Ultra-Deepwater Production Systems Technical Progress Report

October 1, 2002 - September 30, 2003

**K.L. Smith, ConocoPhillips Company, Houston, Texas and
M.E. Leveque, ConocoPhillips Company, Houston, Texas**

Title Page

Report title: Technical Progress Report-Annual

Reporting Period Start Date: 9/30/2002

Reporting Period End Date: 9/30/2003

Principal Authors: K. (Ken) L. Smith and M. (Marc) E. Leveque

Date Report was Issued: May, 2004

Doe award number: DE-FC26-00NT40964

**Submitting Organization: ConocoPhillips Company
600 N. Dairy Ashford
Houston, Texas 77079**

Significant subcontractor: Kvaerner Oilfield Products Inc.

Disclaimer:

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof.

Abstract:

This report includes technical progress made during the period October, 2002 through September, 2003. At the end of the second technical progress report, the ConocoPhillips opportunities to apply subsea processing in the Gulf of Mexico had been exhausted, and an alternative site was identified in Norway. This was a non-ConocoPhillips operated field, and the subsea processing was proposed as a phased development approach with 2-phase separation at the field, and then gas and liquids exported via pipeline to remote platform locations for processing. Although the unrisked economics were quite favorable, the risked economic evaluation compelled the operator to develop the field with the more conventional and proven Floating Production, Storage and Offloading (FPSO) option. Work on the subsea processing was suspended at this time.

Discussions with DOE regarding two other step-change deepwater technologies ensued. One was an effort to develop a light-weight, high pressure composite production riser. A field demonstration of the design would then be performed by deploying a limited number of composite joints in a Gulf of Mexico deepwater development. The other was to begin the process of taking drilling with casing technology to the deepwater. This is called, “close-tolerance liner drilling”. It was agreed that both technologies should be pursued, and the work began.

During this reporting period, the initial production riser design had been completed and preliminary test sample components were being fabricated. Regarding the liner drilling, the sub-contractors were selected, the design basis was agreed and designs progressed towards meeting a projected first quarter, 2004 onshore test program.

Table of Contents:

1. Title page
2. Disclaimer
3. Abstract
4. Table of contents
5. List of Graphical Materials
6. Introduction
7. Executive Summary
8. Results and Discussion
9. Conclusion

List of Figures:

- **Figure 1 - Subsea field development concept layout utilizing subsea processing**
- **Figure 2 - Photographs of various SSP components**
- **Figure 3 - Cross section of production riser coupling**
- **Figure 4 - Configuration of close tolerance liner drilling system**

Introduction:

The report herein is a summary of technical progress of three projects to demonstrate hydrocarbon drilling and production methods applicable to deep and ultra deepwater field developments in the Gulf of Mexico and other like applications around the world. This work advances technology that will lead to more economic development and exploitation of reserves in ultra-deep water or remote areas. In some cases, these technologies may be enabling: allowing for economic production where conventional technology simply cannot. Reserves in these areas can add significantly to reducing the United States dependence on foreign oil supplies. Importantly, all three projects are considered as first steps in their respective technology application areas which, once proven, could lead to wide industry uptake and expansion of their applicabilities.

Executive Summary:

There are three key components of our joint study and technology development efforts that will be described. The benefits of each with regard to technology enhancement and technology enablers in deep and ultra-deepwater hydrocarbon basins with particular emphasis on the Gulf of Mexico potential application will also be described. The areas to be addressed are Sub-Sea Processing (SSP) technology development and key findings relating to application in the Gulf of Mexico, Composite Production Riser Demonstration planned for late 2004, and finally Close Tolerance Liner Drilling technology development and demonstration.

Sub-Sea Processing:

Neither of the two site evaluations for Gulf of Mexico locations led to viable deployment of the SSP system, and a third site, located in Norway, was identified. ConocoPhillips is a minority interest owner in the field, and proposed the SSP package as a solution for a two-phase development.

The comparative economics were run on this case vs. more conventional development concepts. On an unrisks basis, this development concept was significantly more economic than the more conventional Floating Production, Storage and Offloading (FPSO). However, once the mechanical risk weightings were applied, the FPSO option was selected, and the operator is now implementing that concept. This once more illustrates that there is a need for further field demonstration of subsea processing. The mechanical risks, both real and perceived, must be reduced.

After this evaluation, no more opportunities could be found within the ConocoPhillips portfolio. It was agreed with DOE that further work in this area should be suspended, and work in other areas of very significant promise should be initiated. There were two areas that ConocoPhillips was aggressively pursuing. The first was an enabling technology: composite production risers.

Composite Production Riser

The lower weight of the composite production riser will lead to significantly reduced top tension requirements, and therefore, smaller floating structures in deep waters. A number of previous research projects have yielded encouraging results in confirming the validity of this concept. These projects have included the manufacture and extensive shop testing of prototype joints and, in one instance (Heidrun drilling riser), limited offshore trial. In spite of these early successes, the technology has yet to be adopted for a full deepwater field development. This is attributed to reluctance to commit to what could be a billion dollar investment or more, on the basis of "first use" of a new technology. The objective of this project is to overcome this resistance.

The Composite Production Riser project was initiated as a joint industry project by ConocoPhillips (project manager), Kvaerner Oilfield Products and ChevronTexaco in March 2003, with financial support from the United States Department of Energy's National Energy

Technology Laboratory. The goal is the installation of up to ten composite joints in one of the steel risers from the ConocoPhillips operated Magnolia tension leg platform (TLP) in the Gulf of Mexico, in 4,674 feet of water, by the end of 2004.

A quantitative risk analysis (QRA) was first performed by a joint team of ConocoPhillips and Det Norske Veritas. This analysis concluded that the introduction of the prototype composite joints would not significantly increase the overall risk to the Magnolia TLP. It also identified a number of areas requiring special attention, mainly in the design of the thin inner steel liner.

DeepWater Composites AS was then contracted to perform the detailed engineering and fabrication of the composite joints, based on the above QRA and the Magnolia steel riser design criteria. A test program was also developed to verify the design. A preliminary detailed design was established by July 2003, and procurement of materials for the test samples was initiated. Welding procedure qualifications for the thin inner liner were performed in September, and, as of the date of this report, work had begun on the fabrication of samples for preliminary component testing.

Close Tolerance Liner Drilling

ConocoPhillips has enjoyed tremendous benefits from Tesco's Casing DrillingTM technology in South Texas. Virtually all drilling problems have been eliminated. Such technology is not yet used offshore in floating drilling operations, yet the drilling problems are vast and extremely expensive.

In deepwater Gulf of Mexico sub-salt wells, one specific hole interval has cost ConocoPhillips 20 to 40 million US dollars in trouble cost. It was felt that if a liner drilling system could be developed to allow one to case off the problems rather than fight them, then most of these costs could be avoided. Two sub-contractors were contracted to jointly develop a "close tolerance liner drilling" system, specifically targeting the 11-3/4" liner to be drilled through 13-5/8" casing: Tesco Corporation and Baker Hughes Incorporated, a premiere liner hanger company.

Work commenced in March, 2003. The design basis for the system was jointly agreed between Tesco, Baker Hughes and ConocoPhillips's deepwater business unit. A novel design evolved whereby the liner hanger and liner are hung on the drill string, and the drill string and bottom hole assembly (BHA) extend through the liner. All mud returns came up the inside of the liner. This results in two significant component designs: the novel liner hanger and running tool with the returns ports on the inside, and a seal above the liner hanger which isolates the liner annulus from the drill pipe above the liner. Baker Hughes is responsible for developing the liner hanger and running tool, and Tesco is responsible for developing the seal.

Since then, the design work progressed on all fronts, and the project team is on track to delivering the system, ready to use in a test well, by the first quarter of 2004.

Results and Discussion:

Each of the three projects is discussed separately below. This is the last of the reports on the subsea processing system deployment, however.

SUBSEA PROCESSING:

In the previous reporting period, two locations were investigated. They were in the Gulf of Mexico in approximately 4700' of water. In one case, the design called for a 33,000 BOPD SSP system with separate liquid export and gas export to a nearby facility. Power and control would come from that facility. The second system was similar in design but rated for 20,000 BOPD.

The first Gulf of Mexico location was an SSP and 4 wells approximately 5 miles from the host facility. The unrisks reserves ranged from 50 to 200 million barrels of oil recoverable. On an unrisks basis, this was shown to be economically viable. Once the risks associated with altering the host facility to accept the regional tie-in, with increased well count and expense due to reservoir compartmentalization, and the added geologic risk of a reservoir seal due to the underlying salt dome induced fracture system, the opportunity failed to meet fully risks economic hurdles.

The second location was to be one subsea well, producing to an SSP system and pumping the produced fluids to the host platform approximately 3 miles away. When this site was evaluated for the SSP application, the reserves interpretation indicated that primarily gas would be produced, which reduced the economic benefit of the installation. Well drilling costs were much higher than normal in the area, nearly \$70 million, due to reservoir geometry and the need to sidetrack this well after three years of production to drain the remaining 40% of the recoverable reserves.

During this reporting period, a third field development opportunity was identified. A two-phase development was proposed for a non-operated, smaller field in Norway.

The first phase provided for the drilling of 5 wells, tied back to a subsea separation package. Two export lines would be run: one for gas and one for liquids. The gas

Figure 1 – Subsea field development concept layout utilizing subsea processing.

would be processed and sold in Norway, and the liquids would have been separated and sold in the U.K. This SSP package would be used during the predominately water-free production period, estimated to be two years.

The second phase would add a water-handling package to the first subsea installation, and another separation package would have been added for additional field development. Five more wells would be drilled and tied back to this second package.

Figure 2 – Subsea Processing Components

This proposal offered several technical benefits.

- Initial capital expense would be significantly less than all other options. In fact, the initial facilities installation could be justified with only one additional appraisal well.
- The SSP package offered the flexibility of using existing platforms for processing the well fluids. The platforms could be selected based on spare capacity, most attractive commercial offer, or other criteria.
- The SSP package could be easily modified to accommodate the higher water-cut portion of the life, and the expenses to do so could be deferred.

Even in the 400' water depth proposal described, these benefits yielded very significant unrisks economic advantage: over 200 million dollars net present value. However, once the mechanical risk factors were applied with consequential interruptions in production, the more conventional and proven FPSO option was selected by the operator.

Despite the negative economic evaluations, there was sufficient technical work done to confirm that there are no technology gaps remaining for the SSP system. All that remains now is more field demonstration to help identify and resolve any real mechanical issues, and to help assuage the perceived risks associated with SSP.

COMPOSITE PRODUCTION RISER DEMONSTRATION :

Not all deepwater fields can be produced using SSP technology; floating structures are needed. As exploration and production of oil and gas move into deeper water, weight, cost, and reliability of water-depth sensitive systems such as risers become increasingly important. Composite materials offer several attractive properties, such as high specific strength and stiffness, lightweight, corrosion resistance, high thermal insulation, high damping, and excellent fatigue performance, making them a good candidate for deepwater risers. In addition, the use of composites permits greater design flexibility for tailoring properties to meet specific design requirements, thus promoting better system-oriented and cost-effective solutions. Capitalizing on these advantages for composite riser applications results in lower system cost and higher reliability for deepwater developments. Therefore, major efforts have been devoted during the last few years to assess the potential of composite materials for deepwater riser applications.

In spite of this high level of interest in composite risers and the large business opportunity, the commercial application of composite risers has remained tentative because of uncertainties associated with the difficulty of introducing new technology. This difficulty arises from emotional and perceived technical barriers in addition to serious concerns regarding potential escalation of cost and delays in schedule. It is believed that these barriers are generally removed after the first use. As a means of addressing the first use issue, field demonstration in the Gulf of Mexico is considered a key component for both industry and regulatory acceptance.

With a substantial financial contribution from the United States Department of Energy, Kvaerner Oilfield Products, ChevronTexaco and ConocoPhillips have initiated a Joint Industry Project to design, qualify and fabricate five to ten composite production riser joints for installation on one of the production riser strings on the Magnolia Tension Leg Platform (TLP) in the Gulf of Mexico. The success of this project in securing MMS approval, installing and operating the composite risers joints on Magnolia will open the door for exploitation of the economic advantages of the composite riser technology in deep and ultra-deep water field development. The Magnolia field, operated by ConocoPhillips, is in the facilities construction stage. The completion of this project will be consistent with the Magnolia Project schedule, with riser installation expected to take place in the third quarter of 2004. The lead contractor for the design, testing and fabrication of the composite joints is DeepWater Composites AS.

Also included in the project is an evaluation of in-service inspection methods that have the potential of being monitored remotely or by an ROV. The result will be to prove the technology in the Gulf of Mexico deep water and obtain actual performance data for application to future developments.

Magnolia Production Riser System General Description

The Magnolia TLP is to be installed in the Garden Banks Block 783 in the Gulf of Mexico. Approximate water depth at the platform location is 4,674 feet, a new record for a TLP. Production wells (up to 9) will be tied back to the TLP from the subsea wellhead utilizing an 11-3/4" OD production riser with a 4-1/2" production tubing inside. During normal production operations, well fluids will be flowing through the tubing. Completion, future workovers and potential sidetrack activities requiring removal of the tubing will be conducted through the 11-3/4" production riser. This wide variety of service conditions makes this project ideally suited for proving the composite riser technology.

The Magnolia production wells are being pre-drilled by a deepwater semisubmersible drilling rig and will be temporarily suspended at the subsea wellhead until TLP installation. The production riser will be latched onto the subsea wellhead at the seabed elevation, and will extend through the water, splash zone, air gap, and terminate in the wellbay at the surface (dry) tree. A tensioning system will support the riser from the tree deck. The riser will be installed and removed from the platform, by a workover/completion rig. Interfaces relevant for the composite riser joints will be connections to steel joints, as well as installation and handling issues.

Design Basis and Performance Requirements

The design philosophy for the composite riser joints is that they shall meet the same requirements as specified for the steel production risers when applicable. It is required that the composite riser shall have at least the same safety level as the steel production riser. A global system analysis including the composite joints will be performed to establish the riser loadings (extreme and fatigue loading). The final number of composite riser joints also has to be verified from the global riser analysis, i.e., whether the proposed system can meet the clearance requirements (clearance between composite production riser and adjacent steel production risers).

The following are some of the key design data for Magnolia riser strings:

- Water depth: 4,674'
- Minimum riser initial center to center spacing: 20'
- Riser ID: 9.625"
- Minimum drift diameter: 9.5"
- Make up Joint Length: 62.75'
- Applied top tension:
 - Normal production: nominal 647 kips
 - Well killed, 100-year hurricane: 1,318 kips
- Annulus content, normal production operation: Nitrogen at 100 psi
- Factory acceptance test, steel joints: 11,250 psi
- Rated working pressure: 10,000 psi
- Maximum Temperature: 165°F

Design Life 20 years

CO₂ : 0.5 mol %

H₂S: none

Composite Riser Joint General Description

The basic concept of the Magnolia composite production riser joints will be similar to that used in a previous field demonstration of a high-pressure composite drilling riser joint on the Heidrun TLP in the North Sea.

A composite production riser joint consists of the following component parts (see Figure 3):

Inner liner: A thin (0.165" wall) steel inner liner is used as a gas permeability barrier. During production operations, the annulus is normally filled with nitrogen, and no corrosion allowances are needed.

Rubber layers: A rubber layer (HNBR) between the inner steel liner and the composite body will be applied, as the secondary seal. A rubber layer will also be used as the external liner, to prevent water ingress into the composite body. Additionally, and subject to detailed design and testing, a layer of permeable material may be inserted between the steel liner and the inner rubber layer, if it is shown to mitigate liner collapse risk.

Composite body: Carbon fibers in helical and hoop directions together with an epoxy resin system will be applied as the structural composite laminate.

Outer protection: Glass fiber and epoxy resin composite is used as a compaction wrap and scuff protection layer over the external rubber jacket. Alternative materials for the outer protective layer will also be investigated.

Metal Composite Interface (MCI): Loads applied to the steel connector extensions are transferred into the Structural Composite Overwrap (SCO) through the grooves in the MCI. MCI geometry and construction result in a true mechanical interlock between the SCO and fitting, with all load transfer through bearing between composite and metal surfaces.

Threaded connectors: The end connectors will be identical to the ones selected for the steel joints. This means that a composite joint can be directly inserted between two steel joints, without any adapter.

Steel Spoolpiece: A 4.6 ft long tubular spoolpiece, cut from the same pipe used for the steel joints, will be welded between the box connector and the MCI. Its only purpose is to allow handling and make up of the composite riser joints on the completion rig, using the same tooling package as for the steel joints. Therefore, the insertion of composite joints in the riser will not have any rig time impact. In the

Technical drawing of the Magnolia Composite Production Riser Assembly, showing longitudinal and cross-sectional views.

Longitudinal Section Dimensions:

- Overall Length: 630.37 (152.53 FEET)
- Box Connector Length: 93.46 (17.79 FEET)
- Spool Piece Length: 55.52 (4.63 FEET)
- Pin Connector Length: 39.64 (3.3 FEET)
- Internal Section Length: 66.03 (15.5 FEET)
- Internal Section Length: 10.5 (0.88 FEET)
- Diameter: Ø9.595

Cross-Section (Detail B) Dimensions:

- Width: 12.3
- Layers (from top to bottom):
 - Outer Protection
 - HNBR Rubber
 - Structural Composite
 - HNBR Rubber
 - Steel Liner

Composite Riser Properties

By comparison, a steel riser joint weighs approximately 127.4 lb/ft in air. The relative weight reduction in buoyed conditions is further enhanced by the larger displacement volume and lower density of the composite material.

Design Verification Testing

The purpose of the tests is to validate the accuracy of the finite element analysis and to demonstrate confidence that the manufactured composite production riser joint meets all the requirements, as well as establish base data for evaluating actual performance on Magnolia. In order to achieve these goals, a number of full-scale diameter/short length (10 ft) composite riser joints will be tested under a sequence of static and fatigue loads. The test program will include an internal pressure test and axial load test (both taken to ultimate failure), an external (collapse) pressure test to a level in excess of Magnolia water depth, axial fatigue tests, and external impact tests to gauge the efficacy of the external protective glass fiber layer.

In Service Inspection

In service inspection is recognized as an important element in capturing operational performance data for future applications. ConocoPhillips has demonstrated the successful use of fiber optics in monitoring progressive delamination damage to composite riser laminates. In addition, tests will also be conducted on the use of trip metal. Evaluation of these methods will be considered as part of the current program. Selected test joints will be fitted with such monitoring devices, and measurements will be taken during the design verification testing. Depending on the test results, the potential for offshore deployment will be investigated. Once the riser is in operation, visual ROV inspections will be performed. Inside caliper logs will also be run through the riser during workover operations to ascertain the integrity of the inner steel liner. Whenever the riser is pulled after a number of years of service, the composite joints will be shipped to a suitable facility for close examination and post-operation testing.

Project Status

A risk assessment has been conducted using Det Norske Veritas (DNV) Failure Mode and Effect Analysis (FMEA) methodology. A joint team of DNV and ConocoPhillips technical personnel performed this risk assessment. The study highlighted some issues to be addressed in the detail design (mainly related to the vulnerability of the inner steel liner to buckling), but concluded that the introduction of the composite joints in one of the riser strings will not significantly impact the Magnolia TLP risk exposure.

Detailed engineering and design work, including an initial finite element analysis model, fabrication specifications and drawings, followed through Summer 2003. The procurement of long lead items for the test samples has been initiated and ten sets of field joint threaded connectors (identical to the steel joints) have also been ordered. A first technical challenge, the qualification of welding procedures for the thin (0.165") inner steel liner, has been successfully overcome. As of this writing, preliminary test samples were being fabricated, for the purpose of evaluating a way to alleviate the buckling tendency of the inner steel liner, as well as developing a high pressure seal between MCI and inner rubber liner.

CLOSE TOLERANCE LINER DRILLING:

With very mature fields, where reserves per well are steadily decreasing, the economic limit will eventually be reached. This was the case in ConocoPhillips' South Texas Lobo Field, and in 2000, the business unit was faced with the dilemma of significantly improving cost performance or abandoning further development of the field. The Lobo asset team explored various ways to find this potential step-change, and Casing DrillingTM was recognized as a drilling technique that offered this potential.

Casing DrillingTM is a process whereby the drilling assemblies are not run on drill pipe, but are instead run extending from the end of the casing that will be set at the end of the drilled interval. As such, a casing-drilling rig will not utilize drill pipe at all. The "drill string" is the casing itself.

The anticipated value of Casing DrillingTM was the elimination of the time required to condition the hole and trip out drill pipe at each casing point. The Lobo wells have 3 or 4 casing strings, so this time could be fairly significant in comparison to the total drilling time. The realized benefits far exceeded this expectation; the casing-drilled wells very seldom experienced the typical drilling challenges found in the Lobo Field.

- The Queen City, notorious for lost circulation problems, became quite manageable.
- In some cases, a casing string has been avoided.
- The mud weights required to control the well are reduced by up to .5 ppg.
- Stuck pipe has all but disappeared.

Today, after drilling about 60 wells, there has only been one case of stuck casing, and that did not cause the loss of a well. The casing while drilling rigs are preferentially directed towards the most troublesome areas of the field. The minimum economic field size in Lobo has been reduced significantly, breathing new life into the field.

Taking Casing DrillingTM Offshore

The onshore application of the Casing DrillingTM has been highly successful, but the actual cost savings are diminished as the daily spread costs in South Texas are not that great. On the other hand, if similar time-related savings and problem avoidance are applied to the deepwater areas of the Gulf of Mexico, the savings could approach several million dollars per well. This was the rationale used to launch the "Close-tolerance liner drilling" effort.

This effort is targeted towards floating operations in the deeper water Gulf of Mexico. The wells are all subsea, so drilling is never done with casing in the rotary table. Instead, the casing is always run on the drill string, hence the term "liner drilling". Inherent in the deepwater wells is also the need for up to 8 or 9 casing strings, so the "close tolerance" aspect is needed.

ConocoPhillips initiated discussions with several vendors in early 2003 to ascertain the commitment that each was willing to make in delivering liner drilling to Industry. After these discussions, Tesco and Baker Hughes were asked to cooperatively develop this technology. The two companies offered expertise that when combined, would develop a technically superior system capable of safely and efficiently drilling the subsea wells.

System Description

The first liner size to be worked on has been the 11-3/4" OD liner run inside of 13-5/8" casing (12.375" ID). There are several requirements for this hole interval that drive the liner drilling system design:

- 5000' length
- Setting depths to 25,000',
- Directional drilling capability,
- Formation evaluation (Logging while drilling capability), and
- Synthetic based drilling mud.

The directional drilling and logging while drilling requirements require that the liner have a drilling assembly hanging below it, similar to the way that the onshore casing while drilling is done. The annular clearance between the liner and the casing is so tight, that it would be impossible to circulate mud returns up this annulus without fracturing the exposed formation. Therefore, the design also requires that returns come up the inside of the liner.

Meeting these two broad requirements requires that the drill pipe be run through the liner with the drilling tools hanging below it. Consequently, the liner is hung from the liner hanger and is not exposed to the drilling torque. Circulation ports had to be designed into the liner hanger to accommodate the mud returns.

Figure 4 – Liner Drilling Configuration

There are two other requirements that impact the design: the desire to sweep the open hole annulus of any cuttings, debris or influx materials, and the need to address a well control

incident when the liner and drill string are across the BOP stack. To meet the first requirement, a reverse-circulation port was built into the liner running tool, and it is ported to divert a small portion of the mud from the drill string down the backside of the liner. This can only be done with the introduction of a seal at the top of the liner hanger that forces the mud to go down the tight annulus rather than directly out above the liner top. This is called the “Dynamic Casing Seal” (DCS). To meet the second requirement, an “Inner Annulus Valve” (IAV) had to be built into the running tool that allowed rapid closure of the liner by drill pipe annulus when needed. This isolates the drilling riser from the conduit through the liner to the wellbore below the blowout preventer.

Testing:

The new liner drilling system must be exhaustively tested before it will be used offshore. The testing objectives include:

- Prove that the seal integrity is maintained after tripping into the well for 15,000’ and while drilling for the subsequent 5000’.
- Prove that the liner hanger and packer can withstand the loads and conditions associated with drilling 5000’.
- Prove that the liner can withstand the cycles associated with rotating for that same duration.
- Prove that the IAV and reversing port and valve maintain their integrity over this duration.
- Understand the unique hydraulics associated with this system. Especially challenging are the surge and swab characteristics of the system.

At the time of this writing, the plans for this testing are being developed. It is anticipated that the shop testing will occur in December 2003, followed by onshore drilling operations testing in January 2004.

Drilling and Well Control Procedures:

In parallel with the liner drilling system development, the procedures for using it safely and efficiently had to be developed. This was an iterative process, as many of the procedures led to design features that needed to be included in the liner drilling system. Conversely, limitations in the mechanical design had to be overcome with adjustments in the drilling and well control procedures.

Ideally, the liner drilling sequence would be:

1. Drill the hole interval.
2. Hang the liner.
3. Cement the liner.
4. Set and test the liner top packer.

5. Pull out of the hole with the drilling assembly.

However, the equipment necessary to do this would be extraordinarily complicated. The liner drilling team opted instead to do the operations in two trips: the first for drilling the interval, hanging the liner and setting the packer, and the second for cementing the liner and testing the packer. In effect, the trade-off was taking more time in return for reducing mechanical risk of failure.

The liner being used will be near-flush OD, as opposed to a threaded and coupled connection. This is not a typical drilling connection, so finite element analysis and fatigue testing is being done on the connections being considered. The only torque experienced by the liner will be associated with hole friction, or with inertia. The latter concern is one reason that many different pipe rotary speeds are being looked at to minimize problems with critical speeds causing dynamic vibration.

There appear to be very few significant differences in the drilling procedures otherwise. There are a few key areas where additional diligence is required. One is hydraulics; the equivalent circulating density (ECD) is higher with liner drilling than it is conventionally. Surge and swab pressures are also higher, so additional care must be taken while tripping. Another focus area is the dynamics of the drill string. At this time, it is not known exactly how the drilling assembly will behave, but extensive predictive modeling has been done, and it will be validated during the upcoming testing program.

One consequence of the vibration concerns is the selection of a concentric reamer as the hole opening device that must be below the liner. These devices typically can enlarge a hole by about 20% over its pilot hole diameter. However, the liner drilling requires about a 30% enlargement. So one vendor extended the capability of its concentric reaming tool to meet this need. That tool will be run in the test well also.

Well control appears to be fairly routine in most situations. The one exception is when the liner, encasing the drill string, is across the blowout preventer (BOP) when an influx is observed. The BOP is not capable of shearing both the liner and the drill string. This is a very low probability event, but it must be provided for. This need resulted in the Inner Annulus Valve, referred to earlier. Its purpose is to provide an effective barrier against wellbore pressure so that the liner and drill string can be stripped through the BOP and run to bottom so that the well can be killed using routine well control procedures.

Path Forward:

The testing should end in January, 2004. Assuming success, preparations will be made to take the equipment to a deepwater drilling rig shortly thereafter. Those preparations will include the development of the training materials to acquaint the drill crews with the equipment and educate them as to the differences in the drilling and well control procedures.

If the close tolerance liner drilling yields the same benefits as have been seen onshore, this technology and drilling technique may well become quite common, helping to open the door to more economic exploitation of the deepwater reservoirs, and the exploitation of smaller reservoirs.

Experimental Apparatus: None

Experimental and Operating Data: None. Findings and data associated with analyses are in the body and conclusions of this report.

Data Reduction: This is included in the main discussion. Inputs and interpretations from geoscientists for example as to the ratio of oil to gas in the reservoir was garnered at team meetings and used in our economic evaluations that ensued.

Hypothesis and Conclusions:

The deepwater environment is fraught with very significant economic challenges. It is vital that Industry learn to lower the costs associated with its development. Technologies such as subsea processing, composite production risers and close tolerance liner drilling are only a few of the technologies that Industry and the Department of Energy are collaborating on. With time, that partnership will yield great dividends for our industry, and for the United States taxpayers in the form of increased royalty revenues from this resource base.

The subsea processing technology is quite advanced, and has been successfully applied in Norway by Norsk Hydro. It is only a question of time before additional deployments are done, and with that further proof, the benefits of the technology will become more widely apparent and Industry will actively extend its application. However, no ConocoPhillips opportunities have yet been identified which can economically apply the SSP technology.

Informal feedback from various deepwater operators has shown a high level of interest in the composite production riser project. It appears that many see the potential for this technology, but most are waiting for someone to be the “first mover”. Because this project involves inserting a limited number of composite joints in a steel riser, the composite joints will be subject to all the high loads seen by the steel riser. This translates into more severe design criteria than a lighter weight, full composite riser would be subjected to. As such, the Magnolia composite riser is more technically challenging. However, the work performed so far shows that this challenge can be successfully met in time for the Magnolia TLP installation in 2004.

The close tolerance liner drilling project is well underway. Thus far, there are no identified technical hurdles which cannot be overcome. The project is on track to perform onshore field testing in 1Q, 2004. Assuming success, it will then be ready for offshore application. ConocoPhillips, for one, desires to have this technology available as the preferred way of avoiding or overcoming problems associated with sub-salt drilling in deepwater. We firmly believe that the various casing while drilling technologies hold tremendous promise. Indications are from the various related conferences that much of Industry is also starting to take notice.

Invoice Summary Sheet: DEFC2600NT40964

1. October 2000 to June 2000	Total Cost Incurred	\$494,797.28
	Conoco Inc.	\$324,458.78
	Kvaerner (10/2000 to 4/26/2001)	
	\$170,338.50	
	DOE reimbursed	
2. June 2000 to September 2001	\$164,932.43	
	DOE Balance	\$1,835,067.57
	Total Cost Incurred	\$281,471.40
	Conoco Inc	\$42,594.59
	Kvaerner (4/27/01 to 6/29/01)	
3. October 2001 to August 2002	\$238,876.81	
	DOE reimbursed	
	\$93,823.80	
	DOE balance	\$1,741,243.77
	Total Cost Incurred	\$361,784.72
	Conoco Inc.	\$361,784.72
	DOE reimbursed	
	\$120,594.91	
	DOE balance	\$1,620,648.86