FACULTY OF SCIENCE AND TECHNOLOGY

MASTER'S THESIS

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Use of Life Cycle Costing to Compare and Assess Business Performance Differences and Opportunities Regarding Traditional Topsides versus Subsea Chemical Storage and Injection for Subsea Wells

Figure 1: Subsea Chemical Storage System [1]

Summary

As a significant aspect of sustainable development, Equinor is currently engaged in a substantial technology advancement involving subsea all-electric (AE) functions as a replacement for the conventional topside electro-hydraulic (EH) functions. Within the AE function, subsea infrastructure developers are planning and developing a Subsea Chemical Storage and Injection System (SCSIS) on the seafloor infrastructure. The system consists of storage units for chemical products located on the seafloor, connected to the manifold for onwards distribution. It serves as an alternative to the conventional distribution system where chemical products are stored in storage tanks on the topsides facility (e.g. fixed or floating platform) and injected into the subsea production system via an umbilical.

The primary objective of this thesis was to conduct an evaluation of the business performance differences between the EH function and the AE function within the domain of chemical injection, over a 20-year design life. To achieve this objective, the thesis employed the life cycle costing methodology as presented in ISO 15663:2021. The methodology served as a comprehensive tool for comparing the life cycle costs of two alternative options. By identifying cost elements and cost drivers for each of the options associated with the main elements of life cycle costing, namely CAPEX, OPEX, and LOSTREV, the life cycle costing methodology could be utilized. Furthermore, by employing a diverse range of economic evaluation measures, coupled with trade-off considerations in life cycle costing such as HSE and sustainability factors, the thesis study aimed to determine which option offered superior benefits.

The economic evaluation measures encompassed a variety of Monte Carlo simulations implemented within an Excel model to facilitate probabilistic cost estimations for each of the economic evaluation measures. The model was executed utilizing modified Equinor-specific data that aligned with the technical and operational basis outlined in Chapter 2 of the thesis. These modifications ensured that the data employed in the analysis were tailored to meet the specific requirements and standards established in the theoretical framework of the thesis.

The thesis has demonstrated that employing the life cycle costing methodology for a project with a 20-year life cycle yields significant insights that aid in the decision-making process for investments within the petroleum industry. The accuracy of the cost estimations has been substantiated through a comparative analysis conducted on an offshore project of comparable scale, as well as consultation with Equinor representatives. Moreover, the thesis has illustrated that employing a probabilistic estimation methodology, supported by both top-down and bottom-up estimation approaches, can effectively address substantial uncertainties inherent in the life cycle cost analysis, resulting in sound results.

Acknowledgements

I am grateful to Equinor for providing me with the opportunity of writing this thesis in collaboration with them. Regarding my main supervisors at Equinor, I extend my sincere appreciation to Runar Østebø, for his extensive knowledge and valuable contributions to the topic of life cycle costing. His guidance and assistance during my time at Equinor have also been invaluable. I would also like to express my gratitude to Cecilie Vistnes who has connected me with the right people in the cost estimation department at Equinor as well as providing me with valuable knowledge on cost estimation. Finally, I would like to thank Torstein Vinterstø for his immense knowledge contribution on subsea infrastructure and technology development.

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At the University in Stavanger, I would like to extend my thanks to my supervisor Roy Endre Holsvik Dahl for his guidance on cost estimation methodologies and his unwavering assistance throughout the writing process of this thesis.

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Abbreviations

AE	All-electric
CAPEX	Capital Expenditure
CDU	Controls Distribution Unit
CI	Corrosion Inhibitor
CIS	Chemical Injection System
CIU	Chemical Injection Unit
CMATE	Cost Maintenance Analysis Tool Equinor
COR	Code of Resource
CV	Construction Vessel
EH	Electro-Hydraulic
EPU	Electrical Power Unit
eSCM	electrical Subsea Control Module
FPSO	Floating, Production, Storage, and Offloading
FSV	Field Supply Vessel
HPU	Hydraulic Power Unit
HSE	Health, Safety and Environment
HV	High Voltage
HVAC	Heating, Ventilation and Air Conditioning
LCC	Life Cycle Cost
LCV	Light Construction Vessel
LOSTREV	Lost Revenue
MCS	Monte Carlo Simulation
MNOK	Million Norwegian Kroner
NOK	Norwegian Kroner
O&M	Operations and Maintenance
OFL	Operational Function Location
OPEX	Operating Expenditure
PA	Production Availability
PBS	Physical Breakdown Structure
ROV	Remotely Operated Vehicle

SAB	Standard Activity Breakdown
SCCS	Standard Cost Coding System
SCSIS	Subsea Chemical Storage and Injection System
SCSIU	Subsea Chemical Storage and Injection Unit
SD	Shutdown
SHPU	Subsea Hydraulic Power Unit
SI	Scale Inhibitor
SPS	Subsea Production System
TUTA	Topside umbilical termination assembly
UTA	Umbilical termination assembly
WBS	Work Breakdown Structure

Definitions

Asset	Item, thing, or entity that has potential or actual value to an organization [2, p. 2].
Capital expenditure	Investment used to purchase, install, and commission an asset [2, p. 2].
Code of resource	Hierarchical structure of SCCS that classifies all project resources according to the type of contract/resource that is involved in the activity and has an associated set of rates [2, p. 3].
Cost data	Cost information associated with a defined cost element [2, p. 3].
Cost driver	Major cost element which, if changed, will have a major impact on the life cycle cost of an option [2, p. 3].
Cost element	Subset at any level of the total cost for a cost breakdown structure [2, p. 3].
Cost item	Particular part/level that is coded/classified using the SCCS [2, p. 3].
Discount rate	Rate of return used in determining the net present value of future cash flow [2, p. 4].
Economic evaluation measure	Quantitative measure used to quantify economic characteristics [2, p. 4].
Life cycle	Series of identifiable stages through which an item goes, from its conception to disposal [2, p. 4].
Life cycle cost (LCC)	Total cost incurred during the life cycle [2, p. 5].
Life cycle cost analysis	Systematic evaluations and calculations carried out to assess competing options using economic evaluation measures as part of life cycle costing [2, p. 5].
Life cycle costing	Process of evaluating the difference between the life cycle cost of two or more alternative option [2, p. 5].
Life cycle phase	Discrete stage in the life cycle with a specified purpose [2, p. 5].

Lost revenue (LOSTREV)	Income loss that occurs when generated income are less than expected due to external or internal factors [2, p. 5].
Net present value (NPV)	Present value that is calculated by discounting the future net cash flow with the required rate of return as the discount rate [2, p. 5].
Operating expenditure (OPEX)	Expenses used for operations and maintenance, including associated costs such as logistics and spares [2, p. 6].
Payback period	Period after which the initial investment has been paid back by the accumulated net revenue counted from the first income [2, p. 6].
Physical breakdown structure (PBS)	Hierarchical structure of SCCS that defines the types of physical asset components of field installations being delivered by the activity [2, p. 6].
Production availability	Ratio of production to planned production, or any other reference level, over a specified period of time [2, p. 6]
Profitability index (PI)	Ratio of NPV of the project divided by the discounted CAPEX [2, p. 6].
Required rate of return	Discount rate required by the decision-maker for minimum profit for the investment project [2, p. 6].
Standard activity breakdown structure (SAB)	Hierarchical structure of SCCS that defines the type of activity that is being performed [2, p. 7]
Standard cost coding system (SCCS)	Standard system for classification and coding cost estimates, monitoring and final quantities and cost data [2, p. 7]
Sustainability	State of the global system, including environmental, social and economic aspects, in which the needs of the present are met without compromising the ability of future generations to meet their own needs [2, p. 7]

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1 Introduction

This chapter provides an overview of the background and context of the thesis, introducing the research questions that serve as its guiding principles. It includes the scope and limitations of the study, presenting the boundaries within which the research is conducted. Additionally, this chapter provides the methodology employed for data collection and scrutiny, ensuring the quality and validity of the findings. Furthermore, the chapter outlines the structure and organization of the thesis, presenting the logical arrangement that has been adopted to address the research questions and deliver a coherent and comprehensive academic work.

1.1 Background

As a part of the 2022 Equinor Energy transition plan, Equinor is committed to minimizing carbon emissions throughout the various stages of oil and gas production while still meeting the global energy demand [3]. Achieving this objective requires innovation and adaption to new sustainable technologies.

As a significant aspect of sustainable development, Equinor is currently engaged in a substantial technology advancement involving subsea all-electric (AE) functions as a replacement for the conventional topside electro-hydraulic (EH) functions. Within the AE function, subsea infrastructure developers are planning and developing a Subsea Chemical Storage and Injection System (SCSIS) on the seafloor infrastructure. The system consists of storage units for chemical products located on the seafloor, connected to the manifold for onwards distribution. It serves as an alternative to the conventional distribution system where chemical products are stored in storage tanks on the topsides facility (e.g. fixed or floating platform) and injected into the subsea production system via an umbilical.

From an economic perspective, relocating chemical storage tanks and pumping operations from topside to the seafloor, combined with the implementation of AE system replacing hydraulic power, can lead to a reduction in overall field capital expenditure (CAPEX) when dealing with complex fields. Moreover, significant operational expenditure (OPEX) savings are also expected due to the simplicity in design of the SCSIS.

The primary objective of this thesis is to establish a foundation for the application of life cycle costing methodology in the context of SCSIS technology development. This objective is accomplished through a comprehensive estimation of costs associated with the two competing options (EH and AE in context of chemical injection) and an evaluation process that adheres to the methodology outlined in the recently published life cycle costing standard, ISO 15663:2021, titled “Petroleum, Petrochemical, and Natural Gas Industries – Life Cycle Costing”.

1.2 Problem Statement and Research Questions

Problem statement:

Use of life cycle costing to compare and assess business performance differences and opportunities regarding traditional topsides versus subsea chemical storage and injection for subsea wells.

Research Questions:

- Based on the technical and operational basis, results from economic evaluation measures, and trade-off considerations, which option is ranked the more viable option regarding the subject matter?
- How can the lowest ranked option improve to become the preferred option?
- To what grade of applicability is the ISO 15563:2021 standard for this type of technology development? How can life cycle costing assessment be improved for further studies?

1.3 Scope and Limitations

The scope of this thesis was to analyse and evaluate the differences in business performance between the EH function and the AE function, with a specific focus on the contribution of chemical injection systems, over a designated design life. The methodology employed to assess and analyse these performance differences were limited to the approach outlined in ISO 15663:2021 for life cycle costing. By employing this methodology, the thesis aimed to provide valuable insights and guidance for organizations involved in the development of new subsea technology, facilitating informed decision-making processes, and fostering cost-effective and sustainable solutions within the industry. The analyses within life cycle costing were carried out through the development of an Excel model that incorporated several economic evaluation measures outlined in ISO 15663:2021, while also considering pertinent trade-off considerations that were deemed relevant for the life cycle costing assessment.

1.4 Data Collection

Due to limited availability of data concerning the new technology related to the subject matter, an extensive collection of data that was considered relevant to the topic, was conducted. The relevance of the collected data was assessed through a validation process, involving a comparison of technical and operational information between the EH solution and the AE solution, followed by a thorough examination to ensure alignment with the subject matter. Employing Excel tools, the physical properties of each option were translated into corresponding costs for the purpose of conducting a life cycle costing assessment. The data collection process was organized into two distinct methodologies: qualitative and quantitative. A detailed description of the methodologies employed for data collection is presented further in this subchapter.

1.4.1 Qualitative methods

Qualitative methods were important for gathering technical information on the subject matter, but also methodology for enhancing the life cycle costing assessment on which the thesis is based. In order to enhance the calibre of the qualitative data collected, several practical activities were employed during the research process. These activities encompassed:

- **Conference papers and standards:** A wide range of data on the subject was gathered to ensure comprehensive coverage. Subsequently, the data was examined to identify any significant deviations or variations on the subject matter. Equinor granted access to OnePetro, a comprehensive database containing numerous conference papers related to field developments, papers on life cycle costing, as well as technical descriptions on chemical injection systems and the SCSIS. These were:
    - Conference papers on long tieback distances: [4 – 7]
    - Conference papers on the SCSIS: [8 – 16]
    - Conference papers on technological development: [17 – 18]
    - Conference papers on Chemical injection: [19 – 23]
    - Conference papers on life cycle costing: [24 – 26]

  Equinor also provided furnished restricted reports and standards to support the assessment of life cycle costing. These standards were:
    - Standards: [2] and [27 – 30]
    - Restricted sources were altered in this thesis to ensure such classification.

- **Extensive data collection on public data**: Search engines were utilized to access relevant and reliable sources of information. Emphasis was placed on accessing peer-reviewed data published after 2010 where it was possible, while some articles are as old as 2005. Additionally, textbooks, theses, and articles related to the subject matter were collected to ensure credibility and accuracy in information. In the data collection process of the thesis, search engines such as Oria were utilized, as it provided access to the entire reading material available in the library database of the University in Stavanger. This database was instrumental in finding relevant materials related to the SCSIS that was not from conference papers. Google Scholar, another search engine, was employed to identify articles on specific subtopics, this bolstering the objectivity of the research. Main sources extracted from public data were:
    - Textbooks related to the subject matter: [31 – 35]
    - Textbooks on economics: [36] as well as notes from the master's study.
    - Theses on SCSIS: [37 – 39]
    - Articles: [40 – 46]
    - Presentations: [47 – 48]
    - Websites:
        - Norwegian Petroleum: For examination of costs and production relative to various fields.
        - Norwegian Petroleum Directorate: For understanding decommissioning in Norwegian petroleum as well as future technology development.
        - Equinor: For information pertaining to various fields used in the thesis.
        - Norwegian Environment Agency: For investigating health, safety and environmental (HSE) measures as well as sustainability in Norwegian petroleum.
        - Other websites deemed reliable for subtopics on the subject matter, such as Schlumberger, Siemens, Hitachi etc.
- **Consulting with external supervisors at Equinor:** Some information pertaining to the subject matter was obtained from external supervisors at Equinor, leveraging their expertise and insights on the subject. Consulting was also conducted to verify and validate the technical and operational information obtained, ensuring its accuracy and relevance.

1.4.2 Quantitative methods

Quantitative methods were important to identify actual costs on identified cost elements, and if they contribute as a cost driver or not. For the life cycle costing assessment, a foundation presenting all relevant costs for the subject matter was important for a thorough estimation used for later evaluation. The life cycle costing assessment relied on data acquisition facilitated by the cost estimation department at Equinor. To ensure accuracy and quality in data, various measures were implemented for each of the following data types:

- **Generic data:** This entailed quantitative data gathered from public sources such as those presented in conference papers, which included engineering components relevant to the subject matter as well as some potential component dimensions. Design of the SCSIS was extracted from several conference papers as presented in Chapter 1.4.1 and were then scrutinized by studying similarities between the possible SCSIS'. Websites encompassing data relevant to the oil industry such as production rates, tax rates, oil price, and costs in the petroleum industry were also included as generic data. These were:
    - Price of oil: [49]
    - Tax rates: [50]
    - Costs and production in the petroleum industry: [51 – 52]
- **Equinor specific data:** This entailed Equinor specific data that were not published, such as cost estimation models in Excel (CostCalc) and benchmarking, as well as Power BI tools which included key figures of Equinor specific OPEX estimates. CAPEX related data was gathered from the CostCalc spreadsheet, while OPEX related data was extracted from Cost Maintenance Analysis Tool Equinor (CMATE). Another excel tool that was utilized for the topside estimation was BulkMate, which based on key figures could calculate cost of entire topside systems with only equipment weight as input. Equinor also provided with restricted reports on the topside vs subsea case, where some numbers were included in the thesis but slightly altered to ensure such document classification.
- **Expert judgement:** During the entire quantitative method, Equinor supervisors provided their expertise and insights, contributing to the data collection process. Regular meetings were also conducted with Equinor representatives to gather additional expert judgement and ensure the data collected reflect typical industry practice, while not entirely specific for specific assets.

1.5 Thesis Layout

Chapter 1 – Introduction: Introduction to the thesis with scope and limitations, as well as data collection methodology for the thesis.

Chapter 2 – Theory: Encompasses the theory supporting life cycle costing, cost estimation methodologies, technical and operational basis regarding chemical injection for subsea wells, the influence of sustainability, and economic uncertainties affecting the chosen subject matter.

Chapter 3 – Methodology: Presents how the thesis research was conducted and methodology of the ISO 15663 was implemented in the thesis. The chapter also covers economic evaluation measures utilized in the life cycle costing assessment.

Chapter 4 – Data: Encompasses calculation of all input data that is used for the life cycle cost analysis model created in Chapter 5.

Chapter 5 – Life Cycle Cost Analysis: Estimation model with economic evaluation measures supporting decision-making in life cycle costing. The chapter also includes limitations to the model.

Chapter 6 – Discussion: Validation of result, discussion of research questions as well as statements on the SCSIS presented in the thesis.

Chapter 7 – Conclusion: Conclusion answering the problem statement and research questions related to the thesis.

References

2 Theory

This chapter encompasses the theory supporting life cycle costing including cost estimation methodologies, technical and operational basis regarding chemical injection for subsea wells, the influence of sustainability on the subject matter, and economic uncertainties affecting the subject matter.

2.1 Life Cycle Costing

Life cycle costing is a methodology utilized for comprehensive assessment of evaluating life cycle cost differences between two or more competing options throughout their complete design life. This subchapter is divided into three: Firstly, the main elements of life cycle costing are presented and how the subject matter may impact them. Secondly, the standards support life cycle costing are presented and what role they have in the life cycle costing assessment. Finally, the cost estimation methodologies utilized as part of calculating the life cycle costing main elements are presented.

2.1.1 Life Cycle Costing Main Elements

Within the context of subsea production systems, the application of the life cycle costing approach enables the evaluation of the costs pertaining to subsea production throughout its entire life cycle. This encompasses various stages ranging from initial design and manufacturing to subsequent operations, maintenance, and ultimately decommissioning. By facilitating an inclusive analysis of all relevant costs, the life cycle costing methodology aids in determining the most efficient strategy for managing the system over its complete life cycle. The life cycle cost main elements are CAPEX, OPEX, and LOSTREV, which is assessed individually as part of this subchapter.

2.1.1.1 CAPEX

Capital expenditure (CAPEX) is defined as “investment used to purchase, install and commission an asset” [2, p. 2] Regarding the subject matter, potential CAPEX cost elements are:

- Management cost
- Engineering cost
- Equipment cost
- Transportation cost
- Installation cost
- Commissioning/decommissioning cost

The estimate of CAPEX is contingent upon operational assumptions related to the specific subject matter, such as technology and design, system configurations, and equipment quality, among others. Consequently, it is crucial for the CAPEX estimate to accurately reflect technical expertise, allowing for the selection and adaption of pertinent details in accordance with the associated life cycle phase. For instance, high quality equipment may incur a higher CAPEX estimate due to its enhanced reliability, subsequently mitigating potential operating expenditures (OPEX) [2, pp. 59-60].

When estimating CAPEX, it is paramount that the cost data is scrutinized in a rigorous and consistent manner. To ensure the relevance of the CAPEX estimation, cost elements necessitate concise definitions and comprehensive content. The level of granularity in the CAPEX estimation should be tailored to the specific life cycle phase and the pertinent subject matter at hand.

Decommissioning

The decommissioning process represents a distinct phase within the life cycle phase of a project, typically occurring during its final stages. The cost of decommissioning should be implemented as part of the CAPEX estimate to prepare the project for the later stages. It can even be considered as a separate project in itself, characterized by a comprehensive set of cost elements that encompass the conclusion of a project’s lifespan [2, p. 60].

Expenses associated with the decommissioning of the subject matter may include, but are not limited to, the following:

- Management cost
- Maintenance cost
- Demolition cost
- Engineering cost
- Transportation cost
- Site restoration cost
- Scrap handling cost

2.1.1.2 OPEX

Operating expenditure (OPEX) is defined as “expenses used for operation and maintenance, including associated costs such as logistics and spares” [2, p. 6]. Typical OPEX cost elements applicable to the subject matter include, but are not limited to, the following:

- Operations man-hour cost
- Cost of chemicals
- Cost of logistics
- Maintenance cost
- Modification cost

OPEX is contingent upon the technical and operational assumptions inherent in the CAPEX estimation, encompassing factors such as technology, system configuration, and equipment quality. Furthermore, OPEX is influenced by the maintenance plan, integrity management, repair strategy, and other considerations throughout the project’s life cycle. Estimations assigned to OPEX should accurately reflect the level of knowledge pertaining to the subject matter in the corresponding life cycle phase [2, p. 61].

When evaluating OPEX, the cost data needs to be utilized in the same manner as that of CAPEX. The relevant cost elements for OPEX should possess clarity and conciseness to facilitate meaningful comparisons among OPEX components. The level of detail for a cost element should be determined and adjusted to align with the relevant life cycle phase of the subject matter.

2.1.1.3 LOSTREV

Lost revenue (LOSTREV) is defined as "income loss that occurs when generated income are less than expected due to external or internal factors" [2, p. 5] and encompasses specific cost elements that contribute to the overall decline in potential revenue. Similar to CAPEX and OPEX, LOSTREV necessitates a precise definition and comprehensive content. When comparing various alternatives, revenue loss is typically influenced by factors such as production capacity and reservoir profiles. Additionally, LOSTREV may account for costs incurred due to time-related disruptions, such as delays, which directly impact project revenue. To calculate LOSTREV throughout the life cycle of a project, predictions of production assurance can be employed. The predictions enable the translation of lost production and production availability into economic terms [2, pp. 62-63]. For the subject matter, LOSTREV elements may include:

- Lost production (planned/unplanned)
- Lost operating time
- Lost deliveries

LOSTREV should reflect technical knowledge on the subject matter and level of detail concerning cost elements should be determined and adjusted to align with the corresponding life cycle phase. For example, high quality equipment is likely to reduce LOSTREV due to increased equipment availability [2].

2.1.1.4 Summary

Figure 2 illustrates relationship between the life cycle costing main elements; CAPEX, OPEX and LOSTREV. Each element requires estimations techniques that cover both qualitative and quantitative studies, and analyses. The figure illustrates trade-off considerations to minimize costs and create value for the stakeholders. Value is created by balancing both cost factors and revenue factors.

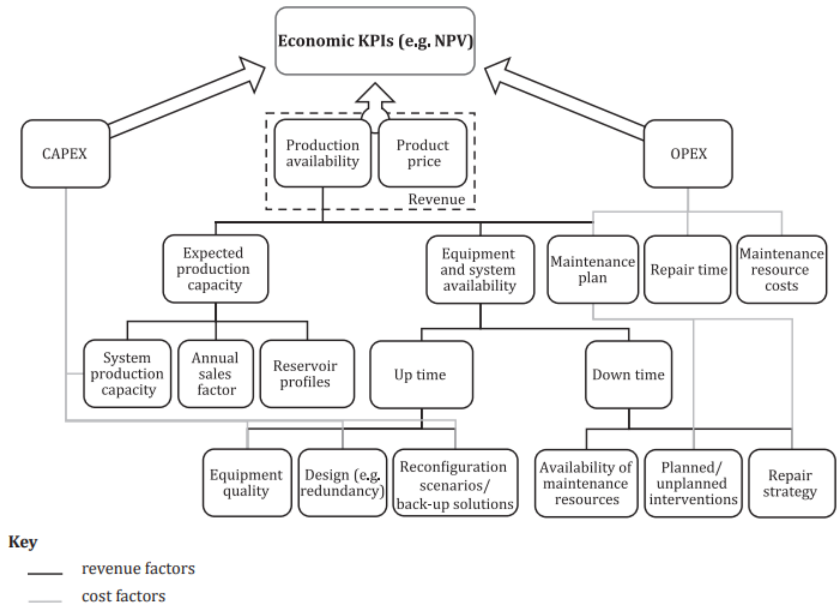

Figure 2: Influence factors of production assurance on project economy [29, p. 19]

Figure 3 presents the total cost of Norwegian petroleum projects from 2010 to 2027, incorporating various factors such as investments, operating costs, exploration costs, disposal and cessation, and others. It offers an estimation of the relative contributions of the life cycle costing main elements, in the overall costs of these projects. Conversely, the calculation of LOSTREV entails an examination of production availability and prevailing oil price.

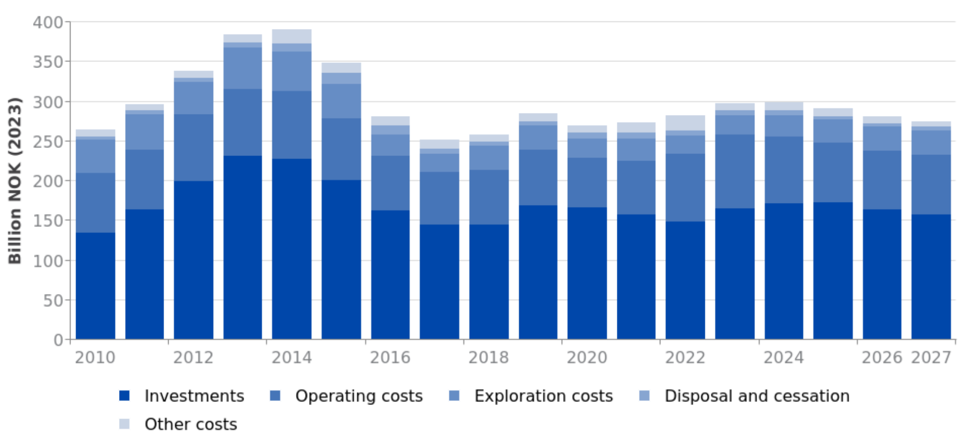

Figure 3: Costs in Norwegian petroleum 2010-2023 with prognosis 2024-2027 [51]

2.1.2 Standards of Life Cycle Costing

Life cycle costing can be utilized as a systematic approach aimed for assessing and comparing various alternative options to achieve the objectives of a business, by considering the associated revenues and costs. It involves the process of planning, estimating, and monitoring revenue and cost differences throughout an asset's design life [2]. By closely monitoring these fundamental factors, the decision-making process can be facilitated when evaluating alternative options.

Deciding to develop and deploy new technologies in substantial projects or during operations to enhance performance can largely be based on consideration of life cycle economics. The use of life cycle costing can be an alternative to assess and compare different technology solutions or to investigate inputs subjected to critical economic assessments. This chapter covers important standards for the assessment of life cycle costing, and how they apply to the methodology.

2.1.2.1 ISO 15663:2021

The new international standard ISO 15663 was published in 2021. The standard provides methodology to be used to identify subject matters and assess alternative competing solutions and their cost implications, with also considering HSE and sustainability relationships. The document specifies requirements for and gives guidance on the application of life cycle costing to create value for the development activities and operations associated with drilling, exploitation, processing, and transportation of petroleum, petrochemical and natural gas resources [2, p. 1]. This chapter encompasses the main elements of ISO 15663:2021.

Purpose and Application

The standard offers comprehensive framework for the implementation of life cycle costing methodologies, specifically tailored to generate value for activities and operations associated with production and transport of petroleum, petrochemical and natural gas resources. Moreover, the standard provides clear definitions for key cost-related terminologies in accordance with its guidelines [2, pp. 8-9].

The standard is aimed to strengthen the industry cost management for business value creation and provide decision support when selecting between alternative options on a subject matter. This is also aligned with the individual corporate objectives such as HSE or sustainability [26].

Limitations

ISO 15663:2021 primarily concentrates on the assessment of competing options specific to a subject matter, rather than encompassing the comprehensive evaluation of project economics, such as field development or investment appraisals. Nevertheless, the standard does offer guidance for the selection of pertinent cost elements to ensure the cost-effective implementation of life cycle costing [2, pp. 10-11].

Some parts of the methodology outlined in ISO 15663 necessitate the utilization of external analysis tools to accurately predict the life cycle costing associated with different alternative options. These techniques are not exclusive to life cycle cost analysis and can be found in other relevant standards such as ISO 14224:2016 and ISO 20815:2018 [2, p. 10]. This is portrayed below in Figure 4.

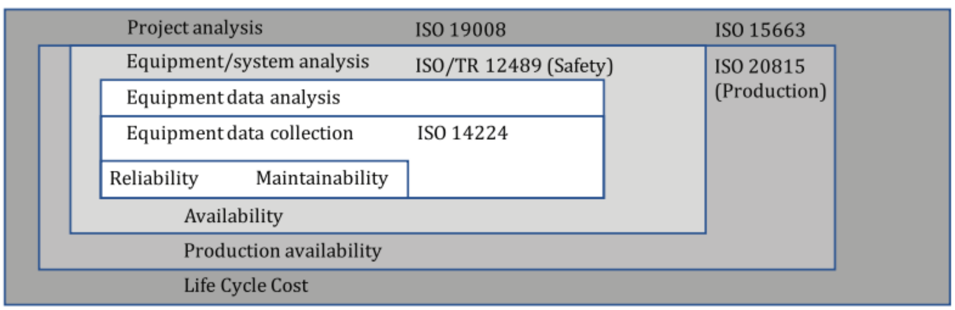

Figure 4: Relationship between analyses on different taxonomy levels [29, p. 45]

The document serves as a compendium of best practices encompassing analytical concepts and commonly employed methods for life cycle costing. However, ISO 15663:2021 does not incorporate individual company guidelines pertaining to aspects such as perspectives on uncertainty and risk, treatment of cash flow, or other decision-making factors.

It is important to acknowledge that not all choices among competing options are solely driven by economic value considerations. Various business drivers can influence a decision, even if they do not yield immediate economic benefits. Factors such as new technologies, sustainability objectives, impacts related to climate change, market context, and more, can all play significant roles in shaping decisions between alternative options [2, p. 11].

Considerations

HSE: Health, safety and environmental (HSE) considerations often exert significant influence when evaluating competing options [2, p. 11]. For many cases, compliance with minimum HSE requirements becomes a crucial aspect when scoping life cycle costing initiatives. The recommended option should consistently align with the HSE requirements, serving as a complementary factor. The relevance of HSE considerations can vary depending on the specific phase of the life cycle costing analysis. Consequently, execution of the life cycle cost (LCC) analysis may encounter difficulties due to uncertainties in the decision-making process. For example, an increase in CAPEX to enhance the HSE level of a company can be a financially advantageous, as it concurrently reduces OPEX and LOSTREV associated with failure in HSE [2, p. 11]. Relevant OPEX elements may encompass environmental measures or heightened safety protocols throughout the life cycle, while significant changes in project schedules can amplify LOSTREV. Regulatory provisions aimed at mitigating potential hazards or accidental events can be structured to facilitate informed decision-making. Furthermore, striking a balance between HSE considerations and costs becomes crucial when alternative options present distinct maintenance approaches [2, p. 11].

Sustainability and climate change: The sustainability and climate change considerations have reached unprecedented levels, rendering them crucial aspects to be considered within the assessment of life cycle costing. These considerations extend beyond cost-related terms and encompass the associated benefits derived from each option, thereby exerting a substantial influence on the decision-making process. When evaluating competing options, measuring the corresponding emission footprint can serve as a robust metric to gauge the sustainability factor and should be integrated into the life cycle costing analysis if possible [2, pp. 11-12].

Benefits of Life Cycle Costing

Use of life cycle costing has various benefits [2, pp. 12-13] as presented in Table 1:

Table 1: Benefits of life cycle costing

Benefits	Description
Strategic alignment	Engineering decisions after considering effects on potential future OPEX and revenue profile.
Improved framework for performance contracts and life cycle costing	This will enhance the total quality of materials and services from supply through development of performance contracts between operators, contractors, and vendors.
Improved decision criteria for selecting a profitable option	Support the decision-making process by considering the establishment of predefined criteria when ranking options with respect to their value.
Increased operating predictability	Early identification of OPEX is crucial to minimize the likelihood of cost overruns. Additionally, incorporating technical operating experience in the initial stages of project development is advantageous when evaluating different options.
Targeted planning of the life cycle costing activities	Throughout planning of all development stages is imperative to allocate adequate resources for the assessment of life cycle costing. The utilization of comprehensive life cycle costing model facilitates the identification, targeting, and reduction of cost drivers. Furthermore, integrating the LCC model with sensitivity analysis enables the identification of critical functions within the system.
Long-term economical perspective	The life cycle costing approach provides an early diagnosis of the economic performance of a project.

Life Cycle Phases

Life cycle phases are divided into seven stages which are represented in Figure 5.

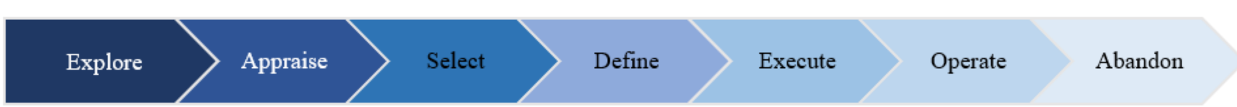

Figure 5: Life cycle phases [2, pp. 13-14]

During the various life cycle phases life cycle costing can be applied. Table 2 presents some examples of life cycle costing within the life cycle phases [2, pp. 13-14]:

Table 2: Life cycle costing within the life cycle phases

Explore	The exploration phase primarily centers on identification of business opportunities. During this phase life cycle costing can be employed to rank business opportunities exploiting comprehensive life cycle costing considerations.
Appraise	The appraisal phase of a project revolves around the identification and assessment of feasible concepts. In this phase, the primary emphasis lies in including and comparing major technical options. The focal point is on thoroughly examining the trade-off between key costs and revenues, ensuring a detailed description of the relevant factors.
Select	The select phase encompasses the development and selection of concept. During this phase, various technical and operational solutions are thoroughly studied and compared, ensuring that the favorable option is selected. The evaluation process in this phase includes both CAPEX and OPEX to ensure a comprehensive assessment.
Define	The definition phase pertains to the conceptual system design and engineering design of a project. Within this phase, life cycling costing activities typically involve examination and identification of technical options concerning facilities, process, and delivery. Subsequently, the preferred concept is defined based on the findings of the analysis conducted.
Execute	The execution phase covers the scope of work that involves system and equipment optimization while adhering to the constraints established during the “define” phase. Within this phase, the objective is to achieve the optimal functioning of the system and equipment, considering the previously defined parameters. Furthermore, this phase enables the assessment of pertinent economic evaluation measures, providing valuable insights for decision making.
Operate	The operate phase entails the optimization of a diverse array of operations and support activities during the life cycle. Additionally, life cycle costing can also be applicable when evaluating modifications or extensions to operations beyond the initially planned design life.
Abandon	The abandon phase revolves around examination of how and when to decommission and dispose of all parts of an asset.

This thesis is dedicated to exploring and analyzing the "**define**" phase of the project's life cycle, with a specific focus on examining and identifying options regarding the chosen subject matter.

In a project life cycle, the greatest potential to exert influence on the project outcome lies within the "appraise" and "select" phase, gradually diminishing as the project progresses [2, p. 15]. The associated costs of the project begin at a relatively low level during the early stages and gradually escalate until the completion of the "abandon" phase. Figure 6 illustrates the relationship between the opportunity for influence and the cost of changes throughout the life cycle. It should be noted that the "exploration" phase is not depicted in the figure, as the entire project is typically built upon the business opportunities identified during the initial phase of exploration.

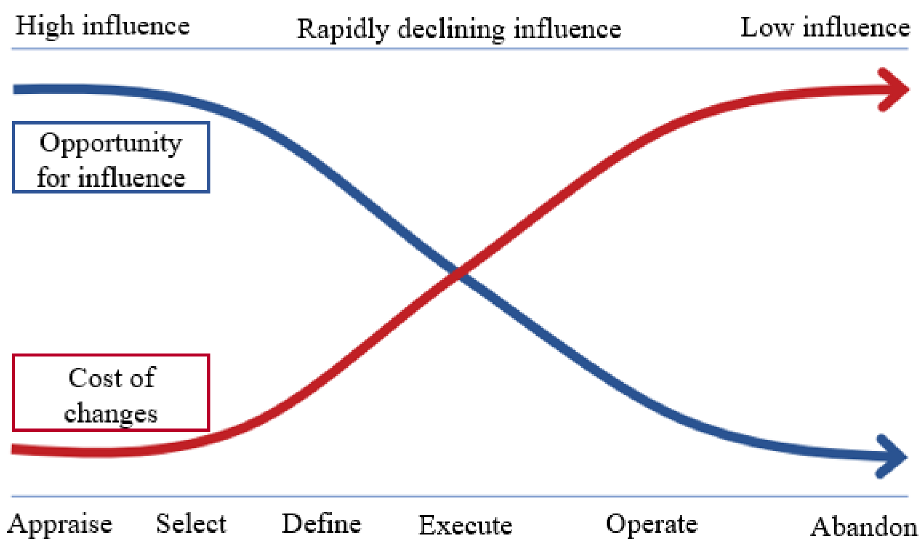

Figure 6: Opportunity to influence vs cost of change during a project's life cycle [2, p. 15]

Management of Life Cycle Costing

The most important part about managing life cycle costing is to ensure cost-efficiency and adding value. While the proceeding subchapters have introduced the fundamentals of life cycle costing, a comprehensive understanding of the detailed analyses and accurate prediction of relevant economic evaluation measures necessitates critical examination and structured management [2, pp. 16-17]. Life cycle costing serves as a valuable decision support tool when assessing potential benefits and value associated with the development of new technologies.

The analyses conducted in the life cycle costing assessment play a crucial role in investment considerations, underscoring the importance of well-developed and properly presented levels of life cycle costing to support high-quality decision making. Furthermore, it is imperative to clearly define the roles of life cycle costing, ensuring accuracy in role responsibilities, and effectively communicate the economic objectives. The management of life cycle costing also encompasses formulation of strategies and planning of activities.

Given the interdisciplinary nature of life cycle costing, which includes domains such as economics, engineering, and analysis, implementing a system that manages interdisciplinary and ensures effectiveness and efficiency can yield significant benefits. Following are some crucial elements in for managing life cycle costing [2, p. 17]:

- Developing capability and competencies in life cycle costing
- Identification of subject matter and relevant life cycle costing activities
- Select proper considerations in project, operations strategies, and planning cycles
- Defining needs in project to establish roles, resource allocation and requirements
- Life cycle costing activities should reflect customer-client relationship
- Life cycle costing as decision support for acquisition of equipment and/or services

Objectives and plan

Following are the main objectives to managing life cycle costing:

- To achieve agreement at a management level on asset objectives and how life cycle costing is linked to these objectives
- To communicate these objectives and the role of life cycle costing throughout the organization
- To define the purpose of life cycle costing prior to any activities taking place

2.1.2.2 ISO 19008:2016

The international standard ISO 19008:2016 has been developed to establish specifications for a standard cost coding system (SCCS) to be used for classifying costs associated with development and operation of oil and gas production and processing facilities [27, p. 1]. The adoption of a SCCS aims to facilitate the organization of exploration, development, and operational costs, allowing for comparative analysis across different projects and assets. The international standard provides a comprehensive code system that serves as a foundation for estimating cost and collecting historical data, supporting benchmarking and further analysis. Moreover, the standard promotes the consistent capture of data such as physical quantities, qualities, or properties. The SCCS is structured around three key aspects:

- PBS: Physical breakdown structure (physical asset)
- SAB: Standard activity breakdown (activity)
- COR: Code of resource (resource)

Thus, the SCCS comprises these three complementary and distinct sub-classifications, with each one addressing a specific aspect of cost classification. The primary content of ISO 19008:2016 revolves around the principles and utilization of guidelines for the SCCS [25, p. 4].

Application

Physical breakdown structure (PBS): The hierarchical structure provided by the PBS encompasses both the physical and functional components of petroleum facilities or projects throughout various development phases. It is designed to be independent of project-specific attributes, such as area, module, preassembly, unit, structure, subproject, or classification systems [27]. The breakdown structure is then divided into two groups, A and B. These groups are offshore installations and onshore installations respectively. Offshore installations (PBS A) are confined to include all offshore, nearshore/inshore, and ashore facilities. Figure 7 illustrates the hierarchy in the PBS.

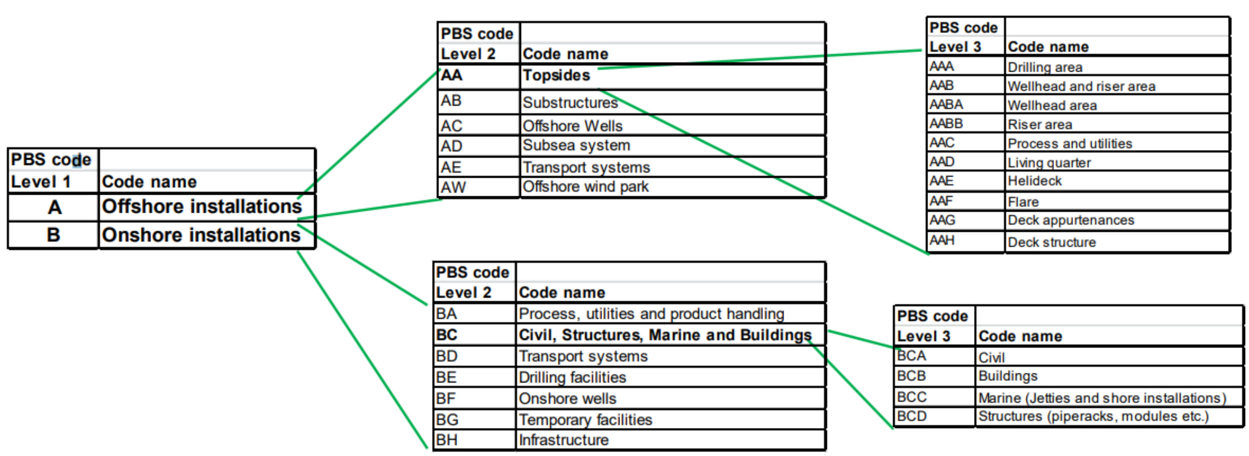

Figure 7: PBS hierarchy [47]

Standard activity breakdown (SAB): The SAB is a breakdown structure that facilitates the organization and estimation of costs for different phases of a petroleum project. It provides an activity-based breakdown of project scope, enabling the preparation of phased cost estimates and serving as a basis for estimating presentations and cost reporting. SAB includes all activities associated with planning and execution of a petroleum project. The SAB structure is divided into SAB code prefixes, which are designed to be applicable throughout all phases of an oil and gas project. Figure 8 illustrates the breakdown structure of SAB as well as the SAB phase prefixes.

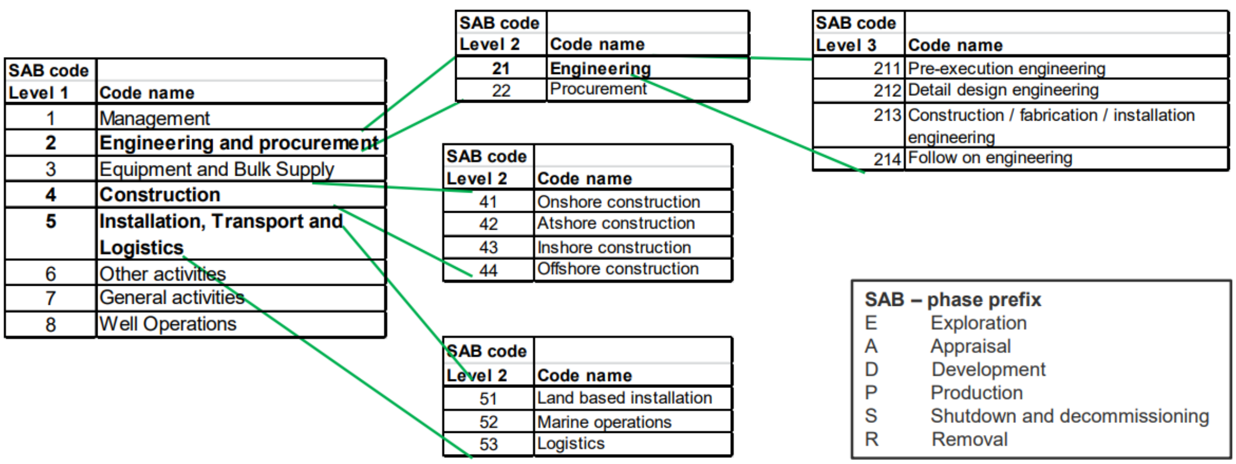

Figure 8: SAB breakdown structure and phase prefix [47]

Code of resource (COR): The COR classification system categorizes all resources engaged in a project based on the type of contract or resource involved in the activity. Each resource category within the COR is associated with a set of rates, allowing accurate cost estimation and analysis. COR encompasses the entire range of resources involved in the development of both onshore and offshore facilities. Figure 9 illustrates the COR classification system.

COR code Level 1	Code name
COR code	Code name
A	General costs
E	**Equipment**
B	Bulk materials
K	Engineering personnel
R	Engineering overheads
L	Direct labour
M	Indirect labour
C	Construction overheads
H	Company personnel
Q	Company personnel overheads
S	Unit work
X	Marine operations and logistics
Y	Land based plant and equipment

COR code Level 2	Code name
EA	Architectural equipment
ED	Drilling equipment
EE	Electrical equipment
EG	Heating, ventilation and air conditioning (HVAC) equipment
EJ	Instrumentation equipment
ER	**Mechanical equipment**
ES	Safety/escape and firefighting equipment
ET	Telecommunication equipment
EU	Subsea equipment
EV	Mooring and marine equipment
EY	Transfer and control equipment

COR code Level 3	Code name
ERC	Miscellaneous mechanical equipment
ERD	Drivers and power transmissions
ERF	Heaters, boilers, furnaces and flares
ERH	Heat transfer equipment
ERK	Compressors, blowers and expanders
ERM	Material and product handling equipment
ERN	Mechanical equipment – solids
ERP	Pumps
ERT	Storage tanks/containment equipment – atmospheric
ERV	Vessels and columns – pressurised
ERX	Miscellaneous package units

Figure 9: COR classification system [47]

Requirements

Each cost item within the context of a specific scope is associated with relevant aspects and classified accordingly with the SCCS. Each asset within the project is assigned a unique numerical or alphabetical code, reflecting its classification. These individual codes are then combined to form a code composition representing associated costs. The composed codes follow the sequence of PBS, SAB, and COR, which ensures consistent and standardized categorization.

Costs and quantities can be both summarized and decomposed from different perspectives. Each cost item should be allocated one SCCS code at each level of summarization, this is for the sake of coherence and data integrity purposes. Figure 10 illustrates the SCCS classification structure.

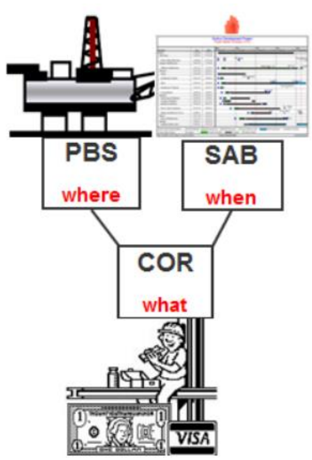

Figure 10: Illustration of SCCS classification structure [47]

2.1.2.3 ISO 20815:2018

ISO 20815:2018 delineates the fundamental principles and practices of production assurance within the intricate systems and operations of the petroleum industry [29, p. 1]. The document encompasses a wide spectrum of activities, including those related to upstream, midstream, downstream facilities. Its primary emphasis lies in ensuring production assurance throughout the stages of petroleum production and processing, with particular attention given to the analysis of reliability and maintenance pertaining to interconnected components. By adhering to the guidelines stipulated in the standard, stakeholder can attain cost-effective solution that span the entire life cycle of an asset development project. The structured framework presented in ISO 20815 revolves around key elements vital to achieving production assurance. The standard is structured around the following main elements [29, p. 1]:

- Production assurance management in optimal economy of the facility through all life cycle phases, while considering constraints such as HSE, sustainability and quality
- Planning, execution, and implementation of reliable technology
- Application of maintenance and reliability data
- Technology development, design, and operational improvement, based on reliability

2.1.2.4 ISO 14224:2016

The ISO 14224:2016 standard serves as a fundamental framework for the systematic collection of reliability and maintenance data relevant to equipment utilized across various facilities and operations within the petroleum industry's life cycle [28, p. 1]. It plays a crucial role in facilitating effective communication of operational experiences by providing a standardized "reliability language" through well-defined terms, definitions, and principles for data collection. ISO 14224:2016 defines a minimum amount of data that is required to be collected, and target two main issues [28, p. 1]:

- Data requirement for the categories of data to be used for further various analyses
- Standardized data format to encourage the exchange of reliability and maintenance data between plants, owners, manufacturers, and contractors

Main categories that are to be collected are then:

1. Equipment data
2. Failure data
3. Maintenance data

The data provided in the categories will further be used for the following areas:

1. Reliability
2. Availability/efficiency
3. Maintenance (e.g., corrective or preventive)
4. Safety and environment

2.1.3 Cost Estimation Methodologies

Cost estimation serves as a crucial tool in projecting the quantity, cost, and price of resources essential for the successful implementation of a project. Its primary purpose lies in equipping decision-makers with the necessary information to make informed investment decisions and select the most viable alternatives [53]. A plethora of cost estimation methods are available, and this chapter encompasses the specific ones employed within the context of this thesis.

2.1.3.1 Top-Down & Bottom-Up Estimation

When it comes to cost estimation in project management, two primary methodologies are commonly employed: top-down estimation and bottom-up estimation.

Top-down estimation is a technique wherein the effort, cost, or resources for a project or task, are initially estimated as a whole and subsequently divided into smaller, more manageable parts. This approach relies on historical data, standards, or expert judgment to establish an initial estimate for the project, which is then further subdivided into smaller components based on specific assumptions or criteria. The resulting aggregate figure may represent either the total cost of the entire project or a significant portion of a work breakdown structure (WBS). Top-down estimation is frequently employed during the early phases of the project life cycle, such as the “explore” and “appraise” stages.

The accuracy of a top-down estimate hinges on the availability and quality of historical data. Contingency factors, accounting for uncertainties in the total cost, are determined based on the estimator’s discretion and informed by historical information. Nevertheless, top-down estimation carries certain limitations. Compared to other estimation techniques, it tends to be less precise as it relies on assumptions and generalizations rather than detailed data and rigorous analysis. Moreover, it may overlook critical details and lack transparency, which can pose challenges when adjusting the estimate as new information emerges.

In contrast, during the later stages of a project when the scope is well-defined, a bottom-up estimation methodology can yield higher accuracy. This approach entails breaking down the project into a detailed WBS and estimating the cost associated with each individual work package from the bottom up. The budget for the project is then derived by summing up the costs of all the work packages.

Bottom-up estimation requires a clearly defined scope and a comprehensive understanding of the costs and input factors associated with each work package within the WBS. Unlike top-down estimation, bottom-up estimation demands more labour-intensive efforts and necessitates estimators with a diverse skill set. The detailed estimates generated through this approach tend to be more precise; however, they are typically conducted closer to decision gateways, where management evaluates the estimates. In the early stages of life cycle cost estimation, if a top-down estimate is deemed sufficiently accurate, it is generally the preferred choice of methodology.

2.1.3.2 Deterministic & Probabilistic Estimation

A deterministic approach to cost estimation involves a methodology that relies on specific and known data inputs to generate a precise cost estimate for a project. This approach assumes that variables such as the project's scope of work, schedule, and resource requirements are fixed and known with certainty. One notable advantage of the deterministic approach is its ability to provide a highly accurate estimate, assuming that the input variables are accurately known. However, a limitation of this approach is its failure to account for uncertainties or risks that may arise during the project, potentially leading to cost overruns and delays. Consequently, many organizations try to complement deterministic methods with probabilistic estimation techniques.

In contrast, the probabilistic approach to cost estimation differs significantly from the deterministic approach. It involves estimating project costs by considering the uncertainty and risk associated with the project. Instead of assuming fixed and certain project variables, the probabilistic approach utilizes probability distributions to represent the range of possible values for each variable. This enables the calculation of the likelihood of different cost outcomes based on various combinations of input variables. While the probabilistic method is more time-consuming than the deterministic method, it offers a clearer and more realistic understanding of the potential costs associated with a given option. Furthermore, it assists project managers in identifying and effectively managing risks.

The distribution of costs for the subject matter option is determined by the probability distribution of relevant cost drivers. By employing this approach, it becomes possible to calculate the distribution of the final cost estimate and present the key results within the estimate. These results may be:

- Expected values
- P-values (P0-P100)
- Standard deviations
- Confidence intervals

Deterministic and probabilistic approach both applies to top-down and bottom-up estimation, the distinction is not exclusive to neither.

2.1.3.3 Monte Carlo Simulation

The probabilistic approach to cost estimation involves the identification of a range of possible values for input variables and the subsequent execution of multiple simulations to generate a range of potential cost outcomes. Statistical techniques, such as Monte Carlo simulations, are commonly employed for this purpose [36].

In a Monte Carlo simulation, a computer model is constructed to represent the probabilistic calculation under study, incorporating relevant inputs and their associated means and standard deviations. Random values are generated for each input variable, and the model is iteratively executed multiple times, typically ranging 1,000, 10,000 or 100.000 iterations. The simulation results are then recorded to construct a statistical distribution depicting the range of possible outcomes for the system.

Monte Carlo simulations are particularly useful for modeling complex calculations, especially in situations where the behavior of the subject studied is challenging to predict or where there are numerous input variables with intricate interactions that are not fully understood. By utilizing this modeling technique, decision-makers can gain valuable insights into the risks and uncertainties associated with a specific scenario, enabling them to make informed choices based on this information.

2.2 Technical and Operational Basis

This subchapter comprehensively covers the technical and operational basis that underpin the technological advancement of the subject matter. It is structured into three distinct sections. Firstly, a case study is presented, outlining the essential technical and operational requirements for each alternative option being considered. Secondly, the subchapter expounds on the concept of flow assurance and the application of production chemicals within the scope of this thesis. Lastly, the subchapter will conclude by presenting the options relevant to this thesis and exploring various cost elements that are anticipated to influence the LCC analysis.

2.2.1 Case Study

Some foundational parameters are included to the case study in support of the life cycle costing assessment. These parameters showcase the subsea production field utilized for the assessment with some minimum acceptance criteria on infrastructural design that are equal for both options. The following points provide clarity in the field architecture for the subject matter:

- Design life: 20 years
- Tieback distance: 20 km
- Water depth: 300 m
- Type of field: Oil
- Ambient pressure/temperature at seabed: 300 bar / 4℃
- Subsea architecture: 4 Wells and 1 manifold (10000 PSI)
- Topside host facility: Floating, production, storage, and offloading (FPSO) vessel
- Flowrate: 50.000 barrels/day
- Operating pressure: 200-450 bar
- Operating temperature: 50-150℃

Distribution network for either option should deliver the chemicals presented in Table 3.

Table 3: Injection properties for the case study

Product	Injection point	Injection rate	Injection mode	Max pressure at injection point (bar)
CI	XT	8.3 L/h max	Continuous	450
SI	XT	8.3 L/h max	Continuous	450
Biocide	End of line	200 L/h	5 h/week	450
MEG	XT	5000 L/h	Preservation 30’ /Well	550

Further in this subchapter are the chemicals utilized for the case study presented and corresponding properties assessed.

Flow Assurance & Chemicals

The characterization of fluid properties and the development of an effective flow assurance concept are crucial steps in ensuring the smooth operation of fluid transport systems. To initiate this process, a comprehensive analysis of the fluids present in the reservoir was conducted. This analysis encompassed a thorough examination of the fluid properties, which subsequently informed the design considerations for the subsea equipment related to each competing options, such as determining the appropriate size and insulation requirements. By understanding the fluid characteristics, it became possible to identify the necessary chemical treatments that should be employed during oil production, as well as the most suitable procedures for their injection.

Common flow assurance challenges include the formation of wax, hydrates, scale, asphaltenes, erosion, and emulsion-related issues [31, pp. 331-347]. The occurrence of these challenges can lead to a decrease in production availability or even necessitate extensive workovers, resulting in increased OPEX due to maintenance activities and potential LOSTREV caused by a reduction in production levels. To mitigate these problems, a diverse range of chemicals are introduced into the subsea system at strategic locations. The subsequent sections encompass the utilization and advantages of these chemicals in relation to the subject matter.

Corrosion Inhibitor

Corrosion inhibitor (CI) plays a vital role in mitigating internal corrosion within pipelines [31, p. 16]. These inhibitors function by decreasing the interaction between oxidizing agents and the metal surfaces, as illustrated in Figure 11. One approach involves utilizing "surface-active" corrosion inhibitors, which obstruct the access of oxidizing agents to the metal surface. Alternatively, corrosion can be prevented by removing the oxidizing agents from the extracted fluid.

The content within the inhibitor influences the applicability of the CI and its overall environmental impact. Therefore, before deployment in the field, it is imperative to subject the entire inhibitor package to rigorous testing, not solely focusing on the active chemical ingredients within the inhibitor. This comprehensive evaluation ensures that the inhibitor meets the required performance standards and aligns with environmental considerations.

Figure 11: Corrosion formation in pipelines [54]

Scale Inhibitor

Scale inhibitors are administered continuously into the production flow as a preventive measure against scale formation, as illustrated in Figure 12. In most instances, only a minute dosage of scale inhibitor is required at any given time to effectively hinder scale deposition. The primary role of scale inhibitors is to impede the growth of scale crystals, necessitating their injection into the system prior to the initiation of scale solidification. Scale precipitation can pose significant challenges to tubing integrity; hence, it is advantageous to inject the scale inhibitor downhole, specifically targeting the precipitation initiation point. Furthermore, in accordance with Bai and Bai's findings, it is recommended to inject scale inhibitor at the subsea well tree to avert scale formation in manifold systems, pipelines, or the tree itself [31, pp. 537-539].

Figure 12: Formation of scale in pipeline [55]

Biocides

Biocides play a crucial role in mitigating sulphide production and microbiologically induced corrosion in various applications [34, p. 327], as illustrated in Figure 13. Their primary objective is to eliminate microorganisms, particularly bacteria, that thrive on a diverse range of nitrogen, phosphorus, or carbon compounds necessary for their growth. The presence and proliferation of bacteria can lead to flow blockages, thereby compromising production efficiency. Biocides find utility both upstream and downstream during oil and gas production. They are also employed in drilling and fracturing operations, as well as well treatments, to minimize the formation of hydrogen sulphide, sulphide scales, and corrosion, thereby enhancing overall well productivity. Two distinct classes of biocides exist: oxidizing biocides and non-oxidizing organic biocides. In seawater lift systems, oxidizing biocides such as chlorine/hypochlorite are commonly employed. Non-oxidizing organic biocides, on the other hand, interfere with the biological processes of microorganisms without causing their complete elimination. This type of biocide is less likely to induce corrosion compared to oxidizing biocides [34, p. 327].

It is essential to consider the potential adverse impacts of biocidal products on human health and the environment. The Norwegian Directorate of the Environment has enacted legislation to regulate the use of biocides [56]. The primary objective of this legislation is to ensure the protection of animal and human life while facilitating trade between European nations. The legislation outlines national requirements, fees, and specifies which biocides are approved or not approved for use in production processes.

Figure 13: Formation of microorganisms in pipelines [57]

Methanol and MEG

Methanol (MeOH) and mono-ethylene-glycol (MEG) are prominent examples of hydrate inhibitors. These inhibitors find significant application in regions characterized by low temperatures, where rapid cooling of the subsea system may lead to the formation of hydrate. The role of a thermodynamic inhibitor, such as methanol or MEG, is to alter the chemical potential of water, similar to the addition of antifreeze in water. During operations involving hot hydrocarbon fluids, these chemicals are injected into the tree and occasionally downhole, just above the subsurface safety valve. By adopting this approach, the formation of hydrates in the choke and downhole regions can be effectively prevented, particularly transient operations [31, pp. 461-466]. Figure 14 illustrates formation of hydrates in pipelines.

Figure 14: Formation of hydrates in pipelines [48]

2.2.2 Subject Matter Options

This subchapter presents the field architecture for each of the competing options. Firstly, the chemical injection method utilized for the individual option is presented and important components of the system are described. Secondly, a figure illustrating the option relevant to the subject matter is presented. Finally, since the subject matter is a technology development regarding AE functions, benefit statements of the SCSIS option are presented to summarize the subchapter.

2.2.2.1 Option A: Topside

The topside chemical injection system (CIS) incorporates a chemical injection unit (CIU) that comprise of instrumented storage tanks for each chemical, facilitating the supply of chemicals to the injection pumps. In the context of the topside configuration, a topside umbilical termination assembly (TUTA) serves as the interface linking the CIS to the umbilical, which extends down to the seafloor. The umbilical is responsible for conveying electricity, fibre optic signals, hydraulics, and chemicals from topsides to the subsea production system (SPS). An umbilical termination assembly (UTA) establishes the interface between the umbilical and the manifold that distribute chemicals to the downstream users. The distribution model for Option A is displayed in Figure 15, providing a visual representation of the chemical distribution arrangement.

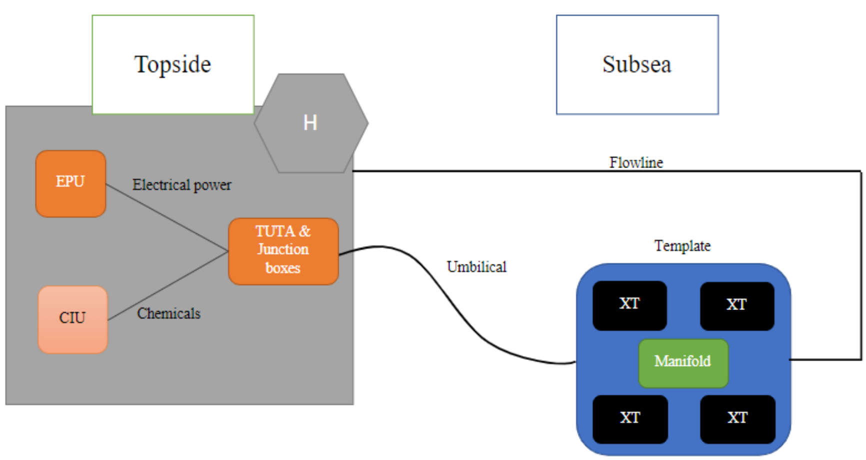

Figure 15: Schematic for Option A

2.2.2.2 Option B: Subsea

The SCSIS presents a proposal to relocate the chemical storage and injection operations to a nearby subsea architecture. In this configuration, power and control functionalities are transmitted from the topside facility through a dedicated power cable. The power cable serves as a conduit for conveying electricity and fibre optic signals to a subsea power system, prior to its connection to a manifold module. The manifold module receives the signals and facilitates the transfer of chemicals from the SCSIS to the designated injection points through individual jumpers corresponding to each storage unit. Figure 16 provides a simple illustration of the chemical distribution model for Option B.

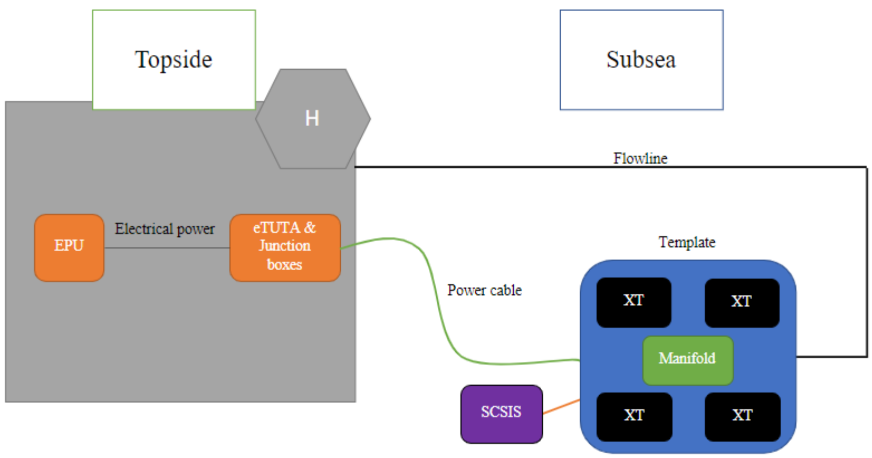

Figure 16: Schematic for Option B

2.2.2.3 Benefits of the SCSIS

The conventional topside solution involves storing chemicals on topside assets and delivering them to the subsea system through an EH umbilical. In contrast, the alternative AE solution proposes the relocation of chemical injection assets to the subsea environment, offering numerous anticipated benefits. These benefits, as outlined in Table 4, were derived from various conference papers and Equinor reports, and they encompass ten key expected benefits associated with the advancement of this technology.

Table 4: Benefit statements of Option B

Benefit statement	Description
1. Enable longer tiebacks	In scenarios involving long tie-back lengths, a limiting factor is pumping the viscous chemicals through a narrow-diameter tube, particularly in terms of generating the necessary pressure to inject the chemicals into the wellhead. To address this issue, one solution is to dilute the chemicals prior to their delivery to the subsea production field (SPF). However, this dilution compromises the efficacy of the chemical treatment and necessitates a larger quantity of chemicals to be stored on the topside facility. The SCSIS eliminates the requirements for chemical dilution since chemicals are stored close to their injection points.
2. Lower development costs	The removal of a burdensome and costly umbilical, coupled with the potential for reusing the SCSIS for other fields, presents opportunities for equipment relocation in cases where the field is underperforming, or early abandonment is necessary. Furthermore, the SCSIS offers the advantage of serving as an early production tool, as its deployment is considerably faster compared to that of an umbilical. This expeditious deployment facilitates earlier cash flow generation and accelerated acquisition of valuable production data.
3. Reduce host platform space and weight requirements	By implementing the SCSIS, the spatial and weight demands on the host platform are diminished. This reduction in requirements offers potential cost savings for new platform constructions when subsea units are incorporated during the design phase. Additionally, for existing brownfield platforms, the newfound space and weight allowances provide opportunities for enhanced sustainability measures and the accommodation of other critical equipment.
4. Eliminate hazardous chemical interaction with offshore personnel	The SCSIU is installed and refilled from an FSV, never to encounter platform personnel. This can result in large HSE benefits.
5. Lower chemical cost	A chemical service model employed in the context of the SCSIS aims to alleviate cost burdens typically associated with onshore chemical delivery models. In umbilical applications, the focus is often on engaging a single supplier to ensure compatibility and prevent issues such as cocktail blending and umbilical blockages. However, the SCSIS offers individual storage

	modules for each chemical, enabling users to inject chemicals into the system without apprehension regarding cocktail blending and umbilical blockage risks. Consequently, decisions regarding chemical suppliers can be based on factors such as performance and price, rather than being restricted to a common supplier.
6. Modular design benefits	The implementation of the SCSIS simplifies the design, fabrication, and installation processes by utilizing standardized and modular components. The use of modular storage modules reduces OPEX and the potential of LOSTREV. Additionally, modular units offer increased flexibility to adjust the number of subsea units as field requirements evolve.
7. Facilitate platform lower manning	By eliminating the requirement for chemical storage tanks on the platform, there is a reduced need for personnel to handle tasks such as installation, refilling, and repair. Consequently, the workload on the host facility, for instance the case FPSO, is significantly reduced.
8. Ease host tie-in burdens	The process of connecting production to a non-owned host facility is simplified when the field is equipped with its own SCSIS, as it eliminates the need for the host platform to accommodate chemical injection requirements. This reduces the complexity associated with tying in production and facilitates smoother integration between the field and the host facility.
9. Lower project risk	The sole connection between the topside facility and the subsea production system is a standard power cable, which offers advantages in terms of reduced weight and increased flexibility compared to a standard EH umbilical. Additionally, the implementation of the SCSIS enables the utilization of smaller vessels during marine operations, presenting opportunities for enhanced operational efficiency and cost-effectiveness.
10. Higher reliability	In the event of damage occurring during installation or the field's operational lifespan, repairing an umbilical is not a simple task, potentially necessitating the procurement of new umbilical parts. This can lead to significant repercussions in terms of project cost, production, and execution. Conversely, a power cable has the potential for retrieval and on-deck repair, thereby mitigating the impact on schedules and production, and offering a more flexible and cost-effective solution.

2.2.3 Cost Elements

A cost element is a subset at any level of the total cost for a cost breakdown structure [2, p. 3], meaning the cost of an object or item, resource, activity, or a combination of these. Regarding the subject matter, a variety of cost elements have been identified, these are also presented from Chapters 2.1.1.1 to 2.1.1.3. This subchapter assesses cost elements applying to CAPEX, OPEX and LOSTREV for the subject matter.

2.2.3.1 Equipment and Engineering

Equipment and engineering constitute essential cost elements that significantly contribute to CAPEX but also applies to OPEX [2, pp. 59-60]. In the context of the subject matter, the expenses related to equipment and engineering manifest during the procurement and fabrication stages of the major components associated with each individual option. This subchapter evaluates the major components in each competing option, providing relevant technical information that should be incorporated in the overall cost estimation.

Option A

Chemical injection Unit (CIU): The design of the topside CIU must be carefully planned to accommodate the required chemicals and volumes, ensuring efficient petroleum production throughout the project's lifespan. It is imperative that the entire system, including storage tanks and injection units, be constructed using durable and flexible stainless-steel materials, exhibiting strength, redundancy, and forgiving characteristics [23, p. 4]. Adequate sizing of the topside chemical tanks is essential to minimize the frequency of refilling operations. The emphasis on a flexible system stems from the need to facilitate easy expansion and modification, should the requirements change. This flexibility is crucial in scenarios where a particular chemical is no longer needed after the initial startup phase or when a new application suddenly becomes necessary. All systems should be designed to account for “worst-case scenarios”, incorporating backup systems or secondary equipment for critical components. Figure 17 illustrates a typical chemical injection package, containing multiple CIU’s.

Figure 17: Chemical injection package [58]

Umbilical: Umbilicals are designed to meet the specific operational requirements of each field. They serve several critical functions, including subsea production and water injection well control, well workover control, subsea system monitoring, chemical injection, and provision of electrical power to the subsea system [31, pp. 63-70]. To fulfill these tasks, an umbilical comprises various cables and components such as electrical cables, hydraulic lines, optical fibers, and chemical injection lines, all of which are safeguarded within an outer casing. Figure 18 illustrates a typical cross-section of an electro-hydraulic umbilical. The structural configuration of the umbilical is significantly influenced by factors such as the number of hydraulic lines, injection pressure, tie-back length, and the anticipated flow rate of chemicals.

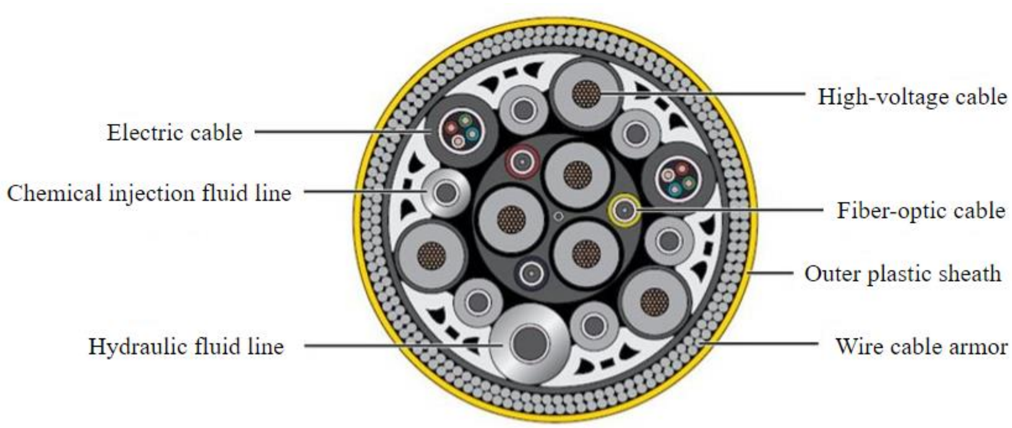

Figure 18: Subsea umbilical cross-section [59]

Other Equipment: In this thesis, the cost of the topside CIS is estimated by associating the weight of the equipment with the appropriate cost coding assortment. Table 5 encompasses various equipment categories relevant for the topsides CIS that are crucial to consider during a comprehensive technical cost element analysis for Option A, but are not thoroughly assessed individually:

Table 5: Option A topsides CIS equipment categories

Equipment
Electronics
HVAC
Surface protection
Instruments
Piping
Telecom

Option B

Subsea chemical storage module: The subsea chemical storage and injection unit represents a significant component within the overall subsea system. During the production of petroleum, the storage unit experiences a depletion in its containment level. Given the low liquid level within the tank and the substantial pressure exerted at the bottom of the sea, it is imperative for the storage module to possess deformable characteristics or the ability to withstand external pressure. To this end, a flexible membrane design is employed, enabling the chemicals to freely adjust to counteract the applied pressure. The membrane is further safeguarded by a protective structure equipped with a water ingress port to facilitate the flow of seawater inside the tank. The system is also engineered to ensure cost-efficient launch and installation, as well as to minimize weight and the need for corrosion protection. The installation of Subsea Chemical Storage and Injection Units (SCSIUs) can be achieved through both individual lifting and submerged tow methods. The storage volume is determined based on the chemical consumption rate and the frequency of refilling. By employing a minimum of two storage units for each chemical (except Methanol or MEG since they are not operating continuously), petroleum operations can proceed uninterrupted during the refilling process.

The SCSIS encompasses several key elements, including the chemical storage unit, fluid transfer and isolation system, injection pumps, re-filling system, control and instrumentation, power supply, and structure and foundation [4, p. 8]. A potential design of the SCSIS and the SCSIU are presented in Figure 19 and Figure 20, even though other design possibilities exist.

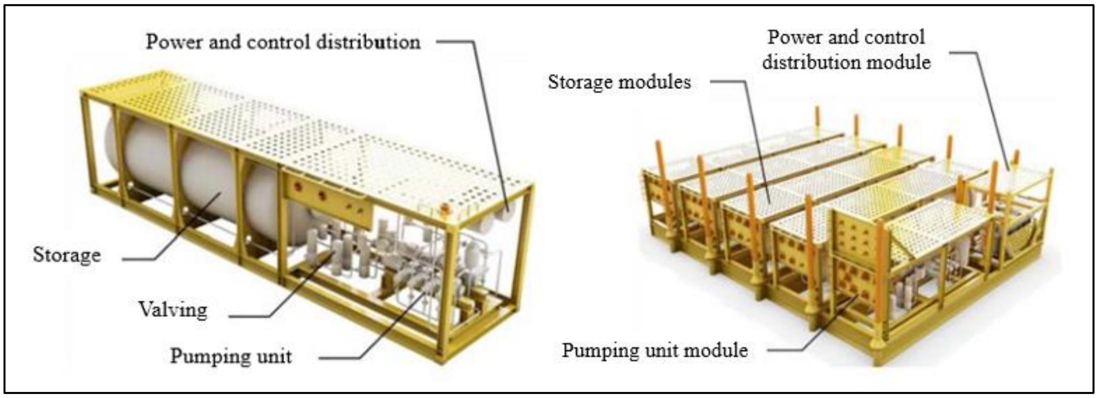

Figure 19: Potential SCSIS design [15, p. 5]

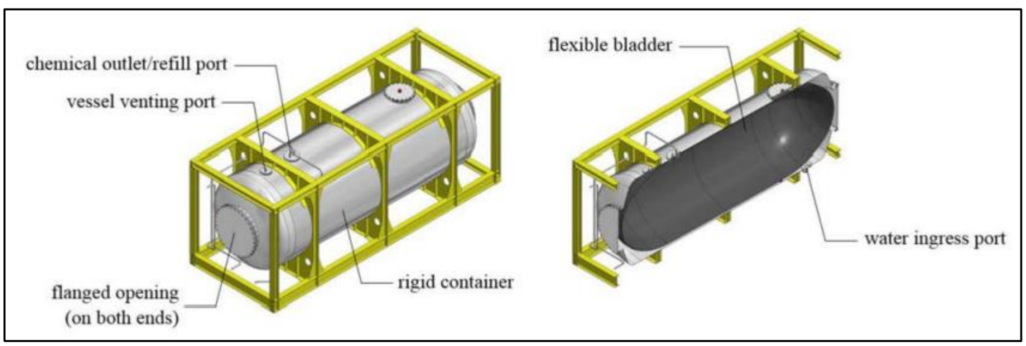

Figure 20: Potential SCSIU design [15, p. 12]

The SCSIU needs to satisfy numerous requirements while at the same time be cost-efficient and reliable [16, pp. 4-5]. Some of these requirements are:

- Compatibility between chemicals and materials
- Prevention of chemical leaks and seawater ingress
- Transport, handling, and installation of tanks
- Weight of thanks – empty and full, both in air and submerged

- Routine maintenance and filling of chemicals
- Cleanliness requirements for the chemicals

Design parameters with weights for the SCSIS are presented in Table 6. Most of the design parameters were extracted from [11, p. 8] but was altered to meet the design requirements that are evident from several conference papers.

Table 6: Design parameters with weights for the SCSIS

Component	Description
Overall system	• Qualified for 3000 metre water depth and 10-year design life
Frame	• 1 SCSIU frame = 3m (width) x 3m (height) x 7m (length) = 63 m^3 • Minimum total SCSIS frame (7 tanks) = 441 m^3 • **Dry weight: 140 t**
Storage tanks	• 28 m^3 (+4 m^3 reserve) • **Dry weight = 7×10 t = 70 t**
Bladders	• 32 m^3 • Flexible bladder compatible with production chemicals • Custom design • **Dry weight: N/A**
Pumps	• Rated up to 10.000 psi • 1 Intermittent injection pump (225 kW) total weight: **2.5 t** • 6 Continuous injection pumps (each 15 kW) total weight: **7.5 t** • **Dry weight: 10 t**
Valves and actuators	• Electric motor valve actuators • **Dry weight: N/A**
Power, monitoring, and control system	• Interface between topside and subsea • **Dry weight: 10 t**
Piping	• Flexible jumpers with connection, rated to 20ksi • **Dry weight: 20 t**
SCSIS	• **Total dry weight: 250 t**

Description of some important components within the SCSIS

Table 7 shows some important components that are integrated in the SCSIS. These are presented to enhance the technical and operational basis of the life cycle costing assessment.

Table 7: Description of some components withing the SCSIS

Component	Description
Cluster frame	The cluster frame is a steel structure containing all the chemical storage units, as well as termination assemblies, control, instrumentation and power distribution units, fluid transfer system, and subsea injection pumps. The frame is made of steel profiles for installation on a flat surface.
Valves	Valves are typically mounted within a pipeline system and regulate the flow of fluid within the system by opening, closing, or partially obstructing the passageway. Valves are controlled by actuators, which can be either electrically actuated or hydraulically. Some important parts to consider when selecting valve are design, weldability, operational speed, ROV intervention and fluid displacement during operation [31, pp. 18-25].
Injection Pump	The positive displacement pump increases the pressure of a liquid by operating on a fixed volume in a limited space. Furthermore, the displacement pump can handle high viscosities, high pressure, and low velocities with high accuracy, which is some of the most important requirements for subsea chemical injection. Since no displacement pump has been utilized subsea, already existing topside chemical pumps can be marinized and be adapted to this application.
Flow Meter	Flowmeter is an information tool used for: Confirming that the pumped flowrate is compliant with injection requirements, calculating the residual volume of chemical working as level monitoring meaning, and integrating the set of data provided to topside for condition monitoring purpose [15, p. 15].
Subsea Transformer	The subsea transformer reduces high voltage to a level that can be used for pumps, motors, and compressors, while still providing reliable performance [60].
LV Switchgear	The Low voltage switchgear is responsible for power distribution and protection of other units in the subsea power grid [61]. The switchgear will receive medium voltage from the stepdown transformer, and then distribute low voltage to different consumers.

Soft Start	Soft starters are used to limit the surge of a current and control the electric acceleration phase, resulting in a safer and smoother start-up of petroleum production components [62].
SCSI eSCM	The SCSI requires its own electrical subsea control module (eSCM) to operate. SCM are most utilized for well control during oil and gas production. The eSCM regarding SCSI includes functions to actuate flow control, choke valves, shutoff valves, downhole safety valves, and chemical injection valves [31, pp. 207-209]. Furthermore, the eSCM can be used for monitoring pressure, temperature, and flow rate.

Power cable: The power cable serves as the crucial link between the topside and subsea levels, facilitating the transmission of high voltage (HV) electrical power and communication through its embedded fiber lines. The simplification of the power cable offers the advantage of enabling repairs to be carried out in the event of any issues that may arise. Additionally, the power cable is equipped with multiple fiber lines, allowing for reconfiguration in the case of a failure. Figure 21 provides a possible cross-sectional representation of the power cable, illustrating its internal structure and components.

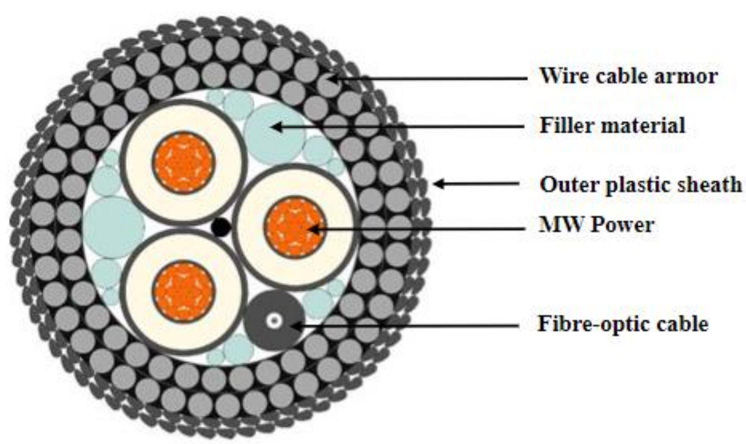

Figure 21: Possible subsea power cable cross-section [63]

2.2.3.2 Marine Operations

Marine operations are according to ISO 19903:2019: “planned and controlled vertical or horizontal movement of a structure or component thereof over, in or on water” [64]. In relation to the subject matter, both options require and offshore installation campaign as well as continuous refilling operations to cover the demand of production chemicals. This subchapter encompasses information around the main marine operations that contribute as a cost element for the life cycle costing assessment.

Transportation and Installation

By implementing a design solution that incorporates lightweight materials, the subsea system can achieve a reduced weight profile at the seabed, enabling the utilization of field supply vessels (FSV) with low crane capacity [16, p. 6]. Lower crane capacity can result in cheaper vessels, thus reducing the field OPEX.

The installation process entails the initial deployment of the cluster frame, which is accomplished through a single lift operation. Subsequently, the SCSIUs are individually installed and connected to the system. To ensure optimal weight management, it is important that the SCSIUs are empty during the lifting operations. While it is possible for most vessels to install the cluster frame separately from the storage tanks, if time efficiency is prioritized, all components can be installed simultaneously. However, this would require a larger crane capacity, leading to increased costs. In summary, heavy lifts exceeding 150 metric tons will be executed by regular construction vessels (CV), while light construction vessels (LCV) will handle operations throughout the field's lifespan. Table 8 presents a typical installation campaign, along with the vessel requirements and the duration of each installation activity.

Table 8: SCSIS vessel requirement for installation (altered numbers from CostCalc)

Activity	Vessel	Duration
Mobilization of cluster frame	CV	2 days
Transit to installation site	CV	2 days
Installation of cluster frame	CV	2 days
Mobilization of storage units and subsea power system	LCV	6 days
Transit from installation site	LCV	2 days
Installation of storage units	LCV	4 days
Connect SCSIS to manifold and test	LCV	1 day
Filling of storage units	LCV	2 days
Commissioning of the SCSIS	LCV	1 day
Total		**22 days**

While installing large components such as tank modules, operators often impose restrictions for other field activities or installations. By considering safe zones for installation activities near the SCSIS, following consequences may be avoidable [16, p. 7]:

1. Shut down or restart require a large volume of MEG, affecting CAPEX and OPEX
2. Loss in SPS availability, resulting in LOSTREV

Logistics & Refilling

Effective logistics pertaining to the deployment, retrieval, and refilling of tank modules play a crucial role in maintaining uninterrupted production availability. It is desirable to conduct displacement or refilling operations for tank modules without the need to shut down individual wells or the entire SPS. An approach that can prove valuable, although not included in the estimation provided later in this thesis, involves the utilization of a wet storage template. This template allows both filled and empty tank modules to be stored before or after operations [16, p. 7]. Implementation of such a system has the potential to reduce potential OPEX by minimizing the requirement for FSV trips. The feasibility and suitability of employing a wet template depend significantly on the field's depth and distance to the service base, necessitating a thorough assessment for each potential field.

During operations, regular refilling and monitoring of the chemical storage tanks are essential for both options. It was assumed in this study that an FSV was available for refilling purposes when necessary. Several parameters influence the refilling options, which include:

- Water depth
- Pressure
- FPSO host facility
- Size and complexity of tank modules
- Time interval between refilling
- Cost
- HSE
- Maintenance

Based on the parameters affecting refilling strategy, the following refill options were:

- Refilling by lifting tanks and reinstalling separately
- Refill by use of downline attached to FSV

Adapting existing technology for refilling topside storage tanks to meet the specific requirements of the SCSIS is considered the preferred approach, as indicated from restricted reports provided by Equinor. This strategy ensures that no modifications to the FSV’s are necessary to accommodate the SCSIS.

The following refilling activities, along with their corresponding durations, are outlined for both Option A and Option B. Table 9 shows refilling activities and durations for Option A. Table 10 presents the activities and durations for refilling with a downline from the supply vessel to the SCSIS, while Table 11 provides the duration for lifting, refilling, and reinstalling the SCSIS. All refilling sequences can be performed with a light construction vessel (LCV).

Table 9: Option A refilling (activities and duration)

Activity	Duration
Onshore logistics for purchase and storage of various chemicals	N/A
Onshore preparation of ship and storage tanks	N/A
Transit to offshore facility by use of an LCV	2 days
Lifting of storage tanks onto FPSO and offload empty ones from FPSO	6 hours
Manual handling of storage tanks from CIU storage area	4 hours

Refilling of integrated CIU	4 hours
LCV transit to port	2 days
Cleaning of fluid before transfer to injection pump	6 hours
Regular inspection of level indicators	4 hours
Total	**5 days**

Table 10: Option B refilling with downline (activities and duration)

Activity	Duration
Onshore logistics for purchase and storage of various chemicals	N/A
Onshore preparation of ship and storage tanks	N/A
Transit to offshore site by use of an LCV	2 days
Mobilize refilling bundle and connect to SCSIS	1 day
Inject chemical to SCSIS storage units	18 hours
Disconnect refilling bundle	6 hours
LCV transit to port	2 days
Total	**6 days**

Table 11: Option B refilling with reinstalling (activities and duration)

Activity	Duration
Onshore logistics for purchase and storage of various chemicals	N/A
Onshore preparation ship and filled storage tanks (ensuring high cleanliness)	N/A
Mobilization of new SCSIU’s on the LCV	1 day
Transit to offshore site by use of an LCV	2 days
Replace old modules with new ones	2 days
LCV Transit to port	2 days
Total	**7 days**

2.2.3.3 Maintenance

Maintenance regarding the subject matter encompasses maintaining equipment and system integrity throughout the entire design life of each option. This is fulfilled by solid planning and monitoring of equipment, as well as keeping up with scheduled inspections and keeping spare parts on the host facility [65]. Unpredicted maintenance operations can be costly and affect downtime, so implementing a comprehensive maintenance routine is crucial to anticipate and address any potential issues for both competing options. Reports from Equinor have also addressed the expected mobilization time for unpredicted repair and intervention resources as presented in Table 12.

Table 12: Mobilization time for repair/intervention resources

Type	Mobilization time
FSV	72 hours
Topsides maintenance personnel	12 hours

Option A

For the topside solution, maintenance activities that can be performed on the topside facility are carried out by offshore personnel. Based on reports, mobilization of topside maintenance personnel can typically be accomplished within a 12-hour timeframe. Preventive maintenance for the topside CIS can be conducted at any given moment. However, maintenance tasks associated with subsea assets will likely require support from an FSV.

Option B

In the subsea solution, maintenance operations are primarily conducted by personnel on an FSV. However, the design of the SCSIS allows for conventional subsea inspection and maintenance using remotely operated vehicles (ROVs) [16, p. 10], which introduces some possibilities. According to restricted reports, mobilization of an FSV for maintenance purposes can be accomplished within a 72-hour timeframe. Preventive maintenance is feasible for retrievable components, while the foundation remains permanently on the seafloor.

Table 13 summarizes the planned maintenance activities for the chemical injection systems of both competing options, frequency of the activities, durations, and planned down time for each activity.

Table 13: Planned maintenance activities

System	Activity	Frequency	Duration	Planned down time
Topside CIU	Tank refill	0.5 years	12 hours	Tanks can be inspected and refilled without impacting operations
	Inspection and maintenance	Frequently	N/A	
SCSIS	Storage module refilling	0.5 years	48 hours	Downtime equal to refilling duration
	Injection skid inspection and maintenance	3 years	24 hours to retrieve existing skid and replace with spare	Planned replacement of pumps skids align with other field-wide maintenance outages
Topside CIU and SCSIS	High flow injection skid's function testing	Monthly	1 hour	N/A

2.2.3.4 Management and Reliability

Management and reliability cover how each competing option is managed and how reliability of the system is ensured to reduce operational downtime. This subchapter encompasses tasks that are part of operations, as well as reliability measures that can be considered for each option.

In Option A, offshore personnel are responsible for tasks such as platform installation, pumping operations, and refilling of tank modules. Conversely, in Option B, onshore personnel and FSVs oversee the entire operation, including the installation and handling of chemicals. This managerial approach can potentially reduce the need for offshore manpower and associated costs.

Ensuring system reliability is crucial and involves addressing issues such as seawater ingress into chemicals, leakage protection to the sea, backflow from injection points to storage tanks, and condition performance monitoring [16, pp. 8-10]. A reliable system reduces the need for interventions and workovers, thereby minimizing OPEX and LOSTREV during production. Key reliability measures for the SCSIS include:

- **Backflow protection**: Provided by a combination of check valves, actuated valves, and injection pumps. These valves and pumps are already integral to the functionality of the SCSIS, so the risk to personnel in case of failure is minimal.
- **Seawater leakage detection in chemicals**: This necessitates technology screenings to detect changes in the properties of seawater and chemicals. Seawater leakage into the chemicals has limited to no effect on the hardware of the SCSIS since the materials used are not affected by corrosion when exposed to seawater.
- **Chemical leakage detection into the sea:** Inventory monitoring of chemicals at various locations, such as flow meters, pump speed, and stroke.
- **Fluid cleanliness**: The reliability of a pump is contingent upon the cleanliness of the fluid being pumped. A high-pressure fluid with a significant number of particles can accelerate pump wear.
- **Flushing of chemical lines:** Removing debris from manufacturing and installation processes is crucial during the commissioning phase or after module replacement, as any debris can have detrimental effects.

ISO 20815:2018 provides a framework for presenting production loss categories, that may impact OPEX and LOSTREV. Figure 22 represents the relationship between some production assurance terms.

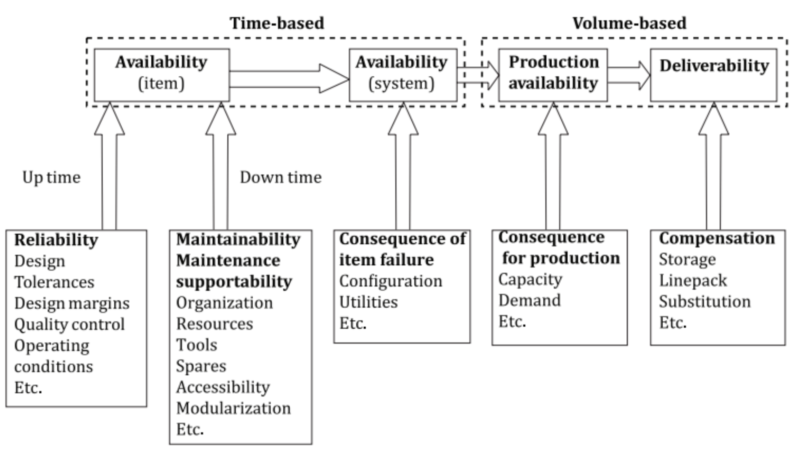

Figure 22: Illustration of the relationship between some time-based and volume-based production assurance terms [29, p. 57]

2.3 Sustainability

The Norwegian petroleum industry adhere to stringent HSE standards, surpassing those of many other countries. HSE considerations are an integral part of Norwegian political policies governing the petroleum sector. In order to mitigate the impact of chemical emissions in close proximity to production fields, these emissions are regulated through emission permits. Internationally, such regulations fall under the purview of the Oslo-Paris (OSPAR) Convention, which aims to protect marine life and the environment in the North-East Atlantic region [66]. To ensure sustained value creation on the Norwegian Continental Shelf, there is an increasing demand for knowledge and technology, necessitating continuous advancements in these areas.

2.3.1 Retrievability

In the case of Option A, the equipment recovery process closely resembles the logistics involved in its initial installation, which are handled by the construction vessel. Conversely, for Option B, the recovery of equipment may present challenges in certain fields. The SCSIS is designed with a foundation structure that facilitates modularity and ease of retrieval. The structural configuration of the storage modules enables individual storage tanks to be retrieved by light construction vessels, even if they still contain chemicals.

2.3.2 Safety and Environmental Concerns

HSE plays a significant role in Equinor's vision for zero harm [67]. One of the significant sources of emissions to the sea during petroleum production is the presence of remaining chemicals after drilling [66]. Measures to mitigate this issue include cleaning the chemicals before their release, underground deposition, or transporting them onshore for appropriate treatment as hazardous waste.

With the implementation of the SCSIS, the handling of production chemicals is carried out either by offshore operations personnel on an FSV or by trained personnel stationed onshore, depending on the more advantageous refilling sequence. Trained personnel, equipped with the necessary expertise in subsea operations, are responsible for tasks such as refilling, inspection, and maintenance of the chemicals. This approach ensures that personnel at the host facility are never exposed to hazardous chemicals, providing an advantage to the oil company operator. Adequate sealing of the chemical tanks is crucial to minimize the risk of spillage and the exposure of harmful chemicals to personnel and the environment. The removal of the CIS from the topside also reduces the overall weight of the topside structure and creates additional free space, leading to potential economic benefits and enhancing platform safety measures [13, pp. 4-5].

2.4 Economic Uncertainties for The Subject Matter

The decision to develop new technology, specifically the relocation of the chemical storage and injection system from topside to subsea, is primarily driven by considerations of life cycle economics. A comprehensive comparison of these alternatives necessitates the inclusion of information about the components involved, as well as an assessment of potential risks and uncertainties. This chapter focuses on the uncertainties associated with the development of such technology.

1. Reservoir Complexity

The characteristics of the reservoir play a significant role in determining the design and manufacturing requirements of the subsea equipment. Reservoir complexity influences the manufacturing and welding specifications of the SCSIS to ensure its compatibility with field demands. For instance, reservoirs characterized by high temperatures or pressures necessitate the construction of a more robust SCSIS capable of withstanding these challenges. The water depth of the field also impacts the development process, imposing limitations and increasing both installation time and cost.

2. Production Rate

The production rate of the field directly influences the equipment requirements and their quantities. Higher production rates typically demand larger quantities of equipment and necessitate more frequent maintenance to ensure smooth production processes. While a high production rate can lead to economic profits, it also entails additional operational costs and potential revenue losses due to downtime. Malfunctions in the SCSIS or depleted chemical storage tanks resulting from high production rates can adversely impact overall profitability.

3. Field Life and Decommissioning

In many offshore fields, the costs associated with decommissioning are higher than necessary due to inadequate analysis and decision-making during the engineering and construction phases [40]. The decommissioning process can incur significant costs, reaching billions of NOK, which could be mitigated by implementing comprehensive evaluation and standardization during the project's “define” phase. The deployment of SCSIS on the seafloor affects the decommissioning process by introducing additional challenges related to the removal of seabed architecture. Furthermore, the absence of an umbilical connection impacts the decommissioning of the offshore project, considering the different properties associated with the power cable.

4. Flow Assurance

Flow assurance, as emphasized by Bai & Bai, is of utmost importance in subsea engineering design [31]. It entails ensuring a continuous flow of hydrocarbons from the reservoir to the end user throughout the project's lifespan, regardless of the environmental conditions. Maintaining flow assurance requires regular maintenance and repair activities. Neglecting flow assurance can result in disruptions to field production, leading to downtime and associated costs to restart production. These operations can be both expensive and time-consuming. Issues related to flow assurance can decrease production availability and result in additional expenses. Moreover, inadequate flow assurance increases the risk of spills, leaks, and other safety and environmental incidents, which can lead to fines, cleanup costs, and harm to the company's reputation.

5. Interventions and Workover

Interventions during the field's operational life are inevitable and require maintenance activities to sustain production levels. Such maintenance interventions may involve well-specific operations or complete workovers. Factors affecting downtime in high-capacity petroleum projects can have a significant impact on profitability, as revenue is lost during periods of inactivity.

6. Environmental Conditions

Environmental conditions, such as adverse weather or the presence of ice ridges, can impede petroleum production by delaying operations and maintenance activities due to hazardous conditions for supply vessels and personnel working on or near the offshore facility. Furthermore, addressing the specific soil conditions of the field is crucial, as they can significantly impact installation costs and decommissioning processes.

7. Regional development

Regional development in petroleum extraction faces challenges in certain regions characterized by a lack of infrastructure and environmental issues. These conditions make the extraction process difficult. Additionally, the development of fields in such regions impacts the availability of installation vessels and incurs costs related to mobilization and demobilization.

8. Technical Development

Subsea technical development encompasses engineering and technological advancements in petroleum exploration and production. It encompasses equipment and systems, aiming to enhance production efficiency while ensuring personnel and environmental safety. The introduction of new solutions and technological developments brings various benefits to the SPS.

9. Politics

Politics exert a significant influence on petroleum production through diverse means. Governments play a key role in regulating the petroleum industry, establishing policies that dictate exploration and production conditions for companies. Regulations may determine the permissible extent of environmental pollution and impose penalties for non-compliance. Governments can also regulate the industry through taxation and subsidies [50]. High taxes on petroleum sales can impede companies' profitability, subsequently affecting technology development for the respective entities.

10. Schedule

The scheduling of subsea operations impacts numerous aspects and leads to increased project costs. Project delays can result in resource shortages, including specialized personnel, materials, and equipment, leading to increased costs due to heightened demand. Inflation may raise the cost of equipment and materials, while extended work duration necessitates overtime pay, thus increasing labor costs. Delays also result in revenue loss due to the inability to commence production or other revenue-generating activities.

11. Equipment Accessibility

Offshore petroleum production necessitates heavy lifting vessels for the installation of new offshore components, be it topsides or subsea structures. The requirement for compatible equipment for transportation, installation, maintenance, and other activities is crucial to sustain production, thereby affecting CAPEX and OPEX in various ways.

12. Market Accessibility

The market for subsea components is driven by supply and demand, significantly influencing several factors related to the overall availability of these components. High demand and limited supply can escalate procurement costs, ultimately increasing the overall component costs. Scarcity may lead to the utilization of lower-quality components, impacting the reliability and performance of the subsea system. Moreover, market accessibility of subsea components can influence the project design of the subsea system, as some components may not be readily accessible. Limited component availability can elongate lead times for delivery and procurement, resulting in project delays.

3 Methodology

This chapter is divided into two sections. Firstly, Chapter 3.1 describes how the life cycle costing methodology was utilized in this thesis. Secondly, Chapter 3.2 presents the formulas and acceptance criteria for each economic evaluation measure used during the life cycle cost analysis in Chapter 5.

3.1 Life Cycle Costing Steps

This subchapter encompasses the life cycle costing methodology provided from ISO 15663:2021 [2, pp. 21-29]. The methodology chapter of the standard is divided into four main steps, each step with various tasks to fulfil the life cycle costing assessment in a consistent manner. Methodology for life cycle costing activities is illustrated in the four steps visualized in Figure 23. Each task underlying the steps are also presented in the figure.

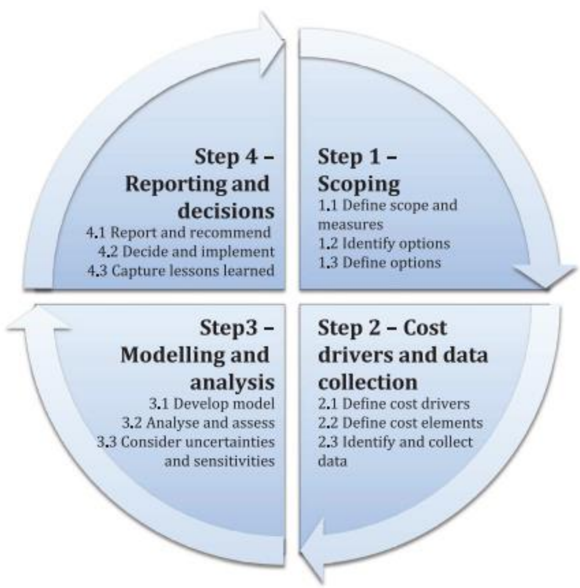

Figure 23: Sub-division of the life cycle costing methodology [2, p. 21]

3.1.1 Step 1 – Scoping

The aim of this stage was to identify alternative options pertaining to the relevant subject matter. This step involved developing an understanding of the issues, relationships, assumptions, and requirements relevant to the work ahead [2, p. 21]. Step 1 necessitated effective communication and discussion among project team members. In the context of life cycle costing assessment, step 1 was an indispensable requirement.

3.1.1.1 Defining Scope and Measures

For this thesis, the objective had already been defined and approved by Equinor. The objectives were thoroughly discussed with relevant personnel responsible for life cycle costing, as well as those with technical and economical expertise related to the subject matter. This ensured a comprehensive understanding of the desired outcomes of the thesis.

The assessment of life cycle costing did not only consider economic factors but also incorporated non-economic considerations such as sustainability and health, safety, and environment (HSE) aspects [2, pp. 22-24]. Various economic evaluation measures were employed to determine the preferred option. In this thesis, the chosen measures included:

- Life cycle cost (LCC)
- Net present value (NPV)
- Profitability index (PI)
- Payback period
- Internal rate of return (IRR)

Economic evaluation measures were limited to the estimation of differences. Hence, differences between options were considered under the three following categories:

- CAPEX
- OPEX
- LOSTREV

If decommissioning cost made a significant importance for the alternative options, the decommissioning cost was separated out explicitly.

3.1.1.2 Identifying Options

The process of identifying competing options necessitated a systematic and structured approach. A multidisciplinary team, previously established and approved by Equinor prior to the initiation of this thesis, was responsible for identifying options relevant to the subject matter. This collaborative effort ensured a comprehensive assessment of the investment by considering various perspectives. The options were identified to be:

- Option A: Topside chemical injection and storage system
- Option B: Subsea chemical injection and storage system

The generation of options and the identification of cost drivers were vital components in conducting a thorough life cycle cost analysis for the identified investment alternatives [2, p. 24]. These activities played a crucial role in evaluating the financial implications associated with each option.

3.1.1.3 Defining Options

The potential options have been subjected to a qualitative screening process where the aim was to find justification to exclude potential options and sub-options. As a result, a set of two agreed options were derived from this process. The options were subjected to both technical and operational functionalities and life cycle costing evaluation.

3.1.2 Step 2 – Cost Drivers and Data Collection

The general objective of step 2 was to develop a well-structured breakdown of costs by considering cost elements associated with the subject matter. This systematic approach involved defining all relevant cost data, which then was utilized as an integral component of the life cycle costing process. A crucial aspect of this assessment was to place emphasis on identifying the key cost drivers [2, p. 24].

3.1.2.1 Defining Cost Drivers

In the process of defining cost drivers, it was imperative to adopt a philosophy that encompasses all relevant costs. The approach employed aimed to discover the significant costs attributable to the subject matter under consideration [2, p. 25]. For each option, a comprehensive assessment was conducted to encompass all costs incurred throughout the lifecycle of the equipment, system, or product. Additionally, particular attention was given to exploring the distinctive characteristics of each option and analysing their corresponding CAPEX and OPEX.

Furthermore, it was important to identify and compare the shared costs between the options. If certain costs were common to both options, they may have been excluded from the assessment since they did not serve as a cost driver for the individual option. The outcomes of these activities facilitated the determination of whether a given cost element qualified as a cost driver.

3.1.2.2 Defining Cost Elements

The foundational step in listing cost elements was the compilation of a comprehensive inventory of potential cost drivers. The identification of a cost element necessitated a careful evaluation of the asset's functions and its interdependencies with other systems. It was essential to assess the level of detail required to effectively differentiate between the options under consideration. The primary objective of defining cost elements was to select those that possess the potential to significantly influence costs. Consequently, the output of this task was a well-defined list of cost elements and if they contributed as a cost driver or not. The results of this assessment were incorporated into the life cycle cost analysis.

3.1.2.3 Identifying and Collecting Data

To initiate this process, a thorough review of available data sources pertaining to the subject matter was conducted as presented in Chapter 1.4. Equinor possesses centralized cost databases such as CostCalc and CMATE that is normally utilized for offshore development projects. Through the application of parametric techniques, cost and quality figures for each competing option were obtained from these sources.

3.1.3 Step 3 – Modelling and Analysis

Step 3 entailed the development of a comprehensive life cycle model aimed at generating economic evaluation measures and establishing a ranking of options. In addition, a comparison and analysis of the cost drivers was conducted. Within this step, particular attention was given to identifying the uncertainties and risks associated with the data supporting the numbers used for the economic evaluation measures.

3.1.3.1 Developing Model

The life cycle costing model was constructed as a spreadsheet in Excel, designed to offer a detailed and transparent assessment of the variations among the competing options. Rigorous evaluation was conducted to ensure the model's credibility, accuracy, and ability to produce realistic results.

The model's development involved providing input data for multiple Monte Carlo simulations that calculated costs and their corresponding probabilities. These simulations yielded estimates for all the economic evaluation measures chosen for this thesis, incorporating different means and standard deviations.

3.1.3.2 Analysing and Assessing

Evaluations that were carried out:

- Ranking of options in accordance with decision criteria specified
- Summary of economic evaluation measures (identified cost drivers)

For enabling confidence in the results, these important questions to the assessment were carried out:

- Were individual cost totals in line with expectation?
- Why did an option perform better than the other?

3.1.3.3 Considering Uncertainties and Sensitivities

For the options, their ranking was also determined by evaluating the level of uncertainty associated with the relevant cost drivers. Uncertainty, in this context, referred to the degree of variability or lack of precise information relevant to a specific value required for predicting the estimated costs used in life cycle costing.

For each of the factors that were subjected to uncertainty, it was established:

- How much the estimate had to change to alter the ranking of options
- How likely it was for the estimate to change by that amount

3.1.4 Step 4 – Reporting and Decision-Making

The primary objective of step 4 was threefold. Firstly, it entailed the reporting of the analysis findings and subsequently formulating recommendations aligned with the initial decision criteria. Secondly, it involved endorsing a decision through the provided recommendations and determining the implementation of an option, with also including areas with potential for further research. Lastly, it encompassed a review of the application of the 4-step methodology, aimed at identifying potential avenues for organizational learning and improvement.

3.1.4.1 Reporting and Recommending

The presentation of the results was incorporated within Chapter 5 and Chapter 6 of the thesis, encompassing a comprehensive report. The recommendation of a specific option was presented in the following manner:

- The selected preferred option, with supporting arguments
- Definition of how additional work can be implemented to further differentiate the options
- Future studies, what work can be further researched

3.1.4.2 Deciding and Implementing

The previous subchapter formed a base for decision-making. However, to ensure quality in selecting and implementing an option, other activities that were considered includes:

- Technical and operational basis
- Uncertainty in calculations
- Other business objectives (e.g. HSE or sustainability)

3.1.4.3 Capturing Lessons Learned

The purpose of lessons learned was to capture valuable insights from the perspective of life cycle costing and effectively communicate the experiences gained through the application of life cycle costing principles. The primary objective was to foster a continuous improvement process for future studies in the field of life cycle costing.

3.2 Economic Evaluation Measures

To understand and implement data in the life cycle costing assessment, economic evaluation measures were utilized and agreed in accordance with Equinor functions methods. Assumptions for the technical and operational basis were used in the calculations.

3.2.1 Life Cycle Cost (LCC)

The utilization of LCC evaluation aimed to determine the relative desirability of both options by calculating all cost drivers that were related to each life cycle costing main element. This evaluation encompassed not only the direct costs but also factors in the impact on revenue streams as a significant cost driver.

LCC is the sum of these factors [2, p. 70]:

- CAPEX
- OPEX
- LOSTREV

3.2.2 Net Present Value (NPV)

Net present value was applied to evaluate desirability for an option investment. NPV was calculated in the following manner [2, p. 69]:

$$N_{\mathrm{PV}} = F_0 + \frac{F_1}{(1+d)} + \frac{F_2}{(1+d)^2} + \frac{F_3}{(1+d)^3} + \ldots + \frac{F_n}{(1+d)^n}$$

or

$$N_{\mathrm{PV}} = \sum_{t=0}^{n} \frac{F_t}{(1+d)^t}$$

Where:

N_{PV} was the net present value (NPV)

F_t was the net cash flow at time *t* (net cash flow is the algebraic sum for each period of cash inflow minus cash outflow)

F_0 represented net cash flow at time *t* = 0 (meaning when the decision is taken for initial investment)

t was the time (for instance days, months, years)

d was the discount rate

n was the number of time periods taken into consideration

The NPV of a project is derived by discounting the net cash flow with a discount rate that reflects the required rate of return that a company has [2, p. 69]. The discount rate utilized during the calculation represented Equinor's requirement for return on the subject matter investment for a specific level of risk.

The decision criteria associated with NPV calculation for this thesis was as follows:

- If NPV was positive, the option investment provided a positive return, so the option was accepted
- If NPV was negative, the option investment provided a negative return, so the option was rejected

3.2.3 Profitability Index (PI)

The PI is defined as the NPV of the project divided by the discounted CAPEX. The calculation of PI followed this equation [2, p. 73]:

$$I_{\mathrm{P}} = \frac{N_{\mathrm{PV}}}{C_{\mathrm{PV}}}$$

Where:

I_P was the profitability index (PI)

N_{PV} was the net present value (NPV)

C_{PV} was the present value of CAPEX (discounted)

Decision criteria:

- PI > 1, the option was considered profitable and was accepted.
- PI < 1, the option was considered non-profitable and was rejected.

3.2.4 Payback Period

Payback period is a simple method to determine if an option is desirable. It quantifies the duration expressed in years, needed to regain the initial investment through the future cash flows generated by the option. The payback period was determined by applying the following equation [2, pp. 73-74]:

$$Y_{\mathrm{PB}} = Y_2 - Y_1$$

Where:

Y_{PB} was the payback period

Y_2 was the year in which the cumulative sum of net cash flow is greater than zero

Y_1 was the year in which income starts

When cash flows fluctuate over time, the payback period was calculated by summing the net cash flows until the year where the cumulative cash flow was greater than zero, meaning the investment was covered.

3.2.5 Internal Rate of Return (IRR)

IRR is a time-discounted measure used to assess the attractiveness of an investment. It quantifies the maximum rate of return that an investment can generate before the project ceases to be financially viable. The computation for IRR was calculated with the following equation [2, p. 71]:

$$N_{\mathrm{PV}} = \sum_{t=0}^{n} \frac{F_t}{(1 + d_{\mathrm{R}})^t} = 0$$

Where:

N_{PV} was the net present value (NPV)

F_t was the net cash flow at time period t

d_{R} was the internal rate of return (IRR)

t was the time period in years

n was the number of time periods

Decision criteria:

- If the IRR was higher than the discount rate, the option provided a higher return on the investment than the required minimum, hence the option was accepted.
- If the IRR was lower than the discount rate, the option provided a lower return on the investment than the required minimum, hence the option was rejected.

4 Data

This chapter provides a comprehensive overview of the data collected for each of the three main elements involved in life cycle costing. Initially, the chapter examines the influence of different cost elements and determines whether they act as significant cost drivers in relation to the subject matter. Subsequently, the cost elements are evaluated to ascertain their variations across the options and their respective impacts on life cycle costing. Once the cost drivers are identified, essential input data for each of the main elements of life cycle costing are presented. These input data serve as a foundation for the development of an estimation model, which is discussed and presented in the next chapter.

4.1 Cost Elements & Cost Drivers

This subchapter gives a presentation of the potential cost elements pertaining to the subject matter introduced in Chapter 2.2 for both Option A and Option B. The tables presented in this subchapter encompass individual cost elements along with accompanying comments, which are derived from the technical and operational information gathered in Chapter 2. Upon presenting all the cost elements for the competing options, an evaluation was conducted to determine whether parts of the cost element function as a cost driver or not. Finally, when the cost drivers were located, a WBS showcasing the work packages of each cost driver for both competing options was illustrated in support of bottom-up estimation.

4.1.1 Option A: Cost Elements

Table 14-17 in this subchapter presents the cost elements likely to apply to the subject matter, as well as comments on each cost element. The tables were divided into four, where each life cycle costing main elements were covered, as well as decommissioning.

Table 14: Option A CAPEX related cost elements

Cost elements	Comments
Management cost	• Supply vessel from shore cover transportation and lifting of chemicals modules onto FPSO (base case). • Offshore personnel manage installation on platform and pumping of tank modules. • Offshore personnel cover monitoring and controlling tank modules while operative.
Equipment cost	• EH system requiring an umbilical with hydraulic and chemical lines, with electric and fiber optic connections as well, which will overall make a large cross-section umbilical. • Equipment related to topside CIS such as instruments, piping, and electronics. Also presented in Table 5.
Engineering cost	• Engineering for the EH system must meet design requirements. • Engineering cost related to procurement and fabrication of the EH system equipment relevant to the subject matter.
Transportation cost	• Day-rates for FSV to transport system components to offshore facility.
Installation cost	• Onshore personnel cover installation on the FPSO while construction vessel covers installation of umbilical and CIS equipment. • Day-rates for FSV when installing umbilical system and topside CIS.
Commissioning cost	• Other start-up costs that will prove relevant for Option A.

Table 15: Option A decommissioning related cost elements

Cost elements	Comments
Management cost	• Surveys and tests need to be performed before decommissioning starts to ensure structural integrity. • Preparation and removal of the EH system both on topside facility and substructure. • Managing the removal of a CIS which is more integrated to offshore facility than the SCSIS.
Operations & Maintenance cost	• Operations should still run under the decommissioning phase. Extra maintenance cost is likely to apply during this phase.
Demolition cost	• Onshore recycling and disposal.
Engineering cost	• Day-rates for construction vessels to remove components relevant to the EH system.
Transportation cost	• Day-rates for FSV to transport system components to onshore disposal and recycling.
Site restoration cost	• The operator of the field has a responsibility to ensure that no hazard to marine life or environment is inflicted during and after decommissioning if any infrastructure is left in place.
Scrap handling cost	• After removed infrastructure is transported onshore to a disposal yard, several potential recycling companies can sort, dismantle, and recycle offshore components.

Table 16: Option A OPEX related cost elements

Cost elements	Comments
Operations man-hour cost	• Man-hour cost related to maintaining and controlling the EH system.
Cost of logistics	• Mobilization time and handling of refilling (manpower demand, schedule implications etc.)
Operations & Maintenance cost	• Empty chemical storage modules are refilled by either lifting barrels containing chemicals from the FSV to the FPSO, or by connecting a refilling line from the FPSO to the tanks on FSV and then refill. • Maintenance cost related to man-hour operations when system requires it, both topside and subsea. • Preventive maintenance cost.
Modification cost	• Cost related to modifying the EH production system during the design life if required. • Differs depending on the regional and technical development of the field.

Table 17: Option A LOSTREV related cost elements

Cost elements	Comments
Lost production	• Lost revenue related to utilizing production equipment that are not up to the current technology standard.
Lost operating time	• Lost revenue related to operating time of the SPS being lower than wanted. • Expected that offshore personnel can solve most topside implications within a 12-hour timeframe.
Lost deliveries	• Deliveries such as components or chemical products that are lost or delayed due to hazardous conditions (such as weather implication), or wrong deliveries when components arrive.

4.1.2 Option B: Cost Elements

Table 18-21 in this subchapter presents the cost elements likely to apply to the subject matter, as well as comments on each cost element. The tables were divided into four, where each life cycle costing main elements were covered, as well as decommissioning.

Table 18: Option B CAPEX related cost elements

Cost elements	Comments
Management cost	• Onshore personnel handle chemicals for the SCSIS. FSV and vessels cover management of installing, refilling, and maintaining tank modules. • Offshore personnel cover monitoring and controlling tank modules while operative.
Equipment cost	• AE power cable system requiring electricity and fiber optic signals through a power cable with small cross-section. • All equipment required for the SCSIS such as storage units, pumps, monitoring etc. Also presented in Table 6 and Table 7. • Equipment related to a subsea power system for driving subsea chemical injection pumps.
Engineering cost	• Engineering for the AE system must meet design requirements. • Engineering cost related to procurement and fabricating of the AE system equipment relevant to the subject matter.
Transportation cost	• Day-rates for FSV to transport system components to production field and offshore facility. • Day-rates for FSV when installing power cable system and SCSIS.
Installation cost	• FSV vessels with quite low crane capacity cover all installation of subsea components related to Option B.
Commissioning cost	• Other start-up costs will prove relevant for Option B.

Table 19: Option B decommissioning related cost elements

Cost elements	Comments
Management cost	• Surveys and tests need to be performed before decommissioning starts to ensure structural integrity. • Preparation and removal of the AE system both on topside facility and substructure. • Managing the removal of the modular components in the SCSIS.
Maintenance cost	• Operations should still run under the decommissioning phase. Extra maintenance cost is likely to apply during this phase.
Demolition cost	• Onshore recycling and disposal. • Possibility of power cable and SCSIS to be reused for other fields.
Engineering cost	• Day-rates for lifting vessels to remove components relevant to the AE system.
Transportation cost	• Day-rates for FSV to transport system components to onshore disposal and recycling.
Site restoration cost	• The operator of the field has a responsibility to ensure that no hazard to marine life or environment is inflicted during and after decommissioning if any infrastructure is left in place.
Scrap handling cost	• After removed infrastructure is transported onshore to a disposal yard, several recycling companies can sort, dismantle, and recycle offshore components for a price.

Table 20: Option B OPEX related cost elements

Cost elements	Comments
Operations man-hour cost	• FSV personnel cover most logistics, maintenance, and refilling of the SCSIS. • Man-hour cost related to monitor and controlling the AE system.
Cost of logistics	• Mobilization time and handling of refilling (manpower demand, schedule implications etc.)
Operations & Maintenance cost	• Empty chemical storage modules are refilled with downline from the FSV to the SCSIS or by lifting and re-installing already filled storage tanks. • Maintenance is accomplished with the use of an FSV which can lift SCSIS components up on deck for inspection. For some maintenance operations ROV can also be utilized on the seafloor. • The modular components of the SCSIS contribute to minimized infrastructure, which will provide less maintenance requirements. • Power cable can be retrieved for on-deck repair, minimizing impact on project schedule and production. • Preventive maintenance possible for retrievable parts.
Modification cost	• Cost related to modifying the AE production system when required. • Modern AE and standardized system are cheaper to modify. • Based on standardized and modular components, simplifying both design and fabrication. • Differs depending on the regional and technical development of the field.

Table 21: Option B LOSTREV related cost elements

Cost elements	Comments
Lost production	• Lost revenue related to utilizing production equipment that is faulty.
Lost operating time	• Lost revenue related to operating time of the SPS being lower than wanted. • Hazardous conditions such as weather can affect the FSV refilling and maintenance operations more than for option A. • Expected that offshore personnel can solve most SCSIS implications within a 72-hour timeframe.
Lost deliveries	• Deliveries such as components or chemical products that are lost or delayed due to hazardous conditions or wrong deliveries when components arrive.

4.1.3 Cost Drivers

Drawing upon the evaluated options, a preliminary understanding of potential cost drivers was outlined. This subchapter focuses on the presentation and ranking of cost elements based on their uniqueness across competing options. If cost elements were shared among the options, they were excluded from the LCC analysis in this thesis. Conversely, if cost elements differed among the options, their inclusion in the LCC analysis was examined. For the options that were deemed relevant for the LCC, a determination was made regarding the contribution of each cost element as a cost driver. Table 22 presents the comprehensive list of cost elements and their corresponding categorization as cost drivers.

Table 22: List of cost elements and cost drivers

ID	Cost element description	Is it common between options? (Yes/No)	Is it included in the LCC analysis? (Yes/No)	Is it a cost driver? (Yes/No)
1	Offshore management	No	Yes	Yes
2	Onshore management	No	No	No
3	Commissioning	No	Yes	No
4	Umbilical	No	Yes	Yes
5	SCSIS	No	Yes	Yes
6	Subsea power system	No	Yes	Yes
7	Power cable	No	Yes	Yes
8	Hydraulic power unit (HPU)	No	No	No
9	Subsea HPU	No	No	No
10	CIS	No	Yes	Yes
11	Operations & maintenance	No	Yes	Yes
12	Logistics	No	Yes	Yes
13	Installation	No	Yes	Yes
14	Demolition cost	No	No	No
15	Scrap handling	Yes	No	No
16	Site restoration	Yes	No	No
17	Lost production	No	Yes	Yes
18	Lost deliveries	Yes	No	No
19	Lost operating time	Yes	No	No

4.1.4 Work Breakdown Structure

In order to facilitate bottom-up estimation and improve the comprehensibility of the analysis, a WBS was employed for each option. The WBS allowed for the decomposition of each cost driver into smaller, more manageable components, which could be separately estimated and analysed. By aggregating the estimates from the individual components, a more comprehensive top-down assessment of the total cost could be obtained. The WBS for each option is illustrated in Figure 24 and Figure 25, providing a visual representation of the breakdown of cost drivers.

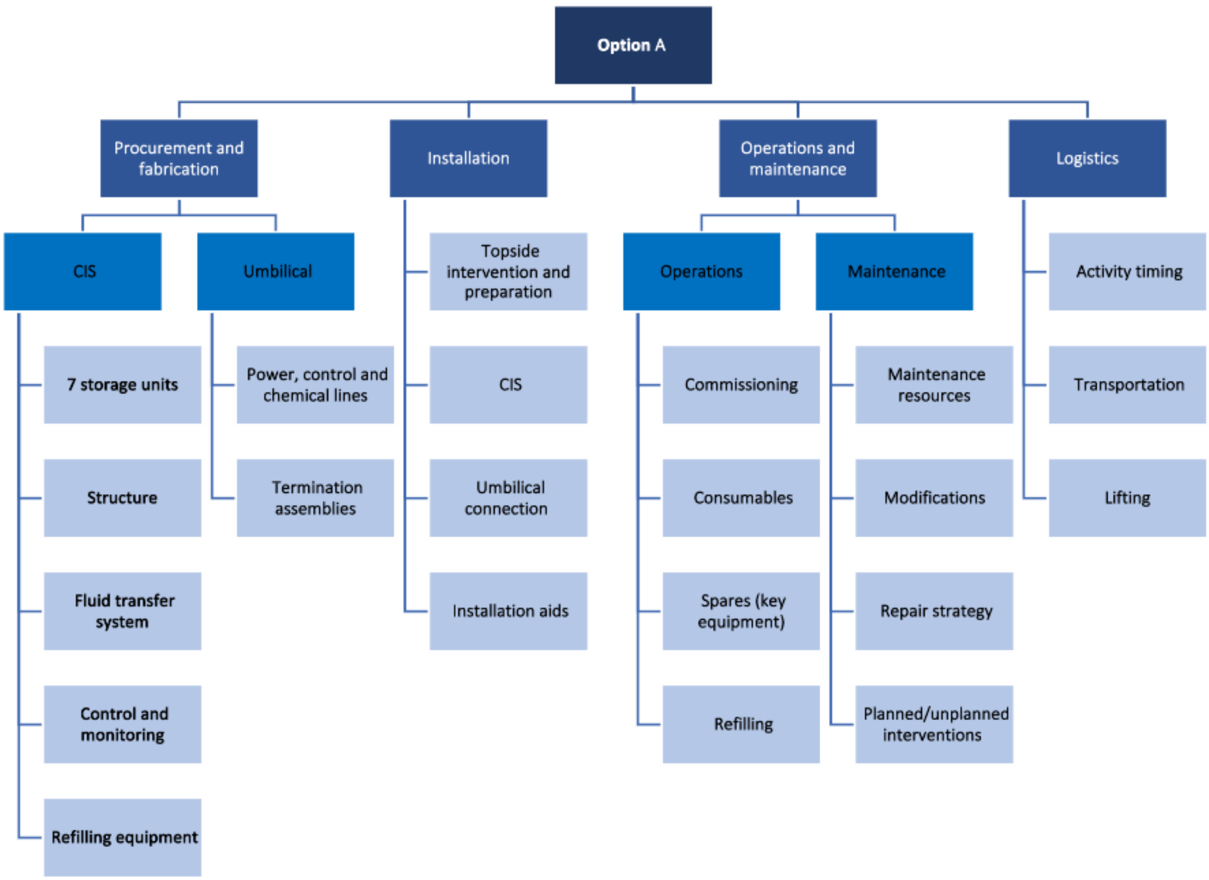

Figure 24: Option A WBS

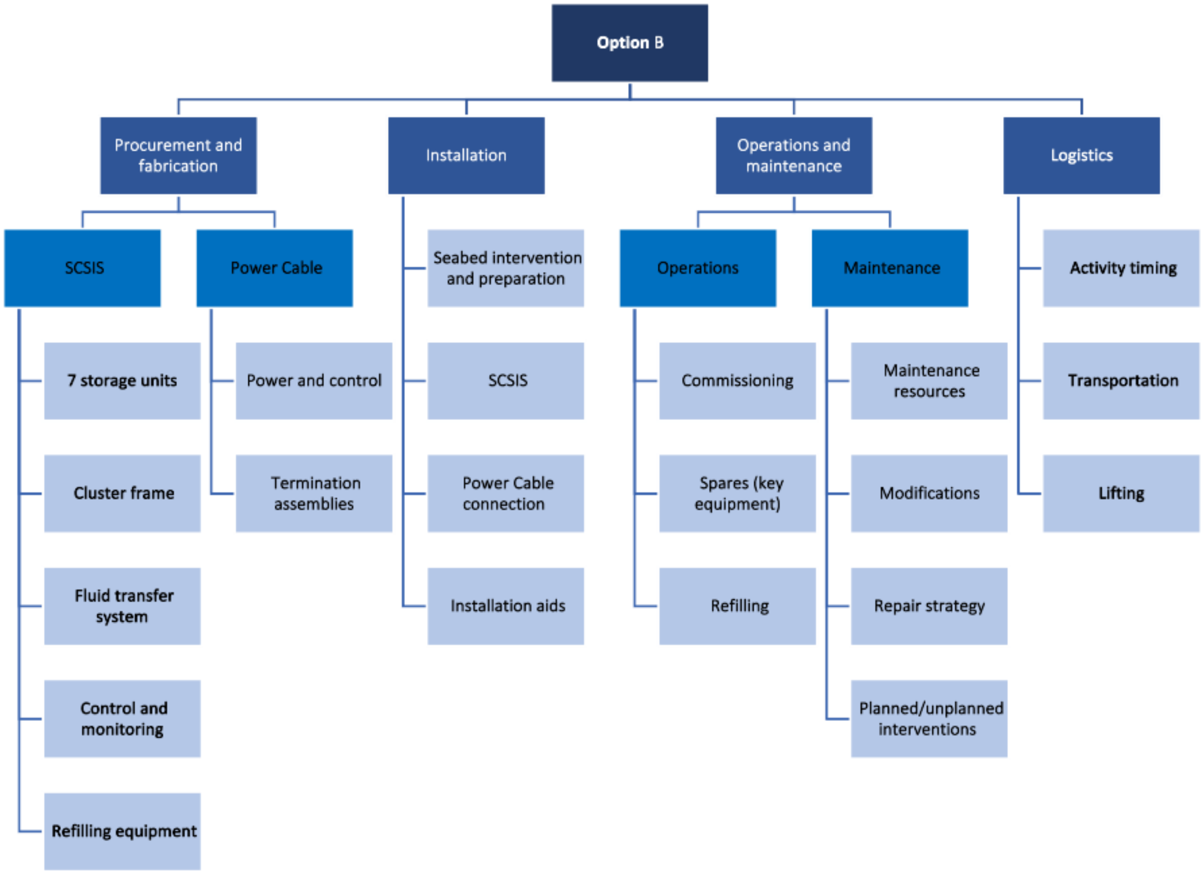

Figure 25: Option B WBS

4.2 CAPEX

This subchapter encompasses all CAPEX input data necessary for the LCC analysis presented in Chapter 5. It is structured into separate sections for Option A and Option B, aiming to ascertain the precise costs associated with CAPEX-related cost drivers for each of the competing options. The subchapter will be summarized visualizing the CAPEX inputs to the estimation model in the subsequent chapter.

4.2.1 Option A

In the first part of this subchapter, the composition of the umbilical structure to meet case study demands, along with the associated quantities and costs of its components, are presented. Tables in this part encompass design and fabrication parameters for a 20 km long standard umbilical, as well as a 630 m long dynamic umbilical that will reach down to the production system from the FPSO. The second part of the subchapter covers the CAPEX estimation of the topside CIS where weight of the system is implemented into BulkMATE, and then by inserting the bulk weight of the CIS into CostCalc, the CAPEX estimation of the CIS is presented.

4.2.1.1 Umbilical

Standard umbilical Input

Table 23 provides the cost per meter of a standard umbilical featuring a MEG centerline. As can be seen, unit costs were not included as part of the representations due to the classification as restricted. The cross-section of the umbilical was adjusted by modifying the quantity variables in the highlighted section to align with the requirements of the EH system, as agreed upon with Equinor. Consequently, the cost per meter for a MEG umbilical with 20 km tieback distance was determined to be **0.0077 MNOK**.

Table 23: Standard umbilical with centerline for MEG (NOK/meter) from CostCalc

Standard umbilical with centerline for MEG (NOK/meter)							
	Qty	Unit Cost	0-5 km	5-20 km	20-40 km	40-60 km	Above 60 km
Steel Pipe, 1/2 inch (DP 759 bara), HP	2						
Steel Pipe, 5/8 inch (DP 517 bara), LP	2						
Steel Pipe, 5/8 inch (DP 517 bara), Injection	3						
Steel Pipe, 5/8 inch (DP 517 bara), Spare	1						
Fiber cable (24 SM)	2						
Electric Quads, 16 mm^2	6						
Steel Pipe, 2.5 inch (DP 517 bara), for MEG	1						
Umbilical Materials (Misc.)	1						
Umbilical Sheath	1						
Umbilical Fluids	1						
Load-out (6 km/day)							
Total direct cost per meter			**6,319**	**6,319**	**6,319**	**6,319**	**6,319**
Spare parts							
Routine testing (incl. FAT)							
Factory & Load-out rigging							
Minor factory logistics							
Craneage							
Other logistics							
Total indirect cost per meter			**3,378**	**676**	**282**	**169**	**121**
Total cost per meter			**9,697**	**6,995**	**6,600**	**6,488**	**6,440**
Used in EST Model (NOK/meter)			**10,667**	**7,694**	**7,260**	**7,137**	**7,083**

Dynamic umbilical Input

Table 24 presents the comprehensive cost of a dynamic umbilical incorporating MEG lines for a riser length of 630 meters. It was not industry standard to have large MEG centerlines as part of a dynamic umbilical, hence it was divided into 12 smaller lines. It is important to note that this length has been accounted for in the input sheet and has been agreed upon with external supervisors at Equinor. The quantity field in the input sheet corresponds to the values specified in the standard section of the umbilical. Total cost per meter was calculated by adding both indirect cost and direct cost of the umbilical together, as well as adding the factor of a dynamic umbilical. By multiplying the total cost per meter by the distance of 630 meters, and adding the parameters presented at the bottom of the table, the total cost attributed to the dynamic umbilical was determined to be **44 MNOK**.

Table 24: Dynamic umbilical with MEG lines (total MNOK) from CostCalc

Dynamic umbilical with 12 off 3/4" MEG lines (NOK/meter)		Length per riser (m)	630
	Qty	**Unit Cost**	
Steel Pipe, 1/2 inch (DP 759 bara), HP	2		
Steel Pipe, 5/8 inch (DP 517 bara), LP	2		
Steel Pipe, 5/8 inch (DP 517 bara), Injection	3		
Steel Pipe, 5/8 inch (DP 517 bara), Spare	1		
MW Power, 240 mm2	0		
Fiber cable (24 SM)	2		
Electric Quads, 16 mm^2	6		
Steel Pipe, 3/4 inch (DP 345 bara), for MEG	12		
Steel Pipe, 1.0 inch (DP 345 bara), for MEG	0		
Steel Pipe, 2.5 inch (DP 517 bara), for MEG	0		
Umbilical Materials (Misc.)	1		
Umbilical Sheath	1		
Umbilical Fluids	1		
Load-out (6 km/day)			
Total direct cost per meter			**7,319**
Spare parts			
Routine testing (incl. FAT)			
Factory & Load-out rigging			
Minor factory logistics			
Craneage			
Other logistics			
Total indirect cost per meter			**13,406**
Total cost per meter			**20,726**
Factor for dynamic umbilical			20,726
Used in EST Model (NOK/meter)			**41,451**
Cost per dynamic umbilical			**MNOK**
Variable procurement & fabrication cost per dynamic umbilical			
Bending stiffener	1		
Bending stiffener connector	1		
Bending restrictors	1		
Buoyancy system	1		
Pull-in head and hang off assembly	1		
Riser anchor system	1		
Purchase of reel	0		
Total cost per dynamic umbilical			**44.0**

Umbilical Cost

As can be seen in Table 25, implementing correct umbilical type, tieback distance, number of umbilicals, jumpers, and transitions joints, the total umbilical procurement cost was calculated to be **319 MNOK** if rounded to the closest million. The total procurement cost also generated and included engineering, preliminaries, and termination assemblies, which was not covered in Table 23 and Table 24.

Table 25: Umbilical procurement cost from CostCalc

UMBILICAL	Subsea Production System	
Description		Umb
PROCUREMENT	NOK 318,964,721	
STATIC UMBILICAL		
Umbilical type		1
	Without MEG line = 0	
	With centerline for MEG = 1	
	Power umbilical = 2	
Total Length	Km	20
No of	No of	1
DYNAMIC UMBILICAL RISER (lazy	No of	1
UMBILICAL JUMPERS	No of	0
FLYING LEADS	No of Sets of 3 x Electric, 1 x	0

Umbilical Marine Operations Cost

The installation of the umbilical is carried out using a reeling method, necessitating the utilization of a topside winch and three tie-ins (two for the standard umbilical and one for the dynamic umbilical). The overall cost associated with the installation process is presented in Table 26 and amounts to **110 MNOK** if rounded to the closest million.

Table 26: Umbilical installation cost from CostCalc

OPERATIONS	NOK 109,928,391	
INSTALLATION		
Lay method		1
	Reeling =1	
Piggy back	As main line=2	
Piggy back	As guest line=3	
Pull-in umbilical in I/J-tube	No of	0
Topside winch	No of	1
Personnel ass.	No of	0
TIE-IN	No of	3

4.2.1.2 Chemical Injection System Cost

By leveraging the Johan Castberg field equipment list specifically designed for chemical injection purposes, the dry weight of the topside chemical injection modules was ascertained through expert judgment facilitated by Equinor. As the operational location function (OLF) code for chemical injection fell within the "Process Support and Utility" category (code 42), inputting an equipment weight of 80 tons (comprising 7x7 tons for chemical storage and 31 tons for power, control, and monitoring) yielded the following CIS weight data as presented in Table 27.

Table 27: Decomposition of total CIS weight from BulkMATE

Code	Area	Equip.	Arch.	Electr.	Hvac	Instr.	Piping	Surf.	Safety	Tele	Bulk	Struct.	Total
10 - 15	*Drilling*										-		-
18 - 19	*Flowlines (wellhead & riser area)*	-	-	-	-	-	-	-	-	-	-	-	-
18 - 19	*Wellhead & Risers area (MEL)*	-	-	-	-	-	-	-	-	-	-	-	-
											-		-
20 - 29	Main Process	-	-	-	-	-	-	-	-	-	-	-	-
30 - 39	Export and Byproduct Handling	-	-	-	-	-	-	-	-	-	-	-	-
40 - 69	Process Support and Utility	80.0	-	12.0	2.4	4.0	40.0	2.4	-	0.8	61.6	140.0	281.6
70 - 79	Safety Systems	-	-	-	-	-	-	-	-	-	-	-	-
80 - 85	Electrical Power Generation and Distribution	-	-	-	-	-	-	-	-	-	-	-	-
86 - 87	Automation and Telecommunication	-	-	-	-	-	-	-	-	-	-	-	-
88	Earthing and Lighting	-	-	-	-	-	-	-	-	-	-	-	-

The initial estimate for the instrument weight was established at 2.4 tons; however, with valuable insights provided by Equinor, this value was revised to 4 tons to align with more realistic figures. Consequently, the overall weight of the topside CIS amounted to **281.6 tons**. This value was extracted and integrated into CostCalc to determine the comprehensive cost of the entire CIS.

Table 28 presents the comprehensive top-down calculation of all cost codes encompassed in the estimation process of the CIS. As depicted in the table, these cost codes correspond to the same physical breakdown structure denoted as "AA = Topsides," [27] albeit with distinct codes of resource. Based on this breakdown, the anticipated cost estimate for a CIS weighing 281.6 tons amounted to **286 MNOK** before incorporating contingency factors. This value was inserted into the analysis chapter of the thesis for further examination and evaluation.

Table 28: Topside CIS cost estimate from CostCalc

Project:		Topside Chemical Injection			
Alternative:		Option A			
Table-1; Cost Summary			Table-1a; Topside part		
PBS	COR	Description	Gross dry weight Tonnes	Constant Cost kNOK-23	Fractions of Base Estimate
AA	E	Equipment (incl capital spares)	80	69 312	24 %
AA	B	Bulk Materials	202	26 666	9 %
AA	K	Design Engineering		34 638	12 %
AA	K	Shop Engineering		6 428	2 %
AA	LXB	Onshore Construction		48 933	17 %
AA	LX	Onshore Commissioning		2 801	1 %
AA	BND	Grillage / seafastning / loadout / weighing		1 925	1 %
AA	LX	Assembly Yard Hook-up and Commissioning		0	0 %
AA	LX	Inshore Hook-up and Commissioning		0	0 %
AA	LX	Offshore Hook-up & Commissioning		4 713	2 %
AA	XK	Transport		25 554	9 %
AA	XC	Marine Operations		31 511	11 %
AA	XO	Flotel		0	0 %
AA	X	Logistic		972	0 %
AA	H	Management		27 880	10 %
AA	AC	Insurance		4 220	1 %
AA		Sum Base Estimate	282	285 552	100 %
AA	AV	Topside contingency percent		15 %	
AA	AV	Topside contingency cost		42 833	
AA		Expected Cost Estimate	282	328 385	
NOK / kg (Base Estimate)				1 014	
NOK / kg (Expected Cost)				1 166	

4.2.2 Option B

In the first part of this subchapter, the composition of the power cable structure to meet case study demands, along with the associated quantities and costs of its components, are presented. Tables in this part encompass procurement and fabrication parameters for a 20 km long power cable, as well as a 630 m long dynamic power cable that will reach down to the production system from the FPSO. The second part of the subchapter covers the CAPEX estimation of the SCSIS and subsea power system where technical information and weights for the system is implemented into CostCalc, top-down estimating the SCSIS based on technical and operational basis of the system.

4.2.2.1 Power Cable

Standard Power Cable Input

The estimation of the power cable entailed considering a triad MW power, fiber cables, and electrical quads. As can be seen in the calculation presented in Table 29, unit costs for components within the cable are not presented, as well as unit costs for other important factors, to ensure the restricted classification. With the incorporation of the agreed-upon quantities, the cost per meter for a 20 km tieback distance was determined to be **0.0044 MNOK**. This calculation accounted for the various components and specifications involved in the power cable system.

Table 29: Power cable (NOK/meter) from CostCalc

Power cable (NOK/meter)							
	Qty	**Unit Cost**	**0-5 km**	**5-20 km**	**20-40 km**	**40-60 km**	**Above 60 km**
Steel Pipe, 1/2 inch (DP 759 bara), HP	0						
Steel Pipe, 5/8 inch (DP 517 bara), LP	0						
Steel Pipe, 5/8 inch (DP 517 bara), Injection	0						
Steel Pipe, 5/8 inch (DP 517 bara), Spare	0						
MW Power, 240 mm2	3						
Fiber cable (24 SM)	2						
Electric Quads, 16 mm^2	2						
Steel Pipe, 2.5 inch (DP 517 bara), for MEG	0						
Umbilical Materials (Misc.)	1						
Umbilical Sheath	1						
Umbilical Fluids	1						
Load-out (6 km/day)							
Total direct cost per meter			**3,334**	**3,334**	**3,334**	**3,334**	**3,334**
Spare parts							
Routine testing (incl. FAT)							
Factory & Load-out rigging							
Minor factory logistics							
Craneage							
Other logistics							
Total indirect cost per meter			**3,378**	**676**	**282**	**169**	**121**
Total cost per meter			**6,712**	**4,009**	**3,615**	**3,503**	**3,454**
Used in EST Model (NOK/meter)			**7,383**	**4,410**	**3,977**	**3,853**	**3,800**

Dynamic Power Cable Input

Table 30 presents the cost assessment of a dynamic power cable with a riser length of 630 meters. The specified length was pre-established and agreed upon with Equinor, ensuring consistency in the input sheet. The quantity field in the input sheet corresponds to the values indicated in the static portion of the power cable. Consequently, the total cost of the dynamic component amounted to **39 MNOK**, calculated in the same manner as the dynamic umbilical with MEG lines. This evaluation encompassed the necessary considerations and quantities associated with the dynamic power cable system.

Table 30: Dynamic power cable cost from CostCalc

Dynamic power cable (NOK/meter)		Length per riser (m)	630
	Qty	Unit Cost	
Steel Pipe, 1/2 inch (DP 759 bara), HP	0		
Steel Pipe, 5/8 inch (DP 517 bara), LP	0		
Steel Pipe, 5/8 inch (DP 517 bara), Injection	0		
Steel Pipe, 5/8 inch (DP 517 bara), Spare	0		
MW Power, 240 mm2	3		
Fiber cable (24 SM)	2		
Electric Quads, 16 mm^2	2		
Steel Pipe, 1.0 inch (DP 345 bara), for MEG	0		
Steel Pipe, 2.5 inch (DP 517 bara), for MEG	0		
Umbilical Materials (Misc.)	1		
Umbilical Sheath	1		
Umbilical Fluids	1		
Load-out (6 km/day)			
Total direct cost per meter			**3,334**
Spare parts			
Routine testing (incl. FAT)			
Factory & Load-out rigging			
Minor factory logistics			
Craneage			
Other logistics			
Total indirect cost per meter			**13,406**
Total cost per meter			**16,740**
Factor for dynamic umbilical			16,740
Used in EST Model (NOK/meter)			**33,480**
Cost per dynamic umbilical			**MNOK**
Variable procurement & fabrication cost per dynamic umbilical			
Bending stiffener	1		
Bending stiffener connetor	1		
Bending restrictors	1		
Buoyancy system	1		
Pull-in head and hang off assembly	1		
Riser anchor system	1		
Purchase of reel	0		
Total cost per dynamic umbilical			**39.0**

Power Cable Cost

As evident from the aforementioned estimation, by accurately incorporating the appropriate umbilical type, tieback distance, number of power cables, jumpers, and transition joints, the total cost of power cable procurement amounted to approximately **264 MNOK** as presented in Table 31 when rounded to the nearest million. The total procurement cost also generated and included engineering, preliminaries, and termination assemblies, which was not covered in Table 29 and Table 30. It was noteworthy that many of these inputs aligned with the previous umbilical calculation. However, for the SCSIS, a total of 7 jumpers were necessary to facilitate the operation of the chemical injection pumps.

Table 31: Power cable procurement cost from CostCalc

UMBILICAL	Subsea Production System	
Description		Umb
PROCUREMENT	NOK 263,818,539	
STATIC UMBILICAL		
Umbilical type		2
	Without MEG line = 0	
	With centerline for MEG = 1	
	Power umbilical = 2	
Total Length	Km	20
No of	No of	1
DYNAMIC UMBILICAL RISER (lazy wave)	No of	1
UMBILICAL JUMPERS	No of	7
FLYING LEADS	No of Sets of 3 x Electric, 1 x Hydraulic, 1 x FO & 1 x 2" MEG	0

Power Cable Marine Operations Cost

Installing the power cable is executed with a reeling method and requires one topside winch as well as 17 tie-ins (2 for each SCSIU, 1 for the dynamic power cable, and 2 for the standard power cable). As a result, the overall cost of the power cable installation, including the jumpers, amounted to **139 MNOK** when rounded to the closest million, as can be seen in Table 32.

Table 32: Power cable installation cost from CostCalc

OPERATIONS	NOK 139,370,891	
INSTALLATION		
Lay method		1
	Reeling =1	
Piggy back	As main line=2	
Piggy back	As guest line=3	
Pull-in umbilical in I/J-tube	No of	0
Topside winch	No of	1
Personnel ass.	No of	0
TIE-IN	No of	17
STAB-IN (for Flying Leads)	No of (equal to no of sets)	0

4.2.2.2 Subsea Chemical Storage and Injection System

Obtaining accurate numbers to facilitate the calculation of the SCSIS cost posed challenges due to low recordings on costs for this technology development. However, with the assistance of expert judgment from Equinor and the utilization of key design parameters in a calculation sheet for subsea processing, an estimative approach was employed to derive a top-down estimation of the SCSIS. Specifically, Option B necessitated a subsea power system capable of distributing an adequate level of voltage to drive the pumps of the SCSIS. By aggregating the costs presented in Tables 33-34, the total procurement cost associated with the subsea power system and SCSIS was determined as presented below.

Table 33: Subsea power system cost

Subsea Power System	Cost (MNOK)
Preliminaries & System Engineering	17
Subsea Transformer Module	86
Protection Structure and Foundation for Subsea Power System	30
Logistics & Support	2
SUM (MNOK)	**135**

Table 34: SCSIS cost

Subsea Chemical Storage and Injection System	Cost (MNOK)
Preliminaries & System engineering	104
Cluster frame	39
Manifold module	40
Storage tanks	124
Chemical injection pumps	140
Subsea control systen (incl. flying leads)	65
Topside power and control system	50
Tools	30
Test, handling and transportation equipment	15
Testing	20
Logistics and support	11
SUM (MNOK)	**638**

Total CAPEX of the SCSIS was then equal to:

$$SCSIS\ CAPEX = 135\ \text{MNOK} + 638\ \text{MNOK} = \mathbf{773\ MNOK}$$

SCSIS and Subsea Power System Marine Operations

The installation costs associated with the SCSIS and Subsea Power System were computed by considering the anticipated duration of the installation campaign, as identified in Chapter 2.2.3.2 of the thesis, and multiplying it by the daily rates applicable to the corresponding FSV required. When incorporating preliminaries, engineering, materials fabrication, and logistics into the calculation, the results presented in Table 35 are cost inputs obtained for further analysis.

Table 35: Option B subsea components marine operations cost

SCSIS and Subsea Power System Marine Operations	Cost (MNOK)
Mobilization	13
Transportation	10
Installation	33
Preliminaries	7
Engineering	3
Materials, fabrication and logistics	7
SUM (MNOK)	**73**

4.2.3 Input to Model

This subchapter covers all costs contributing to CAPEX for Option A and Option B, using input data from the two previous subchapters. Cost difference between the competing options was also calculated by subtracting the conventional solution (Option A) from the new solution (Option B).

CIS & Production stations: Procurement and Fabrication:

- Option A (CIS): 286 MNOK
- Option B (SCSIS and subsea power system): 773 MNOK

Production stations: Marine operations

- Option A: Included in CIS cost estimate
- Option B: 73 MNOK

Cost contributors estimate within subsea production stations are presented in Table 36.

Table 36: Option B subsea production station marine installation cost from CostCalc

Production Stations Installation	Option B (MNOK)
Preliminaries	7
Engineering	3
Materials, Fabrication & Logistics	6
Survey	0
Installation	57
Seabed Intervention	0
Well Commissioning	0
Special Operations	0
Sum Production Stations Installation	**73**

Umbilical/Power cable: Procurement & fabrication

- Option A: 319 MNOK
- Option B: 264 MNOK

Cost contributors within the procurement of an umbilical or power cable are presented in Table 37.

Table 37: Umbilical/Power Cable procurement and fabrication cost from CostCalc

Umbilical/Power Cable Procurement & Fabrication	Option A (MNOK)	Option B (MNOK)	Difference (MNOK)
Preliminaries	32	26	-6
Engineering	16	13	-3
Static Umbilical	186	117	-69
Dynamic Umbilical	52	47	-5
Umbilical Jumpers & Flying Leads	0	41	41
CDU	28	15	-13
Testing	5	5	0
Special Procurement	0	0	0
Sum Umbilical/Power Cable Procurement & Fabrication	**319**	**264**	**-55**

Umbilical/Power Cable Marine Operations:

- Option A: 110 MNOK
- Option B: 139 MNOK

Cost contributors for the marine operations in relation to the umbilical or power cable are presented in Table 38.

Table 38: Umbilical/Power Cable marine operations cost from CostCalc

Umbilical/Power Cable Marine Operations	Option A (MNOK)	Option B (MNOK)	Difference (MNOK)
Preliminaries	8	10	2
Engineering	5	7	2
Materials, Logistics & Support	9	11	2
Survey	20	20	0
Installation of Umbilical/Power Cable	51	51	0
Installation of CDU	0	0	0
Tie-ins & Installation of Flying Leads	17	40	23
Seabed Intervention	0	0	0
Special Operations	0	0	0
Sum Umbilical/Power Cable Marine Operations	**110**	**139**	**29**

Summarizing all costs for each option, the CAPEX (initial investment) was equal to:

- Option A: **715 MNOK**
- Option B: **1,249 MNOK**
- Difference: **534 MNOK**

4.3 OPEX

This subchapter encompasses all OPEX input data necessary for the LCC analysis presented in Chapter 5 - Analysis. It is structured into separate sections for Option A and Option B, aiming to ascertain the precise costs associated with OPEX-related cost drivers for each of the competing options.

4.3.1 Option A

OPEX for Option A was expected to be a combination of vessel transportation cost and OPEX related to CIS. Vessel transportation key figures were gathered through CostCalc and multiplied with days required of an FSV for refilling purposes, as presented in Table 9. Data regarding CIS operations and maintenance, however, was gathered through CMATE, one of the Equinor tools presented in Chapter 1.4.2 of the thesis. For discovering key figures regarding CIS, some specific fields with floating host facility structures have been utilized since they in many ways are similar to that of an FPSO. Fields assessed for the OPEX estimation and the number of subsea wells corresponding to the field are presented in Table 39.

Table 39: Fields studied for OPEX calculation with number of subsea wells

OPEX fields	Subsea wells
Aasta Hansteen	8 [68]
Heidrun	21 [69]
Kristin	26 [70]
Norne	49 [71]
Snorre	41 [72]
Troll	136 [73]
Åsgard	77 [74]
Total	358

In order to conduct a more comprehensive estimation of OPEX, it was crucial to consider the historical context of Aasta Hansteens acquisition [68]. The initial OPEX data for the field started to render in 2018, meaning total OPEX calculations had to be calculated accordingly. Prior to 2018, the total number of wells stood at 350, whereas in 2018 and subsequent years, it reached 358.

This led to a cumulative OPEX of **111,119 MNOK**, rounded to the nearest million, for all 7 fields during the period of 2012-2021. This resulted in yearly OPEX for 1 well to be equal to **31.5 MNOK**. When determining the OPEX of the CIS, all the aforementioned factors were considered during the calculation. The utilization of CMATE enabled a more detailed examination of the maintenance contribution within the overall OPEX.

Within the OPEX maintenance data from CMATE, the key focal point was in discerning the contribution of the CIS, as it directly pertained to the subject at hand. Consequently, the aggregate maintenance OPEX cost equaled **25,447 MNOK.** The total maintenance OPEX associated with CIS was estimated to be **480.4 MNOK.** This value in relation to the total maintenance OPEX is important during Chapter 5.

4.3.2 Option B

The calculation of Option B's OPEX entailed the utilization of an appropriate maintenance vessel for refilling and inspection, coupled with the corresponding vessel day-rates. This calculation further incorporated data extracted from both Tables 10-11, and Table 13, encompassing operational days and relevant details pertaining to refilling and maintenance methodologies. By incorporating these factors, the OPEX associated with the SCSIS was estimated.

4.4 LOSTREV

LOSTREV was computed by quantifying the production loss resulting from the downtime of the various competing options, and subsequently multiplying it by the prevailing spot price of crude Brent oil. The production availability for these options is presented in Table 40, meanwhile, the spot price is depicted in Figure 26. In the specific case of May 2023, the spot price was determined to be 76 USD [49]. In light of the thesis' scope, where currency exchange rates were not assessed, a rough estimation of approximately **800** Norwegian kroner **(NOK)** per unit/barrel was attributed to be the spot price.

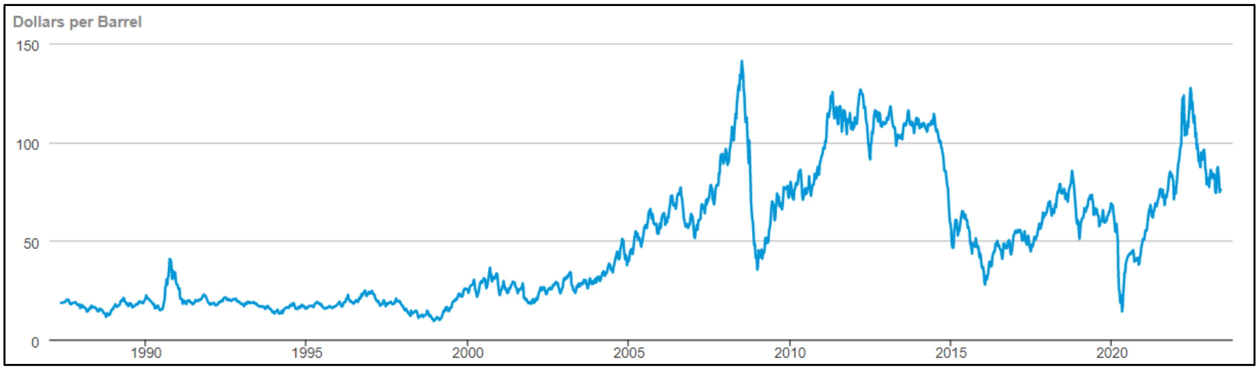

Figure 26: Weekly Europe brent spot price [49]

Nevertheless, it is important to note that the aforementioned value is inherently dynamic and can experience significant fluctuations within certain intervals [49]. The analysis portion of this thesis delves deeper into the examination of the fluctuation in unit prices. Furthermore, the total production of crude oil barrels commenced at a daily production rate of 50,000 barrels, as documented in Equinor restricted reports, and gradually declined over subsequent years. This aspect is thoroughly assessed in the forthcoming chapter.

Production Availability

Table 40 illustrates the comparison of projected operational, technical, and production availabilities between Option A and Option B. These anticipated numbers were extracted from restricted reports on the CIS vs SCSIS and served as metrics for fundamental assumptions, constituting input data employed in the subsequent analysis.

Table 40: Availabilities for Option A and B

Option	Operational availability	Technical availability	Production availability
A	98.6%	99.8%	99%
B	94.1%	99.5%	96%

For the chemical injection criticality, some potential impacts on operations were considered. Production shutdown could massively affect LOSTREV. These impacts considerations were also extracted from restricted reports on flow assurance. The production system relative to the case study would shut down if:

- CI and SI were unavailable for more than 3 days → Shutdown until repaired
- Biocide was unavailable for more than 3 weeks → Shutdown until repaired
- MEG was unavailable when required → Shutdown for **1 month**

The production allowances are illustrated in Figure 27.

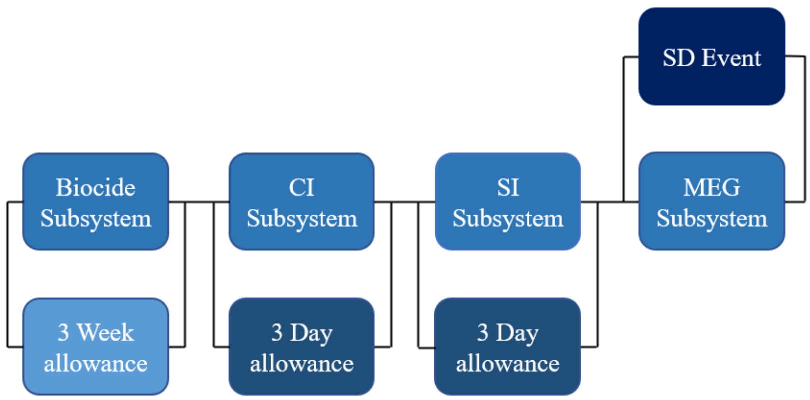

Figure 27: Production allowances for case study chemicals

5 Analysis

The following chapter provides a comprehensive assessment of the life cycle costing estimation accompanied by economic evaluation measures, which are instrumental in facilitating the decision-making processes of petroleum investments. Firstly, the analysis is presented by beginning with an in-depth exploration of life cycle cost, taking into consideration all life cycle costing main elements and utilizing Monte Carlo simulations where uncertainty was large. Subsequently, the estimation of the NPV, PI, IRR and payback is presented. Both NPV and PI are calculated with various discount rates to investigate how profitability varies when discount rate is larger than expected. The life cycle costing assessment was executed in the "define" phase, as previously mentioned in Chapter 2.1.2.1, meaning calculations are performed according to DG3 as illustrated in Table 41. This entailed ensuring that the costs fell within a ±20% estimate, while maintaining an 80% confidence that technical information was ±10%.

Table 41: Cost- and technical estimation confidence based on estimation class and decision gate

Estimate Class	Decision Gate	Cost Estimate Accuracy at 80% Confidence	Accuracy of Techical Information at 80% Confidence
Class A	DG0	N/A	N/A
Class B	DG1	±40%	±25%
Class C	DG2	±30%	±15%
Class D	DG3	±20%	±10%

CIS factor

CIS factor is the percentage contribution of CIS to OPEX for a well. This was calculated by dividing maintenance related to CIS on total maintenance cost. This factor was utilized for almost every calculation to discover the actual contribution of operating cost factors and revenue factors related to the subject matter, to the life cycle costing assessment. The factor is equal to **1.89%.**

5.1 Life Cycle Cost Analysis

The LCC analysis are systematic evaluations and calculations carried out to assess competing options using economic evaluation measures as part of life cycle costing [2]. All life cycle costing economic evaluation measures relevant to this this thesis, as presented from Chapter 3.2, were calculated and evaluated in this chapter.

5.1.1 Estimation of Life Cycle Cost

One of the economic evaluation measures for this life cycle costing assessment was LCC. The LCC of an option encompasses the aggregation of three key components: CAPEX, OPEX, and LOSTREV. In the estimation model, these primary elements were examined individually, assessing the economic implications of cost drivers on the overall cost over a 20-year time frame. By analyzing each component's economic impact, a comprehensive understanding of the factors influencing the option's total LCC was obtained.

5.1.1.1 CAPEX

From Chapter 4.2, input data regarding CAPEX cost for each cost driver was further utilized in this chapter. The data regarding CAPEX mean costs are presented in Table 42.

Table 42: Main CAPEX cost drivers

Option	Cost driver	Cost (MNOK)
A	CIS	286
A	Umbilical	429
B	SCSIS	773
B	Power Cable	403
B	Installation SCSIS	73

The CAPEX estimation for Option A involved utilizing key figures obtained from the BulkMate CIS calculation and the CostCalc subsea estimation for umbilical cost. The umbilical cost encompassed both the procurement and installation expenses. The installation cost of the CIS was included as part of the cost estimate for the entire system. The CIS and umbilical costs were based on verified key figures and did not necessitate a simulation for determining P-values.

On the other hand, CAPEX estimation for Option B was more uncertain compared to Option A. Therefore, the estimation for Option B involved gathering figures from chapter 4.2 and multiplying the costs with a change factor derived from a normal distribution. The normal distribution was constructed through a Monte Carlo simulation, which incorporated a mean value of 1 and a standard deviation of 20% (DG3) for all CAPEX cost drivers associated with Option B. The simulation was executed 10,000 times. The normal distribution resulting from the simulation is presented in Figure 28.

Monte Carlo inputs:

- Mean = 1
- Standard deviation = 0.2
- Iterations = 10000

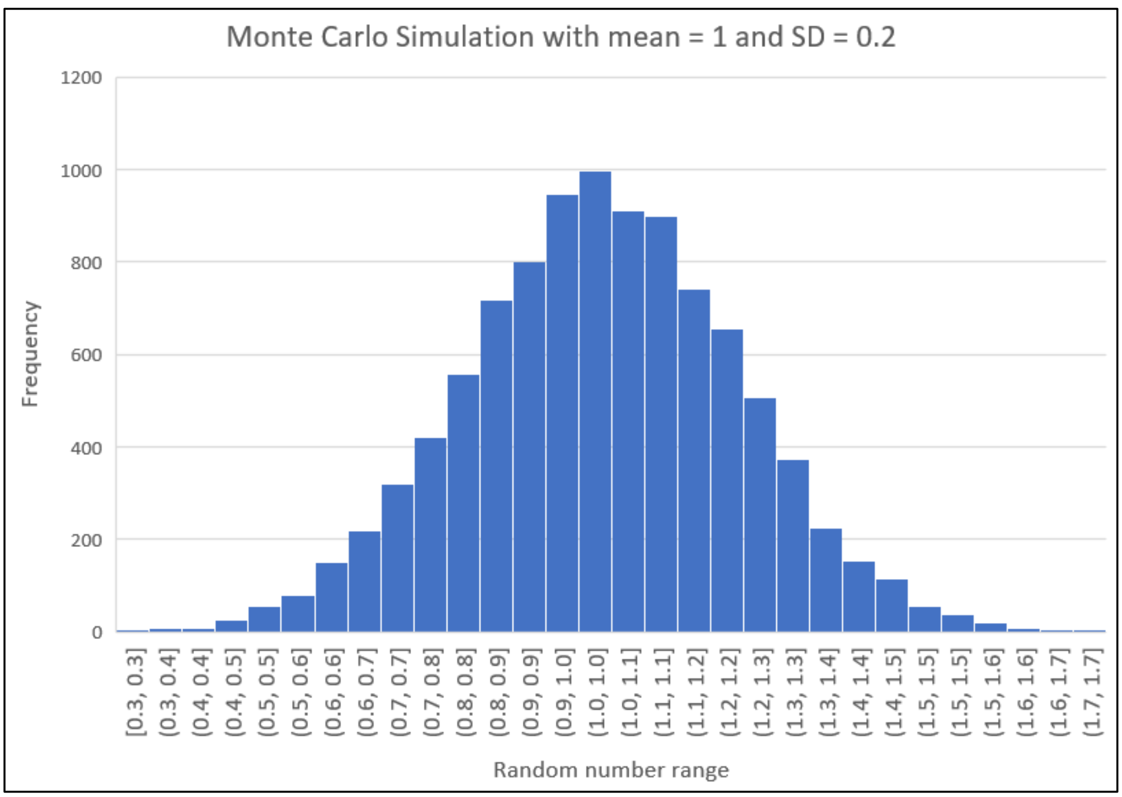

Figure 28: Option B CAPEX Monte Carlo simulation

By multiplying the costs of each cost driver with the respective change factor from the normal distribution, the results yielded the updated costs along with its associated probability. The computation of the new cost for the individual cost drivers was calculated in the following manner:

$$New\ cost\ = Expected\ cost \times Normal\ distribution\ factor$$

Considering the aforementioned considerations, Tables 43-45 display the outcomes of the costs in relation to the corresponding probabilities, thereby illustrating the likelihood of each cost being the accurate value. Additionally, the difference between the mean cost and the resulting values is presented in the tables to provide a comprehensive overview of the extent of cost variations.

Table 43: SCSIS CAPEX with corresponding probabilities

SCSIS cost		
P-value	Total cost (MNOK)	Differential cost (MNOK)
Min	219	- 554
P1	416	- 357
P5	516	- 257
P10	572	- 201
P15	612	- 161
P20	645	- 128
P25	671	- 102
P30	694	- 79
P40	734	- 39
P50	773	0
P60	812	39
P70	856	83
P75	878	105
P80	905	132
P85	934	161
P90	970	197
P95	1,025	252
P99	1,134	361
Max	1,348	575

Table 44: Power Cable CAPEX with corresponding probabilities

Power Cable cost		
P-value	Total cost (MNOK)	Differential cost (MNOK)
Min	114	- 289
P1	214	- 189
P5	269	- 134
P10	299	- 104
P15	319	- 84
P20	336	- 67
P25	349	- 54
P30	361	- 42
P40	382	- 21
P50	402	- 1
P60	423	20
P70	445	42
P75	457	54
P80	471	68
P85	486	83
P90	505	102
P95	533	130
P99	591	188
Max	703	300

Table 45: SCSIS Installation CAPEX with corresponding probabilities

SCSIS Installation cost		
P-value	Total cost (MNOK)	Differential cost (MNOK)
Min	21	- 52
P1	39	- 34
P5	49	- 24
P10	54	- 19
P15	58	- 15
P20	61	- 12
P25	63	- 10
P30	65	- 8
P40	69	- 4
P50	73	0
P60	77	4
P70	81	8
P75	83	10
P80	85	12
P85	88	15
P90	92	19
P95	97	24
P99	107	34
Max	127	54

The outcomes derived from the Monte Carlo simulation for Option B were subsequently calculated in a sensitivity analysis, calculating the probabilities associated with specific outputs and their corresponding costs. In this analysis, the column input pertains to the SCSIS and its installation, while the row input pertains to the power cable and the installation thereof. This analysis allowed for a comprehensive examination of the interrelationship between these inputs and their impact on the overall costs. The sensitivity analysis is presented in Table 46.

Table 46: Sensitivity analysis of Option B total CAPEX

			SCSIS P-value Cost (MNOK)																		
		Cost	Min	P1	P5	P10	P15	P20	P25	P30	P40	P50	P60	P70	P75	P80	P85	P90	P95	P99	Max
	Cost	358	242	452	572	628	665	699	727	754	800	842	886	934	960	988	1,022	1,063	1,122	1,238	1,558
PC P-value Cost (MNOK)	Min	115	321	547	646	701	742	771	797	822	864	902	943	986	1,011	1,037	1,070	1,109	1,170	1,273	1,534
	P1	216	436	662	761	816	857	886	912	937	979	1,017	1,057	1,101	1,125	1,152	1,185	1,224	1,285	1,388	1,649
	P5	273	486	712	811	866	907	936	962	987	1,029	1,067	1,108	1,151	1,176	1,202	1,235	1,274	1,335	1,438	1,699
	P10	299	514	740	839	894	935	964	990	1,015	1,057	1,095	1,136	1,179	1,204	1,230	1,263	1,302	1,363	1,466	1,727
	P15	317	534	761	860	915	955	985	1,011	1,035	1,078	1,116	1,156	1,200	1,224	1,250	1,284	1,322	1,384	1,487	1,747
	P20	333	549	776	875	930	970	1,000	1,026	1,050	1,093	1,131	1,171	1,215	1,239	1,265	1,299	1,337	1,399	1,502	1,762
	P25	346	562	789	887	943	983	1,013	1,039	1,063	1,106	1,144	1,184	1,228	1,252	1,278	1,312	1,350	1,412	1,515	1,775
	P30	359	575	801	900	955	996	1,025	1,051	1,076	1,118	1,156	1,197	1,240	1,265	1,291	1,324	1,363	1,424	1,527	1,788
	P40	381	596	823	922	977	1,017	1,047	1,073	1,097	1,140	1,178	1,218	1,262	1,286	1,312	1,346	1,384	1,446	1,549	1,809
	P50	401	615	842	941	996	1,037	1,066	1,092	1,116	1,159	1,197	1,237	1,281	1,305	1,332	1,365	1,404	1,465	1,568	1,829
	P60	422	636	862	961	1,017	1,057	1,087	1,112	1,137	1,180	1,217	1,258	1,302	1,326	1,352	1,385	1,424	1,486	1,589	1,849
	P70	445	658	885	984	1,039	1,079	1,109	1,134	1,159	1,202	1,240	1,280	1,324	1,348	1,374	1,407	1,446	1,508	1,611	1,871
	P75	457	671	897	996	1,051	1,092	1,121	1,147	1,172	1,214	1,252	1,292	1,336	1,360	1,387	1,420	1,459	1,520	1,623	1,884
	P80	471	684	910	1,009	1,064	1,105	1,135	1,160	1,185	1,227	1,265	1,306	1,349	1,374	1,400	1,433	1,472	1,533	1,636	1,897
	P85	487	701	927	1,026	1,081	1,122	1,151	1,177	1,202	1,244	1,282	1,323	1,366	1,391	1,417	1,450	1,489	1,550	1,653	1,914
	P90	506	720	947	1,046	1,101	1,141	1,171	1,197	1,221	1,264	1,302	1,342	1,386	1,410	1,436	1,470	1,508	1,570	1,673	1,933
	P95	534	751	978	1,077	1,132	1,172	1,202	1,228	1,252	1,295	1,333	1,373	1,417	1,441	1,468	1,501	1,540	1,601	1,704	1,965
	P99	590	804	1,030	1,129	1,184	1,225	1,254	1,280	1,305	1,347	1,385	1,426	1,469	1,494	1,520	1,553	1,592	1,653	1,756	2,017
	Max	742	936	1,162	1,261	1,316	1,357	1,386	1,412	1,437	1,479	1,517	1,558	1,601	1,626	1,652	1,685	1,724	1,785	1,888	2,149

While Option B exhibited significant variation in output probabilities, Option A demonstrated a comparatively smaller deviation of 20% for maximum and minimum scenarios, as illustrated in Table 47. The results pertaining to the CAPEX estimation of Option A and Option B were employed in the subsequent calculation of LCC.

Table 47: Option A total CAPEX in various scenarios

Cost driver	Mean cost (MNOK)	Max cost (MNOK)	Min cost (MNOK)
Umbilical + installation	429	515	343
Topside CIS	286	343	228

5.1.1.2 OPEX

Based on the findings presented in the preceding chapter, it was determined that the primary cost drivers associated with OPEX encompassed operations and maintenance, logistics, as well as transportation costs. In the case of Option A, the majority of OPEX pertaining to the CIS was due to offshore personnel engaged in the handling and operation of the system. Conversely, for Option B, the predominant OPEX was due to external personnel involved in the FSV operations. This subchapter aims to elucidate the annual OPEX specifically related to the CIS and subsequently explore the OPEX associated with the FSV operations.

Chemical Injection System

How CIS OPEX was calculated:

1. The total OPEX of 7 fields, as presented in Table 39, comprising a cumulative count of 358 subsea wells, was computed using CMATE.
2. To determine the yearly OPEX per well, the total OPEX incurred before 2018 was divided by the number of wells (350 wells). Similarly, the total OPEX incurred from 2018 onwards was divided by 358 wells
3. The maintenance cost within the overall OPEX was retained for further examination.
4. Within the maintenance category, particular attention was given to the contribution of the CIS towards the total OPEX.
5. By dividing the CIS maintenance cost by the total maintenance cost, the CIS factor of 1.89% was ascertained, indicating the proportionate influence of the CIS on the overall OPEX.
6. Utilizing this factor, the yearly CIS OPEX for the case study was determined by multiplying it by the yearly OPEX for a single well and then scaling it up by a factor of 4 to align with the parameters of the case study.

Yearly CIS related OPEX for 4 wells (case study) is presented in Table 48.

Table 48: Yearly CIS OPEX calculation

OPEX	Cost (MNOK)
Total OPEX	111,118.60
Yearly OPEX per well	31.50
Total maintenance cost	25,446.64
Total maintenance OPEX CIS	480.44
Yearly CIS OPEX per well	0.59
Yearly CIS OPEX (4 wells)	2.38

In the context of this thesis, it was expected that the availability of additional space on the FPSO vessel is limited, thus precluding the storage of chemicals on the topside facility. Consequently, it becomes necessary to transport chemicals to the field on a biannual basis to ensure an uninterrupted operational workflow. In order to compute the costs associated with the FSV, several critical factors came into play:

- Based on vessel times and refilling as presented in Chapter 2.2.3.2, Option A required less time to refill storage modules than Option B.
- Light construction vessel was utilized for both options when the task was refilling tank modules.
- Option B had all operations and maintenance covered by inspection on a construction vessel once every 3 years to maintain system integrity. This inspection was estimated to take 1 day longer than regular refilling operations.
- Unprevented maintenance is covered in production availability for LOSTREV.

FSV rates for this thesis were determined to be **2.5 MNOK** for a CV, while for the LCV it was determined to be **1.7 MNOK**. The FSV cost for both options and routine maintenance for Option B are presented in Table 49.

Table 49: FSV yearly transportation costs

FSV cost	Option A	Option B	Rutine maintenance
FSV supply days	5	6	7
Trips per year	2	2	0.33
Total yearly vessel cost (MNOK)	17.00	20.40	5.83

The total yearly OPEX for Option A and Option B are then calculated as follows:

$$Option\ A: OPEX = 17\ \text{MNOK} + 2.38\ \text{MNOK} = \mathbf{19.38\ MNOK}$$

$$Option\ B: OPEX = 20.40\ \text{MNOK}\ + 5.83\ \text{MNOK}\ =\ \mathbf{26.23\ MNOK}$$

5.1.1.3 LOSTREV

Estimation of LOSTREV was executed with a Monte Carlo simulation on key factors in the subject matter that can affect LOSTREV, in this case: production availability and unit price. Other factors could also affect LOSTREV, but for the sake of simplifications these were determined to not fluctuate. The results of the simulation were implemented as part of the LCC economic evaluation measure.

Input

As a part of this study, the potential LOSTREV could have a major impact on the ranking of options. LOSTREV was estimated based on the following parameters:

1. Production availability:
    a. Option A: 99%
    b. Option B: 96%

    These numerical values were derived from restricted reports and possess a high degree of accuracy. However, minor adjustments were made to ensure the preservation of restricted classification. These figures served as the initial reference point for the average production availability. According to assumptions made by the Norwegian Petroleum industry [52], it was anticipated that production availability will gradually decline over time as the field progresses and necessitates increased maintenance and modifications. During the initial five years of the field's lifecycle, it was expected that the production availability would remain relatively stable, aligning closely with the mean production availability. Nevertheless, the design characteristics of Option B, such as the power cable design and the simplified modular structure of the SCSIS, contributed to a slower rate of decline in production availability. Consequently, the input data for production availability was incorporated in the following manner:

   a. Option A: Starts at **99%** then decreases by **0.2%** every year after the 5^{th} year.
   b. Option B: Starts at **96%** then decreases by **0.1%** every year after the 5^{th} year.

2. Units produced:

   The initial production rate commenced at **50,000** units per day and subsequently decreased by **1,000** daily units annually after 5 years. To calculate the total units produced, the daily unit count was multiplied by 365 days per year and then by a span of 20 years.

3. Price per unit:

   Started with a random value with mean equal to 800 NOK (as discussed in Chapter 4.4) with a standard deviation of 5%.

4. CIS factor:

   Equaled 1.89%.

The aforementioned values represented the expected values for each parameter, which subsequently underwent scrutiny through the Monte Carlo simulation. This simulation method enabled the generation of diverse outcomes for each parameter, as well as the overall potential LOSTREV.

The LOSTREV calculation:

$$LOSTREV = (1 - PA) \times TUP \times PPU \times CISF$$

Where:

LOSTREV = Lost revenue

PA = Production availability

TUP = Total units produced

PPU = Price per unit

CISF = Chemical Injection System Factor

In the context of oil production, it was anticipated that production availability would exhibit temporal variations and experience a gradual decline as the field production advanced [52]. Simultaneously, the oil and gas market are renowned for its inherent volatility, as it undergoes substantial fluctuations over time due to external and internal market forces [49]. Given these uncertainties, employing a Monte Carlo simulation was deemed a suitable approach for addressing and quantifying uncertainties. This simulation methodology enabled the generation of a range of potential outcomes for LOSTREV, which subsequently were incorporated in the life cycle cost analysis, providing valuable insights for decision-making purposes.

Production Availability

The production availability remained constant for both options during the initial five-year period, aligning with the previously presented values in the preceding subchapter. However, after this timeframe, the annual production availability gradually diminished at a consistent rate of 0.2% for Option A and 0.1% for Option B. Further exploration of production availability was conducted through the examination of three distinct scenarios: minimum, expected, and maximum. Each scenario possessed its own mean value and standard deviation, corresponding to the respective option being evaluated. The calculation of production availability for a given year was performed using the following equation:

$$PAS = YPA - YPA \times NDF$$

Where:

PAS = Production Availability Scenario

YPA = Yearly Production Availability

NDF = Normal Distribution Factor

It was anticipated that Option A's production availability would be moderately influenced by the minimum scenario compared to Option B. Conversely, Option A was expected to be slightly less affected by the maximum scenario compared to Option B. Moreover, the standard deviation for Option B was determined to be larger than that of Option A, primarily due to increased uncertainties in production, resulting in longer tails in the normal distribution. The production availability parameters for the normal distribution are presented in Tables 50-51 for Option A and Option B, respectively.

Table 50: Option A Production availability scenarios for MCS

Option A Production availability	mean	st.dev
Minimum	1.0%	0.1%
Expected	0.0%	0.1%
Maximum	0.0%	0.0%

Table 51: Option B Production availability scenarios for MCS

Option B Production availability	mean	st.dev
Minimum	0.5%	0.2%
Expected	0.0%	0.2%
Maximum	-1.0%	0.2%

The scenarios regarding production availability had the same probability of becoming the actual production availability for a specific year. As a result, the mean production availability for a specific year was:

$$Mean\ PA = \frac{Minimum\ PA + Expected\ PA + Maximum\ PA}{3}$$

The equation provided above illustrates the calculation of the mean production availability, wherein all production availability scenarios are assigned equal probabilities of occurrence. By summing up the mean production availability values across the 20-year lifespan and subsequently dividing by 20 years, the mean production availability for the life cycle costing assessment was determined. This value is presented in Table 52 as a reference.

Table 52: Competing options production availabilities

Mean Production Availability	Option A	Option B
Triangular	97.97%	95.52%

As the production availabilities are derived from random draws of change variables following a normal distribution with previously specified mean and standard deviation, these values varied slightly for each iteration within the LOSTREV Monte Carlo Simulation.

Unit Price

The oil and gas markets are characterized by a high level of volatility, making it challenging to accurately forecast market changes over a 20-year field lifespan. The unit price calculation involved taking the price from the preceding year and selecting a change variable at random from a normal distribution with specified mean and standard deviation. As outlined in the previous chapter, the unit price commenced at 800 NOK in year 0. Subsequently, the yearly unit price was determined using the following equation:

$$YUP = LYUP - LYUP \times NDF$$

Where:

YUP = Yearly unit price

$LYUP$ = Last year unit price

NDF = Normal distribution factor

Given the highly volatile nature of oil and gas prices, accurately predicting both maximum and minimum scenarios became challenging. As a result, only a single scenario was considered. However, Figure 26 from Chapter 4.4 demonstrates that during periods of significant market price fluctuations, a longer-tailed normal distribution, characterized by a larger standard deviation, is demanded to represent the uncertainty surrounding price movements and potential outcomes. The mean value and standard deviation for the Brent oil price are presented in Table 53, underscoring the statistical parameters employed in the analysis.

Table 53: Brent oil price MCS input

Brent Oil Price		
Unit price	mean	st.dev
Expected	0%	5%

By summing up the mean prices across all 20 years and subsequently dividing by 20, a mean unit price specific to the lifespan scenario was derived for implementation in the LOSTREV Monte Carlo simulation. As only a single scenario was employed for the unit price calculation, the mean unit price underwent significant variations for each simulation conducted. The total distribution of unit prices, along with their corresponding probabilities, are presented in Table 54.

Table 54: Mean prices and corresponding probabilities

P-values	Mean oil price
Min	547.7
P1	584.5
P5	645.7
P10	672.2
P15	690.4
P20	707.7
P25	721.9
P30	740.1
P40	766.2
P50	791.6
P60	819.8
P70	851.8
P75	872.1
P80	887.0
P85	906.6
P90	936.6
P95	988.5
P99	1079.5
Max	1290.1

LOSTREV Results

This section presents the outcomes of the Monte Carlo simulation, wherein the LOSTREV calculation was iterated 1000 times, incorporating variable variations within the LOSTREV formula for each simulation run. The results encompass sample information, mean values, standard deviations, and the distribution of LOSTREV accompanied by P-values, highlighting the relationship between LOSTREV and its associated probability. Furthermore, a comprehensive summary of the Monte Carlo outcomes is provided, alongside the assessment of maximum and minimum scenarios for annual LOSTREV, should there be a substantial increase or decrease in prices throughout the lifecycle. The results of the LOSTREV Monte Carlo simulation are presented in Tables 55-56 for Option A with Figure 29 illustrating the normal distribution, while Option B is presented in Tables 57-58 with Figure 30 illustrating the normal distribution.

Table 55: Option A LOSTREV mean and standard deviation

Option A		
Samples	1000	
LOSTREV mean	112	MNOK
LOSTREV St.dev	15	MNOK

Table 56: Option A LOSTREV with corresponding probabilities

Option A	
P-values	LOSTREV (MNOK)
Min	75
P1	83
P5	89
P10	94
P15	97
P20	100
P25	102
P30	104
P40	107
P50	111
P60	114
P70	118
P75	121
P80	123
P85	127
P90	132
P95	139
P99	154
Max	185

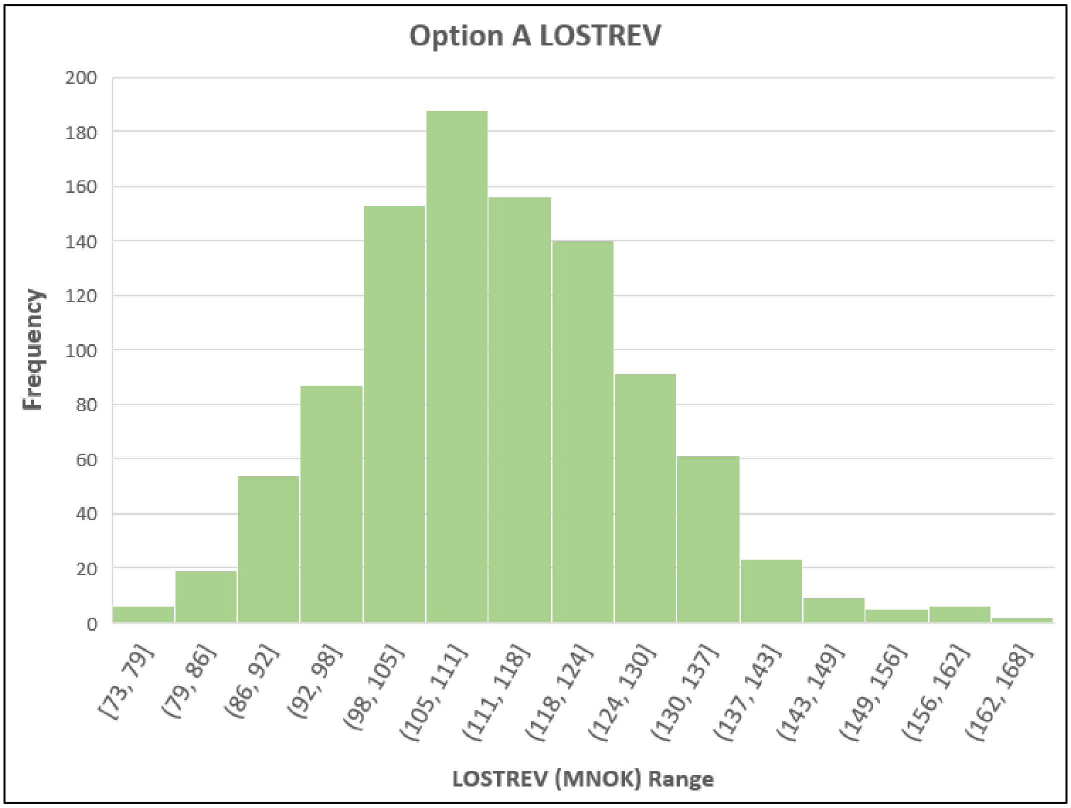

Figure 29: Option A LOSTREV distribution model

Table 57: Option B LOSTREV mean and standard deviation

Option B		
Samples	1000	
LOSTREV mean	244	MNOK
LOSTREV St.dev	33	MNOK

Table 58: Option B LOSTREV and corresponding probabilities

Option B	
P-values	LOSTREV (MNOK)
Min	148
P1	181
P5	194
P10	205
P15	211
P20	217
P25	222
P30	227
P40	235
P50	241
P60	251
P70	260
P75	265
P80	270
P85	276
P90	286
P95	301
P99	332
Max	381

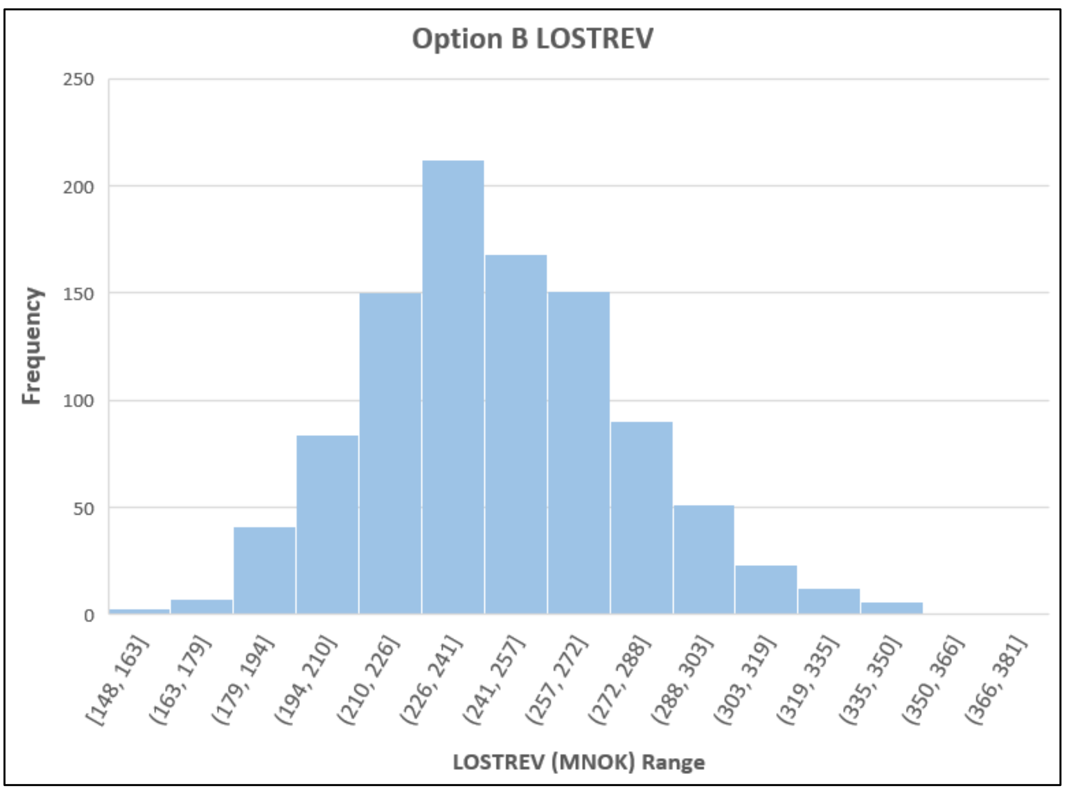

Figure 30: Option B LOSTREV distribution model

LOSTREV Summary

To summarize the results of the LOSTREV model, there was a substantial difference between the two options as presented in Table 59. Main reason for this difference from the production availability difference between the two competing options. When price fluctuate to the degree that was utilized in this thesis, the effect on minimum and maximum LOSTREV were also extreme.

Table 59: LOSTREV results of options

Total LOSTREV	Option A (MNOK)	Option B (MNOK)	Difference (B-A)
Minimum LOSTREV	74	174	100
P5 LOSTREV	89	196	106
Mean LOSTREV	112	245	133
P95 LOSTREV	137	300	163
Maximum LOSTREV	162	370	208
90% Confidence LOSTREV	48	104	56

An additional crucial aspect of LOSTREV pertained to the impact of downtime resulting from flow assurance issues, whereby production ceases temporarily. As outlined in the preceding chapter, downtime for the production system could occur for several days, several weeks, or even an entire month in cases where a specific chemical cannot be provided within the designated timeframe. Table 60 shows the LOSTREV attributed to downtime, with variations in unit prices. The unit prices utilized for this calculation were obtained by extracting the maximum and minimum values from the 20-year lifespan simulation, which was repeated 1000 times. Subsequently, the maximum and minimum unit price values were determined from the overall simulation results. These values are denoted in Table 60 as either price ceilings or price floors.

Table 60: Potential LOSTREV due to downtime

Scenario	Input (NOK/Barrel)	4 days downtime (MNOK)	2 weeks downtime (MNOK)	1 month downtime (MNOK)
Highest price ceiling	1,546	5.8	20.3	45.0
Lowest price ceiling	686	2.6	9.0	20.0
Highest price floor	907	3.4	11.9	26.4
Lowest price floor	404	1.5	5.3	11.8

These numbers offer valuable insights into the potential impact of chemicals on LOSTREV. While these specific numbers may not be directly utilized in the life cycle cost calculation, they constitute an essential factor to consider in the decision-making process when evaluating different options. They provide a comprehensive understanding of how LOSTREV can be influenced when the market experiences greater than usual fluctuations, thereby informing decision-makers about the potential risks and uncertainties associated with the options under consideration.

5.1.1.4 Results

By incorporating all main elements of LCC into different scenarios, the total LCC for each option was computed. For Option A, the scenarios were categorized into three cases: maximum, most likely, and minimum, wherein the deviation of the maximum case and minimum case was set at 20% (DG3). Each Option A case was calculated with the following procedure:

- Maximum case: Mean CAPEX (+20%), mean OPEX (+20%) and maximum LOSTREV.
- Most likely case: Mean CAPEX, mean OPEX and mean LOSTREV.
- Minimum case: Mean CAPEX (-20%), mean OPEX (-20%) and minimum LOSTREV

In contrast, the LCC for Option B exhibited higher uncertainty, necessitating an examination of additional scenarios for a comprehensive analysis. Option B was also divided into three cases (maximum, most likely, and minimum), encompassing various scenarios where CAPEX and LOSTREV underwent significant increases or decreases. As presented in Chapter 2.1.1.1 of this thesis, increasing CAPEX has the potential to reduce OPEX and LOSTREV, whereas lower CAPEX can lead to higher OPEX and LOSTREV. These scenarios were included to explore the implications of such variations.

For each of the 7 Option B scenarios, each calculations had the following procedure:

1. Maximum: Mean CAPEX (+20%), mean OPEX (+20%) and maximum LOSTREV.
2. Most likely: Mean CAPEX, mean OPEX and mean LOSTREV.
3. Minimum: Mean CAPEX (-20%), mean OPEX (-20%) and minimum LOSTREV.
4. Extremely low CAPEX and high OPEX/LOSTREV: P5 CAPEX, mean OPEX (+20%) and P95 LOSTREV.
5. Low CAPEX: P20 CAPEX, mean OPEX and mean LOSTREV.
6. High CAPEX: P80 CAPEX, mean OPEX and mean LOSTREV.

7. Extremely high CAPEX and low OPEX/LOSTREV: P95 CAPEX, mean OPEX (-20%) and P5 LOSTREV.

The results of the LCC economic evaluation measure are presented in Table 61 and illustrated in Figure 31.

Table 61: Results of the LCC evaluation measure

LCC RESULTS		CAPEX (MNOK)	OPEX (MNOK)	LOSTREV (MNOK)	TOTAL (MNOK)
Option A	Maximum case (+20%)	857	465	162	1,485
	Most likely case	715	388	112	1,214
	Minimum case (-20%)	572	310	74	956
Option B	Maximum case (+20%)	1,500	630	370	2,500
	Most likely case	1,250	525	245	2,020
	Minimum case (-20%)	1,000	420	174	1,594
	P5 CAPEX, high OPEX & P95 LOSTREV	811	630	300	1,741
	P20 CAPEX & Mean OPEX/LOSTREV	1,000	525	245	1,770
	P80 CAPEX & Mean OPEX/LOSTREV	1,400	525	245	2,170
	P95 CAPEX, low OPEX & P5 LOSTREV	1,601	420	196	2,217

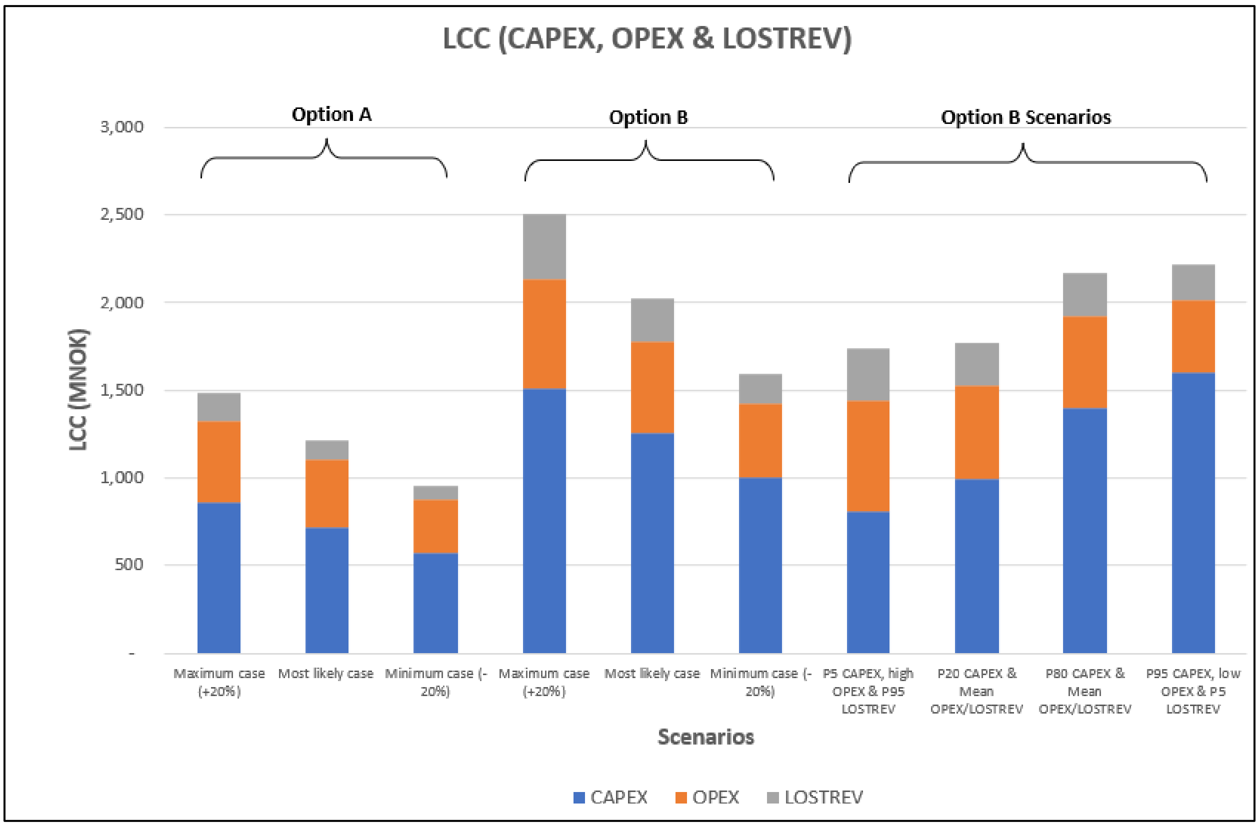

Figure 31: Column chart of LCC results

Then to summarize how much difference is between Option A and Option B in life cycle cost context, the results are presented in Table 62, with Figure 32 to visualize the difference for all life cycle costing main elements.

Table 62: LCC differences for competing options

LCC Difference	CAPEX (MNOK)	OPEX (MNOK)	LOSTREV (MNOK)	TOTAL (MNOK)
Maximum case	650	164	208	1,022
Most likely case	542	137	133	812
Minimum case	433	110	100	643

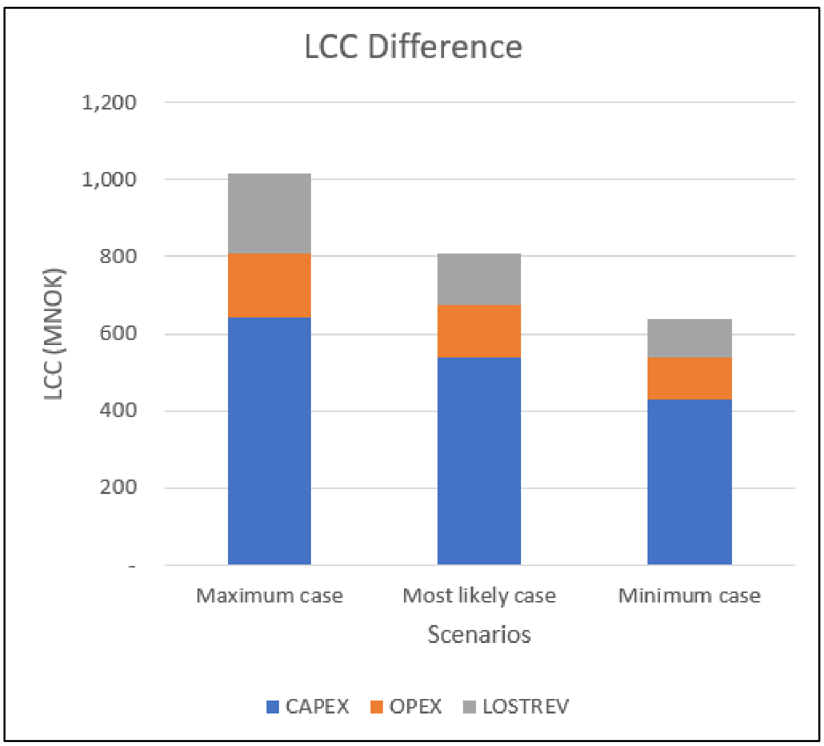

Figure 32: Illustration of differences in LCC results

5.1.2 Estimation of Net Present Value and Profitability Index

This subchapter focuses on the computation of NPV and PI using the formulas for economic evaluation measures presented in Chapter 3.2. A fundamental component in determining the NPV of each option lies in the assessment of its associated cash flows. Accordingly, this subchapter entails a comprehensive analysis of the cash flows for the competing options. Subsequently, the NPV was calculated by incorporating relevant factors such as initial investments and discount rates. Finally, a sensitivity analysis was conducted to examine how changes in the discount rate affect both the NPV and PI.

5.1.2.1 Cash Flow

NPV was calculated by first discovering a proper cash flow that can be utilized for the NPV formula. The cash flow calculation was executed with the following procedure:

1. Oil price was equal to the mean oil price at **800 NOK** per barrel and did not change during the NPV calculation.
2. The oil field production capacity was a constant value of **50000 barrels** each day.

$$Unit\ price \times Production\ capacity \times 365\ days = Maximum\ yearly\ revenue$$

3. Production availability was constant and closely related to mean production availabilities presented in Equinor restricted reports: **99%** for Option A and **96%** for Option B.

$$Maximum\ yearly\ revenue \times\ Production\ availability\ = Total\ yearly\ revenue$$

4. The percentage revenue income of an option was calculated by multiplying the total yearly revenue with the CIS factor at **1.89%**. This value provided a clearer picture on income relative to the subject matter.

$$Total\ yearly\ revenue \times CIS\ factor = Yearly\ revenue$$

5. The OPEX value for an option was extracted from the LCC calculations and was constant for each year over the 20-year time period.

$$Yearly\ Revenue - \ OPEX = \ Earnings\ before\ tax\ (EBT)$$

6. Tax was equal to the general corporate tax rate of **22%** [50] for both options.

First year cash flow was then equal to:

$$EBT\ \times (1 - Tax) = First\ Year\ Cash\ Flow$$

Cash flows for Option A and Option B are presented in Tables 63-64.

Table 63: Option A cash flow

Option A		
Price oil barrels	800	NOK
Daily unit production	50000	Units
Days in year	365	Days
Max yearly Revenue	14,600.0	MNOK
Production availability	99.0%	
Total yearly revenue	14,454.0	MNOK
CIS percentage income	1.89%	
Yearly revenue	273.2	MNOK
Cashflow year 1		
Yearly revenue	273.2	MNOK
OPEX	19.4	MNOK
Earnings before tax	253.8	MNOK
Tax	22%	
First year cashflow	**198.0**	MNOK

Table 64: Option B cash flow

Option B		
Price oil barrels	800	NOK
Daily unit production	50000	Units
Days in year	365	Days
Max yearly revenue	14,600.0	MNOK
Production availability	96.0%	
Total yearly revenue	14,016.0	MNOK
SCSIS percentage income	1.89%	
SCSIS revenue	264.9	MNOK
Cashflow year 1		
Yearly revenue	264.9	MNOK
OPEX	26.2	MNOK
Earnings before tax	238.7	MNOK
Tax	22%	
First year cashflow	**186.2**	MNOK

5.1.2.2 Model Development and Results

When a cash flow was considered for the NPV calculation, the initial investment and discount rate needs to be implemented. Following are the parameters utilized in the calculation of NPV:

1. The initial investment is fixed and equal to the CAPEX estimates discovered in Chapter 4.2.3 of the thesis.
    a. Option A: **715 MNOK**
    b. Option B: **1,249 MNOK**
2. The discount rate was constant at **10%** during the NPV estimation. The discount rate was equal for both options since uncertainty was already considered as part of the CAPEX, OPEX and LOSTREV estimate. The discount rate was also validated by external supervisors at Equinor.
3. A Monte Carlo simulation simulating the change in cash flow each year, in this case the value of oil and resulting cash flow for the corresponding year. The simulation was utilized to showcase the fluctuations in cashflow because of the highly volatile oil market.

The Monte Carlo simulation was employed to simulate the annual change in cash flow. This simulation was conducted with a mean value of **0** and a standard deviation of **5%,** consistent with the approach used to calculate unit price in Chapter 5.1.1.3. The simulation was utilized to demonstrate the fluctuations in cash flow due to the inherent volatility of the oil market or other uncertainties such as the ones presented in Chapter 2.4. Tables 65-66 shows input values for the NPV calculation visualized:

Table 65: Option A input to NPV calculation

Option A		
Data		Currency
Initial investment	715	MNOK
Cash flow year 1	198.0	MNOK
Discount rate	10%	
Time (years)	20	
	Mean	**St.dev**
Cash flow	0%	5%

Table 66: Option B input to NPV calculation

Option B		
Data		Currency
Initial investmen	1,249	MNOK
Cash flow year 1	186.2	MNOK
Discount rate	10%	
Time (years)	20	
	Mean	**St.dev**
Cashflow	0%	5%

During the NPV calculation as each year goes by, the cash flows for each individual year was calculated by taking the previous yearly cash flow where t = current year, and then multiplying with the normal distribution factor in the following manner:

$$Cashflow_t = Cashflow_{t-1} \times Normal\ distribution\ factor$$

To discover the present value for a particular year, the discounted cash flow factor that is later multiplied with the yearly cashflow was calculated with this equation:

$$Discount\ factor = \frac{1}{(1+d)^t}$$

Where:

d Discount rate

t Year in which the cash flow is discounted

The present value for the particular year at hand was then:

$$Present\ value = Yearly\ cashflow \times\ discount\ factor$$

The Monte Carlo simulation simulated random NPV outputs based on 10,000 iterations. Tables 67-68 present the results of the NPV Monte Carlo simulation, while Figures 33-34 illustrate the resulting NPV ranges and their corresponding frequency.

Table 67: Option A NPV and PI results

Option A		
NPV Monte Carlo		Currency
Number of samples	10,000	
NPV Mean	958	MNOK
NPV St.dev	185	MNOK
Min value	472	MNOK
Max value	1,632	MNOK
5% Percentile	675	MNOK
95% Percentile	1,271	MNOK
90-Percentile	597	MNOK
Mean PI	2.34	

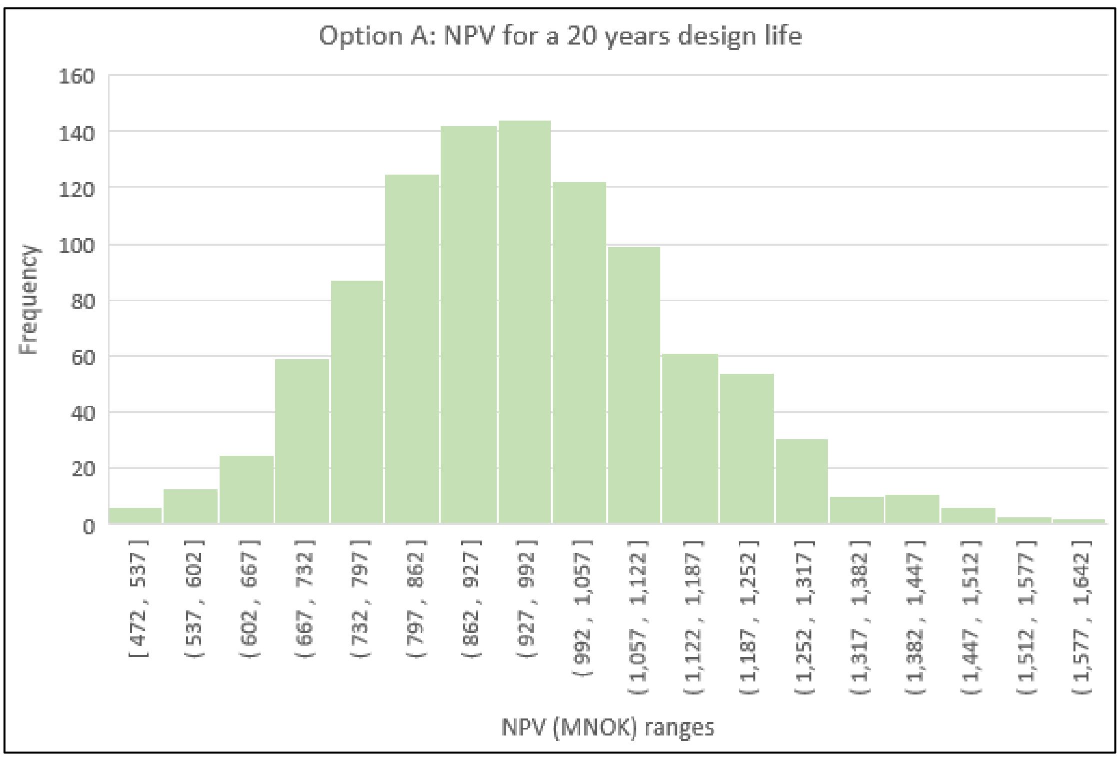

Figure 33: Option A NPV for a 20 years design life

Table 68: Option B NPV and PI results from MCS

Option B		
NPV Monte Carlo		Currency
Number of samples	10,000	
NPV Mean	332	MNOK
NPV St.dev	164	MNOK
Min value	-98	MNOK
Max value	930	MNOK
5% Percentile	63	MNOK
95% Percentile	627	MNOK
90-Percentile	564	MNOK
Mean PI	1.27	

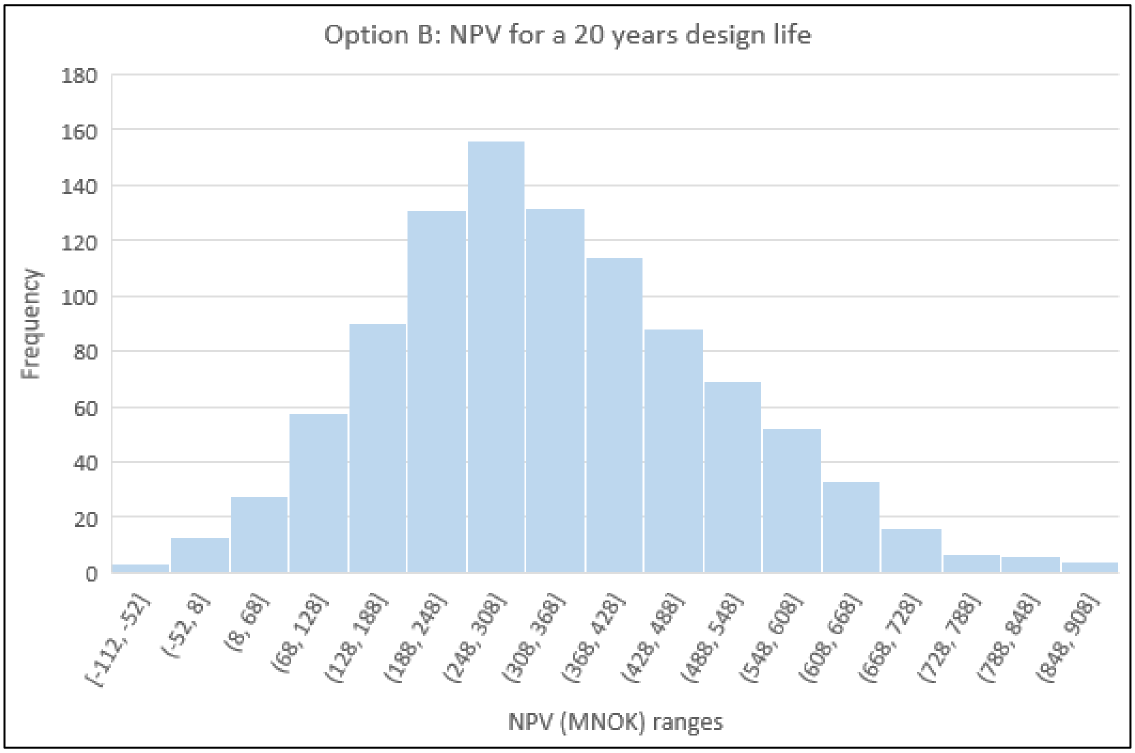

Figure 34: Option A NPV for a 20 years design life

The analysis revealed that the mean NPV for both options surpass zero, indicating their respective value. Based on the NPV criteria presented in Chapter 3.2.2, both options were accepted. However, Option A indicated a considerably better result than Option B, providing a mean NPV of **626 MNOK** larger than the NPV of Option B in a design life of 20 years. Additionally, the samples of Option A never fell below 0, meaning that each of the 10,000 scenarios run in this simulation could be accepted. This is not the case for Option B, where 362 scenarios out of the 10,000 fell below 0, meaning there was a 3.62% chance of Option B to not reach the NPV acceptance criteria. The standard deviation for both options was notably comparable, as anticipated based on the simulation. Given the limited tail of the NPV simulation model, the extreme maximum and minimum values could be excluded from the results, while the 5th percentile and 95th percentile remained relevant.

Moreover, the results for both options exhibited a profitability index exceeding 1, indicating their economic viability. Option A provided a PI over double the acceptance criteria, showcasing its high profitability, while Option B was just slightly over the acceptance criteria.

5.1.2.3 NPV and PI as a Function of Discount Rate

As it is described in the ISO 15663:2021 Annex C [2, pp. 69-70], it can be wise to investigate how the NPV profile moves when it is a function of discount rate. The discount rate represents an organization's requirement for a return on an investment, at a specific level of risk. Since risk was not thoroughly assessed in this thesis, a sensitivity presenting various discount rates and resulting NPV's was utilized.

The sensitivity was carried out with the following parameters:

1. Cash flow: Were constant for both options in every year equal to the ones presented in Tables 63-64.
2. Initial investment: Were equal to CAPEX for both options gathered from Chapter 4.2.3 of the thesis.
3. Discount rate: Were between 5-25% for both options with intervals of 1%.

NPV for Option A and Option B as a function of discount rate applied are presented in Tables 69-70.

Table 69: Option A NPV and PI as a function of discount rate

Results of Sensitivty		
Discount rate	**NPV (MNOK)**	**PI**
5%	1738	3.43
6%	1543	3.16
7%	1371	2.92
8%	1218	2.70
9%	1082	2.51
10%	961	2.35
11%	853	2.19
12%	756	2.06
13%	668	1.94
14%	589	1.82
15%	518	1.72
16%	452	1.63
17%	393	1.55
18%	339	1.47
19%	289	1.41
20%	244	1.34
21%	202	1.28
22%	163	1.23
23%	128	1.18
24%	94	1.13
25%	64	1.09
26%	35	1.05
27%	8	1.01
28%	-17	0.98
29%	-40	0.94
30%	-62	0.91

Table 70: Option B NPV and PI as a function of discount rate

Results of Sensitivty		
Discount rate	**NPV (MNOK)**	**PI**
5%	1057	1.85
6%	874	1.70
7%	712	1.57
8%	568	1.45
9%	440	1.35
10%	327	1.26
11%	225	1.18
12%	133	1.11
13%	51	1.04
14%	-23	0.98
15%	-91	0.93
16%	-152	0.88
17%	-207	0.83
18%	-258	0.79
19%	-305	0.76
20%	-348	0.72
21%	-387	0.69
22%	-424	0.66
23%	-457	0.63
24%	-488	0.61
25%	-517	0.59
26%	-544	0.56
27%	-569	0.54
28%	-593	0.53
29%	-615	0.51
30%	-635	0.49

Figure 35 summarizes and illustrates how the NPV changed as the discount rate increased.

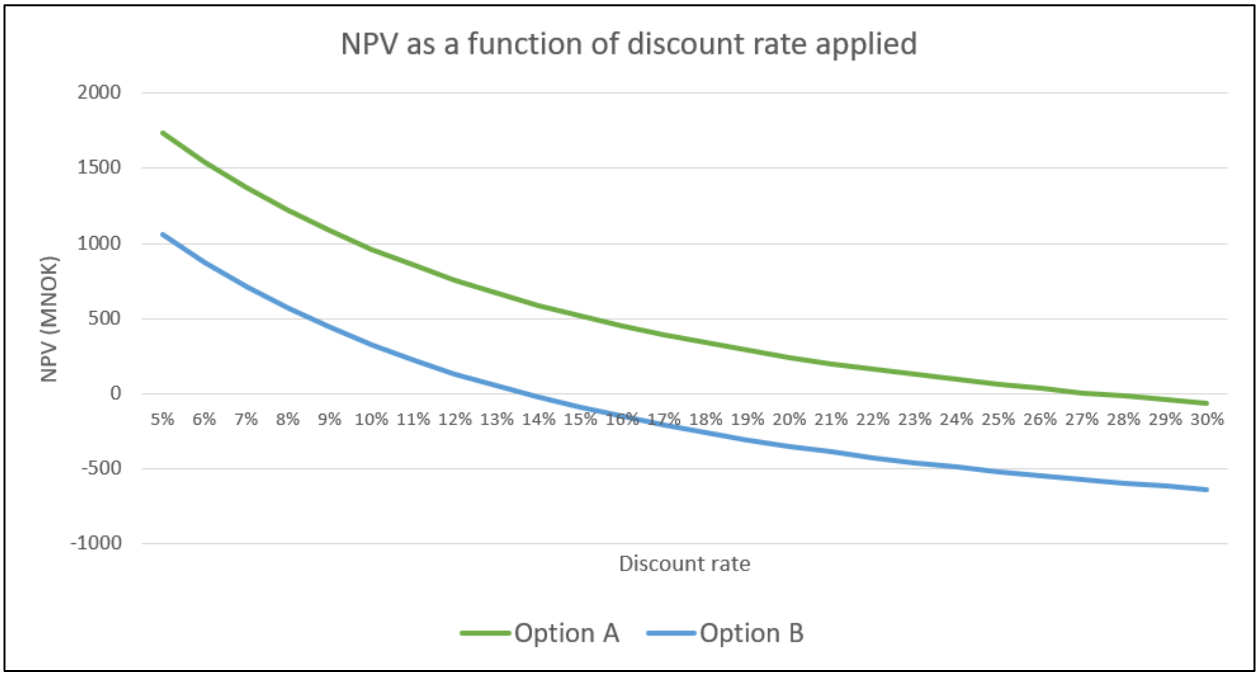

Figure 35: NPV as a function of discount rate applied

Given the presented conditions, it was evident that Option A surpasses Option B in terms of having a lower initial investment and higher cash flow. As a result, the NPV curves for these options will never intersect across various discount rates.

5.1.3 Estimation of Payback Period

The payback period was determined by evaluating the cumulative present value over the 20-year duration and identifying the point at which the value transitioned from negative to positive. The estimations involved a Monte Carlo simulation consisting of 100 iterations to obtain mean values as well as minimum and maximum values derived from a normal distribution. This involved identifying the intersection point between the cumulative value and the year input. The outcomes of the payback period estimations are displayed in Tables 71-72.

Table 71: Option A payback period results

Option A	
Payback period Monte Carlo	
Number of samples	100
Mean	5.8 Years
St.dev	0.7 Years
Min period	4.2 Years
Max period	7.8 Years
P5	4.7 Years
P95	7.0 Years
90-Percentile	2.3 Years

Table 72: Option B payback period results

Option B	
Payback period Monte Carlo	
Number of samples	100
Mean	13.4 Years
St.dev	1.6 Years
Min period	9.3 Years
Max period	19.6 Years
P5	10.7 Years
P95	15.9 Years
90-Percentile	5.1 Years

As indicated in the aforementioned tables, Option B exhibited a considerably longer payback period compared to Option A, with nearly twice the duration. Moreover, the standard deviation for Option B was also almost twice as large as that of Option A, indicating a higher level of uncertainty regarding the expected duration of the payback period. With 90% confidence, it could be stated that the payback period for Option A would deviate by only 2.3 years from the mean of 5.8 years, whereas for Option B, the deviation would be 5.1 years from the mean value of 13.4 years. Solely based on the assumptions regarding the payback period, Option A could be considered the more favorable option.

5.1.4 Estimation of Internal Rate of Return

The IRR is determined by identifying the discount factor at which the NPV of the initial investment and yearly cash flow equals zero. This signifies the threshold at which the project ceases to be profitable. The calculation followed the same methodology as described in Chapter 3.2.5. To investigate the variability of IRR results, a Monte Carlo simulation consisting of 100 iterations was conducted, incorporating mean, minimum, and maximum values, as well as a 90 percent confidence interval. The outcomes of the internal rate of return calculations are presented in Tables 73-74.

Table 73: Option A IRR results

Option A	
IRR Monte Carlo	
Number of samples	100
Mean	27.5%
St.dev	2.3%
Min IRR	21.8%
Max IRR	34.6%
P5	23.1%
P95	31.0%
90-Percentile	7.9%

Table 74: Option B IRR results

Option B	
IRR Monte Carlo	
Number of samples	100
Mean	13.8%
St.dev	1.82%
Min IRR	9.5%
Max IRR	18.2%
P5	10.7%
P95	16.5%
90-Percentile	5.8%

The presented findings demonstrate that Option A exhibits a significantly higher IRR compared to Option B with a difference of 13.7%. Additionally, Option A provided a minimum IRR that is still twice as large as the set discount rate, showcasing the potential security with this option. Out of the 100 IRR samples, Option B provided an IRR lower than the acceptance criteria of 10% 6 times, meaning there was a 6% probability of Option B not fulfilling the set acceptance criteria. However, by subtracting the IRR standard deviation from the IRR mean of Option B, it still fulfilled the requirements of being a profitable Option. The results indicated that investing in technology such as the subject matter would yield greater profitability for Option A in comparison to Option B. Nonetheless, it was noteworthy that both options met the acceptance criteria, which was set at a discount rate of 10% for the calculation of NPV. Therefore, it was feasible to consider accepting either option.

5.2 Limitations to the Model

The current model employed in this study exclusively utilizes economic evaluation measures outlined in ISO 15663:2021 for the purpose of life cycle costing. As part of the model's development process, certain limitations were identified and addressed to ensure alignment with the established research questions of the thesis. It was crucial to make certain assumptions in order to obtain valid and reliable results for the thesis. This section aims to identify the weaknesses inherent in the model and discuss their implications on the key components of life cycle cost analysis and economic evaluation measures.

Engineering

Engineering represented a significant source of uncertainty in this thesis, primarily attributed to the limited availability of technical information pertaining to the subsea solution. The estimation of technical input data required for the calculation of Option B was primarily derived from reports, academic papers, and extensive consultations with representatives from Equinor. Upon the determination of CAPEX’s associated with the subsea system, a specialist in subsea costing meticulously verified that the figures for each cost contributor adhered to contemporary industry standards.

Topside equipment

The computation of the CIS was contingent upon pivotal parameters relevant to topside equipment. The extraction of CIS inputs encompassed a broad spectrum of utility systems, covering a total of 30 distinct systems (BulkMate OFL code, Table 27) . This multiplicity of systems significantly increased the likelihood that the CAPEX cost for the CIS could surpass the estimate employed in this particular estimation.

Exact number of wells

The specific quantity of wells considered in this thesis was derived from Norwegian Petroleum and validated with a restricted report by Equinor from 2019, implying that the current number may differ from the one utilized in this analysis. Information pertaining to each field was also obtained from Norwegian Petroleum, although this data was not entirely precise with the numbers extracted from the report. For the OPEX calculation, input data spanning the period from 2012 to 2021 was collected, meaning yearly OPEX for each well have potentially changed the last 2 years. It was important to acknowledge that while the CIS factor of 1.89% remains unaffected by yearly production wells, it was likely to impact the annual OPEX per well, potentially leading to increased costs.

Currency

All calculations within the model are denominated in Norwegian krone (NOK), without explicit consideration of the implications for other currencies. Notably, the oil price utilized in the LOSTREV calculation does not incorporate currency exchange rates within the model when determining the unit price. The unit price commences at a baseline value of 800 NOK and undergoes modifications solely through the application of Monte Carlo simulations.

Oil Market

The examination of the future oil market was not within the scope of this model. This was due to high uncertainty as presented in Figure 26. A study of the oil market could also be extremely time consuming, so as a simplification measure, the model incorporated changes based on the overall uncertainty for each subsequent year, utilizing mean values and standard deviations that effectively capture the volatile nature of the market.

Units Produced

As this thesis did not focus on the analysis of a specific reservoir for the life cycle costing assessment, the determination of units produced established a baseline of 50,000 units per day in the initial year. Additionally, in order to account for the progressive nature of the field, the daily units produced experienced a reduction on a yearly basis.

Discount Rate

The discount rate is never a constant value and should reflect the overall uncertainty of every project. The selection of the discount rate for the economic evaluation measures was simplified and guided by Equinor since the project has not yet been started and the uncertainty related to the cash flow of the project was not estimated. It is important to note that the discount rate remains consistent across both options.

Contingency

The inclusion of contingency cost in the cost drivers has been omitted due to the inherent uncertainty surrounding the contingency cost for topside equipment.

6 Discussion

This chapter aimed to address the research questions proposed in Chapter 1.2, considering the theoretical framework of the subject matter and the findings obtained from the life cycle cost analysis. The chapter begins with a validation of the results pertaining to Option B, employing a comparative analysis with a project of similar case and scale. Subsequently, an examination was conducted to evaluate the correctness of the benefits statements put forth for the SCSIS as outlined in Chapter 2.2.2.3. This assessment determined whether these statements are accurate, false, or require further research. Furthermore, trade-off considerations that are not incorporated in the cost estimate are deliberated upon as part of the life cycle costing assessment. The potential impact of these trade-offs on the ranking of options was explored. Moreover, the implications of cost drivers on the main elements of life cycle costing are presented and discussed. The likelihood of cost variations associated with these drivers, which may influence the ranking of options, was also evaluated.

6.1 Validation of Results using Comparative Analysis

To ensure the credibility and robustness of the thesis results, it was considered essential to conduct a comparative analysis with previous projects of similar scale and technological advancement. In the specific context of projects involving the implementation of SCSIS as opposed to CIS, the available literature was limited to a single restricted report offering economic cost estimates. Although the report itself remains anonymous for the purposes of this thesis, it is worth noting that the estimators and authors of the report have been deemed reliable sources by Equinor. The estimate of the case report is executed in DG1, meaning a potential estimate deviation of ±40%.

The field consists of the following SCSIS related CAPEX cost drivers:

- 7 Subsea chemical storage units
- 2 intermittent injection booster modules
- 6 continuous injection booster modules
- 1 power, monitoring, and control system
- 2 Subsea umbilical termination assembly
- 1 Cluster frame

The cumulative weight of the system under consideration is approximately 240 tons, which closely aligns with the weight estimation of 250 tons employed in this thesis. However, the report did not encompass the cost of a subsea power system or a power cable. In terms of subsea wells, the field being examined yields an equivalent number of wells as the case study, necessitating the pumping of comparable quantities of chemicals. Although the storage units employed in the field are slightly smaller than those utilized in this thesis, they still entail the same number of yearly trips by FSVs for refilling purposes. Furthermore, the field incorporates subsea intervention methods in a manner similar to the subject matter, leading to comparable OPEX costs associated with maintenance, transportation, and logistics.

The total cost of the system is:

- SCSIS: 251 MNOK (without subsea power system)
- Umbilical: 151 MNOK
- Installation: 28 MNOK
- OPEX: 20 MNOK

The estimated values in this thesis are notably lower than those presented in the aforementioned study. However, it was crucial to acknowledge that the estimation in the report was conducted in 2019, implying that the costs associated with subsea equipment may have undergone changes. The CostCalc sheet offers insights into the year-on-year escalation of subsea component costs. The indexes used for the calculation were not perfectly accurate, but still gave a sufficient representation of the cost increase for SPS in the last four years:

$$Subsea\ production\ stations\ (SPS)\ cost\ index = 1.61$$

Multiplying the cost index factor to the estimates from 2019, provided the following increase in the case report:

- SCSIS: 404 MNOK
- Umbilical: 243 MNOK

Marine operations on the other hand have a different cost index, utilizing the index for 2023 and 2019 to find the differential factor between the two, provided the following result:

$$Marine\ operations\ cost\ index = 1.67$$

Costs relevant to marine operations are then equal to:

- Installation: 47 MNOK
- OPEX: 33.5 MNOK

Differences between estimations

The CAPEX's outlined in the report remained notably lower compared to the estimations conducted for Option B in this thesis. Conversely, OPEX's are projected to be higher than the one calculated in this thesis. It was crucial to note that the estimations provided in the report carry a margin of error of approximately ±40% due to their classification as DG1. Consequently, the evaluation of the differences was based solely on the anticipated costs. The variances between Option B and the project outlined in the report are presented below:

- SCSIS difference: **233 MNOK**
- Power cable/umbilical difference: **21 MNOK**
- Installation difference: **165 MNOK**
- OPEX difference: **- 5.5 MNOK**

Main reasons for difference between the two estimations were:

1. **SCSIS**
    - Size of the storage units: The storage tanks employed in this thesis were marginally larger than those specified in the report, despite the production systems being designed to operate at the same rate.
    - Chemical injection pumps: The estimation of cost for the SCSIS in this thesis might be overestimated. This stemmed from uncertainties surrounding the number and power requirements of the pumps necessary for the system.
    - Power and control system: The estimation for the power and control system could be decreased due to the scarcity of technical input available for the SCSIS, leading to uncertain results.

- Spares: The allocation of 100 MNOK for spares in the SCSIS might be excessive. A more efficient approach could be for the producer to focus solely on critical components such as spare holdings, thereby potentially reducing the overall cost.

2. **Power cable:**
   - Design: Differences in design between the power cable and the umbilical. The power cable utilized in this thesis was also considerably longer than the one presented in the report.
3. **Installation**:
   - Power cable
     - Transit: In this thesis, the installation scope encompassed a power cable spanning 20 km, whereas the report exclusively considered the installation of an umbilical that reaches the SCSIS within the safety zone of the platform. Furthermore, the case study necessitated a significantly longer transit duration to reach the installation site compared to the case report.
     - Length of power cable to install: The extended tieback distance of the case study in this thesis incurred additional engineering costs compared to the report.
     - Mobilization: The report assumed a mobilization duration of 12 hours, whereas, in this thesis, due to the significantly longer power cable, the mobilization time extended to 3 days, which appeared to be a reasonable estimate.
     - Survey: The report did not include the cost of survey activities. In contrast, this thesis incorporated a pre-lay survey duration of 7 days and an as-built survey duration of 6 days. The overall cost of these surveys was projected to be slightly below 20 MNOK.
     - Jumpers: For the subject matter, the operations related to jumpers entailed substantial costs, primarily due to the time-consuming nature of installing 7 jumpers and potential waiting periods. Additionally, equipment associated with tie-in played a significant role, as 17 of such equipment pieces were required. It was important to note that the installation of jumpers was not addressed in the report.
   - SCSIS
     - Installation: The report estimated a total installation duration of 6.5 days (inclusive of mobilization, transit, and installation) for the SCSIS. Conversely, in this thesis, the estimated timeframe for SCSIS and a subsea power system installation amount to 22 days in total. Within this timeframe, 13 days were allocated solely for installation activities. Additionally, a larger construction vessel was required for this installation campaign, leading to increased costs.

    - Mobilization: The report assumed a mobilization period of 1 day, while in this thesis, it was determined to be 5 days in accordance with Equinor standards. This substantial difference raised uncertainty regarding whether the report underestimated the mobilization duration or if it was overestimated in the thesis.
    - Transportation cost: The report dedicated a total of 2 days for transportation during the installation phase, whereas the thesis study estimated a duration of 4 days. This difference can be attributed to the field's location being further out in the North Sea compared to the report.
- OPEX:
    - Spares: In the report, spares were considered as part of OPEX, contributing 16 MNOK to the overall OPEX. However, in this thesis, the cost of spares was accounted for within the CAPEX estimation.
    - Maintenance: The maintenance costs between the two studies were largely similar, with the thesis showing a marginal difference of 0.5 MNOK higher than the report.
    - Commissioning: The report included commissioning activities within the OPEX category, while the thesis incorporated these activities as part of the CAPEX estimation.
    - Refilling of chemicals: Refilling of chemicals emerged as a significant cost driver for the OPEX in the thesis, but it was not considered as part of the cost analysis in the report.

Summary of validation using comparative analysis

From the comparative analysis it could be assumed that the result of the Option B cost estimation was a valid result. Estimations for the SCSIS and marine operations regarding Option B were likely to be close to the report or slightly overestimated in this thesis, meaning that difference between options were more equal than first analysed during Chapter 5. The report included an estimate of the SCSIS in DG1, meaning that the actual cost may differ up to 40%. Hence, the costs discovered on the SCSIS in this thesis are deemed valid. For further validation of the results it would be interesting to investigate actual costs compared to those estimated in this thesis.

6.2 SCSIS Benefits Statements

This subsection critically evaluated the benefit statements of Option B, as outlined in Chapter 2.2.2.3 of this thesis, by examining their reliability in light of the findings and results obtained throughout the study. The benefits of the SCSIS were included as part of a qualitative evaluation, apart from the economic evaluation. If Option B fulfilled some of the statements, this would apply to the ranking of options.

Enable longer tiebacks

The removal of chemical lines and the EH umbilical, combined with precise monitoring and control of the SCSIS and chemicals in close proximity to the subsea wells, held the potential to enhance production efficiency, equipment reliability, and minimize scheduling implications. However, further research is required to determine the extent to which this would support production availability and to explore the SCSIS in greater detail.

Lower development cost

The impact of decommissioning on the SCSIS and the potential effects of relocating the SCSIS or power cable after use to new fields was not thoroughly assessed in this thesis, as this was not estimated to become a significant cost driver between the two options. Consequently, it was challenging to ascertain the precise influence of these factors. Investigating the decommissioning aspect of Option B could be an interesting area for future research. Furthermore, the timing of production and installation steps in Option B warrants further investigation, as this thesis relied on mean timing estimates based on assumptions.

Reduce host platform space and weight requirements

While this study included the weight of the CIS at 281.6 tons, it did not address the weight implications of the CIU on the topside facility or its impact on other processes and personnel on the FPSO. Future research could explore how a system weight of 281.6 tons and a volume of approximately 250 m^3 affect sustainability and storage possibilities on the topside facility.

Eliminate hazardous chemical interaction with offshore personnel

Option B presented a significant advantage by eliminating the need for offshore personnel on the host facility to handle or encounter hazardous chemicals stored topside during production. Nonetheless, the risk of exposure remained for personnel working on the FSV during refilling and maintenance activities. However, not storing chemicals topside during production eliminates the risk of chemical leakage on the topside facility and exposure to chemicals during production.

Lower chemical cost

The utilization of several storage units in Option B allowed for more flexibility in choosing external chemical suppliers based on performance and price. Since this thesis did not cover the cost of chemicals as part of the CAPEX or OPEX estimate, further research on their cost implications could prove valuable before deciding on the preferred option.

Modular design benefits

When components are less integrated to the FPSO, they can be easily replaced with spares if needed, reducing costs associated with maintenance and operations and minimizing potential downtime. Option B offered greater flexibility but at an additional CAPEX. However, the relationship between Option B and spares, and its impact on cost remains highly uncertain. Further research is warranted to explore the technical operational benefits of the SCSIS.

Facilitate platform de-manning

The removal of chemical storage tanks and tasks related to maintaining the CIS eliminated the need for topside personnel to handle these activities. Consequently, manpower requirements on the topside facility decreased, leading to reduced topside OPEX and improved HSE outcomes. The impact of de-manning the offshore facility to meet new demands was not thoroughly covered in this thesis, even though it can contribute as a cost driver. This merits investigation for future research.

Ease host tie-in burdens

Option B's modular components could easily be installed to a host facility, removing the need for a completely new CIS installation topside. The only topside requirement for the SCSIS to perform its tasks was power and communication through a power cable with fiber optic signals. Assessing the commissioning of new developments like the SCSIS would be prudent for further research.

Project risk

Compared to the EH umbilical, the power cable was smaller in dimension, lighter, and more flexible. Consequently, the risk of cable damage or destruction during installation and operations was reduced. A smaller vessel has been utilized during the marine operations campaign of the power cable, which reduces the day-rate of FSV's. However, since the SCSIS required 7 injection pumps, meaning 14 additional tie-ins, this increased the days that an FSV was required, increasing the total cost of marine operations.

Reliability

Given the substantial cost of an umbilical of this size, exceeding 400 MNOK, repairing the umbilical under production could have severe cost implications. Investigating the comparative reliability of Option A and Option B became highly beneficial for a comprehensive analysis of how reliability influences costs. While this thesis primarily focused on the impact of production availability on LOSTREV, further research could delve into the effects of reliability measures on both CAPEX and OPEX.

6.3 Trade-Off Considerations

Based on the economic evaluation measures conducted in Chapter 5, Option A exhibited a projected cost difference of 806 MNOK, positioning it as the more financially advantageous option for the subject matter. However, it was crucial to acknowledge that ISO 15663:2021 highlighted the significance of other factors, such as HSE considerations, as well as sustainability, when assessing trade-offs for the life cycle costing assessment. Life cycle costing main elements as well as trade-off considerations are illustrated in Figure 36. These additional factors introduced further complexities and influenced the overall evaluation of the options beyond purely economic considerations.

Figure 36: Trade-off considerations in life cycle costing [2, p. 59]

In the subsequent sections, the potential impact of trade-off considerations on potentially modifying the ranking of options were discussed prior to reaching a final decision.

HSE

Ensuring and maintaining HSE should be given the utmost priority in most production cases. Safeguarding HSE is invaluable, and its significance is difficult to overstate. However, when comparing and ranking alternative options based on their respective approaches to HSE, an evaluation could be conducted by assessing their outcomes.

Option A, as discussed in the theoretical section of this thesis, was considered the “conventional” solution. This implied that the solution had been tried and tested over many years, minimizing uncertainty and risk associated with this technology. However, this solution required offshore facility personnel to handle highly hazardous chemicals. Additionally, the CIS was located on the topside facility, meaning that even personnel not directly involved in maintenance or refilling activities may still have been exposed to the chemicals inside the tanks in the event of an accident.

Option B introduced novel methods for handling chemical injection, which introduced a certain level of uncertainty. This uncertainty was particularly prominent during the initial production phase and the first routine maintenance operations. However, as the field progresses, this solution would become a standardized process, mitigating much of the associated uncertainty. Moreover, the SCSIS in Option B eliminated exposure to hazardous chemicals on the topside facility, resulting in significant HSE benefits.

Assessing the value of HSE in investments of this magnitude was challenging. Further evaluation of HSE and risk considerations should be applied to the subject matter before making an investment decision.

Sustainability

Equinor's transition plan [3] includes a focus on becoming more sustainable. In relation to the subject matter, sustainability encompassed not only improvements in HSE but also considerations such as platform de-manning, retrievability of assets, and their disposal once production is completed.

Option A contributed to sustainability by being a well-established and proven solution for field production. This familiarity and reliability in production enabled more certainty, facilitating the execution of sustainable practices such as efficient refilling operations and optimized transportation methods. However, the larger and heavier topside umbilical used in Option A incurs high consequences on the environment and additional disposal costs yet to be thoroughly assessed. Since Option A had a way lower CAPEX compared to its competitor, the cost savings can be potentially invested in other aspects of production that greatly enhance sustainability. Further research and analysis could be conducted to explore this aspect in more depth.

Option B contributed to sustainability by eliminating chemical tanks and hazardous substances from the topside facility, thereby reducing the manpower demand and the weight of the topside equipment by approximately 281.6 tons. This approach addresses both environmental concerns and enhances safety by minimizing the handling of dangerous substances. However, before implementing Option B, an assessment of potential sea leakage should be conducted to ensure environmental safety. Furthermore, since topside space and weight were determined to be valuable resources, cost savings related to topside assets should be carefully analyzed before deciding on the implementation of this option.

6.4 Ranking of Options

In order to summarize the ranking of an option, it was essential to conduct an assessment that determined the extent to which a significant cost driver or trade-off consideration must vary to influence the ranking of options. This assessment helped identify the key factors that could potentially alter the ranking of options. Additionally, this subchapter delves into the cost drivers that significantly impact the main elements of the life cycle costing and presents relevant considerations.

CAPEX

The two options exhibited an initial investment difference of 534 MNOK, favouring Option A. However, this disparity could potentially be mitigated through the implementation of straightforward measures, which have yet to be analysed and determined for their applicability to this study. A substantial portion of the CAPEX discrepancy stemmed from the equipment cost of the SCSIS in Option B, which was subject to significant uncertainty in its technical aspects. Furthermore, the installation duration for Option B was considerably longer due to the inclusion of multiple subsea tie-ends, rendering the installation difference highly relevant to the subject matter. The incorporation of selling or reusing modular components after their use may have led to a reduction in CAPEX if decommissioning was considered within the CAPEX estimate. In Table 75, the cost drivers associated with CAPEX, along with the potential for their alteration and the likelihood of such changes occurring to influence the ranking of options are presented. Decommissioning is also included as part of the table since this can contribute as a cost driver if the field life is much shorter than 20 years.

Table 75: CAPEX cost drivers change possibilities and likelihood

Cost driver	What must be changed?	Likelihood
SCSIS	The cost of the SCSIS needs to be specifically assessed and reduced by conducting a thorough analysis of the specific field under consideration, rather than relying on generalized values. The inclusion of subsea pumps in the SCSIS significantly contributed to the equipment cost, thus conducting further research to identify means of simplifying the system would undoubtedly enhance the viability of Option B.	**Medium –** This is since the report provided by Equinor showcased that equipment cost to the SCSIS could potentially be lowered.
Subsea power system	The operation of the pumps within the SCSIS necessitated the utilization of specialized equipment, such as a subsea transformer module with a protective structure. However, it was possible that the energy requirements for the pumps have been overestimated in the scope of this thesis, indicating potential opportunities for cost reduction.	**High –** Overestimation of energy consumption is likely, actual cost is lower than the one estimated in this thesis.
Topside CIS	In the context of this thesis, it is worth considering that if the weight of the topside equipment has been underestimated, it can have a significant impact on the initial investment of Option A. This has the potential to substantially increase the investment required for Option A, thereby narrowing the gap in CAPEX between the two options.	**High – (**Weight = cost) can easily be diverse from actual cost, meaning there is likely cost is underestimated.
Power cable	A reduction in weight and diameter of the power cable, both from an engineering perspective and the effectiveness of the installation campaign. If tie-ins between the SCSIS and the subsea production system can be more effective, this will also decrease cost immensely. Option B has the potential to be more cost-effective than its counterpart.	**Low –** Thorough estimation and comparative analysis showcased that cost estimation was not likely to be much diverse from reality.
Umbilical	In the context of this thesis, it is worth considering that if the dimensions and marine operations campaign of	**Low –** The cost of the umbilical utilized for

	the umbilical was underestimated, it could have a significant impact on the initial investment of Option A. If the reliability of the umbilical is less than estimated in this thesis, meaning more spare parts are required, this will also increase Option A CAPEX.	this thesis was based on several umbilicals within the CostCalc excel model.
Marine operations	The installation cost of a conventional integrated CIS is characterized by a higher level of uncertainty compared to the SCSIS. In the event that the installation campaign scope and timeframe for Option A align more closely with that of Option B, this will have a significant impact on the ranking of options, favoring Option B.	**Medium –** CIS is more integrated to the offshore facility than SCSIS, meaning that larger installation cost than what was calculated might apply.
Decommissioning	The comprehensive analysis of equipment decommissioning was not adequately addressed in this thesis. However, if there exists a potential for the sale or reutilization of modular components from Option B in other fields, it will positively impact the ranking of the option.	**Medium –** For fields life below 10 years, reuse of Option B equipment can be a possibility.

OPEX

As calculated in the analysis chapter of the thesis, the differential yearly OPEX between Option A and Option B was equal to 6.83 MNOK in favour of Option A, which meant that for a 20-year time frame the total cost estimate difference on OPEX was equal to 136.6 MNOK in favor of Option A. The main reason for this difference was the methods of maintenance, where Option A had most of its maintenance carried out by offshore facility personnel, while for Option B the maintenance process was carried out by external personnel on an FSV. Table 76 evaluates how each OPEX related cost driver must change to affect the ranking of an option, as well as including the likelihood of this change happening.

Table 76: OPEX cost drivers change possibilities and likelihood

Cost driver	What must be changed?	Likelihood
Operations and Maintenance	Presently, all the O&M activities associated with Option B were carried out by personnel aboard an FSV. This resulted in higher costs compared to Option A, as it necessitated the periodic deployment of construction vessels with a substantial day-rate for inspection and maintenance purposes every three years. Conversely, Option A did not require the use of a construction vessel, and its maintenance costs were based on the overall contributions of the CIS on all O&M activities. If opportunities arise to optimize maintenance operations and effectiveness of the refilling process, such as through the combination of maintenance and refilling tasks or improved scheduling practices, significant cost savings for Option B can be realized. Furthermore, simplification of the maintenance procedures could further contribute to potential cost reductions. These considerations have the potential to influence the ranking of options by enhancing the cost-effectiveness of Option B.	**Medium –** The CostCalc model is based on several projects and is not likely to alter drastically in schedule. However, there is large uncertainty in a SCSIS, and more effective ways of handling O&M is highly likely to be discovered.
Transportation	The transportation cost from the FSV constituted as the primary component of OPEX for both options. Given that availability was deemed a limited resource within the scope of this thesis, the tank module refilling was scheduled to occur twice annually. It was anticipated that the refilling process for Option A would be slightly more efficient than that of Option B. If Option B could enhance productivity without incurring additional CAPEX, it would positively impact its ranking in comparison to Option A.	**Medium** – The CostCalc model calculates the days required for transportation but is not certain in how long refilling operations will take. Refilling days estimated can differ from reality.

LOSTREV

As can be seen in Table 59 from Chapter 5.1.1.3, the mean LOSTREV difference between the options was roughly 133 MNOK. The main reason for this difference was based on production availability of the two systems, which were different by 3%.

Table 77: LOSTREV cost driver change possibility and likelihood

Cost driver	What must be changed?	Likelihood
Production availability	The sole differentiating variable for LOSTREV between the options was their production availability. Therefore, any increase in production availability for Option B or a decrease for Option A would lead to a change in the ranking of the options. Enhancing the production availability for Option B could be achieved through improvements in the O&M strategy, such as reducing vessel mobilization time or optimizing spares holdings. Additionally, it was assumed that the production availability of Option B would decline at a slower rate compared to Option A. Thus, if the performance of the Option A solution were to deteriorate more rapidly than anticipated, or the opposite, it would also impact the ranking of the options.	**High –** Estimation of production availability is still in the early stages where opportunity to influence is high, so implementing measures to equalize the production availabilities is expected to happen in the future.

Considerations

Considerations relevant for this thesis were HSE and sustainability. The potential modifications to address these considerations were primarily applicable to Option A, as Option B was anticipated to already enhance HSE and sustainability. The strategies for Option A to meet these requirements are outlined in Table 78.

Table 78: Trade-off considerations change possibilities and likelihood

Consideration	What must be changed?	Likelihood
HSE	The thesis interpreted that Option B offered a superior HSE solution compared to Option A. To influence the ranking of options based on HSE considerations, Option A would need to reduce manpower requirements and invest in additional measures to enhance health and environmental safety during chemical handling.	**Medium** – High likelihood of including more HSE measures, but not likely to decrease manpower demand.
Sustainability	Option B demonstrated a more favourable sustainability solution compared to Option A. To potentially impact the ranking of options based on sustainability, Option A would need to enhance various sustainability aspects, including decommissioning and retrievability. This could involve developing simpler and modular components, which would reduce the need for extensive equipment production and minimize environmental impacts.	**Low –** The conventional solution has been utilized for several years, and effective changes such as the ones described takes time to implement. Hence the likelihood of the change is therefore low.

7 Conclusion

The present thesis has demonstrated that employing the life cycle costing methodology for a project with a 20-year life cycle can yield significant insights that aid in the decision-making process for investments within the petroleum industry. The accuracy of the cost estimations has been substantiated through comparative analysis conducted on an offshore project of comparable scale, as well as consultation with Equinor representatives. Moreover, the thesis has illustrated that employing a probabilistic estimation methodology, supported by both top-down and bottom-up estimation approaches, can effectively address substantial uncertainties inherent in the life cycle cost analysis, resulting in sound results. Table 79 provides a summary of the outcomes derived from the life cycle cost analysis.

Table 79: Results of the life cycle cost analysis for competing options

Economic evaluation measure	Project target	Option A	Option B
Life cycle cost (LCC)	As low as possible	1214 MNOK	2020 MNOK
Net present value (NPV)	> 0	958 MNOK	332 MNOK
Profitability index (PI)	> 1	2.34	1.27
Payback period	As low as possible	5.8 years	13.4 years
Internal rate of return (IRR)	> 10%	27.5%	13.4%

Based on the data presented in Table 79, it was evident that both competing options met the required criteria for acceptance in terms of NPV, PI, and IRR calculations. However, Option B exhibited substantially higher LCC, and payback period compared to Option A, indicating the need for the inclusion of other trade-off considerations such as HSE factors and sustainability aspects. These considerations have been thoroughly evaluated within the framework of this thesis; however, their impact on altering the ranking of options remains limited at present. Based on the findings derived from this thesis, Option A, which represented the conventional solution, currently emerged as the more financially viable option.

The cost differences between options related to each life cycle costing main elements, with most significant cost drivers are presented below:

- CAPEX (534 MNOK): Equipment and engineering, and marine operations

- OPEX (137 MNOK): Transportation, inspection, and maintenance
- LOSTREV (133 MNOK): Lost production

The design of Option B is currently in its preliminary stages, leaving room for potential simplification of the engineering design or a decrease in the cost of components within SCSIS. Such optimizations could potentially elevate Option B to a more profitable position before the investment is finalized. Additionally, enhanced planning measures have the potential to mitigate marine operations and reduce schedule-related implications for both options. Furthermore, by increasing the production availability of Option B, the potential for minimizing lost revenue arises, although its impact on altering the ranking of options remains uncertain. It is worth noting that Option B encompassed a range of trade-off considerations relevant to the subject matter. A comprehensive exploration of the significance of these considerations could offer valuable insights and contribute to the overall assessment of life cycle costing.

Below is a list of further research that was no covered in this thesis:

- The significance of HSE and sustainability improvements on the subject matter and if they can alter the ranking of options.
- Examine the impact of less weight, and man-hours required on the host facility, and how this applies to life cycle costing.
- More research on the SCSIS, both technical and economical, to add the possibility of deterministic cost estimation.
- Extensive research on decommissioning of competing options, and if there is a potential for the SCSIS and power cable to be re-used for more than one field.
- Include all components within the SCSIS to ISO 19008:2016 to enhance cost estimation.

ISO 15663:2021 has demonstrated itself as a valuable tool and resource for evaluating competing options within the subject matter. Not only has the standard provided with economic evaluation measures in support of decision-making between alternative options, but also guidance on considerations to acknowledge as part of the life cycle costing assessment, which ultimately will impact the ranking of options. When utilized in conjunction with other industry standards pertinent to life cycle costing, as those presented in Figure 4, this standard can prove valuable for organizations that want to improve their decision-making process regarding development investments in the petroleum industry. However, in context of the subject matter, ISO 19008:2016 was not utilized to its full potential due to the absence of cost codes specific to Option B, rendering it unsuitable for creating a comprehensive cost breakdown structure.

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