Choice of Development Concept—Platform or Subsea Solution?

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Summary

A real choice exists today on a number of discoveries between platform-based or subsea development solutions. Statistics from the Norwegian continental shelf (NCS) show that fields developed with fixed platforms have a substantially higher recovery factor. The potential for a later commitment to improved oil recovery (IOR) is determined largely by the original development solution. Through the use of cases and examples, this paper discusses principles for valuation of the enhanced flexibility offered by platform-based development solutions and sequential subsea solutions. It illustrates that valuing the various types of flexibility is difficult, which leads to the following question: Are development solutions being selected without taking sufficient account of option values?

Introduction

Technological progress with subsea production has been rapid. Such installations can now be used in most conditions, and costs have been reduced sharply. A real choice exists today on a number of discoveries between platform-based or subsea development solutions. In particular, a subsea facility could be a good solution for fields with small resources or in deep water where the distance to land or to existing platforms is short. The choice of concept is a complex business, with input from many interested parties and technical disciplines. Examples of key developments on the NCS that faced a demanding choice of concept are Ormen Lange and Snøhvit in the Norwegian Sea and Barents Sea, respectively. These fields have been developed with subsea solutions even though that has required long tiebacks to land-based terminals. Platforms were one alternative studied.

Investment in subsea installations is lower, but drilling costs remain high throughout the field's producing life, and licensees may often have to pay tariffs to infrastructure owners. In other cases, the same partners own both the subsea field and the processing facilities, as with the aforementioned Ormen Lange and Snøhvit examples. If, as in these cases, the development involves a tieback of subsea facilities to a newly built land-based terminal, this will be included as investment in the net-present-value (NPV) calculations. On the other hand, when the choice is to tie back to an existing processing facility owned by the licensee, which could now or over time be used by other projects (owned by the same licensee or others), an opportunity cost must always be calculated for use of the capacity. Fixed platforms offer a number of advantages, which need to have a value put on them. Such installations permit a flexible drainage strategy, particularly if the platform has its own drilling facilities. They offer lower marginal costs for IOR campaigns after a few years of learning lessons on the field, and they normally have higher regularity over their producing life. New recovery technology, which emerges after development has ended, is often easier to adopt when a platform has been chosen.

The recovery factor is defined as the proportion of the oil in a reservoir that is recovered. A key concept in this context is stock-tank oil originally in place (STOOIP). "Stock tank" is the volume at normal pressure and temperature. STOOIP must not be confused with oil reserves, which are the volume that can be recovered technically and commercially (Osmundsen 2010). The recovery factor for offshore oil fields normally lies between 10 and 60%, but can reach close to 80% in certain favorable cases (Energy Information Administration 2008).

Approved oil-company plans at the end of 2010 would mean that 54% of the oil in fields developed on the NCS remains unrecovered (IOR Expert Committee 2010). Norway has achieved high recovery factors compared with other countries. A global overview of recovery factors is provided in Sandrea and Sandrea (2007). They report an overall factor of 46% for the North Sea, and describe this as the highest in the world. According to Laherrere (2006), the global average recovery factor is 27% (derived from the Information Handling Services database, which covers approximately 11,500 fields). Nevertheless, substantial financial gains could be made from improving the recovery factor; an increase of just 1% in oil production beyond today's approved plans could yield net revenues on the order of USD 20–30 billion at current oil prices (Melberg 2009). It is difficult to make accurate cost estimates here, and it is consequently of equal interest to look at the corresponding gross revenue, which is on the order of USD 50–60 billion. As always, revenues must agree with costs, but a potential for profitability very probably exists for both government and oil companies.

The development concept is one element that influences the recovery factor, and that offers a choice. Reservoir, fluid, and rock properties are more important, but are determined by nature in the same way as porosity, permeability, and the quantity of gas dissolved in the oil together with heavier components that can cause wax formation and raise oil viscosity, thereby hampering production. The recovery factor depends also on the efforts made by the oil companies to maintain production over time, including injection of water, gas, and chemicals in addition to well workovers and new drilling. But the choice of development concept has a great impact on the cost of subsequent IOR work. Therefore, it is interesting for government and companies to study the validity of decision criteria for concept choice—the extent to which these take account of the relationship between concept choice and recovery factor.

Real Options in Oil Recovery

The potential for a later commitment to IOR is determined to a great extent by the original development solution. One based on a dedicated drilling rig, for instance, will normally have greater potential than platforms without such facilities or than subsea solutions in which a mobile rig must be chartered each time. This

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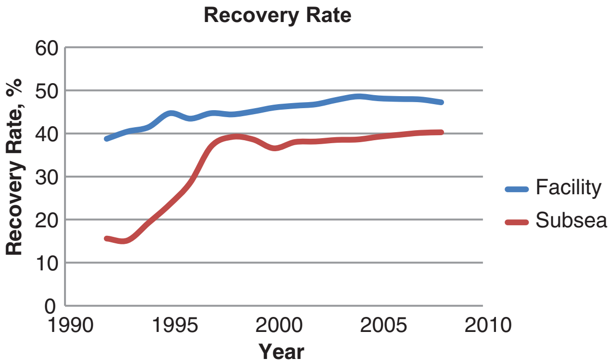

Fig. 1—Average recovery factors for fields with a platform and those developed with subsea wells. Platforms are defined here as fixed structures with a drilling module (Nordvik et al. 2010).

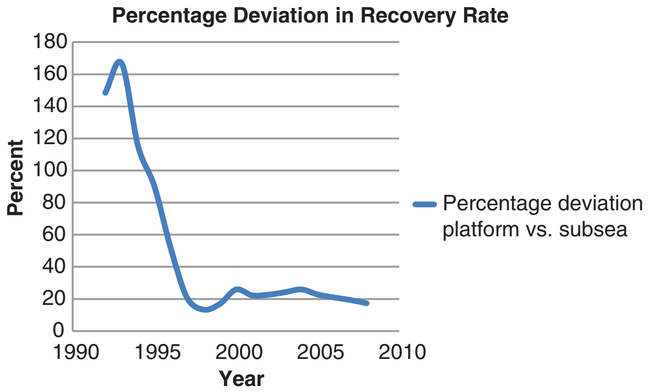

Fig. 2—Percentage difference in average recovery for fields with fixed platforms and those developed with subsea completions (Nordvik et al. 2010).

affects not only the flexibility for, but also the marginal cost of, workovers or new wells.

One advantage of subsea installations is lower initial investment. On the other hand, costs are higher for operation and maintenance, tariffs may often have to be paid for processing, flexibility is lost, and it is far more expensive to drill new wells or implement necessary changes to existing ones. Installing a platform with drilling facilities makes it easier and less expensive to intervene in wells, run measuring devices, and identify and diagnose improvement possibilities. Opportunities for injection are greater, and more wells can be drilled. It is also simpler and less expensive to implement necessary changes, including alterations to the drainage strategy. An improvement measure on a subsea well often requires five times the earnings potential than would be needed for an intervention in a platform well. Delays to well intervention are one consequence of this. The backlog in well maintenance has led to production losses that cannot be recovered and to the downgrading of reserves (IOR Expert Committee 2010). At the same time, a platform solution will provide greater assurance that the position has been understood while providing a better database and lower operational risk, which relates in part to weather conditions (drilling from a platform or a jackup rig cantilevered over a wellhead installation is seldom halted by bad weather). A platform solution avoids the restrictions on well numbers imposed by a subsea development. Operations can also be optimized regardless of sharply fluctuating rig rates.

On the other hand, there are other operational risks that the platform with rig suffers from and the subsea alternative does not [e.g., the simultaneous operations of production and drilling (or completion or workover) on the same platform]. Platform solutions also have their restrictions. The number of wells from a single point (the case of a platform-with-a-rig solution) is restricted not only because of the number of slots in the template, but also because directional/horizontal drilling is feasible for reservoir targets up to only approximately 7 km. For the subsea solution, restrictions apply for subsea wells producing to existing fixed platforms, but it is possible to connect subsea wells to floating production units (e.g., semisubmersibles without rigs, and floating production, storage, and offloading units). The Marlim oil field in Brazil, for example, has more than 100 subsea wells connected to several floating production units without rigs.

The threshold for making changes to subsea wells is often very high. It is possible, for instance, to find oneself in conditions in which rig rates are increased for many days because of bad weather. Platform wells also have better production regularity, while mechanical damage can, as a rule, be repaired and wells brought back on stream in reasonable time. Taken together, these considerations mean that developments based on platforms with their own drilling facilities have a substantially higher recovery factor. This is illustrated in **Fig. 1**.

The difference in recovery factor between fields with fixed platforms and those developed with subsea completions equals seven percentage points. For fields included in the statistics, this translates into 17% higher production on average with a platform. The reason for the difference is that, while the recovery factor is calculated in relation to the STOOIP, the production increase is calculated in relation to existing output; in other words, the denominator in the latter fraction is substantially smaller. We can see from **Fig. 2** that the percentage difference fell sharply until 1998 (when it was 13%), and thereafter flattened out, although with some fluctuations.

When interpreting these data, some caveats are worth pointing out. When using statistics, the possibility of sampling errors must always be borne in mind. Ideally, the recovery factor for different development concepts should be compared for the same field; however, that is not possible. Thus, parts of the discrepancy in the average extraction rate may be caused by factors other than development concept. One such factor is reservoir size. Because smaller fields are not able to carry the higher capital investment of a platform development, the average reservoir size is lower for subsea fields. Smaller fields, in general, have lower extraction rates than larger fields (e.g., because some IOR techniques are not profitable on a small reservoir and because larger fields can prolong the extraction time by becoming hosts for tie-ins for other reservoirs). Developments proceed with incomplete information, but the companies know a good deal from interpreting seismic and well data. Because they are often able to make a concept choice suited to the reservoir, the variation in recovery factor between platforms and subsea completions (as shown in Figs. 1 and 2) may be somewhat exaggerated. Moreover, the data series does not cover technological developments over the last few years that are likely to have reduced the benefit of a platform development. Examples are light well intervention, multilateral wells, subsea processing, downhole measurements and flow control, and improved reservoir monitoring. In comparison of platform (with rig) vs. subsea solutions, it should also be noted that in the 1990s, the oil price was low and, in many cases, the subsea alternative could be the only one with positive NPV. Similarly, some discoveries were fields with small volumes so that, again, the subsea concept could be the only economic solution. Of course, insisting on a platform concept in these cases would not improve the recovery factor, because the fields in these cases would not have been developed. Still, there are many field developments in which both subsea and platform concepts are possible from an economic point of view. In these cases, investing in a platform concept that offers more flexibility may pay off because of the uncertainties associated with reservoir engineering.

In particular, this applies to complex reservoirs, for which more data acquisition, sidetracks, and well interventions are required to achieve high recovery rates. Hence, valuation of production options is important.

Real-option theory is a well-developed discipline that makes it possible to price a number of real options. A key textbook in this area is Dixit and Pindyck (1994). In my experience, however, existing oil-company models fail to pick up all real-option elements. More sources of flexibility exist than those shown in **Table 1**, including the concept that subsea solutions require developments in rig rates to be modeled. Conditions could also arise in which production is lost because of rig shortages. This could be caused by a lack of tradition or by difficulties associated with the valuation of these options.

Closed-form option models are not able to analyze many of the real options listed in petroleum projects. This is partly because the latter are complex, partly because they are not independent, and partly because the option models, which originate in the pricing of securities, build on assumptions that are inappropriate for choosing concepts in petroleum developments (Pilipovic 2007).

Table 2 illustrates points at which economic conditions for petroleum projects in general deviate from those of stock options, making it more difficult to price petroleum options. Real-option-pricing theory has developed further and, currently, is able to accommodate several of those pricing challenges adequately (Haug 1997). However, for the particular case of pricing production flexibility, additional challenges exist. Concepts such as reservoir complexity and technical flexibility are not readily captured by economic option models, because we do not have knowledge of relevant distribution functions, nor are these functions likely to satisfy regularity assumptions on which pricing formulas are based.

Still, it is possible to capture parts of the real-option values described in Table 1: higher value for the option to expand the production (IOR option) as a result of the lower exercise price to implement the IOR project. The additional real-option value of the platform with rig compared with the subsea alternative is caused mainly by the lower exercise price (or exercise cost) of options related to wells as a result of the less-expensive rig in platform-based development compared with rigs in floating units. This lower exercise price, together with the higher rig availability, increases the option value of (a) workover in wells that stopped production because of technical problems or workover in wells aiming to improve production with acid fracturing or another method. The high rig rate makes the exercise price too high to perform some workovers in the subsea alternative; (b) recompletion opportunities (this is important for fields with different reservoirs at different depths or many noncommunicating layers). The lower exercise price for platforms with rigs makes it more likely to exploit these reinvestment opportunities than in the case of subsea development; and (c) IOR investments in the end of oilfield life, mainly when the IOR method demands well reconfiguration (e.g., tubing replacement). These less-expensive exercise costs for workover, recompletion, and IOR options (and the increased availability of rigs) generate a higher production and oil recovery for a platform-with-rig alternative than with subsea-based development.

To ensure that all real-option effects related to concept choices are included, it could make sense to use simpler models, such as sensitivity analyses, which take into account the differing drilling costs and production volumes related to the various options.

A simple approach to the issue of development with a platform or with a subsea solution is to regard this as a classic choice between expenditure today vs. expenditure tomorrow. A platform-based development involves a higher initial investment, but lower drilling costs and tariff savings over the field's producing life. However, the difference in cost structure has an additional effect, which represents the main point of this article—lower post-development drilling costs also yield a higher recovery factor and, therefore, increased revenues. In the following section, I will review a simple example that can illustrate the effect on the income side.

Example

The financial effect of increased production on the choice of a platform-based development will depend critically on whether the expected increase in volume takes the form of higher ongoing output (greater plateau production) or an extended producing life for the field. The first of these effects could be obtained when a development is tailored optimally to the reservoir. Succeeding in that (with the aid of good reservoir understanding and a reservoir that is not too complex) means a high recovery factor can also be achieved with a subsea solution. If, on the other hand, the reservoir is complex and surprises are encountered, the increased flexibility offered by a platform will provide higher plateau production. In other cases, the greater flexibility will be experienced primarily in the field's final phase by allowing its producing life to be extended. Because of discounting, volume increases in the final phase will exert less influence on the NPV.

These effects can be illustrated by a simple calculation. I am assuming here a model field that can produce 100, 150, or 200 million bbl of oil from a platform-based development. By applying the average recovery factor for the NCS in 2008 (47% for platforms and 40% for subsea completions), it is determined that the corresponding recovery for a subsea solution would be 85, 127, or 170 million bbl. A lead time of 3 years is assumed. For simplicity's sake, the production rise from choosing a platform rather than a subsea solution is assumed to occur on a straight-line basis over 15 years when the increase takes effect in plateau output. When the improvement alternatively comes at the end of the field's producing life, it is assumed to be allocated on a straight-line basis over 5 years, so that the overall production period extends to 20 years. The real discount rate is set at 10% (Boston Consulting

TABLE 1—REAL OPTIONS IN THE CHOICE OF CONCEPT FOR OFFSHORE PETROLEUM DEVELOPMENT—INCREASED OPPORTUNITIES FROM CHOOSING A PLATFORM

Real Options Related to Platform-Based Developments
Flexible drainage strategy
Technical flexibility, greater potential
Financial flexibility, lower marginal costs for extra measures
Lower operational risk
Greater regularity

TABLE 2—COMPARISON OF A STANDARD STOCK OPTION AND A COMPLEX ENERGY OPTION

Standard Stock Option	Petroleum Projects
Price option	Option on price, volume, and timing
Price process: random walk	Price process: mean reversion
Independent periods	Not independent
Good liquidity	Lack of liquidity
Arbitrage	Limited arbitrage
Absence of seasonal effects	Seasonal effects in gas markets
Absence of convenience yield	Considerable convenience yield

Group 2005), oil price at USD 90/bbl in real terms, and the US dollar exchange rate at NOK 6.

From **Fig. 3**, we see that the gain in NPV of revenue through the rise in volume could be as high as USD 1 billion. This revenue increase is supplemented by the NPV of savings in operating costs over the field's lifetime from a platform-based development solution, which includes lower drilling costs and tariffs paid to infrastructure owners over the field's producing life. The discounted sum of these two effects—higher revenues and saved operating costs—represents the rise in initial investment one should be willing to bear to opt for a platform-based solution. Fig. 3 shows that this willingness to pay varies substantially with expected reserves.

This is only a rough example. Other assumptions could obviously yield different results. A lower rate of return would boost NPV. Interest rates have fallen substantially since 2005, and are not expected to rise in the near future, which would encourage lower required rates of return. The same effect would be achieved by assuming a real rise in oil prices in the time to come. A different production profile, which takes longer to reach plateau, would reduce the NPV to a certain extent.

The difference in recovery factor between subsea solution and platform-based solution is the most important parameter here; it is also the most difficult to estimate. By using average figures, I implicitly assume an arbitrary decision, which is probably incorrect. If the oil companies succeed systematically in making a concept choice tailored to the reservoir, the expected difference between the two development concepts will be lower than average figures for the NCS suggest.

Subsea solutions are often selected because a platform-based development would not be profitable—initial investment is significantly lower with seabed installations. In deep water, a subsea approach is often the only one possible. However, the appropriate solution for many developments is a matter of doubt. Large reserves point toward a platform-based concept because achieving a high recovery factor makes good economic sense. Additionally, a complex reservoir (increasingly common on the NCS) favors a platform approach because such reservoirs require greater flexibility. In such a case, a subsea facility would mean high costs in the form of new wells and workovers, and major assets could remain in the ground because the wrong development solution was chosen. On the other hand, a platform could also represent an erroneous approach if the reservoir has been overvalued. The resulting development could fail to justify the investment cost. One could argue that complex reservoirs demand the exercise of learning options (investment in information) before committing huge investment in the overall oilfield development. Complex reservoirs typically have relevant dynamic uncertainties (e.g., stabilized productivity index after some weeks or months of production, which can be very different from the initial productivity index, mainly in carbonates) that can be reduced with one or a few subsea wells. The platform-with-rig solution is best suited for oil fields with low uncertainty so that the location of the template and the processing capacity/top-facilities decisions can be made with a reasonable degree of certainty. Note that from the platform template location, it is not feasible (technically and/or economically) to reach reservoir targets with a distance of more than approximately 7 km from the template location with directional or horizontal wells. Therefore, the definition of the platform template location is important, and, for complex fields, could be important to the dynamic information (from initial production) provided by the subsea alternative, at least for the first wells.

In short, there are real options that favor the platform-with-rig solution (workover, recompletion, and IOR; the last two are options to expand the production), and real options that favor the subsea solution if applied sequentially (learning options). In many cases, the combination of these two solutions—a few subsea wells in the beginning followed by an optimized platform by use of the information from subsea wells—looks to be a more-convenient method to develop petroleum fields using modern real-option concepts.

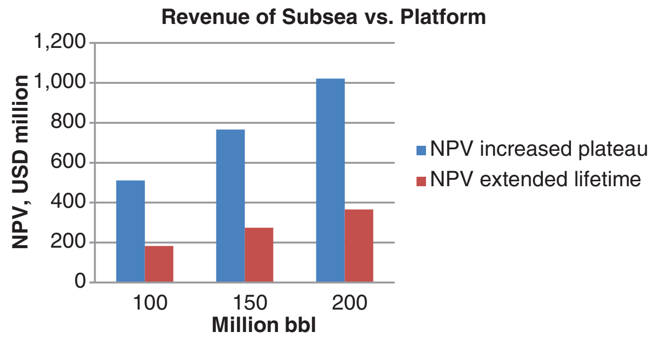

Fig. 3—The rise in revenue for a model field measured by NPV in USD millions for a platform-based vs. a subsea development, with total production from the model field of 100, 150, and 200 million bbl.

When a development decision is taken, knowledge of the field will be limited, including future opportunities and challenges that might arise in its producing life. Flexibility is crucial to a valuation. The danger is that the greatest weight will be given to initial investment savings, because these are the easiest to tackle or because a short-term approach is being taken. The development team will be satisfied if it can achieve a reasonable project, and the company and its present management receive positive media coverage. However, what matters in the long run for an oil company is the life-cycle economics expressed in the project's NPV, including the relevant options available. However, it must be stressed in this context that realizing these options could involve substantial additional costs that would need to be taken into account.

Oil companies have developed financial models that take into account many such options. Accuracy in applying these models depends on good communication between the various disciplines and close collaboration. Decision-support models have been improved substantially, but they call for suitable input parameters. According to company financial teams, they do not always get these from their petroleum-technology colleagues when seeking to calculate real-option values. The option models are often complex and difficult to solve, and could have limited freedom in terms of input format. Obtaining suitable input depends on detailed knowledge of the decision-support models among petroleum technologists and on their willingness to estimate suitable parameters. Ideally, the various sides should also agree on what constitutes suitable input to the decision analysis. If the input parameters are not tailored to the models, the danger is that the size of the initial investment dominates when decisions are made. Naturally, developing decision models tailored to available and relevant parameters also poses a challenge to the economists. A problem the latter face is that time will be a critical factor. The financial analysis is the final link in the chain, and the analysts have little time available. This does not seem to be the best point for the oil companies to reduce the time taken—quite the contrary, in fact.

Defending more-expensive solutions on the basis of gut feeling and industrial instinct calls for considerable courage on the part of management. It is frequently the case that quantitative effects dominate qualitative ones—the former are often harder to challenge and easier to audit afterwards. An increased concentration on auditing and transparency can have the unintended consequence that excessive weight is given to easily measureable conditions when making decisions. At certain times, too, management of the operator company (or the partners in the license) works with a self-imposed rationing of capital, and may then opt for the less-expensive solution, even though this yields a lower expected NPV (Osmundsen et al. 2006; 2007).

Supplementary Considerations. It was demonstrated in the preceding example that platform-based developments provide greater flexibility, which permits a higher recovery factor and, thereby, substantial additional revenues. However, a number of advantages of subsea systems have not been taken into account in this discussion and numerical example. An important characteristic of subsea solutions is that they simplify a phased delineation and development of fields, and, therefore, normally provide an earlier start to production with the gathering of useful information. They usually involve predrilling, so that plateau production is reached more quickly. Predrilling can also be conducted with fixed installations, but that involves additional investment and risk. Faster development and shorter time to plateau almost always increases NPVs. However, this argument assumes that a rig is available. To the extent that a tie-in is required to an existing installation, this opportunity must be available with the desired capacity at the anticipated time. This does not apply if subsea wells are linked to floating production units. These units may have valuable options to abandon because they can be relocated to another petroleum field after petroleum-field exhaustion. Experience shows that these requirements are not always met. It was necessary to wait for spare capacity until other fields went off plateau, and tariff negotiations took time. A tieback may also require modifications, which have often turned out to be more expensive and more time-consuming than the NPV calculations assumed. However, it is clear that not having to design, order, and build one or more platforms with equipment and so forth helps in terms of timing. Pumps, compressors, and turbines/generators have all taken several years to deliver in periods. I have been unable to obtain figures on development times for alternative concepts.

The number of well slots on a platform is determined before construction begins. Extra wells must wait for spare slots (additional slots are inexpensive if they are included from the start). Additional slots may therefore pose a greater challenge on a platform than with a subsea solution to which more templates can be installed. The challenge is to secure enough capacity in pipelines and control systems. Pre-investment is cheaper than wisdom after the event, but has an immediate impact on NPV calculations. Another strength of subsea solutions is that drilling locations can be dispersed to optimum points in relation to the reservoir, avoiding unnecessarily long and expensive wells.

Payment for tie-in and tariffs for subsea solutions primarily involve marginal costs on the platforms and a share of the fixed operating costs. Should a new platform be built, all operating costs must be borne by the discovery itself. However, this difference is only relevant for a tieback phased in toward the end of a field's producing life; all costs must otherwise be met by the new fields. Major unexpected maintenance-related costs have arisen for fields in their final phase. As a rule, all tied-in fields must contribute to meeting these, and a subsea solution can quickly prove to have been suboptimal in such circumstances.

Inadequate Well Maintenance

The main problem facing subsea developments is that the threshold for new infill wells and well interventions is too high. Active efforts are being made by the industry to lower this through the use of cheaper rigs, light well-intervention vessels, and standardized solutions.

Bente Nyland, director-general of the Norwegian Petroleum Directorate, has said that the maintenance backlog for subsea systems represents a challenge in the work of recovering the profitable reserves from existing fields on the NCS. "Many wells are out of operation," she told Offshore.no. "Subsea developments present many advantages, but some challenges as well. And the industry must put better maintenance systems in place" (Stangeland 2011).

So why have subsea wells not been maintained? Reserves frequently represent a conservative figure, and such estimates may often indicate in a given year that too little oil remains to justify a well intervention in the light of high rig rates. If this condition remains fairly constant for a few years, the realization with hindsight is often that one should have intervened earlier and made more money, but that it is now definitely too late. Additionally, rig avai ability and total drilling costs were not given enough emphasis to ensure optimum earnings. The combination of small reserves and an uncertain upside for remaining resources in a field led, and continues to lead, to well intervention on subsea installations being neglected.

Plans to build light intervention rigs existed as early as the late 1980s, but foundered through lack of collaboration in the industry, new business models in the oil companies, and uncertain crude prices in the early 1990s. The fields were in full plateau production, and nobody wanted to become unpopular by proposing that a great amount of money be spent on something that was a problem for the future. The concentration on short-term production indicators could have played a part here. Well tools were developed circa 1990, when the subsea licensees joined forces to create a pool of installation and maintenance equipment. The same shouldhave been done for light well-intervention vessels. As illustrated in Fig. 2, developments have shown that this was an erroneous decision. The well-maintenance backlog is now substantial and has led to production losses that cannot be retrieved (consider the downgrading of reserves on the Halten Bank).

Case: Gullfaks South

Gullfaks South lies due south of Gullfaks in the northern North Sea. It has been developed with 12 subsea templates tied back to the Gullfaks A and C platforms.

Description of the Field.

- Discovery year: 1978
- Development approved: 29 March 1996
- On stream: 10 October 1998
- Operator: Statoil Petroleum A/S
- Present licensees: Petoro A/S 30.00%, Statoil Petroleum A/S 70.00%

Gullfaks South has been developed in two phases. The plan for development and operation (PDO) of Phase I embraced the production of oil and condensate from the 34/10-2 Gullfaks South, 34/10-17 Rimfaks, and 34/10-37 Gullveig deposits. Approved on 8 June 1998, the PDO of Phase II embraced the Brent group in Gullfaks South. The 34/10-47 Gulltopp discovery was incorporated in Gullfaks South during 2004. Gulltopp was produced through an extended-reach well drilled from Gullfaks A. The PDO for Rimfaks IOR and the 33/12-8 A Skinfaks discovery was approved on 11 February 2005, and embraced a new template and a satellitewell. Incorporated in Gullfaks South, Skinfaks came on stream in January 2007.

The Gullfaks South reservoirs lie in Brent group sandstones from the middle Jurassic, and in the Cook, Statfjord, and Lunde formations of the early Jurassic and late Triassic. Production occurs from the Brent group and Statfjord formation. These reservoirs lie 2400–3400 m deep in rotated fault blocks. Gullfaks South's reservoirs are segmented extensively by many faults, and the Statfjord formation has poor flow properties. The other formations have fairly good reservoir quality.

Production from Gullfaks South is now being pursued by pressure reduction after gas injection ceased in 2009. On Rimfaks, the Brent group is producing with full pressure maintenance by gas injection, while the Statfjord formation has partial pressure support by the same means. The Gullveig and Gulltopp deposits are being produced by pressure reduction and natural waterdrive, and their output will be influenced by Gullfaks production. Oil is piped to Gullfaks A for processing, storage, and export by shuttle tanker, while the rich gas is processed on Gullfaks C and exported by means of Statpipe to Kårstø for further processing and dry-gas export to continental Europe (Nordvik et al. 2010).

Controversial Development Solution. Gullfaks South is an example of a controversial choice between a platform and a subsea installation. The project was regarded as marginal, and earlier developments on Gullfaks (all platform-based) had involved high capital spending (with substantial overruns) and are viewed with hindsight as having low profitability. Gullfaks South lies in relatively shallow water, and the reservoir was known to be complex. An optimistic plan was drawn up with a minimum of wells. Originally, discussions on the choice of solution indicated that a platform could be defended if recovery were increased by 4 or 5%. Disagreement prevailed in the licence over the development solution, but the majority was convinced that it would be possible to achieve a recovery factor similar to those of the other Gullfaks fields, even with a subsea installation and despite the complex reservoir. Gullfaks South's wells were drilled by a semisubmersible. Progress was poor, and costs were doubled. While platform-based developments also experience cost overruns (such as those on Gullfaks), these are of a much lower order of magnitude (in percentage terms). A number of problems have been experienced during the production phase that could have been resolved better with a platform solution. According to unofficial estimates, 20–25% of the reserves will be recovered compared with 60–70% for the other Gullfaks fields. The loss of reserves is substantial, and, even allowing for possibly greater reservoir complexity, industry observers maintain that Gullfaks South could probably have attained a recovery factor of approximately 40% with a fixed installation and a drilling rig constantly available.

The lessons have hopefully been learned from this experience. We see that many NCS developments have opted for a platform, including Ringhorne, Kvitebjørn, Gudrun, and Valemon. Relatively high oil prices at the decision point may have been a factor here.

Conclusion

Developers have eventually become better at and more conscious about implementing real options in their decision-support systems when choosing development concepts for petroleum fields. There are real options favoring the platform-with-rigs solution (workover, recompletion, and IOR; the last two are options to expand the production), and real options favoring the subsea solution if it is applied sequentially (learning options). In many cases, the combination of these two solutions (a few subsea wells in the beginning followed by an optimized platform by use of the information from subsea wells) looks to be a more-convenient approach to develop the petroleum fields using modern real-option concepts.

But, are developers taking into account all of the relevant options? In practice, the position is probably that the large number of complex and mutually dependent real options available in such circumstances does not fit completely with existing decision models. Model calculations must be supplemented accordingly by judgements. It is important that petroleum-technology expertise be incorporated in such decisions. This case, perhaps, also represents an example of the way in which decision makers can be influenced trongly in certain circumstances by "the latest experience," and that their perspective can thereby become suboptimal. At certain times, the perspective at the decision point seems to be the lowest possible initial investment. Accordingly, it is important that companies work systematically on learning and experience transfer in a decision-making context.

Another relevant question is whether the basic estimates used as input to the decision models are the best. Experience from the NCS and the UK continental shelf shows that the number of wells required in a field development is often underestimated—by 30%, according to an unofficial estimate. This points to a platform based solution in which drilling is less expensive once the initial investment has been made. If real options and the best cost estimates are not taken adequately into consideration in the decision analysis, a substantial IOR potential could have been lost as early as the choice of development solution. A subsea facility is often a relevant option in very deep water. Some exceptions exist here; a floating installation is being considered for the Luva field in 1270 m of water, for instance.

It is also a good choice for small fields and reservoirs with a low level of complexity. The technological progress made in cooperation with the major suppliers, a number of whom have their main base in Norway, has been useful and necessary, and has represented an impressive export success. Continuous advances in subsea technology have also gone some way in reducing the disadvantages of subsea developments. When choosing a concept, it must be considered that topside technology developments and new-production solutions devised after the development date will often be easier to adopt if a platform has been chosen. Pilot projects are essential for assessing alternative IOR methods, both present and future. These are easier to pursue from a fixed installation; therefore, platform-based developments are favorable for continued innovation on the NCS.

This analysis has illustrated that the choice of concepts is complex, with input from many parties and technical disciplines. Establishing good communication is crucial here. When choosing a concept, it is often impossible to establish which solution is unambiguously and objectively the best because so many sources of uncertainty exist. In such circumstances, decisions are influenced not only by knowledge but also by power. The relative strengths of the various technical disciplines (reservoir, drilling, facilities, and project execution) will mean a great deal in practice. This is difficult to handle in all organizations. Much can be achieved through the requirements and internal control bodies established by the company for work processes and the way in which assignments should be handled.

In addition, it is important that a balance of power exist between these disciplines. The limited power and influence of people with subsurface expertise represents a problem in this context. There are several reasons for this. In numerical terms, the petroleum-technology disciplines (including geology, geophysics, reservoir engineering, and production engineering) form a relatively small group. Furthermore, a culture of seeking senior executive positions no longer seems to exist within Norway's petroleum-technology disciplines, as it does among economists and in part of the facilities discipline. Efforts should be made to correct this imbalance, partly by adjusting the composition of company managements and partly by taking more care to include arguments from petroleum technologists in decision processes.

When the subsurface community comes up with a new idea, it is met with a well-nourished structure of control that consists not of hunters, but of controllers and critics. These functions are also important, but a balance must exist. Furthermore, the facilities discipline can have its own agendas that do not always coincide with high reservoir utilization. Subsurface expertise needs support and backing in executive management. This should be perceived as natural, because the greatest challenges to the oil companies for the moment are on the resource side, related to production curves and reserves replacement. It is appropriate therefore, that subsurface expertise strengthen its position in the top management of companies, through the creation of a post of resource vice president, for instance. The top management and board should have a cross-disciplinary composition, and a number of considerations indicate that subsurface expertise is not represented adequately.

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