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Expediting Exploration and Development of Deepwater fields in West Africa

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Abstract:

The history of oil exploration includes the natural evolution from land to offshore to deeper water offshore. Underneath a vast majority of the oceans, in 500 ft to 10,000 ft water depths, oil and gas fields have been discovered with some of them developed and producing millions of barrels of oil. The Golden Triangle of this deep water production is the Gulf of Mexico, offshore Brazil, and offshore West Africa. More deep water oil and gas fields have been discovered in these three areas than all the rest of the world's deep water regions. However, there have been a large number of deep water fields that will not be developed for years to come, even with high oil prices. Why? Another reality is geophysics and geological analysis shows there are even more deep water fields, probably a greater number than have been discovered, yet to discover. Yet the vast majority of these fields will not be drilled. Why? The simple answer to both questions is that conventional perceptions of reserves and deep water technology, costs, time, and the deployment of human resources continue to limit the development of these deep water fields.

This paper explains why billions of barrels of deep water oil and gas, already discovered, will not be developed in the foreseeable future, using the conventional deep water technology practiced by almost all the oil companies. The paper also explains why companies will not pursue a great many hot prospects for exploration in deep water when the prospects look too small. The bottom line is: most concession holders of what is considered marginal oil and gas deep water fields will not exploit these fields to commerciality.

The paper introduces another possible, non-conventional approach for exploiting what is considered marginal deep water prospects, both discovered and yet to be discovered. This new deep water enabling technology can commercialize deep water fields in a fraction of the time compared to the conventional exploration and production processes. Overall, using this new technology there is a significantly higher NPV, due to timing; significant reduction in financing volume due to low CAPEX and instant cash flow, and a significant reduction in need for large engineering and technical capacity due to less complexity. There are significantly increased production volumes due to easy application of enhanced production methods. The conclusion: there is no longer a dependence of Big Oil for development of deep water

reservoirs in many parts of the world, especially West Africa. This enabling technology and its impact on all aspects of exploration, drilling, evaluation, early production, and intervention are explained in this paper.

Like any new technology that is considered a ***disruptive technology*** it requires champions who will defy the conventional ways of doing things and to take the risk for doing something new. This paper describes a new business model that can be used by West African IOCs and NOCs to expedite the development of what is considered marginal deep water fields.

Conventional deep water technology is limited by field size?

The convention deep water approach for exploration is highly driven by seismic and other geophysical processes that identify what are considered **prospects and leads** with the prospects having a much higher probability for finding oil and/or gas as compared to a lead. Usually, the prospect is drilled and if a discovery is made a very short well test is sometimes done. In many cases, depending on the rules of the concession owners (government), testing i.e., burning oil and/or gas might not be permitted. The exploration company evaluates the discovery in conjunction with the geophysics and tries to estimate the in-place reserves and possible recoverable oil. Most exploration and production companies have developed economic criteria that includes: field size (estimated recoverable oil), production over time, cost of oil, in-country economics i.e. taxes, bonuses, and other financial conditions. Then, the company usually risks the inputs of time and costs with the field performance to define the economics for developing the field. This evaluation, especially for deep water, almost always considers the accepted conventional technology process for deep water development.

Conventional deep water technology deals with a few major components:

1. Large expensive Mobile Offshore Drilling Units, or MODUs for short,
2. Large and expensive Floating Production Storage Off-take vessels, or FPSOs; or other floating structures like tension leg platforms, and SPARs, that house production and sometimes drilling and/or completion workover rigs;
3. Subsea completions that tie back to some production facility via manifolds and production risers.

The variation of the field development plan can differ from operator to operator on the selection of rigs, production facilities, and the type of development i.e. subsea wells tied back to a production facility, dry tree wells from some type of floating platform, or a mix of the two. How these three major elements are designed defines the capital (CAPEX) and operating costs (OPEX) and the time from discovery to first oil. On average this can be from four to ten years.

The result from this economic evaluation is a project rating. Each project is then ranked with other projects in the company that have been separately rated. Different companies have different ways of doing this evaluation, but for the most part the variation between companies is how the company treats risk factors, level of contingencies for capital spending, and estimates of time to do various tasks. Over time these companies develop threshold parameters for reserves, production, rate of return, net present value, and finding and development costs. If a project does not meet these threshold parameters the project is declared non-commercial. Over the last two decades economics, based on today's conventional time and costs, indicate that the deep water field threshold size for many companies must be greater than 100 million barrels of recoverable oil. This is usually for the larger majors and independents. Smaller E&P companies might consider a range between 50 to 100 million barrel fields, mainly because they do not have as big an inventory of competing projects as the bigger companies.

Understanding the oil company ranking system is critical in understanding why many deep water fields are ranked as non-commercial or declared as non-commercial. Also, many companies have another threshold which relates to the manpower necessary to do all the engineering and operations to commercialize a deep water field. Unlike onshore or near shore field development, conventional deep water technology is more complex and requires a higher level of expertise and experience. Because of the skill and complexity most companies have the mindset that it takes the same manpower to develop a 70 million barrel deep water field as a 500 million barrel field. Hence, for many companies, even if the economic ranking showed a smaller deep water field to be highly economic, many companies would defer developing the smaller field because of manpower issues and reserve materiality.

There are other more technical issues why some deep water fields do not rank high for near term commercialization. Heavy oil is a major issue. Even on-shore heavy oil is a challenge, being highly dependent on oil prices. On-shore heavy oil fields usually have close spacing between wells, many are horizontal wells, most have electric submersible pumps (ESPs), and in some fields thermal processes are used to enhance recovery. Offshore, the cost for drilling more development wells already taxes the economics, and if the field is in deep water (over 500 ft of water depth) the cost of a lower generation MODU would be an excessive cost. But the biggest factor for deep water is the cost to run, maintain, and service the ESPs that are necessary for commercial production rates. Even for relatively shallow water heavy oil fields with reserves over 500 million barrels the conventional deep water technology will not make the economic thresholds. Therefore, most heavy oil fields in water depths more than 500 ft will not be commercialized in the foreseeable future even with $140/bbl oil prices (which means the heavy oil price will be somewhere between less than half to maybe sixty percent of normal oil prices).

Another major reason companies are deferring or even backing away from some deep water discoveries are the up-front capital demands for field development without a good understanding of the reservoir complexity. Many deep water fields that appear as large reserves at first, when put on production, show the field has barriers that form compartments that require different well placements and probably more wells for production and injection. Also, many of the deep water fields need immediate water and/or gas injection to enhance recovery as well as artificial lift of some sort. The increase in the recovery factor, just being able to use some sort of artificial lift, on these deep water fields can be between 6% and 12%. By using timely water injection the recovery factor can be increased by another 10% to 20%. Without artificial lift and water injection most deep water marginal fields will suffer severe production declines and very low recoveries.

Experience in the Gulf of Mexico, many West African fields, and Brazil seem to support this experience. That is why deep water operators are becoming more and more conservative about commissioning fields, especially if it demonstrates a high level of reservoir uncertainty.

The bottom line to the previous discussion is most deep water fields between 50 and 100 million BOE will not be developed in the near future, even with $100 oil. There might be a few exceptions but not many. And for deep water heavy oil, even monster fields, the conventional deep water approach condemns these resources to be non-commercial. This presents a major problem for governments who own and want their resources developed. Only the bigger fields that rank high on budget prioritization process will be commissioned, and because of the conventional way for doing deep water technology, first oil will take 4 to 10 years.

There are another two major reasons that most major International E&P companies are in no hurry to develop a field and put it on early production. Once a field is discovered the company can book a certain amount of reserves. Since most publically listed oil companies derive the majority of its worth from booked reserves, putting a field on early production really has a limited advantage. In fact, many oil companies manage the appraisal program for a discovery in a manner to add incremental reserve replacements over some time period. Much of what is behind the scenes has nothing to do with expediting early production but how it could impact share prices. In essence, most major E&P companies have completely different drivers than most NOCs and the smaller IOCs. For the majors (including the larger independents) reserves and share price drive the process, whereas, for the NOC and smaller IOCs it is production and cash flow. And even then, a small IOC that is not publically listed versus a small IOC that is listed there is a major difference between reserves and production. The non-listed company is like the NOC, its worth is production not share price.

This presents a challenging scenario for most West African counties who rely on the major E&P companies for development of their resources. Once all the larger deep water fields of conventional oil (not heavy oil) are discovered and the average field size goes below a certain threshold value the remaining discoveries will not be commercialized until oil prices increase to some higher value or some other advantageous factors materializes. As for exploration, if the seismic indicates less than acceptable potential reserves, the exploration of these prospects is unlikely to occur unless tied to maintaining the concession or defaulting on the exploration agreement. A good example of this is the JDZ where seismic excited the industry with all the indicators of hydrocarbons. But then the reality set in where the probable field size was ranging from 5 to 50 million BOE which was later confirmed by a discovery. At water depths of 6000 to 7000 ft, with the prospects spread far enough apart to challenge conventional development for such small reserves, industry cooled down on the JDZ. Yet there are hundreds of millions of BOE that will not be developed in the near future. This is a potential sad economic loss for Nigeria and San Tome. All along the West African coast there are deep water fields already discovered that are deemed non-commercial that could be producing thousands of barrels of oil per day, yielding much needed cash for the countries' development.

Finally, there is the perception that deep water technology can only be done by a select group of companies that possess the conventional deep water technology capability. This means that many African IOCs are reluctant to venture into deep water, or if they do, it must obtain a partner that can do deep water technology. Also, financial institutions do not like to finance small companies or specific field development projects because they think the risk is too high. Only large oil companies can attract corporate financing versus project financing. Couple this with the perception that the local IOC does not have the technical expertise or financial strength to do a deep water development there is little chance a local IOC can exploit any deep water field without enticing a bigger E&P company to join them and operate.

However, the oil industry has faced similar problems before where some type of resource was deemed non-commercial, and some enabling technology was discovered that changed what was non-commercial to commercial. The next section presents such a new enabling technology that could change commercialization of deep water smaller fields and heavy oil deep water fields.

The new enabling deep water technology—the Self Standing Riser (SSR)

Throughout history enabling technologies have made a major impact in re-defining human progress. So what is an enabling technology? It is some new approach that can either cause something to be done that was not possible before like electricity, or another approach that profoundly changes a technology that changes a resource base. A good example is the innovation of the steel belted radial tire which made the conventional rubber tire obsolete. Most recently and profoundly, the micro-chip has changed our way of life with personal computers, cell phone communications, the auto and aircraft industry, and much, much more. This simple innovation of the micro-chip impacted a way of life and industry on this planet.

In the oil business enabling technologies have dramatically changed how we explore and produce oil and gas. Probably, one of the major enabling technologies was 3-D seismic, but there were others over the history of the business like hydraulic fracturing, horizontal drilling, water flooding, and measurement and logging while drilling and others. The impact of these enabling technologies increased the amount of oil and gas that could be found and exploited. ***Enabling technologies are game changing technologies.***

However, most new enabling technologies are slow to impact and in many cases take years before the impact can be realized. Why? Usually, an enabling technology competes against an established technology, which is considered safe, and less risky. And the more disruptive the new enabling technology is, the more the resistance there is to adapt the new technology. Most of the established construction and service industry has a huge vested financial interest in not implementing the new simplified solutions that are being presented in this paper, as it may severely affect their profit. Further, large groups of a certain category of people with oil companies will feel that their positions are threatened because their specific technical or operational expertise may not be a critical factor for the company going forward. However, there are always individuals and companies, and sometimes even governments who defy the conventional way of doing something, and will be willing to implement a new technology that can cause a major change and make a major economic impact.

The offshore industry started in shallow water and went deeper and deeper until now the industry is drilling and producing at depths never before contemplated. This deep water industry evolved from shallow water where the rigs got bigger more expensive and complex. There were two directions to manage production, depending on the field size, location, and water depth. One was the subsea completion and the other was the dry tree solution. Huge investments were made in the technologies associated with this conventional approach. No one challenged this gradual evolution of how to do deep water exploration and production until just recently (2004). A large independent charged its technical experts to step back and see if there was a different way to do deep water exploration and production? The result of this initiative was the birth of a new enabling, game changing technology for deep water which, also, would be very disruptive to the deep water drilling, subsea, and production industries.

Like the micro-chip, the Self Standing Riser or SSR offers an entirely new approach for the exploration and production of many deep water fields which could make it possible for companies and governments who relied on the deep water specialty groups to exploit their deep water resources, now to do it themselves. This enabling technology, more profoundly, offers the possibility to cost effectively develop deep water resources that were considered non-commercial by conventional standards and even expedite first oil to less than one year as compared to 4 to 10 years. This technology also significantly reduces the required capital necessary to develop these resources. Then what is this SSR technology and how can it have such a major impact on deep water oil and gas resources?

As the deep water industry evolved it borrowed many of its innovations from the maritime industry—one being the use of structural buoyancy devices to support production lines from the sea floor. Figs. 1-3 show examples of three SSR for production line support. However, no one really visualized using the SSR for other tasks to change the way drilling or production was done, except for a shallow water application in Indonesia for wireline intervention. See Figs. 4a and 4b.

Fig. 1

Fig. 2

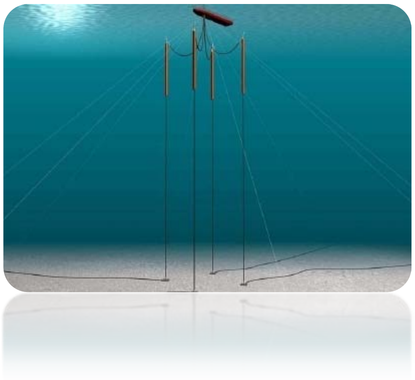
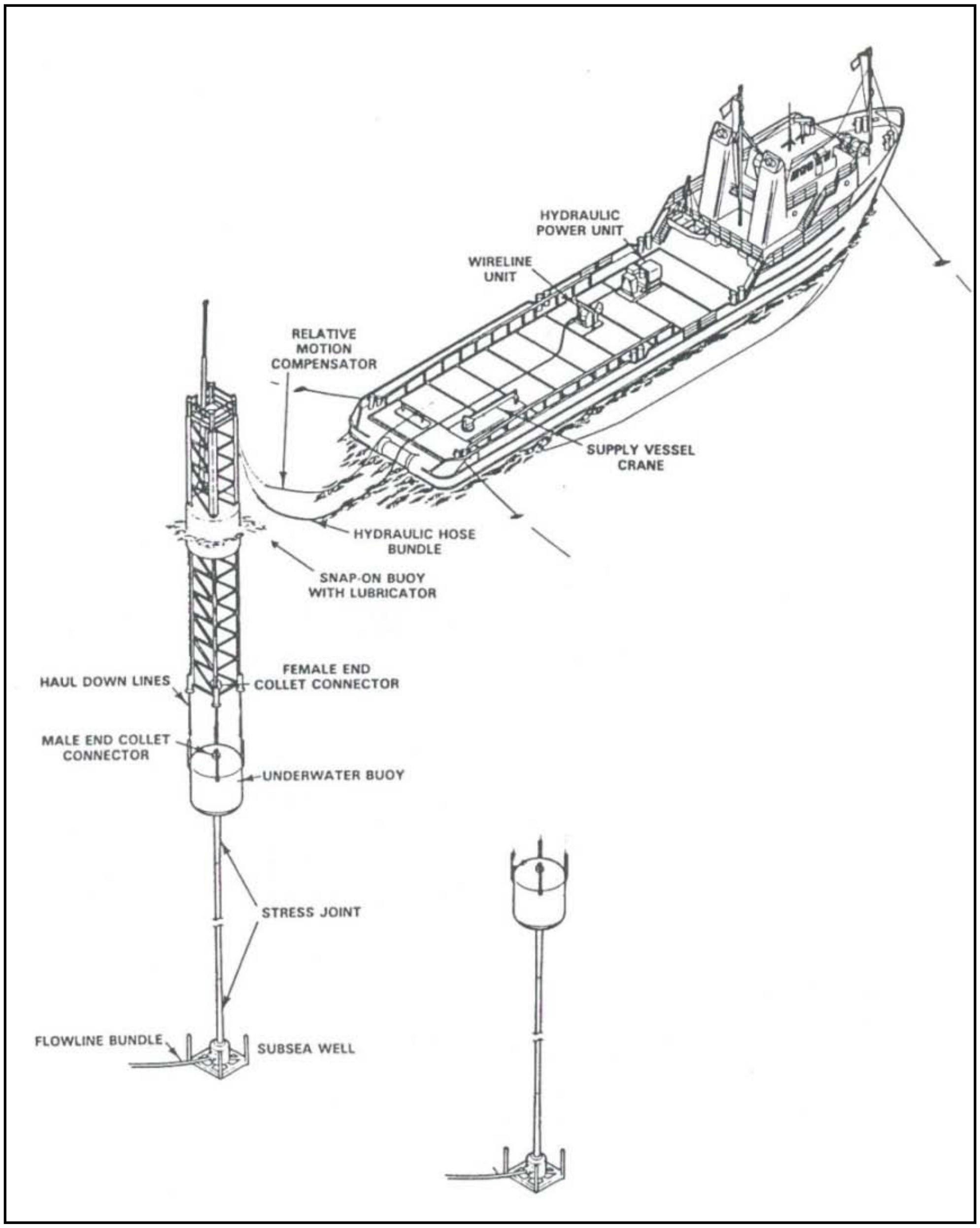


Fig. 3

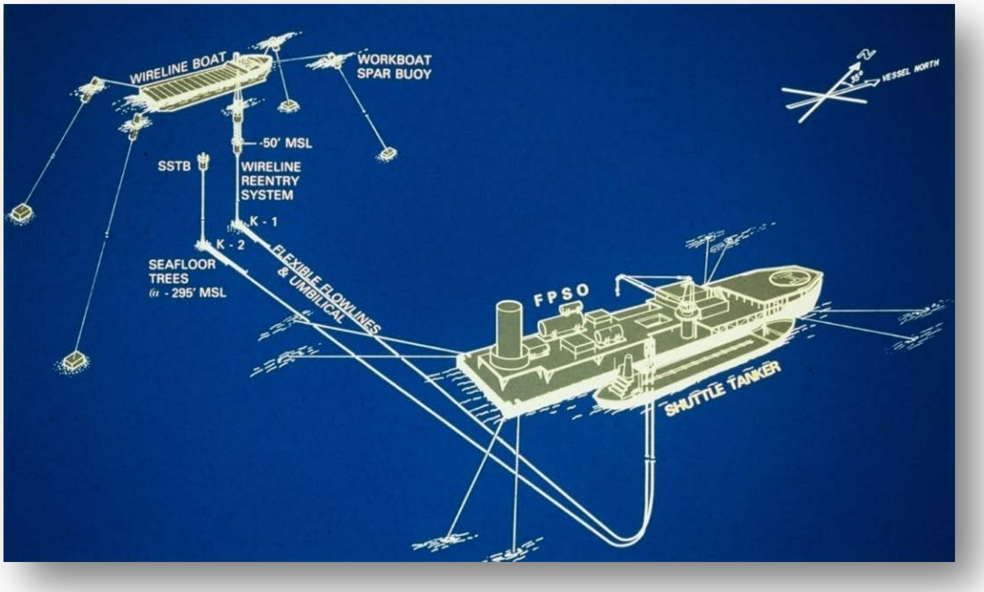
Examples of Self Standing Risers (SSRs) being used to support production lines

Fig. 4a



Shallow Water Self Standing Riser System for Wireline Intervention

Fig. 4b **Example of SSR System for Wireline intervention used in Indonesia Field Shall Water**



The author asked the questions: "Can a SSR be used as a drilling and production riser?" also, "Why couldn't a SSR move most of the subsea equipment from the sea floor to near the surface?" These questions ultimately lead to a series of patents for an adjustable SSR that would either attach to a wellhead or a subsea production tree.

Fig. 5 shows one depiction of the patented SSR for drilling and production from a well head at the sea floor and a SSR connected to an existing subsea production tree for intervention and the possible use for artificial lift. Then why is

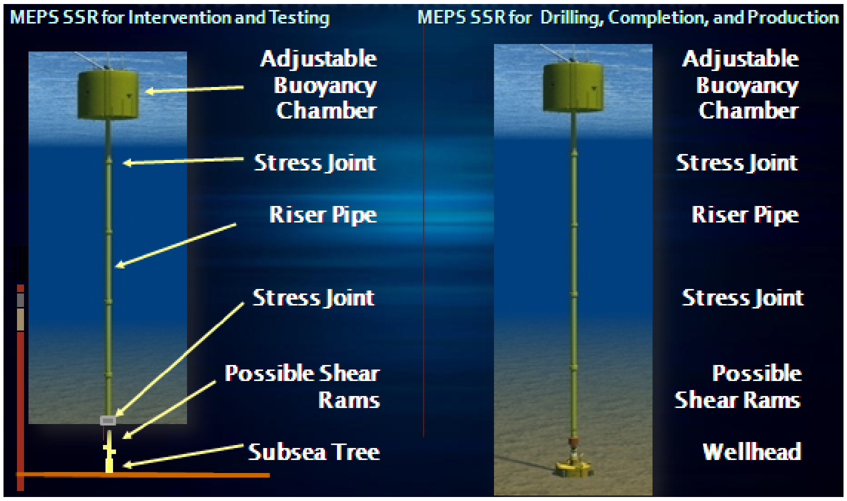
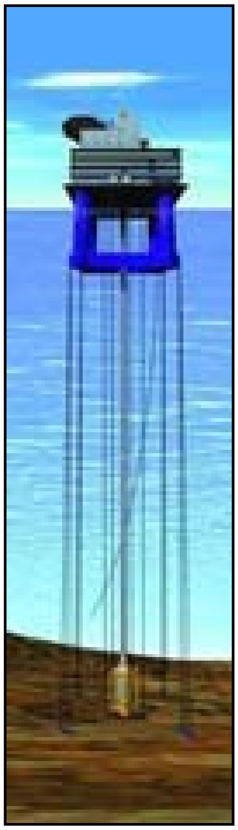


Fig. 5 **Adjustable Self Standing Riser with Adjustable Buoyancy Chamber**

this SSR different from the others? First of all, no SSR was designed to attach to a well head to drill, complete, test, produce or intervene with the wellbore. The patented SSR is really an adjustable SSR where the buoyancy chamber(s) can be placed anywhere in the riser system and the buoyancy chamber can be adjusted for various operational buoyancy needs. The simplicity of the design is based on years of experience for designing, building, and operating tension leg platforms. For over two decades these platforms, anchored to the sea floor (see Fig. 6) with steel legs have with stood the forces of the surface weather, including hurricanes, and high near surface currents. What made this possible were material science innovations, the metallurgy, to fabricate special steel stress joints that resist high bending forces and fatigue for the life of the structure. It is the same technology that is used in the design of the adjustable SSR. These stress joints are most typically run at the areas of highest bending stresses and fatigue which is usually at the seafloor and at the base of the buoyancy devices. The stress joints are usually less than forty feet in length and tapered to the riser pipe diameter. The riser pipe is usually a high strength casing with special couplings to resist unscrewing. The last major component is the buoyancy device which is called an ***Adjustable Buoyancy Chamber or ABC.*** (See Fig. 7) This chamber is actually multiple chambers to make sure if one chamber, for some reason, starts losing ballast the other chambers can still support the riser. In fact extra chambers are used as a back-up for the buoyancy support. Also, the buoyancy chamber can be a closed (like a submarine) or have an open bottom. The closed buoyancy design is practical for depths of less than 200 ft., whereas, the open bottom design can be run to any depth.

Fig. 6



Tension Leg Platform (TLP)

The big question is how the adjustable SSR with an ABC is a major enabler for deep water. Let's start with drilling. Deep water wells are drilled with MODUs and are implemented at depths where jack-up rigs are not feasible which is around 500 ft. To drill in deep water requires a drilling riser and a subsea blow out preventer system. To handle the weight of the riser and BOPs, which can reach well over one million pounds, the MODU needs deck space to store the riser and winches that can tension the riser to resist the currents and movement of the vessel. Over the years many of the older rigs have been upgraded to handle these big risers, but to do this major investments needed to be made to make upgrades, buy new riser pipe and subsea BOPs. That is why the per day rig rates, even for the older MODUs are so high. And for the super new builds that cost in excess of $500 million and some costing nearly a billion dollars, the per day rig rates can be double of the older renovated rigs. For deep water the spread costs of a traditional MODU can range from $500k per day to $1,000k per day. This can account for up to 25% of a field development, and in some cases where completions are time consuming, it can be significantly more. Basically, it is the big riser, winches, and heavy BOPs that drive the MODU costs up. If the MODU is dynamically positioned (no anchors) the costs go higher.

Figure 7 – **Self Standing Riser Buoyancy Device Run in the Gulf of Mexico**

What happens if a SSR is used? First the SSR is smaller in diameter and lighter than the conventional riser system. Since the BOPs are run on the top of the BOPs they are lighter, and instead of costing around $20 million they are approximately $3 to $5 million. There is no need for an ultra large expensive MODU since the SSR supports the riser which is essentially casing and the lighter BOPs. This means any MODU or drilling type barge that can anchor can drill at water depths never before contemplated. So instead of spread costs of $500k to $1,000k per day the drilling spread costs might be $200k to $400k per day—a major cost savings. So the SSR greatly impacts the drilling and completion costs for deep water—a perceived disruptive technology to the offshore drilling industry.

The impact of the SSR as a major enabling technology continues to have even a bigger impact after the well has been drilled. Conventional deep water technology might test a discovery, using a burner (a common practice started in the North Sea) and used in West Africa. Usually these tests are less than a day and are becoming less popular because the burner technology cannot guarantee hydrocarbon leakage. For those who have witnessed such tests there is no escaping the oil sheen on the surrounding waters from the non-burned oil. Whereas, with the SSR approach, once the well is drilled, the rig can be used to land a production tree, connected to the wellhead on the top of the ABC. The drilling unit can depart, and the well can be connected to a production facility which early on can be a floating production unit or FPU. (See Fig. 8)

The oil is processed and transferred to a small tanker. What this means is the well starts producing oil, immediately. Two things happen:

1. Much needed well test data is obtained to further define the development of the field, and
2. Oil production starts and provides immediate cash flow which can be applied to the remaining field development.

In other words, the SSR enables a completely different financial model which is a pay-as-you-go, since the proceeds from the oil can further finance the field development. This reduces the CAPEX necessary for the field development, greatly enhances the Net Present Value, NPV, and the Rate of Return or ROI. Now deep water fields with recoverable reserves as low as 20 million BOE could be made financially attractive with cash flow in less than one and a half year's time. And if there are clusters of smaller fields near each other, multiple SSRs and production units can be used and coupled via submerged pipe lines at depths between 300 ft and 500 ft to a common tanker. Again using buoyancy chambers to support the pipelines (see Fig. 7).

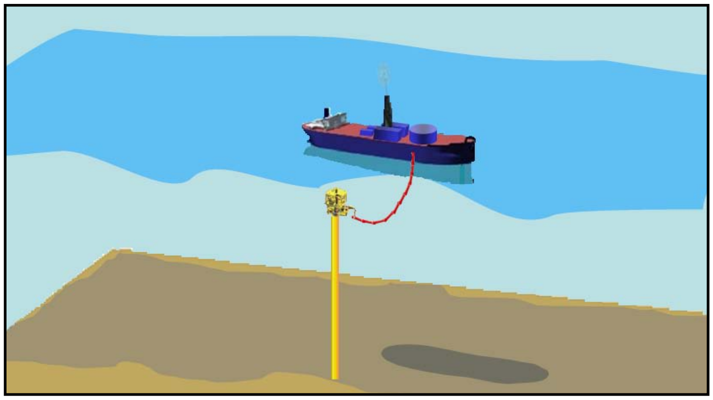
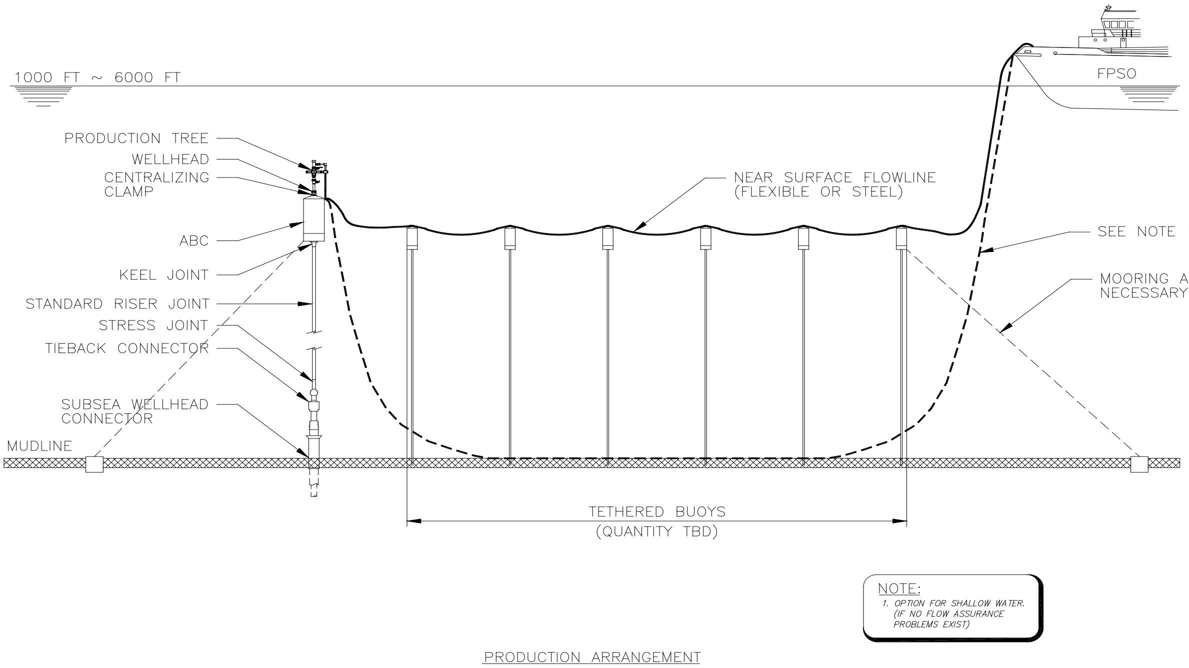


Fig. 8 **Example of SSR and FPU/FPSO used for Early Testing and Production**

Fig. 9 Production Scenario Using SSR and Supported Pipeline



What the SSR enables is numerous approaches to drilling, production design variations that accommodate a field size and architecture, water depth, surface conditions, production and injection patterns, etc. Because the top of the ABC is within 100 ft to 150 ft (diver depth), with the production tree near the surface such artificial lift technologies like electric submersible pumps (ESPs), and gas lift can be deployed and easily maintained. This provides higher production rates and recovery factors for the field. There are little if no flow assurance problems since the production tree is near the surface (which is a costly problem for some deep water fields).

The question that begs answering is: if the adjustable SSR technology is so good why hasn't someone tried it? From 2005 to 2007 Anadarko Petroleum Corporation funded the engineering, wave tank tests, and finally a field test in the Gulf of Mexico where a specially designed SSR was deployed off the coast of Texas in 3400 ft of water.

The top of the ABC is at 100 ft below the surface. Fig. 10 shows the system installed and Fig. 11 shows after two years of service and two hurricanes. The next step is to use this technology in a real application on a declared non-commercial oil or gas field.

Fig. 10 **Top of ABC Just Installed October 2006**

Fig. 11 **ABC SSR Installation after Two Years of Service in Gulf of Mexico**

As a side note, this same SSR technology is being supported by two U.S. government funded projects to investigate the use of the SSR system for deep water wire line and coiled tubing intervention and early well testing for the Gulf of Mexico. Refer to the web site of Nautilus International LLC. to obtain more detailed information about these projects.

Without a doubt the best area to test the SSR concept is West Africa. There are scores of deep water marginal fields too small to interest the major oil companies yet too expensive for conventional exploitation by smaller IOCs or NOCs. It is a dilemma. The major companies that hold the concessions where these fields occur declare them non-commercial and the smaller IOCs, NOCs, and governments believe that only the conventional deep water technology can commercialize these fields. It is the main purpose of this paper to show there is another way?

A new business model, using the enabling technology of the SSR to explore, develop, and commercialize the declared marginal oil fields in deep water:

Now after years of development work, thorough testing and studies of the optimal conditions for the applications of this technology, we are finally ready for the commercial phase with full deployment of this new method. As explained before deep water fields declared non-commercial are either held by major oil companies which the fields do not meet the economic metrics to sanction development, or by NOCs that believe there is no alternative to the conventional deep water approach used by the major oil companies and, therefore, has to be non-commercial. And the small IOCs, who also might consider developing the resource, are constrained by the conventional economic model which implies a major up-front investment, or CAPEX to finance the expensive cost for using a conventional drilling approach and then to wait for some production solution like an FPSO. This means having enough capital for the drilling and production facility costs before any oil is produced. Then there is the factor of delay times for rig availability, subsea equipment, and finally the production facility. Also, these small IOCs are probably not aware of the alternative SSR technology which is one reason this paper is being written. ***There is another way where smaller IOCs and NOCs in West Africa can potentially commercialize discovered non-commercial oil fields in deep water with a fraction of the CAPEX and OPEX and establish first oil and cash flow in less than a year and a half.*** How can this be done?

Consider the concept of a company that is capitalized with enough money and technical expertise to focus its activities on already found deep water oil fields that are declared non-commercial. The company would have alignment with the NOC, Government or small IOC i.e. minimize CAPEX and OPEX, and get first oil as quickly as possible, always maintaining the flexibility to expand development faster or to slow down in the event of reservoir uncertainty. Always, production and high recovery factors would be the business drivers. Today, such a company does not need a huge work force of technical experts. Service companies have operational expertise to do everything from supervising drilling, reservoir and production engineering, operating production facilities, and even logistics. This new company might have a small staff of financial personnel, some geo-scientists, and project managers and coordinators, thus keeping the overhead at a minimum. What enables this type of approach is the application of the ***SSR*** technology. One company, MEPS-FirstOil holds the exclusive license to deploy this technology, worldwide. Any drilling company, service provider, IOC, NOC can have access to the technology to exploit these marginal deep water oil fields. There is no need to rely on or wait for the major oil company to finally get to some type of future development. The SSR technology, for the first time, opens the possibility to create new ventures with creative financing for local IOCs and NOCs.

The challenge is simple: if you are an IOC or NOC that has what has been called a non-commercial oil or gas field in deep water and want to have production and cash flow in 1 to 1 ½ years consider this new enabling SSR technology. Don’t let these discovered resources sit for another 10 to 20 years before someone decides for you to finally commercialize them. The history of the oil business shows where smaller operators took risks and jumped in front of the majors with new technologies. If you are interested in pursuing this exciting technology contact the authors for further information.

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Dr. Millheim has over 40 years experience in the E&P business and currently serves as Managing Director of MEPS-FirstOil and Nautilus International LLC. Dr. Millheim has worked for Conoco, Amoco Production Co, and Anadarko Petroleum Corp. in various operational, research, and management roles for two thirds of his E&P career. Dr. Millheim ran his own business in Australia for five years doing drilling operations in Australia, Indonesia, Timor, and Papua New Guinea. Dr. Millheim served as the Director of Drilling and Production Institute, Mining University of Leoben, and Director for the Mewbourne School of Petroleum Engineering at the University of Oklahoma. During his long career he served as a high level consultant for various international companies including Royal Dutch Shell, BHP, Santos, Wintershall, RWE-DEA, OMV, JNOC, PDVSA, Petrobras, Schlumberger, Noble Drilling and government institutions such as the DOE and the CSIRO.

Dr. Millheim is known in the industry as a leading innovator of various technologies in drilling, deep water operations, and arctic technologies. He has over a dozen inventions, was a pioneer in: directional and horizontal drilling, slim hole drilling, drilling analytics, bit technology, real time drilling control centers, offshore technologies, arctic drilling. He has authored more than 60 papers and articles on drilling, management of engineering, systems dynamics, and other technical and management oriented subject matter.

Dr. Millheim holds a Doctorate in Mining Engineering from the Mining University of Leoben, a Masters Degree in Petroleum Engineering from the University of Oklahoma, and a Bachelors of Science in Petroleum Science from Marietta College. He is a long time member of the National Academy of Engineers, winner of numerous industry awards, and a long time contributor to the Society of Petroleum Engineers. He is the co-author of the best selling SPE Applied Drilling Engineering Textbook. Dr. Millheim can be contacted via email at keith.millheim@meps-firstoil.com or by phone at 832.631.6174.