# Deepwater future

### Introduction

The offshore drilling contractors who will emerge as leaders will be those who have the flexibility to still invest in technological development. Others will only play catch up, trying to learn how to perform turnkey and total management drilling and less able to adopt technology as slow learning curves erode profits.

However, more advanced technologies are needed for ever-increasing water depths with higher flow rate wells, and the market will insist that such developments continue. Research and development spending will not continue at today's pace, less may be invested, but more may be demanded of it.

### People power.

One will have to move credibly into the role of a major operator's out sourced drilling department. Training and developing such credibility is a factor someone must pay for. Such decision-making will affect all aspects of a driller's business and each will have to shoulder the rapid change and responsibility if the contractor wishes to emerge at the top for the next century and beyond.

### $xx/bbl?

$14/bbl presents the average oil price over the last 100years.
This may change but may not be significant in the next 50years as we move into deepwater environments. Before the industry can truly unlock the deepwater potential, both technological, environmental, and regulatory challenges must be overcome to ensure profitability. The future of deepwater development can only be realised through sound environmental, technological, and safety innovations.

**The environmental question**

Of the three categories previously mentioned, environmental concerns in deepwater is the single biggest challenge the industry faces. It is not a question of operators being friendly to the environment - it is a political and public relations issue.

*e.g. If government or activist groups do not feel an operator is protecting the environment, then it is quite possible the entire industry could be shut out of a region.*

Operators must therefore minimise the impact on the environment, make sure efforts answer the questions and concerns of regulators and the public. Such concern must come before technology and safety because it has the potential to close down, not just a single project, but an entire region.

## World-wide experience

The overall trend for exploration and production moving into deeper waters is resulting in an increased use of drilling, completion and sub sea technology, often in conjunction with floating production systems.

### USA, Gulf of Mexico (GoM)

Deep water development is currently undertaken in the Gulf of Mexico in water depths up to 3,000m. Success being attributed to organisational and technological lessons learned, transferred and adapted for use in the GOM. Improving accuracy of 3D seismic technology has had an impact. The "Deep Star" consortium of companies have proved to be a working demonstration of a new trend in co-operative working. This group has developed solutions to overcome technical and commercial barriers in deeper waters.

### Brazil

Petrobras' expertise lies particularly in deep water with approximately 25% of reserves in water depths of between 1500ft and 3000ft of water. Drilling & completion development concepts are based on the use of few, high productivity, sub sea horizontal wells, connected through sub sea manifolds and sub sea booster systems to a floating production unit with shuttle tanker. Produced gas is either compressed for re-injection or pumped ashore. Due to the large number of long step-out wells, Petrobras has jointly developed an electrical submersible pump for installation in sub sea wells. As facilities increase, Petrobras is seeking to standardise components. A task undertaken jointly with industry *e.g. trees from different manufacturers can be interchanged.*

Floating production systems are mostly based on older semi-submersibles or oil tankers converted to process ships. Other FPS conversions have been ordered, some using advanced turret systems for anchoring while others will use taut leg and other mooring methods. Tending to favour floating production units, because of their performance track record to date and allowance for phased developments, that reduce risks and capital (loss) exposure.

Petrobras has a R&D programme driven by the requirement for deepwater development. They have 11 systematic projects to extend their capabilities and knowledge. The basic goals for the project include:

- Reduce operating costs by some 30-40%
- Increase the productivity of the fields located between 400 and 1000m water depth (containing 37% of Brazils reserves)

**North West Europe.**

*The North Sea boasts 40% of the sub sea trees installed world wide, according to Sub sea-Data-Bases. The most ambitious sub sea projects have been offshore Norway, e.g. Norsk Hydro's development of the giant Troll field with more than 100 planned sub sea wells tied back to a floating production system . Included are 54 sub sea wells in the Troll West Phase III gas project. Production from these wells will flow to six sub sea manifolds and then to the FPSO in Block. The Troll West Phase II oil project will utilise 22 sub sea wells tied into five sub sea manifolds and then to the FPSO. Norsk Hydro is also developing the Visund field with as many as 23 sub sea completions in about 1,000 ft of water*. Kvaerner is supplying the trees for this field as well as for the Troll field development. Statoil, is very active with the Åsgard field development. Where 60 sub sea wells will be completed in about 1,000 ft of water. The wells would be tied from several surrounding blocks to the Åsgard FPSO and FPS semi-submersible.

When reviewing the Norwegians state of the art systems, one must not self-indulge into all singing and dancing new technology *I.e. It does not make business sense to re-invent the wheel when uncertainty, costs, oil price, skills and resources available all can effect risks potential loss & profitability.*

Also no one can doubt Statoil's Asgard project as a state of the Art sub sea project. The board of directors however did lose their jobs due to cost overruns. Cost that made previous financial disappointments look like minor accounting errors. *In that total project costs of NKr 47.2 (£4) billion escalated to Nkr 64.1 (£5.3) billion. The FPSO hull was a major culprit (£100million) over budget, drilling costs 45% (£250 million) over budget and sub sea equipment 44% (£125 million) over budget.*

It is thus surely more viable thus use "off the shelf, tried and tested, fit for purpose" technology for a deepwater field development. This does not exclude technical innovation or improvement, as there is room for many.

*Improved systems and technical application must essentially comply to reduce risk and potentially any loss.*

## Deepwater Riserless Drilling

Deepwater drilling provides well containment currently use a BOP and marine riser placed above the seabed. The capacity of this marine riser is about 400 bbl for every 1,000 ft of length. Such mud volumes within the riser constitutes the majority of the total mud system and is of no benefit in the drilling process. This weighted mud column also introduces unnecessary hydrostatic pressures, that impacts casing design. Often multiple casing strings then require “big bore” sub sea wellhead design and higher load capacity marine riser and rig equipment to support the riser and mud column. All resulting in more drilling constraints and added risk, time, specification and costs to projects as water depth increases.

A new drilling approach is therefore needed, where the obvious is to eliminate the constraint provided by the mud and marine riser column above the seabed, thereby reducing the hydrostatic pressure at the seafloor to that of a column of seawater. The drilling rig is now essentially located on the seafloor, with riser removed the riser and replaced by a contained mud return conduit at the wellhead.

### Depth constraints

The industry is now fast approaching drilling in water depths of 10,000 ft on the slope and more than one operator is planning on drilling the distal plain beyond the Sigsbee Escarpment in the US Gulf of Mexico at the turn of the century. *I.e where water depth averages 12,000 ft.* However, current equipment cannot take the industry into such depths without changes. Three problems existing with today’s technology:

1. The 21-in. riser cannot be pushed much further.

2. Even if the rig could support the riser length, the riser cannot withstand the stresses.

3. Well control is marginal at best at maximum water depths now.

Riserless drilling thus presents a viable option provided technological capabilities can be proven.

**Riserless experience**

Texas A&M operates a drillship in a riserless configuration to obtain deep ocean floor borings and has worked in 17,400 ft water depths and drilled/cased up to 8,200 ft below the mud line. As many as three strings of casing have been run and cemented using a guide line-less re-entry system.

Station keeping is limited by contact of the drillpipe with the side of the moonpool and is estimated to be 20% of water depth. Ocean depths of 3,000 ft or less are considered shallow water. Due to the reduction in weight and space, the drill ship operates for several months at a time without re-supply and is self sufficient.

Riserless drilling offers the capability to drill for hydrocarbons in water depths previously thought impossible. The development of a sub sea BOP system capable of accommodating a riserless system would be one of the enabling technologies for drilling in very deep water. Riserless drilling can be justified for water depths in excess of 7,000 ft and that 5$^{th}$ or 6$^{th}$ generation drilling rigs will adopt the method.

Benefits

There are many benefits to drilling without a riser:

- Station keeping: reducing waiting-on-weather time or a less expensive mooring system could be deployed. In the case of a dynamically positioned rig, this would reduce the incidents of drive off and provide for fewer/smaller thrusters.
- Wider well pattern: In development scenarios, a wide pattern of sub sea wells could be drilled with a more flexible mooring system.
- Smaller production structure: The reduction in weight and space would greatly reduce the cost of the floating production structure. Riserless drilling would provide for drilling and workover capability without a large weight and space penalty.
- Rig upgrade: If the weight requirement for drilling in deepwater can be substantially reduced, then smaller semi-submersible drilling rigs can be used. In effect, a third generation rig could be configured to drill in 6,000-ft water depths.
- Time and cost: Elimination of casing points to the average $1 million per casing point.
- Alternative fluids: Use of a closed system to support riserless drilling will allow other drilling methods not normally considered in floating operations to be used. They include foam drilling fluids, air drilling, under-balanced drilling, and reverse circulation drilling.
- Circulate out kicks: Another benefit to the use of a return line is the additional system to circulate out gas kicks, which expand

rapidly above the blow out preventer (BOP) on the seabed. An 11-in. mud return line with a surface choke could handle up to 5,000 psi, while the conventional choke and kill lines would be available to handle higher pressures at the seabed.

With a mud return line and surface choke in place, the well can be secured and the expanding gas handled separately from the well systems located on the seafloor. Kicks could be detected by an increase in pressure at the seafloor, minimizing the influx.

**Joint industry projects**

Conoco and The Hydril Company have undertaken to determine if concepts can be progressed to reduce weight and space requirements for semi-submersibles and drillships. A secondary pursuit will be to reduce the casing points required to drill deepwater wells.

The casing point issue is related to rapid deposition and young sediments (Gulf of Mexico, Brazil, Nigeria) where the industry experiences high pore pressures and low fracture gradients. In other areas (North Sea, West of Shetlands) we experience low pore pressures and high fracture gradients. Therefore, casing points are not the issue, but weight and space for the rig are.

The initial phase will involve evaluating which methods have the best chance of succeeding. The goal is to have a commercial system developed in 3-5 years. The cost of the initial phase is estimated at $250,000-500,000. Bringing a concept to commercial development could conceivably cost $20-30 million. Conoco and Hydril have elected, contingent on additional industry participation, to go ahead with the initial phase and extend an invitation to interested operators and drilling contractors who wish to join in the joint industry project.

Technical objectives

The Conco/Hydril program's objective is to identify the most likely concept of riserless/return line drilling that can be implemented with existing technology. Prior concepts will be analysed and input will be sought from participants for various system configurations. If required, outside services will be contracted.

Each configuration will be analysed hydraulically and dynamically. Particular emphasis will be placed on transient conditions. Preliminary loads, forces, and energy requirements will be calculated for each system. From this analysis, a recommendation for the most likely system will be developed. Included will be a proposed workplan, cost estimate, and time schedule for the implementation of design and prototype testing for the system(s) identified as having the best potential for succeeding. Full commercial development would likely cost $20-30 million.

Conoco will offer the following concepts for the program:

1. Selective use of riserless drilling for the range of casing sizes between 20 in. down to 11-3/4 in. Reduction of hydrostatic by means of gas lift, pumping, or glass beads. Fluid returns would be via a return line and the drill string would not be contained within a riser. The return line could either be a dedicated line or the choke line.

2. With the present 21-in. riser, incorporate a sub sea rotating head, bypass piping, and control system, and reduce the hydrostatic in the marine riser by use of glass beads. The application goal would be to reduce casing points and tensioning requirements. This would be a partial solution that could be addressed short term. The use of glass beads for underbalanced drilling has been utilized by the Russians.

3. Using a small diameter marine riser (13-5/8 in.), reduce the hydrostatic in the small riser through use of gas lift or glass beads. If enough casing points were eliminated, this smaller riser could be adapted for deepwater exploratory drilling for "throw away" wells, which would allow for a reasonable hole diameter (8-1/2 in.) for evaluation purposes. This system could be used as a staged development of concept.

4. With any sized riser, utilise a rotating head and control system in conjunction with a pump and bypass manifold to reduce the hydrostatic.

5. With a rotating head and sub sea controls, examine reverse circulation using both a pressurised system with light mud and heavier mud with internal gas lift inside the drill string. Utilise the kill and choke lines as a means of directing flow to the annulus.

6. Use a sub sea buoy to tension a return line, riser, or marine riser.

7. A staged development concept would be to isolate the current marine riser with a rotating BOP and reduce the density of the mud column by use of glass beads. Returns would be diverted around the rotating BOP back into the marine riser. The mud would mix with glass beads and carrier fluid (base mud) to lighten the mud column. A sub sea choke would be used for well control. A differential pressure of zero psi would be maintained on the rotating BOP during normal drilling operations.

A high capacity centrifugal pump could be used to circulate a mixture of glass beads and clean mud to lighten the column in the marine riser. Separation of the glass beads will be done at the surface by use of settling pits. This would partially solve the problem by reducing the number of casing points and reducing weight, however it would not eliminate the large diameter drilling riser. However, the concept would provide for introducing equipment in stages to the deepwater drilling industry.

Workplan

The hydraulic behaviour should be analysed for each of the cases considered. Included in the hydraulic analysis would be the input requirements for pump or gas lift as required.

Novel fluid density reduction concepts, such as foam, glass beads, and others, would be analysed as required. The initial work will involve screening the various concepts. More detailed hydraulic work will follow for configurations with the most promise.

The configuration of the equipment will be dynamically analysed as to practicality for use in floating drilling operations. The emphasis will be on interference between return lines, risers, and exposed drillstring's. Characteristic vessel motion will be included. More detailed dynamic behaviour work will follow for configurations with the most promise.

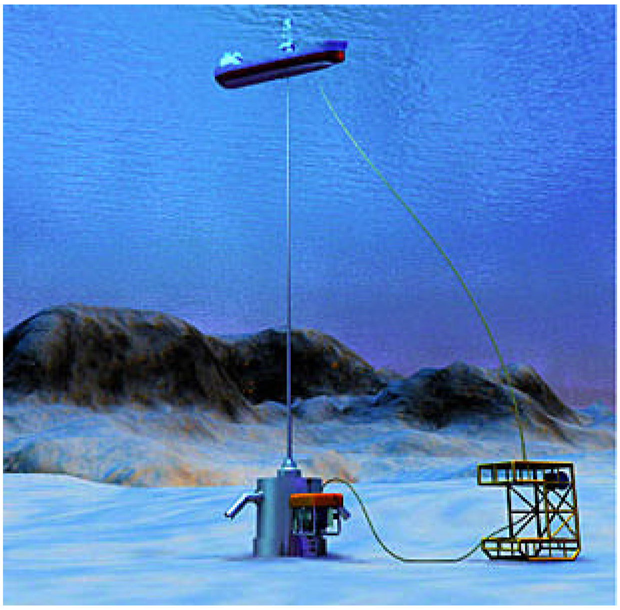
The design concepts for those configurations with the most promise will be provided. A more detailed hydraulic and dynamic analysis will be performed for those concepts. Conceivably more than one concept could be selected.

The development of a deepwater system to reduce casing points, in conjunction with reducing drilling costs and making more drilling units available for deepwater work, are critical to working in depths beyond the 7,000-8,000 ft contour. Without it, development drilling will be enormously expensive and limit the development of discoveries with medium and small reserves.

Further, if the industry is to be able to drill, develop, and produce successfully in water depths beyond 10,000 ft, alternatives to conventional systems will be necessary.

**Seabed drilling fluid diverter**

The shallow water flow diverter joint industry project (JIP) is moving toward construction of a prototype, following completion of design.



Project development has completed the necessary work and construction of a prototype si nearing.

The SWF diverter is designed to allow an operator to regulate the back-pressure on the formation while drilling through shallow water flow zones. The device fits on top of the low-pressure well housing and has chokes that can be opened or closed via a remotely operated vehicle (ROV). By regulating the pressure at the wellhead via the chokes, the operator can control the down hole pressure.

Rotating head

The key component to this modular tool is the sub sea rotating head. This device makes the diverter a versatile tool with applications beyond its driving goal of overcoming SWF problems. With the addition of a free standing return riser to transport returns to the surface from the sub sea wellhead and the addition of a mud lift device (gas lift, pumping, etc.) the diverter could perform the function of a top hole riserless drilling system with the same benefits of a disposable mud system. This free standing riser technology exists and could be integrated into the system with relatively little difficulty. In fact, it is this application that is generating some interest from operators in the North Sea. While riserless drilling might be a practical application of this development, the scope of the current project is not that far reaching.

It is envisage that the SWF Diverter will not be built and sold as a product. The tool will come to market as a call-out service. Operators will contract for the tool as they would with any other service item.

Moving to control

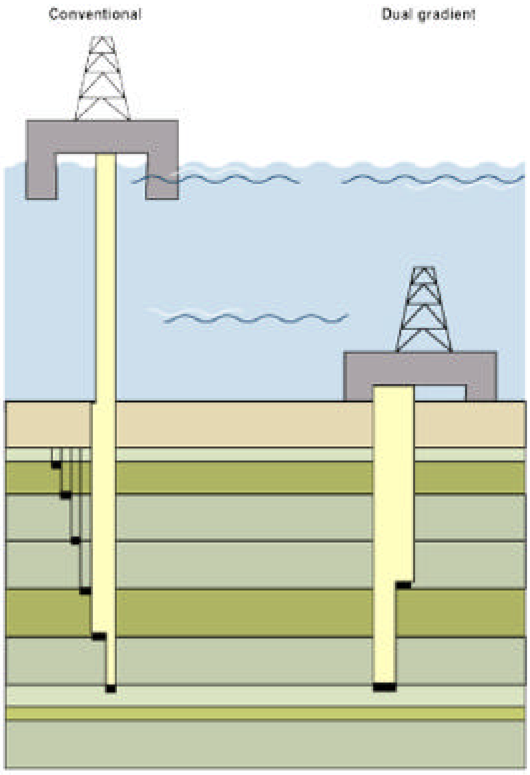
The move from containment to control is an important one because it will minimize hole enlargement due to the SWF. The primary technologies at work in this system, the sub sea rotating head, and hydraulic sub sea latching technologies are all currently under development by ABB/Vetco Gray.

**"Dual gradient" deepwater drilling**

Due to reduced operating margins between pore and fracture pressure gradients in deep and ultra deep water, young, rapidly deposited, depositional basins around the world. The industry is now reaching operating limits of existing deepwater drilling technologies. Changes in perspective on well engineering design are thus required.

As drilling engineers accept the fact that the seawater column is a necessary constraint, new engineering designs would have to revolve around this fact. Also no technology currently exists to take away the effects of the seawater hydrostatic column.

There is also no argument to the facts that riser costs, design issues and operating constraints placed on the drilling equipment required are a major contributor to total well costs in deepwater wells. Systems retaining the use of a riser past 10,000 ft and deeper will continue to drive costs higher, not "lowering drilling costs" as operators have been giving to the industry for the past few years.



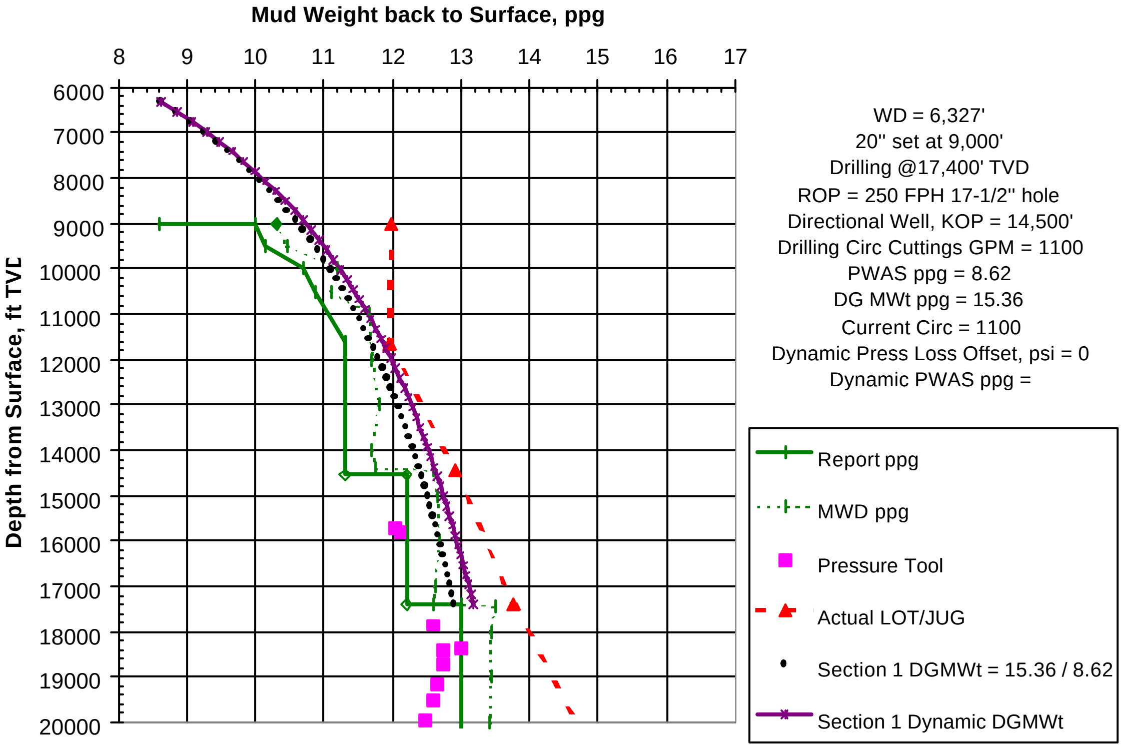

Recent industry projects (JIP) have however revealed riserless drilling concepts that use what has been termed dual gradient drilling (DGD) approach.

Dual gradient allows several advantages over current conventional drilling techniques. E.g.

- Reduced casing strings
- Increased drilling efficiency due to increased margin between Fracture Gradient and Effective Mud Weight
- Allows synergies with gauge hole drilling technologies, i.e. Auto-Track and increased efficiency in salt drilling processes
- Increased completion efficiency due to improved design – larger bores
- Allows earlier delivery of wells vs single gradient drilling
- Larger production hole
- Enhanced well control features.

Design integrate seabed blow out prevention, return line concepts, and existing marine riser or sub sea divertion equipment. In the case of the riser, the riser is filled with seawater to equalize internal pressure with the seawater hydrostatic pressure outside of the riser. Also serving as a guide for drillstring tubulars into the wellbore, and support for the mud lines and umbilicals. The invention of rotating pressure control equipment was one of the first steps toward for riserless drilling concepts.

The final steps for riserless drilling will be eliminating the riser altogether, and increasing reliability of seafloor "working" components. A support structure for mud return lines and umbilicals will be required, but should not be too difficult to design. The learning curve in these earlier steps should also yield improvements in the sub sea pumping, monitoring, and control equipment. The next step for this design will be



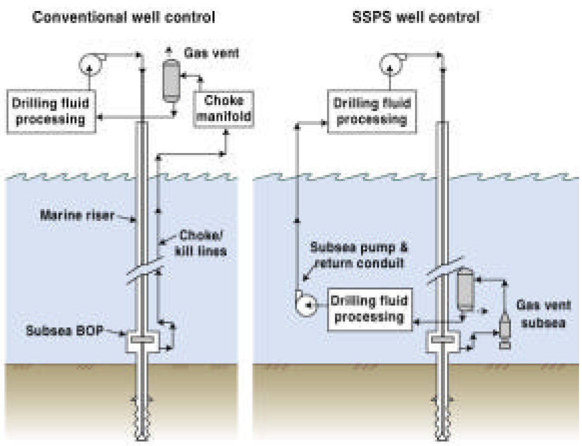

the use of a remote, stand alone riser, and a self-supporting riser. This step will lend to the use of sub sea wellhead templates with flexible, retractable return lines moved from wellhead to wellhead, as required, and the mud lift system central to all of them. Such concepts will have no minimum operational water depth. Economic advantages start to be realized around 4,000 ft water depth. Geologic and directional drilling questions have also to be carefully recognised, analysed and determined.

Well control issues would be determined with new procedures and operating practices developed with a dual gradient approach. Riserless dual gradient systems will have to afford accurate constant pressure monitoring on the well, both flowing and static.

The figure above illustrating the required level of pressure monitoring, operating margins and realisation to understand and determine the information being fed back to the rig to ensure that primary well control is maintained. Early kick detection would have to be achieved sub surface in pore pressure regimes with reduced margins for error. Drillers would have to be educated, trained and developed to detect, evaluate, and act on a possible well influx situation. If the decision was made to initiate kick circulation procedures, the systems will still require the monitoring of drill pipe, annular and sub sea mud pump pressures, the build of appropriate kill-weight mud, and employment of the "most appropriate method" of circulating out the kick fluid. Dual gradient systems will always be controlled "on choke" or dynamically shut in. Reliability and robustness of equipment will be an important design and operating reliability issue. Constant choke control throughout the drilling phases is where confusion will starts, and the emphasis to the needs and requirements of re-education of drilling personnel. Standard procedures in the past *i.e. shut in the well, wait, evaluate, consult operator personnel, then weight up the mud and kill the well*, will all be changed.

Dual gradient systems will work under unbalanced U-tube scenarios. Training drilling personnel to understand the physics behind this fundamental change, and how to deal with problems using this concept will take time.

## Dual gradient drilling (DGD) solution




Dual gradient drilling may be the key technology to take exploration drilling out past 12,000-ft water depth. It should improve the margin between fracture gradient and pore pressures in deepwater wells, allowing casing strings to be set deeper and reducing the cost in time and materials to drill a well.

Two key hurdles are viewed as:

- Primary sub sea cuttings separation allows the company to use electrical submersible pumps (ESP).
- Sub sea well control vents gas

sub sea, protecting rig personnel and eliminating the need for high-pressure containing equipment downstream of the sub sea choke.

Such alterations means the fluid returns conduit will not be high pressure.

### Sub sea well control

Another element key to the dual gradient system is sub sea well control. As with the circulating system, the well control system is designed to mimic conventional surface processes sub sea.

### Full drilling function

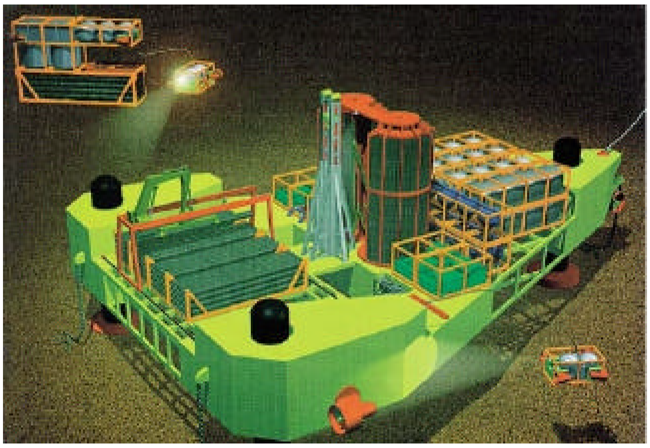
A broader margin between the pore pressure and fracture gradient are key to a successful drilling program. There is a broad range of advantages offered by dual gradient drilling, explained Gonzalez:

- Casing strings can be run deeper without the risk of exposing the formation to the high pressures of the mud column. This not only means fewer casing strings, but a larger wellbore at TD.
- Smaller deck loads for rigs and lower hook loads will result. This means smaller rigs might be called into service to drill deepwater wells.

**Seafloor drilling option for deepwater wells**

A radical new approach may offer the step change needed to take exploration drilling off the continental shelf and past the 12,000-ft water depth contour. In that Shell is sponsoring the revolutionary research to move the drilling rig from the surface to the sea floor. A panel was organized in 1997, preliminary feasibility study and conceptual design phase studies completed in 1999.

Sub sea rig concept



Phase I concept as the diagram shows, was not as radical as expected. The design developed essentially a submerged jack-up rig, that would be controlled and supplied with electrical power from a dedicated surface vessel. Umbilical's would supply necessary compressed air for buoyancy and manipulaton and possibly liquids such as cement or additives. The rig being envisaged to contain a variable buoyancy system allowing it to descend, in a controlled manner, to the seafloor. On the seabed, legs would extend to level the rig, and the buoyancy would be dumped. In soft soil areas, suction anchors or mud mats could be used to anchor the vessel.

The vessel would additionally require a fully automated drilling package, would use some form of hydraulic derrick similar to the modern, automated packages now in use on many deepwater vessels, except it would be capable of working fully submerged at designated water depths.

Submerged functionality would be required for virtually all the systems considered on such a vessel. In some cases however there may be no need to reinvent the wheel, where existing systems would be perfectly adequate. In other areas challenges would have to be met, especially in ultra deep water depths envisaged e.g. > 12,000ft.

Fluid circulation

The mud would be circulated through a closed-loop system to keep it separate from the seawater. Cut tings would be filtered out in gravity separators and then either dumped on the seabed or returned to the surface for further processing. The cement would be premixed on the surface using a two-part system, similar to epoxy or long-term retarders, to keep it in a liquid state at the seabed. All liquids on the rig would be contained in pressure-compensated tanks attached to the rig. These containers would be removable so they could be returned to the surface by an ROV for refilling.

### System advantages

The initial advantage of the sea bed drilling would offer an option to the high cost of ultra-deepwater drilling rigs. By placing it on the seabed, the Shell team identified a number of advantages over similar surface systems:

- The sub sea rig apart from the length of the main control umbilical, a lift line, and the ROV umbilicals is virtually unaffected by water depth.
- Seabed drilling drastically reduces the time required for tripping pipe, the time savings could easily add up to several days per well.
- Three days to trip a riser 3,000 meters and 2-3 days to retrieve it, would be eliminated, as would the time it consumes.
- No affect by weather conditions. While drilling might be interrupted, the rig would not be moved off station. Once the surface vessel returns and reconnects the umbilicals, drilling could continue.
- Safety: i.e. no contact between personnel and the drillfloor, which is one of the most dangerous areas on any rig.
- Fewer crew members required to run this automated equipment.
- Safer circulation of gas kicks because of the high ambient pressure at the seabed and reduced kick expansion reducing risk of a blow out.
- Optimum wellbore fluid pressure regime. *Mud density is greater than seawater, which leads to large differential pressures at the seabed, between the riser and the surrounding seawater, and in the well.* By locating the mud pumps at the seabed, the hydrostatic mud pressure in the well will be related to the ambient hydrostatic pressure at the seabed, rather than sea-level pressure.
- More direct control of pressure at the bottom of the well using traditional methods. This one facet of the seabed system offers several advantages including reduced wellhead size, a smaller number of casing strings, the ability to drill deeper wells and improved productivity, thanks to less impairment from high differential pressures.

### Technical requirements

Among the technical requirements of the rig were several broad areas of technology, each of which would have to be advanced to make the concept work. This would include ROVs, composite materials, umbilicals, drilling equipment submerged capabilities, mud systems, hydraulic motive power systems, electrical distribution equipment, and down hole instrumentation. The list reads like a glossary of drilling technology, but developers point out that the required systems exist in some form, and would only need to be adapted, modified, or simply qualified for this job.

While there are a variety of technical hurdles to overcome, the cost estimates for the development and construction of the first sub sea rig was placed at $471 million. While this is a substantial investment, it is reasonably competitive with the cost of ultra-deepwater MODUs now under construction. If time savings are realized, it is possible the seafloor rig could optimise other advantages over new but still conventional surface technology. At the same time, it remains one-of-a-kind, unproven technology. Once one of the rigs is built and placed in operation, the cost per unit would drop.

### Slimhole options

Rather than competing head-to-head with conventional technology, the idea would be to drill slim 3-in. wells from the seabed for the express purpose of performing the initial logging run. This run would provide a number of measurements including gamma ray, resistivity, neutron-density, and sonic. Using logging while drilling (LWD) technology deployed by a small coiled tubing drilling unit, this slimhole run could give producers a good indication of the prospectivity of a given formation. By designing a small sub sea drilling unit that only drills slimholes, costs of drilling such “finder” wells could be reduced about 75% of that of conventional drilling.

Savings would accrue in the following areas:

- Smaller derrick
- Smaller pumps due to the improved hydraulics
- Less required deck space
- A smaller volume of required mud
- A smaller number of drilling tubulars.

The drilling unit would be deployed from a surface support vessel and controlled by an umbilical. The rig would drill a minimum sized hole in the reservoir to accommodate an LWD run. Based on the results of the LWD tool run, a decision could be made whether to proceed with full-scale drilling. This would greatly reduce the expense of drilling a dry hole in ultra-deepwater and add to the certainty of prospects in these high-priced water depths

## Dual activity drilling vessels

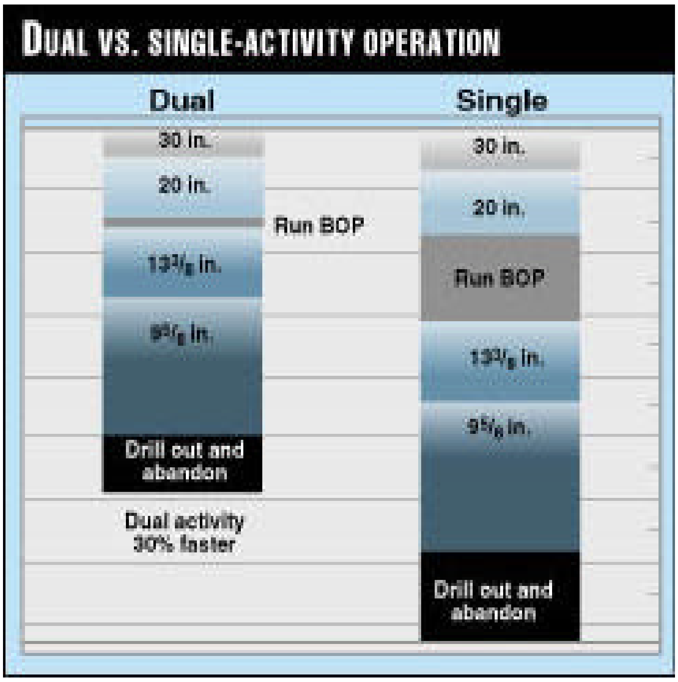
The Enterprise Class III, dual-activity rigs designed to drill, test, and complete ultra-deepwater wells to 35,000-ft drilling depth in water depths up to 10,000 ft. The dual-activity designs were developed to provide cost-effective solution for world-wide ultra-deepwater drilling operations. Such drillships are designed to deliver higher levels of efficiency and safety required for the economic development of ultra-deepwater reserves.

The drillships combine dual-activity drilling equipment packages consisting of advanced, high-capacity drilling equipment with a modified double-hulled shuttle tanker design. The result of such combinations are large multipurpose drilling rig designed to reduce well construction time, provide extended well testing and storage with capabilities to operate in harsh environments world-wide. *E.g. designed to heave less than 7 ft in a 50-year Gulf of Mexico winter storm.*

Variable deck load and storage capabilities also providing the capability to drill and complete multiple wells before re-supply of well consumables is required.

### Dual activity operations

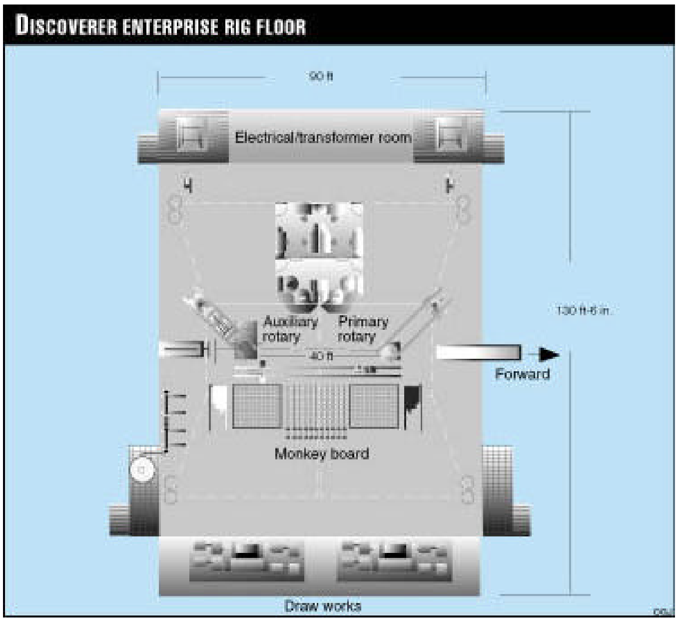
Dual-activity operations reduce well construction time by enabling operations to be conducted simultaneously in parallel, rather than sequentially in series as has traditionally been required due to equipment limitations. Dual-activity operations include increase in well construction quality, reduction of non productive time due to advanced inspection and pre-testing capabilities, flexibility to perform a wide range of sub sea jobs, and redundancy of technically advanced high-capacity drilling equipment.



Simultaneous operations necessitate however a higher level of pre job-specific planning to ensure the maximum reduction in critical path time is achieved. The scheduling of equipment and personnel coupled with real-time management of dual-activity operations will be essential to success. Rig floor equipment on the Enterprise Class drillships is designed to minimise traditional roughneck "hands-on" work by utilising a series of semi-automated pipe-handling equipment operated from remote touch screen and discrete controls.

Pipe-handling equipment is capable of handling up to 20-in. OD tubular's in Range II fourbles (a four-stand) or Range III triples.

Dual-activity capability is provided by a forward work area and an aft work area, each centred around a rotary table.




The rotary tables are spaced 40 ft apart above an 80-ft by 30-ft moonpool and are serviced by independent drilling equipment packages utilising a dual 2 by 2,000,000-lb derrick.

The forward work area is equipped with tensioners and will be utilised as the primary rotary for drilling with riser and the BOP stack. The aft work area will be utilised for riserless drilling operations and will serve as a staging ground for preparation and testing of equipment to be utilized in the forward work area. Non-drilling sub sea operations will also be performed from the aft work area.

The aft work area includes a 95-ft powered mousehole and a pick-up/lay-down system, and is designed to make up or lay down stands of drillstring or casing in singles. The pick-up/lay-down system picks a horizontal single off the conveyor and presents the single to the mousehole or the rotary in the vertical to be made up by an iron roughneck. The reverse process is utilised to lay down singles. The aft work area can be upgraded to serve as a second primary rotary for drilling with riser and a BOP stack concurrent with the forward work area.

Each pipe racking system can access drill string or casing stands from any position in the fingerboards and deliver the stand to either of the rotaries or the mousehole. Travelling assembly dolly retract capabilities will decrease tripping and connection times by allowing simultaneous operations with pipe-handling equipment at the rotary. Tripping can be conducted with elevators on the travelling block with the top drive assembly parked. An adjustable casing fingerboard, a casing iron roughneck, and a hydraulic cathead are shared between work areas. Total pipe setback capacity shared between work areas is over 80,000 ft.

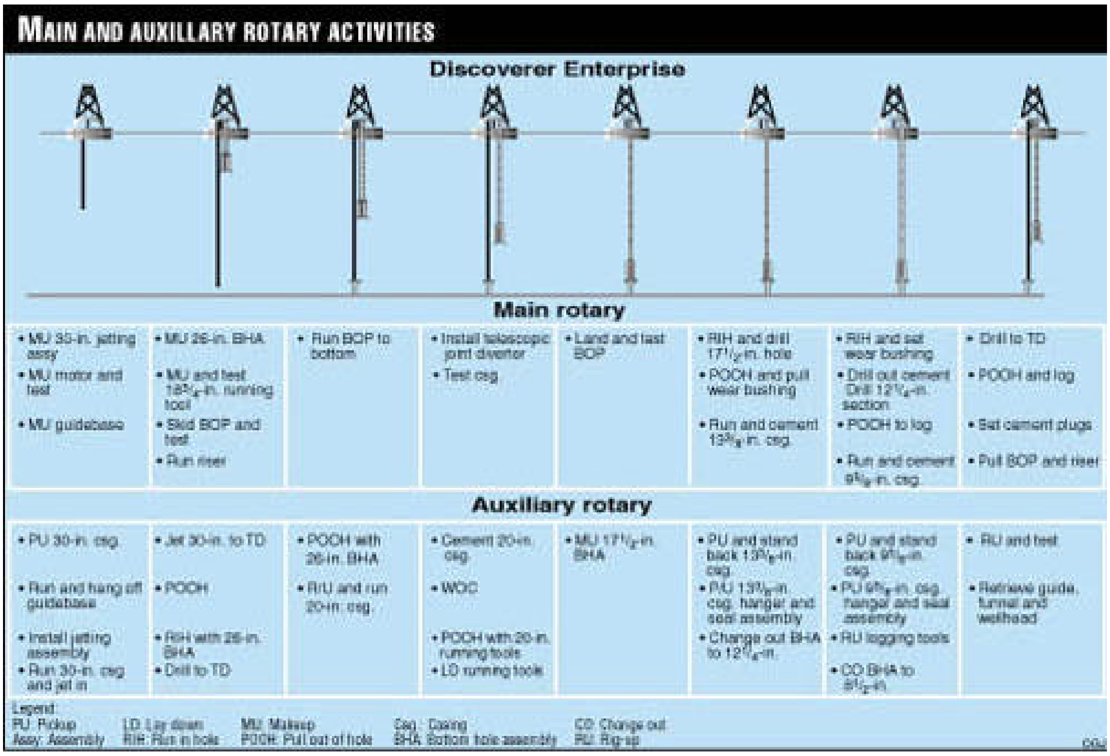
**Dual activity Drilling equipment**

The drilling equipment to be used for dual activity drilling includes the following:

- Two rotary support tables - 601/2-in., 1,000-ton hydraulic rotary tables and hydraulic power slips up to 750 tons.
- Two crown mounted compensators - 500 tons passive dynamic capacity each with 25-ft stroke, 1,000 tons retracted capacity.
- Two crown block/travelling block/rotating hooks - 1,000-ton powered rotating hook includes load pins to measure hookload.
- Two top drives - 1,150 HP 650-ton AC top drives with parking system.
- Two link/elevator sets - 500-ton links and hydraulic insert type elevators on both top drive and travelling block.
- Two drawworks - 5,000 HP DC with 2-in. drill line and regenerative braking rated for 1,000 tons with 12 lines.
- Two pipe racking system - vertical travelling column assembly with two hoisting jaws capable of handling Range II fourbles or Range II triples up to 30,000 lb.
- Two fixed fingerboard assemblies - capable of holding 30,375 ft of Range III triples of 6 5/8-in drill pipe, 1,240 ft of Range II fourbles of 6 5/8-in. heavy weight drill pipe, and 2,852 ft of Range II fourbles of 6 3/4-in., 8 1/4-in., and 9 1/2-in. drill collars.
- Two drillstring iron roughnecks - capable of handling up to 93/4-in drill collars with 100,000 ft-lb make-up torque and 120,000 ft-lb break-out torque, hydraulic spinning and torque wrench designed to handle stabilisers.
- Two manipulator arms - hydraulic work basket equipped with a maximum capacity of 14,000 lb at 8 ft and 1,500 lb at 48 ft.
- Four winches - hydraulic with 3/4-in. wire rope regulated for 12,000-lb line pull.
- Two driller work stations - four touch-screen displays controlling drilling and monitoring equipment in conjunction with joysticks through a computer network, located in climate-controlled cabins.
- Two assistant driller work stations - two touch-screen displays controlling drilling and monitoring equipment in conjunction with joysticks through a computer network, located in climate-controlled cabin.
- Two rig floor control panel - allows control of selected drilling equipment from rig floor.

**Typical dual activity operations**

A hazardous operations process is utilised to evaluate safety considerations for simultaneous dual-activity operations. It is anticipated that many new dual-activity capabilities will be identified as work experience with the Enterprise Class drillships and sub sea operations grow and new technology is introduced.




Upon arrival on location, the aft work area will be utilised to jet structural pipe in, drill conductor hole, and run and cement conductor casing and the wellhead while running the BOP stack in the forward work area. The drillships will be capable of saving several days of rig time by making short well mobilizations at one to two knots with the riser and BOP stack suspended.

While conducting normal drilling operations through the riser in the forward work area, operations that can be conducted out of the critical path in the aft work area include:

- Inspect, make up, and rack back drill pipe and BHA's
- Function test motors and MWD equipment
- Make up, test, and rack back casing, hangers, running tools, and cementing equipment
- Make up, test, and hang-off or rack back electric line logging equipment
- Make up, test, and rack back DST equipment
- Make up, test, and rack back completion equipment
- Make up, test, and run sub sea trees to the mudline
- Jet template structural pipe
- Batch drill and set template conductor casing and wellhead
- Install sub sea equipment (pilings, manifolds, jumpers, and flowlines)

## FPSOs with drilling

Sub sea systems will be the dominant deepwater development solution of the future. Hurdles to overcome in water depths > 1000ft would be; more efficient drilling and completion operations, cost effective paraffin inhibitors, less frequent well intervention techniques, overcoming hydrate problems on long, cold offsets, fit for purpose people, process, production and profits. The addition of a drilling function, preferably riserless, to floating production, storage, and offloading (FPSO) systems, could conceivably make profitable deepwater plays in this water depth anywhere in the world with minimum reliance on shore-based facilities.

Designs for the first FPSO's with drilling have already been presented by Kvaerner, offering a cost-effective all-in-one solution for drilling, production, and workover activities for reservoir and production management. Such a vessel would be attractive in remote deepwater environments with high drilling and well maintenance requirements, such as required in Northern Europe. Such a stand-alone concept is a prime example of the sobering role technology must play in the future of deepwater drilling and development. Technology of the future will have to offer a short-term economic dividend to play a role in this developing market.

## 6th Generation rigs

The sixth generation mobile offshore drilling unit will probably will contain radical changes in both appearance and structure from conventional rigs.
Judging by the research currently ongoing, to meet the needs of the operators and the drilling contractors, you can expect some or all of the following:

- **Multi-functional vessels**: The units will incorporate the ability to readily load on and load off skid-mounted equipment to conduct complete well site operations (*e.g. rotary and coiled tubing drilling, production, extended well testing, workover, and installation of sub sea and pipeline production equipment*).

- **More compact**: Reductions of size and weight will provide a more compact unit, but because of environmental forces, the footprint and freeboard for both jack up and semi submersible units are unlikely to change much.

- **20-25% less weight**: Modular on-and-off movement of equipment to accommodate changing functions will keep deck weight down. New lightweight fire-blast walls, lower accommodations requirements, and wider use of composites will also help.

- **Fewer people**: Two-person drilling crews and fewer contractor personnel armed with a wide array of computers and video communications gear with experts on line will keep crew numbers down.

- **Reduced mast**: Hydraulic push-pull systems will replace the conventional derrick and draw works *(reducing the mast sail area and associated surface area exposed to overturning forces)*

- **Lower centre of gravity**: In addition to a minimised superstructure and drill floor mast, multiple pipe sections will be racked below the drill floor full time and only laid horizontally for testing purposes.

- **Reduced keel and draft**: Reducing the superstructure, mast, sail area, and lowering the centre of gravity

## Deep draft semi

Deep draft semi-submersible concepts, such as the TPG 3300, is designed for a wider arena, up to ultra-harsh (North West Atlantic). A three-year study was recently concluded concerning issues associated with a West of Shetland installation. The three-phase study was co-financed initially by BP and then BP Amoco, with Statoil joining in for the third phase. The reasoning was if the technology could be demonstrated to work in normally rough conditions, it could also be considered for more tranquil locations. With this view in mind, tank tests are scheduled to simulate the platform behaviour.

TPG 3300 comprises basically: An outfitted, water-tight hull with drilling and production facilities on the deck. Leg columns to provide buoyancy, including the mechanism to raise the deck above the water line. The legs can be latticed, or alternatively the lower sections can be adapted for oil storage. A flooded pontoon 80-110 meters above sea level, providing resistance to heave cantenary mooring or taut rope mooring system. Heave characteristics of the platform are low, which permits use of rigid conductors and risers and dry Christmas trees. Unlike other deep draft semis, it can be constructed at a shallow water site, with pre-commissioning concluded prior to the field tow-out. Also, it does not require a heavy lift vessel for the installation.

TPG 3300's leg buoyancy adopts the same principle as a semi-submersible, although the shape has been optimized - hexagonal, with three chords that mate with the lattice leg sections - to minimize drag.

## 3D-4D Seismic

At the head of the new technology parade 3D seismic data processing and management will be used to find more new hydrocarbon deposits for less.

Improvements to 3D include shortening cycle time to a fraction of it's original time. Also, better on-site quality control allows surveyors to avoid performing useless, time-consuming surveys that must be repeated weeks or even months later. Innovations to 3D seismic will not end with the 20th century. Time-lapse 3D, or 4D, in which surveys are run over the same ground at different times will allow production managers to see fluid movement, flood fronts, missed hydrocarbon deposits, and infield drilling opportunities.

## More wells, one location

Multi-laterals wells are latest innovations from the world of horizontal drilling. As with simple horizontal wells, they act like giant fractures draining the formation towards the main wellbore. And like their parent horizontals, they bring a nearly unlimited number of wells to a single surface facility. But producing more hydrocarbons may be only the first multilateral application. Theoretically, they could be used to form a multi-function network, or "underground factory" wherein laterals off a single wellbore could be designed for production, separation, water and gas injection, and monitoring. Part of the necessary technology, surface controlled down hole tools, and systemisation of all field functions are already the subject of service company alliances.

## MWD, LWD, FEWD, SWD

Of course, no convoluted well path would have been possible without some technologies brought to the marketplace since oil prices collapsed a decade ago. Top drive drilling motors, a novelty in 1990 is now a standard of any rig upgrade.
They are valued by directional drillers for their ability to rotate and pump in 90 ft sections of drill pipe. In the 21st century, top drives will send rotary tables the way of cable tools, at least offshore.

Of equal importance to the proliferation of horizontal wells has been the continuing improvement of behind-the-bit measurement tools (MWD) that communicate bit direction and location to the surface in real-time.

From those MWD tools, evolved real-time logging (LWD) tools that include resistivity, density, and neutron porosity logs. Lately, several manufacturers have overcome the obvious difficulties of placing an acoustic tool in a down hole drilling environment and developed a sonic-log-while-drilling tool. Sonic logs add to LWD a seismic correlation ability that was the last remaining advantage of wireline logs. If the technology, essentially formation evaluation while drilling (FEWD) fulfills its promise, a great many wells will be drilled in the 21st century without the expense and time of wireline logs.

At least one more major step is still to come from real-time drilling measurements. By combining ever more powerful computer processing, increasingly sophisticated FEWD, and precise bit direction control, wells will eventually be drilled using real-time seismic data from ahead of the bit (SWD).

It is not too fantastic to imagine a near-future driller in a climate-controlled room, manipulating bit direction with a joystick in response to the real-time data being transmitted to his computer screen. Using parameters programmed into a computer, the driller may even become redundant.

## Production Risks & requirements

Deepwater activities engender their own technical issues. Among the more daunting are hydrate and paraffin sub sea pipeline blockage. Generally considered little more than a nuisance in most areas, the high flow rates, remoteness, and miles of natural cold water bath through which deepwater production must pass make it quite serious for producers.

Deepstar consortium have commissioned a facility to test vendors' hydrate and paraffin remediation equipment in a simulated five-mile long blocked pipeline.

Statoil will soon drill an offshore well under balanced. Besides having implications for extended-reach drilling, an under balanced well could conceivably be drilled with only a return line between the sub sea wellhead and the rig eliminating the riser.
On a second front a composite drilling riser is in testing stages and should be ready for a field run within a year. The composite riser, also a Deepstar-initiated project, will weigh a fraction of comparable steel risers. But steel or composite, water current questions as yet unanswered, including possible harmonic motion and the difficulty of returning a riser to within inches of a spot two miles away through moving water.

**Future Requirements**

- Flow assurance and flow management from reservoir to export
- Longer tie back distance (50miles+)
- Enhanced reservoir performance and increased economic yield
- Seabed process facilities

## Intelligent completions

Controlled or sensor automation in down hole completions, that could result in selective, isolated, mixed flows for compartments within the reservoir is also an area for the future.

Such systems are however in their infancy with the high cost of well intervention and reliability issues required in deepwater systems. Such in ovation must however must be assured that it is being used for value added reasoning.

Such completion systems should therefore first be proved in a more accessible environment or a more selective one