Optimization of Integrated Template Structures for Arctic Subsea-Production Systems

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Summary
This paper analyzes the various selection methods of integrated template structures (ITSs) for use in the Arctic environment. First, an analysis of several actual projects is carried out, with the specific features of each described thoroughly. An important part of the work is devoted to the requirements of ITSs conceived in relevant NORSOK (Norsk Sokkels Konkuranseposisjon), International Organization for Standardization (ISO), and DNV (Det Norske Veritas) standards. The main elements of subsea production modules are examined in this work, along with their specific characteristics and components.

Operation and installation of subsea modules in the Barents Sea are also analyzed in this paper. Four scenarios, with differing numbers of ITSs (two, three, four, and six) and differing quantities of well slots in each, are considered. For each scenario, a study of related marine operations (required for installation) is performed, and a program for installation-cost estimates is developed, resulting in the determination of an optimal design for the ITSs. Various parameters affecting the cost of subsea infrastructure are analyzed and studied from different perspectives (e.g., geometrical well-pattern systems, distance between drilling slots, drilling and construction costs). Risk analyses of the threats and consequences involved in the process are performed, and risk-assessment matrices and mitigation actions are established. As a result, a model for selecting an optimal ITS for the Arctic/Sub-Arctic region is created.

Introduction
Some of the already-executed offshore projects (from Terra Nova and White Rose on the Grand Banks of Newfoundland in eastern Canada to Snøhvit in northern Norway) are followed by those still being prepared, such as Goliat and Skrugard in northern Norway. All these projects may be considered as true milestones toward oil and gas development in the Arctic region. Therefore, a review of these projects was performed while writing this paper to provide an important basis in experience. Because of this accumulated experience, we can turn future concepts into today's reality.

This paper states important facts regarding ITSs and describes specific requirements for the Arctic environment. When dealing with operations in Arctic regions, a careful selection of installation vessels is very important; therefore, we present a short comparison of these vessels in a later subsection. Finally, because risk analysis must be performed before the start of any operation, a section regarding risk assesment is also included.

This paper presents the analysis of ITS selection in three parts—installation costs, construction costs, and total expenditures. After the evaluation of marine operations, risk assessment during the ITS installation in the Barents Sea is presented. The paper describes the selection of the optimal number, layout, and structure of the ITSs according to the environmental challenges of the Barents Sea.

Operational Criteria
Harsh conditions in the Arctic environment (low temperatures, icing, snow, fog, and polar night) result in difficulties in development and operation, which lead to seasonal weather limitations, requiring "winterization" and complex logistics. These conditions also make emergency evacuation and rescue difficult.

The severe climate conditions in the Arctic make the development and execution of offshore and subsea marine operations extremely challenging (Titov and Pedchenko 2009). The following are some of the features that affect offshore operations, subsea construction work, and field development (Gudmestad et al. 1999):

- Remote location—coastal infrastructure and complex logistics
- Need for an uninterrupted supply of materials
- Transfer and evacuation of personnel
- Harsh Arctic conditions—seasonal weather limitations/seasonal installation
- Open sea—risk of severe weather conditions
- High cost
- Additional cost because of the long distance for export of gas and condensate
- Lack of technology, competence, and experience in offshore-field development
- Emergency response time
- Severe climate conditions
- Presence of ice
- Environmental risks
- Very short time frame for operations

Operational criteria are based on several weather parameters. For instance, wave height and period are important for heave motions of a semisubmersible rig. Long-period swells may be worse for many vessels than a high, but short-period, wave. One may conclude, therefore, that the operation should be aborted in case of long wave periods. Critical vessel parameters for different combinations of significant wave height and spectral periods are calculated to determine the operational criteria. Furthermore, even scenarios of climate variations should be taken into account, according to which there will be a tendency to warming in the Barents Sea (Titov and Pedchenko 2009).

In the environmental conditions of the Barents Sea, a monohull crane vessel could settle into resonance with waves (according to data, the waves are mainly in the range of T_s=3 to 13 seconds). It is convenient to change the natural period of the vessel to a greater value by increasing dead weight, which reduces the energy of resonance. Sometimes, choosing an alternative crane is the only solu-

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TABLE 1—THE HEAVE PERIOD OF THE INSTALLATION VESSELS

Vessel	Heave Period* (seconds)	Comments
Monohull	11.6	May settle into resonance with waves. Need to change the natural period to a greater value where the energy of resonance is small (i.e., increase the dead weight).
Semi-submersible	21.3	Applicable for Barents Sea
Barge	5–7	Unsuitable

*Note that the heave period does not change much when the installation vessel gets the ITS onboard.

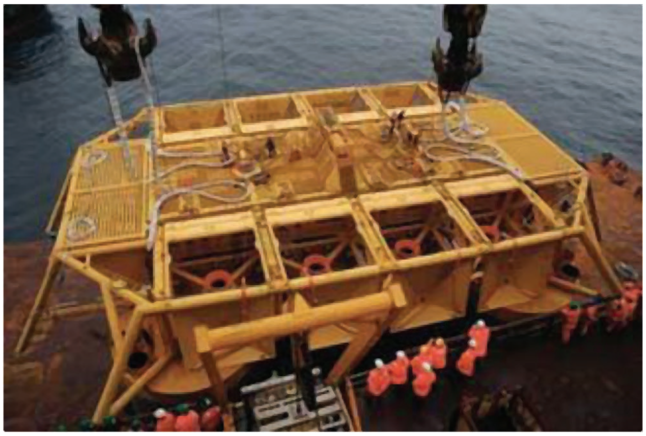

Fig. 1—Eight-well-slot ITS: This subsea structure has eight well slots, with hatches on the roof of the template to provide access to the wellheads.

tion. The use of a crane barge should be neglected because of low natural period **(Table 1).**

Technical Requirements for the Arctic/Sub-Arctic Region

Arctic completions are driven basically by economics. Wells in the far north are expensive to drill and to complete. As a result, remotely actuated downhole-flow-control equipment, multiple chemical-injection lines, and downhole gauges must be incorporated to complete a successful well. This clearly increases the complexity of these operations and reduces the overall reliability (INTECSEA WorleyParsons Group 2014).

Industry and regulators are becoming increasingly aware that long, multiphase flowlines reduce backpressure, flow rates, and recovery (*NORSOK R-CR-002* 1995; *NORSOK U-001* 2002; *NORSOK J-003* 2003; *NORSOK N-004* 2004; *NORSOK N-001* 2012). The following paragraphs present technical and operational challenges for subsea facilities in the Arctic/Sub-Arctic regions.

Arctic subsea production has a number of technical issues. To design an ITS **(Fig. 1),** several design criteria have to be listed **(Table 2).** Some of these criteria are already recognized and known (input), but the other criteria have to be determined as output data (*ISO 19900:2002*; *ISO 13628-1:2005; ISO 13628-4:2010; ISO 13628-7:2005*).

There are several other aspects of ITS design in the Arctic regions or the Arctic environments that face additional challenges to engineers. Because of a harsh environment and the presence of ice, the objective is to determine a template type. Special requirements and design details are reviewed.

ITS Cost/Benefit Analysis for the Barents Sea

The Shtokman project is evaluated as an example of possible projects in the Arctic/Sub-Arctic environment. During the Shtokman front-end-engineering-design (FEED) studies carried out by Gazprom, Total, and Statoil in 2012, it was planned to produce gas with three twin four-slot ITSs. During Phase I of the field development, 20 wells were scheduled to be drilled (Pavlov 2011). We have analyzed this recommendation and considered four different scenarios of subsea-production systems with two, three, four, or six ITSs for the field development:

- A4 (base case): six ITSs with four well slots (as proposed originally by the operator)
- A6: four ITSs with six well slots

TABLE 2—ARCTIC ITS DESIGN CRITERIA

Input	Output
Bottom conditions—Soil shear strength is the ability of the seabed to support the load of a template or a manifold and how a template could be buried (ISO 2002).	ITS sizing, number of templates, jumpers, connectors
Geohazard analysis	ITS arrangement selection
Seismic-wave-propagation analysis	Selection of the leak-detection system
Planned product properties and contents	Stability analysis and determination type of foundations and/or trenching/buried requirements
Production volumes	Cost estimates
Water depth	Determine the most cost-effective method to install ITS in this very dynamic region and provide necessary protection.
Number of wells—The number of wells served by a template will determine its size.	ITS installation studies to verify multiple installation options, which can be maintained for cost and contractor competitiveness (templates are commonly installed by a drilling rig as the first step before drilling).
Bottomhole zone locations	Risk analysis regarding external factors and definition of risk-reduction measures
Interferences because of another pipeline (not as relevant)	Material specifications

TABLE 3—ASSUMPTION REGARDING THE DAILY RENT OF THE EQUIPMENT			
Scenarios/ Case (USD/D)	A4 (< 500 t)	A6 or A8 (1000 t)	A12 (2200 t)
Supply vessel	15,000	15,000	15,000
Diving-support vessel	70,000	70,000	70,000
Cargo barge	30,000	50,000	100,000
Monohull vessel	200,000	250,000	–
SSVC	–	500,000	700,000
Wet tow	400,000	–	–

- A8: three ITSs with eight well slots
- A12: two ITSs with 12 well slots

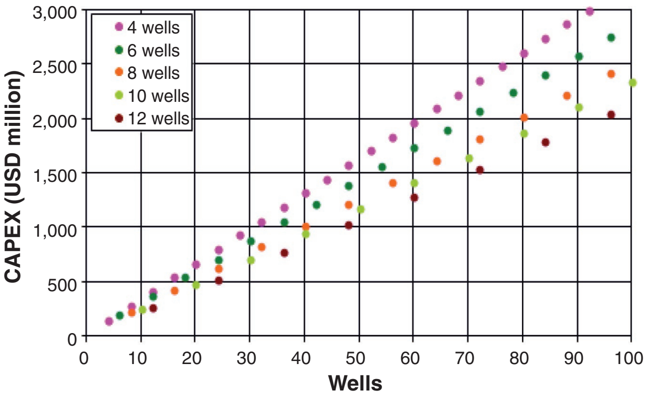

Fig. 2—ITS costs (wells=well slots). The correlation of the template costs can be found from the angles of the slopes; therefore, the cost for the predefined number of templates can be assumed easily. The solutions with a higher number of well slots in the ITS have a lower total CAPEX (Grekov and Kornienko 2007).

Offshore installation of various modules is a challenging operation, especially when the units are in the air and in the splash zone. On those occasions, a module faces the largest forces in its lifetime. Because of the weather and seasonal limitations, installation is carried out during the summer (May to August/September).

Several types of vessels that may take part in those installation operations are recognized. Because of heavy-cargo transportation and heavy-lift operations, it is necessary to ensure the stability and response of the vessel in waves.

ITS-Installation Cost/Benefit Analysis. An increasing challenge at the Shtokman field is to design, construct, and install an offshore installation that provides an acceptable return on investment. However, the considerations discussed in the following and the cost-reduction elements suggested may be applied to any offshore-field development. The primary cost reductions are obtained by

- Maximizing the use of industry capabilities
- Implementing new organizational principles
- Focusing on functional requirements
- Shortening project-execution time

Each installation operation requires at least one supply vessel and one diving-support vessel. Template transportation requires a cargo barge, and several types of crane vessels (e.g., monohull, semisubmersible, crane barge, or wet tow) may contribute to lifting operations **(Table 3).**

Transfer costs must be included as well. These are the fees for mobilization to site and demobilization of all vessels. It was assumed that the vessels were transferred from the port of Stavanger to the Murmansk harbor. The demand on the vessel market was examined during logistic studies, and the vessels were ordered in advance.

For Scenarios A8 and A12, the installation time is longer because of the slow transit speed of the semisubmersible crane vessel (SSCV) from the mobilization harbor to the offshore location. The time estimate must be very careful and detailed. The calculations are simplified by assuming that there is no waiting time for any of the vessels. In other words, all vessels arrive at Murmansk at the same time, which requires various departure times because the transfer speed differs among the mobilized fleet. Total costs and time in days onsite are provided in **Table 4.**

One of the most important factors in cost estimates of the installation is the rental cost of the third-party equipment. Expenditures are the highest for a crane vessel. The most economically effective scenario is A4, which features six production templates with four well slots each, while Scenarios A6 and A4 have approximately the same costs for the installation.

Transfer costs are also very high. The logistics plan must be consistent and well thought out. Any waiting time not related to weather conditions must not be allowed. It is also necessary to reduce the waiting time resulting from the cargo vessel bringing templates to the offshore location for Scenarios A8 and A4. In other words, none of the supporting vessels (e.g., cargo vessels carrying templates to site) should await the rest of the installation fleet or vice versa. One should also note that Scenarios A12 and A8 are very expensive because of the extremely high daily rent for SSCVs. Despite Scenarios A12 and A8 having a greater number of well slots and therefore a smaller number of ITSs, operational time for those scenarios is almost the same as that for Scenarios A6 and A4, which makes Scenarios A12 and A8 not relevant.

Cost/Benefit Analysis for the ITS Construction. The capital expenditure (CAPEX) of the ITS can be evaluated, excluding drilling costs, by use of a plot presented by Grekov and Kornienko (2007), as shown in **Fig. 2.** The results allow the possibility to calculate the costs of the ITSs with the simple dependency from Fig. 2. Having the final number of wells and the suggested numbers of ITSs, we can then state the total cost of the project. The difference between CAPEX increases with the higher number of wells in the field. This is important to understand and keep in mind for the first and

TABLE 4—TOTAL COSTS OF THE INSTALLATION OPERATIONS

Scenario	Number of Well Slots	Number of ITSs	Installation Period (days)	Cost of Installation (USD million)	Costs With the Waiting-on-Weather Factor (USD million)
A12	12	2	35	19.175	29.795
A8	8	3	39	15.580	23.835
A6	6	4	29	6.925	10.775
A4	4	6	35	6.875	10.655

TABLE 5—CAPEX OF THE ITSs FOR THE SHTOKMAN PHASE I FIELD DEVELOPMENT

Scenario	ITS Slot Quantity	Total Number of Well Slots	Number of ITSs	CAPEX (USD million)
A12	12	24	2	518.4
A8	8	24	3	600.0
A6	6	24	4	698.4
A4	4	24	6	780.0

TABLE 6—FDE-PROGRAM OUTPUT DATA

Scenario	Number of ITSs	Template Costs (USD million)	Drilling Costs (USD million)	Infield Pipeline Costs (USD million)
A12	2	480	1,330	294
A8	3	585	1,106	299
A6	4	680	974	303
A4	6	720	820	310

subsequent phases of the project. The CAPEX of the ITS for the Shtokman Phase I field development was calculated on the basis of Fig. 2, and the results are listed in **Table 5.**

According to Table 5, the structures with 12 well slots are much less expensive to construct; however, the drilling costs are much higher because the horizontal parts of the wells are longer. It is very important to take into consideration the drilling cost in our model.

ITS Cost/Benefit Analysis With Drilling Included. Because the drilling cost is one of the most important factors in development, another cost model that takes into account all cost items is considered here. To estimate drilling costs, a field-development cost-evaluation program developed at the University of Stravanger is used; however, the program has been modified by the authors of this paper to better reflect the Shtokman field conditions and parameters. According to the Shtokman project input data (Zakarian et al. 2009), which are used with the field-development-evaluation (FDE) program, the output results featured in **Table 6** are obtained.

The template costs listed in Table 6 are very similar to the results obtained from the previous analysis. The drilling costs, however, play a major role here and are considered as the most important factor. The total cost of each scenario (including the drilling operations) is presented in **Table 7.**

According to the FDE-program output data and the analysis model used, Scenario A4 is the most economically attractive scenario for the Shtokman project. Drilling costs, however, will need to be evaluated with greater certainty. Scenario A6 is also economically attractive and could be applied alternatively during the Shtokman project Phases 1, 2, and 3.

Risk Analysis for the ITS Installation

As was mentioned previously, the installation process is a very challengeing task in the Arctic. Several important hazards have been identified regarding installation operations of ITSs, and are ranked in the following list. These hazards will be analyzed further and addressed during the detailed design.

1. Weather conditions (unpredictable weather)
2. Engine breakdown
3. Poor sea fastening
4. Personal accidents or injury
5. Loss of structural integrity (e.g., hull, ballast, support-structure failure)
6. Loss of stability (e.g., ballast failure, cargo loads)
7. Loss of marine/utility systems (e.g., propulsion, power generation, navigation system)
8. Loss of stability during lift operations

TABLE 7—TOTAL COSTS FOR THE SUBSEA DEVELOPMENT, DRILLING INCLUDED

Scenario	Number of ITSs	Total Costs (USD million)
A12	2	2,104
A8	3	1,990
A6	4	1,957
A4	6	1,850

9. Vessel delay (because of long transfer distance)
10. Wire damage (because of large snap load in the wire)
11. Insufficient fuel quantities (because of long installation operation)
12. Collision/impact (e.g., support vessel; passing vessel; standby vessel; and aircraft crash on barge; this includes military and fishing vessels and naval vessels, including submarines and flotel) or capsizing (because of heavy-lift operations)

We could exclude several causes because of summertime installation (e.g., icing, large waves, equipment freezing), of which the main consequences are delays, capsizing, and loss of cargo (e.g., loss of an ITS).

Because of the complexity of working offshore with subsea facilities, it is difficult to foresee all possible consequences in the event that something goes wrong. An offshore installation or vessel has personnel onboard; however, the conducted risk analysis focuses on technical aspects (Trbojevic et al. 2008).

For each scenario, we must conduct a risk assessment. In other words, competent risk-assessment personnel, together with the project team, should carry out a site-specific job risk assessment (JRA) before work begins. This is normally performed with a JRA form. The risk-assessment personnel should ensure that appropriate controls have been fulfilled for those hazards that are identified in the written risk assessment. The risks shall be handled as an integral part of the installation plan (*DNV-RP-H101* 2003).

A risk-assessment matrix is used with the JRA (Gudmestad 2002). This allows for quantification of the probability and the severity of the hazards for a particular activity. The product of the two indicates the level of risk. Risk-assessment approaches are used increasingly for the assessment of major hazards and to demonstrate that risks have been reduced to an “as low as reasonably practicable” (ALARP) level [i.e., to the second (yellow) zone in

Hazard-Severity Category	Descriptive Words	Probability Rating A Very Likely	B Likely	C Possible	D Unlikely	E Very Unlikely
1	Very high				9	6,12
2	High			1		5,7,8
3	Moderate					
4	Slight			10,11		2,3
5	Negligible					4

Fig. 3—Qualitative risk-assessment matrix for Scenario A4 after risk mitigation. It is assumed that after the risk-reducing measures, all 12 hazards will be located in acceptable/negligible zones. The installation of four-well-slot structures is common, well-known, very confident, and conservative.

the risk-assessment matrix **(Fig. 3)**]. Those levels need to be evaluated and various risk-reducing measures applied where necessary. All risks are considered with the ALARP principle in mind (i.e., moved to the second zone—the yellow-marked field—in the risk-assessment matrix).

A risk-priority code of less than 3 is not acceptable for hazards that target personnel. The potential costs of any given loss may vary depending on the company and the operations (*IMCA SEL 019* 2007). There are different installation procedures and different risks among the four scenarios. The risk rating will move toward the higher values because of the more-complex and heavy-lift operations of larger templates. All processes and all items during installation must be considered to establish the risk-assessment matrix for each scenario. According to the list of hazards and JRA that have been performed during the research, the risk-assessment matrices have been filled out and are shown in Fig. 3.

The most dangerous scenario is A12. With 12 well slots, the structure weighs more than 2200 t, and its installation would be a most difficult issue to resolve in the Arctic. There is a need for risk-reducing measures for heavy-lift operations. The loss of stability and wire damage because of an extremely heavy structure provide risk value, setting this activity in the red zone, which is not acceptable.

The risk-rating values move from the green (acceptable) zone toward the ALARP zone, and then further to the "not acceptable" zone, meaning that the large and heavy structure of A12 may be considered as unsafe to install with the knowledge and experience now available. There seems to be no justification for accepting the risk of installing an A12. Moreover, installation costs for scenarios with 8- and 12-well-slot structures are much higher than for smaller ITSs, which could further lead to higher economic risks and losses. The safest scenarios for the installation of ITSs in the Arctic region and the Barents Sea are A4 and A6. We state this even though Scenarios A4 and A6 will involve increased activity because of the installation of a greater number of templates. The construction work will, however, be performed with more flexibility to select a weather window. Smaller templates mean reduced consequences in the unlikely event of any accident or template loss ("do not put all eggs in only two baskets").

Discussion

Here, all scenarios presented in the preceding sections are discussed to provide a clear picture of what has been accomplished. A cost/benefit analysis has been performed for the installation operations. The installation-cost calculations are approximate and may vary because of market demand, price uncertainty, and time factor. The transfer periods for the vessels are not the same in all cases—Scenarios A8 and A12 will take longer because of the slow transit speed of the SSCV. The time estimation should be very dependable. During the calculations, the waiting periods for the crane vessels were included in the transfer costs of the rest of the operational fleet.

The most economically effective scenarios are A4 and A6, with four- and six-well-slot ITSs, respectively, that have the same installation cost. Scenarios A12 and A8 give us installation costs that are very high because of the extremely expensive daily rent for the SSCV. Scenarios A12 and A8 do have a greater number of well slots and a lower number of ITSs, but those cases are considered as not relevant because the operation times for A12 and A8 are almost the same as those for Scenarios A6 and A4.

Possible underestimation of the construction cost could be another issue. Because of the large number of production wells that are needed to develop oil and gas fields in the Arctic, overall costs for ITS construction could be much higher with four-well-slot ITSs. A model for the ITS construction cost/benefit analysis has been suggested. We can assume the costs of ITSs with the simple correlation provided in Fig. 2. With the final number of wells and suggested number of ITSs, the total cost of the project can be determined. The differences between the CAPEX values increase with the greater number of wells in a field. It is our determination that the structures with 12 well slots will be much less expensive to construct; however, the drilling costs would be much higher because the horizontal portions of the wells will be longer.

By use of an FDE program to calculate costs, all relevant Shtokman project input data have been implemented. The FDE program has provided us with good output results, which gave us an understanding of the total field-development cost. According to the suggested model for the construction-cost estimation and the FDE program, approximately the same results are obtained as for the ITS construction costs. Furthermore, the FDE program gives an estimate of the drilling costs, which are very important, especially in the Arctic. However, those estimates require a more-detailed approach during the FEED studies. Therefore, it is important to be in contact with the drilling department during the subsea-development concept studies.

Use of eight-well-slot ITSs could also be a good design for the subsea infrastructure. There are some past examples in which this type of ITS has been used for the main subsea field-development design. On the other hand, we have to be aware of the following challenges:

- High potential risk during the installation
- Need for the use of large-capacity construction vessels
- High capital costs of mobilizing large construction vessels to remote areas
- High drilling cost because of the long horizontal part of the wells

The 12-well-slot option could, in our opinion, be neglected because of the following:

- High risks during installation
- Long horizontal distances between wellheads and the bottom-hole production zone
- High installation and drilling costs and poor drilling flexibility (A12 would be the most expensive installation scenario for the Shtokman project)
- Long infield flowlines

It is important to point out that the Arctic is not the place to deploy risk and uncertainty. Furthermore, the net present value (NPV) of the investments and operational costs is not discussed here. It is, however, a fact that small ITSs with fewer wells can be installed as the field development progresses, thus avoiding early CAPEX.

Conclusion

The following conclusions can be drawn from the observations presented and the results obtained in this paper. This research topic is important because, as economically viable oil and gas fields deplete, exploration and discovery are moved to other regions, such as the Arctic, that hold valuable mineral deposits. First, one must analyze past projects and accumulated experience.

The severe climate conditions in the Arctic make the development and execution of offshore and subsea marine operations extremely challenging (Titov and Pedchenko 2009). Features, factors, and specific environmental conditions affecting safe offshore operations, subsea construction work, and field development have been listed and described, establishing some special requirements that must be implemented during Arctic subsea field projects.

Another challenging problem is the installation process itself. What types of vessels are required for the Arctic environment? Four types of vessels have been reviewed in answering this question: monohull, semisubmersible crane, barge crane, and wet-tow vessels. Several subjects are to be considered when planning offshore operations. This paper examines vessel stability and the ability of the vessel to respond in waves. Stability checks are used to calculate the capability of a vessel to perform all planned operations. The main considerations are buoyancy and maintaining stable equilibrium during all phases of operations.

For the metocean conditions of the Barents Sea, SSCVs and monohull vessels are considered, even when operating during the summer season (May–August/September). Because of heavy-cargo transportation and heavy-lift operations, one must be certain of a vessel's stability and ability to respond in heavy seas. The period of heave, added mass, and other characteristics were considered during the selection of the installation vessels for the Shtokman area. The monohull crane vessel could easily settle into resonance with waves in the Barents Sea conditions (according to data, the waves are mainly T_s=3 to 13 seconds). It is more convenient to change the natural period of the selected vessel to a greater value, in which the energy of the resonance is lower. This means to increase the dead weight or choose a different vessel. The crane barge is not used because of low natural period (5 to 7 seconds).

Four different scenarios for subsea-production systems, with two, three, four, or six ITSs were analyzed and chosen for consideration:

- A4: six ITSs with four well slots
- A6: four ITSs with six well slots
- A8: three ITSs with eight well slots
- A12: two ITSs with 12 well slots

For each scenario, an analysis of the related marine operations was performed. This part was divided into three parts—installation costs, construction costs, and total expenditures. An ITS installation time schedule has presented. Cost/benefit analysis of the installation operations depends on a quantitative analysis of the full information related to these procedures.

It is very interesting that the installation costs of A4 and A6 scenarios are not so different from each other, even though Scenario A6 is slightly more economical to construct and faster to install. We recommend Scenarios A4 and A6 as possible scenarios for the Shtokman Phase I field development and Scenario A8 as a possible scenario for the future phases of the Shtokman project. Even so, Scenario A4, with six ITSs and four well slots in each, is the most attractive scenario when drilling expenses and operational aspects are considered. Scenario A4 is based on proven technology and is easy and inexpensive to install. It also offers drilling flexibility and includes a short well-path deviation from the bottomhole, which decreases the drilling costs.

CAPEXs have been discussed in this paper, while operational expenditures have not. It should be realized that ITSs with fewer well slots could provide fewer problems for the total production should it be necessary to close down all wells in one ITS for maintenance in the Arctic/Sub-Arctic regions. Furthermore, NPV of the investments and included operational costs have not been discussed. It is, however, a fact that small ITSs with fewer wells can be installed as the field development progresses, thus avoiding early CAPEX.

During the writing of this paper, we faced several challenges that were very interesting to resolve. The Arctic region is a relatively new area for the oil and gas industry. It must be understood that there is uncertainty and unpredictability in this region; therefore, the role of risk assessment and analysis cannot be underestimated. Risk analysis is supposed to be performed before any operations. Moreover, the number of accidents should be decreased toward zero. It is vitally important to delineate and take into account any possible unwanted scenarios in the Arctic.

Hazard identification and qualitative risk analysis have been performed according to risk-management papers (Trbojevic et al. 2008; *DNV-RP-H101* 2003), and JRAs have been established for all scenarios. Furthermore, we have also evaluated the risk-assessment matrices. Nevertheless, a risk-assessment program and risk-evaluation documents have to be prepared before the project will succeed in passing the execution decision gate.

Path Forward

The selection of a subsea-development scheme and subsea structures for the Arctic/Sub-Arctic environments is a long and elaborate process that should be carried out by several specialists from different company departments. The following steps should be considered during this process:

- Consider the effects of metocean criteria for the season during which installation will take place.
- Develop different conceptual solutions.
- Compare concepts on the basis of evaluation of construction, installation, and drilling costs.
- Evaluate the risks involved in installation and operations for the different conceptual solutions.
- The final decision regarding subsea-template solution should be made by taking into account the costs for those conceptual solutions that have an acceptable risk during installation and operations.

In conclusion, the Arctic poses particular challenges with respect to metocean conditions and logistics (because of the long distance from infrastructure). Smaller ITSs are therefore more desirable because they afford more flexibility with respect to selection of drilling location and allow the use of smaller-sized construction vessels compared with the larger-sized templates. We are of the opinion that these results could be useful for selecting templates for future projects in Arctic/Sub-Arctic regions.

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