Solveig Segment D - DG1 Report

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1 Introduction

1.1 Purpose

This is the DG1 Report for Solveig Segment D. The purpose of this document is to show how Solveig Segment D can be developed either as a standalone concept or together with Segment B Synrift, as a phase 2 of the Solveig development. Hence, the purpose of this document is to;

- Describe how a Segment D standalone case might look like
- Describe how Solveig Phase 2 (Ph2) as described in PDO (Solveig Ph2 PDO case), will be significantly altered if Segment D resources is included in the Ph2 development (Solveig combined Ph2 case).
- Describe work needed to be done to mature Segment D to Concept select and PDO alone (Segment D standalone case) or together with other Solveig resources (Solveig combined Ph2 case).

Hence, the following names and references are used throughout this document:

- Solveig Ph2 PDO Case: Segment B as described in the PDO
- Segment D standalone: Solveig Ph2 is only one new well in Segment D
- Solveig Combined Ph2 case: Segment D and Segment B developed together
- Solveig Ph2: Either segment D standalone or the combined case (B + D)

1.2 Supporting Documentation

Supporting documents are listed in Section 16 References. Luno II is the original name of Solveig, hence references to Luno II might occur in some references.

All abbreviations are listed in Section 18 Abbreviations.

1.3 Exploration and Licence History

Lundin Energy Norway was awarded the PL359 licence on 6 January 2006 (APA 2005) with Premier Oil Norge AS. There have been several licence transfers, the latest transfer being Lundin Energy Norway's increase in ownership from 50% to 65%, due to purchase of Equinor's share of 15% in 2018. The PL359 licencees are listed in Table 1.1.

The PL359 licence was split into three different areas 6 January 2016, when the second extension beyond the initial 10-year period was approved. Area 1 (PL981) and Area 3(PL338E) were relinquished on 6 January 2018. The work program for PL359 was completed when Solveig PDO was submitted 27 March 2019 and approved 26 June 2019.

The first well in the licence, 16/4-5 (2010), was dry but proved oil shows in faulted/fractured but tightly cemented granitic basement. The Luno II discovery was made by the second well in the licence, 16/4-6 S (drilled in 2013) and was further appraised by the wells 16/5-5 (late 2013), 16/4-8 S (2014), 16/4-9 S (2015), 16/4-11 (2018) and 16/4-13(2020. The discovery consists of four segments; Segment A, Segment B, Segment C and Segment D, with wells in each segment. Solveig Ph1 has drilled three (3) production wells 16/4-BA-1 H/AH (BA-1 H), 16/4-BB-1 H/AH(BB-H) and 16/4-BC-1 H (BC-1 H) and will drill two (2) water injectors 16/4-BD-1 H (BD-1 H) and 16/4-BE-1 H (BE-1 H) in 2021/2022.

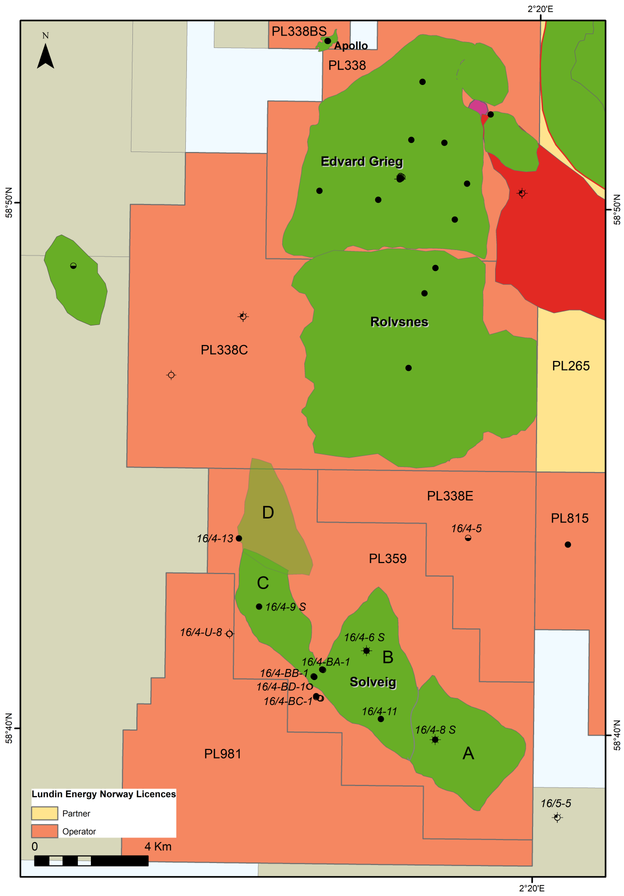

Fig. 1.1 PL359 area map *PL359 was split into Area 1, Area 2 and Area 3 in 2016. Area 1 and Area 3 were relinquished in 2018. These two areas are now PL981 and PL338E, respectively.*

Table 1.1 Licence ownership in PL359

Company	Working Interest
Lundin Energy Norway AS (Operator)	65%
OMV (Norge) AS	20%
Wintershall Dea Norge AS	15%

Well summary
Well 16/4-6 S proved a 40 m oil column with an oil-water contact (OWC) at 1950 m Mean Sea Level (MSL) in a thick sequence of relatively homogeneous sandy sediments with moderate reservoir quality. In total, 280 m of the reservoir sequence was drilled below BCU/top reservoir. The oil is saturated black oil with a thin gas cap. The gas-oil contact is at 1910 m MSL. The reservoir in well 16/4-6 S is 5 bar depleted with respect to hydrostatic and surrounding fields. One production test - Drill Stem Test (DST) was performed in the oil column, which produced at a rate of 2000 barrels per day.

Well 16/5-5 was drilled in late 2013, with the objective of proving extension of the Solveig discovery into the neighbouring licence PL410. The well penetrated a thick sequence of tight and strongly fractured sandstones partly filled with heavy biodegraded oil. The reservoir pressure in the water zone is 1 bar below hydrostatic.

Appraisal well 16/4-8 S drilled in Segment A proved an oil column of around 30 m in a sequence of sandstones with medium reservoir quality. This well is the deepest of the wells and penetrated a 560 m thick sandy sequence resting on top of a 205 m conglomeratic section. The oil-water contact is uncertain, due to a compositional oil gradient, but is probably close to 1940 m MSL. The oil is a moderately biodegraded oil with high asphaltene content. The well proved a gas-oil contact at the same depth as 16/4-6 S (1910 m MSL). The reservoir pressure is approximately 2 bar below hydrostatic. The DST test showed poorer reservoir productivity than expected (450 barrels per day), probably as a result of by two main factors; the faulted and fractured character of the reservoir at the well position and the relatively high viscosity of the asphaltene rich produced oils.

Appraisal well, 16/4-9 S (Segment C), proved an oil column of around 25 m with an oil-water contact at 1954 m MSL. In total, a 374-metre thick reservoir sequence was drilled below BCU/top reservoir. The reservoir consists of a pebbly sandstone overlain by a more conglomeratic sequence with moderate reservoir quality (the Lower Outer Wedge). Well 16/4-9 S proved a light oil. No gas was encountered in the well location; however a gas cap might be present up-dip. The reservoir was 9 bar depleted. One DST was performed in the oil column producing at a rate of 1000 barrels per day.

Appraisal well 16/4-11 was drilled 2.5 kilometres south of the 16/4-6 S discovery well with the aim of confirming that the undrilled formations in Segment B contain reservoir quality rocks. A total oil column of about 20 meters was identified in Triassic Aeolian sandstones with good to very good reservoir quality in the Upper Outer Wedge. The oil/water contact was identified at 1946.5 m MSL. The reservoir rocks, including the water zone, comprise sandstones and conglomerate sandstones, with a total thickness of approximately 400 meters with variable reservoir quality, primarily from moderate to very good. Well 16/4-11 proved a light oil. No gas was encountered in the well location. The reservoir was 9 bar depleted.

The appraisal well 16/4-13 ST2 was drilled to evaluate the hydrocarbon potential of the untested northernmost segment of the Solveig Field, Segment D. Well 16/4-13 S and technical sidetrack well 16/4-13 ST2 proved an oil column of 10 m in conglomeratic sandstone in the target interval (Triassic to Paleozoic age). The oil-water contact was encountered at 1950 m MSL. The entire reservoir interval, including the water zone, consisted of conglomeratic sandstones with a total thickness of around 380 metres. The formation pressures observed in well 16/4-13 ST2 align with the pressures observed in well 16/4-6 S, which was drilled in April 2013.

Extensive data acquisition and sampling were undertaken including conventional coring, side wall coring, pressure measurements and fluid sampling. Wells 16/4-6 S, -8 S and -9 S were production tested (DSTs).

2 Executive Summary

Background
Solveig is a field located in the PL359 licence on the south-west flank of the Utsira High in the Norwegian sector (block 16/4) of the North Sea, also referred to as the Utsira High Area, . Luno II was used as the working name for Solveig until Solveig PDO was approved 26 June 2019.

Fig. 2.1 Location of the Solveig field

Solveig is developed as a phased development where Phase 1 was a firm commitment in the PDO submitted 27 March 2019.

Solveig Ph1 is a subsea tie-back to the EG platform with three (3) oil producers and two (2) water injectors. Production started Q3 2021. In the Solveig PDO, a potential Ph2 was described as one(1) additional oil producer and one (1) additional water injector in Segment B Synrift, tied back to EG via Ph1 subsea infrastructure. Solveig Ph2 was described in the PDO, however subject to a separate investment decision based on the performance of Ph1. Segment D was undrilled at the time of the Solveig PDO submittal. It was drilled in 2020. Including the Segment D resources will significantly alter the Solveig Ph2 Concept.

Solveig is part of PL359, located 15 km south of PL338 EG. Lundin Energy Norway acquired Equinor's 15% share in PL359 in 2018. Ownership in both licences is thus completely aligned, with Lundin Energy Norway holding 65% (Operator), OMV (Norge) 20% and WintershallDea Norway 15%. This alignment of ownership interests allows for optimisation of production and value from both fields flowing through the EG facility.

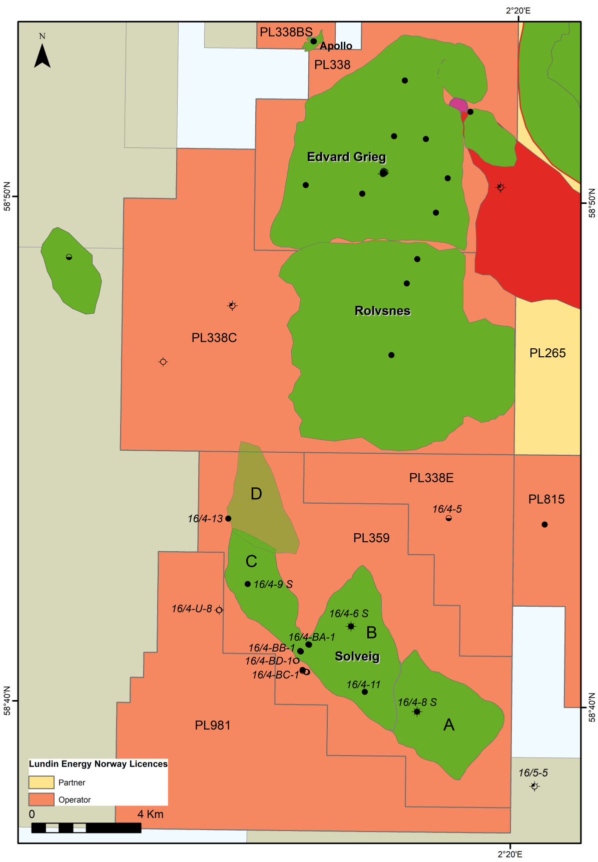

Fig. 2.2 PL359 area

The Solveig discovery has been penetrated by five(5) exploration wells in Segments A, B (2 off), C and D. In Segment A the asphaltene content dissolved in the oil is high and further work is needed to mature these resources. For this reason, Segment A was not included in the Solveig PDO. Segment D was drilled after Solveig PDO submittal.

Solveig Development Concept

Solveig is a subsea tie-back to the EG platform. Solveig Ph1 has three (3) oil producers and two (2) water injectors with production started Q3 2021, ref. Fig. 2.3. Satellite wells was chosen to allow for optimal well placement and reduce drilling and completion risks.

The Segment D standalone case is one (1) oil producer combining a depletion section in Segment D with an infield section in Segment C. The well is tied back to EG through Solveig Ph1 subsea infrastructure, ref. Fig. 2.5

Including the Segment D standalone case into the Solveig Ph2 development will give the Solveig combined Ph2 case shown in Fig. 2.6, with two(2) producers and one (1) water injector targeting resources in Segment B Synrift, Segment C and Segment D.

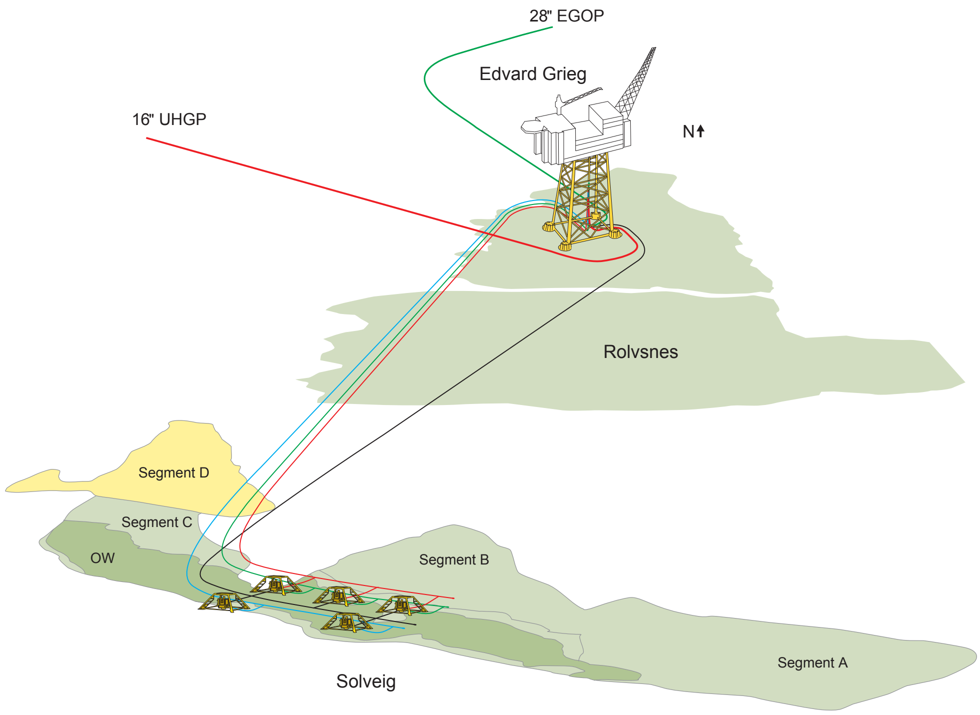

Fig. 2.3 Solveig Phase 1 field layout *Solveig is connected to EG through umbilical (black), production flowline (green), gas injection pipeline(red) and water injection pipeline (blue).*

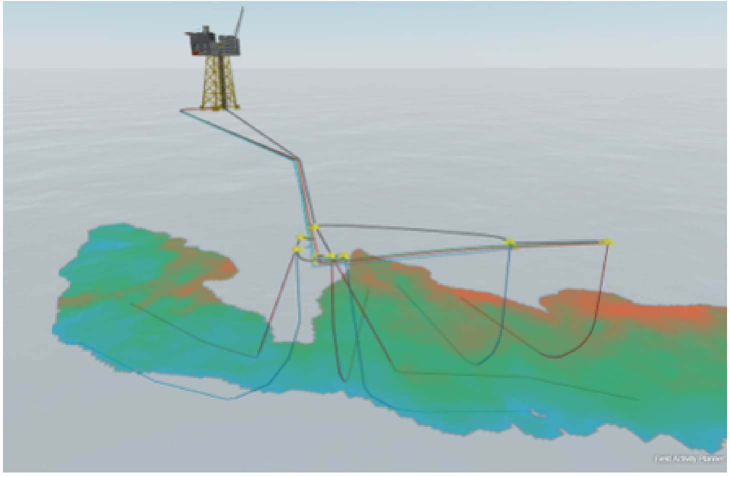

Fig. 2.4 Solveig Ph2 PDO case *The figure shows Solveig Ph1 and Solveig Ph2 as described in the PDO*

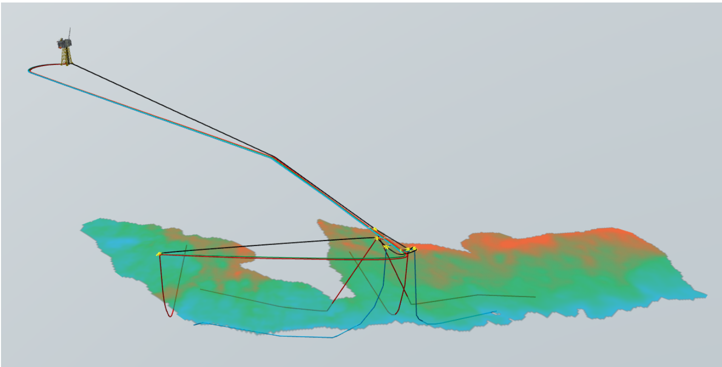

Fig. 2.5 Solveig Segment D standalone case *The figure shows Solveig Ph1 development together with the Solveig Segment D stand alone case*

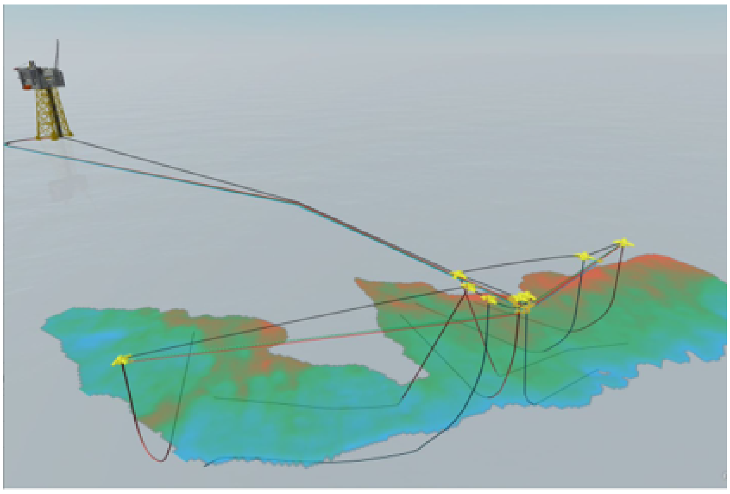

Fig. 2.6 Solveig combined Ph2 development *The figure shows Solveig Ph1 and Solveig combined Ph2 case*

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Stabilised oil is transported through EG Oil Pipeline (EGOP), Grane Oil Pipeline (GOP) and stored at the Sture terminal (OTS) for further offloading to the market.

Rich gas is transported through Utsira High Gas Pipeline (UHGP) to the Scottish Area Gas Evacuation (SAGE) System. At the SAGE terminal in St. Fergus the rich gas will be separated into sales gas and NGLs. The sales gas enters the market at National Transmission System (NTS) inlet and the NGLs is transported to Shell Esso Gas and Associated Liquids (SEGAL) fractionation plant at Mossmorran. NGL products are stored and offloaded at Braefoot Bay.

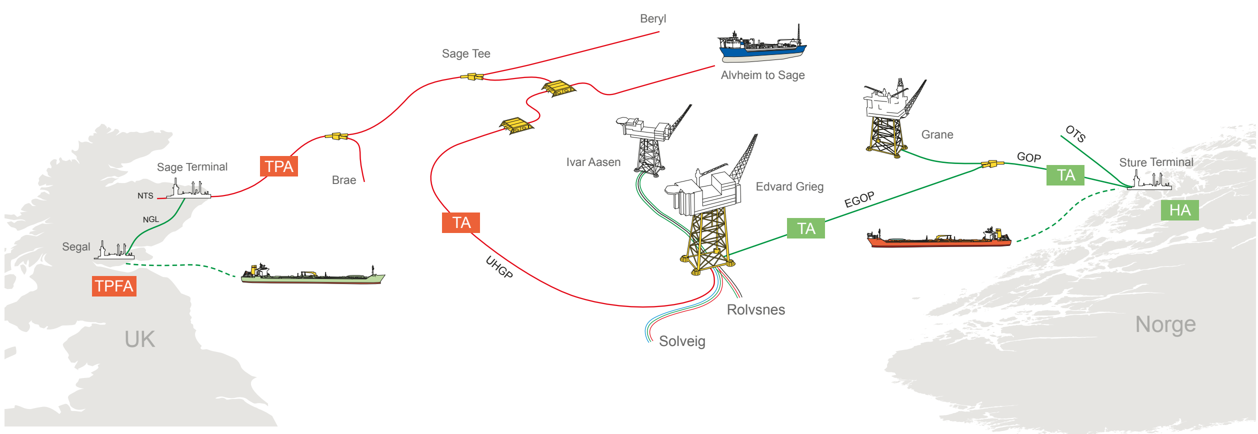


Fig. 2.11 Solveig infrastructure *//TA: Transport Agreement // TPFA: Transport, Processing and Fractionation Agreement // HA: Handling and storage Agreement // TPA: Transport and Processing Agreement*

Project Execution Plan

The execution plans for Segment D standalone case and Solveig combined Ph2 case are shown in Fig. 2.12 and Fig. 2.13, respectively. The planned first oil date will be reviewed before PDO submission to reflect the results of actual Solveig production and the influence of other projects/market effects etc.

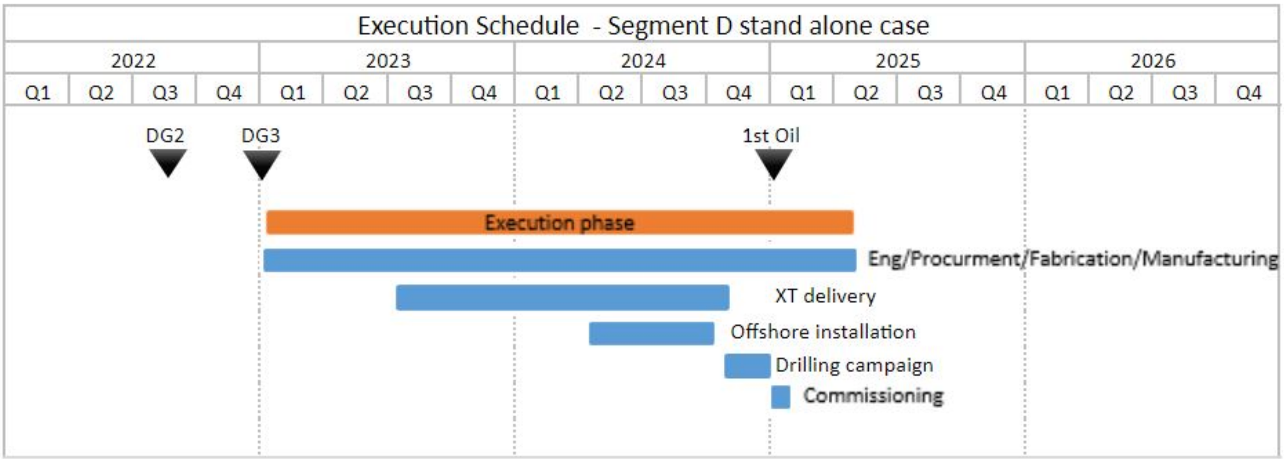


Fig. 2.12 Execution schedule for the Segment D standalone case

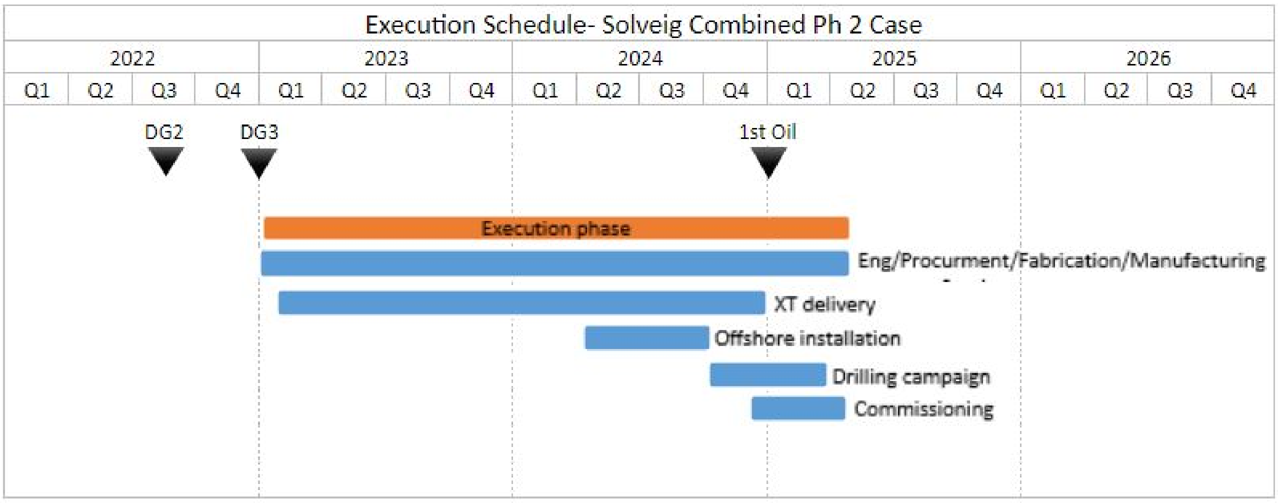
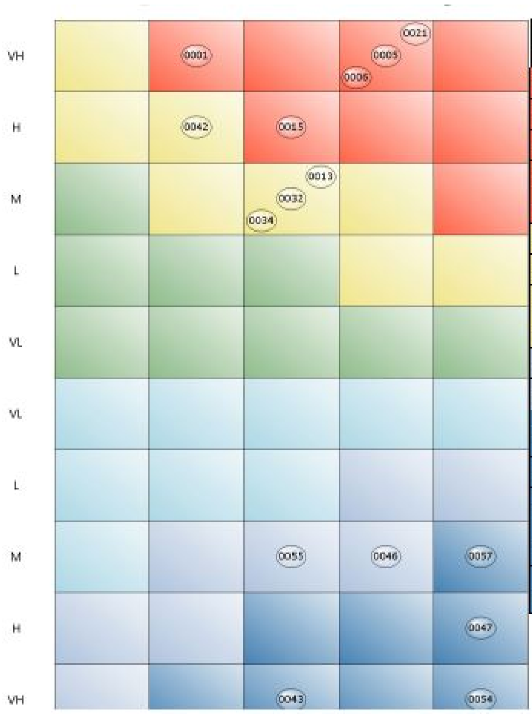


Fig. 2.13 Execution plan for Solveig combined Ph2

Project Risks and Mitigations

The top 10 risks for Solveig Ph2 (Segment D or Combined B/C) development as pr. November 2021. The risks will be continually updated and e.g the BC-1H well risk with resources being too low should be updated to recoverable resources being too low.



Risk ID	Title
P-0005	Solveig Ph2 resources too low
P-0006	Solveig BC-1H resources too low
F-0021	Upturn in SURF & SPS market leading to increase in cost/availability
S-0001	Production experience from Solveig coming too late
F-0015	Too tight schedule pre DG3
D-0042	Crater developing during drilling of top holes
D-0032	Limited planning time/equipment lead time
D-0034	Shallow gas
F-0013	Contractor capacity
F-0055	EG well known host
P-0046	Project Organisation
P-0057	Well establihed Partners in lisence which has delivered Edvard Grieg and SOlveig Phase 1 together
P-0043	Favourable tax regime for PDO submission within 2022
P-0044	Project Synergies
P-0047	Contracting Strategy
P-0054	Utsira High is a well established area

Fig. 2.14 Top 10 risks: threats and opportunities

Project cost and economics
Total investments for the Segment D standalone case amount to 1 922MNOK$_{22}$. For the Solveig combined Ph2 case the total cost increase to 3 889MNOK$_{22}$, ref Table 2.2.

Total operational expenditures for Solveig Segment D standalone amount to 661MNOK$_{22}$. Approximately 55% relates to direct field operating costs and G&A, 15% relates to transportation tariffs and 30% relates to power and environmental costs. The total operational expenditures for Solveig combined Ph2 amount to 1 702 MNOK$_{22}$.

Total income for Solveig Segment D standalone amounts to 3 222 MNOK$_{22}$, split between 90 % liquids and 10% sales gas. Total income for Solveig combined Ph2 amounts to 8 406 MNOK$_{22}$, split between 83% liquids and 17% sales gas.

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Valuation
Table 2.3 shows a summary of the project economics at 60 USD$_{22}$/bbl.

In the Solveig Segment D standalone case, after tax (a.t.) NPV7 (real) amounts to 183 MNOK, with break-even oil price at 44 USD$_{22}$/bbl and real IRR at 23%. The tornado in Fig. 2.17 shows that economics of the project is highly sensitive to oil price, volume and also CAPEX. Furthermore, pre-tax economics are also marginal for the Segment D Standalone case.

The Solveig combined Ph2 case yields significantly improved economics with break-even oil price at 37 USD$_{22}$/bbl and real IRR of 33 % after tax. Economics are also significantly improved on a before tax basis. The improvement relative to the Standalone case is is primarily due to the lower investment (23 USD$_{22}$/bbl) required to produce the additional 10 mmboe in this case, ref. Fig. 2.63.

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3 Area Assessment

3.1 Tie-in to Existing Local Infrastructure

All services (tie-in, processing, gas lift, water injection, chemicals, power and controls) will be supplied by EG, ref. Section 8 Use and Modifications of Existing Facilities. Solveig Ph2 wil be connected to EG through Ph1 subsea infrastructure.The services are provided from EG to Solveig Ph1 via:

- Single 10" Pipe-inPipe (PiP) production pipeline, with pipeline end Manifold (PLEM) with subsea connection point for future phases
- 8 " water injection pipeline, with pipeline end Manifold (PLEM) with subsea connection point for future phases
- 4" Gas lift pipeline, with pipeline end Manifold (PLEM) with subsea connection point for future phases
- Umbilical, with Tie-in point at the first Integrated Sattelite Structure for future phases

The EG platform is connected to Oseberg Transport System (OTS) through the Edvard Grieg Oil Pipeline (EGOP) and Grane Oil Pipeline (GOP) and to the Scottish Area Gas Evacuation System (SAGE) through the Utsira High Gas Pipeline (UHGP), ref. Section 13 Commercial Agreements

3.2 Alignment with Development of Other Local Deposits

There is potential for contingent and prospective recoverable resources in the area, both within PL359 and in the neighbouring area (e.g. PL338C and PL167), Fig. 3.1 .

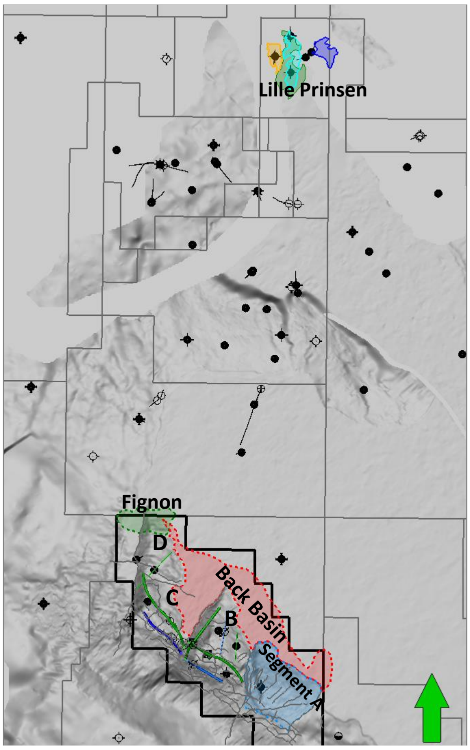

Fig. 3.1 Prospective resources on the Haugaland High

3.2.1 Segment A

Segment A was appraised by well 16/4 8 S, which proved different pressure and OWC in relation to Segment B. A continuous sedimentary package is present between the two segments, however, a heavily faulted and fractured zone just west of 16/4-8 S is thought to be the barrier between the segments. The Outer Wedge is present only at the very tip of Segment A. Although the well shows fair reservoir properties in fluvial-aeolian sandstones, the produced oil encountered in 16/4-8 S is asphaltene-rich. The asphaltene content of the produced oil increases towards the OWC where maximum produced oil asphaltene content can be as high as 35% by weight. The Solveig project is not familiar with any chemicals that will enable production of oil with this high asphaltene content through the Solveig Subsea Production System (SPS) and EG process system. Laboratory testing of mixing Segment A oil samples with samples from Segment C and EG has been conducted with negative results. Further work will be required to move Segment A resources into an upside scenario. Segment A was therefore not included in the field development plan at this point.

3.2.2 Prospective resources in PL359

Fignon and back-basin prospects are seen as future potential phases of the Solveig development. The plan is to further mature these prospects. Fignon is a strong amplitude anomaly which coincides with a four-way structural closure at top Utsira Formation. The Utsira Formation comprises 100-200m of mature well-sorted, fine-medium grained sands. Oil fill is possible; however, the main risk in the prospect is the fluid type, especially since gas was found in the PL674 BS Zulu structure, also showing a similar amplitude anomaly as Fignon. The PL359 back-basin area has reservoir potential in porous fractured basement similar to what is proven in Rolvsnes and Tellus (16/1-12, -25 S, 16/1-28 S and -15). There is a chance that thin remnants of Jurassic/Cretaceous sands may be locally preserved on basement. The back-basin area will be further evaluated in light of the results of the Rolvsnes Extended Well test in PL338C, which started in Q3 2021.

3.2.3 Rolvsnes

Rolvsnes is situated just south of EG on the Utsira High in licence PL338C, another Lundin Energy Norway operated licence.

On the Utsira High, basement rock comes up into the area oil column at some locations. Several wells have been drilled into basement, most finding hard, tight granite, but finding weathered basement in the north (Tellus) and the south (Rolvsnes) of EG.

The strategy for development of the basement rock reservoir in Rolvsnes is stepwise testing and development, allowing for early reservoir experience with limited economical exposure, delayed costs and early production.

The first step of testing was performed by the formation test of 16/1-28 ST2 in August 2018. The test proved that it is possible to drill long horizontal wells in granite basement with alternating hardness, and that the well can be completed with a high number of isolating packers, thus achieving close to zero formation damage; hence connecting to the natural productivity and allowing for production to the full potential of the reservoir at the well location.

The second step is EWT which started in Q3 2021. The Rolvsnes EWT has been developed as a subsea tie-back to the EG platform. Rolvsnes EWT and Solveig Ph1 were handled as one project in the execution phase, together with the topside modifications on EG. Synergies with regards to project organisations, mob-demob of vessels and rig etc gave significant reduction in cost and risk for all three projects.

Development of Solveig Ph2 together with Rolvsnes full-field is a potential opportunity which will be evaluated in the Concept and FEED phase.

3.2.4 Lille Prinsen

Lille Prinsen is in PL167, which is another Lundin Energy Norway operated licence. The Lille Prinsen project will be mature in parallel with Solveig Ph2 and Rolvsnes full-field. It will be focus on ensuring synergies between the three projects where applicable.

4 Societal Ripple Effects

Asplan Viak will perform an analysis of the societal ripple effects of the development project on behalf of Lundin Energy Norway. The analysis will be included in the application for approval of fulfilled impact assessment to the authorities.

5 Reservoir description and drainage strategy

The Segment D reservoir basis is described in this Chapter and is further documented in 2021 Resource Committee meetings [50, 51, 52]. More detailed 16/4-13 S well results can be found in the Final Well and Discovery reports [48, 49]. The 2020 H1 Case A dynamic model used for Segment C infill potential evaluation is documented in a 2020 RC meeting [55].

The Segment B Synrift reservoir basis is not described in this document. Reference is made to the Solveig PDO Subsurface report [4] for reservoir modelling, well placement, production technology and development strategy and to the Q4 2021 Resource Committee meeting [53] for the volumetric update based on the development well results.

5.1 Geology and geophysics

5.1.1 Geological setting and stratigraphy

The Solveig Field is located in PL359 in a series of sub-basins on the South-Western margin of the Haugaland High (southern Utsira High) as illustrated in Fig. 5.1. The reservoirs in the Solveig Field are sandstones and conglomeratic sandstones of Triassic to Paleozoic in age. At the Basement level the Utsira High is segmented into larger and smaller sub-basins, with the Solveig Field sub-basin including a series of half-grabens bounded by a steeply dipping basement surface to the east. The Solveig Field can be split into 4 segments A-D (Fig. 5.2). Segment D is the northernmost segment and was appraised by well 16/4-13 ST2 during Q1 of 2021. Well 16/4-13 ST2 is the sixth well drilled in PL359 and the fifth well on the Solveig Field structure. The Solveig Field structure, including the Segment D discovery itself is a combined stratigraphic and structural trap which at the BCU is a regional four-way dip closure. Cretaceous marls and chalk constitute the top seal and dip seal towards the west and south with a stratigraphic pinchout against the basement making up the seal towards the east and the north.

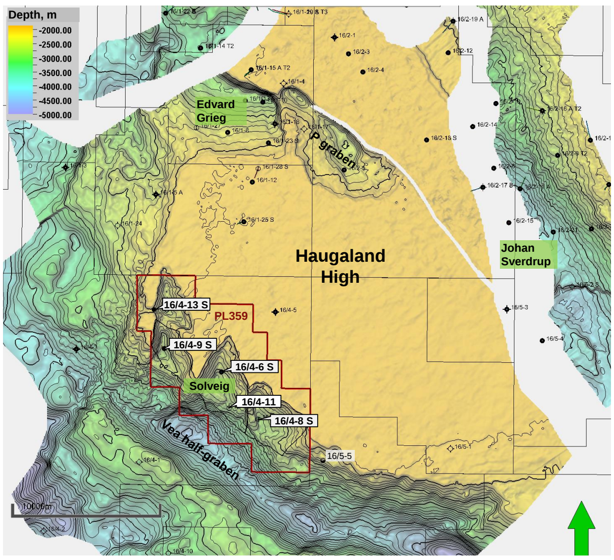

Fig. 5.1 Top Basement depth map of the Utsira High

There are two main reservoir intervals in the Solveig Field Fig. 5.3. The upper "Outer Wedge" reservoir is probably of Triassic age, and the underlying "Synrift" reservoir is probably Paleozoic and either Permian or Devonian in age. The two reservoirs are separated by a major angular unconformity. The Synrift sediments typically dip at 15-20 degrees to the WSW whereas the overlying Outer Wedge sediments are associated with shallower dips of around 10 degrees to the SW. The Synrift reservoir is underlain by coarse-grained "Basal Conglomerates" which are primarily non-reservoir. These conglomerates are interpreted to lie directly on Caledonian Basement.

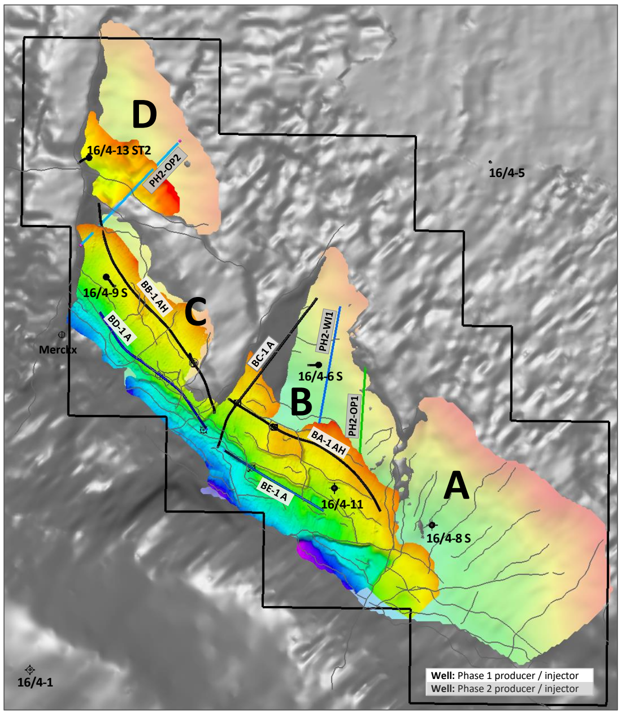

Fig. 5.2 Solveig Field, Segment A, B, C and D

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The Triassic Outer Wedge reservoir was deposited in a desert environment and includes, aeolian, fluvial and alluvial sediments. The sediments are thought to represent an idealized proximal to distal evolution of facies within a wadi setting Fig. 5.4. The reservoir has been subdivided into 2 main units. The Lower Outer Wedge is a widespread conglomeratic unit which was deposited directly on the major unconformity. In Segment B, in the 16/4-11 well, the Lower Outer Wedge is overlain by fluvial and high quality aeolian sandstones of the Upper Outer Wedge. In Segments C & D, the Upper Outer Wedge is characterised by coarser-grained and more proximal facies including pebbly sandstones deposited in a distal alluvial fan environment.

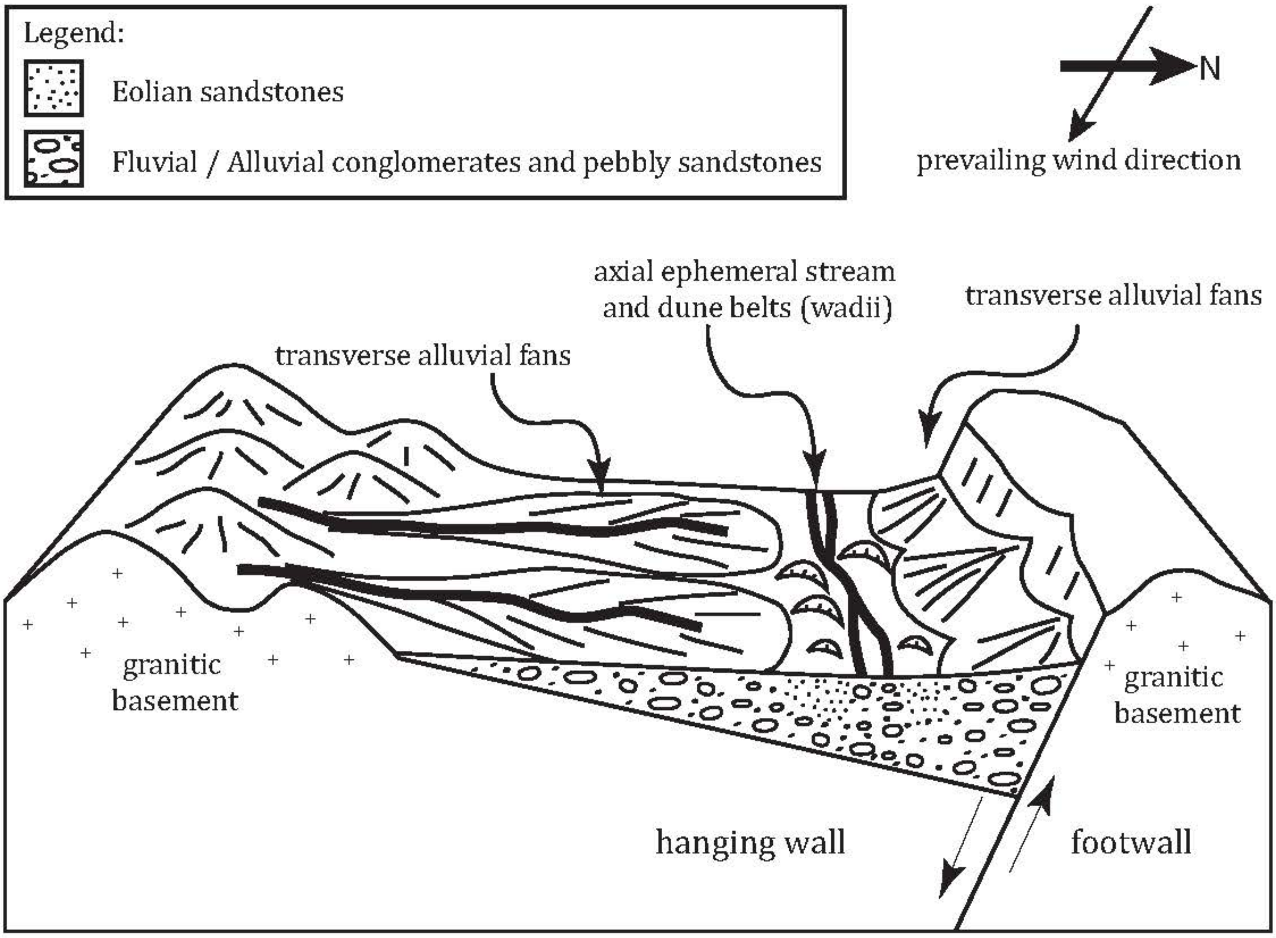

Fig. 5.4 Conceptual model of the Solveig Field Outer Wedge Reservoir.

The Paleozoic Synrift reservoir was also deposited in a desert environment. The Synrift has however probably been buried to depths of over 3 km and and is generally of lower reservoir quality than the overlying Outer Wedge.

A log correlation between the 16/4-13 ST2 and the 16/4-9 S wells of Segments D & C is illustrated in Fig. 5.5.

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The uncertainty in the depth prognosis of the Top Reservoir level was estimated to be +/- 20 m. The Top Reservoir/BCU came in 9.4 m TVD deeper than prognosed. The updated plane BCU-map post 16/4-13 ST2 is generated with trend-lines curving parallel to the south-western corner of the high (Fig. 5.8 C). Later drilling of the BB-1 AH production well along Segment C the Top Reservoir came in close to this map.

The internal reservoir reflectors in the Segment D are depth converted individually using constant velocities based on the sonic measurements in 16/4-13 ST2. The internal reservoir velocities correspond well with observations in the existing Solveig wells. Lower Outer Wedge (LOW) was correctly identified on seismic.

5.1.3 Petrophysical interpretation

The Upper Outer Wedge interval consists of fine- and coarse-grained sandstones and matrix supported pebble conglomerates, with the best facies represented as thin strata. The variability of the these shifting facies is challenging for the logs to capture, hence they are possibly undershooting the best intervals. At the same time, though, they will also be overestimating the poorer intervals. The hydrocarbon fluorescence on the UV-photos of the A-cut is moderate with the thin (< 1 dm) intervals with well sorted sandstone having the most pronounced hydrocarbon fluorescence. There are currently some uncertainties related to the general reservoir properties as there is a considerable discrepancy between the dynamic properties from the XPT and the permeability measurements from CCA. See Fig. 5.9 for comparison between statistically sampled CCA plugs (black), CCA plugs from specifically chosen facies (red) and XPT mobilities (blue). The best parts of this zone are having good properties, albeit in thin intervals.

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The Lower Outer Wedge is comprised of conglomerate with clasts varying in size from pebbles to cobbles. Both matrix- and clast supported conglomerates are observed. The reservoir properties for this is poor, as only occasional coarse sandstone intervals are observed.

The Lower Synrift consists of bedded sandstones with occasional thin conglomeratic layers. The highest porosity is found at the upper half of the zone. At the same time, though, there appears to be a higher content of clay and fines over the same interval. The mobility measurements are single to double digits and the reservoir properties are considered moderate.

The Basal Conglomerate zone is comprised of sequences of coarse/pebbly sandstones at the top and trends towards clast supported towards the bottom. The zone is considered non-net as the porosity is low. Only tight formation tests were obtained. There is a heavily altered transition zone from 2376 m MD down to the basement zone.

The Basement zone is fractured and altered. Two depths with occasional elevated porosities were assessed with the XPT tool and yielded ~1 mD/cP mobilities and supercharged pressures.

The average reservoir properties for the reservoir sections are shown in Table 5.1

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5.2 Reservoir engineering

The Segment D simulation model was built from the Segment D static model described in the previous chapter. Grid size used is the same as in the static grid (25m by 25m cells laterally with 1-2 m thick cells vertically). A large part of the static grid is deep into the aquifer and cells deeper than 2100 m were de-activated in the simulation model to save simulation time. The pore volume of the de-activated cells was added back to the lowermost cell in each grid column of the active grid. The bottom aquifer pore volume is approximately 8 times the hydrocarbon zone pore volume. No additional regional aquifers have been considered at this point. A view of the grid is given in Fig. 5.15.

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Additionally, the previously developed Solveig full field simulation model 2020 H1 Case A v2, was used for evaluating Segment C infill potential in conjunction with Segment D development wells. This model is not described further in the DG1 report, but relevant references are found at the beginning of the chapter.

Segment C and D have different oil characteristics, pressures and oil-water contacts. Hence it is assumed no flow between segments will take place and the models are run separately.

The Segment C Outer Wedge oil from 16/4-9 S is a light crude with a stock tank density of 835 kg/Sm3 (38° API) and a low viscosity of 0.28 cp. The oil has an asphaltene content of less than 1 %. The gas-oil ratio varies between 220-240 Sm3/Sm3 in the oil column. The Segment D oil from 16/4-13 ST2 is more similar to the Rolvsnes oil than to any of the other Solveig oils. The stock tank density is 847 kg/Sm3 (36° API), the oil viscosity is 0.44 cp and the gas-oil ratio is 160 Sm3/Sm3. The oil has an asphaltene content of less than 1 %.

No gas-oil contact has been found in either segment. Predicted gas-oil contact from PVT in 16/4-13 ST2 is 1844 m TVD MSL, well above the top of the reservoir. In 16/4-9 S a possible gas-oil contact between 1913 and 1926 m TVD MSL was predicted with 1921 m TVD MSL as the most likely depth. This depth is used in the Segment C simulation model. Fig. 5.16 shows predicted GOC from PVT.

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Asphaltene content was measured on core chips throughout the oil column of 16/4-13 ST2. The asphaltene distribution pattern resembles what was found in the 16/4-9 S well (dispersed), but with less overall weight of extracted asphaltene per unit weight of rock. Asphaltene corrections are made the same way as described for Segment C in the Solveig PDO. The estimated porosity correction from asphaltene is shown in Fig. 5.17 and compared with the corresponding porosity correction made in 16/4-9 S.

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5.3 Drainage strategy

Current reservoir drainage strategy for the Segment D stand-alone case is depletion drive using one horizontal producer. This well is extended to also cover an in-fill target in the north-western corner of Segment C. Segment C is developed with water injection pressure support in Phase 1. The in-fill target may thus experience some water injection support. Segment C injection is not expected to affect Segment D. Differences in pressure, oil water contact and oil composition are too large to allow direct communication.

The well design has a reservoir section of 2800 m and smart completion to allow for production optimization. The smart completion is placed to separate Segment C from Segment D in the well. Different well placement options have been tested and the well selected for the Segment D stand-alone case (Ph2-OP2) is shown in Fig. 5.18 together with the Phase 1 Segment C wells (producer BB-1 AH and water injector BD-1 H). Completion depth is set to 1931 m TVD MSL, 19 m above the oil-water contact.

In-fill well potential in Segment C was estimated before BB-1 AH drilling was completed. The potential was estimated from Segment C simulation model assuming the BB-1 AH well shown in Fig. 5.18. Actual drilled trajectory and completion of BB-1 AH together with geological interpretation of well results and production experience will be included in further evaluations of the Segment C in-fill potential towards DG2.

The well will be connected to the Solveig-Edvard Grieg pipeline via a single subsea satellite manifold.

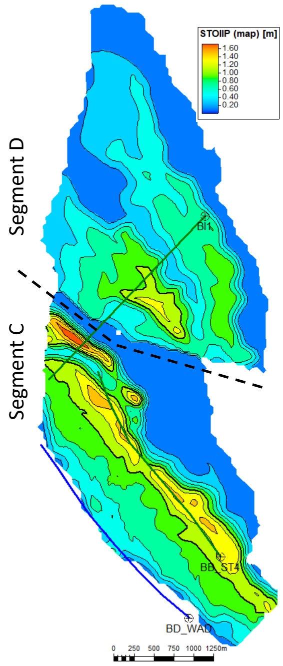

Fig. 5.18 Well layout. for the Segment D stand-alone case *Phase 1 Segment C wells shown together with the Segment D stand-alone case well for development of Segment D. Displayed Segment C wells are the ones used in the Segment C simulation model to estimate in-fill well potential and not actual drilled wells. Well names correspond to those used in the simulation model.*

5.4 Production profiles

Simulated oil production profiles for Segment D are shown in Fig. 5.19, together with the simulated infill profile from Segment C. The gas production profile is shown in Fig. 5.20. In the Segment D simulation model the producer flows through a 5.5" vertical lift performance curve to the subsea manifold. Minimum manifold pressure during production is set to 45 bar. The infill well in Segment C is simulated in the Solveig full field model (2020 H1 Case A v2) and controlled by the production network. Peak oil production rate from Segment D is around 1000 Sm^3/sd, with a fast decline so that first year production averages 569 Sm^3/cd. The profiles are unconstrained by any potential capacity limitations down-stream the test separator. These profiles together with the Segment B Synrift profiles are also found in 17.1 Tabulated Production Profiles.

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5.5 Production technology

The completion scenario assumed for the Solveig Segment D stand-alone case is a smart well completion similar to the Solveig phase 1 completion design with one zone producing from Segment D and the other zone producing from Segment C. Water injection is part of the Segment C phase 1 development so seawater breakthrough must be accounted for in this part of the well. The Segment D part of the well will not experience seawater breakthrough in the Solveig Segment D stand-alone case since a water injector is not included. This segment is assumed to be produced by pressure depletion. The formation water sample from 16/4-13 ST2 shows higher levels of barium than in the water sample from 16/4-9 S. The likelihood of downhole scaling in the reservoir section of the Segment D part of the horizontal well is minimal as long as water injection is not part of the development scenario. However, where the water from the Segment D commingles with the water from Segment C there is a significant potential for scaling and as this area is most likely upstream of any scale inhibitor injection point there will be a need for scale squeeze since water injection is part of the Segment C development scenario. Smart well solution enables the two zones to be produced individually in order to minimize any issues from commingled production. Gas-lift is needed for well start-ups and for production optimization with increasing water cuts. A multiphase flow meter (MPFM) is installed on the well for a robust measurement solution. Downhole scale inhibitor injection should be accounted for but downhole asphaltene inhibition is not expected to be needed based on the phase 1 drilling and production experience.

5.6 Recommendations for next phase

The reservoir description focus for the next phase will be to integrate fully the well results and lessons learned from the 16/4-13 ST2 well in the reservoir models. The results of the Segment C horizontal producer and pilot wells (16/4-BB-1 AH and H) Fig. 5.2 also have impact on the interpretation of Segment D and adjacent northern area of Segment C. In particular the toe section of the 16/4-BB-1 AH well may have significant implications for the area and understanding of reservoir distribution.

Geophysics:

Geophysical activities for the next phase will include the following.

- Update of depth conversion and structure maps incorporating recent wells result including the 16/4-13 ST2 and 16/4-BB-1 AH wells.
- Update of the seismic horizon and fault interpretation on latest seismic processing of merge survey LN19M07 (to be finished early 2022).
- Re-evaluation of the segment boundary (bounding faults) between Segments D and C.

- Re-evaluate the amplitude variability observed in the Eastern part of Segment D directly under the Chalk.
- Depth uncertainty study including learnings from Edvard Grieg

Geology and Reservoir Model:

New geological models incorporating new well data, geophysical and petrophysical interpretations and updated geological understanding will be built. The models will cover the Segments D and C so as to allow evaluation of Segment C infill potential together with Segment D production.

Petrophysics:

Continue the analysis of the data from 16/4-13 ST2 well:

- Further assessment of core data, including core viewing for subsurface team.
- Processing of NMR data to obtain better match between K_{NMR} and K_{CCA}.
- Φ/K-modeling.
- Updated saturation models incorporating results of MICP data from 16/4-13 ST2.

Reservoir and Drainage Strategy:

- Post-BB-1 H update of Segment C in-fill potential with basis in updated geological models and production experience.
- Potential for multilateral production well.
- Potential for water injection.
- Uncertainty analysis.

Production Technology:

- Evaluate consequences of other reservoir drainage mechanisms and methods.
- Use experience from phase 1 production and injection to further optimize future well design.

6 Drilling and Completion

This section provides a summary of the completed drilling and well work.

6.1 Drilling Concept

The Segment D, Ph2-OP2 well will be developed as a single subsea satellite tied back to the EG-platform via Solveig Ph1. The well is assumed being drilled from a dual derrick or highly efficient semi-submersible drilling unit with offline capability. The drilling concept complexity level of the Ph2-OP2 well is considered similar to the Solveig Ph1 wells, see Table 6.1 , hence planning and execution will largely be based on D&C experiences from the Solveig Ph1 campaign.

Table 6.1 Overview Solveig wells (phase 1 & 2)

Phase	Sequence	Well name	Description	Lengths			Segment	Completion	
				Total	Pilot	Reservoir		Lower	Upper
1	1	BA-1 H/AH	Horizontal OP in Outer Wedge	5225 m	614 m	2829 m	Segment B	Screens	Smart
	2	BC-1 H	Horizontal OP in Outer Wedge/Synrift	5000 m	-	2630 m	Segment B	Screens	Smart
	3	BB-1 H/AH	Horizontal OP in Outer Wedge/Synrift	6312 m	490	3872 m	Segment C	Screens	Smart
	4	BE-1 H	Horizontal WI in Outer Wedge	3890 m (planned)	-	1724 m (planned)	Segment B	Screens	Conventional
	5	BD-1 H	Horizontal WI in Outer Wedge	5200 m (planned)	-	2600 m (planned)	Segment C	Screens	Conventional
2	6	Ph2-OP1	Horizontal OP in Synrift	4115 m (planned)	-	1775 m (planned)	Segment B	Screens	Conventional
	7	Ph2-WI1	Horizontal WI in Synrift	4838 m (planned)	-	2485 m (planned)	Segment B	Screens	Conventional
	8	Ph2-OP2	Horizontal OP in Outer Wedge/Synrift	5316 m (planned)	-	2760 m (planned)	Segment C/D	Screens	Smart

Table 6.2 Phase summary

Number of wells	1 OP
Total rig days (incl. rig move)	70
Drilling and completion days	66

The well will be planned and executed according to the prevailing revision of NORSOK D-010 and Lundin Energy Norway's governing documents. It is planned with a 2D well profile to reduce risk of wellbore stability problems in the overburden. The basic plan is to kick off the well from vertical direction around 700 mTVD MSL and build up inclination to ±40°. Then a tangent section will be drilled until close to the bottom of the Lower Hordaland Group where inclination will be built to land the well horizontally in the reservoir section. In addition to wellbore stability, the tangent section is important to mitigate buckling when running lower completion in the ±2760 m horizontal reservoir section. The wellpath, which is planned with a DLS<3°/30, will be further optimized and planned in detail during the next planning phase, see Fig. 6.1

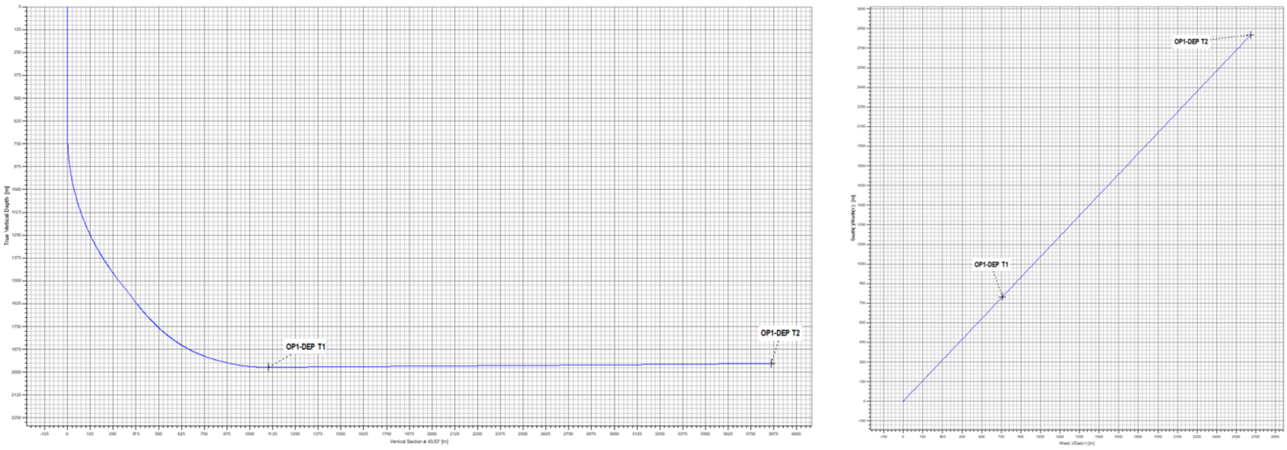


Fig. 6.1 Section- and plan view of the BI-1 H well

According to the plan, drill cuttings from the top hole sections will be disposed on the seabed. Sections with water based drilling fluid will have return to the rig where the fluid will be screened before the solids are disposed to sea. Cuttings from sections with oil-based drilling fluid will be transported to shore for destruction. The final fluid program will be concluded based on the final well profile, geo-mechanical considerations, further engineering and conclusions/lessons learned from Solveig Ph1.

The material selection will in the base case be equal as for Solveig Ph1. The well shall be designed with gas lift, and the material strings for the oil producers with gas lift have been designed with carbon steel with sour service classification to ensure robustness towards Sulfide Stress Cracking (SSC) if H_2S is present in the lift gas. This aligns the Solveig well design with specifications on Edvard Grieg topside and lift gas pipeline from Edvard Grieg to Solveig with acceptance of up to 50 ppm H_2S in the lift gas coming from Edvard Grieg. This design will also allow for a tubing leak scenario where the production casing/liner can be exposed for reservoir fluid with up to 80 ppm H_2S as stated in the Solveig design basis.

The base case well program consists of a standard 4-string design with the hole sizes, tubular types and setting depths as outlined in Table 6.3. A 10-3/4" tie-back casing is included to allow for gas lift in the production wells and to allow for sufficient hole cleaning capabilities when drilling the long horizontal sections. An evaluation on the use of a production casing (instead of liner w/tieback) will be concluded based on Solveig Ph1-experiences.

Table 6.3 Casing program

Hole size	Csg size	Comment	Setting depth
42" x 36"	36" x 30"	Conductor	±77 m below seabed
26"	20"	Surface casing	±50 m MD above Utsira Formation
17 ½"	13-5/8"	Intermediate casing	In lower part of Hordaland Group ±80 m TVD above Top Horda fm
12 ¼"	10-3/4"	Production tie-back	Set ±10 m MD inside Shetland Group
12 ¼"	9-5/8"	Production liner	
8 ½"	Sand screens		

A preliminary well schematic is presented in Fig. 6.2. Mud weights, casing material weight/grade and setting depth-philosophy are based on Solveig Ph1 and need to be revisited as details and concepts are matured.

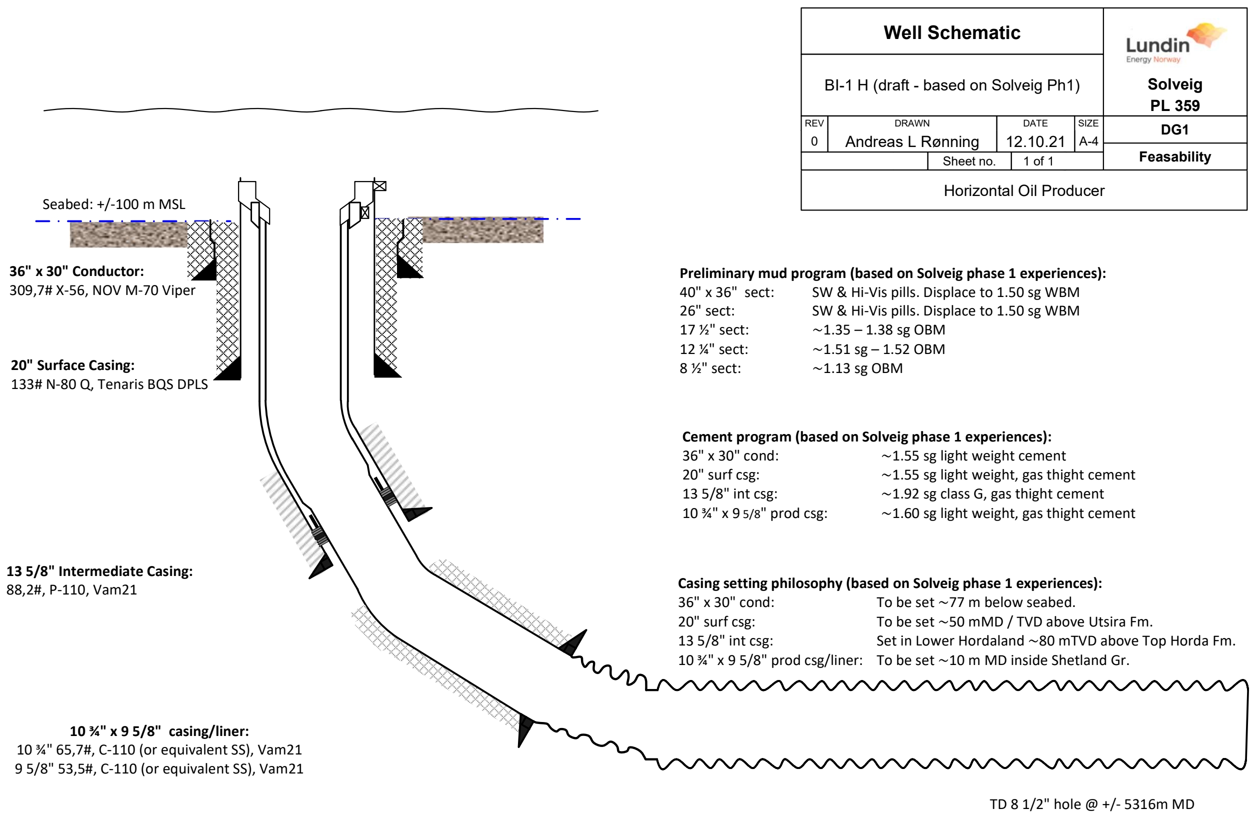


Fig. 6.2 Preliminary well schematic

6.2 Drilling Schedule

A preliminary time estimate have been produced based upon Solveig Ph1, EG, Johan Sverdrup, Ivar Aasen and exploration wells drilled at Utsira High. The drilling and completion schedule is based on a planned start-up of drilling operations in October 2024 to achieve first oil in Q1 2025. The drillex estimate is based on rate of penetration of 120 meter/day, which includes 10% WOW and 15 % NPT, and 21.5 days for the SMART completion. The total preliminary time estimate is 70 days (for drilling and completion), including 4 days rig move, Fig. 6.3. This forecast is based upon drilling the Segment D well as a single well, however the well is also considered part of a potential Solveig Phase 2 campaign. Fig. 6.4 show the latter campaign-case, a total of 179 days for the complete campaign including a 6 days rig move.

The Segment D standalone case drilling and completion schedule assumes:

- Dry hole days based on: 120 meter/day
- Subsea structures pre-installed and no conflicts with marine operations
- Anchors pre-laid
- 4 days rig moves including 3 days rig move to/from location, 1 day to hook up on first well after passing 500 m zone
- No batch drilling operations due to satellite layout and one well
- No commissioning with rig
- No clean up to the rig
- Time allowance:10% WOW, 15% NPT is included in operation duration with 120 m/d
- Contingency:15% contingency on all costs

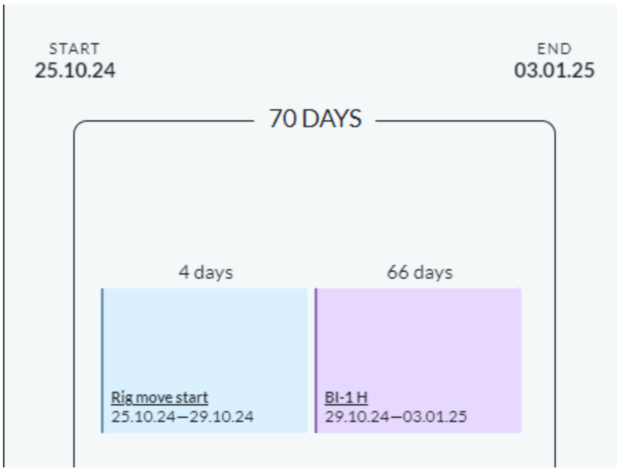


Fig. 6.3 Drilling schedule: Segment D, single well

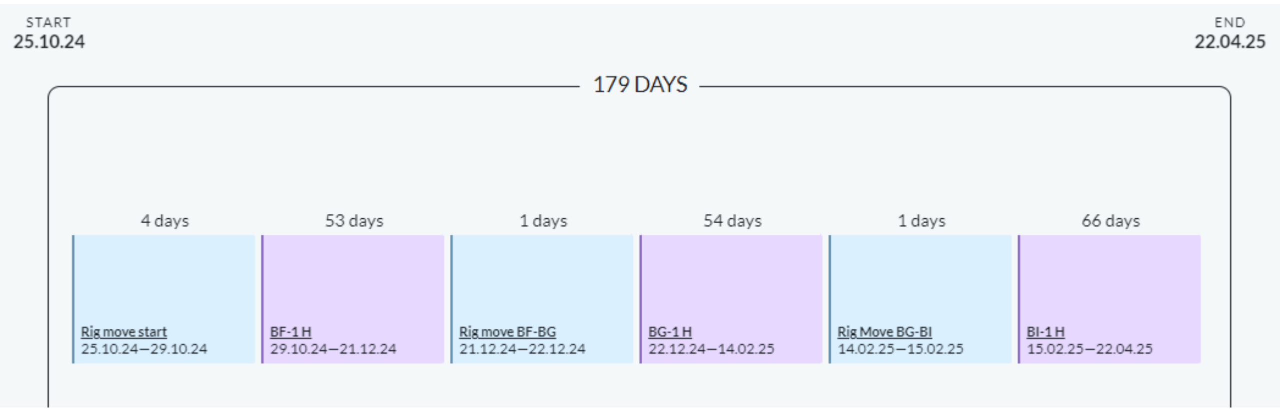


Fig. 6.4 Preliminary Drilling schedule: Segment D included in Solveig Ph2

The Solveig combined Ph2 case as in Fig. 6.4 drilling and completion preliminary schedule assumes:

- Dry hole days based on: 120 meter/day (Segment C/D), 125 meter/day (oil producer Segment B) and 140 meter/day (Water injector Segment B)
- Subsea structures pre-installed and no conflicts with marine operations
- Anchors pre-laid
- 6 days rig moves including 3 days rig move to/from location, 1 day to hook up on first well after passing 500 m zone, and 1 day for rig move between wells

- No batch drilling operations due to satellite layout and one well
- No commissioning with rig
- No clean up to the rig
- Time allowance:10% WOW, 15% NPT is included in operation duration meter/day
- Contingency:10% contingency on all costs except 15% contingency drilling Segment D

6.3 Well Intervention and workover

The base case well intervention preparedness for Solveig Ph2 is based on the use of a riserless light well intervention (RLWI) vessel. This method is selected due to better availability, shorter mobilisation time and reduced cost compared with the use of a drilling rig. The plan is to source the vessel for such operation in the spot market via established contracts.

For heavy well intervention, a semi-submersible drilling rig will be mobilised. If the well barrier integrity situation requires, the well should be plugged by use of a RLWI.

The different well intervention activities are categorized in Section 6.3.2, 6.3.3 and 6.3.4 respectively.

6.3.1 Well Intervention strategy

No intervention, clean-up or workover activities are planned for on Segment D. Planned wireline activities during the completion and VXT installation phase is limited to installation and pulling of the tubing hanger plug. These operations are planned to be performed from the rig for the base case. The tubing hanger plug pulling operation could potentially be performed from a RLWI (Riser Less Well Intervention) vessel. The gas lift valve will be pre-installed in side pocket mandrel (with a pre-set shear-open pressure) installed as part of the completion string and no intervention activities for valve installation are planned for.

Gas lift valves will be based on track record trigger the need for intervention activities for valve replacement during the lifetime of the well. For the gas lifted producers an ASV is included as an option for the base case to reduce the need for light intervention activities for change of leaking gas lift valves acting as barrier valves.

In case of leaking DHSV it is proposed to include and optional contingency DHSV nipple profile to accommodate a wireline insert valve. Such an operation will involve light intervention activity.

For workover operations or P&A operations involving pulling of upper completion string several activities can be performed by intervention activities. This includes, but is not limited to well kill, setting of plugs, lock-open of DHSV, release of production packer and ASV-packer. All these operations can be performed from a vessel.

Work-Over and intervention philosophy is split in planned categories as follows:

1. Light intervention
2. Heavy intervention and through tubing services
3. Heavy well workover

Each category with suitable method is further elaborated below.

6.3.2 Light Intervention

Riser Less Well Intervention work is limited to wireline, tractor and pumping services and can be performed from a boat. Examples of operations are listed below:

- Installation and pulling of plugs
- Contingency removal of glass plugs.
- Install straddle inserts
- Perforation (and re-perforation)
- Installation and change of inserts-DHSV
- Installation and change of gas lift valves and chemical injection valves.
- Scale removal (milling)
- Scale squeeze
- Production logging
- Caliper runs
- Leak detection
- Sand removal (limited volumes)
- Installation/retrieval of XTs.

6.3.3 Heavy Workover

Heavy well intervention includes activities as listed below:

- Retrieval/Replacement of installed completion
- Clean up and well testing

For such activities a drilling rig will be required.

6.3.4 Heavy well workover

Heavy well workover typically include activities as listed below:

- Tubing replacement
- Well abandonment programs

6.4 Completion

The completion design for Ph2-OP2 well is centred around the following concept:

- Gas lifted production well with long horizontal reservoir section, sand control and zonal control for 2 zones.

The completion design for Ph2-OP2 well shown in Fig. 6.5 and is considered similar to the Solveig Ph1 wells. The planning and execution will largely be based on completion experiences from the Solveig Ph1. Other completion requirements are specified in Ref. /3/and Ref. /5/.

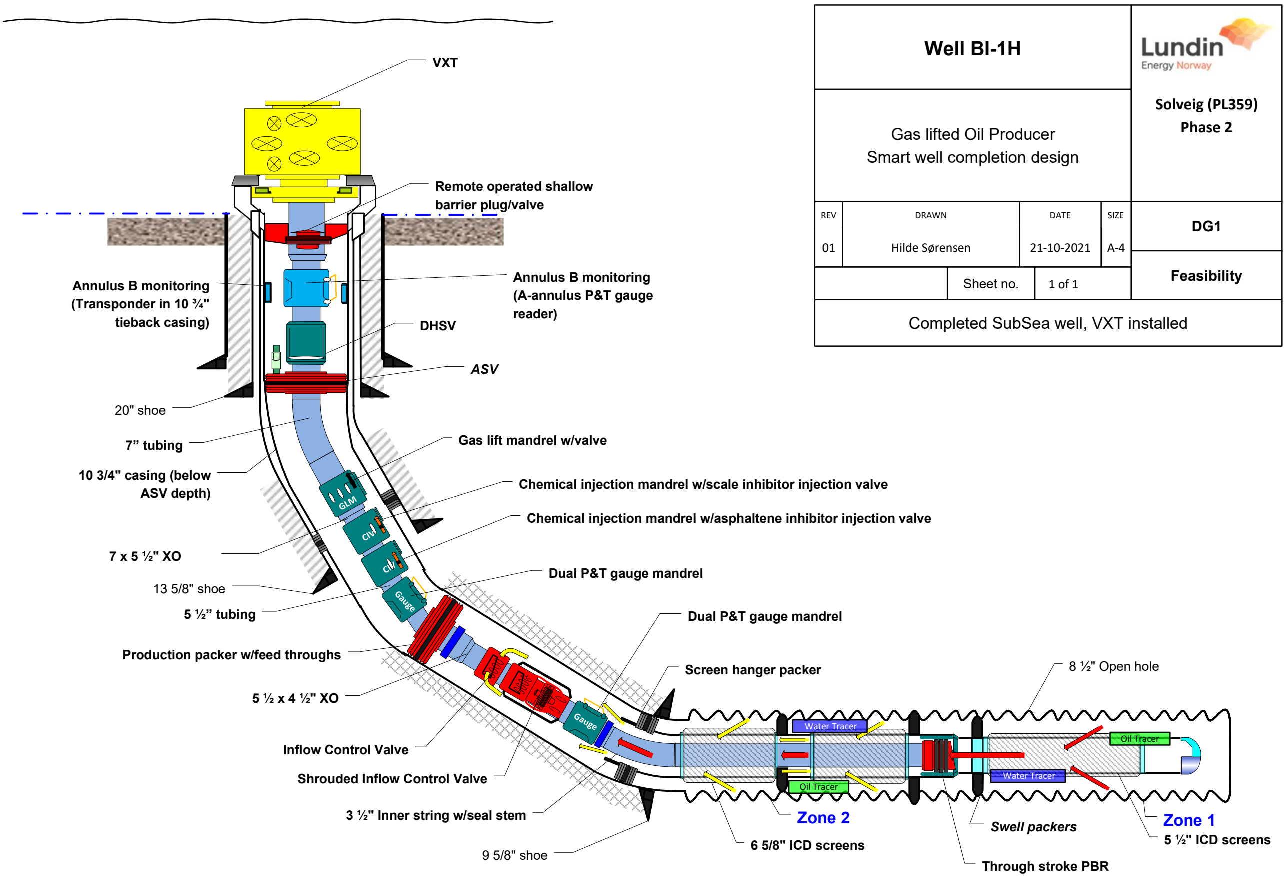


Fig. 6.5 Gas lifted oil producer (Smart)

Reservoir completion

Stand-alone sand screens are considered for the reservoir section for this smart producer. Inflow regulation is planned regulated through the application of inflow control devices (ICD's) and annular flow control methods.

Upper Completion

The required top completion working pressure and temperature rating facilitate standard 345 bar rated equipment. The temperature rating also enables standard components to be used. Planned completion for this 2 zone smart producer well is with tapered 7" x 5 1/2" x 4 1/2" or 3 1/2" completion strings and designed for gas lift.

Completion Fluids

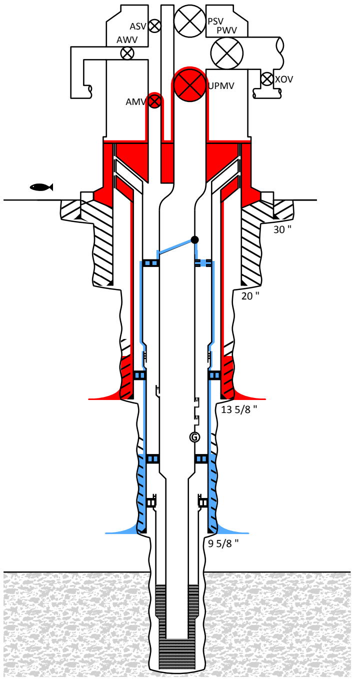
The reservoir completion fluid selection is dependent on the choice of drilling mud, sand face and potential sand screen test results. Based on the forecast pore pressure and temperature in the reservoir, standard reservoir completion fluids can be identified regardless of the choice of drilling mud and reservoir completion type. Similar completion fluid design as for the Solveig Ph1 wells will be considered.

6.5 Well Integrity

The well Ph2-OP2 is planned designed, constructed, operated and will eventually be abandoned according to a combination of industry standards (e.g. NORSOK D-010), industry guidelines (e.g. Norwegian Oil and Gas organization's recommended guidelines for well integrity), and Lundin Energy Norway's governing documentation (e.g. well barrier integrity manual).

The planned casing design and prognosed formation integrity for Ph2-OP2 well allow two fully independent barrier envelopes, where the intermediate casing shoe is located in a formation with sufficient integrity to withstand both the reservoir as well as the lift gas pressure. The well design requires, that the production liner/casing and the intermediate casing equipment all are certified gas tight. This barrier definition also creates an element of primary barrier envelope redundancy in case the annulus safety valve should fail periodic leak testing. This option requires a barrier certified gas lift valve solution. Selecting the primary barrier envelope as shown in Fig. 6.6 as the base case allows faster periodic leak testing with less production loss.

Field : D-Segment Well : D-segment (field development) Schematic : LU.V 4.1-a1 rev. 5 Date : 21-Oct-2021	Well design pressure 345 bar Reservoir pressure 184.0 bar Prepared by : Hilde Sørensen Verified by : Randi Næss



Prepared by Lundin

Depth reference: RKB West Bollsta, RKB - MSL

Producer
Operation - Barriers against reservoir
Planned

Primary barrier elements

Element	Qualification	Monitoring
Downhole safety valve	Inflow test	Periodic inflow testing
Annulus safety valve	Inflow test	Periodic inflow testing
Tubing	Pressure test to WDP	Periodic inflow testing
Production packer	Pressure test to WDP	Periodic testing when required (ASV failure/GLV testing/observation)
Tieback production casing/liner PBR system	Pressure test to WDP	B-annulus pressure
Production liner top packer	Pressure test to WDP	B-annulus pressure
Production liner	Pressure test to WDP	Periodic pressure testing/observation/lift gas performance
Production liner cement	Formation test, job performance or bond log	Not accessible
Formation (in-situ)	Formation integrity test	Not accessible

Secondary barrier elements

Element	Qualification	Monitoring
Subsea production tree	Pressure test to WDP	Periodic testing
Tubing hanger	Pressure test to WDP	Regularity monitoring (cavity expansion bottle)
Wellhead	Pressure test to WDP	External observation
Intermediate casing hanger	Pressure test to WDP	B-annulus pressure/observation
Intermediate casing	Pressure test to WDP	B-annulus pressure/observation
Intermediate casing cement	Formation test, job performance or bond log	Not accessible
Formation (in-situ)	Formation integrity test	Not accessible

Healthy well, no or minor issue

Note:

Page 1 of 1

Fig. 6.6 WBS Producer well - Barrier against reservoir

6.6 New Technology

The feasibility concept does not include any new technologies, however the following sub chapters includes technologies that will be evaluated in the concept phase. All new and novel technologies shall be qualified to Technology Readiness Level (TRL) and TRL5 before installed in a LENO operated well.

6.6.1 MLT

Multilateral technology (MLT) is not included in the feasibility concept/budget, however this concept will be considered for the DG2-phase. The concept evaluation will include the following considerations (based on the system installed on 16/1-A-16, Fig. 6.7 :

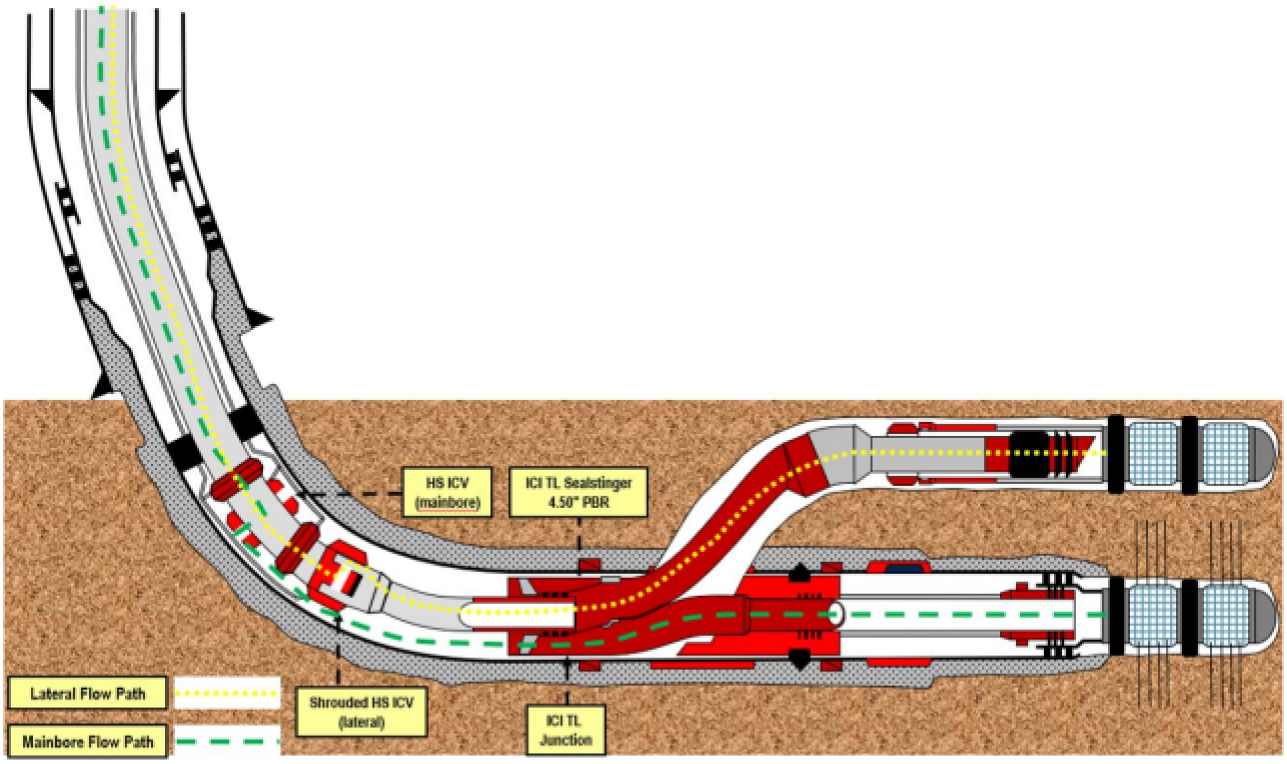


Fig. 6.7 Halliburton 9 5/8" FlexRite ICI TL

- Adapt A-16 MLT concept (Halliburton 9-5/8" FlexRite ICI TL) for EGTB Future /Segment D if possible as this concept is qualified and installed on Edvard Grieg, i.e. TRL 6.
- Evaluate to underream 12-1/4" hole section to 13-1/2"due to large OD on several components on the MLT liner (not done on 16/1-A-16)
- Evaluate placement of MLT window and type of window (pre-milled or whipstock latch system)

Assess if additional qualification testing is required for interfaces such as fluid and equipment (dimensions, fluid loss device, access to lateral/mainbore, etc.)

6.6.2 Fishbones

Fishbones is not included in the feasibility concept/budget, however this concept may be considered for the DG2-phase. The concept includes the following consideration, steps and technology:

- Fishbones drilling is currently field proven for LENO, up to 61 subs. The system is defined as TRL6
- The Fishbones drilling technology has limited production history and potential further enhancement of the current design, based on experiences from 16/1-A-16 and 16/1-A-17, will reduce the readiness to TRL4-5
- Navigated well stimulation technology, which enables orientation of the Fishbones needles in the reservoir, is currently at TRL3

6.6.3 Fiber Optic technology

Fiber Optic technology is not included in the feasibility concept/budget, however this concept will be considered for the DG2-phase. The fiber optic installation for a subsea well is considering as new technology for LENO and must be qualified to TRL5. Interfaces and integrations e.g tubing hanger subsea tree and lower completion equipment must also be included in this process.

- Fiber optic technology in the reservoir is classified as ~TRL4 as the wet mate connector has failed several times during/after installation. The system is installed on the NCS, but the track record for the wet mate is questionable/low reliability.
- Further evaluation of this technology is necessary and design changes may be required to achieve acceptable reliability
- The fiber optic/subsea-interface is qualified for an other operator. The same design should be adapter for EGTB to avoid extensive qualification testing. Still the interface is considered to be at TRL4 depending on the fiber specifications, etc.

6.6.4 Electrical Completion Systems

Electrical completion systems is not included in the feasibility concept/budget, however this concept will be considered for the DG2-phase. The Electrical completion systems for a subsea well is considering as new technology for LENO and must be qualified to TRL5. Interfaces and integrations e.g tubing hanger subsea tree and subsea control module must be included in this process.

- Electrical completion systems is not qualified to TRL4 as of today. The industry is working towards a pilot well to qualify the system. Ongoing qualification program of individual components in the period, to be finalized by 2023
- Individual components such as electrical ICV's and electrical DHSV's are available and field proven today. Still it will require an assessment addressing required qualification program to implement the technology subsea and get the technology qualified to TRL5 and 6 (i.e. SIT)

6.7 Lessons learned from Solveig Ph1

As of November 2021, three wells have been drilled and completed, while the third well is currently being drilled (BB-1 H/AH). An operational experience register is continuously being updated, some of these are:

- When drilling tophole, crater has been developing around tail pipe and subsea structure. Typically crater development is observed while drilling pilot/top hole. Crater seen developing to ~13 m in diameter and depth up to 3 m. The crater is complicating drilling, running and cementing of the conductor
- Little to no issues seen drilling 12-1/4" section through Hordaland group. One reason might be the placements of the ISS and ability to plan 2D-wellbores through geological stable areas

- Introducing high performance OBM in both overburden and reservoir has contributed to the overall success rate (increased hole cleaning, low ECD, inhibition, lubrication)
- Two production liners cemented in place with high cement bond. On BB-1 H/AH a production casing was introduced in order to exclude the time running a tieback. The casing was run and cemented without any issues, and sufficient zonal isolation was achieved. However, the CBL later showed channelling on parts of the lowside of the casing.
- The reservoir sections have been drilled with high success. Both drill pipe, RSS, BHA and bit selection had excellent performance and fit for purpose.
- Drill pipe selection; Experience from the Solveig Ph1 campaign indicates that the same drill pipe should be used throughout the complete Ph2 campaign (and not alternate between wired drill pipe (WDP) and conventional drill pipe as done on Ph1). A possible decision on use of WDP should be made prior to the rig intake and thus should be considered included in the rig contract (additional evaluations with regards to experiences on the use of 5-1/2" string vs tapered 5" x 5-7/8" string in Ph1 should also be made prior to the rig intake)

6.8 Recommendations for next phase (D&C)

- Crater around spud location, tail pipe and subsea structure needs to be addressed. Need to check alternatives to both subsea structure design including tail pipe length and ways to optimize the drilling, running and cementing of the conductor. In addition, the jumpers needs to be off seafloor to prevent not to be covered by cement.
- Continuously look into Solveig Ph1 drilling and completion experiences to optimize the concept design and selection of equipment
- Slim hole design should be considered. Revisit Solveig Ph1 simulations on APB and look into possibilities/limitations in designing a subsea slim hole production design
- Evaluate design vs APB in B-annulus. Need to summarize experiences on potential pressure build up during production on the Solveig wells
- Optimizing the well design with regards to running production casing instead of production liner and tieback. Look into BB-1 H/AH experiences. Casing running need to be further optimized in terms of centralization, displacement rate, etc
- Possibility for MLT design. Experiences from EG Infill campaign and further maturing of concept on the Segment D-well
- Possibility for Fishbones completion. Experiences from EG Infill campaign and further maturing of concept on the Segment D-well
- Fiber technology to be evaluated to be a part of the completion installation
- Evaluate Electrical Completion Systems
- Due to well head fatigue observed from conductor analysis from Phase 1, the Reactive Flex Joint (RFJ) is strongy recommended to reduce the well head fatigue.

7 Subsea Development

This section provides a summary of the subsea development for Solveig Ph2. This includes the Subsea Production System (SPS), the Subsea Umbilicals, Risers and Flowlines (SURF) scope, and flow assurance, planned marine construction activities and subsea metering system.

All production from Solveig Ph2 will go to EG and umbilical services, gas lift and water injection (where applicable) will be provided by EG. The tie-in locations will be the end of the Solveig Ph1 production, water injection and gas lift pipelines and umbilical tie-ins will be from Solveig well location BA-1.

To minimise requirements for spares, avoid qualifications, reuse engineering etc., as much as possible of the equipment delivered and qualified during the execution of Solveig Ph1 will be used. Lessons learnt from Solveig Ph1 will be taken into account where required.

The following equipment will be used:

- Wellhead
- Tubing Hanger
- Vertical XT (VXT)
- VXT Control Modules (PCR-x, PCR-D and HCR)
- eAtuators
- Flow Control Modules
- Connection System

Two alternatives development concepts are evaluated in this report:

- Segment D standalone case
- Solveig combined Ph2 case

Segment D standalone case

This is a case with a single production well combining a depletion section in Segment D with an infield section in Segment C. The well is located approximately 4.5km north-west of the Solveig Ph1 development.

The Segment D standalone development will produce to and receive gas lift from EG via Solveig Ph1 installed subsea infrastructure. The scope for this development consists of:

- 1 off Satellite Structure
- 1 off Production Well
- Insulated flexible production flowline
- Uninsulated flexible gas lift flowline
- Control umbilical.

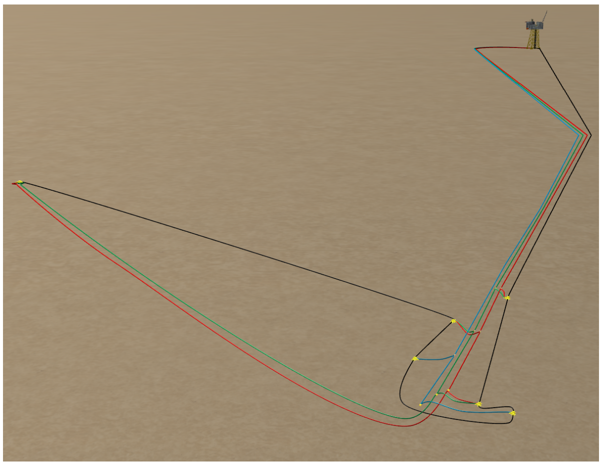


Fig. 7.1 Segment D standalone case *Solveig Segment D stand alone case tied back to Solveig Ph 1 subsea infrastructure*

Solveig combined Ph2 case

An alternative being evaluated is Solveig combined Ph2 case, where Segment D is developed in parallel with Segment B Synrift.

The segment B Synrift development will consist of one (1) production well and one (1) water injection well, located respectively 3.1km and 2.1km southeast from the Solveig Ph1 tie-in locations, ref. Fig. 7.2.

The Solveig combined Ph2 case requires the installation of production and gas lift tie-in manifolds to connect both fields to the Solveig Ph1 system. The scope for the Solveig combined Ph2 case consists of:

- 3 off Satellite Structures
- 2 off Production Wells
- 1 off Water Injection Well
- 1 off Production Tie-in Manifold
- 1 off Gas Lift Tie-in Manifold
- Insulated flexible production flowlines and jumper
- Uninsulated flexible gas lift & water injection flowlines and jumpers
- Control umbilicals.

All flowlines and umbilicals will be jet trenched and all structures will be overtrawlable and have dropped object protection.

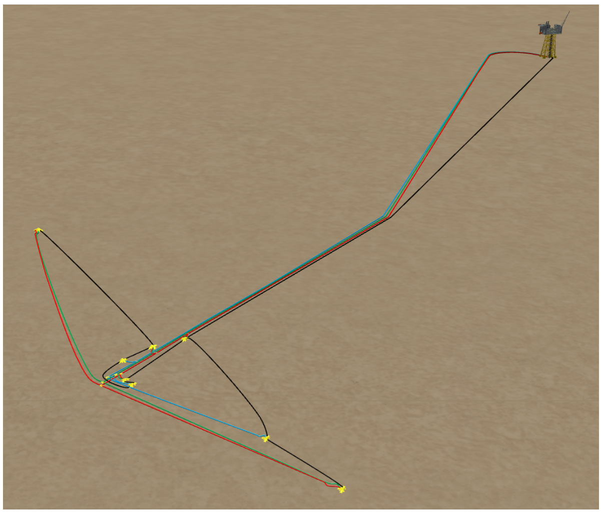


Fig. 7.2 Solveig combined Ph2 case *Solveig combined Ph2 case tied back to Solveig Ph1 subsea infrastructure.*

7.1 Subsea Umbilicals, Risers and Flow lines

Preliminary pipeline design and sizing have been derived in the feasibility phase, ref. 7.3 Flow Assurance. Preliminary sizing has also been done for the water injection flowline (6" ID) and for the gas lift flowline (4" ID), however further optimisation is expected in next phase.

Solveig Ph2 will most likely use flexible flowlines for production, water injection and gas lift. Umbilicals will have similar design as for Solveig Ph1, using Umbilical Termination Units (UTA's) at each end.

Segment D stand alone case

- 4.8km 8" ID insulated production flexible flowline;
- 4.9km 4" uninsulated flexible flowline; and
- 4.4km control umbilical from Ph1 production well (BA-1 H) to Segment D production well (Ph2-OP2).

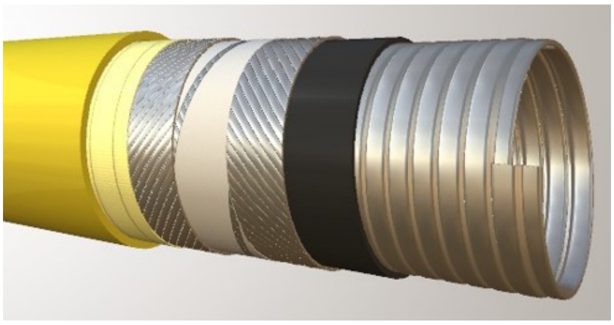


Fig. 7.3 Insulated Flexible Rough Bore Production Flowline
Gas Lift flowline will be similar in design but without the insulation layer under the external sheath

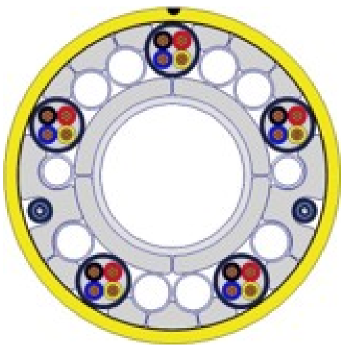


Fig. 7.4 Control Umbilical *Picture is showing Solveig Ph1 static umbilical cross-section. Ph.2 cross section will be similar in design.*

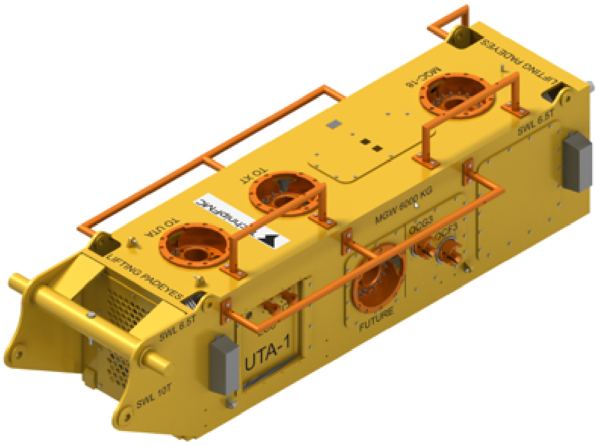


Fig. 7.5 Umbilical Termination Assembly (UTA) *Solveig Ph1. design will be re-used on Solveig Ph.2*

Solveig combined Ph2 case

- 4.6km 8" ID insulated production flexible flowline
- 4.7km 4" ID uninsulated flexible gas lift flowline
- 4.4km control umbilical
- 3.1km 8" ID insulated production flexible flowline
- 3.1km 4" ID uninsulated flexible gas lift flowline
- 2.1km 6" ID uninsulated flexible water injection flowline;
- 2.3km control umbilical from Ph1 production well (16/4-BA-1 H) to Segment B water injection well (Ph2-WI1)
- 1.1km control umbilical from Segment B water injection well (Ph2-WI1) to Segment B production well (PH2-OP1)
- 0.2km 9.5" ID flexible production jumper (between production tie-in manifold and Ph.1 production PiP pipeline PLEM)
- 0.3km 4" ID flexible gas lift jumper (between gas lift tie-in manifold and Ph.1 production PiP pipeline PLEM).

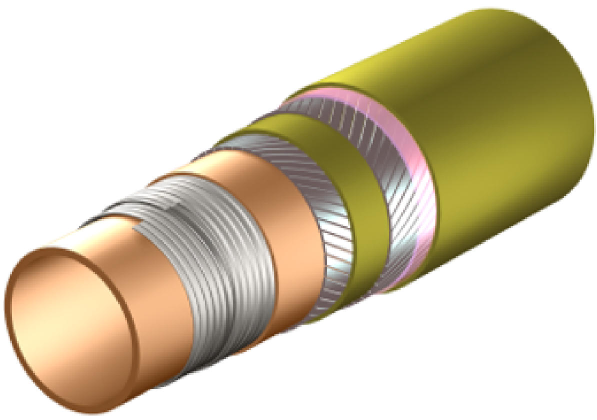


Fig. 7.6 Uninsulated Flexible Smooth Bore Water Injection Flowline

The flexible flowlines and the umbilicals will be jet trenched and protected with overtrawlable GRP covers, concrete mattresses and rock-dump at the tie-in locations.

Cathodic protection system will be installed, either from the connecting structures or from bracelet anodes directly on the flexible flowlines.

This umbilical design is consisting of:

- Chemicals lines including a spare (5+1 off)
  - Wax inhibitor
  - Corrosion inhibitor
  - Scale inhibitor
  - Asphaltene Inhibitor
  - Demulsifier
- Hydraulic lines (4 off)
- Mono-Ethylene Glycol (MEG) centre tube
- Five (5) electrical quads (4 power lines per quad)
- Two (2) fiber tubes (24 fiber per cable) are included .

Fibre Optic Flying Leads (OFL's), Electrical Flying Leads (EFL's) and a single Hydraulic Flying Leads HFL) will connect the satellite VXT to the umbilical UTA. The HFL will contain all MEG, chemical and hydraulic lines.

7.2 Subsea Production System (SPS)

Solveig Ph2 will re-use majority of the Solveig Ph1 design for SPS equipment.

Satellite Protection Structure

The satellite protection structure design has not been selected for Solveig Ph. 2 Lundin has previously used two designs in the development of the Solveig Ph1 and Rolvsnes EWT fields.

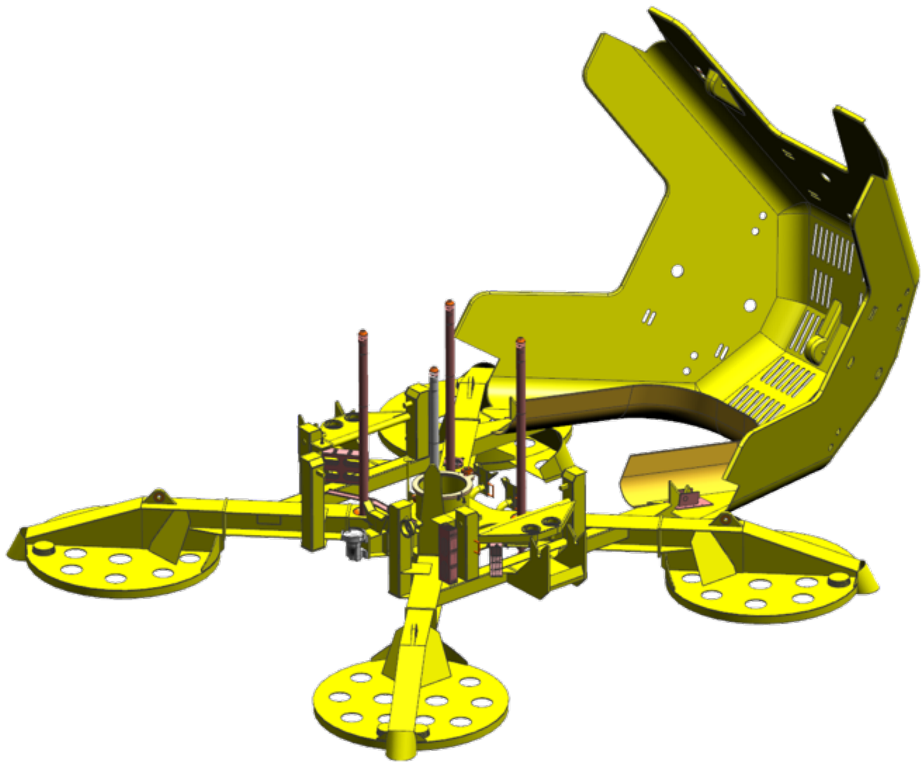


Fig. 7.7 Integrated Satellite Structure (ISS) *Protection Structure use on Solveig Ph1.*

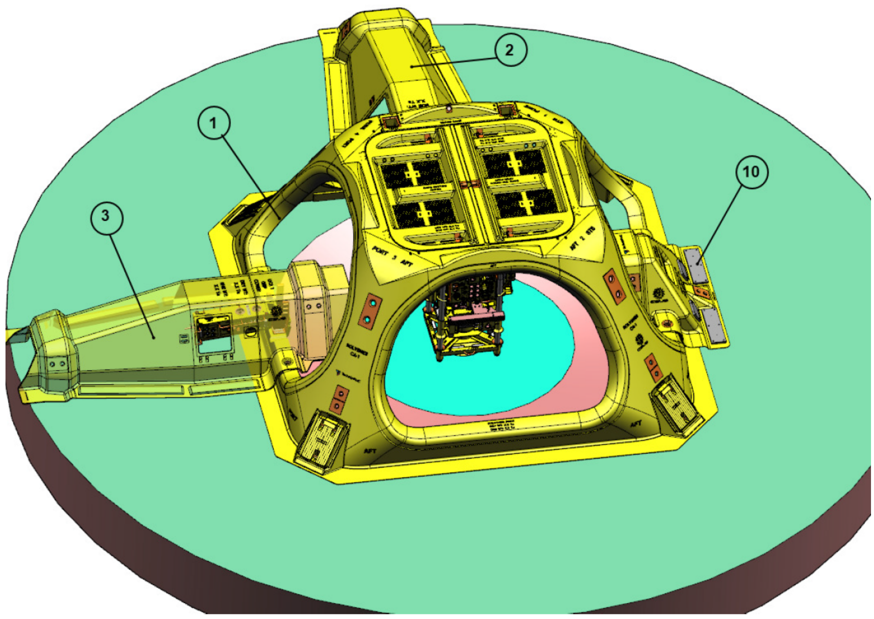


Fig. 7.8 Satellite Protection Structure *Protection Structure used on Rolvsnes EWT*

The design will meet the following minimum requirements:

- Provide structural protection against snag and dropped objects loads as defined in NORSOK U-001
- Provide drill bit and conductor guiding during top hole drilling program,
- Interface to drill cuttings and cement return removal system
- Top up cement funnels to allow for grouting outside conductor pipe
- Provide vertical support for drilling loads as defined in Norsok U-001
- Allow ROV access for periodic inspection program of the subsea facility.

The Integrated Satellite Structure (ISS) provides guiding, hang off and support for one (1) wellhead (WH) system and associated equipment. The connection towards the XT is done through a horizontal connector, thus reducing cost and time for meteorology and spool designs. Standard mud mats provide interface towards soil. The satellite supports the 36" WH conductor and reduces the WH loads. Impact loads from trawling are transferred via the structure to the soil, hence the conductor housing and the high-pressure housing are shielded from these loads. Once the protection cover is open, the structure provides good all-around access for Remote Operated Vehicle (ROV) intervention.

The Rolvsnes EWT protection structure is freestanding and does not provide guiding, hang-off and support for the wellhead.

Both of them are installed by a heavy construction vessels. By selecting an ISS type of structure, the marine campaign can be completed before the rig arrives. If a Rolvsnes EWT type of protection structure is selected, then the flexible jumper pull-in and connections will be done after the rig has completed on the well.

Lundin Energy Norway will take into account lessons learnt from both the Solveig Ph1 and the EWT project and additional evaluations will be done as part of the Concept studies to establish which type of design that shall be used for Solveig Ph2.

Wellhead (WH) System

The WH system to be installed will be a conventional and field-proven three (3) hanger system rated to 1035 bar working pressure. The selected system will include a rigid lock down system to improve fatigue resistance towards operational and hydrodynamic forces.

The system will include the following sub-elements:

- 36" low pressure housing c/w 2" WT extension and swaged down to 30" X 1" WT as per final wellhead fatigue analysis results
- 18-3/4" 1035 bar high pressure housing c/w 20" - 1" WT casing extension
- 13-5/8" casing hanger
- 10-3/4" casing hanger
- Two grouting funnels placed 180° apart.

All seal assemblies will be of metal to metal design. Single trip running tools will be used where possible to ensure a safe and efficient installation program.

The selected UWD-15-SHD wellhead system is shown below in Fig. 7.9.

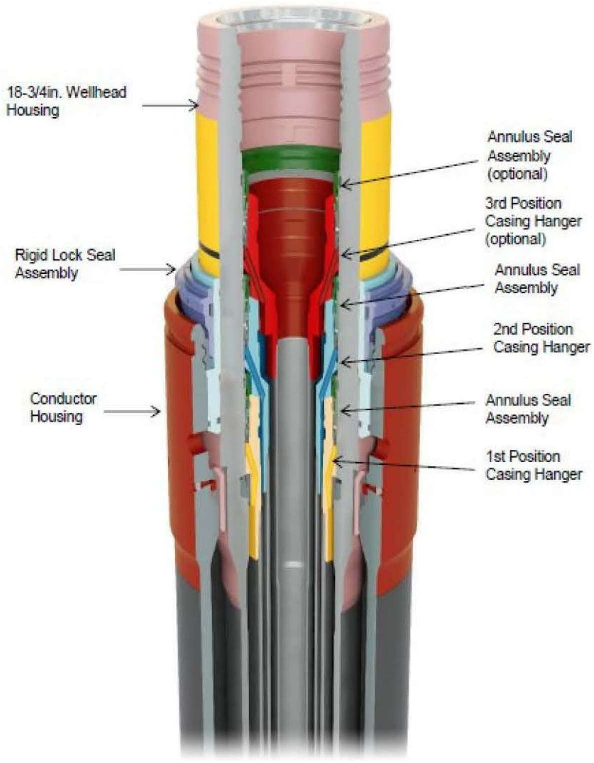


Fig. 7.9 Wellhead System *Solveig Ph.1 wellhead system*

When the Blow Out Preventer (BOP) is installed onto the wellhead, a load relief system (preferably reactive flex joint) will be required to reduce fatigue damage to an acceptable level.

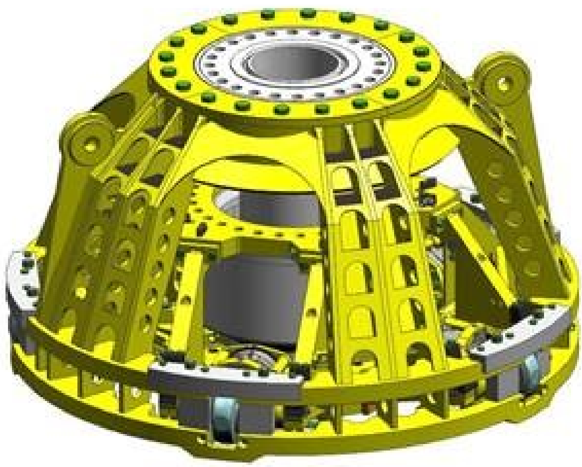


Fig. 7.10 Reactive flex joint.

Relief of WH loads through use of tender line support (strapping) is available as a back-up system. This system enables load transfer from the BOP to free-standing anchors on seabed, and consequently, the back-up solution can be implemented without impact on other parts of the SPS equipment.

Fig. 7.11 BOP strapping

VXT System

Solveig Ph2 will re-use the Ph1 Vertical XT (VXT) system, which is generally based on the Equinor NCS 2017+ requirements, a full bore concentric 7" x 5" x 2" design.

In accordance with requirements given in PL 359 - Solveig functional and operational requirements [3], the subsea XT will be of concentric VXT rated to 690 bar, have a temperature class U-P with a material selection equal to API 6A – trim HH. For annulus bores/valves the material trim will be EE with all seal surfaces having CRA inlay welding.

Utilising this VXT design ensures:

- Reduced wellhead loads
- Standardization of production and injection XT
- Increased availability of workover equipment from existing Tool Pools
- Well clean-up to platform/host facility
- The selected XT is similar and meet functional and technical requirements as defined for the NCS 2017+ initiative
- The required main interface and operational functionality include:
  - XT 18-3/4" 690 bar H4 top re-entry profile with a VX primary sealing profile
  - XT (production and injection) interchangeability with minor component up-grade
  - Subsea system architecture that allows for installation and well workover (light and heavy)
  - Production control system that is compatible with both the IWOC as well as ROV deployed subsea system controls
  - Artificial lift for oil producer availability through gas lift in A-annulus
  - Dual barrier elements towards the environment by XT design
  - Allowance for B-annulus monitoring
  - Allowance for hydrate remediation during installation, start-up, operation and shut-in conditions
  - Possibility to install the XT using drill pipe or deployment wire without supporting barrier elements as LRP, EDP and IWOC system
  - Production/annulus stabs and electrical / hydraulic stingers provide wet-mate communication between the bottom face of the XT and the top face of the TH.

The same VXT design is used for both production and water injection wells, with the different configuration managed in the Flow Module (FM). The FM also contains the elements that may need to be replaced during the life of field, such as instrumentation (PT/TT sensors, metering, erosion probe, etc), chemical injection valve, Multifase Flowmeter (MPFM) and choke valves.

The recommended XT design is presented figures below:

Fig. 7.12 VXT *View showing Interface towards the flowline*

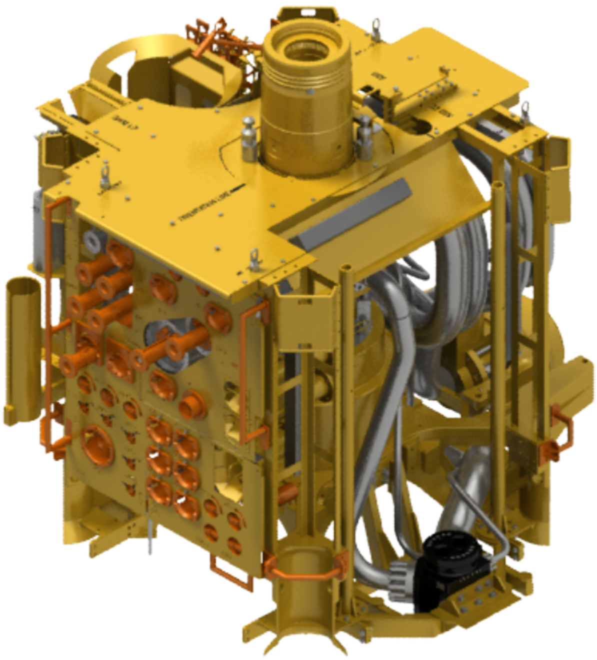


Fig. 7.13 VXT *View showing the interface towards the Flow Module*

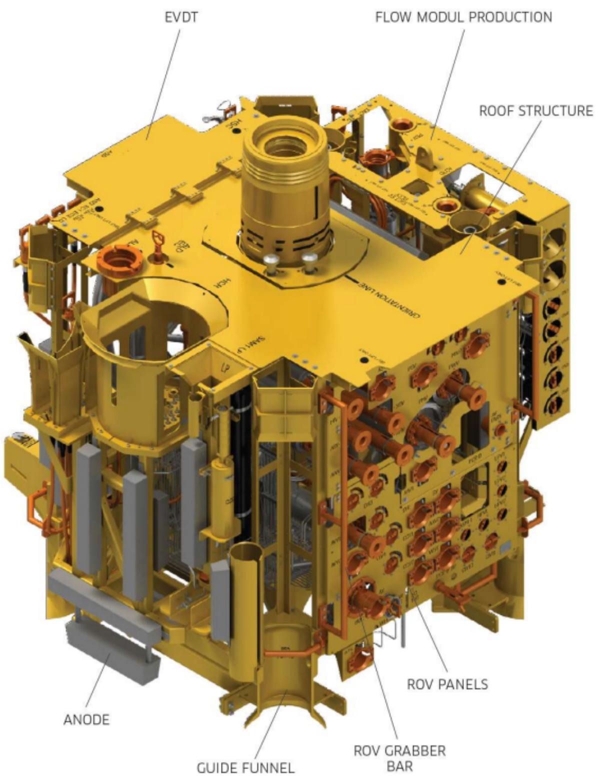


Fig. 7.14 VXT with Flow Module

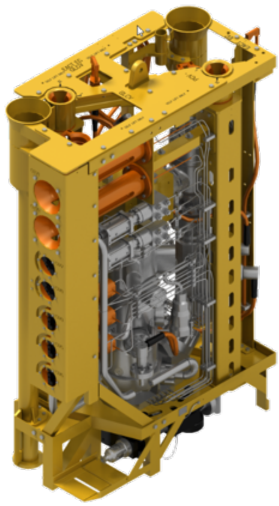


Fig. 7.15 Flow Module

Tubing Hanger (TH)

The TH system is rated to 690 bar being oriented and installed into the high pressure housing. The design includes the following features:

- The TH will be 7" concentric design
- The TH will be orientated, landed and locked by use of a simplified landing string
- All TH's will have pre-installed pup pieces prior to shipment offshore. For production wells (B-annulus monitoring requirement), specific assembly for extended assembly will be pre-installed as part of onshore pre-deployment program
- The TH is set up with two plug profiles to enable the installation of either a mechanically retrievable plug (base case) or a pump open glass plug (opportunity)

- Annulus access and isolation is enabled via an Annulus Isolation Valve (AIV) integrated in the TH body, operable both mechanically and hydraulically
- All wetted areas by production or injection fluids meets API material trim HH
- Allows for seal test and soft landing function
- The TH is designed to allow for a minimum 2 thread re-cuts. Tubing thread type will be as specified by completion program

The TH design allows nine (9) available downhole control line functions. The TH and XT will be set up to allow completion of the well with smart well technology. With the requirement to multidrop the tubing and B-annulus instrumentation, the following functionality has been selected:

- 3 X HP hydraulics for Smart Well functionality
- 1 X HP hydraulics for DHSV
- 1 X HP hydraulics for ASV
- 1 X LP hydraulics for ASV setting line
- 2 X Downhole Chemical Injection lines
- 1 X EL for (all) Downhole instrumentation

The selected TH design is presented below:

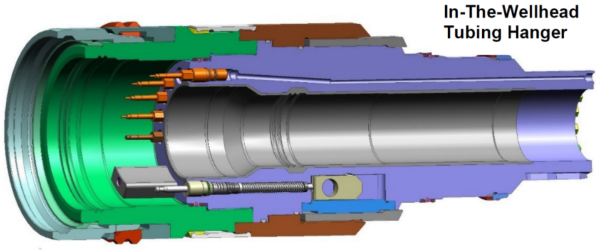


Fig. 7.16 In-Wellhead Tubing Hanger

Control System
Solveig Ph2 will be connected to the Ph1 topside control system via Solveig Ph1 control umbilical infrastructure.

The subsea control system will be based on a same system open return hydraulic system as deployed on Solveig Ph1, the KS800 (previously know as Next Generation Automation).

In this system, the subsea control system is split into 3 different units:

- Power and Communication is in a separate module called PCR-X
- Interfaces towards downhole instrumentation is in a separate module named PCR-D.
- Hydraulic functions of the system resides in a third module name Hydraulic Control Router (HCR).

Valves in the pipeline system that requires remote actuation will be fitted with electrical actuators controlled from the PCR-X though electrical jumpers.

It is anticipated that the Solveig Ph1 subsea leak detection system will be used also for Ph2 (subject to BAT). This is a combination of physical units (Naxys A5 passive acoustic system) and software based monitoring, Flow Advisory System (FAS). Additionally, an active acoustic system will be evaluated as part of the concept studies. The radar-based leak monitoring system installed at EG will be utilized in the overall leak detection strategy.

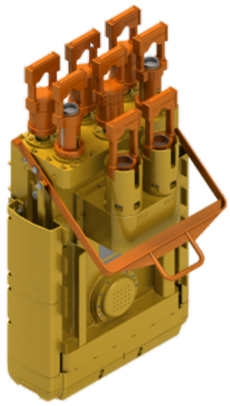


Fig. 7.17 PCR-X Module

Fig. 7.18 Hydraulic Control Router (HCR)

Tooling
As for Solveig Ph1, all required tooling will be rental tools from SPS Contractor or other contractors (e.g. advanced ROV HPU for subsea VXT installation). Tooling includes all tools and services required to perform the installation campaigns (marine and drilling).

7.3 Flow Assurance

Feasibility studies have included flow assurance [54] and the following has been done as a part of the studies:

- Sizing of the flowlines
- Optimisation of the gas lift rates
- Steady state simulations
- Slug tracking simulations
- Unplanned shut-down simulations
- De-pressurisation
- Start-up simulations.

Sladdet

The steady state analysis shows the arrival temperatures at Edvard Grieg range from 32.3°C to 53.1°C with production PiP pipeline and 29.5°C to 50.0°C for an eight (8) inch insulated flexible flowline, which are above the Wax Appearance Temperature (WAT) and Wax Dissolution Temperature (WDT) of respectively 23°C and 29°C. The arrival conditions are also well above Hydrate Equilibrium Temperature (HET).

The unplanned shut down analysis performed is showing that the lowest No-Touch Time (NTT) with PiP production pipeline for for Ph2 is 17 hours. Using insulated flexible flowlines for Ph2 this is reduced to 14 hours.

The hydrate management strategy for Solveig is based on MEG injection and de-pressurization. The Solveig Ph1 short tie-in jumpers, which have a shorter NTT than the Production PiP will be inhibited with MEG. However, the step-out distances for Solveig Ph2, both for the Segment D stand alone case and for the Solveig combined Ph2 case are too long to inhibit with MEG. Hence, injection will be used to inhibit sections of the system with shorter NTT than the pipeline. If a shut-down last longer than the Ph.2 production pipelines NTT, then the entire system must be de-pressurized and restart will be done against low pressure in the separator.

Chemical injection management strategy
Based on the flow assurance performed, the temperature (at EG) of the production flow from Solveig Ph1 and Ph2 wells will be 5 to 6°C above WAT for all production cases considered. The analysis is based on use of insulated 8" flexible production flowlines with a U-Value of 3 W/m2K. Wax inhibitor is available at the production XTs (downstream choke) for use during prolonged turn-down periods.

Downhole scale inhibitor is expected to be injected and is included in the design (on VXT).

Downhole asphaltene inhibitor is included in the design (on VXT).

Corrosion inhibitor is included in the design (upstream choke on the VXT). Inner pipe in the Solveig Ph1 production PiP pipeline is made from carbon steel and injection of corrosion inhibitor is required.

One full spare chemical injection system is included in the design.

Slugging
Hydrodynamic slugging is expected within the Solveig Ph2 pipeline, especially in the early years. Maximum liquid surge volume is approximately 4.15m^3, which will not cause any production impacts.

Terrain/riser slugging will be expected in certain low production scenarios. The pipeline will be laid on downward slope from Solveig Ph2 through Ph1 and to EG, which will result in liquid accumulation during shut-downs, with subsequent start-up slugs. Topside choking will be used during both start-up and normal operation as required.

7.4 Marine Construction Activities

There are many projects that are planned to submit a PDO before the end of 2022 and the SURF vessel resources will have high utilisation, particularly the rigid reel lay vessels. The possible lack of availability of rigid lay vessels has been considered in the feasibility studies and flexible flowlines have been selected for Solveig Ph2 and this will mitigate the availability issue. A Multi Service Vessel (MSV 1) can install the flexible flowlines and umbilicals with the use of:

- Carousel or Reels; and
- Vertical Lay System (VLS) or a Horizontal Lay System (HLS).

The subsequent trenching, tie-in activities and installation of protection covers can be performed by the same vessel or a Light Construction Vessel (MSV 2) can be used.

Some rock cover installation with specialised rock installation vessel will be required.

Depending on the final selection of the satellite structure design, the installation will be done either with a Heavy Construction Vessel or an MSV 1.

The schedule will be further developed during the concept phase and the Front End Engineering Design (FEED) phase. Whether SURF can complete all installation activities prior to arrival of the Rig or if split SURF installation campaigns are required will depend on the selection of the satellite protection structures. SIMOPS plans will be developed during FEED to ensure Rig and SURF marine campaigns are properly managed.

7.5 Subsea Flow Measurement Systems

Solveig Ph2 will have one (1) MPFM on each production well and will use existing Solveig Ph1 MPFM on the topside inlet side. The topside MPFM will be used for hydrocarbon allocation of production. With this set-up, the subsea meters can be continuously monitored by-difference against the topside MPFM.

GL and WI will be measured topside with single phase meters at export from EG. Subsea, the wells will be measured with single phase metering for water injectors. Gas lift rate per well is calculated with virtual metering from the subsea gas lift choke pressure drop.

7.6 Alignment with Future Business Opportunities

There is sufficient capacity in the Solveig Ph1 pipelines, umbilical and control system to include either Segment D standalone case or the Solveig combined Ph2 case.

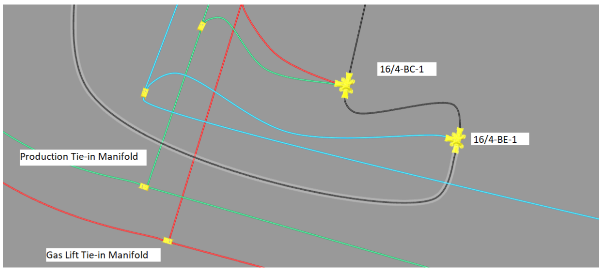


Fig. 7.19 Solveig Ph2-16_02 Tie-in to Solveig Ph.1

The layout (Fig. 7.19) has future tie-in locations for production and gas lift. Future production tie-in location can also be utilised for wax scraping or integrity pigging operations.

7.7 Lessons Learnt

The lessens learnt process from Solveig Ph1 an Rolvsnes EWT is at time of writing work in progress.

Key lessons learnt from Solveig Ph1 and Rolvsnes EWT that currently however are addressed in the concept study are:

- Production PiP scouring
- Satellite structure foundation scouring
- Soil collapse while drilling top holes, the drilling experience is also described Section 6.7 Lessons learned from Solveig Ph1
- Umbilical loadout

As the project moves into the FEED phase additional lessons learnt will be taken into account.

7.7.1 Production PiP Pipeline

The Solveig Ph1 and Rolvsnes EWT production PiP pipeline was designed to be left on seabed and not be buried. In the period between initial installation in 2020 and summer of 2021 there was scouring along the pipeline resulting in many free spans of varying length. The engineering assessment performed in summer of 2021 concluded that the pipeline needed to be rock dumped.

For the Segment D standalone case and for Solveig combined Ph2 case, the flow assurance has concluded that smaller diameter pipeline is adequate and that flexible flowlines can provide sufficient insulation to meet the operational requirements. Flexible flowlines will also be used for gas lift and for water injection and all flowlines, as well as the umbilicals, will be jet trenched.

7.7.2 Satellite Structure Foundation Scouring

Scouring around the foundation of the Integrated Satellite Structures (ISS) have been experienced at all well locations on Solveig Ph1, and significant remedial work was required. This work included grouting under the mudmats, rock installation at the location of the mudmats and installation of a rock berm round the ISS structure.

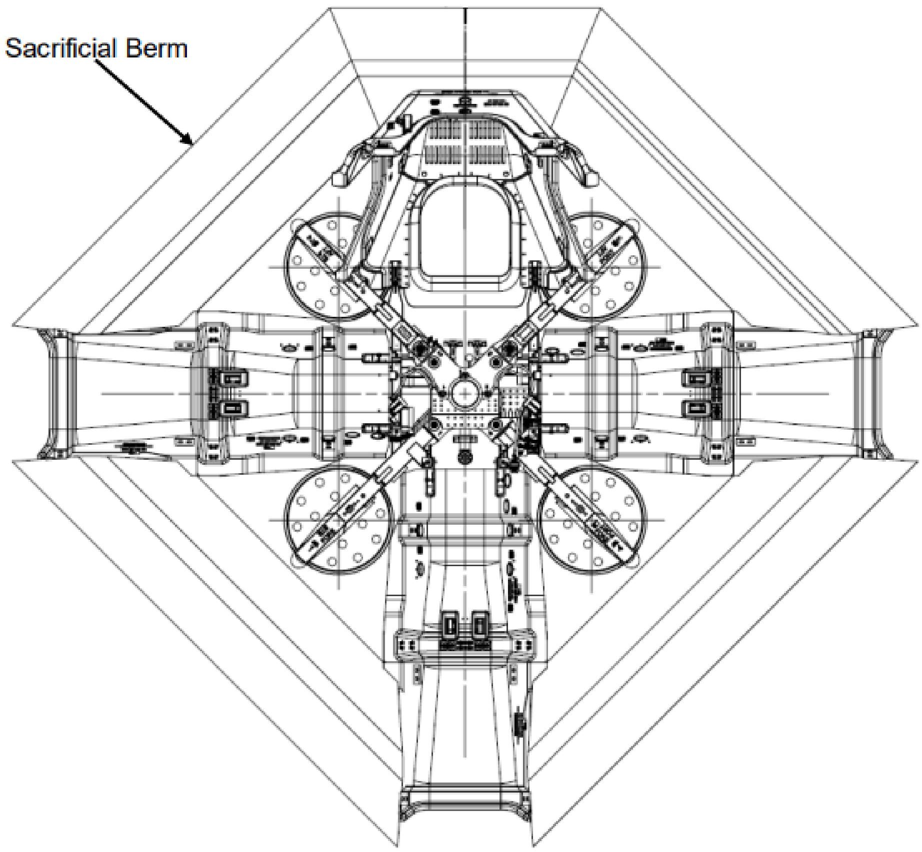


Fig. 7.20 ISS Scout Protection

The issue is being addressed as part of the ongoing subsea concept studies.

7.7.3 Soil Collapse while drilling Topholes

During drilling of pilot holes and topholes of all wells on both Solveig Ph1 and Rolvsnes EWT there have been soil failures, which has resulted in craters with diameter of up to 13m and depth up to 3m.

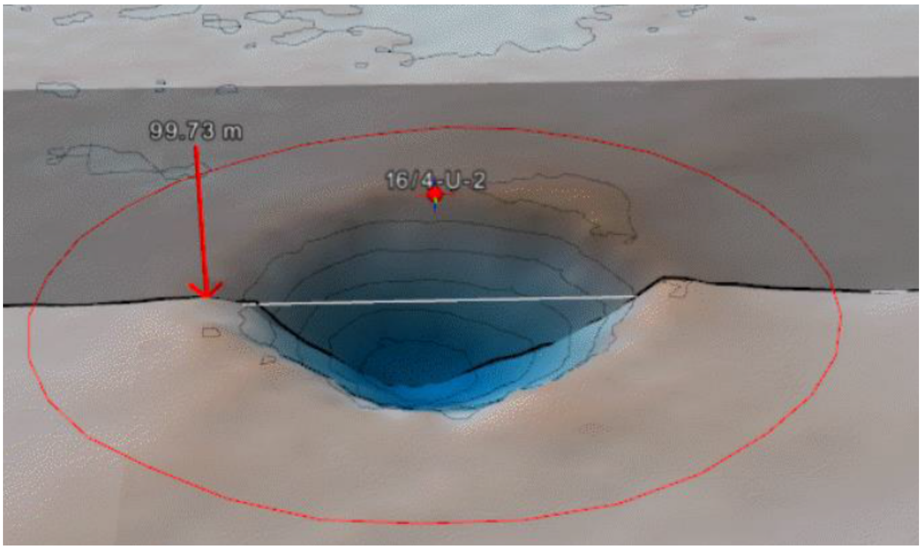


Fig. 7.21 Soil Crater *Soil craters have been experience at all shall gas pilot holes and at all wells while drilling the topholes.*

The size of the craters are such that there is a risk of destabilising the protection structures, both the Integrated Satellite Structure used on Solveig Ph1 and the protection structure use on Rolvsnes EWT.

Remedial work has been required at all satellite locations to fill in the craters.

The subject is currently being addressed in the subsea concept study.

7.7.4 Umbilical Loadout

One umbilical was damaged on Solveig Ph1 during the load-out at the manufacturer's site in Newcastle. The load-out was done from manufacturer's quayside carousel to carousel located under deck on the installation vessel.

An alternative method will most likely be adopted for Solveig Ph2.

7.8 Recommendations for next phase

The subsea concept study is currently ongoing and includes:

- tie-in of additional well(s) in the existing subsea controls (subsea and topside)
- firm up on the design of flexible flowline
- tie-in engineering, including future tie-in points
- further evaluation of geotechnical data and scouring protection
- further evaluate changes to the satellite structures
- further develop Ready For Operations (RFO) activities
- pipeline route and geotechnical survey

Best Available Technique (BAT) evaluation is ongoing internally within Lundin. Additionally, Subsea Contractor will be involved in some of the issues, e.g. subsea leak detection, underwater drones for subsea inspection, monitoring and (possibly) intervention.

8 Use and Modifications of Existing Facilities

This section provides a summary of the use and modifications for existing facilities. For the case of Solveig Phase 2 Segment D, host will be Edvard Grieg.

8.1 Introduction

For Segment D standalone case as well as for the Solveig combined Ph2 case, all production to EG as host will be done via existing Solveig Ph1 subsea tie-in. Minimal host modification are expected on EG.

8.2 Modifications for Solveig Ph2

The host preparation for both Segment D standalone case and Solveig combined Ph2 case will consists of:

- Modifications and additions to the existing Electrical, Instrument and Telecom (EIT) systems, including
  - Installation of additional SCU controllers at EG. Controller nodes have already been allocated for future expansion under Solveig Ph1.
  - Software updated and SCU configuration
  - Relevant modifications to control system network infrastructure with new system nodes (Emergency Shut Down (ESD), Process Shut Down (PSD), Process Control System (PCS)) and vendor cabinets in existing rooms
- NOTE: Limited MEG and gas handling capacity has been identified by host-- this needs to be further evaluated in the next phase of the project inclusive of any synergies with other tie-back projects.

8.3 Lessons Learned from Solveig Ph1

Experience transfer and handover from Solveig Ph1 will be completed in FEED and execution phases. A comprehensive summary for Solveig Ph1 host modifications has been prepared and will be evaluated as the project progresses. In specific, items related:

- Planning & sequencing of works
- Scope definition and maturation.

8.4 Main Activities in Concept and FEED Phase

Host modification activities in Concept and FEED will consist of the following:

- Concept selection considering synergies with other host tie-back projects (e.g. Lille Prinsen, Rolvsnes full field, etc)
- Further evaluate any bottlenecks including the limited MEG and gas handling capacity identified by host

- Concept maturation to acceptable DG3 basis
- Preparation for contracting & execution strategy

9 Operation and Maintenance

Fig. 9.1 Edvard Grieg Platform

9.1 Operating Principles

The operating principles for Solveig Ph 2 (Segment D or Combined B/C) are based on the following:

- The design of the Solveig Ph2 SPS shall minimize the need for operator intervention and potential for human error during operation
- The systems will therefore be designed with a high degree of automation, sequences, and logic to perform and secure functions, and Condition Monitoring (CM) function for operation support
- Solveig Ph2 SPS will be operated from the EG CCR as an integrated part of EG operations
- The normal operation shut down, start-up philosophy and procedures will be developed based on Lundin Energy Norway's requirements and recommended practice
- All control and monitoring will be executed by EG CCR operators with existing SAS
- Failure in the control system for one well will not affect the operation of other wells. Other wells will also include the future wells
- Subsea control system is designed to limit discharges to sea
- Valve commands to one valve will not affect other valves on the same hydraulic system
- Any alarm or event will support the CCR operator in making the right decision and must clearly state the fault and mitigating action
- High degree of sequences for start-up and shut down of subsea wells.

9.2 Organisation and Staffing

There will be no extra staffing requirement in EG CCR to monitor or operate Solveig Ph2 wells.

The Solveig Ph2 subsea control system (SCS) will be integrated with existing EG SAS using dedicated Solveig Ph2 SAS controllers - SCU. The SCU can be an integrated direct communication control solution without any gateway.

EG and Solveig Ph2 will be organized within Lundin Energy Norway Operations. The activity will be organized according to Lundin Energy Norway's common operating model and operated and maintained according to Lundin Energy Norway's work processes for operation and maintenance in Lundin Energy Norway's Management System. The operation of Solveig Ph2 from the EG platform increases the equipment and complexity level and consequently the personnel and support functions for both the offshore and onshore organization. The staffing level for the operation of EG is 40 POB.

9.3 Maintenance

The following elements will be part of the Solveig Ph2 operation and maintenance principles:

- Flow assurance/hydrate control
- Principles for start-up and shut-down
- Valve testing
- Well testing
- Inspection program
- Intervention and simultaneous operation
- Corrosion and erosion control
- Monitoring and metering.

HSE will be a focus area for all operational procedures, with special attention to vessels/crews involved in installation and operation. In principle, all operations will be performed from the CCR on EG.

There is no planned replacement or maintenance of the subsea components for the Solveig Ph2 field, as all subsea systems are designed with a lifetime of 25 years. To avoid frequent replacement, the following design criteria are:

- Critical subsea components are redundant to avoid unplanned shutdowns due to a single failure
- Continuous surveillance and function-testing of critical components is included in the subsea control system and will indicate if any of the critical systems need to be replaced
- There will be a bi-annual external inspection of the total subsea system and regular internal inspection of the production flowline
- Critical components for the operation of the subsea system are replaceable.

9.4 Logistics

The simplified licence coordination agreement between Solveig and EG will define the scope of work (SOW) and responsibility for the operation, ref. Section 13 Commercial Agreements. The following assumptions are made regarding logistics:

- All normal operations of Solveig Ph2 SPS systems and shared facilities on EG are performed by the EG organization according to agreed procedures, manuals, and programs at a predefined tariff rate
- All logistics of chemicals to Solveig Ph2 are handled by EG in accordance with commercial agreements
- All subsea interventions, well operations, and inspections will be performed by Solveig Ph2.

9.5 Lessons learned from Solveig Ph1

- Commissioning procedures should be developed by the contractor and reviewed by the company
- Exchange of personnel between Field Development and Operations for valuable operational experience and capacity to the projects
- Early involvement of Operations in the Project to communicate operations requirement
- Quality in Commissioning and handover/takeover process
- Preparation for operation plan should be ready before DG3
- Handover/takeover procedure to operation to be reviewed
- Preparation for operation organization roles and responsibility
- Involvement of Technical Authority (TA) in reviewing of documents from projects should be looked into in next phase for better process.

9.6 Main activites in Concept and FEED phase

- Update Operational Requirements for topside and subsea
- Follow up projects and contracts
- Follow up Packages
- Preparation for operations plan and budget

10 Decommissioning

The Asset Retirement Obligations (ARO) include Plug & Abandonment (P&A) of wells, facilities decommissioning and removal after cessation of production /27/. The following basic assumptions are made:

- P&A and decommissioning performed immediately after Cessation of Production (CoP)
- Removal start immediately after P&A and decommissioning, i.e. no “cold phase” is assumed
- Subsea production structures are taken to shore for dismantling
- Infield lines and pipelines assumed covered including free ends and free spans
- Umbilical assumed covered, but jumpers removed
- No reuse – all is assumed scrapped
- Removal methods based on today’s technology.

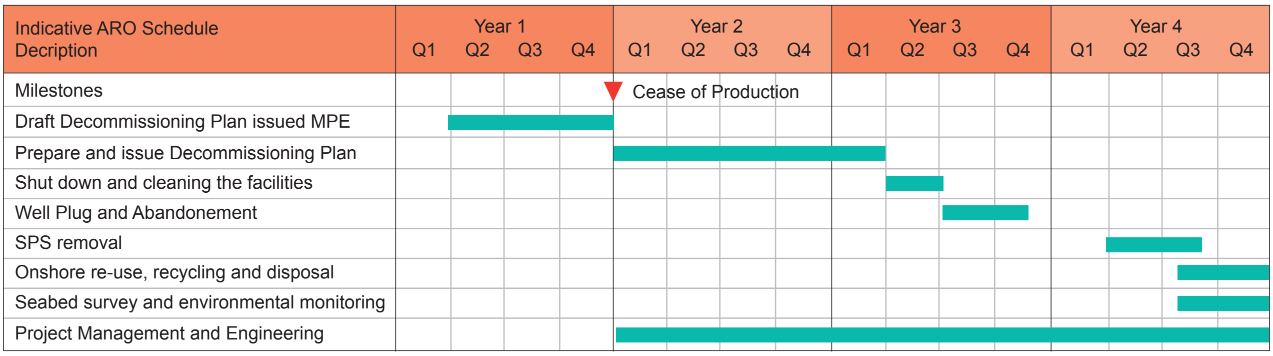


Fig. 10.1 Indicative Decommissioning schedule

10.1 Wells P&A

The well will be plugged and abandoned according to prevailing rules and regulations at the time of operation. Time and cost is based on P&A according to NORSOK D-010 rev.5.

The well design and execution phase will be optimized for an effective future plugging and abandonment phase. Job logs from the casing cement jobs and cement bond logs for casing strings with barrier requirement will be collected.

The primary P&A concept is to place a common (primary/secondary) barrier against the reservoir in the production liner/casing. It is also possible to set a secondary barrier in the intermediate casing if this shoe represents sufficient formation integrity and there is no sand zone with cross flow potential present in the shoe area.

Lundin Energy Norway

Field	: D-Segment	Well design pressure 345 bar	
Well	: D-segment (field development)	Reservoir pressure 184.0 bar	
Schematic	: LU.V 5.7-a1 rev. 1	Prepared by	: Andreas Rønning
Date	: 04-Oct-2021	Verified by	: Randi Næss

Permanent abandonment

Permanent P&A

Planned

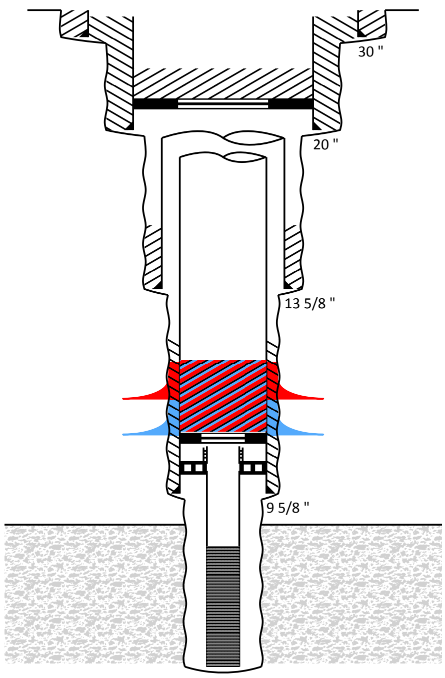
Primary barrier elements

Element	Qualification	Monitoring
Cement plug	Pressure test to 70 Bar above frac at 9 5/8" shoe. Dress plug until hard cement verified	Not accessible
Production casing cement	Cement bond log	Not accessible
Formation (in-situ)	FIT or prognosis strength	Not accessible

Secondary barrier elements

Element	Qualification	Monitoring
Cement plug	Pressure test to 70 Bar above frac at 9 5/8" shoe. Dress plug until hard cement verified	Not accessible
Production casing cement	Formation test, job performance or bond log	Not accessible
Formation (in-situ)	FIT or prognosis strength	Not accessible

Healthy well, no or minor issue



Note:
Cement plug #1 will be set on a pressure tested foundation (mechanical plug) inside the 9 5/8" liner. This plug will act as a common well barrier element (primary and secondary).

The 9 5/8" liner cement shall be verified by a bonding log to confirm minimum 2x30 m cement (common barrier).

Cement plug #2 (environmental plug) is set on a mechanical plug tested to 35 bars above frac at 20" shoe.

Prepared by Lundin

Depth reference: RKB West Bollsta, RKB - MSL

Page 1 of 1

Fig. 10.2 Permanent P&A

10.2 Facilities

Decommissioning and removal of the facilities will comprise the following steps:

- After production ceases, there will be continuous monitoring from EG, and EG services will have to be maintained until P&A of the wells have been completed: including pressure and temperature data monitoring of the wells; hydraulic systems to allow operation of the subsea valves; injection facilities from EG to the wells; vent core from the wells to EG.
- Umbilical will be flushed and cleaned, disconnected and left in trenched position. Umbilical Termination Assemblies (UTA's) will be cut from the umbilical and recovered while the remaining ends of the umbilical will be buried.
- Flexible flowlines will be flushed and cleaned, positively isolated and left in trenched position. Flexible Flowline ends not trenched will be buried during the decommissioning.
- Flexible jumpers will be flushed clean, disconnected and retrieved to the surface
- Production and Gas Lift Tie-in Manifolds will be recovered.
- GRP protection covers will be recovered.
- XTs and Satellite Structures will be recovered.
- Prepare and carry out necessary environmental monitoring
- Inspect the seabed to ensure no hazards are left behind.
- Equipment as e.g. HPU, chemical system and controls on EG is assumed removed within the EG ARO scope of work.

11 Technical Qualifications and BAT assessment

Assessment of Technology Readiness Level (TRL)
Equipment and systems to be used subsea shall be field-proven to TRL 7 based on American Petroleum Institute (API) standard 17N Annex B.10. All items shall be assessed by the contractors and the results presented for Lundin Energy Norway review and acceptance.

For items identified as not at TRL 7, the current TRL shall be identified along with a technical risk categorisation (TRC) (Ref API 17N Annex A) highlighting the risk associated with the type of change from qualified technology.

Items subject to Qualification Testing
For each item with TRL < 7 a programme shall be established detailing the steps required to demonstrate the required reliability and integrity.

Best Available Technology (BAT)

BAT assessments and other decisions with influence on the environmental aspects will include evaluation of the effect on the environment.

12 Health, Safety and Environment

12.1 HSE Objective and Goals

12.1.1 HSE Objective

The HSE objective is to safeguard personnel and assets that may be put at potential risk by the activities of the company and its contractors and to minimize the potential impact of its operations on the environment in the realisation of the project.

12.1.2 HSE Goals

Lundin Energy Norway has adopted the HSE zero harm philosophy, which mean that our goal is:

- Zero injuries and work related illnesses
- No harm to the environment
- No damage to and loss of assets

12.2 HSE Management

Lundin Energy Norway, will ensure that HSE issues are managed systematically and adequately throughout the Solveig Ph2 (Segment D or Combined B/C) development project. The project will be executed in accordance with the company requirements described in the Lundin Management System and supported by project specific procedures.

In Lundin Energy Norway, HSE is a line management responsibility. The project director is accountable for HSE performance within the project. All project managers, discipline leads and project team members are responsible for HSE within their defined functions and areas of responsibility. The project HSE manager is responsible for developing and implementing the HSE program, ensuring that HSE issues are identified and properly addressed in a timely manner.

Norwegian regulatory requirements and therein recognised norms and standards (NORSOK and others) are governing for the Solveig Ph2 field development. Standards of particular relevance to HSE and technical safety include:

NORSOK S-001: Technical Safety (Rev. 6, Nov. 2020)
NORSOK S-002: Working Environment (Rev. 5, Mar. 2018)
NORSOK S-003: Environmental Care (Rev. 4, Oct. 2017)
NORSOK WA-S-006: HSE Evaluation of suppliers and HSEQ requirements in contracts (2020)
NORSOK Z-013: Risk and emergency preparedness assessment (Rev. 3, Oct. 2010)
DNVGL RP-N101: Risk Management for subsea operations (Sep. 2019)

12.3 Barrier Management

Barrier management is an integral part of Lundin Energy Norway's risk management system for managing major accident risk. Barriers are established to prevent or reduce consequences of Major Accident Hazards (MAHs) for Solveig Ph2 during the operational phase.

The scope of the barrier management for the Solveig Ph2 (Segment D or Combined B/C) project is limited to systems delivered by subsea contractor, as well as subsurface (completion). Barrier management for EG topside modifications is covered within the framework of the existing EG Barrier Management Manual, and was performed as part of Phase1.

The following activities are included in the barrier management process:

- Review of the Barrier HAZID from Phase 1 to, to identify potential need for an update related to Solveig Ph2. A review of related technical, operational or organizational barrier elements. The Barrier HAZID covered normal operation (including well integrity), as well as Inspection, Maintenance and Repair (IMR), Light Well Intervention and rig operations.
- Update of the existing Barrier Management Manual for EG Tie-backs, to reflect Solveig Ph2, describing how the Lundin Energy Norway Barrier Management Strategy /34/ is implemented for the Solveig Ph2 project. The Barrier Management Manual describes the barrier functional hierarchy and relation between barrier functions/elements and Performance Standards.
- Review of the subsea Design Performance Standards, established in phase1. The Performance Standards define functional, integrity and survivability requirements for defined barrier functions.The main intention is to group requirements for barrier functions and elements, in order to ensure systematic follow-up. An update of Performance Standard will be done if found required for Phase2, and based on Phase1 experience. Assurance activities will be performed for each Performance Standard, i.e. whether to be followed up and verified as part of design review activities, mechanical completion, commissioning and/or during operation.
- During operation, the status of the barrier functions and elements will be visualized in the barrier panel at EG. The barrier panel is used for operational support, in case of detected deficiencies of barrier elements. Any barrier degradation issues are handled in Synergi. This is already implemented as part of phase1 and used by Operations, and to be updated with additional Phase2 barrier elements.

During the project execution phase (up to and including commissioning), the assurance activities will be documented using the Project Information Management System (PIMS) for full traceability.

12.4 Working Environment

Regulatory requirements, recognized standards such as NORSOK S-002 and R-002, and Lundin Energy Norway's governing documents shall be used for design, planning and execution of the work.

12.5 Natural Environment

In accordance with Norwegian regulations, corporate policies and joint industry goals, Lundin Energy Norway has the following environmental goals applicable for all operations on the Norwegian Continental Shelf (NCS):

- Minimize impact on the natural environment
- Zero non-compliance with permit conditions
- Deliver superior environmental performance
- Prepare for future challenges and opportunities through industry collaboration and leadership

These goals are accomplished by thoroughly mapping and understanding the environmental aspects when planning the activities and by selecting and implementing the Best Available Techniques (BAT) for all operations.

The main environmental aspects related to the Solveig Ph2 development are:

- Emissions to air
- Discharges to sea
- Effect of the discharges to sea on natural resources in the vicinity of the activity
- Environmental risk and oil spill contingency.

An application for approval of fulfilled impact assessment, adressing these aspects, will be preared and submitted to the authorities in paralell with DG2.

BAT assessments and other decisions with influence on the environmental aspects will include evaluation on the effect on the environment.

12.6 Emergency Preparedness

Lundin Energy Norway has an emergency response organization in place, prepared to handle any emergency situation affecting the company; its personnel, assets or activities. The emergency response organization works on three levels: Level 1 is direct response, Level 2 is tactical response and Level 3 is strategic response. Level 2 and Level 3 teams are located onshore and will provide resources, information, advice and support during an emergency incident. Level 2 and 3 each consist of six teams of trained personnel with dedicated roles, on duty 24/7 with one hour mobilization time.

This emergency response plan describes the required level of response to hazardous situations, accidents and major security events that might arise in conjunction with Lundin Energy Norway activities. An emergency in this context is a Defined Situation of Hazard and Accident (DSHA) or when a hazardous event is unresolved and has the potential of becoming a DHSA. These events will be identified in the rig-, vessel- or site Emergency Preparedness Analysis (EPA), or by onshore work sites including Lundin Energy Norway offices. The purpose of the emergency response procedures is to give members of the emergency response teams the necessary guidelines and instructions when exposed to an emergency incident to help affect the outcome in the best possible manner.

The project shall be supported by an oil spill contingency plan. Oil spill contingency will mainly be safeguarded by the Norwegian Clean Seas Association for Operating Companies (NOFO). Through

NOFO, agreements have been established with governmental and inter-municipal emergency preparedness, relating to the potential use of resources, mainly connected to the coastal zones and beach zones.

12.7 Lessons learned from Solveig Ph1

Contractor categorizations and management of Incidents

Under the Solveig Ph1 project a number of incidents were reported where it was not evident how and to which degree Company should be involved. The Project was missing a clear strategy on the follow-up of contractors and sub-contractors based on pre-assessment of parameters such as scope of work, HSE trending, estimated number of work hours, audit history, presence of company representative etc. A new work process is being drafted for use in future projects.

HSE training of hired personnel and site representatives

Due to COVID-19 and restrictions on national and international travelling, the importance of site representatives and hired personnel also monitoring and reporting on HSE performance became evident. This had been included as a general requirement in some of the job descriptions, but only vessel representatives were provided with extended HSE training. The extent and requirements in future projects shall be determined based on contractor categorization, ref. item above.

12.8 Recommendations for next phase

Establish Project HSE Plan, assess KPIs

Revise procedure for follow-up strategy and contractor catagorization.

Establish HSE functional requirements

Establish Permits and Consents plan

Perform Environmental Hazard Identification (ENVID) and BAT assessments

13 Commercial Agreements

The hydrocarbon stream from Solveig Ph2 (Segment D or Combined B/C) will be processed on Edvard Grieg platfrom into stabilized oil and rich gas.

Stabilized oil will be transported through EGOP, GOP and stored at the Sture terminal as part of the OTS and offloaded to the market.

Rich gas will be transported through UHGP to the SAGE System. At the SAGE terminal in St. Fergus, the rich gas will be separated into sales gas and NGLs. The sales gas will enter the market at the inlet of National Transmission System (NTS) and the NGLs will be transported to Shell Esso Gas and Associated Liquids (SEGAL) fractionation plant at Mossmorran. NGL products are stored and offloaded at Braefoot Bay.

The commercial plan is to utilize the downstream agreements already in place for Solveigh Ph1 and explore the possibility for amendments related to capacity rights etc. The aim is to agree on necessary amendments by DG2 and conlude the amedments by DG3.

Similar to Solveig Ph1, rich gas from Solveig Ph2 is expected to be outside the required SAGE inlet specification as regards ethane ratio. A discussion is ongoing in the UK related to the change of the NTS inlet specification related to Wobbe Index and ICF (Incomplete Combustion Factor). Conclusion is anticipated in 2022. A change will significantly ease the issue related to the SAGE inlet specification.

Table 13.1 shows a list of downstream agreements which are illustrated in Fig. 13.1.

Table 13.1 List of downstream agreements

List of downstream agreement
EGOP Transportation Agreement (EGOP TA)
GOP Transportation Agreement (GOP TA)
OTS Handling and Storage Agreement (OTS HA)
UHGP Transportation Agreement (UHGP TA)
SAGE Transportation and Processing Agreements (SAGE TPA)
SEGAL Fractionation and Transportation Agreements (SEGAL FTA)

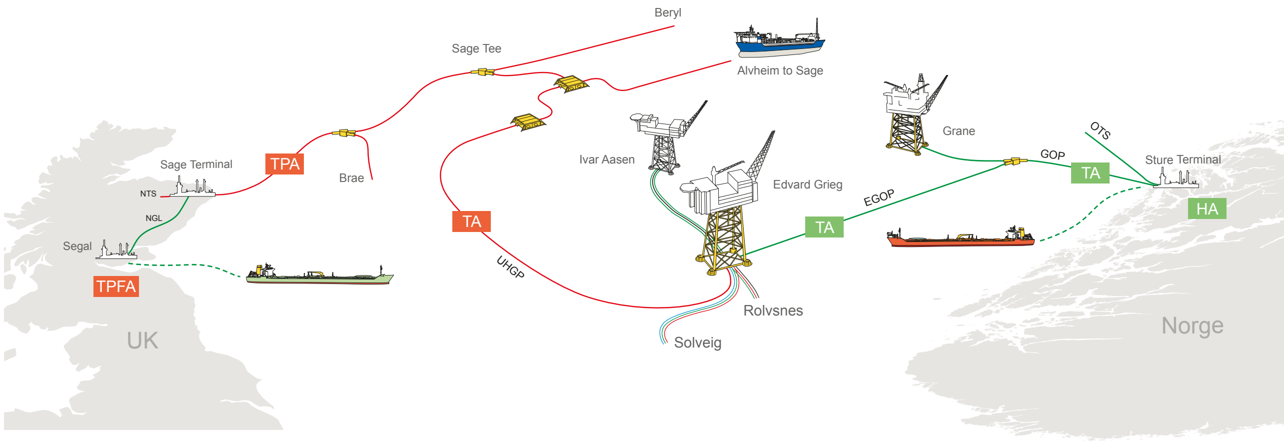


Fig. 13.1 Downstream agreement illustration

Simplified licence coordination agreement between PL338 and PL359

PL338 and PL359 has entered into a simplified coordination agreement. The agreement simplify administration, optimize future development and operations, and reduce operating expenditures thereby enhancing the value from both licensees. In addition there will be no need for tie-in and processing agreements between the licences.

Other Agreements

The development of Solveig Ph2 will require a number of crossing and proximity agreements to be in place prior to drilling and installation activities. Such agreements will be based on the NCS oil industry established standard agreements.

14 Development Costs

14.1 Investments

This Chapter describes the investment cost for Segment D standalone case (Table 14.1) and Solveig combined Ph2 case (Table 14.2).

The cost estimates have been established based on Lundin Energy Norway's estimating procedures, where input are based on a combination of external study work, internal evaluations, Company's subsea CoopA agreement and experience data.
The cost estimates are considered class 'B' estimates with an overall cost accuracy of +/- 40%.

Other owners costs

The other owners costs are mainly based on experience data of the Solveig and Rolvsnes EWT execution projects. Both the Segment D standalone case and Solveig combined Ph2 case are based on the assumption that the same management, subsurface and operation preparation teams are needed to execute the different cases.

Facilities

Facilities management

Facilities management are mainly based on experience data of the Solveig and Rolvsnes EWT execution projects. Both the Segment D stand alone case and Solveig Combined Ph2 case are based on the assumption that the same Facilities management teams are needed to execute the different cases.

SPS & SURF

The SPS & SURF cost estimate are estimated based on an internal cost estimate model which accounts for the established Corporate Agreement between the Operator and a preferred Contractor. Additionally the cost estimating model is based on experience data from Solveig and Rolvsnes EWT execution projects and benchmarked against other projects.

Subsea completion

SPS commissioning is included with 7 MNOK per well, based on experience data from Solveig and Rolvsnes EWT execution projects.

Topside modifications
There are no modifications required for the Segment D standalone case or the Solveig combined Ph2 case. 5 MNOK per well have been included for SAS upgrades.

Facilities contingency

15% contingency of the total Facilities estimate have been included for both the Segment D stand alone case and Solveig Combined Ph2 case.

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16 References

The name Luno II found in the documents below all refer to the Solveig Field in PL359.

Table 16.1 Document references listed in Solveig PDO

Ref	Document Title	Document Number	To be updated prior to DG2/ DG3
1	Luno II DG3 report	23590-LUNAS-Z-RA-00023	New document needed for DG3
2	Luno II Design Basis	23590-LUNAS-Z-FD-00001	Update at DG2 and DG3
3	Luno II Functional and Operational Requirement	23590-LUNAS-Z-RD-00002	Update at DG2 and DG3
4	Solveig DG3 Subsurface Report	23590-LUNAS-X-RA-00005	New document needed
5	Solveig PDO, Main Plan Drilling and Well Activities	006179	New document needed
6	Solveig DG3 Facilities report	23590-LUNAS-Z-RA-00025	
7	EG Tie-backs HSE Program	52001U-LUNAS-S-TA-00001	New document needed
8	Konsekvenser ved utbygging og drift av Luno II	23590-LUNAS-S-RA-00001	New document needed
9	PL 359 Luno II søknad om oppfylt utredningsplikt - tilleggsopplysninger	006477	N/A
10	EG Tie-backs Risk Management Manual	52001U-LUNAS-S-MA-00001	Update at DG2 and DG3
11	Solveig Case Book	23590-LUNAS-F-RA-00001	N/A
12	Luno II DG2 Concept screening report	23590-LUNAS-Z-RA-00004	New document needed
13	Luno II Risk Evaluation of Subsea Concepts	23590-LUNAS-Z-RA-00020	N/A
14	Luno II Project Execution and Overall Procurement Strategy (PEOPS)	23590-LUNAS-Z-TA-00001	New document needed
15	Solveig Project Control Basis	23590-LUNAS-F-TA-00001	New document needed

16	Luno II Project Execution Plan	23590-LUNAS-F-TA-00002	New document needed
17	EG Tie-backs Project Quality Plan	52001U-LUNAS-Q-TA-00001	Update at DG2 and DG3
18	Luno II DG2 Presentation	23590-LUNAS-Z-RA-00026	New document needed
19	LENO HSE Risk Acceptance Criteria	9000-LUNAS-S-FD-0001	APOS HS. DK03-Risk Management
20	Principles for a round table negotiations regarding tie-in of Luno II facilities to Edvard Grieg facilities	002420	N/A
21	Edvard Grieg: Key Interfaces for Subsea Tie-ins	23380-LUNAS-M01-Z-FD-00002	
22	Luno II SPS & SURF early phase contract strategy	004219	New document needed
23	Evaluation report Cooperation Agreement for Luno II and Utsira High SPS/SURF Development	LENO 000811	n/A
24	Topside Modifications FEED Study Summary Report	23380M-LUNAS-A-RA-00001	New document needed
25	Flow assurance study Luno II	23590-LUNAS-Z-RD-00002	New document needed
26	NPD guidelines for designation of wells and wellbore		
27	Luno II Annual ARO Assessment	23590-LUNAS-Z-RA-00024	Updated each year
28	Cost sharing agreement regarding Edvard Grieg Topside Modifications Related to Tie-in of the Luno II and the Rolvsnes Field to the Edvard Greig Platform between the Edvard Grieg Group and the Luno II Group and the Rolvsnes group.	006220 Dated 15.10.2018	N/A
29	Edvard Greig Tie-backs - Interface Procedure	52001U-LUNAS-Z-KA-00001	
30	Samfunnsmessige konsekvenser utbygging og drift av Luno II PL359	23590-LUNAS-Z-RA-00021	New document needed
31	PL359 Luno II Request for use	002110	N/A
32	Response to PL359's Request for Use of Edvard Grieg (EG) facilities	005898	N/A
33	HSE Management in Development Projects	90000-LUNAS-S-RD-00001	VOID

34	LENO Barrier Management Strategy	90000-LUNAS-Z-QP-00002	ProArc 003490
35	EG Tie-backs Change Management Procedure	52001U-LUNAS-Q-KA-00001	Update at DG2 and DG3
36	EG Tie-backs Risk Matrix	52001U-LUNAS-S-LA-00001	Keep as is
37	Design Basis for EG Topside Modifications for tie-ins	23380-LUNAS-M01-Z-FD-0001	
38	Solveig Plan for Utbygging og Drift (PUD) - Sammendrag		N/A
39	Tillegg til dokumentet "Konsekvenser ved utbygging og drift av Luno II" - Vedlegg til PUD for Solveig Ph2	23590-LUNAS-S-RA-00004	N/A
40	Engineering Numbering System (ENS)	23380-LU-000-Z-SA-00002	
41	Mechanical Completion Manual	90000-LUNAS-Z-KA-00001	Update with lesson learned form EGTB Ph1
42	Preservation Manual	90000-LUNAS-Z-KA-00002	Update with lesson learned form EGTB Ph1
43	Commissioning Manual	90000-LUNAS-Z-KA-00003	Update with lesson learned form EGTB Ph1
44	HSE Activity Plan	52001U-LUNAS-S-TA-00002	New document, update at DG2 and DG3
45	Svarbrev: Søknad om samtykke til inngåelse av vesentlige kontraktsmessige forpliktelser for Luno II	18/459-13	N/A
46	Svarbrev: Søknad om samtykke til inngåelse av vesentlige kontraktsmessige forpliktelser for Luno II	18/459-22	N/A
47	Svarbrev: Luno II - godtgjøring av at utredningsplikt er oppfylt	18/459-23	N/A

Table 16.2 New documents developed as part of Solveig Ph2 work

Ref	Document Title	Document Number	To be updated prior to DG2/ DG3
48	Geological Final Well Report Exploration Well 16/4-13 S and ST2	009600	N/A
49	16/4-13 S Discovery Report	N/A	N/A
50	PL359 RC mtg hand-out 09.06.21 - 16/4-13 well results	N/A	N/A
51	PL359 RC mtg hand-out 23.09.21 - Seismic interpretation, structural and facies model	N/A	N/A
52	PL359 RC mtg hand-out 27.10.21 - Solveig Segment D reservoir basis	N/A	N/A
53	PL359 RC mtg hand-out 24.11.21 - Solveig Segment B Synrift volumetric update	N/A	N/A
54	Solveig Phase 2 Feasibility Flow Assurance Report	32002B-LUNAS-P-RA-00001	Update at DG2 and DG3
55	PL359 RC mtg hand-out 20.05.20 - 2020 H1 Case A model - dynamic model	N/A	N/A

17 Appendices

17.1 Tabulated Production Profiles

Table 17.1 Average production rates - Solveig Segment D stand-alone case

	Segment D depletion			**Segment C infill extention[*)]**			**Total**		
	Oil	*Rich Gas*	*Water*	*Oil*	*Rich Gas*	*Water*	*Oil*	*Rich Gas*	*Water*
Year	Sm3/d	MSm3/d	Sm3/d	Sm3/d	MSm3/d	Sm3/d	Sm3/d	MSm3/d	Sm3/d
2025	569	0.09	51	116	0.02	0	686	0.11	51
2026	165	0.02	104	188	0.03	3	353	0.05	107
2027	108	0.02	113	190	0.03	16	298	0.05	129
2028	82	0.01	112	190	0.03	58	272	0.04	170
2029	66	0.01	109	173	0.03	155	239	0.04	263
2030	52	0.01	101	93	0.01	217	146	0.03	317
2031	45	0.01	100	37	0.01	243	83	0.01	343
2032	39	0.01	96	23	0.00	263	62	0.01	359
2033	34	0.01	91	18	0.00	281	52	0.01	373
2034	29	0.01	84	14	0.00	284	43	0.01	368
2035	26	0.01	80	12	0.00	294	38	0.01	374
2036	24	0.01	76	11	0.00	301	34	0.01	378
2037	22	0.01	72	9	0.00	302	30	0.01	375
2038	20	0.01	69	7	0.00	305	27	0.01	375
2039	18	0.01	66	5	0.00	312	23	0.01	378
2040	17	0.01	63	3	0.00	307	20	0.01	371
2041	16	0.01	60	0	0.00	128	16	0.01	188
Total MSm3/ GSm3	0.49	0.09	0.53	0.40	0.06	1.27	0.89	0.15	1.80

)Process correction factors used for Segment C: Oil expansion factor = 1.107, Gas shrinkage factor = 0.868 (no factors used for Segment D)

Table 17.2 Average production rates - Solveig combined phase 2 case

Year	***Segment B Synrift (Q3 2021 update)***			***Total (including Segment D and C from above table)***		
	Oil	Rich Gas	Water	Oil	Rich Gas	Water
Year	Sm3/d	MSm3/d	Sm3/d	MSm3/d	Sm3/d	Sm3/d
2025	505	0.27	0	1191	0.38	51
2026	455	0.51	0	808	0.56	107
2027	342	0.17	0	641	0.21	129
2028	268	0.10	0	540	0.15	170
2029	232	0.08	0	471	0.12	263
2030	201	0.06	0	347	0.08	317
2031	174	0.05	0	256	0.06	343
2032	150	0.03	0	212	0.05	359
2033	130	0.03	0	182	0.04	373
2034	112	0.02	0	156	0.03	368
2035	97	0.02	0	136	0.02	374
2036	84	0.01	0	119	0.02	378
2037	73	0.01	0	103	0.02	375
2038	63	0.01	0	90	0.01	375
2039	54	0.01	0	78	0.01	378
2040	47	0.00	0	67	0.01	371
2041	41	0.00	0	57	0.01	188
Total	1.11	0.50	0	1.99	0.65	1.80

Process correction factors used for Segment B Synrift: Oil expansion factor = 1.107, Gas shrinkage factor = 0.868
No water has been included for this incremental profile since the water production from Solveig will be initially reduced by bringing on Phase 2 Synrift

17.2 Tabulated Operational Expenditures

Table 17.3 Solveig Segment D - DG 1 Reference Case OPEX

Segment D	Unit	Sum	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Operating	$MNOK_{22}$	273	0	0	0	19	19	19	19	19	19	19	19
Oil tariffs	$MNOK_{22}$	40	0	0	0	12	6	5	5	4	2	1	1
Gas & NGL tariffs	$MNOK_{22}$	63	0	0	0	17	9	7	7	7	4	2	2
G&A	$MNOK_{22}$	77	2	13	44	3	1	1	1	1	1	1	1
Environmental	$MNOK_{22}$	62	0	0	11	0	0	0	0	0	0	0	0
Power	$MNOK_{22}$	197	0	0	0	14	14	14	14	14	14	14	14
Sum	**$MNOK_{22}$**	**661**	**2**	**13**	**55**	**65**	**49**	**47**	**46**	**45**	**41**	**38**	**38**
Cum. Sum	$MNOK_{22}$	NA	2	16	71	135	185	232	278	324	365	403	441
Segment D	**Unit**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**
Operating	$MNOK_{22}$	19	19	19	19	19	19	0	0	0	0	0	0
Oil tariffs	$MNOK_{22}$	1	1	1	1	1	0	0	0	0	0	0	0
Gas & NGL tariffs	$MNOK_{22}$	2	2	1	1	1	1	0	0	0	0	0	0
G&A	$MNOK_{22}$	1	1	1	1	1	1	0	0	0	0	0	0
Environmental	$MNOK_{22}$	0	0	0	0	0	0	0	0	0	0	0	0
Power	$MNOK_{22}$	14	14	14	14	14	14	0	0	0	0	0	0
Sum	**$MNOK_{22}$**	**37**	**37**	**37**	**37**	**36**	**36**	**0**	**0**	**0**	**0**	**0**	**0**
Cum. Sum	$MNOK_{22}$	478	515	552	588	625	661	661	661	661	661	661	661

Table 17.4 Solveig Combined Ph2 OPEX

Combined Ph2	Unit	Sum	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Operating	$MNOK_{22}$	900	0	0	0	53	53	53	53	53	53	53	53
Oil tariffs	$MNOK_{22}$	93	0	0	0	20	14	11	9	8	6	4	4
Gas and NGL tariffs	$MNOK_{22}$	283	0	0	0	59	89	34	24	19	13	10	7
G&A	$MNOK_{22}$	158	2	24	50	46	2	2	2	2	2	2	2
Environmental	$MNOK_{22}$	29	0	0	10	20	0	0	0	0	0	0	0
Power	$MNOK_{22}$	239	0	0	0	14	14	14	14	14	14	14	14
Sum	**$MNOK_{22}$**	**1 702**	**2**	**24**	**60**	**212**	**172**	**114**	**102**	**96**	**89**	**83**	**80**
Cum. Sum	$MNOK_{22}$	NA	2	26	86	298	470	584	686	782	871	954	1 034
Combined Ph2	**Unit**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**
Operating	$MNOK_{22}$	53	53	53	53	53	53	53	53	53	0	0	0
Oil tariffs	$MNOK_{22}$	3	3	2	2	2	2	1	1	1	0	0	0
Gas and NGL tariffs	$MNOK_{22}$	6	5	4	3	3	2	2	2	1	0	0	0
G&A	$MNOK_{22}$	2	2	2	2	2	2	2	2	2	0	0	0
Environmental	$MNOK_{22}$	0	0	0	0	0	0	0	0	0	0	0	0
Power	$MNOK_{22}$	14	14	14	14	14	14	14	14	14	0	0	0
Sum	**$MNOK_{22}$**	**78**	**77**	**75**	**74**	**74**	**73**	**72**	**72**	**72**	**0**	**0**	**0**
Cum. Sum	$MNOK_{22}$	1 113	1 189	1 265	1 339	1 413	1 486	1 558	1 630	1 702	1 702	1 702	1 702

Table 17.5 Solveig Segment D - DG 1 Reference Case Income

Segment D	Unit	Sum	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Oil	$MNOK_{22}$	2 771	0	0	0	803	414	349	320	280	171	97	72
Sales gas	$MNOK_{22}$	318	0	0	0	84	43	37	36	33	20	12	10
NGL	$MNOK_{22}$	134	0	0	0	36	18	16	15	14	8	5	4
Sum	**$MNOK_{22}$**	3 222	0	0	0	923	475	402	371	327	199	114	86
Cum. Sum	$MNOK_{22}$	NA	0	0	0	923	1 399	1 801	2 172	2 499	2 698	2 812	2 898
Segment D	**Unit**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**
Oil	$MNOK_{22}$	61	51	45	41	35	31	0	0	0	0	0	0
Sales gas	$MNOK_{22}$	9	8	7	6	6	6	0	0	0	0	0	0
NGL	$MNOK_{22}$	4	3	3	3	3	3	0	0	0	0	0	0
Sum	**$MNOK_{22}$**	**73**	**62**	**55**	**49**	**44**	**40**	**0**	**0**	**0**	**0**	**0**	**0**
Cum. Sum	$MNOK_{22}$	2 971	3 033	3 088	3 138	3 182	3 222	3 222	3 222	3 222	3 222	3 222	3 222

Table 17.6 Solveig Combined Ph2 Income

Combined Ph2	Unit	Sum	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Oil	$MNOK_{22}$	6 393	0	0	0	1 395	947	750	636	552	406	300	249
Sales gas	$MNOK_{22}$	1 416	0	0	0	297	446	169	118	96	67	48	37
NGL	$MNOK_{22}$	597	0	0	0	125	188	71	50	40	28	20	16
Sum	**$MNOK_{22}$**	**8 406**	**0**	**0**	**0**	**1 818**	**1 581**	**990**	**804**	**688**	**502**	**368**	**302**
Cum. Sum	$MNOK_{22}$	NA	0	0	0	1 818	3 399	4 389	5 193	5 881	6 383	6 751	7 053
Combined Ph2	**Unit**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**
Oil	$MNOK_{22}$	213	182	159	140	121	105	91	79	67	0	0	0
Sales gas	$MNOK_{22}$	29	24	19	15	13	12	10	9	7	0	0	0
NGL	$MNOK_{22}$	12	10	8	7	6	5	4	4	3	0	0	0
Sum	**$MNOK_{22}$**	**255**	**216**	**187**	**162**	**139**	**122**	**105**	**91**	**77**	**0**	**0**	**0**
Cum. Sum	$MNOK_{22}$	7 308	7 524	7 711	7 872	8 012	8 133	8 238	8 329	8 406	8 406	8 406	8 406

18 Abbreviations

Table 18.1 Abbreviations

AI	Acoustic impedance
ALD	Acoustic Leak Detector
APA	Awards in Pre-defined Areas
API	American Petroleum Institute
ARO	Asset Retirement Obligations
ASV	Annulus Safety Valve
BAT	Best Available Technology
BCU	Base Cretaceous Unconformity
BOG	Beslutning om gjennomføring (Licence DG3)
BOP	Blow Out Preventer
BOV	Beslutning om videreføring (Licence DG2)
BTE	Best Technical Estimate
Capex	Capital Expenditure
CCR	Central Control Room
CM	Condition Monitoring
CMS	Completion Management Systems
CoP	Cessation of production
DG2	Decision Gate 2
DG3	Decision Gate 3
DHPG	Down Hole Pressure Gauge
DHSV	Down Hole Safety Valve
Drillex	Drilling Expenditure
DSHA	Defined Situation of Hazard and Accident
DST	Drill Stem Test
ECD	Equivalent Circulating Density
ECS	Elemental Capture Spectroscopy
EDP	Emergency Disconnect Package
EFAT	Extended Factory Acceptance Test
EG	Edvard Grieg
EGOP	Edvard Grieg Oil Pipeline

EGTM	Edvard Grieg Topside Modifications
EIA	Environmental Impact Assessment
EIT	Electrical, Instrument and Telecommunication
EPA	Emergency Preparedness Analysis
EPC	Engineering, Procurement and Construction
EPCI	Engineering, Procurement, Construction and Installation
EPU	Electric Power Unit
ESD	Emergency Shut Down
F&G	Fire & Gas
FAS	Flow Advisory System
FAT	Factory Acceptance Test
FEED	Front End Engineering Design
FID	Final Investment Decision
FMECA	Failure Mode, Effects and Criticality Analysis
FWL	Free Water Level
GL	Gas Lift
GOC	Gas Oil Contact
GOP	Grane Oil Pipeline
GOR	Gas Oil Ration
GRP	Glass Reinforced Polyester
GTC	General Terms and Conditions
HA	Handling Agreement
HAZID	Hazards Identification
HAZOP	Hazard and Operability
HFL	Hydraulic Flying Lead
HOC	Head Office Cost
HPU	Hydraulic Power Unit
HSE	Health, Safety and Environment
HSEQ	Health Safety Environment and Quality
IA	Ivar Aasen
IC	Interfacing Contractor
ICD	Inflow Control Device
ICV	Inflow Control Valve
ID	Internal Diameter

ILT	In-Line Tee
IO	Input / Output
IOR	Improved Oil Recovery
IRR	Internal Rate of Return
ISS	Integrated Satellite Structure
JOA	Joint Operating Agreement
JS	Johan Sverdrup
KPI	Key Performance Indicator
L2S	Licence2Share
LET	Lomeland, Ebeltoft og Thomas
LIC	Lead Interface Contractor
LLI	Long Lead Items
LRP	Lower Riser Package
LWD	Logging While Drilling
MAH	Major Accidents Hazard
MC	Mechanical Completion
MEG	Mono-Ethylene Glycol
MLT	Multi Lateral Technology
MNOK	Millioner Norske Kroner (million NOK)
MPE	Ministry of Petroleum and Energy
MPFM	Multi Phase Flow Meter
MPP	Manpower Projection Plan
MSL	Mean Sea Level
MSV	Multi Service Vessel
NCS	Norwegian Continental Shelf
ND	Nominal Diameter
NGA	Next Generation Automation
NGL	Natural Gas Liquid(s)
NMR	Nuclear Magnetic Resonance
nmVOC	Non methane Volitile Organic Carbones
NOFO	Norsk Oljevernforening For Operatørskap (Norwegian Clean Seas Association for Operating Companies)
NORSOK	NORsk SOkkels Konkurranseposisjon
NPD	Norwegian Petroleum Directorate

NPV	Net Present Value
NTT	No Touch Time
Opex	Operational Expenditure
OTS	Oseberg Transport System
OWC	Oil Water Contact
P&A	Plug & Abandonment
PCS	Process Control System
PDO	Plan for Development and Operations
PEP	Project Execution Plan
PIMS	Project Information Management System
PiP	Pipe-in-Pipe
PL	Production Licence
PLEM	Pipeline End Manifold
PSA	Petroleum Safety Authority
PSD	Process Shut Down
PVT	Pressure, Volume, Temperature
QRA	Quantitative Risk Assessment
R&D	Research and Development
RFC	Ready for Commissioning
RFCC	Ready for Commissioning Certificate
RFJ	Reactive Flex Joint
RFO	Ready-for-operation
RFOC	Ready for Operation Certificate
RLWI	Riserless Light Well Intervention
ROV	Remote Operated Vehicle
RWP	Rosenberg WorleyParsons
SAGE	Scottish Area Gas Evacuation
SAS	Safety and Automation System
SCAL	Special Core Analysis
SCU	Subsea Control Unit
SEGAL	Shell Esso Gas and Associated Liquids
SIMOPS	Simultaneous operations
SOW	Scope of Work
SPS	Subsea Production System

SSIV	Subsea Safety Isolation Valve
SURF	Subsea Umbilicals, Flowlines and Risers
TA	Transportation Agreement
TPOSA	Transportation, Processing and Operating Services Agreement
TRC	Technical Risk Categorisation
TRL	Technology Readiness Level
TRT	Tree Running Tool
TVD	True Vertical Depth
UHGP	Utsira High Gas Pipeline
UPS	Uninterruptible Power Supplies
UR	Ultimate Recovery
UTA	Umbilical Termination Assembly
VXT	Vertical XT
WAG	Water Altering Gas
WAT	Wax Appearance Temperature
WBS	Well Bore Schematics
WH	Well Head
WI	Water Injection
WLR	Wellhead Load Relief
WOR	Workover Riser
XT	X-mas tree (well valve tree)

wintershall

OMV

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