Chair of Petroleum and Geothermal Energy Recovery

Master Thesis

Rig-less ESP Candidate Selection and Implementation Plan

Written by:
Nesrine Haddar, BSc
M01435460

Advisors:
Univ.-Prof. Dipl.-Ing. Dr.mont. Herbert Hofstätter
MSc. Adel Elhooni
Dipl.-Ing. Mohsen Fakhari

Leoben, 24.09.2018

EIDESSTATTLICHE ERKLÄRUNG

Ich erkläre an Eides statt, dass ich die vorliegende Diplomarbeit selbständig und ohne fremde Hilfe verfasst, andere als die angegebenen Quellen und Hilfsmittel nicht benutzt und die den benutzten Quellen wörtlich und inhaltlich entnommenen Stellen als solche erkenntlich gemacht habe.

AFFIDAVIT

I hereby declare that the content of this work is my own composition and has not been submitted previously for any higher degree. All extracts have been distinguished using quoted references and all information sources have been acknowledged.

Danksagung / Acknowledgement

Foremost, I would like to express my sincere thanks to my OMV advisor MSc Adel Elhooni for his patience, motivation, and immense knowledge. His continuous guidance helped me a lot completing this master thesis.

Besides, I would like to thank all of the Production Technology team, headed by Dipl.-Ing. Reinhard Pongratz, for answering all of my questions, for sharing their knowledge and experience, and for being very supportive.

My sincere gratitude also goes to Dipl.-Ing. Luis Lobianco from Schlumberger, and to Dipl.-Ing. Bernd Kometer from OMV Gänserndorf, who supported and helped me a lot during this thesis.

I would like to thank Univ.Prof. Dipl.-Ing. Dr. mont. Herbert Hofstätter and Dipl.-Ing. Mohsen Fakhari for their assistance and their continuous support.

Finally, I would like to thank my parents and two sisters for supporting me throughout my studies, for believing in me, and for always being a shoulder I could lean on.

Kurzfassung

Eine der größten Herausforderungen, die beim Betrieb von „ESP-Systemen“ in abgelegenen Gebieten oder auf hoher See auftreten können, ist die Nichtverfügbarkeit von „Workover-Rigs“ und die relativ hohen Kosten für „Workover-Jobs“. Dies kann die Profitabilität von Bohrlöchern drastisch verringern, insbesondere wenn die mittlere Zeit zwischen Ausfällen (MTTR) des Pumpensystems relativ gering ist und häufige Reparaturen oder ein Austausch des „Downhole-Assembly“ erforderlich sind. Genau dieser Fall trifft auf ein Feld zu, an dem OMV arbeitet. Das Feld befindet sich in einer Wüste, gelegen im Süden des Landes, wo alle zuvor genannten Probleme auftreten. Die Masterstudie wurde deshalb durchgeführt, um die möglichen Alternativen zu bewerten und um die optimale Lösung auszuwählen zu können.

Als mögliche Lösung um diese Probleme zu vermeiden, wurden „Rigless-ESP-Alternativen“ entwickelt, bei denen der „ESP-Assembly“ eingführt und aus dem Loch herausgezogen wird, ohne dabei einen „Workover-Rig“ zu benötigen. Diese Technologien werden über „Slick-Line-“, „Wireline-“ oder „Coiled-Tubing-Einheiten“ implementiert. Dies ermöglicht die Reduzierung von Arbeitskosten und -zeiten, sowie die Minimierung der Betriebskosten und Produktionsverzögerungen.

Diese Masterarbeit wurde in Zusammenarbeit mit OMV durchgeführt, um „Rig-Less-ESP-Lösungen“ für das untersuchte Feld auszuwählen. Die Auswahl der „Rig-Less-ESP-Lösung“ bestand aus zwei Hauptteilen:
(1) Auswahl geeigneter Bohrlöcher, die für die „Rig-Less-Technologien“ am besten geeignet waren, mittels einer primären Selektion und eines Bohrlochbewertungsprozesses unter Verwendung von Multikriterien-Entscheidungsanalyseverfahren;
(2) Auswahl und Design der optimalen „Rig-Less-Technologie“, die in den ausgewählten Bohrlöchern installiert werden soll, einschließlich der Anwendbarkeitsüberprüfung der Technologien, „ESP-Designs“ und Empfehlungen für eine Wirtschaftlichkeitsprüfung.
Zu guter Letzt wurde ein „Workflow“ des „Rig-Less-ESP-Implementierungsplans“ erstellt, der die notwendigen Schritte für die Auswahl der Bohrlöcher und Technologien auflistet.

Abstract

One of the major challenges that can arise when operating ESP systems in remote areas or offshore is the unavailability of workover rigs and the relatively high cost of workover jobs. This might drastically decrease the profitability of the wells, especially if the mean time between failures of the pumping system is relatively low and workovers to repair or replace the downhole assembly are more often required. This case applies to a field in which OMV is operating. The field is located in the southern desert of the country, where all aforementioned problems are occurring. This master study was therefore carried out to evaluate the possible alternatives and select the optimum solution.

As a possible solution to avoid these problems, rig-less ESP alternatives were developed where the ESP assembly is deployed and pulled out of hole without the need of a workover rig. These technologies are implemented via slick-line, wireline, or coiled tubing units. This enables the reduction of workover costs and time, minimizing the operating costs and production deferments.

This master thesis was conducted in collaboration with OMV in the purpose of selecting rig-less ESP candidates for the field under investigation. The rig-less ESP candidate selection consisted of two main parts:
(1) the selection of the well candidates most suitable for the rig-less technologies, via a primary selection and a well ranking process using multi criteria decision analysis methods;
(2) the selection and design of the most optimal rig-less technology to be installed in the chosen wells, including applicability check of the technologies, ESP designs, and recommendations for the economic evaluation.
Finally a workflow of the rig-less ESP implementation plan was created, listing the necessary steps for the well and technology candidates selection.

List of Tables

Table 1: Available rig-less ESP suppliers....20
Table 2: ZEiTECS shuttle system specifications [6]....26
Table 3: PMM motors specifications [7]....29
Table 4: Colibri installations [8]....30
Table 5: Key specifications summary [6] [7] [8]....33
Table 6: Wells data....36
Table 7: Wells data....37
Table 8: Well deliverability scale....39
Table 9: GVF vs liquid rates [stb/d] for all 23 wells....42
Table 10: Primary well selection results....43
Table 11: Scales and scores of the 9 criteria....45
Table 12: Scores of the wells for each criterion....46
Table 13: Scale for pairwise comparisons....48
Table 14: AHP comparison matrix....49
Table 15: Priority vector....49
Table 16: Random consistency index RI....50
Table 17: CI and CR results....50
Table 18: Well candidate ranking....51
Table 19: Well data for technology applicability evaluation....52
Table 20: Basis of design....54
Table 21: PVT data of the 5 wells....69

List of Figures

Figure 1: Typical ESP configuration including surface and downhole installations [2, p. 2] 4
Figure 2: Typical ESP centrifugal pump [1, p. 630] 5
Figure 3: Radial and mixed flow pump stages [3, p. 23; 26] 6
Figure 4: Derivation of pump's H-Q curve [3, p. 28] 7
Figure 5: Power conditions in a centrifugal pump stage [3, p. 29] 7
Figure 6: Pump performance curves of an ESP at different frequencies [3, p. 169] 8
Figure 7: Bag type chamber [3, p. 95] 9
Figure 8: Labyrinth type chamber [3, p. 92] 9
Figure 9:Thrust bearing [3, p. 89] 9
Figure 10: Gas handling application ranges [4, p. 43] 12
Figure 11: Different coiled tubing ESP installations [3, p. 352] 17
Figure 12: CT with ESP cable led inside [6] 18
Figure 13: Arutunoff cable suspended ESP installation [3, p. 351] 20
Figure 14: Schlumberger external cable CT deployed ESP system [6] 21
Figure 15: REDACoil possible installations [6] 22
Figure 16: Xmas tree arrangement for REDACoil [6] 23
Figure 17: Run-life data from Qatar [6] 24
Figure 18: ZEiTECS shuttle rig-less ESP replacement system [6] 25
Figure 19: ACP completion [7] 27
Figure 20: Retrievable components [7] 28
Figure 21: Wet mate connector and tubing bore [7] 29
Figure 22: Carrying cable [8] 30
Figure 23: Colibri ESP 217 series [8] 31
Figure 24: 217 series pump curve 109 stages at 3000RPM (50 Hz) [8] 32
Figure 25: 217 series pump curve 109 stages at 8500RPM (140 Hz) [8] 32
Figure 26: Field overview 34
Figure 27: GVF vs liquid rate [stb/d] 41
Figure 28: Primary well selection results 44
Figure 29: Well candidate ranks 51
Figure 30: DesignRite pump design window 55

Figure 31: DesignRite housing selection 56
Figure 32: DesignRite motor selection window 57
Figure 33: De-rate factors 59
Figure 34: Floater vs compression pumps [6] 60
Figure 35: Rig-less ESP candidate selection workflow 65

Abbreviations

ESP	Electrical Submersible Pump
CPF	Central Processing Facility
CT	Coiled Tubing
WO	Workover
MTBF	Mean Time Between Failures
ARZ	Alumina Reinforced Zirconia
IPR	Inflow Performance Relationship
VLP	Vertical Lift Performance
REDA	Russian Electrical Dynamo of Arutunoff
USA	United States of America
VSD	Variable Speed Drive
H	Head
Q	Flow rate
BHP	Break Horse Power
BRP	Best Efficiency Point
AC	Alternative Current
GVF	Gas Void Fraction
T	Temperature
P	Pressure
CO_2	Carbon Dioxide
H_2S	Hydrogen Sulfide
RIH	Run In Hole
POOH	Pull Out Of Hole
MLE	Motor Leas Extension
ID	Inside Diameter
OD	Outside Diameter
TTC	Through Tubing Conveyed
AWG	American Wire Gauge
CRA	Corrosion Resistant Alloy
UK	United Kingdom
TVD	Total Vertical Depth
BOP	Blow Out Preventer
API	American Petroleum Institute
ACP	Annular Connection Port
ICP	In-line Connection Port
PMM	Permanent Magnetic Motor
MD	Measured Depth
BH	Bottom Hole
AGH	Advanced Gas Handler
MGH	Multiphase Gas Handler
VGSA	Vortex Gas Separator Assembly
N/A	Not Applicable
TOPSIS	Techniques for Order Performance by Similarity to Ideal Solution
AHP	Analytic Hierarchy Process
GOR	Gas Oil Ratio

PVT	Pressure Volume Temperature
PI	Productivity Index
JP	Jet Pump
GL	Gas Lift
AOF	Absolute Open Flow
WC	Water Cut
Rs	Solution GOR
VS	Versus
CI	Consistency Index
RI	Random consistency Index
CR	Consistency Ratio
TOL	Top Of Liner
BHP	Bottom Hole Pressure
BHT	Bottom Hole Temperature
CR-CT	Compression Ring Central Tandem
GLR	Gas Liquid Ratio
LSBPB	Labyrinth Series Bag Parallel Bag
HSE	Health Safety Environment
WL	Wireline
NVP	Net Present Value
DCF	Discounted Cash Flow
SSSV	Subsurface Safety Valve
KPI	Key Performance Indicator

Nomenclature

°C	Degree Celsius
°F	Degree Fahrenheit
Bar	Pressure unit
Psi	Pound per Square Inch
STB	Stock Tank Barrel
Bbl	Barrels
Ft	Feet
D	Day
In	Inches
M	Meters
Hz	Hertz
HP	Horsepower
Deg	Degrees
Bpd	Barrels per day
Lb	Pound
V	Volts
A	Amperes
Lb/ft	Pound per foot
EUR	Euros
Ppf	Pound per foot
RPM	Rotations Per Minute

Table of content

Page

1 INTRODUCTION 1

2 ELECTRICAL SUBMERSIBLE PUMPS 3

2.1 General Overview 3

2.2 Miscellaneous Downhole Equipment 10

2.3 Influencing Factors on ESP Design 11

2.4 Advantages and Limitations 14

3 RIG-LESS ESPS 16

3.1 Conventional ESP Deployment 16

3.2 Rig-less ESP technologies 16

3.2.1 Coiled Tubing deployed ESP system 17

3.2.2 Wireline deployed ESP system 19

3.2.3 Power Cable deployed ESP system 20

3.3 Available Suppliers & Key Specifications 20

3.3.1 Schlumberger External Cable CT deployed ESP system 21

3.3.2 Schlumberger REDACoil ESP 22

3.3.3 Schlumberger ZEiTECS Shuttle 25

3.3.4 AccessESP Wireline deployed ESP system 27

3.3.5 NOVOMET Colibri ESP 30

3.3.6 Key Specifications Summary 32

4 WELL CANDIDATE SELECTION 34

4.1 Field Overview 34

4.1.1 Location 34

4.1.2 Wells data 35

4.2 Well Selection tool 38

4.2.1 Primary Well Selection 38

4.2.1.1 Well deliverability scale 38

4.2.1.2 Maximum oil rate potential 39

4.2.1.3 Primary well selection results 42

4.2.2 Well Candidate Ranking 44

4.2.2.1 TOPSIS 44

4.2.2.2 Weights calculation using the AHP method 47

4.2.2.3 Well candidate ranking results....51

5 TECHNOLOGY CANDIDATE SELECTION 52

5.1 Evaluation of technology applicability in the wells....52

5.2 ESP design....53

5.2.1 Basis of design....54

5.2.2 Design steps and recommendations....55

5.2.3 Safety Design Measures....59

5.3 Economic Evaluation....61

5.4 HSE Considerations....62

5.5 Assessment of the Rig-less ESP Technologies Limitations and Risks....62

6 RIG-LESS ESP CANDIDATE SELECTION IMPLEMENTATION PLAN....64

7 CONCLUSIONS AND RECOMMENDATIONS....66

8 REFERENCES....68

APPENDICES....69

Appendix A....69

Appendix B....70

1 Introduction

The key to estimate the well performance and to optimize the well and reservoir productivity is to understand the principle of fluid flow through the production system, where fluids are transported from the reservoir to the surface facilities.

In the early stages of their lives, oil wells tend to flow naturally to the surface as their bottom-hole pressures are able to overcome the hydrostatic pressure of the fluid column and the pressure losses along the flow path of the produced fluids to the separator. This can be further described by the inflow performance relationship IPR and the vertical lift performance VLP, which relate the well flowing pressure to the surface production rate. The intersection of the IPR and the VLP, also known as the operating point, depicts what the well will produce for a given operating condition and thus yields the well deliverability.

Throughout its life, the reservoir becomes unable to provide sufficient energy to produce the reservoir fluids at economic rates, either because of its depletion or due to increased back pressure on the well. In this case, artificial lift systems can be used to supply the required energy to the production system and to, eventually, enhance the production.

Several different lifting mechanisms are available. Therefore, a good understanding of the various components of the system and of their interaction is required in order to select the optimal artificial lift method and thus optimize the well productivity.

The electrical submersible pump is one of the most widely installed artificial lift systems in the petroleum industry for its diverse advantages. The conventional and most common ESP configuration is the tubing deployed ESP system, where the ESP assembly is mounted to the tubing whereby the connection for production is provided. One major disadvantage related to this ESP configuration is the fact that a workover rig is always required to deploy the ESP assembly when needed. This is mainly crucial in cases where the rigs are unavailable or have a high cost, especially in remote fields or offshore fields, and where the mean time between failures of the ESP is very short. These effects can lead to high production deferment volumes and high operating expenditures, which may decrease the profitability of the well and its economic limit.

Other alternatives were developed seeking to expand the applicability of the ESP systems in these unfavourable conditions. Rig-less ESP technologies were designed in order to be able to deploy and pull the ESP assembly in a rig-less intervention using slick-line, wireline, or coiled tubing. Different rig-less deployment methods exist and are supplied by diverse providers. These designs would minimize the workover duration, reduce the operating expenditures, and reduce the production deferments.

This problem was encountered in the field this thesis is studying, where workover rigs are not always available and therefore are very expensive. In addition, the waiting time for intervention is rather high, which induces high production deferment volumes. Combined with a low mean time between failures for the existing ESP systems, these issues tremendously affect the economics of the ESP applications, reducing the wells profitability.

The purposes of this master thesis are to, first, assess the wells and select the well candidates that are most suitable for the installation of a rig-less ESP system, and second, to evaluate the rig-less technologies available in the market and select the optimum technology to be applied.

On one hand, an excel tool was created to perform the well candidate selection applying multi-criteria decision analysis methods. On the other hand, the technology candidate selection workflow includes the applicability evaluation of the technologies, the ESP design, and an economic evaluation.

Due to confidentiality reasons, the economic evaluation could not be performed as it was not possible to gather budgetary proposals from the suppliers as well as other relevant data from OMV. For this reason, the final technology selection was not performed, nevertheless, a workflow was created to be followed by the branch office to finalize the selection.

The results and findings of this thesis work will be presented and discussed in the following chapters.

2 Electrical Submersible Pumps

Electrical submersible pumps, also known as ESPs, are one of the widely used artificial lift methods. This chapter will include an overview of electrical submersible pumping systems, their components, their working principle, the various factors influencing the ESP designs, and their advantages and limitations.

2.1 General Overview

Electrical submersible pumping was invented and developed by Armais Arutunoff in the late 1910s. The young Russian inventor then established the company Russian Electrical Dynamo of Arutunoff, from which the widely known acronym REDA was acquired. In 1926, the first electrical submersible pump, or ESP, was successfully installed and operated in Kansas, USA. In order to overcome the diverse challenges that this artificial lift method faces, continuous and various improvements throughout ESP's life were made, which developed the nowadays state-of-the-art ESP system. [1, p. 625]

The electrical submersible pump, ESP, has been used in the oil and gas industry as an efficient and reliable artificial lift method for production of moderate to high volumes of reservoir fluids, typically with a range between 150bpd to 150 000bpd (24 to 24 600 m^3/day), which can be extended significantly by using variable speed drives VSDs. [1, p. 625]

ESP systems comprise both surface and downhole components. They consist of surface controls, a submerged three-phase electrical motor driving a multistage centrifugal pump, a seal-chamber section, also known as protector, and an electric cable run from the surface whereby power is supplied to the motor. A conventional ESP system is shown in figure 1, where surface and downhole installations can be seen.

Surface components: The surface components of the ESP system may include an electricity supply system, which can be provided by a commercial power distribution system or portable power source like a diesel generator for example, a transformer, and a motor controller. Previously, switchboards and soft starters were used as motor controllers. However, due to the many limitations and challenges they had, these fixed-frequency units became outdated as improvements were made and variable speed drives, or VSDs, started to be used instead. In fact, VSDs allow a wide flexibility of the ESP system compared to the conventional installations with constant motor speeds, which permits perfect matching of the well's productivity and the lift capacity of the system. This enables the adjustment of the system to extensive changes in well inflow conditions or great uncertainties regarding it. As a matter of fact, even though VSDs increase the initial capital cost and the design complexity, they broaden the range of application of the ESP, allow the efficiency optimization of the downhole system, maximize well production, isolate the downhole equipment from surface power disturbances, and reduce the starting stresses. [1, p. 657; 660] [3, p. 183]

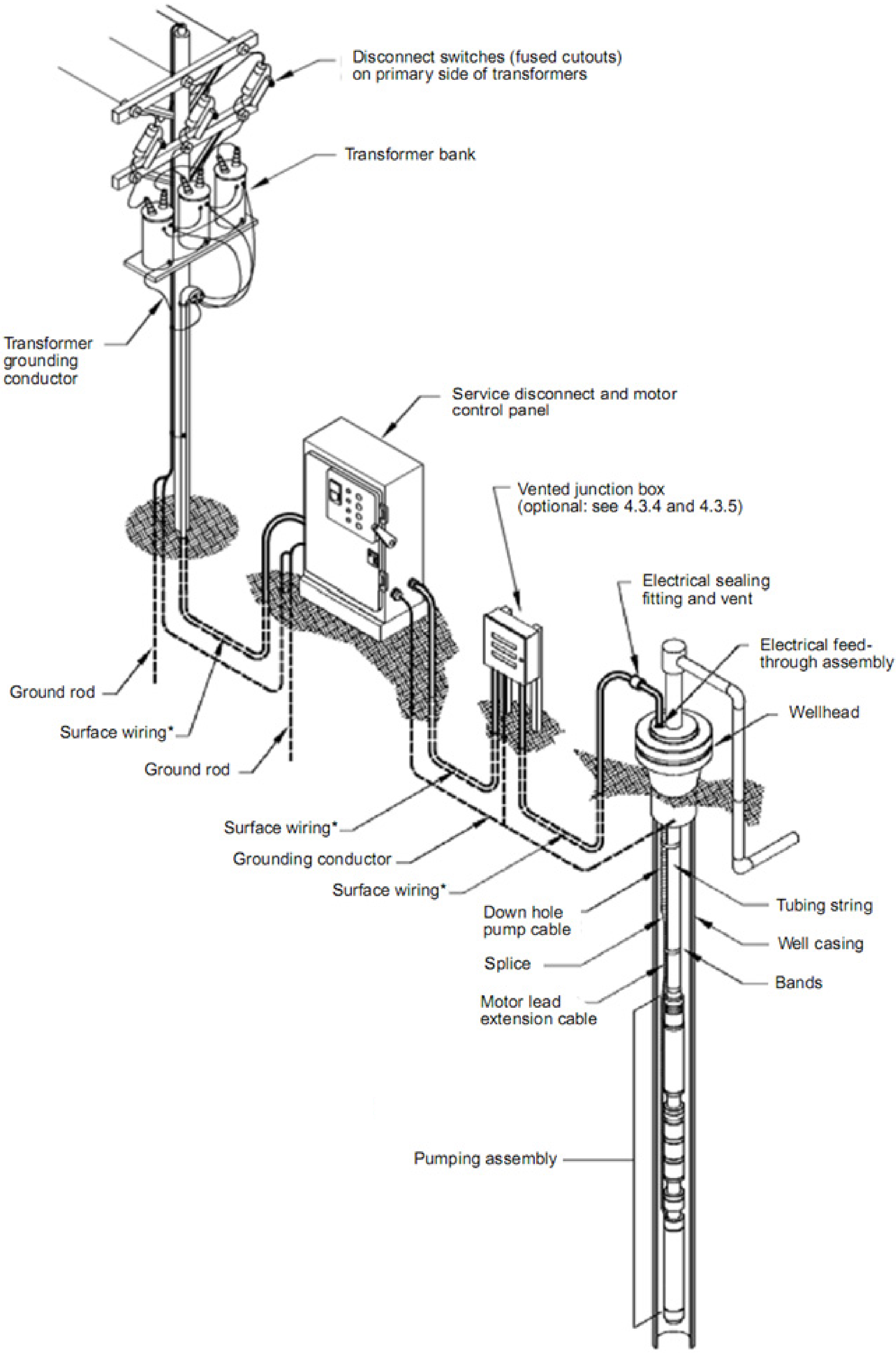


Figure 1: Typical ESP configuration including surface and downhole installations [2, p. 2]

Multistage centrifugal pump: The multistage centrifugal pump contains a selected number of stacked stages comprising a rotating impeller inside a closely fitted stationary diffuser. Its working principle consists in lowering the back-pressure in the wellbore and transferring pressure to the fluid so that it will flow at the desired rate. This is accomplished in each of the pump's stages by increasing the kinetic energy of the fluid due to the rotary motion of the impeller's vanes, where it attains a high velocity at the impeller's discharge, and then by converting the kinetic energy to pressure energy as the high-velocity fluid enters the diffuser. The stages are stacked in series to incrementally increase the fluid pressure where the discharge of one stage is led to the intake of the next stage. The number of stages is dictated by the operating requirements of the well and the completion design. [1, p. 626]

A typical ESP pump cross section is shown in figure 2. The pump is composed of diverse parts, each having a different role. These are, from top to bottom, as listed in the figure:

- Discharge head / tubing connection, which provides a female threaded connection to the production tubing.
- Top bearing.
- Housing, which holds and aligns all components of the pump, as well as contains the pressure. The housing configuration can be either a floater type, where the impellers are freely moving in the diffuser or a compression type, where the impellers are rigidly fixed to the shaft and move with it.
- Pump stages. There are two types of stages available which can be employed depending on the operating flow rate of the ESP. These are: radial stages, where the flow enters the impeller or diffuser parallel to shaft's axis and exits perpendicular to it in a radial direction, and mixed-flow stages where the flow exits the impeller at an angle less than 90 deg to the shaft. The two stages types can be seen respectively in figure 3.
- Pump intake, from which the fluid enters the pump. Different types of intakes are used depending on the type of fluid being produced. A standard intake is used when

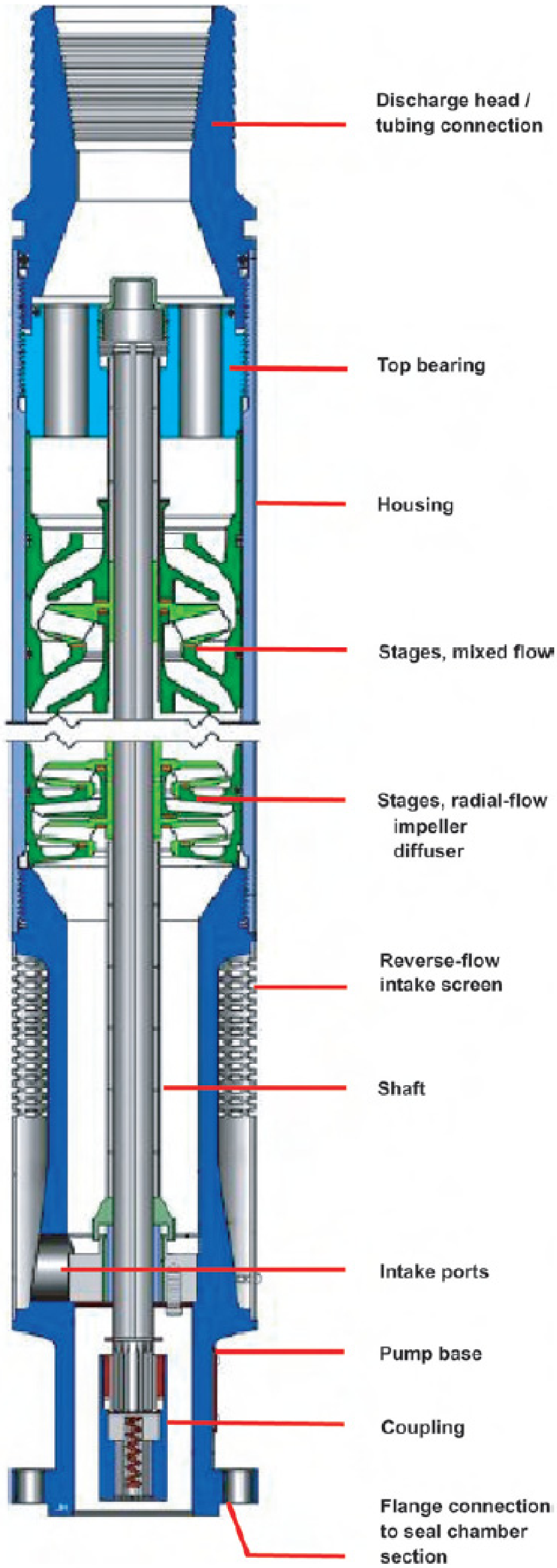


Figure 2: Typical ESP centrifugal pump [1, p. 630]

the fluid is all liquid or has very low free-gas content. A reverse-flow intake allows the natural separation of the lighter gases from the liquid and is used when the free-gas content is high enough to cause pump performance problems. Downhole mechanical separation devices can also be installed to handle free gases. These can be vortex-type separator and rotary centrifuge-type separator.

- Shaft, which is connected to the motor and the seal-chamber section by a coupling, therefore, it transmits the rotary motion of the motor to the impellers.
- Intake ports.
- Pump base, which directs the fluid entering the bottom of the pump to the first stage.
- Coupling.
- Flange connection to seal chamber section. [1, pp. 629-632]

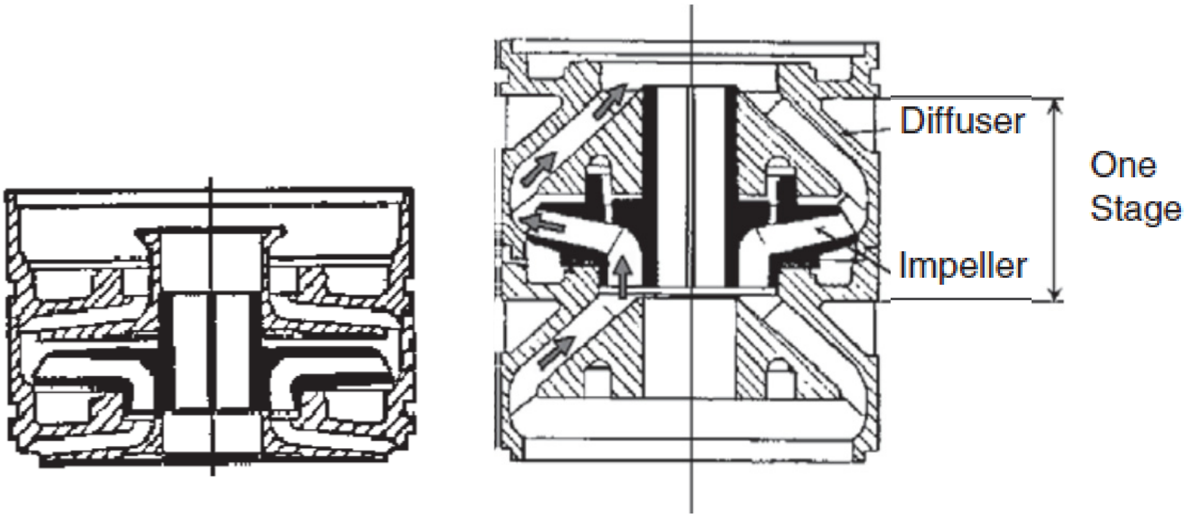


Figure 3: Radial and mixed flow pump stages [3, p. 23; 26]

The pressure increase in the pump’s stages is proportional to the fluid’s density. Thus, “head”, being a constant and independent of the fluid’s density for a given pump and given flow rate, is being used instead of pressure when dealing with centrifugal pumps in calculations involving their performance and use. The theoretical head can be calculated. However, the actual head is different than the theoretical head due to different losses: hydraulic losses resulting from fluid friction in the impellers, shock losses occurring at the entrance and the exit of the impeller, and leakage losses representing liquid rate losses through the clearances between the rotating and stationary parts of the pump stages. The actual head H versus flow rate Q curve would therefore be a representation of the centrifugal pump performance. An illustration of the pump’s H-Q curve along with the theoretical head and the different losses is schematically depicted in figure 4. [3, p. 27;28]

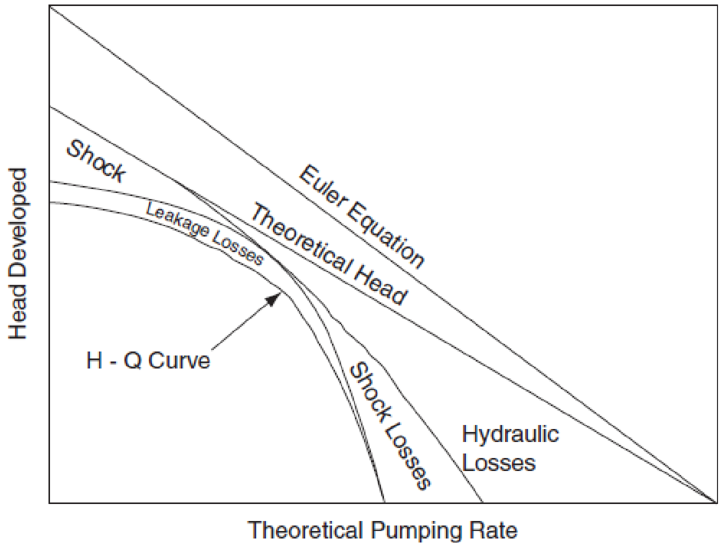


Figure 4: Derivation of pump's H-Q curve [3, p. 28]

The power required to drive the pump is represented by the brake horsepower, which must be supplied by the motor and has to overcome the energy required to pump the given liquid rate plus all the energy losses. A schematic illustration of the power conditions in a centrifugal pump is shown in figure 5 below. [3, p. 28;29]

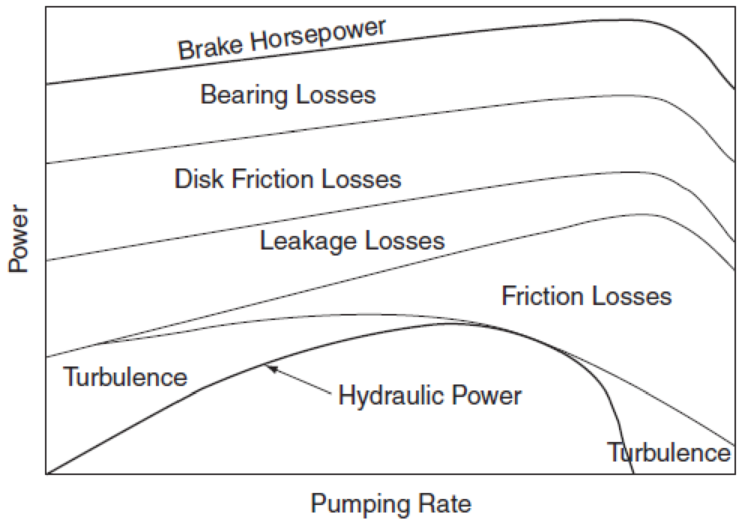


Figure 5: Power conditions in a centrifugal pump stage [3, p. 29]

The energy efficiency of the pump can be therefore derived from the brake horsepower BHP required and the hydraulic power spent on liquid transfer by dividing the hydraulic power, also known as useful power, by the BHP. The pump efficiency curve will follow the shape of the hydraulic power curve if plotted versus the liquid rate, and from which the best efficiency point BEP of the pump can be estimated. The BEP would then be the flow rate at which the pump efficiency is at its maximum. [3, p. 29]

As mentioned before, the use of variable speed drives widens the applicability range of the ESP system. This means that by varying the frequency of the AC current delivered to the motor, the motor speed changes since it is a direct function of the frequency. Therefore, the pump performance, its H-Q curve, and the BHP change according to the affinity laws. In addition, the BEP changes with each frequency. The effects of varying the frequency on the pump performance can be seen in figure 6 below.

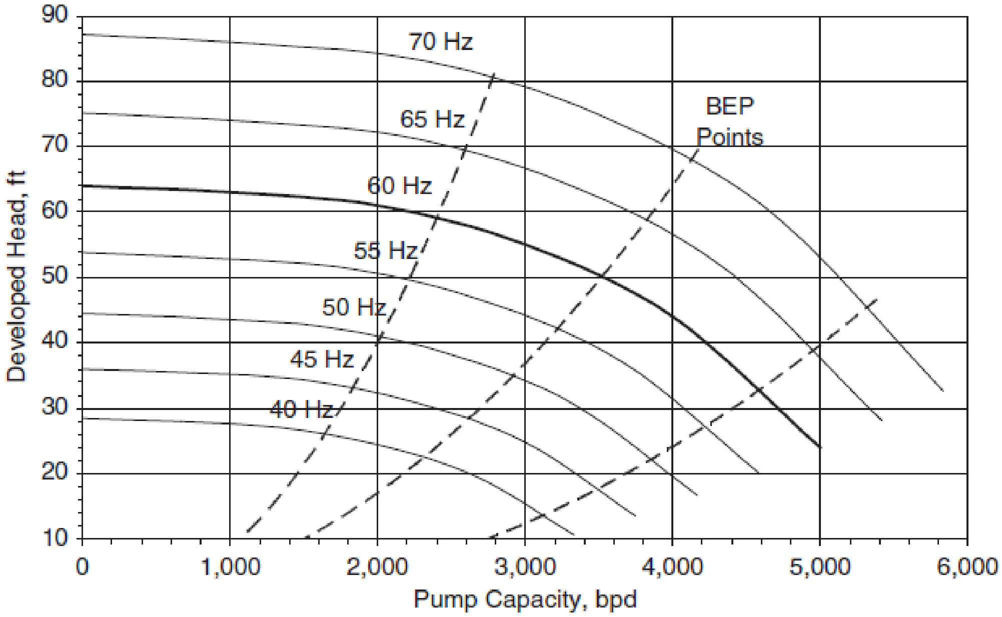


Figure 6: Pump performance curves of an ESP at different frequencies [3, p. 169]

When designing the multistage centrifugal pump, it is necessary to make sure that the well performance curve is as close as possible to the best efficiency points, preferably to the right of the latter, and therefore the system can be adjusted in case of over- or underestimation of the reservoir inflow performance.

Electric motor: In order to operate the pump, an electric motor is used, which, in most cases, is a three-phase, two-pole, squirrel cage induction motor, available in a variety of operating voltages, currents, and horsepower ratings. The motor needs to deliver the required power to drive the pump and the entire other system components. In conventional ESP settings, the motor is usually set below the pump, where it is cooled by the wellbore fluids flowing past it to the intake of the pump by convective heat transfer.

Seal section: Also known as the protector section, is set between the pump intake and the motor. Its main functions are first to isolate and protect the motor from well fluids that risk to contaminate the motor oil, second to equalize the pressure in the wellbore with the pressure inside the motor in case of expansion or contraction of the motor oil due to temperature changes, and finally to carry and absorb the axial thrust developed by the pump.

The isolation of the motor oil from the well fluid and the pressure equalization are ensured by the isolation chambers. These can be classified into two groups: the labyrinth and the bag type chambers.

The labyrinth type chambers allow the well and motor fluid to be in direct contact, where the separation between both is guaranteed due to gravitational forced. Therefore this requires that the protector oil has to be lighter than that produced and that the well deviation doesn’t exceed 45deg, otherwise, this chamber type will not perform properly. [3, p. 91]

The bag type chambers contain a positive barrier between the motor oil and the well fluid in the shape of a flexible bag made of an elastomer with high performance. The bag being flexible allows the expansion and contraction of the motor oil as it expands or contracts correspondingly. [3, p. 95]

The two chamber types are presented in the figures below.

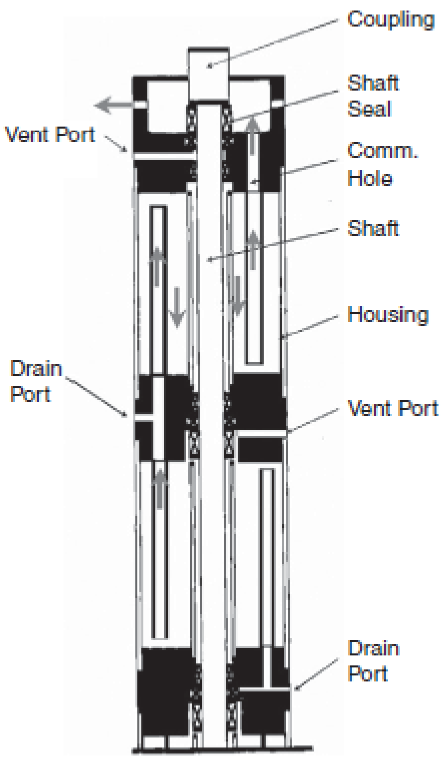


Figure 8: Labyrinth type chamber [3, p. 92]

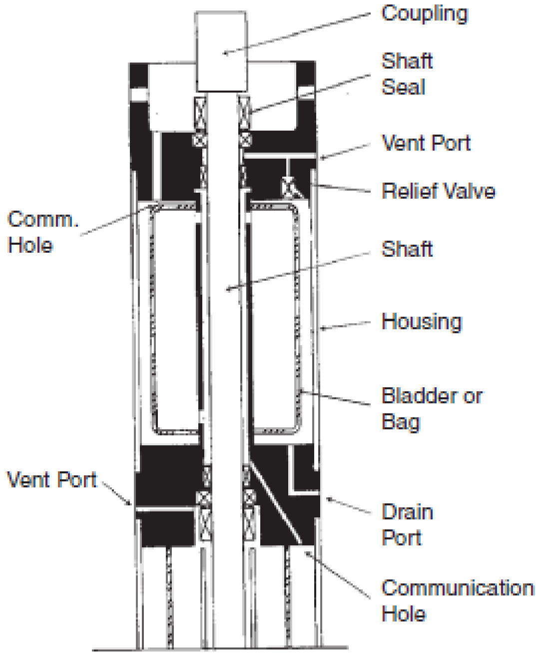


Figure 7: Bag type chamber [3, p. 95]

In its normal operation, the ESP system encounters different upward and downward forces which can be partially or totally transferred to the protector section where the axial thrust is absorbed by the thrust bearing.

The components of a thrust bearing are depicted in the figure below.

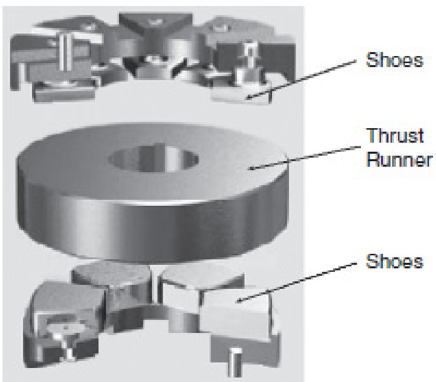


Figure 9:Thrust bearing [3, p. 89]

Electric cable: The three-phase electric power required to operate the pump need to be transmitted from the surface to the electric motor through three wires of the ESP cable, which can be considered as long, thin conductors with a resistance proportional to their length and inversely proportional to their cross-section. A voltage drop occurs along the cable, which should be accounted for when determining the surface voltage supply required to be delivered to the pump.

2.2 Miscellaneous Downhole Equipment

In order to ensure a proper operation of the ESP system, several additional pieces of equipment can be run into the well. Some of these accessories are explained below.

Downhole sensors: Downhole sensors may be installed to continuously acquire real time measurements such as pump intake and discharge pressures and temperatures, motor oil or motor winding temperature, as well as vibrations and current leakage rate. [1, p. 666]

ESP packers: The application of ESP packers is required in cases where the isolation of the annular area above the ESP is needed in order to segregate two separate zones or to reduce the corrosion damage caused by the wellbore fluids to the casing. Typically, unless a vented packer is installed, the use of ESP packers prevents venting the free gas up the annulus. Their design allows for electrical power communication to the motor through an electrical cable feed through, which is a feature added to the normal packer functions. [1, p. 667]

Centralizers: In several cases and especially in cases where the ESP is installed in deviated wellbores, centralizers may be used in order to centre the motor and the pump in the wellbore and therefore allow the ESP to have a standoff clearance and prevent the rubbing of the power cable against the casing string. [1, p. 667] [3, p. 115]

Check and drain tubing valves: Check valves are simple gravity valves that can be installed above the discharge of the ESP pump in order to maintain the liquid column in the tubing during equipment shutdown periods. They prevent downward flow of the fluids and thus the reverse rotation of the pump and the whole ESP unit, which can cause several kinds of damage to the shaft, motor, or cable in cases where unit power is applied during the back spinning of the pump. Whenever a check valve is installed, a tubing drain valve should be used and installed directly above the check valve. Its role is to drain the tubing from the liquid column before pulling the tubing string to the surface. [3, p. 111; 112]

Screens and filters: Screens and filters may be used in some cases in order to prevent the large solid particles from entering the pump intake. One disadvantage regarding this kind of installations is the fact that they can be plugged by solid particles, restricting the flow and limiting the production. In cases where a check valve is installed above the pump, reverse flow cannot be performed and the entire bottom-hole assembly would need to be pulled out in order to clean the plugged ports.

Gas separators: The pump performance is deteriorated due to free gas interference in the pump. Therefore, the use of gas separators is required in cases where the volume fraction of free gas at the intake of the pump cannot be handled by the pump stages alone, and possible problems like cavitation and gas locking may occur. There are two types of gas separators: static gas separators, whose working principle is the gravitational separation by redirecting the fluid flow and allowing free gas to separate and escape into the annulus; and dynamic gas separators, also known as rotary gas separators, which work similarly to a centrifuge. Gas separators are characterized by their separation efficiency, which is the volume of the free gas separated divided by the volume of the free gas at the suction point of the pump. In some cases, gas separators cannot handle the volumes of gas at the intake, which requires the use of advanced gas handlers. [3, p. 99; 100]

Y-tool or Bypass: The Y-tool is an inverted Y-shaped special crossover assembly that allows the intervention below the ESP pump through a bypass. They may also be used in case of dual ESP installations, where two or more ESP systems are installed concurrently in the wellbore. [1, p. 671; 672]

2.3 Influencing Factors on ESP Design

Abrasive solids: Reservoir fluids very often contain abrasive particles, which the standard ESP pump does not tolerate. Catastrophic failures of the pump can be caused due to metal loss at critical points in the pump.

The damage occurring on the pump can be classified into erosion, occurring on the metal surface, and abrasion, occurring between two metal surfaces due to mechanical wear. Many factors influence the magnitude of damage caused by these types of wear: The hardness of the metal and that of the solid particles, as well as the latter's concentration, shape, size, toughness, and particle size distribution. An aggressiveness index can therefore be defined considering all of the said factors in order to depict the relative destructive power of a particular sand sample. [3, p. 156]

Three types of wear affecting the pump stage and its performance can be identified:

- Radial wear: Where the radial-support bushing system of the pump is damaged due to wear causing the pump to lose its lateral stability which eventually increases the vibrations and starts impacting the top of the seal section. In this case, leakage across the sealing face might occur and leads to leakage of the well fluid towards the motor.
- Downthrust wear: Caused by particles between the thrust washer and diffuser pad which induces the lower shroud of the impeller to break and the latter eventually loses a part of its performance efficiency due to recirculation flow.
- Erosion wear: This is the wear that takes place along the flow path of the stages and may be a potential failure mode of the pumps. [1, p. 681]

Generally, some protective measures can be taken in order to decrease the impacts of abrasive wear. Namely, stabilizers can be used for radial support, compression pumps can be employed to avoid downthrust wear, pump stages can be coated in order to increase resistance to abrasion, and screens across the pump intake may be installed… [3, p. 160;161]

GVF at pump intake: ESP pumps are generally designed to handle incompressible fluids and do not compress gas efficiently. Therefore, the presence of free gas at the pump intake affects the performance of the ESP system in several ways.

Generally, as the gas void fraction, also known as gas volume fraction or GVF, increases at the pump intake, the pump-stage head and flow deteriorate. In fact, the presence of gas causes an unstable operation of the pump where heading or surging might occur. The latter can lead to gas locking where no pumping action takes place. In addition, the discharge pressure of the pump can be drastically reduced which means that the head performance of the pump stages is decreased and unstable head production and cavitation can therefore occur. Premature failure of the ESP can also happen due to vibrations. [3, p. 136]

Well fluid properties, pump intake pressure, well temperature, and the pressure drawdown all influence the volume of free gas at the pump intake, which needs to be handled to avoid all the mentioned issues. Several techniques can be applied for the sake of avoiding or reducing the volume of gas at the pump suction. Namely, natural separation of the liquid and gas phases in the casing annulus, which might sometimes be insufficient thus other measures would be necessary. Besides, changing the pump stages from radial flow to mixed flow stages can increase the gas handling capabilities of the ESP pump. Moreover, gas separators or gas handling devices can be exerted as well as special pump types, tapered pumps, and over-staged pumps. The figure below illustrates the application ranges of different gas handling solutions. [3, p. 140]

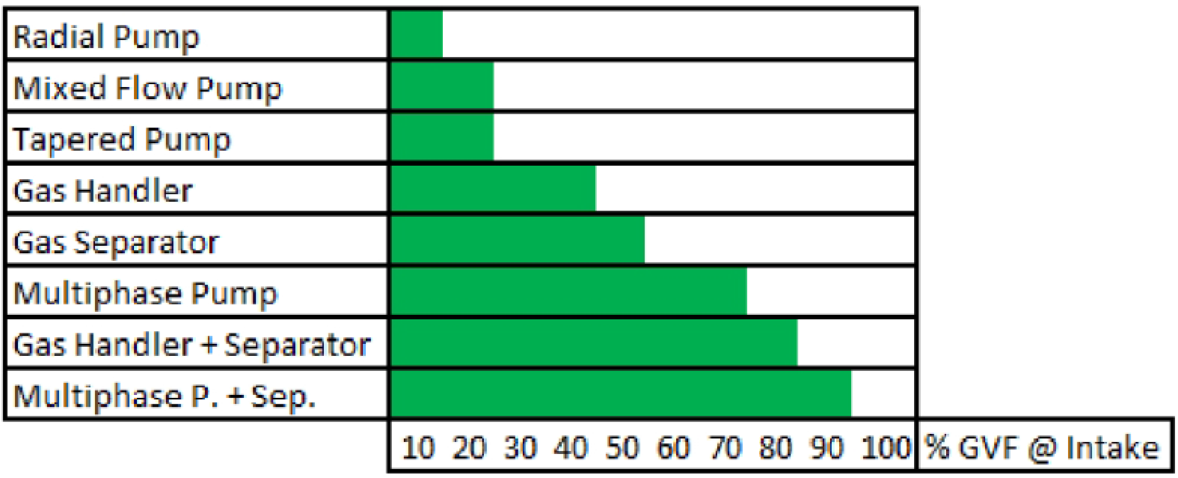


Figure 10: Gas handling application ranges [4, p. 43]

Viscosity: A small increase in well fluids viscosity can lead to additional internal losses in a centrifugal pump due to the resulting resistance. This diminishes the flow capacity of the pump stages. In addition, affected to a lesser extent than the latter, the total dynamic head also decreases with increasing viscosity. Besides, as viscosity increases, the BHP increases rapidly and efficiency eventually decreases. [1, p. 684]

These effects can be overcome by applying certain treatment methods such as water injection, chemical injection, temperature increase, and dilution. Thus the viscosity decreases and the effects are reversed. [1, p. 684]

Temperature: The application of ESP units has been always limited by the wellbore temperature. In fact, the maximum ambient temperature where the standard ESP equipment can be applied is approximately 250°F. Installations above this value can lead to deterioration of the equipment and eventually to its failure. The performance of the equipment is drastically affected by high temperatures and these effects can be summarized as following:

- Strength and service life of sealing elastomers in the ESP units are decreased.
- Burnouts in the motor or the electric cable may be caused due to loss of the dielectric strength of their insulations.
- Power loss in the cable may be increased because of the increase in the electrical resistance of the conductor.
- Dissimilar metals constituting the equipment expand differently, which induces mechanical failure in the rotating machinery.
- It raises the susceptibility of scale formation on the inside and outside surfaces of ESP equipment.

Applications of the ESP system in high temperature well mainly influence the design of the seal section, the power cable, and the motor, which is the most critical component in the ESP unit. This will eventually increase the cost of the unit. [3, p. 166]

Dogleg Severity: Wellbore doglegs above the recommended range can cause premature failures on the pump system by inducing stresses on the assembly during installation.

Pump setting depth: In general, it is recommended to set the ESP as deep as possible in order to obtain the highest possible production rate, to minimize the volume of free gas at the pump intake, and to reduce the risk of pump-off in case the liquid level is uncertain. However, with increasing setting depth of the pump the installation and running costs increase, and the risks of damage during the installation and of plugging due to solids are higher. The pump setting depth can also be limited due to wellbore restrictions, well trajectory, operating temperature, and motor voltage requirements. Therefore, one should take into account all the mentioned factors to choose the optimum pump setting depth.

Corrosive fluids: CO_2, H_2S, and some types of bacteria can be major sources of corrosion. ESP units are usually protected against CO_2 corrosion by using protective coatings or by using high-chromium alloys in the components exposed to corrosion. Copper-based alloys of the ESP equipment are mainly attacked by H_2S. Therefore, to control this type of corrosion, the latter should be replaced by suitable materials or isolated from the wellbore fluids. [1, p. 686]

Scale, paraffin, and waxes: Scale, paraffin, and asphaltenes can be adverse to the performance and run-life of the entire ESP system. On one hand, scales can plug the flow paths of the pump stages as well as precipitate on the outside surfaces of the motor and protector section, which reduces the cooling capability of the two units causing both to run hotter. On the other hand, asphaltenes can only cause the blocking of the pump stages. Although it is not possible to eliminate them, the reduction of these problems can be accomplished by applying synthetic coatings to the surfaces affected or by injecting chemical inhibitors. [1, p. 686]

2.4 Advantages and Limitations

There are several advantages for the application of electrical submersible pumps. In fact, they require minimal space in terms of surface equipment, they are quiet, safe, and sanitary, which make them well suited to the offshore environment and urban areas where little surface space is available or environmental regulations are strict. In addition, it can be installed in highly deviated up to horizontal wells, provided that it is set in a straight section. ESPs also require low maintenance as long as the installation was designed and operated properly. Besides, performing corrosion and scale treatments is relatively easy. ESPs are produced in different and diverse diameters allowing for a wide range of flow rates in order to optimize the lift and the head that can be produced from various casing sizes. Their energy efficiency is relatively high for systems that produce more than 1000 bpd. [1, p. 417] [3, p. 7]

Nevertheless, ESPs suffer from several limitations. As a matter of fact, a reliable source of electric power of relatively high voltage must be available to ensure the proper operation of the ESP. Furthermore, standard equipment is limited to approximately 250°F, which makes the temperature a limiting factor. In case of higher temperature, the use of special material is required and can increase the temperature limit to about 400°F. Additionally, ESPs are highly sensitive to sand and abrasive materials in well fluids. These solid particles can easily damage the moving parts of the pump, which shortens its life expectancy. The use of special abrasion-resistant materials would be required in this case, but it would increase the capital costs of the pump. Even though ESPs are also used to lift viscous fluids, increasing viscosity would increase the power requirements and reduce the lift of the pump. Besides, the performance and efficiency of the pump are drastically affected by the presence of free gas in the produced fluid. Free gas can cause an unstable pump operation where surging or heading occurs, which can even lead to cavitations or gas locking where no pumping action takes place. If more than 20% of free gas enters the pump, it is required to use gas separators or gas handlers, which again increases the capital costs. Another disadvantage that ESP systems have is the high workover costs, which sometimes makes it uneconomical to use ESPs as the artificial lift system especially in cases where the mean time between failures is short and in regions where the workover rigs are not available or very expensive; offshore environments for example. [1, p. 417;418] [3, p. 8]

The industry has been looking for other alternatives and innovations to develop robust system designs that will extend the applicability of electrical submersible pump systems in order to overcome the challenges that they encounter, to improve the design reliability, to increase the ESP run life, and to improve the economics of ESP systems.

One of the developments that have been investigated is alternative and more cost-effective deployment methods of the ESP system. This mainly consists of rig-less interventions to deploy and pull the downhole equipment using low-cost standard slick-line, coiled tubing, or downhole tractor conveyance. This rig-less ESP design would allow the deployment or retrieval of ESP assemblies in a matter of hours, minimizing the high rig expenses as well as the production losses. The rig-less deployment of ESP systems is going to be further explained and focused on in the following parts of the thesis.

3 Rig-less ESPs

3.1 Conventional ESP Deployment

The conventional and most common ESP configuration is basically the installation that had been described previously, where the ESP assembly is mounted to the tubing whereby the connection for production is provided. The electric motor is at the bottom of the assembly where it is cooled by the well fluid passing by its perimeter. On top of the motor, the protector section is located providing seal and protection for the safe operation of the system. Above the latter, the pump intake or gas separator is situated, wherefrom well fluids can enter the centrifugal pump, the heart of the ESP system, where pressure energy is transmitted to the fluids allowing them to be lifted to the surface.

One issue related to this tubing deployed installation is the fact that a workover rig is always required to retrieve the ESP assembly in case of failure or sub-optimal performance. In some cases, the unavailability of workover units, their high cost, or the short mean time between failures (MTBF) of the ESP system can decrease the profitability of the well and its economic limit.

This is exactly the major problem in the country, where workover rigs are not always available and therefore are very expensive. Combined with a low MTBF of the ESP system and a long waiting time for intervention, where production is deferred, these tremendously affect the economics of the ESP operations. Therefore, the objective is to find new deployment means that reduce the operational expenditures in order to extend the economic lifetime of the wells and increase their profitability.

3.2 Rig-less ESP technologies

As mentioned before, rig-less ESP technologies were and are being developed due to the fact that conventional tubing deployed ESP systems may significantly affect the economic profitability of the wells because of high workover costs or workover rigs unavailability in some cases, which is the situation in the studied field.

Rig-less deployed ESP systems do not require a workover rig for the pull-out-of-hole (POOH) or run-in-hole (RIH) of the downhole ESP assembly in case of failure or sub-optimal performance. Instead, coiled tubing, slick-line, or wireline units are used for the intervention depending on the employed technology.

Three different methods of rig-less deployed ESP systems are available nowadays. These are: Coiled tubing deployed, wireline deployed, and power cable deployed ESP systems.

Coiled tubing and wireline deployed ESP technologies can be found in the master thesis done by Sebastian Barnabas Buha in collaboration with OMV in 2014 as a further reference, where he did a detailed description of both technologies, their limitations, the minimum well requirements, as well as a high level economical comparison between conventional and rig-less ESP installations.

Power cable deployed ESP systems, on the other hand, are a rather newly developed technology that is being developed and will be described in more detail in a following subchapter.

3.2.1 Coiled Tubing deployed ESP system

The application of coiled tubing deployed ESP systems consists in lowering and retrieving the bottom-hole ESP assembly with coiled tubing. Therefore, only a CT injector unit is used for the RIH and POOH of the ESP assembly instead of a workover rig. There are four different possible installations of the assembly which are depicted in figure 11 below.

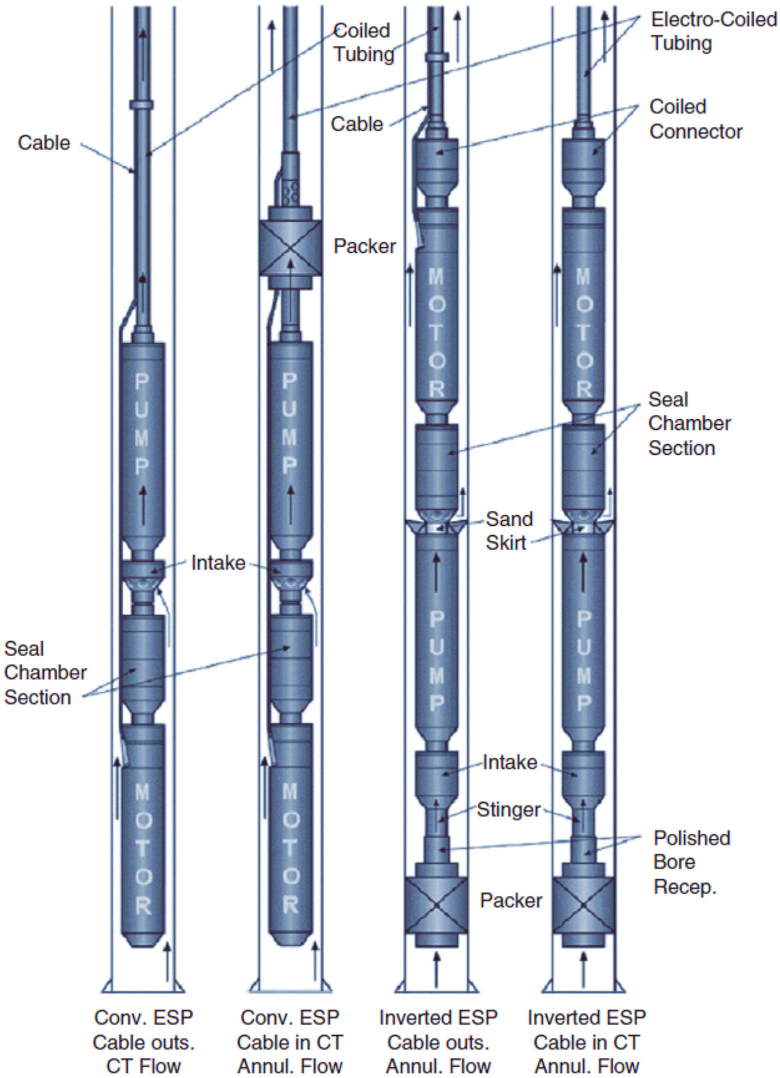


Figure 11: Different coiled tubing ESP installations [3, p. 352]

ESP units with cable led outside the CT string: In these installations the electric power cable is clamped to the coiled tubing string. Both conventional and inverted ESP installations are possible. Using a conventional ESP unit, the production of the wellbore fluids can be done through the coiled tubing. Therefore, in this case, the installation is typically simple and identical to the conventional ESP installation with the only difference being the use of a CT string instead of a conventional tubing string. On the other hand, the installation of an inverted ESP system, where the electric motor is located at the top with the pump below, doesn't allow production through the CT string due to the inverted arrangement, and therefore annular production is required. This is done through a modified discharge head that directs the fluid flow into the annular space. The use of a retrievable packer is also needed in this case in order to isolate the pump's suction and discharge sides. One advantage of the inverted ESP configuration would be the elimination of the need for a motor lead extension (MLE), which represents the most vulnerable part of the ESP power cable.

Advantages of the external cable CT deployed ESP systems can be illustrated in the fact that conventional ESPs, conventional vertical x-mas trees, and standard CT equipment are used, therefore no special equipment are required except for the connection between the pump assembly and the CT string and in case of inverted ESP configuration. In addition, it enables a fast deployment of the retrievable ESP assembly compared to the conventional tubing deployed ESP systems, which also reduces the operational expenditures.

However, due to the small coiled tubing ID, the depth and rate are limited because of the induced high friction pressure losses, which also increases the motor power required. Furthermore, it should be taken into account that both a CT spooler and a cable spooler are required for this type of installations, which might yield to space restrictions on the well site causing a problem, especially in the case of offshore platforms. Additionally, as the power cable needs to be band on the CT string, the running and pulling speeds are limited and the use of a snubber or lubricator system is not possible, which eliminates the possibility of live-well interventions. Another issue that should be accounted for is corrosion. In fact, CT strings are manufactured out of carbon steel and are usually not intended for long time period applications, which increases the corrosion potential compared to normal tubing strings. The application of corrosion inhibitors and corrosion resistant material is possible but for additional costs.

ESP units with cable led inside the CT string: Installations that use an internal cable CT deployed ESP comprise an electric power cable pre-installed within the coiled tubing string and therefore protected against mechanical damages and damages caused by wellbore fluids. Control lines can also be included alongside the power cable. Figure 12 illustrates the CT with the power cable led inside.

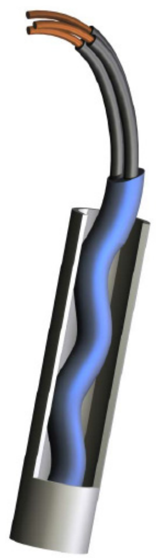


Figure 12: CT with ESP cable led inside [6]

Both conventional and inverted ESP assemblies are possible. In both cases, wellbore fluids flow through the annular space to the surface and the application of packers is required in order to isolate the intake and the discharge of the pump.

Since the power cable is internally pre-installed, and there is no need of clamping it to the CT, the maximum allowable running and pulling speeds of the CT can be applied, which decreases the intervention time compared to the external cable CT deployed ESP systems. Moreover, it would be also possible to perform live-well interventions and avoid expensive well killing operations.

One disadvantage of this technology is the increased weight of the downhole assembly due to the combination of the CT string and the power cable. One other limiting factor could be the maximum length of the CT due to its unconventional manufacturing process. Similarly to the previous technology, corrosion may represent an issue. As a matter of fact, in case of damage of the CT string, wellbore fluids can flow to the surface through the CT, where no safety barrier can avoid such issue.

3.2.2 Wireline deployed ESP system

Similarly to the other rig-less ESP deployment methods, wireline deployed ESP systems are developed as an alternative deployment technology that would reduce the workover requirements and costs in some cases. Two different modalities are available for the wireline deployed ESP systems. These are: the through tubing conveyed ESPs and the wireline deployed ESPs. Both technologies include some permanently installed components and other retrievable components that can be RIH or POOH with a wireline or a coiled tubing.

Through tubing conveyed ESP systems: A permanent assembly generally composed of the motor, a seal, the production tubing, and the power cable being clamped to it, is installed in the wellbore. While on the other hand, the pump is lowered through the tubing using a wireline or coiled tubing. A mechanical connection is established between the ESP and the seal downhole, whereas the wireline or the coiled tubing is retrieved before starting production. [5, p. 3]

Some limitations can be encountered using this type of installation. Namely, as the permanent components of the pumping system, including the motor, are installed at the end of the production tubing, reservoir access is not granted, which eliminates the possibility of performing well interventions that require reservoir access without a workover rig. In addition, in case of failure of the motor or the power cable, the retrieval of the whole downhole assembly using a workover rig is required. Furthermore, a specially manufactured pump is needed for such applications, which causes long waiting times for pump delivery from the vendor in case of pump failure.

Wireline deployed ESP systems: Similarly to the TTC ESP system, the production tubing, with the ESP power cable externally clamped to it, is permanently installed into the borehole. This configuration requires an electrical connection to the retrievable ESP assembly (including the motor at the bottom) to be made downhole. This is carried out through a three-phase, high voltage wet-connection system. The latter consists of two components, one of which is permanently deployed in the well, while the mating component is fixed to the ESP assembly at the base of the motor. Landing and locating devices are installed in some configurations in order to hold the ESP in place, to align the connectors for a successful mating, to locate the ESP at the correct depth, and to prevent it from counter-rotating during start up. [5, p. 3;4]

A standard ESP system is used for these kinds of installations, which allows rapid response to unexpected failures. The weak points of this deployment method are mainly the permanent installation of the power cable and the injection lines, which requires a workover rig in case of failures, and the uncertain reliability of the wet connection.

3.2.3 Power Cable deployed ESP system

In the early 1970s, cable suspended units were introduced by Arutunoff, where a conventional ESP unit is suspended at the end of an electrical cable, which is specially manufactured and reinforced in order to resist the stress caused by the weight of the assembly (figure 13). A pump shoe at the end of the production tubing carries the weight of the unit and provides seal between the suction and discharge of the pump. The well fluids are produced to the surface through the tubing string. The application of such installations was limited to shallow wells due to the restricted strength of the electrical power cable. In addition, it was expensive to manufacture and more complicated to lengthen the cable due to its dual functionality of carrying load and electricity. Besides, special tools and handling are required for these special reinforced cables. [3, p. 350;351]

To overcome these limitations, some companies tried to optimize the cable deployed ESP system, namely NOVOMET, who succeeded in introducing its new product Colibri, a cable deployed ESP, which will be further explained in a following subchapter.

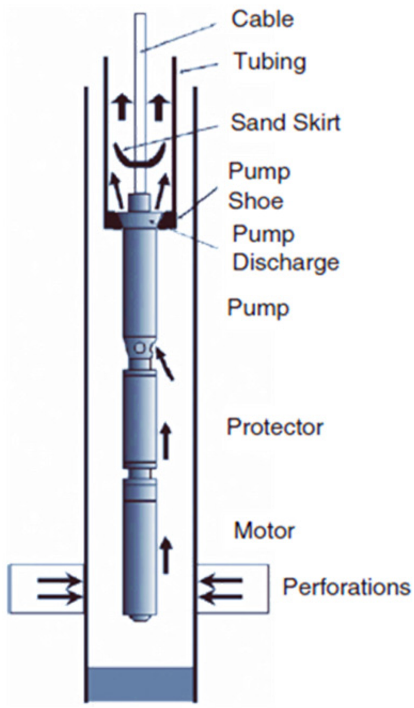


Figure 13: Arutunoff cable suspended ESP installation [3, p. 351]

3.3 Available Suppliers & Key Specifications

Different suppliers are available for the diverse technology types. They were contacted to provide additional information for the sake of the thesis. Those who gave a feedback are summarized in table 1 below.

Table 1: Available rig-less ESP suppliers

Technology	***Coiled Tubing Deployed ESP***		***Wireline Deployed ESP***	***Power Cable Deployed ESP***
	Cable External	***Cable Internal***		
Suppliers	*Schlumberger*	*Schlumberger* (REDACoil)	*Schlumberger* (ZEiTECS) *AccessESP*	*NOVOMET* (Colibri)

Each technology, as well as its key specifications, for each supplier is going to be further explained in the following subchapters.

3.3.1 Schlumberger External Cable CT deployed ESP system

This technology consists in a cable external coiled tubing deployed ESP, where the power cable is clamped onto the CT. The production path is therefore through the small ID coil, which means that this system is generally suited to applications in shallow lower flow rate wells.

Figure 14 illustrates the external cable CT deployed ESP system.

A standard ESP system is used in this installation, where the ESP is assembled similarly to the conventional ESP system. ESPs are available from 338/375 series upward, and for a minimum casing size of 4-½“.

Using a CT connector, the CT is mechanically connected to the standard threaded discharge head at the top of the pump. A similar CT connector is used at the surface to connect the CT to the tubing hanger and a conventional vertical ESP production tree can be used.

The application of a gas separator is possible as the fluid flows through the coil and the gas would be vented from the annulus. An advanced gas handler or a multiphase gas handler is possible to be installed as well.

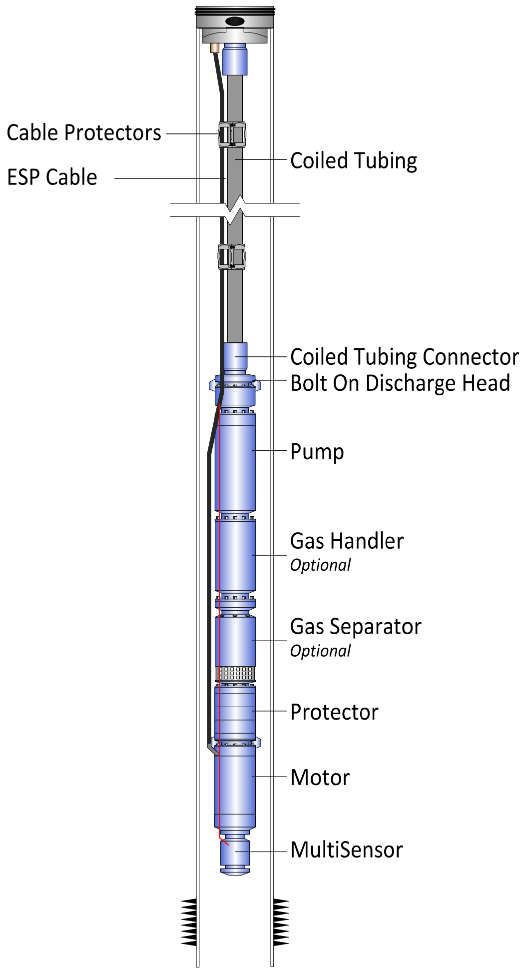


Figure 14: Schlumberger external cable CT deployed ESP system [6]

Maximum bottom-hole temperatures and pressures are application dependent. The standard equipment is rated to 302°F (150°C) and 5,000psi, which can be extended if required.

For this application, any CT can be used, where the size selection would primarily be based on the required tubing size for the desired outflow considering the friction pressure losses, as well as the limits regarding length and OD due to the availability of the CT equipment, the shipping, the weight, etc. A coiled tubing modelling software can be used to analyse the wellbore profile, to check the forces and stresses on the CT to ensure its applicability, and to check if the required ESP setting depth can be reached, without the CT becoming helically buckled. [6]

3.3.2 Schlumberger REDACoil ESP

The REDACoil technology is a cable internal CT deployed ESP system which comprises inverted ESP equipment with a power cable pre-installed within the coiled tubing. This system provides a larger flow area, which makes it suitable for higher flow rate applications.

The system uses 'standard' coiled tubing, which is more cost effective than alternative solutions. Typically, it uses a 2-3/8" coiled tubing, with a pre-installed #2AWG ESP cable supported by friction, where it forms a natural helix inside the CT to support its own weight. This means that the system is tolerant to differences in coil and cable length that may be caused due to temperature changes, pressure effects, and mechanical effects during deployment. [6]

The current REDACoil equipment is based on 538/540/562 series ESPs. These could be run directly into 7" casing depending on environment and permissible barriers, or into a 7" tubing string completion with a 9-5/8" production casing. Smaller series REDACoil ESP equipment, for smaller casing and tubing completions has been partially developed and is awaiting commercialization. These are illustrated in the figure below. [6]

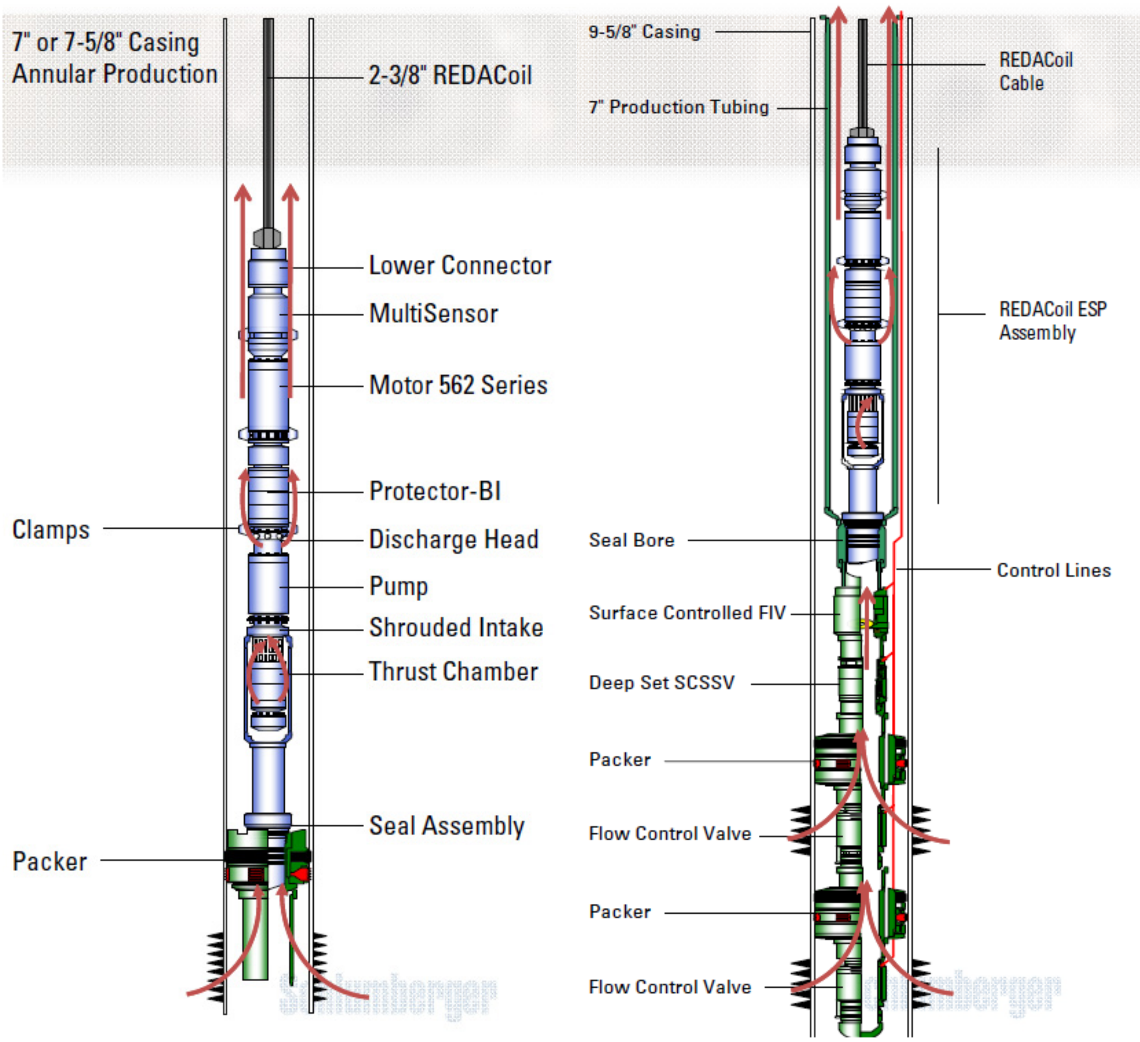


Figure 15: REDACoil possible installations [6]

The longest REDACoil made to date has been 10,000ft long, and was deployed in Norway. For any application, CT modeling software can be used to determine if the required ESP setting depth can be reached. The coiled tubing software analyses the well bore profile, checks the forces and stresses on the coiled tubing to ensure its suitability for the application, and checks that the ESP can be deployed to the required depth without the CT becoming ‘helically buckled’. [6]

The maximum bottom hole temperature depends on the application. The required operating current for the motor will effect the maximum temperature rating. In addition, the heat rise calculated for the application is dependent on variables (temperature, efficiency, fluid velocity, density). However, generally the standard equipment is rated up to 302°F (150°C), which can be extended if required. [6]

Similarly, the maximum bottom-hole pressure is application dependent. But generally, for standard equipment it would be rated to 5,000psi. [6]

In typical REDACoil completions, it is not possible to include a gas separator as the production flow path is annular, i.e. outside of the CT. The flow path for vented gas from a gas separator needs to be isolated form the pump discharge, and this would not be the case. Nevertheless, either an advanced gas handler or a multiphase gas handler can be included in the installation. [6]

Typically standard grades of coiled tubing are used (HS80 or HS90). These grades are low alloy, which have excellent resistance to H_2S, but are not suited to CO_2 environments. In cases of high levels of CO_2, corrosion inhibitors need to be injected continuously, or a strategy of elective pulls after a certain period can be employed. Alternatively, use of CRA coiled tubing could be investigated although the cost would increase significantly. [6]

For REDACoil, a modified tree arrangement is used which has a horizontal production outlet below the coiled tubing hanger. The latter is illustrated in the figure below. [6]

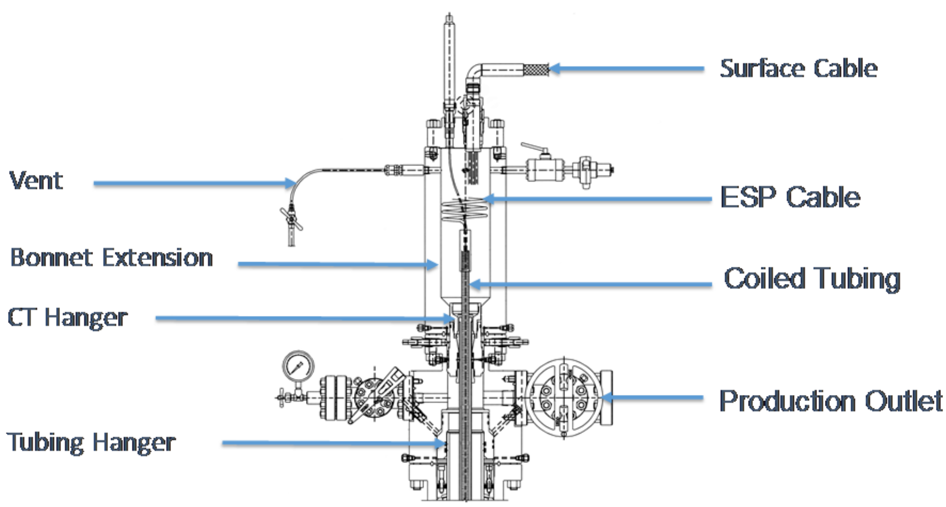


Figure 16: Xmas tree arrangement for REDACoil [6]

The REDACoil system has been implemented in 38 wells. These projects were located in the UK, Qatar, Brunei, Venezuela, Norway, and Malaysia. The largest project was in Qatar where 21 wells were completed with REDACoil in one offshore field. It has been active for more than 20 years where several ESP replacements were performed. In total, over 200 ESP deployments have been performed over the 38 REDACoil wells. [6]

The REDACoil systems in Qatar are running in a corrosive environment due to high CO_2 and H_2S. In some cases, elective pulls are performed to replace the coil tubing after a set period to avoid corrosion. The advantage of the REDACoil system is in enabling ESP replacements to be completed quickly, and without waiting for a conventional workover rig.

Some run-life data from Qatar is shown below. Current MTBF is approximately 700 days. However, these data are not corrected for elective pulls.

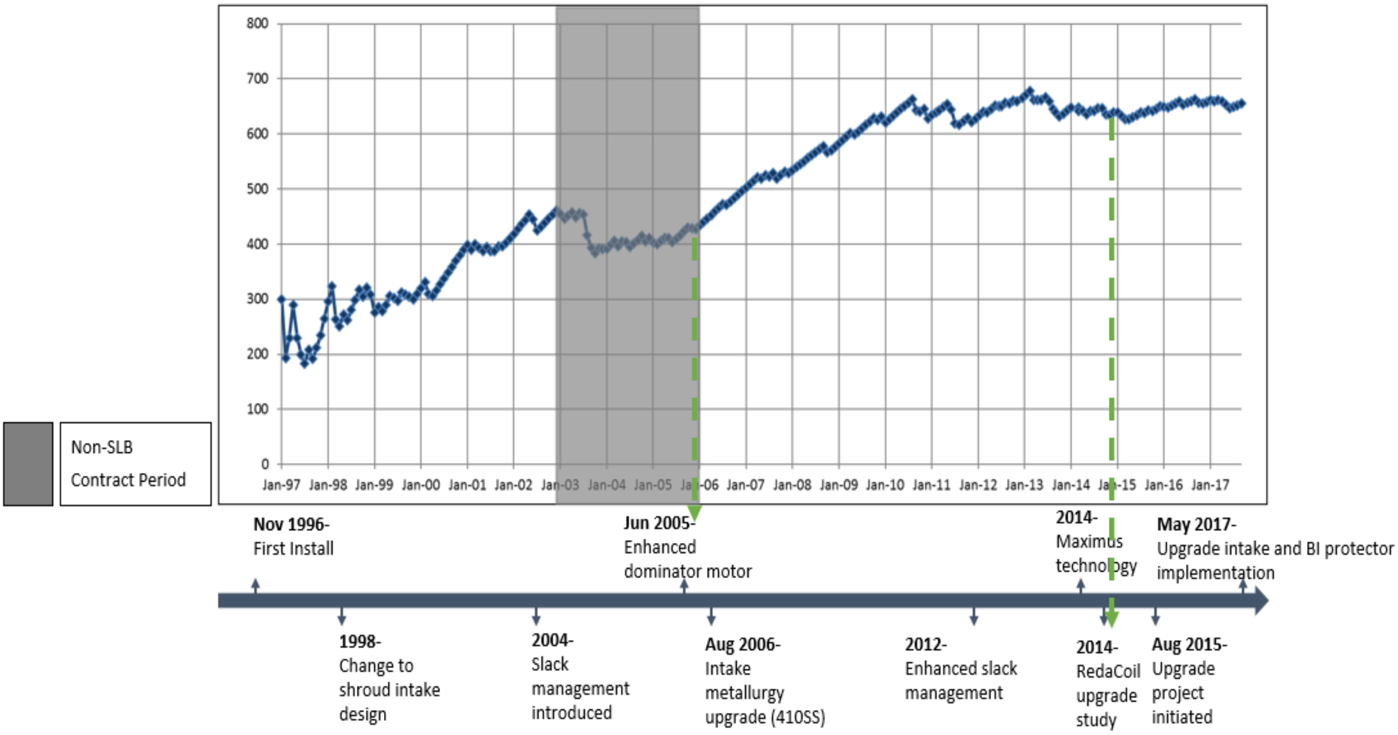


Figure 17: Run-life data from Qatar [6]

Schlumberger has the largest track record of REDACoil systems. The ESP equipment has been continually improving since its introduction to the industry. The most recent updates have included the upgrading of the REDACoil ESP to maximus connections, which are the standard for Schlumberger's conventional ESP equipment, the improvement of the lower connector design with pressure testable flanges for integrity testing during field make up, and the improvement of the flow area to reduce erosion (the REDACoil intake has a smaller OD than the standard ESP, due to the requirement for intake to be within a shroud). [6]

3.3.3 Schlumberger ZEiTECS Shuttle

The ZEiTECS shuttle system is a wireline deployed ESP system illustrated in the figure 18.

The system consists of essentially a docking station equipped with a wet connector, a slip-lock assembly, a semi-permanent tubing with the power cable clamped on it, and an ESP system run through the tubing.

The ESP can be run with an induction motor running at standard frequencies or with a permanent magnet motor supplied by Schlumberger running at high frequencies. [6]

To date, 14 successful commercial installations and two installation failures had been made. In addition, 13 successful replacements in the commercial wells had been carried out. More than 15 systems are currently in various locations awaiting deployment. Only two failures linked to permanent power delivery system had been registered, one linked to the failure of the split-phase penetrator (human error during assembly) and one to mechanical damage to the wet-mate connector; the root cause of failure is not yet known. No failure of the cable had been observed with over 13,000 operating days on the installed systems. [6]

The system is 5,000 psi rated. This defines the maximum TVD of installation based on hydrostatic pressure at ESP setting depth. [6]

The wet connectors are rated to 302°F (150°C) maximum conductor temperature. Hence, the maximum bottom-hole temperature of 250°F (124°C) is recommended. [6]

The connectors are rated to 5,000V, 125A, limiting the maximum horse power to 700hp. [6]

The maximum length of the wireline/slick-line used for the rig-less deployment of the ESP system depends on the type of the braided line and mast capacity used for installation, but it can be up to 15,000ft, if required. [6]

The installation of a gas separator is possible provided the annular gas production is allowed. The application of an advanced gas handler is also possible.

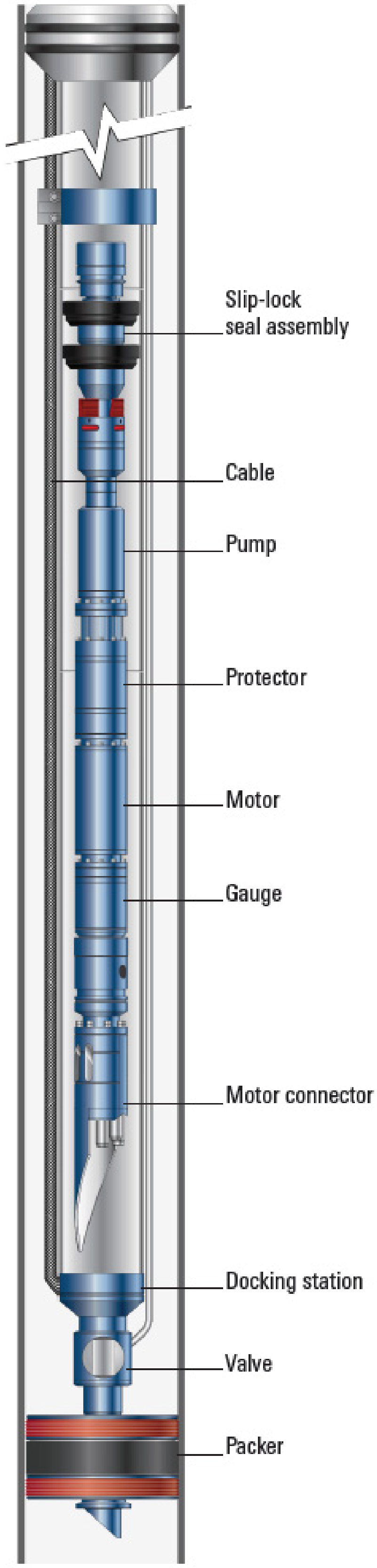


Figure 18: ZEiTECS shuttle rig-less ESP replacement system [6]

The materials used in the shuttle system are mainly 13Cr L80, which dictates application limits. Other system specifications are listed in table 2.

Table 2: ZEiTECS shuttle system specifications [6]

	450/500	***550***	***700***
ESP size, series	338/375	400/450/456	513/538/540/562
Min. casing size, in	7	7-5/8	9-5/8
Max. casing weight, lbm/ft	35	26	53.5
Min. tubing OD, in	4.5	5.5	7
Max. tubing weight, lbm/ft	12.6	17	29
Drift through diameter of docking station, in	2.12*	2.99**	1.69
Max. OD of semi-permanent components, in	5.875	6.210	8.571
Max. OD of retrievable components, in	3.823	4.767	6.055

*Rigid tool passage, in: 1.93
** Rigid tool passage, in: 2.55

The ESP Shuttle requires the wellhead, the x-mas tree, and the BOP (if used) to have an internal bore similar to that of the production tubing. In general, if a vertical tree is used, it should correspond to the internal bore of the production tubing, i.e. 7-1/16” API tree for the 700 series, 5-1/18” API tree for the 550 series and 4-1/6” API tree for the 450 series shuttle.

In addition, both tubing hanger and adaptor flange above may require to be eccentric to accommodate standard ESP cable wellhead penetrators. This restriction does not apply in cases where:

- An additional casing spool is introduced below the tree,
- A 550/450 series ESP shuttle with 5.5” or4.5” tubing is installed in a 9-5/8” casing, or
- The wellhead and the tubing hanger designs assume the use of split-phase penetrator systems.

An examination by the operator and the supplier is required to determine whether eccentric or concentric tubing hanger and adaptor flanges are required. It is also important to verify the existing wellhead and tree systems in order to determine whether surface set-up modifications are required and whether they are possible.

A rough estimation of the ZEiTECS shuttle cost would be between 250k and 400k EUR plus the price of the ESP and the tubing joints.

3.3.4 AccessESP Wireline deployed ESP system

AccessESP provides a wireline deployed ESP system where the ESP should be provided by another supplier. The AccessESP system consists of a semi-permanent completion and a retrievable assembly. The semi-permanent completion is deployed with the tubing string. The retrievable assembly is designed to be removed and redeployed through tubing with conventional light intervention equipment. [7]

AccessESP provides two types of semi-permanent completions; these are:

- Annular connection port (ACP): It draws fluid through a perforated intake into the tubing string from the annulus similarly to a conventional ESP. This system allows gas to be diverted to the annulus, reducing the amount of gas that must pass through the pump. The ACP is compatible with casing sizes of 7”, 29 ppf and larger. [7]

- In-line connection port (ICP): Consists of an ACP with an integral ‘shroud’. This configuration draws fluid from below the ICP and does not expose the annulus to produced fluids (dead annulus). With the ICP all production fluids, including gas, must pass through the pump. The ICP is compatible with casing sizes of 9-5/8” and larger. [7]

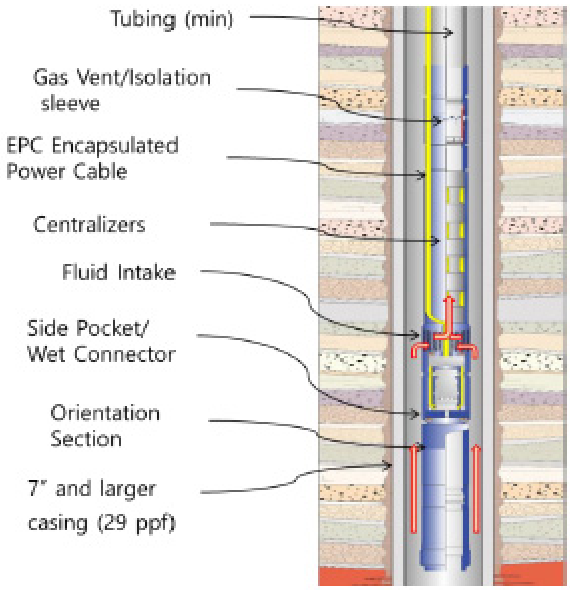


Figure 19: ACP completion [7]

The two systems are functionally identical, the only difference is the location and configuration of the pump intake. [7]

Access ESP offers 2 options for the system. These are Access375 and Access450. The Access375 system is designed for 4-1/2” tubing or larger.

AccessESP works with and can integrate all major providers’ pumps. Typically, in a 7” casing, 338 series pumps are used, reducing the OD to 3.80” to fit inside 4-1/2” tubing.

It is also possible to install a gas separator if annular gas production is possible. And the installation of an AGH is also possible.

The retrievable string of an Access375 system is illustrated in the figure 20, where all components are listed along with their supplier, length, and maximum OD.

Run	Make-up	Description	Supplier	Length feet	Max O.D.
Run #4 1.25 ft		**Tubing Stop** 4.0" GS Profile	AccessESP	1.25	3.72
Run # 3 5 ft		**Tubing Packoff** 4.0" GS x 2-7/8" 10rnd NU box	AccessESP	2.83	3.72
		Standing Valve 2-7/8" 10rnd NU pin x box	AccessESP	1.32	3.72
		Stinger 2-7/8" 10rnd NU box	AccessESP	0.88	3.72
Run # 2 Typically 40 – 45 ft	Make-up 2b Typ. 15 – 25 ft	**PBR** 4.0" GS x 2-7/8" 10rnd NUB box	AccessESP	2.10	3.72
		Crossover pin x pin	AccessESP	1.50	3.72
		Pump	ESP Provider	TBD	3.80
	Make-up 2a Typ. 15 – 25 ft	**Pump Intake**	ESP Provider	1.00	3.80
		Upper Mating Unit	AccessESP	1.29	3.75
Run # 1 39, 46 or 53 ft, depending on Motor size	Make-up 1b 23, 30 or 37 ft	**Lower Mating Unit**	AccessESP	1.31	3.75
		Upper Seal / Protector Section	ESP Provider	6.10	3.75
		Lower Seal / Protector Section	ESP Provider	6.10	3.75
		Access375 Permanent Magnet Motor 130 HP 250 HP 400 HP	AccessESP	 9.10 16.40 23.70	 3.75 3.75 3.75
	Make-up 1a 16 ft	**ESP Gauge**	AccessESP	3.38	3.75
		Plug Arm Assembly c/w Female Wet Connect	AccessESP	11.83	3.75
		Motor Guide	AccessESP	0.5	3.75

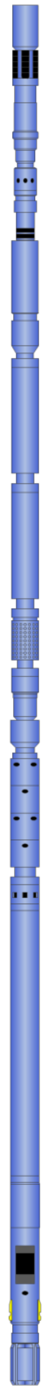


Figure 20: Retrievable components [7]

The AccessESP is rated to a maximum bottom-hole temperature of 150°C and a maximum bottom-hole pressure of 517bar, or 7,500psi. In addition, it not limited in terms of inclination, as there were successful installations up to 90 deg. At this inclination, the deployment is no longer possible with slickline, therefore, a CT or a wireline tractor has to be used. [7]

Installations in excess of 9,000ft TVD are being discussed. However, in deviated wells, the effective length can be 2 to 3 times the TVD, where installations at 19,000ft MD are also being discussed. [7]

AccessESP has not experienced any cable failures on the 10 commercial systems installed. This is due to the fact that the power cable is enclosed inside 3/8” Incalloy 825 steel tubes, which are oil filled and pressure compensated. This ensures a constant internal overpressure and thus avoids ingress of well fluids. [7]

As depicted in the figure 20, the AccessESP system uses permanent magnetic motors, which are more efficient than the traditional induction motors but are relatively new to the industry so it is impossible to prove their long term reliability. There are several options for the PMM motors. These are summarized in the table below. [7]

Table 3: PMM motors specifications [7]

System size	***Power [HP]***	***Length [ft]***	***Weight [lbs]***
Access375	130	9	250
3.75 in	250	16	450
(4.5/5.5in tubing)	400	24	620
Access450	400	17	620
4.5in	800	32	1,200

AccessESP has located the wet connect system in a side pocket mandrel outside the main tubing bore, leaving it with no obstruction. In addition, the wet system has a spring loaded protective cover that slides over the wet connector when the ESP is disengaged. This allows for major through-tubing operations to the producing zone when required, and doesn’t allow sand accumulation in the tubing which prevents any sand related issues when connecting and disconnecting the ESP. The wet mate connector can be seen in the figure below. [7]

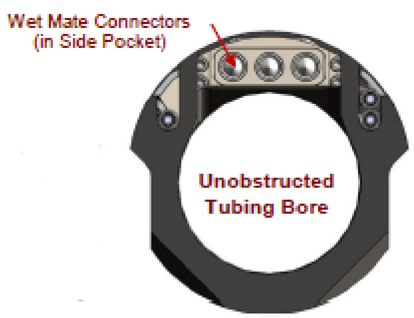


Figure 21: Wet mate connector and tubing bore [7]

3.3.5 NOVOMET Colibri ESP

The Colibri ESP manufactured by NOVOMET is a cable deployed ESP. It is a rather new technology to the petroleum industry where five installations have been performed as shown in the table below. [8]

Table 4: Colibri installations [8]

Location	*Client*	*Depth*	*Installation date*	*Pull Date*	*Remarks*
USA	Par Development	3,700 ft	31/08/16	05/10/16	Onshore
Russia	Slavneft	1960m	24/80/16	23/09/16	Onshore
Russia	Slavneft	1960m	09/12/16	20/02/17	Onshore
Romania	OMV Petrom	1200m	29/11/16	25/10/17	Onshore
Malaysia	Petronas	35-40m	02/11/16	03/11/16	Pilot
Malaysia	Petronas	550m	24/05/17	running	Offshore

The system is rated to a maximum bottom-hole temperature of 150°C, where the main limit is the power cable. A prototype was produced with a design handling 200°C. The maximum bottom-hole pressure is limited to 320 bar, 4,640psi. And while accepted maximum TVD is 15,000ft, the maximum that have been really reached is 1,960m. [8]

The maximum allowed inclination that the system allows is 50 deg. But future new developments will enable installation at up to 90deg. [8]

The installation of a gas separator is not possible but it is possible to install an advanced gas handler. [8]

New solutions were developed without needing any x-mas tree upgrades. However, a special carrying cable is needed to carry the load an provide electricity to the PMM motor used in the system. The carrying power cable has three c copper conductors and steel wires inside as depicted in figure 22. [8]

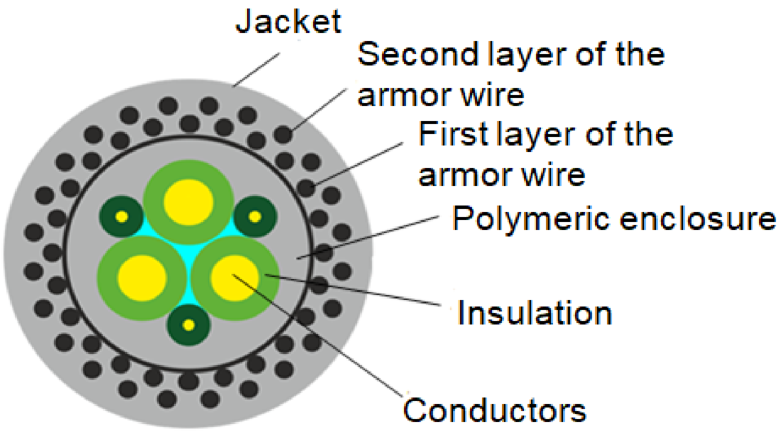


Figure 22: Carrying cable [8]

The cable is an AWG#8 cable and has a nominal diameter of 0.77”. Its breaking load is rated to 18,000lbf and weights 0.68 lbs/ft. [8]

NOVOMET offers 3 ESP series. These are 217, 272, and 319 series. Only the 217 series was tested, and the other two are to be announced in the future. [8]

The Colibri ESP 217 is set inside the tubing with a minimum size of 2-7/8”. The maximum ESP OD in this case is 2.17”, whereas centralizers can be larger in diameter depending the tubing ID. A Colibri ESP 217 series is illustrated in the figure below. [8]

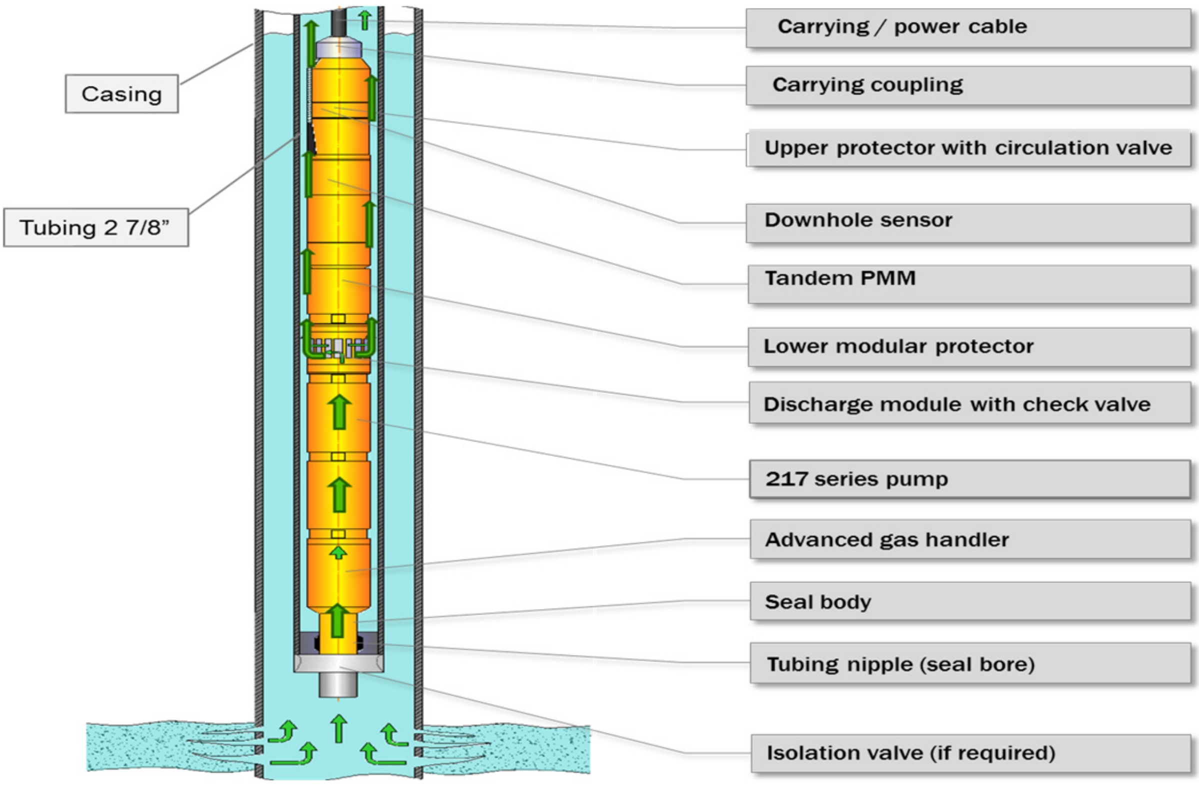


Figure 23: Colibri ESP 217 series [8]

This system is limited in terms of the load that the power cable has to carry and of the ESP size. This restricts the installation depth and the production rates.

The Colibri ESP runs with a tandem permanent magnetic motor with a nominal power of 110HP at 8500 RPM. In fact, order to be able to deliver a higher head and a higher flow rate, the ESP needs to run at a high frequency compared to conventional. This would cause major issues in case of sand production in the well. [8]

217 series pump curves of 109 stages at 3000 RPM (50 Hz) and 8500 RPM (140 Hz) are shown in figures 21 and 22. [8]

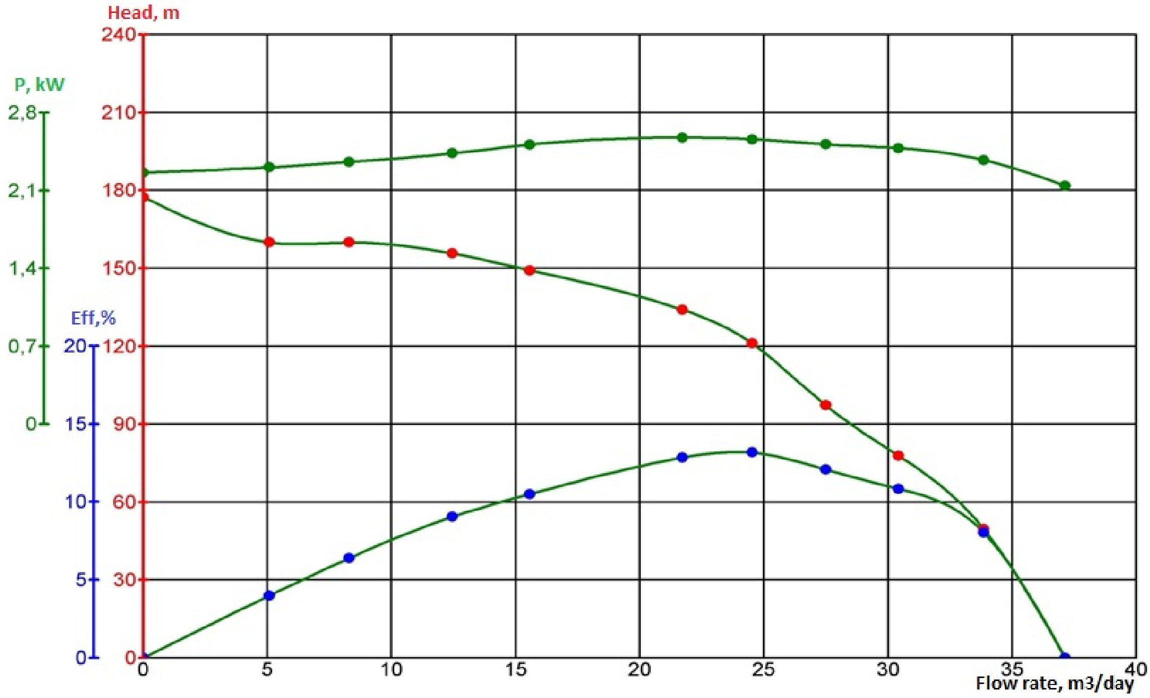


Figure 24: 217 series pump curve 109 stages at 3000RPM (50 Hz) [8]

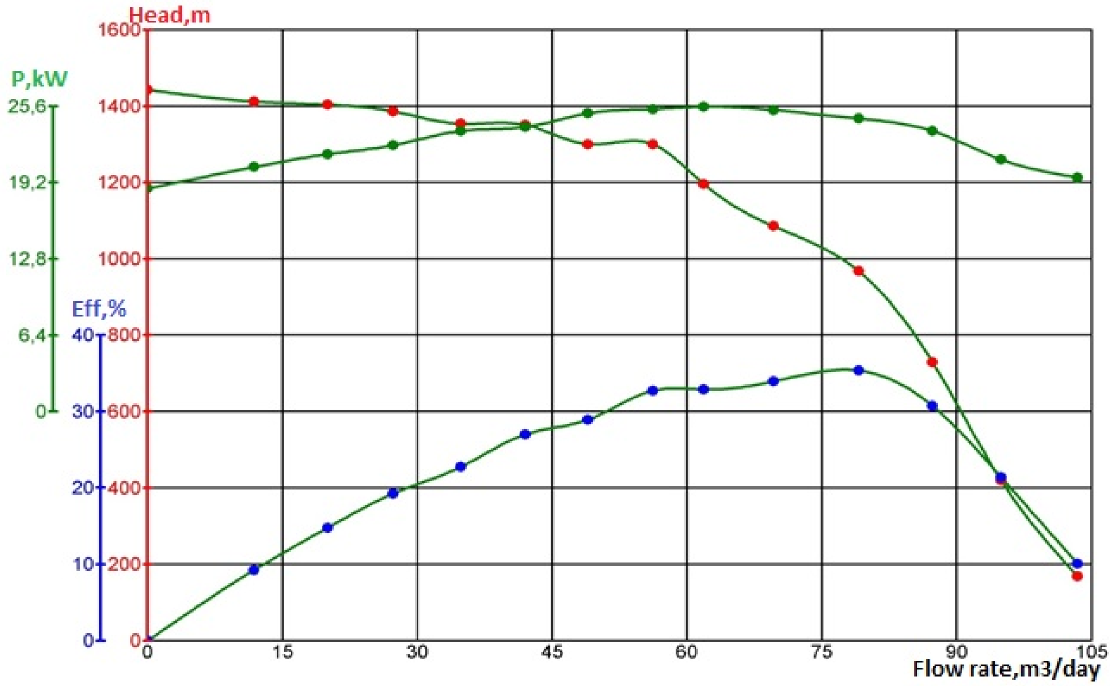


Figure 25: 217 series pump curve 109 stages at 8500RPM (140 Hz) [8]

3.3.6 Key Specifications Summary

Key specifications of the mentioned technologies are summarized in table 5.

Table 5: Key specifications summary [6] [7] [8]

Technology	***Coiled tubing deployed ESP***		***Wireline deployed ESP***		***Power cable deployed ESP***
	Cable external	**Cable internal**			
Supplier	**Schlumberger**	**Schlumberger REDACoil**	**Schlumberger ZEiTECS**	**AccessESP**	**NOVOMET Colibri**
Max TVD of installation	Using CT modelling software	Using CT modelling software. Longest installation is 10,000 ft in Norway	Defined by the maximum pressure	>9,000ft TVD >19,000ft MD	15,000ft Max installed: 6400ft
Max BH temperature	Application dependent. Up to 302°F (150°C)		302°F (150°C) 250°F (124°C) is recommended	302°F (150°C)	302°F (150°C) Possible new design: 392°F (200°C)
Max BH pressure	Application dependent. 5,000psi for standard equipment		5,000psi	7,500psi	4,640psi
Min casing/tubing sizes	4 ½” casing	7” casing (annular production) 9 5/8” casing with a 7” tubing	Depending on shuttle size: 7” (max weight 35ppf) & 4.5” tubing 7-5/8” (max weight 26ppf) & 5.5” tubing 9-5/8” (max weight 53.5ppf) & 7” tubing	ACP: 7” (max weight 29ppf) & 4.5” tubing ICP: 9-5/8”	Min tubing size: 2-7/8”
Available ESP sizes	From 338/375 series upward	538/540/562 series	Depending on shuttle size: 338/375 series, 400/450/456 series, and 513/538/540/562 series	Depending on tubing size: 338/375 series for 4.5” tbg 400/450 series for 5.5” tbg	217 series 272 & 319 series to be announced
CT/ Cable sizes	Any coiled tubing can be used depending on installation depth and carried load	Typically 2 3/8” coiled tubing is used, with pre-installed #2AWG ESP cable. Other sizes may be possible	A flat AWG#4 flat cable is required	N/A	AWG#8 round cable
Reservoir access	Possible	Possible	Possible	Possible	Possible
Gas handling devices	Gas separators and advanced gas handlers	AGH only	Gas separators and AGH	Gas separators and AGH	Only AGH

4 Well Candidate Selection

The well candidate selection represents the first part of the thesis work. For this purpose an excel tool was created. Firstly, a primary selection is performed in order to classify the wells based on their maximum oil rate potential and to preselect the wells that have oil potentials which justify the investment of a rig-less ESP technology. Secondly, the tool ranks the wells whose oil rate potential exceeds the minimum proposed for the pre-selection using the TOPSIS algorithm along with the AHP method. The ranking process is based on a number of criteria which will be listed and further explained in a following sub-chapter.

This section will include an overview of the field and the wells, on which this study was performed, an introduction and explanation of the tool including the primary selection and well ranking results.

4.1 Field Overview

4.1.1 Location

A geographical map of the field can be seen in the figure below.

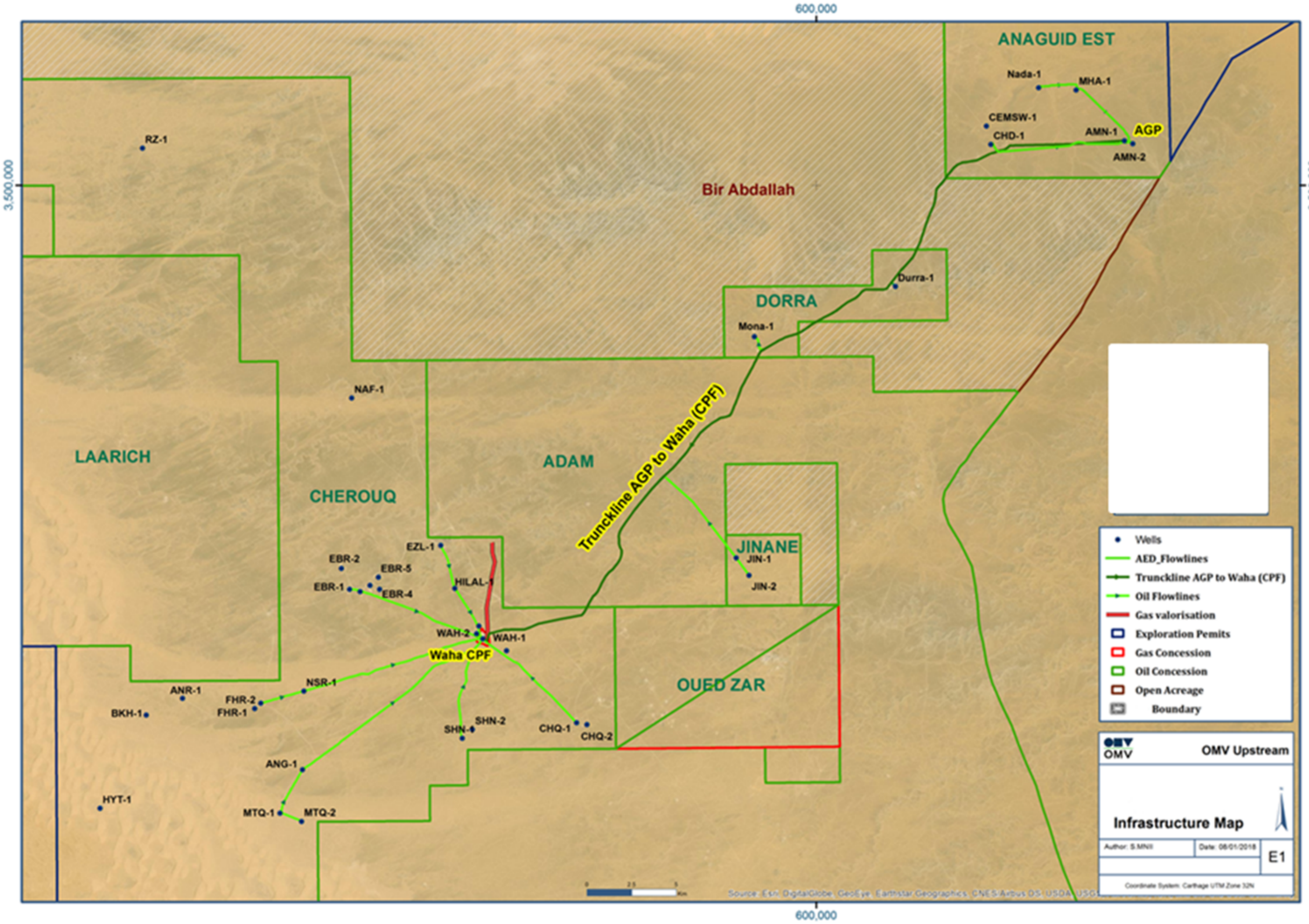


Figure 26: Field overview

The field is situated in the southern desert of the country, where three assets are being considered in this thesis work. These are: Cherouq concession, Anaguid EST concession, and Durra concession.

17 wells from the Cherouq concession, 5 wells from the Anaguid EST concession, and 1 well from the Durra concession are being considered in the thesis work. This adds up to a total of 23 wells.

4.1.2 Wells data

The well data were gathered from the OMV branch office and were quality checked and studied. A part of the gathered data were used to update the PROSPER files of the wells in order to be used in the primary well selection. While another part was used in the well candidate ranking process.

Some issues regarding the data were noticed. And these can be summarized in the following points:

- All 23 wells produce commingled from different reservoir layers.
- The layers have different reservoir pressures, PIs, and fluid properties, but the wells cannot be modelled as a multi-layer model because of the lack of data.
- PVT data are not available for most of the layers. Therefore, there is a big uncertainty in the PVT data used in the PROSPER models, and in the ESP designs performed using the Schlumberger software DesignRite.
- Some unrealistic values were observed in the well test data especially in the GOR measurements.
- Most of the wells are not producing continuously either because of pump failures or because of unavailability of injection gas lift.
- Water cuts are fluctuating in all wells, therefore, a calculated average water cut over a period of one month was considered as the current water cut. This also is considered as uncertainty as it influences the calculated oil rates.
- For some wells, well tests were performed between 2 to 6 years ago, which adds uncertainty to some PROSPER models.
- Data regarding the sand production, scale, paraffin, and corrosion are given qualitatively because of the lack of quantitative measurements. They were given on a scale from severe, moderate, low-moderate, negligible, to no. These data were used in the well candidate ranking process.

The unavailability of the PVT data for most of the formations, the commingled production, and the uncertainty of the gathered data represent a source of unreliability of the PROSPER models used, which should be taken into consideration and therefore, safety margins were accounted for in the following steps.

The 23 wells along with their data are listed in tables 6 and 7.

Table 6: Wells data

Wells/Data	Type of well	Production method	Well test date	Productivity index [stb/day/psi]	Liquid rate [stb/d]	AOF [stb/d]	Water Cut [%]	Top of perforations [m]
Amani 1	Vertical	JP	17/12/2017	0,63	871	1603	25%	2672
Amani 2	Vertical	ESP/JP	27/11/2017	1,01	1442	2502	40%	2635
Chadha 1	Vertical	JP	25/12/2017	0,15	390	464	65%	2870
Maha 1	Vertical	JP	Allocated data	0,18	346	595	47%	2796
Nada 1	Vertical	ESP/JP	24/12/2017	0,29	619	886	55%	2778
Angham 1	Vertical	GL	22/02/2012	0,17	284	756	80%	3583
Cherouq 1	Vertical	GL	December 2017	2,20	1459	7620	96%	3194
Cherouq 2	Vertical	GL	29/11/2017	0,18	363	413	50%	3488
El Azzel 1	Deviated	GL	07/05/2013	1,69	1973	5271	94%	2233
El Badr 1	Vertical	GL	06/12/2017	1,32	1458	2987	50%	3337
El Badr 4	Vertical	GL	31/05/2015	0,13	206	380	95%	3453
El Badr 5	Deviated	GL	21/07/2013	0,28	563	898	96%	3450
El Badr 6	Vertical	GL	05/12/2017	0,47	773	1150	52%	3261
Farah 1	Vertical	GL	16/04/2018	0,21	391	544	69%	3550
Farah 2	Vertical	GL	07/12/2017	0,06	124	132	16%	3417
Methaq 1	Vertical	GL	24/06/2012	0,30	925	1577	99%	3570
Methaq 2	Vertical	GL	09/12/2017	0,29	434	555	42%	3738
Shaheen 1	Vertical	GL	28/07/2014	0,96	1075	1970	75%	3143
Shaheen 2	Vertical	GL	11/02/2014	1,16	1352	4202	95%	3150
Waha 1	Vertical	GL	12/11/2014	0,07	99	325	95%	3513
Waha 2	Vertical	GL	02/02/2017	1,80	818	6301	74%	3476
Waha 3	Vertical	GL	01/12/2017	0,06	107	122	1%	3543
Mona 1	Vertical	ESP	23/11/2017	1,21	1538	4060	81%	3007

Table 7: Wells data

Wells/Data	Sand production	Temperature [°C]	Corrosion	Scale and Paraffin	Electricity availability
Amani 1	Severe	81	Negligible	Moderate-Low	Yes
Amani 2	Severe	93,33	Negligible	Moderate-Low	Yes
Chadha 1	Moderate	80	Negligible	Moderate	No
Maha 1	Moderate-Low	80	Negligible	Moderate	No
Nada 1	Moderate-Low	80	Negligible	Moderate	Yes
Angham 1	Moderate-Low	96,11	Moderate	Moderate-Low	No
Cherouq 1	Moderate	91,67	Severe	Moderate	No
Cherouq 2	Moderate	87,3	Severe	Moderate	No
El Azzel 1	Moderate-Low	67,8	Moderate	Moderate	No
El Badr 1	Moderate-Low	96	Severe	Moderate	No
El Badr 4	Moderate-Low	86	Moderate	Moderate	No
El Badr 5	Moderate-Low	93	Moderate	Moderate	No
El Badr 6	Moderate	91	Moderate	Moderate	No
Farah 1	Moderate-Low	96,3	Moderate	Moderate	No
Farah 2	Moderate-Low	90	Moderate	Severe	No
Methaq 1	Moderate-Low	91,67	Moderate	Severe	No
Methaq 2	Moderate-Low	98,8	Moderate	Moderate-Low	No
Shaheen 1	Moderate	92,22	Moderate	Severe	No
Shaheen 2	Moderate-Low	92,22	Moderate	Severe	No
Waha 1	Moderate-Low	93,33	Moderate	Moderate	Yes
Waha 2	Moderate	92,5	Severe	Moderate	No
Waha 3	Moderate	88	Moderate	Severe	No
Mona 1	Moderate	90	Negligible	Moderate	Yes

4.2 Well Selection tool

The first objective of this thesis work is the selection of the well candidates that are best suitable for the rig-less ESP technologies.

As having been mentioned before, rig-less ESPs mainly differ from the conventional ESPs in terms of deployment methods. This means that the centrifugal pump used is the same as that used in a conventional system in most of the cases. This being established, the technical evaluation of the suitability of a rig-less ESP in one well would be similar to that of the conventional ESP. This means that the influencing factors on both systems are more or less similar.

In order to select the wells candidates for the rig-less ESP technology, a well selection tool in excel was created. The selection process consists of two steps. The first step is the primary well selection, where a pre-selection of the wells is performed, based on their maximum daily oil rate potential and on a well deliverability scale. The second step is the well candidate ranking where the TOPSIS algorithm along with the AHP method are used to rank the well candidates based on a number of criteria.

4.2.1 Primary Well Selection

The primary selection section of the tool performs a pre-selection of the wells by classifying them based on a well deliverability scale and on their maximum daily oil rate potential. It classifies the wells deliverability into “very weak”, “weak”, “moderate”, “good”, and “very good”, where it permits a clear overview of the deliverability of the wells and sets a minimum oil rate potential limit. The limit is the oil rate value that separates the weak from the moderate well deliverability. The wells that have a maximum oil rate potential below the latter will not be considered in the following step, i.e. the well candidate ranking. This pre-selection allows a more credible and more reliable ranking in the following section.

Two things have to be understood here. These are the well deliverability scale and the maximum oil rate potential of the wells.

4.2.1.1 Well deliverability scale

Oil fields are different in terms of production rates and productivity. Therefore, the well deliverability scale cannot be standardized for general use and should be inputted by the user of the tool based on his subjective judgment and experience. It should also take into account the minimum oil rate desired to justify the investment of a rig-less ESP, and the degree of accuracy or uncertainty of the data used and provided.

As mentioned in the previous point, several issues regarding the data were noticed. The most relevant in this case is the uncertainty of the data which affect the credibility and the reliability of the PROSPER models used in this primary selection. In addition to that, the oil production rates in these three assets vary on a wide range, where the highest current oil rate is of 865stb/d (Amani 2) while the lowest current oil rate is of only 5stb/d (Waha 1).

These factors along with a subjective judgment outlined the well deliverability scale as following:

Table 8: Well deliverability scale

Well deliverability Scale	***Min oil rate [stb/d]***	***Max oil rate [stb/d]***
Very weak	*0*	*150*
Weak	*150*	*350*
Moderate	*350*	*550*
Good	*550*	*750*
Very good	*750*	*-*

4.2.1.2 Maximum oil rate potential

Different well variables were discussed to choose the most suitable option to perform the well deliverability comparison. These are: the absolute open flow potential AOF, the maximum oil rate, i.e. AOF multiplied by one minus the water cut, the difference between the AOF and the operating rate, and the maximum oil rate potential (variable of pump setting depth and GVF).

It was found that, in order to compare the wells' deliverability in a straightforward way while giving all wells the same chances, the maximum oil rate potential was the most suitable option and therefore chosen as the comparison variable for the following reasons:

- It is not possible to reach the AOF –or the maximum oil rate– practically, therefore it wouldn't be a reliable comparison variable.
- Even though produced liquid rates can be high enough for ESP application, the oil rates might be too small in cases where the WC is very high to justify the investment of a rig-less ESP.
- Fluid properties in the wells are different, and amongst which is the solution gas oil ratio Rs. The latter impacts the allowed pressure drawdown that can be obtained in the wellbore without exceeding the desired GVF at the pump intake. And thus, it influences the production rates.

This being established, the primary selection is thus based on comparing the maximum possible oil rate potential of the different input wells.

The oil potential is a function of the pump setting depth and GVF at the pump intake, supposing that an ESP in installed in each of the given wells.

In order to have the maximum oil rate potential, the theoretic pump setting depth should be set at the deepest possible point above the perforations for each of the wells. Any restrictions in the wellbore that can prevent the running in hole of the ESP or the setting of the ESP should be accounted for.

One of these restrictions can be the dogleg severity, which should satisfy these two conditions: Dogleg severity at pump setting depth should be <=1deg/100ft [4, p. 37], and the maximum dogleg severity until pump setting depth should be <=6deg/100ft. [4, p. 36] These values should be later checked and verified with the manufacturer of the ESP if it would be installed.

In the case of the 23 wells, the theoretical pump setting depth used was that of the top of perforations as there were no restrictions limiting the installation or RIH of the ESP.

Once the pump setting depth has been determined, an ESP pre-design should be done in PROSPER using the updater PROSPER files of the wells in order to determine the maximum potential oil rates. The pump design itself will not affect the following procedures as it will be explained later.

As mentioned in a previous chapter, ESPs are very sensitive to free gas entering the pump as this does cause many issues, amongst which cavitations and gas lock. The volume fraction of the gas at the pump intake is indicated as the gas void fraction or GVF. ESPs with radial flow stages can handle up to 10% GVF, those with mixed flow stages can handle 20% GVF, the use of an advanced gas handler or AGH increase the system's ability to handle 45% GVF, while the use of a multiphase gas handler or MGH increase it to 75%. Needless to mention that with the increasing gas handling capability, the cost of the ESP string increases.

In order to give all wells the same chances in the comparison process the maximum oil rate potential was found the best comparison option since the reservoir fluids are different in terms of fluid properties, specifically solution gas oil ratio Rs, and the drawdown is limited by the desired GVF at the pump intake. In other words, in a simple case considering two wells with similar PIs, where the first well has a reservoir fluid with a high Rs value, while the second well has a reservoir fluid with a low Rs. For a certain desired GVF at the pump intake (20% for example), the first well with the high Rs can reach this value with lower drawdown and therefore lower liquid rate compared to the second well where a higher drawdown is theoretically possible before the desired GVF at the pump intake is reached.

Considering that the oil potential is a function of GVF, the tool gives the user the possibility of choosing the desired GVF at the pump intake based on which the determination of the maximum oil potential of the wells and the pre-selection are performed. The GVF can be selected from 0%, 10%, 20%, 45%, and 75%, the values corresponding to the technologies mentioned earlier. The GVF selection should account for the certainty of the PVT data of the wells and of the PROSPER model used, the future behaviour of the wells, and the investment cost versus production difference.

In the case of the three assets, a GVF of 20% was chosen. The selection was conservative, due to the uncertainty of the PVT data, in addition, with the installation of an AGH, it allows a higher fraction of gas at the pump intake in case where the well behaviour was not as expected.

By choosing the desired GVF, the maximum oil rate potential of the wells can be determined from PROSPER. After doing the ESP pre-design setting the pump at the maximum possible setting depth, GVF versus liquid rate can be plotted and the rate values can be exported and filled in the excel tool.

It should be noted that the ESP design itself doesn't have an effect on the plot GVF vs liquid rate. This is because PROSPER supposes that the pump is able to provide as much pressure drawdown as required. It then uses, on one hand, the IPR data to calculate the pressure drawdown needed to obtain a certain rate, and on the other hand, uses the PVT data to obtain the free gas volume at the pump intake for the calculated pressure drawdown.

Below, an example of a GVF vs liquid rate curve is shown.

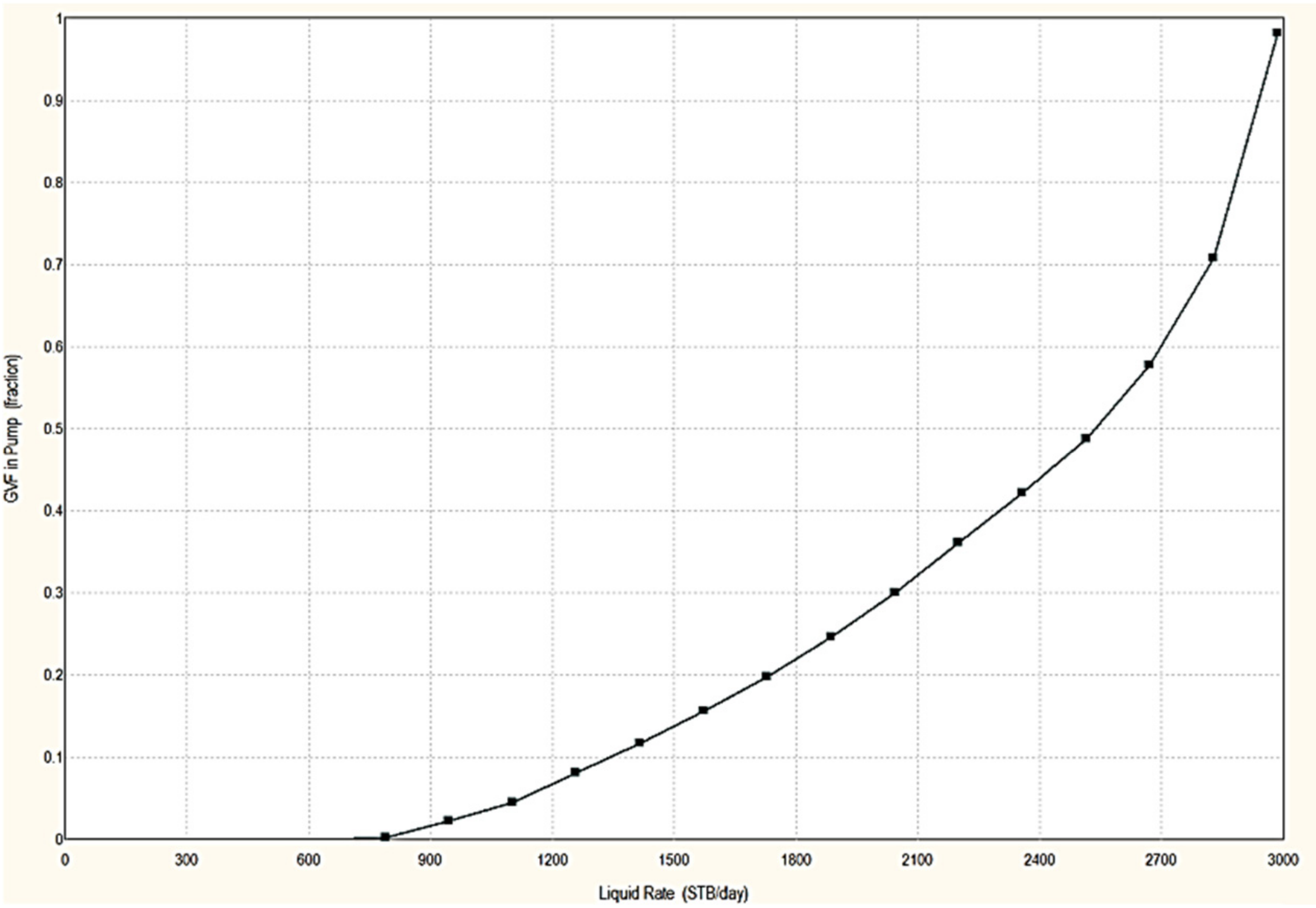


Figure 27: GVF vs liquid rate [stb/d]

Liquid rate values obtained from the PROSPER files for the different GVF values are illustrated in table 6. It should be noted that these are the maximum liquid rate potentials for each GVF value which have to be multiplied by one minus the water cut to obtain the maximum oil rate potentials.

Table 9: GVF vs liquid rates [stb/d] for all 23 wells

GVF [%]	0%	10%	20%	45%	75%
Amani 1	759,5	985	1150	1410	1543
Amani 2	1185,5	1770	2060	2363	2443
Chadha 1	244,21	334	382	433	452,3
Maha 1	287,44	427	447	498	559
Nada 1	419,67	605,8	698,87	818	862
Angham 1	437,83	585	655	715	739
Cherouq 1	0	5612,5	6500	7234	7470
Cherouq 2	0	109	206	336	390
El Azzel 1	4712,5	5060	5135	5266	5266
El Badr 1	1415,4	1980	2300	2733	2902
El Badr 4	160,2	322	346	365	376
El Badr 5	378,3	777	830	868	894
El Badr 6	545,2	795	908	1060	1119
Farah 1	258	396	451	503	528
Farah 2	48,65	72	87	112	126
Methaq 1	157,6	1290	1382	1435	1471
Methaq 2	0	0	29,7	366	513
Shaheen 1	416	1140	1480	1780	1902
Shaheen 2	1770,2	3560	3825	4035	4145
Waha 1	239,2	300	309	315,5	323,5
Waha 2	4641	5365	5725	6045	6195
Waha 3	70,36	86	93	107	117
Mona 1	1960,5	2910	3050	3390	3800

4.2.1.3 Primary well selection results

As mentioned before, a GVF of 20% was found the optimum option to perform the primary selection. Therefore, having obtained the maximum oil rate potentials and having set the well deliverability scale, the tool determines whether each well has a well deliverability of “very good”, “good”, “moderate”, “weak”, or “very weak”.

In the primary selection, all wells that have a well deliverability of “very weak” or “weak” are to be ignored in the following steps. This means that, at their optimum conditions (ESP set at the maximum possible depth) and for the chosen GVF, these wells do not provide an oil potential high enough to justify the investment and thus be considered as candidates. On the other hand, the wells that have a well deliverability of "moderate", "good", or "very good" are to be considered in the well ranking process.

Listed in the table and figure below are the primary well selection results and classification.

Seven wells had a maximum oil rate potential at 20% GVF at the pump intake that exceeds the limits set in the well deliverability scale, i.e. 350stb/d.

Four wells had a well deliverability evaluation of "very good". These are: Amani 1, Amani 2, El Badr 1, and Waha 2. One well, Mona 1, had a well deliverability of "good". And two wells had a well deliverability of "moderate": El Badr 6 and Shaheen 1.

These 7 wells will then be considered in the following step, the well candidate ranking.

Table 10: Primary well selection results

Wells/ Results	Current Oil rate [stb/d]	Oil rate potential [stb/d]	Evaluation of well deliverability
Amani 1	***652,884***	***862,5***	***Very good***
Amani 2	***864,924***	***1236***	***Very good***
Chadha 1	136,633	133,7	Very weak
Maha 1	183,4383	236,91	Weak
Nada 1	278,3997	314,4915	Weak
Angham 1	56,8	131	Very weak
Cherouq 1	58,3552	260	Weak
Cherouq 2	181,4	103	Very weak
El Azzel 1	118,38	308,1	Weak
El Badr 1	***728,945***	***1150***	***Very good***
El Badr 4	10,306	17,3	Very weak
El Badr 5	22,519	33,2	Very weak
El Badr 6	***371,088***	***435,84***	***Moderate***
Farah 1	121,21	139,81	Very weak
Farah 2	103,96344	73,08	Very weak
Methaq 1	9,25	13,82	Very weak
Methaq 2	251,72	17,226	Very weak
Shaheen 1	***268,625***	***370***	***Moderate***
Shaheen 2	67,6	191,25	Weak
Waha 1	4,955	15,45	Very weak
Waha 2	***212,68***	***1488,5***	***Very good***
Waha 3	106,1665	92,535	Very weak
Mona 1	***292,201***	***579,5***	***Good***

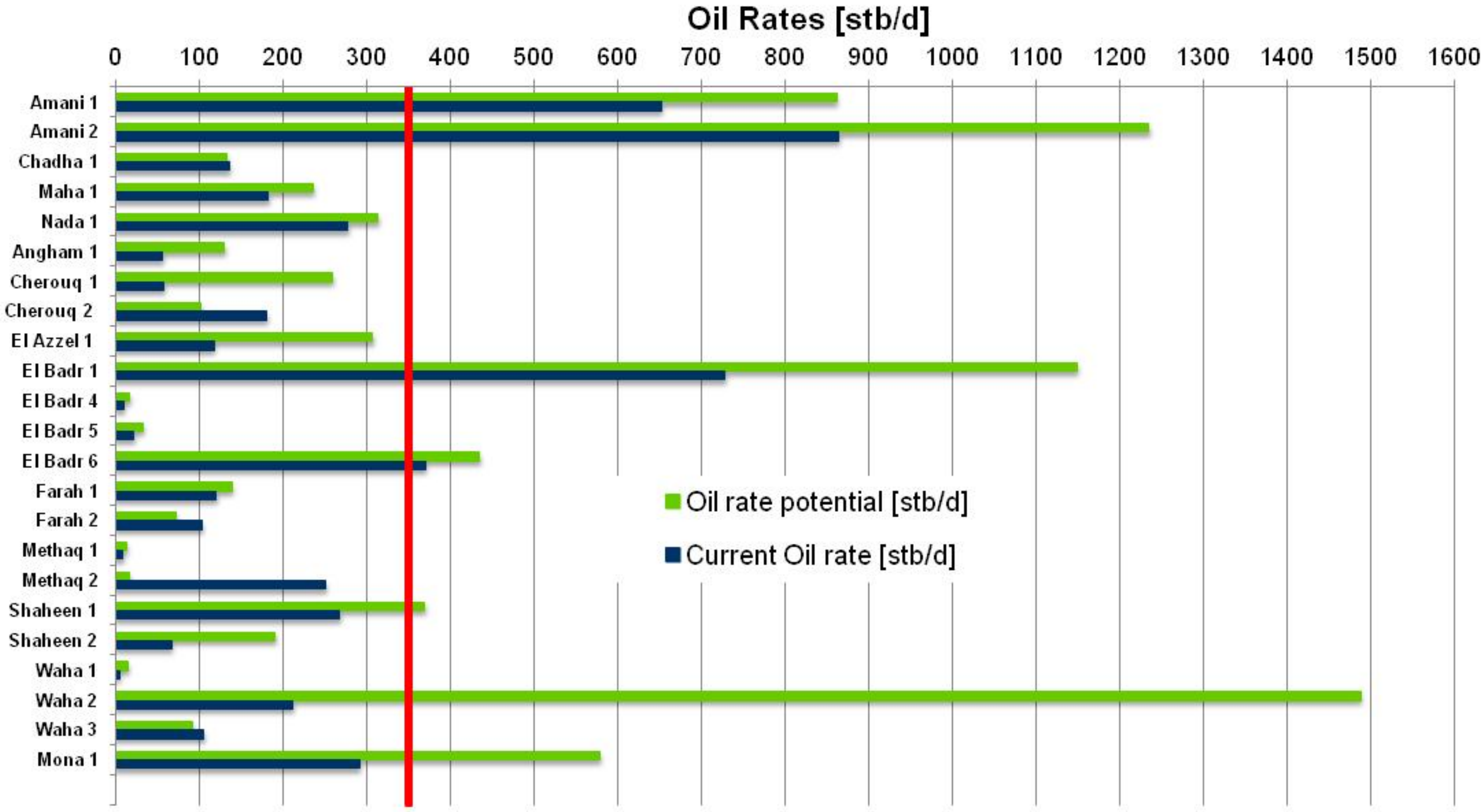


Figure 28: Primary well selection results

The red line in the figure above represents the limit oil potential value of 350stb/d. The blue bars illustrate the current oil rate, while the green bars represent the oil rate potential of the wells at GVF of 20%.

4.2.2 Well Candidate Ranking

The following step in the excel tool is the ranking of the 7 well candidates that have been pre-selected. The well candidate ranking is performed by using the TOPSIS algorithm along with the AHP method for the determination of the weights of the used criteria.

This part includes an explanation of the TOPSIS algorithm and the AHP method, and a summary of the results.

4.2.2.1 TOPSIS

TOPSIS is the abbreviation for Technique for Order Performance by Similarity to Ideal Solution. It is a multi-criteria decision analysis process which results in the ranking of the different input alternatives based on a certain number of criteria. [9]

A large number of industrial areas use the TOPSIS algorithm along with AHP for selection of vendors, products, logistic providers, network, and so on. This is due to its simplicity and wide application. In addition, the concept of TOPSIS is rational and it allows objective weights to be incorporated into the process. [9]

The algorithm hypothesizes two artificial solutions; these are: the positive ideal solution having the best level for values of the considered alternatives, and the negative ideal solution having the worst level for the values of the same. The closeness to the ideal and to the negative ideal solutions are calculated and based on which the relative closeness to ideal is determined. [9] Furthermore, it should be noted that TOPSIS assumes n alternatives or options, which, in this case, are the 7 wells, and m criteria or attributes. Each alternative has to have a score with respect to each criterion. The criteria that were used in this case were the following:

- Sand production
- GVF at intake
- Temperature
- Pump setting depth
- Corrosion
- Scale and paraffin
- Oil rate potential
- Water cut
- Electricity availability

An evaluation procedure was implemented in the system to give scores to each one of the wells relative to each criterion depending on the data received from the branch office. The scoring interval was between 1 and 10, where 1 is the lowest grading and 10 is the highest grading. The scales and scores of the criteria were decided on with the help of a Schlumberger technical sales engineer with a wide experience in ESPs. They are illustrated in the table below.

Table 11: Scales and scores of the 9 criteria

	Sand production					
Scale	**Severe**	**Moderate**	**Moderate-Low**	**Negligible**		**No**
Score	1	2	3,5	8,5		10
	GVF at intake					
Scale	**0%-10%**	**10%-20%**	**20%-45%**	**45%-75%**		**>75%**
Score	10	9	8	3		1
	Temperature [°C]					
Scale	**<=70**	**70-90**	**90-100**	**100-110**	**110-120**	**<120**
Score	10	9	7,5	3	2	1
	Pump setting depth [m]					
Scale	**<=1000**	**1000-1500**	**1500-2000**	**2000-2500**	**2500-3000**	**<3000**
Score	10	9	6	3	2	1
	Corrosion					
Scale	**Severe**	**Moderate**	**Moderate-Low**	**Negligible**		**No**
Score	1	2,5	5	8,5		10

	Scale and Paraffin				
Scale	**Severe**	**Moderate**	**Moderate-Low**	**Negligible**	**No**
Score	1	2,5	5	8,5	10
	Oil rate Potential [stb/d]				
Scale	**350-500**	**500-700**	**700-900**	**900-1100**	**<1100**
Score	1	4	7	9	10
	Water Cut [%]				
Scale	**0%-25%**	**25%-50%**	**50%-75%**	**75%-90%**	**<90%**
Score	10	8,5	6	2,5	1
	Electricity availability				
Scale	**Yes**		**No**		
Score	10		4		

Based on the score scales and the data provided, the algorithm inputs the scores in an m by n matrix as following:

Table 12: Scores of the wells for each criterion

Criteria/Wells	*Amani 1*	*Amani 2*	*El Badr 1*	*El Badr 6*	*Shaheen 1*	*Waha 2*	*Mona 1*
Sand production	1	1	3,5	2	2	2	2
GVF at intake	8	8	8	8	8	8	8
Temperature	9	7,5	7,5	7,5	7,5	7,5	9
Pump setting depth	2	2	1	1	1	1	2
Corrosion	8,5	8,5	1	2,5	2,5	1	8,5
Scale and Paraffin	5	5	2,5	2,5	1	2,5	2,5
Oil rate Potential	7	10	10	1	1	10	4
Water Cut	10	8,5	8,5	6	6	6	2,5
Electricity availability	10	10	4	4	4	4	10

Let x_{ij} be the score of option j with respect to criterion i. Therefore, the m by n matrix would be a matrix X= (x_{ij}) where iϵ {1,…,m} and jϵ {1,…,n}. The TOPSIS algorithm normalizes these scores following the formula below and therefore constructs a normalized decision matrix R=(r_{ij}) where iϵ {1,…,m} and jϵ{1,…,n}. [9]

$$r_{ij} = x_{ij} / (\Sigma x^2_{ij}) \text{ for } i = 1, \dots, m \text{ and } j = 1, \dots, n \qquad (1)$$

Since the criteria do not have the same importance, a weight w_i was assigned to each criterion. These weights are determined using the AHP method which will be explained later. The algorithm then multiplies each row of the normalized matrix R by its associated weight as shows the formula: [9]

$$v_{ij} = w_i \, r_{ij} \text{ for } i = 1, \dots, m \text{ and } j = 1, \dots, n \qquad (2)$$

A weighted normalized decision matrix $V=(v_{ij})$ where $i\epsilon \{1,\ldots,m\}$ and $j\epsilon \{1,\ldots,n\}$ is finally generated.

As mentioned before, this method hypothesizes two artificial alternatives. These are the ideal alternative, or solution, having the best level for all attributes considered, and the negative ideal alternative having the worst attribute values.

In this case, the ideal solution would be the vector $V_{Ideal}=\{\max(v_{ij});\ j=1,\ldots,n\}$. And the negative ideal solution would be the vector $V_{Negative\ Ideal}=\{\min(v_{ij});\ j=1,\ldots,n\}$. [9]

The separation measures from the ideal and negative ideal alternatives for each option are then calculated respectively as following: [9]

$$S_{Ideal,j}= [\Sigma_i (v_{Ideal,i} - v_{ij})^2]^{½} \text{ for } j=1,\ldots,n \qquad (3)$$

$$S_{Negative\ Ideal,j}= [\Sigma_i (v_{Negative\ Ideal,i} - v_{ij})^2]^{½} \text{ for } j=1,\ldots,n \qquad (4)$$

These separations measures represent the distance that each of the wells has from the ideal and the negative ideal solutions generated. These are then used to calculate the relative closeness to ideal Cj for each well as shown in the equation below. [9]

$$C_j = S_{Negative\ Ideal,j} / (S_{Ideal,j} + S_{Negative\ Ideal,j}) \qquad (5)$$

C_j is a value between 0 and 1 and can be represented in percentages. It would then illustrate how much in percentage a well is close to the ideal alternative and based on these values, the well ranking is performed. [9]

The well ranking results will be presented in a following subchapter.

It should be noted that without having implemented the primary well selection, the TOPSIS ranking would have been negatively influenced. This is because the ideal and negative ideal solutions would have been generated using values from wells that are not relevant as well candidates due to their very low oil production. For example, in case a well has the highest scores for all criteria except for the oil rate potential, where it has a very low oil rate, it can influence the ideal solution which makes it rank higher in the list of wells without actually being an appropriate candidate. Therefore, the pre-selection more or less refines the data used by the algorithm to have a more accurate and reliable ranking.

4.2.2.2 Weights calculation using the AHP method

The 9 criteria that were used in the well ranking have different influence degrees on the system and therefore different importance. This is depicted by the application of weights that illustrate the assumed difference in importance.

While some criteria represent the influencing factors on the ESP system, namely the sand production, the GVF at the pump intake, the well temperature, corrosion, and scale and paraffin, other criteria represent more the logistics factors.

In fact, the water cut as a criteria comes from the water handling problems that are faced in this field. Accordingly, a well that produced less water rates would be preferred to a well that has a very high water cut. In addition, pump setting depth was set as a criterion to promote shallower wells over deep well, especially that most of the rig-less technologies are rated to a maximum depth of 3000m, and accounting for the increasing system cost with increasing depth. Furthermore, electricity availability represents the additional time and cost due to the installation of a new power source. Finally, the oil rate potential would be a representation of the revenues gained from the wells.

It can be agreed on that having to compare 9 diverse criteria makes the weights determination difficult to accomplish accurately without subjective influences and very probable errors. For this reason, the AHP method was applied in order to simplify the comparison process, and generate the weights mathematically while being able to evaluate the comparison consistency.

AHP is the abbreviation of Analytic Hierarchy Process. It is one of the multi criteria decision making methods which consists in deriving ratio scales from pair-wise comparisons. In this thesis work, the purpose of the AHP process is to derive the relative priorities, or weights, of the criteria. It can be stated that the AHP method has the great advantage of simplicity. Regardless the number of criteria used, it is only required to compare a pair of elements at any time. [10]

The comparisons between the criteria have to be done based on a numeric scale as the following:

Table 13: Scale for pairwise comparisons

1	*"A is as important as B"*
2 - 3	*"A is moderately more important than B"*
4 - 5	*"A is strongly more important than B"*
6 - 7	*"A is very strongly more important than B"*
8 - 9	*"A is extremely more important than B"*
1/2 - 1/3	*"A is moderately less important than B"*
1/4 - 1/5	*"A is strongly less important than B"*
1/6 - 1/7	*"A is very strongly less important than B"*
1/8 - 1/9	*"A is extremely less important than B"*

The scale mathematically indicates the ratio of importance of two criteria A and B. This means that if a criterion A was judged to be strongly more important than a criterion B given a value of 5, this would mean that A is 5 times more important than B and, vice versa, B is 1/5 times more important than A.

As 9 criteria were used, 36 comparisons were performed and a 9 by 9 comparison matrix was created. In the comparison matrix when comparing the importance of criterion with itself, the input value is 1 since the importance of a criterion A compared to itself is the same. In the matrix, the pair-wise comparisons are done always by comparing the criteria in the rows to those in the columns. This is shown as well as the comparison factors in the table below.

Table 14: AHP comparison matrix

	Sand production	GVF at intake	Temperature	Pump setting depth	Corrosion	Scale and Paraffin	Oil rate Potential	Water Cut	Electricity availability
Sand production	1	3	3	2	2	2	1/9	2	5
GVF at intake	1/3	1	1	1/2	1/2	1/3	1/9	1/2	2
Temperature	1/3	1	1	1/2	1/2	1/2	1/9	1/2	3
Pump setting depth	1/2	2	2	1	1/3	1/3	1/9	2	2
Corrosion	1/2	2	2	3	1	1/2	1/9	2	4
Scale and Paraffin	1/2	3	2	3	2	1	1/9	2	4
Oil rate Potential	9	9	9	9	9	9	1	9	9
Water Cut	1/2	2	2	1/2	1/2	1/2	1/9	1	2
Electricity availability	1/5	1/2	1/3	1/2	1/4	1/4	1/9	1/2	1

The comparisons were decided on with the help of a Schlumberger technical sales engineer with a wide experience in ESPs and a wide knowledge of the influencing factors on the ESP systems and their importance.

It can be understood from here that the AHP method is not completely free from subjective judgments and human errors due to inconsistent comparisons. However, it should be noted that it represents a way to simplify these comparisons, reduce the inconsistency, and therefore reduce the error.

The calculation of the weights vector, or the priority vector, is then done by the determination of the eigenvectors and the eigenvalues of the obtained matrix. The priority vector would then be the normalized eigenvector that corresponds to the highest eigenvalue.

The priority vector is shown in the table below.

Table 15: Priority vector

	Priority vector
Sand production	11,16%
GVF at intake	3,55%
Temperature	3,97%
Pump setting depth	5,46%
Corrosion	7,81%
Scale and Paraffin	9,49%
Oil rate Potential	51,22%
Water Cut	4,96%
Electricity availability	2,40%

In order to integrate the eigenvectors and values calculation in the excel tool, an add-in, RealStats-2010, was uploaded and installed in excel. This calculation can also be performed in MATLAB or on an online platform.

The following step in the AHP method is to verify the consistency of the criteria comparisons. It is more or less impossible to avoid some inconsistencies in the final matrix of judgment since its values come from the subjective preferences of individuals. It was proven that in a consistent reciprocal matrix, the largest eigenvalue is equal to the size of the comparison matrix. A measure of consistency was therefore given, called consistency index CI using the following formula. [10]

$CI= (\lambda_{max}-n)/(n-1)$ where λ_{max} is the maximum eigenvalue and n is the matrix size (6)

The calculated maximum eigenvalue is equal to 9.572 while the matrix size is 9.

The consistency evaluation is then done by the calculation of a consistency ratio CR which compares the consistency index CI of the matrix with the random consistency index RI as shows the formula below. [10]

$$CR= CI/RI \qquad (7)$$

RI is defined as the average CI of 500 randomly generated reciprocal matrices. And can be obtained from the table below.

Table 16: Random consistency index RI

n	1	2	3	4	5	6	7	8	9	10
RI	0	0	0.58	0.9	1.12	1.24	1.32	1.41	1.45	1.49

Some inconsistency is expected and allowed in AHP analysis. The inconsistency will be acceptable if the CR is less than 10%, otherwise the revision of the comparisons would be needed. [10]

The results of the CI and the CR are listed in the table below.

Table 17: CI and CR results

Consistency	
CI	**7,15%**
CR	**4,93%**

As seen from the results, the CR of 4.93% is in the acceptable range, which makes the priority vector, or the weights reliable.

4.2.2.3 Well candidate ranking results

Having determined the criteria, their weights, and the scores of the wells relative to each criterion, the well candidate ranking can be performed. The well ranking results are illustrated in the table and figure below.

Table 18: Well candidate ranking

Well Name	*Relative closeness to ideal*	*Rank*
El Badr 1	74,81%	1
Waha 2	63,30%	2
Amani 2	60,62%	3
Amani 1	51,36%	4
Mona 1	40,77%	5
El Badr 6	22,28%	6
Shaheen 1	19,86%	7

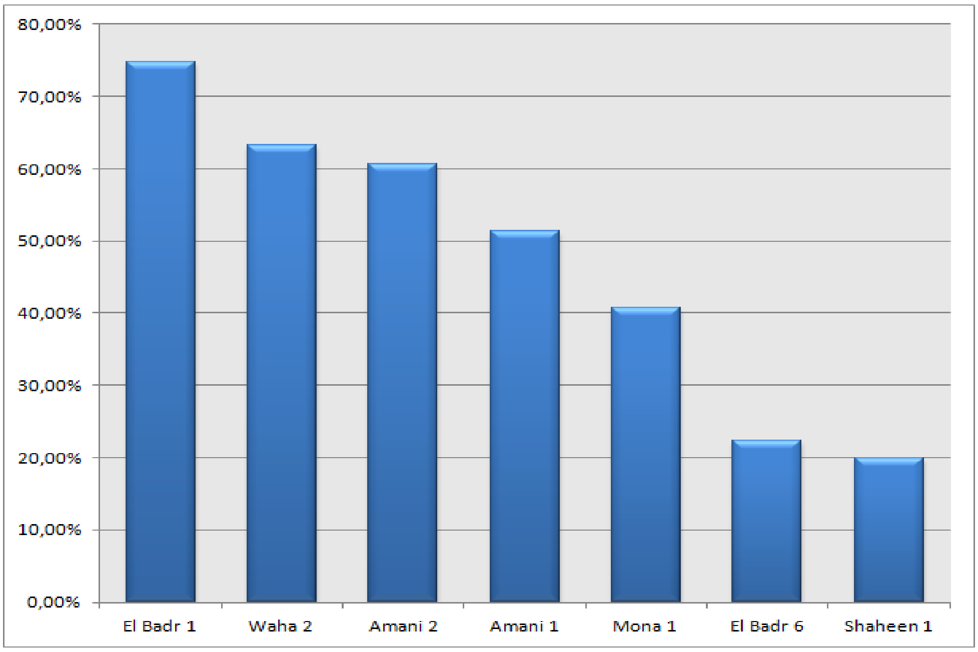


Figure 29: Well candidate ranks

For simplicity reasons, and because the wells El Badr 6 and Shaheen 1 have low oil rate potential compared to the rest of the wells, it was agreed that only the first 5 wells will be considered in the next part of the thesis work, the technology candidate selection.

It should be mentioned that after the final technology selection, the new design data like pump setting depth and GVF can be inputted in the excel tool to obtain a new ranking of the wells based on these data.

5 Technology Candidate Selection

The second part of the thesis work is the technology candidate selection. The available rig-less ESP deployment methods vary in terms of technology, costs, and key specifications. All of these factors need to be accounted for when choosing the most suitable technologies for the 5 selected wells.

The technology candidate selection was done by, firstly, evaluating the technical applicability of each of the technologies developed by the suppliers in the 5 wells, secondly, performing an ESP design for the proposed scenarios, and finally proposing a workflow for the economic evaluation of these scenarios.

These steps will be further explained in the following subchapters.

5.1 Evaluation of technology applicability in the wells

For the evaluation of the technology applicability in the 5 chosen wells, the well data were compared to the key specifications of each technology. These key specifications were summarized previously in table 5.

The three most relevant factors that were checked are the BHT, BHP, and casing sizes. The well data corresponding to these factors are listed in the table below.

Table 19: Well data for technology applicability evaluation

Well	***BHT [°C]***	***BHP [psi]***	***Liner size***	***TOL***
Amani 1	81	3,590	7” #32	*1,600m*
Amani 2	93.33	3,500	7” #32	*1,592m*
El Badr 1	96	3,057	7” #29	*1,650m*
Mona 1	90	4,485	7” #29	*1,544m*
Waha 2	92.5	3,945	7” #29	*1,544m*

On one hand, comparing the BH temperatures and pressures of the wells to those restricting the technologies, it can be stated that all 5 wells are in the acceptable working interval of all 5 technologies.

On the other hand, comparing the casing sizes and their maximum weights restricted by the technologies to the well completions, the following can be concluded:

- All technologies can be applied in Ameni 1 and Ameni 2 except for the AccessESP wireline deployed system since the technology is limited to a 7” casing with a maximum weight of 29ppf while both wells are completed with 7” liners with a weight of 32ppf.

- All technologies can be installed in El Badr 1, Mona 1, and Waha 2 as they comply with the restrictions imposed by the technologies.
- RedaCoil technology can only be applied if annular production is possible.

Annular production is not illegal in the country. However, an exemption from OMV is needed to be able to apply this production type. As no data were provided in this regard, the wells integrity as well as the completions states need to be checked by the branch office before deciding on whether to consider the RedaCoil technology.

In the following steps, the wells integrity will be considered good enough for producing from the annulus.

Concerning the NOVOMET Colibri ESP technology, the ultra slim ESP of 2.17” cannot deliver the heads required and the rates desired for the five wells unless it is operated at very high frequencies, up to 140 Hz, compared to the conventional frequency operating range (between 35 Hz and 65 Hz).

In this regard, one issue that needs to be considered is the sand production. Needless to say that ESP pumps are sensitive to abrasive wear and to sand presence in the produced fluid. Some mitigation measures to reduce harmful effects of sand on the ESP system can be added to the system, among which abrasive resistant materials and sand filters in the pump intake. These measures can be very useful and may enable the pump to operate for longer periods of time in sandy environments before failing. If this is the case for normal pump operation frequencies, operating the ESP with higher frequencies in sandy environments can reduce drastically the running time of the pump and causes it to fail more frequently.

For this particular reason, the NOVOMET technology for cable deployed ESP has to be discarded while the other technologies will be considered in the following steps.

5.2 ESP design

After the evaluation of the technologies applicability, it was found that the technologies that can be applied in the wells and that will be considered are Schlumberger’s cable external CT deployed system, RedaCoil technology, and Zeitecs technology, and AccessESP’s wireline deployed system.

Based on this, an ESP design for each well and for each technology was performed using the Schlumberger’s software DesignRite 8.0, which was the only ESP design software available within OMV.

It should be recalled that AccessESP only provides the deployment system and doesn’t provide the ESP itself. Nevertheless, it can employ any conventional ESP matching its required specifications from any provider. In addition, the required specifications for the pump design of the AccessESP system are similar to those of the Zeitecs technology. For this reason, the ESP design of both technologies will be identical. Therefore, 3 designs per well for the 5 selected wells had to be done, summing up to 15 in total.

5.2.1 Basis of design

Taking into account the key specifications of the considered technologies, a basis of design was determined for each.

As mentioned before, the 5 wells are completed with 7” liners, which represents a restriction for the technologies and limits the pump and motor sizes.

In addition, the CT size for the cable external CT deployed system was set at 2-3/8” OD.

Besides, the wireline deployed ESP systems require a tubing size of 4.5”.

Regarding the RedaCoil technology, fluid production would be through the annulus, but since annular production is not possible to model in the DesinRite software, the cross sectional area of the annular space between the CT and the casing was calculated and converted into an equivalent diameter of 5.709” or 5.69” depending on the well.

Furthermore, gas separators will only be used in the cable external CT deployed system. This is because the annular gas separation is possible for this technology, which is not the case for the RedaCoil system. Furthermore, even though the installation of a gas separator is possible for the Zeitecs and AccessESP systems, it was not recommended due to the small ESP size and the possible risk of blockage of the gas flow path and the eventual failure of the system. On the other hand, the installation of an advanced gas handler is possible for all cases.

Regarding the pump setting depth, a maximum of 10,000ft TVD should not be surpassed.

It should be noted that no design rates were given for neither of the wells.

The production type, the tubing sizes, gas separation possibilities, and the applicable pump series for each technology are summarized in the table below.

Table 20: Basis of design

	Cable external CT deployed system	***RedaCoil***	***Zeitecs / AccessESP***
Production	Tubular (CT)	Annular	Tubular (Tubing)
Tubing	OD: 2.375“ ID: 1.991"	Equivalent diameter ID: 5.709" or 5.69”	OD: 4.5" ID:4"
Separation	Annular gas separation	No gas separation	No gas separation
	VGSA / AGH	AGH	AGH
Series	338/375 – 400/456	538/540/562	338/375

5.2.2 Design steps and recommendations

DesignRite is a Schlumberger ESP designing software that contains all ESP related catalogues from the provider. A picture of the software's pump design window is shown in the figure below.

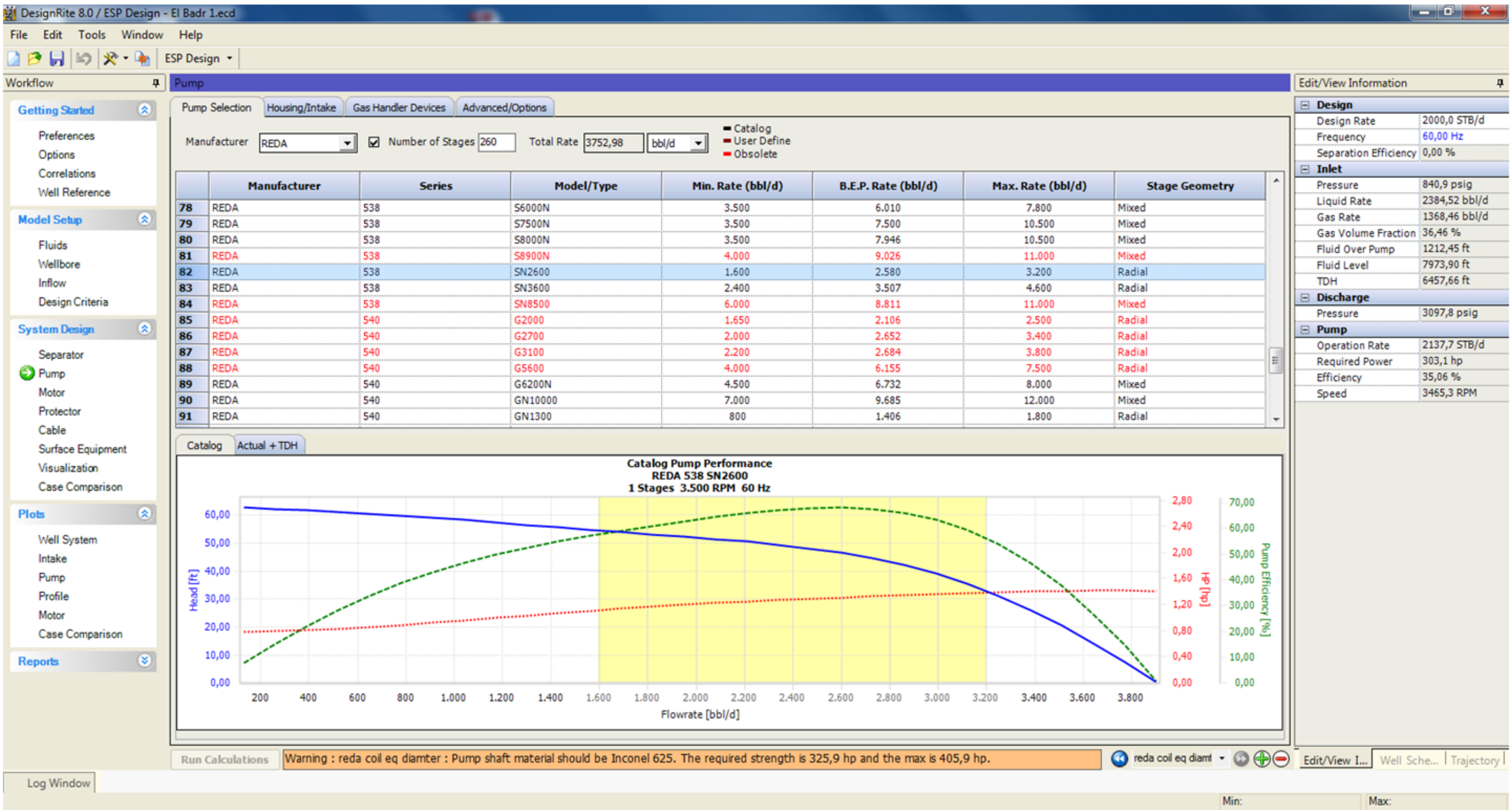


Figure 30: DesignRite pump design window

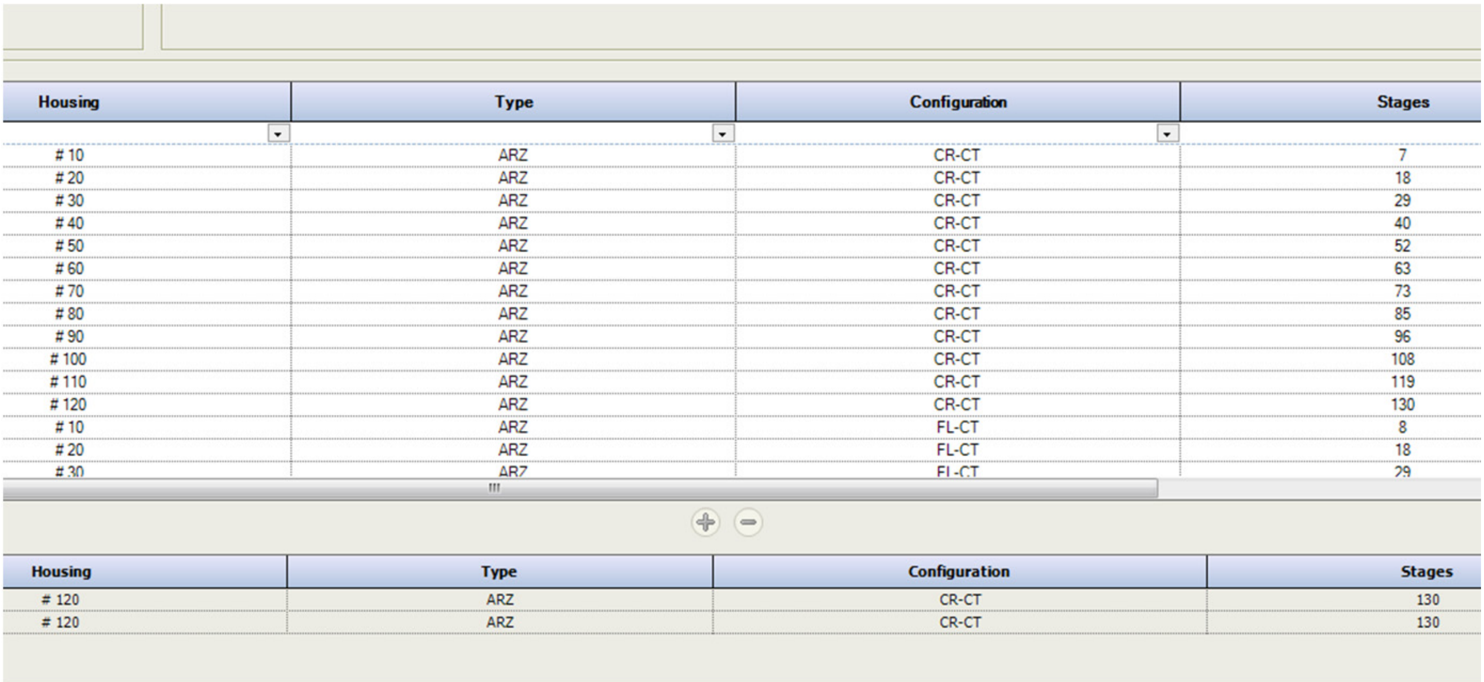
The ESP design should start by inputting the well data including the PVT, completion, and inflow data, and the design criteria in the "Model Setup" section. The PVT data used for the designs are listed in Appendix A. Moreover, the completion input data adopted those specified in the basis of design. Regarding the design criteria, all ESPs were designed within a frequency envelop of 50 to 60 Hz, while the design rates and pump setting depths were chosen and optimized accordingly for each well since no design data were given by the OMV branch office.

In the "System Design" section, the pump, motor, protectors, and cable can be selected and designed. In all segments, the basis of design should be followed.

The pump design should be done based on the desired production rate, the pump setting depth, and the total dynamic head required to lift the fluid to the surface, along with taking into account the used ESP sizes.

By selecting a pump, the software calculates the number of stages needed for the delivery of the specified rate and head at the defined frequency and draws the pump H-Q curve and the system curve for these criteria. It is recommended to design the pump so that the system curve would be within the operating range of the pump, ideally close to the best efficiency point. It is also advised not to exceed a number of 350 stages. If either is the case, the selection of a more efficient pump, or changing the design frequency while reducing the number of stages is required. Pump data base also gives information regarding the stage geometry, i.e. radial stages or mixed flow stages. Mixed flow stages have a higher ability of handling free gas entering the pump. They can handle up to 20% GVF at the pump intake. For this reason, and to be on the safe side, only mixed flow stage pumps were considered.

The software also allows the selection of the pump housings, where the use of 3 pump housings maximum is suggested. In the housing selection, the pump configuration and type have to be chosen. This can be shown in the figure below.



Housing	Type	Configuration	Stages
# 10	ARZ	CR-CT	7
# 20	ARZ	CR-CT	18
# 30	ARZ	CR-CT	29
# 40	ARZ	CR-CT	40
# 50	ARZ	CR-CT	52
# 60	ARZ	CR-CT	63
# 70	ARZ	CR-CT	73
# 80	ARZ	CR-CT	85
# 90	ARZ	CR-CT	96
# 100	ARZ	CR-CT	108
# 110	ARZ	CR-CT	119
# 120	ARZ	CR-CT	130
# 10	ARZ	FL-CT	8
# 20	ARZ	FL-CT	18
# 30	ARZ	FL-CT	29

Housing	Type	Configuration	Stages
# 120	ARZ	CR-CT	130
# 120	ARZ	CR-CT	130

Figure 31: DesignRite housing selection

In the case of the 5 wells, due to the uncertainty of the well behaviour and fluid properties and the more or less high sand production, the selection of a compression pump housing with a central tandem CR-CT is suggested. In addition, it is also recommended to use abrasive resistant materials ARZ as a mitigation measure to the sand production issue.

Housings can contain different number of stages per housing. And because an additional housing means additional costs, the less housings used for an ESP design the better. This also applies for equipment handling, RIH, and POOH, the less equipment to be mounted together, the easier and less risky is the handling. Therefore, the number of housings used has to be optimized by optimizing the number of stages. This can be reached by changing the frequency within the design envelop in order to find the optimum stage count while maintaining the desired flow rate.

Furthermore, the pump design should also allow a certain flexibility in terms of water cut and GLR fluctuations. This is done by assuming worst case scenarios and testing whether the pump would operate in these conditions. If not, an optimization of the design should be performed. A worst case scenario can be where the well is producing with a 100% water cut, with highly increased produced gas rate, with a decreased PI value, or with a depleted reservoir pressure.

After the pump selection, the GVF at the pump intake should be checked to decide whether the use of a gas handling device is needed or not. In the performed designs, the GVF was always set around or below 20% and this is mainly done by either selecting a proper gas separator or an advanced gas handler. In some cases, while designing the WL deployed ESPs, no AGH was available in the software that matched the desired criteria. However, an A18-33 AGH, which is not listed in the data base can be applied in these circumstances.

In case the gas handling devices are not sufficient to keep the GVF at the pump intake at the desired value, the pump setting depth should be optimized by setting it deep enough to reduce the volume of free gas to the desired value. Care should be taken not to surpass the depth limit of 10,000ft restricted by the technologies. In this case, it might be necessary to either increase the number of stages or the operating frequency to be able to compensate for the increased head required.

The next step is the motor selection. The motor selection window can be seen in figure 32.

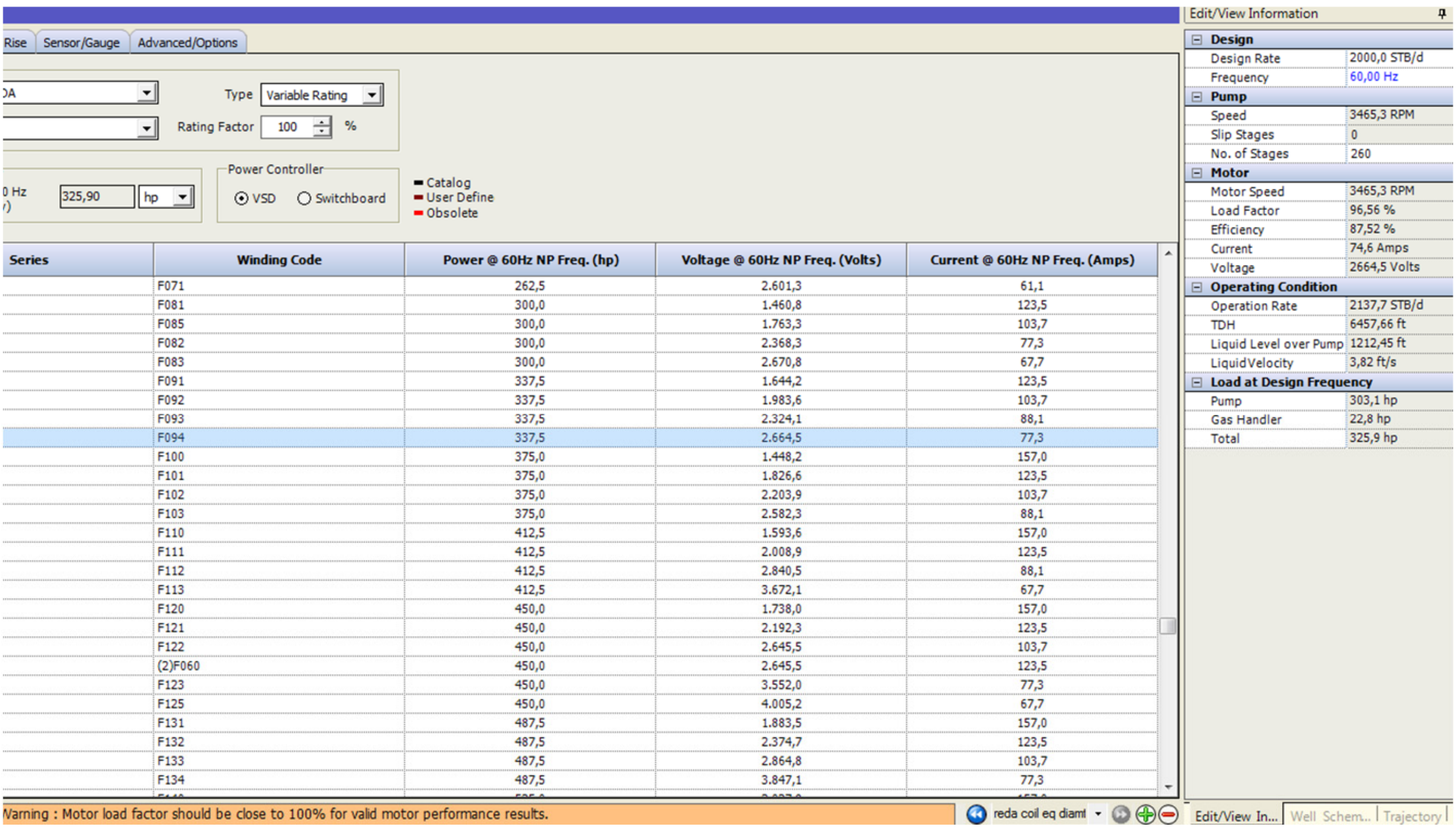


Figure 32: DesignRite motor selection window

The selected motor should deliver the horse power required to operate the entire system. It is recommended to have a motor load factor around 80% at the operating frequency to allow a certain flexibility to increase the frequency if needed.

Nevertheless, since the well behaviour is not constant over time and due to the uncertainties in the well data, the selected pump motor should not only deliver the horse power required by the system at the design frequency but also be able to deliver the power needed at the worst case scenarios that had been identified. For this reason, a bigger motor is sometimes needed to be able to run the pump at these harsh scenarios. In this case, having a higher rated capability, the motor load factor at the normal operating conditions would be lower than recommended. Therefore, the de-rating of the motor is sometimes necessary in order to comply with the mentioned recommendation. This means that the motor would be operated at less than its rated maximum capability but can be rated back to its original state if higher loads are expected and the operation frequency has to be increased.

After the motor selection, the next step would be to select the protector section and the cable.

Generally, the use of one protector section is sufficient. However, the data uncertainty might compel the installation of another protector to ensure the system reliability. This is the case of the 5 wells. Besides that, the bottom-hole temperatures of the wells are rather high, around 90°C in average, which makes the motor oil expand considerably. This then requires the use of two bag sections in parallel in addition to the labyrinth section of the protector. Thus the protector used would be a LSBPB if applicable.

Additionally, the produced oil specific gravity is lower than that of the lightest protector oil available for the Schlumberger protectors. This might cause improper functioning of the protector and its eventual failure as it wouldn't be able to prevent the well fluid from entering the motor. In order to avoid this risk, all of the ESP designs used two LSBPB protectors when the technology allowed it.

Occasionally, the selection of two LSBPB sections is not allowed in the software. Namely the design of the RedaCoil ESP for the wells Ameni 1 and Waha 2, and the design of the WL deployed ESP of the wells Ameni 1 and Ameni 2. In these cases, one protector section was selected. However, this needs to be further checked with the provider.

Regarding the power cable selection, a rule of thumb advises that the voltage losses through the cable shouldn't be more than 10% of the surface voltage supply. Power cables were selected accordingly to satisfy this suggestion, while keeping into account the technologies requirements. Particularly, the Zeitecs shuttle imposes the use of an AWG#4 flat cable for its 450 shuttle.

One ESP design among the 15, that is the Waha 2 WL deployed ESP design, was not able to be performed for the following reasons:

- Waha 2 has a very high rate potential up to 5,000stb/day which cannot be delivered by a 338 series pump as the largest pump available is A2700N with an operating range way less than the desired rate.
- Even after reducing the design rate to 3,000stb/day the 338 pump would require more than the maximum advised number of stages and housings to deliver the necessary head and rate at the conventional operating frequencies.
- Even though the number of pump stages was reduced to 350 while increasing the operating frequency, the required horse power to be delivered by the motor was too high for a 375 series motor.

For these reasons, it was decided to discard this technology for the well Waha 2.

Finally, 14 ESP designs were performed in total and the general reports of these designs can be found in Appendix B.

5.2.3 Safety Design Measures

Some safety measures were taken while performing the ESP designs. These are listed and explained below.

Firstly, it should be understood that gas interference in the ESP de-rates the pump stages and reduces their capability to deliver a certain head. In case the ESP design does not account for this possible head degradation, the pump risks not to operate properly if ever. Therefore, in order to avoid this risk, there have to be some safety factors when designing an ESP pump. In this regard, it is advised to apply de-rating factors of the head delivered and the power required by the pump. In fact, it is recommended to de-rate the head up to 90% and to increase the power to 120%. These factors can be inputted in the pump selection advanced options section as shown in the figure below.

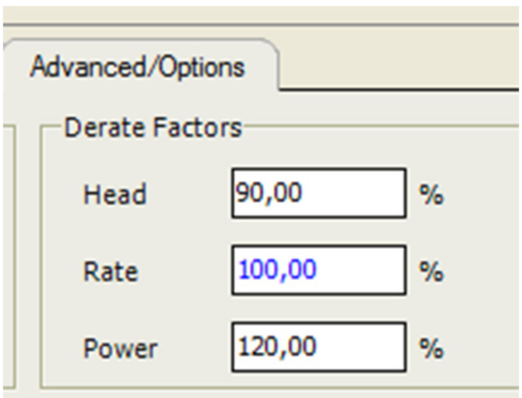


Figure 33: De-rate factors

Secondly, as mentioned before, CR-CT pump housings were selected to avoid any risks related to the severe to moderate sand production in the wells, the data uncertainty, and the unexpected reservoir behaviours.

It has to be noted that fluctuating and unstable well behaviours change the thrust loads on the pump impellers. In the case of a floater pump, this leads to its operation in the down-thrust or up-thrust areas outside of the recommended operation range. This eventually causes the thrust washers on the impellers and diffusers to deteriorate and leads to more severe issues. In addition, since abrasive solids are present in the produced fluid, it is more beneficial to handle the thrust in an area where the thrust bearings are lubricated by the motor oil rather than the well fluid, which is the case for compression pumps, where all impellers are rigidly fixed to the shaft and all thrust developed is transferred to the protector shaft directly. As long as the protector has a great enough capacity, the pump operating range can be also extended over a much wider interval without any increased wear or reduced life. The two types of pumps along with the areas where the thrust is carried are illustrated in the figure below.

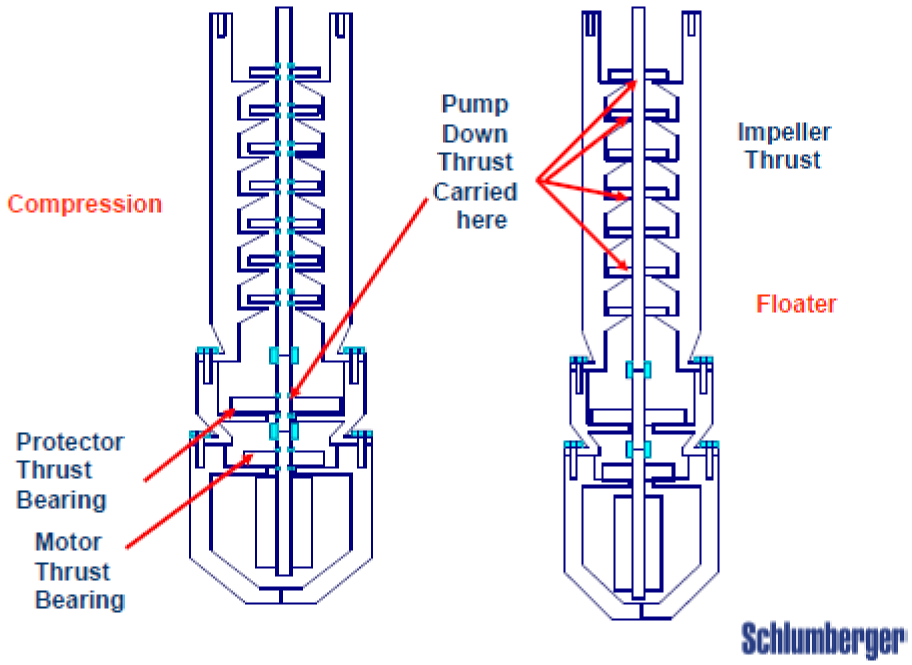


Figure 34: Floater vs compression pumps [6]

Thirdly, the motor selection, as explained before, was performed based on its capability to operate at identified worst case scenarios where harsh conditions are faced.

Finally, two protector sections were used in most of the cases due to the data unreliability and to the fact that the produced oil is lighter than the lightest protector oil existing in the catalogues. This was done as a safety measure to avoid well fluid from entering to the motor by setting the second protector as a backup to the first in case it fails.

5.3 Economic Evaluation

The economic evaluation is the last step of the technology candidate selection process and the final ranking of the well candidates. After checking the applicability of each of the technologies for the selected wells and designing the ESPs that could be run in each case, the next step is to select the technology that would justify the investment of the rig-less ESP technology, contribute to the highest profitability, and satisfy the expected KPIs set by the branch office. These KPIs, or key performance indicators, can include costs, profits, payback period, rate of return, etc...

A discounted cash flow and NPV calculations should be performed over a period of at least 5 years in order to be able to, first, compare the different rig-less technology cases with each other for each well, second, choose the optimum technologies relying on the specified KPIs, third, compare the current well status, or the original case, with the cases of the selected rig-less technologies for all well candidates, and finally, evaluate the wells profitability and decide whether the investment is justified.

For these calculations, many input data need to be gathered. These include mainly the capital expenditures, operating costs, and production profile, which differ with the technology and the well. In fact, on one hand, approximations of total costs of ownership in each case has to be identified. These may require the collection of information involving the MTBF, rig costs, wireline, slick-line, and CT units costs, as well as a quote and a budgetary proposal for every case that should be demanded from the supplier. On the other hand, a production profile for all cases should be determined, taking into account all the assumptions that were previously set, with the help of the reservoir engineers responsible for the field.

Moreover, another important factor for the discounted cash flow and NPV calculations required for this comparison and selection process is a clear understanding of the contract between OMV and the country, as well as the country's tax regime. In addition, forecasts of the discount rates and the oil prices for the following years need to be acquired from OMV's management since these are crucial for the calculations.

After gathering all the necessary data, a first comparison should be performed between the applicable technologies for each well, in order to choose the technology based on a subjective judgement of the KPIs and other factors like HSE considerations and risk assessments.

Following the technology selection, another comparison of the selected rig-less technology with the original well status has to be done in order to evaluate the well profitability and whether the investment of a rig-less ESP is justified. This is done by assessing the profit margin with regards to the risks that may be faced.

The final step is to perform a final well ranking based on the DCF and NPV calculations, the technical applicability of the systems, the HSE considerations, and a risk assessment.

Regarding the case of the studied field, budgetary proposals from the suppliers as well as necessary information from the contract between OMV and the country could not be gathered due to confidentiality reasons. For this reason, the economic evaluation and the final technology selection and well candidate ranking could not be performed and will be transferred to the OMV branch office to complete.

5.4 HSE Considerations

The HSE factors that need to be taken into consideration can be summarized in the following points:

- Ensuring that the service is compliant with well barrier acceptance criteria: generally two well barriers should be present in all times
- Checking the well integrity and the casing state in case of annular production and asking for exemption after studying the risks
- Checking the applicability of SSSVs for all technologies: it was checked and the installation of an SSSV is possible in all cases.
- The deployment of the ESP should be done following the process and procedures of OMV or the supplier.

These considerations are important to work with in order to ensure the safety of the personnel, equipment, and environment and to ensure accident free procedures.

5.5 Assessment of the Rig-less ESP Technologies Limitations and Risks

Some limitations follow the rig-less ESP technologies and may cause them to become a bottle neck in some cases.

As a matter of fact, all technologies are limited depth wise which restricts the pump setting depth and therefore the production potential.

In addition, in the case of cable external CT deployed ESPs, and as it can be seen in the pressure profile curves for the corresponding ESP design general reports in appendix B, the small ID of the coiled tubing, through which the production is performed, induces friction pressure losses that can be as high as 250 psi (Amani 2). These friction pressure losses can further increase in case of scale accumulations on the inside walls of the CT. They hinder the production and reduce the flow rates which limits the wells potential. As a rule of thumb, a 10bar friction losses is an acceptable number for the latter. Another weak point in this technology is the CT yield strength which may not be able to handle all the loads that occur while handling or operating the system. The stresses on the CT need therefore to be checked using a CT modelling software available from the supplier.

Besides, the wireline deployed ESP systems are ESP-limited due to its small size. In fact, the 338/375 series ESP systems would sometimes be unable to deliver the required head or limit the production rate. This was the case of Waha 2 where the design of a 338 ESP was not possible as explained in a previous point.

Regarding the RedaCoil technology, its main disadvantage is the annular production that requires a good casing integrity which may or may not be the case in these 5 wells. On the other hand, the risk of damaging the casing is high especially in case of CO_2 presence in the produced fluid and in cases of high water cuts. It should be mentioned here that the produced waters have a very high salinity and chloride content, which further increases the corrosion risks.

Another limitation that is not directly related to the technologies is the sand production. One of the main causes of previous failures of ESP pumps in some wells in the field is sand and abrasives content in the produced fluids. Even though some protection and mitigation measures were taken in the ESP designs, sand would still be an issue that needs to be treated. It therefore would be recommended to design and install gravel packs in the wells where the rig-less ESP is to be installed in order to reduce the risks of premature failures due to sand production.

6 Rig-less ESP Candidate Selection Implementation Plan

A workflow of the rig-less ESP implementation plan was done and will be explained in this chapter.

After gathering all necessary data, the rig-less ESP implementation plan should start first with the selection of the well candidates most suitable for the technology. This is done by first performing a pre-selection of the wells based on their maximum oil rate potential. This primary selection eliminates the wells that, at their optimum conditions and for a desired GVF, do not have high enough oil rates to justify the investment of a rig-less ESP system. Following is the well candidate ranking, where the pre-selected wells are ranked based on a number of technical and logistic criteria. This is done using the TOPSIS algorithm along with the AHP method as a multi-criteria decision analysis tool. The number of wells that would be considered in the following step can be chosen based on a subjective judgement.

After the well ranking comes the technology candidate selection. The latter includes three sub-steps. First, a technology applicability check is needed to be performed in order to eliminate the technologies that are unsuitable or inapplicable in the wells. Second, an ESP design using a designing software, in this case DesignRite was used, should be performed for each technology in each well. The designs should preferably be done in a conservative way where safety measures are taken in order to reduce any possible risk. This would primarily depend on the well conditions and the degree of certainty of the data gathered. Finally, an economic evaluation needs to be done. This requires the calculation of the DCF and NPV for every studied case. A comparison between the technology candidates has to be performed in order to choose the optimum technology satisfying the specified KPIs. Another comparison between the selected technology and the original well status has to be done in order to evaluate the profitability versus the risks to decide whether or not the investment of the rig-less technology can be justified.

Following the technology candidate selection, a final well ranking can be done taking into consideration the technical, logistic, and economic factors as well as the HSE considerations and risk assessment.

Final decisions have to be done based on the previous points in order to determine the number of wells where the rig-less ESP systems would be installed.

The rig-less ESP candidate selection workflow is depicted in figure 35.

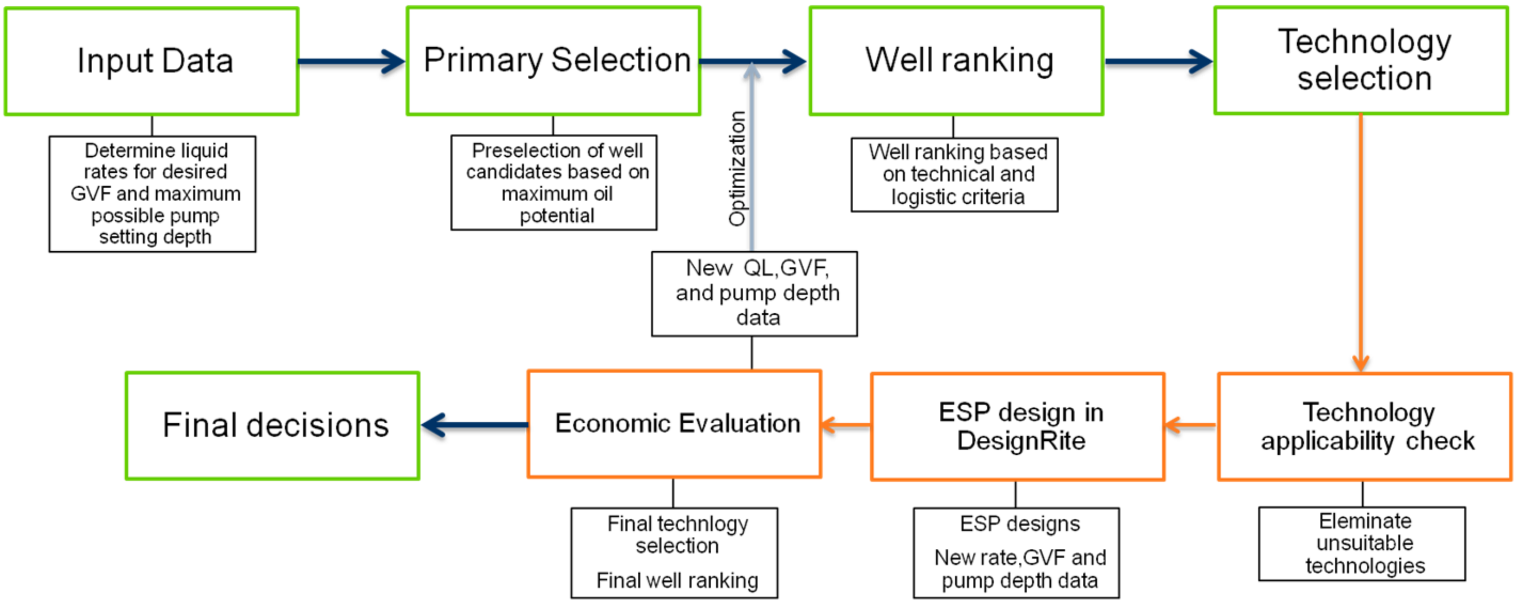


Figure 35: Rig-less ESP candidate selection workflow

7 Conclusions and Recommendations

This master thesis was done in collaboration with OMV in the purpose of selecting rig-less ESP candidates in one field they operate and where challenges were encountered when operating conventional ESP systems in terms of unavailability of workover rigs and their relatively high cost. Combined with a low mean time between failures for the existing ESP systems, the economics of the ESP operations are drastically affected reducing the wells profitability and economic limit.

The rig-less ESP candidate selection consisted of a selection of the well candidates most suitable for this technology, via a primary selection and a well ranking process, and the selection of the optimal rig-less technology to be installed in the latter including applicability check of the technologies, ESP designs and recommendations for the economic evaluation.

In a first step, all available well data were gathered and studied. Due to several factors, it was concluded that there was a relatively high uncertainty in the data related to the wells' performance and reservoir behaviour and properties. As a matter of fact, the 23 studied wells produce commingled from different layers which have different reservoir characteristics. In addition, PVT data were not available for most of the layers and well tests data were assembled 2 to 6 years ago. Besides, data regarding the sand production, scale, paraffin, and corrosion were given qualitatively because of the lack of quantitative measurements.

A part of the data was used in updating and matching the PROSPER files used in the primary selection of the well candidates, while another part was needed in the well ranking process. In addition, the PVT data were used in the ESP designs done with the Schlumberger software DesignRite. This means that probable errors due to data uncertainty can be present in all the mentioned steps.

The first part of the thesis work is the well candidate selection, where an excel tool was created to accomplish this. A pre-selection was performed to eliminate the wells that, at their optimum conditions and at a pre-defined GVF at the pump intake do not have a maximum oil rate potential high enough to justify the investment in a rig-less technology. A well candidate ranking was then performed using the TOPSIS algorithm and the AHP method and accounting for 9 different criteria. Both steps require a subjective judgement from the user of the tool to decide on the well deliverability scale and to do the pair-wise comparisons between the criteria to determine their relative importance and assign a weight to each of them. This means that, due to the inclusion of the human factor and due to a probable comparisons inconsistency, errors may occur. The final results of the well candidate selection is a ranking of 7 well candidates, the first 5 from which were considered in the following step.

The second part of the thesis is the technology candidate selection which began with an assessment of the key specifications required by the available technologies with regards to the wells in order to check their applicability in the wells. The technologies that were considered were Schlumberger's cable external CT deployed ESP system, RedaCoil, and

Zeitecs, AccessESP's wireline deployed ESP system, and NOVOMET's Colibri ESP. One technology was eliminated as it cannot be applied in any of the well candidates. This is the power cable deployed Colibri ESP provided by the supplier NOVOMET.

Following was the ESP design for all possible cases using DesignRite, a Schlumberger software for ESP design. Several safety measures were taken in the ESP designs to mitigate the data uncertainty and to make sure that the signs are robust. These can be summarized in the use of de-rate factors (90% of the head and 120% of the power), the use of compression pumps instead of floater pumps due to data uncertainty and sand production, designing the ESP system so that it would operate at the defined worst case scenarios, and the use of two protector sections LSBPB LSBPB.

The economic evaluation could not be performed due to confidentiality reasons as it was not possible to obtain budgetary proposals from the suppliers as well as other relevant data from OMV. For this reason, the final technology selection was not performed.

An assessment of the rig-less technologies limitations and risks was finally done, where it was concluded that limitations may cause these technologies to be considered a bottle neck in some case. These can be summarized in the following points:

- All technologies are limited depth wise restricting the production potential
- Cable external CT deployed ESP systems are limited in terms of the small coiled tubing ID which induces high friction pressure losses and hinder the production.
- The CT yield strength has to be checked as it may not be able to handle all loads imposed on the system.
- Wireline deployed ESP systems are ESP-limited due to its small size which may not be able to deliver the required head or rate.
- The main disadvantage of the RedaCoil technology is the annular production. Data regarding well integrity and casing states were not provided. Therefore these need to be checked before deciding on whether to install this technology.

It was also found that sand production is one major issue encountered in the studied field and is one of the major causes of failure of previously installed conventional ESP pumps. Even though some protection and mitigation measures were taken in the ESP designs, sand would still be an issue that needs to be treated. It is therefore recommended to install gravel packs in the affected wells and especially in wells where the rig-less ESP is to be installed.

Finally a general rig-less ESP implementation plan and workflow was built explaining the well candidates and rig-less technology selection processes.

8 References

[1] Society of Petroleum Engineers, Petroleum Engineering handbook - Volume IV Production Operations Engineering - Chapter 13.

[2] G. Takacs, Electrical Submersible Pumps Manual, Burlington: Gulf Professional Publishing, 2009.

[3] American Petroleum Institute, *API RP 11S3, Recommended Practice for Electrical Submersible Pump Installations, second edition,* Washington, DC, March 1999.

[4] OMV, „Processes & Procedure for Electrical Submersible Pump (ESP) U.C.09-HQ-PRO-004," Vienna, 2017.

[5] C. Blum, J. Jimenez, L. Pozo, N. Garibay, N. Griffiths, L. Constante und E. Padilla, *SPE 165076: Alternative deployment of an ESP system in South America,* Cartagena, Colombia, 2013.

[6] Ltd, Courtesy: Schlumberger.

[7] Ltd, Courtesy: AccessESP.

[8] Ltd, Courtesy: NOVOMET.

[9] R. Bhattacharya, „LinkedIn," 6 May 2016. [Online]. Available: https://www.linkedin.com/pulse/topsis-whats-dr-rabindranath-bhattacharya/.

[10] E. Mu und M. Pereyra-Rojas, „Understanding the Analytic Hierarchy Process," in *Practical decision making*, Springer, 2017, pp. 7-22.

Appendices

Appendix A

Table 21: PVT data of the 5 wells

Well	PVT				
	Bubble point pressure [psi]	Bubble point temperature [°C]	GOR [scf/stb]	Formation volume factor [rb/stb]	Viscosity [cp]
Amani 1	2352	77.3	800	1.457	0.413
Amani 2	2352	77.3	470	1.457	0.413
El Badr 1	1969	100	647	1.427	0.388
Mona 1	No PVT data Available				
Waha 2	1311.7	92.5	432	1.302	0.51

Appendix B

Technical Design: Amani 1 Cable External CT deployed ESP

General Information

Contact Details

Project	*Cable External CT deployed ESP*
Field & Lease	*Anaguid EST*
Well Name	*Amani 1*

Input Data and Information

Production and Fluid Data

Oil Gravity	*40*	*ºAPI*	Water Specific Gravity	*1,2*	
Water Cut	*25*	*%*	Gas Specific Gravity	*0,87*	
GOR	*800*	*SCF/STB*	Bubble Point	*2352*	*psig*

Wellbore Information

Wellhead Temperature	*86*	*ºF*	Bottom Hole Temperature	*177,8*	*ºF*
Perforation Depth	*8763,12*	*ft*			

Casing	Length (ft)	OD (in)	ID (in)	Roughness (in)	Flow Type
1	*5561,02*	*9,625*	*8,681*	*0,00065*	*TUBULAR*
2	*3202,1*	*7*	*6,094*	*0,00065*	*TUBULAR*

Tubing	Length (ft)	OD (in)	ID (in)	Roughness (in)	Flow Type
1	*8483,38*	*2,375*	*1,991*	*0,00065*	*TUBULAR*

Desired Operating Conditions

Pump Depth	*8530,18*	*ft*	Frequency	*50*	*Hz*
Design Rate	*1100*	*STB/d*	Wellhead Pressure	*118*	*psig*
Pump Speed	*2839,3*	*RPM*			

Equipment and Results

Pumping Conditions

Production Rate	*1130,7*	*STB/d*	TDH	*2728,16*	*ft*
Intake Pressure	*1627,4*	*psig*	Pump Speed	*2839,3*	*RPM*
Discharge Pressure	*2580,5*	*psig*	Separation Efficiency	*98,23*	*%*
Mixture Gradient	*0,349*	*psi/ft*			

Pump Information

Device Information	*REDA 400 DN1800*			
Stages	*234*			
Staging Configuration	*CR-CT*		Staging Type	*ARZ*

Gas Separator

Device Information	*REDA 400/400 VGSA D20-60, 400/400*				
Power	*2,5*	*hp*	Efficiency	*98,23*	*%*
Free Gas Into Pump	*0,37*	*%*			

Motor Nameplate Information

Device Information	*REDA 456 Maximus 4072*				
Volts	*2141,5*	*Volts*	Power	*90,3*	*hp*
Speed	*2839,3*	*RPM*	Amp	*27,1*	*Amps*
Rating Factor	*86*	*%*	Winding Number	*4072*	
Instrument Tube OD					

Cable Information

Type	*ELB*
Conductor Size	*4*

Length	*8630,18*	*ft*
KV	*4*	*kV*
Temperature Rating	*450*	*ºF*

Protector

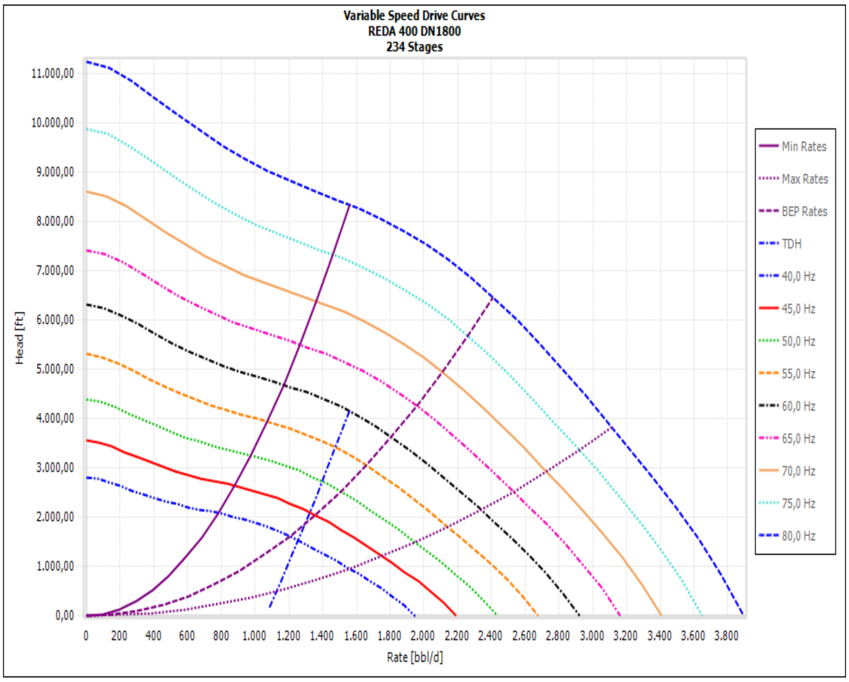
Thrust Bearing Type	*400 Maximus HL*	Oil Type	*REDA OIL #5*

Number of Seals	*4*
Configuration	*LSBPB LSBPB*
Number of Chambers	*6*
Components	*TANDEM*

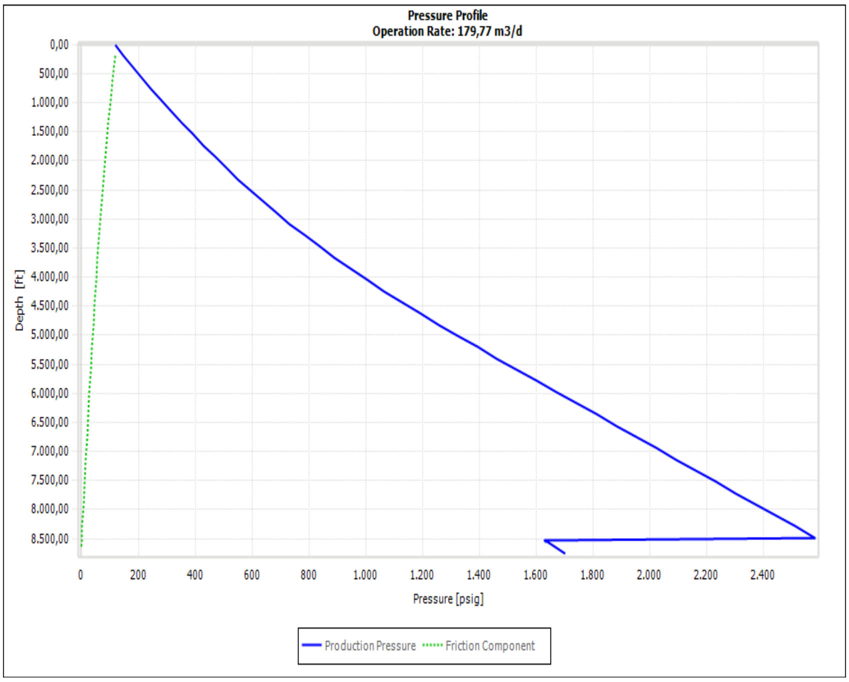
Conditions at Operating Frequency

Operating Frequency	*50*	*Hz*	Volts @ Junction Box	*1864,7*	*Volts*
Motor Amp	*18,6*	*Amps*	KVA @ Junction Box	*60*	
Total Motor Load	*43,2*	*hp*	Motor Volts	*1784,6*	*Volts*

VSD Curve



Pressure Profile Curve



Technical Design: Amani 1 REDACoil ESP

General Information

Contact Details

Project	*RedaCoil ESP*
Field & Lease	*Anaguid EST*
Well Name	*Amani 1*

Input Data and Information

Production and Fluid Data

Oil Gravity	*40*	*ºAPI*	Water Specific Gravity	*1,2*	
Water Cut	*50*	*%*	Gas Specific Gravity	*0,87*	
GOR	*800*	*SCF/STB*	Bubble Point	*2352*	*psig*

Wellbore Information

Wellhead Temperature	*86*	*ºF*	Bottom Hole Temperature	*177,8*	*ºF*
Perforation Depth	*8763,12*	*ft*			

Casing	Length (ft)	OD (in)	ID (in)	Roughness (in)	Flow Type
1	*5561,02*	*9,625*	*8,68*	*0,00065*	*TUBULAR*
2	*3202,1*	*7*	*6,094*	*0,00065*	*TUBULAR*

Tubing	Length (ft)	OD (in)	ID (in)	Roughness (in)	Flow Type
1	*8510,48*	*6*	*5,612*	*0,00065*	*TUBULAR*

Desired Operating Conditions

Pump Depth	*8530,18*	*ft*	Frequency	*50*	*Hz*
Design Rate	*1000*	*STB/d*	Wellhead Pressure	*118*	*psig*
Pump Speed	*2905,3*	*RPM*			

Equipment and Results

Pumping Conditions

Production Rate	*1057,9*	*STB/d*	TDH	*1342,33*	*ft*
Intake Pressure	*1763,1*	*psig*	Pump Speed	*2905,3*	*RPM*
Discharge Pressure	*2291,3*	*psig*	Separation Efficiency	*0*	*%*
Mixture Gradient	*0,367*	*psi/ft*			

Pump Information

Device Information	*REDA 400 D1400N*		
Stages	*141*		
Staging Configuration	*CR-CT*	Staging Type	*ARZ*

Advanced Gas Handler

Device Information	*REDA 400/400 AGH*

Motor Nameplate Information

Device Information	*REDA 562 Maximus F036*				
Volts	*1488*	*Volts*	Power	*90*	*hp*
Speed	*2905,3*	*RPM*	Amp	*36,4*	*Amps*
Rating Factor	*80*	*%*	Winding Number	*F036*	
Instrument Tube OD					

Cable Information

Type	*ELB*	
Conductor Size	*4*	
Length	*8630,18*	*ft*
KV	*4*	*kV*
Temperature Rating	*450*	*ºF*

Protector

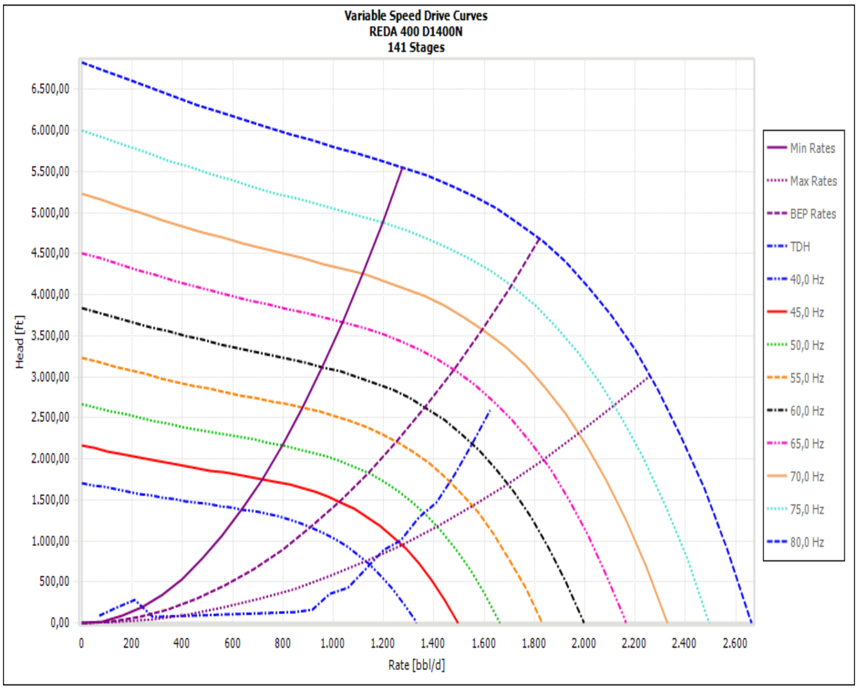
Thrust Bearing Type	*562 Maximus HL*	Oil Type	*REDA OIL #5*

Number of Seals	*2*
Configuration	*LSBPB*
Number of Chambers	*3*
Components	*SINGLE*

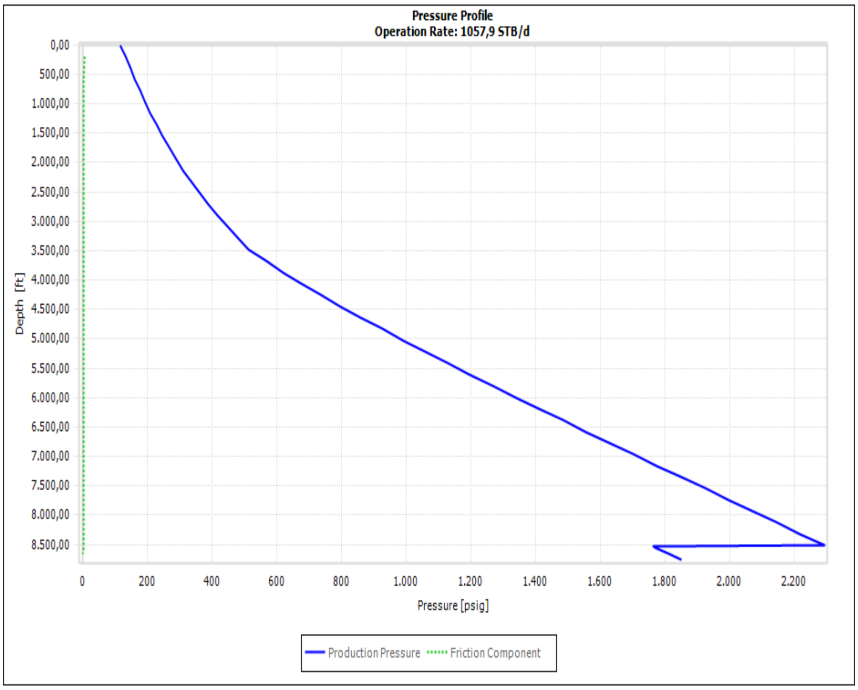
Conditions at Operating Frequency

Operating Frequency	*50*	*Hz*	Volts @ Junction Box	*1337,1*	*Volts*
Motor Amp	*22,5*	*Amps*	KVA @ Junction Box	*52,04*	
Total Motor Load	*34,8*	*hp*	Motor Volts	*1240*	*Volts*

VSD Curve



Pressure Profile Curve



Technical Design: Amani 1 Wireline deployed ESP

General Information

Contact Details

Project	*Wireline deployed ESP*
Field & Lease	*Anaguid EST*
Well Name	*Amani 1*

Input Data and Information

Production and Fluid Data

Oil Gravity	*40*	*ºAPI*	Water Specific Gravity	*1,2*	
Water Cut	*50*	*%*	Gas Specific Gravity	*0,87*	
GOR	*800*	*SCF/STB*	Bubble Point	*2352*	*psig*

Wellbore Information

Wellhead Temperature	*86*	*ºF*	Bottom Hole Temperature	*177,8*	*ºF*
Perforation Depth	*8763,12*	*ft*			

Casing	Length (ft)	OD (in)	ID (in)	Roughness (in)	Flow Type
1	*5561,02*	*9,625*	*8,68*	*0,00065*	*TUBULAR*
2	*3202,1*	*7*	*6,094*	*0,00065*	*TUBULAR*

Tubing	Length (ft)	OD (in)	ID (in)	Roughness (in)	Flow Type
1	*8510,68*	*4,5*	*4*	*0,00065*	*TUBULAR*

Desired Operating Conditions

Pump Depth	*8530,18*	*ft*	Frequency	*50*	*Hz*
Design Rate	*1000*	*STB/d*	Wellhead Pressure	*118*	*psig*
Pump Speed	*2815,4*	*RPM*			

Equipment and Results

Pumping Conditions

Production Rate	*1013,5*	*STB/d*	TDH	*592,01*	*ft*
Intake Pressure	*1849,9*	*psig*	Pump Speed	*2815,4*	*RPM*
Discharge Pressure	*2101,3*	*psig*	Separation Efficiency	*0*	*%*
Mixture Gradient	*0,365*	*psi/ft*			

Pump Information

Device Information	*REDA 338 AN1500*		
Stages	*94*		
Staging Configuration	*CR-CT*	Staging Type	*ARZ*

Advanced Gas Handler

Device Information	*REDA 387/387 AGH*

Motor Nameplate Information

Device Information	*REDA 375 AS J203*				
Volts	*1605,5*	*Volts*	Power	*57,1*	*hp*
Speed	*2815,4*	*RPM*	Amp	*25,8*	*Amps*
Rating Factor	*80*	*%*	Winding Number	*J203*	
Instrument Tube OD					

Cable Information

Type	*ELB*	
Conductor Size	*4*	
Length	*8630,18*	*ft*
KV	*4*	*kV*
Temperature Rating	*450*	*ºF*

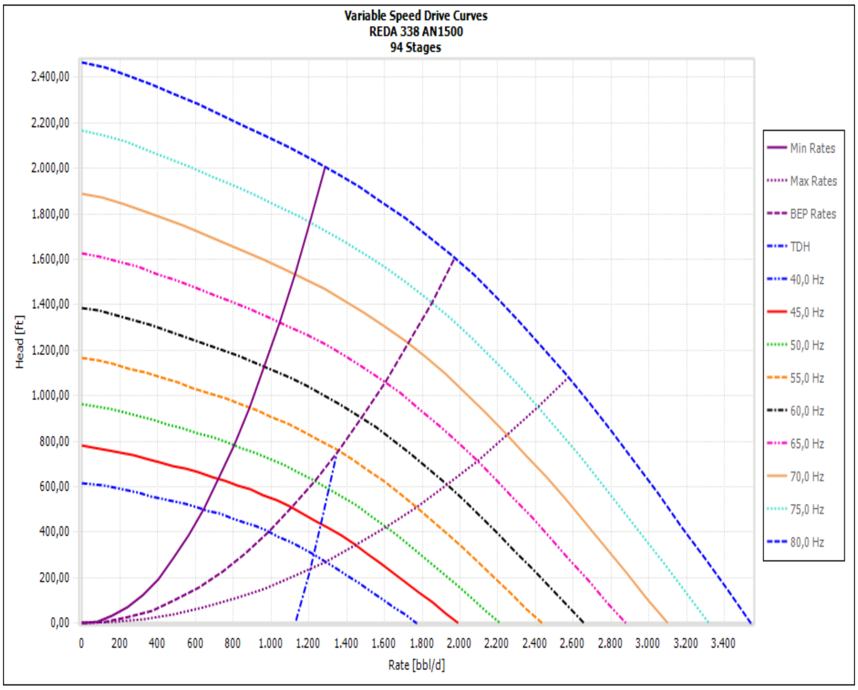
Protector

Thrust Bearing Type	*325 Maximus HL*	Oil Type	*REDA OIL #5*
Number of Seals	*3*		
Configuration	*LSBSB*		
Number of Chambers	*3*		
Components	*SINGLE*		

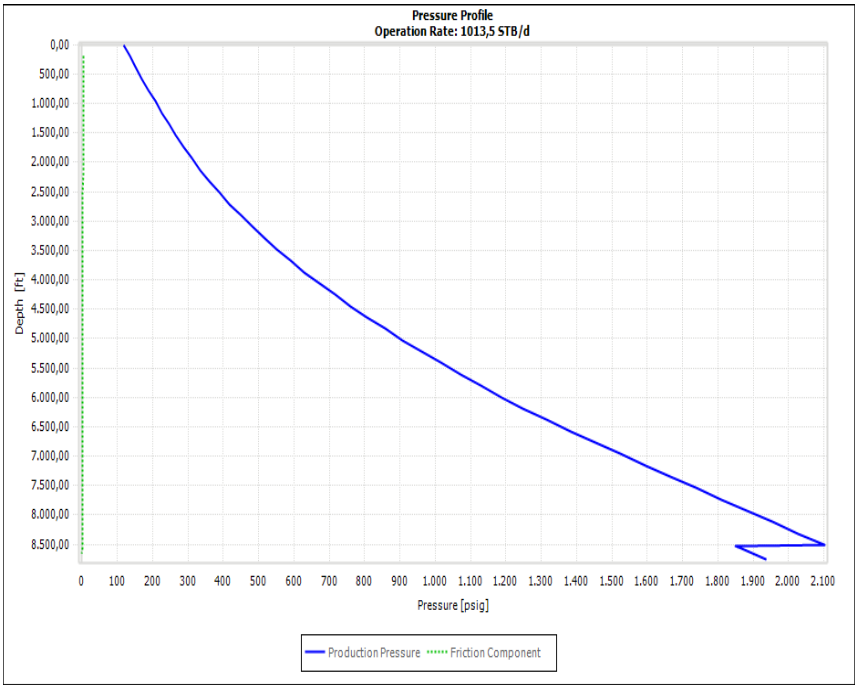
Conditions at Operating Frequency

Operating Frequency	*50*	*Hz*	Volts @ Junction Box	*1392,6*	*Volts*
Motor Amp	*12,7*	*Amps*	KVA @ Junction Box	*30,65*	
Total Motor Load	*22,1*	*hp*	Motor Volts	*1337,9*	*Volts*

VSD Curve



Pressure Profile Curve



Technical Design: Amani 2 Cable External CT deployed ESP

General Information

Contact Details

Project	*Cable external CT deployed ESP*
Field & Lease	*Anaguid EST*
Well Name	*Amani 2*

Input Data and Information

Production and Fluid Data

Oil Gravity	*40*	*ºAPI*	Water Specific Gravity	*1,15*	
Water Cut	*40*	*%*	Gas Specific Gravity	*0,87*	
GOR	*470*	*SCF/STB*	Bubble Point	*2352*	*psig*

Wellbore Information

Wellhead Temperature	*78,8*	*ºF*	Bottom Hole Temperature	*199,4*	*ºF*
Perforation Depth	*8615,49*	*ft*			

Casing	Length (ft)	OD (in)	ID (in)	Roughness (in)	Flow Type
1	*5200,13*	*9,625*	*8,681*	*0,00065*	*TUBULAR*
2	*3431,76*	*7*	*6,094*	*0,00065*	*TUBULAR*

Tubing	Length (ft)	OD (in)	ID (in)	Roughness (in)	Flow Type
1	*8460,98*	*2,375*	*1,991*	*0,0006*	*TUBULAR*

Desired Operating Conditions

Pump Depth	*8530,18*	*ft*	Frequency	*55*	*Hz*
Design Rate	*2000*	*STB/d*	Wellhead Pressure	*300*	*psig*
Pump Speed	*3096,3*	*RPM*			

Equipment and Results

Pumping Conditions

Production Rate	*1862,7*	*STB/d*	TDH	*5752,46*	*ft*
Intake Pressure	*1473,1*	*psig*	Pump Speed	*3096,3*	*RPM*
Discharge Pressure	*3547,7*	*psig*	Separation Efficiency	*94,17*	*%*
Mixture Gradient	*0,36*	*psi/ft*			

Pump Information

Device Information	*REDA 400 D3550*		
Stages	*270*		
Staging Configuration	*CR-CT*	Staging Type	*EXS4*

Gas Separators

Device Information	*REDA 400/400 VGSA D20-60, 400/400*	
Power	*2,8*	*hp*
Natural Separation Efficiency	*0*	*%*
Separator 1 Efficiency Separator Efficiency	*94,17*	*%*
Total Separation Efficiency	*94,17*	*%*
Free Gas Into Pump	*1,11*	*%*

Motor Nameplate Information

Device Information	*REDA 456 Maximus 4171*				
Volts	*2117,8*	*Volts*	Power	*255*	*hp*
Speed	*3096,3*	*RPM*	Amp	*78,6*	*Amps*
Rating Factor	*100*	*%*	Winding Number	*4171*	
Instrument Tube OD					

Cable Information

Type	*ELB*
Conductor Size	*4*

Length	*8630,18*	*ft*
KV	*4*	*kV*
Temperature Rating	*450*	*ºF*

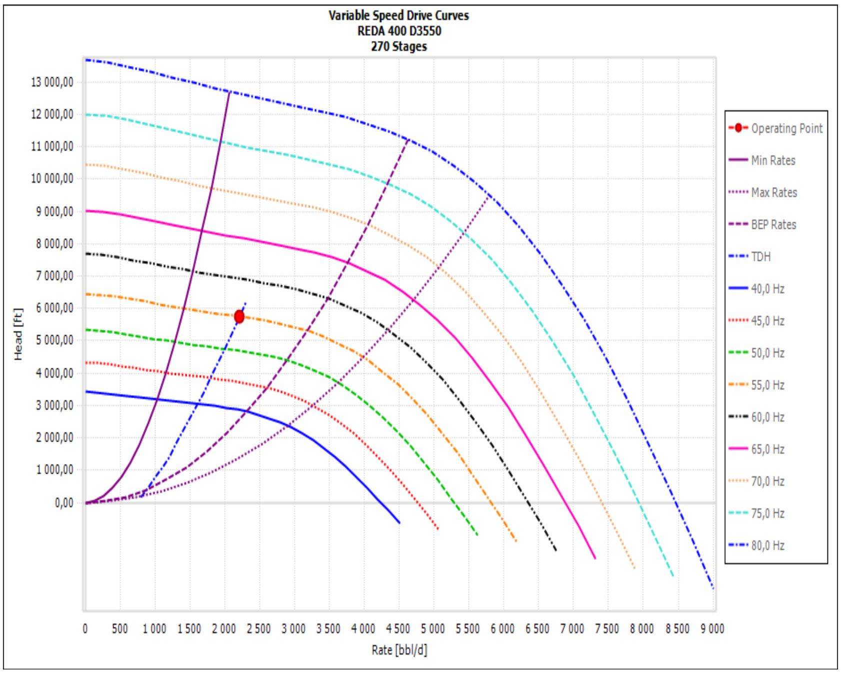
Protector

Thrust Bearing Type	*400 Maximus HL*	Oil Type	*REDA OIL #5*
Number of Seals	*4*		
Configuration	*LSBPB LSBPB*		
Number of Chambers	*6*		
Components	*TANDEM*		

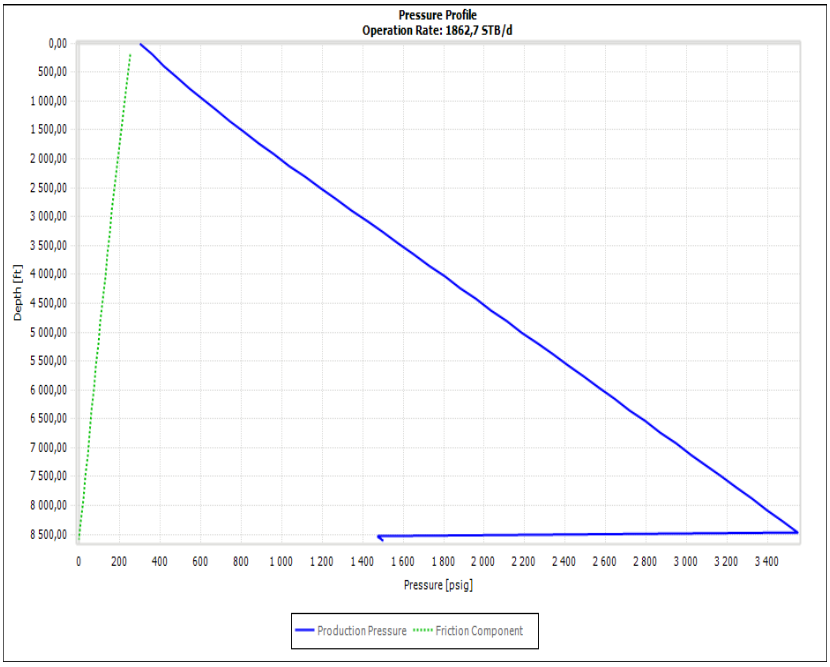
Conditions at Operating Frequency

Operating Frequency	*55*	*Hz*	Volts @ Junction Box	*2218,3*	*Volts*
Motor Amp	*60,6*	*Amps*	KVA @ Junction Box	*232,4*	
Total Motor Load	*168,1*	*hp*	Motor Volts	*1941,3*	*Volts*

VSD Curve



Pressure Profile Curve



Technical Design: Amani 2 REDACoil

General Information

Contact Details

Project	*RedaCoil ESP*
Field & Lease	*Anaguid EST*
Well Name	*Amani 2*

Input Data and Information

Production and Fluid Data

Oil Gravity	*40*	*ºAPI*	Water Specific Gravity	*1,15*	
Water Cut	*40*	*%*	Gas Specific Gravity	*0,87*	
GOR	*470*	*SCF/STB*	Bubble Point	*2352*	*psig*

Wellbore Information

Wellhead Temperature	*78,8*	*ºF*	Bottom Hole Temperature	*199,4*	*ºF*
Perforation Depth	*8615,49*	*ft*			

Casing	Length (ft)	OD (in)	ID (in)	Roughness (in)	Flow Type
1	*5200,13*	*9,625*	*8,681*	*0,00065*	*TUBULAR*
2	*3431,76*	*7*	*6,094*	*0,00065*	*TUBULAR*

Tubing	Length (ft)	OD (in)	ID (in)	Roughness (in)	Flow Type
1	*8478,22*	*6*	*5,612*	*0,0006*	*TUBULAR*

Desired Operating Conditions

Pump Depth	*8530,18*	*ft*	Frequency	*58*	*Hz*
Design Rate	*2000*	*STB/d*	Wellhead Pressure	*300*	*psig*
Pump Speed	*3349,8*	*RPM*			

Equipment and Results

Pumping Conditions

Production Rate	*1904,8*	*STB/d*	TDH	*4213,94*	*ft*
Intake Pressure	*1404,8*	*psig*	Pump Speed	*3349,8*	*RPM*
Discharge Pressure	*2892,7*	*psig*	Separation Efficiency	*0*	*%*
Mixture Gradient	*0,33*	*psi/ft*			

Pump Information

Device Information	*REDA 400 D2400N*		
Stages	*220*		
Staging Configuration	*CR-CT*	Staging Type	*ARZ*

Advanced Gas Handler

Device Information	*REDA 400/400 AGH*

Motor Nameplate Information

Device Information	*REDA 562 Maximus F071*				
Volts	*2601,3*	*Volts*	Power	*262,5*	*hp*
Speed	*3349,8*	*RPM*	Amp	*61,1*	*Amps*
Rating Factor	*100*	*%*	Winding Number	*F071*	
Instrument Tube OD					

Cable Information

Type	*ELB*	
Conductor Size	*4*	
Length	*8630,18*	*ft*
KV	*4*	*kV*
Temperature Rating	*450*	*ºF*

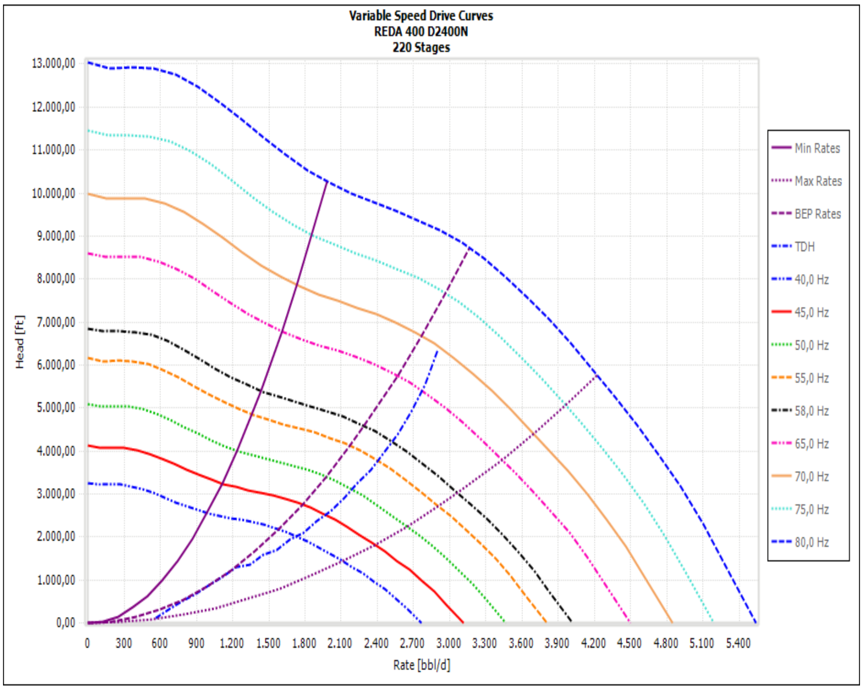
Protector

Thrust Bearing Type	*540 Maximus HL*	Oil Type	*REDA OIL #5*
Number of Seals	*4*		
Configuration	*LSBPB LSBPB*		
Number of Chambers	*6*		
Components	*TANDEM*		

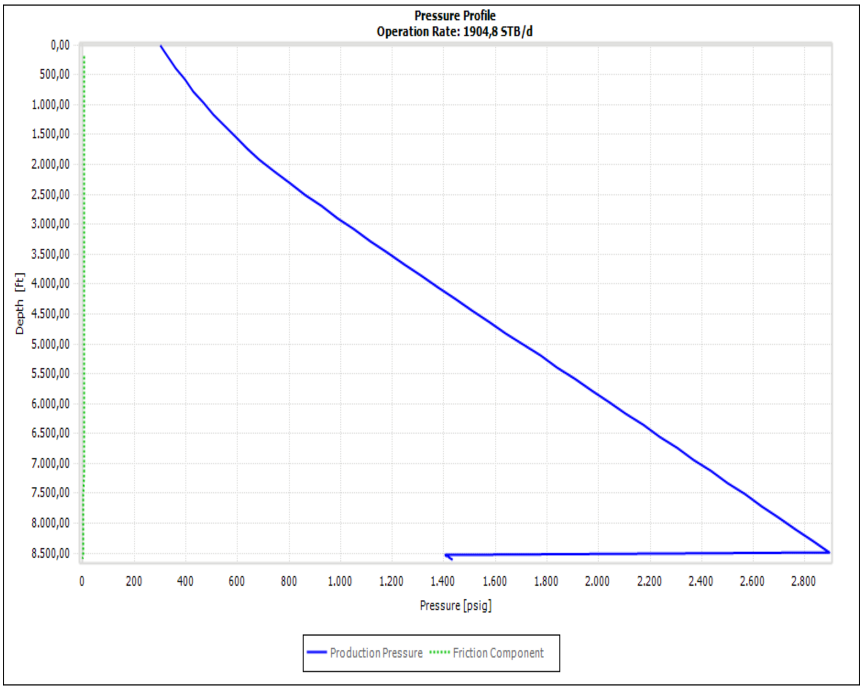
Conditions at Operating Frequency

Operating Frequency	*58*	*Hz*	Volts @ Junction Box	*2694,6*	*Volts*
Motor Amp	*40,2*	*Amps*	KVA @ Junction Box	*187,46*	
Total Motor Load	*130*	*hp*	Motor Volts	*2514,6*	*Volts*

VSD Curve



Pressure Profile Curve



Technical Design: Amani 2 Wireline deployed ESP

General Information

Contact Details

Project	*Wireline deployed ESP*
Field & Lease	*Anaguid EST*
Well Name	*Amani 2*

Input Data and Information

Production and Fluid Data

Oil Gravity	*40*	*ºAPI*	Water Specific Gravity	*1,15*	
Water Cut	*40*	*%*	Gas Specific Gravity	*0,87*	
GOR	*470*	*SCF/STB*	Bubble Point	*2352*	*psig*

Wellbore Information

Wellhead Temperature	*78,8*	*ºF*	Bottom Hole Temperature	*199,4*	*ºF*
Perforation Depth	*8615,49*	*ft*			

Casing	Length (ft)	OD (in)	ID (in)	Roughness (in)	Flow Type
1	*5200,13*	*9,625*	*8,681*	*0,00065*	*TUBULAR*
2	*3431,76*	*7*	*6,094*	*0,00065*	*TUBULAR*

Tubing	Length (ft)	OD (in)	ID (in)	Roughness (in)	Flow Type
1	*8442,58*	*4,5*	*3,958*	*0,0006*	*TUBULAR*

Desired Operating Conditions

Pump Depth	*8530,18*	*ft*	Frequency	*60*	*Hz*
Design Rate	*2000*	*STB/d*	Wellhead Pressure	*300*	*psig*
Pump Speed	*3348*	*RPM*			

Equipment and Results

Pumping Conditions

Production Rate	*1900,2*	*STB/d*	TDH	*4214,61*	*ft*
Intake Pressure	*1415,7*	*psig*	Pump Speed	*3348*	*RPM*
Discharge Pressure	*2800,7*	*psig*	Separation Efficiency	*0*	*%*
Mixture Gradient	*0,328*	*psi/ft*			

Pump Information

Device Information	*REDA 338 A2700N*			
Stages	*324*			
Staging Configuration	*CR-CT*		Staging Type	*ARZ*

Pump Intake

Device Information	*REDA 338/375 338/375*		Power	*0*	*hp*

Motor Nameplate Information

Device Information	*REDA 375 AS (2)J202*				
Volts	*2980,5*	*Volts*	Power	*142,8*	*hp*
Speed	*3348*	*RPM*	Amp	*35*	*Amps*
Rating Factor	*100*	*%*	Winding Number	*(2)J202*	
Instrument Tube OD					

Cable Information

Type	*ELB*	
Conductor Size	*4*	
Length	*8630,18*	*ft*
KV	*4*	*kV*
Temperature Rating	*450*	*ºF*

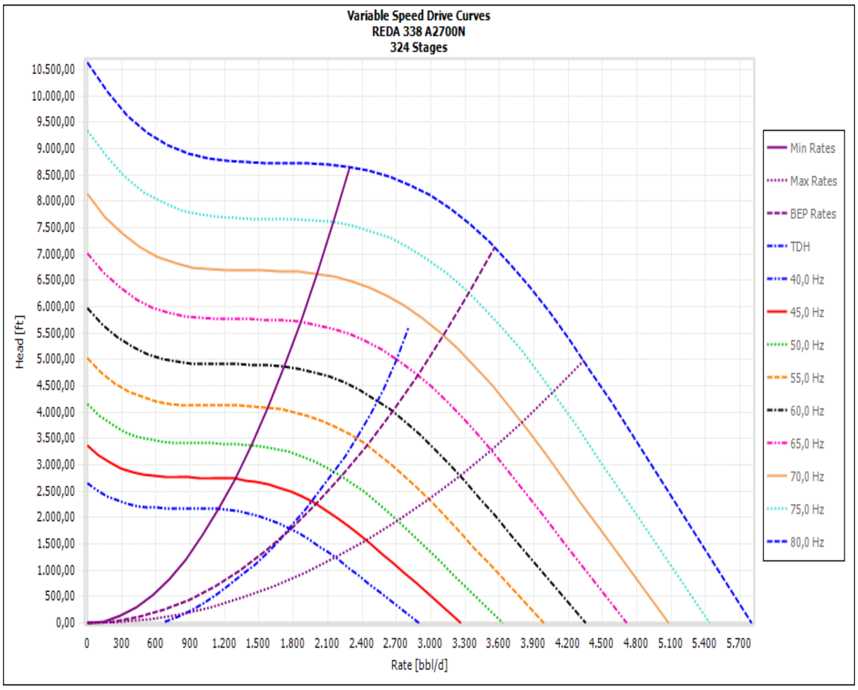
Protector

Thrust Bearing Type	*325 Maximus HL*	Oil Type	*REDA OIL #5*
Number of Seals	*3*		
Configuration	*LSBSB*		
Number of Chambers	*3*		
Components	*SINGLE*		

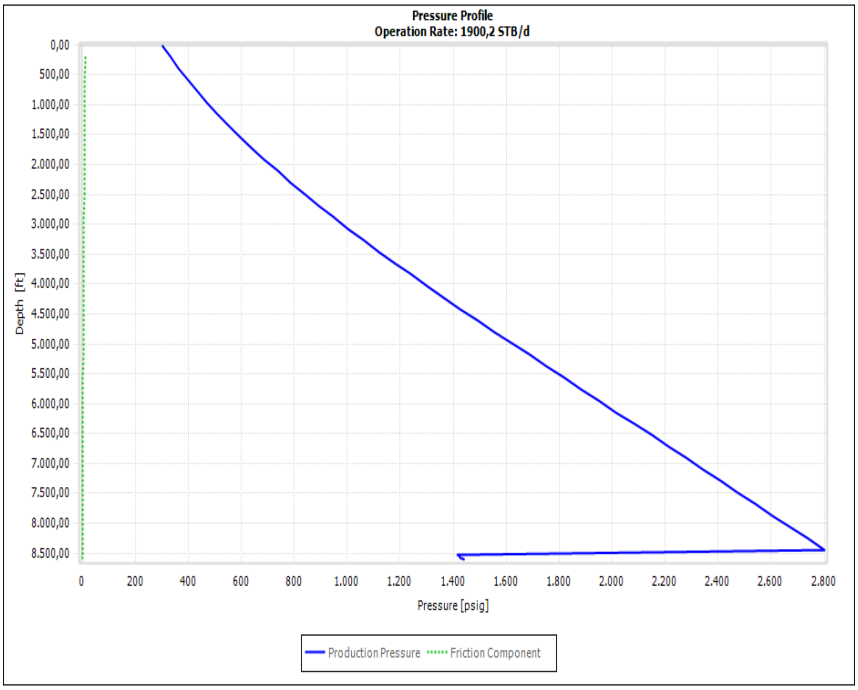
Conditions at Operating Frequency

Operating Frequency	*60*	*Hz*	Volts @ Junction Box	*3100,1*	*Volts*
Motor Amp	*27*	*Amps*	KVA @ Junction Box	*144,57*	
Total Motor Load	*118,4*	*hp*	Motor Volts	*2980,5*	*Volts*

VSD Curve



Pressure Profile Curve



Technical Design: El Badr 1 Cable External CT deployed ESP

General Information

Contact Details

Project	*Cable External CT deployed ESP*
Field & Lease	*Cherouq*
Well Name	*El Badr 1*

Input Data and Information

Production and Fluid Data

Oil Gravity	*40,5*	*ºAPI*	Water Specific Gravity	*1,15*	
Water Cut	*50*	*%*	Gas Specific Gravity	*0,82*	
GOR	*647*	*SCF/STB*	Bubble Point	*1969*	*psig*

Wellbore Information

Wellhead Temperature	*95*	*ºF*	Bottom Hole Temperature	*204,8*	*ºF*
Perforation Depth	*10950*	*ft*			

Casing	Length (ft)	OD (in)	ID (in)	Roughness (in)	Flow Type
1	*5400*	*9,625*	*8,68*	*0,00065*	*TUBULAR*
2	*5550*	*7*	*6,184*	*0,00065*	*TUBULAR*

Tubing	Length (ft)	OD (in)	ID (in)	Roughness (in)	Flow Type
1	*9118,05*	*2,875*	*2,441*	*0,00065*	*TUBULAR*

Desired Operating Conditions

Pump Depth	*9186,35*	*ft*	Frequency	*60*	*Hz*
Design Rate	*2000*	*STB/d*	Wellhead Pressure	*230*	*psig*
Pump Speed	*3377,8*	*RPM*			

Equipment and Results

Pumping Conditions

Production Rate	*2024,4*	*STB/d*	TDH	*7584,14*	*ft*
Intake Pressure	*871,2*	*psig*	Pump Speed	*3377,8*	*RPM*
Discharge Pressure	*3875,5*	*psig*	Separation Efficiency	*98,59*	*%*
Mixture Gradient	*0,396*	*psi/ft*			

Pump Information

Device Information	*REDA 400 D2400N*		
Stages	*351*		
Staging Configuration	*CR-CT*	Staging Type	*ARZ*

Gas Separator

Device Information	*REDA 538/540 VGSA S20-90, 538/540*				
Power	*6*	*hp*	Efficiency	*98,59*	*%*
Free Gas Into Pump	*0,71*	*%*			

Motor Nameplate Information

Device Information	*REDA 456 Maximus 4102&4112*				
Volts	*2615,7*	*Volts*	Power	*315*	*hp*
Speed	*3377,8*	*RPM*	Amp	*78,6*	*Amps*
Rating Factor	*100*	*%*	Winding Number	*4102&4112*	

Cable Information

Type	*ELB*	
Conductor Size	*2*	
Length	*9286,35*	*ft*
KV	*4*	*kV*
Temperature Rating	*450*	*ºF*

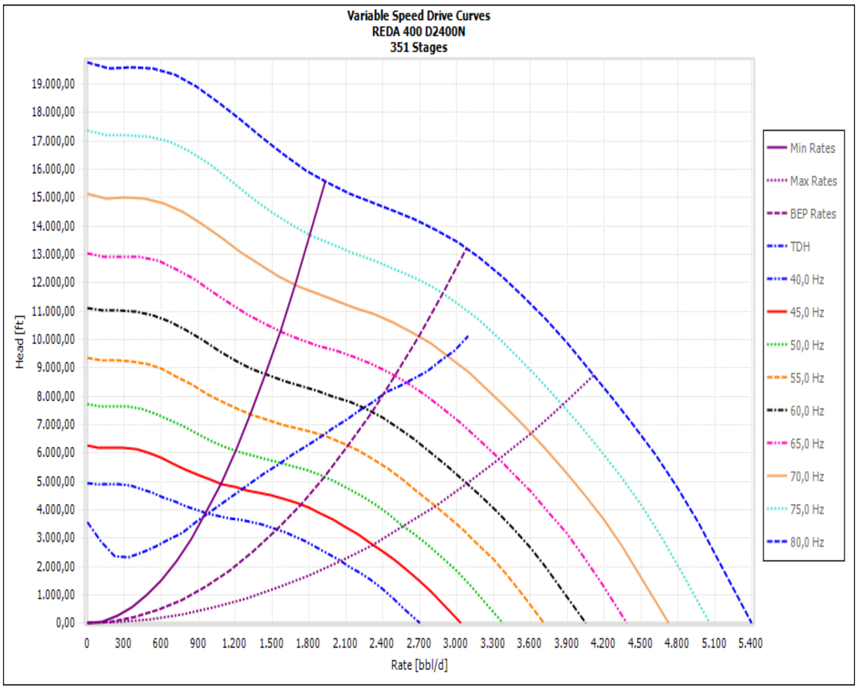
Protector

Thrust Bearing Type	*540 Maximus HL*	Oil Type	*REDA OIL #5*
Number of Seals	*4*		
Configuration	*LSBPB LSBPB*		
Number of Chambers	*6*		
Components	*TANDEM*		

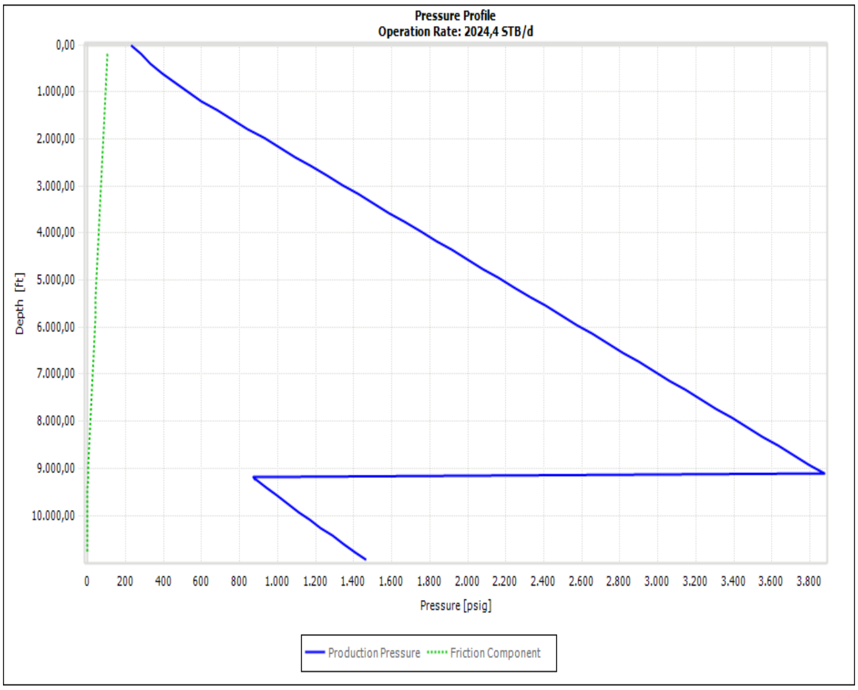
Conditions at Operating Frequency

Operating Frequency	*60*	*Hz*	Volts @ Junction Box	*2801,9*	*Volts*
Motor Amp	*60,8*	*Amps*	KVA @ Junction Box	*294,68*	
Total Motor Load	*227,8*	*hp*	Motor Volts	*2615,7*	*Volts*

VSD Curve



Pressure Profile Curve



Technical Design: El Badr 1 REDACoil

General Information

Contact Details

Project	*RedaCoil ESP*
Field & Lease	*Cherouq*
Well Name	*El Badr 1*

Input Data and Information

Production and Fluid Data

Oil Gravity	*40.5*	*ºAPI*	Water Specific Gravity	*1.15*	
Water Cut	*50*	*%*	Gas Specific Gravity	*0.82*	
GOR	*647*	*SCF/STB*	Bubble Point	*1969*	*psig*

Wellbore Information

Wellhead Temperature	*95*	*ºF*	Bottom Hole Temperature	*204.8*	*ºF*
Perforation Depth	*10950*	*ft*			

Casing	Length (ft)	OD (in)	ID (in)	Roughness (in)	Flow Type
1	*5400*	*9.625*	*8.681*	*0.00065*	*TUBULAR*
2	*5550*	*7*	*6.184*	*0.00065*	*TUBULAR*

Tubing	Length (ft)	OD (in)	ID (in)	Roughness (in)	Flow Type
1	*9146.65*	*6*	*5.709*	*0.00065*	*TUBULAR*

Desired Operating Conditions

Pump Depth	*9186.35*	*ft*	Frequency	*57*	*Hz*
Design Rate	*2000*	*STB/d*	Wellhead Pressure	*230*	*psig*
Pump Speed	*3292*	*RPM*			

Equipment and Results

Pumping Conditions

Production Rate	*2038.3*	*STB/d*	TDH	*5867.99*	*ft*
Intake Pressure	*856.2*	*psig*	Pump Speed	*3292*	*RPM*
Discharge Pressure	*3052.7*	*psig*	Separation Efficiency	*0*	*%*
Mixture Gradient	*0.352*	*psi/ft*			

Pump Information

Device Information	*REDA 538 S4000N*		
Stages	*112*		
Staging Configuration	*CR-CT*	Staging Type	*ARZ*

Gas Handler #1

Device Information	*REDA 538/540 MGH*

Motor Nameplate Information

Device Information	*REDA 562 Maximus F082*				
Volts	*2368.3*	*Volts*	Power	*300*	*hp*
Speed	*3292*	*RPM*	Amp	*77.3*	*Amps*
Rating Factor	*100*	*%*	Winding Number	*F082*	
Instrument Tube OD					

Cable Information

Type	*EL*	
Conductor Size	*2*	
Length	*9286.35*	*ft*
KV	*5*	*kV*
Temperature Rating	*450*	*ºF*

Protector

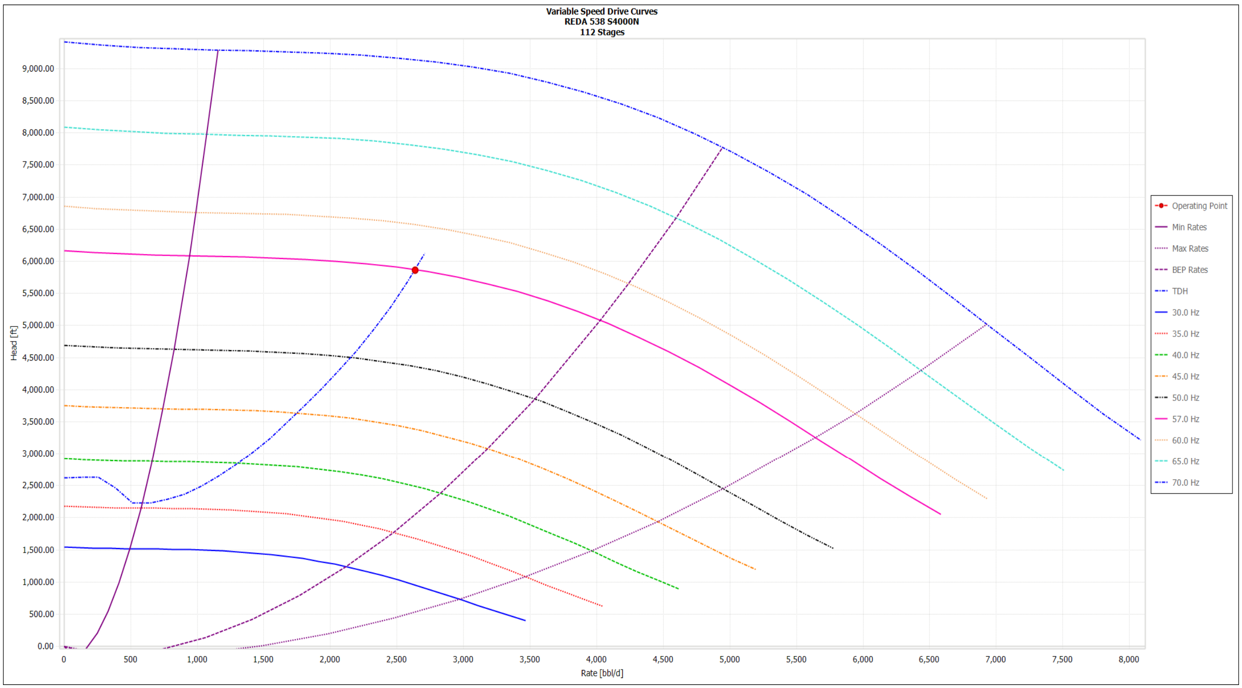
Thrust Bearing Type	*540 Maximus KTB*	Oil Type	*REDA OIL #5*

Number of Seals	*4*
Configuration	*LSBPB LSBPB*
Number of Chambers	*6*
Components	*TANDEM*

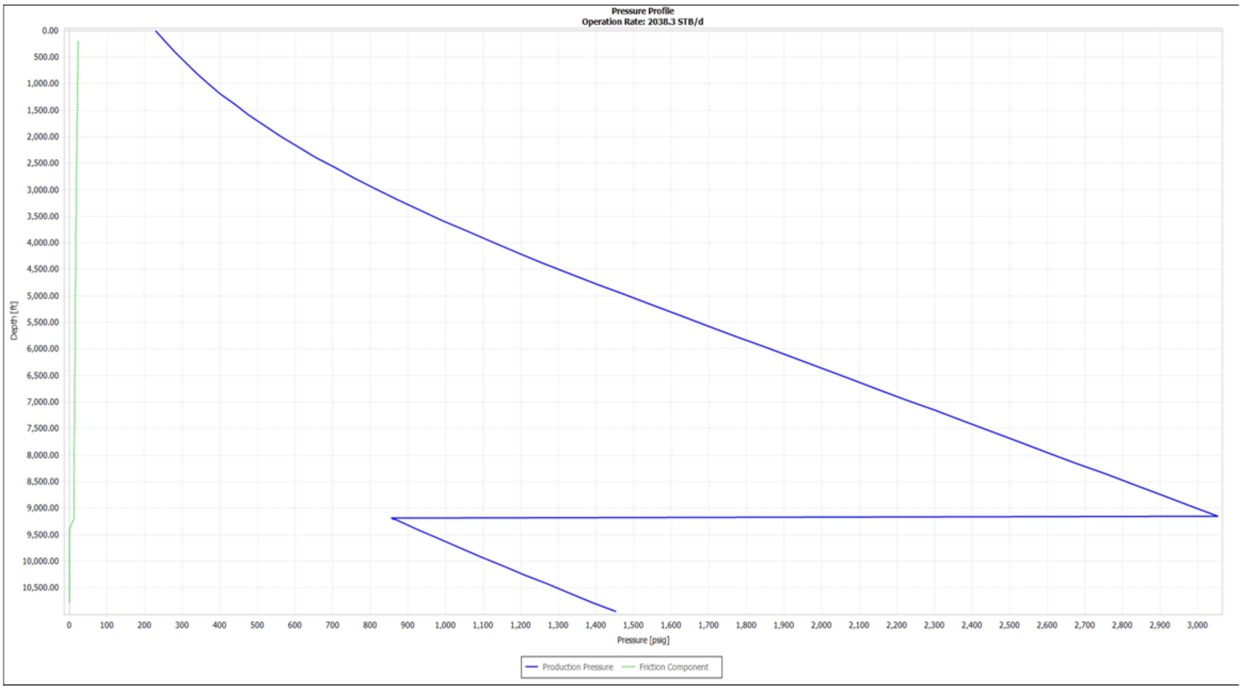
Conditions at Operating Frequency

Operating Frequency	*57*	*Hz*	Volts @ Junction Box	*2454*	*Volts*
Motor Amp	*66.4*	*Amps*	KVA @ Junction Box	*282.09*	
Total Motor Load	*229.3*	*hp*	Motor Volts	*2249.9*	*Volts*

VSD Curve



Pressure Profile Curve



Technical Design: El Badr 1 Wireline deployed ESP

General Information

Contact Details

Project	*Wireline deployed ESP*
Field & Lease	*Cherouq*
Well Name	*El Badr 1*

Input Data and Information

Production and Fluid Data

Oil Gravity	*40,5*	*ºAPI*	Water Specific Gravity	*1,15*	
Water Cut	*50*	*%*	Gas Specific Gravity	*0,82*	
GOR	*647*	*SCF/STB*	Bubble Point	*1969*	*psig*

Wellbore Information

Wellhead Temperature	*95*	*ºF*	Bottom Hole Temperature	*204,8*	*ºF*
Perforation Depth	*10950*	*ft*			

Casing	Length (ft)	OD (in)	ID (in)	Roughness (in)	Flow Type
1	*5400*	*9,625*	*8,68*	*0,00065*	*TUBULAR*
2	*5550*	*7*	*6,184*	*0,00065*	*TUBULAR*

Tubing	Length (ft)	OD (in)	ID (in)	Roughness (in)	Flow Type
1	*9098,55*	*4,5*	*4*	*0,00065*	*TUBULAR*

Desired Operating Conditions

Pump Depth	*9186,35*	*ft*	Frequency	*60*	*Hz*
Design Rate	*2000*	*STB/d*	Wellhead Pressure	*230*	*psig*
Pump Speed	*3348*	*RPM*			

Equipment and Results

Pumping Conditions

Production Rate	*1511,2*	*STB/d*	TDH	*4813,81*	*ft*
Intake Pressure	*1265,7*	*psig*	Pump Speed	*3348*	*RPM*
Discharge Pressure	*3027,3*	*psig*	Separation Efficiency	*0*	*%*
Mixture Gradient	*0,365*	*psi/ft*			

Pump Information

Device Information	*REDA 338 A2700N*		
Stages	*324*		
Staging Configuration	*CR-CT*	Staging Type	*ARZ*

Motor Nameplate Information

Device Information	*REDA 375 AS (2)J202*				
Volts	*2980,5*	*Volts*	Power	*142,8*	*hp*
Speed	*3348*	*RPM*	Amp	*35*	*Amps*
Rating Factor	*100*	*%*	Winding Number	*(2)J202*	
Instrument Tube OD					

Cable Information

Type	*ELB*	
Conductor Size	*4*	
Length	*9286,35*	*ft*
KV	*4*	*kV*
Temperature Rating	*450*	*ºF*

Protector

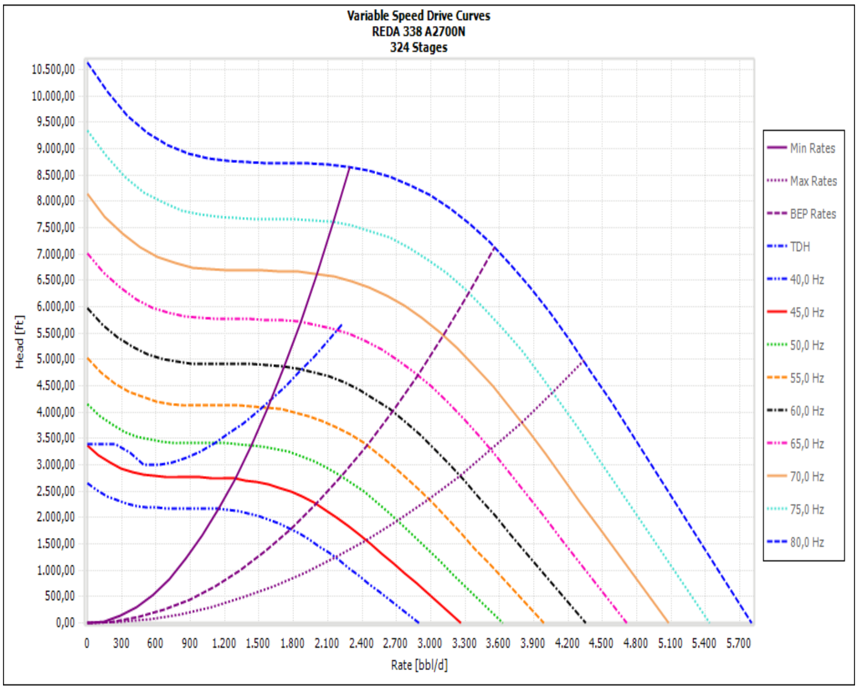
Thrust Bearing Type	*540 Maximus HL*	Oil Type	*REDA OIL #5*

Number of Seals	*4*
Configuration	*LSBPB LSBPB*
Number of Chambers	*6*
Components	*TANDEM*

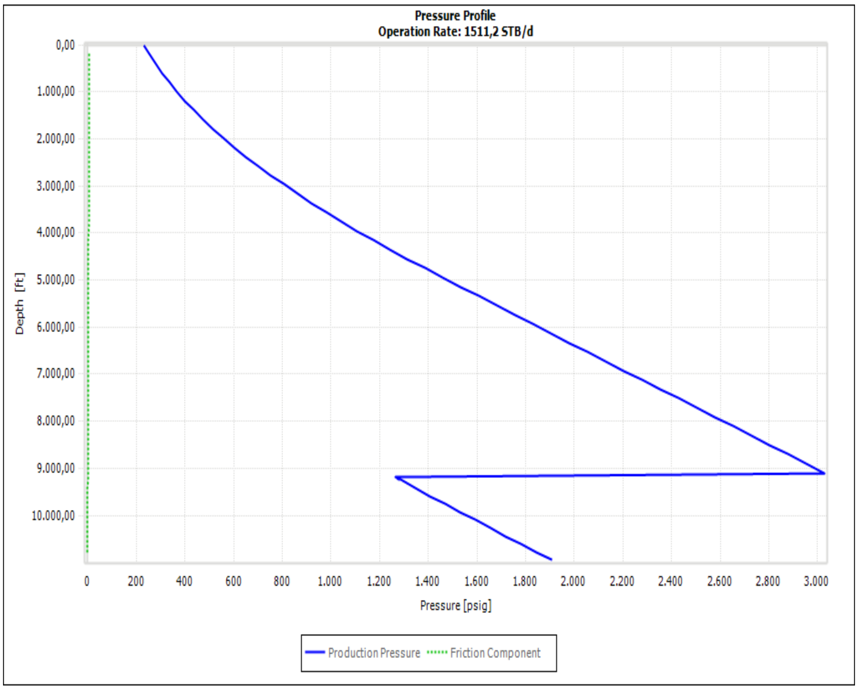
Conditions at Operating Frequency

Operating Frequency	*60*	*Hz*	Volts @ Junction Box	*3111,4*	*Volts*
Motor Amp	*27,7*	*Amps*	KVA @ Junction Box	*148,99*	
Total Motor Load	*122,1*	*hp*	Motor Volts	*2980,5*	*Volts*

VSD Curve



Pressure Profile Curve



Technical Design: Mona 1 Cable external CT deployed ESP

General Information

Contact Details

Project	*Cable external CT deployed ESP*
Field & Lease	*Durra*
Well Name	*Mona 1*

Input Data and Information

Production and Fluid Data

Oil Gravity	*42,2*	*ºAPI*	Water Specific Gravity	*1,2*	
Water Cut	*81*	*%*	Gas Specific Gravity	*0,81*	
GOR	*1330*	*SCF/STB*	Bubble Point	*4203,2*	*psig*

Wellbore Information

Wellhead Temperature	*86*	*ºF*	Bottom Hole Temperature	*194*	*ºF*
Perforation Depth	*9865,49*	*ft*			

Casing	Length (ft)	OD (in)	ID (in)	Roughness (in)	Flow Type
1	*5085,3*	*9,625*	*8,681*	*0,00065*	*TUBULAR*
2	*4780,18*	*7*	*6,184*	*0,00065*	*TUBULAR*

Tubing	Length (ft)	OD (in)	ID (in)	Roughness (in)	Flow Type
1	*4874,66*	*2,875*	*2,441*	*0,00065*	*TUBULAR*

Desired Operating Conditions

Pump Depth	*4921,26*	*ft*	Frequency	*58*	*Hz*
Design Rate	*2000*	*STB/d*	Wellhead Pressure	*370*	*psig*
Pump Speed	*3265,2*	*RPM*			

Equipment and Results

Pumping Conditions

Production Rate	*2027,6*	*STB/d*	TDH	*4265,4*	*ft*
Intake Pressure	*720,1*	*psig*	Pump Speed	*3265,2*	*RPM*
Discharge Pressure	*2740,9*	*psig*	Separation Efficiency	*94,54*	*%*
Mixture Gradient	*0,473*	*psi/ft*			

Pump Information

Device Information	*REDA 400 D2400N*			
Stages	*234*			
Staging Configuration	*CR-CT*		Staging Type	*ARZ*

Gas Separator

Device Information	*REDA 400/400 VGSA D20-60, 400/400*				
Power	*2,9*	*hp*	Efficiency	*94,54*	*%*
Free Gas Into Pump	*3,05*	*%*			

Motor Nameplate Information

Device Information	*REDA 456 Maximus 4142*				
Volts	*2639,9*	*Volts*	Power	*210*	*hp*
Speed	*3265,2*	*RPM*	Amp	*52*	*Amps*
Rating Factor	*100*	*%*	Winding Number	*4142*	

Cable Information

Type	*ELB*	
Conductor Size	*4*	
Length	*5021,26*	*ft*
KV	*4*	*kV*
Temperature Rating	*450*	*ºF*

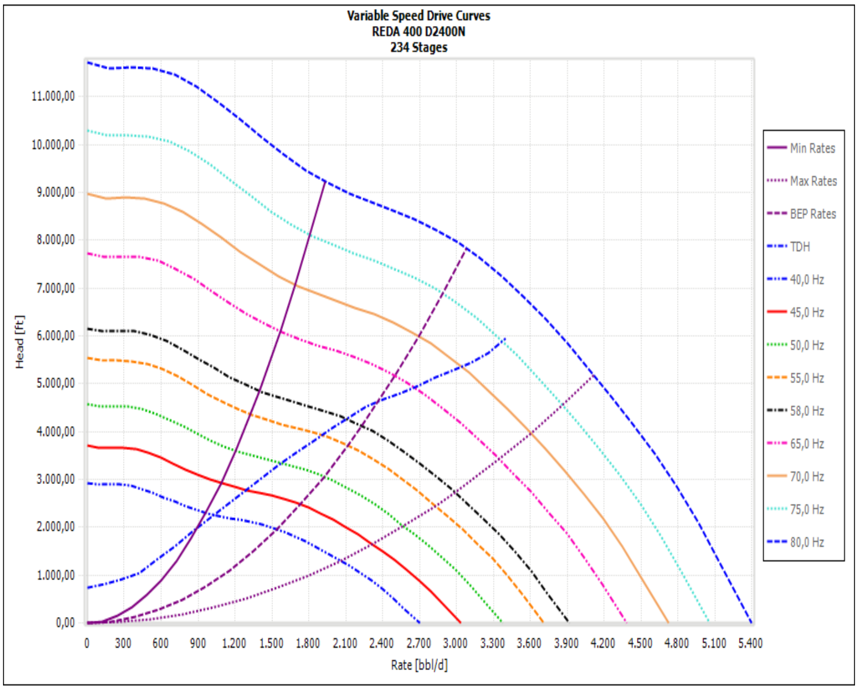
Protector

Thrust Bearing Type	*400 Maximus HL*	Oil Type	*REDA OIL #5*
Number of Seals	*4*		
Configuration	*LSBPB LSBPB*		
Number of Chambers	*6*		
Components	*TANDEM*		

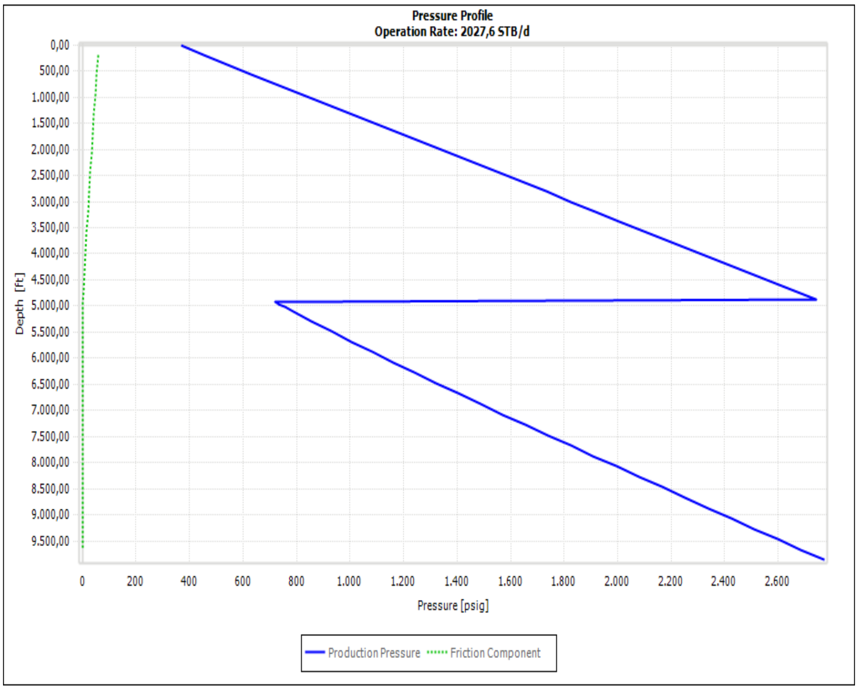
Conditions at Operating Frequency

Operating Frequency	*58*	*Hz*	Volts @ Junction Box	*2657,8*	*Volts*
Motor Amp	*42,8*	*Amps*	KVA @ Junction Box	*196,79*	
Total Motor Load	*161,2*	*hp*	Motor Volts	*2551,9*	*Volts*

VSD Curve



Pressure Profile Curve



Technical Design: Mona 1 REDACoil

General Information

Contact Details

Project	*RedaCoil*
Field & Lease	*Durra*
Well Name	*Mona 1*

Input Data and Information

Production and Fluid Data

Oil Gravity	*42.2*	*ºAPI*	Water Specific Gravity	*1.2*	
Water Cut	*81*	*%*	Gas Specific Gravity	*0.81*	
GOR	*1330*	*SCF/STB*	Bubble Point	*4203.2*	*psig*

Wellbore Information

Wellhead Temperature	*86*	*ºF*	Bottom Hole Temperature	*194*	*ºF*
Perforation Depth	*9865.49*	*ft*			

Casing	Length (ft)	OD (in)	ID (in)	Roughness (in)	Flow Type
1	*5085.3*	*9.625*	*8.68*	*0.00065*	*TUBULAR*
2	*4780.18*	*7*	*6.18*	*0.00065*	*TUBULAR*

Tubing	Length (ft)	OD (in)	ID (in)	Roughness (in)	Flow Type
1	*9142.25*	*6*	*5.7*	*0.00065*	*TUBULAR*

Desired Operating Conditions

Pump Depth	*9186.35*	*ft*	Frequency	*60*	*Hz*
Design Rate	*3000*	*STB/d*	Wellhead Pressure	*370*	*psig*
Pump Speed	*3465.3*	*RPM*			

Equipment and Results

Pumping Conditions

Production Rate	*3238.8*	*STB/d*	TDH	*6244.39*	*ft*
Intake Pressure	*1199.3*	*psig*	Pump Speed	*3465.3*	*RPM*
Discharge Pressure	*3899.1*	*psig*	Separation Efficiency	*0*	*%*
Mixture Gradient	*0.408*	*psi/ft*			

Pump Information

Device Information	*REDA 538 S4000N*		
Stages	*132*		
Staging Configuration	*CR-CT*	Staging Type	*ARZ*

Gas Handler #1

Device Information	*REDA 540/540 AGH*

Motor Nameplate Information

Device Information	*REDA 562 Maximus F112*				
Volts	*2840.5*	*Volts*	Power	*412.5*	*hp*
Speed	*3465.3*	*RPM*	Amp	*88.1*	*Amps*
Rating Factor	*100*	*%*	Winding Number	*F112*	

Cable Information

Type	*EL*	
Conductor Size	*2*	
Length	*9286.35*	*ft*
KV	*4*	*kV*
Temperature Rating	*450*	*ºF*

Protector

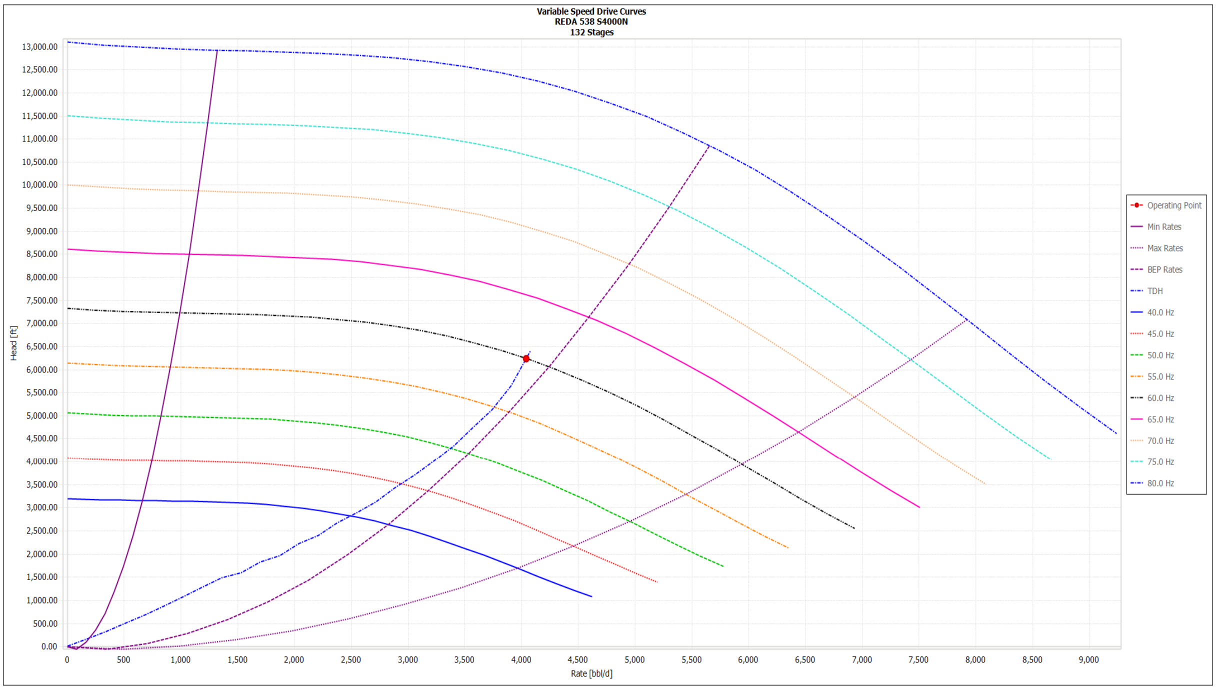
Thrust Bearing Type	*540 Maximus HL*	Oil Type	*REDA OIL #5*

Number of Seals	*4*
Configuration	*LSBPB LSBPB*
Number of Chambers	*6*
Components	*TANDEM*

Conditions at Operating Frequency

Operating Frequency	*60*	*Hz*	Volts @ Junction Box	*3109.8*	*Volts*
Motor Amp	*85.9*	*Amps*	KVA @ Junction Box	*462.16*	
Total Motor Load	*400.9*	*hp*	Motor Volts	*2840.5*	*Volts*

VSD Curve



Pressure Profile Curve

Technical Design: Mona 1 Wireline deployed ESP

General Information

Contact Details

Project	*Wireline deployed ESP*
Field & Lease	*Durra*
Well Name	*Mona 1*

Input Data and Information

Production and Fluid Data

Oil Gravity	*42,2*	*ºAPI*	Water Specific Gravity	*1,2*	
Water Cut	*81*	*%*	Gas Specific Gravity	*0,81*	
GOR	*1330*	*SCF/STB*	Bubble Point	*4203,2*	*psig*

Wellbore Information

Wellhead Temperature	*86*	*ºF*	Bottom Hole Temperature	*194*	*ºF*
Perforation Depth	*9865,49*	*ft*			

Casing	Length (ft)	OD (in)	ID (in)	Roughness (in)	Flow Type
1	*5085,3*	*9,625*	*8,68*	*0,00065*	*TUBULAR*
2	*4780,18*	*7*	*6,18*	*0,00065*	*TUBULAR*

Tubing	Length (ft)	OD (in)	ID (in)	Roughness (in)	Flow Type
1	*9114,45*	*4,5*	*4*	*0,00065*	*TUBULAR*

Desired Operating Conditions

Pump Depth	*9186,35*	*ft*	Frequency	*50*	*Hz*
Design Rate	*2000*	*STB/d*	Wellhead Pressure	*370*	*psig*
Pump Speed	*2790*	*RPM*			

Equipment and Results

Pumping Conditions

Production Rate	*1558,2*	*STB/d*	TDH	*2129,9*	*ft*
Intake Pressure	*2888,7*	*psig*	Pump Speed	*2790*	*RPM*
Discharge Pressure	*3890,4*	*psig*	Separation Efficiency	*0*	*%*
Mixture Gradient	*0,43*	*psi/ft*			

Pump Information

Device Information	*REDA 338 A2700N*		
Stages	*243*		
Staging Configuration	*CR-CT*	Staging Type	*ARZ*

Advanced Gas Handler

Device Information	*REDA 387/387 AGH*

Motor Nameplate Information

Device Information	*REDA 375 AS J160&(2)J181*				
Volts	*2740,6*	*Volts*	Power	*185,7*	*hp*
Speed	*2790*	*RPM*	Amp	*49,5*	*Amps*
Rating Factor	*100*	*%*	Winding Number	*J160&(2)J181*	

Cable Information

Type	*ELB*	
Conductor Size	*4*	
Length	*9286,35*	*ft*
KV	*4*	*kV*
Temperature Rating	*450*	*ºF*

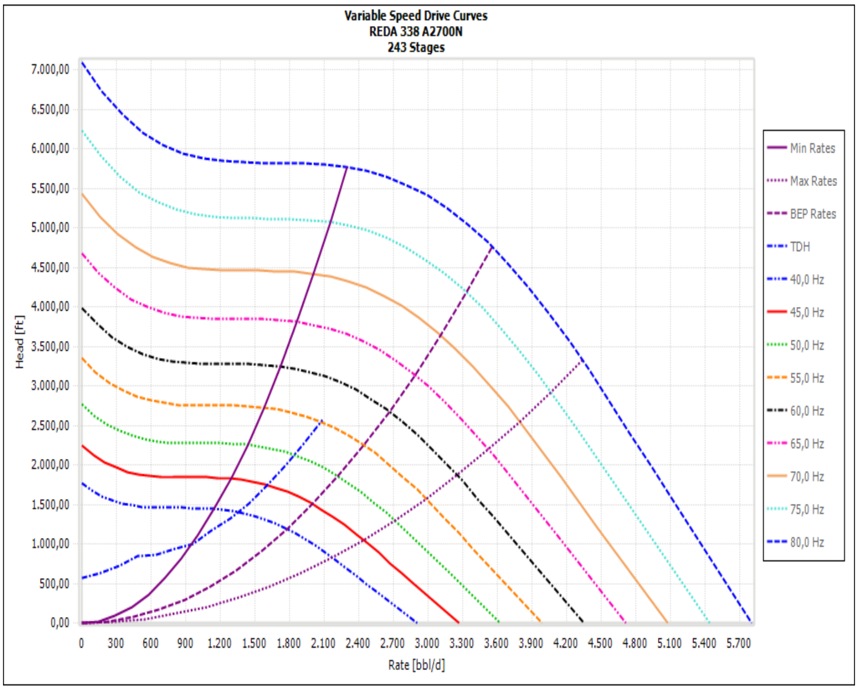
Protector

Thrust Bearing Type	*325 Maximus HL*	Oil Type	*REDA OIL #5*
Number of Seals	*4*		
Configuration	*BSBSL*		
Number of Chambers	*3*		
Components	*SINGLE*		

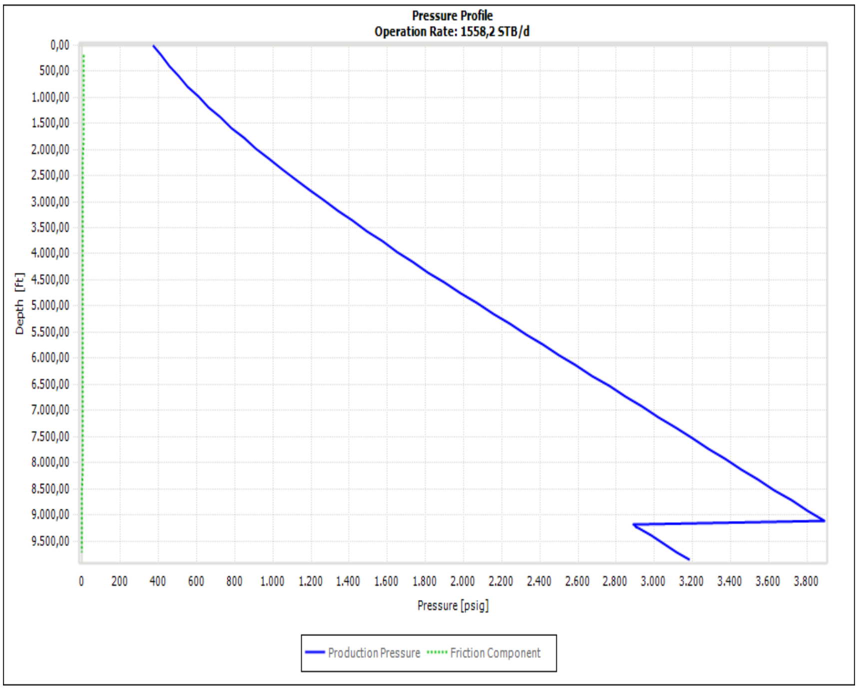
Conditions at Operating Frequency

Operating Frequency	*50*	*Hz*	Volts @ Junction Box	*2401,4*	*Volts*
Motor Amp	*25*	*Amps*	KVA @ Junction Box	*103,9*	
Total Motor Load	*75,7*	*hp*	Motor Volts	*2283,9*	*Volts*

VSD Curve



Pressure Profile Curve



Technical Design: Waha 2 Cable external CT deployed ESP

General Information

Contact Details

Project	*Cable external CT deployed ESP*
Field & Lease	*Cherouq*
Well Name	*Waha 2*

Input Data and Information

Production and Fluid Data

Oil Gravity	*40*	*ºAPI*	Water Specific Gravity	*1,15*	
Water Cut	*74*	*%*	Gas Specific Gravity	*0,86*	
GOR	*432*	*SCF/STB*	Bubble Point	*1311,7*	*psig*

Wellbore Information

Wellhead Temperature	*86*	*ºF*	Bottom Hole Temperature	*198,5*	*ºF*
Perforation Depth	*11404,2*	*ft*			

Casing	Length (ft)	OD (in)	ID (in)	Roughness (in)	Flow Type
1	*5036,09*	*9,625*	*8,681*	*0,00065*	*TUBULAR*
2	*6368,11*	*7*	*6,184*	*0,00065*	*TUBULAR*

Tubing	Length (ft)	OD (in)	ID (in)	Roughness (in)	Flow Type
1	*8110,9*	*2,875*	*2,441*	*0,00065*	*TUBULAR*

Desired Operating Conditions

Pump Depth	*8202,1*	*ft*	Frequency	*55*	*Hz*
Design Rate	*3500*	*STB/d*	Wellhead Pressure	*230*	*psig*
Pump Speed	*3096,3*	*RPM*			

Equipment and Results

Pumping Conditions

Production Rate	*2859,6*	*STB/d*	TDH	*6703,45*	*ft*
Intake Pressure	*975,7*	*psig*	Pump Speed	*3096,3*	*RPM*
Discharge Pressure	*3918,9*	*psig*	Separation Efficiency	*83,5*	*%*
Mixture Gradient	*0,439*	*psi/ft*			

Pump Information

Device Information	*REDA 400 D3500N*				
Stages	*356*				
Staging Configuration	*CR-CT*		Staging Type	*ARZ*	

Gas Separator

Device Information	*REDA 400/400 VGSA D20-60, 400/400*				
Power	*2,8*	*hp*	Efficiency	*83,5*	*%*
Free Gas Into Pump	*0,92*	*%*			

Motor Nameplate Information

Device Information	*REDA 456 Maximus 4151&4122*				
Volts	*3362,4*	*Volts*	Power	*405*	*hp*
Speed	*3096,3*	*RPM*	Amp	*78,9*	*Amps*
Rating Factor	*100*	*%*	Winding Number	*4151&4122*	

Cable Information

Type	*ELB*	
Conductor Size	*2*	
Length	*8302,1*	*ft*
KV	*4*	*kV*
Temperature Rating	*450*	*ºF*

Protector

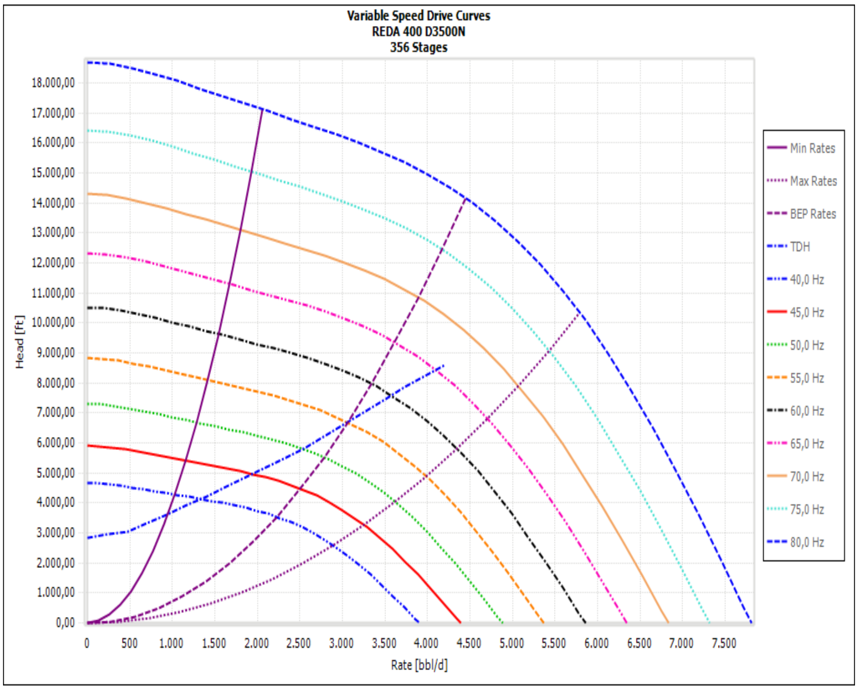
Thrust Bearing Type	*400 Maximus HL*	Oil Type	*REDA OIL #5*

Number of Seals	*4*
Configuration	*LSBPB LSBPB*
Number of Chambers	*6*
Components	*TANDEM*

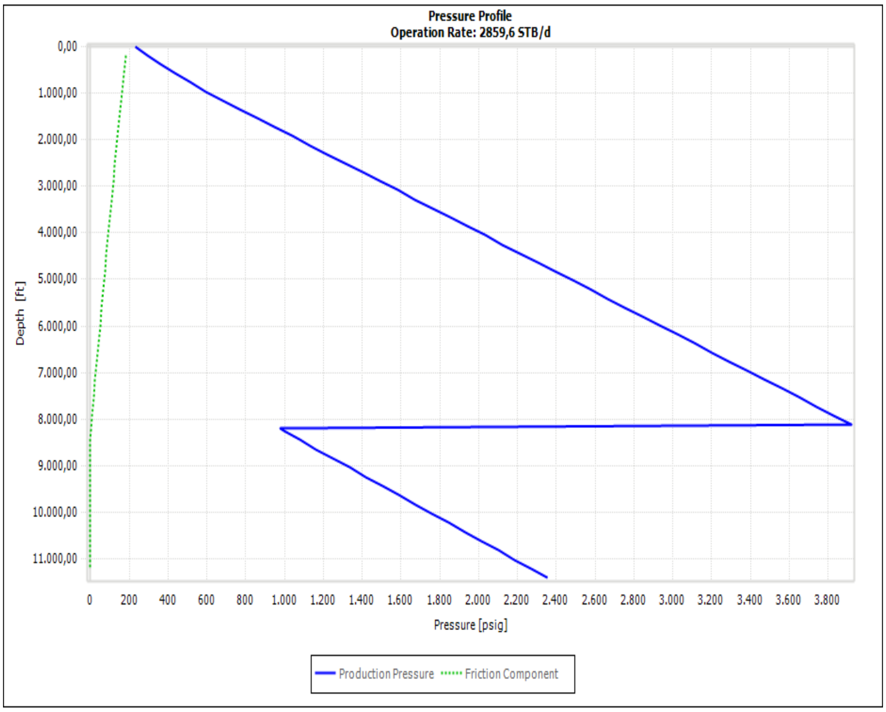
Conditions at Operating Frequency

Operating Frequency	*55*	*Hz*	Volts @ Junction Box	*3045,5*	*Volts*
Motor Amp	*70,9*	*Amps*	KVA @ Junction Box	*373,61*	
Total Motor Load	*308,8*	*hp*	Motor Volts	*2854*	*Volts*

VSD Curve



Pressure Profile Curve



Technical Design: Waha 2 REDACoil

General Information

Contact Details

Project	*RedaCoil*
Field & Lease	*Cherouq*
Well Name	*Waha 2*

Input Data and Information

Production and Fluid Data

Oil Gravity	*40*	*ºAPI*	Water Specific Gravity	*1,15*	
Water Cut	*74*	*%*	Gas Specific Gravity	*0,86*	
GOR	*432*	*SCF/STB*	Bubble Point	*1311,7*	*psig*

Wellbore Information

Wellhead Temperature	*86*	*ºF*	Bottom Hole Temperature	*198,5*	*ºF*
Perforation Depth	*11404,2*	*ft*			

Casing	Length (ft)	OD (in)	ID (in)	Roughness (in)	Flow Type
1	*5036,09*	*9,625*	*8,681*	*0,00065*	*TUBULAR*
2	*6368,11*	*7*	*6,184*	*0,00065*	*TUBULAR*

Tubing	Length (ft)	OD (in)	ID (in)	Roughness (in)	Flow Type
1	*9451,79*	*6*	*5,7*	*0,00065*	*TUBULAR*

Desired Operating Conditions

Pump Depth	*9514,44*	*ft*	Frequency	*56*	*Hz*
Design Rate	*5000*	*STB/d*	Wellhead Pressure	*230*	*psig*
Pump Speed	*3234,3*	*RPM*			

Equipment and Results

Pumping Conditions

Production Rate	*4843,9*	*STB/d*	TDH	*8575,18*	*ft*
Intake Pressure	*494,2*	*psig*	Pump Speed	*3234,3*	*RPM*
Discharge Pressure	*4244,9*	*psig*	Separation Efficiency	*0*	*%*
Mixture Gradient	*0,424*	*psi/ft*			

Pump Information

Device Information	*REDA 538 S6000N*		
Stages	*210*		
Staging Configuration	*CR-CT*	Staging Type	*ARZ*

Advanced Gas Handler

Device Information	*REDA 540/540 AGH*

Motor Nameplate Information

Device Information	*REDA 562 Maximus (2)F100*				
Volts	*2896,4*	*Volts*	Power	*750*	*hp*
Speed	*3234,3*	*RPM*	Amp	*157*	*Amps*
Rating Factor	*100*	*%*	Winding Number	*(2)F100*	

Cable Information

Type	*ELB*	
Conductor Size	*1*	
Length	*9614,44*	*ft*
KV	*5*	*kV*
Temperature Rating	*450*	*ºF*

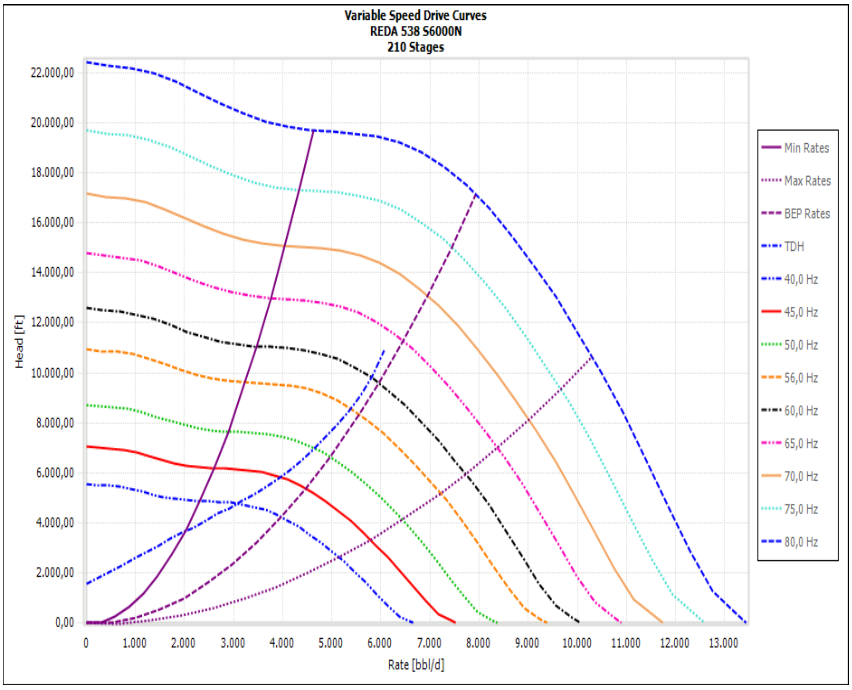
Protector

Thrust Bearing Type	*562 Maximus HL*	Oil Type	*REDA OIL #5*
Number of Seals	*2*		
Configuration	*LSBPB*		
Number of Chambers	*3*		
Components	*SINGLE*		

Conditions at Operating Frequency

Operating Frequency	*56*	*Hz*	Volts @ Junction Box	*3107,6*	*Volts*
Motor Amp	*147,4*	*Amps*	KVA @ Junction Box	*792,28*	
Total Motor Load	*643,7*	*hp*	Motor Volts	*2703,3*	*Volts*

VSD Curve



Pressure Profile Curve