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I

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This thesis comprises the deliverables of the work conducted at the University of Stavanger during the spring semester 2020. It is also the culmination of five years of studying at the UiS.

The chosen thesis topic has enabled me to employ a broad spectrum of acquired knowledge and skills, cross-disciplinary work and a big-picture mindset on a highly relevant research topic. The thesis work has required me to look beyond the technical analyses and evaluate the value creation impact of the analyses and decision making, at both the strategic and tactical level.

The thesis work was conducted in the midst of the Covid 19 pandemic, which introduced difficult working conditions and made it challenging for supervisors to provide support. Nevertheless, I would like to express my gratitude to those that helped me and gave me support during this project.

I would like to thank Aker BP for giving me the opportunity to work with such an interesting and real-life problem, which I believe is highly relevant for a future career as a petroleum engineer.

I especially would like to thank my academic supervisor, professor Reidar B. Bratvold, for his knowledge sharing and dedication towards decision making. It has been inspiring to work together with such an expert In the decision analysis field.

I would also like to show appreciation to my wife and family, who supported me and encouraged me throughout my studies and especially through this challenging last period of writing this thesis.

Sincerely, thank you all!

Abstract

Whether facing pandemics, negative oil prices or other crises, the key to value creation is to make good decisions. Decisions are always about the future and the one thing we know for sure about the future is that it is uncertain. The focus of this thesis is on the challenge of making good decisions in the context of re-developments of challenging brown fields. We develop a robust decision-making framework that embraces uncertainty and discuss and illustrates its practical implementation using the Tambar East field as an example.

The Tambar East field is situated in a complex geological structure, highly compartmentalized and containing challenging reservoir fluids which causes deposition of solids in the reservoir and wellbore. Due to these difficulties, the field is temporarily plugged, and a compelling re-development program is required to revitalize a potential Tambar East development. Moreover, the recent, largely pandemic driven, dramatic drop in oil prices has not increased the likelihood that a re-development of the field will result in value creation.

The focus of the thesis is on the front-end-analysis (framing, objective setting and alternative generation) of the re-development decision; i.e., for the purpose of determining the key value drivers as well as the underlying cause of poor performance. The front-end-analysis is especially important in a brown field development, where the framing of the problem and identifying the value drivers is a complex process that could vary a lot from field to field. The potential scope of such a brown field development could be massive and it needs to be managed properly, ensuring that the answers we get are answering the right questions and problems at hand.

The key contribution of this thesis is to provide a robust, high-quality decision-oriented methodology for (brown) field development. Moreover, the thesis provides an in-depth discussion of the importance of embracing uncertainty to maximize value creation from brown fields through robust decision-making. Finally, the thesis presents a framework applicable for any decision making- and field development process, with the purpose of achieving clarity and insight through decision-oriented analysis which ultimately will result in making better decisions. The main idea is that:

"The only way to purposefully create (or destroy) value is through our decision."

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1 Introduction

1.1 Background

The oil adventure started in Norway in the 1960s. Many offshore oilfields were discovered and developed. More and more advanced technology was employed to further develop the industry. Several early oilfields discovered on the NCS were giants situated in "obvious" geological structures – low hanging fruits that were quite straight forward to develop and produce from, at least with today's technology. New discoveries are now few and far between, so value creation from optimizing the production and re-development of existing fields (brown fields) is what many operators are currently focusing on. The vast majority of these potential developments are marginal projects with material; i.e., decision-relevant, uncertainty in the value metric.

The only way to create value is through our decisions. Given this, competitive advantage can be generated by being very good at making high-quality decisions in complex and uncertain environments. Crucial in making high-quality decisions is information. Information refers to what the decision maker knows, and perhaps even more important, what he does not know; i.e. uncertainty, at the time of the decision. In other words, a requirement for high-quality decision making is the unbiased quantification of material uncertainties. So, if a company ignores uncertainty or does a poor job in assessing/quantifying uncertainty, it cannot possibly make high-quality value maximizing decisions.

Aker BP's vision is to be the world leading independent offshore E&P company and arguably a crucial element to that journey is to embrace uncertainty for the purpose of making high-quality decisions (Aker BP, 2020). E & P companies are usually spending a lot of time on detailed modeling and a lot less on the up front framing and structuring. Engineers and geoscientists (and economists) like their models and often model what they can model instead of what they should model to make high-quality decisions. From my experience, this applies to Aker BP as well.

The subsurface itself is deterministic, however, we do not have complete information about the deterministic subsurface. Due to this lack of information, we are uncertain about the subsurface and typically apply probabilistic thinking and terminology to express our uncertainty (lack of knowledge) The lack of complete information arises

from the inaccessible nature of the subsurface. Determining true parameters like porosity, permeability, geological structures and faults etc. is impossible – they will be approximations and averages at best. Numerous data sources are available for a brown field with a production history – such as: seismic, well logs, core sampling, well testing and production data – but they are only able to locally describe a small fraction of the reservoir. The data sources should be utilized fully to help us quantify our uncertainty, and thus informing decisions. Uncertainty has two consequences: risk and opportunities. Engineers tend to over focus on the downside; i.e., the risk. This thesis will attempt to put more effort on exploring the opportunities and upside potential for value creation that arises from the uncertainty of a brown field, which usually differs from the uncertainty of a green field

Usually, the aim of an oil-company is to maximize shareholder value. In a perfect world, the NPV acts as a proxy and direct measure of shareholder value. A crucial part of that strategy is to evaluate the feasibility of extending the lifetime of the fields as they progress through their life cycle, using NPV as the value metric

Aker BP has a portfolio of several mature oil fields on the NCS. One of those is the Ula & Tambar area which is currently undergoing a re-development phase in order to maximize value by extending its lifetime. This is done by following several approaches including increasing recovery of existing reservoirs (IOR/EOR) and adding reserves by drilling new wells and tiebacks to stand-alone discoveries. Exploiting this tieback strategy is how the Tambar East field became viable; as a tieback to the Tambar and Ula facility. Tambar East has been a challenging, underperforming contribution to the value creation of the greater Ula area. It has experienced several production and performance problems and is currently shut-in and temporarily plugged. Tambar East has not been an Aker BP priority the last couple of years and a compelling re-development program is required to re-vitalize it. To date it has only reached a recovery factor of about 4%, thus the improvement potential is significant.

This thesis is aspiring to re-vitalize Tambar East by unlocking its potential through a robust decision making process. Decision analysis – a systematic and structured way of making decisions – where one takes into account the uncertainty of the parameters involved in the decisions, will be employed. By unlocking the Tambar East potential, the opportunity side of uncertainty could be exploited. This thesis will employ a broad spectrum of applied sciences, using multiple disciplines from reservoir engineering –

such as petrophysics, reservoir chemistry, reservoir modeling and simulations, well-testing and geophysics – coupled with disciplines from economics, such as statistics, uncertainty analysis and decision making. Although the thesis is focused on the Tambar East field, the value creation and decision making philosophy and methodology used is applicable for any brown field development.

1.2 Key contributions

The first key contribution of this thesis is to develop a robust, high-quality decision-oriented methodology for (brown) field development, using Tambar East as a complex implementation example.

Moreover, as uncertainty is a major element of every brown field development, the thesis provides an in-depth discussion of the importance of embracing uncertainty in order to maximize value creation from brown fields through robust decision-making.

Finally, the thesis presents a framework applicable for any decision making- and field development process, with the purpose of achieving clarity and insight through decision-oriented analysis, which ultimately should result in making better decisions and achieving better outcomes.

1.3 Procedure & tools

The thesis pursued two main dimensions, which are heavily intermingled: Petroleum focused subsurface analysis and decision analysis.

A substantial fraction of the total workload of the thesis has been about technically analyzing Tambar East reservoir properties, production history and various information sources. The main purpose of that was to achieve an in-depth understanding and interpretation of the field's value drivers and causes for it performing worse than expected; to a level where a critical assessment of previous subsurface engineering work conducted on Tambar East could be performed credibly. Several advanced software tools have been used for these analyses and will be briefly mentioned throughout the thesis where it is applicable. However, an in-depth description of the tools will not be provided, but rather analyses and evaluation of the output will be presented. No technical software specific knowledge is a prerequisite for reading and understanding the thesis.

The technical analyses described above is a subset of the decision analysis methodology applied on Tambar East. The methodology was tailored to a brown field, which increases the attention to the framing phase due to its complexity and variation. Supporting software for the decision analysis was mainly Microsoft Excel with suitable decision analysis software add-inns (@Risk, Precision tree)

1.3.1 Front-end-analysis importance

In decision analysis context, a high-quality decision is considered high-quality on six dimensions: Frame, Values, Alternatives, Information, Logic and Commitment to action. The front-end-analysis comprises the first three dimensions (Bratvold & Begg, 2010). Decision quality will be addressed separately in this thesis. The focus of the thesis is on the front-end-analysis (framing, objective setting and alternative generation) of the re-development decision; i.e., for the purpose of determining the key value drivers as well as the underlying cause of poor performance. The front-end-analysis is especially important in a brown field development, where the framing of the problem and identifying the value drivers is a complex process that could vary a lot from field to field. The potential scope of such a brown field development could be massive and it needs to be managed properly, ensuring that the answers we get are answering the right questions and problems at hand.

Although engineers and geoscientists often spend most of their analysis time and effort on the detailed modeling and evaluation; the quality of any decision depends much more on the quality of the front-end clarification and presentation of that decision, than on the back-end evaluation of alternatives. You cannot make a good decision by choosing the best alternative from a narrow range of alternatives using an inferior set of objectives to evaluate those alternatives. This important point is succinctly made in a quote that is attributed to Albert Einstein:

"If I were given one hour to save the planet, I would spend 55 minutes defining the problem and five minutes resolving it."

For the above mentioned reasons, front-end-analysis was chosen as the focus of the thesis, assuming it would provide a more relevant and valuable contribution to the work already conducted on Tambar East.

1.4 Outline/structure

It is assumed that the reader of this thesis has more or less the same knowledge as the author regarding petroleum engineering and the use of statistics & probability to support reservoir management decisions, as well as of the oil industry on the Norwegian Continental shelf. In case of knowledge gaps for the reader I encourage to seek alternative sources.

A decision driven philosophy is something which requires some mindset "rewiring" to fully grasp. Throughout the thesis I have been using a positive redundancy of necessary and judicious repetitions of key principles and ideas, that reverts to the overarching philosophy of decision making. This deliberate repetition is partly included to help the reader connect and accelerate the understanding of the topic, but also to further develop and mature key concepts in a broader thesis context for the author (Rachel Wheeler, 2018).

The thesis is divided into ten chapters, as seen on the list of content. However, it is maybe more convenient to structure the thesis into three parts for a better overview:

Part 1(chap 1–3): Part one contains the background information necessary to set the scene for the upcoming analyses. Firstly, it comprises the introduction, then relevant and specific theory that might be new and unfamiliar to the author and reader, and finally a chapter on the decision making model being used on the Norwegian continental shelf (NCS)

Part 2(chap 4 – 8) This part includes a thorough front-end-analysis of Tambar East. Mostly focusing on framing, objective setting and identifying the key value drivers and uncertainties, which constitutes the foundation for strategy development. It starts of by introducing the Tambar East field and its peculiarities and ends with a set of clearly defined development strategies.

Part 3 (chap 9 – 10) The last part contains the decision modeling phase of decision analysis, which culminates with a discussion on recommendation on development strategies that maximizes value creation, according to clearly defined objectives. The final chapter is the wrap up with a conclusion and recommendation for future work, both academically and for the Tambar East subsurface team.

1.4.1 Units and definitions

A consistent set of European field units will be used throughout the thesis

table 1.4-1: *Units*

Properties	Unit
Length	Meters [m]
Volume	Barrels [bbl]
Viscosity	Centipoise [cP]
Permeability	Millidarcy [mD]
Porosity	Fraction [-]
Pressure	Bar or PSI
Gas oil ratio	Standard cubic feet/standard barrels [scf/stb]
Density	Kg/m^3 or API
Production rate	Barrels per day [bpd]

In petroleum engineering it is customary to use the roman letter M or m for 1000, not to be confused with the SI convention (M=million and m=milli). E.g. "MM bbl" means "million barrels" and "MM USD" means "million US dollars"

1.4.2 Reference documents

The thesis work has been using various external, publicly available sources. These are all referred to consecutively in the text and listed in the included bibliography. The proposed decision analysis methodology in this thesis is, to a large degree, honoring the philosophy and methodology as proposed by Bratvold & Begg (2010) in the book "Making good decisions". Therefore, that book is considered the main reference book for theory and fundamental concepts throughout the thesis. It is recommended to revert to this book if the thesis is deliberately short and inadequate in explaining certain terms and concepts. Other decision analysis literature has been used to compare and contrast the methodology, as well as provide nuances to it. In addition to that – I have used, evaluated and assessed numerous internal Aker BP documents, reports, presentations and statements, as well as conducted many informal oral interviews. These documents will not be referred to explicitly as they are not publicly available, unless the nature of the documents says otherwise. (E.g., I am referring to a document called "guidelines on uncertainty management in Aker BP", since it has extra relevance for the thesis topic and context for the company)
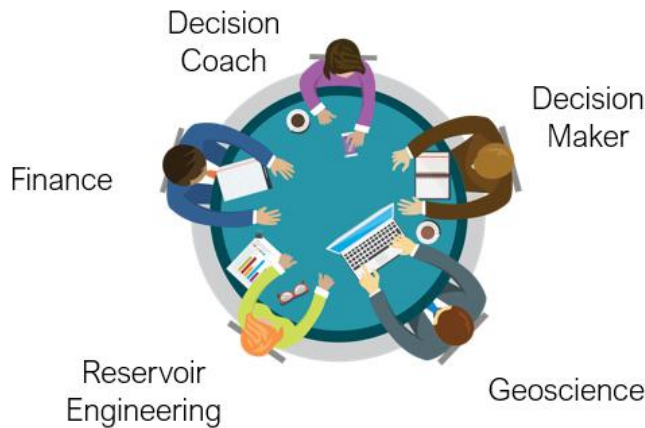
2 Theory

2.1 Decision analysis theory

figure 2.1-1: *Project team* (Bratvold, 2020)

Decision analysis is a discipline that comprises various methods, techniques and attitudes to help decision makers choose wisely under these conditions of uncertainty. Decision making under uncertainty entails that there is more than one alternative. If there's only one alternative, there's no decision to make. Decision analysis is a multi-disciplinary science that draws on mathematics, psychology, management science and modern decision theory. It inherits learnings from traditional areas such as – economics, business, finance, probability and statistics, computer science, engineering and psychology (Newendorp & Schuyler, 2000). Figure 2.1-1 illustrates a simplified project team for a field development. The decision maker could be a project manager, or any leader granted the decision authority for the specific project. The decision coach would be an individual responsible for the decision analysis process, ideally someone with in-depth and broad knowledge on the methodology applied. However, a decision coach is currently seldom included in project teams in the oil & gas sector (Bratvold & Begg, 2010).

Ideally, the decision analysis process should be an ongoing dialogue between decision makers and the ones conducting the analysis. By doing that, one minimizes waste of resources and achieves insight (Bratvold & Begg, 2010). An example of this periodic interaction between project team and decision makers is illustrated in figure 2.1-2.
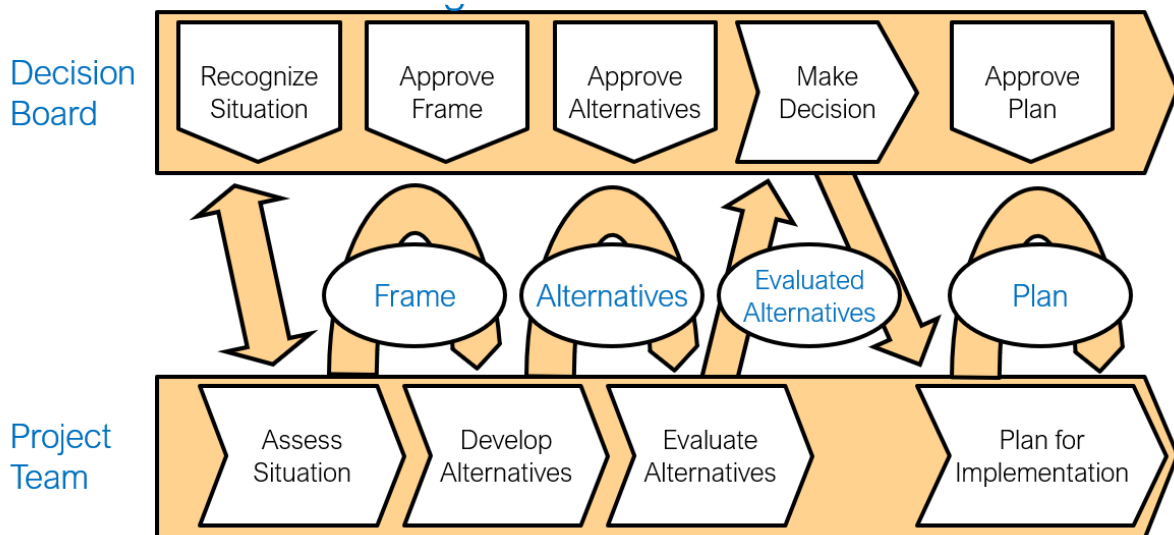
figure 2.1-2: *Project progress and dialogue* (Bratvold, 2020)

The idealized dialogue is arguably in contrast to the common practice of decision analysis, where the decision analysis is conducted in silos, without communication across the organization and with the decision makers. Another common misconception is that decision analysis is the same as forecasting and predictions, a misconception which could cause waste of time and resources. An analysis to support decision making – only needs to be sufficiently thorough and accurate in order to choose the best course of action at a given time (Bratvold & Begg, 2010).

To fully grasp what decision analysis is all about, it might be useful to look at McNamee & Celona (2008) who states that decision analysis operates at four different levels:
:

1. **A philosophy**: it entails a rational, consistent way to make decisions with two key contributions or insights: 1 – Uncertainty is part of our incomplete knowledge of the world and 2 – the clear distinction between outcome and decision
2. **A decision framework**: providing concepts and precise language to assist the decision makers
3. **A decision-making process**: A step-by-step procedure, providing a recipe on how to conduct the systematic analysis and break it down into manageable size and complexity
4. **A methodology(tools):** Decision analysis comes with a package of useful tools to assist in the analysis – such as influence diagrams probability trees and sensitivity plots.

2.2 Decisions

A decision can be defined as a "conscious, irrevocable allocation of resources to achieve desired objects" (Bratvold & Begg, 2010). Further, Bratvold and Begg(2010) states that there are three elements comprising the foundation of what decisions are evaluated against: objectives, alternatives and information. Figure 2.2-1 illustrates the elements of a good decision analysis process. *Information* comprises what we know about the business opportunity in question and what we don't know – i.e., the uncertainty. *Alternatives* provides the available courses of action for the business opportunity. *Values* or objectives are what we want to achieve. Lastly, *logic* is applied to tie it all together in order to reach a decision (McNamee & Celona, 2008).
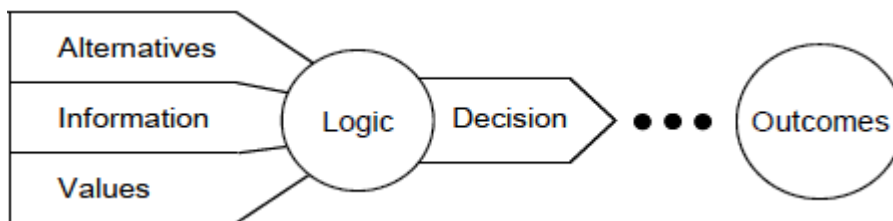
figure 2.2-1: *Decision analysis elements* (McNamee & Celona, 2008)

Decisions in an exploration & production oil company (E & P) is quite often challenging to make and entails complex scenarios and conflicting interests. With each decision, there are normally many stakeholders such as the operating company, partner companies, environmental organizations and the government. They all have different objectives and priorities which complicates a decision. Bratvold & Begg (2010) indicates some common challenges in the industry as follows:

- **Uncertainty**: More or less all decisions are made with uncertain information, often derived from models, simplifications and limited data. The subsurface is not easily accessible and data only exists for a small portion of it. E.g. formation coring and well logging.
- **Complexity**: Numerous decisions to be made, and each with underlying factors, sequential and interactions between decisions and the uncertainty is often complex.

- **Multiple, conflicting objectives**: Often, multiple objectives are being used in decision making, thus complicating the evaluation and comparison of different decision alternatives. E.g. profitability in future cash flow or ultimate recovery
- **Anxiety about consequences**: Some decision outcomes potentially has major ramifications and could affect the decision maker and all the stakeholders.

2.2.1 Decisions and outcomes

Normally, when you think of a good decision you might associate it with a good outcome and vice versa. However, decision analysis insight, as mentioned above, makes an important distinction between outcomes and decisions. Bratvold & Begg (2010) defines a good outcome as "a future state of the world that we prize relative to other possibilities", whereas a good decision is "an action we take that is logically consistent with our objectives, the alternatives we perceive, the information we have, and the preferences we feel". In an uncertain situation, a good decision could lead to a bad outcome or vice versa. E.g. a high and increasing oil price would naively assess majority of investments, and thus decisions, being conducted as good, based on various evaluation methods of profitability such as net present value or internal rate of return. However, it doesn't take into account uncertainty or the chance factor and it requires a portion of luck.

One of the main contributions of decision analysis is to be able to distinguish good decisions from bad ones, independently of the outcome. Usually, the outcome of a decision will not be available until a later stage, often the decision makers and analysts has moved on to other projects and responsibilities. Further, looking at the result of the decisions made, is of limited value as it only provides info about the chosen alternative. Bratvold & Begg (2010) makes a useful clarification that "at the time when a decision is made, it is only possible to control the decision quality – while the result or outcome also depend on the implementation and chance factor". Figure 2.2-2 illustrates and summarizes these dependencies between decision quality and outcome as we described them.
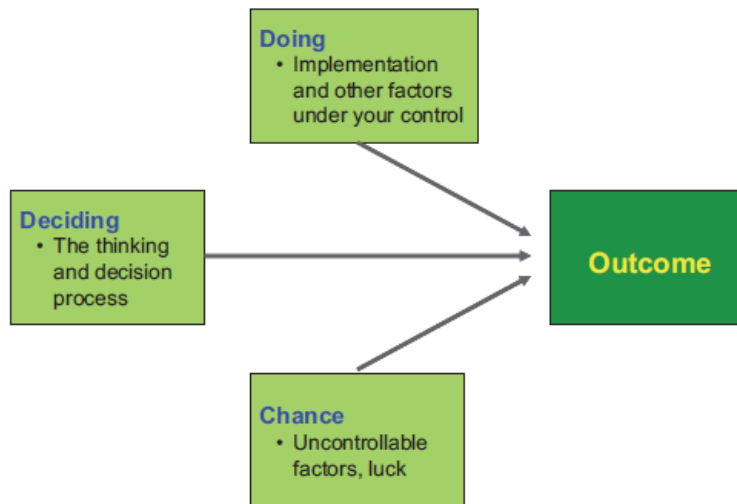
figure 2.2-2: *Factors influencing decision outcomes* (Bratvold & Begg, 2010)

2.3 Uncertainty

We are surrounded by uncertainty and are willing to accept it if it is not affecting the outcomes of decisions. However, uncertainty when a lot is at stake is another story altogether. Usually, we try to manage the uncertainty by applying intuition, gut feeling and previous experience. This intuitive, non-analytic approach has proved to provide sub-optimal decisions. Engineers are often tasked to reduce the uncertainty to a manageable level and engage in technical analyses and finely tuned predictions to minimize uncertainty. However, uncertainties also provide opportunities and potential upsides that could be exploited (Bratvold & Begg, 2010).

In decision analysis, the term probability is used to quantify uncertainty. Probability language provides us with a precise language for describing uncertainty. Probabilistic approach is suitable when there is a lack of knowledge of what a certain outcome would be. The uncertainty arising from the lack of knowledge would be personal, thus varying from person to person. Gaining knowledge would ultimately reduce the uncertainty and it has a certain value, commonly referred to as value of information (Bratvold & Begg, 2010).

2.3.1 Definitions

The terms uncertainty and risk are commonly used throughout different disciplines and industries to represent the chance that an outcome or investment's actual gains will differ from an expected outcome (Chen, 2020). The two terms are used

interchangeably and inconsistently, which could be a potential source of misunderstandings and miscommunication. Bratvold & Begg (2010) proposes a refining of the terms related to uncertainty, by breaking it down to three separate terms. Figure 2.3-1 visualizes the understanding and usage of the terms *uncertainty, risk and opportunity.*
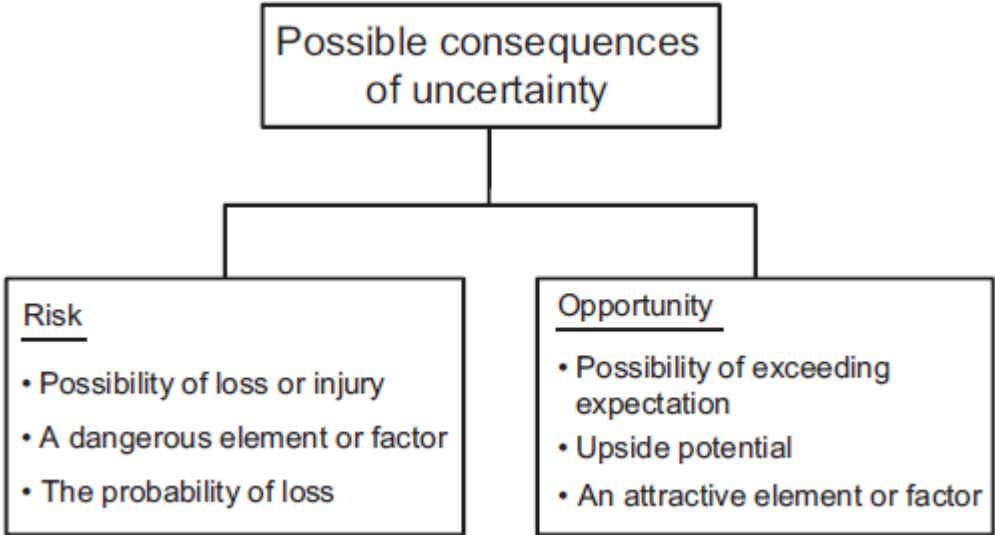
figure 2.3-1: *Uncertainty, risk and opportunities*(Bratvold & Begg, 2010)

Uncertainty: It entails that a person doesn't know if a statement is true or false, a subjective aspect of our state of knowledge, i.e. the lack of knowledge. E.g. uncertainty with regards to statements about future events such as the oil price; or statements concerning the states of nature such as the amount of oil present in an oil reservoir (STOOIP)

Risk: An undesirable consequence of uncertainty – the downside with a probability of loss. Desirable uncertainty reduction will in reality be risk mitigation. For risk to be present, there must be something at stake, such as monetary value.

Opportunity: Represents the upside of uncertain events or the desirable consequences of uncertainty.

According to these notations, uncertainty has two consequences, namely risk and opportunity. Bratvold & Begg (2010) claims that the oil industry has traditionally devoted disproportional time and money to reduce the downside of uncertainty (risk),

with the purpose of preventing value loss. In their opinion, more effort should be spent on exploring the opportunities and upside potential for added value creation.

Such a refining of term definitions is useful, but it represents only one version of it. There is no consensus across the industry and there could even be lack of consensus within a single company. Employees with a financial background has traditionally a different understanding and usage of the term risk for instance. An oil company is not working in isolation either, as it cooperates with stakeholders such as partner oil companies, contractors and governments. The term convention should therefore ideally be aligned and communicated across the industry to avoid confusion.

2.3.2 Uncertainty's importance

More and more E & P companies are realizing that one should have a solid grasp on uncertainty and the majority of the companies are in the implementing phase. In decision analysis the term material uncertainty is frequently used to describe uncertainties that are important and has the potential of affecting decision making. According to Bratvold & Begg (2010), the main reasons that uncertainty is important and should be included in decision processes are the following:

- Uncertainty is important for **generating decision support packages** and indicating the important decision-making factors.
- Uncertainty aids the engineers and analysts in **presenting the findings/results** with its implications and limitations, instead of a definite answer to problems
- Uncertainty helps the decision makers and stakeholders to **interpret the information** that analysts and experts provide and assess the level of alignment.
- The common practice of developing the **most likely base case** – without uncertainty – where the expected input value provides the expected output value has been proven to be a **poor method.**
- Uncertainty is **unavoidable** and should be **embraced** such that the decision makers can **anticipate and prepare for the consequences**. It should be managed by **reducing** it such that it **makes economic sense** and planning for its consequences.

- Quantifying and **reducing uncertainty** creates no value on its own, however, it **creates value in its potential to change value creating decisions**, i.e., material uncertainties

Finally, the importance of embracing uncertainty is summarized in a claim from Bratvold & Begg (2010):

"The companies most skilled in eliciting, assessing and characterizing uncertainty will make the best decisions and create competitive advantage"

2.3.3 Influence diagrams and decision trees

Two useful graphical representation tools, quite commonly used in decision analysis under uncertainty, is the influence diagram and the decision tree. Influence diagram is an intuitive and visual way of structuring the uncertainties in a project and how they are linked with each other. Moreover, it is useful to provide a big picture of the situation. The influence diagram shows the dependencies and relationships between decisions, uncertainties and objectives. It is an especially useful tool in the early stage of a project to accelerate the brainstorming and to communicate complex problems in an intuitive way (Decision Nodes, 2020). Decision trees are used to provide a framework for calculations and insight towards possible solutions (McNamee & Celona, 2008). Both tools will be used in the decision modeling part of the thesis.

2.3.4 Value of Information (VoI) and Value of Flexibility (VoF)

VoI and VoF analysis is not covered in detail in this thesis but the theory is briefly included here. Uncertainty can be dealt with in three different ways: Ignore uncertainty, gather information to reduce uncertainty and lastly develop a flexible response to the uncertainties as they are being resolved. Ignoring the uncertainty has historically been the oil and gas industry standard and will lead to suboptimal resource allocation and value creation (Bratvold & Begg, 2010).

VoI: Information gathering to reduce the uncertainty is not free and it should only be done if it is positively influencing decision making. A Value of Information analysis or methodology aims to address whether the uncertainty reduction can change decisions and whether the uncertainty reduction is worth what it costs to reduce it. VoI analysis also addresses which potential information sources is most valuable and in which sequence the information sources should be used (Bratvold & Begg, 2010).

Output from the VoI is the expected value of information, EVI (the maximum you should pay for information) and the expected value of perfect information, EVPI (upper bound on how much one should pay for perfect information) (Wayne L. Winston & Albright, 2019).

VoF: Flexible responses to the uncertainties could be dedicated to mitigating the negative aspect of the uncertainty or to allow for capturing of the positive aspects. The goal of the VoF analysis is to determine whether the expected benefit of the flexibility outweighs the cost of it. Bratvold & Begg (2010) lists a few common situations where the flexibility option might be viable:

- "When the value of acquiring information is close to 0, or it is not possible to reduce uncertainty
- When flexibility is more valuable than acquiring information
- When residual uncertainty after information is acquired
- When flexibility creates additional value"

The VoF is related to how one can think creatively about projects and separate the decisions into distinct decisions over time, with the possibility to learn between them. The flexibility is suitable to capture unlikely but highly profitable events. The VoF is crucial in a phased field development and including flexibility in the field development could potentially create value from the opportunity that arises from the uncertainty.

Implementing difficulties: Bratvold & Begg (2010) describes a situation where implementing VOI and VoF is often difficult since it is a quite unfamiliar way of handling uncertainty. Being flexible and think outside the box is often not rewarded. Part of that picture is that the decision makers need to be willing to risk added expenditures for flexibility or gathered information even though it might not contribute to any value creation. Moreover, the decision makers are quite often risk averse and with a bias towards ignoring or underestimating the uncertainty. Educating the decision makers on these aspects and assess the decision maker's process instead of the decision outcome would provide an incentive to the decision makers to embrace VoI and VoF.

2.4 Methodology

The step-by-step process in decision analysis could vary slightly from industry to industry and between different architects. Bratvold & Begg (2010) proposed a process or methodology consisting of 3 main phases and further broken down into 8 steps. Figure 2.4-1 conceptually visualizes the decision analysis process:
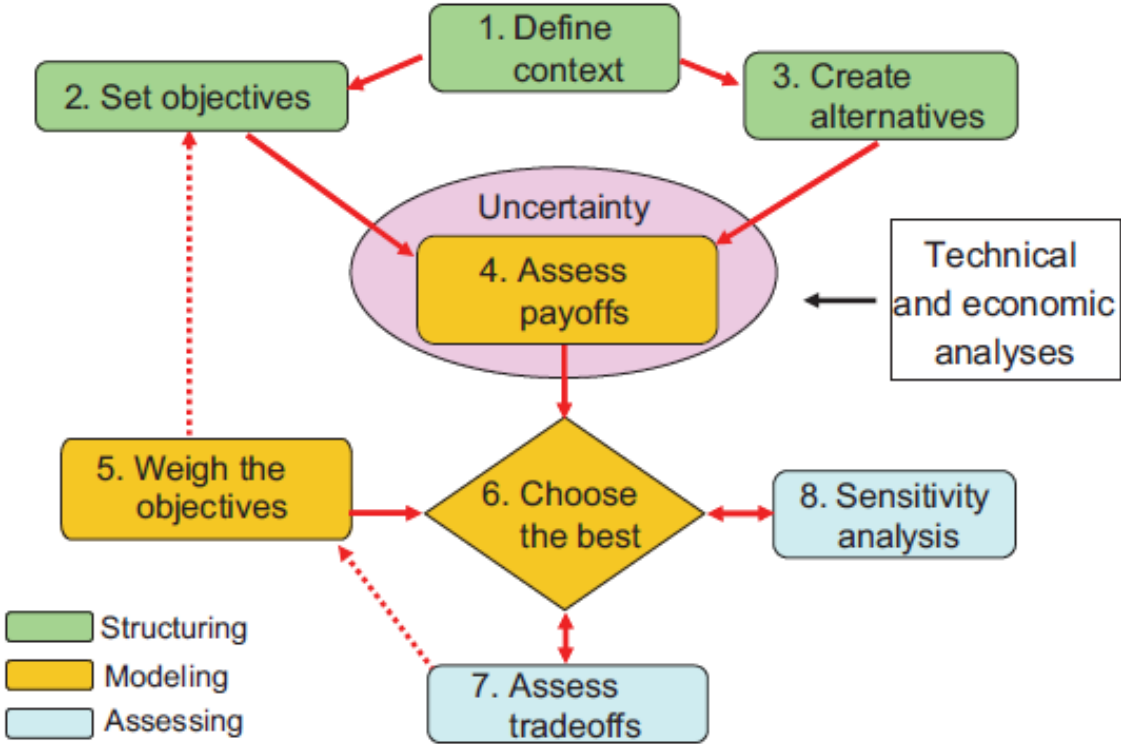

figure 2.4-1: *Decision analysis process*(Bratvold & Begg, 2010)

First phase is the *structuring or framing phase* indicated by green boxes. It includes a step of setting objectives, defining context and creating alternatives. This phase corresponds to the front- end-analysis that was described previously. Second phase is the decision *modeling part, where evaluation* and calculations are conducted, including expected payoff and weighted value calculations. The last phase is the *assessing* phase which comprise a sensitivity analysis to test robustness and an assessment of objective tradeoffs.

The methodology is scalable and thus adjustable to varying time and resources available, typically determined by the significance of the decision and the maturity of the project. This methodology will serve as the basis for the decision analysis conducted in this project, with emphasis on the framing phase, i.e., the front-end-

analysis. Bratvold & Begg(2010) further emphasizes that even though the methodology contains numeric calculations and analytics, the real value lies in the structured thinking and insight that the methodology provides. This philosophy agrees with McNamee & Celona's take on decision analysis as described in chapter 2.1.

Several variations to this methodology are presented below. They all understands decision analysis the way Ronald A. Howard intended it– he is considered to be the father of decision analysis(INFORMS, 2020). These variations all have slightly different emphases on the decision analysis elements but are largely the same.

Newendorp & Schuyler (2000) introduced the following methodology:

1. Identify what choices, or, alternatives, are available
2. Identify the possible outcomes that could occur for each decision alternative
3. Project the profit or loss (usually present value of the future net cash flow, but may be some other measure of value) for each possible outcome
4. Judge the probability of each possible outcome
5. Compute a weighted average profit (or measure of value) for each decision choice, where the weighting factors are the respective outcome probabilities. This weighted average is called the expected value of the decision alternative.

Another representation of this process was introduced by the management consulting company Decision Nodes (2020):

A. Frame	B. Alternatives	C. Evaluate	D. Decide	E. Implement
Setting the right frame is the initial activity in the exploration process.	After the frame has been set, feasible alternatives to move the project forward are identified and assessed.	The alternatives are evaluated using decision analysis modelling techniques and tools. The goal is to evaluate alternative actions and consequences and enhance the team's understanding of the decision problem.	When a proper decision basis has been prepared by the project team, the project manager decides whether or not the proposal is ready for presentation to decision-makers.	When a decision (or a set of decisions) has been made, the project can move forward to the next decision gate.

figure 2.4-2: *Alternative decision analysis process* (Decision Nodes, 2020)

McNamee & Celona (2008) introduces the distinction between deterministic and probabilistic evaluation and the iterative or cyclic nature of the process. Initial knowledge feeds into the decision analysis basis development where alternatives and objectives are identified. From that basis, a base-case input is used on a model to conduct the deterministic analysis, without including randomness/chance and probability distributions. A sensitivity analysis (E.g. tornado plot) is run on the deterministic output to find the material, potentially decision changing uncertainties. Then, a probabilistic analysis is conducted, which embraces uncertainty, represented by either discrete or continuous probability distributions (E.g. normal- and triangular distribution or Swanson's mean). Finally, an appraisal on the output is culminating in actions taken, or a decision to re-iterate and start the cycle over again. McNamee & Celona's structure of the decision analysis cycle is implemented in the decision modeling part of the methodology developed in this thesis, as seen in figure 2.4-1. Figure 2.4-3 summarizes the cycle explained above:
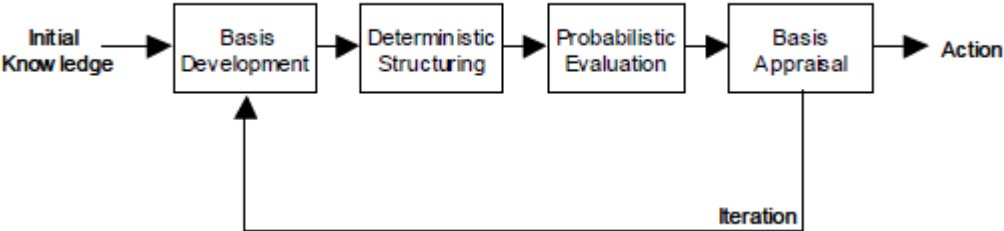

figure 2.4-3: *The decision analysis cycle* (McNamee & Celona, 2008)

2.4.1 Developing alternatives and objectives

Alternatives: In any decision situation, there must be a set of alternatives or courses of action to choose from. The decision alternatives can vary from the simplest case of choosing between A and B, to more complex and sequential alternatives. A series of sequential decisions are, in this context of decision making called a strategy (Bratvold & Begg, 2010). The majority of the analytic framing part of this work is focusing on understanding the key value drivers and problems at hand and developing alternatives and strategies to overcome those problems.

Objectives: Choosing between course of actions in a given situation requires that one knows what the decision is intended to achieve. A prerequisite for high-quality decision making is a set of objectives or criteria which the worth of each alternative is evaluated

against. Objectives are specific and measurable things that one wants to achieve. The objectives are usually governed by the overarching values of the decision maker or company. In addition, for each objective, one can attach an attribute and a weighting factor to indicate the decision maker's preference for the objective. These elements could be structured in a value tree or value hierarchy. Bratvold & Begg (2010) provides several compelling arguments for the importance of a value tree

- "Adds transparency to the decision-making methodology on judging of alternatives
- Exposes and eliminates hidden agendas
- Clarity on how the objectives are considered by the decision maker
- Facilitate communication and buy-in"

Figure 2.4-4 from Bratvold & Begg (2010) shows the framework of such a value tree
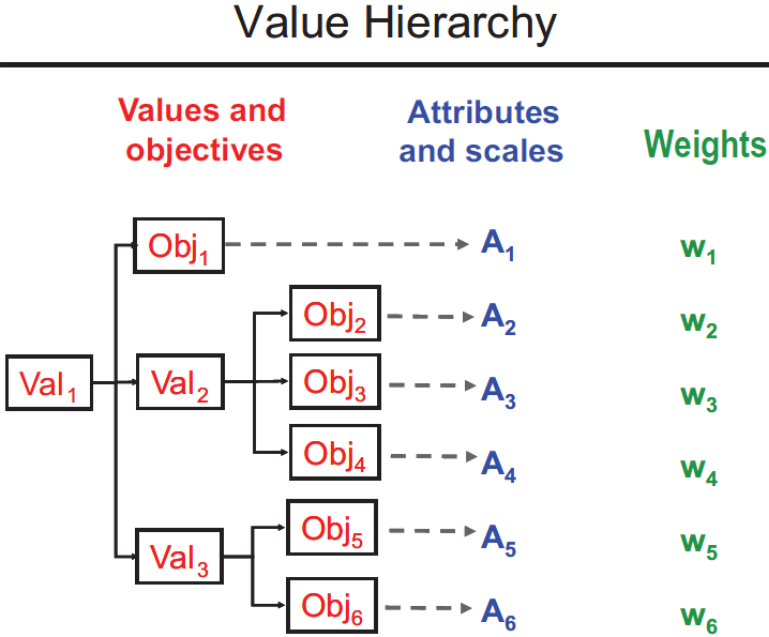
Value Hierarchy

Values and objectives	Attributes and scales	Weights
Obj_1 ----→	A_1	w_1
Obj_2 --→	A_2	w_2
Val_1 Val_2 Obj_3 --→	A_3	w_3
Obj_4 --→	A_4	w_4
Obj_5 --→	A_5	w_5
Val_3 Obj_6 --→	A_6	w_6

figure 2.4-4: *Value hierarchy*(Bratvold & Begg, 2010)

Multiple objective: Usually there are multiple objectives to decision making which introduces some challenges: First, multiple objectives might imply multiple attributes and scales (e.g. compare monetary value and volumes) Then, the decision maker might have varying preferences towards the different objectives. Lastly, one objective's level of achievement might be in direct conflict or impair other objectives. The latter challenge of objectives with conflicting interests could be addressed by objective tradeoff.

3 NCS Decision model

All the E & P companies are committed to follow the same structure on resources- and project management and reporting as determined by the Norwegian petroleum directorate (NPD). The decision analysis methodology developed through this thesis fits nicely into the bigger scheme of the NPD decision model which is being presented in this chapter.

3.1 Resources

Several terms regarding volumes of hydrocarbons are being used for a reservoir. The amount of hydrocarbons/petroleum initially in place in a reservoir is the fundamental starting point for volume calculations. In an oil reservoir one uses the term STOOIP – stock tank oil original-in-place, referring to the oil in place before production has started, measured at surface conditions. Equation 3-1 is used for calculating the STOOIP.

Equation 3-1: STOOIP

$$STOOIP = \frac{A * h * \varphi * S_o}{B_o}$$

Where A is the area or acreage of the reservoir, h is the net thickness of the reservoir, φ is the reservoir porosity, S_o is the oil saturation in the pores and the B_o is the oil formation volume factor. Of this oil in place volume, only a fraction of it can and will be produced. This fraction is given by the term "recovery factor".

The hydrocarbon volumes involved in the different development projects on the NCS are divided into different categories as illustrated on figure 3.1-1. The framework is provided by the Petroleum Resource Management System (PRMS) and it is based on project maturity – discovered vs undiscovered and commercial vs non- and sub commercial projects (SPE, 2018).
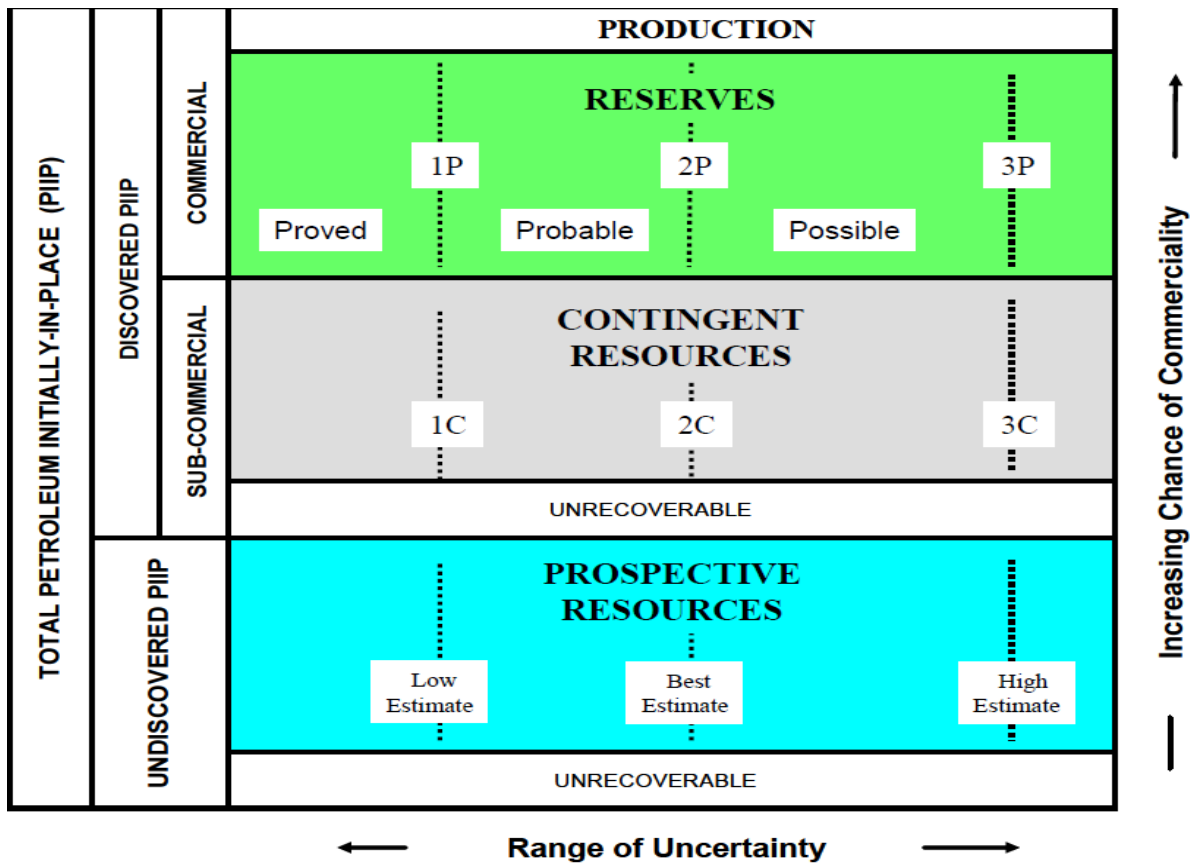
figure 3.1-1: *PRMS Resources classification* (SPE, 2018)

The Norwegian Petroleum directorate (NPD) developed a similar framework in parallel with PRMS and they are aligned. Management of the petroleum resources on the NCS is an important task for the authorities and the resources is classified according to their position in the development chain, from discovery to when they have been produced. Moreover, each operating company is required to report their resources annually as part of the Norwegian revised national budget (RNB). The reporting comprises part of the basis for the government's Oil and gas policies, fiscal and national budget, and great emphasis is placed on ensuring high-quality reporting (NPD, 2020a).

The petroleum resources are further divided into various classes and categories, reflecting the different level of knowledge, uncertainty and maturity of a project/volume. The NPD classes agrees with PRMS as shown in figure 3.1-1. These NPD classes are reserves, contingent resources and undiscovered resources. Figure 3.1-2 outlines the classification framework for the resources. The **F** and **A** indicated on the figure is used to distinguish between first development projects and additional projects arising from improved recovery on previously developed projects. In other words, F indicates green

field while A indicates brown field. Reserves and contingent resources comprise the total discovered recoverable resources, where contingent resources needs additional work to render it commercial, thus lacking a decision on its commercial potential (NPD, 2018).
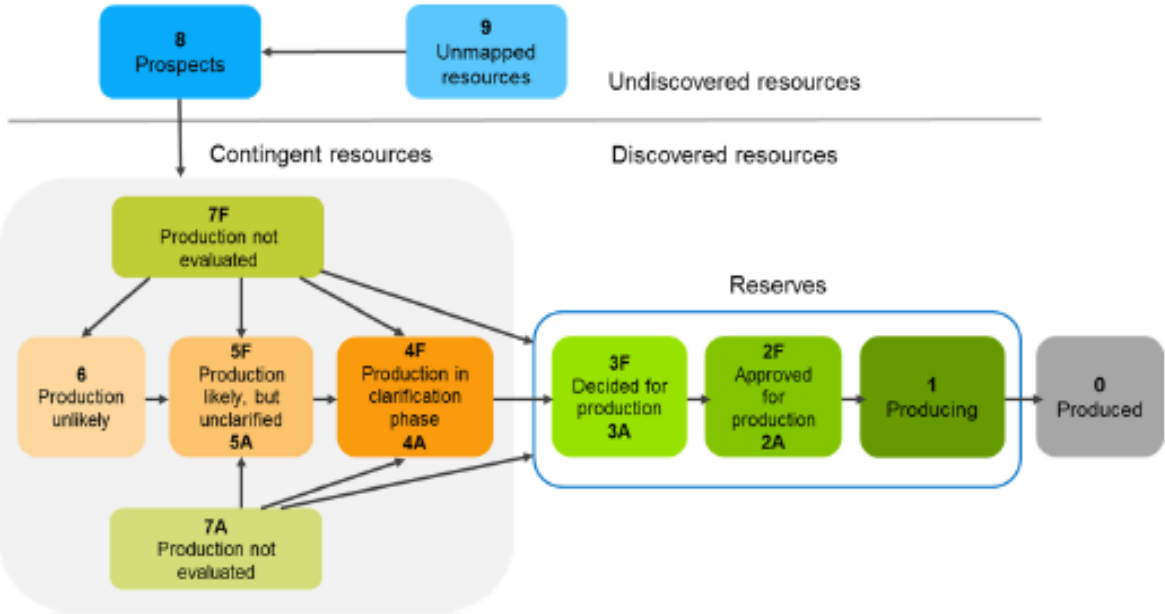

figure 3.1-2: *NPD classification system* (NPD, 2018)

Tambar East will be thoroughly introduced in the next chapter, but a few comments on its resource categories are provided here. Tambar East has resources in category 0 and 1, which are already produced volumes or will be produced with the current development concept. In addition to that, it has category 7A contingent resources that needs to be evaluated further (preliminary planned infill well)

A systematic list of the different classes, sub-classes and categories are provided in table 3.1-1. Basically, it shows the same as figure 3.1-2, except it includes uncertainty categories which will be covered in a separate section.

table 3.1-1: *Classes and categories used on NCS (NPD, 2018)*

Class	Resource Class (Sub-class)	Resource Class Code	Project category	Uncertainty - category
	Produced	RC0		
Reserves	In production	RC1		L, B, H
	Approved for production	RC2	F, A	L, B, H
	Decided for production	RC3	F, A	L, B, H
Contingent resources	Production in clarification phase	RC4	F, A	L, B, H
	Production likely, but not clarified	RC5	F, A	L, B, H
	Production unlikely	RC6		L, B, H
	Production not evaluated	RC7	F, A	L, B, H
Undiscovered resources	Prospects	RC8		L, B, H
	Unmapped resources	RC9		L, B, H

3.2 Project management

The NPD resource classification system is used for petroleum reserves and resources on the NCS and is directly linked to the projects level of maturity. Further, the maturation level of projects is linked to decision milestones. These milestones are defined by NPD as follows (NPD, 2018):

– **Decision to initiate – BOI (**abbreviated in Norwegian): Start of feasibility studies. DG0

– **Decision to concretize – BOK**: Milestone where the licensees have identified at least one technically and financially feasible concept that provides a basis for commencing studies that lead to concept selection. DG1

– **Decision to continue – BOV**: Milestone where the licensees decide to continue studies for one concept that leads to a decision to implement. DG2

– **Decision to implement –BOG**: Milestone where the licensees make an investment decision which result in submission of a PDO. DG3

Finally, a connection between the resource categories, decision milestones and project maturity has been provided by NPD as shown on figure 3.2-1.
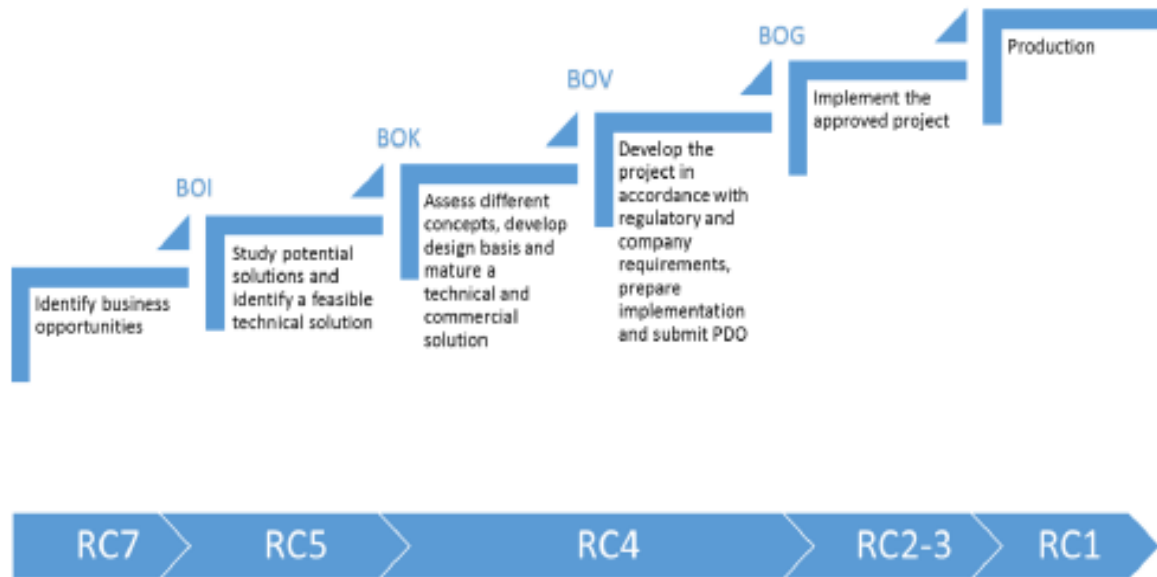

figure 3.2-1: *Connection between resource categories and project maturity* (NPD, 2018)

Investment projects in E & P companies are largely governed by the field development process as illustrated on figure 3.2-2. It arises from the Capital Value Process originally developed by Amoco, and eventually introduced into the BP system (Marchant, Wilson, & Bamford, 2001). The process is divided into phases with decision gates (DG), associated with project milestones. The content and requirements of the different phases and passing of the decision gates are thoroughly described in the Business development system (BMS) of each company. A short description of the content of the respective DGs are provided in figure 3.2-2. Pre-determined stakeholders/decision makers are responsible for signing of on the decision gate reviews, a pre-requisite for passing through the gates.

A commonly used tool in Aker BP to assist in making the decisions are a decision support package (DSP). Typically, the DSP follows a pre-determined template where the decision makers efficiently can get up to speed on the status of the project – the feasibility and business case, quantitative and qualitative analysis, opportunities and risks and finally the way forward – are typical ingredients of a DSP. A separate DSP is usually compiled for each stage gate review. Ideally, the decision makers should be

heavily involved in constructing the DSP, as previously discussed in chapter 2.1 and visualized in figure 2.1-2, where the decision analysis is a dialogue between analysts and decision makers.
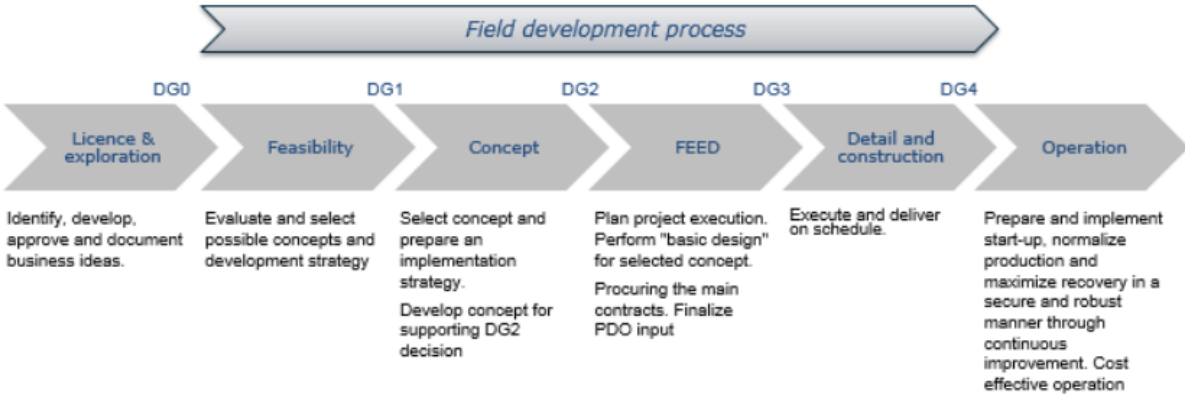

figure 3.2-2: *Field development process*(Norsk olje og gass, 2020)

3.3 Green field versus brown field development

Green field: Could be defined as fields with no prior production, accumulations in the field development (DG1 – DG3) or early production phase. Main uncertainties are often related to seismic interpretation and depth conversion, conceptual uncertainty in facies distribution and properties away from well control and undrilled segments of reservoir. An important part of green field development is to consider whether to develop the field or not. Moreover, the scope of the development and whether one should focus on a phased development where key decisions can be made in several stages of the development should be considered. Such a phased development will also allow for greater degree of flexibility and a good candidate for applying Value of Information (VoI) and VoF analysis. Key elements in a green field would be to drill appraisal wells, collect data such as core data and fluid sampling in order to reduce uncertainty and mitigate risk (Bahri, 2014).

Brown field: Defined as mature fields with extensive well coverage and production history. Main uncertainties in this phase may vary depending on the field, however, in general the systematic uncertainty related to the petrophysical interpretation tends to be more important, relative to green fields. Brown fields has a lot of available data which allows for thorough analyses and interpretations of the reservoir. A major

difference from green fields is the availability of dynamic data and production data. This will allow for history matching of your static and dynamic model, which if done correctly, should increase the quality of your model and its ability to predict with greater accuracy. In Aker BP, ensemble based modeling is being implemented on some of its reservoir models, used to capture the uncertainty in the subsurface and predict future production. Every brown field has a production history, some fields are producing as expected with high uptime and meeting expected production profiles, while others experiences a lot of downtime and not meeting the production forecasts. Understanding and interpreting the underlying causes for poor performance or exploiting an unrealized potential upside are crucial elements to a brown field development. A brown field development is typically focusing on extending the field lifetime through infill drilling, increased recovery, potential tie-ins and addressing the showstoppers, i.e., the value drivers.

3.4 Decision making objectives on NCS

There are a few criteria or objectives that are relevant for a field development on the Norwegian continental shelf. The most commonly used and relevant criteria are introduced below.

Maximize Expected Net Present Value E(NPV):

In a perfect world (efficient markets, no arbitrage, etc.) the NPV is a direct measure of shareholder value. The markets are not perfect but as there is no broadly accepted measure that is better than the NPV, it is commonly used as a measure of a project's contribution to the company's shareholder value. Thus, the value-maximizing metric is NPV.

Net present value calculation is a common method to evaluate payoffs on investments. NPV calculates a discounted future cashflow and compare it to an initial investment. Typically choosing the alternative strategy that generates the highest expected net present value.

Equation 3-2: Net present value

$$NPV = -C_0 + \frac{C_1}{1+r} + \frac{C_2}{(1+r)^2} + \cdots + \frac{C_T}{(1+r)^T}$$

Where C_0 is initial investment cost, C is cashflow, r is discount rate and T is time period. When conducting probabilistic analysis, the term expected net present value is used, E(NPV). The method is considered robust and has few weaknesses compared to other objectives such as Internal rate of return (IRR), according to Aker BP's financial analysts.

Maximize recovery/maximize value creation: Another objective is to "maximize recovery" or "maximize value creation". It is an objective which is partly open for interpretations, where it allows for the different E & P companies to refine the objective as they see fit. Maximizing value creation could be to maximize the recovery factor of the field, i.e., the fraction of the STOOIP which is actually produced.

Due to the discounting of future cash flow, quite often it is more profitable, in NPV metric, to establish a relatively high early production rate. However, this high initial rate could potentially compromise or reduce the ultimate recovery of the field by pressure depleting the reservoir too rapidly. In other words, ideally there should be a tradeoff between these two objectives as they might have conflicting interests.

Moreover, during a fields late-life, an operator needs to continually assess the value of continuing to produce. The NPV should also be used for this and, hence, there is a need for doing an updated NPV evaluation every year which, in turn, requires a forecast of uncertain future production, cost, reserves, etc. In many cases, an increase in the recovery factor; i.e., produce as much as possible, over the next few years will maximize NPV. However, at some point the NPV goes negative and then nobody will argue that the goal is to maximize produced volume (ultimate recovery) as this will lead to a financial loss and reduced shareholder value.

Minimize economic risk: Choosing a risk attitude is part of any decision making process. An investor could be risk averse, risk neutral or a risk lover/seeker depending on whether they prefer low risk or high return. Risk neutral means that you are indifferent to risk and chooses according to expected values (Scott, 2020). Minimizing economic risk could be to minimize the probability of investments that generates negative NPV

Safety: Safety is always a priority for E & P companies; arguably it should be included as one of the objectives in the decision making process. Ideally, safety should be

included with weights or preferences stating its importance relative to the other objectives.

Reputation: E & P companies pays a lot of attention to its reputation. The reputation is what secures finances, production licenses and talented people. Therefore, reputation could be one of the objectives that you should include in a decision analysis

3.5 Other decision parameters & constraints

The E & P companies usually have other parameters that they evaluate in a decision making process, in addition to the objectives mentioned above. The most frequently used is mentioned below.

Internal rate of return (IRR): IRR evaluates how high the discount rate of an investment theoretically could be without generating negative discounted future cash flow. This parameter has several well-known weaknesses and it is impractical to use for choosing between alternative investments, especially when including uncertainty and a probabilistic distribution. Moreover, it is usually highly correlated with expected net present value, thus only providing marginal insights. IRR could be included as a constraint to investment decisions. (E.g. IRR>20%)

Break-even analysis

A break-even price could be defined as: the metric that represents the oil price that a company needs to generate enough cash so it can cover its capital spending and dividend payouts (Mercer Capital, 2018). What is included in the projects and company's break-even price will vary across regions and companies and should be taken into consideration when comparatively evaluating different projects. Whether dividends should be included or not is also questionable. The break-even analysis is used as a stress-test of investments – to assess how robust it is in terms of volatility in input parameters, specifically oil price.

Aker BP currently has a communicated break-even oil price constraint of 35 USD per barrel. No new projects will be sanctioned if they require a break-even price higher than that. Figure 3.5-1 shows the Brent oil price development thus far in 2020, it has been highly volatile and below 35 USD for longer periods. This illustrates the weakness of this constraint on break-even price, as it is quite challenging to choose a sensible level. Moreover, an inconsistency occurs when a project generating positive expected

net present value will not be sanctioned if it has a break-even price above the constraint, thus reducing value creation. This last inconsistency is related to the risk profile briefly mentioned above and is a company policy.
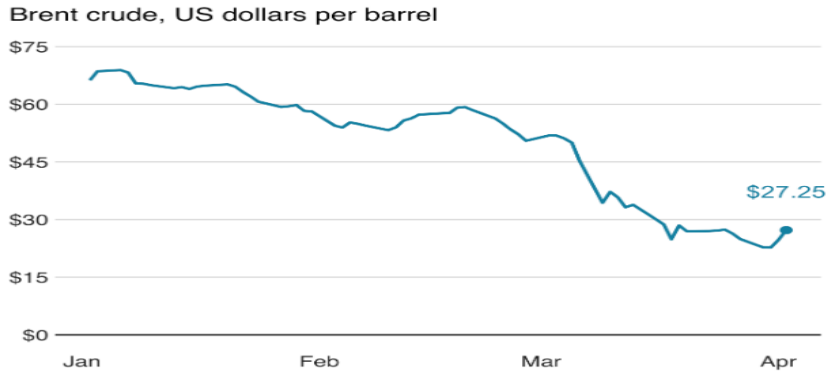

figure 3.5-1: *Brent crude price, USD per barrel* (Bloomberg, 2020)

Cost of production (COP)

This metric considers the operating expenditures (OPEX) without including investment costs, i.e., the capital expenditures (CAPEX) of a project. Particularly, with an E & P company, it would be the day-to-day expenses the company incurs when producing barrels of oil equivalents (Ross, 2020). All E & P companies, especially in downturns, are actively seeking to minimize the COP. This term is especially relevant in periods of very low oil-price, acting as a determinant of when to close-down the production of a field, if the oil price received is not covering the operating expenditures.

3.6 Uncertainty categories

The NPD requests the resources reported to be tagged with an uncertainty category (NPD, 2020a). In order to provide the associated probabilities, one uses percentiles denoted P and a number to indicate the percentage that exceeds a certain value (DNVGL, 2016).

Low estimate: The low estimate expresses potential negative deviation with regard to mapping of the reservoir, rock and fluid parameters and the production rate. The associated probability of being able to produce at least the low estimate is indicated by a P90 percentile. According to the uncertainty terminology introduced by Bratvold &

Begg – as described in section 2 – the low estimate would inform about the risk of the project.

Base estimate: The qualified best estimate of volume that are expected to be recovered. It should reflect the current understanding of the reservoir and either be calculated deterministically or stochastically. If the latter is the case it will be stated as the expected value. The probability of the base case is indicated by the P50 percentile(median)

High estimate: The high estimate expresses the potential positive changes (upside) that arises when mapping the reservoir and its parameters. This can be considered the opportunity of the project. The probability of it occurring is indicated by the P10 percentile.

4 The Tambar East field

This chapter initiates the structuring phase (phase one) of the decision analysis. The culmination or output from phase one is a clearly defined project with context, clearly defined objectives and development strategies. Phase one is covered in chapter 4 – 8 of the thesis.

4.1 Location and installations

Tambar East is a field located in the southern part of the Norwegian sector in the North Sea, about 17 kilometers south east of the Ula field and two kilometers east of the main Tambar field. Figure 4.1-1 displays the field layout, where Tambar East is highlighted with a bold green line. The field lies partly in block 1/3 and 2/1. The water depth in the area is 70 meters. Tambar East extends into three different production licenses (PL065, PL 300 and PL 019B) and an agreement has been made regarding the unitization and operating the Tambar East unit reservoir.
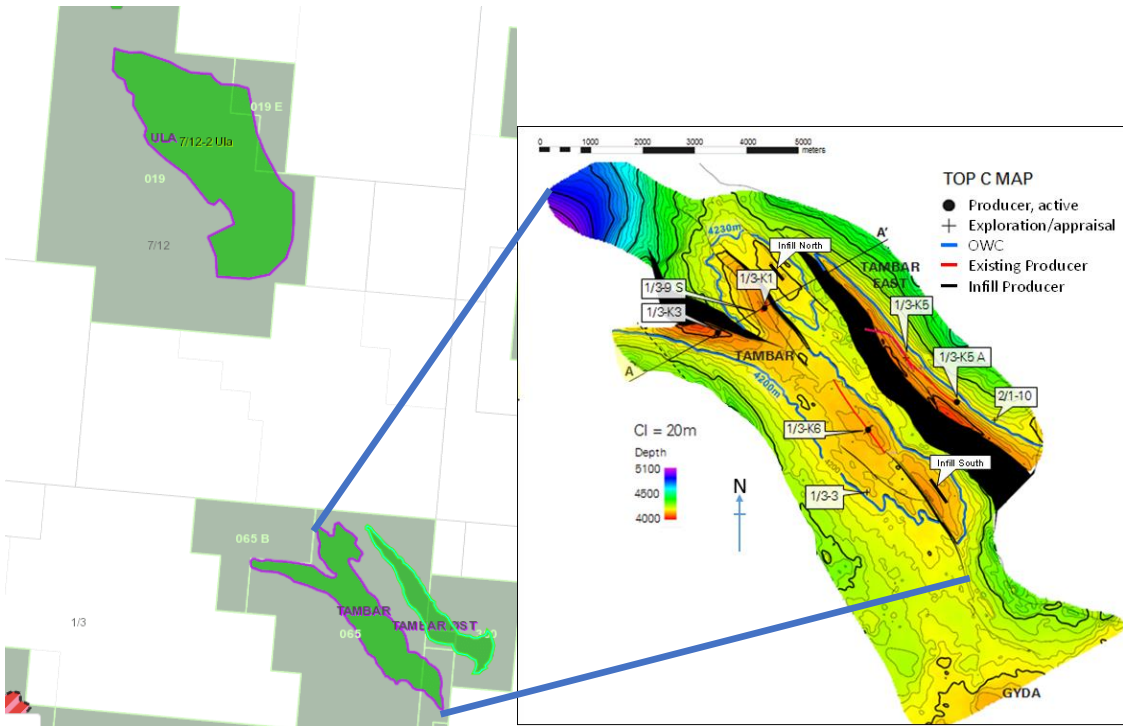

figure 4.1-1: *Tambar East location, situated east of Main Tambar field and southeast of the Ula field.*(NPD, 2020)

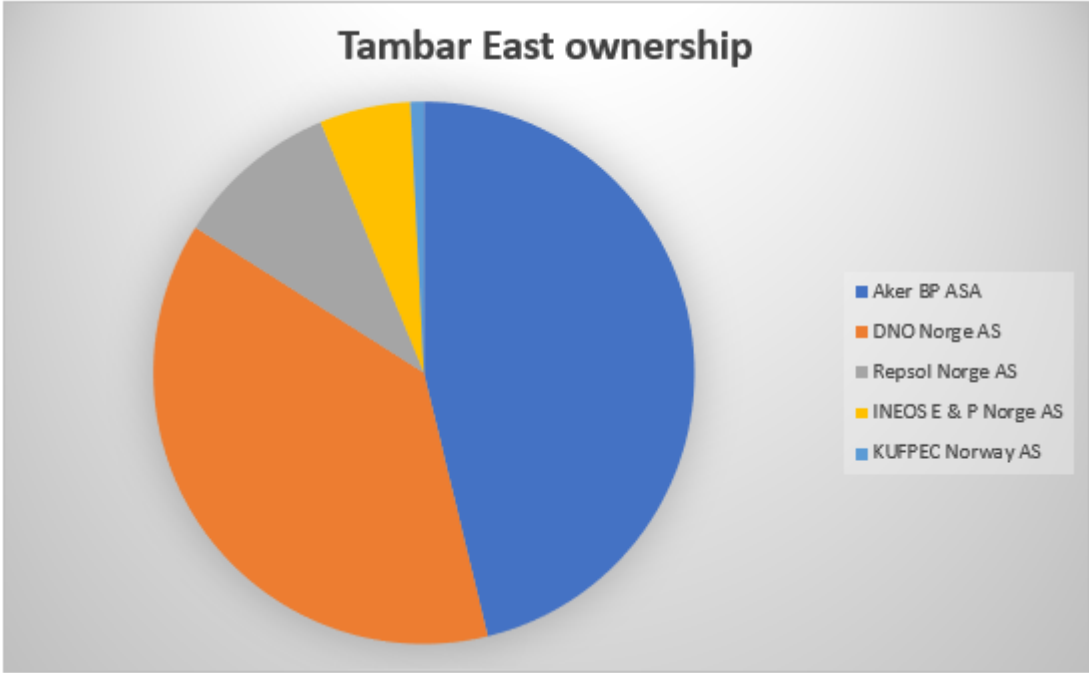The ownership of Tambar East is as follows:

figure 4.1-2: *Tambar East ownership*

The field has been developed with one production well connected to the Tambar facility seen on figure 4.1-3. The Tambar facility consists of a remotely controlled wellhead platform without processing equipment, also known as a NUI, normally unmanned installation. The produced oil is transported by pipeline to the Ula platform, where it is processed and exported to Teeside in the UK, via Ekofisk. The produced gas is injected into the ULA reservoir and used for improved oil recovery purposes (NPD, 2020c).

figure 4.1-3: *Tambar wellhead platform*

4.2 Field history

In November 1991, an exploration well denoted 2/1-10 was drilled in the area that later was known as Tambar east. The primary purpose of the exploration well was to evaluate the Upper Jurassic Ula formation, and if successfully, to prove a volume of oil that was commercial as a tieback to the Gyda platform located south of the area. The well itself was plugged and abandoned as a dry well, but several logs were conducted, together with coring of the formation and would later provide insight when discovering and developing the Tambar/Tambar east field.

An appraisal well was drilled on Tambar in 1998, which proved substantial reserves for an economic development and Tambar therefore started production in 2001.

In 2007 the Tambar East structure, a tilted fault block structure, was penetrated and proved up by well 1/3-K-5 T2 and subsequently developed with producer 1/3-K-5 A. K-5 A has been on production since 2007. Due to some unforeseen production difficulties – that will be thoroughly addressed in other part of the thesis – the K-5 A well was shut in and temporarily plugged in fall 2019 and remains plugged as per spring 2020.

4.3 Overall reservoir management

The drainage strategy of the reservoir is to produce the reservoir with primary depletion with oil/gas expansion as the main reservoir drive mechanisms, i.e., without adding to the original energy sources in the reservoir(Petrowiki, 2020b). The reservoir is assumed to be very compartmentalized, with a fairly low degree of communication between the compartments. Reservoir management of Tambar East is seen in conjunction with reservoir management on Tambar since they share facilities. Tambar is also produced with primary depletion, with a declining reservoir pressure. A multi-phase Pump (MPP) is installed on Tambar to reduce the backpressure on the wells and thus allowing continued production with declining reservoir pressure. Projects to install artificial lift on Tambar (TAL) was completed in 2018.

K-5 A is unable to produce towards the increased back pressure that arises from new infill wells being put on production on Tambar. Therefore, the K-5 A well was shut in and plugged and its flowline was redirected to be used for one of the other wells on Tambar main (K-4). Moreover, the Tambar facility's fire system is only able to manage four live wells simultaneously and there are currently five wells including K-5 A. There

is no pressure support by injection or aquifer on Tambar East and thus the reservoir pressure will continue to decrease with production. Production on Tambar East is further complicated by precipitation of asphaltenes in the wellbore and probably also in the near wellbore area of the reservoir and is currently managed by limiting reservoir drawdown, hence staying above the asphaltene onset pressure. Tambar East has produced about 1.89 MM bbl of oil and has to date reached a very low recovery factor of about 4%, compared to an average on the Norwegian continental shelf of about 47% (Smalley et. al., 2018). Reservoir compartmentalization, low reservoir quality and asphaltene prone oil are suggested as main explanations according to internal documents, which will be evaluated thoroughly in this thesis.
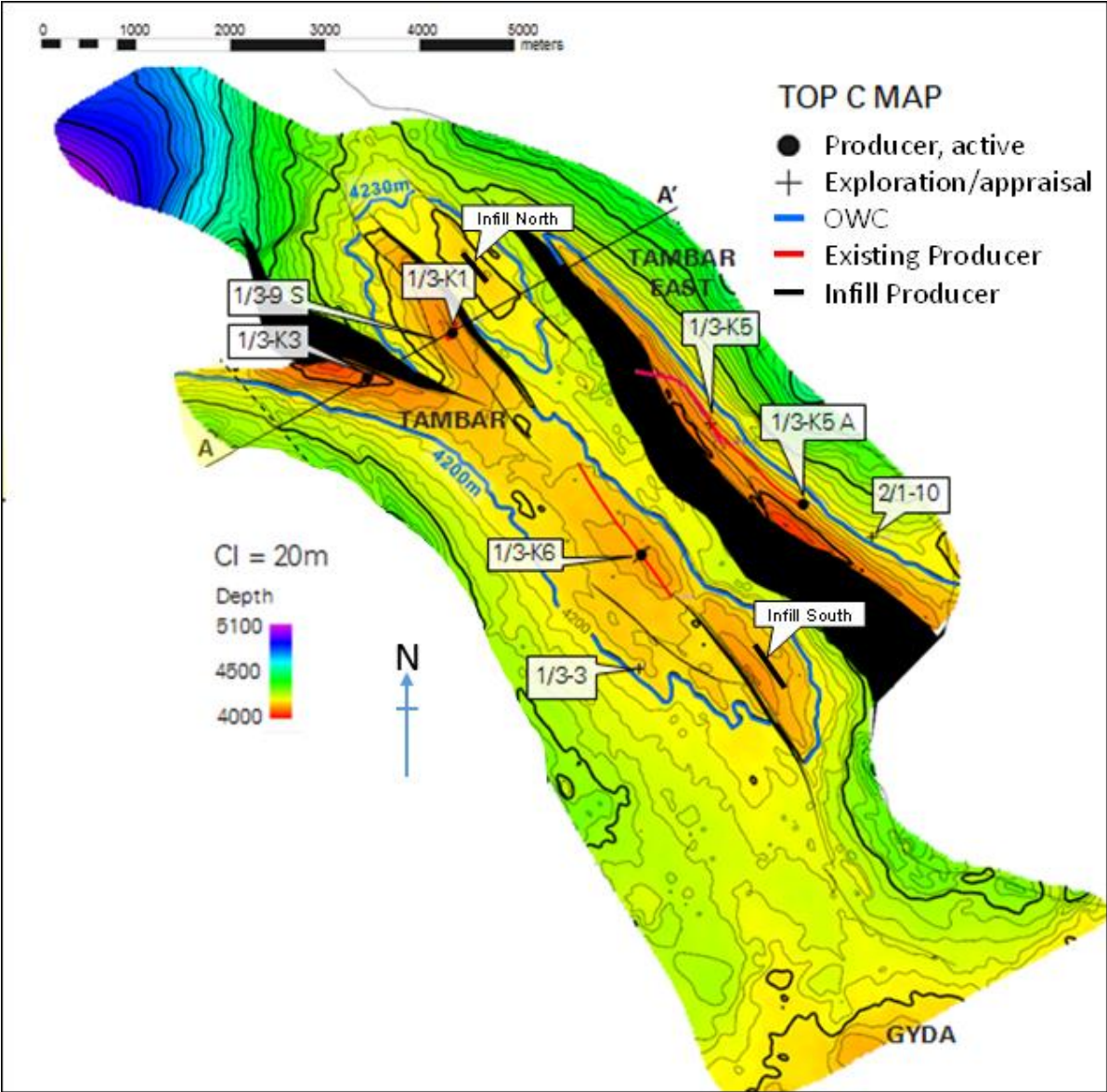
4.4 Geology and reservoir

figure 4.4-1: *Tambar topographic map*

Tambar East is an upfaulted structure which is separated from the main field by the Hidra fault, a major NNW–SSE fracture that downthrows ca 200m to the west. The Hidra fault, separating Tambar East and Tambar main can be observed as the largest dark shaded area in figure 4.4-1. Whether the structure on Tambar East was in communication with Tambar main was uncertain at the time Tambar East was drilled and developed. Tambar East reservoir is situated in the Gyda member of the upper Jurassic Farsund formation, which is further subdivided into units D1, D2, C, B, A. Units D1 and D2 are shallow marine argillaceous sandstones – i.e., consisting of silt and

clay sized particles – which has very low permeability and not conventionally considered reservoir quality rock. Unit C consists of the comparatively best reservoir sand, while unit B has fairly good quality sand with interbedded, strongly cemented stringers. The upper half of unit A consists of good quality reservoir but becomes increasingly argillaceous towards the base. Figure 4.4-2 shows a sketch of the reservoir cross-section along NE – SW direction
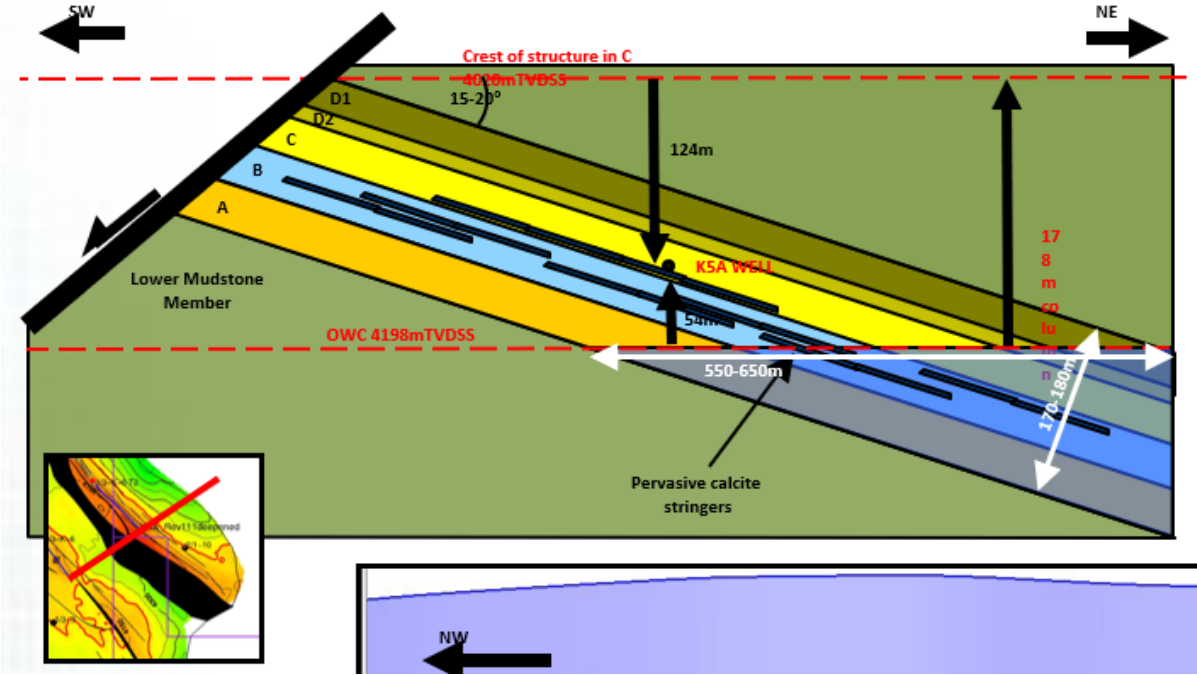

figure 4.4-2: *Tambar East reservoir cross-section*

4.5 Production well, K-5 A

The full name according to NPD name convention is 1/3-K-5 A, but for future reference throughout the remaining parts of this document it is known with the short version K-5 A. It is the only production well on Tambar East, therefore information about its design, behavior and performance is vital in order to analyze and describe the Tambar East reservoir. As previously mentioned, altering the design on K-5 A could be one of the chosen scenarios to revitalize Tambar East. Evaluating the past to improve the future work is paramount in reservoir and well engineering.

4.5.1 Drilling & completion

Well K-5 T2 was drilled as a pilot hole to evaluate the reservoir section of the Tambar East structure. The well was designed to be sidetracked as a horizontal producer if the results of the pilot proved to be favorable. K-5 T2 identified a hydrocarbon column

within the Gyda sandstone reservoir interval. Well K-5 A was initiated as a sidetrack from K-5 T2 and entered the top of the promising unit C sand with a near horizontal inclination. Inclination continued to build until reaching horizontal, which it maintained throughout its path towards total depth (TD). The horizontal well trajectory was within the lower third of the unit C sand, approximately "70 m above the interpreted OWC". Figure 4.5-1 shows the well trajectory of K-5 T2 and K-5 A
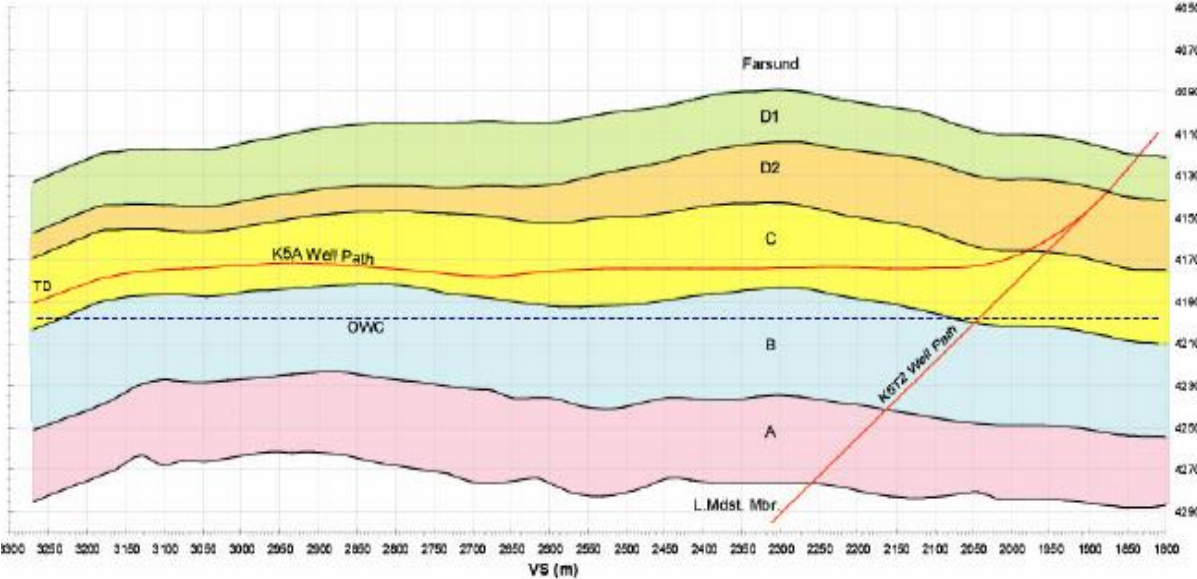

figure 4.5-1: *K-5 T2 and K-5 A well trajectory*

4.5.2 Production

K-5 A started production in October 2007. The initial decline rate observed was significantly higher than expected – an indication of an unresolved issue in the well. Therefore, a wireline investigation was initiated. The wireline tool string was covered in asphaltenes after the investigation was conducted. Asphaltene presence was also confirmed on fluid-sample-analysis. The asphaltene precipitation was partly managed by constraining the wellhead pressure by choking back production.

The downhole pressure gauge – installed upon completion of the well – failed during the initial production of the well. All downhole pressures and reservoir pressures are therefore estimated using fluid gradients etc. and quite uncertain. The estimated reservoir pressure was declining and due to the asphaltene issue, a reduction of the back pressure was not viable. Since 2013, K-5 A has been producing intermittently as

the well had to be shut-in when the flowing wellhead temperature was less than 25 degrees Celsius, or when the flowing wellhead pressure was less than 27 Barg, due to asphaltene precipitation in the near wellbore area. Additional wells came on stream on Tambar main, which increased the backpressure on Tambar East. In 2017, K-5 A was shut in and its flowline was re-directed to be used on a Tambar main well, K4. Finally, the well was plugged in fall 2019 and is plugged as per spring 2020. The plot on figure 4.5-2 shows the production rates measured on well tests conducted on K-5 A during the years of production.
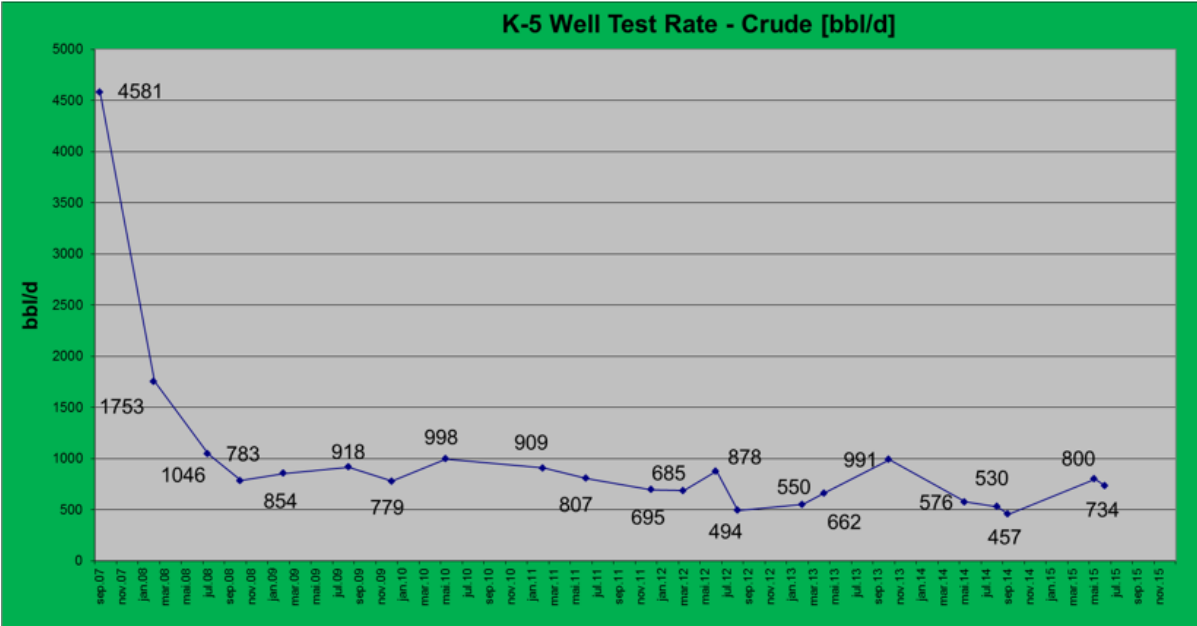

figure 4.5-2: *Oil production rates on K-5 A well tests*

4.5.3 Decline curve analysis (DCA)

Understanding Tambar East performance is, to a large extent, about understanding the behavior of K-5 A. A DCA is considered a purely empirical method with no physical laws governing the flow of oil and gas in the reservoir. The method evaluates the historical (declining)production rates and predicts the future performance of the well based on the history. A key assumption to this method is that the observed production trend will continue, which is not often the case for a well due to various actions being conducted in the reservoir. E.g. injection in the reservoir or altered back-pressure from adjacent wells. The DCA was generated by using equation 4-1, originally proposed by J.J Arps. The q is production rate, q_i is initial production rate, t is accumulated time since start of production, d_i is initial decline rate at t=0 and b is the curvature constant (Fetkovich, Fetkovich, & Fetkovich, 1996).

Equation 4-1: DCA, production rate

$$q = \frac{q_i}{(1+bd_i t)^{\frac{1}{b}}}$$

The decline curve analysis (DCA) was conducted using a software tool called Oilfield manager (OFM), developed by Schlumberger-Next. In addition to utilizing the basic equation, it has a built-in feature of selecting the best fit forecast. A major use of the DCA is reserves estimation, and quite frequently used as a cross-check instrument, together with the output from reservoir simulations and production profiles generated from it. Since the DCA doesn't have an underlying advanced theoretical basis, it has a certain appeal to non-technical institutions (E.g. financial), compared to more technical methodologies such as reservoir modeling (Fetkovich et al., 1996).

The plot on figure 4.5-3 shows the DCA conducted on K-5 A, where oil rate is plotted against cumulative oil rate. 10 years of production is forecasted from Feb 2020 to Feb 2030, represented by the red curve. The red dots represent the historical production rates and the fitted curve is blue. The DCA indicates remaining reserves of 1.38 MM bbl with the existing development concept. Key parameters from the analysis is provided in the upper right corner, including the parameters given by equation 4-1.

As mentioned in chapter 4.3, K-5 A has some complex production and pressure constraints to avoid asphaltene precipitation: stay above the asphaltene onset pressure or shut in the well. The DCA assumes a pressure/production rate decline and it will overestimate the reserves in the Tambar East due this pressure constraint. Moreover, K-5 A has had an intermittent and cyclic production behavior, which ideally should be captured in a DCA and reserves estimation. Matching the cyclic production would substantially reduce the reserves estimation for K-5 A. DCA is a rather simple tool with several limitations and weaknesses that one should be aware of – a complex production regime being one of them.
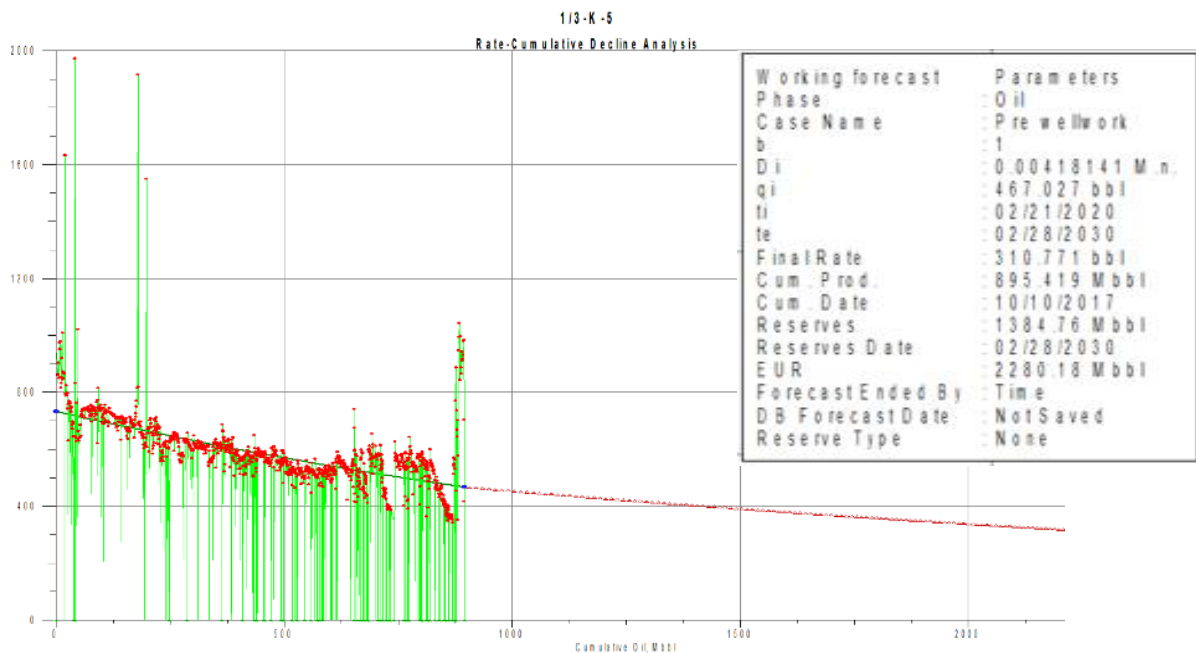
figure 4.5-3: *Decline curve analysis K-5 A*

4.6 Post well review & lessons learned

4.6.1 Prior knowledge & assumptions

The K-5 A was planned as a horizontal well in the C-sand with approximately 1000m of reservoir section. Internal documents identified the main subsurface uncertainties as:

Petroleum system: Source rock (sufficient source rock to charge the Tambar East structure) and migration (necessary pressure gradient for migration into TE)

Oil-water-contact (OWC): If the structure is sourced in the first place, then what is controlling the OWC? Limited access to charge for fill to spill, fault seal (most obvious leak point would be across the Hidra fault to the south of 2/1-10) and perched water. Internal documents (Nov 2006) indicated the trap configuration – governing the placement of the OWC. The interpretation was based on the sealing capability of the Upper Jurassic sands against the Triassic low net-to-gross sands across the Hidra fault – separating Tambar main and Tambar East. Figure 4.6-1 illustrates the sensitivities on the OWC, broken down to **most likely, minimum and maximum case.** Spill point in a trap is defined as the low point under which hydrocarbons will escape when the trap is full, thus corresponding to the OWC

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1. **Most likely** spill point in Tambar East was estimated to be 4170 mTVD. It assumed no fault seal between the upper Jurassic C-sand and the Triassic across the Hidra fault but would require the D-sand to seal against the Triassic across the Hidra fault. The 4170 mTVD spill point was based on the most likely mapping and depth conversion of the C-sand

2. **Minimum** spill point in Tambar East was estimated to be 4130 mTVD. It assumed the spill in 1 to be 4160m TVD to account for uncertainty in mapping and depth conversion of the C-sand. It also assumed no seal between the poor reservoir quality upper Jurassic D-sand and the Triassic across the Hidra fault.

3. **Maximum** spill point in Tambar East was set to 4195mTVD. It was constrained by the 2/1-10 well which had water-up-to (WUT) 4196 mTVD.
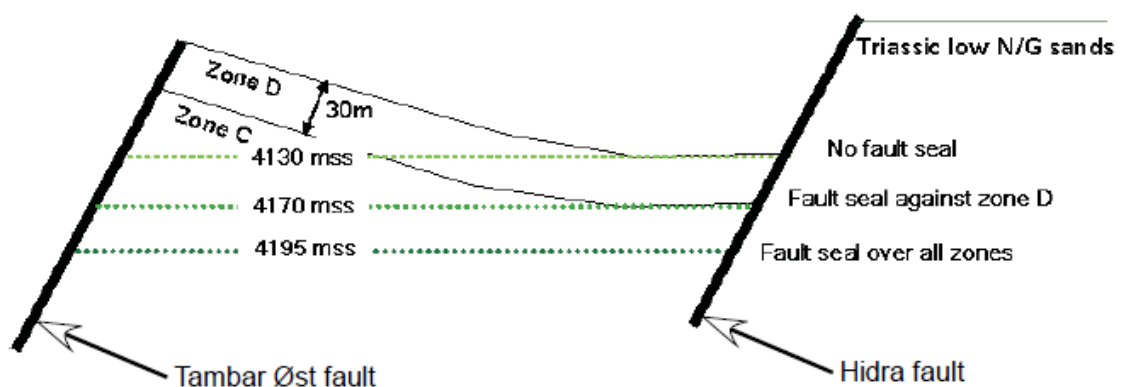
figure 4.6-1: *Tambar East trap configuration* (Aker BP, 2020)

Pressure: Whether Tambar and Tambar East were in pressure communication was heavily debated pre-drilling. Pressure measurements from exploration well 2/1-10 suggested that they might be. TE pressures could therefore be close to initial (8700 Psi/600 Bar) or close to Tambar pressures (4000Psi – 276 Bar), dependent on the pressure communication.

The quite high reservoir temperature of about 160 deg C was also pinpointed as a challenge. Reservoir models predicted an initial reservoir pressure of about 6500 PSI/448 Bar. The stated reward or the price of the well was "potentially 13 million barrels of oil equivalents discovered with no accidents, no harm to people and no damage to the environment".

Technical well objectives were defined prior to drilling the wells K-5 T2 and K-5 A and served as evaluation criteria post drilling

K-5 T2 objectives

- ✓ Prove sufficient oil saturation to justify placing a horizontal producer in the fault block
- ✓ Prove sufficient oil column and establish the OWC
- ✓ Determine reservoir quality
- ✓ Establish accurate structural depth of top units D1, D2, C, B, A and base reservoir
- ✓ Collect reservoir properties for optimizing horizontal well placement

K-5 A objectives

- ✓ Meet both BP and statutory HSE standards
- ✓ Drill a total of 700 – 1200m reservoir section
- ✓ Collect log data in the Tambar sandstone that proves oil bearing reservoir to justify completion as an oil producer
- ✓ Well placed in lower part of unit C to avoid gas production from crest
- ✓ Deliver an oil producer capable of initial well rates of 13.000 barrels per day.

4.6.2 Posterior knowledge and review

After putting a well on production, a post well review is required as part of the project management methodology. A summary of the key metrics from the post well review is listed in table 4.6-1. Color coding was used to indicate level of performance, relative to the prognosed values. Red was poor, orange medium and green was good.

table 4.6-1: *Post well review – key metrics*

	Prognosed	Actual
Top reservoir depth(D1)	4069 mTVDSS	4074 mTVDSS
OWC	4170mTVDSS	4198.4mTVDSS
Reservoir pressure	6300 PSI- 434 Bar	8675 PSI – 598 Bar
Total reservoir thickness	145m	151.9 m
Unit D porosity	0.10	0.06
Unit C porosity	0.20	0.14
Unit B porosity	0.10	0.09
Unit A porosity	0.18	0.16
Data to justify completion		
Perforated reservoir section length	700-1200m	1239m
Well positioning	Lower C unit	Lower C unit, but resting on calcite stringer
Initial rate after 3-month production	13 000 bpd	3 000 bpd
STOIIP	39.5 MM bbl	57.9 MM bbl
Reserves	8.76 MM bbl	6.3 MM bbl
	13.5 MM bbl oil equivalent	7.0 MM bbl oil equivalent

Comments to the post well review made by involved representatives: "The K5-T2 pilot hole encountered a 178 m oil column with an OWC, porosity came in lower than prognosed which had an even more pronounced effect on permeability, structure was filled to maximum case i.e. 4198 mTVDSS, roughly aligned with WUT encountered in 2/1-10, reservoir pressure was un-depleted at 8675 PSI at OWC. Reservoir quality improved gradually along borehole, calcite stringer may impact well productivity, unexpected oil type encountered-asphaltenes depositing in tubing, PVT analysis indicate low GOR and high viscosity."

According to internal planning documents, the presence of laterally extensive calcite stringers was flagged and considered for unit B in Tambar East but not unit C. The calcite stringer that was encountered in the horizontal section may be causing a significant reduction in production. The oil type encountered in Tambar East was significantly different from the crude oil produced from Tambar main (low GOR, asphaltenes and higher viscosity) This had apparently not been flagged as a risk prior to drilling and has had a significant impact on production. Further, reservoir quality was not considered as a large uncertainty prior to drilling, the perceived largest subsurface risks are mentioned above

5 Key value drivers

When the thesis work on Tambar East was initiated, several engineers within the Tambar area subsurface team, that knew the Tambar East history and performance, were questioned about their interpretation and understanding of Tambar East. The purpose was to determine a starting point for evaluating possible value drivers of Tambar East. They were all mostly pointing in the same direction regarding the value drivers, or reservoir issues and problems as they were commonly called by the subsurface team. Loosely based on these nominated key value drivers, a thorough and separate technical analysis and evaluation was conducted. The output of this technical analysis concluded on three key value drivers of Tambar East: Compartmentalization, reservoir fluid containing asphaltenes and the reservoir pressure. This chapter is a technically heavy chapter which requires substantial petroleum specific knowledge to fully understand. The main findings and summary of this chapter is included and discussed in chapter 6 and 8.

5.1 Compartmentalization

5.1.1 Fault blocks – lateral compartmentalization

Tambar East reservoir is heavily faulted. Several models have been proposed in order to interpret the reservoir faulting, volumes and communication. It is not the intention of this work to dive too deep into the geophysics and geology of Tambar East, rather understand and interpret the basics and its consequences. The geological model on Tambar East as per 2010 indicated a STOOIP of about 56 MM bbl of oil. Material balance calculations conducted estimated that at least 16 MM bbl of STOOIP has been contacted by the existing producer on the field, K-5 A.

Thus far, the well has only produced about 1.9 MM bbl of oil. According to the drilling engineers that analyzed the well after it reached a stable production rate, K-5 A was not believed to be representative of what could potentially be achieved with a carefully planned and executed sidetrack or new well. It was assessed that only about 15% of the perforated completion interval contained flow. Further, engineers previously involved with Tambar East claimed that "due to the nature and complexity of the reservoir; simulation and history matching was believed to play a less important role in understanding the reservoir and well placements" This is a powerful statement, one

which should be re-visited with new insights and better modeling skills and tools to verify its validity.

The faults are difficult to detect on seismic since they have a small throw. Other methods besides seismic to detect the faults has been used – such as coherency mapping – in order to define the faults location and geometry. Due to the difficulty of mapping the faults through seismic interpretation, there was significant uncertainty associated with volumes adjacent to faults, which was reinforced by observing fault positioning differences across different seismic datasets. Nevertheless, the STOOIP volumes on Tambar East has been interpreted and divided into fault compartments, assisted by employing coherency data which increased the accuracy of the fault mapping. Figure 5.1-1 shows the different fault blocks identified with their associated STOOIP. The STOOIP sums to 56 MM bbl and fault block 2 containing the production well holds 10.7 MM bbl. This interpretation was considered a base case without uncertainty and performed by the BP subsurface team.

To illustrate the uncertainty associated with the interpretation, it was observed that a partner company conducted a separate STOOIP evaluation with a significantly different outcome. Basically, they concluded that the two biggest fault block's volume should be halved compared to the BP evaluation, primarily owing to the positioning of faults. A modified STOOIP would then be ~ 41 MM bbl, a reduction of about 27 %. A thorough re-processing of the seismic data was recommended in 2013 to improve fault imaging and positioning of faults, especially a reconciliation of fault block 4 and 5 which was under scrutiny by a partner company. A 4D seismic was proposed to indicate which compartments had actually been depleted by K-5A.

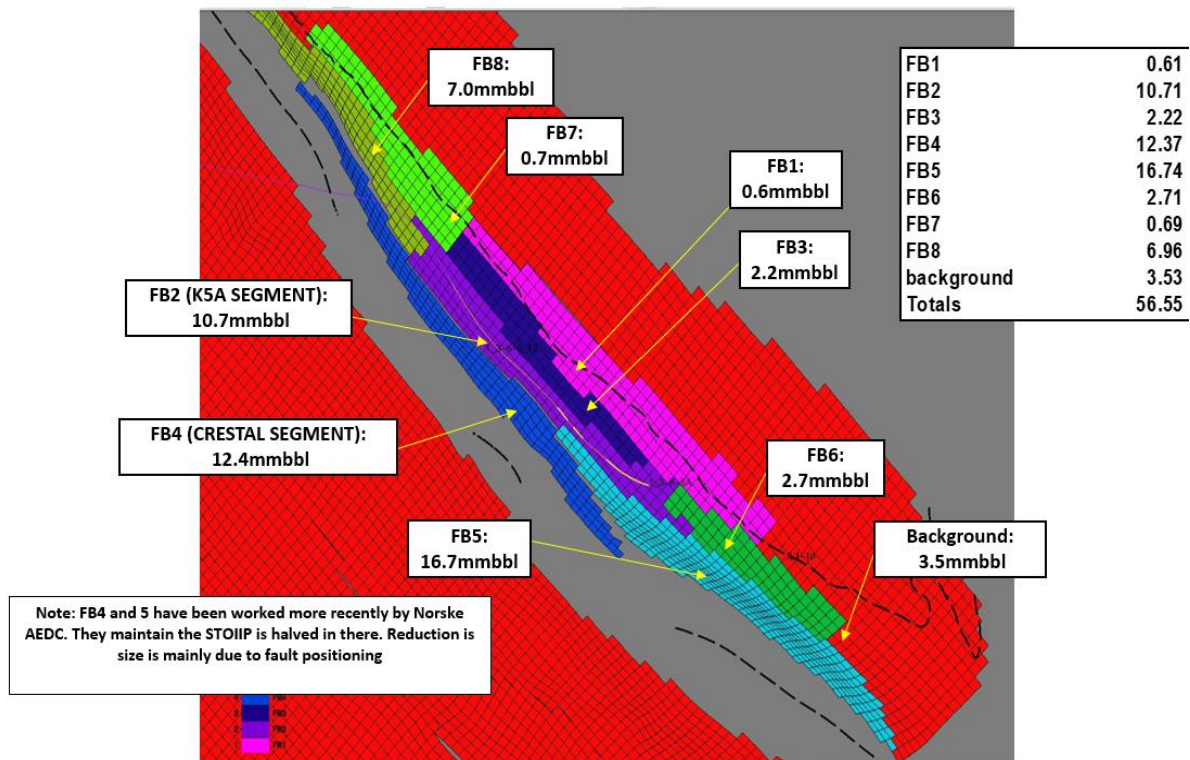| FB1	0.61
FB2	10.71
FB3	2.22
FB4	12.37
FB5	16.74
FB6	2.71
FB7	0.69
FB8	6.96
background	3.53
Totals	56.55

figure 5.1-1: *Tambar East STOOIP segmented*

There is evidently significant uncertainty on the STOOIP volumes and also quite large uncertainty on the volume that remains uncontacted by the current development concept. The uncertainty will be evaluated separately in a later section.

5.1.2 Material balance

An informative method to evaluate volumes and connectivity for a compartmentalized reservoir is to conduct a material balance calculation. A software called MBAL, made by Petroleum Experts, was used for the material balance reservoir analysis. In compartmentalized reservoirs, with partially sealing faults, the reservoir can be modelled and history matched by creating multi-tank models with transmissibilities. (Petex, 2020). The material balance is based on the principle of conservation of mass: Mass of fluids originally in place = Fluids produced + remaining fluids in place. It uses a conceptual model of the reservoir to predict the reservoir behavior based on the effects of reservoir fluids production. The material balance equation is zero-dimensional, based on a tank-model and does not consider geometry of the reservoir, drainage area, position of wells or orientation of wells etc. (PETEX, 2005). Figure 5.1-2 illustrates the material balance model for Tambar East, where the green squares represents the tanks or volumes and the blue diamond to represent transmissibility – interface/communication between tanks. Previous analysis has indicated no aquifer

influx on Tambar East – no influx is a prerequisite for this model. This simplified model was used to quantify the volume contacted by the production well and the analysis was enhanced by history matching with production data, i.e., production rates and bottom-hole pressures. The transmissibility is a measure of the conductivity of the formation corrected for viscosity of the flowing fluid (Petrowiki, 2013).
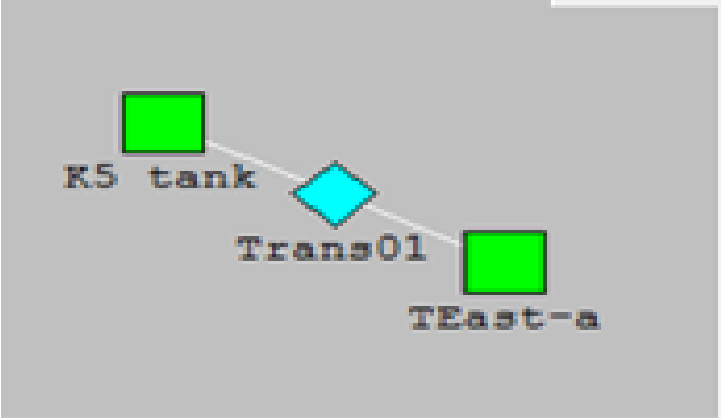

figure 5.1-2: *2-tank material balance model in MBAL*

Numerous previous analyses have been conducted on Tambar East material balance, honoring updated production data, fault interpretation and updated PVT data/equation of state. The objective of the modeling is to match production data and the simulated data for the estimated 2-tank model. The model can then be tuned to reproduce the production history. Such an analysis was conducted in 2012 by BP subsurface team. Figure 5.1-3 shows the matching of tank pressure against time and calculated oil production rate. The matched tank pressure indicated a 2-tank model, where the K-5 A tank holds 3.1 MM bbl and the other tank – representing the remaining part of Tambar East being contacted by the well – holds about 16 MM bbl of oil. Accordingly, the current development regime on Tambar East only contacts about 33 % of the reservoir STOOIP. Mainly due to faults compartmentalization but the presence of calcite stringers is also constraining the reservoir drainage.
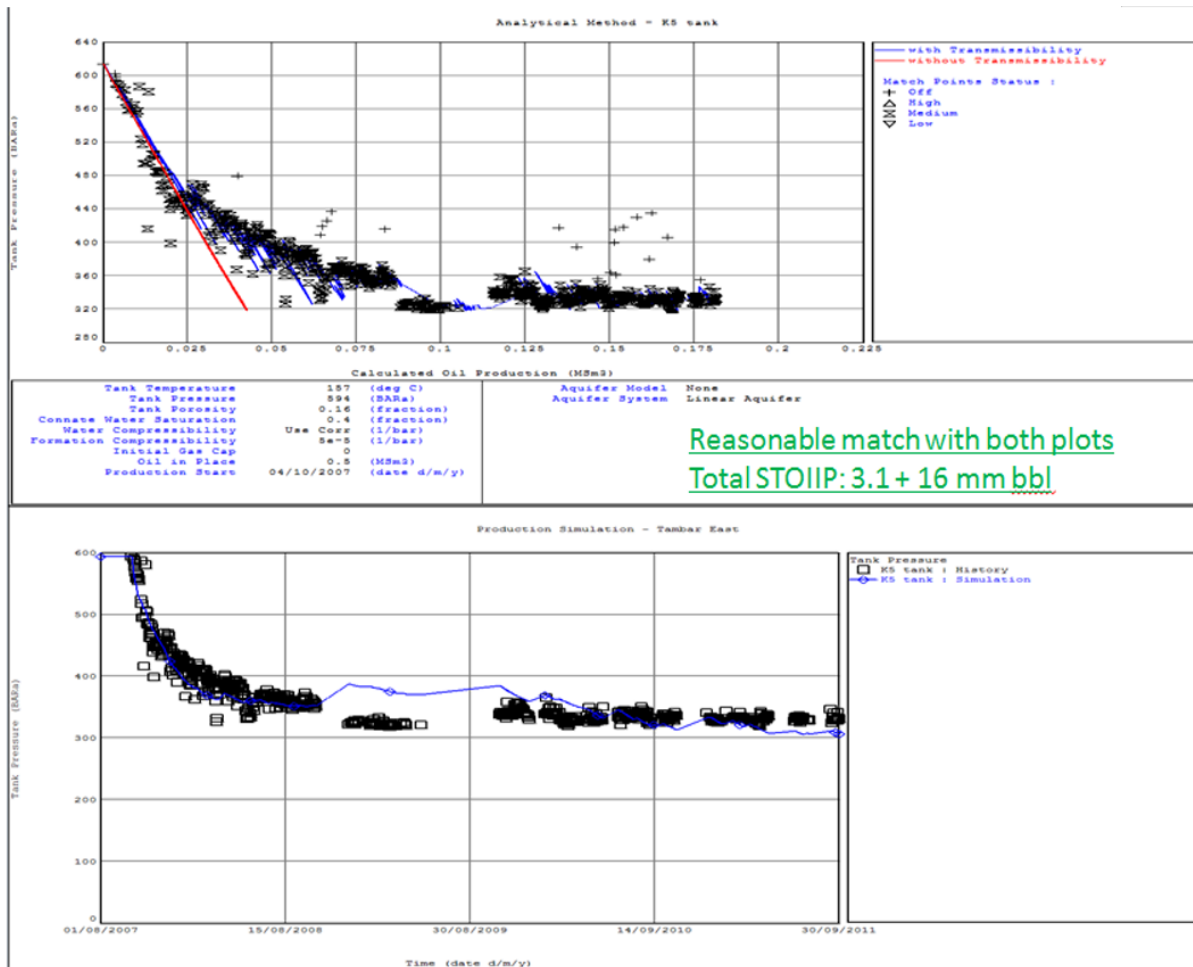
figure 5.1-3: *Matched tank pressure, calculated oil production rate on top plot and against time on bottom plot*

5.1.3 Calcite stringer – vertical compartmentalization

A part of understanding the underperformance of the K-5 A well is the logging and interpretation of LWD. The density and resistivity log indicated the presence of calcite stringers close to the wellbore. Stringers are large numbers of thin, tiny and closely spaced mineralized veins originating from the main orebody. The calcite is non-permeable and could potentially act as a barrier in the reservoir, thus inhibiting/reducing flow in the reservoir. Figure 5.1-4 shows the K-5 A well trajectory coupled with a section of the well logging indicating a laterally extensive calcite stringer in the reservoir section of the well, in the C sand. The well trajectory is shown as the grey line in the bottom third of the C reservoir unit, in yellow, on the cross-section plot. The calcite stringer interval is indicated by black arrows and blue lines in the yellow C unit. Such an extensive barrier, over 500m long, would severely inhibit the inflow to the

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well. The well seems to be resting on top of the calcite stringer. Further, cores of a neighboring well, the previously mentioned exploration well 2/1-10, contained calcite which is believed to correlate with the calcite stringer found in K-5 A.
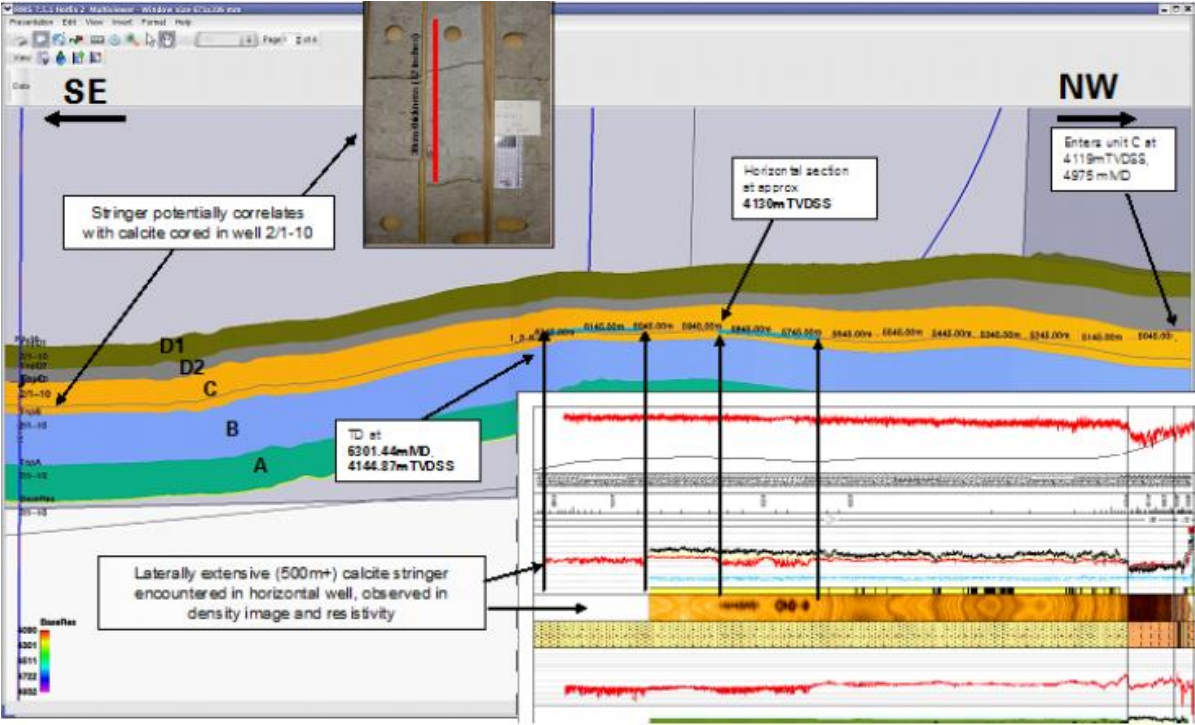
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figure 5.1-4: *K-5 A well trajectory & calcite stringer presence*

Moreover, a cross-sectional sketch of the Tambar East reservoir indicated the presence of several calcite stringers, especially in the B sand unit below the targeted C-sand (see figure 4.4-2.) How these B-sand stringers have been detected is unclear and needs to be investigated further. The calcite stringers could also be present in other reservoir units and needs further evaluation if planning a sidetrack or new well. The calcite stringers effect could be mitigated by hydraulic fracturing; however, one wants to avoid fracturing into the water zone, below the oil-water contact (OWC).

5.1.4 Compartmentalization: Development alternatives

Analyses above concludes that the reservoir is heavily compartmentalized both laterally (faults) and vertically (calcite stringers). The K-5 A well is only contacting a small fraction of the reservoir and inflow is limited by the calcite stringers. To improve the drainage of the reservoir it boils down to three alternatives: drill a new well (or sidetrack), improve the existing well or gather more information.

Infill wells: The term used is infill drilling. It is the addition of wells in a field which decreases the well spacing in the reservoir. It is commonly used to accelerate the recovery and increasing the ultimate recovery – especially in heterogenous reservoirs – by improving the continuity between injectors and producers. Moreover, as the well spacing is decreased, the fluid flow paths are changed and the sweep area is increased, thus sweeping into previously unswept areas of higher hydrocarbon saturation (Schlumberger oilfield glossary, 2020). An optimal placement of an infill well is crucial for this alternative to be viable. The infill well should penetrate other parts of the reservoir, either laterally or vertically. This would allow more of the STOOIP to be contacted by the development concept and the possibility to avoid the calcite stringers.

Three alternative infill well paths have been suggested. Figure 5.1-5 shows the three proposed well paths (green curves) with alternative A, B and C. Alternative A and B penetrates the lower A sand, while the alternative C penetrates the same C sand that the existing producer does. Revert to figure 4.5-1 for a reminder of the sand unit distribution on Tambar East. Moreover, worth noticing that alternative A and B is a sidetrack from existing well K-5 A, whereas alternative C is a new well entirely.
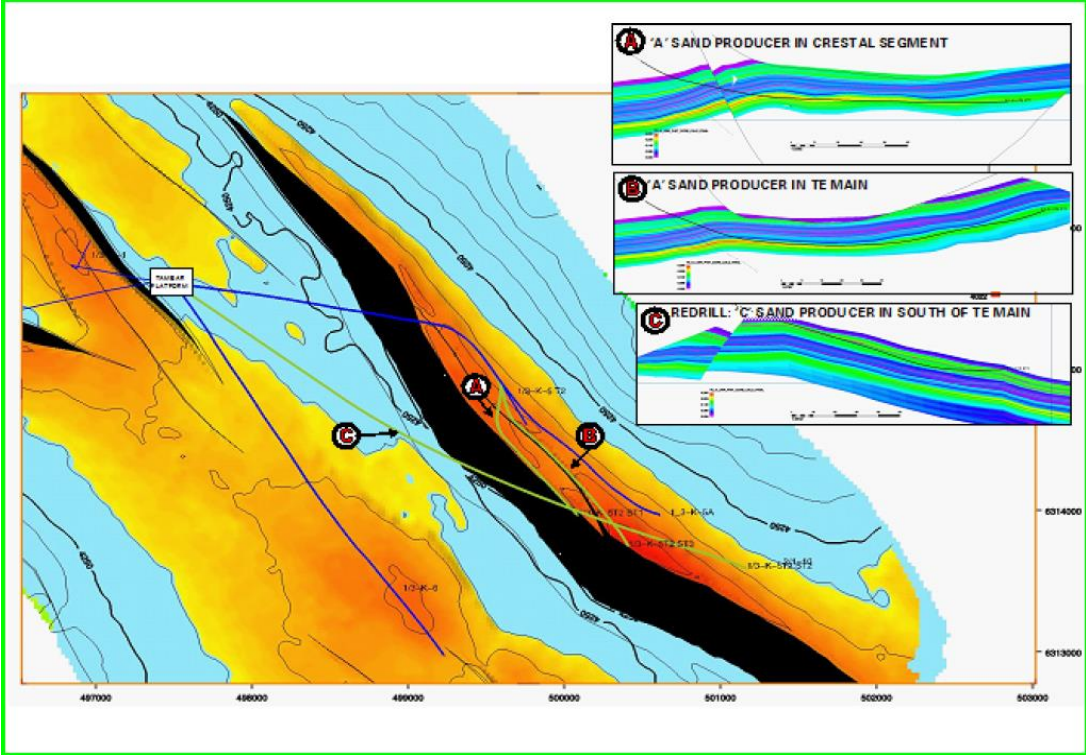

figure 5.1-5: *Potential infill well options*

Improved recovery: An alternate (but not mutually exclusive) option to increase recovery through infill drilling on Tambar East is stimulation of the existing producer K-

5 A. Production from the well is thought to be inhibited by near wellbore damage and the calcite stringer which the well rests on. Hydraulic fracturing is the most feasible stimulation method but has significant challenges and limitations. Fracturing is a process where fluids are pumped into a wellbore at such a high rate that it breaks down the formation, creating fractures into the reservoir. The fractures will bypass near formation damage and potential calcite stringers and increase the apparent permeability of the reservoir. Generally, fracturing is used to increase the flowrate of oil from low-permeability reservoirs and near-wellbore damaged reservoirs. Also, the fracturing will decrease the pressure drop that arises from asphaltene deposition (Petrowiki, 2020a).

The fracture needs to be restrained such that it doesn't fracture into the water zone, below the OWC. The Tambar East reservoir has such a high temperature that it will also require the use of a special fracturing fluid that can withstand the temperature without degrading over time. Conventional fracturing technology makes it difficult to direct several fractures along the well path. Moreover, fracturing requires a clean out on coiled tubing which historically has been a challenge for this particular well.

Information gathering: Another options that is often overlooked is the option to collect more information regarding the degree of compartmentalization. Relevant information sources could be to refine the static modeling of the reservoir, interpret recent 4D seismic survey of the area, or even consider drilling appraisal wells or surveillance wells. The information gathering should only be conducted if it adds value – consider reducing the material uncertainty such that it could potentially impact decisions. The Value of Information was addressed in chapter 2.3.4.

Advanced technology: A compartmentalized reservoir could benefit from newer technology like multilateral completions (MLT), that allows the drilling and completion of multiple lateral boreholes within a single main bore. This would allow a single well to drain several compartments in the reservoir, thus increasing the productivity index of the area. An extension to the multilaterals is the technology "Fishbones", which can stimulate a reservoir in what they claim is a safer, greener and more cost-effective way. Aker BP has previously used Fishbones technology on wells in carbonate reservoirs with success. However, feasibility studies on implementing multilaterals and Fishbones has neither been previously conducted for Tambar East; nor has it been

part of the scope for this thesis, but falls into the category of recommended future work (Aker BP, 2020b). Figure 5.1-6 illustrates the multilaterals and Fishbone technology.
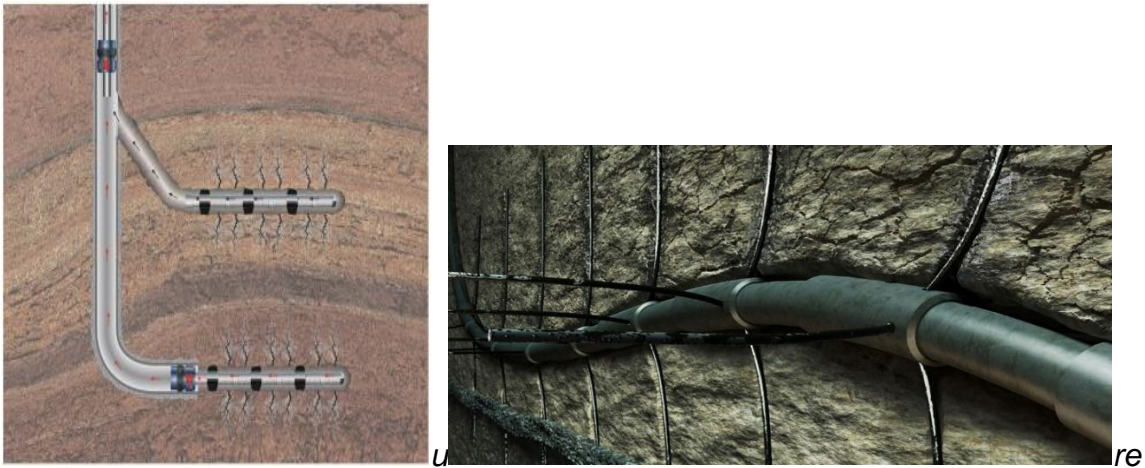

figure 5.1-6: *Left: MLT, Right: Fishbones* (Aker BP, 2020b)

5.2 Asphaltenes/PVT

5.2.1 Asphaltene basics

Asphaltenes are very heavy hydrocarbon molecules whose solubility in the crude oil is dependent on changes in the volume proportion of lighter components in the crude oil. Asphaltenes are not a discrete chemical structure, but rather a hydrocarbon fraction classified by their solubility. Generally insoluble in a low molecular weight alkane and quite soluble in benzene/toluene. Asphaltene content and behavior is dependent on crude oil composition and its corresponding pressure. Asphaltenes may deposit within an oil and gas system at a location mainly determined by the prevailing pressure at that location. Usually, it precipitates out of solution between reservoir pressure and the bubble point pressure (Mullins, Pomerantz, Andrews, & Zuo, 2015). Figure 5.2-1 illustrates the nature of asphaltene precipitation, where it can be seen that – for a given temperature – the asphaltene onset pressure (AOP) is reached somewhere between reservoir pressure and saturation pressure.
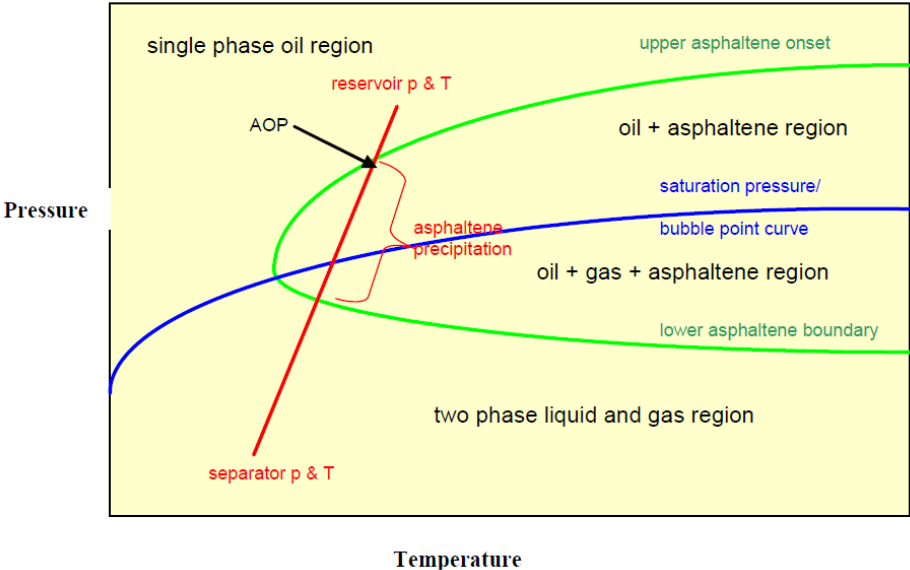

figure 5.2-1: *Asphaltene onset envelope* (Aker BP, 2020)

5.2.2 K-5 A fluid

Bottom hole fluid sample was collected and analyzed. A complete PVT analysis was conducted by an external lab. A geo-chemical study was also conducted which concluded:

"Tambar East field oil was generated by a less mature and slightly more terrestrially influenced kitchen than of the main Tambar field oils. The relatively lower maturity of Tambar East field oil is consistent with its relatively low API gravity and gas oil ratio (GOR)"

Standard PVT analyses were conducted on the fluid sample from K-5 A, including constant mass expansion, differential liberation, single- and multiple stage separation. In addition, a SARA analysis and asphaltene on-set test was also conducted.

The SARA analysis is a method to describe a crude oil compositionally by dividing the components according to their polarizability and polarity. The method divides an oil into its **s**aturate, **a**romatic, **r**esin and **a**sphaltene (SARA) fractions. Saturates and aromatics are non-polar and polarizable respectively, while resins and asphaltenes have polar substituents. This classification is useful since it evaluates the fraction of the oil that is causing asphaltene stability issues/asphaltene problems (Fan, Wang, & Buckley, 2002).

The summary of the SARA analysis conducted is listed in table 5.2-1. The weight percent of asphaltenes is determined to be 1.6 %

table 5.2-1: *SARA analysis*

Saturates	Aromatics	Resins	Asphalthenes
53.0 Wt%	43.1 Wt%	2.4 Wt%	1.6 Wt%

A separate asphaltene content analysis was also conducted on two occasions and showed an asphaltene content of between 2% – 2.5%. There was an indication of an increasing trend, but too few datapoints to conclude.

Yet another method to evaluate the asphaltene risk is to use the De Boer plot, which plots the degree of undersaturation of the Tambar East crude against the density of the reservoir oil. This plot shows crude oil having a high risk of asphaltene deposition in the top left corner of the plot. This method is commonly used to screen crude oils for asphaltene problems. The De Boer plot on figure 5.2-2 illustrates the asphaltene precipitation potential for K-5 A. It clearly shows that K-5 A crude oil falls into the asphaltene problematic region.
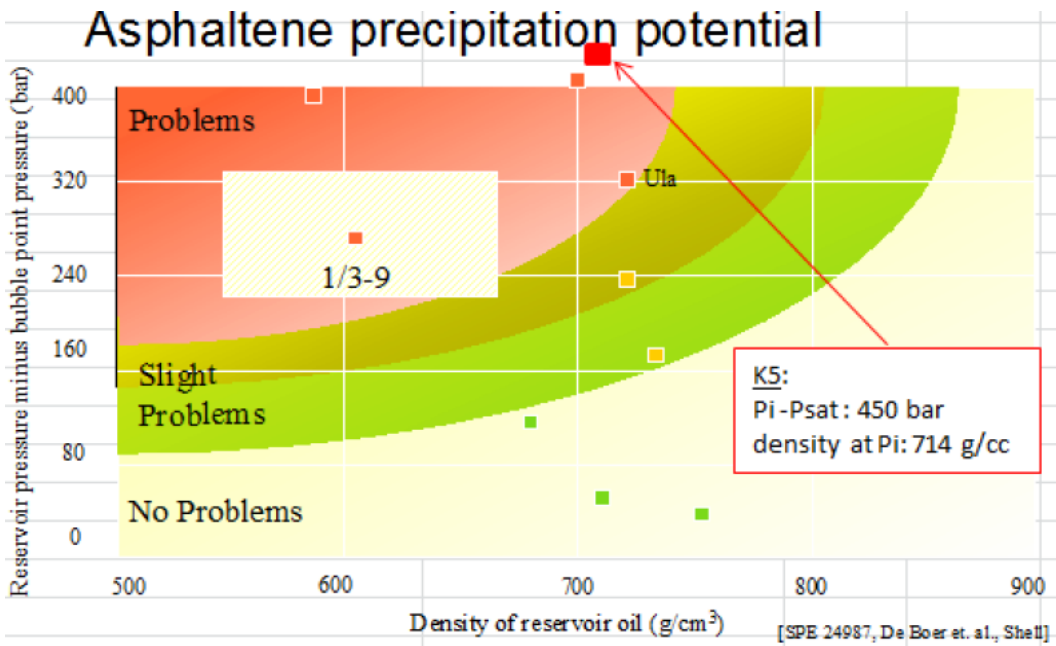
Asphaltene precipitation potential

figure 5.2-2: *De Boer plot*(Aker BP, 2020)

The SARA and De Boer method both confirms that asphaltenes is an issue on K-5 A. Therefore, an asphaltene on-set pressure test was conducted using a spectroscopy that optically detect asphaltene precipitation implicitly as a function of pressure. Figure 5.2-3 shows the graphical determination of the asphaltene on-set pressure (AOP). The AOP is determined as the pressure corresponding to where the kink on the curve is. AOP is read of at 3610 PSI or 249 Bar.

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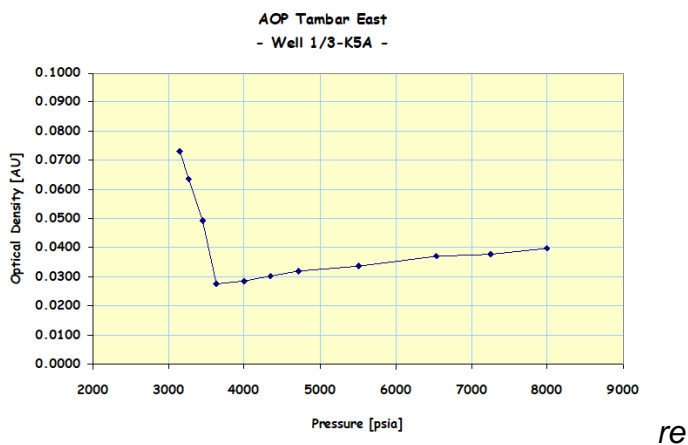
figure 5.2-3: *Asphaltene on-set pressure test (AOP)*

A summary of the key PVT parameters of Tambar East crude oil is provided in table 5.2-2.

table 5.2-2: *PVT and fluid parameters K-5 A*

Reservoir temperature	157 °C
Initial reservoir pressure	594 Bar
Saturation pressure	148 Bar
Density stock tank oil	845 kg/m3 35.9 API
Solution gas oil ratio	845.3 scf/stb
Viscosity @ saturation pressure	0.294 cP
Isothermal compressibility @ reservoir temp and sat.pres	1.933E-05
Asphaltene content	~2%
Asphaltene on-set pressure	249 Bar

It was suggested by BP geochemistry experts that the asphaltene issue was due to gravity segregation, where heavy components could accumulate on the calcite layer that the well rests on. This proposed theory should be investigated further as it could be a potential significant upside for existing well or new sidetrack/new wells.

Asphaltene deposition in the near-wellbore reservoir will cause a reduced permeability, described by an increased skin factor and cause reduced inflow and production rate. Asphaltene precipitation in the wellbore will deposit on the wellbore wall and ultimately reduce the inner diameter of the production conduit. This precipitation is something which actually could be a benefit in the case of low reservoir pressure, where lifting issues would occur otherwise due to liquid loading etc. K-5 A experienced low production rates – normally too low for stable flow with the existing tubing size – but in fact it was able to produce stable most likely due to the asphaltene deposits, thus reducing inner diameter of the tubing.

5.2.3 Asphaltene: Development alternatives

Choosing a development strategy for handling asphaltenes is highly dependent on the extent or magnitude of asphaltene presence in the reservoir. Worst case is that the asphaltene content determined by fluid sample analyses on K-5 A is representative for reservoir fluid in the entire reservoir. Best case would be that the asphaltene is only present in the near-wellbore area of the K-5 A well, trapped against the calcite stringers that the well rests on due to gravity segregation. In the latter case, asphaltene would be a limited problem in time and space. The chosen development strategy should be

a robust solution which properly manages the asphaltene issue. Possible course of actions are presented below.

- Ignore the production rate decline and conduct periodic solvent flushes to restore productivity.
- Deliberately produce the well below bubble point, so that asphaltene solids damage is well away from the wellbore and has little impact upon productivity.
- Accept a decline but conduct period stimulations; usually combination of solvent cleanout and then a squeeze of asphaltene dispersant. The squeeze lifetime is generally not good.
- Install downhole chemical injection line and run the reservoir and well so that onset pressure is below the location where chemicals are injected.
- Develop a chemical package that can be introduced as an asphaltene dispersant via the gas lift system.
- Produce at current conditions until reservoir pressure is close to AOP.
- Use gas lift to shift onset location far into the reservoir.
- Stimulation by hydraulic fracturing, as mentioned in section 5.1.4 for handling compartmentalization, would also be effective for bypassing the asphaltene in the near-wellbore area.

Information gathering: Since the optimal strategy depends so highly on the extent and configuration of the asphaltene presence, further investigations and analyses on the asphaltene issue should be initiated as it is currently a material uncertainty on the performance of the reservoir. Moreover, the asphaltene issue is potentially impacting all other development strategies significantly.

5.3 Reservoir pressure

5.3.1 Tambar East Reservoir pressure

Estimating reservoir pressure is of great importance as the reservoir pressure is the driving force behind fluid production. However, acquiring the correct reservoir pressure of a producing reservoir is challenging and requires, among other things, that the producing wells are shut in while estimating the reservoir pressure. Once the K-5 A well was completed, a wireline logging operation was conducted on it. A formation fluid test called MDT provided PVT data from the virgin formation fluid before commencing production. Further, PVT sampling downhole was taken from the well, as part of a wireline investigation initiated following the underperformance and rapid rate and pressure decline seen in the initial production months. A permanent downhole pressure gauge was installed upon completion of the well, but it failed to communicate to the surface.

Therefore, the two bottom-hole pressure measurements mentioned above (MDT and PVT sampling) from 2007 are the only bottom-hole pressure measurements available. Other available pressure measurements taken are from long lasting shut-in tubing head pressure measurements (THP) taken at the wellhead(surface), where fluid gradients are used to calculate downhole pressures. Long shut-ins are required to allow the well and reservoir pressure to equalize and thus approximate true reservoir pressure. The required shut-in period is depending on reservoir size and permeability, i.e., the pressure wave propagating through the reservoir. To find the appropriate gradients in the well, echometer surveys which can detect the liquid level in a shut-in well was frequently used to reduce the gradient uncertainty included in bottom-hole pressure calculations.

 As previously mentioned, Tambar East is producing by primary pressure depletion with no effort to maintain the pressure. The pressure is declining as fluid is produced from the reservoir, and with the compartmentalization previously described the pressure decline is bigger than expected from a reservoir of such a size. Pressure analysis and estimations are of great importance and consumes a lot of time in a subsurface team. Moreover, pressure measurements are associated with some uncertainty and interpretations. Figure 5.3-1 displays initial pressures and gradients in wells in the Tambar area, including the 1/3-K-5 well on Tambar East. It shows that the

two Tambar East wells 1/3-K-5 and 2/1-10 have similar pressures, even though they are 15 years apart (highlighted by red frame). It proves that production and depletion on Tambar main has not affected Tambar East, i.e., Tambar East is a separate compartment and not in communication with Tambar main.
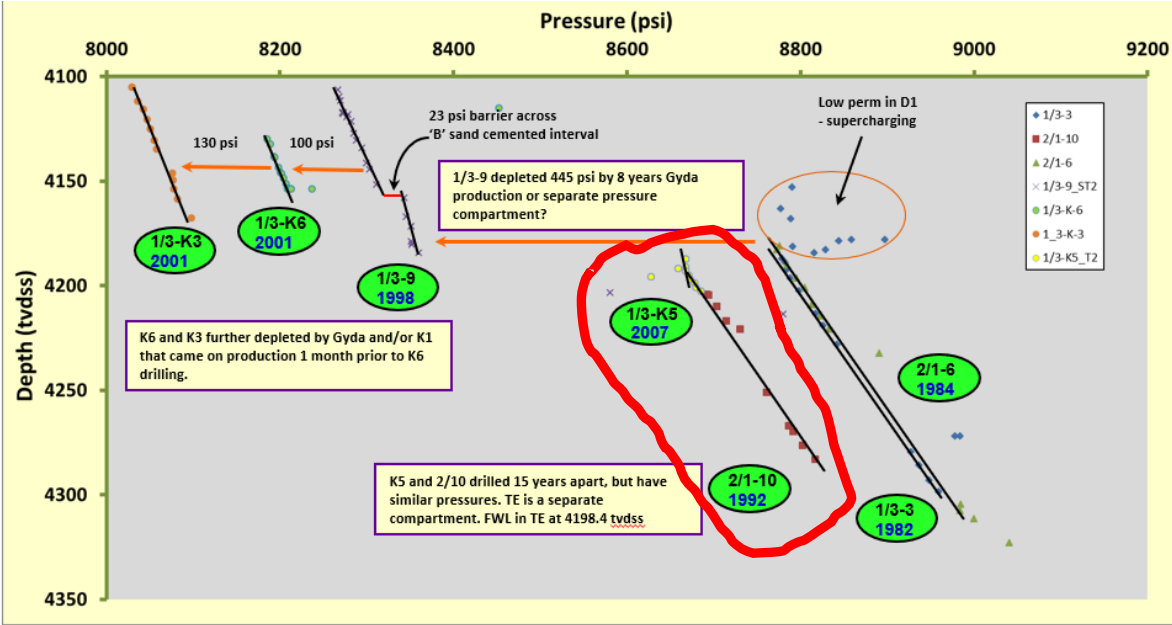

figure 5.3-1: *Tambar pressure history*

5.3.2 Pressure analysis

As mentioned above, the available pressure data from the well during production is wellhead data only. Calculations are needed in order to transform the data to bottom-hole data, and then from bottom-hole pressures to estimates or approximations of the reservoir pressure by pressure transient analysis. Several software tools are available for that purpose and BP historically used a tool called PIE. Figure 5.3-2 shows the analyzed reservoir pressures during the first couple of years of production for the well K5-A, with uncertainty represented by separate datapoints. According to these estimates, the reservoir pressure decreased by almost 3000 PSI/207 Bar during two years of production, which is substantial and higher than expected.
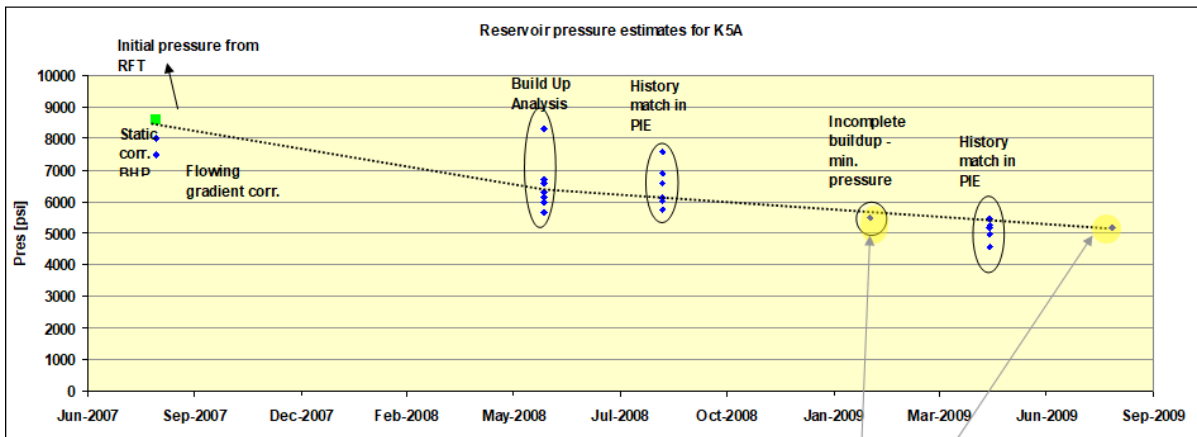
figure 5.3-2: *Reservoir pressure estimates for K-5 A*

Separate analyses were conducted by field partners and it is provided by the plot on figure 5.3-3. The plot contains data about the bubble point pressure, asphaltene onset pressure and estimated bottom-hole pressures (estimated from tubing head pressures)
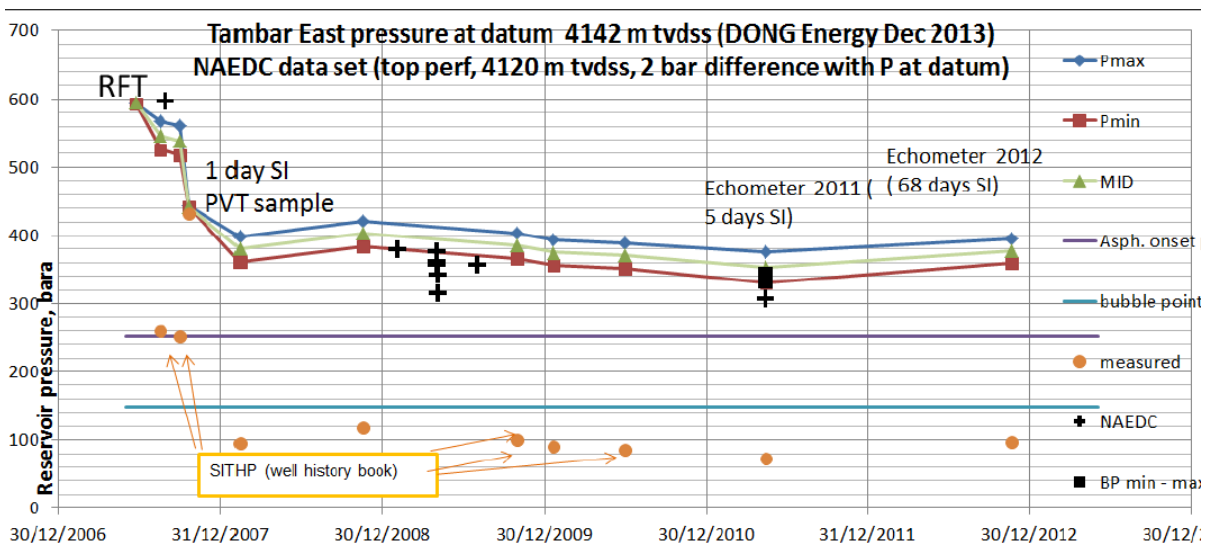

figure 5.3-3: *Tambar East bottom-hole pressures*

The last echometer survey was conducted in 2012, it measured a shut-in wellhead pressure of 97 bar after about 68 days of shut-in. The liquid level was found at 83mMD RKB which provided an estimated reservoir pressure range of 385 – 406 Bars at 4200 mTVDSS. Between 2012 and 2017 quite few pressure analyses were conducted, but when the flowline on K-5 A was used for another Tambar main well in 2017, a plan was developed to run wireline surveillance and plug K-5 A. As part of that surveillance plan, the reservoir pressure was estimated from shut-in tubing head pressures. The pressures were estimated at 4127 mTVD RKB after long shut-ins and the uncertainty

60

in pressure gradients and measurements are reflected in the confidence interval. (0.06 Bar/m gradient and ±0.005 Bar/m gradient uncertainty) Table 5.3-1 summarizes those reservoir pressure estimates.

table 5.3-1: *Estimated reservoir pressures*

When	Est pressure [Barg]	Confidence interval [Barg]
August 2017	360	±35
April 2018	360	+65/-35
May 2018	386	±20
October 2018	400	±20
May 2019	403	±20
July 2019	403	±20

5.3.3 Low reservoir pressure: Development strategies

As previously mentioned, the well is currently plugged, and flowline is used for another well on Tambar due to the high backpressure on Tambar. When dealing with the declining reservoir pressure there is usually two obvious choices: artificial lift (gas lift) and water injection.

Artificial lift: Gas lift adds energy to the wellbore by injecting gas downhole to reduce the average density of the produced fluid, thus reducing the gravity pressure drop when lifting the fluid from downhole to the surface. This would allow the well to produce at lower reservoir pressure and increase the wellhead pressure. Gas lift was installed on Tambar as part of the Tambar artificial lift project in 2018. Moreover, the main issue with the current development concept is the high backpressure from Tambar, arising from the other Tambar main wells. Therefore, gas lift would allow Tambar East to produce with higher backpressure. Gas lift could also be part of an asphaltene mitigation strategy as described in chapter 5.2.3.

Water injection: Water injection is frequently used as an increased oil recovery (IOR) method to improve the sweep of the reservoir and maintain the original reservoir pressure. Water injection requires drilling of injection wells and a water handling system. Water injection on Tambar East needs to be evaluated as part of a bigger water injection strategy on Tambar main, which is currently not installed. Water injection requires major modifications on the Ula and Tambar installation. Moreover, the formation water on Tambar and Tambar East is extremely challenging from a

production chemistry perspective, and it contains a very high concentration of barium ions, which is incompatible with the injected seawater. Barium ions react with sulphate ions in seawater and precipitates in the reservoir and wellbore as Barium-Sulphate. A separate water treatment/sulphate removal facility needs to be installed prior to commencing water injection. Evaluating water injection quantitatively is beyond the scope of this work since it needs to be analyzed for the entire Tambar area.

Time: The relatively low reservoir pressure on Tambar East is currently too low with the prevailing backpressure from the Tambar facility. However, the producing Tambar main wells experiences a pressure decline with time and thus eventually the backpressure will be reduced to manageable levels for K-5 A, enabling it to produce.

6 Uncertainty management

6.1 Tambar East

Prior to drilling the production wells, the material subsurface uncertainties were identified as the Oil-water-contact (OWC), the reservoir pressure and whether the petroleum system had provided sufficient hydrocarbon accumulations into Tambar East reservoir. By drilling the well K-5 A, the previously identified key uncertainties were significantly reduced. Initial wireline-pressure measurements taken proved un-depleted reservoir pressure and the OWC was determined by well logging. Well logging also indicated a substantial column of oil-bearing formation, i.e., reducing the uncertainty of the petroleum system. These material subsurface uncertainties were crucial to the initial green field development analyses that were conducted, and for the decision on whether to develop the field or not.

The material uncertainties of Tambar East changed when transitioning from a green field- to a brown field development. This reinforces the importance of managing the uncertainty in such a way that it is focusing on the important uncertainties which might affect the decision making, at the given time in the field development project. Moreover, reducing the number of uncertainties to manageable levels is crucial for a proper decision analysis. One should ask the question: How could this uncertainty influence the payoffs of the chosen objectives for the project?

Determining the candidates for main subsurface uncertainties, post drilling, that could affect decision making is partly a subjective exercise. Informal interviews with engineers engaged with Tambar East concluded that the main uncertainty is related to the degree of compartmentalized structure of the reservoir and the extent of the asphaltene presence in the reservoir fluid. The material uncertainties emerging from the interviews are structured in an uncertainty table 6.1-1. The uncertainty table is a useful tool to structure the key uncertainties, their potential for decision changing and which information sources to exploit for a sensible reduction of the uncertainties. These material uncertainties should feed into a base case deterministic analysis to determine their impact on the chosen objective.

table 6.1-1: *Uncertainty table*

Key uncertainties	Fault block connectivity/compartmentalization	Degree of asphaltene presence in the reservoir	Reservoir pressure	Calcite stringers severity
Future decisions which could change	Re-vitalize TE or permanently plug it? Re-development concept? Infill well or improve existing well? Number and type of wells? Employ advanced technology such as multilateral and Fishbones?	Mitigation strategy? Inhibition or intermittent treatment? Project stopper or alternative solution? Drill pilot well prior to new wells? Do nothing or act?	Primary depletion or add energy to sub-surface (artificial lift or water injection)? Project stopper or mitigating solution? Field lifetime? Tambar facility capacity?	Well placements? Deviated drilling through it impossible? Stimulation of existing well?
Information sources to consider	4D seismic Appraisal and observation well Pressure transient analysis for reservoir boundaries Well logs Static reservoir model	Specific Asphaltene modeling Vertical segregation theory Appraisal well Pilot well Updated well fluid samples	Wireline intervention, pressure measurements Appraisal well Pilot well	Experience gathering Well logging Calcite stringer modeling Appraisal well Pilot well

6.2 Aker BP

The importance of embracing uncertainty in the field development process has been elaborated in the previous chapters. This section will briefly evaluate how Aker BP incorporates uncertainty into the organization and the analyses being conducted. Aker BP has a reference document called "guidelines for uncertainty analysis in field development". This document is considered a "best practice" document and states that the recommended methodology for handling uncertainty in Aker BP is a workflow that enables probabilistic forecasting. Discipline experts working on each of the phases in a field development project usually have a good understanding of uncertainties within their discipline, even though the quantifying part is quite often challenging.

Moreover, it is commonly a big challenge to transfer uncertainty from one discipline to another, instead of deterministic input data. The uncertainty might evaporate in the process, ending up at the decision makers table as solely deterministic data. Aker BP aims to promote good communication and transparency of uncertainty, both between disciplines and between different development phases. Much of the philosophy on uncertainty in the guidelines document is inspired by Bratvold & Begg (2010), as is the uncertainty section 2.3 in this project thesis. The reference document also states that decisions in Aker BP is made on P50 values (median) and not mean, which is aligned with reserves reporting.

Good communication across the company requires a common understanding of terms. According to the guidelines document, uncertainty is defined in Aker BP as: "a lack of knowledge that prevents the precise determination of either the current state or a future outcome" Moreover, the document doesn't make the same distinction between uncertainty and risk that was covered in section 2.3.1 as proposed by Bratvold & Begg (2010). Risk is defined as: "a circumstance that can happen which has consequences for something of value to us, and it is the effect of uncertainty on objectives". In other words, risk is used for both the potential downside and upside of uncertainty. Replacing risk, as it was proposed by Bratvold & Begg, is the word threat. Figure 6.2-1 illustrates these terms as they are being used in Aker BP.
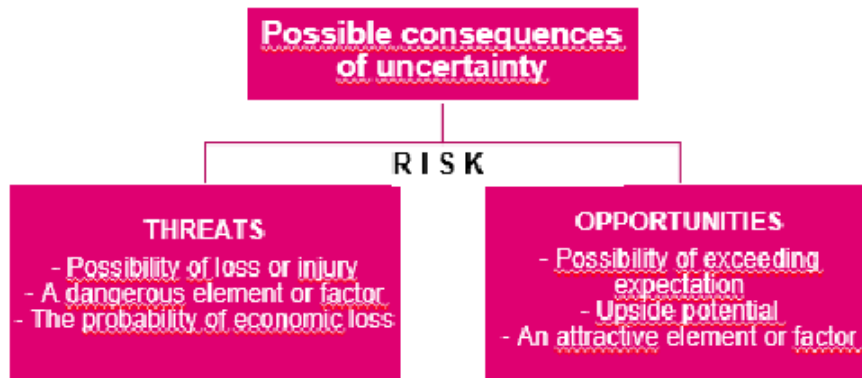
figure 6.2-1: *Uncertainty terms in Aker BP*

A consistent use of uncertainty related terms is highly recommended across the entire corporation Aker BP, and ideally between companies that Aker BP works in alliances and partnerships with. The impression is that Aker BP wants to embrace uncertainty and implement it fully into the analyses being conducted, but they are – similar to other E & P companies – not there yet. The extent of uncertainty and probabilistic modeling being used varies from business unit to business unit.

6.3 Uncertain times

The thesis work on Tambar East was initiated in fall 2019. Tambar East had been a rather low priority project since 2014 due to several difficulties. However, it was decided to conduct analyses on Tambar East and assess its potential for re-vitalizing it. At the time, the Brent Crude oil price – which is predominantly used for oil price on the NCS – was floating around 60 USD per barrel. As we all now, the first quarter of 2020 was an extraordinary quarter in many aspects. The Covid-19 situation and the coinciding sharp drop in global oil prices caused previously established truths about the industry to vaporize. Aker BP as a company responded to the situation by significantly altering their investment program. At the company's capital markets update in February 2020, it was informed that the company are putting all non-sanctioned field development projects on hold and postponing several exploration wells (Aker BP, 2020a).

Obviously, this affects Tambar East as well as other projects. A reduction in oil price from 60 USD to well below 30 USD is affecting most field development projects, and it shows the importance of including material uncertainty in the analyses. The oil price is quite often a material uncertainty that is highly volatile and almost impossible to predict

with any accuracy. However, the analyses should still contain calculations including the uncertainty of the oil price, or rather a stress-test of how low oil price the project can handle and still create value. An in-depth analysis of the oil price uncertainty will not be part of the thesis scope, but some initial considerations were included for context purposes.

7 Tambar East objectives

7.1 Objective setting

Values and objectives setting are the responsibility of executive management and decision makers. The objectives or decision criteria in a company could vary from project to project and with time. Companies could also vary how they prioritize, e. g. growth or value creation. Keep in mind that the objectives have two main applications: to assist in identifying good alternatives, but equally important to help in choosing between alternatives (Bratvold & Begg, 2010).

7.2 Value hierarchy in Aker BP

Aker BP is a public company with a focus on maximizing shareholder value. Figure 7.2-1 shows a modified value hierarchy for Aker BP. The hierarchy on the left is the one currently used in decision making for field development/investment analysis in Aker BP. On the right hand side, a proposed value hierarchy that honors the value hierarchy structure described in chapter 2.4. It includes non-monetary objectives such as safety and reputation, as well as information about the economic risk profile of the decision makers. Attributes and scale for the different objectives is provided, together with weights or relative preference for each objective. The proposed value hierarchy should be considered food for thought for executive management and decision makers in Aker BP.

The proposed value hierarchy introduces some challenges. If "Maximize recovery/added reserves" is one of the attributes, then at some point, increasing reserves on a specific field will be a money losing activity, but if the goal is to maximize reserves, it must be assumed that the company would be willing to lose money to do so. Moreover, "Minimize economic risk" – the best way to achieve this is to never develop a field. Minimizing NPV < 0 will often lead to reduced E(NPV) (and value creation). Therefore, "maximize recovery" and "minimize economic risk" should not be used as a sole objective but instead as a weighted factor, as part of several objectives, including NPV.

In addition to the value hierarchy, you could add constraints or stress tests such as a maximum break-even oil price or minimum internal rate of return (IRR). I propose that

the constraints that are highly correlated and inferior to NPV, should not be used as objectives on its own.
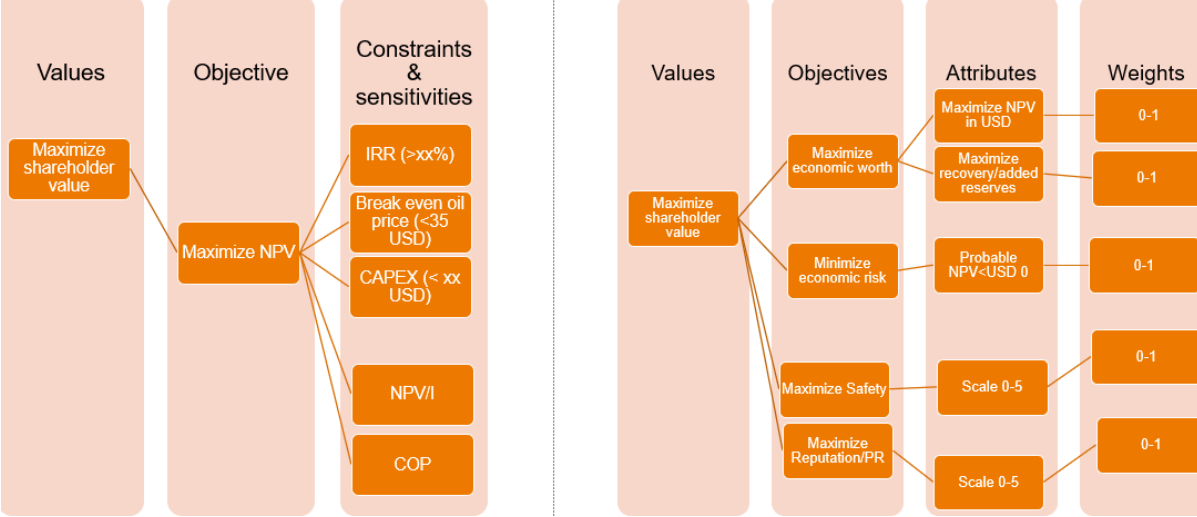

figure 7.2-1: *Value hierarchy in Aker BP*

It is highly recommended that such a value hierarchy should be clearly communicated across every company so that there is no doubt in what the company wants to achieve and how it prioritizes. This applies to all employees involved in the business, not only the decision makers. All members of a decision driven organization should know which direction it is going, how it will get there and how it will be evaluated, without any hidden agendas or biases.

In the context of this thesis, the non-monetary objectives of safety and reputation will not be further evaluated but still included in the proposed methodology framework.

The objectives that will be used for the decision modeling are:

- Maximizing expected net present value, E(NPV)
- Maximizing recovery, added reserves
  Minimizing economic risk (NPV<0)

8 Strategy development

8.1 Key value drivers, impact and alternatives

In this section, impact and alternatives for the key value drivers of Tambar East will be introduced and discussed methodically. First, a quick summary of the main reservoir problems presented in previous chapters:

- Lateral compartmentalization
- Vertical compartmentalization
- Asphaltene prone oil
- Low reservoir pressure
- Facility capacity constraint

As part of the annual reporting to RNB, the identification of the most obvious condition that could stop project implementation is requested information. The conditions are called project stoppers by the NPD (2020a) – the project stoppers are listed below and underlined project stoppers are applicable for Tambar East field development

"None, <u>uncertainty in resource volume</u>, <u>reservoir properties</u>, technology lacking, lack of infrastructure in the area, no gas solution, <u>lack of capacity in existing systems</u>, no commercial agreement, rig availability, environmental requirements, HSE requirements and other".

The key value drivers listed above, that were thoroughly analyzed in the previous chapters, needs to be addressed in order to revitalize Tambar East fully. Engineering solutions needs to be implemented to mitigate the negative effect the problems have on the objectives for Tambar East, but equally important is it to exploit the upside potential that lies within these value drivers, hence the name. Table 8.1-1 provides the framework of the value drivers, their impact on value creation and mitigating development alternatives.

Table 8.1-1: Key value drivers, impact and alternatives

Problem	Lateral compartmentalization (Faults)	Vertical compartmentalization (Calcite stringers)	Reservoir fluids(asphaltenes)	Low reservoir pressure	Facility constraint
Impact	Poor drainage with conventional wells →contacts small fraction of STOOIP → Large pressure drop and reduced production rate → reduced lifetime of well → Lower NPV and recovery	Drainage and inflow to well significantly inhibited → complicates deviated drilling → reduced production rate → reduced lifetime of well → Lower NPV and recovery	Reduced permeability of reservoir and size of production conduit → Pressure management → Choking back production lower production rate → Lower NPV and recovery	Declining reservoir pressure → declining production rates → lifting issues and backpressure → Shut in → No production → currently no contribution to NPV and no incremental recovery	Due to underperformance from other 4 problems the well is shut in and plugged → No contribution to NPV or incremental recovery
Alternatives	- Infill well - Sidetrack - Multilateral - Fishbone - Multilateral fishbone	- Hydraulic fracturing - Infill well - Multilateral - Fishbone - Multilateral fishbone	- P & T management - Inhibitor injection - Solvent stimulation - Gas lift - Hydraulic fracturing	- Water injection - Gas lift - Time	- Re-prioritize slots on facility - Subsea template

8.2 Strategies

Based on the value drivers, impact and alternatives presented on the previous table, several strategies for Tambar East were developed. The strategies should be significantly different. McNamee & Celona (2008) states that there are a couple of common problems when developing these strategies. Firstly, avoiding tunnel vision is crucial, where the analysts only evaluates a few fundamentally similar alternatives. This could be solved by conducting creative group exercises when developing these strategies. No analysts should conduct the strategy development in isolation. Another common problem that arises in finding these strategies is the complex nature and multiplicity of the alternatives. Choices must be made in several decision areas, and they each have a set of possibilities. This could easily grow out of manageable proportions. McNamee & Celona (2008) proposes to limit the strategies to three to five different alternatives to make it feasible. Five different strategies were developed for evaluation of Tambar East brown field development:

1. **Fix/improve existing well**
   - <u>Rationale</u>: Low cost alternative, reduce risk of over-capitalizing
   - <u>Objective</u>: Allow the well to come back on stream
2. **Conventional infill well(s)**
   - <u>Rationale</u>: Already perforated formation is drained and locally troublesome.
   - <u>Objective</u>: Drain other parts of the reservoir, laterally or vertically.
3. **Advanced completion infill well(s) (e.g. MLT)**
   - <u>Rationale:</u> Reservoir is heavily compartmentalized, conventional wells of limited drainage potential.
   - <u>Objective:</u> Drain larger portion of the reservoir with multilateral.
4. **Phased development**
   - <u>Rationale:</u> Project is low priority at the unfavorable prevailing economic conditions.
   - <u>Objective:</u> Analyze, understand and interpret reservoir without committing capital resources. Information gathering and flexibility implementation.
5. **Ambitious development**
   - <u>Rationale</u>: Exploiting the potential upside of the Tambar East uncertainty.

- Objective: Develop Tambar East with "all means" available, including water injection and EOR

A useful tool to identify the alternative strategies is the strategy table. It is a convenient way to clearly define and structure the alternative strategies. Moreover, it is also a powerful and visual communication tool within the project organization and on the decision makers level (McNamee & Celona, 2008). The strategy table consists of columns with decision areas and possible choices listed down the rows in each column. One complete strategic alternative can then be extracted by connecting the different decision alternatives into a strategy thread. One strategy thread represents a set of actions that should fit together. The strategy table has an iterative nature and it might very well be that new hybrid strategies appears after such an exercise (Decision Nodes, 2020). Strategy table 8.2-1 shows the proposed strategy threads for Tambar East development. In the specific example – the strategy tread 2: conventional infill well is highlighted. The decisions made in each decision area are indicated by a colored number box. The strategy table is not a quantitative tool, but once you get familiar with it, it's an effective way of applying intuition and experience to a rather complex situation. Moreover, the strategy table can be used to eliminate most of the possible strategies that are considered inconsistent, inferior or undesirable (McNamee & Celona, 2008).

table 8.2-1: *Strategy table for Tambar East*

Strategy		Drilling & wells		Asphaltene treatment		Artificial lift		Information & appraisal		IOR/EOR		Slot constraints	
Fix/improve existing well	1	Multilaterals	3 / 5	Inhibition	2 / 3 / 5	Install gas lift	2 / 3 / 5	Appraisal well		Water injection or EOR	5	Re-prioritize slots	1
Conventional infill well(s)	2	New well or sidetrack	2	intermittent treatment		Consider gas lift	1	Value of information/Value of flexibility	1 / 2 / 4	Evaluate water injection/EOR	1 / 2 / 3	Increase capacity	2 / 3 / 5
Advanced completion infill well(s) (E.g. MLT)	3	Hydraulic fracturing	1	P & T constrained	1	None	4	New technology R & D(E.g. Fishbones)	3 / 5	Time	4	None	4
Phased development	4	None	4	Information gathering	4			None		None			
Ambitious IOR development	5			None									

Highlight strategy	2

The output of the strategy table is the desired strategy threads which represents the strategy alternatives that feeds into the decision modeling. Moreover, the provided strategies above is a major output from the front-end-analysis, i.e. the framing and structuring part of the decision analysis.

9 Tambar East decision modeling

Thus far, the main focus has been on the structuring phase of the decision analysis process, as described by Bratvold & Begg in section 2.4. In other words, the frond-end analysis is completed – focusing on understanding the decision at hand, its value and uncertainty drivers. The Tambar East development project now has been structured with clearly defined objectives and a set of creative and useful strategies to be evaluated. However, the decision analysis methodology is iterative in nature and it might be useful or necessary to go back to the framing part and re-do some of that work after conducting the decision modeling. Perhaps some added value drivers and material uncertainties appears and requires some extra attention.

This part covers phase 2 and 3: Modeling and evaluation of the project, as well as conducting a sensitivity analysis. In case of multi objective decision making – a weighing of the objectives is part of this phase. The payoffs for different objectives and strategies will be calculated, assessed and compared. This phase will comprise deterministic and probabilistic modeling. It will use visualization tools such as influence diagrams, decision trees, tornado/sensitivity plots and probability distributions. The calculations and evaluations conducted in this section will serve as a framework and exemplified way of conducting the analyses. The deterministic and probabilistic modeling was conducted on one of the chosen strategies: Strategy 2-conventional infill wells, as an example of how it could be done.

Modeling how technical reservoir parameters are affecting the value creation or the reserves, requires the use of advanced reservoir simulators and tailored software. Industry standard software such as Petrel, Eclipse and ResX would be able to handle this uncertainty estimations and quantifications, but the use of these programs is outside the scope of the thesis. Accessing real data on uncertainty quantification of the reservoir proved to be unrealistic to achieve within the time window available for this thesis. Therefore, suitable Excel models were constructed instead, with necessary assumptions and simplifications implemented. Some of the input parameters used are correct and up to date, while others are constructed and assumed. In lack of a reservoir simulator or complex modeling tools, several of the reservoir properties have been given a normalized scale to allow for use in the Excel model. The input parameters used is listed in table 8.2-1.

table 8.2-1: *Modeling input parameters*

Parameter	Unit/attribute	Low	Base	High
STOOIP, field	MM bbl	46,5	51,6	67,3
STOOIP, perforated faultblocks	MM bbl	18,9	20	22,3
Fault block connectivity	scale, 0-1	0,4	0,5	1
Asphaltene presence	scale, 0-1	0,5	0,6	0,9
Calcite stringer severity	scale, 0-1	0,4	0,5	0,8
Reservoir pressure	scale, 0-1	0,9	0,95	1
Poroperm	scale, 0-1	0,45	0,5	0,9
Oil price	USD/bbl	20	40	60
CAPEX	MM USD	35	38	45
OPEX/COP	USD/bbl	8	12	17
Reserves	MM bbl	1,79	2,86	4,14
Discrete probabilities	Swanson's rule, %	30	40	30
Discount rate	10 %			
Risk profile	Neutral			
Future field-lifetime	10 years			
Cont. distr reservoir parameters	triangular distributions			

9.1 Tambar East influence diagrams

In chapter 2.3, the influence diagram was introduced. It can be configured in many ways and degrees of complexity. Figure 9.1-1 shows an influence diagram for Tambar East development that is illustrating the complexity of the development decision context. Uncertainties are given by the red circle nodes, decisions by green squares nodes and objective/criteria in blue diamond node. "Maximize recovery" was chosen as the objective for this influence diagram on Tambar East. The uncertainties identified in chapter 6 as the key uncertainties or material uncertainties are bigger in size for visualizing purposes. The arrows indicate dependencies between objects.
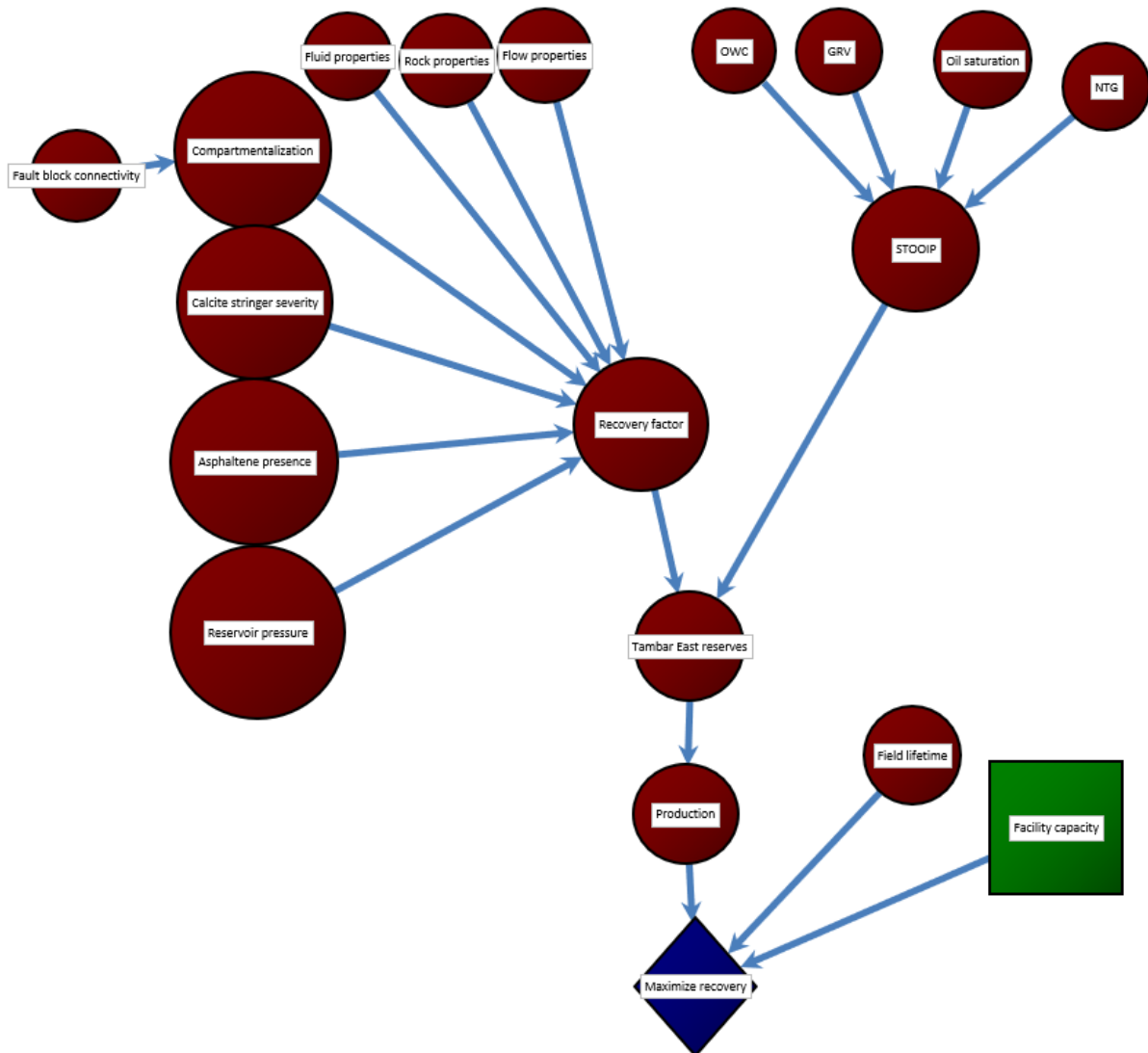
figure 9.1-1: *Influence diagram Tambar East Brown field development*

The influence diagram used as foundation for probabilistic modeling should be simplified by excluding non-material uncertainties. Many of the nodes in figure 9.1-1 were not included as explicit variables in the probabilistic analyses. However, a complete influence diagram encourages systematic thinking about all the uncertainties involved. (McNamee & Celona, 2008) Moreover, which uncertainties that are material will change as a field development progresses. In the Tambar East field development, it was observed that uncertainties related to reservoir volumes (STOOIP) were identified as material uncertainties for green field development, while other uncertainties were determined as material uncertainties for brown field development

A simplified influence diagram for the Tambar East brown field development was designed, focusing on the material uncertainties and corresponding decisions.

Economic parameters such as operating expenditures (OPEX), capital expenditures (CAPEX) and oil price was also included since the objective in this case was the expected net present value E(NPV).   Figure 9.1-2 shows that simplified influence diagram, same notation and symbols used as in figure 9.1-1
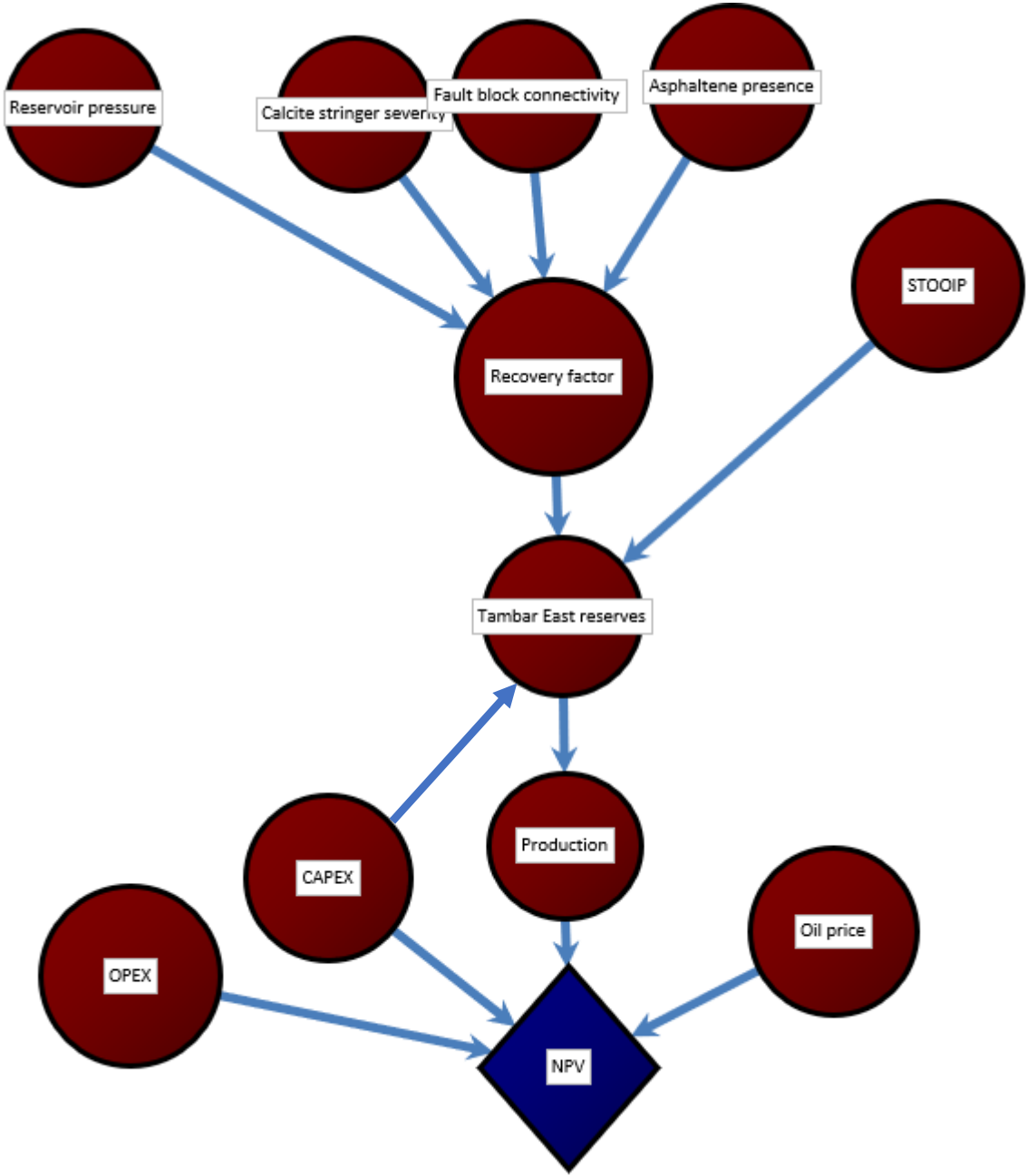
figure 9.1-2: *Simplified Influence diagram for Tambar East brown field development*

9.2 Deterministic/base case modeling

The proposed key uncertainties in chapter 6 was modelled by a base case deterministic model to determine which uncertainties has the biggest impact on the objective. Figure 9.2-1 shows the output of a sensitivity analysis on strategy 2: infill well, illustrated by a tornado chart. NPV in MM USD is the metric objective and each uncertainty has a green downside and purple upside. Low and high values (P10 and P90) was used for each uncertainty. From this analysis and chart, it was concluded that "STOOIP" and "reservoir pressure" were not material uncertainties, i.e., uncertainty drivers. Since a change in them only caused a slight change in the objective.

Moreover, according to this analysis it seems like there could be a substantial upside potential with several of these material uncertainties. Poroperm, i.e., porosity and permeability, also have a substantial upside. Generally, the porosity and permeability were not indicated as material uncertainties initially, however, this analysis concludes that it should indeed be included as a material uncertainty. This is an example of the iterative nature of the decision making process. We should revert to the front-end-analysis and re-evaluate with respect to the porosity and permeability of the reservoir, since it seems to be a highly material uncertainty.
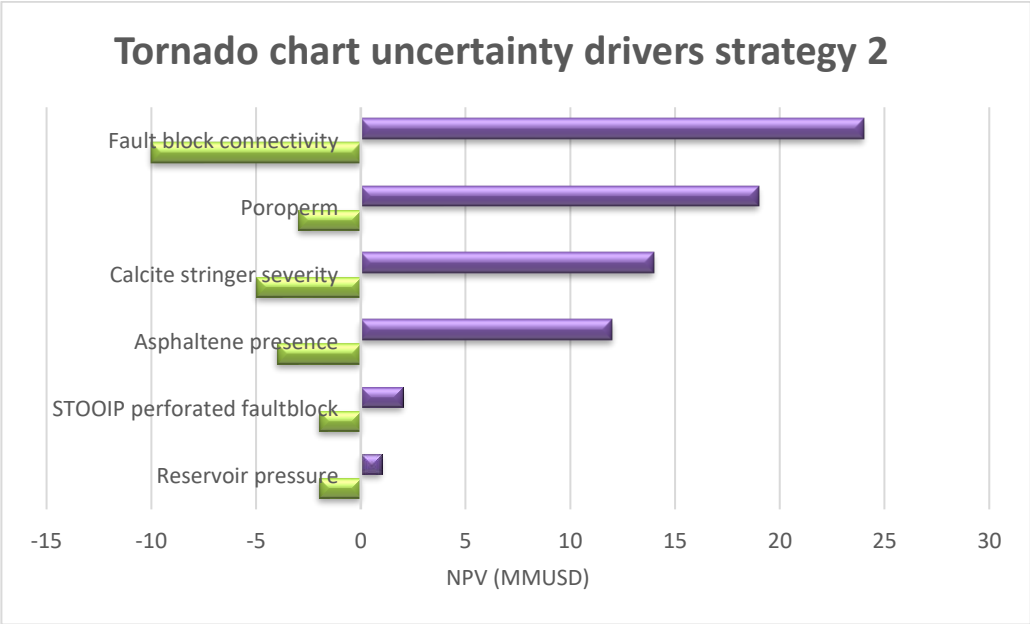
figure 9.2-1: *Tornado chart strategy 2*

Similar sensitivity analysis could be conducted for each development strategy (1 & 3-5) to determine the material uncertainty for each strategy. The material uncertainties

should then be included in the decision tree probabilistic analysis or evaluated with a probabilistic Monte Carlo approach.

9.3 Probabilistic modeling

In probabilistic modeling one can use a discrete probability distribution and decision trees to calculate the expected monetary value, more specifically the expected net present value (NPV). A more thorough approach is to do a Monte Carlo simulation where all the input parameters is assigned a continuous probability distribution (e.g. normal, log normal, triangular or uniform distribution) and many iterations (1000) are performed

9.3.1 Monte Carlo simulation, reserves

For Tambar East brown field development, a probabilistic Monte Carlo approach was chosen to quantify the Tambar East reserves. Each reservoir parameter was assigned a triangular distribution (minimum, most likely and maximum value). The software tool @Risk was used to perform the simulations (add-inn to Excel). Figure 9.3-1 shows the output of the Monte Carlo simulation using 1000 iterations. The Tambar East reserves is visually presented as a probability density distribution (PDF). The mean is 2.86 MM bbl with a standard deviation of 0.97 MM bbl. The P10 and P90 values is provided on the plot as 4.14 MM bbl and 1.79 MM bbl respectively. The key output data is also provided under the statistics table to the right of the PDF.
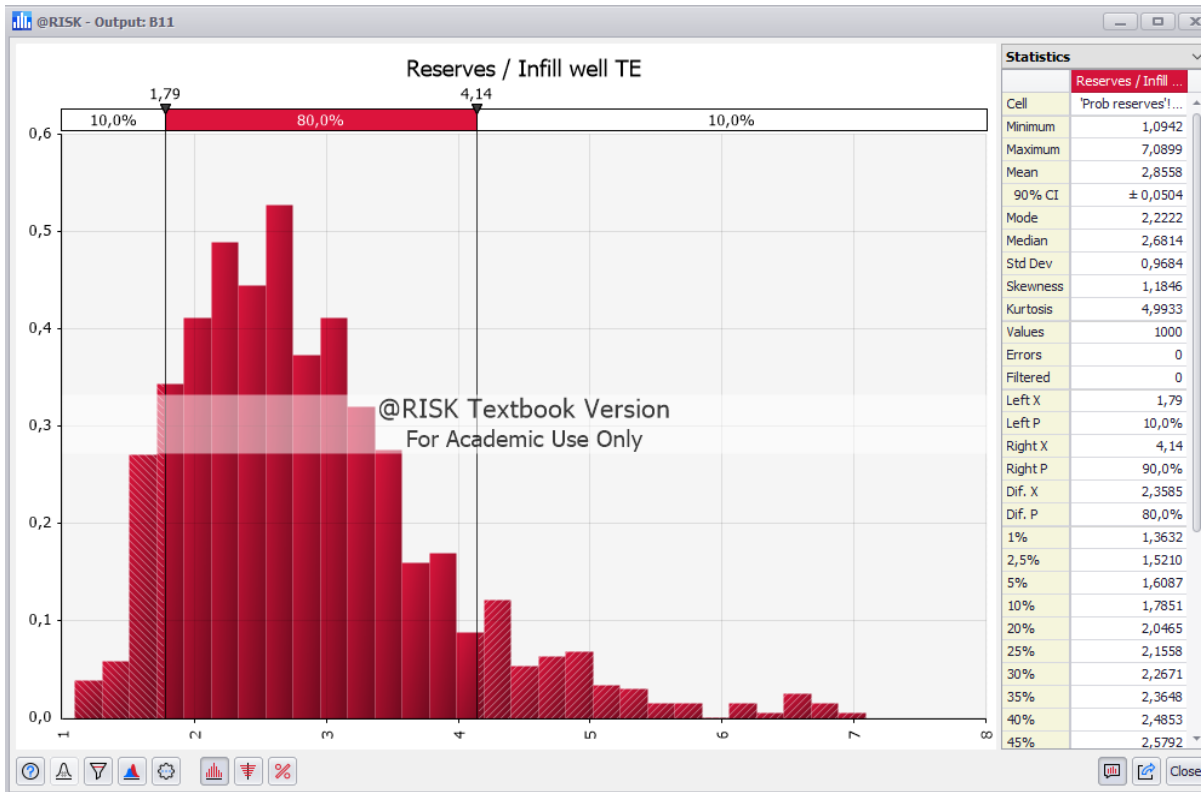
figure 9.3-1: *Reserves probability density distribution strategy 2*

A tornado chart was also generated as part of the simulation output and the figure 9.3-2 below shows how the uncertainties impact the reserves. It was observed that the ranking of these uncertainties was agreeing with the sensitivity analysis-tornado chart from the deterministic analysis in chapter 9.2. As an example, according to this chart, the potential upside of the uncertainty regarding the fault block connectivity is 1.16 MM bbl
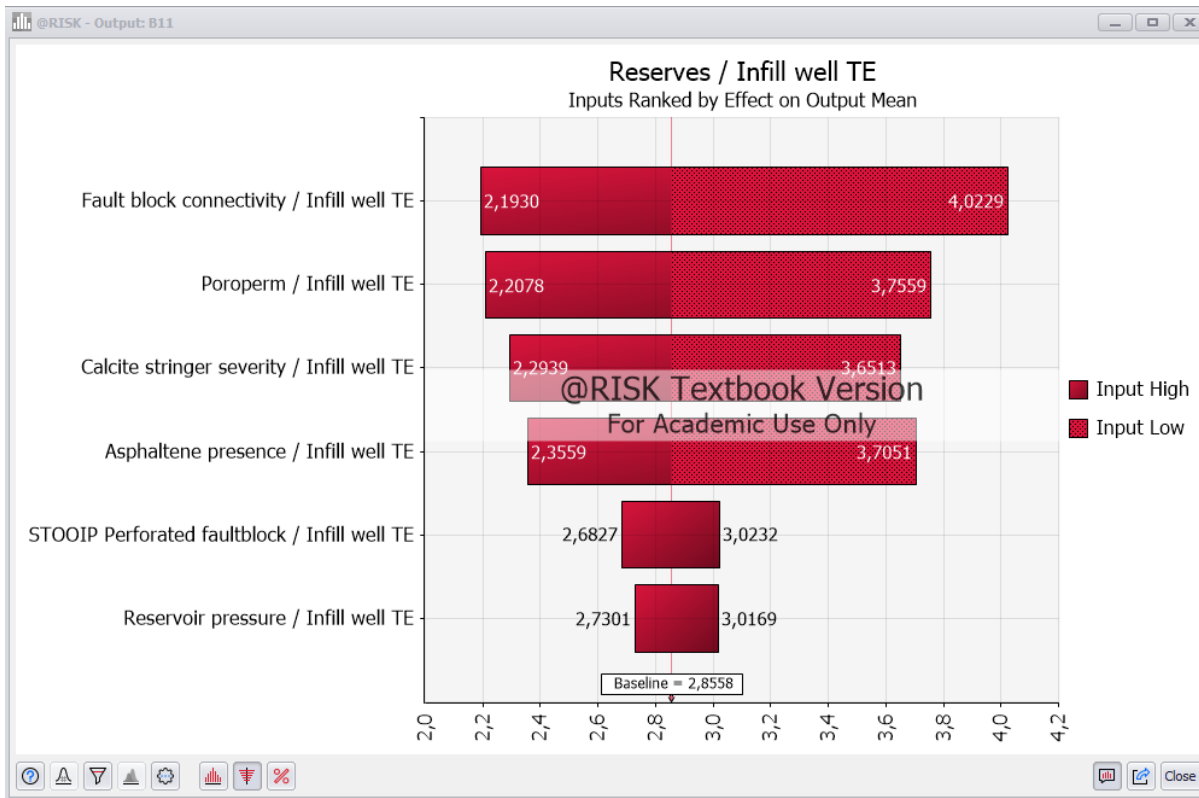
figure 9.3-2: *Tornado chart, reserves sensitivity*

Another commonly used sensitivity analysis chart is the spider chart which shows how the objective changes as the various inputs changes with a given percentage. Figure 9.3-3 illustrates that for the simulation of reserves on Strategy 2. Obviously, the results of the tornado chart agree with the spider chart, but the graphical representation is different. It is obvious by evaluating the spider chart that the STOOIP uncertainty, represented by the yellow curve, is not able to change the output objective drastically as we see the gradient of the yellow curve is very low.

The probability distribution of the Reserves for strategy 2 serves as input to a probabilistic analysis on the objective NPV using discrete distributions and decision trees. A decision tree can quickly grow out of manageable size, therefore only material uncertainties should be included as chance nodes with separate branches.
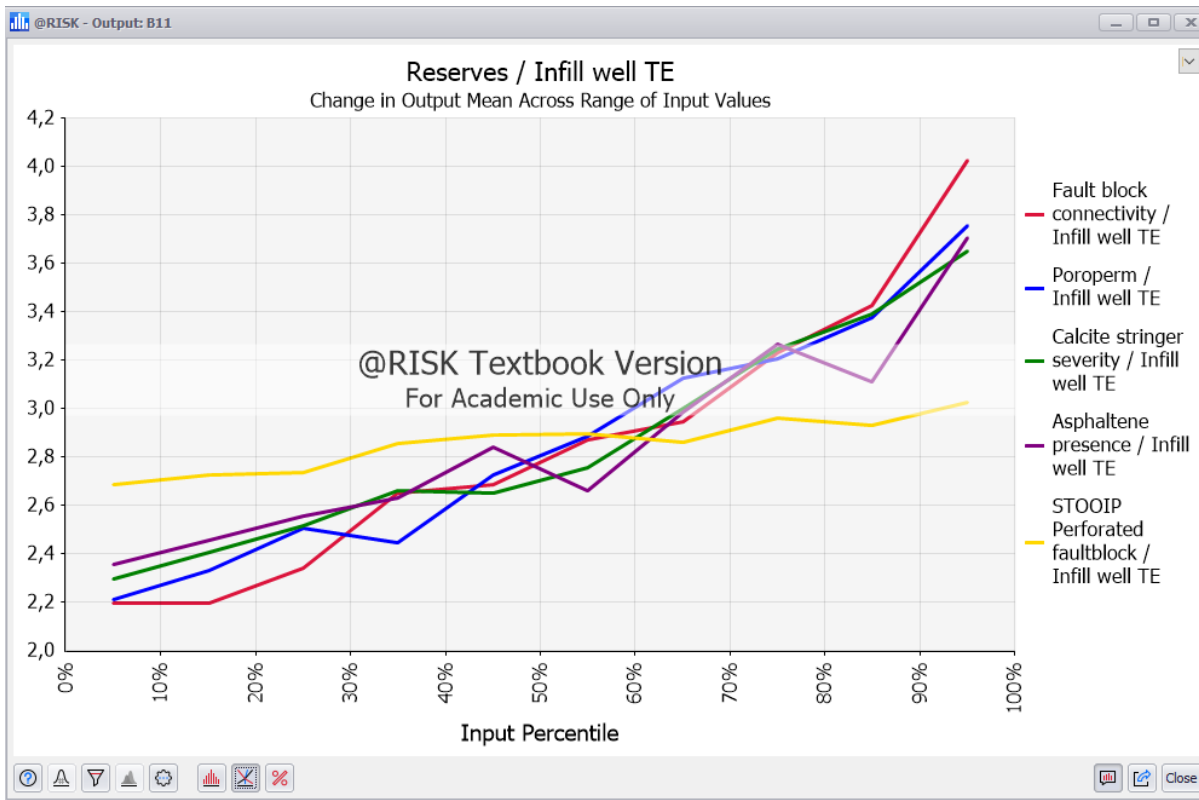
figure 9.3-3: *Spider chart, reserves sensitivity*

9.3.2 Decision tree analysis, NPV

Two material uncertainties were implemented in the decision tree analysis: reserves and oil price – see input table for details.

The other variables were kept deterministic. The model included necessary parameters for the NPV calculations. A risk neutral profile was assumed, i.e., preferences towards expected monetary value. A discount rate of 10% and field lifetime of 10 years was used. For the discrete probability distributions, Swanson's rule was used, which means that P90=30%, P50=40% and P10=30%). The mean is then: $0.3P_{10}+0.4P_{50}+0.3P_{90}$ Swanson's mean is commonly used in estimating discrete probability distributions in the oil and gas industry. It is especially suitable to approximate mean values for a modestly skewed distribution (Hurst, 2000).

Figure 9.3-4 shows the decision tree that was generated in Excel using a Palisade decision tool called Precision tree.
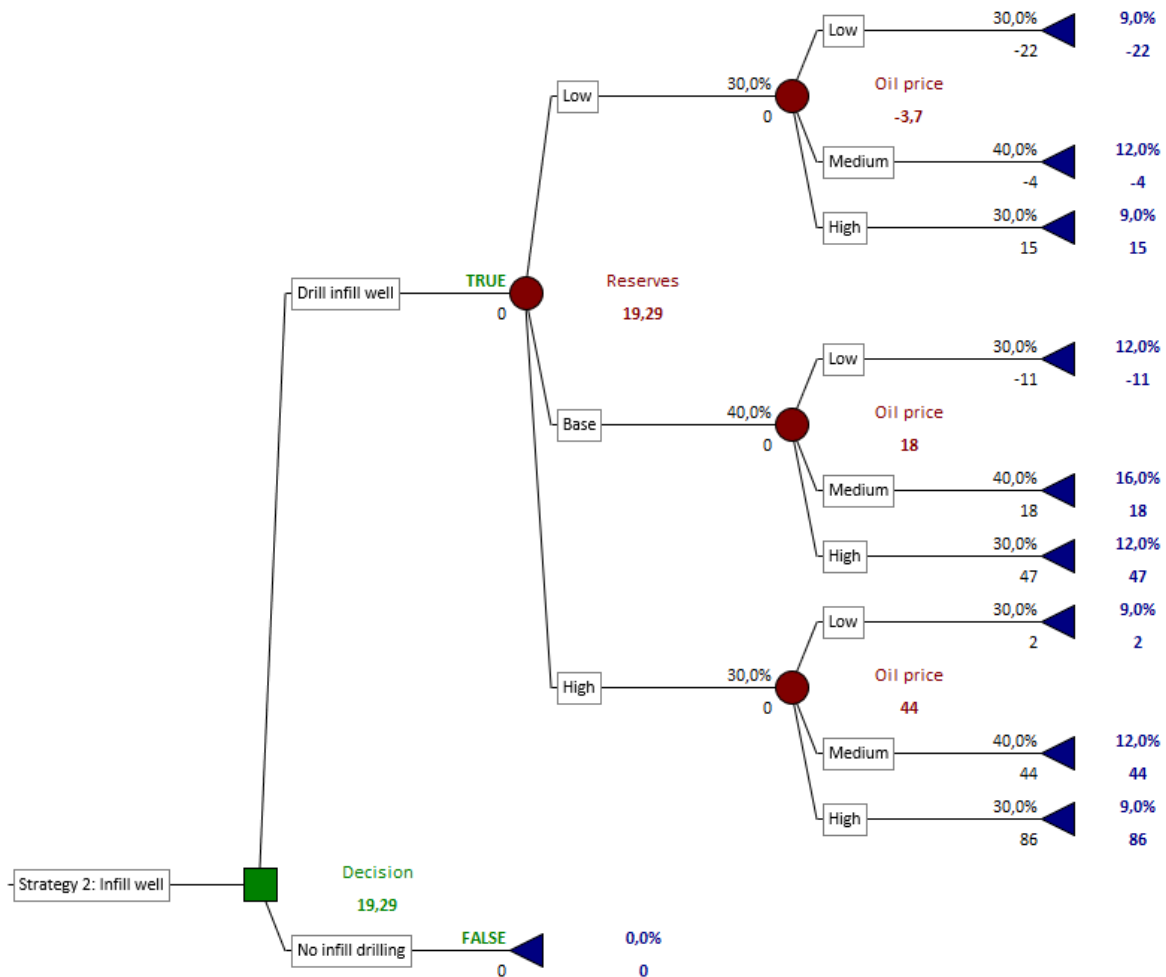
figure 9.3-4: *Decision tree strategy 2 development*

The symbol convention agrees with the influence diagrams used previously; green nodes are decisions; red circular nodes are uncertainties or chance. The expected net present value of Strategy 2 is 19,29 MM USD. The software indicates the most profitable branch of the decision tree by using true and false indicators. The expected NPV for each branch and sub-branch is indicated by red numbers. The final expected NPV for the decision tree is given by the green number next to the decision node.

A more thorough uncertainty and statistical analysis can also be conducted, based on the output from the decision tree analysis. A probability distribution over the different branches of the tree above can be a nice way to visualize how many potential outcomes from the tree causes a negative monetary value. From figure 9.3-5, it was concluded that three out of nine outcomes resulted in a negative NPV – i.e., with low reserves and corresponding oil price low or medium; and in the case of medium reserves with corresponding low oil price. The blue bars represent the decision to drill

the infill well, while the red bar represents the decision to not drill, hence NPV=0 (assuming no sunk costs etc.)
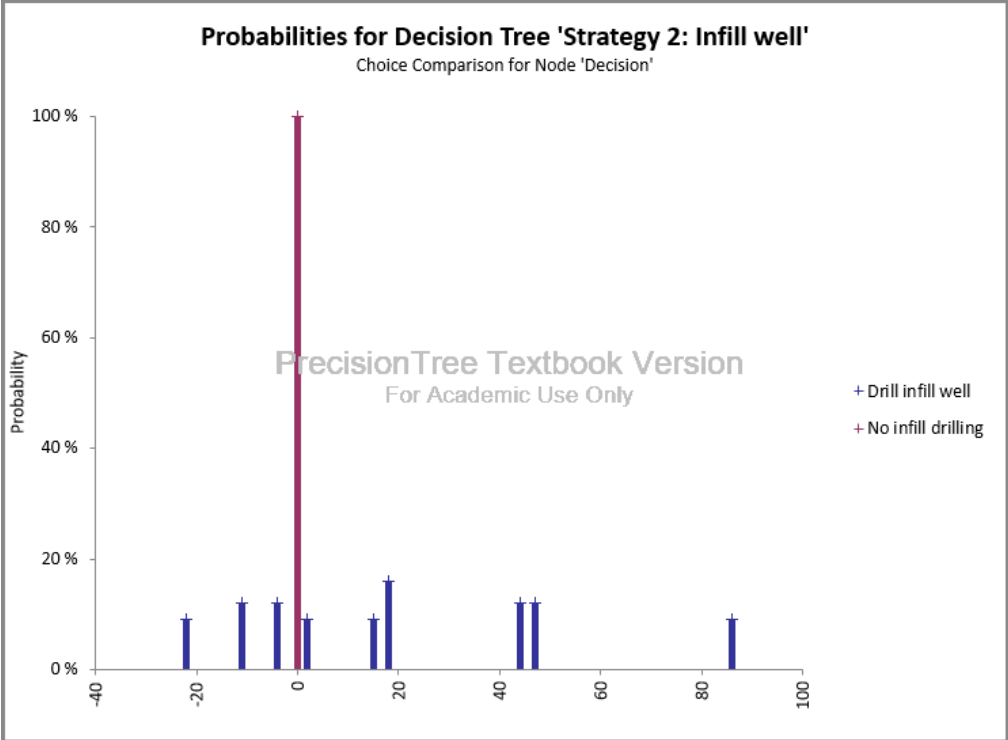
figure 9.3-5: *Discrete probability density distribution from decision tree analysis of strategy 2*

Another visual representation of the probability is the cumulative probability distribution arising from the decision tree, which shows, among other things, the probability to incur a loss on the investment/decision. According to the output chart from the precision three software seen on figure 9.3-6, it was observed that there was a 33% chance of a loss (read of by a table attached to the chart) on this investment decision. Again, the blue curve represents the decision to drill the infill well, while the red line to not drill. In addition to maximizing the monetary value, one of the objectives could be to minimize risk, i.e., P(NPV<0). Therefore, these probability charts would be a valuable tool in assessing how the different strategies perform on that metric.
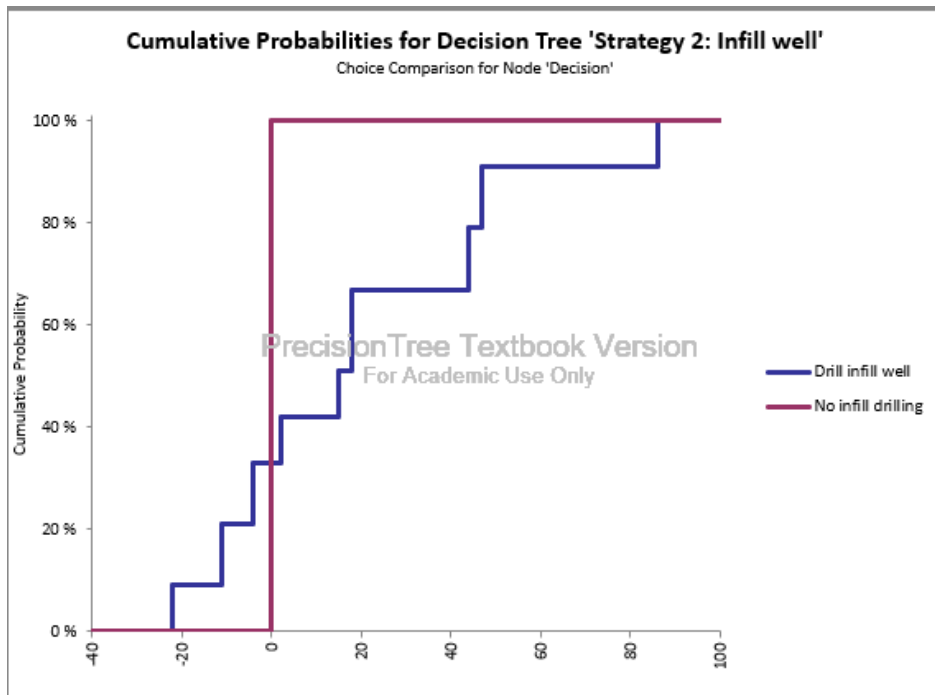
figure 9.3-6: *Discrete Cumulative probability function for Strategy 2*

The output of the probabilistic modeling is the expected payoffs of the different alternatives, together with a sensitivity analysis. The main purpose of the sensitivity analysis is to determine how sensitive the payoffs are to changes to the input parameters, i.e., the uncertain parameters and parameters where there is a choice. The sensitivity analysis should answer the following question: "How accurately do we need to know these inputs? If a large variation in an input parameter only changes the output payoff slightly, then there is no need to spend time and money in trying to further quantifying or reducing the uncertainty (Bratvold & Begg, 2010).

In the Tambar East case, modeling showed us that a couple of the uncertain input parameters that were assumed as material pre decision modeling, was not in fact material. The reservoir pressure and STOOIP uncertainty were identified as non-material uncertainties, and thus the project team shouldn't spend a lot of time on further quantifying those uncertainties or include them as uncertain parameters in the probabilistic modeling (Monte Carlo simulation or decision tree analysis)

9.4 Determining the best strategy

The next step in the decision analysis is to establish a framework for assessing alternatives against the objectives (Bratvold & Begg, 2010). This is a process which involves several steps:

1. Objectives and alternatives are collected into a <u>payoff matrix</u> that lists how each alternative score. These scores are then transformed into values with one common scale so they can be comparatively evaluated, e.g. 0-1 or 0-100
2. Remove objectives that doesn't <u>distinguish between the alternatives</u>
3. Remove alternatives that doesn't meet given <u>constraints</u>(e.g. maximum break even oil price) and remove alternatives which is <u>dominated</u> by others(refer to Bratvold & Begg (2010) for more on domination
4. <u>Applying weights</u> to objectives according to their importance in distinguishing between alternatives. Consider <u>swing weighting</u> which takes into account the relative payouts between alternatives. Swing rank will then be according to range in payoffs for a given objective
5. Determining <u>best alternative</u> by calculating the overall value for each alternative, i.e., the weighted sum in each column. The alternative with the highest value should theoretically be chosen (provided we are sure about our preference for outcome, risks, relative importance etc.
6. In the case of conflicting objectives, you can apply <u>tradeoff theory</u> which is derived from portfolio allocation theory. From applying tradeoffs, you can generate an efficient frontier of viable development strategies. Tradeoff has not been part of this thesis scope but tradeoff is a separate step in the methodology proposed by Bratvold & Begg – the reader is referred to Bratvold & Begg (2010) for more details on tradeoff theory

Table 9.4-1 illustrates a hypothetical example of a payoff matrix with weights and swing ranks as described above. In this example, location value or alternative A has the highest total value of 65.6 and thus should logically be chosen as the preferred development alternative.

table 9.4-1: *Exemplified payoff matrix* (Bratvold & Begg, 2010)

Objectives				Location Values				
Name	Swing Rank	Weights Abs.	Weights Norm.	A	B	C	D	E
Safety, 0–10 scale	3	60	0.18	40	10	0	100	80
NPV, USD million	1	100	0.29	70	0	100	30	60
IRR, %	4	40	0.12	100	40	90	0	30
Reserves added, million STB	5	30	0.09	90	80	100	70	0
First year production, million STB	2	90	0.26	60	100	50	0	40
Risk, probable NPV<USD 0	6	20	0.06	40	80	0	100	90
Total		340	1.00	65.6	44.6	61.8	39.0	51.2

A similar matrix could be constructed for Tambar East brown field development. A reminder of the different proposed strategies is provided in figure 9.4-1:

1: Fix/improve existing well	• Rationale: Low cost alternative, reduce risk of over-capitalizing • Objective: Allow the well to come back on stream
2: Conventional infill well(s)	• Rationale: Already perforated formation is drained and locally troublesome • Objective: Drain other parts of the reservoir, laterally and/or vertically
3: Advanced completion infill well(s) (e.g. MLT)	• Rationale: Reservoir is heavily compartmentalized, conventional wells of limited drainage potential • Objective: Drain larger portion of the reservoir with multilateral
4: Phased development	• Rationale: Project is low priority at the unfavorable prevailing economic conditions • Objective: Analyze, understand and interpret reservoir without committing capital resources.
5: Ambitious development	• Rationale: Exploiting potential upside of the Tambar East uncertainty • Objective: Develop Tambar East with "all means" available, incl injection and EOR measures

figure 9.4-1: *Tambar East brown field development strategies*

Required data for the extended payoff matrix is the chosen objectives and attributes, weights/preferences, swing ranks and the payoffs of the different strategies for each objective (on a uniform value scale). The matrix looks deceivingly simple, but it implicitly comprises all the key elements of the decision analysis. In a decision driven organization, all the work being conducted should be linked to such a payoff matrix (Bratvold & Begg, 2010).

Table 9.4-2 presents such a payoff matrix that could be used for Tambar East. Generating the data for the matrix is the primary role of the technical, economic and commercial studies being done, as part of the decision analysis. As previously mentioned, the thesis focus was on the front end analysis, i.e., the structuring part of the analysis. The remaining elements to this payoff matrix in the context of the Tambar East thesis work is to do weighting of the objectives together with decision makers and complete the payoff calculations for the remaining strategies (all except strategy 2). The bottom table includes symbols to indicate remaining work. (Orange tick boxes on completed tasks, blue graphics for remaining payoff calculations and a big black organizational structure symbol to indicate that this information should be determined on top in the organization and communicated throughout the organization)

table 9.4-2: *Payoff matrix, Tambar East brown field development*

Objectives				Strategies				
Name	Swing rank	Weights		1	2	3	4	5
		Abs.	Norm					
NPV, MM USD								
Reserves added, MM bbl								
Risk, probable NPV<USD 0								
Safety, 0-5 scale								
Reputation,0-5 scale								
Total								

Objectives				Strategies				
Name	Swing rank	Weights		1	2	3	4	5
		Abs.	Norm					
NPV, MM USD								
Reserves added, MM bbl								
Risk, probable NPV<USD 0								
Safety, 0-5 scale								
Reputation,0-5 scale								
Total								

9.5 Decision quality

In a previous section, distinguishing between decisions and outcomes was covered in detail. Therefore, assessing the decision quality on other metrics than the outcome is necessary. As we argued, outcome is not a good indication of decision quality and moreover, it might not be readily available at the time one conducts the decision quality evaluation. Part of a proper decision analysis process is to evaluate the decisions and the corresponding process. To evaluate the decisions, a repetition of what a good decision entails is useful, according to Bratvold & Begg(2010):

"A good decision is logically consistent with maximizing the value of the decision, given the following:

- The alternatives that have been created or identified
- The decision-maker's objectives and associated weights
- The forecasted payoffs based on the information we have
- The decision maker's preferences for payoffs, as specified by the value function "

Bratvold & Begg (2010) borrows a decision quality framework from McNamee & Celona (2008). The framework is shown on figure 9.5-1 and it introduces six dimensions of high quality decision making, which is aligned with the previously described decision analysis methodology. In other words, evaluating along the six dimensions of high quality decision making is evaluating how well you conducted the proposed decision analysis methodology. The reader is referred to Bratvold & Begg (2010) for more information on that subject. Figure 9.5-2 shows the chain or framework converted into a Spider chart, which is useful for quantitative evaluation of the decision quality

figure 9.5-1: *Decision quality chain* (Bratvold & Begg, 2010)
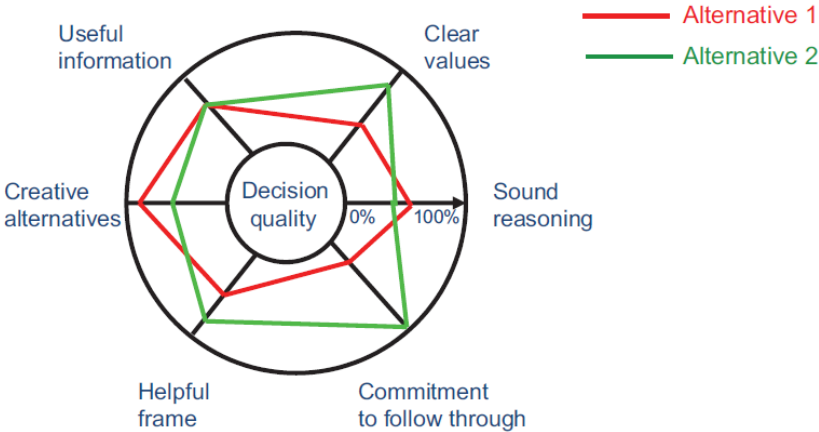
figure 9.5-2: *Decision quality spider chart* (Bratvold & Begg, 2010)

10 Conclusion, recommendations and future work

10.1 Conclusion

The topic of this thesis was decision making in the context of field development. Decision analysis was coupled with a technical subsurface analysis to develop a robust decision making methodology tailored to brown field development, but also applicable for any decision making process or field development. Brown field development usually requires a shift in the focus of the field development decision analysis, since there is a lot more available data compared to green fields, which often lacks data. Due to the potential variation in a brown field, an increased attention to the front-end-analysis is crucial to succeed in the re-development, making sure that we provide high-quality answers to the right questions and problems. Identifying the value and uncertainty drivers in a project is key to develop robust development strategies.

The key to identify the real value of decision analysis is to realize that the only way we can consistently create more value is through making better decisions. By nature, we humans are not granted this great talent of intuitive decision making skills in complex and uncertainty environments, instead we need to couple it with experience and a consistent, structured way of dealing with decision making, i.e., acquiring proficiency in decision analysis.

The thesis also included a thorough discussion on the importance of embracing uncertainty. Uncertainty is usually regarded as something with negative consequences, but the focus of this thesis has been to provide insight and clarity on the opportunities and the upside potential that arises from uncertainty. We create value by making decisions, but we can also create value from the uncertainty, either by gathering information or introducing flexibility and creativity in our development plans, that accounts for this uncertainty. Ultimately you have a choice; either allow to be limited by uncertainty or open up for the potential that arises from uncertainty. This train of thought on uncertainty and decision analysis is still not widespread in the oil and gas industry but it is picking up momentum.

Thorough analyses and evaluation have shown that Tambar East has been and is a challenging and complex field to develop. The Tambar East field is situated in a complex geological structure, highly compartmentalized and containing challenging reservoir fluids which causes deposition of solids in the reservoir and wellbore. In many ways it has been regarded as the black sheep of the Ula-Tambar family – largely considered a failure. Several value drivers and material uncertainties were identified through the thesis work, which should receive some extra attention by further analysis and uncertainty management.

A set of creative alternative strategies were developed, ranging from minor changes – i.e. the low hanging fruits – to quite ambitious development plans which truly exploits the upside potential of Tambar East. The latter strategy really encourages to think outside the box and exploit new technologies and analysis methods. By honoring the decision analysis methodology, as proposed by Bratvold & Begg, we propose a set of high quality decisions on Tambar East brown field development, which includes clearly defined alternatives and objectives, an unbiased quantification of uncertainty, consistently forecasted payoffs and finally a logical method to evaluate alternatives against objectives.

10.2 Further academic research

As previously mentioned, the main focus of the thesis was the front-end-analysis. As a continuation of that work, it would be interesting to include more research work on creating value from uncertainty, i.e., the value of information (VoI) and value of flexibility (VoF), which were only briefly introduced in the thesis. Moreover, a second look on assessing decision quality, tailored to brown field development would be especially useful. Moreover, through the thesis the project decisions have been evaluated. However, Aker BP has a portfolio of existing and new investment opportunities (fields and projects) and any such investment should be evaluated in the context of the portfolio – will it improve the risk/reward status of the corporate portfolio?

10.3 Future work

Tambar East has naturally not received a lot of attention and manhours the last couple of years, but hopefully this thesis will serve as an inspiration and a solid starting point for picking up Tambar East once more, when the time is right. It is recommended that the subsurface team focus on the value and uncertainty drivers of the reservoir.

Further, reducing the uncertainty of the material uncertainties identified and screen Tambar East for the feasibility of introducing new technology. The list below of future work is non-exhaustive but could serve as a starting point for the subsurface team:

- Refine static and dynamic reservoir model, reduce material uncertainties.
- Reinterpret 4D seismic.
- Screening for water injection (IOR) and artificial lift.
- Screening for suitable EOR methods: WAG, low saline injection etc.
- Injected water treatment study (sulfur removal)
- Screening for multilateral and fishbones potential.
- Advanced asphaltenes studies. E.g. study the vertical segregation theory.

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