Ultra-Deepwater Production Systems Technical Progress Report

September 30, 2001 – September 30, 2002

E. T. Cousins Conoco, Inc. Houston, Texas

Title Page

Report title: Technical Progress Report-Annual

Reporting Period Start Date: 9/30/2001

Reporting Period End Date: 9/30/2002

Principal Author: E. (Eddie)T. Cousins

Date Report was Issued: April, 24 2003

Doe award number: DE-FC26-00NT40964
Submitting Organization: Conoco Inc.*
600 N. Dairy Ashford
Houston, Texas 77252
Significant subcontractor: Kvaerner Oilfield Products Inc.

***Note- Conoco Inc. merged with Phillips Petroleum in September 2002. The company name now is ConocoPhillips Inc.**

Disclaimer:

Abstract:

This report includes technical progress made during the period October 2001 to October 2002. At the end of the first technical progress report the project was moving from feasibility of equipment design work to application of this equipment to the actual site for potential demonstration. The effort focuses on reservoir analysis cost estimations of not only the sub-sea processing unit but also the wells, pipelines, installation costs, operating procedures and economic modeling of the development scheme associated with these items. Geologic risk analysis was also part of the overall evaluation, which is factored into the probabilistic economic analysis. During this period two different potential sites in the Gulf of Mexico were analyzed and one site in Norway was initiated but not completed during the period. A summary of these activities and results are included here.

Table of Contents:

List of Graphical Materials:

- **Summary cost sheet**

Introduction:

The report herein is a summary of technical progress of the project to demonstrate ultra deepwater hydrocarbon production methods applicable to deep and ultra deepwater field developments in the Gulf of Mexico and other like applications around the world. The importance of this work is based on the advancement of technology, which will enable development, and exploitation of reserves in ultra- deep, remote areas beyond the capabilities of conventional technology. Reserves in these areas can add significantly to reducing the United States dependence on foreign oil supplies.

Executive Summary:

Two site evaluations were made and the analysis associated with each of these Gulf of Mexico locations were done to a level of accuracy to move them to the project funding investment decision level. The first site evaluation included geologic and reservoir evaluation, fluid chemistry impacts, capital cost evaluations, and economics. The second site approximately 3 miles east of the Magnolia Field was next evaluated in a similar way. Neither location would support a positive investment recommendation after risking these prospects was done.

The first site was approximately five miles west of Magnolia Field in 4700' of water and required four wells, one pipeline for gas, one pipeline for oil / water stream, the sub-sea process and all associated flowlines and umbilicals for control, power etc. The overall cost estimate for early feasibility economics indicated a capital cost estimate of more than two hundred million dollars to install. The geologic setting in this area is seismically very complex with very steeply dipping structures due to salt induced fracture systems over the area of potential development. The risk model available during the study phase of this site was applied to the capital cost estimates done as part of this feasibility effort. The geologic complexity and potential for no competent structural seal proved too risky for investment managers to support further engineering efforts to move this project forward. The cost estimating work on equipment and wells was used in the next site application since they were relatively close in distance, water depth, and so on.

The second evaluation was done on an offset to the main Magnolia Field in GB 784. The main Magnolia project development plan did not include this offset because it was too far away and too risky to drill to three miles from the tension leg platform location. Work was completed here to show that tieback to Magnolia did not economically justify further investigation, as all cases in the P10/ P90 range of outcomes were sub-economic based on currently available data.

Early views of reserves accumulation size and fluid characteristics have been modified significantly with new seismic data and associated interpretation. This new information indicates the much higher likelihood that the reservoir is gas whereas prior interpretations of existing data indicated oil. The accumulation size across the full range of reserve possibilities was also reduced.

One of the cost elements namely the drilling and completion cost was significantly increased also after the February 2002 peer review meeting. It was agreed that because of the structural complications associated with these reserves in 784 that the production well cost of approximately forty million dollars for drilling and completion would require a sidetrack step out in about three years after first production in order to produce the remaining forty percent recoverable reserves now indicated. The sidetrack added some thirty million dollars to the well cost. After reserve size and hydrocarbon types were

evaluated the resulting probabilistic economics and expected monetary value were negative.

The sub-sea separation and pumping equipment necessary to operate in these water depths and with these fluid characteristics are currently available on the market and application of this technology need only meet economic hurdles to be applicable. Soon after completing this evaluation another opportunity to apply sub-sea processing in Norway arose. This new opportunity was reviewed with DOE Project managers at the end of 2002 and work began here moving towards reserves, costing and so on after determining this met project requirements even tough it was not in the Gulf of Mexico like the first two evaluations.

Results and Discussion:

Conoco and Kvaerner completed the first feasibility study for application of sub-sea separation and pumping technology in 2001 with financial support from the Department of Energy and two-thirds cost shared by Conoco and Kvaerner. The study focused on an offset block to the Magnolia development with a potential for four wells tied back to a sub-sea processing unit capable of handling 33,000 Bopd with liquid export and gas export to Magnolia for further processing and sale.

The design objectives were to prove technical feasibility for such a system that would be capable of operating in water depths of up to 10,000 feet of water in the Gulf of Mexico and at a step out nominally of 50 miles from a host facility. Included in these objectives was the eventual identification of technology gaps that might exist in order to meet design conditions. One such area of technology was the need for electrically powered controls and the associated rangeability for the production life of the reserves to be harvested. Reliability issues and intervention for maintenance and reconfiguration were also prime considerations to be studied.

Early generic economics indicated that the sub-sea processing concept afforded advantages to project value due to lower capital cost, short life cycle benefits, relative insensitivity to water depth, and low operating expense relative to conventional manned operations. The carrot associated with this technology in deep water could be as much as one hundred million dollars per application due to these benefits. Some enhanced recovery benefits were also identified due to the lower abandonment pressures possible, however the reservoir fluids could mitigate these benefits if high GOR characteristics were present. It was also clear that very deep-water applications of this technology may prove to be enabling technology and or much more economically viable than conventional means.

Offset to Magnolia Evaluation #1:

The first feasibility run with sub-sea separation and pumping evaluated a reservoir development 5 miles from Magnolia in approximately forty seven hundred feet of water. Unrisked recoverable reserves ranged from fifty million barrels of oil recoverable to two hundred million barrels of oil recoverable. The reservoir structure was heavily faulted and discontinuous due to salt dome structural influence and recovery as well as well trajectory issues became high risk factors. Conoco investment interest in this area was and still is debatable due to the high risk of capital recovery from an investment of approximately two hundred million dollars with sub-sea processing here. It was shown that economic viability of such a development could occur at fifty million barrels of oil recoverable, un-risked, with a host facility in range. As the situation developed further and business unit evaluations focused more on Magnolia as the better development option and manageable risk level it became clear that a more regional development with risk and capital implications would not meet investment decision makers' entry criteria.

It should be stressed however that the benefits associated with this feasibility effort helped to crystallize design issues and identify technology gaps for this specific application. One large benefit was that all elements of the system recommended for application here were sourced and no fundamental technologies were missing completely. The only component not commercially available was an electrically actuated control valve in the separation control process. The actuator has been designed and built but not yet applied in this environment.

Offset to Magnolia #2:

A second feasibility estimate was done on the GB784 offset to Magnolia GB783. This opportunity was a one well tie–back some three miles from Magnolia center. Reserves estimates at the start of this effort ranged from eight million barrels oil equivalent recoverable to twenty five million barrels of oil equivalent recoverable. Water depth here was also approximately forty seven hundred feet deep and reservoirs (B-20) similar to the main field. Before running any cost estimates it was necessary to work the reservoir issues in more detail first since opinions on range of reserve size, drive mechanisms, fluid characteristics and reservoir pressures varied widely. A task force led by Jim Young and including Susan Young, Bill Landrum, and others from the Magnolia Finding team evaluated the data available in late 2001/early 2002 and held a peer assist meeting in February 2002 to review resulting reservoir descriptions, early development costs and associated economics for the tie-back.

During the peer review new data (3D-seismic) was made available on the reservoir being evaluated. The oil to gas reserve ratio case and total reserve size ranges changed as a result of this new data. This had the effect of reducing the potential development value significantly. The ratio of oil to gas initially was seventy percent to thirty percent. This changed to thirty percent to seventy percent oil to gas with new data and consensus of the geologic and geophysical people in the peer assist.

Secondly it was determined that due to the reserve distribution and reservoir structural anomalies the initial well cost of nearly forty million dollars would need to be increased by approximately thirty million dollars net present cost to account for a sidetrack in year three of production to recover forty percent of the original estimate of recoverable reserves.

The resultant P50 reserve sizes were reduced to the P90 levels on the original reserve size estimates indicating a recoverable range of eight million barrels of oil equivalent from twelve million barrels. Additional action items listed below were raised at the peer assist meeting and are in the process of being cleared.

- Establish Ps for both B-20/25 and B-15 horizons on risk sheet
- Evaluate 'P' Series prospect identified
- Check 785#1 porosity and water saturation in B-20/25
- For oil, 800 scf/stb GOR too low, use 50%-1800 scf/stb and 50%-2800 scf/stb
- B-20/25 probability of gas = 70% and probability of oil = 30%

- Check estimated saturation pressure
- Oil recovery factors look high, typical associated gas RF = 50-60%, NA gas RF = 55-60%
- Check CAPEX range for SS Equipment
- Topsides Equipment requirement - methanol storage, pump & recovery. Power - - Don't include cost for Hull since this will ultimately be required by some SS project
- Fixed O&O - $1.85MM/yr
- Oil well O&O - $.9MM, $1.2MM, $1.5MM / well
- Gas well O&O - $0.6MM, $0.75MM, $0.9MM/ well
- Processing cost $0.22 / bbl
- Need sidetrack cost for Southern Pod of B-20/25
- B-15 down dip continuous aquifer toward Magnolia
- Due to the B-20/25 structure shape including local high areas and saddles and potential for bottom water drive, it was recommended to use the main area with a .83 N/G as the P50. The southern pod could be accessed after depletion of the B-15 with a sidetrack. P10 case would include a larger area & P90 case would have same area with a lower N/G.
- Recommended range for Water encroachment angles - 90 deg, 180 deg, 270 deg
- Assume Royalty Relief

After reviewing these new data and further consultation with the Magnolia team the summary data and economic ranges have resulted in a negative economic result for the sub-sea tieback prospect.

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 benefits of the sub-sea separation application here are primarily in the area of flow assurance in reducing the requirement for methanol injection .The current scheme for Magnolia production includes methanol injection and recovery systems to control hydrate formation in the flowlines. The 784 offset would require additional methanol treating and processing capacity on Magnolia or perhaps pipeline heating for the 3-mile tieback. The SSP unit installed cost estimate of twenty three million dollars can be compared to these other options when data is available. Further work to develop these comparison figures was not done since the reserve picture deteriorated and drilling capital cost increased significantly with the peer assist information mentioned above.

It is still a possibility that the offset GB784 prospect may be tied back to Magnolia in the future with acquisition of more data that could improve the risk picture now seen. If an exploration well is drilled there and higher oil content with lower reservoir pressures and confirmation of water production potential then SSP should again be evaluated with the other options for development. It is clear however that at this time a tie back to Magnolia with current risk levels and capital cost requirements, that recovery of these reserves would not be economic.

Invoice Summary Sheet: DEFC2600NT40964

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

*Note: There is one invoice for Kvaerner costs through the end of 2002 for approximately $53,000 of which $17,666 approximately should be invoiced. This may still be in the mill somewhere but this should be the last invoice bringing the total DOE balance to date of approximately $1,602,982.86. I will follow up here to verify that last invoice.