Master's thesis

NTNU
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The effects of subsurface uncertainty on economic risk when developing the Mackerel satellite field in the North Sea

Master's thesis in MTPETR
Supervisor: Harald Arne Asheim
September 2019

NTNU
Kunnskap for en bedre verden

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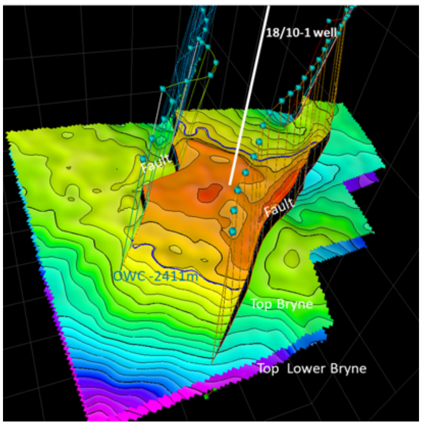

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Preface

This thesis is the concluding work of a Master of Science degree at the Department of Geoscience and Petroleum at NTNU, Trondheim.

I wish to thank my supervisor, Prof. Harald Arne Asheim, for the valuable guidance and support he has provided me with during the final year of my studies.

I wish to extend my thanks to Mr Sveinung Langvik, Senior Development Engineer at Repsol, who provided assistance in formulating the objective of this study. I also wish to thank Mr Raul Rodriguez Cano, Reservoir Engineer, for his support in guiding the construction of the model and for his time and patience in showing me how to operate the Petroleum Experts software. For this effort I am very grateful. I also want to acknowledge the assistence I received from Mrs Stacy Scott and Mr Sven Gundersen in the subsurface team, for their valuable knowledge and input towards the modelling.

Finally, I would like to thank the company, Repsol Norge AS, for providing me with this opportunity to work in collaboration with their employees on one of their exciting projects. The views expressed in this study are those of the author only and do not neccessarily reflect the views of Repsol Norge AS or its employees.

Alexander Taranger King

Abstract

This study investigates the effect of subsurface uncertainty within a small North Sea oil reservoir on the economic attractiveness of development as measured by production and reserve recovery, and ultimately by the Net Present Value (NPV) and Internal Rate of Return (IRR).

Two factors of uncertainty are considered in this study; the static uncertainty of the initial oil in place and the dynamic uncertainty of reservoir connectivity. The compounded uncertainty of reservoir parameters net-to-gross, porosity and oil saturation is calculated by applying Monte Carlo Simulations. A range of three cases representing low (P90), medium (P50) and high (P10) values for initial oil in place is run against a range of three cases of recovery factors; 20%, 30% and 40% to couple the static and dynamic uncertainty for a total of nine subsurface realisations.

A model is constructed using MBAL and PROSPER software to simulate production from the field using limited data and information on the field.

An economic analysis is performed on the nine subsurface realisations to determine the NPV and IRR values for a pre- and post-tax evaluation of economic risk. The economic risk is defined as the deviation of NPV from the most likely realisation defined by the P50/30% recovery factor.

The study finds that the development proposal is positive pre-tax for 8 of 9 investigated realisations, with only 1 realisation yielding a small net negative return on investment. The other realisations yield modest positive returns on investments, hence the development could be considered given the assumptions made. Futher efforts to investigate the economic viability of the project are recommended.

Sammendrag

Denne oppgaven undersøker effekten av usikkerhet i et lite Nordsjøfelt på om det er økonomisk forsvarlig å bygge det ut basert på produksjon, utvinningsgrad og endelig nåverdi (NPV) og internrente (IRR).

To usikkerhetsfaktorer blir betraktet i denne oppgaven: statisk usikkerhet forbundet med opprinnelig oljereserver (IOIP) og dynamisk usikkerhet, som er forbundet med intern kommunikasjonen innad i reservoaret. Kombinert usikkerhet av reservoar parameterne net-to-gross, porøsitet og oljemetning blir beregnet ved bruk av Monte Carlo simuleringer. Et utvalg av tre tilfeller som representerer lave (P90), middels (P50) og høye (P10) forekomster blir forbundet med tre tilfeller av utvinningsgrad; 20%, 30% og 40% som gir totalt ni ulike realisasjoner av hvordan og hvor mye reservoaret kan produsere.

En modell blir satt opp ved bruk av MBAL og PROSPER programvare for å simulere produksjon fra feltet med begrenset tilgang på informasjon og data tilgjengelig på forhånd.

En økonomisk studie blir deretter foretatt på de ni realisasjonene for å fastsette NPV- og IRR-verdier både før og etter skatt. Økonomisk risiko blir undersøkt, der risiko er definert som avvik fra NPV-verdien til realisasjonen som er mest sannsynlig, med P50/30% utvinningsgrad.

Studien fant ut at utbyggingsforslaget er positiv før-skatt i 8 av de 9 undersøkte realisasjonene og at i kun 1 tilfelle er det en liten netto-negativ avkastning på investeringen. I de andre realisasjonene er det mulighet for en beskjeden positiv avkastning, gitt antagelsene som er blitt gjort. Dermed kan dette utbyggingsforslaget potensielt bli vurdert som attraktivt. Videre undersøkelser for å undersøke den økonomiske levedyktigheten av prosjektet anbefales.

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Nomenclature

ABEX	Abandonment Expenditures
CAPEX	Capital Expenditures
COP	Cessation of Production
DCF	Discounted Cashflow
DST	Drill Stem Test
E&P	Exploration and Production
GOR	Gas-Oil-Ratio
GRV	Gross Rock Volume
ID	Inner Diameter
IOIP	Initial Oil In Place
IPR	Inflow Performance Relationship
IRR	Internal Rate of Return
MBAL	Material Balance Program
MBE	Material Balance Equation
MCS	Monte Carlo Simulation

NCS	Norwegian Continental Shelf
NOK	Norwegian Kroner
NPV	Net Present Value
NTG	Net-To-Gross
OPEX	Operational Expenditures
OWC	Oil-Water Contact
P&A	Plugging and Abandonment
PDE	Partial Differential Equations
PO	Produced Oil
PROSPER	Well Modelling Program
PVT	Pressure-Volume-Temperature
RF	Recovery Factor
TVD	True Vertical Depth
USD	United States Dollar
WC	Water Cut

Chapter 1

Introduction

After decades of production, many larger Norwegian oil fields are approaching end-of-life (Kaplan, 2017). Norwegian petroleum production is expected to decrease significantly unless replaced by new production capacity. See Figure 1.1. To keep production at or near current levels, many newer developments of smaller petroleum resources will be required. Successive Norwegian governments have sought to encourage wider exploration efforts, while also incentivising development of existing petroleum discoveries. An important factor as to why many of these discoveries have yet to be developed is due to the fact that they are considered marginal discoveries with many uncertainties that may impact the economic attractiveness for development.

A marginal field refers to an oil or gas field that may not produce a sufficient return on investment to justify development at a given time. Marginal fields are usually smaller accumulations of hydrocarbons with correspondingly shorter production periods compared to larger developed fields, such as Statfjord, Sleipner, Gullfaks, and recently, Johan Sverdrup.

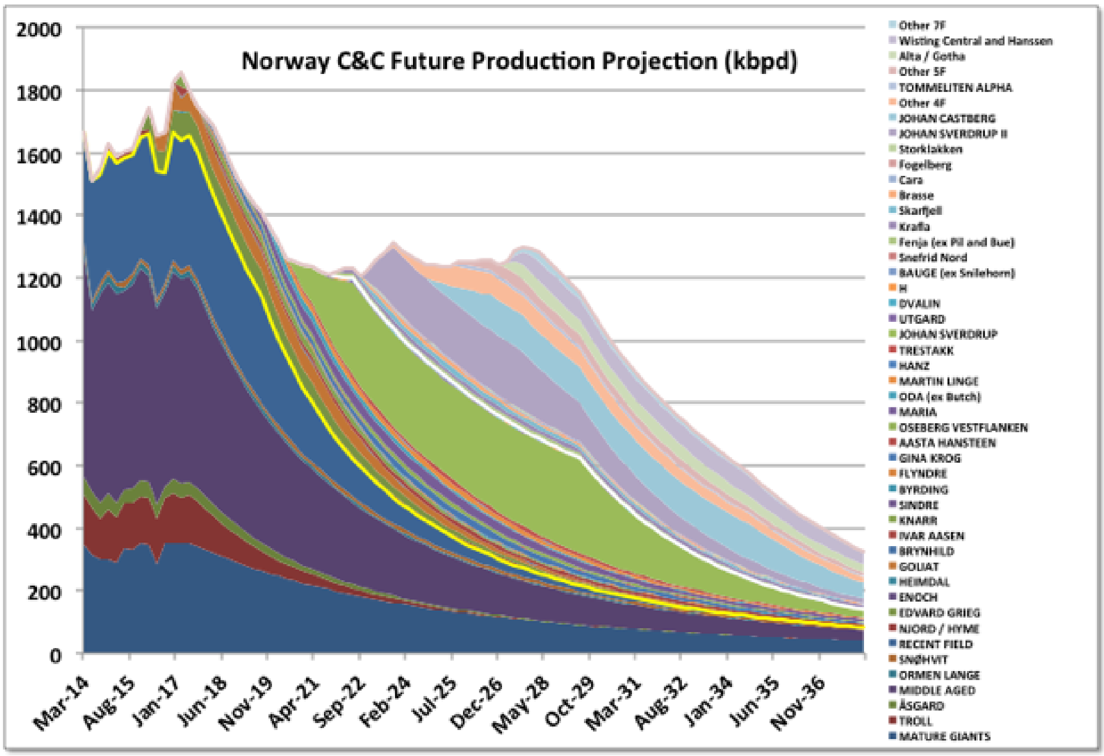

Figure 1.1: Norway future production projection (Kaplan, 2017).

The potential to develop a marginal field will increase given favourable technical and economic conditions. Examples of this can include better geological understanding, robust modelling results, lower costs, use of existing infrastructure, favourable expectations of oil price development and stability, tariff regimes in infrastructure, to name a few.

A major challenge when making the decision to develop marginal fields is managing the risk that the development is not profitable for the investor. This risk is often a consequence of uncertainties in the reservoir itself, because this will directly impact the production rates and recoverable reserves. In smaller oil fields, such subsurface uncertainties can make the difference between a project yielding a sufficient return or failing to meet hurdle rates, which are the ultimate economic test given to developments such as Net Present Value (NPV) or Internal Rate of Return (IRR).

1.1 The Mackerel Discovery

Mackerel is a small oil discovery located in block 18/12 in the southern part of the North Sea. The presence of hydrocarbons at Mackerel was proven by exploration well 18/10-1, which was drilled in an area of 120 m water depth in October 1979 to a true vertical depth (TVD) of 2800 m MD in the Triassic Skagerrak formation. The well encountered oil accumulations in Middle Jurassic sandstones, revealing two oil bearing zones at different pressures. Measurements read that the upper zone is slightly overpressurized in comparison to the lower layer, suggesting a lack of vertical communication within the reservoir. Free gas was not detected, indicating the absence of a reservoir gas cap. The oil has a composition very similar to that of the nearby Vette discovery, which is located 17 km to the north-west of Mackerel.

Figure 1.2: Location of Mackerel and Vette discoveries in the North Sea.

Both the Mackerel and Vette discoveries are part of license PL972 which was awarded by the Norwegian Ministry of Energy in January 2019 to a consortium of companies including Repsol Norge AS (40%), Dyas Norge AS (30%) and M Vest AS (30%). Repsol Norge AS ("Repsol") is operator and in charge of developing the license on behalf of the licence partners. The license partners have entered into an Area of Mutual Interest Agreement (AMI) with the purpose of developing the license. License PL972 covers the adjacent blocks 17/2 and 18/10, which are located in the North Sea approximately 110 km south-west of Egersund and 50 km north-east of the Repsol-operated Yme field.

The application area includes the three confirmed dicoveries; 17/12-1R Vette/Bream (1972), 17/12-2, Brisling (1973) and 18/10-1 Mackerel (1980). The Mackerel discovery consists of a horst, a raised fault block bounded by normal faults, which is part of an extended structure of several adjacent blocks. The hydrocarbon potential of the other blocks has not been confirmed and will require further investigation at a later stage. License PL972, including discoveries and leads can be viewed in Figure 1.3

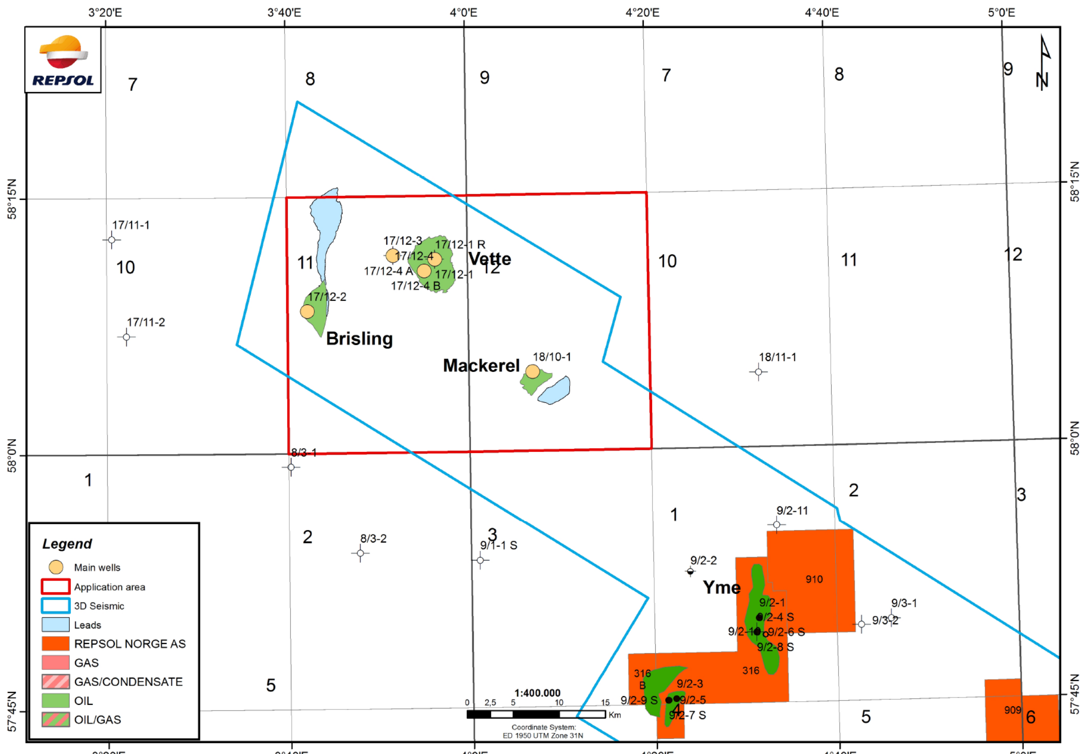

Figure 1.3: Overview of Licence PL972 containing the Mackerel and Vette fields.

Data obtained from exploration well 18/10-1 has been made available. This includes the well log and data from the Drill Stem Test (DST) measurements, which were carried out during the original exploration operations in 1980. The DST data includes well-testing rates, pressure buildup tests, and measurements on the reservoir properties. The vertically drilled exploration well 18/10-1 targeted the centre of the reservoir and the DST was carried out in the upper zone of the reservoir.

1.2 Development Strategy

A new concept for development of the adjacent Vette discovery has been proposed by operator Repsol, which envisions a re-use case of field installations from the Gyda Field. Technology for lifting large platform decks in one single lift is now available using vessels such as Allseas' "Pioneering Spirit", enabling new options for prolonging the usage of existing infrastructure. Cessation of Production (COP) at Gyda took place at the end of Q2, 2019. A two year period of plugging and abandonment (P&A) activity will be carried out before the decommissioning process begins. Both topsides and jacket will be lifted independently and transported onshore for refurbishment and upgrading. The Vette development concept assumes the re-use of the Gyda topside and jacket, with a new subsea storage tank and offloading system for export. Power requirements will be met by a combination of renewable facillities (offshore wind) and natural gas power generation (tubines).

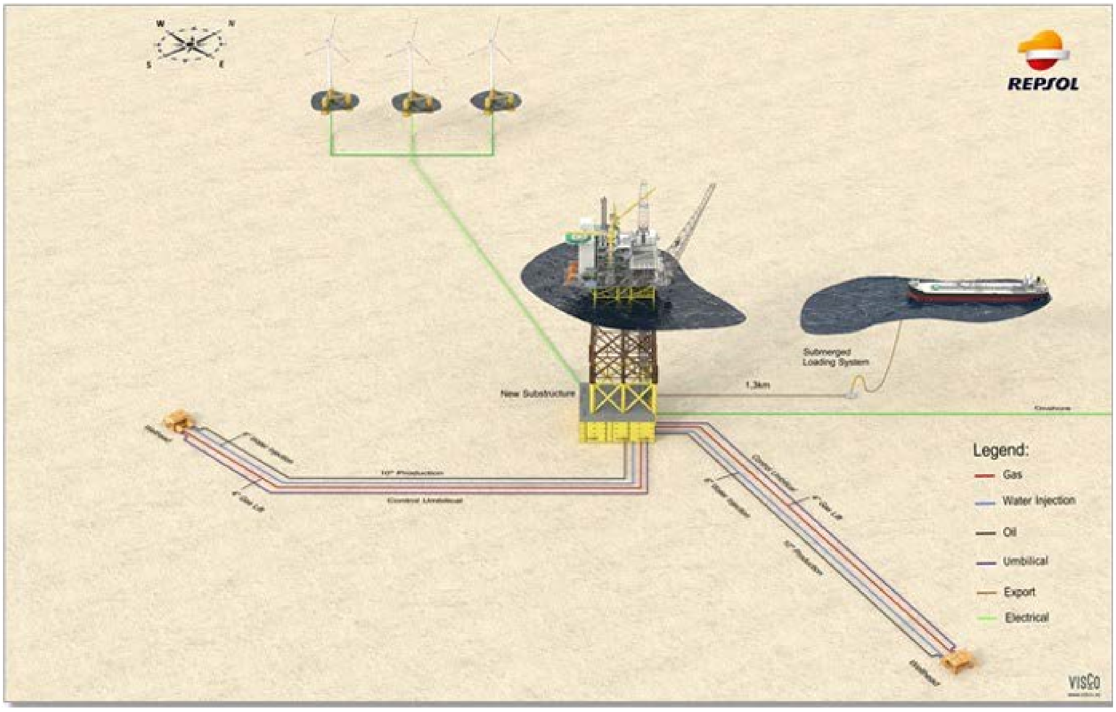

Figure 1.4: Vette new development with Mackerel tie-back

The Gyda topside facilities have a crude oil capacity of 11 000 m^3/d, which exceeds the production volume estimates from Vette alone. The ullage enables development flexibility across the whole licence. The licence partners plan for the Vette installations to act as a hub for further subsea tie-back developments to nearby discoveries and leads. The development of Vette is assumed as a fixed or given precondition for the development of Mackerel, which due to low estimated reserves will have to be developed as a tie-back to installations located at Vette. The inital oil reserves are believed to be relatively small, owing to the limited reservoir area and thin oil column. Any investment decision to develop Mackerel will therefore have to successfully maximise the value of the asset to be able to meet investment hurdles.

Due to the lack of communication between the two oil-bearing zones, it has been proposed to develop the field with two horizontal production wells. Such a small field with limited aquifer support will also require water injection to maintain production rates. The decision to have two producers and one injector is assumed as a given for this study.

1.3 Uncertainty and Risk

Any predevelopment process is designed to maximise asset value and is inherently prone to the possibility of such value not materialising. The potential loss to economic value by failing to go to a development phase represents the risk linked to the project, as incurred E&P costs will be lost.

Risk is inherent in all field development plans. A significant cause of risk is the uncertainty in reservoir characterisation and its effects on production forecasting . An improper management of subsurface uncertainty in the field development plan and facility design process is often a reason for project suboptimisation which can result in the project failing to meet production and economic objectives.

A significant part of any field development planning exercise resides in adequately quantifiying reservoir uncertainty, particularly when information availability is limited due to sparse coverage of the field in the exploration and appraisal phase (Boschee et al., 2013). This uncertainty can be reduced to some extent, but can never be eliminated due to heterogeneous reservoir properties. For marginal fields, accurate appraisal of the project downside becomes crucial, as some development options can carry a substantial probability of a negative a NPV or low IRR's. Project economic viability therefore relies on reservoir risk minimisation. A complete and detailed risk analysis can be applied to identify key contributors to reservoir uncertainty and determine the combined effect and impact on asset economics. The evaluation and quantification of the impact of key subsurface uncertainty factors is compounded by the combinations of development options. This can be represented by a very high number of numerical simulations (Graf, Henrion, Bellavance, Fernandes, et al., 2005), called Monte Carlo Simulation (MCS), will will be discussed in Section 2.2.1

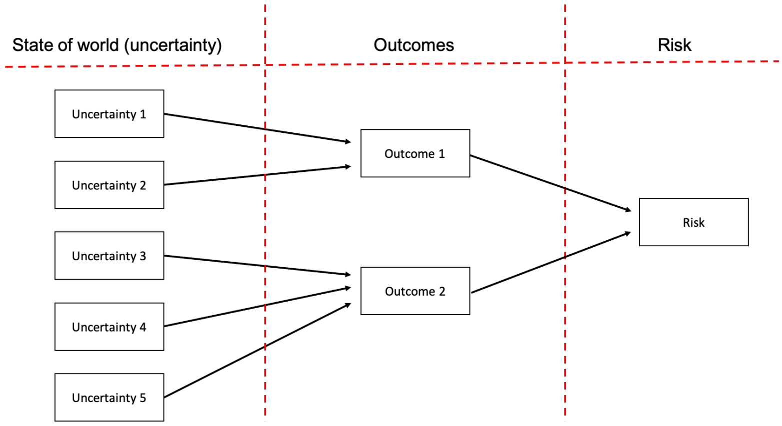

Figure 1.5: Relationship between uncertainty, outcome and risk.

Figure 1.5 illustrates the relationship between uncertainty, which is inherent in the field of petroleum and how combination of different uncertainties may translate into various outcomes, which define the risk. Such risk can be technical or commercial of nature.

1.3.1 Definitions

In field development studies, it important to distinguish the difference between uncertainty and risk while avoiding using these terms in an interchangable and undisciplined manner. A lack of definition and consistent interpretation of the specific meaning of these terms and their applicability can be an obstacle for a field development plan.

The advantage of adapting strict definitions for these terms and applying them consistently can benefit the project by enforcing the distinction between inherent uncertainty and that risk is the consequence of that uncertainty in regards to specified project targets. This study adopts the definitions of uncertainty and risk from NORSOK; NS-ISO31000:2009.

Uncertainty - a state where there is a lack of information or a lack of understanding or knowledge concerning an event and its consequence or possibility of happening.

The uncertainty is defined here as the variability of possible outcomes resulting from the selection of physical parameters and carrying its own probabiility.

Risk - the effect of uncertainty in the context of a target or purpose.

Risk is therefore an interpretation of how uncertainty impact a specific target that the project aims to achieve.

1.3.2 Causes of Reservoir Uncertainty

Economic attractiveness will determine if the Mackerel field is to be developed. This attractiveness is directly linked to the amount of oil present and the recoverability of oil. The uncertainties affecting these factors will be those in the reservoir. The two key factors of uncertainty in the reservoir are

1. Uncertainty linked to the Initial Oil In Place (IOIP) of the reservoir.

2. Uncertainty linked to the reservoir Recovery Factor (RF).

The IOIP is determined by a wide range of reservoir parameters which are derived from geological, geophysical, petrophysical and petrochemical information. The RF of the reservoir is determined by the ability of the reservoir to produce. This is influenced by how the IOIP is produced, by what method, design and execution strategy.

The inherent parameters which contribute to IOIP can be described as the *static* component of uncertainty, whereas the RF can be labelled the *dynamic* component of uncertainty. These two factors of uncertainty will be further discussed in Chapter 4.

Risk is the result of uncertainty in the context of a target. The target of this field development project is to maximise the asset value of Mackerel. An industry standard for maximising economic value is to measure the Net Present Value (NPV) and/or the Internal Rate of Return (IRR) of a development proposal. The pre-tax NPV is the difference between the present value of cash inflows and the present value of cash outflows as measured at the point in time of the decicion being made. For an oil field development, the cash inflow is the revenue made from the production and sales of petroleum products to an external buyer. The present value of cash outflows is the economic cost of developing and operating the asset in order to initiate and maintain production rates from the asset. For post-tax analysis the payment of tax has to be included to access the post-tax NPV/IRR. For this thesis work, risk therefore should be interpreted as the economic consequence through the effect on NPV/IRR, caused by the impact of reservoir uncertainties on initial reserves (the IOIP) and the ability to produce them (the RF).

During the concept comparison and selection phase of E&P projects, decicion makers estimate the value of competing development concepts (Jablonowski, Wiboonkij-Arphakul, Neuhold, et al., 2008). Using such estimates, it is then possible to rank options and to compare different concepts based on their respective NPV/IRR figures. These estimates are of high importance as they determine which concept is selected, and has a strong influence on field architecture such as initial capacity of facilities, well counts, production rates and project scheduling. Concept selection has therefore a crucial impact on the value ultimately derived from the asset.

To limit the scope of this work, the only development concept which will be evaluated in this study is a subsea tie-back solution with 2 producer wells and 1 water injector well. It is also the most likely given the small prospect size and marginal nature of the field.

1.4 Scope of Work

The objective of this thesis work is to investigate how subsurface uncertainties can impact the economic risk of developing the Mackerel discovery. Because there are a number of subsurface uncertainties that may affect the amount of oil recovered, a scope of work is defined to focus this study. The work will focus on key reservoir parameters that are direct inputs into the equation for IOIP as well as determining a method for quantifying the uncertainty of productivity through varying the recovery factor.

The subsurface parameters that affect the IOIP can be deduced by decomposing and presenting it in the equation form (*Reservoir Engineering For Other Disciplines*, 2012). With no gas cap, saturation of gas can be neglected and the IOIP equation becomes

$$N = \frac{GRV \cdot NTG \cdot \phi \cdot (1 - S_w)}{B_o} \tag{1.1}$$

Where: N is the initial oil in place (IOIP).
GRV is the gross rock volume enclosed between the top of reservoir and the oil-water contact (OWC).
NTG is the net-to-gross ratio of this GRV that is of reservoir quality.
ϕ is the mean porosity of reservoir quality rock.
S_w is the mean water saturation.
B_o is the formation volume factor of the hydrocarbon.

As there is no free gas present in the reservoir, the term $(1 - S_w)$ may be replaced with S_o, which is the oil saturation. The NTG, ϕ and S_o are often refered to be petrophysical factors, as they are derived from well logs. These parameters represent the physical properties of the reservoir that determine the quantity of hydrocarbons present. The uncertainty for each of these parameters will have an impact on the total IOIP. The GRV is the total rock volume enclosed between the top of the reservoir and the WOC and has been extensively studied and documented. Its value therefore represents a less of an uncertainty to the equation for IOIP and will not be included in this work as a major factor for uncertainty.

The extent to which the reservoir is producible is directly dependent on the internal communication of the reservoir (Dake, 1983). The extent to which the reservoir sand channels are in communication cannot be deduced from a single exploration well, and an assumption is required.

The only way to determine such communication is to produce the field. The Recovery Factor (RF) is simply the percentage ratio of oil produced, N_p, over IOIP, N, at standard conditions.

$$RF = \frac{N_p \cdot B_o}{N} \cdot 100\% \tag{1.2}$$

Where:
N_p is the volume of Oil Produced.
B_o is the oil formation volume factor.
N is the Initial Oil In Place.

Together, the uncertainties in the static reservoir (IOIP) and dynamic recovery factor (RF) present a range of different outcomes when producing the field. To limit the extent of investigation required to cover all the uncertainties, the scope of this work will be to create a series of deterministic subsurface realisations, with the aim of capturing the combined uncertainty of the static IOIP with the dynamic performance of the reservoir by varying the Recovery Factor.

The target of this work is to investigate how the subsurface uncertainty will affect the NPV/IRR of the development, as a measurement of risk. The NPV/IRR calculations will be made for each discrete subsurface realisation, followed by a comparison between NPV and IRR figures. These combine both the physical outcomes and the economic issues such as CAPEX, OPEX and oil prices.

This investigation will be carried out by applying the following steps:

1. Determing key reservoir characteristics by interpreting data from the original 18/12-1 well and combine with the most recent interpretations by the Operator.

2. Construct a material balance model by using a tank model to simulate the reservoir in MBAL.

3. Verify a well production model using PROSPER to recreate well 18/10-1 performance.

4. Propose two new production well completions in PROSPER and determine reservoir performance.

5. Couple the reservoir performance and material balance models and apply this to determine production capabilities at the Mackerel field.

6. Determine static reservoir uncertainty by applying Monte Carlo Simulation to determine the compounded uncertainty of reservoir parameters NTG, ϕ, S_o on IOIP.

7. Investigate the effects of dynamic reservoir uncertainty by tuning the Recovery Factor to simulate reservoir connectivity.

8. Combine the dynamic and static uncertainty models into nine subsurface realisations and then perform a calculation of NPV and IRR for each subsurface realisation.

9. Quantify and present risk for all cases where risk is defined as relative deviation of the NPV and changes in IRR from the most likely caase.

1.5 Working Tools

MBAL and PROSPER are analytical engineering toolkits, developed and mantained by Petroleum Experts. MBAL has been developed to model the material balance by simulating the reservoir as a tank model. PROSPER enables the simulation of well production in user-defined well configurations. The advantage of using Petroleum Experts is that the products are integrated, which enables the coupling of reservoir model with well production models.

1.5.1 MBAL - Material Balance Modelling Program

MBAL enables non-dimensional reservoir analysis to be conducted over the lifecycle of a field, from the early development stages when limited data is available. It can be updated as more information becomes available from seismic, geological models or from new wells drilled or from history matching once production is underway. With PVT and cumulative production data, the user is able to find the amount of oil in place and any associated drive mechanisms. MBAL can also be applied to model compartmentalised reservoirs by creating multi-tank models with transmissibilities between tanks.

Material Balance

Material Balance is a primary tool for evaluating past reservoir performance and predicting future production. It utilises traditional plotting techniques and mutlivariable regression for determining hydrocarbons in place and estimating aquifer type and size. It constructs a tank model and can then be used for forward prediction. Comprehensive well inflow, outflow and facilities constraints permit accurate production modelling of the reservoir.

Monte Carlo Volumetrics

The Monte Carlo Volumetrics is a simple statistical tool that provides estimations of original hydrocarbons in place given distributions for reservoir properties such as porosity, water saturation, reservoir volume and fluid PVT properties. The module complements the Material Balance and can be used for forward prediction cases or to make a first estimate prior to history matching.

1.5.2 PROSPER - Well Modelling Program

PROSPER is a tool for multi-phase flow modelling. It performes well simulations and is capable of modelling well performance, design and optimisation. PROSPER can therefore be applied to describe most physical phenonmena occuring in wells and pipelines. The physics of multi-phase flow is conceptually simple, but complex in practice. Attempts to describe multi-phase flow in a mechanistic way have not been entirely successful to date. Computation methods in current use use a combination of physically realistic models and empirical correlations to provide useful results in engineering calculations. PROSPER will be applied to this study to recreate the production rates obtained from well 18/10-1. The software enables the user to input theoretical well paths and define completed production zones.

Chapter 2

Methodology

This chapter describes the general overview of the work performed for this study.The chart below shows a summary of the workflow followed:

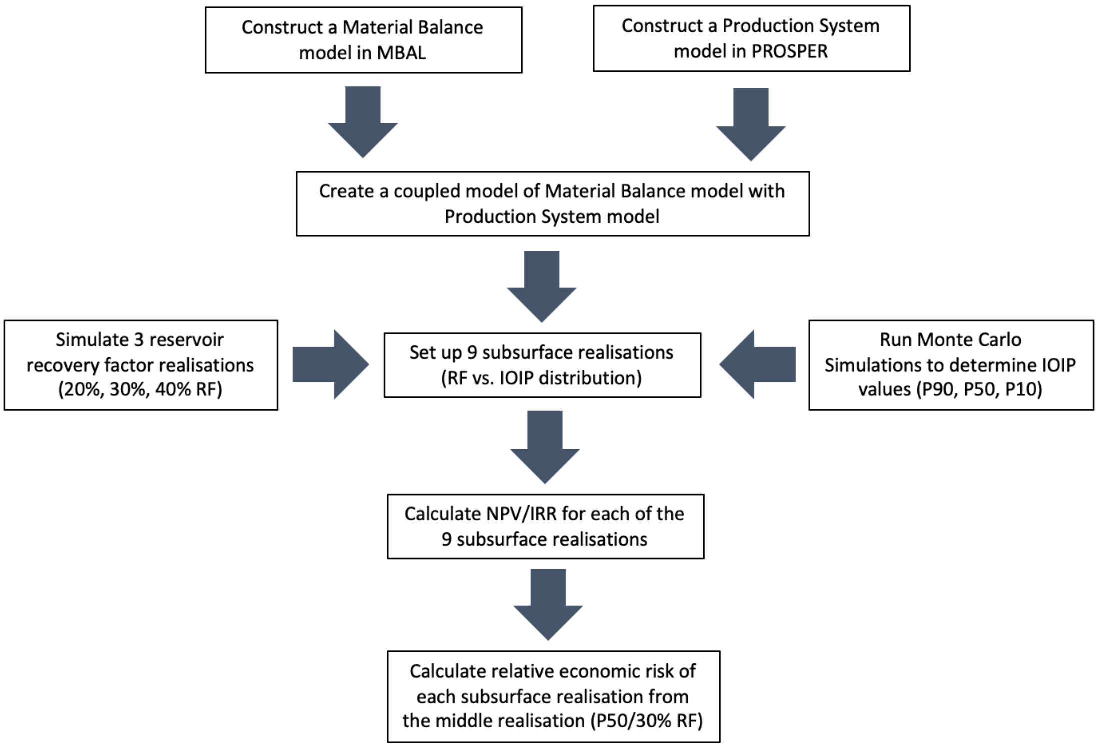

Figure 2.1: The study workflow diagram

2.1 Modelling the Reservoir

2.1.1 Material Balance model

The Material Balance model will be set up in MBAL using data and information obtained from the original 18/10-1 well log. Two simple, cuboid, homogeneous tank model will be constructed using the mean reservoir parameters available from the data provided by the Repsol subsurface team. The tanks will simulate the two reservoir zones which are not in communication. The use of MBAL is suitable for this purpose as it is a quick alternative to more extensive reservoir simulation tools and making performance prediction when time and resources are limited (Idogun, Jeboda, Charles, Ufomadu, et al., 2015).

2.1.2 Production System model

A production system of two production wells will be set up. Inflow Performance Relationships (IPR) curves will be determined for two horizontal well completions targeting the reserves in the two reservoir zones. These will be modelled based on production rates obtained from the 18/10-1 well DST.

2.1.3 Coupled Model

The coupled model will combine the Material Balance model with the IPR curves generated by the Production system model. The flow through the completed horizontal production wells from the two reservoir zones is comingled, giving a single flow rate output. Pressure support is provided to the reservoir using a water injection well.

2.2 Modelling Uncertainty

2.2.1 Static Uncertainty

The static uncertainty in the homogeneous model is primarily related to the equation for IOIP, see Equation 1.1.This study will investigate how the uncertainty of the following reservoir parameters will affect the IOIP:

- Net-To-Gross
- Porosity
- Oil Saturation

Discrete values for these parameters were obtained from the 18/10-1 well log and form the basis of the static reservoir uncertainty analysis. The study will apply a simplification in which the average parameter values will be identified and used. As the reservoir exhibits signs of compartmentalisation, the parameter values for the specific section of reservoir will be used by constructing multiple tanks.

The reservoir parameter uncertainty is calculated using a statistical technique called Mont Carlo Simulation (MCS). In applying the MCS, a table of random numbers is drawn up for each independent parameter. In each table, the maximum and minimum values of the numbers and their probability distribution, correspond with those assumed for the parameter itself (Dake, 1983). A number is extracted at random from each table and IOIP is computed for that case. This is (for this study) repeated 1000 times, with each case being calculated for a randomly selected set of values from the tables. MCS allows for practical aggregation and quantification of parameter uncertainty which enables investigation of the impact of these uncertainties on decision alternatives. MCS is commonly used in the oil and gas industry, for example to estimate the hydrocarbon reserves in place (Bratvold and Begg, 2010). For this work, MCS is used to calculate the effect of subsurface uncertainties on IOIP, which then is combined with the well production model to assess the impact of reserves uncertainty on oil production outcomes.

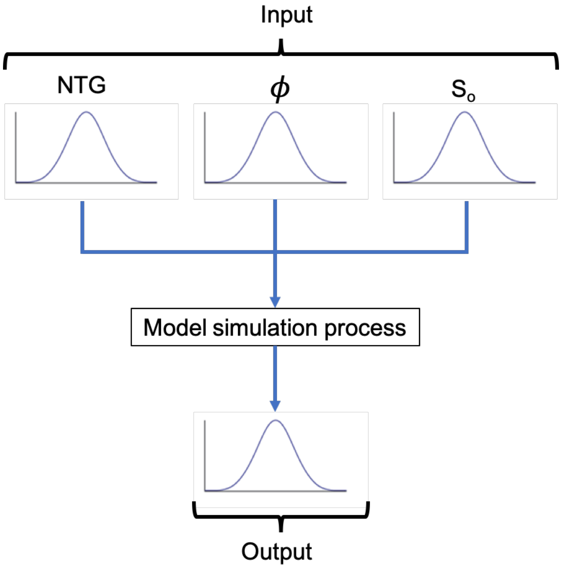

Figure 2.2: Compounded uncertainty

The MCS will produce values of IOIP which follow a normal distribution that are the result of the input value distribution for P90, P50 and P10 realisations. The reserve categories are conventionally defined as follows (Dake, 1983):

proven reserves:
reserves corresponding to 90% probability on the distribution curve,

probable reserves:
reserves corresponding to the difference between 50 and 90% probability on the distribution curve,

possible reserves:
reserves corresponding to the difference between 10 and 50% probability on the distribution curve.

2.2.2 Dynamic Uncertainty

As discussed in Chapter 1, the dynamic uncertainty is related to which extent the reservoir is in communication and is producible. Reservoir connectivity cannot be modelled explicitly using MBAL software, therefore the reservoir connectivity will be simulated by changing the RF manually by changing the parameters affecting the relative permeability curves.

As the RF is the volume ratio of oil extracted versus the total in place, a parameter which is a driver of the RF can be used to simulate the connectivity by altering its value. The residual oil saturation, S_{or}, is the fraction of oil remaining in the pore space of the oil bearing reservoir after displacement by water inflow. The RF is highly sensitive to changes in this parameter. Therefore, S_{or} can be employed as a tuning instrument that enables manual alterations of the RF value. An increase of the S_{or} value will cause RF to decrease, while decreasing S_{or} will increase the RF. This will be done across a range of S_{or} values to give the desired cumulative oil production values for selected cases of 20%, 30%, 40% RF.

2.3 NPV, IRR and Risk Calculation

The purpose of this study is to quantify economic risk that results from subsurface uncertainties. The study performs an economic analysis based on the principle of *ceteris paribus* or all other things held constant. This means that the NPV/IRR calculations for each subsurface realisation will only be affected by the uncertainty in the subsurface. All cost-related input and external factors such as the oil price will be maintained at a constant figure or rate throughout the duration of field development and operations.

The cost-related inputs, including capital expenditures (CAPEX), operational expenditures (OPEX) and abandonment expenditures (ABEX) are suggested inputs provided by the Operator field development team and are derived from in-house studies. The introduction of early tentative cost estimates is useful for making predictive NPV/IRR calculations. For the purpose of this study, the accuracy of place-holder cost figures is of little consequence to the scope of work, as the point of interest is the difference in relative NPV/IRR depending on subsurface realisation. Although, ultimately a range of subsurface realisations will need to be able to meet company financial hurdles for financial returns on investment.

Chapter 3

Coupled Reservoir Model Preparation

3.1 General

This chapter focuses on the steps of preparation and quality control of a coupled model consisting of the reservoir and inflow performance models.

A simplistic analogy of a reservoir system is a tank containing fluids under pressure (Stanko, 2019). A well connected to this tank can act as an exit point for the drainage of these fluids. The average reservoir pressure drives fluid from the tank to the wellbore. The exit restriction represents pressure losses that occurs when the flow passes through the formation towards the well. When fluid is drained from the tank, representing the formation, the tank pressure is reduced, therby simulating the depletion of reservoir pressure. The result is a reduction in the flow rate that the tank can deliver at a fixed wellbore pressure. This analogy is illustrated in Figure 3.1.

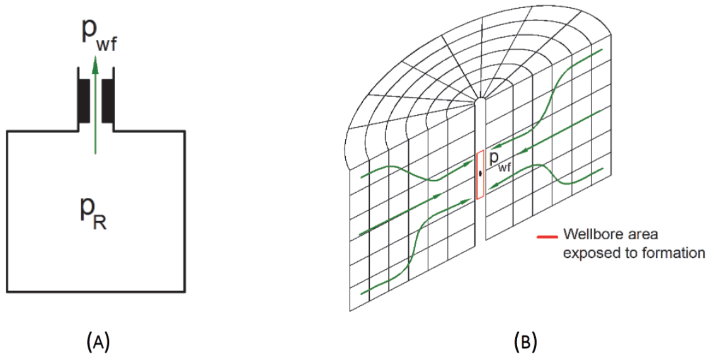

Figure 3.1: (A)Tank analogy of a (B) reservoir system (Stanko, 2019)

Depletion performance of the reseroivr can typically be modelled using material balance. The reservoir is represented by a tank with oil and water under pressure. The calculations are made stepwise, where the amount of oil and water produced from the reservoir is given as an output and new values for saturation of fluids and pressure inside the tank is calculated by applying conservation of mass.

The material balance model requires IOIP values as input and can therefore not be used alone to predict the production output of the reservoir with time. For that, an additional model must be constructed to quanifty the pressure drop between the reservoir and a downstream condition, such as the bottom hole pressure. This is the Inflow Performance Relationsship (IPR).

3.2 Constructing a Tank Model

This section will focus on the preparation of the reservoir model. A homogeneous model will be set up using MBAL software to simulate the Mackerel reservoir. The selection of a homogeneous model to simulate a reservoir of high complexity and of which limited information is available is a simplification that will require assumptions.

3.2.1 Identifying Reservoir Characteristics

The Mackerel discovery consists of a faulted anticline formation that has accumulated oil which has migrated from source rocks to the south-west. The cap rock and faultlines have provided sealing for the migrating oil, trapping it in Jurassic sandstones of the Bryne Formation.

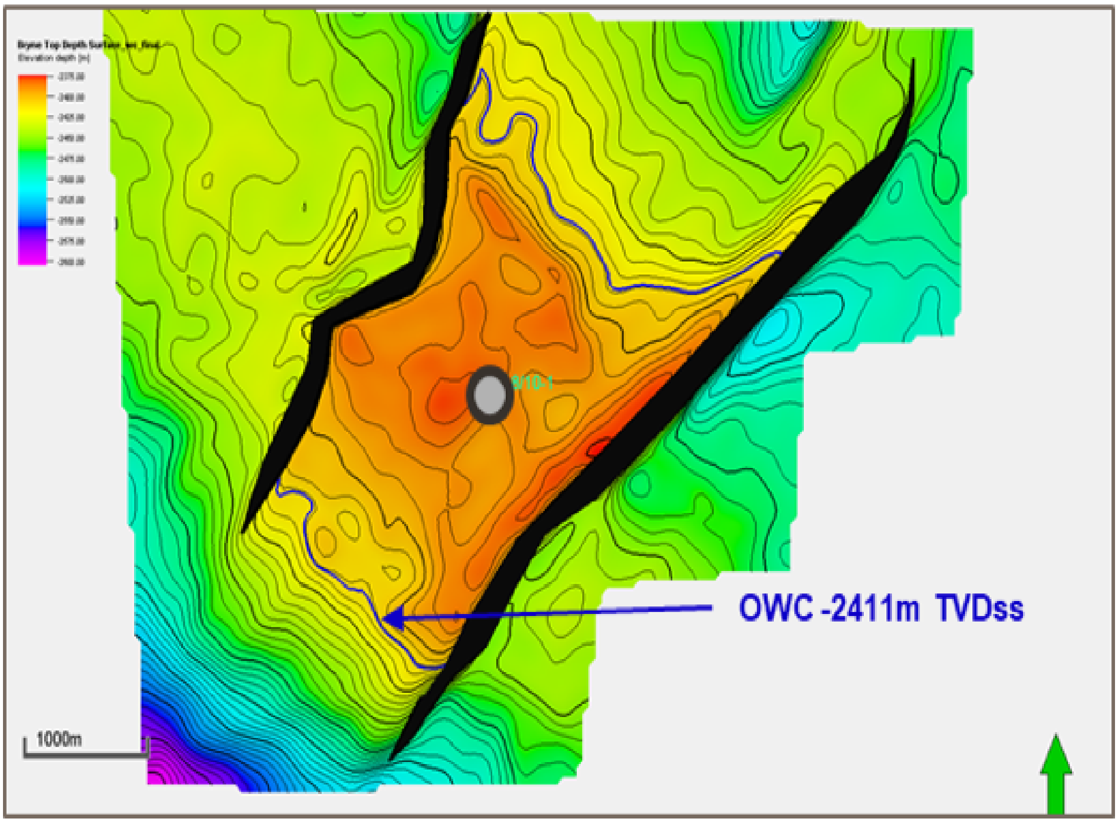

Figure 3.2: Seismic survey map of the Mackerel field.

The reservoir rock is believed to have been formed by fluvial deposition, which has resulted in an intricate system of sandstone channels. These are believed to contain oil, however the communication between these channels is unknown. The reservoir extends roughly 2500 m along a south-west to north-east axis and 2000 m between the sealing faultlines. This can be viewed in Figure 3.2. The total reservoir area enclosed has been determined to be approximately $6.4 \cdot 10^6\ m^2$. The Gross Rock Volume (GRV) is the entire volume of the reservoir rock enclosed by the sealing faults, the cap rock above the reservoir and the OWC beneath it has

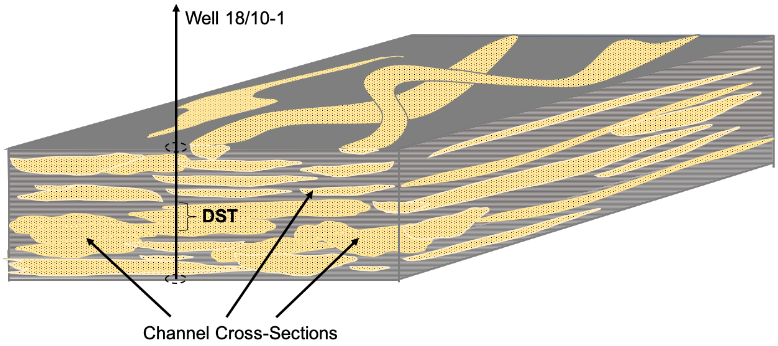

Figure 3.3: Mackerel Reservoir Cross-Section.

been surveyed and accurately calculated to $110 \cdot 10^6\ m^3$.

Well 18/12-1 was drilled in the centre of the field, where it passed through a 32 m oil pay zone starting at 2405 m. The well was drilled vertically and the Oil-Water Contact (OWC) was detected at 2437 m TVD. Interpretation of the well data and geophysical measurements has been performed by the Repsol subsurface team. The reservoir can be be separated into three distinct zones. These have been labelled B1, B2 and B3 and may be viewed together with the log in Figure 3.4. A discontinued pressure gradient suggests limited or no communication between zones B2 and B3. Zones B1 and B2 show no such pressure discontinuity and are therefore believed to be in communication. Only 2.5 meters of zone B3 extends above the OWC. The rest of zone B3 is below the OWC and extends to the beginning of the Lower Bryne formation at 2500 m TVD.

While the Mackerel reservoir encompasses the entire volume of these zones, not all of the reservoir contains oil. In order to estimate a figure for the IOIP, a calculation of net pay must be made. The purpose of making net pay calculations is to eliminate nonproductive rock intervals and hence determine what volume of the reservoir rock will be productive. Net pay estimates can be made from analysing and extrapolating the original exploration well log.

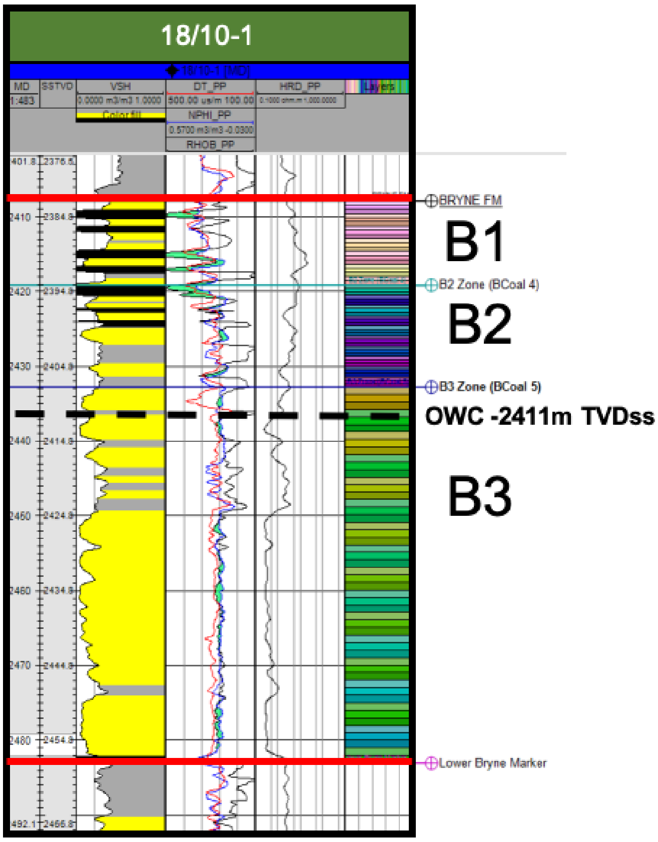

Figure 3.4: Log of well 18/10-1.

The main parameter determining a zone's payability is the permeability. Permeability is a medium's capability to transmit fluids through its network of interconnected pores. Permeability is directly related to the porosity of the medium. From first-principle calculations using Darcy's law, it is possible to define net pay by applying a fluid-flow cutoff (Dake, 1983). The choice of a specific cutoff is somewhat arbitrary, but should be related directly to the hydrocarbon mobility within the medium in question. A cutoff of 1 mD is widely accepted as a standard in the industry (Lyons & Plisga, 2011). Any section of the reservoir with a permeability lower than 1 mD will be excluded from the net pay and instead be considered part of the non-paying zones.

In the Mackerel field, the gross pay consists of sands separated by layers of coal with some shale present towards the lower part of zone B2, as can be seen in Figure 3.4. The net pay is notably smaller than the gross pay, with a 1 mD cutoff yielding 8.3 m of net pay. The net pay is used in relation to the gross rock of the formation.

This net-to-gross can be expressed as NTG = Net Pay Thickness / Gross Thickness. The summary of parameters from the zones is given in Table 3.1 below.

Table 3.1: Summary of key reservoir parameters by zone.

Interval	Pressure bar	Gross thickness m	Net pay m	NTG -	ϕ -	S_w -	k_{log} mD
B1 + B2	257.9	24.9	12.7	0.51	0.20	0.39	300.0
B3	253.0	67.7	2.5	0.04	0.23	0.63	365.4

The absence of pressure communication between zones B2 and B3 is indicative that there is little possibility of cross-flow. The decision has been made to simulate the reservoir using two separate reservoir models with their own parameters. Zones B1+B2 will be grouped together as a single reservoir unit. Zone B3 will be modelled separately.

From Figure 3.4, one may observe that the initial reservoir division shows Zone B3 including the entire reservoir section from 2432.7 m to 2500.4 m. This includes the reservoir below the OWC located at 2437 m, leaving only 4.3 m of gross pay from the oil column at the top of the B3 zone. Of these 4.3 m, the oil is found in 2.5 m zone of continuous net pay layer. The aquifer located below the OWC is believed to be in poor communication with this layer of oil. The second well will target the B3 Zone, hence for this study, the B3 Zone will be defined to consist only of the upper 2.5 m oil bearing section of the zone.

3.2.2 Reservoir Simplification

In order to construct a reservoir model, a simplification will be made by transforming the anticline, fault-bounded reservoir as seen in Figure 3.2 into rectangular reservoir units. As can be seen from both the log and Table 3.1, the B3 zone contains very little net pay compared to the gross thickness of the zone. The remainder of B3 is situated below the OWC and will therefore not contribute to the IOIP. To avoid a high water cut, the B3 zone should be produced by a well targeting the upper net pay zone. Due to the cuboid shape of the reservoir, a cuboid approximation will be assumed. This simplification has been visually represented in Figure 3.5, which shows an approximated cross section running in a southwest-to-northeast axis parallel to the boundary faults.

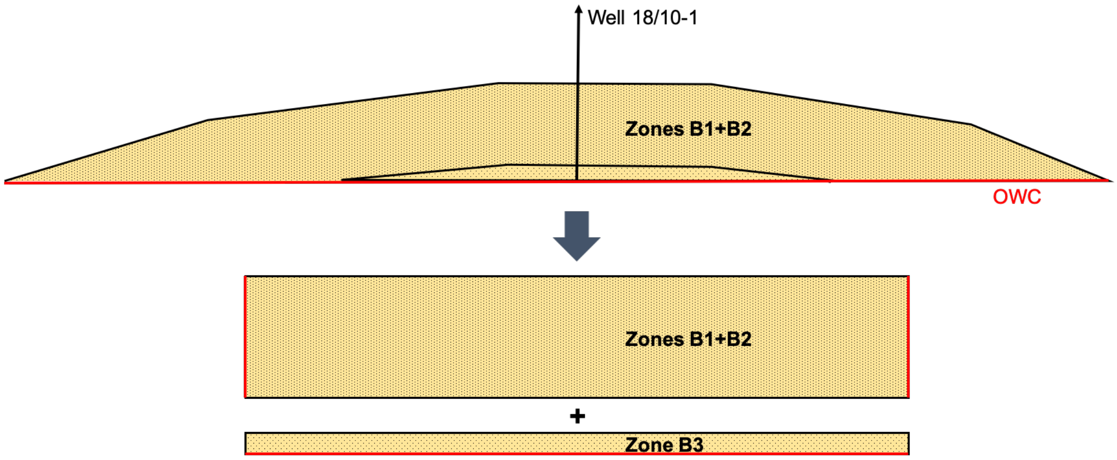

Figure 3.5: Transforming anticline reservoir.

This is then simplified into a rectangle which, when counting reservoir width into the plane, forms a cuboid reservoir model as seen in Figure 3.6.

Taking the known $GRV = 110 \cdot 10^6\ m^3$, and following the assumption that the reservoir is a cuboid, it is possible to calculate the lenght and width of the reservoir using the following equation:

$$GRV = h \cdot L^2 \tag{3.1}$$

where h = 27.5 is the height of the oil column stretching from the cap rock to the OWC, and $L = 2000$ m are the equidistant lengths of the cuboid's length and width. The are quite similar to the actual length and width of the reservoir (2500 m x 2000 km).

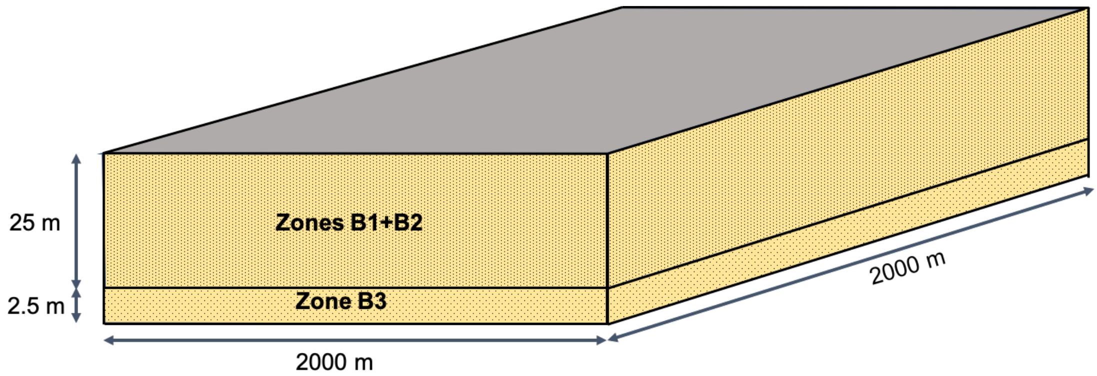

Figure 3.6: Cuboid approximation of the reservoir.

With the thickness of each zone being used for the model now determined, it is possible to use this information to obtain GRV for both Zone B1+B2 and Zone B3. The B1+B2 zone constitutes a GRV of $100 \cdot 10^6$ m^3 and the B3 zone is $10 \cdot 10^6$ m^3.

3.2.3 Model Setup in MBAL

The purpose of using MBAL is to construct a tank to simulate the material changes in the reservoir before, during and after production. MBAL enables the simulation of the reservoir by constructing tanks which takes an input values of IOIP and additional reservoir parameters. If the reservoir is compartmentalised, e.g. not in communication, it can be simulated in MBAL by setting up a system of multiple tanks, where each tank is given its own Material Balance Equations.

Material Balance Equations (MBE)

The main principle of MBE is that of material conservation (Dake, 1983). This type of model excludes internal reservoir fluid flow and considers only fluid production from the reservoir and injection into it, as well as fluid and rock expansion/compression effects.

The MBEs are based on simple mass balances of the fluids present within the reservoir (Kleppe, 2017). This can be represented as

$$\left\{\begin{array}{c}\text{Amount of fluids present}\\ \text{in the reservoir initially}\\ \text{(st. vol.)}\end{array}\right\} - \left\{\begin{array}{c}\text{Amount of}\\ \text{fluids produced}\\ \text{(st. vol.)}\end{array}\right\} = \left\{\begin{array}{c}\text{Amount of fluids remaining}\\ \text{in the reservoir finally}\\ \text{(st. vol.)}\end{array}\right\}$$

This can be applied to the fluid groups present in the Mackerel reservoir, oil, water and gas:

Oil material balance

$$\left\{\begin{array}{c}\textit{Oil present}\\ \textit{in the reservoir}\\ \textit{initially}\\ \textit{(st. vol.)}\end{array}\right\} - \left\{\begin{array}{c}\textit{Oil}\\ \textit{produced}\\ \textit{(st. vol.)}\end{array}\right\} = \left\{\begin{array}{c}\textit{Oil remaining}\\ \textit{in the reservoir}\\ \textit{finally}\\ \textit{(st. vol.)}\end{array}\right\}$$

This can be expressed by the following equation:

$$N - N_p = \frac{V_p S_o}{B_o} \tag{3.2}$$

where N is IOIP, N_p is oil produced, V_p is pore volume, S_o is oil saturation.

Water material balance

$$\left\{\begin{array}{c}\textit{Water present}\\ \textit{in the reservoir}\\ \textit{initially}\\ \textit{(st. vol.)}\end{array}\right\} - \left\{\begin{array}{c}\textit{Water}\\ \textit{produced}\\ \textit{(st. vol.)}\end{array}\right\} + \left\{\begin{array}{c}\textit{Water}\\ \textit{injected}\\ \textit{(st. vol.)}\end{array}\right\} + \left\{\begin{array}{c}\textit{Aquifer}\\ \textit{influx}\\ \textit{(st. vol.)}\end{array}\right\} = \left\{\begin{array}{c}\textit{Water remaining}\\ \textit{in the reservoir}\\ \textit{finally}\\ \textit{(st. vol.)}\end{array}\right\}$$

This can be expressed by the following equation

$$\frac{V_{p1}S_{w1}}{B_{w1}} - W_p + W_i + W_e = \frac{V_p S_w}{B_w} \tag{3.3}$$

where the subscript with "1" indicates an initial state, as opposed to present state that lacks this subscript.

Gas material balance

$$\left\{\begin{array}{c}\textit{Solution gas}\\ \textit{present in the}\\ \textit{reservoir initially}\\ \textit{(st. vol.)}\end{array}\right\} + \left\{\begin{array}{c}\textit{Free gas}\\ \textit{present in the}\\ \textit{reservoir initially}\\ \textit{(st. vol.)}\end{array}\right\} - \left\{\begin{array}{c}\textit{Gas}\\ \textit{produced}\\ \textit{(st. vol.)}\end{array}\right\} + \left\{\begin{array}{c}\textit{Gas}\\ \textit{injected}\\ \textit{(st. vol.)}\end{array}\right\}$$

$$= \left\{\begin{array}{c}\textit{Solution gas}\\ \textit{present in the}\\ \textit{reservoir finally}\\ \textit{(st. vol.)}\end{array}\right\} + \left\{\begin{array}{c}\textit{Free gas}\\ \textit{present in the}\\ \textit{reservoir finally}\\ \textit{(st. vol.)}\end{array}\right\}$$

$$NR_{so1} + \frac{mNB_{o1}}{B_{g1}} - R_pN_p + G_i = (N - N_p)R_{so} + \frac{V_pS_g}{B_g} \tag{3.4}$$

Since the reservoir has no gas cap and no gas in to be injected, this can be simplified to

$$NR_{so1} - R_pN_p = (N - N_p)R_{so} \tag{3.5}$$

No free gas will be present in the reservoir finally due to the pressure support of the water injection.

The sum of saturations in the reservoir adds up to 1.

$$S_o + S_w + S_g = 1.0 \tag{3.6}$$

and the pore volume change is given by

$$V_p = V_{p1}(1 + c_r \Delta p) \tag{3.7}$$

where c_r is the rock compressibility

$$c_r = (\frac{1}{\phi})(\frac{\partial \phi}{\partial P})_T \tag{3.8}$$

By combining the five Equations 3.2-3.7 above, one can obtain a complete expression for Black Oil MBE:

$$F = N(E_o + E_{f,w}) + (W_i + W_e)B_w + G_i B_g \tag{3.9}$$

where the production terms are given by

$$F = N[B_o(R_p - Rso)B_g] + W_p B_w \tag{3.10}$$

and the oil and solution gas expansion terms are

$$E_o = (B_o - B_{oi}) + (R_{soi} - R_{so})B_g \tag{3.11}$$

Finally, the rock and water compression/expansion is given by

$$E_{f,w} = -(1 + m)\left(\frac{c_w S_{wi} + c_r}{1 - S_{wi}}\right) B_{oi} \Delta p \tag{3.12}$$

Water Influx

As material is produced from the reservoir, it is replaced by an influx of water from the supporting aquifer. Water influx models are mathematical models that simulate and predict this influx performance. They are used to predict water influx and when successfully integrated into a reservoir simulation, can simulate performance of water drive reservoirs.

The Mackerel field is supported by a weak aquifer, implying a limited water drive mechanism. For this study the Fetkovich Finite Aquifer Model was selected for its applicability to simulate field performance using horizontal well completions (Bahadori, Jamili, & Zendehboudi, 2013).

Pseudo-Steady State (PSS) water influx model is based on Fetkovich (Fetkovich et al., 1971). The model is characterised by its assumption of a finite aquifer, modelled as a tank, a geometry independent transfer coefficient that prescribes how much water flows between aquifer and reservoir. PSS is ideal for limited aquifers, such as that at Mackerel with medium to high mobility. The model simultaneously solves the aquifer influx equation with the MBE for the reservoir.

The Fetkovich water influx equation states

$$W_e = \frac{W_{ei}}{p_i}(p_i - p)\big(1 - e^{-Jp_it/W_{ei}}\big) \tag{3.13}$$

where W_{ei} is the initial encroachable water = Initial Water In Place (IWIP) $\cdot p_i c_w$, where p_i is the initial pressure and c_w is the compressibility of water. The transfer coefficient or influx equation is given by

$$J = \frac{fkh}{141.2\mu\big[ln\frac{r_e}{r_p} - \frac{3}{4}\big]} \tag{3.14}$$

and where f = encroachment angle / 360 deg. k is permeability, h is the thickness of the zone, μ is viscosity, r_e is the distance to the outer boundary and r_p is the distance to the well boundary.

The values provided in Table 3.2 are selected based on current understanding of the aquifers. The "B3" zone will experience bottom drive aquifer influx, wheras the "B1+B2" will receive aquifer influx from the flanks, which due to model configuration is simulated by a linear aquifer. Relating to Equation 3.14, the encroachment angle is 180 deg for zone B1+B2 and 90 deg for zone B3. The volume of the underlying aquifer is believed to be limited in size. The impact of water influx is limited from the lack of water drive. This is due to the low aquifer volumes, with expected aquifer to oil volume ratio being roughly 5:1 and due to low aquifer permeability.

Table 3.2: Model Water Influx Specifications

Interval	Aquifer System	Res.Thick. m	Res. Width m	Aquifer Vol. Mm^3	Aquifer Perm. md
B1 + B2	Linear	25	2000	35	500
B3	Bottom Drive	n/a	2000	5	100

3.3 Field Performance Modelling

In models of field performance, the well inflow at a particular time is usually represented by an IPR equation (Inflow Performance Relationship). It is typically a smooth, monotonic curve that provides the bottom-hole pressure that must be applied at the sand face to deliver a specific standard condtion flow rate.

IPRs are typically derived by solving analytically the partial differential equations (PDE) of reservoir flow while introducing simplifications and assumptions. The derivation enables an expression that relates reservoir and bottom-hole pressure with reservoir rates for different flow regimes. Commonly, the IPR is created for a single phase that is produced and then converted into others by using a measured ratio, notably the gas oil ratio, GOR, and water cut, WC. These ratios are often assumed to remain constant even when rate is varied.

The IPR describes the reservoir deliverability for a given depletion state and assuming that a pseudo-steady state has been reached in the reservoir. The well inflow decribed by the IPR provides the bottom-hole pressure that has to be applied at the sand face to deliver a specific standard condition rate.

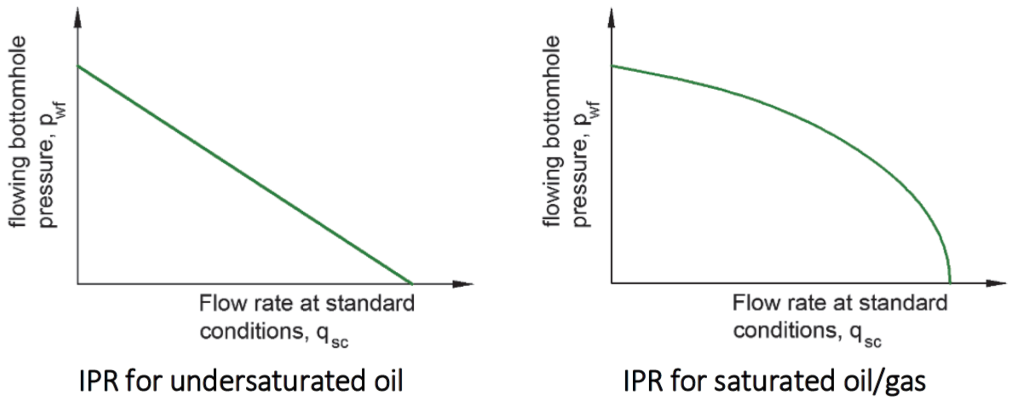

Figure 3.7: IPR curve (Stanko, 2019).

For the Mackerel field, the low GOR and bubble-point pressure suggests an undersaturated oil. The generated IPR curves can therefore be expected to resemble the curve to the left in Figure 3.7.

The equations used in PROSPER are derived by applying mass, momentum and energy conservation equations to the element being analysed. These equations are then simplified to reduce the number of unknowns by introducing relationships between variables and emperical correlations.

A set of equations are then solved simultaneously per element in an iterative manner (Stanko, 2019). The benfit of solving them simultaneously is that conditions in each upstream or downstream element are themselves the upstream or downstream conditions for another element. Computing the flow equilibrium of the production system in such a manner is done using Newton methods to minimise pressure residuals.

In general, most IPR equations have the following structure:

$$Q = U \int_{P_{wf}}^{P_R} F(p) \cdot dp \tag{3.15}$$

Where the U coefficient is a function of reservoir rock properties, the drainage geometry and other non-ideal phenonema such as skin and partial penetration. $F(p)$ is a pressure function, which depends on fluid properties derived from PVT analysis and on relative permeability of the phase.

The flow in the tubing, casing and pipelines is represented by equations that predict temperature and pressure drops. Constant fluid properties are assumed and a length discretization and step-wise calculation is then performed to capture the fluid behaviour.

The well system can be described by an energy balance expression. This equation is simply a statement of the privinple of conservation of energy over an incremental length element of the tubing, i.e. the energy entering the stystem must be equal to the energy leaving the system plus the energy exchanged between the fluid and its surroundings.

For a wellbore pressure computations, this can be expressed differentially as total dp/dZ, or rate of change of pressure with respect to length of tubing.

The pressure drop in a well containing only liquids is contributed by three components; gravity, friction and acceleration (Beggs, Brill, et al., 1973). These components can be viewed in Equation 3.16.

$$\frac{dp}{dZ_{total}} = g \cdot \rho_L \cdot cos\theta + f \cdot \frac{\rho_L v^2}{2D} + \rho_L \cdot v \cdot \frac{dv}{dZ} \tag{3.16}$$

where g is the gravitational constant, ρ is the liquid density, θ is the angle of flow, f is the friction factor, v is the liquid velocity

For liquid wells, the gravity term is the dominant component of the well pressure loss. Liquid density may be calculated from the oil and water densities with assumption of no-slip between the oil and water phases as follows

$$\rho_L = \rho_o f_o + \rho_w f_w \tag{3.17}$$

where the oil fraction f_o can be described by

$$f_o = \frac{Q_o}{Q_o + Q_w} = \frac{Q_{o_{SC}} B_o}{Q_{o_{SC}} B_o + Q_{w_{SC}} B_w} \tag{3.18}$$

3.3.1 PVT Matching

In order to capture the aforementioned fluid behaviour required to accurately model the IPR of a well, a process of PVT matching must be conducted.

From samples, the solution GOR, oil gravity, gas gravity and water salinity of the reservoir oil has been measured. This data is then fed into PROSPER, which calculates the PVT of the reservoir oil using Black Oil correlations.

Black Oil PVT is used for the vast majority of applications. Oil and water takes the surface production of oil and associated gas together with the water cut to determine the well mass flow rate. PVT correlations are used to fid the amount of gas at each pressure and temperature. B_o, B_g and B_w are evaulated at each calculation step to find the phase densities.

From the 18/10-1 fluid tests, the GOR was found to be 9.7 m^3/m^3, tank oil density is 843 kg/m^3 and the gas gravity (where air = 1) is 0.724.

PROSPER allows the user to determine the optimal correlation model for the bubble point pressure P_b, solution GOR R_s and formation volume factor B_o by comparing correlations devised by Glaso et al., Standing, Lasater, Vazguez-Beggs, Petrosky, Al-Marhoun and De Ghetto. PROSPER matches the input values agains these correlation models, giving the output in terms of standard deviations from each respective correlation. It was found that Al-Marhoun offers the lowest standard deviation between correlation to input data (Al-Marhoun et al., 1988). This can be seen in Appendix B.

Next, the Oil Viscosity correlation must be matched using the input data. A Newtonian Fluid model is assumed for this reservoir. PROSPER models the input against correlations devised by Beal et al. Beggs et al., Petrosky et al., Egbogah et al., Bergman-Sutton, De Ghetto et al., as well as De Ghetto et al. modified. A comparison of the output revealed that the correlation devised by Beal et al. offered the optimal match and was therefore selected for use in the model (Beal et al., 1946). The output may be viewed in Table 3.3.

Table 3.3: PVT matching output data

Bubble Point, P_b BARa	Oil FVF, B_o m^3/Sm^3	Oil Viscosity, μ_o cP
34	1.071	1.63

3.3.2 Modelling IPR for Exploration Well 18/10-1

The data acquired from 18/12-1 DST enables the constructed of simulated IPR using PROSPER. The production test was made through a tubing with 7" Inside Diameter (ID). For a vertical undersaturated oil well, the P.I. entry IPR is applicable. The reservoir pressure and user-input productivity index are used to calculate the production rate above the bubble point. Below the bubble point, the Vogel empirical IPR is used to estimate two-phase flowing pressures. The reservoir pressure and P.I. of drawdown is required input, which can be determined from the

$$Q_o = J(P_R - P_{wf}) \tag{3.19}$$

Where J is the productivity index. This can be rewritten to express the flow rate as an ou

$$Q_o = \frac{4\pi kh(P_R - P_{wf})}{\mu_o B_o \left[ln\left(\frac{4A}{\gamma C_A r_w^2} \right) + S \right]} \tag{3.20}$$

The Darcy IPR is the classic radial flow equation producitivty index. The form used in PROSPER is in terms of drainage area and Dietz shape factor. The required input data are reservoir pressure and temperature, permeability, reservoir thickness, C_A, wellbore radius, drainage area. The C_A is the Dietz shape factor, which takes into account geometry of the affected area and the reservoir thickness. Assuming radial inflow for a time-limited DST, the value can be determined by reading the table in Appendix B as 31.6. It is believed that the extent of drainage effect extended 700 feet into the reservoir. This gives a drainage area of 291 863 m^2, assuming radial inflow. The skin factor has been calculated by the Repsol subsurface team from a pressure buildup test. This gave skin factor S = -1.4. The skin factor is then manually computed in PROSPER. The parameter input for Darcy IPR can be viewed in Table 3.4.

Table 3.4: Darcy IPR model input parameters

k	h_{DST}	P_R	μ_o	B_o	A	C_A	r_w^2
md	m	BARg	cP	m^3/Sm^3	m^2	–	m
85	11	257.9	1.071	1.63	291 863	31.6	0.1

By computing this parameter input, the Darcy IPR model can be run in PROSPER. To verify the accuracy of the model, the production test can be computed in the same chart and should intersect with the IPR curve. The bottomhole flowing pressure and oil flow rate were P_{wf} = 191.12 $BARg$ and $Q = Q_o$ = 295 Sm^3/d, respectively. The IPR curve can be viewed in Figure 3.8.

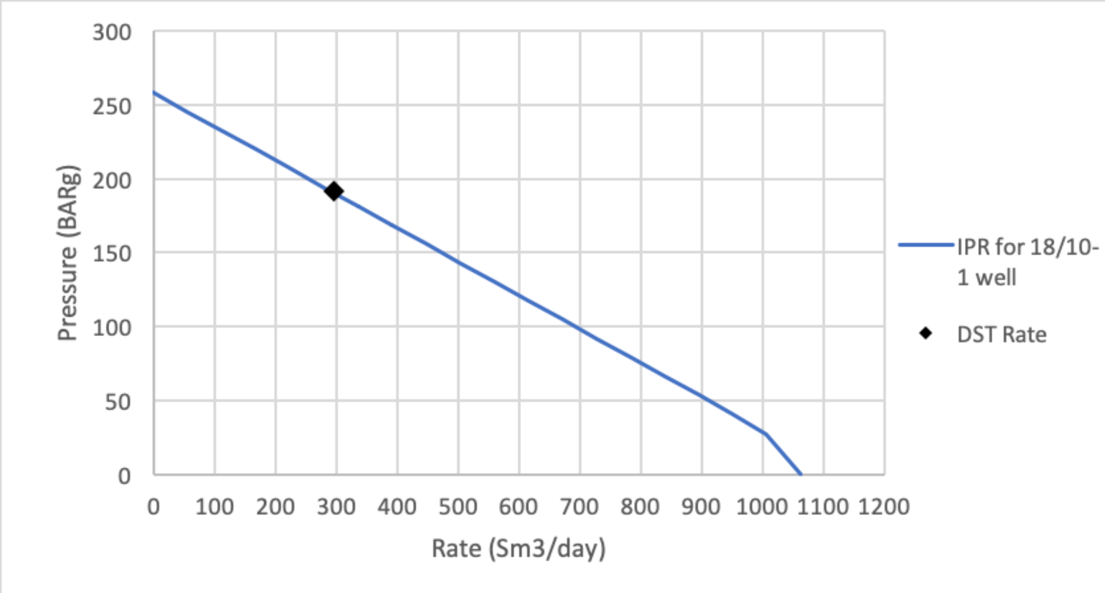

Figure 3.8: IPR curve for well 18/10-1 with DST rate indicated.

From Figure 3.8, one can observe that the DST rates align with the IPR curve. The significance of the IPR model successfully matching the production test rates is that one may deduce that it is possible to accurately model future well developments using the same input values in PROSPER.

3.3.3 Modelling IPR for New Well Completions

The production of the reservoir will best be performed using horizontal wells that target the larger oil-bearing channels. This is intuitive, as increasing the exposed section length through the reservoir will increase the well's ability to produce said reservoir. The wells will be completed using the same 7" ID tubing as for well 18/10-1.

Horizontal wells offer the best solution for producing the numerous fluvial channels in the reservoir. Such a well development would aim to establish communication with as many of these channels as possible.

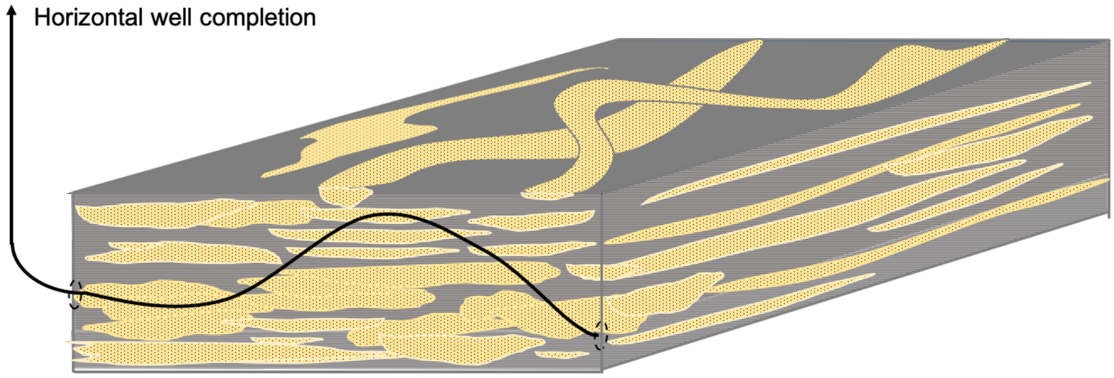

Figure 3.9: Possible horizontal well completion.

As such a development represents a complicated modelling challenge, therefore a simplification will be made to simulate the horizontal completion as being perfectly parallel with the upper and lower bound of the reservoir zone through which it is drilled.

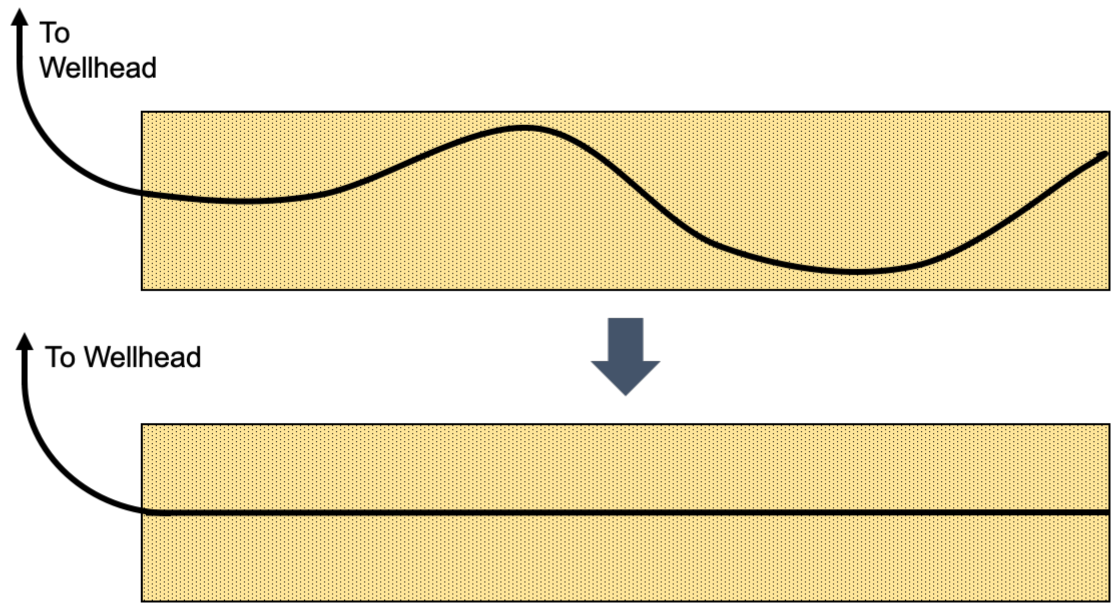

Figure 3.10: Simplification of horizontal well completions.

The in-built PROSPER horizontal well model can be used for horizontal wells drilled in a rectangular reservoir volume where pressure drops along the wellbore is insignificant, e.g. in moderate to low permeability formations such as that found at Mackerel. The Kuchuk and Goode P.I. model is used.

The model assumes that the horizontal well is parallel to the reservoir boundaries and the dstance from the well to any lateral boundary is large compared to the distance from the well to the top and bottom well boundaries. This condition is almost always met in practice, and the Mackerel field will be no exception with high aspect ratios for both B1+B2 and B3 zones.

The inflow performance of a well is related to the steady-state or pseudo steady-state behavior. For a reservoir with no-flow boundaries, the difference between the average pressure of the reservoir and the wellbore pressure approaches a constant value, which is called the pseudosteady-state pressure (Goode, Kuchuk, et al., 1991).

The dimensionless pseudosteady-state pressure

$$P_{wD} = (P - P_w)\frac{2\pi kh}{\mu Q} \tag{3.21}$$

Inflow performance is expressed (in oilfield units) by

$$J = 7.08 \cdot 10^{-3}\frac{k_H h}{\mu B_o(p_{wD} + S_m^*)} \tag{3.22}$$

where $k_H = \sqrt{k_x k_y}$ (x & y are in horizontal plane) and J or the Productivity Index is a direct measurement of well performance (STB/D-psi). S_m^* is defined by

$$S_m^* = \frac{h}{2L_{1/2}}\sqrt{\frac{k_x}{k_z}}S_m \tag{3.23}$$

where S_m is the van Everdingen mechanical skin, which is an unknown value in this study. It is requires a pressure difference due to skin ΔP_S and is given by

$$S_m = \frac{2\pi L_{1/2}\sqrt{k_x k_y}}{\mu Q}\Delta P_S \tag{3.24}$$

where h is the reservoir height, z_w is the distance from the horizontal well to the bottom of the reservoir. The horizontally completed section of the reservoir is presumed to be lie in the middle of the reservoir, with equal distance between the boundaries on each side and the heel and toe of the well, respectively. $L_{1/2}$ is half the length of the completed section. This is illustrated in Figure 3.11.

The permeabilities k_H and k_V are in the horizontal and vertical directions. As discussed in the Methodology chapter, the model used in this study assumes isotropic permeability.

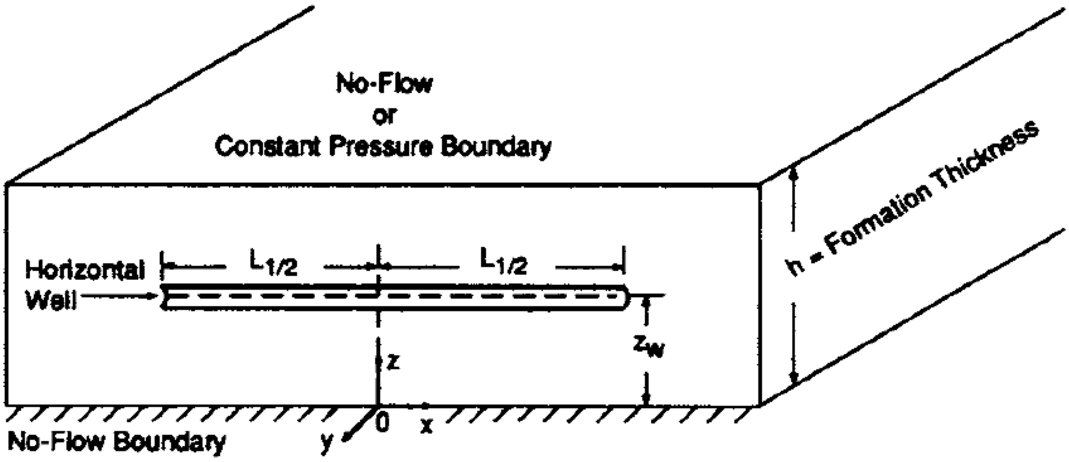

Figure 3.11: Horizontal well mode (Kuchuk et al., 1991)

The skin damage entered should be the mechanical skin damage. For this study it is assumed that the skin for horizontal wells is negligible, given the low skin observed from the original 18/12-01 well DST. The same well diameter r_w is assumed for the horizontal completion as was done for well 18/12-1. The new horizontal wells will assume 1000 m completed sections in a perfectly symmetrical arrangement within the respective reservoir zones. This leaves 500 m between the toe/heel of the wells and the nearest reservoir edge. On either side of the completed well, the reservoir stretches 1000 m.

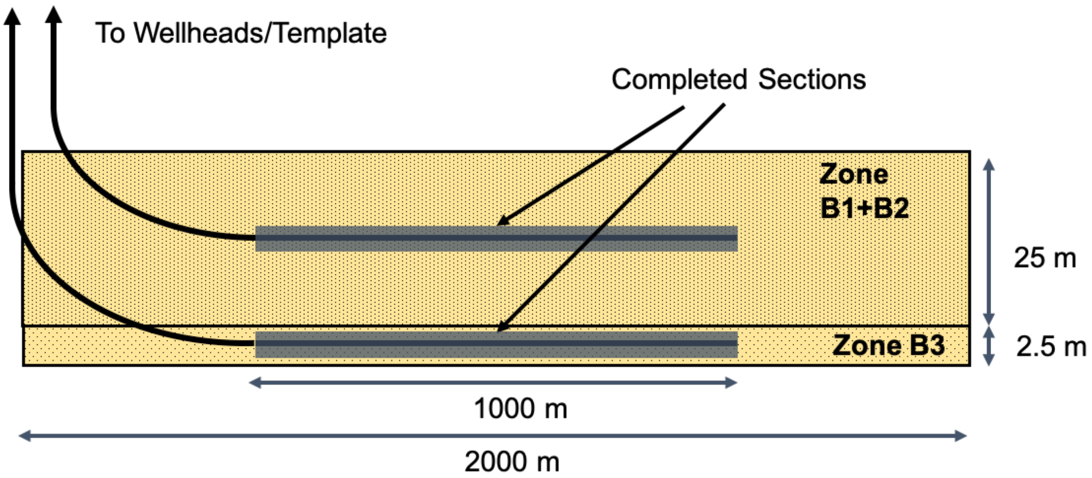

Figure 3.12: Horizontal well completions.

As the wells are producing from hypothetical directions, no anisotropic factors will be considered in this study. It is assumed that permeability is isotropic of nature, meaning that the reservoir flowing ability is the same independent of flow vector.

The input parameters for the horizontal wells of each zone is given in Table 3.5.

Table 3.5: Horizontal well input parameters per zone.

Parameter	Unit	Zone B1 + B2	Zone B3
Reservoir Pressure	BARg	257.9	253.0
Reservoir Permeability	md	280.0	535.6
Reservoir Thickness	m	25	2.5
Wellbore Radius	cm	21.27	21.27
Horizontal Anisotropy	fraction	1	1
Vertical Anisotropy	fraction	1	1
Length of Well	m	1000	1000
Reservoir Length	m	2000	2000
Reservoir Width	m	2000	2000
Distance from length edge to well	m	1000	1000
Distance from width edge to well	m	500	500
Distance from bottom to centre of well	m	12.50	1.25

The PROSPER model also requires a deviation survey for the proposed wells. The wells will be completed vertically from the manifold located at the sea bed until reaching a depth of 2000 m TVD. From this depth, the wells will gently deviate until reaching respective zones. The deviation survey can be viewed in the Appendix B.

After computing the deviation survey of the wells and the inflow parameters of Table 3.5, the IPR curves of the horizontal well can be produced.

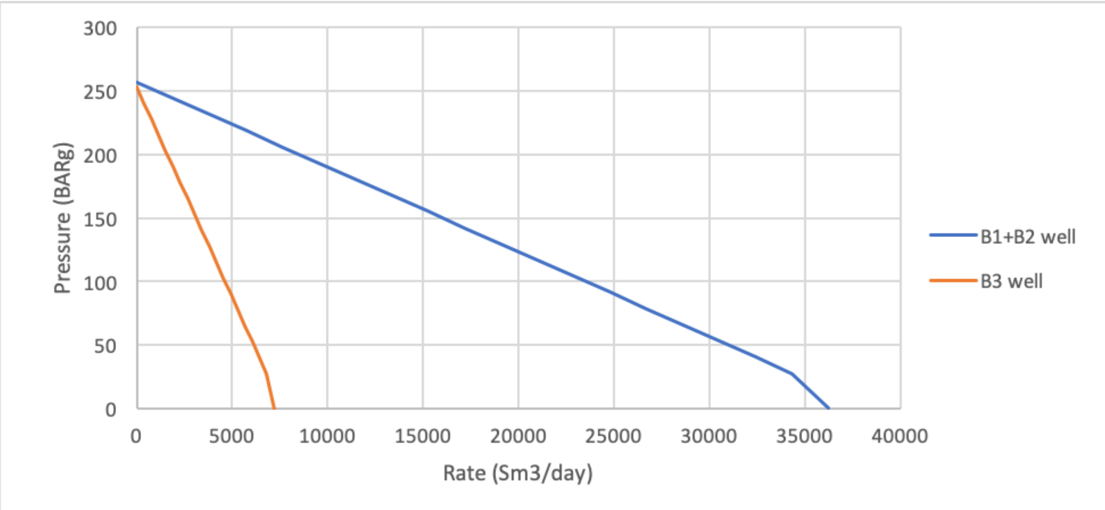

Figure 3.13: IPR curves for proposed horizontal wells through zone B1 + B2 and zone B3 respectively.

Comparing with the Figure 3.8, one may appreciate how the IPR curve has expanded significantly, enabling higher rates for the same decrease in pressure. This is the result of the horizontal well experiencing inflow from a much larger part of the reservoir zone, as opposed to the original vertical 18/10-1, which produced only for a narrow 10 meter zone of the reservoir. The IPR curve for the B3 zone horizontal well is less expanded than that for zones B1+B2, as the reservoir thickness is only 1/10 of the latter.

3.4 Coupling Material Balance and Production System Models

The production profile of a field is generated by considering the interaction between the reservoir and the production system. The MBAL tanks model the material present within the reservoir, starting at a time t_1, including initial conditions such as pressure P_{Ri}, saturations of gas S_{gi}, oil S_{oi} and water S_{wi}. The outflow from the tank is determined by the IPR curves. The pressure and flow rate readings are matched, producing a productivity index for each well, which controls the production from each tank. The in-built MBE controls the material present against the material produced with each time step t_{i+1} to deliver the oil produced N_p and the resulting RF as a percentage of the IOIP. The procedure for modelling this interaction is provided in the following figure.

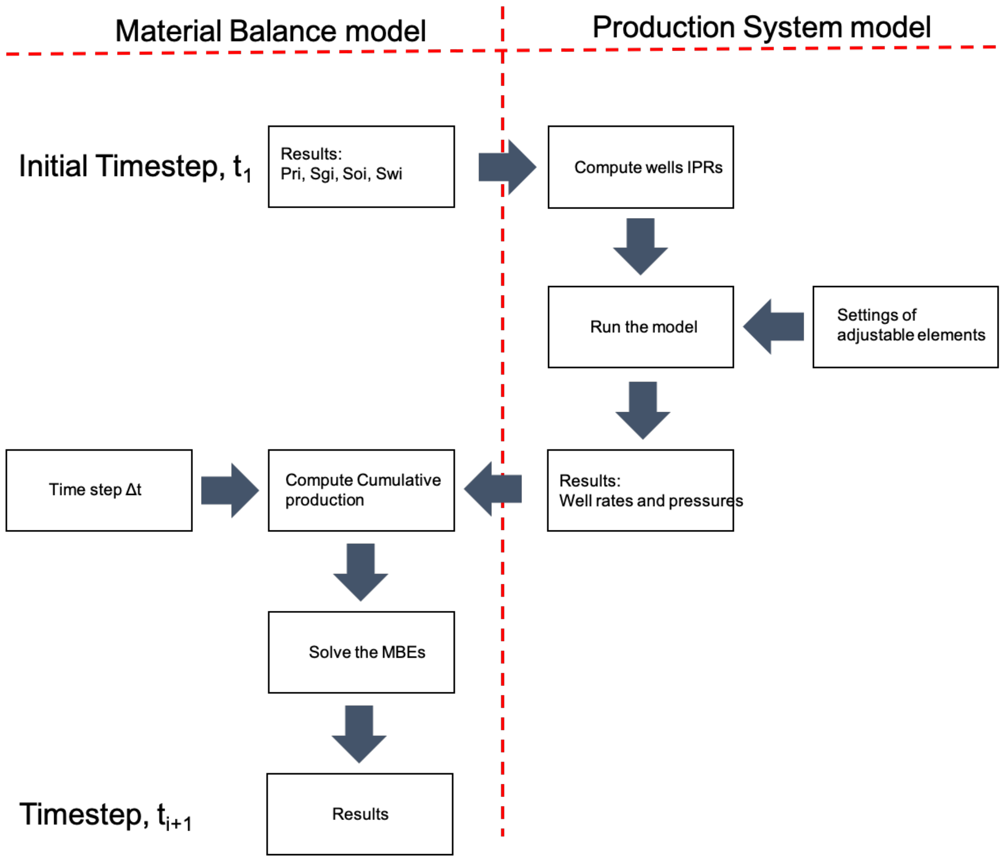

Figure 3.14: Explicit coupling of Material Balance model with Production System model

The model assumes water injection supplied by an injector well in zone B1+B2 to maintain reservoir pressure. The justification for injecting into this zone is that it is modelled to be ten times larger than zone B3. An injector well here will therefore have a larger effect on field production. The coupled model when assembled in MBAL is illustrated below:

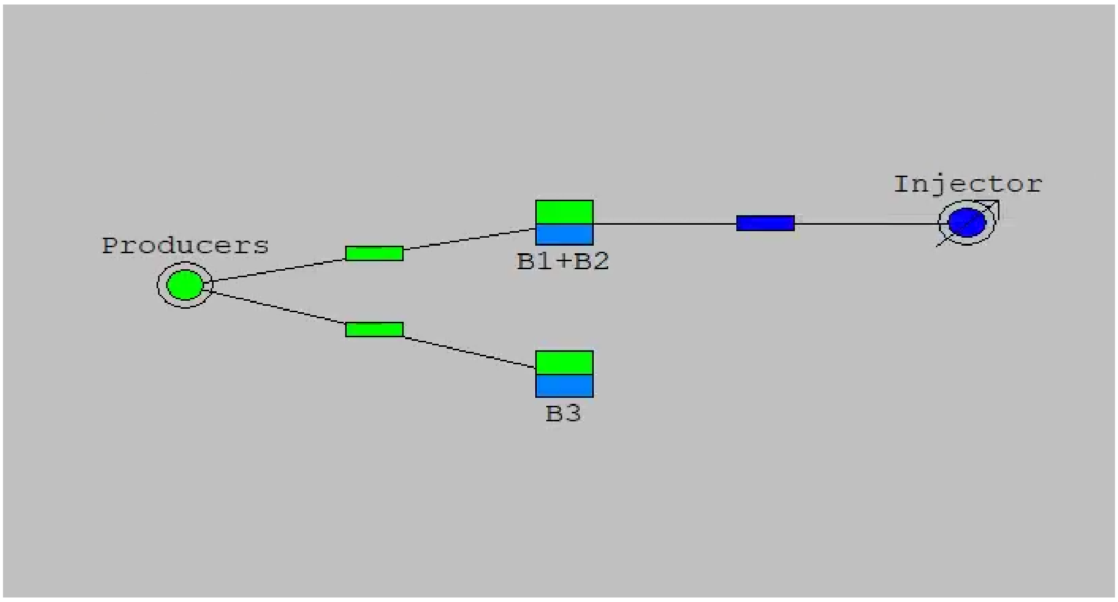

Figure 3.15: Coupled model setup in MBAL.

The reservoir has been divided into two tanks with their individual IOIP values manually computed. The IOIP values and the method by which they were obtained is explained in Chapter 4. Both tanks have pressure support from aquifer influx. The tanks are connected to the "producers" with inflow determined by the respective IPR curves for each zone. The "B1+B2" tank also has an injector connected, providing pressure support by water injection.

3.4.1 Well Type Specifications

Injector Well

The injector inflow performance must be specified to enable the simulation of water injection. The purpose of the water injection is to maintain reservoir pressure.

To ensure this pressure support is provided throughout the production of the reservoir, the bottomhole flowing injection pressure is set to 260 BARg, ensuring a margin above the initial reservoir pressure. The injectivity index describes the amount of outflow from the injector well into the reservoir. This has been set to 50 $Sm^3/day/bar$. This figure is selected rather arbitrarily, as it would be dependent on the geometry and placement of the injector well. Instead of specifying the injector well geometry or placement, the injectivity index is selected to provide a degree of pressure support. For comparison, this injectivity index is roughly 1/3 of the producer well in the same zone. The rates provided by the injector well are not examined for technical feasibility.

Production Wells

The production system has two boundaries where the pressure is fixed, being the reservoir pressure and separator pressure. To find the operating point, a point of interest must first be selected in the system (Stanko, 2019). One must then compute the available pressure curveres upstream of the point, down to the boundary node. Then, compute the required pressure curve considering the system downstream to the point of interest up to the boundary node. Finally one then intersects the curves to find the operating flow rate.

For this system, the point of interest is the heel of the production well. At this point, the available pressure is determined by the well IPR curve. Provided a separator pressure is available, the downstream pressure curve required can be determined by calculating pressure losses in the 17 km flowline from Vette (separator) to the Mackerel manifold located on the sea floor. From there the total flow Q_t is split between the tubing flow from each reservoir zone, Q_{B1+B2} and Q_{B3}. These flows experience pressure losses due to friction and gravity within the production tubing.

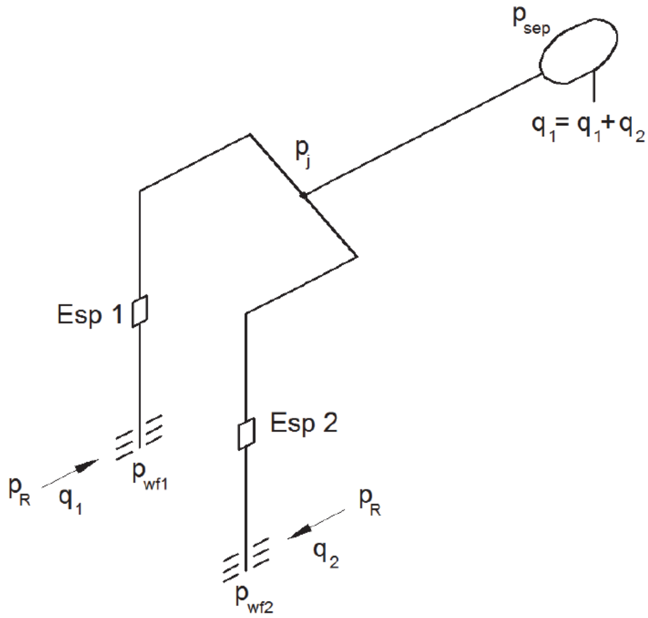

Figure 3.16: Two ESP-lifted wells with common wellhead manifold discharging to a pipeline (Stanko, 2019).

The pressure losses within the flowline and production tubing should be modelled to assess the effects on production capability. However this would require additional work which complicates the modelling and extends beyond the scope of this study. Instead, a simplification is made where the tubing head pressure P_{th} is held constant by the introduction of ESP units in both wells, as can be seen in Figure 3.16. These will be located in the heel of the well, bridging the pressure between the tubing head pressure and the bottom hole flowing pressure P_{wf}. It is assumed that the ESPs generate sufficient pressure boosting such that P_{th} = 50 BARg for both production wells. This study assumes that the ESPs used are capable of bridging the pressure gap between the bottom hole flowing pressure P_{wf} and the tubing head pressure P_{th}.

3.4.2 Production Optimisation and Constraints

A set of constraints are placed on the model to better capture a realistic production system. The reason for introducing such constraints is to set limitations which enables the model to realistically simulate the production cycle. For instance, the volume flow rates must follow theoretical and practical limitations. The constraints which will be applied to the model are introduced here.

Flowing Bottomhole Pressure

When modelling production, it is usual to model the Vertical Lift Performance (VLP or outflow) in addition to the IPR (Stanko, 2019). The VLP relation describes the bottomhole (i.e. sandface pressure) as a function of flow rate. The VLP is used together with the IPR to determine the natural point of production for the system. The VLP depends on several factors including fluid PVT properties, well geometry, tubing size, surface pressure, water cut and GOR.

For this study, a simplification has been made which negates the need to model VLP. Instead, the production will be ensured by introducing artificial lift. Artificial lift is usually achieved by installing either a gas-lift injection system or by Electrical Submersible Pump (ESP). This study will assume the use of an ESP system in both production wells to maintain a constant bottomhole pressure of 50 BARg. This assumption allows for a simpler system that avoids the challenges associated with modelling VLP, which requires a prepared well design. For the Mackerel field specifically, the choice of ESP over gas-lift is reasonable as the reservoir has no free gas and only a limited supply of gas in oil due to low GOR. The flow at the heel of the well, where the ESP is to be located, consists only of liquid (oil and water mixture). For this study, it is assumed that the ESP will not negatively affect production. The selection of ESP also eliminates the requirement for separated solution gas to be returned from the processing unit at Vette by its own dedicated flowline. The separated solution gas will be used for power generation at Vette and is not of importance to this study.

Flow Handling Capacity

For this study, a maximum liquid flow rate for the comingled flow is set to 10 000 STB/day. This constraint is placed to ensure production rates are maintained within theoretical and practical limitations of the flowline and tubing line (Rudenno, 2012).

Cessation of Production

Over the course of production, the water cut is expected to increase progressively. As the primary target of the development is asset optimisation, the model will assume continued production (without downtime) provided the operation is profitable, e.g. as long as annual revenue from produced oil exceeds the operating cost. At this point production is ceased. Assuming a constant oil price of 60 USD/STB, and a constant OPEX figure of 5.5M USD per year, the breakeven production rate becomes 252 STB/day. This oil flow rate should not be confused with the liquid flow rate, which is maintained at full production capacity of 10 000 STB/d.

Chapter 4

Uncertainty Analysis

This chapter covers the uncertainty analysis of the subsurface properties of the Mackerel field. As first outlined in the Introduction, the uncertainty of the field can be understood to be both static and dynamic in nature. Specifically, the static subsurface uncertainty is the uncertainty of parameters affecting the IOIP. The dynamic uncertainty refers to the uncertainty of how the reservoir will produce using the well system proposed in Chapter 3. This dynamic uncertainty reflects the lack of information on the connectivity between the channel sands in the reservoir. The consequence of such uncertainty cannot be modelled directly in the applied software, but can be substituted by considering the reservoir RF.

4.1 Static Reservoir Uncertainty

The static reservoir uncertainty reflects the uncertainty of reservoir parameters. This uncertainty is considerable as the field analysis only has a single well log available from which deductions regarding the entire field area must be made. One method to quantify such uncertainty is by using the Monte Carlo Simulation (MSC). MSC is a tool to perform uncertainty analysis on any project with uncertain input data. The input data is selected from figures representative of the reservoir, e.g. the log data from well 18/10-1, which is then used in iterative statistical calculations to find the most likely outcome and the range of the probable outcomes.

The MCS allows for multiple parameter input, which are allocated probability distributions. As limited information is available on the reservoir, this study will assume normal distributions for the selected input parameters which affect the IOIP figure. These parameters were the net-to-gross NTG, the porosity ϕ and the initial oil saturation S_o. The subsurface team has reported the standard deviation σ for porosity to be 0.037 and 0.118 for the initial oil saturation.(SEE APPENDIX). Determining the uncertainty of NTG is made more challenging by the lack of logs from multiple exploration wells, which would enable for a more precise estimation. The Repsol subsurface team advices that the NTG may vary by as much as ± 30% from the mean of 57%, within a confidence interval of 80%, given by P10 and P90. This can be translated to a 1.29 σ uncertainty (Walpole, Myers, Myers, & Ye, 1993). The standard deviation for NTG becomes 0.233.

For normally distributed uncertainty, the MCS requires two inputs for each parameter; the mean value and the standard deviation. For this study, the data from well 18/12-1 is assumed to be the mean value. The standard deviations are those figures provided by Repsol. These can be viewed in Table 4.1.

Table 4.1: Reservoir paramter uncertainty distributions.

Zone:	B1 + B2			B3		
	NTG	ϕ	S_o	NTG	ϕ	S_o
	-	-	-	-	-	-
Mean	0.57	0.20	0.61	1.0	0.23	0.372
Std. Deviation	0.233	0.037	0.118	0.233	0.037	0.118

The MCS runs a specified number of cases. For this study 1000 cases will be run to ensure a statistically significant output for the IOIP. The relative frequence of IOIP for the B1+B2 and B3 zones can then be plotted, along with the oil expectation. This can be viewed in Figure 4.1 and Figure 4.2, respectively.

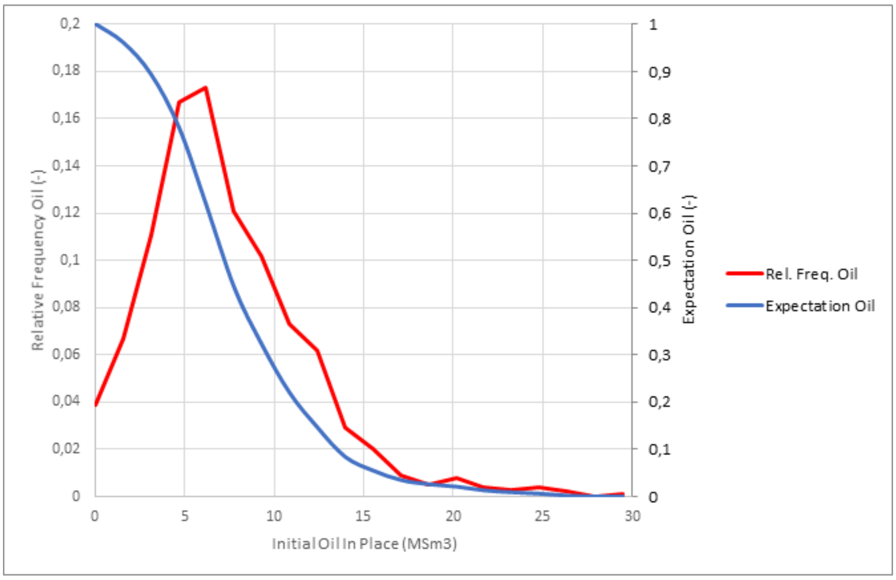

Figure 4.1: Initial Oil In Place for zone B1 + B2.

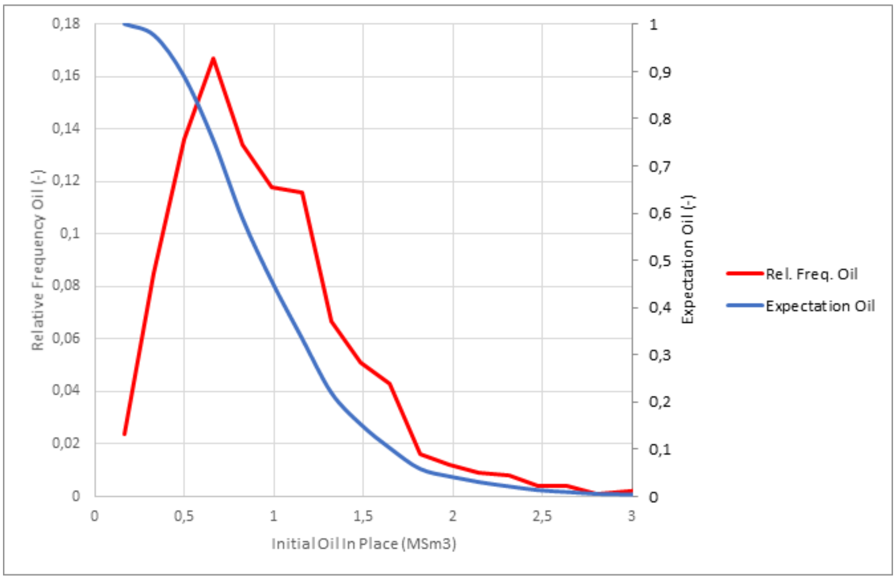

Figure 4.2: Initial Oil In Place for zone B3.

The results of the MSC can be discretised. In the petroleum industry it is customary to describe the uncertainty in terms of low (P90)/high (P10) range ("Petroleum Resources Management System", 2018). When the range of uncertainty is represented by a probability distribution, a low, a mean and a high is set such that there should be at least a 90% probability (P90) that the quantities recovered will equal or exceed the lower estimate. The same logic should be considered when reading figures for P50 and P10, with P10 representing a level where there is only a 10% chance of values being exceeded.

The lower, middle and upper confidence estimates for IOIP can be viewed in Table 4.2.

Table 4.2: Initial Oil In Place low (P90), mean (P50) and high (P10) figures.

Zone	Probability -	Initial Oil In Place MSm^3
B1 + B2	P90	3.88
	P50	7.04
	P10	11.84
B3	P90	0.48
	P50	0.95
	P10	1.56

4.2 Dynamic Reservoir Uncertainty

The dynamic uncertainty reflect the amount of oil produced versus the amount of original oil present, i.e the definition of Recovery Factor (RF). The connectivity of the reservoir is not easily modelled in MBAL, but the effect of the connectivity can be simulated by altering the RF by employing a tuning parameter which is a direct input to the RF. As discussed in the Methodology chapter, the residual oil saturation, S_{or}, is a used to make the desired alterations to the RF to 20%, 30% and 40%.

4.2.1 Relative Permeability Curves

Relative permeability k_{rj} is a term used to relate the absolute permeability (100% saturation with a single fluid) of a porous system, to the effective permeability of a particular fluid in the system, when that fluid occupies only a fraction of the total pore volume. The relative permeability is a strong function of phase saturation S_j. The relationship between relative permeability and residual saturation is a function of rock-fluid properties (e.g pore size distribution) and wettability. In mathematical modelling of multiphase flow it is conventional to assume that relative permeabilities are the functions of saturation only (Zolotukhin & Ursin, 2000).

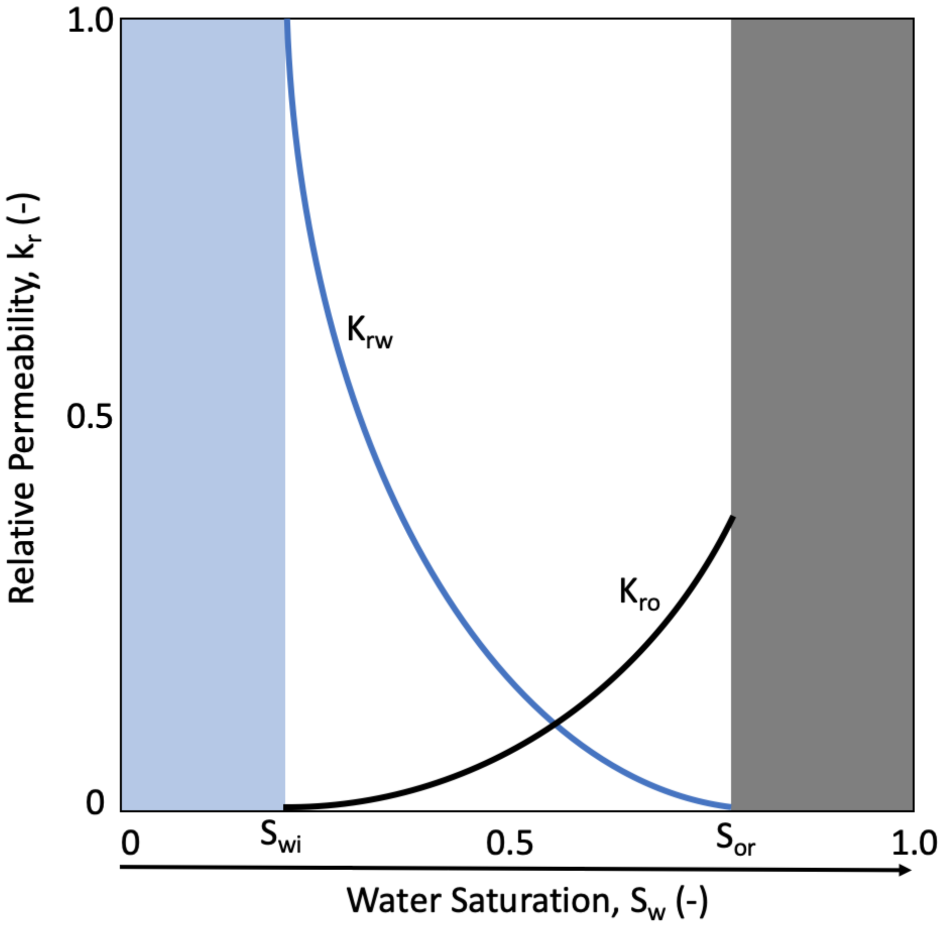

Figure 4.3: A typical relative permeability curve from a water flood.

The residual oil saturation k_{ro} is the fraction of a pore volume still containing oil after water has displaced the initial oil saturation. The degree of displacement is determined by the capillary pressure present in the pore volume. Residual oil saturation is the ratio of the immobile residual oil volume divided by the effective porosity. Effective porosity is the ratio of porous volume in communication over the total porosity of the system.

In displacements controlled by capillarity, which are typical of oil reservoir floods, these pore-level events are governed by the local pore geometry, pore topology, and fluid properties, but the pressure field initiates these pore-level events and integrates them with the externally imposed Darcy flow (Mohanty, Davis, Scriven, et al., 1987).

Relative permeability in MBAL is for the tank as a whole and each well uses the same base set of relative permeability curves. Breakthrough constraints are used to modify the production performance of each individual well. From the relative premeability curves at the current reservoir saturation and PVT at the current reservoir pressure, MBAL calculates the fractional flow for water and gas. For an oil/water system (Brooks & Corey, 1964), the relative permeabilities of oil and water can be expressed by

$$k_{ro} = k_{ro,cw}\left(\frac{1 - S_w - S_{or}}{1 - S_{cw} - S_{or}}\right)^{n_o} \tag{4.1}$$

$$k_{rw} = k_{rw,or}\left(\frac{S_w - S_{cw}}{1 - S_{cw} - S_{or}}\right)^{n_w} \tag{4.2}$$

with $k_{rw,or}$ and$k_{ro,cw}$ the end-point relative permeabilities respectively. The n_w and n_o are so called Corey Exponents for water and oil.

Relative permeabilities values are entered in tables, where the user can specify the residual saturation, end point of the relative permeability and the Corey Exponent for each phase in the reservoir.

The chosen parameter to modulate the Recovery Factor is the residual oil saturation, as this parameter can be adjusted with great affect. The RF is sensitive to these adjustments; increasing the residual oil saturation decreases the RF, while decreasing the residual oil saturation produces a higher RF as less oil remains in the connected pore volume after water intrusion. The rate at which this intrusion is achieved can be adjusted by manipulating the relative permeability curve of oil using the exponent. Sensitivity studies using numerical simulation have shown that this behavior has the most important effect on recovery rates (Laroche, Chen, Yortsos, Kamath, et al., 2001).

4.2.2 Cumulative Production

By using the residual oil saturation as a tuning operator for the recovery factor, it is possible to determine the cumulative production for each of the subsurface realisations. The summary of cumulative production for each subsurface realisation is presented in Table 4.3.

Table 4.3: Cumulative oil production for each subsurface realisation.

Oil produced (MSm^3)		Initial Oil In Place		
		P90	P50	P10
	20%	0.88	1.60	2.68
Recovery Factor	30%	1.31	2.41	4.57
	40%	1.75	3.21	5.37

Chapter 5

Economic Analysis

A simple economic analysis is performed for each subsurface realisation. This enables the evaluation of the economic robustness of the development.

5.1 Discount Factoring

Economic analysis in the oil and gas industry is usually performed using the discounted cashflow technique (DCF) analysis. This examines the pre- and post-tax cash flow of the project under various scenarios.

A pre-tax analysis is a simple technique and is essentially an income versus cost analysis. It applies a discount factor to each year and attempts to estimate the ultimate value of the investment based on the future cash flows generated by the investment over the lifetime of the investment e.g. the field develeopment. It estimates the final value of an investment today, based on projections of how much money it will generate in the future.

The major pillar of DCF is the concept of the time value of money. The time value of money assumes that any nominal monetary amount today is worth more than it is tomorrow. This is due to the fact that money can be invested 'risk free' (in US T bonds) and make a non-zero return, plus an investor should be rewarded for the additional risk they are taking by investing in a project (for example). Therefore, a discount rate, which is compounded each year is applied to the cashflows.

The most fundamental application of the 'Time Value Concept' applies the following variables to give the Future Value (FV) using annual compounding;

$$FV_n = PV \cdot \left[1 + D\right]^n \tag{5.1}$$

Or, re-arranging this for PV gives;

$$PV_n = \frac{FV}{\left[1 + D\right]^n} \tag{5.2}$$

where PV is the Present value of money, D is the Discount Rate and n is the number of years.

The result of this escalation in the future value of todays money is that future year values are discounted by the compound rate from the start year of the project, year 0. Each year has a Discount Factor as a result of the Discount Rate (D) and the number of years since start (n). This is shown below for 10% and 12% discount rates. It means that, for example, a unit of income in year 6, at 10% discount rate, is worth only 0.56 (56% of a unit of cost in year 0). The year 6 discount factor is 0.51 for a 12% discount rate meaning the future value is worth only 0.51 (51% of the original cost in year 0). The higher the discount rate and the further away in time, the less the value relative to todays values.

Table 5.1: Discount Factors

Years (n)	0	1	2	3	4	5	6
Annual Discount Factor (10 %)	1.00	0.91	0.83	0.75	0.68	0.62	0.56
Annual Discount Factor (12 %)	1.00	0.89	0.80	0.71	0.64	0.57	0.51

When analysing a project, the two main performance indicators of an investment are the Net Present Value (NPV) at the specified Discount Rate (D%) and the Internal Rate of Return (IRR%).

The NPV is the value of the cashflow for the investment discounted at the applicable discount rate. This should be positive for a viable project, and the more positive the NPV the better the project in terms of return per unit of investment.

The IRR is the discount rate applicable to the cashflows to give an NPV of zero, it is a measure of the robustness of the project. Many companies have a 'hurdle rate' for the IRR. This means that they will not accept projects for which the IRR is below a certain percentage such as 8%, 12% or even 15%. The higher the IRR required the more robust the project and the quicker the required payback time. If a company sets a hurdle rate, the best project is the one giving the highest NPV of those which have a sufficiently high IRR. It must therefore pass the following tests:

1. If the IRR meets the hurdle rate (e.g. 12%)?, and

2. Which of the realisations gives the highest NPV given it meets the IRR hurdle.

5.2 Analysis

5.2.1 Pre-Tax Analyis

The expenditure figures were supplied by Repsol. These figures might not be final, but for the purpose of this study they act as placeholder values to enable this economic analysis.

The capital expenditure (CAPEX) is 2500 million NOK / 275 million USD for the wells, template and flowlines. The Operational Expenditure (OPEX) is fixed at 50 million NOK / 5.5 million USD per year. Abandonment Expenditures (ABEX) are taken to be 20% of the CAPEX, giving a cost of 500 million NOK / 55 million USD.

The oil price is assumed to be constant at 60 USD/STB or 545 NOK/STB. This assumes a constant exchange rate of 0.11 USD per NOK or 9 NOK per USD. The exchange rate is collected from Norges Bank on 19/08/19 (norges bank.no, n.d.)

Table 5.2: Summary of economic assumptions made.

Conversions / Inputs:	Values
Discount rate, D (%)	10
Days in year	365
Oil price [USD/STB]	60
Sm^3/STB	6.29
USD/NOK	0.11
CAPEX (MNOK)	2500
OPEX (MNOK/a)	50

In a pre-tax analysis, the CAPEX and OPEX costs are treated equally. In reality, capex is more expensive than OPEX as it is depreciated over a number of years rather than being deducted in total in the year it is incurred. In the case of Norway, CAPEX is depreciated over a 6 year period making it less valuable a deduction every year when inflation and real discount rates are applied.

The production profiles have been generated and can be viewed in Appendix C. As mentioned in Section 3.4.2, the economic cut off was set at the point when the value of the production in any year is less than the OPEX. Therefore, the last year of production, year n, is identified and abandonment is triggered when the Annual Revenue < Annual OPEX. This condition being met results in abandonment of the field in year $n + 1$ at a cost of 500 million NOK or 55 million USD.

5.2.2 Post-Tax Analyis

The economic analysis cannot be conclusive without considering inflation and taxation towards the host government. The outlines of the Norwegian Petroleum Taxation system is shown in Table 5.3.

There is a normal corporate tax paid on profits after operating costs (OPEX) and depreciation (NPD, n.d.). It is also possible to deduct interest payments but I will ignore this and assume the project is financed by shareholder equity (not loans). This profit is taxed at a 22% Corporate Tax rate.

In addition to Corporate Tax there is a Special Petroleum Tax at 56%. This is paid in addition to the 22% Corporate Tax giving a marginal tax rate of 78% (22% + 56%), although there is some shelter on this in the form of an uplift on the investment costs at 5.2% for 4 years.

Table 5.3: The main elements of the Norwegian Petroleum Tax system (norskpetroleum.no)

+ Operating income (norm prices)
- Operating expenses - Linear Depreciation for investments (6 years) - Exploration expenses, R&D and decom. - Environmental taxes and area fees - Net financial costs
= Corporation tax base (22%)
- Uplift (5.2% of investments for 4 years)
= Special tax base (56%)

So, the Norwegian tax system allows costs to be recovered by deducting from tax at 78%, but it also takes approximately 78% of profits made beyond this. It is therefore an aggressive tax regime.

Chapter 6

NPV Results and Discussion

6.1 Pre-Tax Results

The results are shown in detail in Appendix D. The summary of the results is shown here. It shows a range of NPV 10% results between -53 million USD and 659 million USD for a 2500 million NOK / 275 mill USD investment. The mean, P50/30% recovery factor realisation gives 308 million USD (NPV10), with a corresponding pre-tax IRR of 55%.

Table 6.1: NPV 10% results pre-tax.

NPV 10% pre-tax (M USD)		Initial Oil In Place		
		P90	P50	P10
	20%	-53	146	352
Recovery Factor	30%	73	308	545
	40%	156	443	659

Table 6.2: IRR results pre-tax.

IRR pre-tax (%)		Initial Oil In Place		
		P90	P50	P10
	20%	N/A	40%	59%
Recovery Factor	30%	25%	55%	66%
	40%	39%	63%	71%

The NPV and IRR values over the range of uncertainties indicate that the development of Mackerel is robust project pre-tax based on anything other than the Low P90/20% RF subsurface realisation.

These pre-tax results are shown graphically below for the NPV 10% pre-tax in Figure 6.1 and the IIR % in Figure 6.2.

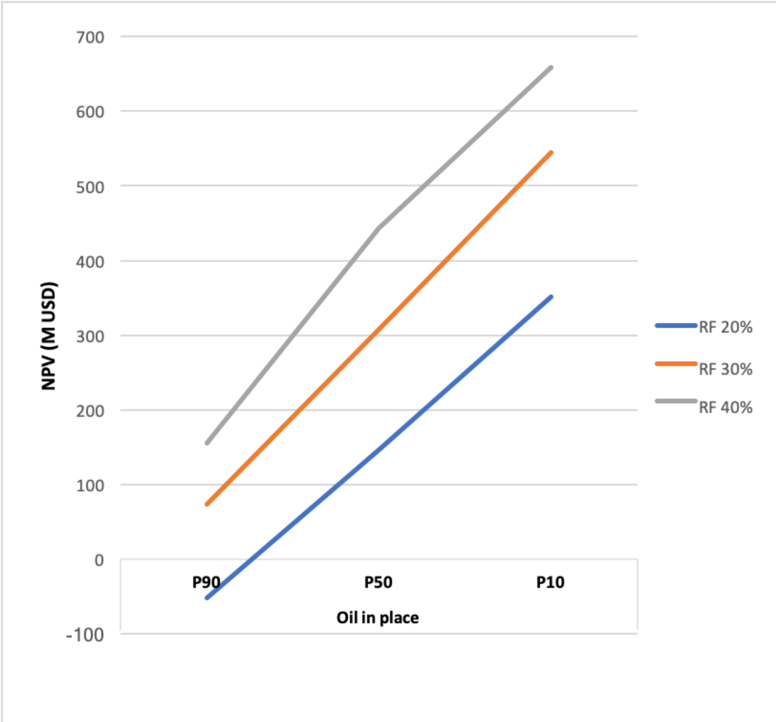

Figure 6.1: NPV 10% pre-tax analysis

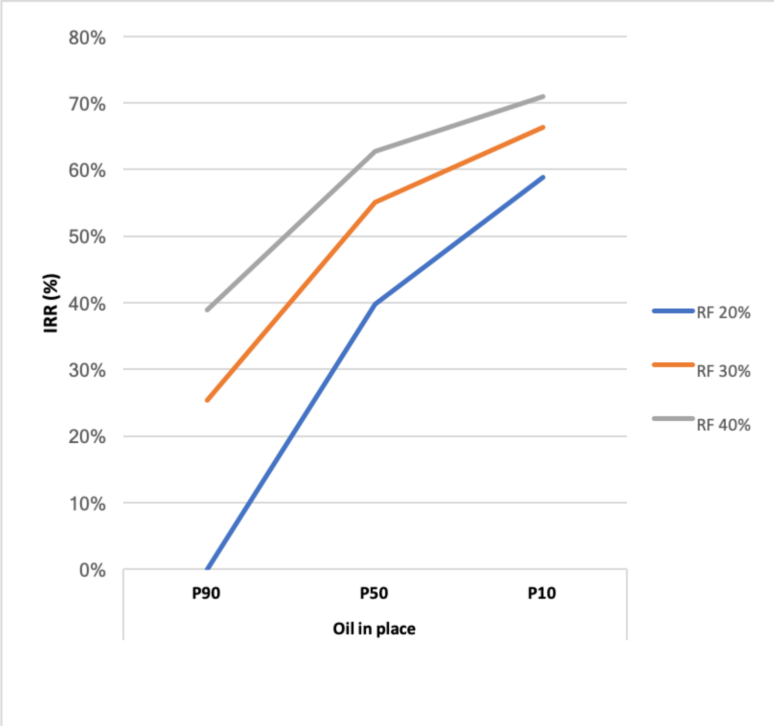

Figure 6.2: IRR pre-tax analysis

6.2 Impact of Uncertainty on Pre-Tax NPV/IRR

By setting the middle subsurface realisation with P50 IOIP together with 30% recovery factor) to zero, the relative differences in terms of NPV due to the subsurface uncertainties can be expressed and a pre-tax 10% NPV value. This can be viewed in Table 6.5.

Table 6.3: Delta NPV results relative to the P50/30% RF realisation.

NPV 10% (MUSD)		Initial Oil In Place		
		P90	P50	P10
	20%	-360	-161	44
Recovery Factor	30%	-234	-	237
	40%	-152	136	351

By illustrating the deltas in histogram format, the economic risk of subsurface uncertainty becomes apparent when comparing the subsurface realisations.

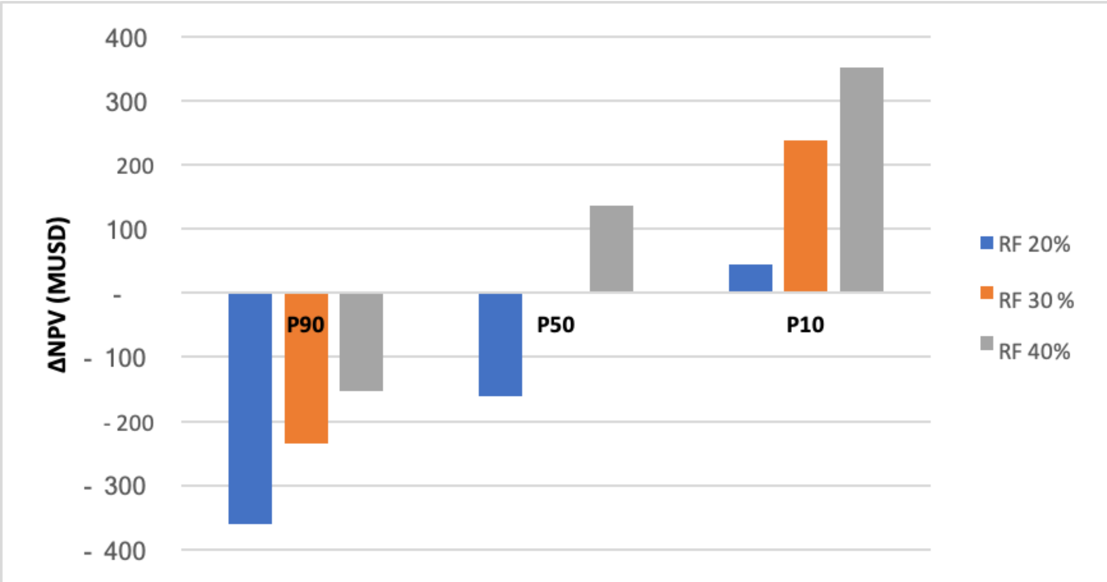

Figure 6.3: NPV deviations for each Realisation

As can be seen in Figure 6.3, the economic risk tends to the negative as the delta values for P90 realisations are more negative than the P10 realisations are positive.

To provide this with more context, a normalisation of the uncertainty over the investment (CAPEX) has been set up in Table 6.4.

Table 6.4: Delta NPV results relative to the P50/30% RF realisation.

Normalised NPV 10% Uncertainty / CAPEX		Initial Oil In Place		
		P90	P50	P10
	20%	-131%	-50%	16%
Recovery Factor	30%	-85%		86%
	40%	-55%	49%	128%

6.3 Post-Tax Results

A simple tax model representing the Norwegian tax system outlined in Table 5.3 has been set up. It shows the effect of the high tax rates in Norway where a marginal rate of 78% is applied. This post-tax model has ben applied to the central cases and the various recovery factors of 20%, 30% and 40%. The oil price of 60USD/bbl, the Opex of 5.5million USD/a and the abandonment cost of 55 million USD were assumed to be real terms and are escalated with inflation of 2% per annum for the duration of the project. A 10% (nominal) discount rate is then applied.

It is assumed that the project is ringfenced for tax and that there are no synergies with the rest of the company portfolio to allow OPEX or depreciation to be deducted and tax saved earlier, so the actual economics may be better than assessed here.

The results are shown below. The high marginal taxation of 78% removes a large part of the pre-tax NPV values making the project borderline/marginal (15% IRR) in the P50/30% RF realisation, but very marginal for the P50/20% RF realisation with an IRR of 7%. Although, there may be portfolio upside as stated above.

Table 6.5: Pre- and post-tax NPV 10% and IRR figures for three P50 realisations.

	Pre-Tax		Post-Tax	
Realisation	NPV (10%)	IRR	NPV 10%	IRR%
P50, 20 %	146	40%	22	7%
P50, 30 %	308	55%	36	15%
P50, 40 %	443	63%	84	20%

6.4 Sensitivity Analysis

A simple sensitivity analysis has been performed on the cashflows. Zone B1+B2 represents 87-88% of the IOIP and zone B3 is 12-13%. However, a production well is dedicated to B3 alone. If one was to prorate the production and cut out an estimated 60 million USD investment for the B3 well, then the project is boosted as shown in Table 6.6. It can therefore be proposed that the development could be considered with only one well in zone B1+B2, or perhaps with two wells to access more of the B1+B2 reservoir and thereby increase the RF.

Table 6.6: Sensitivity analysis for removing B3 well.

	NPV (MUSD)	IRR (%)
Proposed development	36	15
Drop B3 well	41	17

Chapter 7

Discussion

In this chapter, the model will be evaluated for its ability to properly simulate the real world conditions found in the Mackerel Field and suggestions will be presented to aid future development studies towards the field.

The model was constructed with the most recent available information from a number of different sources. The data on which this study relies is sourced from the original Elf Petroleum log of well 18/10-1 and DST and has been complemented by subsequent work, including that of the Repsol subsurface team and interpretations made.

The reliability of the original 18/10-1 data has not been assessed by the author of this study, but it should be noted that differences were noticed between the interpretations made by the Repsol subsurface team and that of the original survey authors. This study adhered to a principle that the current Operator information would supercede that found in older documents. The use of the DST data was the only data available on reservoir productivity and were therefore central to obtaining the IPR curves. Notes from the DST reporting scheme indicated multiple unsuccessful or unqualified DST results. The accuracy of the DST data could therefore be treated with a degree of caution. When modelled in PROSPER, the DST rates did intersect with the Darcy model-generated IPR curve, however this could be a case of causality.

The decision to model the reservoir as a homogeneous model with horizontal well completions is perhaps the most important assumption made in the course of the study. In a complicated fluvial channel reservoir such as Mackerel, the use of a homogeneous model is a clear limitation for performing accurate modelling. More likely, the completion of such wells would be performed with drilling targeting the most promising sand beds with lateral perforations set to increase access to unconnected sand beds and increase overall productivity.

The Gross-Rock-Volume (GRV) figure was provided by the Repsol subsurface team. This figure was deemed reliable and so an uncertainty analysis was not performed on GRV. The decicion to model the anticline reservoir bounded by faults as a cuboid reservoir exhibiting the same thickness and properties as those found by the 18/10-1 well log represents a gross simplification. While providing a suitable reservoir for PROSPER to model the horizontal well completion IPRs, it also prevented for accurate simulation of behaviour typically found in the inclined flanks for water influx. The decision to model the B1+B2 zone as being of a 10:1 magnitude larger than zone B3 is likely an overestimation of the size of zone B3, due to the close proximity of the OWC to the top of B3.

The decision to model static reservoir uncertainty using normal distributions was an assumption made in light of limited information from only a single exploration well. Realistically these reservoir parameter uncertainties would not follow a normal distribution but instead follow some skewed distribtuion form. More information should be collected to gain an improved understanding of how the uncertainy is distribtued.

The decision to model recovery factor as a proxy for reservoir connectivity does not factor in the complexities of producing a fluvial channel reservoir system. Recovery factor is also determined by the location of production wells and injector well the connectivity between them.

The decision to place one producer in the B1+B2 zone and one in B3 could prove to be an unrealistic method to produce the reservoir. As the B3 zone only is 2.5m thick between the upper sealing shale and the OWC, it is unclear if such a thin zone of oil could be produced by a horizontal well in the way it was set up in the PROSPER model. The limited reserves in zone B3 may not justify its own production well. This is also discussed in Section 6.4 from an economic perspective.

The effect of the aquifer influx is minor, due to limited aquifer permeability and aquifer size. The values used were recommendations made by the Repsol subsurface team due to limited data available, as little is known about the properties of the aquifer. The selected aquifer permeabilities therefore should be considered as somewhat arbitrary, however values were chosen using a similar order of magnitude as the reservoir permeabilities.

As the production commences, there will be eventual water breakthrough, leading to an increase in the Water Cut (WC) of the liquid flow. This can be viewed in Appendix C. For this study, it has been assumed that the separator at Vette is capable of handling any WC without adverse affects on production rates.

The ability to maintain production is dependent on the installed ESP being capable of delivering sufficient tubing head pressure. A study on deliverability with realistic ESP capabilities should be conducted. Such a production study would benefit from comparing the option of alternatives to artificial lift, such as re-using the separated solution gas for gas-lifing purposes. Production downtime has not factored for the production model. In reality, well maintenence would be required periodically, or if a production issue should arise, thereby making the 365 days per year production model very theoretical and optimistic.

The company tax situation not factored into the economic study. As stated, the post-tax model uses a marginal tax of 78%. If any early losses can be offset on other profits then this will boost the post-tax economics. A more detailed study of expenditures is recommended to improve the precision of the economic model that has been performed.

Chapter 8

Conclusion

From the work conducted in this study, the following may be concluded:

- A coupled model consisting of a material balance and production system was successfully set up and yielded plausible production rates.

- The compounded uncertainty of NTG, ϕ and S_o, calculated using Monte Carl Simulations, provides a wide distribution of possible Initial Oil In Place figures, which was used to create P90, P50 and P10 values of static reservoir uncertainty.

- The uncertainty of reservoir connectivity was modelled by changing the relative permeability curves to simulate dynamic uncertainty with 20%, 30% and 40% recovery factors.

- The development proposal appears to be positive pre-tax. The only realisation that yielded a negative result was the P90/20% Recovery Factor realisation with only a net negative of -53 million USD.

- The economic risk (Δ pre-tax NPV 10%) to developing the field for a range of 9 subsurface realisations have been calculated.

- The post-tax analysis indicates an IRR of 15% for the P50/30% RF base case and an NPV 10% of 36 million USD. This could be a viable project given the assumptions made.

- Simple economic analysis shows that the well in zone B3 may not add value to this project, as it exploits only 12% of the IOIP. Cutting out the well into zone B3 may boost the IRR by 2% to 17% and increase post-tax NPV 10% from 36 to 41 million USD. Drilling 2 wells into zone B1+B2 may be a better option. Further study is recommended to investigate the economic risk of drilling a well into zone B3.

- Limitations of the model's capability to capture real-world issues have been addressed and possible improvements have been suggested for future consideration.

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Appendix A

MBAL Model Input

A.1 Initial Oil In Place distribution data

Zone B1+B2			Zone B3		
IOIP	Expectation	Rel. Freq.	IOIP	Expectation	Rel. Freq.
	Oil	Oil		Oil	Oil
(MSm3)	(fraction)	(fraction)	(MSm3)	(fraction)	(fraction)
-	1.00	0.00	0.14	1.00	0.01
1.19	1.00	0.01	0.28	0.99	0.04
2.38	0.99	0.06	0.42	0.95	0.10
3.57	0.93	0.10	0.56	0.85	0.12
4.76	0.82	0.17	0.70	0.73	0.13
5.95	0.66	0.17	0.84	0.60	0.13
7.14	0.49	0.12	0.98	0.47	0.13
8.33	0.36	0.12	1.12	0.34	0.11
9.52	0.25	0.09	1.26	0.22	0.06
10.71	0.16	0.06	1.40	0.16	0.06
11.90	0.10	0.03	1.54	0.11	0.04
13.09	0.06	0.02	1.68	0.07	0.02
14.28	0.04	0.01	1.82	0.04	0.01
15.48	0.03	0.01	1.96	0.03	0.01
16.67	0.02	0.01	2.10	0.02	0.01
17.86	0.01	0.00	2.24	0.01	0.01
19.05	0.01	0.00	2.38	0.01	0.00
20.24	0.01	0.00	2.52	0.01	0.00
21.43	0.00	0.00	2.66	0.01	0.00
22.62	0.00	0.00			

Figure A.1: Data for IOIP distributions

A.2 Relative Permeabilities

Table A.1: Relative permeability for the P90/20% realisation

	Zone B1+B2			Zone B3		
	residual sat.	End point	n_j	residual sat.	End point	n_j
rel.perm water	0.610	0.60	2	0.372	0.600	2
rel.perm oil	0.161	1	12	0.161	1	12
rel.perm gas	0.200	0.600	1	0.200	0.600	1

Table A.2: Relative permeability for the P90/30% realisation

	Zone B1+B2			Zone B3		
	residual sat.	End point	n_j	residual sat.	End point	n_j
rel.perm water	0.610	0.60	2	0.372	0.600	2
rel.perm oil	0.118	1	8	0.118	1	8
rel.perm gas	0.200	0.600	1	0.200	0.600	1

Table A.3: Relative permeability for the P90/40% realisation

	Zone B1+B2			Zone B3		
	residual sat.	End point	n_j	residual sat.	End point	n_j
rel.perm water	0.610	0.60	2	0.372	0.600	2
rel.perm oil	0.079	1	6	0.079	1	6
rel.perm gas	0.200	0.600	1	0.200	0.600	1

Table A.4: Relative permeability for the P50/20% realisation

	Zone B1+B2			Zone B3		
	residual sat.	End point	n_j	residual sat.	End point	n_j
rel.perm water	0.610	0.60	2	0.372	0.600	2
rel.perm oil	0.155	1	12	0.155	1	12
rel.perm gas	0.200	0.600	1	0.200	0.600	1

Table A.5: Relative permeability for the P50/30% realisation

	Zone B1+B2			Zone B3		
	residual sat.	End point	n_j	residual sat.	End point	n_j
rel.perm water	0.610	0.60	2	0.372	0.600	2
rel.perm oil	0.115	1	8	0.115	1	8
rel.perm gas	0.200	0.600	1	0.200	0.600	1

Table A.6: Relative permeability for the P50/40% realisation

	Zone B1+B2			Zone B3		
	residual sat.	End point	n_j	residual sat.	End point	n_j
rel.perm water	0.610	0.60	2	0.372	0.600	2
rel.perm oil	0.076	1	6	0.076	1	6
rel.perm gas	0.200	0.600	1	0.200	0.600	1

Table A.7: Relative permeability for the P10/20% realisation

	Zone B1+B2			Zone B3		
	residual sat.	End point	n_j	residual sat.	End point	n_j
rel.perm water	0.610	0.60	2	0.372	0.600	2
rel.perm oil	0.165	1	12	0.165	1	12
rel.perm gas	0.200	0.600	1	0.200	0.600	1

Table A.8: Relative permeability for the P10/30% realisation

	Zone B1+B2			Zone B3		
	residual sat.	End point	n_j	residual sat.	End point	n_j
rel.perm water	0.610	0.60	2	0.372	0.600	2
rel.perm oil	0.207	1	4	0.207	1	4
rel.perm gas	0.200	0.600	1	0.200	0.600	1

Table A.9: Relative permeability for the P10/40% realisation

	Zone B1+B2			Zone B3		
	residual sat.	End point	n_j	residual sat.	End point	n_j
rel.perm water	0.610	0.60	2	0.372	0.600	2
rel.perm oil	0.140	1	4	0.140	1	4
rel.perm gas	0.200	0.600	1	0.200	0.600	1

Appendix B

PROSPER Model Input

B.1 PVT Matching

Figure B.1: Matching of PVT with emperical correlations.

B.2 Well Deviation Surveys

18/10-1 well		B1+B2 well		B3 well	
MD	TVD	MD	TVD	MD	TVD
m	m	m	m	m	m
0	0	0	0	0	0
2800	2800	1500	1500	1500	1500
		1800	1800	1800	1800
		2005	2000	2005	2000
		2120	2100	2120	2100
		2250	2200	2250	2200
		2500	2300	2500	2300
		2950	2400	2950	2400
		3300	2410	3300	2430

Figure B.2: Deviation survey data for PROSPER well models

B.3 Inflow Performance Relationship rates

18/10-1 well		B1+B2 well		B3 well	
Liquid Rate Sm3/day	Pressure BARa	Liquid Rate Sm3/day	Pressure BARa	Liquid Rate Sm3/day	Pressure BARa
0.00	257.91	0.00	257.91	0.00	253.00
59.19	245.16	867.01	245.16	214.37	240.51
118.37	232.41	1 734.03	232.41	428.74	228.02
177.56	219.67	2 601.04	219.67	643.11	215.53
236.74	206.92	3 468.05	206.92	857.48	203.04
295.93	194.17	4 335.07	194.17	1 071.85	190.55
355.11	181.42	5 202.08	181.42	1 286.22	178.06
414.30	168.67	6 069.09	168.67	1 500.59	165.57
473.49	155.92	6 936.10	155.92	1 714.96	153.08
532.67	143.17	7 803.12	143.17	1 929.33	140.59
591.86	130.42	8 670.13	130.42	2 143.70	128.10
651.04	117.67	9 537.14	117.67	2 358.07	115.61
710.23	104.93	10 404.20	104.93	2 572.44	103.12
769.41	92.18	11 271.20	92.18	2 786.81	90.62
828.60	79.43	12 138.20	79.43	3 001.18	78.13
887.79	66.68	13 005.20	66.68	3 215.55	65.64
946.97	53.93	13 872.20	53.93	3 429.92	53.15
1 006.16	41.18	14 739.20	41.18	3 644.29	40.66
1 065.34	27.94	15 606.20	27.94	3 858.66	27.62
1 124.53	0.94	16 473.20	1.09	4 073.03	0.94

Figure B.3: IPR data for PROSPER well models

B.4 Dietz Shape Factor

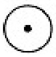
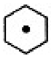
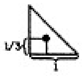
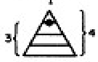
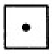
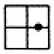
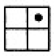
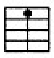
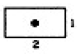
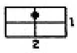
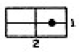
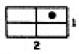
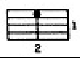
IN BOUNDED RESERVOIRS	C_A	$\ln C_A$	$1/2 \ln\left(\frac{2.2458}{C_A}\right)$	EXACT FOR $t_{DA} >$	LESS THAN 1% ERROR FOR $t_{DA} >$	USE INFINITE SYSTEM SOLUTION WITH LESS THAN 1% ERROR FOR $t_{DA} <$
	31.62	3.4538	−1.3224	0.1	0.06	0.10
	31.6	3.4532	−1.3220	0.1	0.06	0.10
	27.6	3.3178	−1.2544	0.2	0.07	0.09
	27.1	3.2995	−1.2452	0.2	0.07	0.09
	21.9	3.0865	−1.1387	0.4	0.12	0.08
	0.098	-2.3227	+1.5659	0.9	0.60	0.015
	30.8828	3.4302	−1.3106	0.1	0.05	0.09
	12.9851	2.5638	−0.8774	0.7	0.25	0.03
	4.5132	1.5070	−0.3490	0.6	0.30	0.025
	3.3351	1.2045	−0.1977	0.7	0.25	0.01
	21.8369	3.0836	−1.1373	0.3	0.15	0.025
	10.8374	2.3830	−0.7870	0.4	0.15	0.025
	4.5141	1.5072	−0.3491	1.5	0.50	0.06
	2.0769	0.7309	+0.0391	1.7	0.50	0.02
	3.1573	1.1497	−0.1703	0.4	0.15	0.005

Figure B.4: Dietz shape factor chart

Appendix C

Production Data

P90/20% RF													
Time	Reservoir Average Pressure	Oil Recovery Factor	Oil Rate	Water Rate	Liquid Rate	Avg.Oil Rate	Avg.Gas Rate	Avg.Water Rate	Avg.Liq Rate	Water Cut	Cum Oil Produced	Cum Gas Produced	Cum Wat. Produced
(date m/d/y)	(BARg)	(percent)	(STB/day)	(STB/day)	(STB/day)	(STB/day)	(MMscf/day	(STB/day)	(STB/day)	(percent)	(MSm3)	(MMscf)	(MMSTB)
01/01/2026	256.56	-	10 000.00	-	10 000.00						-	-	-
01/07/2027	210.96	12.01	5 060.01	4 939.98	9 999.99	5 236.69	0.29	4 763.30	9 999.99	47.63	0.52	180.69	0.41
01/06/2028	214.85	15.52	1 481.36	8 518.65	10 000.00	1 476.42	0.08	8 523.56	9 999.98	85.24	0.68	233.54	3.09
01/04/2029	215.24	16.98	847.73	9 152.26	10 000.00	835.97	0.05	9 164.03	9 999.99	91.64	0.74	255.49	6.32
01/03/2030	215.29	17.91	592.83	9 407.17	10 000.00	582.07	0.03	9 417.99	10 000.10	94.18	0.78	269.43	9.71
01/02/2031	215.30	18.59	455.39	9 544.61	10 000.00	446.06	0.02	9 553.93	10 000.00	95.54	0.81	279.65	13.16
01/01/2032	215.30	19.13	369.44	9 630.54	9 999.98	361.34	0.02	9 638.62	9 999.97	96.39	0.84	287.72	16.66
01/06/2033	312.61	19.58	301.66	9 698.33	9 999.99	310.64	0.02	9 689.36	9 999.99	96.89	0.86	294.51	20.24
01/05/2034	312.47	20.00	260.16	9 739.86	10 000.00	267.88	0.01	9 732.15	10 000.00	97.32	0.87	300.17	23.78

Figure C.1: Production data for P90/20% RF realisation.

P90/30% RF													
Time	Reservoir Average Pressure	Oil Recovery Factor	Oil Rate	Water Rate	Liquid Rate	Avg.Oil Rate	Avg.Gas Rate	Avg.Water Rate	Avg.Liq Rate	Water Cut	Cum Oil Produced	Cum Gas Produced	Cum Wat. Produced
(date m/d/y)	(BARg)	(percent)	(STB/day)	(STB/day)	(STB/day)	(STB/day)	(MMscf/day	(STB/day)	(STB/day)	(percent)	(MSm3)	(MMscf)	(MMSTB)
01/01/2026	256.56	-	10 000.00	-	10 000.00						-	-	-
01/07/2027	209.85	12.98	8 088.42	1 911.56	9 999.98	8 043.79	0.44	1 956.24	10 000.00	19.56	0.57	195.25	0.14
01/06/2028	214.62	19.77	3 008.98	6 991.03	10 000.00	3 013.28	0.16	6 986.72	10 000.00	69.87	0.86	297.34	1.92
01/04/2029	215.13	22.64	1 602.36	8 397.64	10 000.00	1 586.38	0.09	8 413.64	10 000.00	84.14	0.99	340.50	4.77
01/03/2030	215.16	24.35	1 072.26	8 927.77	10 000.00	1 056.07	0.06	8 943.91	9 999.98	89.44	1.06	366.31	7.94
01/02/2031	215.15	25.56	800.87	9 199.14	10 000.00	786.59	0.04	9 213.46	10 000.10	92.13	1.12	384.56	11.25
01/01/2032	215.15	26.50	637.17	9 362.83	10 000.00	624.73	0.03	9 375.27	10 000.00	93.75	1.16	398.64	14.63
01/06/2033	310.51	27.27	513.72	9 486.29	10 000.00	528.05	0.03	9 471.95	9 999.99	94.72	1.19	410.27	18.13
01/05/2034	310.27	27.91	438.07	9 561.92	9 999.99	450.25	0.02	9 549.74	10 000.00	95.50	1.22	419.84	21.59
01/04/2035	310.07	28.46	381.48	9 618.48	9 999.97	392.06	0.02	9 607.92	9 999.99	96.08	1.24	428.09	25.08
01/03/2036	309.90	28.94	337.60	9 662.46	10 000.10	346.94	0.02	9 653.05	9 999.99	96.53	1.26	435.34	28.59
01/01/2037	309.75	29.37	302.58	9 697.39	9 999.97	310.94	0.02	9 689.06	10 000.00	96.89	1.28	441.79	32.11
01/07/2038	215.17	30.00	280.55	9 719.44	9 999.99	274.01	0.01	9 726.03	10 000.00	97.26	1.30	447.71	35.71

Figure C.2: Production data for P90/30% RF realisation.

P90/40% RF													
Time (date m/d/y)	Reservoir Average Pressure (BARa)	Oil Recovery Factor (percent)	Oil Rate (STB/day)	Water Rate (STB/day)	Liquid Rate (STB/day)	Avg.Oil Rate (STB/day)	Avg.Gas Rate (MMscf/day	Avg.Water Rate (STB/day)	Avg.Liq Rate (STB/day)	Water Cut (percent)	Cum Oil Produced (MSm3)	Cum Gas Produced (BSm3)	Cum Wat. Produced (MSm3)
01/01/2026	256.56	-	10 000.00	-	10 000.00						-	-	-
01/07/2027	209.53	13.24	9 190.65	809.35	10 000.00	8 914.41	0.49	1 085.61	10 000.00	10.86	0.58	199.18	0.07
01/06/2028	214.19	22.35	4 742.39	5 257.60	9 999.99	4 739.44	0.26	5 260.57	10 000.00	52.61	0.98	336.20	1.21
01/04/2029	214.98	26.93	2 551.76	7 448.23	9 999.99	2 531.64	0.14	7 468.34	9 999.98	74.68	1.18	405.16	3.59
01/03/2030	215.02	29.64	1 667.88	8 332.09	9 999.97	1 646.17	0.09	8 353.83	10 000.00	83.54	1.30	445.85	6.49
01/02/2031	215.02	31.51	1 221.42	8 778.56	9 999.97	1 201.90	0.07	8 798.09	9 999.99	87.98	1.38	474.00	9.61
01/01/2032	215.02	32.93	957.22	9 042.78	9 999.99	940.15	0.05	9 059.82	9 999.97	90.60	1.44	495.32	12.86
01/06/2033	308.79	34.08	763.67	9 236.28	9 999.95	784.03	0.04	9 216.00	10 000.00	92.16	1.49	512.70	16.25
01/05/2034	308.43	35.02	645.13	9 354.82	9 999.95	662.27	0.04	9 337.77	10 000.00	93.38	1.53	526.86	19.64
01/04/2035	308.14	35.83	557.47	9 442.49	9 999.96	572.24	0.03	9 427.78	10 000.00	94.28	1.57	538.96	23.06
01/03/2036	307.90	36.53	490.13	9 509.86	9 999.99	503.08	0.03	9 496.91	10 000.00	94.97	1.60	549.51	26.50
01/01/2037	307.70	37.15	436.85	9 563.21	10 000.10	448.38	0.02	9 551.61	9 999.99	95.52	1.62	558.84	29.97
01/07/2038	215.05	37.72	402.52	9 597.47	9 999.99	393.68	0.02	9 606.29	9 999.97	96.06	1.65	567.36	33.53
01/06/2039	215.06	38.22	366.18	9 633.81	9 999.99	358.03	0.02	9 641.95	9 999.98	96.42	1.67	574.93	37.03
01/05/2040	215.06	38.68	335.66	9 664.34	10 000.00	328.11	0.02	9 671.89	10 000.00	96.72	1.69	581.83	40.54
01/03/2041	215.06	39.10	309.67	9 690.33	10 000.00	302.65	0.02	9 697.35	10 000.00	96.97	1.71	588.18	44.07
01/02/2042	215.06	39.49	287.30	9 712.71	10 000.00	280.73	0.02	9 719.31	10 000.00	97.19	1.73	594.06	47.60
01/01/2043	215.06	40.00	267.84	9 732.17	10 000.00	261.67	0.01	9 738.39	10 000.10	97.38	1.74	599.52	51.14

Figure C.3: Production data for P90/40% RF realisation.

P50/20% RF													
Time (date m/d/y)	Reservoir Average Pressure (BARg)	Oil Recovery Factor (percent)	Oil Rate (STB/day)	Water Rate (STB/day)	Liquid Rate (STB/day)	Avg.Oil Rate (STB/day)	Avg.Gas Rate (MMscf/day	Avg.Water Rate (STB/day)	Avg.Liq Rate (STB/day)	Water Cut (percent)	Cum Oil Produced (MSm3)	Cum Gas Produced (MMscf)	Cum Wat. Produced (MMSTB)
01/01/2026	256.55	-	10 000.00	-	10 000.00						-	-	-
01/01/2027	351.17	7.07	9 419.74	580.31	10 000.00	9 961.36	0.55	237.20	10 198.60	2.33	0.58	199.03	0.09
01/01/2028	360.93	12.61	4 523.28	5 476.68	9 999.96	7 803.29	0.43	2 196.72	10 000.00	21.97	1.03	354.94	0.89
01/01/2029	359.63	14.84	2 057.88	7 942.09	9 999.98	3 136.22	0.17	6 863.78	9 999.99	68.64	1.21	417.78	3.40
01/01/2030	357.73	16.01	1 307.80	8 692.18	9 999.98	1 652.53	0.09	8 347.46	10 000.00	83.47	1.31	450.79	6.45
01/01/2031	356.56	16.82	959.00	9 041.04	10 000.00	1 131.09	0.06	8 868.91	10 000.00	88.69	1.38	473.39	9.68
01/01/2032	355.82	17.43	757.64	9 242.36	10 000.00	862.13	0.05	9 137.87	10 000.00	91.38	1.43	490.62	13.02
01/01/2033	356.10	17.92	625.19	9 374.78	9 999.97	696.22	0.04	9 303.78	10 000.00	93.04	1.47	504.57	16.43
01/01/2034	355.05	18.34	533.72	9 466.34	10 000.10	585.01	0.03	9 414.99	10 000.00	94.15	1.50	516.26	19.86
01/01/2035	354.67	18.70	465.22	9 534.76	9 999.97	504.56	0.03	9 495.44	10 000.00	94.95	1.53	526.34	23.33
01/01/2036	354.41	19.01	412.25	9 587.72	9 999.96	443.47	0.02	9 556.52	10 000.00	95.57	1.55	535.20	26.82
01/01/2037	354.98	19.29	369.38	9 630.62	10 000.00	394.98	0.02	9 605.01	10 000.00	96.05	1.58	543.11	30.33
01/01/2038	354.14	19.55	335.60	9 664.39	9 999.99	356.73	0.02	9 643.27	10 000.00	96.43	1.60	550.24	33.85
01/01/2039	353.90	19.78	307.15	9 692.87	10 000.00	325.18	0.02	9 674.83	10 000.00	96.75	1.62	556.74	37.38
01/01/2040	353.74	19.99	283.08	9 716.90	9 999.99	298.65	0.02	9 701.34	9 999.99	97.01	1.63	562.70	40.92
01/01/2041	354.39	20.00	262.00	9 737.98	9 999.98	275.68	0.02	9 724.32	10 000.00	97.24	1.65	568.23	44.48

Figure C.4: Production data for P50/20% RF realisation.

P50/30% RF													
Time (date m/d/y)	Reservoir Average Pressure (BARg)	Oil Recovery Factor (percent)	Oil Rate (STB/day)	Water Rate (STB/day)	Liquid Rate (STB/day)	Avg.Oil Rate (STB/day)	Avg.Gas Rate (MMscf/day	Avg.Water Rate (STB/day)	Avg.Liq Rate (STB/day)	Water Cut (percent)	Cum Oil Produced (MSm3)	Cum Gas Produced (MMscf)	Cum Wat. Produced (MMSTB)
01/01/2026	256.55	-	10 000.00	-	10 000.00						-	-	-
01/01/2027	354.70	7.08	9 726.15	273.81	9 999.96	9 978.96	0.55	255.42	10 234.40	2.50	0.58	199.38	0.09
01/01/2028	364.52	13.64	7 803.74	2 196.21	9 999.95	9 242.33	0.51	886.21	10 128.50	8.75	1.12	384.05	0.42
01/01/2029	362.58	17.99	4 362.56	5 637.51	10 000.10	6 105.80	0.33	3 894.20	10 000.00	38.94	1.47	506.38	1.84
01/01/2030	358.28	20.42	2 639.53	7 360.49	10 000.00	3 433.00	0.19	6 567.01	10 000.00	65.67	1.67	574.97	4.24
01/01/2031	355.79	22.00	1 843.93	8 156.05	9 999.98	2 227.15	0.12	7 772.86	10 000.00	77.73	1.80	619.47	7.08
01/01/2032	354.28	23.16	1 406.92	8 593.12	10 000.00	1 627.67	0.09	8 372.33	10 000.00	83.72	1.89	651.99	10.13
01/01/2033	354.06	24.07	1 132.39	8 867.65	10 000.00	1 276.07	0.07	8 723.94	10 000.00	87.24	1.97	677.55	13.32
01/01/2034	352.69	24.81	947.57	9 052.42	9 999.99	1 048.02	0.06	8 951.97	9 999.99	89.52	2.03	698.49	16.59
01/01/2035	352.07	25.44	813.38	9 186.66	10 000.00	888.25	0.05	9 111.74	9 999.99	91.12	2.08	716.24	19.92
01/01/2036	351.63	25.99	711.87	9 288.11	9 999.98	769.98	0.04	9 230.02	10 000.00	92.30	2.13	731.63	23.29
01/01/2037	352.04	26.47	631.69	9 368.38	10 000.10	678.39	0.04	9 321.61	10 000.00	93.22	2.16	745.22	26.70
01/01/2038	351.08	26.90	568.63	9 431.37	10 000.00	606.69	0.03	9 393.32	10 000.00	93.93	2.20	757.34	30.13
01/01/2039	350.75	27.29	516.49	9 483.50	9 999.98	548.48	0.03	9 451.53	10 000.00	94.52	2.23	768.30	33.58
01/01/2040	350.50	27.65	472.91	9 527.08	9 999.99	500.19	0.03	9 499.81	10 000.00	95.00	2.26	778.29	37.04
01/01/2041	351.06	27.97	435.42	9 564.57	9 999.99	459.12	0.03	9 540.88	10 000.00	95.41	2.29	787.49	40.54
01/01/2042	350.22	28.27	404.21	9 595.80	10 000.00	424.73	0.02	9 575.28	10 000.00	95.75	2.31	795.98	44.03
01/01/2043	349.98	28.55	376.82	9 623.17	9 999.99	395.02	0.02	9 604.99	10 000.00	96.05	2.33	803.87	47.54
01/01/2044	349.82	28.82	352.81	9 647.22	10 000.00	369.04	0.02	9 630.96	10 000.00	96.31	2.36	811.24	51.05
01/01/2045	350.43	29.06	331.18	9 668.87	10 000.00	345.85	0.02	9 654.15	10 000.00	96.54	2.38	818.17	54.59
01/01/2046	349.65	29.29	312.69	9 687.28	9 999.97	325.80	0.02	9 674.20	10 000.00	96.74	2.40	824.68	58.12
01/01/2047	349.46	29.51	295.88	9 704.10	9 999.98	307.87	0.02	9 692.14	10 000.00	96.92	2.41	830.83	61.65
01/01/2048	349.33	29.72	280.73	9 719.31	10 000.00	291.71	0.02	9 708.30	10 000.00	97.08	2.43	836.66	65.20
01/01/2049	349.98	29.92	266.66	9 733.34	10 000.00	276.83	0.02	9 723.17	10 000.00	97.23	2.45	842.21	68.76
01/01/2050	349.23	30.00	254.49	9 745.58	10 000.10	263.74	0.01	9 736.27	10 000.00	97.36	2.46	847.48	72.31

Figure C.5: Production data for P50/30% RF realisation.

P50/40% RF													
Time	Reservoir Average Pressure	Oil Recovery Factor	Oil Rate	Water Rate	Liquid Rate	Avg.Oil Rate	Avg.Gas Rate	Avg.Water Rate	Avg.Liq Rate	Water Cut	Cum Oil Produced	Cum Gas Produced	Cum Wat. Produced
(date m/d/y)	(BARg)	(percent)	(STB/day)	(STB/day)	(STB/day)	(STB/day)	(MMscf/day	(STB/day)	(STB/day)	(percent)	(MSm3)	(MMscf)	(MMSTB)
01/01/2026	256.55	-	10 000.00	-	10 000.00						-	-	-
01/01/2027	355.85	7.09	9 828.87	171.16	10 000.00	9 986.05	0.55	169.34	10 155.40	1.67	0.58	199.52	0.06
01/01/2028	364.26	13.93	8 812.15	1 187.83	9 999.98	9 638.63	0.53	680.22	10 318.90	6.59	1.14	392.11	0.31
01/01/2029	364.95	19.50	6 444.64	3 555.33	9 999.97	7 822.98	0.43	2 177.02	10 000.00	21.77	1.59	548.84	1.11
01/01/2030	359.83	23.30	4 274.58	5 725.45	10 000.00	5 354.11	0.29	4 645.89	9 999.99	46.46	1.90	655.82	2.80
01/01/2031	356.10	25.86	2 993.44	7 006.58	10 000.00	3 619.21	0.20	6 380.79	9 999.99	63.81	2.11	728.13	5.13
01/01/2032	353.67	27.73	2 251.61	7 748.38	9 999.99	2 623.96	0.14	7 376.05	10 000.00	73.76	2.27	780.56	7.82
01/01/2033	352.83	29.17	1 785.29	8 214.69	9 999.98	2 026.53	0.11	7 973.47	10 000.00	79.73	2.39	821.16	10.74
01/01/2034	351.04	30.33	1 473.47	8 526.54	10 000.00	1 639.97	0.09	8 360.02	9 999.99	83.60	2.48	853.92	13.79
01/01/2035	350.11	31.31	1 250.32	8 749.64	9 999.96	1 372.58	0.08	8 627.42	10 000.00	86.27	2.56	881.35	16.94
01/01/2036	349.44	32.14	1 083.68	8 916.28	9 999.96	1 177.24	0.06	8 822.75	9 999.99	88.23	2.63	904.87	20.16
01/01/2037	349.65	32.87	953.89	9 046.10	9 999.99	1 028.13	0.06	8 971.86	9 999.99	89.72	2.69	925.47	23.45
01/01/2038	348.56	33.52	852.26	9 147.78	10 000.00	912.16	0.05	9 087.85	10 000.00	90.88	2.74	943.69	26.76
01/01/2039	348.10	34.10	769.21	9 230.73	9 999.94	819.02	0.04	9 180.97	9 999.99	91.81	2.79	960.06	30.11
01/01/2040	347.76	34.63	700.40	9 299.56	9 999.96	742.49	0.04	9 257.51	10 000.00	92.58	2.83	974.89	33.49
01/01/2041	348.21	35.11	641.87	9 358.10	9 999.97	678.10	0.04	9 321.90	10 000.00	93.22	2.87	988.48	36.91
01/01/2042	347.31	35.56	593.05	9 406.92	9 999.97	624.25	0.03	9 375.74	10 000.00	93.76	2.91	1 000.95	40.33
01/01/2043	347.00	35.97	550.61	9 449.34	9 999.96	578.08	0.03	9 421.92	10 000.00	94.22	2.94	1 012.50	43.77
01/01/2044	346.78	36.35	513.63	9 486.35	9 999.98	537.98	0.03	9 462.02	10 000.00	94.62	2.97	1 023.25	47.22
01/01/2045	347.32	36.70	480.66	9 519.32	9 999.98	502.52	0.03	9 497.49	10 000.00	94.97	3.00	1 033.32	50.70
01/01/2046	346.50	37.04	452.30	9 547.65	9 999.96	471.79	0.03	9 528.21	10 000.00	95.28	3.03	1 042.75	54.17
01/01/2047	346.26	37.36	426.76	9 573.30	10 000.10	444.46	0.02	9 555.54	10 000.00	95.56	3.05	1 051.63	57.66
01/01/2048	346.10	37.65	403.82	9 596.17	9 999.99	419.96	0.02	9 580.04	10 000.00	95.80	3.08	1 060.02	61.16
01/01/2049	346.69	37.94	382.74	9 617.24	9 999.98	397.61	0.02	9 602.39	9 999.99	96.02	3.10	1 067.98	64.67
01/01/2050	345.92	38.20	364.33	9 635.68	10 000.00	377.85	0.02	9 622.15	10 000.00	96.22	3.12	1 075.53	68.19
01/01/2051	345.72	38.46	347.33	9 652.68	10 000.00	359.87	0.02	9 640.13	10 000.00	96.40	3.14	1 082.72	71.70
01/01/2052	345.59	38.70	331.76	9 668.18	9 999.95	343.41	0.02	9 656.59	10 000.00	96.57	3.16	1 089.58	75.23
01/01/2053	346.21	38.94	317.16	9 682.80	9 999.96	328.07	0.02	9 671.93	10 000.00	96.72	3.18	1 096.16	78.77
01/01/2054	345.47	39.16	304.29	9 695.75	10 000.00	314.35	0.02	9 685.65	10 000.00	96.86	3.20	1 102.44	82.30
01/01/2055	345.29	39.37	292.19	9 707.78	9 999.97	301.66	0.02	9 698.35	10 000.00	96.98	3.22	1 108.46	85.84
01/01/2056	345.19	39.58	280.97	9 719.08	10 000.10	289.86	0.02	9 710.15	10 000.00	97.10	3.24	1 114.26	89.39
01/01/2057	345.82	39.78	270.26	9 729.71	9 999.97	278.70	0.02	9 721.31	10 000.00	97.21	3.25	1 119.84	92.95
01/01/2058	345.10	40.00	260.78	9 739.21	9 999.99	268.63	0.01	9 731.37	10 000.00	97.31	3.27	1 125.21	96.50

Figure C.6: Production data for P50/40% RF realisation.

P10/20% RF													
Time	Reservoir Average Pressure	Oil Recovery Factor	Oil Rate	Water Rate	Liquid Rate	Avg.Oil Rate	Avg.Gas Rate	Avg.Water Rate	Avg.Liq Rate	Water Cut	Cum Oil Produced	Cum Gas Produced	Cum Wat. Produced
(date m/d/y)	(BARg)	(percent)	(STB/day)	(STB/day)	(STB/day)	(STB/day)	(MMscf/day	(STB/day)	(STB/day)	(percent)	(MSm3)	(MMscf)	(MMSTB)
01/01/2026	256.54	-	10 000.00	-	10 000.00						-	-	-
01/01/2027	268.49	4.32	9 812.82	187.16	9 999.98	9 983.06	0.55	18.00	10 001.10	0.18	0.58	199.46	0.01
01/01/2028	262.64	8.45	8 388.95	1 611.06	10 000.00	9 536.34	0.52	463.66	10 000.00	4.64	1.13	390.00	0.18
01/01/2029	260.59	11.50	5 241.56	4 758.43	9 999.99	7 021.24	0.38	2 978.76	10 000.00	29.79	1.54	530.67	1.27
01/01/2030	259.46	13.30	3 144.82	6 855.19	10 000.00	4 157.36	0.23	5 842.63	10 000.00	58.43	1.78	613.74	3.40
01/01/2031	259.13	14.44	2 138.30	7 861.72	10 000.00	2 640.60	0.14	7 359.40	10 000.00	73.59	1.94	666.50	6.08
01/01/2032	258.96	15.26	1 596.92	8 403.10	10 000.00	1 881.87	0.10	8 118.13	10 000.00	81.18	2.05	704.10	9.05
01/01/2033	259.12	15.89	1 266.00	8 734.02	10 000.00	1 448.45	0.08	8 551.56	10 000.00	85.52	2.13	733.12	12.18
01/01/2034	258.79	16.40	1 046.99	8 953.00	9 999.99	1 173.42	0.06	8 826.59	10 000.00	88.27	2.20	756.56	15.40
01/01/2035	258.69	16.82	890.98	9 109.03	10 000.00	984.46	0.05	9 015.55	10 000.00	90.16	2.25	776.23	18.69
01/01/2036	258.63	17.19	774.65	9 225.35	9 999.99	846.88	0.05	9 153.13	10 000.00	91.53	2.30	793.15	22.03
01/01/2037	258.83	17.51	684.14	9 315.86	10 000.00	742.01	0.04	9 257.99	10 000.00	92.58	2.35	808.02	25.42
01/01/2038	258.55	17.80	613.01	9 387.00	10 000.00	660.32	0.04	9 339.67	9 999.99	93.40	2.39	821.21	28.83
01/01/2039	258.48	18.05	554.86	9 445.14	10 000.00	594.59	0.03	9 405.41	9 999.99	94.05	2.42	833.09	32.26
01/01/2040	258.44	18.29	506.62	9 493.38	9 999.99	540.54	0.03	9 459.45	10 000.00	94.59	2.45	843.89	35.71
01/01/2041	258.67	18.50	465.60	9 534.40	10 000.00	495.07	0.03	9 504.93	10 000.00	95.05	2.48	853.81	39.19
01/01/2042	258.40	18.70	431.19	9 568.82	10 000.00	456.91	0.03	9 543.09	10 000.00	95.43	2.51	862.94	42.68
01/01/2043	258.35	18.88	401.27	9 598.75	10 000.00	424.10	0.02	9 575.90	10 000.00	95.76	2.53	871.42	46.17
01/01/2044	258.32	19.06	375.17	9 624.84	10 000.00	395.59	0.02	9 604.41	10 000.00	96.04	2.55	879.32	49.68
01/01/2045	258.55	19.22	351.93	9 648.05	9 999.98	370.40	0.02	9 629.60	9 999.99	96.30	2.58	886.74	53.20
01/01/2046	258.29	19.37	331.80	9 668.20	10 000.00	348.47	0.02	9 651.53	9 999.99	96.52	2.60	893.70	56.72
01/01/2047	258.25	19.51	313.67	9 686.33	10 000.00	328.91	0.02	9 671.09	10 000.00	96.71	2.61	900.27	60.25
01/01/2048	258.23	20.00	297.37	9 702.61	9 999.99	311.38	0.02	9 688.62	10 000.00	96.89	2.63	906.50	63.79

Figure C.7: Production data for P10/20% RF realisation.

P10/30% RF													
Time (date m/d/y)	Reservoir Average Pressure (BARg)	Oil Recovery Factor (percent)	Oil Rate (STB/day)	Water Rate (STB/day)	Liquid Rate (STB/day)	Avg.Oil Rate (STB/day)	Avg.Gas Rate (MMscf/day	Avg.Water Rate (STB/day)	Avg.Liq Rate (STB/day)	Water Cut (percent)	Cum Oil Produced (MSm3)	Cum Gas Produced (MMscf)	Cum Wat. Produced (MMSTB)
01/01/2026	256.54	-	10 000.00	-	10 000.00						-	-	-
01/01/2027	268.48	4.32	9 820.16	179.84	10 000.00	9 981.48	0.55	19.97	10 001.40	0.20	0.58	199.43	0.01
01/01/2028	262.80	8.52	8 942.92	1 057.07	9 999.99	9 691.29	0.53	308.71	10 000.00	3.09	1.14	393.07	0.12
01/01/2029	261.01	12.20	7 344.97	2 655.02	10 000.00	8 472.49	0.46	1 527.51	10 000.00	15.28	1.63	562.81	0.68
01/01/2030	259.71	15.04	5 512.41	4 487.60	10 000.00	6 567.63	0.36	3 432.37	10 000.00	34.32	2.02	694.04	1.93
01/01/2031	259.11	17.15	4 105.77	5 894.23	10 000.00	4 880.97	0.27	5 119.03	10 000.00	51.19	2.30	791.56	3.80
01/01/2032	258.77	18.75	3 155.41	6 844.58	9 999.99	3 683.17	0.20	6 316.83	10 000.00	63.17	2.51	865.15	6.11
01/01/2033	258.80	20.00	2 513.79	7 486.22	10 000.00	2 879.33	0.16	7 120.67	10 000.00	71.21	2.68	922.84	8.71
01/01/2034	258.38	21.01	2 068.88	7 931.11	9 999.99	2 330.81	0.13	7 669.19	10 000.00	76.69	2.82	969.41	11.51
01/01/2035	258.22	21.85	1 746.48	8 253.50	9 999.99	1 942.57	0.11	8 057.44	10 000.00	80.57	2.93	1 008.22	14.45
01/01/2036	258.10	22.57	1 504.55	8 495.46	10 000.00	1 656.51	0.09	8 343.49	10 000.00	83.43	3.02	1 041.32	17.50
01/01/2037	258.27	23.19	1 316.64	8 683.36	10 000.00	1 438.14	0.08	8 561.86	10 000.00	85.62	3.11	1 070.13	20.63
01/01/2038	257.94	23.74	1 168.69	8 831.31	10 000.00	1 267.69	0.07	8 732.31	10 000.00	87.32	3.18	1 095.46	23.82
01/01/2039	257.85	24.23	1 048.57	8 951.41	9 999.98	1 131.21	0.06	8 868.79	10 000.00	88.69	3.25	1 118.06	27.06
01/01/2040	257.78	24.67	949.47	9 050.53	10 000.00	1 019.61	0.06	8 980.39	10 000.00	89.80	3.31	1 138.43	30.33
01/01/2041	257.98	25.07	865.96	9 134.02	9 999.98	926.47	0.05	9 073.53	10 000.00	90.74	3.36	1 157.00	33.65
01/01/2042	257.69	25.44	795.83	9 204.18	10 000.00	848.38	0.05	9 151.62	10 000.00	91.52	3.41	1 173.95	36.99
01/01/2043	257.62	25.78	735.41	9 264.59	9 999.99	781.73	0.04	9 218.27	10 000.00	92.18	3.46	1 189.57	40.36
01/01/2044	257.57	26.09	683.00	9 317.01	10 000.00	724.20	0.04	9 275.81	10 000.00	92.76	3.50	1 204.03	43.75
01/01/2045	257.79	26.38	636.80	9 363.20	10 000.00	673.81	0.04	9 326.19	10 000.00	93.26	3.54	1 217.53	47.16
01/01/2046	257.51	26.66	596.64	9 403.37	10 000.00	629.92	0.03	9 370.08	9 999.99	93.70	3.57	1 230.12	50.58
01/01/2047	257.46	26.91	560.80	9 439.23	10 000.00	591.06	0.03	9 408.93	9 999.99	94.09	3.61	1 241.93	54.01
01/01/2048	257.43	27.15	528.77	9 471.24	10 000.00	556.43	0.03	9 443.57	10 000.00	94.44	3.64	1 253.05	57.46
01/01/2049	257.65	27.38	499.72	9 500.27	9 999.99	525.19	0.03	9 474.81	10 000.00	94.75	3.67	1 263.57	60.93
01/01/2050	257.39	27.60	473.95	9 526.04	9 999.98	497.34	0.03	9 502.66	10 000.00	95.03	3.70	1 273.51	64.40
01/01/2051	257.34	27.80	450.40	9 549.60	10 000.00	472.10	0.03	9 527.91	10 000.00	95.28	3.73	1 282.94	67.87
01/01/2052	257.31	28.00	428.95	9 571.08	10 000.00	449.13	0.02	9 550.88	10 000.00	95.51	3.75	1 291.91	71.36
01/01/2053	257.55	28.18	409.10	9 590.89	9 999.99	427.98	0.02	9 572.01	9 999.99	95.72	3.78	1 300.49	74.86
01/01/2054	257.29	28.36	391.26	9 608.75	10 000.00	408.85	0.02	9 591.15	10 000.00	95.91	3.80	1 308.66	78.36
01/01/2055	257.25	30.00	374.69	9 625.32	10 000.00	391.23	0.02	9 608.77	10 000.00	96.09	3.82	1 316.47	81.87

Figure C.8: Production data for P10/30% RF realisation.

P10/40% RF													
Time	Reservoir Average Pressure	Oil Recovery Factor	Oil Rate	Water Rate	Liquid Rate	Avg.Oil Rate	Avg.Gas Rate	Avg.Water Rate	Avg.Liq Rate	Water Cut	Cum Oil Produced	Cum Gas Produced	Cum Wat. Produced
(date m/d/y)	(BARg)	(percent)	(STB/day)	(STB/day)	(STB/day)	(STB/day)	(MMscf/day	(STB/day)	(STB/day)	(percent)	(MSm3)	(MMscf)	(MMSTB)
01/01/2026	256.54	-	10 000.00	-	10 000.00						-	-	-
01/01/2027	268.51	4.33	9 908.79	91.19	9 999.98	9 990.52	0.55	10.25	10 000.80	0.10	0.58	199.61	0.00
01/01/2028	262.91	8.59	9 433.89	566.12	10 000.00	9 855.66	0.54	144.34	10 000.00	1.44	1.15	396.53	0.06
01/01/2029	261.12	12.64	8 565.39	1 434.61	9 999.99	9 324.13	0.51	675.87	10 000.00	6.76	1.69	583.34	0.30
01/01/2030	259.80	16.17	7 281.85	2 718.16	10 000.00	8 139.98	0.45	1 860.02	10 000.00	18.60	2.17	745.98	0.98
01/01/2031	259.04	19.08	5 914.83	4 085.16	9 999.99	6 728.78	0.37	3 271.22	10 000.00	32.71	2.56	880.42	2.18
01/01/2032	258.51	21.43	4 750.38	5 249.63	10 000.00	5 419.49	0.30	4 580.51	10 000.00	45.81	2.87	988.71	3.85
01/01/2033	258.39	23.32	3 852.77	6 147.23	10 000.00	4 366.79	0.24	5 633.20	10 000.00	56.33	3.13	1 076.19	5.91
01/01/2034	257.85	24.87	3 185.47	6 814.53	10 000.00	3 572.67	0.20	6 427.33	9 999.99	64.27	3.33	1 147.58	8.26
01/01/2035	257.61	26.16	2 685.72	7 314.28	10 000.00	2 981.78	0.16	7 018.22	10 000.00	70.18	3.51	1 207.15	10.82
01/01/2036	257.41	27.26	2 304.99	7 695.02	10 000.00	2 535.94	0.14	7 464.06	10 000.00	74.64	3.65	1 257.82	13.54
01/01/2037	257.52	28.21	2 007.88	7 992.13	10 000.00	2 192.37	0.12	7 807.63	10 000.00	78.08	3.78	1 301.75	16.40
01/01/2038	257.14	29.04	1 773.39	8 226.62	10 000.00	1 923.06	0.11	8 076.94	10 000.00	80.77	3.89	1 340.17	19.35
01/01/2039	257.01	29.78	1 583.61	8 416.38	9 999.98	1 707.74	0.09	8 292.27	10 000.00	82.92	3.99	1 374.29	22.37
01/01/2040	256.90	30.45	1 427.59	8 572.41	9 999.99	1 532.19	0.08	8 467.81	10 000.00	84.68	4.08	1 404.90	25.47
01/01/2041	257.07	31.05	1 296.83	8 703.19	10 000.00	1 386.40	0.08	8 613.60	10 000.00	86.14	4.16	1 432.68	28.62
01/01/2042	256.75	31.59	1 187.20	8 812.80	10 000.00	1 264.46	0.07	8 735.55	10 000.00	87.36	4.23	1 457.94	31.81
01/01/2043	256.66	32.10	1 093.29	8 906.70	9 999.98	1 160.92	0.06	8 839.08	10 000.00	88.39	4.30	1 481.14	35.03
01/01/2044	256.59	32.56	1 012.20	8 987.81	10 000.00	1 071.94	0.06	8 928.06	10 000.00	89.28	4.36	1 502.56	38.29
01/01/2045	256.78	32.99	941.13	9 058.89	10 000.00	994.45	0.05	9 005.55	10 000.00	90.06	4.42	1 522.48	41.59
01/01/2046	256.49	33.39	879.37	9 120.64	10 000.00	927.06	0.05	9 072.95	10 000.00	90.73	4.48	1 541.00	44.90
01/01/2047	256.42	33.77	824.55	9 175.46	10 000.00	867.67	0.05	9 132.33	10 000.00	91.32	4.53	1 558.34	48.23
01/01/2048	256.37	34.12	775.75	9 224.23	9 999.98	814.95	0.04	9 185.05	10 000.00	91.85	4.57	1 574.62	51.59
01/01/2049	256.58	34.46	731.72	9 268.26	9 999.98	767.63	0.04	9 232.37	10 000.00	92.32	4.62	1 590.00	54.96
01/01/2050	256.30	34.77	692.61	9 307.37	9 999.98	725.46	0.04	9 274.54	10 000.00	92.75	4.66	1 604.50	58.35
01/01/2051	256.25	35.07	657.07	9 342.94	10 000.00	687.39	0.04	9 312.61	10 000.00	93.13	4.70	1 618.23	61.75
01/01/2052	256.20	35.35	624.77	9 375.22	9 999.99	652.86	0.04	9 347.14	9 999.99	93.47	4.74	1 631.28	65.16
01/01/2053	256.42	35.62	595.04	9 404.97	10 000.00	621.21	0.03	9 378.79	10 000.00	93.79	4.77	1 643.72	68.59
01/01/2054	256.16	35.88	568.25	9 431.74	9 999.98	592.56	0.03	9 407.45	10 000.00	94.07	4.81	1 655.56	72.03
01/01/2055	256.11	36.12	543.48	9 456.52	10 000.00	566.25	0.03	9 433.76	10 000.00	94.34	4.84	1 666.88	75.47
01/01/2056	256.07	36.36	520.65	9 479.36	10 000.00	542.02	0.03	9 457.99	10 000.00	94.58	4.87	1 677.71	78.92
01/01/2057	256.30	36.58	499.32	9 500.68	10 000.00	519.48	0.03	9 480.53	10 000.00	94.81	4.90	1 688.11	82.39
01/01/2058	256.04	36.80	479.92	9 520.09	10 000.00	498.84	0.03	9 501.16	10 000.00	95.01	4.93	1 698.08	85.86
01/01/2059	255.99	37.01	461.75	9 538.27	10 000.00	479.65	0.03	9 520.36	10 000.00	95.20	4.96	1 707.66	89.33
01/01/2060	255.97	37.21	444.81	9 555.21	10 000.00	461.78	0.03	9 538.23	10 000.00	95.38	4.99	1 716.89	92.82
01/01/2061	256.19	37.40	428.82	9 571.19	10 000.00	444.96	0.02	9 555.04	10 000.00	95.55	5.01	1 725.80	96.31
01/01/2062	255.94	37.59	414.16	9 585.86	10 000.00	429.45	0.02	9 570.56	10 000.00	95.71	5.04	1 734.39	99.81
01/01/2063	255.90	37.76	400.30	9 599.68	9 999.98	414.88	0.02	9 585.13	10 000.00	95.85	5.06	1 742.67	103.31
01/01/2064	255.88	37.94	387.28	9 612.75	10 000.00	401.19	0.02	9 598.82	10 000.00	95.99	5.09	1 750.69	106.81
01/01/2065	256.11	38.11	374.86	9 625.15	10 000.00	388.18	0.02	9 611.83	10 000.00	96.12	5.11	1 758.47	110.33
01/01/2066	255.86	38.27	363.43	9 636.59	10 000.00	376.13	0.02	9 623.88	10 000.00	96.24	5.13	1 765.98	113.84
01/01/2067	255.82	38.43	352.53	9 647.48	10 000.00	364.71	0.02	9 635.30	10 000.00	96.35	5.15	1 773.27	117.36
01/01/2068	255.80	38.58	342.23	9 657.79	10 000.00	353.91	0.02	9 646.09	10 000.00	96.46	5.17	1 780.34	120.88
01/01/2069	256.03	38.73	332.32	9 667.69	10 000.00	343.58	0.02	9 656.43	10 000.00	96.56	5.19	1 787.22	124.41
01/01/2070	255.78	38.87	323.18	9 676.83	10 000.00	333.96	0.02	9 666.04	10 000.00	96.66	5.21	1 793.90	127.94
01/01/2071	255.75	39.02	314.40	9 685.60	10 000.00	324.79	0.02	9 675.21	10 000.00	96.75	5.23	1 800.39	131.47
01/01/2072	255.73	39.15	306.05	9 693.97	10 000.00	316.07	0.02	9 683.94	10 000.00	96.84	5.25	1 806.70	135.01
01/01/2073	255.96	39.29	297.98	9 702.02	10 000.00	307.67	0.02	9 692.34	10 000.00	96.92	5.27	1 812.87	138.55
01/01/2074	255.72	39.42	290.51	9 709.49	10 000.00	299.82	0.02	9 700.18	10 000.00	97.00	5.28	1 818.86	142.09
01/01/2075	255.69	39.54	283.30	9 716.70	10 000.00	292.31	0.02	9 707.69	10 000.00	97.08	5.30	1 824.70	145.64
01/01/2076	255.67	39.67	276.41	9 723.59	10 000.00	285.13	0.02	9 714.88	10 000.00	97.15	5.32	1 830.39	149.18
01/01/2077	255.91	39.79	269.71	9 730.30	10 000.00	278.17	0.02	9 721.83	10 000.00	97.22	5.33	1 835.97	152.74
01/01/2078	255.66	39.90	263.51	9 736.51	10 000.00	271.67	0.01	9 728.33	10 000.00	97.28	5.35	1 841.39	156.29
01/01/2079	255.63	40.00	257.48	9 742.52	10 000.00	265.40	0.01	9 734.60	10 000.00	97.35	5.36	1 846.70	159.85

Figure C.9: Production data for P10/40% RF realisation.

Appendix D

NPV and IRR calculations

D.1 Pre-Tax

P90/20% RF									
Time		Q_cum.prod	Q_prod	Revenue	CAPEX	OPEX	ABEX	Cash flow	Discount cash flow
Year	Year.no	MSm3	STB	USD	USD	USD	USD	USD	USD
01/01/2026	0	-	-	-	275 000 000	-	-	- 275 000 000	- 275 000 000
01/01/2027	1	0.52	3 301 156	198 069 332	-	5 500 000	-	192 569 332	175 063 029
01/01/2028	2	0.68	965 572	57 934 297	-	5 500 000	-	52 434 297	43 334 129
01/01/2029	3	0.74	401 032	24 061 892	-	5 500 000	-	18 561 892	13 945 824
01/01/2030	4	0.78	254 676	15 280 549	-	5 500 000	-	9 780 549	6 680 246
01/01/2031	5	0.81	186 800	11 208 025	-	5 500 000		5 708 025	3 544 235
01/01/2032	6	0.84	147 482	8 848 898	-	5 500 000		3 348 898	1 890 366
01/01/2033	7	0.86	123 970	7 438 177	-	5 500 000		1 938 177	994 591
01/01/2034	8	0.87	103 401	6 204 079	-	5 500 000		704 079	328 458
01/01/2035	9						55 000 000	- 55 000 000	- 23 325 369
01/01/2036	10							-	-
01/01/2037	11							-	-
01/01/2038	12							-	-
01/01/2039	13							-	-
01/01/2040	14							-	-
01/01/2041	15							-	-
01/01/2042	16							-	-
01/01/2043	17							-	-
01/01/2044	18							-	-
01/01/2045	19							-	-
01/01/2046	20							-	-
01/01/2047	21							-	-
01/01/2048	22							-	-
01/01/2049	23							-	-
01/01/2050	24							-	-
01/01/2051	25							-	-
01/01/2052	26							-	-
01/01/2053	27							-	-
01/01/2054	28							-	-
01/01/2055	29							-	-
01/01/2056	30							-	-
01/01/2057	31							-	-
01/01/2058	32							-	-
01/01/2059	33							-	-
01/01/2060	34							-	-
01/01/2061	35							-	-
								NPV:	**- 52 544 491**
								IRR:	**#NUM!**

Figure D.1: NPV calculations for P90/20% RF realisation.

P90/30% RF									
Time		Q_cum.prod	Q_prod	Revenue	CAPEX	OPEX	ABEX	Cash flow	Discount cash flow
Year	Year.no	MSm3	STB	USD	USD	USD	USD	USD	USD
01/01/2026	0	-	-	-	275 000 000	-	-	- 275 000 000	- 275 000 000
01/01/2027	1	0.57	3 567 134	214 028 069	-	5 500 000	-	208 528 069	189 570 972
01/01/2028	2	0.86	1 865 230	111 913 819	-	5 500 000	-	106 413 819	87 945 305
01/01/2029	3	0.99	788 558	47 313 506	-	5 500 000	-	41 813 506	31 415 106
01/01/2030	4	1.06	471 511	28 290 659	-	5 500 000	-	22 790 659	15 566 327
01/01/2031	5	1.12	333 559	20 013 522	-	5 500 000	-	14 513 522	9 011 755
01/01/2032	6	1.16	257 135	15 428 112	-	5 500 000	-	9 928 112	5 604 160
01/01/2033	7	1.19	212 413	12 744 798	-	5 500 000	-	7 244 798	3 717 727
01/01/2034	8	1.22	174 925	10 495 494	-	5 500 000	-	4 995 494	2 330 435
01/01/2035	9	1.24	150 771	9 046 278		5 500 000		3 546 278	1 503 968
01/01/2036	10	1.26	132 404	7 944 270		5 500 000		2 444 270	942 372
01/01/2037	11	1.28	117 875	7 072 476		5 500 000		1 572 476	551 143
01/01/2038	12	1.30	108 188	6 491 280		5 500 000		991 280	315 852
01/01/2039	13	1.31	87 557	5 253 408		5 500 000		- 246 592	- 71 429
01/01/2040	14						55 000 000		
01/01/2041	15								
01/01/2042	16								
01/01/2043	17								
01/01/2044	18							-	-
01/01/2045	19							-	-
01/01/2046	20							-	-
01/01/2047	21							-	-
01/01/2048	22							-	-
01/01/2049	23							-	-
01/01/2050	24							-	-
01/01/2051	25							-	-
01/01/2052	26							-	-
01/01/2053	27							-	-
01/01/2054	28							-	-
01/01/2055	29							-	-
01/01/2056	30							-	-
01/01/2057	31							-	-
01/01/2058	32							-	-
01/01/2059	33							-	-
01/01/2060	34							-	-
01/01/2061	35							-	-
								NPV:	**73 403 693**
								IRR:	**25 %**

Figure D.2: NPV calculations for P90/30% RF realisation.

P90/40% RF									
Time		Q_cum.prod	Q_prod	Revenue	CAPEX	OPEX	ABEX	Cash flow	Discount cash flow
Year	Year.no	MSm3	STB	USD	USD	USD	USD	USD	USD
01/01/2026	0	-	-	-	275 000 000	-	-	- 275 000 000	- 275 000 000
01/01/2027	1	0.58	3 639 054	218 343 260	-	5 500 000	-	212 843 260	193 493 873
01/01/2028	2	0.98	2 503 407	150 204 445	-	5 500 000	-	144 704 445	119 590 451
01/01/2029	3	1.18	1 259 799	75 587 936	-	5 500 000	-	70 087 936	52 658 104
01/01/2030	4	1.30	743 478	44 608 680	-	5 500 000	-	39 108 680	26 711 755
01/01/2031	5	1.38	514 270	30 856 224	-	5 500 000	-	25 356 224	15 744 220
01/01/2032	6	1.44	389 540	23 372 382	-	5 500 000	-	17 872 382	10 088 494
01/01/2033	7	1.49	317 519	19 051 152	-	5 500 000	-	13 551 152	6 953 884
01/01/2034	8	1.53	258 708	15 522 462	-	5 500 000	-	10 022 462	4 675 552
01/01/2035	9	1.57	221 031	13 261 836		5 500 000		7 761 836	3 291 776
01/01/2036	10	1.60	192 663	11 559 762		5 500 000		6 059 762	2 336 301
01/01/2037	11	1.62	170 585	10 235 088		5 500 000		4 735 088	1 659 619
01/01/2038	12	1.65	155 677	9 340 650		5 500 000		3 840 650	1 223 749
01/01/2039	13	1.67	138 191	8 291 478		5 500 000		2 791 478	808 592
01/01/2040	14	1.69	126 177	7 570 644		5 500 000		2 070 644	545 265
01/01/2041	15	1.71	115 988	6 959 256		5 500 000		1 459 256	349 334
01/01/2042	16	1.73	107 307	6 438 444		5 500 000		938 444	204 233
01/01/2043	17	1.74	99 822	5 989 338		5 500 000		489 338	96 813
01/01/2044	18						55 000 000	- 55 000 000	- 9 892 233
01/01/2045	19								
01/01/2046	20								
01/01/2047	21								
01/01/2048	22								
01/01/2049	23								
01/01/2050	24								
01/01/2051	25								
01/01/2052	26								
01/01/2053	27								
01/01/2054	28								
01/01/2055	29								
01/01/2056	30								
01/01/2057	31								
01/01/2058	32								
01/01/2059	33								
01/01/2060	34								
01/01/2061	35								
								NPV:	**155 539 782**
								IRR:	**39 %**

Figure D.3: NPV calculations for P90/40% RF realisation.

P50/20% RF									
Time		Q_cum.prod	Q_prod	Revenue	CAPEX	OPEX	ABEX	Cash flow	Discount cash flow
Year	Year.no	MSm3	STB	USD	USD	USD	USD	USD	USD
01/01/2026	0	-	-	-	275 000 000	-	-	- 275 000 000	- 275 000 000
01/01/2027	1	0.58	3 636 293	218 177 582	-	5 500 000	-	212 677 582	193 343 256
01/01/2028	2	1.03	2 848 508	170 910 496	-	5 500 000	-	165 410 496	136 702 889
01/01/2029	3	1.21	1 147 988	68 879 274	-	5 500 000	-	63 379 274	47 617 787
01/01/2030	4	1.31	603 211	36 192 660	-	5 500 000	-	30 692 660	20 963 500
01/01/2031	5	1.38	412 939	24 776 310	-	5 500 000	-	19 276 310	11 969 072
01/01/2032	6	1.43	314 689	18 881 322	-	5 500 000	-	13 381 322	7 553 407
01/01/2033	7	1.47	254 871	15 292 248	-	5 500 000	-	9 792 248	5 024 972
01/01/2034	8	1.50	213 546	12 812 730	-	5 500 000	-	7 312 730	3 411 443
01/01/2035	9	1.53	184 171	11 050 272		5 500 000		5 550 272	2 353 857
01/01/2036	10	1.55	161 905	9 714 276		5 500 000		4 214 276	1 624 786
01/01/2037	11	1.58	144 544	8 672 652		5 500 000		3 172 652	1 111 995
01/01/2038	12	1.60	130 266	7 815 954		5 500 000		2 315 954	737 934
01/01/2039	13	1.62	118 692	7 121 538		5 500 000		1 621 538	469 702
01/01/2040	14	1.63	109 006	6 540 342		5 500 000		1 040 342	273 955
01/01/2041	15	1.65	100 892	6 053 496		5 500 000		553 496	132 503
01/01/2042	16						55 000 000	- 55 000 000	- 11 969 602
01/01/2043	17								
01/01/2044	18								
01/01/2045	19								
01/01/2046	20							-	-
01/01/2047	21							-	-
01/01/2048	22							-	-
01/01/2049	23							-	-
01/01/2050	24							-	-
01/01/2051	25							-	-
01/01/2052	26							-	-
01/01/2053	27							-	-
01/01/2054	28							-	-
01/01/2055	29							-	-
01/01/2056	30							-	-
01/01/2057	31							-	-
01/01/2058	32							-	-
01/01/2059	33							-	-
01/01/2060	34							-	-
01/01/2061	35							-	-
								NPV:	**146 321 454**
								IRR:	**40 %**

Figure D.4: NPV calculations for P50/20% RF realisation.

P50/30% RF									
Time		Q_cum.prod	Q_prod	Revenue	CAPEX	OPEX	ABEX	Cash flow	Discount cash flow
Year	Year.no	MSm3	STB	USD	USD	USD	USD	USD	USD
01/01/2026	0	-	-	-	275 000 000	-	-	- 275 000 000	- 275 000 000
01/01/2027	1	0.58	3 642 721	218 563 285	-	5 500 000	-	213 063 285	193 693 895
01/01/2028	2	1.12	3 373 836	202 430 189	-	5 500 000	-	196 930 189	162 752 223
01/01/2029	3	1.47	2 234 963	134 097 768	-	5 500 000	-	128 597 768	96 617 406
01/01/2030	4	1.67	1 253 157	75 189 402	-	5 500 000	-	69 689 402	47 598 799
01/01/2031	5	1.80	812 982	48 778 950	-	5 500 000	-	43 278 950	26 872 823
01/01/2032	6	1.89	594 216	35 652 978	-	5 500 000	-	30 152 978	17 020 570
01/01/2033	7	1.97	467 095	28 025 724	-	5 500 000	-	22 525 724	11 559 258
01/01/2034	8	2.03	382 558	22 953 468	-	5 500 000	-	17 453 468	8 142 172
01/01/2035	9	2.08	324 250	19 454 970		5 500 000		13 954 970	5 918 270
01/01/2036	10	2.13	281 037	16 862 232		5 500 000		11 362 232	4 380 632
01/01/2037	11	2.16	248 329	14 899 752		5 500 000		9 399 752	3 294 556
01/01/2038	12	2.20	221 471	13 288 254		5 500 000		7 788 254	2 481 578
01/01/2039	13	2.23	200 211	12 012 642		5 500 000		6 512 642	1 886 480
01/01/2040	14	2.26	182 599	10 955 922		5 500 000		5 455 922	1 436 715
01/01/2041	15	2.29	168 069	10 084 128		5 500 000		4 584 128	1 097 404
01/01/2042	16	2.31	155 048	9 302 910		5 500 000		3 802 910	827 624
01/01/2043	17	2.33	144 167	8 650 008		5 500 000		3 150 008	623 212
01/01/2044	18	2.36	134 732	8 083 908		5 500 000		2 583 908	464 739
01/01/2045	19	2.38	126 618	7 597 062		5 500 000		2 097 062	342 886
01/01/2046	20	2.40	118 881	7 132 860		5 500 000		1 632 860	242 714
01/01/2047	21	2.41	112 402	6 744 138		5 500 000		1 244 138	168 121
01/01/2048	22	2.43	106 490	6 389 382		5 500 000		889 382	109 257
01/01/2049	23	2.45	101 332	6 079 914		5 500 000		579 914	64 764
01/01/2050	24	2.46	96 300	5 777 994		5 500 000		277 994	28 224
01/01/2051	25						55 000 000	- 55 000 000	- 5 076 280
01/01/2052	26								
01/01/2053	27								
01/01/2054	28								
01/01/2055	29							-	-
01/01/2056	30							-	-
01/01/2057	31							-	-
01/01/2058	32							-	-
01/01/2059	33							-	-
01/01/2060	34							-	-
01/01/2061	35							-	-
								NPV:	**307 548 041**
								IRR:	**55 %**

Figure D.5: NPV calculations for P50/30% RF realisation.

P50/40% RF									
Time		Q_cum.prod	Q_prod	Revenue	CAPEX	OPEX	ABEX	Cash flow	Discount cash flow
Year	Year.no	MSm3	STB	USD	USD	USD	USD	USD	USD
01/01/2026	0	-	-	-	275 000 000	-	-	- 275 000 000	- 275 000 000
01/01/2027	1	0.58	3 645 307	218 718 396	-	5 500 000	-	213 218 396	193 834 905
01/01/2028	2	1.14	3 518 500	211 110 012	-	5 500 000	-	205 610 012	169 925 630
01/01/2029	3	1.59	2 863 523	171 811 350	-	5 500 000	-	166 311 350	124 952 179
01/01/2030	4	1.90	1 954 429	117 265 728	-	5 500 000	-	111 765 728	76 337 496
01/01/2031	5	2.11	1 321 152	79 269 096	-	5 500 000	-	73 769 096	45 804 805
01/01/2032	6	2.27	957 904	57 474 246	-	5 500 000	-	51 974 246	29 338 107
01/01/2033	7	2.39	741 780	44 506 782	-	5 500 000	-	39 006 782	20 016 647
01/01/2034	8	2.48	598 619	35 917 158	-	5 500 000	-	30 417 158	14 189 829
01/01/2035	9	2.56	501 061	30 063 684		5 500 000		24 563 684	10 417 400
01/01/2036	10	2.63	429 733	25 783 968		5 500 000		20 283 968	7 820 348
01/01/2037	11	2.69	376 331	22 579 842		5 500 000		17 079 842	5 986 380
01/01/2038	12	2.74	332 993	19 979 556		5 500 000		14 479 556	4 613 633
01/01/2039	13	2.79	298 964	17 937 822		5 500 000		12 437 822	3 602 794
01/01/2040	14	2.83	271 036	16 262 166		5 500 000		10 762 166	2 834 015
01/01/2041	15	2.87	248 203	14 892 204		5 500 000		9 392 204	2 248 419
01/01/2042	16	2.91	227 887	13 673 202		5 500 000		8 173 202	1 778 727
01/01/2043	17	2.94	211 030	12 661 770		5 500 000		7 161 770	1 416 918
01/01/2044	18	2.97	196 374	11 782 428		5 500 000		6 282 428	1 129 950
01/01/2045	19	3.00	183 982	11 038 950		5 500 000		5 538 950	905 663
01/01/2046	20	3.03	172 220	10 333 212		5 500 000		4 833 212	718 426
01/01/2047	21	3.05	162 219	9 733 146		5 500 000		4 233 146	572 027
01/01/2048	22	3.08	153 287	9 197 238		5 500 000		3 697 238	454 191
01/01/2049	23	3.10	145 551	8 733 036		5 500 000		3 233 036	361 060
01/01/2050	24	3.12	137 940	8 276 382		5 500 000		2 776 382	281 874
01/01/2051	25	3.14	131 398	7 883 886		5 500 000		2 383 886	220 023
01/01/2052	26	3.16	125 360	7 521 582		5 500 000		2 021 582	169 622
01/01/2053	27	3.18	120 076	7 204 566		5 500 000		1 704 566	130 020
01/01/2054	28	3.20	114 730	6 883 776		5 500 000		1 383 776	95 956
01/01/2055	29	3.22	110 138	6 608 274		5 500 000		1 108 274	69 865
01/01/2056	30	3.24	105 798	6 347 868		5 500 000		847 868	48 590
01/01/2057	31	3.25	102 024	6 121 428		5 500 000		621 428	32 376
01/01/2058	32	3.27	98 061	5 883 666		5 500 000		383 666	18 171
01/01/2059	33	3.28	94 602	5 676 096		5 500 000		176 096	7 582
01/01/2060	34						55 000 000	- 55 000 000	- 2 152 838
01/01/2061	35							-	-
								NPV:	**443 180 788**
								IRR:	**63 %**

Figure D.6: NPV calculations for P50/40% RF realisation.

P10/20% RF									
Time		Q_cum.prod	Q_prod	Revenue	CAPEX	OPEX	ABEX	Cash flow	Discount cash flow
Year	Year.no	MSm3	STB	USD	USD	USD	USD	USD	USD
01/01/2026	0	-	-	-	275 000 000	-	-	- 275 000 000	- 275 000 000
01/01/2027	1	0.58	3 644 218	218 653 106	-	5 500 000	-	213 153 106	193 775 551
01/01/2028	2	1.13	3 481 156	208 869 388	-	5 500 000	-	203 369 388	168 073 875
01/01/2029	3	1.54	2 570 031	154 201 866	-	5 500 000	-	148 701 866	111 721 913
01/01/2030	4	1.78	1 517 588	91 055 298	-	5 500 000	-	85 555 298	58 435 420
01/01/2031	5	1.94	963 943	57 836 550	-	5 500 000	-	52 336 550	32 496 880
01/01/2032	6	2.05	686 994	41 219 628	-	5 500 000	-	35 719 628	20 162 799
01/01/2033	7	2.13	530 184	31 811 046	-	5 500 000	-	26 311 046	13 501 727
01/01/2034	8	2.20	428 349	25 700 940	-	5 500 000	-	20 200 940	9 423 888
01/01/2035	9	2.25	359 348	21 560 862	-	5 500 000		16 060 862	6 811 373
01/01/2036	10	2.30	309 154	18 549 210	-	5 500 000		13 049 210	5 031 035
01/01/2037	11	2.35	271 602	16 296 132	-	5 500 000		10 796 132	3 783 978
01/01/2038	12	2.39	241 033	14 461 968	-	5 500 000		8 961 968	1 773 078
01/01/2039	13	2.42	217 068	13 024 074	-	5 500 000		7 524 074	1 353 271
01/01/2040	14	2.45	197 317	11 839 038	-	5 500 000		6 339 038	1 036 483
01/01/2041	15	2.48	181 215	10 872 894	-	5 500 000		5 372 894	798 646
01/01/2042	16	2.51	166 811	10 008 648	-	5 500 000		4 508 648	609 256
01/01/2043	17	2.53	154 797	9 287 814	-	5 500 000		3 787 814	465 318
01/01/2044	18	2.55	144 418	8 665 104	-	5 500 000		3 165 104	353 473
01/01/2045	19	2.58	135 550	8 132 970	-	5 500 000		2 632 970	267 314
01/01/2046	20	2.60	127 184	7 631 028	-	5 500 000		2 131 028	196 685
01/01/2047	21	2.61	120 076	7 204 566	-	5 500 000		1 704 566	143 022
01/01/2048	22	2.63	113 660	6 819 618	-	5 500 000		1 319 618	100 657
01/01/2049	23						55 000 000	- 55 000 000	- 3 813 884
01/01/2050	24								
01/01/2051	25								
01/01/2052	26								
01/01/2053	27							-	-
01/01/2054	28							-	-
01/01/2055	29							-	-
01/01/2056	30							-	-
01/01/2057	31							-	-
01/01/2058	32							-	-
01/01/2059	33							-	-
01/01/2060	34							-	-
01/01/2061	35							-	-
								NPV:	**351 501 758**
								IRR:	**59 %**

Figure D.7: NPV calculations for P10/20% RF realisation.

P10/30% RF									
Time		Q_cum.prod	Q_prod	Revenue	CAPEX	OPEX	ABEX	Cash flow	Discount cash flow
Year	Year.no	MSm3	STB	USD	USD	USD	USD	USD	USD
01/01/2026	0	-	-	-	275 000 000	-	-	- 275 000 000	- 275 000 000
01/01/2027	1	0.58	3 643 640	218 618 385	-	5 500 000	-	213 118 385	193 743 986
01/01/2028	2	1.14	3 537 716	212 262 969	-	5 500 000	-	206 762 969	170 878 487
01/01/2029	3	1.63	3 101 285	186 077 070	-	5 500 000	-	180 577 070	135 670 225
01/01/2030	4	2.02	2 397 434	143 846 010	-	5 500 000	-	138 346 010	94 492 186
01/01/2031	5	2.30	1 781 768	106 906 098	-	5 500 000	-	101 406 098	62 965 209
01/01/2032	6	2.51	1 344 488	80 669 250	-	5 500 000	-	75 169 250	42 431 082
01/01/2033	7	2.68	1 053 952	63 237 144	-	5 500 000	-	57 737 144	29 628 284
01/01/2034	8	2.82	850 848	51 050 898	-	5 500 000	-	45 550 898	21 249 830
01/01/2035	9	2.93	709 135	42 548 076		5 500 000		37 048 076	15 712 001
01/01/2036	10	3.02	604 658	36 279 462		5 500 000		30 779 462	11 866 815
01/01/2037	11	3.11	526 410	31 584 606		5 500 000		26 084 606	9 142 495
01/01/2038	12	3.18	462 755	27 765 318		5 500 000		22 265 318	7 094 416
01/01/2039	13	3.25	412 938	24 776 310		5 500 000		19 276 310	5 583 660
01/01/2040	14	3.31	372 242	22 334 532		5 500 000		16 834 532	4 433 058
01/01/2041	15	3.36	339 094	20 345 634		5 500 000		14 845 634	3 553 927
01/01/2042	16	3.41	309 720	18 583 176		5 500 000		13 083 176	2 847 280
01/01/2043	17	3.46	285 314	17 118 864		5 500 000		11 618 864	2 298 730
01/01/2044	18	3.50	264 369	15 862 122		5 500 000		10 362 122	1 863 719
01/01/2045	19	3.54	246 631	14 797 854		5 500 000		9 297 854	1 520 273
01/01/2046	20	3.57	229 962	13 797 744		5 500 000		8 297 744	1 233 407
01/01/2047	21	3.61	215 747	12 944 820		5 500 000		7 444 820	1 006 023
01/01/2048	22	3.64	203 167	12 190 020		5 500 000		6 690 020	821 842
01/01/2049	23	3.67	192 222	11 533 344		5 500 000		6 033 344	673 793
01/01/2050	24	3.70	181 529	10 891 764		5 500 000		5 391 764	547 402
01/01/2051	25	3.73	172 346	10 340 760		5 500 000		4 840 760	446 783
01/01/2052	26	3.75	163 917	9 835 044		5 500 000		4 335 044	363 734
01/01/2053	27	3.78	156 684	9 401 034		5 500 000		3 901 034	297 562
01/01/2054	28	3.80	149 262	8 955 702		5 500 000		3 455 702	239 630
01/01/2055	29	3.82	142 783	8 566 980		5 500 000		3 066 980	193 341
01/01/2056	30						55 000 000	- 55 000 000	- 3 151 970
01/01/2057	31							-	-
01/01/2058	32							-	-
01/01/2059	33							-	-
01/01/2060	34							-	-
01/01/2061	35							-	-
								NPV:	**544 647 210**
								IRR:	**66 %**

Figure D.8: NPV calculations for P10/30% RF realisation.

P10/40% RF									
Time		Q_cum.prod	Q_prod	Revenue	CAPEX	OPEX	ABEX	Cash flow	Discount cash flow
Year	Year.no	MSm3	STB	USD	USD	USD	USD	USD	USD
01/01/2026	0	-	-	-	275 000 000	-	-	- 275 000 000	- 275 000 000
01/01/2027	1	0.58	3 646 942	218 816 520	-	5 500 000	-	213 316 520	193 924 109
01/01/2028	2	1.15	3 597 691	215 861 478	-	5 500 000	-	210 361 478	173 852 461
01/01/2029	3	1.69	3 413 017	204 781 014	-	5 500 000	-	199 281 014	149 722 775
01/01/2030	4	2.17	2 971 459	178 287 534	-	5 500 000	-	172 787 534	118 016 211
01/01/2031	5	2.56	2 456 245	147 374 700	-	5 500 000	-	141 874 700	88 093 026
01/01/2032	6	2.87	1 978 331	118 699 848	-	5 500 000	-	113 199 848	63 898 363
01/01/2033	7	3.13	1 598 415	95 904 888	-	5 500 000	-	90 404 888	46 392 002
01/01/2034	8	3.33	1 304 169	78 250 116	-	5 500 000	-	72 750 116	33 938 466
01/01/2035	9	3.51	1 088 485	65 309 070		5 500 000		59 809 070	25 364 884
01/01/2036	10	3.65	925 699	55 541 958		5 500 000		50 041 958	19 293 341
01/01/2037	11	3.78	802 478	48 148 692		5 500 000		42 648 692	14 948 106
01/01/2038	12	3.89	702 027	42 121 614		5 500 000		36 621 614	11 668 775
01/01/2039	13	3.99	623 402	37 404 114		5 500 000		31 904 114	9 241 485
01/01/2040	14	4.08	559 307	33 558 408		5 500 000		28 058 408	7 388 656
01/01/2041	15	4.16	507 477	30 448 632		5 500 000		24 948 632	5 972 504
01/01/2042	16	4.23	461 560	27 693 612		5 500 000		22 193 612	4 829 977
01/01/2043	17	4.30	423 820	25 429 212		5 500 000		19 929 212	3 942 888
01/01/2044	18	4.36	391 301	23 478 054		5 500 000		17 978 054	3 233 511
01/01/2045	19	4.42	364 002	21 840 138		5 500 000		16 340 138	2 671 743
01/01/2046	20	4.48	338 402	20 304 120		5 500 000		14 804 120	2 200 538
01/01/2047	21	4.53	316 701	19 002 090		5 500 000		13 502 090	1 824 545
01/01/2048	22	4.57	297 517	17 851 020		5 500 000		12 351 020	1 517 273
01/01/2049	23	4.62	280 974	16 858 458		5 500 000		11 358 458	1 268 492
01/01/2050	24	4.66	264 809	15 888 540		5 500 000		10 388 540	1 054 703
01/01/2051	25	4.70	250 971	15 058 260		5 500 000		9 558 260	882 189
01/01/2052	26	4.74	238 265	14 295 912		5 500 000		8 795 912	738 025
01/01/2053	27	4.77	227 446	13 646 784		5 500 000		8 146 784	621 418
01/01/2054	28	4.81	216 250	12 975 012		5 500 000		7 475 012	518 342
01/01/2055	29	4.84	206 752	12 405 138		5 500 000		6 905 138	435 296
01/01/2056	30	4.87	197 821	11 869 230		5 500 000		6 369 230	365 011
01/01/2057	31	4.90	190 147	11 408 802		5 500 000		5 908 802	307 841
01/01/2058	32	4.93	182 096	10 925 730		5 500 000		5 425 730	256 976
01/01/2059	33	4.96	175 114	10 506 816		5 500 000		5 006 816	215 577
01/01/2060	34	4.99	168 572	10 114 320		5 500 000		4 614 320	180 616
01/01/2061	35	5.01	162 848	9 770 886		5 500 000		4 270 886	151 976
							55 000 000	- 55 000 000	- 55 000 000
								NPV:	**658 932 103**
								IRR:	**71 %**

Figure D.9: NPV calculations for P10/40% RF realisation.

D.2 Post-Tax

P50/20% RF									
Time			Q_cum.prod	Q_prod	Revenue	CAPEX	Depreciation	OPEX	Abandonment
Year	Year.no	Inflation facto	MSm3	STB	USD	USD		USD	USD
01/01/2026	-	1	0	-	-	275 000 000	-	-	-
01/01/2027	1	1.02	0.578107	3 636 293	222 541 133	-	45 833 333.33	5 610 000	-
01/01/2028	2	1.04	1.03097	2 848 508	177 815 280	-	45 833 333.33	5 722 200	-
01/01/2029	3	1.06	1.21348	1 147 988	73 095 237	-	45 833 333.33	5 836 644	-
01/01/2030	4	1.08	1.30938	603 211	39 176 099	-	45 833 333.33	5 953 377	-
01/01/2031	5	1.10	1.37503	412 939	27 355 048	-	45 833 333.33	6 072 444	-
01/01/2032	6	1.13	1.42506	314 689	21 263 435	-	45 833 333.33	6 193 893	-
01/01/2033	7	1.15	1.46558	254 871	17 565 986	-	-	6 317 771	
01/01/2034	8	1.17	1.49953	213 546	15 012 155	-	-	6 444 127	
01/01/2035	9	1.20	1.52881	184 171	13 206 098	-	-	6 573 009	
01/01/2036	10	1.22	1.55455	161 905	11 841 648	-	-	6 704 469	
01/01/2037	11	1.24	1.57753	144 544	10 783 353	-	-	6 838 559	
01/01/2038	12	1.27	1.59824	130 266	9 912 520	-	-	6 975 330	
01/01/2039	13	1.29	1.61711	118 692	9 212 469	-	-	7 114 836	
01/01/2040	14	1.32	1.63444	109 006	8 629 842	-	-	7 257 133	
01/01/2041	15	1.35	1.65048	100 892	8 147 209	-	-	7 402 276	
01/01/2042	16	1.37							75 503 214
01/01/2043	17	1.40							
01/01/2044	18	1.43							
01/01/2045	19	1.46							
01/01/2046	20	1.49							
01/01/2047	21	1.52							
01/01/2048	22	1.55							
01/01/2049	23	1.58							
01/01/2050	24	1.61							
01/01/2051	25	1.64							
01/01/2052	26	1.67							
01/01/2053	27	1.71							
01/01/2054	28	1.74							
01/01/2055	29	1.78							
01/01/2056	30	1.81							
01/01/2057	31	1.85							
01/01/2058	32	1.88							
01/01/2059	33	1.92							
01/01/2060	34	1.96							
01/01/2061	35	2.00							

Figure D.10: Post-tax analysis for P50/20% RF realisation (1/2).

P50/20% RF									
Corporate Tax Base	Loss carried forward for CT	Corporate Tax	Uplift	Special tax base	Loss carried forward for SPT	Special Tax	Total tax	Cash flow (mod)	Discount cash flow 10%
USD				USD		USD	USD		USD
								- 275 000 000	- 275 000 000
171 097 800		37 641 516	14 300 000	156 797 800		87 806 768	125 448 284	91 482 849	83 166 227
126 259 747	-	27 777 144	14 300 000	111 959 747	-	62 697 458	90 474 603	81 618 478	67 453 287
21 425 259	-	4 713 557	14 300 000	7 125 259	-	3 990 145	8 703 702	58 554 890	43 993 156
- 12 610 611	- 12 610 611	-	14 300 000	- 26 910 611	- 26 910 611	-	-	33 222 722	22 691 566
- 24 550 730	- 37 161 341	-		- 24 550 730	- 51 461 341	-	-	21 282 604	13 214 823
- 30 763 791	- 67 925 132	-		- 30 763 791	- 82 225 132	-	-	15 069 542	8 506 364
11 248 215	- 56 676 917	-		11 248 215	- 82 225 132	-	-	11 248 215	5 772 113
8 568 029	- 48 108 888	-		8 568 029	- 82 225 132	-	-	8 568 029	3 997 049
6 633 089	- 41 475 799	-		6 633 089	- 82 225 132	-	-	6 633 089	2 813 077
5 137 179	- 36 338 621	-		5 137 179	- 82 225 132	-	-	5 137 179	1 980 605
3 944 794	- 32 393 827	-		3 944 794	- 82 225 132	-	-	3 944 794	1 382 626
2 937 190	- 29 456 637	-		2 937 190	- 82 225 132	-	-	2 937 190	935 879
2 097 632	- 27 359 005	-		2 097 632	- 82 225 132	-	-	2 097 632	607 609
1 372 709	- 25 986 295	-		1 372 709	- 82 225 132	-	-	1 372 709	361 477
744 933	- 25 241 363	-		744 933	- 82 225 132	-	-	744 933	178 331
- 75 503 214	- 100 744 576	-		- 75 503 214	-157 728 346	-	- 58 892 507	- 16 610 707	- 3 614 974
-				-					-
							NPV	**52 304 148**	**- 21 560 785**
							IRR	**6.6%**	

Figure D.11: Post-tax analysis for P50/20% RF realisation (2/2).

P50/30% RF									
Time			Q_cum.prod	Q_prod	Revenue	CAPEX	Depreciation	OPEX	Abandonment
Year	Year.no	Inflation facto	MSm3	STB	USD	USD	USD	USD	USD
01/01/2026	0	1	0	-	-	275 000 000	-	-	-
01/01/2027	1	1.02	0.579129	3 642 721	222 934 550	-	45 833 333.33	5 610 000	-
01/01/2028	2	1.04	1.11551	3 373 836	210 608 369	-	45 833 333.33	5 722 200	-
01/01/2029	3	1.06	1.47083	2 234 963	142 305 624	-	45 833 333.33	5 836 644	-
01/01/2030	4	1.08	1.67006	1 253 157	81 387 427	-	45 833 333.33	5 953 377	-
01/01/2031	5	1.10	1.79931	812 982	53 855 902	-	45 833 333.33	6 072 444	-
01/01/2032	6	1.13	1.89378	594 216	40 151 044	-	45 833 333.33	6 193 893	-
01/01/2033	7	1.15	1.96804	467 095	32 192 747	-	-	6 317 771	-
01/01/2034	8	1.17	2.02886	382 558	26 893 646	-	-	6 444 127	-
01/01/2035	9	1.20	2.08041	324 250	23 250 490			6 573 009	
01/01/2036	10	1.22	2.12509	281 037	20 554 967			6 704 469	
01/01/2037	11	1.24	2.16457	248 329	18 525 969			6 838 559	
01/01/2038	12	1.27	2.19978	221 471	16 852 719			6 975 330	
01/01/2039	13	1.29	2.23161	200 211	15 539 633			7 114 836	
01/01/2040	14	1.32	2.26064	182 599	14 456 106			7 257 133	
01/01/2041	15	1.35	2.28736	168 069	13 571 909			7 402 276	
01/01/2042	16	1.37	2.31201	155 048	12 770 902			7 550 321	
01/01/2043	17	1.40	2.33493	144 167	12 112 099			7 701 328	
01/01/2044	18	1.43	2.35635	134 732	11 545 811			7 855 354	
01/01/2045	19	1.46	2.37648	126 618	11 067 485			8 012 461	
01/01/2046	20	1.49	2.39538	118 881	10 599 055			8 172 711	
01/01/2047	21	1.52	2.41325	112 402	10 221 863			8 336 165	
01/01/2048	22	1.55	2.43018	106 490	9 877 855			8 502 888	
01/01/2049	23	1.58	2.44629	101 332	9 587 412			8 672 946	
01/01/2050	24	1.61	2.4616	96 300	9 293 541			8 846 405	
01/01/2051	25	1.64							90 233 330
01/01/2052	26	1.67							
01/01/2053	27	1.71							
01/01/2054	28	1.74							
01/01/2055	29	1.78							
01/01/2056	30	1.81							
01/01/2057	31	1.85							
01/01/2058	32	1.88							
01/01/2059	33	1.92							
01/01/2060	34	1.96							
01/01/2061	35	2.00							

Figure D.12: Post-tax analysis for P50/30% RF realisation (1/2).

P50/30% RF									
Corporate Tax Base	Loss carried forward	Corporate Tax	Uplift	Special tax base	Loss carried forward for SPT	Special Tax	Total tax	Cash flow (mod)	Discount cash flow 10% Real
USD									USD
								- 275 000 000	- 275 000 000
171 491 217		37 728 068	14 300 000	157 191 217		88 027 081	125 755 149	91 569 401	83 244 910
159 052 836	-	34 991 624	14 300 000	144 752 836	-	81 061 588	116 053 212	88 832 957	73 415 667
90 635 647	-	19 939 842	14 300 000	76 335 647	-	42 747 962	62 687 805	73 781 176	55 432 889
29 600 717	-	6 512 158	14 300 000	15 300 717	-	8 568 401	15 080 559	60 353 491	41 222 246
1 950 125	-	429 027		1 950 125	-	1 092 070	1 521 097	46 262 361	28 725 286
- 11 876 183	- 11 876 183	-		- 11 876 183	- 11 876 183	-	-	33 957 151	19 167 926
25 874 976	-	5 692 495		25 874 976	-	14 489 987	20 182 482	5 692 495	2 921 150
20 449 520	-	4 498 894		20 449 520	-	11 451 731	15 950 625	4 498 894	2 098 767
16 677 481	-	3 669 046		16 677 481	-	9 339 389	13 008 435	3 669 046	1 556 034
13 850 497	-	3 047 109		13 850 497	-	7 756 279	10 803 388	3 047 109	1 174 793
11 687 410	-	2 571 230		11 687 410	-	6 544 950	9 116 180	2 571 230	901 201
9 877 389	-	2 173 026		9 877 389	-	5 531 338	7 704 364	2 173 026	692 393
8 424 797	-	1 853 455		8 424 797	-	4 717 886	6 571 342	1 853 455	536 880
7 198 973	-	1 583 774		7 198 973	-	4 031 425	5 615 199	1 583 774	417 057
6 169 633	-	1 357 319		6 169 633	-	3 454 994	4 812 314	1 357 319	324 931
5 220 580	-	1 148 528		5 220 580	-	2 923 525	4 072 053	1 148 528	249 953
4 410 772	-	970 370		4 410 772	-	2 470 032	3 440 402	970 370	191 982
3 690 457	-	811 901		3 690 457	-	2 066 656	2 878 556	811 901	146 027
3 055 023	-	672 105		3 055 023	-	1 710 813	2 382 918	672 105	109 895
2 426 344	-	533 796		2 426 344	-	1 358 753	1 892 548	533 796	79 345
1 885 698	-	414 854		1 885 698	-	1 055 991	1 470 845	414 854	56 059
1 374 966	-	302 493		1 374 966	-	769 981	1 072 474	302 493	37 160
914 466	-	201 183		914 466	-	512 101	713 283	201 183	22 468
447 136	-	98 370		447 136	-	250 396	348 766	98 370	9 987
- 90 233 330	- 90 233 330	-		- 90 233 330	- 90 233 330	-	- 70 381 997	- 19 851 333	- 1 832 199
-				-					-
-				-					-
-				-					-
-				-					-
-				-					-
-				-					-
-				-					-
-				-					-
							NPV	**131 505 150**	**35 902 809**
							IRR	**15 %**	

Figure D.13: Post-tax analysis for P50/30% RF realisation (2/2).

P50/40% RF									
Time			Q_cum.prod	Q_prod	Revenue	CAPEX	Depreciation	OPEX	Abandonment
Year	Year.no	Inflation facto	MSm3	STB	USD	USD	USD	USD	USD
01/01/2026	0	1	0	-	-	275 000 000	-	-	-
01/01/2027	1	1.02	0.57954	3 645 307	223 092 764	-	45 833 333.33	5 610 000	-
01/01/2028	2	1.04	1.13892	3 518 500	219 638 856	-	45 833 333.33	5 722 200	-
01/01/2029	3	1.06	1.59417	2 863 523	182 327 579	-	45 833 333.33	5 836 644	-
01/01/2030	4	1.08	1.90489	1 954 429	126 932 195	-	45 833 333.33	5 953 377	-
01/01/2031	5	1.10	2.11493	1 321 152	87 519 487	-	45 833 333.33	6 072 444	-
01/01/2032	6	1.13	2.26722	957 904	64 725 336	-	45 833 333.33	6 193 893	-
01/01/2033	7	1.15	2.38515	741 780	51 124 303	-	-	6 317 771	-
01/01/2034	8	1.17	2.48032	598 619	42 082 675	-	-	6 444 127	-
01/01/2035	9	1.20	2.55998	501 061	35 928 885			6 573 009	
01/01/2036	10	1.22	2.6283	429 733	31 430 513			6 704 469	
01/01/2037	11	1.24	2.68813	376 331	28 075 195			6 838 559	
01/01/2038	12	1.27	2.74107	332 993	25 338 908			6 975 330	
01/01/2039	13	1.29	2.7886	298 964	23 204 485			7 114 836	
01/01/2040	14	1.32	2.83169	271 036	21 457 583			7 257 133	
01/01/2041	15	1.35	2.87115	248 203	20 042 946			7 402 276	
01/01/2042	16	1.37	2.90738	227 887	18 770 376			7 550 321	
01/01/2043	17	1.40	2.94093	211 030	17 729 535			7 701 328	
01/01/2044	18	1.43	2.97215	196 374	16 828 209			7 855 354	
01/01/2045	19	1.46	3.0014	183 982	16 081 666			8 012 461	
01/01/2046	20	1.49	3.02878	172 220	15 354 609			8 172 711	
01/01/2047	21	1.52	3.05457	162 219	14 752 202			8 336 165	
01/01/2048	22	1.55	3.07894	153 287	14 218 743			8 502 888	
01/01/2049	23	1.58	3.10208	145 551	13 771 118			8 672 946	
01/01/2050	24	1.61	3.12401	137 940	13 312 041			8 846 405	
01/01/2051	25	1.64	3.1449	131 398	12 934 351			9 023 333	
01/01/2052	26	1.67	3.16483	125 360	12 586 752			9 203 800	
01/01/2053	27	1.71	3.18392	120 076	12 297 376			9 387 876	
01/01/2054	28	1.74	3.20216	114 730	11 984 821			9 575 633	
01/01/2055	29	1.78	3.21967	110 138	11 735 268			9 767 146	
01/01/2056	30	1.81	3.23649	105 798	11 498 284			9 962 489	
01/01/2057	31	1.85	3.25271	102 024	11 309 882			10 161 738	
01/01/2058	32	1.88	3.2683	98 061	11 088 007			10 364 973	
01/01/2059	33	1.92	3.28334	94 602	10 910 770			10 572 273	
01/01/2060	34	1.96	0						107 837 182
01/01/2061	35	2.00	0						

Figure D.14: Post-tax analysis for P50/40% RF realisation (1/2).

P50/40% RF									
Corporate Tax Base	Loss carried forward	Corporate Tax	Uplift	Special tax base	Loss carried forward for SPT	Special Tax	Total tax	Cash flow (mod)	Discount cash flow 10% Real
USD									USD
								- 275 000 000	- 275 000 000
171 649 431		37 762 875	14 300 000	157 349 431		88 115 681	125 878 556	91 604 208	83 276 553
168 083 323	-	36 978 331	14 300 000	153 783 323	-	86 118 661	123 096 992	90 819 664	75 057 574
130 657 602	-	28 744 672	14 300 000	116 357 602	-	65 160 257	93 904 929	82 586 006	62 048 088
75 145 485	-	16 532 007	14 300 000	60 845 485	-	34 073 472	50 605 478	70 373 340	48 065 938
35 613 709	-	7 835 016		35 613 709	-	19 943 677	27 778 693	53 668 349	33 323 823
12 698 109	-	2 793 584		12 698 109	-	7 110 941	9 904 525	48 626 917	27 448 627
44 806 531	-			44 806 531	-	25 091 658	25 091 658	19 714 874	10 116 848
35 638 549	-			35 638 549	-	19 957 587	19 957 587	15 680 961	7 315 284
29 355 876	-	6 458 293		29 355 876	-	16 439 291	22 897 583	6 458 293	2 738 947
24 726 044	-	5 439 730		24 726 044	-	13 846 585	19 286 314	5 439 730	2 097 251
21 236 637	-	4 672 060		21 236 637	-	11 892 517	16 564 577	4 672 060	1 637 529
18 363 578	-	4 039 987		18 363 578		10 283 604	14 323 591	4 039 987	1 287 264
16 089 649	-	3 539 723		16 089 649		9 010 203	12 549 926	3 539 723	1 025 332
14 200 449	-	3 124 099		14 200 449		7 952 252	11 076 351	3 124 099	822 673
12 640 670	-	2 780 947		12 640 670		7 078 775	9 859 723	2 780 947	665 737
11 220 055	-	2 468 412		11 220 055		6 283 231	8 751 643	2 468 412	537 198
10 028 207	-	2 206 206		10 028 207		5 615 796	7 822 001	2 206 206	436 486
8 972 854	-	1 974 028		8 972 854		5 024 798	6 998 826	1 974 028	355 046
8 069 204	-	1 775 225		8 069 204		4 518 754	6 293 979	1 775 225	290 263
7 181 899	-	1 580 018		7 181 899		4 021 863	5 601 881	1 580 018	234 860
6 416 037	-	1 411 528		6 416 037		3 592 981	5 004 509	1 411 528	190 741
5 715 855	-	1 257 488		5 715 855		3 200 879	4 458 367	1 257 488	154 477
5 098 172	-	1 121 598		5 098 172		2 854 976	3 976 574	1 121 598	125 258
4 465 636	-	982 440		4 465 636		2 500 756	3 483 196	982 440	99 743
3 911 018	-	860 424		3 911 018		2 190 170	3 050 594	860 424	79 414
3 382 952	-	744 249		3 382 952		1 894 453	2 638 703	744 249	62 447
2 909 501	-	640 090		2 909 501		1 629 320	2 269 411	640 090	48 825
2 409 188	-	530 021		2 409 188		1 349 145	1 879 166	530 021	36 753
1 968 122	-	432 987		1 968 122		1 102 149	1 535 136	432 987	27 295
1 535 796	-	337 875		1 535 796		860 045	1 197 921	337 875	19 363
1 148 143	-	252 592		1 148 143		642 960	895 552	252 592	13 160
723 034	-	159 068		723 034		404 899	563 967	159 068	7 534
338 497	-	74 469		338 497		189 558	264 028	74 469	3 206
-107 837 182	- 107 837 182	-		- 107 837 182		-	- 84 113 002	- 23 724 180	- 928 624
-									-
							NPV	**223 213 696**	**83 720 912**
							IRR	**20 %**	

Figure D.15: Post-tax analysis for P50/40% RF realisation (2/2).

D.3 Sensitivity

Time			Q_cum.prod	Q_prod	Revenue	CAPEX	Depreciation	OPEX	Abandonment	Corporate Tax Base
Year	Year.no	factor	MSm3	STB	USD	USD	USD	USD	USD	USD
01/01/2026	0	1	0	-	-	215 000 000	-	-	-	
01/01/2027	1	1.02	0.51053	3 211 227	196 527 091	-	35 833 333	5 610 000	-	155 083 758
01/01/2028	2	1.04	0.98337	2 974 193	185 660 994	-	35 833 333	5 722 200	-	144 105 460
01/01/2029	3	1.06	1.2966	1 970 223	125 448 973	-	35 833 333	5 836 644	-	83 778 996
01/01/2030	4	1.08	1.47223	1 104 715	71 746 772	-	35 833 333	5 953 377	-	29 960 061
01/01/2031	5	1.10	1.58617	716 682	47 476 462	-	35 833 333	6 072 444	-	5 570 685
01/01/2032	6	1.13	1.66945	523 829	35 394 998	-	35 833 333	6 193 893	-	- 6 632 229
01/01/2033	7	1.15	1.73492	411 766	28 379 392			6 317 771	-	22 061 621
01/01/2034	8	1.17	1.78853	337 242	23 707 990			6 444 127	-	17 263 863
01/01/2035	9	1.20	1.83398	285 841	20 496 380			6 573 009		13 923 371
01/01/2036	10	1.22	1.87336	247 747	18 120 151			6 704 469		11 415 682
01/01/2037	11	1.24	1.90817	218 914	16 331 496			6 838 559		9 492 938
01/01/2038	12	1.27	1.93921	195 237	14 856 449			6 975 330		7 881 120
01/01/2039	13	1.29	1.96727	176 495	13 698 904			7 114 836		6 584 067
01/01/2040	14	1.32	1.99286	160 969	12 743 725			7 257 133		5 486 592
01/01/2041	15	1.35	2.01641	148 160	11 964 264			7 402 276		4 561 988
01/01/2042	16	1.37	2.03814	136 682	11 258 139			7 550 321		3 707 818
01/01/2043	17	1.40	2.05835	127 090	10 677 374			7 701 328		2 976 047
01/01/2044	18	1.43	2.07723	118 772	10 178 165			7 855 354		2 322 811
01/01/2045	19	1.46	2.09498	111 619	9 756 498			8 012 461		1 744 037
01/01/2046	20	1.49	2.11164	104 799	9 343 556			8 172 711		1 170 845
01/01/2047	21	1.52	2.12739	99 088	9 011 044			8 336 165		674 879
01/01/2048	22	1.55	2.14232	93 876	8 707 785			8 502 888		204 896
01/01/2049	23	1.58							67 806 668	- 67 806 668
01/01/2050	24	1.61								
01/01/2051	25	1.64								
01/01/2052	26	1.67								
01/01/2053	27	1.71								-
01/01/2054	28	1.74								-
01/01/2055	29	1.78								-
01/01/2056	30	1.81								-
01/01/2057	31	1.85								-
01/01/2058	32	1.88								-
01/01/2059	33	1.92								-
01/01/2060	34	1.96								-
01/01/2061	35	2.00								-

Figure D.16: Sensitivity analysis on P50/30% RF realisation (1/2).

Loss carried forward	Corporate Tax	Uplift	Special tax base	Loss carried forward for SPT	Special Tax	Total tax	Cash flow (mod)	Discount cash flow 10% Real
USD	USD	USD	USD	USD	USD	USD	USD	USD
							- 215 000 000	- 215 000 000
	34 118 427	11 180 000	143 903 758		80 586 104	114 704 531	76 212 560	69 284 145
-	31 703 201	11 180 000	132 925 460	-	74 438 258	106 141 459	73 797 335	60 989 533
-	18 431 379	11 180 000	72 598 996	-	40 655 438	59 086 817	60 525 512	45 473 713
-	6 591 213	11 180 000	18 780 061	-	10 516 834	17 108 048	48 685 347	33 252 747
-	1 225 551		5 570 685	-	3 119 583	4 345 134	37 058 884	23 010 651
- 6 632 229	-		- 6 632 229	- 6 632 229	-	-	29 201 104	16 483 262
-	4 853 557		22 061 621	-	12 354 508	17 208 064	4 853 557	2 490 642
-	3 798 050		17 263 863	-	9 667 763	13 465 813	3 798 050	1 771 818
-	3 063 142		13 923 371	-	7 797 087	10 860 229	3 063 142	1 299 071
-	2 511 450		11 415 682	-	6 392 782	8 904 232	2 511 450	968 273
-	2 088 446		9 492 938	-	5 316 045	7 404 491	2 088 446	731 988
-	1 733 846		7 881 120	-	4 413 427	6 147 273	1 733 846	552 457
-	1 448 495		6 584 067	-	3 687 078	5 135 572	1 448 495	419 577
-	1 207 050		5 486 592	-	3 072 491	4 279 541	1 207 050	317 854
-	1 003 637		4 561 988	-	2 554 713	3 558 350	1 003 637	240 263
	815 720		3 707 818	-	2 076 378	2 892 098	815 720	177 524
	654 730		2 976 047	-	1 666 586	2 321 316	654 730	129 535
	511 018		2 322 811	-	1 300 774	1 811 793	511 018	91 911
	383 688		1 744 037	-	976 661	1 360 349	383 688	62 736
	257 586		1 170 845	-	655 673	913 259	257 586	38 289
	148 473		674 879	-	377 932	526 406	148 473	20 063
	45 077		204 896	-	114 742	159 819	45 077	5 538
- 67 806 668	-		- 67 806 668	- 67 806 668	-	- 52 889 201	- 14 917 467	- 1 665 955
			-					-
			-					-
			-					-
			-					-
			-					-
			-					-
			-					-
			-					-
			-					-
						NPV	**120 087 241**	**41 145 635**
						IRR	**17 %**	

Figure D.17: Sensitivity analysis on P50/30% RF realisation (2/2).

NTNU

Kunnskap for en bedre verden