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The Next Generation Production Drilling Semisubmersible Based Deepwater Field Development System

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Abstract

The traditional Production Drilling Semisubmersible (PD Semi) platform has served as a reliable production hub for developing medium to large deepwater fields that can be substantially drained from a single drill center. Several recent breakthroughs in well construction and completion technologies have significantly improved well rates and ultimate recovery, as well as drilling and intervention efficiency. There have been concurrent advances in drilling and production riser, mooring and process system technology, as industry continuously strives to drive down capital costs of deepwater field developments.

Most of these initiatives are unrelated, with specific and localized objectives. Taken independently, they provide incremental economic benefits when viewed in a field development context. The PD Semi (and other floating platforms) have been slow to realize the significant benefits that could be derived by incorporating some of these technologies, because of the historically segmented approach to design.

A systems engineering approach applied to a PD Semi based field development system is used to enable the identification and integration of "high impact" well construction, completions, drilling, riser, mooring and process technologies to create a new generation PD Semi platform. The result is a step change reduction in capital costs for deep and ultradeepwater developments as opposed to an incremental change achieved by simple extrapolation of current practice.

Introduction

The inflation-adjusted price for oil and gas has remained flat over the long term. The offshore industry is challenged to maintain or continuously reduce finding and development costs per boe, even as the quest for new hydrocarbon sources progresses steadily into deeper and more remote waters.

Several major hydrocarbon reservoirs have been discovered in the Gulf of Mexico, Brazil and West Africa in 1500 to 2000m. Operators have invested large sums in lease acquisition and seismic evaluations of prospects down to 3000 m. in anticipation of discovering rich hydrocarbon deposits. Significant exploration and appraisal drilling programs are in progress in the 2000 to 3000 m. water depth range.

Led by rapid advances in seismic, well construction and completions technologies, finding and development costs have fallen steadily in the last ten years. However, capital costs of surface production facilities have not kept pace. With today's proven field development systems, the size of recoverable reserves needed to justify development in ultradeepwater remains unacceptably high.

Production drilling or production only semisubmersible platforms with subsea trees have been selected in preference to dry tree platforms for several large deepwater developments in the North Sea, Brazil and recently the Gulf of Mexico (GoM). In ultradeepwater a conventional PD Semi with subsea wells is a proven and commercially attractive alternative to a conventional production drilling spar platform with surface trees. It also provides greater flexibility to accommodate reservoir uncertainty and lower technical, cost and schedule risk (Ref. 1).

This paper demonstrates the value of utilizing a systems engineering approach to identify "high-impact" emerging technologies. These span a broad spectrum of disciplines and enable the creation of a next generation PD Semi platform field development system. This system will have the potential to significantly reduce capex in deep and ultradeepwater developments. Potential capex reductions for this new generation PD Semi system are calibrated against a conventional PD semisubmersible (extrapolation of current practice) in 3000 m. of water. All emerging technologies included are, or will be, commercially available within a three year horizon.

Systems Engineering Approach

Full field development economics require that a field development system be assessed in its totality over its life cycle, including capex, drillex, opex, cycle time (discovery to peak production), production availability and reservoir management. This paper focuses principally on capex of the production facility. A systematic process, similar to that described in Ref. 2, is used to assess all current and emerging technologies for each subsystem of the PD Semi field development system, from reservoir to export pipelines. From this process, several "high impact" enhancing or enabling technologies are identified for inclusion in the next generation PD Semi. A primary selection criteria is that the technology be "maturable" (in commercial application) within three years. Figure 1 is a schematic of the new generation PD Semi field development system, highlighting the selected high impact, enhancing technologies.

Field development is preceded by exploratory and appraisal drilling and occasionally completion of production wells. The high cost and technical challenges of drilling deepwater, deep zone wells has long been an industry concern. Consequently significant intellectual capital and development funding has been directed toward enabling and cost reducing technologies in these areas. This effort has resulted in many breakthroughs. Those that will both reduce drillex and have a direct beneficial impact on the platform capex are dual activity drilling, dual gradient drilling, slim-bore drilling, high pressure drilling risers with surface BOPs, expandable casing and free standing drilling risers. Each will provide benefits such as lower day rates, reduced drilling time, reduced drilling consumables and higher well rates. A further assessment of these technologies concluded that the expandable casing technology would provide the biggest capex "bang for the buck" because it enables use of a significantly smaller marine drilling riser and BOP. This in turn leads to significant drilling equipment cost and topside drilling payload reductions, resulting in a smaller platform. The benefits increase with water depth.

Downhole completion technologies have been leading the way to improved deepwater economics by improving reservoir management, per well flow rates, ultimate recovery and reduced well intervention. Short listed technologies include multi-lateral wells, downhole separation and "intelligent" or "smart" well completions. Of these, the SmartWell^{TM} completion was picked because of its maturity and its potential to significantly reduce platform topside process payload by controlling the amount of produced water and gas to be treated on the platform.

Water depth drives the cost of station-keeping and production/export riser systems. Conventional practice is to use wire-chain spread moorings with suction piles and steel catenary risers. The increasing weight of these systems adversely impacts platform size and installation costs. From the Deepstar led "System and Value Engineering" initiative to identify high value enabling and enhancing technologies for floating systems in ultradeepwater (Ref. 2) it was concluded that polyester moorings and offset free standing production risers had the greatest potential to reduce cost. These technologies reduce not only the cost of the system, but also of the production platform that supports them.

It will be demonstrated how the implementation and integration of selective high impact technologies to create a new generation PD Semi will result in a significant reduction in topside payload, platform size and capex, without sacrificing functionality.

Next Generation PD Semi Major Subsystems

Breakthrough technologies that are integrated into the next generation PD Semi field development system shown in Figure 1. are described. The discussion is limited to a high level overview describing the function, benefit and development status.

Smart Well Completions. Advances in well completion technology utilizing various combinations of downhole tools and sensors, enable operators to control and monitor flow from multiple producing intervals in the well in real time. These are commonly referred to as Smart or Intelligent wells. A typical smart completion is show in Figure 2. Well monitoring functions include sensors to measure temperature, pressure and flow rates. Control functions include remote operated sliding sleeves to control flow quickly in response to changing downhole conditions. The combination of real time information on well performance and the ability to control flow from reservoir to well bore has resulted in dramatic improvements in well flow rates and total recovery, key elements in improving deepwater field development economics (Ref 3,4).

Additional benefits of SmartWell^{TM} technology can be realized by the PD Semi. Up to 25% reduction in weight and cost of topside process train is achievable by reducing the percentage of produced water cut and gas breakthrough into the well bore. Drillex is reduced by producing the reservoir more efficiently from fewer production wells. Opex is reduced by significantly reducing the need for downhole intervention, normally required with conventional wells to measure downhole conditions or to shut off depleted zones. SmartWell^{TM} completions have been installed and are functioning in several deepwater GoM and North Sea wells, and are a commercially available technology.

Expandable Casing with Slim Bore BOP/Drilling Riser. Simply stated, expandable casing technology enables the radial expansion of a string of casing with special downhole tools by permanent deformation of the pipe through a cold working process. Originally devised as a means of in-situ repair of damaged or corroded casing and pipelines, the technology is being increasingly utilized as a means of achieving step change reductions in drilling cost by reducing the size, number of casing strings and time required to reach targeted depths relative to a conventional well construction program.

Figure 3 illustrates the progression of well construction designs enabled by expandable casing technology. For deepwater well construction a conventional design would typically require five or more varying diameter casing strings with an 18 ¾-inch subsea BOP and a 21-inch low pressure marine riser. Nested expandable solutions currently available enable use of a slimmer bore 13 5/8-inch subsea BOP/16-inch marine riser. Evolution to a true monobore design, currently in final engineering, will enable use of a single 9 5/8-inch casing size, resulting in a continuous inner diameter from target depth to mudline wellhead. This in turn will enable a 10-inch BOP/12-inch marine riser system. The direct consequence of expandable casing technology is a dramatic improvement in drilling efficiency, together with a reduction in cost of drilling consumables (mainly casing, cement and mud) relative to conventional wells.

The consequential cost benefit to the PD Semi that will drill local development wells is equally dramatic. A major driver of size and capex of a deepwater PD Semi is the weight and footprint of drilling riser and BOP stowed on the platform. A reduction in size from an 18 ¾-inch BOP/21-inch riser to a 10-inch BOP/12-inch riser in 10,000 ft. of water will result in a 40% reduction in weight and cost of the riser/BOP equipment alone. Every tonne of topside weight reduction yields about 10,000 USD savings in platform cost. Additional platform capex savings resulting from monobore well construction are:

- Reduction in casing rack storage area and weight and associated handling equipment.
- Reduction in bulk and liquid mud and cement storage volumes.
- Reductions in riser tensioning, derrick hook load, mud return system, mud pumping requirements and associated power generation.
- The lighter riser/BOP system is considerably easier, faster and safer to deploy and retrieve than the conventional riser/BOP, which could take several days in 3000 m. of water.

Further improvements in drilling efficiency are achievable via the deployment of a high-pressure marine riser and surface BOP. This operation has been successfully used to reduce drilling costs in South East Asia from Semi MODUs and it will debut shortly in the GoM.

The use of slim-bore drilling has been quite extensive. Petrobras has successfully drilled over 41 slender wells in the Campos Basin alone and achieved an average improvement of 17% drilling efficiency over conventional wells. Expandable solutions have been proven in several successful installations and field tests (Ref 5, 6). As of January 2002, approximately 50 expandable casing systems have been installed for 15 different operators, some in ultradeepwater wells.

Production Riser System. For deep and ultradeepwater fields developed by a PD Semi, subsea trees are located beneath the platform to enable access for drilling and workover. Several trees are manifolded on the seabed and the comingled flow is routed to the platform via production risers. Many existing and emerging riser configurations and materials are available (Ref. 6). Selecting a reliable and cost-effective riser system with high operability is critical to the field development system. Flexible risers, the popular choice for most production semis in service today, have technical limits related to water depth, diameter and pressure. A limited number of “first generation” (circa 1985) tower risers have been used in conjunction with deepwater PD Semis. Current trends on Spars and TLPs favor the use of Steel Catenary Riser (SCRs) for export service because of their apparent simplicity and low installed cost. However, for semisubmersibles, SCRs are more complex due to the higher vessel motions and the need for insulation for production service. Additionally, the number of flowlines often required can result in a complex field layout. This complexity increases with water depth and can impact the cost-effectiveness of such systems. A simpler, more attractive production riser alternative to the SCR is proposed, as shown in Figure 4 (Ref. 8).

The Single Line Offset Riser (SLOR^{TM}) is a free standing riser in either a single or pipe-in-pipe configuration using steel pipe. It is offset a short distance from the manifold and connected to the vessel using a short section of flexible pipe. Whilst it is accepted that the design is new, it is based on proven wellhead and drilling technology and, in many respects, is similar to a Spar top-tensioned riser, but without the complex vessel interface.

SLOR^{TM} designs are available for deepwater applications down to 3000 m. in environments ranging from mild (West Africa), to moderate with extreme events (GoM) to harsh (North Sea). The riser is assembled using non-welded threaded connections allowing use of high strength steel pipe. It is supported by a combination of air-cans and syntactic buoyancy material. At the base the riser is connected to a jetted conductor pile. The entire assembly can be installed rapidly from any deepwater-drilling vessel using standard rig equipment and procedures. The designs are modular and all hardware components are field proven in similar applications.

Table 1 compares the relative features of the SLOR^{TM}

versus the Steel Catenary Riser. The SLOR^{TM} is effectively decoupled from the floating platform unlike the SCR, and imposes significantly lower horizontal and vertical loads on the platform. In ultradeepwater, the result is a substantial reduction in size of the mooring system. The SLOR^{TM} affords greater installation flexibility, a major driver of installed cost of deepwater risers. Its small footprint results in reduced seabed congestion, increased safety from dropped objects and flexibility for future tiebacks. In short, the offset riser configuration has the potential to reduce costs and increase design and installation flexibility of the PD Semi based field development system.

A second generation of freestanding offset risers is currently in-service in the recently commissioned Girassol field in 1,200 m. water depth. This has provided experience with the offset riser configuration. Furthermore, the SLOR^{TM} configuration has been selected for the Kizomba field development also in 1,200 m. water depth. Consequently, the design and installation procedures and component hardware of the offset riser are field proven and the system is considered mature.

Mooring System. Multi-leg wire-chain spread moorings with drag or suction pile anchors have long been the workhorse for permanently moored production platforms. Industry has developed a high level of confidence in manufacture, installation and long term behavior of these systems. They have been employed on production platforms in the GoM in 1500 m. of water with planned installations in 2000 m. Installed cost of a deepwater PD Semi wire-chain spread moored system is of the order of 10% of total capex and will command a larger percentage of the capex pie in ultradeepwater. Because of the relatively high unit wet weight of wire rope, a progressively larger percentage of rope break strength is used to pretension the platform to maintain the watch-circle radius required for the production and drilling riser systems. Although wire-chain systems are technically viable for mooring large PD Semis in the ultradeep, the efficiency degrades and costs escalate in increasing water depths.

In the early 1990's, industry recognized that significant cost-reductions and performance improvements in the mooring systems were attainable by substituting lightweight synthetic fiber rope for wire rope. Of the many types of synthetic fibers investigated, parallel lay polyester fiber ropes emerged as the front runner because of its lightweight, low modulus, fatigue endurance and relatively low cost/tonne of break strength. Petrobras pioneered the use of polyester rope in floating platforms and to date have over 20 installed or planned polyester moorings since 1997. There have been scattered applications of synthetic moorings in the benign waters in SE Asia. While the significant cost and technical advantages of polyester are recognized for mooring FPSs in the North Sea and GoM, acceptance has been more cautious and there have been no applications to date.

The major concern expressed by a majority of GoM operators is lack of "long term" experience, particularly with regard to potential degradation due to low cycle fatigue, marine growth, undetected damage during installation and the lack of a suitable inspection and discard criteria (Ref. 9, 10). The first significant steps toward acceptance and commercialization of polyester rope for FPS moorings, following years of analytic studies, labratory and field tests were taken in 2001, when BP and Shell used preset polyester moorings to position semisubmersible drill rigs in the ultradeepwater GoM to drill exploratory wells. Industry (API, Class Societies) has developed definitive design guidelines for synthetic moorings, although there is some variability in recommended safety factors.

The main benefit of polyester rope moorings is the potential for significant reduction in installed cost for a deepwater PD Semi in the GoM versus a wire rope mooring. This is tempered by the fact that a contingency may be required to account for possible replacement because of uncertainty in design life. Other direct and potentially significant knock-on cost benefits of polyester rope are reduced watch circle, which impacts production risers and drilling operability, and reduced vertical loads which could reduce hull size. There appears to be general consensus that the application of polyester rope for mooring FPSs in the GoM is less than three years away.

Incremental cost savings can be achieved by substituting vertical loaded anchors for suction piles, which require considerably less steel for equivalent holding power. New installation techniques pioneered in the GoM such as the SEPLA system will potentially enable lower installation costs than suction piles.

Topside Process System. The operating weight (equipment, bulk, support steel, liquids) of a conventional topside facility to process 150 kbopd with a 2000 GOR is substantial and requires a large deck area. A 10-20% reduction in operating weight and footprint will have significant impact on size and capex of the floating platform. An analysis of the apportioning of the weight reveals that about 50% of the weight is contained in about 15% of the process and utility systems. There is limited opportunity to reduce weight and size in the remaining 85% of the equipment.

The systems with greatest opportunity for weight reduction are separators, water treatment, water injection, gas compression, power generation and living quarters. Smart well completions enable the continuous monitoring and control of produced water and gas breakthrough. This in turn enables potentially large reduction in size of separators, water treatment, water injections and gas compression systems versus conventional completions and smaller reductions in power generation system and living quarters resulting from reduced manning realized by SmartWell^{TM} technology.

Additionally and separately, process equipment suppliers have introduced new process technologies (Ref. 11,12 & 13) aimed at compacting large weight and space consuming equipment. An example of this is the use of cyclonic technology for gas/liquid separation that minimizes liquid residence time and sensitivity to upset conditions. Depending on flow rate, fluid properties, GORs etc, the savings in operating weight and equipment footprint could be substantial. Further opportunities present themselves for adapting compact process technology being developed for subsea processing

3,000 m. GoM Field Development Case Study

A case study for a PD semi based field development in 3,000 m. is used as a basis to quantify capex savings achievable by integrating the high impact technologies described into a next generation PD Semi versus a conventional PD Semi. Table 2 presents the basis of design for an ultradeepwater GoM field, with the PD Semi designed for 150 kbopd peak production from 16 local wells.

A PD Semi is sized with conventional well construction and completions (18-3/4-in BOP with 21-in marine riser), SCR production and export risers and wire-chain moorings with suction piles. A next generation PD Semi is then sized with Smartwell^{TM} completions, monobore well construction utilizing expanable casing, SLOR producion risers and polyester moorings with vertically loaded anchors. In each case, a state-of-the-art GVA four column, ring-pontoon hull with integrated box deck is the chosen hull configuration. Figure 5 shows a block diagram of the main deck arrangement for the two designs. The technologies incorporated into the next generation PD Semi allow the deck size to be reduced by approximately one-third compared to a conventional PD Semi.

Table 3 compares major components of variable drilling deck loads and shows 50% savings in weight with the monobore system. Besides significant reduction in BOP/Riser weight, additional reductions in casing, liquid mud, bulk mud and cement are realized as a result of the monobore well and slim bore drilling riser.

Table 4 compares major weight categories of the two PD Semis. There is a 3,000 tonne (20%) reduction in process facility operating load from Smartwell^{TM} completions. A similiar reduction in drilling payload is achieved by incorporating monobore drilling and well construction technology. The combined mooring and riser vertical loads on the platform are reduced by 6,000 tonnes (50%) by substituting SLOR production risers and polyester moorings. The hull designed for these reduced loads has about 6,000 tonnes (20%) less hull steel and outfit weight.

Table 5 summarizes the capex saving of the next generation PD Semi for this case study. The $137 million USD savings indicated represents about a 20% capex reduction relative to a conventional PD Semi. A three month schedule savings to first oil is also achievable because of the reduced size and complexity of hull and topsides and the decoupling of production riser and hull designs.

Summary and Conclusions

Producing ultradeepwater fields is the next challenge for the industry. Exploration has begun and development will follow in 2-3 years. The PD Semi is a proven and robust development hub for exploiting deepwater fields worldwide. Extrapolating conventional technology to ultradeepwater developments while technically feasible might, in many cases, be cost prohibitive.

A systems engineering approach that includes total field development, from reservoir to pipelines, is used to identify high impact technologies, and selectively apply these technologies to create the next generation PD Semi for deep and ultradeepwater fields. These include SmartWell^{TM} completions, monobore wells, slimbore-drilling risers, SLOR production risers and polyester moorings. The net effect is a significant reduction in topside drilling and process operating payloads and hull size relative to a conventional PD Semi, with the same capabilities.

A case study for a 3,000m GoM field development reveals that a 20% capex reduction is achievable along with a three-month schedule compression to first oil. All technologies utilized are in commercial application, with industry-wide acceptance expected within three years. Therefore, the high contigencies normally used for non-conventional solutions will not be required.

From a field economics perspective, an additional 20-30% reduction in drillex and opex is attainable with monobore drilling and SmartWell^{TM} completions. The next generation PD Semi will both enable and provide a step change in the economics of producing hydrocarbon reservoirs in ultradeepwater basins around the world.

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Table 1 – Comparison of SCR and SLOR Production Risers

Item	SCR	Single Line Offset Riser (SLOR)	Advantage / Comment
Installation	• Special Pipelay Vessel • Co-install with platform • Platform deck area required for pull in winches	• MODU or Platform • Preinstall or Co-install	• SLOR/ Lower installation cost and increased flexibility.
Water Depth Sensitivity	• Increasing length and wall thickness.	• Same but less impact because of shorter overall length.	• SLOR/ Increase SCR hang off weight may limit installation vessels.
Seabed Congestion	• SCR seabed flowline laid in large loops requiring large corridors.	• Narrow corridors.	• SLOR/ SCR seabed congestion limits corridor for future tie-backs & increases risk of dropped object damage.
Coupling/Impact on Platform and Mooring	• Potentially large unbalanced horizontal and vertical loads on platform. • Strong dynamic coupling to platform motions.	• Relatively light platform loads. • Light dynamic coupling.	• SLOR/ Design and installation effectively de-coupled from platform and mooring. SCR loads will strongly impact platform & mooring design and vice versa.
Design	• Strong linkages to platform motions. • Uncertainty in predicted response in touch down zone.	• Weak link to platform motions. • Response prediction more robust.	• SLOR/ Less uncertainty in design & life cycle performance prediction.
Flow Assurance	• Longer length from manifold to platform. • Accessible for coiled tubing intervention & pigging. • Gas Lift from riser base possible but difficult.	• Shorter flow path from well to platform. • Access possible but more difficult. • Gas Lift from riser base simpler with concentric riser configuration.	• SCR/SLOR has lower heat loss but access for wax/hydrate blockage re-mediation, more difficult.

Table 2 – Design Basis for Next Gen. vs. Conventional PD Semi Case Study

Water Depth	3000 m
Location	Gulf of Mexico
Type of Field	Oil (w/ associated gas)
Peak Production Rate	150 KBOPD
Design Life	25 years
Local Producing Wells	16
Reservoir Fluids	Normal pressure and temperature

Table 3 – Key Components of Variable Drilling Loads: Next Gen. vs. Conventional PD Semi

	Conventional Drilling Program (18-3/4" BOP)	Monobore Drilling Program (10" BOP)
Marine Riser Weight (dry)	2,750	1,650
Subsea BOP/LMRP Weight (dry)	260	150
Onboard Casing Storage Capacity	750	200
Liquid Mud to Displace Riser	860	310
Bulk Storage Capacity	1,200	450

Note: Weight in Tonnes

Table 4 – Comparison of Major Weight Categories: Next Gen. vs. Conventional PD Semi

	Conventional	Next Gen.	Comments
Facilities Payload (Operating)	12,400	9,600	Reduced facility size due to Smart well completions and compact process technologies
Drilling Payload (Operating)	11,700	8,700	Reduction due to Monobore drilling technology
Hull Weight (including accomodations/utilities)	33,750	27,750	Reduced hull size resulting from payload decrease
Mooring/ Riser Vertical Tension	12,500	6,500	Reduced loads from SLOR risers and Polyester Moorings, reduced hull size

Note: Weight in Tonnes

Table 5 – Capex Savings: Next Gen. vs. Conventional PD Semi (MM$)

Topside Facility	33
Drlling Facility	24
Hull	32
Topside Integration / HUC	4
Mooring (Installed Cost)	19
Riser/Subsea (Installed Cost)	25
TOTAL COST REDUCTION	**137**

Note: Cost reductions include engineering, procurement, fabrication and installation

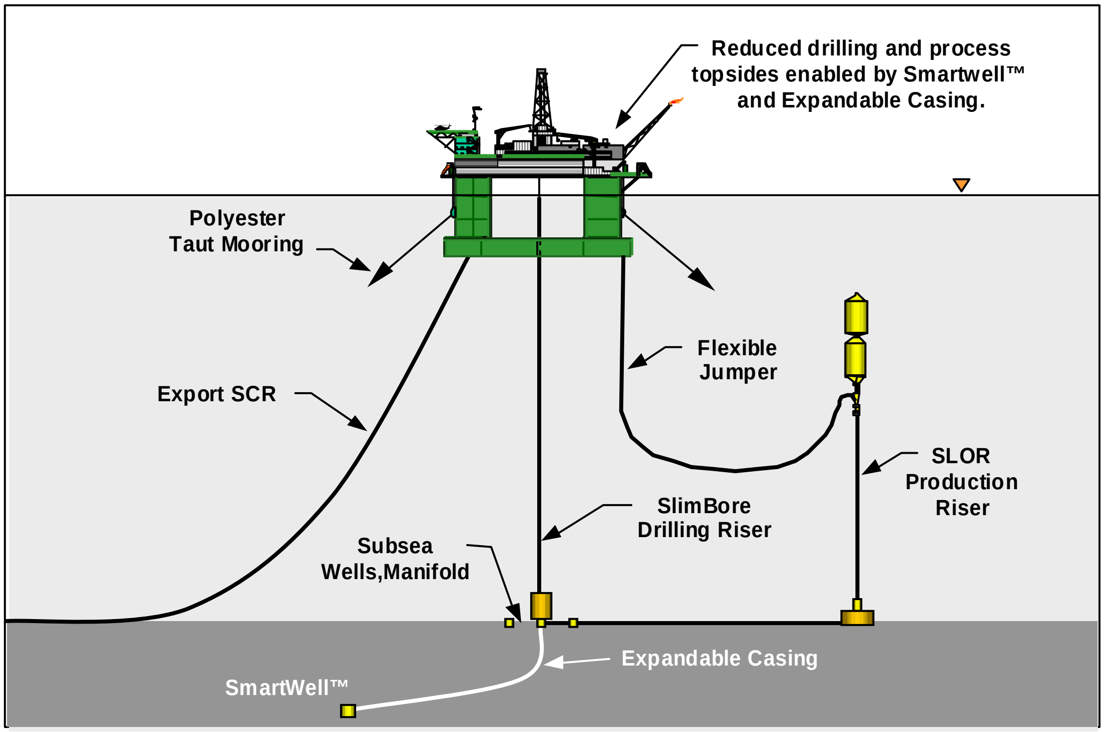
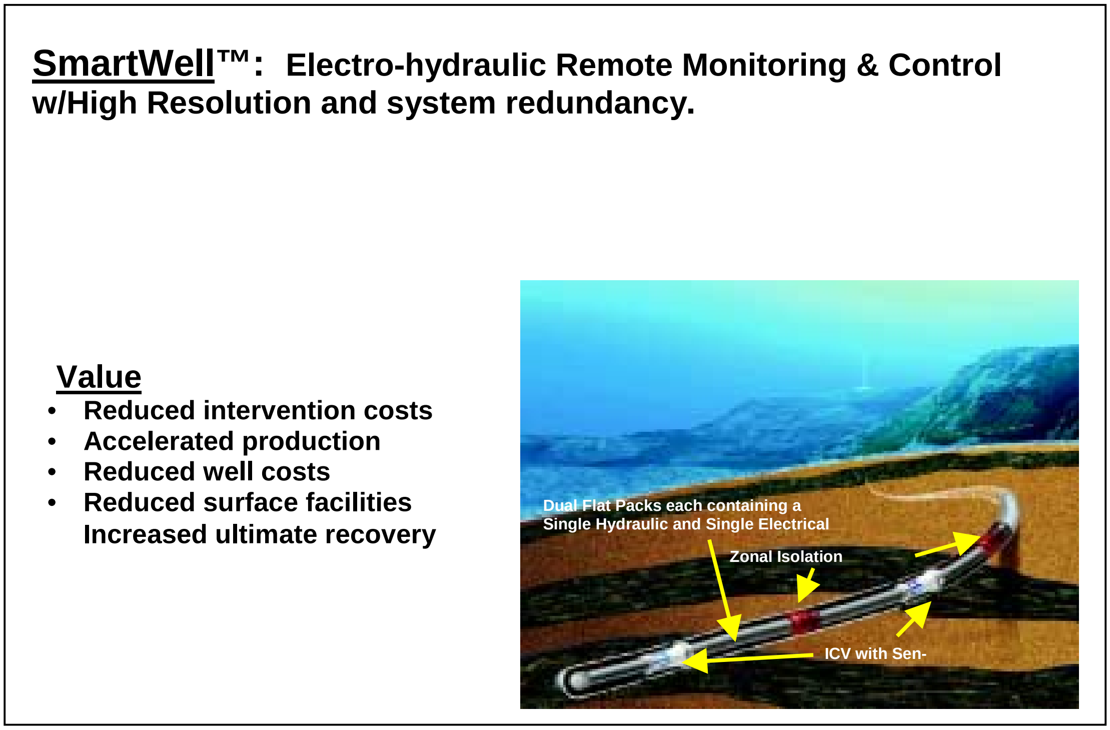


Figure 1 – New Generation Production Drilling Semisubmersible Field Development System

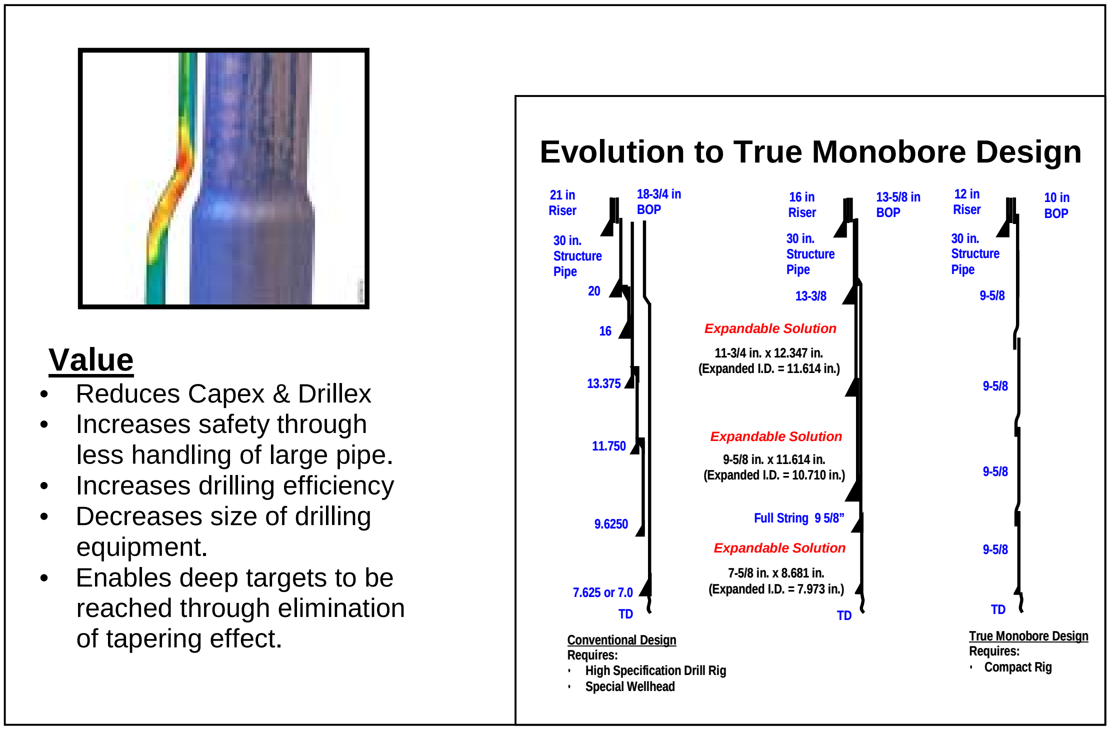


SmartWell™: Electro-hydraulic Remote Monitoring & Control w/High Resolution and system redundancy.

Value
- Reduced intervention costs
- Accelerated production
- Reduced well costs
- Reduced surface facilities

  Increased ultimate recovery

Figure 2 – Typical Intelligent Well Completion



Value

- Reduces Capex & Drillex
- Increases safety through less handling of large pipe.
- Increases drilling efficiency
- Decreases size of drilling equipment.
- Enables deep targets to be reached through elimination of tapering effect.

Evolution to True Monobore Design

Conventional Design
Requires:
- High Specification Drill Rig
- Special Wellhead

True Monobore Design
Requires:
- Compact Rig

Figure 3 - Expandable Tubular vs. Conventional Well

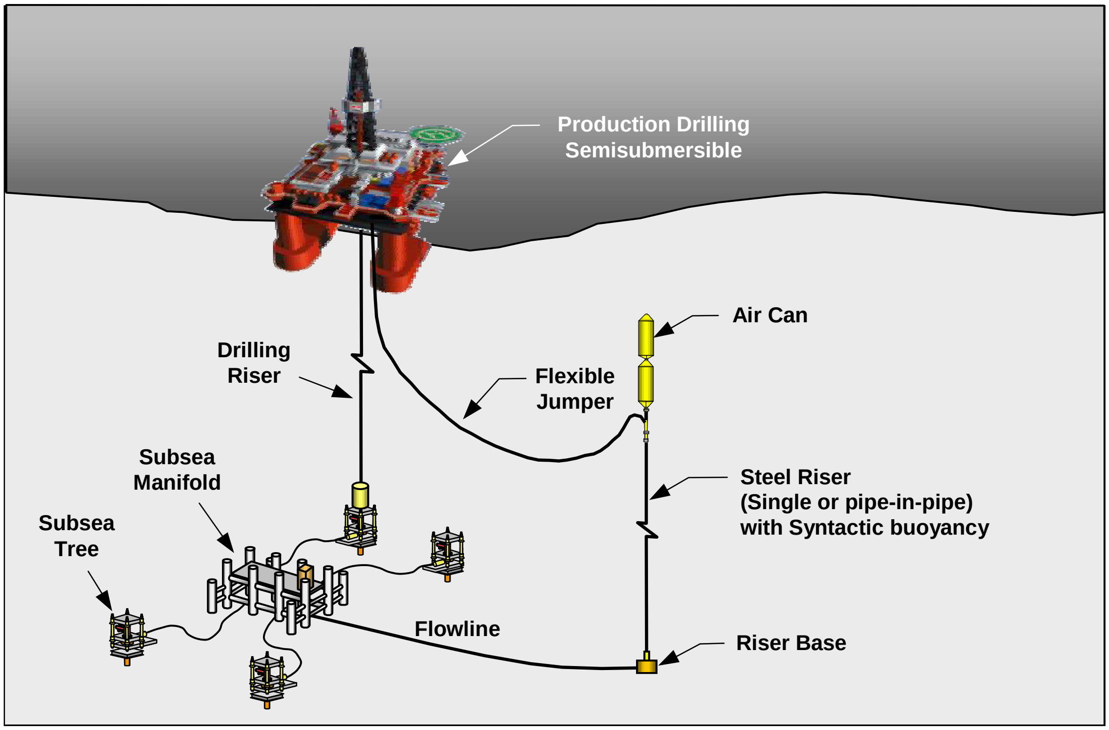
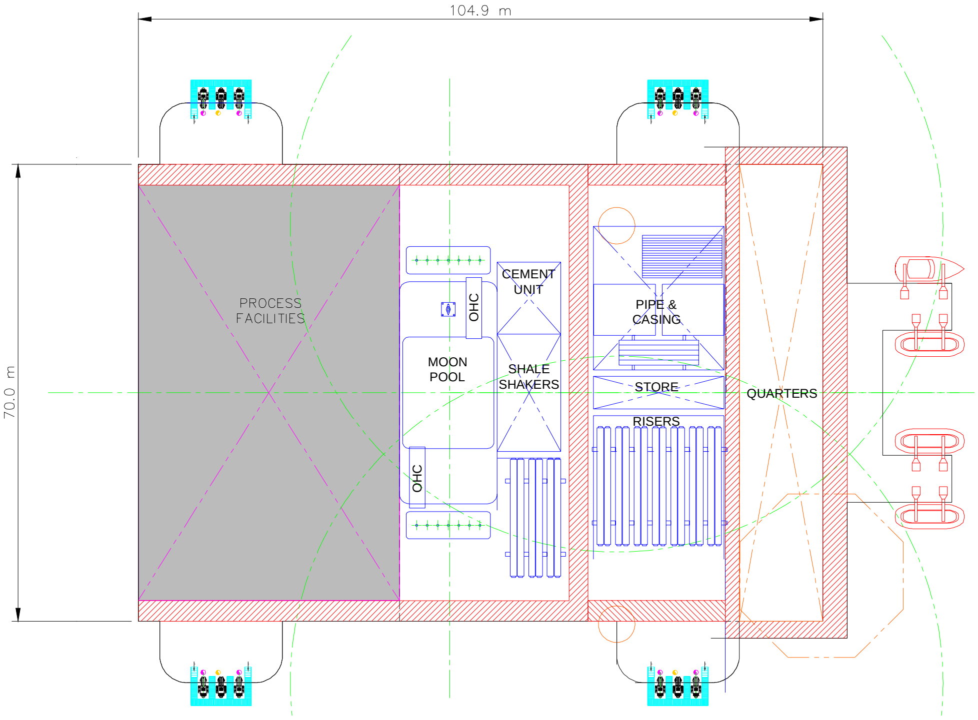
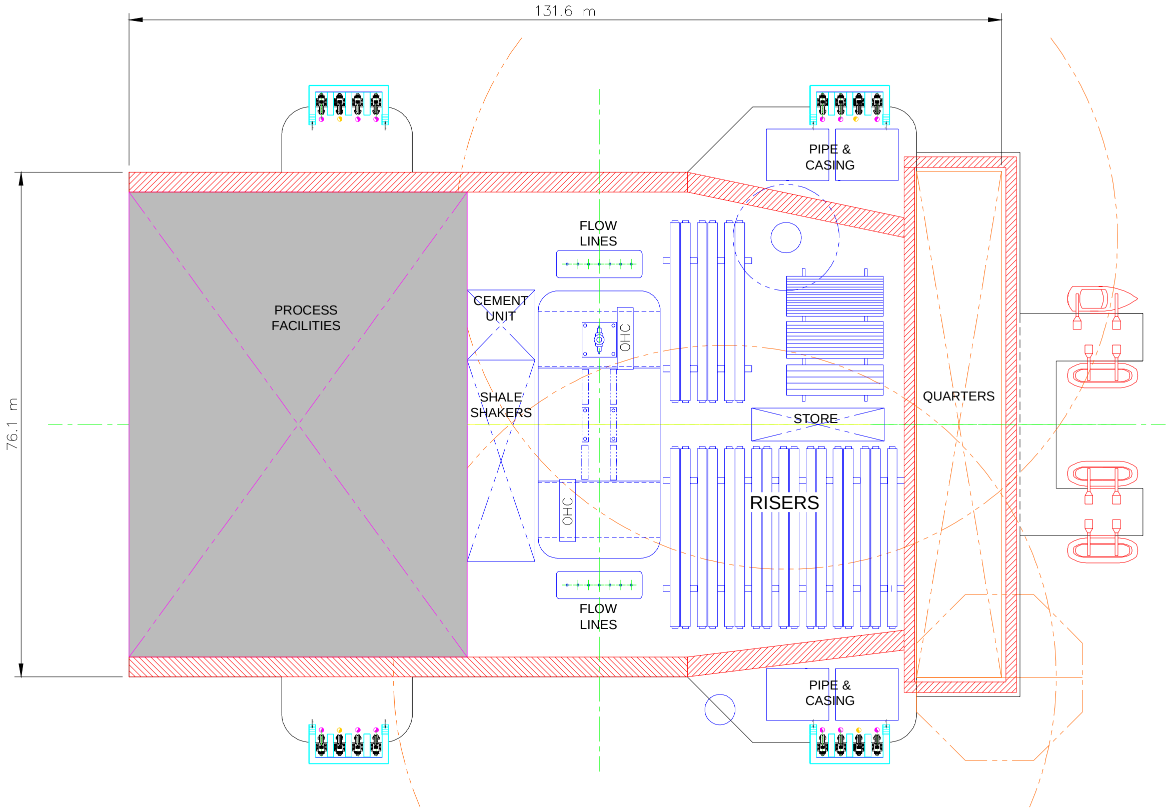


Figure 4 - Single Line Offset Free Standing Production



A) New Generation Semi



B) Conventional Semi

Figure 5 – Main Deck Block Diagram: Next Generation vs. Conventional PD Semi