# Well Designs & Cost Estimates

## Deliverable D4.1 CTS EUDP Project

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| Doc. No.: | WPDK2025-RE324 | Project No.: | WPDK2025-PROTH-04 |
| Date: | 12.12.2025 | | |
| Revision: | 1 | | |

The CTS project is funded by CETPartnership, the Clean Energy Transition Partnership under the 2022 CETPartnership joint call for research proposals, co-funded by the European Commission (GA N°101069750) and with the funding organizations detailed on https://cetpartnership.eu/funding-agencies-and-call-modules. ”

## Revisions

| Rev. | Date | Description |
|---|---|---|
| | | |
| | 15.12.2025 | Version accepted by WP lead and CTS project coordinator |
| 1 | 12.12.2025 | Revision with review comments incorporated |
| 0 | 17.11.2025 | First issue |

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# National Acknowledgements for CETPartnership

**Norway**: The Research Council of Norway (RCN)

**Denmark:** EUDP - Energy Technology Development and Demonstration Programme

**Estonia:** The Estonian Ministry of Climate supports this research within the TARGET FUNDING AGREEMENT nr 4-1/23/201.

Some data are available from the CCUS ZEN project, which has received funding from the EU Horizon Europe (No. 101075693), UK Research and Innovation - Innovative UK under Innovation Funding Service (ISF).

**Romania:** Executive Agency for Higher Education, Research, Development and Innovation Funding (UEFISCDI)

**Ukraine:** Ukrainian researchers are supported by the Research Council of Norway (RCN)

**Portugal:** Fundação para a Ciência e Tecnologia supports the CTS project in Portugal**.**

# CONTENTS

# 1. Introduction

The present report on well design and cost estimates is WellPerform's main contribution to the CTS project (**C**$O_2$ **T**ransport and **S**torage directly from a ship) having the overall objective of demonstrating techno-economic applicability of direct $CO_2$ injection from ship to unlock CCS potential for the industry. This is done by increasing flexibility and versatility of the CCS value chain, reducing costs and show storage potential in the four defined offshore regions: the Norwegian and Danish North Sea, Black Sea, Baltic Sea and Atlantic coast of Portugal.

The direct injection from ship for $CO_2$ storage aims to provide a low-cost, scalable and flexible solution that can be applied worldwide with a relatively short implementation time.

CTS project primarily aims at reducing costs and improving efficiency along the value chain. By utilizing offshore geological storage and building the trustful communication with local stakeholders in the selected geographical locations, CTS contributes to strengthening the acceptance of CCS technologies.

## 1.1. Purpose of the present document – reporting on Task 4.1

Reporting of Task 4.1 includes the preparation of conceptual well design based on preliminary subsurface information and data from each geographic region which is used for high level well cost estimates.

Based on the subsurface information received from each geographical region for a possible geological storage site (summarised in Appendix I) three conceptual well designs are prepared to capture the different predicted depths to the reservoirsFigure 1-1. The three conceptual well designs made are referred to, respectively, as shallow, intermediate and deep wells (Figure 1-1), which represents designs applicable to the four geographical regions.

Well designs as presented in Section 3 are made with the overall objectives to allow for safe and successful drilling to the reservoir and to complete the well with materials suitable for CO2 injection. Drilling of wells to shallow as well as greater depths in the offshore environment has been done successfully by the oil and gas (O&G) industry for many decades and is not a great challenge if thoroughly designed and planned for the actual subsurface conditions. The completion of wells for $CO_2$ storage injection, however, is an emerging field of experience and many parameters including reservoir and seal properties, the injectivity rates and continuity, $CO_2$ fluid composition and its content of impurities will impact the optimum design and material selection. Since all this detailed information is not available at the present stage conceptual designs are prepared based on some general assumptions as presented.

Materials suitable for the harsh $CO_2$ environment must be selected to secure well integrity and to secure optimum well operations over the well life of 30 years. A review of the major considerations for material selection is presented in Section 4.

In Section 5 the possibility of re-using existing Oil & Gas wells and the associated cost is considered conceptually based on an example of a typical deep well with a horizontal section in the reservoir. In scenarios where an existing well in a depleted O&G field is to be converted to a $CO_2$ injection well this will usually require two overall project tasks: I) a thorough investigation of present well status and integrity, II) Preparation of a re-completion program based on the well investigation results to ensure the well's functionality and long term integrity to $CO_2$ storage injection and subsequently carry out the actual well operations.

High level well cost estimates as presented in Section 6 are made with emphasis on presenting transparent and consistent cost estimates to enable comparison of the economic evaluation in the geographical areas of the CTS project. The well cost estimates will be used by the project for high-level budgets for CAPEX in the geographical areas as part of the overall assessment of technical and economic feasibility of a $CO_2$ injection project in each area.

High level risk assessments addressing the drilling and completion of new wells, and the re-completion of existing wells in depleted oil & gas fields, and general project risks are presented together with identified risk mitigating actions are presented in Section 7.

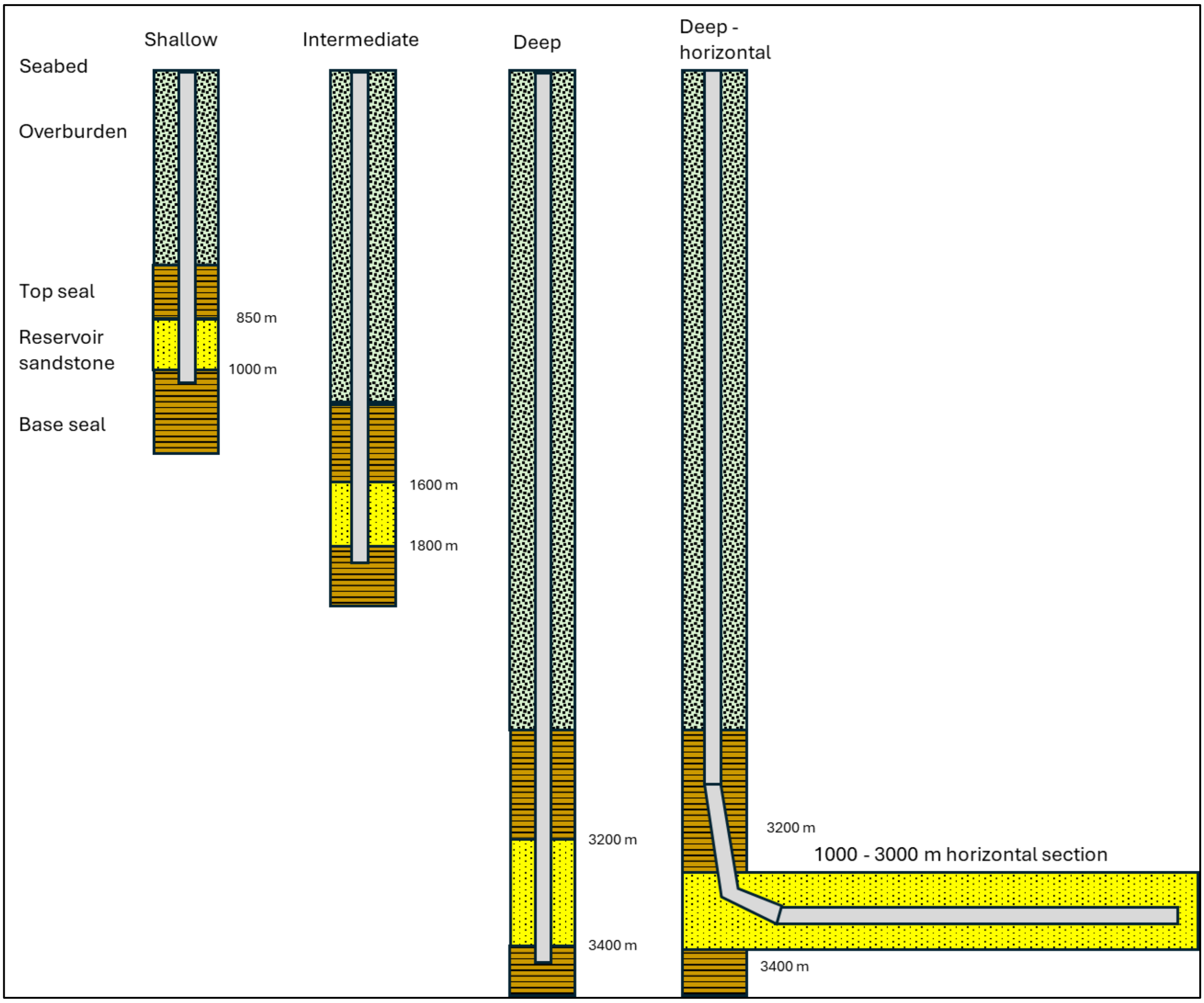


*Figure 1-1: Conceptual illustration of the reservoir depth for the three well types Shallow, Intermediate and Deep, and a typical deep horizontal Oil & Gas well to be re-completed for $CO_2$ injection.*

## 1.2. Preparation of well cost estimates

The well cost and the risk assessment will feed into the overall assessment of Task 3.2 (Techno-economic drivers and challenges for direct ship injection) of the CTS project.

The purpose is to deliver well cost and risk assessment – based on conceptual well designs for:

- New wells for $CO_2$ storage injection into reservoirs at different depths (shallow, intermediate and deep) with subsea completion
- Re-completion of existing O&G well to $CO_2$ injection at an existing platform facility

Cost information needed for Work Package 3 (WP3):

- Well drilling
- Completion new well
- Re-completion of existing well
- P&A (Plug & Abandonment) cost
- Well maintenance (OPEX) cost

## 1.3. $CO_2$ injection wells general concept

A $CO_2$ well delivery project is in many aspects like delivering wells for hydrocarbon production, geothermal energy production and other purposes. The main difference is the materials used for well completion which must be resistant to a harsh $CO_2$ environment. These materials are more expensive and often the lead time is longer than for more standard materials used in the offshore industry, which may impact overall project schedule.

# 2. Geology & Subsurface Overview

This section presents general geological information received from each geographic region representing potential locations for drilling a new well into an aquifer for $CO_2$ storage injection (Information summarised in Appendix I) . The information includes geological prognosis and predicts lithologies of overburden sections, the reservoir and the seal sections. For each region this information is presented as graphic lithological columns and used together with the information about potential geological hazards for the well designs (Section 3).

It is inferred that all the proposed well locations are targeting saline aquifers in un-tested subsurface structures. Thus, a new well to be planned and drilled into an untested reservoir is regarded as an exploration well with dual purposes:

- To acquire detailed information on the reservoir and seal properties, formation water composition, temperature and pressure.
- To complete the well with materials suitable for a harsh $CO_2$ injection environment, if the well encounters reservoir and seal properties suitable for safe $CO_2$ injection storage.

## 2.1. Norwegian North Sea

The general subsurface information received from the Norwegian North Sea assumed well location is presented in Table 2-1 below.

A lithological column presenting the information is illustrated in Figure 2-1 showing the depth to reservoir and seal intervals. It shows that two Middle Jurassic reservoir sandstones intervals are expected to occur in the depth interval from approximately 3100 m to 3400 m below seabed. The overlying Upper Jurassic shale dominated section constitute the primary seal.

No drilling hazards or over pressured zones are predicted to occur in the area and hydrostatic gradients are expected. However, the well is drilled into a reservoir occurring at a depth where several oil discoveries have been made in the vicinity. Therefore, the possibility of encountering hydrocarbons should be thoroughly evaluated including contingencies for drilling into a hydrocarbon bearing sandstone rather than the expected / required aquifer for $CO_2$ storage.

| **Norwegian North Sea** | **Information (Based on Yme 9/2-1)**<br>https://factpages.sodir.no/en/wellbore/pageview/exploration/all/1038 |
|---|---|
| Water depth (meters) | 80-90 metres |
| Top reservoir (meters below mean sea level) | 3000 m -3100 m |
| Reservoir thickness (meters) | Av. 86m Sandnes, 100m Bryne |
| Total depth of well (meters below sea level) | 3655 |
| Reservoir lithology | Sandnes: massive white, very fine to coarse grained glauconitic sandstone<br>https://factpages.sodir.no/en/strat/pageview/litho/formations/139<br><br>Bryne: interbedded sandstones, siltstones, shales and coals. The sandstones are white to grey, very fine to coarse grained, poorly sorted, friable to hard and occasionally kaolinitic. The shales are generally grey to brown, micaceous, occasionally silty, non-calcareous and often carbonaceous.<br>https://factpages.sodir.no/en/strat/PageView/Litho/Formations/19 |

| **Norwegian North Sea** | **Information (Based on Yme 9/2-1)**<br>https://factpages.sodir.no/en/wellbore/pageview/exploration/all/1038 |
|---|---|
| Reservoir pressure | Hydrostatic<br>https://factpages.sodir.no/pbl/wellbore_pressure_plot_pdfs/1038_Formation_pressure_(Formasjonstrykk).pdf |
| PPFG (Pore Pressure and Fracture Gradient) | Typically 1.3 times hydrostatic |
| Temperature gradient | 4 + 31⁰C /km |
| Reservoir temperature | 116 ⁰C @3755 TVD m RKB |
| Reservoir porosity (average) | Sandnes 21%<br>Bryne 17% |
| Reservoir permeability (average) | 500 mD (mean) P10 – 900mD |
| Preliminary injection rate minimum, average, maximum value | 0.5 Mtpa; 1 Mtpa; 2 Mtpa |
| *Lithology log | https://factpages.sodir.no/pbl/wellbore_composite_logs/1038.pdf |
| Presence of any lithologies/ formations in overburden known to cause drilling hazards /problems such as overpressured zones, swelling clays, thick chert layers, other? | Shallowest section may contain bouldes<br>Well 9/2-1 discovered hydrocarbons in the Middle Jurassic sandstones<br>From page 34<br>https://factpages.sodir.no/pbl/wellbore_documents/1038_9_2_1_COMPLETION_REPORT_AND_LOG.pdf |

*Table 2-1: Information received for Norwegian North Sea new well location.*

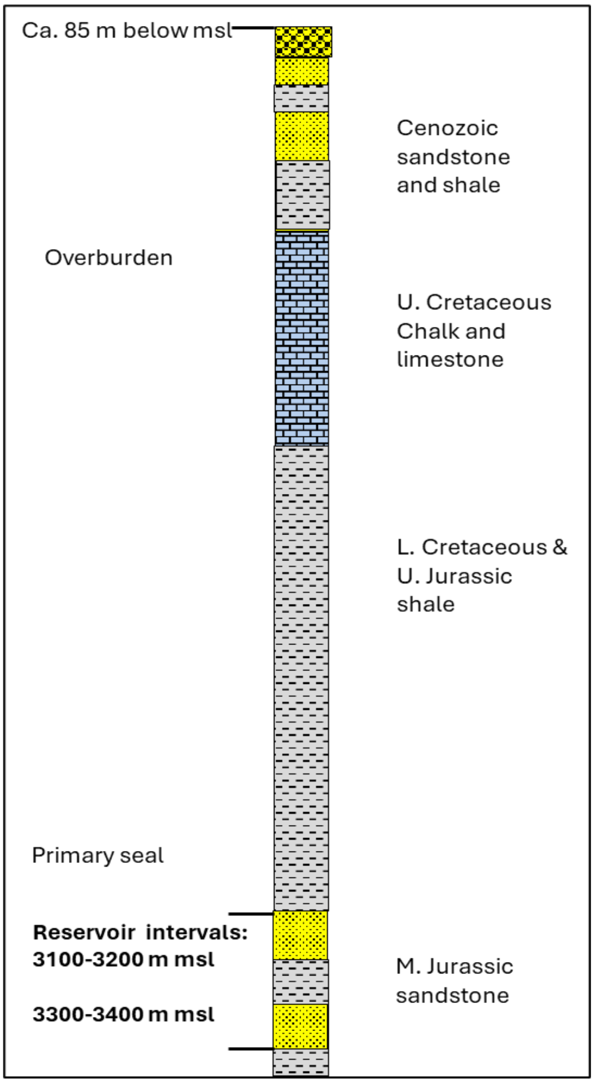


*Figure 2-1: Norwegian North Sea lithological and stratigraphic summary section showing the presence of Middle Jurassic reservoir sandstones in the interval from 3100 to 3400 m below sea level based on the Yme 9/2-1 well.*

## 2.2. Danish Basin – Inez structure

The general subsurface information received from the Danish North Sea is the Inez structure located in the Danish Basin is presented in Table 2-2 below.

A lithological column presenting the information is illustrated Figure 2-1 in showing that Triassic reservoir sandstones are expected to occur at the depth interval from approximately 1600 to 1800 m below seabed.

The overlying Upper Jurassic shale dominated section constitute the primary seal.

| **Danish Basin, Inez structure** | **Information**<br>Based on INEZ-1 well: |
|---|---|
| Geographic region | Danish Basin |
| Water depth (meters) | 35-40 metres |
| Top reservoir (meters below mean sea level) | 1600-1650 m |
| Reservoir thickness (meters) | Av. 148 m |
| Total depth of well (meters below sea level) | 1700-1800 m |
| Reservoir lithology | Sandstone |
| Reservoir pressure | The Danish Basin and the Danish part of the German Basins are considered normally pressured based on experience gained from drilling activities. |
| PPFG (Pore Pressure and Fracture Gradient) | Pore pressure gradient is considered to be hydrostatic<br>Fracturing gradient is usually considered to be 80% and 95% of the lithostatic pressure |
| Temperature gradient | ~ 30$^0$C /km |
| Reservoir temperature | ~155-160 $^0$C @ 1900 m.MD |
| Reservoir porosity (average) | 20-25% |
| Reservoir permeability (average) | 400-800 mD |
| Preliminary injection rate minimum, average, maximum value | 0.5 Mtpa<br>1 Mtpa<br>2 Mtpa |
| Presence of any lithologies/ formations in overburden known to cause drilling hazards /problems such as overpressured zones, swelling clays, thick chert layers, other? Please describe | n.a |

*Table 2-2: Danish Basin subsurface information.*

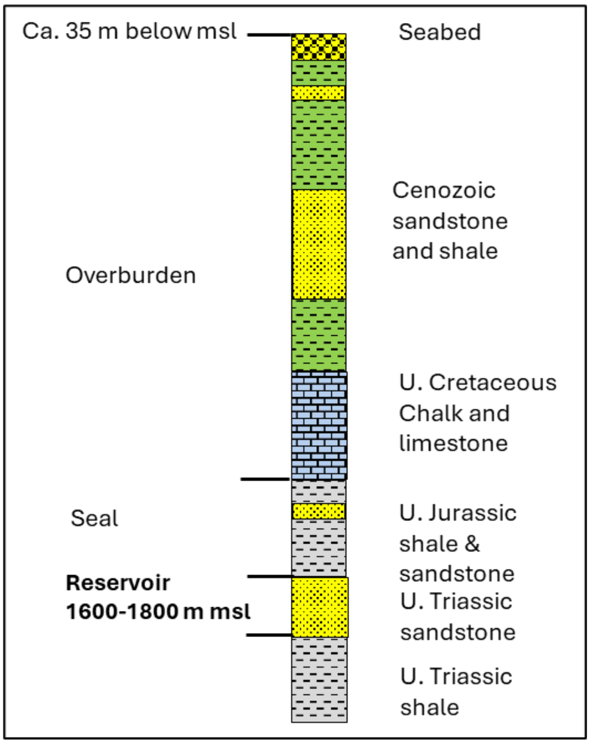


*Figure 2-2: Danish Basin lithological and stratigraphic summary section showing the presence of Late Triassic reservoir sandstone in the interval from 1600 to 1800 m below sea level based on the Inez-1 well.*

## 2.3. Baltic Sea

The general subsurface information received for a new well in the Baltic Sea region is presented in **Error! Reference source not found.**Table 2-3 below.

A lithological column presenting the information is illustrated in Figure 2-3 showing that reservoir sandstones are expected to occur at the depth interval from approximately 850 to 900 m below seabed.

The primary seal is provided by the overlying Ordovician clayey limestones. The overlying Silurian section of carbonate and shales can be regarded as a secondary seal.

No geological drilling hazards or over pressured zones are predicted to occur in the area and hydrostatic gradients are expected.

| Baltic Sea | Information |
|---|---|
| Water depth | 36.5 m |
| Top reservoir (meters below mean sea level) | 848 |
| Reservoir thickness (meters) | 53 |
| Total depth of well (meters below sea level) | 901 (to the bottom of reservoir) |
| Reservoir lithology | Sandstone with 10% interlayers of claystone |
| Reservoir pressure | 9.3 |
| PPFG (Pore Pressure and Fracture Gradient) | n.a. |
| Temperature gradient | 4.1°C/100 m |
| Reservoir temperature | 36 °C |
| Reservoir porosity (average) | 21 % |
| Reservoir permeability (average) | 380 mD |
| Preliminary injection rate minimum, average, maximum value | 0.9, 1.0, 1.5 Mt/y (based on experience in other regions with sandstone reservoirs of high quality) |

| Baltic Sea | Information |
|---|---|
| Presence of any lithologies/ formations in overburden known to cause drilling hazards /problems such as over pressured zones, swelling clays, thick chert layers, other? | During drilling of the reference well E6 no hazards were reported. |

*Table 2-3: Baltic Sea subsurface information.*

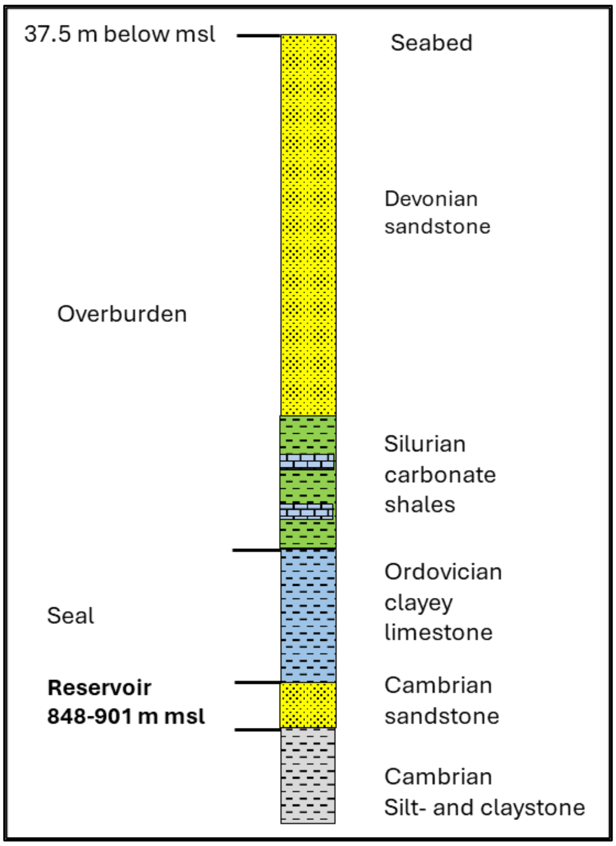


*Figure 2-3: Baltic Sea lithological and stratigraphic summary section showing the presence of Cambrian reservoir sandstone in the interval from 848 m to 901 m below sea level.*

## 2.4. South Atlantic Portugal

The general subsurface information received from the South Atlantic Portugal assumed well location is presented in Table 2-4below.

A lithological column presenting the information is illustrated in Figure 2-4 showing the depth to reservoir and seal intervals. It shows that Lower Cretaceous reservoir sandstones are expected to occur at the depth interval from approximately 860 to 1210 m below seabed.

The overlying Cenomanian limestone interval constitutes the primary seal.

No drilling hazards or over pressured zones are predicted to occur in the area and hydrostatic gradients are expected.

| South Atlantic Portugal | Information |
|---|---|
| Water depth (meters below mean sea level) | 84 m |
| Top reservoir (meters below mean sea level) | 860 m |
| Reservoir thickness (meters) | 350 m |
| Total depth of well (meters below sea level) | 1210 m |
| Reservoir lithology | Siliciclastic deposits of the Torres Vedras Group (Early Cretaceous); 80% sand and 20% clay |
| Reservoir pressure | n.a |
| PPFG (Pore Pressure and Fracture Gradient) | Hydrostatic Gradient: 10.7 kPa/m<br>Pore pressure: 12 MPa<br>Fracture pressure: 16.5 MPa |
| Temperature gradient | 28ºC/km |
| Reservoir temperature | 42-45ºC |
| Reservoir porosity (average) | 14% |
| Reservoir permeability (average) | 122 mD ($10^{-6}m^2$) |
| Preliminary injection rate minimum, average, maximum value | 0.3 Mton/yr (min); 0.7 Mton/yr (max); 0.5 Mton/yr (avg) |
| Presence of any lithologies/ formations in overburden known to cause drilling hazards /problems such as overpressured zones, swelling clays, thick chert layers, other? | Lithologies from the overburden are mainly composed by carbonates or siliciclastic rocks. |

*Table 2-4: Atlantic coast Portugal subsurface information.*

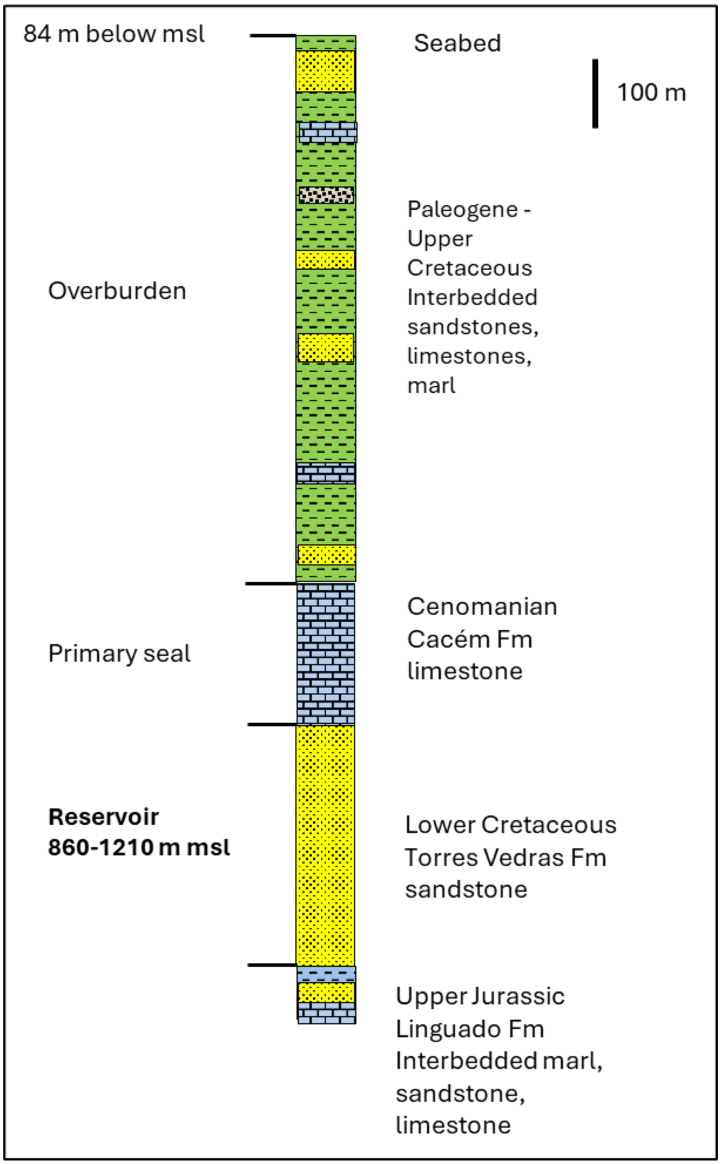


*Figure 2-4: South Atlantic Portugal lithological and stratigraphic summary section showing the presence of Lower Cretaceous reservoir sandstone in the interval from 860 m to 1210 m below sea level.*

## 2.5. Black Sea

The general subsurface information received from the Black Sea assumed well location is presented in Table 2-5 below.

A lithological column presenting the information is illustrated in Figure 2-5 below showing the depth to reservoir and seal intervals. It shows that a total thickness of approximately 300 meters of Lower Cretaceous reservoir sandstone is expected to occur in the depth interval from approximately 2700 m to 3400 m below seabed.

The overlying section of Upper Cretaceous shale and limestone constitutes the primary seal.

No drilling hazards or over pressured zones are predicted to occur in the area and hydrostatic gradients are expected. However, due to the depth of the reservoir around 3000 m the possibility of encountering hydrocarbons should be thoroughly evaluated including contingencies for drilling into a hydrocarbon bearing sandstone rather than the expected / required aquifer for $CO_2$ storage.

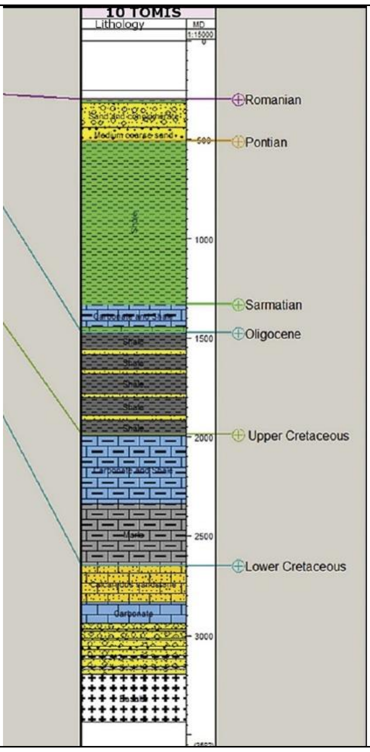
| **Black Sea** | **Information (based on well 10 Tomis)** |
|---|---|
| Water depth (meters) | 47 |
| Top reservoir (meters below mean sea level) | 2625 (2700) |
| Reservoir thickness (meters) | <300 |
| Total depth of well (meters below sea level) | 3437 |
| Reservoir lithology | grey sandstones with calcareous cement (Quartz sandstones with calcareous cement, greenish gray, fine to coarse, medium to well sorted with glauconite) |
| Reservoir pressure | n.a. |
| PPFG (Pore Pressure and Fracture Gradient) | n.a. |
| Temperature gradient | n.a. |
| Reservoir temperature | n.a. |
| Reservoir porosity (average) | ≥30% |
| Reservoir permeability (average) | 200 mD |
| Preliminary injection rate minimum, average, maximum value | n.a. |
| *Lithology log |  |
| Presence of any lithologies/ formations in overburden known to cause drilling hazards /problems such as overpressured zones, swelling clays, thick chert layers, other? Please describe | Based on the publicly available data to date, no overburden lithological formations have been identified that present a significant risk potential during drilling operations. The geological succession does not indicate the presence of overpressured zones, problematic swelling clays, thick chert layers, or other lithological units known to cause operational difficulties. |

*Table 2-5: Black Sea area subsurface information.*

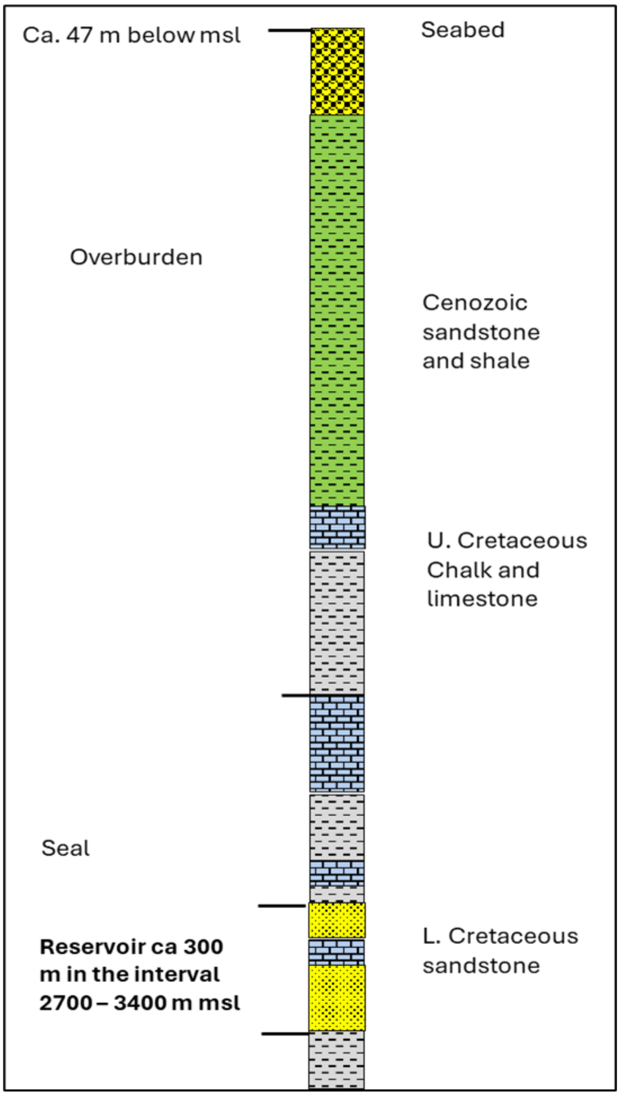


*Figure 2-5: Black Sea stratigraphic summary section based on the well 10 Tomis showing the presence of several Lower Cretaceous reservoir sandstones in the interval from 2700 m to 3400 m below sea level.*

## 2.6. Existing oil & gas well in depleted reservoir, Danish North Sea

Data on well design, integrity and reservoir conditions from an existing producer in a Danish North Sea oil and gas field has not been made available to WellPerform. The plugged and abandoned West Lulu-1 well has been identified to represent a typical oil and gas production well drilled into Middle Jurassic sandstones in the Danish North Sea. Based on the information presented in Table 2-6 below an illustration of the well trajectory and depth to reservoir is presented in Figure 1-1 .

| Danish North Sea Harald West Field | Information based on Legacy well LULU-1 P/A 1984 |
|---|---|
| Water depth (meters below mean sea level) | 65 m |
| Top reservoir (meters below mean sea level) | 3500-4000 m |
| Reservoir thickness (meters) | 120 m |
| Total depth of well (meters below sea level) | 4000 m |
| Total length of well (meters) | Up to 6000 m, 2000 m horizontal in reservoir section |
| Reservoir lithology | Middle Jurassic sandstone |

| **Danish North Sea Harald West Field** | **Information based on Legacy well LULU-1 P/A 1984** |
|---|---|
| Reservoir pressure | Depleted reservoir, unknown pressure |
| PPFG (Pore Pressure and Fracture Gradient) | n.a. |
| Temperature gradient | 35ºC/km |
| Reservoir temperature | 116ºC at 3500 m tvd |
| Reservoir porosity (average) | 20-25% |
| Reservoir permeability (average) | 100-200 mD |
| Preliminary injection rate minimum, average, maximum value | 0.5 Mton/yr (min); 2.0 Mton/yr (max); 1.0 Mton/yr (avg) |

*Table 2-6: Data from the legacy Lulu-1 well drilled into the Harald West Field, Danish North Sea.*

# 3. Well Conceptual Designs

This section describes conceptual designs for both new wells and re-completion of the existing wells. Design of the new wells is more dependent on subsurface assumptions compared to existing wells. Existing wells involve less assumptions since some boundary conditions related to well are known, such as depth of casing strings, water depth, subsurface information etc. Nevertheless, while assessing following conceptual designs it should be noted that various assumptions are used during the process, and by no means the proposed conceptual designs are final. Detailed engineering design is required for each well to mature proposed concepts.

## 3.1. Conceptual design for new $CO_2$ injection wells

The CCS exploration and injection wells are conceptualized based on the limited available information regarding specific location and subsurface conditions. For the conceptual well designs and well costs basic common assumptions are used for consistency to enable comparison between different CCS project cost scenarios. There will be three different wells that conceptualized from conductor setting till handover of the well to production team. In this section there is also chapter about re-completion of existing well into $CO_2$ injection well. Throughout the document re-completion and re-purposing used interchangeable for the same objective to convert existing legacy well into CCS well.

The facility interfaces with $CO_2$ injection wells are also important to address in terms of design and cost and will be mentioned briefly to ensure these subjects will be covered in potential more detailed future studies.

### 3.1.1. General Assumptions for New $CO_2$ Injection Wells

Below are listed some general assumptions used for the well design, drilling and completion

- Lifetime is 30 years (2030 is year one, same starting point for all scenarios).
- Sub-sea completion and interface for transporting by ship.
- Vertical wells.
- Use Northern Light $CO_2$ liquid stream specifications for material selection.
- Intermittent injection (as ships may not arrive continuously or may be delayed due to bad weather).
- Standard data acquisition program incl. logging, coring, fluid sampling, pressure and temperature.
- Installation of downhole monitoring equipment for pressure and temperature measurements.
- Future (2060) P&A cost using NORSOK standard requirements.

Wells are conceptualized as following (see also Figure 1-1), first well as shallow exploration and injection well (SXI-1) in Baltic Sea or South Atlantic Ocean, second well is intermediate depth exploration and injection well (IXI-1) with one additional casing string comparing to SXI-1, and it is drilled in Danish North Sea / Inez Structure. Third and last well concept is deep $CO_2$ injection well in Black Sea or Norwegian North Sea (DXI-1). General operational steps for all types of well are outlined below:

- Rig / Platform Mobilization
- 30" Conductor Driving
- 23" hole/18-5/8" surface casing (only for IXI-1 and DXI-1)
- 16" hole/13-3/8" intermediate/surface casing
- 12-1/4" hole/9-5/8" Production Casing
- 8-1/2" hole/7" liner

- Data acquisition & test
- Plug & Abandon
- Completion
- Suspension
- Rig Down Prepare to Skid/Move

Generally, extensive data acquisition (DA) and testing only take place for exploration wells, since these three wells conceptualized as such, DA cost is also estimated. For all wells, there is P&A cost however, this operation will happen at the end of well life (circa 2060). Also, suspension phase will not happen if well is handed directly over to injection operations team after completion.

#### *Data acquisition programme*

A data acquisition programme is included for the well cost based on standard data acquired for drilling deep wells. Since the proposed wells are drilled into previously untested saline aquifers the data acquisition programme should be as for an exploration well targeted to enable characterization and evaluation of the potential reservoir and overlying sealing formations. Core data, reservoir fluids, pressure and temperature are also used for reservoir management during $CO_2$ injection. ISO standards for geological $CO_2$ storage require comprehensive subsurface data and studies to justify the site is suitable and safe. Thus, the well cost will include acquisition of the necessary minimum amount of data.

#### *Well Integrity and P&A Strategy*

There are various industry standards which outline well integrity philosophy for wells. In this study Norsok and Offshore Energy UK standards are taken as basis while conceptualizing the wells. Summary of key aspects of well $CO_2$ well integrity presented on following paragraph.

Well integrity for $CO_2$ injection wells necessitates robust design and strict adherence to containment principles due to the challenging environment posed by $CO_2$ [1]. The general requirement is to operate with two defined well barrier envelopes that extend across the full cross section of the well and include all annuli [2] [1]. The well design pressure (WDP) for injection wells must be established based on the maximum possible generated injection pressure from the topside system, accounting for factors like shutdowns and PSV response [2]. A primary consideration is the *chemical compatibility* of all well components, as materials must resist degradation and corrosion from acidic fluids (carbonic acid) resulting from the interaction of $CO_2$ with water, along with resisting impurities like $H_2S$ and hydrogen that may cause embrittlement [1]. Regarding geomechanical integrity, if injection pressure exceeds the formation's fracture closure pressure, the production packer must be set at a depth that guarantees the casing, or any leak below the packer, will not fracture the cap rock or leak to shallower formations under maximum injection pressure [2]. Throughout operations, continuous monitoring is required, specifically of accessible annuli pressures, flow rates, and temperatures, which must be trended and compared to detect any leaks or anomalies [2].

The exploration wells will be eventually P&A according to industry best practices and standards [2] [1].

### 3.1.2. Well schematics and design for drilling and completion

Conceptual well designs for $CO_2$ injection wells generated based on industry knowledge and standards that are governed all O&G well designs for many decades. In fact, general principles of $CO_2$ injection well design is not different from traditional O&G wells. However, there are specific nuances that must be considered for CCS wells. First principles of exploration well designs based on standards like NORSOK D-10 [2] (or ISO 16530-2) to ensure well integrity. Additionally, CCS specific standard ISO 27914 [3] consulted for general $CO_2$ well construction principles, and OEUK $CO_2$ Well Decommissioning Guidelines (for P&A) [1] etc.

The provisional well design is based on a provided subsurface lithology and a target horizon at top reservoir sandstone at depths as presented in well schematics in Figure 3-1, Figure 3-2 and Figure 3-3 .

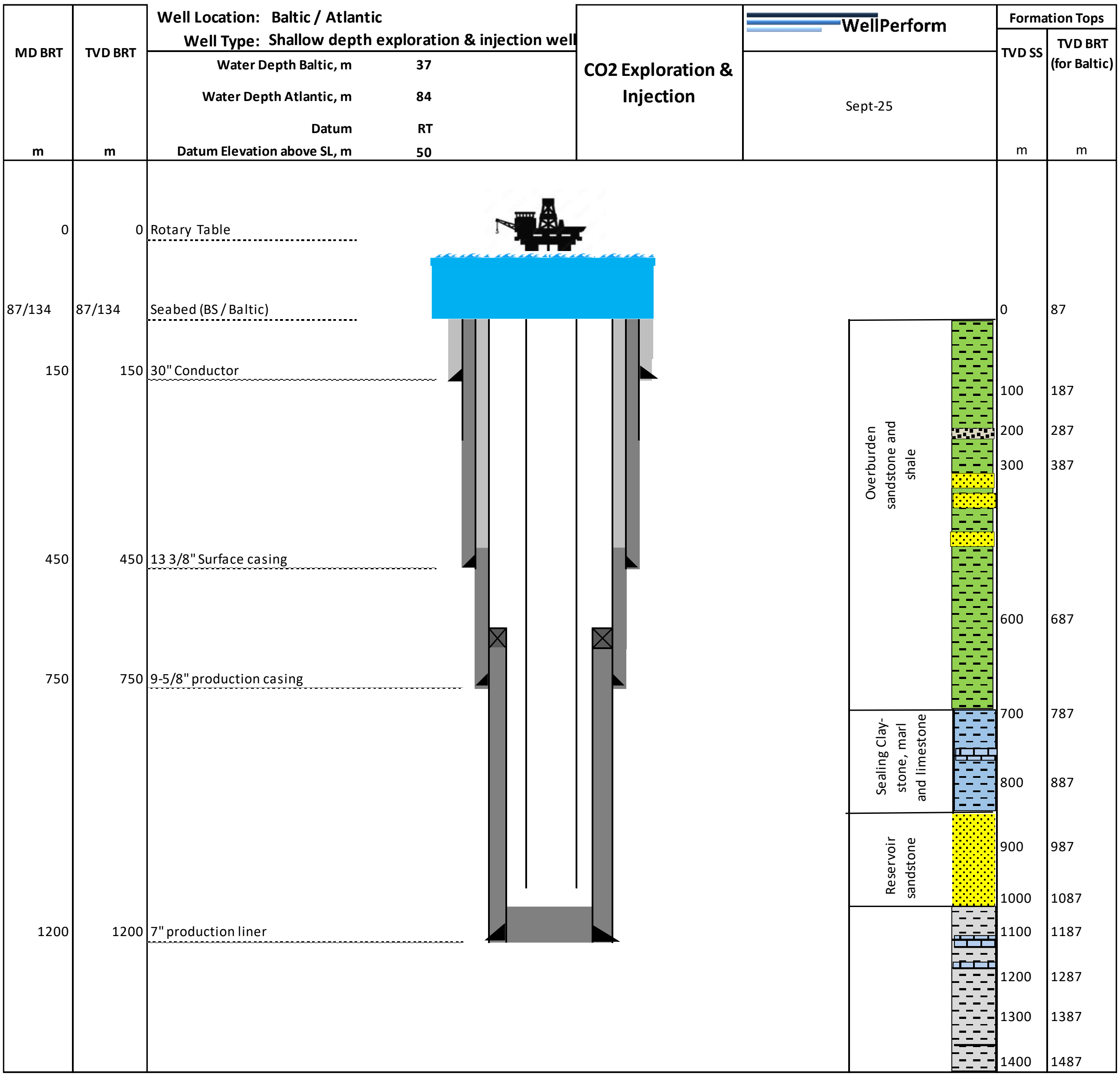


*Figure 3-1: Well Schematics – Shallow Depth Well – SXI-1*

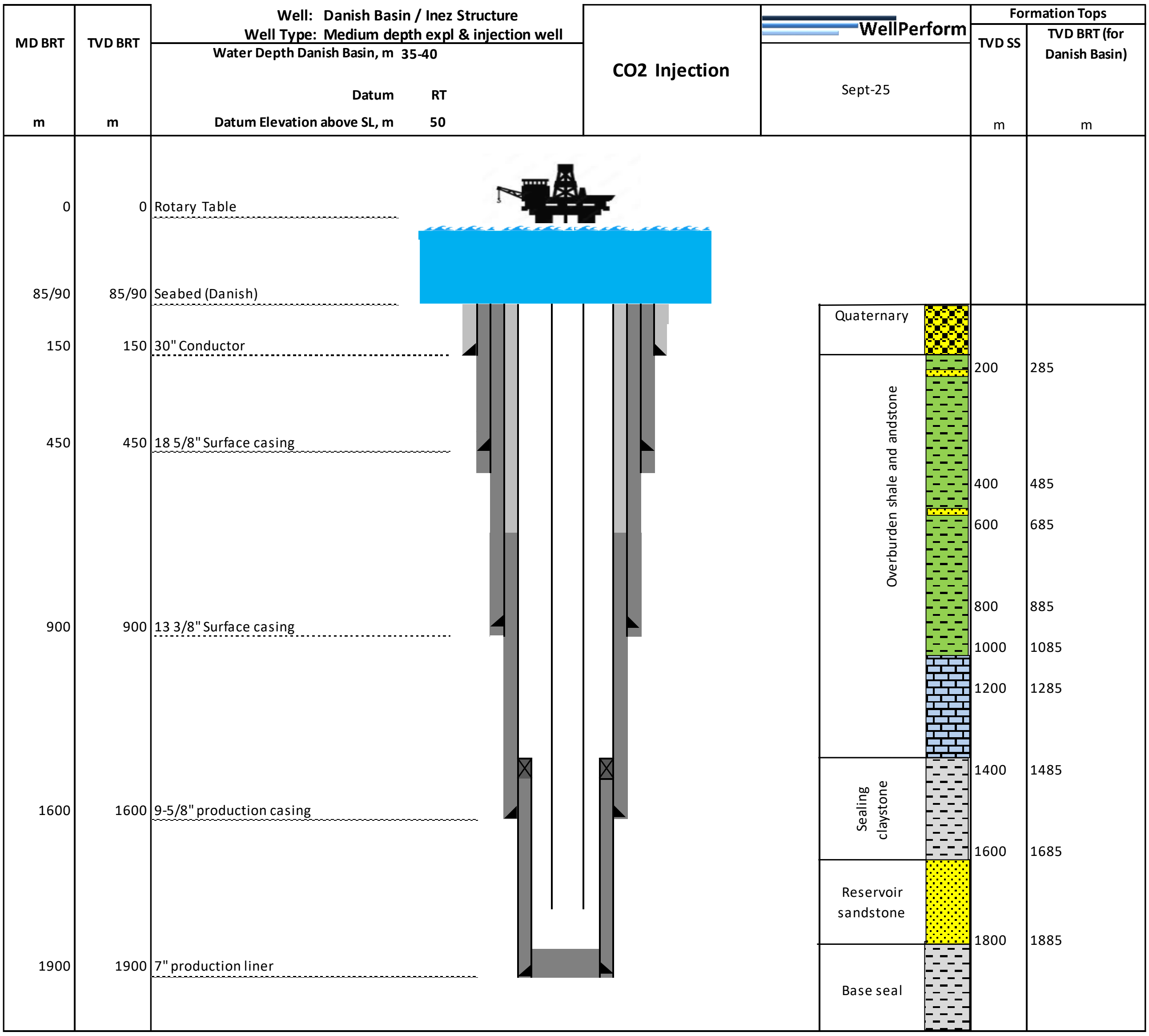


*Figure 3-2: Well Schematics - Intermediate Depth Well – IXI-1*

**Well:** Black Sea / Norwegian North Sea
**Well Type:** Medium depth expl & injection well

| | |
|---|---|
| WD Black Sea, m | 47 |
| WD Norwegian NS,m | 85 |
| Datum | RT |
| Datum Elevation above SL, m | 50 |

**CO2 Injection**

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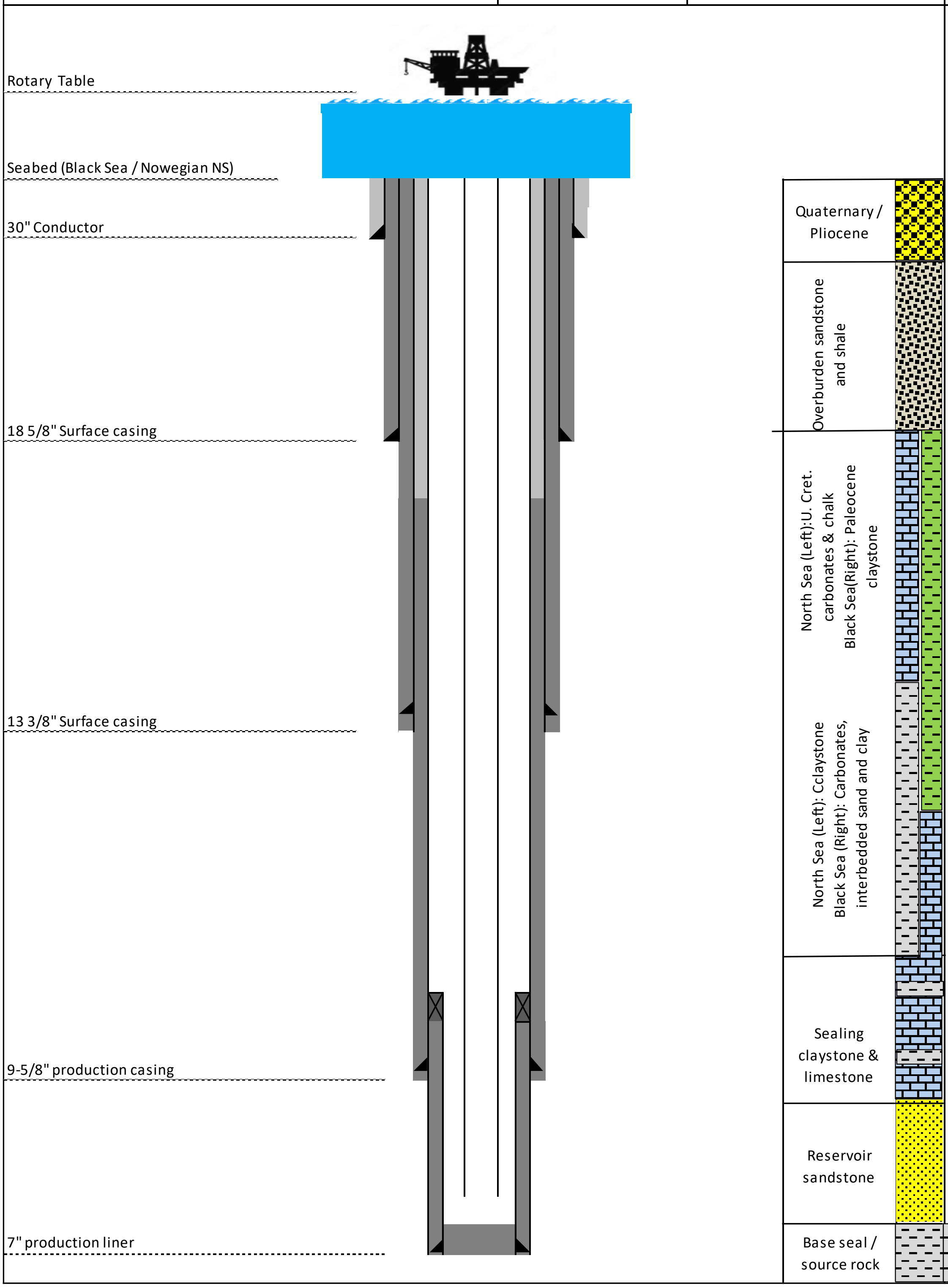


| Formation Tops | |
|---|---|
| TVD SS<br>m | TVD BRT (Black Sea)<br>m |
| 0 | 97 |
| 200 | 297 |
| 400 | 497 |
| 600 | 697 |
| 800 | 897 |
| 1000 | 1097 |
| 1200 | 1297 |
| 1400 | 1497 |
| 1600 | 1697 |
| 1800 | 1897 |
| 2000 | 2097 |
| 2200 | 2297 |
| 2400 | 2497 |
| 2600 | 2697 |
| 2800 | 2897 |
| 3000 | 3097 |
| 3200 | 3297 |
| 3400 | 3497 |

*Figure 3-3: Well Schematics - Deep Well – DXI-1*

For all wells a similar design is selected to make viable cost comparison on different designs. Differentiating factor between the wells are mainly subsurface differences in terms of top reservoir depth and total depth of the wells. Selected casing sizes and seats are listed in Table 3-1

| | Shallow Well | Intermediate Well | Deep Well |
|---|---|---|---|
| **Well type** | Exploration and $CO_2$ injection | Exploration and $CO_2$ injection | Exploration and $CO_2$ injection |
| **Well Name** | SXI-1<br>Shallow Exploration & Injection Well | IXI-1<br>Intermediate Exploration Injection Well | DXI-1<br>Deep Exploration Injection Well |
| **Basin** | Baltic / Atlantic | Danish Basin / Inez Structure | Norwegian North Sea / Black Sea |
| **Conductor** | 30”<br>150 m TVD | 30”<br>150 m TVD | 30”<br>150 m TVD |
| **Surface casing** | 13-3/8”<br>450 m TVD | 18-5/8”<br>450 m TVD | 18-5/8”<br>450 m TVD |
| **Intermediate casing** | n.a. | 13-3/8”<br>900mTVD | 13-3/8”<br>1800 |
| **Production casing** | 9-5/8”<br>750 m TVD | 9-5/8”<br>1550 m TVD | 9-5/8”<br>2800m TVD |
| **Liner** | 7” Liner<br>1200 m TVD | 7” Liner<br>1900 m TVD | 7” Liner<br>3600 m TVD |

*Table 3-1: Provisional casing sizes & depths for conceptual exploration & injection wells.*

### 3.1.3. Section summaries

#### *Conductor section*

To build proper foundation of the well and protect unconsolidated formation it is planned to run conductor 50-100 m below seabed. Conductors can be drilled-in, driven or jetted to their final setting place. Depending on formation strength and regional experience, any one of the above methods can be selected. Several surveys need to be conducted before deciding on installation methodology, such as:

- Bathymetric survey.
- Side Scan Sonar Survey.
- Shallow seismic survey.
- Soil boring and in-situ tests.
- TV inspection (by ROC to assess seafloor, subsea structures, and soil conditions).

For exploration wells it is common to use drill-in method or jetting while for development wells driving is preferred. Generally, for multi-well campaigns conductors are batch driven, which helps teams to accumulate learnings and optimize operational times. For the conceptual well designs in this report, 40-60 m below seabed is selected as conductor setting depth. The conductor size is assumed to be 30” which is common strategy for exploration wells. Smaller conductor size of (like 24” or 20”) could be an option for shallower exploration well SXI-1 depending on the detailed casing design.

#### *Surface hole section*

This section’s objective is to drill through the unconsolidated and weak formations and set the surface casing into a competent shale formation in the lithological sequence. For the provisional planning, this hole section will be drilled with a diverter system. The surface hole size and casing are conceptualized to be 23" or 24" and 18-5/8" for wells IXI-1 or DXI-1.

For the shallower exploration well (SXI-1) surface casing is selected to be 13 3/8" which will be installed inside 16" hole section. Due to large annular space left behind (30" and 13 3/8") potential tapered string at top of the 13-3/8" (such as 20") can be used. This will make BOP (Blow Out Preventers) installation feasible afterwards. If a smaller size conductor is used in the previous section, then tapered string is not needed and 13-3/8" can be set inside 16" hole.

It is planned to drill and cement the surface casing in place with top of cement at surface. Mud system for this section is an inhibited water-based system.

### *Intermediate hole section*

For well type IXI-1 and DXI-1 an intermediate hole section has been included in the conceptual design. Objective of this hole section and intermediate casing is to seal off weaker overburden layers. While these overburden formations layered with shale/ sandstone sequences in Danish Basin/Inez Structure, in Black Sea it is homogenous claystone and Norwegian North Sea this section is known for chalk / carbonates. In any of these cases, intermediate casing must secure the hole and reduce the risk of instability before entering the lower, more inhomogeneous and potentially highly pressured zones. Since subsequent sections require longer exposure time, this in turn requires protecting weaker formations with intermediate casing. The hole size can be 16" or 17 ½" for the casing size 13-3/8". This hole section will be drilled with a suitable BOP.

It is conceptualized to cement the 13-3/8" casing with top of cement at 300 m inside previous shoe. Mud system for this section is a high performance, water-based system. Especially for subsurface sections where reactive shales exist, proper inhibition in mud system is crucial.

For SXI-1 well there will not be intermediate hole section.

### *12-1/4" Hole Section and 9-5/8" Production Casing*

Purpose of this hole section is to drill to top of reservoir and isolate all shallower formations from the reservoir. In all conceptual cases reservoir covered with seal layer and TD of the 12-¼" hole section is at the bottom of this seal layer. After drilling TD, 9-5/8" production casing will be installed. This hole section will be drilled with suitable BOP.

It is planned to cement the production casing with top of cement minimum 300 m into the previous casing. The mud system for this section is a high performance, water-based system.

### *8-1/2" hole section and 7" Production Liner*

Reservoir section will be drilled 8-1/2" hole section, same size for all conceptual wells. In line with objectives of the $CO_2$ exploration wells, this section assumed to have comprehensive data acquisition plan to learn more about reservoirs. Coring, open hole logging, real-time pressure measurements are among the conceptualized data acquisition plan. These measurements require multiple trips and stop time during drilling so this section can take relatively longer to complete than others. The hole section will be drilled through the entire reservoir layer into the top of the underlaying source formation. Total depth (TD) of the well, also incorporates around 150 m completion sump in case well is converted to be keeper well with standard completion system. All wells will have the final casing string run as a 7" production liner with minimum 50 m overlap with the 9-5/8" production casing. It is planned to fully cement the 7" liner (i.e. top of cement is at top of liner). Mud system for this section is a drill-in water-based system.

### *Completion and clean-up*

Upon a successful well drilling phase and confirmation of favourable reservoir conditions exploration wells can be converted to injection wells. For that reason, the completion operations will take place to equip the well to start the $CO_2$ injection. The completion is planned to be a perforated liner over the sandstone reservoir sections and completion string will be run as lower and upper completion assemblies. Depending on detailed well engineering analysis tubing size could be any size in range of 3 ½" and 5 ½". After completion, the well will be cleaned up and well injections will take place. This will mark end of the construction phase and well will be handed over to injection operations team.

## 3.2. Conceptual Design for Re-completion of Existing Well

Conceptualizing for re-completion of the existing well is difficult since all re-entry and re-completion operations dependent heavily on the status of the well. However, this section outlines key operational steps that will be taken during converting existing well into $CO_2$ injection well.

- Mobilization / Demobilization.
- Workover – Well integrity assessments, re-entry operations.
- Data Acquisition.
- Re-Completion – removing old completion (de-completion) and re-completing the well.
- P&A (future cost).

# 4. Material Selection Considerations

In the provisional designs of the $CO_2$ injection wells all flow wet materials are defined as Cr25. It is possible that this can be relaxed but that will require thorough investigation of the operating conditions, $CO_2$ composition, reservoir fluid analysis etc.

## 4.1. Super Critical $CO_2$

$CO_2$ in the supercritical phase ($scCO_2$) is generally considered inert related to steel corrosion. $CO_2$ has been used for Enhanced Oil Recovery (EOR) for more than 30 years, so relevant experience, studies, and testing is available. However, in the EOR field, the wells can be Plugged and Abandoned (P&A'ed) when a $CO_2$ breakthrough is observed. A similar approach can be used in case of out of zone injection $CO_2$ is observed in any of the wells.

The following review is based on a mix of inhouse experience and available literature about the subject. The focus is on the impact on wells and their integrity to prevent uncontrolled injection or release of $CO_2$ to the environment. Surface equipment such as Xmas tree and well-head is included in the following, but other surface equipment such as pumps, lines, tanks etc., are not.

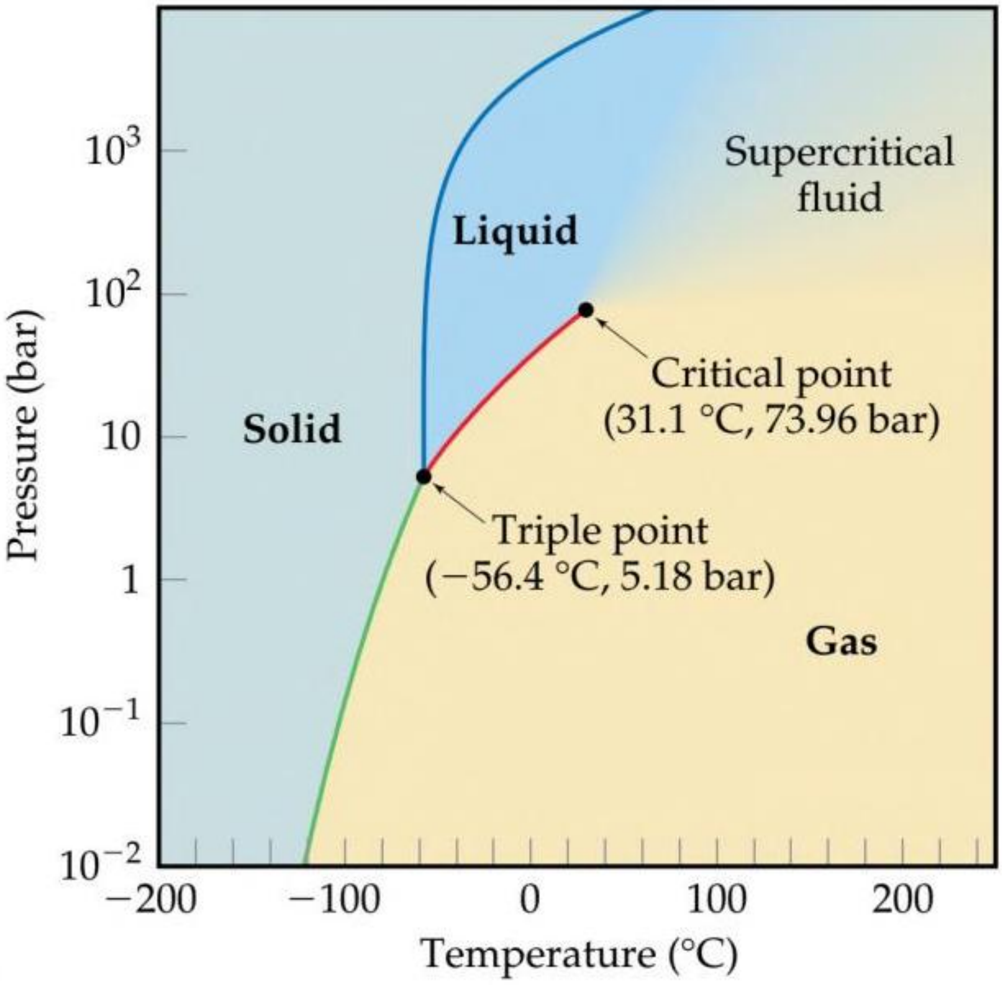


*Figure 4-1 Phase diagram for $CO_2$* [4]

The phase diagram for $CO_2$ [4] can be seen in Figure 4-1. It should be noted that in conditions above 31 °C and 74 bar, the $CO_2$ is in the supercritical phase.

## 4.2. Impact of $SO_2$ and $NO_2$ on Corrosion of Well Tubulars and Equipment

In CCS wells it is assumed that $CO_2$ is in supercritical phase (sc$CO_2$). Generally, the sc$CO_2$ is referred to as "clean", but the reality is that for industrially captured $CO_2$, it rarely is. Up to 2% of the "clean" sc$CO_2$ consist of impurities such as $NO_x$, $SO_x$ and $O_2$. These impurities dissolve readily in water and induce an aqueous phase at much lower water concentrations than the "pure" sc$CO_2$'s solubility levels, typically 1900-3200 ppm at 100 bar / 4-25 °C.

When $SO_2$, water and $O_2$ are present sulphureous and sulphuric acids ($H_2SO_3$ and $H_2SO_4$) might form. Corrosion might then occur at water levels down to as low as 500ppm. Then corrosion is further accelerated with the presence of $NO_2$. A test reveals that corrosion rates up to 1.6mm/year can occur under the right conditions [1]. This is to say that even sc$CO_2$ might not be inert if impurities are present and still might cause corrosion that needs to be accounted for.

## 4.3. Joule-Thomson Effect

It is understood that the $CO_2$ injection will happen through transporting $CO_2$ by ships to the site and empty each ships' tanks at a time into the well. Depending on the setup, this could mean intermittent injection with a change in pressure in the well from injection to static which again depends on the tubing size and pump rate. This might cause the sc$CO_2$ to change phase leading to a drop in temperature. Studies show that these drops can be up to -60 °C in extreme cases [5] and perhaps exceeding the specification envelope for the completion and tubulars both in terms of temperature and stress due to contraction, ultimately posing threats to well integrity (on tubing, valves, cement, etc.) as well as flow assurance specific problems (hydrates formation, etc.) and operating challenges.

Effect of Joule-Thomson shall be further analysed during detailed design phase of exploration wells and prevention measures of this phenomenon shall be addressed. Literature studies have been performed by Nemo and NORCE as part of the project and suggest injection of Glycol after each injection phase to avoid freezing of formation water and to reduce backflow of mixed water and $CO_2$. Lab studies to calibrate the temperature effect of amount of glycol in liquid $CO_2$ shall be part of a detailed design.

## 4.4. Impact of $H_2O$ Presence

The corrosivity of steel in an aqueous solution of $CO_2$ is quite well described and documented in the literature – less so when it comes to highly concentrated $CO_2$ under liquid or supercritical conditions.

Generally, pure and dry sc$CO_2$ is considered non-corrosive to a large extend. Some literature indicates minor or 0.01mm/year [5].

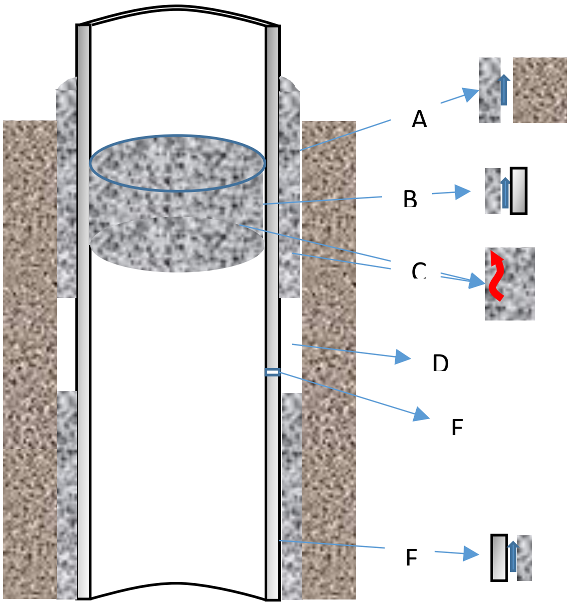
For aqueous $CO_2$ or supercritical $CO_2$ in contact with water, the picture is different. The corrosion behaviour for aqueous $CO_2$ increases with temperature and pressure but not on a linear scale when it comes to carbon steel. The corrosion is partly weight-loss corrosion but also severe pitting corrosion. Research shows that even sc$CO_2$ will dissolve water and form weak acidic fluid [6] but to a less degree than aqueous $CO_2$, this process is depended on the injection rate [7].

The corrosion related to the aqueous solution of high concentration $CO_2$ can be considerable in extreme cases up to 15-17mm/year for carbon steel [5]

Use of 13%Cr limits the weight-loss corrosion but not pitting. The use of Super 13%Cr limits weight-loss corrosion and pitting further, whereas 25Cr only sees a limited amount of corrosion under any water-wet conditions.

## 4.5. Cement Selection & Compatibility

Cement is essential for establishing barriers around the wellbore that prevent unwanted fluids from entering the wellbore or, worse, into the environment. Figure 4-2 illustrates [8] possible barrier failure for cement.



A. Poor bond between cement and formation leading to path where hydrocarbons or $CO_2$ can travel up
B. Poor bond between cement plug and casing leading to path where hydrocarbons or $CO_2$ can travel up
C. Micro fractures in cement either due to wrong recipe, cement degradation or over stress cement
D. No cement due to wrong placement or losses during cement job
E. Casing leaks due to corrosion, poor connections or overstressed OTCG
F. Poor bond between casing and cement leading to path where hydrocarbons or $CO_2$ can travel up

*Figure 4-2 Cement placement in a well and possible failure mechanisms – modified after reference* [8]

The above-described cement failures and risks are general risks applying to all wells irrespective of the purpose of the wells. In the conceptual wells for CTS EUDP project, the additional issue of how $CO_2$ affects the cement also needs to be considered and described below.

The effect of $CO_2$ injection on oil-field cement is quite well described in the literature and can be summarized as a 3-step process: Carbonic acid diffusion, cement dissolution, calcium carbonate precipitation. The last step leads to more calcium carbonate in the system which in turn enhance chain of the reaction again. This process leads to cement leaching which is increase in porosity and permeability of the cement [9]. The above process relies on the presence of water. Formation water is assumed to be present to a certain extent above the Gas/Water contact due to imbibition and the general water wet environment.

To minimize effect of degradation of $CO_2$ either different cement system is used in industry such as Blas-furnace slag (BFS) or other types of modified Portland cement (with more flexible particles). In addition to these, recent studies show adding additives can be more effective to create $CO_2$ resistant slurries [10] [11].

# 5. Re-use of Existing O&G Wells in Depleted Fields

By re-using an existing well drilled and completed across a reservoir section suitable for $CO_2$ storage injection the cost of drilling is saved. However, depending on the wells previous functions and maintenance the integrity for $CO_2$ injection can be a key determinant of the

For re-use of an existing oil & gas well by re-completing the well for $CO_2$ injection it is necessary to perform a detailed feasibility study of the well integrity as the basis for planning and execution of the re-completion. This should be carried out in a stepwise process addressing the subjects as listed below:

1. Review of existing well data
2. Evaluation of material concerning life cycle and recommended well assessment logging program
3. Evaluation of well integrity issues for existing wells in the structure and any legacy wells/sidetracks
4. Identification of risks and showstoppers for $CO_2$ injection
5. Cost estimate for conversion of the existing wells
6. Recommendations for further studies

For the cost estimate of re-completing an existing well the estimated cost of an integrity study including logging (cement and casing) is presented. In case high quality and recent data is available from the well, this cost will be significantly reduced.

While considering of re-purposing existing O&G wells, future P&A scenarios also must be analysed during detailed design phase. Offshore Energy UK guideline [1] outlines four additional suitability criteria while considering existing well for $CO_2$ injection well. These criteria also correspond to steps 2,3 and 4 written above:

- The suitability of the existing casing and cement construction of the well for $CO_2$ injection at the proposed injection conditions i.e., rates, $CO_2$ stream composition, pressures and temperatures (including cycling) over the anticipated operational lifetime of the store.
- The adequacy of the existing casing and cement design and method of construction for future permanent well decommissioning as a former $CO_2$ injection well
- The suitability of the existing completion, instrumentation, wellhead, and Xmas tree arrangement for $CO_2$ injection at the proposed injection conditions i.e., rates, $CO_2$ stream composition, pressures, temperatures and anticipated operational lifetime
- The need to remediate or modify an existing reservoir completion e.g., perforation interval, screens, gravel pack etc. to permit $CO_2$ injection and the likely impact on the well's long-term suitability as an injection well or on a $CO_2$ storage operator's ability to permanently decommission it.

# 6. Well Cost Estimates

This section presents high-level cost estimates of mobilization, demobilization, drilling, completion, data acquisition and abandonment cost for the three conceptual new well designs presented in Section 3.1 and for re-used wells as presented in Section 5.

## 6.1. Introduction

The estimated well costs are prepared with a high-level break down of cost to enable the costs to be used for the different regions and different project scenarios providing transparency for the economic evaluations. The estimated well costs are prepared based on the present-day available information about rig rates, technology and other well construction costs and come with uncertainty as presented.

General assumptions include the following: rig rate, conceptual well design such as number of well sections, vertical or deviated wells, completion materials for $CO_2$ injection (casing and cement), expected OPEX, expected injection well lifetime, Data Acquisition, P&A cost, installation of monitoring equipment in well and/or on seabed.

It needs to be highlighted that these estimated costs are conceptual and can vary significantly from detailed cost estimates, for these purposes 20% contingency rate included in all well cost estimates. Cost estimations in this report are based on deterministic methods.

Evaluation of porosity and permeability of the storage unit and primary seal is required as per ISO 27914 [3]. Also, same standard requires dedicated cased hole logging for production casing/liner to ensure well integrity. The assumptions for the cost estimates are presented in below Table 6-1.

| # | Area | Assumptions |
|---|---|---|
| 1 | Time estimates | The time estimates are based on the conceptual hole sections and benchmarked with relevant offshore wells drilled in Europe. New wells are assumed to be vertical. |
| 2 | Cost estimate level | Level 1 – scope phase (contingency cost included) |
| 3 | Rig rate | Drilling rig rates between changes between €95,000/day and €430,000 [12]. For the conceptual cost estimation, it is assumed that Jack-up rig will be used at rate of €200,000/day. The actual day rate will have a major influence on the total well cost.<br>It should be noted that rig cost in Norway is 15-20% higher than surrounding countries (due to harsh weather environment and regulations). Generally, Norway, set pace for rig rates for all surrounding countries in the North Sea. [13] |
| 4 | Completion | The entire reservoir section is completed with 7" cemented liner and perforated over the relevant sandstone sections. All completion and/or casing and Liner which is formation or $CO_2$ "wet" is designed with CR 25 tubulars. |
| 5 | Well Test | Injection rates / downhole pressure & temperature included in short well test. |

| # | Area | Assumptions |
|---|---|---|
| 6 | Casing design | The conceptual casing design casing is as defined in Section 3. Shoe setting depths are selected based on the experience in the area and/or best practices in industry. Well lifetime is assumed to be 30 years. |
| 7 | Site survey | The cost of the site survey is included in the estimates and is estimated to app. €0.5M assuming seabed surveys, future ship-well interfacing survey, soil survey, TV survey and all reporting regarding this. |
| 8 | Data Acquisition | Downhole monitoring equipment and coring of seal and reservoir sections (two coring points). Additional fluid and pressure measurements, cased hole logging etc. |
| 9 | Well / Ship Interface | It is assumed that additional studies / surveys to be done to confirm well / ship interface. |
| 10 | Exchange rates | USD: 0.85 EUR; DKK: 0.134 EUR<br>NOK: 0.09 EUR; GBP: 1.15 EUR |
| 11 | Contingency Percentage | 20% contingency cost assumed for unforeseen events and uncertainty on the assumed costs. Typical non-productive time (NPT) events include following: Hole Problems, Stuck Pipe, Rig Repair, Well Control Issues & Weather. |
| 12 | Other | Additional costs for regulatory permits/delays for rigs in North Sea.<br>P&A cost at the end of the well lifetime included.<br>Mob & demob cost of the drilling units and data acquisition tools. |

*Table 6-1: Assumptions used for estimating costs for conceptual wells.*

Some of the costs assumed to be same for each type of the well, since they are irrespective of the depth of the well drilled. These costs summarized as following:

- Mob-demob
- Data Acquisition
- P&A

Obviously, data acquisition and P&A could be affected by the depth of the well and zone of the interest in each well. Such potential cost differences on above mentioned phases are included in 20% contingency.

Cost of repurposing existing well into $CO_2$ injection well also estimated and summary outlined in the Section 6.5.

When using the total expected well cost for the different scenarios in the economic model for a success case development, it is recommended to leave out the included 20% contingency and P&A cost if the contingencies are already included (avoiding contingencies on contingencies).

## 6.2. Shallow Well Type

The shallow well SXI-1 is estimated to cost approximately €35M. Main driving factor behind lower cost comparing to other wells is length of the well. Cost line items that calculated based on total time spent on well location affected. It is estimated that it would take significantly less time to drill all hole section at the SXI-1. In addition, to short well length, there is also fewer hole sections (four in total) compared to IXI-1 and DXI-1 wells. The key assumptions for shallow well are listed below:

Table 6-2 shows estimated shallow well cost including contingency.

| Phase | Cost (€) |
|---|---|
| Mobilization / Demobilization | 2,100,000 |
| Drilling operations | 11,800,000 |
| Data Acquisition | 4,900,000 |
| Completion | 4,500,000 |
| P&A | 6,400,000 |
| *Sum* | 29,700,000 |
| *Sum including contingency* | 35,640,000 |

*Table 6-2:Cost per phase for Shallow Exploration & Injection Well - SXI-1.*

## 6.3. Intermediate Well Type

This conceptualized well type is in-between the deep and the shallow well. Relatively longer hole sections lead to increased drilling time and completion time. Considering that majority of the well cost are also time-dependent intermediate well cost is approximately €40M. Intermediate well type is conceptualized in Danish Basin / Inez Structure at water depth of 35-40m.

| Phase | Cost (€) |
|---|---|
| Mobilization / Demobilization | 2,100,000 |
| Drilling operations | 14,200,000 |
| Data Acquisition | 4,900,000 |
| Completion | 5,600,000 |
| P&A | 6,400,000 |
| *Sum* | 33,200,000 |
| *Sum including contingency* | 39,800,000 |

*Table 6-3: Cost per phase for Intermediate Depth Exploration & Injection Well - IXI-1.*

## 6.4. Deep Well Type

The most complex conceptual design is the deep well type, assuming subsurface conditions of Black Sea or Norwegian North Sea. Hole sections are longer in this type of well with longer duration required for surface, intermediate and reservoir hole sections. Drilling cost for the well is estimated to be approximately €50M. Completion cost is slightly higher due to time-dependent operations (running completion) in the completion phase. Summary table for costs per phase shown in the Table 6-4.

| Phase | Cost (€) | Cost (€) |
|---|---|---|
| Rig Rate | 200,000 / day | 300,000 / day |
| Mobilization / Demobilization | 2,100,000 | 2,100,000 |
| Drilling operations | 20,000,000 | 24,700,000 |
| Data Acquisition | 4,900,000 | 5,600,000 |
| Completion | 8,200,000 | 9,600,000 |
| P&A | 6,400,000 | 8,200,000 |
| *Sum* | 41,600,000 | 50,200,000 |
| *Sum including contingency* | 49,920,000 | 60,240,000 |

*Table 6-4: Cost per phase for Deep Exploration & Injection Well - DXI-1.*

## 6.5. Recompletion of existing O&G well

Following assumptions are made while calculating high level cost for re-completion of the existing O&G well:

- Well Integrity Assessment of the legacy wells in area and donor well.
- Workover operations to re-enter to well and remediate casing or cement if needed.
- Data acquisition to confirm integrity of the well.
- Re-completion well for purpose of $CO_2$ injection.

| Phase | Cost (€) |
|---|---|
| Mobilization / Demobilization | 2,100,000 |
| Workover | 12,700,000 |
| Data Acquisition | 2,900,000 |
| Re-Completion | 9,300,000 |
| P&A | 6,400,000 |
| Sum | 33,400,000 |
| Sum including contingency | 40,100,000 |

*Table 6-5: Cost per phase for repurposing existing well.*

## 6.6. Comments to well cost

This section compares well costs for conceptual scenario for new wells and re-completion of the existing well. Comparison of total well costs for each scenario shown in the Figure 6-1. The cost for new wells is heavily affected by the target drilling depth. So, the deeper the well target the higher cost for new wells. Well depths only affect drilling and completion cost, and it is assumed that well depths don’t affect mob& demob, P&A and with minor impact on Data Acquisition operations. Another key factor that affects total well costs is contingency portion assumed for each well. It is assumed cost could increase around 20% for each hence contingency percentage applied for each of the well.

Permanent plug and abandonment (P&A) cost is future cost that will be realized at the end of the life of the well. Hence, it should be subtracted from the total well cost when comparing well construction cost. Comparison graph of the well construction costs for new wells and re-completed existing well is shown in the Figure 6-2.

Well Construction cost includes a comprehensive data acquisition programme, which will be needed for the first well to be drilled in an untested area, however, if more development wells are to be drilled this cost will be significantly lower.

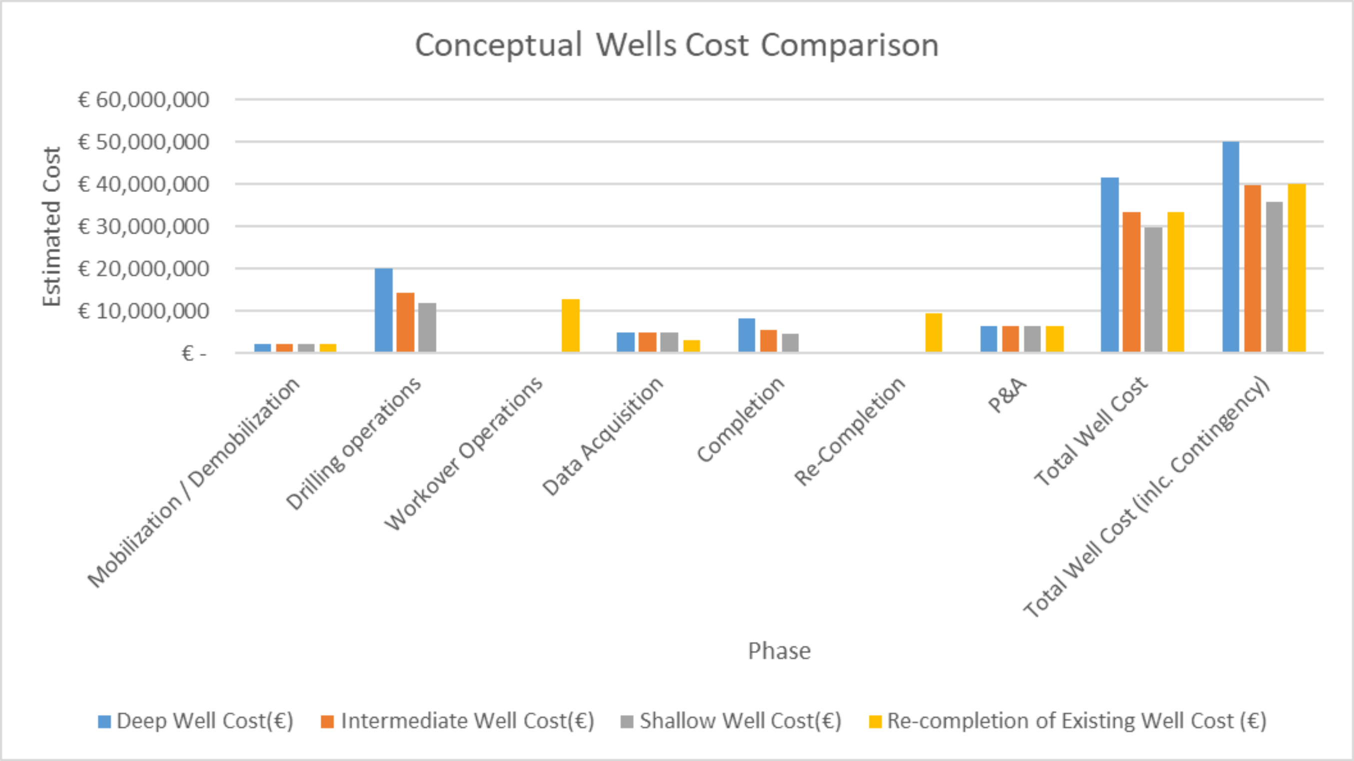


*Figure 6-1: Cost by phase for conceptual well designs (both new wells and existing well re-completion).*

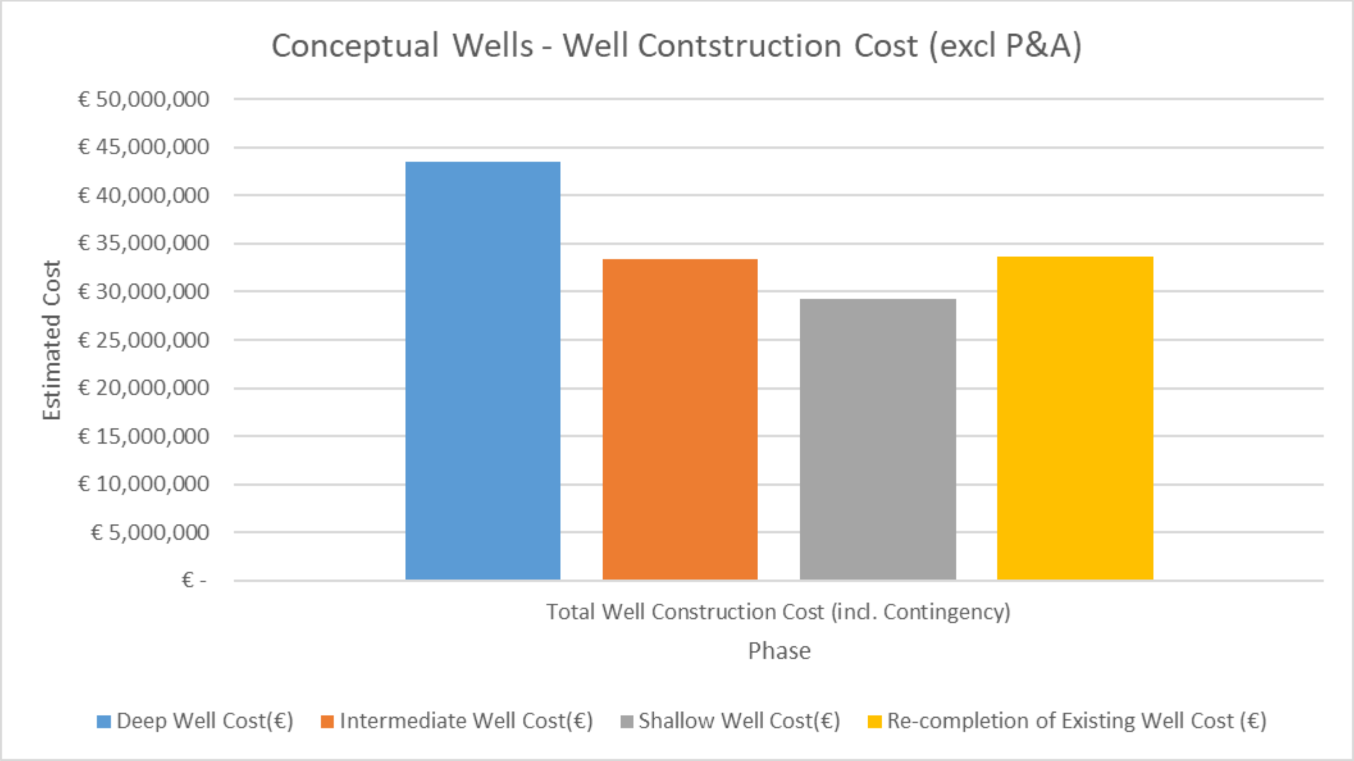


*Figure 6-2: Well construction cost comparison excluding future P&A cost.*

## 6.7. Conceptual well delivery timeline

An indicative timeline for well delivery has been developed to aid early project planning and risk assessment. The timeline shown in Figure 6-3 illustrates the typical well delivery schedule for four categories of wells: Shallow, Intermediate Depth, Deep, and Re-completion of existing oil and gas wells.

Across all types, the Project Definition Phase usually takes two months to define project objectives and resources planning based on close communication with the project team and the well delivery team / drilling department. Design Phase usually takes about four to five, ranging from four months for shallow wells to five months for deep and re-completion wells. The Planning Phase generally lasts around two to three months, slightly longer for deeper or more complex wells. The Design and Planning Phases are also phases where Long Lead Items (LLI) ordered. Generally, it takes ten months to get LLI delivery. The Operations Phase occurs afterwards, lasting two to three months depending on well depth and scope. Although re-completion of existing wells requires less construction time due to existing infrastructure, it still demands significant time to evaluate well suitability for $CO_2$ injection, particularly from a well integrity perspective. Between planning phase and operational phase usually two months required to get all required permits to initiate operations, but this may depend on local authority requirements. Overall, well delivery durations tend to increase with depth and complexity — deeper wells take longer to plan and execute. However, regional factors such as logistics, regulatory frameworks, and available infrastructure can greatly influence these timelines, leading to variations from the average durations presented.

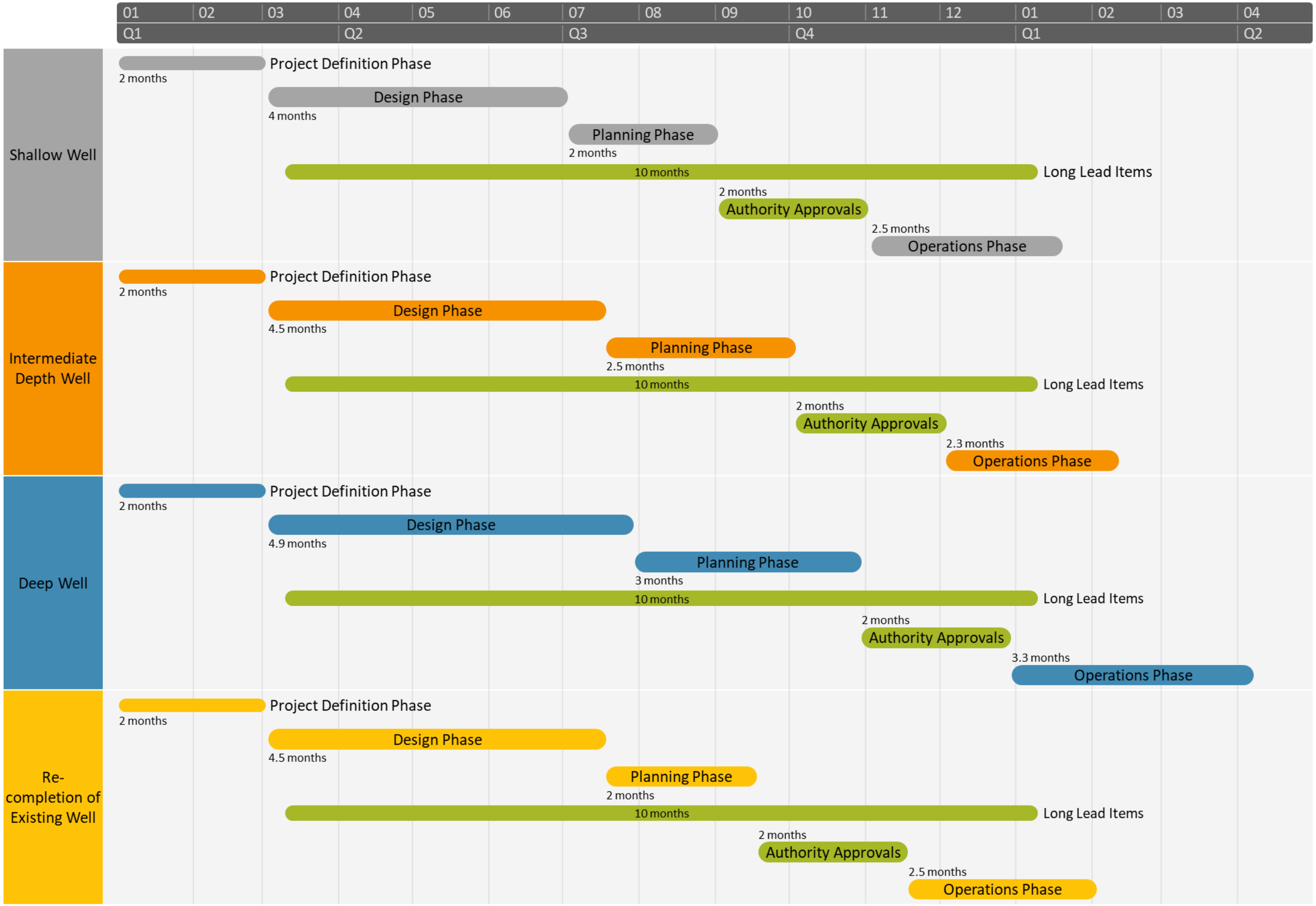


*Figure 6-3: Indicative project timeline for new wells and re-completion of existing well.*

# 7. Risk Assessment

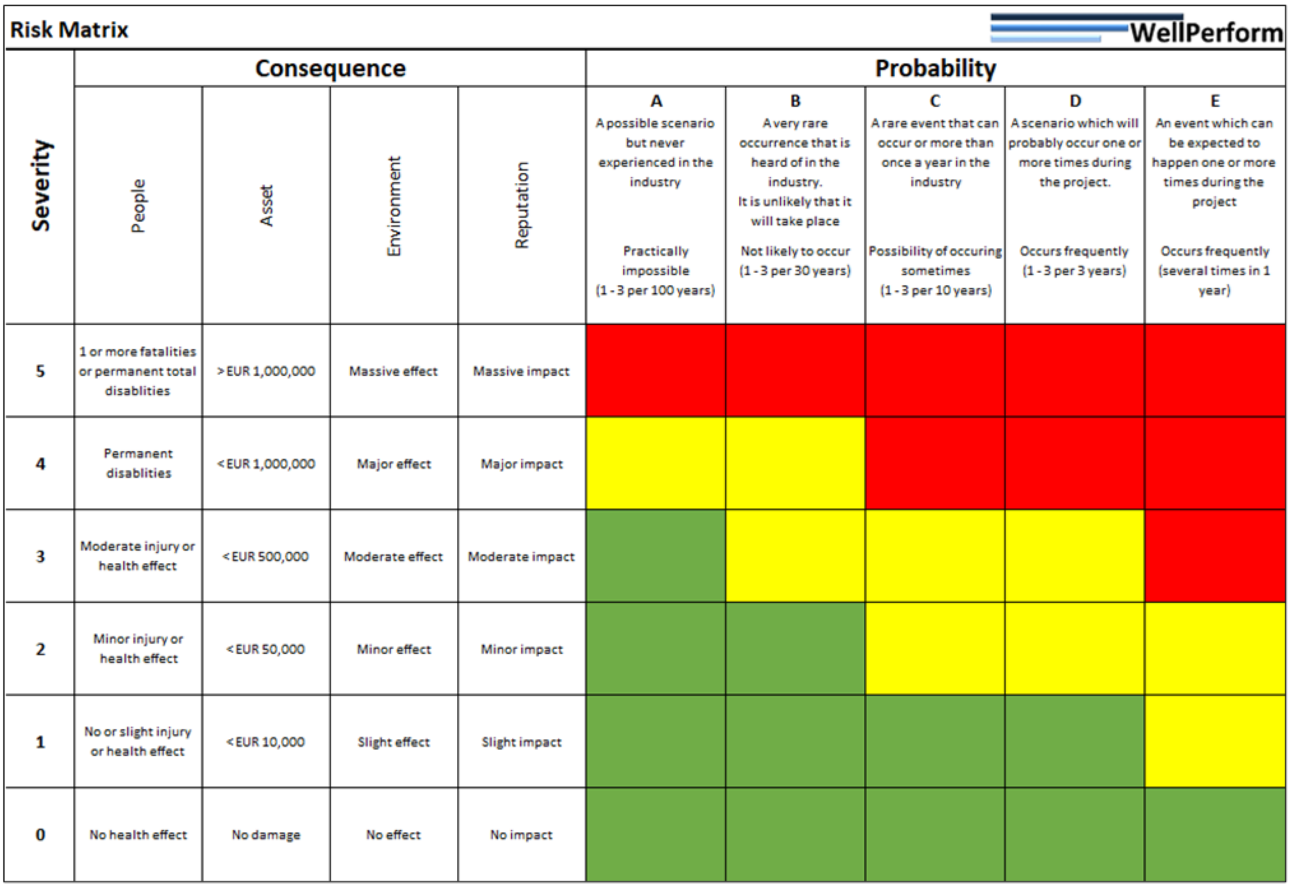
High-level risk assessments regarding well delivery have been made for the listed three subjects:

- Planning and drilling a new $CO_2$ injection well into an un-tested saline aquifer
- Re-completion of an existing well in a depleted oil & gas fields
- General major project risks related to delivery of an injection well for $CO_2$ for storage

The aim is to present identified major risks and identified risk mitigating actions. The risk matrix as presented in Figure 7-1 below is used to describe the probability of occurrence and the severity, which can be in terms people injuries, asset(project) economics, environment and reputation. The risk is the product of the probability and the consequence.

The risk is presented as identified initial risk and the final risk after the mitigating means have been applied. Numerous high risks mainly in terms of cost are identified both for new and existing wells, however, in general many mitigations have been identified which may reduce the risk to an acceptable level. For each area risked a plot is presented illustrating the initial risk and the risk after mitigating in terms of probability of risk and the severity of the risk.

Moving forward with specific projects detailed risk assessments must be carried out for each phase of the well delivery project to identify contingencies and mitigating actions to ensure the project is carried out based on the ALARP risk principle "As Low As Reasonably Practicable".



**Risk Matrix** WellPerform

| Severity | Consequence | | | | Probability | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | People | Asset | Environment | Reputation | A<br>A possible scenario but never experienced in the industry<br>Practically impossible (1 - 3 per 100 years) | B<br>A very rare occurrence that is heard of in the industry. It is unlikely that it will take place<br>Not likely to occur (1 - 3 per 30 years) | C<br>A rare event that can occur or more than once a year in the industry<br>Possibility of occuring sometimes (1 - 3 per 10 years) | D<br>A scenario which will probably occur one or more times during the project.<br>Occurs frequently (1 - 3 per 3 years) | E<br>An event which can be expected to happen one or more times during the project<br>Occurs frequently (several times in 1 year) |
| 5 | 1 or more fatalities or permanent total disablities | > EUR 1,000,000 | Massive effect | Massive impact | 🟥 | 🟥 | 🟥 | 🟥 | 🟥 |
| 4 | Permanent disablities | < EUR 1,000,000 | Major effect | Major impact | 🟨 | 🟨 | 🟥 | 🟥 | 🟥 |
| 3 | Moderate injury or health effect | < EUR 500,000 | Moderate effect | Moderate impact | 🟩 | 🟨 | 🟨 | 🟨 | 🟥 |
| 2 | Minor injury or health effect | < EUR 50,000 | Minor effect | Minor impact | 🟩 | 🟩 | 🟨 | 🟨 | 🟨 |
| 1 | No or slight injury or health effect | < EUR 10,000 | Slight effect | Slight impact | 🟩 | 🟩 | 🟩 | 🟩 | 🟨 |
| 0 | No health effect | No damage | No effect | No impact | 🟩 | 🟩 | 🟩 | 🟩 | 🟩 |

*Figure 7-1: WellPerform Risk Matrix showing the level of severity, the risk probability, the consequence and the associated risk colour coding.*

## 7.1. Risk Assessment Drilling New Well

The risk assessment addresses the risks of drilling and completing a $CO_2$ injection well in an un-drilled structure without having detailed subsurface data available for the well design for $CO_2$ injection as well as for the preparation of a drilling programme.

| Risk description | Effect | Initial risk | Mitigations | Final risk |
|---|---|---|---|---|
| Subsurface properties in a new $CO_2$ injection drilled as an exploration well may be different those assumed for the pre-drilling well design. | Well design is sub-optimal for $CO_2$ injection well into actual reservoir, which may cause injection at lower rates than predicted, poor reservoir management, well lifetime, well integrity, and OPEX during well life. | 🟥 | Make a detailed assessment of subsurface uncertainties to be designed for.<br>Consider drilling the well as an exploration well with the option for subsequent re-completion into an injection well only in a success case. | 🟨 |
| Unpredicted / unknown geological hazards including the presence of hydrocarbons and over-pressured zones complicates drilling operations of the planned well. | Well control issues, hydrocarbon spill to environment, injuries, running casing, time and cost overruns. | 🟥 | Ensure thorough subsurface evaluations are made based on representative off-set wells.<br>Have an experienced subsurface team to make a detailed analysis of the risk of hydrocarbon presence | 🟨 |
| Well location is decided based on limited subsurface data such as seismic data without good well tie(s) | The well is drilled in a structural sub-optimal position leading to access to less connected storage volume than expected | 🟨 | Ensure adequate amount of data is available. Have a technically qualified and experienced subsurface team in the project team. | 🟩 |
| Required subsurface properties are not encountered in new $CO_2$ injection. | Storage volume and / or injectivity is smaller than assumed for the project business case. | 🟨 | Make a detailed assessment of subsurface risks and uncertainties to provide a range of scenarios of storage volume and injectivity prior to drilling decision. | 🟩 |

*Figure 7-2: Risk assessment of drilling new well for $CO_2$ injection in un-tested structure / reservoir*

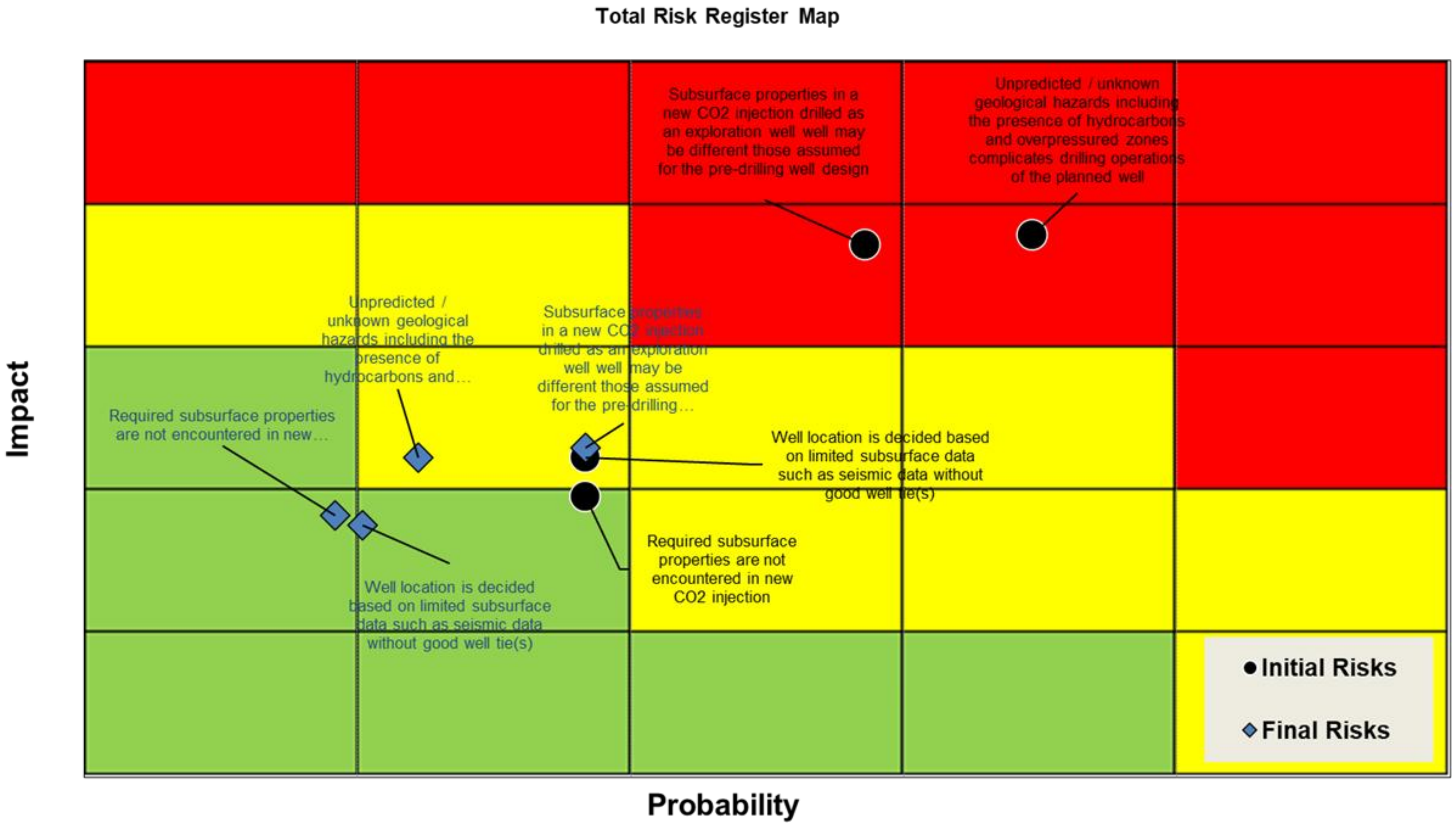


*Figure 7-3: A graphical representation of the risk assessment drilling new $CO_2$ injection well. Black dots show initial risk, blue squares show how carrying out mitigating actions may reduce the risk. The text in the diagram is the initial risk as also presented in Figure 7-2.*

## 7.2. Risk Assessment Re-completion of Existing O&G Wells

The risk assessment addresses the risks of re-completing an existing oil & gas well in a depleted reservoir into a $CO_2$ injection well.

| Risk description | Effect | Initial risk | Mitigations | Final risk |
|---|---|---|---|---|
| Existing data from active/legacy wells in the field are not suitable for evaluation of subsurface properties for $CO_2$ storage, eg. present reservoir fluid composition, seal properties and geomechanical behaviour. | Authority permission cannot be obtained for $CO_2$ storage injection if data cannot support storage integrity. | 🟥 | Acquire additional well log data from existing wells in the area. | 🟨 |
| Facilily integrity and remaining lifetime is not in alignment with the required lifetime for $CO_2$ injection project. | Upgrade of facilities is needed, which may come with a very high cost and risk of budget overrun, the $CO_2$ injection well has to be abandoned earlier than planned. | 🟥 | Carry out detailed analysis of facility integrity for a detailed time and cost estimate for required upgrades. | 🟨 |
| Recompletion of an existing O&G well to $CO_2$ injection will require thorough integrity evaluation of all existing wells in the field and potentially require P&A and/or re-completion to $CO_2$ resistant materials to ensure storage integrity | If many wells are drilled into the reservoir, this task is very comprehensive and comes with a high risk of cost and budget overruns. | 🟥 | Select a well for $CO_2$ injection in a depleted field with few wells active / abandoned wells to limit the task and the cost. | 🟩 |
| Liability to P&A requirements after re-entry, if the legacy well is deemed to be unsuitable for $CO_2$ storage injection | Additional cost, time, risk of non-compliance with present day regulations | 🟨 | Detailed analysis of available data, scope definition, detailed P&A planning. | 🟩 |
| Integrity evaluation of well status shows cement has poor CO2 resistance. | Re-establishment of cement and / or other well barriers may be associated with high operational risk and high risk of cost overruns. | 🟨 | Detailed analysis of available data on well completion incl materials and present status should be made before selecting an existing well for potential re-completion to $CO_2$ injection well. | 🟩 |
| Uncertain well integrity due to absence on data on casing and other well barrier elements. | Program and cost for re-completion to $CO_2$ injection is highly uncertain, risk of time and budget overruns | 🟨 | Plan a stepwise program for re-completion starting with logging for integrity evaluation, then, based on well integrity, make detailed plan for re-completion. Material non-destructive test. for well barriers of the tubulars. | 🟩 |
| Well location in the depleted reservoir is not optimal for $CO_2$ storage injection in terms of structural position and/or | Injectivity rate is less than predicted, storage volume is less than predicted, | 🟨 | Prepare thorough subsurface evaluation of $CO_2$ migration from injection point into the into structure and the | 🟩 |

| **Risk description** | **Effect** | **Initial risk** | **Mitigations** | **Final risk** |
|---|---|---|---|---|
| reservoir connectivity (access to storage volume). | jeopardize project business case. | 🟨 | reservoir connectivity across the storage unit based on representative static and dynamic modelling of scenarios. | 🟩 |

*Figure 7-4: Risk assessment of re-completing existing oil & gas well into a $CO_2$ production well*

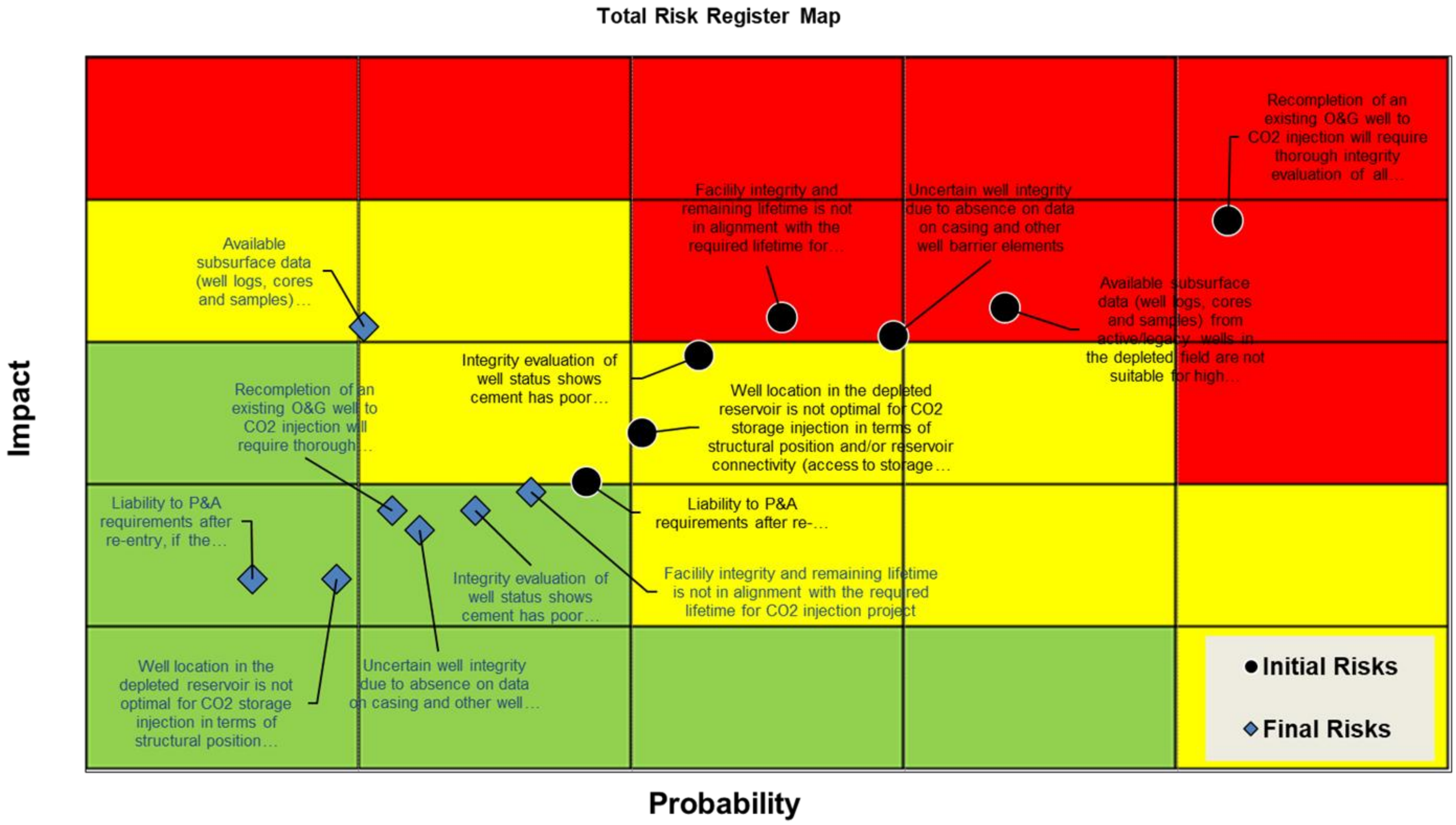


*Figure 7-5: The diagram is a graphical representation of the risk assessment of re-completion an existing well in a depleted oil & gas field into a CO2 injection well. Black dots show initial risk, blue squares show how carrying out mitigating actions may reduce the risk. The text in the diagram is the initial risk as also presented in Figure 7-4.*

## 7.3. Risk Assessment General Project Risks

The risk assessment addresses some general project risks associated with planning and delivery of a $CO_2$ injection well fulfilling technical as well as authority required functionality and integrity during the CCS project lifetime.

| Risk description | Effect | Initial risk | Mitigations | Final risk |
|---|---|---|---|---|
| Cost uncertainty / overruns. | Budget overruns and loss of project economic feasibility | 🟥 | Prepare a realistic and detailed well delivery timeline<br>Prepare contracting strategy for drilling services and suppliers (eg. Rig contractor).<br>Ensure well delivery is carried out by experienced and qualified team.<br>Prepare procurement strategy to capture some financial risks. Tight control of time and budgets. | 🟨 |
| Impurities in industrially captured $CO_2$. | Unpredicted corrosion of tubing and casing. | 🟨 | Project to define $CO_2$ stream composition and quality for design purposes and ensure $CO_2$ capture industry can deliver the required specs. | 🟩 |
| Available subsurface data does not fulfill authority requirements for a storage license. | Storage license is not obtained. | 🟥 | Ensure comprehensive and high-quality datasets are acquired to enable all necessary studies to be performed. Engage with qualified service providers. Ensure experienced subsurface and drilling personnel are part of the project team. Acquire additional data. | 🟨 |
| Unrealistic / tight timeline for delivery of $CO_2$ injection well. | Suboptimal well design, drilling risks, cost overruns | 🟥 | Have experienced and qualified personnel in the well design and planning team. Early engagement with service providers to get information about long lead time equipment and supplies. | 🟩 |
| Unplanned intermittent injection due to vessel delay, bad weather, lack of $CO_2$ supply | Damage to well resulting in compromised integrity, reservoir damage causing lower injectivity and need for well intervention – i.e. shut down of well and additional cost. | 🟨 | Conservative well design, include ranges on design parameters to cater for uncertain $CO_2$ injection rates and periods without injection. | 🟩 |

*Figure 7-6: Risk assessment of general project risks for well delivery of a CO2 injection well.*

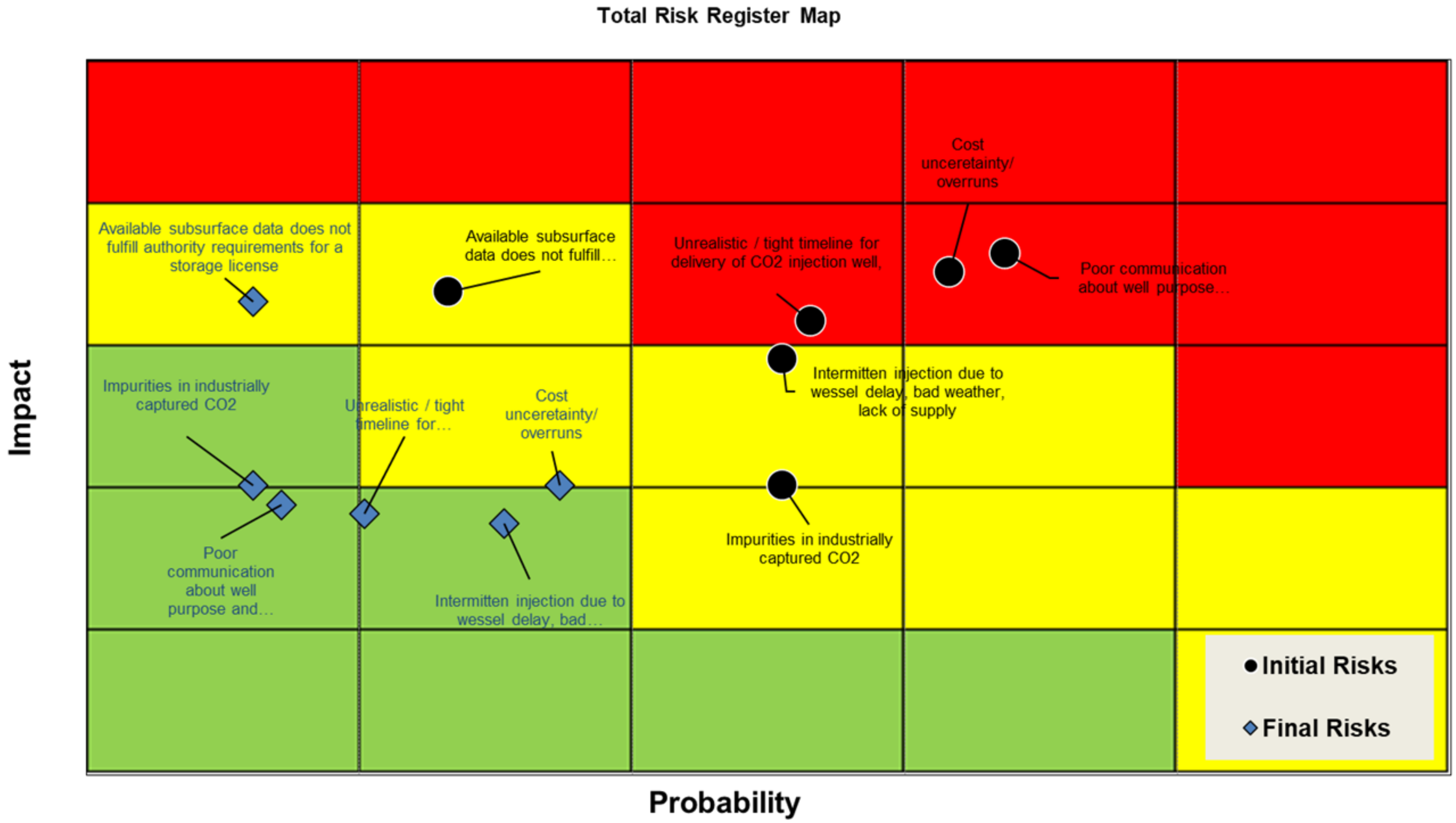


*Figure 7-7: The diagram is a graphical representation of the risk assessment of general project risks related to well design and delivery of a $CO_2$ injection well. Black dots show initial risk, blue squares show how carrying out mitigating actions may reduce the risk. The text in the diagram is the initial risk as also presented in risk the register in Figure 7-6.*

# 8. Concluding Remarks

Successful operations in the offshore environment are highly depending on competent and experienced personnel as well as using high quality equipment and service providers. Making premature decisions on issues such as well location, well design, drilling parameters and data acquisition programs may come with a high cost. Thus, thorough planning through established processes is key to success and highly recommended moving forward.

Underestimating the technical competences needed and time required to carry out subsurface evaluations, well design, planning and drilling, and subsequent subsurface data analysis may come with a high cost in terms of not reaching the project target / goal and / or high time and budget overruns. Since there is a large amount of experience from drilling and re-entering offshore wells, many of the risks can be significantly reduced by ensuring technically competent and experienced personnel are contributing to the project throughout well delivery process.

The well delivery process follows a structured sequence of definition, design, planning, and operations, each contributing significantly to total project duration. Deeper and more complex wells naturally require more time, particularly in design, planning, and operational execution. Procurement of long-lead items and permitting also add substantial time, emphasizing the need for early planning and coordination. While estimated project timeline in the study provide a useful baseline, regional factors and project-specific conditions can cause meaningful variations in overall timelines. Such factors can also cause significant variations on the overall cost of the wells.

The cost analysis presented in this study, shows that deep wells are consistently the most expensive across all phases, driven largely by higher drilling and completion expenses. Intermediate and shallow wells follow similar cost trends but at lower magnitudes, reflecting reduced operational complexity. Re-completion of existing wells is significantly cheaper overall, though certain phases—such as workover or data acquisition—can still represent substantial costs. When contingency is included, total well costs rise notably for all well types, highlighting the importance of robust planning and risk management in budgeting.

The decision whether to drill a new well for $CO_2$ injection or to re-complete an existing well comes with risks and challenges that in some respects are quite different even though the timeline related to the well specific operations for delivery of a $CO_2$ injector may look comparable.

Drilling a new well into an untested aquifer in an untested structure / trap is usually associated with a significant uncertainty on reservoir properties and storage volume. This is a risk for the project business case as well as for designing and delivering the optimum injection well to deliver the required injectivity rates and lifetime.

Re-completion of an existing well may be very complex and time consuming in terms of investigating current integrity and the need for upgrades. In addition, the operations needed to re-complete a well to ensure integrity, functionality and lifetime may be complex and associated with large uncertainty in terms of time and cost. Additionally, the integrity of the old facility and existing wells (active and legacy wells) in the depleted field may need significant upgrades to enable safe $CO_2$ injection storage during the required injection period and storage lifetime which may be a high project risk in terms of time and cost needed as well as authority approvals.

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# Appendix I

Table summarising preliminary well data provided from project teams from each geographical region and how the wells are grouped into shallow, intermediate and deep wells, respectively, based on the depth to top reservoir.

| | **Shallow well** | **Deep well** | **Shallow well** | **Intermediate well** | **Deep well** |
|---|---|---|---|---|---|
| Geographic region | **Baltic** | **NO/NSEA**<br>Sandnes / Bryne formation, middle Jurassic | **Atlantic coast of Portugal** | **DK Danish Basin /Inez** | **Black Sea** |
| Water depth (meters below mean sea level) | 36.5 m | 80-90 metres | 84 | 25-40 | 47 |
| Top reservoir (meters below mean sea level) | 848 | 3000-3100 | 860 | 1600-1650 | 2625 (2700) |
| Reservoir thickness (meters) | 53 | Av. 86m Sandnes, 100m Bryne | 350 | Avg. 148 | <300 |
| Total depth of well (meters below sea level) | 901 (to the bottom of reservoir) | 3655 | 1210 | 1700 – 1800 | 3437 |
| Reservoir lithology | Sandstone with 10% interlayers of clay rocks | Sandnes: massive white, very fine to coarse grained glauconitic sandstone | Siliciclastic deposits of the Torres Vedras Group (Early Cretaceous); 80% sand and 20% clay | L. Jurassic Sandstone | grey sandstones with calcareous cement (Quartz sandstones with calcareous cement, greenish gray, fine to coarse, medium to well sorted with glauconite) |
| Reservoir pressure | 9.3 | Hydrostatic | | Normally pressured | |
| PPFG (Pore Pressure and Fracture Gradient) | No data | Typically 1.3 times hydrostatic | Hydrostatic Gradient: 10.7 kPa/m<br>Pore pressure: 12 MPa<br>Fracture pressure: 16.5 MPa | hydrostatic | |
| Temperature gradient | 4.1°C/100 m | 4 + 31$^{0}$C /km | 28ºC/km | 30gr C / km | Avg. 4.1gr C/km<br>Highly variable (10-80gr C/ km) |
| Reservoir temperature | 36 °C | 116 $^{0}$C @3755 TVD m RKB | 42-45ºC | 155-160 @ 1900 tvd | |

| | **Shallow well** | **Deep well** | **Shallow well** | **Intermediate well** | **Deep well** |
|---|---|---|---|---|---|
| Reservoir porosity (average) | 21 % | Sandnes 21%<br>Bryne 17% | 14% | 20-25 | >= 30% |
| Reservoir permeability (average) | 380 mD | 500 mD (mean) P10 – 900mD | 122 mD ($10^{-6}m^2$) | 400-800 mD | 200 mD |
| Injection rate minimum, average, maximum value | 0.9, 1.0, 1.5 Mt/y (based on experience in other regions with sandstone reservoirs of high quality) | 0.5 Mtpa<br>1 Mtpa<br>2 Mtpa | 0.3 Mton/yr (min); 0.7 Mton/yr (max); 0.5 Mton/yr (avg) | 0.5 Mtpa<br>1 Mtpa<br>2 Mtpa | |
| *Lithology log | From lith-log:<br>Caprock is L. Ordovician claystone and limestone 40-44 m<br>Top seal at 808 to 813 m.<br>Reservoir: M.Cambrian Sst. Top at 849- | | Include a schematic drawing or table as attachment showing main units | | |
| Presence of any lithologies/ formations in overburden known to cause drilling hazards /problems such as overpressured zones, swelling clays, thick chert layers, other? Please describe | During drilling of the well E6 **no hazards** were reported. | | Lithologies from the overburden are mainly composed by carbonates or siliciclastic rocks. | | Based on the publicly available data to date, no overburden lithological formations have been identified that present a significant risk potential during drilling operations. The geological succession does not indicate the presence of over-pressured zones, problematic swelling clays, thick chert layers, or other lithological units known to cause operational difficulties. |