Modeling Operational Parameters to Support Evaluation of Subsea-to-Shore Production System Implementation

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Abstract. The subsea-to-shore system represents an alternative approach to traditional offshore oil production, emphasizing environmental improvements by reducing carbon emissions through alternative energy sources like hydroelectric power. This system incorporates an onshore processing unit, eliminating the need for a Stationary Production Unit (SPU), thereby reducing costs, offshore personnel exposure, and its associated occupational risks. Additionally, terrestrial processing units offer greater flexibility for expansion and installation of new modules compared to SPUs, which are constrained by limited space. This paper aims to establish critical parameter limits essential for implementing the subsea-to-shore system based on a representative production field. Key parameters include distance to the coastline and various export pipeline diameters suitable for specific water depths, ensuring optimal operational performance. These studies utilized multiphase flow simulation software, leveraging data approximations from Norway's Ormen Lange Field, one of the largest gas fields, as a foundational basis. Results derived from the applied model and variables provide preliminary insights into the feasibility of implementing such systems, prompting further discussion within the scientific community regarding advancements in oil and gas production systems.

Keywords: submarine systems, production systems, subsea-to-shore.

1 Introduction

Offshore operations often face challenges such as limited space, restricted production system capacity, and high costs associated with additional facilities. Therefore, studying different production systems becomes crucial to select the optimal option considering economic, financial, operational, and engineering variables. These production systems consist of various equipment installed on the seabed, designed to transport fluids from one or more subsea wells to a processing facility. This facility can either be offshore, as in the case of a Stationary Production Unit (SPU), or onshore directly connected to the coast via a subsea-to-shore system.

The choice of the most suitable subsea system hinges on critical factors including the number and positioning of wells, reservoir characteristics, pipe specifications (such as diameter and length), surface facilities like the type of SPU and process plant limitations, desired production conditions, and lifting equipment considerations [1].

The subsea-to-shore system offers numerous advantages, such as reduced carbon emissions through onshore processing and decreased offshore personnel, thereby lowering exposure to associated risks. Despite its potential, as a nascent system, ongoing technological advancements are necessary to optimize seabed equipment layout and ensure flow assurance.

This paper aims to establish critical parameter values essential for implementing the subsea-to-shore system, utilizing a representative production field based on the Ormen Lange field. Key parameters include distance from the coast and various export pipeline diameters tailored to specific water depths to ensure optimal operational performance. Multi-phase flow simulation software has been employed to compare different scenarios proposed in this study.

The structure of this paper is as follows: Section 2 introduces the theoretical framework; Section 3 outlines the methodology; Section 4 presents the case study; Section 5 discusses the results obtained from the multi-phase flow simulation software; and finally, Section 6 presents the conclusions drawn from this research.

2 Theorical reference

Each oil field possesses unique characteristics that dictate the selection of the most suitable subsea system based on its operational requirements. In traditional subsea systems, offshore platforms can be either fixed or floating. The well completion varies depending on the location of the Christmas Tree: it can be dry, where the equipment is located at the surface, or wet, when positioned on the seafloor.

A notable alternative to traditional systems is the subsea-to-shore approach, which eliminates the need for a SPU by connecting seabed equipment directly to an onshore facility. For instance, the Ormen Lange field, discovered by Norsk Hydro in 1997 and commencing production in 2007, exemplifies this approach. Located in the Norwegian Sea at depths ranging from 800 m to 1100 m, approximately 120 km west-northwest of the Nyhamna Processing Plant [2], the reservoir has a depth of around 3000 m. Its challenging topography, marked by irregular depressions caused by the Storegga Slide [3], underscores its complex operational environment.

The subsea layout comprises 24 wellheads connected to the Nyhamna onshore plant via two 30 inches multiphase production lines. Following processing, the dry gas is transported through a 1200 km pipeline to Easington, United Kingdom [2]. The Nyhamma onshore facility has the capacity to export about 84 million standard cubic meters of gas per day [4].

3 Methodoly

3.1 Multiphase flow correlation

This study utilized a multiphase flow simulation software widely employed in the oil and gas industry for steady-state analysis. The software is capable of modeling multiphase flows, heat transfer, and fluid properties, specifically designed for application in subsea production facilities. It facilitates nodal analysis and ensures flow assurance by utilizing a diverse array of multiphase flow correlations.

The software incorporates numerous multiphase flow correlations that enable calculation of flow regimes, slug characteristics, and pressure losses across all nodes along production lines. Severe slugging occurs due to liquid accumulation or instability caused by changes in pipeline profile inclination. The software predicts hydrodynamic slugs, scaling their size and frequency based on pipeline length to optimize subsea layout.

The Hagedorn & Brown correlation was applied for vertical multiphase flow, while the Beggs & Brill correlation was used for horizontal multiphase flow. The Hagedorn & Brown correlation calculates pressure loss based on experimental studies of pressure gradients in continuous two-phase flow through small-diameter vertical tubes [5]. On the other hand, the Beggs & Brill correlation computes pressure loss and holdup for various pipeline inclination angles [6].

3.2 Hydrates

Flow assurance issues can arise during fluid transportation in production lines, with one of the primary concerns being the formation of solids such as hydrates. Hydrates are crystalline compounds formed when gas molecules are surrounded by water molecules. They typically form under operational conditions where water and gas come into contact at low temperatures and high pressures, particularly in turbulent flow regimes. Hydrates have the potential to cause blockages in oil production lines and equipment, leading to reduced flow rates, increased pumping power requirements, and operational risks [7].

The software utilized in this study includes a pre-defined data package capable of generating hydrate formation curves within the phase envelope. It enables the creation of production profiles overlaid on phase envelopes to predict the occurrence and location of hydrate formation, providing information on hydrate formation temperatures and delta hydrate subcooling temperatures. This analysis aids in determining the potential for hydrate formation in individual wells or extensive networks and assesses the effectiveness of hydrate inhibitors, facilitating the calculation of necessary treatment quantities to prevent hydrate formation.

3.3 Nodal analysis

Nodal analysis is a method used to assess well performance, with applications spanning well design, completion, artificial lift selection and design, equipment sizing, system bottleneck identification, and flow assurance analysis. The adopted software enables users to generate input and output graphs at any system point and conduct sensitivity analyses on various system variables combining the various components of a given oil or gas production or transportation system. The process involves dividing the system at a specific point of interest, referred to as the nodal analysis point. Pressure solutions are then computed separately for the upstream (inflow) and downstream (outflow) subsystems from this point. The system's operating point, where there is no pressure differential at the nodal analysis point between the subsystems, is determined by graphically intersecting the inflow and outflow performance curves for each well (Fig. 1).

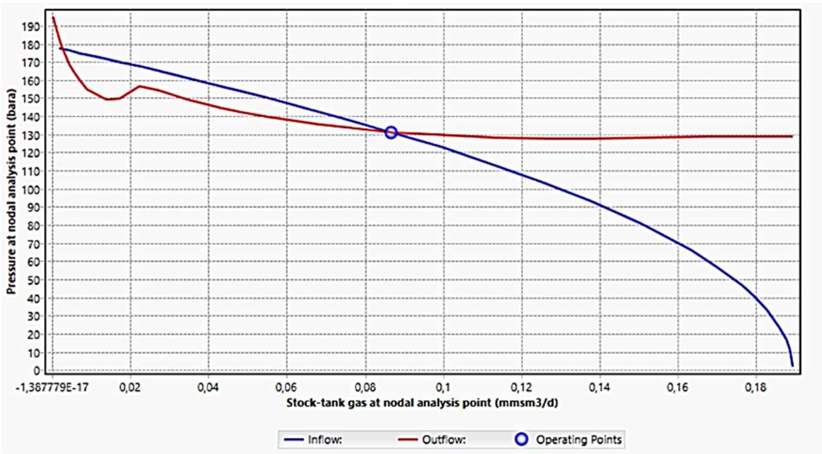

Figure 1. Nodal analysis flowchart

4 Case study

This study conducted 12 simulations, focusing on the production system layout originating from the Ormen Lange field. The scenarios considered various input variables, including production fluids, tubes geometry and cost distances. Three types of production fluids were analyzed, each based on compositions found in both the Ormen Lange and Brazilian gas reservoirs.

4.1 Production fluids

Fluid A was formulated based on the composition of fluids from the Ormen Lange field [8], while Fluids B and C reflect typical gas compositions from pre-salt and post-salt reservoirs in Brazil [9]. This results in distinct input scenarios with varying fluid compositions (A, B, and C), as detailed in Tab. 1.

Table 1. Fluid molar fraction

Component	Molar fraction (%)		
	Fluid A	Fluid B	Fluid C
Water	1.852	0.944	0.943
Methane	85.185	66.100	75.024

Ethane	3.704	10.67	6.88
Propane	0.926	6.988	4.713
Isobutane	0.926	0.944	0.943
Butane	0.926	2.927	2.733
Pentane	0.926	1.039	3.11
Hexane	0.926	0.944	0.943
Heptane	0.926	0.944	0.943
Octane	0.926	0.944	0.943
Nonane	0.926	0.944	0.943
Nitrogen	0.926	3.305	0.943
Carbon dioxide	0.926	3.305	0.943

4.2 Case scenarios

A subsea-to-shore scenario was designed, featuring a total of thirty-two production wells distributed evenly across four intermediate manifolds, each equipped with 8 slots. These intermediate manifolds direct flow to a central production manifold located at distances of 1000, 3700, 5000, and 13000 meters from their respective points of origin. The central production manifold consolidates production from all 32 wells and directs it to a subsea separator located 1 km away. Following separation into oil, gas and water phases, the fluids are transported via pipeline to the coastline. This separation process is critical for water removal, thereby mitigating potential flow assurance issues such as hydrate formation.

The Ormen Lange field system includes compression equipment and Monoethylene Glycol (MEG) injection lines to prevent hydrates. However, the subsea-to-shore system developed in this study features four intermediate production manifolds, a central production manifold, a subsea multiphase liquid-gas-water separator, multiphase pumps in the export pipeline leading to the coastal processing plant and the produced water is injected into the system, as illustrated in Fig. 2.

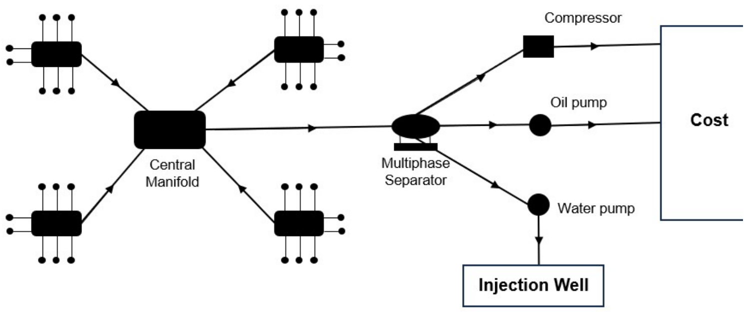

Figure 2. Case study layout

Table 2 outlines various cases combining factors such as distance to shore, diameter of export pipelines, and fluid types.

Table 2. Study cases

Case	Fluid	Diameter (pol)	Coast distance (km)
1	A	12	120
2		12	220
3		30	120
4		30	220
5	B	12	120
6		12	220
7		30	120
8		30	220

9	C	12	120
10		12	220
11		30	120
12		30	220

5 Results

Twelve simulations were conducted for each of the three fluids (A, B and C). Each simulation included the installation of 500 hp pumps and a subsea compressor positioned between the three-phase separator and the onshore processing plant in order to maintain line pressure. The distance from the separator and the pump is 1 km, while the flowline spans either 120 km or 220 km in total length. This export line considered is a steel tube with internal diameter of either 12 or 30 inches, depending on the specific case studied.

Figures 3, 4 and 5 represents the pressure profile along the production system for each fluid case.

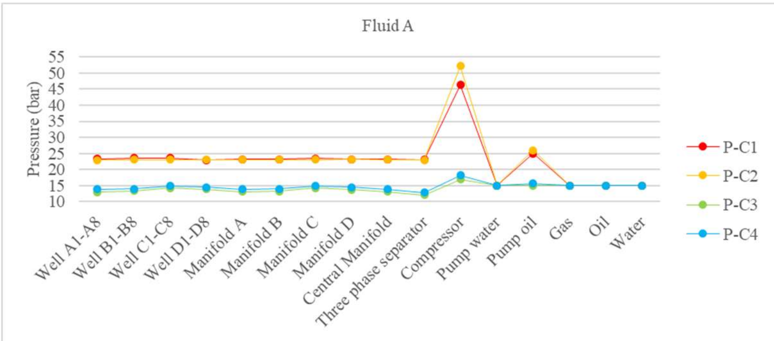

Figure 3. Pressure profile with Fluid A

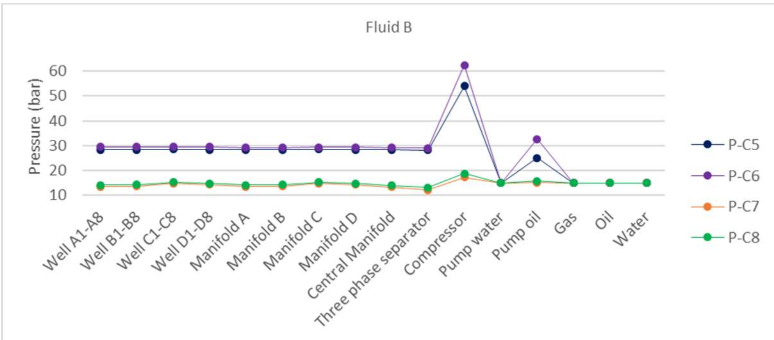

Figure 4. Pressure profile with Fluid B

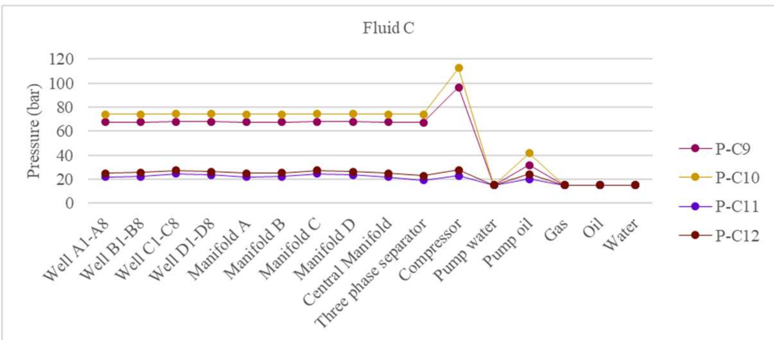

Figure 5. Pressure profile with Fluid C

The correlation between the hydrate and dew lines with the pressure-temperature (P-T) conditions along the gas production pipeline is illustrated in Fig. 6, 7 and 8.

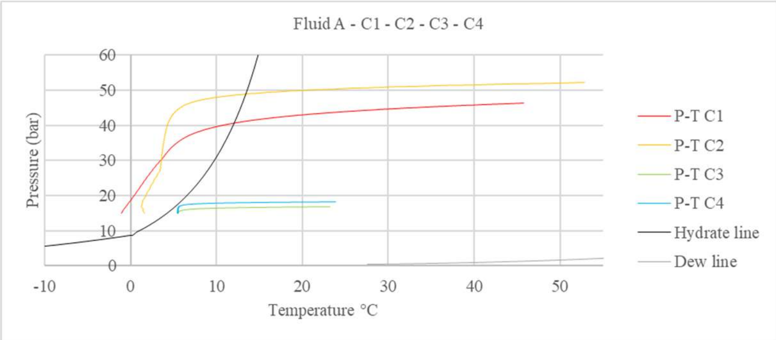

Figure 6. P-T Fluid A

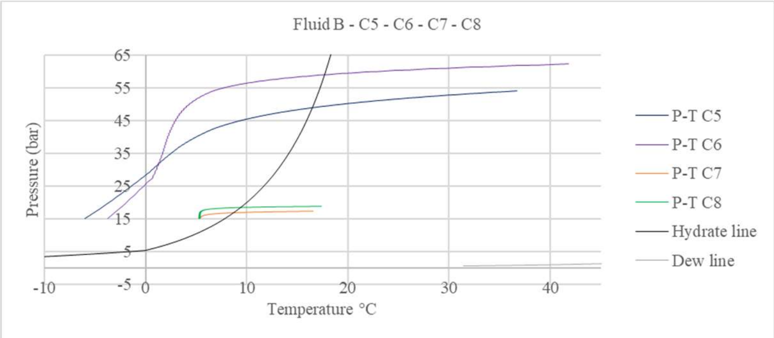

Figure 7. P-T Fluid B

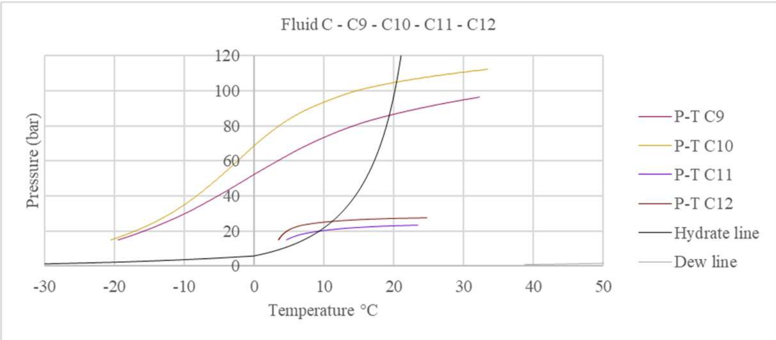

Figure 8. P-T Fluid C

Lower temperatures and higher pressures increase the likelihood of hydrate formation. This can be assessed by overlaying pressure and temperature curves with the phase envelope. Points falling to the left of the hydrate line on the plot indicate expected hydrate formation, while those to the right suggest it is unlikely. Additionally, when the pressure drops below the dew point, liquid hydrocarbons are present within the system, which further increases the potential for hydrate formation. Considering all these factors, we observe that, in all cases, only the section through the compressor shows an increase in pressure and temperature, making it free from hydrate formation.

Although cases C1, C2, C5, C6, C9, and C10 all have a diameter of 12 inches, their performance varied. Cases located further from the shore (C2, C6, and C10) required a higher compressor demand to achieve the target pressure at the system's exit points.

In contrast, cases C3, C4, C7, C8, C11, and C12 have a diameter of 30 inches and place less strain on the compressor. Analyzing the P-T curve behavior, we see that it does not experience significant variations throughout the system, consistently meeting the pressure criterion until the end of the system.

6 Conclusions

The pressure profiles along the production system for different fluids exhibit consistent behavior: higher temperatures correspond to higher pressures, as depicted in the previously presented graphs (Figures 3, 4 and 5). Moreover, there is a noticeable decrease in system pressure with increasing distance from the coast, necessitating the use of pumps and equipment to maintain operational pressure and ensure fluid flow. Additionally, larger diameter tubes result in lower observed pressures within the system.

In all cases, hydrate formation is evident on the left side of the hydrate line curve in the production system. To mitigate hydrate formation and potential blockages, it is crucial to maintain operating conditions outside the hydrate formation region. Strategies for prevention include employing thermodynamic inhibitors (such as methanol, ethanol, and monoethylene glycol), thermal insulation, heating methods (electrical or hot fluid circulation), pressure control measures, and water removal from the production system.

In conclusion, while this study provides valuable insights into subsea-to-shore data, further research is crucial to explore the avenues mentioned above. Pursuing these next steps will advance our understanding, refine methodologies, and enhance oil and gas production systems. These steps include conducting simulations using different fluids, such as light oil, varying combinations of API gravity (density), gas-oil ratio (GOR), and water cut (BSW). Additionally, expanding simulations to include fields that better represent conditions in Brazil and developing response surfaces using techniques such as linear regression and neural networks will be crucial steps forward.

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