# CHAPTER 1

# INTRODUCTION

## 1.1 Background of Study

Usually, oil wells in early stages of their lives flow naturally to the surface and are called flowing wells. Flowing production means that the pressure at the well bottom is sufficient to overcome the sum of pressure losses occurring along the flow path to the separator. When this criterion is not met, natural flow ends and the well die. The two main reasons of a well's dying are:

- The flowing bottomhole pressure drops below the total pressure losses in the well
- Pressure losses in the well become greater than the bottomhole pressure needed for moving the wellstream to the surface

To overcome these problems, artificial lift methods can be used to assist wells to sustain flow of oil to surface at adequate rates. Artificial lift enable 'dead well' to flow by adding energy to fluid stream and reducing fluid gradient below the reservoir sand face pressure.[1]

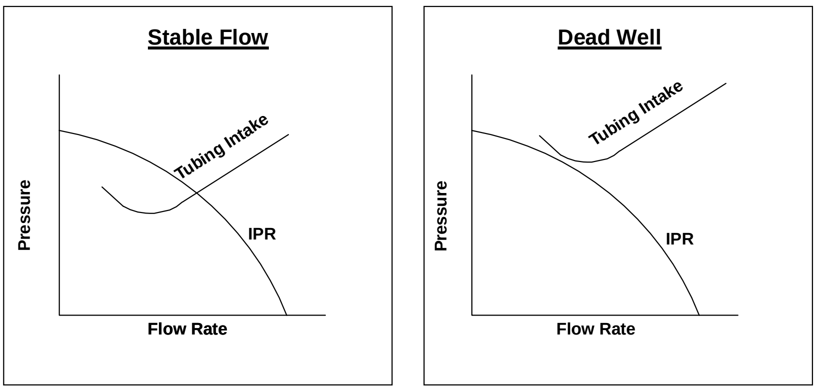



Figure 1 : The IPR Curve for Stable Flow and Dead Well

One widely used type of artificial lift method uses a pump set below the liquid level as to increase the pressure and to overcome the pressure losses occurring along the flow path such as electrical submersible pump (ESP). Other lifting methods use gas injected from the surface into the well tubing to help lifting of well fluids to the surface. But in this research, it will more focus on electrical submersible pump, operating features and design ESP system for given case study.

As for the early history part, ESP was invented and developed by a Russian named Armais Arutunoff in the late 1910's. Arutunoff make his first experiments in the Baku oilfields near the Caspian Sea and was later the founder of the company Russian Electrical Dynamo of Arutunoff (REDA). From the early days, ESP units have excelled in lifting much greater liquid rates than most of the other types of artificial lift and have found their best use in high-rate onshore and offshore applications. High gas production, quickly changing liquid production rates, viscous crudes and various conditions once very detrimental to ESP operations are now easily handled by present-day units. And it is believed that today approximately 10% of the world's oil supply is produced with submersible pumping installations. [1]

## 1.2 Problem Statement

In order to design the ESP installation, the selection for well candidate must be done to determine the right candidate to be installed on this artificial lift method. After consider some criteria and factors, the PP-7 well, Pelanduk Putih Field in Offshore Sabah was selected. Talking about this well, the PP-7 well has reservoir problems such as pressure depletion, high water cut, that can causes sand formation and then the sand production will be occurred. As planned during development period, this PP-7 well was installed with gas lift method, but after several years, this artificial lift type cannot run anymore as the side pocket mandrel has mechanical problem and then was categorized as idle well.[8] By having and understanding a little bit of well history, it is necessary for production engineer to design the most ideal ESP systems that can overcome the production problem and can extend life of the systems as installation cost of ESP are very expensive.[9]

## 1.3 Objective and Scope of Study

The main objective is to design the suitable ESP component to be used for high water cut well which is PP-7, Pelanduk Putih Field, Offshore Sabah.This design will be done by running in production software such as PROSPER to find the most efficiency and optimum ESP components. By having different types of the component such as the pump, the author will compare the efficiency and number of stages of the different type pumps in same operation condition.

For scope of study, thoughout 2 semester period of this research project, in first period, the author need to have the study on theory, engineering application and installation procedures of the artificial lift application especially on ESP system. The related cases and some reading regarding ESP from papers, journals and books also can enhance the understanding of ESP operational and design installation. The summary of engineering analysis and operational procedures of ESP systems are discussed in the literature review part. From the results done, we can determine the suitable ESP components such as pump, motor and the cable from running different types of components from different manufacturers.

## 1.4 Scope of the Project

The scope of study will involve the study of artificial lift method, electrical submersible pump system and the application of PROSPER software which is used for modelling the optimum ESP system. This project will involve the study of the effect of different pumps at different stages in the same electric frequency and well properties.

### *1.4.1 Relevancy of the Project*

Electrical submersible pump is still new in upstream operation by PETRONAS in Offshore Malaysia. Most of artificial lift are used is gas lift method in PETRONAS operations. Since the installation cost of ESP is very expensive, the proper planning and design of these systems must be fully studied. If not, the pump will run out of range and run life will be shortened.[4]

### *1.4.2 Feasibility of the Project within the Scope and Time Frame*

During the first semester of Final Year Project (FYP I), the target of this project is to be able to understand the engineering application behind ESP and interpret the related graphs such as IPR graph and so on. In this period also, the author need to study on related equation involve as well as get to familiar with the software to be used. In semester 2 (FYP II), all related data will be extracted from the reports. By entering the data into the software, the ESP model will created and will look for the optimum design in order to achieve its maximum run life.

# CHAPTER 2

# LITERATURE REVIEW

## 2.1 Artificial Lift Method

Artificial lifting methods are used to produce fluids from wells already dead or to increase the production rate from flowing wells. If the producing bottomhole pressure becomes so low that it will not allow the well to produce at a desired flow rate, then some sort of artificial energy supply will be needed to lift the fluid out of the wellbore. Energy can be supplied indirectly by injecting water or gas into the reservoir to maintain reservoir pressure or through a variety of artificial lift methods that are applied at the producing well itself.[2] There are many artificial lift methods, such all are variations or combinations of three basic processes:

a) lightening of the fluid column by gas injection (gas lift)

b) subsurface pumping (beam pumps, hydraulic pumps, electric submersible centrifugal pumps)

c) piston-like displacement of liquid slugs (plunger lift)

Although the use of many of those lifting mechanisms may be restricted or even ruled out by actual field conditions such as well depth, production rates desired, fluid properties and so on, more than one lift system turns out to be technically feasible. It is the production engineer's responsibility to select the type of lift that provides the most profitable way of producing the desired liquid volume from the given wells. After a decision is made concerning the lifting method, a complete design of the installation for initial and future conditions should follow.[5]

## 2.2 Electrical Submersible Pump Components

### *2.2.1 Introduction*

During its long history, the ESP system proved to be an efficient artificial lift selection to produce liquid from the production wells. The ESP unit is run on the tubing string and is submerged in well fluids. The electric submersible motor is at the bottom of the unit and is cooled by the wellstream passing by its perimeter. It is connected to the seal section that provides many crucial functions for the safe operation of the unit. On top of the protector a pump intake or gas separator is situated which allows well fluids to enter the pump as well as can remove low quantities of free gas from the wellstream at the same time. Liquid is lifted to the surface by the centrifugal pump. On the surface equipment, it includes a junction box where downhole and surface electric cables are joined and a control unit that provides measurement and control functions. The ESP unit receives AC electricity from a set of transformers which supply the required voltage by stepping up or down the voltage available from the surface electric network.[2]

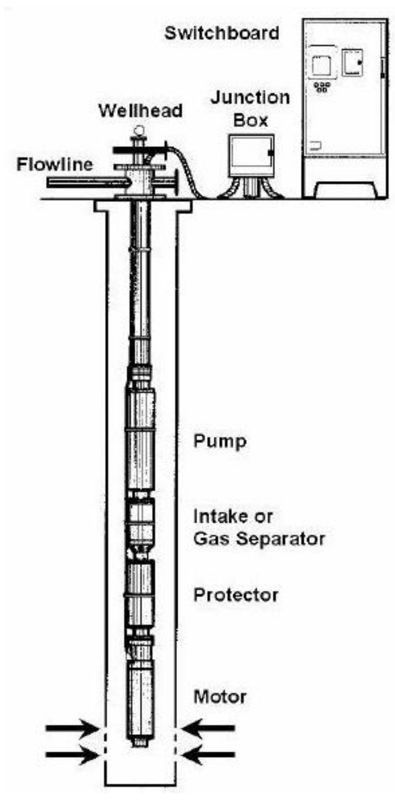



Figure 2 : ESP System Components

There are some advantages and disadvantages of ESP itself as follows:

Advantages

- High fluid volume capability
- Can be used in high water cut well
- Can be fitted with downhole pressure sensor (data transmission via power cable)
- Compatible with crooked or deviated wellbores
- Corrosion and scale treatments are relatively easy to perform
- Available in a range of sizes and capacities
- Lifting cost for high volumes typically very low

Disadvantages

- Cable insulation deteriorates in high temperatures (+350ºF)
- System is depth limited (+10,000 ft) due to cable cost and inability to provide sufficient power
- Large casing/liners are required (7” above)
- Entire system is downhole, therefore, problems and maintenance require the unit to be retrieved from the wellbore
- More detailed engineering required for design

### *2.2.2 The Submersible Pump*

In ESP unit, the submersible pump is one of important equipment. The design and analysis of the ESP system need the basic comprehension and understanding of the operation of the pump. The submersible pumps used in ESP installations are multistage centrifugal pumps operating in a vertical position and the basic operational principle remained the same. Produced liquids, after being subjected to great centrifugal forces caused by the high rotational speed of the impeller, lose their kinetic energy in the diffuser where a conversion of kinetic to pressure energy takes place.

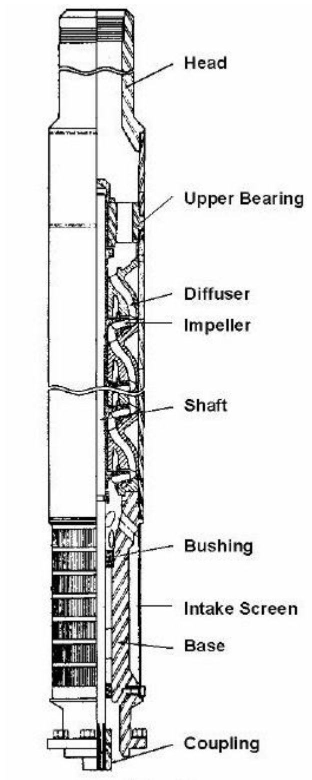



Figure 3 : Main Parts of an ESP Pump

The figure above shows the main parts of an ESP pump containing mixed-flow stages. The pump shaft is connected to the gas separator or the protector by a mechanical coupling at the bottom of the pump. Well fluids enter the pump through an intake screen and are lifted by the pump stages. Other parts include the radial bearings (bushings) distributed along the length of the shaft providing radial support to the pump shaft turning at high rotational speeds.

An optional thrust bearing takes up part of the axial forces arising in the pump but most of those forces are absorbed by the protector’s thrust bearing.

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

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

The ESP installations will run on AC power with a constant frequency of 60 Hz or 50 Hz. ESP motors in 60 Hz electrical systems rotate at a speed of about 3,500 RPM, meanwhile in case of a 50 Hz power supply the motor speed is about 2,900 RPM. Usually, present-day ESP pumps come in different capacities from a few hundred to around 80,000 bpd of liquid production rate and in outside diameters from around 3” up to 11”. [1]

### *2.2.3 The ESP Motor*

ESP motors are three-phase, two-pole, squirrel cage induction type electric motors. The construction of squirrel cage induction motors is the simplest among electric motors. They are also the most reliable motors due to the fact that their rotor is not connected to the electric supply. At the same time, these motors are the most efficient ones available they are very popular in oilfield applications. [1]

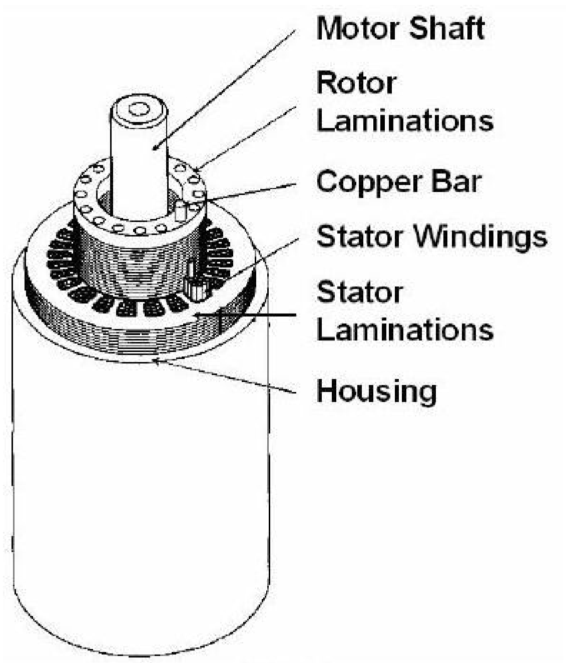



Figure 4 : Construction details of an ESP motor’s stator and rotor

Inside the motor housing and attached to it is the stator, a hollow cylinder made up of a great number of tightly packed thin steel discs called laminations. Stator laminations prevent the creation of wasteful eddy currents in the metal body of the stator. They have several “slots” accommodating the insulated copper stator windings connected to the AC power.[1] There are three pairs of coils displaced at 120° along the perimeter of the motor and connected to one of each electric phase. The two coils of each pair are wound facing each other on opposite sides of the stator.

Inside the stator and separated from it by an annular “air gap” is the rotor, consisting of rotor laminations containing in their slots a set of copper bars. These are joined at their ends by so-called “end rings” (copper washers), making up the “squirrel cage”.[7]

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

To prevent electrical failures in windings, the motor must have a sophisticated insulation system including:

- insulation of the individual wires making up the windings
- insulation between the windings and the stator
- protection against phase to phase faults

Windings in ESP motors, just like in other electric motors, are encapsulated with an insulating material to:

- improve the dielectric strength of winding insulation,
- improve the mechanical strength of windings and eliminate wire movement, and
- protect wires and end coils from contaminants.

#### *2.2.3.1 Operational Features*

ESP motors are very different from electric motors in everyday use on the surface. The most important differences are listed in the following, a basic comprehension of which is necessary to fully understand the operational features of ESP motors.[6]

a) Since they must be run inside the well’s casing string, their length to diameter ratio is much greater than that of surface motors.

b) Motor power can only be increased by increasing the length of the unit.

c) Surface motors are usually cooled by the surrounding air whereas ESP motors are cooled by the convective heat transfer taking place in the well fluid flowing past the motor.

d) Because of the great difference between the heat capacities of air and liquids and the accordingly higher cooling effect, electric current densities more than ten times higher than those in surface motors can be used in ESP motors without severe overheating.

e) ESP motors have exceptionally low inertia and accelerate to full speed in less than 0.2 seconds when starting.

f) ESP motors are connected to their power source by long well cables, where a substantial voltage drop can occur.

### *2.2.4 The Seal Protection*

In small or non-industrial submersible pumps, the electric motor is completely sealed against the produced liquid so as to prevent short-circuits and burning of the motor after it is contaminated with well fluids. Since the motor must be filled up with high dielectric strength oil, ESP motors operating at elevated temperatures, if completely sealed, would burst their housing due to the great internal pressure developed by the expansion of the oil. This is the reason why ESP motors must be kept open to their surroundings but at the same time must still be protected from the harmful effects of well fluids. This is provided by connecting a seal section or protector between the motor and the centrifugal pump.

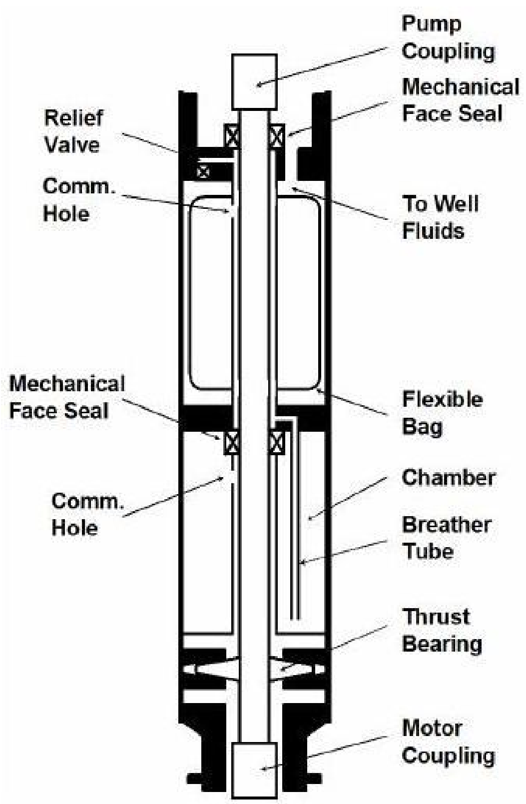



Figure 5 : Schematic Drawing of an ESP Seal Section

An ESP protector performs the following five very crucial functions and in so doing ensures the proper operation of the whole installation:

1. It ensures that no axial thrust load developing in the ESP pump's stages during operation is transmitted to the motor shaft. Thrust loads transmitted to the pump shaft are supported by the protector that contains the ESP unit's main thrust bearing. This thrust bearing must be capable to overcome the net axial force acting on the pump shaft.

2. The protector isolates the clean dielectric oil with which the motor is originally filled up from well fluids that are usually loaded with dirt, water and other impurities. It must ensure that no well fluid enters the motor during operation. This is a basic requirement because contamination of the clean motor oil can cause premature motor failures due to
   - The loss of lubrication in the structural bearings and the consequently increased wear in bearing surfaces.
   - The decrease of the electrical insulation strength of the motor oil causing short circuits in the motor's stator or rotor windings.

3. It allows for the expansion and contraction of the high quality oil the motor is filled up with. Since the protector is connected directly to the motor, motor oil expanding due to well temperature and due to the heat generated in the motor can enter the protector during normal operation. Similarly, during shutdowns, the oil contained in the motor shrinks because of the decreased motor temperature and part of it previously stored in the protector can be sucked back to the motor space.

4. By providing communication between well fluids and the dielectric oil contained in the motor, the protector equalizes the inside pressure with the surrounding pressure in the well's annulus. Inside and outside pressures being approximately equal, leakage of well fluids past the sealed joints and into the motor is eliminated. This feature

- allows the use of low-pressure and consequently lower cost seals.
- greatly increases the reliability of the ESP system.

5. It provides the mechanical connection between the motor and the ESP pump and transmits the torque developed by the motor to the pump shaft. The couplings on the protector's shaft ends must be capable to transmit not only the normal operating torques but the much greater torques occurring during system startup.

### *2.2.5 The Gas Separator*

It follows from the operational principle of centrifugal pumps that free gas entering the pump suction deteriorates the pump's performance. This is caused by the great difference between the specific gravities of liquids and gases. The centrifugal pump imparts a high rotational velocity on the fluid entering its impeller but the amount of kinetic energy passed on to the fluid greatly depends on the given fluid's density. Liquid receives a great amount of kinetic energy that, after conversion in the pump stage, increases the pressure. Gas cannot produce the same amount of pressure increase. This is the reason why centrifugal pumps should always be fed by gas-free, single-phase liquid for ensuring reliable operation.[8]

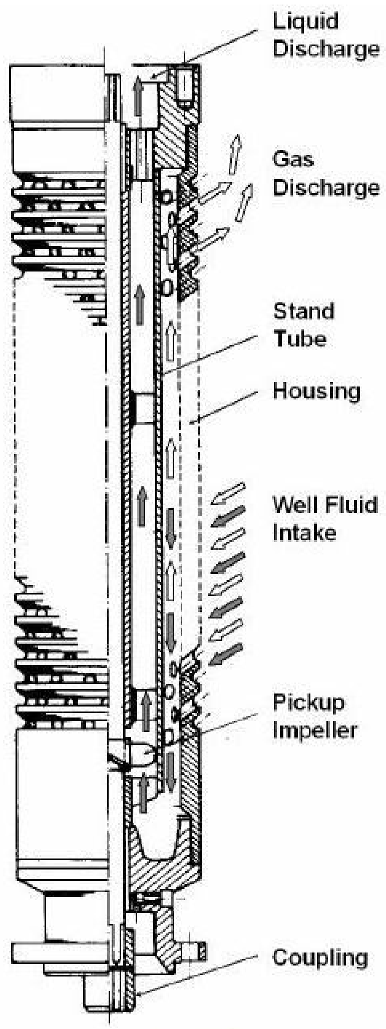



Figure 6 : Construction of Gas Separator

The existence of free gas at pump suction conditions affects the operation of the ESP pump is several ways.

- The head developed by the pump decreases as compared to the performance curve measured with water
- The output of a pump producing gassy fluids fluctuates, cavitation can also occur at higher flow rates causing mechanical damage of the pump stages
- In cases with extremely high gas production rates, gas locking may occur when no pumping action is done by the pump completely filled with gas

## 2.3 Well Inflow Performance

### *2.3.1 Introduction*

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

- selection of the right type of lift
- detailed design of production equipment
- estimation of future well performance

Therefore, the production engineer must have a clear understanding of the effects governing fluid inflow into a well. Lack of information may lead to over-design of production equipment or equipment limitations may restrict attainable liquid rates. Both of these conditions have an undesirable impact on the economy of artificial lifting and can be the cause of improper decisions as well.

### *2.3.2 The Productivity Index Concept*

The simplest approach to describe the inflow performance of oil wells is the use of the productivity index (PI) concept. It was developed using the following assumptions :

- Flow is radial around the well
- A single phase and incompressible liquid
- Permeability in the formation is homogeneous
- The formation is fully saturated with the given liquid

$$PI = \frac{Q}{P_r - P_{wf}}$$

where:

$Q$ = liquid rate, STB/d

$P_r$ = reservoir pressure, psi

$P_{wf}$ = flowing bottomhole pressure, psi

The equation states that liquid inflow into a well is directly proportional to pressure drawdown, as plotted in the graph below. The use of the PI concept is straightforward. If the average reservoir pressure and the productivity index are known, use of the equation gives the flow rate for any flowing bottomhole pressure. The well's PI can either be calculated from reservoir parameters or measured by taking flow rates at various $P_{wf}$.

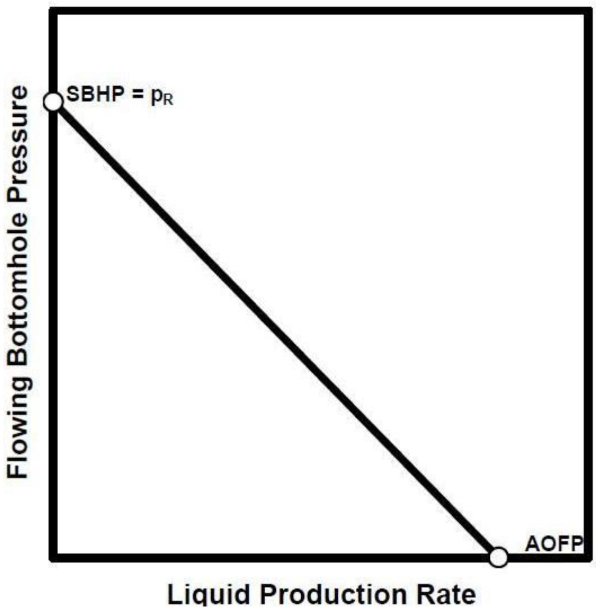



Figure 7 : Well Inflow Performance with the Constant PI Concept

### 2.3.3 Inflow Performance Relationships

In many wells on artificial lift, bottomhole pressures below bubble-point pressure are experienced. There is a free gas phase present in the reservoir near the wellbore and the assumptions that were used to develop the PI equation are no longer valid.

The main cause of a curved shape of inflow performance is the liberation of solution gas due to the decreased pressure in the vicinity of the wellbore. This effect creates an increasing gas saturation profile toward the well and simultaneously decreases the effective permeability to liquid. Liquid rate is accordingly decreased in comparison to single-phase conditions and the well produces less liquid than indicated by a straight-line PI curve. Therefore, the constant PI concept cannot be used for wells producing below the bubble-point pressure.

#### 2.3.3.1 Vogel's IPR Correlation

Vogel used a numerical reservoir simulator to study the inflow performance of wells depleting solution gas drive reservoirs. He considered cases below bubble-point pressure and varied pressure drawdowns, fluid and rock properties. After running several combinations on the computer, Vogel found that all the calculated IPR curves exhibited the same general shape. The shape is approximated by a dimensionless equation as follows:

$$\frac{Q}{\boldsymbol{Q_{max}}} = \mathbf{1 - 0.2}\left[\frac{\boldsymbol{P_{wf}}}{\boldsymbol{P_r}}\right] - \mathbf{0.8}\left[\frac{\boldsymbol{P_{wf}}}{\boldsymbol{P_r}}\right]^{\mathbf{2}}$$

where:

$\boldsymbol{Q}$ = production rate at bottomhole pressure $\boldsymbol{P_{wf}}$, STB/d

$\boldsymbol{Q_{max}}$ = maximum production rate, STB/d

$\boldsymbol{P_r}$ = average reservoir pressure, psi

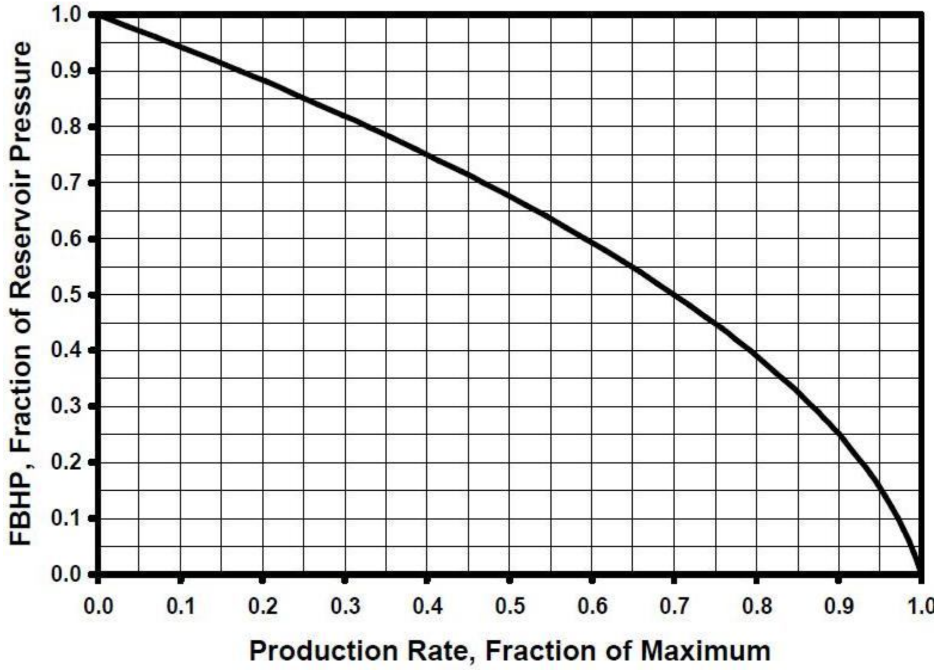



Figure 8 : Vogel's Dimensionless IPR Curve

## 2.4 Related Equations

$$Productivity\ Index, PI\ =\ \frac{Q}{P_r - P_{wf}}$$

$$Pump\ Intake\ Pressure, PIP\ =\ P_{wfd} - \left[\frac{(Datum\ Depth - Pump\ Depth) - SG_L}{2.31}\right]$$

$$Dynamic\ Lift\ =\ Pump\ Vertical\ Depth - \left[\frac{PIP * 2.31}{SG_L}\right]$$

$$Total\ Firction\ Loss\ =\ \frac{Friction\ Loss * Pump\ Depth}{1000}$$

$$Head\ =\ \frac{THP * 2.31}{SG_L}$$

$$Total\ Dynamic\ Head, TDH\ =\ Dynamic\ Lift + Total\ Friction\ Loss + Head$$

$$Number\ of\ stages\ =\ \frac{TDH}{head/stage}$$

$$BHP\ = \frac{bhp}{stg} * number\ of\ stages * SG_L$$

## 2.5 PROSPER

PROSPER is a well performance, design and optimization program which is part of the Integrated Production Modeling Toolkit (IPM). PROSPER can assist the production and reservoir engineer to predict tubing and pipeline hydraulics and temperatures with accuracy and speed. This tool is the industry standard well modeling with the major operators worldwide.

PROSPER is designed to allow the building of reliable and consistent well models, with the ability to address each aspect of wellbore modeling, PVT (fluid characterization), VLP correlations (for calculation of flow-line and tubing pressure loss) and IPR (reservoir inflow).

PROSPER provides unique matching features, which tune PVT, multiphase flow correlations and IPR to match measured field data, allowing a consistent well model to be built prior to use in prediction (sensitivities or artificial lift design). PROSPER enables detailed surface pipeline performance and design such as flow regimes, pipeline stability, slug size and frequency. [10]

### *2.5.1 Applications of PROSPER*

- Design and optimize well completions including multi-lateral, multi-layer and horizontal wells.
- Design and optimize tubing and pipeline sizes.
- Design, diagnose and optimize gas lifted, hydraulic pumps and ESP wells.
- Generate lift curves for use in simulators.
- Calculate pressure losses in wells, flow lines and across chokes.
- Predict flowing temperatures in wells and pipelines.
- Monitor well performance to rapidly identify wells requiring remedial action.
- Calculate total skin and determine breakdown (damage, deviation or partial penetration).

- Unique black oil model for retrograde condensate fluids, accounting for liquid dropout in the wellbore.
- Allocate production between wells.

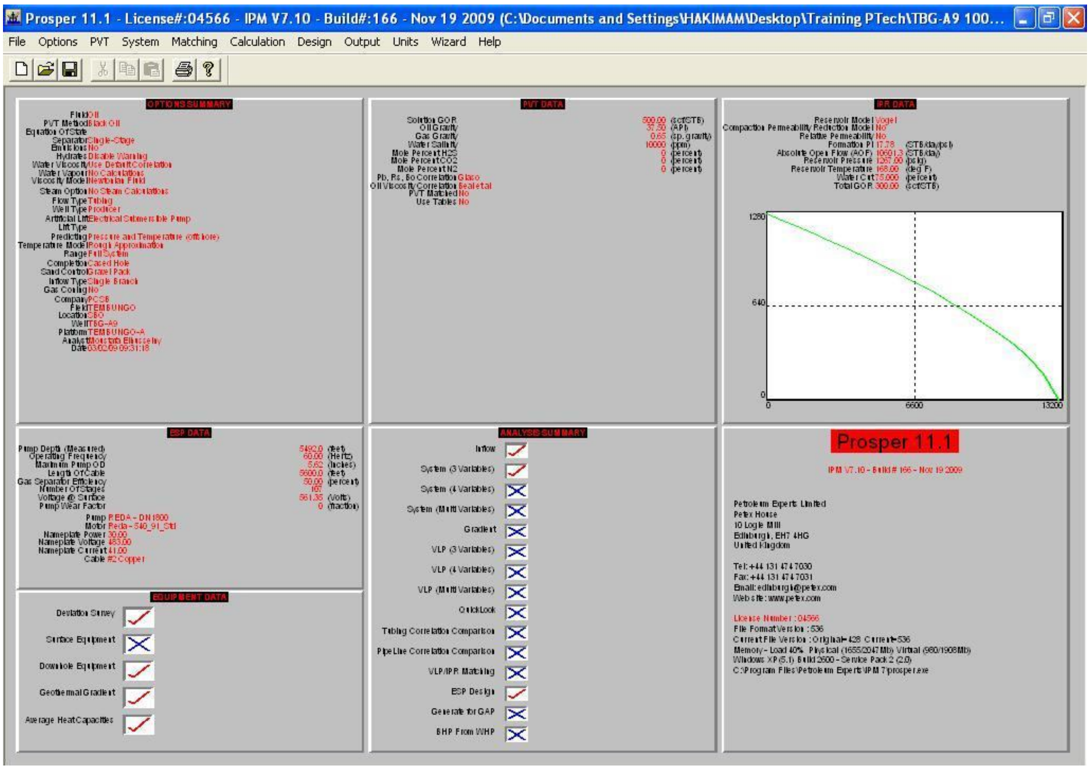



Figure 9 : Main Screen of PROSPER

# CHAPTER 3

# PROJECT METHODOLOGY

## 3.1 Research Methodology

- Understand the engineering application behind ESP components such as pump, motor and gas separator.
- Design the installation of electrical submersible pump components.
- Analysis the results and find the ideal and optimum one.

## 3.2 Key Milestone

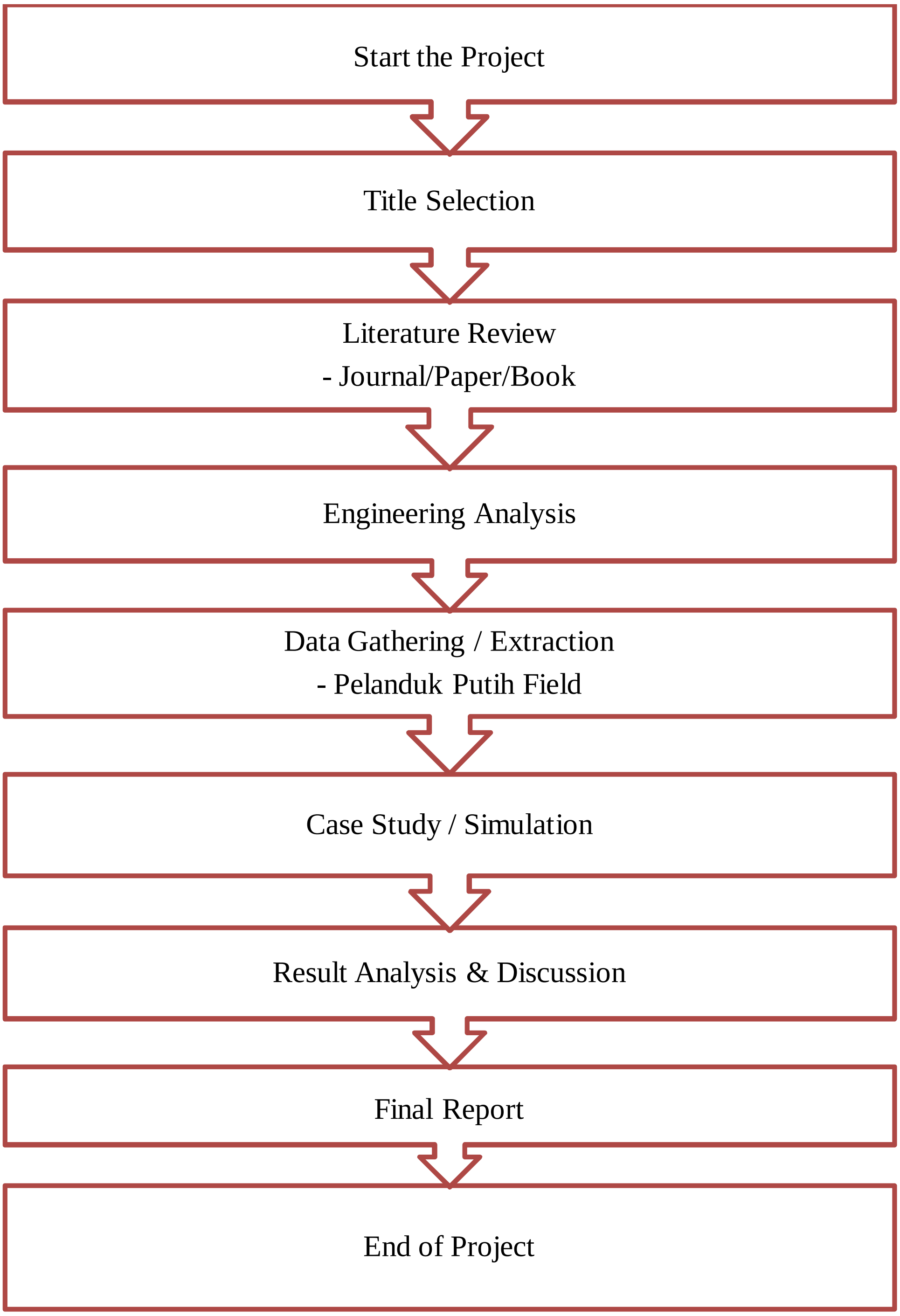
FYP 1

- Gathering information (literature review & theory) from technical papers, journals and reference books.
- Study and understand the basic function and engineering concept

FYP II

- Gathering all the required data
- Design for the pump model from different types
- Find the optimum and economical ESP pump design for case study
- Discuss about the finding from the model

### 3.3 Project Activities



### 3.4 Gantt Chart

**The Gantt chart is attached in Appendices*

Noted that the Gantt chart is a guideline for the project timeline and can be changed from time to time depending on circumstances.

### 3.5 Tools Required

For this final year project, there are some production engineering software are required such as PROSPER to accomplish this final year project. This software will be used to analysis and determine the optimum ESP component in order to be used in high water cut well. The optimum ESP components will extend the life of ESP system as well as enhance field economics.

### 3.6 Modelling Works

a) Define related data and objective in PROSPER.

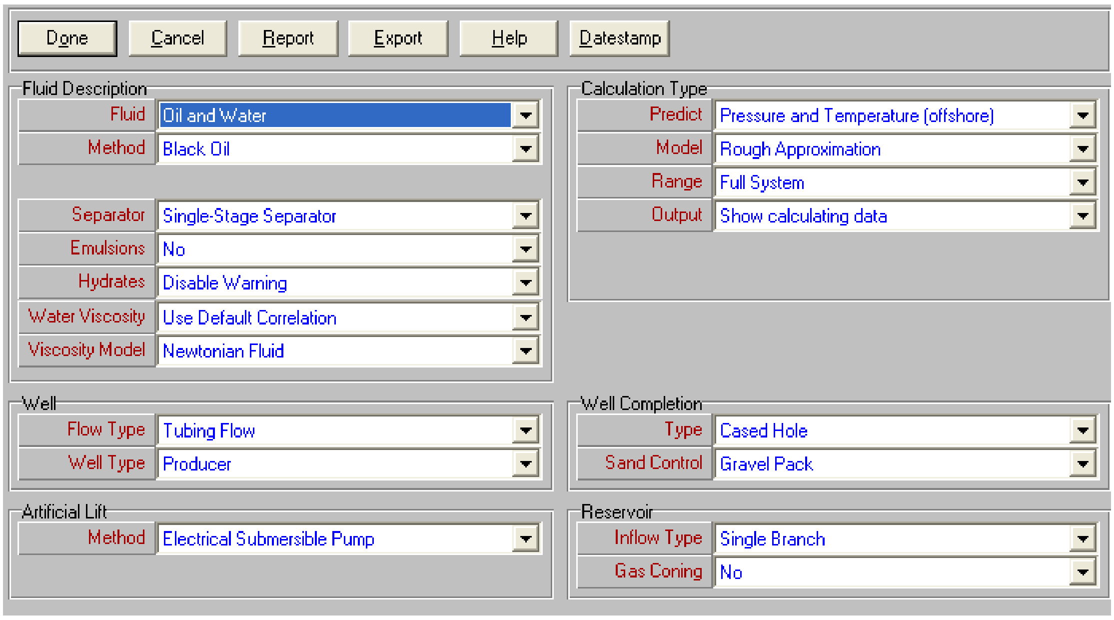



Figure 10 : Well Summary Section

b) Input PVT model

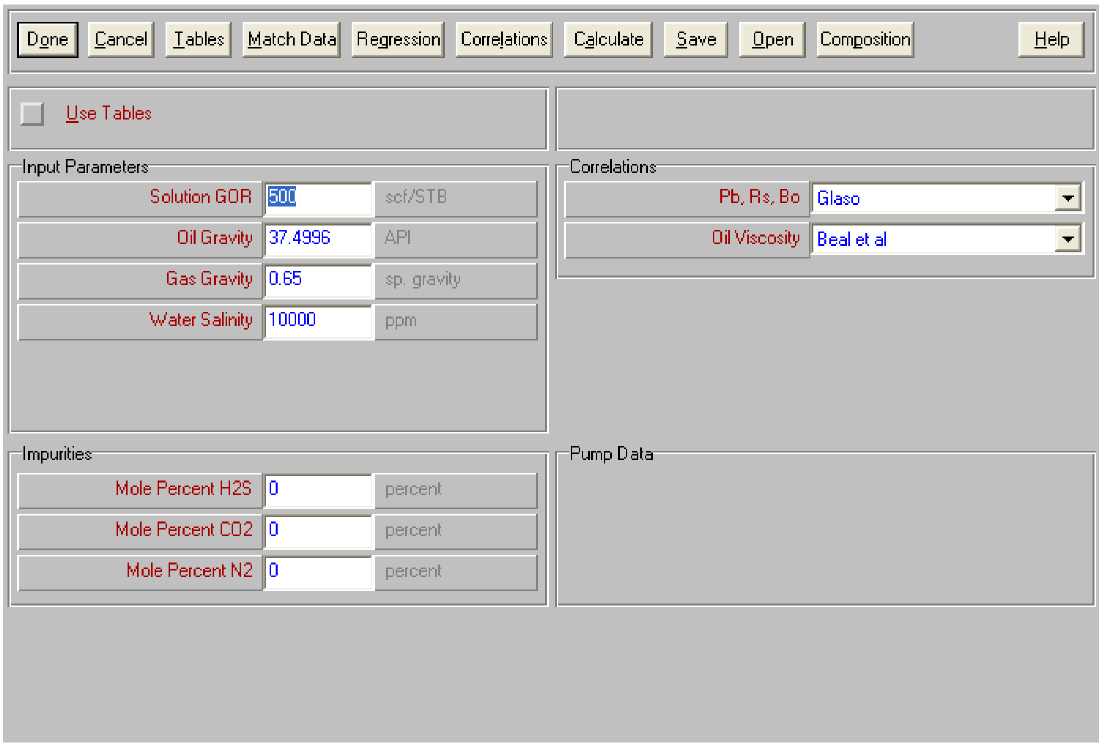



Figure 11 : PVT Data Section

c) Input equipment data: deviation survey, equipment, geothermal gradient.

- All roughness of tubing / casing = 0.0006 in
- Overall heat transfer coefficient (OHTC) = 8.5 BTU/hr/ft2/F

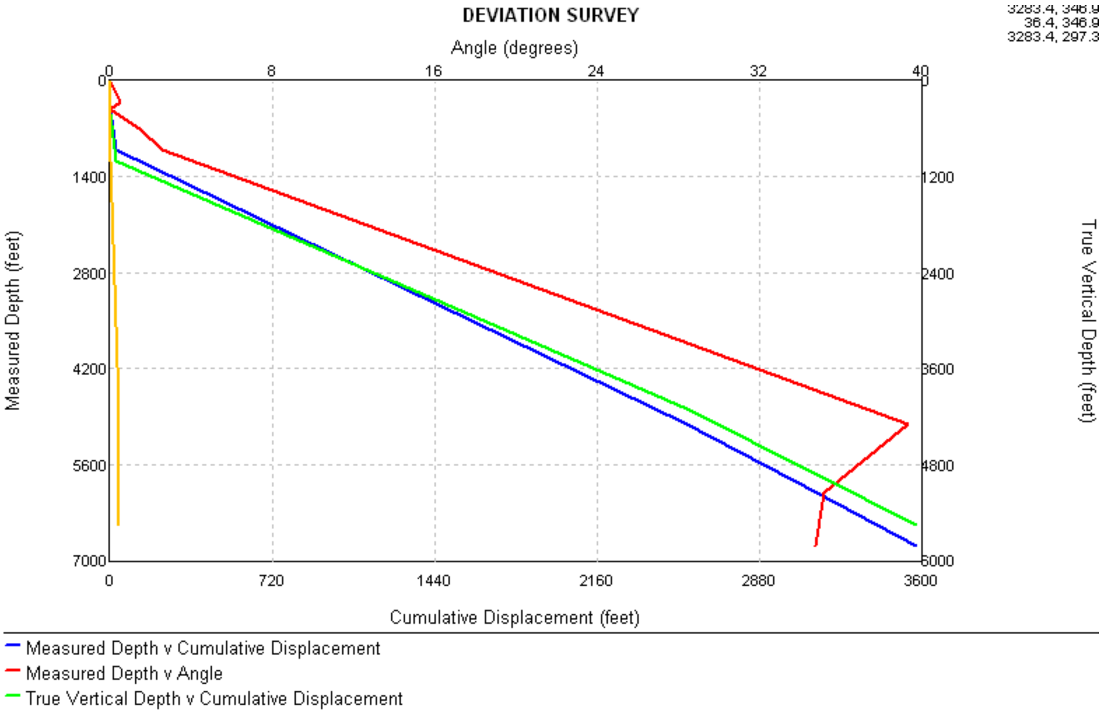



Figure 12 : Deviation Survey Section

d) Define for downhole equipment by inserting well completion data

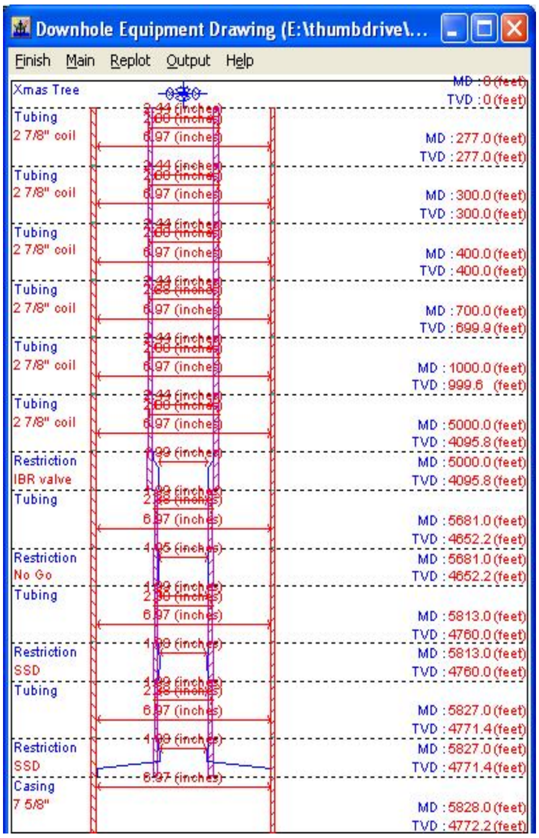



Figure 13 : Downhole Equipment Section

e) Perform a new ESP lift design

- Prosper filters out pumps, motors and cable that meet the design parameters from a databases.

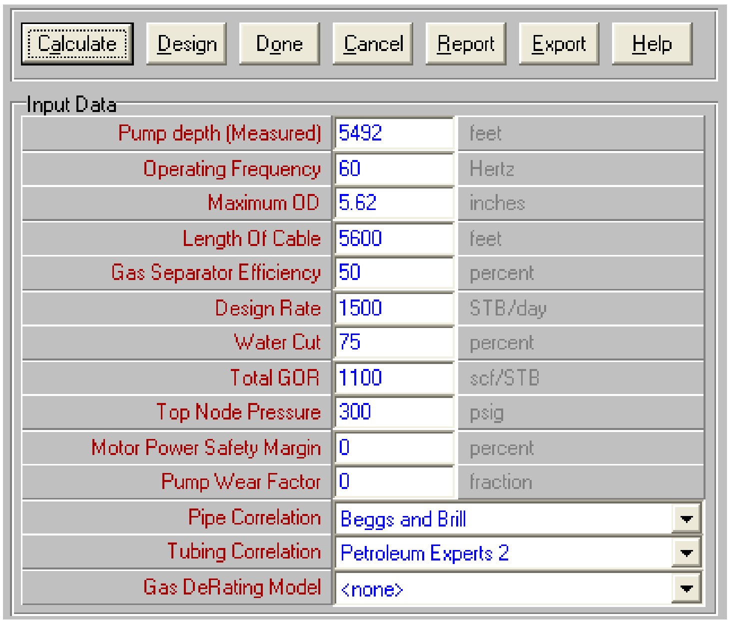
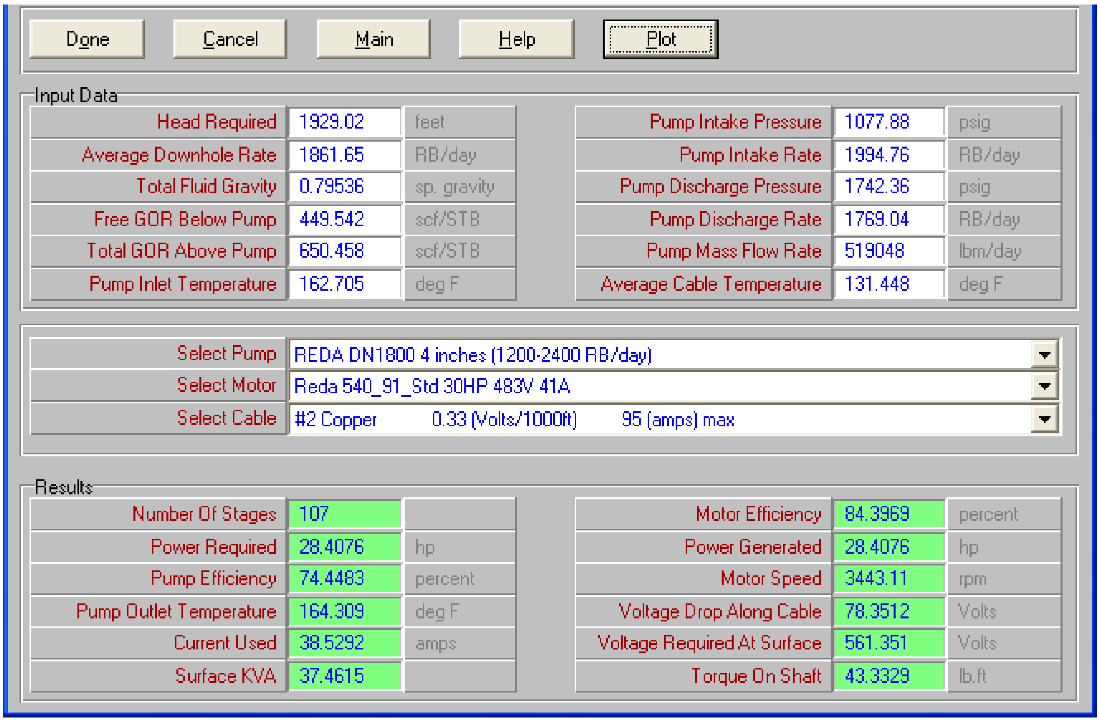



Figure 14 : ESP Design & Gas Separation Calculation



Done | Cancel | Main | Help | Plot

Input Data

| | | | | | |
|---|---|---|---|---|---|
| Head Required | 1929.02 | feet | Pump Intake Pressure | 1077.88 | psig |
| Average Downhole Rate | 1861.65 | RB/day | Pump Intake Rate | 1994.76 | RB/day |
| Total Fluid Gravity | 0.79536 | sp. gravity | Pump Discharge Pressure | 1742.36 | psig |
| Free GOR Below Pump | 449.542 | scf/STB | Pump Discharge Rate | 1769.04 | RB/day |
| Total GOR Above Pump | 650.458 | scf/STB | Pump Mass Flow Rate | 519048 | lbm/day |
| Pump Inlet Temperature | 162.705 | deg F | Average Cable Temperature | 131.448 | deg F |

| | |
|---|---|
| Select Pump | REDA DN1800 4 inches (1200-2400 RB/day) |
| Select Motor | Reda 540_91_Std 30HP 483V 41A |
| Select Cable | #2 Copper 0.33 (Volts/1000ft) 95 (amps) max |

Results

| | | | | | |
|---|---|---|---|---|---|
| Number Of Stages | 107 | | Motor Efficiency | 84.3969 | percent |
| Power Required | 28.4076 | hp | Power Generated | 28.4076 | hp |
| Pump Efficiency | 74.4483 | percent | Motor Speed | 3443.11 | rpm |
| Pump Outlet Temperature | 164.309 | deg F | Voltage Drop Along Cable | 78.3512 | Volts |
| Current Used | 38.5292 | amps | Voltage Required At Surface | 561.351 | Volts |
| Surface KVA | 37.4615 | | Torque On Shaft | 43.3329 | lb.ft |

Figure 15 : ESP Design Input

f) The graph will be shown as all data are valid. All results from this modelling will be discussed in next chapter.

# CHAPTER 4

# RESULT AND DISCUSSION

## 4.1 Data Gathering and Analysis

For a proper design of an ESP installation, the available of many different data is necessary. The most important data is the reliable information on the well's productivity so that the desired fluid rate from the well can be established. The fluid rate is always an input parameter in the design of ESP installations because the selection of the submersible pump can only be accomplished in the available of the desired rate. There are different pumps that have different recommended application ranges.

Necessary input data can be grouped as given below.

1. Well Physical Data.
   - Casing and liner sizes, weights, and setting depths.
   - Tubing size, type, weight, and thread.
   - Total well depth.
   - Depth of perforations or open hole interval.
   - Well inclination data.

2. Well Performance Data.
   - Tubinghead pressure at the desired rate.
   - Casinghead pressure.
   - Desired liquid production rate.
   - Static bottomhole pressure or static liquid level.
   - Flowing bottomhole pressure or dynamic liquid level.

- Productivity Data (*PI* or $q_{max}$ for the Vogel model)
- Producing gas-oil ratio.
- Producing water cut or water-oil ratio.
- Bottomhole temperature at desired liquid rate.

3. Fluid Properties.

- Specific or API gravity of produced oil.
- Specific gravity of water.
- Specific gravity of produced gas.
- Bubble point pressure.
- Viscosity of produced oil.
- PVT data of produced fluids (volume factors, solution *GOR*).

4. Surface Power Supply Parameters.

- Primary voltage available at the wellsite.
- Frequency of the power supply.
- Available power supply capacity.

**PP-7 Well Data**

| Data | | | Units |
|---|---|---|---|
| Well Data | Perforation Depth (datum) | 5887 | feet |
| Production Data | THP | 660 | psig |
| | Test Rate | 1982 | bpd |
| | Bottomhole Pressure $P_{wf}$ | 2052 | psig |
| | Reservoir Pressure, $P_r$ | 2150 | psig |
| | Reservoir Temperature, $T_r$ | 168 | degree F |
| | GOR | 460 | scf/bbl |
| | Water Cut | 0 | percent |
| | Pressure @ Perforation (5887ft) | 2150 | psig |
| | Calculated PI | 21 | bopd/psi |
| Fluid Condition | Specific Gravity Water | 1.02 | sp.gravity |
| | Specific Gravity Oil | 35.3 | API |
| | | 0.848 | sp.gravity |
| | Specific Gravity Gas | 0.65 | sp.gravity |
| | Bubble Point Pressure | 2150 | psig |
| | Water Salinity | 10000 | ppm |

Table 1 : Well Test Data in 1977

| Data | | | Units |
|---|---|---|---|
| Well Data | Perforation Depth (datum) | 5887 | feet |
| | Pump Depth | 5492 | feet |
| | Datum Depth | 5416 | feet |
| Production Data | THP | 300 | psig |
| | Test Rate | 1500 | bpd |
| | Bottomhole Pressure $P_{wf}$ | 1180 | psig |
| | Reservoir Pressure, $P_r$ | 1267 | psig |
| | Reservoir Temperature, $T_r$ | 168 | degree F |
| | GOR | 500 | scf/bbl |
| | Water Cut | 75 | percent |
| | Desired Production Rate, $Q_d$ | 1500 | bpd |
| | Total GOR | 1100 | scf/bbl |
| Fluid Condition | Specific Gravity Water | 1.02 | sp.gravity |
| | Specific Gravity Oil | 37.5 | API |
| | | 0.848 | sp.gravity |
| | Specific Gravity Gas | 0.65 | sp.gravity |
| | Bubble Point Pressure | 2150 | psig |
| | Water Salinity | 10000 | ppm |

Table 2 : Well Test Data in 2009

| Deviation Survey | |
|---|---|
| 0 | 0 |
| 300 | 299.99 |
| 400 | 399.99 |
| 700 | 699.99 |
| 1000 | 999.6 |
| 5000 | 4095.76 |
| 6000 | 4912.9 |
| 6776 | 5550.5 |

Table 3 : Deviation Survey

| Geothermal Gradient | |
|---|---|
| Formation Measured Depth | Formation Temperature |
| 0 | 60 |
| 277 | 40 |
| 6022 | 168 |
| | |
| OHTC = 8.5 | |

Table 4 : Geothermal Gradient Data

### 4.2 Experimentation / Modelling

By using well data in 1977 and 2009, the results as shown in the graphs below:

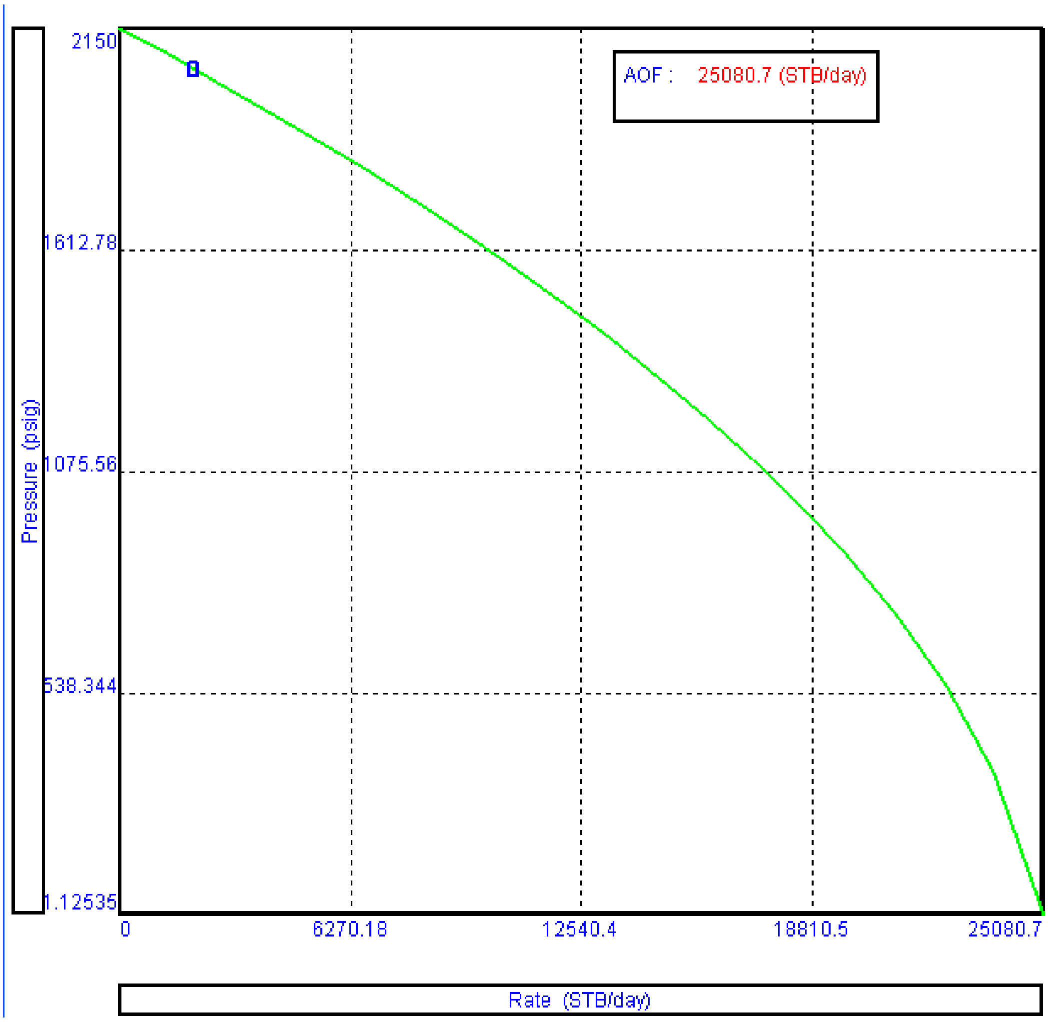



Figure 16 : IPR Plot for Natural Flow Based on Well Data in 1977

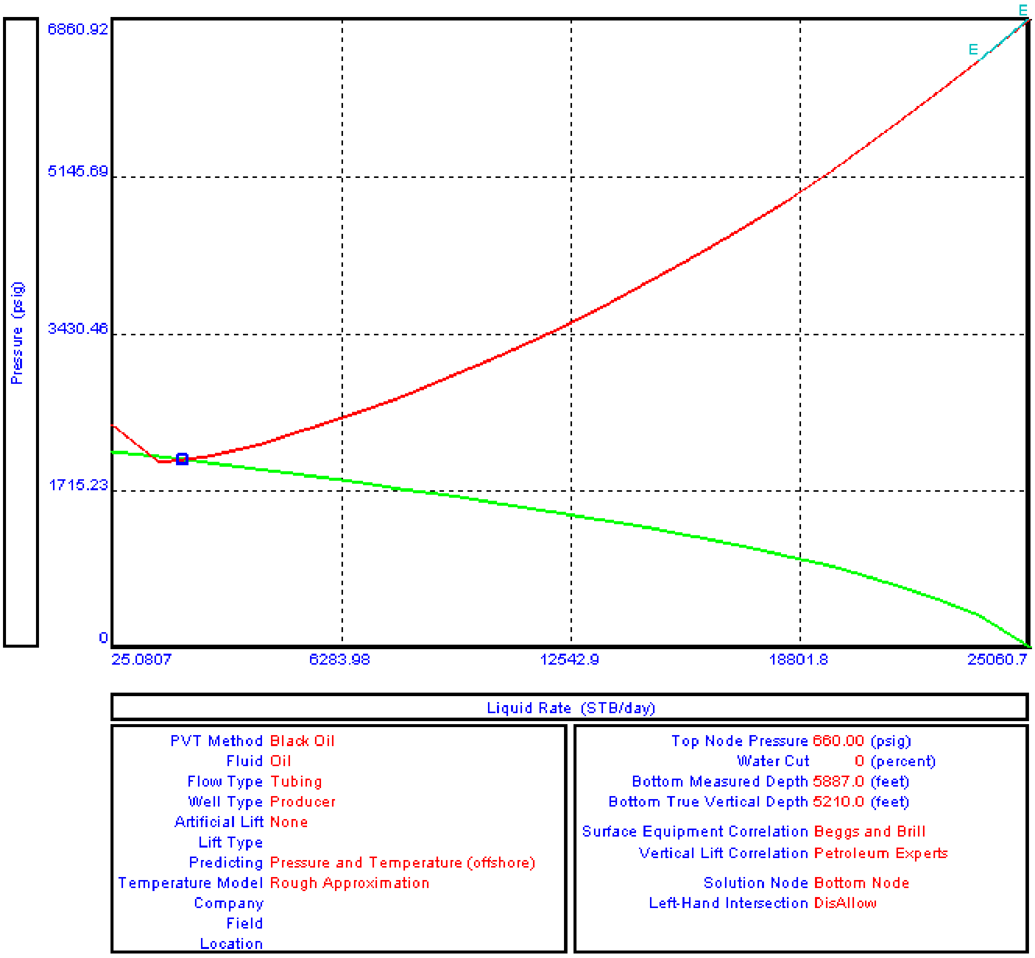



Figure 17 : Graph of Inflow vs Outflow Based on Well Data in 1977

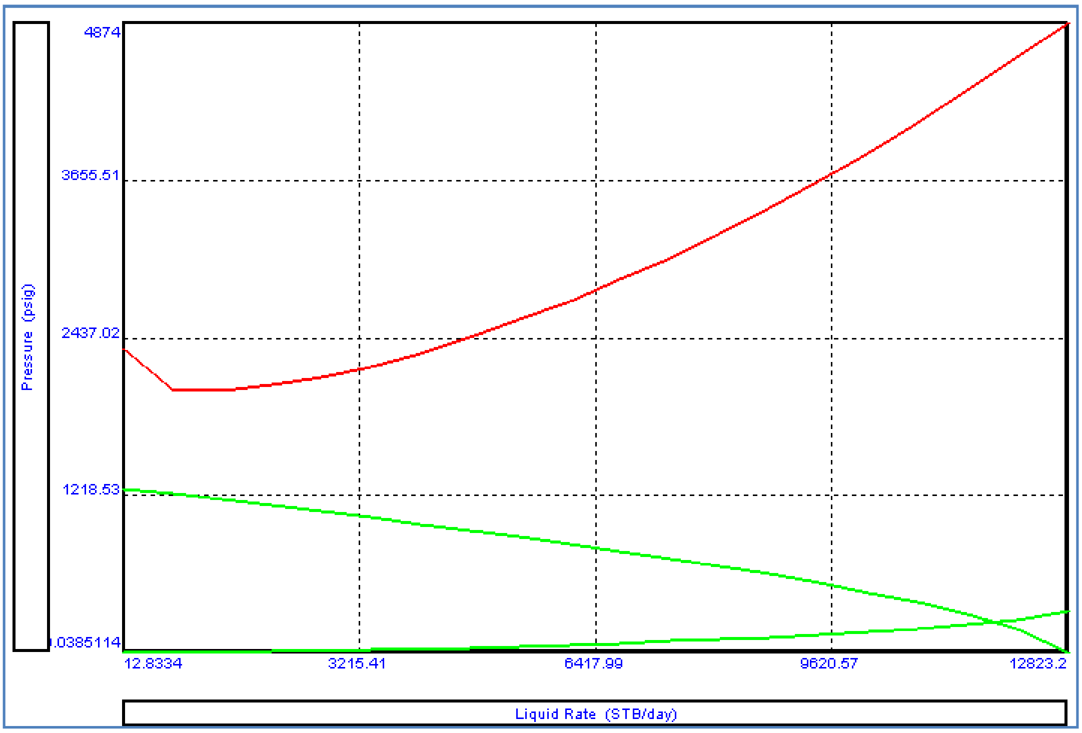



Figure 18 : Graph of Inflow vs Outflow Before ESP Installation

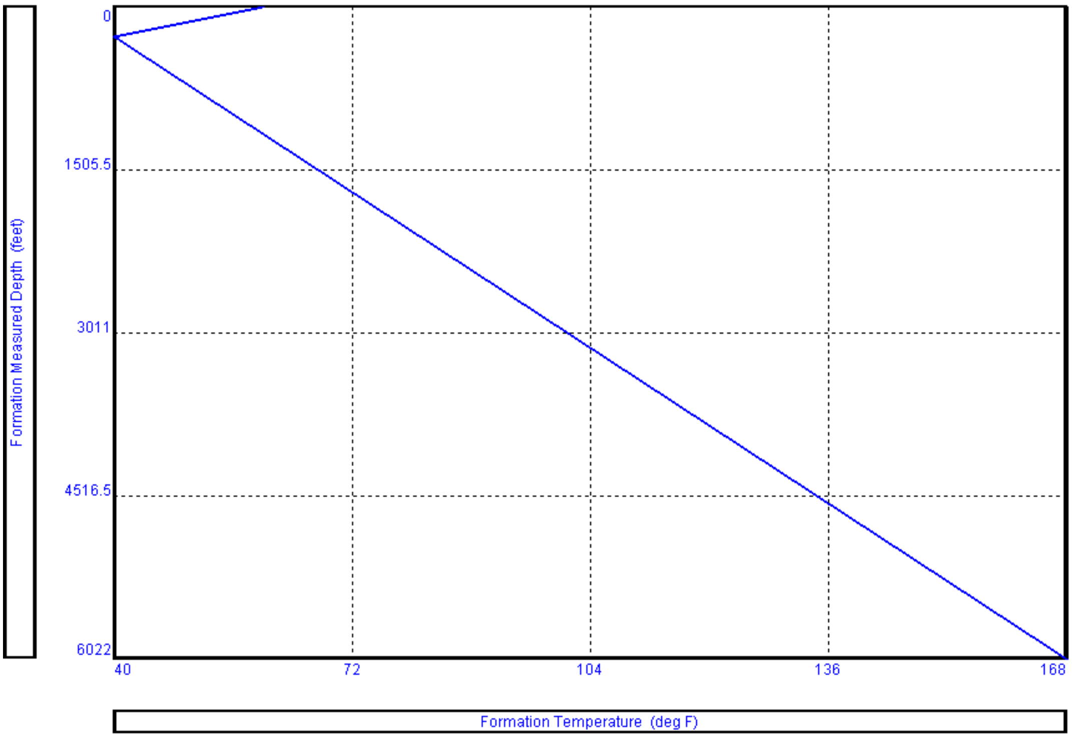



Figure 19 : Geothermal Gradient

By using PROSPER software, the results obtained as show as below.

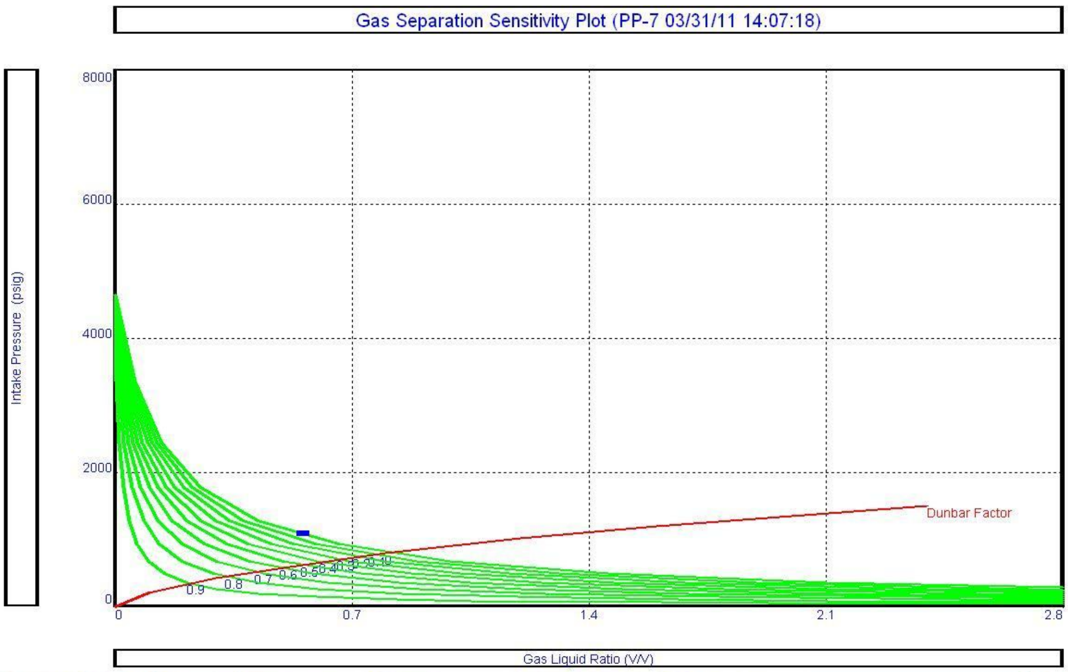



Figure 20 : Gas Separation Sensitivity Plot

The Dunbar plot is a plot of intake pressure against gas entering the pump. The different lines on the Dunbar plot are different levels of gas separation efficiency at pump intake. When the test point plots above the Dunbar factor, a gas separator is not necessary at pump inlet. If the test point plots below the Dunbar factor, a gas separator with an efficiency corresponding to the line it plots on is required at pump inlet. Then, the separator efficiency is entered in ESP design and pump calculations are repeated to ensure the point above the Dunbar factor line.

After installed with ESP, there is an intersection between red line and green line. It means that the well can reproduce back again 1349 STB/Day.

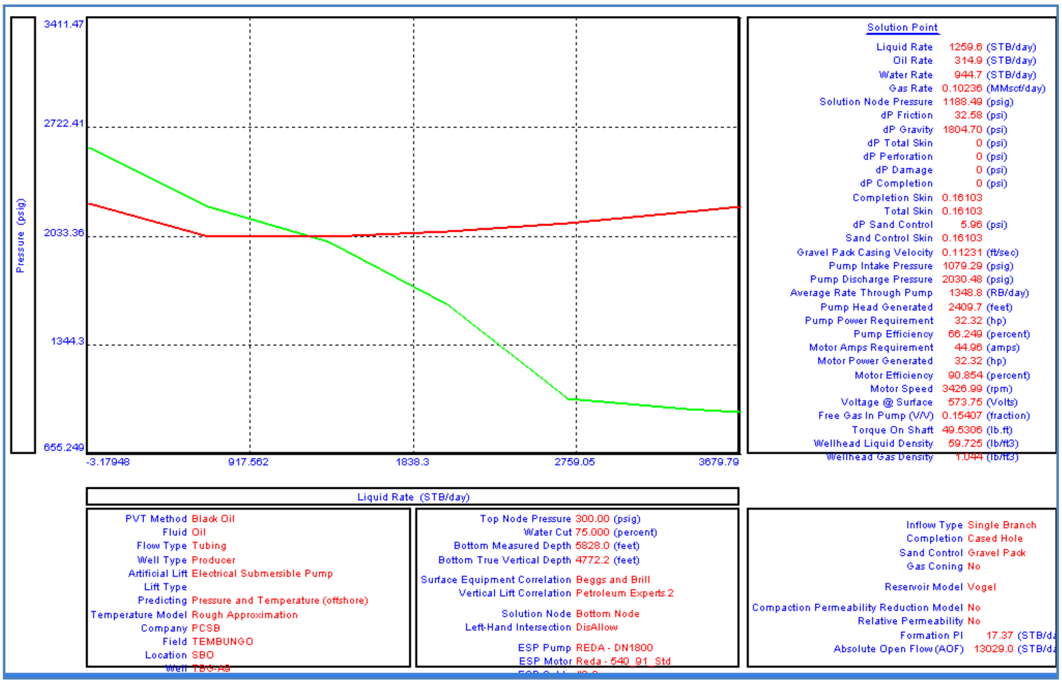



Figure 21 : Pump Discharge Pressure vs VLP Pressure Curves

## 4.3 Discussions

**Submersible Pump Design**

**Option 1**

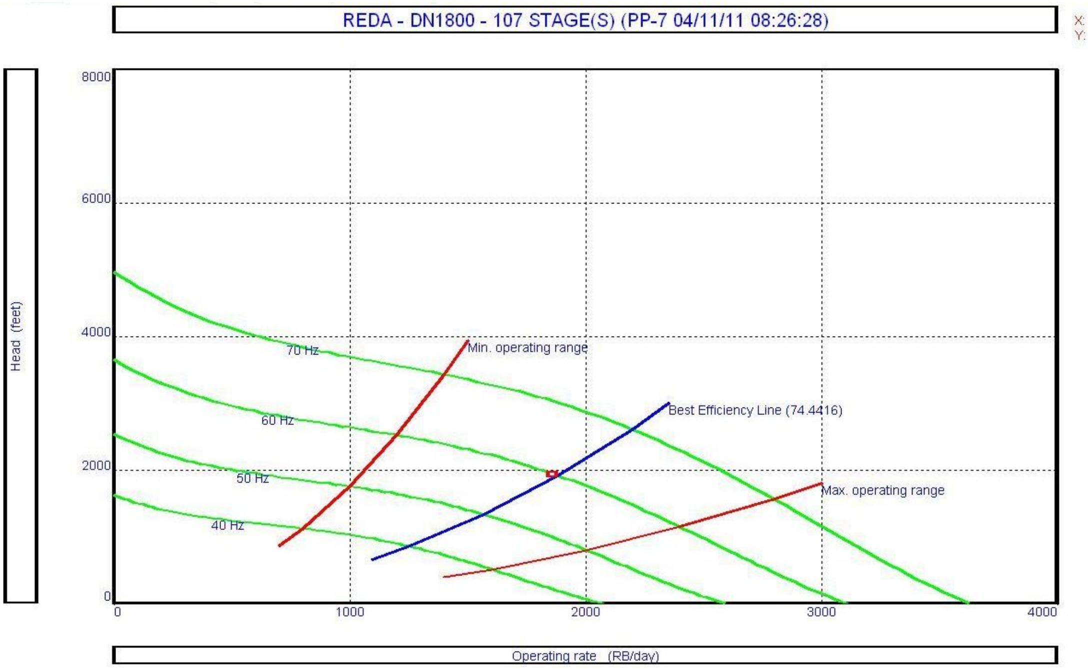



Figure 22 : Head Performance Curves of DN1800 Pump at Different Frequencies

Figure 22 displays the head performance curves of DN1800 submersible pump at different frequencies. The three lines represent the loci of:

- The minimum operating range / the lower limits of the recommended liquid rates
- The best efficiency points
- The maximum operating range / the upper limits of the recommended liquid rates

As this pump is driven by a 60 Hz electric supply, its recommended range is between the rates of 1200 and 2400 STB/Day. It can easily be seen that by regulating the electric frequency from 40 Hz to 70 Hz, the pump can cover a much wider range of flow rates, approximately from 800 STB/Day to 2800 STB/Day. This extended operational range gives the much needed flexibility for the operator and makes it possible to easily compensate for any uncertainties or changes that may occur in the well's inflow parameters.

This submersible pump needs 107 number of stages. The power required is about 28.4076 hp and the pump efficiency is 74.4483%. The motor efficiency is 84.3969% and it is about 3443.11 RPM for motor speed.

**Option 2**

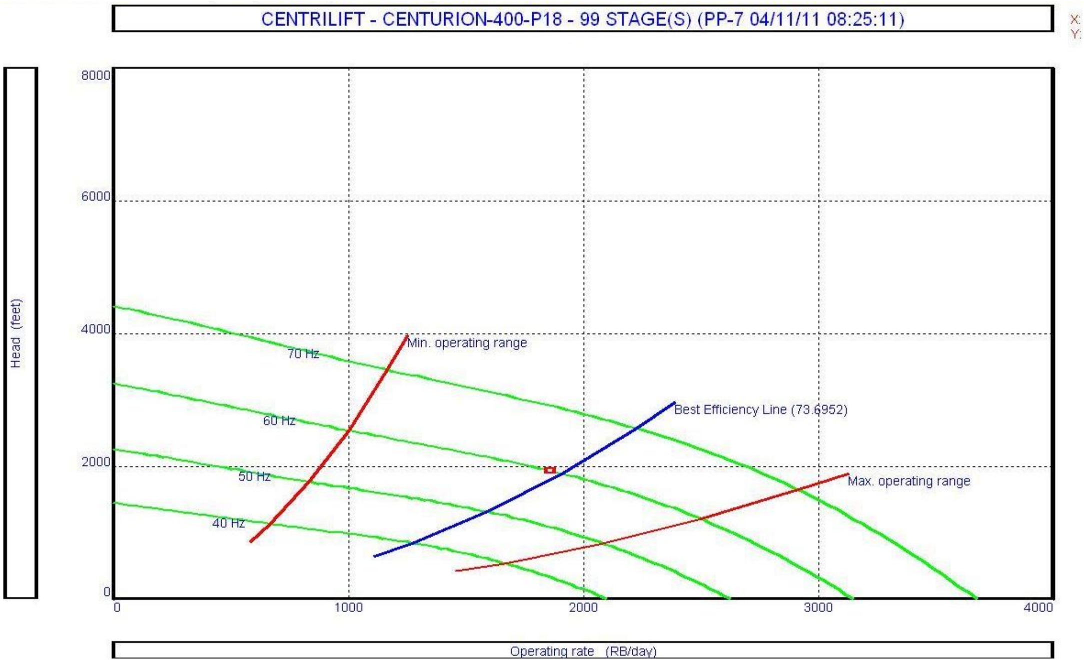



Figure 23 : Head Performance Curves of Centurion-400-P18 Pump at Different Frequencies

Figure 23 displays the head performance curves of Centurion-400-P18 submersible pump at different frequencies. The three lines represent the loci of:

- The minimum operating range / the lower limits of the recommended liquid rates
- The best efficiency points
- The maximum operating range / the upper limits of the recommended liquid rates

As this pump is driven by a 60 Hz electric supply, its recommended range is between the rates of 1000 and 2500 STB/Day. It can easily be seen that by regulating the electric frequency from 40 Hz to 70 Hz, the pump can cover a much wider range of flow rates, approximately from 700 STB/Day to 2900 STB/Day. This extended operational range gives the much needed flexibility for the operator and makes it possible to easily compensate for any uncertainties or changes that may occur in the well's inflow parameters.

This submersible pump needs 99 number of stages. The power required is about 28.5085 hp and the pump efficiency is 73.6765%. The motor efficiency is 84.4114% and it is about 3442.51 RPM for motor speed.

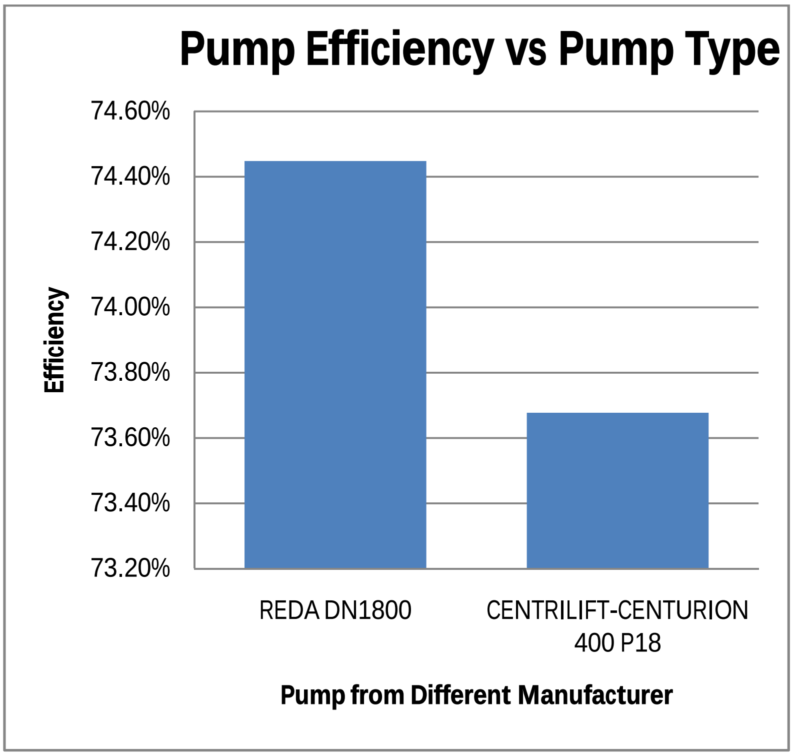



Figure 24 : Graph of Pump Efficiency vs Pump Type

As for comparison, the author found that REDA DN1800 pump is more ideal compared to Centrilift Centurion-400-P18 pump. From the graph above, it can see that the REDA DN1800 pump has more efficiency, besides just required only about 28.4076 horse power. The motor speed also about 3443.11 RPM, just near to theorical motor speed, which is about 3500 RPM in 60 Hz electric supply.

# CHAPTER 5

# CONCLUSION AND RECOMMENDATION

## 5.1 Conclusion

As a conclusion, by implement this final year project, the author have analyzed the production problem and designed the electrical submersible pump (ESP) system that meet the well data and the problems. Furthermore, ESP is the most ideal artificial lift method for this PP-7 well, which has high water cut and pressure depletion problem. By installed ESP, it allows recovering more oil in less time, which will enhance field economics. Since there are various designs of ESP system worldwide today, we need to design the most optimum and ideal ESP systems as mentioned in the project objective early. Again, ESP is a dynamic displacement, multistage centrifugal turbine pump coupled by a short shaft to a downhole electrical motor,which is supplied with electrical power by a cable extending to the surface. As in production engineer disipline, it is a need to design the most ideal ESP system in order to extend the life of ESP components since the ESP components are very expensive investment for the company. From this research, it can conclude that REDA DN1800 pump is the most suitable submersible pump for this case study. With the pump efficiency about 74.4483%, this well can produce about 1349 STB/Day.

## 5.2 Recommendation

The results obtained in this research are relevant with the objectives. If this project is expanded in wider scope like considering more parameters, we will be able to study a lot more theories and in the same time gain more knowledge in the artificial lift discipline. Here, I would like to suggest several recommendations to this research:

a) To make economical analysis for each ESP components. From this, we can choose the more efficiency and more economical one.
b) To analysis the difference in term of economics, run life and installation method of conventional tubing deployed and coiled tubing deployed.
c) To develop ESP design and installation in special conditions like in gassy well.

# REFERENCES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