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FACULTY OF MINING, GEOLOGY AND PETROLEUM ENGINEERING

Master study in Petroleum Engineering

POTENTIAL OF THE HYDRAULIC CONCENTRIC TUBULAR PUMPING SYSTEM

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POTENCIJAL HIDRAULIČKE PUMPE SA KONCENTRIČNIM OPREMANJEM TUBINGA

Sven Curiš

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Sažetak

S obzirom na globalni porast potražnje za energijom, prije svega nafte i plina, industrija dolazi svakodnevno do novih inovacija u svrhu zadovoljavanja sve veće potražnje. Jedno od rješenja u proizvodnji nafte i plina može biti i hidraulička pumpa u bušotini s koncentričnim opremanjem tubinga, koja je proizvedena i testirana u Sveučilištu u Leobenu u Austriji. Za bolje razumijevanje samog proizvodnog sustava, u ovom radu predstavljena su tri znanstvena rada posvećena ovom sustavu. Na temelju njih su postavljeni teoretski slučajevi gdje se provela ekonomska usporedba između ovog proizvodnog sustava i dubinskih sisaljki s klipnim šipkama koje se najčešće koriste u naftnoj industriji. Nakon izračuna u postavljenim slučajevima, može se doći do zaključka kako općenito takva inovacija zahtijeva manje energije u odnosu na najčešću proizvodnu opremu, što može dovesti do pomicanja granice ekonomičnosti u proizvodnji nafte te konačno do povećanog iscrpka ležišta.

Ključne riječi: koncentrično opremanje, hidrauličke pumpe, dubinske sisaljke s klipnim šipkama, financijska analiza, troškovi

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University of Zagreb
Faculty of Mining, Geology
and Petroleum Engineering

Master's Thesis

POTENTIAL OF HYDRAULIC CONCENTRIC TUBULAR PUMPS
Sven Curiš

Thesis completed in: University of Zagreb
Faculty of Mining, Geology and Petroleum Engineering
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Abstract

In regards with the global increase in energy demand, especially regarding oil and gas, the industry brings up new innovations daily in order to satisfy the increasing demand. One of the solutions in oil and gas production could be the hydraulic concentric tubular pump, which is invented and tested at the Montanuniversität Leoben, Austria. For a better understanding of this artificial lift system, three scientific works are presented dedicated to this system. Based on them theoretical cases were made and an economic comparison has been made between this system and the sucker rod pumps, which are the most common in the oil industry. After the calculations in set cases, it may be concluded that in general this innovation requires less energy in comparison with the most common artificial lift system, which can postpone the economic limit in oil and gas production and in the end increase the ultimate recovery factor of a reservoir.

Key words: concentric completion, hydraulic pump, sucker rod pumps, financial analysis, costs

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Sven Curiš

CONTENT

1. INTRODUCTION……………………………………………………………………..1

2. GLOBAL ENERGY TRENDS…………………………………………………………..2

3. OIL RECOVERY METHODS AND HYDRAULIC PUMPING.………………………..6

3.1. General principles of oil and gas production……………………………………………6

3.2. Hydraulic pumping in general…………………………………………………………..10

4. HYDRAULIC CONCENTRIC TUBULAR PUMPING SYSTEM……………………..16

4.1. Design………………………………………………………………………………16

4.2. Working principle…………………………………………………………………17

4.3. Surface facilities……………………………………………………………………18

5. CASES SETUP……………………………………………………………………21

5.1. Potential application for the hydraulic concentric tubular pumping system…………21

5.2. Creation of cases……….…………………………………………………………...24

5.2.1. Base case……………………………………………………………………..28

5.2.2. Case 2………...……………………………………………………………………30

5.2.3. Case 3……………………………………………………………………...31

5.2.4. Case 4……………………………………………………………………...33

6. SURFACE FACILITIES DESIGN……………………………………………………35

6.1. Separator design basics……………………………………………………………36

6.2. Surface facilities design results……………………………………………………42

6.2.1 Base case.…………………………………………………………………….42

6.2.2. Case 2….…………………………………………………………………….44

6.2.3. Case 3.……………………………………………………………………….46

6.2.4. Case 4……………………………………………………………………...48

7. ECONOMIC COMPARISON OF THE TWO SYSTEMS.……………………………..50

7.1. Event list during the project……………………………………………………..54

7.2. Base case…………………………………………………………………………56

7.3. Case 2……………………………………………………………………………..62

7.4. Case 3……………………………………………………………………………..64

7.5. Case 4……………………………………………………………………………..67

7.6. Summary………………………………………………………………………………69

8. CONCLUSION & RECOMMENDATIONS…………………………………………….70

9. LITERATURE……………………………………………………………………….71

LIST OF TABLES

Table 2-1. World primary energy consumption…………………………………………………2
Table 5-1. Key performance indicators for artificial lift systems………………………………22
Table 5-2. Additional key performance indicators for standard artificial lift systems regarding EOR reservoirs……………………………………………………………………………...23
Table 5-3. Summary of key parameters…………………………………………………..34
Table 6-1. Separator design for single well scenario for Base case……………………………42
Table 6-2. Surface pump design for single well scenario for Base case……..………………...42
Table 6-3. Separator design for triple well scenario for Base case……..……………………...43
Table 6-4. Surface pump design for triple well scenario for Base case……..………………....43
Table 6-5. Separator design for single well scenario for Case 2………………………………..44
Table 6-6. Surface pump design for single well scenario for Case 2………..…………………44
Table 6-7. Separator design for triple well scenario for Case 2………………………………...45
Table 6-8. Surface pump design for triple well scenario for Case 2………..………………..…45
Table 6-9. Separator design for single well scenario for Case 3………………………………..46
Table 6-10. Surface pump design for single well scenario for Case 3………..………………..46
Table 6-11. Separator design for triple well scenario for Case 3………………………………47
Table 6-12. Surface pump design for triple well scenario for Case 3………..………………...47
Table 6-13. Separator design for single well scenario for Case 4………………………………48
Table 6-14. Surface pump design for single well scenario for Case 4………..………………..48
Table 6-15. Separator design for triple well scenario for Case 4…………………………….…49
Table 6-16. Surface pump design for triple well scenario for Case 4………..………………...49
Table 7-1. Financial analysis for the CT pumping system in Base case single well scenario......57
Table 7-2. Financial analysis for the CT pumping system in Base case single well scenario (continued)…………………………………………………………………………........57
Table 7-3. Financial analysis for the SRP pumping system in Base case single well scenario....58
Table 7-4. Financial analysis for the SRP pumping system in Base case single well scenario (continued)……………………………………………………………………………....59
Table 7-5. Summary of economic parameters…………...……………………………………69

LIST OF FIGURES

Figure 2-1. World primary energy supply by source……….……………………………………3
Figure 2-2. World oil demand forecast by sector until 2050…………………...………………..4
Figure 2-3. World natural gas demand forecast by sector until 2050………...…………………5
Figure 3-1. Improvement of IPR and VFP curve…………………………...……………...6
Figure 3-2. Typical production curves for oil recovery stages………………………………..7
Figure 3-3. Typical primary, secondary, and tertiary cumulative recovery factors……………...9
Figure 3-4. Fixed pump installation types…………………………………………………...10
Figure 3-5. Free pump installation types……………………………………………………11
Figure 3-6. Double-acting reciprocating pump……………………………………………...13
Figure 3-7. Comparison of standard and concentric tubular completion………………………14
Figure 4-1. Pump design……………………………………………………………………16
Figure 4-2. Surface facilities………………………………………………………………...19
Figure 4-3. Surface facilities for gas wells…………………………………………………..20
Figure 5-1. Market share of artificial lift systems……...……………………………………21
Figure 5-2. Technical characteristics of the Base case dependent on tubing liquid level…...…28
Figure 5-3. Technical characteristics of the Case 2 dependent on tubing liquid level………...30
Figure 5-4. Technical characteristics of the Case 3 dependent on tubing liquid level………...32
Figure 5-5. Technical characteristics of the Case 4 dependent on tubing liquid level…...…......33
Figure 6-1. Horizontal separator……………………………………………………………35
Figure 6-2. Z-factor diagram……………………………...………………………………...36
Figure 6-3. Determination of maximal separator diameter…………………………………….40
Figure 7-1. Comparison of net earnings on a yearly basis for Base case single well scenario.....60
Figure 7-2. Comparison of net earnings on a yearly basis for Base case triple well scenario......61
Figure 7-3. Comparison of net earnings on a yearly basis for Case 2 single well scenario...…...62
Figure 7-4. Comparison of net earnings on a yearly basis for Case 2 triple well scenario...........63
Figure 7-5. Comparison of net earnings on a yearly basis for Case 3 single well scenario...…...65
Figure 7-6. Comparison of net earnings on a yearly basis for Case 3 triple well scenario...……66
Figure 7-7. Comparison of net earnings on a yearly basis for Case 4 single well scenario……67
Figure 7-8. Comparison of net earnings on a yearly basis for Case 4 triple well scenario...........68

LIST OF ABBREVIATIONS

EOR-Enhanced Oil Recovery

USD-United States Dollar

CNG-compressed natural gas

LNG-liquefied natural gas

IPR-inflow performance relationship

VFP-vertical flow performance

WAG-water-alternating gas

OPF-open power-fluid

CPF-closed power-fluid

CCTVT-Concentric Coiled Tubing Vacuum Technology

USA-United States of America

SRP-Sucker Rod Pump

ESP-Electric Submersible Pump

HP-Hydraulic Pump

GL-Gas Lift

PCP-Progressive Cavity Pump

CT-concentric tubular

TVD-true vertical depth

API-American Petroleum Institute

SR-slenderness ratio

GOR-gas oil ratio

CAPEX-Capital Expenses

OPEX-Operative Expenses

EBITDA-Earnings Before Interests, Taxes, Depreciation, and Amortization

NPV-Net Present Value

ROI-Return on Investment

€-Euro

LIST OF SI UNITS USED

%-percent

EJ-exajoule

RPM-revolutions per minute

mPa·s-millipascal second

ppm-parts per million

kg/m^3-kilogram per cubic meter

bar-bar

kW-kilowatt

HP-horsepower

W-Watt

°C-degrees Celsius

m/s-meters per second

µm-micrometer

Pa·s-pascal second

m-meter

m^2-square meter

m^3/s-cubic meter per second

K-Kelvin

s-second

m/s^2-meter per square second

m^3/m^3-cubic meter per cubic meter

m^3/d-cubic meter per day

m^3/h-cubic meter per hour

l/stroke-liter per stroke

kWh/d-kilowatt hour per day

kWh-kilowatt hour

MWh-megawatt hour

€/MWh-Euro per megawatt hour

€/m-Euro per meter

1. INTRODUCTION

According to the global energy trends, energy consumption is constantly rising, and it will rise until it reaches a peak demand, despite the global population and economy increase. Main reason for the decline in global energy demand is improved energy efficiency. Although oil and gas demand will also reach a peak demand and later the consumption will decline, reserves need to be constantly renewed. This may be done either by exploration and production from new oil and gas fields or improve the recovery of existing fields with enhanced oil recovery (EOR) methods. EOR methods also require efficient and flexible pumping systems, where the hydraulic concentric tubular pumping system comes in as an innovation. This new pumping system may also help to improve the production of reservoir which are richer with natural gas. In this thesis, three works will be presented, which cover the hydraulic concentric tubular pumping system. It is designed and manufactured in cooperation with the industry and tested in the Pump Test Facility at the Montanuniversität Leoben in Austria. This thesis will cover the technical properties of the pump and the potential for future application in the industry which always requires new reserves.

To show the potential of this pumping system, few theoretical cases will be introduced, which cover the heavy oil reservoirs with the possibility to use EOR methods and the gas condensate reservoirs which are richer in natural gas. To emulate these reservoirs, water cut is assumed to increase by 1% yearly for heavy oil reservoirs and by 2% yearly for gas condensate reservoirs. Also, surface facilities design is going to be necessary in order to completely design the pumping system. These surface facilities may provide the injection fluid to up to three wells, which is the reason why the triple well scenarios are also going to be applied. These cases will be put in an economic comparison between the hydraulic concentric tubular pumping system and the most common artificial lift system used today in the oil and gas industry, namely the sucker rod pumps. In order to design a sucker rod pump system which will be compared in a way that the same production rate and the same setting depth will be put in these cases, the RODSTAR software is going to help to achieve that goal. In the economic comparison, a list of failures will be presented which may occur during the selected project duration and the Net Present Value and Return on Investment rate for both systems will be calculated.

2. GLOBAL ENERGY TRENDS

The world's primary energy consumption is constantly rising. The growth rate of primary energy consumption in 2018 in comparison to 2017 is estimated to be 2.9%, which is more than the average in the past 10 years of 1.5%. Annual world's primary energy consumption form 2008 until 2018 can be seen in Table 2-1. (BP, 2019).

Table 2-1. World primary energy consumption (BP, 2019)

Year	Primary energy consumption (Petajoule)	Growth
2008	490 069	/
2009	483 169	-1.4%
2010	506 598	4.8%
2011	519 318	2.5%
2012	526 511	1.4%
2013	536 722	1.9%
2014	541 763	0.9%
2015	546 193	0.8%
2016	553 855	1.4%
2017	564 154	1.9%
2018	580 495	2.9%

The fall of growth in 2009 can be explained with the global recession which occurred in 2008, followed by the sudden growth of 4.8% in 2010. Another fall of growth, this time a fall to 0.9% can be explained with the crash of the oil price in 2014 from 160 United States Dollars (USD) per barrel (1 barrel=159 l) to around 50 USD per barrel. Despite the big fall in oil price, total primary energy consumption continued to grow to 2018's rate of growth of 2.9% with the average oil price of 65 USD per barrel (BP, 2019).

In the future the primary energy is expected to grow further until 2030 when the peak is predicted to be reached, despite the continuous population and economy growth. Although the world will be engaging in more energy consuming activities, such as heating, lighting, and transport, and it will be also producing more goods, it will do so with less energy. Owing to the steady electrification of the world's system and to cumulative advances in energy efficiency, the world will need less energy within a few decades. The graphical forecast of future primary energy supply by source can be seen in Figure 2-1. (DNV GL, 2019, a).

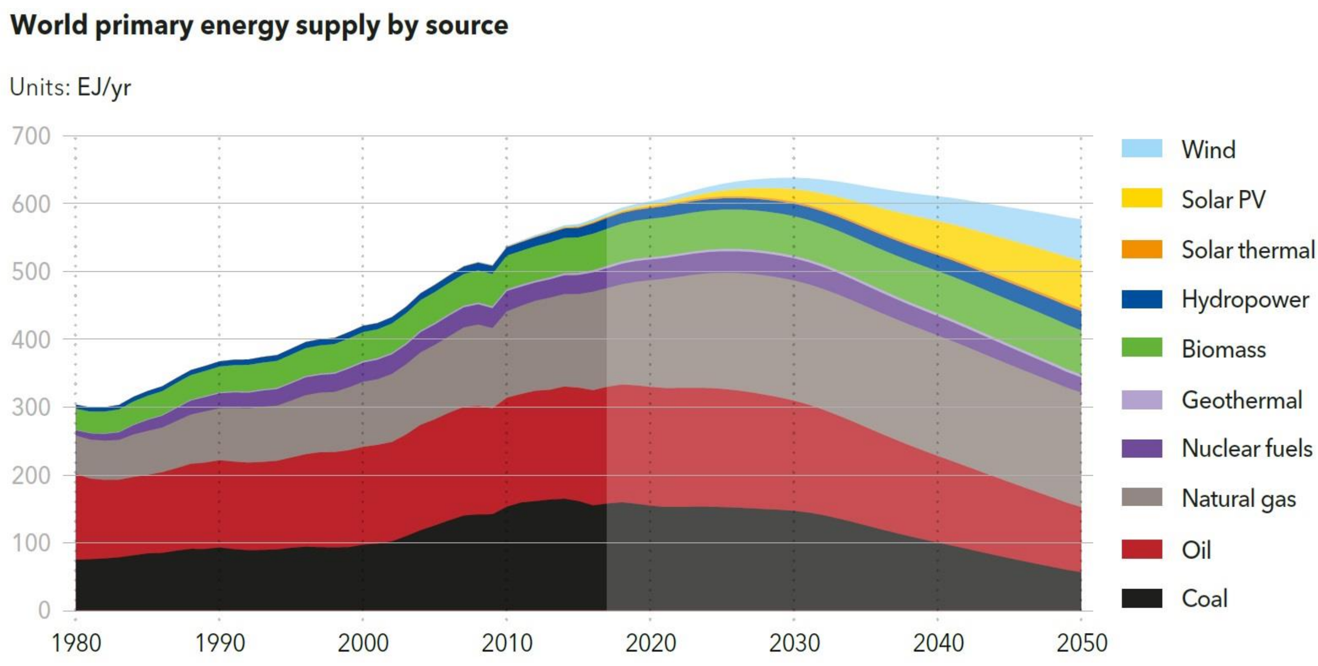

Figure 2-1. World primary energy supply by source (DNV GL, 2019, a)

As it can be seen in the previous figure, the peak energy supply is predicted to be 638 exajoule (EJ) by 2030. After that, this forecast predicts the drop of primary energy supply to 577 EJ by 2050. It is also visible that the renewable sources will be more and more present in the future as the primary energy sources, but the fossil fuels will still form the majority of world's primary energy supply by 2050. Regarding fossil fuels, oil and coal's energy supply will drop in the future, but the natural gas will rise because it is the cleanest fossil fuel, which is the best candidate as a transitional fuel to the low-carbon society (DNV GL, 2019, a).

Even though the global oil demand is forecasted to be reduced in the future, there will be a continued need to replace the reserves that are being depleted daily, long after the peak demand is reached. These will likely be developed from both smaller and often technically challenging reservoirs than those in operation today. The industry must continue to innovate and implement new solutions, to develop such resources in cost-effective and lower-carbon ways. While transport remains a major source of oil demand throughout the forecasting period, reliance on oil for this purpose will reduce by just over 50% between 2030 and 2050, from 8.9 million cubic meters per day to 4.5 million cubic meters per day. This will be influenced by growing use of electric and hybrid vehicles. What will the world oil demand be in the future can be seen in Figure 2-2. (DNV GL, 2019, b).

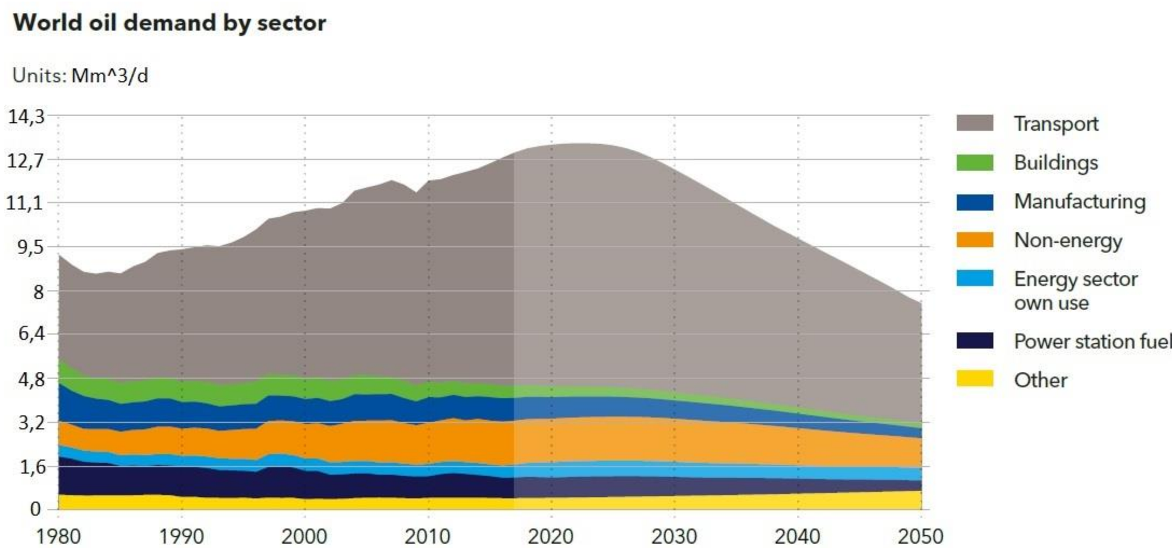

Figure 2-2. World oil demand forecast by sector until 2050 (DNV GL, 2019, b)

Unlike oil, gas has a much brighter future in the global energy mix. The global demand for the least carbon intensive fossil fuel has risen and will keep increasing in the future. According to DNV GL's forecast, gas demand will peak in 2033 at just below 5500 billion cubic meters per year. Thereafter, gas consumption will plateau and reduce slightly to 5170 billion cubic meters per year by 2050. The nature of the gas consumption will begin to change dramatically, as the gas supply begins to be decarbonized through the introduction of new forms of gas such as biogas, hydrogen, and syngas. Power generation will be the main consumer of gas in most regions, challenged by manufacturing in China, India, and Latin America. Gas use in power generation will increase over the next 15 years before levelling off and then declining towards the end of the forecast period, when wind and solar start to dominate power supply. Global gas consumption for buildings remains stable over the forecast period, while in manufacturing will increase in both relative and absolute terms to become the most demand intensive sector for gas beyond 2035. Gas use in transport will increase in the maritime and heavy vehicle sectors, in the form of compressed natural gas (CNG), including bio-CNG, and liquified natural gas (LNG). However, it will decline in light vehicle combustion engines in which batteries for fuel cells will take precedence. It is predicted that natural gas will meet 10% of all transport consumption of energy in 2050. Graphically the forecast is visible in Figure 2-3. (DNV GL, 2019, b).

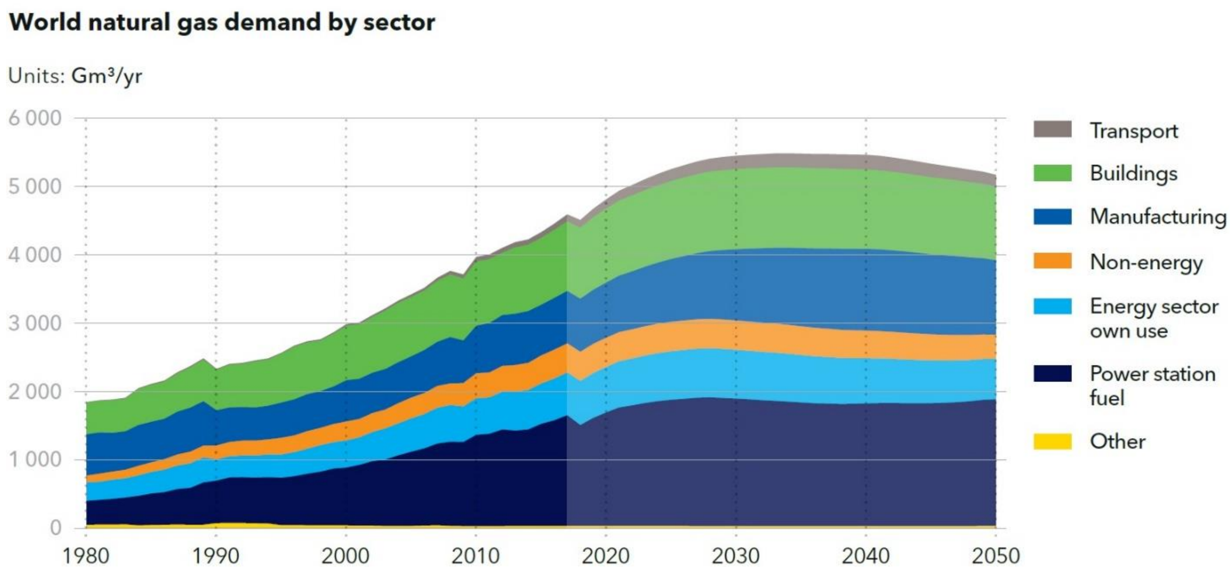

Figure 2-3. World natural gas demand forecast by sector until 2050 (DNV GL, 2019, b)

3. OIL RECOVERY METHODS AND HYDRAULIC PUMPING

3.1. General principles of oil and gas production

The production of oil can be classified into three main stages:

- primary recovery,
- secondary recovery,
- tertiary recovery.

Primary recovery is the natural fluid flow from reservoir through the well up into the surface without any need for artificial lift systems. Secondary oil recovery does include artificial lift systems, which are used to stimulate pressure in the well in order to increase oil production rate (e.g. gas lift, sucker rod pump system). It also includes injection wells with injection fluids like formation water which can maintain reservoir pressure. The ways of improvement of Inflow Performance Relationship (IPR) and Vertical Flow Performance (VFP) curve is presented in Figure 3-1.

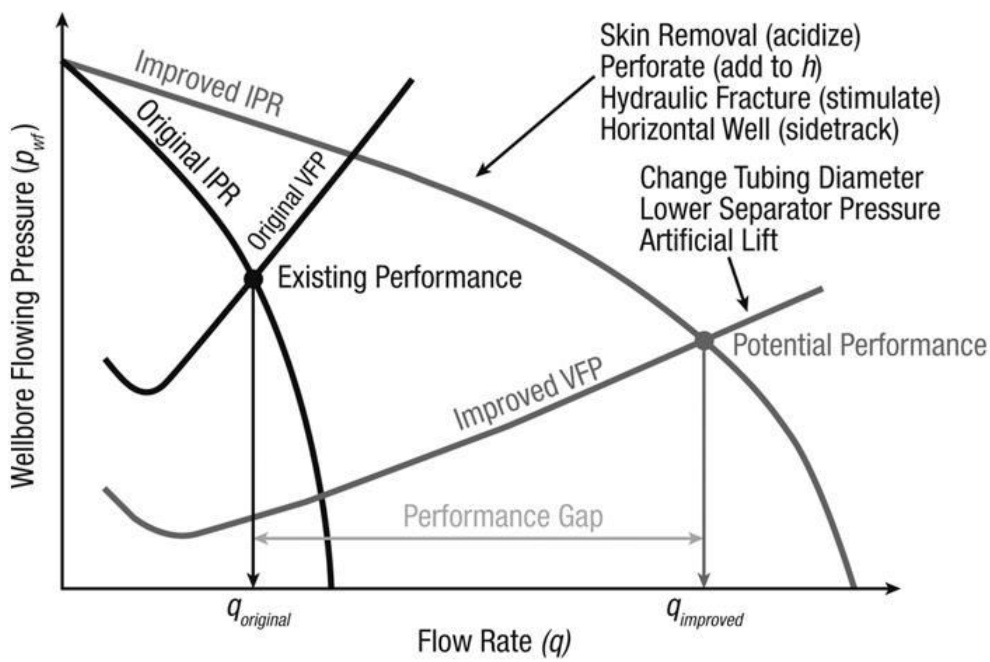

Figure 3-1. Improvement of IPR and VFP curve (Brkić, 2016)

Tertiary oil recovery is also known as enhanced oil recovery. EOR methods are applied at a later stage in reservoir lifetime to further increase the total oil recovery from the reservoir. Typical production curves with all three oil recovery stages can be seen in Figure 3-2.

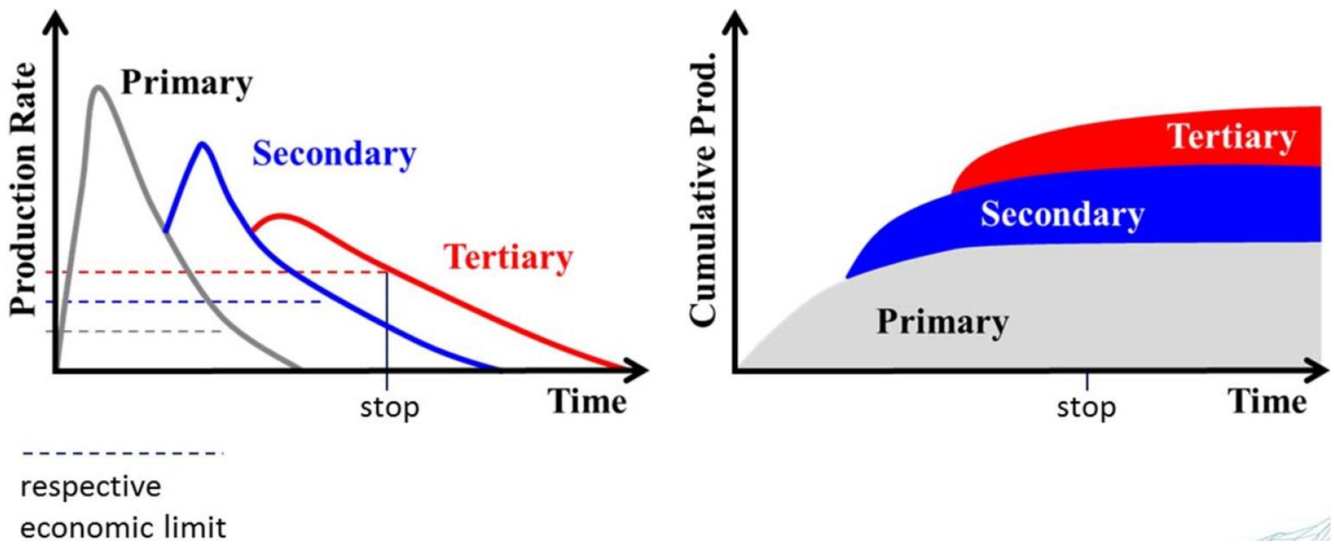

Figure 3-2. Typical production curves for oil recovery stages (Ott, 2018)

EOR methods can be divided into three techniques:

- thermal recovery,
- gas injection,
- chemical injection.

Thermal oil recovery contains several methods such as steam injection or fire flooding to reduce the viscosity of the oil in the reservoir, thus improving the ability of the high viscous oil to flow through the porous rock into the production well. The challenges of this type of EOR method are beside high temperatures and an increased water cut the fact that this type of recovery often employs deviated wells and the installed artificial lift system needs the capability to produce crude oil with moderate to high viscosity (Langbauer et al., 2018, a).

Gas injection is the most common EOR method. Gases such as natural gas, hydrogen, or carbon dioxide are injected to keep on the one hand the reservoir pressure high and on the other hand it expands in the reservoir to push additional oil to the producing well. It also improves the displacement process by adjusting the interfacial tension. In addition, if carbon dioxide is used for injection it will interact with the crude oil and will reduce the oil viscosity. The producing well must handle larger amounts of gas and when carbon dioxide is used, it can mix with water and create carbonic acid, which can interact with the installed equipment (Langbauer et al., 2018, a).

Chemical injection involves the injection of solutions to increase the mobility of the oil by reducing the surface tension. In polymer flooding polymer molecules often in combination with surfactants are mixed to the injected water to increase the viscosity of water, resulting in the reduction of water fingering tendency and to increase the sweep efficiency. Another chemical injection method is the water-alternating gas injection (WAG) which alters the injection of formation water, where surfactants may also be added, and carbon dioxide, resulting in a quick recovery of oil. Challenges for this method are the chemicals in produced fluid and relatively high viscous oils (Langbauer et al., 2018, a).

When these methods are successfully applied, they can increase the ultimate recovery by a single digit percentage. In the left part of Figure 3-3., a scenario is shown where during reservoir lifetime, all three recovery stages are applied in order to maximize the recovery factor. From the original oil in place, it can be seen stepwise that the recovery stages are applied one by one. On the right side of the same Figure, there are three scenarios shown which may represent ranges of the recovery factor for various reservoirs. Low scenario has the greatest residual percentage, the average is the same as in the left part of the Figure, and high could be one of the best case scenarios regarding total reservoir recovery.

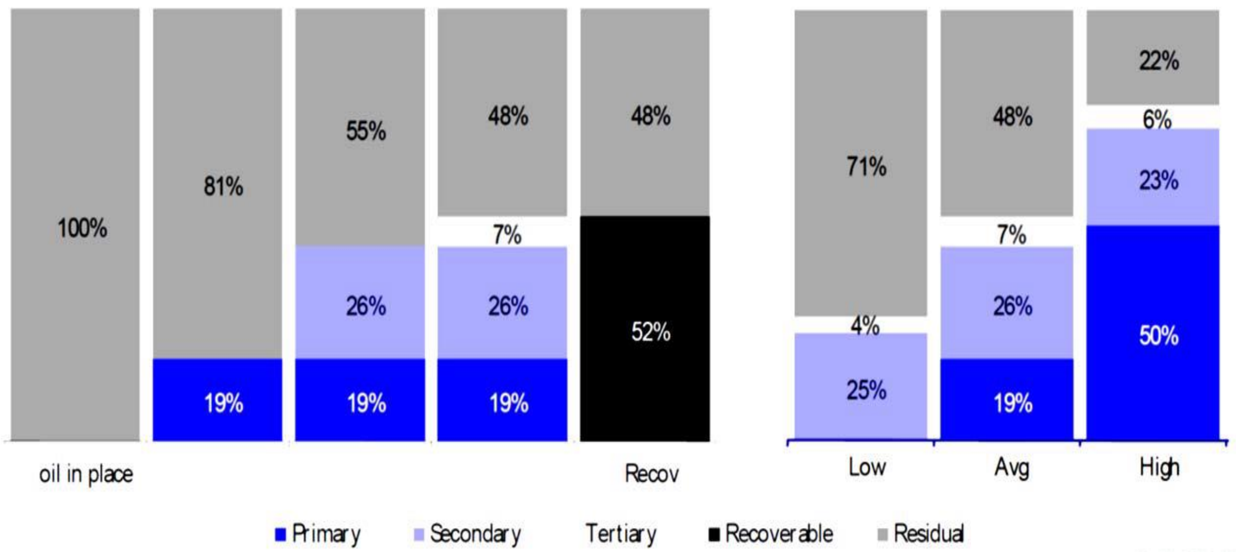

Figure 3-3. Typical primary, secondary, and tertiary cumulative recovery factors (Ott, 2018)

Unlike oil reservoirs, the recovery of natural gas from its reservoirs is slightly higher. In contrast to oil reservoirs, where the reservoir pressure can be kept almost constant, the pressure of gas reservoirs is continuously dropping by ongoing production thus over time the gas production rate declines. Gas production is typically accompanied by a small amount of water. As long as the production rate is high, water droplets are transported by gas flow to the surface. The decline in production rate results in liquid loading of gas wells, which can result in a liquid accumulation at the bottom of the wellbore. The result is an increase in bottom hole pressure, caused by the hydrostatic pressure of the liquid column. This leads to a production decrease and even to a stop of gas production (Langbauer et al., 2018, b).

The industry applies several different methods to overcome this problem. These are (Langbauer et al., 2018, a):

- tubing string size optimization (smaller tubing increases flow velocity),
- reduction of the wellhead pressure (boost of gas into flowlines with compressors),
- foam lift systems (changes surface tension),
- artificial lift systems.

3.2. Hydraulic reciprocating piston pump systems

The working principle of a hydraulic pump is to bring pressure from the surface down to the pump, which is installed at reservoir depth. This is done using a power fluid, normally oil or water, which is pumped down and returned either as a mixture of power fluid (also called open power-fluid system) and reservoir fluid in one tubing or separated in a dual tubing string completion (closed power-fluid system). There are two different downhole installation types for an open power-fluid system (OPF) available (Judmaier, 2019):

- fixed pump installation,
- free pump installation.

In fixed pump installation, the pump is attached to the end of the power fluid tubing and it has two variants which are shown in Figure 3-4. (Lake, 2007).

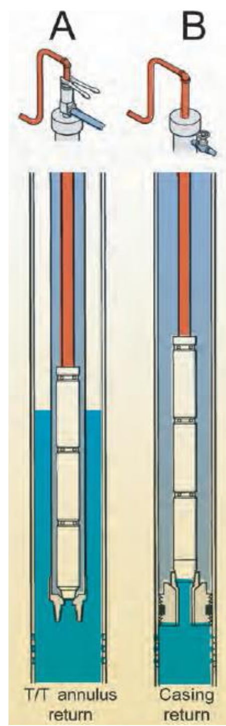

Figure 3-4. Fixed pump installation types (Lake, 2007)

The variant A shows a concentric tubing string system, where the power fluid is injected in the inner tubing. Produced fluid flows in the tubing-tubing annulus, while the free gas is produced in the casing-tubing annulus. Variant B is a single tubing system where the produced fluid flows in the casing-tubing annulus, whereby tubing is fixed by a packer. The challenge regarding this variant is that pump must handle all free gas (Langbauer, 2018, a).

In the free pump installation, the downhole pump is designed to be circulated in and out of the well inside the power fluid string. Two variants of this pump installation are shown in Figure 3-5. (Lake, 2007).

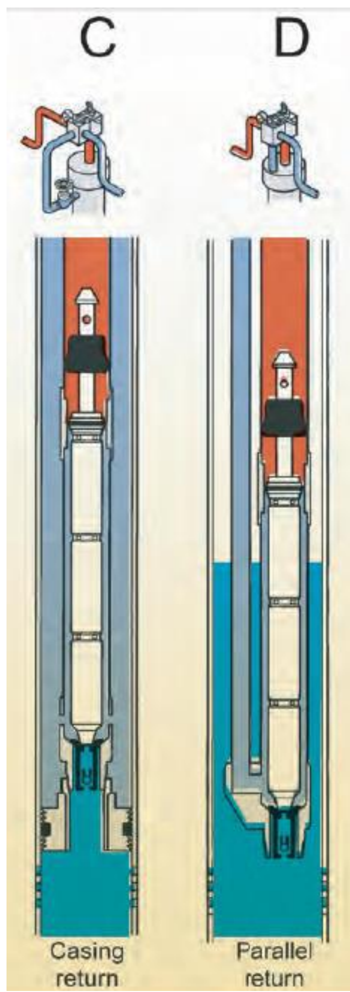

Figure 3-5. Free pump installation types (Lake, 2007)

Variant C shows a single tubing string where the pump fits inside the tubing string and the tubing string is fixed by a packer. As in variant B in the fixed pump installation, pump must handle all the free gas. Variant D shows a dual tubing completion where the 2-tubing string are separated from each other. If no contact of power fluid and casing is desired, this variant is preferable. Annulus can be used to produce free gas (Langbauer, 2018, a).

One of the biggest advantages of the free pump installation, compared to the fixed pump installation, is the possibility of circulating the pump in and out of the well, without running a tubing. In case of servicing the pump, this means a much faster and therefore much more cost-effective workover process. Additionally, the production losses are clearly decreased because of the lower standstill period during the change of the pump (Judmaier, 2019).

The reciprocating pumps can be either single-acting or double-acting. A single-acting pump closely follows rod-pump design practices and it is called this way because it displaces fluid on either the upstroke or downstroke. It cannot do it in both of them. Double-acting pump has suction and discharge valves for both sides of the plunger, which enables it to displace fluids to the surface on both the upstroke and downstroke. With either system, motion of the plunger away from a suction valve lowers the pressure that holds the valves closed. It opens as the pressure drops, and well fluids are allowed to enter the barrel or cylinder. At the end of the stroke, the plunger reverses, forcing the suction valve to close and opening the discharge valving. An example for double-acting pump is shown in Figure 3-6. (Lake, 2007)

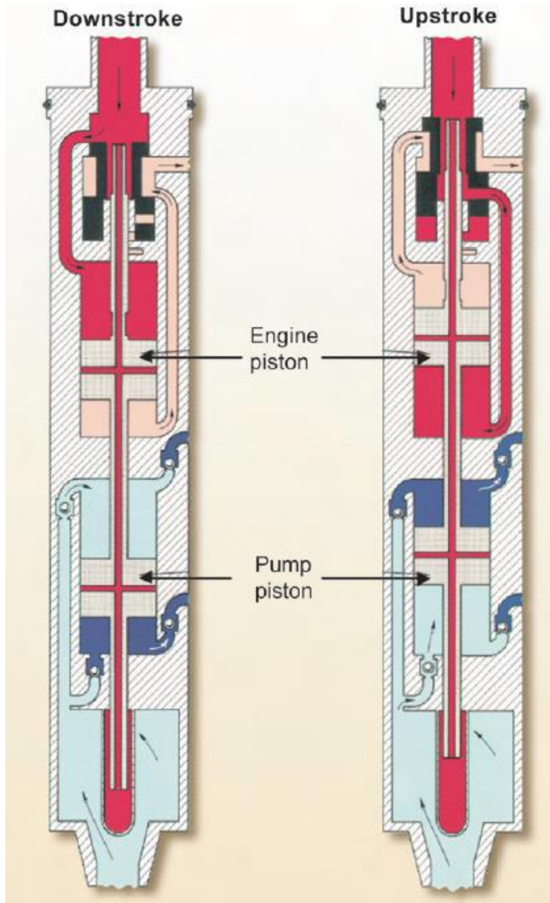

Figure 3-6. Double-acting reciprocating pump (Lake, 2007)

The rod is quite short and extends only to the engine pistons. The engine piston is constructed similarly to the pump plunger and is exposed to the power-fluid supply that is under control of the engine valve. The engine valve reverses the flow of the power fluid on alternate half-strokes and causes the engine piston to reciprocate back and forth. Four-way engine valves are used with engines that switch from high-pressure to low-pressure power-fluid exhaust on both sides of the engine piston in an alternate manner. These engine valves are used with double-acting pump ends to give equal force on both the upstroke and downstroke. Three-way engine valves are used with unequal-area engine pistons that always have high-pressure power fluid on one side and switch the power-fluid from high to low pressure on the other face of the piston. This type of engine valve is used on single-acting pumps that do not require a high force on the half-stroke because it is not displacing produced fluid to the surface (Lake, 2007).

For the application of a closed power-fluid system (CPF), two different kinds of designs are possible (Langbauer et al., 2018, b):

- standard dual completion,
- concentric tubular completion.

Comparison of these two systems can be seen in Figure 3-7.

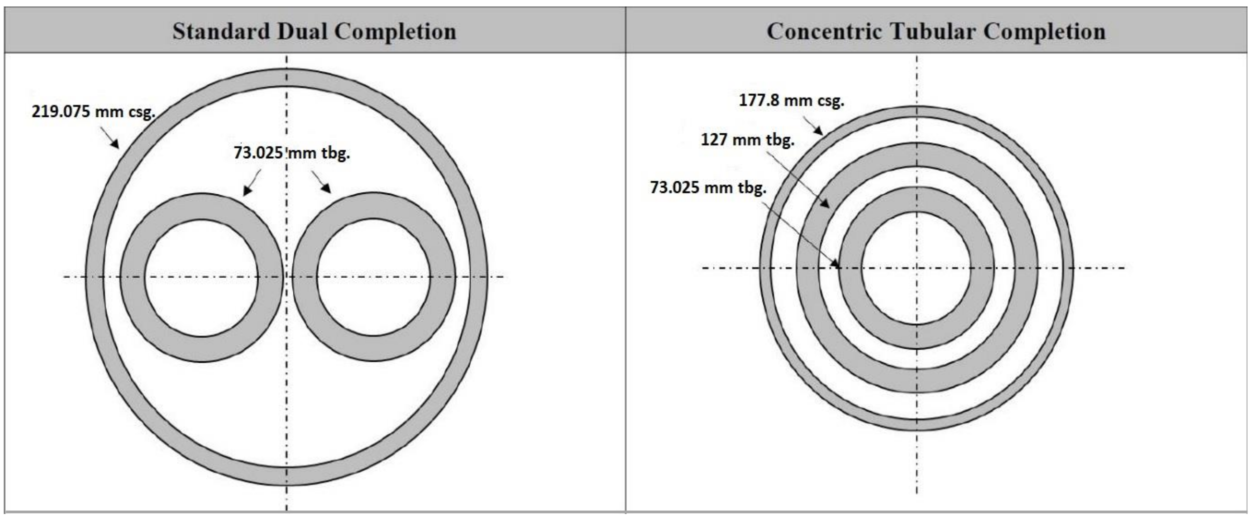

Figure 3-7. Comparison of standard and concentric tubular completion (Langbauer et al., 2018, b)

In the standard dual tubular completion, the power fluid for pressurizing the pump is filled into one of the two tubing strings, while in the other one the reservoir fluid is produced. In this kind of hydraulic pump completion, the annulus between the casing and the tubing strings is used to produce gas coming with the reservoir fluid. In the concentric tubular completion, one tubing string is installed in the other one which results in having two annular spaces. The power fluid is pumped down in the inner tubing string and pressurizes the pump, which produces the reservoir fluid in the inner tubing-tubing annulus. The outer annulus between outer tubing string and casing is like in the standard dual tubular completion used for producing gas (Judmaier, 2019).

The noteworthy advantages for the concentric tubular completion are a smaller required wellbore diameter thus less drilling costs and larger cross-sections opened for flow. A standard dual completion with two 73.025 mm (2 7/8’’) tubing strings requires at least a 219.075 mm (8 5/8’’) production casing, whereas a comparable concentric tubular system can be installed in a 177.8 mm (7’’) production casing. The installation and landing of a concentric tubular completion is slightly more complicated than a standard dual completion. At the bottom, packers or anchors can fix both tubing strings, whereas at the surface additional wellhead equipment is required for dual completion too (Langbauer et al. 2018, b).

In the oil and gas industry, concentric tubular technology is already applied in production and cleaning operations. A production example is a well in COPA field in Colombia, where the concentric tubing string allowed to install two Electronic Submersible Pump systems to produce from two different production zones, which were separated by a packer. The economic effects were that the costs associated with the drilling process reduced by 38%, 14% on the total drilling and completion investment and 50% on the environmental impact in the field (Mata et al., 2013).

Example for cleaning operations is the Concentric Coiled Tubing Vacuum Technology (CCTVT) was applied in the Tyonek field, located in Alaska, USA. This technology helped in removing sand from the reservoir. It has a low reservoir pressure, which means that traditional two phase sand removal operations using coiled tubing had not been successful. The CCTVT provided a second annular return route for wellbore solids while simultaneously boosting the return pressure. This permitted the cleanout to be performed with fluid only, which was a significant logistical and financial saving over two phase operations. The results were that CCTVT successfully removed significant quantities of solids from 5 low pressure wells, which provided incremental production in 4 wells. Over 16.3 tons of sand were removed and due to the unique nature of CCTVT operations, experienced supervision for these operations is required (Rafferty et al., 2007).

4. HYDRAULIC CONCENTRIC TUBULAR PUMPING SYSTEM

4.1. Design

This pumping system is designed and installed at the Pump Test Facility of the Montanuniversität Leoben in Austria. Unlike other hydraulic pumping systems, the new pump consists out of two pistons that are running in barrels, connected to each other with no connection to the surface. This piston arrangement, which represents the pump, can be lowered down to reservoir depth using a slickline or by circulation, which is very cost effective and fast in operation. If the pressure from the reservoir together with the tubing-annulus pressure, applied from the surface are high enough to exceed the downward acting forces, the pump moves upward and sucks the reservoir fluid through perforations in the casing and the ball valves 1 and 2 in the tubing shoes into the intake chamber. Reducing the tubing annulus pressure leads to a downward movement of the pump and the fluid in the intake chamber is pushed through the lower plunger, ball valve 3 and the connection channel into the discharge chamber, where it is produced through the predrilled section and the tubing (Judmaier, 2019). The scheme of the pump is shown in Figure 4-1. (Langbauer et al., 2018, a).

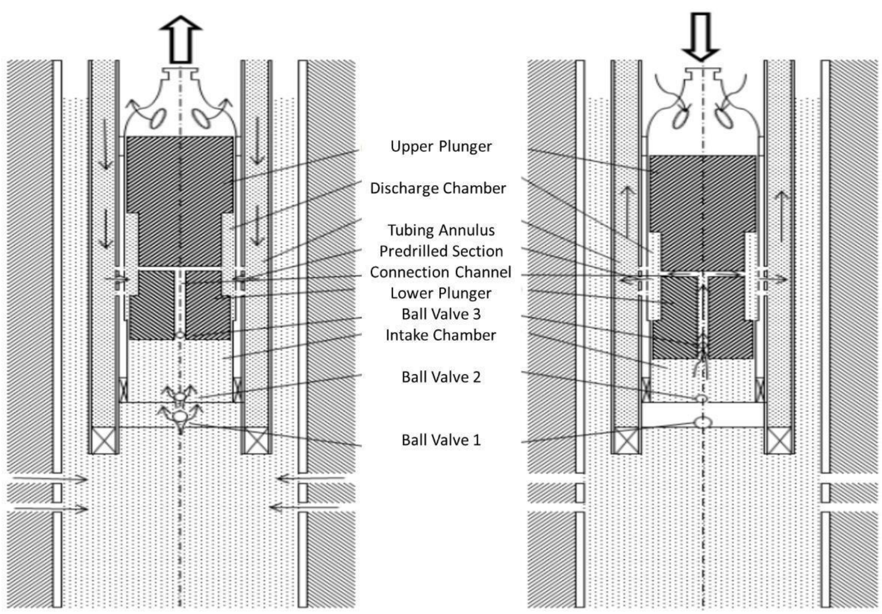

Figure 4-1. Pump design (Langbauer et al., 2018, a)

4.2. Working principle

The working principle of hydraulic piston pumps can be compared most likely to that of sucker rod pumps, because of the similar structural components, as check valves, pump plunger, and barrel are used. Typical single-acting systems only force fluid into the discharge channel of the pump during the upstroke or the downstroke, whereas double-acting pumps can utilize both strokes for fluid displacement.

The working principle of the presented new hydraulic piston pump is very simple. The inner tubing string is completely or partially filled with liquid, depending on the plunger assembly size. A high rate fluid production requires a big lower plunger sizes and a partially filled tubing string is required, whereas a low rate fluid production can be achieved by a completely filled tubing string.

When the low rate operation mode is selected, the pump can be circulated in and out by fluid pressure. For high rate production, the liquid level in the tubing string needs to be held constant at a defined level; slip volume through the pump must be compensated for. A wireline is required to pull and install the downhole pump. The tubing-tubing annular space is filled with discharged fluid. A directional valve at the surface connects the tubing-tubing annulus to the flow line and alternative to a high-pressure tank.

To initialize upward movement of the plunger assembly, a directional valve connects the high-pressure tank to the tubing-tubing annulus and disconnects the flow line. Reservoir fluid is sucked into the intake chamber of the downhole pump. As soon as the directional valve disconnects the high-pressure tank from the tubing-tubing annulus and connects the flow line instead, the plunger assembly is pushed downwards by the hydrostatic pressure of the liquid in the inner tubing string. Reservoir fluid is discharged and produced to the surface. The pressure magnitudes define the motion characteristics of the pump piston assembly. The annulus formed by the outer tubing and the casing is used for gas production.

The advantages of the new hydraulic pumping system are just one moving component (the plunger assembly) and most components are standardized sucker rod pump parts, thus cheap manufacturing costs. The limitation of the pump is the fact that during the upward and downward motion both liquid columns must be accelerated and decelerated (Langbauer et al., 2018, b).

4.3. Surface facilities

The surface facilities are regularly seen as a crucial point because of their high footprint on the ground level. For the hydraulic concentric tubular pump system, the following surface equipment is required:

- pressure vessels,
- storage tank,
- multiplex positive displacement pumps,
- separators and further equipment.

Overall high footprint can be reduced if the surface facility system is used for multiple wells at once as a multi-pad solution. This is suitable for small areas where several well were drilled, which are subject to production. Such places can be e.g. offshore platforms or areas with higher population or limited space.

Mostly positive displacement pumps are used at the surface facilities of a hydraulic pumping unit. This is common pumps with three or five horizontal plungers (triplex and quintuplex respectively) powered by electric motors. Alternatively, multistage centrifugal pumps could be an option, but it is rarely a viable option due to efficiency issues. Pumps are usually driven at a speed of 200-450 revolutions per minute (RPM) to reduce vibrations, noise emission and prevent dynamic problems. Pulsation dampeners are installed downstream of the pump, to reduce the effect of pulsating flow. These dampers can also detain pipe vibrations and lower the load on the pump itself.

A control manifold is installed to distribute the power fluid to each well. These manifolds are normally constructed in a modular way to handle a different number of wells. At the wellhead of a hydraulic pump installation, a wellhead control valve or a four-way valve is installed which can be switched into different modes. This is essential for free pumping systems to retrieve the pump by reverse circulation. A pressure gauge and a constant pressure controller are also installed. Separators are installed for the separation of reservoir fluid, power fluid and gas. A power fluid treating facility is required to remove abrasive materials such as solids in order to reinject the power fluid by desired standards. Typical surface facilities for this pumping system is shown in Figure 4-2. (Langbauer et al., 2018, b).

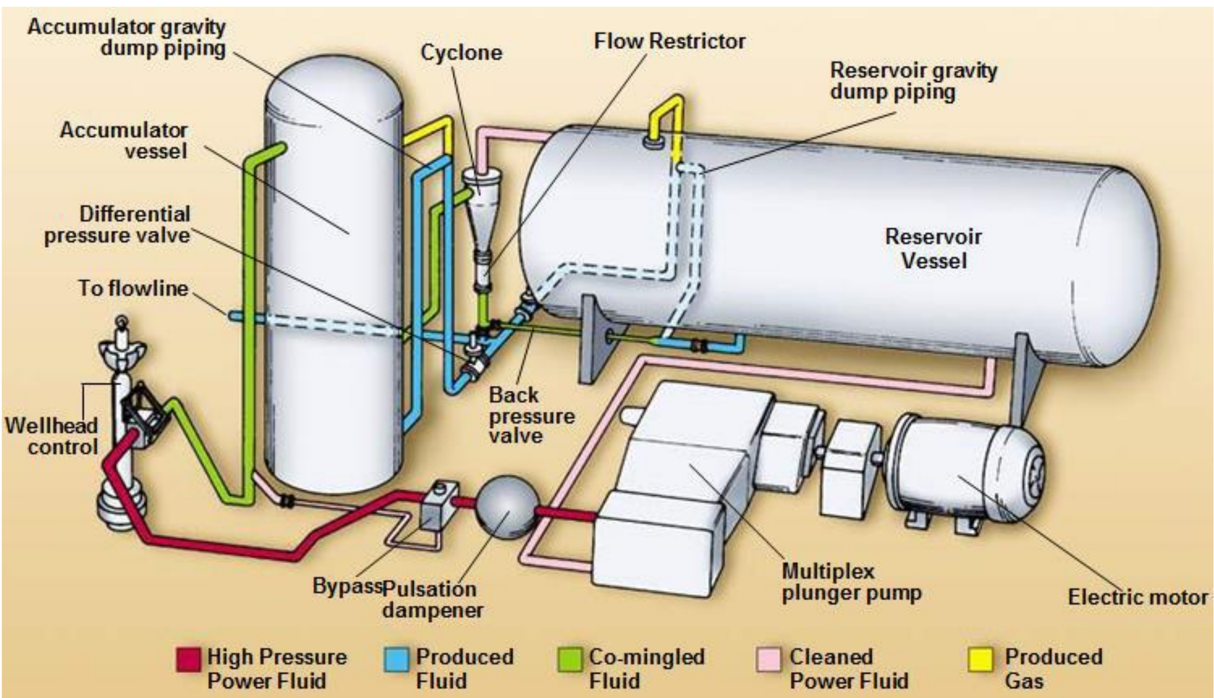

Figure 4-2. Surface facilities (Lake, 2007)

Regarding gas wells, the complexity and the footprint of surface facilities using the hydraulic concentric tubular pumping system are much smaller. During the downstroke of the plunger assembly, fluid is pushed in the tubing-tubing annulus to surface. Through the directional valve 1 it is directed into the flow line that is connected to the separator. In the separator light weight condensates are separated, pushed into the flow line and just the heavier fluid is used as a power fluid. Power fluid is compressed into a high-pressure tank by the continuously operating positive displacement pump. The high-pressure tank is connected to the directional valve 1. To change pump motion into downstroke, directional valve 1 switches, the connection to the separator is blocked and power fluid from the high-pressure tank is pushed into the tubing-tubing annulus. For the high rate fluid production directional valve 2 is required to keep the liquid level in the inner tubing by pumping a defined amount of power fluid constant. Figure 4-3. shows the surface facilities for the gas wells and the downstroke motion of the plunger assembly (Langbauer et al., 2018, b)

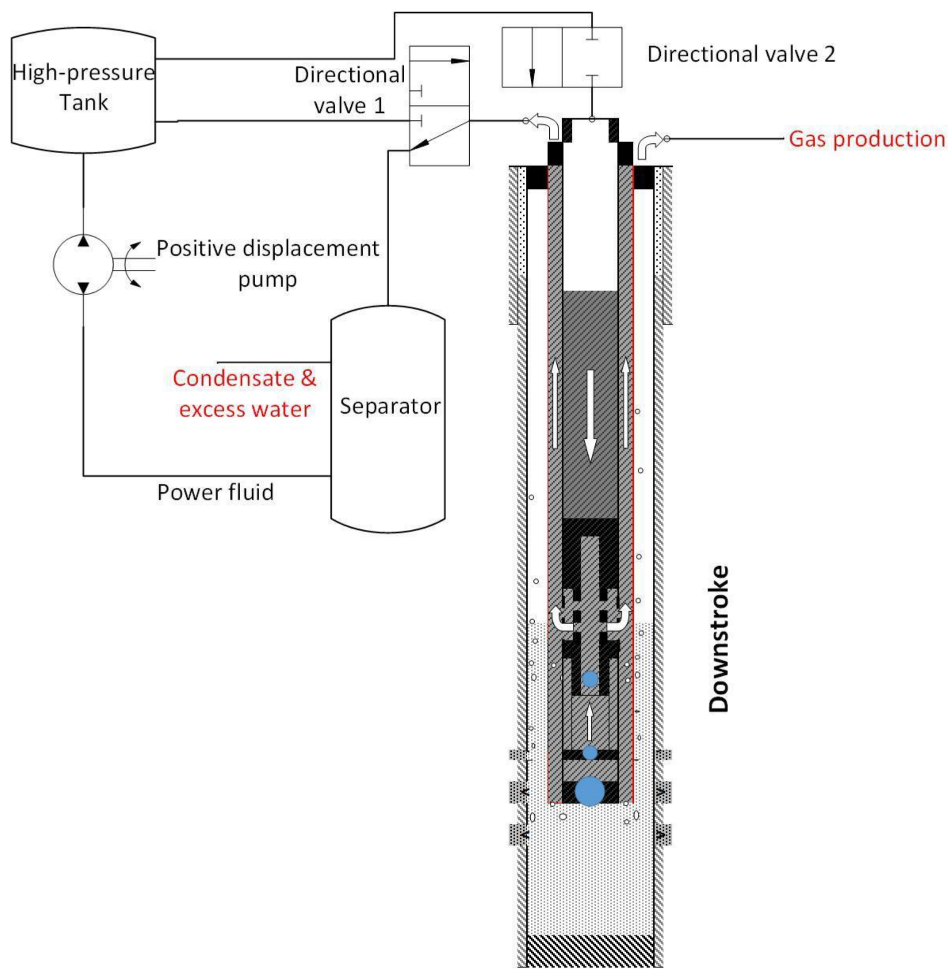

Figure 4-3. Surface facilities for gas wells (Langbauer et al., 2018, b)

5. CASES SETUP

5.1. Potential application for the hydraulic concentric tubular pumping system

Typical artificial lift systems which are used in petroleum industry are:

- Sucker Rod Pump (SRP),
- Electric Submersible Pump (ESP),
- Hydraulic Pumps (HP),
- Gas Lift System (GL),
- Progressive Cavity Pump (PCP).

Even though Hydraulic Pumps, Gas Lift Systems and Progressive Cavity Pumps have a relatively small market share, which can be seen in Figure 5-1., they can still be compared with the most common artificial lift systems regarding certain advantages and disadvantages in specific well and reservoir conditions. Table 5-1. shows the key performance indicators for artificial lift systems.

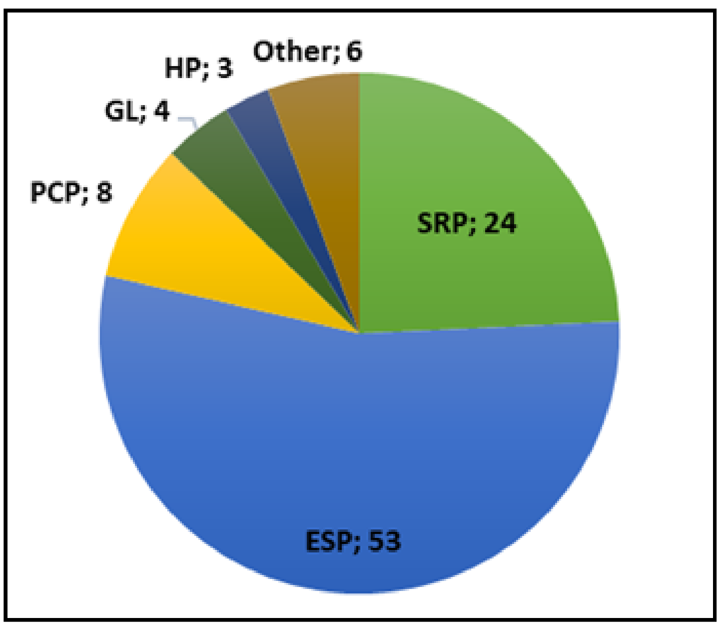

Figure 5-1. Market share of artificial lift systems (Langbauer, 2018, b)

Table 5-1. Key performance indicators for artificial lift systems (Langbauer et al., 2018, b)

	SRP	ESP	HP	GL	PCP
Gas handling ability	Poor (for free gas through a pump)	Poor (for free gas >5% through a pump)	Poor (for free gas through a pump)	Excellent	Poor (for free gas through a pump)
Temperature limitation	Good	Fair	Excellent	Excellent	Poor
Depth limit	Fair	Good	Excellent	Good	Fair
Well inclination	Poor	Good	Excellent	Excellent	Poor
Well intervention	Fair (Workover rig required)	Fair (Workover rig required)	Excellent (circulation form surface, wireline)	Fair (Workover rig required)	Fair (Workover rig required)
Water Cut	Excellent	Excellent	Excellent	Poor	Excellent
Corrosion handling ability	Good to excellent	Fair	Good/excellent (using chemical treatment in the power fluid)	Good (inhibitor in the injection gas)	Fair
Low volume lift capabilities	Excellent	Poor	Excellent	Fair	Excellent
Surface facilities footprint	Fair	Good	Poor	Poor	Excellent

There are additional key performance indicators in EOR reservoirs for artificial lift systems which are defined in Table 5-2.

Table 5-2. Additional key performance indicators for standard artificial lift systems regarding EOR reservoirs (Langbauer et al., 2018, a)

	SRP	ESP	HP	GL
Organic precipitations	Fair (treatment required)	Fair (treatment required)	Good/excellent	Fair (treatment required)
High viscosity fluid handling capability	Good (for up to 200 mPas and low rates)	Fair (limited to about 200 mPas)	Good/excellent (for fluid density less than 1029 kg/m^3 with viscosity less than 800 mPas	Fair (problems for fluid density of 959 kg/m^3 and higher, 20 mPas viscosity)
Sand and solids handling ability	Fair (high solids and sand production is troublesome for low oil viscosity)	Poor (requires <100 ppm solids)	Fair to poor (operating with 3% sand)	Excellent

As it can be seen in Table 5-1. and Table 5-2., most limitations are handled good or excellent with the Hydraulic Pump Systems. They may work well for lots of kinds of well, e.g. deep high temperature wells or inclined wells. It may also work good for mature fields, when the production rate is reduced, and water cut is increased. For hydraulic concentric tubular pumping system, specifically, gas handling ability is good because free gas goes through the casing-tubing annulus and surface facilities footprint can be mitigated when a surface facility system is installed to inject the power fluid in multiple wells via control manifold. Sucker Rod Pump is suitable only for vertical production wells. Depth of the pump is also limited, because of rod string length and maximum load which a pump jack can handle. ESP can be only installed if a high fluid flow rate is expected. Sand and solids are also a big problem for ESP systems, where solids with concentration in the fluid less than 100 ppm is required to run the system smoothly.

5.2. Creation of cases

The cases which will be presented in this thesis are created by the author. The intention is to cover both the heavy oil reservoirs, which require EOR for better production and the reservoirs, which contain more natural. There will be 2 cases for each of those two scenarios and the difference in technical characteristics between them will be the stroke length of the concentric tubular (CT) pumping system. Each case is going to have a single well variation and triple well variation as surface facilities costs are reduced for concentric tubular system for triple well compared to three surface facility systems for single well variation. The injection fluid density is assumed to be the same as production fluid density due to the fact that concentric tubular pumping system went under several test runs, where water was both injection and production fluid at the same time. For further economic calculations, the cost of injection fluids and operator salary will be neglected. Cases will be economically compared with the sucker rod pumps, as the working principle for both systems is the same.

General reservoir characteristics which are common for all four cases are the following:

- Reservoir pressure=75 bar,
- True vertical depth (TVD) of the reservoir is 1500 m.

Also, all reservoirs have the following completion scenario:

- Outer tubing diameter of 0.1397 m (5.5 inches) (only for CT system),
- Tubing diameter of 0.0889 m (3.5 inches) (for both systems),
- Concentric tubular system will have piston dimensions of 0.0635 m (2.5 inches) and 0.05715 m (2.25 inches) which is the diameter of upper and lower piston, respectively.

The charts, which will be presented later for concentric tubular pumps, will show the technical characteristics of the system for each case depending on various tubing fluid levels. The fluid level, in consultancy with Senior Researcher Langbauer, has a target pump efficiency of 50% for hydraulic concentric tubular pumps. It was selected in order to maximize the production rate for each case without compromising the efficiency too much, so the required power will not be too high compared to the useful power. Graphs will show the following pump characteristics:

- Liquid level in meters (m),
- Production rate expressed in cubic meters of liquid per day (m^3/d),
- Equivalent pressure or the casing head pressure in static conditions, expressed in bar,
- Strokes per minute (SPM) multiplied by 10 for better visual presentation,
- Pump power (useful power) multiplied by 10 for better visual presentation (kW) and,
- Pump efficiency.

The production rate with the following equation:

$$Q=SPM*V*60*24 \tag{5-1.}$$

where:

- Q is the daily production rate (m^3/d),
- SPM is number of strokes per minute and,
- V is volume produced per one stroke (m^3).

Strokes per minute are easily calculated as one minute divided by the duration of one stroke. The volume is calculated with the following equation:

$$V=l_s*A_{lp} \tag{5-2.}$$

where:

- V is the volume produced per one stroke (m^3),
- l_s is the stroke length (m) and,
- A_{lp} is the area of the lower piston (m^2).

The casing head pressure is calculated as follows:

$$p_{ch}=(p_{wh}*dA+F_i-p_r*A_{lp}-F_a)/(dA*100\,000) \tag{5-3.}$$

where:

- p_{ch} casing head pressure (bar),
- p_{wh} is the wellhead pressure (Pa),
- dA is the difference between upper and lower piston area (m^2),
- F_i is the fluid force inside the inner tubing (N),
- p_r is the reservoir pressure (Pa) and,
- F_a is the fluid force in tubing-tubing annular area (N).

The useful power is a product of useful energy during one stroke multiplied with the duration of upstroke or downstroke. Pump efficiency is the same useful energy divided by the total consumed energy during one stroke.

The sucker rod pumps, which will be compared to the concentric tubular system are chosen with the help of program RODSTAR, which is a simple tool to optimize the sucker rod pump selection based on a couple of parameters. These may be broken down in following steps (Svinos, 2013):

- Enter target production or IPR data,
- Enter rod grade or material,
- Enter rod diameter limits,
- Enter pumping unit and stroke,
- Run the program,
- In case of overloaded or underloaded rods, the rod grade or material had to be adjusted;
- In case of overloaded or underloaded gearbox, the pumping unit had to be adjusted;
- In case everything is good, the sucker rod pumping system is optimized.

For the purpose of this thesis, the target production is the same for both systems as the costs between them are compared. This means that for each case, when the production rate is being calculated for the concentric tubular system, the same value is inserted in RODSTAR for the sucker rod pump. Regarding the rod string, it can be automatically optimized by the software so that was the selected step in order to optimize the rod grade and materials. The only limit is that the rods are not wider in diameter than the polished rod, which is in every case 25.4 mm (1 inch). In all cases, the sinker bars are also necessary, which can be wider than the polished rod. The reason that is that they absorb the downhole compressive forces and keep the other rods in tension (Downhole Diagnostic, 2014). Plunger size for all cases is going to be 63.5 mm. Once the pumping unit has been selected, the program is run to evaluate the whole system based on the parameters. Two main barriers are the loads of rod string and the gearbox. In cases where rods and/or gearbox of the pump jack are overloaded or underloaded, then a new selection has to be made in order to comply with these two constraints. The evaluation of the sucker rod pumping units is also going to be shown here with the Figures created in RODSTAR. They will show the following evaluation scores:

- Balanced gearbox loading score,
- Maximum rod loading score,
- Structure loading score,
- System efficiency score,
- Bottom minimum stress score and,
- Minimum polished rod loading score.

If there are warnings and recommendations on how to improve the system, there will be a note for each of these categories. The main goal for this thesis regarding sucker rod pump design was to comply with the constraints and to maximize the total score of the sucker rod pump system.

5.2.1. Base case

Base case is one of two heavy oil cases where the fluid density has a value of 1030 kg/m^3, with the stroke length of the concentric tubular pumping system of 6 meters. This case will be the reference to other cases as their technical and reservoir characteristics will be compared to this one. Initial water cut for this case is assumed to be 80%. Figure 5-2. shows the technical characteristics of the Base case depending on the liquid level of production fluid.

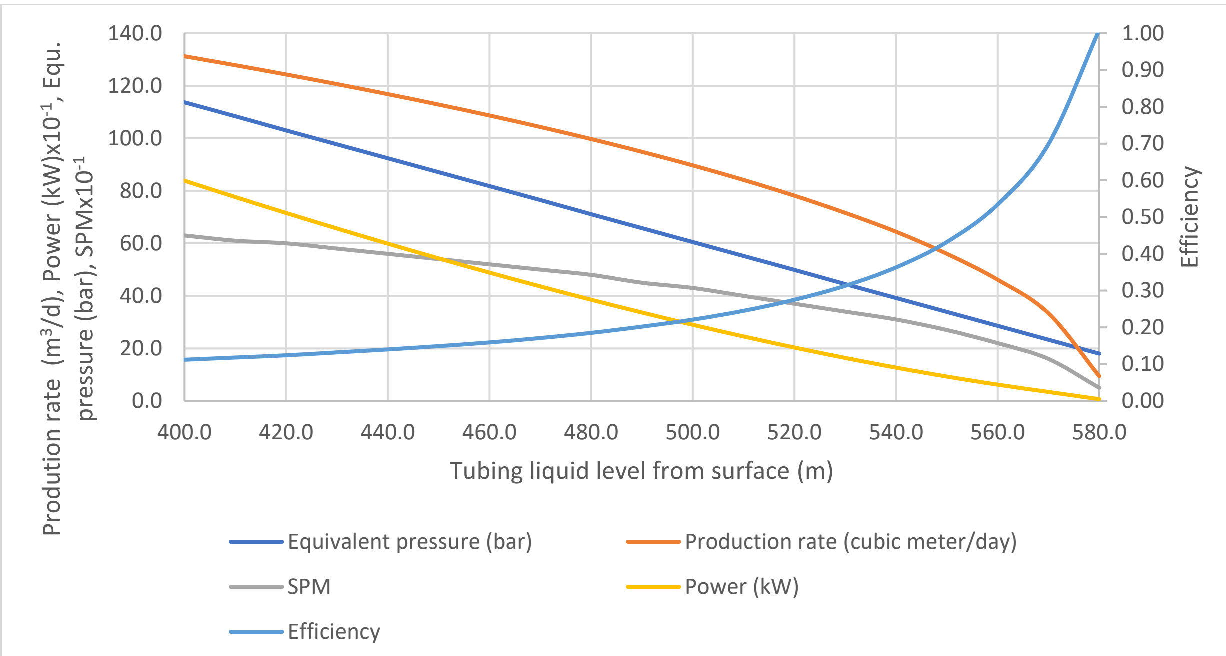

Figure 5-2. Technical characteristics of the Base case dependent on tubing liquid level

As earlier mentioned, the target pump efficiency is about 50% so based on this chart, the selection is that the tubing liquid level will be on the depth of 560 meters. Other important characteristics, which will be noted here are the daily liquid production of 46.18 cubic meters. As the water cut has a value of 80%, the liquid can be broken down into water which has a density of 1050 kg/$m^3$and oil with the density of 950 kg/m^3. The number of strokes per minute for this case is going to be 2.2 SPM.

The sucker rod pump which is being selected for this case for comparison is the Lufkin Mark II pump with the API size being M-114-143-74. The letter and the numbers may be explained as follows:

- M stands for the Mark II pumping unit,
- 114 stands for the maximum torque expressed in pounds inches,
- 143 stands for maximum dynamic polished rod load expressed in 100 pounds of force,
- 74 stands for maximum polished rod stroke length expressed in inches.

The pump setting depth for the sucker rod pump system in this case is 600 meters. It is an insert pump where the rod string is structured as following:

- Norris K40 rods with the diameter of 19.1 mm and the length of 450 meters,
- Norris K40 rods with the diameter of 15.9 mm and the length of 100 meters,
- Flexbar C sinker bars with the diameter of 38.1 mm and the length of 50 meters.

The motor, which is being used for this case is a NEMA D motor with a power of 6 kW (8 HP). The system efficiency is 59%, which is slightly better than the 53% from the concentric tubular system and the number of strokes per minute is also greater due to the fact that this pump has much smaller stroke length than the concentric tubular pumping system. In this case, 74 inches is equal to 1.8796 meters, which is a little bit more than 3 times smaller than 6 meters, which has the other system. The number of strokes per minute here is 6.64. The reason the stroke length is not long is that RODSTAR software reported the error, stating that the gearbox was underloaded. For this reason, the sucker rod pumps with smaller maximum torque, which also has less polished rod stroke length. According to the RODSTAR report, the system design score is graded as 95%. All the categories, which are mentioned in Chapter 5.2., have a score of 100, except the structural loading which has a score of 70. The warning was that the structural loading was very low (54%). In order to optimize that, a pumping had to be selected with lower structural rating so that the loading is between 70% and 95%. As this is not one of the key constraints to design the sucker rod pumping system, the selected pumping system was appropriate for this case.

5.2.2. Case 2

The second case has almost all the same characteristics as the Base case. The difference is that the stroke length of the concentric tubular pumping system is extended from 6 to 8 meters. Consequently, the production rate is Case 2 is greater than in Base case, as this can be seen in Figure 5-3.

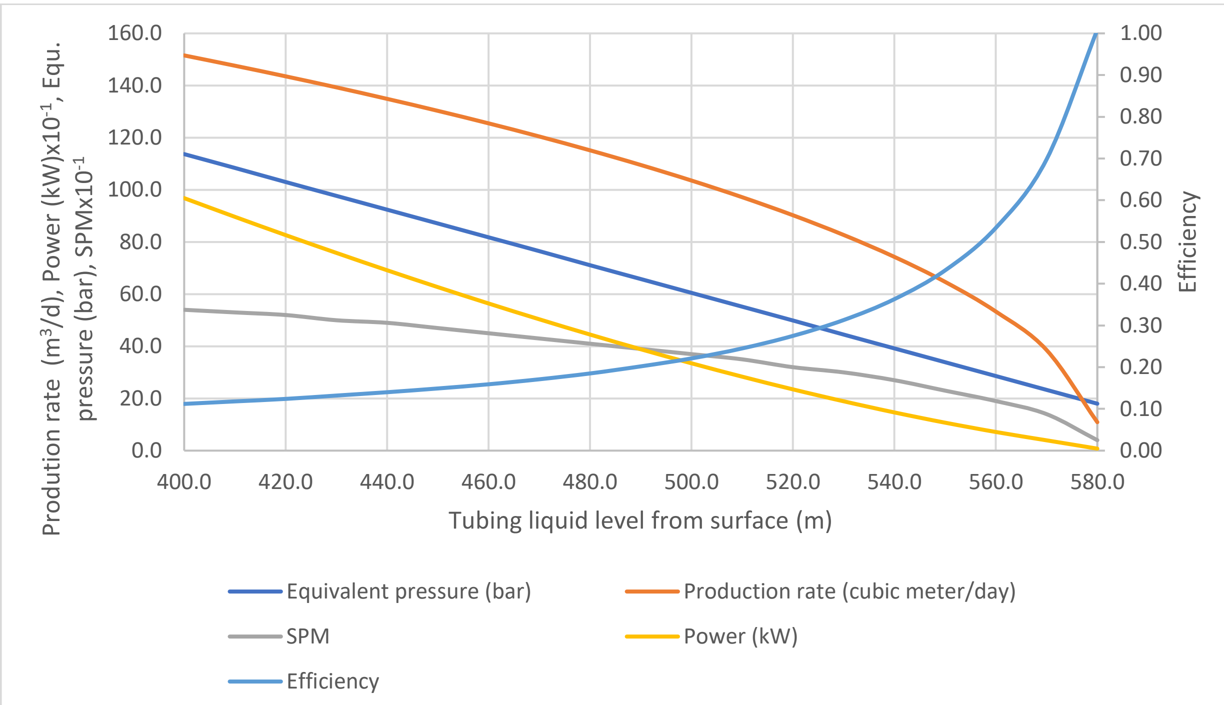

Figure 5-3. Technical characteristics of the Case 2 dependent on tubing liquid level

Tubing liquid level for this case remains unchanged, as the target efficiency is reached at that depth. The production rate increased from 46.18 to 53.33 cubic meters of liquid per day. With the greater stroke length, the number of strokes per minute is decreased from 2.2 SPM to 1.9 SPM. Also, the subsurface pump power increased from 619 to 715 W.

The sucker rod pump for this case remains the same, but some changes had to be made in order to produce the required amount of liquid. The rod string went through the following changes:

- Length of Norris K40 rods with the diameter of 19.1 mm decreased by 18.28 meters,
- Length of Norris K40 rods with the diameter of 15.9 mm increased by 7.14 meters and,
- Length of Flexbar C sinker bars with the diameter of 38.1 mm increased by 9 meters.

The pump motor power was increased from 6 to 7.46 kW (from 8 to 10 HP) and the number of strokes per minute increased to 7.63 SPM. The evaluation of the system shows a system design score of 95%. As in Base case, all the categories have a perfect score, except the structure loading which has a score of 70. The reason for it is that the structural loading is very low (56%). As it is not one of the key constraints, the pumping unit is suitable for Case 2.

5.2.3 Case 3

The next two cases simulate reservoir conditions, where more natural gas and much lighter oil are present. The main change, which this case has compared to Base case is that the fluid density will be 900 kg/m^3. The water cut is assumed to be 50%, which means that the water density is assumed to be 1050 $kg/m^3$and the oil density is only 750 kg/m^3. This means that the oil may be classified as a gas condensate. As mentioned before, the injection fluid is also lighter comparing to the previous two cases. The technical characteristics for Case 3 are shown on Figure 5-4.

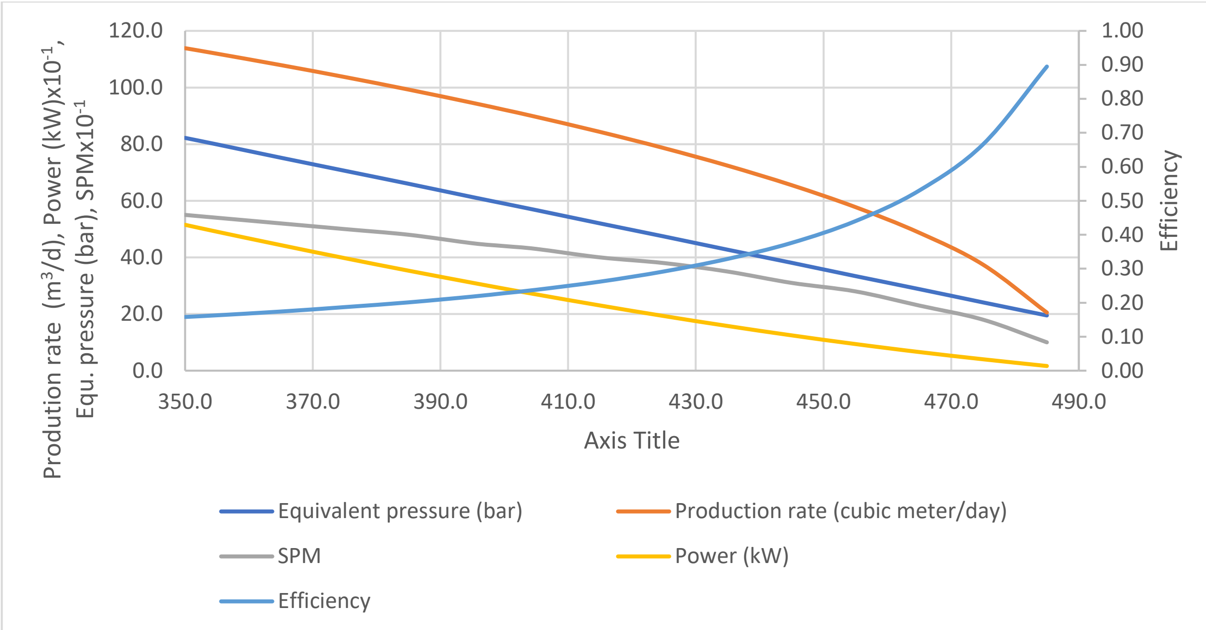

Figure 5-4. Technical characteristics of the Case 3 dependent on tubing liquid level

In general, the target tubing liquid level is shallower than in previous two cases. In this case, the tubing liquid level is going to be 465 meters with the pump efficiency of 53%. Also compared to Base case, the daily production rate slightly increased due to the fact that both the power and production fluid have smaller densities. The casing head pressure in static conditions, strokes per minute and pump power also experienced a slight increase in their values in comparison to Base case. Specifically, the number of strokes per minute increased to 2.3 SPM, pump power increased to 658 W and the casing head pressure in static conditions increased to 28.8 bar.

For this and the final case, a new sucker rod pump is introduced, namely the Lufkin Conventional pump. The reason for introducing this pump is that it showed better scores on RODSTAR compared to Mark II pump. This pump has the size by API of C-80-119-54. As the tubing liquid level for the concentric tubular pumping system introduced, the pump setting depth for the Lufkin Conventional pump is reduced to 500 meters, which is 100 meters less compared to the previous two cases. The number of strokes per minute for this system in this case is 9.54 SPM, due to the fact that the maximum polished rod length is even smaller than selected Mark II pump for previous two cases (54 inches is equal to 1.3716 meters).

The rod string is made in this case as follows:

- Norris K40 rods with the diameter of 15.9 mm and the length of 440 meters and,
- Flexbar C sinker bars with the diameter of 38.1 mm and the length of 60 meters.

The motor has the same power as in Base case and the system efficiency is 53%, which is the same in concentric tubular pumping system for this case. The evaluation for Case 3 in RODSTAR shows that the system design score is 95%. All the categories have a perfect score, except the structure loading has a score of 70. The reason for it is that the structural loading is very low (52%). This is not one of the key constraints so the pumping system is suitable for Case 3.

5.2.4. Case 4

In the final case for this thesis, the stroke length for the concentric tubular pumping system is extended to 8 meters. As shown in Case 2, this will make changes in technical characteristics comparing to Case 3 as this may be shown in Figure 5-5.

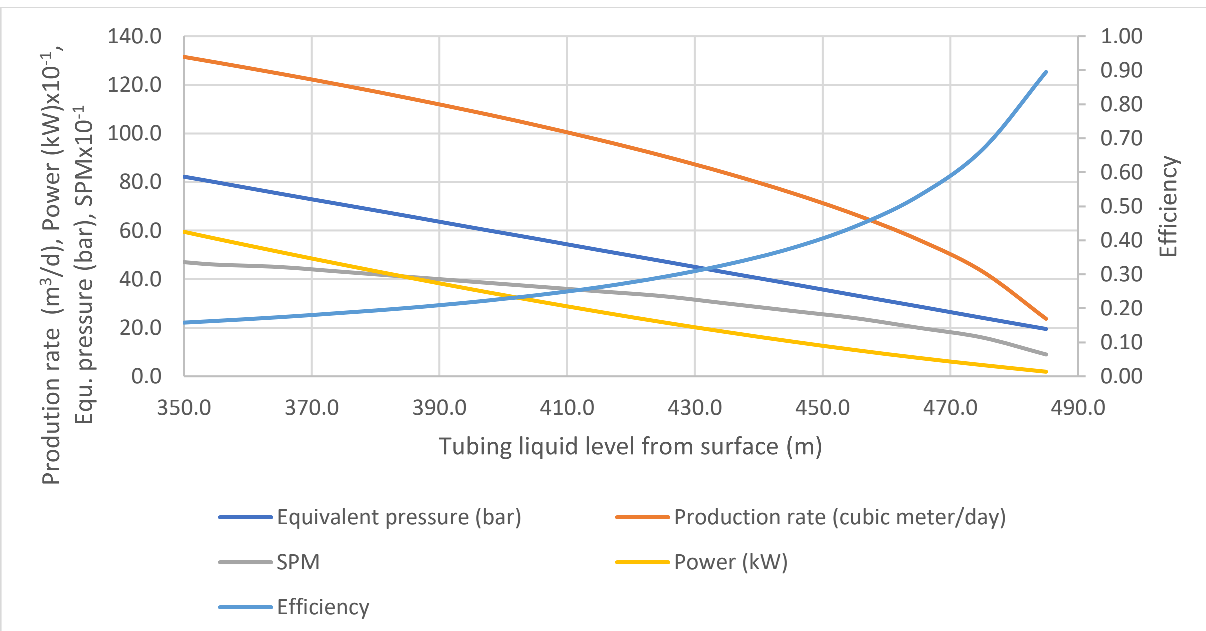

Figure 5-5. Technical characteristics of the Case 4 dependent on tubing liquid level

The tubing liquid level remained unchanged compared to Case 3 as it has the same pump efficiency as the previous case. The production rate increased to 56.262 cubic meters per day, which is almost 8 cubic meters per day more of liquid. The number of strokes per minute is 2 SPM. Pump power increased to 760 W, which is the greatest pump power out of all cases.

The sucker rod pump system for this case does not have a great amount of differences from the previous case as the pump has the same classification, the rod string is the same and the system efficiency is the same. The differences here are the greater motor power, which is 10 HP and the number of strokes per minute increased to 10.65 SPM. Evaluation shows that the system design score for this pumping system is 95%. As it in all previous cases, all categories have a perfect score except the structural loading, which has a score of 70. The reason for it is that the structural loading is very low (51%). As this is not one of the key constraints for sucker rod pump design, this pump is appropriate for the final case. To summarize the key parameters for economic calculations, Table 5-3. is presented here.

Table 5-3. Summary of key parameters

	Base case	Case 2	Case 3	Case 4
CT required power (W)	1238	1430	1317	1521
CT useful power (W)	661	764	698	806
SRP size	M-114-143-74	M-114-143-74	C-80-119-54	C-80-119-54
SRP pump size (mm)	63.5	63.5	63.5	63.5
Polished rod diameter (mm)	25.1	25.1	25.1	25.1
Norris K40 rod length (d=19.1 mm) (m)	450	434	0	0
Norris K40 rod length (d=15.9 mm) (m)	100	106	440	440
Flexbar C sinker bar length (m)	50	60	60	60

6. SURFACE FACILITIES DESIGN

Surface facilities for sucker rod pump system is already designed with the help of RODSTAR. This chapter will focus on surface facilities design for concentric tubular pumping system cases. There are three surface facilities components which have to be designed, these are:

- separator,
- surface injection pump for power fluids,
- storage tank.

Out of these three components, separator design is the most complex due to a lot of assumptions and calculations, which have to be done along the way. Separator is usually referred to as the first vessel on surface, reached by the mixed well stream, in which the separation starts. Typically, separation happens in 2 or 3 stages when the pressure is in range from 2.73 to 21.7 bar (25 to 300 psig) and 3 or 4 stages when the pressure is in range from 21.7 to 49.28 bar (300 to 700 psig). For the hydraulic concentric tubular pumping system, a three-phase separator is required in order to separate gas, oil, and water in one stage. For this reason, a horizontal three phase separator is a good fit, because it can better handle three phase separation than vertical separators. Other advantages are greater liquid capacity and there is no opposite flow direction of droplets and gas. Typical horizontal separator is shown in Figure 6-1. (Arnold, Stewart, 2008)

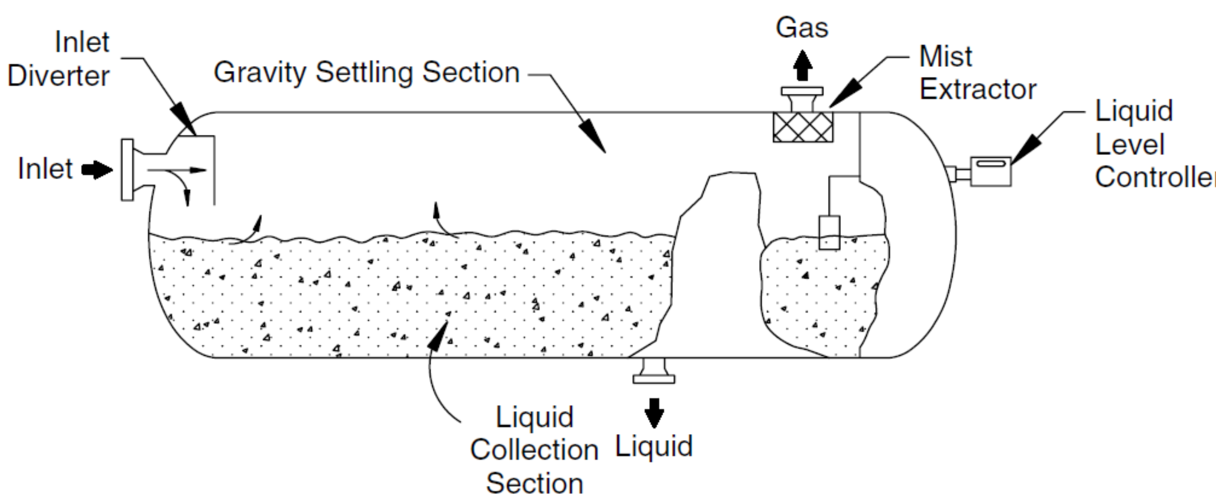

Figure 6-1. Horizontal separator (Arnold, Stewart 2008)

6.1. Separator design basics

For the separator design, gas separation is usually calculated first. First and foremost, the gas characteristics have to be determined due to separation conditions. As the separation will happen in one stage here in order to mitigate surface facilities costs, the separation pressure is assumed to be 2.5 bar or 22 psig. The separation temperature is assumed to be the temperature in standard conditions, which will be 15 °C. After that, the pseudoreduced temperature and pressure have to be calculated. They can be calculated by dividing the separation temperature and pressure with the pseudocritical temperature and pressure of the natural gas, respectively. With these two variables calculated, Z-factor can be determined by the chart shown in Figure 6-2. (Arnold, Stewart, 2008)

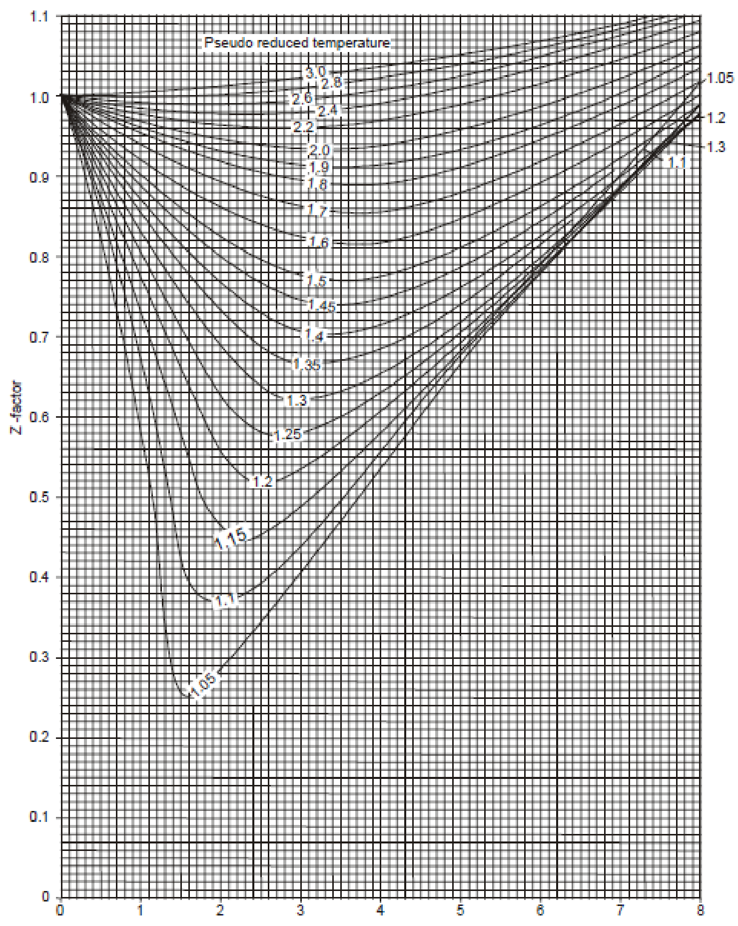

Figure 6-2. Z-factor diagram (Arnold, Stewart, 2008)

Because of the low temperature and pressure conditions, Z factor in these cases is equal to 0.99 so the gas in these conditions behaves almost like an ideal gas. Also, gas density and viscosity have to be calculated in order to proceed with gas separation calculations. For these calculations, the assumption is that the specific gravity of natural gas is 0.8. After this has been done, there are multiple formulas which have to be used in iterations. They will be listed here with the first one being the initial terminal velocity calculation (Arnold, Stewart, 2008):

$$v_t = 0{,}036[(\frac{\rho_l - \rho_g}{\rho_g})\frac{d_m}{C_D}]^{0.5} \tag{6-1.}$$

where:

- v_t is terminal velocity (m/s),
- ρ_l is liquid density (kg/m^3),
- ρ_g is gas density (kg/m^3),
- d_m is the droplet size (assumed 500 microns or micrometers) and,
- C_D is the drag coefficient (for first iteration, this has a value of 0.34).

The second one is the calculation of the Reynolds number (Arnold, Stewart, 2008):

$$Re = \frac{v_t \rho_g d_m}{\mu_g} \tag{6-2.}$$

where:

- Re is Reynolds number (-),
- v_t is terminal velocity (m/s),
- ρ_g is gas density (kg/m^3),
- d_m is the droplet size (μm) and,
- μ_g is gas viscosity (Pa·s).

Finally, the new value for the drag coefficient is calculated as follows (Arnold, Stewart, 2008):

$$C_D = \frac{24}{Re} + \frac{3}{\sqrt{Re}} + 0.34 \qquad (6\text{-}3.)$$

where:

- C_D is the drag coefficient (-) and,
- Re is the Reynolds number (-).

The new value of the drag coefficient is inserted into the terminal velocity equation and the whole process is repeated until the difference between the old and new value of drag coefficient is sufficiently small. Finally, the gas capacity can be calculated as follows (Arnold, Stewart, 2008):

$$d * L_{eff} = \frac{2*Q_g}{\pi} * \frac{p_{atm}}{p_{sep}} * \frac{Z*T_{sep}}{T_{st}} * \sqrt{\frac{3}{g} * \frac{\rho_g}{\rho_l - \rho_g} * \frac{C_D}{d_m}} \qquad (6\text{-}4.)$$

where:

- d is separator diameter (m),
- L_{eff} is the separator effective length (m),
- Q_g is gas flow (m^3/s),
- p_{atm} is the atmospheric pressure (1.01325 bar),
- p_{sep} is the separation pressure (bar),
- Z is the Z factor (-),
- T_{sep} is the separation temperature (K),
- T_{st} is the standard temperature (288.15 K),
- ρ_g is gas density (kg/m^3),
- ρ_l is liquid density (kg/m^3) and,
- g is the gravitational constant (9.81 m/s^2).

For liquid capacity, retention time for oil and water has to be determined. Rules to determine oil retention time for three phase separation are following (Arnold, Stewart, 2008):

- For gas condensate, retention time is from 2 to 5 minutes,
- For light crude oil (specific gravity 0.82-0.875) is from 5 to 7.5 minutes,
- For intermediate crude oil (specific gravity 0.875-0.94) is from 7.5 to 10 minutes and,
- For heavy oil, the retention time is at least 10 minutes.

Water retention time has to be less than the oil retention time. The first step is the calculation of oil pad height, which will determine also the maximal possible separator diameter. With the assumption that the separator is half full, the ratio of fraction of water cross section area and total cross section area may be calculated as follows (Arnold, Stewart, 2008):

$$\frac{A_w}{A} = 0.5\frac{Q_w t_{r(w)}}{Q_w t_{r(w)} + Q_o t_{r(o)}} \tag{6-5.}$$

where:

- $\frac{A_w}{A}$ is the fraction of water cross sectional area (-),
- Q_w is the water flow rate (m^3/s),
- Q_o is the oil flow rate (m^3/s),
- $t_{r(w)}$ is the water retention time (s) and,
- $t_{r(o)}$ is the oil retention time (s).

The maximal separator diameter may be determined with the diagram presented in Figure 6-3. (Arnold, Stewart, 2008).

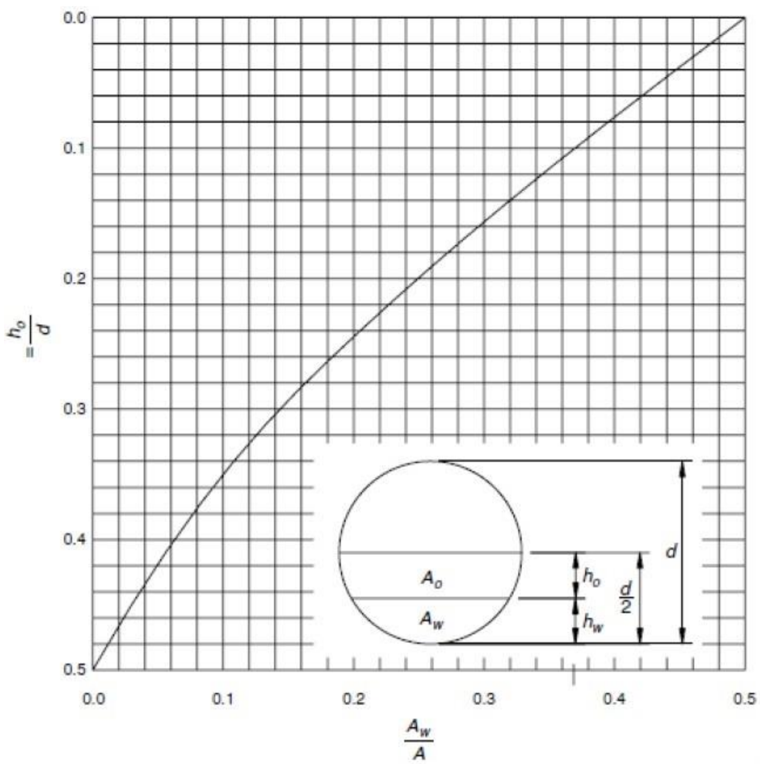

Figure 6-3. Determination of maximal separator diameter (Arnold, Stewart, 2008)

Finally, to determine the effective length, the following formula is used (Arnold, Stewart, 2008):

$$d^2 L_{eff} = \frac{\pi}{8}(\mathrm{Q_w t_{r(w)}} + \mathrm{Q_o t_{r(o)}}) \qquad (6\text{-}6.)$$

where:

- d is the separator diameter (m) and,
- L_{eff} is the separator effective length (m).

When effective length for liquid and gas for a certain diameter is calculated, the longer effective length is selected to determine the seam to seam length of the separator. For all cases, it will be seen that the liquid effective length is longer than the gas effective length. In that case, the seam to seam length is determined as follows (Arnold, Stewart, 2008):

$$L_{ss} = \frac{4}{3} L_{eff} \qquad (6\text{-}7.)$$

where:

- L_{ss} is the separator seam to seam length (m).

Finally, slenderness has to be calculated, which is the ratio of seam to seam length and separator diameter. When the liquid capacity is dominant, slenderness ratio has to be between 3 and 4 and then the separator selection is completed.

On the other side, in case the gas effective length would be dominant, then the seam to seam length will be calculated as follows (Arnold, Stewart, 2008):

$$L_{ss} = L_{eff} + d \qquad (6\text{-}8.)$$

The slenderness (SR) for this case needs to be between 4 and 5 and then the selection is completed.

Regarding surface injection pumps for power fluids, there are two variables which have to be calculated in order to design it, namely injection rate and pump power. Injection rate is calculated with the injection volume in one stroke and number of strokes per minute. Injection volume in one stroke is calculated as a difference between the fluid volume in tubing per stroke and the produced volume of reservoir fluid in a stroke. Multiplied with strokes per minute, injection rate per minute is calculated which is simply converted in injection rate per second. Pump power is calculated by multiplying the casing head pressure in static conditions, which is also the injection pressure of the power fluid, with the injection rate. For storage tanks, it is decided that a storage capacity of 10 cubic meters will be sufficient as the daily production rates and injection rates are small.

6.2. Surface facilities design results

6.2.1. Base Case

For the single well scenario, there are following important parameters which are not earlier mentioned:

- oil retention time is 10 minutes,
- water retention time is 6 minutes,
- gas oil ratio (GOR) is 400 m^3/m^3,
- oil viscosity has a value of 100 mPas,
- water density is 1050 kg/m^3,
- oil density is 950 kg/m^3,
- water cut is 80% and,
- liquid flow rate is 46.18 m^3/d.

Tables 6-1. and 6-2. show the surface facilities parameters for single well scenario in Base case.

Table 6-1. Separator design for single well scenario for Base case

Diameter (m)	L_{eff} (gas) (m)	L_{eff} (liquid) (m)	L_{ss} (m)	SR
0.4064	0.0255	3.364	4.485	11.037
0.508	0.0204	2.153	2.871	5.651
0.6096	0.0170	1.495	1.993	3.270
0.762	0.0136	0.957	1.276	1.674

Table 6-2. Surface pump design for single well scenario for Base case

Injection rate (l/stroke)	3.71
SPM	2.2
Injection rate (m^3/h)	0.49
Casing head pressure (bar)	28.6
Pump power (W)	389

The selected separator has a diameter of 0.6096 m and the chosen length of separator is 2.1 m. For the surface pump, the power which the pump consumes is equal to 389 W.

For triple well scenario, the flow rate of liquid is of course three times bigger than for the single well scenario in Base case. Another change, which had to be made, is that the water retention time is extended to 8.5 minutes, while the oil retention time remained the same. Table 6-3. and 6-4. show the design for surface facilities in triple well scenario for Base case.

Table 6-3. Separator design for triple well scenario for Base case

Diameter (m)	L_{eff} (gas) (m)	L_{eff} (liquid) (m)	L_{ss} (m)	SR
0.4064	0.0766	13.060	17.414	42.848
0.508	0.0613	8.359	11.145	21.938
0.6096	0.0511	5.805	7.739	12.696
0.762	0.0409	3.715	4.953	6.500
0.9144	0.0341	2.580	3.440	3.762

Table 6-4. Surface pump design for triple well scenario for Base case

Injection rate (l/stroke)	11.13
SPM	2.2
Injection rate (m^3/h)	1.47
Casing head pressure (bar)	28.6
Pump power (W)	1167

The chosen separator for this scenario has a diameter of 0.9144 m and a length of 3.8 m. Surface pump which will be used in this scenario has a power of 1167 W.

6.2.2. Case 2

As the liquid flow rate is greater than in base case (53.33 m^3/d), small adjustments had to be made. The water retention time in the single well scenario got shorter and it lasts only 5 minutes. Table 6-5. and Table 6-6. show the surface facilities design in the single well scenario for Case 2.

Table 6-5. Separator design for single well scenario for Case 2

Diameter (m)	L_{eff} (gas) (m)	L_{eff} (liquid) (m)	L_{ss} (m)	SR
0.4064	0.0295	3.428	4.570	11.246
0.508	0.0236	2.194	2.925	5.758
0.6096	0.0197	1.524	2.031	3.332
0.762	0.0157	0.975	1.300	1.706
0.9144	0.0131	0.677	0.903	0.987

Table 6-6. Surface pump design for single well scenario for Case 2

Injection rate (l/stroke)	4.95
SPM	1.9
Injection rate (m^3/h)	0.56
Casing head pressure (bar)	28.6
Pump power (W)	448.3

Compared to the single well scenario in Base case, the separator for Case 2 will have same dimensions, which means that there will be no extra costs when production rate is going to increase. Regarding surface pump, this is not the case as in Case 2 a stronger surface pump is required compared to Base case (pump power of 448 W, compared to 389 W).

For triple well scenario, the water retention time got shortened to 8 minutes compared to triple well scenario in Base case. Table 6-7. and Table 6-8. show the surface facilities design for the triple well scenario in Case 2.

Table 6-7. Separator design for triple well scenario for Case 2

Diameter (m)	L_{eff} (gas) (m)	L_{eff} (liquid) (m)	L_{ss} (m)	SR
0.4064	0.0885	14.397	19.200	47.233
0.508	0.0708	9.214	12.285	24.183
0.6096	0.0590	6.399	8.531	13.995
0.762	0.0472	4.095	5.460	7.166
0.9144	0.0393	2.844	3.792	4.147
1.0668	0.0337	2.089	2.786	2.611

Table 6-8. Surface pump design for triple well scenario for Case 2

Injection rate (l/stroke)	14.85
SPM	1.9
Injection rate (m^3/h)	1.69
Casing head pressure (bar)	28.6
Pump power (W)	1344.9

The selected separator has the same dimension as in the triple well scenario in Base case, which means that there will be no extra costs from this side in order to increase the production rate. A stronger pump power has to be installed for this case (1345 W). It has to be noted that in the separator design the slenderness is slightly greater than require. The problem which occurred during calculations is that with smaller retention times of oil or water, the maximal separator diameter would also reduce, and it would be smaller than the selected one. As the water cut will increase in the future, slenderness will be reduced so this slenderness could in this case also be allowable.

6.2.3. Case 3

As this case handles a different fluid, there are some changes in input data which had to be made:

- gas oil ratio is 800 m^3/m^3,
- oil viscosity has a value of 10 mPas,
- oil density is 750 kg/m^3,
- oil retention time is maximally 5 minutes and,
- liquid flow rate is 48.72 m^3/d

In the single well scenario, the oil retention time is 5 minutes and the water retention time is 3 minutes. Table 6-9. and Table 6-10. show the surface facilities design for the single well scenario for Case 3.

Table 6-9. Separator design for single well scenario for Case 3

Diameter (m)	L_{eff} (gas) (m)	L_{eff} (liquid) (m)	L_{ss} (m)	SR
0.4064	0.1460	2.088	2.784	6.849
0.508	0.1168	1.336	1.781	3.507
0.6096	0.0973	0.928	1.237	2.029
0.762	0.0778	0.594	0.792	1.039
0.9144	0.0649	0.412	0.550	0.601

Table 6-10. Surface pump design for single well scenario for Case 3

Injection rate (l/stroke)	3.71
SPM	2.3
Injection rate (m^3/h)	0.51
Casing head pressure (bar)	28.8
Pump power (W)	409.6

The selected separator has a diameter of 0.508 m and a length of 1.8 m. The surface pump in this scenario requires a power of 410 W.

In the triple well scenario, the oil retention time is 3 minutes, which is 2 minutes shorter compared to the single well scenario in this case and the water retention time lasts 2 minutes. Table 6-11. and Table 6-12. show the surface facilities design for triple well scenario for Case 3.

Table 6-11. Separator design for triple well scenario for Case 3

Diameter (m)	L_{eff} (gas) (m)	L_{eff} (liquid) (m)	L_{ss} (m)	SR
0.4064	0.4379	3.914	5.219	12.842
0.508	0.3503	2.505	3.340	6.575
0.6096	0.2919	1.740	2.320	3.805
0.762	0.2335	1.113	1.485	1.948
0.9144	0.1946	0.773	1.031	1.127

Table 6-12. Surface pump design for triple well scenario for Case 3

Injection rate (l/stroke)	11.13
SPM	2.3
Injection rate (m^3/h)	1.54
Casing head pressure (bar)	28.8
Pump power (W)	1228.8

In this scenario, the selected separator has a diameter of 0.6096 and the selected length is 2.4 m. Surface pump requires a power of 1230 W in order to inject the power fluid smoothly.

6.2.4. Case 4

Final case has a slightly greater flow rate than the previous case (56.262 m^3/d). In the single well scenario, the oil retention time is 5 minutes and the water retention time is 2 minutes. Table 6-13. and Table 6-14. show the surface facilities design for the single well scenario in Case 4.

Table 6-13. Separator design for single well scenario for Case 4

Diameter (m)	L_{eff} (gas) (m)	L_{eff} (liquid) (m)	L_{ss} (m)	SR
0.4064	0.1685	2.109	2.813	6.921
0.508	0.1348	1.350	1.800	3.543
0.6096	0.1124	0.938	1.250	2.051
0.762	0.0899	0.600	0.800	1.050
0.9144	0.0749	0.417	0.556	0.608

Table 6-14. Surface pump design for single well scenario for Case 4

Injection rate (l/stroke)	4.95
SPM	2
Injection rate (m^3/h)	0.594
Casing head pressure (bar)	28.8
Pump power (W)	475.2

The separator in this case has the same dimensions as in Case 3, which then requires zero costs when the management wants to increase the production rate compared to Case 3. The surface pump will be the same as in Case 3, but this time the required power is 475 W.

In a triple well scenario, no changes were made compared to the single well scenario in this case. Table 6-15. and Table 6-16. show the surface facilities design for this scenario in Case 4.

Table 6-15. Separator design for triple well scenario for Case 4

Diameter (m)	L_{eff} (gas) (m)	L_{eff} (liquid) (m)	L_{ss} (m)	SR
0.4064	0.5056	6.328	8.438	20.763
0.508	0.4045	4.050	5.400	10.630
0.6096	0.3371	2.813	3.750	6.152
0.762	0.2697	1.800	2.400	3.150
0.9144	0.2247	1.250	1.667	1.823

Table 6-16. Surface pump design for triple well scenario for Case 4

Injection rate (l/stroke)	14.85
SPM	2
Injection rate (m^3/h)	1.78
Casing head pressure (bar)	28.8
Pump power (W)	1425.6

The separator has a larger diameter compared to the triple well scenario in Case 3. The dimensions required for this case is the diameter of 0.762 m and the chosen length is 2.4 m. The surface pump requires a power of 1425 W, which will require a surface pump of greater dimensions in comparison to the triple well scenario in Case 3.

7. ECONOMIC COMPARISON OF THE TWO SYSTEMS

In this chapter, both systems will be compared from the economic point of view in order to see which pumping system is economically more viable. In the single well scenario for Base case, the tables will be shown where there is going to be a lot of data, which have to be briefly explained first. These are:

- water cut,
- income,
- capital expenditures (CAPEX),
- operating expenses (OPEX),
- total expenses,
- earnings before interest, taxes, depreciation, and amortization (EBITDA),
- royalties,
- amortization,
- income tax and,
- net earnings.

For other scenarios, Figures will be shown where the net earnings for both hydraulic concentric tubular pumping systems and sucker rod pumps are going to be compared on a yearly basis during the project period. Also, the net present value (NPV) and return of investment (ROI) is going to be calculated for both pumping systems.

The water cut represents the fraction of water out of the total liquid flow rate. For example, if the water cut is 0.8, this means that 80% of total flow rate is water and 20% of it is oil. As the time goes by in the predicted project period of 10 years, the water cut will increase. This may be also explained with the natural law of reduction in production due to the fact that reservoir energy gets weaker over time (Dekanić, 2017). Reservoir pressure here is assumed to be constant. It is assumed that the water cut in Base case and Case 2 is going to be increased by 1% on a yearly basis and for Case 3 and Case 4 the increase is going to be 2% on a yearly basis.

There are two sources of income, namely oil and gas. The oil price is usually referred to as USD per barrel. Reference price here is the Brent oil with a value of about 41 USD per barrel (Oil price, 2020). After the conversion, this price can be expressed as 229.5 Euros per cubic meter of oil. Reference price here is the gas price at the Central European Gas Hub in Baumgarten, Austria, which is 6.788 Euros per MWh (CEGH, 2020). After the conversion, this gas price has a value of 0.072 Euros per cubic meter of natural gas. The exchange rate which was used for this conversion was that one USD is equal to 0.89 Euros (XE Currency Converter, 2020). The prices and the exchange rate were taken from the values at the end of June 2020.

Capital expenditures (CAPEX) are funds used by a company to acquire, upgrade, and maintain physical assets such as property, plants, buildings, technology, or equipment. CAPEX is often used to undertake new projects or investments by a company (Kenton, 2020). In these cases, the CAPEX is going to be all of the equipment which has to be bought in order to start hydrocarbon production.

Operating expenses (OPEX) are the costs a company incurs for running their day-to-day operations. These expenses must be ordinary and customary costs for the industry in which the company operates. Companies report OPEX on their income statements and can deduct OPEX from their taxes for the year in which the expenses were incurred (Ross, 2019). The operating expenses which are going to be used in these cases are:

- Energy costs (price of electricity is 0.1 €/kWh),
- Workover costs and,
- Costs of new equipment after the existing one failed.

Total expenses are expressed here as the sum of CAPEX and OPEX.

EBITDA is a measure of a company’s overall financial performance and is used as an alternative to net income in some circumstances. It is a more precise measure of corporate performance since it is able to show earnings before the influence of accounting and financial deductions. Simply put, it is a measure of profitability (Hayes, 2020). In these cases, it is calculated as a difference between income and total expenses.

Royalties are a commonly used method of revenue taken by the government. They are based on hydrocarbon production volume and exports. They are an attractive solution for the government because they ensure a constant income as soon as production starts (Karasalihović Sedlar et al., 2017).

For this example, the Austrian royalties will be taken as a reference. They have a sliding scale for royalties, which works different for oil and gas. For oil, the royalty scale works as follows (Kolovrat, 2019):

- 15% for an oil price until 460 Euros per ton of oil,
- 15 to 20% for an oil price from 460 until 670 Euros per ton of oil and,
- 20% for an oil price above 670 Euros per ton of oil.

Regarding the reference price, the oil price is for all cases under 460 Euros per ton of oil, so 15% from the income of oil will be taken as a royalty.

For natural gas, the royalty scale works as follows (Kolovrat, 2019):

- 19% for a price of 5100 Euros per one Terajoule of energy,
- 19 to 22% for a price from 5100 until 8200 Euros per one Terajoule of energy,
- 22% for a price above 8200 Euros per one Terajoule of energy.

As the gas price is also low for all cases, the referent royalty percentage will be 19%.

Amortization is the total value of equipment which is spread across a certain time period. During its usage, equipment is losing its value. That value is carried on to the production price of final products. From the economic point of view, amortization is an expression of value of equipment consumption. This expenditure is accounted as an expense before the income tax.

There are five methods by which amortization can be calculated (Jukić, 2017):

- Linear (constant amortization value through whole lifetime of the equipment),
- Progressive (amortization percentage is increasing over time),
- Degressive (amortization percentage is decreasing over time),
- Functional (amortization depends on the intensity of equipment usage) and,
- Combined.

For these cases, a linear depreciation will be taken with an equipment lifetime for this purpose of 5 years. This means that every year, 20% of the original equipment value is taken for amortization value. As the new equipment will come in during project time, their amortization value will be added on.

With the royalties and amortization calculated, gross income may be obtained by deducting the royalties and amortization from EBITDA. Then the income tax comes finally into the equation.

Income tax is charged when the company has a profit which covers all the previous expenses. For these cases, the reference value for the income tax is the Austrian one, namely 25% (Kolovrat, 2019).

With the income tax accounted, the final cash flow is the net earnings, which will be accounted for the Net Present Value (NPV) of the cases.

NPV is an investment decision tool which evaluates project’s value by discounting the net earnings during the economic life of the project to the present value. This is done with the choice of discount factor, which is chosen by the investor (Karasalihović Sedlar, 2017). For these cases, the discount factor is 8% and the economic life of all the cases will be 10 years.

The Return on Investment (ROI) is a performance measure used to evaluate the efficiency of an investment. ROI tries to directly measure the amount of return on a particular investment, relative to the investment’s cost. To calculate ROI, the benefit of an investment is divided by the cost of the investment. The result is expressed as a percentage or a ratio (Chen, 2020).

7.1. Event list during the project

The events which occurred during these ten years in Base case (heavy oil reservoir) and Case 3 (gas condensate reservoir) for hydraulic concentric tubular pumping system are listed below:

- Year 1: Initial installation (concentric tubular installation required);
- Year 3: Subsurface pump failure for hydraulic system (pump circulation required);
- Year 5: Separator failure for hydraulic system (surface maintenance cost required);
- Year 7: Subsurface pump failure for hydraulic system (pump circulation required);
- Year 9: Surface pump failure for hydraulic system (surface maintenance cost required);
- Year 10: Subsurface pump failure for hydraulic system (pump circulation required).

For the sucker rod pump system, the events which occurred during the project period are listed below:

- Year 1: Initial installation (SRP system with new tubing installation required);
- Year 3: Plunger, rod string and tubing string failure for sucker rod pump system (SRP system with new tubing installation required);
- Year 5: Pump jack maintenance for sucker rod pump system (pump jack maintenance cost required);
- Year 7: Plunger and rod string failure for sucker rod pump system (SRP system installation required);
- Year 9: Pump jack maintenance for sucker rod pump system (pump jack maintenance cost required);
- Year 10: Plunger, rod string and tubing string failure for sucker rod pump system (SRP system with new tubing installation required).

For Case 2 and 4, it is assumed that the management decided to increase production. This was done by increasing the stroke length in the CT completion and by installing a stronger motor in SRP system. The events which happened for these two cases for hydraulic concentric tubular pumping system are listed below:

- Year 1: Installation of required equipment for production increase, (surface facilities installation where necessary);
- Year 2: Subsurface pump failure for hydraulic system (pump circulation required);
- Year 4: Separator failure for hydraulic system (surface maintenance cost required);
- Year 6: Subsurface pump failure for hydraulic system (pump circulation required);
- Year 8: Surface pump failure for hydraulic system (surface maintenance cost required);
- Year 9: Subsurface pump failure for hydraulic system (pump circulation required).

For the sucker rod pump system, the following events happened during the project period:

- Year 1: Installation of required equipment for production increase (equipment installation done where required);
- Year 2: Plunger, rod string and tubing string failure for sucker rod pump system (SRP system with new tubing installation required);
- Year 4: Pump jack maintenance for sucker rod pump system (pump jack maintenance cost required);
- Year 6: Plunger and rod string failure for sucker rod pump system (SRP system installation required);
- Year 8: Pump jack maintenance for sucker rod pump system (pump jack maintenance cost required);
- Year 9: Plunger, rod string and tubing failure for sucker rod pump system (SRP system with new tubing installation required).

For every surface facilities failure, in consultancy with Senior Researcher Langbauer, it is assumed that it takes 5 days to install new equipment and for subsurface equipment it takes around 5 days to install new equipment and 20 days to organize rig, equipment from stock, etc... As the pump circulation method is faster and less production losses will happen, it is assumed that for the pump circulation method, only 6 days are lost in production.

The installation costs which will occur in all cases are the following:

- Pump circulation costs: 10 000 €,
- SRP installation cost: 40 000 €,
- Tubing installation cost: 20 000 €,
- Concentric tubular installation cost: 50 000 €,
- Surface facilities maintenance cost: 2000 € and,
- Surface pump jack maintenance cost: 5000 €.

7.2. Base case

The equipment price list for concentric tubular system is the following:

- 0.0889 m (3.5 inch) tubing: 40 €/m (length is 1500 m),
- 0.1397 m (5.5 inch) tubing: 75 €/m (length is 1500 m),
- Subsurface pump: 5500 €,
- Separator for single well scenario: 25 000 €,
- Separator for triple well scenario: 32 000 €,
- Surface pump for single well scenario: 2500 €,
- Surface pump for triple well scenario: 3500 € and,
- Storage tank: 15 000 €.

For the single well scenario, the combined power for the subsurface and surface pump, which is the sum of power required for surface and subsurface pump, is about 1.63 kW, which means that the daily consumption of electric energy is going to be 39 kWh. Tables 7-1. and 7-2. show the financial analysis for the concentric tubular pumping system in the single well scenario.

Table 7-1. Financial analysis for the CT pumping system in Base case single well scenario

Year	Water cut	Income (€)	CAPEX (€)	OPEX (€)	Total expenses (€)	EBITDA (€)
1	0.8	810 683	270 500	1328	271 828	538 855
2	0.81	826 777	0	1425	1425	825 352
3	0.82	770 387	0	16 902	16 902	753 485
4	0.83	739 748	0	1425	1425	738 323
5	0.84	686 696	0	28 406	28 406	658 290
6	0.85	652 719	0	1425	1425	651 294
7	0.86	599 190	0	16 902	16 902	582 288
8	0.87	565 670	0	1425	1425	564 264
9	0.88	515 022	0	5905	5905	509 116
10	0.89	470 792	0	16 902	16 902	453 890

Table 7-2. Financial analysis for the CT pumping system in Base case single well scenario (continued)

Year	Royalties (€)	Amortization (€)	Income tax (€)	Net earnings (€)
1	125 200	44 100	92 389	277 166
2	127 686	44 100	163 392	490 175
3	118 977	44 100	147 602	442 806
4	114 245	44 100	144 994	434 983
5	106 052	44 100	127 035	381 104
6	100 084	6100	136 097	408 292
7	92 538	6100	120 913	362 738
8	87 364	6100	117 700	353 100
9	79 539	6600	105 744	317 233
10	72 708	1600	94 896	284 687

The NPV for this scenario is 2.56 million Euros. The return of investment rate calculated for this case is 1.3.

The price list for SRP is:

- Pump jack: 50 000 €,
- Subsurface pump (63.5 mm): 3600 €,
- 0.0889 m (3.5 inch) tubing: 40 €/m (length is 1500 m),
- Norris K40 sucker rods (19.1 mm): 61 €/piece (one piece is 9.14 m long),
- Norris K40 sucker rods (15.9 mm): 58 €/piece (one piece is 7.62 m long),
- Flexbar C sinker bars (38.1 mm): 100 €/piece (one piece is 3 m long) and,
- Polished rod (25.1 mm): 10 €/m (length is 9.14 m).

The electricity consumption for this SRP system is 124 kWh/d, which is almost four times more than the concentric tubular pumping system. Tables 7-3. and 7-4. show financial analysis for single well scenario in Base case for SRP system.

Table 7-3. Financial analysis for SRP system in Base case single well scenario

Year	Water cut	Income (€)	CAPEX (€)	OPEX (€)	Total expenses (€)	EBITDA (€)
1	0.8	810 683	179 123	4216	173 339	627 344
2	0.81	826 777	0	4526	4526	822 251
3	0.82	729 615	0	133 339	133 338	596 275
4	0.83	739 748	0	4526	4526	735 222
5	0.84	686 696	0	9464	9464	677 232
6	0.85	652 719	0	4526	4526	648 193
7	0.86	567 478	0	53 339	53 339	514 140
8	0.87	565 690	0	4526	4526	561 164
9	0.88	515 022	0	9464	9464	505 558
10	0.89	445 876	0	133 339	133 339	312 537

Table 7-4. Financial analysis for SRP system in Base case single well scenario (continued)

Year	Royalties (€)	Amortization (€)	Income tax (€)	Net earnings (€)
1	125 200	23 825	119 580	358 740
2	127 686	23 825	167 685	503 056
3	112 680	23 825	114 943	344 828
4	114 245	23 825	149 288	447 864
5	106 052	23 825	136 839	410 517
6	100 805	13 825	133 391	400 173
7	87 640	13 825	103 169	309 506
8	87 364	1825	117 994	353 981
9	79 539	1825	106 049	318 146
10	68 860	13 825	57 463	172 389

The NPV for the SRP system in the single well scenario is 2.51 million €. The return on investment ratio calculated for this case is 1.24. Comparing these two NPV's, the difference between them is small, about 50 000 Euros. The reason could be high capital expenses for concentric tubular system due to the required surface facilities. On the other hand, the operating costs are lower as it consumes much less energy compared to SRP system. Also, the concentric tubular system has a greater return on investment rate. The ROI for hydraulic concentric tubular pumping system is 1.3, while for the sucker rod pump system the ROI is 1.24. Comparison of net earning between these two systems on a yearly basis during the project period is shown on Figure 7-1.

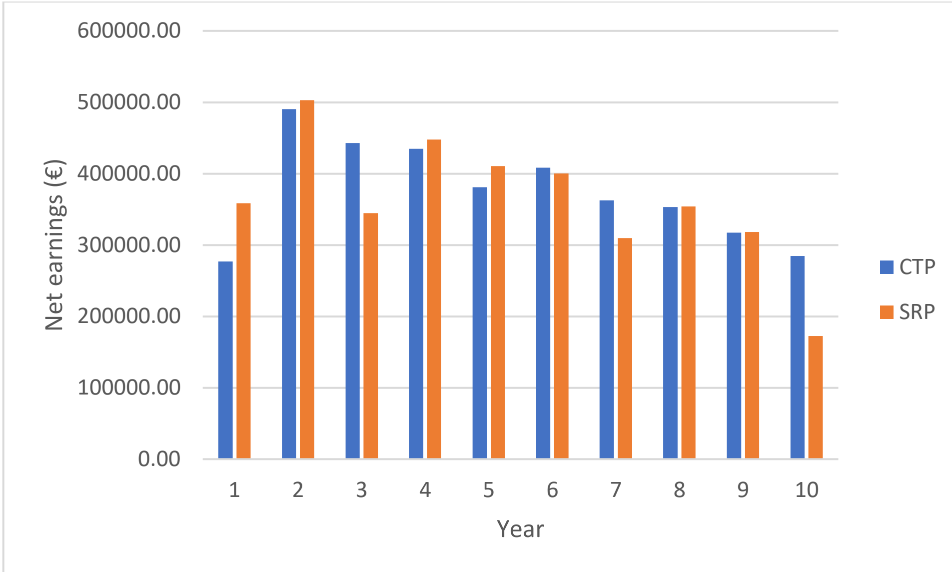

Figure 7-1. Comparison of net earnings on a yearly basis for Base case single well scenario

The greatest difference in net earnings can be seen in year 1 in favor of the sucker rod pump system. On the other side, in years 3 and 10 the greatest difference in net earnings can be seen in favor of hydraulic concentric tubular system pump. This could mean that in short term the sucker rod pump system is economically better option, while in long term the hydraulic concentric tubular pumping system is better.

In the triple well scenario, the subsurface facilities for both systems will be tripled, but the greatest difference here is that the surface facilities for the concentric tubular pumping system will have a slight increase in costs, because a single surface facility can provide enough power to all 3 wells. For the concentric tubular pumping system, subsurface pump and both tubing string costs are tripled from the single well scenario. The energy consumption for this system is 117 kWh/d. For the SRP system, the costs and the energy consumption gets tripled for the triple well scenario, which means that the daily energy consumption for the sucker rod pump system in this scenario 372 kWh. The comparison of net earnings between these two systems is shown in Figure 7-2.

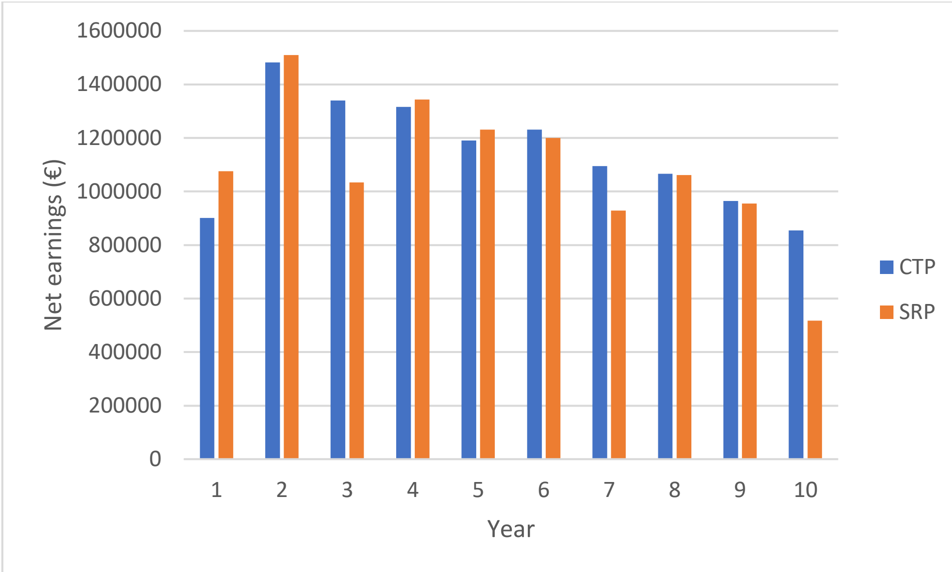

Figure 7-2. Comparison of net earnings on a yearly basis for Base case triple well scenario

The NPV for the concentric tubular pumping system in this scenario is 7.82 million €. The calculated ROI is 1.35, which is greater than in single well scenario. The reason for the increase in ROI for the CT pumping system is that a single surface facilities system supplies 3 well with the power fluid, which is cheaper than 3 surface facilities systems supply individually their own well.

For the sucker rod pump system, the NPV in this scenario is 7.53 million €. As all the equipment is tripled compared to the single well scenario, the ROI is the same as there, namely 1.24.

When the NPV values are compared between the two systems in this case, the difference between them is about 0.3 million Euros in favor of the concentric tubular pumping system. The reasons are reduced capital expenses because surface facilities are not such a great cost and smaller operating expenses, as the difference in energy consumption between two systems is increased compared to single well scenario. As previously mentioned, the ROI increased for the concentric tubular pumping system comparing to the single well scenario.

7.3. Case 2

As mentioned before, in this case the management decided to increase the production, which means that year one in this case will be when the water cut is 81%. Here the CAPEX will be the equipment which has to be installed in order to make this production increase happen.

For the single well scenario, the only change which needs to happen in the concentric tubular pumping system is a new surface injection pump (2700 €) will be installed (maintenance cost included). The daily energy consumption is 45 kWh.

For the SRP system, new pump jack with a stronger engine has to be installed and the rod string has to be rearranged. The CAPEX here are the new sucker rods required for rearrangement and the installation cost of the whole system. Daily energy consumption is 143 kWh. The comparison of net earnings on a yearly basis between the two systems is shown in this scenario on Figure 7-3.

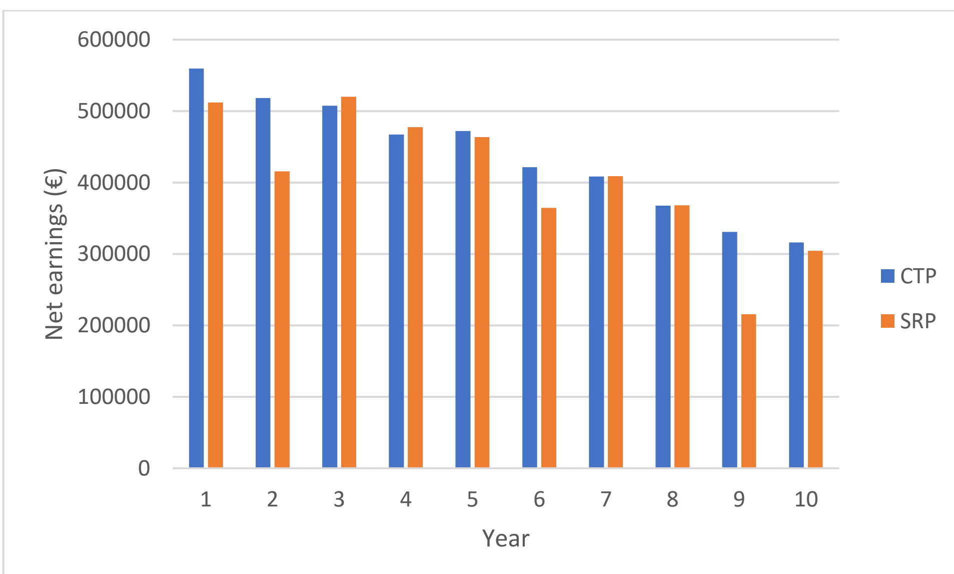

Figure 7-3. Comparison of net earnings on a yearly basis for Case 2 single well scenario

The NPV in this scenario for the concentric tubular pumping system is about 3 million Euros. The ROI ratio calculated for this scenario is 1.53.

For the sucker rod pump system, the NPV in this case is 2.83 million €. ROI ratio for this scenario is 1.35. As it can be seen, it is much easier to make production changes with the concentric tubular pumping system as this requires almost zero cost, eventually new surface facilities are required together with their maintenance cost to install it.

When the net earnings are compared, it can be seen that the greatest difference in favor of sucker rod pumps is in year 3. On the other side, second and ninth year have the greatest difference in favor of hydraulic concentric tubular pumping system. Those are the years when the tubing failure occurred in the sucker rod pumping system and the whole subsurface and tubing had to be changed.

In the triple well scenario, for the concentric tubular pumping system a new surface pump is required (3750 € plus maintenance costs). Daily energy consumption for this system is 135 kWh. For sucker rod pump system is the same story as in the single well scenario in this case with the CAPEX now being tripled. Daily energy consumption is 429 kWh. Figure 7-4. shows the triple comparison between net earnings between both pumping systems.

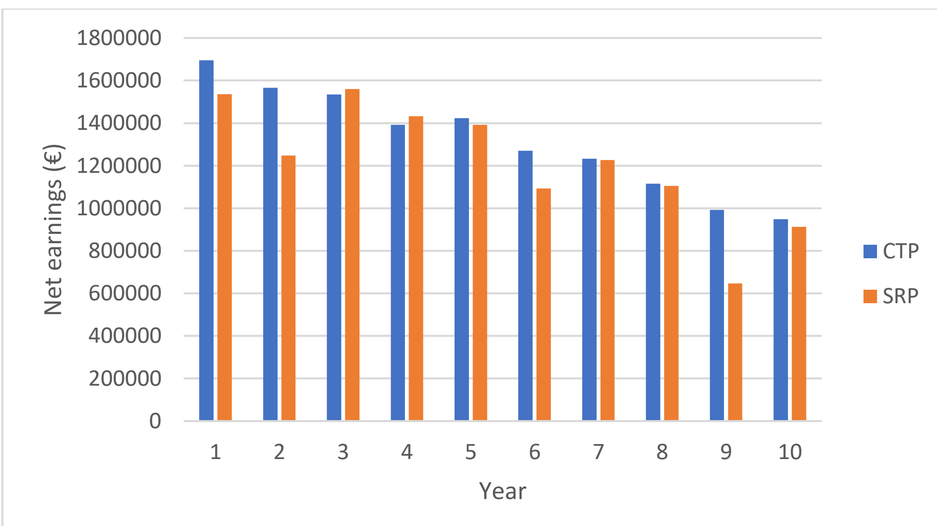

Figure 7-4. Comparison of net earnings on a yearly basis for Case 2 triple well scenario

The NPV calculated for the concentric tubular pumping system is about 9.2 million Euros. The return on investment rate here is 1.55, which is a slight increase compared to single well scenario for this pumping system.

The NPV for this case for sucker rod pumping system is around 8.5 million €. The ROI stays the same as in single well scenario in this case.

With the NPV's being compared, it can be seen that the difference in the triple well scenario between these two systems is much greater than in the single well, due to the fact that low capital expenses have to be made in order to extend the stoke length of the concentric tubular pumping system and install the required surface facilities for it. Also, the daily energy consumption in this case is three times lower compared to the sucker rod pump system, which is the primary reason of low operating expenses.

7.4. Case 3

In the following two cases, condensate is being produced with less water cut in the liquid and a greater gas oil ratio. As this simulates a gas condensate reservoir, the water cut goes every year up by 2 percent. It is expected that income will increase a couple of times because of that and the expenses for sucker rod pumping system are lower due to the shallower pump setting depth.

In the single well scenario for concentric tubular pumping system, separator costs 22 000 € and surface pump costs 2700 €. Daily energy consumption for this system in this scenario is 41.5 kWh.

For SRP system, Lufkin Conventional pump is installed and the price of it is the same as Mark II pump. All components have the same price, except the rod string, which does not have the 19.1 mm sucker rods in its string. Daily energy consumption for this case in this scenario is 106 kWh. Figure 7-5. shows the comparison between the net earnings on a yearly basis between both pumping systems.

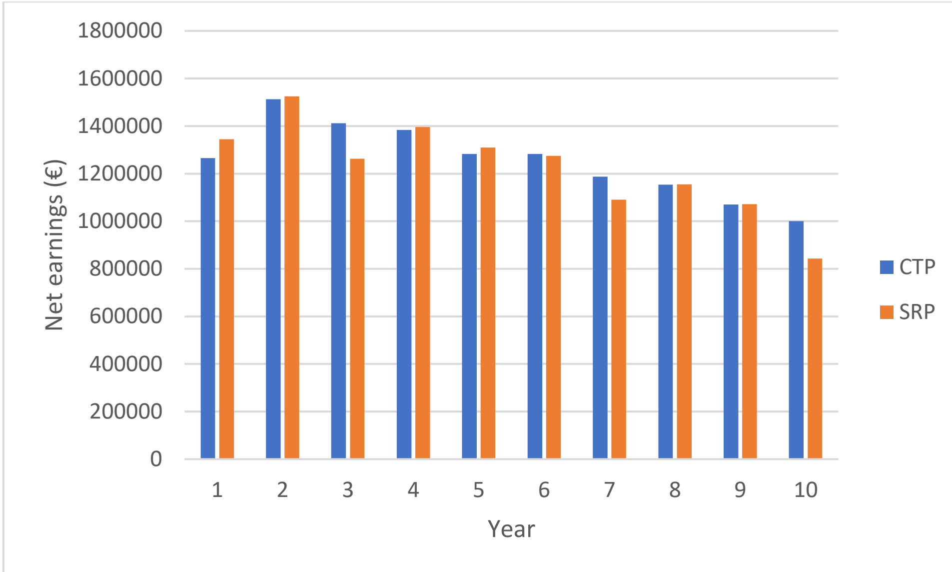

Figure 7-5. Comparison of net earnings on a yearly basis for Case 3 single well scenario

The NPV for this scenario regarding the concentric tubular pumping system is around 8.6 million Euros. Also, the calculated ROI rate is 1.56.

For the sucker rod pumping system, the NPV for this case is around 8.45 million €, which is about 150 000 € less than for concentric tubular system. Calculated return of investment rate for this pumping system in this scenario is 1.53.

For triple well scenario, the separator price is 28 000 € and the surface pump costs 3500 €. Subsurface components cost three times more as it is required to install everything for 3 wells. Daily energy consumption in this scenario for this system is 124 kWh.

For the sucker rod pump system, all the costs are simply tripled comparing to the single well scenario. Daily energy consumption in this case is 318 kWh. Figure 7-6. shows the comparison of net earnings between the two pumping systems.

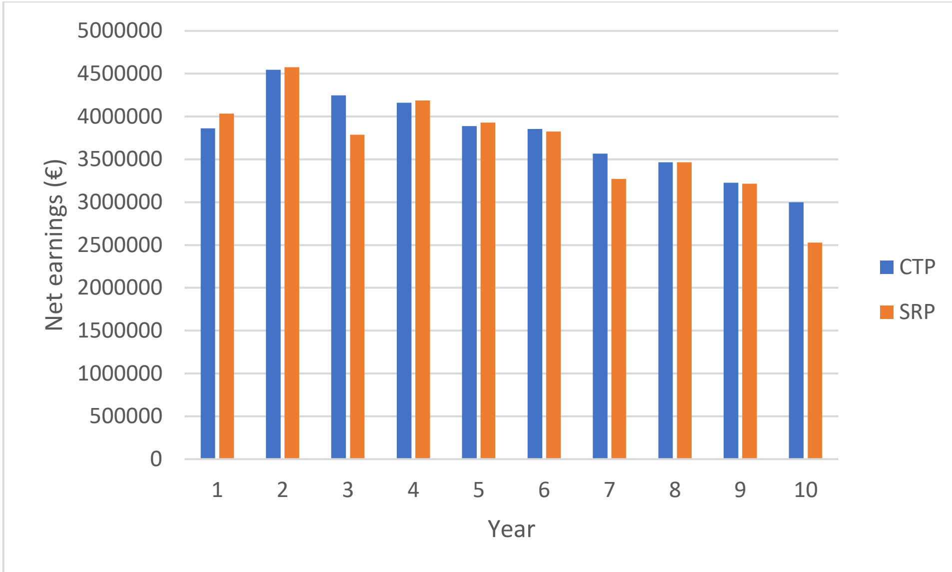

Figure 7-6. Comparison of net earnings on a yearly basis for Case 3 triple well scenario

The NPV calculated for concentric tubular pumping system in this scenario is almost 26 million Euros. The ROI rate is increased from the single well scenario to 1.58.

For the sucker rod pumping system, the NPV is around 25.4 million Euros. ROI stays the same as in single well scenario, which is 1.53.

When the economic parameters are being compared, it can be seen that the difference in NPV and ROI between these two systems is greater in this scenario comparing to the single well scenario in this case. Comparing the net earnings between these two systems, the greatest difference between them is in first year in favor of sucker rod pump system. On the other hand, years 3 and 10 have the greatest difference in favor of hydraulic concentric tubular pumping system.

7.5. Case 4

As in Case 2, this case also simulates the decision to increase production from the well. In the single well scenario, both pumping system have virtually 0 capital expenses as the required equipment is the same as in Case 3. Daily energy consumption for concentric tubular pumping system in this case is 48 kWh and for the sucker rod pumping system it is 121 kWh. Figure 7-7. show the comparison of net earnings on a yearly basis for this scenario.

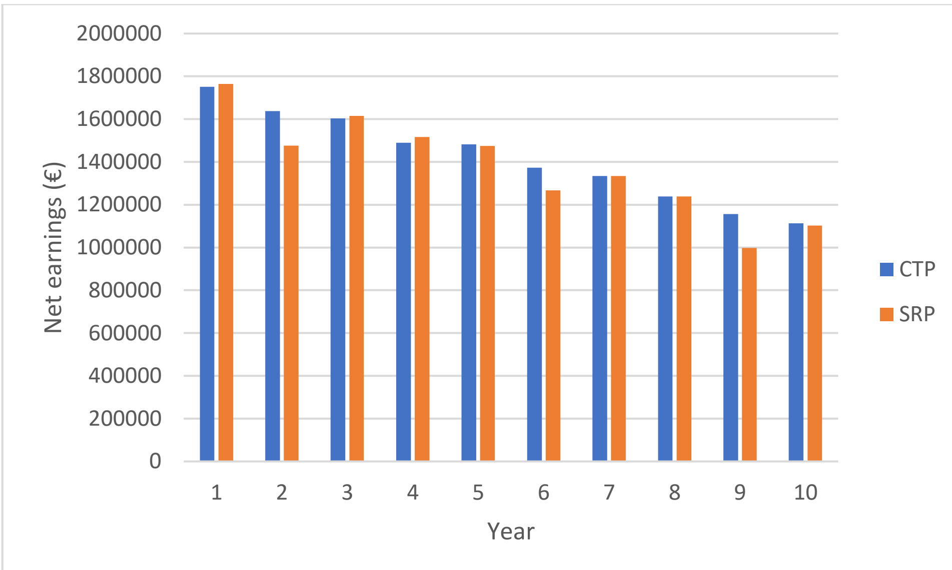

Figure 7-7. Comparison of net earnings on a yearly basis for Case 4 single well scenario

For the concentric tubular pumping system, the calculated NPV for this scenario is around 9.8 million Euros. The ROI calculated for this system is 1.64. On the other hand, the NPV for sucker rod pump system is around 9.55 million Euros and the ROI is 1.59.

Comparing these values, the difference between the NPV's in this scenario is 250 000 Euros in favor of concentric tubular system. The reasons for this difference are the operating expenses, are always smaller due to much less energy consumption comparing with the sucker rod pump system. This may be visible also at Figure 7-7. where the greatest difference in net earnings is in years 2 and 9 in favor of concentric tubular system.

In the triple well scenario, new separator and a new surface pump have to be installed in order to increase production for the concentric tubular pumping system compared to the surface facilities in the triple well scenario in Case 3. As only the new surface facilities have to be installed, this means that the capital expenses will be low. Daily energy consumption for this system in this scenario is 144 kWh.

For the sucker rod pump system, there are virtually 0 capital expenses as only new motor has to be installed to increase production. Daily energy consumption for this system is 363 kWh. Figure 7-8. shows the comparison of net earnings between these two systems in this scenario.

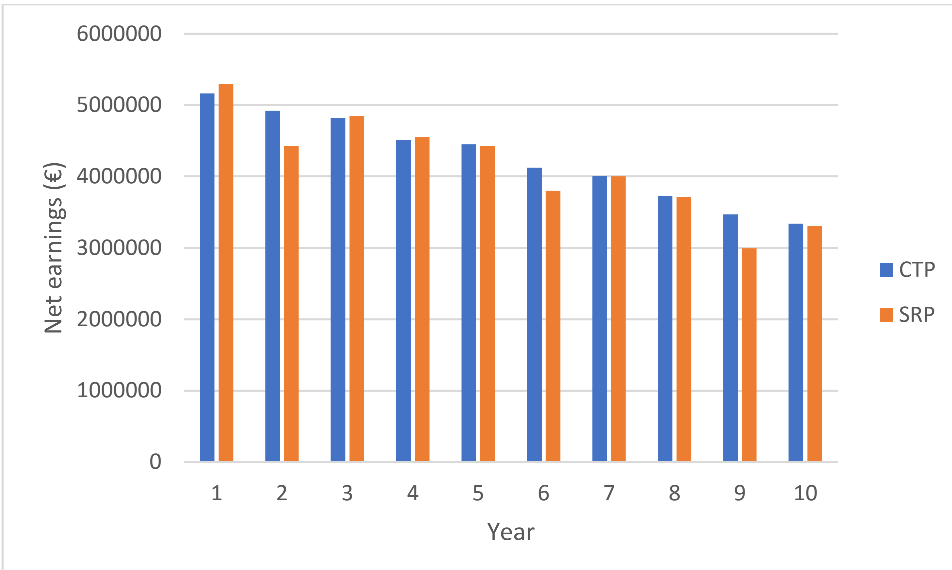

Figure 7-8. Comparison of net earnings on a yearly basis for Case 4 triple well scenario

For this scenario, the NPV for concentric tubular pumping system is around 29.4 million Euros. The ROI calculated for this pumping system in this scenario is 1.65, which is an increase compared to the single well scenario due to the fact that one surface facility system supplies all three wells.

For the sucker rod pumps, the NPV is around 28.7 million Euros, which is 700 000 Euros less compared to the concentric tubular pumping system. The ROI stays the same compared to single well scenario, which is 1.59.

7.6. Summary

To summarize the economic comparison, it is seen that in all cases the net present value and the return of investment rate is greater for the hydraulic concentric tubular pumping system. Table 7-5. shows the summary of the economic calculations.

Table 7-5. Summary of economic calculations

Case (scenario)	NPV CT (€)	NPV SRP (€)	ROI CT	ROI SRP
Base case (single well)	2.56 million	2.51 million	1.3	1.24
Base case (triple well)	7.82 million	7.53 million	1.35	1.24
Case 2 (single well)	3 million	2.83 million	1.53	1.35
Case 2 (triple well)	9.2 million	8.5 million	1.55	1.35
Case 3 (single well)	8.6 million	8.45 million	1.56	1.53
Case 3 (triple well)	26 million	25.4 million	1.58	1.53
Case 4 (single well)	9.8 million	9.55 million	1.64	1.59
Case 4 (triple well)	29.4 million	28.7 million	1.65	1.59

The first reason why it is so could be found in lower operative expenses due to lower energy consumption. The second reason is that the workover costs are less than in sucker rod pumps and when the pump circulation is required, there is no time wasted to wait for the workover rig because there is no need for one. Third reason links to the second, which is that there is less non-productive time. As mentioned, subsurface pump workover with the pump circulation lasts only 6 days, while on the other hand, the workover which requires the workover rig lasts 25 days. When the net earnings on a yearly basis are being compared between these two systems, the sucker rod pumps have a better net earnings in the first year. In some cases, the second year is also better for the sucker rod pumps. This means in the short term sucker rod pumping system is economically more viable artificial lift system. However, the hydraulic concentric tubular pumping system is more viable in the long term due to reduced operating costs and reduced non-productive time. This may be a good solution to extend the reservoir lifetime by postponing the economic limit when the concentric tubular pumping system is used.

8. CONCLUSION & RECOMMENDATIONS

The hydraulic concentric tubular pumping system has surely a good potential to be applied in the oil and gas industry. After the examples given in the cases in this thesis, a conclusion can be made that in general this pumping system gives better net present value compared to the most common artificial lift system, the sucker rod pumps. In single well scenarios, the CAPEX would be really high because of high surface facilities costs, which are required in order to supply the pumping system with the power fluid. For this reason, in order to mitigate CAPEX as much as possible, it is desired to use one surface facility system to supply the power fluid for multiple wells which use this hydraulic pumping system. The operating expenses are reduced as energy demand for this system is as much as three times lower than for the sucker rod pumps. This means that this pumping system has greater energy efficiency. In general, the hydraulic concentric tubular pumping system consumed three times less energy than the sucker rod pumps did. It may be also noted that in order to change the production rate, it is easier to do for the hydraulic concentric tubular pumping system, as this may be easily changed. Only constraint for that are the required surface facilities for that scenario. For the sucker rod pumps, this was harder to do as a new motor had to be installed in the pump jack and in some cases the rod string had to be rearranged, which is time consuming and requires a workover rig. The hydraulic concentric tubular pumping system may also postpone the economic limit of a reservoir, which means that total recovery factor could be increased with this pumping system. Overall, it is a good innovation which should get attention from the oil and gas industry because of all these reasons.

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Izjava

Izjavljujem da sam diplomski rad izradio samostalnu pomoću stečenog znanja na Rudarsko-geološko-naftnom fakultetu te služeći se navedenim referencama.

Affidavit

I declare that I wrote this thesis and performed the research myself using the knowledge gained on the Faculty of Mining, Geology and Petroleum Engineering and the cited literature.

Sven Curiš

Sven Curiš, 11.9.2020

KLASA: 602-04/20-01/08
URBROJ: 251-70-03-20-2
U Zagrebu, 10.09.2020.

Sven Curiš, student

RJEŠENJE O ODOBRENJU TEME

Na temelju Vašeg zahtjeva primljenog pod KLASOM: 602-04/20-01/08, UR. BROJ: 251-70-12-20-1 od 10.01.2020. godine priopćujemo temu diplomskog rada koja glasi:

POTENTIAL OF THE HYDRAULIC CONCENTRIC TUBULAR PUMPING SYSTEM

Za voditeljicu ovog diplomskog rada imenuje se u smislu Pravilnika o diplomskom ispitu dr. sc. Daria Karasalihović Sedlar, redovita profesorica Rudarsko-geološko-naftnog fakulteta Sveučilišta u Zagrebu.

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