Reassessment of Multiphase Pump on Field-Case Studies for Marginal-Deepwater-Field Developments

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Summary

Subsea-processing technology (SPT) is one of the frontier tools currently been explored by the oil and gas industry to open new opportunities and achieve more-effective exploitation of offshore oil and gas reserves. Exploration and production has moved into unlocking reserves that are less attractive and in difficult environments (e.g., marginal deepwater fields). These marginal fields are located remotely offshore and require one form of processing or another before they can be productive commercially. This paper focuses on the applicability of SPT employing multiphase pumps (MPPs) to develop marginal fields commercially. This was as a result of the technology selection established by a comparison of performances of several SPTs for effective development of marginal fields using tools [e.g., quality function deployment (QFD)], and evaluated further using an analytical hierarchical process (AHP), resulting in the most effective innovative SPT for marginal-field development. The result from these tools was validated further in their applications to real-life fields, and this is achieved by specific field-case simulation studies using the OLGA transient multiphase flow dynamic model program to commercially develop marginal fields.

Introduction

The challenges faced by the present offshore industry indicates that the era of "easy oil" is over with more of the oil and gas reserves being discovered in unconventional and remote fields (Magi et al. 2011; Liddle 2012). The majority of the world's exploration and production companies have a significant number of these fields in their portfolio (Nischal et al. 2012). An offshore marginal field is a field that may not produce enough hydrocarbons to make it worth developing at a particular time because of technical, economic, geological, and geographical reasons, but can become economically viable if the previously stated conditions change (Nischal et al. 2012; Abili et al. 2012). For successful development of marginal fields economically, optimal production of hydrocarbons is the key (Di Silvestro et al. 2011). In the development of marginal fields, innovative solutions are necessary because conventional solutions will not serve to make such field developments economically viable. Recent industrial effort has been focused on the accelerated development of SPT (Vu et al. 2009). One of the innovative solutions is through the handling and treatment of produced oil and gas at or below the seabed for transport to topside facilities to mitigate flow-assurance issues (e.g., hydrate formation, oil and gas conditioning). Subsea processing considers effective solutions for oil-production enhancement for fields having challenging reservoir characteristics (Di Silvestro et al. 2011).

Some of the notable benefits of subsea processing include mitigation of hydrate formation, management of pressure-related issues resulting from the production of heavy oil, increase in wellhead pressure, and increased hydrocarbon production from fields with low pressure profiles. In ultradeepwater and deepwater fields, subsea processing is the most effective solution because such fields are beyond human intervention (divers), and it is used to boost hydrocarbon production from greenfields or brownfields, which reduces production cost and reducing the need for topside processing, resulting in increased oil-recovery rate in fields with declining oil production and fields with high water cuts.

Because economic drivers (e.g., high demand for hydrocarbon and high oil price in subsea processing) are observed as key enablers for the economic development of deeper or more-remote reserves, and subsea technology has indeed come of age in the last 30 years (Liddle 2012). There has been a steady increase in industrial research and development in the area of subsea processing. Subsea-processing systems have progressed from initial pilot tests in the 1970s, which saw the development of such fields as the Zakum field in Abu Dhabi by Total and BP, in the Gulf of Mexico's submerged processing system. The 1980s experienced such developments as the first diverless subsea tree and production system, the Highlander field subsea slug catcher, the Argyll subsea separator, and the British Offshore Engineering Technology Company (Songhurst and Eyre 1990). The 1990s and 2000s saw such developments as Good Fellow Associates subsea production system in Alpha Thames, Kvaerner's subsea booster station, Glass Bardex (Santana Lima et al. 2011), the Vertical Annular Separation and Pumping System (VASPS) developed by Petronas, DEEPSEP Mai and Petronas, ABB COS WAS, subsea separation in Perdido (Vu et al. 2009; Gilyard and Brookbank 2010), Pazflor (Eriksen et al. 2012), and Parque des Conchas (BC-10) (Deuel et al. 2011; Howell et al. 2010). Furthermore, the 2000s experienced such projects as Troll, Tordis (Gjerdseth et al. 2007), and Pazflor (Bon 2009), and advances in subsea compression, power transmission, and generation.

This paper explores subsea processing in developing offshore fields, satisfying both economic and technical constraints faced by offshore projects. This will involve concept selection from some of the most innovative solutions and advances in the area of subsea processing to date and also performance analysis of the optimal technology. The concept selection in Appendix A was completed using QFD and AHP. From the concept selection, an optimal or near-optimal solution of SPT was then applied to an offshore-field development. The application of the optimal solution is simulated using the OLGA transient multiphase flow dynamic model program, and the production profiles obtained from the simulation are compared with the reservoir's production profile. The present paper considers results presented on subsea MPPs as a possible solution to develop marginal offshore fields commercially.

Results and Analysis of Field-Case Study

The simulation covers an 8-year production period simulated over four isolated cases with varying water cuts and productivity index (PI). This simulation compared the most-innovative and -effective

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Fig. 1—Subsea multiphase booster pump (*Source: Framo*).

SPT resulting from the QFD and AHP analysis, which is "multiphase pumping." The base case is modeled in a transient-multiphase-flow program without any form of subsea processing, gas, or water injection. Field A is a typical example, and the current production profile uses an electrical submersible pump (ESP) (Grupping 1989) to boost production; however, this is not modeled here because of the difficulty in handling free gas at suction conditions because this reduces the efficiency of the pump and creates difficulty in modeling an advanced gas handler or gas separator for an ESP in the transient-multiphase-flow program.

Hence, for each of the four isolated cases in the 8-year period, we ran four concurrent simulations for different field-development profiles. The field-development profiles were simulated for two production cases:

- Case A produces fields without Subsea processing (base case without SPT)
- Case B produces fields with subsea processing using multiphase pumping.

Field A. The field is located in the North Sea, at a water depth of more than 180 m and a seabed temperature of 4°C. A 26 000-m length of pipeline at an uneven seabed is expected to create slugs in the flowline. The well that was considered was a deviated well with a vertical depth of 1848 m from the seabed and a horizontal distance of 800 m from the wellhead. It is a high-pressure field with reservoir pressure in excess of 200 bar and temperature in excess of 70°C. Production is through water-injection, tied back to a floating production, storage, and offloading vessel (FPSO).

Field B. This field is located off the Gulf of Guinea offshore West Africa, at a water depth of more than 1000 m and a seabed temperature of approximately 5°C. The well is modeled using a vertical profile that is 2000 m below the seabed and is a distance of 6 m from the wellhead. The length of the flowline from the well to the floating production and storage facility is 9 km. The flowline profile is uneven, with areas of inclination and declination because of the seabed topography; hence, slugging is expected. It is a high-pressure field, with pressure in excess of 340 bar and temperature of 93°C. Production is through water injection, tied back to an FPSO.

Multiphase Pump

The multiphase pump that was used for this analysis is a Framo-HX 360-1200-38 pump. With a differential pressure of 150 bar and a pressure rating of 15,000 psi, it has the capability of handling fluids with viscosities in the range of 2 to 4,000 cp and a gas volume fraction of 100%. This pump profile and characteristics are modeled in a transient multiphase-flow program using the Framo pump component with a power rating of 1.5 MW. **Fig. 1** shows a standard Framo subsea multiphase booster pump.

TABLE 1—WATER CUT AND PI FOR SELECTED YEAR OVER 8 YEARS

	Year			
	1	3	6	8
Water cut (%)	0	47	79	86
PI	16.8	7.3	10.3	13.3

Assumptions on the Transient-Multiphase-Flow Simulation

We assumed the source at the inlet to be a pressure node. The model for simulation contained one well from the reservoir. It consists of a wellhead and manifold. The wellhead and manifold are represented by open nodes allowing mass flow through them. The multiphase pump was modeled using a Framo pump, an inbuilt multiphase pump on the transient-multiphase-flow program. The simulation is concluded at the riser base of the pipeline, using a pressure node to simulate the riser base. This simulation does not cover produced-water reinjection (PWRI). We assumed a constant heat-transfer rate for the media through which the fluid passes through the well and seabed conditions. The water cut increases from an initial rate of 0% to 86% at varying years, with varying PIs, as shown in **Table 1.** The well positive flow is modeled using a linear equation. At the reservoir level, we assume the fluid to be in a single phase. Table 1 shows the water cut and PI used for this simulation.

Each simulation was modeled for a 12-hour period to allow for a stable system and avoid unpredictable conditions caused by startup operations.

A brief description of the graph legends obtained from the simulation is shown here:

- The black line on the graph represents Year 1 of simulation; that is, water cut=0% and PI=16.8(–).
- The red line on the graph represents Year 3 of simulation; that is, water cut=47% and PI=7.3(–).
- The blue line on the graph represents Year 5 of simulation; that is, water cut=79% and PI=10.3(–).
- The green line on the graph represents Year 8 of simulation; that is, water cut=86% and PI=13.3(–).

Slugging Analysis

Slugging refers to a variation and irregularities in the flow of gas and liquid surges in pipelines and flowlines, posing major flow-assurance issues. Slugging is classified into two cases:

- Gravity-induced slugging: This category covers terrain-induced slugs that are caused by uneven seabed and depth.
- Operational and transient slugging: This category covers operational-induced slugging caused by factors such as startup-operation changes in gas-production rate.

Slugging is undesired because of the following issues:

- Severe mechanical vibrations in the pipeline, which can result in damage to the pipeline or possibly cause resonance with the pipeline
- Reduction in oil- and gas-production rates
- Damage to equipment (e.g., separator, pumps) both subsea and upstream if not controlled
- Damage to pipeline and flowlines caused by erosion and fatigue as a result of liquid buildup and variations in velocity of fluid particles
- An increase in cost because more production facilities (e.g., slug catchers) are required for handling

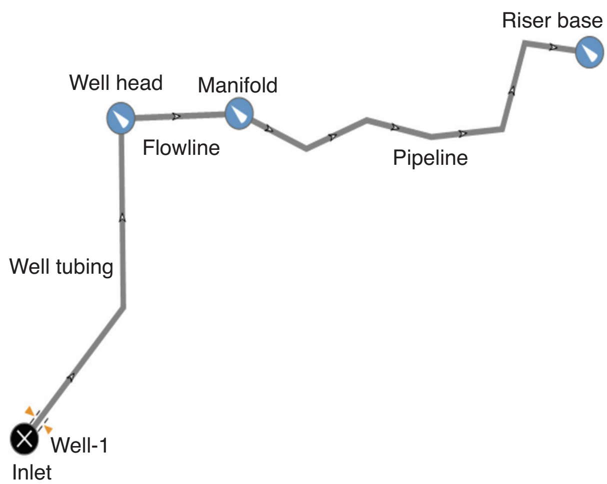

Fig. 2—Transient-multiphase-flow-model representation of Field A, Case 1 (base case).

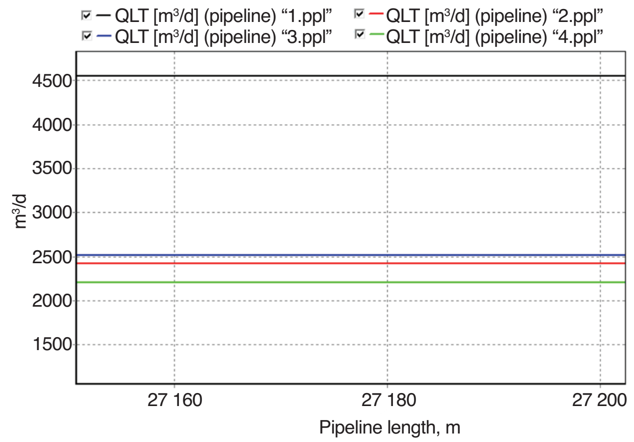

Fig. 3—Profile plot of flow rate vs. pipeline length for Field A, Case 1.

Analysis of Field A, Case 1 (Base Case)

The transient-multiphase-flow model for Case 1 of Field A is described in **Fig. 2.**

Model Description. The well is a deviated well at a depth of more than 1800 m below seabed, a temperature of 70°C, and pressure of more than 200 bar. The well tubing was modeled using steel and formation, which is in essence rock. The well tubing has a nominal diameter of 5.5 in. and wall thickness of 0.304 in. The overall heat-transfer coefficient is taken to be 12.5 W/m2·°C. The wellhead is taken as an open node, the dimension of which is computed by OLGA in the cause of running simulation. The pipeline is modeled using 12.75-in. American Petroleum Institute (API) 5L grade X52 line pipe with a thickness of 0.5 in., which is insulated with two layers of insulation (5-mm polypropylene and 20-mm polyethylene foam). The pipeline is neither buried nor trenched on the seabed. The total pipeline length from wellhead to riser base is in excess of 27 km. The pipeline depth undulates between 145 and 180 m below seabed. Because of this undulation, severe slugging occurred at some sections of the pipeline.

The well was simulated using a pressure node because there is no need to enter flow rate of fluid. The output (the riser base) is also simulated using a pressure node, with the arrival temperature and pressure defined. The transient-multiphase-flow program modeled the flow from the well to the riser base, thereby computing the flow rate, flow profile amount, and types of fluids produced. This base-case simulation was simulated for a period of 12 hours for each set of varying criteria. This is to have a true picture of the production profile, hence eliminating initial surges in flow rate caused by startup operations.

Results. The graph in Fig. 8 shows the system flow rate over an 8-year period without any form of subsea processing. Year 1 simulation shown by the black plot on the graph has a high flow rate of approximately 4570 m^3/d. This is a result of high pressure in the reservoir, high PI, and low water cut. Year 3 of simulation is shown by the red plot on the graph. There is a rapid drop in flow rate of the system to approximately 2445 m^3/d as a result of the increase in water cut of the reservoir and fall in PI. Year 5 of simulation shows an increase in flow rate of the system to approximately 2520 m^3/d. This is a result of an increase in PI, despite a higher water cut compared with Year 3 of simulation. Year 8 of simulation shows a decrease in flow rate to approximately 2245 m^3/d. This is a result of high water cut and slugging in the system.

Therefore, an approximate 50% drop in production-flow rate is observed between Year 1 and Year 8 with the application of subsea processing.

However, the profile plot for Year 1 and Year 3 pressure variations in **Fig. 3** showed that slugging was not predominant in the system (a plot of flow regime in the internal diameter of the pipeline—not shown here—indicates that flow at some regions of the pipeline is in the slugging region). It was more or less existent. Plots of pressure from Year 1 to Year 3 showed a decrease in pressure. Increasing the water content of Case 1 led to an increase in slugging frequency within the pipeline, high pressure variations, and changes in flow rate. Sensitivity analysis was carried out by varying both the PI and the water cut. Results from the analysis showed that slugging developed at a PI of approximately 79 (–) and low water cut above 55% for Case 1. This led to pressure differentials of approximately 15 bar within the pipeline and flow-rate variation of approximately 7000 m^3/d. The slug regime in Fig. 3 is termed hydrodynamic-induced slugging because slugs result from large variations in the number of waves at the gas/liquid interface during stratified flow and the slugs tend to be long at approximately more than 600 m. Hydrodynamic slugging can cause fluctuation in production rates because of the low points on the flowline and liquids building up at these points.

A continuous increase in water cut and reduction in PI take place at Year 8 before the slug regime leads to backpressure or negative pressure of up to 17 bar in the pipeline. This leads to an uneven flow rate in the system, with a reduction in production and with system instabilities and flow-assurance issues. This can be observed clearly in the profile plot in **Fig. 4.**

Observed clearly from the slugging and production-flow-rate analysis, the Well in Field A might prove technically not feasible and uneconomical to produce or continue production, especially from Year 5, where there is a need to boost production and severe slugging on the system. Consequently, the field cannot be exploited effectively and efficiently without some application of subsea processing.

Analysis of Field A, Case 2

The transient-multiphase-flow model for Case 2 of Field A is described in **Fig. 5.**

Model Description. The reservoir, flowline, and pipeline characteristics are similar to the case described for the base case in Case 1. This model incorporates a multiphase pump along the pipeline close to the manifold. The pump characteristics are modeled using

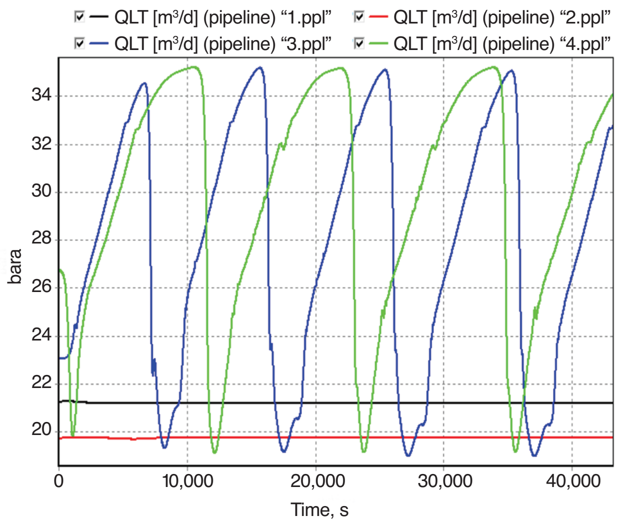

Fig. 4—Profile plot of pressure variation over time for Field A, Case 1.

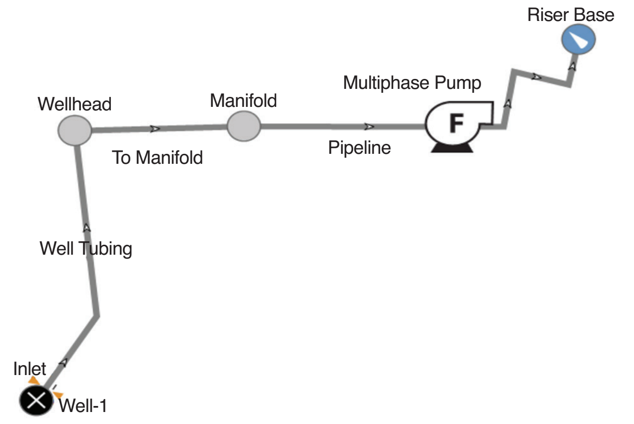

Fig. 5—Profile plot of pressure variation over time for Field A, Case 1.

the Framo-Hx360-1800-38 with a discharge coefficient of 0.84 and pump characteristics already defined.

Results. Year 1 of simulation, as shown in **Fig. 6,** is a system with a fairly high flow rate of approximately 4060 m^3/d close to the riser base of the pipeline, which is explained by the low water cut and high PI from the reservoir. By Year 3, there is a steep fall in production rate. The production rate or flow rate falls to approximately 2300 m^3/d. This can be explained by the rapid increase in water cut of the system from 0 to 47%, drop in PI from 16.8(–) to 7.3(–), and of course inception of slugs. Year 5 shows a slight increase in flow rate to approximately 2500 m^3/d. This is explained by the increase in PI over the previous year. Year 8 of simulation, shown by the green plot in Fig. 6, shows an increase of flow rate to approximately 2700 m^3/d as a result of a high PI of approximately 86%. This is the second highest flow rate on the graph and is explained by the multiphase pump and reduction in slugging in the system. Therefore, an approximately 33% reduction in production-flow rate is observed from Year 1 to Year 8 with the application of subsea processing. Thus, a PI increase of 17% is gained with the application of subsea processing in Field B compared with Case 1.

During Year 1 of simulation in **Fig. 7,** there is a slight variation in pressure (0.2 bar) and a flow-rate variation (300 m^3/d). These variations are a result of startup of the multiphase pumping, pipeline topography with regions of undulation, and position of the multiphase pump on the pipeline (the longer the length the fluid flows through the pipeline, the greater the separation of phases in the system). All these result in regions of instability along the pipeline. This variation in pressure completely evens out after approximately 2 to 3 hours of operation of the system. By Year 3 of simulation, shown by the red plot in Fig. 7, there is a slight increase in pressure variation of the system in the region of 0.4 bar and variations in flow rates of 2000 m^3/d. This slight variation evens out after approximately 2 to 3 hours.

The fifth year of simulation does not show any remarkable variation in flow rate. This can be explained as a result of the high PI of this year. Year 8 of simulation results in a higher magnitude of variations in pressure compared with the previous years for this case. There is an onset of slugging caused by the factors mentioned previously, in addition to high water cut of the reservoir. Year 8 is characterized by pressure variations in the region of 0.6 bar and flow-rate variations in the region of 11 000 m^3/d.

After 2 to 3 hours of operation, this fluctuation evens out to give a fairly stable flow (i.e., slight or minimal variation in pressure, resulting in a more stable system).

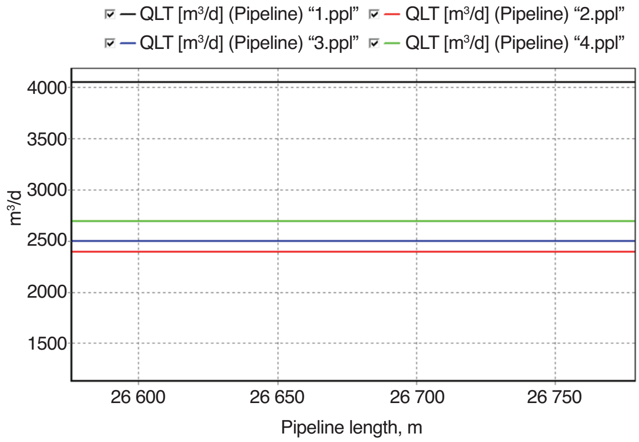

Fig. 6—Profile plot of flow rate vs. pipeline length for Field A, Case B.

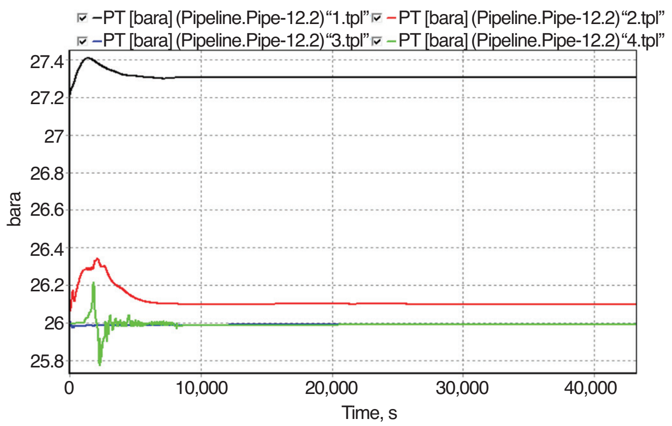

Fig. 7—A plot of pressure variations in the pipeline vs. time for Field A, Case 2.

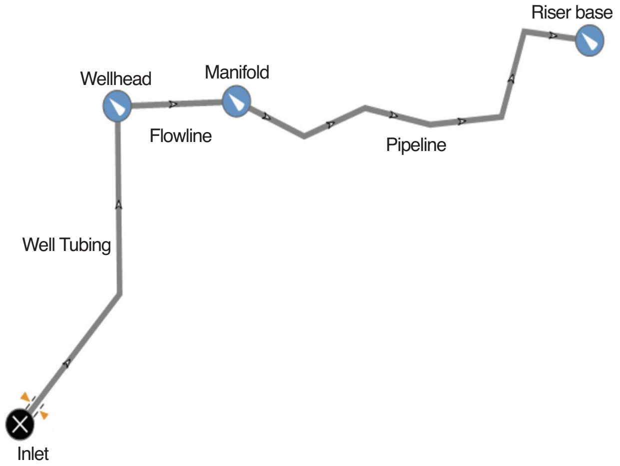

Fig. 8—Transient-multiphase-flow-model representation of Field B, Case 1.

Analysis of Field B, Case 1 (Base Case)

Model Description. The well is slightly deviated, with a deviation of 5 m from the wellhead and a depth of more than 2300 m below seabed. The well has a temperature of 95°C and pressure of more than 350 bar. The well tubing was modeled using steel and formation, which is in essence rock and sand. The well tubing has a nominal diameter of 5.5 in. and wall thickness of 0.304 in. The overall heat-transfer coefficient is taken to be 13.2 W/m2·°C. The wellhead is taken as an open node, the dimension of which is computed by OLGA in the running simulation. The pipeline is modeled using 12.0-in. API 5L grade X52 line pipe, with a thickness of 0.625 in., that is insulated with two layers of insulation (7.5-mm polypropylene and 20-mm polyethylene foam). The pipeline is neither buried nor trenched on the seabed. The total pipeline length from wellhead to riser base is in excess of 9 km. The pipeline depth undulates between 950 and 1150 m. This uneven pipeline profile with regions of inclination and declination increases the probability of terrain-induced slugging, as shown in **Fig. 8.** This case simulation was simulated for a period of 12 hours.

Results. The profile plot in **Fig. 9** shows the production rate of Field B without any form of subsea processing. Year 1 of simulation of the reservoir shows a high flow rate of approximately 2035 m^3/d as a result of high pressure in the reservoir, high PI, and low water cut. During Year 3 of production, there is a rapid drop in flow rate of the system to approximately 860 m^3/d as a result of the increase in reservoir water cut and fall in PI.

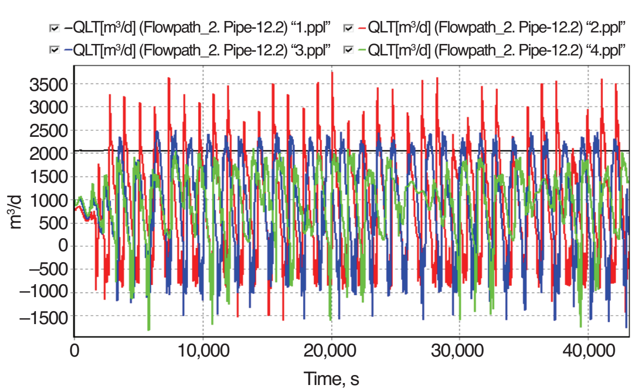

Fig. 10—Profile plot of volume variation vs. time for Field B, Case 1.

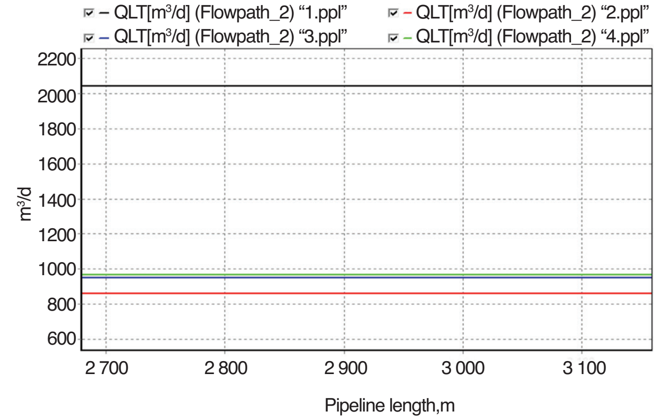

Fig. 9—Profile plot of flow rate vs. pipeline length for Field B, Case 1.

Year 5 of simulation shows a slight increase in flow rate of the system to approximately 930 m^3/d. This is as a result of increase in PI, despite a higher water cut compared with Year 3 of simulation. Year 8 of simulation shows an increase in flow rate to approximately 943 m^3/d compared with Year 5 as a result of an increase in PI. Therefore, an approximately 64% percentage reduction in production rate is observed from Year 1 to Year 8.

The rate of change of volume simulated in **Fig. 10** is directly proportional to the rate of change of pressure. Year 1 simulation shows a fairly stable system with little or no slugging. From Year 3 to Year 8, there is severe slugging and variations in production rate of up to 4500 m^3/d in the pipe as a result of an increase in water cut, reduction in PI, and also the depth of the field. During Year 3, production of this field will be extremely difficult without some form of processing or slug-mitigation procedures.

Analysis of Field B, Case 2

Model Description. The reservoir characteristics, flowline, and pipeline are similar to the case described for the base case in Case 1. This model incorporates a multiphase pump along the pipeline close to the manifold. The pump characteristics are modeled using the Framo-Hx360-1800-38 with a discharge coefficient of 0.84 and pump characteristics already defined.

Results. From the plot profile in Year 1, as shown in **Fig. 11,** the production profile gives a flow rate of approximately 2085 m^3/d.

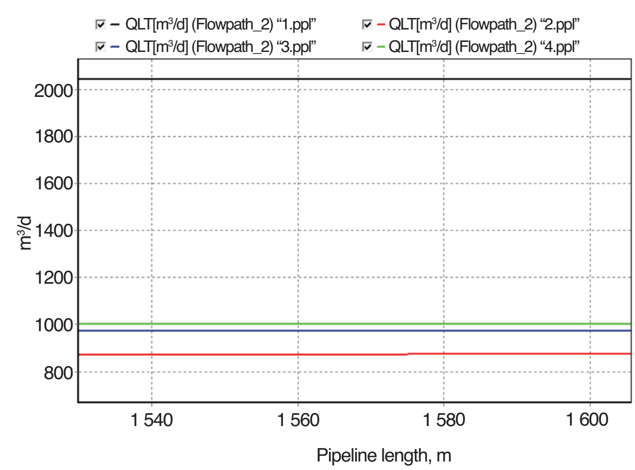

Fig. 11—Profile plot of flow rate vs. pipeline length for field B, Case 2.

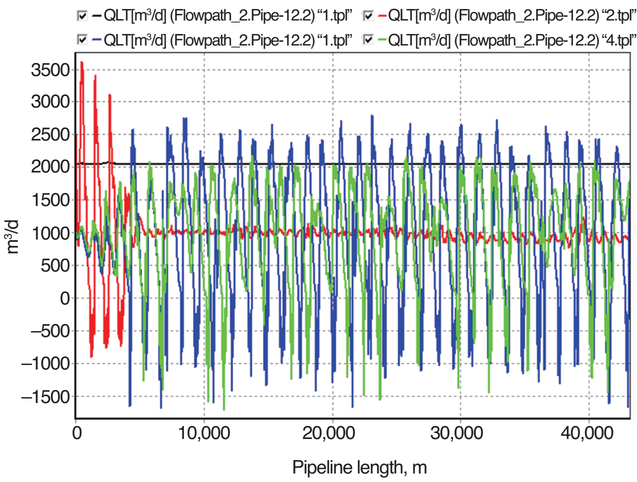

Fig.12—Profile plot of volume variation vs. time for Field B, Case 2.

Similar to all the cases decribed next, there is a sharp drop in production-flow rate to 880 m^3/d for Year 3. For Year 5, there is a slight increase in production rate up to Year 8, with a production rate of 1000 m^3/d.

Therefore, the production rate from Year 1 to Year 8 shows a 53% reduction in production. Thus, an increase of PI of 11% results with the application of subsea processing in Field B, compared with Case 1.

From the plot profile in **Fig. 12,** Year 1 of production for this field shows a fairly stable system, with little or no slugging. At Year 3, there is severe slugging in the system at the first 2 hours of production—this is a result of startup operations. The rate of variation is then reduced as the system begins to normalize. This shows there is slugging in the system, but not in the severe region. Years 5 and 8 production profile shows the flowline is under severe slugging, with varitions in production rate up to 4200 m^3/d.

Summary of Field-Case-Simulation Studies

With the application of subsea processing on the two Field A and B case studies, multiphase pumping shows a marginal gain in PI of 14% for Year 8 production from both cases, as shown in **Fig. 13**.

The severity of slugging in Year 3 of production is manageable; hence, production of this field at this period is feasible.

For Years 5 through Year 8, there is severe slugging in the system but not as severe as in the base case. Hence, multiphase pumping offers a minute improvement in the mitigation of slugging in the system caused by high water cuts, low PI, and severe slugging. However, multiphase pumping can be applied effectively to deepwater marginal fields with other forms of slug-mitigation processes (e.g., proportional-integral derivative, gas injection) to achieve high potentials on production.

Furthermore, from a cost analysis, a 17% increase in PI when compared with no subsea processing would yield additional revenue of

$$\text{Revenue}=\text{Recoverable Reserves}\times\text{Price of Oil}, \quad (1)$$

where recoverable reserves are assumed to be 35 million bbl and oil price per barrel is \$80. Hence, the revenue for 17% production increase will be

$$35\ \text{million}\times 80=\$28\ \text{billion}\ . \quad (2)$$

Therefore, 28 billion×0.17=\$476 million, an incentive to employ MPP to develop marginal fields commercially.

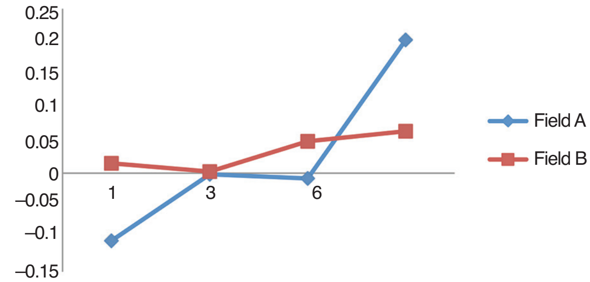

Fig.13—Profile plot of volume variation vs. time for Field B, Case 2.

From the simulation analysis discussed in the present paper, there are significant advantages in the use of multiphase pumping for field development, such as

- Increasing PI by 17 and 11% in Year 8 of analysis of Field A and B production, respectively, when compared with the field with no subsea processing.
- Significant savings in capital expenditures and operational expenditure because it can be used to develop deepwater marginal fields without the need for large footprints on topside processing facilities.
- Environmentally friendly because all fluids produced from the well are pumped directly to the receiving facility. There is no injection or disposal of associated fluids.

Therefore, the derivable incentive of SPT gives confidence in developing shallow and deepwater marginal fields for the offshore industry.

Conclusions

These conclusions apply in a general sense to marginal subsea tiebacks. No specific field application is presented herein, but several typical cases have been presented. Thus, the initiative of readers would be required to follow the logical path through which MPP was recommended for marginal-deepwater-field development.

The analysis shows that multiphase pumping in terms of performance offers a relatively high value for shallow marginal fields. This results in an even production profile, with variable increase in production, thereby reducing flow-assurance issues, thus extending the field's productive life. The analysis shows this also increases the life of the field's production facilities, and is best implemented at the later stage of the field's life or when the water cut of the reservoir fluid is greater 70%. MPPs should be kept as close to the wellhead as possible so as to prevent separation in fluid phases because they flow through the pipeline and contribute to managing flow-assurance issues. According to Grynning et al. (2009), MPPs are known to have a maximum step-out distance of approximately 30 km for longer distances. The procedure of using MPPs and boosting stations, as described by Abili et al. (2012), can be applied. Applying this procedure will lead to longer tiebacks and a reduction in cost as a result of fewer production facilities on the seabed. Multiphase pumping is also environmentally friendly because it eliminates flaring and PWRI or seabed disposal, which results in pollution of the underwater environment. An increase in reliability and availability of multiphase pumping technologies, especially in the area of seals improvement and its application across numerous fields in the offshore industry, makes it an excellent choice for application to remotely marginal field developments.

For deepwater fields, though, multiphase pumping offers a slight advantage compared with a field without any form of SPT. Hence, multiphase pumping will yield a high production rate if applied in conjunction with a tailored flow-assurance strategy. In Case 2, both Field A and Field B analyses should be complemented by use of a water-injection well because this boosts the pressure of the production well and helps mitigate flow-assurance issues. It should be modeled using a higher-capacity pump than those used for these simulations.

The offshore industry will benefit significantly when the subsea MPP technology is applied to commercially develop deepwater fields.

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Appendix A

Concept Selection. The present paper follows a three-stage approach, as can be observed in **Fig. A-1**. Because of the large number of SPTs available off the shelf, a pairwise comparison of the SPTs for marginal-field development will be tedious and time consuming, hence the SPTs are narrowed down to a smaller number to allow for effective pairwise comparison. The first concept-selection stage is handled using QFD. The results from QFD were refined further using AHP (second-stage concept selection). The viability of high-ranking solutions from the AHP analysis were further verified by simulating their applications on a real-life field as a case study using the OLGA program. This leads to an innovative and effective solution for an offshore marginal field with a subsea-processing system. The methodology for this work is an iterative process to obtain a near-optimal solution.

QFD. QFD is a well-established systematic approach used to support system requirements prioritization and relate stakeholders' need to technical requirements (Breyfogle 2003; Dieter 1997). QFD carried out an evaluation of SPTs against the set expectations from industry experts and expected objectives for offshore-field development.

QFD was used initially because of the uniqueness of its methodology and approach in concept selection. It can collate and evaluate data from different sources. Such data used for the QFD process can be captured statistically and evaluated in days, even for complex situations. The user can readily evaluate what con-

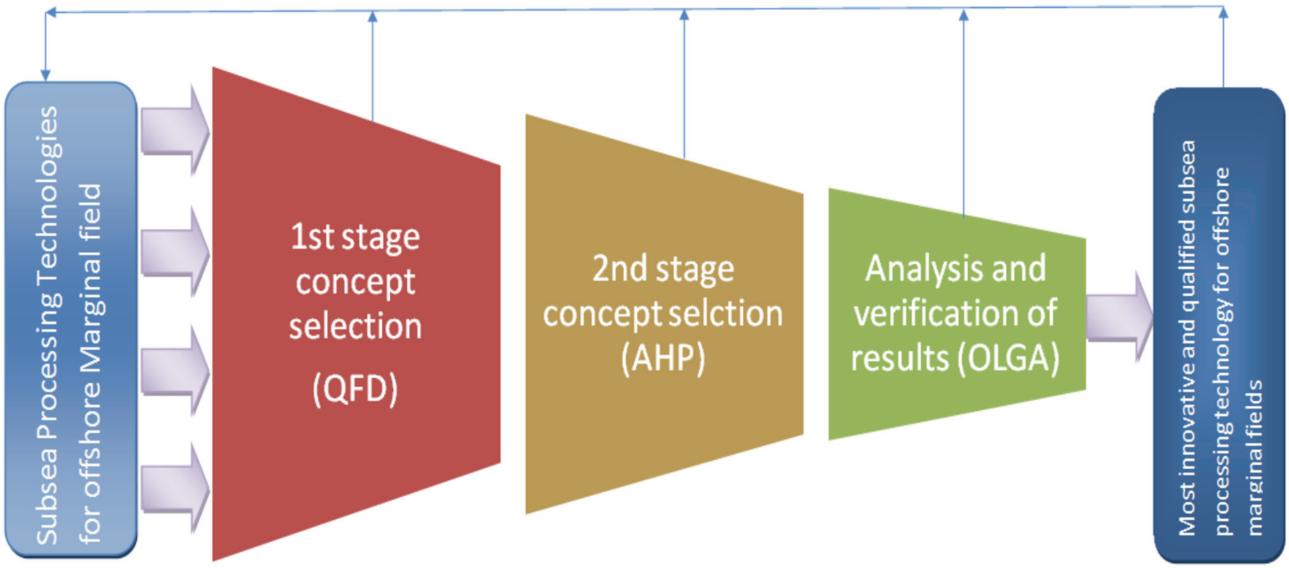

Fig. A-1—Flow chart of concept selection.

cepts are feasible and not feasible, and limits of feasibility of concepts under evaluation from QFD analysis. The limits of feasibility help to prevent failure by suggesting the limits of failure, hence reducing concept-development plan and costs. QFD has been applied to company product development and resulted in a 33% reduction in development time and 50% increase in productivity (Guinta and Praizler 1993).

QFD as a method is often used as an interdisciplinary approach in the planning, design, and development of products. It clearly defines the basic consumer needs and wants in the product, then proceeds to evaluate each proposed product or service capability in terms of ability to meet the needs and wants of the consumer (Guinta and Praizler 1993; Shillito 1994; Cohen 1995; Revelle et al. 1998). The QFD concept uses matrices in its analysis. The first set of matrices is called the house of quantity (HOQ); this is the basic building block or product-planning phase that highlights the consumer's need for the products and how this can be achieved. It is normal practice to extend or integrate the result of QFD analysis with the other leading-edge value-improvement processes. QFD forms the basis for other concept-improvement models [e.g., customer-oriented product conception, concept evaluation, and weighted concept selection with AHP (Shilito 1994; Acclaro® 2012)].

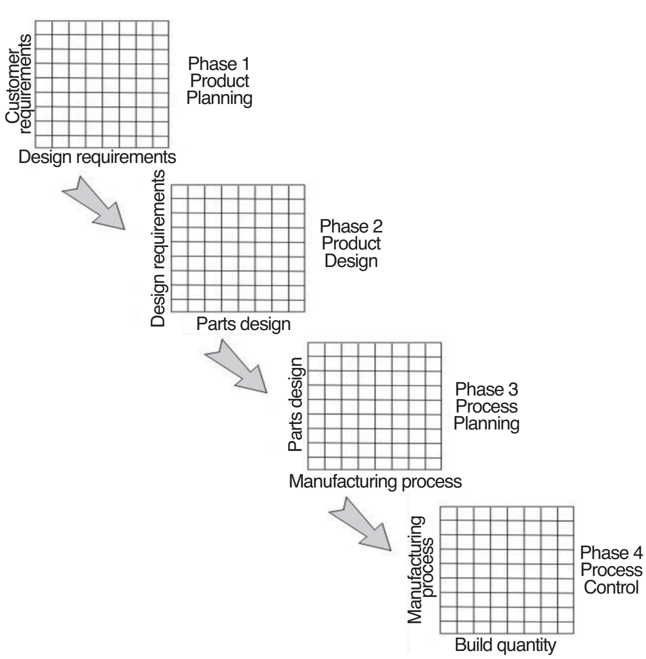

Fig. A-2—The four phases of QFD development (Revelle et al. 1998).

The methodology or phases of QFD, however, start with the needs of the customer and are then applied to the entire product life cycle. QFD is implemented usually in four phases: product planning, product design, process planning, and process control, as shown in **Fig. A-2.** Each stage is made up of an HOQ, otherwise called the QFD matrix.

The box with the "criteria for effective development of marginal fields" in **Fig. A-3** is usually referred to as the voice of customer (VOC), also known as the "What." This is the objective function of QFD, which states the major requirements the customer (operator) needs in the product (SPT). The "How" refers to the measures (technical) to achieve the "What." A relationship matrix evaluates the relationship between the "How" and "What." A correlation matrix refers to the relationship that exists between the various "How" factors. Technical assessments refer to the result of the evaluation performed in the relationship matrix that is the qualitative assessment of the "How" meeting the needs of the "What." The Relative Score section refers to the relative ranking of the technical assessments of the SPTs. For a more detailed look at QFD, VOC, and HOQ, the literature can be consulted (Guinta and Praizler 1993; Shillito 1994; Cohen 1995; Revelle et al. 1998).

As stated by Magi et al. (2011), the major constraints of marginal fields are cost and technical innovation (technology breakthroughs). These will form the major requirements of marginal fields because SPT is expected to tackle these requirements. The requirements or needs are rated and ranked by industry experts, thus are quantifiable to be used for the QFD analysis.

However, the requirements for marginal-field processing are exhaustive. **Table A-1** shows some of the common requirements considered during the design stage. The requirements shown in Table 1 were ranked by experts on a scale of 1 to 10. This is then scaled down to the QFD requirements by multiplication with a factor of 0.5, as observed on the "Adjusted Ratings for QFD" column.

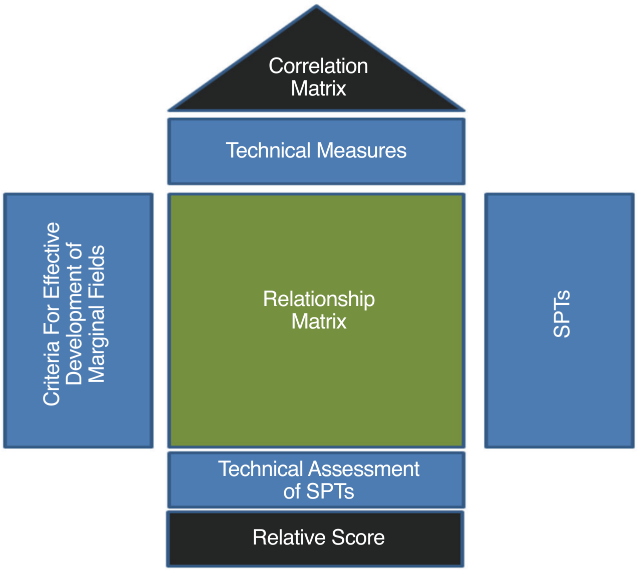

Fig. A-3—QFD relationship matrix.

Furthermore, **Table A-2** shows some of the solutions that could be used for the effective exploitation of marginal fields. These possible solutions are referred to as the "Hows."

The requirements are then used in the HOQ on the criteria column, with all possible subsea-processing solutions applied in the "How" column. Evaluation of the QFD process are carried out using Acclaro Software. The results from the QFD evaluation is shown graphically. The final result illustrated on a graph in **Fig. A-4** is obtained from the Relative Importance column of the HOQ.

There is a need to screen out some of the SPTs shown as a result of the QFD analysis. Systems with a relative performance of greater than 10 are considered for the next phase of selection. These systems are considered to be the most-feasible solutions for subsea processing on marginal fields, given that they show a high level of satisfying marginal-field exploitation requirements. Although single-phase pumping (SPP) meets the 10 relative importance criteria, it will not be considered further because in most marginal fields, we expect multiphase fluids. The SPTs considered for the next phase are listed below.

- Three-phase separation, oil boosting, PWRI with SPP, and gas compression
- Three-phase (gas/oil/water) separation, PWRI with SPP, and oil boosting
- MPP
- Gas/liquid separation and liquid boosting with MPP
- Gas/liquid separation and liquid boosting with ESP (VASPS)

The next phase can be carried out by a number of analytical processes, but we did focus on using AHP to scale down the SPTs to an efficient solution.

AHP and Analysis. AHP involves pairwise comparison of a group of attributes; that is, two attributes are compared against each other at any time until the possible number of pairwise comparisons is completed. The basic intent of AHP is to enable the decision maker to structure multiattribute decision making, usually in the form of an attribute hierarchy. Each level's attribute is compared among each other relative to the preceding level's attribute (Saaty 2008; Saaty 1990).

The following steps adopted from Saaty (1990), Ramanathan (2001), and Saaty (1980) are employed for carrying out AHP:

1. The problem statement should be defined clearly; objectives, criteria, and alternatives (SPTs) should also be stated clearly.
2. The hierarchical process should be developed starting with the objective being on the topmost level. The intermediate level should include the criteria for evaluating the SPTs, while the subsequent level should be the alternatives, to be evaluated, as shown in **Fig. A-5.**
3. A matrix with elements ($m \times n$). For this study, m=n is constructed for each element of the lower levels; that is, for every level there should be a number of matrix corresponding to the elements in that level and the elements of the matrices should consist of members of the subordinate level.

TABLE A-1—RANKING OF SUBSEA-MARGINAL-FIELD REQUIREMENTS

SPT Requirements For Marginal Field	Ratings	Adjusted Ratings for QFD
Deepwater application	7	3.5
Handle multiphase fluids	9	4.5
Handle high water cut	5	2.5
Handle sand production	4	2
Long step-out distance/field layout	7	3.5
Incorporates water-handling capability	9	4.5
Reservoir pressure	8	4
PI	3	1.5
Potential increase in production	5	2.5
Crude-oil specific gravity and viscosity	6	3
Gas-volume fraction	7	3.5
Production method	4	2
Reliability	10	5
Cost	8	4
Environmental performance	8	4
Power requirement	5	2.5
Maturity	7	3.5
Simplicity	6	3
Accessibility	7	3.5

TABLE A-2—SPTs FOR MARGINAL-FIELD PROCESSING		
S/N	Subsea Processing Technologies	Nomenclature
1	Single-phase pumping	SPP
2	Multiphase pumping	MPP
3	Gas/liquid separation and liquid boosting using MPP	G/L SL MPP
4	Gas/liquid separation and liquid boosting using SPP	G/S SL SPP
5	Gas/liquid separation and liquid boosting using ESP	G/S SL ESP
6	Subsea raw-seawater reinjection	SWRI
7	Three-phase(gas/oil/water) separation, produced water reinjection and liquid boosting using MPP	3-PSPM
8	Three-phase separation oil boosting, PWRI with SPP and gas compression	3-POPS
9	Gas/liquid cylinder cyclone	G-LCC

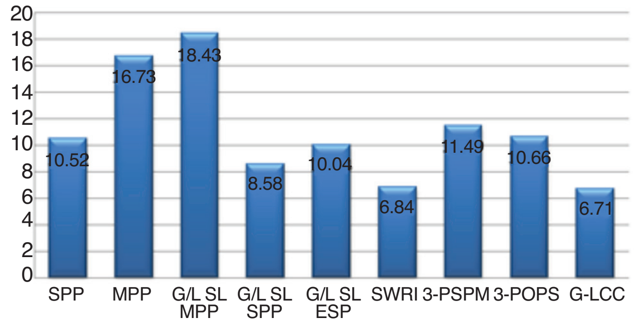

Fig. A-4—Results from QFD analysis of SPTs.

4. An assessment of the matrices was carried using the fundamental scale of pairwise comparison shown in **Table A-3.** The assessment is a pairwise comparison of each of the elements in the matrix with respect to the criteria on the upper level of the comparison. They are compared in terms of how each element is superior over the other with respect to the criteria in the upper level.
5. The number of decisions or judgments required to develop a set of matrices is given by $(n^2-n)/2$. This is for the preceding step describe earlier, where n is the size of the matrix.
6. The reciprocal of values from evaluation of the matrices compared using the fundamental scale of pairwise comparison is computed.
7. Synthesis of the values of the reciprocal is carried out using eigenvectors—this is called hierarchical synthesis. Eigenvectors by weights of the criteria and the sum are taken over all weighted eigenvector entries corresponding to those in the next lower level of the hierarchy.
8. The consistency index (CI) is used to check the consistency of the pairwise comparisons. This is performed by using the eigenvalue λ_{max}. Decision matrices can be checked using the consistency ratio (CR) of CI. The value of CR acceptable for this work is 0.10. Decisions can be reviewed until the constituency ratio becomes consistent, that is, below the CR value of 0.1

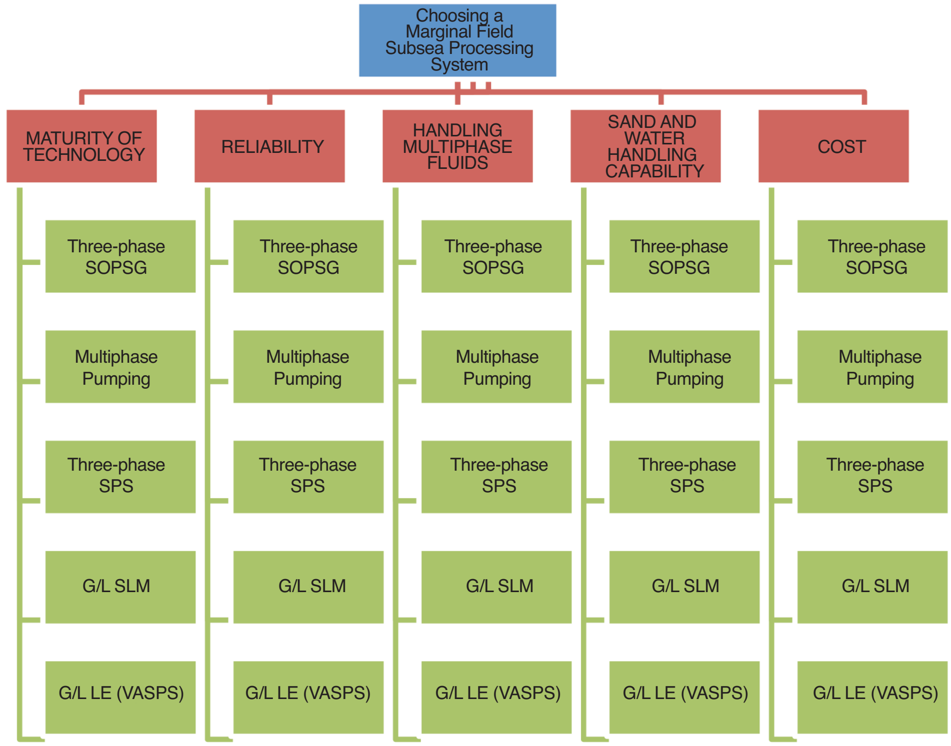

Fig. A-5—Analytical hierarchy process for SPT selection.

TABLE A-3—AHP'S FUNDAMENTAL SCALE OF PAIRWISE COMPARISON		
The Fundamental Scale for Pairwise Comparisons		
Intensity of Importance	Definition	Explanation
1	Equal importance	Two activities contribute equally to the objective.
3	Moderate importance	Experience and judgment slightly favor one activity over another.
5	Strong importance	An activity is favored strongly over another, its dominance demonstrated in practice.
7	Very strong importance	Experience and judgment slightly favor one activity over another.
9	Extreme importance	The evidence favoring one activity over another is of the highest possible order of affirmation.
2,4,6,8	For compromise between the above values	Sometimes one needs to interpolate a compromise judgment numerically because there is no good word to describe it.

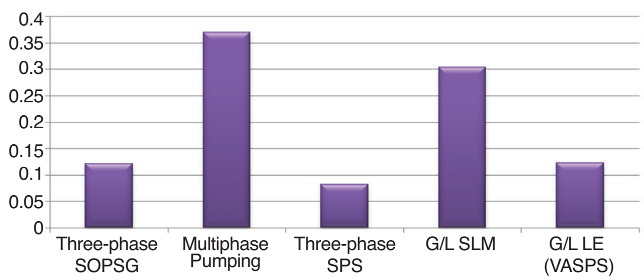

Fig. A-6—Ranking chart of SPTs for marginal fields.

9. $\mathrm{CI} = \dfrac{\lambda_{\max} - n}{n-1}$, where n is the matrix size.
10. The final step involves obtaining the overall relative score of each option, hence the ranking in satisfying the stated objectives. This is achieved by a combination of the criteria weight to that of the alternative SPTs.
11. The last seven steps are carried on all levels of the hierarchical process.

From the AHP analysis, the most effective optimum solution available currently on the market after pairwise comparison of the five posiible solutions is multiphase pumping, as shown in **Fig. A-6.** This optimum solution came up with a relative ranking weight of 0.37 on a scale of 0 to 1, followed closely by gas/liquid separation and liquid boosting using a multiphase pump. The result is expected because of the numerous advantages multiphase pumping possesses, which include the elimination of the need for subsea equipment (e.g., separators, compressors, heaters, and separate flowlines). In essence, by the elimination of this equipment at a subsea level, subsea multiphase pumping helps in cost reduction. Multiphase pumping, either as subsea equipment or an ESP, is used in more than 140 applications worldwide; hence, it is a relatively mature technology with high reliability (Hua et al. 2012; Marvin 1998).

The two most commonly used MPPs for subsea processing are the helico-axial-pump (HAP) and the twin-screw-pump (TSP) types. For this study, HAP is used for the following reasons:

- HAP is known to achieve higher production rates than TSP when used in the same conditions.
- HAP has a wider operating range than TSP. HAP has a normal range of runs between 3,500 to 6,500 rev/min compared with 1,500 to 2,400 rev/min for TSP. HAP has a higher differential-pressure rating of close to 200 bar, compared with 100 bar for TSP. HAP has a pressure rating of 15,000 psi vs. TSP with 5,000 psi.
- HAP is more effective in handling produced sand than TSP because of the type of internal clearance it possesses.
- Generally, HAPs are known to provide a cost-effective and technical solution for subsea-processing needs.

Multiphase pumping is thus simulated for a real field-case study to validate its performance on subsea processing applied to offshore-marginal-field developments.

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