Enhancing Marginal Field Development Economics: Leasing Operated Production Facility Approach

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1. INTRODUCTION

Expenditure on the exploration and production of hydrocarbons from oil and gas fields around the world, including the evaluation and interpretation of seismic surveys, exploration and appraisal drilling, development planning, development drilling, engineering, procurement and installation of production facilities and pipelines, operation and maintenance of reservoirs, wells and facilities, facility upgrades, logistical support and eventual decommissioning, reaches several billions of dollars every year. All stages of the exploration and production process require detailed assessments, both technical and commercial, before decisions are made on the development options. These decisions will ultimately dictate the level of success of the overall field development.

Advanced techniques and technologies are now available that enable operators to gain a better understanding of their reservoirs (e.g. 3D seismic surveys), as well as giving them more innovative solutions for accessing their reserves (e.g. horizontal drilling). However, whilst having more information and options available at each stage of the field evaluation and development process increases the likely chance of success of the overall project, only once a well has been drilled, tested and produced over a reasonable period of time will the operator truly understanding the real production issues associated with their field and therefore the real value of their asset.

Leased production facilities have been utilized for surface well testing, both onshore and offshore, for many years. These facilities provide invaluable data on the

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productivity of the reservoir which the operator can then use when making important field development decisions. However, well testing is specifically only a short term evaluation (typically 14 to 21 days, depending on the number of zones being tested). The next step, following the well test, can still be a difficult one to take; either to carry out a longer term extended well test or to install a production facility on the field.

2. LITERATURE REVIEW

Kieft, T. G. (1995) conducted a study on "Development of a Marginal Field through Leased Facilities". The study indicates the application of leased production facilities to enable commercial development of the reserves and examines tie relationship necessary between Oil Company and contractors to achieve a successful project for a small offshore field named File (North Sea) that is remote from existing infrastructure and offers the potential to recover some 34 mmbbls of 34° API crude oil over an anticipated life of 4 years.

Also MacLean, A. (2005) conducted a study on "Enhancing Marginal Field Development Economics by Leasing Operated Production Facilities" and highlighted the contribution of the leasing operated approach in the oil and gas industry. The study also suggested the comparison between the traditional methods and leased approach.

3. OBJECTIVE OF THE STUDY

Oil and gas hydrocarbons in a specific field are depletable reserves. Once the first barrel has been produced, the asset, in a sense, is on a declining curve. That barrel once produced, cannot be produced again. The objective of the study is to suggest the approach which can enhance the economics of marginal field development. There are various examples all around the globe which tells that this approach has contributed a lot to save the cost and time. Still there are number of possibilities which can give better results further.

The paper focuses on Nigeria petroleum fields which contains one hundred and eighty-three marginal oil fields with estimate to contain over 2.3 billion barrels of Stock Tank Oil Initially in Place (STOIIP). A considerable amount of oil is retained in the ground even after being subjected to many years of primary recovery methods. In order to recover a significant amount of the retained oil, special equipment and technology (such as thermal injection equipment) is required. Furthermore, since the technology required is unconventional, it is considerably more expensive, with the result that the cost of recovery (operational cost) may be so great as to render the venture unprofitable. So there is a wide scope of the lease operated technology players. The forecasting of the economic development of the Nigerian petroleum fields is done in the paper.

4. RESEARCH METHODOLOGY

Data collection (secondary data), data is collected for the various oil and gas fields all around the globe by referring the literature.

The data is collected for Shell Soroosh and Lundin Petroleum Isis fields from the SPE News (April 2007 edition) for quoting the examples where the leasing operated facility approach worked out and provided good results.

Also the data is collected for Nigerian Petroleum Field for application of the suggested technique and forecasting its benefits.

5. DATA ANALYSIS AND INTERPRETATION

(i) MARGINAL FIELD: DEFINITION AND GENERAL CONCEPT

A field which due to prevailing geologic, geographic, economic and technological constraints may not be considered to be cost effective for development by its owners, but the development of which may be profitable under different or changed set of circumstances.

Basically a producer would regard an oil and gas field as being marginal on two grounds :

(a) ***economic*****:** where the revenue generated from a field is (in the producers opinion) insufficient to justify continued or further investigation in that field, whether in its own right or in comparison to other fields which the producer has interests in as part of a wider production portfolio;

(b) ***strategic*****:** where the field no longer fits into the producer's strategic aspirations; it may be that the field is performing adequately in economic terms, but the producer wishes to divest its interests because the field does not fit with the producer's commercial strategy (for example in the light of the decision of a producer to discontinue operations within a particular country or region).

(ii) TRADITIONAL APPROACHES TO FIELD DEVELOPMENT

1. Extended Well Testing: Following the well test on a field, an operator may consider progressing the field development by undertaking a longer period of testing; i.e. an extended well test (EWT). An EWT is typically carried out over a period of between 1 and 6 months, producing crude oil from the well and flaring the associated gas. This offers the operator the opportunity to obtain early revenue from sale of the crude produced during the EWT, enhancing the overall field development cash flow. However, the EWT also offers the potential value of the information learned from the extended production operations; how does the well perform; are the results as expected; do the results affect the way the field should be developed, the facilities required and the estimated value of the asset?

EWTs are often carried out using conventional well testing equipment which is readily available from the oilfield services industry. This enables these still relatively short term production operations to be completed at reasonable cost. However, in many cases this is not practical, particularly with the increased focus on environmental issues often prohibiting the continuous flaring of gas during the EWT. Whilst this does not preclude the completion of an EWT, the engineering of the EWT system required is often now more involved with the production equipment becoming relatively complex (e.g. gas compression facilities). The number of EWTs carried out has therefore been seen to reduce in recent years.

2. Field Development: The design and engineering of full field development facilities is a major undertaking which can encompass conceptual studies, detailed feasibility studies, selection of alternatives, definition of the development solution, planning and detailed scoping, detailed design and specification, engineering, procurement, construction, installation, commissioning and start-up. Significant engineering resources and capabilities are required to meet the complex equipment requirements; oil needs to be stabilized and processed to meet export specifications, produced water may need cleaning to meet environmental regulations for disposal, gas may need processing for use as fuel and compression for export, as required, and additional systems may be necessary for water injection, power generation, fiscal metering and export of the produced fluids. The facility must also meet the stringent certification requirements for a production installation, with the appropriate safety and environmental regulations required for the long term operation of the plant.

Traditionally, such facilities have been provided on an engineering, procurement and construction (EPC) basis. The EPC approach and working methodologies of EPC contractors have been developed to enable large scale, resource intensive engineering projects to be completed, and have been widely used in the oil and gas industry. While the EPC approach can be very successfully employed, such contracts can also suffer problems; delays in the decision making process can compress the execution phase, creating time pressure leading to “same as before” solutions and slippages to the overall project schedule; EPC contracts tend to focus on capital costs (CAPEX) rather than life of field cost; contracts won on a lowest fixed price basis can lead to a defensive relationship between the operator and the contractor rather than a collaborative one so that any changes and amendments can only drive the overall contract price upwards. As a result the project can take longer to complete, the solution can be less innovative than originally planned, installed cost to the operator can be higher than originally forecast, and operating costs (OPEX) can be higher than planned over the life of the facility. However, the EPC approach is well understood within the oil and gas industry and therefore remains the predominant contracting model for full field development facilities.

(iii) DEVELOPMENT ECONOMICS

When formulating their field development plans, operators need to include allowances for the risks to the project. Based on these traditional approaches, these allowances will include factors for risks due to the lack of real production information on the reservoir and wells, risks of project schedule and cost overruns, and risks of uncertainties surrounding project CAPEX and OPEX costs.

With higher oil prices and maturing/declining assets, many operators are now turning their attention to more difficult development opportunities. These include fields where difficulties, and hence additional risks, have previously been identified associated with the reservoir, produced fluids and/or local infrastructure, which have meant that the development of the field has been considered as uneconomic or marginal. Based on the traditional field development approaches, with the additional allowances for these additional risks in the field development being included in the opportunity assessment, many of these projects have therefore failed to meet the operators' economic targets necessary for approval to proceed.

6. USE OF LEASED OPERATED PRODUCTION FACILITIES

Oilfield service companies have traditionally provided facilities and manpower to the operators on a leased, operated and maintained basis. Typical services include exploration testing, appraisal testing, development well clean-up, well unloading and in-line production testing, combining the use of fit-for-purpose equipment with qualified, experienced operations personnel. By applying these traditional well testing services to EWTs, operators have also been able to access a cost effective solution to obtain early revenue from sale of the crude produced during the EWT as well as providing information on how the well performs over an extended period.

Furthermore, utilizing production facilities provided on a similar leased, operated and maintained basis but contracted over a longer period of time has offered operators an alternative model for managing their risks on projects where traditional approaches have failed to provide a workable solution to a field development need.

7. KEY FEATURES

Key features of this leased operated approach to production facilities are as follows:

- Use of fit-for-purpose production facilities rather than over prescriptive project specifications.
- Use of readily available equipment where possible.
- Flexibility is built into the facility process design.
- Fast track mobilization to provide early cash flow; for example, the equipment is modularized to reduce time required on-site for installation, hook-up and commissioning activities.

- Reduced CAPEX at the project front-end; payments being deferred with revenue from production being used to cover OPEX.
- Service often supplemented, where appropriate, by support and logistics infrastructure, further reducing operator front-end CAPEX commitment.
- Information gathered on the real world performance and productivity of the wells, enabling informed decisions to be made on the future of the field.
- Flexible contracting arrangement which allows an early demobilization, contract extension or facility purchase, as appropriate, to meet the evolving field life plans.
- The service company will reuse equipment on future contracts; equipment costs can therefore be shared over a number of contracts during its design life.
- The operator's exposure to project and capital risk is minimized.

These features can be built into the overall field development model, enabling evaluation of the leased operated approach to production facilities and comparison with the development economics offered by a traditional EPC approach for the facilities.

8. RESULTS AND DISCUSSIONS

IMPROVED FIELD DEVELOPMENT ECONOMICS BY LEASING

The use of leased operated production facilities should be considered early in the process of formulating the field development plans to enable the operator to gain the most benefit. The traditional EPC approach to production facilities commits the operator early in the field development, effectively limiting their choices to either developing the field with major capital expenditure or not developing the field at all. By comparing, the leased operated approach allows the operator to consider sequentially taking up options to move the field development forward, one step at a time, without the major CAPEX commitment of the EPC approach.

Using leased operated facilities should therefore be considered as a phased developmental approach which enables the operator to make rational decisions based on the known facts as the development moves forward. Evaluating this approach can, however, cause problems when using traditional economic models. As indicated by Claeys and Walkup, typical discounted cash flow (DCF) techniques (including typical decision analysis or Monte-Carlo simulation) capture only part of an asset's value and exclude the significant value derived from the management options inherent in the asset.

For example, methods such as valuing the asset based on Net Present Value (NPV) taking into consideration the likely outcomes and cash flows (income and expenditures) required for the development do not account for the changing conditions, new information and flexibility open to the operator after the initial "go or no-go" project decision is taken. Hence, the NPV is static and, if initial evaluations lead to a negative NPV, the recommendation would be that field development does not proceed. Using such techniques to evaluate a phased developmental approach based on leased operated facilities does not, therefore, show any benefit in the economics of the field development model.

Considering an operator evaluating development of an asset based on a traditional EPC approach where this evaluation gives a negative NPV, the recommendation would be that the field development does not proceed. If the NPV is close to zero then the field would be considered marginal and the decision on whether to proceed or not would be a difficult one to take.

Alternatively, using a phased approach based on leased operated production facilities gives the opportunity to allow re-evaluation of the development's progress during the development process. For example, the decision could be taken to proceed based on a limited production scenario with an EWT. The cost of this phase can be estimated, with allowances made for early termination in case of failure. Potential income from the produced crude can also be included in the economic model. Subject to the success of the EWT, a rational decision can be taken on whether or not to proceed further, and at what speed to expand the production facility, so that at each stage during the field development options are valued based on:

- Stopping further development
- Expanding to the next phase of development (e.g. EWT to EPF, EPF to temporary facility, etc)
- Expanding more aggressively to a larger phase of development (e.g. EWT to permanent facility).

The value of the asset should then be considered using a real options approach based on these possible phases with their associated rational decision options. Value can then be taken for reduced risks at each stage due to the availability of real production information on the reservoir and wells, better understanding of project schedule and cost issues, and other uncertainties surrounding project CAPEX and OPEX costs.

However, many operators are more used to field development solutions utilizing large scale, high CAPEX, owned and operated facilities, so that this approach has not always been considered. Assessment of the NPV of an operator's asset has therefore often been restricted by the limited available information and the limited range of perceived methods of developing the field. However, with increased pressure to reduce both development risk and cost, dynamic analysis based on a sequential investment model as presented in this paper provides a more efficient method for operators to both obtain better well data and to bring their fields on-stream so that, ultimately, the analysis can show that a project is in fact viable when developed using a phased leased operated approach, even if the overall project NPV appeared marginal or even negative when evaluated using the more traditional methods.

9. CASE STUDIES

Whether driven by commercial or technical constraints, contractual requirements or field development uncertainties, operators are now realizing the benefits of this approach. In some cases this may be for production operations during field evaluation and extended well testing, it could be as the first step of a full field development or as a longer term full field development solution. In each case the flexibility offered not only gives a cost effective next step to achieve production from the field, but also gives additional information from the production operations that can be utilized to further develop the value of the asset.

The following case studies give an outline of some typical solutions already provided on this basis:

1. ***Shell Soroosh,*** Shell Exploration BV was selected by the National Iranian Oil Company (NIOC) to develop the Soroosh and Nowrooz oil fields located 120 km offshore Iran in around 30-40 m water depth. When completed, Shell anticipates that the two developments will produce at a combined peak rate of 190,000 bbls/day of oil, with the Nowrooz field producing via facilities to be installed on the Soroosh field. This is one of the biggest single offshore oil and gas conversion projects undertaken in the region for several years.

The overall field development plans included an early production phase requiring fast track mobilization of a production unit to the field. Not only was the schedule for this aggressive, but a solution was needed that would meet the project's economics over the short 20 months required operating life of the facility.

To execute the project, Expro Swire Production Limited acquired the ex-Mansal "Muna" Mobile Offshore Production Unit (MOPU), renaming it "ESP 1" and mobilizing it to Dubai for conversion. The vessel was re-certified, machinery zero houred, marine system modifications made and the vessel's accommodation module refurbished. Meanwhile, the process system also received substantial modifications including both upgrades and additional process modules to handle the Soroosh well fluids and operating requirements, plus the addition of an 8 MW power generation module to provide power for the ESPs. The resulting system has a crude oil production capacity of 100,000 bbls/day and a water injection capacity of 50,000 bbls/day.

To facilitate initial stand-alone operations a temporary wellhead deck structure was fabricated and installed to support four well caissons from the MOPU, with a bridge giving access and support of flow lines, cables and instrumentation. The structure would later be built into the field's Northern wellhead platform, once this was installed on site.

As a result Shell was able to achieve production from the Soroosh field earlier than would otherwise have been possible and without the significant investment of an owned and operated field infrastructure. The conversion work was completed fast track in less than 32 weeks, with the MOPU then sailing out to the field location. The full contract to supply, install and operate the MOPU was carried out by Expro Swire Production Limited on a turnkey, leased, operated and maintained basis, including demobilization of the facility at the end of the contract once the permanent field infrastructure was installed and operational.

2. ***Lundin Petroleum Isis,*** In 1996 Coparex Netherlands B.V, Atlantis Technology Services and ETAP acquired interests in the Isis field, located 150 km offshore Tunisia. Their development plan included an initial phase requiring three horizontal subsea wells with umbilical controlled trees and flow lines connecting to flexible risers and producing oil to a Floating Production Storage and Offloading (FPSO) vessel.

The contract for provision of the FPSO was placed with Victoria Oilfield Development Ltd (subsequently acquired by Brovig-RDS), who would use their own Tripod Catenary Mooring System (TCMS) to moor the vessel. Their scope included the supply, installation and commissioning of the FPSO followed by its lease, operation and maintenance based on a minimum four year contract term. Expro would supply the process topsides elements of this scope, again including their lease, operation and maintenance, together with the associated onshore management and logistics support organization. By utilizing this turnkey approach and leasing the operated facilities, Coparex was able to limit risk exposure and minimize facilities and support infrastructure CAPEX.

Brovig-RDS purchased the 'Northia' shuttle tanker for the project, renamed it 'Ikdam' and converted it into a 600,000 bbl capacity FPSO at Malta Dry Docks.

Construction of Expro's 30,000 bbls/day process topsides and 3 MMscfd gas compression modules was completed in five months from order placement to completion of the mock hook-up, before delivery to Malta for installation on the FPSO. This required concurrent mobilization in four countries with an aggressive fast track delivery.

Once on site the final testing and approval of the vessel's safety systems could be completed and, within 24 hours, well fluids from the first production well, Isis 8, were delivered to the FPSO. These were followed two days later as the second well, Isis 7, was opened up.

The contracts for delivery, operation and maintenance of the process topsides were performance driven, with risk/reward elements linked to delivery and performance of the facilities. By aligning the goals of the field owner (the field has since been acquired by Lundin Petroleum) and the facility providers, the Isis project demonstrates that fit-for-purpose topsides can be engineered, constructed and installed fast track without the traditional lead times of an EPC type project. Furthermore, since start-up the overall production uptime has exceeded 98%.

10. NIGERIAN PETROLEUM FIELD

Marginal oil fields in the Niger Delta Basin are scattered in the oil producing states in the Niger Delta Area. These areas include Edo, Ondo, Delta, Bayelsa, Rivers, Akwa Ibom, Cross River, Imo and Abia States. The fields contain several reservoirs at different depths with total oil reserve of 1.3 billion barrels. In 1999 the Nigerian Department of Petroleum Resources identified 116 marginal oil fields. At the end of the bidding that was conducted for these fields, 24 operating licenses were awarded to different indigenous oil companies, as shown by the map of the area and the list of reserves. The Marginal oil fields are expected to improve the Nigerian oil reserves which stood at 36.2 billion barrels as at January 2007, hoping to reach 40 billion barrels by 2010.

CHALLENGES OF MARGINAL OIL FIELD DEVELOPMENT IN THE NIGER DELTA BASIN

Finance: The companies have limited assets and finance to operate and participate effectively in the business. It is estimated that a marginal field in the Niger Delta Basin will cost about US$40 to US$70mm as development cost for a few years. Foreign technical or financial partner will in most cases contribute 40% of this amount. The government has therefore opted to use the Joint Venture Agreement, Production Sharing Contract and Service Contract to finance the operations.

Other ways that Marginal Oil Fields operators can raise funds is by going to the capital market. They can in the alternative involve private investors including foreign financial and technical partners through private issuance of shares. The Marginal Oil Fields operators may also approach international banks, foreign equity partners, The World Bank, regional bank and financial institutions.

Technology: Technology is another challenge of the Marginal Oil Fields of Nigeria as the existing technologies are expensive, but changing the technical and economic conditions of Marginal Oil Fields can increase return on investment. Marginal Oil Fields operators should therefore be prudent in their choices of technology. There are technologies that can be cost effectively applied by the Marginal Oil Fields operators to increase return on investment e.g. Extended reach, Infill drilling, Slim-hole drilling, Coil tubing, Down hole electric submersible pump, Surface multiphase pump, Intelligent well completion, Lease production facilities –a-fit-for-purpose production facility on a leased operated and maintained basis.

Geological Complex Formations: In some situations (e.g. as in Malaysia), there could be experience of geologically complex or difficult to produce reservoirs, challenging drilling environment and infrastructure constraints. These situations are also present in Nigerian fields apart from the complex geological situation. In the Niger Delta Basin the geology of the area has been studied and known and exploration activities have shown hydrocarbon reservoirs scattered over the entire area both onshore and offshore or deep water offshore.

Development Cost of Infrastructure: Marginal Oil Fields should be developed with good development and management economics, strictly to increase recovery and avoid risk or waste. In most cases the development cost of materials, fabrication yards, construction of barges, drilling and environmental concerns, continue to escalate and all these reduce return on investment for the operators.

OPPORTUNITIES OF MARGINAL OIL FIELDS DEVELOPMENT IN THE NIGER DELTA BASIN

There are many opportunities for the operators of Marginal Oil Fields in the Niger Delta Basin and all the stakeholders, indigenous oil companies, technical and financial partners, host communities and above all, Nigerians will benefit from the development of the Marginal Oil Fields. The Federal Government aiming at increasing production rate to 4 million barrels/day to achieve vision 2010 launched the Marginal Oil Fields Development program with its laudable objectives. We can say authoritatively that:

1. Today there are about 200 Marginal Oil Fields indicated in the Niger Delta Basin and there are ample opportunities in developing these fields.

2. The fields have reserves range of 1-5 million barrels of oil. This will definitely guarantee return on investment in short term for the investors.

3. The Niger Delta Basin has familiar geological structures and therefore exploration and field development would be relatively easier than some other zones with complex geological structures.

4. Hydrocarbon reservoirs are scattered all over the region onshore, offshore and deep water offshore.

5. In Nigeria there is availability of high level technical manpower with oil industry experience.

6. The Federal Government has put regulatory laws in place for investment inflow and fund out flow for technical and financial partners.

7. The security issue of the region is receiving adequate attention and indigenous companies are eager to work together with overseas partners to explore the region.

CONCLUSION

We have seen that there are about 200 Marginal Oil Fields identified in the Niger Delta Basin with reserve range of 1-5 million barrels of oil. A major constraint in the development of these fields is finance and funding. The problem of funds could be solved by sourcing for funds internally and externally from financial institutions or foreign partners. We are also aware of existing technologies like multilateral well drilling, intelligent well completion etc which could be cost effectively used to increase production. The geology of the basin is well known, reducing the challenges usually associated with such fields.

So by using the leased facilities such as extended well testing and surface production facilities these opportunities can be utilized in optimized manner.

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