Sudan University of Science and Technology

College of Post Graduate Studies

Department of Petroleum Engineering

Thesis Title:

Production optimization of Sufyan Oil Field in Sudan

عنوان البحث:

الإنتاج الأمثل لحقل سفيان النفطي بالسودان

A Thesis Submitted to the College of Graduate Studies as partial fulfillment for the Degree of Master of Science in Petroleum Engineering

Student:
Hussam Eldeen Ahmed Mohammed Abdorhman

Research Supervisor:
Assistant Professor. Fatima Ahmed Elberir

Oct 2020

الاستهلال

قال تعالى: (اقْرَأْ وَرَبُّكَ الْأَكْرَمُ (3)الَّذِي عَلَّمَ بِالْقَلَمِ (4) عَلَّمَ الْإِنْسَانَ مَا لَمْ يَعْلَمْ (5))

Declaration

I confirm that the work entitled **Production optimization of a Sudanese oil Field -Case Study for (Sufyan Field)** contains no material previously published by any other person except where due acknowledgment has been made. This thesis contains no material which has been accepted for the award of any other degree or diploma in any university.

Name: Hussam Eldeen Ahmed Mohmmed

Signature: **Date 02/Oct/2020**

Declaration

I'm **Dr. Fatima Ahmed ELberir** confirms that the work entitled **Production optimization of a Sudanese oil Field -Case Study for (Sufyan Field)** is an original work prepared by **Hussam Eldeen Ahmed.** The work was submitted to the College of Graduate Studies as a partial fulfillment for the Master Degree of Science in Petroleum Engineering. I hereby certifies that the work was prepared under my direct supervision; also I declare that to the best of my knowledge, the thesis does not contain any previously published material, except where this is appropriately cited through full and accurate referencing. Therefore, the researcher is allowed to submit this work as a final dissertation report.

Supervisor: Dr. Fatima Ahmed ELberir **Date: 02/Oct/2020**

Declaration of Copy rights

I am **Hussam Eldeen Ahmed Mohmmed** the author of this thesis, I transfer the copy, distribute and publish to the college of graduate studies Sudan university of science and technology

Name: Hussam Eldeen Ahmed Mohmmed

Signature: **Date 02/Oct/2020**

DEDICATION

To my beloved country, our soul is profoundly established and grown here, and we will never quit our visionary view to see SUDAN great to where it belongs.

To those who sacrificed their lives for the greater good of our nation.

To my family, whom supported me endlessly. Specially my mother, my father, my wife, my mother in law and my sisters, those who stood behind my back bushing me to be better and better.

AKNOWLEGMENTS

I would honorably send my gratitude to our sincere mentors throughout the Msc program, for them all I proudly stand here because of you and what you have done.

My sincere gratitude for my supervisor throughout my undergraduate academical studies and definitely post graduate studies assistant professor Fatima Elberir, whom, she spares no efforts to support and mentor me through this research.

To my team-mate and my cross-shift Mr. Mohanned Mahgoup, who shared his views, discussions and not least his experience with me, resulting in describing fully the potential possibilities of production optimization in this study.

Table of Contents

ABSTRACT XI

تجريد XII

Chapter 1 Introduction 2

1.1 General Introduction: 2

1.2 Problem Statement: 2

1.3 Research Objective: 3

1.4 Field Overview: 3

Chapter 2 Literature review 6

2.1 What is Production Optimization? 6

2.2 Production and Well potential: 6

2.3 Production System and analysis: 8

2.4 Other Previous Studies for Production Optimization: 9

2.5 Artificial Lift Review: 10

2.5.1 Progressive Cavity Pump: 10

2.5.2 Rod Pump: 11

2.6 Artificial lift selection: 12

2.7 Types of Network Systems: 12

2.8 Optimization approaches: 14

2.8.1 Simulation approach: 14

2.8.2 Optimization approach: 14

2.9 Flow Equilibrium in Production Networks: 14

2.10 Finding Optimum Operating Conditions (Controls) of an existing Production System: 15

Chapter 3 Methodology 17

3.1 Introduction 17

3.2 Data Collection from Sufyan oilfield 17

3.3 Model preparation 20
3.4 Model Calibration: 20
3.4.1 Fluid Model Calibration: 20
3.4.2 Inflow Performance Calibrations 21
3.4.3 Calibrating flow in the wellbore 22
3.4.4 Tubing Performance Calibration: 24
3.4.5 Well calibration for equipment setting: 25
3.5 Optimization for Field Network: 28
3.6 Economic Evaluation for optimization scenarios: 30
Chapter 4 Results and Discussion 32
4.1 Introduction: 32
4.2 Pressure data matching: 32
4.3 General Results Outlines: 33
4.4 Model Scenarios Result: 35
4.4.1 Sufyan-W6 Scenarios: 36
4.4.2 Sufyan-E-02 Scenarios: 37
4.4.3 Higra-01 Scenarios : 38
4.4.4 Suf-N3 scenarios: 38
4.4.5 Suf-SE01 Scenarios: 39
4.4.6 Suf-03 Scenarios: 40
4.5 Overall Scenarios Result: 41
4.6 Economic Evaluation for optimization scenarios: 42
Chapter 5 Conclusions and Recommendations 46
5.1 Conclusions: 46
5.2 Recommendations: 47
References 48

List of Tables

Table 2-1: Lift method selection matrix (Sandy Williams, 2008) 12

Table 3-1: Wells coordinates OGMs tied-in to..........31

Table 3-2: Wells density of produced fluid with API and Viscosity measured at lab 32

Table 3-3: General data used to build model..........19

Table 3-4: Calibration parameters and their functions..........21

Table 3-5: Artificial lift types and their recommendation for tuning parameters (pipesim software) 25

Table 4-1: Comparison between all scenarios. 41

Table 4-2: Estimated cost for workovers (Sufyan workover history data) 42

Table 4-3: Estimated Capex and Opex for optimization scenarios..........43

List of Figures:

Figure 1: Sufyan field structures (Sufyan Production Performance Review, Nov. 2016). 4

Figure 2: (A) Production Potential Calculation VS (B) Well Potential Calculations. Stanko (2019)..........7

Figure 3: Effect of declining reservoir performance on production. (Petrosreamz, 2016)..........8

Figure 4: IPR curve Stanko (2019)..........8

Figure 5: Layout of two Production Systems (Stanko, 2019)..........9

Figure 6: Schematics of two hierarchical networks (Economides et.all. 2007)..........13

Figure 7: An example of nonhierarchical network (Economides et.all. 2007)..........13

Figure 8: Production Network with 3 Wells available Junction Pressure Curve for Three Wells and Required Junction Pressure Curve for The Pipeline (Stanko 2019) 15

Figure 9: phase behavior for different compositional and block oil model (PIPESIM 2017.2 software help notes)..........21

Figure 10: Using multipoint to calculate PI (Pipesim software)..........22

Figure 11: Kudu 98k 1200EW PCP Slip, Head and Rate factors (Pipesim software) 27

Figure 12: Pressure profile of an ESP lifted well 28

Figure 13: Optimization algorithm flow chart (Stanko, 2019) 29

Figure 14: Static gradient survey for Suf-03 data matching....32

Figure 15: Overall network pressure profile for OGMs to Hadida FPF 34

Figure 16: Overall network simulation result showing pressure profile from wells....35

Figure 17: Sufyan-W6 (WD1500) case....36

Figure 18: Sufyan-W6 (WD850) case....36

Figure 19: Sufyan-W6 (PCP 45E2400) case 36

Figure 20: Sufyan-E-02 (WD1500) case....37

Figure 21: Sufyan-E-02 (PCP 45E2400) case 37

Figure 22: Higra-01 (PCP 45E2400) case 38

Figure 23: Suf-N3 (WD850) case 39

Figure 24: Suf-N3 (PCP 45E2400) case....39

Figure 25: Suf-SE-01(ESP) case 39

Figure 26: Suf-SE-01 (PCP 45E2400) case 40

Figure 27: Suf- 03 frequency increment case 40

Figure 28: Comparison between all scenarios....42

Figure 29: Production per each optimization scenario....43

Figure 30: NPV result per each optimization scenario....44

Figure 31: NPV result per each optimization scenario showing payback period (Step is monthly 44

ABSTRACT

Production problems encountered during field life vary in its complexity and its. Production optimization is considered vital factor in which production challenges are analyzed and several proposals are considered to tackle problems. Many Sudanese oil field suffer from production decline due to various problems such as artificial lift malfunctions and design difficulties. Therefore, Sufyan field was selected to this study due to sharp production decline caused by such problems. The Sufyan field is located is western side of Block 6, Sudan. Sufyan area for the time being, the field consist of twelve structures with proved oil. Production started on Mar.15, 2015 from Suf-1 and EPF Start pumping fluid on 20. Apr, 2015. The research studied the artificial lift performance in Sufyan wells after production network model was initiated, considering artificial lift factors; in which pump sizing was main factor. The low performance pumps were replaced and multiple scenarios were applied to optimize and conclude the best remedy action to be proposed. Optimum scenario was therefore selected; consider overall production increment by 2000 BOPD and 14 % decrement in cost due to artificial lift change.

تجريد

تتعدد مشاكل الانتاج التي تواجه استمراريته علي طول فترته وتختلف في تعقيداتها وتأثيرها. تعتبر أمثلة الانتاج من العوامل الحيوية والتي يتم فيها تحليل معوقات الانتاج وتقديم مقترحات للتعامل مع المشاكل. عديد من الحقول السودانية عاني من انخفاض الانتاج لاساب متعددة منها تعطل الرفع الصناعي وما يصاحبه من مشاكل وصعوبات التصميم المصاحبة. ولهذا السبب تم اختيار حق سفيان لهذه الدراسة بسبب الانخفاض الكبير في الانتاج بسبب هذه المشاكل. يقع حق سفيان في المنطقة الغربية من مربع 6 النفطي. في الوقت الحالي يتكون الحقل من اثناعشر تركيب طبقي مثبت احتواءه علي النفط. بدأ الانتاج منه في 15 مارس 2015 من بئر (Suf-01). بدأ تدفيع الخام من محطة المعالجة المبكرة في 20 ابريل 2015 .تناول البحث اداء طلمبات الرفع الصناعي في حق سفيان بعد ان تمت نمذجة لشبكة الانتاج مكتملة. وأخذ في الاعتبار عوامل الرفع الصناعي والتي من اهمها حجم الطلمبات المستخدم. الطلمبات ذات الاداء المنخفض تم استبدالها وعدد من السيناريوهات تمت نمذجته للوصول للانتاج الامثل وتقديم مقترح بالمعالجات المطلوبة. تم بعدها اختيار افضل سيناريو للانتاج محققا زيادة في الانتاج باكثر من 2000 برميل ونقصان في التكلفة بحوالي 14%.

Chapter 1
Introduction

Chapter 1 Introduction

1.1 General Introduction:

Production optimization means determination and implementation of the optimum values of parameters in the production system to maximize hydrocarbon production rate (or discounted revenue) or to minimize operating cost under various technical and economic constraints. Production optimization can be performed at different levels such as well level, platform/facility level, and field level. (Economides et.all. 2007)

Maximizing production from oil fields is considered to be one of the necessary tasks to be carried out. Integrated network modeling and optimization is then considered to be one of the most effective tools and promising studies, since, it uses already existed facilities to maximize network production and tackle back pressure and bottlenecking occurs during hydrocarbon extraction and production. It is not reliable to only depend on operational intuition and empirical field practice for individual ESP control. Rather, a model-based optimization system has been implemented, taking into account all field and well constraints. (Stanko, 2015)

In this study, production modeling for Sufyan filed existing facilities and optimization is carried out to overcome artificial lift challenges, where performance of current lifting pumps is evaluated to decrease deferment of oil caused by improper selection and sizing for artificial lift. Sufyan field is located far west in Block 6 and the nearest processing facility is away by more than 50Km from the early production facility (EPF) and 37Km from the oil gathering manifold No 3 (OGM3) (closest OGM to Hadida Field Processing Facility). Which creating additional constraint factor challenging production and require surface boosting pump to be used to reduce excessive head from lifting pumps.

1.2 Problem Statement:

The production of Sufyan field has fluctuated and decreased sharply, caused by pumps failure due inaccurate pump sizing and selection and other operation issues. Other factors such as high wax content as well as high pour point creating some obstacles and require specific jobs, flow line flushing to be carried out regularly which creates unsteady flow of hydrocarbon to the processing facilities. Further, due to sub-fields location and distance some of Sufyan field wells are joined directly to EPF and Hadida FPF which creates additional flow constraint factor to the field production. Moreover, instability of production mainly due to fast pressure decline. The network aimed to propose proper sizing for artificial lift pump and investigate failures occurred to eliminate improper sizing issues, while studying ESPs and PCPs running frequencies to ensure that frequencies applied are best of its possible adjustment to maximize production. The study will be carried out using a commercial multiphase flow simulator for production and network modeling and optimization.

1.3 Research Objective:

I. Study SUFYAN field production and analyze its performance throughout field life.
II. Build an integrated network modal for downhole components and surface facilities for the field.
III. Study current production performance for Sufyan field and investigate artificial lift performance.
IV. Identify and conclude best production scenario to be implemented in the field.

1.4 Field Overview:

Sufyan field is located is western side of Block 6, Sudan. Sufyan area for time being is consist of nine (12) structures with oil discoveries (Suf-1, Sufyan S, Suf E-1, Suf N-1, Suf SE-1, Sufyan E-1, Nassma-1, Sufyan W-1, Sufyan-3, Suf S, Higra-1 and Sufyan NW).

Production started on Mar.15, 2015 from Suf-1 and EPF Start pumping Fluid on 20.Apr, 2015, during April and May, 2015 one by one commission for Sufand Sufyan Wells and accordingly the production increase gradually. Abu Gabra formation is the primary target (light crude with high pour point and wax content) while Bentiu is the secondary target (medium heavy crude with low pour point). Crude oil is generally light at all fields (36-42 API), high pour point (36-51OC) and high wax content (10-35%). Generally, AG reservoirs are receiving poor aquifer support. Major reasons for Sufyan Production instability are fast pressure decline as result of small structures (within one-year pressure decline from 4500 psia to 3400 psia) besides artificial lift failure. As per 31, Dec, 2017, total fluid production: 5743 BLPD (Barrel of liquid per day) Oil: 5392 BOPD (Barrel of oil per day) and average WC: 6.1 %. Till 31-Mar 2018, 22 wells had been commissioned, 19 wells are active, 1 well intermittent producer and 2 wells are Idle. Pump systems (ESP, PCP and BPU) are used as artificial lift.(Sufyan Production Performance Review, Nov. 2016).

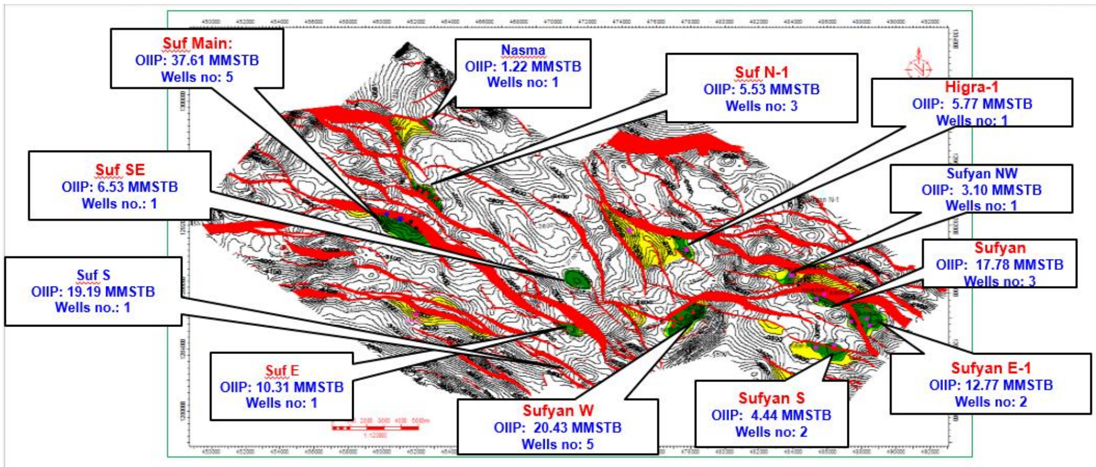

Figure 1.1: Sufyan field structures (Sufyan Production Performance Review, Nov. 2016).

Many problems challenging Sufyan field production, complexity of production and artificial lift types used is one of these challenges; where PCP, ESP and BPU are all used. Moreover, a significant pressure variation between wells and in accordance the productivity difference is challenging the optimization of this field.

For many wells artificial lift has been selected based on well conditions, top of liner, for instance, hindering lowering ESP closer to perforation. While sharp decline in pressure, make it necessary to replace ESP by shallow positioned PCP and later BPU used to enhance lifting capacity for these wells. Changing the artificial lift used is interrupting production and creates additional deferment for production.

Chapter 2
Literature review

Chapter 2 Literature review

2.1 What is Production Optimization?

In order to optimize the value of an asset it is necessary to understand the performance of the system by building a model. This model helps to understand well performance and conduct well analysis and can then be used to optimize the system by modeling the effects of changes in the reservoir inflow performance, produced fluids, and production system parameters for a single well or a complete field. In which entire production system elements (Pumps, flowlines, compressors, and downhole tools and equipment) are analyzed as one unit. In addition to that, any one of these segments should be evaluated separately. The performance of the production string is modeled by generating a vertical lift performance (VLP) curve which combines with the IPR to define the total well performance.

Hanssen, et, all (2015) highlighted “Production optimization” as study for production uncertainties, where model should be built to deal with production deferment caused by these challenging uncertainties.

Satyendra, et al, (2006) considered that the optimization for production ensures that wells and facilities are operating at their peak performance to maximize production at all times. Considering that the complexity of maintain the asset tuned to the optimal operating conditions.

For a particular time “t” there will be either a unique rate that the field can produce (if there are no adjustable elements in the system or they have a fixed setting) or a maximum rate that the field can produce (if there are adjustable elements). Stanko (2019), refers to this unique or maximum rate that the field can produce at a given point in time as: “production potential”. The two systems (reservoir and production system) are governed by different physical phenomena. However, the performance of the field is defined by the interaction between these two systems. From reservoir side, production system defines as back pressure acting against sand face. When seen from the production system side, the reservoir defines the amount of fluids coming into the well (well productivity).

2.2 Production and Well potential:

Stanko (2019) discussed the difference between production potential and well potential in every time step by the reservoir simulator. The well potential is “the producing rate obtained when the minimum bottomhole pressure is applied on the well boundary” (Stanko, 2019). To illustrate how the difference between two concepts, consider a single well system in which wellhead pressure is kept constant. The well potential of the reservoir simulator is estimated using a constant bottom hole pressure as shown in Figure 2(B), only taking into account the reservoir deliverability (inflow performance relationship). The production potential is calculated by performing a hydraulic equilibrium calculation at the bottomhole intersecting the IPR and tubing performance relationship (TPR) shown in Figure 2(A). These two values will be equal only when the minimum bottomhole pressure specified equals the equilibrium bottomhole pressure (in the fig. when pR = pR3). For the other IPRs however, the production potential is over predicted, this example of illustration is given by (Stanko, 2019).

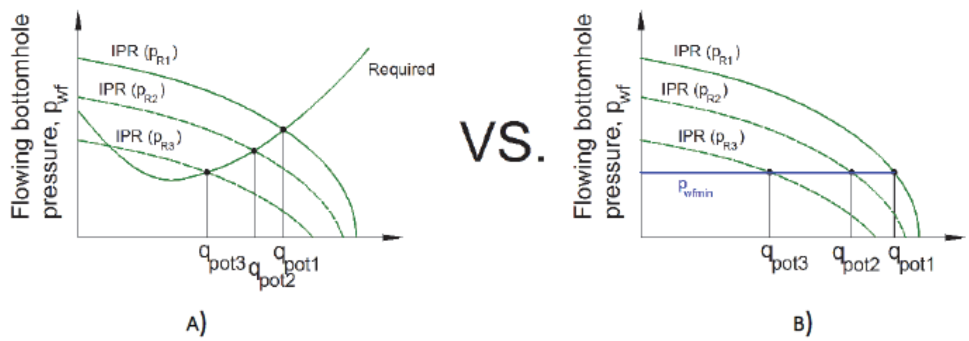

Figure 2: (A) Production Potential Calculation VS (B) Well Potential Calculations. Stanko (2019)

Therefore, the decrease in reservoir deliverability causes a decrease in production potential with time, while, consider changes in the production system can increase or decrease the production potential with time, depending on the type of change.

Analyzing the reservoir pressure decline effects is best done downhole using intake pressure curve, assuming the PI remains constant (no impairment) while the reservoir pressure declines, then as shown in Figure 3, The corresponding change in production could be calculated. For instance, another (usually smaller) tubing size will need to be installed if pressure declines too far.

J. D. Jansen et. all, (2009), concluded that by plotting the intake pressure curve for this tubing on the same figure, it will be possible to see for how long this will extend the life of the well, and whether the cost is justified in terms of the extra oil recovered.

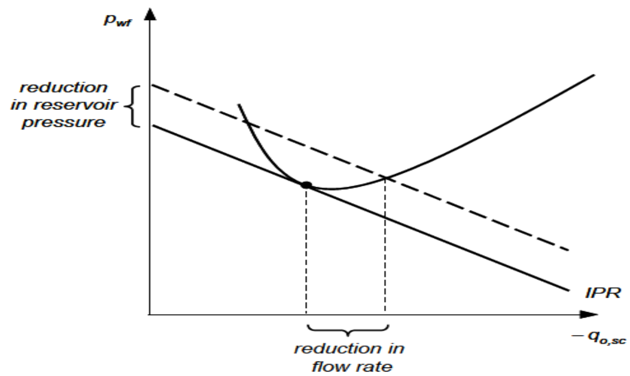

Figure 3: Effect of declining reservoir performance on production. (Petrosreamz, 2016)

2.3 Production System and analysis:

The interaction between the various elements in a single-phase fluid flow network can usually be described in terms of two pairs of variables: pressure and flow rate, and temperature and heat flow. They are examples of pairs of effort and flow variables, concepts which play a key role in the branch of engineering known as systems dynamics. (Petrosreamz, 2016)

The well inflow is typically represented by an IPR equation (Inflow performance relationship) that provides the bottomhole pressure that has to be applied at the sand face to deliver a specific standard condition rate (Figure 4). The IPR describes the reservoir deliverability for a given depletion state and assuming that a pseudo-steady state has been reached in the reservoir. Satyendra, et al, (2006) argued that many optimization approaches are both time consuming and error prone due to large data volume and complexity considered.

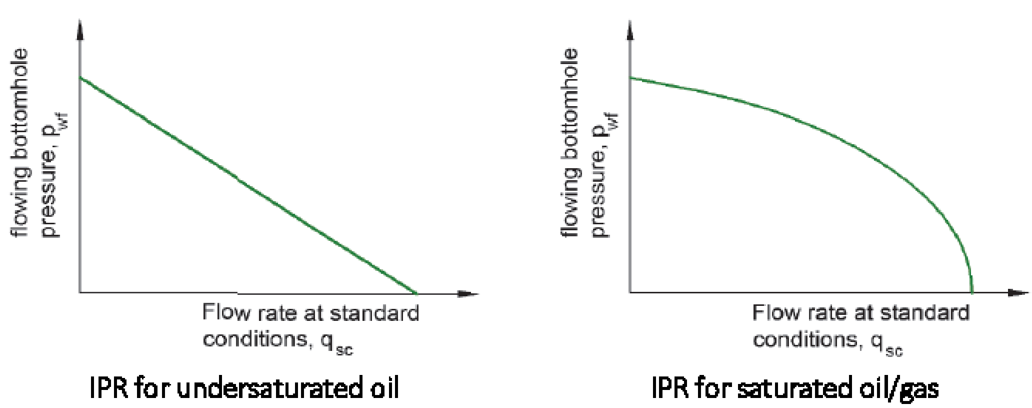

Figure 4: IPR curve Stanko (2019)

The flow in tubular conduits such as tubing, casing and pipelines are represented with equations that predict the temperature and pressure drops. Usually these equations use constant fluid properties, so a length discretization and a step wise calculation have to be performed to capture fluid behavior. The separator is represented by a constant pressure value. (Economides et.all. 2007).

The thermodynamic properties of reservoir fluids, like pressure, temperature, density or viscosity, can have a strong influence on the flow in a well and the production rate. A simplified model of two-phase hydrocarbon mixture behavior is the black oil model which is most widely used model. The black oil model is also a two-component model, which, however, assumes a constant composition of the gas phase and only accounts for compositional variations in the liquid phase. The standard reference for black oil correlations is Standing (1962), while many other correlations have been developed over the past half century. J. D .Jansen et, al, (2009) showed that when the fluid travels from the reservoir(s) (source) to the separator(s) (sink), it must overcome energy losses (e.g. pressure and temperature drop) and sometimes “compete” with other fluids in transportation conduits. In contrast with the reservoir, the field life analysis of a production system is performed assuming that changes in reservoir deliverability are slow enough so that the system progresses continuously from one steady state to another.

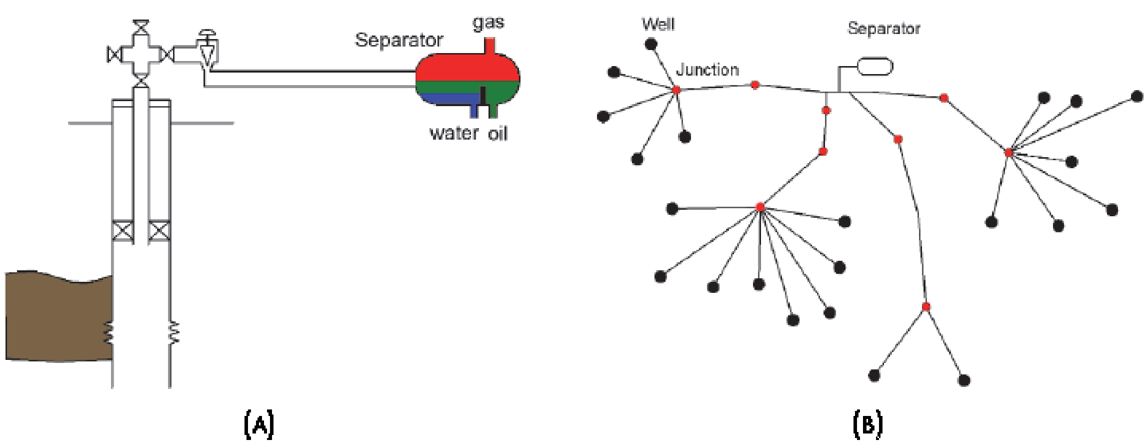

Figure 5: Layout of two Production Systems (Stanko, 2019)

2.4 Other Previous Studies for Production Optimization:

I. P. Aditama et. all (2010) concluded that wells productivity is affected be several factors. Those factors are overestimation of reservoir pressure or total reservoir permeability effective permeability, formation damage, reservoir heterogeneity, completion ineffectiveness (Shallow entry, limited access, low perforation density and restriction in wellbore (Paraffin, Asphaltene, scale, gas hydrates and sand).

Ayob (2013) claimed that production information for inflow such as reservoir pressure and temperature, fluid type and rock characteristics, and well information (well geometry, artificial lift) can be used to model production system. Since, model is built; any production problem could then be dealt with and rectified. Optimization objective is to find out which well component is restricting production rate from maximum possible rate.

Pengju et.al (2002) argued that major production increment could be obtained from production optimization. Simple model is used for single well, while more advanced systems are used for large complex systems. Significant production increase could be obtained through applying Network optimization. It may be worthwhile to analyze the incremental production after each step, in order to determine if it is worth implementing the more difficult and more expensive changes. In order to achieve a higher fidelity production model, the model should be regularly updated and calibrated with new well test data. A closed loop approach has been suggested to sustainably maximize the production over time. Network level optimizations are more realistic than well level.

2.5 Artificial Lift Review:

For some petroleum fields, optimization of production operations can be a major factor for increasing production rates and reducing production costs. While for single wells or other small systems simple nodal analysis can be adequate, large complex systems demand a much more sophisticated approach.

2.5.1 Progressive Cavity Pump:

PCPs are an excellent technology and most rapidly evolving technology in artificial lift market due to their high efficiency and low up-front capital investment which make this technology highly attractive, Williams (2008).

Major advantages of PCPs are its ability to handle solids while achieving high drawdown. The successful application for PCPs requires proper elastomer selection, rod sizing and pump design. The combination of rate and pressure pose additional difficulties for a PCP. Consider it is sensitivity to doglegs and well deviation. Gas oil ratio is considered as critical factor in PCP design, where the maximum GOR applicable for routine PCP is around 15% gas fraction according to Williams (2008), unless using gas separator or other techniques.

The objective of dynamic production optimization is to find the best operational settings at a given time, subject to all constraints, to achieve certain operational goal Challenging application of PCP in some Sufyan field wells is due to high TDH, low reservoir pressure and gas oil ratio, which hider the optimum utilization for this technology via available PCP models at field warehouse and stock.

2.5.2 Rod Pump:

Widely and in many of low productivity wells, Rod pump used successfully. Many would argue that Rod pump should be first choice as artificial lift method due to their advantages. Since, it can be run into liners or even below perforation level even with smaller casing size, which ensures volumes of natural gas are separated naturally. It is low flow rate production is providing additional preference for this pumping type in low productivity wells. However, it is considered unsophisticated, due to the calculation of free gas affection on pump is limited, compared with PCP and ESP design's software, Williams (2008).

2.5.3 Electrical Submersible Pump:

ESP can produce at high rate and achieve low bottomhole pressures. Yet, the ability to apply ESP in Sufyan filed is affected by liner casing depth and size, low reservoir pressures and solids production. Pumps (4.5" OD and above) are normally above casing liner 5" ID. Gas separator is used in some wells for gas handling. Solids caused many malfunctions lead to pump stuck of ESPs. Which requires workover to pull out ESP string and check pump. In addition to that, ESP accelerates water production and it was clear that water cut increases during many of ESP producing wells.

G. Vachon, (2005) described that the successful production via ESP depends on operating within optimum range for the pump. However, due to change in reservoir pressure over time, the ESP may not be able to continue producing within optimum range and its efficiency may drop to an unacceptable level.

Therefore, downhole monitoring sensors (for temperature and both pressures intake and discharge) are utilized to record parameters. Unfortunately, some downhole sensors are out of service in Sufyan ESP wells. It is necessary to tune ESP design in accordance to the weight of lifted fluid and total head required during well life, G. Vachon, (2005). This is dependent on well information. If the quality of data provided is poor (such as productivity index and reservoir pressure), the design will be questionable and will result in misapplied pump and costly operation.

In Sufyan field, many of ESPs used are producing below their optimum range. This is why main review for field production was regard ESP wells and their performance.

2.6 Artificial lift selection:

Williams, 2008 showed that many matrices are available for artificial lift comparison and selection Table 2-1. Those matrices are very general with wide range of operability. While for any field case small details could be crucial in selection of appropriate lifting method. However, the best way to select the most appropriate lifting method is by eliminate or de-select methods that are not applicable based on field and wells characterization.

Table 2-1: Lift method selection matrix (Williams, 2008)

	Rod Lift	Progressing Cavity	Gas Lift	Plunger Lift	Hydraulic Piston	Hydraulic Jet	Electric Submersible
Operating Depth	100' - 16,000' TVD	2,000' - 6,000' TVD	5,000' - 15,000' TVD	8,000' -	7,500' - 17,000' TVD	5,000' - 15,000' TVD	1,000'- 15,000' TVD
Operating Volume (Typical)	5 - 5000 BPD	5 - 4,500 BPD	200 - 30,000 BPD	1 - 5 BPD	50 - 4,000 BPD	300 - >15,000 BPD	200 - 30,000 BPD
Operating Temperature	100° - 550° F	75°-250° F	100° - 400° F	500° F	100° - 500° F	100° - 500° F	100° - 400° F
Corrosion Handling	Good to Excellent	Fair	Good to Excellent	Excellent	Good	Excellent	Good
Gas Handling	Fair to Good	Good	Excellent	Excellent	Fair	Good	Poor to Fair
Solids Handling	Fair to Good	Excellent	Good	Fair	Poor	Good	Poor to Fair
Fluid Gravity	>8° API	<35° API	>15° API	GLR Required 300 SCF/BBL/	>8° API	>8° API	>10° API
Servicing	Workover or Pulling Rig	Workover or Pulling Rig	Wireline or Workover Rig	Wellhead Catcher or Wireline	Hydraulic or Wireline	Hydraulic or Wireline	Workover or Pulling Rig
Prime Mover	Gas or Electric	Gas or Electric	Compressor	Wells' Natural Energy	Multicylinder or Electric	Multicylinder or Electric	Electric Motor
Offshore Application	Limited	Good	Excellent	N/A	Good	Excellent	Excellent
Overall System Efficiency	45% - 60%	40% - 70%	10% - 30%	N/A	45% - 55%	10% - 30%	35% - 60%

2.7 Types of Network Systems:

Hierarchical and Non-Hierarchical networks are common two types in production optimization. A Hierarchical network is defined “as treelike converging system with multiple inflow points (sources) and one outlet (sink)” see (Figure 6). Where flow direction is known and for the purposes of simulation nodal analysis could be used where sequential solving approaches are used such as PIPESIM.

A nonhierarchical network is defined as “a general system with multiple inflow points (sources) and multiple outlets (sinks)”. Due to loop existence flow direction in some portion may not be certain. See the (Figure 7) arrows in the figure represent flow directions determined by computer program. Simulation for such networks could be obtained using simultaneous solving approaches such as GAP, HYSYS.

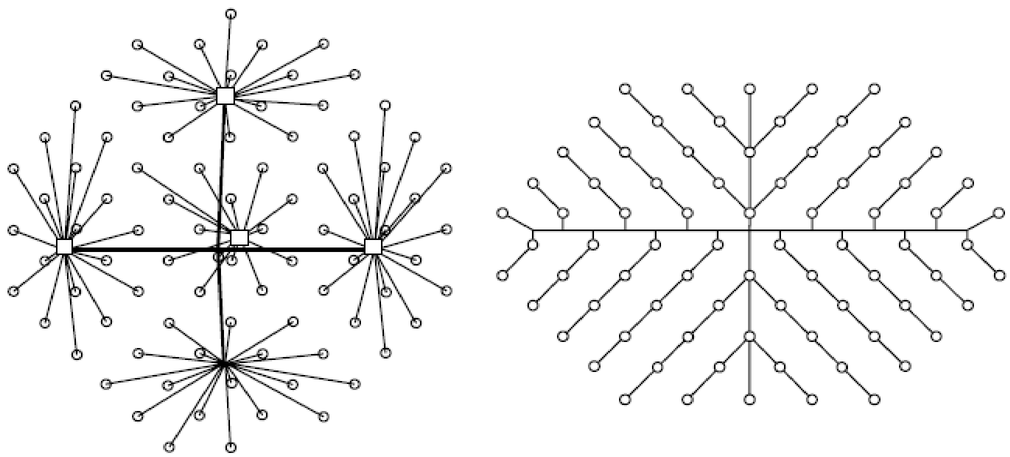

Figure 6: Schematics of two hierarchical networks (Economides et.all. 2007)

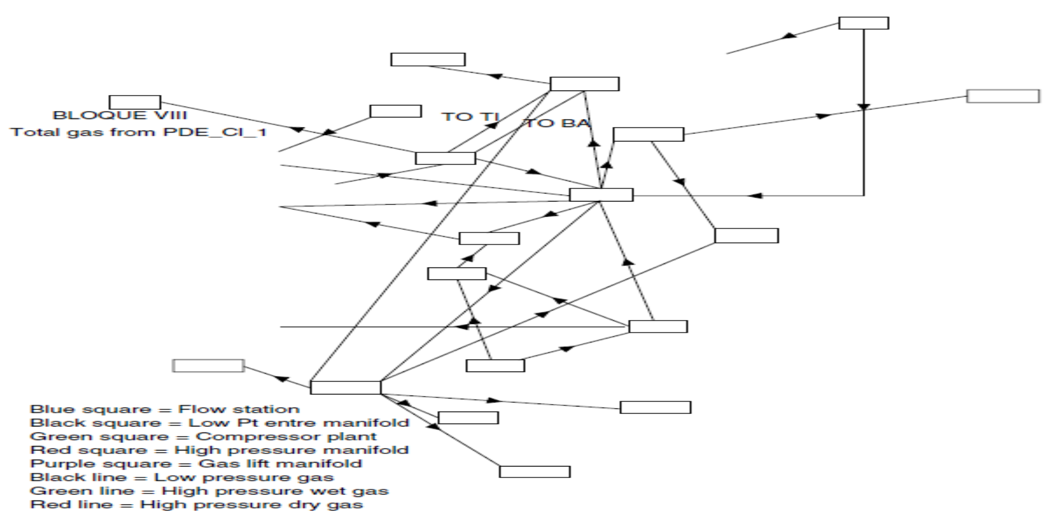

Figure 7: An example of nonhierarchical network (Economides et.all. 2007)

2.8 Optimization approaches:

Satyendra, et al, (2006) considered many optimization approaches are both time consuming and error prone due to large data volume and complexity considered. Measure- Calculate – control cycle tends to be more efficient as an optimization technique if it is tools are available for real time monitoring and controlling.

Two approaches for optimization are widely used for field level production optimization:

2.8.1 Simulation approach:

Computer program is used to simulate flow conditions (pressures and flow rates) where trial-and-error approach is used, fixed values of variables in each run is used. Input parameters are manually entered. Based on these parameters, different scenarios are investigated, where, optimum scenario is then selected from the results. Therefore, it is considered as more time consuming.

2.8.2 Optimization approach:

It is based on intelligence. J. D. Janson (2009) described this approach by, it allows computer to determine some parameters for each run. Parameter values are optimized to ensure maximum constraints. This approach is considered more efficient than simulation one

2.9 Flow Equilibrium in Production Networks:

For networks, a particular flow from a well could affect flow from other wells to some degree. Therefore, hydraulic interaction should be accounted for during optimization and modeling. Consider as an example the case shown in Figure 8 where there is a production system with three wells, a pipeline and a separator. The point is interest is defined as the junction where the production of the three wells is commingled. The available pressure curve is calculated for each well from the reservoir to the junction and the required pressure curve is calculated for the pipeline from the separator to the junction.

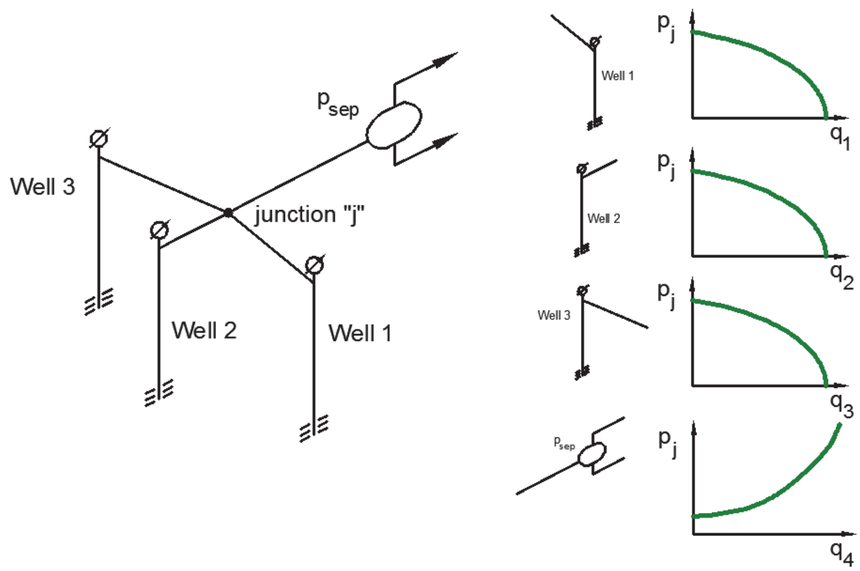

Figure 8: Production Network with 3 Wells available Junction Pressure Curve for Three Wells and Required Junction Pressure Curve for The Pipeline (Stanko 2019)

The mass conservation equation at the junction is checked to verify that the operating junction pressure is physically consistent. It is also possible to assume an equilibrium rate for each well and then check that the junction pressure is the same for all wells and pipeline. (Stanko, 2019)

2.10 Finding Optimum Operating Conditions (Controls) of an existing Production System:

When the production system has adjustable elements, it is usually desirable to find the particular setting of such elements that provide optimum production and dealing with constraints available (Hanssen, et, all, 2015). Some typical constraints are: keeping water production within processing capacity, oil and gas within sale specifications, electrical power availability. In most cases, constraints can become limiting factors that impede to reach an optimum value of the objective function. This optimization is reached for each depletion rate as reservoir pressure could decrease with time, optimum conditions and parameters should there is recalculated.

Chapter 3
Methodology

Chapter 3 Methodology

3.1 Introduction

This chapter outlines the steps of Network Simulation modeling to be done in order to achieve the objectives of this study. Data used such as completion type, tubing properties, and reservoir fluid properties. The model construction for each well in the field and procedures are all described in the following sections.

The created model will be used to optimize the production, optimization criteria are usually defined for maximum oil production, or optimum revenue. Optimization can be applied to management of existing fields or to create production strategies for future asset development.

3.2 Data Collection from Sufyan oilfield

The data used in this study:

- Completion data (Table 3-2).
- Reservoir Data (Table 3-2).
- PVT Data (Table 3-1).
- Well's information and GIS Data (Table 3-5).

This data was used for model calibration and production adjustment, part of this data was recorded from well sensors, other from well workover files and some are calculated and readjusted during modeling to match recorded data.

Table 3-1: Wells density of produced fluid with API and Viscosity measured at lab

Well Name	Density(g/cm^3)			Viscosity(mPa.s)				
	15.6℃	50℃	API 15℃	29℃	40℃	45℃	50℃	60℃
Suf-E-1	0.8398	0.8144	36.76		118		22	
Suf-N-1	0.8111	0.7771@60	42.70				20	10
Suf-N-1	0.821	0.795	40.61					
Suf-N-1	0.8292	0.8035	38.90				21	9
Suf-SE-1	0.8134	0.7872	42.20				18	8
Suf-SE-1	0.831	0.8053	38.54		457		150	93
Suf-SE-2	0.842	0.8166	36.33				38	12
Suf-2	0.8214	0.7954	40.53		22		11	
Suf-E-1	0.8351	0.8096	37.71		49.2		11.6	
Suf-E-1	0.8398	0.8144	36.76		118		22	
Suf-E-1	0.8382	0.8127	37.09			40	20	
Suf-1	0.927	0.904	20.95	1444	666			
Suf-3	0.8332	0.8076	38.09			27	16	6
Suf-3	0.8282	0.8025	39.11			24	13	6
Suf N -3	0.8269	0.8011	39.39				12	6
Suf-E1	0.8339	0.8083	37.95				19	8
Suf-SE1	0.8407	0.8153	36.59				28	9
Sufyan-W1	0.8341	0.8086	37.9				25	10
Suf-N-4	0.8151	0.7889	41.85				34	6
Sufyan-E-1	0.8380	0.8125	37.13				84	14
Suf-5	0.8261	0.8003	39.54			21	15	
Sufyan-W-2	0.8263	0.8005	39.5			25	12	
Sufyan-3	0.8361	0.8106	37.5			52	21	
Sufyan-3								
Sufyan-E-2	0.8343	0.8087	37.87			12.5		
Shoka E-1	0.9765	0.9543	13.27	760300	166300		50256	
Sufyan-S-2	0.8267	0.7930	39.49				9.7	7
Sufyan-4	0.8365	0.8106	37.49				8	5
Higra-1	0.8223	0.7960	40.41				15	6

Table 3-2: General data used to build model

Well Name	Pr	Tr	PI STB/D/Psi	Pump Type	Eff %	Fluid STB/D	Current WC %	Depth ft	Choke in	No. stages
Higra-1	2713	212	0.3	ESP WG1600	0.15 (Head)	229	20	8202	1.4	136
Suf E-1	3218	243	0.3	ESP WE1500	0.37 H	416		7546	0.394	104
Suf E-2	4271	243	0.45	ESP WE1500	0.27 H	533	4	7546	0.4724	154
Suf N-1	2690	185	0.2	ESP WE1500	0.257 H	258	75	7579	2.0	184
Suf N-3	2550	184	0.65	PCP 400-60E1800	0.162 Slip	98	40	4419		
Suf N-4	2900	206	0.2	BPU	0.095 Slip 65%	116	0	6549		
Suf SE-1	3750	216	0.25	PCP 400-60E1800	0.75 H	221	24	5245		
Suf-1	1536	141	0.35	PCP GLB300	0.5 (H) 0.9(F)	217	34	4258		
Suf-2	2750	200	0.11	BPU	0.042 (Slip)	81	0	6566		
Suf-3	2754	217	0.63	ESP WD850	1H 0.6(Rate)	201	0	8253	1.2	
Suf-5	2809	216	0.45	ESP WD1750	0.53 H 0.8 R	400		7680	0.551	82
Sufyan E-2	3516	223	0.5	ESP WD850	0.35 H 0.7(Rate)	259	0	7546	0.6	237
Sufyan S-1	3642	200	0.16	PCP 312-40E1800	1	124	74	5249		
Sufyan S-2	3936	223	0.065	BPU	0.069 Slip 55%	90	0	6566		
Sufyan W-1	2950	200	0.65	ESP WD850	0.9 S	338	65	7218	0.866	237
Sufyan W-6	3200	235	0.17	ESP WG1600	0.15 H 0.8 Rate	126	0	8530	0.7	135
Sufyan W-7	2850	212	0.6	ESP WD850	1	359	8	9383	1	288
Sufyan-03	4217	206	0.45	ESP WE1500	0.22H 0.9R			8169	0.354	77
Sufyan-04	3434	200	0.2	PCP 312-40E1800	0.45H			5243		
Sufyan-E1	3459	200	0.63	500-86E2000	0.4H 0.7 flow			4615		
Sufyan-W2	3033	206	0.34	ESP WD850	0.83H			7709	0.433	288
Sufyan-W8	3014	234	0.7	PCP 400-60E1800	0.23Slip 0.5H			4613		

3.3 Model preparation

The Network model has been constructed with various well and reservoir parameters which have been either measured from field or calculated from well parameters as input for network model. Surface facilities are to be then added to the wells model and connected with wells, representing full network of Sufyan field. After finished construction of field network, Model calibration has to be carried out.

3.4 Model Calibration:

While adjusting well models by using various parameters adjustment, there should be boundaries to match the model while honoring the physics of the system, rather than simply absorbing uncertainties and errors in measurement. Therefore, realistic range of tuning parameters should be defined based on uncertainties in the source of the data. Tuning parameter should be trending in similar direction and not to vary erratically over time.

Well model calibration generally should be performed in the following order:

1. Fluid model (especially bubble point)
2. Inflow performance (matching data using pressure calculated values for wells, and sensor data from downhole sensors in ESP wells).
3. Tubing performance (data matching using pressure gradient survey or simple adjustments based on WHP, WHT)
4. Equipment sittings such as ESP, PCP and BPU. Pumps boosting downhole pressure by calibrating pressure difference between intake and discharge for ESP) and another pumping systems PCP and BPU.

System analysis has to be carried out to specify uncertainties during model initiation or calibration to tune it to field status.

3.4.1 Fluid Model Calibration:

It is recommended to use black oil model for oil producing wells, according to software developer (Schlumberger). While for wet gas and volatile oil it is recommended to use compositional model for more accurate representation though the model (Figure-9).

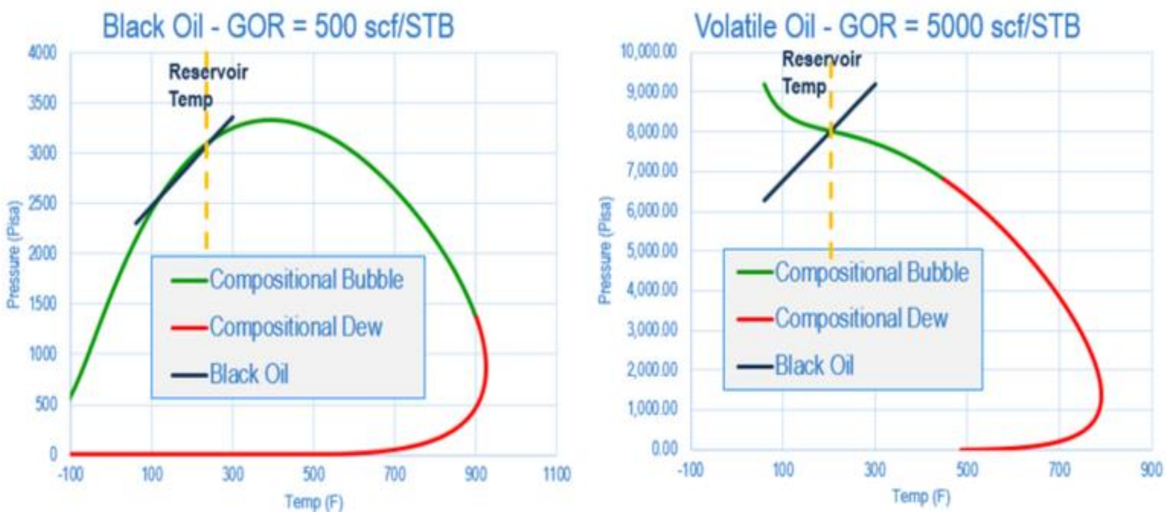

Figure 9: Phase behavior for different compositional and block oil model (PIPESIM software help notes)

Single phase fluid model is shared among most of completed wells. For all of light oil producers, single fluid model was used, therefore, API among all these completions used as single average value. While for Heavy oil producer, separated oil model with different API was applied.

Two types of fluids properties are classified, 'dynamic and intrinsic'. Intrinsic properties such as API are considered constant among shared completions. While dynamic such as water cut and Gas oil ratio are varied across shared completions according to phase contact, well location, conning effects, variations in relative permeability, etc. (PIPESIM 2017.2 software help notes).

3.4.2 Inflow Performance Calibrations

During Operations, you may not have detailed data typically used for completion design. In these cases, it is recommended to use test data to calibrate the IPR model (Table 3-4). Depending on the calibration data, the following IPR models and adjustments are recommended.

Table 3-4: Calibration parameters and their functions

Calibration Data	Liquid Vertical Well PI+Vogel	 Darcy
Well test, Pressure Transient analysis	Update Pr	Update K, h, s
Well test: stabilized flow (multipoint/ isochronal)	Fit IPR	update S
BHP Guage	Fit IPR	update S
Only WHP, flowrate	Clac IPR	update S

Note:

- Unless the near wellbore completion is stimulated, skin will always increase over time.
- "Fit" refers to entering test data in the IPR menu
- "Calc" refers to using the "Custom variable" in the system analysis or PT profile task
- "Update" refers to either directly entering the results of an analyzed well test or using the "Custom variable" in the system analysis or PT profile task

If a multipoint or isochronal well test is available, the IPR may be fitted by entering the test data in the completion menu (Figure-10). If only a single well flow rate is available (or multiple rates for different times), the IPR parameter (productivity index for example) may be calculated using the "Custom Variable" in either the PT profile or System Analysis task.

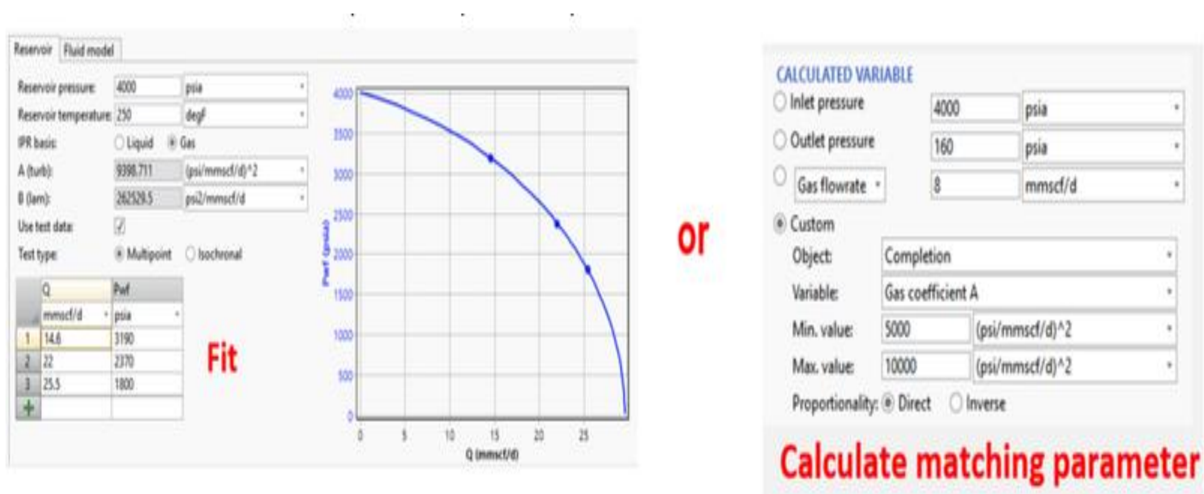

Figure 10: Using multipoint to calculate PI (Pipesim software)

3.4.3 Calibrating flow in the wellbore

The Data Matching process is recommended for use to calibrate the pressure and temperature changes in the wellbore. The data matching process will adjust correction factors for holdup, friction. Data may include some or all of the following:

- Production log data (Downhole Pressure, Temperature and Sometimes Phase Holdups)
- Bottomhole pressure gauge data.
- Pump intake or discharge pressure
- Temperature (reservoir and wellhead)
- Flow rates (metered)

Most of these data are listed in Table 3-5.

Table 3-5: Wells coordinates OGMs tied-in to

ALIAS	EASTING_X	NORTHING_Y	LONG_NAME	OGM_NAME	PROD_FIELD
Suf E-1	471529.672	1285122.109	Suf E-1	OGM-2	Sufyan
Suf E-2	470887.967	1285269.024	Suf E-2	OGM-2	Sufyan
Suf N-1	463074.77	1293784.81	Suf N-1	OGM-1	Sufyan
Suf N-2	461110.258	1294843.762	Suf N-2	OGM-1	Sufyan
Suf N-3	462540.988	1294074.993	Suf N-3	OGM-1	Sufyan
Suf N-4	462195.144	1294282.268	Suf N-4	OGM-1	Sufyan
Suf S-1	471357.302	1279128.592	Suf S-1		Sufyan
Suf SE-1	471537.939	1287964.363	Suf SE-1	OGM-2	Sufyan
Suf W-1	454224.791	1290578.662	Suf W-1	OGM-4	Sufyan
Suf-1	461609.137	1292236.564	Suf-1	OGM-1	Sufyan
Suf-2	460228.6	1292740.731	Suf-2	OGM-1	Sufyan
Suf-3	461623.695	1290952.843	Suf-3	OGM-1	Sufyan
Suf-4	461942.063	1291823.42	Suf-4	OGM-1	Sufyan
Sufyan E-2	488271.028	1285996.334	Sufyan E-2	OGM-3	Sufyan
Sufyan-4	485335.686	1287274.453	Sufyan-4	OGM-3	Sufyan
Sufyan W-2	476960.408	1285569.295	Sufyan W-2	OGM-4	Sufyan
Sufyan W-6	477399.983	1286050.717	Sufyan W-6	OGM-4	Sufyan
Sufyan-1	485800.589	1287566.322	Sufyan-1	NO Casing	Sufyan
Sufyan-3	487367.297	1285814.033	Sufyan-3	OGM-3	Sufyan
Sufyan W-7	478249.97	1286813.961	Sufyan W-7	OGM-4	Sufyan
Sufyan W-8	477705.004	1286454.993	Sufyan W-8	OGM-4	Sufyan
Sufyan E-3	487365.141	1287434.522	Sufyan E-3	OGM-3	Sufyan
Sufyan N-1	485695.318	1294097.819	Sufyan N-1	DRY	Sufyan
Sufyan S-1	486361.868	1284282.42	Sufyan S-1	OGM-3	Sufyan
Sufyan S-2	485293.738	1284134.697	Sufyan S-2	OGM-3	Sufyan
Sufyan W-1	478137.546	1286426.265	Sufyan W-1	OGM-4	Sufyan
Suf-5	460999.978	1292430.412	Suf-5	OGM-1	Sufyan
Sufyan E-1	488432.33	1285552.999	Sufyan E-1	OGM-3	Sufyan

i. **Fluid level:**

A proper knowledge of PCP and PBU optimization is obtained by the application of fluid level and well optimization. Where Pwf and Pr are calculated based on Fluid level and casing pressure and gas in annulus.

$$P_{wf} = P_c + \rho_g g h_g + \rho_l g h_l \quad \text{...} \ (3\text{-}1)$$

Where:

Pwf: wellbore flowing pressure

Pr: average reservoir pressure

Pressure distribution across producing well is revised to ensure all pressures across the well are matching flowing condition in the field.

ii. **Productivity index (PI)**

The (straight line) productivity index relationship for liquid reservoirs is perhaps the simplest and most widely used IPR equation. It states that rate is directly proportional to pressure drawdown between the bottom hole and the reservoir.

$QL = J\text{L}.(Pws - Pwf)$ .... (3-2)

3.4.4 Tubing Performance Calibration:

Steady state pressure gradient in single phase sections is given by:

$$\frac{dP}{dL} = \left(\frac{dP}{dL}\right) elev + \left(\frac{dP}{dL}\right) fric + \left(\frac{dP}{dL}\right) acc \quad \text{...} \ (3\text{-}3)$$

Where elevation, friction and acceleration components of the pressure drop are:

$$\left(\frac{dP}{dL}\right) elev = -\rho g \sin\theta \quad \text{...} \ (3\text{-}4)$$

$$\left(\frac{dP}{dL}\right) fric = -\frac{f \rho v^2}{2D} \quad \text{...} \ (3\text{-}5)$$

$$\left(\frac{dP}{dL}\right) acc = -\rho v \frac{dv}{dL} \quad \text{...} \ (3\text{-}6)$$

There are a number of different ways of calculating the friction factor, which usually depends on the Reynolds number:

$$Re = \frac{\rho v D}{\mu} \quad \text{...} \ (3\text{-}7)$$

The above case is valid for natural flowing wells. For artificially lifted wells calibration should also be done for equipment used downhole to assist fluid flow.

3.4.5 Well calibration for equipment setting:

A final step in well calibration involves matching equipment settings. This should be performed only after all other steps in the calibration process are made. Ideally, multiple data points should be considered. Depending on the equipment present, the following calibration factors over a period of time which is possible using the “change-in-step” sensitivity option within may be adjusted:

Table 3-5: Artificial lift types and their recommendation for tuning parameters (pipesim software)

Equipment	Recommended tuning parameter	Calibration task
ESP	Head derating factor	PT Profile or System Analysis
PCP	slip factor	PT Profile or System Analysis
Rod Pump	slip coefficient	PT Profile or System Analysis
Jet Pump	loss coefficient	PT Profile or System Analysis
Gas lift	Valve tuning factor	Gas lift diagnostics
Choke or SSSV	Flow coefficient for primary phase	PT Profile or System Analysis
Downhole seperator	Efficiency	PT Profile or System Analysis

Here only three types of equipment (BPU, PCP and ESP) will be considered due to the application of it in Sufyan field. While for each type calibration parameters are specified and defined from network modeling software.

I. BPU:

SLIPCOEF: coefficient to specify the change in flowrate with respect to Delta pressure (m^3/day/bar or bbl./day/psi). This is used to compute the pressure rise across the device when the actual flowrate is less than the specified nominal rate.

MAXDP: Maximum pressure rise the device is allowed to exhibit (psi or bar). This is used to prevent excess rod loading.

EFFICIENCY= Overall efficiency of the pump which is used to compute the power requirement.

Nominal rate: The actual volumetric flowrate that the pump would produce if it were pumping with no back-pressure at its discharge (m3/sec or ft3/min).

II. PCP

PCP in comparison to ESP, will tend to deviate from catalog performance curves in field operations. This is due to the sensitivity of slip to fluid properties and operating conditions which impact elastomer swelling. Therefore, PCP generally require some degree of calibration to match field data. Consider the Kudu 98k 1200EW PCP (Figure 11). A combination of rate, head and slip factors may be adjusted to modify the performance curve. Generally, modification of the slip factor alone should be sufficient to achieve a match.

As shown in the (Figure11), the following adjustments are made to the catalog curve based on the factors specified:

- The rate factor will shift the entire curve vertically along the rate axis (green)
- The head factor will shift the entire cure horizontally along the head axis (red)
- The slip factor controls the degree of deviation from the ideal (no leakage) curve (blue)

Slip factor: Allows the pump flowrate to be adjusted for downward fluid slippage between the pump rotor and the stator (default = 1).

Head factor: Allows the pump head to be adjusted to better match field performance data or account for wear (default = 1).

Flowrate factor: Allows the pump flowrate to be adjusted (default = 1).

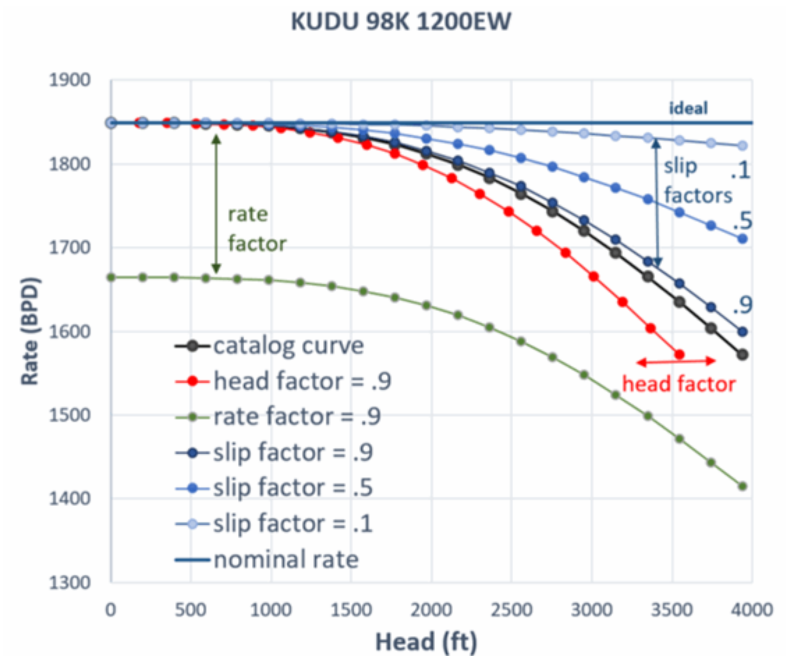

Figure 12: Kudu 98k 1200EW PCP Slip, Head and Rate factors (Pipesim software)

Note:

- Slip factors represent adjustment to slip effect only, relative to catalog and nominal rates.
  - slip factor of 0 = nominal rate (cannot solve model due to infinite head)
  - slip factor of 1 = catalog rate
- Slip factor scales linearly.
- Slip factor is applied AFTER rate and head factors.

III. ESP

Head derating factor: allows the pump efficiency to be factored (default = 1).

Rate derating factor: allows flow rate to be factored. (Default=1).

Viscosity Correction: all pump performance curves are based on water systems; this option will correct for oil viscosity. Figure (12) illustrates a pressure profile (shown in blue) for an ESP lifted well. Well will not produce without this pump and considered dead. with the fluid column in the tubing represented by the static gradient (dP/dz) b. A designed rate, QL, and the corresponding bottomhole flowing pressure, Pwf, are identified from the (sideways projected) IPR curve. To achieve this rate, the pump must be designed to provide a pressure boost equivalent to ΔPpump, which is the pressure difference between the discharge and the intake of the pump. When the pump discharges pressure at the depth shown, the fluids flow to the surface at the specified wellhead pressure, Pwh.

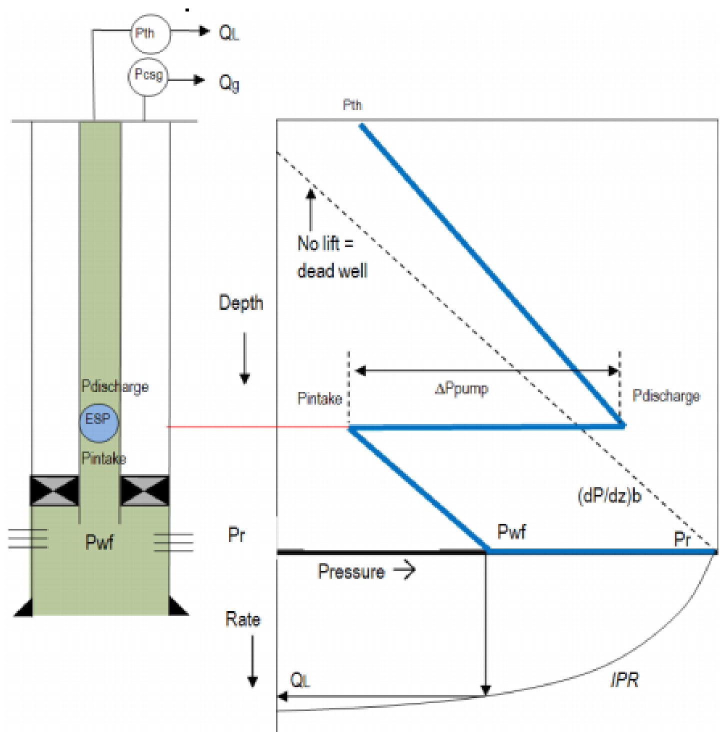

Figure 13: Pressure profile of an ESP lifted well

One possible mathematical formulation to find the hydraulic equilibrium of the system is to solve the set of equations:

$$p_j = F_1(q_1, f_1)$$
$$p_j = F_2(q_2, f_2)$$
$$p_j = F_1(q_1, q_2) \quad \text{(3-8)}$$

Note that solving the hydraulic equilibrium of the network has been added as a constraint. This means that any optimal solution found has to be a feasible operating condition in the numerical model of the network. This strategy is used often when optimizing production networks.

3.5 Optimization for Field Network:

After model has been calibrated and match the field status to an acceptable difference. Optimization on well base should be done to maximize production from wells and overall field. Classification for producing wells has to be carried out to specify which well could be increased and efficacy of this increment.

For BPU wells, the case was to do nothing due to low submergence from well history. Due to the low productivity and acceptable running efficiency.

For wells running with good efficiency for their pumps (range might vary according to pump type and well status) the scenario followed was to keep those producing after calibrating model to their field status. For wells with low pump efficiency. Scenarios applied for those wells are to change their pumps size and type and check their production after amendments and the potential increment. Figure 13 represents flow chart of optimization methodology followed by Stanko after model was initiated.

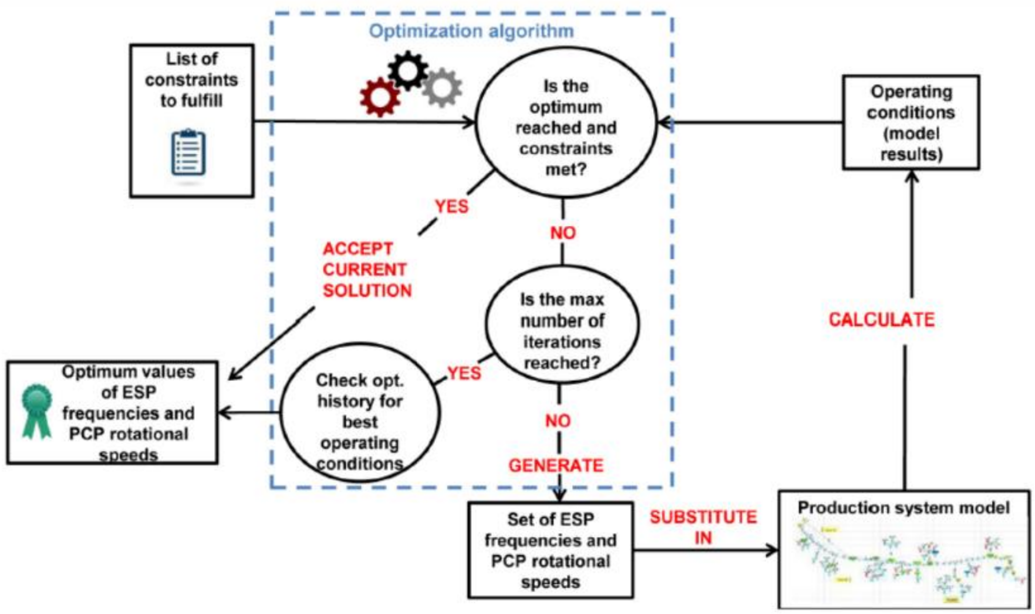

Figure 14: Optimization algorithm flow chart (Stanko, 2019)

The model-based optimization estimates values of ESP frequency and PCP, BPU rotational speed that yield a significant increase in oil production while honoring multiple operational constraints. The increment apparently comes from increasing the production of low water cut wells and reducing the backpressure on good producers by lowering the production of high water cut wells.

3.6 Economic Evaluation for optimization scenarios:

Net present value has to be used to compare optimization scenarios and estimate added value of this scenarios. Assuming the field rate is a continuous function. The following equations are used based on (Stanko, 2019), NPV is calculated by:

$$For\ t < t_p \qquad q_f = q_{p,f} \quad \ldots\ldots (3\text{-}9)$$

$$For\ t \geq t_p \qquad q_f = q_{p,f} \cdot e^{-m\cdot(t-t_p)} \quad \ldots\ldots (3\text{-}10)$$

$$t_p = \left(\frac{q_{ppo}}{q_{p,f}} - 1\right) \cdot \frac{1}{m} \quad \ldots\ldots (3\text{-}11)$$

$$m = A \cdot N_w \cdot J \quad \ldots\ldots (3\text{-}12)$$

$$q_{ppo} = N_{wells} \cdot J \cdot \left(p_i - p_{wf,min}\right) \quad \ldots\ldots (3\text{-}13)$$

$$A = \frac{B_o}{\left[N \cdot B_{o,i} \cdot \left(c_o + \frac{c_w \cdot S_w + c_f}{S_o}\right) + V_a \cdot \phi_a \cdot B_w \cdot \left(c_w + c_f\right)\right]} \quad \ldots\ldots (3\text{-}14)$$

$$NPV_{rev} = \int_0^t q_f(t) \cdot P_o \cdot e^{-i\cdot t} dt \quad \ldots\ldots (3\text{-}15)$$

Where:

- q1 q2, Rates of wells 1 and 2.
- Pi, Pj Junction pressure, unknown variable
- F1 Pressure drop function for well 1 representing the compound pressure change from reservoir, tubing, pump, tubing and flowline
- F2 Pressure drop function for well 2 representing the compound pressure change from reservoir, tubing, pump, tubing and flowline
- F3 Pressure drop function for the pipeline, representing the pressure loss in the pipeline.
- f1, f2Rotational speed of ESP pumps 1 and 2 respectively.

Chapter 4

Results and Discussion

Chapter 4 Results and Discussion

4.1 Introduction:

In this chapter the results obtained from initiated model and the optimization scenarios will be discussed in details.

4.2 Pressure data matching:

By using pressure correlation matching, different two phase flow correlations such as Hagedorn and Brown Revised (HBR), Duns and Ros (DR), Orkiszewski (ORK), Tulsa Hagedorn and Brown (THB), Beggs and Brill Revised (BBR), Original Beggs and Brill (BBO), Govier and Aziz (GA) and Mukherjee and Brill (MB) were selected to predict pressure drop in the field wells. Hagedorn and Brown Revised (HBR) was found to be the most suitable correlation to be used due to its low RMS compared to others multiphase correlations. (Figure 14).

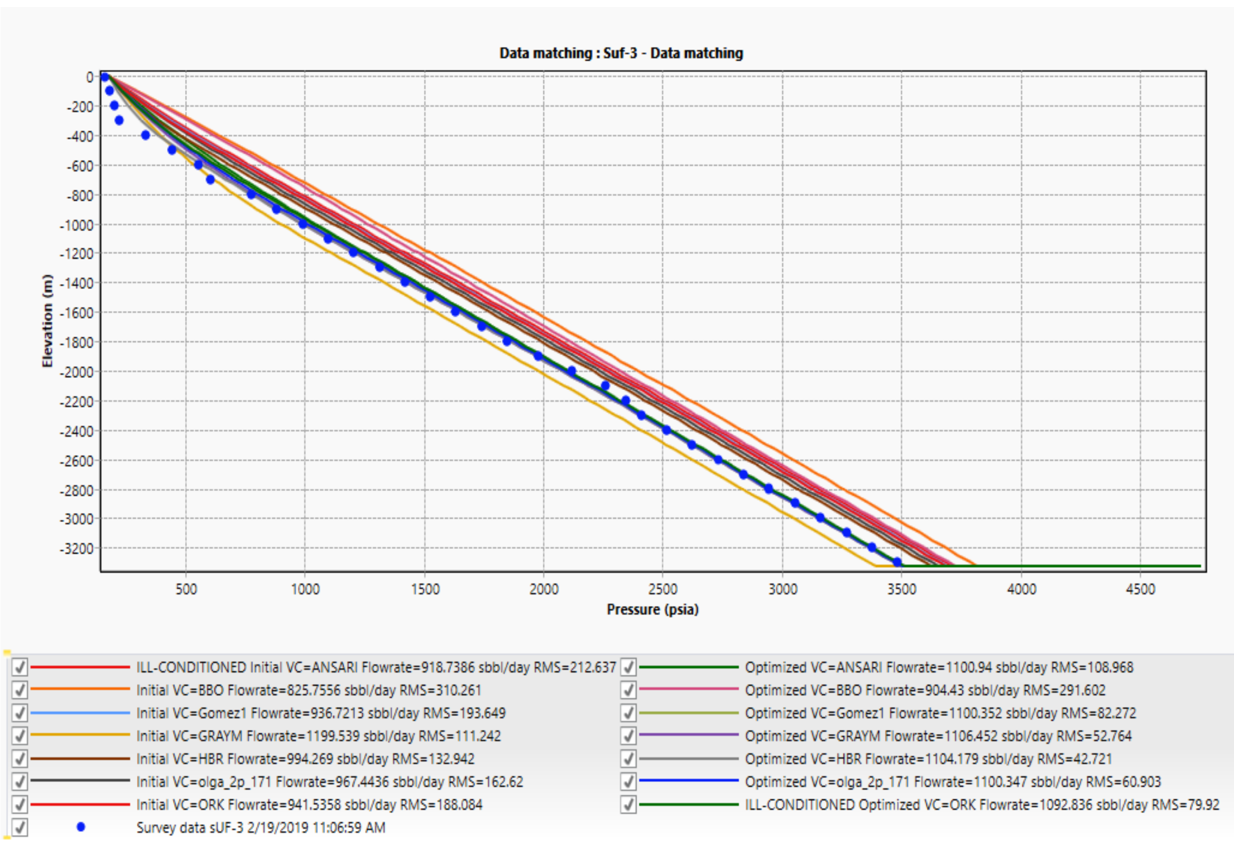

Figure 15: Static gradient survey for Suf-03 data matching

4.3 General Results Outlines:

- For ESP, the efficiency of the pump does not change with speed changes (PIPESIM 2017.2 software help notes), as per this conclusion and to ensure matching downhole flow conditions to the filed status; other adjustments have to be done to get matching between model and field status. For example, **Suf-E-2**, productivity was increased from 0.29 Stb/d/psi (tested data) testing record to 0.45 Stb/d/psi to match ESP downhole sensor reading. Pump head (factor) was almost (0.27) instead of default (1) to get required WHP.
- **Sufyan-W1** calculated PI was very high (20 Stb/d/psi) due to change in fluid level was not significant during well DFL update. But, after modeling by matching intake pressure for the pump, the corresponding PI was (0.65 Stb/d/psi) which is within range of adjacent wells and field overall.
- For BPU wells, pump efficiency does not change significantly in pump overall performance (PIPESIM 2017.2 software help notes). Therefore, slip coefficient is used. Slip coefficient is a dominant factor in adjusting WHP for BPU wells, the default slip is 0.002 Stb/d/psi outlet pressures at wellhead was in the range of 8000 Psi, causing all wells flowing to the same manifold to contribute nothing to the flow, and software skipping those wells due to high pressure at manifold. Therefore, slip coefficient was adjusted for BPU wells to match field data. Slip coefficient in BPU was very low so increment was necessary to adjust WHP for those wells, keep into consideration positive displacement pump could possibly affect adjacent wells flowing to the same manifold, those producing via ESP especially.
- For BPU optimization, slip coefficient range that used to adjust outlet pressure is widely differ from well to another (0.042, 0.069 and 0.095) compared to initial value around (0.0005). This resulted in keep BPU wells producing by their field status and no alteration for their cases were applied.
- ESP is severely affected by back pressure. During well wise optimization, head factor has been reduced down to 0.27 (default 1.0) to match field status. However, while running the integrated network, the outlet pressure and flow rate values were different significantly from field status (0 to 11 psi) for wellhead pressure for instance; therefore, head factor value was readjusted again up to (1) to match field for some wells.

- For **Sufyan-W8**, the head factor was dominant during optimization for well as PCP producer. While adjusting WHP to match field current status pressure decreased from 1106 psi down to 450 psi, this was corresponding to head factor adjustment from (1) to (0.5), therefore slip factor was accordingly adjusted from (1) to (0.23) increase flow rate to be about 250 STB/D.
- For **Higra-01**, for instance, testing PI measured is 0.82 Stb/d/psi and Pr 3000Psi, matching this criterion to the model, there was severe deviation in results even after adjusting pressure to the calculated current value. Therefore, to match ESP sensor parameters, the model PI has to be adjusted down to 0.3 stb/d/psi.

Figure 15 shows the overview for pressure flow chart from Sufyan OGMs to Hadida FPF. While, Figure 16 shows the pressure profile for wells to their OGMs and then to Hadida FPF.

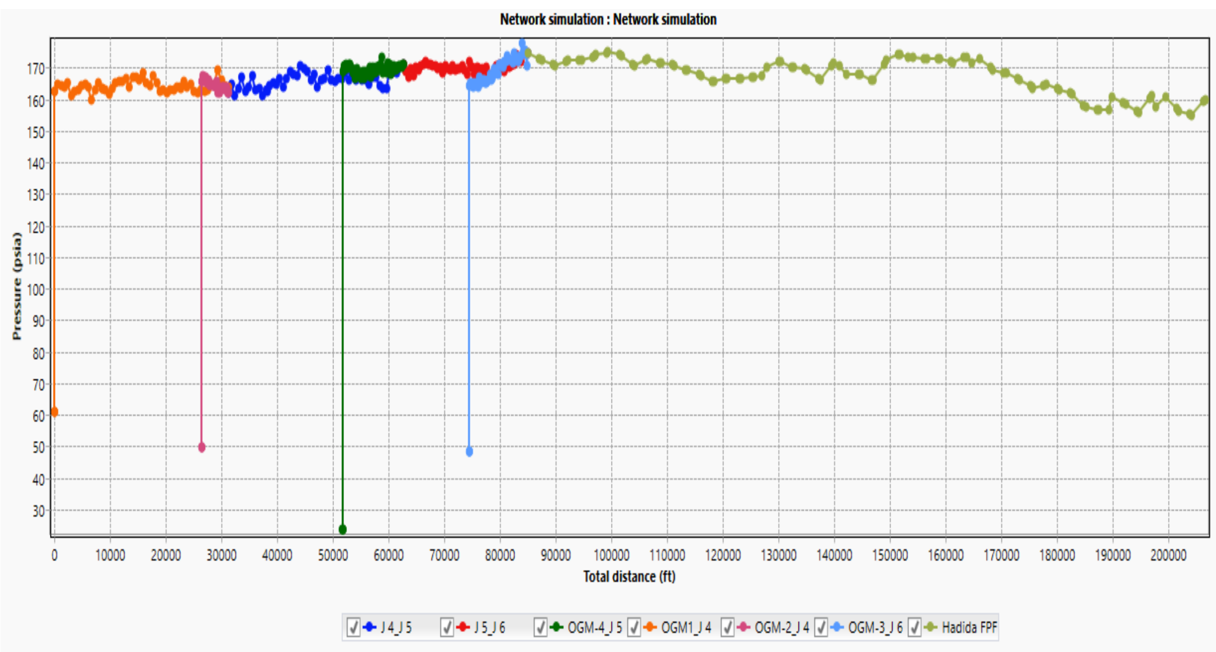

Figure 16: Overall network pressure profile for OGMs to Hadida FPF

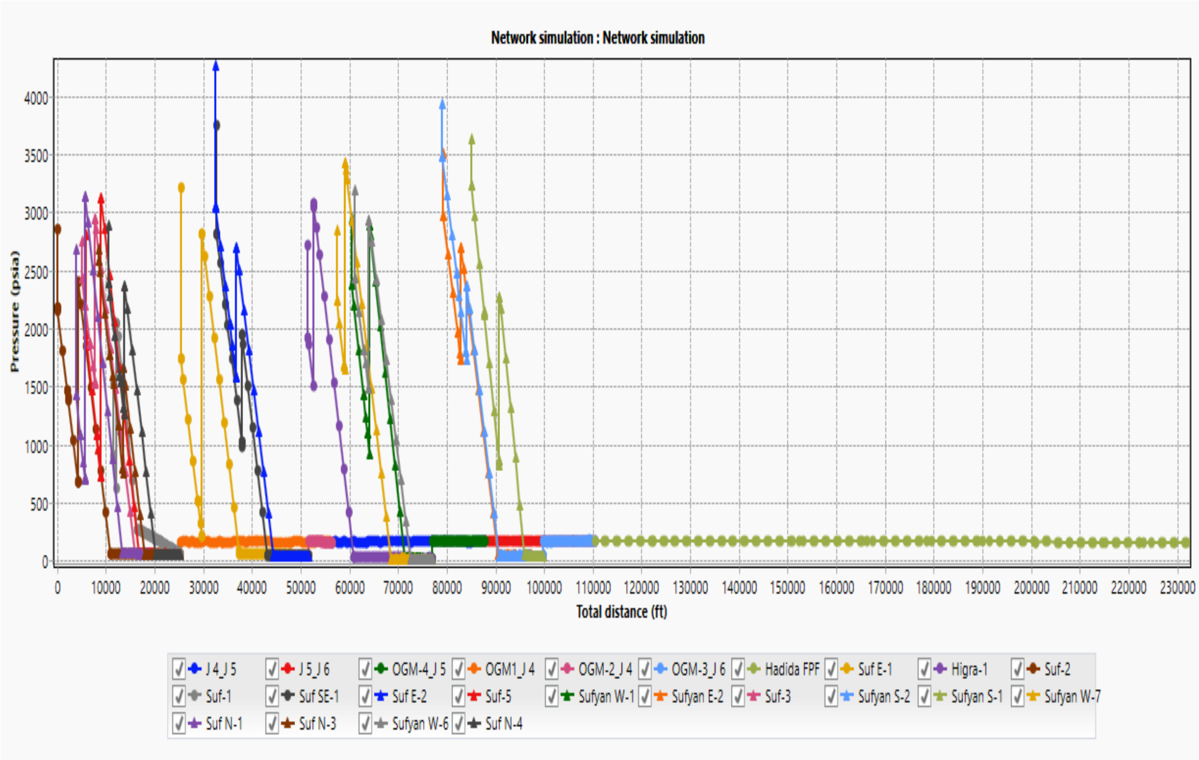

Figure 17: Overall network simulation result showing pressure profile from wells

4.4 Model Scenarios Result:

In general, several scenarios were applied to the model with consideration of the well production situation (Table 4-1). For instance, current artificial lift efficiency, frequency adjustment trials, and convert to anther artificial lift scenario.

Table 4-1: all scenarios used in this analysis.

No	Applied Scenarios
1	45E2400 Case @ 40hz
2	ESP optimization
3	45E2400 Case @ 50Hz
4	45E2400 50 and 40Hz, W6 ESP
5	All wells with shut in
6	All wells + PCP and W6 ESP case

ESP cases run by using 60Hz as a default frequency. Suf-N1 and Sufyan-S01, due to water cut exceeding 70% cases of scenarios applied for these wells give marginal change on their production. Therefore, it was ignored.

4.4.1 Sufyan-W6 Scenarios:

Current pump ESP WG1600, after apply smaller pump size ESP-WD1500 (184, 154 and 101), no increase in production was observed. When WD850 applied, flow rate increased from 126 Stb/d to 263 Stb/d (Head 0.9 Rate 0.65), has been shown in Figure 17 and Figure 18.

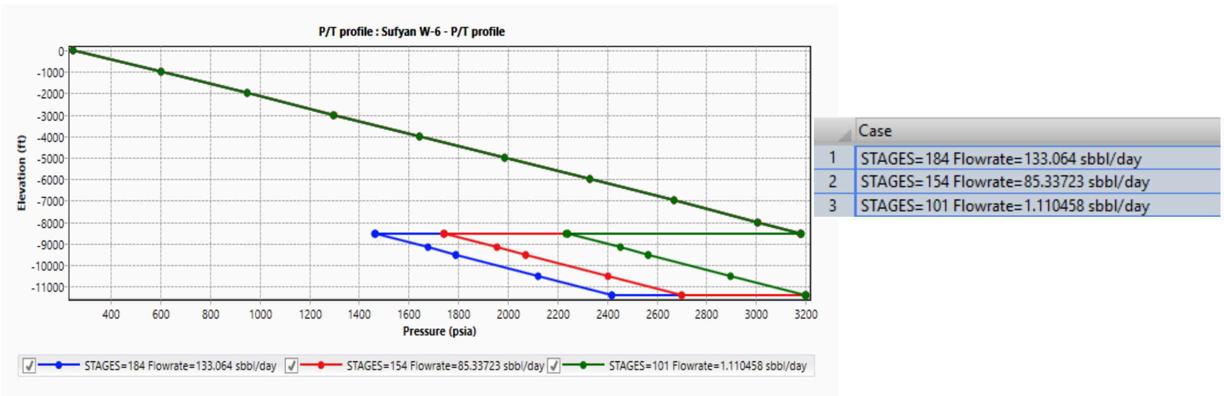

Figure 18: Sufyan-W6 (WD1500) case

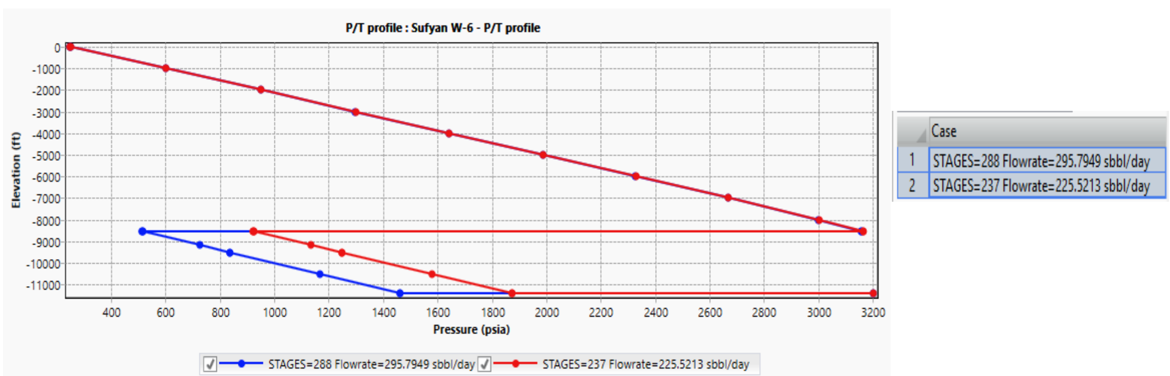

Figure 19: Sufyan-W6 (WD850) case

A PCP 45E2400 case was performed using 0.9 slip, 0.65 head and 0.8 flowrate factors, yet, max flowrate obtained is 216 stb/d. Figure 19.

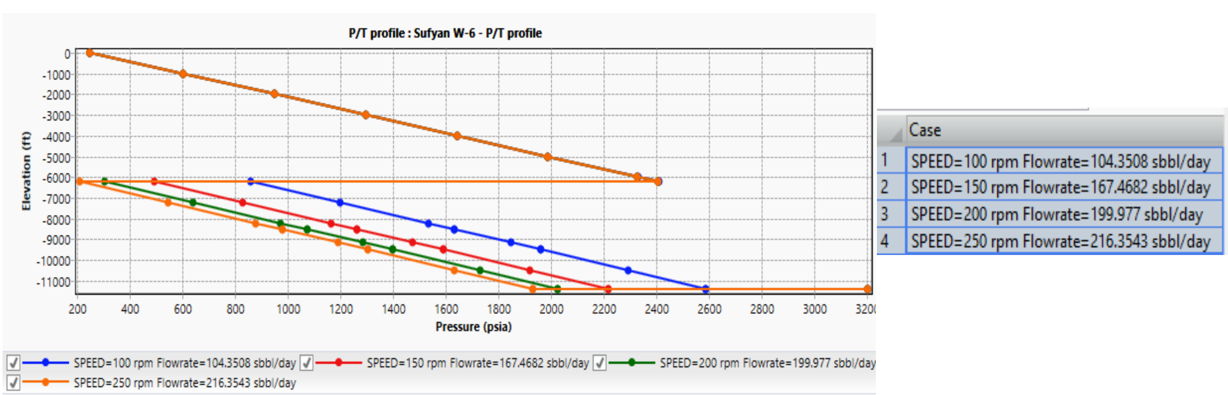

Figure 20: Sufyan-W6 (PCP 45E2400) case

4.4.2 Sufyan-E-02 Scenarios:

Well is producing 260STB/d.

Case 1:

Changes pump size from WD850 to WD1500. Using three different number of stages scenario. Results are varying in range from 381 to 103 STB/D. Apply 154stages (0.3Head factor) 338STB/D was obtained. Figure 20.

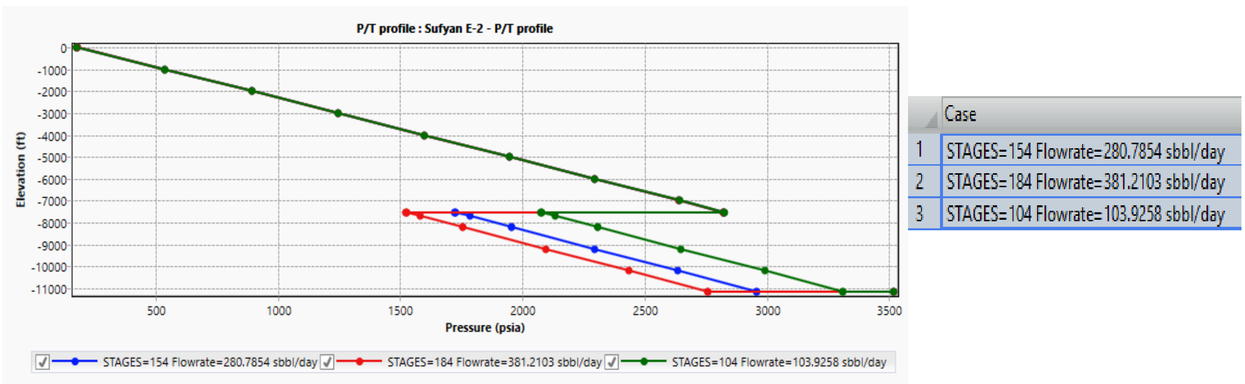

Figure 21: Sufyan-E-02 (WD1500) case

Case 2:

PCP 45E2400 was applied. Frequency sensitivity was performed from 100rpm to 250rpm. Results were as follow: Figure 21.

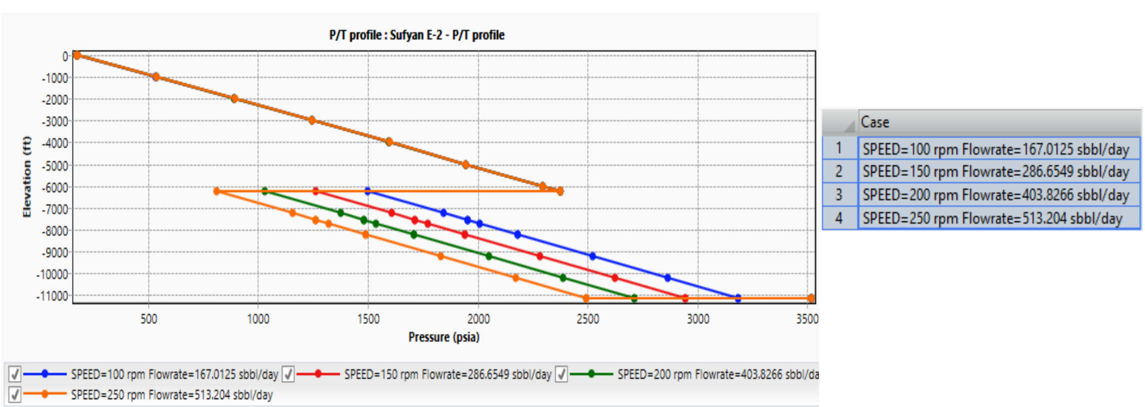

Figure 22: Sufyan-E-02 (PCP 45E2400) case

4.4.3 Higra-01 Scenarios :

ESP WG1600 pump was replaced by WD850 using 237 and 288 stages, flow rate was 204 and 297 STB/D respectively. No significant increment in production obtained considering uncertainties associated with ESP pumps, variation in flow rate caused by head factor change is ESP reducing the opportunity of success if applied. No change in flow rate was observed using different bean size. Yet, considering current ESP head rating (0.15), the scenario should be revised with ESP engineer before applying into filed. From WD850 performance in Sufyan field for wells with Pr less than 3000Psi which affect intake pressure head factor recorded was more than 0.8. Using (0.6 Head factor) and (0.6 Rate factor) 347 stb/d (263 bopd).

Case 2:

PCP 45E2400 was applied; good response in production was obtained. (0.9, 0.65 and 0.8) for Slip, Head and flow rate factor respectively. Figure 22.

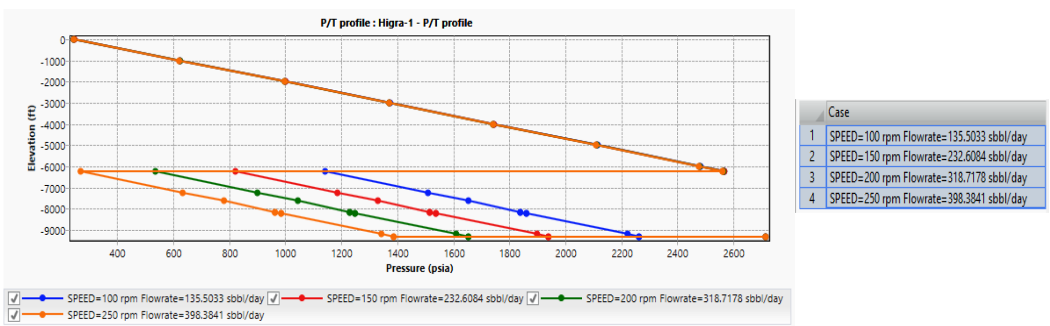

Figure 23: Higra-01 (PCP 45E2400) case

4.4.4 Suf-N3 scenarios:

Case 1:

The well suffered from low pump submergence caused by shallow placed PCP at 1347m. Case applied is to run ESP WD850 (237) stages, production obtained is 299stbd which is 192bopd increment by more than 100% in production compared to the current situation. (Production difference due to model flow) Figure 23.

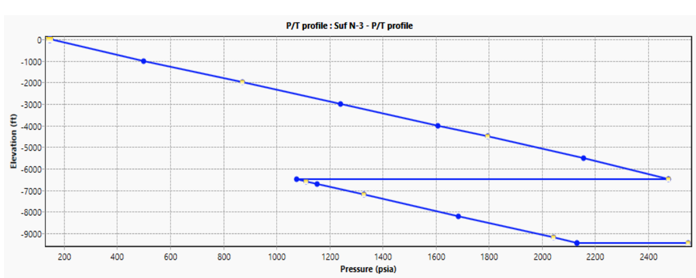

Figure 24: Suf-N3 (WD850) case

Case 2:

PCP 45E2400 was applied by lowering PCP to 1900m, an increment in production was observed with different frequencies. Figure 24

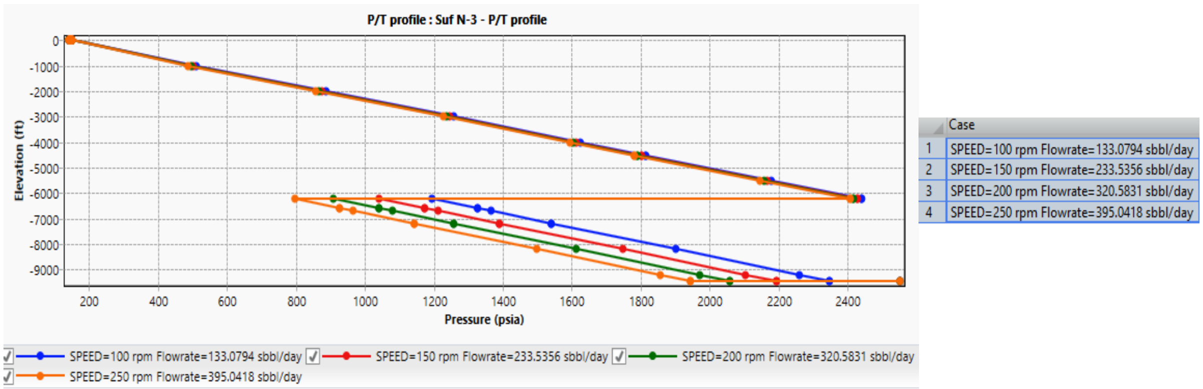

Figure 25: Suf-N3 (PCP 45E2400) case

4.4.5 Suf-SE01 Scenarios:

Case 1:

Potential increase in production for this well was obtained when replace PCP by deep ESP (237stages) placed at 2200m, production obtained 372stbd (335 bopd) via 0.6Head and Rate factors compared to 176 bopd. Figure 25.

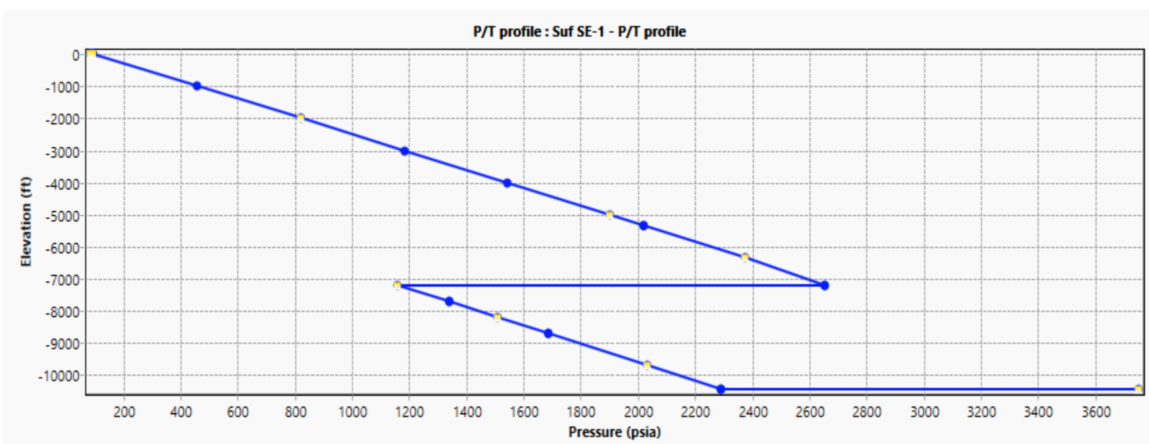

Figure 26: Suf-SE-01(ESP) case

Case 2:

Running PCP 45E2400 a new set might be available in field. Good performance was observed. Sensitivity for frequency was performed results were as follow.

Special constraints were used for PCP parameters (0.9, 0.65 and 0.8 for slip, head and flowrate factors respectively). Figure 26.

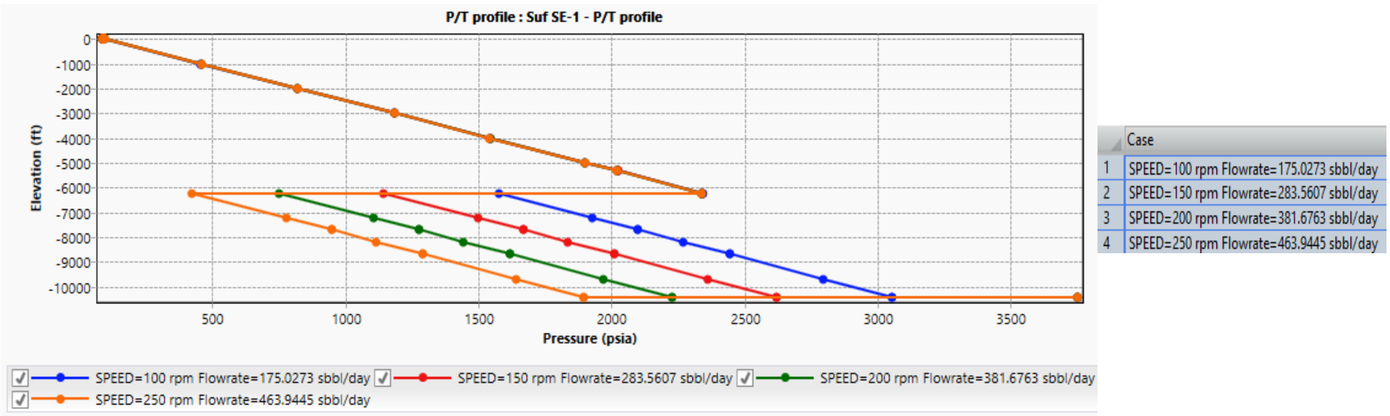

Figure 27: Suf-SE-01 (PCP 45E2400) case

4.4.6 Suf-03 Scenarios:

Frequency increment case was applied. Significant change in well production was obtained. From around 200 stb/d @ 45Hz to around 430 Stb/d @ 55 Hz. Figure 27.

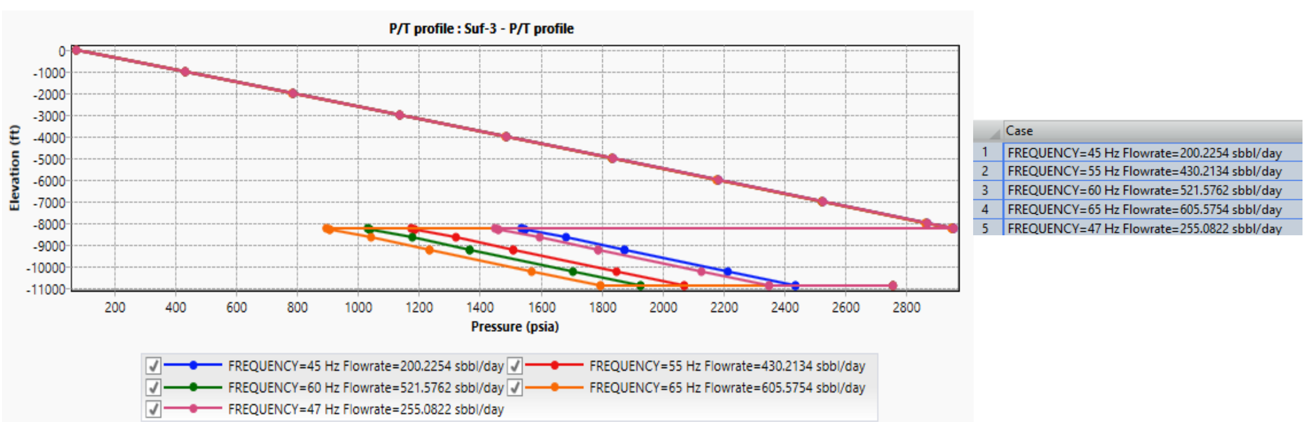

Figure 28: Suf- 03 frequency increment case

4.5 Overall Scenarios Result:

This result represents the cases comparison between all scenarios applied to the model, and results obtained. Table 4-2 and the figure 28 explain these results and compare several wells under different scenarios, the next step is using these results for the economical comparison to evaluate which scenario is more feasible and to be applied in the field.

Table 4-2: Comparison between all scenarios.

Well Name	Base Case	ESP Case	PCP 45E2400 Case 40hz	PCP 45E2400 Case 50	All wells with shut in
Higra-1	183	264	260	321	186
Suf E-1	371	371	368	371	375
Suf E-2	542	542	535	542	557
Suf N-1	90	98	88	89	93
Suf N-3	54	192	209	209	55
Suf N-4	100	99	99	99	103
Suf SE-1	210	335	113	421	115
Suf-1	144	144	143	144	147
Suf-2	77	77	76	77	78
Suf-3	200	196	190	196	221
Suf-5	172	171	169	171	180
Sufyan E-1	0	0	0	0	166
Sufyan E-2	271	338	412	525	293
Sufyan S-1	27	27	27	27	27
Sufyan S-2	95	95	95	95	96
Sufyan W-1	171	171	171	171	177
Sufyan W-2	0	0	0	0	262
Sufyan W-6	128	263	208	264	133
Sufyan W-7	302	302	302	302	309
Sufyan W-8	0	0	0	0	255
Sufyan-3	0	0	0	0	634
Sufyan-4	0	0	0	0	127
Total Prod	***3138***	***3684***	***3465***	***4022***	***4588***

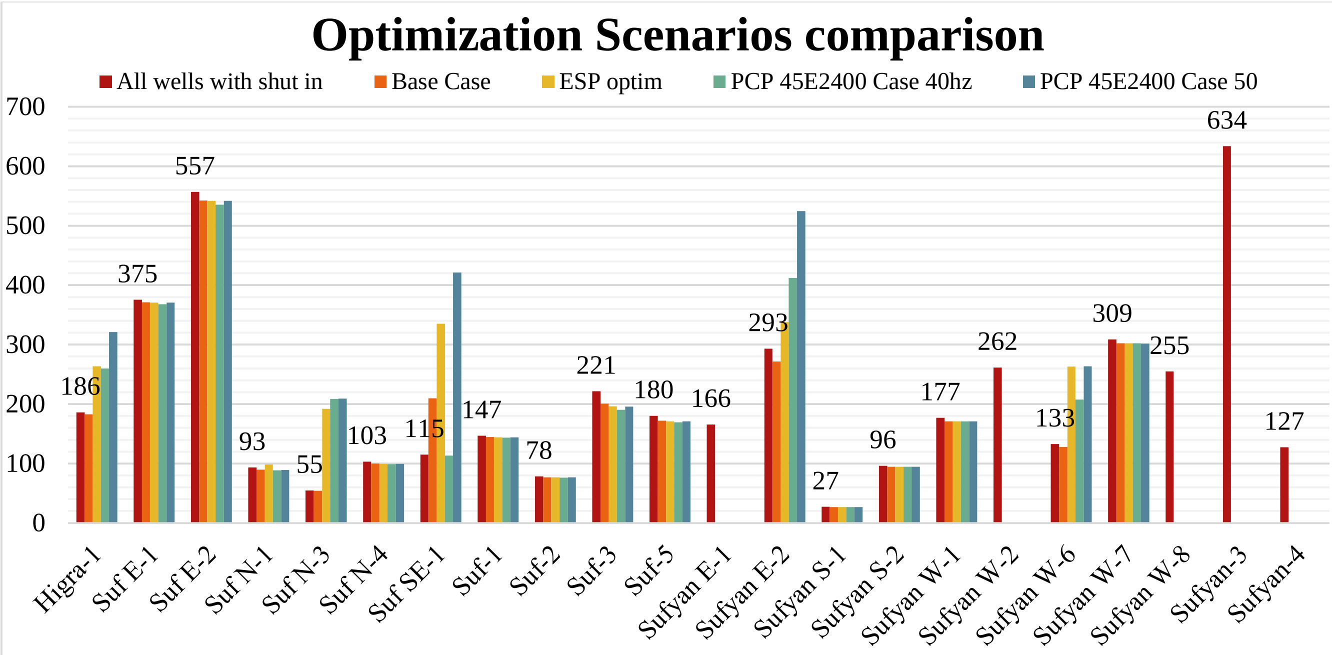

Figure 29: Comparison between all scenarios.

4.6 Economic Evaluation for optimization scenarios:

The main factor affecting the cost of this scenario was the initial cost of artificial lift workovers. This average cost taken from workover history in Sufyan field. Net present value was used to compare between the various scenarios.

Table 4-3: Estimated cost for workovers (Sufyan workover history data)

Scenario	Workover Cost (USD)
ESP convert to PCP	173,994
ESP repair	77,464
PCP repair	116,149

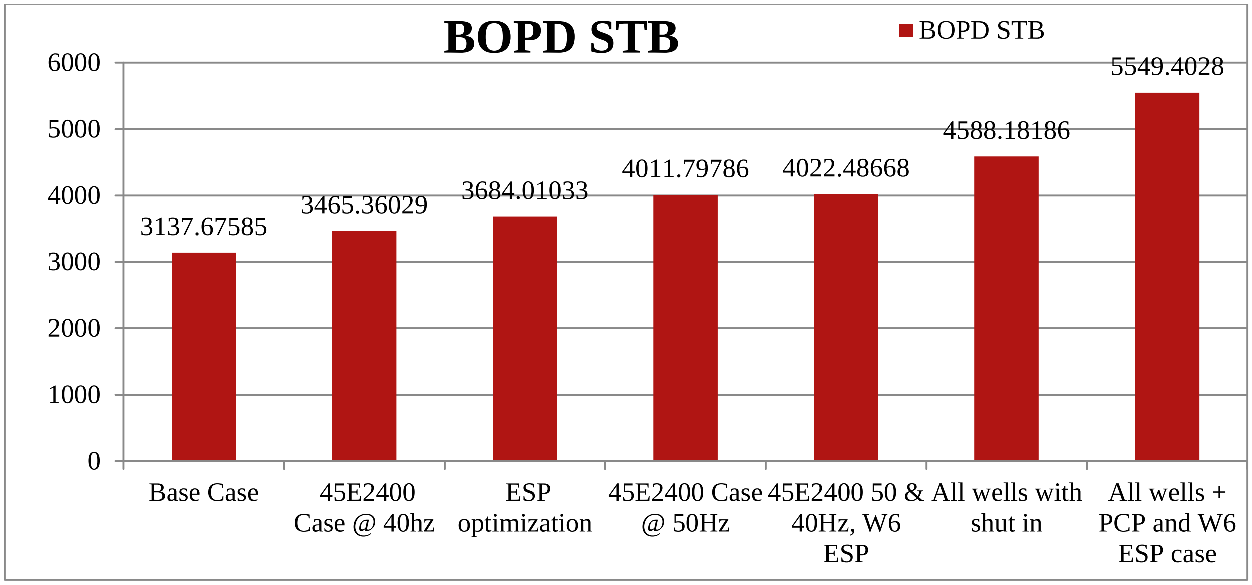

Figure 30: Production per each optimization scenario.

Table 4-4: Estimated Capex and Opex for optimization scenarios

	BOPD STB	**Increment %**	**No.of wells**	**Cost for 2years**		
Base Case	**3138**		**17**	**Initial Capex $**	**Do nothing OPEX $**	**OPEX and Capex $**
45E2400 Case @ 40hz	3465	10	17	580,749 $	2,190,000 $	580,749 $
ESP optimization	3684	17	17	464,787 $	2,190,000 $	2,654,787 $
45E2400 Case @ 50Hz	4012	28	17	580,749 $	2,190,000 $	580,749 $
45E2400 50 and 40Hz, W6 ESP	4022	28	17	947,439 $	2,190,000 $	1,239,439 $
All wells with shut in	4588	46	22	503,379 $	2,190,000 $	3,423,379 $
All wells + PCP and W6 ESP case	5549	77	22	1,450,817 $	2,190,000 $	1,893,282 $

Net Present Value Results obtained are shown in figure (4-17) and (4-18).

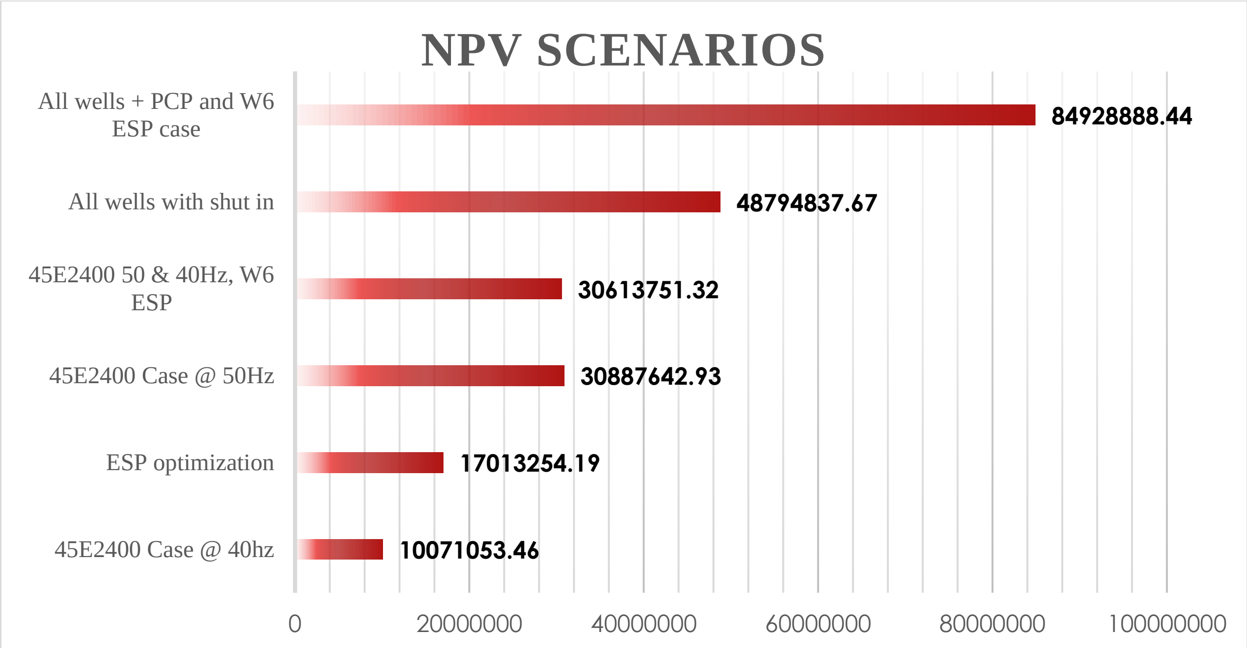

Figure 31: NPV result per each optimization scenario.

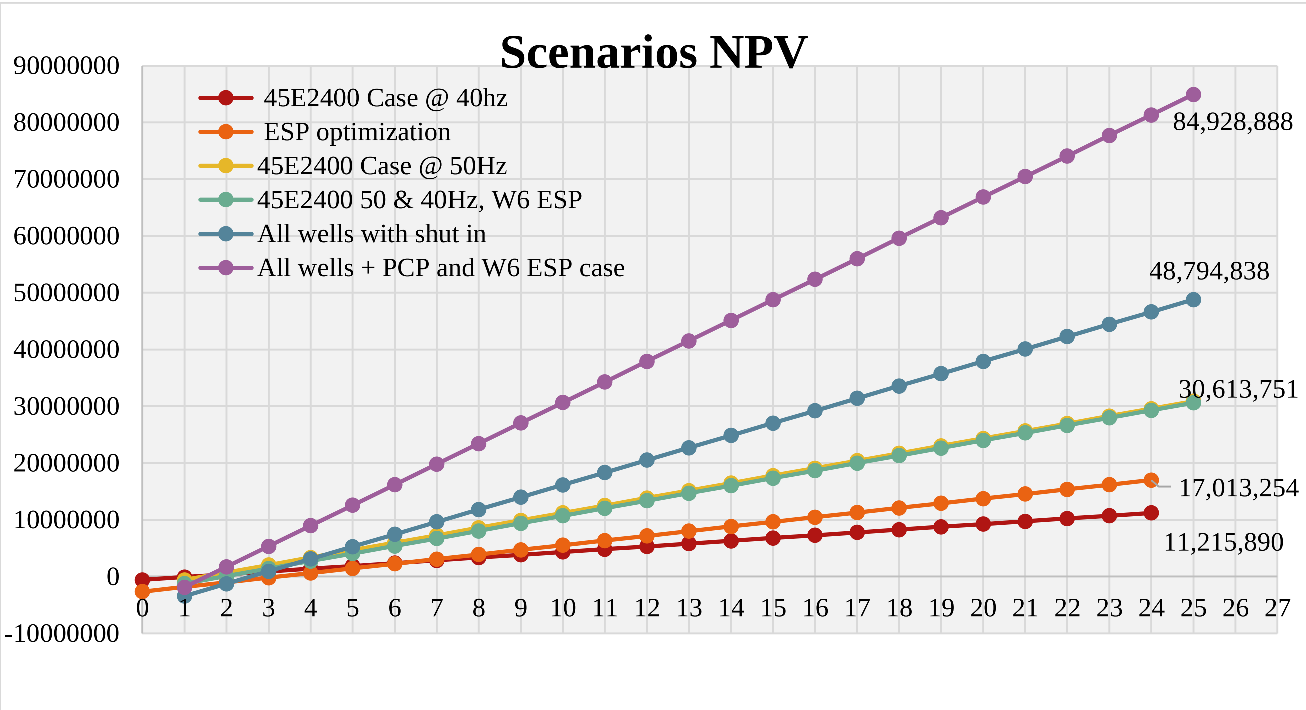

Figure 32: NPV result per each optimization scenario showing payback period (Step is monthly

Chapter 5

Conclusions and Recommendation

Chapter 5 Conclusions and Recommendations

5.1 Conclusions:

In this study the production performance of Sufyan field was investigated the field is suffering from sharp decline in reservoir pressure for many of Sufyan and Suf wells which affected artificial lift selection, pump sizing and performance, a production network model was initiated for surface and downhole production system for the field. Starting from reservoir up to wellhead then flows to gathering manifolds and finally to field processing facility. The study investigated the production performance of each producing well, and the production decline causes and proposes remedy actions to be applied to recover and increase production and to tackle production concerns.

, the below points conclude the main finding of the research:

- Hagedorn and Brown Revised (HBR) correlation was found to be the most suitable correlation to be used due to its low RMS compared to others two phase correlations.
- The created network model was calibrated to ensure reliable results using the actual production performance of the wells, sometimes empirical factors were used to match the actual performance such as BPU slip coefficient and the ESP head factor.
- The main artificial lift methods used were ESP, PCPs and BPUs. Sufyan field wells which completed via 5 1/2” linear casing, causing some difficulties to run bigger size artificial lift under liner depth, the simulation results showed that most of PCP wells are running within optimum range, therefore, PCP wells kept running with no alteration in their artificial lift types. Also, the BPU wells are producing normally, considering the low productivity of those wells if compared with other wells from same field.
- From the modeling many ESP wells suffered from very low pump performance due to the wrong pump size selection and sharp decline in reservoir pressure, when replaced by deep setting depth PCPs encouraging results were obtained. Only one well was replaced with a new ESP which is showed a good performance.
- Big size ESPs which anticipated producing more fluid than smaller size ESPs, when compared to the current pumps performance; it showed that smaller pumps tend to produce more steadily with high production rate, this mainly caused by down thrust issue in ESP which in long run affect pump efficiency and overall performance.

- Several scenarios for production optimization were applied and compared economically, the optimum case was to convert 4 wells running with ESPs to produce with deep setting depths PCPs and change ESP size for one well which is resulted in 70 % production increment and reduction in production cost.

5.2 Recommendations:

- The study recommended to use created PIPESIM model which could be valid for any future studies and ground model after update well parameters if any alteration occurred.
- Currently, it's recommended to apply optimum scenario for Sufyan field by replacing low performance pumps and apply workover to recover shut in wells, this scenario will increase the field production from 3138 BOPD to 5549 BOPD.
- For sharp decline in reservoir pressure, horizontal wells could be more preferable. Future studies should be deal with this pressure issue.
- In Sufyan field, Power supply is a concern in significant wells artificial lifting running with ESPs as per production performance record. Therefore, it is essential to guarantee power availability for future applications and if any infill drilling proposed in future.
- In future, for BPU wells; the created model could work as benchmark and should be used to predict and diagnose problems if detected.

References

1. Milan Stanko, *Petroleum production systems*, Nerwegian University of Science and Technology, Trondheim, Norway, Apr. 2019.
2. Hoffman, Petrosreamz; M.E. Stanko, NTNU, *Real-Time Production Optimization of a Production Network wtith ESP-Boosted Wells: A Case Study,* SPE-184189, presented at the SPE Middle East Artificial Lift Conference and Exhibition held in Manama, Kingdom of Bahrain, 30 November-01 December 2016.
3. *Sufyan Production Performance Review,Petroenergy Nov. 2016.*
4. *Standing, M.B. and Katz, D.L.: "Density of Natural Gases," Trans., AIME (1942) 146, 140.*
5. *Milan Stanko, Miguel Asuaje,; Cesar Diaz, and Miguel Guillmain,; Manuel Borregales, and Diana Gonzalez,; Michael Golan, Model-Based Production "Optimization of the Rubiales Field", Colombia SPE Annual Technical Conference and Exhibition held in Houston, Texas, USA, 28–30 September 2015*
6. *P. Aditama et. all Construction and implementation of integrated production network model in complex onshore operation. SPE paper 128381, presented in SPE Oil and Gas India Conference and Exhibition held in Mumbai, India, 20-22 January 2010.*
7. Kristian G. Hanssen, Bjarne Foss, Production Optimization under Uncertainty - Applied to Petroleum Production, IFAC-Papers On Line, Volume 48, Issue 8,2015, Pages 217-222, ISSN 2405-8963.
8. *Sthener R.V Campos, Urucu Field Integrated Production Modeling, SPE paper 128742, presented in SPE intelligent energy Conference and Exhibition held in Utrecht, The Netherlands, 23-25 Mar 2010.*
9. *Anand Kumar Jha, et. all, Implementation of integrated Network Optimization Model for Mumbai High Field- Crucial to Field-Wide Optimization, SPE paper 123799, Presented at the 2009 SPE offshore Europe Oil and Gas Conference and Exhibition held in Aberdeen, UK, 8-11 September 2009.*
10. Michael J Economides, A. Daniel Hill , Christine Ehlig-Economides (2007). *Petroleum production systems (Elsevier, 2007)*
11. *Pengju. Wang; M. L. Litvak, BP, USA; Khalid Aziz, Optimization of Production from Mature Fields, Stanford University, USA 2002.*

12. *Satyendra P Sinha, Ibrahim Al-kandar, and Khalaf Al-Anezi; Using an Integrated Approach to Production Optimization in A Mature Field: Burgan Field; search and discovery article; January 12, 2006.*
13. *J. D. Janson and P.L.Currie, 2009 Modelling and Optimization Oil. Modelling and optimization of oil and gas production systems TU Delft, 2009*
14. *-Mohammed A. Ayoub, Abdollah Esmaeili, "Production Optimization of an Oil Reservoir", Platform Journal of Engineering, Science and Society Vol. 9 Issue 1, pp. 27-35, (January - June 2013). ISSN 1511-6794*