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INTEGRATED FIELD DEVELOPMENT PROJECT REPORT

EVUALUATION OF BOTH RESERVOIR AND WELL DELIVERABILITY FOR VIC BILH FIELD

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MARCH, 2024

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CHAPTER 1

1.1 INTRODUCTION

The Vic-Bilh field is located in the southern part of the Aquitaine sedimentary basin, and more precisely in the Adour sub-basin. The Aquitaine Basin of southwestern France lies in the foreland of the Pyrenean fold-and-thrust belt. The structural evolution of this basin was strongly influenced by early basement tectonics dating from the Variscan and Hercynian orogeny. The subsequent evolution was governed by extensional block faulting and associated salt diapirism during Jurassic and Early Cretaceous times, and by compressional deformations during the Late Cretaceous through the Oligo-Miocene Pyrenean Orogeny. (Ziegler & Horvath, 1996)

The South Aquitaine area represents the largest gas producing and the second largest oil producing province of France. Exploration in the Aquitaine Basin started in the I930's and resulted in 1939 in the discovery of the St. Marcet gas field. The potential of the area was later on confirmed by the discoveries of the Upper Lacq oil field in 1949, the giant Deep Lacq gas/condensate field in 1951 and the Meillon gas field in 1965. In the same area, several smaller sized fields, such as Ucha, Lacommande, Rousse and Cassourat fields, each having gas reserves were also discovered in the same period. In the 1970's, exploration interests moved northward towards the basin edge, resulting again in the discoveries of five sizeable oil fields, namely Pecorade, Vic Bilh, Lagrave, Castera Lou and Bonrepos-Montastruc (Ziegler & Horvath, 1996). The Vic Bilh oil field was discovered in 1979 by a high-resolution seismic survey. Initial exploration efforts focused on identifying the potential of the field and assessing its commercial viability. Extensive geological and geophysical studies were conducted to understand the reservoir characteristics and estimate the oil reserves

1.2 Regional geology of the Vic Bilh field

The Aquitaine basin can be divided into three main geological provinces, running from north to south: the North Aquitaine Platform, the Pyrenean Foreland, and the Pyrenean Mountain chain. The Vic Bilh is situated within the Pyrenean Foreland. This province contains all major discoveries in the Aquitaine Basin. The structuration of the foreland was primarily acquired during the Early Cretaceous extensional phase which controlled the subsidence of the Arzacq and Tarbes basins(Ziegler & Horvath, 1996). These basins, which contain over 5000 m of Barremian to Albian sediments, are flanked by Early Cretaceous platforms and salt ridges. The latter are located along the margins of these basins. The Arzacq and Tarbes basins were partially inverted during the Late Cretaceous and Tertiary phases of the Pyrenean orogeny. at the beginning of the Jurassic, when the earth's crust began to stretch and thin. During this phase, a depression gradually develops, leading to the accumulation of a thick sedimentary pile. It is at this stage that source rocks and reservoir rocks are deposited. The organic matter that accumulates is buried to a sufficient depth, where it undergoes transformation into either Kimmeridgian-age or Barremian-age parent rock(I-GENERAL NOTIONS AND DEFINITIONS, n.d.). The organic matter buried often consist of microalgae and microorganisms and they are broken down particularly by oxidation, to form kerogen over a geologic time scale as a result of compaction cementation, recrystallization and reactions. Then after the kerogen reaches higher levels of thermal maturity it undergoes additional process to form hydrocarbons in which these hydrocarbons migrated from the source rock of the Kimmeridgian age to the reservoir rock of the Vic Bilh field

1.2.1 Source Rock

Significant reserves of oil and substantial amounts of gas have been found in the Aquitaine Basin, indicating the presence of extensive source rocks with high hydrocarbon generation potential. These rocks have expelled significant quantities of oil and gas. Although some source potential has been recognized in Tertiary, Albian and Liassic shales, these formations have contributed little and the main source-rocks are clearly associated with the Barremian and Kimmeridgian formations(Ziegler & Horvath, 1996).

The marine Barremian source-rocks contain type II-III organic matter. And the marine Kimmeridgian source-rocks appear to have the best petroleum potential. Their organic matter is again primarily of type II-III. TOC values range between 2 and 7% (Ziegler & Horvath, 1996).

1.2.2 Reservoir rock

The Vic Bilh has two reservoirs which is the Portlandian Mano dolomites and Barremian limestones. The Barremian reservoir (Lower Cretaceous, carbonate) which brings together two reservoir units; the south Barremian (exploitation by certain gas cap) and North Barremian. The Portlandian Mano dolomites has Brèche de Garlin reservoir: this is the major drain of Vic-Bilh (best reservoir: variable permeability from 1 to 100 mD), Mano Dolomites: reservoir of variable quality (best to the east of the field) with an average porosity of 10% and a permeability of 0.01 to 10 mD(I-GENERAL NOTIONS AND DEFINITIONS, n.d.).

On the eastern Jurassic shelf of the Aquitaine Basin, reservoirs are represented by the early Kimmeridgian Meillon dolomites (average thickness 200 m), the Portlandian Mano dolomites (150-200 m) and the Garlin Breccias. In the Meillon, Ucha, Lacommande and Rousse trend of structures, these reservoirs are totally or partially gas bearing. Although porosities of Jurassic carbonates are rather poor (2 to 4% matrix porosity for the Mano dolomites and 4 to 8% for the Meillon dolomite), effective permeability is primarily provided by fissures and fractures, allowing for good well productivities(Ziegler & Horvath, 1996).

And on the western Jurassic outer shelf is the Lacq, Pecorade and Vic Bilh fields, only the Mano dolomites are preserved within this Jurassic sequence. Although petrophysical characteristics are better here, they remain in average poor (porosity 2-10%). Production is again primarily associated with intensely fractured reservoirs(Ziegler & Horvath, 1996).

1.2.3 Trapping Mechanisms

The traps of the Vic Bilh fields are clearly related to structures inherited from the Early Cretaceous extension and associated salt tectonics along the margins of the Arzacq basin (erosional pinch-outs of the Jurassic and Barremian reservoirs. These traps were modified during the Pyrenean orogeny which is responsible for the present structural configuration of the area.

The Vic Bilh field is located in the distal parts of the Pyrenean foreland, along the northeastern margin of the Arzacq Basin, which was affected by Early Cretaceous salt tectonics and limited inversion during the Tertiary Pyrenean phases. The trap of this field is formed by an erosional pinch-out of Jurassic carbonates along the northern salt ridges of the Arzacq Basin(Ziegler & Horvath, 1996). The main halo kinetic episode is again pre-Barremian in age, as attested by the transgression of the Barremian and early Aptian sediments over deeply eroded Jurassic carbonates and Triassic and Liassic evaporites at the top of the salt dome. The reservoir comprises the Portlandian Mano dolomites and Barremian limestones. The top seal is formed by the early Aptian shales of the Sainte-Suzanne Formation; Albo-Aptian shaly limestones are thought to provide lateral seals. The oil contained in the Vic Bilh structure was derived from Kimmeridgian and Barremian source-rocks which probably reached maturity during the Oligo-Miocene at the same time as the trap was closed.(Ziegler & Horvath, 1996)

CHAPTER 2

2.1 Seismic Survey

In the past, exploring for petroleum was a matter of good luck and guesswork. Drilling near oil or natural gas seeps where hydrocarbons were present on the surface was the most successful hydrocarbon-finding method in the early days of oil exploration. The seismic method plays a prominent role in the search for hydrocarbons. Seismic exploration consists of three main stages: data acquisition, processing, and interpretation.(Yilmaz, 2008) Today, petroleum explorationists use sophisticated technologies, scientific principles, and guidelines to find oil and gas(Mouillac, 2017)**.** Land surveys were performed to help identify the areas that were the most promising from the Vic Bilh field.

The aim was to identify specific minerals underground, to estimate the volume of oil and gas reserves before drilling. Geologists studied rock formations and layers of sediment within the soil to identify if oil or natural gas is present

2.1 Seismic Acquisition Design

In exploring the Vic Bilh field, seismic surveys were conducted to further comprehend the geology of the field. The orientation, source type, and geometry of the survey were evaluated and discussed to suit the field.

In seismic surveys, 2D/3D, Source type, and Geometry are all crucial portions that define how the survey is conducted and the type of information to be gathered.

The 2D seismic was used ahead of the 3D because it is the initial exploration phase and therefore, we need a faster, easier, and less expensive way to get data.

The source type of a seismic survey describes the method used to generate the seismic waves that travel through the rock. They are mostly chosen according to the location of the field i.e. offshore or onshore. Vibroseis Trucks were chosen to be used because they are large trucks that use vibrating plates to create controlled, continuous vibrations on land since our field is an onshore field. Although, expensive, vibroseis trucks give a higher resolution as compared to other source types(Air guns and thumpers).

Geometry describes the spatial arrangement of the source (generating the sound waves) and receivers (capturing the returning waves) during the survey. Line Acquisition is the basic setup for 2D surveys, with a linear arrangement of receivers along a single line on the surface. It was chosen to go with 2D seismic

2.2 Data Processing and Interpretation

The basic processing of the seismic data consisted of editing, amplitude recovery, deconvolution, static and move-out corrections, common depth, filtering, and display. (J. L. Mari, n.d.)

The basic processing of seismic data involves several key steps that are essential for analyzing and interpreting the data accurately. Here is what each step involves:

Editing: This involves the initial step of quality control of the seismic data. Any unnecessary noise or artifacts are cleansed to ensure that the data is clean and ready for further processing.

Amplitude Recovery: This focuses on restoring the true amplitude information of the seismic signal which may have been changed during acquisition or processing, to accurately represent the subsurface properties.

Deconvolution: Deconvolution is a process that aims to enhance the temporal resolution of seismic data by compressing the seismic wavelet to improve the clarity and definition of subsurface reflections.

Static and Move-Out Corrections: Static corrections refer to adjusting for variations in arrival times caused by near-surface velocity heterogeneities, ensuring that seismic events are rightly positioned in time. Move-out corrections account for variations in move-out caused by variations in subsurface velocity.

Common Depth Point (CDP) Stacking: CDP stacking is a technique used to enhance signal-to-noise ratio by summing seismic traces from common midpoint gathers, aligning them in time, and stacking them to create a clearer image of subsurface structures.

Filtering: Filtering involves applying frequency filters to separate specific frequency ranges in the seismic data, helping to enhance certain features or remove unwanted noise.

Display: The final step involves visualizing the processed seismic data in various forms such as time slices, depth sections, or amplitude maps for interpretation and analysis.

The interpretation of the acquired seismic data was carefully done and a conclusion was drawn that, the seismic interpretation suggests a promising area for hydrocarbon exploration. Further integration with well data and potentially 3D seismic acquisition will be crucial for a more comprehensive understanding of the subsurface and to de-risk drilling decisions.

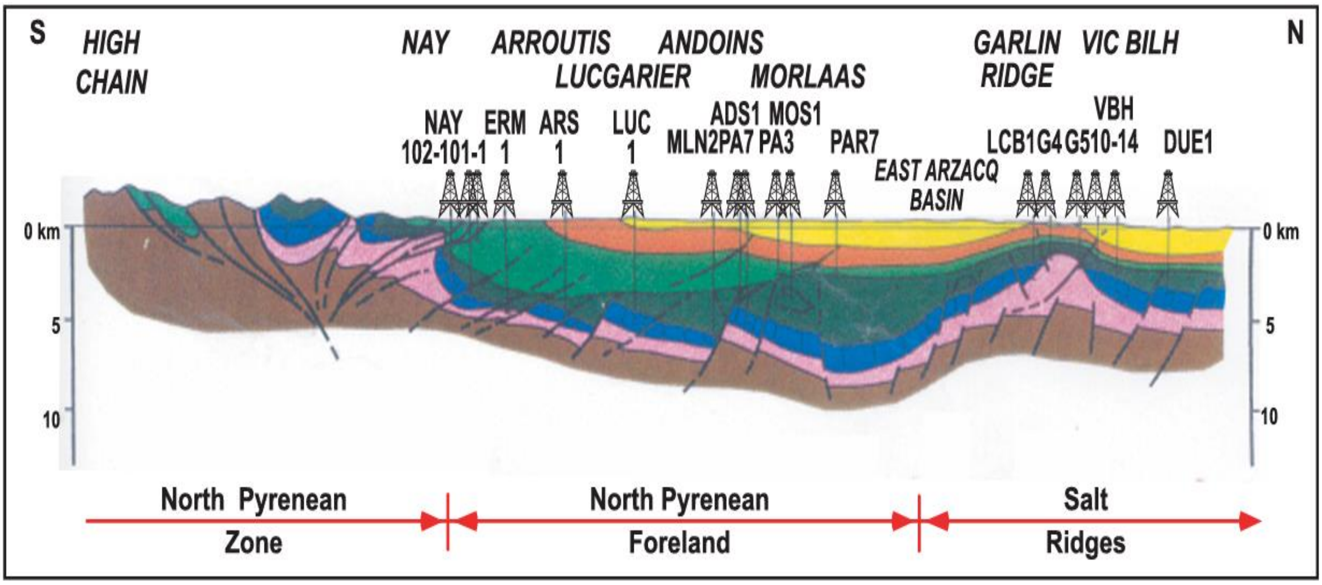

Table 1 Geological cross-section through the South Aquitaine sub-basins(M. et al., n.d.)

2.3 Identification of Potential Hydrocarbon Traps

Trap formation is governed by three main parameters: the geometry of the reservoir, the sedimentary sealing history, and the tectonic history. A hydrocarbon trap is a closed structure with a reservoir rock overlain by impermeable strata. The seal/reservoir interface may conform with the boundary of the two formations, but it is often a complex of unconformities and fault contacts between the reservoir body and various seals. Two basic types of potential traps exist, namely stratigraphic traps and structural traps. (Koch, 1982)

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2.4 Seismic conclusion

Based on the processing and interpretation of the seismic data, the following conclusions can be made:

Hydrocarbon Presence: A prominent anticlinal structure was identified at approximately 2500 meters depth within the target formation. This structure demonstrates characteristics of a potential hydrocarbon reservoir, including strong seismic reflections and a clear closure.

Reservoir Quality: The seismic amplitude variation suggests lateral variations within the reservoir. Areas with higher amplitude anomalies may represent zones with better reservoir quality, possibly due to higher porosity or fluid content.

Potential Challenges: A network of faults was observed cutting through the reservoir. Further investigation is required to assess the impact of these faults on reservoir continuity and fluid flow.

2.5 Recommendations

From these findings, it is recommended to drill a well within the central portion of the identified anticline to confirm the presence of hydrocarbons and evaluate reservoir properties. Additionally, advanced seismic processing techniques may be employed to provide a better understanding of fault distribution and its impact on the reservoir.

CHAPTER 3

Drilling Program

It is assumed that the mud logs from the appraisal wells have a formation pore pressure gradient of 0.446 psi which is close to the normal pressure (0.465 psi/ft). The pressure gradient in the reservoir is 0.499 psi/ft. From the leak-off test, the fracture pressure gradient is between 0.728-0.754 psi/ft. Due to the complexity of the geology of the Vic Bilh field, there is an anticipation of overpressure(due to the presence of faults). Due to the very low permeability of the field, an underbalanced drilling technique would have been suitable to reduce any further damage to the formation. However, with well control and simplicity being our main goal due to the complex nature of the formation and the presence of overpressure zones, we went in for overbalanced drilling so that there could be adequate control over the well. Oil-based mud was used in the reservoir zone to reduce any further damage to the form High-performance water based mud was used for the other hole sections; a movable land rig was selected since it meets the specifications such as drilling depth, hoisting system, BOPs, etc. The derrick can withstand weights higher than the maximum weight expected to be exerted on the rig which is about 500,000 lb (weight of the production casing including the pull-off margin)

3.2 Well General Details

This section of the drilling program includes simple information such as the well coordinates, field or structure, well depth operator and owner company data

Location: France **Field/ Structure: Vic Bhil Oil Field**

Well name	Co-ordinates	
Vic_Alpha (exploratory)	276875.82	614958.09
	276970.42	614933.09

	277171.56	614933.1
Vic_Omega (development)	276233.94	615233.09
	276334.61	615333.09
	276228.29	615583.09
Vic_Beta(development)	276299.56	614633.1
	276326.31	614683.09
	276153.9	615983.1

Table 2 Well type and coordinates

Total Depth: 2700m

Operator oil or gas Company: Total Energies

Target Tolerance: +5m

Rig Name:

Type of the drilling rig: mobile land rig with top drive

3.3 Well Objectives

The well objective is manly provided by the exploration division. It entails the geologic targets, hydrocarbon prospects, and data acquisition.

- **Geological targets**: this involves identifying the particular geological formations or zones that the drilling will explore. In the case of Vic Bilh field, the geological targets are
- **Hydrocarbon prospects**: this includes making an evaluation or assessment of the potential for oil and gas in the target formation. This assessment is based on a combination of geological, geophysical. This includes geophysical analysis to identify potential reservoirs that could hold hydrocarbons. It also includes using seismic data to map the subsurface structures and identify traps where hydrocarbons may accumulate. The term prospect is used when there is a high enough confidence level in the data to justify the investment of drilling a well to test for the presence of hydrocarbon. This is the final step before the actual drilling process.
- **Data acquisition**: this is where the drilling engineers specify the types of samples and the logs to be collected during drilling to obtain information about the subsurface.

Some other drilling objectives include maximizing hydrocarbon recovery, minimizing drilling time and cost, reducing risks and uncertainties, enhancing safety and reliability, and complying with environmental and regulatory standards

3.4 Casing Program

The casing program is a very key component of the drilling program. It involves the design and implementation of casing strings for the enhancement of the structural integrity of the wellbore

Why casing

- To stabilize the wellbore
- Isolate different pressure zones
- Support wellhead and BOP

Before initiating the drilling program, parameters such as the pore pressure, formation fracture pressure are needed to know the depths at which casing strings will be set and to also know the loads anticipated during the well's life

3.4.1 Pore Pressure Determination

We must obtain the pore pressure data accurately to perform a good casing program. The pore pressure data was obtained from mud logs from the appraisal wells. It was also compared with seismic data and offset well data. Offset wells introduce more realistic data, but sometimes you need to drill exploratory wells that have no offset data and an estimation process of pore pressure shall be done by analyzing seismic data with certain software (PetroWiki's Seismic velocity modeling Springer's Seismic velocity modeling, GeoScience Software). Seismic data can also be utilized to calculate pore pressure and hence an indication of any pore pressure abnormalities.

3.4.2 Formation Fracture Pressure

The formation fracture pressure can be obtained from leak-off tests. It can also be estimated using anticipated geology and offset well data. The fracture pressure helps greatly in selecting the casing shoe depth. Once we perform leak-off test, it will be easy to estimate the fracture pressure in other depths of the well using equations as 'Daines' with values of Poisson's Ratio for given formations.

3.4.3 Setting Casing depth

This refers to the specific depths at which the casing strings are set in the wellbore to ensure structural integrity. The casings are set based on the pore pressure and fracture pressure gradients. It also depends on the competence of the formation with high fracture pressure. Pressures are converted into equivalent mud density which helps in determining the safe drilling window and the appropriate mud weight to be used. After the pore pressure and fracture pressure charts have been performed and included in the drilling program, the Drilling Engineer should liaise with Production Engineers to decide on the likely size of the final production conduit so as to decide about the different casing sizes required to be lowered at various casing seats selected.

When the mud weight at a particular depth falls out of the safe drilling window, that section is cased before drilling continues to avoid fracturing the formation. It should however be noted that that casing shoes should be set on shales and not sandstone.

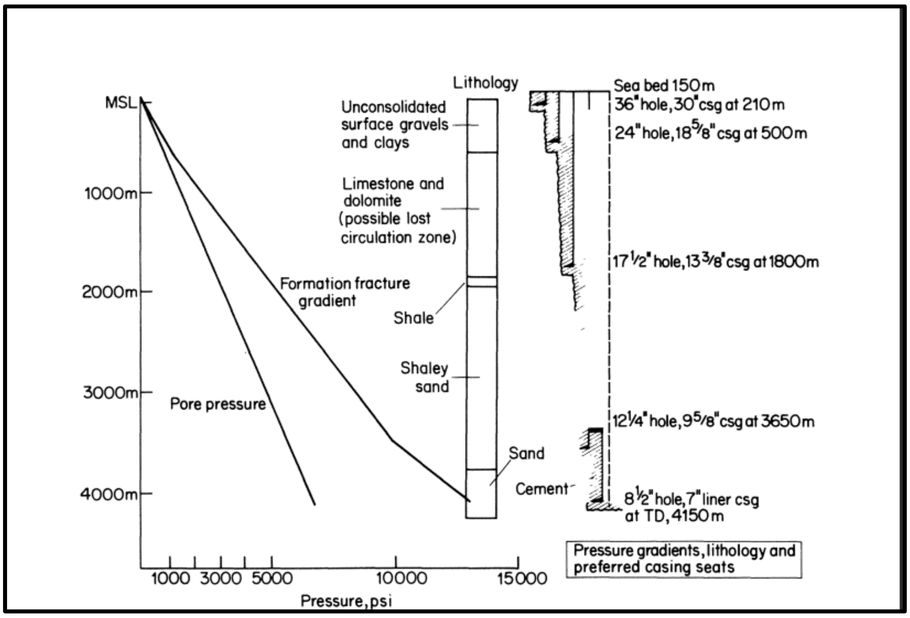


Figure 1 Casing depth design

3.4.3 Casing Program

The design of a casing program involves the selection of setting depths, casing sizes, and grades of steel that will allow for the safe drilling and completion of a well to the desired producing configuration. The selection of the number of casing strings and their respective setting depths is

based on geological conditions and the protection of freshwater aquifers. The selection of casing string sizes is generally controlled by three major factors:

• Size of the production tubing string

• Number of casing strings required to reach the final depth, and

• Drilling conditions.

There are three main processes which have been followed in the casing design. The first step was to determine the casing sizes and the setting depths which depend on the hole section conditions (formation type). For the surface and intermediate casing strings, the maximum pressures that can be encountered while drilling which might occur when circulating out a gas influx has been calculated and compared with the fracture formation pressure to determine the shallowest depth at which the casing can be set safely. The second step in the casing design was the definition of the operational scenarios which leads to burst, collapse and axial loads being applied to the casing. The design scenario which was considered for collapse of casing is when the casing is fully evacuated due to lost circulation whilst drilling whereas for burst is when the well is closed in after a gas kick. It is worth noting that Collapse, burst, and compression and bending forces are usually not a problem for the conductor casing. Finally, the appropriate weight and grade of casing has been selected after calculation of burst, collapse & axial loads. For the Surface casing API connection will be used because there are no high pressures expected in the shallow formations. H_2S is expected to present in the 17 ½" and 12 ¼" hole sections, thus the casing grade L-80 with VAM connection has been chosen to withstand H_2S and high pressures. The table below shows the casing data which will be used for the Vic Bilh field. These data have been derived by the casing design process which has been mentioned.

Hole size (in)	**Casing**	**OD (in)**	**Set Depth TVD (ft) RKB**	**Grade**	**Nominal Weight (lbs/ft)**	**Connections**	**Remarks**
36''	Conductor	30"	328	K-55	106.3	API	seal off unconsolidated formations at shallow depths
26''	Surface	20"	2953	K-55	106.3	API	seal off any fresh water sands, and support the wellhead and BOP Equipment.

17 ½’’	Intermediate	13 3/8”	4500	L-80	72	VAM	isolate unstable shales and lost circulation zones between the surface casing and the production casing
12 ¼’’	Production	9 5/8”	6808	L-80	47	VAM	isolate pay zone interval from other formations

Table 3 Casing program design

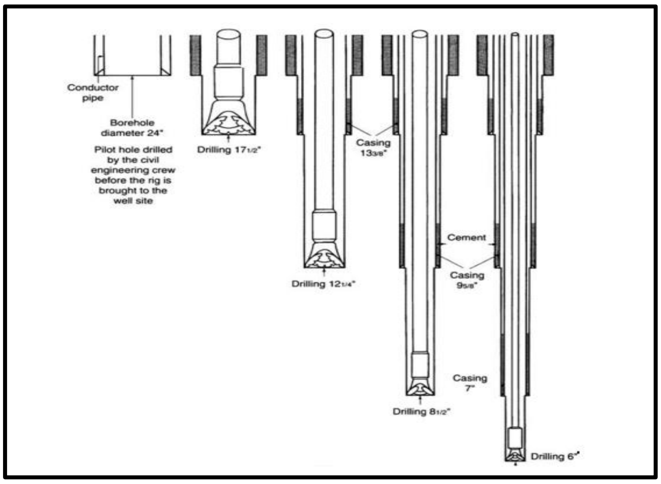


Table 4 Casing and drill pipes design

3.5 Casing Design (burst, collapse, and tension)

A fundamental concern for safety throughout both the drilling and production phases is the configuration of the casing string. It is often designed to withstand challenging operational circumstances. The maximum load concept is one of the methods for analyzing potential drilling problems that is used the most frequently. Casings are designed based on their burst, collapse, tensile or biaxial loading. Casing strings are typically created for the following conditions in order to choose the best weights, grades, and section lengths:

- Burst
- Collapse
- Tension

“Burst conditions are established, and the least-expensive pipe that will satisfy the burst load is tentatively selected. Subsequently, the collapse loads are defined, and the tentative selection is evaluated for collapse resistance. If any section from the tentative design does not meet the collapse load limits, it is upgraded with a pipe of a sufficient collapse rating. At this point, the tentative design uses the least-expensive pipe that satisfies both the burst and collapse requirements”

Tension loads are defined by computing the buoyant forces acting on the pipe and the pipe weight.The buoyant forces are defined as the product of the wellbore pressures acting on horizontal cross-sectional areas. Forces acting on the vertical sections of the casing are considered negligible since the inside and outside forces cancel (approximately) each other

An ellipse of elasticity used to rate the casings in burst, collapse and tension

3.5.1 Collapse and Burst Rating

Casing type	**Casing size, OD(in)**	**Hole size**	**Weight(lb/ft)**	**Wall thickness(in)**	**Burst load(psi)**	**Collapse load(psi)**	**Yp(psi)**	**Setting depth(ft)**	**grade**
Conductor	30	36	106.3	0.875	-	-	-	328	K- 55
surface	20	26	106.3	0.5	3109	2363	71063	2953	K-55
intermediate	13 3/8	17 1/2	72	0.495	6131	4764	113242	4500	L-70
production	9 5/8	13 1/4	47	0.472	11420	4805	133072	6808	L-80

Tension rating

Casing type	**Casing size, OD(in)**	**Hole size**	**Weight(lb/ft)**	**Wall thickness(in)**	**Mud weight(ppg)**	**Bouyant force, Fb (lb)**	**Yp(psi)**	**Setting depth, TVD(ft)**	**Pipe weight ,Wp (lbm)**
Conductor	30	36	106.3	0.875	-	-	-	328	54586

surface	20	26	106.3	0.5	10.4	81084	71063	2953	489900
intermediate	13 3/8	17 1/2	72	0.495	14.4	124488	113242	4500	554400
production	9 5/8	13 1/4	47	0.472	20	129790	133072	6808	418300

3.6 Wellhead Selection

A component at the surface that provides the structural and pressure-containing interface for drilling and production equipment

- Provides the suspension point for BOP during drilling and X-mas tree during production
- Hangs casing string and tubing
- Seals tubing and casing annulus
- Allows for injection of steam, gas, water, chemicals
- Contains pressure
- Allow access to annulus

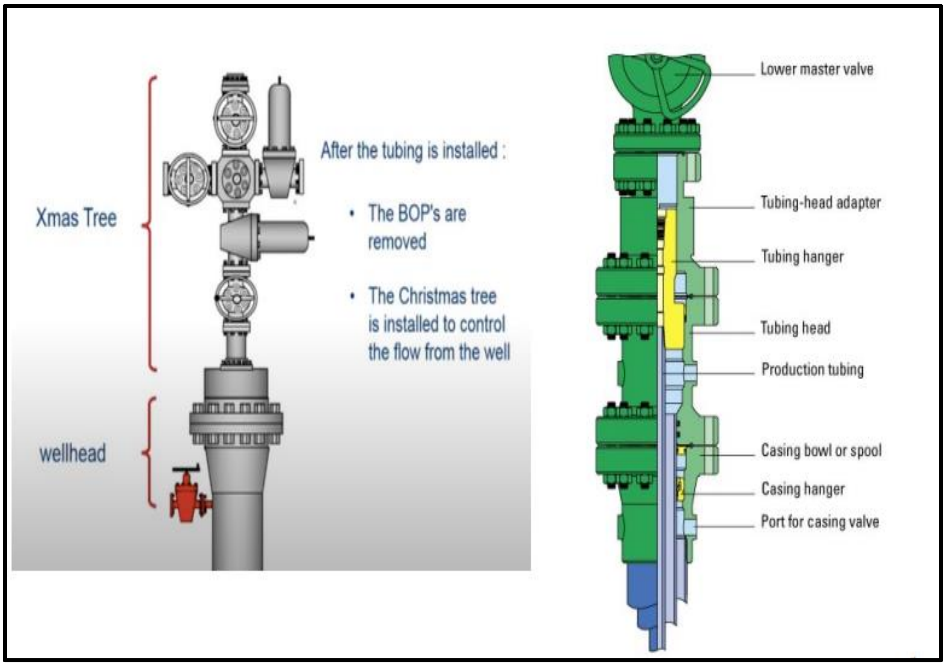


Table 5 Parts of a Wellhead

After the casing design has been completed, there will be enough information to guide us select the appropriate wellhead. The wellhead must have a correct pressure rating , be designed for desired applications like (H_2S), and be able to accommodate all designed and contingent casing strings.

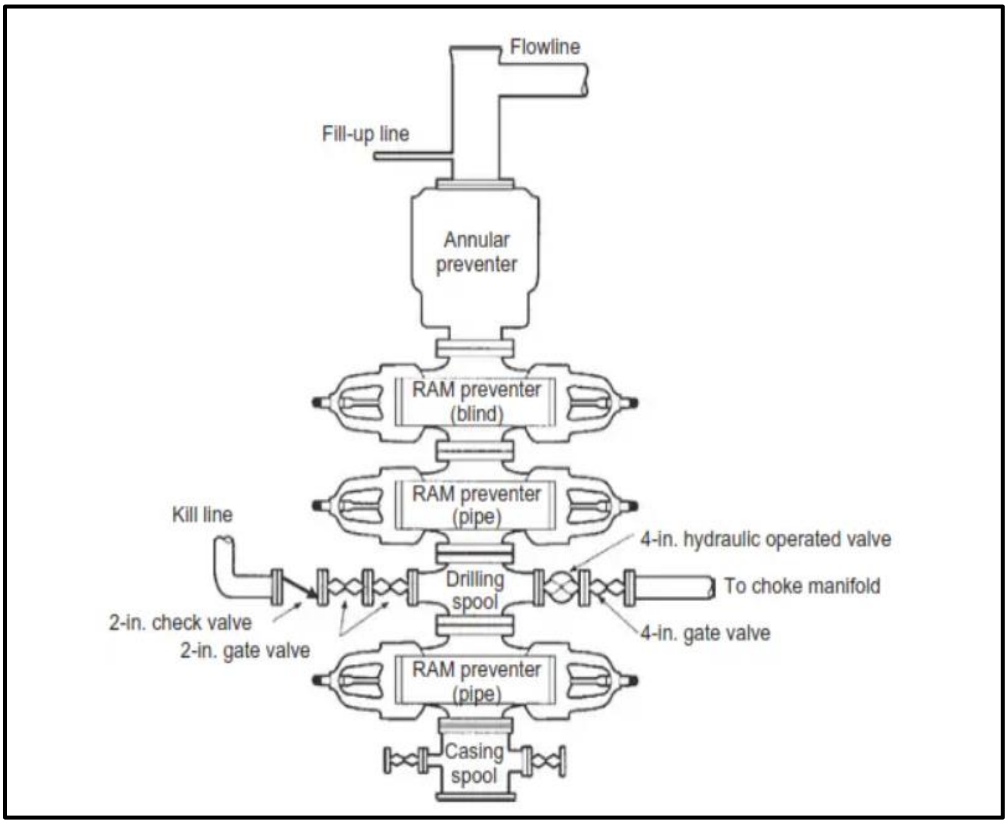
Having selected the wellhead, its specification should be included I the drilling program along with a sectional view of its component stack-up

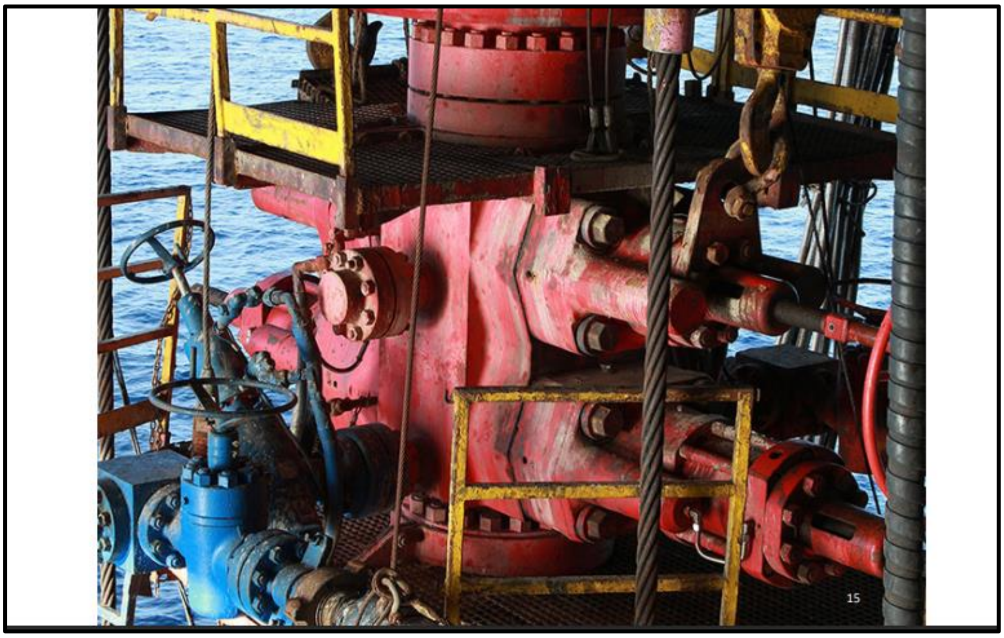
3.7 Bop Requirement And Installation

The BOP systems are essential safety devices in drilling operations, designed to prevent the uncontrolled release of well fluids. The Blow Out Preventer Stack requirement for a certain well shall rely on the company policy and anticipated BHPs. BOP must undergo pressure test frequency. That is, it must be pressure tested when installed and also before drilling out each string of casing or liner.

The BOP stack helps stop uncontrolled flow under all drilling conditions;

- Drilling
- Tripping- in or out of the hole
- Running casing
- When there is no drill string inside the well





API Classification: BOP equipment is classified based on working pressure ratings, typically ranging from 2000 psi to 15,000 psi.

Stack Configuration: The BOP stack usually made up of an annular BOP on top, followed by one or more ram-type preventers. The arrangement may include a drilling spool with side outlet connections for the choke and kill lines.

Regulatory Compliance: Operators must ensure that BOP systems comply with the regulations set by governing bodies, such as the Bureau of Safety and Environmental Enforcement (BSEE) in the United States

3.8 Cementing Design Program

To conduct a good cementing job, centralizers will be used and the casing will be rotating during the cementing operation. Since the shallow formation is unconsolidated, the conductor will be cemented to the seabed. The surface casing will be cemented to the seabed to provide good support for the casing string. Since there are no expected problems in the 17 ½'' hole section, the intermediate casing will be cemented to 740 ft. The production casing will be cemented to 6440 ft above the casing shoe to isolate the casing from possible corrosive formation fluids that might be encountered. Cement Class G will be used (this is the common cement class used in the North Sea). A summary of the cementing process is shown in the table below .

Casing (in)	20''	13 3/8''	9 5/8''
Casing shoe (TVD)	2953	4500	6808
Cement class	G	G	G
Cement density (ppg)	13.1	14.5	15.5
Slurry volume (ft3)	2530	2963	2475
No of sacks	1346	1567	1309
Volume mix water (ft3)	1830	1050	877
Displacement mud (bbl)	465	616	554

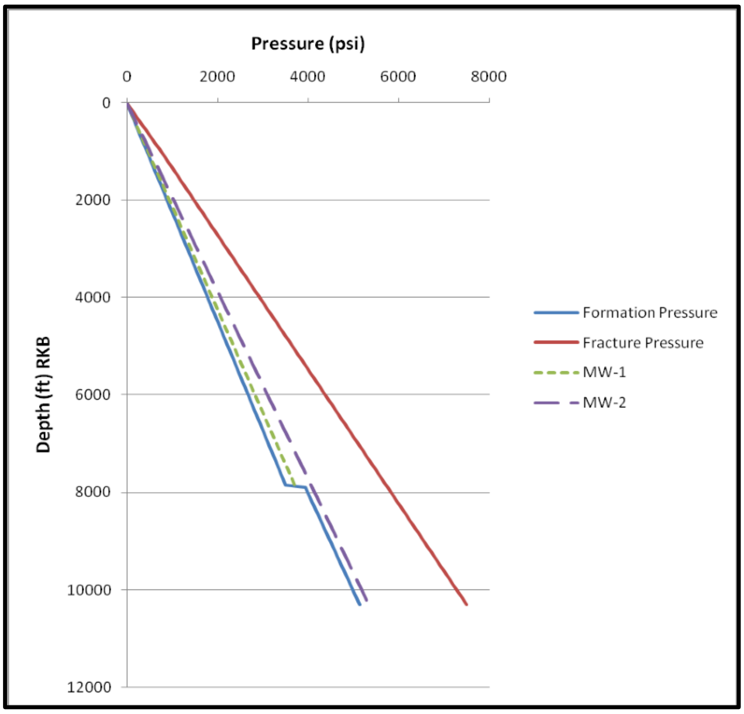
3.9 Directional Drilling Program

Due to the complexity of the Vic Bilh field, directional drilling would be employed to be able to access target in inaccessible areas of the field. The Kick off point of the deviated wells will be around 4700 with 2 degrees/100 ft build-up rate. In other words, the first three-hole sections (36'', 26'' & 17 ½'') will be vertical. The last hole (12 ¼'') will contain the kick-off point, build-up section, and the tangent section which will enter the reservoir at 60°. The table below gives an overview of the directional drilling of the deviated wells in the Vic Bilh field.

Hole Section	Max. Inclination (deg.)	BUR (deg/100ft)	TVD ft RKB
36”	0	0	700
26”	0	0	1300
17 ½”	0	0	4700
	0	Kick off point	4800
	60	2	5000
12 ¼”	60	0	6808

3.10 Pressure Profile And Mud Program

From appraisal mud logs, the formation pressure gradient above the reservoir is 0.446 psi/ft and the fracture formation gradient is 0.754 psi/ft. The formation pressure changes once the cap rock is \reached, at around 7900 ft (RKB), to 0.499 psi/ft whereas the fracture pressure gradient is 0.728 psi/ft until the bottom of the reservoir. There is no indication of any over-pressured zone from the appraisal mud logs. However, there are some shale zones above the reservoir. Based on the mud logs and the leak-off test available from the appraisal wells, the mud weight has been calculated including the overbalanced pressure of 200 psi



3.11 Drilling fluid selection

The major factors that influence the process of selecting the drilling fluid are the type of formation (geological section), drilling performance, and the related environmental issues. High-performance water-based mud (HPWBM) would be used for the surface and the intermediate hole sections whilst an oil-based mud would be used for the reservoir section with the additives for drilling the wells of the Vic Bhil field. Polymers will be added to WBM to increase its viscosity to drill the 36’’ and 26’’ hole sections. The drilling solids will be controlled by using de-silters. The next hole section (17 ½’’) will be drilled using HPWBM which is the most preferable in terms of cost and environmental considerations. Since some shale will be encountered in drilling 17 ½’’ section, KCL polymer is used to minimize the problems associated with drilling through shale sections. The ph level of the mud will be maintained by adding bentonite and soda. To control the fluid loss, clay will be added. The final hole section (12 ¼’’) will be drilled by using OBM which can reduce formation damage caused by the drilling fluid and it will give a better cementing job. Since it is expected that H_2S is present in the reservoir; NaOH will be added to the mud. The table below shows a summary of drilling fluids and the major additives that will be used.

Depth (ft) RKB	Hole size	Drilling Fluid	Additives	Remarks
0	36"	WBM	Polymers	Unconsolidated formations at shallow depths
328				
1300	26"			
4700	17 1/2"	HPWBM	KCL polymer	Shaley zones
5000	12 1/4"			
5500		OBM	NaOH, betonite and soda	Reservoir section, presence of H2S
6200				
6808				

3.12 Bit And Hydraulics Program

The main objectives of bit selection are minimizing the drilling time (maximizing the ROP) and keeping the number of trips as low as possible. To meet these objectives, the drilling bits should be selected carefully. The essential elements to be considered in bit selection are the formation type of the drilled hole and the cost. For the shallow soft formation (36'' hole), a roller-cone bit with long, thin, and widely spaced teeth (preventing bit balling) will be used. In 26'' hole section, the formations are less soft with some of the shale zones. Therefore, shorter and wider teeth bits are required and so, roller cone bits with insert bits will be implemented. In the next two hole sections (17 ½'' & 12 ¼''), consolidated formations are encountered and since the operating costs of offshore are high, the PDC bits will be used. PDC bits provide long bit runs and high ROP, which both are important in the longest sections (17 ½'' & 12 ¼'' hole section) of the well, which will reduce the number of trips required and thus minimize the drilling time (which is very important in areas of high operating costs). summaries the bit selection of each hole section.

Hole (")	**TVD (ft) RKB**	**Bit Type**	**Formation Type**
36	328	Roller Cone (milled tooth)	Soft formation
26	2953	Roller Cone (insert bit)	Moderately hard formation
17 ½	4700	PDC	Hard Formation
12 ¼	6808	PDC	Hard Formation

3.13 Data Acquisition During Drilling

In exploration drilling it is imperative that no source of data should be neglected while drilling is in progress - it can never be certain that circumstances will not arise which will lead to abandonment of the well before it can be logged comprehensively by wireline. The important sources of data while drilling is in progress are: drilling logs; mud logs; MWD (measurement while drilling) logs; The sophisticated MWD methods are under active development and are entering more common usage

Drilling log: The driller's log is the most immediate information available, especially the rate of penetration under otherwise constant conditions, such as weight on bit, rotary speed and mud density. In general, shales are harder to drill than the moderately high porosity sands and loosely consolidated sandstones that constitute good reservoir rocks. Changes in rate of penetration can then frequently be correlated with sand and shale intervals, and prior indication of a porous sand interval can instigate a close examination of appropriate cuttings. A very sudden substantial increase in drilling rate should lead to a cessation of drilling while a check test is made for fluid influx and a possible kick.

Mud logging: This involves the continuous analysis of gases extracted from the circulating mud by a chromatograph and a sour gas (H_2S) detector. While background methane is always present, a change in methane concentration, and particularly increases in ethane and heavier hydrocarbons, will frequently indicate the presence of hydrocarbon bearing intervals. Given such indications, the mud itself will be tested directly for hydrocarbon content (ultraviolet light/fluorescence or total analysis by distillation for hydrocarbons).

Cutting logs: Provided that the travel time log between bottom hole and surface can be established, cuttings at the surface can be collected and examined for apparent porosity, permeability and hydrocarbon content, and shaly samples examined for stratigraphic and palaeontologic evidence of age. Obviously, cuttings will have been washed thoroughly by the drilling fluid stream and only residual oil traces will remain. These may, however, be detectable by examination of the solvent extract or cut for fluorescence under ultraviolet light.

3.14 Risk And Uncertainties

The main risks and uncertainties to be considered are summarized in the table below

Risk	**Comments and possible actions that can be taken**
Bad weather could cause a delay in drilling program	Allowing extra days in the planning of drilling for weather changes.
overpressure zones	From the logs of the appraisal wells, there are signs of overpressure zones. The drilling crew should be prepared in case of such a zone is detected during the drilling.
The BOP Operational efficiency	Regular check-ups for the pressure Frequent pressure testing should be carried out

Experiencing a kick which costs time to do killing operation	A proper mud weight will be used. Experienced personnel who can detect early signs of a kick.
Drillstring gets stuck in the deviated section.	The rotary steerable system will be used with centralizers.
poor cement job	Selecting appropriate additives, and centralizers. Deciding the TOC carefully.

CHAPTER 4

4.1 Formation Evaluation

Petrophysics is the study of rock properties and rock-fluid properties, this helps to understand the nature of the rock under study. Petrophysics enables the determination of reservoir and fluid characteristics such as lithology and bed boundaries, porosity and permeability, fluid properties such as saturation, types, etc., and flow between different fluid phases.

However, these properties and characteristics of the reservoir rock can be obtained directly or indirectly from analysis of data obtained from logging tools as well as core analysis.

Formation evaluation is to study and understand the reservoir based on its interactions with the logging tools as well as from the core data analysis. This, in turn, will help in the determination of the reservoir rocks and fluid characteristics

well logs play a crucial role in providing valuable information about the subsurface rock properties and fluid characteristics. Well logs are continuous recordings of various measurements taken along the borehole during the drilling process or after the well has been drilled. These logs are used to interpret the lithology, porosity, permeability, fluid content, and other important parameters that are essential for reservoir characterization and production optimization.

Gamma-Ray Logs: Gamma-ray logs measure the natural radioactivity of the formations, which is primarily caused by the presence of certain radioactive elements, such as potassium, thorium, and uranium. These logs are used to identify shale formations, which typically have higher radioactivity levels, and to differentiate between shale and non-shale lithologies.

Density Logs: Density logs measure the bulk density of the formations by detecting the attenuation of gamma rays emitted from a radioactive source. They are used to estimate porosity, and lithology, and identify potential hydrocarbon-bearing zones.

Neutron Logs: Neutron logs measure the hydrogen content of the formations by detecting the slowing down (moderation) of neutrons emitted from a radioactive source. They are primarily used to estimate porosity and lithology, and can also be used to identify gas-bearing zones.

Resistivity Logs: Resistivity logs measure the electrical resistance of the formations encountered by the borehole. They are primarily used to distinguish between porous and permeable formations containing hydrocarbons (which are electrically resistive) and those containing conductive formation water. Common types of resistivity logs include the induction log, later log, and micro-resistivity logs.

Sonic Logs: Sonic logs measure the transit time of sound waves through the formations. They are used to estimate porosity, identify lithologies, and detect fractures or other mechanical properties of the formations.

These well logs are typically combined and analyzed together to provide a comprehensive understanding of the reservoir properties. The interpretation of well logs involves cross-plotting and integrating the data from multiple logs, along with other available information such as core analysis, seismic data, and production data. (Asquith, et al 2004)

4.2 Well Log Analysis

Lithology is the study of the general physical characteristics of a rock. Reservoir rocks can be divided into two lithological types, namely, sandstone and carbonates. Sandstones are formed from grains that have undergone sedimentation, compaction, and cementation. Carbonates are principally formed on carbonate platforms by a combination of biogenic and abiogenic processes. In our case, the reservoir rock is a complex carbonated rock, made of limestone ($CaCO_3$).

Gamma ray logs were used to identify the reservoir's shale and sandstone zones. The gamma ray logs measure the natural gamma radiation emitted by the formation. The shale zones are identified as having high gamma ray readings due to the presence of radioactive minerals like uranium, thorium, and potassium. On the other hand, sandstone zones have low gamma ray readings due to the absence of these radioactive minerals. The gamma-ray logs were analyzed to identify the reservoir's shale and sandstone zone

Two reservoir units were identified in vic bilh field, the upper and the lower reservoir units: the Barremian reservoir (Lower Cretaceous, carbonate) which brings together 2 reservoir units: South Barremian (exploitation by certain gas cap wells) and North Barremian; both reservoir unit were determined to be highly heterogeneous.

The well log suite included comparing density, neutron porosity, resistivity, water saturation, gamma ray, and calculated total porosity logs to identify oil-bearing intervals. The pores were assumed to contain oil instead of gas, other than that dissolved in the oil, based on the trend between (South Barremian (exploitation by certain gas cap wells) and North Barremian). To briefly show how the logs were analyzed, Figure 1 and 2 is a picture of the log suite for the detailing the response of the logs.

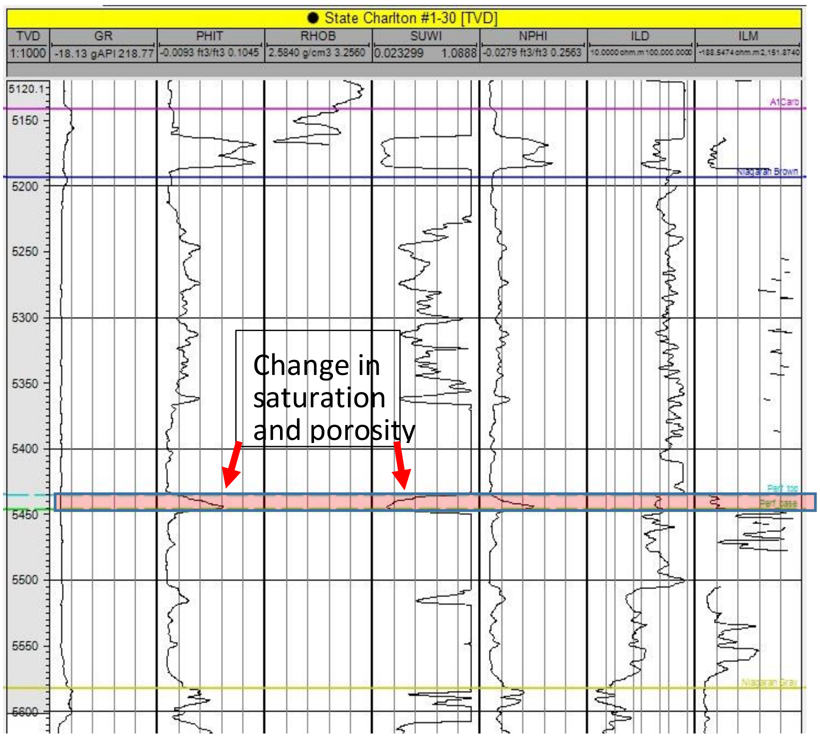


Figure 1:

As can be seen in figure above from left to right, the suite contains a gamma ray log, a deep induction resistivity log, a medium depth induction resistivity log, a bulk density log, a water saturation log, a calculated total porosity log, and a neutron porosity log. Everything is useful, but the saturation curve, porosity curves, and resistivity logs are most helpful for finding oil zones. For example, at around 5430 feet from the figure above, the water saturation curve drops while the porosity Change in saturation and porosity curve increases. This identifies an oil zone because without gas in the reservoir, hydrocarbon saturation is inversely proportional to water saturation (thus, if water saturation decreases, oil saturation increases), and if porosity increases, there is more fluid occupancy. All of the wells had similar trends when they were analyzed at different depths

4.3 Porosity

Porosity is the amount of space in the rock that can contain hydrocarbons. Therefore, determining the pore space of the reservoir rocks is vitally important as this allows the volume of hydrocarbons to be calculated. Porosity can be calculated from Density, Neutron and Sonic logs. However, a combination of these logs are often used to acquire better values of porosity. In this case, only Density-Neutron logs are used due to the presence of gas which has major impact (overestimation) on porosity calculations using Sonic logs. The porosity of the VIC BILH reservoir is calculated and averaged between 1 to 15 percent.

4.4 Hydrocarbons In Place

4.4.1 Probabilistic Method

The probabilistic method is used to estimate STOIIP and GIIP with the consideration of uncertainty in each parameter used in the estimation. There are three Probabilistic methods can be used in the estimation of STOIIP and GIIP; Monte Carlo, Parameter method and Three-Point method. The Monte Carlo method is the most commonly used in the estimation of STOIIP and GIIP, therefore, it will be used in the probabilistic volume analysis.

4.4.2 Monte Carlo Method

The Monte Carlo distribution is used to estimate STOIIP and GIIP by allowing more realization of the parameters by combination of maximum volume and minimum saturation. Monte Carlo presents a skewed distribution for volume and saturation and a normal distribution for porosity. The deterministic element in the Monte Carlo is provided in the selection of the parameter distributions. The random component comes from the random sampling of the distribution.

The Monte Carlo distribution is done by using MBAL on PROSPER software. It is recommended to exceed 1000 trials when using this software so that the values will show a range of uncertainty than to be a simple deterministic solution. The Monte Carlo simulation produces results for a small number of combinations of variables, which approximates a distribution of all possible combinations. The more the set of combinations are made the closer the Monte Carlo result will be to the theoretical result of using all possible combinations.

If two variables are dependent, the value chosen in the simulation for the dependent variable can be linked to the randomly selected value of the first variable using the defined correlation.

The Monte Carlo method is the most appropriate method for project with large varieties of uncertainty, but however the parameter distribution should not be normal or else it will reduce the power of the Monte Carlo distribution. The parameters should also be independent for effective Monte Carlo results or else it will lead to a deterministic solution which is not a representation of uncertainty. (Williams, G. J. (2012)

4.4.3 Probabilistic STOIIP and GIIP

Figure 5.1 and Figure 5.2 show the probabilistic distribution for STOIIP and GIIP values respectively. The P50 value for STOIIP is 2075 MMstb, with P90 and P10 values of 704 MMstb and 3745 MMstb respectively. The P90, P50 and P10 values for GIIP is 282, 830 and 1.5e+6 MMscf respectively.

Table below shows the summary of the probabilistic values for STOIIP and GIIP.

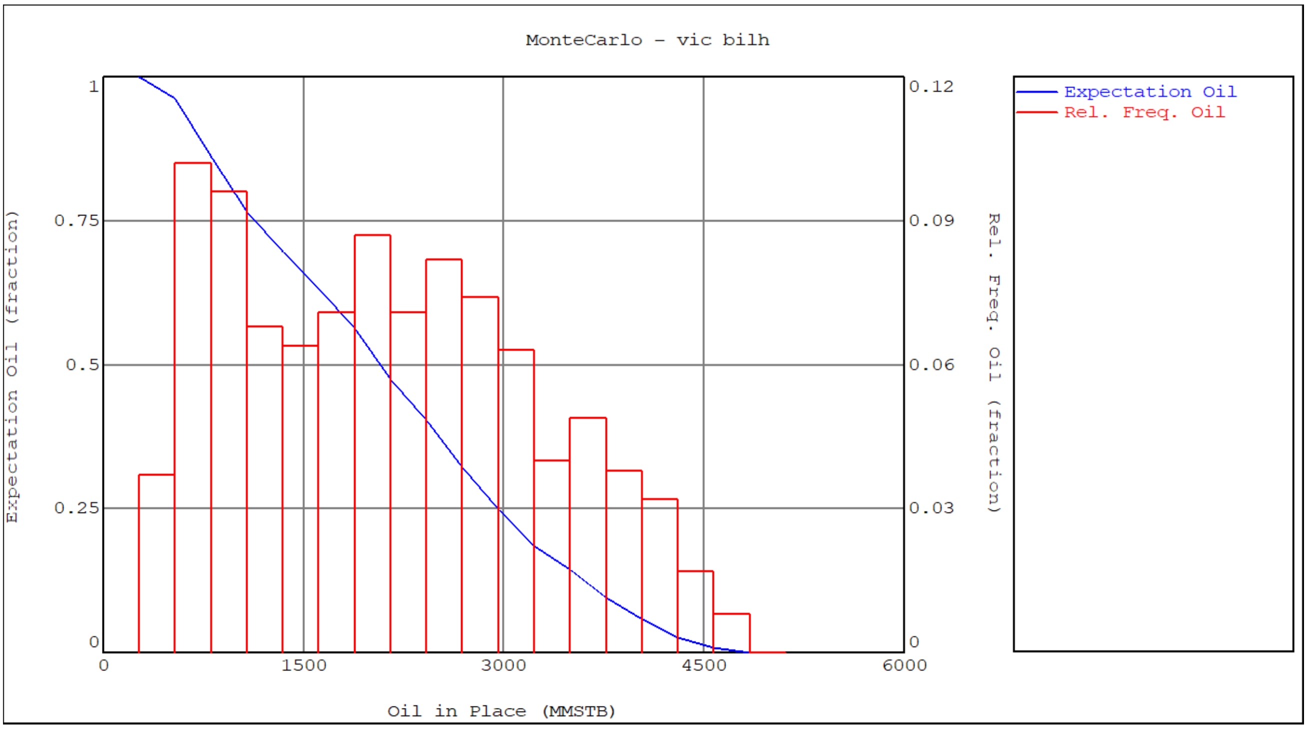


Figure 5.1: Probability and Cumulative Distribution Functions of STOIIP

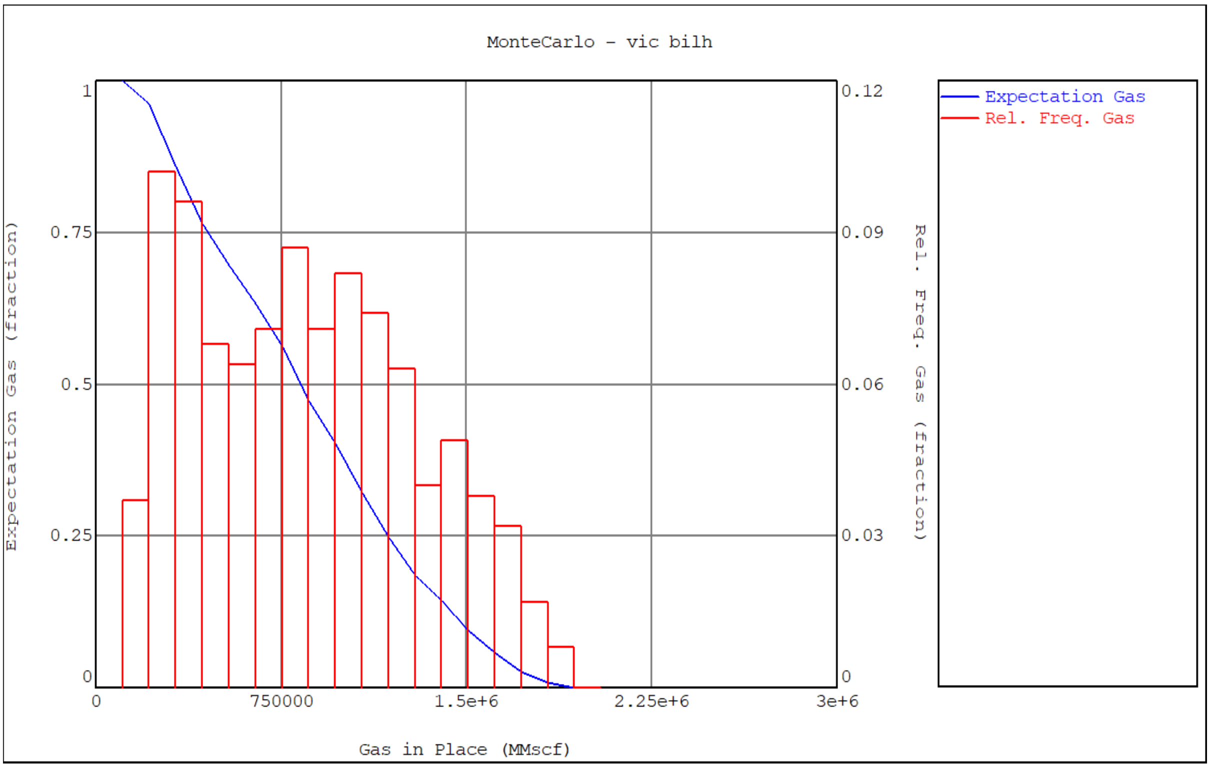


Figure 5.1: Probability and Cumulative Distribution Functions of GIIP

Probabilistic STOIIP and GIIP value

PROBABILITY	OIL IN PLACE MMSTB	GAS IN PLACE MMSCF
P90	704.473	281789
P50	2075.66	830265
P10	3745.77	1.49831e+6

CHAPTER 5

5.1 Reservoir Description & Geological Modeling

The Vic-Bilh field is located in the southern part of the Aquitaine sedimentary basin in France.It is characterized by a faulted anticline trap, which is a type of geological structure that forms a closed volume for hydrocarbons to accumulate. The rock in this field is limestone, specifically from the Barremian and Berriasian ages of the Cretaceous period. The depth ofthe reservoir ranges from 2250 to 2700 meters, with a complex number of reservoirs. The area of the field is approximately 16 square kilometers, and the thickness of the reservoir is 400 meters. The reservoir is characterized by its variable usefulness thickness, with a largeoil column of 400 meters. The estimated oil in place is 26 million tonnes.

5.2 Reservoir Geometry and Stratigraphic Framework.

The Vic-Bilh oil field, situated within the Aquitaine sedimentary basin in southern France, contains diverse hydrocarbon reservoirs defined by their unique geologic characteristics (Smith et al., 2015). One such reservoir resides within Upper Cretaceous sedimentary rocks deposited approximately 66-100 million years ago during the Late Cretaceous period (Jones,2017). Understanding the geometry and stratigraphy of this reservoir is crucial for evaluatingits hydrocarbon potential.

The Vic-Bilh field consists of two main types of reservoirs: the Barremian reservoir and thedolomitic reservoirs from the Portlandian (Liu et al., 2018).

The Barremian reservoir, which belongs to the Lower Cretaceous period, comprises two reservoir units: the South Barremian and the North Barremian. These reservoirs are made upof carbonate rocks (Roberts et al., 2014).

The dolomitic reservoirs from the Portlandian period include the Brèche de Garlin reservoir and the Mano Dolomites reservoir. The Brèche de Garlin reservoir is considered the major drain of the Vic-Bilh field, with variable permeability ranging from 1 to 100 millidarcies (mD)(Chen et al., 2016). The Mano Dolomites reservoir has variable quality, with the best qualityfound in the eastern part of the field. It has an average porosity of 10% and a permeability ranging from 0.01 to 10 mD (Miller et al., 2018).

The reservoirs in the Vic-Bilh field are formed within a regional geological context. The field is located in the southern part of the Aquitaine sedimentary basin, specifically in the Adour sub-basin (Zhou et al., 2019). The basin's geological history dates back over 200 million years, starting from the beginning of the Jurassic period (Wei et al., 2013). During this time,the earth's crust began to stretch and thin, forming a depression where a sedimentary pile gradually accumulated, reaching a thickness of several thousand meters (Jones, 2017). The source rock and reservoir rocks were deposited during this phase (Liu et al., 2018). The organic matter contained in the source rock of the Kimmeridgian age started its migration towards the surface through porous rocks or faults (Roberts et al., 2014). The existence of impermeable rocks or "covers" and the presence of folded/faulted structures formed duringthe Pyrenees compressive phase allowed for the accumulation of oil at depth and the formation of the Aquitaine oil fields (Zhou et al., 2019). Understanding the reservoir geometry and stratigraphic framework is crucial for the exploitation of hydrocarbons in the Vic-Bilh field (Smith et al., 2015). It helps identify the distribution and characteristics of the reservoirs, enabling efficient drilling and production strategies (Chen et al., 2016)

5.3 Reservoir Zonation (Based On Flow Properties)

Considering the flow properties and reservoir characteristics, the Vic-Bilh field can be zoned based on its productivity potential. The zonation can be classified into multiple zones, taking into account the different levels, thickness, and permeability of the reservoirs (Smith et al.,2015). The areas with higher permeability and better porosity, along with fractures, are likelyto exhibit better flow properties and higher production rates (Chen et al., 2016). These zones can be targeted for increased drilling and production activities (Roberts et al., 2014).

Furthermore, the planned water flooding technique can be employed to enhance recovery in the Vic-Bilh field. By injecting water into the reservoir, the dissolved gas and active aquifer can aid in displacing oil and improving the overall recovery factor, which is anticipated to be around 20% (Liu et al., 2018). Waterflooding is a widely used enhanced oil recovery method where injected water sweeps residual oil from reservoir pore spaces, improving displacement efficiency (Shirzaei et al., 2020). Reservoir simulation studies can help identify optimally located injection and production wells for effective waterflood implementations (Abbasy et al., 2019). Reservoir simulation is a valuable tool used to model and predict fluid flow behavior in the reservoir. By utilizing reservoir simulation software, engineers can simulate various scenarios and assess the impact of different production strategies on the reservoir performance.

Proper characterization of heterogeneous reservoir properties such as permeability variations is crucial for successful waterflood design and management over the project lifetime (Zhou et al., 2019). The Vic-Bilh field exhibits significant reservoir heterogeneity, meaning that the flow properties and characteristics can vary greatly within the reservoir. This heterogeneity can be attributed to factors such as variations in lithology, depositional environments, and diagenetic processes. Continued performance monitoring coupled withdynamic reservoir modelling will also help maximize the economic waterflood recovery for the multi-zoned Vic-Bilh reservoirs (Fathi et al., 2010).

5.3 Petrophysical Property Distribution(Porosity, Permeability)

The petrophysical property distribution in the Vic-Bilh field includes porosity and permeability. Porosity refers to the amount of empty space within the reservoir rock wherehydrocarbons can be stored. In this field, the porosity is described as being less than 15%(low porosity),indicating that the rock has a relatively low capacity to hold hydrocarbons.

Permeability, on the other hand, refers to the ability of the rock to allow fluids, such as hydrocarbons, to flow through it. In the Vic-Bilh field, the permeability ranges from 0.1 to 5

millidarcy (mD), with additional contribution from fractures in the rock. This means that the rock has varying degrees of connectivity between its pores, allowing hydrocarbons to move through it to some extent. Fractures are fractures or cracks in the rock formation that enhance the connectivity between pores, allowing for increased fluid flow. The presence offractures can significantly impact the reservoir's permeability and, consequently, the productivity of the wells.

Petrophysical properties of porosity and permeability play a crucial role in determining the productivity and recovery potential of the reservoir. In this case, the relatively low porosity and moderate permeability of the Vic-Bilh field suggest that the reservoir may be challengingto produce efficiently.

5.4 Static Reservoir Model Construction (Integration Of Seismic And Well Data).

To construct a static reservoir model for the Vic-Bilh field, the integration of seismic and welldata is crucial. Seismic data is obtained through the use of seismic surveys, which involve sending sound waves into the ground and recording the reflections of these waves off subsurface rock layers. This data provides valuable information about the geological structures present in the reservoir, such as faults, folds, and stratigraphic layers.

Well data, on the other hand, is acquired through drilling wells into the reservoir and collecting various measurements and samples. This data includes well logs, which providedetailed information about the physical properties of the rock layers, such as porosity and permeability, as well as core samples that are analyzed in the laboratory to determine rockcomposition and fluid properties.

The first step in constructing the static reservoir model is to tie the well data to the seismic data. This involves correlating the information obtained from well logs with the seismic reflections observed in the seismic data. By matching specific features in both datasets, such as seismic horizons and well markers, engineers can establish a consistent frameworkfor the model.

Once the well data is tied to the seismic data, the next step is to interpolate and extrapolatethe properties between the wells using geostatistical techniques. This process involves analyzing the spatial variability of reservoir properties and using statistical methods to estimate the properties in areas where no well data is available. This allows for a more complete representation of the reservoir's properties and helps identify areas of higher or lower hydrocarbon saturation.

The final result of static reservoir model construction is a detailed three-dimensional representation of the reservoir, including its geometry and properties. This model serves asthe foundation for further reservoir engineering studies, such as reservoir simulation and development planning.

The integration of seismic and well data is essential for building an accurate static reservoir model. Seismic data helps identify the spatial distribution of geological features, while well data provides direct measurements of reservoir properties at specific locations. By

combining these datasets, petroleum engineers can create a more comprehensive understanding of the reservoir's characteristics and behavior.

5.5 Uncertainty Analysis And Risk Assessment

Uncertainty analysis and risk assessment play crucial roles in petroleum exploration andproduction, including in the case of the Vic-Bilh field. These processes help evaluate thelikelihood and potential impact of uncertainties and risks associated with the field's reservoirs and production operations.

In the context of the Vic-Bilh field, uncertainty analysis involves quantifying the uncertainties in key parameters and variables that affect reservoir behavior and production performance.

These uncertainties can arise from various sources, such as reservoir properties, fluid properties, and production data. By accounting for these uncertainties, engineers can betterunderstand the range of possible outcomes and make informed decisions.

To address these uncertainties, engineers employ various techniques such as stochastic modeling and history matching. Stochastic modeling involves generating multiple realizations of reservoir properties based on statistical distributions, which captures therange of possible values. History matching involves calibrating reservoir models to matchhistorical production data, allowing for improved understanding of reservoir behavior anduncertainty reduction.

Risk assessment, on the other hand, focuses on evaluating the potential impact of uncertainties on project outcomes and making decisions under uncertainty. This involves identifying and analyzing various risks that could impact the success of the Vic-Bilh field,such as geological risks, operational risks, market risks, and regulatory risks.

Geological risks could include uncertainties in reservoir extent, connectivity, or presence of compartmentalization. Operational risks may involve uncertainties in drilling and completion operations, well performance, or facility reliability. Market risks could relate to fluctuations inoil and gas prices, while regulatory risks could involve changes in environmental regulations or licensing requirements.

To assess these risks, engineers employ techniques such as probabilistic analysis, sensitivity analysis, and decision tree analysis. Probabilistic analysis involves quantifying the likelihoodand impact of different risk scenarios using probability distributions. Sensitivity analysis helps identify key parameters or variables that have the most significant impact on project outcomes. Decision tree analysis helps evaluate different decision options by considering their potential outcomes and associated risks.

CHAPTER 6

Well Deliverability

Well deliverability is determined by the combination of well inflow performance and wellbore flow performance. Whereas the former describes the deliverability of the reservoir, the latter presents the resistance to the flow of production string (Petroleum Production Engineering: A Computer-Assisted Approach, 2007).

Given that, well modeling was performed using PROSPER on the Vic bilh well, of which the natural operating flow rate was determined, sensitivity analysis(tubing size, water cut, reservoir pressure) was performed, and finally the choice of artificial lift techniques for production optimization.

DATA VALUES

API gravity=25

GOR=400 SCF/STB

Gas gravity=0.735

Initial reservoir pressure=4500

Reservoir temperature=220°F

Skin=0

Reservoir permeability=300md

drainage area=3954 acres

reservoir depth= 1312 ft

watercut=10%

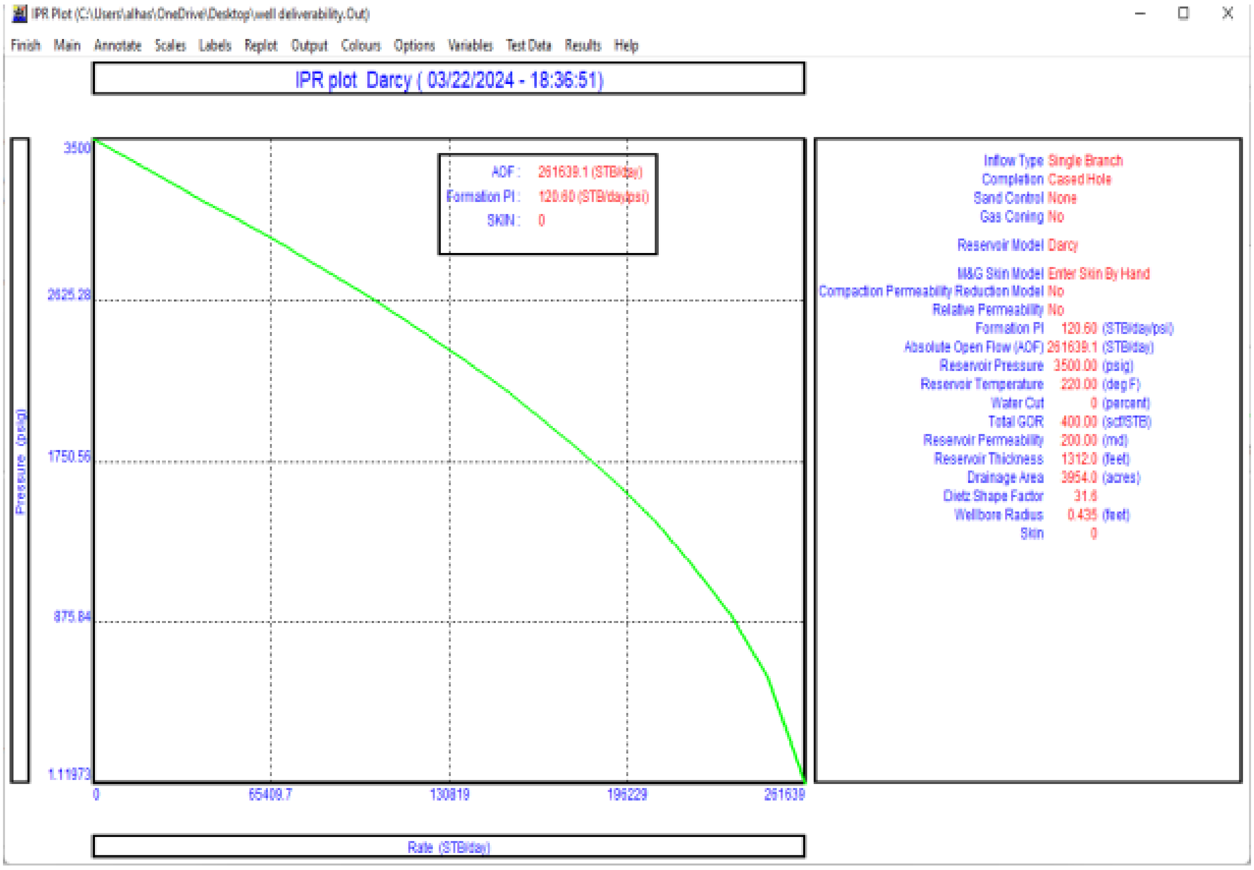
6.1 Productivity Index

The productivity index is a measure of the well potential or ability to produce and is a commonly measured well property (B. C. Craft, Murray F. Hawkins, 1959). That is, It measures the deliverability of the well.

On the Vic bilh well, the **PI=**120.6 STB/day/psi

It was obtained from the inflow performance relationship(**IPR**)

The AOF=261639.1 STB/day at Pwf=0



6.3 Natural Operating Flowrate

To further up, we determined the natural flow rate of the fluid. that is, the well flow rate using the natural drive.

By cross plot of the IPR and TPR, the natural flow rate(oil rate) was known, and results are tabulated below:

well	Liquid rate(stb/day)	Oil rate(stb/day)	Water rate/(stb/day)	Gas rate(stb/day)

Vic bilh	25481.1	22933	2548.1	9.173

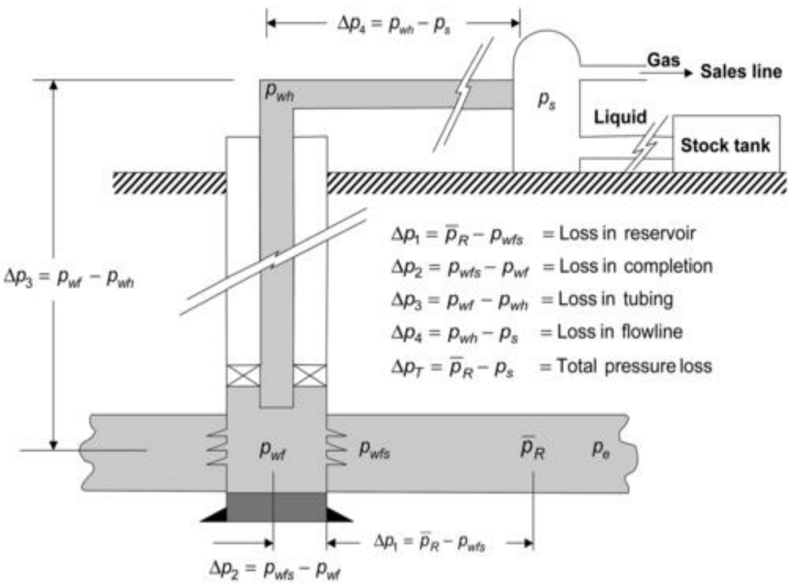
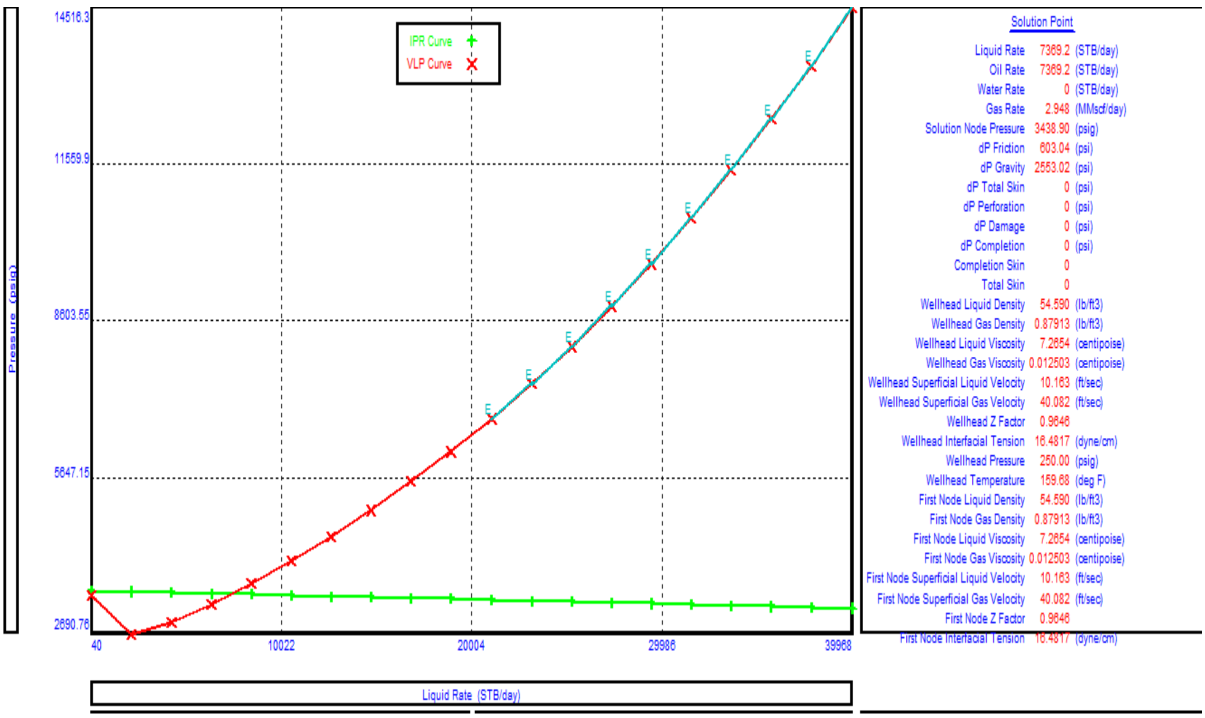


Figure 2 Production System and associated pressure losses

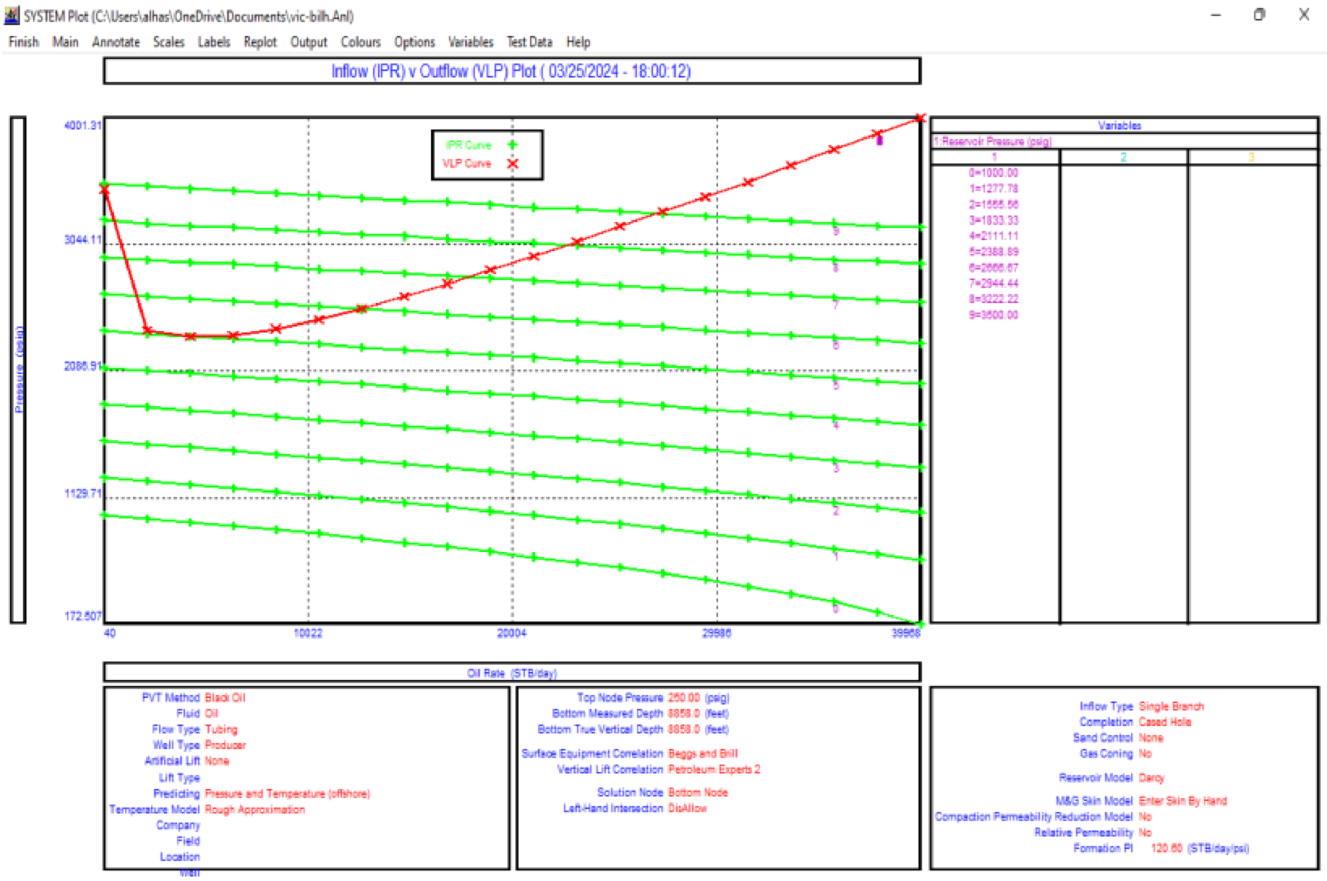
From the figure above, we can relate the flow from the reservoir to the wellbore through to the surface.



6.4 Sensitivity Analysis

in this section, we are interested in how flowrate varies with reservoir pressure, tubing size and water cut to obtain the optimum flowrate when considering those factors under analysis.

- Sensitivity analysis on reservoir pressure with flowrate



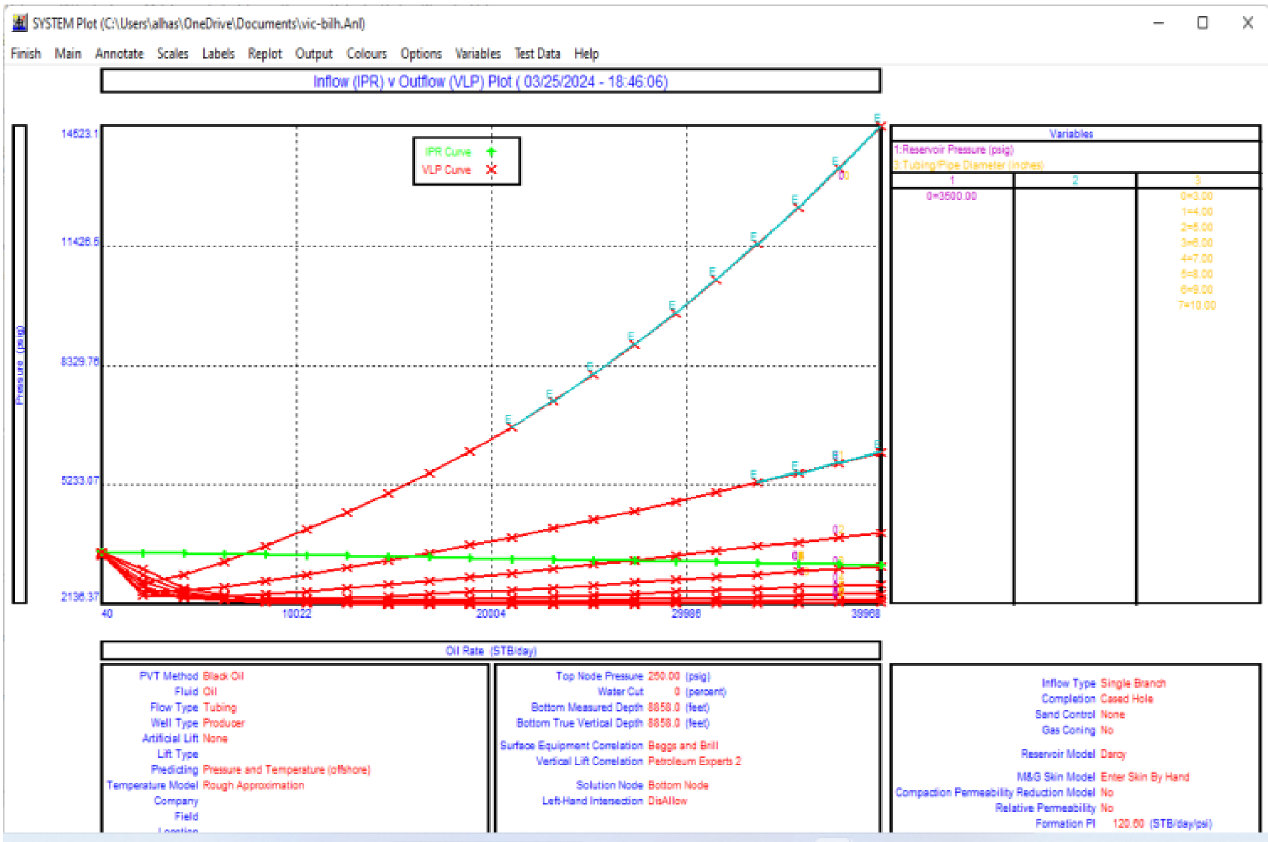
From the plot, it was realized that as we increase the reservoir pressure in the vic-bilh oil Field, it increase it flowrate.

<u>Why varying the reservoir pressure with flowrate</u>:

To determine the new reservoir pressure and the flowrate when there is rock and fluid properties changes. Since the reservoir in the vic-bilh field is heterogenous, its rock and fluid properties change can alter the reservoir pressure with a corresponding change in flowrate. Hence the need to perform sensitivity analysis.

Since we begin our reservoir pressure at 3500psi, the oil flowrate is at maximum with a value of **22933STB/day**

- Sensitivity analysis on tubing size

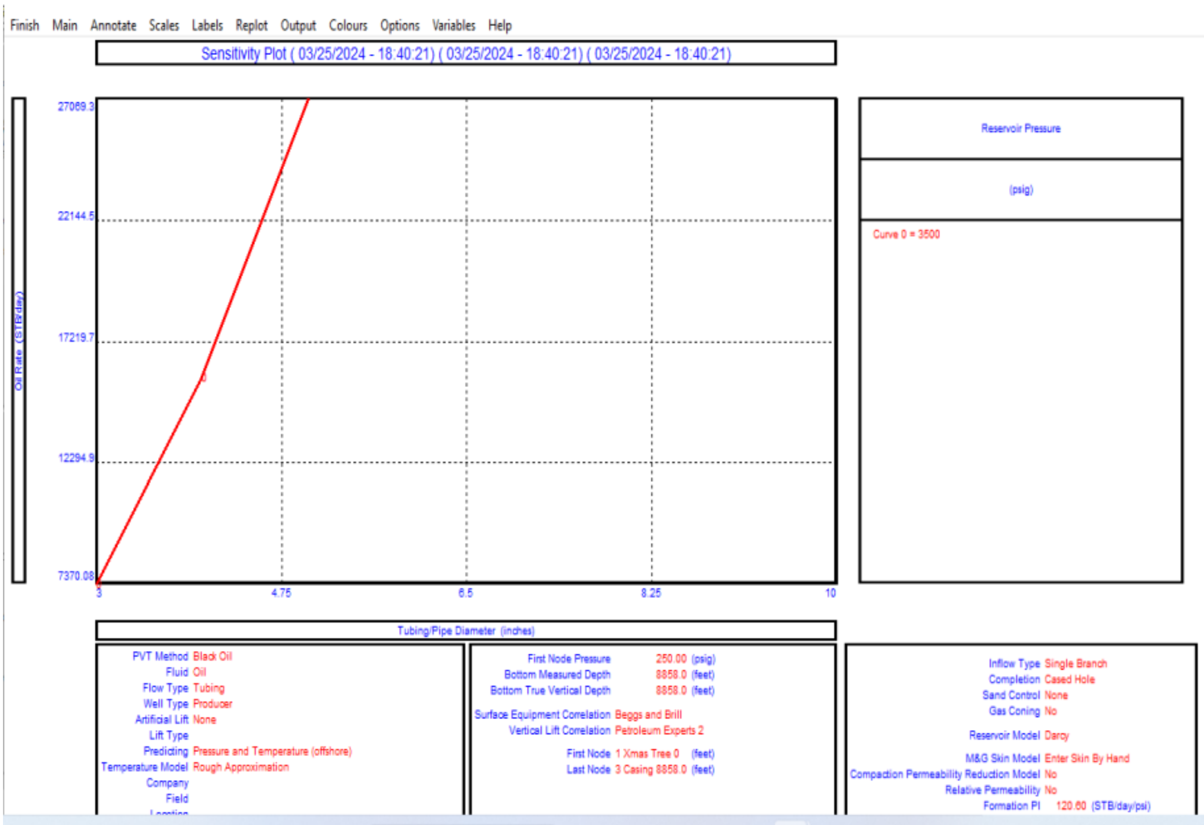


The fluid flow rate through production tubing in the well depends on the optimum tubing size selection.

Therefore, sensitivity analysis was performed to know the optimum production tubing size for our well design.

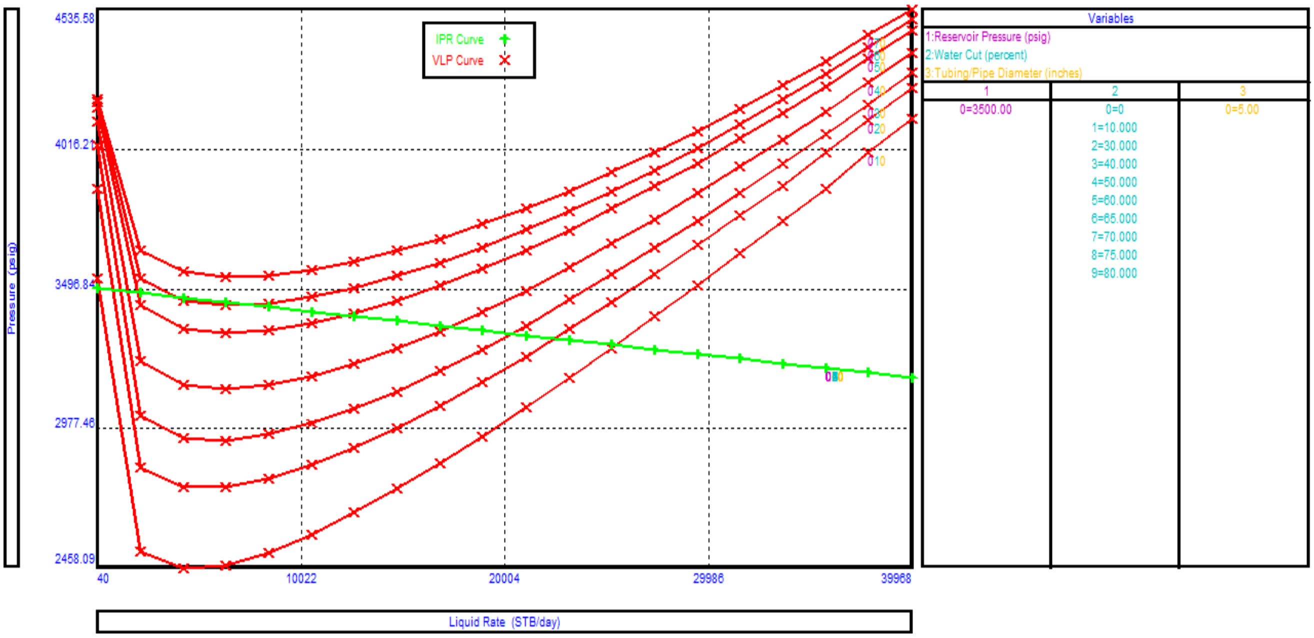
Our tubing size selection was in ID, 5in ID, 6in ID, and 7in ID

From the sensitivity plot, the production rate increases as we increase the tubing size but starts to decline at 5in. this can be illustrated below:



In conclusion, the optimum tubing size selected for the design was 5in at an oil flowrate of **22933STB/day**

- ➢ Sensitivity analysis on watercut in variation with oil flowrate

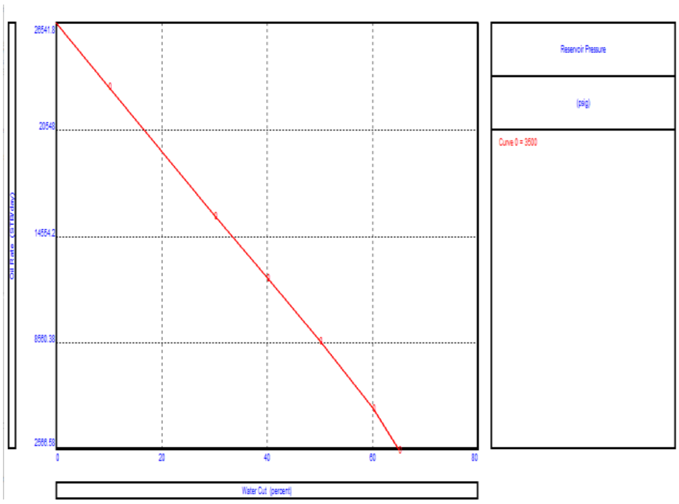


Watercut is basically is the amount of water produce in proportion to the liquid production.

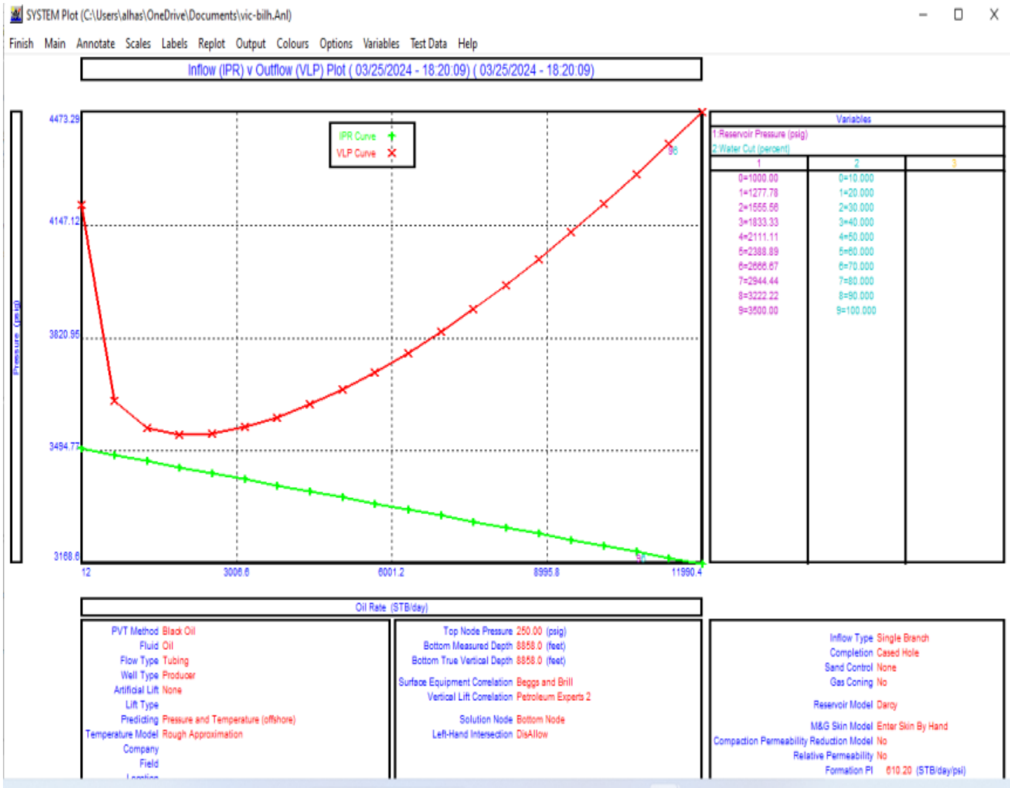
Water production is something we least expect in our production and so it production can be serious problem in the industry.

So sensitivity analysis was mainly performed to know at what percent watercut will there be no oil production. From analysis of the plot, these observations were noted:

- The flowrate decreases as we increase the watercut



- Production ceases exactly at a watercut of 70%



Summary of result

Reservoir Pressure	Optimum tubing size	watercut	Liquid rate(STB/day)	Oil rate(STB/day)	Water rate(STB/day)	Gas rate(STB/day)
3500	5	10	25481.1	22933	2548.1	9.173
3500	5	70	0	0		

6.5 Artificial Lift Design

Many reservoirs need more energy to produce fluids at economical rates throughout their lifetime. When this happens, artificial lift equipment boosts production by contributing energy. This system component has surface and subsurface elements. Subsurface pumps supply this energy directly to the fluid, surface compression equipment can lower wellhead pressure, or gas can be injected into the production string to lessen the fluid gradient (petrowiki-Alexey Borisenko,Inflow and outflow performance, 2023).

Artificial lift design is implemented to supplement the natural energy of the reservoir to optimize production.

At a water cut of 70%, there is no production due to holdup.

In bringing the liquid holdup to the surface, we recommend implementing an artificial lift design.

In our case, two designs were used based on the pre-knowledge cost of design, and the designs used were gas lift design and Electrical Submersible Pump(ESP).

6.6 Gas Lift Design

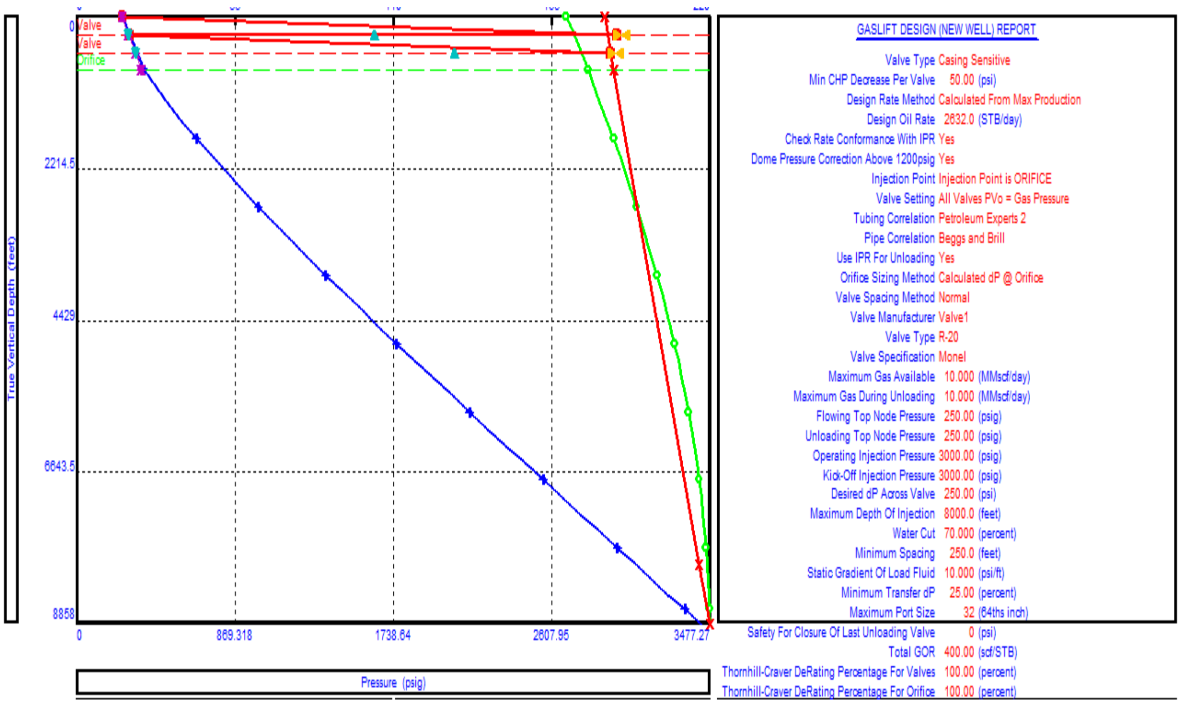
The entire purpose of a gas lift system is to reduce the bottomhole flowing pressure of the well. Anything that restricts or prevents this from occurring will have an impact on the system and must be considered in the design (Brown, K. E. , 1967).

In on-shore fields, gas lift affects the size and location of gathering lines and production stations. Artificial lift should be considered before a casing program is designed. Casing programs should allow the maximum production rate expected from the well without restrictions. Skimping on casing size can ultimately cost lost production that is many times greater than any savings from smaller pipe and hole size (Brown, K. E. , 1967).

Choosing a proper injection gas pressure is critical in a gas lift system design.

Our design is based on injection gas pressure of 3000psi which was used to obtain the target rate.

Below is the the result of our final design of the gas lift system:



GasLift Design - RESULTS (vic-bilh.Anl)

Calculate | Done | Main | Cancel | Report | Export | Help | Change Valve | Valve Performance | Stability

Valve Number and Quantity		Input Parameters: Valve Type	Measured Depth	True Vertical Depth	Tubing Pressure	Calculated Parameters: Valve Opening Pressure	Valve Closing Pressure	Dome Pressure	TestRack Opening Pressure	Opening CHP	Closing CHP
			feet	feet	psig	psig	psig	psig	psig	psig	psig
1	1	Valve	271.72	271.72	290.612	3017.2	2970.85	2296.32	2336.03	3000	2953.65
2	1	Valve	536.053	536.053	330.814	2983.94	2938.84	2261.64	2300.76	2950	2904.9
3	1	Orifice	787.178	787.178	368.792					2900	

Valve Details

Valve Type	Manufacturer	Type	Specification
Casing Sensitive	Valve1	R-20	Monel

Optimum Gaslift gas injection rate	Oil rate (STB/day)	Gas rate(STB/day)	Water rate(STB/day)
1.54472	**2624.2**	**1.050**	**6123.2**

ESP Design

The electrical submersible pump, typically called an ESP, is an efficient and reliable artificial-lift method for lifting moderate to high volumes of fluids from wellbores. These volumes range from a low of 150 B/D to as much as 150,000 B/D (24 to 24,600 m^3/d) (Noonan, Shauna. Electric Submersible Pump (ESP), 2013).

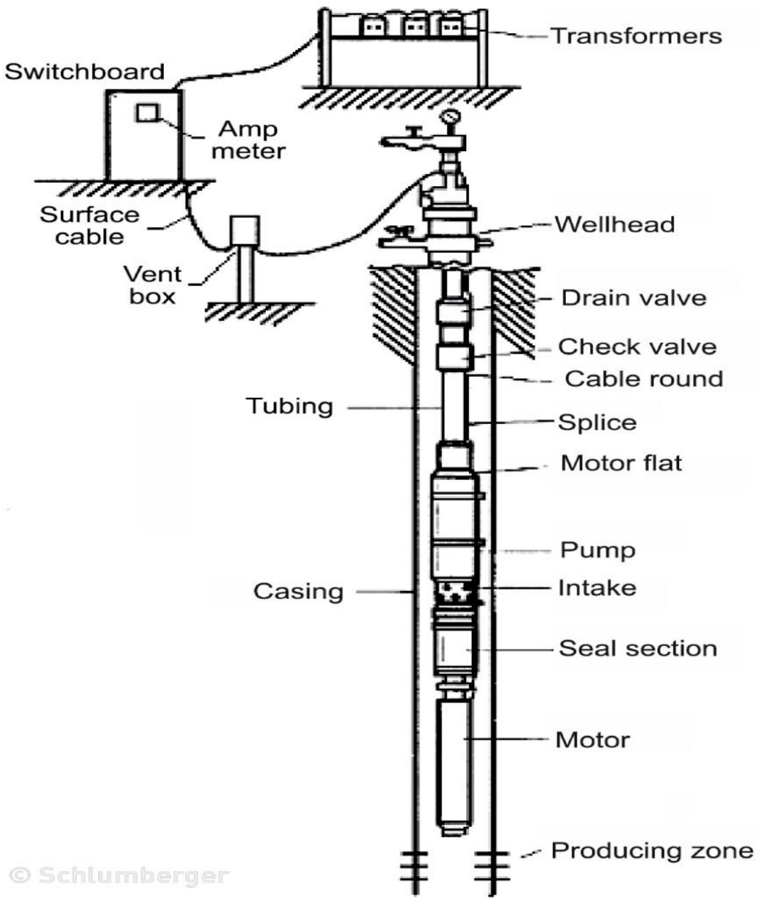
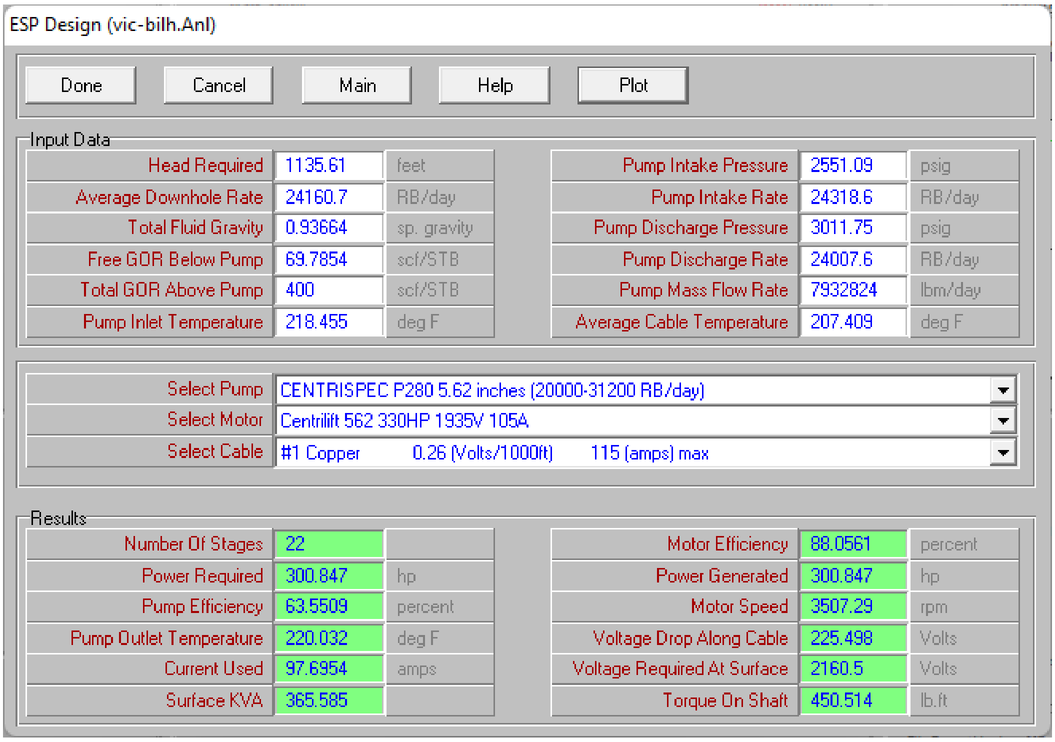


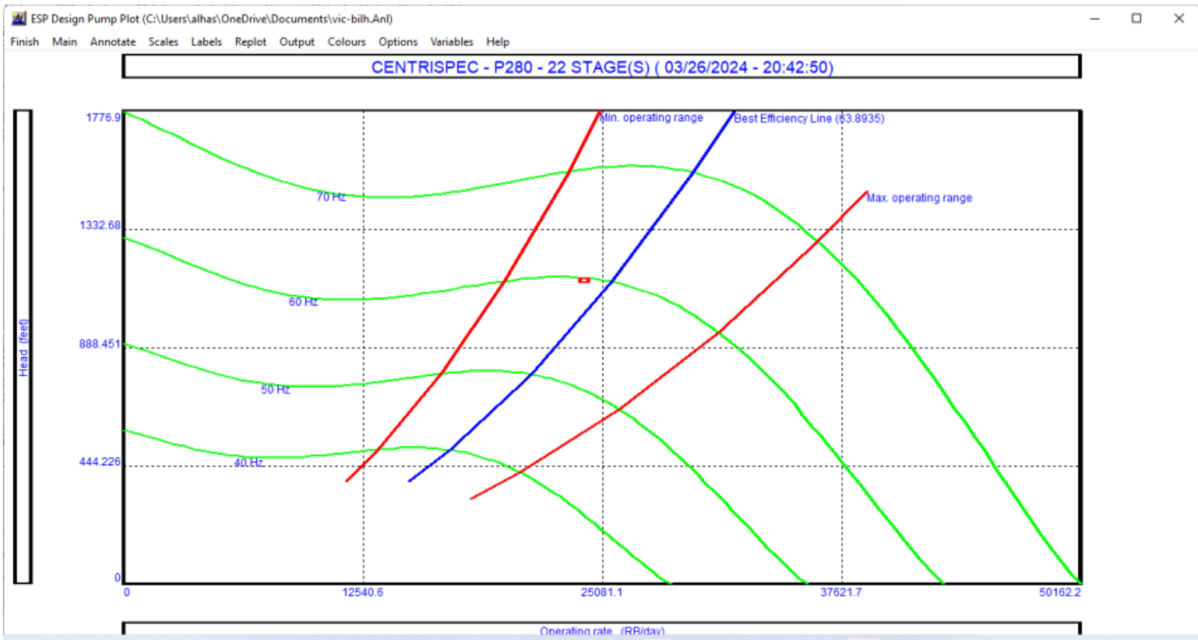
Figure 3 ESP Design

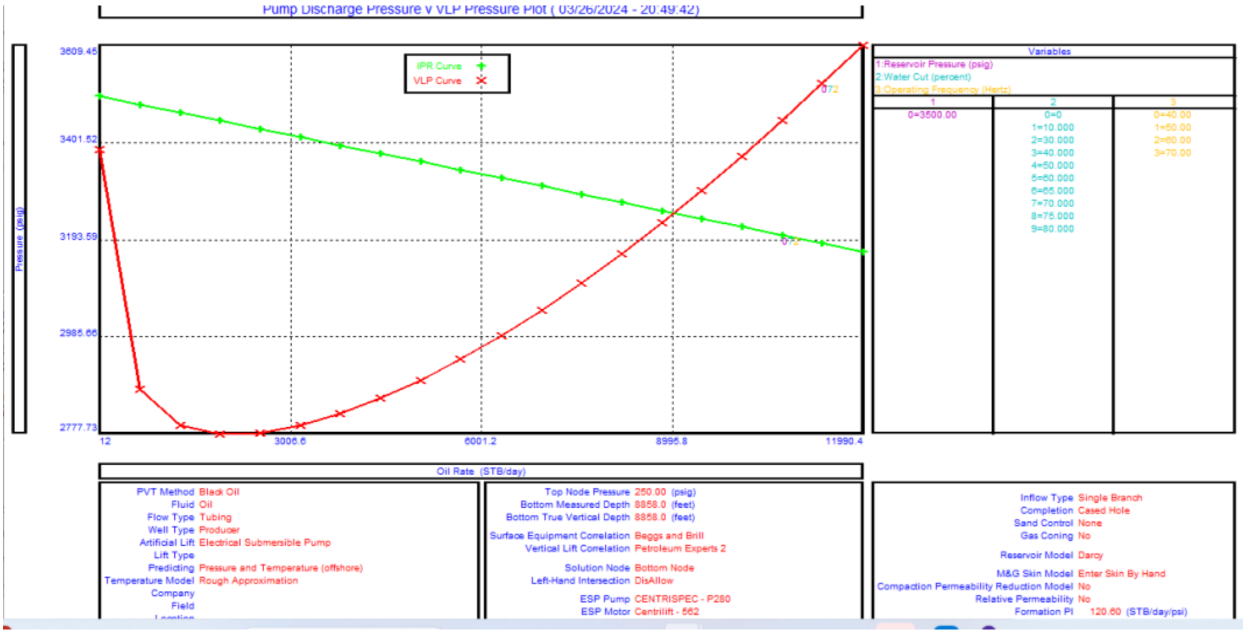
From our design, the following parameters were in concern with the selection of:

- Pump
- Motor
- Cable



The operating efficiency is determined using the tester in the diagram below:





From the diagram, the ESP can deliver a target rate of approximately **8996STB/day**

CHAPTER 7

Reservoir Drive Mechanisms & Recovery Efficiency

Reservoir drive mechanism is a term that is used to describe the predominant force or forces that push the production of reservoir fluids. Recovery of hydrocarbons from an oil reservoir is recognized in several recovery stages. These are; EZEW

- Primary recovery
- Secondary recovery
- Tertiary Drive Mechanism or Enhanced Oil Recovery
- Infill recovery

7.2 Primary Recovery Mechanisms

This is the recovery of hydrocarbons from the reservoir using the natural energy of the reservoir as a drive. It is necessary to know the driving mechanisms that control the behavior of fluids within reservoirs. There are six driving mechanisms that provide the natural energy necessary for oil recovery:

• Rock and liquid expansion drive

• Depletion drive

• Gas cap drive

• Water drive

• Gravity drainage drive

• Combination drive

In this type of reservoir, we will talk about only two drive mechanisms. They are the depletion drive and water drive mechanism.

Depletion drive mechanism

About the oil reservoir of Vic Bilh Field, a depletion drive mechanism (dissolved gas drive) is needed. During production, the oil then rises by itself under the original pressure of the reservoir. The pressure decreases throughout the production. As pressure falls below the bubble-point pressure, gas bubbles are liberated within the microscopic pore spaces. These bubbles expand and force the crude oil out of the pore space. This reservoir pressure behavior is attributed to the fact that no extraneous fluids or gas caps are available to provide a replacement for the gas and oil withdrawals.

Water drive

As oil is oil is exploited, the reservoir produces an increasingly large portion of water. In this case, acquire is needed for this function. As production continues, and the oil is extracted from the reservoir, the reservoir pressure decline is usually very gradual. The reason for the small decline in reservoir pressure is that oil withdrawals from the reservoir are replaced almost volume for volume by water encroaching into the oil zone.

Secondary Recovery Planning EZE

Secondary recovery methods are defined as processes that are used to increase hydrocarbon recovery from the reservoir beyond primary recovery. Typical secondary recovery methods are considered to be intervention methods implemented during the primary recovery period to improve projected low hydrocarbon recovery from the primary process.

Waterflood

Re-injection of reservoir water into the reservoir facilitates the oil extraction process. Reservoir water is re-injected via wells called injected wells. Water injection makes it possible to maintain the pressure by replacing the volumes of fluid extracted with the equivalent volumes of water, and the other hand to sweep (direct) the oil towards to production wells. Waterflood aims to improve oil recovery. Waterflooding of hydrocarbon reservoirs is generally an immiscible displacement process since water is virtually immiscible with hydrocarbons even at high pressures

Gas injection

Gas injection is a type of technique which is used to enhanced oil recovery which helps improve the recovery of hydrocarbons in the reservoir. Gas injection is used to maintain the gas cap pressure even if oil displacement is not required. In the process of injection of gas, the natural gases used are nitrogen gas or carbon dioxide.

7.3 Estimation of Ultimate Recovery (EUR)

EUR helps to evaluate the potential of the oil reservoir and plan its development. There are methods used to estimate the ultimate recovery of the reservoir. EUR also predicts the hydrocarbons in the reservoir during production. Estimating ultimate recovery helps to evaluate the total amount of recoverable hydrocarbons in the reservoir. The reasons for estimating ultimate recovery are as follows;

Estimating EUR is very important for evaluating the economic viability of oil and gas projects. It allows the calculation of the project costs and assesses the profitability of developing the reservoir.

The methods for estimating recovery are explained below;

Material Balance Equation: The material balance equation (MBE) has long been recognized as one of the basic tools of reservoir engineers for interpreting and predicting reservoir performance. The MBE, when properly applied, can be used to:

- Estimate initial hydrocarbon volumes in place
- Predict future reservoir performance
- Predict ultimate hydrocarbon recovery under various types of primary driving mechanisms

Reservoir simulation: This method is about creating the mathematical models which are used in the reservoir. These models can be based on geological, geophysical, and engineering data. These models can also simulate the fluid flow within the reservoir which help engineers to predict the production data rates.

Decline Curves Analysis: Decline curves are one of the most extensively used forms of data analysis employed in evaluating gas reserves and predicting future production. The decline-curve analysis technique is based on the assumption that past production trends and their controlling factors will continue in the future and, therefore, can be extrapolated and described by a mathematical expression.

7.4 Reservoir Simulation Modelling

The term "reservoir simulation" is generally used to describe the activities involved in the building and execution of a model that represents the reservoir, such that the behavior of the model mirrors or "simulates" as much as possible the observed behavior of the reservoir.

Numerical reservoir simulators are classified based on reservoir type, reservoir process, and formulation of the simulator. The following types of reservoir simulators are commercially available in the petroleum industry:

Black oil simulators: oil, water, and gas are treated as separate immiscible phases. This simulator can be used on dry gas, and black oil reservoirs, and immiscible recovery processes. The black oil simulator is the "work-horse" of the petroleum industry concerning reservoir simulation.

Compositional simulators: oil and gas are represented as hydrocarbon components. Water is present as a phase. This type of simulator is used on volatile oil, and gas condensate reservoirs, and miscible gas-enhanced oil recovery processes.

Dual-porosity simulators: used on naturally fractured reservoirs that exhibit dual porosity behavior.

Thermal simulators: used for simulating thermal processes, such as cyclic steam injection, steam flooding, and in-situ combustion

Chemical flood simulators: applicable to enhanced oil recovery processes using alkalis, surfactants, and polymers

Streamline simulators: This class of simulators is widely used in the industry for upscaling of large geologic models, modeling waterflooding, and other uncomplicated reservoir processes. Streamline simulators can be used in conjunction with the other grid-based simulators, and are not considered a substitute for them.

CHAPTER 8

8.1 Storage And Transportation

8.1.1 Oil Storage

Storage tanks were utilized to accumulate and safeguard the yield of crude oil. These tanks were necessary due to the inherent variability of both production rates and market demand. By using storage tanks, operators can regulate the flow of oil, stabilizing the supply chain and mitigating the risks associated with fluctuations in production or unforeseen disruptions. Additionally, oil storage tanks facilitate the separation of oil from water and other possible contaminants that might have been present, thereby ensuring that the quality of the crude oil is maintained before it is sent downstream.

Oil Storage tanks constructed were in accordance with UL (Underwriters Laboratories) 142 standards. This was because it was specifically used for aboveground tanks. UL 142 is a standard developed by UL (Underwriters Laboratories), which is a global safety certification company. The storage tanks were designed to ensure that aboveground storage tanks for flammable and combustible liquids, such as oil, are manufactured in a way that minimizes the risk of leaks, spills, and fires, which can be devastating to the environment and local communities. The tanks were built with steel to withstand such risks. (WB Geyer, 1992)

Oil produced is a hazardous liquid that can cause significant environmental damage if it leaks. Storage tanks built to UL 142 standards were equipped with features such as secondary containment, which is an additional barrier that prevents oil from escaping into the environment in the case of a tank failure. This reduces the risk of soil and water contamination and the associated clean-up costs.

UL 142-compliant tanks were designed not just for safety, but also for operational efficiency. They were constructed to allow for easy access for inspection, maintenance, and cleaning, which helps maintain the quality of the stored oil and extends the lifespan of the tanks.

8.1.2 Transportation

Oil Produced

Crude oil moves from wellhead to refinery using barges, tankers, over land, pipelines, trucks, and railroads. Pipelines and liquefied natural gas (LNG) tankers transport natural gas.

Pipelines play a very critical role in the transportation process because most of the oil moves through pipelines for at least part of the route. After the crude oil is separated from natural gas, pipelines transport the oil to another carrier or directly to a refinery. Petroleum products then travel from the refinery to market by tanker, truck, railroad tank car, or pipeline. (I Animah et.al, 2020)

Gas Produced

The method of exporting the produced gas and government regulations will not allow us to flare all of the gas that is expected to be produced. Consequently, the produced gas will be treated to remove associated oil and reinjected back into the reservoir.

Water Produced

The produced water will be treated and reinjected back into the reservoir to maintain pressure and increase the oil rate.

8.2 Environmental Impact Assessment And Mitigation Strategies

8.2.1 Environmental Assessment Regulation

The Basic of 1992 mandates that all forms of wealth are under the ownership and management of the state, as delineated in Article 14 of the Basic Law. This encompasses resources found:

- Beneath the earth's surface or upon it
- Across the expanse of land
- Within the sovereign maritime territories

The Basic Law establishes the framework for harnessing, safeguarding, and cultivating these resources to advance the state's well-being, security, and economic interests. The Supreme Council for Petroleum and Minerals is responsible for formulating decisions and outlining the overarching strategies pertaining to petroleum investments.

8.2 Registration of undertaking and permit request

Operations at Vic Bilh will begin before the formal registration process and before being undertaken by the Environmental Protection Agency. All activities have been registered by Article 32 of the Basic Law established in 1992.

8.3 Report of the registration

Location: North-eastern margin of the Arzacq Basin.

Activity Undertaken	Environmental impacts
Drilling waste	Pollution of water bodies and soil
Oil spills	Destruction of aquatic life
Disposal of produced water	Contamination of water bodies
Noise pollution	Habitat disturbance

8.4 Environmental Impact Assessment

The Basic Law of 1992(Environmental Regulation Article 5) governs the environmental impact assessment (EIA) requirements, which include:

Obtaining the license for starting a project, establishment, or activity including environmental impact assessment (Article 4).

Ensuring that parties who are licensed to prospect, extract, or exploit onshore or offshore oil and gas fields carry out periodical monitoring of the environmental impact resulting activities taking place in the production fields, land, and marine transportation routes. (S Ngene et.al, 2016)

Prohibiting the discharge of any polluting substance resulting from drilling, exploration, testing of wells or production into the water environment or land area in the vicinity of referred activities, unless there is a safety measure in place for treatment of discharged waste and polluting substances by the most recent technical systems available in accordance with the conditions provided for in the approved regional and international conventions and protocols (Article 16 to 18,Environmental Law).

All employees are required to apply the HSE measures to carry out the work assigned to him by the company to prevent accidents or cause harm to personnel and installations. The impacts described in this section are potential impact that might be faced with the prospect and with proper measures can be mitigated

8.5 Aquatic Environmental Protection Measures

To safeguard the aquatic environment, the following protocols must be strictly adhered to:

- All types of spills (chemical/mud/cuttings/oil), contaminated soil, and waste resulting from drilling activities must be promptly cleared from the site.
- A designated team is responsible for inspecting the surrounding area of the camp and rig site, extending up to 100 meters beyond the fence perimeter in all directions. Any waste discovered during these inspections must be promptly removed and disposed of properly.
- Due to stringent environmental regulations, it is advised that the CONTRACTOR confines their operations within the designated work site. No equipment or structures are permitted outside the fenced area. Any damages resulting from non-compliance will be the sole responsibility of the CONTRACTOR.
- Any instances of oil spillage must be immediately reported to regulatory authorities, and measures for soil remediation/reclamation must be promptly undertaken.
- Every effort must be made to prevent or minimize pollution within the limits allowed by relevant laws during the course of work.
- The team is accountable for the thorough cleanup and removal of all waste materials and equipment from the work area, including pipelines, plastic waste, electrical wires, scraps, wreckage, and surplus pipes. These cleanup operations must be conducted in accordance with regulatory instructions and laws.

8.6 Waste Management

All waste generated must be handled by the Integrated Waste Management Contractor stationed at the drilling site. It will then be dispatched to the COMPANY's authorized recyclable waste contractor. Drill cuttings, following treatment by Hi-G dryers, will be stored in a specially constructed lined pit designated for this purpose.

Treated Produce Water and Wastewater

Treatment of Produce Water and Wastewater According to the 1992 Environmental Regulation (Article 13), it is imperative to prevent any form of direct or indirect contamination of surface, ground, and coastal waters by solid or liquid waste. Compliance involves employing the best available methods and technologies that adhere to set standards and criteria.

Produce water typically carries soluble and insoluble organic compounds along with solid particles, originating from rock leaching and pipeline corrosion. Various treatment approaches, including physical, chemical, biological, and membrane processes, are available. Notably, when reintroducing produced water, it is essential to remove acidic gases like H2S to prevent corrosion and hydrate formation. Additionally, the addition of inhibitors is recommended during the re-injection process. Wastewater separated from drill cuttings must be securely stored in designated lined pits. (JA Veil, 2002)_

Furthermore:

- Treated wastewater should not be dispersed unless it meets EPA requirements.
- Used oil from plants and machinery must be stored in sealed containers and later sent for recycling at the company's approved facility.
- Biodegradable food waste should be segregated into designated compartments provided by waste contractors at drilling sites and subsequently transported to the company's approved landfill site.

8.7 Hazard Identification & Assessment

Operations at the drilling site have undergone thorough scrutiny to ensure that every conceivable risk has been accounted for. This includes a comprehensive assessment of potential dangers and their impacts, alongside an evaluation and comprehension of the associated risks. Moreover, measures have been instituted to effectively manage and mitigate these risks.

The following outlines some of the potential risks that may arise during operations:

Heat Stress: Working in extreme temperatures presents a series of daily challenges. However, with the right precautions, it is feasible to endure such conditions over extended periods.

Working at Heights: Tasks that necessitate climbing ladders or erecting scaffolding should be circumvented whenever feasible. If such work is indispensable, it should be executed promptly and cautiously, ensuring ladders are not leaned against unstable or breakable surfaces.

Fall Risks: These risks may be linked to the erection and dismantling of the derrick. To ensure safety and accessibility, appropriate handrails, guardrails, stairways, walkways, and ladders must be put in place, and any stairs with defective or missing steps must be discarded.

Tripping and Slipping Hazards: These often result from improperly placed items like electrical cables, storage containers, pipes, or tools. To prevent these hazards, tools should be tidily stowed after use and adequate storage should be provided. Additionally, cones, flags, and other warning devices can be employed to highlight areas with potential trip hazards.

Load Lifting: All ropes, shackles, and hooks used for material handling must have certification from a recognized authority confirming their safety. Crane operators should follow standard hand signals, which should be depicted on illustrations at the job site. All substantial equipment lifting operations must be conducted using cranes.

This section highlights the crucial hazards identified for the drilling operation or location. It confirms that all significant risks and effects have been recognized, with the risks evaluated and comprehended, and that appropriate measures are established to manage these risks.

8.8 Occupational Health and Safety

Article 122 of labor laws mandates that employers are obligated to ensure that the work environment is kept clean and sanitary, including proper lighting and water provision, and that they adhere to established regulations, procedures, and standards regarding occupational safety.

Training and Awareness Initiatives

It is incumbent upon the company to ensure ongoing education and raising of awareness regarding health and safety among its employees. This includes the organization of routine meetings to discuss tool-related safety (toolbox talks), the provision of concise training programs, and the conducting of practice emergency response drills.

Comprehensive occupational health and safety assessments are crucial for identifying potential hazards or risks. These assessments are instrumental in the development of health and safety management strategies, the architectural planning of the facility, the creation of secure operational systems, and the formulation of safety procedures aimed at minimizing risks to the lowest feasible level. (S Rana, 2010)

Occupational health and safety considerations have a direct or indirect impact on the environment. Therefore, offshore facilities are constructed to reduce or prevent the likelihood of injuries or accidents. The following factors should be taken into account.

8.9 Occupational Health and Safety (OHS) Considerations

Prevention and Control of Fire and Explosions: It is imperative to test the atmospheric conditions to avert any potential explosions before conducting tasks that could cause ignition, such as using a drilling machine or grinder. Always verify with the supervisor that these tests have been carried out.

Air Quality Management: Perform gas testing as needed to ensure the air is safe for on-site personnel to breathe. Maintain a sufficient supply of calibrated gas detectors.

Handling of Hazardous Materials: Workers dealing with materials like pipe scales, drilling mud, and sludge, which may contain high levels of radioactive substances, are at an elevated risk of exposure. Utilize the designated Personal Protective Equipment (PPE) when managing these materials.

Safe Personnel Transport and Vessel Access: When boarding vessels, workers should utilize accommodation ladders or gangways to mitigate the risk of slips and falls – never attempt to jump onto a moving vessel. Lifejackets are mandatory during boarding, and adherence to the supervisor's instructions is crucial.

Well Blowout Prevention: Test Blowout Preventers (BOPs), choke lines, valves, and Kelly cocks at working pressure upon installation and then at suitable pressures for the well section periodically, at least weekly. Ideally, perform these tests using water. Before drilling out of any casing, except for the conductor casing, ensure all blowout prevention equipment is pressure tested to achieve a consistent pressure reading for ten minutes. Drilling should only proceed once the equipment has passed these tests and is confirmed to be reliable and adequate.

8.10 Occupational Disease

An occupational disease refers to any abnormal condition or disorder, not stemming from an occupational injury, that arises due to exposure to work-related environmental factors. This could encompass both immediate and long-term illnesses or diseases contracted through inhalation, absorption, ingestion, exposure to repetitive trauma, or direct skin contact. Occupational diseases can be categorized into seven groups:

a) Diseases or disorders of the skin linked to occupation

b) Lung diseases caused by dust

c) Respiratory ailments due to exposure to toxic substances

d) Poisoning from the systemic effects of toxic materials

e) Health disorders resulting from physical agents

f) Conditions associated with repetitive injury

g) Any other types of occupational diseases

8.11 Vic Bilh's principles for oilfield safety

In our continuous mission to enhance safety consciousness across our team and to share essential safety practices with our contractors who render services at our sites:

- Smoking is only permitted in designated areas
- Ensure that all energy sources are secured before commencing any task
- Always acquire and adhere to a work permit
- Wear the appropriate personal protective equipment for life safety as needed
- Perform required gas detection tests
- Refrain from conducting activities in trenches that lack proper support systems
- Safety signs must remain intact and safety-critical devices must not be tampered with
- Follow all regulations for safe material handling
- Abstain from alcohol and drug use while on duty
- Comply and intervene

Maintaining the safety principles will protect lives. One who chooses not to implement chooses not to work for Vic Bilh.

As an employee, my responsibilities include:

- Declining any tasks that contravene the Life Saving Rules;

- Taking action and notifying the relevant authorities if I witness any breaches of the Life Saving Rules.

Regarding Personal Protective Equipment (PPE), all workers on-site must don appropriate PPE that corresponds with their specific job requirements. This entails:

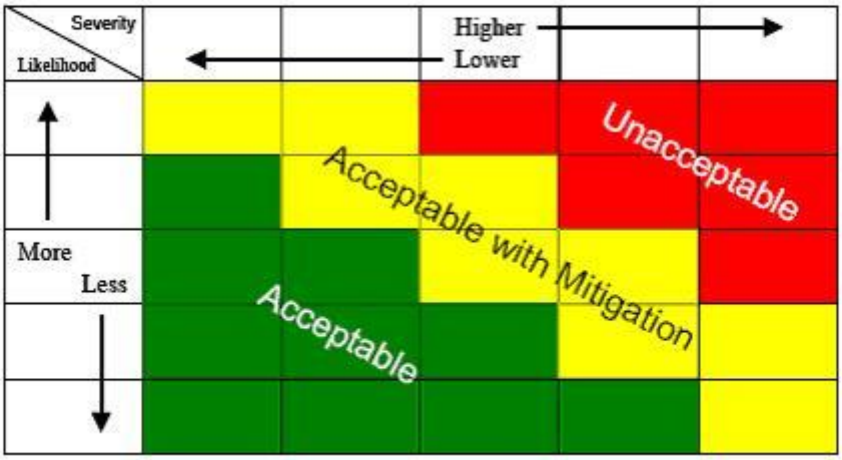
- Evaluating the necessary types and amounts of PPE;
- Distributing the requisite PPE to all employees;
- Ongoing supervision at the workplace to verify the PPE program's effectiveness.

All individuals involved in activities that pose a risk of harm or illness are obligated to use appropriate safety attire and devices.

Depending on the job's nature and the potential hazards present, such protective gear may include, PPE that meets global quality standards, crafted from thin, cotton fabric that is absorbent, light-colored, and sufficiently loose to facilitate circulation of air and blood, while also keeping the wearer clean and comfortable in various positions, including standing, bending, and stooping, and appropriate for the tasks to be performed under current weather conditions.

Specifically, workers should be equipped with:

- Full-body coveralls;
- Safety helmets;
- Protective footwear;
- Eye protection including welding shields and safety goggles;
- Hearing protection;
- Hand protection gloves;
- Safety lines and body harnesses.



Risk Assessment matrix

8.12 HAZOP scheme

Before any derrick or mast is raised or lowered, the tool pusher (or another qualified individual) must perform a thorough inspection of the hoisting equipment. Additionally:

- Ensure that any unsecured tools and materials are cleared from the mast.
- All necessary support cables must be adequately secured before any weight is applied to the derrick.
- Workers must not be positioned beneath a derrick while it is in the process of being raised or lowered.
- Load-supporting hydraulic jacks need to be equipped with safety lock features, dual valves, or a similar protective mechanism.
- A secondary escape route must be available in the event of a blowout.
- Drilling Fluid Preparation Guidelines

- Ensure that Material Safety Data Sheets (MSDS) for all chemicals are on hand. Do not use any chemicals until their MSDS are provided.
- Supply all necessary Personal Protective Equipment (PPE) to the workforce.
- Provide suitable respirators for protection.

- Establish eye wash facilities in proximity to the work area.
- Ensure that the area is well-ventilated.

Tubular Handling and Fitting Protocols

- Keep pipe racks well-maintained and in proper working order.
- When moving pipes on the rack, always push them away from your body to prevent injuries to feet or legs.
- Exercise extra caution when stacking the initial layer of pipes.
- Utilize a hook for moving pipes to and from the racks to avoid hand injuries.
- When handling pipe joints, workers should position themselves at the ends to quickly move away from any joint that may roll unexpectedly or become unmanageable.
- Always verify that the elevators are the correct size for the casing or other equipment being handled.

Casing and Cementing Procedures

- Ensure that the flow line and cement lines are firmly fastened and pressure-tested at their rated capacities upon installation, as well as before operation.
- Implement daily pumping through kill lines and choke lines, with routine retesting for reliability.
- Restrict access to the vicinity of the cementing head exclusively to personnel actively involved in the operation.
- Mandate the thorough cleansing of all lines after utilization.

8.13 HSE Reports

The supervisor shall submit the following reports to the Company’s Site HSE Representative: Daily

HSE Report, Weekly Waste Generated, Weekly Medical, Weekly APR.

And specifying the following information:

- Personnel involved in the Contract (both work site operators and staff)
- Total hours logged by the aforementioned staff members
- Instances of injuries resulting in time off work following the incident
- Aggregate days of work missed due to the aforementioned injuries
- Count of injuries that did not result in time away from work
- Potential incidents or conditions that, while not causing harm, had the potential for injury under less favorable circumstances.

8.14 Decommissioning

Our team is committed to the meticulous dismantling of all equipment, tools, and infrastructure. We will adhere to the guidelines set forth by environmental regulatory bodies to ensure that each site is returned to its original state. This includes the removal of:

- Mobile rig
- Casing, production tubing, and liners
- Surface-level facilities
- Pipelines

CHAPTER 9

COST ESTIMATION & PROJECT SCHEDULE

One of the most important steps to assess the profitability, feasibility, and aid in budget drawing of every oil and gas field is to give a very good cost estimation of the whole project aided by the properties of the said field. This takes into account all the all-estimated expenditure throughout the lifecycle of the project. This expands from the cost involved in exploration and appraisal all the way to production and finally decommissioning. A very good project estimation helps an investment make an informed decision driven by data regarding potential return of investment, project feasibility, and finally resources to allocate for that very project(Hafner and Luciani, no date).

The environment where the oil and gas fields are found account magnificently in the cost estimation process. The Vic-Bihl oil field is an onshore oil and gas field. Vic-Bihl is found in the Pyrenees-Atlantique department which belongs to the Aquitaine region in southwestern France. A detailed cost estimation analysis includes both Capital expenditure- CAPEX, this is usually required upfront for the development of the field, and Operation expenditure- OPEX which is accumulated while production is ongoing. This usually covers the cost of all intangibles or the cost of services employed on the field.

9.1 ECONOMICS AND COMMERCIAL CONSIDERATIONS

In every economical valuation in an oil and gas framework, the development of the field is done in a cost-effective manner. This means all available options are considered and the most suitable ones are chosen to solve the problem at a cost-efficient valuation. With regard to the development of the field: the number of wells (50), characteristics of the land, and most importantly the mobility factor is taken into consideration. The conventional Rotary rig or the traditional drilling rig. These undertake drilling by rotating the whole string leading to the bit. It is suitable for wide range of formation. Considering the Top drive rigs, it features a top drive system for rotating and circulating drill strings. It has a higher drilling efficiency and most importantly has the ability to adapt to different formations. The Mobile rig is one to be considered as well. It has the ability to be transported between drilling locations. It is usually suitable for multiple drilling well task due to it short set-up time and overall flexibility.(Ma et al., 2016)

9.2 ECONOMIC ANALYSIS

It is possible to calculate the worth of oil and gas resources by utilizing the variables found in geography, geology, economy, and other fields. The economic assessment of resources must be completed when a petroleum company decides to invest in oil exploration. A model for the economic evaluation of oil and gas resources is provided, based on the analyses of significant factors. Numerous elements in this model will be handled mathematically. The net present value of specific oil and gas resources can be determined using this useful model (Yun-k, 2002).

A detailed economic analysis of an onshore field located in France usually involves the detailed assessment of their financial feasibility and financial viability for development of such fields in the country. According to research, France as a country has very limited oil and gas production, with only a little about 1.6 percent of its locally consumed oil and gas being produced domestically(Guénaire *et al.*, no date). The country imports the majority of its crude oil, with the main suppliers being Kazakhstan, the Russian Federation, Iran, Saudi Arabia, Norway, and Algeria(Guénaire *et al.*, no date)

The following factors is needed to make an accurate and a detailed economic analysis of the field:

- Cost involved: The expenses related to exploring, drilling, producing, transporting, and decommissioning an onshore oil and gas field in France would be included. These prices may differ based on the particular site, the geology, and other elements.
- Revenue: The price at which oil and gas are sold will determine the proceeds from the sale; this price is determined by the state of the world market. France's non-producer status means it has no control over its oil price(Guénaire *et al.*, no date).
- Net Present Value: The project's net present value would be determined by deducting all costs from all revenues and then using an appropriate discount rate to reduce the total costs to their present value. This would yield an approximation of the project's total profitability.
- Internal Rate of Return: Finding the discount rate at which the project's net present value equals zero would be the first step in calculating the internal rate of return. This would yield a projected return on investment for the project.

- Government Take: Royalties, taxes, and other revenue-sharing mechanisms would probably give the French government a share in the project. In the economic analysis, this would have to be taken into account.
- Environmental and Social Costs: It would also be necessary to take into account the project's social and environmental costs, including how it would affect the environment, wildlife, and nearby communities. Models such as the Market Simulation Model (MarketSim) and the Onshore Environmental Cost Model (OECM) would be used to estimate these costs(Bureau of Ocean Energy Management, 2016)

9.3 Fiscal Regime

The Vic Bihl Oil and Gas field is located in the North of Pau in the southwestern France. Therefore, the fiscal regime of Frace was used in the evaluation of all the needed parameter with regards to economic analysis.

June 1979: A number of factors, such as shifts in government revenue, changes in the GDP composition, and policy decisions, impacted France's oil and gas fiscal regime. The GDP's composition changed during this time, with the oil sector's percentage falling from 50% to 42% in 1977 and expected to drop even further to 37% in 1978. Significant changes in fiscal policy were made in oil-exporting nations in 1974 and 1975. A few important components were the expansion or introduction of direct and indirect subsidies, the decrease or removal of specific domestic taxes, and the removal of user fees for services provided by the government, such as healthcare and education. These measures attempted to control inflation and raise living standards(Morgan, no date)

A comparative analysis of the federal oil and gas fiscal system also made clear how important it is to take into account variables other than those that the government takes into account when assessing fiscal systems. When comparing fiscal systems in the oil and gas sector, a composite index comprising metrics for profitability, revenue risk, and fiscal stability offers a more thorough comparison(*Comparative Assessment of the Federal Oil and Gas Fiscal System Final Report Bureau of Land Management CERA*, no date)

9.4 Petroleum Revenue Tax

The sources cited do not specifically address France's 1979 petroleum revenue tax (Ta). On the other hand, the sources talk about how petroleum products are taxed domestically, which is a significant source of income for most nations. There is a large range in the tax rates on petroleum products, and the taxation of petroleum products varies significantly between nations and over time('null-001.1994.issue-032-en (3)', no date). Petroleum revenue typically makes up between 7 and 30 percent of total revenue in developing nations, which translates to 1 and 3.5 percent of GDP('null-001.1994.issue-032-en (3)', no date). In some industrial countries, petroleum revenue has amounted up to 2 percent of GDP('null-001.1994.issue-032-en (3)', no date)

Only 1% of France's oil consumption was supplied by domestic production in 2018, indicating the small role that the domestic oil industry plays in the country.The majority of France's crude oil comes from imports, with Kazakhstan, the Russian Federation, Iran, Saudi Arabia, Norway, and Algeria being its top suppliers. Oil is freely traded through agreements and direct contracts, as well as the stock market, and the state keeps an eye on the conditions surrounding this trading(Guénaire *et al.*, no date).

Net Present Value (NPV): A financial metric called net present value (NPV) takes time value of money into account when assessing the profitability of investments or projects. To find out if a project is viable, it subtracts the initial investment from the present value of anticipated future cash flows. Whereas a negative NPV implies a loss, a positive NPV shows potential profitability. NPV is computed by applying a selected discount rate to future cash flows, which reduces them to their present value. NPV compares projects based on their potential returns, assisting businesses in making well-informed investment decisions. Profitability is indicated by an NPV larger than zero, whereas a negative NPV implies a loss. Businesses usually combine NPV with other measures to evaluate investments in a thorough manner. When calculating net present value (NPV), all cash flows are discounted to a single point in time, taking into account both inflows and outflows during the course of the project.

Internal Rate of Returns: One financial concept used to assess the profitability of a project or investment is the internal rate of return, or IRR. When the net present value of the future cash flows equals the initial investment, it is known as the annualized effective compounded return rate or rate of return. Put another way, it's the interest rate at which the total present value of benefits (positive cash flows) and the total present value of costs (negative cash flows) equals one another. The discount rate that brings the future cash flows' net present value (NPV) to zero is used to compute the internal rate of return, or IRR. It is frequently used in capital budgeting to assess the viability of a project. A project is deemed economically attractive if its internal rate of return (IRR) surpasses the minimum acceptable rate of return. When comparing various projects or investments, IRR is a helpful metric to have because it presents a solitary, easily comparable percentage figure. It does, however, have certain drawbacks, such as the reinvestment assumption, which makes the assumption that all cash flows are reinvested at the IRR. In real-world circumstances, this might not always be the case. Furthermore, IRR may not always be the most useful metric for choosing investments because it can be deceptive when comparing projects of various sizes or durations (What Is Internal Rate of Return (IRR)? Definition and Examples, 2023)

Profit to Investment Ratio: The ratio of a proposed project's payoff to investment is called the profit to investment ratio (PIR), sometimes referred to as the profitability index (PI) or value investment ratio (VIR). Because it enables you to qualify the amount of value created per unit of investment, it is a useful tool for ranking projects. Payback Period = Investment / Annual Net Cash Flow. The time it takes to recoup the cost of an investment is referred to as the payback period. In a nutshell, it's the amount of time it takes for an investment to break even.

The payback period is crucial because the primary reason that individuals and businesses invest their money is to get paid back.

Net Cash Flow: A critical financial tool for evaluating a company's financial health is the net cash flow (NCF) formula, which shows how much money is coming in or going out over a given time.

NCF = Total Cash Inflow - Total Cash Outflown time period.

9.4.1 Objectives

The economical analysis of Viv Bihl field turns to;

i. Using the fiscal terms governing the development of the Vic Bihl field, to create an economic model.
ii. To carry out an economic analysis of the suggested solutions and choose which is optimal for field development.
iii. To use sensitivity analysis to determine which variables have the biggest effects on economics and to rank them according to importance.

9.5 Capital Expenditure(Capex) Estimation

(Drilling, Facilities And Infrastructure)

9.5.1 Drilling Cost

The well depth was given in a range of (2250-2700m) and the industry rate as at 1979 cost for drilling a well is estimated to be $350 per meter. The field in question necessitated 50 well. With an average depth of about 2500m, the total drilling cost is approximately;

Total Drilling Cost = Number of wells * Average well depth* Cost per meter

= 50*2500*350 = $43750000.00

9.5.2 Production Facilities

The Vic Bihl Field has been stated to be an onshore field, this necessitates a central processing facility (CPF). This is to take care of the separation of Oil, water and Gas. With a production rate of 200000 t/year and estimated reserve of about 5 Mt, the central Processing facility will cost about **$25000000.00 .**

Due to the planned waterflood mechanism, it will be imperative to acquire a water handling system for an onshore field. This is estimated to cost about **$7500000.00**

An oil storage facility or tank will cost about **$2000000.00**

Total Production Facilities = Central Processing Facility + Water handling system + Oil tank Storage

= $25000000 + $7500000 + $2000000 = $ 34500000.00

9.5.2 Infrastructure

For a typical on shore well, we will need an extensive pipeline network to transport oil. Given the area of the oil field is estimated at 16 km^2 , assuming a standard 5 km radius from the central collection point, the total pipeline length would be approximately 31.4 km (circular area). Estimated cost is about $150000.00/km

PIPELINE COST = Pipeline length * Cost per kilometer

= **31.4 * 150000 = $4710000.00**

TOTAL CAPEX = DRILLING COST + PRODUCTION FACILITY + INFRASTRUCTUE

= **$43750000.00 + $ 34500000.00 + $4710000.00**

= $82960000.00

PARAMETER	TOTAL($)
DRILLING COST	**43750000**
PRODUCTION FACILITY	**3450000**
INFRASTRUCTURE	**4710000**
TOTAL	**$82960000**

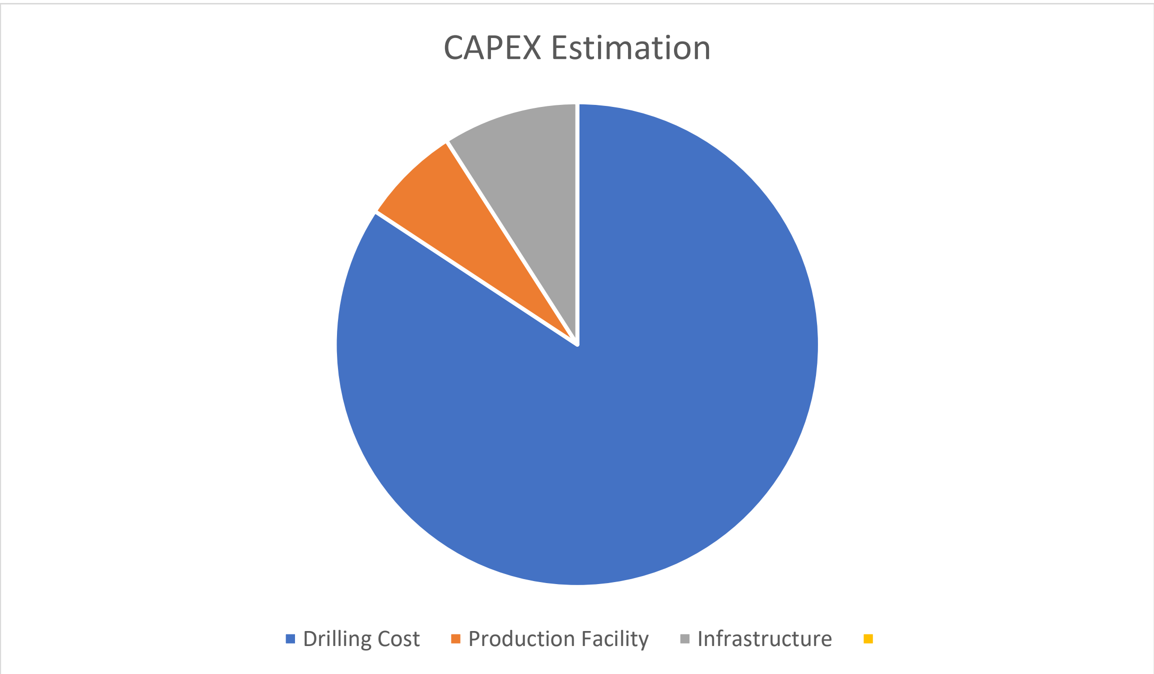


Figure 4: CAPEX ESTIMATION

Operational Expenditure

PARAMETER	Purpose
OIL TREATMENT	
LABOUR COST	Salary for full time and part time staff
MAINTENANCE AND REPAIR	Repair works for all the wells
UTILITIES	Electricity for pumps, compressors and others
ADDITIONAL COST	Cost to cover unforeseen Circumstances
TOTAL	

General Opex will be classified in Lift Cost, Operational Cost and Maintenance Cost.

Average industry standard for Lift Cost (Oil treatment) is estimated as $5/bbl , Operational Cost is about $3/bbl and maintenance about $4/bbl.

Daily Oil rate = 200000 t/year / (365 days/year) = 547.95 t/day

Convert to bbl/day = 4023.5 bbl/day

Daily Opex = Production rate * Total opex per barrel

= 4023.5 * 12/bbl = $48282.00 bbl/day

Yearly Opex = 48282 * 365 = $17622930.00

Table 6: Price of oil per barrel from 1979 to 1991

Year	Oil Prices($)
1979	15.85
1980	37.42
1981	35.75
1982	33.8
1983	29.08
1984	28.91
1985	26.94
1986	14.85
1987	18.06
1988	14.87
1989	18.23
1990	23.72
1991	20.04

The above table gives you the range of oil prices from 1979 to 1991. The average oil price is given as **$23.74**

ECONOMIC ASSUMPTION

A number of assumptions were made to aid in the development of the project's cash flow and economic assessment. The following are the presumptions made:

i. **Time Origin**

The effective date is given as June 1979.The first cumulative oil was gotten at January 1997. The economic analysis will be taken from that year.

ii. **Project Evaluation**

A look forward evaluation is employed in the analysis.

iii. Oil Price

The oil price is taken as USD 23.74 per barrel. This is constant through about.

9.6 Production Forecast

The economic analysis takes into account the production rates for each of the projected development scenarios in terms of the greatest oil recovery factor. Every well's annual production is limited to 260000 STB/year.

The subsequent trio of cases have been chosen for the economic assessment:

- Product Type: Crude oil
- Duration of Production: 25 Years
- Total No. Of wells: 50
- Number of producing wells: 20
- Number of injectors: 5

Table 7:Table of Projected oil produced from 1986 to 2009

Year	Oil Rate/year(m^3/year)	Oil Rate/Year(tonnes/year)	Oil Rate/Year (bbl/Year)
1986	182500	155982.906	1143354.701
1987	197100	168461.5385	1234823.077
1988	211700	180940.1709	1326291.453
1989	239075	204337.6068	1497794.658
1990	252215	215568.3761	1580116.197
1991	262800	224615.3846	1646430.769
1992	278130	237717.9487	1742472.564
1993	297475	254252.1368	1863668.162
1994	297475	254252.1368	1863668.162
1995	297475	254252.1368	1863668.162
1996	281050	240213.6752	1760766.239
1997	260975	223055.5556	1634997.222
1998	239075	204337.6068	1497794.658
1999	221555	189363.2479	1388032.607
2000	200750	171581.1966	1257690.171
2001	182500	155982.906	1143354.701
2002	166075	141944.4444	1040452.778
2003	144175	123226.4957	903250.2137
2004	122275	104508.547	766047.6496
2005	105850	90470.08547	663145.7265
2006	96360	82358.97436	603691.2821
2007	81760	69880.34188	512222.906
2008	67160	57401.7094	420754.5299
2009	32120	27452.99145	201230.4274
SUM	**4717625**	**4032158.12**	**29555719.02**

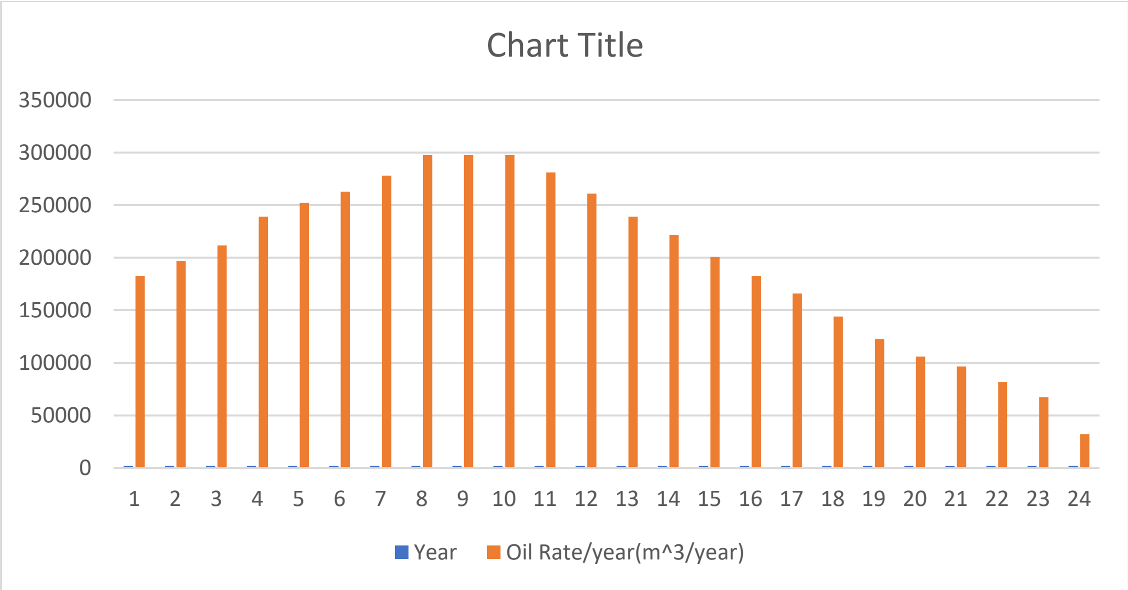


Figure 5: A graph showing the production profile

The graph above depicts the predicted production profile. It clearly indicates the build build-up leading to the plateauing region and finally the decline phase showing that the depletion pattern of the reservoir in general.

Year	Oil Rate/Year (bbl/Year)	REVENUE	EXPENSES	NET CASH FLOW
1985	0	0	($82,960,000)	($82,960,000)
1986	1143354.701	$27,143,241.60	($17,622,930)	$9,520,311.60
1987	1234823.077	$29,314,699.85	($17,622,930)	$11,691,769.85
1988	1326291.453	$31,486,159.09	($17,622,930)	$13,863,229.09
1989	1497794.658	$35,557,645.18	($17,622,930)	$17,934,715.18
1990	1580116.197	$37,511,958.51	($17,622,930)	$19,889,028.51
1991	1646430.769	$39,086,266.46	($17,622,930)	$21,463,336.46
1992	1742472.564	$41,366,268.67	($17,622,930)	$23,743,338.67
1993	1863668.162	$44,243,482.18	($17,622,930)	$26,620,552.18
1994	1863668.162	$44,243,482.18	($17,622,930)	$26,620,552.18
1995	1863668.162	$44,243,482.18	($17,622,930)	$26,620,552.18
1996	1760766.239	$41,800,590.52	($17,622,930)	$24,177,660.52
1997	1634997.222	$38,814,834.06	($17,622,930)	$21,191,904.06
1998	1497794.658	$35,557,645.18	($17,622,930)	$17,934,715.18
1999	1388032.607	$32,951,894.09	($17,622,930)	$15,328,964.09
2000	1257690.171	$29,857,564.66	($17,622,930)	$12,234,634.66
2001	1143354.701	$27,143,240.60	($17,622,930)	$9,520,310.60
2002	1040452.778	$24,700,348.94	($17,622,930)	$7,077,418.94
2003	903250.2137	$21,443,160.07	($17,622,930)	$3,820,230.07
2004	766047.6496	$18,185,971.20	($17,622,930)	$563,041.20
2005	663145.7265	$15,743,079.55	($17,622,930)	($1,879,850.45)
2006	603691.2821	$14,331,631.04	($17,622,930)	($3,291,298.96)
2007	512222.906	$12,160,171.76	($17,622,930)	($5,462,758.24)
2008	420754.5299	$9,988,712.54	($17,622,930)	($7,634,217.46)
2009	201230.4274	$4,777,210.35	($17,622,930)	($12,845,719.66)
			Average Value Profit = $195742420.46	
SUM	**29555719.02**	$701,652,740.46	($505,910,320)	$195,742,420.46

PROFIT = TOTAL REVENUE – TOTAL EXPENSES

= $701,652,740.46 - $505910320 = **$195742420.46**

	DISCOUNT FACTOR(10%)	PRESENT VALUE	CUM SUM NCF	CUM SUM PV
0	1	-82960000	-82960000	-82960000
1	0.909090909	8654828.727	-73439688.4	-74305171.27
2	0.826446281	9662619.711	-61747918.55	-64642551.56
3	0.751314801	10415649.2	-47884689.46	-54226902.36
4	0.683013455	12249651.79	-29949974.28	-41977250.57
5	0.620921323	12349521.9	-10060945.77	-29627728.68
6	0.56447393	12115493.88	11402390.69	-17512234.79
8	0.46650738	11076442.72	35145729.36	-6435792.071
9	0.424097618	11289712.78	61766281.54	4853920.708
10	0.385543289	10263375.25	88386833.72	15117295.96
11	0.350493899	9330341.14	115007385.9	24447637.1
12	0.318630818	7703747.742	139185046.4	32151384.84
13	0.28966438	6138539.745	160376950.5	38289924.59
14	0.263331254	4722771.044	178311665.7	43012695.63
15	0.239392049	3669632.128	193640629.8	46682327.76
16	0.217629136	2662612.968	205875264.4	49344940.73
17	0.197844669	1883542.698	215395575	51228483.43
18	0.17985879	1272936.006	222472994	52501419.43
19	0.163507991	624638.1432	226293224	53126057.58
20	0.148643628	83692.4867	226856265.2	53209750.06
21	0.135130571	-254025.2646	224976414.8	52955724.8
22	0.122845974	-404322.8251	221685115.8	52551401.97
23	0.111678158	-610070.7767	216222357.6	51941331.2
24	0.101525598	-775068.4928	208588140.1	51166262.7
25	0.092295998	-1185608.518	195742420.5	49980654.19

PROFIT TO INVESTMENT RATIO(P/I)	**2.3594795**
NET PRESENT VALUE TO INVESTMENT (NPV/I)	**0.120306**

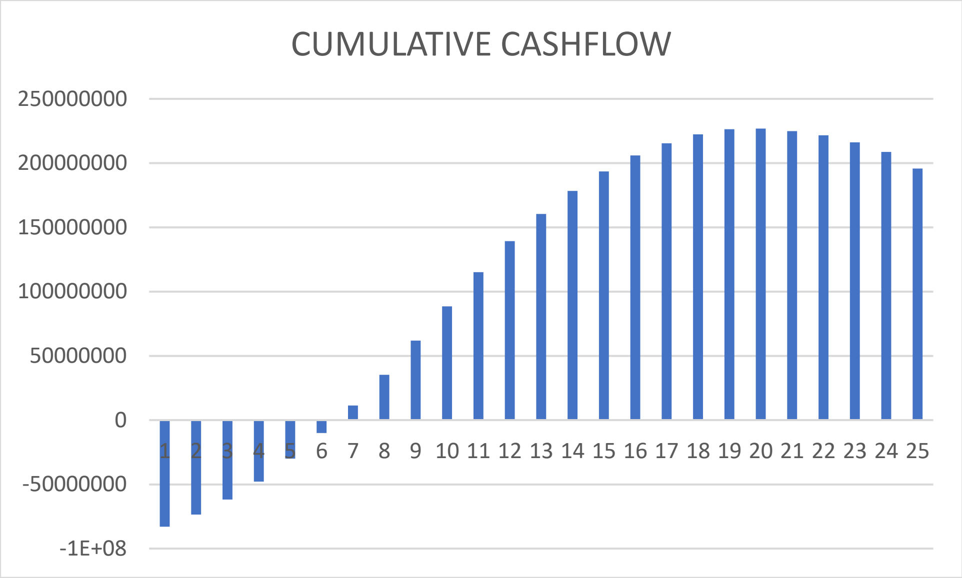


Figure 6: cumulative Cash flow

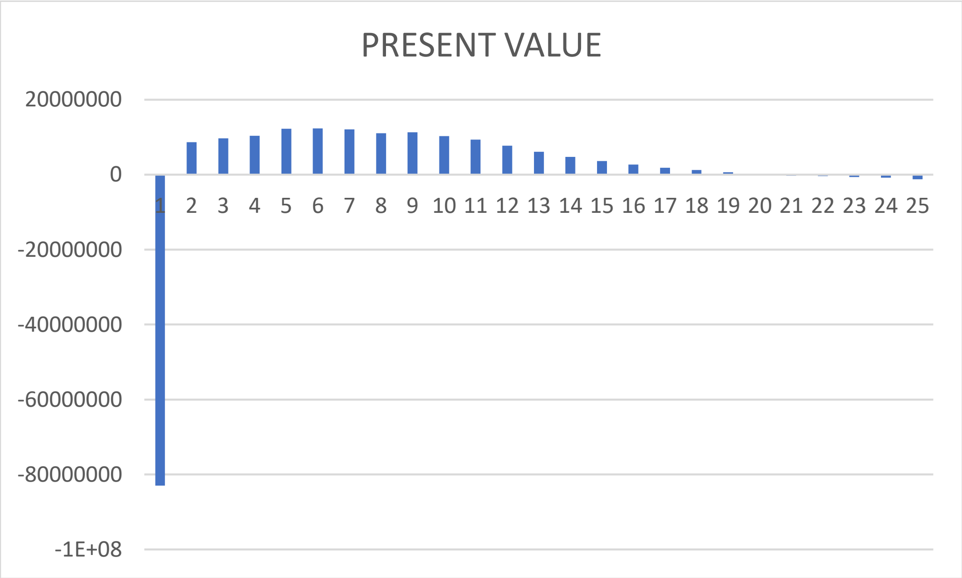


Figure 7: Prevent Value represented

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