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College of Petroleum Engineering and Technology
Department of Petroleum Engineering

Bachelor of Technology

Production Optimization for a Sudanese Field

Case Study Fula North

This dissertation is submitted as a partial requirement of B.Tech Degree (Honor) in Petroleum Engineering

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الاستـهلال

قال تعالى :

{ أَمَّنْ هو قانتٌ آناءَ اللَّيلِ ساجداً وقائماً يَحذَرُ الآخرةَ ويَرجو رحمةَ ربِّهِ قلْ هل يستوي الَّذين يعلمونَ والَّذين لا يعلمونَ إنَّما يَتَذكَّرُ أولوا الألباب }
(39 الزمر آية 9)

Abstract

Most of the Sudanese fields face the challenges of maintaining production rates, which are decreasing at a large rate annually. This project aims to find a solution that helps to improve the production rates in Fula Field by identifying the possible causes and factors influencing them using the developed model to represent the pipe networks.

Transport network lines play an effective role in the transfer of crude from wells to central treatment plants. The internal diameter decrease of these pipes due to the wax deposits and the heavy crude components lead to an increase in flow pressures from the wells and through the assembly pipes, which leads to a decrease in daily production rates.

The Network molding is used to analyze field data and to find ideal conditions and optimal production that can be achieved under the operational conditions and available equipment and thus help to make decision and future planning for field development.

As a result of this study it was found that the decrease in production is due to the decrease of internal diameter of the pipes due to the accumulation of viscous heavy oil and sand with will create a back pressure affecting the total wells performance.

المستخلص

أغلب الحقول الســودانيه تعاني تحديات المحافظه علي معدلات الإنتاج التي تتناقص بمعدلات كبيره ســنويا. هذا المشـــروع يهدف إلي إيجاد حل يســاعد علي تحســين معدلات الإنتاج في حقل الفوله عن طريق التعرف علي الأسباب المحتمله و العوامل المؤثره عليها بإستخدام برامج مطوره لتمثيل نمازج شبكات الأنابيب.

خطوط شبكة النقل تلعب دورا فعالا في نقل الخام من الآبار إلي محطات المعالجه المركزيه نقصان القطر الداخلي لهذه الأنابيب بسـبب ترسـبات الشـمع و مكونات الخام الثقيله تؤدي إلي إرتفاع في ضـغوط الجريان من الآبار و خلال أنابيب التجميع مما يؤدي إلي نقصان معدلات الإنتاج اليوميه.

تم إســتخدام برنامج محاكاة الشــبكات لتحليل البيانات الحقليه و إيجاد الظروف المثلي و الإنتاج الأمثل الذي يمكن تحقيقه تحت الظروف التشغيليه و المعدات المتاحه و بالتالي المساعده علي إتخاذ القرار و التخطيط المستقبلي لتطوير الحقل.

كنتيجه لهذه الدراســه وجد أن نقصــان الإنتاج هو نتيجه لنقصــان القطر الداخلي للأنابيب بسـبب تراكم الشـمع و الرمل بالإضافه المركبات الهيدروكاربونيه الثقيله.

ACKNOWLEDGMENT

First of all, we would like to express our sincere gratitude to Mr. Mohaned M. M. Khairy, who always found time and put in an effort for supporting and guidance through this study at the SUST college of petroleum engineering and technology as well as providing the licensed software and motivation required to complete the project.

We would like to extend our appreciation to all colleagues for their support during this research, we would also like to extend our appreciation toward Petro-energy production engineers for their support regarding obtaining the data required to complete this project.

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Chapter 1 Introduction:

1.1 Introduction:

Heavy oil has been playing a critical role in today's world energy supply. The total amount of heavy oil in place is five to ten times greater than that of the current proven conventional crude. One of the recovery methods, which produces both oil and unconsolidated sands, is known as Cold Heavy Oil Production with Sand (CHOPS). The advantages of CHOPS lie in its commercial success as an inexpensive start up application for heavy oil reservoirs as well as its considerable recovery rates. The general reservoir characteristics associated with successful applications of CHOPS have been established, particularly highlighted in thin reservoirs with non-active edge and bottom water. Heavy oil researchers have accumulated local knowledge for the CHOPS fields; particularly, research groups in Alberta have taken integrated approaches to the questions posed by the field success of cold production. CHOPS gives high early production rates and becomes very efficient in the thin reservoirs where some thermal methods have been economically unsuccessful.

Aggressive sand production was encountered in California prior to the First World War. Two key mechanisms lead to the success of cold production in laboratory and field studies: foamy oil flow and wormhole network growth. A variety of numerical models are presented and compared. Such models can be mainly divided into two broad categories: preliminary model and comprehensive model. With a large number of variables still in limited recognition for the complex mechanisms, several models lack capability in fully simulating CHOPS processes, while progress was achieved in modeling the reservoir heterogeneity with the integration of seismic attributes at specific fields. A detailed discussion of the strengths and weaknesses of cold production models is proposed. The paper ends with the future work of modeling proposed on cold production.

1.2 Research objective:

The main goal of this study is to use network modeling to quickly identify and accurately quantify bottleneck and other opportunity to reduce backpressure on the system and improve the production, this includes the following:

1. To identify production bottlenecks and constraints
2. To optimize production from the networks
3. To analyze surface facilities to find production constrains to identify the common production problems.
4. To add suitable surface facility to increase the flow rate.
5. Comparing of lifting methods (PCP & Sucker rod Pump).

1.3 Problem Statement:

The most common problems related to heavy oil in Fula Field are the high viscosity and massive sand production which is vividly decrease the potential production.

This study will discuss these problems from a production optimization overview to analyze the wells from the down hole to the gazering system for better understanding for the pressure distribution and viscosity through the system.

1.4 Fula Field Background:

Fula Field is located in Block 6 of Sudan, it contributes with reasonable amount of production in block 6.

There are three producing formation of Fula field which are Bentiu and Aradeiba formation (Heavy oil) and Abu Gabra formation (Light oil), Fula Field was put into production since November, 2003, it's consist of 146 producing wells, 138 are pumping wells, 5 are flowing wells and 3 gas producing wells, 15 oil gathering manifold (OGM), 12 OGMs are for heavy oil production wells and 3 for light oil production wells in addition to the gas gathering distribution manifold (GGDM) which is use to gather the gas from producing wells and redistribute it for different use such as; Gas lifting wells, power station, compressors etc…, Most of producing wells are used Progressive Cavity Pump (PCP).

The total fluid production about 26000bbl/d, with water cut about 70%,

The crude oil API is 17 to 19, density about 0.9378(g/cm3) @ 15ºC and pour point is about 0ºC to 4ºC.

Figure (1.1) OGM

Figure (1.2) Sand Trap

Chapter two

Chapter 2:

Literature review and theoretical Background:

2.1 Production Systems Overview

2.1.1 Integrated production system concepts:

1. Fluid flows from the reservoir via wellbore to surface (hydraulic system)

2.1.2 Production Systems includes:

1. Reservoir (Inflow Performance Relationship)
2. Wellbore (Completions, Tubing etc.)
3. Surface Facilities (Flow lines, Separator, Pipelines, etc.)

2.1.3 Production systems can be very simple to complex:

1. Simple – Reservoir, completion, tubing, surface facilities.
2. Complex- Artificial lift system, Water injection and Multiple wells
   Design of a production systems never be separated into reservoir and piping systems.
3. The amount of Oil and Gas flowing into the well from reservoir depends on pressure drop in the piping system.
4. Piping system pressure drop depends on amount of the fluid flowing through it.
   Therefore, entire production systems must be analyzed as a unit.

2.1.4 Each part of the total system may be the responsibility of different personnel:

1. reservoir to wellbore (reservoir engineer).
2. wellbore to wellhead (production engineer/completions engineer or production technologist).
3. wellhead to separator (facilities or process engineer).
4. motor to generator (electrical engineer).
5. wellbore and wellhead (mechanical engineer or drilling engineer).
6. All part of the same flow system, which should always be considered as a whole.

2.1.5 Systems analysis concepts:

1. Consider pressure loss from reservoir to separator as a continuous fluid flow system
2. Break down into logical components: reservoir, completion, wellbore, surface choke, surface flow line.
3. Aim is to reduce pressure drops at all times in order to minimize bottom hole flowing pressure
4. Major pressure loss component us the wellbore.

2.2 Fluid properties:

Usually referred to as PVT (pressure, volume, temperature),the most critical part of petroleum engineering since fluid flow depends on PVT properties.

Most commonly used to: determine the following oil, gas and water properties

1. wellbore related: phase proportions and volumes, densities, interfacial tension
2. reservoir related: fluid compressibility, viscosities

fluid types can be defined in terms of density (SG or API gravity) and gas-oil ratios (GORs):

	S. G	API Gravity	GOR (scf/STB)
Heavy oil	0.93	12 – 25	<100
Black oil	0.85	25 – 40	100 – 2,500
Volatile oil	0.81	40 – 50	2,500 – 4,500
Gas condensate	0.75	50 – 70	4,500 – 50,000
Wet gas		50 – 70	50,000– 100,000
Dry gas		N/A	>100,000

Table (2.1) fluid types

2.2.1 Fluid properties are determined by:

1. taking bottom hole sample (single phase) or separator samples of oil and gas and recombining
2. transferring to laboratory (under pressure) for detailed measurement

2.3 Pressure loss in the wellbore:

1. flow up the wellbore can be laminar or turbulent, single or multiphase, vertical or inclined
2. multiphase flow is complex and cannot be described completely by equations
3. models rely on correlations to allow calculation of pressure loss
4. dominant component is hydrostatic head (gravity pressure loss)
5. secondary component is resistance to flow (friction pressure loss)
6. for oils, gravity term is minimum of 80% of the total (but typically 10%)
7. for heavy oils, gas volumes are small and gravity term is typically 95%+
8. for volatile oils and gas-condensates (gassy oils), friction term may be up to 40%
9. for high rate gas wells, friction can be significant (up to 50%)
10. gravity term depends on fluid densities and proportions (oil, water, gas)
11. friction term depends on velocity (flowrate), tubing diameter and fluid viscosity
12. total pressure loss in the wellbore is often abbreviated as vertical lift performance (VLP)

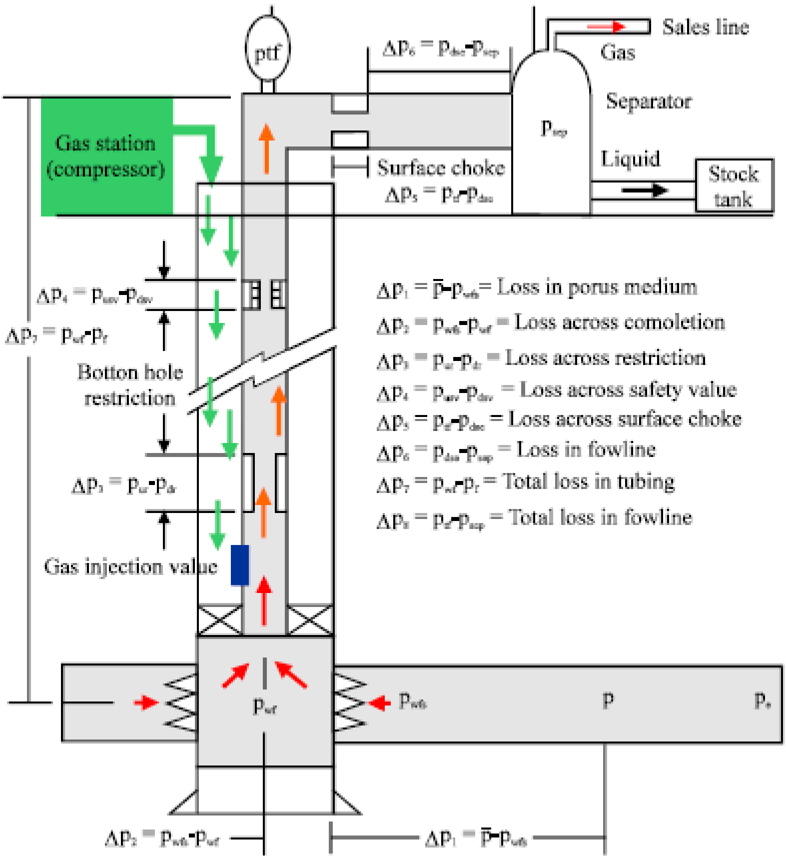


Figure (2.1) Production Systems

2.3.1 Pressure loss in the wellbore (Friction):

A. Frictional pressure loss main dependencies are mixture velocity, pipe diameter and viscosity
B. Inversely proportional to diameter to the fifth power
C. Very sensitive to gas volumes
D. Tubing roughness (granularity of the tubing inside wall) is only relevant in turbulent flow

2.3.2 Pressure loss in the wellbore (Acceleration):

1. Results from kinetic energy losses due to the rate of change of velocity
2. Usually only significant at the top of the wellbore with low flowing pressures and large gas volumes

2.4 Well performance basics:

Production in naturally flowing well will decline as a result of:

1. increase in water cut (coning, aquifer influx, water injection)
2. increase in wellhead pressure (higher flow line back pressure, facilities constraints)
3. decrease in reservoir pressure (natural depletion, lack of support high offtake)
4. decrease in well productivity (scaling, skin, damage, emulsions)

This production decline occurs due to pressure changes in the well and reservoir system:

1. increasing back pressure on the reservoir (increase in water cut or wellhead pressure)
2. lower pressure in the reservoir itself (as a result of production)
3. increasing pressure drop from the reservoir into the wellbore (perforations blocking, skin)

A well flows due to pressure drawdown on the reservoir (i.e. how hard you suck on the reservoir rock), as water cut increases or reservoir pressure decreases, the drawdown decreases and so does flowrate.

Either try to increase the reservoir pressure, shut-off water production or install artificial lift, a measure of the well's productivity is its flowrate divided by drawdown this is known as the well productivity index or PI.

2.5 Heavy Oil Production with Sand (CHOPS):

The major heavy oil production technology addressed will be CHOPS: Cold Heavy Oil Production with Sand.

CHOPS is defined as primary heavy oil production that involves the deliberate initiation of sand influx into a perforated oil well, and the continued production of substantial quantities of sand along with the oil, perhaps for many years.

For this report, heavy oil is empirically defined as all liquid and semi-solid petroleum less than 20°API gravity, or more than 100 cp viscosity at reservoir conditions. No differentiation will be made between heavy oil and oil sands ("tar sands"), though some use <12°API gravity and >10,000 cp as criteria to define oil sands, and the value of 10°API gravity is often used to differentiate between heavy oil and super-heavy oil (or bitumen, or oil sands, or tar sands, or extra-heavy crudes).

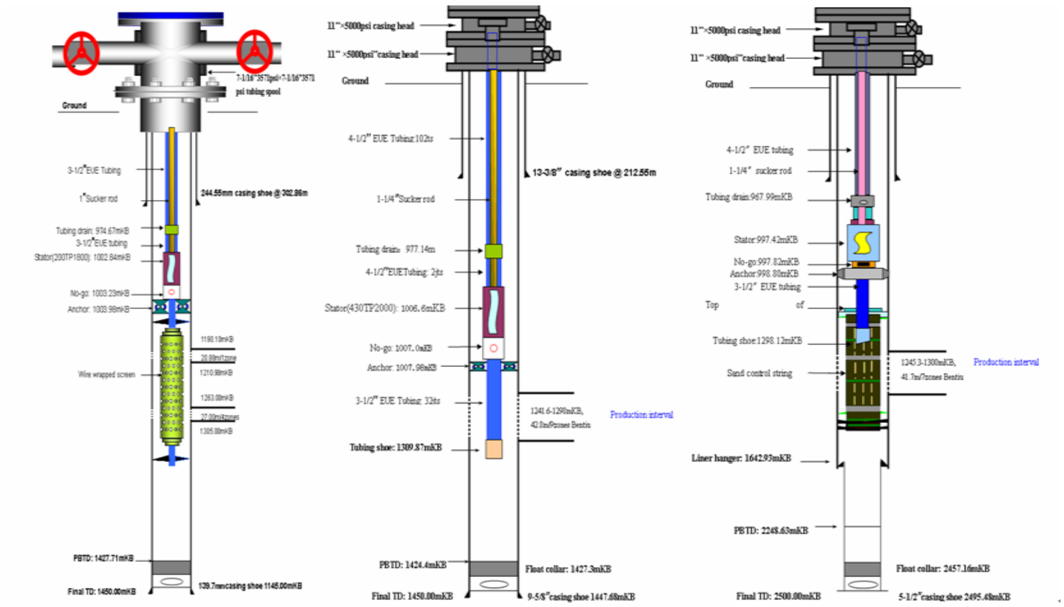
The advantages of CHOPS lie in its commercial success as an inexpensive start up application for heavy oil reservoirs as well as its considerable recovery rates. The general reservoir characteristics associated with successful applications of CHOPS have been established

Al-Awad (2001) discussed The Mechanism of Sand Production Caused by Pore Pressure Fluctuations in Saudi Field, The Mechanism of Sand Production Caused by Pore Pressure Fluctuations—Sandstone core samples cored from an outcrop layer of a Saudi sand producer reservoir were tested under simulated bottom hole stress-fluid flow conditions to investigate the process of increased sand production after well shut-in or work-over jobs (i.e. pore fluid pressure fluctuation). Bottom hole stress-state was simulated by using an experimental set-up consisting of a stiff compression machine equipped with a high-pressure Hoek cell, a servo-controlled confining pressure system and a pore pressure and flow generation system. This set-up enables the measurement of fluid flow and sand movement under simulated in situ stresses, In this work, 3% saline water and 1.5 cP light oil were used as pore filling fluids as well as displacement fluids. Displaced fluid and sand were produced through the outlet port of the Hoek cell (diameter = 4.25 mm). It has been found that an increased amount of sand was produced when the production process was restarted after a shut-in period of 24 h. Higher amounts of sand were produced when successive shut-in processes were performed, Furthermore, the amounts of produced sand decreased when the pore fluid pressure was brought to its initial value (i.e. immediately before the next shut-in). This decline is attributed to the increase of the effective confining pressure which tends to hold sand grains together as a replacement for the damaged cementing material. As indicated by the compressive tests, about 8% to 15% reduction in the strength of the tested sandstone was recorded after the conduction of three successive cycles of production using light oil and saline water. This reduction in rock strength was caused by the fluctuation in the pore fluid pressure during sand production process.

(Wang, 2005) Studied Integrated Well-Completion Strategies with CHOPS to Enhance Heavy-Oil Production in Fula Oilfield, Fula oil field is composed of unconsolidated sandstones, buried as deep as 3500ft, with high porosity (31%) and permeability (2 Darcy) , producing viscous oil with 19-21°API on the south flank of Muglad Basin. It is well-known that under proper conditions formation flow characteristics can be improved by non-thermal massive sand production and foamy oil behavior, referred to CHOPS. Integrated well completion strategies with CHOPS were used to increase heavy oil production. Limited sand influx provides a means for effective sand control while eliminating the need
for conventional sand control processes. The principle of limited sand flux is 'coarse sands controlled and finer sands produced', which is using the screen liner to inhibit 0.5mm or larger sands flowing into the wellbore, in addition, the rest smaller solids can be produced to the surface by viscous oil. Experiments were conducted to study the capability of lifting sands by crude oil. It showed that the sand of 0.9mm can be allowed to move up with heavy oil to the surface while 510 mPa.s of viscous oil is lifted in 3 1/2 in tubing. Using progressing cavity pump deliberately initiated sand influx but only 15% solids were controlled to form wormhole to improve permeability of the pay zone. This paper describes initial field test results of the new system that 20 heavy oil wells were equipped with PCP which is helpful for handling sanding effectively. The sand cuts range from 0.1 to 12% by volume. Average oil rate of each well is up to 580bopd from 175bopd before CHOPS. The best well can produce as much as 1200 BOPD. Oil production has reached to 2,450,000 bbl/y with attractive result, Technical difficulties for CHOPS in Fula Oilfield are:

Buried depth of the reservoir is deep 1200 ～1300m (3800～4200ft), whereas buried depth of most of the cold heavy oil production oilfields is lower than 800m (2600ft) in the world, Completion method shall be optimized by research on the boundary between CHOPS and limited sand influx, During study on sand settling in the wellbore, it requires to select reasonable size of the production string and working system to reduce sand settling rate, Oil production with sand will results in pump attrition and pump efficiency reduction even pump stuck or buried by sand, so sand washing technology is needed to be studied as well as After sand production, oil/sand processing technology is required on surface.

Below Sketch Map of Three Completion Strings Applied in Fula Oilfield illustrate control of sand production technology in well bore:



a b c

Figure (2.2) control of sand production technology in well bore, (Wang, 2005)

a. Perforation + Sand Control by Screening Liner

b. Perforation Completion

c. Perforation + Slotted Liner Completion and the below sketch illustrate the sand control technology at the surface (well head settling tube):

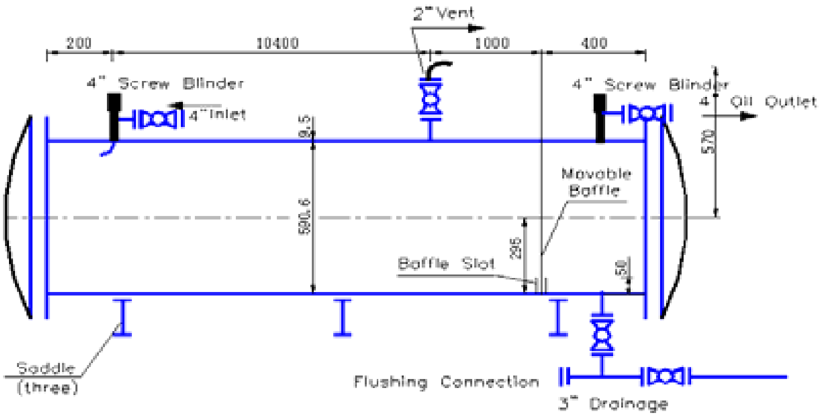


Figure (2.3) Sand Trap, (Wang, 2005)

Bernard Tremblay and Ron Sawatzky, 2002, studied Sand Production Processes after 10-year examination of Lloydminster and Cold Lake reservoirs, they have identified how sand production acts as one of the key mechanisms involved in cold production. In this process, sand production is encouraged in order to increase reservoir access and therefore improve oil recovery. Their experiments simulating sand production into a well have supported field tracer tests indicating that channels (wormholes) develop in a formation during cold production. These laboratory and field observations have helped convince some well operators of the benefits of sand production. They established a set of criteria in terms of sand strength and pressure gradient, in addition to foamy oil behavior, which allow them to screen potential reservoirs for cold production. As a result of their investigations into wormhole growth and sand transport in particular, they have developed a numerical simulation model of sand production. This model has been incorporated into a comprehensive field-scale model of cold production, the study focused on investigate sand production strategies for a variety of processes including:

1. Cold production with massive sand production through perforations
2. Primary recovery with controlled sand production through slots
3. Solvent-stimulated processes that could extend cold production processes to extra-heavy oil and bitumen.

The below picture shows Wormhole growth in a sand pack and the development of an open channel:

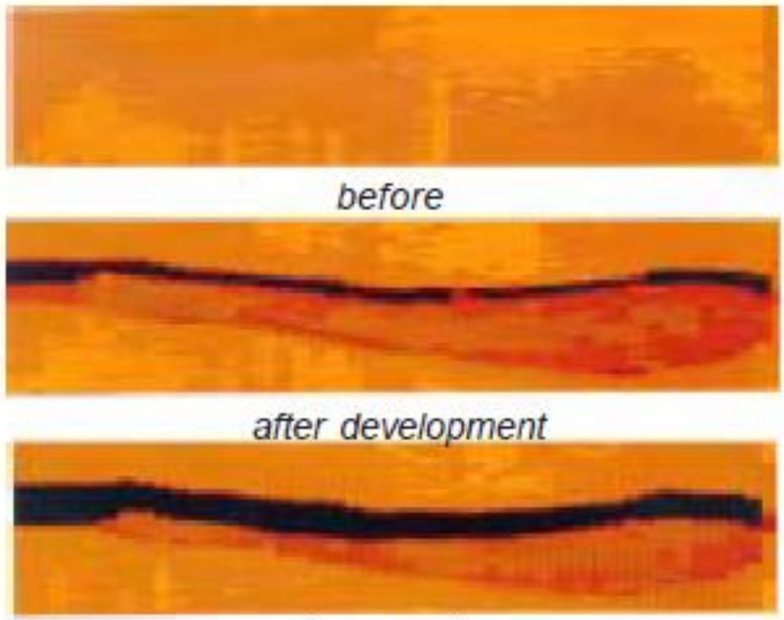


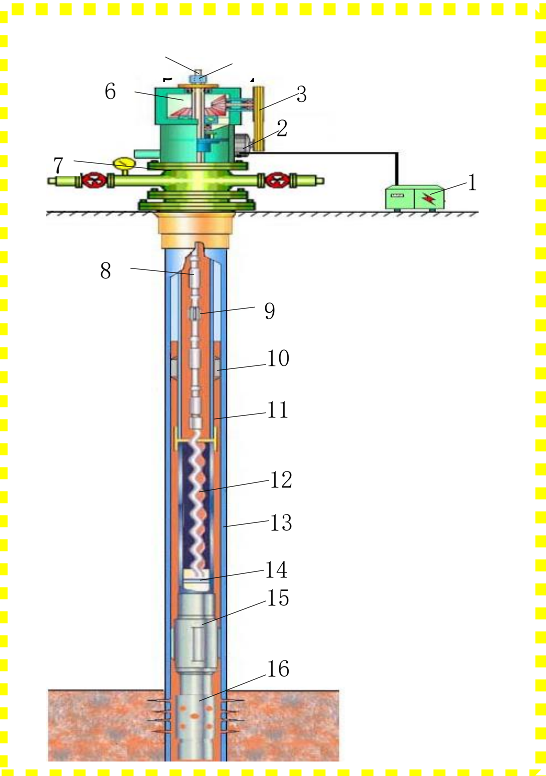
Figure (2.4) Wormhole, (Ron Sawatzky, 2002)

2.6 Progressive Cavity Pump (PCP):

1. The most rapidly developing method of artificial lift method.
2. Invented in the 1920s and first patented between 1930 and 1942 by French Scientist Professor Rene Moineau.
3. Widely used in food, mining and chemical industries.
4. Applied in the oil industry during the 1970s in Canada for production of heavy crudes.
5. Application of PCPs is growing rapidly in land-based operations and an offshore field trial has been performed in West Africa.
6. PCPs have higher system efficiency than other common artificial lit methods.
7. Low initial capital investment and inexpensive to operate/maintain.
8. The PC pump is suitable to various situations including high viscosity oil and sandy crude etc… this beside it also applies for field trail, gas and water disposal on coal bed.

2.6.1 A PCP system is made up of three principal components:

1. the downhole pump comprising of the rotor and stator
2. the rod string which provides the torque to turn the pump
3. surface drive system (drive unit, speed reducer and prime mover)



1-control unit
2-electric motor
3-belts/pulley
4-polish rod clamp
5-polish rod
6-gear reducer
7-special wellhead
8-sucker rod
9-sucker rod centralizer
10-tubing centralizer
11-tubing
12-PCP
13-casing
14-tag bar/stop pin
15-anchoring tool
16-screen pipe

Figure (2.5) PCP Pump Component (Bernard 2002)

2.7 Sucker Rod Pump (SRP):

Sucker rod pump, abbreviated as SRP is a very old technique in the oil industry for lifting of crude oil from the wells and the fact it is the most widely used mode of artificial lift system in the present-day scenario.

SRP System Components:

1- Surface unit.
2- Sub-surface sucker rod pump.
3- Sucker rods.

2.7.1 Surface unit:

Consist of prime mover (electric motor or gas engine), gear box, crank, pitman arm, walking beam horse head, wire line connected to the polish rod & some auxiliaries.

Pumping unit cum the prime mover at the surface converts the rotary motion of the prime mover into reciprocating/vertical motion with the help of several links arrangements.

2.7.2 Sub-surface sucker rod pump:

It is sub-surface reciprocating pump actuated by the up & down motion of sucker rods, which is connecting link between surface unit & sub-surface pump it consists of:

1. Barrel, Plunger, Standing valve.
2. Traveling valve & Pump seat.

2.7.3 Sucker rods:

It is the vital link between the sub- surface pump and pumping unit, these sucker rod are available as per API.

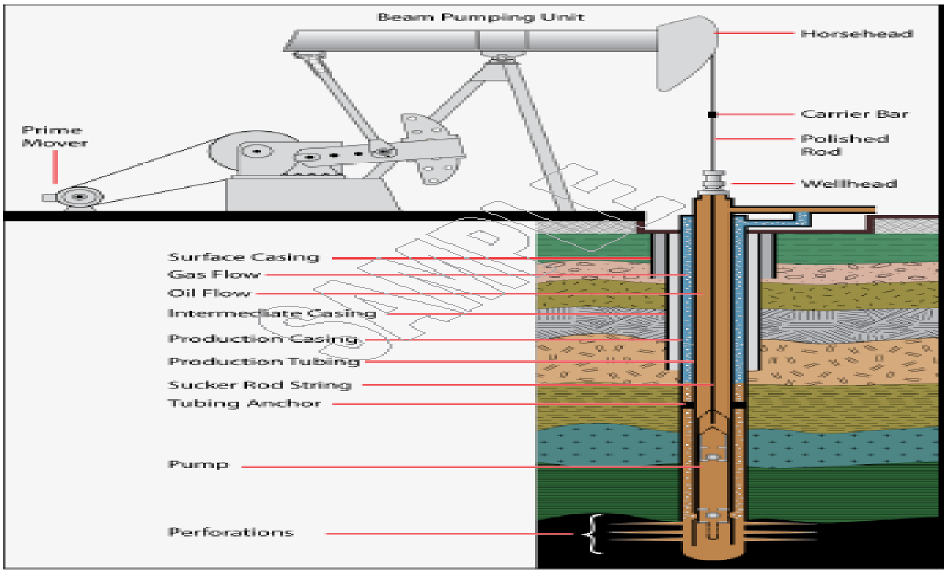


Figure (2.6) Sucker Rod Pump (Bernard 2002)

2.8 PCP and Rod Pump comparison:

Pump Type	Advantages	Disadvantages
PCP	**- Very efficient - Low equipment purchase cost - Good for viscous fluids - Handles gas and sand - No additional fluids introduced - Low operating cost -Various power sources**	**- High rate (up to 5000 bfpd) - Deep wells (>7500 ft) - High temperature - Chemical attack on elastomers - Torque limits on rod - Directional (high dogleg) wells - Wireline intervention limited - Stuffing box leaks**
Rod Pump	**- Lowest equipment cost - Low operating cost - Simple to design and operate - High temperature - High viscosity - Various power sources**	**- Low rate (up to 1000 bfpd) - Limited depth (<10,000 ft) - Directional (high dogleg) wells - Solids cause erosion of pump - Gas lowers volumetric efficiency - Not applicable offshore - Wireline intervention limited - Obtrusive surface configuration - Stuffing box leaks**

Table (2.2) PCP and Rod Pump comparison (Bernard 2002)

Clemente Marcelo Hirschfeldt, Rodrigo Ruiz; 2009, studied Selection Criteria for Artificial Lift System Based on the Mechanical Limits: Case Study of Golfo San Jorge Basin in Argentina, the artificial lift systems are distributed as follows: 9,648 Sucker Rod Pumps (SRP), 1,615 Progressing Cavity Pumps (PCP) and 1,336 Electric Submersible Pumps (ESP). There are some important experiences with gas lift, plunger lift and hydraulic jet pump, but are not considered in this study. Close than 90% of the pumps are installed between 3,000ft to 8,000ft depth, producing flow rates over 1,500 bpd of fluid, more than 3.1 MMbpd of water are injected in 2,400 wells in water flooding projects, therefore 41% of the oil is produced from this method. Due to the mature state of the basin, every year, new water flooding projects are implemented for increasing and to hold the oil production of the basin. With every new project, not only increases the gross production per well, but also increases the depth of the new reservoirs, the combination of these factors resulted in a higher power to be transmitted from the prime mover to the pump, coupled with the increasing down hole temperature, Another factor, is the restriction provided by the most common casing diameter (5 ½ “), limiting the outside diameter of the pumps, the tubing’s and sucker rod sizes, and the shaft diameter too in some systems, In order to overcome these conditions, not only requires new technology in materials and design, but criteria for operation on the surface to achieve it, This paper presents a theoretical and practical analysis of the mechanical and operational limit of the most used artificial lift systems in Golfo San Jorge Basin such as the PCP, ESP and SRP, The analysis not only considers the technical aspects of each critical component and new technologies, but also is supported by reservoir information, operational conditions from 11,000 wells and software simulations for each system, One of the main objectives of this paper is to provide a guide for selecting and designing artificial lift Systems as SRP, PCP and ESP in similar oilfields and conditions.

Yongbin Wu, 2013, discussed EOR Strategies for a Conventional Heavy Oil Reservoir with Large Aquifer in Greater Fula Oilfield, Sudan.

Thermal recovery technology particularly cyclic steam stimulation (CSS) is always an effective means to develop the conventional heavy oil reservoirs, which can be validated from literature. While most of the heavy oil reservoirs developed by CSS are the thick, well-deposited, high quality reservoirs and there are no much reports of producing oil from mid-depth oil reservoirs with large aquifers.

In this paper, according to the petrophysical properties and geologic characteristics of the target block in Greater Fula oilfield in Sudan, based on the oil test results, detailed 3D geologic model is established and the type well model for CSS and SF is extracted, to study the real performance with the real geological properties.

The development zone, the perforation strategies, the cyclic steam injection quantity, the steam injection rate, soak time, and cyclic period are optimized for CSS. Based on the production performance of CSS, the optimal cycles of CSS followed by SF is determined. And the well pattern and well spacing, the parameters of SF such as unit steam injection rate, steam quality, effects of bottom aquifer on the SF are also simulated and optimized. The simulation results indicate that the thermal recovery technique especially 4 cycles of CSS followed by SF can acquire satisfied performance, which shows an effective and economic future in the development of the heavy oil deposits in Greater Fula Oilfield.

Bhatkar 2013 discussed Optimizing crude oil production in Sucker Rod Pumping wells using QRod Simulator, Mainly due to its long history, sucker-rod pumping is a very popular means of artificial lift all over the world; roughly two-thirds of the producing oil wells are on this type of lift. To maximize profits from these wells in the ever-changing economic situation with rising costs of electric power, installation designs must ensure optimum conditions. They used QRod Program which is the most widely used, program for the design and prediction of the performance of Sucker Rod Beam Pumping Installations.

The program uses a wave equation solution to accurately predict the surface dynamometer loads, gearbox torque and pump capacity, with a minimum amount of input. The effect of changing a parameter such as tubing anchor, stroke length, stroke rate, and pump diameter can be immediately seen in the dynamically updated plots. After a review of the surface and downhole energy losses in sucker-rod pumped wells, some key considerations on the ways to improve system efficiency are given. The most important task is the proper selection of the pumping mode, i.e. the combination of plunger size, pumping speed, stroke length, and rod taper design for lifting the prescribed amount of liquid to the surface. The paper gives aspects and details of optimizing sucker rod pumping operation by using QRod simulator along with practical examples.

Chapter three methodology:

Chapter 3: Methodology:

PIPESIM is built & innovated by Schlumberger, it's a way use to simulate individual well and network models. PIPESIM combines best-in-class science with an unparalleled productivity environment to enable engineers to optimize production systems from the reservoir to the sales point. These release notes describe the most significant enhancements and known limitations.

The PIPESIM steady-state multiphase flow simulator offers complex production and injection networks analysis. the well, pipeline, and flow assurance capabilities are all within a shared common environment, powered by the most rigorous field wide solver.

The solver is suitable for networks of any size and topology, including complex loop structures crossovers .by modeling the entire production or injection system as the network interdependency of wells and surface equipment can be accounted for, and the deliverability of the system can be determined.

PIPESIM network simulation and optimization capabilities enable users to:

1. Design the best well, pipeline, and facilities design
2. Identify production bottlenecks and constraints
3. Optimize production from complex networks
4. Handle multiple system constraints
5. Quickly identify locations in the system most prone to flow assurance issues such as erosion, corrosion, and hydrate formation
6. Quantify the benefits of adding new wells, compression, pipeline, etc.
7. Determine optimal locations for pumps and compressors
8. Design and operate water or gas injection networks
9. Analyze hundreds of variables such as pressure, temperature and flow assurance parameters through Complex flow paths
10. Evaluate benefits of loops and a crossover to reduce backpressure
11. Calculate full field deliverability to ensure contractual delivery Rates can be met
12. Optimize the allocation of lift gas amongst wells

In this study it was decided to follow the following steps while building network model and various sensitivity study:

1. Data Collection and Validation.
2. Physical Model Building and Validation.
3. PVT modeling.
4. Multiphase Flow Correlation Matching.
5. Network Balancing and fine tuning.

3.1 Data Collection:

Data Collection is the first and foremost requirement of a model building effort. Since field is structurally and otherwise a dynamic environment it was essential that model building and validation should be done by matching model result to certain cut-off date instead of trying to match a moving target.

In order to ensure speed and efficiency on data Collection process, a detailed list of data requirement was prepared upfront. The data included depth reference, well diagram, deviation survey data, and pressure survey data of the well and nearby wells, production test data and well history. Meetings among various discipline and groups were organized to ensure clear understanding of data requirement and objective of the study. The data were manually collected from various groups and locations of Petro-energy.

3.2 Physical Model Building:

A hydraulic network in PIPESIMIM is made up of single branches or segments connected at points called nodes. The segment may be just a connector or it may contain pressure loss devices such as pipes and piping equipment connected in series. Nodes can be boundary nodes (Sources and Sinks) or internal nodes (junctions). The net flow in a junction node is zero. A boundary node can be a:

1. Source node: where fluids flow into the network; node flow rate is positive.
2. Sink node: where fluids flow out of the network; node flow rate is negative.

3.2.1 Layer 1 FPF and OGMs:

In PIPESIM graphical user interface (GUI) The network layout has been logically organized using PIPESIM's folder option to enable easy navigation to various parts of the model, Figure (below)

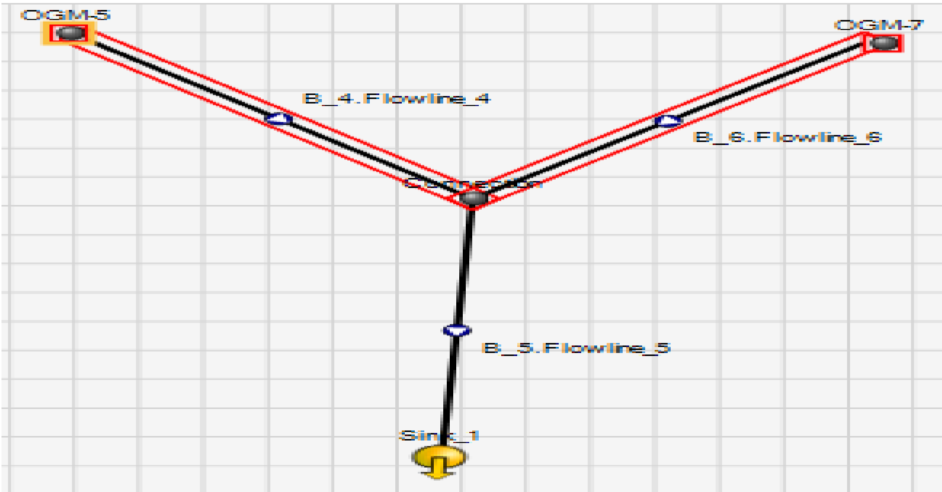


Figure (3.1) Network Layout

Tow trunk lines connecting OGM's together and one trunk line connect to FPF these trunk lines data such as:

1. Horizontal distance.
2. Inner diameter.
3. Wall thickness.
4. Roughness.
5. Ambient Temperature was input for each line, Figure(3.2)

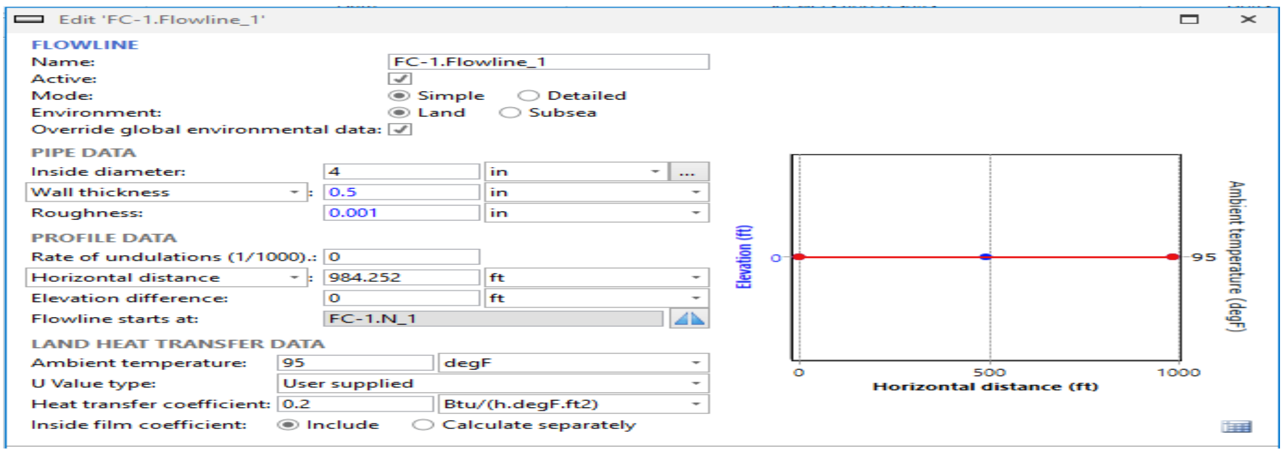


Figure (3.2) Flow lines Data

3.2.1 Layer 2: wells and flow lines connected to OGMs:

Sources and production wells are connected to each OGM by a flow line data were input to this flow line as same as the data used to build the trunk lines illustrated in next figure (3.3) show how these wells and flow lines are distributed.

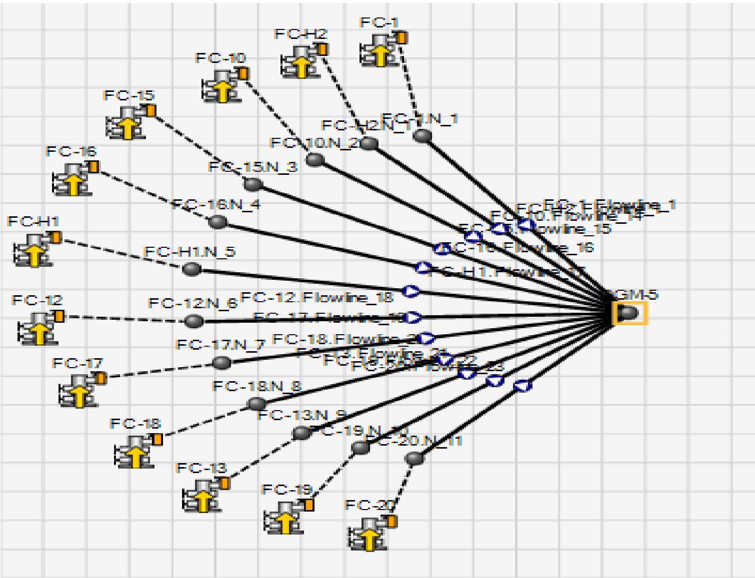


Figure (3.3) Wells and flow lines layout

3.2.1 Layer 3: Wells Model

Wells operated by PCP, the input data required are:

1. Production rate.
2. Temperature.
3. Fluid properties.
4. Pumps data.
5. Completion data.
6. Reservoir data.
7. Flow lines data.
8. OGMs and trunk lines data.

As illustrated in the figure (3.4) and figure (3.5)

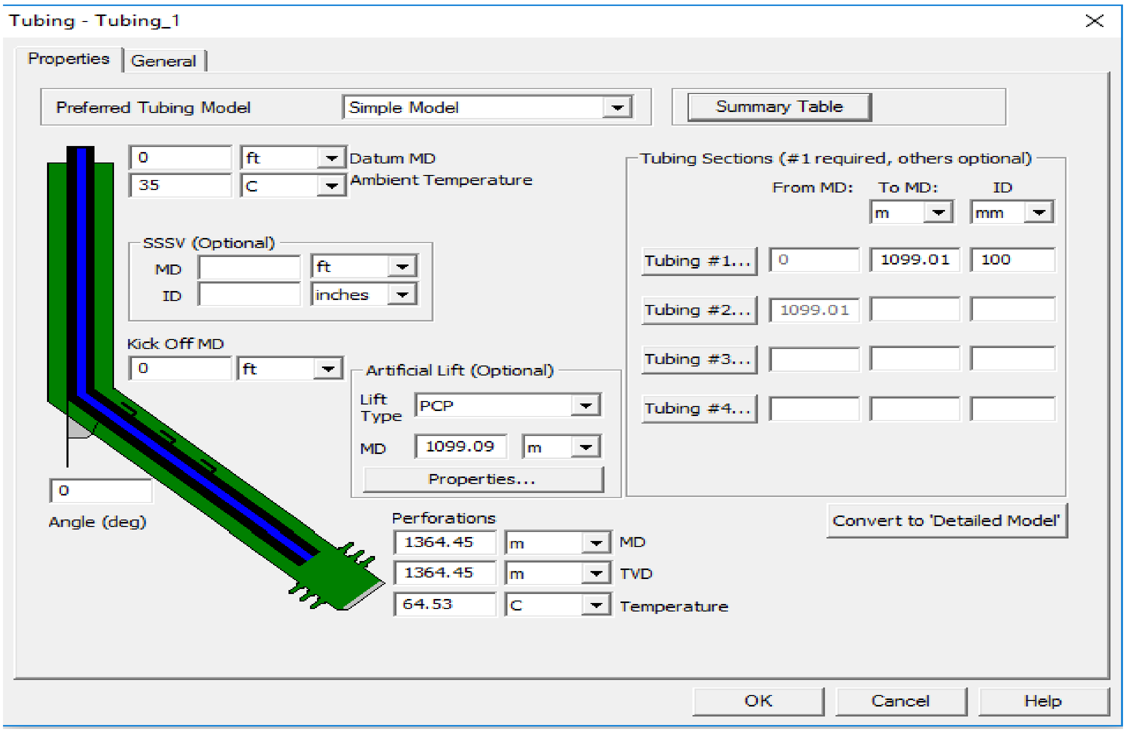
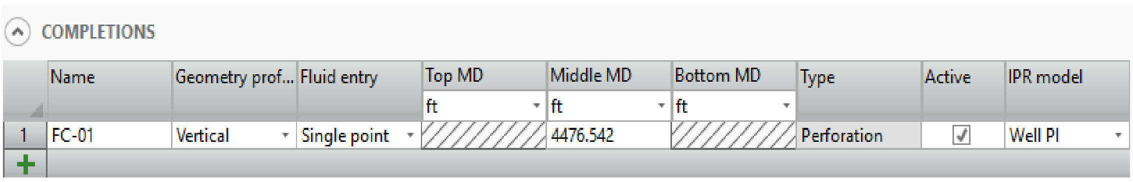


Figure (3.4) Tubing



COMPLETIONS

	Name	Geometry prof...	Fluid entry	Top MD	Middle MD	Bottom MD	Type	Active	IPR model
				ft	ft	ft			
1	FC-01	Vertical	Single point		4476.542		Perforation	✓	Well PI

Figure (3.5) Completion Data

3.3 PVT Data and fluids properties:

A black oil model was selected since it is typically applicable for GOR less than 2,000 STB/SCF data required include:

1. GOR
2. API
3. WC %

As illustrated in Figures (3.6)

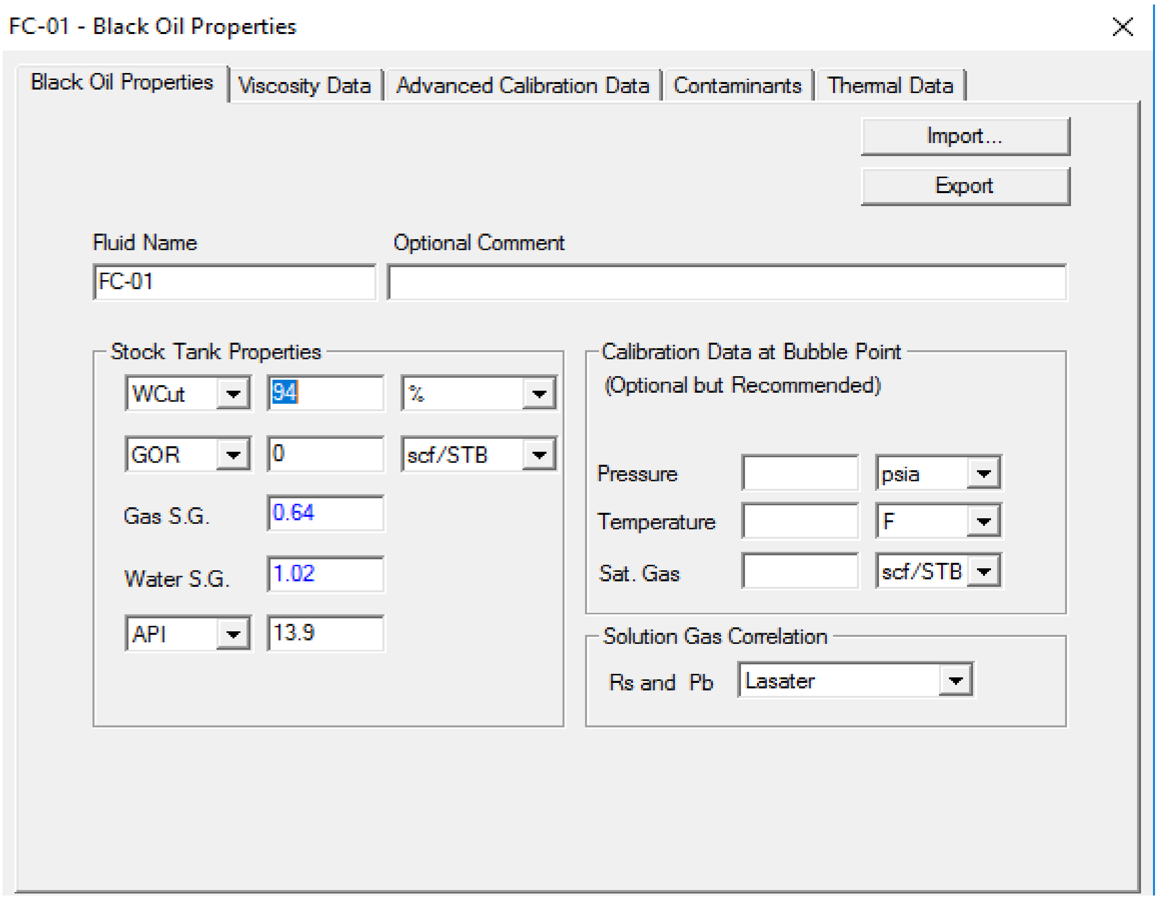
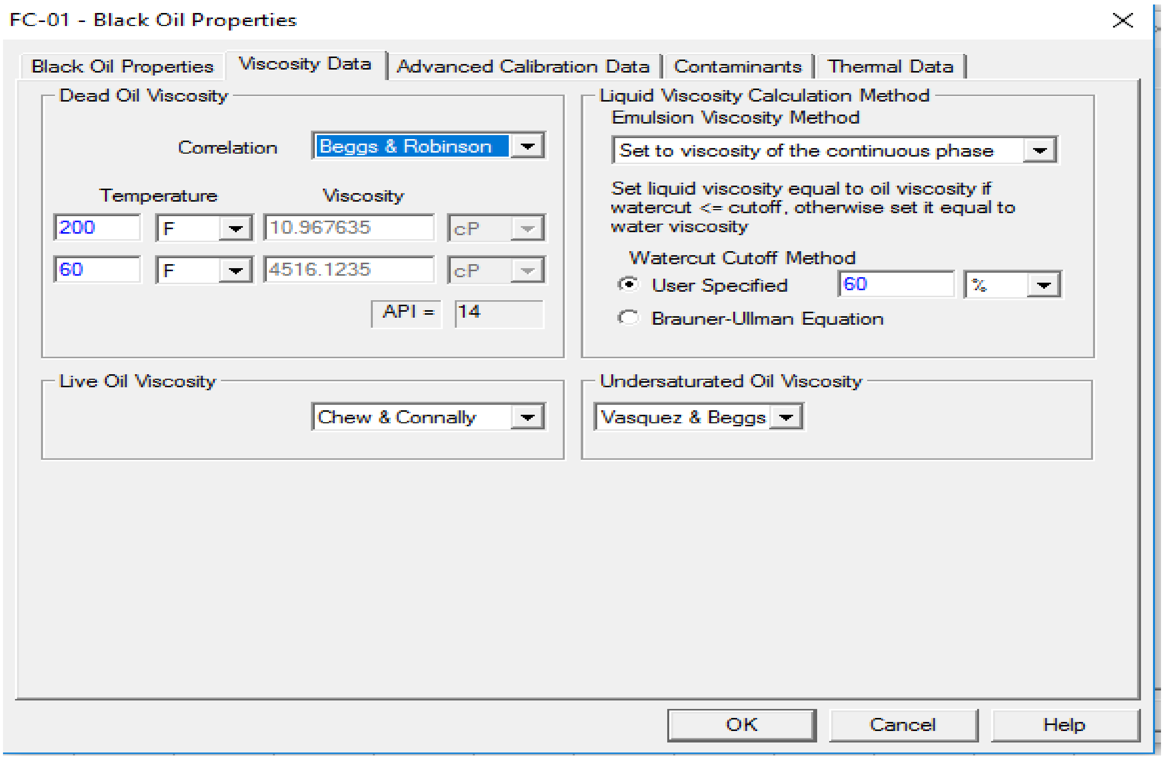


Figure (3.6) Black Oil Model

Viscosity data were collected from the laboratory and it was input as specified in figure (3.7)



viscosity in a specified temperature as illustrated in figure (3.7)

3.4 Flow correlation:

Flow correlation was selected from variety of correlation provided by software based on best match for vertical flow correlation Hagedown & Brown correlation was selected, for horizontal correlation Beggs & Brill revised correlation was selected

Flow lines inlet pressure matching was carried out to ensure that the measured flow lines inlet pressure and that calculated by the models are consistent. Matching the surface flow lines pressure was done to confirm the applicability of selected flow correlations for surface network.

3.5 Network Balancing and fine tuning:

3.5.1 Running the model

After applying previous steps to construct the model and balancing the data a model checked and Verified for errors, the model became ready and it was run successfully.

Chapter four…Results

Chapter 4

Result and discussion

In this chapter we will discuss the result after running and validating the data.

From the selection criteria of artificial lift found that the PCP is the best option for application in the Field under study.

4.1 Completion Overview:

The figure (4.1) illustrate completion diagram includes tubing, pump, pump depth, etc…

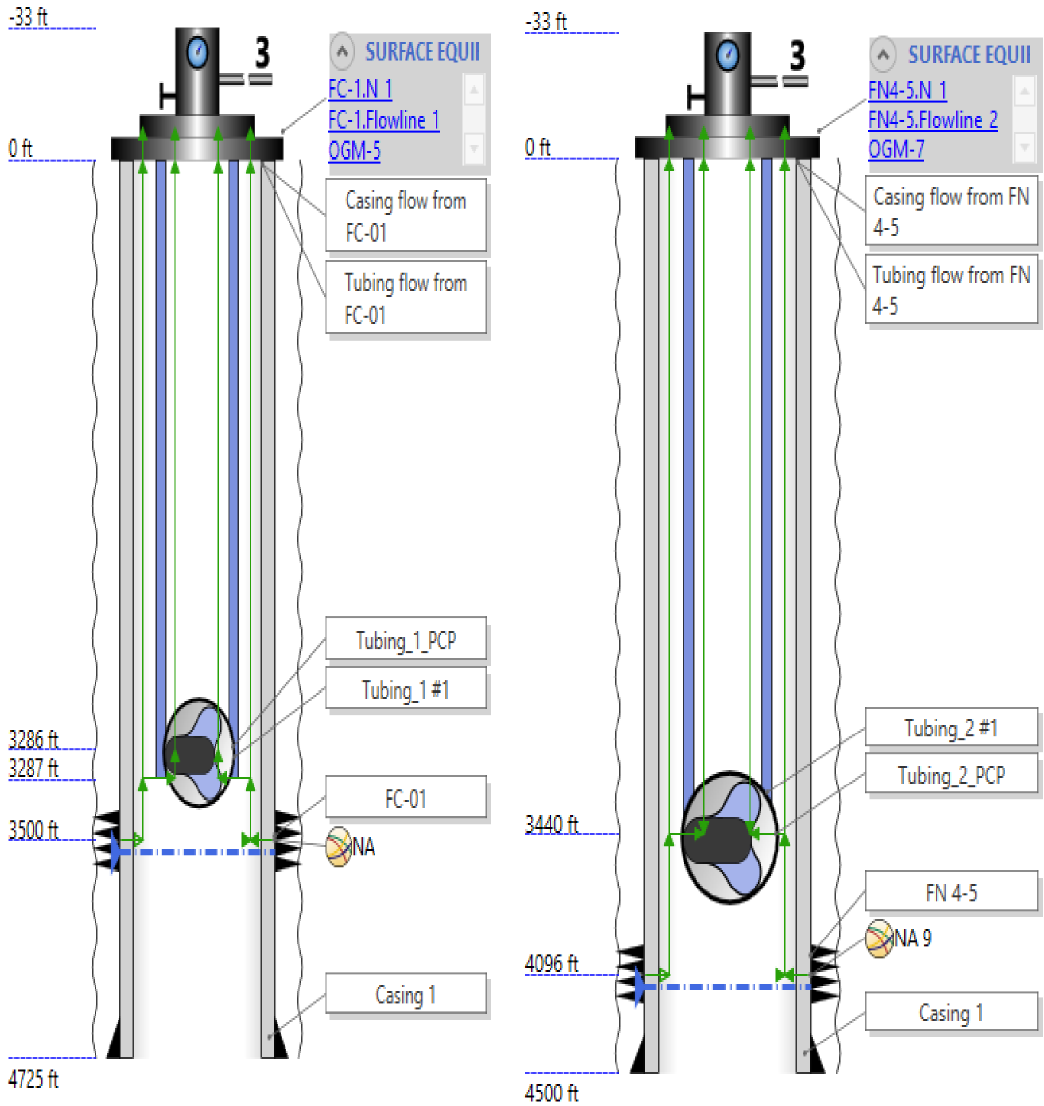


Figure (4.1) completion configuration

4.2 Network:

The figure (4.2) illustrate the built model (Network) includes all wells, flow lines, OGMs, trunk lines, connection point as well as sink.

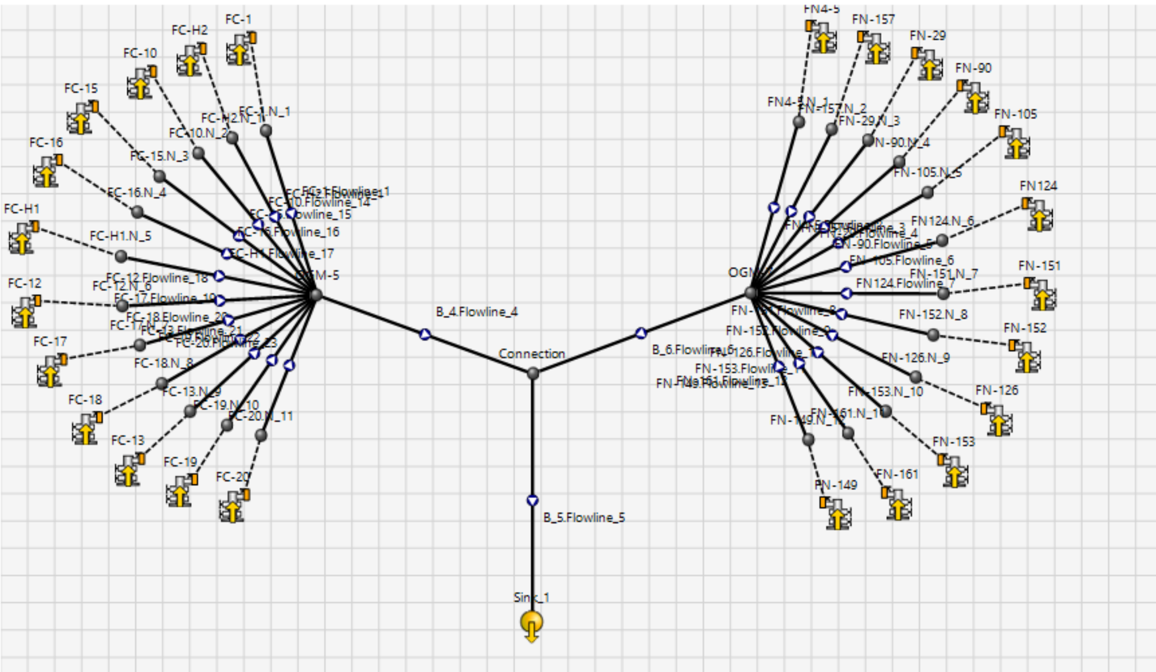


Figure (4.2) Network

The production optimization study for Fula Field was successfully conducted, the result and main findings are illustrated in the following steps:

4.3 distance VS different parameters:

The distance VS different parameters are calculated by the model as shown below:

The figure 4.3 illustrate total distance VS pressure for all producing wells., for example FC-16 suffering of high pressure difference percentage in flow line pressure with distance

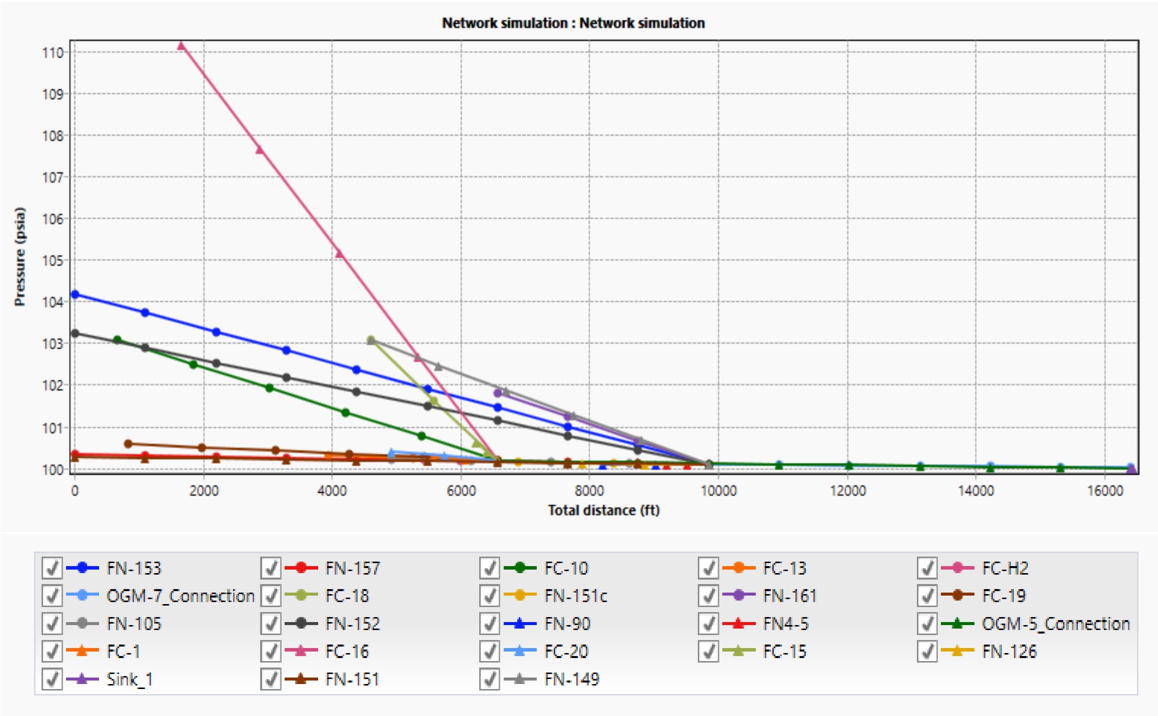


Figure (4.3) **total distance VS pressure**

The figure 4.4 illustrate total distance VS Erosion velocity ratio for all producing wells, as shown the erosion velocity is less than 1 % which indicate good performance.

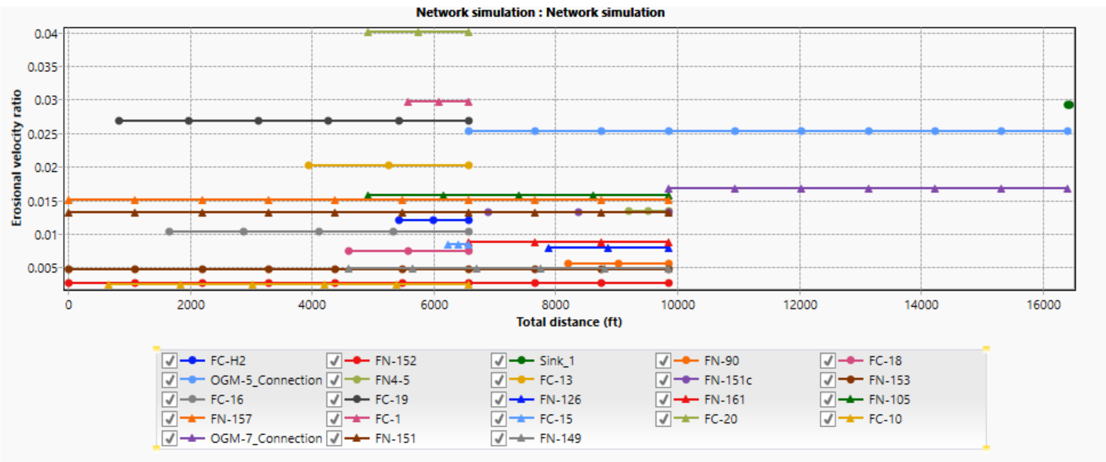


Figure (4.4) **total distance VS Erosion velocity ratio**

The figure 4.5 illustrate total distance VS liquid velocity per second for different producing wells,

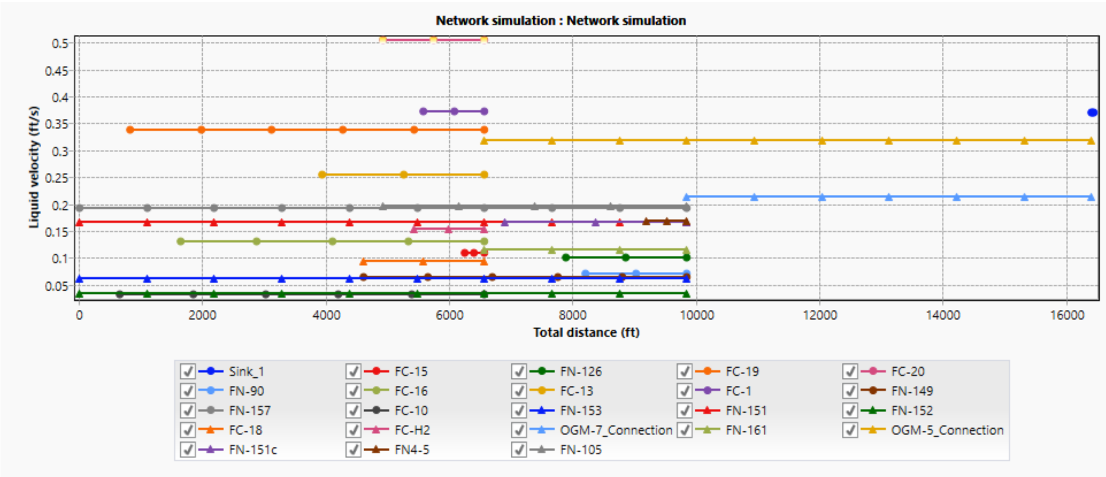


Figure (4.5) total distance VS liquid velocity

The figure 4.6 illustrate total distance VS Temperature for different producing wells, it's clear that the temperature dropped with distance which causes increase in viscosity, to solve this problem surface heater can be added to the wells flow line in order to heat the oil and sustain temperature value so as to reduce the viscosity.

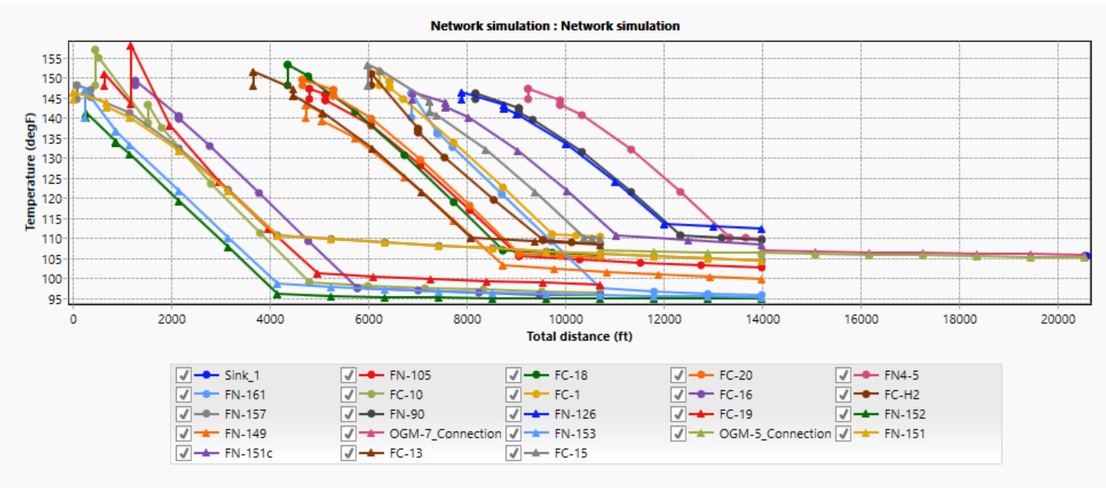


Figure (4.6) distance VS Temperature

The figure 4.7 illustrate total length VS Flowing liquid viscosity for all producing wells and OGMs, showing that the viscosity increase with distance due to decrease in temperature which may cause back pressure on producing wells, to solve this problem heating for oil in surface flow lines is recommended or adding chemical in order to reduce the viscosity, also transfer pump can be attached to OGMs in order to increase transfer rate and decrease the back pressure for de-bottleneck purpose.

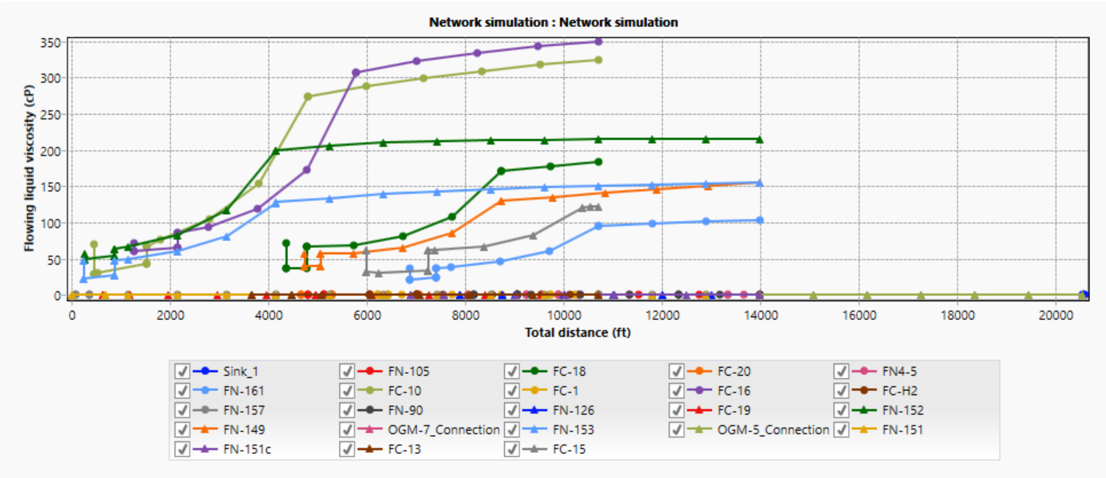


Figure (4.7) total length traversed VS Flowing liquid viscosity

The figure 4.8 illustrate total distance VS flowing water cut for different producing wells

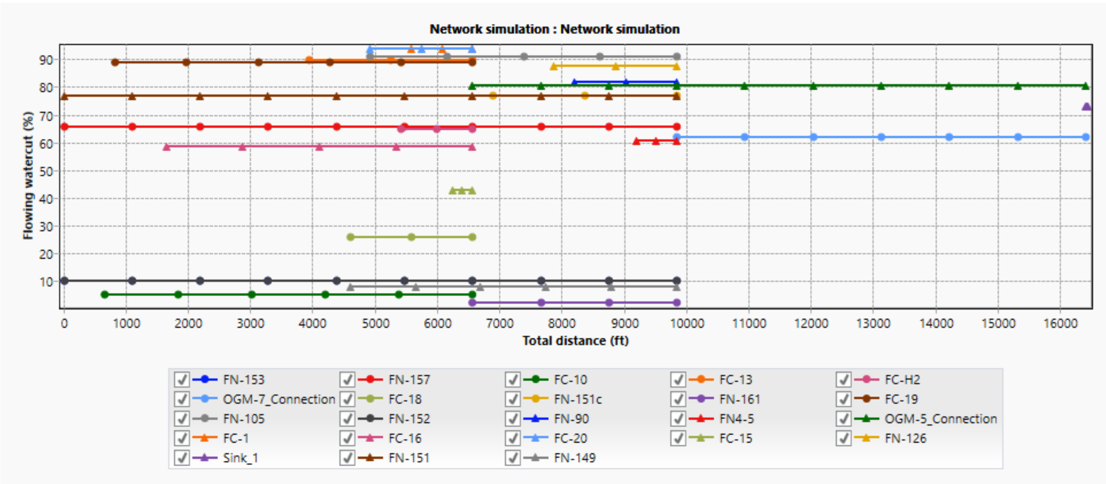


Figure (4.8) total length traversed VS flowing water cut

4.4 Wells Nodal Analysis:

Nodal analysis will be used to calibrate the created wells and to generate the pressure and flow rate associated with each one of them.

The result will be compare to the actual flow to ensure that this model pressure variation will represent the current case.

Nodal analysis result also could be used to get a clear image on what happening on the downhole and how the pump power decreasing the outflow performance to lift the wellbore fluid.

The figure 4.9 illustrate operation Pressure and flow rate for Fula centre-01

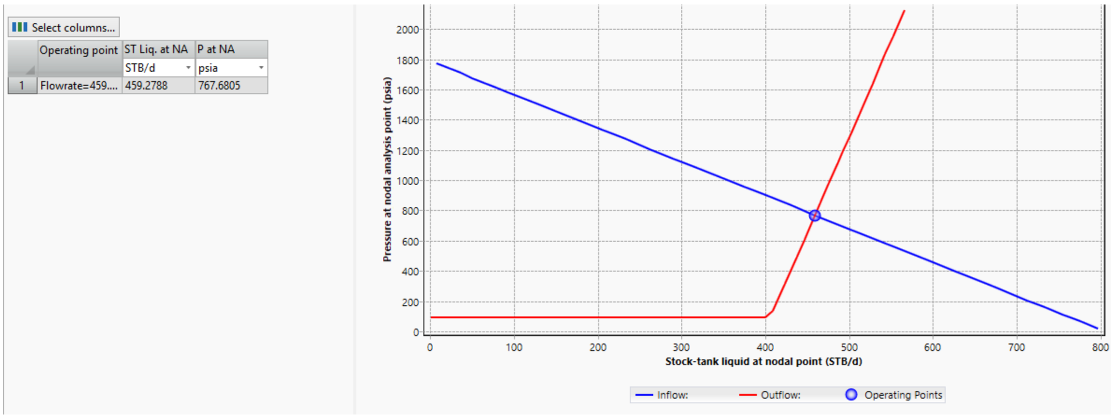


Figure (4.9) nodal analysis for Well Fula Centre-01

The figure 4.10 illustrate operation Pressure and flow rate for Fula Centre-10

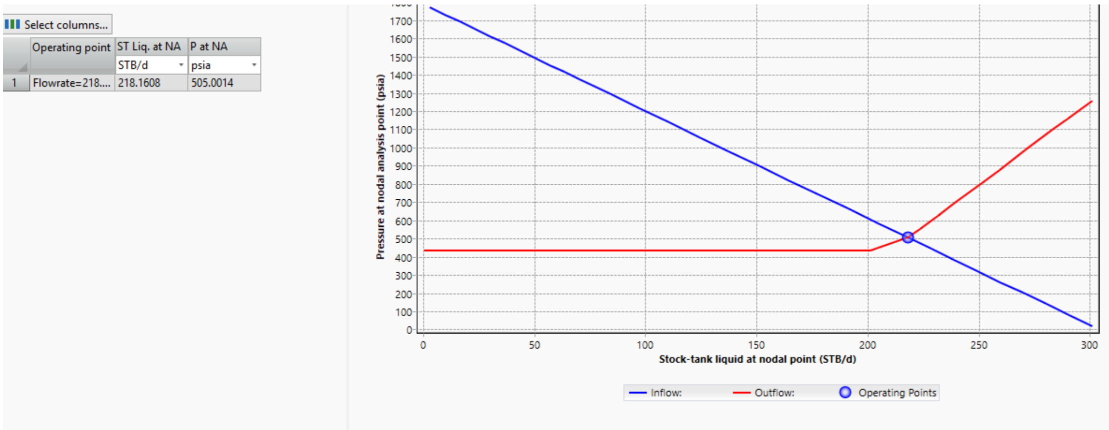


Figure (4.10) nodal analysis for Well Fula centre-10

The figure 4.11 illustrate operation Pressure and flow rate for Fula centre-13

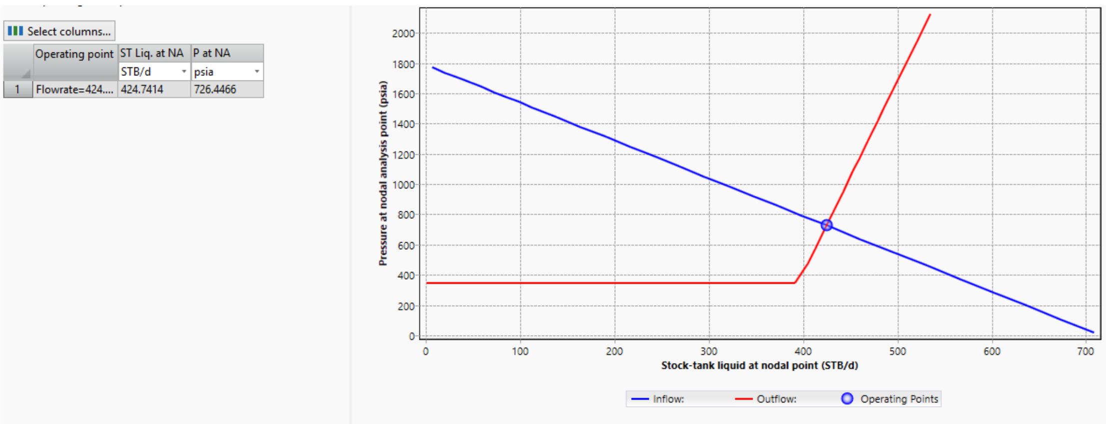


Figure (4.11) nodal analysis for Well Fula Centre-13

The figure 4.12 illustrate operation Pressure and flow rate for Fula Centre-15

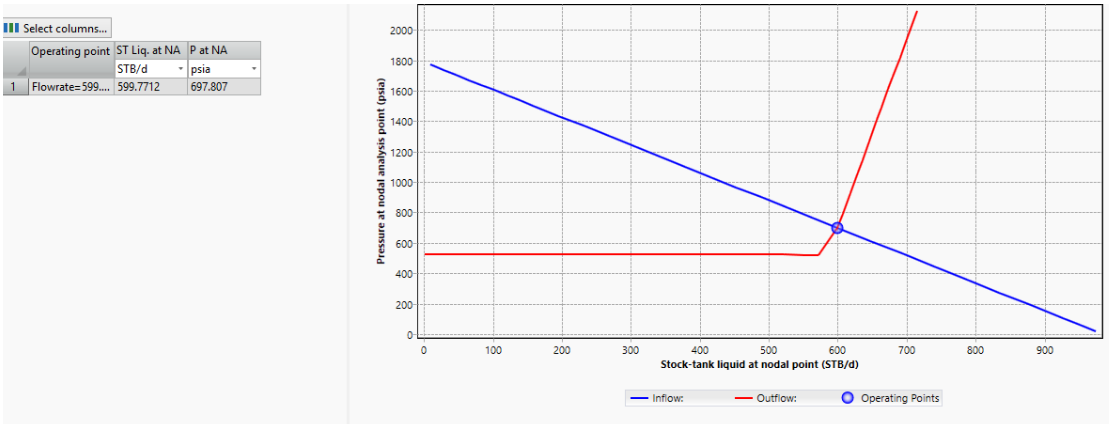


Figure (4.12) nodal analysis for Well Fula Centre-15

The figure 4.13 illustrate operation Pressure and flow rate for Fula Centre-16

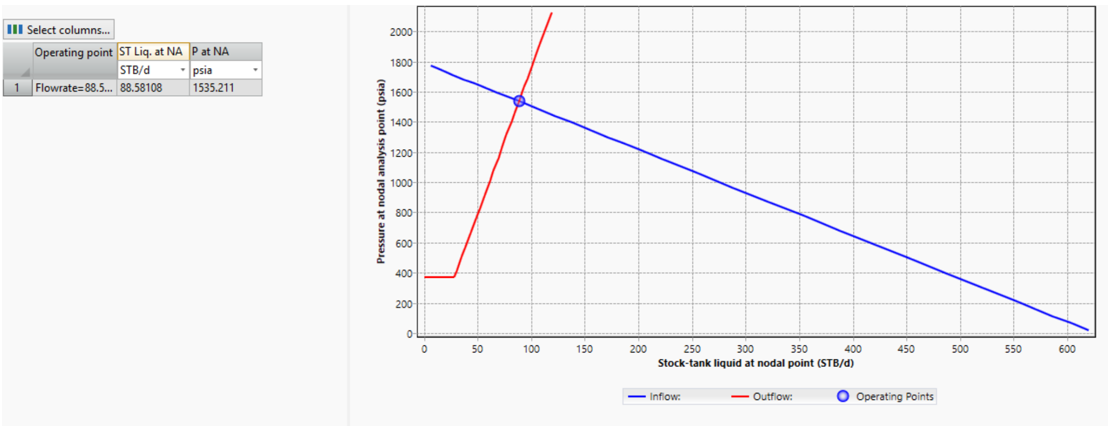


Figure (4.13) nodal analysis for Well Fula centre-16

The figure 4.14 illustrate operation Pressure and flow rate for Fula Centre-18

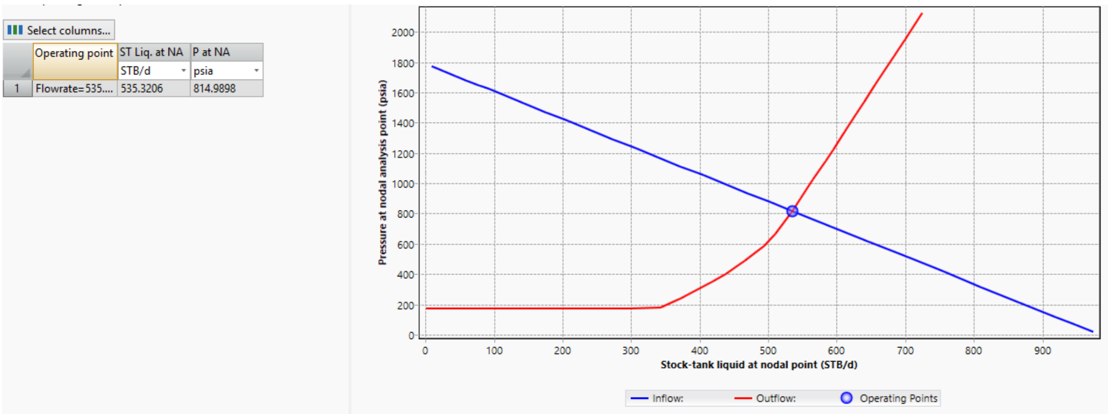


Figure (4.14) nodal analysis for Well Fula Centre-18

The figure 4.15 illustrate operation Pressure and flow rate for Fula Centre-19

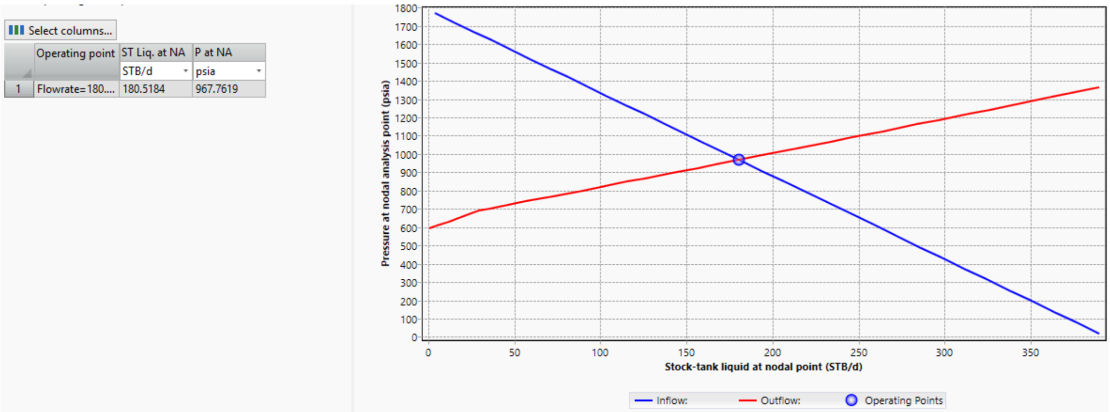


Figure (4.15) nodal analysis for Well Fula Centre-19

The figure 4.1.4.8 illustrate operation Pressure and flow rate for Fula Centre-20

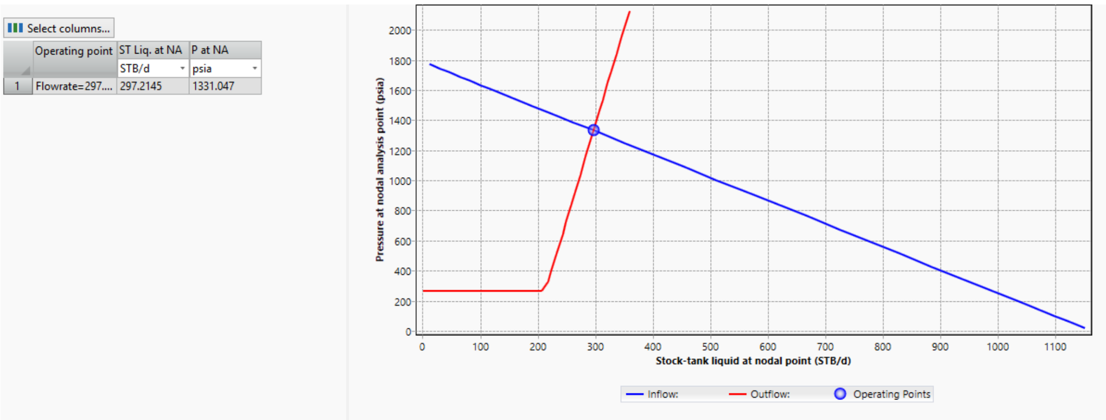


Figure (4.1.4.8) nodal analysis for Well Fula Centre-20

The figure 4.16 illustrate operation Pressure and flow rate for Fula Centre Horizontal-02

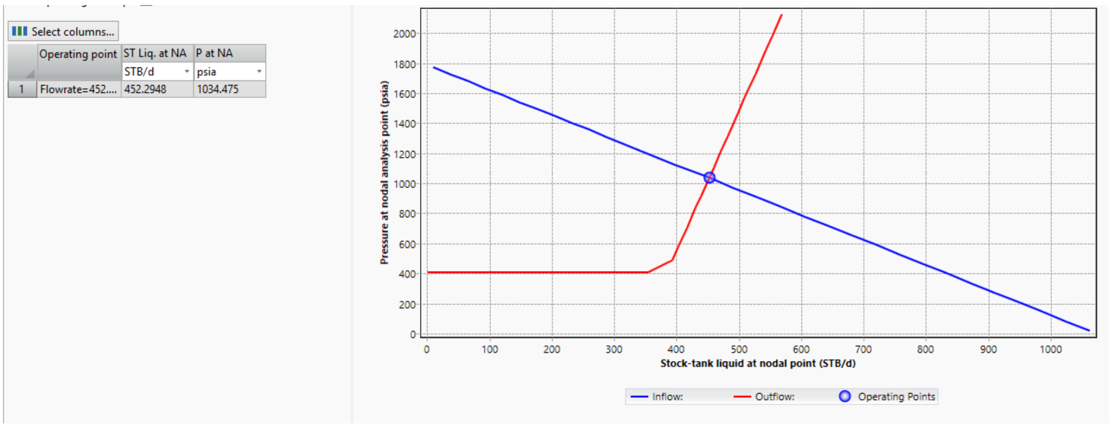


Figure (4.16) nodal analysis for Well Fula Centre H-02

The figure 4.17 illustrate operation Pressure and flow rate for Fula North-4-5

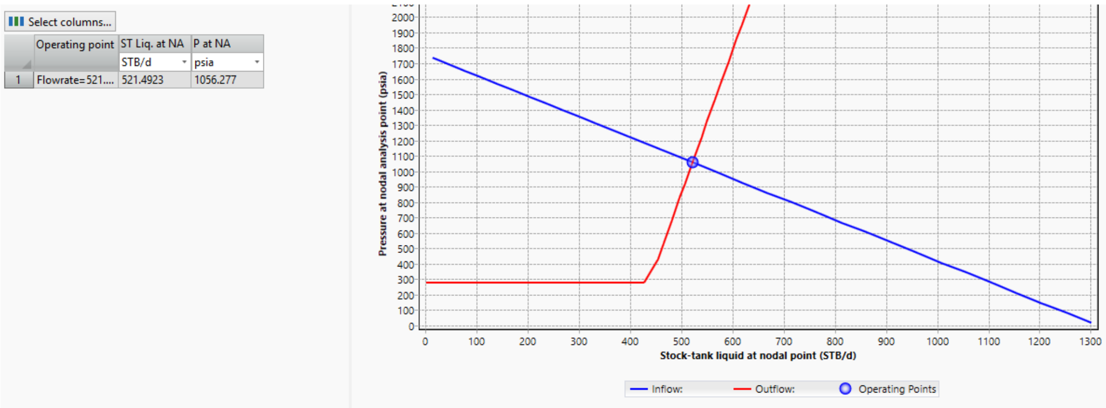


Figure (4.17) nodal analysis for Well Fula North-4-5

The figure 4.18 illustrate operation Pressure and flow rate for Fula North-90

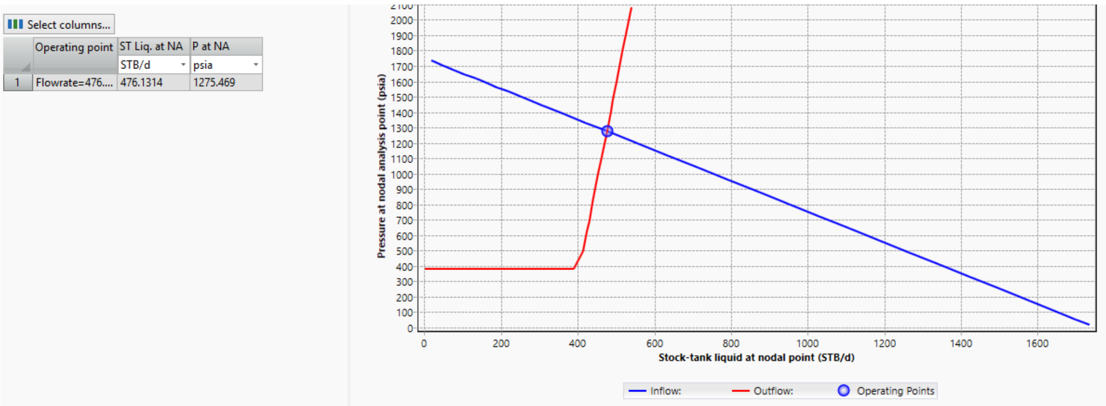


Figure (4.18) nodal analysis for Well Fula North-90

The 4.19 figure illustrate operation Pressure and flow rate for Fula North-105

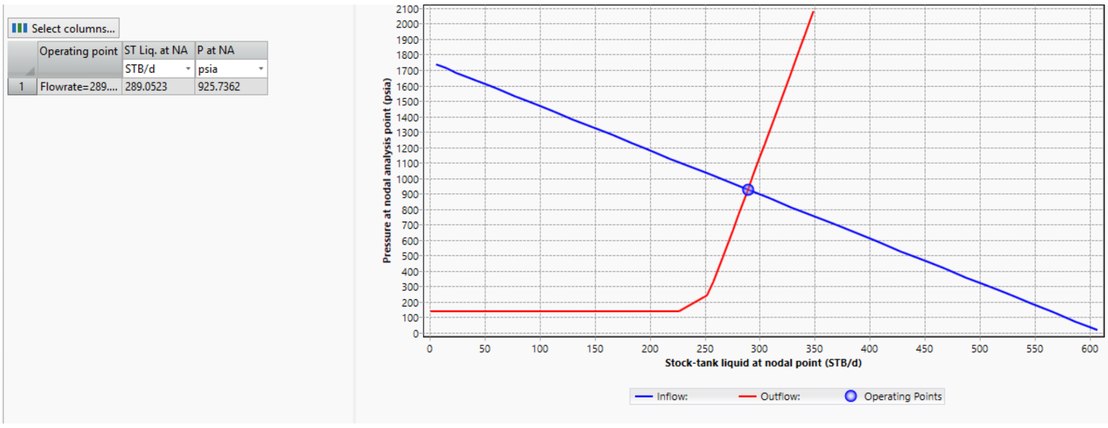


Figure (4.19) nodal analysis for Well Fula North-105

The figure 4.20 illustrate operation Pressure and flow rate for Fula North-124

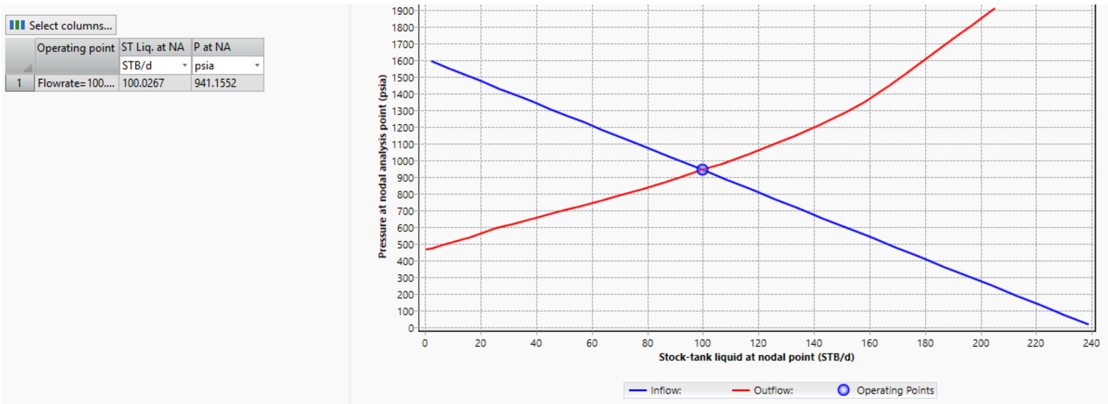


Figure (4.20) nodal analysis for Well Fula North-124

The figure 4.21 illustrate operation Pressure and flow rate for Fula North-126

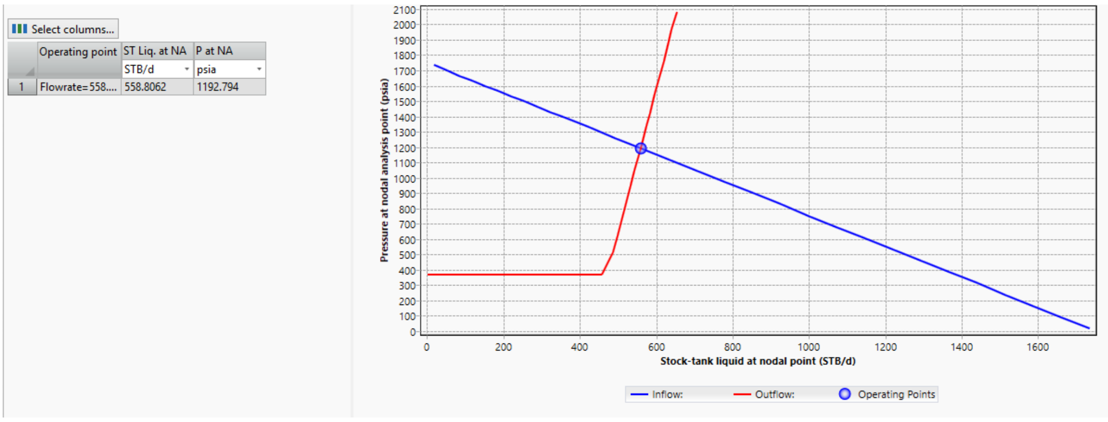


Figure (4.21) nodal analysis for Well Fula North-126

The figure 4.22 illustrate operation Pressure and flow rate for Fula North-149

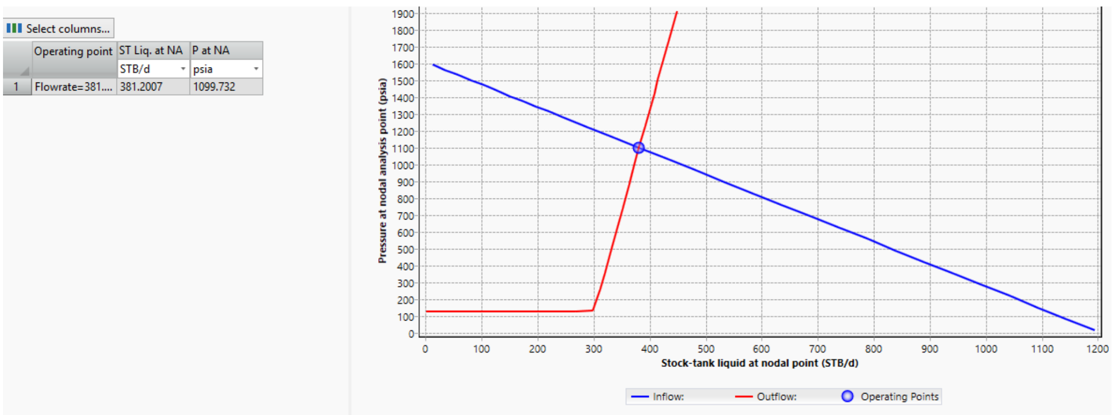


Figure (4.22) nodal analysis for Well Fula North-149

The figure 4.23 illustrate operation Pressure and flow rate for Fula North-151

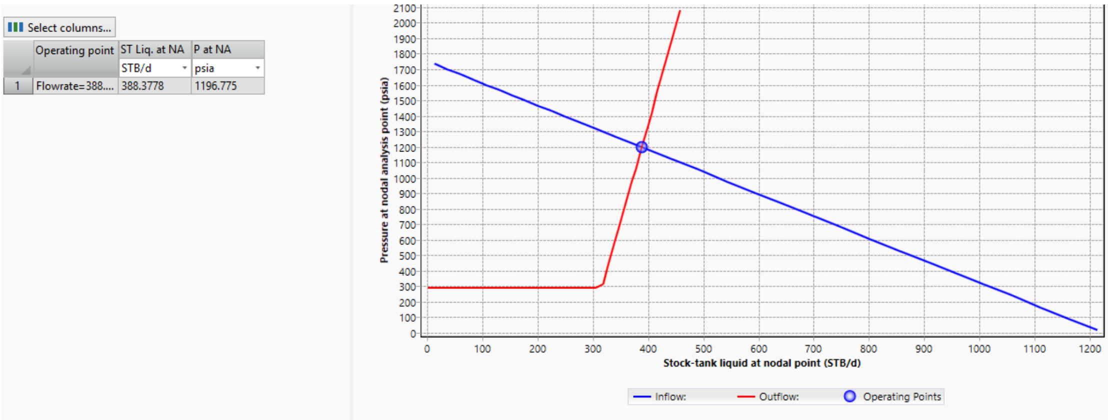


Figure (4.23) nodal analysis for Well Fula North-151

The figure 4.24 illustrate operation Pressure and flow rate for Fula North-152

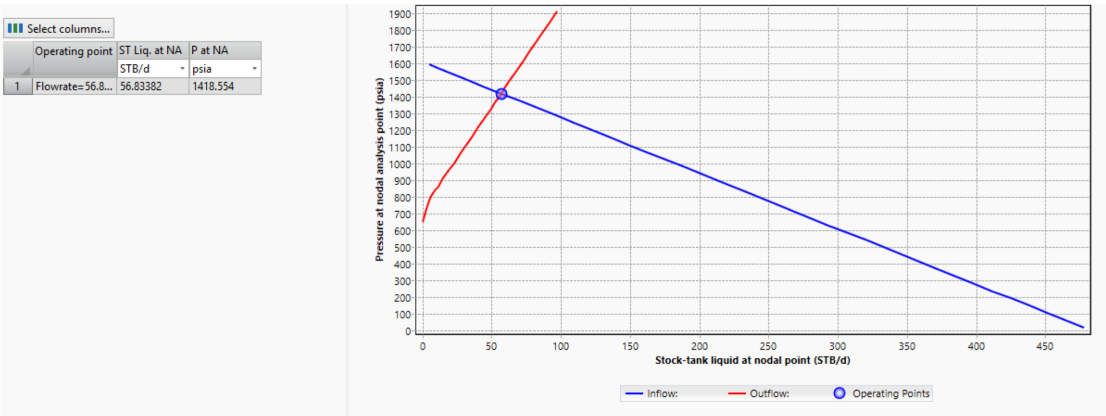


Figure (4.24) nodal analysis for Well Fula North-152

The figure 4.25 illustrate operation Pressure and flow rate for Fula North-153

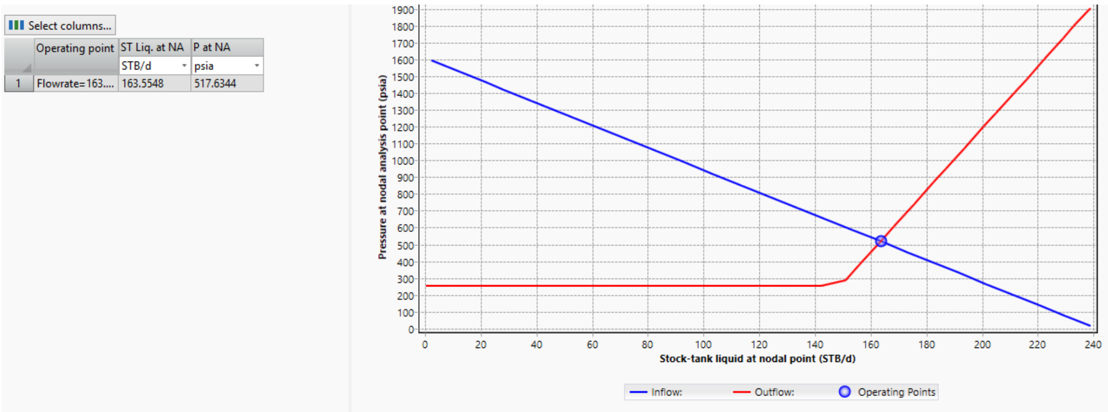


Figure (4.25) nodal analysis for Well Fula North-153

The figure 4.26 illustrate operation Pressure and flow rate for Fula North-157

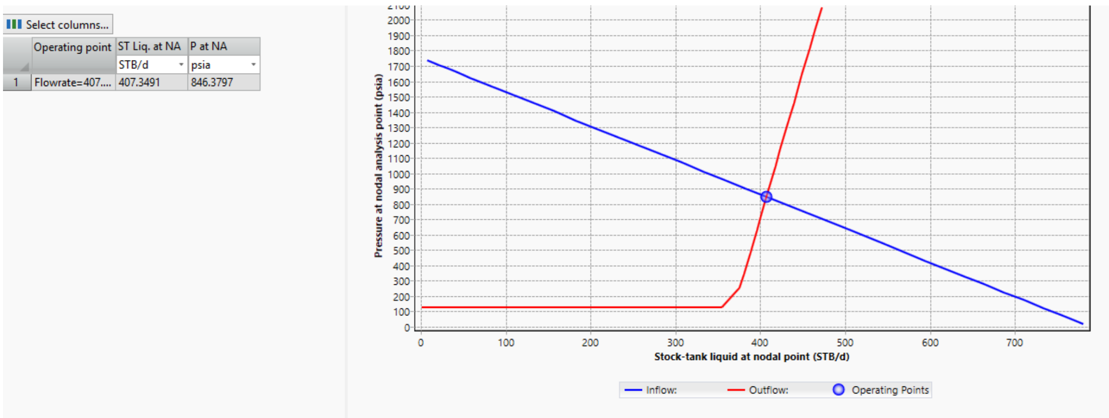


Figure (4.26) nodal analysis for Well Fula North-157

The figure 4.27 illustrate operation Pressure and flow rate for Fula North-161

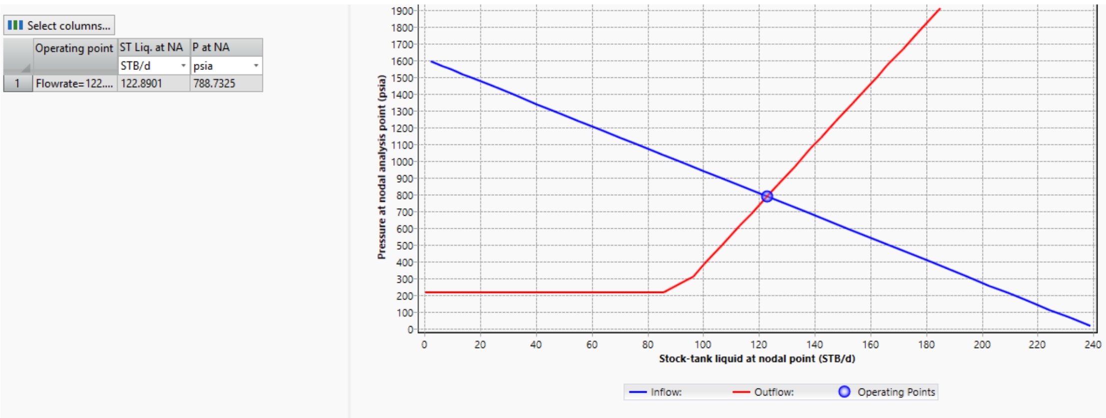


Figure (4.27) nodal analysis for Well Fula North-161

4.5 Pressure Difference results:

The OGM-5 and OGM-7 which have excessive pressure in comparison with the model pressure 38% and 7% deference respectively which may cause reduction in production rate for the connected wells, it was found that adding transfer pump or chemical injection to OGMs may reduce the back pressure as well as cleaning the OGMs truck lines by hot water or using pigging technique so as to enable us reduce the back pressure or de-bottleneck.

Table 4.1 illustrate comparison between the actual data and the model data in term of pressure

4.1 illustrate measured pressure VS Simulation pressure:

	P measured	P simulation	Error %
OGM-5	185	115	38
OGM-7	109	101	7
Sink_1	85	75	12
FC-1	102	115	-13
FC-10	116	94	19
FC-13	115	64	44
FC-15	108	112	-4
FC-16	98	102	-4
FC-18	139	112	19
FC-19	140	113	19
FC-20	198	115	42
FC-H2	175	145	17
FN-105	114	113	1
FN-126	99	104	-5
FN-149	115	124	-8
FN-151	124	116	6
FN124	117	143	-22
FN-152	94	100	-6
FN-153	111	114	-3
FN-157	94	92	2
FN-161	96	92	4
FN4-5	105	147	-40
FN-90	117	105	10

Table (4.1) Simulation and Measured Pressure

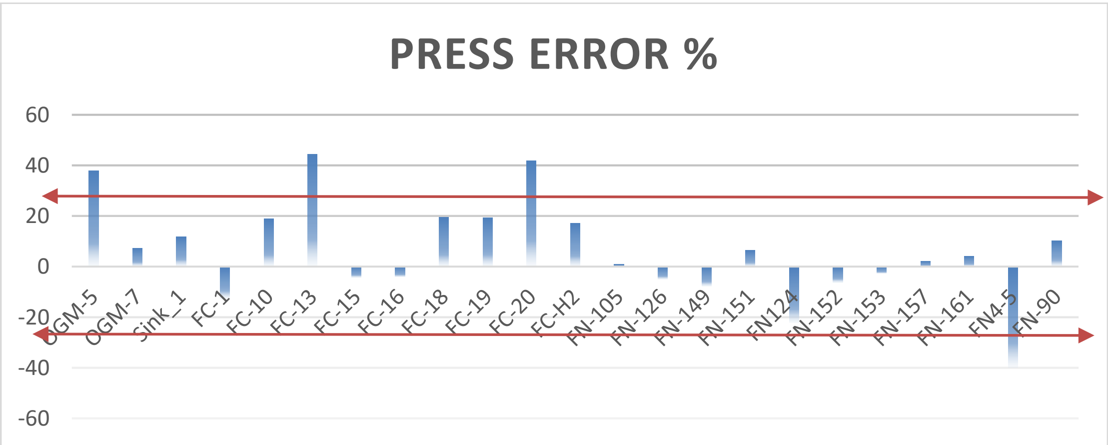


Figure (4.28) Simulation and Measured Pressure

Chapter five…Conclusion and Recommendation

Chapter 5 Conclusion and Recommendation:

5.1 Conclusion

- Fula Field model which comprise surface flowlines network and wells have been successfully constructed.

- Fula Field surface flowlines network deliverability was investigated in the current operation condition.

- The more economic and effective network de-bottlenecking was successfully assessed.

- Additional net oil gains of approximately 375 BOPD is expected.

- Net production gain by the above production optimization can assist and share to sustain and increase Fula field production rate for coming years.

- The models are for field optimization under different operation condition and should be updated regularly.

- This study confirms that modeling network analysis can help to bring production closer to the technical potential of the field production, it can help to identify the impact that all changes together have on the performance of the network.

5.2 Recommendation:

- As this studies focus on identifying actual bottlenecks and future bottlenecks, accurate representation of the network is crucial.

- Good data is the key to success and that design data of equipment and pipelines alone is not sufficient.

- If actual performance data is not available, performance testing prior these type of studies will be highly required.

- It's crucial that the client is a member of the study team.

- Precise of input the data in the network is crucial to gain reasonable result.

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Appendixes