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Study of development alternatives for remote offshore, low energy reservoirs: the Wisting field case

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Abstract

This work summarizes a series of analysis conducted to determine an optimized field development plan for Wisting oil field. The field presents several unique challenges, such as low reservoir pressure, very shallow reservoir depth and remoteness from the available infrastructure.

The study used a homogeneous reservoir simulation model built during the Specialization Project. Some of the crucial data, such as porosity, permeability and horizontal-to-vertical permeability ratio had a huge uncertainty involved in it. In order to account for this, 27 reservoir models with a combination of those uncertain properties were constructed and integrated with the 3 production network models. As a result, 81 integrated models were run and the oil production data was then used to evaluate the NPV (Net Present Value) of each of the considered cases.

3 production network models have been used for the analysis – wells with no artificial lift, wells with gas lift and subsea multiphase boosting. Gas lift rate optimization study was conducted to maximize the production and the economics of this development option. Multiphase booster pump power requirements, which would meet the field operational conditions were also determined.

NPV was set as an objective to decide on the most preferable development alternative. The capital expenditures for each of the development options were estimated with a commercial software, which was available for a limited period. The CAPEX values were then used in NPV calculations.

A simplified EXCEL tool was also developed for estimation of capital expenditures. The motivation for this was to have a robust tool for CAPEX calculations after the student license of the commercial software was set to expire. The output of the developed simplified tool was then compared to and tuned with the output from the commercial software.

Several sensitivity studies involving CAPEX and oil prices variation were performed for the previously obtained NPV values for the coupled simulations. As a result, a normal NPV probability distribution was obtained and presented in the report.

Acknowledgement

I would like to express my sincere gratitude to Pr. Milan Stanko for supervising and advising me throughout the project. It has been a pleasure to work with him and learn from his immense knowledge and experience. I would also like to thank PhD candidate Diana Rengifo and Post-Doc Mariana Diaz for contributing to the project and dedicating time in helping through some of the difficulties faced during the analysis.

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1. Introduction

1.1. Wisting oil field

The oil and gas production in Norway has been steadily declining since 2004. There have been signs of recovered and even increased production during the last two years at the time of depressed oil prices (NorskPetroleum, 2017). However, the production is set to continue its downward trend in the near future. Norwegian government as well as the companies working on the NCS (Norwegian Continental Shelf) have been actively seeking ways of stabilizing hydrocarbon production and increasing the available reserves. For many years, the North Sea region has been the main source of steady oil supply. Even though there is still some potential to explore the province can already be considered mature.

In June 2017, Norway's Ministry of Petroleum and Energy announced that a record 93 blocks would be offered for exploration activity in the Barents Sea (NPD, 2017). New and relatively unexplored areas in northern parts of the Norwegian sector of the Barents Sea will be actively searched for oil and gas in the coming years. There are already two fields producing in the Barents Sea, Goliat oil field and Snøhvit gas development (NorskPetroleum, 2017). A number of projects are expected to come online in the near future. Amongst them is Johan Castberg multiple reservoir development, which awaits a final investment decision to be made in second half of 2017 (Statoil, 2017). Another prospect that is also being actively evaluated for different development alternatives is Wisting oil field located in the northern part of the Barents Sea and explored under production license PL537. The field is expected to be developed by an FPSO (Floating Production Storage Offloading) unit and produced oil will be exported via a tanker.

A number of operational challenges have to be solved if the field is going to be put on production. Amongst them is very low reservoir pressure and temperature (70 bar and 16 ^{o}C @

664 meters below sea level), unusually shallow location of the reservoir (a mere 255 meters below seabed), remoteness from the available infrastructure (310 km from the shore) as well as harsh Arctic weather conditions. Due to the low reservoir pressure the field will need both a reservoir pressure support program and some kind of artificial lift or boosting to produce economic oil rates. Wisting oil field will be produced with subsea wells tied to the FPSO. It is already decided that 30 wells will be drilled into the reservoir, 15 oil producers and 15 water injectors. It is expected that the water injection will start at the same time as the production commences. The current analysis, which is supervised by a research center for subsea production and processing, SUBPRO, explores two types of production enhancing techniques: gas lift and subsea multiphase boosting. The current study aims to evaluate expected NPV of Wisting field given the existing reservoir uncertainties and different production network alternatives.

The objectives of the thesis work are:

- Build reservoir simulation models based on the work from the Specialization Project with different combinations of the most uncertain reservoir parameters
- Build two production networks: with gas lift; with subsea boosting
- Couple and run reservoir models with the three production networks (the Base Case scenario was already built during the Specialization Project)
- Determine an optimum coupling configuration setting (coupling location, coupling scheme, network-balancing scheme etc.) that will enable fast running of multiple coupled models and ensure high accuracy of the results
- Build a simplified CAPEX (Capital Expenditure) tool to evaluate offshore field development projects and compare the results against a provided commercial software for CAPEX estimation
- Estimate NPV based on the oil production profiles from the coupled models. Run sensitivities for CAPEX and oil price variation and plot expected NPV probability distribution for different development alternatives.

1.2. Specialization project summary

The following is a short summary of the work performed during the Specialization Project:

- All the available Wisting field data was gathered and analyzed

- A simplified reservoir simulation model was built with the available data
- An optimized production and water injection scenario was proposed as a result of extensive stand-alone reservoir simulation runs
- Two production networks (with and without multiphase boosting) were built based on the work of SUBPRO summer student, Even Kornberg
- The constructed reservoir simulation model was coupled and run with two production networks. The results of the runs from the two coupled models were analyzed and it was concluded that subsea multiphase boosting would add significant production gains to the field development.

The final goal of the Specialization Project was to build a reservoir model and two production network, couple them and evaluate the benefit of applying subsea boosting with coupled models. The constructed Wisting field homogeneous reservoir model involved a lot of uncertainty as it employed numerous assumptions and some of the crucial data was not available. A sensitivity analysis evaluating the impact of uncertain reservoir characteristics on the field oil production was also performed during the Specialization Project. This analysis was conducted only with the standalone reservoir simulation model. As a result of these sensitivities, the uncertainty range in the total field oil output was determined.

A more detailed description of the performed work can be accessed in the Specialization Project report.

1.3. Tools

Five software packages have been used during the thesis work:

1) ECLIPSE dynamic numerical reservoir simulator

ECLIPSE is an oil and gas dynamic reservoir simulator originally developed by Exploration Consultants Ltd. (ECL) and currently owned and marketed by Schlumberger. The simulator provides the industry with the most complete and reliable set of numerical solutions for accurate prediction of dynamic behavior for all reservoir types and available development alternatives (Schlumberger, 2017). ECLIPSE allows modeling of flow and fluid interactions in the reservoir as well as in the production string provided VLP tables are entered into the model.

2) PIPESIM steady-state production network simulator

PIPESIM is also owned and maintained by Schlumberger. It is a steady-state flow simulator, which can be used to perform well modeling, artificial lift design, nodal analysis, pipeline, and process equipment simulation (Schlumberger, 2017). In the current analysis, PIPESIM is used to model the fluid flow both from the bottom of the tubing up to separator entry. A small study, which compares the fluid modeling in the production string with ECLIPSE (using VLP tables) and PIPESIM has also been performed.

3) AVOCET IAM software package

AVOCET is a production operations software platform, which can couple dynamic reservoir simulation to steady-state production network models. The software also belongs to Schlumberger, which can be considered beneficial as this excludes any problems that may arise due to incompatibility of programs from another software provider. Running coupled simulations in AVOCET allows engineers to evaluate the effects of backpressure and constraints of the production network on the reservoir performance. The tool can also give a comprehensive insight into the impact of changing production conditions on the overall field deliverability, such as altered separator pressure or an addition of a new element to the production system (e.g. booster pumps). Software packages that can perform hydrocarbon processing calculations and economic analysis can also be added to the coupled models in AVOCET platform (AVOCET, 2017).

4) Aspen HYSYS hydrocarbon processing simulation and optimization software package

Aspen HYSYS is one of the industry's leading process simulators, which is used by major oil and gas companies as well as refineries and engineering firms to design and optimize operations. The newest versions also allow project economics calculation and optimization. In the current analysis, HYSYS is used to estimate the expected power requirement for multiphase subsea boosters given the predicted field performance and reservoir fluid composition.

5) PROSPER well modelling program

Designed and maintained by Petroleum Experts (PetEx) company, PROSPER provides a finely engineered well performance, design and optimization tool for modelling a huge number of well configurations available across the oil industry. In the current report, PROSPER is used to generate tubing tables for input in the ECLIPSE reservoir simulation model. It could also be done in PIPESIM, but the author had already had some experience in generating tubing tables with PROSPER. Therefore, it was decided to proceed with PROSPER to save the time that could have been spent on learning the procedure in PIPESIM.

2. Methodology

This chapter describes the general overview of the work performed during the thesis time. The chart below shows a summary and workflow of the thesis project:

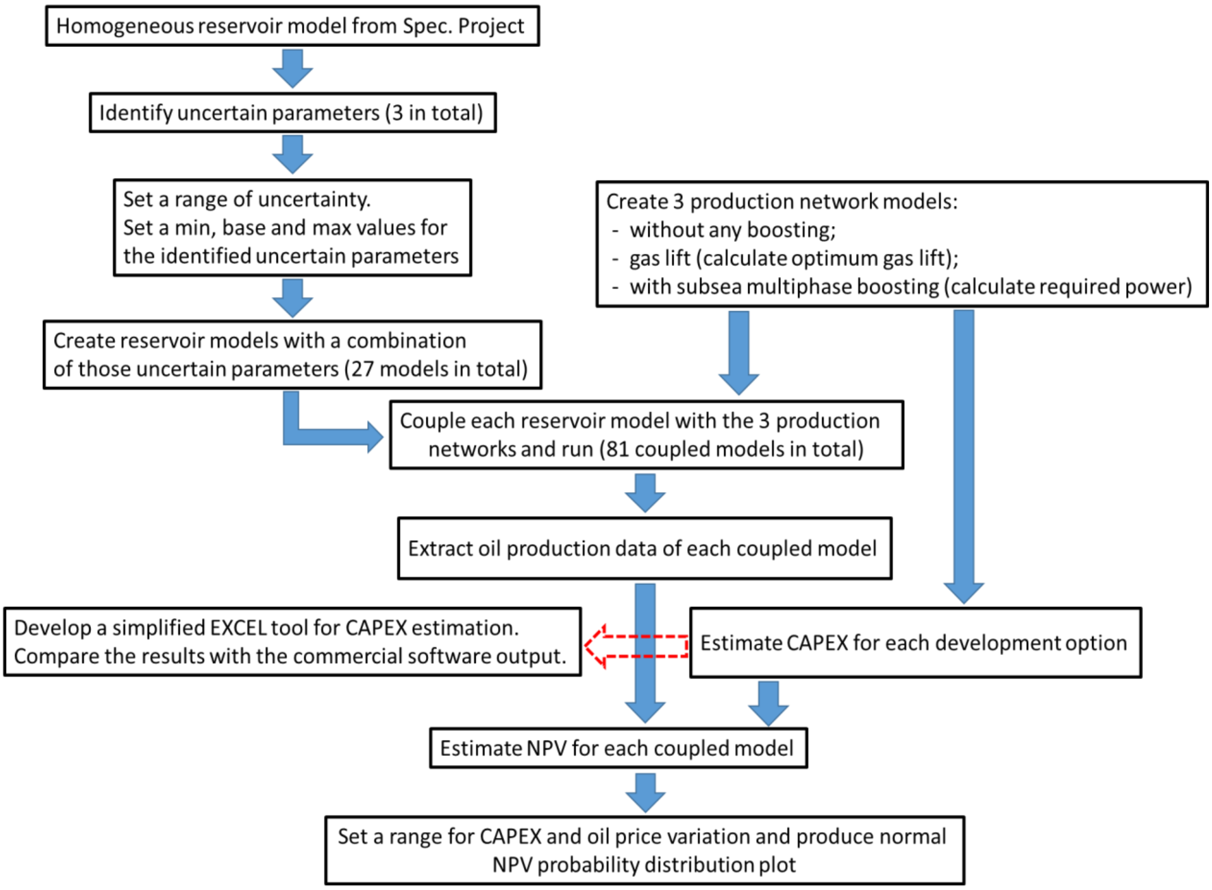

Figure 1. The project workflow diagram

The thesis project is based on some of the work that was already performed during the Specialization Project. The current analysis uses the homogeneous reservoir model and the production network built during the Project.

The main goal of this thesis work is to perform integrated uncertainty analysis, which will involve the uncertainties in the reservoir model and different production network schemes. This includes NPV estimation for all integrated models built during the study as well as sensitivity analysis with CAPEX and oil price variation. The following text elaborates the thesis workflow shown in ***Figure 1***.

Reservoir model

The constructed homogeneous reservoir model includes a lot of uncertainty. On the other hand, it is very difficult to justify preparation of a heterogeneous model for Wisting, because no data is available on the lateral and vertical connectivity of the reservoir. Therefore, it is believed that at this stage every heterogeneous reservoir model built for this kind of analysis will have much more uncertainty compared to the already available homogeneous model just because the latter one has some data to rely on. The uncertainty in the homogeneous reservoir model is mainly related to the following data:

- Porosity
- Horizontal permeability
- K_v/K_h ratio

Table 1. The uncertainty range of the investigated reservoir properties

Parameter	Min	Base case	Max
Porosity, [fraction]	0.2	0.25	0.3
Horizontal perm-ty, [md]	350	700	1050
K_v/K_h, [fraction]	1/15	1/10	1/5

The base case properties listed in ***Table 1*** were obtained from different sources. Only the porosity value belongs to Wisting field, but even in this case only a statement saying that the porosity is in the 20 to 30 per cent range has been provided. Therefore, the base case value has been set to be in the middle or 25 per cent. The horizontal permeability value is obtained from Snøhvit gas field located in the Barents Sea (Halland et al.). It is believed that both Wisting and Snøhvit reservoirs produce from the Stø formation, which stretches continuously all along the between these two fields and far beyond. The K_v/K_h ratio was not available at all and using this value is based on the fact that this value is very common on the NCS (Aurand, K., 2016).

It is obvious that all these uncertainties have to be included in the economic evaluation of the proposed development alternatives. Considering all these facts, the properties in ***Table 1*** have been used to generate reservoir models with different combination of the listed values. In total, 27 reservoir models have been prepared for the purpose of the analysis.

Table 2. Reservoir models with different combination of uncertain parameters

Case	Porosity [fraction]	Horizontal perm-ty [md]	K_v/K_h [fraction]
1	0.2	350	1/10
2	0.2	700	1/10
3	0.2	1050	1/10
4	0.2	350	1/5
5	0.2	700	1/5
6	0.2	1050	1/5
7	0.2	350	1/15
8	0.2	700	1/15
9	0.2	1050	1/15
10	0.25	350	1/10
11	0.25	700	1/10
12	0.25	1050	1/10
13	0.25	350	1/5
14	0.25	700	1/5
15	0.25	1050	1/5
16	0.25	350	1/15
17	0.25	700	1/15
18	0.25	1050	1/15
19	0.30	350	1/10
20	0.30	700	1/10
21	0.30	1050	1/10
22	0.30	350	1/5
23	0.30	700	1/5
24	0.30	1050	1/5
25	0.30	350	1/15
26	0.30	700	1/15
27	0.30	1050	1/15

Creating so many reservoir models with different combination of uncertain parameters aims at capturing the range of economic uncertainty associated with it. If the reservoir model was based on real-field data the necessity to conduct the same procedure would probably be reduced or even eliminated to some degree. In any case, even reservoir models based on the real field information bear a significant portion of uncertainty. Reservoir engineers perform numerous runs with the simulation models to reduce those uncertainties. There is also much more ambiguity in the reservoir characteristics and future performance at this stage of the field life, when there is almost no production data, compared to the time when the field will already produce certain amount of oil. Therefore, the usage of so many reservoir simulation models to reduce the economic uncertainty can be considered beneficial.

Production network

The most likely development plan for Wisting field is considered to be subsea wells tied to an FPSO. It is already confirmed that the field will be developed with 15 oil producers and 15 water injectors. It is assumed that the water injection will start at the same time as the oil production. The subsea oil producers will be tied to 5 subsea production templates resting on the seabed. The produced oil will most likely be transported via a crude carrier (tanker) to the shore. The current analysis will therefore only explore two different techniques to improve oil production and their relative benefit against the base case production network scheme relied only on natural depletion. The production network schemes considered in the analysis are:

1. Subsea wells tied to the FPSO (no artificial lift; no boosting)
2. Subsea gas lifted wells tied to the FPSO
3. Subsea wells with subsea multiphase booster pumps tied to the FPSO

The 1st network scheme was built during the Specialization Project based on the work of Even Kornberg, SUBPRO summer student. The latter two are based on the 1st network with the addition of gas lift and subsea multiphase boosting respectively. The work related to the production network part is mainly focused on calculating the optimum gas injection rate and multiphase pumps' power requirements to boost the production.

Coupled models

The 27 ECLIPSE reservoir simulation models and 3 PIPESIM production networks are then coupled to run 81 coupled simulations in AVOCET. The oil production data is then extracted from the integrated runs and used for NPV calculation. One of the challenges of this study was the long running time of the coupled models. During the Specialization Project, only 2 coupled model were run in AVOCET. It took 8 hours to run each model on a private personal computer. As the number of AVOCET runs in the thesis work was quite high a study was performed to reduce the running time of coupled simulations. Different setup configurations have been tested and their effect on the run time and accuracy of the results is explained in this report.

CAPEX and NPV

The required CAPEX for the field development of subsea wells tied to an FPSO with three different production network schemes is calculated by a commercial software. The software was only available under a trial student license for a limited time period. Therefore, one of the objectives of this work was to develop a simple EXCEL tool for CAPEX calculations. The results of the simplistic tool are compared to the CAPEX values from the commercial software. The current analysis uses only the output from the provided software. The software can also produce the OPEX

NPV is calculated with an EXCEL tool developed for this purpose for all coupled models using the yearly oil output (81 coupled models were launched. 78 produced results. 3 coupled models did not initialize. The reasons are explained in the ***Results and Discussion*** chapter). Moreover, a sensitivity involving ±25 per cent variability in CAPEX and oil price is performed and as a result NPV normal probability distribution is plotted and presented in the report.

3. Coupled model preparation

3.1. General

The chapter focuses on the preparation and quality control of the numerous steps in this analysis. As the reservoir model was built during the Specialization Project, only the main steps of constructing it and the major characteristics are highlighted in this chapter. The chapter also describes the PIPESIM production networks. The current study involves using of artificial lift as a means to increase the oil production. Therefore, gas lift injection rate optimization study was performed and the optimum gas lift injection parameters are presented in this chapter. Additionally, the power requirements for subsea multiphase boosters have also been estimated and the obtained results shown in the following sections.

3.2. Reservoir model

This section will focus on the details of Wisting reservoir simulation model built specifically to conduct this study. The model was constructed during Specialization Project, which also had the aim of uncertainty analysis, but somewhat in a smaller scale. The model was built from scratch with very limited available data. Some of the information was taken from other fields on the NCS, some of it was assumed based on the most common values encountered in the industry for that set of data and some was generated using the available techniques to generate artificial data (such as relative permeability curves). The summary of the reservoir simulation model is presented in this chapter without diving too deep into the technical details of the work to build the model. The detailed procedure of the model construction is available in the Specialization Project, which can be accessed upon request.

3.2.1. Reservoir model characteristics

In order to construct the reservoir model some of the input information has to be used. One of the most important procedures to follow during this process is to match the estimated value of STOOIP with the oil volume in the model. The oil in place volume had already been calculated and taken from published documents to use in the analysis (OMV, 2016). ***Table 3*** shows the STOOIP values calculated by the probabilistic approach.

Table 3. STOOIP and recoverable reserves of Wisting field

Resources			
Stø & Fruholmen formations	**low**	**medium**	**high**
	STB	STB	STB
Gross in place	8.50E+08	1.15E+09	1.45E+09
Recoverable	**2.00E+08**	**3.00E+08**	**5.00E+08**

Combined with the available data shown in ***Table 4*** the reservoir area was calculated using the simple STOOIP equation:

$$STOOIP = \frac{A \cdot h \cdot \varphi \cdot (1 - S_{wi})}{B_o} \quad (1)$$

Where

STOOIP – stock tank oil initially in place, [Sm^3]

A – reservoir area, [m^2]

h – reservoir oil zone thickness, [*m*]

φ – porosity

S_{wi} – initial water saturation

B_o – oil formation volume factor, [m^3/Sm^3]

Table 4. Reservoir rock and fluid properties used for Wisting area calculation

Property	Value	Unit
Porosity	0.25	fraction
Reservoir thickness	60	m
Initial water saturation	0.1	fraction
B_o	1.107	m^3/Sm^3

The resultant areas for the three probabilistic STOOIP values are then calculated. In order to simplify the procedure and reduce the amount of calculations the medium case is then selected for further analysis.

Table 5 .Corresponding areas of the top of the grid structure of the reservoir model

Grid			
Case	**low**	**medium**	**high**
A [m^2]	1.11E+07	1.50E+07	1.89E+07
Size [m]	100	100	100
Number of grid blocks	1110	1502	1893

The resultant area was then used to construct the reservoir grid model with the properties shown in *Table 6*. There is great uncertainty involved in some of the properties used for the reservoir model, such as permeability and porosity. This is thoroughly discussed in the Specialization Project report.

Table 6 .The reservoir grid properties

Parameter	Value	Unit
Horizontal permeability (oil zone), $k_{x,y}$	700	mD
Horizontal permeability (aquifer), $k_{x,y}$	400	mD
K_V/K_h	1/10	-
Grid cells in i-direction	68	-
Grid cells in j-direction	22	-
Grid cells in k-direction	15	-
Cell size, DX	100	m
Cell size, DY	100	m
Cell size, DZ (Oil zone)	5	m
Cell size, DZ (Aquifer)	20	m
Aquifer thickness	60	m

The resultant reservoir model with the grid properties shown in ***Table 6*** and the initial fluid saturations is shown in ***Figure 2***.

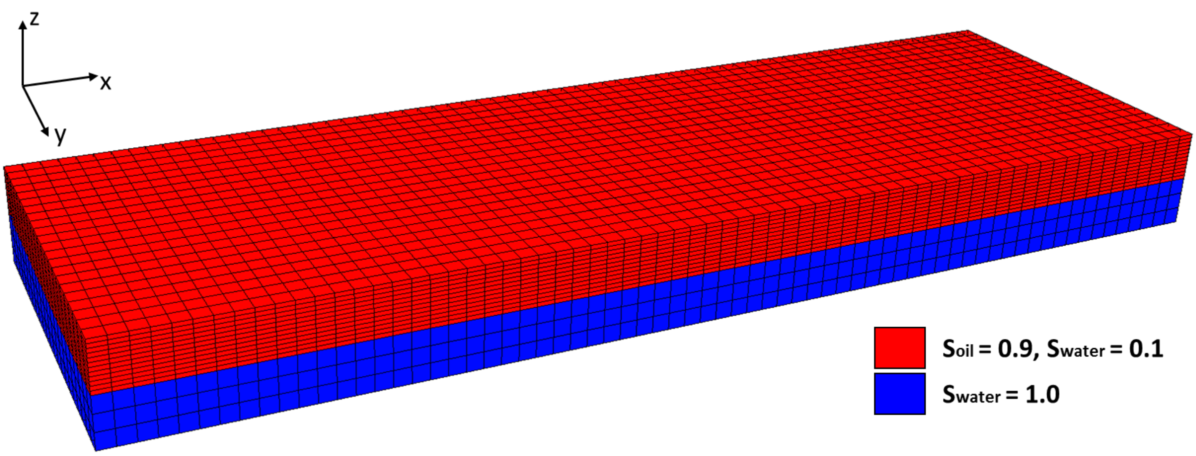

Figure 2. Grid structure with populated rock and fluid properties

3.2.2. Saturation and relative permeability tables

In dynamic reservoir simulation models fluid saturation distribution is calculated at each time step. In order to do so relative permeability curves for all fluids in reservoir fluid must be available. The reservoir processes such as fluid displacement patterns, water- and gas-breakthrough times, as well as initial and final fluid saturations are largely affected by the relative permeability curves.

The curves had not been made available when the model construction began. Therefore, they had to be either borrowed from other existing fields with similar properties to Wisting or artificially generated by using available techniques such as Corey exponents. In the initial simulation runs, saturation tables from Gulltopp were applied in the model. Gulltopp is located approximately 10 km west of the main Gullfaks field in block 34/10 in the southern part of the North Sea (Kleppe, 2015). The reservoirs both in Gulltopp and Wisting are in under-saturated condition and therefore there are no initial gas caps in the fields. The simulation runs with initial Gulltopp relative permeability curves produced a huge number of warnings, which significantly slowed the model. It was then decided to smooth the initial curves with Corey constants.

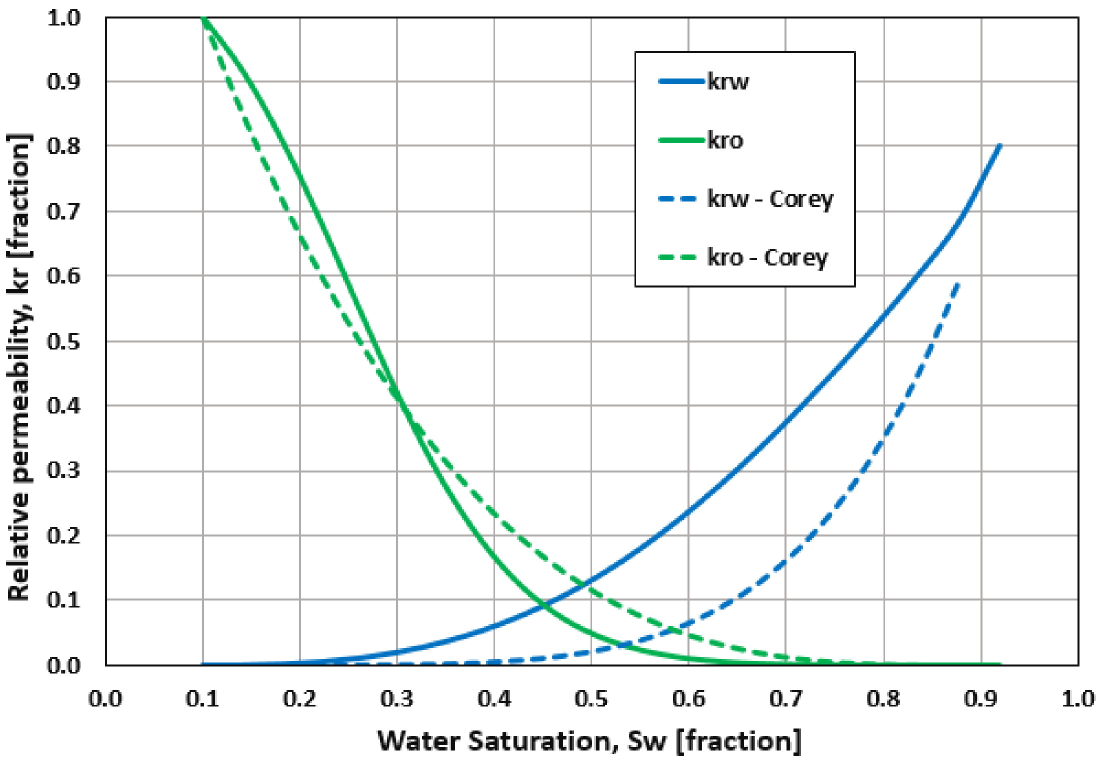

Figure 3 .Relative permeability vs Water saturation

Figure 3 shows the resultant curves from using the Corey exponents. The dashed lines are artificially generated with this technique, while the solid lines represent the original Gulltopp data. By having a closer look, it is possible to see that artificially generated curves are a little bit smoother, which in the end proved to be decisive in reducing simulation run times. Moreover, the generated curves have a minor shift to the right compared to the original data. This will delay a water breakthrough and lead to higher oil recoveries. A minor shift in the shape of the curves can lead to different results. The involved uncertainty of this data was investigated and described in the Specialization Project.

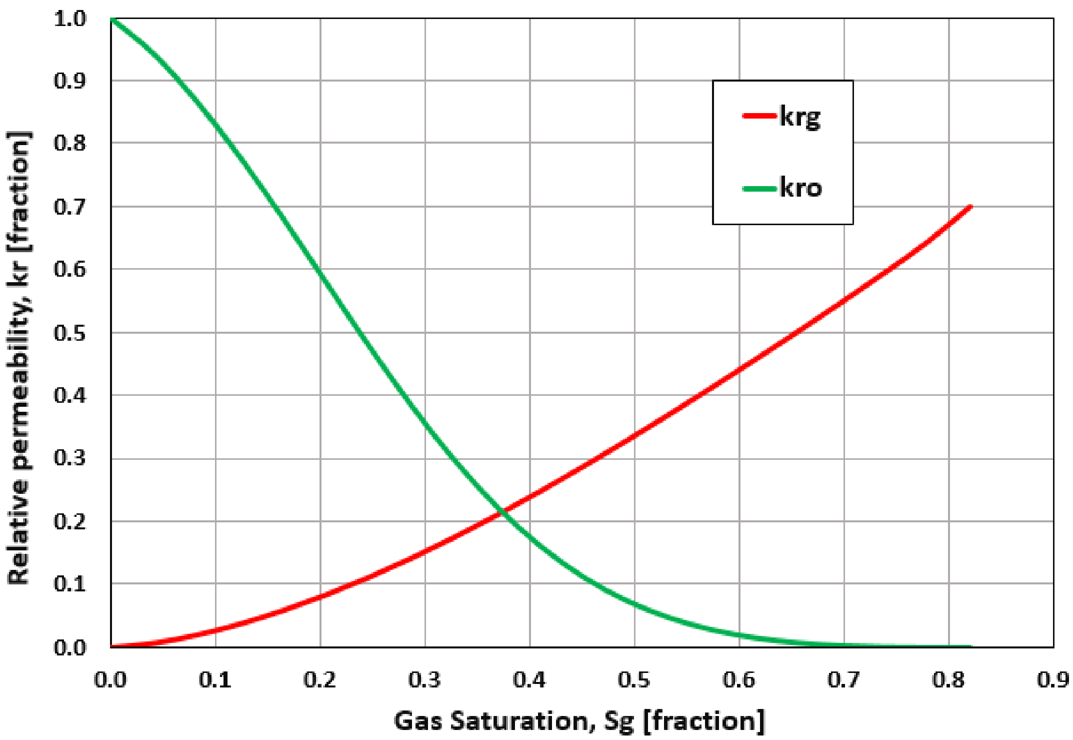

Figure 4. Gulltopp gas-oil modified relative permeability curves for Wisting simulation input

Figure 4 shows the gas-oil relative permeability curves used in the current model. The data is also taken from Gulltopp field. It has not been extensively modified as the curves are smooth enough and do not cause any warnings in the simulation runs. The only applied modification has been changing of the end-point fluid saturations to match the STOOIP and to avoid possible re-iterations due to a mismatch with the initial saturation input during simulation runs.

3.2.3. Wells

According to the initial development plan, Wisting oil field is projected to have 30 development wells of which 15 will be oil producers and the rest will be water injectors. As the well density is quite low it is planned to drill the producers with long horizontal completion intervals to cover larger area of the reservoir. ***Figure 5*** shows the well placement on the reservoir grid. The distance between the wells and the reservoir boundaries is the same for all producers.

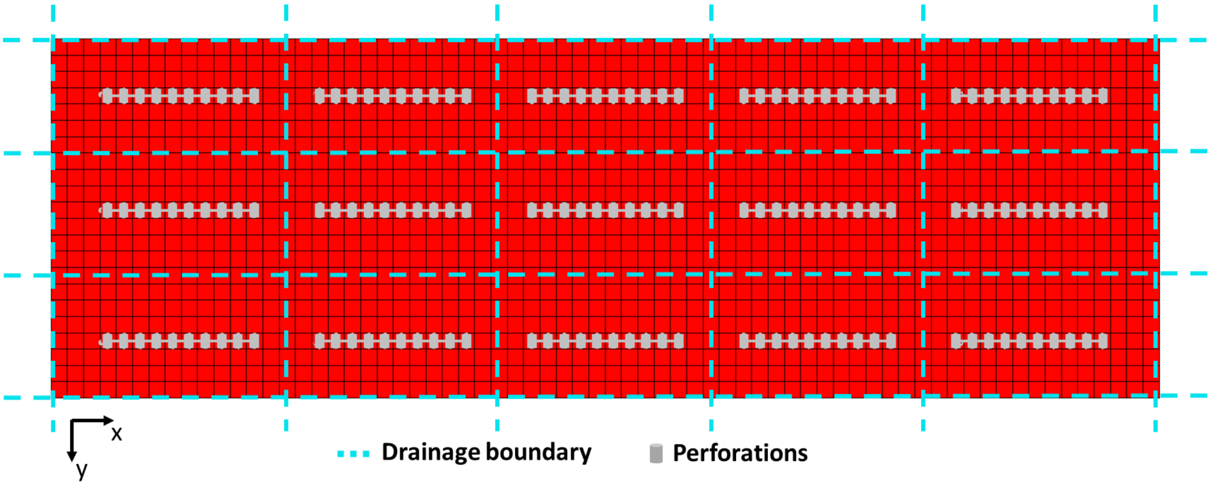

Figure 5. A top view of the reservoir grid with producer wells perforation interval

The water injectors are assumed to be vertical and completed in the assumed aquifer zone beneath the oil bearing reservoir. They are aligned on the edges of the reservoir in a so-called peripheral water injection. As the model is homogeneous the relative placement of the injectors should not have a major effect on the output, but the applied strategy is believed to have an advantage based on the documented evidence from the fields around the globe highlighted in the Specialization Project report.

Figure 6 shows the reservoir model with the production and injector wells.

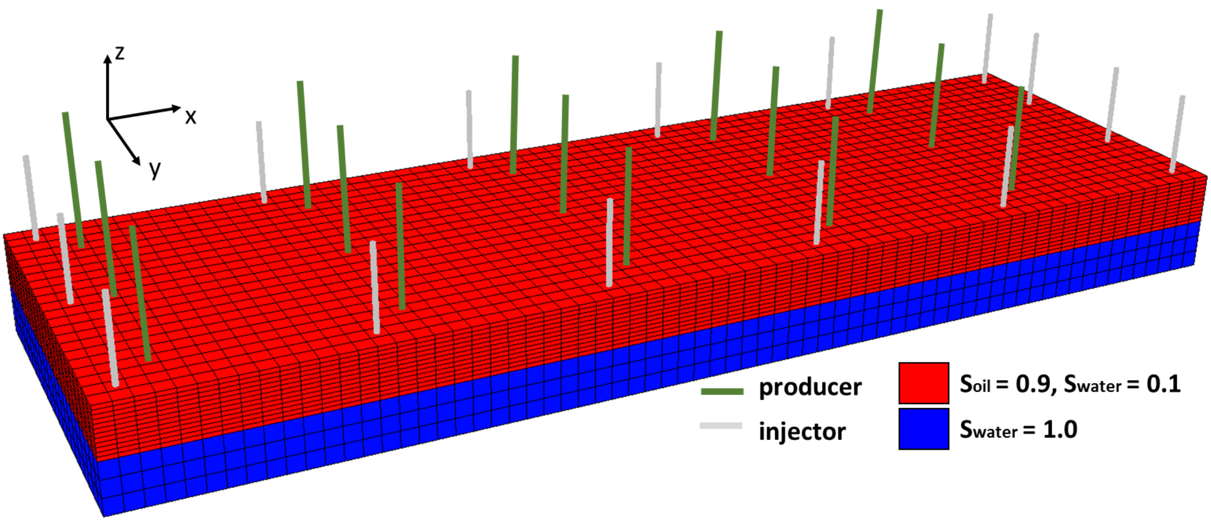

Figure 6. Reservoir model grid with producers and injectors

The details of the oil producers in the reservoir model are shown in ***Table 7***. It can be seen that the wells have very long horizontal completion intervals. This strategy had already been tested by OMV on their appraisal well **7324/7-3 S** and it proved suitable for future development plan.

Table 7. Production well specifications in the reservoir simulation model

Parameter	Value / Specification	Unit
Number of producers	15	-
Type	Horizontal	-
Perforation interval	1000	m
Horizontal section	1000	m
Drainage area (per well)	~ 1	km^2

Table 8 highlights some of the details of the water injection wells. It can be noticed that the perforation interval is only 60 meters. One of the reasons is that the injectors are assumed to be vertical in the model and completed only in the aquifer zone. Another reason is that there is no information about a possible size of the aquifer. Therefore the aquifer has been assumed to have the same thickness as the oil bearing interval, which is equal to 60 meters. Moreover, due to the absence of information about possible aquifer support it is modelled as a static body of water in the current model. At this stage, it is very difficult to have data about a future aquifer support as this kind of data will usually be available after some time after production commencement. A probable aquifer support in the current model can also be simulated by changing the water injection rates of the available injector wells.

Table 8. Water injection well details in the reservoir simulation model

Parameter	Value / Specification	Unit
Number of injectors	15	-
Type	vertical	-
Perforation zone	aquifer	-
Perforation interval	60	m
Vertical section	60	m

3.2.4. Field production and injection strategy

An extensive study was performed to determine the optimum oil plateau production and water injection strategy during the Specialization Project. Initially, different oil plateau rates without any injection were tested to analyze the reservoir deliverability. The results were then used to deliver an optimum plan for water injection. The study is well explained in the project report and can be referred to if more details are needed. Only the final results as well as some of the minor details will be provided in the current report.

As already mentioned, Wisting field is planned to have 15 oil producers and 15 water injectors. The field production and injection targets will be achieved by implementing Group Control option in ECLIPSE. It allows controlling the production on the field basis. If one of the wells has a water- or gas-breakthrough due to which the well production drops, the simulator will try to increase the oil rate of the remaining wells to produce at the target rate. The same principle is applied for water injectors in the model.

Numerous sensitivities were run during the Specialization Project. According to the analysis and considering the preferred capacity for the future development plan an optimum field production and injection strategy has been developed. It is important to mention that these sensitivities were performed with a standalone reservoir simulation model.

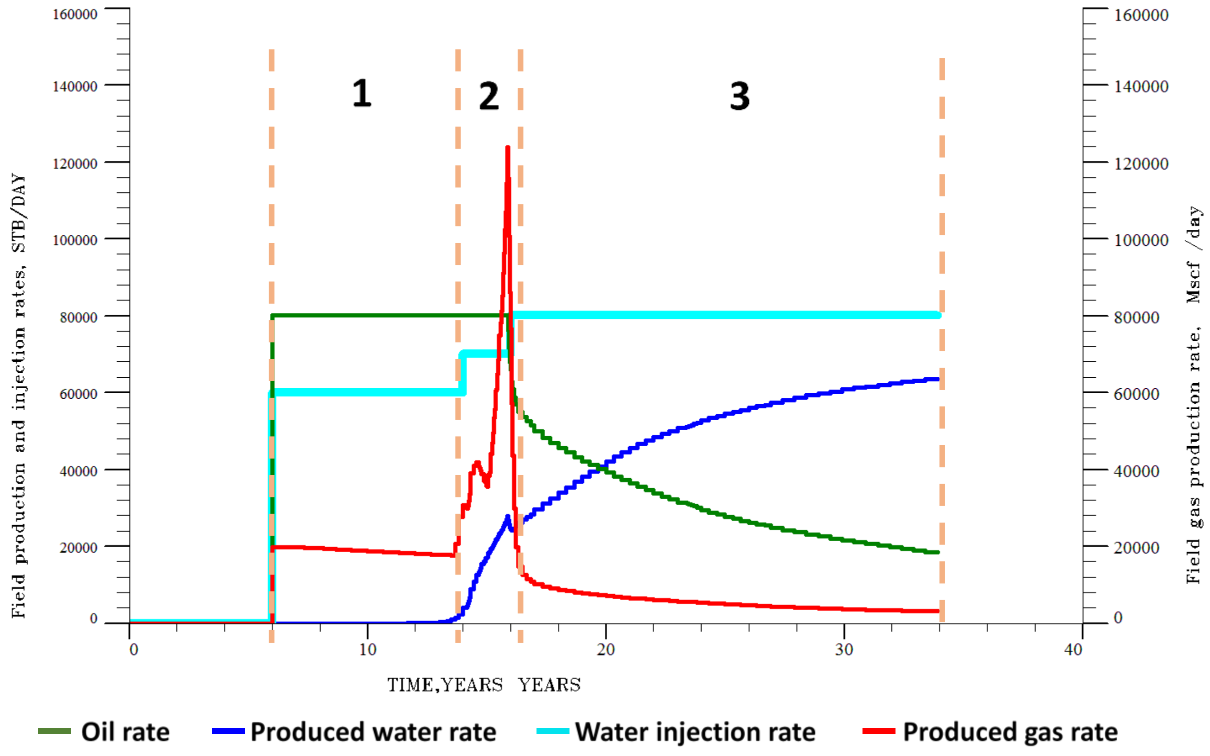

Figure 7. Production and injection reservoir simulation output data for the preferred field development plan

Figure 7 demonstrates fluid production and injection rates for the base case reservoir simulation model. The sensitivities performed during the project were mainly aimed at determining the optimum initial plateau oil production rate and water injection strategy. According to the performed sensitivity runs, the most favorable plateau oil production rate is 80 mbd. This rate suits well the volume of the expected reserves in place. The higher rates yield much shorter plateau periods and earlier water- and gas-breakthrough times. The injection strategy was chosen to vary according to field performance and is divided into three major intervals as displayed on ***Figure 7***.

1 – The period with constant water injection rate of 60 MSTB/d. It is assumed that water injection rate early in the field life will be less than the plateau oil rate.

2 – The period with constant water injection rate of 70 MSTB/d. The injection rate is increased manually to imitate the produced water re-injection because of water breakthrough during this period.

3 – The period with constant water injection rate of 80 MSTB/d. The water injection rate manually increased from 70 MSTB/d in order to imitate the increased produced water re-injection.

Below is the summary of the production and injection plan to be implemented in the reservoir simulation model:

Table 9. Summary of the production and injection strategy implemented in the ECLIPSE model

Parameter	Value / Characteristic	Comments
Oil production plateau rate [stb/d]	80 000	Plateau duration will change depending on res. and prod. network characteristics
Water injection rate [stb/d]	variable	The injection rate is varied depending on the development needs
Min. BHP constraint [bara]	40	Having lower pressure would be unrealistic
Production control	GROUP	Applied to produce at the target field rate
Injection control	GROUP	Applied to inject at the target field rate

3.3. Production network

The Wisting field will be produced with 15 subsea oil producer wells and 15 water injectors tied to the FPSO unit. The base scenario assumes that the 15 satellite wellheads will be connected to 5 production manifolds (3 wells for each manifold). The reason for having satellite wellheads is to cover the largest possible reservoir area. The analyzed PIPESIM production networks only consider the oil producers.

Three production network scenarios used for the current analysis are:

- Base case
- Base case with subsea booster for each cluster
- Base case with gas lift

The description of each case is shown below in the following sections.

3.3.1. Base case

This scenario is the basis for the next two production network design alternatives. The current development plan assumes that the field will be produced with subsea wells tied to an FPSO. It was constructed based on the work of SUBPRO summer student, Even Kornberg. The main idea behind this production network design is that the field is depleted without using any artificial lift and boosting. Obviously, this strategy will not yield much oil production due to low reservoir pressure and relatively deep-water depth in the field location. The reservoir may not produce oil at all if the reservoir permeability in vertical and horizontal direction is poor and hence, their respective ratio is low, which will make the water-flooding program highly inefficient. However, it is crucial to test the current scenario to evaluate the potential deliverability of the field using only depletion strategy. The results may help to arrive at an optimized solution for the artificial lift to be used for the field.

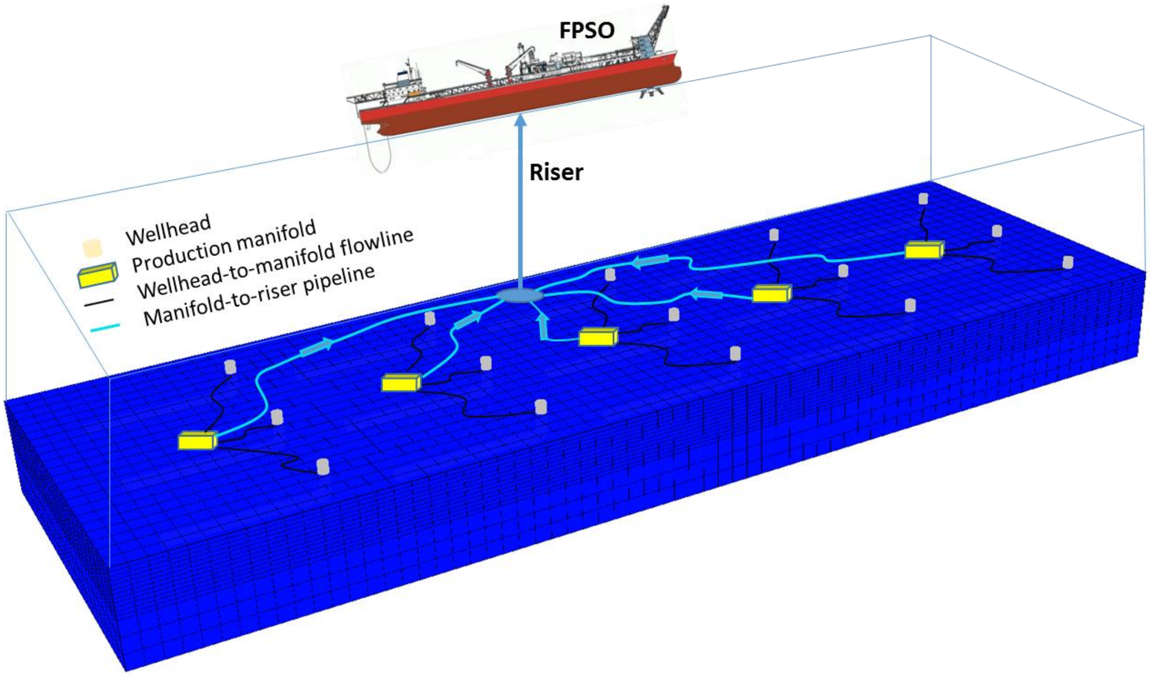

Figure 8. Base case production network

The figure above shows the layout of the system for the base case scenario with no boosting and no gas lift injection.

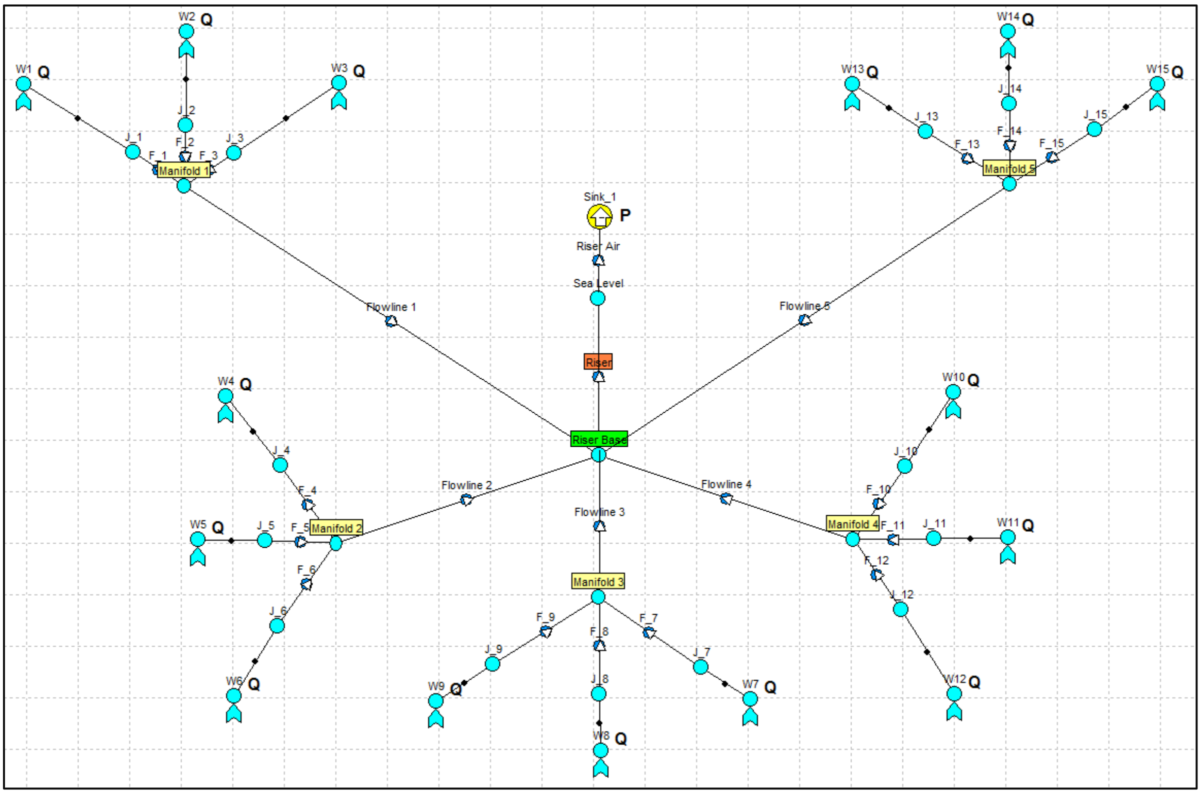

Figure 9. PIPESIM production network

Figure 9 shows the production network built in PIPESIM. It is not drawn to the actual scale, but the flowlines are placed in such a manner to illustrate that some of the manifolds are located further from the riser base compared to others. The geometry and length of the flowlines as well as tubular properties are absolutely the same for all three cases considered in this study (depletion drive; subsea multiphase boosters; gas lifted wells). The only difference is the type of artificial lift (or its absence in "no boosting" case) that is applied to each of those development alternatives.

Table 10. Tubular properties in the production network models (from Even Kornberg's work)

Tubular	ID [inches]	Length [m]	Roughness [mm]	Orientation
Production tubing	3.92	1470	0.02540	Vertical/horizontal
Wellhead-to-manifold flowline	3.82	600	0.04572	horizontal
Manifold 1-to-riser-flowline	7.81	3000	0.04572	horizontal
Manifold 5-to-riser-flowline	7.81	3000	0.04572	horizontal
Manifold 2-to-riser-flowline	7.81	1500	0.04572	horizontal
Manifold 4-to-riser-flowline	7.81	1500	0.04572	horizontal
Manifold 3-to-riser-flowline	7.81	300	0.04572	horizontal
Riser	10.02	480	0.04572	vertical

Table 10 presents the respective properties of the production network tubulars. It can be noticed that the manifolds are placed quite distantly from each other. As there are fifteen producing wells in total and each of the manifolds will gather production from three wells there are some concerns that this will not be enough to sweep the reservoir oil efficiently. However, application of long horizontally drilled sections of up to 1000 meters is expected to improve the reservoir coverage and hence the ultimate recovery factor.

3.3.2. Base case with subsea booster for each cluster

As the field has a very limited energy to lift the reservoir fluids to the producing platform it is crucial to consider different alternatives of artificial lift and boosting to recover the economical volumes of hydrocarbons. This section briefly describes the production network with multiphase subsea boosting, which is expected to add additional energy to the system and yield higher volumes of hydrocarbons from the reservoir.

All the essential properties, such as tubular dimensions, flowline lengths and all the remaining ones from the first production network are the same in this development scenario. The only difference is the addition of five subsea multiphase boosters to the system. Each of the pumps is tied to one of the five production manifolds in the network. The boosters are located downstream of the manifolds to create additional suction and boost the produced fluids further to the riser base and up to the host platform.

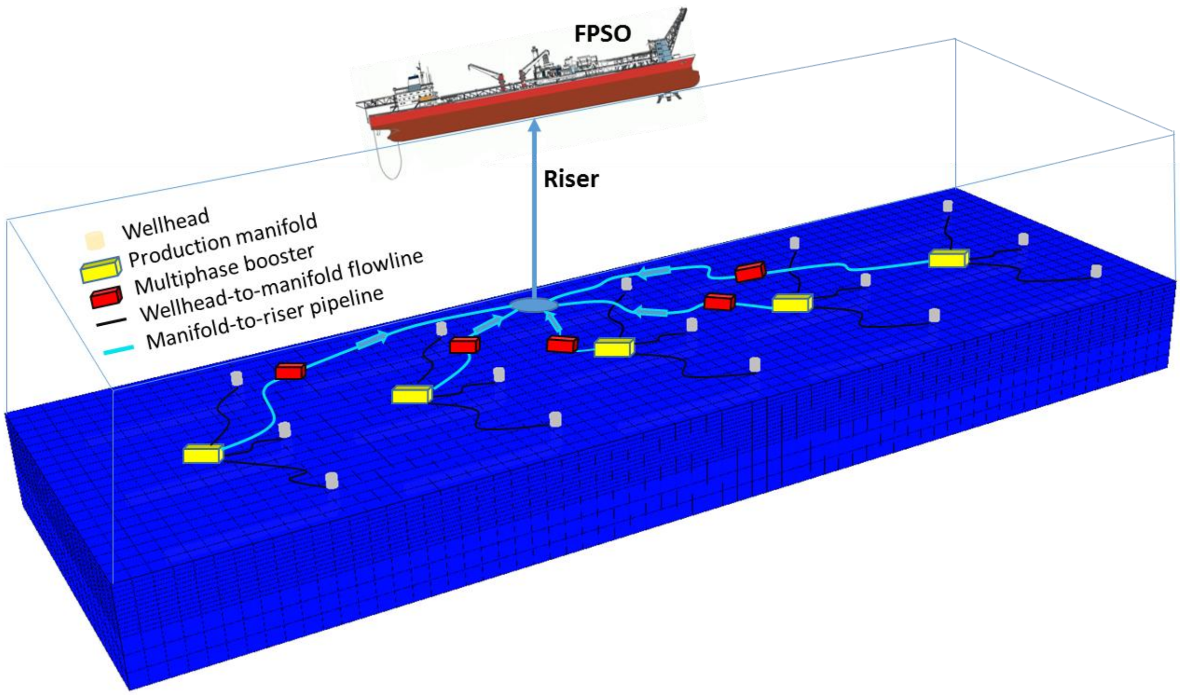

Figure 10. Production network schematic for base case with subsea booster for each cluster

Figure 10 shows the location of the pumps in the production network. It also presents the relative location of manifolds in the system. It is clear at this stage that unless the field is produced with long horizontally drilled sections the field coverage will be poor and huge quantities of oil will be left behind.

The production network described in this section requires the power of multiphase boosters to be specified. In order to find an optimum pump capacity in terms of power, which will satisfy the field requirements, a sensitivity study has been performed. Aspen HYSYS V8.8. has been used for this purpose.

The power requirement for each of the subsea pumps is estimated in a step-wise manner. In the work performed during the Specialization Project the only specified pump parameter was the pressure boost (or differential) to be provided by it. However, in reality pumps installed in the field have to be specified in terms of power (KiloWatts - KW or Mega-Watts) that they are going to provide and that is given by the capacity of the motor used.

The full procedure for calculating the pump power requirements is shown in **Appendix A** - ***Power estimation of multiphase boosters***.

The following table summarizes the characteristics of multiphase boosters used in for this production network:

Table 11. Number of pumps and pump characteristics used in the production network model with subsea boosting

Parameters	Value	Unit
Number of pumps	5	-
Power	550	kW
Provided pressure boost	30	bar

3.3.3. Base case with gas lift

This section describes the Wisting field development alternative with the aid of gas lift technology. The tubular properties and the field network are the same as in the Base Case scenario. The only difference is that this production network scheme assumes that all the 15 oil producers will be gas-lifted from the beginning of field life or shortly afterwards.

Below is the table summarizing the main gas lift design parameters used in this PIPESIM model:

Table 12. Main gas lift design parameters to be used in integrated simulation runs

Parameter	Value	Unit
Valve depth, TVD	260	meter
Gas injection rate	40000	Sm3/d

The procedure for obtaining the parameters shown in ***Table 12*** is presented in **Appendix B. *Estimation of required gas lift injection rate***.

3.3.4. Coupling settings

There is a certain setup procedure for coupled simulations that has to be followed in order to properly connect a reservoir model to a production model. The integrated simulation model in AVOCET enables to take into account the backpressure of the production network on the reservoir model and produce more accurate production and reservoir performance predictions compared to standalone reservoir simulation output. It should be noted that the current analysis only considers coupling of ECLIPSE and PIPESIM models. During the course of thesis work, an effort was made to connect a process network modelled in Aspen HYSYS to the existing

ECLIPSE-PIPESIM coupled model. The attempt did not succeed because one of the essential built-in packages to handle Black-Oil properties within HYSYS from an external provider required a separate license. The AspenTech company was contacted for an advice and they proposed to use “*Oil and Gas Feed*” option available in the basic license. Their proposal did not work as this option was incompatible with AVOCET and did not produce results when coupled with the integrated ECLIPSE-PIPESIM model. The problem could have probably been solved if the reservoir model was changed from Black-Oil fluid model to compositional. However, this would be a longer procedure and require more time than initially allocated for the thesis work. Besides, the Black-oil reservoir simulation model had already been constructed at that point and it was decided to proceed with only ECLIPSE-PIPESIM coupled model. It is believed that the production data obtained from this integrated model will be very close to the volumes obtained with an additional HYSYS process model due to the fact that the initial GOR values in the reservoir are quite low (about 50 Sm^3/Sm^3). Therefore, the analysis of different coupling settings was focused on integrating only the reservoir simulation and production network models.

In order to launch a model a certain procedure has to be followed. The model setup and other relevant details are presented in **Appendix C. *Stepwise guide of coupling ECLIPSE and PIPESIM models in AVOCET***.

Table 13 shows some of the most important settings used in the coupled models.

Table 13. Some of the applied coupling settings for optimized AVOCET runs

Coupling parameters	Applied option
Coupling location	Bottom hole
Coupling scheme	Loose
Network-balancing scheme	Obey Eclipse limits

The justification for selecting coupling location and coupling scheme is presented in **Appendix D** and **Appendix E** respectively. The Obey Eclipse Limits network-balancing scheme has been selected because this setting is recommended in the AVOCET 2014.1 manual.

4. Economic analysis

4.1. Introduction

In order to properly evaluate different development alternatives it is crucial to include project economics into the analysis. Nowadays, a decision to proceed with the development of oil and gas projects almost entirely depends on the economic attractiveness. The economics of hydrocarbon exploitation projects highly depend on capital expenditures (CAPEX) that are spent to bring them online. Therefore, the oil majors invest substantially in developing tools that will enable calculation of CAPEX in a reliable and robust way.

The current analysis involve estimation of CAPEX for three different development alternatives

- FPSO development with subsea templates with no artificial lift
- FPSO development with subsea templates with gas lifted wells
- FPSO development with subsea templates with five multiphase boosters on the seabed

The estimation has been performed using a simplified cost estimation tool created in Microsoft EXCEL. The EXCEL spreadsheet was prepared using data available in the public domain, press articles and several assumptions. The output has been compared against a commercial software that provided a student license for a limited time period. The development of the tool is presented in **Chapter 5**. Due to license restrictions, the software name is not released and no screenshots or details of the data input interface is given.

4.2. CAPEX estimation of multiphase boosters

The provided commercial software does not account for multiphase subsea boosters. Therefore, the cost of subsea boosters is taken from Draugen field on the Norwegian Continental Shelf located at an average water depth of 270 meters and operated by A/S Norske Shell. The field now owns two subsea multiphase booster stations (1 + 1 spare) each having 0.75 MW of power (Offshore MAGAZINE, 2016). The total cost of the boosting station installation with a complete system for topside power and control, umbilicals and supporting equipment, and the full subsea pump module and manifold was 100 million USD (Offshore Energy Today, 2012). Hence, it is assumed that each subsea pumping system costs 50 million USD and there will be 5 in total. It is considered to be an acceptable assumption since multiphase pumps for Wisting field have previously been estimated to require 550 kW or 0.55 MW power each. Moreover, it is quite challenging to find detailed open-source data about the cost of subsea systems and appliances installed on offshore projects. Therefore, multiphase booster costs from Draugen field development are used in the CAPEX calculation. The final CAPEX for the field development with subsea boosting will equal the CAPEX of the first case with the cost of five multiphase boosters (= CAPEX1 + 250 million USD).

4.3. CAPEX estimation

The provided software is capable of estimating CAPEX and operational expenses (OPEX) for different types of offshore projects. The interface allows building a project from scratch with minimum input data. The final CAPEX value may change depending on the project. For example, projects in the North Sea had higher development costs compared to CIS (Commonwealth of Independent States).

The second and third development scenarios are based on the first one with the addition of the respective artificial lift and subsea boosting options. It must be noted that the software does not have an option of adding subsea multiphase boosters to the cost of field development. Therefore, CAPEX for the development with subsea multiphase boosting is calculated by adding the cost of the first alternative with no artificial lift to the cost of five multiphase boosters for an available source. Below is the table showing the final CAPEX values for three development alternatives:

Table 14. CAPEX for 3 development alternatives from the commercial software (oil transported via tanker to the shore)

Case	CAPEX	Unit
No artificial lift	2.200	Billion USD
Gas lifted wells	2.243	Billion USD
Multiphase boosters	2.450	Billion USD

There are some major assumptions behind these development scenarios that have to be mentioned:

Table 15. Some of the assumptions behind the development scenarios

Fluid type	Assumption / Comment
Oil	Transported to the shore via a tanker from a third party provider
Associated gas	Used for electricity generation by a turbine on the topsides facility
Produced water	Reinjected into the formation to support the reservoir pressure

As can be seen from ***Table 14***, adding an artificial lift and boosting significantly increases the capital expenditures. All the three scenarios presented above assume that the oil will be exported via a tanker to an onshore processing facility. Some additional scenarios have also been explored even though they might seem a bit less realistic at this stage to be approved for field development due to associated costs. These alternatives assume transporting oil via a subsea pipeline to a nearby facility located 150 km away or to the shore at a 310 km distance. The addition of a pipeline increases CAPEX significantly. Moreover, the OPEX (which can also be calculated by using the software) also soars quite substantially. However, it seems relevant to explore this alternative as well to determine a balanced field development scenario.

Table 16. CAPEX for 3 development alternatives from the commercial software (oil transported via a 310-km long subsea pipeline to the shore)

Case	CAPEX	Unit
No artificial lift	2.472	Billion USD
Gas lifted wells	2.505	Billion USD
Multiphase boosters	2.722	Billion USD

Table 16 shows previously mentioned three scenarios but with an addition of a subsea pipeline oil transport option instead of a tanker. The 310-km long subsea pipeline adds almost 300 million USD to the CAPEX compared to the cases with a tanker for oil transport. It has to be mentioned that the software does not include the cost of additional oil export pumps to provide energy for oil pipeline transport.

The CAPEX values obtained from the software are used to generate NPV for reservoir simulation models with different uncertainties. The generated NPV distribution is presented and analyzed in the Results section.

4.4. Comparison of CAPEX from the simplified tool and the software

This section provides the comparison of the CAPEX values generated by the provided commercial software and the newly developed tool.

Table 17. Comparison of CAPEX from the commercial software and the developed simplistic tool

Cost contributor	**Cost [million USD]**			
	Commercial Tool		**Simplistic Tool 2**	
	Oil tanker	Oil pipeline	Oil tanker	Oil pipeline
Topsides	436	397	491	491
Supporting structure (FPSO hull)	313	317	65	65
Drilling (15+15)	753	753	1 112	1 112
Subsea templates	698	698	300	300
Pipeline (310 km)	-	306	-	310
Power (gas turbine)	-	-	11	11
Total	2 200	2 472	1 979 (2 527*)	2 289 (2 837*)

Table 17 compares CAPEX figures obtained from the commercial software and the two versions of the simplistic tool. The table provides the cost values for two cases:

- With oil transportation via a to be rented tanker (does not include initial capital investment)
- With oil transportation via a specifically built pipeline (requires additional initial capital expenditure to build)

The two cases assume neither subsea boosting nor gas lift in the field development plan. Additionally, in the Total CAPEX section (the last row of the table) the simplistic tool provides two values. The ones in the brackets indicate the CAPEX calculated with a correlation for subsea templates. The other two values (1979 & 2289) are estimated using the subsea infrastructure of Ormen Lange field as an analog.

The values of the total CAPEX looks more or less similar for both tools. However, FPSO hull capital expenditure calculated with the simplistic tool is much lower compared to the one obtained with the commercial software. If the weight of the topsides facility is assumed to be the same as the topsides weight the FPSO hull cost becomes more or less for both tools. However, this assumption cannot be supported with available data. Therefore, in order to reduce the uncertainty the CAPEX values from the commercial software will be used in all further NPV analysis. The tool can be modified if new data and supporting information is obtained.

4.5. NPV calculation and assumptions

A simple NPV calculation tool has been developed to estimate the profitability of the projects. The following assumptions have been made:

- Gas revenues are not considered in the calculations. It is assumed that gas is too far to transport, therefore it will either be reinjected into the reservoir or used for electricity generation with a gas turbine
- OPEX for the three different cases are as follows:

Table 18. Average yearly OPEX for the evaluated cases (oil transport via tanker)

Case	OPEX	Unit
No artificial lift	200	Million USD/year
Gas lift	210	Million USD/year
Subsea multiphase boosting	220	Million USD/year

The OPEX figures for the cases with no artificial lift and gas lift are generated by the commercial software. The software generates the yearly OPEX based on the field development configuration and oil production rate. The provided values are averaged yearly operational expenses for the entire field life. The commercial software does not provide a subsea multiphase boosting option. Therefore, OPEX for the third case is assumed based on a notion that pumps would need more maintenance and workover compared to gas lifted wells, and, hence, OPEX for this case should be somewhat higher compared to the development with gas lifted wells.

- CAPEX is depreciated in the first two years before the field is put online
- All the wells are assumed to be already drilled and completed before the field startup
- Inflation rate is not considered in the calculations.
- Discount rate is assumed to be 8 per cent. Tax and government royalties are not added to the calculation workflow.

A summary of parameters used in the NPV study is shown below:

Table 19. Parameters used in NPV calculation

Parameter	Value	Unit
Base case oil price	50	USD / stb
Discount rate	8	per cent
OPEX increase	5	per cent / year
Inflation rate	0	per cent
Field life duration	27	years
Number of operational days	355	days/year

NPV calculation spreadsheet with an example calculation is shown in the **Appendix F. *Economics***.

5. Simplified CAPEX tool

One of the goals of this work has also been building a simple CAPEX estimation spreadsheet that could be used for initial project evaluation and teaching purposes. One of the major challenges in creating the tool has been a lack of open-source, easily accessible and structured cost data about the major worldwide offshore projects and the relevant equipment used in those developments. Moreover, the equipment providers usually do not usually provide the relevant cost data on their corporate websites. Due to this, the cost data in the tool is taken from different sources. Some of the cost figures have been difficult to obtain and, instead, some correlations have been used to generate the relevant cost values.

It order to simplify the task it was decided to break up the possible capital expenditures into major parts. It is assumed that the following items are the main cost contributors for CAPEX for an offshore oil field development:

- Supporting structure (e.g., jacket, hull of an FPSO etc.) and topsides facility (assumed to have the same cost per tonne for all supporting structures)
- Subsea facilities (e.g., templates, manifolds etc.)
- Drilling
- Transport of gas or oil via a newly built pipeline
- Power generation (e.g., cost of laying a subsea cable or installing a gas turbine in place)

Table 20. Identified major cost contributors in an offshore field development

Cost contributor	Example	Comment
Supporting structure and topsides facility	Jacket, FPSO, TLP, semisubmersible integrated platform etc.	Supporting structures may require different capital expenditures. Topsides facilities assumed to have the same cost for all supporting structures
Drilling	Drilling rig rate; type of well	The tool does not provide a detailed well cost breakdown
Subsea facilities	Templates, manifolds, satellite wellheads etc.	Difficult to find open-source data
Oil and gas transport	Subsea pipeline	Added to the total CAPEX if pipeline is built specifically for the project (tanker transport and joining available pipeline network is not part of CAPEX)
Power generation	Subsea electric cable; gas (or diesel) turbine on the platform	Gas turbine may not be as expensive as laying a subsea cable

Surely, the cost contributors might be very different depending on the type and location of the project, but it was important to generalize some of the concepts to prepare a more or less universal and robust tool.

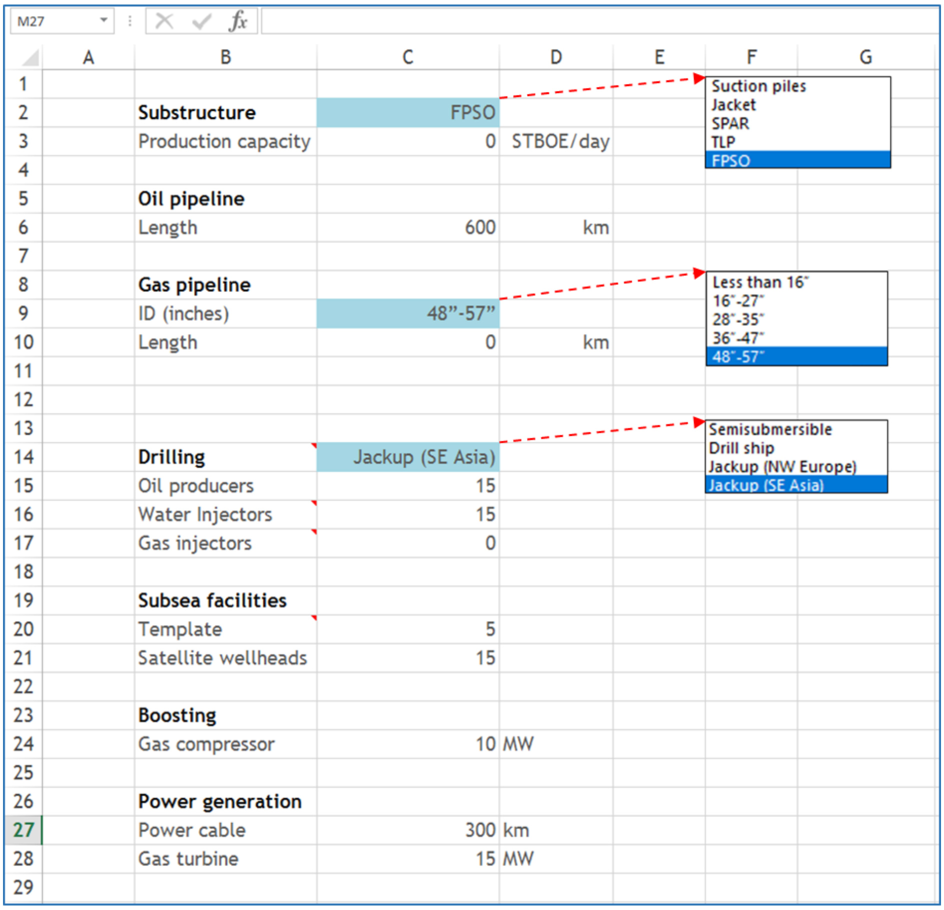

Figure 11. User input window of the developed simplistic CAPEX calculation tool

Figure 11 shows the user input window of the simplistic CAPEX calculation tool. As can be seen it consists of seven major input parts, all of which can be categorized into previously listed five main cost contributors. The data and assumptions behind all of them are discussed below.

<u>Substructure and topsides facility:</u>

It is assumed that any hydrocarbon offshore structure consists of two major parts: supporting structure and the topsides facility. Supporting structures can be various such as jackets, suction piles platform, hull of an FSPO etc. All of them have different cost values. The different cost figures are taken from a website, which analyzed numerous offshore projects and came up with average cost values per unit of weight for different offshore supporting structures and topsides facilities (Offshore Fabrication Costs, 2011):

Table 21. Cost of different offshore supporting structures and topsides facilities

Supporting structure	Cost	Unit
Suction piles	5 000 – 15 000	USD/ton
Jacket	10 000 – 20 000	USD/ton
SPAR	10 000 – 20 000	USD/ton
TLP	10 000 – 20 000	USD/ton
FPSO	25 000 – 40 000	USD/ton
Topsides	**Cost**	**Unit**
Topsides facility	35 000	USD/ton

According to the website, this table provides a range of fabrication costs, which is taken from public data sources and personal direct experience. It is assumed that the topsides facilities have the same cost for different kind of substructures.

The weight of topsides facilities for an offshore field is calculated according to the following relationship:

$$T = 0.06 \cdot C + 6349$$

Where

T – Topsides facility weight, [*ton*]

C – Production capacity, [*BOE/d*]

This relationship obtained from a graph (**Appendix F**, ***Figure 45***) from by an international agency specializing cost management consultancy (AACE International, 2011).

The weight of the supporting structure is obtained using the weight of the topsides facility (Mainal, 1990):

$$T = 3.931 \cdot S + 5.638$$

Where

T – Topsides facility weight, [10^3 *ton*]

S – Substructure weight, [10^3 *ton*]

This correlation is obtained from the graph generated with the data gathered from North Sea oil fields by Universiti Teknologi Malaysia (**Appendix F, *Figure 46***).

10% additional weight is added to the final weight results of the topsides facility and the supporting structure as a contingency measure. It must also be noted that these relationships are very approximate and are based on a sample of data. Therefore, the results should be used cautiously. It is recommended to compare the final values with analog projects with similar design capacity and specifications.

Drilling:

In order to calculate the drilling costs statistical data from the rig contractors on the NCS has been used (Osmundsen et al., 2009):

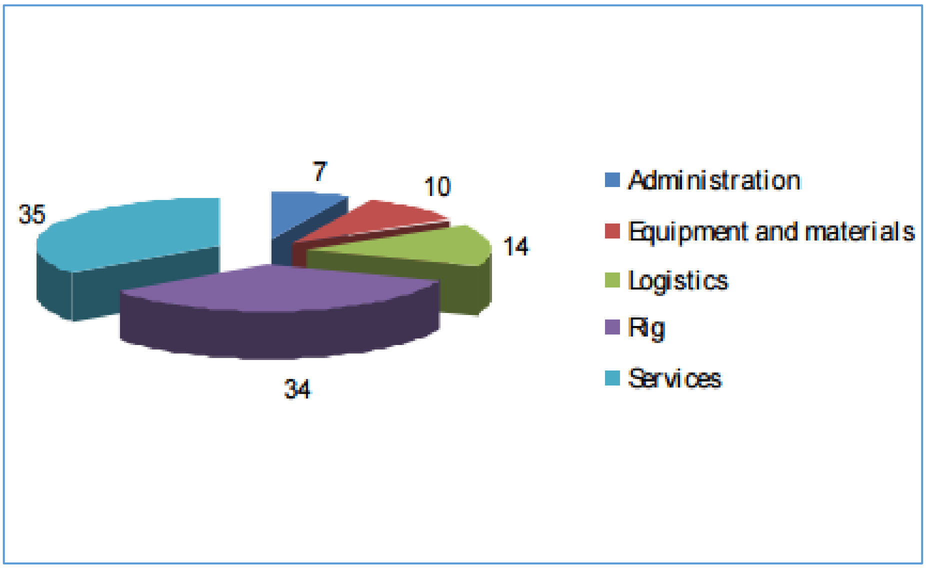

Figure 12. Percentage shares of typical composition of drilling costs.

*Copied from a report by University of Stavanger (Osmundsen et al., 2009)

The figure shows the major cost contributors for drilling operations on the NCS. It would go beyond the scope of the current report to try to prepare a detailed cost breakdown for drilling operations on the NCS. Therefore, ***Figure 12*** has been taken as a basis for all further assumptions. The most recent drilling rig daily rate is available from IHS Markit, which updates the rates for different rig types and locations every month (IHS Markit, 2017). The following assumptions are then used to calculate the well cost:

- Oil producers are drilled in 60 days
- Water injectors are drilled in 30 days
- Gas injectors are drilled in 30 days

After multiplying the number of days by the daily rig rate it is then assumed that this cost comprises 34 per cent of the total well drilling expense. By applying a simple calculation the total well cost can then be found.

It should be noted that the number of days for drilling a well in the developed tool has been adapted for Wisting oil field. The reservoir is only 250 meters below the seabed and it took approximately 50-60 days to drill the first appraisal well with a more than 1000-meter horizontal completion section. The water and injectors are assumed to be completed vertically. Therefore, their drilling is assumed to be 2 times shorter. So, if the reservoir location is very deep and if there is available data about the exploration and appraisal wells in the area, the number of days to finish a well in the tool should be tuned accordingly to have more representative results.

Oil and gas pipelines

There are not many recently built oil pipelines. The literature suggests 1 million USD/Km as an average cost of laying oil pipelines worldwide. Amongst the most recently built pipelines on the NCS with the available cost data Kvitebjørn Oil Pipeline has an average cost of 1.01 million USD/km (NPD, 2013). Based on this, the subsea oil pipeline cost is set to 1 million USD/km in the tool without considering the diameter of the tubulars.

The gas pipeline data was more accessible and easier to obtain. In Figure 31, it is shown that there are several pipeline diameter ranges that can be chosen from. There is different cost information associated with each diameter range. The information is obtained from a detailed annual report by the European based Agency for the Cooperation of Energy Regulators (ACER, 2015).

Power generation:

There are two possibilities to choose from in the tool:

4. The power is generated on the platform with a gas turbine

5. The power is brought to the platform via a subsea electric cable

The gas turbine cost data is in the form of USD per MegaWatts (MW). It is taken from a report by the Agency for the Cooperation of Energy Regulators (ACER, 2015). In order to have an idea of much energy would be necessary to run platform with a certain design capacity the following relationship is used (Mainal, 1990):

$$P = 0.17 \cdot C + 14.74$$

Where

P – Power necessary to run the facility, [*MW*]

C – Production design capacity of the platform, [10^3 *STB/day*]

If the power will be brought to the platform via a subsea electric cable then the length of the line has to be provided in the spreadsheet. The price of 1 km subsea cable is set to be 1 million USD/km. It is based on the data from Goliat field in the Barents Sea (RIGZONE, 2010).

Subsea facilities:

The detailed information about costs of subsea projects on the NCS is difficult to obtain. Therefore, two different methods are used to estimate the costs of the subsea facilities. As a result, two spreadsheets for CAPEX estimation are developed with different techniques of obtaining the cost figures for subsea equipment.

The first method is based on the correlation. The correlation is derived from the following figure (G.Moen, 2014):

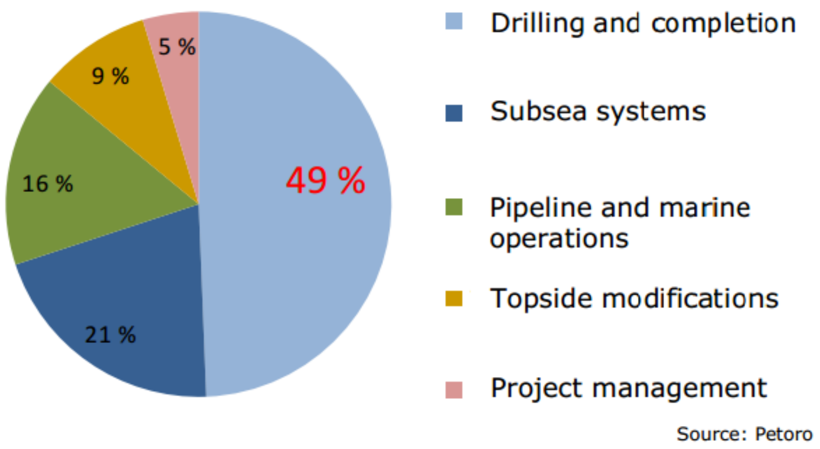

Figure 13. Cost split of a typical subsea oil template with 4 wells on the NCS

*Copied from (Moen, 2014)

Figure 13 demonstrates a cost split for a typical subsea template with 4 wells on the NCS. At this stage, it can already be assumed that the drilling costs have been calculated based on previously mentioned correlations. Therefore, the estimated drilling expenditures can be assumed to constitute 49 per cent of a total subsea template cost. It is assumed that this price includes all the required equipment as well as the installation and administration expenditures as shown in ***Figure 13***.

The second methodology is based on a real cost figure from Ormen Lange gas field located on the NCS. The field has been online since 2007. The field is being developed with two subsea templates each having 8 well slots. The total cost of two templates with eight X-mas trees was 160 million USD. Therefore, it is assumed that a cost of one well slot in a template with all the necessary equipment would cost 20 million USD. Therefore, for this methodology, the only input for cost calculation of subsea facilities is the number of oil production wells (SUBSEAIQ, 2017).

The tool does not provide a robust way of calculating the cost of multiphase booster pumps. There is very little open-source information about subsea pumps. Therefore, the cost of additional 5 subsea boosters for the corresponding production network configuration is accounted for by adding the cost of multiphase boosters at Draugen field on the NCS. The cost of adding one subsea pump is hence set to be 50 MM USD (Offshore MAGAZINE, 2016). The same procedure was applied for the CAPEX values calculated by the commercial software, because it did not estimate the subsea booster cost.

6. NPV Results and discussion

The main goal of this analysis has been to evaluate the uncertainty in the reservoir parameters as well as the field performance with different production network configurations. The evaluation function is set to be the final NPV.

Then, the obtained oil production data from the reservoir simulation models in combination with CAPEX and OPEX from the commercial software is used to calculate NPV. Some sensitivities are also applied to evaluate the project profitability. CAPEX and oil price is varied by ±25 per cent and the resulting NPVs are then calculated.

Figure 14 shows the NPV relative probability distribution for the performed cases:

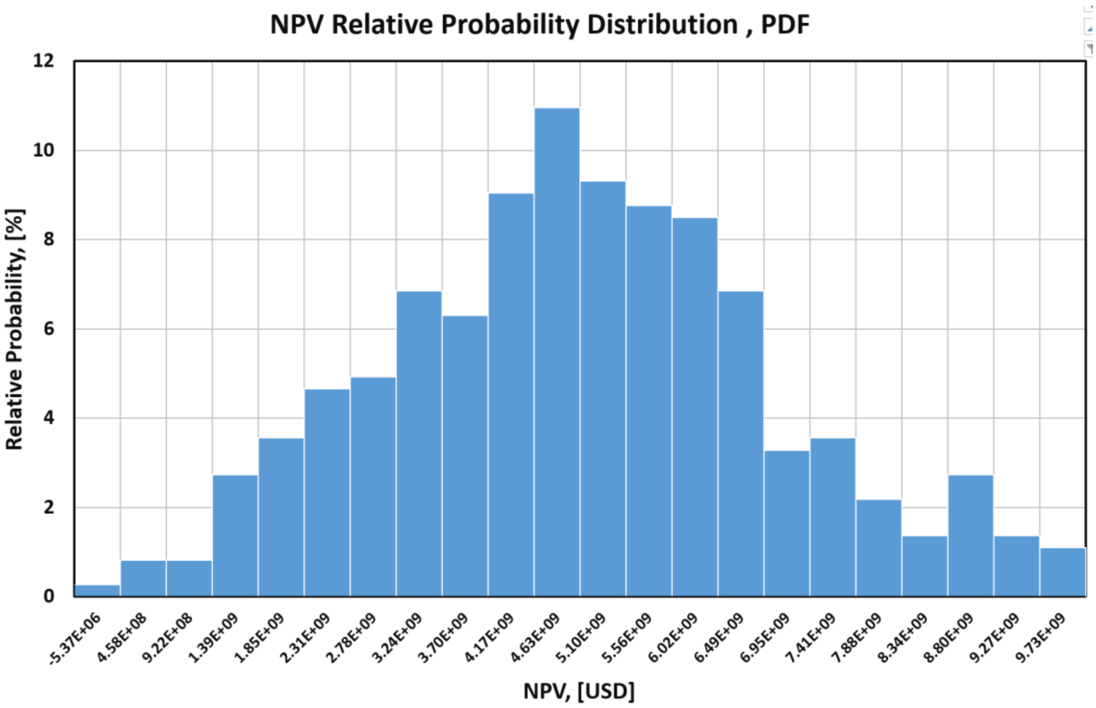

Figure 14. Relative Probability Distribution Frequency for Wisting NPV (390 cases)

In total, **81** (27 reservoir simulations coupled with 3 different production networks) coupled models were launched. It was possible to run and complete all the 27 standalone reservoir simulation models in ECLIPSE, but 3 out of 81 coupled models did not initialize, most likely due to the fact that those three reservoir models were not able to produce given the combination of reservoir characteristics and production network constraints. This assumption looks highly likely as 2 (case 2 and case 8 from ***Table 2***) out of 3 coupled models that did not initialize were a combination of the network with no boosting option and relatively low reservoir rock properties (low porosity). One more case, which did not initialize is made of a reservoir simulation model with the lowest permeability (350 md) and porosity (0.2) values and a production network with gas lifted wells.

390 NPV values were then generated by using ±25 per cent oil price and CAPEX variation. The values plotted in ***Figure 14*** show more or less normal distribution with the most expected NPV value being in the range of 4.17 to 5.10 billion USD. The range can be reduced and the graph can be smoothed if more cases are run and added to the plot. It is expected to see more or less smoother graph if at least 1000 NPV values are considered in the data range.

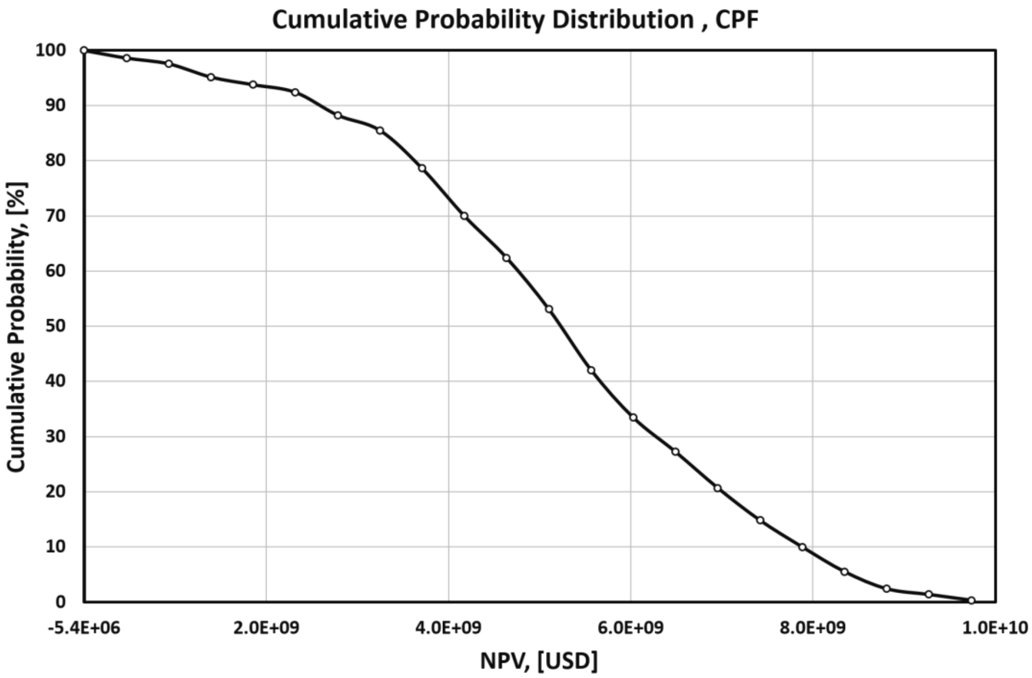

Figure 15. Cumulative probability distribution for NPV (390 cases)

Figure 15 shows a cumulative probability distribution for calculated NPV values. Like in the previous figure, the graph does not appear to be smooth. The reason for this is that the number of cases that were run should be increased. However, even this plot permits deriving some important values from it. For example, according to the graph the field cannot yield more than 10 billion USD NPV. It should also be noted that out of 390 obtained NPV values only one was non-economical.

Table 22. Probabilistic NPV values for Wisting field (390 cases)

NPV [billion USD]		
P10	**P50**	**P90**
7.11	4.42	1.82

The values shown in the table provide three probabilistic NPV values for Wisting field. P10 value means that there is 10 per cent chance that the final NPV will be more than 7.11 billion USD. P90 shows that there is 90 per cent probability of having NPV higher than 1.82 billion USD. The most probable NPV is 4.42 billion.

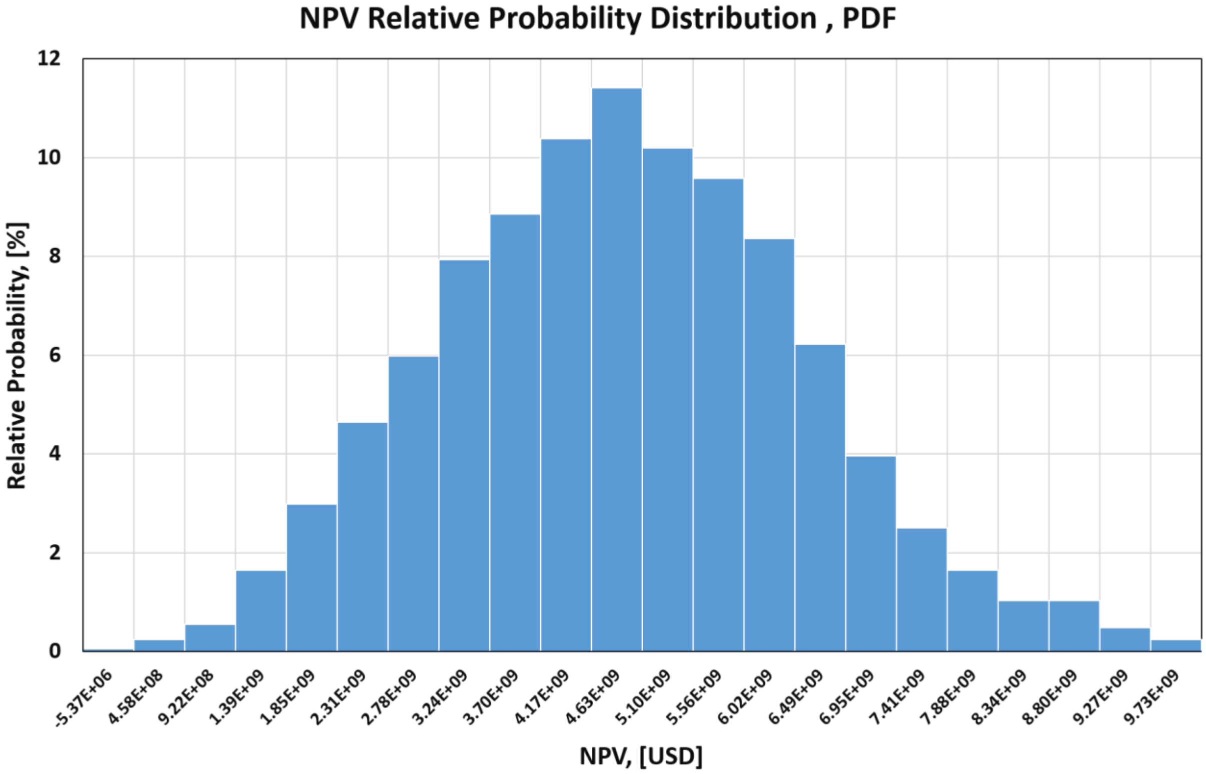

Figure 16. Relative Probability Distribution Frequency for Wisting NPV (1638 cases)

In order to smooth the plot of NPV distribution frequency more sensitivities with CAPEX and oil price were performed. The sensitivities included 5, 10, 15 and 25 per cent variation in the capital expenditures and oil price. As a result, 1638 NPV scenarios were created and the resulting graph is shown ***Figure 16***. The NPV distribution on the figure be considered normal as per definition. The same can be said about the Cumulative Probability Distribution plotted with a greater number (1638 vs 390) cases.

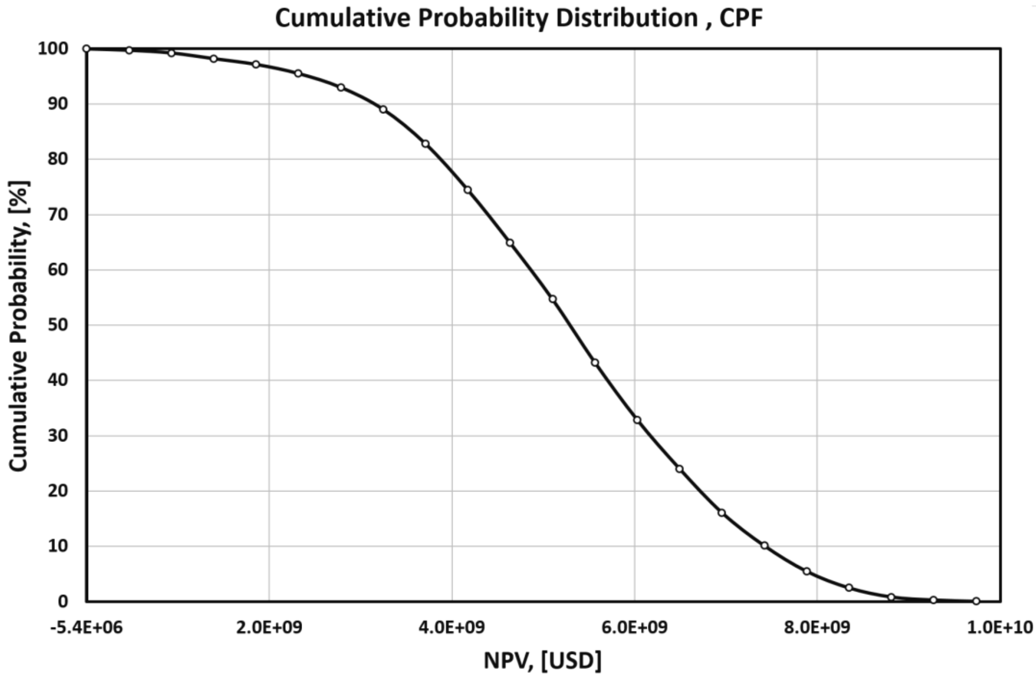

Figure 17. Cumulative probability distribution for NPV (1638 cases)

An analysis of the NPV figures show that there is a difference between the probabilistic NPV values obtained with a smaller (390) and greater number of samples (1638). The P50 values are still the same, but P90 and P10 are quite different.

Table 23. Probabilistic NPV values for Wisting field (1638 cases)

NPV [billion USD]		
P10	**P50**	**P90**
6.58	4.42	2.30

Table 23 can be considered as having more accurate results compared to ***Table 22***. The more cases are considered in the analysis the narrower will be the NPV range between these three probabilistic values. The reason of showing the NPV results for these two samples of data is to highlight the importance of the quality assurance during this kind of analysis. It is important to present all the assumptions behind the calculations to properly evaluate the development alternatives and make better decisions.

These presented values can vary depending on the reservoir performance and the financial terms, such as oil price, inflation/discount rate, royalties etc. The assumptions behind these NPV figures should always be considered when sharing these results.

A few more cases have been considered in the study. So far, dhe development alternatives analyzed in terms of NPV have not considered the addition of a pipeline-to-shore scenario to transport the produced oil. The following figures contain the addition of a 310-km oil export pipeline to the total CAPEX. All the previous steps have also been applied for these scenarios. The CAPEX and OPEX have been generated by the provided commercial software.

Table 24. Average yearly OPEX for the evaluated cases (oil transport via tanker)

Case	OPEX	Unit
No artificial lift	300	Million USD/year
Gas lift	310	Million USD/year
Subsea multiphase boosting	320	Million USD/year

The same procedure for NPV calculation was applied and the results shown in ***Figure 18*** and ***Figure 19*** below.

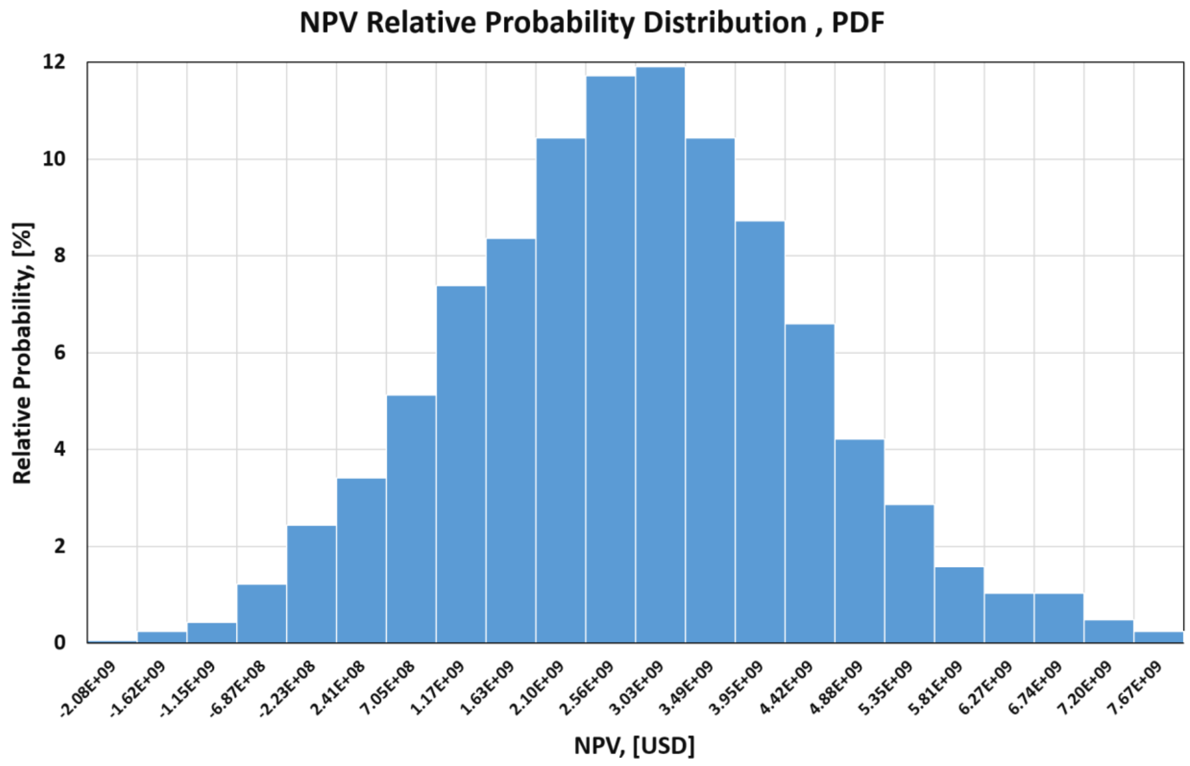

Figure 18. Relative Probability Distribution Frequency for Wisting NPV (oil transport via a 310-km pipeline)

It can be seen that the addition of the pipeline shifted the NPV distribution to the left.

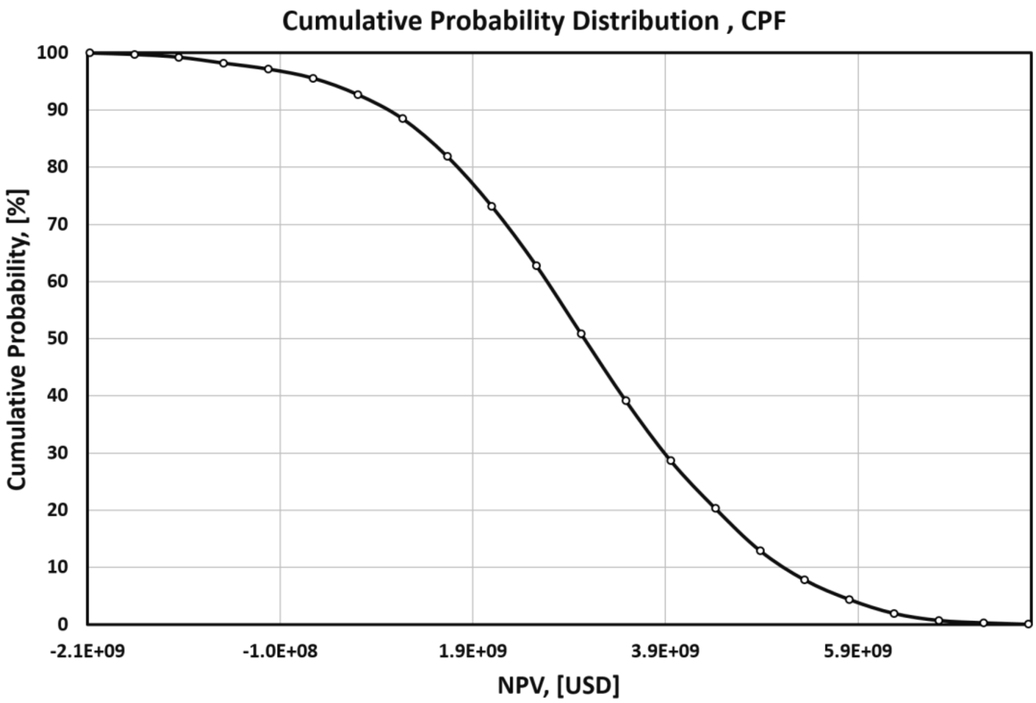

Figure 19. Cumulative probability distribution for Wisting NPV
(oil transport via a 310-km pipeline)

The probabilistic NPV values for Wisting field development with a 310-km oil export pipeline are shown in ***Table 25***.

Table 25. Probabilistic NPV values for Wisting field development with 310-km oil transport pipeline

NPV [billion USD]		
P10	**P50**	**P90**
4.55	2.51	0.47

Even though the values are lower compared to the previous case with oil export via a tanker, the current development scheme also seems to be profitable. However, it should be mentioned that the CAPEX calculated for this development option did not consider the cost of export oil pump. The provided software did not have an option of adding pumps to development cost. The additional cost of an export booster may significantly reduce the final NPV, but there are no available figures about an approximate export pump cost support the claim.

7. Conclusions

- 27 reservoir models were built in order to analyze the uncertainty involved in the 3 reservoir characteristics: porosity, permeability and K_v/K_h.
- 3 production networks were considered for the analysis: Base Case, Base case with gas lift and Base Case with subsea booster for each cluster. The latter 2 were prepared and optimized during the course of this project.
- 81 coupled simulations were prepared. 78 models successfully were successfully completed and analyzed. 3 coupled models did not initialize due to an unfavorable combination of reservoir properties and reservoir network backpressure, which prevented the reservoir model to produce fluids to the topsides facility.
- An optimum coupling configuration was determined, which reduced the run time from 90 minutes to 20-30 minutes. The accuracy was not compromised. On average, the difference in the results between the model using a configuration applied during the Specialization Project (the highest accuracy) and coupled models with the new configuration was 5 - 8 %.
- A simplified CAPEX estimation tool was built based on the open source literature, publications and several assumptions. Two different methods were employed for calculating of the subsea equipment (manifolds, templates etc.) - one using a correlation based on the statistical data from the NCS, another using analog real field development data
- NPV was estimated using the oil production data from the coupled models. ±25 per cent variation in CAPEX and oil price was applied to perform sensitivities and plot an expected NPV probability distribution for the three base case scenarios with oil transport via a tanker. Additionally, the NPV was estimated for the base case scenarios with oil

transport via a 310-km pipeline to the shore. The same variation of 25 per cent for CAPEX and oil price was used to perform sensitivity analysis and plot NPV normal probability distribution. The final probabilistic NPV values for Wisting oil field development are shown below:

Table 26. Final NPV for Wisting oil field development

NPV [10E9 USD]			
Case	P10	P50	P90
Oil transport via tanker	6.58	4.42	2.30
Oil transport with 310-km pipeline	4.55	2.51	0.47

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Appendix A. Power estimation of multiphase boosters

Appendix A describes the procedure involved in the calculation of power requirements of subsea multiphase pumps.

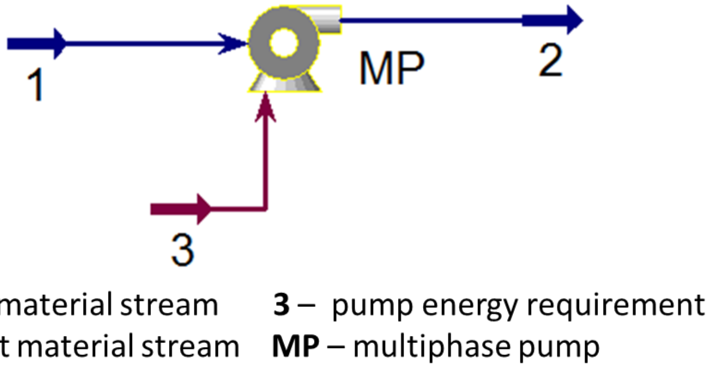

Figure 20. HYSYS simulation setup

Figure 20 shows the HYSYS simulation setup for calculation of power requirements of each of the five subsea multiphase pumps. The pump has a yellow frame in the figure. This is a warning message from HYSYS showing that the stream entering the pump is two-phased. There are several parameters that have to be specified for the for the inlet stream ("Flow from manifold") of the pump. These are:

1. Pressure
2. Temperature
3. Fluid composition
4. Molar flow
5. Pressure boost to be provided by the pump (dP)

The pressure at the inlet of the pump is the approximate expected pressure at the template (or wellhead). It is derived from a coupled AVOCET run with no pressure boosting. The temperature at the pump inlet is assumed to be equal to the initial reservoir temperature (16 ^{o}C). The fluid composition that was used for the analysis in ***Table 27***.

Table 27. Assumed Wisting Fluid Composition for HYSYS input

Component	Molar fraction	MW [g/mol]
CO2	0.01	44.01
Methane	0.25	16.04
Ethane	0.03	30.07
Propane	0.03	44.10
i-Butane	0.01	58.12
n-Butane	0.02	58.12
22-Mpropane	0.00	72.15
i-Pentane	0.02	72.15
n-Pentane	0.01	72.15
n-Hexane	0.03	85.20
C7+	0.59	219.00
Total	**1.00**	**142**

In order to calculate the molar flow the following steps must be undertaken:

1. Determine the average daily liquid flow rate that will be produced during the field life time
2. Determine the average daily gas rate that will be produced during the field life time
3. Estimate the mass flow rate of gas and liquid with the equation ***(2)***:

$$q_{mass} = \frac{q \cdot \rho}{24} \tag{2}$$

Where

q_{mass} – Hourly mass flow rate of oil or gas, [*kg/h*]

q – Volumetric flow rate oil or gas, [sm^3/day]

ρ - Density of oil or gas, [kg/m^3]

4. Calculate the total hourly mass flow rate by adding oil mass flow rate to the corresponding daily mass rate of gas.
5. Calculate the molar flow rate by dividing the total mass rate by the molecular mass of the stream as shown in equation ***(3).*** This equation is valid for oil and gas mixture.

When the water breaks through, the water stream will be added the gas and oil stream. It order to simplify the calculations the water stream is excluded from the calculations with equation ***(3)***. The justification for this is presented further in **Appendix A**.

$$q_{mol} = \frac{q_{t,mass}}{MW} \qquad \textbf{(3)}$$

Where

q_{mol} – hourly molar flow rate of the stream entering the pump, [*mol/h*]

$q_{t,mass}$ – hourly total mass flow rate of liquid and gas, [*kg/h*]

MW – molecular weight of the multiphase stream, [*kg/mol*]

In order to find a representative value for the liquid rate input into HYSYS the base case reservoir simulation model was run and analyzed.

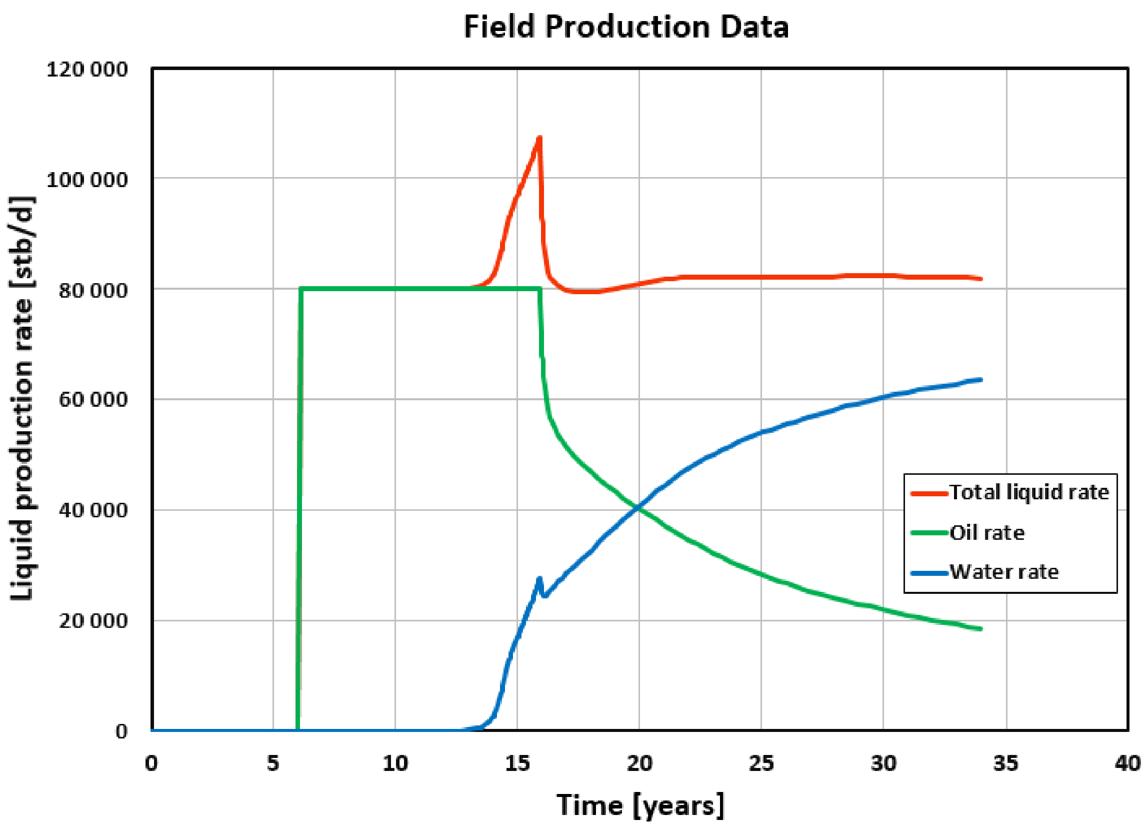

Figure 21. Field daily liquid production data from the base case reservoir simulation model

From ***Figure 21***, it can be assumed that the average production liquid rate will be approximately 80 MSTB/d. There is a spike in total liquid production in year 15, which can be attributed to the water breakthrough. Afterwards, the total daily produced liquid rate levels out at 80

MSTB/d. If the pumps are manufactured according to the maximum fluid production rate it will not be beneficial for the field economics, because much of that extra capacity will remain idle due to the fact that the field will not produce above installed capacity of 80 MSTB/d.

The surface gas production rate will also remain more or less constant according to the reservoir simulation results.

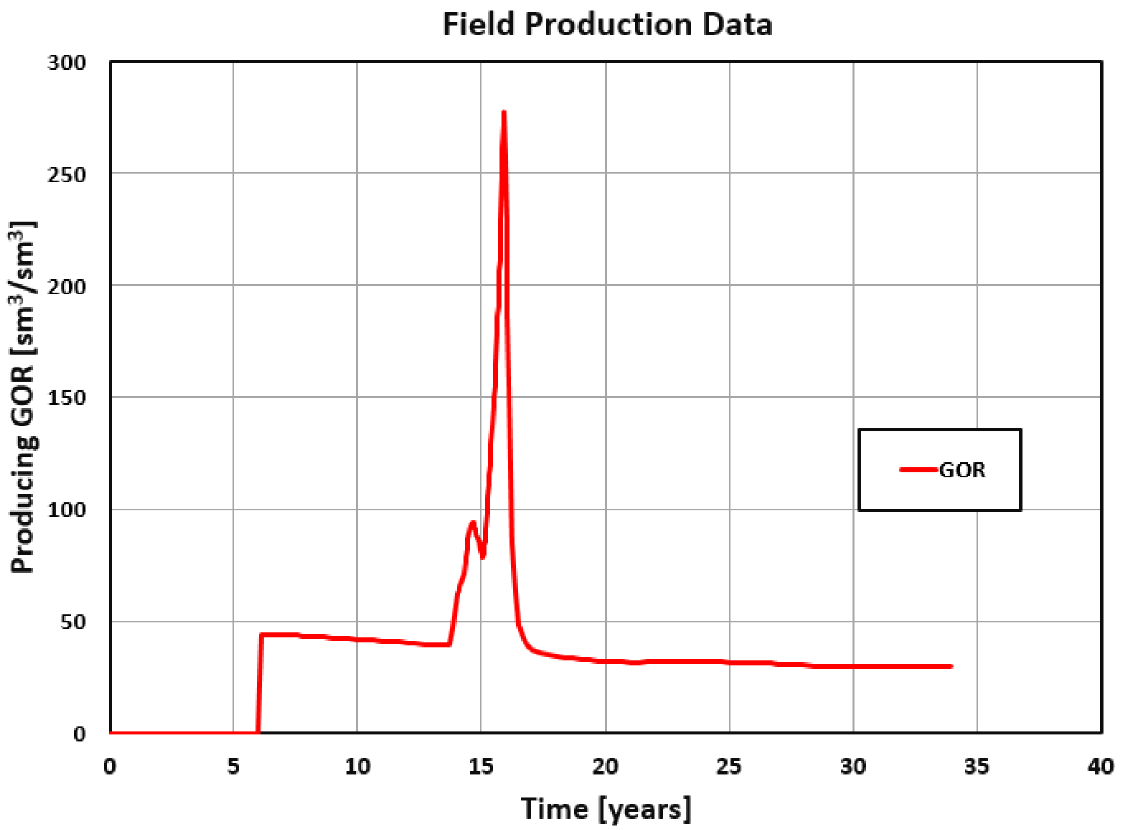

Figure 22. Field daily gas production data from the base case reservoir simulation model

Figure 22 shows that the daily producing surface GOR will be approximately 44 standard cubic meters of gas per a standard cubic meter of oil until a major gas breakthrough in year 15. Afterwards, GOR remains slightly lower compared to the initial value till end of field life. In order to simplify the calculations of molar flow for multiphase pumps it will be assumed that the average gas production during the field life will be the same as in the beginning of the production. It can be considered as an acceptable assumption, because the gas flow will not contribute as much to the mass flow rate as the produced oil and water.

In order to complete the calculations, it is necessary to estimate the molecular weight of the multiphase stream entering the pumps. One of the major assumptions considered in the procedure is that the water contribution to the molecular weight is not taken into account. One of the reasons was that the applied HYSYS package (Peng-Robinson fluid package in combination with “No Oil & Gas Feed” option) could not properly handle the water presence in the stream. Instead, the water contribution is accounted for from a volumetric standpoint. The total liquid production is used for mass rate calculations, where both oil and water volume rates are taken into account, but in the molar rate calculations, only oil and gas stream molecular weight is applied. The current assumption is thought to be reasonable because the oil density is quite high and is equal to 845 kg/m^3. Nevertheless, it is recommended to take into account the water contribution to the stream density in all future work to optimize the pump design capacity if more advanced software packages are available.

As the composition is known it is possible to calculate the molecular weight of the fluid stream entering the pump inlet. One more important assumption to be taken into account is that the oil stream entering pump inlet consists of oil and solution gas, i.e. it is assumed that the stream does not contain amount of gas equal to the initial GOR. Otherwise, the composition will be different from the one presented earlier. It is still possible with a number of assumptions to determine the hydrocarbon composition for different GOR values, but it will not be very beneficial as explained earlier from the results of reservoir simulation runs. Produced GOR remains in the range of 30-34 Sm^3/Sm^3 after the gas breakthrough in year 15. So, as mentioned earlier the GOR value used for molar rate calculations is 44.6 Sm^3/Sm^3, which was obtained in a two-stage separator test in a PVT facility.

Table 28. Parameters for molar flow calculation

Component	Gravity	Density [kg/m3]	Flow rate [Sm3/d]
Oil	0.83	830	12720
Gas	0.86	1.05	5.67E+05
MW [kgmol/kmol]	142		

Table 28**Table 24** shows the required parameters to calculate the molar flow. The density values are estimated by multiplying oil and gas gravities by respective values of water and air density at standard conditions (15.6 ^{o}C, 1 atm). The oil flow rate is 80 MSTB/d converted to SI

units, whereas the gas flow rate corresponds to the initial solution GOR of 44.6 Sm^3/Sm^3 multiplied by the initial flow rate of 12720 Sm^3. The total molecular weight MW is estimated using the following equation (WHITSON et al., 2000):

$$M = \sum_{i=1}^{N} M_i n_i \qquad \textbf{(4)}$$

Where

M – total molecular weight of the oil and gas stream, [*g/mol*]

M_i – molecular weight of each component, [*g/mol*]

n_i – the number of moles (or molar fraction) of each component, [*mol*] or fraction.

Then, mass rate for gas and oil is calculated according to equation ***(1)*** and their corresponding values are added together to yield the total mass rate. Following this, the total mass rate is divided by the molecular weight of undersaturated oil at reservoir conditions to produce the molar rate value, which is input into HYSYS processing simulator. There is one more parameter to be defined in the pump characteristics in HYSYS software, which is the pressure boost or pressure differential to be provided by the pump. As the pumps will be placed on the seabed the pressure differential has to be enough to overcome the hydrostatic pressure of the fluid in the riser up to the topsides facility.

Several integrated AVOCET models have been run with different pump boosting pressures. The results have shown that the pumps with pressure differentials of more than 30 bara provide excessive suction pressure, which in turn causes negative pressures in the wellhead nodes and simulation fails. The most consistent results have been obtained with pump pressure boosting capacity of 30 bara. Therefore, the pump power capacity is calculated according to that pressure differential. The same pressure differential was used in the Specialization Project.

Finally, all the necessary requirements were input into HYSYS model shown in ***Figure 20***. The input and the final pump power capacity is displayed in ***Table 29***. The software produces the required power to lift the hydrocarbons to surface.

Table 29. Input data and the resulting multiphase pump capacity in HYSYS

	Parameter	Value	Unit
Input	Pressure	10	*bara*
	Temperature	16	*^{o}C*
	Molar flow rate	654	*kgmol/hour*
	Composition	***Table 27***	-
	Pump dP	30	*bara*
Output	Pump Power	550	*kW*

The pump inlet pressure is set to be 10 bara. This is assumed to be the minimum pressure at the pump inlet. The power requirement of pumps reduce as the pump inlet pressure increase. Therefore, the minimum inlet pressure yields the maximum power necessary to boost the fluids by the pressure differential of 30 bara. The calculated 550 kW power requirement will be used in all integrated AVOCET simulations with subsea multiphase boosting.

Appendix B. Estimation of required gas lift injection rate

<u>Background information</u>

Before proceeding with the optimization of the gas lift design for the field it is important to discuss some of the main features and design considerations for this particular artificial lift technique. Two main design criteria is considered in the current report:

- Gas lift injection valve depth
- Gas lift injection rate

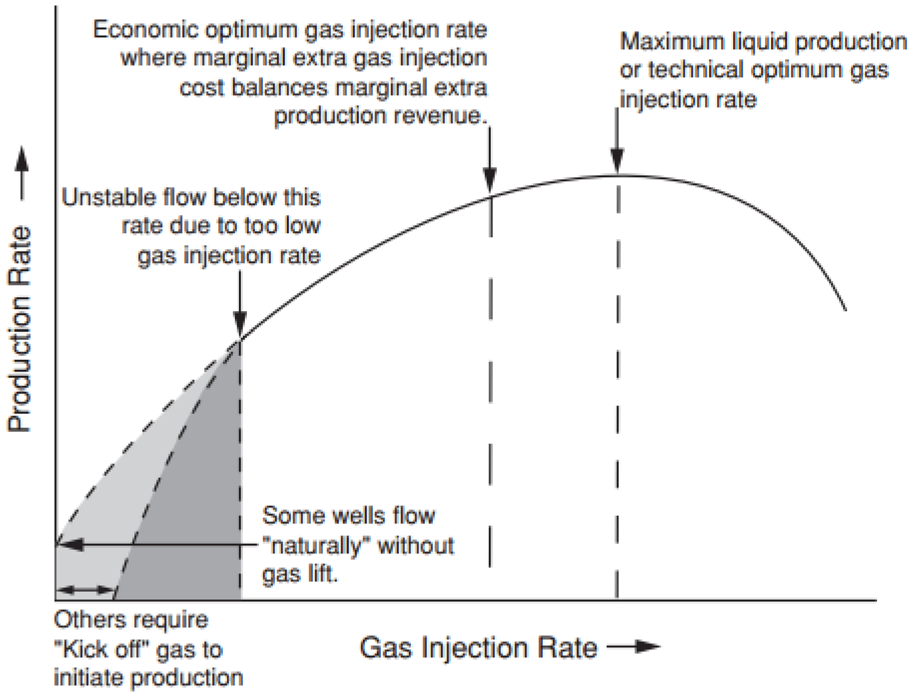

Figure 23. Effect of gas injection rate on oil production rate

*Copied from (Heriot Watt, 2012)

Figure 23 shows that oil production increases with increased gas lift rate until the maximum oil rate is achieved. Afterwards, the increase in gas lift injection rate is not accompanied by elevated oil production. Instead, oil production decreases. It can be explained by the fact that initially the injected gas decreases the average fluid density in the tubing as its rate is increased. As the gas injection rate is increased the frictional losses due to higher mass of flowing fluid in the tubular also increases. At the maximum liquid production point, the decrease in the average fluid density and increase in frictional losses due to gas injection are perfectly balanced. However, a further increase in gas rate leads to frictional losses being greater than the reduction in the density of the fluid column, which in turn leads to lower oil production rate. Even though the optimum gas injection rate leads to the highest oil flow rates it is often not the most economic operating point. The better financial value is achieved by injecting gas at the "economic optimum gas injection rate" point, which is located slightly to the left of the "maximum liquid production" point on ***Figure 23***. This is due to the fact that the further increase of gas injection rate from economic optimum point leads to lower production gains per injected gas volume. Therefore, it is important to consider all of those factors while performing the gas lift design (Heriot Watt, 2012).

The second crucial parameter to consider during gas lift design work is the installation depth of the operating gas injection valve. Usually it is desirable to set it as deep as possible in the production string. The deeper valve setting would allow greater reduction of the hydrostatic column and hence a greater increase in oil flow rates due to decrease of bottom-hole pressure. However, it is not always possible to set the valves at the deepest point in the tubing string. The reasons for this may vary, but are generally due to either economic or equipment constraints.

Wisting field gas lift optimization

PIPESIM software package is used to determine the optimum gas rate and installation depth for Wisting oil field production wells. There are several alternative ways to design gas lift in PIPESIM. For the purpose of the report, the "Lift Gas Response" option will be used. It allows performing quick sensitivities with gas lift several gas lift parameters at a time and is not difficult to use.

In order to proceed with gas lift optimization several parameters have to be defined in the corresponding PIPESIM window.

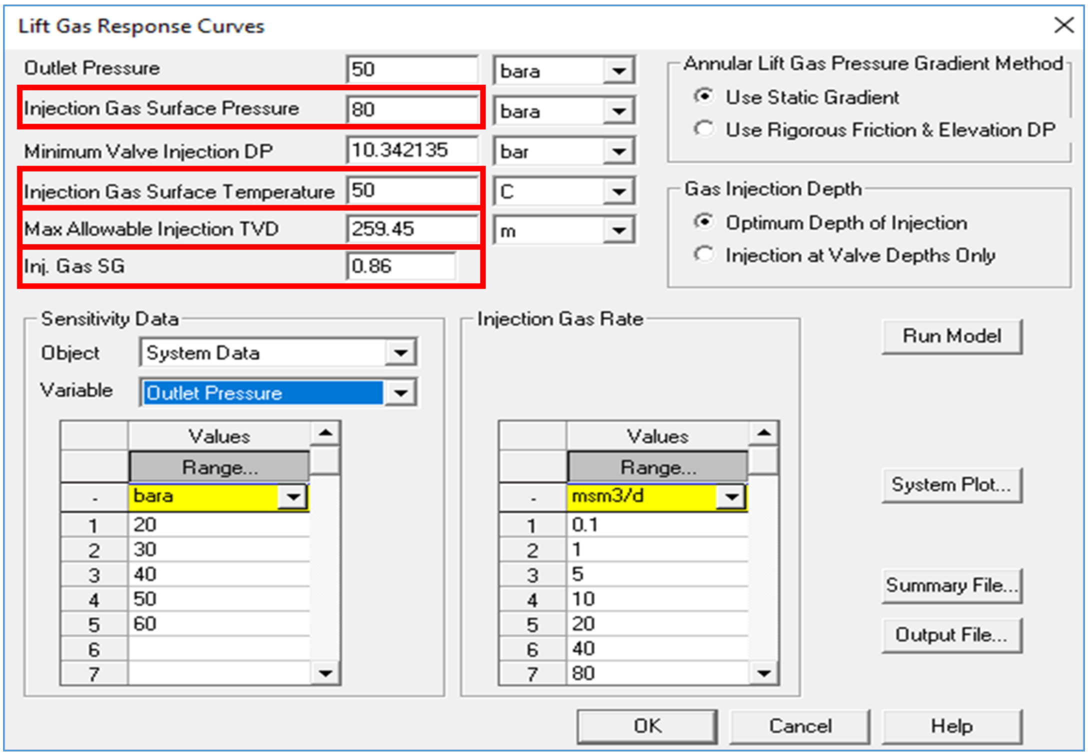

Figure 24. Gas lift sensitivity window in PIPESIM

Figure 24 shows the gas lift sensitivity window in PIPESIM. It can be accessed by entering the well configuration data through the main window and following the path shown in ***Figure 25***.

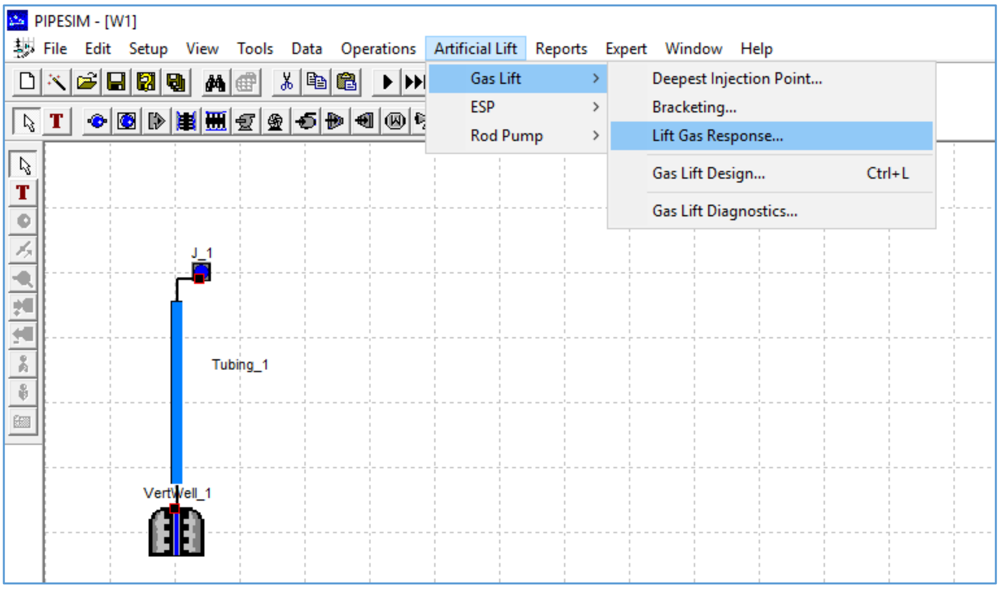

Figure 25. Lift Gas Response access path

The data to be manually entered is highlighted with a red frame on ***Figure 25***. The used gas gravity value is 0.86. It is assumed that the gas for gas lift will be provided from the produced fluid in the location. No gas is therefore will be transported to the location. It is a relevant assumption as there are no near-by producing platforms and the closest development is Snøhvit, which is several hundred kilometers away.

As the reservoir location is very shallow from the seabed, it can be assumed that the operating valve can be set at the well target depth. Therefore, the valve is installed at the maximum true vertical depth, which is the corresponding value taken from the first exploration well drilled in the location.

The aim of further analysis is to determine the optimum gas lift injection rate. Before starting the analysis it is also important to specify the injection point in the system. There are basically two ways to model gas lift systems in PIPESIM (PIPESIM, 2012):

1. Gas Lift injection points:
   This option uses fixed gas injection rates and depths. It is assumed that the specified rate of the gas is fully injected into the production tubing at the requested depth and it does not consider the available injection pressure.
2. Gas Lift Valve System:
   The installation depth of the valves is specified. The gas is injected at the deepest possible depth depending on the available surface pressure. The Gas Lift Diagnostics option can be used, which enables calculation of the actual gas throughput for each valve based on the surface injection pressure, valve specifications, as well as valve status for this operation. For this, valve details (valve size etc.) have to be provided.

Only "Gas Lift injection points" option is applied in the current analysis. All further discussions in this section are based on the implementation of this option. This option does not consider the calculation of annulus losses. Therefore the surface pressure is not considered in gas lift calculations. PIPESIM will force the gas into the gas lift valve with the pressure value assigned in the user input window.

In order to access this utility within PIPESIM the tubing string should be clicked twice and the window shown below will open.

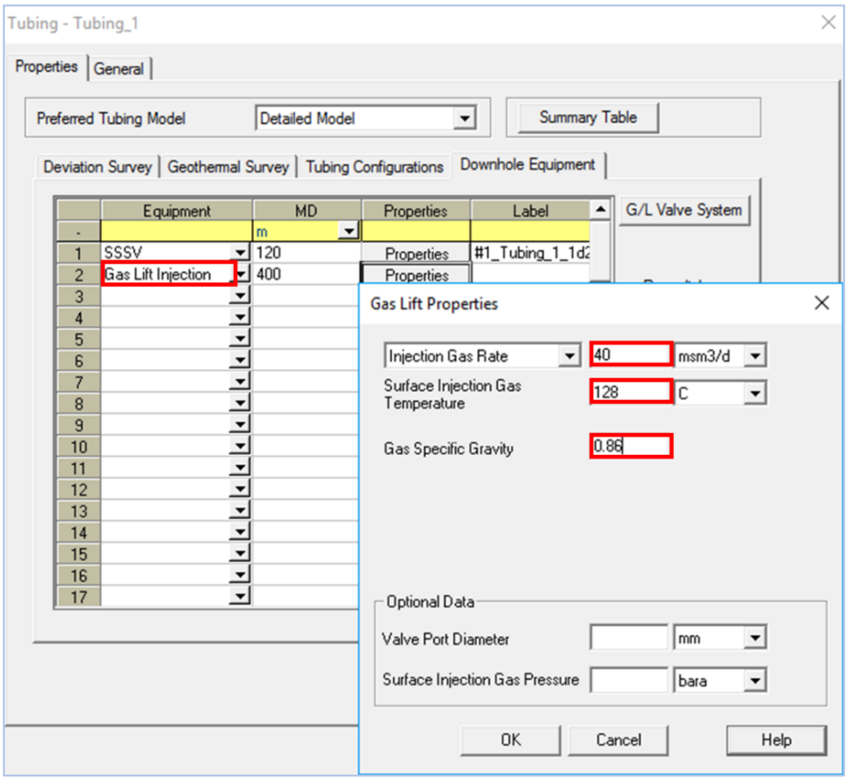

Figure 26. Gas lift injection parameters input window in PIPESIM

In the "Downhole Equipment" section the "Gas Lift Injection" should be selected from the dropdown menu. In the "Properties" section the following parameters should be specified:

- Injection gas rate
- Surface gas injection temperature
- Gas specific gravity
- Valve Port Diameter (not mandatory)
- Surface Injection Gas Pressure (not mandatory)

The mandatory input is highlighted with red frames on ***Figure 26***. The gas injection rate and temperature sections can be filled with "best guess" numbers for now. It is important to put some numbers in these fields, otherwise the sensitivities using "Lift Gas Response" option will not be possible. These values will not affect the gas rate sensitivity results.

The surface gas injection pressure and temperature can be calculated with the following relationship for gas compressors (Pumps & Systems, 2017):

$$\frac{T_d}{T_s} = \left(\frac{P_d}{P_s}\right)^{\frac{k-1}{k}} \qquad (5)$$

Where

P_s and P_d – compressor suction and discharge pressure, *[bara]*

T_s and T_d – compressor suction and discharge temperature, *[K]*

k – specific heat ratio, which is defined as a ratio of specific heat for a gas in a constant pressure process to a specific heat for a gas in a constant volume process. *K* value is different for various gas types.

Table 30. Ratio of specific heat values for different gases *(Pumps & Systems, 2017)*

Gas	Ratio of Specific Heat, *k*
Carbon Dioxide, CO_2	1.30
Helium, *He*	1.66
Hydrogen, H_2	1.41
Methane (or natural gas), CH_4	1.31
Nitrogen, N_2	1.40
Oxygen, O_2	1.40
Standard Air	1.40

The inlet pressure is assumed to be 20 bara, which is the pressure at the Sink in the PIPESIM model (separator pressure). It has also to be noted that the discharge pressure will approximately be equal to the pressure at the operating point. This is because the gas has a very low density and hence the difference between the surface injection pressure and the pressure at the gas lift operating valve will be negligible.

The minimum pressure to lift the hydrocarbons from that depth is 80 bara for gas lift rate of 40000 Sm^3/day. A further increase in pressure does not yield any additional production, because the PIPESIM forces the gas rate in the injection point without considering the annulus in the numerical calculation (for Gas Lift Injection Point option in PIPESIM). Based on this, the minimum surface pressure to lift hydrocarbons from the target depth is set to be 80 bara for further sensitivities.

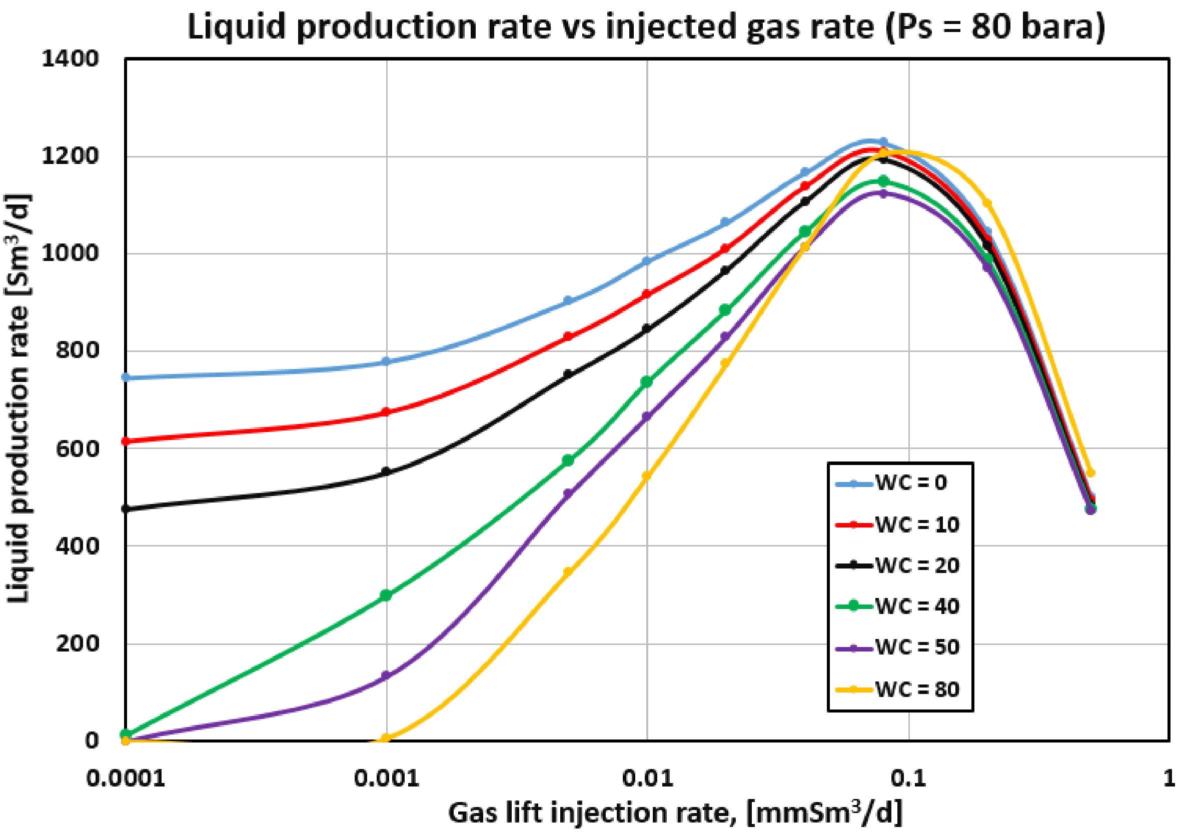

Figure 27. Liquid production rate vs injected gas rate for surface injection pressure of 80 bara

It should be noted beforehand that the injected gas temperature did not affect the liquid production rate, because the flow in the annulus is not solved with the applied option in PIPESIM. However, the gas injection temperature is a significant parameter during the gas lift and production equipment design stage. It becomes crucial to predict the operating conditions during this step in order to assure that equipment will withstand the given operating environment. Therefore, the temperature is calculated according to equation ***(5)***, even though this value will not affect the liquid production in the current PIPESIM arrangement. The input data for gas lift injection rate sensitivities is shown in ***Figure 32***.

Table 31. Some of the input data into PIPESIM for gas rate sensitivities

Parameter	Value	Unit
Well Productivity Index, *PI*	900	Sm3/d/bara
Injection gas surface pressure, P_s	80	bara
Injection gas surface tem-re, T_s	128	ºC
Valve operating depth, TVD_v	260	meter
Injection gas specific gravity, *SG*	0.86	-

The well productivity index is derived from the ECLIPSE reservoir simulation model, which can generate PI as an output. The shown injection gas surface injection pressure and temperature are the gas parameters at the outlet of the compressor. It is assumed that the inlet temperature of the gas is 16 ^oC and inlet pressure is 20 bara. This input is used together with equation ***(5)*** to generate P_s and T_s values.

Finally, the simulation can be set up and different gas injection rates can be tested to determine the optimum value.

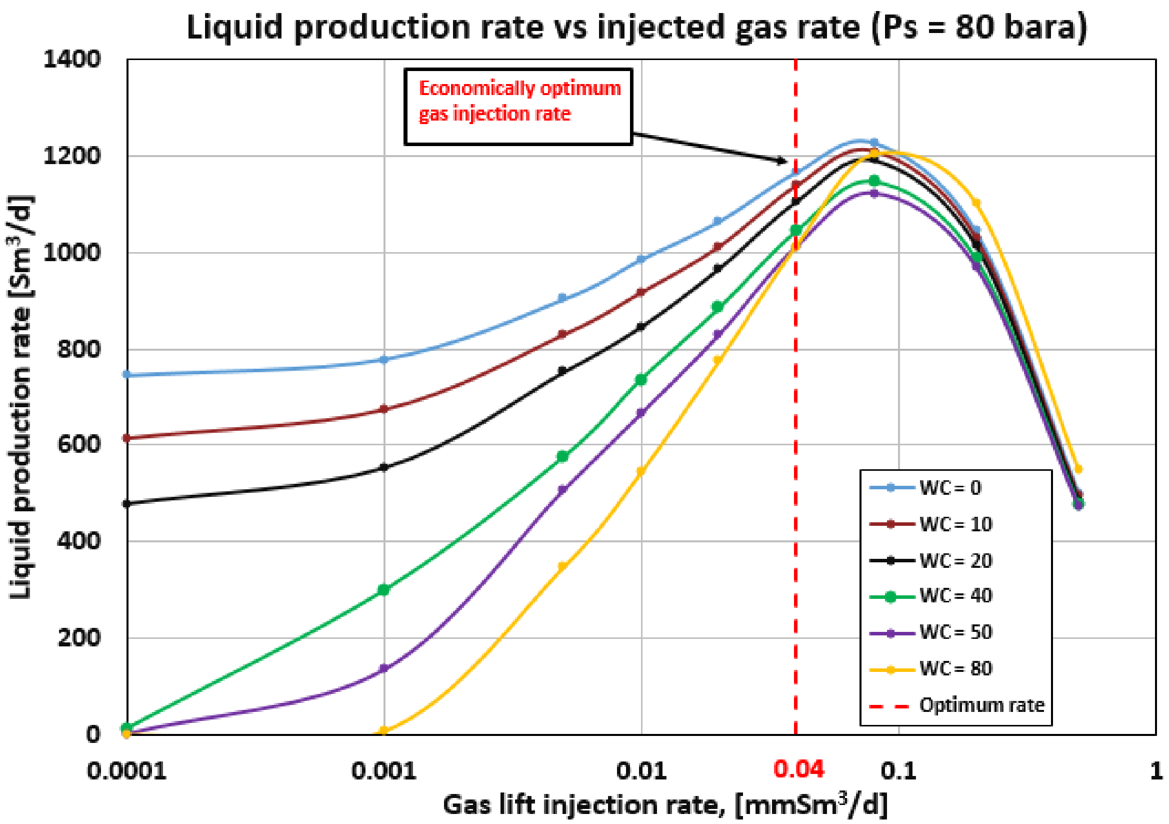

Figure 28. Sensitivity results to determine the optimum gas injection rate

Figure 28 shows the results for some of the sensitivity runs in PIPESIM testing different gas lift injection rates. This figure is using the same data set as ***Figure 27***. The difference is that the economic gas rate is highlighted on the latter. It has already been mentioned that the optimum economic gas lift injection rate is usually slightly smaller compared to the rate leading to the maximum liquid production. It has been determined that the optimum economic injection rate is equal to approximately 40000 Sm^3/d for all times of reservoir simulator. Increasing the injection rate further leads to a lower production gain per volume of additional injected gas. Therefore, this value will be used in all further integrated simulation runs. The exact economic value of injecting this gas rate is not performed in this report.

Table 32. Main gas lift design parameters to be used in integrated simulation runs

Parameter	Value	Unit
Valve depth, TVD	260	meter
Gas injection rate	40000	Sm3/d

Table 32 shows the final gas lift design parameters to be used in integrated simulation runs.

Appendix C. A stepwise guide of coupling ECLIPSE and PIPESIM models in AVOCET

There are extensive tutorials within AVOCET, which give a very detailed procedure about all the steps that should be taken to build and run coupled models. The tutorials and manual can be accessed through the main window in AVOCET and clicking on  sign in the upper right corner as shown on the figure below:

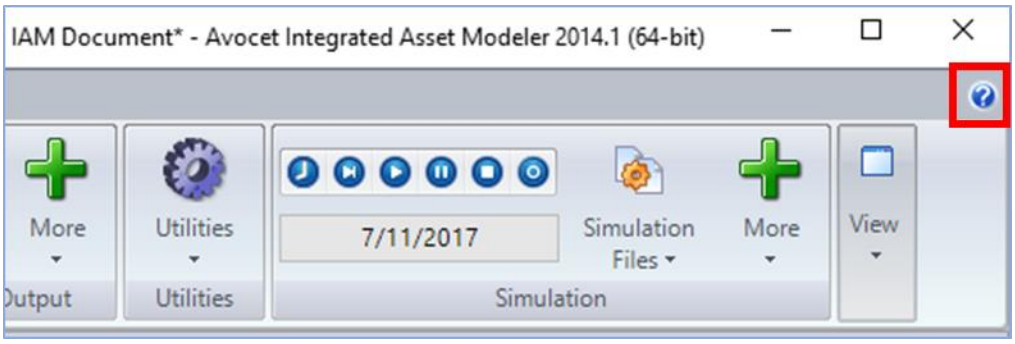

Figure 29. AVOCET manual can be accessed by clicking on the highlighted square

A reader should expect a general procedure to initialize a model and more focus to be put on the details that have been a source of various challenges with AVOCET during the thesis work.

<u>Launching AVOCET and simulation configuration setup</u>

The procedure starts with launching AVOCET and creating a new integrated simulation file. A new file can be created by clicking the IAM sign in the top left corner of the software window and clicking the ***New Document*** tab. Before activating the reservoir and network models the simulation has to be configured in a proper way. Otherwise, the models will not even initialize. ***Figure 30*** shows the Simulation configuration tab in AVOCET, which has to be the same for all users. It is strongly recommended to use the provided links as they appear in ***Figure 30*** before launching the runs.

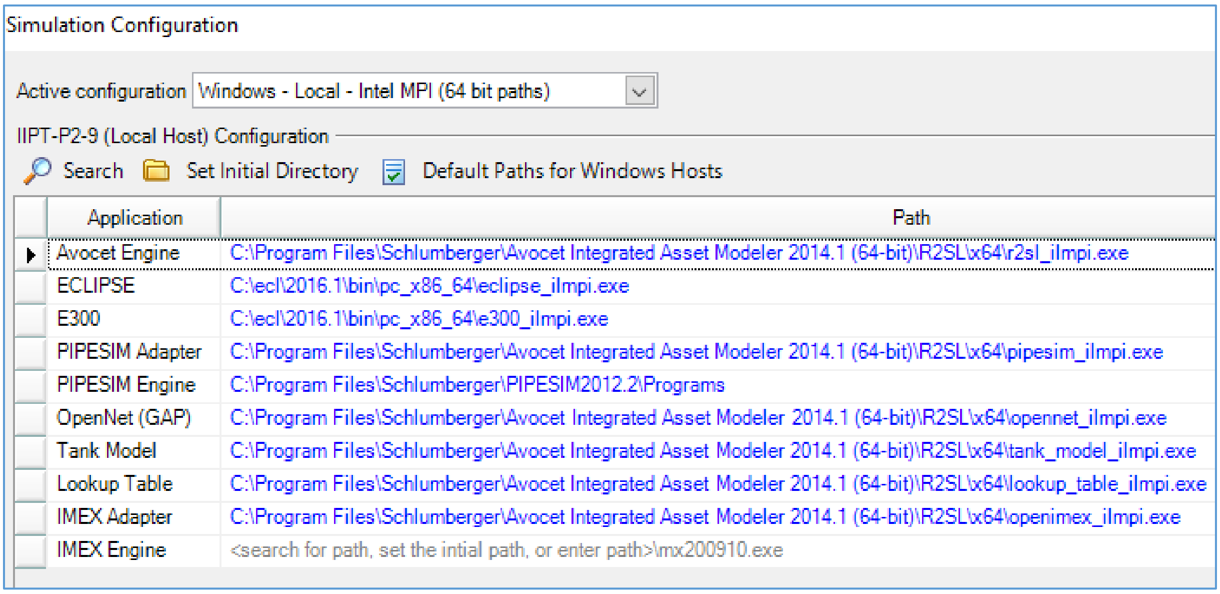

Figure 30. Simulation configuration tab in AVOCET

<u>Model activation</u>

After completing simulation configuration setup, the models to be coupled have to be activated. It is recommended to keep the ECLIPSE reservoir simulation model and the PIPESIM production network model in the same folder.

The ***Main Flow Diagram*** will activate after creating a new simulation file. A list of programs that could be added to the integrated model appears within the ***Main Flow Diagram***. ECLIPSE and PIPESIM should be selected from that list and dragged to the ***Main Flow Diagram*** window. Following this, separate windows in the form of ***ECLIPSE Model – 1*** and ***PIPESIM Model – 1*** will be created. They can be used to load the respective reservoir simulation and production network models for coupling in AVOCET. In order to load the reservoir simulation model ***ECLIPSE Model – 1*** window has to be accessed and the required model navigated in the opened window and activated with ACTIVATE button.

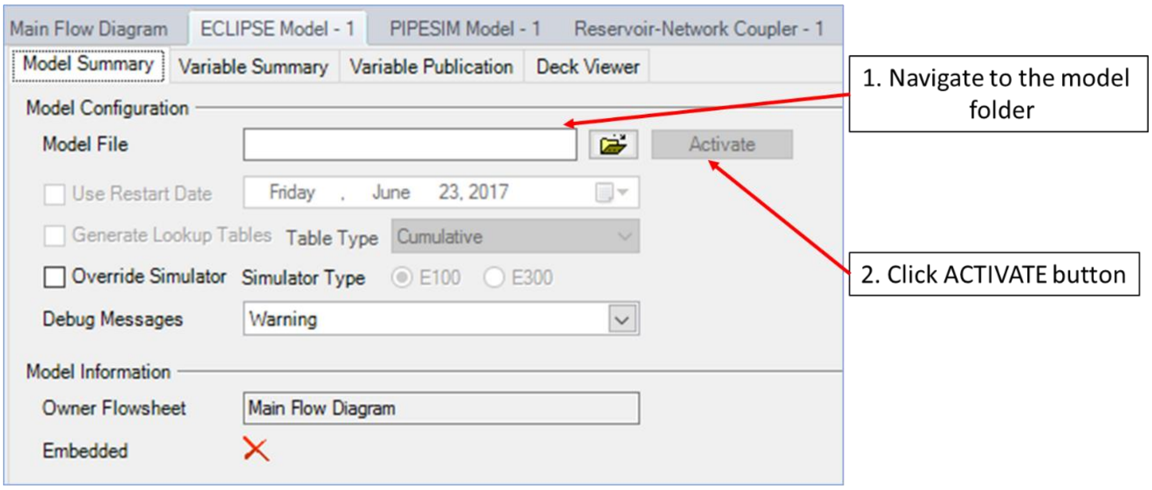

Figure 31. Reservoir simulation model access and activation window

Figure 31 shows the reservoir simulation access window and the procedure to activate the ECLIPSE model. The procedure is the same for PIPESIM production network models.

Connecting of models

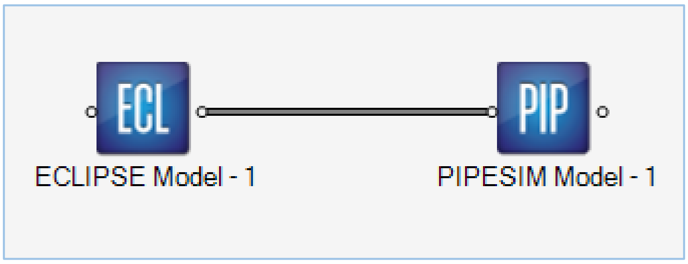

Figure 32. The main flow diagram to connect the models in AVOCET

In order to connect the ECLIPSE model to PIPESIM model either icon can be clicked by one of the circles on the sides of the software icon as shown on ***Figure 32*** in the ***Main Flow Diagram***. The appeared connection line should be dragged to the second icon. Following this action, a ***Reservoir-Network Coupler - 1*** window tab will appear, where the location of the coupling and the type of interaction between the models can be specified. The following has to be defined in this window:

- Well (ECLIPSE)
- Node (PIPESIM)
- Coupling location
- Coupling constraint

A node can be a well, a sink, or a source in PIPESIM, which has to be connected to a corresponding well in the ECLIPSE model. The coupling location can be either at the bottom hole or at the wellhead. If the models are coupled at the wellhead then PROSPER has to be used to generate vertical lift tables and input into ECLIPSE model to simulate the flow in the tubing. In case of bottom hole coupling, PIPESIM will model the flow in the tubing. Choosing the Coupling Constraint allows AVOCET to arrive at a converged solution during the network balancing process. By default, the Bottom Hole coupling will choose Volume Rate as a constraint and Top Hole (wellhead) coupling location is selected, Top Hole pressure is automatically selected as a default constraint (Avocet, 2014). The ***Reservoir-Network Coupler*** window is shown on ***Figure 33*** with all the available choosing option for the required parameters. The report focuses on Bottom Hole coupling with Volume Rate as a constraint. The advantages and downsides of using Bottom Hole versus Top Hole as well as some of the work performed to investigate it are discussed in **Appendix D**.

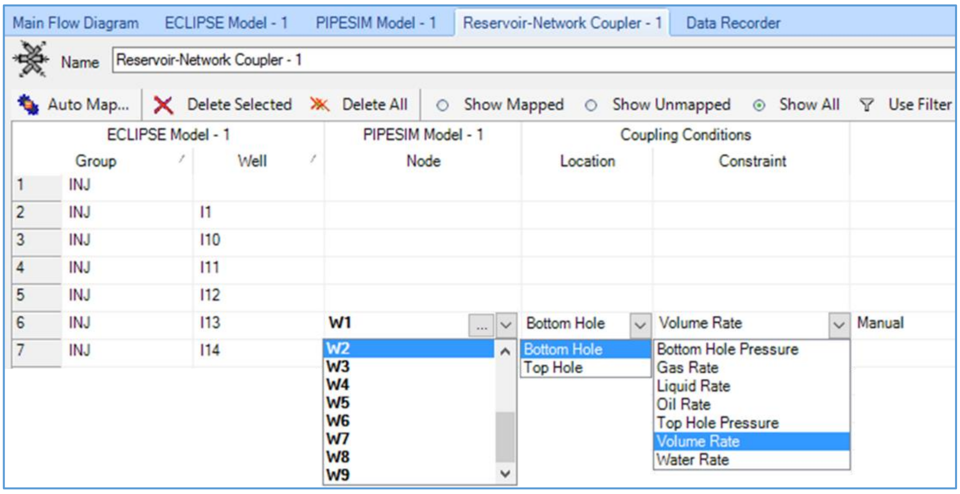

Figure 33. Reservoir – Network coupling configuration setup window

The mapping or connecting wells in ECLIPSE to nodes in PIPESIM can be also performed automatically if their respective titles is the same. Therefore, it is recommended to name the wells in reservoir simulation and production network models with the same titles to save the time during mapping if they contain a large number of wells.

<u>Data reporting</u>

The ***Data Recorder*** section is used to report the data of interest. The required output can be recorded both in the form of tables and plots by selecting the required data set from the Model

Browser and dragging to Datasets or Graphs as shown on ***Figure 34***. It is possible to build graphs with two sets of data on the *y*-axis and only time variable on the *x*-axis.

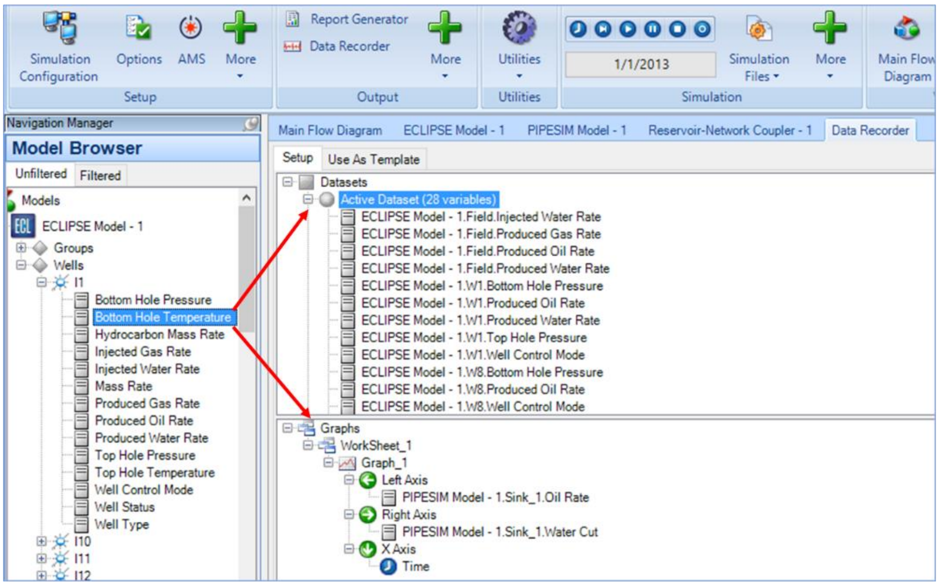

Figure 34. Data Recorder access window in AVOCET

In order to run the simulation the  icon in the ***Home*** quick access bar should be clicked and Time Controller window will open. This control window is used to set up the frequency of simulation data output. It can be changed by clicking on the Step Interval drop-down tab and choosing a suitable value. The simulation is ready to run and it can be launched by clicking the  icon.

Appendix D. Study on bottom-hole and wellhead coupling

Appendix D describes the two different coupling location alternatives for coupling of reservoir and production models in AVOCET and their subsequent effect on the simulation runtime and accuracy of the results. It is important to highlight some of the theory behind each of the coupling location and their respective benefits as well as disadvantages, which is performed in this chapter.

One can use a PIPESIM or an ECLIPSE model to simulate the vertical flow performance (VFP) or so-called tubing tables in the wellbore. If ECLIPSE is chosen to do this, then **Top Hole** has to be selected as the coupling location, while if VFP is modeled with PIPESIM, **Bottom Hole** would be the coupling position. There is also a **Group Coupling** option available in AVOCET, which was not implemented in the current work, because it did not quite fit for the purpose of the analysis. However, a brief note about a possible application of **Group Coupling** is provided at the end of this chapter.

<u>Bottom hole coupling</u>

This type of coupling assumes that a reservoir simulation model is connected to the production network at the bottom hole locations of the wells. This option allows modeling of wells' vertical flow performance in PIPESIM.

Setup can be started by inputting the well configuration into PIPESIM model.

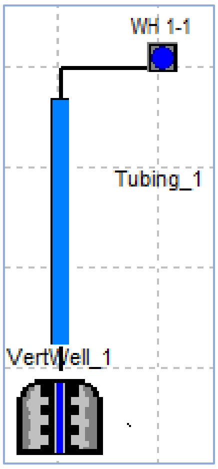

Figure 35. Well configuration for "bottom hole coupling" in PIPESIM

Figure 35 shows the well configuration in PIPESIM for bottom hole coupling with a reservoir simulation model. The *Vertical Completion* is connected to the tubing on the figure. It is important to include the reservoir interval either in the form of vertical or horizontal completion. The reservoir and fluid specification data, such as well PI, static pressure and temperature, GOR etc., will be dismissed during coupled simulation runs. Therefore, it will not matter if the reservoir completion interval is specified as horizontal or vertical. The only purpose for inputting a reservoir interval in the PIPESIM model is having a connection point with the reservoir model. Therefore, it is recommended to use Vertical Completion in PIPESIM models for coupled runs as it needs less data input for the reservoir specification.

It is also crucial to have exactly the same TVD (true vertical depth) in the production string in the PIPESIM model and BHP depth in WELSPECS (Well specification data) section of the ECLIPSE reservoir simulation filed. ***Figure 36*** demonstrates the location of the corresponding depth data inputs in PIPESIM and ECLIPSE that have to be exactly the same. In this analysis, all the wells are assumed to be identical in terms of well deviation survey and production string configuration.

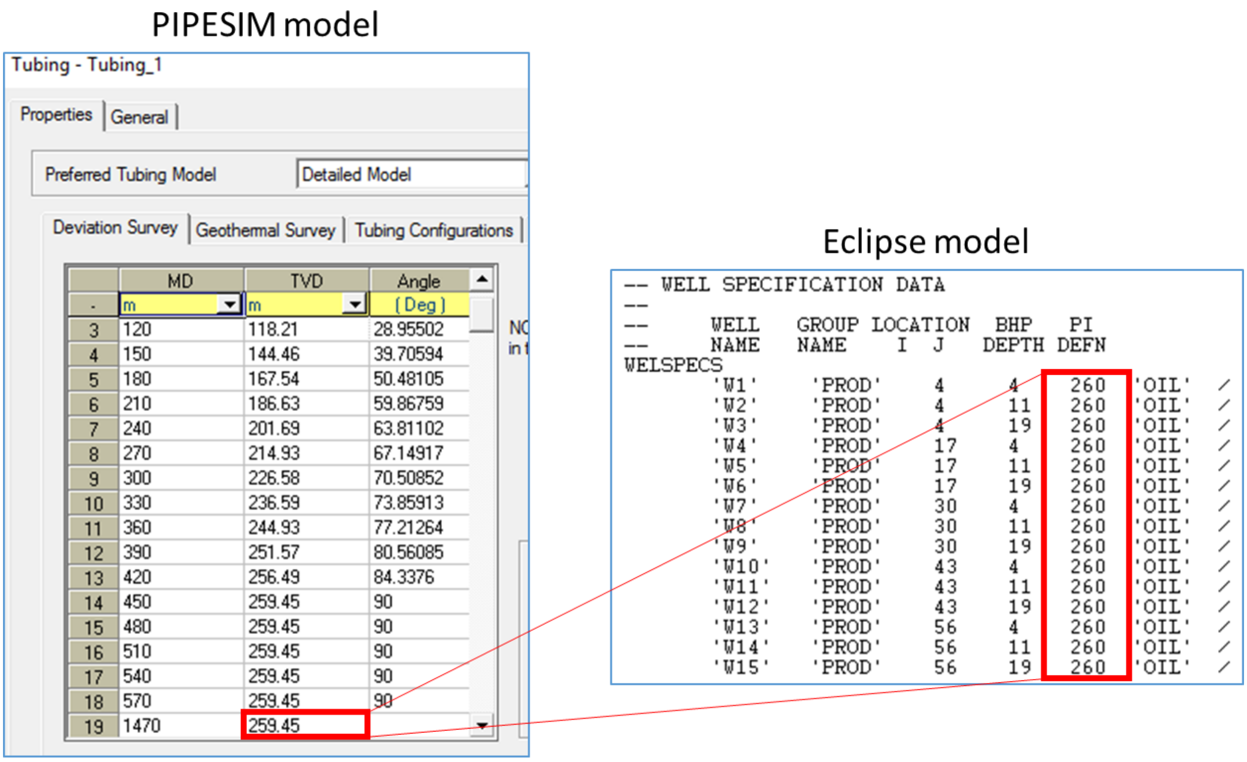

Figure 36. The final TVD depth in the PIPESIM model and BHP depth in ECLIPSE have to be equal

The ECLIPSE model should also contain the minimum bottom hole pressure constraint. The wells in the model will produce at their maximum capacity until the minimum allowed bottom hole pressure is reached.

```
WCONPROD
     'W1'    'OPEN' 'GRUP'  5*   40 /
     'W2'    'OPEN' 'GRUP'  5*   40 /
     'W3'    'OPEN' 'GRUP'  5*   40 /
     'W4'    'OPEN' 'GRUP'  5*   40 /
     'W5'    'OPEN' 'GRUP'  5*   40 /
     'W6'    'OPEN' 'GRUP'  5*   40 /
     'W7'    'OPEN' 'GRUP'  5*   40 /
     'W8'    'OPEN' 'GRUP'  5*   40 /
     'W9'    'OPEN' 'GRUP'  5*   40 /
     'W10'   'OPEN' 'GRUP'  5*   40 /
     'W11'   'OPEN' 'GRUP'  5*   40 /
     'W12'   'OPEN' 'GRUP'  5*   40 /
     'W13'   'OPEN' 'GRUP'  5*   40 /
     'W14'   'OPEN' 'GRUP'  5*   40 /
     'W15'   'OPEN' 'GRUP'  5*   40 /
```

Figure 37. WCONPROD section with minimum BHP constraint in the ECLIPSE reservoir simulation model

WCONPROD keyword with the corresponding input in ECLIPSE allows selecting the well control method and specifying the production constraints as shown on ***Figure 37***.

In AVOCET, the *Bottom Hole* coupling location and *Volume Rate* have to be selected as the coupling conditions in the ***Reservoir-Network Coupler*** window.

Wellhead coupling

The idea behind **Top Hole** or wellhead coupling is that ECLIPSE model contains VFP tables describing the pressure loss in the tubing. Wellhead coupling can be advantageous because it allows to produce more accurate prediction of group production rates as it is handled internally by ECLIPSE. The accuracy also depends on the fact if the tables contain the whole range of producing conditions through the entire life of the well, such as GOR, water-cut etc. Otherwise, an extrapolation may occur during simulation runs, which would in turn lead to erratic well behavior and convergence issues in the network balancing process. Furthermore, there is an assumption that some fluid properties (such as density, viscosity etc.) remain more or less constant throughout the well life. If these properties change significantly, the accuracy of VFP tables can be compromised (Avocet, 2014).

The first thing to do to set up wellhead coupling is to generate VFP tables. In order to produce them, PETEX PROSPER well modeling software is used. The well configuration and fluid properties have to be filled in the required fields in PROSPER before switching to the sensitivity section. In there, the possible range of operating conditions are entered and the corresponding tables can be generated. The file should then be saved in the format that can be used in ECLIPSE reservoir model. It is recommended to store the VFP file in the same folder with the reservoir simulation and production network files.

Afterwards, some additional keywords have to be added to the reservoir simulation file so that the tables can be used by ECLIPSE. WCONPROD part of Schedule section of the ECLIPSE reservoir simulation file will look different compared to the reservoir model with bottom hole pressure constraint.

```
WCONPROD
     'W1'    'SHUT' 'GRUP'  6*   10    1 /
     'W2'    'SHUT' 'GRUP'  6*   10    1 /
     'W3'    'SHUT' 'GRUP'  6*   10    1 /
     'W4'    'SHUT' 'GRUP'  6*   10    1 /
     'W5'    'SHUT' 'GRUP'  6*   10    1 /
     'W6'    'SHUT' 'GRUP'  6*   10    1 /
     'W7'    'SHUT' 'GRUP'  6*   10    1 /
     'W8'    'SHUT' 'GRUP'  6*   10    1 /
     'W9'    'SHUT' 'GRUP'  6*   10    1 /
     'W10'   'SHUT' 'GRUP'  6*   10    1 /
     'W11'   'SHUT' 'GRUP'  6*   10    1 /
     'W12'   'SHUT' 'GRUP'  6*   10    1 /
     'W13'   'SHUT' 'GRUP'  6*   10    1 /
     'W14'   'SHUT' 'GRUP'  6*   10    1 /
     'W15'   'SHUT' 'GRUP'  6*   10    1 /
```

Figure 38. WCONPROD section with minimum THP constraint in the ECLIPSE reservoir simulation model

The 10th column on ***Figure 38*** is the minimum operating Tubing Head Pressure or THP that is allowed to be reached during production operations. If the well produces at the maximum capacity and wellhead pressure drops below the value of the tubing head pressure in WCONPROD, the simulator will automatically lower the fluid production rate to meet this operational constraint. The last column contains the number of the VFP table used in the simulation. It comes from the first column in the VFPPROD section of the tubing table generated by PROSPER. One more addition compared to the reservoir model with a well bottom hole constraint is that there is one more keyword added to the file:

VFPPDIMS

20 7 10 9 /

Where the columns represent the following (from left to right; according to AVOCET 2015.1 manual):

1 – The maximum number of flow values per table

2 – The maximum number of tubing head pressure values per table

3 – The maximum number of water fraction values per table

4 – The maximum number of gas fraction values per table

5 – The maximum number of Artificial Lift Quantities per table (DEFAULT: 1)

6 – The maximum number of production well VFP tables (DEFAULT: 1)

These values can then be extracted from the generated VFP table as shown below:

```
-- LIQ units - sm3/day  ( 20 values )
     6.4    340.5    674.6   1008.7   1342.8
  1676.9   2011.0   2345.1   2679.2   3013.3
  3347.4   3681.5   4015.7   4349.8   4683.9
  5018.0   5352.1   5686.2   6020.3   6354.4 /

-- THP units - Barsa  ( 7 values )
   10.00    20.00    30.00    40.00    50.00
   60.00    70.00 /

-- WCT units - sm3/sm3  ( 10 values )
       0      0.1      0.2      0.3      0.4
     0.5      0.6      0.7      0.8      0.9 /

-- GOR units - sm3/sm3  ( 9 values )
      40      100      200      300      400
     500      600      700      800 /
```

Figure 39. The corresponding values to use with VFPPDIMS keyword

The last two columns were skipped as there was only one artificial lift to be tested and one VFP table in the model.

The PIPESIM model will also be different to the one used for bottom hole coupling. Wells in the network with bottom hole coupling have their tubing configuration specified, but in wellhead coupling, there is no tubing specified in PIPESIM as the pressure drop in the production string is simulated in ECLIPSE.

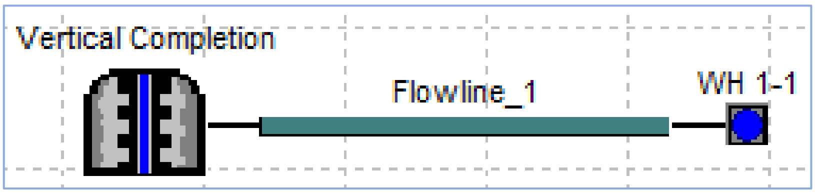

Figure 40. Well configuration for "wellhead coupling" in PIPESIM

Figure 40 shows the well configuration for running integrated simulations with wellhead coupling. The difference with integrated models coupled at the bottom hole is that the tubing is not specified. The reservoir section or vertical completion (as it appears on the figure) still has to be added to the system. The flowline should be connected to the Vertical Completion. The required numbers in the vertical completion configuration can be filled with random values as they will be overwritten during integrated simulation runs. Even though production wells in Wisting oil field are completed horizontally the completed intervals are specified as vertical in PIPESIM. This is because during coupled simulation runs AVOCET ignores all the reservoir as well as fluid data in PIPESIM and uses the values extracted from the ECLIPSE reservoir model.

There is also one more minor change in this PIPESIM model compared to the bottom hole coupling case. As the tubing is missing the wellhead has to be connected to the reservoir completion interval directly in the PIPESIM production network. It is not possible to do it with a standard *Connector* in PIPESIM. The wellhead, which represents a Boundary Node, has to be "physically" connected to the reservoir interval with a flowline. Otherwise, the coupled simulation will not be possible. In order to solve this problem and at the same time make this wellhead coupled model comparable to the bottom hole case, a short (= 1 m) flowline is added to connect the reservoir interval with the wellhead node (***Figure 40***). The flowline has the same properties (ID, roughness etc.) as the production tubing. During a coupled simulation run, AVOCET will ignore the reservoir data in PIPESIM and transfer the boundary conditions from ECLIPSE to PIPESIM at the entrance of the Flowline_1. The addition of a one meter horizontal flowline should not add much additional pressure drop to the system. This last step is recommended to perform for wellhead coupling. There is no available literature on what changes have to be made to the production network in PIPESIM to perform top hole coupling with AVOCET. Therefore, the trial-and-error method of discovering this procedure took much time and effort.

<u>Comparison</u>

Numerous integrated simulation cases with different coupling locations (wellhead vs bottom hole) have been run to test the performance and the accuracy of the results. At the very beginning, the main goal was to make the simulations run as fast as possible due to the number of coupled simulations to be analyzed.

In general, the models coupled at the top hole took less time to complete. The required time to complete a run was between 10 to 40 minutes. However, the top hole coupled simulations showed an unstable performance. Some of the runs could just not be launched for unknown reasons. The simulations would also sometimes abandon and stop running in the middle of the runs. A possible solution in the form of increasing the range of WC, GOR and THP values used to generate tubing VFP tables in PROSPER was applied. However, it did not yield considerable improvements. The problematic runs would still abandon at the same time steps and stop producing results. One more issue with top hole coupling was that the simulations would slow down considerably when the water breakthrough occurred. The same was true for the gas breakthrough process. Therefore, an attempt was made to change the multiphase flow calculator for pressure drop in PIPESIM models. In the models ran until that point ***No Slip Assumption*** had been used. The models did not initialize and abandon almost immediately after launching when an attempt was made to run the models with different multiphase flow correlations (such as Beggs & Brill and Duns & Ros).

In general, integrated models coupled at the bottom hole took slightly more time to complete (8-12 minutes longer), but they showed more stability. Considerably fewer cases compared to wellhead coupled models did not initialize from the very beginning or stop running during simulations.

In a real field scenario, the engineers usually use the wellhead constraint to control well production operations. Even though, analysis of top hole coupled models would seem more realistic to proceed with it was unrealistic to run all the required cases with this type of coupling. (There were 81 coupled models to run. It is discussed further in the report.) Considering the scope of work, it was decided to proceed with bottom hole coupling as it showed more stability and allowed to launch and complete more cases compared to wellhead coupled models.

However, it is recommended to use top hole coupled models if the scope of work does not require running a large number of coupled simulations as it would simulate the real field producing conditions more accurately.

The location of the choke in the coupled models plays a crucial role, because it is an element of control. If the coupling point is the wellhead, then it is very easy to calculate choke opening to provide the desired rate. If the coupling is made at the bottom hole, the choke opening has to be estimated by running the network solver multiple times and this is why it takes more time.

The table below adapted from AVOCET 2014.1 manual summarizes the advantages and disadvantages of each coupling location discussed above. It also provides a brief description of **Group Coupling** method, which was not applied in the current analysis.

Table 33. Summary of the different coupling locations available in AVOCET

*Table adapted from AVOCET 2014.1 manual

Location	Advantages	Disadvantages
Bottom hole	-More accurate well modelling (full pressure traverse calculations) -Flow assurance (detailed heat transfer and compositional effects)	-Pressure discontinuity at bottom hole for ECLIPSE internal group rate control -Unstable regions on well curves could cause convergence issues -More computing power is needed for solving an extra branch per well
Top hole	-Needs relatively few computing resources due to fewer branches in network model and wellbore lookup in reservoir -Unstable regions on well curves are “smoothed” in reservoir VLP curve -Pressure is matched at a point where a wellhead choke would be located in reality -More accurate rate allocation per well for ECLIPSE internal group control	-Loss of resolution in the wellbore calculation (less accurate than bottom hole coupling) -Currently not compatible with certain network balancing schemes
Group	-A large production network can be substantially decreased in size. E.g., if 20 wells produce into the same manifold, it is possible, by using group coupling, to eliminate all those wells from the network simulation.	-Loss of resolution in the production network simulation

Appendix E. Study on tight and loose coupling schemes

In order to run coupled (or integrated) simulations the reservoir model has to be connected to the production model. There has to be a way of communication between the surface and sub-surface models. There are different levels of coupling, all of which can affect both the speed of simulation runs and the accuracy. This section describes some of theory and AVOCET setup of the two (tight and loose) available coupling options in AVOCET.

Tight coupling

The concept of tight coupling can be explained with an example shown on ***Figure 41***. In this example the system is balanced with the chosen network-balancing scheme, which can be obeying ECLIPSE limits, fast PI, full IPR etc. In the figure, N_i represents the number of Newton iterations, whereas T_j is the time step. At T_0, ECLIPSE starts performing a network balance. This is repeated until the NUPCOL iterations limit prescribed in the ECLIPSE reservoir simulation file is reached (N_2 in this case). It might be necessary to perform additional iterations to assure full convergence of the reservoir (N_3, N_4). At the end of the current time step, the updated constant well target rates are passed on to the next time steps (t1, t2), during which ECLIPSE calculates the rates without considering the effect of the production network (Avocet, 2014).

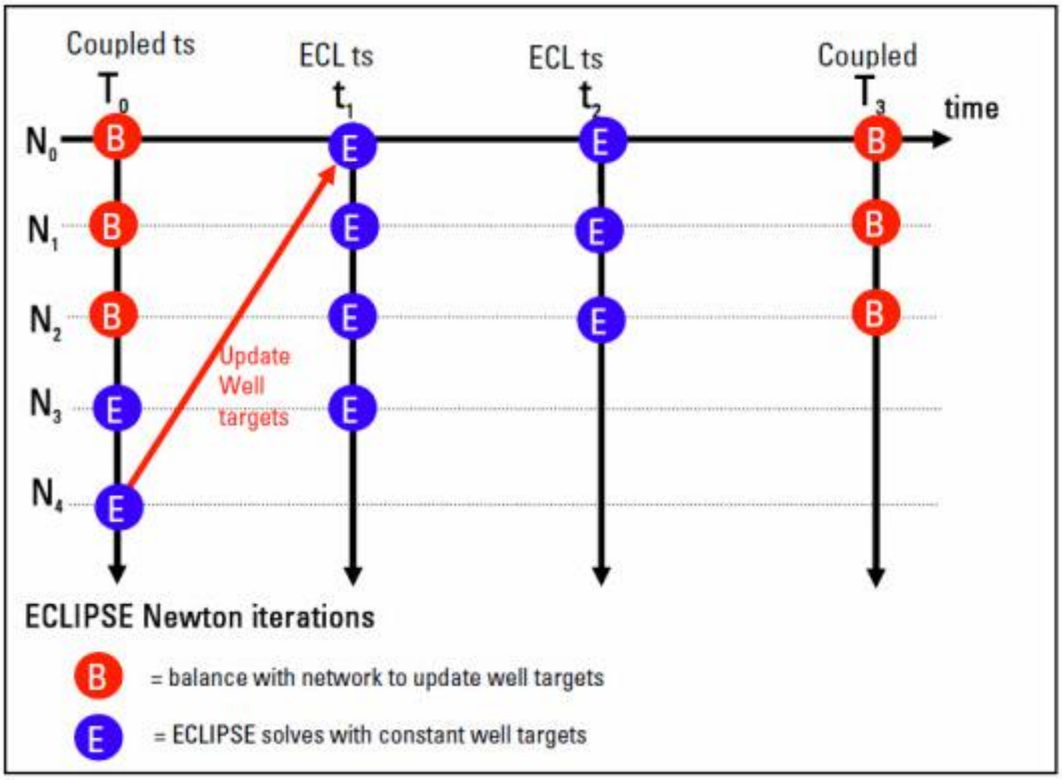

Figure 41. Tight coupling network balancing scheme

*Figure copied from AVOCET 2014.1 manual

In order to set up the tight coupling in AVOCET ***Options*** tab in AVOCET **Home** window has to be accessed. Then, in the **Network-Balancing** scheme *Convergence* has to be selected as shown on ***Figure 42***.

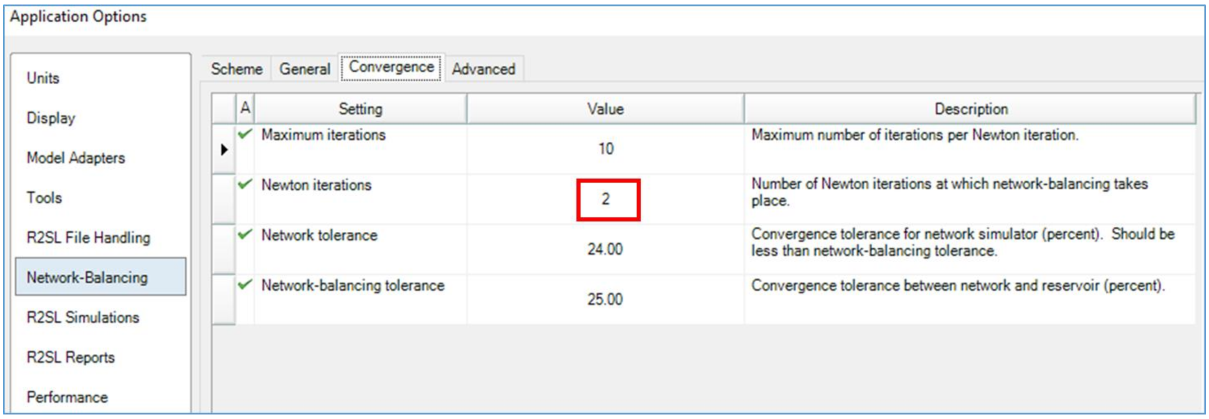

Figure 42. Network-Balancing Convergence tab configuration for tight coupling in AVOCET

As long as the number of Newton iterations is set to a number greater than zero the coupling is considered to be tight.

Loose coupling

Loose coupling can be considered as a type of tight coupling but with NUPCOL iterations number set to zero. This kind of a system assumes a single reservoir-network balance iteration at the beginning of the time step. As a solution is determined, the ECLIPSE model completes the time step without additional interaction with the production network. This scheme is the only available solution for integrating several reservoirs, as they may require a different number of Newton iterations to complete the same time step.

An example of loose coupling is shown on ***Figure 43***. At the beginning of the time step, ECLIPSE runs and solves the reservoir model and performs a reservoir-network balance. The coupled solution is then used for the rest of the Newton iterations as well as following standalone ECLIPSE time steps.

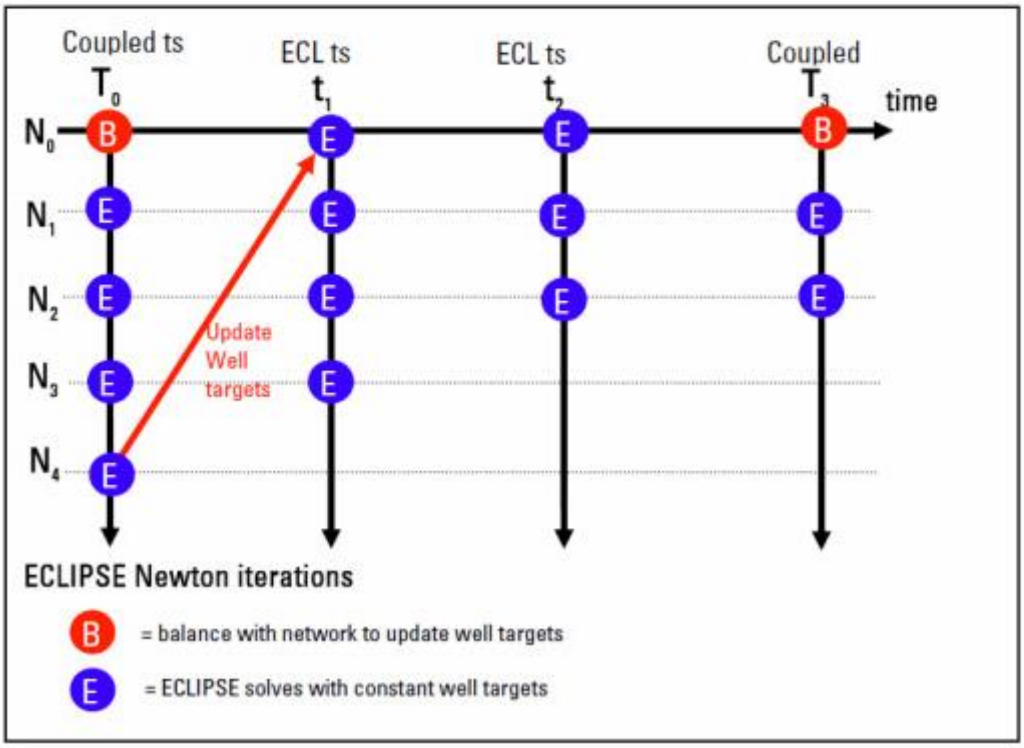

Figure 43. Loose coupling network balancing scheme

*Figure copied from AVOCET 2014.1 manual

The number of Newton iterations in the **Network-Balancing** has to be set to zero to implement the tight coupling scheme (***Figure 44***).

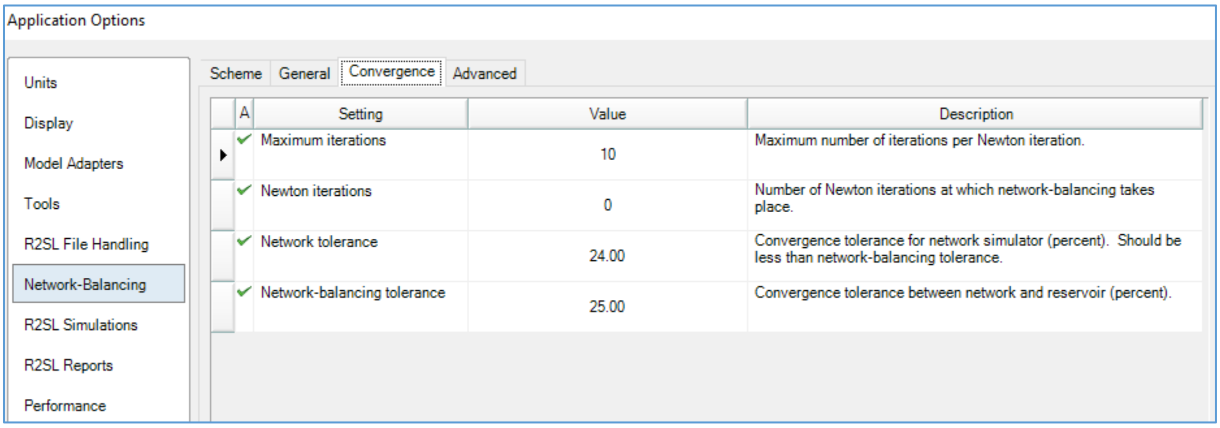

Figure 44. Network-Balancing Convergence tab configuration for loose coupling in AVOCET

Comparison

Advantages and disadvantages of each coupling scheme are shown in ***Table 34***.

Table 34. Summary of two types of coupling schemes

*Table adapted from AVOCET 2014.1 manual

Method	Advantages	Disadvantages
Tight coupling	The reservoir and the network are balanced at the end of each time step as a result of coupling at the Newton level. During the coupling process, the effect of the network is modelled in the reservoir. This is especially important if the well interaction has a big effect on reservoir performance.	A high number of network-balancing iterations is needed. E.g., for a reservoir and network to be balanced at 3 Newtons and 5 iterations for each balancing process, the network will be solved a total of 15 times. This could require an unacceptably large amount of computational resources depending on the size of the network.
Loose coupling	The simulations are faster and require fewer computational resources	At the end of a time step, balancing process can be less accurate compared to tight coupling.

Considering the fact that a total 81 number of coupled models (discussed further in the report) had to be run a decision was made to proceed with Loose Coupling. The results produced by both schemes did not display a substantial difference (5 - 8 %). This is because the changes in the reservoir model do not happen very quickly. For example, the water cut does not increase substantially from 0 to 50 per cent within one year. The areas with some difference in the output happened at the time intervals, when either water or gas breakthrough occurred. Apart from this, the fluid rates and pressures showed good similarity. Therefore, using loose coupling was selected as a preferred method as it would require less computational power (can be run on a personal computer) and time to complete the simulations.

Appendix F. Economics

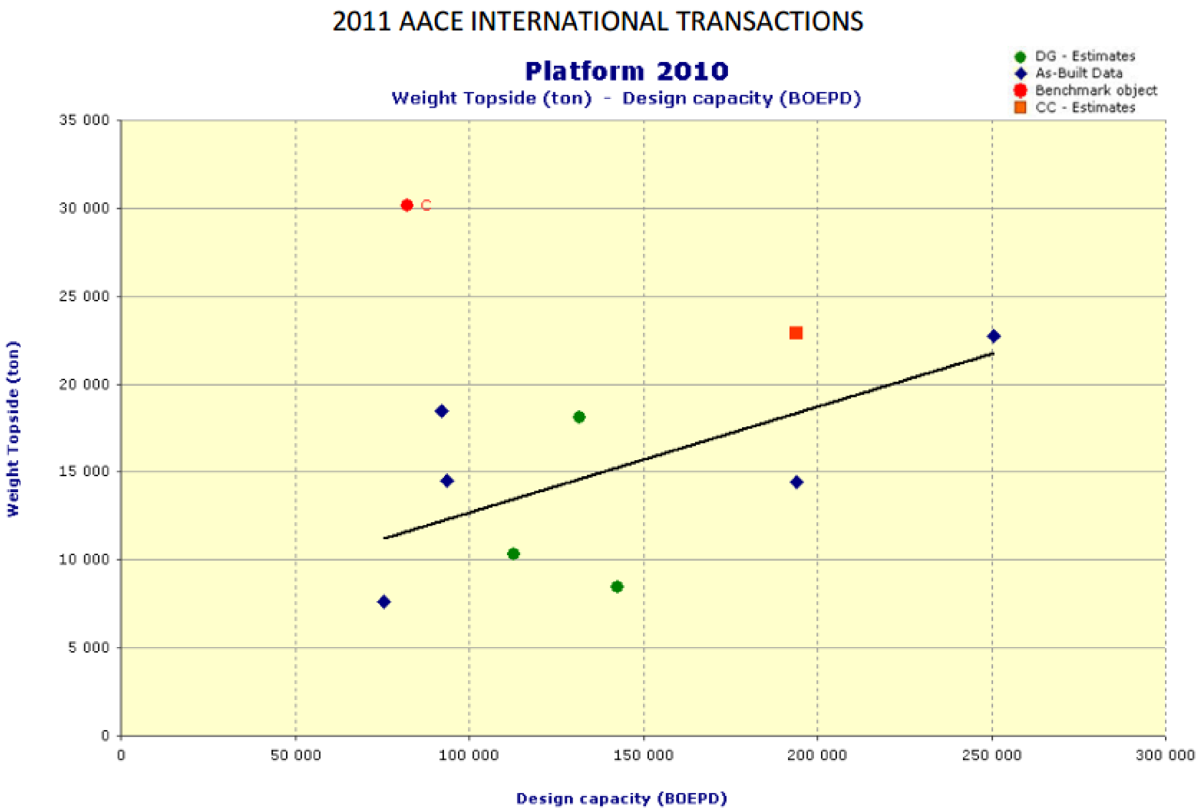

Figure 45. Topside weight vs design capacity

*Copied from (AACE International, 2011)

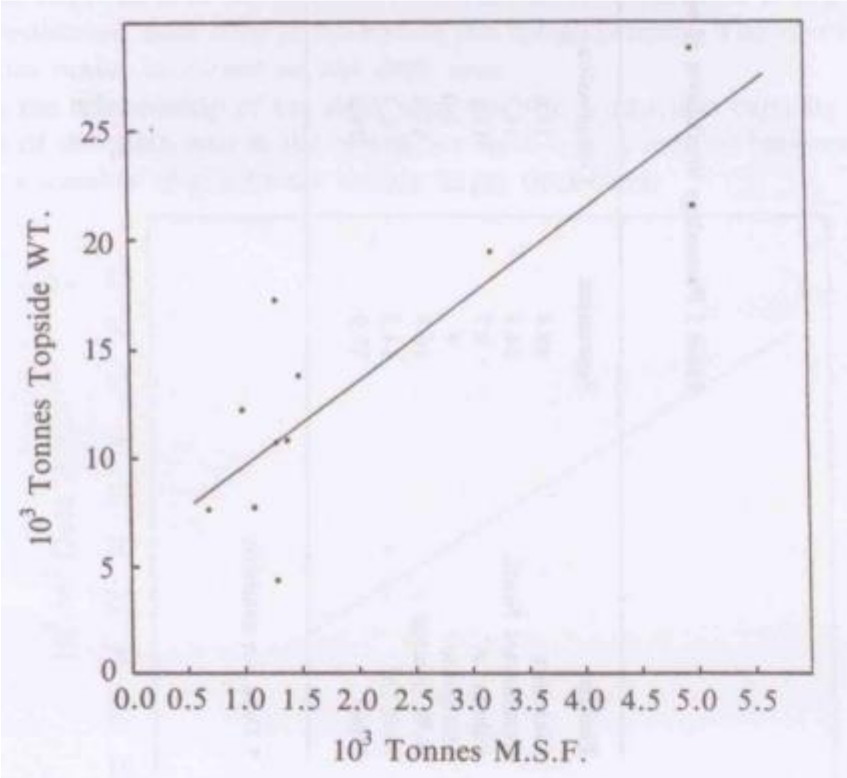

Figure 46. Topside weight vs supporting structure weight

*Copied from (Mainal, 1990)

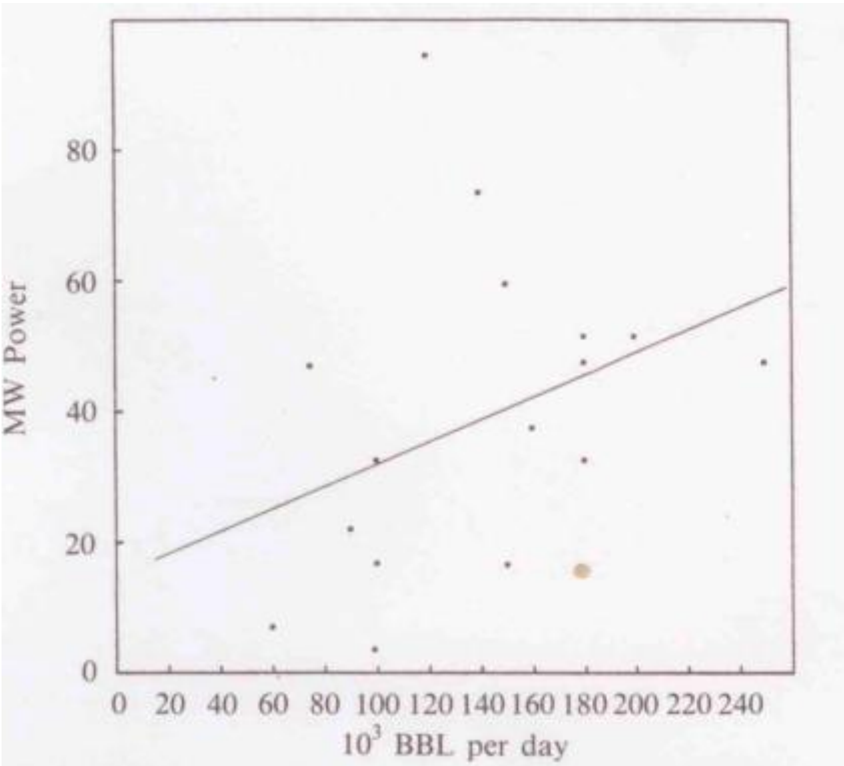

Figure 47. Platform power consumption vs oil production capacity

*Copied from (Mainal, 1990)

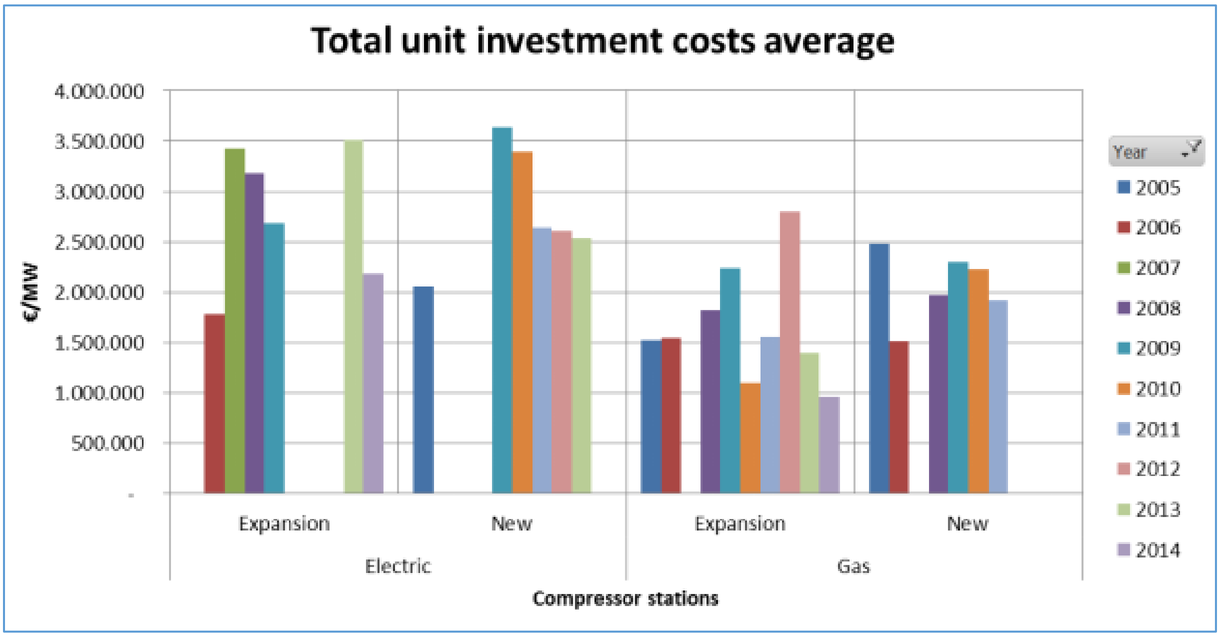

Figure 48. Indexed unit investment costs compressor stations, evolution 2005-2014 by ranges of power and technology (annual average, €/MW)

*Copied from (ACER, 2015)

Date	Time	qoil	Np	Gp	Revenues	CAPEX	OPEX	Total cost	Cash flow	Discounted cash flow	NPV
[d-mmm-yy]	[years]	[stb/d]	[stb/year]	[scf/year]	[USD/year]	[USD]	[USD]	[USD]	[USD]	[USD]	[USD]
1-Jan-18	0	0	0		0.00E+00	8.41E+08	0.00E+00	8.41E+08	-8.41E+08	-8.41E+08	-8.41E+08
1-Jan-19	1	0	0		0.00E+00	8.41E+08	0.00E+00	8.41E+08	-8.41E+08	-7.79E+08	-1.62E+09
1-Jan-20	2	80000	2.84E+07		1.42E+09		2.32E+08	2.32E+08	1.19E+09	1.02E+09	-6.01E+08
1-Jan-21	3	80000	2.84E+07		1.42E+09		2.43E+08	2.43E+08	1.18E+09	9.34E+08	3.33E+08
1-Jan-22	4	80000	2.84E+07		1.42E+09		2.55E+08	2.55E+08	1.16E+09	8.56E+08	1.19E+09
1-Jan-23	5	80000	2.84E+07		1.42E+09		2.68E+08	2.68E+08	1.15E+09	7.84E+08	1.97E+09
1-Jan-24	6	80000	2.84E+07		1.42E+09		2.81E+08	2.81E+08	1.14E+09	7.17E+08	2.69E+09
1-Jan-25	7	53839	1.91E+07		9.56E+08		2.95E+08	2.95E+08	6.60E+08	3.85E+08	3.08E+09
1-Jan-26	8	38370	1.36E+07		6.81E+08		3.10E+08	3.10E+08	3.71E+08	2.00E+08	3.28E+09
1-Jan-27	9	39566	1.40E+07		7.02E+08		3.26E+08	3.26E+08	3.77E+08	1.88E+08	3.46E+09
1-Jan-28	10	36685	1.30E+07		6.51E+08		3.42E+08	3.42E+08	3.09E+08	1.43E+08	3.61E+09
1-Jan-29	11	33494	1.19E+07		5.95E+08		3.59E+08	3.59E+08	2.35E+08	1.01E+08	3.71E+09
1-Jan-30	12	29833	1.06E+07		5.30E+08		3.77E+08	3.77E+08	1.52E+08	6.05E+07	3.77E+09
1-Jan-31	13	29833	1.06E+07		5.30E+08		3.96E+08	3.96E+08	1.34E+08	4.91E+07	3.82E+09
1-Jan-32	14	29833	1.06E+07		5.30E+08		4.16E+08	4.16E+08	1.14E+08	3.87E+07	3.86E+09
1-Jan-33	15	24584	8.73E+06		4.36E+08		4.37E+08	4.37E+08	-2.04E+05	-6.42E+04	3.86E+09
1-Jan-34	16	23299	8.27E+06		4.14E+08		4.58E+08	4.58E+08	-4.48E+07	-1.31E+07	3.84E+09
1-Jan-35	17	23299	8.27E+06		4.14E+08		4.81E+08	4.81E+08	-6.78E+07	-1.83E+07	3.83E+09
1-Jan-36	18	19625	6.97E+06		3.48E+08		5.05E+08	5.05E+08	-1.57E+08	-3.93E+07	3.79E+09
1-Jan-37	19	19625	6.97E+06		3.48E+08		5.31E+08	5.31E+08	-1.82E+08	-4.22E+07	3.74E+09
1-Jan-38	20	19292	6.85E+06		3.42E+08		5.57E+08	5.57E+08	-2.15E+08	-4.61E+07	3.70E+09
1-Jan-39	21	18962	6.73E+06		3.37E+08		5.85E+08	5.85E+08	-2.48E+08	-4.94E+07	3.65E+09
1-Jan-40	22	18338	6.51E+06		3.25E+08		6.14E+08	6.14E+08	-2.89E+08	-5.31E+07	3.60E+09
1-Jan-41	23	16736	5.94E+06		2.97E+08		6.45E+08	6.45E+08	-3.48E+08	-5.93E+07	3.54E+09
1-Jan-42	24	15709	5.58E+06		2.79E+08		6.77E+08	6.77E+08	-3.98E+08	-6.28E+07	3.47E+09
1-Jan-43	25	15198	5.40E+06		2.70E+08		7.11E+08	7.11E+08	-4.41E+08	-6.44E+07	3.41E+09
1-Jan-44	26	14977	5.32E+06		2.66E+08		7.47E+08	7.47E+08	-4.81E+08	-6.50E+07	3.34E+09
1-Jan-45	27	13798	4.90E+06		2.45E+08		7.84E+08	7.84E+08	-5.39E+08	-6.75E+07	3.28E+09
1-Jan-46	28	13798	4.90E+06		2.45E+08		8.23E+08	8.23E+08	-5.78E+08	-6.70E+07	3.21E+09

Figure 49. NPV calculation spreadsheet