IPTC 15235

Self Standing Riser Offers Alternative to Conventional Deep Water Approach for Developing Marginal Deep Water Oil and Gas Resources

Keith K. Millheim, SPE, Nautilus International LLC and Geir Aune, MEPS-First Oil Ltd.

This paper was prepared for presentation at the International Petroleum Technology Conference held in Bangkok, Thailand, 15–17 November 2011.

Abstract

In water depths greater than 150 meters hundreds of oil and gas discoveries have been made and deemed non-commercial for one reason or another. Many of these fields are in concessions or leases without any hope of near term development because the conventional approach for developing an offshore field requiring a MODU, subsea completions, and some type of floating production system is cost prohibitive. Also, many of the current concession holders without deep water experience feel deep water technology is too complex and risky to venture into without a super-major or major independent with deep water experience as their operating partner. Also, geophysical technology has delineated hundreds of high probability deep water oil and gas leads that will not be drilled because the indicated field sizes are too small. Yet the history of basin development clearly shows most of the big fields are found first and are few. Most of the further discoveries follow a log normal distribution where size of the field reduces but the frequency of the smaller fields increases. **The challenge is how to make these marginal deep water oil and gas fields commercial.**

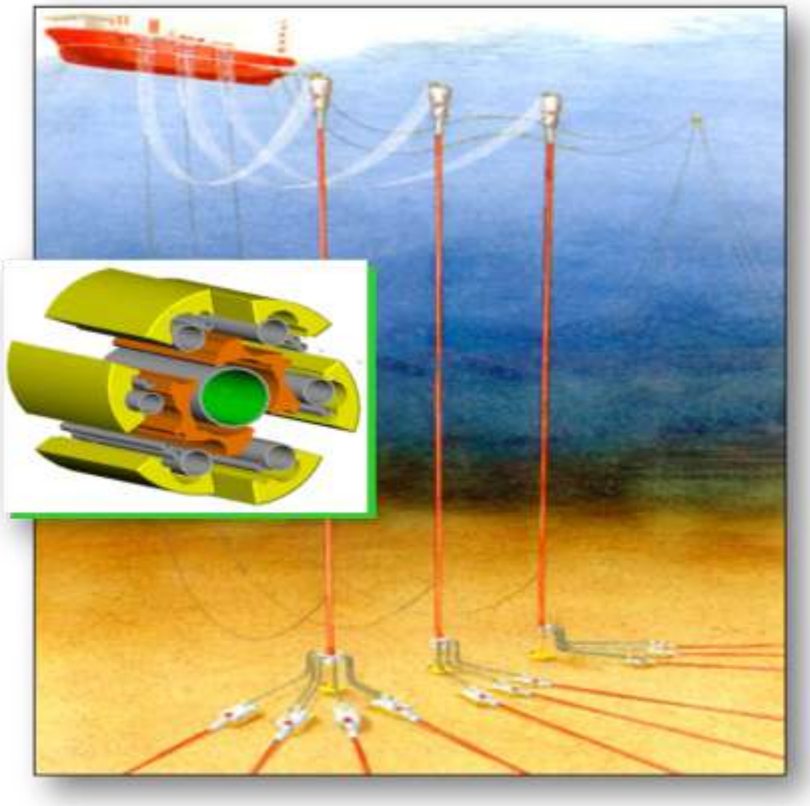
This paper presents the Self Standing Riser (SSR) technology as an enabling technology which could be the solution for commercializing ***non-economic*** deep water oil and gas fields. This paper describes the SSR and how it can enable lower cost drilling, achieve faster first oil, lower the required capital that is necessary to commission a project, and how the early production can be used to provide capital to complete the project.

A field test of an SSR in 1000 meters of water for nearly four and a half years is cited as well as the next steps to use the SSR for a marginal field development (see Figure 1 showing the buoyancy device after 2 years). How the SSR provides a new way for intervention in deep water using coiled tubing, and the possibility for developing deep water heavy oil and other applications also will be discussed.

The Self Standing Riser (SSR), sometimes referred to as a free standing riser, evolved as subsea completions became more of a standard to develop many offshore fields using FPSOs where the free standing riser was used to support the heavy production risers (Figure 2).

Figure 1: Field Test of SSR in Gulf of Mexico after Two Years

Figure 2: Girassol Field Riser Towers (Subsurface Riser Tower, Flexible Hoses to FPSO, Seafloor subsea wells)



One novel application of the free standing riser was used by a company for wireline intervention for some shallow water fields in Indonesia (Kadl, 1988). Another effort to sell the free standing riser concept was introduced by Atlantis (Magnussen, 2001) to enhance the use of smaller MODUs to extend their capacity to drill in deeper waters. This concept never was commercialized. Probably, the most publicity of the free standing riser came from the BP/Horizon event where two risers were shown as stand-by production risers. These risers were anchored by chains attached to the sea floor (British Petroleum, 2010). This is the common design of the free standing riser which is being used by a number of major oil companies as a production riser solution (Hatton, 2002). Except for Wybro's wireline free standing riser (Kadl, 1988) there is no known application of a free standing riser attached to a wellhead or subsea production tree.

Millheim (2008) presented the concept of the SSR where the riser would be attached to a wellhead or a subsea production tree. At that time a SSR was installed in the GOM in 1000 meters of water and connected to a conventional wellhead attached to a suction anchor. This unit was in place until 2011 when it was removed and examined with no noticeable structural damage. During the sea trials this SSR was exposed to two named storms and possibly some residual loop currents. These encouraging results suggest that the commercial application of the SSR is ready.

Based on the successful design analysis, wave tank tests, and finally, a long term field test, this paper describes how many non-commercial deep water fields could be made commercial by using the SSR technology.

What is the SSR and why is it different from the free standing riser?

Figure 3 is a depiction of a stack up of a typical SSR similar to the one used in the GOM field test which could be used for drilling or production. Later, a typical stack up for an SSR used for intervention will be discussed.

Using the SSR for drilling or production assumes two possible scenario's: 1. A MODU connects to the SSR and drills and completes the well, making it ready for production, and 2. A MODU drills the entire well conventionally with the rig's riser and subsea BOPs, and then a production SSR is installed to complete and put the well ready for production. Both cases are discussed.

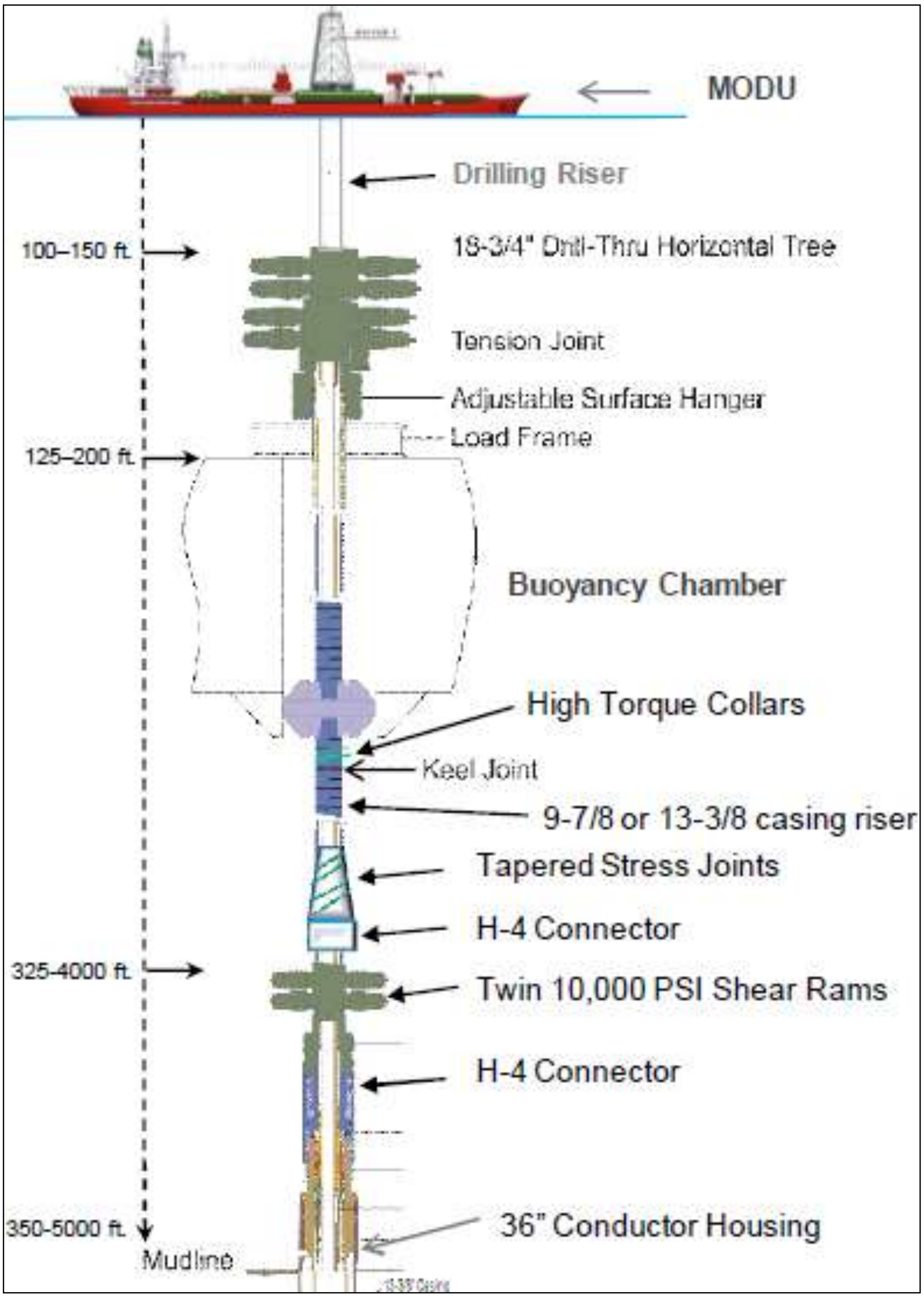
Drilling the well using the SSR

The scenario for using the SSR for drilling a well is based on the following assumptions: 1. The MODU would be anchored, and 2. The MODU sets the conductor, then drills the surface hole conventionally (i.e. pump and dump). Then the surface casing is run and cemented with a conventional wellhead.

Figure 3: SSR Well System Stack-Up – Drilling Mode

A example of casing design:

- A 36" conductor pipe would be landed (same as conventional drilling).
- A 17 ½" hole would be drilled, using the common pump and dump (no drilling riser) method.
- A 13 3/8" casing would be run and cemented with a common H-4 type of connector ready to receive a shear ram package and the SSR (13-3/8 casing riser)
- A 12 ¼" hole section is drilled throug the SSR with a BOP placed ontop of the buoyancy chamber.
- A 9 5/8" inch casing is landed at the mudline. Another 9 5/8" tieback casing would run from the mudline casing to the wellhead at the top of the buoyancy chamber. This would give a dual barrier for the completed well.
- The well would be completed with a 7" liner .



The SSR is run and attached to the wellhead using a standard tie back connector (see Figure 4). The safety shut-off device (see Figure 5), SSD (twin shear rams), could be run on drill pipe and latched to the wellhead and then the SSR run and latched to the SSD, or the SSD could be run on the bottom of the SSR and latched to the well head (Figure 6).

Figure 4: Standard Tie Back Connector

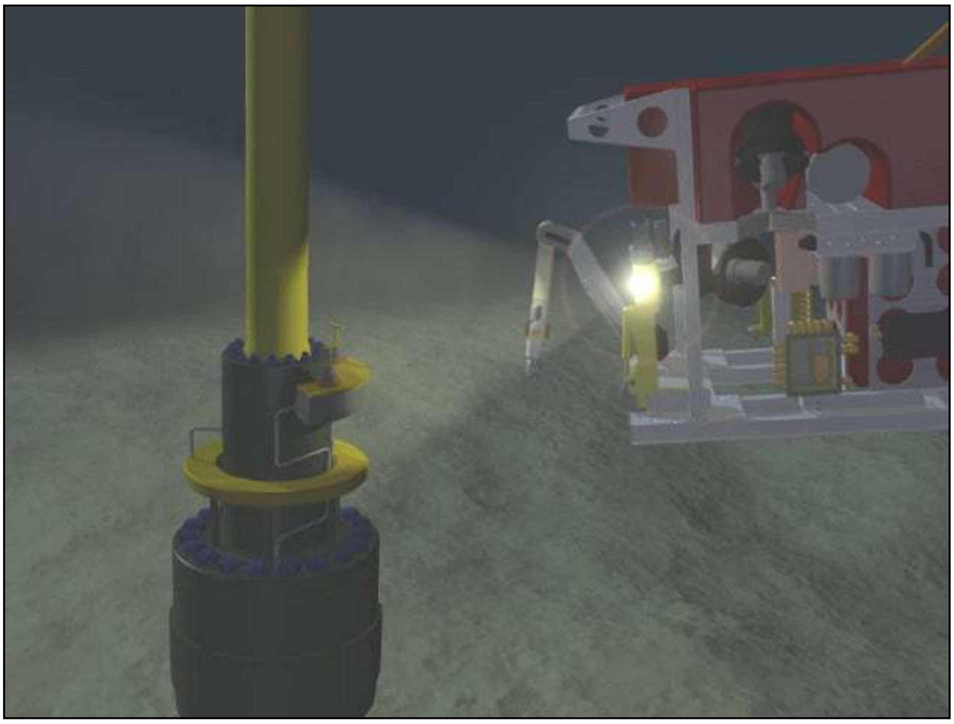
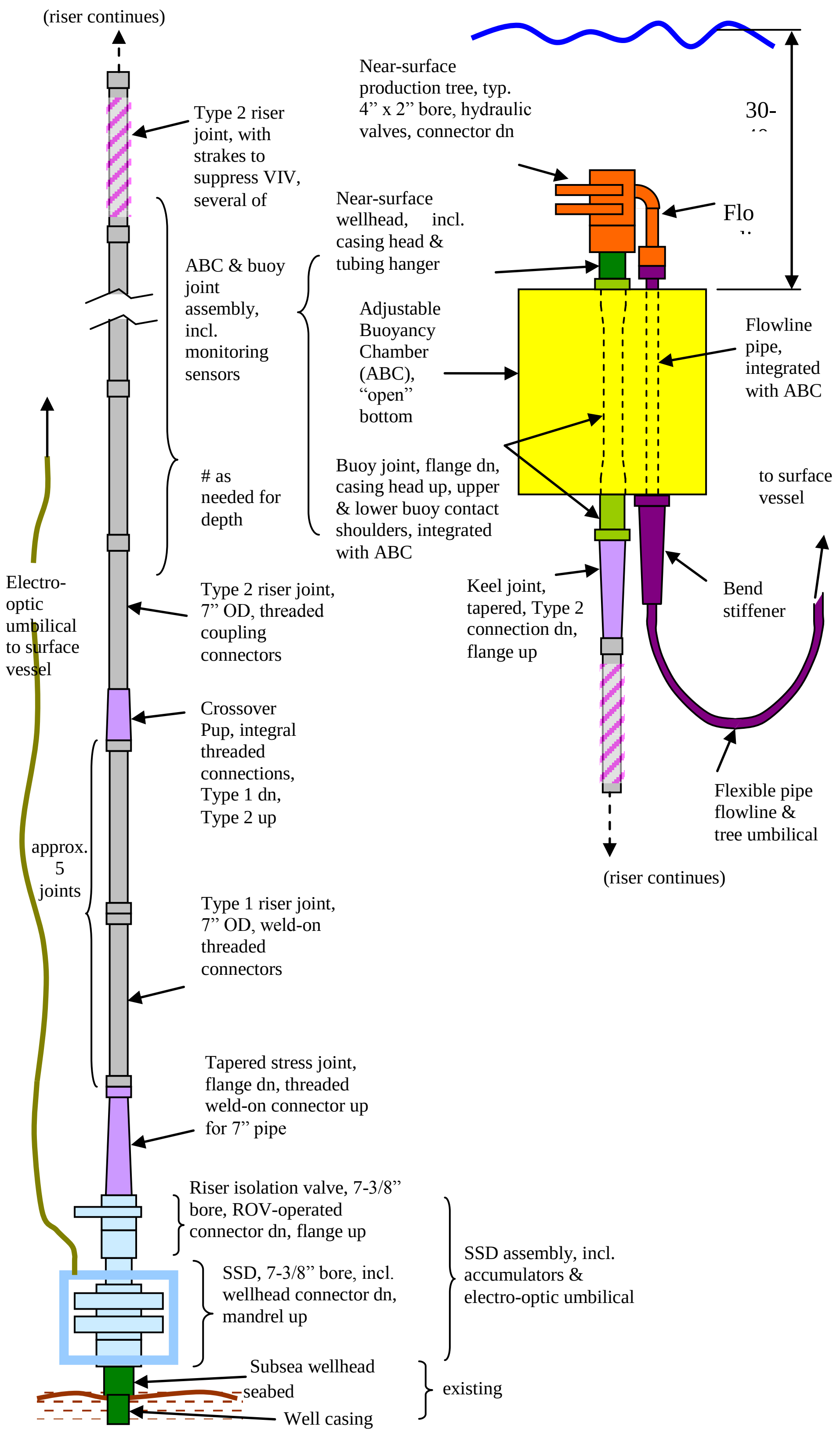


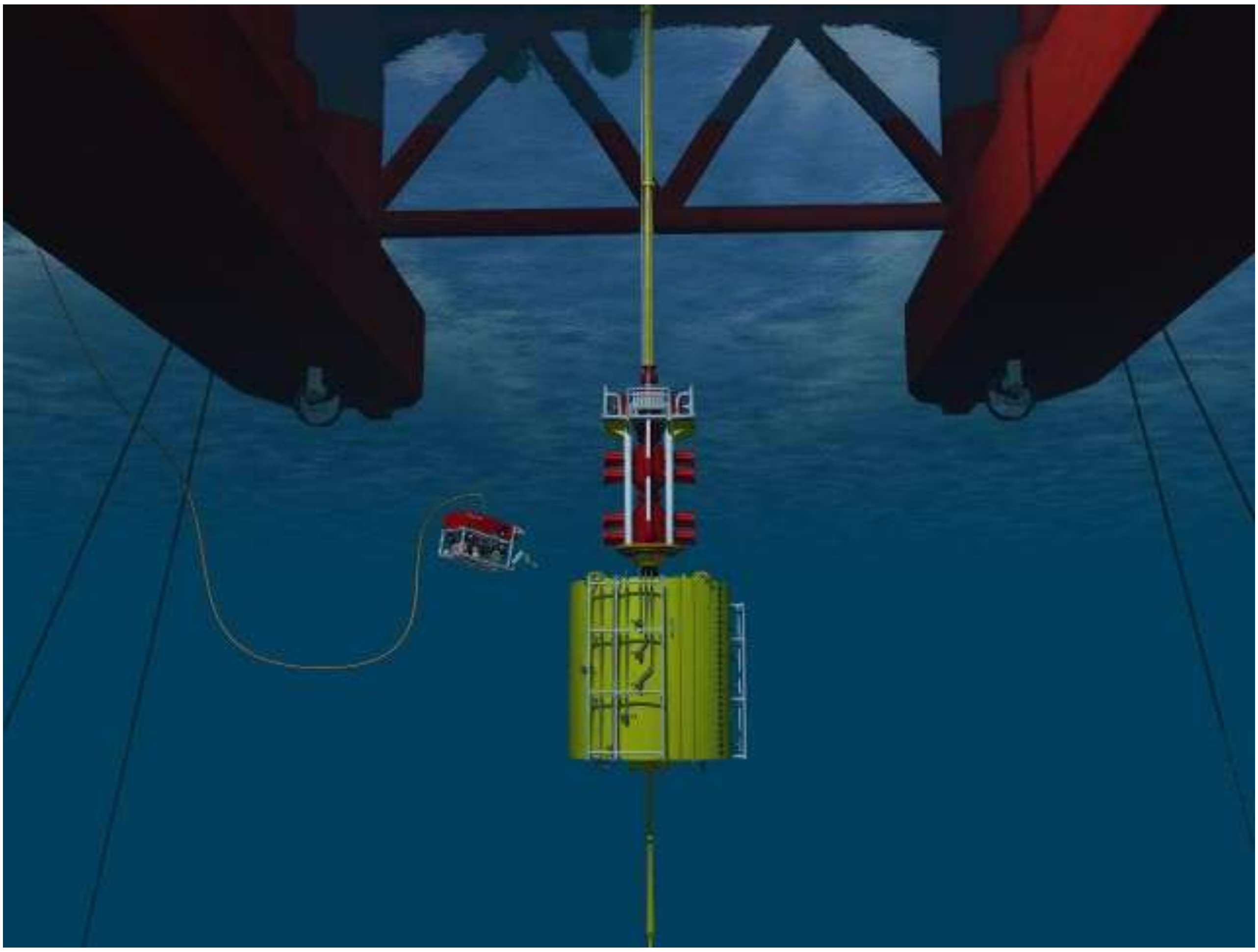
Figure 5: Safety Shut-off Device

Figure 6: SSD Connected to the Wellhead



Once the SSR is connected and tensioned via adjustable buoyancy, the spacing of the buoyancy chamber from the surface is determined based on local surface weather conditions, currents, and other considerations. For West African conditions the buoyancy chamber would probably be 30 to 40 meters from the surface. The rig would land a conventional BOP stack with shear rams, annular rams and pipe rams. Unlike the conventional approach which would require a deep water subsea stack the SSR approach only requires a near surface BOP stack (see Figure 7) normally used by the shallow water MODUs, using a hydraulic activation system rather than the complex MUX operated system. Once the near surface BOPs are attached conventional drilling can proceed with intermediate casing and finally the production string, which can be run to the surface and landed in the wellhead, or a production liner can be set. Usually, for a normal pressured environment up to three strings, not counting the surface casing, can be accommodated using the SSR.

Figure 7: Near Surface BOP Stack



To complete the well, and possibly test and produce the well the same MODU could be used, or the MODU could set the production tree, and temporarily abandon the well. Then a vessel with a coiled tubing unit could move over the well, set completion BOPs, complete the well. Either the well could be tested (drawdown and build-up tests), or put on production and tested later. This assumes some production facility is ready to process the flow and treat the fluids.

Drilling conventionally and setting the SSR once the well has been drilled and cased

It is possible that some operators might chose to use a MODU and conventionally drill the well using the subsea BOPs and drilling riser. Once the well has been drilled, the well can be temporally abandoned and the rig released. If this scenario is used a smaller SSR can be used (7 3/8 to 7 ½ in). Whereas, using the SSR for drilling and completing a 13 3/8 or 9 5/8 SSR would be required. The production SSR with a SSD would be latched to the wellhead and prepared to set the production tree and BOPs for completion operations. Either a light intervention unit or a vessel with coiled tubing could be used for the completion. All the various options are the operator's choice, depending on economics, logistics, risk and safety considerations (see Figure 8 for the production SSR stack-up).

Production designs using the SSR approach

Economic analysis will clearly show that achieving early production is the key to convert the marginal fields to commerciality. However, achieving this early production, cost-effectively, requires a difference approach for the type of facilities used to process and store the fluids. There are options. Currently there is a glut of older twin skinned tankers still in good condition that can be purchased for less than $20 million. These tankers usually have from 300,000 to 350,000 barrels of storage capacity. Most marginal oil fields in West Africa require four to six wells to effectively exploit the field to achieve 25 to 50 % of the oil in place. This depends on the productivity of the wells, early injection and other factors. However, many of the West African type wells can sustain flow rates of 2000 to 5000 BOPD. Assume a marginal deep water field with four producers and two injectors can sustain 3000 BOPD for five years, which is a combined total flow of 12,000 BOPD. Assuming a water production can occur in two to three years the production facility might need to treat up to 25,000 BFPD. This size and type of treating facility can easily be skid mounted and adapted to the smaller tankers in less than nine months. This is the mini FPSO approach (see Figure 9a, 9b, and 9c).

Figure 8: SSR System Well Stack Up – Production Mode

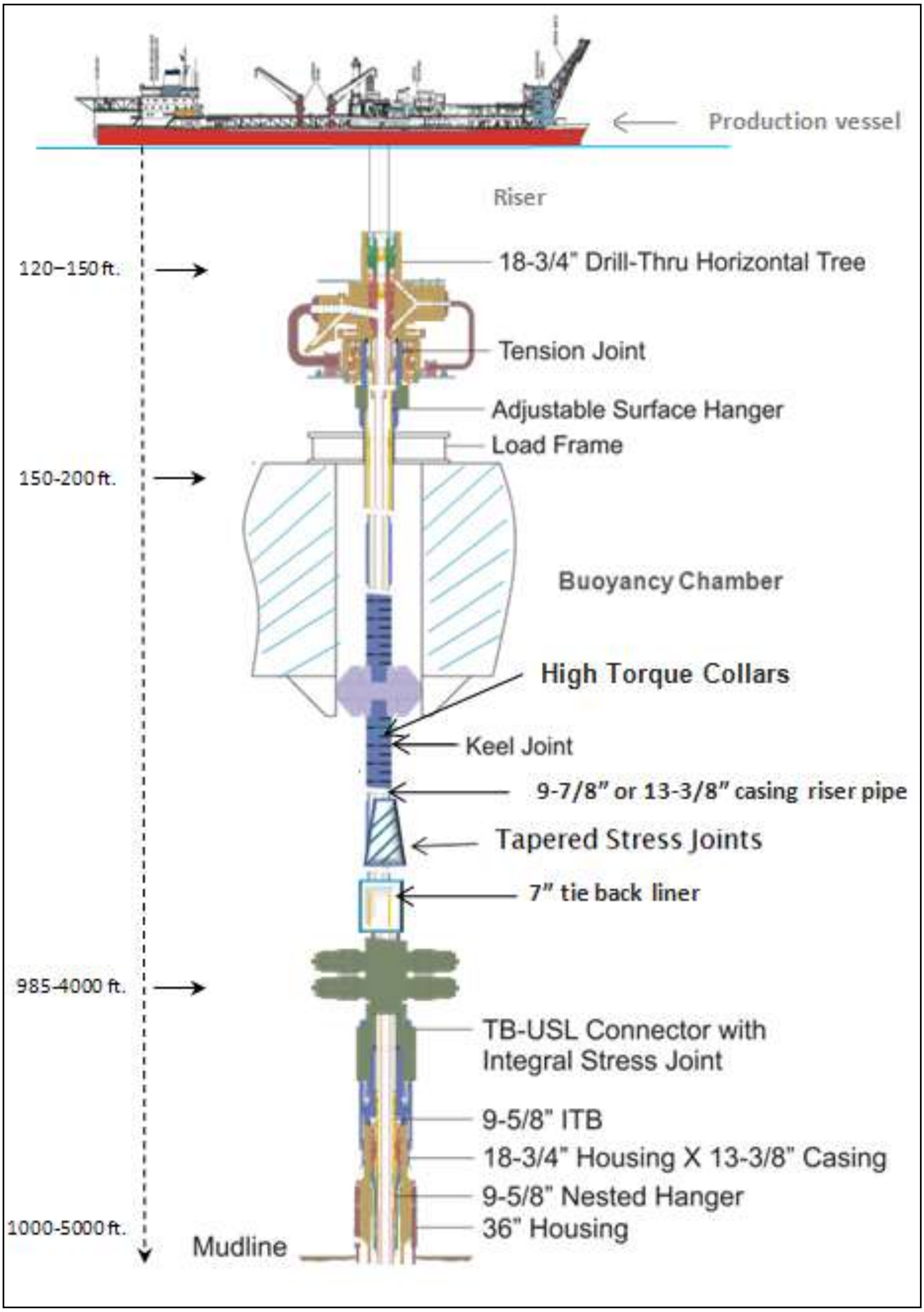


Figure 9a: Mini FPSO Approach

Figure 9b: Typical Deck Layout for FPU or FPSO

Figure 9c: Small Production Unit (FPU or FPSO) - Munim

Another approach is to use small FPUs which process all the fluids and re-inject the gas and water for up to two to three wells. Figure 10a and 10b are examples of small FPUs. The processed dead oil is sent to a leased tanker. A number of these units have been operational for years in the GOM, Mexican waters.

Figure 10a: Mini FPU Approach - Crystal Ocean

Figure 10b: Mini FPU Approach - Bourbon Opale

A planned development of a marginal deep water field is designed to go from drilling to completion to production without major delays, and to use a low cost approach for the production system and facilities. Except for the SSD there is no other subsea equipment required. The shallow water production tree is a fraction of the cost of the deep water subsea production tree, which are essentially off the shelf items. There are no complex manifolds or pumps, just a quick disconnect jumper from the production tree to the production facility. Since the production tree is at water depths of 30 to 40 meters (diver depth) routine maintenance is easily conducted either with ROVs or divers. Most of the flow assurance problems that plague deep water production trees, like wax buildup and hydrate formation, are almost non-existent at the shallower warmer waters.

Example of a conventional approach to a marginal field development

There are numerous reasons marginal fields are classified as non-commercial, but, by far, the most common reason is a company's threshold to develop based on recoverable reserves. Most deep water E&P Companies have set reserve thresholds anywhere from 100 million BOE to 500 million BOE for deep water field exploitation. A typical marginal deep water field in West Africa can range from 10 million BOE to 50 million BOE. One such field that was studied had nearly 43 million BOE in 1000 meters of water. Reservoir analysis showed that four producers, each with a 400 meter horizontal could produce 10,000 BOPD with a maximum well drawdown of less than 1000 psi. Water injection would commence almost immediately and electric submersible pumps would be used in the four producers. Based on this scenario the field would sustain a constant 10,000 BOPD for nearly five to eight years before going on decline. Assuming an effective injection program nearly 25 million BO could be produced in five to eight years. Why would an oil company not develop such a field?

A conventional approach, after discovery, would possibly be running more seismic tests (one year). Then a decision to drill one or two appraisal wells could be made (one year). Assessment of the two appraisal wells dictates drilling four more producers and at least one injector (one year). A decision to go ahead would require ordering all the subsea equipment and securing an existing FSPO for lease (two years). If the FPSO is not available for lease there could be another year or two delay. Once the equipment is delivered, there is the completion of the wells and hooking up all the subsea equipment and tie-back to the FSPO (one year). Total number of years could be between four and six years. During this time, all of the capital investment had to be made without one drop of oil being produced. Furthermore, the human capital to develop this small field is probably 70 to 80% of that required to develop a 300 million BOE field which more than likely produces 50,000 to 70,000

BOPD. And as long as the operator has larger field development options there is little doubt the operator will deploy its human resources and capital on the larger projects. Also, for marginal field development, there is little room for mistakes like drilling too many wells during the appraisal and development stage, not knowing the characterization of the reservoir, or having many delays or over-expenditures. Even if everything goes right, $300 to $400 million would be spent without realizing one dollar of revenue. Also, these types of wells need ESPs to maintain production. This means intervention to install and remove the ESPs. Average cost of an intervention in deep water is $14 million (Stanton, 2006). Even with four wells producing the intervention costs have a major effect on the economics of the field. This is why most deep water E&P companies will not risk capital, human resources, and reservoirs to develop smaller deep water marginal fields.

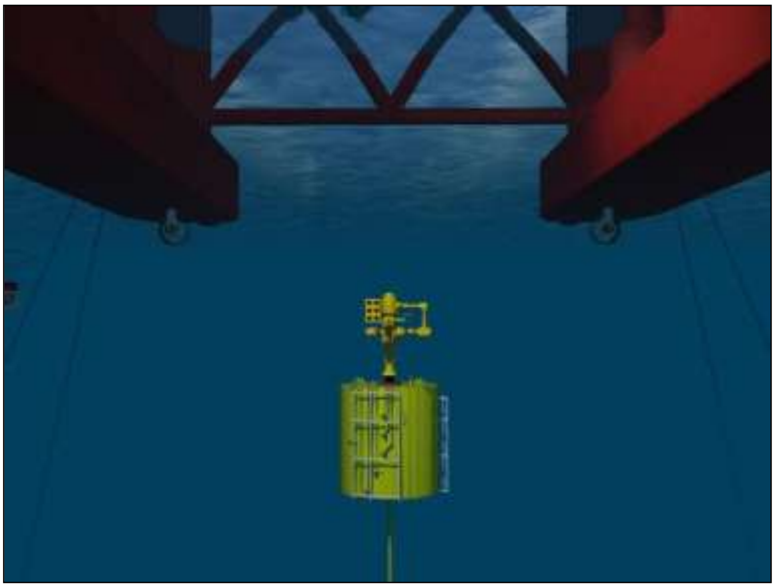
Developing the same margin field using the SSR technology

There are two basic approaches to applying the SSR technology for the development of the example field: 1. Drilling using the SSR, and 2. Drilling conventionally, and completing and putting on production using the SSR. Both approaches have merit.

Drilling with SSR has the economic advantage of using an older MODU with limited water depth range. These MODUs can be obtained at a fraction of the cost of the newer generation rigs. Using the SSR for drilling with a lower cost anchored MODU could conceivably half the cost for each well with some other advantages. Drilling with the SSR provides two barriers to flow with the SSD and the near surface BOPs. Any testing or trouble shooting of the BOPs can be done at a fraction of the time of a subsea BOP system since the BOPs are only 30 to 40 meters below the surface. Once the well is cased and cemented the lower cost MODU can do the completion operations, and ready the well for production by setting the production tree on the wellhead on the buoyancy chamber (see Figure 11).

As shown by Figure 12a-b the field would have two producers and one injector at each end of the field. Producer one would be put on production as the rig is drilling the first production well. This means 2,500 BOPD are being produced after the well is completed. This immediately starts generating cash flow to start paying down the operational costs such as drilling and

Figure 11: Production Tree on the Wellhead on the Buoyancy Chamber



completions as well as starting to payout the facilities costs. Table 1 shows a schedule of the field development. Note, by the end of the first year the field is producing 5000 BOPD and has active injection. The second tranche of wells is completed by the end of the second year where the field is producing 10,000 BOPD from four wells and two injection wells. It can be shown that by the end of the year the field has generated enough cash flow to cover most of the capital investment and operating costs of the production facilities, SSRs, and downhole pumps. By the beginning of year three the concession owners are generating revenues, and paying royalties, taxes, and profits.

Drilling conventionally and installing a production riser has some economic ramifications that impact the overall drilling costs and the time to payout. Also, there is the choice to complete the well with the drilling unit; to bring in an intervention unit capable of running the SSR, tubing, and the production tree, or to bring in a vessel capable of running the SSR and to use coiled tubing to complete the well and put it on production. Each scenario impacts the overall economics and time to production.

Table 1: Schedule of Field Development

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Move in Drill well #1		Complete, Test Put on Production		2500 BOPD - Well #1								2500 BOPD - Well #1											
				Move in and drill well #2		Complete, test, put on production		2500 BOPD - Well #2				2500 BOPD - Well #2											
								Move in and drill well #3		Complete, put on Injection well		0 BOPD (Injection Well #3)											
												Drill well #4		Complete and put on Production		2500 BOPD - Well #4							
																Drill well #5		Complete and put on Production		2500 BOPD - Well #5			
																				Move in and drill well #6		Complete, put on Injection well	

Figure 12a: Two Producers and an Injector Well

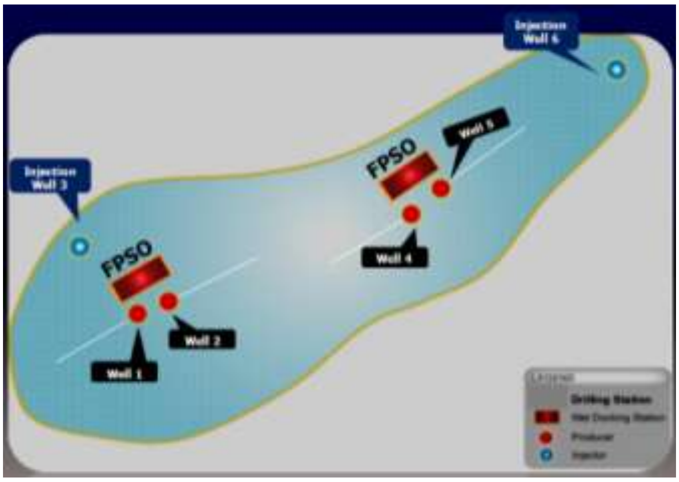


Figure 12b: Two Production Wells

Using the drilling unit (conventional MODU) to drill and complete the well will take essentially the same time as a MODU with the SSR for drilling. The overall drilling costs will possibly double because of the higher rig rates as compared to the SSR drilling unit previously discussed. Once the well is drilled and completed it would be temporally abandoned. The MODU could set the production SSD and SSR (7 3/8 in SSR as compared to the 13 3/8 in SSR), the tie back liner in the SSR, and the production tree. The MODU would move out, the production facility would be connected to the SSR, and production would start. Using the MODU for all the activities would definitely increase the overall costs of the completed well plus tie up the rig for longer times, keeping the rig from starting the drilling on the next well.

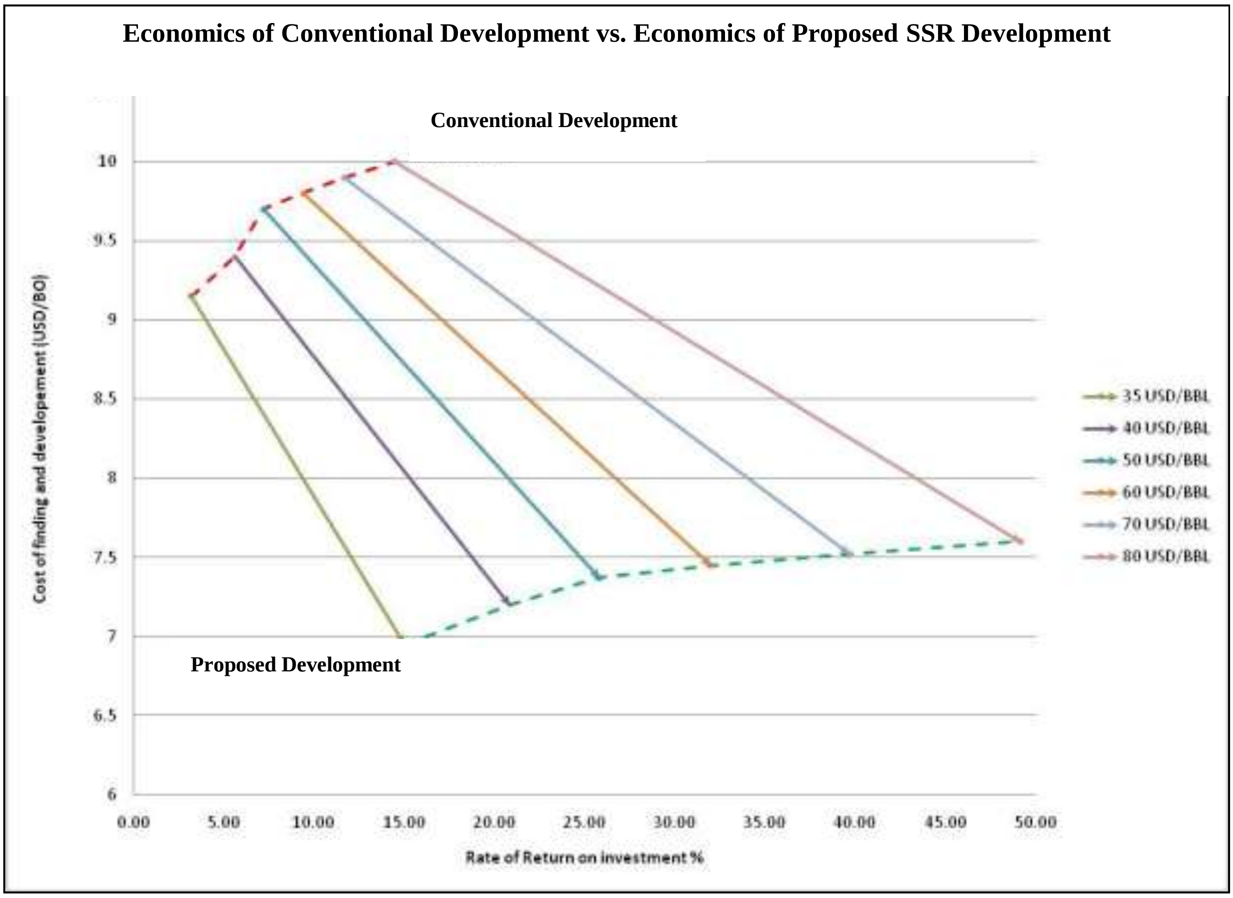
The better option while using the conventional MODU drilling approach is for the rig to set the production casing, cement the casing, and temporally abandon the well, thus, removing the high-cost unit for a more inexpensive intervention vessel to complete the well and put it on production. This also frees up the rig to go to the next well to drill and to continue on until all six wells are finished. Once the rig is off the well, an intervention unit moves in and installs the production SSD/SSR. Depending on the intervention vessel type the well can be completed with either regular tubing or coiled tubing, which is more economical. Using this option the intervention unit would follow behind the drilling unit until the field was totally developed (i.e. four producers and two injectors).

Whatever option is selected by the operator, the field will be totally developed in two years and obtaining first oil within the first six months. (Figure 13 shows one economic comparison) Depending on rig rates, the conventional MODU approach is still very economical as compared to the conventional development approach (i.e. subsea completions with a dedicated FPSO).

Other applications for the SSR

Even though the main advantage of the SSR technology is for the development of the smaller deep-water fields previously described, there are other potential applications for the SSR technology: 1. Deep water heavy oil; 2. Early development of larger fields; 3. Development of step out wells in larger fields which are non-economic to tie back to the production facility; 4. Using the SSR technology to take over production when the wells on the field reach its economic limit; 5. Using the SSR to connect to existing subsea production trees to do coiled tubing and wireline intervention through the SSR, 6. Early well testing via the subsea production tree; and 7. Injection through the SSR connected to the subsea tree.

Figure 13: Economic comparison of conventional field development vs. proposed development (less than 50 MMBOE)



General assumptions:

- Water depth 1200 ft.
- Permeability's average 200 md.
- No water drive.
- 30 API gravity oil
- GOR 1000 scf/bbl .
- The base line cost included all bonuses, royalties, and taxes etc.. Cost recovery was 80% before taxes and royalties.

Conventional development:

- Six producers and four injectors
- Average plateau production per well 4000 bopd
- A FPSO with capacity up to 30,000 bopd.
- First oil after five years include seismic, exploration well, three appraisal wells, purchase of equipment, drilling production wells and completing and putting wells on production.

Proposed development:

- Six wells on production, starting production after drilling first well.
- Four Water injection wells
- Average plateau production per well 4000 bopd.
- A FPSO with capacity up to 30,000 bopd.
- First Oil after 18 months

Deep water heavy oil in-place reserves are estimated in the billions of barrels of oil. There have been numerous discoveries of such fields from West Africa to offshore Mexico (GOM). The problem with developing the heavy oil reserves is simply economics. On average three heavy oil wells are required to one conventional oil well to achieve 3000 to 4000 BOPD, and this assumes there is some type of injection. Also, most heavy oil wells need to have a horizontal leg to even achieve 1000 to 1500 BOPD which requires more drilling and complex completions. The heavy oil well must have an ESP to move the oil to the production facility. Even with the improvements of the ESP technology, there is a need to constantly change the ESPs every one to two years. This means the intervention using an expensive MODU or intervention vessel.

Using the SSR technology, the overall drilling and completion costs can be reduced because of the lower rig rates that can be achieved using the SSR, but the big key is the more cost-effective way to do intervention. Since the wellhead is near the surface, ESPs can be installed and removed by a vessel using coiled tubing. Note it is not the purpose of this paper to cover the heavy oil application of the SSR technology, but to expose its potential use. This will be done by a future paper.

Early deep water field development has been done by a few companies like Petrobras (Rosengren, 2006). The two fold advantage is the early evaluation of the reservoir and the generation of cash flow. However, the economics and timing to do such early production are a problem. The well has to be completed, some type of production facility has to be mobilized, and the problem with the produced gas has to considered, especially with the gas flaring becoming less of an option.

Using the SSR technology, like developing a marginal deep water field as previously discussed, early production from one or more wells to a smaller production facility (10,000 to 15,000 BOPD) could be done, especially if an injection well can be designed to re-inject the produced gas. This could be expanded to a staged field development, which could also expedite revenues to assist in reducing initial capital demands.

Extension of a field necessitates that step out wells sometimes are required. Sometimes an injection well is required at a part of the reservoir that is too far from the production facility where it would be cost prohibitive to drill and tie back to the production facility. This can also be the case for part of the reservoir where the oil cannot be drained and the economics are marginal to drill and tie back to the production facility. For this situation, where injection or production might be advantageous and is not economical the SSR technology offers the temporary solution to drill a well and install an SSR for injection or production to a small vessel that could process the fluids or provide injection.

Economic limit of deep water wells. In many fields the economic limit is reached and the well is shut-in. There is a possibility that a SSR system could be installed on the existing production tree with some type of artificial lift to prolong the economic life of the well. This is possible since the SSR is a temporary structure that could be installed for short periods of time like one to three years and then removed. This tail end production could be profitable for a smaller company using this approach to squeeze the last barrels of oil from the reservoir.

Coiled tubing intervention through a SSR for deep water provides a way to go into any subsea well and do all types of intervention from cleaning out sand, to pulling SSVs, drilling horizontal extensions, recompletions, installing ESPs, and even plugging the well. Recently RPSEA commissioned a major feasibility study for coiled tubing intervention (Yemington, 2010). Papers by Millheim (2010) present the findings of the study.

Early deep water reservoir appraisal is yet another application for the SSR technology where a SSR is installed on a subsea production tree and the well tested. RPSEA sponsored a major study to examine ways to early test in deep water and presented two SSR systems that could be feasible. Millheim (2010) presented papers on the outcome of this study (Millheim, 2011b).

Injection using the SSR is another application where the SSR is connected to an existing production tree and water is injected from a small vessel through the SSR. The advantage of this approach is again the portability of the SSR to install and remove when desired. This might be important as production wells water out where an injector could be installed to help with the pressure maintenance of the reservoir. Also, if EOR is contemplated the SSR with a small vessel could make this technology viable for some deep water reservoirs.

SSR Risk, Safety, and environmental considerations

The only known application of the SSR connected to a wellhead was for wireline intervention of shallow water wells in Indonesia (Kadl, et al, 1988). Since then there has been no known application of where a SSR is connected to a wellhead or a production tree. As mentioned before, using the SSR to support production lines and to be a conduit for production has been done before (Maclure, 2011). Yet there is reluctance for using a SSR on a wellhead or production tree since it has not been done except for the SSR field test in the GOM (Millheim, 2011b). The main reasons for concern center on the fear that the SSR will fatigue and fail. Other fears are that the buoyancy chamber will lose ballast causing the SSR to bend and sink, or that the SSR will catastrophically fail, launch, and damage the hull of any vessel above it. After the BP/Horizon event there are concerns about functioning flow barriers to prevent a subsea blowout causing a major environmental event. For drilling, there is the concern about a drive off of a dynamically positioned MODU. Since the SSR has not been used for drilling, production, or intervention some of the previously cited risks provide enough uncertainty to inhibit its first real application. However, if each of the concerns are analyzed it can be shown that for many situations the SSR can be as safe as or safer than conventional subsea systems.

The risk of fatigue failure of a steel member is a legitimate risk if the structural design is not rigorous to prevent such a failure. Over the past twenty years tension leg platforms and SPARS have relied on tensioned pipe with stress joints to resist the constant motion of the surface conditions and currents. This is accomplished by years of development of materials that are fatigue-resistant and analytical tools that can take all the forces and dynamics and predict the fatigue characteristics of a structural component. Since a SSR is really a mini-SPAR where the buoyancy chamber is completely below the surface the same conventional analysis can help design a structure to resist the surface effects, currents, continuous motion, etc. So the risk of fatigue failure of a SSR properly designed is the same of a tensioned leg platform or a SPAR.

The risk of buoyancy failure because of loss of ballast is also a legitimate concern. Most buoyancy chambers are open-bottom so that pressure equalization is easily achieved at any depth. This is very difficult with a closed bottom design where, in essence, the buoyancy chamber is more like a submarine hull which has to have the structural strength to go to a certain depth. The cost to build and the care to install makes the closed bottom buoyancy device non-economic and more risky. As with any design the open bottom buoyancy device must have features to prevent ballast failures. Most common leaks can occur from bad welds, corrosion, and structural damage from collision. Like any welded structure there are practices for construction and quality assurance that must be achieved. A typical buoyancy chamber has multiple compartments and usually has one or more redundant compartments in the event a leak occurs in one of the active compartments. Also, continuous monitoring of the SSR, including buoyancy is easily done by monitoring the chambers for pressure and the overall tension of the SSR. There are hoses to the buoyancy chamber to adjust the ballast. In the event there are indications of loss of buoyancy, gas can be injected into the standby chambers to compensate for the loss. Divers or a ROV can be deployed to examine for the leak and can help facilitate the repair. Corrosion failure is managed by the standard use of anodes which can be examined from time to time and replaced if necessary. Sea growth over time is easily removed by high pressure jetting using a ROV or by divers. Collision by some vessel other than a submarine is non-existent since the buoyancy chamber is set deep enough to be out of range of the deepest draft vessels. Only fishing lines and nets can tangle on the chamber. Therefore, the risk of failure of the buoyancy chamber is no more risky than buoyancy structures used in other marine operations.

The concern of the SSR catastrophically failing and launching to the surface was recently reinforced by the failure of a production free standing riser in the GOM. The design of the free standing riser commonly used for production line support or as a conduit is not the same design as presented in this paper. Instead of using stress joints at the critical areas of bending stress the free standing riser is anchored by a chain at the bottom and connected to the buoyancy device by chain at the top. The advantage of this type of design is: there is no need for stress joints. However, what has occurred is the failure of a link of chain. Another failure occurred years ago offshore Indonesia, during a drilling campaign using a semi-submersible to drill in deeper water. These wells were being drilled with surface BOPs and as the depths reached the limit of the rig tensioners a simple buoyancy device was added below the water to help support the riser. There were no stress joints installed at the critical bending stress areas and the riser pipe failed beneath the buoyancy device and launched, doing some structure damage to the rig structure. The failure was clearly a failure to consider the bending stresses around the buoyancy device. However, the legacy of this event as well as the production riser failure has caused concern about riser applications. The SSR system describe in this paper is not chain anchored and uses stress joints with an over design for fatigue and tension failure. Also, for the production SSR the tie back liner provides a second structural element to prevent catastrophic failure of the SSR where it will launch. Also, there are safety designs to minimize the launching of the SSR. Again, the risk of a properly designed SSR using stress joints is very low.

Flow barriers for the SSR are critical for the future acceptance of the SSR for drilling, production and intervention operations. The BP/horizon event cast doubts on the functionality of the BOPs to contain a potential subsea blowout. The consequence of the event has spearheaded a more rigorous approach to flow containment from training to equipment design.

For drilling, production, and intervention the standard SSR system would have two major barriers to flow: 1. A safety shut-in device (SSD) or also called a shut-in device (SID) which is a twin shear ram mounted on the wellhead or the subsea tree (for intervention), and 2. A near surface BOP system mounted on the top of the buoyancy device. This is very similar to the surface BOP system covered by Bybee in the April issue of the JPT (Bybee, 2011) except the BOPs for the SSR are supported by the SSR and the disconnect occurs with the riser above the BOPs. The scheme provides two flow barriers as compared to one for a conventional MODU or intervention operation. Also, for production there is always a tie back liner in the SSR which provides two barriers of riser containment. Because of having two barriers to flow with the containment devices and the riser and inner liner, the SSR should pose less risk than a conventional deep water system. Also, since the BOPs are near the surface maintenance and repair are simplified and easier to do.

A drive off of a MODU is a major concern when using a riser. In the case of using the SSR for early drilling and completion projects an anchored MODU or vessel eliminates the risk of a drive off. For the production SSR system the vessel can be anchored or if using a dynamically positioned vessel a quick disconnect of the jumper to the production vessel is standard. Therefore, the drive off from the SSR poses little risk.

Overall, the risk assessments of the SSR will always need to be made like with any facility and operation. However, all indications seem to show that the SSR can be run and operated safely and not posing any more risk to the environment than a conventional deep water system for drilling, completion, production, and intervention.

Observations and Conclusions

1. Rigorous analysis, wave tank tests, and a field test in the Gulf of Mexico indicate the SSR attached to a wellhead or subsea tree is a viable option to a conventional subsea system in many geographical locations, especially West Africa.

2. There are hundreds of discovered deep water fields worldwide that are deemed non-commercial either because of reservoir size, reservoir fluids, or other considerations. In many cases these fields will remain undeveloped because of economics or companies prepared to risk deep water operations.

3. The SSR technology to develop marginal or non-commercial oil can require less capital investment and can obtain early first oil/cash flow, helping to self finance the exploitation of many non-commercial deep water fields.

4. There are other possible applications of the SSR technology for deep water heavy oil, early production for larger deep water fields, tail end production, intervention, temporary water injection, and early well testing.

5. The perceived risks for using an SSR can be shown to be no more risky than conventional deep water operations, and in some cases less risky. Of course, there are situations where the SSR technology is not practicable, for example, drilling in high pressured areas where multiple casing strings are required (greater than five casing strings).

6. The SSR technology has been proven to a point to where a major field test to develop a marginal deep water field needs to be attempted to confirm not only the viability of the SSR design and operational performance, but also to confirm the economic advantage for using the SSR approach.

References

British Petroleum, “Deepwater Horizon Containment and Response: Harnessing Capabilities and Lessons Learned”, September 2010, pg. 24-26.

Bybee, K., “Drilling from an FPDSO: A Two Stack Approach”, Journal of Petroleum Engineering, April 2011, pg. 62.

Hatton, S, McGrail, J, and Walters, D, “Recent Developments in Free Standing Riser Technology”, 3rd Workshop on Subsea Pipelines, 2002.

Kadl, I., Conoco Indonesia; Wybro, P.G., Conoco Inc.; Rodriguez, F.H., Conoco Inc., ”Subsea Wirelining Innovation Operational at Kepiting”, Ocean Industry, June 1988, pp. 26 – 30.

Maclure, D. (2H Offshore Engineering Ltd.), & Walters, D. (2H Offshore Inc.) “Freestanding Risers in The Gulf Of Mexico – A Unique Solution For Challenging Field Development Configurations”, 2H Offshore, 2011.

Magnussen, T. “Atlantis Deepwater Riser Concept Updated”, Drilling Contractor, July/August 2001. Pg. 44-45.

Millheim, K. K. “The Next Major Challenge for Deep Water: Developing Marginal Fields, Offshore Technology Conference”, May 2008, Paper Number 19642-MS, DOI 10.4043/19642-MS.

Millheim, K.K., Williams, T.E., Yemington, C.R. “Coiled-Tubing Intervention and Drilling System Using Cost-Effective Vessels”, Society of Petroleum Engineers ICoTA Conference - March 23-24, 2010, SPE 130688.

Millheim, K. K., “FINAL Report - Early Reservoir Appraisal Utilizing a Well Testing System”, RPSEA and Nautilus International LLC Project No.: 08121-2501-02, Houston, 13 May 2011.

Millheim, K. “Self Standing Riser (SSR), An Environmentally-Friendly Intervention, Completion and Well Testing Enabler for Deepwater”, Sub-Saharan African Oil & Gas Conference, Houston, 2011.

Rosengren, M. and Svendsen, A., Frontier Drilling do Brasil, Vitoria, Brazil. “Heavy crude production successful in Brazil's deep water: Proper study and implementation brings Jubarte field's thick crude to market”. World Oil, March 2006, Vol. 227 No. 3.

Stanton, P., Technip. “Overview of Deepwater Production and Drilling Risers”, AADE presentation, Feb. 2006.

Yemington, C. “Coiled Tubing Intervention using a Cost Effective Vessel”, RPSEA and Nautilus International LLC Project 1502, Houston, 2010.