pump and motor that can be run in the well. Generally the lowest cost, both initial and operating, will result from using a pump and motor of the largest diameter that will physically fit in the casing. The tubing size depends on the produced flow rate and is usually related to the pump diameter, i.e., the majority of installation are for tubing flow since the pump is generally run on a tubing string without a packer, although casing flow can be used in a well if desired [2]

3.3.1.2 Inflow performance of well

The proper design of any artificial lift system requires an accurate knowledge of the fluid rates that can be produced from the reservoir through the given well. Present and also future production rates are needed to accomplish the following basic tasks:

- Selection of the right type of lift,
- Detailed design of production equipment, and
- Estimation of future well performance.

The inflow performance of a well represents the ability of that well to produce fluids. This ability depends on the type of reservoir, the drive mechanism, the reservoir pressure, formation permeability and other factors. It is common to assume that inflow is proportional to $\overline{\mathrm{Pr}}$ (average reservoir pressure) if the well conditions are Constant. In **Figure 3-13**, curve 1 depicts a linear relationship between flowing bottomhole pressure and flow rate. In this case productivity index, PI is constant. PI is defined in **Equation 3-1** as barrels of total production per day per pressure drop (psi) [2]

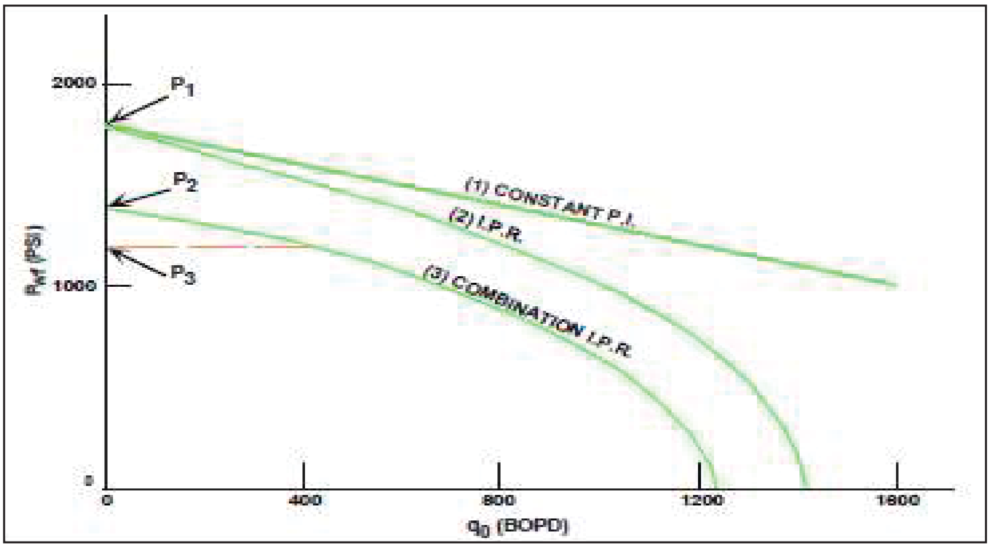


Figure 3-13: Inflow Performance Curves (PI) [17]

$$PI = \frac{Q}{\overline{pr} + Pwf} \qquad 3-1$$

Where:

Q = Flow rate, blpd

PI = Productivity Index, (bpd/psi)

$\overline{Pr}$ = Average static reservoir pressure, (psi)

Pwf = Flowing bottom hole pressure, (psi).

It is known that for many wells, this relationship is curved (curve 2, 3) as shown in **Figure 3-13**; the PI varies with flowing bottomhole pressure. The reservoir pressure is usually below the bubble point pressure and various amounts of gas will grow in the reservoir, so Vogel found that as depletion occurs in a solution gas drive reservoir, the productivity of typical well decreases. This occurs mainly because the reservoir pressure is reduced, and since increasing gas saturation causes grater resistance to oil flow.

The result is a progressive decline of the IPR. Vogel, then, developed an empirical equation 2 for the shape of the IPR of a well producing from a depletion-drive reservoir in which the average reservoir pressure is less than the bubble-point pressure [20]

$$\frac{Q}{Qmax} = 1.0 - 0.2\left(\frac{Pwf}{\overline{Pr}}\right) - 0.8\left(\frac{Pwf}{\overline{Pr}}\right)^2 \qquad 3-2$$

Where:

Q = Total liquid flow rate at stock tank conditions, blpd

Qmax = Maximum flow rate at Pwf=0 psig, blpd

$\overline{\text{Pr}}$ = Average static reservoir pressure, psig

Pwf = Bottomhole flowing pressure, psig

The Vogel relationship can be considered as a general equation for solution gas drive reservoirs producing below the bubble point pressure. Above the bubble point pressure the straight line PI is considered adequate. The flow rate below the bubble point pressure using the Vogel equation in the general form is [20]

$$\acute{Q} = Qb + (Qmax - Qb) * \left[1.0 - 0.2\left(\frac{P\acute{w}f}{Pb}\right) - 0.8\left(\frac{P\acute{w}f}{Pb}\right)^2\right] \qquad 3-3$$

Where:

Q́ = Flowrate below bubble point pressure, blpd

Qb = Flowrate at bubble point, blpd

Qmax = Maximum oil flow rate at Pwf = 0, blpd

Pb = Bubble point Pressure, psig

Pẃf = Bottomhole flowing pressure below bubble point pressure, psig

The Vogel relationship was developed assuming water cut of 0 % (100% oil) and may give unacceptable or unreliable results when the water cut exceeds 60%. As the water cut in well increases, the amount of free gas available to break out of the oil phase is less since there is less oil phase in the total fluid.

If it is assumed that the PI method is adequate for the well with 100% water cut, then a well with a water cut between 0% and 100% will have an IPR somewhere between the Vogel (100% oil) and PI relationship (100% water) [17] , [18] , [20]

3.3.2 Whether or not gas to be pumped

As a general rule, most installations pump the production up the tubing without a packer in the well. This means that gas can be vented out the casing or routed through the pump. If there is gas in the well that means presents between the producing fluid level and the bottom of the well, a wide range of gas and liquid combinations that are significant to the pump's size and location in the well. It is impossible to say that any one criteria is always the best for selecting the pump and its location, since well and reservoir data available is not always of the same reliability, reservoir conditions may be changing with time, and other factors may be different from one well to another. The pump and motor are both affected by how much gas passes through the pump. Generally, gas will have a beneficial effect in the tubing and will reduce the horsepower required from the motor but will require the pump to handle a larger flow rate. The pump's ability to perform is greatly affected by the ratio of free gas to liquid that it must handle. As long as all the gas is in solution, the pump will perform normally as it would with a liquid of lower density and will continue to do so until the free gas to liquid ratio reaches about 0.1. Above about 0.1 the pump will likely begin to produce less than normal head and, as the free gas increases, will eventually gas lock and stop pumping any appreciable amount of fluid [2]

3.3.3 Gas separation

One of the unsolved problems that we have today in electrical pumping is how to determine that volume of gas, which it is possible to vent. In early years the gas may have been vented to the atmosphere, but present day practices prohibit this practice. The casing can be tied to the flow line near the wellhead. In some cases a separate gas vent line may be necessary to prevent increasing the wellhead pressure on the casing, we can control, to some extent, the volume of gas vented.

However we must be careful to leave the pump under a certain distance of liquid submergence. The blowing of casing gas around the bottom of the pump inlet is not a desirable practice and could lock or load the well, that is, with liquid in the tubing and gas in the pump we could reach dead locked conditions [2]

3.3.4 Deviated Wells

The electrical submersible pump is designed to operate in generally vertical position. It can, however, operate in deviated wells as long as it can pass through any deviations without getting bound up. The pump itself will, if necessary, function in a position approaching horizontal. The limit of deviation from the vertical is determined by the unit's ability to maintain separation of its motor's oil and the well fluid. This is a matter of the manufacture's design [2]

3.3.5 Packers

The preferred manner to run an electrical submersible pump is without a packer so it is hanging free on the tubing string. It can be run beneath a packer, but this must be a special installation because the cable for power to the motor must by-pass through the packer. If a packer is required in the well, its selection should be made with care so the pump will have only a very little or no compressive weight on it [2]

3.3.6 Viscosity Effects

Viscosity affects the performance of centrifugal pumps by lowering the head –capacity curve, reducing the efficiency as shown in **Figure 3-14**, and making the highest efficiency occur at a lower flow. For any one pump the effect on produced head is greater at higher flows and less at lower flows i.e., the head –capacity curves tend to rotate about the head at zero flow.

For an ideal, frictionless liquid, performance curves would be straight lines and could be determined easily. Their shape, however, changes considerably if real liquid are pumped because the shape is affected by frictional and from drag losses. It is impossible to determine a given pump's performance curves by calculations because many design and manufacturing parameters (blade angle, gap width, surface roughness, etc.) affect these losses. Centrifugal pump performance curves, therefore, are always established experimentally by actual measurements, with water as a conventional test liquid. Performance curves provide realistic values when the liquid has a viscosity that is about 1 cSt. In many cases, however, the liquid pumped (such as heavier crudes, etc.) may be more viscous. In these cases, pump performance considerably changes from that shown by the curves.

Viscous liquids cause hydraulic losses in the pump, so that at grater viscosities, pumping head and pump efficiency decrease while required power increase. The pumping head and pump efficiency curves valid for the viscous liquids fall below the corresponding water performance curves, while the shut-off head point remains the same, regardless of viscosity [1] , [21]

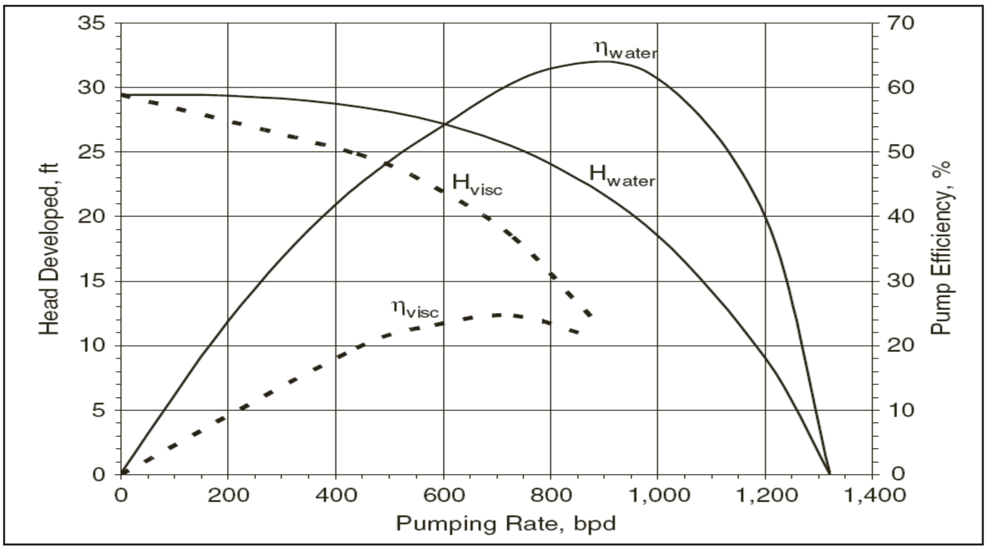


Figure 3-14: Influence of Viscosity on Head and Performance Curve of the Pump [1]

3.3.7 Temperature

The bottomhole temperature is important for installing an electrical submersible pump. It is necessary to know at what temperature the motor is going to operate. In high temperature wells it is necessary to maximize the velocity past the motor for better cooling by running the maximum diameter motor or, if this is not satisfactory, using a shroud. Also, the cable is selected with temperature being one of the controlling factors. Even though the pump may not be set on bottom, a high rate of production will move the fluids rapidly up the tubing, bringing a much higher temperature to the pump than that existing under static conditions. Higher temperature at the pump reduces the motor life.

Cables are available that will operate successfully up to 350 F^{o}. But become more costly as the temperature becomes high. Temperature must also be known to determine the total intake volume especially for handling gas [1] , [2]

3.3.8 Operating vs. Unloading Conditions

In the final horsepower selection of the motor, the operating hp requirements may be less than the unloading horsepower requirements. However, the unloading rate can be decreased to a value much less than the operating rate for unloading purposes. There will be an instance when an oil well has been loaded with brine and the horsepower required for operation may be much less than the hp required for unloading. It may be necessary to compromise between the two hp requirements, keeping in mind that a motor can be overloaded as much as 20% for the short time period necessary to unload the well [1] , [2]

3.4 Design of Electrical Pump

The design of an ESP installation, like other artificial lift methods, involves a number of factors and varies significantly with well conditions and the type of fluids to be pumped. Good quality data covering these conditions to sizing the pump equipment is necessary to proper installation design. This section presents a logical step by step procedure for sizing submersible pumps and to design a complete ESP system.

3.4.1 Data Requirements

It is important to match the ESP capability with the well's inflow performance and the data are required to size and select an ESP system can be divided into the following categories:

3.4.1.1 Casing Size, Weight, and Setting Depth

Submersible pumps are manufactured with different outside diameters. The casing sizes, along with the internal diameter of the casing, must be known to ensure the pumping unit will fit inside the casing. **Table 3-1** illustrates approximate outside diameter diameters of equipment available from submersible pump suppliers for different casing O.D.'s. For any given diameter of pump housing and shaft, the impeller diameter will be constant [1] , [21]

Table 3-1: Pump, Motor, Seal Series selection, from [21]

API CASING O.D.	WEIGHT		EQUIPMENT SERIES APPLICABLE		
	LB/FT	KG/M	MOTOR	SEAL SECTION	PUMP
4 1/2" (114.3MM)	9.5 10.5 11.6	14.1 15.6 17.3	375	338	338
5 1/2" (139.7MM)	*20.0 17.0 15.5 14.0	29.9 25.3 23.0 20.7	375-450	338-400	338-400
6 5/8" (168.3MM)	28.0 24.0 20.0	41.7 35.8 29.9	375-450 375-450 544-562	338-400 338-400-513	338-400 338-400-513
7" (177.8MM)	32.0 29.0 26.0 23.0	47.6 43.3 38.7 34.1	375-450 544-562	338-400-513	338-400-513
	20.0 17.0	29.9 25.3			338-400 513-562
7 5/8" (193.7MM)	39.0 33.7 29.7 26.4 24.0 20.0	58.1 50.2 44.3 34.4 35.8 29.9	375-450 544-562	338-400 513	338-400 513-562
8 5/8" (219.1MM)	49.0 44.0 40.0 36.0 32.0	72.8 65.5 59.4 53.5 47.6	375-450 544-562-725	338-400 513-675	338-400 513-562-675
9 5/8" (244.5MM)	58.4 47.0 40.0 36.0 29.3	86.8 69.9 59.4 53.5 43.6	375-450 544-562-725	338-400 513-675	338-400 513-562-675
10-3/4" (273.0MM)	55.5 32.7	82.7 48.5	375-450 544-562-725	338-400 513-675-875	338-400-513 562-675-875
13-3/8"	83.0	123.4			338-400-513

3.4.1.2 Perforated Intervals or Open Hole Depth

Bottom hole and perforated interval depths, respectively, determine the maximum possible pump setting depth and the maximum depth that the pump can be set without needing a motor jacket [1] ,[9] , [21]

3.4.1.3 Tubing Size

The size of the tubing used determines how much friction loss must be included in the total head design. Tubing size should be evaluated for most economical size to use with the anticipated volume to be pumped [1] ,[9] [21]

3.4.1.4 Specific Gravity

The specific gravities and their percentages of the liquids and gas making up the mixture being pumped determine to a large extent the motor horsepower. Therefore, the specific gravity of the water and gas, oil API gravity, water cut and G.O.R are needed [1] ,[9] , [21]

3.4.1.5 Viscosity

Viscosity, if available, is needed since published pump performance curves are based on water tests. If the viscosity is greater than that of water, a correction must be made to the head capacity and horsepower curves. Standard correlations exist with which viscosity can be approximated from the oil's API gravity and temperature [1] ,[9] , [21]

3.4.1.6 Temperature

Temperature of the wellhead and bottom hole are needed, mainly if there is gas present since the amount of gas in solution and the volume of any free gas are sensitive to the temperature and its change throughout the well and tubing. Also the selection of motor cable materials is affected by the temperature of the liquid to which it is exposed [1] ,[9] , [21]

3.4.1.7 Inflow performance

For determining well capabilities so that the unit can be sized for proper volume at selected pump setting depth[1] ,[9] , [21]

3.4.1.8 PVT Data

PVT data in the form of pressure, solution gas oil ratio, and formation volume factor is needed if gas is present. If for any particular case the P.V.T. data is unknown, it can be approximated from standard correlations [1] ,[9] , [21]

3.4.1.9 Discharge Pressure Required at Tubing Wellhead

This additional pressure must be included in the total dynamic head calculation [1] ,[9]

3.4.1.10 Voltage

Available voltage at well location is used for sizing the transformer and other electrical components [1] ,[9] , [21]

3.4.2 Calculation of Specific Gravity (SpGr)

$$SP.Gr = \frac{141.5}{131.5 + API°} \qquad 3-4$$

$$SP.Gr = \left(SP.grw * (WC)\right) + \left(SP.gro * (1 - WC)\right) \qquad 3-5$$

Where:

Spgro = Specific gravity for oil

Spgrw = Specific gravity for water

SpGr = Average Specific gravity

3.4.3 Calculating Producing Pressure and Pump Intake Pressure (FBHP & PIP).

3.4.3.1 Flowing Bottom Hole Pressure

The well's flowing bottomhole pressure (FBHP) is easily calculated from **equation 3-6**, if the constant PI equation describes the well inflow[1] , [2] , [4] :

$$\mathrm{Pwf} = \mathrm{SBHP} - \frac{\mathrm{Q}}{\mathrm{PI}} \qquad 3-6$$

Where:

SBHP = static bottomhole pressure, psi

Q = liquid rate, STB/d

PI = productivity index, STB/d/psi.

If well inflow follows the Vogel model then FBHP is found from **Equation 3-2**

3.4.3.2 Calculate Pump Intake Pressure (PIP)

$$PIP = FBHP - \left((Dperf. - Psd) * Sp.Gr/\frac{Psi}{ft}\right) \qquad 3-7$$

Where:

D perf. = Depth of perforations, ft

Psd = Pump sitting depth, ft

SpGr = average specific gravity

3.4.4 Gas, Oil, and Water Calculations

Equipment selection and design can be much more complicated in the case of presence of excessive amount of gas. From intake to discharge, volume, density and pressure values are changing in the liquid and gas mixture. Presence of gas at the discharge of the tubing can result a reduction in the required discharge pressure. Separation of the liquid and gas phase in the pump stages and slippage between phases can cause lower pump head than the required value. A submergence pressure below the bubble point to keep the gas all in liquid phase is the ideal case, in the reverse condition free gas volume must be separated from the other fluids by the help of gas separators.

Depending on the amount of gas and well conditions combinations of equipments are available. Some equipments use the natural buoyancy of the fluids for separation while some can use the fluid velocity to produce a rotational flow for inducing radial separation of gas.

In order to decide which kind should be used it is necessary to determine the gas effect on fluid. If solution gas/oil ratio (RS, scf/stb), the gas volume factor (Bg, bbl/Mcf) and the formation volume factor (Bo, rbbl/stb) are not available from the well data they should be calculated. Those ratios were used for calculating the amount of water oil and free gas in the solution, and their effect on the fluid characteristics. Determining RS with Standing's equation [1] :

$$\mathrm{Rs} = \gamma g * (\mathrm{PIP}|18 * 10^{\gamma})^{1.205} \qquad 3-8$$

Where:

γ = 0.00091 T - 0.0125API°

PIP = pump intake pressure, psi

T = suction temperature, F

γg = gas specific gravity

API = oil API gravity

3.4.4.1 Determining Bo & Bg with Standing's Equations

$$Bo = 0.972 + 0.000147 * F^{1.175} \qquad 3-9$$

$$Bg = 5.04 * (Z) * (T/PIP) \qquad 3-10$$

Where:

$$F = Rs * \left(\frac{\gamma g}{\gamma o}\right)^{0.5} + 1.25 * T \qquad 3-11$$

Bo = Oil volume factor at pump suction pressure, bbl/STB

Bg = Gas volume factor at pump suction pressure, bbl/STB.

γ_o, γ_g = Oil and Gas specific gravities, –

Rs = Solution gas/oil ratio, scf/STB

T = suction temperature, F°

Z = Gas compressibility factor (0.81 to 0.91)

3.4.4.2 Total Volume of Fluids Entering to the Pump and Percentage of Free Gas at the Pump

Intake can be calculated by the assist of Rs, Bo and Bg [1]

Total Volume of gas = TG = BOPD * GOR /1000 3-12

Solution gas = SG = BOPD * Rs /1000 3-13

Free gas = FG = TG – SG 3-14

Volume of oil at pump intake = VO = BOPD * Bo 3-15

Volume of free gas at pump intake= Vg = FG * Bg 3-16

Volume of water at pump intake = VW = Q * WC% 3-17

The total volume of fluid at pump intake: VT = VO + VW + Vg 3-18

Free gas percentage = Vg / VT * 100 3-19

As the percentage of gas at pump intake smaller than 10% by volume it is expected that pump performance will not be affected by gas, so no need for gas separator [1] , [2] , [4]

3.4.5 Total Dynamic Head Calculations

In order to accurately select the submersible pump for a given installation one has to calculate the required hydraulic head against which the pump is to operate under the predicted conditions. The head or the equivalent pressure at the setting depth of the pump has three components:

- Gravitational component,
- Frictional pressure drop, and
- Well head pressure.

The hydraulic head required to lift the desired liquid rate for a given pump setting depth is called total dynamic head (TDH).

In order to determine the number of pump stages, the total (TDH) concept is used. This concept assumes that the pressure developed by each pump stage is constant; thus, fluid density and volume are assumed to remain unchanged throughout the pump from intake to discharge. All pump stages lumped together for calculating total pump discharge head and power required to drive the pump. Total dynamic head (TDH) can be calculated by the equation given below [1] , [2] , [4]

$$\mathrm{TDH} = \mathrm{Ld} + \mathrm{Hf} + \mathrm{Pd} \qquad 3-20$$

Where:

Ld = the dynamic fluid level, the level at which fluids in the casing annulus stabilize while producing the desired liquid rate.

$$Ld = \frac{Lset * grado + CP - PIP}{grad.o - grad.g} \qquad 3-21$$

Where:

Lset = TVD of pump setting, ft

PIP = Pump intake pressure, psi

CP = Casing head pressure, psi

grado, gradg = Oil and gas gradients in the annulus, psi/ft.

Hf = Frictional pressure drop (converted to head loss), that occurs in the tubing string while producing the desired rate and can be calculated from **Figure 3-15**

Pd = the head required at the wellhead to move the produced liquids into the surface gathering system and is converted from the value of given wellhead pressure.

$$Pd = (2.31/\gamma_{mix}) * (Whp - CP) \qquad 3-22$$

Where:

Whp = Wellhead pressure, psi

Cp = Casing head pressure, psi

γ_{mix} = Specific gravity of the produced liquid

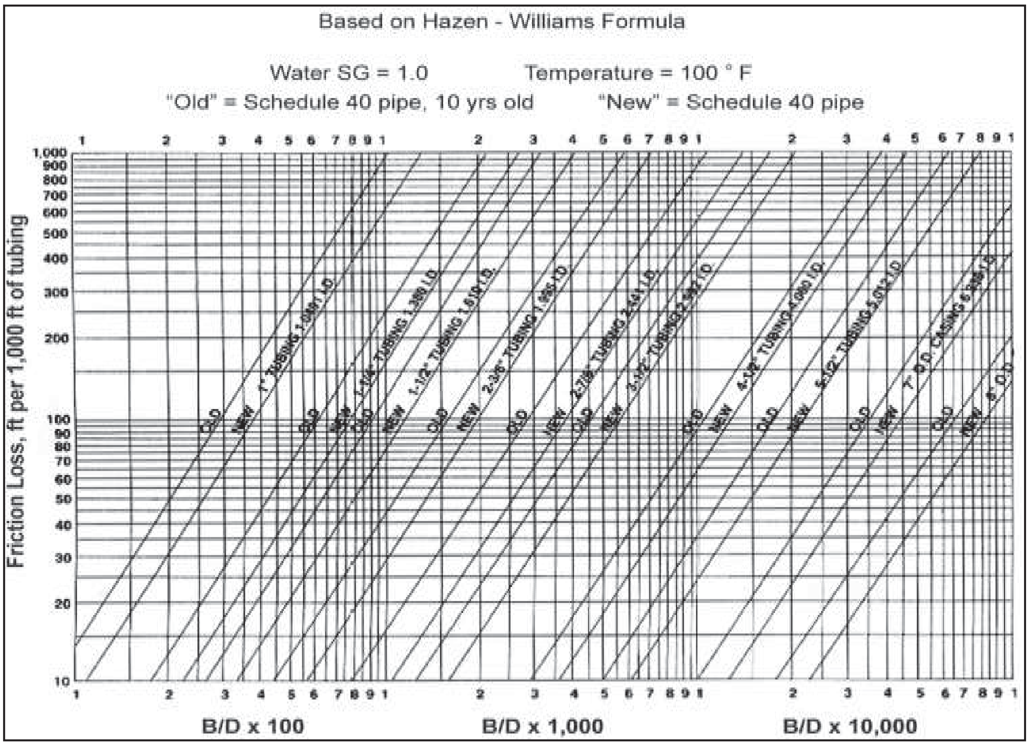


Figure 3-15: Friction loss in tubing [23]

3.4.6 Selection of Pump Type

Once the total intake volume of liquids plus free gas is known, a pump type can be selected. Centrifugal pumps are manufactured in different types that vary in stage design, dimension, etc. The proper design of an installation requires that the right type of pump be selected. The main selection criteria are casing size restrictions. Normally the largest series (diameter) that will fit inside the casing is selected because efficiencies tend to be higher and equipment costs are lower. If the depth of the dynamic liquid level is not exactly known or it is expected to change, pumps with steep head-rate characteristics are to be preferred. Such pumps will lift the desired liquid volume with widely changing liquid levels. When pumping gassy fluids, a steep pump characteristics curve is advantageous. Use of a gas separator with such a pump enables relatively high gas-liquid ratio wells to be economically lifted [1] , [22]

3.4.7 Selection of Equipment Components

3.4.7.1 Submersible Pump

In the previous the required pump type and the value of total dynamic head (TDH) has been determined. It is only remains to find the number of stages to develop a hydraulic head equalling TDH, and to find the right pump from the manufacturer’s line. The heads developed by each stage of a multistage centrifugal pump are additive. Based on this condition the required number of stages can be found from the value of TDH and the head developed by one stage. As some manufacturers plot pumps performance curves for 100 stages, a uniformly applicable Equation is given below[1] , [4]

$$Z = (TDH/Ho) * Zo \qquad 3-23$$

Where:

Z = Number of required pump stages,

Zo = Number of stages on the performance

Ho = Head developed by Zo stages and read from the pump performance curve at the desired liquid rate.

3.4.7.2 Gas Separator

In wells with negligible or low gas production gas separators are not needed. Higher free gas volumes require the use of gas separators the size of which is selected according to recommendations given by the manufacturer [1]

3.4.7.3 Motor Selection

The electric motor is specified by selecting its power rating and outside diameter. Normally the largest series (diameter) that will fit inside the casing is selected because of lower initial costs and slightly better efficiency and better cooling. The horsepower rating must be equal to the pump’s power, seal’s power and intake’s power requirement under the design conditions. In addition, allowances should be made for possible changes in the producing water cut over the life of the pump. Start up conditions should also be considered, especially if heavy kill fluids are used or if a high producing water cut exists at start up.

Motor power is found using pump performance curves where power required to driving the stated number of stages is also plotted. The following equation is used.

$$Motor\ Hp\ = \frac{BHP}{Stage} * (Stage) * (SP.Gr) + (Seal\ HP) + Intake\ HP \qquad 3-24$$

For a given O.D. and horsepower rating, several motors with different voltages are usually available. Selecting the right value needs considerations on available surface voltage, voltage drop in the power cable, and equipment prices. Power cable losses should be less than 10% of the total energy consumed by the pumping system. In deep and/or higher temperature wells, higher voltage motors are often selected to reduce power cable losses. Higher voltage motor needs less current to develop the same horsepower and thus reduce the operating temperature of the power cable. Cable life can be increased and, as the cable is the most vulnerable component of the ESP unit, production economics improve. Since surge current at start-up can be at least three times normal running current, voltage drops down the cable for low voltage high current motors means that the voltage available at the motor is low and there may not be enough torque to start the unit if sand is present or the unit is worn. High voltage low current motors have the advantage of higher starting torques [1]

3.4.7.4 Seal Selection

Protector size is determined based on motor and pump data using information from the manufacturer. The main function of the seal or protector is to absorb the axial load from the pump Seals, thus this is the reason why seals are selected principally on the basis of calculated thrust load developed by the pump.

In addition to thrust load, a number of other features have to be considered when selecting the proper protector for a particular application:

- The right size (series) is to be chosen,
- The protector shaft should be capable to transfer the required power, and
- The protector's oil expansion capacity should be sufficient.

The available sizes of seals are compatible with motor and pump series and the proper outside diameter is selected to match the ODs of the selected motor and the pump. When using motors and pumps with different outside diameters, special adapters or subs may be required[1] , [2]

3.4.7.5 Power Cable Selection

The basic considerations for cable size selection are voltage drop along the cable, and physical dimensions. The voltage drop in a cable is found from the motor current for different conductor sizes using charts developed by cable manufacturers. The selection of optimum cable conductor size involves both technical and economical consideration. The most major technical considerations are cable amperage and its effect on heat rise, as well as starting considerations for the submersible motor. There are usually several conductor sizes that satisfy the technical aspects of sizing.

Beside considerations of cable amperage on conductor temperature rise, cable conductor sizing can dramatically affect reliable motor starting. If the conductor size is too small, the voltage drop in the cable, due to high motor starting currents, may not allow adequate starting torque for long term reliable starting. Practical operating experience has also shown that a good practice is to assure the motor has at least 50% of its nameplate voltage available at the motor terminals during starting.

This assures that adequate torque is available for reliable starting in most installation. As a guide the current carrying capacities of some of the cables are listed in **Table 3-2**. Another chart used in sizing of submersible pump cable is the cable voltage loss chart as shown in **Figure 3-16**

From an economic point of view it becomes important to recognize not only the initial costs associated with cable purchase but also are able to calculate power costs associated with cable losses. It can be shown that the smallest possible size may not be the best selection [1] , [2]

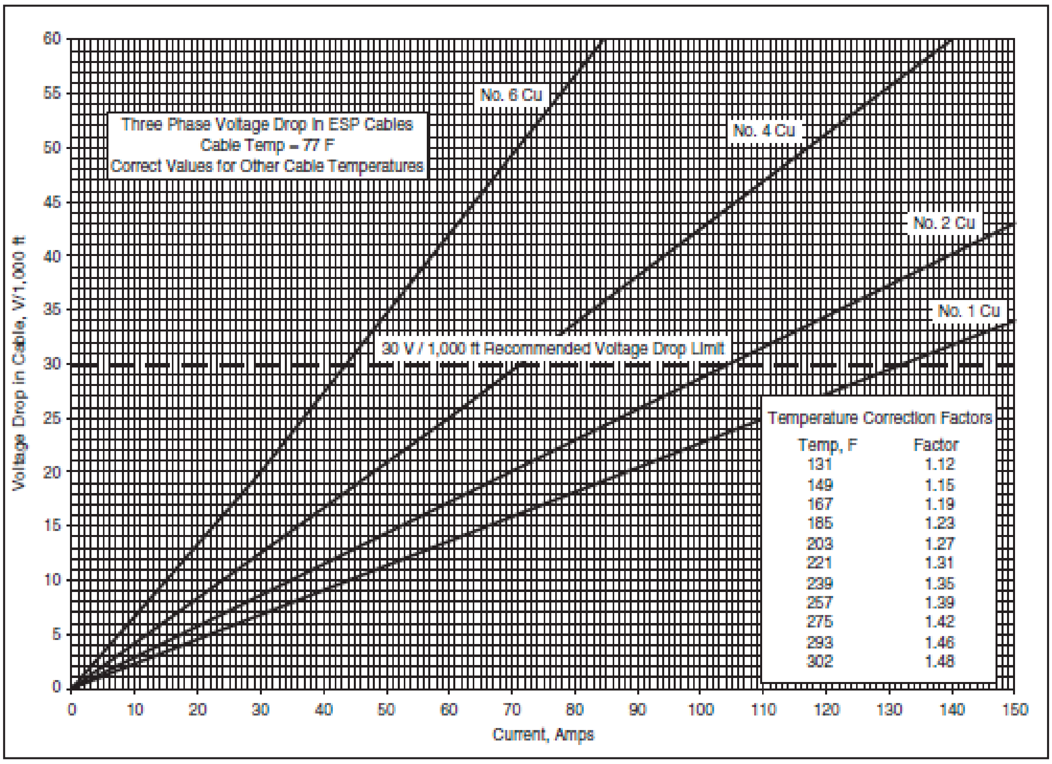


Figure 3-16: Typical Values of Voltage Drops in Copper Conductors [1]

Table 3-2: Cable Current Carrying Capacity [24]

Copper conductor No.	Aluminium conductor No.	Maximum amperes
1	2/0	110
2	1/0	95
4	2	70
6	4	55

3.4.7.6 Surface Equipment Selection

Surface equipments include the switchboard, transformers, and the wellhead. The most important of these is the selection of the switchboard's size and power rating. Selection of the switchboard is based on the voltage and power required at the surface. Surface voltage is the sum of motor nameplate voltage and voltage drop across the cable [1] .

The type of transformer required depends on the primary power system and required surface voltage. Three phase auto-transformers are generally required for increasing voltage from 440-480 volts to the system volt. A bank of three single phase transformers is usually needed for reducing the high voltage primary source to required surface voltage [1]

The following equation will help to select;

$$KVA = \frac{1.73 * Vs * Am}{1000} \qquad 3-25$$

Where:

KVA	=	Transformer size, kV-amps
Vs	=	System voltage, V
A m	=	Motor amperage, amp

CHAPTER 4: Analysing and Production Optimization of ESPs in Sarir Field

4.1 Introduction

Analysing ESP system and production optimization in Sarir Field will be performed by using SubPump and Avocet well surface Modeler Softwares. Five oil wells of C-main reservoir in sarir field will be used as case study (C-001-65, C-046-65, C-101-65, C-105-65 and C-144-65). Analysing ESP system will provide us with good understanding that helping in design and redesign the pump correctly and result in minimize ESP failures, because the ESP equipment in a well can often cost more than $150,000. Also, wells with ESPs typically produce large volumes, meaning that a significant amount of revenue is impacted. Production optimization includes a good understanding about production system and reservoir fluid. Therefore, optimization of field production can't be achieved only by optimization of each individual producer well. It implies the integration of the whole production chain from reservoir, near well-bore zone, well-bore with down-hole ESP equipment, production network up to process facilities and system for transport of oil and gas [29]

Analysing and production optimization in Sarir Field are considered for two cases: (1) Combined ESP/GL, and (2) optimizing the Pump Setting Depth.

4.2 Combined ESP-Gas Lift (Hybrid)

All (350 wells) in the Sarir Field have been installed with an Electrical Submersible Pump which is considered as an effective and economical means of lifting large volume of fluids from great depths under variety of well conditions. Sarir Field produces a low amount of gas about 30 MMSCF/Day, therefore gas lift wasn't considered as a main artificial lift method. nevertheless in this study has suggested applying gas lift method with ESP as a secondary method on five wells of Sarir Field to invest a certain amount of produced gas and achieve the benefits from gas injection technology in lighten up the fluid density which result in minimize the total energy requirement and maximize the production [30] , [31] , [32] Gas lift in this approach is used to lighten up the total fluid density in the tubing above the pump and hence reduce the size of the pump (number of stages). **Figure 4-1** shows the pressure profile inside the tubing with the ESP system working alone and the pressure profile of a combined artificial lift system, where the fluid column has been lightened due to the injected gas. Less differential pressure through the pump means less energy to be supplied by the system to the fluids to reach the production facilities [30] , [31] , [32]

The basic design of hybrid system is combining between gas lift mode and ESP system. Even though not many books explain about this hybrid system in details, however GL and ESP individual design is described in most of artificial lift book. Understanding ESP and GL design and concept are necessary before implementing this technology [30] , [31] , [32]

The surface gas lift design requires gas compressor, knock out drum to separate gas and liquid, dehydration unit, manifold to distribute the gas and additional flow line which uses a gas injection line from the gas manifold to the wells. In the ESP system the main equipment required mainly related to the electrical system such as the power supply, transformer, switchboard, junction box and tail cable which go to the well head. All of that equipment is installed at the sarir field area since the beginning [33]

In This study the approach of ESP/Gas lift hybrid will apply on five wells (C-001-65, C-046-65,C-101-65, C-105-65 and C-144-65) in the Sarir Field by installing one gas injection valve above the pump with 1000 feet as shown in **Figure 4-2**and the calculations will present by SubPump software as will be shown in the chapter 5.The function of installing gas valve in the tubing is to lighten the fluid column and obtain some benefits from gas injection as follow: [30] , [31] , [32]

- Reduces ESP discharge pressure requirements
- Increased volumetric efficiency-higher liquid volumes
- Superior reservoir draw down-increased production
- Reduction in pump and motor requirements
- Lower energy consumption
- Reduces electrical conduit requirements
- Gas lift provides backup to ESP pump failure

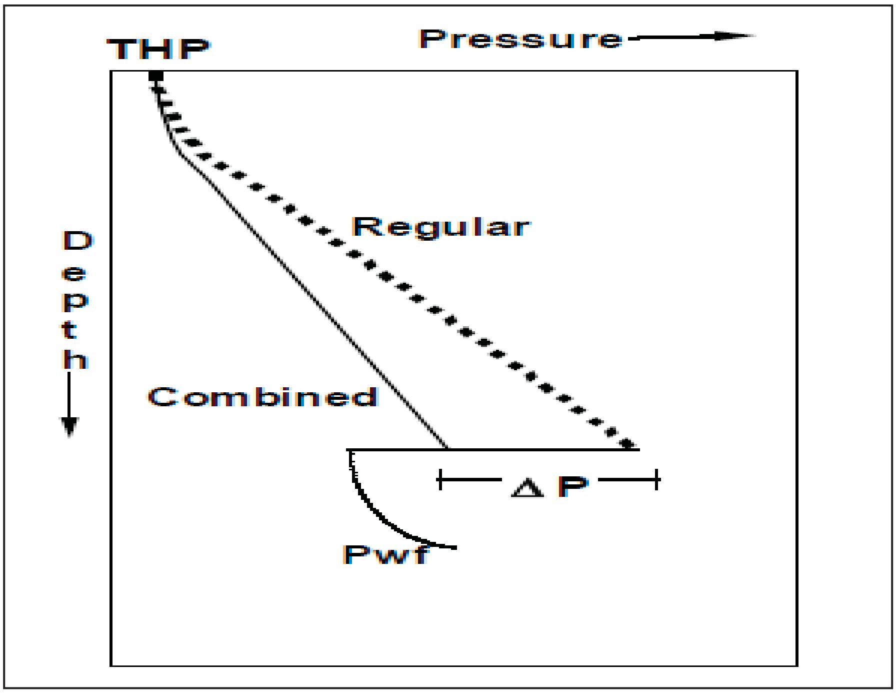


Figure 4-1: Pressure Profile for Regular and Combined System [30]

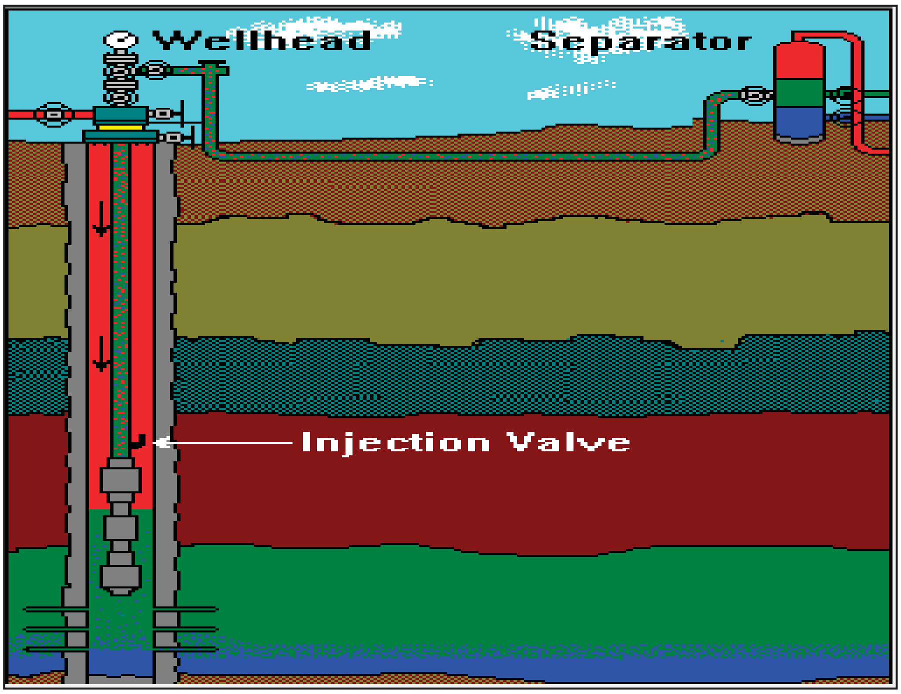


Figure 4-2: Combined ESP/Gas lift [29]

4.3 Optimizing the Pump Setting Depth

As well known, for any particular stock tank flow rate, the value of the natural free gas vented fraction is a function of the pump submergence. If the pump inlet pressure is greater than the saturation pressure and this is greater than the tubing wellhead pressure, the value of the natural free gas vented fraction may be varied between 0 and 1, by considering this fact .Avocet Well and Surface Modeler software will present the calculation for the optimum pump setting depth, aiming to minimize the tubing length, cable length and the power losses in the system [2] , [35]

4.4 SubPump Software Overview

SubPump is an advanced windows software package for designing an efficient electric submersible pumping (ESP) system (in design mode) and/or analyzing an existing ESP system (in analysis mode) by creating optimum performance for current well conditions or analyzing the performance of an existing ESP system. Wellbore configuration, fluid analysis, and inflow performance are used as a basis of a SubPump analysis [29]

This software incorporates the most widely used empirical correlations to predict the fluid properties and pressure drop.

The SubPump software allows accurate calculations of important downhole parameters including pump intake pressure, pump intake volume (including free gas), pump pressure and fluid density profile. Lifting cost parameters such as power requirements of pump and motor pump and motor performance and overall system efficiency are also determined.

In design, SubPump software allows a quick evaluation of many different equipment configurations to obtain an efficient and economical installation, even allows conducting a combined ESP and gas lift study (Hybrid) to enhance oil production.

The pump database contains catalog specifications from various pump manufacturers and housing data for selected pumps. The motor database contains catalog specifications for the corresponding manufacturer’s electric motor. In addition, there is seal database and cable database to complete the component selection of the system.

In analysis, the components of the system can be selected. SubPump calculates the input data and presents the results on several graphs and reports that can be viewed. The manufacturers included in the SubPump software are Centrilift, ESP, ODI, Alans, and Reda [29]

4.5 Avocet Well and Surface Modeler Software Overview

Avocet Well and Surface Modeler is a newly Design Module software package provides a comprehensive well performance analysis solution for a complete electric submersible pump (ESP) system design.

The Avocet Well and Surface Modeler software contains a comprehensive database of components, including the latest ESP technology and equipment. With the Avocet WSM–ESP package you can accurately design and select each system component for your well—subsurface pump, motor, gas-handling device, protectors, cables, surface switchboard, and variable speed drive. Designed by leading Schlumberger artificial lift application engineers, this totally new technology incorporates an intuitive workflow-based approach that leads a design engineer through the design process.

The sophisticated WSM–ESP Design Module software package sizes and analyzes an entire ESP system, optimizing ESP design and greatly increasing ESP running life for increased production. The module provides the latest information on ESP equipment and utilizes the fluid, well, and reservoir information to predict the inflow and outflow performance of an ESP system design. The ESP Design Module provides a comprehensive selection of fluid models and correlations to match measured well data. An extended set of empirical and mechanistic flow correlations is available to match field performance.

Accurate determination and prediction of well productivity are major factors in the design and selection of an ESP, and the Avocet WSM–ESP Design Module simplifies the well analysis process. The Avocet WSM–ESP software covers the design of the traditional low gas-oil ratio (GOR) well application and the design methods and equipment required for high GOR applications.

It also has a simplified design workflow for very high water cut wells, and provides the option to select REDA gas handling devices; the REDA gas separation guideline algorithm is built in for specific gas separators and has more flexibility in stage-by-stage handling of gas, which is a necessary ESP design component for high GOR wells.

In order to ensure the longest ESP operation in a well, accurate prediction of each ESP component performance at field conditions is of the highest importance. The Avocet WSM–ESP Module applies the latest ESP equipment analysis technology to all components—including performance and power requirement prediction for separation equipment, advanced features to adjust pump or other component performance to match measured data, the application of both motor and pump heat to increase effects on equipment performance and of a complete heat transfer from the reservoir to the separator, and powerful sensitivity features to confirm that the design is robust when there is uncertainty in the field performance [34]

4.6 Softwares Required Input Data

4.6.1 Wellbore

Wellbore information includes the wellbore correlation, tubing and casing dimension, pump depth (stated as total tubing depth), perforation depth, static bottom hole temperature at top of perforation, pumping well head temperature at surface, and for deviated wells directional information [29] , [34]

4.6.2 Fluid Data

These include oil gravity, gas specific gravity, water cut, water specific gravity, salinity, GOR, GLR, gas impurities (Co_2, H_2S, N_2), bubble point pressure, solution gas oil ratio [29] , [34]

4.6.3 PVT Correlations

The PVT correlations are included the following[29] , [34] :

- Viscosity Correlations

  A group of PVT correlations to be used for viscosities of dead oil, saturated oil, under saturated oil, gas, and water PVT correlations can be used for oil density, bubble point pressure, solution GOR, oil compressibility, oil formation volume factor, and Z factor.

- PVT Lab Data

  PVT lab data are used to adjust calculated properties using the selected PVT correlations. The PVT lab data are pressure, solution GOR, oil formation volume factor, and Z factor.

- Viscosity Calibration

  Using the viscosity calibration data, the software calibrates the calculated viscosity with the selected viscosity correlations.

4.6.4 Inflow Performance

These Softwares allow determining the performance method and set variables for that method.

The following performance methods are available in the Softwares [29] ,[34] Productivity Index

The Softwares calculate the productivity Index (PI) based on the following data:

- Static bottom hole pressure, or static fluid level and casing pressure
- Fluid rate at test bottom hole pressure
- Test bottom hole pressure, or test fluid level

- Vogel and Vogel corrected for water cut methods

  Vogel uses similar information as productivity index method to present inflow performance for pressure below the bubble point. Vogel corrected for water cut is used to correct for water cut. Water cut value is required for this method.

The Vogel data items are listed below [29] [34]

- Static bottomhole pressure can either be entered directly or calculated from the fluid level.
- Static fluid level and casing pressure
- Fluid rate at test bottom hole pressure
- Test bottom hole pressure at test flow rate
- Test fluid level for calculating the test bottomhole pressure BHP at the flow rate.
- Casing pressure that is maintained the casing under test conditions.

4.6.5 Pressure/ Rates

In pressure/rate processes the Softwares design procedure has three options[29] , [34]

1. Pump Intake Conditions

The Softwares calculate pump intake pressure based on the following data:

- Total fluid rate
- Pump depth
- Flowing bottomhole pressure from the IPR equations.

In case of pump setting depth is above the perforations the pump intake pressure is calculated from the following **Equation 4-1**:

$$PIP = P_{wf} - (TVD_{top\ perf} - TVD_{pump}) * \gamma_f \qquad 4\text{-}1$$

In case of pump setting depth is below the perforations the pump intake pressure is calculated from the following **Equation 4-2**:

$$PIP = P_{wf} + (TVD_{pump} - TVD_{top\ perf}) * \gamma_f \qquad 4\text{-}2$$

2. Total Fluid Rate

In case of pump setting depth is above the perforations, the flowing bottomhole pressure at the upper perforation is calculated from the total liquid gradient, pump intake pressure, and depth of upper perforation and pump from the following **Equation 4-3**.

$$P_{wf} = PIP + (TVD_{top\ perf} - TVD_{pump}) * \gamma_f \qquad 4\text{-}3$$

The total fluid rate is subsequently calculated from the IPR equations discussed previously using the selected method PI, Vogel, or Vogel corrected for water cut.

3. Pump Setting Depth

In case of pump setting depth is above the perforation, the flowing bottomhole pressure is calculated from the IPR at the upper perforation depth. The following **Equation 4-4** calculates the pump setting depth [11]

$$TVD_{pump} = TVD_{top\ perf} - (P_{wf} - PIP)/\ \gamma_f \qquad 4\text{-}4$$

Where:

γ_f = Liquid gradient, psi/ft

$TVD_{top\ perf}$ = Vertical depth of top perforation, ft

TVD_{pump} = Vertical depth of pump intake, ft

PIP = Pump intake pressure, psia

P_{wf} = Flowing bottom hole pressure, Psia

4.7 Softwares design calculations using Nodal concept

Nodal analysis is an excellent tool for optimizing the objective flow rate of both oil and gas wells. Every component in producing well or all wells in producing system can be optimized to achieve the maximum flow rate economically

The production system can be relatively simple or can include many components in which energy or pressure losses occur. **Figure 4-3** illustrates a number of the components in which pressure losses occur. The procedure consists of selecting a division point or node in the well and dividing the system at this point. All of the components upstream of the node comprise the inflow section, while the outflow section consists of all of the components downstream of the node. A relationship between flow rate and pressure drop must be available for each component in the system. The flow rate through the system can be determined once the following requirements are satisfied [18] , [19] , [35] :

- Flow into the node equals flow out of the node
- Only one pressure can exist at a node.

At a particular time in the life of the well, there are always two pressures that remain fixed and are not functions of flow rate. One of these pressures is the average reservoir pressure, P_r and the other is the system outlet pressure. The outlet pressure is usually the separator pressure, P_{sep}, but if the well is controlled by a surface choke the fixed outlet pressure may be the wellhead pressure P_{wh}. Once the node is selected, the node pressure is calculated from both directions starting at the fixed pressures [18] , [19] , [35]

Inflow to the node:

$$\overline{PR} - \Delta \text{ (upstream components)} = P_{node} \quad \text{4-5}$$

Outflow from the node:

$$P_{sep} + \Delta \text{ (downstream component)} = P_{node} \quad \text{4-6}$$

The pressure drop, Δp, in any component varies with flow rate, q .Therefore; a plot of node pressure versus flow rate will produce two curves, the intersection of which will give the conditions satisfying requirements 1 and 2, given previously.

The effect of a change in any of the components can be analyzed by recalculating the node pressure versus flow rate using the new characteristics of the component that was changed. If a change was made in an upstream component, the outflow curve will remain unchanged. However, if either curve is changed, the intersection will be shifted, and a new flow capacity and node pressure will exist. The curves will also be shifted if either of the fixed pressures is changed, which may occur with depletion or a change in separation conditions. **Figure 4-4** illustrates the comparison of intake curves for artificial lift methods. It can be observed from the figure that electrical submersible pump keeps the bottomhole pressure low, thus, creates large amount of pressure drawdown to reach high production rates [18] , [19] , [35]

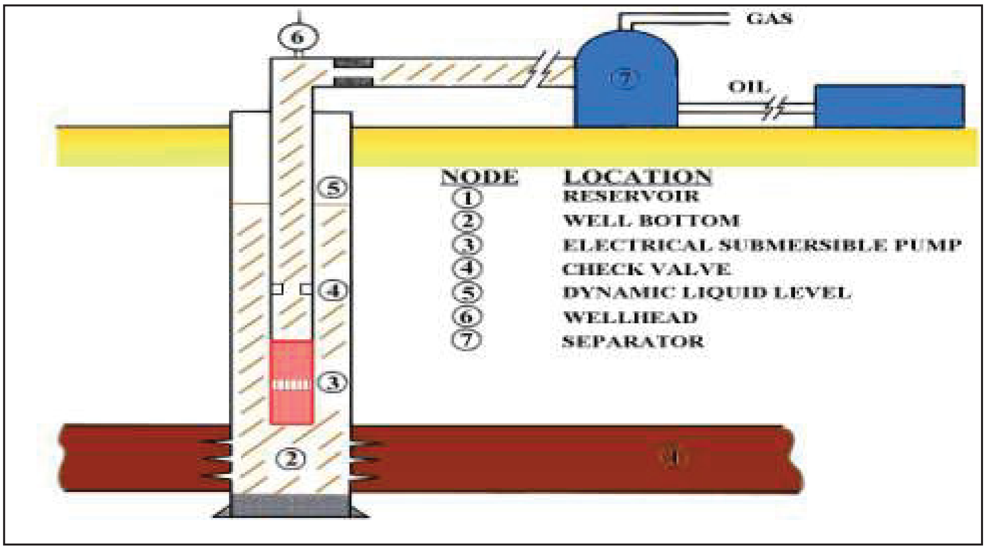


Figure 4-3: Pressure Losses in a Production System[18]

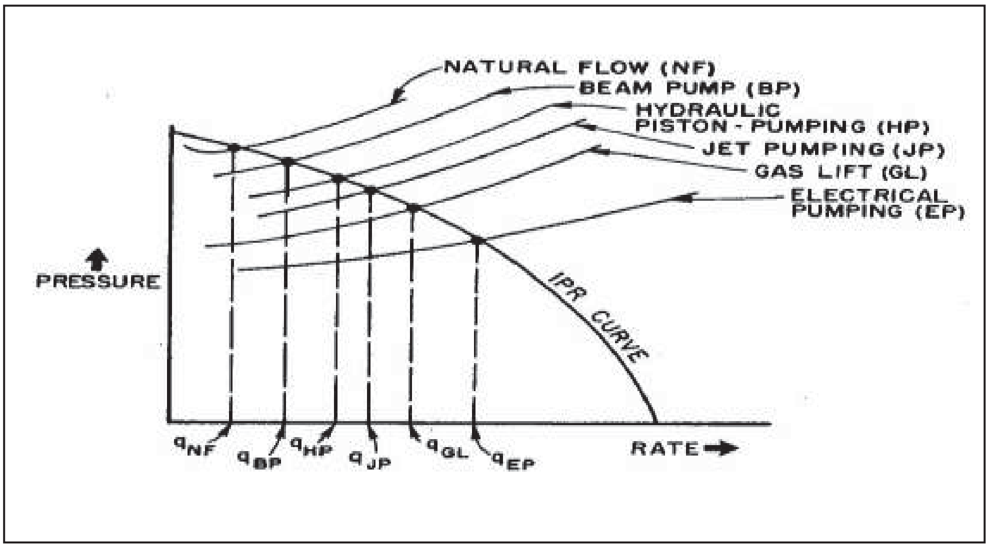


Figure 4-4: Tubing Intake Curves for Artificial Lift Systems [35]

Inflow to node:

$$\overline{PR} - \Delta Pres. - \Delta P\ tubing = P_{wh} \qquad 4\text{-}8$$

Outflow from node:

$$P_{sep} + \Delta P\ flowline = P_{wh} \qquad 4\text{-}9$$

The effect of increasing the tubing size, as long as the tubing is not too large, is to give a higher node or wellhead pressure for a given flow rate, because the pressure drop in the tubing will be decreased. This shifts the inflow curve upward and the intersection to the right. A larger flow line will reduce the pressure drop in the flow line, shifting the outflow down and the intersection to the right. The effect of a change in any component in the system can be isolated in this manner. Also, the effect of declining reservoir pressure or changing separator can be determined. A more frequently used analysis procedure is to select the node between the reservoir and piping system. The inflow and outflow expressions for the simple system will then be:

Inflow to node:

$$\overline{PR} - \Delta Pres. = P_{wf} \qquad 4\text{-}10$$

Outflow from node:

$$P_{sep} + \Delta P\ flowline + \Delta P\ tubing = P_{wf} \qquad 4\text{-}11$$

A producing system may be optimized by selecting the combination of component characteristics that will give the maximum production rate for the lower cost. Although the overall pressure drop available for a system, (P_{res}-P_{sep}), might be fixed at a particular time, the producing capacity of the system depends on where the pressure drop occurs. If too much pressure drop occurs in one component or module, there may be insufficient pressure drop remaining for efficient performance of the other modules. Even though the reservoir may be capable of producing a large amount of fluid, if too much pressure drop occurs in the tubing, the well performance suffers. For this type of well completion, it is obvious that increasing reservoir performance by stimulation would be a waste of effort unless larger tubing was installed. If tubing is too large, the velocity of the fluid moving up the tubing may be too low to effectively lift the liquids to the surface. This could be caused by either large tubing or low production rates. The fluid velocity is the production rate divided by the area of the tubing[18] , [19] , [35] .

As tubing size is increased, the friction losses decrease, which results in a lower P_{wf} and, therefore, a larger inflow. However, as the tubing size is further increased, the well begins loading with liquid and the flow becomes intermittent or unstable. As the liquid level in the well builds, the well will eventually die [18] , [19] , [35]

Once a well that is producing liquids along with the gas reaches the stage in which it will no longer flow naturally, it will usually be placed on artificial lift. The nodal systems analysis approach may used to analyze many producing oil and gas well problems. The procedure can be applied to both flowing and artificial lift wells, if the effect of artificial lift method on the pressure can be expressed as a function of flow rate. The procedure can also be applied to the analysis of injection well performance by appropriate modification of the inflow and outflow expressions. A partial list of possible applications is given as follows[18] :

1. Selecting tubing size
2. Selecting flow line size
3. Gravel pack design
4. Surface choke sizing
5. Subsurface safety valve sizing
6. Analyzing an existing system for abnormal flow restrictions
7. Artificial lift design
8. Well stimulation evaluation
9. Determining the effect of compression on gas well performance
10. Analyzing the effects of perforating density
11. Predicting the effect of depletion on producing capacity
12. Allocating injection gas among gas lift wells
13. Analyzing a multiwell producing system
14. Relating field performance to time

4.7.1 Application of Nodal Analysis to Electrical Submersible Pumping Wells

In order to perform a nodal analysis on a submersible pumping well, the node is selected at the pump. The pump can be handled as an independent component in the system in a manner similar to that used in gravel-packed completions. The node pressure is either the pump intake pressure P_{up} or the pump discharge pressure P_{dn}. The pressure gain that the pump must generate for a particular producing rate is $\Delta P = P_{dn} - P_{up}$. The pressure traverse below the pump will be calculated based on the formation gas/liquid ratio and the casing size. The traverse in the tubing above the pump will be based on the gas/liquid ratio entering the pump and the tubing size. The inflow and outflow expressions are [18]

Inflow:

$$\overline{PR} - \Delta P_{res} - \Delta P_{CSg}\ (below\ pump) = P_{up} \qquad 4\text{-}12$$

Outflow:

$$P_{sep} + \Delta P_{flowline} + \Delta P_{tbg}\ (above\ the\ pump) = P_{dn} \qquad 4\text{-}13$$

The following procedure may be used to estimate the pressure gain and power required to achieve a particular producing capacity.

Inflow:

- Select a value for liquid producing rate $q_{L.}$
- Determine the required P_{wf} for this q_L .using the reservoir performance procedures.
- Determine the pump suction pressure P_{up} using the casing diameter and the total Producing GLR to calculate the pressure drop below the pump
- Repeat for a range of liquid producing rates and plot P_{up} versus. q_L .

Outflow:

- Select a value for $q_{L.}$
- Determine the appropriate GLR for tubing and flow line pressure drop calculations.
- Determine P_{up} and fluid temperature at the pump at this q_L value from inflow calculations.

- Determine dissolved gas Rs at this pressure and temperature.
- Estimate fraction of free gas E_s , separated at the pump. This will be dependent whether or not a downhole separator is to be used. If not use $E_s = 0.5$
- Calculate the GLR downstream of the pump from

$$GLR_{dn} = (1 - E_s) * (R_{total} - R_s * f_o) \quad 4\text{-}14$$

Where:

R_{total} = Total producing gas/liquid ratio,

R_s = Solution gas/oil ratio at suction conditions, and

f_o = Fraction of oil flowing

- Determine P_{dn} using GLR_{dn} to calculate the pressure drop in the tubing and the flowline if the casing gas is vented. If the casing tied into the flow line, the total GLR will be used to determine the pressure drop in the flow line.
- Repeat for a range of q_L and plot P_{dn} vs. q_L on the same graph.
- Select various producing rates and determine the pressure gain Δp required to achieve an intersection of the inflow and outflow curves at these rates. The suction and discharge pressures can also be determined for each rate.
- Calculate the power requirement, pump size, number of stages, etc., at each producing rate.

The required horsepower can be calculated from:

$$\text{HP} = 1.72 \times 10^{-5} \times \Delta P \times (q_0\ B_o + q_w\ B_o) \qquad 4\text{-}15$$

Where:

HP = horsepower required

Δp = pressure gain, psi

q_o = oil rate, STB/day

q_w = water rate, STB/day

Bo = oil formation volume factor at suction conditions, bbl/STB, and

Bw = water formation volume factor at suction conditions

The pressure gain can be converted to head gain if necessary for pump selection. This is accomplished by dividing the pressure gain by the density of fluid being pumped. The actual plotting of the data is not required if the pump is to be selected for specific rates, as all the necessary information is calculated before plotting.

4.8 Softwares Output Data

4.8.1 Graphs

On the graphs, which can show multiple cases each curve has the case number next to it. Also, all curves for given case are in shades of the same colour.

The available graphs in the Softwares are listed below [29] ' [34]

- Inflow performance,
- Inflow performance (W/Gas),
- Pump performance (TDH),
- Pump performance (HP, Eff),
- Standard catalog pump curve,
- Total volume through pump,
- Percent free gas at pump intake,
- Well pump-off time,

- Motor performance,
- Temperature gradient,
- Motor efficiency and power factor,
- Motor name plate amps and RPM,
- Pump performance (TDH and Design), and
- Directional survey.

4.8.2 Reports

The available reports in SubPump and Avocet software are Summary report, detailed report, Limits report, Equipment report, and Input data report [29] , [34]

CHAPTER 5: Results and Discussion

5.1 Introduction

The objective of my work is to present a thorough analysis and production optimization of ESP design based on computer programs package SubPump and Avocet Well Surface Modeler. Based on detailed data gathered from five wells in the Sarir Field C-001-65, C-046-65, C-101-65, C-105-65, and C-144-65, calculations were performed to:

- Check and analysis the present Installation,
- Optimizing the pump setting depth by using Avocet well and Surface Modeler software.
- Optimize the rate and minimize the discharge pressure of the pump , power consumption and number of stages based on combined ESP/Gas lift (hybrid) by using SubPump Software,

5.2 WELL NO. C-001-65

- Well History

C-001-65 was completed as an oil producer in April 1961. During a workover in November 1991, the well was equipped with an ESP. Present estimated reservoir static pressure is 2400 Psi at datum level of 8595 Ft GL. Present production intervals are: (8626`-8740`)ft and (8750`-8804`)ft .

- Casing and Tubing Data

Table 5-1shows the data of Casing and Tubing for Well C-001-65

Table 5-1: Casing and Tubing for Well C-001- 65 [26]

Item	OD, in	ID, in	Weight, Ib/ft	Roughness	Depth ,ft
Casing	13 3/8	12.415	68	0.00065	2905
Casing	9 5/8	8.681	47	0.00065	8217
Casing	7	6.366	23	0.00065	9082
Tubing	3 1/2	2.992	9.3	0.00065	5417

- Well Testing Data

Table 5-2 summarizes production test data for C-001 -65, which is based upon the recent well testing report dated on 25/04/2009. **Figure 5-1** gives details of oil, water production and water cut from June 1978 to June 2008.

Table 5-2: Production Test Data for Well C-001-65 [26]

Static Bottom Hole Pressure (psi)	2400
Flowing Bottom Hole Pressure (psi)	2235
Bubble Point Pressure (psi)	600
Productivity Index (PI) (bbl/day/psi)	14.8
Gross Fluid Rate (STB/day)	2450
Well Head Pressure (psi)	150
Casing Pressure (psi)	10
Gas Oil Ratio GOR (SCF/STB)	230
Choke (in)	48/64
Water Cut (WC)	51%
Salinity (ppm)	130877
Oil Specific Gravity (γ_o)	0.85
Water Specific Gravity (γ_w)	1.1
Gas Specific Gravity (γ_g)	0.91
Bottom Hole Temperature (T_b), F°	225
Well Head Temperature (T_{wh}), F°	117
Dynamic Fluid Level (ft)	2445
Perforations Depth (ft)	8626

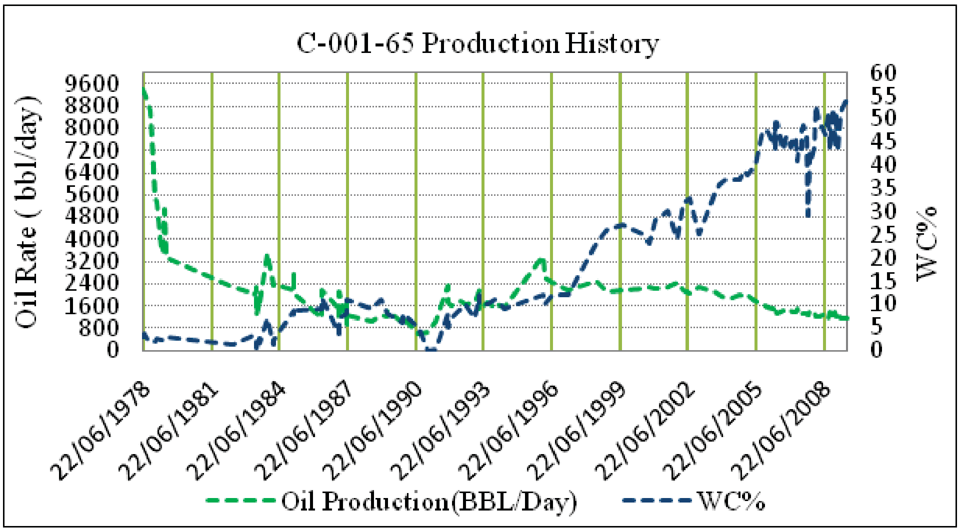


Figure 5-1 : C-001-65 Production History [26]

- Current Electrical Submersible Pump Data for well C-001-65

Table 5-3: Current ESP Data of Well C-001-65 [26]

Installation Date	14/03/2007
Pump Type	GN-3100 , 120 Stage
Motor Type	456series ,4142, 168 hp, 2506 v ,43 Am
Protector Type	LSB
Setting Depth (ft)	5417

- C-001-65 ESPs Run Life History

Table 5-4 and **Figure 5-2** show the ESPs run life and failure mode of C-001-65 as of 14/03/2007.

Table 5-4: Pump Run Times and Failure Modes for C-001-65 [26]

Pump Type	Installation Date	Failed Date	Run Days	Reason of Failures
GN-2500	20/11/1991	02/03/1993	468	Motor
GN-2500	25/03/1993	03/12/1995	983	Motor Lead Cable
32MOF	08/01/1996	04/05/1997	482	Cable
GN-4000	24/05/1997	10/10/1998	504	Motor
GN-3100	30/10/1998	05/09/2000	676	Cable
GN-4000	10/10/2000	29/04/2003	931	Pig tail and Cable
GN-4000	26/07/2003	05/06/2004	315	Cable
GN-4000	20/08/2004	30/12/2004	132	Cable
GN-4000	30/01/2005	10/02/2006	376	Motor
GN-3100	17/03/2006	15/03/2007	363	Cable
GN-3100	14/03/2007			Running
Average Run Days			523	

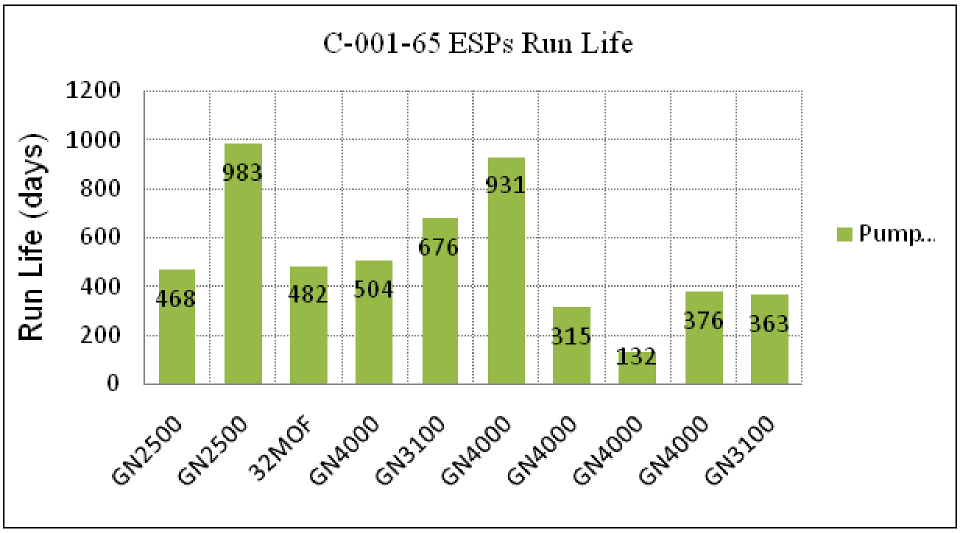


Figure 5-2: ESPs Run Life of C-001-65 [26]

5.2.1 C-001-65 ESP Analysis

One of the objectives of Nodal systems analysis is the determination of the flow rate of a given production system. The solution of this problem is illustrated through this case.

The well C-001-65 as shown in **Figure 5-3** is a higher producer and has a surface choke. The well's production system is divided at Node 6 (see **Figure 4-3**, **CHAPTER 4:**) with one subsystem consisting of the wellhead, the flowline, and the tubing string, and the other being the formation. The pressure vs. rate diagram of the formation is the familiar IPR curve. The other curve is constructed by summing the separator pressure and the pressure drops in the flow line (wellhead pressure curve) and by further adding to these values the pressure drop in the tubing string. The resulting curve is the tubing intake pressure vs. production rate. The total system's rate is found at the intersection of this curve with the IPR curve and is 3060 BFPD in the present case.

5.2.1.1 C-001-65 Current Installation Analysis

- C-001 -65 Inflow Performance Graph

As shown in **Figure 5-3** the current production rate is 2450 BFPD. The SubPump software shows the total system's rate is found at the intersection of the outflow curve with the IPR curve and is 3060 BFPD.

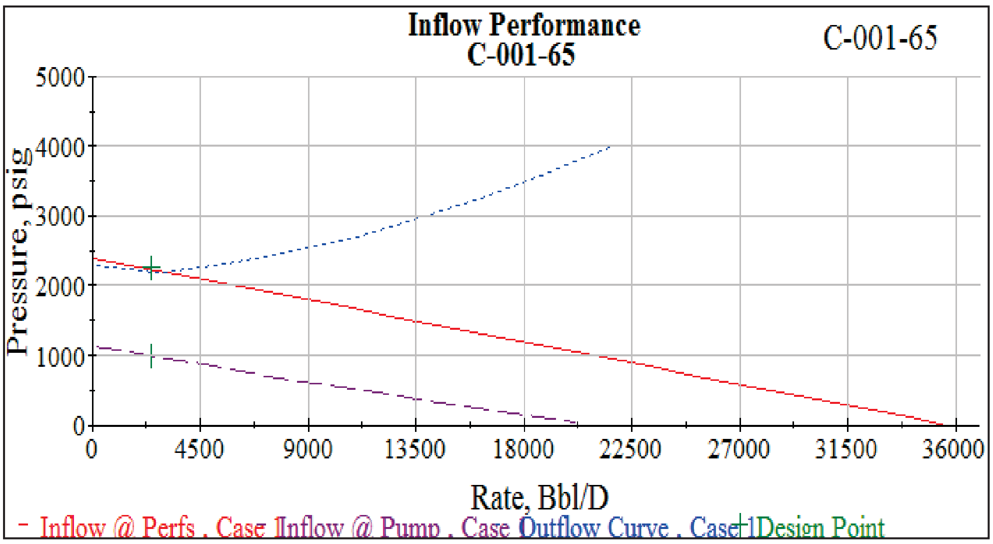


Figure 5-3: Finding the Production Rate for C-001-65 with the Nodal Theory

- C-001-65 the Current Standard Catalog Graph

In **Figure 5-4**, the standard pump catalog graph for Reda Pump GN3100 contains the head, horsepower, and efficiency of the pump as calculated from the coefficients. (This data is based on water).

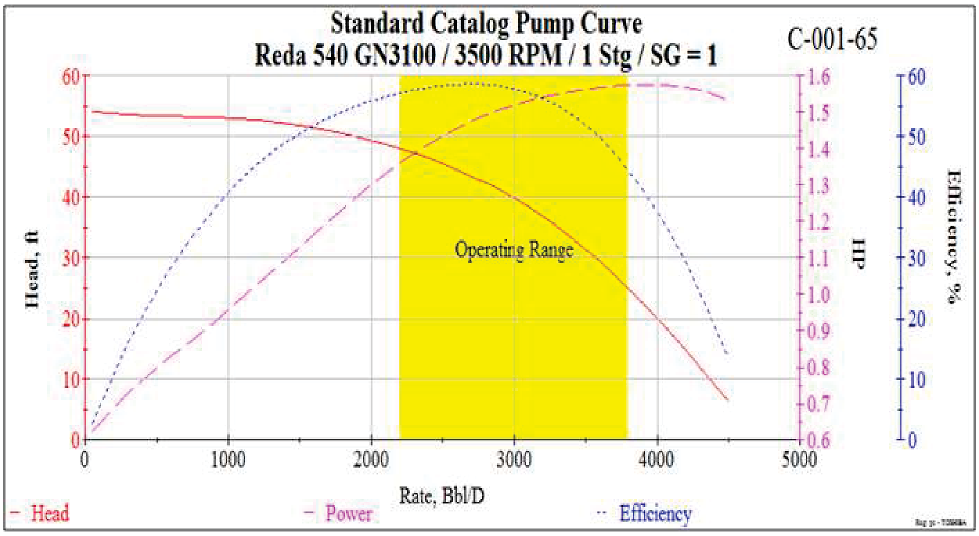


Figure 5-4: Current Standard Catalog Pump Curve

- C-001-65 Pump Performance (HP & Eff)

In **Figure 5-5**, the pump performance and efficiency graph shows the best efficiency point (BEP) of the original equipment GN-3100 in C-001-65.

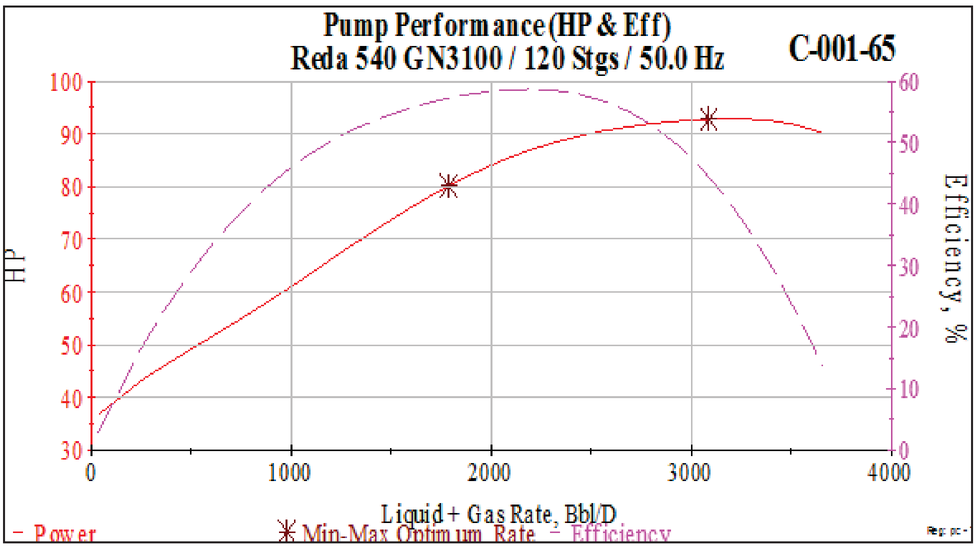


Figure 5-5: C-001-65 the Pump Performance (HP & Eff)

- C-001-65 Performance Curve (TDH @ Design)

In **Figure 5-6**, the pump performance (TDH at Design) graph shows the final design at the design frequency with the operating point located at the intersection of the pump performance curve and the well system curve. Note that the intersection of the curves on this plot represents the point at which the well would be expected to produce under stable condition (2650 STB/D).

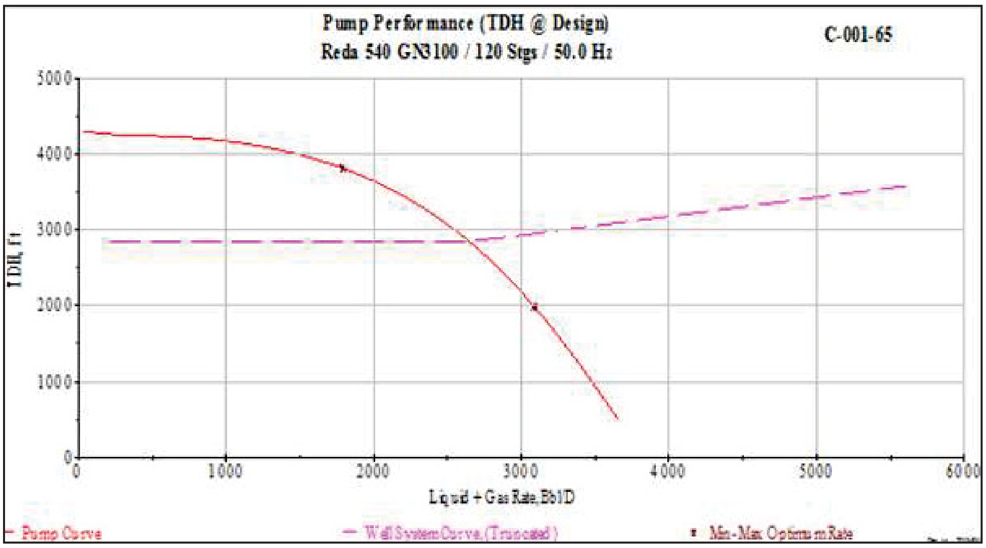


Figure 5-6: Pump Performance Curve (TDH @ Design) of C-001-65

5.2.2 Optimizing the Pump Setting Depth

Based on what have been explained in **SECTION Error! Reference source not found.** of **CHAPTER 4:** the setting depth of the current design of C-001-65 is shifted up with considering that the pump intake pressure (PIP) should be greater than the bubble pint pressure to avoid free gas. By taking into account this fact Avocet well and Surface Modeler software will present the calculation for the optimum pump setting depth, aiming to minimize the tubing length, cable length and the power losses in the system.

- C-001-65 Inflow Performance Graph

As shown in **Figure 5-7** the Avocet well and Surface Modeler software graph shows the IPR curve and the optimum system's rate at pump setting depth 4950 ft. Fluid rate and pump intake pressure are 2603 BFPD, 817 Psia respectively. Based on this rate the pump should be selected.

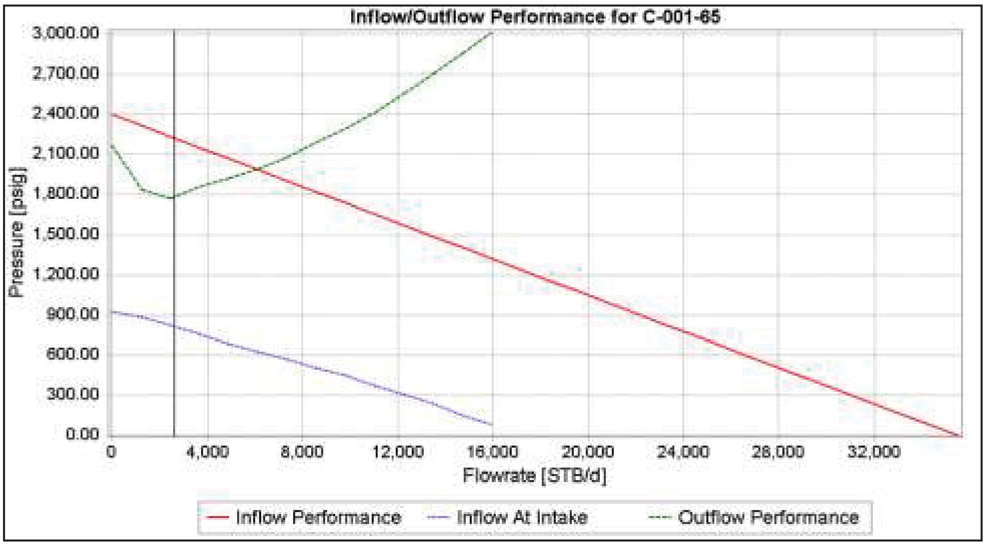


Figure 5-7: Finding the Optimum Production Rate and Minimum Pump Setting Depth for C-001- 65 with Nodal Theory

- C-001-65 Actual Pump Performance Curve at Design Frequency 50 HZ

  In **Figure 5-8** the actual pump performance and efficiency graph shows the recommended pump 400 D3500N needed to handle the rate of 2750 BFPD with 66.37% volumetric efficiency.

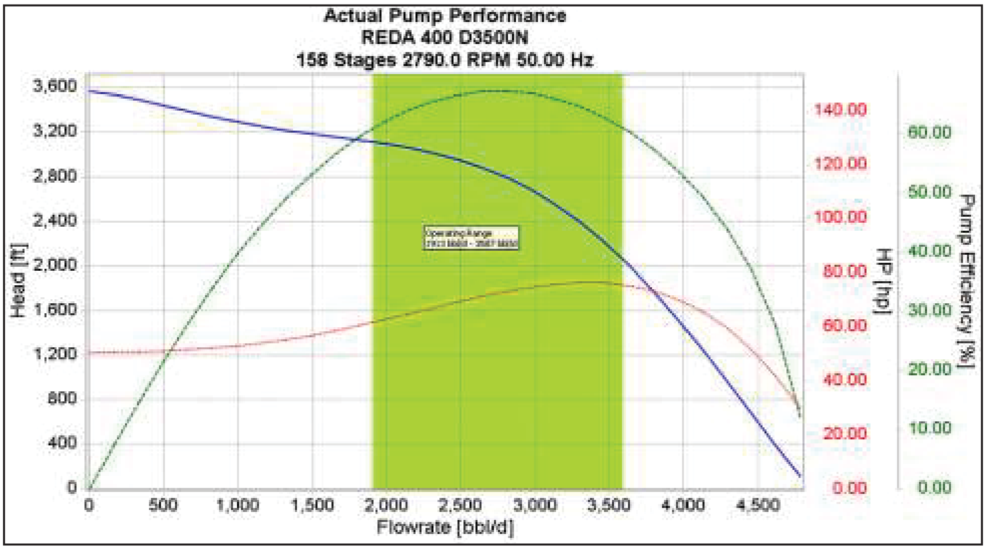


Figure 5-8: Actual Pump Performance

- Pump performance (TDH @ Design)

  In **Figure 5-9**, the pump performance of 400 D3500N pump (TDH at Design) graph shows the final design at the design frequency 50 HZ with the operating point located at the intersection of the pump performance curve and the well system curve.

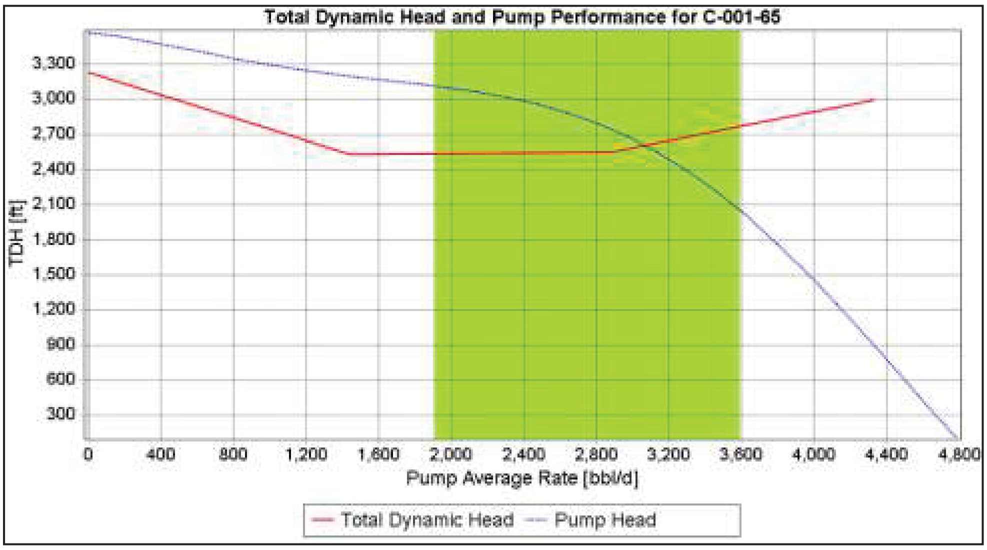


Figure 5-9: Pump Performance (TDH @ Design)

5.2.2.1 Comparison of the current design and proposed design

In the following **Table 5-5**, short comparison of the current and proposed design of finding the optimum pump setting depth for well C-001-65. The calculations required for an actual comparison can be based on the exact analysis and optimization.

As shown in **Table 5-5**, with considering the pump intake pressure, the proper pump installation for optimum pump rate and minimum pump setting depth is selected.

It is obvious that the current installation is not the most efficient stage at the established design conditions. After considering the mentioned criteria, new pump size is selected:

- For optimum pump rate with minimum pump setting depth, pump size 400 D3500N with 158 stages and 66.37% volumetric efficiency is selected. The motor selected is a 100.4hp, 1580.5 V/50 Hz. Total fluid rate increased by 6.4%, from 2447 to 2603 B/D. In addition to 467 feet of tubing (15 joints) and cable are minimized. Cable power losses are minimized by selection of a higher-voltage/lower-amperage motor.

Table 5-5 : C-001-65 Comparison Results of Current Case and Optimizing the Pump Setting Depth case

Item	Current Status	Optimum Design
Pump Data		
Manufacturer	Reda	Reda
Series	540	400
Model	GN3100	D3500N
Number of stages	120	158
Min. Efficiency, %	56.31	66.37
Production Data		
Surface rate (O+W), Bbl/D	2447	2603
Pump Setting Depth, ft	5417	4950
Dynamic fluid level, ft	2972	2980
Fluid over pump, ft	2444	1969
Total dynamic head, ft	2850	2608
Pump intake pressure, Psig	996	818
Motor Data		
Manufacturer	Reda	Reda
Series	456	375AS
Design Frequency, Hz	50	50
Operating power, HP	101	100.5
Cable Data		
Manufacturer	Philip	REDA
Type	Devi lead EPDM/Lead	REDALEAD
Size	1 Cu	1 Cu
Shape	Flat	Flat
Length	5517	5050

5.2.3 Combined ESP and Gas lift (Hybrid)

The application of combined artificial lift systems yields improved production in terms of costs and rates at better conditions than could be expected from using only one of the individual systems. So in this study have been suggested to combining gas lift method as a secondary method with the existing lifting method (ESPs) in C-001-65.To achieve the benefits of gas injection; one gas lift mandrel and valve are located at 4000 feet from surface and about 1000 feet above the pump and the optimal amount of gas injection is 200M scf/day. Calculations are performed by using SubPump software. **Table 5-6** shows a summary of the calculations and benefits from the ESP-GL system in C-001-65 with keeping the current design. The key issue for the changes and benefits, as a result of injecting gas to lighten the fluid column, is the reduction in the pump discharge pressure. There is reduction up to 460 psi, with a percentage of 21 % as compared with the discharge pressure of a regular ESP system. All the other results and benefits are proportional to this pressure reduction.

Table 5-6: Summary of the Calculations of “Electrogas” Combined System in the C-001-65

Description		
Gas injection Point ,ft	4000	
Amount of gas injection , MSCF/day	200	
Production Conditions	Before gas injection	After gas injection
Fluid Rate , BFPD	2447	2451
Water cut , %	51	51
Pump Discharge Pressure ,psi		
Current ESP , psi	2177.2	
ESP-GL , psi	1749	
Reduction , psi	428.2	
Required Equipment size saving		
Stages before gas injection	120	
Stages after gas injection	77	
Saving stages , %	36	
TDH reduction , %	36	
Required HP before gas injection	101 /50 HZ	
Required HP after gas injection	65.7 /50 HZ	
Saving HP , %	35	

5.2.3.1 Proposed Design with Gas Injection

The current design of C-001-65 has been redesigned to be compatible with increasing the rate as result of the benefits of gas injection and production optimization by combined ESP/GL systems. The selected pump is 540 GN-4000 with 86 stages and 67.35% volumetric efficiency. The motor selected is a 70 hp, 1431.5 V/50 Hz. The **Figure 5-10** & **Figure 5-11** show the standard catalog pump curve and pump performance (TDH @ Design) of the selected pump GN-4000, respectively. Total fluid rate increased by19%, from 2447 to 2914 B/D. In addition to 167 feet of cable and tubing (5.5 joints) are minimized. Cable power losses are minimized by selection of a higher-voltage/lower-amperage motor. **Table 5-7** shows a short comparison of the current and proposed design for well C-001-65.

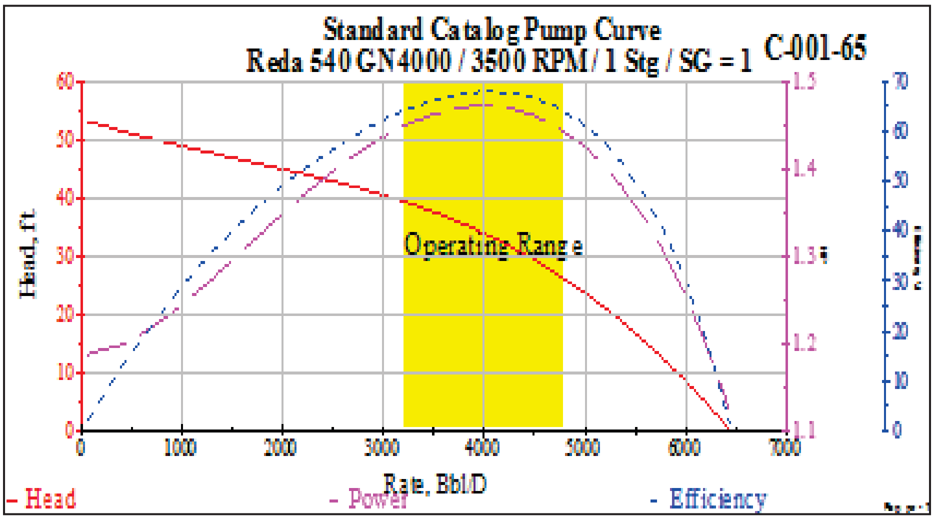


Figure 5-10: Standard Catalog of Recommended Pump

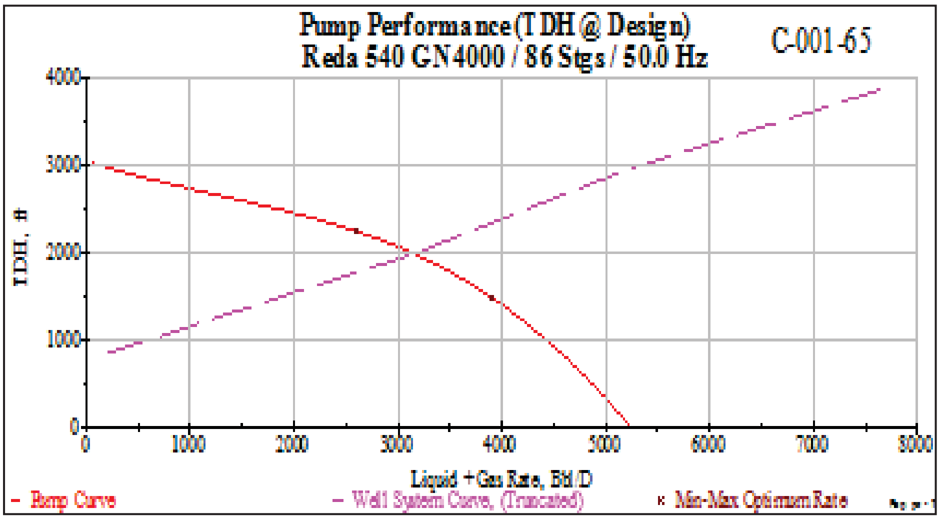


Figure 5-11: Pump Performance (TDH and Design)

Table 5-7: Short Comparison of the Current and Proposed Design for Well C-001-65 in Case of Gas injection

Item	Current Status	Proposed Design With 200 M SCF/D Gas Injection at 4000 ft
Pump	GN-3100	GN-4000
Stages	120	86
Rate (bbl/day)	2449	2916
Depth (FT)	5417	5250
Required Power (HP) @ 50HZ	101.1	70.1
TDH (ft)	2851	1984
Discharge pressure	2177	1716
Pump Intake (psi)	996	908

Detailed optimizing and analysis results of C-001-65 for the two mentioned approaches are presented in **APPENDIX A**.

5.3 WELL NO. C-046-65

- Well History

C-046-65 was completed as an oil producer in March 1965. During a workover in July 1991, the well was equipped with an ESP. Present estimated reservoir static pressure is 2600 Psi at datum level of 8546 Ft GL. Present production intervals are: (8570`-8595`)ft , (8603`-8628`)ft , (8635`-8660`)ft and (8672`- 8687`)ft.

- Casing and Tubing Data

Table 5-8 shows the data of Casing and Tubing for Well C-046-65

Table 5-8: Casing and Tubing for Well C-046-65 [26]

Item	OD, in	ID, in	Weight, Ib/ft	Roughness	Depth ,ft
Casing	13 3/8	12.415	68	0.00065	2899
Casing	9 5/8	8.921	36	0.00065	7083
Casing	7	6.366	23	0.00065	9019
Tubing	3 1/2	2.992	9.3	0.00065	5048

- Well Testing Data

Table 5-9 summarizes production test data for C-046 -65, which is based upon the recent well testing report dated 0n 02/07/2009. **Figure 5-12** gives details of oil, water production and water cut from June 1978 to June 2008.

Table 5-9: Production Test Data for Well C-046-65 [26]

Static Bottom Hole Pressure (psi)	2600
Flowing Bottom Hole Pressure (psi)	2433
Bubble Point Pressure (psi)	600
Productivity Index (PI) (bbl/day/psi)	15
Gross Fluid Rate (STB/day)	2870
Well Head Pressure (psi)	150
Casing Pressure (psi)	20
Gas Oil Ratio GOR (SCF/STB)	185
Choke (in)	64/64
Water Cut (WC)	46%
Salinity (ppm)	195000
Oil Specific Gravity (γ_o)	0.84
Water Specific Gravity (γ_w)	1.152
Gas Specific Gravity (γg)	0.91
Bottom Hole Temperature (T_b), F°	225
Well Head Temperature (T_{wh}), F°	117
Dynamic Fluid Level (ft)	2142
Perforations Depth (ft)	8570

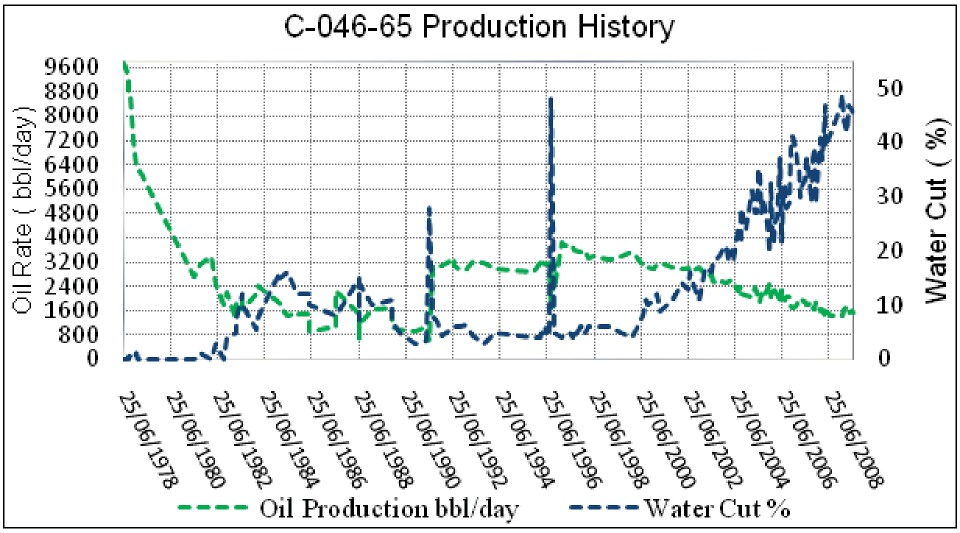


Figure 5-12: C-046-65 Production History [26]

- Current Electrical Submersible Pump Data for well C-046-65

Table 5-10: Current ESP Data of Well C-046-65[26]

Installation Date	11/11/2008
Pump Type	GN-4000 , 105 Stage
Motor Type	456series ,4104 , 120 hp, 1588 v , 48.5 Am
Protector Type	LSB
Setting Depth (ft)	5048

- C-046-65 ESPs Run Life History

Table 5-11 and **Figure 5-13** show the ESPs run life and failure mode of C-046-65 as of 11/08/2008.

Table 5-11: Pump Run Times and Failure Modes for C-046-65 [26]

Pump Type	Installation Date	Failed Date	Run Days	Reason of Failures
32MOF	21/07/1991	06/11/1992	474	Motor Grounded
GN4000	14/12/1992	11/12/1996	1458	Cable Blown
GN4000	26/01/1997	22/12/1999	1060	Motor Grounded
GN4000	04/02/2000	23/03/2000	48	Protector Failure
GN4000	05/04/2000	24/01/2005	1755	Pig Tail Blown
GN4000	26/02/2005	30/10/2008	1342	Motor Grounded
GN-4000	11/11/2008			Running
Average Run Days			1023	

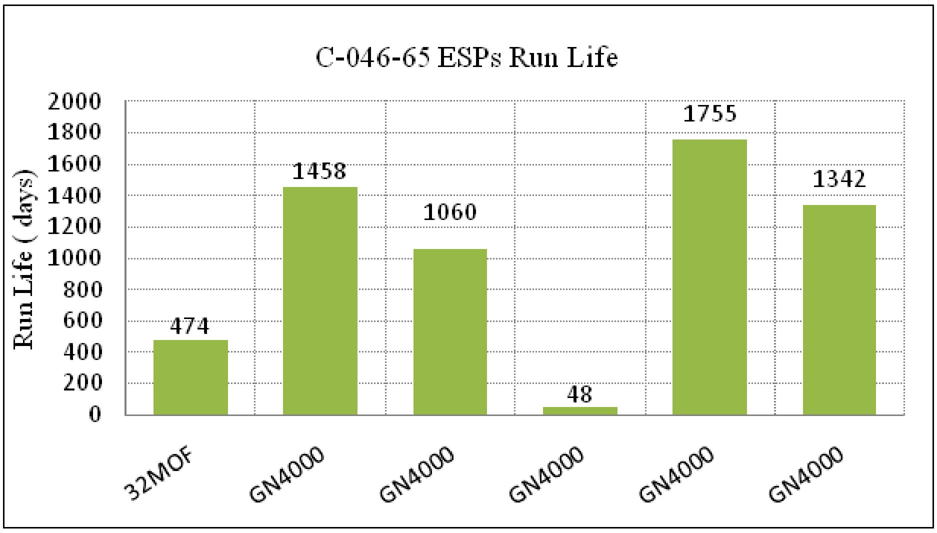


Figure 5-13: ESPs Run Life of C-046-65[26]

5.3.1 C-046-65 ESP Analysis

5.3.1.1 C-046-65 Current installation analysis

As shown in **Figure 5-14** the current production rate is 2870 BFPD. The SubPump software shows the total system's rate is found at the intersection of the outflow curve with the IPR curve and is 6120 BFPD.

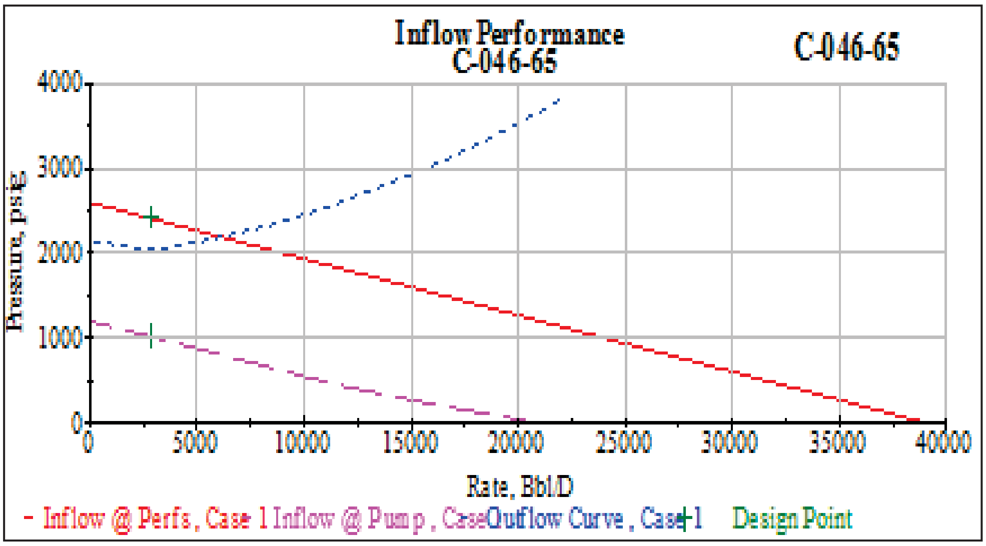


Figure 5-14: Finding the production Rate for C-046-65 with the Nodal Theory

- C-046-65 the Current Standard Pump Catalog Graph

In **Figure 5-15**, the standard pump catalog graph for Reda Pump GN4000 contains the head, horsepower, and efficiency of the pump as calculated from the coefficients. (This data is based on water).

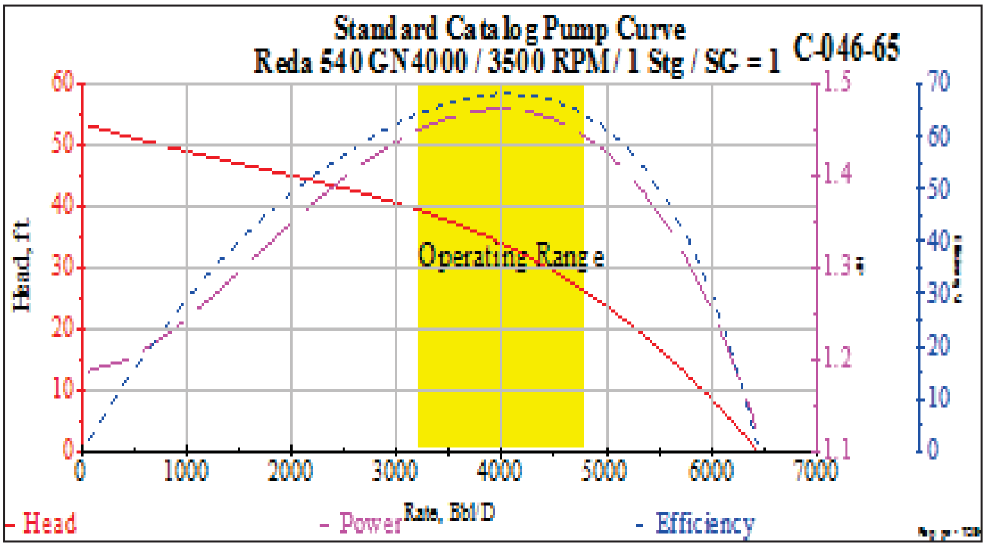


Figure 5-15: Current Standard Catalog Pump Curve

- C-046-65 Pump Performance (HP & Eff)

In **Figure 5-16**, the pump performance and efficiency graph shows the best efficiency point (BEP) of the original equipment GN-4000 in C-046-65.

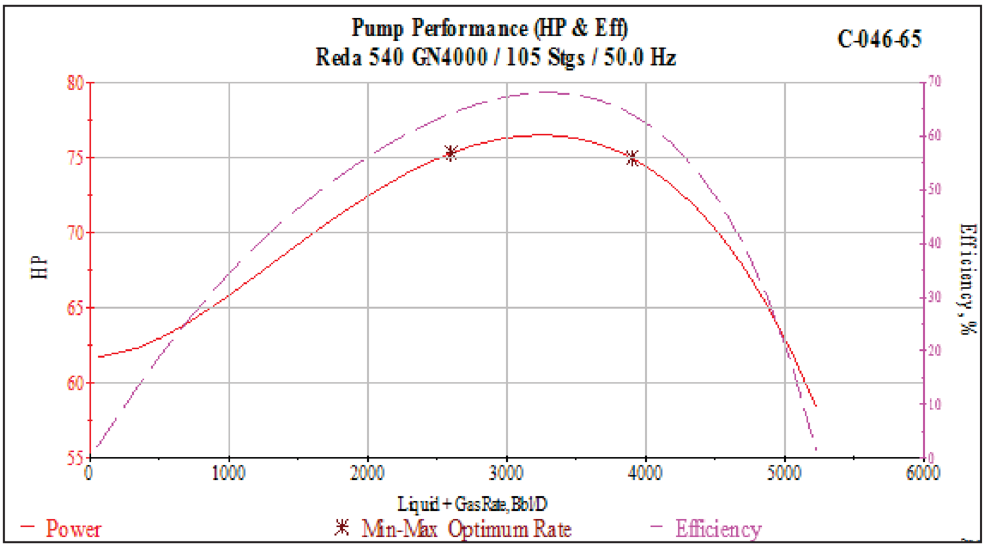


Figure 5-16: C-046-65 Pump Performance (HP and Eff)

- Pump Performance (TDH @ Design)

In **Figure 5-17**, the pump performance (TDH at Design) graph shows the final design at the design frequency with the operating point located at the intersection of the pump performance curve and the well system curve. Note that the intersection of the curves on this plot represents the point at which the well would be expected to produce under stable condition (3070 bbl/day)

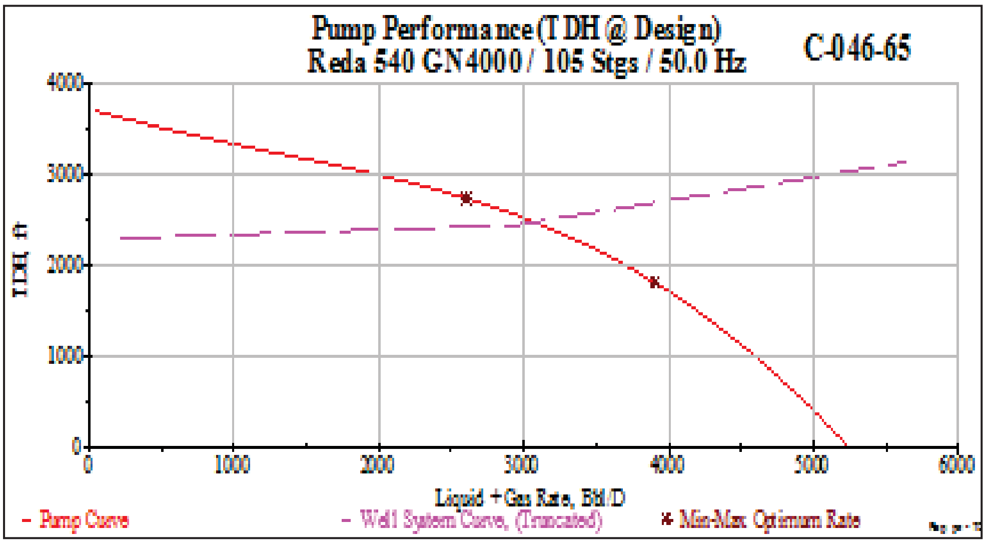


Figure 5-17: C-046-65 Pump Performance (TDH and Design)

5.3.2 Optimizing the Pump Setting Depth

- C-046-65 Inflow Performance Graph at 4668 feet

As shown in **Figure 5-18,** the Avocet software graph shows the IPR curve and optimum system's rate at pump setting depth 4668 ft. Fluid rate and pump intake pressure are 4003 BFPD, 807 Psia, respectively. Based on this rate the pump should be selected.

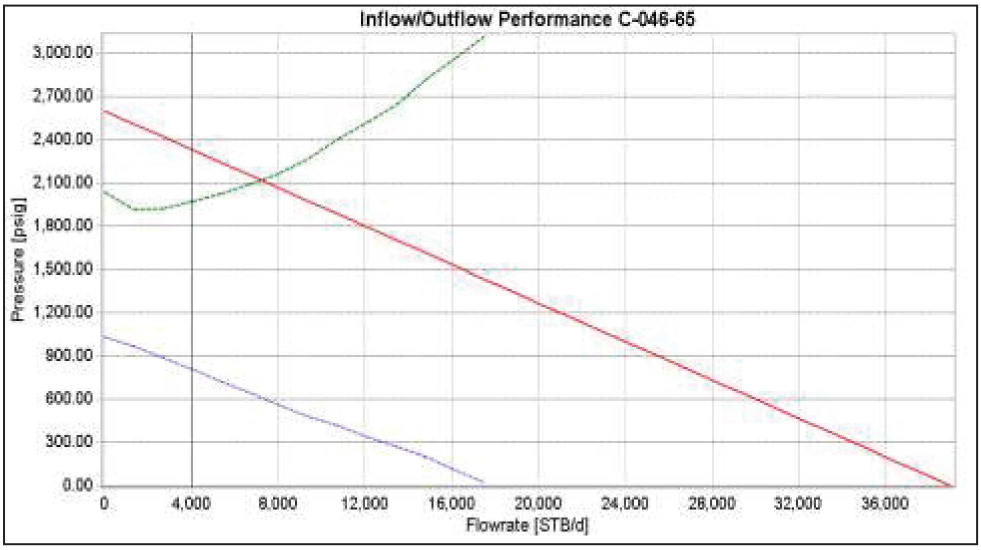


Figure 5-18: Finding the Optimum Production Rate and Minimum Pump Setting

- C-046-65 Pump Performance Curve

Figure 5-19 shows the actual pump performance, pump head, total dynamic head and pump efficiency of the pump 540, GN-5200(150 stages, 66.11% volumetric efficiency) which is selected to handle 4003 bbl/day at design frequency 50 HZ with the operating point located at the intersection of the pump head curve and the well system curve.

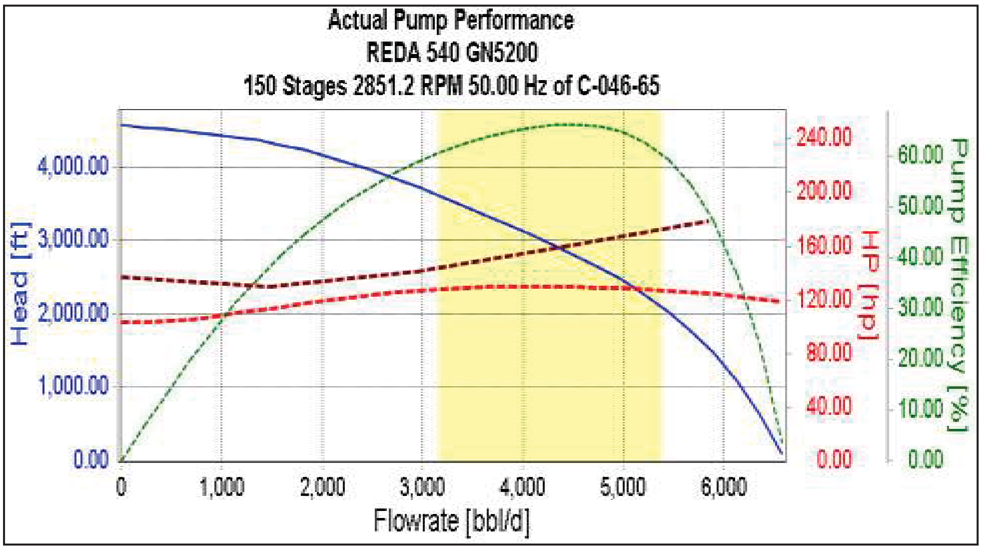


Figure 5-19: Actual Pump Performance & TDH

5.3.2.1 Comparison of the current and proposed design

In the following **Table 5-12**, short comparison of the current and proposed design of finding the optimum pump setting depth for well C-046-65. The calculations required for an actual comparison can be based on the exact analysis and optimization, as shown in **Table 5-12**. With considering the pump intake pressure, the proper pump installation for optimum pump rate and minimum pump setting depth is selected.

It is apparent that the current installation is not the most efficient stage at the established design conditions. After considering the mentioned approach, new pump size is selected:

- For optimum pump rate with minimum pump setting depth, pump size 540 GN-5200 with 150 stages and 66.11% volumetric efficiency is selected. The motor selected is a 150 hp, 1893.4 V/50 Hz. Total fluid rate increased by 40%, from 2850 to 4003 B/D. Besides 380 feet of tubing (12 joints) and cable are minimized. Cable power losses are minimized by selection of a higher-voltage/lower-amperage motor.

Table 5-12: C-046-65 Comparison Results of Current Case and Optimizing Pump Setting Depth Case

Item	Current Status	Optimum Design
Pump Data		
Manufacturer	Reda	Reda
Series	540	540
Model	GN4000	GN5200
Number of stages	105	150
Min. Efficiency, %	67.34	66.11
Production Data		
Surface rate (O+W), Bbl/D	2850	4003
Pump Setting Depth, ft	5048	4668
Dynamic fluid level, ft	2594	2737
Fluid over pump, ft	2454	1930
Total dynamic head, ft	2475	2906
Pump intake pressure, Psig	1013	807
Motor Data		
Manufacturer	Reda	Reda
Series	456	456
Design Frequency, Hz	50	50
Operating power, HP	85.6	160
Cable Data		
Manufacturer	Philip	REDA
Type	Devi lead EPDM/Lead	REDALEAD
Size	1 Cu	1 Cu
Shape	Flat	Flat
Length	5148	4768

5.3.3 Combined ESP and Gas lift (Hybrid)

The function of combined artificial lift systems yields enhanced production in terms of costs and rates at better conditions than could be expected from using only one of the individual systems. therefore in this study have been suggested to combining gas lift method as secondary method with ESP in C-046-65.In order to achieve the benefits of gas injection; one gas lift mandrel and valve are located at 4000 feet from surface and about 1000 feet above the pump and the optimal amount of gas injection is 300 Mscf/day. Calculations are performed by using SubPump software. **Table 5-13** shows a summary of the calculations and benefits from the ESP-GL system in C-046-65. The key issue for the changes and benefits, as a result of injecting gas to lighten the fluid column, is the reduction in the pump discharge pressure. There is reduction up to 250 psi, with a percentage of 14 % as compared with the discharge pressure of a regular ESP system. All the other results and benefits are proportional to this pressure reduction.

Table 5-13: Summary of the Calculations from "Electrogas" Combined System in the C-046-65

Description		
Gas injection Point ,ft	4000	
Amount of gas injection , MSCF/day	300	
Production Conditions	Before gas injection	After gas injection
Fluid Rate , BFPD	2850	2845
Water cut , %	46	46
Pump Discharge Pressure ,psi		
Current ESP , psi	2048	
ESP-GL , psi	1798	
Reduction , psi	250	
Required Equipment size saving		
Stages before gas injection	105	
Stages after gas injection	59	
Saving stages , %	44	
TDH reduction , %	44	
Required HP before gas injection	85.6 /50 HZ	
Required HP after gas injection	49.4 /50 HZ	
Saving HP , %	42.2	

5.3.3.1 Proposed Design with Gas Injection

The current design of C-046-65 has been redesigned to be compatible with increasing the rate as result of the benefits of gas injection and production optimization by combined ESP/GL systems. The selected pump is 540 GN-5200 with 109 stages and 65.8% volumetric efficiency. The motor selected is a 103.9 hp, 2415.5 V/50 Hz. The **Figure 5-20** & **Figure 5-21** show the standard catalog pump curve and pump performance (TDH @ Design) of the selected pump GN-5200, respectively. Total fluid rate increased by 49%, from 2850 to 4272 B/D. **Table 5-14** shows a short comparison of the current and proposed design for well C-046-65.

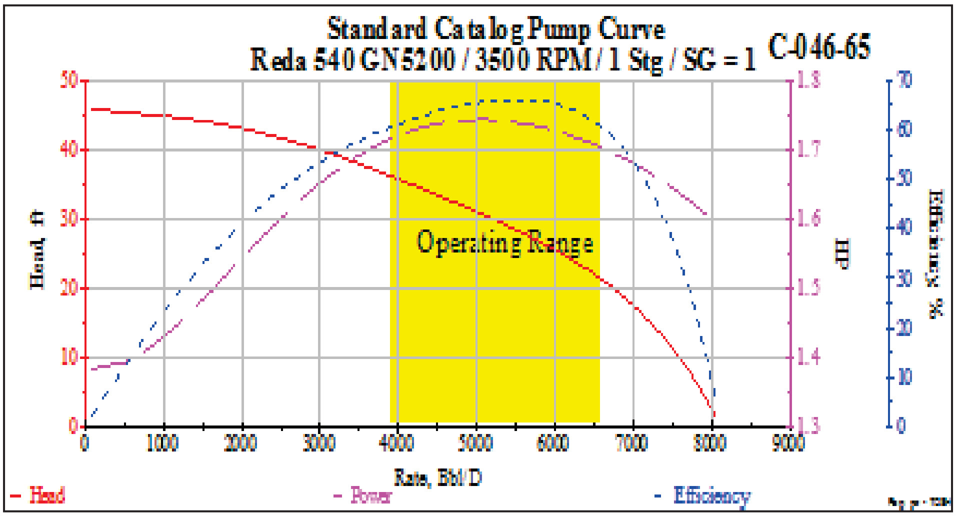


Figure 5-20: Standard Catalog of Recommended Pump

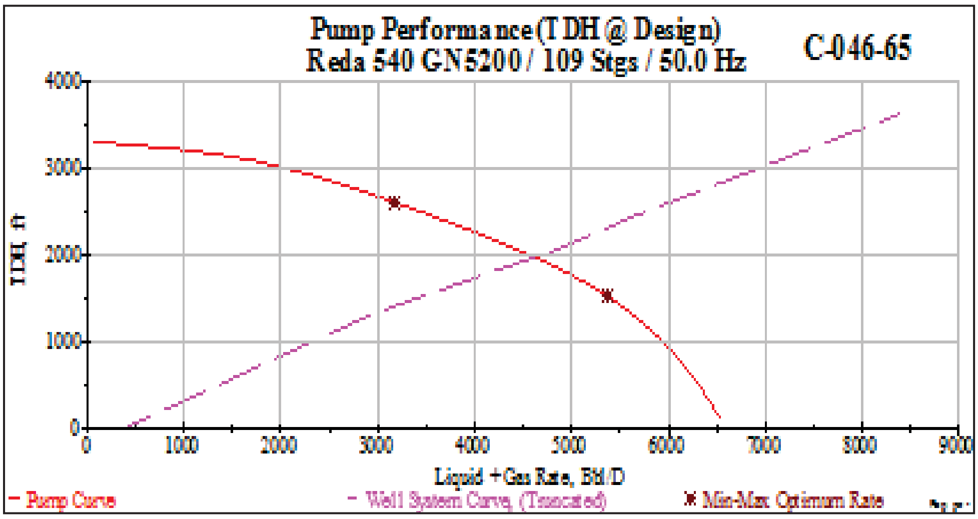


Figure 5-21: Pump Performance (TDH and Design)

Table 5-14: Short Comparison of the Current design and Proposed Design for well C-046-65 in Case of Gas Injection

Item	Current Status	Proposed Design With 300 M SCF/D Gas Injection at 4000 ft
Pump	GN4000	GN-5200
Stages	105	109
Rate (bbl/day)	2850	4272
Depth (FT)	5048	5048
Required Power (HP) @ 50HZ	85.6	49.4
TDH (ft)	2475	2069
Discharge pressure	2047	1798
Pump Intake (psi)	1013	907

Detailed optimizing and analysis results of C-046-65 for the two mentioned approaches are presented in **APPENDIX B**

5.4 WELL NO. C-101-65

- Well History

C-101–65 was completed as an oil producer in April 1971. During a workover in July 1991, the well was equipped with an ESP. Present estimated reservoir static pressure is 2400 Psi at datum level of 8585 ft GL. Present production intervals are: (8610- 8640)ft , (8653-8682)ft , and (8708-8720).

- Casing and Tubing Data

Table 5-15 shows the data of Casing and Tubing for Well C-101-65

Table 5-15: Casing and Tubing for Well C-101-65 [26]

Item	OD, in	ID, in	Weight, Ib/ft	Roughness	Depth ,ft
Casing	13 3/8	12.515	61	0.00065	3152
Casing	9 5/8	8.835	40	0.00065	7145
Casing	7	6.366	23	0.00065	8844
Tubing	3 1/2	2.992	9.3	0.00065	5537

- Well Testing Data

Table 5-16 summarizes production test data for C-101 -65, which is based upon the recent well testing report dated on 21/08/2009. **Figure 5-22** gives details of oil, water production and water cut from June 1978 to June 2008.

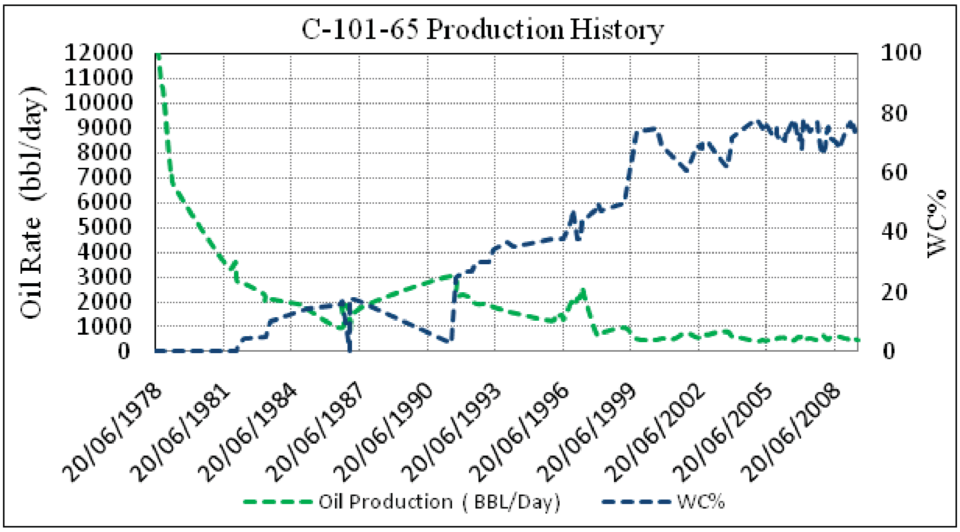


Figure 5-22: C-101-65 Production History [26]

Table 5-16:Production Test Data for Well C-101-65[26]

Static Bottom Hole Pressure (psi)	2400
Flowing Bottom Hole Pressure (psi)	2303
Bubble Point Pressure (psi)	600
Productivity Index (PI) (bbl/day/psi)	19.84
Gross Fluid Rate (STB/day)	1925
Well Head Pressure (psi)	125
Casing Pressure (psi)	20
Gas Oil Ratio GOR (SCF/STB)	185
Choke (in)	48/64
Water Cut (WC)	73%
Salinity (ppm)	39000
Oil Specific Gravity (γ_o)	0.85
Water Specific Gravity (γ_w)	1.028
Gas Specific Gravity (γ_g)	0.91
Bottom Hole Temperature (T_b), F°	225
Well Head Temperature (T_{wh}), F°	117
Dynamic Fluid Level (ft)	2425
Perforations Depth (ft)	8610

- Current Electrical Submersible Pump Data for Well C-101-65

Table 5-17: Current ESP Data of Well C-101-65[26]

Installation Date	21/03/2008
Pump Type	GN-2000 , 145 Stage
Motor Type	456series ,4083 , 93.1 hp/60HZ, 1431 v , 43 Am
Protector Type	LSB
Setting Depth (ft)	5537

- C-101 -65 ESPs Run Life History

Table 5-18 and **Figure 5-23** show the ESPs run life and failure mode of C-101-65 as of 21/03/2008.

Table 5-18: Pump Run Times and Failure Modes for C-101-65 [26]

Pump Type	Installation Date	Failed Date	Run Days	Reason of Failures
GN3100	07/07/1991	27/08/1996	1878	Pump Worn Out
GN4000	12/10/1996	10/04/1997	180	Motor Grounded
GN4000	29/04/1997	07/06/1997	39	Motor Grounded
GN4000	12/07/1997	02/08/1997	21	Motor Grounded
GN2000	23/08/1997	16/04/1998	236	No Flow
GN2000	01/07/1998	26/02/2001	971	Cable Grounded
GN1600	01/05/2001	17/04/2002	351	Motor grounded
GN2000	04/06/2002	03/07/2004	760	Motor Grounded
GN2000	26/08/2004	18/06/2006	661	Lower pig Tail Blown
P21	24/08/2006	12/03/2008	566	Motor Grounded
GN2000	21/03/2008			Running
Average Run Days			566	

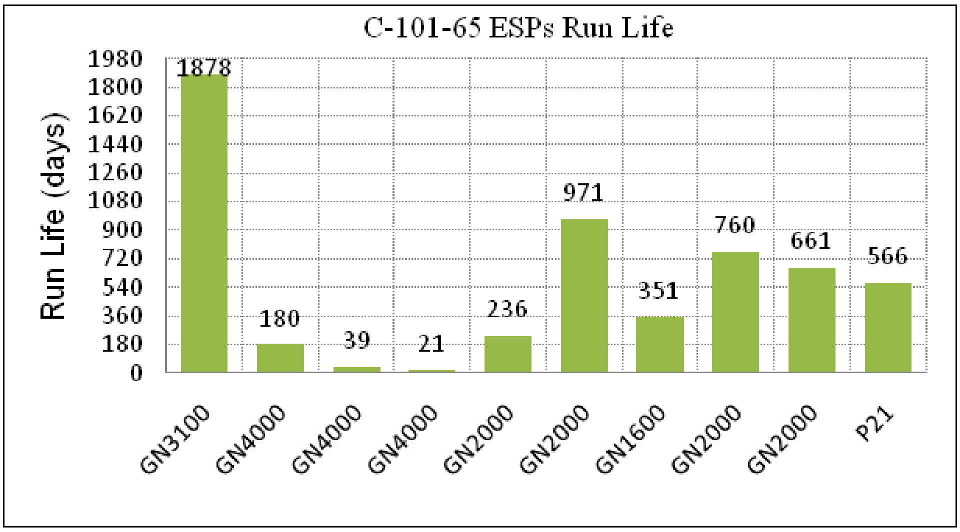


Figure 5-23: ESPs Run Life of C-101-65[26]

5.4.1 C-101-65 ESP Analysis

5.4.1.1 C-101-65 Current installation analysis

As shown in **Figure 5-24**the current production rate is 1925 BFPD. The SubPump software shows the total system's rate is found at the intersection of the outflow curve with the IPR curve and is 2440 BFPD.

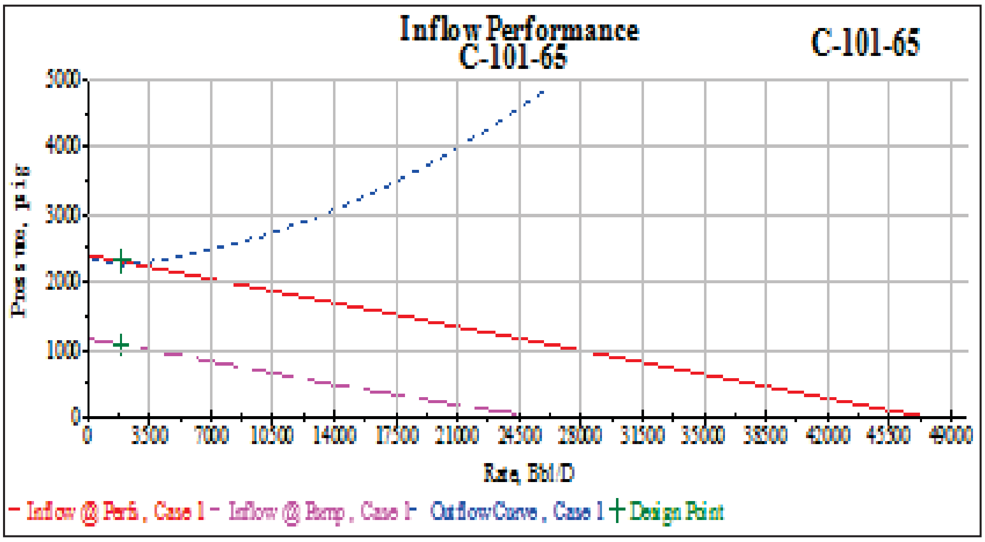


Figure 5-24: Finding the Production Rate for C-101-65 with the Nodal Theory

- C-101-65 the Current Standard Pump Catalog Graph

In **Figure 5-25**, the standard pump catalog graph for Reda Pump GN2000 contains the head, horsepower, and efficiency of the pump as calculated from the coefficients. (This data is based on water).

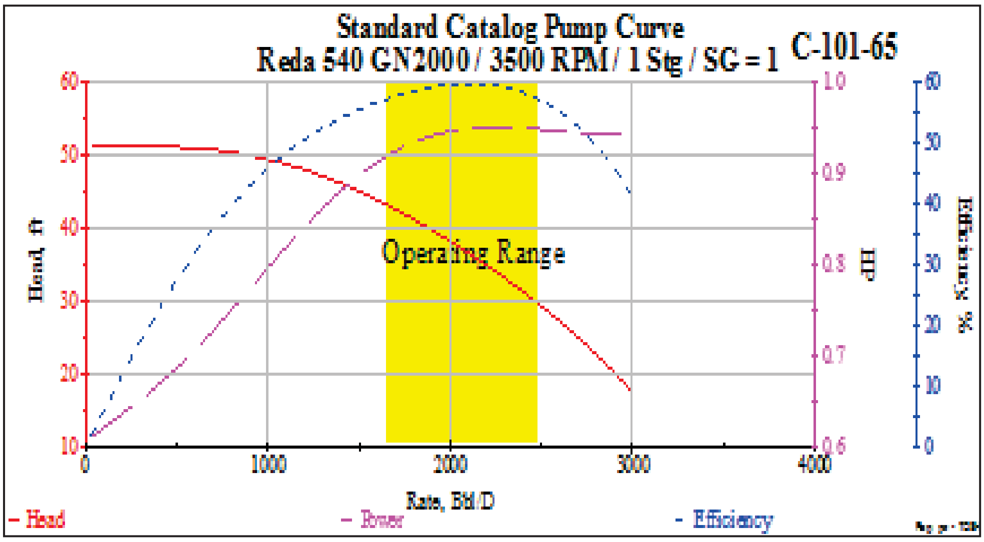


Figure 5-25: Current Standard Catalog Pump Curve

- C-101-65 Pump Performance (HP & Eff)

In **Figure 5-26**, the pump performance and efficiency graph shows the best efficiency point (BEP) of the original equipment GN-2000 in C-101-65.

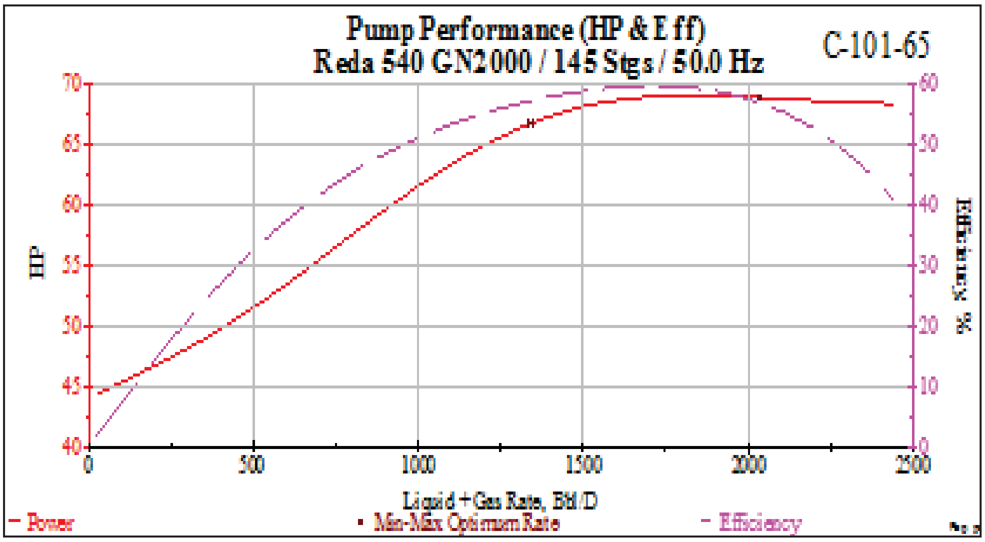


Figure 5-26: C-101-65 Pump Performance (HP and Eff)

- Pump Performance (TDH @ Design)

In **Figure 5-27**, the pump performance (TDH at Design) graph shows the final design at the design frequency with the operating point located at the intersection of the pump performance curve and the well system curve. Note from this graph that the current pump will be operated at flow rate greater than the maximum recommended pumping rate and this leads to destroy the pump in early time. And the intersection of the curves on this plot represents the point at which the well would be expected to produce under stable condition (2018 bbl/day).

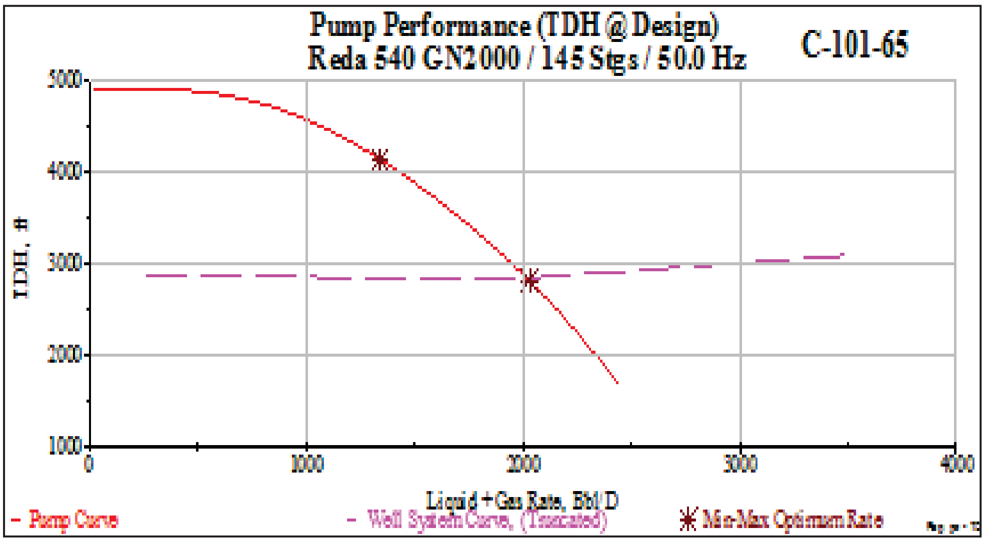


Figure 5-27: C-101-65 Pump Performance (TDH and Design)

5.4.2 Optimizing the Pump Setting Depth

- C-101-65 Inflow Performance Graph at 5000 feet

As shown in **Figure 5-28** the Avocet software graph shows the IPR curve and optimum system's rate at pump setting depth 5000 feet. Fluid Rate and pump intake pressure are 2095 BFPD, 850 Psia, respectively. Based on this rate the pump should be selected.

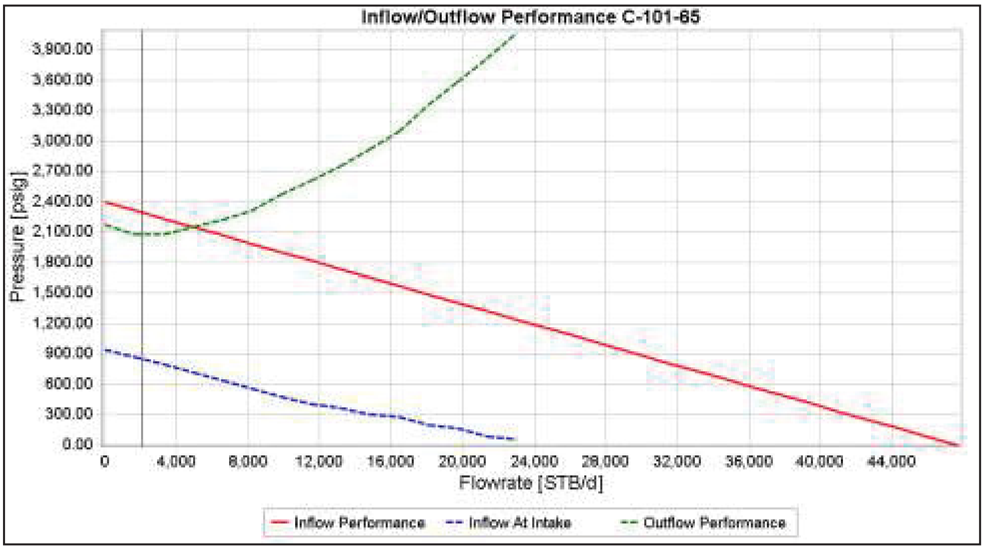


Figure 5-28: Finding the Optimal Production Rate and Minimum Pump Setting Depth of C-101 with Nodal Theory

- C-101-65 Pump Performance Curve

Figure 5-29 shows the actual pump performance, pump head, total dynamic head and pump efficiency of the pump 538, SN-2600, 101 stages ,67.68% volumetric efficiency which is selected to handle 2095 bbl/day at design frequency 50 HZ with the operating point located at the intersection of the pump head curve and the well system curve.

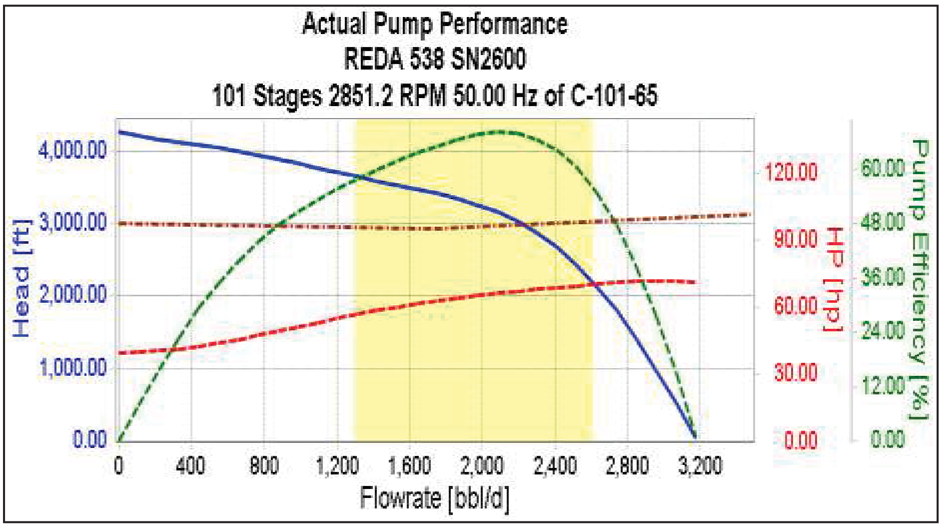


Figure 5-29: Actual Pump Performance & TDH

5.4.2.1 Comparison of the Current design and Proposed Design of C-101-65

In the following **Table 5-19**, short comparison of the current and proposed design of finding the optimal pump setting depth for well C-101-65. The calculations required for an actual comparison can be based on the exact analysis and optimization, as shown in **Table 5-19.** With considering the pump intake pressure, the proper pump installation for optimum pump rate and minimum pump setting depth is selected.

It is obvious that the current installation is not the most efficient stage at the established design conditions after considering the mentioned approach; therefore new pump size is selected.

- For optimum pump rate with minimum pump setting depth, pump size 538 SN-2600 with 101 stages and 67.68% volumetric efficiency is selected. The motor selected is a 98.7 hp, 1324.3 V/50 Hz. Total fluid rate increased by 9.3%, from 1917 to 2095 B/D. Besides 537 feet of tubing (17 joints) and cable are minimized. Cable power losses are minimized by selection of a higher-voltage/lower-amperage motor.

Table 5-19: Comparison Results of Current Case and Optimizing the Pump Setting Depth Case

Item	Current Status	Optimum Design
Pump Data		
Manufacturer	Reda	Reda
Series	540	538
Model	GN2000	SN2600
Number of stages	145	101
Min. Efficiency, %	57.2	67.68
Production Data		
Surface rate (O+W), Bbl/D	1917	2095
Pump Setting Depth, ft	5537	5000
Dynamic fluid level, ft	2956	2973
Fluid over pump, ft	2580	2027
Total dynamic head, ft	2836	2993
Pump intake pressure, Psig	1074	851
Motor Data		
Manufacturer	Reda	Reda
Series	456	456
Design Frequency, Hz	50	50
Operating power, HP	72.2	98.7
Cable Data		
Manufacturer	Philip	REDA
Type	Devi lead EPDM/Lead	REDALEAD
Size	1 Cu	1 Cu
Shape	Flat	Flat
Length	5637	5100

5.4.3 Combined ESP and Gas lift (Hybrid)

The purpose of combined artificial lift systems yields enhanced production in terms of costs and rates at better conditions than could be expected from using only one of the individual systems. therefore in this study have been suggested to combining gas lift method as secondary method with ESP in C-101-65.To achieve the benefits of gas injection; one gas lift mandrel and valve are located at 4000 feet from surface and about 1000 feet above the pump and the optimal amount of gas injection is 300 Mscf/day. Calculations are performed by using SubPump software. **Table 5-20** shows a summary of the calculations and benefits from the ESP-GL system in C-101-65. The key issue for the changes and benefits, as a result of injecting gas to lighten the fluid column, is the reduction in the pump discharge pressure. There is reduction up to 561 psi, with a percentage of 25 % as compared with the discharge pressure of a regular ESP system. All the other results and benefits are proportional to this pressure reduction.

Table 5-20: Summary of the Calculations of "Electrogas" Combined System in the C-101-65

Description		
Gas injection Point ,ft	4000	
Amount of gas injection , MSCF/day	300	
Production Conditions	Before gas injection	After gas injection
Fluid Rate , BFPD	1917	1922
Water cut , %	73	73
Pump Discharge Pressure ,psi		
Current ESP , psi	2262	
ESP-GL , psi	1701	
Reduction , psi	561	
Required Equipment size saving		
Stages before gas injection	145	
Stages after gas injection	77	
Saving stages , %	47	
TDH reduction , %	47	
Required HP before gas injection	77.6 /50 HZ	
Required HP after gas injection	42.4 /50 HZ	
Saving HP , %	45.3	

5.4.3.1 Proposed Design with Gas Injection

The current design of C-101-65 has been redesigned to be well-matched with increasing the rate of gas injection and production optimization by combined ESP/GL systems. The selected pump is 540 G2700 with 62 stages and 65.55% volumetric efficiency. The motor selected is a 46.5 hp, 1199 V/50 Hz. The **Figure 5-30** & **Figure 5-31** show the standard catalog pump curve and pump performance (TDH @ Design) of the selected pump G2700, respectively. Total fluid rate increased by16.5%, from 1917 to 2235 bbl/d. **Table 5-21** shows a short comparison of the current and proposed design for well C-101-65.

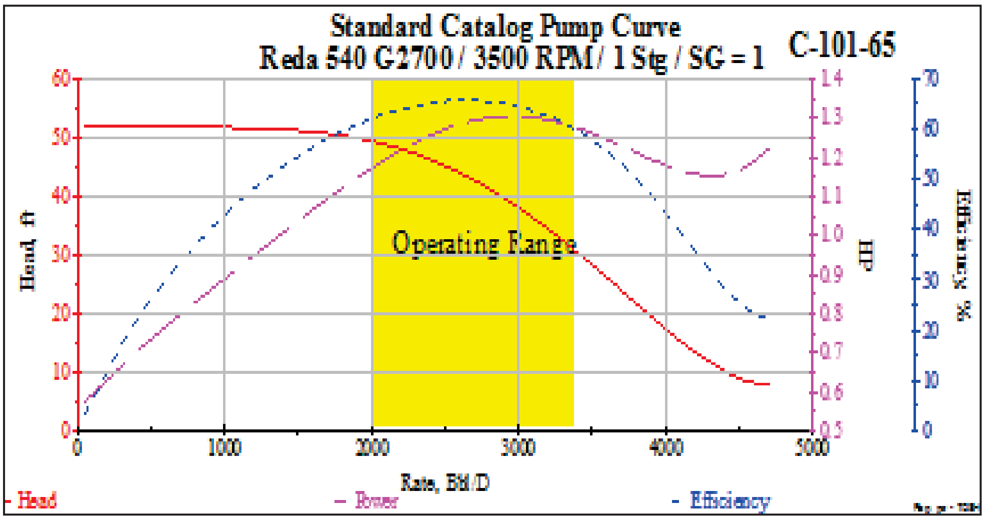


Figure 5-30: Standard Catalog of Recommended pump

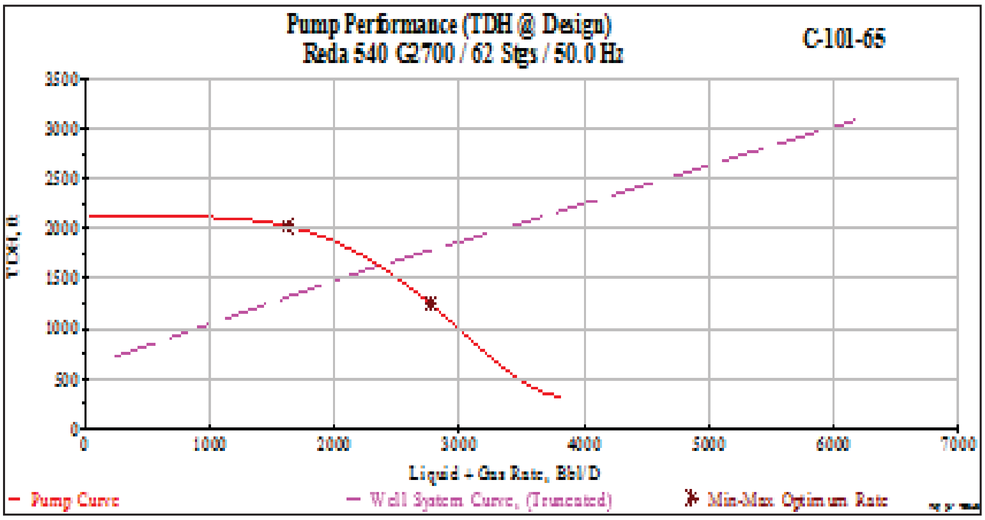


Figure 5-31: Pump Performance (TDH and Design)

Table 5-21: Short Comparison of the Current and Proposed Design of Well C-101-65 in Case of Gas Injection

Item	Current Status	Proposed Design With 300 MSCF/day Gas Injection at 4000 ft
Pump	GN2000	G2700
Stages	145	62
Rate (bbl/day)	1917	2235
Depth (FT)	5537	5337
Required Power (HP) @ 50HZ	77.6	46.4
TDH (ft)	2835	1614
Discharge pressure	2262	1654
Pump Intake (psi)	1074	981

Detailed optimizing and analysis results of C-101-65 for the two mentioned approaches are presented in **APPENDIX C**

5.5 WELL NO. C-105-65

- Well History

C-105 –65 was completed as an oil producer in September 1973. During a workover in November 1992, the well was equipped with ESP. Present estimated reservoir static pressure is 2400 Psi at datum level of 8622ft GL. Present production intervals are: (8648-8664) ft, (8685-8721) ft and (8729-8767) ft.

- Casing and Tubing Data

Table 5-22 shows the data of Casing and Tubing for Well C-105-65

Table 5-22: Casing and Tubing for Well C-105-65[26]

Item	OD, in	ID, in	Weight, Ib/ft	Roughness	Depth ,ft
Casing	13 3/8	12.615	54.5	0.00065	3215
Casing	9 5/8	8.835	40	0.00065	7182
Casing	7	6.366	23	0.00065	8868
Tubing	3 1/2	2.992	9.3	0.00065	5431

- Well Testing Data

Table 5-23 summarizes production test data for C-105-65, which is based upon the recent well testing report dated on 29/08/2009. **Figure 5-32** gives details of oil, water production and water cut from September 1978 to September 2008.

Table 5-23: Production Test Data for Well C-105-65 [26]

Static Bottom Hole Pressure (psi)	2600
Flowing Bottom Hole Pressure (psi)	2233
Bubble Point Pressure (psi)	600
Productivity Index (PI) (bbl/day/psi)	18.5
Gross Fluid Rate (STB/day)	2212
Well Head Pressure (psi)	200
Casing Pressure (psi)	15
Gas Oil Ratio GOR (SCF/STB)	233
Choke (in)	64/64
Water Cut (WC)	42 %
Salinity (ppm)	124160
Oil Specific Gravity (γo)	0.84
Water Specific Gravity (γw)	1.095
Gas Specific Gravity (γg)	0.91
Bottom Hole Temperature (T_b), F°	225
Well Head Temperature (T_{wh}), F°	117
Dynamic Fluid Level (ft)	2330
Perforations Depth (ft)	8648

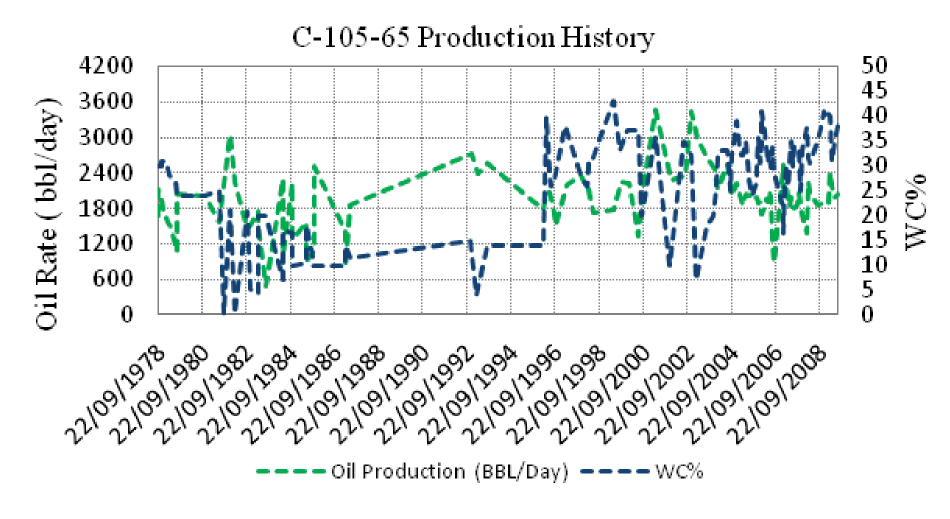


Figure 5-32: C-105-65 Production History [26]

- Current Electrical Submersible Pump Data for well C-105-65

Table 5-24: Current ESP Data of Well C-105-65[26]

Installation Date	16/03/2009
Pump Type	GN4000 , 142 Stage
Motor Type	456 Series ,4124, 131.5 hp, 2147 v ,43 Am
Protector Type	LSB
Setting Depth (ft)	5431

- C-105-65 ESPs Run Life History

Table 5-25and **Figure 5-33**show the ESPs run life and failure mode of C-105-65 as of 14/03/2007.

Table 5-25: Pump Run Times and Failure Modes for C-105-65 [26]

Pump Type	Installation Date	Failed Date	Run Days	Reason of Failures
26MOF	05/11/1992	07/06/1993	214	Motor Grounded
32MOF	21/08/1993	21/01/1995	518	Motor Grounded
32MOF	13/05/1995	22/11/1995	193	Motor Grounded
32MOF	27/12/1995	21/01/1997	391	Motor Grounded & Motor Lead Extension
GN3100	03/02/1997	04/08/1997	182	Motor Lead Grounded, Lower Pig Tail Faulty
GN4000	29/08/1997	11/08/1999	712	Pump Rough and Cable Blown
GN4000	31/08/1999	23/11/1999	84	Motor Grounded, FCE Blown @ Pothead
GN4000	09/01/2000	22/12/2000	348	Pump Seized, Cable Blown
GN4000	06/04/2001	09/06/2003	794	Motor Grounded
GN4000	03/08/2003	12/05/2004	283	Motor Grounded
GN4000	04/07/2004	10/03/2008	1345	Pump Seized and Motor Grounded
GN4000	13/03/2008	09/03/2009	361	Motor Grounded
GN4000	16/03/2009			Running
Average Run Days			452	

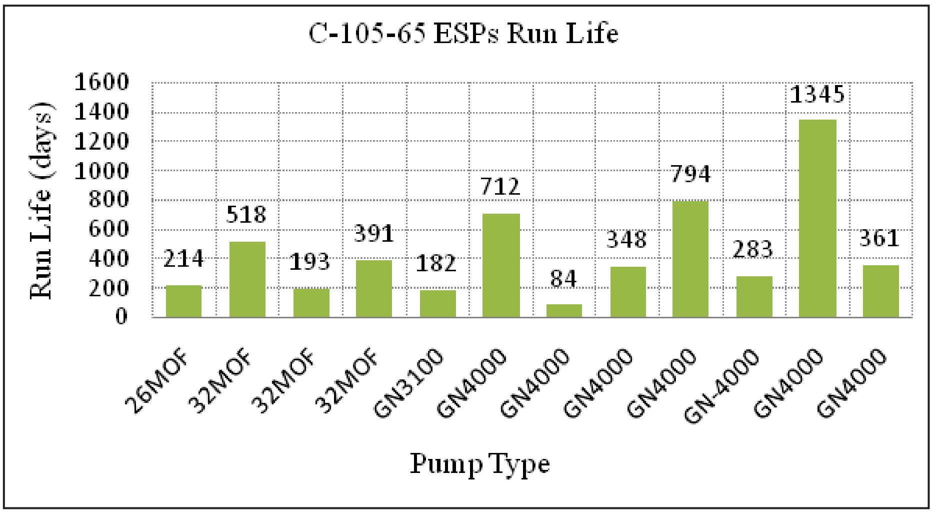


Figure 5-33: ESPs Run Life of C-105-65 [26]

5.5.1 C-105-65 ESP Analysis

5.5.1.1 C-105-65 Current installation analysis

As shown in **Figure 5-34** the current production rate is 3199 BFPD. The SubPump software shows the total system's rate is found at the intersection of the outflow curve with the IPR curve and is 3675 BFPD.

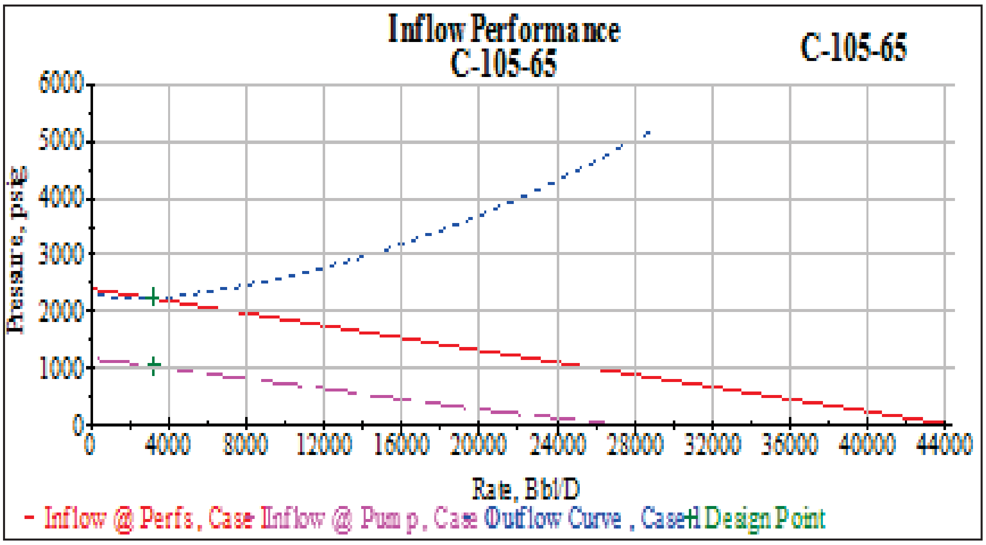


Figure 5-34: Finding the Production Rate for C-105-65 with the Nodal Theory.

- C-105-65 the Current Standard Pump Catalog Graph

In **Figure 5-35**, the standard pump catalog graph for Reda Pump GN4000 contains the head, horsepower, and efficiency of the pump as calculated from the coefficients. (This data is based on water).

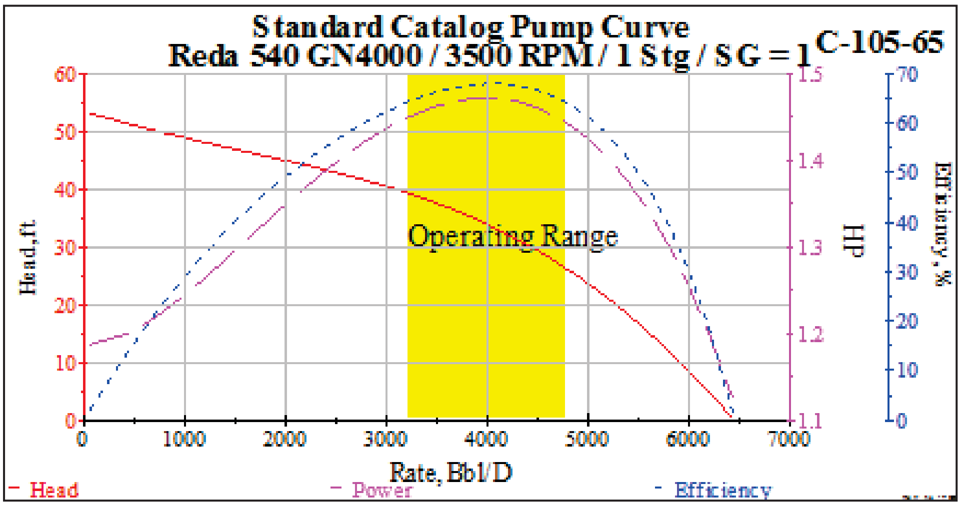


Figure 5-35: Current Standard Catalog Pump Curve

- C-105-65 Pump Performance (HP & Eff)

In **Figure 5-36**, the pump performance and efficiency graph shows the best efficiency point (BEP) of the original equipment GN-4000 in C-105-65.

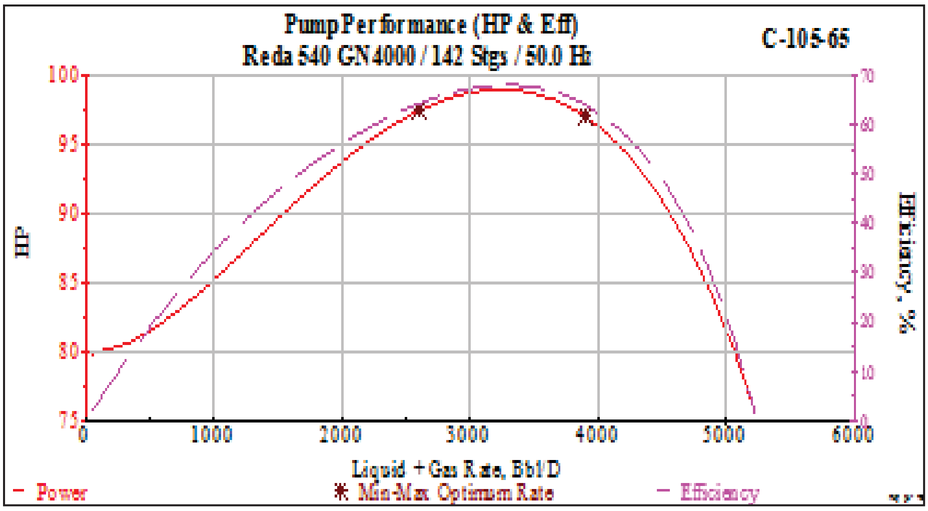


Figure 5-36: C-105-65 Pump Performance (HP and Eff)

- Pump Performance (TDH @ Design)

In **Figure 5-37**, the pump performance (TDH at Design) graph shows the final design at the design frequency with the operating point located at the intersection of the pump performance curve and the well system curve. Note that the intersection of the curves on this plot represents the point at which the well would be expected to produce under stable condition (3070 bbl/day)

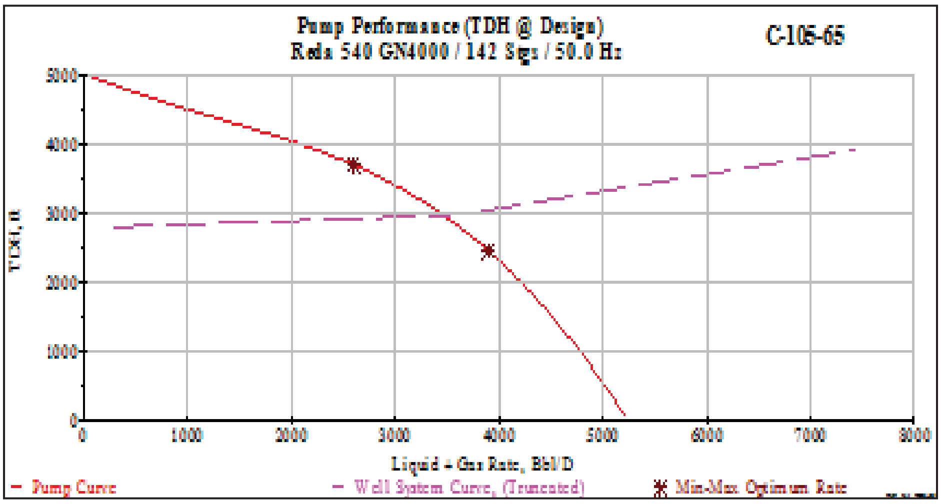


Figure 5-37: C-105-65 Pump Performance (TDH and Design)

5.5.2 Optimizing the Pump Setting Depth

- C-105-65 Inflow Performance Graph at 4900 feet

As shown in **Figure 5-38** the Avocet software graph shows the IPR curve and optimum system's rate at pump setting depth 4900 ft. Fluid rate and pump intake pressure are 3478 BFPD, 842 Psia respectively. Based on this rate the pump should be selected.

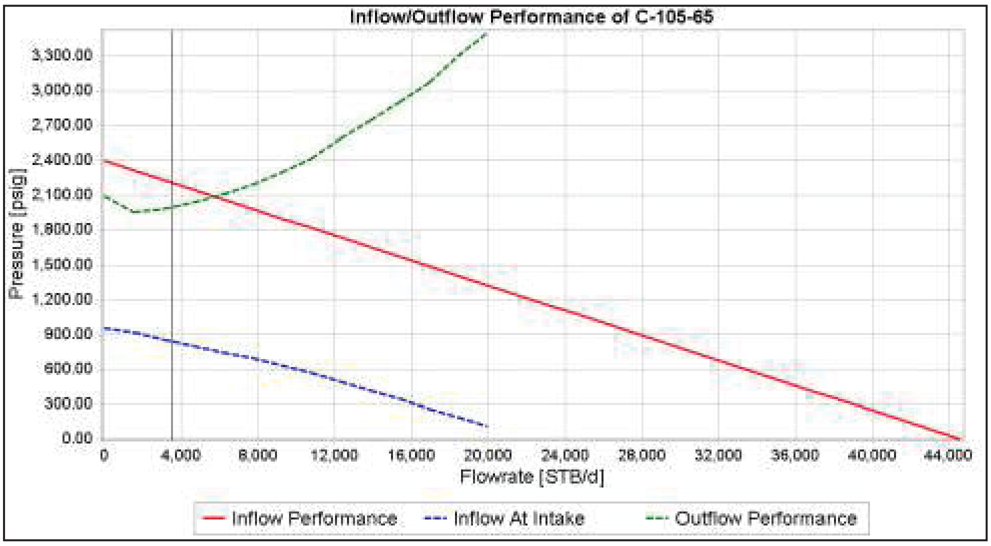


Figure 5-38: Finding the Optimum Production Rate and Minimum Pump Setting Depth for C-105-65 with Nodal Theory

- C-105-65 Pump Performance Curve

Figure 5-39 shows the actual pump performance, pump head, total dynamic head and pump efficiency of the pump 440, D4300N, 245 stages, 68.54% volumetric efficiency which is selected to handle 3478 bbl/day at design frequency 50 HZ with the operating point located at the intersection of the pump head curve and the well system curve.

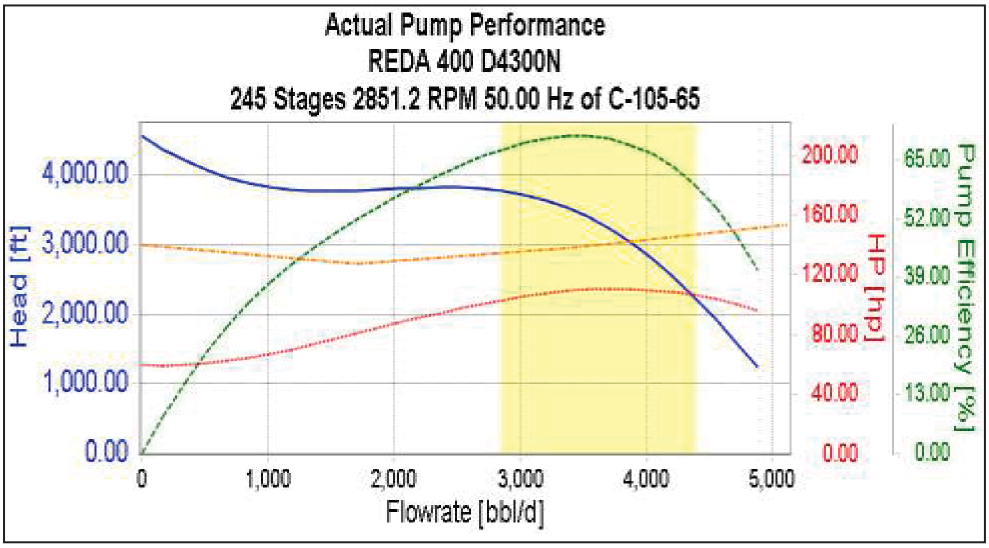


Figure 5-39: Actual Pump Performance & TDH

5.5.2.1 Comparison of the Current design and Proposed Design

In the following, **Table 5-26** short comparison of the current and proposed design of finding the optimum pump setting depth for well C-105-65. The calculations required for an actual comparison can be based on the exact analysis and optimization, as shown in **Table 5-26** with considering the pump intake pressure, the proper pump installation for optimum pump rate and minimum pump setting depth is selected.

It is apparent that the current installation is not the most efficient stage at the established design conditions. After considering the mentioned approach, new pump size is selected:

- For optimum pump rate with minimum pump setting depth, pump size 440 D4300N with 245 stage and 68.54% volumetric efficiency is selected. The motor selected is a 110.5 hp, 1791 V/50 Hz. Total fluid rate increased by 8.7 %, from 3199 to 3478 B/D. In addition to 531 feet of tubing (17 joints) and cable are minimized. Cable power losses are minimized by selection of a higher-voltage/lower-amperage motor.

Table 5-26: C-105-65 Comparison Results of Current Case and Optimizing the Pump Setting Depth Case

Item	Current Status	Optimum Design
Pump Data		
Manufacturer	Reda	Reda
Series	540	440
Model	GN4000	D4300N
Number of stages	142	245
Min. Efficiency, %	67.78	68.54
Production Data		
Surface rate (O+W), Bbl/D	3199	3478
Pump Setting Depth, ft	5431	4900
Dynamic fluid level, ft	2812	2786
Fluid over pump, ft	2619	2113
Total dynamic head, ft	2963	3048
Pump intake pressure, Psig	1037	842
Motor Data		
Manufacturer	Reda	Reda
Series	456	456
Design Frequency, Hz	50	50
Operating power, HP	109.5	110.5
Cable Data		
Manufacturer	Philip	REDA
Type	Devi lead EPDM/Lead	REDALEAD
Size	1 Cu	1 Cu
Shape	Flat	Flat
Length	5531	5000

5.5.3 Combined ESP and Gas lift (Hybrid)

The function of combined artificial lift systems yields improved production in terms of costs and rates at better conditions than could be expected from using only one of the individual systems. Hence in this study have been suggested to combining gas lift method as secondary method with ESP in C-105-65.To achieve the benefits of gas injection; one gas lift mandrel and valve are located at 4000 feet from surface and about 1000 feet above the pump and the optimal amount of gas injection is 250 Mscf/day. Calculations are performed by using SubPump software. **Table 5-27** shows a summary of the calculations and benefits from the ESP-GL system in C-105-65. The key issue for the changes and benefits, as a result of injecting gas to lighten the fluid column, is the reduction in the pump discharge pressure. There is reduction up to 411 psi, with a percentage of 18.5 % as compared with the discharge pressure of a regular ESP system. All the other results and benefits are proportional to this pressure reduction.

Table 5-27: Summary of the Calculations of "Electrogas" Combined System in the C-105-65

Description		
Gas injection Point ,ft	4000	
Amount of gas injection , MSCF/day	250	
Production Conditions	Before gas injection	After gas injection
Fluid Rate , BFPD	3199	3196
Water cut , %	42	42
Pump Discharge Pressure ,psi		
Current ESP , psi	2226	
ESP-GL , psi	1815	
Reduction , psi	411	
Required Equipment size saving		
Stages before gas injection	142	
Stages after gas injection	92	
Saving stages , %	35	
TDH reduction , %	35	
Required HP before gas injection	109.5 /50 HZ	
Required HP after gas injection	72 /50 HZ	
Saving HP , %	34.2	

5.5.3.1 Proposed Design with Gas Injection

The current design of C-105-65 has been redesigned to be well-matched increasing the rate as result of the benefits of gas injection and production optimization by combined ESP/GL systems. The selected pump is 540 GN-5200 with 97 stage and 65.5% volumetric efficiency. The motor selected is a 89.2 hp, 1587.6 V/50 Hz. The **Figure 5-40** & **Figure 5-41** show the standard catalog pump curve and pump performance (TDH @ Design) of the selected pump GN-5200, respectively. Total fluid rate increased by 12.4 %, from 3199 to 3596 B/D. **Table 5-28** shows a short comparison of the current and proposed design for well C-105-65.

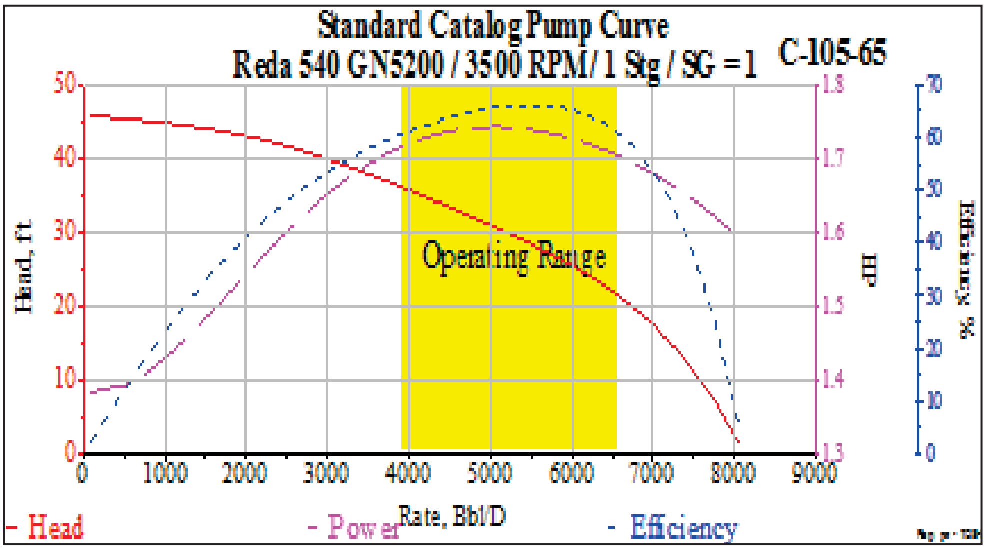


Figure 5-40: Standard Catalog of Recommended Pump

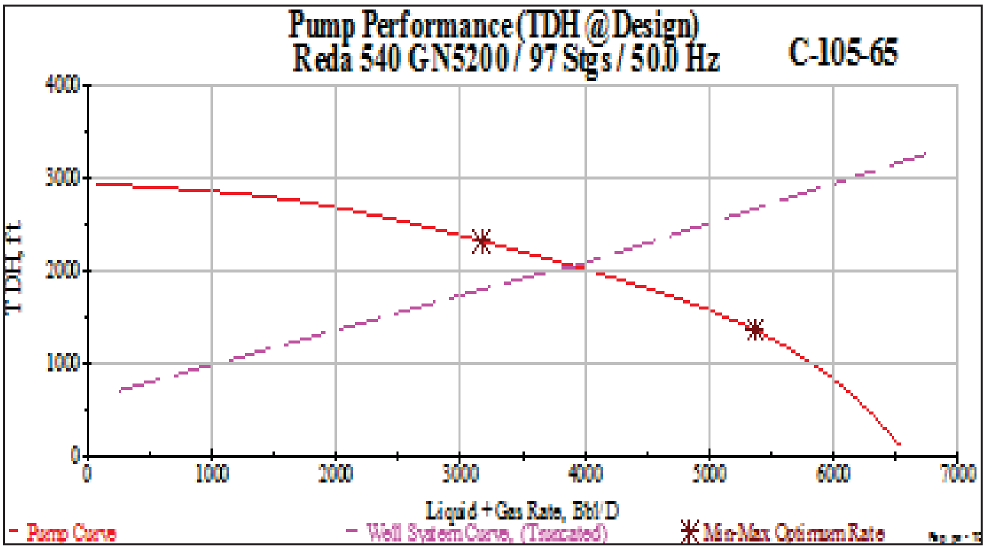


Figure 5-41: Pump Performance (TDH and Design)

Table 5-28: Short Comparison of the Current and Proposed Design of Well C-105-65 in Case of Gas Injection

Item	Current Status	Proposed Design With 250 MSCF/D Gas Injection at 4000 ft
Pump	GN4000	GN5200
Stages	142	97
Rate (bbl/day)	3199	3596
Depth (FT)	5048	5048
Required Power (HP) @ 50HZ	109.5	89.2
TDH (ft)	2963	2045
Discharge pressure	2226	1726
Pump Intake (psi)	1037	908

Detailed optimizing and analysis results of C-105-65 for the two mentioned approaches are presented in **APPENDIX D**

5.6 WELL NO. C-144-65

- Well History

C-144 –65 was completed as an oil producer in May 1976. During a workover in December 1992, the well was equipped with ESP. Present estimated reservoir static pressure is 2645 Psi at datum level of 8533 ft GL. Present production intervals are: (8630-8640) ft, (8704-8740) ft and (8752-8780) ft.

- Casing and Tubing Data

Table 5-29 shows the data of Casing and Tubing for Well C-144-65

Table 5-29: Casing and Tubing for Well C-144-65[26]

Item	OD, in	ID, in	Weight, Ib/ft	Roughness	Depth ,ft
Casing	13 3/8	12.615	54.5	0.00065	3052
Casing	9 5/8	8.835	40	0.00065	7180
Casing	7	6.366	23	0.00065	8880
Tubing	3 1/2	2.992	9.3	0.00065	4879

- Well Testing Data

Table 5-30 summarizes production test data for C-144-65, which is based upon the recent well testing report dated on 7/08/2009. **Figure 5-42** gives details of oil, water production and water cut from June 1978 to June 2008.

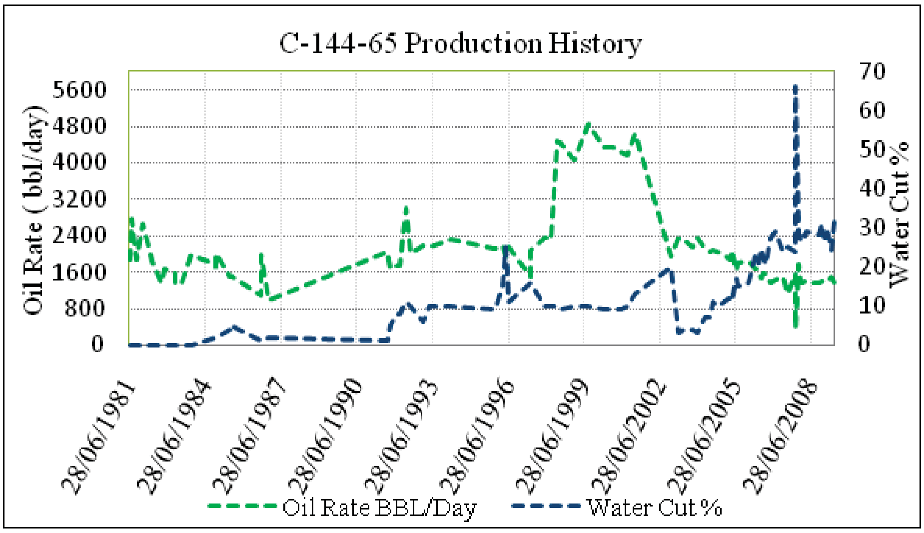


Figure 5-42:C-144-65 Production History[26]

Table 5-30: Production Test Data for Well C-144-65[26]

Static Bottom Hole Pressure (psi)	2600
Flowing Bottom Hole Pressure (psi)	2400
Bubble Point Pressure (psi)	650
Productivity Index (PI) (bbl/day/psi)	10.32
Gross Fluid Rate (STB/day)	2064
Well Head Pressure (psi)	335
Casing Pressure (psi)	20
Gas Oil Ratio GOR (SCF/STB)	185
Choke (in)	32/64
Water Cut (WC)	29 %
Salinity (ppm)	198309
Oil Specific Gravity (γo)	0.84
Water Specific Gravity (γw)	1.155
Gas Specific Gravity (γg)	0.91
Bottom Hole Temperature (Tb), F°	225
Well Head Temperature (Twh), F°	117
Dynamic Fluid Level (ft)	1638
Perforations Depth (ft)	8553

- Current Electrical Submersible Pump Data for well C-144-65

Table 5-31: Current ESP Data of Well C-144-65 [26]

Installation Date	11/08/2007
Pump Type	GN2500 , 112 Stage
Motor Type	456 Series ,4083, 96 hp, 1431 v ,43 Am
Protector Type	LSB
Setting Depth (ft)	4879

- C-144-65 ESPs Run Life History

Table 5-32 and **Figure 5-43** show the ESPs run life and failure mode of C-144-65 as of 11/08/2007.

Table 5-32: Pump Run Times and Failure Modes for C-144-65 [26]

Pump Type	Installation Date	Failed Date	Run Days	Reason of Failures
19MOF	12/08/1991	02/06/1992	295	Motor Grounded
GN2500	11/06/1992	25/10/1993	501	Pump Plugged
GN2500	17/11/1993	10/04/1997	1240	Motor Grounded & Pump
GN3200	01/05/1997	25/04/1998	359	Motor grounded
GN5600	24/05/1998	13/11/1998	173	Pump Seized and MLC
52MOF	19/12/1998	05/02/2000	413	MLC Blown @ Motor Plug in.
52MOF	14/03/2000	01/03/2001	352	Motor grounded and cable
GN5600	05/03/2001	10/06/2001	97	Motor grounded
GN2500	28/06/2001	05/12/2002	525	Motor Grounded and Pump
GN-2100	05/12/2002	08/08/2007	1707	No Flow
GN2500	11/08/2007			Running
Average Run Days			566	

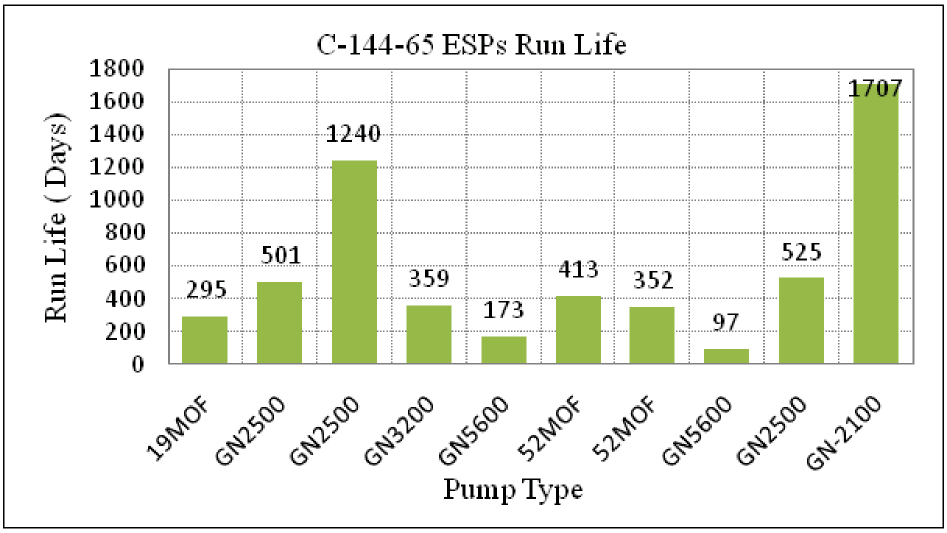


Figure 5-43: ESPs Run Life of C-144-65[26]

5.6.1 C-144-65 ESP Analysis

5.6.1.1 C-144-65 Current installation analysis

As shown in **Figure 5-44** the current production rate is 2043 BFPD. The SubPump software shows the total system's rate is found at the intersection of the outflow curve with the IPR curve and is 4400 BFPD.

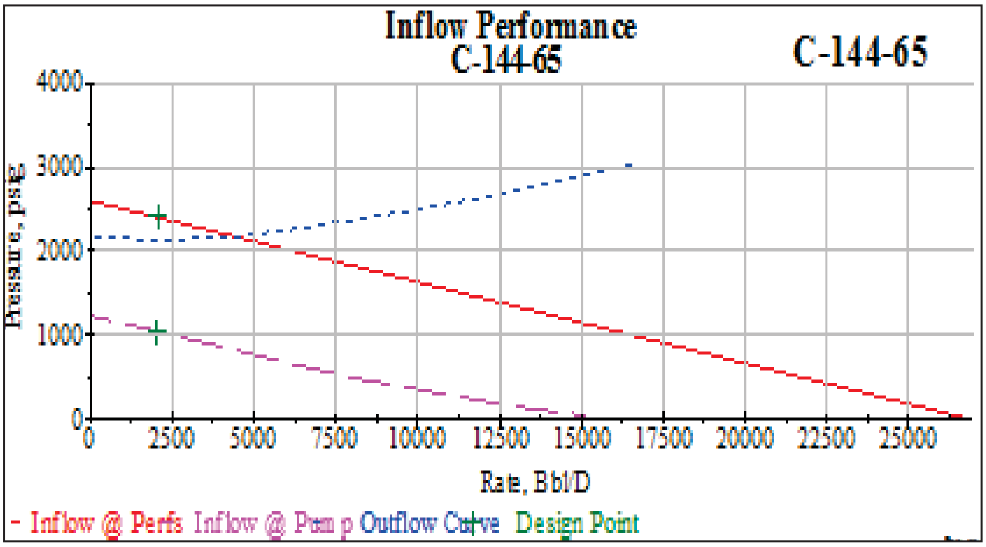


Figure 5-44: Finding Production Rate for C-144-65 with Nodal Theory.

- C-144-65 the Current Standard Pump Catalog Graph

In **Figure 5-45**, the standard pump catalog graph for Reda Pump GN2500 contains the head, horsepower, and efficiency of the pump as calculated from the coefficients. (This data is based on water).

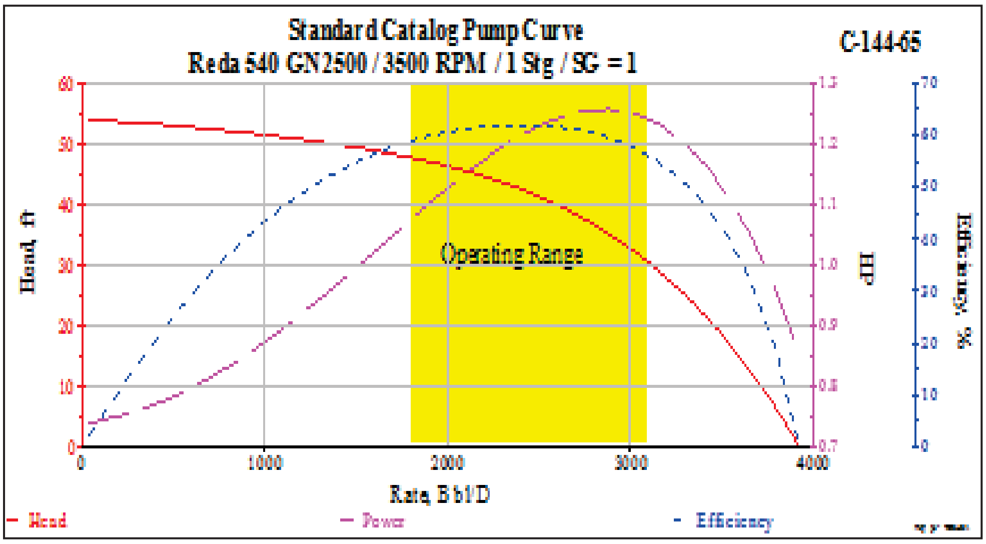


Figure 5-45: Current Standard Catalog Pump Curve

- C-144-65 Pump Performance (HP & Eff)

In **Figure 5-46**, the pump performance and efficiency graph shows the best efficiency point (BEP) of the original equipment GN-2500 in C-144-65.

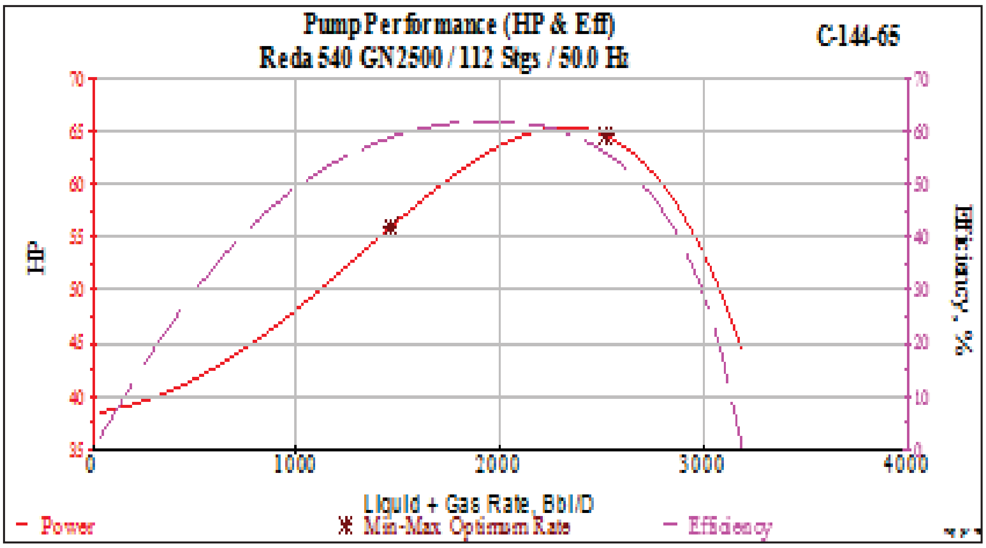


Figure 5-46: C-144-65 Pump Performance (HP and Eff)

- Pump Performance (TDH @ Design)

In **Figure 5-47**, the pump performance (TDH at Design) graph shows the final design at the design frequency with the operating point located at the intersection of the pump performance curve and the well system curve. Note that the intersection of the curves on this plot represents the point at which the well would be expected to produce under stable condition (3500 bbl/day).

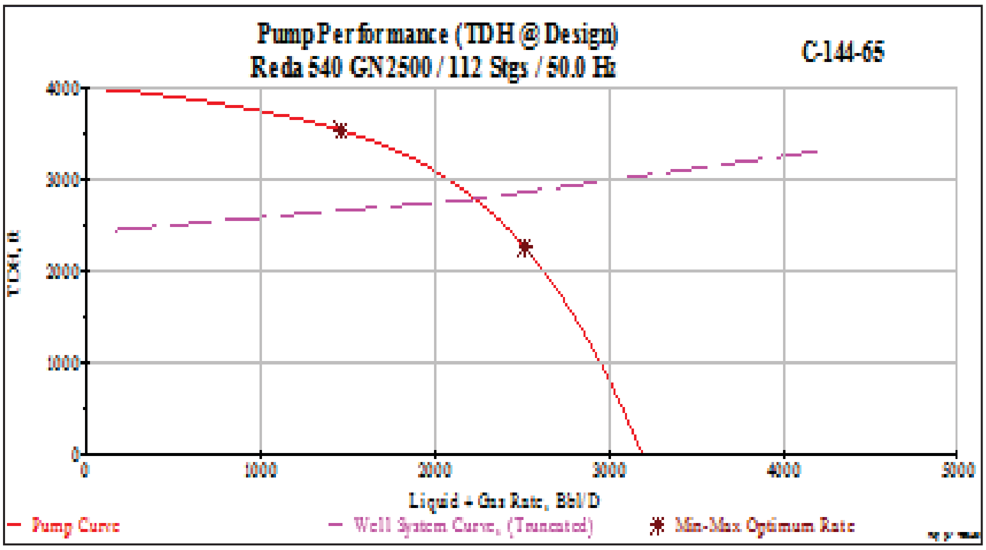


Figure 5-47: C-144-65 Pump Performance (TDH and Design)

5.6.2 Optimizing the Pump Setting Depth

- C-144-65 Inflow Performance Graph at 4529 feet

As shown in **Figure 5-48** the Avocet software graph shows the IPR curve and optimum system's rate at pump setting depth 4529 ft. Fluid rate and pump intake pressure are 3339 BFPD, 800 Psia respectively. Based on this rate the pump should be selected.

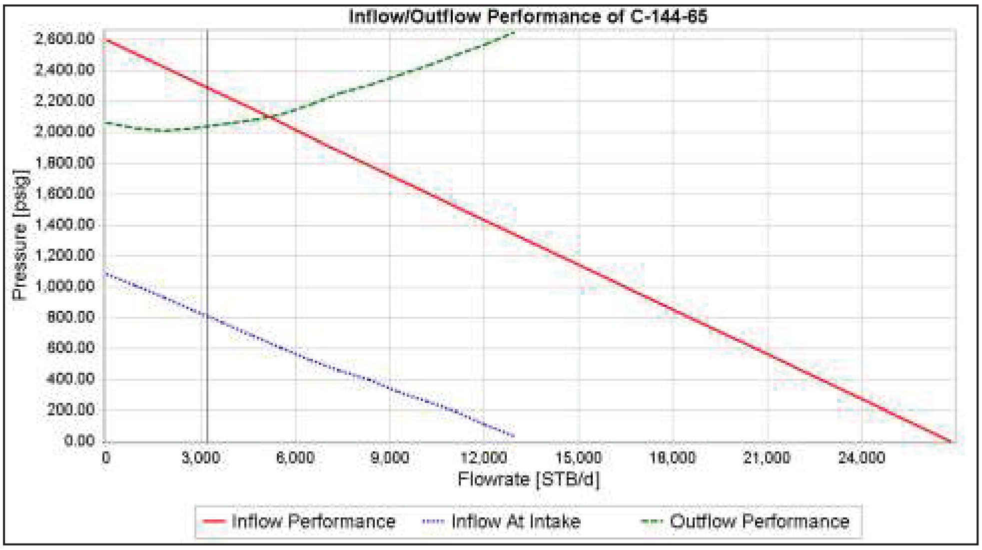


Figure 5-48: Finding the Optimum Production Rate and Minimum Pump Setting Depth for C-144-65 with Nodal Theory

- C-144-65 Pump Performance Curve

Figure 5-49 shows the actual pump performance, pump head, total dynamic head and pump efficiency of the pump 538, S5000N, 114 stages, 70.85% volumetric efficiency which is selected to handle 3340 bbl/day at design frequency 50 HZ with the operating point located at the intersection of the pump head curve and the well system curve.

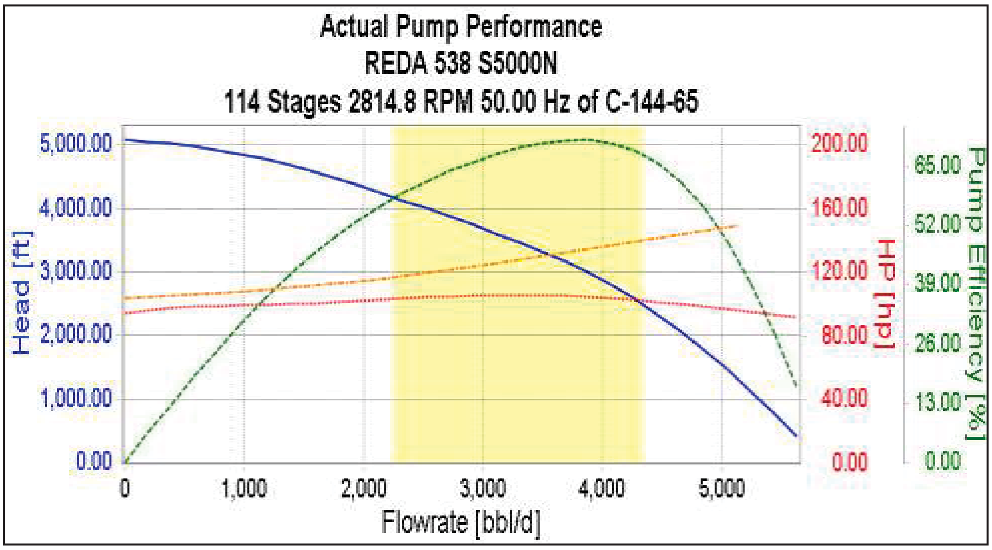


Figure 5-49: Actual Pump Performance & TDH

5.6.2.1 Comparison of the Current design and Proposed Design

In the following **Table 5-33**, short comparison of the current and proposed design of finding the optimum pump setting depth for well C-144-65. The calculations required for an actual comparison can be based on the exact analysis and optimization, as shown in **Table 5-33**. With considering the pump intake pressure, the proper pump installation for optimum pump rate and minimum pump setting depth is selected.

It is apparent that the current installation is not the most efficient stage at the established design conditions after considering the mentioned approach; therefore new pump size is selected:

- For optimum pump rate with minimum pump setting depth, pump size 538 S5000N with 114 stage and 70.85% volumetric efficiency is selected. The motor selected is a 143.9 hp, 1478.7 V/50 Hz. Total fluid productions increased 63.4%, from 2043 B/D to 3339 B/D. In addition to 350 feet of tubing (11 joints) and cable are minimized. Cable power losses are minimized by selection of a higher-voltage/lower-amperage motor.

Table 5-33: C-144-65 Comparison Results of Current Case and Optimizing the Pump Setting Depth case

Item	Current Status	Optimum Design
Pump Data		
Manufacturer	Reda	Reda
Series	540	538
Model	GN2500	S5000N
Number of stages	112	114
Min. Efficiency, %	60.97	70.85
Production Data		
Surface rate (O+W), Bbl/D	2043	3339
Pump Setting Depth, ft	4879	4529
Dynamic fluid level, ft	2209	2465
Fluid over pump, ft	2670	2033
Total dynamic head, ft	2789	3185
Pump intake pressure, Psig	1039	800
Motor Data		
Manufacturer	Reda	Reda
Series	456	456
Design Frequency, Hz	50	50
Operating power, HP	73.2	143.9
Cable Data		
Manufacturer	Philip	REDA
Type	Devi lead EPDM/Lead	REDALEAD
Size	1 Cu	1 Cu
Shape	Flat	Flat
Length	4979	4629

5.6.3 Combined ESP and Gas lift (Hybrid)

The function of combined artificial lift systems yields improved production in terms of costs and rates at better conditions than could be expected from using only one of the individual systems. Hence in this study have been suggested to combining gas lift method as secondary method with ESP in C-144-65.To achieve the benefits of gas injection; one gas lift mandrel and valve are located at 4000 feet from surface and about 1000 feet above the pump and the optimal amount of gas injection is 300 Mscf/day. Calculations are performed by using SubPump software. **Table 5-34** shows a summary of the calculations and benefits from the ESP-GL system in C-144-65. The key issue for the changes and benefits, as a result of injecting gas to lighten the fluid column, is the reduction in the pump discharge pressure. There is a reduction up to 598.6 psi, with a percentage of 28 % as compared with the discharge pressure of a regular ESP system. All the other results and benefits are proportional to this pressure reduction.

Table 5-34: Summary of the Calculations of "Electrogas" Combined System in the C-144-65

Description		
Gas injection Point ,ft	4000	
Amount of gas injection , MSCF/day	300	
Production Conditions	Before gas injection	After gas injection
Fluid Rate , BFPD	2043	2050
Water cut , %	29	29
Pump Discharge Pressure ,psi		
Current ESP , psi	2136	
ESP-GL , psi	1538	
Reduction , psi	598	
Required Equipment size saving		
Stages before gas injection	112	
Stages after gas injection	58	
Saving stages , %	48	
TDH reduction , %	48	
Required HP before gas injection	73.2 /50 HZ	
Required HP after gas injection	36.4 /50 HZ	
Saving HP , %	50.2	

5.6.3.1 Proposed Design with Gas Injection

The current design of C-144-65 has been redesigned to be compatible with increasing the rate as result of the benefits of gas injection and production optimization by combined ESP/GL systems. The selected pump is 540 GN-5200 with 118 stage and 64.33% volumetric efficiency. The motor selected is a 106.2 hp, 1300 V/50 Hz. The **Figure 5-50**& **Figure 5-51**show the standard catalog pump curve and pump performance (TDH @ Design) of the selected pump GN-5200, respectively. Total fluid rate increased by 90 %, from 2043 B/D to 3886 B/D. **Table 5-35** shows a short comparison of the current and proposed design for well C-144-65.

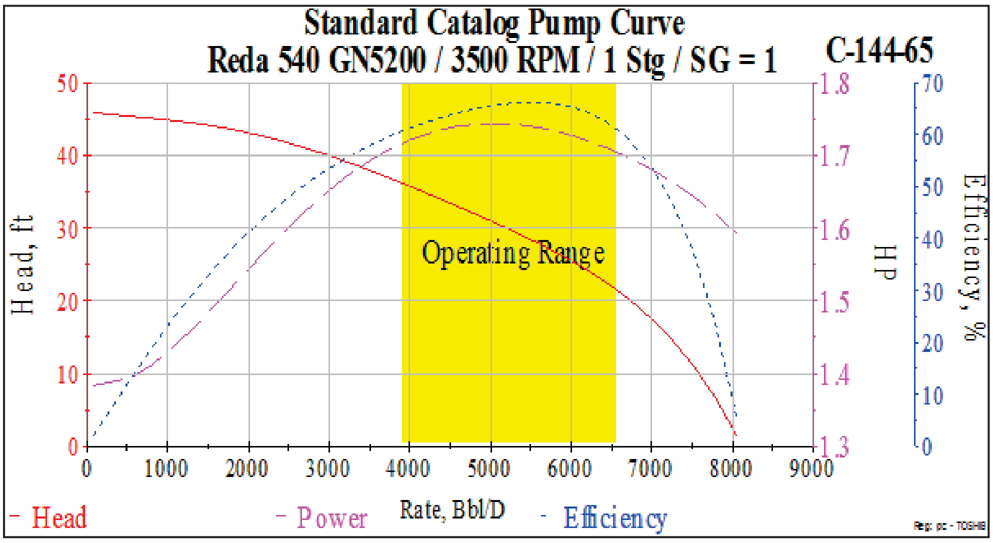


Figure 5-50: Standard Catalog of Recommended Pump

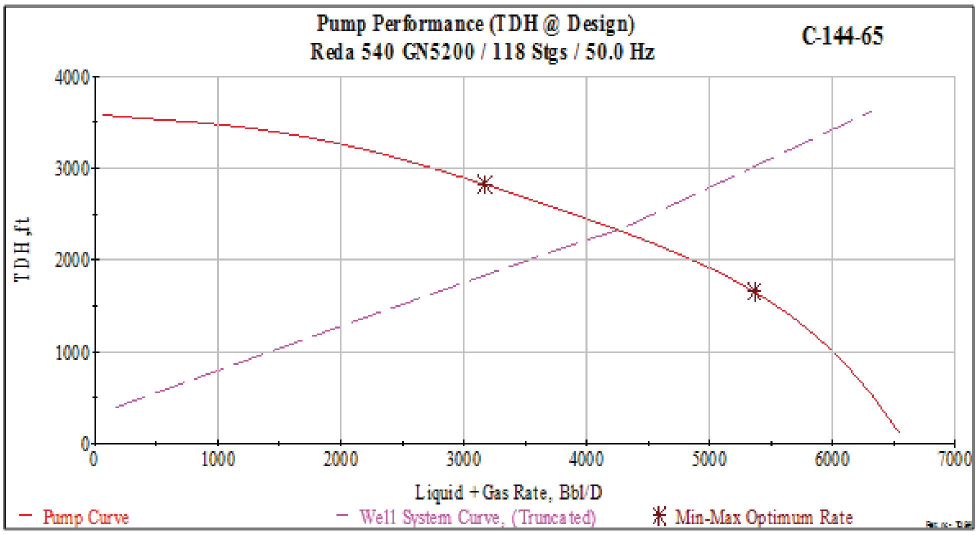


Figure 5-51: Pump Performance (TDH and Design)

Table 5-35: Short Comparison of the Current and Proposed Design of Well C-144-65 in Case of Gas Injection

Item	Current Status	Proposed Design With 250 MSCF/D Gas Injection at 4000 ft
Pump	GN2500	GN5200
Stages	112	118
Rate (bbl/day)	2043	3886
Depth (FT)	4879	4529
Required Power (HP) @ 50HZ	73.2	106.2
TDH (ft)	2789	2163
Discharge pressure	2136	1687
Pump Intake (psi)	1039	902

Detailed optimizing and analysis results of C-144-65 for the two mentioned approaches are presented in **APPENDIX E**

5.7 Economic Evaluation

The water cut of the selected wells increases annually with certain percentage as shown in **Table 5-36** based on the history of the water cut this study assumes that the oil production declines dramatically as result of increasing the water cut (WC%).

Table 5-36: Yearly Water Cut increasing of the Tested Wells [26]

Well	Yearly Water Cut Increase %
C-001-65	4.5
C-046-65	4.5
C-101-65	5.8
C-105-65	4
C-144-65	4

All information, including costs of the personnel, maintenance and equipment costs were gathered from Production Group of Arabian Gulf Oil Company (AGOCO) [26] .Economic evaluation was based on three cases; case one Current Status. Whereas case two is ESP/GL Combined and third case is optimizes the pump setting depth.

In order to accomplish the economic evaluation, income and cost items of the production operation should be established.

Step-1: Determining income parameters

Petroleum industry includes an inter-connected system which starts with petroleum research than production and continuing with refinery, delivery, distribution and storage. In this relation crude oil prices are the concern of the study. Petroleum consumption and exploration of new wells are the primary factors affecting the oil prices. But political events are also important in oil prices as they can result in shortage or oversupply. Beginning from 2010, five years period of evaluation was made in this study. According to the assumption of the International Energy Agency's (IEA) by 2014 the oil prices will be around \$60 per barrel [36] ,however, the analysis was carried out at three different oil prices scenarios (\$40/bbl,\$ 60/bbl,\$ 80/bbl)in this study. If the crude oil prices will be higher than these assumptions, higher net cash flow will be gained from this study.

Step-2: Cost items

Disbursements include personnel payments, maintenance expense, energy costs, tax, and insurance. Initial investment includes the prices of the ESP units and gas compressor unit which including engine, scrubber, cooler and controls. Compressor is shared by five wells. ESP units, gas compressor packaged unit, downhole valves with latches, side pocket mandrel prices are given in appendix F. According to Arabian Gulf oil company that the barrel of oil costs \$3/bbl and this cost including (personnel payment, maintenance, energy costs, tax and insurance).

Regarding to the mean time between failures (MTBF) in Sarir field is 750 day, thus it is assumed in 2013 that all the five wells need workover and the period of the work over results in production losses for 6 days for each well. This assumption will apply to the three cases (current status, ESP/GL combined and finding optimum pump setting depth).

As it was mentioned in previous sections of this study the wells used in this study are already producing with ESP lift methods.

5.7.1 ECONOMIC ANALYSIS

Economic comparisons of the three cases were performed based on net cash flow instead of other key performance indicators due to the small size of investment compared with the net cash flow .Furthermore; the total investment is recovered in the first year.

For each case there is one table including oil production, revenue, disbursement, future expenditure and net cash flow. As stated previously that the Crude oil price was assumed \$40/bbl as low price scenario, \$60/bbl as middle price scenario, and \$80/bbl as high price scenario. One barrel of oil costs 3 \$/bbl .The cost of the work over rig that used for replacing the equipments is 60,000 \$. In addition, the price of Gas compressor packaged unit was included in the initial investment of the second case and the ESP unit's prices were included in the initial investment of the three cases.

5.7.1.1 Current Status (First Case)

Table 5-37 **, 5-38, 5-39** represent the income of the current status of the five wells which was calculated at three different oil prices ($ 40/bbl, $ 60/bbl, and $ 80/bbl). These tables include the initial investment in year 2010 and future expenditure in 2013. The difference between net incomes and disbursement gives the yearly net cash flow which is considered as economic indicator in this study.

Table 5-37: Investment and Income of the first Case at low price scenario ($ 40/bbl)

Year	Oil Production bpd	Oil Price $/bbl	Income $/y	Disbursement $/y	Future expenditure $/y	Net Cash Flow $/y
2010						-1,036,734
2011	6560	40	95,776,000	8,380,400	0	87,395,600
2012	6275	40	91,615,000	8,016,313	0	83,598,688
2013	6002	40	72,024,000	7,667,555	1,036,734	63,319,711
2014	5741	40	83,818,600	7,334,128	0	76,484,473
2015	5492	40	80,183,200	7,016,030	0	73,167,170
Total Net Cash Flow						$382,928,907

Table 5-38: Investment and Income of the first Case at middle price scenario ($ 60/bbl)

Year	Oil Production bpd	Oil Price $/bbl	Income $/y	Disbursement $/y	Future expenditure $/y	Net Cash Flow $/y
2010						-1,036,734
2011	6560	60	143,664,000	8,380,400	0	135,283,600
2012	6275	60	137,422,500	8,016,313	0	129,406,188
2013	6002	60	108,036,000	7,667,555	1,036,734	99,331,711
2014	5741	60	125,727,900	7,334,128	0	118,393,773
2015	5492	60	120,274,800	7,016,030	0	113,258,770
Total Net Cash Flow						$594,637,307

Table 5-39: Investment and Income of the first Case at high price scenario ($ 80/bbl)

Year	Oil Production bpd	Oil Price $/bbl	Income $/y	Disbursement $/y	Future expenditure $/y	Net Cash Flow $/y
2010						-1,036,734
2011	6560	80	191,552,000	8,380,400	0	183,171,600
2012	6275	80	183,230,000	8,016,313	0	175,213,688
2013	6002	80	144,048,000	7,667,555	1,036,734	135,343,711
2014	5741	80	167,637,200	7,334,128	0	160,303,073
2015	5492	80	160,366,400	7,016,030	0	153,350,370
Total Net Cash Flow						$806,345,707

5.7.1.2 Combined ESP/GL (Second Case)

Tables 5-40, 5-41, 5-42 represent the net cash flow of the second case at the three different oil prices. But the initial investment of this case includes the cost of the gas lift requirements and ESP units. The benefits of Combined ESP/GL generated a huge net cash flow as shown in the follow tables.

Table 5-40: Investment and Income of the second Case at low oil price scenario ($ 40/bbl)

Year	Oil Production bpd	Oil Price $/bbl	Income $/y	Disbursement $/y	Future expenditure $/y	Net Cash Flow $/y
2010						-3,702,779
2011	9182	40	134,057,200	11,730,005	0	122,327,195
2012	8785	40	128,261,000	11,222,838	0	117,038,163
2013	8406	40	100,872,000	10,738,665	1,022,779	89,110,556
2014	8043	40	117,427,800	10,274,933	0	107,152,868
2015	7696	40	112,361,600	9,831,640	0	102,529,960
Total Net Cash Flow						$534,455,962

Table 5-41: Investment and Income of the second Case at middle oil price scenario ($ 60/bbl)

Year	Oil Production bpd	Oil Price $/bbl	Income $/y	Disbursement $/y	Future expenditure $/y	Net Cash Flow$/y
2010						-3,702,779
2011	9182	60	201,085,800	11,730,005	0	189,355,795
2012	8785	60	192,391,500	11,222,838	0	181,168,663
2013	8406	60	151,308,000	10,738,665	1,022,779	139,546,556
2014	8043	60	176,141,700	10,274,933	0	165,866,768
2015	7696	60	168,542,400	9,831,640	0	158,710,760
Total Net Cash Flow						$830,945,762

Table 5-42: Investment and Income of the second Case at high oil price scenario ($ 80/bbl)

Year	Oil Production bpd	Oil Price $/bbl	Income $/y	Disbursement $/y	Future expenditure $/y	Net Cash Flow$/y
2010						-3,702,779
2011	9182	80	268,114,400	11,730,005	0	256,384,395
2012	8785	80	256,522,000	11,222,838	0	245,299,163
2013	8406	80	201,744,000	10,738,665	1,022,779	189,982,556
2014	8043	80	234,855,600	10,274,933	0	224,580,668
2015	7696	80	224,723,200	9,831,640	0	214,891,560
Total Net Cash Flow						$1,127,435,562

5.7.1.3 Optimizing Pump Setting Depth (Third Case)

In this case the ESP designs of the five wells in the current status have been resized with shift up the pump to depth at which the pump intake pressure is greater than the saturation pressure and this approach resulting in minimize the tubing length (2135 ft, 68 joint), saved about $19,250 of tubing cost as well cable length (2135 ft), saved $29,890 of cable cost. In addition to the income from improving the production rate with new ESPs design. **Table 5-43, 5-44, 5-45** depict the income and the initial investment of the third case at the three oil price scenarios.

Table 5-43: Investment and Income of the third Case at low oil price scenario ($ 40/bbl)

Year	Oil Production bpd	Oil Price $/bbl	Income $/y	Disbursement $/y	Future expenditure $/y	Net Cash Flow $/y
2010						-1,151,028
2011	8390	40	122,494,000	10,718,225	0	111,775,775
2012	8027	40	117,194,200	10,254,493	0	106,939,708
2013	7680	40	92,160,000	9,811,200	1,151,028	81,197,772
2014	7348	40	107,280,800	9,387,070	0	97,893,730
2015	7031	40	102,652,600	8,982,103	0	93,670,498
Total Net Cash Flow						$490,326,454

Table 5-44: Investment and Income of the third Case at middle oil price scenario ($ 60/bbl)

Year	Oil Production bpd	Oil Price $/bbl	Income $/y	Disbursement $/y	Future expenditure $/y	Net Cash Flow $/y
2010						-1,151,028
2011	8390	60	183,741,000	10,718,225	0	173,022,775
2012	8027	60	175,791,300	10,254,493	0	165,536,808
2013	7680	60	138,240,000	9,811,200	1,151,028	127,277,772
2014	7348	60	160,921,200	9,387,070	0	151,534,130
2015	7031	60	153,978,900	8,982,103	0	144,996,798
Total Net Cash Flow						$761,217,254

Table 5-45: Investment and Income of the third Case at high oil price scenario ($ 80/bbl)

Year	Oil Production bpd	Oil Price $/bbl	Income $/y	Disbursement $/y	Future expenditure $/y	Net Cash Flow $/y
2010						-1,151,028
2011	8390	80	244,988,000	10,718,225	0	234,269,775
2012	8027	80	234,388,400	10,254,493	0	224,133,908
2013	7680	80	184,320,000	9,811,200	1,151,028	173,357,772
2014	7348	80	214,561,600	9,387,070	0	205,174,530
2015	7031	80	205,305,200	8,982,103	0	196,323,098
Total Net Cash Flow						$1,032,108,054

According to those tables the first case has a NCF of $382,455,907 at $ 40/bbl, $ 594,637,307 at $ 60/bbl, and $ 806,345,707 at $ 80/bl.The second case has a NCF of $534,455,962 at $ 40/bbl, $830,945,762 at $ 60/bbl, and $ 1,127,435,562 at $ 80/bbl, while the third case has a NCF of $ 490,326,454 at $ 40/bbl , $ 761,217,254 at $ 60/bbl, and $ 1,032,108,054 at $ 80/bbl . Comparing the NCF of each case at the three oil prices, it was noticed that the second case and the third case generated a huge NCF measure up to the first case. The increment in the NCF of the second case is a result of combined ESP/GL which has a several benefits and advantages such as the increasing in the NCF by 39.7 % from the first case, in addition to production improving, power saving and reduction in number of required pump stages. Regarding to the NCF of the third case also increased by 28.2% from the first case as result of changing the ESPs design and set the pumps at the optimal depth.

CHAPTER 6: Conclusions

6.1 General Recommendation

- **Testing**

A careful study should be undertaken on any pump installation that does not produce as originally designed since the problems may be either with the pump and motor assembly or may be a well bore deficiency. As a much information as possible should be collected to improve the installation and size the pump correctly.

A means of gauging should be provided on start-up. The unit should be closely observed for the next couple of days and good initial start up data obtained. Periodic tests and equipment analysis are required to obtain the most efficient service from any artificial lift system.

- **Data Gathering**

The importance of collecting good production and operating data on an installation cannot be overstressed. This data will be used as follows:

1. To check the installed design.
2. For resizing, which is necessary in some cases,
3. Catching and preventing possible problems that could cause failures.
4. Economical evaluation.
5. As an aid in analyzing and determining the reason for any failures.
6. A detailed understanding of the technical reason for a problem allows a technical solution, which may have a higher cost but is cheaper in the long term.

- **Communications**

A good line of communication should exist between the field representative and company representatives. In addition send a witness to the teardown of failed equipment and make sure the witness is experienced. The job of data gathering and well monitoring should be a combined effort. Once a submersible pump is correctly sized and its operation is properly monitored, the installation becomes a relatively trouble-free operation.

- **Power Supply**

Presently the Sarir field's wells are feed from 33KV line was run from nearby field (Messla field) about 40 Kilo meter, and 11KV line distribution constructed through out the field. Unstable power supply due to a long distance between the source and the wells leads to unbalanced phases, voltage spikes and power fluctuating. These problems cause an ESP more susceptible to electrical failures, therefore highly recommended to install Micro Turbine in the base of Sarir field to overcome these problems and provide "clean" electric supply.

- **Downhole Monitoring**

MultiSensor monitoring system should install as part of each ESP system in Sarir field, to provide downhole data to monitor well performance and improve ESP management.

- **Variable Speed Drive (VSD)**

VSD technology should install with downhole ESP system in Sarir field, to aid in optimizing the ESP management by providing flexibility to respond to uncertain operating conditions and maintaining drawdown constraints during start up operations. Also to optimize ESPs power consumption.

- **Sand Production**

Apply advanced method/procedure to monitor sand concentration in fluid produced from wells to signify sand producer wells instead of the current practice which relay on the fill length measurements while workover

6.2 Conclusions and Recommendation Based on Combined ESP/GL and Optimizing Pump Setting Depth

The results of this study lead to the following conclusions about ESP’s in the Sarir oil field.

- Avocet and SubPump softwares output provides the user with key diagnostic information to improve system design for optimizing production or for reducing lifting costs. Key information includes pump intake pressure, volumes of liquid and free gas at the pump intake, pump profile, pump and system efficiencies.
- The approach of Combined ESP/GL in this study yields improved production in terms of costs and rate at better conditions than could be expected from using a conventional design of ESP system.
- In order to avoid gas lock problems, with a simultaneous gas injection from the surface for gas lifting .Two alternatives have to be used to solve that situation. The first alternative is to inject the gas into the gas conduit which parallel to production string and connected to the gas lift mandrel. The second alternative is to install packer above the pump and below the side pocket mandrel.
- Applying the approach of combined ESP/GL in this study on the Sarir field’s five wells gives high benefits and revenue ,so highly recommended to apply this approach on the rest of the sarir field’s wells to obtain more benefits and revenue
- The total increment in the oil production of the five wells by applying the approach of combined ESP/GL is 40%.In addition to the net cash flow (NCF) of the five wells also increased with 40 % as compared with the first case
- Combined gas lift with ESP in this study causes reduction in ESP discharge pressure which resulted in saving power and stages by 40%
- The approach of optimizing the pump setting depth of the five wells in this study resulted in minimize 2135 ft tubing and cable, in addition to the production improving
- The total increment in the oil production of the five wells by applying the approach of optimizing the pump setting depth is 28%.In addition to the net cash flow (NCF) of the five wells also increased with 28 % as compared with the first case

- Application of ESP/GL combined gives better results than that of optimizing the pump setting depth when the net cash flows are compared.
- Based on the Nodal concept, the optimization for the five wells is achieved for the following goals:
    1. Maximize the production by combined ESP with gas lift
    2. Optimum pump rate with minimum pump setting depth were determined, aiming to maximize the rate, minimize the tubing length and cable length, and the power losses in the system.

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APPENDIX A

A. 1: SubPump Detailed Report of C-001-65 (Analysis of Current Design)

GENERAL DESCRIPTION

Company Name:	Arabian Gulf Oil Company
Well Name:	C-001-65
Field Name:	Sarir Field
Reservoir Name:	C-main
Analyst:	Waleed M. E. Mohammed
Calculation Type:	Rigorous Design
Location:	Concession -65
Comments:	Analysis of Current Design
Date:	13/04/2010

WELLBORE DATA

	No.	OD in	Wt lb/ft	ID in	Rough in	Bottom MD ft	Top MD ft
Tubing	1	3.500	9.30	2.992	0.0006500	5417	0.00
Casing	1	7.000	23.00	6.366	0.0006500	9082	0.00

Pump Depth, ft:	5417
Top of Perfs. or Datum Pt. (MD), ft:	8626
Reservoir Temperature, °F:	225.0
Wellhead Temperature, °F:	117.0

Tubing Outflow Correlation: Orkiszewski (1967)

PVT CORRELATIONS

Description	Method
Oil Viscosity, (Dead)	Beggs & Robinson
Oil Viscosity, (Saturated)	Beggs & Robinson
Oil Viscosity, (Unsaturated)	Vasquez & Beggs
Gas Viscosity	Lee
Water Viscosity	Matthews & Russell
Oil Formation Volume Factor	Vasquez & Beggs
Water Formation Volume Factor	HP41C
Oil Density	Katz
Z-Factor	Dranchuk, Purvis
Oil Isothermal Compressibility	Vasquez & Beggs
Water Isothermal Compressibility	Meehan
Solution Gas/Oil Ratio	Lasater
Bubble Point Pressure	Lasater
Gas Density	Beggs
Water Density	Beggs
Oil Surface Tension Correlation	Baker and Swerdloff
Water Surface Tension Correlation	Hough

FLUID DATA

Standard Temperature, °F:	60	Prod. Gas/Oil Ratio, scf/bbl:	230.0
Standard Pressure, psi:	14.7	Prod. Gas/Liq. Ratio, scf/bbl:	112.7
Oil Gravity, °API:	35.0	Bubble Point Pressure, psia:	600.0
Gas Specific Gravity, :	0.950	Solution GOR, scf/bbl:	128.5
Water Specific Gravity:	1.100	Average Fluid Viscosities, cP:	0.6
Water Salinity, ppm:	130404	Fluid Grad. @ Pump Intake, psi/ft:	0.415
Water Cut, %:	51.0		

Viscosity Calibration Data

Pnt. #	Press. psia	Temp. F°	User Visc. Cp	Type	Calc. Visc. Cp	Calib. Factor
1	3000.0	225.0	1.9	Dead	1.3	1.412
2	2000.0	170.0	1.7	Dead	2.3	0.753
3	1000.0	140.0	1.6	Dead	3.4	0.471
Flowline Pressure, psig: 150.0						

INFLOW DATA

IPR Calculation Method: Productivity Index	
Fluid Rate at Test BHP, Bbl/D:	2450.00
Productivity Index, blpd/psi:	14.848
Bubble Point Rate, Bbl/D:	35636.36
Max. Oil Flow Rate, Bbl/D:	35636.36
Max. Total Flow Rate, Bbl/D:	35636.36

	Static	Test
Casing Pressure, psig:	20.0	0.0
Fluid Level, ft:	0.00	00.00
Bottom Hole Pressure (BHP), ft:	2400.0	2235.0

PRESSURE/RATE DATA

Design Criteria - Solved For: Pump Intake Conditions	
Total Fluid Rate, Bbl/D:	2450.00
Pump Depth, ft:	5417.00
Fluid Over Pump, ft:	2444.54
Pumping Fluid Level, ft:	2972.46
Pump Intake Pressure, psig:	995.6
Total Dynamic Head, ft:	2849.73
Flowline Pressure, psig:	150.0
Casing Pressure, psig:	10.0
Bottom Hole Pressure, psig:	2235.0
Gas through Pump:	Gas Compressed

GAS SEPARATOR PERFORMANCE

Packer Installed?	No
Free Gas Avail. at Pump, %	9.5
Natural Gas Separation, %:	70.0
Free Gas into Pump, %	1.24
Gas Separator Installed?	Yes
Gas Separator Efficiency,	60.00

WELL SYSTEM CURVE DETAIL

Points	(+) Tubing Head ft	(-) PIP Head ft	(=) TDH ft	Surface Rate O+W Bbl/D	Avg. Pump Rate O+W+G Bbl/D	Pumping Fluid Level ft
1	5519.82	2688.07	2831.75	201.42	217.54	2679.38
2	5272.87	2367.86	2905.02	2694.03	2909.66	3007.35
3	5581.97	2005.74	3576.23	5186.64	5601.77	3379.02
4	5996.68	1640.65	4356.03	7679.25	8293.89	3754.56
5	6501.60	1335.26	5166.34	10171.86	10986.00	4068.21
6	7118.53	1007.12	6111.41	12664.47	13678.12	4402.23
7	7800.71	672.58	7128.13	15157.08	16370.23	4747.09
8	8597.09	366.22	8230.86	17649.68	19062.34	5066.59
Pump off	9512.63	34.99	9477.65	20142.29	21754.46	5415.72
Design	5251.63	2401.89	2849.73	2450.00	2646.10	2972.46

THEORETICAL PUMP PERFORMANCE

	Intake	Discharge	Surface
Oil Rate, Bbl/D:	1340.78	1333.17	1199.22
Gas Rate through Pump, Bbl/D:	33.11	13.66	N/A
Gas Rate from Casing, Bbl/D:	242.80	N/A	N/A
Total Gas Rate, Mscf/D:	N/A	N/A	275.82
Free Gas Percent, %:	1.24	0.53	N/A
Water Rate, Bbl/D:	1288.83	1285.06	1248.17
Total Liquid Rate, Bbl/D:	2629.61	2618.23	2447.39
Pressure, psig:	995.8	2177.2	150.0
Specific Gravity Liquid, wtr=1:	0.92	0.92	N/A
Specific Gravity Mixture, wtr=1:	0.91	0.92	N/A
Liquid Density, lb/cf:	57.381	57.347	N/A
Mixture Density, lb/cf:	56.727	57.100	N/A
Mixture Viscosity, CST:	N/A	N/A	N/A
Mixture Viscosity, SSU:	N/A	N/A	N/A
Solution GOR, scf/bbl:	142.2	142.2	N/A
Solution GWR, scf/bbl:	2.2	2.2	N/A
Liquid FVF, res/surf:	1.0	1.07	N/A
Mixture FVF, res/surf:	1.09	1.08	N/A
Gas Deviation Factor:	0.837	0.750	N/A

PUMP DATA

Manufacturer:	Reda
Series:	540
Model:	GN3100
Number of Stages:	120
Stages with Free Gas:	120
Additional Stages due to Gas:	0
Minimum Recommended Rate, Bbl/D:	1788.36**
Maximum Recommended Rate, Bbl/D:	3088.98**
Rate at Peak Efficiency, Bbl/D:	2237.50**
Power at Peak Efficiency, HP:	102.3**
Frequency, Hz:	50.0
** = Corrected for Frequency & Viscosity	

	Design	120 Stages
Total Dynamic Head (TDH), ft:	2849.73	2877.03
Surface Rate (O+W), Bbl/D:	2450.00	2572.54
Avg. Pump Rate (O+G+W), Bbl/D:	N/A	2778.44
Pump Intake Pressure, psig:	995.6	988.5
Operating Power, HP:	N/A	101.0
Pump Efficiency, %:	N/A	56.3

MOTOR DATA

Manufacturer:	Reda
Series:	456
Winding:	4142 - Upper

Name Plate Power, HP:	168.0	Name Plate Frequency, Hz:	60
Name Plate Voltage, Volts:	2505.	Selected percentage of base, %:	100
Name Plate Current, Amps:	43.0		
Adjust for Motor Slip:	Yes	Operating Current, Amps:	32.9
Design Frequency, Hz:	50.	Operating Voltage, Volts:	2088.02
Operating Motor Load, HP: (@ Design Frequency)	101.0	Operating Power Factor, frac:	0.707
Operating Motor Load, :	72.1	Operating Efficiency, %:	83.80
Operating Speed, RPM:	2845	Fluid Velocity, ft/sec:	1.478
Well Fluid Temperature, °F	184.8	Speed Increase Heating, °F:	0.0
Skin Temperature Rise, °F:	14.2	Harmonic Heating due to VSD, °F:	8.5
Avg. Winding Temp. Rise over Skin, °F:	50.3	Total Winding Temp., °F:	249.3

	Catalog	Actual
Total Stages	120	120
Slip Stages	0	0
Total Dynamic Head (TDH), ft	2877.03	2851.47
Surface Rate (O+W), Bbl/D	2572.54	2447.39
Avg. Pump Rate (O+G+W), Bbl/D	2778.44	2643.28
Pump Intake Pressure, psig	988.5	995.8
Operating Power, HP	101.0	91.1
Pump Efficiency, %	56.3	55.7
Operating Speed, RPM	2916	2845

SEAL DATA

Manufacturer:	Reda
Series:	400-456
Bearing Type:	400 STD
Chamber Selection:	LSB
Bearing Cap., lb:	1400.2
Operating Thrust Load, lb:	686.6
Maximum Thrust Load, lb:	1123.7
Power Consumption, HP:	0.4

CABLE DATA

Manufacturer:	Philp
Type:	Devilead EPDM/Lead
Size:	1 Cu
Shape:	Flat
Conductor Type:	Stranded
Max. Cond. Temp., °F:	400.0
Cable Length, ft:	5517.00

	Design Freq.
Frequency, Hz	50
Max. Allowable Amps, Amps	162.8
Amperage, Amps	32.9
Kilovolt Ampere, KVA	124.1
Kilowatts, KW	87.7
Kilowatts, $/mo	0
Surface Voltage, Volts	2177.7
Voltage Drop @ 68.0 °F, Volts	67.1
Voltage Drop @ 225.0 °F BHT, Volts	89.6
Kilowatt Loss, KW	3.6
Required Motor Voltage, Volts	2088.0
Downhole Voltage at Motor, Volts	2088.0
In-rush Motor Voltage Drop, Volts	358.5
Motor Start up Voltage, Volts	1819.1
Start up/Operating Ratio, ratio	0.9

A. 2: SubPump Detailed Report of C-001-65 (Proposed Design of Combined ESP / GL)

GENERAL DESCRIPTION

Company Name:	Arabian Gulf Oil Company
Well Name:	C-001-65
Field Name:	Sarir Field
Reservoir Name:	C-main
Analyst:	Waleed M. E. Mohammed
Calculation Type:	Rigorous Design
Location:	Concession -65
Comments:	Proposed design of Combined ESP/GL
Date:	13/04/2010

WELLBORE DATA

	No.	OD in	Wt lb/ft	ID in	Rough in	Bottom MD ft	Top MD ft
Tubing	1	3.500	9.30	2.992	0.0006500	5417	0.00
Casing	1	7.000	23.00	6.366	0.0006500	9082	0.00

Pump Depth, ft:	5417
Top of Perfs. or Datum Pt. (MD), ft:	8626
Reservoir Temperature, °F:	225.0
Wellhead Temperature, °F:	117.0

Tubing Outflow Correlation: Orkiszewski (1967)

GASLIFT DATA

Injection Rate ,MSCF/D	200
Injection Depth, ft:	4000
Valve Deferential Pressure , psi:	100

COMPRESSOR DATA

Compressor Suction Pressure , psig:	55
Compressor Suction Temperature , F°	120
Compressor Total Efficiency,%:	80
Estimated Flow line pressure Drop , psi:	200
Required HP , HP:	45.9

PVT CORRELATIONS

Description	Method
Oil Viscosity, (Dead)	Beggs & Robinson
Oil Viscosity, (Saturated)	Beggs & Robinson
Oil Viscosity, (Unsaturated)	Vasquez & Beggs
Gas Viscosity	Lee
Water Viscosity	Matthews & Russell
Oil Formation Volume Factor	Vasquez & Beggs
Water Formation Volume Factor	HP41C
Oil Density	Katz
Z-Factor	Dranchuk, Purvis
Oil Isothermal Compressibility	Vasquez & Beggs
Water Isothermal Compressibility	Meehan
Solution Gas/Oil Ratio	Standing
Bubble Point Pressure	Standing
Gas Density	Beggs
Water Density	Beggs
Oil Surface Tension Correlation	Baker and Swerdloff
Water Surface Tension Correlation	Hough

FLUID DATA

Standard Temperature,	60.0	Prod. Gas/Oil Ratio, scf/bbl:	230.0
Standard Pressure, psi:	14.7	Prod. Gas/Liq. Ratio, scf/bbl:	112.7
Oil Gravity, °API:	35.0	Bubble Point Pressure, psia:	600.0
Gas Specific Gravity, :	0.950	Solution GOR, scf/bbl:	128.5
Water Specific	1.100	Average Fluid Viscosity, cP:	0.6
Water Salinity, ppm:	130404	Fluid Grad. @ Pump Intake, psi/ft:	.415
Water Cut, %:	51.0		

Viscosity Calibration Data

Pnt. #	Press. psia	Temp. °F	User Visc. cP	Type	Calc. Visc. cP	Calib. Factor
1	3000.0	225.0	1.9	Dead	1.3	1.412
2	2000.0	170.0	1.7	Dead	2.3	0.753
3	1000.0	140.0	1.6	Dead	3.4	0.471
Flowline Pressure, psig: 150.0						

INFLOW DATA

IPR Calculation Method: Productivity Index	
Fluid Rate at Test BHP, Bbl/D:	2450.00
Productivity Index, blpd/psi:	14.848
Bubble Point Rate, Bbl/D:	35636.36
Max. Oil Flow Rate, Bbl/D:	35636.36
Max. Total Flow Rate, Bbl/D:	35636.36

	Static	**Test**
Casing Pressure, psig:	10.0	0.0
Fluid Level, ft:	0.00	0.00
Bottom Hole Pressure	2400.0	2235.0

PRESSURE/RATE DATA

Design Criteria - Solved For: Pump Intake Conditions	
Total Fluid Rate, Bbl/D:	2870.00
Pump Depth, ft:	5250.00
Fluid Over Pump, ft:	2225.06
Pumping Fluid Level, ft:	3024.94
Pump Intake Pressure, psig:	907.5
Total Dynamic Head, ft:	1961.54
Flowline Pressure, psig:	150.0
Casing Pressure, psig:	10.0
Bottom Hole Pressure, psig:	2206.7
Gas through Pump:	Gas Compressed

GAS SEPARATOR PERFORMANCE

Packer Installed?	No
Free Gas Avail. at Pump, %	10.32
Natural Gas Separation, %:	70.0
Free Gas into Pump, %	1.36
Gas Separator Installed?	Yes
Gas Separator Efficiency,	60.00

WELL SYSTEM CURVE DETAIL

Points	(+) Tubing Head ft	(-) PIP Head ft	(=) TDH ft	Surface Rate O+W Bbl/D	Avg. Pump Rate O+W+G Bbl/D	Pumping Fluid Level ft
1	3374.40	2528.55	845.84	185.93	201.19	2676.96
2	4047.86	2241.72	1806.14	2486.80	2690.85	2970.89
3	4849.09	1914.03	2935.06	4787.67	5180.52	3307.30
4	5471.46	1602.00	3869.46	7088.54	7670.18	3628.22
5	6003.45	1288.20	4715.25	9389.41	10159.85	3949.00
6	6581.26	996.91	5584.35	11690.28	12649.52	4245.72
7	7174.00	697.98	6476.01	13991.15	15139.18	4553.65
8	7842.18	410.23	7431.95	16292.02	17628.85	4853.28
Pump off	8603.19	34.61	8568.58	18592.89	20118.51	5248.76
Design	4150.57	2189.03	1961.54	2870.00	3105.50	3024.94

THEORETICAL PUMP PERFORMANCE

	Intake	Discharge	Surface
Oil Rate, Bbl/D:	1596.84	1588.36	1427.74
Gas Rate through Pump, Bbl/D:	43.22	20.63	N/A
Gas Rate from Casing, Bbl/D:	316.95	N/A	N/A
Total Gas Rate, Mscf/D:	N/A	N/A	328.38
Free Gas Percent, %:	1.37	0.67	N/A
Water Rate, Bbl/D:	1533.7	1530.59	1486.01
Total Liquid Rate, Bbl/D:	3130.55	3118.95	2913.75
Pressure, psig:	905.0	1716.0	150.0
Specific Gravity Liquid, wtr=1:	0.92	0.92	N/A
Specific Gravity Mixture, wtr=1:	0.91	0.91	N/A
Liquid Density, lb/cf:	57.439	57.388	N/A
Mixture Density, lb/cf:	56.713	57.060	N/A
Mixture Viscosity, CST:	N/A	N/A	N/A
Mixture Viscosity, SSU:	N/A	N/A	N/A
Solution GOR, scf/bbl:	143.0	143.0	N/A
Solution GWR, scf/bbl:	2.1	2.1	N/A
Liquid FVF, res/surf:	1.07	1.07	N/A
Mixture FVF, res/surf:	1.09	1.08	N/A
Gas Deviation Factor:	0.848	0.764	N/A

PUMP DATA

Manufacturer:	Reda
Series:	540
Model:	GN4000
Number of Stages:	86
Stages with Free Gas:	86
Additional Stages due to Gas:	0
Minimum Recommended Rate, Bbl/D:	2601.24**
Maximum Recommended Rate, Bbl/D:	3901.87**
Rate at Peak Efficiency, Bbl/D:	3379.17**
Power at Peak Efficiency, HP:	73.2**
Frequency, Hz:	50.0
** = Corrected for Frequency & Viscosity	

	Design	86 Stages
Total Dynamic Head (TDH), ft:	1961.5	2049.11
Surface Rate (O+W), Bbl/D:	2870.00	3043.92
Avg. Pump Rate (O+G+W), Bbl/D:	N/A	3293.69
Pump Intake Pressure, psig:	907.5	897.6
Operating Power, HP:	N/A	70.1
Pump Efficiency, %:	N/ A	67.3

MOTOR DATA

Manufacturer:	Reda
Series:	456
Winding:	4083 - Upper

Name Plate Power, HP:	96.0	Name Plate Frequency, Hz:	60
Name Plate Voltage, Volts:	1431.50	Selected percentage of base, %:	100
Name Plate Current, Amps:	43.0		
Adjust for Motor Slip:	Yes	Operating Current, Amps:	37.3
Design Frequency, Hz:	50.0	Operating Voltage, Volts:	1192.9
Operating Motor Load, HP:	70.1	Operating Power Factor, frac:	0.754
(@ Design Frequency)			
Operating Motor Load, :	87.57	Operating Efficiency, %:	83.80
Operating Speed, RPM:	2845	Fluid Velocity, ft/sec:	1.760
Well Fluid Temperature, °F:	182.7	Speed Increase Heating, °F:	0.0
Skin Temperature Rise, °F:	14.3	Harmonic Heating due to VSD, °F:	10.6
Avg. Winding Temp. Rise over Skin, °F:	62.2	Total Winding Temp., °F:	259.2

	Catalog	Actual
Total Stages	86	86
Slip Stages	0	0
Total Dynamic Head (TDH), ft	2049.11	1983.94
Surface Rate (O+W), Bbl/D	3043.	2913.75
Avg. Pump Rate (O+G+W), Bbl/D	3293.	3152.84
Pump Intake Pressure, psig	897.6	905.0
Operating Power, HP	70.1	62.0
Pump Efficiency, %	67.3	67.8
Operating Speed, RPM	2916	2845

SEAL DATA

Manufacturer:	Reda
Series:	400-456
Bearing Type:	400 STD
Chamber Selection:	LSB
Bearing Cap., lb:	1400.2
Operating Thrust Load, lb:	627.2
Maximum Thrust Load, lb:	1040.2
Power Consumption, HP:	0.4

CABLE DATA

Manufacturer:	Philp
Type:	Devilead EPDM/Lead
Size:	1 Cu
Shape:	Flat
Conductor Type:	Stranded
Max. Cond. Temp., °F:	400.0
Cable Length, ft:	5350.00

	Design Freq.
Frequency, Hz	50
Max. Allowable Amps, Amps	163.5
Amperage, Amps	37.3
Kilovolt Amper, KVA	83.5
Kilowatts, KW	63
Surface Voltage, Volts	1291.5
Voltage Drop @ 68.0 °F, Volts	73.8
Voltage Drop @ 225.0 °F BHT, Volts	98.6
Kilowatt Loss, KW	4.8
Required Motor Voltage, Volts	1192.9
Downhole Voltage at Motor, Volts	1192.9
In-rush Motor Voltage Drop, Volts	394.3
Motor Start up Voltage, Volts	1768.3
Start up/Operating Ratio, ratio	0.9

A. 3: Avocet Detailed Report of C-001-65 (Proposed Design of Optimizing Pump Setting Depth)

GENERAL DESCRIPTION

Project	Optimizing Pump Setting Depth
Prepared by	Waleed M. E. Mohammed
Date	4/14/2010 12:00:00 AM
Company	Arabian Gulf Oil Company
Field & Lease	SARIR FIELD
Well Number	C-001-65
State & Country	Libya

Wellbore Data

Casing					
	Top (ft)	Bottom (ft)	OD (in)	ID (in)	Roughness (in)
1	0.00	9082.00	7.00	6.36	0.00065

Note: All Depths are in MD.

Tubing					
	Bottom (ft)	OD (in)	ID (in)	Roughness (in)	Flow Type
1	4950.00	3.50	2.99	0.00065	TUBULAR

Perforations Depth: 8626.00 ft

Temperature

Wellhead: 178.54 ºF Reservoir: 225.00 ºF

Heat Transfer: Selected Ambient: 60.00 ºF Value: 2.00 Btu/h/oF/ft2

Fluid Correlations

Dead Oil Viscosity	Beggs & Robinson
Saturated Oil Viscosity	Beggs & Robinson
Under saturated Oil Viscosity	Vasquez & Beggs
Gas Viscosity	Lee et al.
Water Viscosity	Van Wingen Chart
Oil FVF above Bubble Point	Vasquez & Beggs
Oil FVF below Bubble Point	Standing
Solution GOR/Bubble Point	Standing
Oil Compressibility	Vasquez & Beggs
Gas Z Factor	Standing

Fluid Data

Oil Specific Gravity, ºAPI	35.00
Gas Specific Gravity	0.95
Water Salinity, ppm	130403
GLR, SCF/STB	112.70
Bubble Point Pressure	Not Calculated
Bubble Point, psig	600.0
Water Cut, %	51.00
Reservoir Temperature, ºF	225.00

Inflow

Performance method	PI
Productivity Index, STB/d/psi	14.80
Static Bottom Hole Pressure, psig	2400.0
Static Casing Pressure, psig	
Measured Flowrate, STB/d	2450.0
Measured Bottom Hole Pressure, psig	2235.0
Measured Casing Pressure, psig	10.0
Reservoir Temperature, ºF	225.00
AOF, bbl/d	35519.93

Desired Operating Conditions

Calculate	PIP
Flowrate, STB/d	2700.0
Pump Depth, ft	4950.00
Intake Pressure, psig	812.2
Frequency, Hz	50.00
Casing Pressure, psig	10.0
Surface Pressure, psig	150.0
Total Dynamic Head (TDH), ft	2663.20
Intake Gas Volume Fraction, %	12.11

Theoretical Pump Performance

	Intake	Discharge
Pressure, psig	817.5	1779.2
Oil Rate, bbl/d	1449.30	1439.38
Gas Rate through Pump, bbl/d	386.56	160.91
Free Gas, %	12.03	5.41
Water Rate, bbl/d	1377.42	1373.17
Total Liquid Rate, bbl/d	2826.73	2812.55
Specific Gravity of Liquid,	0.91	0.91
Specific Gravity of Mixture,	0.81	0.87
Mixture Viscosity, cST	0.32	0.34
Mixture Viscosity, SSU	29.34	29.41
Solution GOR, SCF/STB	128.47	131.54
Solution GWR, SCF/STB	16.72	13.77

Total Surface Liquid Rate: 2603.13 STB/d

Gas Separation

Gas Separator: TANDEM: 400 DRS .875 SFT

Liquid Rate, bbl/d	2932.64
Natural Gas Separation, %	70.00
Separator Efficiency, %	0.00
Total Separation Efficiency, %	0.00
Gas Rate before Separation, bbl/d	404.21
Total Rate before Separation, bbl/d	3336.84
Gas Rate after Separation, bbl/d	404.21
Total Rate after Separation, bbl/d	3336.84
Gas Volume Fraction at Pump, %	12.11
Intake Gas Volume Fraction, %	12.11

Pump

Model: REDA 400 D3500N	
Frequency, Hz	50.00
Number of Stages	158
Stages with Free Gas	158

Operating Condition

Total Dynamic Head (TDH), ft	2607.81
Surface Rate (O+W), STB/d	2603.1
Avg. Pump Rate (O+G+W) bbl/d	3065.53
Pump Intake Pressure, psig	817.5
Operating Power, hp	75.4
Bottom Pump Efficiency, %	66.37
Pump Efficiency, %	66.37

Viscosity Correction Factors

	Calculated	User Entered
Rate	1.00	
Head	1.00	
Power	1.00	
Efficiency	1.00	N/A

Average Pump Viscosity: 0.28

Housing Data

Housing #	Housing Type	Length (ft)	# of Stages
1	ES	19	79
2	ES	19	79
Total		38	158

Advanced Gas Handler

Device information: REDA 400/400 AGH

Motor

REDA 375 AS (2) J181 Dominator (100.00% Rating Factor)

Motor Slip Adjustment: Yes

Nameplate: 60.00 Hz

Power, hp	128.6	Voltage, Volts	1897.0
Amperage, Amps	49.4	Power @ Design Rate, hp	107.1

Operating Condition (50.00Hz)			
Motor Load, hp	100.4	Motor Speed, RPM	2790.0
Efficiency, %	77.60	Fluid Velocity, ft/s	1.17
Power Factor, %	83.38	Voltage, Volts	1580.8
Amperage, Amps	42.4	Load Factor, %	93.74
Total Stages	158	Slip Stages	0
Total Dynamic Head (TDH), ft	2607.81		
Surface Rate (O+W), STB/d	2603.1	Avg. Pump Rate (O+G+W) bbl/d	3065.5
Pump Intake Pressure, psig	817.5	Required Power @ Nameplate Frequency, hp	120.5
Bottom Pump Efficiency, %	66.37	Pump Speed, RPM	2790.0

Fluid Temperature At Intake, ºF	209.50
Skin Temperature Rise, ºF	22.35
Avg. Winding Temp. Rise over Skin, ºF	54.43
Total Winding Temperature, ºF	286.29
Speed Increase Heating, ºF	0.00
Heat Rise due to VSD without Load Filter, ºF	9.25
Heat Rise due to VSD with Load Filter or Sine wave Drive,	0.00

Protector

Thrust Bearing Type	325 Modular	Number of Seals	2
Configuration	LSB	Number of Chambers	2
Components	SINGLE	Oil Type	REDA OIL #5
Total Shut-In Down thrust, lbf	789.84		

Motor Lead Extension

Type	KELTB-LP	Connection Type	TAPE-IN
Length, ft	55.00	KV	3
Minor Armor OD, in	0.38	Major Armor OD, in	0.95
Conductor Size, AWG	6.00	Material/Armor	M

Cable

REDA REDALEAD EL FLAT Stranded

Specifications			
Conductor Size, AWG	1	KV	4000.00
Temperature Rating,	450.00	Length, ft	5050.00

Operating Condition			
Conductor Temperature, ºF	221.04	Voltage Drop, Volts	59.2
KVA,	120.49	Surface Voltage, Volts	1640.1
Max Ampacity, Amps	193.8	Start up Ratio	92.49

APPENDIX B

B. 1: SubPump Detailed Report of C-046-65 (Analysis of Current Design)

GENERAL DESCRIPTION

Company Name:	Arabian Gulf Oil Company
Well Name:	C-046-65
Field Name:	Sarir Field
Reservoir Name:	C-main
Analyst:	Waleed M. E. Mohammed
Calculation Type:	Rigorous Design
Location:	Concession -65
Comments:	Analysis of Current Design
Date:	13/04/2010

WELLBORE DATA

	No.	OD in	Wt lb/ft	ID in	Rough in	Bottom MD ft	Top MD ft
Tubing	1	3.500	9.30	2.992	0.0006500	5048	
Casing	1	7.000	23.00	6.366	0.0006500	9019	0.00

Pump Depth, ft:	5048
Top of Perfs. or Datum Pt. (MD), ft:	8570
Reservoir Temperature, °F:	225.0
Wellhead Temperature, °F:	117.0

Tubing Outflow Correlation: Orkiszewski (1967)

PVT CORRELATIONS

Description	**Method**
Oil Viscosity, (Dead)	Beggs & Robinson
Oil Viscosity, (Saturated)	Beggs & Robinson
Oil Viscosity, (Unsaturated)	Vasquez & Beggs
Gas Viscosity	Lee
Water Viscosity	Matthews & Russell
Oil Formation Volume Factor	Vasquez & Beggs
Water Formation Volume Factor	HP41C
Oil Density	Katz
Z-Factor	Dranchuk, Purvis
Oil Isothermal Compressibility	Vasquez & Beggs
Water Isothermal Compressibility	Meehan
Solution Gas/Oil Ratio	Lasater
Bubble Point Pressure	Lasater
Gas Density	Beggs
Water Density	Beggs
Oil Surface Tension Correlation	Baker and Swerdloff
Water Surface Tension Correlation	Hough

FLUID DATA

Standard Temperature, °F:	60.0	Prod. Gas/Oil Ratio, scf/bbl:	185.
Standard Pressure, psi:	14.7	Prod. Gas/Liq. Ratio, scf/bbl:	99.9
Oil Gravity, °API:	36.0	Bubble Point Pressure, psia:	600.3
Gas Specific Gravity:	0.950	Solution GOR, scf/bbl:	155.6
Water Specific Gravity:	1.152	Average Fluid Viscosity cP:	0.7
Water Salinity, ppm:	195000	Fluid Grad. @ Pump Intake, psi/ft:	.416
Water Cut, %:	46.0		

Viscosity Calibration Data

Pnt. #	Press. psia	Temp. F°	User Visc. Cp	Type	Calc. Visc. Cp	Calib. Factor
1	3000.0	225.0	1.9	Dead	1.3	1.412
2	2000.0	170.0	1.7	Dead	2.3	0.753
3	1000.0	140.0	1.6	Dead	3.4	0.471
Flowline Pressure, psig: 150.0						

INFLOW DATA

IPR Calculation Method: Productivity Index	
Fluid Rate at Test BHP, Bbl/D:	2870.00
Productivity Index, blpd/psi:	15.000
Bubble Point Rate, Bbl/D:	39000.00
Max. Oil Flow Rate, Bbl/D:	39000.00
Max. Total Flow Rate, Bbl/D:	39000.00

	Static	Test
Casing Pressure, psig:	20.0	0.0
Fluid Level, ft:	0.00	2142.00
Bottom Hole Pressure (BHP), ft:	2600.0	2433.0

PRESSURE/RATE DATA

Design Criteria - Solved For: Pump Intake Conditions	
Total Fluid Rate, Bbl/D:	2870.00
Pump Depth, ft:	5048.00
Fluid over Pump, ft:	2454.15
Pumping Fluid Level, ft:	2593.85
Pump Intake Pressure, psig:	1013.7
Total Dynamic Head, ft:	2475.26
Flowline Pressure, psig:	150.0
Casing Pressure, psig:	20.0
Bottom Hole Pressure, psig:	2408.7
Gas through Pump:	Gas Compressed

GAS SEPARATOR PERFORMANCE

Packer Installed?	No
Free Gas Avail. at Pump, %	2.15
Natural Gas Separation, %:	70.0
Free Gas into Pump, %	0.26
Gas Separator Installed?	Yes
Gas Separator Efficiency,	60.00

WELL SYSTEM CURVE DETAIL

Points	(+) Tubing Head ft	(-) PIP Head ft	(=) TDH ft	Surface Rate O+W Bbl/D	Avg. Pump Rate O+W+G Bbl/D	Pumping Fluid Level ft
1	5135.00	2838.73	2296.27	202.98	219.14	2178.23
2	4895.06	2458.03	2437.03	2714.81	2930.9	2569.14
3	5196.57	2064.7	3131.87	5226.6	5642.84	2973.43
4	5590.79	1667.38	3923.4	7738.49	8354.69	3382.82
5	6089.91	1268.24	4821.67	10250.33	11066.55	3792.65
6	6675.8	915.17	5760.62	12762.17	13778.4	4152.86
7	7310.18	606.93	6703.24	15274.00	16490.25	4471.7
8	8068.87	325.53	7743.35	17785.84	19202.1	4766.42
Pump off	8905.28	61.58	8843.35	20297.68	21913.95	5046.32
Design	4909.23	2433.96	2475.26	2870.00	3098.53	2593.85

THEORETICAL PUMP PERFORMANCE

	Intake	Discharge	Surface
Oil Rate, Bbl/D:	1725.43	1716.14	1539.16
Gas Rate through Pump, Bbl/D:	8.11	3.65	N/A
Gas Rate from Casing, Bbl/D:	59.51	N/A	N/A
Total Gas Rate, Mscf/D:	N/A	N/A	284.74
Free Gas Percent, %:	0.26	0.12	N/A
Water Rate, Bbl/D:	1353.91	1350.80	1311.14
Total Liquid Rate, Bbl/D:	3079.34	3066.94	2850.30
Pressure, psig:	1015.0	2047.1	150
Specific Gravity Liquid, wtr=1:	0.92	0.92	N/A
Specific Gravity Mixture, wtr=1:	0.92	0.92	N/A
Liquid Density, lb/cf:	57.575	57.51	N/A
Mixture Density, lb/cf:	57.437	57.461	N/A
Mixture Viscosity, CST:	N/A	N/A	N/A
Mixture Viscosity, SSU:	N/A	N/A	N/A
Solution GOR, scf/bbl:	167.7	167.7	N/A
Solution GWR, scf/bbl:	0.7	0.7	N/A
Liquid FVF, res/surf:	1.08	1.0	N/A
Mixture FVF, res/surf:	1.08	1.08	N/A
Gas Deviation Factor:	0.838	0.756	N/A

PUMP DATA

Manufacturer:	Reda
Series:	540
Model:	GN4000
Number of Stages:	105
Stages with Free Gas:	105
Additional Stages due to Gas:	0
Minimum Recommended Rate, Bbl/D:	2601.24**
Maximum Recommended Rate, Bbl/D:	3901.87**
Rate at Peak Efficiency, Bbl/D:	3379.17**
Power at Peak Efficiency, HP:	89.4**
Frequency, Hz:	50.0
** = Corrected for Frequency & Viscosity	

	Design	105 Stages
Total Dynamic Head (TDH), ft:	2475.26	2518.99
Surface Rate (O+W), Bbl/D:	2870.00	3028.15
Avg. Pump Rate (O+G+W), Bbl/D:	N/A	3269.28
Pump Intake Pressure, psig:	1013.7	1003.5
Operating Power, HP:	N/A	85.6
Pump Efficiency, %:	N/A	67.3

MOTOR DATA

Manufacturer:	Reda
Series:	456
Winding:	4104 - Upper

Name Plate Power, HP:	120.0	Name Plate Frequency, Hz:	60
Name Plate Voltage, Volts	1587.66	Selected percentage of base, %:	100
Name Plate Current, Amps:	48.5		
Adjust for Motor Slip:	Yes	Operating Current, Amps:	41.4
Design Frequency, Hz:	50.0	Operating Voltage, Volts:	1323
Operating Motor Load, HP: (@ Design Frequency)	85.6	Operating Power Factor, frac:	0.749
Operating Motor Load:	85.57	Operating Efficiency, %:	83.80
Operating Speed, RPM:	2845	Fluid Velocity, ft/sec:	1.721
Well Fluid Temperature, °F:	180.6	Speed Increase Heating, °F:	0.0
Skin Temperature Rise, °F:	14.7	Harmonic Heating due to VSD,°F:	10.3
Avg. Winding Temp. Rise over Skin, °F:	60.5	Total Winding Temp., °F:	255.8

	Catalog	Actual
Total Stages	105	105
Slip Stages	0	0
Total Dynamic Head (TDH),	2518.99	2471.01
Surface Rate (O+W), Bbl/D	3028.15	2850.30
Avg. Pump Rate (O+G+W),	3269.28	3077.27
Pump Intake Pressure, psig	1003.5	1015.0
Operating Power, HP	85.6	76.4
Pump Efficiency, %	67.3	67.6
Operating Speed, RPM	2916	2845

SEAL DATA

Manufacturer:	Reda
Series:	400-456
Bearing Type:	400 STD
Chamber Selection:	LSB
Bearing Cap., lb:	1400.2
Operating Thrust Load, lb:	785.7
Maximum Thrust Load, lb:	1276.0
Power Consumption, HP:	0.5

CABLE DATA

Manufacturer:	Philp
Type:	Devilead EPDM/Lead
Size:	1 Cu
Shape:	Flat
Conductor Type:	Stranded
Max. Cond. Temp., °F:	400.0
Cable Length, ft:	5148.00

	Design Freq.
Frequency, Hz	50
Max. Allowable Amps, Amps	164.2
Amperage, Amps	41.4
Kilovolt Ampere, KVA	102.3
Kilowatts, KW	76.6
Kilowatts, $/mo	0
Surface Voltage, Volts	1428.1
Voltage Drop @ 68.0 °F, Volts	78.6
Voltage Drop @ 225.0 °F BHT, Volts	105.0
Kilowatt Loss, KW	5.6
Cost of Voltage Loss, $/mo	0
Required Motor Voltage, Volts	1323.1
Downhole Voltage at Motor, Volts	1323.1
In-rush Motor Voltage Drop, Volts	420.1
Motor Start up Voltage, Volts	1007.9
Start up/Operating Ratio, ratio	0.8

B. 2: SubPump Detailed Report of C-046-65 (Proposed Design of Combined ESP/GL)

GENERAL DESCRIPTION

Company Name:	Arabian Gulf Oil Company
Well Name:	C-046-65
Field Name:	Sarir Field
Reservoir Name:	C-main
Analyst:	Waleed M. E. Mohammed
Calculation Type:	Rigorous Design
Location:	Concession -65
Comments:	Proposed Design of Combined ESP/GL
Date:	13/04/2010

WELLBORE DATA

	No.	OD in	Wt lb/ft	ID in	Rough in	Bottom MD ft	Top MD ft
Tubing	1	3.500	9.30	2.992	0.0006500	5048	
Casing	1	7.000	23.00	6.366	0.0006500	9019	0.00

Pump Depth, ft:	5048
Top of Perfs. or Datum Pt. (MD), ft:	8570
Reservoir Temperature, °F:	225.0
Wellhead Temperature, °F:	117.0

Tubing Outflow Correlation: Orkiszewski (1967)

GASLIFT DATA

Injection Rate ,MSCF/D	300
Injection Depth, ft:	4000
Valve Deferential Pressure , psi:	100

COMPRESSOR DATA

Compressor Suction Pressure , psig:	55
Compressor Suction Temperature , F°	130
Compressor Total Efficiency,%:	80
Estimated Flow line pressure Drop , psi:	200
Required HP , HP:	72.2

PVT CORRELATIONS

Description	Method
Oil Viscosity, (Dead)	Beggs & Robinson
Oil Viscosity, (Saturated)	Beggs & Robinson
Oil Viscosity, (Unsaturated)	Vasquez & Beggs
Gas Viscosity	Lee
Water Viscosity	Matthews & Russell
Oil Formation Volume Factor	Vasquez & Beggs
Water Formation Volume Factor	HP41C
Oil Density	Katz
Z-Factor	Dranchuk, Purvis
Oil Isothermal Compressibility	Vasquez & Beggs
Water Isothermal Compressibility	Meehan
Solution Gas/Oil Ratio	Standing
Bubble Point Pressure	Standing
Gas Density	Beggs
Water Density	Beggs
Oil Surface Tension Correlation	Baker and Swerdloff
Water Surface Tension Correlation	Hough

FLUID DATA

Standard Temperature,	60.0	Prod. Gas/Oil Ratio, scf/bbl:	185.0
Standard Pressure, psi:	14.7	Prod. Gas/Liq. Ratio, scf/bbl:	99.9
Oil Gravity, °API:	36.0	Bubble Point Pressure, psia:	600.3
Gas Specific Gravity:	0.950	Solution GOR, scf/bbl:	155.6
Water Specific Gravity:	1.152	Average Fluid Viscosity, cP:	0.7
Water Salinity, ppm:	195000	Fluid Grad. @ Pump Intake,	0.416
Water Cut, %:	46.0		

Viscosity Calibration Data

Pnt. #	Press. psia	Temp. °F	User Visc. cP	Type	Calc. Visc. cP	Calib. Factor
1	3000.0	225.0	1.9	Dead	1.3	1.412
2	2000.0	170.0	1.7	Dead	2.3	0.753
3	1000.0	140.0	1.6	Dead	3.4	0.471
Flowline Pressure, psig: 150						

INFLOW DATA

IPR Calculation Method: Productivity Index	
Fluid Rate at Test BHP, Bbl/D:	2870
Productivity Index, blpd/psi:	15
Bubble Point Rate, Bbl/D:	39000
Max. Oil Flow Rate, Bbl/D:	39000
Max. Total Flow Rate, Bbl/D:	39000

	Static	**Test**
Casing Pressure, psig:	10.0	0.0
Fluid Level, ft:	0.00	0.00
Bottom Hole Pressure	2600.0	2310.0

PRESSURE/RATE DATA

Design Criteria - Solved For: Pump Intake Conditions	
Total Fluid Rate, Bbl/D:	4500
Pump Depth, ft:	5048
Fluid over Pump, ft:	2219.08
Pumping Fluid Level, ft:	2828.92
Pump Intake Pressure, psig:	907.5
Total Dynamic Head, ft:	2069.55
Flowline Pressure, psig:	150.0
Casing Pressure, psig:	10.0
Bottom Hole Pressure, psig:	2300.0
Gas through Pump:	Gas Compressed

GAS SEPARATOR PERFORMANCE

Packer Installed?	No
Free Gas Avail. at Pump, %	2.43
Natural Gas Separation, %:	70.0
Free Gas into Pump, %	0.3
Gas Separator Installed?	Yes
Gas Separator Efficiency,	60.00

WELL SYSTEM CURVE DETAIL

Points	(+) Tubing Head ft	(-) PIP Head ft	(=) TDH ft	Surface Rate O+W Bbl/D	Avg. Pump Rate O+W+G Bbl/D	Pumping Fluid Level ft
1	2754.41	2838.62	-84.21	203.48	219.95	2152.11
2	3772.68	2456.97	1315.71	2721.52	2941.89	2543.50
3	4514.88	2062.62	2452.26	5239.57	5663.82	2948.48
4	5286.14	1664.28	3621.87	7757.61	8385.76	3358.55
5	5907.49	1264.31	4643.18	10275.65	11107.69	3768.76
6	6589.03	911.25	5677.78	12793.70	13829.62	4128.69
7	7260.85	602.40	6658.46	15311.74	16551.56	4447.92
8	8018.17	320.42	7697.74	17829.78	19273.49	4743.02
Pump off	8888.49	33.86	8854.63	20347.83	21995.43	5046.81
Design	4248.49	2178.94	2069.55	4500.00	4864.37	2828.92

THEORETICAL PUMP PERFORMANCE

	Intake	Discharge	Surface
Oil Rate, Bbl/D:	2589.54	2574.55	2307.12
Gas Rate through Pump, Bbl/D:	13.81	6.39	N/A
Gas Rate from Casing, Bbl/D:	101.24	N/A	N/A
Total Gas Rate, Mscf/D:	N/A	N/A	426.82
Free Gas Percent, %:	0.29	0.14	N/A
Water Rate, Bbl/D:	2029.94	2026.00	1965.33
Total Liquid Rate, Bbl/D:	4619.48	4600.54	4272.45
Pressure, psig:	922.4	1798.4	150.0
Specific Gravity Liquid, wtr=1:	0.92	0.92	N/A
Specific Gravity Mixture, wtr=1:	0.92	0.92	N/A
Liquid Density, lb/cf:	57.593	57.522	N/A
Mixture Density, lb/cf:	57.437	57.452	N/A
Mixture Viscosity, CST:	N/A	N/A	N/A
Mixture Viscosity, SSU:	N/A	N/A	N/A
Solution GOR, scf/bbl:	167.7	167.7	N/A
Solution GWR, scf/bbl:	0.7	0.7	N/A
Liquid FVF, res/surf:	1.08	1.08	N/A
Mixture FVF, res/surf:	1.08	1.08	N/A
Gas Deviation Factor:	0.851	0.768	N/a

PUMP DATA

Manufacturer:	Reda
Series:	540
Model:	GN5200
Minimum Recommended Rate, Bbl/D:	3170.27**
Number of Stages:	109
Stages with Free Gas:	109
Additional Stages due to Gas:	0
Maximum Recommended Rate, Bbl/D:	5365.07**
Rate at Peak Efficiency, Bbl/D:	4592.50**
Power at Peak Efficiency, HP:	109.7**
Frequency, Hz:	50.0
** = Corrected for Frequency & Viscosity	

	Design	109 Stages
Total Dynamic Head (TDH), ft:	2069.55	2041.27
Surface Rate (O+W), Bbl/D:	4500.00	4435.20
Avg. Pump Rate (O+G+W), Bbl/D:	N/A	4794.33
Pump Intake Pressure, psig:	907.5	911.7
Operating Power, HP:	N/A	103.9
Pump Efficiency, %:	N/A	65.8

MOTOR DATA

Manufacturer:	Reda
Series:	456
Winding:	4114 - Upper

Name Plate Power, HP:	132	Name Plate Frequency, Hz:	60
Name Plate Voltage, Volts:	2415.53	Selected percentage of base, %:	100
Name Plate Current, Amps:	35		
Adjust for Motor Slip:	Yes	Operating Current, Amps:	32.1
Design Frequency, Hz:	50.0	Operating Voltage, Volts:	2012.94
Operating Motor Load, HP: (@ Design Frequency)	103.9	Operating Power Factor, frac:	0.771
Operating Motor Load, :	94.48	Operating Efficiency, %:	83.80
Operating Speed, RPM:	2845	Fluid Velocity, ft/sec:	2.580
Well Fluid Temperature, °F:	180.6	Speed Increase Heating, °F:	0.0
Skin Temperature Rise, °F:	11.6	Harmonic Heating due to VSD, °F	11.7
Avg. Winding Temp. Rise over Skin, °F:	68.7	Total Winding Temp., °F:	260.9

	Catalog	Actual
Total Stages	109	109
Slip Stages	0	0
Total Dynamic Head (TDH), ft	2041.27	1972.97
Surface Rate (O+W), Bbl/D	4435.20	4272.45
Avg. Pump Rate (O+G+W), Bbl/D	4794.33	4618.40
Pump Intake Pressure, psig	911.7	922.4
Operating Power, HP	103.9	93.6
Pump Efficiency, %	65.8	66.1
Operating Speed, RPM	2916	2845

SEAL DATA

Manufacturer:	Reda
Series:	400-456
Bearing Type:	400 STD
Chamber Selection:	LSB
Bearing Cap., lb:	1400.2
Operating Thrust Load, lb:	629.7
Maximum Thrust Load, lb:	1138.9
Power Consumption, HP:	0.4

CABLE DATA

Manufacturer:	Philp
Type:	Devilead EPDM/Lead
Size:	1 Cu
Shape:	Flat
Conductor Type:	Stranded
Max. Cond. Temp., °F:	400.0
Cable Length, ft:	5148.00

	Design Freq.
Frequency, Hz	50
Max. Allowable Amps, Amps	164.2
Amperage, Amps	32.1
Kilovolt Amper, KVA	116.5
Kilowatts, KW	89.8
Kilowatts, $/mo	0
Surface Voltage, Volts	2094.5
Voltage Drop @ 68.0 °F, Volts	61.0
Voltage Drop @ 225.0 °F BHT, Volts	81.5
Kilowatt Loss, KW	3.5
Cost of Voltage Loss, $/mo	0
Required Motor Voltage, Volts	2012.9
Downhole Voltage at Motor, Volts	2012.9
In-rush Motor Voltage Drop, Volts	326.2
Motor Start up Voltage, Volts	1768.3
Start up/Operating Ratio, ratio	0.9

B. 3: Avocet Detailed Report (Proposed Design of Optimizing Pump Setting Depth)

General Information

Project	Optimizing Pump Setting Depth
Prepared by	Waleed M. E. Mohammed
Date	4/15/2010 12:00:00 AM
Company	Arabian Gulf Oil Company
Field & Lease	Sarir Field
Well Number	C-046-65
State & Country	Libya

Wellbore Data

Casing					
	Top (ft)	Bottom (ft)	OD (in)	ID (in)	Roughness
1	0.00	9019.00	7.00	6.36	0.00065

Note: All Depths are in MD.

Tubing					
	Bottom (ft)	OD (in)	ID (in)	Roughness	Flow Type
1	4668.00	3.50	2.99	0.00065	TUBULAR

Perforations Depth: 8570.00 ft

Temperature

Wellhead: 117.00 ºF Reservoir: 225.00 ºF

Fluid Correlations

Dead Oil Viscosity	Beggs & Robinson
Saturated Oil Viscosity	Beggs & Robinson
Under saturated Oil Viscosity	Vasquez & Beggs
Gas Viscosity	Lee et al.
Water Viscosity	Van Wingen Chart
Oil FVF above Bubble Point	Vasquez & Beggs
Oil FVF below Bubble Point	Standing
Solution GOR/Bubble Point	Standing
Oil Compressibility	Vasquez & Beggs
Gas Z Factor	Standing

Fluid Data

Oil Specific Gravity, ºAPI	36.00
Gas Specific Gravity	0.95
Water Salinity, ppm	194636
GLR, SCF/STB	99.00
Bubble Point Pressure	Not Calculated
Bubble Point, psig	600.0
Water Cut, %	46.00
Reservoir Temperature, ºF	225.00

Inflow

Performance method	PI
Productivity Index, STB/d/psi	15.00
Static Bottom Hole Pressure, psig	2600.0
Static Casing Pressure, psig	0
Measured Flowrate, STB/d	2870.0
Measured Bottom Hole Pressure, psig	2433.0
Measured Casing Pressure, psig	10.0
Reservoir Temperature, ºF	225.00
AOF, bbl/d	38999.93

Desired Operating Conditions

Calculate	PIP
Flowrate, STB/d	3900.0
Pump Depth, ft	4668.00
Intake Pressure, psig	813.2
Frequency, Hz	50.00
Casing Pressure, psig	20.0
Surface Pressure, psig	150.0
Total Dynamic Head (TDH), ft	2892.02
Intake Gas Volume Fraction, %	2.52

Theoretical Pump Performance

	Intake	Discharge
Pressure, psig	807.0	1967.3
Oil Rate, bbl/d	2418.78	2403.67
Gas Rate through Pump,	112.50	40.32
Free Gas, %	2.54	0.93
Water Rate, bbl/d	1886.74	1879.62
Total Liquid Rate, bbl/d	4305.52	4283.30
Specific Gravity of Liquid,	0.93	0.93
Specific Gravity of	0.90	0.92
Mixture Viscosity, cST	0.41	0.45
Mixture Viscosity, SSU	29.56	29.67
Solution GOR, SCF/STB	132.02	132.02
Solution GWR, SCF/STB	0.00	0.00
Liquid FVF,	1.07	1.06

Total Surface Liquid Rate: 4003.12 STB/d

Liquid Rate, bbl/d	4194.38
Natural Gas Separation, %	70.00
Gas Rate before Separation, bbl/d	362.17
Total Rate before Separation, bbl/d	4556.55
Gas Rate after Separation, bbl/d	108.65
Total Rate after Separation, bbl/d	4303.03
Gas Volume Fraction at Pump, %	7.94
Intake Gas Volume Fraction, %	2.52

Pump

Model: REDA 540 GN5200	
Frequency, Hz	50.00
Number of Stages	150
Stages with Free Gas	150

Intake

Model: REDA 400/400

Operating Condition

Total Dynamic Head (TDH), ft	2906.14
Surface Rate (O+W), STB/d	4003.1
Avg. Pump Rate (O+G+W) bbl/d	4357.98
Pump Intake Pressure, psig	807.0
Operating Power, hp	130.0
Bottom Pump Efficiency, %	66.10
Pump Efficiency, %	66.10

Viscosity Correction Factors

	Calculated	User Entered
Rate	1.00	
Head	1.00	
Power	1.00	
Efficiency	1.00	N/A

Average Pump Viscosity: 0.4

Housing Data

Housing #	Housing Type	Length (ft)	# of Stages
1	ES	16.1	50
2	ES	16.1	50
3	ES	16.1	50
Total		48.3	150

Advanced Gas Handler

Device information: REDA 400/400 AGH

Motor

REDA 456 4160 Dominator (100.00% Rating Factor)

Motor Slip Adjustment: Yes

Nameplate: 60.00 Hz

Power, hp	192.0	Voltage, Volts	1893.7
Amperage, Amps	64.6	Power @ Design Rate,	160.0

Operating Condition (50.00Hz)			
Motor Load, hp	150.0	Motor Speed, RPM	2851.1
Efficiency, %	84.33	Fluid Velocity, ft/s	2.41
Power Factor, %	79.41	Voltage, Volts	1578.1
Amperage, Amps	61.6	Load Factor, %	93.80
Total Stages	150	Slip Stages	0
Total Dynamic Head (TDH),	2906.1		
Surface Rate (O+W), STB/d	4003.1	Avg. Pump Rate (O+G+W) bbl/d	4357.9
Pump Intake Pressure, psig	807.0	Required Power @ Nameplate	180.0
Bottom Pump Efficiency, %	66.10	Pump Speed, RPM	2851.1

Fluid Temperature At Intake, ºF	175.89
Skin Temperature Rise, ºF	14.62
Avg. Winding Temp. Rise over Skin, ºF	58.65
Total Winding Temperature, ºF	249.18
Speed Increase Heating, ºF	0.00
Heat Rise due to VSD without Load Filter, ºF	9.97
Heat Rise due to VSD with Load Filter or Sine wave Drive, ºF	0.00

Protector

Thrust Bearing Type	400 HL	Number of Seals	2
Configuration	LSB	Number of	2
Components	SINGLE	Oil Type	REDA OIL #5
Total Shut-In	4133.33		

Motor Lead Extension

Type	KEOTB	Connection Type	TAPE-IN
Length, ft	55.00	KV	4
Minor Armor OD,	0.43	Major Armor OD, in	1.12
Conductor Size,	6.00	Material/Armor	M

Cable

REDA REDALEAD EL FLAT Stranded

Specifications			
Conductor Size,	1	KV	4000.00
Temperature Rating,	450.00	Length, ft	4768.00

Operating Condition			
Conductor	200.20	Voltage Drop, Volts	79.8
KVA,	176.75	Surface Voltage,	1657.9
Max Ampacity,	206.9	Start up Ratio	89.88

Required Surface Voltage, Volts: 1657.9

APPENDIX C

C. 1: SubPump Detailed Report of C-101-65 (Analysis of Current Design)

GENERAL DESCRIPTION

Company Name:	**Arabian Gulf Oil Company**
Well Name:	C-101-65
Field Name:	Sarir Field
Reservoir Name:	C-main
Analyst:	Waleed M. E. Mohammed
Calculation Type:	Rigorous Design
Location:	Concession-65
Comments:	Analysis of Current Design
Date:	12/04/2010

WELLBORE DATA

	No.	OD in	Wt lb/ft	ID in	Rough in	Bottom MD ft	Top MD ft
Tubing	1	3.500	9.30	2.992	0.0006500	5537.00	0.00
Casing	1	7.000	23.00	6.366	0.0006500	8844.00	0.00

Pump Depth, ft:	5537.00
Top of Perfs. or Datum Pt. (MD), ft:	8610.00
Reservoir Temperature, °F:	225.0
Wellhead Temperature, °F:	117.0

Tubing Outflow Correlation: Orkiszewski (1967)

PVT CORRELATIONS

Description	Method
Oil Viscosity, (Dead)	Beggs & Robinson
Oil Viscosity, (Saturated)	Beggs & Robinson
Oil Viscosity, (Unsaturated)	Vasquez & Beggs
Gas Viscosity	Lee
Water Viscosity	Matthews & Russell
Oil Formation Volume Factor	Vasquez & Beggs
Water Formation Volume Facto	HP41C
Oil Density	Katz
Z-Factor	Dranchuk, Purvis
Oil Isothermal Compressibility	Vasquez & Beggs
Water Isothermal Compressibility	Meehan
Solution Gas/Oil Ratio	Standing
Bubble Point Pressure	Standing
Gas Density	Beggs
Water Density	Beggs
Oil Surface Tension Correlation	Baker and Swerdloff
Water Surface Tension Correlation	Hough

FLUID DATA

Standard Temperature, °F:	60.0	Prod. Gas/Oil Ratio, scf/bbl:	200.0
Standard Pressure, psi:	14.7	Prod. Gas/Liq. Ratio, scf/bbl:	54.0
Oil Gravity, °API:	36.0	Bubble Point Pressure, psia:	600.0
Gas Specific Gravity, :	0.950	Solution GOR, scf/bbl:	133.0
Water Specific Gravity, :	1.028	Average Fluid Viscosity, cP:	0.5
Water Salinity, ppm:	39000	Fluid Grad. @ Pump Intake, psi/ft:	0.419
Water Cut, %:	73.0		

Viscosity Calibration Data

Pnt. #	Press. psia	Temp. F°	User Visc. Cp	Type	Calc. Visc. Cp	Calib. Factor
1	3000.0	225.0	1.9	Dead	1.3	1.412
2	2000.0	170.0	1.7	Dead	2.3	0.753
3	1000.0	140.0	1.6	Dead	3.4	0.471
Flowline Pressure, psig: 125.0						

INFLOW DATA

IPR Calculation Method: Productivity Index	
Fluid Rate at Test BHP, Bbl/D:	1925
Productivity Index, blpd/psi:	19.845
Bubble Point Rate, Bbl/D:	47628.87
Max. Oil Flow Rate, Bbl/D:	47628.87
Max. Total Flow Rate, Bbl/D:	47628.87

	Static	Test
Casing Pressure, psig:	20.0	0.0
Fluid Level, ft:	0.00	2425
Bottom Hole Pressure (BHP), ft:	2400	2303

PRESSURE/RATE DATA

Design Criteria - Solved For: Pump Intake Conditions	
Total Fluid Rate, Bbl/D:	1925.00
Pump Depth, ft:	5537.00
Fluid Over Pump, ft:	2580.59
Pumping Fluid Level, ft:	2956.41
Pump Intake Pressure, psig:	1074.5
Total Dynamic Head, ft:	2835.36
Flowline Pressure, psig:	125.0
Casing Pressure, psig:	20.0
Bottom Hole Pressure, psig:	2303.0
Gas through Pump:	Gas Compressed

GAS SEPARATOR PERFORMANCE

Packer Installed?	No
Free Gas Avail. at Pump, %	2.63
Natural Gas Separation, %:	70.0
Free Gas into Pump, %	0.32
Gas Separator Installed?	Yes
Gas Separator Efficiency,	60.00

WELL SYSTEM CURVE DETAIL

Points	(+) Tubing Head ft	(-) PIP Head ft	(=) TDH ft	Surface Rate O+W Bbl/D	Avg. Pump Rate O+W+G Bbl/D	Pumping Fluid Level ft
1	5602.57	2747.17	2855.40	248.50	261.62	2772.48
2	5492.75	2408.01	3084.74	3323.67	3499.13	3119.40
3	5909.90	2050.32	3859.58	6398.83	6736.65	3485.97
4	6417.43	1687.67	4729.75	9474.00	9974.16	3858.38
5	7122.64	1323.32	5799.32	12549.17	13211.68	4232.28
6	7976.65	983.67	6992.98	15624.34	16449.19	4579.86
7	9000.05	679.96	8320.09	18699.51	19686.71	4892.90
8	10179.32	364.32	9814.99	21774.68	22924.22	5220.66
Pump off	11527.83	63.52	11464.31	24849.84	26161.74	5535.16
Design	5402.65	2567.28	2835.36	1925.00	2026.63	2956.41

THEORETICAL PUMP PERFORMANCE

	Intake	Discharge	Surface
Oil Rate, Bbl/D:	576.15	573.11	517.69
Gas Rate through Pump, Bbl/D:	6.56	2.86	N/A
Gas Rate from Casing, Bbl/D:	48.08	N/A	N/A
Total Gas Rate, Mscf/D:	N/A	N/A	103.54
Free Gas Percent, %:	0.32	0.15	N/A
Water Rate, Bbl/D:	1442.83	1437.90	1399.67
Total Liquid Rate, Bbl/D:	2018.98	2011.01	1917.36
Pressure, psig:	1074.8	2261.9	125.0
Specific Gravity Liquid, wtr=1:	0.93	0.94	N/A
Specific Gravity Mixture, wtr=1:	0.93	0.93	N/A
Liquid Density, lb/cf:	58.232	58.313	N/A
Mixture Density, lb/cf:	58.060	58.245	N/A
Mixture Viscosity, CST:	N/A	N/A	N/A
Mixture Viscosity, SSU:	N/A	N/A	N/A
Solution GOR, scf/bbl:	146.6	146.6	N/A
Solution GWR, scf/bbl:	4.1	4.1	N/A
Liquid FVF, res/surf:	1.05	1.05	N/A
Gas Deviation Factor:	0.836	0.762	N/A

PUMP DATA

Manufacturer:	Reda
Series:	540
Model:	GN2000
Number of Stages, :	145
Stages with Free Gas:	145
Additional Stages due to Gas:	0
Minimum Recommended Rate, Bbl/D:	1341.27**
Maximum Recommended Rate, Bbl/D:	2032.22**
Rate at Peak Efficiency, Bbl/D:	1755.00**
Power at Peak Efficiency, HP:	79.6**
Frequency, Hz:	50.0
** = Corrected for Frequency & Viscosity	

	Design	145 Stages
Total Dynamic Head (TDH), ft:	2835.36	2850.54
Surface Rate (O+W), Bbl/D:	1925.00	2015.42
Avg. Pump Rate (O+G+W), Bbl/D:	N/A	2121.82
Pump Intake Pressure, psig:	1074.5	1070.4
Operating Power, HP:	N/A	77.6
Pump Efficiency, %:	N/A	57.7

MOTOR DATA

Manufacturer:	Reda
Series:	456
Winding:	4092 - Upper

Name Plate Power, HP:	108.0	Name Plate Frequency, Hz:	60
Name Plate Voltage, Volts:	1428.5	Selected percentage of base, %:	100.00
Name Plate Current, Amps:	48.5	Operating Current, Amps:	41.5
Adjust for Motor Slip:	Yes	Operating Voltage, Volts:	1190.41
Operating Motor Load, HP: (@ Design Frequency)	77.6	Operating Power Factor, frac:	0.750
Operating Motor Load, :	86.19	Operating Efficiency, %:	83.80
Operating Speed, RPM:	2845	Fluid Velocity, ft/sec:	1.158
Well Fluid Temperature, °F:	186.5	Speed Increase Heating, °F:	0.0
Skin Temperature Rise, °F:	12.4	Harmonic Heating due to VSD, °F:	10.4
Avg. Winding Temp. Rise over Skin, °F:	60.9	Total Winding Temp., °F:	259.7

	Catalog	Actual
Total Stages	145	145
Slip Stages	0	0
Total Dynamic Head (TDH), ft	2850.54	2836.02
Surface Rate (O+W), Bbl/D	2015.42	1917.36
Avg. Pump Rate (O+G+W), Bbl/D	2121.82	2018.58
Pump Intake Pressure, psig	1070.4	1074.8
Operating Power, HP	77.6	68.9
Pump Efficiency, %	57.7	57.2
Operating Speed, RPM	2916	2845

SEAL DATA

Manufacturer:	Reda
Series:	400-456
Bearing Type:	400 STD
Chamber Selection:	LSB
Bearing Cap., lb:	1400.2
Operating Thrust Load, lb:	697.4
Maximum Thrust Load, lb:	1292.4
Power Consumption, HP:	0.4

CABLE DATA

Manufacturer:	Philp
Type:	Devilead EPDM/Lead
Size:	1 Cu
Shape:	Flat
Conductor Type:	Stranded
Max. Cond. Temp., °F:	400.0
Cable Length, ft:	5637.00

	Design Freq.
Frequency, Hz	50
Max. Allowable Amps, Amps	162.2
Amperage, Amps	41.5
Kilovolt Ampere, KVA	94.0
Kilowatts, KW	70.5
Kilowatts, $/mo	0
Surface Voltage, Volts	1306.1
Voltage Drop @ 68.0 °F, Volts	86.6
Voltage Drop @ 225.0 °F BHT, Volts	115.7
Kilowatt Loss, KW	6.2
Cost of Voltage Loss, $/mo	0
Required Motor Voltage, Volts	1190.4
Downhole Voltage at Motor, Volts	1190.4
In-rush Motor Voltage Drop, Volts	462.9
Motor Start up Voltage, Volts	843.3
Start up/Operating Ratio, ratio	0.7

C. 2: SubPump Detailed Report of C-101-65 (Proposed Design of Combined ESP/GL)

GENERAL DESCRIPTION

Company Name:	**Arabian Gulf Oil Company**
Well Name:	C-101-65
Field Name:	Sarir Field
Reservoir Name:	C-main
Analyst:	Waleed M. E. Mohammed
Calculation Type:	Rigorous Design
Location:	Concession-65
Comments:	Proposed Design of Combined ESP/GL
Date:	12/04/2010

WELLBORE DATA

	No.	OD in	Wt lb/ft	ID in	Rough in	Bottom MD ft	Top MD ft
Tubing	1	3.500	9.30	2.992	0.0006500	5537.00	
Casing	1	7.000	23.00	6.366	0.0006500	8844.00	0.00

Pump Depth, ft:	5537.00
Top of Perfs. or Datum Pt. (MD), ft:	8610.00
Reservoir Temperature, °F:	225.0
Wellhead Temperature, °F:	117.0

Tubing Outflow Correlation: Orkiszewski (1967)

Gas Lift Data

Injection Rate ,MSCF/D	300
Injection Depth, ft:	4000
Valve Deferential Pressure , psi:	100

Compressor Data

Compressor Suction Pressure , psig:	55
Compressor Suction Temperature , F°	120
Compressor Total Efficiency,%:	80
Estimated Flow line pressure Drop , psi:	120
Required HP , HP:	67

PVT CORRELATIONS

Description	Method
Oil Viscosity, (Dead)	Beggs & Robinson
Oil Viscosity, (Saturated)	Beggs & Robinson
Oil Viscosity, (Unsaturated)	Vasquez & Beggs
Gas Viscosity	Lee
Water Viscosity	Matthews & Russell
Oil Formation Volume Factor	Vasquez & Beggs
Water Formation Volume Factor	HP41C
Oil Density	Katz
Z-Factor	Dranchuk, Purvis
Oil Isothermal Compressibility	Vasquez & Beggs
Water Isothermal Compressibility	Meehan
Solution Gas/Oil Ratio	Standing
Bubble Point Pressure	Standing
Gas Density	Beggs
Water Density	Beggs
Oil Surface Tension Correlation	Baker and Swerdloff
Water Surface Tension Correlation	Hough

FLUID DATA

Standard Temperature, °F:	60.0	Prod. Gas/Oil Ratio, scf/bbl:	200.0
Standard Pressure, psi:	14.7	Prod. Gas/Liq. Ratio, scf/bbl:	54.0
Oil Gravity, °API:	36.0	Bubble Point Pressure, psia:	600.0
Gas Specific Gravity, :	0.950	Solution GOR, scf/bbl:	133.0
Water Specific Gravity, :	1.028	Average Fluid Viscosity, cP:	0.5
Water Salinity, ppm:	39000	Fluid Grad. @ Pump Intake, psi/ft:	0.419
Water Cut, %:	73.0		

Viscosity Calibration Data

Pnt. #	Press. psia	Temp. F°	User Visc. Cp	Type	Calc. Visc. Cp	Calib. Factor
1	3000.0	225.0	1.9	Dead	1.3	1.412
2	2000.0	170.0	1.7	Dead	2.3	0.753
3	1000.0	140.0	1.6	Dead	3.4	0.471
Flowline Pressure, psig: 125.0						

INFLOW DATA

IPR Calculation Method: Productivity Index	
Fluid Rate at Test BHP, Bbl/D:	1925.00
Productivity Index, blpd/psi:	19.845
Bubble Point Rate, Bbl/D:	47628.87
Max. Oil Flow Rate, Bbl/D:	47628.87
Max. Total Flow Rate, Bbl/D:	47628.87

	Static	Test
Casing Pressure, psig:	20.0	0.0
Fluid Level, ft:	0.00	2425.00
Bottom Hole Pressure (BHP), ft:	2400.0	2303.0

PRESSURE/RATE DATA

Design Criteria - Solved For: Pump Intake Conditions	
Total Fluid Rate, Bbl/D:	2200
Pump Depth, ft:	5537.00
Fluid Over Pump, ft:	2351.77
Pumping Fluid Level, ft:	2985.23
Pump Intake Pressure, psig:	981.6
Total Dynamic Head, ft:	1614.91
Flowline Pressure, psig:	125.0
Casing Pressure, psig:	20.0
Bottom Hole Pressure, psig:	2289.1
Gas through Pump:	Gas Compressed

GAS SEPARATOR PERFORMANCE

Packer Installed?	No
Free Gas Avail. at Pump, %	2.8
Natural Gas Separation, %:	70.0
Free Gas into Pump, %	0.3
Gas Separator Installed?	Yes
Gas Separator Efficiency,	60.00

WELL SYSTEM CURVE DETAIL

Points	(+) Tubing Head ft	(-) PIP Head ft	(=) TDH ft	Surface Rate O+W Bbl/D	Avg. Pump Rate O+W+G Bbl/D	Pumping Fluid Level ft
1	3273.29	2554.83	718.46	227.79	240.04	2770.16
2	4193.86	2248.10	1945.76	3046.69	3210.51	3084.03
3	5008.98	1922.81	3086.17	5865.60	6180.98	3417.47
4	5755.92	1592.54	4163.38	8684.50	9151.45	3756.64
5	6473.28	1260.22	5213.06	11503.41	12121.92	4097.11
6	7277.58	947.74	6329.84	14322.31	15092.39	4416.79
7	8161.77	671.11	7490.67	17141.21	18062.86	4701.89
8	9170.61	392.95	8777.66	19960.12	21033.33	4990.47
Pump off	10282.89	62.89	10220.00	22779.02	24003.80	5335.23
Design	3959.51	2344.60	1614.91	2200.00	2318.29	2985.23

THEORETICAL PUMP PERFORMANCE

	Intake	Discharge	Surface
Oil Rate, Bbl/D:	672.9	669.15	517.69
Gas Rate through Pump, Bbl/D:	8.23	4.49	N/A
Gas Rate from Casing, Bbl/D:	60.37	N/A	N/A
Total Gas Rate, Mscf/D:	N/A	N/A	103.54
Free Gas Percent, %:	0.35	0.2	N/A
Water Rate, Bbl/D:	1681.15	1677.83	1631.87
Total Liquid Rate, Bbl/D:	2353.24	2346.98	2235.43
Pressure, psig:	979.9	1654.8	125.0
Specific Gravity Liquid, wtr=1:	0.93	0.94	N/A
Specific Gravity Mixture, wtr=1:	0.93	0.93	N/A
Liquid Density, lb/cf:	58.283	58.315	N/A
Mixture Density, lb/cf:	58.096	58.218	N/A
Mixture Viscosity, CST:	N/A	N/A	N/A
Mixture Viscosity, SSU:	N/A	N/A	N/A
Solution GOR, scf/bbl:	147.5	147.5	N/A
Solution GWR, scf/bbl:	4.1	4.1	N/A
Liquid FVF, res/surf:	1.05	1.05	N/A
Gas Deviation Factor:	0.846	0.777	N/A

PUMP DATA

Manufacturer:	Reda
Series:	540
Model:	G2700
Number of Stages, :	62
Stages with Free Gas:	62
Additional Stages due to Gas:	0
Minimum Recommended Rate, Bbl/D:	1625.78.27**
Maximum Recommended Rate, Bbl/D:	2763.82**
Rate at Peak Efficiency, Bbl/D:	2210.83**
Power at Peak Efficiency, HP:	46.3.3**
Frequency, Hz:	50.0
** = Corrected for Frequency & Viscosity	

	Design	62Stages
Total Dynamic Head (TDH), ft:	1614.91	1668.72
Surface Rate (O+W), Bbl/D:	2200.00	2339.58
Avg. Pump Rate (O+G+W), Bbl/D:	N/A	2465.38
Pump Intake Pressure, psig:	981.6	974.9
Operating Power, HP:	N/A	46.5
Pump Efficiency, %:	N/A	65.5

MOTOR DATA

Manufacturer:	Reda
Series:	456
Winding:	4052 - Upper

Name Plate Power, HP:	60	Name Plate Frequency, Hz:	60
Name Plate Voltage, Volts:	1199.26	Selected percentage of base, %:	100.00
Name Plate Current, Amps:	32	Operating Current, Amps:	29.1
Adjust for Motor Slip:	Yes	Operating Voltage, Volts:	999.83
Operating Motor Load, HP: (@ Design Frequency)	46.5	Operating Power Factor, frac:	0.768
Operating Motor Load, :	93.05	Operating Efficiency, %:	83.80
Operating Speed, RPM:	2845	Fluid Velocity, ft/sec:	1.35
Well Fluid Temperature, °F:	183.9	Speed Increase Heating, °F:	0.0
Skin Temperature Rise, °F:	11.5	Harmonic Heating due to VSD,	11.5
Avg. Winding Temp.	67.6	Total Winding Temp., °F:	263

	Catalog	Actual
Total Stages	62	62
Slip Stages	0	0
Total Dynamic Head (TDH), ft	1668.72	1629.22
Surface Rate (O+W), Bbl/D	2339.58	2235.43
Avg. Pump Rate (O+G+W), Bbl/D	2465.38	2355.63
Pump Intake Pressure, psig	974.9	979.9
Operating Power, HP	46.5	40.5
Pump Efficiency, %	65.5	65.2
Operating Speed, RPM	2916	2845

SEAL DATA

Manufacturer:	Reda
Series:	400-456
Bearing Type:	400 STD
Chamber Selection:	LSB
Bearing Cap., lb:	1400.2
Operating Thrust Load, lb:	697.4
Maximum Thrust Load, lb:	1292.4
Power Consumption, HP:	0.4

CABLE DATA

Manufacturer:	Philp
Type:	Devilead EPDM/Lead
Size:	1 Cu
Shape:	Flat
Conductor Type:	Stranded
Max. Cond. Temp., °F:	400.0
Cable Length, ft:	5437.00

	Design Freq.
Frequency, Hz	50
Max. Allowable Amps, Amps	163.1
Amperage, Amps	29.1
Kilovolt Ampere, KVA	54.4
Kilowatts, KW	41.8
Kilowatts, $/mo	0
Surface Voltage, Volts	1077.6
Voltage Drop @ 68.0 °F, Volts	58.6
Voltage Drop @ 225.0 °F BHT, Volts	78.3
Kilowatt Loss, KW	3.0
Cost of Voltage Loss, $/mo	0
Required Motor Voltage, Volts	999.4
Downhole Voltage at Motor, Volts	999.4
In-rush Motor Voltage Drop, Volts	313.0
Motor Start up Voltage, Volts	764.6
Start up/Operating Ratio, ratio	0.8

C. 3: Avocet Detailed Report of C-101-65 (Proposed Design of Optimizing Pump Setting Depth)

General Information

Project	Optimizing Pump Setting Depth
Prepared by	Waleed M. E. Mohammed
Date	16/04/2010 12:00:00 AM
Company	Arabian Gulf Oil Company
Field & Lease	Sarir Field
Well Number	C-101-65
State & Country	Libya

Wellbore Data

Casing					
	Top (ft)	Bottom (ft)	OD (in)	ID (in)	Roughness
1	0.00	8844.00	7.00	6.36	0.00065

Note: All Depths are in MD.

Tubing					
	Bottom (ft)	OD (in)	ID (in)	Roughness	Flow Type
1	5000.00	3.50	2.99	0.00065	TUBULAR

Perforations Depth: 8610.00 ft

Temperature

Wellhead: 117.00 ºF Reservoir: 225.00 ºF

Fluid Correlations

Dead Oil Viscosity	Beggs & Robinson
Saturated Oil Viscosity	Beggs & Robinson
Under saturated Oil Viscosity	Vasquez & Beggs
Gas Viscosity	Lee et al.
Water Viscosity	Van Wingen Chart
Oil FVF above Bubble Point	Vasquez & Beggs
Oil FVF below Bubble Point	Standing
Solution GOR/Bubble Point	Standing
Oil Compressibility	Vasquez & Beggs
Gas Z Factor	Standing

Fluid Data

Oil Specific Gravity, ºAPI	36.00
Gas Specific Gravity	0.95
Water Specific Gravity	1.02
GLR, SCF/STB	51.80
Bubble Point Pressure	Not Calculated
Bubble Point, psig	600.0
Water Cut, %	73.00
Reservoir Temperature, ºF	225.00

Inflow

Performance method	PI
Productivity Index, STB/d/psi	19.85
Static Bottom Hole Pressure, psig	2400.0
Static Casing Pressure, psig	
Measured Flowrate, STB/d	1925.0
Measured Bottom Hole Pressure, psig	2303.0
Measured Casing Pressure, psig	20.0
Reservoir Temperature, ºF	225.00
AOF, bbl/d	47639.91

Desired Operating Conditions

Calculate	PIP
Flowrate, STB/d	2200.0
Pump Depth, ft	5000.00
Intake Pressure, psig	846.3
Frequency, Hz	50.00
Casing Pressure, psig	20.0
Surface Pressure, psig	125.0
Total Dynamic Head (TDH), ft	3005.70
Intake Gas Volume Fraction, %	1.46

Theoretical Pump Performance

	Intake	Discharge
Pressure, psig	851.0	2062.0
Oil Rate, bbl/d	634.00	630.06
Gas Rate through Pump,	32.64	11.85
Free Gas, %	1.45	0.53
Water Rate, bbl/d	1569.35	1563.18
Total Liquid Rate, bbl/d	2203.35	2193.24
Specific Gravity of Liquid,	0.93	0.94
Specific Gravity of Mixture,	0.92	0.93
Mixture Viscosity, cST	0.39	0.41
Mixture Viscosity, SSU	29.51	29.56
Solution GOR, SCF/STB	132.02	132.02
Solution GWR, SCF/STB	0.00	0.00
Liquid FVF,	1.05	1.04

Total Surface Liquid Rate: 2095.64 STB/d

Liquid Rate, bbl/d	2313.13
Natural Gas Separation, %	70.00
Gas Rate before Separation, bbl/d	114.96
Total Rate before Separation, bbl/d	2428.09
Gas Rate after Separation, bbl/d	34.48
Total Rate after Separation, bbl/d	2347.62
Gas Volume Fraction at Pump, %	4.73
Intake Gas Volume Fraction, %	1.46

Pump

Model: REDA 538 SN2600	
Frequency, Hz	50.00
Number of Stages	101
Stages with Free Gas	101

Intake

Model: REDA 400/400

Operating Condition

Total Dynamic Head (TDH), ft	2993.35
Surface Rate (O+W), STB/d	2095.6
Avg. Pump Rate (O+G+W) bbl/d	2216.94
Pump Intake Pressure, psig	851.0
Operating Power, hp	67.4
Bottom Pump Efficiency, %	67.68
Pump Efficiency, %	67.68

Viscosity Correction Factors

	Calculated	User Entered
Rate	1.00	
Head	1.00	
Power	1.00	
Efficiency	1.00	N/A

Average Pump Viscosity: 0.37

Housing Data

Housing #	Housing Type	Length (ft)	# of Stages
1	ES	11.9	101
Total		11.9	101

Advanced Gas Handler

Device information: REDA 540/540 AGH

Motor

REDA 456 4104 Dominator (100.00% Rating Factor)

Motor Slip Adjustment: Yes

Nameplate: 60.00 Hz

Power, hp	120.0	Voltage, Volts	1589.1
Amperage, Amps	48.2	Power @ Design	100.0

Operating Condition (50.00Hz)			
Motor Load, hp	98.7	Motor Speed, RPM	2851.1
Efficiency, %	83.97	Fluid Velocity, ft/s	1.26
Power Factor, %	80.30	Voltage, Volts	1324.3
Amperage, Amps	47.7	Load Factor, %	98.70
Total Stages	101	Slip Stages	0
Total Dynamic Head (TDH), ft	2993.35		
Surface Rate (O+W), STB/d	2095.6	Avg. Pump Rate (O+G+W) bbl/d	2216.9
Pump Intake Pressure, psig	851.0	Required Power @ Nameplate	118.4
Bottom Pump Efficiency, %	67.68	Pump Speed, RPM	2851.1

Fluid Temperature At Intake, ºF	179.79
Skin Temperature Rise, ºF	15.06
Avg. Winding Temp. Rise over Skin, ºF	64.20
Total Winding Temperature, ºF	259.06
Speed Increase Heating, ºF	0.00
Heat Rise due to VSD without Load Filter,	10.91
Heat Rise due to VSD with Load Filter or	0.00

Protector

Thrust Bearing Type	400 HL	Number of Seals	2
Configuration	LSB	Number of	2
Components	SINGLE	Oil Type	REDA OIL #5
Total Shut-In	4826.76		

Motor Lead Extension

Type	KEOTB	Connection Type	TAPE-IN
Length, ft	55.00	KV	4
Minor Armor OD,	0.43	Major Armor OD, in	1.12
Conductor Size,	6.00	Material/Armor	M

Cable

REDA REDALEAD EL FLAT Stranded

Specifications			
Conductor Size,	1	KV	4000.00
Temperature Rating,	450.00	Length, ft	5100.00

Operating Condition			
Conductor	194.38	Voltage Drop, Volts	65.8
KVA,	114.86	Surface Voltage,	1390.1
Max Ampacity,	205.4	Start up Ratio	90.05

Required Surface Voltage, Volts: 1390.1

APPENDIX D

D. 1: SubPump Detailed Report of C-105-65 (Analysis of Current Design)

GENERAL DESCRIPTION

Company Name:	**Arabian Gulf Oil Company**
Well Name:	C-105-65
Field Name:	Sarir Field
Reservoir Name:	C-main
Analyst:	Waleed M. E. Mohammed
Calculation Type:	Rigorous Design
Location:	Concession-65
Comments:	Analysis of Current Design
Date:	13/04/2010

WELLBORE DATA

	No.	OD in	Wt lb/ft	ID in	Rough in	Bottom MD ft	Top MD ft
Tubing	1	3.500	9.30	2.992	0.0006500	5431.00	
Casing	1	7.000	23.00	6.366	0.0006500	8860.00	0.00

Pump Depth, ft:	5431.00
Top of Perfs. or Datum Pt. (MD), ft:	8648.00
Reservoir Temperature, °F:	225.0
Wellhead Temperature, °F:	117.0

Tubing Outflow Correlation: Orkiszewski (1967)

PVT CORRELATIONS

Description	Method
Oil Viscosity, (Dead)	Beggs & Robinson
Oil Viscosity, (Saturated)	Beggs & Robinson
Oil Viscosity, (Unsaturated)	Vasquez & Beggs
Gas Viscosity	Lee
Water Viscosity	Matthews & Russell
Oil Formation Volume Factor	Vasquez & Beggs
Water Formation Volume Factor	HP41C
Oil Density	Katz
Z-Factor	Dranchuk, Purvis
Oil Isothermal Compressibility	Vasquez & Beggs
Water Isothermal Compressibility	Meehan
Solution Gas/Oil Ratio	Standing
Bubble Point Pressure	Standing
Gas Density	Beggs
Water Density	Beggs
Oil Surface Tension Correlation	Baker and Swerdloff
Water Surface Tension Correlation	Hough

FLUID DATA

Standard Temperature, °F:	60.0	Prod. Gas/Oil Ratio, scf/bbl:	233.0
Standard Pressure, psi:	14.7	Prod. Gas/Liq. Ratio, scf/bbl:	135.1
Oil Gravity, °API:	36.0	Bubble Point Pressure, psia:	600.0
Gas Specific Gravity, :	0.950	Solution GOR, scf/bbl:	133.0
Water Specific Gravity, :	1.095	Average Fluid Viscosity, cP:	0.6
Water Salinity, ppm:	124160	Fluid Grad. @ Pump Intake, psi/ft:	0.401
Water Cut, %:	42.0		

Viscosity Calibration Data

Pnt. #	Press. psia	Temp. F°	User Visc. Cp	Type	Calc. Visc. Cp	Calib. Factor
1	3000.0	225.0	1.9	Dead	1.3	1.412
2	2000.0	170.0	1.7	Dead	2.3	0.753
3	1000.0	140.0	1.6	Dead	3.4	0.471
Flowline Pressure, psig: 200						

INFLOW DATA

IPR Calculation Method: Productivity Index	
Fluid Rate at Test BHP, Bbl/D:	3212
Productivity Index, blpd/psi:	18.5
Bubble Point Rate, Bbl/D:	44400
Max. Oil Flow Rate, Bbl/D:	44400
Max. Total Flow Rate, Bbl/D:	44400

	Static	Test
Casing Pressure, psig:	15.0	0.0
Fluid Level, ft:	0.00	2330
Bottom Hole Pressure (BHP), ft:	2400	2233

PRESSURE/RATE DATA

Design Criteria - Solved For: Pump Intake Conditions	
Total Fluid Rate, Bbl/D:	3212
Pump Depth, ft:	5431
Fluid Over Pump, ft:	2618.92
Pumping Fluid Level, ft:	2812.08
Pump Intake Pressure, psig:	1037.3
Total Dynamic Head, ft:	2963.45
Flowline Pressure, psig:	200.0
Casing Pressure, psig:	15.0
Bottom Hole Pressure, psig:	2226.4
Gas through Pump:	Gas Compressed

GAS SEPARATOR PERFORMANCE

Packer Installed?	No
Free Gas Avail. at Pump, %	10.49
Natural Gas Separation, %:	70.0
Free Gas into Pump, %	1.39
Gas Separator Installed?	Yes
Gas Separator Efficiency,	60.00

WELL SYSTEM CURVE DETAIL

Points	(+) Tubing Head ft	(-) PIP Head ft	(=) TDH ft	Surface Rate O+W Bbl/D	Avg. Pump Rate O+W+G Bbl/D	Pumping Fluid Level ft
1	5681.16	2884.32	2796.84	265.98	288.79	2509.31
2	5586.35	2548.82	3037.53	3557.51	3862.63	2852.48
3	6064.57	2152.72	3911.85	6849.03	7436.46	3258.51
4	6700.56	1801.13	4899.43	10140.56	11010.29	3619.76
5	7519.47	1436.66	6082.81	13432.09	14584.12	3994.42
6	8531.23	1046.10	7485.13	16723.61	18157.95	4390.97
7	9694.70	674.90	9019.80	20015.14	21731.78	4773.33
8	11092.38	366.46	10725.92	23306.67	25305.61	5095.55
Pump off	12669.03	50.68	12618.36	26598.19	28879.44	5429.39
Design	5551.74	2588.29	2963.45	3212.00	3487.48	2812.08

THEORETICAL PUMP PERFORMANCE

	Intake	Discharge	Surface
Oil Rate, Bbl/D:	2065.40	2054.09	1855.63
Gas Rate through Pump, Bbl/D:	48.53	20.62	N/A
Gas Rate from Casing, Bbl/D:	355.89	N/A	N/A
Total Gas Rate, Mscf/D:	N/A	N/A	432.36
Free Gas Percent, %:	1.39	0.61	N/A
Water Rate, Bbl/D:	1387.1	1383.06	1343.73
Total Liquid Rate, Bbl/D:	3452.57	3437.15	3199.36
Pressure, psig:	1037.8	2226.1	200.0
Specific Gravity Liquid, wtr=1:	0.89	0.89	N/A
Specific Gravity Mixture,	0.88	0.88	N/A
Liquid Density, lb/cf:	55.443	55.375	N/A
Mixture Density, lb/cf:	54.744	55.105	N/A
Mixture Viscosity, CST:	N/A	N/A	N/A
Mixture Viscosity, SSU:	N/A	N/A	N/A
Solution GOR, scf/bbl:	147.2	147.2	N/A
Solution GWR, scf/bbl:	2.3	2.3	N/A
Liquid FVF, res/surf:	1.08	1.07	N/A
Mixture FVF, res/surf:	1.09	1.08	N/A
Gas Deviation Factor:	0.839	0.759	N/A

PUMP DATA

Manufacturer:	Reda
Series:	540
Model:	GN4000
Number of Stages, :	142
Stages with Free Gas:	142
Additional Stages due to Gas:	0
Minimum Recommended Rate, Bbl/D:	2601.24**
Maximum Recommended Rate, Bbl/D:	3901.87**
Rate at Peak Efficiency, Bbl/D:	3379.17**
Power at Peak Efficiency, HP:	120.9**
Frequency, Hz:	50.0
** = Corrected for Frequency & Viscosity	

	Design	142 Stages
Total Dynamic Head (TDH), ft:	2963.45	2997.54
Surface Rate (O+W), Bbl/D:	3212.00	3372.69
Avg. Pump Rate (O+G+W), Bbl/D:	N/A	3661.95
Pump Intake Pressure, psig:	1037.3	1029.9
Operating Power, HP:	N/A	109.5
Pump Efficiency, %:	N/A	67.9

MOTOR DATA

Manufacturer:	**Reda**
Series:	456
Winding:	4124 - Upper

Name Plate Power, HP:	144	Name Plate Frequency, Hz:	60
Name Plate Voltage, Volts:	2147.25	Selected percentage of base, %:	100
Name Plate Current, Amps:	43		
Adjust for Motor Slip:	Yes	Operating Current, Amps:	38.3
Design Frequency, Hz:	50	Operating Voltage, Volts:	1789.4
Operating Motor Load, HP: (@ Design Frequency)	109.5	Operating Power Factor, frac:	0.763
Operating Motor Load, :	91.29	Operating Efficiency, %:	83.80
Operating Speed, RPM:	2845	Fluid Velocity, ft/sec:	1.932
Well Fluid Temperature, °F	184.8	Speed Increase Heating, °F:	0.0
Skin Temperature Rise, °F:	15.6	Harmonic Heating due to VSD, °F:	11.1
Avg. Winding Temp. Rise over Skin, °F:	65.2	Total Winding Temp., °F:	265.6

	Catalog	Actual
Total Stages	142	142
Slip Stages	0	0
Total Dynamic Head (TDH), ft	2997.54	2962.36
Surface Rate (O+W), Bbl/D	3372.69	3199.36
Avg. Pump Rate (O+G+W), Bbl/D	3661.95	3473.76
Pump Intake Pressure, psig	1029.9	1037.8
Operating Power, HP	109.5	98.7
Pump Efficiency, %	67.9	67.7
Operating Speed, RPM	2916	2845

SEAL DATA

Manufacturer:	**Reda**
Series:	400-456
Bearing Type:	400 HL
Chamber Selection:	LSB-HL
Bearing Cap., lb:	8916.7
Power Consumption, HP:	0.1

CABLE DATA

Manufacturer:	**Philp**
Type:	Devilead EPDM/Lead
Size:	1 Cu
Shape:	Flat
Conductor Type:	Stranded
Max. Cond. Temp., °F:	400.0
Cable Length, ft:	5531.00

	Design Freq.
Frequency, Hz	50
Max. Allowable Amps, Amps	162.8
Amperage, Amps	38.3
Kilovolt Amper, KVA	125.8
Kilowatts, KW	95.9
Surface Voltage, Volts	1894.1
Voltage Drop @ 68.0 °F, Volts	78.4
Voltage Drop @ 225.0 °F BHT, Volts	104.7
Kilowatt Loss, KW	5.3
Required Motor Voltage, Volts	1789.4
Downhole Voltage at Motor, Volts	1789.4
In-rush Motor Voltage Drop, Volts	418.9
Motor Start up Voltage, Volts	1475.2
Start up/Operating Ratio, ratio	0.8

D. 2: SubPump Detailed Report of C-105-65 (Proposed Design of Combined ESP/GL)

GENERAL DESCRIPTION

Company Name:	Arabian Gulf Oil Company
Well Name:	C-105-65
Field Name:	Sarir Field
Reservoir Name:	C-main
Analyst:	Waleed M. E. Mohammed
Calculation Type:	Rigorous Design
Location:	Concession-65
Comments:	Proposed Design of Combined ESP/GL
Date:	13/04/2010

WELLBORE DATA

	No.	OD in	Wt lb/ft	ID in	Rough in	Bottom MD ft	Top MD ft
Tubing	1	3.500	9.30	2.992	0.0006500	5431.00	
Casing	1	7.000	23.00	6.366	0.0006500	8860.00	0.00

Pump Depth, ft:	5431.00
Top of Perfs. or Datum Pt. (MD), ft:	8648.00
Reservoir Temperature, °F:	225.0
Wellhead Temperature, °F:	117.0

Tubing Outflow Correlation: Orkiszewski (1967)

Gas Lift Data

Injection Rate ,MSCF/D	250
Injection Depth, ft:	4000
Valve Deferential Pressure , psi:	100

Compressor Data

Compressor Suction Pressure , psig:	55
Compressor Suction Temperature , F°	120
Compressor Total Efficiency,%:	80
Estimated Flow line pressure Drop , psi:	200
Required HP , HP:	58.3

PVT CORRELATIONS

Description	Method
Oil Viscosity, (Dead)	Beggs & Robinson
Oil Viscosity, (Saturated)	Beggs & Robinson
Oil Viscosity, (Unsaturated)	Vasquez & Beggs
Gas Viscosity	Lee
Water Viscosity	Matthews & Russell
Oil Formation Volume Factor	Vasquez & Beggs
Water Formation Volume Factor	HP41C
Oil Density	Katz
Z-Factor	Dranchuk, Purvis
Oil Isothermal Compressibility	Vasquez & Beggs
Water Isothermal Compressibility	Meehan
Solution Gas/Oil Ratio	Standing
Bubble Point Pressure	Standing
Gas Density	Beggs
Water Density	Beggs
Oil Surface Tension Correlation	Baker and Swerdloff
Water Surface Tension Correlation	Hough

FLUID DATA

Standard Temperature, °F:	60.0	Prod. Gas/Oil Ratio, scf/bbl:	233.0
Standard Pressure, psi:	14.7	Prod. Gas/Liq. Ratio, scf/bbl:	135.1
Oil Gravity, °API:	36.0	Bubble Point Pressure, psia:	600.0
Gas Specific Gravity,	0.95	Solution GOR, scf/bbl:	133.0
Water Specific Gravity, :	1.095	Average Fluid Viscosity, cP:	0.6
Water Salinity, ppm:	124160	Fluid Grad. @ Pump Intake, psi/ft:	0.401
Water Cut, %:	42.0		

Viscosity Calibration Data

Pnt. #	Press. psia	Temp. F°	User Visc. Cp	Type	Calc. Visc. Cp	Calib. Factor
1	3000.0	225.0	1.9	Dead	1.3	1.412
2	2000.0	170.0	1.7	Dead	2.3	0.753
3	1000.0	140.0	1.6	Dead	3.4	0.471
Flowline Pressure, psig: 200						

INFLOW DATA

IPR Calculation Method: Productivity Index	
Fluid Rate at Test BHP, Bbl/D:	3212
Productivity Index, blpd/psi:	19.234
Bubble Point Rate, Bbl/D:	46160.48
Max. Oil Flow Rate, Bbl/D:	46160.48
Max. Total Flow Rate, Bbl/D:	46160.48

	Static	Test
Casing Pressure, psig:	15.0	0.0
Fluid Level, ft:	0.00	2330
Bottom Hole Pressure (BHP), ft:	2400	2233

PRESSURE/RATE DATA

Design Criteria - Solved For: Pump Intake Conditions	
Total Fluid Rate, Bbl/D:	3600
Pump Depth, ft:	5100
Fluid Over Pump, ft:	2279.35
Pumping Fluid Level, ft:	2820.65
Pump Intake Pressure, psig:	905.6
Total Dynamic Head, ft:	2045.93
Flowline Pressure, psig:	200
Casing Pressure, psig:	15.0
Bottom Hole Pressure, psig:	2212.8
Gas through Pump:	Gas Compressed

GAS SEPARATOR PERFORMANCE

Packer Installed?	**No**
Free Gas Avail. at Pump, %	11.73
Natural Gas Separation, %:	70.0
Free Gas into Pump, %	1.57
Gas Separator Installed?	Yes
Gas Separator Efficiency,	60.00

WELL SYSTEM CURVE DETAIL

Points	(+) Tubing Head ft	(-) PIP Head ft	(=) TDH ft	Surface Rate O+W Bbl/D	Avg. Pump Rate O+W+G Bbl/D	Pumping Fluid Level ft
1	3273.72	2567.31	706.41	240.84	262.10	2503.92
2	4216.74	2298.52	1918.22	3221.20	3505.57	2779.24
3	5229.18	1972.06	3257.12	6201.56	6749.05	3114.17
4	5926.96	1693.82	4233.14	9181.92	9992.52	3400.12
5	6671.07	1390.35	5280.72	12162.28	13235.99	3710.78
6	7529.04	1022.14	6506.90	15142.64	16479.47	4084.23
7	8484.66	696.86	7787.81	18123.01	19722.94	4419.06
8	9564.50	439.32	9125.19	21103.37	22966.41	4687.42
Pump off	10750.20	49.73	10700.47	24083.73	26209.89	5098.50
Design	4304.05	2258.12	2045.93	3600.00	3917.81	2820.65

THEORETICAL PUMP PERFORMANCE

	Intake	Discharge	Surface
Oil Rate, Bbl/D:	2323.35	2310.87	2085.73
Gas Rate through Pump, Bbl/D:	61.87	29.37	N/A
Gas Rate from Casing, Bbl/D:	453.74	N/A	N/A
Total Gas Rate, Mscf/D:	N/A	N/A	485.98
Free Gas Percent, %:	1.57	0.78	N/A
Water Rate, Bbl/D:	1557.57	1554.35	1510.36
Total Liquid Rate, Bbl/D:	3880.92	3865.22	3596.09
Pressure, psig:	905.7	1726.3	200.0
Specific Gravity Liquid, wtr=1:	0.89	0.89	N/A
Specific Gravity Mixture, wtr=1:	0.88	0.88	N/A
Liquid Density, lb/cf:	55.554	55.470	N/A
Mixture Density, lb/cf:	54.750	55.107	N/A
Solution GOR, scf/bbl:	148.8	148.8	N/A
Solution GWR, scf/bbl:	2.3	2.3	N/A
Liquid FVF, res/surf:	1.08	1.07	N/A
Mixture FVF, res/surf:	1.10	1.08	N/A
Gas Deviation Factor:	0.85	0.769	N/A

PUMP DATA

Manufacturer:	Reda
Series:	540
Model:	GN5200
Number of Stages, :	97
Stages with Free Gas:	97
Additional Stages due to Gas:	0
Minimum Recommended Rate, Bbl/D:	3170.27**
Maximum Recommended Rate, Bbl/D:	5365.07**
Rate at Peak Efficiency, Bbl/D:	4592.50**
Power at Peak Efficiency, HP:	97.6**
Frequency, Hz:	50.0
** = Corrected for Frequency & Viscosity	

	Design	97 Stages
Total Dynamic Head (TDH), ft:	2045.93	2118.11
Surface Rate (O+W), Bbl/D:	3600.00	3756.10
Avg. Pump Rate (O+G+W), Bbl/D:	N/A	4087.70
Pump Intake Pressure, psig:	905.6	898.9
Operating Power, HP:	N/A	89.2
Pump Efficiency, %:	N/A	64.5

MOTOR DATA

Manufacturer:	**Reda**
Series:	456
Winding:	4104 - Upper

Name Plate Power, HP:	120	Name Plate Frequency, Hz:	60
Name Plate Voltage, Volts:	1587.66	Selected percentage of base, %:	100
Name Plate Current, Amps:	48.5		
Adjust for Motor Slip:	Yes	Operating Current, Amps:	42.6
Design Frequency, Hz:	50	Operating Voltage, Volts:	1323.05
Operating Motor Load, HP: (@ Design Frequency)	89.2	Operating Power Factor, frac:	0.758
Operating Motor Load, :	89.20	Operating Efficiency, %:	83.80
Operating Speed, RPM:	2845	Fluid Velocity, ft/sec:	2.172
Well Fluid Temperature, °F:	180.7	Speed Increase Heating, °F:	0.0
Skin Temperature Rise, °F:	13.8	Harmonic Heating due to VSD, °F:	10.8
Avg. Winding Temp. Rise over Skin, °F:	63.5	Total Winding Temp., °F:	258.0

	Catalog	Actual
Total Stages	97	97
Slip Stages	0	0
Total Dynamic Head (TDH), ft	2118.11	2044.26
Surface Rate (O+W), Bbl/D	3756.10	3596.09
Avg. Pump Rate (O+G+W), Bbl/D	4087.70	3913.56
Pump Intake Pressure, psig	898.9	905.7
Operating Power, HP	89.2	80.0
Pump Efficiency, %	64.5	65.0
Operating Speed, RPM	2916	2845

SEAL DATA

Manufacturer:	Reda
Series:	400-456
Bearing Type:	400 STD
Chamber Selection:	LSB
Bearing Cap., lb:	1400.2
Power Consumption, HP:	0.1

CABLE DATA

Manufacturer:	Philp
Type:	Devilead EPDM/Lead
Size:	1 Cu
Shape:	Flat
Conductor Type:	Stranded
Max. Cond. Temp., °F:	400.0
Cable Length, ft:	5200

	Design Freq.
Frequency, Hz	50
Max. Allowable Amps, Amps	164.2
Amperage, Amps	42.6
Kilovolt Amper, KVA	105.6
Kilowatts, KW	80.1
Surface Voltage, Volts	1432.3
Voltage Drop @ 68.0 °F, Volts	81.7
Voltage Drop @ 225.0 °F BHT, Volts	109.2
Kilowatt Loss, KW	6.1
Required Motor Voltage, Volts	1323.1
Downhole Voltage at Motor, Volts	1323.1
In-rush Motor Voltage Drop, Volts	436.8
Motor Start up Voltage, Volts	995.4
Start up/Operating Ratio, ratio	0.8

D. 3: Avocet Detailed Report of C-105-65 (Proposed Design of Optimizing Pump Setting Depth)

General Information

Project	Optimizing Pump Setting Depth
Prepared by	Waleed M. E. Mohammed
Date	4/16/2010 12:00:00 AM
Company	Arabian Gulf Oil Company
Field & Lease	Sarir Field
Well Number	C-105-65
State & Country	Libya

Wellbore Data

Casing					
	Top (ft)	Bottom (ft)	OD (in)	ID (in)	Roughness
1	0.00	8860.00	7.00	6.36	0.00065

Note: All Depths are in MD.

Tubing					
	Bottom (ft)	OD (in)	ID (in)	Roughness	Flow Type
1	4900.00	3.50	2.99	0.00065	TUBULAR

Perforations Depth: 8648.00 ft

Temperature

Wellhead: 117.00 ºF Reservoir: 225.00 ºF

Fluid Correlations

Dead Oil Viscosity	Beggs & Robinson
Saturated Oil Viscosity	Beggs & Robinson
Under saturated Oil Viscosity	Vasquez & Beggs
Gas Viscosity	Lee et al.
Water Viscosity	Van Wingen Chart
Oil FVF above Bubble Point	Vasquez & Beggs
Oil FVF below Bubble Point	Standing
Solution GOR/Bubble Point	Standing
Oil Compressibility	Vasquez & Beggs
Gas Z Factor	Standing

Fluid Data

Oil Specific Gravity, °API	36.00
Gas Specific Gravity	0.95
Water Salinity, ppm	124160
GLR, SCF/STB	135.14
Bubble Point Pressure	Not Calculated
Bubble Point, psig	600.0
Water Cut, %	42.00
Reservoir Temperature, °F	225.00

Inflow

Performance method	PI
Productivity Index, STB/d/psi	18.56
Static Bottom Hole Pressure, psig	2400.0
Static Casing Pressure, psig	
Measured Flowrate, STB/d	3212.0
Measured Bottom Hole Pressure, psig	2233.0
Measured Casing Pressure, psig	15.0
Reservoir Temperature, °F	225.00
AOF, bbl/d	44551.12

Desired Operating Conditions

Calculate	PIP
Flowrate, STB/d	3500.0
Pump Depth, ft	4900.00
Intake Pressure, psig	841.2
Frequency, Hz	50.00
Casing Pressure, psig	15.0
Surface Pressure, psig	200.0
Total Dynamic Head (TDH), ft	3072.57
Intake Gas Volume Fraction, %	5.01

Theoretical Pump Performance

	Intake	Discharge
Pressure, psig	842.1	1995.7
Oil Rate, bbl/d	2259.27	2245.59
Gas Rate through Pump,	198.09	73.51
Free Gas, %	5.00	1.92
Water Rate, bbl/d	1498.04	1492.43
Total Liquid Rate, bbl/d	3757.31	3738.03
Specific Gravity of Liquid,	0.89	0.89
Specific Gravity of Mixture,	0.85	0.88
Mixture Viscosity, cST	0.42	0.47
Mixture Viscosity, SSU	29.58	29.71
Solution GOR, SCF/STB	132.02	132.02
Solution GWR, SCF/STB	0.00	0.00
Liquid FVF,	1.08	1.07

Total Surface Liquid Rate: 3478.68 STB/d

Liquid Rate, bbl/d	3780.37
Natural Gas Separation, %	70.00
Gas Rate before Separation, bbl/d	665.15
Total Rate before Separation, bbl/d	4445.52
Gas Rate after Separation, bbl/d	199.54
Total Rate after Separation, bbl/d	3979.91
Gas Volume Fraction at Pump, %	14.96
Intake Gas Volume Fraction, %	5.01

Pump

Model: REDA 400 D4300N	
Frequency, Hz	50.00
Number of Stages	245
Stages with Free Gas	245

Operating Condition

Total Dynamic Head (TDH), ft	3048.16
Surface Rate (O+W), STB/d	3478.6
Avg. Pump Rate (O+G+W) bbl/d	3863.93
Pump Intake Pressure, psig	842.1
Operating Power, hp	110.5
Bottom Pump Efficiency, %	68.54
Pump Efficiency, %	68.54

Viscosity Correction Factors

	Calculated	User Entered
Rate	1.00	
Head	1.00	
Power	1.00	
Efficiency	1.00	N/A

Average Pump Viscosity: 0.39

Housing Data

Housing #	Housing Type	Length (ft)	# of Stages
1	ES	21.8	67
2	ES	21.8	67
3	ES	21.8	67
4	ES	14.8	44
Total		80.2	245

Motor

REDA 456 4124 Dominator (100.00% Rating Factor)

Motor Slip Adjustment: Yes

Nameplate: 60.00 Hz

Power, hp	144.0	Voltage, Volts	2149.2
Amperage, Amps	42.7	Power @ Design	120.0

Operating Condition (50.00Hz)			
Motor Load, hp	110.5	Motor Speed, RPM	2851.1
Efficiency, %	84.44	Fluid Velocity, ft/s	2.09
Power Factor, %	79.08	Voltage, Volts	1791.0
Amperage, Amps	40.1	Load Factor, %	92.13
Total Stages	245	Slip Stages	0
Total Dynamic	3048.16		
Surface Rate	3478.6	Avg. Pump Rate	3863.93
Pump Intake	842.1	Required Power @	132.6
Bottom Pump	68.54	Pump Speed, RPM	2851.1

Fluid Temperature At Intake, ºF	178.26
Skin Temperature Rise, ºF	16.08
Avg. Winding Temp. Rise over Skin, ºF	56.82
Total Winding Temperature, ºF	251.17
Speed Increase Heating, ºF	0.00
Heat Rise due to VSD without Load Filter,	9.66
Heat Rise due to VSD with Load Filter or	0.00

Protector

Thrust Bearing Type	400 HL	Number of Seals	2
Configuration	LSB	Number of	2
Components	SINGLE	Oil Type	REDA OIL #2
Total Shut-In	3096.52		

Motor Lead Extension

Type	KEOTB	Connection Type	TAPE-IN
Length, ft	55.00	KV	4
Minor Armor OD,	0.43	Major Armor OD, in	1.12
Conductor Size,	6.00	Material/Armor	M

Cable

REDA REDALEAD EL FLAT Stranded

Specifications			
Conductor Size,	1	KV	4000.00
Temperature Rating,	450.00	Length, ft	5000.00

Operating Condition			
Conductor	188.58	Voltage Drop, Volts	54.0
KVA,	128.21	Surface Voltage,	1845.1
Max Ampacity,	206.0	Start up Ratio	93.96

Required Surface Voltage, Volts: 1845

APPENDIX E

E. 1: SubPump Detailed Report of C-144-65 (Analysis of Current Design)

GENERAL DESCRIPTION

Company Name:	Arabian Gulf Oil Company
Well Name:	C-144-65
Field Name:	Sarir Field
Reservoir Name:	C-main
Analyst:	Waleed M. E. Mohammed
Calculation Type:	Rigorous Design
Location:	Concession-65
Comments:	Analysis of Current Design
Date:	13/04/2010

WELLBORE DATA

	No.	OD in	Wt lb/ft	ID in	Rough in	Bottom MD ft	Top MD ft
Tubing	1	3.500	9.30	2.992	0.0006500	4879.00	
Casing	1	7.000	23.00	6.366	0.0006500	8698.00	0.00

Pump Depth, ft:	4879.00
Top of Perfs. or Datum Pt. (MD), ft:	8553.00
Reservoir Temperature, °F:	225.0
Wellhead Temperature, °F:	117.0

Tubing Outflow Correlation: Orkiszewski (1967)

PVT CORRELATIONS

Description	Method
Oil Viscosity, (Dead)	Beggs & Robinson
Oil Viscosity, (Saturated)	Beggs & Robinson
Oil Viscosity, (Unsaturated)	Vasquez & Beggs
Gas Viscosity	Lee
Water Viscosity	Matthews & Russell
Oil Formation Volume Factor	Vasquez & Beggs
Water Formation Volume Factor	HP41C
Oil Density	Katz
Z-Factor	Dranchuk, Purvis
Oil Isothermal Compressibility	Vasquez & Beggs
Water Isothermal Compressibility	Meehan
Solution Gas/Oil Ratio	Standing
Bubble Point Pressure	Standing
Gas Density	Beggs
Water Density	Beggs
Oil Surface Tension Correlation	Baker and Swerdloff
Water Surface Tension Correlation	Hough

FLUID DATA

Standard Temperature, °F:	60.0	Prod. Gas/Oil Ratio, scf/bbl:	185.0
Standard Pressure, psi:	14.7	Prod. Gas/Liq. Ratio, scf/bbl:	131.3
Oil Gravity, °API:	36.0	Bubble Point Pressure, psia:	650.0
Gas Specific Gravity, :	0.950	Solution GOR, scf/bbl:	145.9
Water Specific Gravity, :	1.155	Average Fluid Viscosity, cP:	0.7
Water Salinity, ppm:	198309	Fluid Grad. @ Pump Intake, psi/ft:	0.392
Water Cut, %:	29.0		

Viscosity Calibration Data

Pnt. #	Press. psia	Temp. F°	User Visc. Cp	Type	Calc. Visc. Cp	Calib. Factor
1	3000.0	225.0	1.9	Dead	1.3	1.412
2	2000.0	170.0	1.7	Dead	2.3	0.753
3	1000.0	140.0	1.6	Dead	3.4	0.471
Flowline Pressure, psig: 335						

INFLOW DATA

IPR Calculation Method: Productivity Index	
Fluid Rate at Test BHP, Bbl/D:	2064
Productivity Index, blpd/psi:	10.320
Bubble Point Rate, Bbl/D:	26832
Max. Oil Flow Rate, Bbl/D:	26832
Max. Total Flow Rate, Bbl/D:	26832

	Static	Test
Casing Pressure, psig:	20.0	0.0
Fluid Level, ft:	0.00	1638
Bottom Hole Pressure (BHP), ft:	2600	2400

PRESSURE/RATE DATA

Design Criteria - Solved For: Pump Intake Conditions	
Total Fluid Rate, Bbl/D:	2064.00
Pump Depth, ft:	4879.00
Fluid Over Pump, ft:	2670.10
Pumping Fluid Level, ft:	2208.90
Pump Intake Pressure, psig:	1039.6
Total Dynamic Head, ft:	2788.80
Flowline Pressure, psig:	335.0
Casing Pressure, psig:	20.0
Bottom Hole Pressure, psig:	2400.0
Gas through Pump:	Gas Compressed

GAS SEPARATOR PERFORMANCE

Packer Installed?	No
Free Gas Avail. at Pump, %	3.3
Natural Gas Separation, %:	70.0
Free Gas into Pump, %	0.41
Gas Separator Installed?	Yes
Gas Separator Efficiency,	60.00

WELL SYSTEM CURVE DETAIL

Points	(+) Tubing Head ft	(-) PIP Head ft	(=) TDH ft	Surface Rate O+W Bbl/D	Avg. Pump Rate O+W+G Bbl/D	Pumping Fluid Level ft
1	5536.66	3093.02	2443.64	151.66	165.88	1759.55
2	5439.81	2661.29	2778.52	2028.44	2218.66	2200.37
3	5538.59	2215.21	3323.39	3905.22	4271.45	2657.18
4	5785.54	1765.89	4019.65	5782.00	6324.23	3118.69
5	6075.76	1321.83	4753.93	7658.79	8377.01	3568.28
6	6371.61	963.41	5408.21	9535.57	10429.80	3933.40
7	6688.08	631.87	6056.21	11412.35	12482.58	4276.89
8	7073.46	325.71	6747.76	13289.13	14535.36	4598.97
Pump off	7539.10	64.49	7474.61	15165.91	16588.14	4877.28
Design	5441.75	2652.95	2788.80	2064.00	2257.56	2208.90

THEORETICAL PUMP PERFORMANCE

	Intake	Discharge	Surface
Oil Rate, Bbl/D:	1623.94	1614.83	1450.77
Gas Rate through Pump, Bbl/D:	9.15	4.05	N/A
Gas Rate from Casing, Bbl/D:	67.07	N/A	N/A
Total Gas Rate, Mscf/D:	N/A	N/A	268.39
Free Gas Percent, %:	0.41	0.19	N/A
Water Rate, Bbl/D:	611.57	610.10	592.57
Total Liquid Rate, Bbl/D:	2235.52	2224.93	2043.34
Pressure, psig:	1041.5	2136.4	335.0
Specific Gravity Liquid, wtr=1:	0.87	0.87	N/A
Specific Gravity Mixture, wtr=1:	0.87	0.86	N/A
Liquid Density, lb/cf:	54.151	54.018	N/A
Mixture Density, lb/cf:	53.952	53.938	N/A
Solution GOR, scf/bbl:	164.1	164.1	N/A
Solution GWR, scf/bbl:	0.6	0.6	N/A
Liquid FVF, res/surf:	1.09	1.09	N/A
Mixture FVF, res/surf:	1.10	1.09	N/A
Gas Deviation Factor:	0.833	0.751	N/A

PUMP DATA

Manufacturer:	Reda
Series:	540
Model:	GN2500
Number of Stages, :	112
Stages with Free Gas:	112
Additional Stages due to Gas:	0
Minimum Recommended Rate, Bbl/D:	1463.20**
Maximum Recommended Rate, Bbl/D:	2519.95**
Rate at Peak Efficiency, Bbl/D:	1998.33**
Power at Peak Efficiency, HP:	78.7**
Frequency, Hz:	50.0
** = Corrected for Frequency & Viscosity	

	Design	**112 Stages**
Total Dynamic Head (TDH), ft:	2788.80	2814.40
Surface Rate (O+W), Bbl/D:	2064.00	2154.19
Avg. Pump Rate (O+G+W), Bbl/D:	N/A	2356.20
Pump Intake Pressure, psig:	1039.6	1031.3
Operating Power, HP:	N/A	73.2
Pump Efficiency, %:	N/A	61.0

MOTOR DATA

Manufacturer:	Reda
Series:	456
Winding:	4083 - Upper

Name Plate Power, HP:	96.0	Name Plate Frequency, Hz:	60
Name Plate Voltage, Volts:	1431.5	Selected percentage of base, %:	100
Name Plate Current, Amps :	43		
Adjust for Motor Slip:	Yes	Operating Current, Amps:	38.5
Design Frequency, Hz:	50.0	Operating Voltage, Volts:	1192.92
Operating Motor Load, HP: (@ Design Frequency)	73.2	Operating Power Factor, frac:	0.764
Operating Motor Load, :	91.54	Operating Efficiency, %:	83.80
Operating Speed, RPM:	2845	Fluid Velocity, ft/sec:	1.234
Well Fluid Temperature, °F:	178.6	Speed Increase Heating, °F:	0.0
Skin Temperature Rise, °F:	24.4	Harmonic Heating due to VSD, °F:	11.2
Avg. Winding Temp. Rise over Skin, °F:	65.8	Total Winding Temp., °F:	268.8

	Catalog	**Actual**
Total Stages	112	112
Slip Stages	0	0
Total Dynamic Head (TDH), ft	2814.40	2783.10
Surface Rate (O+W), Bbl/D	2154.19	2043.34
Avg. Pump Rate (O+G+W), Bbl/D	2356.20	2234.96
Pump Intake Pressure, psig	1031.3	1041.5
Operating Power, HP	73.2	65.3
Pump Efficiency, %	61.0	60.8
Operating Speed, RPM	2916	2845

SEAL DATA

Manufacturer:	Reda
Series:	400-456
Bearing Type:	400 STD
Chamber Selection:	LSB
Bearing Cap., lb:	1400.2
Power Consumption, HP:	0.1

CABLE DATA

Manufacturer:	Philp
Type:	Devilead EPDM/Lead
Size:	1 Cu
Shape:	Flat
Conductor Type:	Stranded
Max. Cond. Temp., °F:	400.0
Cable Length, ft:	4979

	Design Freq.
Frequency, Hz	50
Max. Allowable Amps, Amps	164.9
Amperage, Amps	38.5
Kilovolt Amper, KVA	85.9
Kilowatts, KW	65.6
Surface Voltage, Volts	1287.5
Voltage Drop @ 68.0 °F, Volts	70.8
Voltage Drop @ 225.0 °F BHT, Volts	94.5
Kilowatt Loss, KW	4.8
Required Motor Voltage, Volts	1192.9
Downhole Voltage at Motor, Volts	1192.9
In-rush Motor Voltage Drop, Volts	378.2
Motor Start up Voltage, Volts	909.3
Start up/Operating Ratio, ratio	0.8

E. 2: SubPump Detailed Report of C-144-65 (Proposed Design of Combined ESP/GL)

GENERAL DESCRIPTION

Company Name:	Arabian Gulf Oil Company
Well Name:	C-144-65
Field Name:	Sarir Field
Reservoir Name:	C-main
Analyst:	Waleed M. E. Mohammed
Calculation Type:	Rigorous Design
Location:	Concession-65
Comments:	Proposed Design of Combined ESP/GL
Date:	13/04/2010

WELLBORE DATA

	No.	OD in	Wt lb/ft	ID in	Rough in	Bottom MD ft	Top MD ft
Tubing	1	3.500	9.30	2.992	0.0006500	4879.00	
Casing	1	7.000	23.00	6.366	0.0006500	8698.00	0.00

Pump Depth, ft:	4879.00
Top of Perfs. or Datum Pt. (MD), ft:	8553.00
Reservoir Temperature, °F:	225.0
Wellhead Temperature, °F:	117.0

Tubing Outflow Correlation: Orkiszewski (1967)

GASLIFT DATA

Injection Rate ,MSCF/D	300
Injection Depth, ft:	4000
Valve Deferential Pressure , psi:	100

COMPRESSOR DATA

Compressor Suction Pressure , psig:	55
Compressor Suction Temperature , F°	120
Compressor Total Efficiency,%:	80
Estimated Flow line pressure Drop , psi:	200
Required HP , HP:	72.2

PVT CORRELATIONS

Description	Method
Oil Viscosity, (Dead)	Beggs & Robinson
Oil Viscosity, (Saturated)	Beggs & Robinson
Oil Viscosity, (Unsaturated)	Vasquez & Beggs
Gas Viscosity	Lee
Water Viscosity	Matthews & Russell
Oil Formation Volume Factor	Vasquez & Beggs
Water Formation Volume Factor	HP41C
Oil Density	Katz
Z-Factor	Dranchuk, Purvis
Oil Isothermal Compressibility	Vasquez & Beggs
Water Isothermal Compressibility	Meehan
Solution Gas/Oil Ratio	Standing
Bubble Point Pressure	Standing
Gas Density	Beggs
Water Density	Beggs
Oil Surface Tension Correlation	Baker and Swerdloff
Water Surface Tension Correlation	Hough

FLUID DATA

Standard Temperature, °F:	60.0	Prod. Gas/Oil Ratio, scf/bbl:	185.0
Standard Pressure, psi:	14.7	Prod. Gas/Liq. Ratio, scf/bbl:	131.3
Oil Gravity, °API:	36.0	Bubble Point Pressure, psia:	650.0
Gas Specific Gravity, :	0.950	Solution GOR, scf/bbl:	145.9
Water Specific Gravity, :	1.155	Average Fluid Viscosity, cP:	0.7
Water Salinity, ppm:	198309	Fluid Grad. @ Pump Intake, psi/ft:	0.392
Water Cut, %:	29.0		

Viscosity Calibration Data

Pnt. #	Press. psia	Temp. F°	User Visc. Cp	Type	Calc. Visc. Cp	Calib. Factor
1	3000.0	225.0	1.9	Dead	1.3	1.412
2	2000.0	170.0	1.7	Dead	2.3	0.753
3	1000.0	140.0	1.6	Dead	3.4	0.471
Flowline Pressure, psig: 335						

INFLOW DATA

IPR Calculation Method: Productivity Index	
Fluid Rate at Test BHP, Bbl/D:	2064
Productivity Index, blpd/psi:	10.320
Bubble Point Rate, Bbl/D:	26832
Max. Oil Flow Rate, Bbl/D:	26832
Max. Total Flow Rate, Bbl/D:	26832

	Static	Test
Casing Pressure, psig:	20.0	0.0
Fluid Level, ft:	0.00	1638
Bottom Hole Pressure (BHP), ft:	2600	2400

PRESSURE/RATE DATA

Design Criteria - Solved For: Pump Intake Conditions	
Total Fluid Rate, Bbl/D:	3540
Pump Depth, ft:	4879
Fluid Over Pump, ft:	2311.37
Pumping Fluid Level, ft:	2567.63
Pump Intake Pressure, psig:	902.3
Total Dynamic Head, ft:	2162.97
Flowline Pressure, psig:	335.0
Casing Pressure, psig:	20.0
Bottom Hole Pressure, psig:	2257.0
Gas through Pump:	Gas Compressed

GAS SEPARATOR PERFORMANCE

Packer Installed?	No
Free Gas Avail. at Pump, %	3.85
Natural Gas Separation, %:	70.0
Free Gas into Pump, %	0.48
Gas Separator Installed?	Yes
Gas Separator Efficiency,	60.00

WELL SYSTEM CURVE DETAIL

Points	(+) Tubing Head ft	(-) PIP Head ft	(=) TDH ft	Surface Rate O+W Bbl/D	Avg. Pump Rate O+W+G Bbl/D	Pumping Fluid Level ft
1	3483.99	3092.93	390.95	151.66	166.10	1759.55
2	4044.11	2661.25	1382.87	2028.44	2221.55	2200.36
3	4547.34	2215.14	2332.20	3905.22	4277.01	2657.22
4	5392.14	1765.78	3626.37	5782.00	6332.47	3118.80
5	5794.81	1322.03	4472.78	7658.79	8387.92	3568.04
6	6142.91	963.76	5179.15	9535.57	10443.38	3933.02
7	6511.46	632.07	5879.40	11412.35	12498.84	4276.67
8	6935.44	324.73	6610.71	13289.13	14554.29	4600.00
Pump off	7424.62	64.49	7360.14	15165.91	16609.75	4877.28
Design	4465.50	2302.53	2162.97	3540.00	3877.02	2567.63

THEORETICAL PUMP PERFORMANCE

	Intake	Discharge	Surface
Oil Rate, Bbl/D:	3093.27	3074.44	2758.84
Gas Rate through Pump, Bbl/D:	20.46	9.51	N/A
Gas Rate from Casing, Bbl/D:	150.05	N/A	N/A
Total Gas Rate, Mscf/D:	N/A	N/A	510.38
Free Gas Percent, %:	0.50	0.23	N/A
Water Rate, Bbl/D:	1163.36	1161.15	1126.85
Total Liquid Rate, Bbl/D:	4256.63	4235.58	3885.68
Pressure, psig:	869.9	1687.1	335.0
Specific Gravity Liquid, wtr=1:	0.87	0.87	N/A
Specific Gravity Mixture, wtr=1:	0.87	0.86	N/A
Liquid Density, lb/cf:	54.211	54.041	N/A
Mixture Density, lb/cf:	53.962	53.939	N/A
Solution GOR, scf/bbl:	164.1	164.1	N/A
Solution GWR, scf/bbl:	0.6	0.6	N/A
Liquid FVF, res/surf:	1.10	1.09	N/A
Mixture FVF, res/surf:	1.10	1.09	N/A
Gas Deviation Factor:	0.857	0.763	N/A

PUMP DATA

Manufacturer:	Reda
Series:	540
Model:	GN5200
Number of Stages, :	118
Stages with Free Gas:	118
Additional Stages due to Gas:	0
Minimum Recommended Rate, Bbl/D:	3170.27**
Maximum Recommended Rate, Bbl/D:	5365.07**
Rate at Peak Efficiency, Bbl/D:	4592.50**
Power at Peak Efficiency, HP:	118.8**
Frequency, Hz:	50.0
** = Corrected for Frequency & Viscosity	

	Design	118 Stages
Total Dynamic Head (TDH), ft:	2162.97	2416.03
Surface Rate (O+W), Bbl/D:	3540.00	4027.68
Avg. Pump Rate (O+G+W), Bbl/D:	N/A	4411.12
Pump Intake Pressure, psig:	902.3	856.6
Operating Power, HP:	N/A	106.2
Pump Efficiency, %:	N/A	64.3

Housing Data

# Hsg.	Type	Length, ft	# of Stages
140	FL	20.40	64
120	FL	17.50	54
Total			
260		37.90	118

MOTOR DATA

Manufacturer:	Reda
Series:	456
Winding:	4112 - Upper

Name Plate Power, HP:	132	Name Plate Frequency, Hz:	60
Name Plate Voltage, Volts:	1336.36	Selected percentage of base, %:	100
Name Plate Current, Amps:	64.9.5		
Adjust for Motor Slip:	Yes	Operating Current, Amps:	60.6
Design Frequency, Hz:	50.0	Operating Voltage, Volts:	1083.63
Operating Motor Load, HP: (@ Design Frequency)	106.2	Operating Power Factor, frac:	0.775
Operating Motor Load, :	96.51	Operating Efficiency, %:	83.80
Operating Speed, RPM:	2845	Fluid Velocity, ft/sec:	2.346
Well Fluid Temperature, °F:	178.6	Speed Increase Heating, °F:	0.0
Skin Temperature Rise, °F:	17.7	Harmonic Heating due to VSD, °F:	12
Avg. Winding Temp. Rise over Skin, °F:	70.8	Total Winding Temp., °F:	267.1

	Catalog	Actual
Total Stages	118	118
Slip Stages	0	0
Total Dynamic Head (TDH), ft	2416.03	2322.85
Surface Rate (O+W), Bbl/D	4027.68	3885.68
Avg. Pump Rate (O+G+W), Bbl/D	4411.12	4255.61
Pump Intake Pressure, psig	856.6	869.9
Operating Power, HP	106.2	95.6
Pump Efficiency, %	64.3	66.0
Operating Speed, RPM	2916	2845

SEAL DATA

Manufacturer:	Reda
Series:	400-456
Bearing Type:	400 STD
Chamber Selection:	LSB
Bearing Cap., lb:	1400.2
Operating Thrust Load, lb:	694.5
Maximum Thrust Load, lb:	1160.1
Power Consumption, HP:	0.5

CABLE DATA

Manufacturer:	Philp
Type:	Devilead EPDM/Lead
Size:	1 Cu
Shape:	Flat
Conductor Type:	Stranded
Max. Cond. Temp., °F:	400.0
Cable Length, ft:	4979

	Design Freq.
Frequency, Hz	50
Max. Allowable Amps, Amps	164.9
Amperage, Amps	60.6
Kilovolt Amper, KVA	129.2
Kilowatts, KW	100.1
Surface Voltage, Volts	1232.3
Voltage Drop @ 68.0 °F, Volts	111.2
Voltage Drop @ 225.0 °F BHT, Volts	148.6
Kilowatt Loss, KW	12.1
Required Motor Voltage, Volts	1083.6
Downhole Voltage at Motor, Volts	1083.6
In-rush Motor Voltage Drop, Volts	594.5
Motor Start up Voltage, Volts	637.8
Start up/Operating Ratio, ratio	0.6

E. 3: Avocet Detailed Report of C-144-65 (Proposed Design of Optimizing Pump Setting Depth)

General Information

Project	Optimizing Pump Setting Depth
Prepared by	Waleed M. E. Mohammed
Date	4/16/2010 12:00:00 AM
Company	Arabian Gulf Oil Company
Field & Lease	Sarir Field
Well Number	C-144-65
State & Country	Libya

Wellbore Data

Casing					
	Top (ft)	Bottom (ft)	OD (in)	ID (in)	Roughness
1	0.00	8698.00	7.00	6.36	0.00065

Note: All Depths are in MD.

Tubing					
	Bottom (ft)	OD (in)	ID (in)	Roughness	Flow Type
1	4529.00	3.50	2.99	0.00065	TUBULAR

Perforations Depth: 8553.00 ft

Temperature

Wellhead: 117.00 ºF

Reservoir: 225.00 ºF

Fluid Correlations

Dead Oil Viscosity	Beggs & Robinson
Saturated Oil Viscosity	Beggs & Robinson
Under saturated Oil Viscosity	Vasquez & Beggs
Gas Viscosity	Lee et al.
Water Viscosity	Van Wingen Chart
Oil FVF above Bubble Point	Vasquez & Beggs
Oil FVF below Bubble Point	Standing
Solution GOR/Bubble Point	Standing
Oil Compressibility	Vasquez & Beggs
Gas Z Factor	Standing

Fluid Data

Oil Specific Gravity, °API	36.00
Gas Specific Gravity	0.95
Water Salinity, ppm	198309
GLR, SCF/STB	131.35
Bubble Point Pressure	Not Calculated
Bubble Point, psig	650.0
Water Cut, %	29.00
Reservoir Temperature, °F	225.00

Inflow

Performance method	PI
Productivity Index, STB/d/psi	10.32
Static Bottom Hole Pressure, psig	2600.0
Static Casing Pressure, psig	
Measured Flowrate, STB/d	2064.0
Measured Bottom Hole Pressure, psig	2400.0
Measured Casing Pressure, psig	20.0
Reservoir Temperature, °F	225.00
AOF, bbl/d	26831.95

Desired Operating Conditions

Calculate	PIP
Flowrate, STB/d	3300.0
Pump Depth, ft	4529.00
Intake Pressure, psig	803.3
Frequency, Hz	50.00
Casing Pressure, psig	20.0
Surface Pressure, psig	335.0
Total Dynamic Head (TDH), ft	3201.80
Intake Gas Volume Fraction, %	8.05

Theoretical Pump Performance

	Intake	Discharge
Pressure, psig	799.8	1956.9
Oil Rate, bbl/d	2668.40	2649.83
Gas Rate through Pump,	321.99	114.76
Free Gas, %	8.08	3.05
Water Rate, bbl/d	991.62	987.89
Total Liquid Rate, bbl/d	3660.03	3637.72
Specific Gravity of Liquid,	0.87	0.87
Specific Gravity of Mixture,	0.80	0.85
Mixture Viscosity, cST	0.43	0.49
Mixture Viscosity, SSU	29.61	29.75
Solution GOR, SCF/STB	145.07	145.07
Solution GWR, SCF/STB	0.00	0.00
Liquid FVF,	1.09	1.08

Total Surface Liquid Rate: 3339.07 STB/d

Gas Separation

Gas Separator: RF 540/540

Liquid Rate, bbl/d	3617.05
Natural Gas Separation, %	70.00
Gas Rate before Separation, bbl/d	0.00
Total Rate before Separation, bbl/d	0.00
Gas Rate after Separation, bbl/d	316.67
Total Rate after Separation, bbl/d	3933.72
Gas Volume Fraction at Pump, %	316.67
Intake Gas Volume Fraction, %	3933.72

Pump

Model: REDA 538 S5000N	
Frequency, Hz	50
Number of Stages	115
Stages with Free Gas	115

Operating Condition

Total Dynamic Head (TDH), ft	3185.02
Surface Rate (O+W), STB/d	3339.0
Avg. Pump Rate (O+G+W) bbl/d	3835.29
Pump Intake Pressure, psig	799.8
Operating Power, hp	106.4
Bottom Pump Efficiency, %	70.85
Pump Efficiency, %	70.85

Viscosity Correction Factors

	Calculated	User Entered
Rate	1.00	
Head	1.00	
Power	1.00	
Efficiency	1.00	N/A

Average Pump Viscosity: 0.38

Housing Data

Housing #	Housing Type	Length (ft)	# of Stages
1	ES	11.9	51
2	ES	14.7	64
Total		26.6	115

Advanced Gas Handler

Device information: REDA 540/540 AGH

Motor

REDA 456 4151 Dominator (100.00% Rating Factor)

Motor Slip Adjustment: Yes

Nameplate: 60.00 Hz

Power, hp	180.0	Voltage, Volts	1774.5
Amperage, Amps	64.8	Power @ Design	150.0

Operating Condition (50.00Hz)			
Motor Load, hp	143.9	Motor Speed, RPM	2851.1
Efficiency, %	84.17	Fluid Velocity, ft/s	2.01
Power Factor, %	79.81	Voltage, Volts	1478.7
Amperage, Amps	62.7	Load Factor, %	95.96
Total Stages	115	Slip Stages	0
Total Dynamic Head (TDH), ft	3185.02		
Surface Rate (O+W), STB/d	3339.0	Avg. Pump Rate (O+G+W) bbl/d	3835.29
Pump Intake Pressure, psig	799.8	Required Power @ Nameplate	172.7
Bottom Pump Efficiency, %	70.85	Pump Speed, RPM	2851.1

Fluid Temperature At Intake, ºF	174.25
Skin Temperature Rise, ºF	21.17
Avg. Winding Temp. Rise over Skin, ºF	61.07
Total Winding Temperature, ºF	256.50
Speed Increase Heating, ºF	0.00
Heat Rise due to VSD without Load Filter,	10.38
Heat Rise due to VSD with Load Filter or Sine wave Drive, ºF	0.00

Protector

Thrust Bearing Type	400 HL	Number of Seals	2
Configuration	LSB	Number of	2
Components	SINGLE	Oil Type	REDA OIL #5
Total Shut-In	7571.57		

Motor Lead Extension

Type	KEOTB	Connection Type	TAPE-IN
Length, ft	55.00	KV	4
Minor Armor OD,	0.43	Major Armor OD, in	1.12
Conductor Size,	6.00	Material/Armor	M

Cable

REDA REDALEAD EL FLAT Stranded

Specifications			
Conductor Size,	1	KV	4000.00
Temperature Rating,	450.00	Length, ft	4629.00

Operating Condition			
Conductor	199.46	Voltage Drop, Volts	78.8
KVA,	169.10	Surface Voltage,	1557.6
Max Ampacity,	207.5	Start up Ratio	89.33

Required Surface Voltage, Volts: 1557.6

APPENDIX F

Table F 1: Electrical submersible pump system's pumping units price [26]

Case	Well	Manufacture	Pump			Price $
			Series	Model	Stage Number	
Current Status	C-001-65	REDA	540	GN-3100	120	9090
	C-046-65	REDA	540	GN-4000	105	16030
	C-101-65	REDA	540	GN-2000	145	11000
	C-105-65	REDA	540	GN-4000	142	21680
	C-144-65	REDA	540	GN-2500	112	10566
Combined ESP/GL	C-001-65	REDA	540	GN-4000	86	13129
	C-046-65	REDA	540	GN-5200	109	25025
	C-101-65	REDA	540	GN-2700	62	6458
	C-105-65	REDA	540	GN-5200	97	22271
	C-144-65	REDA	540	GN-5200	118	27000
Optimizing Pump setting Depth	C-001-65	REDA	400	D3500N	158	30000
	C-046-65	REDA	540	GN-5200	150	34400
	C-101-65	REDA	538	SN-2600	101	20570
	C-105-65	REDA	400	D4300N	245	38000
	C-144-65	REDA	540	S-5000N	115	27000

Table F 2: Electrical submersible pump system's motors price [26]

Case	Well	Manufacture	Motor			Price $
			Series	Type	HP/60HZ	
Current Status	C-001-65	REDA	456	4142-upper	168	60000
	C-046-65	REDA	456	4104-upper	120	50000
	C-101-65	REDA	456	4092-upper	108	45000
	C-105-65	REDA	456	4124-upper	144	56000
	C-144-65	REDA	456	4083-upper	96	40000
Combined ESP/GL	C-001-65	REDA	456	4083-upper	96	40000
	C-046-65	REDA	456	4114-upper	132	55000
	C-101-65	REDA	456	4052-upper	60	23300
	C-105-65	REDA	456	4104-upper	120	50000
	C-144-65	REDA	456	4112-upper	132	55000
Optimizing Pump setting Depth	C-001-65	REDA	375	AS2J181	128	65000
	C-046-65	REDA	456	4160-upper	192	80000
	C-101-65	REDA	456	4104-upper	120	50000
	C-105-65	REDA	456	4124-upper	144	56000
	C-144-65	REDA	456	4151-upper	180	65000

Table F 3: Electrical submersible pump system's seals price list [26]

Case	Well	Manufacture	SEAL			Price $
			Series	Bearing	Chamber	
Current Status	C-001-65	REDA	400-456	400STD	LSB	8000
	C-046-65	REDA	400-456	400STD	LSB	8000
	C-101-65	REDA	400-456	400STD	LSB	8000
	C-105-65	REDA	400-456	400HL	LSB-HL	10000
	C-144-65	REDA	400-456	400STD	LSB	8000
Combined ESP/GL	C-001-65	REDA	400-456	400STD	LSB	8000
	C-046-65	REDA	400-456	400STD	LSB	8000
	C-101-65	REDA	400-456	400STD	LSB	8000
	C-105-65	REDA	400-456	400STD	LSB	8000
	C-144-65	REDA	400-456	400STD	LSB	8000
Optimizing Pump setting Depth	C-001-65	REDA	325-375	325Modular	LSB	7400
	C-046-65	REDA	400-456	400HL	LSB	8500
	C-101-65	REDA	400-456	400HL	LSB	8500
	C-105-65	REDA	400-456	400HL	LSB	8500
	C-144-65	REDA	400-456	400HL	LSB	8500

Table F 4: Electrical submersible pump system's cable price list [26]

Case	Well	Manufacture	CABLE				Price $
			Type	AWG	Length ft	Price $/ft	
Current Status	C-001-65	PHILP	EPDM/Lead	1Cu	5517	14	77238
	C-046-65	PHILP	EPDM/Lead	1Cu	5148	14	72072
	C-101-65	PHILP	EPDM/Lead	1Cu	5637	14	78918
	C-105-65	PHILP	EPDM/Lead	1Cu	5531	14	77434
	C-144-65	PHILP	EPDM/Lead	1Cu	4979	14	69706
Combined ESP/GL	C-001-65	PHILP	EPDM/Lead	1Cu	5350	14	74900
	C-046-65	PHILP	EPDM/Lead	1Cu	5148	14	72072
	C-101-65	PHILP	EPDM/Lead	1Cu	5437	14	76118
	C-105-65	PHILP	EPDM/Lead	1Cu	5200	14	72800
	C-144-65	PHILP	EPDM/Lead	1Cu	4979	14	69706
Optimizing Pump setting Depth	C-001-65	REDA	REDA Lead	1Cu	5050	14	70700
	C-046-65	REDA	REDA Lead	1Cu	4768	14	66752
	C-101-65	REDA	REDA Lead	1Cu	5100	14	71400
	C-105-65	REDA	REDA Lead	1Cu	5000	14	70000
	C-144-65	REDA	REDA Lead	1Cu	4629	14	64806

Table F 5: Gas Lift Accessories Price list [26]

Item	Price $
Gas compressor packaged unit (400HP, 2 MMSCF/D , 2 Stage)	2,500,000
Five downhole valves, with latches and side pocket mandrels	30,000
30,000ft of 2 in. ID gas distribution line & Manifold	150,000