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Changing Dynamics in Deepwater Ownership

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Preface

This manuscript is intended to set the stage for a panel discussion, "Changing Dynamics in Deepwater Ownership", scheduled for Wednesday, May 3, 2006. The manuscript includes the white-paper input from participants of this panel, who are;

- Art Herman, Deepwater Project Supervisor, Chevron
- William McHolick, VP Americas Operations & Development, BHP Billiton Petroleum (Americas) Inc.
- Helge Haldorsen, President, Hydro Gulf of Mexico, L.L.C.
- João Figueira, Executive Manager, Petrobras
- Cory Weinbel, General Manager of Production Facilities, Cal Dive International
- Sandeep Khurana (Moderator), Project Manager-Subsea Systems, J P Kenny Inc.

Theme

As the balance of risks and costs has declined due to technology advancements and growing experience, the number of companies involved in the deepwater sector is growing rapidly. Owners, many of them focused on operator roles, have different interests based on their portfolio of deepwater fields. Farm-ins, joint ventures (JVs), and production-sharing contracts (PSCs) are very well defined in exploration, leading to equity ownership, but are lean on field development, project execution and construction of the facility, along with its future handling. Due to huge investments in developing deepwater fields and infrastructure, creative commercial arrangements such as facilities ownership by contractors, production contracts and transportation fee agreements are being considered. The owners compete and interact to ensure that they get the best leverage from their ownership in the field.

However, what impact does the involvement of a non-operating partner have on field development? Is it healthy or does it cause delays? The panel will debate various issues regarding the alignment of operating and non-operating partners.

Some of the issues discussed will be:

- Differing corporate cultures;
- Vying for operatorship and its arrangements in different regions of the world;
- Influencing execution of field development and optimization for future use;
- Implementing new technology, specifically based upon experiences in a different part of the world;
- Integrated project team of owners vs. operator-managed project;
- Contrasts between international vs. GOM JV operating agreements.

Introduction

The number of players with equity ownership in deepwater and ultra-deepwater fields (D&UD) has exploded. Many national oil companies (NOCs) have become field partners outside their own countries and turned from resource holders to viable competitors to international oil companies (IOC). The high cost of deepwater infrastructure development has also brought many large contractors to the equity ownership table. This has created pressure for companies to manage collaborative relationships in a competitive landscape as well as their financial performance.

This manuscript identifies an ownership trend in D&UD fields, and presents a brief background on commercial arrangements among equity owners. It focuses on interaction among equity owners during the project development phase and briefly outlines the ongoing industry debate regarding partnership arrangements. Finally, the panelists' viewpoints on working successfully with equity holders are provided.

D&UD Ownership Trends

During the early 1990s, deepwater developments were a relatively lonely affair. Major oil companies took deepwater development as a campaign and a few independents took opportunistic leases to develop. Some examples are:

- In the U.S. Gulf of Mexico, some companies took the leadership in exploring deepwater as a campaign, as Shell did with its Mars and Mensa fields. Conoco attempted the deepwater Joliet field, using a tension leg platform (TLP), which might have drawn other companies' attention to sharing the risks in the D&UD Gulf of Mexico. Risk-taking independent Oryx (now Kerr-McGee) installed the Neptune spar, starting a wave of deepwater spar developments in the Gulf.

- In Brazil, deepwater was a natural route for growth. Because Brazilian legislation did not allow partnerships under a monopoly, Petrobras worked alone there, discovering large fields, and efficiently and successfully developing the technology to produce them. Today, as a result of legislation changes in the last decade, some D&UD partnerships are underway in Brazilian waters.
- In Equatorial Guinea, a company since acquired by Ocean Energy discovered Zafiro field during the 1990s, during a period of low industry visibility in that country. Following the discovery, the lack of deepwater expertise and possibly insufficient financial capital for development may have led Ocean to apportion some equity to Mobil. Mobil then took operatorship, launched the development phase and brought the field into production.
- Similarly in Equatorial Guinea, opportunistic independent Triton drilled the La Ceiba-1 well that led to the discovery of La Ceiba field, of which it held 100%. While drilling, Triton allotted 15% of the field to Energy Africa and the group was then able to bring the field on stream. Triton was subsequently acquired by Amerada Hess.

As the balance of risks and costs has declined with technology advancements and experience, the number of companies involved in the deepwater sector has grown substantially. In conjunction with the growth in fields and field owners, the number of operators has also increased.

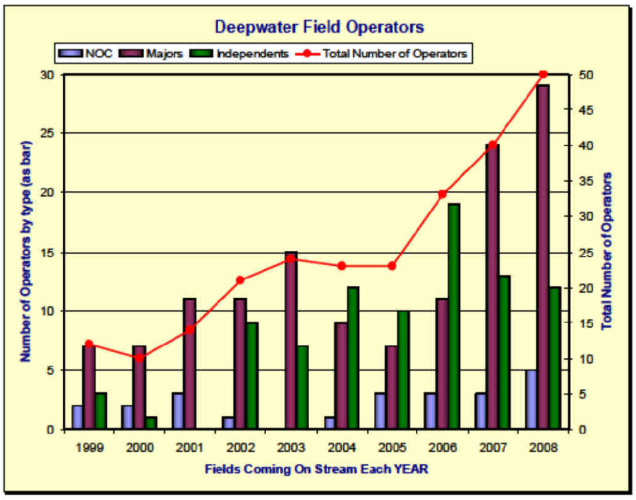

Figure 1: Trend in type of Deepwater Operators (source: Data from Infield systems Limited)

Ownership is divided among majors and independents, with increasing influence of NOCs outside their countries.

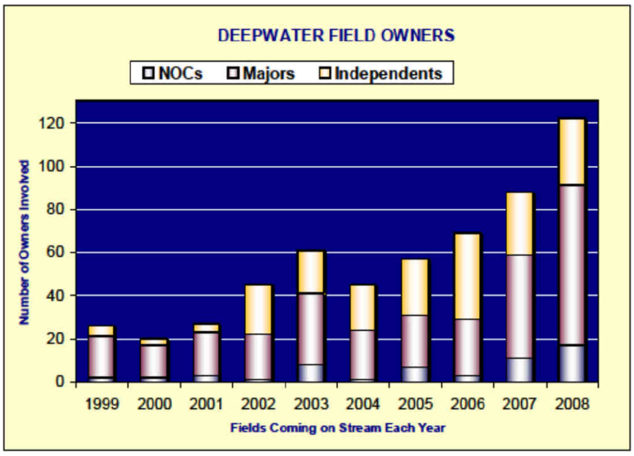

Figure 2: Trend in Type of Deepwater Owners (source: Data from Infield Systems Limited)

With each lease bid round NOCs and newcomers enter the deepwater arena. Companies are competing fiercely to access deepwater exploration acreage in the traditional basins around the world. The availability of D&UD technology, combined with the crucial need for reserves replacement and surplus cash, has encouraged companies to seek positions in exploration acreage. The 2005 bidding round in Nigeria, where the government was able to capture approximately US$1 billion in signature bonuses is a good example. There, blocks OPL 315, 321 and 323 received US$180 million, US$310 million and US$175 million, respectively.

Even in the heavily leased GOM, the number of leases that will be relinquished or will expire is expected to increase dramatically in 2006-2007 as a result of the 1996-1998 leasing boom. Lease expiration projections will pressure leaseholders to drill and evaluate holdings and will provide opportunities for other companies to enter an active play by acquiring expiring leases or obtaining 'farm-outs' from companies with untested acreage.

Indeed, new technologies have provided ways and means for materializing deepwater production. Some cost reduction has been experienced, particularly by companies with a large operational base that can capitalize on synergies. However, the industry is facing higher costs due to the current market. New cost standards are being set for services, deepwater rigs, and materials such as steel for ships, FPSOs, casings, etc.

Ownership 101

In general, the government owns the subsurface resources and offers those to interested parties via lease bid rounds. The highest bidder typically acquires the lease/license/concession for a specific number of years and is termed as the lessee/licensee. In the U.S., the federal government leases offshore minerals to stakeholders known as lessees. In other countries, the governments may license these resources or grant concessions to those willing to make certain financial and activity commitments. The lessee/licensee obtains rights to extract minerals from the lease and, in return, pays a royalty (share of production) to the government.

In some countries the government designates an NOC to manage the country's petroleum interests. The NOC may then work with IOCs via a PSC (production-sharing contract), whereby one party, usually the IOC, takes all the risks and bears all the cost of finding and producing petroleum. The IOC shares production with the NOC and recovers its costs from production.

The capital required for a deepwater field to be economically competitive may be so great that a company may be incapable of proceeding alone. Massive capital investment and goals of reducing D&UD uncertainty and risk are pre-cursors to partnering in the normal course of exploration and production. However, in many situations, the host country's government may impose awarding leases to a group of companies, thereby encouraging partnership, as seen in Angola, Nigeria and the U.K.

Lease sales, farm-ins, farm-outs and swaps are ways of accessing exploration assets and equities, whereas JVs are a form of partnership. The typical commercial arrangements are as follows:

Equity Farm-In and Farm-Out:

These terms were derived from a nineteenth century American practice in which sharecroppers were given an opportunity by farmers to earn a living by working the land in return for a share in the proceeds of the crops.

Under a farm-in arrangement, a non-lessee/-licensee company can acquire an interest from one of the existing lessees/licensees. Typically, interests in leases/licenses are exchanged for exploration or other commitments, or for cash. Therefore farming-in is way of acquiring a lease/license interest, and conversely farming-out is a means of reducing or disposing of a lease/license interest.

In legal terms farm-in and farm-out are agreements whereby the owner of a working interest in an oil and gas lease/license assigns the working interest or portion thereof to another party that desires to drill on the leased/licensed acreage. The assignor usually retains a reversionary interest in the lease/license. The interest received by an assignee is a 'farm-in', and the interest transferred by the assignor is a 'farm-out'.

Joint Ventures:

This defines cooperation of two or more companies that contribute capital in a lease or field development and agree to share profit, loss and control in it. Some countries require foreign companies to form joint ventures with domestic companies in order to enter a market. This requirement often forces technology transfers and managerial control to the domestic partner.

A joint venture may establish a preferential right or right of first refusal between parties to a venture. A preferential right or right of first refusal gives the partners the right and option to acquire an interest from another joint venture partner that decides to divest a portion or all of its interest in the joint venture property.

Unitization:

Lessees/licensees collaborate on a common geological feature. This may be required by the government agency, or be done on the basis of an intergovernmental agreement, for the efficient development of the feature.

Service Agreements with Joint Venture Elements (Operators and Contractors):

Companies needing to obtain capital through financing contracts, with particular implications for security and project-finance agreements, may bring a contractor to the table to offset capital risks. Included in these may be capital costs for the facility and abandonment cost risks a contractor may be willing to take in return for equity in the field.

Transportation and Product Sales Agreement:

Ensuring availability of infrastructure to transport produced oil and gas adds another dimension to the long-term goals of a company owning numerous deepwater leases in an area. That company may bring on-board a midstream or pipeline company to take an equity position in the field development.

Joint Operating Agreements (JOA) Set-Up

When several companies become equity holders in a project they usually make a joint operating agreement (JOA) governing its future operations and execution. The JOA identifies working interest, the percentage of ownership a company has in the joint venture, partnership or consortium. It designates one company as the operator. (The partner with the greatest working interest tends to be the operator, but there may be exceptions.) The operator conducts business on behalf of all the parties and is responsible to non-operators. Generally, as an oil company grows in experience, it seeks to become an operator in order to assume a greater role in management and operations.

Some, but not all, JOAs call for the creation of a management committee comprising owner representatives. Under some JOAs, the operator has the right or option to create a team to run the project on a day-to-day basis; this team may be supplemented with the partner's staff. In JOAs calling for the creation of a management committee, the project team makes recommendations and requests funding from the management committee, which then gets approval from the non-operating partners.

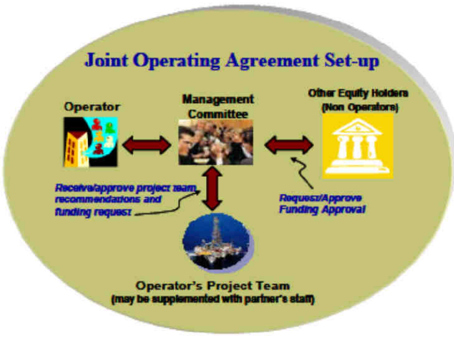

Figure 3: Joint Operating Agreement Set-up

Ongoing Debate

Equity partnerships created during the exploration stage to overcome capital constraints sometime lack the detail necessary to address the orderly administration of field development, project execution and construction of the facility. This can make joint venture operators and partners uncomfortable with their asset development strategy, specifically when it comes to lease/license joint operations.

In certain JOA set-up situations, an operator may seek independence rather than interdependence or collaboration when an exclusive relationship is perceived to be more beneficial. Project teams can still be created but they tend to recommend actions instead of presenting alternatives. This provides the non-operating partner with limited ability to decide on strategy; its role is to agree or disagree with the recommendation.

In other JOA arrangements, the management committee is authorized to investigate alternative solutions for both technical and budgetary issues. This leads to delays and results in stalemates. Furthermore, it deliberately creates costly redundancies in both human and technical resources. Typically, the operator dedicates considerably more technology and team members to the effort (gaining greater control over key decisions and costs), while other interest owners implement "shadow" teams to audit the operator.

Other issues may come into play because JOAs generally do not address future strategy, including selection of export infrastructure, capacity and investment phasing, use of major new technologies.

In short, JOAs set the rules for relationships among the partners. To allow this legal instrument to navigate in the strategy landscape requires necessary creativity, long-term partnering will and paradigm shifts.

PANELIST VIEWPOINTS

Integrated Project Teams

By Art Herman, Deepwater Project Supervisor, Chevron

As evidenced by the number of companies now involved, the deepwater Gulf of Mexico presents significant opportunities for growing production. However, exploration, appraisal and development cost and risks are significant. Additionally, ultra-deep water presents technical challenges for even the most experienced deepwater operators.

At Chevron, we have utilized many types of commercial and equity arrangements for our exploration activities. While these equity arrangements are quite often viewed as a means to reduce costs, there are other key benefits to these types of arrangements. Following are other significant benefits:

- Risk management of the overall portfolio;
- Access to key resources, such as drilling rigs for ultra-deep water;
- Alignment with partners of like-interests and -drivers in a lease area;
- Bringing in of partners with key technical or project experience;
- Gaining access to data that may help to evaluate other opportunities.

All of our deepwater GOM projects, to date, have been executed through the use of an integrated project team (IPT). For company-operated projects, the use of IPTs has been quite valuable. Typically, we form the IPT during the concept-selection phase of a project, with the specific deliverable of the team being a development plan. Additionally, all of our deepwater GOM projects have been executed via IPT. Some of the benefits we have experienced are:

- Gaining experience and expertise of partners;
- Alignment of partners (which usually helps reduce cycle-time for approval of AFEs);
- Personnel for staffing projects (especially with the current industry shortage);
- Better solutions through the diverse experiences that partners bring to the IPT.

We also view IPT participation on non-operated projects as critical, especially for selecting a development concept. It does not make sense to operate every development; given the staff required to serve as operator, it is not plausible to do so for every opportunity. Often, the lease-hold position in an area, experience on similar projects, staff availability, etc. need to be considered before seeking an operator role in a development. However, there can be significant value in participating in an IPT as a non-operator to ensure that the development plan can be influenced to maximize value.

As the industry continues moving toward ultra-deep water, our technical challenges grow and compound. Key technical challenges include: 10,000' water depth, 30,000' deep wells, 15,000 psi shut-in pressures at the seafloor, low permeability reservoirs. Alone, any of these issues represents obstacles to cost-effective development of deepwater fields. However, the industry is now at a point where three or more of these challenges can be present at once. The diverse experience and expertise represented in joint ventures and IPTs will be critical to finding an efficient means to developing these challenging fields.

Playing the Risk Game in Deepwater

By William McHolick, Vice President of Americas Operations & Development, BHP Billiton Petroleum (Americas), Inc.

The deepwater Gulf of Mexico is one of the most attractive high-risk, high-reward business propositions offered the petroleum industry today. Competition in the deepwater is understandably intense amongst the diverse set of players – ranging from the largest fully integrated companies to smaller independents, national oil companies, pipeline companies, and service companies. Whilst the strategies of each player can be quite different, they all have one common need – they must earn an appropriate return for their shareholders. If the reward is insufficient to offset the associated risks, there can be no enterprise.

As they do elsewhere in the industry, players in the deepwater form joint ventures in order to spread risk and leverage each other's skills. To be successful each joint venture partner must understand their company's risk tolerance and align their respective company's decision-making processes to the needs of the joint venture. This alignment process manifests itself around several key decisions. These include:

- How much appraisal investment is necessary to support an initial development decision?
- What should be the scope of the initial development?
- Will the development feature dedicated production systems or not?
- How much pre-investment should be made for future capacity?
- How much funding can the joint venture put at risk to reduce development cycle time – and when?

What makes the deepwater arena unique is the enormous size of these investment decisions and its reliance on multiple companies within a joint venture to spread risk. The introduction of each additional partner increases the difficulty and complexity of achieving alignment within the joint venture.

Portfolio vs. Project

One of the largest obstacles to joint venture alignment is the differing perspectives that each company has within its respective portfolio. A partner who holds the project high in its investment portfolio will want to move quickly and take risks. Whilst another partner may have a more attractive opportunity within its portfolio and may wish to defer or scale back the development. Unfortunately, there are no right or wrong answers to these issues, but rather the need to negotiate and compromise. Some of the questions that must be addressed include:

- How fast is each partner willing to go?
- What is each partner's willingness to sign multi-year contracts?
- How can a company pool activities across joint ventures?

Another obstacle to joint venture alignment is the level of due diligence in today's post Sarbanes-Oxley world that is in conflict with the need to reduce cycle time to ensure an acceptable return on investment. A partnership must invest hundreds of millions of dollars in exploration and appraisal phases, hence reducing time to first production becomes critical for shareholder value creation. Striking this balance within the partnership becomes a critical decision.

Traditionally, the placement of long-lead items has been used to reduce cycle time. However, the levels of these pre-sanction commitments are becoming very large (e.g., ordering new-build rigs), and in some cases a decision must transcend multiple joint ventures in order to be resolved. Individual joint venture partners with more divergent objectives and more rigid decision-making processes will have more difficulty reaching alignment.

A "Tune-up" for the Gulf of Mexico JVOA

The joint-venture operating agreements (JVOAs) in use in the Gulf of Mexico for the past several years evolved from agreements drafted for operations on the continental shelf. A working group is currently addressing unique deepwater issues that aren't fully met with the protocol used in the past. These cover decisions around exploration and appraisal wells and subsequent development issues.

This new deepwater JVOA will more closely reflect how companies make decisions and the investment process required for this. (See Figure 4, "BHP Billiton Tollgate Process".) It recognizes that companies must make a higher level of commitment, i.e., absorbing costs and making huge investments, with less data, significant subsurface uncertainty, and limited existing infrastructure. Issues being addressed include the purchase of long-lead items (pre-development AFEs), batch setting, the need to commit to services and supplies while the project is still under appraisal, and rig slots.

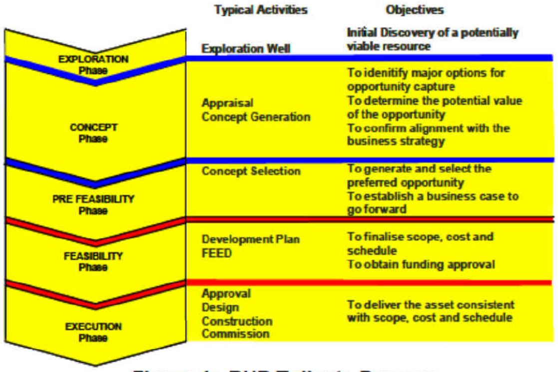

Figure 4: BHP Tollgate Process

Keys to Success in Deepwater

All elements in deepwater exploration and production carry higher risks. Challenges include the remoteness, meta-ocean conditions, and the inclination and ability to play the "risk" game. Among the characteristics that successful joint ventures demonstrate are:

- willingness to take on and manage large risks,
- capacity to identify new trends early and learn from others quickly, and
- capability to adapt one's business model to rapidly evolving commercial realities.

The rewards with deepwater can be substantial. Joint ventures are better positioned to realize them when partners can align the diverse objectives and businesses of different organizations to optimize shareholder value.

Hydro Utilizing Its Core Values in Deepwater Partnerships

By Helge Hove Haldorsen, President of Gulf of Mexico Business Unit

Hydro is a Fortune 500 energy and aluminum supplier founded in 1905, with 35,000 employees in nearly 40 countries. Hydro is also at the forefront of wind and hydrogen energy production.

Norsk Hydro ranks as the world's fifth largest deepwater oil company, based on a comparison of all global companies operating production in water depths of more than 100 meters; in 2005, Hydro operated close to 1 million boepd. Hydro's equity production is projected to exceed 600 000 boepd in 2006. The company's E&P focus areas are: Norway, Russia, Gulf of Mexico (GOM), Angola, Canada, Brazil, Libya and Iran. Interesting exploration positions are held in Madagascar, Morocco and Mozambique.

Hydro is recognized for world-class planning and execution of both small and large field development projects, ensuring they come in on cost, quality and time. Hydro has been a front runner in the application of new technology such as multi-branched horizontal wells, sub-sea separation and long-distance tie-backs to increase recoveries and to cut field development costs. To illustrate: Hydro has drilled 47 multi-lateral wells, with a total of 76 branches. Hydro commenced the drilling of the world's first six-branched horizontal well on December 7, 2005.

Hydro wants its core values -- Determination, Courage, Respect, Cooperation and Foresight -- to be recognized in all parts of its operation and to live up to its mission: To create a more viable society by developing natural resources and products in innovative and efficient ways.

Hydro's GOM entry in 2001 was based on a large yet-to-be-found exploration potential, strong empirical finding rates, a good fiscal regime to the successful explorer, low political risk and a professional regulator (the MMS), oil and gas markets at your door-step, the importance of the GOM technological 'deepwater laboratory', and the possibility of building a balanced asset portfolio over a reasonable period of time (high deal-flow regime).

Hydro has successfully acquired blocks in GOM lease sales over the last four years and in 2005 acquired Spinnaker Exploration Company. This meant a rise in many of the critical 'Ps' in an E&P company: Production (let's call this the P0) and the very familiar probability based nomenclature used in reserves, namely, P1, P2, P3. Of even more importance for the future, however, were P4, the people and the P5, the Portfolio. Hydro now operates or is a partner in a number of producing fields on the Shelf and a large number of exploration blocks both in the deep water and on the Shelf. Furthermore, Hydro is a partner in several deepwater developments: Front Runner, Independence Hub, Thunder Hawk and Lorien. Plans for the Telemark field are currently under evaluation in cooperation with our partner ERT.

The panel discussion during the conference will discuss further:

- The importance of being an operator when it comes to company competence building and value creation, and similarities and differences between the US GOM and the Norwegian Continental Shelf (NCS);
- Hydro's strong track record of accelerating the application of new technology to create value;
- Hydro's multi-lateral drilling experiences and their possible application in deepwater GOM fields;
- Illustrating how Hydro's Capital Value Process (Hydro's decision gate process) can align a partnership.

After the Spinnaker acquisition, the GOM will be one of Hydro's main core areas. Hydro's ambition is profitable growth through its great people, a strong and balanced portfolio, great partnerships and, of course, operatorships on the shelf and in the deep water in cooperation with many uniquely competent and experienced GOM players.

Worldwide Operatorship Set-Ups

By João C.A. Figueira, Executive Manager, Petrobras

Overview

The relationship among companies in the petroleum industry is somewhat different from other industries. Companies can be partners in one given area or block, and fierce competitors next door. A given partnership may or may not be friendly, depending upon the behavior of the operator, whose role is of paramount importance to the partnership. It varies geographically; it varies ideologically; it varies managerially; it varies politically. Also the role of a non-operating party may depend on its financial, technical and technological capabilities; on its previous experiences; on its negotiating abilities. Therefore, a multiple-entry matrix governs the number of possible relationships among partners in a joint venture.

An operator may be self-sufficient enough to annoy a cooperative partner, refusing to hear the latter's contribution or, on the other hand, insufficiently capable to command a horde of sleeping partners, thus leading to a disastrous operation. Another breaking point may arise on establishing the investment's chronogram; priorities can vary substantially from one actor to another, letting the relationship be driven by lawyers and/or landmen navigating in the JOA's landscape. Virtue may reside in solutions carved from the several possible combinations.

Geographical location tends to establish some patterns of behavior. A typical partners′ relationship in the Middle East is usually distinct from one in the North Sea. Generally speaking, ventures in the mature shallow waters of the U.S. Gulf usually behave as if the operator were the only player: the other partners are relegated to be cash-cowed only. In the deepwater or the deep shelf contexts of the U.S. Gulf, on the other hand, given the complexity of the operations and size of the investments involved, the relationships tend to divert towards the cooperative track. The West Africa ventures, in general, demand the technical and budgetary issues be discussed by all partners before a decision is taken. Latin America operations are on the stage, also through a more interchangeable approach. At the end of the day, technology, investment size and reserves ownership may introduce some changes on general geographical tendencies, leading to a more cooperative mood in the partners′ relationship.

Forming Partnerships

In the normal course of the exploration and production business, oil companies share positions in the form of partnerships through joint ventures or associations, in general, aiming at sharing the risks inherent to the activity. How are partnerships formed? There are several ways companies get together:

- Companies with common strategic views and complementary skills usually develop joint bidding agreements (JBAs) and/or areas of mutual interests (AMIs) to file applications for blocks in bidding rounds or direct negotiations with host countries.
- Companies holding working interests in a given contract offer some of their equity through farm-outs, in general seeking for some cost-carry promotion. Major oil companies that offer blocks to farm-outs, however mostly do so when such blocks fail to fulfill their initial expectations.
- Some partnerships are also formed by host-country authorities when awarding blocks, forcing marriages among companies that file individual or consortia applications.
- Unitization of fields that straddle block or country boundaries.
- Equity swaps of contractual rights in blocks among oil companies.

Operatorship

The way some partnerships are formed may explain why relationships are friendly or not. Selecting the operator is not always easy. Most of the major companies and some independents have the operatorship as a strong priority and strategic position. The original equity operator holder of a given block can easily maintain its position as operator when farming out, but other business arrangements may require a lot of time-consuming discussion.

In some forced marriages, including in countries such as Angola, Nigeria and the UK, the operatorship has been arbitrated by the bidding authorities, transferring relationship issues to the Joint Operation Agreements (JOA) discussions.

Deepwater Ownership

As far as the D&UD businesses are concerned, there has been a sort of natural selection by companies that have not only enough financial breadth, but also, and maybe preferably, technical expertise and technological capabilities to work in these environments. These companies share their individually developed learning curves, thereby accelerating the learning curve of the joint venture and adding value to a given exploration block or field development.

One could say that in the early years and through the mid-1990s, deepwater business was a sole activity for many companies, driven mostly by the level of high reserves expectations of major and large IOCs. However, intensive CAPEX and relatively high OPEX costs, together with the 1990s oil price scenarios, led these companies to bring in some partners on the blocks. Also, the lack of good exploration blocks onshore and of traditional basins in shallow water moved deepwater options to a higher popularity.

The case of Petrobras, in Brazil, was somewhat unique. The company moved toward deepwater because it was seen as a natural route to grow in the country. For quite a long time the company was alone because the Brazilian legislation did not allow partnerships. Petrobras discovered large fields and efficiently and successfully developed the technology to bring those fields into production. Nowadays some partnerships are underway in the Brazilian waters, after legislation changes in the mid-1990s. However, Petrobras is still the company that holds the higher capability of adding value in Brazil's E&P business.

In the U.S. Gulf, some companies took the lead in exploring deepwater under 100 percent interest base, like Shell with its Mars and Mensa fields operations. On one hand, Conoco's major disappointment in the deepwater Joliet field, using a TLP, might have driven companies to share the risks in the deepwater Gulf of Mexico. On the other hand, success in some deepwater blocks opened a new front, which provided intense competition and the MMS with the opportunity of successful lease sales.

In Angola, when deepwater blocks were made available to the industry, the government did not award any deepwater block to a single company. Yet in the 1990s and in the UK, apart from some blocks awarded to BP west of Shetlands, most blocks were awarded to groups of companies.

It is also interesting to observe the case of deepwater Equatorial Guinea, where in the 1990s, in the times of that country's potential low visibility by the oil industry, a company then acquired by Ocean Energy started exploration without any competition and discovered Zafiro field. After the discovery, the lack of deepwater expertise and maybe the lack of enough financial muscle to develop the field, led Ocean to farm-out some equity to Mobil, which then took operatorship, launched the development phase and brought it into production. The Zafiro complex is now under operatorship of ExxonMobil, in partnership with Devon Energy (which acquired Ocean) and the Equatorial Guinea state company GE Petrol holding a minor equity. Also in Equatorial Guinea, Triton, an IOC somewhat viewed as opportunistic, started drilling the La Ceiba-1 well, which led to the discovery of La Ceiba field, in which the company held 100% working interest; while drilling, Triton farmed out 15% to Energy Africa. The group was then able to bring the field on stream, but Triton was subsequently taken over by Amerada Hess.

Improving Relationships and Cooperation

Geographical location tends to establish some patterns of behavior. A typical partners′ relationship in the Middle East is usually distinct from one in the North Sea, for example. While in the Middle East the activity is driven by the owner of the assets through a buy-back model contract, in the North Sea there is a need for a tremendous cooperative approach amongst partners, in order to catch the contributions of different views and add value on a typical mature basin.

If one adds some Chinese E&P culture, which is very much concentrated on strong vertically integrated, state-owned companies, then a given partnership faces initial sparkling times to see cooperation taking off, no matter if the venture is in China or elsewhere in the world.

As for the mature shallow waters of the U.S. Gulf, generally speaking, ventures usually behave as if the operator were the sole player; the other partners are relegated to be financial resources only. In the deepwater or the deep shelf contexts of the U.S. Gulf, on the other hand, given the complexity of the operations and size of the investments involved, the relationships tend to divert toward the cooperative track. However, non-operating partners have to work hard on demonstrating their ability to cooperate on a given field development by carrying out their own initial view of a conceptual model. If the operator sees some merits, then it triggers a secondment cooperative approach.

West Africa ventures, in general, demand the technical and budgetary issues be discussed by all partners before a decision is taken, in compliance with JOA governing rules. Latin America operations are on the stage, also through a more interchangeable approach. At the end of the day, technical and technological capabilities, investment size, and reserves ownership may introduce some changes on general geographical tendencies, leading to a more cooperative mood in the partners′ relationship.

Final Considerations

When dealing with complex capital- and technology-intensive projects, the proper partnership crafting may make the difference between success and failure. In this respect, the desirable features to be found in partnerships engaged in such projects can be highlighted as follows:

- Complementary Technological Skills: These set the stage for cooperative work and a truly win-win configuration. A corollary of this requirement is the need for all parties, not only the operator, to be willing to share their own technological solutions to the benefit of the partnership;
- Financial Alignment: Capital-intensive projects are particularly prone to partnership disruptions unless all parties are prepared to meet their respective investment contributions and adopt the same pace for the project implementation. Financial arrangements among partners, such as carried participation, cross-party lending or other creative financing schemes, can contribute significantly to the parties' alignment. Different beneficiaries of the results of the projects may also create significant misalignments, particularly when partnerships involve private (dividend-oriented) and state-owned (tax-, royalty- and profit share-oriented) companies;
- Cultural Tolerance: Corporate cultures may vary substantially, even between companies incorporated in the same country, and certainly between partners from different continents. Sometimes small cultural differences create enormous hurdles in the decision-making process unless they are understood and approached with good common sense;
- Appropriate Formal Instruments: In all cases it is essential that a clear set of governance rules be established from inception of any partnership, such as JBAs, JOAs, JVA, AMIs, etc.;
- People Willing to Reach Common Goals: The most important recipe for success in any form of partnership is a multidisciplinary team of people working toward common goals that are clearly defined from the onset of the project.

The Reality of Third-Party Deepwater Infrastructure Ownership – an Owner's Perspective

By R. Cory Weinbel, Production Facilities Division, Cal Dive International

There are clear benefits to third-party offshore infrastructure ownership for both producers and the oil & gas industry in general. These benefits include the possibility of deferred cash expenditures for producers, lower downside project risk through residual value allocation, the opportunity of third parties to spread risk over multiple projects and implementation of new production paradigms. These advantages come at a cost, in that many project risks are shifted from the producers to the third-party infrastructure owners, requiring these third-party owners to be innovative and assertive. In addition, the third-party owners are often stake-holders in the area-wide infrastructure and thus may be taking on roles and responsibilities that are outside their normal risk profile.

Of the 39 deepwater developments in the Gulf of Mexico, only two currently have production infrastructure owned by third parties. So why are there not more examples of this relationship for use in developing deepwater prospects? Success with third-party infrastructure ownership really finds a foundation in a good, solid relationship between the infrastructure owners and the producers that is based on open communication and trust. Unfortunately, forming this relationship can be difficult due to misperceptions by both parties.

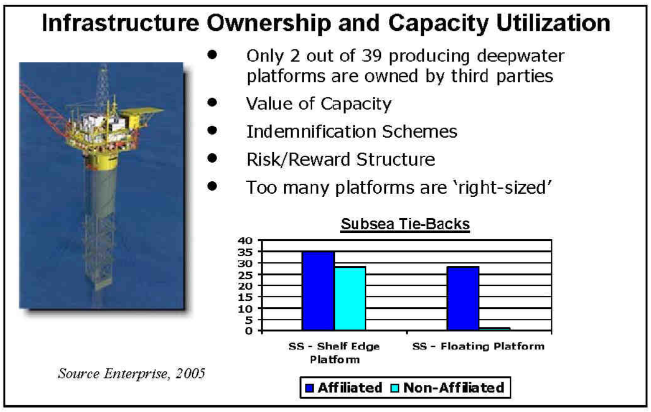

Figure 5: Infrastructure Ownership & Capacity Utilization (source: Enterprise 2005)

Following is an argument for the need for third-party infrastructure ownership, a review of the perceived benefits of third-party infrastructure ownership to lease operators as well as an assessment of the problems that keep this beneficial prospect development structure from gaining a larger slice of the market.

The Need for Third-Party Infrastructure Ownership - Marginal Prospects

Marginal deepwater oil and gas prospects are tending to become the predominate type of prospect available for production exploitation. A marginal prospect is one that is ultimately challenged from making a robust economic return on the proposed development plan. It is conceded now that "marginal" is a relative term when applied to deepwater oil and gas prospects since every prospect will have multiple variables that feed-in to the equation that determines if, indeed, it is marginal. However, it is probably safe to say that deepwater prospects with potential reserves of less than 50MMBOE can be considered marginal. Most in the industry will likely agree that prospects with potential reserves of greater than 100MMBOE will be considered fairly robust and will likely be developed directly by the operator. The prospects with 50MMBOE to 100MMBOE fall into a grey area that will be marginal depending on location, water depth, proximity to transportation infrastructure, quality of the produced fluids, and other variables. Looking at the deepwater prospects in the Gulf of Mexico, below, we see that the mean discovery size is 65MMBOE and that well more than half of all deepwater prospects are smaller than this. In other words, the majority of deepwater prospects are marginal.

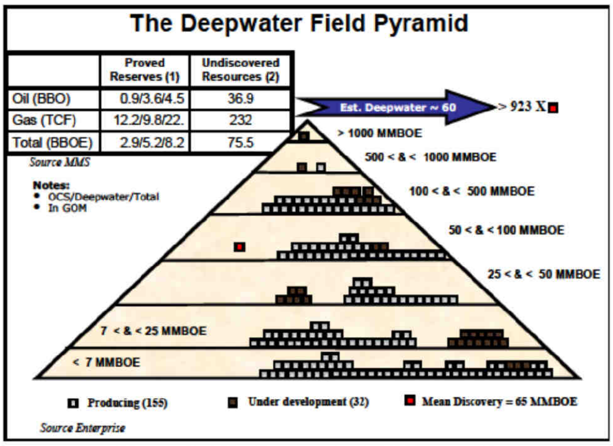

Figure 6: The Deepwater Field Pyramid (source: Enterprise)

The challenge of our industry is to find ways to develop these marginal prospects. One tool in the industry toolbox is to use third-party ownership of infrastructure as a means of making these marginal prospects more economical.

Benefits of Third-Party Infrastructure Ownership to Lease Operators

Third-party ownership of production infrastructure can provide many advantages to operators and owners of offshore production leases. These benefits can be financial, logistical, timing or strategic in nature. The relationship between the lease owner/operator and the third-party infrastructure owner is symbiotic and thus both parties must benefit from the business agreement. Like the lease owner, third-party owners usually benefit economically from the business arrangement but there may be logistical and strategic benefits as well.

As might be expected, the financial benefits of third-party infrastructure ownership are usually the primary driver for this type of business arrangement. Financially the lease owner/operator usually benefits in at least two ways: (1) through deferred expenditures for CAPEX on the installed production infrastructure, and (2) through the reduced total CAPEX exposure on short-duration, marginal prospects. Some producers will also see benefit in the possibility of expensing the infrastructure debt and thereby keeping the large CAPEX exposure off their balance sheets.

Deepwater developments consume a large amount of cash and thus deferment of the CAPEX for the floating production unit can allow cash to be applied instead to drilling and completion activities which are the core business of the producer. Early reallocation of cash from infrastructure to area drilling and completion can lead to larger project upside as area-wide prospects are exploited and tied-back to the third-party-owned infrastructure.

Perhaps one of the most important financial aspects of third-party infrastructure ownership is the protection of the producer's downside reserve case. Consider, for example, that the full value/cost of the floating production unit must be used in the downside project economic analysis when a producer pays for and owns this infrastructure. This risk can be shifted to the third-party owner. The advantage the third-party owner has is the potential redeployment of the infrastructure on additional, later projects. Therefore, the commercial terms can be established to collect payments from the producer for the downside case, which is a fraction of the full new-build cost. In addition to the financial benefits noted above, other advantages of third-party infrastructure ownership include certain logistical, timing and strategic benefits. Logistically, having a third-party owner can be advantageous if there are multiple operators of marginal prospects in the area, making negotiations and the commercial deal structure more straight-forward. Project timing may often be improved as the third-party owner may be able to sanction and execute the project more quickly than many producers. One execution advantage will reside in the fact that many third-party owners have created experienced project teams and also have begun to consider the building of floating production units on speculation. Many third-party owners are also focused on execution of projects using existing technology and avoiding right-sizing of the facility for any specific prospect. Strategic benefits to the producers include the reallocation of capital to drilling and completion in the area, the possibility to keep infrastructure debt off balance sheet, freeing-up capital for other projects, or perhaps even teaming with the third party to consider multiple deployments of the floating production unit.

Perception Problems that Impede Growth of Third-Party Ownership

There are several preconceived notions that producers seem to have that impede the more rapid evolution of the third-party infrastructure ownership model. These notions include the following: 1) third-party infrastructure owners make a huge return on the capital they invest, 2) third-party infrastructure owners hurt the upside of a project, and 3) the interests of third-party owners and producers are not aligned. Let's look at each of these notions and help clarify the reality of the situation through open communication.

The first myth to dispel is that third-party infrastructure owners do not directly make a high return on the money they invest in the floating production infrastructure they own. Third-party ownership of the floating production unit is an enabler! This business is not a huge money maker on its own. All the existing third-party infrastructure owners have other core businesses that are further enabled by ownership of the infrastructure. Cal Dive International, for instance, is able to involve its Marine Contracting division in the installation and construction activities and the ERT Production Company can be involved in the initial or late-life reservoir working interest. By taking a "big picture" view of the development opportunity the third-party owners are able to accept a lower rate of return on the floating production unit ownership, with plans to earn profits through other activities, ownership or through higher payouts if the project performs better than expected.

Speaking of projects performing better than expected, let's look at the second pervasive notion limiting third-party infrastructure ownership wherein producers are concerned that their upside case is damaged at the expense of the profit garnered by the infrastructure owner. As discussed previously, the third-party infrastructure ownership model works best for the more marginal prospects. That being said, the parties will agree on a reasonable profit potential for the most likely (but still marginal) production case. If production performance is better than expected, then the third-party owners normally will earn an additional $1.50 to $4.00 per boe upside as a reward for the risk of participating in this marginal project. Let's put this into perspective by recognizing that the producer will have sanctioned the project without consideration of this upside (i.e. The project should have paid out prior to reaching upside) and that the producer will likely earn up to ten times the amount paid to the third-party owner. Like the producer, the infrastructure owner has taken a risk, and, like the producer, should be rewarded in the occasional upside performance scenario.

Finally, consider the perception that the interests of third-party infrastructure owners and producers are not aligned. Since most commercial deals are structured with both fixed payments and tariffs, it is in the interest of both parties to keep the production facility filled. One very real commercial strategy being considered is the redeployment of infrastructure in the later years of a marginal project to eliminate the cost to the producer and to allow the infrastructure owner to start a new revenue stream.

Overcoming the Perception Problem

Clearly the only way to further evolve and expand the concept of third-party infrastructure ownership in deepwater is to get over these perception problems and collaborate. This collaboration takes trust and open communication among the parties but leads to results that probably would not be attainable by either party acting alone.

Collaboration carries many benefits – it's been said before. Why is it not always done? Let's look at the drilling market for illustrations. Initially, producers had their own drilling rigs and drilled their own wells. Eventually, they decided that ownership of drilling equipment was a whole business in itself that distracted them from their core business of finding and exploiting oil and gas. Thus was born the drilling contractor business. For the past 20 years, producers and drilling contractors operated separately in lock-step in the same market. Today, as offshore rigs become scarce compared to the number of prospects, we are seeing more and more joint relationships between producers and drilling contractors that align their interests and share the risk. This seems like a logical and reasonable evolution so why is this not done more often?

Possible reasons include:

- Producers and third-party owners/contractors often operate under the mode of prisoner's dilemma: they are each trying to work out the best deal without knowing or understanding the other's position and needs.
- Many producers are much larger than their contractors and likely get better financial terms in the market; thus they may perceive little financial advantage to aligning with the contractor.
- There is prior history of non-alignment between the two parties or their predecessors.

How do we overcome these problems and perpetuate the benefits of alignment using third-party infrastructure ownership? The best way may be through establishment of successful examples that others can model.

The problem can be significantly compounded when one of the parties is both a contractor and a producer. A successful example of this is Cal Dive International's participation on the Gunnison project operated by Kerr-McGee Oil & Gas. Cal Dive personnel participating in the project were often asked to make decisions with a "best-for-project" perspective that were not necessarily optimized for the Cal Dive marine contracting business. However, due to the perspective and commitment of Cal Dive top management; these "best-for-project" decisions were made since they ultimately led to the best business decision for Cal Dive and the Gunnison Project as a whole.

One very successful example of collaboration in action between producers and infrastructure owners is the Independence Hub project. The area producers, Anadarko, Devon, Kerr-McGee, and Spinnaker, formed the Atwater Valley Producers Group, which in turn negotiated the commercial proposal with the third-party infrastructure owners, Enterprise and Cal Dive. Although the project is being managed by the owners, the producers are actively involved in the execution through a true integrated project team. This ultra-deepwater project, in 8,000 feet of water, requires the collaboration of all parties with both the producers and infrastructure owners dependent on each other for success. Thus, their interests are clearly aligned. The structure and execution plan for this project were built on the success of the Marco Polo project, which is another example of third-party infrastructure ownership. With these and future successful examples of the third-party infrastructure ownership model, more and more producers will likely use this model to develop marginal prospects.

Abbreviations

AFE:	Approved for Expenditure
AMI:	Area of Mutual Interest
boe:	Barrels of Equivalent
boed:	Barrels of Equivalent per Day
CAPEX:	Capital Expenditure or Costs
D&UD:	Deepwater and Ultra-Deepwater
E&P:	Exploration and Production
FPSO:	Floating Production Storage and Offloading Vessels
FPF:	Floating Production Facility
FPUs:	Floating Production Units
GOM:	Gulf of Mexico
IOCs:	International Oil Companies
IPT:	Integrated Project Team
JBA:	Joint Bidding Agreement
JV:	Joint Venture
JOA:	Joint Operating Agreements
JVOAs:	Joint Venture Operating Agreements (same as JOA)
MMS:	Minerals Management Service (in USA)
MMBOE:	Million Barrels of Equivalent
NCS:	Norwegian Continental Shelf
NOCs:	National Oil Companies
OPEX:	Operational Expenditure or Costs
PSC:	Production Sharing Agreements
ROI:	Return on Investments
TLP:	Tension Leg Platforms.

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