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Department of Energy
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MASTER THESIS

for

Student Ruben Dario Ensalzado

Spring 2016

Optimal diluent allocation in production systems with diluent-ESP-lifted wells

Optimal allokering av diluenten i produksjonssystemer med diluent-ESP løftede brønner

Background and objective

Heavy oil wells producing with electric submersible pumps (ESPs) often have diluent injection at the suction of the pump to reduce the formation oil viscosity thus the frictional pressure losses. The diluent is typically a costly high API oil, so it is of interest to use as little diluent as possible but still achieving a considerable reduction of the back-pressure on the reservoir thus increasing the flow rates of reservoir oil produced.

The ***main objective*** of this master thesis is to study the estimation of optimal diluent allocation on a single well and on a group of wells with ESPs and diluent injection producing viscous oil. The analysis will be done using and in-house numerical simulator developed by the candidate in his specialization project.

The following tasks are to be considered:

1. To compute, on a single well basis, the diluent lift performance curve (reservoir oil production vs. injected diluent flow rate) and identify from it the optimal diluent injection rate. Run sensitivity analysis simulating different well configurations, ESP frequencies, producing water cuts, wellhead pressures, etc. and detect parameters which have a strong influence on the diluent lift performance curve.
2. To compute, on a single well basis, the revenue-based diluent lift performance curve (total revenue from the well vs. injected diluent flow rate) and identify from it the optimal diluent injection rate. Run sensitivity analysis simulating different well configurations, ESP frequencies, producing water cuts, wellhead pressure, diluent cost and oil barrel price and determine which parameters have a strong influence on the diluent lift performance curve.
3. Test several optimization methods to perform optimal diluent allocation on a group of wells assuming that the diluent lift performance curve of any individual well is not affected by the operation of the other wells. The optimization methods to be tested are: sequential allocation using a slope-based ranking method (in house method), simplex method using a piecewise linear representation of the diluent lift performance curve and

non-linear optimization. The optimization algorithms might be programmed by the candidate or commercial software might be employed.

4. Perform optimal diluent allocation using numerical optimization on a group of wells considering the hydraulic interdependence between them.

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Within 14 days of receiving the written text on the master thesis, the candidate shall submit a research plan for his project to the department.

When the thesis is evaluated, emphasis is put on processing of the results, and that they are presented in tabular and/or graphic form in a clear manner, and that they are analyzed carefully.

The thesis should be formulated as a research report with summary both in English and Norwegian, conclusion, literature references, table of contents etc. During the preparation of the text, the candidate should make an effort to produce a well-structured and easily readable report. In order to ease the evaluation of the thesis, it is important that the cross-references are correct. In the making of the report, strong emphasis should be placed on both a thorough discussion of the results and an orderly presentation.

The candidate is requested to initiate and keep close contact with his/her academic supervisor(s) throughout the working period. The candidate must follow the rules and regulations of NTNU as well as passive directions given by the Department of Energy and Process Engineering.

Risk assessment of the candidate's work shall be carried out according to the department's procedures. The risk assessment must be documented and included as part of the final report. Events related to the candidate's work adversely affecting the health, safety or security, must be documented and included as part of the final report. If the documentation on risk assessment represents a large number of pages, the full version is to be submitted electronically to the supervisor and an excerpt is included in the report.

Pursuant to "Regulations concerning the supplementary provisions to the technology study program/Master of Science" at NTNU §20, the Department reserves the permission to utilize all the results and data for teaching and research purposes as well as in future publications.

The final report is to be submitted digitally in DAIM. An executive summary of the thesis including title, student's name, supervisor's name, year, department name, and NTNU's logo and name, shall be submitted to the department as a separate pdf file. Based on an agreement with the supervisor, the final report and other material and documents may be given to the supervisor in digital format.

☐ Work to be done in lab (Water power lab, Fluids engineering lab, Thermal engineering lab)
☐ Field work

Department of Energy and Process Engineering, 18 January 2016

Olav Bolland
Department Head

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Academic Supervisor

Optimal Diluent Allocation In Production Systems With ESP-Lifted Wells

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Summary

In this research, the author presents the development of a numerical model for production systems (wells and surface flowlines) to determine optimal diluent allocation. The model includes the main inflow performance equations to represent reservoir deliverability, pressure and temperature drop calculations in tubing, electric submersible pump (ESP) modeling including viscosity and frequency correction equations, and oil blending models for the injection module. For the injection module, both ASTM D7152-11 standard and Cragoe (1933) methods are available. For the production fluid modeling, the author considered the black oil model to calculate thermodynamic properties and an emulsion model to calculate fluid viscosity depending on its water cut. The gas phase was neglected. The model was developed by using object-oriented programming (OOP) in a commercial software.

1. Introduction

According to the U.S. Energy Information Administration (U.S. Energy Information Administration, 2014), the world expects a growth in demand for oil within the next 25 years, due to the emerging economies of China, India and the Middle East. Between 2010 reported value, and 2040 projections, these countries expect a moderate growth in demand, from 40,0 mn BPD to almost 75,0 mn BPD. In global terms, it is also expected to have a growth rate of 3,2% between these next 25 years, with a liquid oil consumption reaching a peak of 108,0 mn BPD by the end of 2040.

This would represent a big challenge to oil producing companies, considering the current economic scenario, where profits out of the business have reduced significantly since the 2014.

Lower oil & gas prices have been a recurrent topic in annual reports of most oil companies. Statoil (Statoil, 2016) indicated that 2015 was a year of very volatile prices, ranging from USD 66 to USD 35 between May and December, for the reference Brent crude oil. These figures affected the company performance, including significant layoff during last year. BP reported a loss of USD 6.5 bn comparing with the expected results based on 2014 prices (BP, 2016). With these falling revenues, the British company stated that operational cost and activities have to be re-based, and they expect 2016 and the following years to be a period of intense change with ongoing restructuring. Saudi Aramco (Saudi Aramco, 2016) also anticipates the upcoming years to be volatile in terms of oil prices, requiring more smart investments based on a solid risk management framework, and reducing uncertainties in every step of the way. Based on this philosophy, the Saudi state-owned company has reported a steady increase in their oil production since 2011 to 2015, from 9,1 to 10,2 mn BPD.

It is clear that players in the oil market have keep up the pace to this VUCA world we are living in now. Oil companies have the challenge to satisfy this growing demand while dealing with lower prices, especially considering the current depletion of what is known as conventional reservoirs.

Having better understanding about this challenge, it is helpful to have a glance to the characteristics of the current oil reserves around the world. In the following graphs, there is an overview of the oil proved reserve distribution up to the end of 2014. According to BP, (BP, 2015) the total number to date is 1,7 bn barrels.

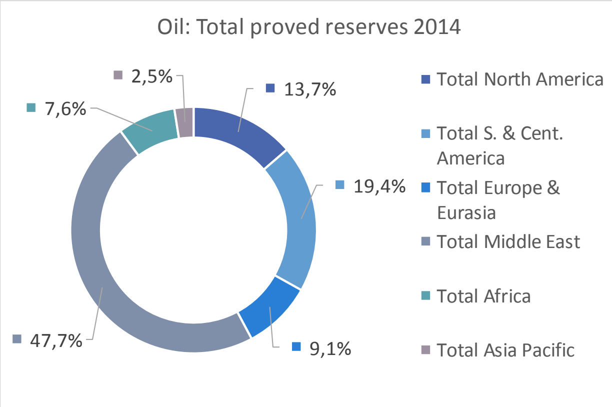


Figure 1. Oil proved reserves up to the end 2014, by region (BP, 2015).

Proved reserves is concept with different meanings for the industry, especially when it comes to its quantification. However, generally speaking it refers to the quantified oil reservoirs available in the world that, with the known technology, expertise and economic conditions, can be recovered at a reasonable return rate (BP, 2015).

As expected, not every barrel of the reported reserves is from the same type. The following plot depicts these oil reserves based on a density classification.

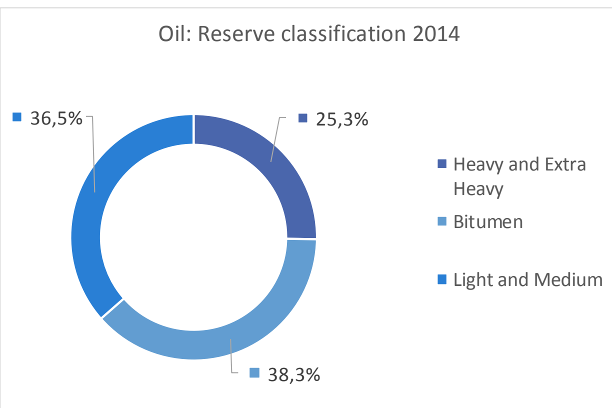


Figure 2. Oil proved reserves up to the end 2014, by type.

The terms light, medium, heavy and extra heavy oil refer to the high density of those oils. As an indicator of crude density, the industry uses API gravity. This unit is inversely proportional to the density or the specific gravity of an oil: the higher the API gravity, the lighter the crude oil and vice versa. As a reference, water API gravity at standard conditions is 10. There is no fixed line between each category about an oil's "heaviness", but the following rules are well accepted:

- Light oil: 32-40 °API
- Medium oil: 32-25 °API
- Heavy oil: 25-10 °API
- Extra-heavy oil: <10 °API

Bitumen is an additional classification, with an API grade lower than 10 API, but with additional consideration about its viscosity.

From the operational point of view, heavy oil, extra-heavy oil and bitumen are considered unconventional resources, since companies will have to invest more in its production, when compared to light and medium oil reservoirs.

Coming back to Figure 2, this means that out of these 1,7 bn barrels, roughly 38% constitutes conventional reserves, and the remaining 62% is unconventional oil. With a R/P ratio of 52 years, oil companies are driven to develop soon new tools and technologies to commercially develop more unconventional reservoirs, which in previous years were not that attractive.

In terms of location, between Canada and Venezuela, they gather around 30-35% of these unconventional resources. However, these American countries are not the only ones that have to be prepared to manage these type of crude oils. In the UK continental shelf, Mariner field is a typical case in Europe. According to Statoil, who holds 65% of its production licenses, Mariner has been subject to a number of development studies by various operators, since its discovery in 1981. However, feasibility studies from then indicated that it was not economically possible to develop it. In 2012, Statoil made the investment decision and the production is expected to commence in 2018 with an average plateau production of 55.000 BPD with total reserves up to 250 mn barrels.

Risk management is the key to drive smarter investments into the business, and the real asset in this project and portfolio management discipline is information. With high-quality data and tools for scenario analysis, it is possible to quantify risks and make decisions for developing new and already existing fields. Mariner field is a sample of this fact.

To reduce the risk, in recent years, virtually every company in the business has invested in developing computational tools for evaluating scenarios, training staff, undergoing feasibility studies, and trying to anticipate to technical challenges before proceeding to operations.

More and better tools have to be developed to help companies with their investment plans in fields that were not considered before. Having more than a billion oil barrels in these kind of reserves should be a good incentive to go in that direction.

With this background, the present study intends to provide tools to analyze a particular technique usually applied to heavy and extra-heavy oil reservoirs: diluent injection. The main objective was to develop a physically accurate and flexible model to study this technique, particularly for production systems with ESP-lifted wells. Among its features, the model should allow performing optimization to allocate an optimal diluent injection rate for single wells and networks.

As per the author's opinion, this particular topic has a promising outlook, but very little has been written about it. New tools to show this technique's performance have to be developed now and fast. This work is a step forward into this direction.

1.1. Problem description

For heavy and extra-heavy oil fields there is often a critical operational problem: oil viscosity. As a general case, oil found on these type of reservoirs has a high viscosity. The more viscous the fluid, the more energy and pressure losses along the production infrastructure. In order to overcome this problem, these fields are often developed with wells equipped with electric submersible pumps (ESP) to lift the pressure of the fluid to the surface. Another way to approach this challenge is to include diluent injection lines at various levels of the well (completion or along the tubing) to reduce the in-situ viscosity, hence reducing the pressure losses. When combined, these two IOR techniques are very promising, since the diluent injection may reduce the power requirement of the ESP and improve its performance.

Diluent injection is not a new term to the industry when it comes to heavy and extra-heavy oil recovery. Since 1999, there are references at SPE journals describing the potential of diluent injection to reduce the in-situ viscosity of these low-gravity oils, increasing the lifting capabilities and ultimately oil recovery. Garnett and Dee (Garnett & Dee, 1999) presented the results from a pilot test in the US including an implementation of light-oil injection in a heavy oil reservoir. They indicated that the oil average recovery increased 50 times using this technique. Rojas (Rojas, 2001) presented results on a new application in Venezuela for bitumen recovery (~8,5 °API) using diluent injection directly at the well completion. For this case study, the oil in-situ viscosity was 5.000 cP, at reservoir conditions (58 °C and 8100 kPa). More recently, in 2010, Brito, Garcia and Brown (Brito, Garcia, & Brown, 2010) presented results on an implementation of diluent and gas injection for the same purpose. This implementation is a step forward to the diluent injection technology, which is already considered traditional in Venezuela. As an interesting fact, they mentioned that in one of the production areas of oil state-own company PDVSA, a total of 343 wells have a diluent-injection implementation, with a combined production of 55.000 BPD. Maintenance for these injection facilities represent a major part of their operational expenditures, therefore they focused on another alternative different that an ESP for diluent injection.

Despite being a standard practice on those countries, there is no information available about whether the diluent injection rate could be optimal or not for a given production system. In gas lifting, gas injection to the well improve the production of a well due to the reduction of density, and consequently reduction on the potential losses in the fluid column. However, after certain injection rate, the additional material added in the system increases the hydraulic losses due to friction (Golan & Whitson, 1996). A similar behavior is expected in diluent injection.

Using diluent injection as an IOR technique also has some operational challenges: availability of diluent on site, capital investment on the infrastructure required, operational expenditure due to diluent injection facilities, among others. Therefore, allocating in advance an optimal diluent injection and performance curves describing its behavior for oil production systems is of great importance to the industry.

Diluent injection is not available in most commercial simulators related to oil production. In its last version, PROSPER® (13.0) from PETEX included this capability with a limited set of oil blending options. Another widely used simulator PIPESIM® for Schlumberger, in its version 2012.2 included diluent and gas injection directly over vertical tubing, but again, with limited capability in terms of blending method and location of the injection point over the well infrastructure. Considering this, most evaluations related to diluent injection are currently running over in-house applications or spreadsheets, difficult to scale up or to use in different scenarios. This fact reduces the risk management and planning capabilities of companies willing to implement this technique in their current assets. Additional to this, it does not provide a platform susceptible to optimization and feasibility analysis in a plain implementation.

As a sample of this issue, some data used as background of this study, includes a development from a software company that coupled different software to produce diluent injection performance curves. During this development several workarounds were made to modelled effectively diluent injection with the existing commercial software.

Therefore, this study attempts to provide an implementation of a physically accurate production model, in which diluent injection can be easily implemented for feasibility studies and economic evaluations.

1.2. Objectives

The main objective of the study was to develop a comprehensive and physically accurate model to represent both single wells and networks, including the following capabilities:

- Using ESP as a fluid lifting method, including as input equipment performance curves and working with affinity laws for centrifugal pumps for correcting performance due to changes on rotational speed.
- Working with viscous fluids, including the required correction factors to the appropriate elements of well infrastructure.
- Using injection points in any part of the well infrastructure (not only completion or tubing), including different methods for crude blending and property calculation.
- Susceptible to optimization using separable and non-separable functions.

As additional specific objectives, the following are included:

- Performing sensitivity analysis on the diluent injection performance of single well infrastructures with respect to the following variables: pump rotational speed, reservoir water cut, and wellhead pressure.
- Implementing optimization techniques in the models developed. In particular, applying separable and non-separable objective function optimization for a case study production network. In this context, separable objective functions refer to the production of individual wells which behavior is independent from other wells, and non-separable objective functions consider that there is dependency between the wells.

2. Nomenclature

2.1. Acronyms

bn	Billion, 10^9
BPD	Barrels per day
ESP	Electric submersible pump
IPR	Inflow performance relationship
IOR	Improved oil recovery
mn	Million, 10^6.
O/W	Oil in Water
OOP	Object-oriented programming
R/P	Reserves-to-production
USD	US dollars
VBA	Visual basic for applications
VUCA	Volatile-Uncertain-Complex-Ambiguous
W/O	Water in Oil

2.2. Greek letters

γ	Specific gravity
ρ	Phase density
θ	Pipe inclination angle
μ	Phase viscosity

2.3. Symbols

B	Phase volumetric factor

C_p	Phase specific heat
d_i	Pipe internal diameter
f_d	Darcy friction factor
g	Gravity acceleration
$\dot{m}$	Mass flow rate
p	Pressure
R_s	Gas in oil ratio
$\dot{q}$	Volumetric flow rate
T	Temperature
u	Phase velocity
U_i	Overall heat coefficient, internal
WC	Water cut
y	Vertical axis/direction

2.1. Subscripts

w	Water phase
o	Oil phase
g	Gas phase
e	Emulsion
∞	Surroundings or environment
sc	Standard conditions

3. Model fundamentals

In Petroleum Engineering, a production system is a set of elements that allow producing oil and gas from a reservoir. Production systems include both wells and surface networks, typically grouped in what the industry qualifies as upstream. These elements can be modelled by a set of mechanical and thermodynamic equations to reproduce how they affect the phase behavior along its path to the surface. Figure 3 provides a simplified sketch from a single well, part of the production systems modelled in this study.

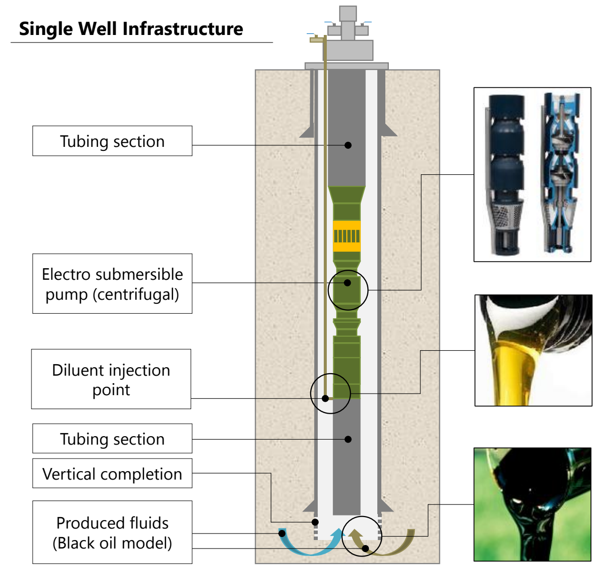


Figure 3. Simplified representation of a single well infrastructure.

Highlighting its elements, the well typically consists of the following elements:

- Vertical completion
- Tubing
- ESP
- Diluent injection point

For developing the production system model, the main governing equations for each element were included. Therefore, no special treatment about mechanical design details was made, e.g., the model does not include material specifications and limitations, system geometry, centrifugal pump operational details (cavitation or erosion due to solids, for example), among others.

In the following sections, there is a complete description of these equations and how they were applied to the element's model.

3.1. Fluid model

To predict the phase behavior for a broad range of crude oils using minimum inputs, the black oil model was selected. For a complete thermodynamic description of the model, a review to (Whitson & Brulé, 2000) is advised. This model was conceived for upstream applications, where typically only operational variables are available, e.g., pressure and temperature.

This model considers three different pseudo fluids characterized by the production fluid phases: gas, oil and water. A set of properties quantitatively describe the mass transfer between the phases, but essentially the model indicates that all phases are different substances. This is applicable for water and hydrocarbon-based phases, but between gas and liquid oil, this is not true. However, for all practical purposes and typical operating ranges for the industry, this model is well-accepted for describing phase behavior.

Black oil model properties are:

- Gas, oil and water volume factor (B_g, B_o, B_w).
- Solution gas oil ratio (R_s).
- Gas-oil ratio (GOR).
- Compressibility factor (C_o).
- Bubble point pressure (P_b).

These properties are dependent of the surface operations used as reference, therefore, the model allows to include tuning factors to adjust the property values to the experimental data. In this way, different crude oil properties can be described using the same correlations. Details on correlations used for each property can be found on this study's appendixes.

Although properties of the gas phase are computed in the model, the gas flowrate is neglected in all relevant calculations.

Additional to these properties, the black oil model was used to calculate local flow rates for all phases, based on flow rates at standard conditions. The transformation matrix for this calculation is given by Equation 1.

$$\begin{bmatrix} \dot{q_g} \\ \dot{q_o} \\ \dot{q_w} \end{bmatrix} = \begin{bmatrix} B_g & -B_g \cdot R_s & 0 \\ 0 & B_o & 0 \\ 0 & 0 & B_w \end{bmatrix} \cdot \begin{bmatrix} \dot{q_{g,sc}} \\ \dot{q_{o,sc}} \\ \dot{q_{w,sc}} \end{bmatrix} \tag{1}$$

The same approach is used to calculate the phases densities. The transformation matrix for this calculation is shown in Equation 2.

$$\begin{bmatrix} \rho_g \\ \rho_o \\ \rho_w \end{bmatrix} = \begin{bmatrix} 1/B_g & 0 & 0 \\ R_s/B_o & 1/B_o & 0 \\ 0 & 0 & 1/B_w \end{bmatrix} \cdot \begin{bmatrix} \rho_{g,sc} \\ \rho_{o,sc} \\ \rho_{w,sc} \end{bmatrix} \tag{2}$$

For computing the viscosity of the oil and water mixture, an emulsion model was used. W/O and O/W emulsions are easily formed on production systems, due to the presence of both phases in virtually all fields.

W/O and O/W emulsions properties have been studied thoroughly by the industry, including characterization of their behavior, developing correlations for calculation and implementation of techniques to modify them in a favorable manner. The following bullet points summarize the factor of interests for this study related to W/O and O/W emulsions behavior.

- The viscosity of a W/O emulsion is generally higher than the value of its oil phase at the same operating/experimental conditions (Duan, Jiaqiang, Jinzhu, Xiaofeng, & Xiaoguang, 2010).
- As water cut increases, W/O emulsion viscosity increases as well, for a given pressure and temperature.
- There is an inversion point at which the emulsion regime changes from W/O to O/W. This inversion point is given within a water cut range of 60%-80% (Rønningsen, 1995).
- After the inversion point, the emulsion viscosity drops suddenly. Depending on the sample, this drop may reach several orders of magnitude.

To illustrate these facts, Figure 4 depicts data of an extra-heavy oil sample, with an inversion point relative to the water cut of 60%.

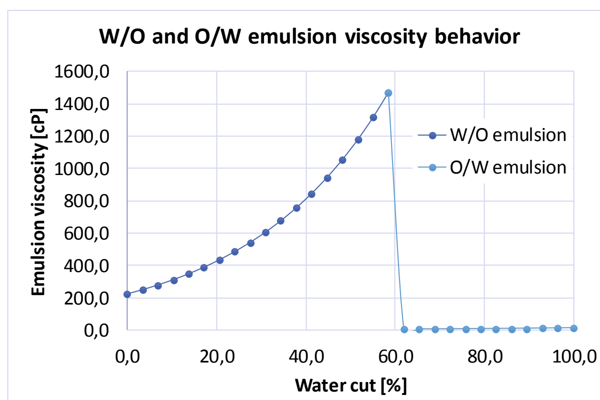


Figure 4. Viscosity behavior of a hydrocarbon-water emulsion in terms of production water cut (%).

To compute the viscosity, the Richardson model was used. Using this model, the viscosity is calculated by using Equation 3.

$$\mu_e = \mu_o \cdot e^{A \cdot \frac{WC}{100}}, \qquad WC < C \tag{3a}$$

$$\mu_e = \mu_w \cdot e^{B \cdot \frac{WC}{100}}, \qquad WC > C \tag{3b}$$

As per the constants A, B, and C, 3,215; 3,089; and 60% were used respectively (Stanko, 2014). To perform calculations with the model, the user has to provide these constants.

3.2. Piping model

In a single well infrastructure, tubing hydraulic losses and energy balances can be modeled as a traditional piping. Also, this model can be used for horizontal and inclined flowlines, since the same physical laws apply.

The following premises were considered to develop these models:

- Single phase flow along the pipe. The fluid model considers two different phases, water and oil, however, for these calculations a pseudo-homogeneous fluid is used, taken a mass average on the thermodynamic properties and using an effective viscosity for transport calculations.
- Using effective viscosity to calculate friction losses. The effective viscosity is defined as the oil-water emulsion viscosity, which will depend on the dominant phase.
- Using weight fraction of the phases (water and oil) to calculate heat capacity and density at each discretization point.
- Using Darcy definition for the friction factor calculation.
- Considering constant mass flow rate along the piping sections. So, in case there is an injection point, the calculation is performed before or after that point.
- Discretizing control volumes to solve the differential equations using finite differences and implementing linear equation solvers. This operation is required since the fluid properties change with temperature and pressure. Therefore, this discretization provides a more accurate calculation of them, along the pipe.

As mentioned, hydraulic losses were calculated using the simplified momentum equation in one dimension, for a homogenous fluid. Equation 4 refers to the formulation for the tubing, but is valid to horizontal and inclined flowlines.

$$-\frac{dp(y)}{dy} = \rho(y) \cdot g \cdot cos(\theta) + f_d \frac{\rho(y) \cdot u(y)^2}{2 \cdot d_i} \qquad (4)$$

For energy balances along the pipe, a general approximation of heat transfer mechanisms was made. In this way, in case the temperature of the fluid is higher than the temperature of the surroundings, the heat from the fluid is transferred to the pipe internal wall by convection, along its thickness by conduction and then, depending on the well infrastructure alternating convection and conduction for in its annular region, casing, cementing, and finally the surrounding soil. To reduce this complexity, an overall heat transfer coefficient has to be provided to solve the model.

The general energy balance for a vertical tubing, rearranged as a suitable finite differences expression, is given by Equation 5.

$$-\frac{dT(y)}{dy} = \frac{d_i \cdot U_i \cdot (T(y) - T_\infty)}{\dot{m} \cdot Cp(y)} \qquad (5)$$

This expression is also valid for horizontal and inclined flowlines.

For the case of vertical tubing inside the well, no special consideration is being made about the casing and all layers affecting the heat conduction radially, the heat transfer coefficient is referred to the internal diameter of the tubing. As for flowlines, a similar approach is considered.

3.3. ESP model

As common industry definition an electric submersible pump, or ESP for short, is a vertical centrifugal pump with multiple stages, designed to be installed inside a well. Therefore, two group of equations to describe the performance of centrifugal pumps were used.

The first group was centrifugal pump affinity laws. These so-called laws allow calculating the performance of a pump, from a reference performance curve. These set of equations relate the following variables:

- Rotational speed
- Head
- Capacity
- Impeller diameter
- Power consumption

The typical performance curves of a centrifugal pump include:

- Head-capacity curves
- Power-capacity curves

The capacity is expressed in terms of volume units per time unit, head is expressed in distance units, and power in terms of energy per time unit.

The second group of equations is related to performance correction due to viscosity of the fluid. Fluid viscosity affects the performance of centrifugal pumps, since they depend on developing kinetic energy due to rotation and then converting this energy into pressure in the pump's volute. The more viscous the fluid, the more frictional losses in the inter blade passages and pump impeller.

Typically, pump manufacturers provide the performance curves using water as a reference fluid ($\gamma_w = 1$), so users can adapt them according to their needs. For completing this correction, the procedure suggested by the American Hydraulic Institute (ANSI/HI Standard 9.6.7, 2010) was used, suitable for centrifugal pumps and viscous liquids up to 4.000 cSt.

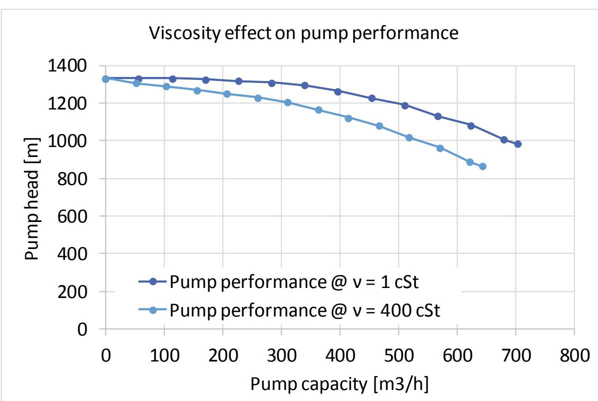


Figure 5. Viscosity effect on centrifugal pumps performance.

In the Figure 5 is depicted the pump performance at two different values of fluid viscosity. Figure 6 depicts the pump performance correcting by both viscosity effect and reduced rotational speed.

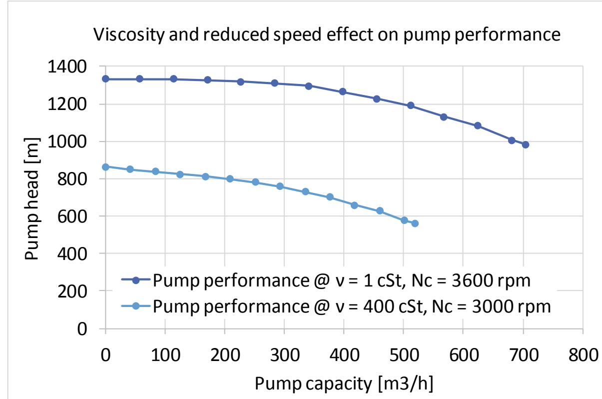


Figure 6. Viscosity and reduced speed effect on centrifugal pump performance.

3.4. Blending model

Oil blending is required in the injection points and in the mixing nodes of a network to compute the new oil properties, such as viscosity, density, and heat capacity. Using these values, new black oil properties are calculated.

For this purpose, two main methods were included in the model: ASTM D7152 (ASTM Standard D7152, 2011) and Cragoe (Cragoe, 1933). Sæten (Sæten, 2014) provided a study case comparing these two methods using North Sea crude oils, particularly from Mariner field. The results for both methods were satisfactory in terms of predicting viscosity values (kinematic or absolute); furthermore, the author suggested that ASTM D7152 method provided a lower deviation with the experimental data available.

3.5. IPR models

The model included five (5) different IPR calculation methods:

- Productivity index
- Jones equation
- Fetkovich equation
- Back pressure equation
- Vogel equation

As a reference formulation about those particular IPR calculation methods, equations given in (Beggs, 2003) were used.

Every model included both variants: oil and gas production. In the current version of the model, the gas phase is neglected, however, the model supports an expansion to gas wells in further research.

4. Methodology

As mentioned before, the main objective of this study was to provide a comprehensive and physically accurate model to evaluation diluent injection and ESP-lifting technologies in single wells and networks. Efforts completed during this semester attempted to continue previous work from the Specialization Project (Ensalzado, 2015), including system integration for single well infrastructure, development of network infrastructure, sensitivity analysis, and optimization.

In the following sections, a more detailed insight about the study development is given.

4.1. Quality management

In order to guarantee that the model provides an accurate representation of physical elements, an extensive quality management phase was deployed. The main topics revised were as follows:

- Viscosity blending accuracy.
- Tubing hydraulic and temperature profiles
- ESP performance
- Black oil property calculation accuracy.

This quality verification was done against two commercial simulators, PIPESIM (version 2012.2) and PROSPER (version 13.0). During the testing, some programming bugs were detected and corrected, but in general terms, the results presented a small deviation within the range of 3%-5% from the aforementioned simulators.

Several factors may explain this deviation, however the differences in the tuning factor programming for the black oil properties seemed to be the most relevant of them. Despite the deviation, the results showed the expected uncertainty and were satisfactory to proceed to the next phase.

4.2. Model development

The model was developed completely in MATLAB (R2015a) using OOP. There is a detailed explanation about the classes capabilities in Section 5.

The low level objects were programmed during the previous semester, so during this period the focus was made in the two integration classes: SingleWellObj and NodeObj. These classes provide the rules for interaction between the low level elements and the model functionality.

4.3. Literature revision

Since most of the literature review related to the governing laws of the model was completed during the fall semester 2015; the main focus during this period was on optimization and programing techniques applicable for the implementation.

The topics revised were as follows:

- Linear programming, including implementation of special-ordered sets (SOS).
- Non-linear optimization theory for convex problems.
- Implementation of optimization in MATLAB, for both linear programming and non-linear systems.
- Advanced programming techniques in Object-oriented languages, applicable to MATLAB, including event handling.

4.4. Peer-to-peer presentations

During the development period, two relevant peer-to-peer presentations were made.

The first one, at the Department of Petroleum Engineering and Applied Geophysics (IPT) Spring PhD Seminars 2016. For this seminar a poster with the main highlights of the research up to date was presented and discussed with peers attending the session. As mentioned before, this particular is a traditional practice in the American continent, but it represents a novelty in developments on the North Sea fields.

The second presentation was done to Petroleum Cybernetics, a group developed by the Department of Technical Cybernetics (ITK) and IPT. During the presentation, the details about the model development were presented and discussed, with particular emphasis on the challenges related to the implementation of optimization techniques.

4.5. Reporting

In order to guarantee that the users can use and extend the model capabilities a set of additional documents were developed. These documents focus on the programming details of the classes including the following topics:

- Properties
- Methods
- Main algorithms of solving

Special emphasis was made on the black oil class (BOObj) and viscosity adjustment and calculation.

As for the first topic, there are several correlations and calculation routines available for computing the black oil model properties. Because of that, an additional report including the correlations and validity ranges was prepared.

In regard to the viscosity adjustment and calculation, something similar was developed. Using experimental data from oil field, a series of validations were made. The results were included in an additional technical report.

5. Programming approach

As mention on the study briefing, OOP was used as the programming technique for developing the model. There are many advantages using this approach for model development, including the following:

- *Extensibility*. It is possible to add system's elements to the model with minimum, if any, modification to the existing classes.
- *Encapsulation*. Procedures, algorithms and correlation for model operation are included in the classes, so the user has no exposure to its logic of execution.
- *Modularity*. The system can be developed in independent modules. Also, instances of these modules can be executed independently from each other.

Most commercial software for petroleum and process engineering support some kind of OOP, especially for customization. For example, PIPESIM® has the package called OpenLink® which allows interacting with external applications such as MS Excel through VBA. RESOLVE® from PETEX also provide this capability, using MS Excel as an interphase to calculate and report variables. PIPEPHASE® from Schneider Electric (former Invensys) also supports extensibility with OOP software or languages.

OOP is based on classes. They can be seen as the template that defines properties, methods and events for a particular object. An object is an instance of a class, i.e., a populated variable based on the class. For describing the model, eight classes were developed:

- BOObj class
- InjectionObj class
- TubingObj class
- FlowlineObj class
- VertCompletionObj class
- ESPObj class
- SingleWellObj class
- NodeObj class

An important remark about the development of these classes is that they all belong to the super class type handle. In MATLAB, there are two different super classes types: handles and values. The main difference between them is that every object created from a handle-type class is passed as a reference to any other instance: therefore, the changes made in any moment will be reflected automatically in every instance in which the object is used. In an object created from a value-type class, an independent copy is given to other instances so the changes are applied locally.

The next sections include a description about the classes hierarchy and main features of each of them.

5.1. Object hierarchy

Classes can have different levels of interaction, so it is convenient to define hierarchies among them. In this way, low level classes can be used to build more complex and specific ones.

In this particular case, for the model developed, a two-level hierarchy was considered. First-level classes are independent building blocks, that require different type of data and run independently from any other. Second-level classes are dependent on first-level classes to operate. This hierarchy is shown in Figure 7.

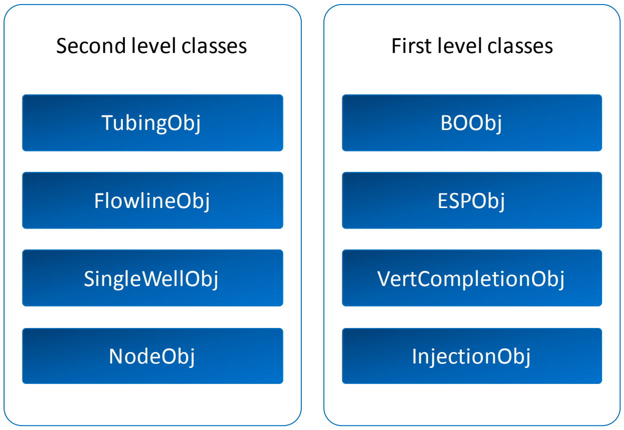


Figure 7. Classes Hierarchy levels.

The second-level classes depend on the first level-classes as shown in the following diagrams.

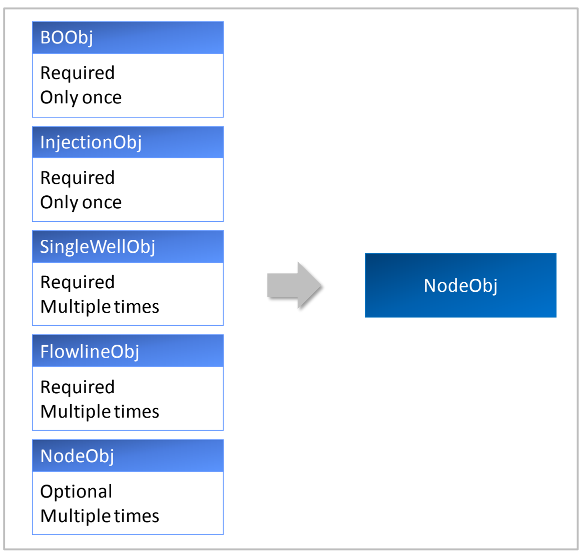


Figure 8. Class dependency: NodeObj class.

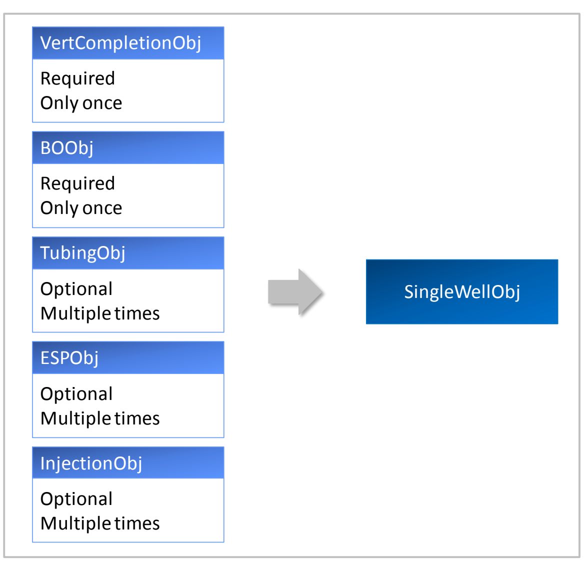


Figure 9. Class dependency: SingleWellObj class.

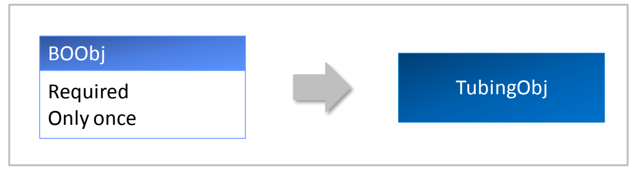


Figure 10. Class dependency: TubingObj class.

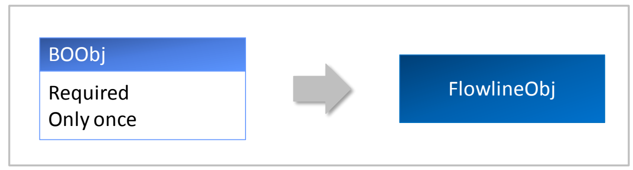


Figure 11. Class dependency: FlowlineObj class.

5.2. BOObj class

This class contains all correlations for property calculation and adjustment algorithms related to the black oil model.

The main function of the class is calculating black oil properties of a given fluid. As mentioned, every second-level class requires a BOObj instance as an input.

The minimum information required by an object from this class is as follows:

- Pressure.
- Temperature.
- Oil specific gravity.
- Gas specific gravity.
- Water specific gravity.
- Oil viscosity reference matrix (two values at different temperature levels, at standard pressure).

5.3. ESPObj class

This class contains all expressions and correlations to describe an ESP performance. It includes:

- Outlet pressure.
- Viscosity adjustment using the ANSI/HI 9.6.7 standard (ANSI/HI Standard 9.6.7, 2010). As suggested by the standard, the maximum viscosity value is 4.000 cSt.
- Adjustment of pump performance due to actual impeller rotational speed using affinity laws.
- Adjustment of pump power consumption for a given impeller rotational speed, using affinity laws.

The minimum information required by an object from this class is as follows:

- Head-capacity performance curve, for a reference fluid (water).
- Reference impeller rotational speed.
- Actual impeller rotational speed.
- Pump best efficiency point (BEP).

5.4. FlowlineObj class

This class contains all expressions to model a horizontal pipeline. This class is very similar to the TubingObj, but it was specially designed to interact with SinglewellObj and NodeObj classes. The energy losses calculation is based on a constant value for the ambient temperature. It allows to perform the following calculations:

- Hydraulic losses due to friction.
- Thermal energy balances.
- Forward and backward calculation.
- Pressure and temperature profiles, given in charts or in plots.

The minimum information required by an object from this class is as follows:

- Black oil model defined by the BOObj class.
- Internal diameter.
- Pipeline roughness.
- Length.
- Ambient temperature.
- Overall heat transfer coefficient.
- Pressure (at one end).
- Temperature (at one end).
- Phases' flowrates (at one end, at actual conditions).
- Phases' flowrates (at one end, at standard conditions).
- Phases' density values (at standard conditions).

5.5. InjectionObj class

This class allows to calculate the properties of an oil blending. As discussed in section 3.4, it applies two different procedures for that: ASTM D7152-11 and Cragoe's.

As a main output, it provides a new reference viscosity matrix for a given blend, to be used in a BOObj object for tuning.

The minimum information required by an object from this class is as follows:

- Diluent flowrate.
- Diluent density.
- Diluent viscosity reference matrix (two values at different temperature levels, at standard pressure).
- Oil flowrate.
- Oil density.
- Injection/blending temperature.

5.6. TubingObj class

This class contains all expressions to model a buried vertical pipeline. This class is very similar to the FlowlineObj, but it was designed to be included as part of SingleWellObj class items. One important different with the FlowlineObj class is that energy losses calculation is based on the geothermal profile instead of a constant ambient temperature.

It allows to perform the following calculations:

- Hydraulic losses due to friction.
- Thermal energy balances.
- Ascending and descending calculation.
- Pressure and temperature profiles, given in charts or in plots.

The minimum information required by an object from this class is as follows:

- Black oil model defined by the BOObj class.
- Internal diameter.
- Pipeline roughness.
- Length.
- Geothermal temperature gradient.
- Overall heat transfer coefficient.
- Pressure (at one extrema).
- Temperature (at one extrema).
- Phases' flowrates (at one extrema, at actual conditions).
- Phases' flowrates (at one extrema, at standard conditions).

5.7. VertCompletionObj class

This class provides all correlations to compute a well's IPR. As described in section 3.5, it is possible to use up to 5 methods for gas and oil wells, providing the appropriate parameters for each model.:

The minimum information required by an object from this class is as follows:

- IPR type.
- Selected IPR parameters.
- Reservoir pressure.
- Reservoir temperature.

5.8. SingleWellObj class

This class is an integration structure. It allows to solve a single well object, identifying every item included and interconnecting them with each other. After that, it applies a solving algorithm to calculate the bottom hole pressure, estimating the well flowrate.

The minimum information required by an object from this class is as follows:

- Black oil model defined by the BOObj class.
- Wellhead pressure.
- Well building items. As a minimum requirement, at least a VertCompletionObj object has to be included. Other items may include TubingObj, ESPObj and InjectionObj objects.

5.9. NodeObj class

This class is an integration structure. It allows to solve a set of branches and nodes, given a fixed pressure. It applies a solving algorithm to calculate wellhead pressures for SingleWellObj objects and node pressures for NodeObj objects.

The minimum information required by an object from this class is as follows:

- Node pressure.
- Branches or nodes, or both. For the case of branches, a combination of a SingleWellObj object and a FlowlineObj,object must be given. For nodes, a combination of a NodeObj and a FlowlineObj object must be provided as input.

6. Sensitivity analysis

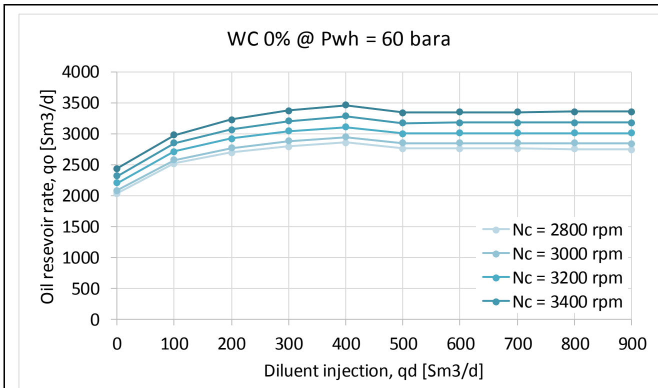
The objective of this analysis was to compute the diluent performance curves of a given single well infrastructure and determine its sensitivity with multiple operational variables.

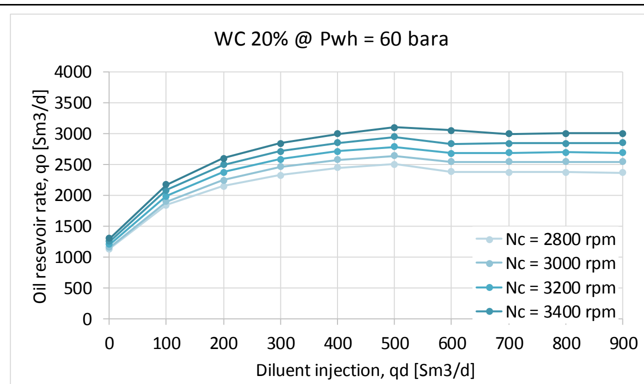
As a base case for performing the study an artificial well example was created. This well included two tubing sections, an ESP, and one diluent injection line. More details could be found on the appendixes section 12.1.

The variables included in this analysis were pump's impeller rotational speed (Nc), reservoir water cut (%) and wellhead pressure (Pwh). For each variable, four (4) plots were given Variables ranged as follow:

- Pump's impeller rotational speed: from 2800 rpm to 3600 rpm.
- Reservoir water cut: from 0% to 70%.
- Wellhead pressure: from 40 bara to 90 bara.

The results are depicted in Figures





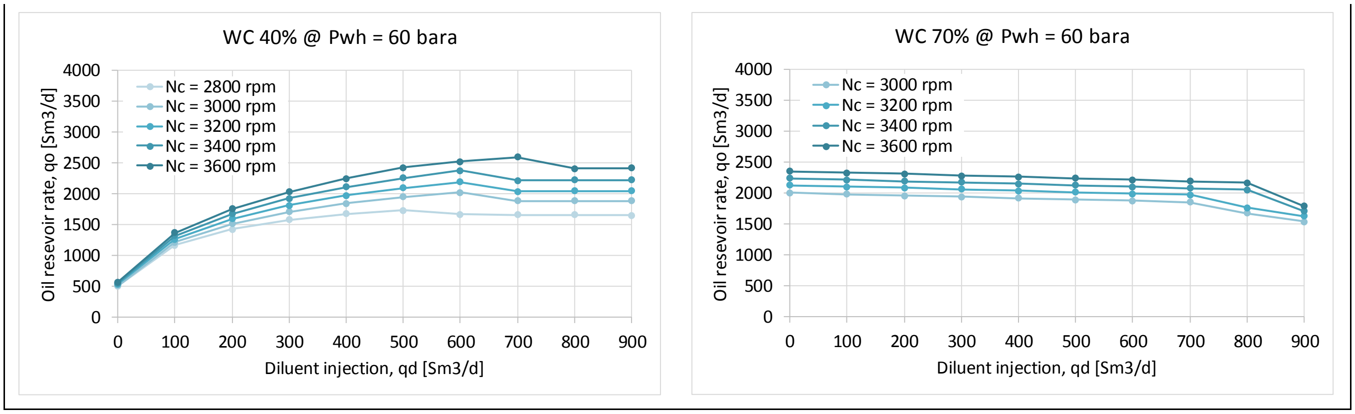


Figure 12. Sensitivity analysis: reservoir water cut effect on diluent injection performance.

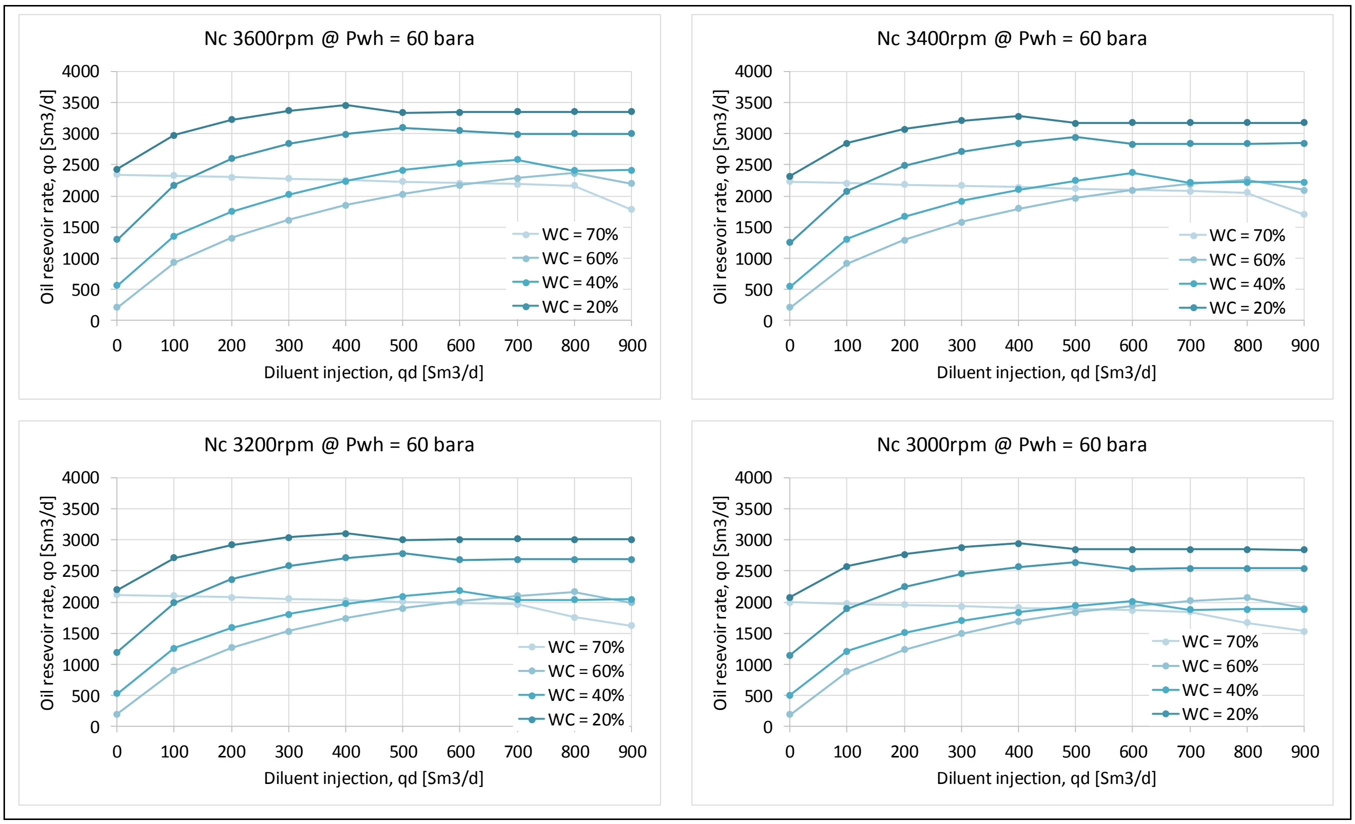
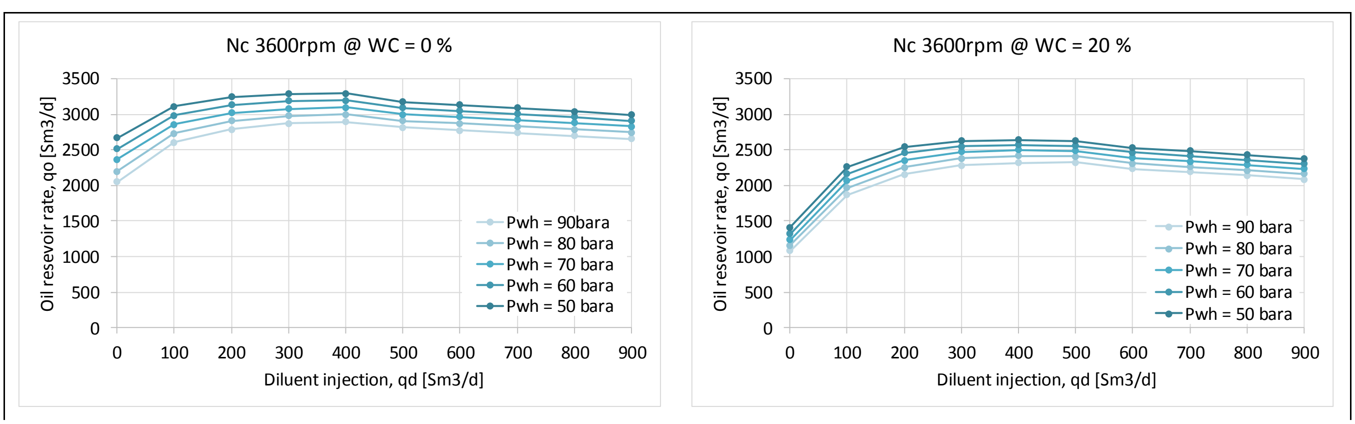


Figure 13. Sensitivity analysis: impeller rotational speed effect on diluent injection performance.



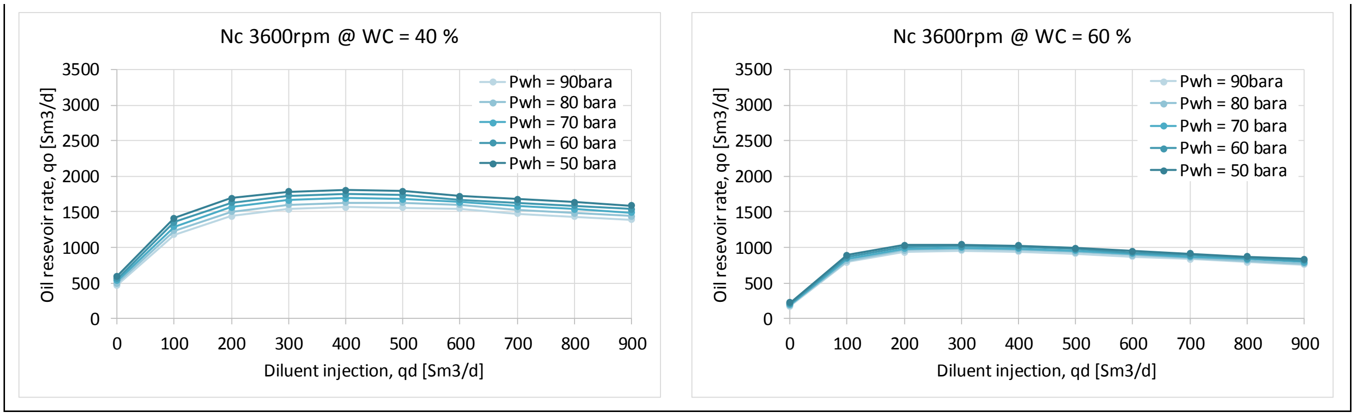


Figure 14. Sensitivity analysis: wellhead pressure effect on diluent injection performance.

After performing the analysis, it was possible to reach the following conclusions:

- Diluent injection improves oil recovery, as long as the liquid phase behaves as a W/O emulsion. For these cases, there is an optimal diluent injection rate.
- Diluent injection does not improve oil recovery when the liquid phase behaves as a O/W emulsion. In all cases tested, diluent injection decreased the oil recovery rate.
- Oil production rate is proportional to the impeller rotational speed of the ESP. Therefore, the higher the rotational speed of the pump, the higher the energy transfer rate to the fluid, hence, the higher the head developed by the fluid.
- Oil production decreases as the reservoir water cut increases. This observation is valid as long the water cut does not reach the inversion point, i.e., the liquid phase behaves as a W/O emulsion. After the inversion point, due to the change of emulsion regime, the production may increase as shown in Figure 13.
- Oil production rate is inversely proportional to the wellhead pressure, as expected. An interesting observation was that the optimal diluent rate did not show an apparent change with the wellhead pressure; therefore, once the optimal is found for a given wellhead pressure, it provides a good approximation of the optimal for other values.

7. Optimization

As mentioned in the study's objectives, after developing the numerical model, two different optimization applying two schemes: separable and non-separable functions.

In optimization, separable objective functions refer to elements of a system or network with no interactions. Therefore, the changes on separable function variable will not affect the remaining targets. Consequently, it is possible to run every system element independently from each other. In Petroleum Production Engineering, this case may represent satellite wells which do not share a cluster or with no interconnection between one and other. Using this approach, the optimization implementation can be run separately from the system; certainly a computational advantage, since it is possible to collect all data from the system performance in a prior stage and later use the information for optimization.

On the other hand, non-separable objective functions refer to elements with mutual dependency, therefore, the performance of one element will affect the remaining elements of the system. In this case, it is not possible to run independently elements from the system. In oil production, it may represent systems with multiple wells interconnected by a cluster, manifold or branch. From the optimization perspective, the optimizer has to run on top of the model application, and requires information from the system at every step. From the computational point of view, it is also more resource demanding than the separable objective function approach.

Despite their differences, these two approaches are of interest of the industry since they represent different real cases; hence, the model developed must be capable to answer to both requirements.

For this study case, the objective function subject to optimization was the reservoir oil production for both individual wells and the network, and the optimization variables were the diluent injection rates in each of the wells. As a reference of the computational performance, all cases were tested in a personal computer with an Intel Core i5-3337U @ 1.80 GHz processor and with 12,0 GB of RAM.

In the following sections there is a complete explanation of these two implementation including computational performance details.

7.1. Separable objective functions

As mentioned before, in the context of this study, separable objective functions refer to the oil production of different single wells with no interconnection. In this way, the performance of each well does not affect the others.

For this approach, a set of artificial wells (up to 100) were modelled. With the well architectures defined, diluent performance curves for each well were computed, ranging the diluent injection rate from 0 to 900 m^3/d. The curves were as shown in Figures 12 to 14. A sample of these curves is available in the appendixes' section 12.3.

In order to optimized this set of data, a mathematical expression depending on the diluent injection rate and resulting in the reservoir oil production must be developed. For doing this, two particular function types were selected: piecewise linear functions and polynomials.

In optimization, using these two types of functions provides different advantages:

- With piecewise linear functions, linear programming optimization techniques can be used. This reduces the complexity of the implementation, dealing only with linear equation systems. The challenge in this case is the optimization problem formulation.
- With polynomials, the gradient and hessian matrices are easily obtained, therefore, optimization algorithms based on them converge efficiently.

7.2. Piecewise linear modelling

As stated in the previous section, the main challenge using piecewise linear modelling is the optimization problem formulation. For this purpose, several options were considered, including using special ordered sets (SOS). In SOS formulation a certain number of optimization variables from a given set can be different than zero. This is a very usual approach in optimization applications in Economics.

However, it was possible to implement a simpler approach, which allowed using a traditional linear programming solver. The model is described by Equation 6.

$$maximize: f(x) = \sum_{j=1}^{n}\sum_{k=1}^{rj} s_{jk}x_{jk} \tag{6a}$$

$$0 \leq x_{jk} \leq d_k - d_{k-1} \tag{6b}$$

$$k = 1, \dots, rj < j = 1, \dots, n \tag{6c}$$

In this equation, the indexes j and k refer to the number of objective functions (number of independent well in this case) and the number of segments for each function respectively. The variable s_{jk} refers to the k^{th} segment slope of the j^{th} function; the variable x_{jk} refers to the diluent injection rate for the k^{th} segment of the j^{th} function, and the variables d_k and d_{k-1} represent the boundaries of the optimization variable x_{jk}. More details of the formulation can be review in (Jensen & Bard, 2003).

For the study, the number of wells was ranged from 10 to 100 and the number of segments from 5 to 10. Additional to this, different proportions of diluent injection were considered; once the unconstrained diluent rate was obtained, the following cases were run using 80%, 60% and 40% of this unconstrained rate. The purpose of this was to determine if additional restrictions to the model had an impact on the optimization performance.

For optimizing the model, the MATLAB® built-in function `linprog` was used. More information about this function can be found in (The MathWorks, Inc., 2016).

The results from these optimization cases and the running time are available on the appendixes' section 12.3.

From the cases tested, there are some worth mentioning observations:

- The execution time for all cases was below fractions of seconds (< 0,2 s).
- The constraint related to the diluent injection rate reduced the run time of the problem in every case.

7.3. Polynomial modelling

For polynomial modelling, approximation polynomials of different order were used and compared. Polynomial expressions were adjusted using the least squares criteria.

Additional to this comparison, as completed for the previous case, different proportions of diluent injection were considered: for this modelling approach proportions of 75% and 50% of the unconstrained rate were used.

The optimization function is described by Equation 7.

$$maximize: f(x) = \sum_{i=1}^{n} f_i(x_i) \qquad (7a)$$

$$subject\ to \sum_{i=1}^{n} x_i \leq q_{d,max} \qquad (7b)$$

In that equation, the function $f_i(x_i)$ refers to the approximation polynomial the i^{th} well and, and x_i to its diluent injection rate. The variable $q_{d,\,max}$ refers to the maximum amount of diluent available.

For optimizing the model, the MATLAB® built-in function `fmincon` was used. Both the gradient and the Hessian matrix were provided, to improve the calculation time. More information about this function can be found in (The MathWorks, Inc., 2016).

The results from the run time of the model using different polynomial degrees are available on the appendixes' section 12.3.

As expected, the run time increased with the number of wells; furthermore, it showed an exponential behavior, as depicted in Figure 15.

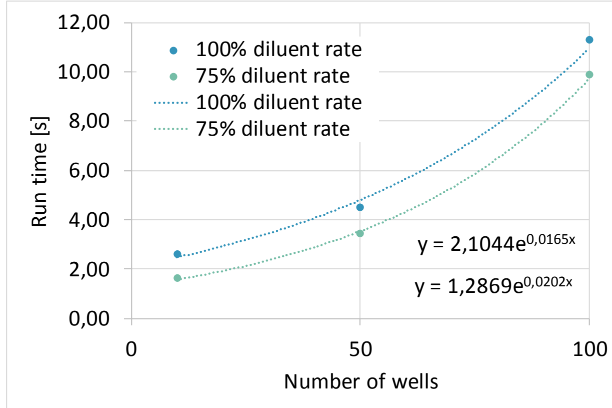


Figure 15. Running time of optimization execution, case: 3rd order polynomials.

From the cases tested, there are some worth mentioning observations:

- The execution time was below 14 s, for all polynomial degrees. In practical terms, no difference was observed in the optimization execution (execution time in s) for different polynomial degrees.
- The mean relative error of the optimal diluent rate, comparing the highest degree expression with the other two for the same conditions, was less than 1,5%.
- The mean relative error of the optimal diluent rate, comparing the highest degree (5th) expression of polynomial modelling with the piecewise linear approximation, was around 15%.
- The constraint related to the diluent injection rate reduced the run time of the problem in every case.

7.4. Non-separable objective functions

As mentioned, in this study's context, non-separable objective functions refer to production networks with different wells interconnected with each other. In this approach, the objective function was defined as the summation of the reservoir oil production of each well included in the network. This can be expressed by Equation 8.

$$maximize: f(x) \qquad (8a)$$

$$subject\ to \sum_{i=1}^{n} x_i \leq q_{d,max} \qquad (8b)$$

For this case, no comparative benchmarking was completed, since the solving time of a network of 3 wells exceed 5 min. All relevant results are included in the following section.

Similar to the optimization of the polynomial model, the MATLAB® built-in function `fmincon` was used. In this case, only the gradient vector was user-defined.

8. Study case

In order to compare the optimization techniques, a study case based on three-well network was built. The network configuration is depicted in Figure 15. The remaining information related to the elements of the wells and the interconnecting objects can be found on the appendixes section 12.2.

The objective of the study case was to define in applicable terms if these techniques could be used separately or if a combination of both could provide better results.

8.1. Network definition

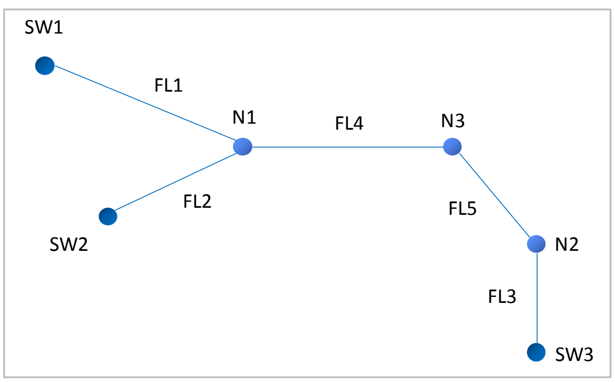


Figure 16. Network interconnection diagram.

Three well branches were built:

- WB1: single well SW1 with flowline FL1.
- WB2: single well SW2 with flowline FL2.
- WB3: single well SW3 with flowline FL3.

With this, node N1 had two branches, WB1 and WB2, while node N2 had the WB3 branch. Additional to those well branches, two node branches were included defined:

- NB1: node N1 with flowline FL4.
- NB2: node N2 with flowline FL5.

Node branches, NB1 and NB2, converged to node N3, which had a given pressure (6500 kPa or 65 bara). The solver engine in node N3 estimated the following variables:

- Wellhead pressure for each well.
- Internal node pressure.
- Flowline flowrates.
- Fluid property at every object.
- Temperature value at every object.

8.2. Optimization results

For this case, the approach was as follows:

- Optimizing the network using as an arbitrary initial point
- With the results, creating the diluent performance curves for each well in the network for the resulting wellhead pressure.
- Approximating the diluent injection performance curves using 6th degree polynomial functions.
- Optimizing the diluent performance curves using separable objective functions.
- Evaluating the network performance with the results from the previous optimization step and compare them.
- In case of difference, running the network optimization using as a starting point the value given by the separable objective function optimization.

After running the system with an arbitrary starting point, the system converged to a maximum, after 24 iterations with an execution time of more than 3,3 h. After completing the procedure described, an evaluation of the network provided a new optimum value with the results from the separable function optimization.

With these new values, a second network optimization stage was performed, taking only 2 steps and roughly 9 min in execution time.

Using the network results, new diluent performance curves for the system were computed.

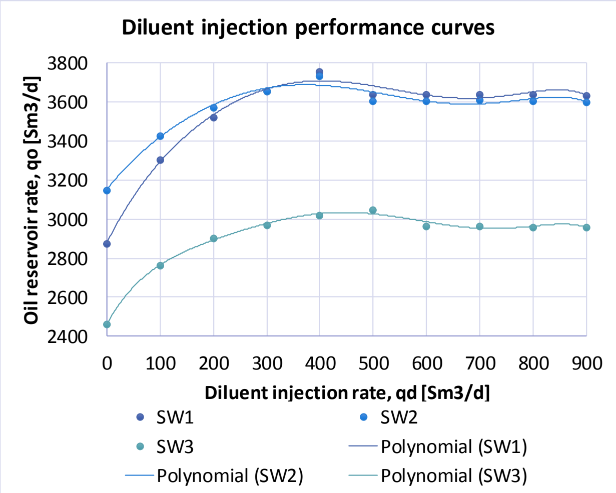


Figure 17. Diluent performance curves for the wells in the study case.

From the cases tested, there are some worth mentioning observations:

- Using a separable objective function optimization could provide better starting points for a global optimization, reducing substantially the execution time.
- An estimation of the network variables should be provided in order to proceed with the separable function optimization. As a first attempt, solving the network with no diluent injection could provide good results. As indicated before, the resulting optimal diluent injection would not show a significant shifting from the real optimal.

9. Conclusions

Related to the main project objective:

- A comprehensive and physically accurate model for production systems was built successfully. The model shown the required flexibility to study diluent injection in ESP-lifted well, both independent and interconnected in a network. The model is easily scalable, since it was implemented using OOP in MATLAB (R2015a).
- The model is based on 8 classes, distributed in 4 first-level and 4 second-level classes. Each class represents a particular element in an oil production system; in detail: the fluid model, tubing and flowlines, IPR models, diluent injection lines, ESP, single wells, and network nodes.
- The model is suited for optimization, either using the built-in MATLAB Optimization Toolbox (`linprog` or `fmincon` functions), or using its outputs to work with a different software.

Related to the project specific objectives, in particular, the sensitivity analysis:

- It was shown that for independent wells with diluent injection, there is an optimum diluent injection rate for a certain set of conditions, when the liquid phase behaves as a W/O emulsion.
- For the O/W emulsion regimes, diluent injection does not improve oil recovery rate in any of the case tested. Furthermore, for these cases, diluent injection reduces reservoir oil rate.
- ESP-lifted wells with diluent injection behave as expected in terms of changes on the pump impeller rotational speed, wellhead pressure, and reservoir water cut. Production is directly proportional to the impeller rotational speed, and it is inversely proportional for the remaining two variables.
- For the cases in which W/O emulsion regime was dominant, no considerable shifting on the optimal diluent injection rate was observed. Therefore, if found for a given set of conditions, this optimal injection rate can be used as an initial estimate for a further optimization stage.

Related to the project specific objectives, in particular optimization of different modelling approaches:

- For separable objection functions, two modelling approaches were tested successfully: piecewise linear representation and polynomial least squares approximation.
- In terms of time execution, optimization of piecewise linear function took less than a second (< 0,2 s), for all cases ranging from 10 to 100 wells. Optimization of polynomial expressions of 3rd, 4th, and 5th degree took less than 15 s, for all cases ranging from 10 to 100 wells.
- In terms of the optimal diluent injection rate, the difference in results between polynomial functions of 3rd, 4th and 5th degree was less

than 1,5%. Comparing the piecewise linear model with the highest polynomial, the difference was around 15%.

- Considering both execution time and results predictions, a polynomial expression of high degree should be preferred over piecewise linear approximation and lower polynomial degree.

Related to the project specific objectives, in particular to the non-separable optimization:

- Using a separable objective function optimization could provide better starting points for a global optimization, reducing substantially the execution time. In the case tested the execution tie could be reduced from more than 3 hours to several minutes.

10. Further work

- *Including compositional fluid model*. For crude oils with a complete phase characterization, the compositional model would provide more accurate results. This inclusion will require developing equation of state for calculating thermodynamic properties, adjusting transport property correlations, and adjusting calculations in the TubingObj and FlowlineObj classes.
- *Including gas phase modeling*. If gas phase is included, then multiphase flow correlation describing phases' velocity, regime, pressure drop and properties are required. This development will extend the capability of the model to traditional production systems in the North Sea.
- *Applying optimization for the remaining variables of the production systems*. In many production systems, an ESP could be connected to a variable frequency drive, to adjust the pump performance depending on the production profile along the day. This approach can be applicable to other system's variables to determine an optimal performance of a field.
- *Including other production system elements*. Chokes, separators, booster pumps are very common equipment in production systems; so developing classes for modeling them will expand the capability of the model.

11. References

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12. Appendixes

12.1. Sensitivity analysis data

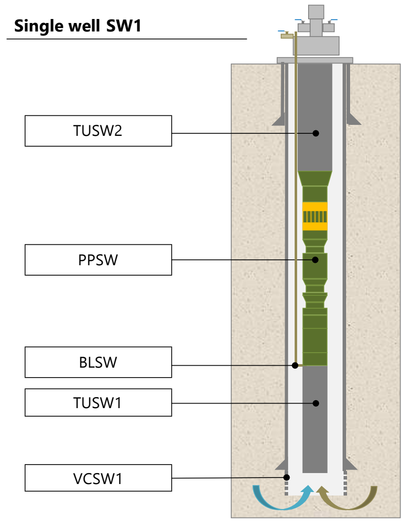


Figure 18. General diagram of single well infrastructure for the sensitivity analysis.

Table 1. Black oil properties for sensitivity analysis.

Fluid properties	SW1 (Oil)	BLSW (Diluent)
°API	14,5	30,8
Specific gravity	0,9692	0,8720
Kinematic viscosity [cP] @ T1 [°C]	960 @ 37,8	9,8 @ 38,0
Kinematic viscosity [cP] @ T2 [°C]	329 @ 50,0	7,5 @ 54,0

Table 2. IPR parameters for sensitivity analysis.

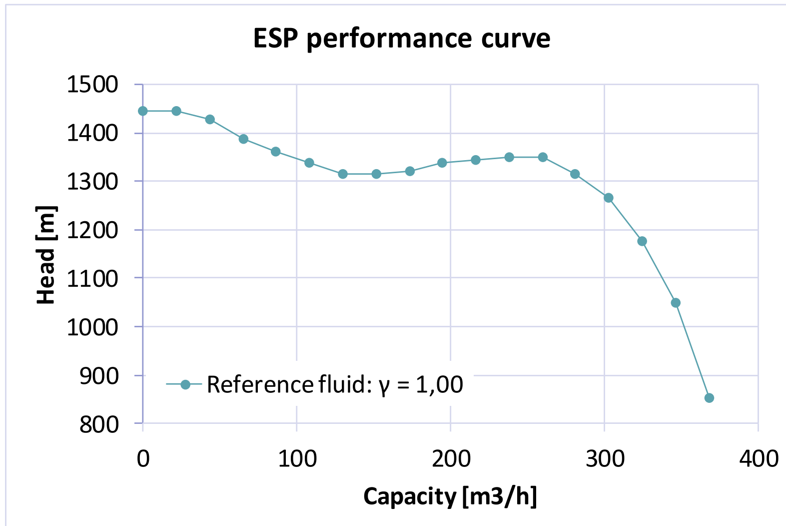
IPR parameters	VCSW1
Type	Oil PI
Reservoir pressure [bar]	200
Reservoir temperature [°C]	45
Productivity index [Sm3/d.bar]	30

Table 3. Tubing parameters for sensitivity analysis.

Tubing parameters	TUSW1	TUSW2
Internal diameter [m]	$1,053.10^{-1}$	$1,053.10^{-1}$
Roughness [m]	$1,524.10^{-5}$	$1,524.10^{-5}$
Heat transfer coef. [kW/m^2.K}	$1,134.10^{-2}$	$1,134.10^{-2}$
Geothermal gradient [°C/m]	$-1,000.10^{-1}$	$-1,000.10^{-1}$
Length [m]	100	500

Table 4. ESP parameters for sensitivity analysis.

Head [m]	Capacity [m³/h]	PPSW performance curve
1446	0	
1446	22	
1428	43	
1386	65	
1362	87	
1338	108	
1314	130	
1314	152	
1320	173	
1338	195	
1344	217	
1350	238	
1350	260	
(*)1314	(*)282	
1266	303	
1176	325	
1050	347	
852	368	



(*) ESP best efficiency point (BEP)

12.2. Study case data

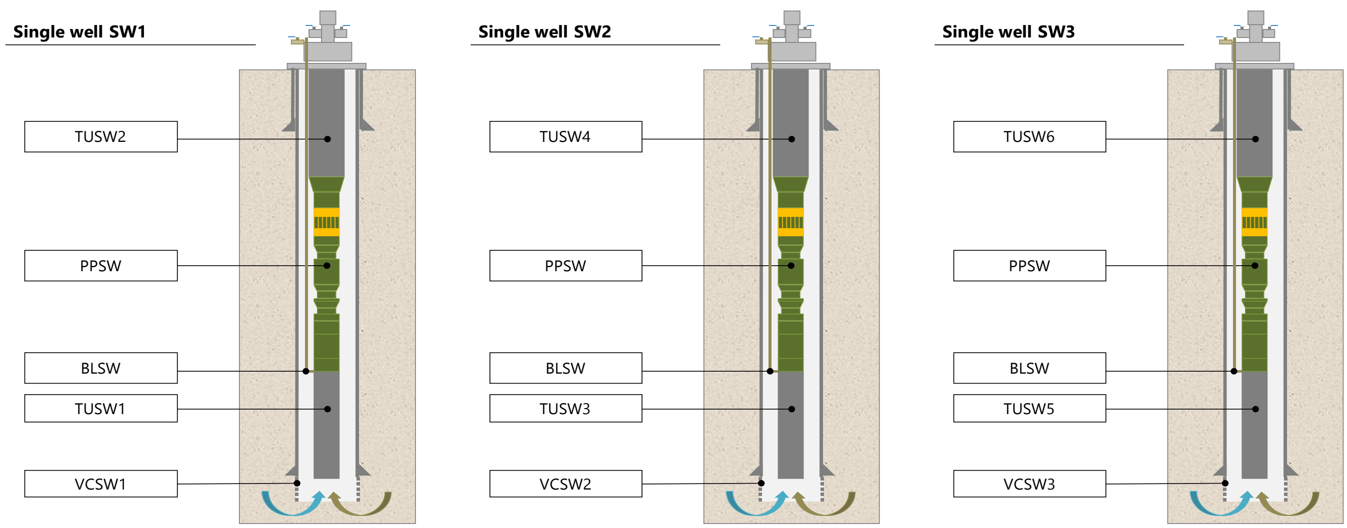


Figure 19. General diagram of single well infrastructure for study case.

Table 5. Black oil properties for study case.

Fluid properties	SW1 (Oil)	SW2 (Oil)	SW3 (Oil)	BLSW (Diluent)
°API	14,5	13,5	13,5	30,8
Specific gravity	0,9692	0,9759	0,9759	0,8720
Kinematic viscosity [cP] @ T1 [°C]	960 @ 37,8	1660 @ 37,8	1660 @ 37,8	9,8 @ 38,0
Kinematic viscosity [cP] @ T2 [°C]	329 @ 50,0	631 @ 50,0	631 @ 50,0	7,5 @ 54,0

Table 6. IPR parameters for study case.

IPR parameters	VCSW1	VCSW2	VCSW3
Type	Oil PI	Oil PI	Oil PI
Reservoir pressure [bar]	200	200	200
Reservoir temperature [°C]	45	55	50
Productivity index [Sm3/d.bar]	30	28	20

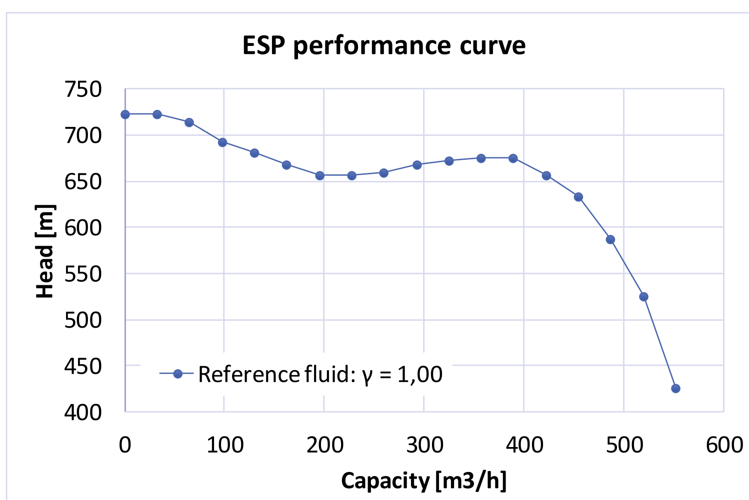
Table 7. Tubing parameters for study case.

Tubing parameters	TUSW1	TUSW2	TUSW3	TUSW4	TUSW5	TUSW6
Internal diameter [m]	$1,053.10^{-1}$	$1,053.10^{-1}$	$1,053.10^{-1}$	$1,053.10^{-1}$	$1,053.10^{-1}$	$1,053.10^{-1}$
Roughness [m]	$1,524.10^{-5}$	$1,524.10^{-5}$	$1,524.10^{-5}$	$1,524.10^{-5}$	$1,524.10^{-5}$	$1,524.10^{-5}$
Heat transfer coef. [kW/m^2.K}	$1,134.10^{-2}$	$1,134.10^{-2}$	$1,134.10^{-2}$	$1,134.10^{-2}$	$1,134.10^{-2}$	$1,134.10^{-2}$
Geothermal gradient [°C/m]	$-2,500.10^{-2}$	$-2,500.10^{-2}$	$-2,500.10^{-2}$	$-2,500.10^{-2}$	$-2,500.10^{-2}$	$-2,500.10^{-2}$
Length [m]	100	300	100	300	100	300

Table 8. Flowline parameters for study case.

Flowline parameters	FL1	FL2	FL3	FL4	FL5
Internal diameter [m]	$1,053.10^{-1}$	$1,053.10^{-1}$	$2,540.10^{-1}$	$2,540.10^{-1}$	$2,540.10^{-1}$
Roughness [m]	$1,524.10^{-5}$	$1,524.10^{-5}$	$1,524.10^{-5}$	$1,524.10^{-5}$	$1,524.10^{-5}$
Heat transfer coef. [kW/m^2.K}	$1,134.10^{-2}$	$1,134.10^{-2}$	$1,134.10^{-2}$	$1,134.10^{-2}$	$1,134.10^{-2}$
Ambient temperature [°C]	15	15	15	15	15
Length [m]	300	200	50	300	300

Table 9. ESP parameters for study case.

Head [m]	Capacity [m^3/h]	PPSW performance curve
723	0	
723	32	
714	65	
693	98	
681	130	
669	163	
657	195	
657	227	
660	260	
669	293	
672	325	
675	358	
675	390	
(*)657	(*)422	
633	455	
588	488	
525	520	
426	553	

(*) ESP best efficiency point (BEP)

12.3. Optimization performance – case: separable objective functions

Table 10. Diluent injection performance curves (10 artificial wells).

	W01	W02	W03	W04	W05	W06	W07	W08	W09	W10
qd(*)	qo(**)									
0	1323	349	664	1031	2433	2281	1411	223	2345	2121
100	2163	1022	1448	1878	2987	2859	2218	891	2326	2100
200	2454	1242	1733	2187	3158	3041	2504	1032	2304	2078
300	2546	1316	1840	2299	3226	3119	2622	1042	2279	2057
400	2569	1331	1870	2328	3236	3136	2655	1024	2256	2034
500	2558	1322	1864	2320	3134	3042	2648	994	2233	2009
600	2464	1271	1798	2227	3088	2997	2540	949	2210	1987
700	2415	1240	1750	2176	3040	2952	2488	911	2187	1965
800	2360	1203	1705	2124	2991	2904	2436	873	2164	1760
900	2305	1168	1660	2070	2938	2853	2378	834	1780	1620

(*) qd: diluent flowrate [m^3/d], (**) qo: oil reservoir flowrate [Sm^3/d]

Table 11. Optimization performance time, case piecewise linear modelling.

	Number of wells		
	10	50	100
Diluent rate [m3/d]	3,10E+03	1,55E+04	2,75E+04
100%	0,0522	0,0941	0,1538
	0,0447	0,0877	0,1681
	0,0532	0,0777	0,1392
	0,0578	0,0808	0,1519
	0,0657	0,0796	0,1387
Execution time [s]	0,0547	0,0840	0,1503
std,dev,sample	0,0077	0,0068	0,0121
Diluent rate [m3/d]	2,48E+03	1,24E+04	2,20E+04
80%	0,0784	0,1189	0,1343
	0,0885	0,1333	0,1555
	0,0722	0,0858	0,1258
	0,0992	0,1213	0,1440
	0,0736	0,1386	0,1911
Execution time [s]	0,0824	0,1196	0,1501
std,dev,sample	0,0114	0,0206	0,0254
Diluent rate [m3/d]	1,49E+03	7,44E+03	1,32E+04
60%	0,0510	0,0866	0,1601
	0,0559	0,1007	0,1618
	0,0699	0,1159	0,1631
	0,0550	0,1133	0,1829
	0,0533	0,1191	0,1858
Execution time [s]	0,0570	0,1071	0,1707
std,dev,sample	0,0074	0,0134	0,0125
Diluent rate [m3/d]	5,95E+02	2,98E+03	5,28E+03
40%	0,0364	0,0780	0,1055
	0,0344	0,0727	0,1201
	0,0410	0,0853	0,1013
	0,0482	0,0817	0,1135
	0,0568	0,0846	0,1168

	Number of wells		
	10	50	100
Execution time [s]	0,0434	0,0805	0,1114
std,dev	0,0092	0,0052	0,0078

Table 12. Optimization performance time, case polynomial approximation (3rd degree).

	Order 3 polynomial		
	Number of wells		
	10	50	100
Reservoir oil production [Sm3/d]	2,31E+04	1,18E+05	2,33E+05
Diluent injection rate [m3/d]	2,99E+03	1,49E+04	2,67E+04
run time [s] at 100%	2,58	4,48	11,28
Reservoir oil production [Sm3/d]	2,27E+04	1,16E+05	2,29E+05
Diluent injection rate [m3/d]	2,24E+03	1,12E+04	2,00E+04
run time [s] at 75%	2,70	5,53	8,98
Reservoir oil production [Sm3/d]	2,14E+04	1,10E+05	2,18E+05
Diluent injection rate [m3/d]	1,49E+03	7,45E+03	1,34E+04
run time [s] at 50%	1,61	3,41	9,86

Table 13. Optimization performance time, case polynomial approximation (4th degree).

	Order 4 polynomial		
	Number of wells		
	10	50	100
Reservoir oil production [Sm3/d]	2,28E+04	1,16E+05	2,30E+05
Diluent injection rate [m3/d]	2,65E+03	1,32E+04	2,39E+04
run time [s] at 100%	2,45	5,96	10,90
Reservoir oil production [Sm3/d]	2,25E+04	1,15E+05	2,28E+05
Diluent injection rate [m3/d]	1,99E+03	9,90E+03	1,79E+04
run time [s] at 75%	1,60	5,34	11,23
Reservoir oil production [Sm3/d]	2,14E+04	1,10E+05	2,18E+05
Diluent injection rate [m3/d]	1,32E+03	6,60E+03	1,19E+04
run time [s] at 50%	1,32	3,17	9,13

Table 14. Optimization performance time, case polynomial approximation (5th degree).

	Order 5 polynomial		
	Number of wells		
	10	50	100
Reservoir oil production [Sm3/d]	2,26E+04	1,16E+05	2,28E+05
Diluent injection rate [m3/d]	2,69E+03	1,34E+04	2,40E+04
run time [s] at 100%	2,84	7,77	10,40
Reservoir oil production [Sm3/d]	2,24E+04	1,15E+05	2,27E+05
Diluent injection rate [m3/d]	2,02E+03	1,00E+04	1,80E+04
run time [s] at 75%	2,02	5,62	9,70
Reservoir oil production [Sm3/d]	2,16E+04	1,10E+05	2,19E+05
Diluent injection rate [m3/d]	1,35E+03	6,68E+03	1,20E+04
run time [s] at 50%	1,50	3,20	6,36