

Ormen Lange Subsea Production System

The Ormen Lange field, in the Norwegian Sea, approximately 100 km off Norway, is within the prehistoric Storegga slide area with water depths reaching 850 m in the main production area. The gas will be produced from up to 24 subsea wells. The well fluid will be transported to the Nyhamna plant through two 30-in. multiphase lines. After processing, the dry export gas will be transported from the onshore plant through a new 42-in. pipeline by way of the Sleipner riser platform and further through a new 44-in. pipeline to the gas-receiving terminal in Easington, England.

Introduction

Fig. 1 shows the development concept selected for Ormen Lange, which comprises a subsea tieback to an onshore processing plant at Nyhamna. Conceptual engineering of the subsea production system was initiated in 2002. The main contracts for subsea-equipment supply, umbilical fabrication, and template installation were awarded between the autumn of 2003 and the summer of 2004. The main part of fabrication and testing took place during 2004–05, with the subsea templates installed offshore in late summer 2005. Umbilical A and the remaining subsea equipment were installed during the summer of 2006, and the first subsea tree was installed on Template

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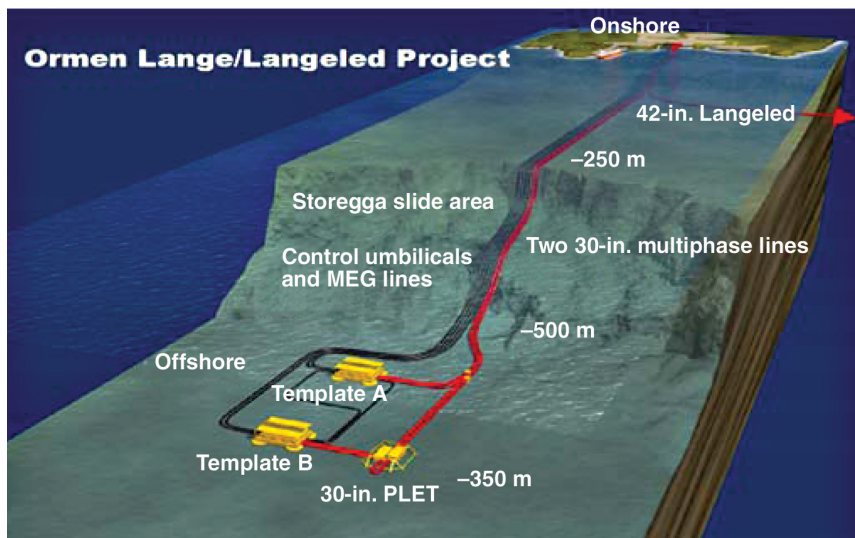


Fig. 1—Ormen Lange initial subsea development.

A in December 2006. Completion of the first subsea well on Template A was scheduled for spring 2007, and subsea production startup was scheduled for autumn of 2007.

Subsea-System Configuration

With the large geographical extent of the Ormen Lange reservoir and the risk of reservoir segmentation, the subsea-system design has a high degree of flexibility, with four planned template locations. Therefore, a phased-development scheme was chosen. The phasing and location of the subsea wells will be timed to maintain plateau production as the field depletes.

Initial Development. The initial subsea development consists of two eight-slot production templates (Templates A and B), approximately 4 km apart in the main production area. Each template is tied back into the two 30-in. multiphase pipelines to shore. As **Fig. 2** shows, these lines are interconnected

through a pipeline-end-termination (PLET) system.

Two main control umbilicals link the onshore plant to the subsea production system; one is connected to Template A and the other to Template B. A crossover-control umbilical interconnects the two production templates, providing redundant hydraulic supply to all the subsea wells.

To prevent hydrate formation, all wells are injected continuously with monoethylene glycol (MEG) through two 6-in. pipelines from the onshore plant. One line is connected to Template A and the other to Template B. A 6-in. crossover-MEG line interconnects the two production templates for added flexibility.

Future Development. Extension of the field may require two additional production templates (Templates C and D). Each template will produce gas through dual infield flowlines tied back to the 30-in. multiphase pipelines to shore. A new infield 6-in. MEG line will be con-

nected to each of the future templates as extensions from Templates A and B. Similarly, a new infield-control umbilical will be connected to each of the new templates as extensions from Templates A and B. The design has provisions for tie-in to a future precompression platform or a subsea compression unit.

Key Technical Challenges

The seabed in the development area is highly irregular, with soil conditions varying from very stiff clay with boulders to soft clay. Also, the environmental conditions are extremely challenging and the installation season is very short.

Currently, there is no fishing activity in the area where the subsea templates are installed. In the future, however, trawling activity may commence; therefore, the large subsea installations are equipped with overtrawlable protection structures.

Hydrate Prevention. Hydrate prevention is a main technical challenge for the system. With the low seabed temperature (-1°C), both hydrates and ice may form, unless the well fluid is sufficiently inhibited. The overall hydrate-prevention strategy is to minimize the risk of operating within the hydrate region by continuous MEG injection at individual subsea trees. For accurate injection control, each well is equipped with an MEG flowmeter and dosage valve.

Long-Offset Control. Control of the subsea production system will be from the onshore terminal at Nyhamna, a distance of 120 km. Availability of the subsea control system on Ormen Lange is strongly emphasized because the production rate from each well is very high and interventions will be both costly and challenging with the water depth and weather conditions. A fiber-optic/electrohydraulic multiplexed control system was designed, built, and tested. Components include high-voltage power transformers, low-pressure hydraulic power, and backup communication on high-voltage power.

High Flow Rates. The initial eight development wells will be 9⁵/₈-in. hybrid well completions with dual downhole safety valves (deep-set) and horizontal subsea trees. The remaining well completions for Templates A and B are planned as 7-in. completions. The average flow rate from each well may

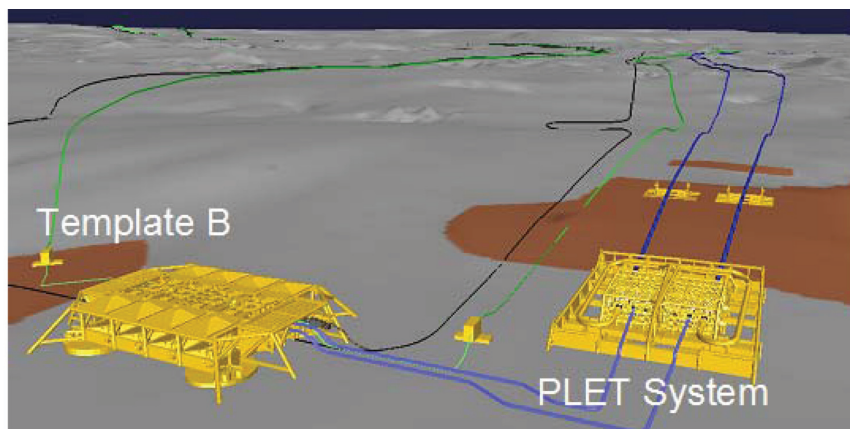


Fig. 2—Installation layout of Template B and PLET system.

be as high as 10^7 std m^3/d . A major challenge for the project has been to ensure that all equipment is designed to accommodate this very high flow rate. Erosion and vibration are two important areas of focus in this respect.

Systems

The design allows simultaneous production and drilling/completions/workover operations. During deployment of heavy equipment in open water from the drilling/completion rig, the rig is positioned at a safe horizontal distance from any subsea installation, even though dropped-object protection is part of the template design. The template system comprises a foundation bottom structure with skirt foundations and a manifold module. The production manifolds have dual production headers. For each well, two hydraulically actuated valves direct gas flow to either of the manifold headers. Umbilicals and pipelines/spools were tied in by use of horizontal-connection systems.

Subsea Tree. The subsea-tree system is a 7-in. horizontal production tree equipped with an annulus bore. The tree is configured with a separately retrievable subsea-control module (SCM) and a choke module, the latter containing instrumentation, flow-control, and measurement equipment. The production flow loop and the MEG, annulus-test, and control lines on the subsea tree are connected to the choke module through a multibore-horizontal hub. A remotely operated vehicle (ROV) panel is attached to the subsea-tree frame structure, and all valves operated by ROV are on this panel. Subsea-tree installation used guideline-

less techniques. The tree is configured with hydraulics to enable a safe operation and testing of tree/running-tool system by use of the workover system.

MEG Distribution. The MEG-distribution system is designed to minimize the risk of hydrate formation. Each well is equipped with a distribution system ensuring that sufficient MEG is injected into each well. The subsea tree system is equipped with two MEG-injection points. During normal production, MEG is injected between the production wing valve and the production choke to ensure good mixing. During well startup and for barrier testing, MEG is injected between the production master valve and the production wing valve.

Completion and Workover. The completion and workover system comprises all equipment and associated control systems required to install, retrieve, and commission a horizontal tubing-hanger system and to perform well interventions and workovers during the operational phase over the life of the field. The workover-control system provides the necessary functionality to control all functions on the completion/workover equipment and subsea tree. It includes facilities to perform normal and emergency shutdown and disconnection of specified functions in automatic sequences upon activation from the surface unit.

Production Control. The production-control system uses a redundant fiber-optic bidirectional point-to-point communication link between land and each SCM. The control system has fully redundant hydraulic, electrical,

and communication systems and is, as much as possible, based on proven subsea-control-system components. The subsea-control unit is installed at the onshore plant at Nyhamna and is a node on the main-control-system network. The subsea- and onshore-control systems are, therefore, fully integrated with no requirement for a subsea master-control station.

PLET. The 30-in. PLET system is installed close to Template B. The PLET-system design comprises a PLET bottom structure, which was installed before pipeline lay down. The protection structure protects equipment from dropped objects and fishing activities. The PLET bottom structure was designed to function as a landing base for the pipeline terminations, the

PLET modules, and the pig loop. The PLET system allows for thermal expansion of the 30-in. pipeline. It provides for tie-in of 16-in. rigid spools from Template B and 12-in. rigid spools from Template C (future).

Achievements

As of February 2007, the design, fabrication, testing, and installation of the Ormen Lange subsea-production system were nearly completed. Templates A and B, the in-line tees, the PLET system, and spools were successfully installed subsea and all tie-ins completed.

Key Success Factors

1. The level of detail and the quality of the conceptual engineering performed before contract award provided a very good basis for project execution

in terms of planning cost estimates, specification of installation vessels, and other such details.

2. Active risk management has been performed throughout the project, whereby key risks have been systematically and proactively identified, evaluated, and acted upon to minimize negative effects and maximize benefit.

3. The project team has executed effective change management, whereby all change proposals have been carefully reviewed and evaluated before implementation or rejection.

4. The project team has performed close and active monitoring of interface work between contractors.

5. Qualification and verification tests of all new components and thorough testing onshore have contributed to smooth and effective offshore operations. **JPT**