230AB

51

CEAC-TR-96-0104

ASSESSMENT OF THE ECONOMIC BENEFITS OF USING COMPOSITE MATERIALS FOR OFFSHORE DEVELOPMENT AND OPERATIONS

PHASE 1

PROPRIETARY INFORMATION

DECEMBER 1996

COMPOSITES ENGINEERING AND APPLICATIONS CENTER FOR PETROLEUM EXPLORATION AND PRODUCTION

UNIVERSITY OF HOUSTON
HOUSTON, TX 77204-0900

230 B

CEAC-TR-96-0104

ASSESSMENT OF THE ECONOMIC BENEFITS OF USING COMPOSITE MATERIALS FOR OFFSHORE DEVELOPMENT AND OPERATIONS

PHASE 1: COST SAVINGS RELATED TO WEIGHT REDUCTION

FINAL REPORT

PROPRIETARY INFORMATION

December 1996

Composites Engineering and Applications Center
for
Petroleum Exploration and Production

University of Houston
Houston, Texas

This study was commissioned by the Composites Engineering and Applications Center (CEAC) for Petroleum Exploration and Production at the University of Houston in response to a request from its membership. The study was carried out by the Offshore Working Group (OWG) led by Richard M. Vennett (CEAC). Other Members of the OWG include Partha Ganguly (BP Exploration), Him Lo (Shell Oil Products) and Jerry G. Williams (Conoco Inc.). The full CEAC membership was called upon as a resource during the conduct of this study. The Center expresses its appreciation to the members which assisted in this project. CEAC members include: Amoco Corporation, BP Exploration Inc., Conoco Inc., Phillips Petroleum Company, Shell Oil Products Company, Ameron Fiberglass Pipe Systems, McDermott International, Smith Fiberglass Products Inc., U.S. Department of Energy and U.S. Minerals Management Service.

Su Su Wang
Distinguished University Professor and
Director

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY

The oil industry continues to search for new ways to reduce the cost of finding and producing oil and gas, especially in the deep water regions of the Gulf of Mexico where the most promising discoveries have been made in the U.S. in recent years. The need to reduce investment and operating costs for deep water developments has led the oil industry to evaluate a number of new technologies that offer the potential to lower the cost of production. Composite materials have been identified as a technology which could provide significant impact, but the payoff has not yet been adequately assessed or quantified.

The members of the Composites Engineering and Applications Center (CEAC) for Petroleum Exploration and Production at the University of Houston initiated this study to assess the overall potential of composite materials to reduce investment and operating costs on future developments in the Gulf of Mexico. Based on the results from Phase 1 of this study, the CEAC members may wish to sponsor additional studies to examine in more detail certain aspects of the offshore application of composite materials.

Assessments of economic viability can be made at different levels of detail and complexity. Level I is simply cost savings resulting from weight reduction by replacing steel with composites. Level II evaluates maintenance and life cycle cost savings associated with operations. Level III considers the enabling benefits of a new technology and the high potential for significant cost savings. Level IV is a system analysis that evaluates various field development configurations to take full advantages of all the benefits available with composite components. This study has mainly concentrated on a Level I approach with some consideration given to a Level II analysis. Although very little work was done evaluating the enabling benefits (Level III) of composites, the potential payoff appears to be tremendous for certain situations.

Two deep water development Case Studies were used in this study: a TLP located in 4,000ft of water and a FPS in 6,000ft, both providing a production capacity of 100,000 BOPD. It was assumed that composites would be used where significant weight savings could be expected and where the performance of the composite components would be comparable or better than the metal component. A value of $8,500 was credited for each ton of topside load saved on a TLP ($4.25/lb) and $7,000 for each ton saved on a FPS ($3.50/lb). A third Case Study centered on a small production structure (SPS), where a value of $2,000 was given to each ton of topside weight saved ($1.00/lb). The SPS case was a minimum facilities installation designed for minimum maintenance.

This study concluded that significant weight could be saved through the use of composites for topside facilities, production risers and structural beam applications. More specifically, the study found that:

- The biggest targets for weight savings in a TLP and a FPS are the production risers, the topside equipment, structural beams, mooring tendons (TLP only) and the drilling equipment.
- The total Level I and Level II economic benefit of using composites estimated over the life of the project for the TLP scenario (with steel mooring tendons) is almost $70 million. This

consists of a net investment cost saving of $25 million, a maintenance cost saving of almost $6 million, and increased revenue of $38 million from reduced production down time. The total weight saving using composite components for the 4,000ft TLP scenario (steel tendons) is 3,140 tons.

- Composite production risers offer the biggest overall weight and cost savings of any major component for a deep water TLP. The net cost savings for composite risers is estimated to be $14.9 million with a weight saving of about 1,810 tons.
- The topside weight can be reduced by approximately 12% through the use of composites. This translates to a cost saving of $10-11 million for a TLP and over $8 million for a FPS. This topside equipment cost saving will increase significantly if composites are used to replace duplex stainless steel, copper-nickel, or titanium piping and vessels instead of carbon steel.
- Composite TLP tendons have the potential to reduce the load carried by the hull in 4,000ft water depths by almost 3,220 tons. Since composite components generally exhibit superior fatigue performance compared to steel, even greater savings would be possible if the composite tendons could be designed with lower overall axial stiffness than that of the steel tendons. Preliminary indications are that composite tendons are not economically attractive based on equivalent axial stiffness in 4,000ft because steel tendons at this depth can be made partially buoyant without a significant cost penalty.
- The economic attractiveness of composite TLP tendons will increase in water depths approaching 6,000ft and beyond, especially if a reliable, low cost spoolable composite installation system is developed, and if the axial stiffness requirements can be reduced.
- The total economic benefit estimated over the life of the project for the FPS scenario is about $52 million. This consists of a net investment cost saving of $8.2 million derived from the topside application of composites but with steel risers, a maintenance cost saving of almost $5.6 million, and increased revenue of $38 million from reduced production down time. The total weight savings for the 6,000ft FPS scenario is about 1,348 tons.
- The total economic benefit estimated over the life of the project for the SPS scenario is about $2.2 million. This consists of $0.73 million in net investment cost saving, a maintenance cost saving of $0.05 million, and increased revenue of $1.40 million from reduced production down time. The total weight savings for the SPS scenario is about 155 tons.
- Composite structural beams fabricated using the low cost pultrusion process have the potential to provide significant weight savings in the topside and deck as replacements for steel structural members. Saving a ton of topside weight with composite beams will increase material cost about $2,050, but this is expected to be offset by lower installation costs.
- Downhole and subsea applications such as composite drill pipe, coiled tubing, and subsea lines may have significant economic payoff by reducing operational costs, but they will generally have very little direct impact on the weight and cost of a TLP or FPS, and thus fell outside the scope of Phase 1 of this study.

Based on the findings of Phase 1, it is recommended that Phase 2 involve a systems level analysis of floating production platforms in ultra deep water and that the areas of composite structural elements , and composite tanks and vessels be given a more detailed assessment. These three new projects will address barriers associated with the application of composites offshore and will accelerate the availability of new, cost-effective technology into deep water E&P operations:

1. Phase 2 of the Offshore Economic Assessment Study will involve a systems level analysis for floating production platforms in 6,000-10,000 feet of water to include platform system configuration, and composite risers and mooring systems for a TLP, FPS, and a Deep Draft Floating Caisson (DDFC) platform. This could lead to a detailed study of composite TLP tendons for ultra deep water if the preliminary economic assessment is favorable.
2. Determine the most effective way to take full advantage of the weight saving potential of hybrid composite beams. Issues such as composite-to-steel beam attachment methods, composite reinforcement of steel beams, and deck configurations optimized to benefit from composite structural members should be addressed.
3. Thoroughly evaluate the use of composite storage tanks and process vessels for topside facilities with emphasis on defining and expanding the temperature and pressure allowable operating ranges, and development of design standards and specifications.

It is anticipated that each of these three project areas may evolve into a JIP with one or more manufacturers as participants in addition to interested oil and service companies. It is recommended that CEAC charter a task group(s) to conduct a preliminary study to define and develop these project areas.

In addition to the recommendations shown above, the Offshore Working Group believes that downhole applications of composites, deferred in Phase 1 because they had little impact on platform weight, have such great potential for reducing costs and offering enabling benefits that they should be investigated in a separate CEAC study.

Also, it is in the best interest of the oil industry to continue to support the NIST ATP projects (drilling riser, drill pipe, production riser, and spoolable tubing) and provide the opportunity to field test full size prototype components once they have successfully passed all the laboratory and preliminary tests. Field testing of these components is a critical and very important step in their final acceptance for use offshore.

As the remaining barriers to the wider application of composite materials are overcome and the oil industry fully accepts composite components where they are cost-effective, the oil industry will achieve a new level of overall cost efficiency. Over the next 3-5 years, many new composite products will successfully emerge from development and field trials to full commercialization. These new products will offer the oil industry additional development and retrofit options plus the enabling benefits of composite materials in certain situations with the associated potential for very significant economic benefits. Benefiting from the great potential of composite materials will require innovative engineering and development concepts. Composite production risers, structural elements, tanks and vessels, spoolable tubing and pipe, drill pipe, downhole tubulars, and mooring tendons have the potential to provide significant cost savings and breakthrough enabling technology to the offshore oil industry. The application of composite materials to the cost effective development of deep water discoveries will continue to be an evolutionary process.

2. INTRODUCTION

2.1 Background

The oil industry continues to search for new ways to reduce the cost of finding and producing oil and gas. This is especially true for reserves found in deep water where the costs of the platform and associated infrastructure are significantly higher. The oil industry has steadily moved into deeper offshore areas around the world over the past 30 years as technology has advanced to keep pace with the increasing need to find and produce more oil and gas (Figure 1). Oil and gas produced from deep water reservoirs sells for the same price as oil and gas produced worldwide from relatively shallow and less costly onshore wells. Fortunately, the size and production capacity of some deep water reservoirs have been sufficient to justify the higher development cost.

The most promising new oil and gas discoveries in the U.S. have been found in the deep water (greater than 1,000ft) areas of the Gulf of Mexico (GOM) (1). The Minerals Management Service (MMS) lists 24 undeveloped discoveries in the GOM below 2,000ft (Table 1). The list in Table 1 includes the Shell Mars development on Mississippi Canyon block 807 which is the most recent deep water development to begin production (June 1996). Figure 2 shows the geographical distribution of these deep water discoveries in the GOM. The GOM OCS lease sale 157 held in April 1996 was heralded as a big success, indicating increasing interest in deep water (2). Forty (40) percent of the leases bid on in the April sale were in water depths beyond 2,700ft. This is an indication of the industry's confidence that commercial quantities of oil and gas will be found in the future in the deep water regions of the GOM. Table 2 lists the top 10 lease holders in OCS sale 157 in water depths beyond 1201ft. All five of the oil companies that are members of CEAC were amongst the top 10 deep water bidders in the April lease sale.

The oil industry employs various field development schemes depending on the water depth and location, reservoir type and size, expected production rate, and location of existing infrastructure amongst other factors. Fields located in shallow water (<300ft) will generally be developed with a steel jacket platform secured to the seabed with piles. As the water depth increases, so does the cost of building and installing a production platform. With increasing water depth and increasing cost, other development schemes must be utilized if the development is to be economically successful. Figure 3 depicts the most common field development systems currently in use offshore. Many offshore developments employ a combination of methods, for example, production from subsea wells sent to the main platform (steel jacket, TLP or FPS) where it is combined with production from the main platform and then shipped to shore through a pipeline or tanker.

The need to reduce the investment and operating costs for deep water developments has led the oil industry to evaluate a number of new technologies that offer the potential to lower the overall cost of production. Composite materials is one such technology. Composite materials are light weight, have high strength and stiffness-to-weight ratios, possess excellent fatigue properties, have relatively low thermal conductivity and are corrosion resistant. These and other desirable

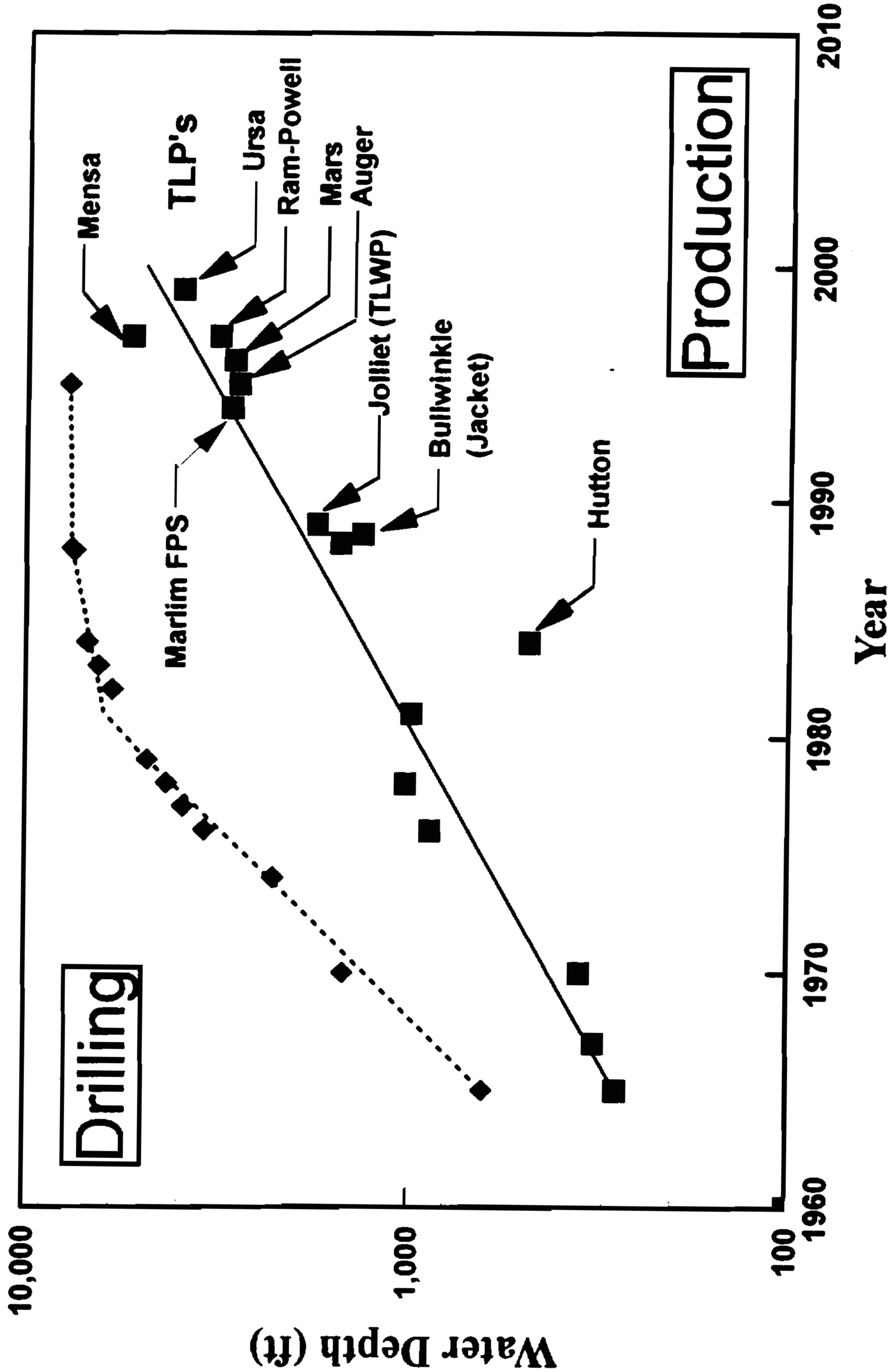

Figure 1. - History of E&P movement into deeper water.

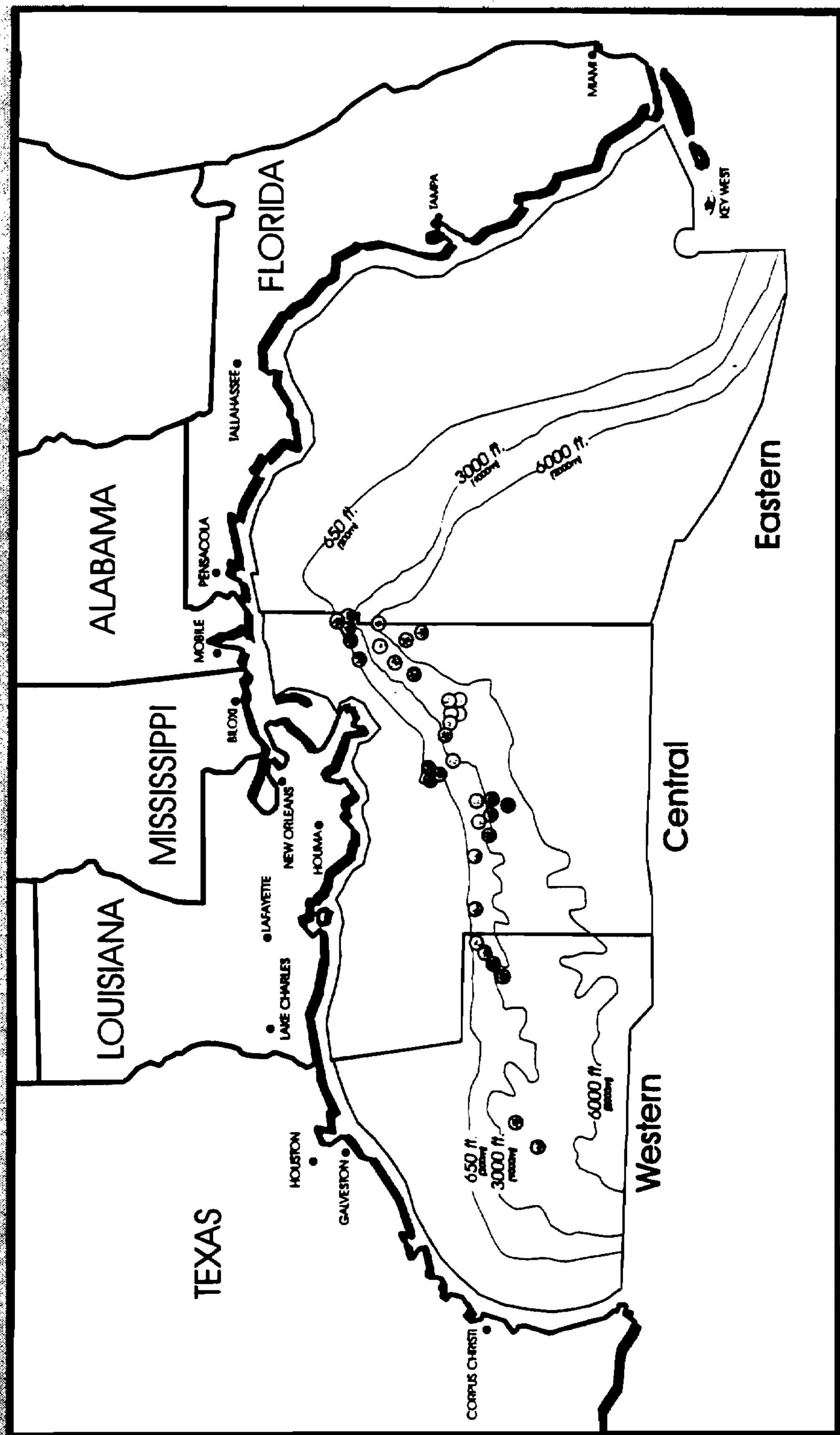

Figure 2. Deep Water Discoveries in the Gulf of Mexico. Source: MMS

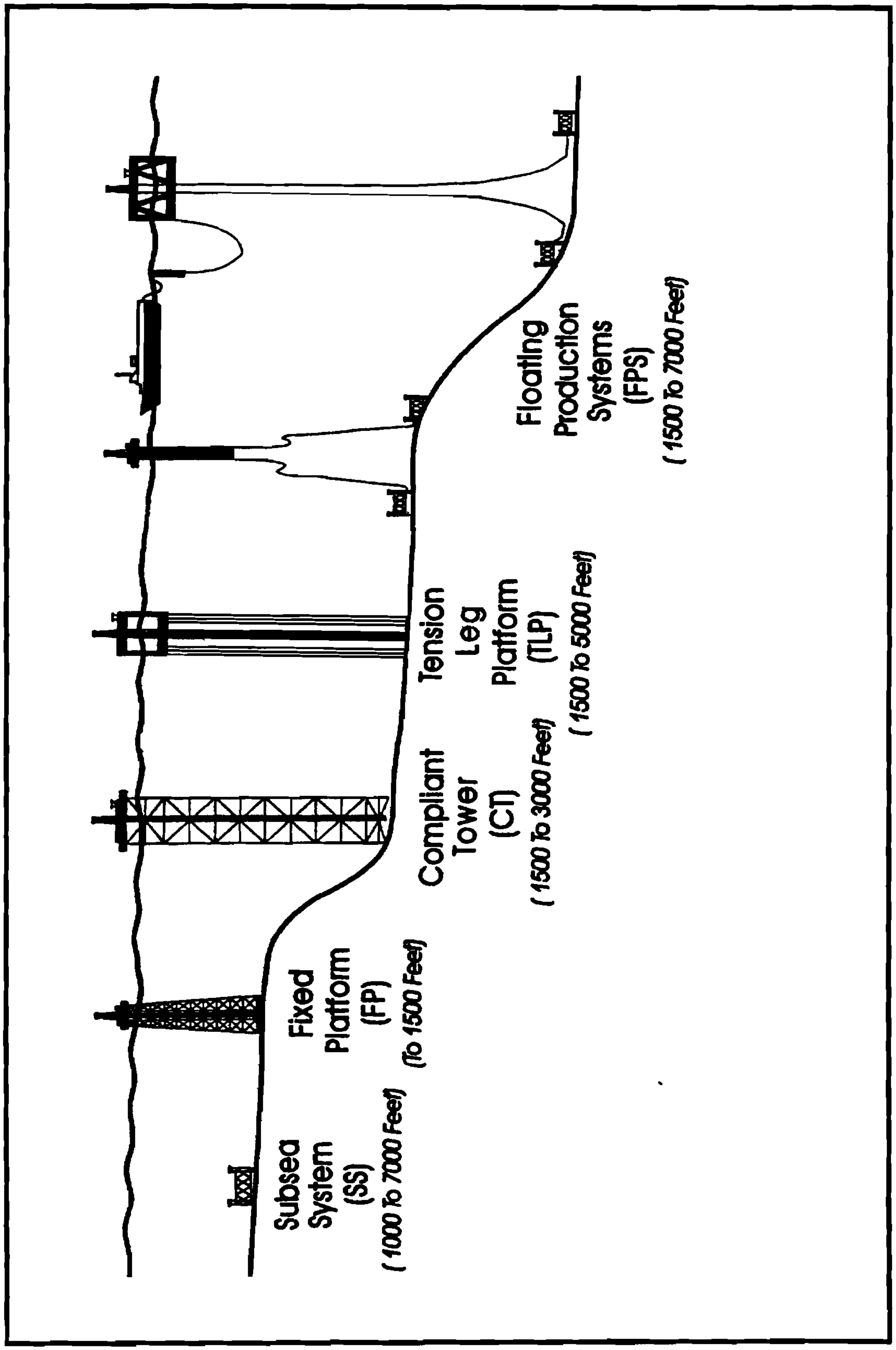

Figure 3. Deep Water Development Systems

characteristics of composites make them a class of materials that have the potential to greatly reduce the cost of producing oil and gas in deep water. The cost of supporting the weight of topside facilities and the vertical tension on the deck and hull produced by risers and the mooring system is estimated to be \$4-5/lb (\$8-10,000/ton) for Tension Leg Platforms (TLP), \$3-4/lb for Floating Production Systems (FPS) and ~\$2/lb for ship/tanker configurations. The potential to save 30 to 60% of the weight of a particular component by using composite materials is, therefore, the main factor driving the evaluation of composites for deep water applications where floating production platforms are preferred or used in combination with subsea developments. These deep water developments can cost \$1+ billion in the GOM and two to three times that amount in the North Sea. The savings in operating and maintenance costs in addition to weight savings are the factors driving the use of composites for small marginal field developments. Maintenance cost

Table 1 - DEEP WATER DISCOVERIES IN THE GULF OF MEXICO BELOW 2,000FT

Name	Area	Block	Depth (ft)	Operator
Coulomb	Mississippi Canyon	657	7520	Shell Offshore
	Mississippi Canyon	522	7195	Shell Offshore
	Desoto Canyon	133	6530	Amoco
	Mississippi Canyon	383	5760	Shell Offshore
Mensa (SS)	Mississippi Canyon	681	5400	Shell Offshore
Mickey	Mississippi Canyon	211	4810	Exxon
Diana (FPS)	East Banks	945	4645	Exxon
Flathead	Mississippi Canyon	899	4452	Shell Offshore
Fuji	Green Canyon	506	4243	Texaco
Ursa (TLP)	Mississippi Canyon	854	3950	Shell Offshore
Venus	Mississippi Canyon	853	3790	Shell Offshore
Vancouver	Green Canyon	472	3780	Shell Offshore
	East Banks	688	3767	Shell Offshore
	Mississippi Canyon	941	3608	Vastar
Gemini	Mississippi Canyon	292	3393	Texaco
Allegheny (FPS)	Green Canyon	254	3225	Enserch
Ram Powell (TLP)	Viosca Knoll	956	3218	Shell Offshore
Marlin	Viosca Knoll	915	3200	Amoco
Blue Throat	Mississippi Canyon	755	3100	Exxon
Mars (TLP+SS)	Mississippi Canyon	807	2933	Shell Offshore
Brutus (SS)	Green Canyon	158	2841	Shell Offshore
Troika	Green Canyon	244	2672	BP
Genesis (DDFC)	Green Canyon	205	2600	Chevron
Bison	Green Canyon	166	2518	Exxon
	Garden Banks	302	2411	Conoco
Cooper (FPS)	Garden Banks	387-388	2080	EP Operating
	Mississippi Canyon	445	2080	Oryx

Sources: MMS ***Offshore Stats*** First Quarter 1996 (1) and various industry journals.
TLP: Tension Leg Platform, FPS: Floating Production System, DDFC: Deep Draft Floating Caisson, SS: Subsea System.
Note: The list contained in Table 1 presents a general overview and is not intended to reflect the development plans of the companies shown.

savings will have even greater impact on the economic viability of high cost deep water developments than on developments in relatively shallow water (Case 3).

Table 1 lists 26 deep water discoveries that are potential field developments and one (Mars) that is already on production. Three to four of these deep water discoveries may come onstream each year over the next 8-10 years. However, 100-120 mainly fixed, jacket-type platforms may be installed each year in relatively shallow water over the same period. For this reason, the Case 3 (SPS) scenario concentrated on these smaller, but more numerous field developments.

Many of the world's major oil companies have come to realize the potential benefits of composite materials for their operations and have begun to evaluate the application of certain composite components for their particular needs (3-16). The Composite Engineering and Application Center (CEAC) for Petroleum Exploration and Production at the University of Houston was requested by its member companies to conduct a study of the economic and enabling benefits to be derived from the use of composite materials with emphasis on deep water developments in the Gulf of Mexico. This report summarizes the results from the first phase of this study. Phase 1 of this study was to evaluate the overall prospects for cost savings through the use of composite components and to identify promising applications for more detailed analysis and evaluation in follow-on studies. The results of this study can be extrapolated to applications elsewhere in the world where the economic benefits may be even greater.

Composite materials can mean very different things to different people, from very sophisticated costly fibers and resins used in the aerospace and defense industries to the fiberglass and polyester material used in small boats. Composites can be classified based on the resin used, including polymer, metal or ceramic matrix composites. All of the composites discussed in this report have a polymer resin matrix.

Many of the materials initially developed for the aerospace and defense industries have become less costly in the past few years and are commonly used in skis, golf clubs, tennis rackets, sports

Table 2 - GULF OF MEXICO OCS SALE 157-APRIL 1996: TOP 10 DEEP WATER LEASE HOLDERS IN DEPTHS BEYOND 1200 FEET (Ranked 1 through 10 by total deep water acreage held)

Lease Holder	1201-2700ft	2701+ft	Total DW Acreage
Texaco	45,696	351,360	397,056
BP Exploration	30,931	355,152	386,083
Chevron	39,744	232,416	272,160
BHP	43,196	193,022	236,218
Amoco	2,876	212,256	215,132
Exxon	0	184,320	184,320
Conoco	5,760	172,800	178,560
Shell	40,320	101,132	141,452
Mobil	2,880	82,944	85,824
Phillips	2,880	69,120	72,000

Source: ***Offshore***, June 1996 (2)

helmets, automobiles, and commercial aircraft. Composite materials are part of a quiet revolution taking place to make many consumer and industrial products lighter, safer, cheaper to operate and with improved performance.

Most of the composite materials currently in use in petroleum operations onshore and offshore are relatively low technology and low cost fiberglass reinforced plastic (FRP). Advances in polymer resins, manufacturing and design methods have improved the properties and performance of FRP components, and expanded the number of applications for this material that has been around for over 50 years. The composite materials discussed in this report are not the high technology, high cost materials commonly associated with aerospace and defense applications. Most of the composite materials are derived from fiberglass and some are a combination of glass and carbon fibers commonly known as a hybrid. Only a few components are composed exclusively of the more expensive aramid (Kevlar®) and carbon fibers. Appendix 1 contains a summary of fiber, resin and composite laminate properties.

The main effort in this study was directed at those applications of composite materials that would have the greatest impact specifically on the weight of floating production platforms (TLP's and FPS's) and capture the associated cost savings for deep water developments. Composite drill pipe, coiled tubing, and subsea flowlines and injection lines are important composite applications being studied elsewhere, as in the NIST ATP projects. Since they do not directly affect the weight of the TLP or FPS, they were not addressed in the current study.

Many of the papers (5,6,7,11,12,17) presented at the First International Workshop on Composite Materials for Offshore Operations in October 1993 at the University of Houston provided valuable input to this study. The next workshop planned for October 1997 is expected to provide an excellent review of the progress being made in applying composite materials to offshore operations.

Some of the information provided in this report came from general industry sources and other information came from referenced documents.

2.2 Basis of Assessment

Two deep water GOM development case studies and one case study for a small production structure or marginal field development were used as the basis for estimating the cost savings to be derived through the use of composite materials. The two deep water case studies were a Tension Leg Platform (TLP) in 4,000 feet of water and a Floating Production System (FPS) in 6,000 feet (see Table 3). It was assumed that the hull, deck and topside equipment would essentially be the same for both scenarios. The major differences would be in the mooring and riser systems, in addition to the value assigned to each ton of topside weight saved. For a TLP, the mooring system is a "tension leg" or tendon that greatly restricts the vertical as well as the horizontal motion of the hull. This restricted motion is necessary because the wellheads are located on the deck and are connected to the seabed by the production risers. With a FPS, a catenary mooring system is used which permits the hull to move to a greater extent than possible with a TLP. The increased vertical and horizontal excursions with a FPS are possible because the wellheads are located on the seabed and the production is brought to the surface via flexible risers of one type or another. The location of the wellhead on the sea bed also allows the pressure rating of flexible risers to be lower than for risers connected to a wellhead on the platform. Most of the effort in this study was done on the 4,000ft TLP scenario, and the results transferred or extrapolated to the 6,000ft FPS scenario.

Case 3 (SPS) examines a small production platform with a production capacity of 10,000 BOE, roughly 10% of the capacity of the deep water TLP (Case 1) and FPS (Case 2). The SPS can also be regarded as a marginal field development with minimum facilities. It is anticipated that future developments in the GOM will emphasize minimum facilities installations designed for low maintenance. Case Studies 1, 2 and 3 are fully described in Appendices 2, 3 and 4.

Table 3 - BASIS OF ASSESSMENT

System	Value	
	TLP and FPS (Cases 1 & 2)	SPS (Case 3)
Location	Gulf of Mexico	Gulf of Mexico
Water Depth	4,000 and 6,000ft	<300ft
Platforms Types	Tension Leg Platform (4,000ft) and Floating Production System (6,000ft)	Fixed jacket or monopod
Deck Type	Non-Integrated Modular Deck	Integrated Deck
Design Life	30 years	15 years
Production Rates: Oil Gas Produced water GOR	100,000 BPD 110,000,000 SCFPD 10,000 BPD 1,100 SCF/B	10,000 BOE
CO_2	<0.1 mole%	<0.1 mole%
H_2S/Sulfur	0	0
Produced Solids, Paraffin and Hydrates	Not considered in this study	Not considered
Wellhead Design Pressure	10,000psi	10,000psi
Number of Risers	15 Production 2 Export 2 Injection 1 Spare	NA
Number of Producing Wells	15	5-10
Individual Well Flowrates (max)	8,000 to 20,000 BPD	500-1,000 BOPD
Flowing Wellhead Temperature	150°F (65°C)	150°F (65°C)
Production Facility Inlet Temperature	150°F (65°C)	150°F (65°C)
Number of Subsea Wells	8 (manifolded)	None
Subsea Flowlines and Risers	2 (8 inch diam. plus control & injection systems)	None
Sea Water Injection	None	None
Quarters	130 beds	None (temporary shelter for 4-5)
Maintenance	Normal	Minimal

The Basis of Assessment contains an oil and gas production stream that is essentially free of excessive corrosion, sand, asphaltene, wax and hydrate problems. These conditions will generally mean that carbon steel rather than duplex stainless steel or some other alloy will be the material used for production tubing, piping, tanks, vessels, flowlines and pipelines. The cost of various composite components in this study was, therefore, compared to a carbon steel base case, the most challenging since it will nearly always be the lowest case option for any production equipment.

All but four of the deep water discoveries in the GOM that are either under production or have announced development plans involve the TLP concept. The TLP/TLWP developments include Conoco's Jolliet TLWP, and Shell's Auger, Mars, Ram-Powell and Ursa TLP's. The exceptions are Enserch's GB 388 FPS located in 2,080ft of water, Chevron's GC 205 (Genesis) Deep Draft Floating Caisson (DDFC) in 2,600ft, Enserch's GC 254 (Allegheny) FPS in 3,225ft, and Oryx's VK 826 DDFC in 1,930ft. Because of the availability of information about TLP's for the GOM, the evolution of the GOM TLP design, and the relative lack of information about GOM FPS, FPSO (ship) and DDFC designs, Phase 1 concentrated most of its effort on TLP's. The potential economic payoff with composites related to weight savings appears to be greatest for a TLP than for a FPS, FPSO or DDFC.

2.3 Methodology Used to Estimate Cost Savings

The approach used in Phase 1 of this study to estimate the cost savings resulting from the use of composite materials was first to establish a Steel Base Case. Then the total weight savings in the topside equipment and the load carried by the deck and hull resulting from the use of composites was determined. That weight savings was translated into a cost savings (W$) due to reduced deck, hull and pile requirements. To this cost savings was added the savings in construction and installation costs (C$) achieved through the use of composites. Then the overall net installed cost premium (P$) resulting from the use of higher cost composite components was subtracted from the weight/construction/installation savings to determine the net project investment savings (N$). The savings in operating and maintenance costs (O$) plus any savings derived from the enabling benefits (E$) of composites would be additional cost savings to be included in any life cycle (LC) cost analysis for the project.

Net Project Investment Cost Benefit: N$ = W$ + C$ - P$

Project Life Cycle Cost Benefit: LC$ = N$ + O$ + E$

When composite materials are simply used as a "drop in" replacement for the metal component, all the benefits of composite materials are not fully realized. By taking a system approach to the use of composite materials and fully accounting for the weight savings produced in the earliest stages of an offshore development project, the offshore operator can save millions of dollars in development costs.

2.4 Assumptions

The basic assumptions used in this study are listed below:

- The steel base case scenarios do not contain any composite components.
- Composites will be used where it makes good engineering and economic sense.
- The topside facilities (equipment modules and deck) are essentially the same for the 4,000ft TLP and the 6,000ft FPS scenarios, though the exact layout or arrangement may differ.
- The NIST Advanced Technology Program (ATP) projects referred to will be successful in developing commercial products within the stated time period of each project.
- The value of weight saved in the load carried by a TLP hull is in the range of $8-10,000/ton. A value of $8,500/ton was used for most calculations in this study.
- The value of weight saved in the load carried by a FPS is in the range of $6-8,000/ton. A value of $7,000/ton was used in this study.
- A value of $1/lb or $2,000/ton was given to the weight saved in the deck and topside equipment of a fixed platform such as the SPS.
- Structural steel costs $0.50/lb or $1,000/ton.
- The export risers are steel in the TLP and FPS scenarios because of the relatively large diameters required.
- All composite components discussed in this report are assumed to be available by the year 2005 with the exception of the TLP tendons, and piping and vessels used in high temperature applications.
- The TLP and FPS topside facilities are designed for normal maintenance, while the SPS is designed for minimum maintenance.

The economic advantage of using composites was assessed by simply assigning a dollar value per unit of weight saved. Values of $8-10,000/ton ($4-5/lb) for TLP's and $6-8,000/ton ($3-4/lb) for FPS's were selected after consulting with oil and service companies concerning current costs to construct these two classes of platforms. These savings are manifested in reduced deck, hull, mooring and seabed anchor systems. Figure 4 shows the investment cost savings as a function of weight saved for three deep water development options: TLP, FPS and a ship configuration. The values credited to weight savings were considerably higher a few years ago ($10-20,000/ton) (17), which made it much easier to demonstrate significant direct cost benefits. The corrosion resistant characteristics of composites also provide life cycle benefits. However, life cycle cost savings are harder to quantify and are generally assigned lower importance than the initial capital investment savings. The economic value for composites, therefore, must come from savings derived from direct cost competition with metals including the value credited from saving weight, and through construction and installation simplification for which a monetary value can be ascribed. The costs of composite components can be minimized through emphasis on using inexpensive glass fibers and resins in low cost automated manufacturing process(es) such as pultrusion, filament winding and vacuum infusion molding. The glass fibers would be supplemented were necessary by higher stiffness carbon fibers and damage tolerant aramid fibers.

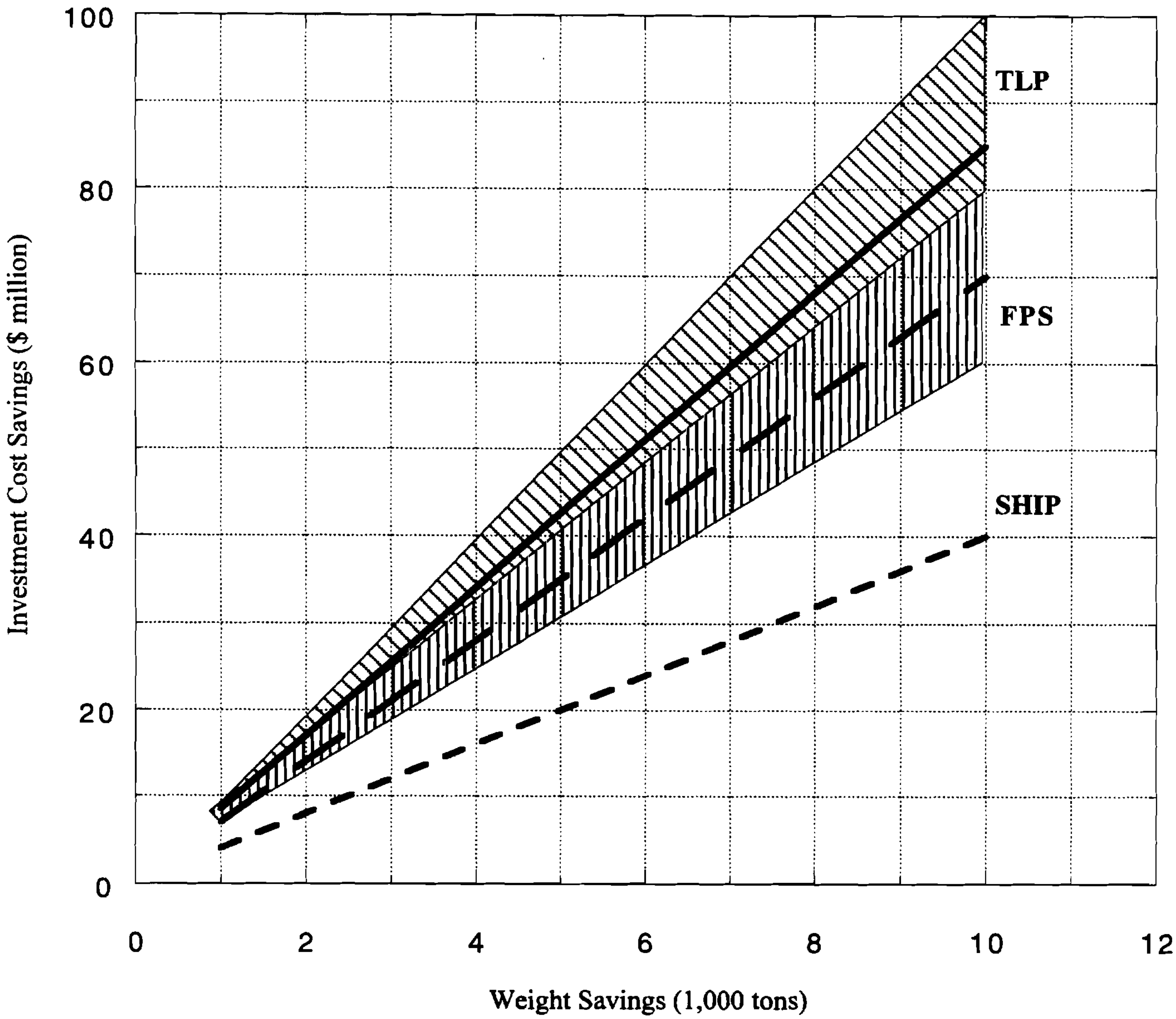

Figure 4. Investment Cost Savings as a Function of Weight Savings for Three Deep Water Platforms Configurations in the Gulf of Mexico

3. CONCLUSIONS

Significant weight can be saved through the use of composite materials for topside facilities, production risers and selected structural beams. In deep water, these weight savings can produce sizable investment cost reductions. Furthermore, because composites are corrosion resistant, reductions in maintenance costs can also be achieved throughout the productive life of the offshore field. For the three development scenarios considered (TLP, FPS and SPS), the following conservative weight and cost savings were estimated based on the information and assumptions used in this study.

1. The biggest targets for weight savings on a TLP are the production risers, the topside equipment, structural beams, mooring tendons and the drilling equipment. All these components except for the tendons and drilling equipment are expected to be commercially available by the year 2005.

2. Composite production risers offer the biggest overall weight and cost savings of any major component for a deep water TLP. The net cost savings for composite risers in 4,000ft is estimated to be $14.9 million, with a total weight saving of 1,808 tons including the use of composite hydraulic accumulator bottles.

3. Total weight savings possible through the use of composite materials for the topside and deck of both the TLP and FPS cases are estimated to be 1,348 tons (12% of the topside weight) by the year 2005. The percentage of weight saved increases to 18% if the drilling module is excluded from the calculation. This weight reduction can result in savings of about $10.5 million for a TLP and $8.3 million for a FPS. The cost saving will increase significantly if, instead of carbon steel, higher cost stainless steel, copper-nickel, or titanium piping and vessels are replaced by composite components.

4. The total cost savings estimated over the life of the project derived by using composites for the topside equipment and the risers but retaining the steel mooring tendons for the TLP scenario is $69.15 million, resulting in a net present value (NPV) of $30 million. This consists of a net investment cost saving of $25.1 million, a maintenance cost saving of $5.64 million, and increased revenue of $38.4 million resulting from reduced production down time. The total weight savings projected for the 4,000ft TLP case will be approximately 3,156 tons.

5. The total cost savings estimated over the life of the project derived from using composites for the topside equipment but retaining steel risers for the FPS scenario is about $52.3 million, with an NPV of almost $20 million. This consists of a net investment cost saving of $8.25 million, a maintenance cost saving of $5.64 million, and increased revenue of $38.4 million resulting from reduced production down time. The total weight savings for the 6,000ft FPS case are estimated to be 1,348 tons.

6. Topside facilities and production risers offer the greatest weight savings potential for FPS's. There may be less economic incentive to use composite production risers for FPS's, however, because there are little or no savings to be gained with the riser tensioner system and each ton

of weight saved on a FPS is not as valuable as on a TLP. However, there may be extenuating circumstances which could change this assessment. For example, the use of composite risers could impact the overall system configuration, something that was outside the scope of this study. The composite drilling riser, once fully developed and proven, may have a significant impact due to reduced deck loads and top tension. This requires more thorough evaluation.

7. Composite drill pipe, coiled tubing, and subsea flowlines and injection lines are other components that may have significant economic payoff in operational costs but since these components have little influence on the overall weight and cost of a floating production platform, they were not addressed in the current study.

8. Composite TLP tendons have the potential to reduce the load carried by a TLP hull in 4,000ft of water by approximately 3,216 tons. However, based on equivalent axial stiffness to steel composite tendons do not appear to be economically attractive for 4,000ft water depths compared to steel tendons. The overall economic attractiveness of composite tendons may be significantly increased if a reliable spooling and deployment method can be developed to install spoolable composite tendons, and if the axial stiffness requirements can be reduced.

9. A composite tendon could provide significant performance and cost advantages in ultra deep (>6,000ft) water where complex engineering solutions are required to resist collapse and supplemental buoyancy is required to support the steel tendon systems. A system analysis of a deep water TLP with composite risers and tendons will be required to properly assess the overall cost effectiveness of composite tendons in ultra deep water. Without composite risers, there may not be composite tendons because of the need to coordinate the responses of the riser and tendon systems.

10. Composite materials have the potential for providing very significant weight savings in the structural area once experience is gained with hybrid composite structural beams to replace traditional steel beams as secondary structural elements in the main deck.

11. Each ton of weight saved through the use of composite structural beams will cost approximately $2,050 ignoring installation costs savings. This is based on a steel to composite beam cost differential of $2.71/lb and a weight saving of 64%.

12. The total cost savings resulting from using composites for topside applications estimated over the life of the SPS scenario is about $2.2 million. This consists of $0.73 million in net investment cost saving, a maintenance cost saving of $0.05 million, and increased revenue of $1.44 million resulting from decreased production down time. The biggest cost saving opportunity for small production structures (SPS) is the topside facilities. Use of composite components for topside facilities will save 50 tons and $635,000.

13. A major benefit from using composites for a topside facility in a minimum maintenance installation may be the ability to tie-in adjacent fields 5-10 years after the end of the original field life. Unmanned platforms with a minimum maintenance design philosophy should be considered for marginal field developments even in water depths greater than 300ft.

14. The use of composite materials for topside facilities can be expected to decrease production down time due to the reduced need for maintenance requiring hot work. Saving even one day of down time per year will increase annual revenue by approximately $200,000 for the SPS, and $2,000,000 for the TLP and FPS, at an oil price of $20/bbl.

15. Composite components will increase the level of safety on a platform because of their lighter weight and non-sparking characteristics. Increased safety will also be achieved in the fabrication yard since lighter equipment will be handled during installation and fabrication.

4. RECOMMENDATIONS

Based on the results from Phase 1 of this study and the needs of the CEAC members, it is recommended that Phase 2 involve a systems level analysis of floating production platforms in ultra deep water and that the areas of composite structural elements, and tanks and vessels be given a more detailed assessment. Three new projects are proposed to address barriers associated with the wider application of composite materials offshore which will accelerate the availability of new cost-effective technology into deep water E&P operations:

1. Phase 2 of the Offshore Economic Assessment Study will determine the cost effectiveness of composite risers and mooring systems as well as topside applications for floating platforms in 6,000 to 10,000ft of water by evaluating various platform system configurations, including subsea equipment. This should be accomplished with the input from a systems level analysis and would include various TLP, FPS, FPSO and DDFC platform configurations to optimize the benefits available with composite components. A team of specialists with skills beyond that of the current CEAC staff and Offshore Working Group will be required to carry-out Phase 2. The use of composite TLP tendons with axial stiffness less than steel should be carefully evaluated because the potential for significant weight and cost savings may be enabling. If the preliminary evaluation of composite tendons indicates they are cost-effective in ultra deep water, a separate JIP may be initiated to investigate composite tendons in greater depth. In-situ monitoring and/or inspection technology incorporating fiber optic sensors may help improve reliability for deep water applications.

2. Determine the most effective way to take full advantage of the weight and cost savings potential of hybrid composite beams currently under development using low cost fabrication processes. This should include an evaluation of the most efficient composite-to-steel beam attachment methods, composite reinforcement of steel beams and a determination of the conditions under which a hybrid steel-composite deck is most cost-effective. Innovative connections and transitions from composite to steel beams as well as deck configurations will be required to maximize the weight saving advantage with composites, and to insure proper and efficient field installation.

3. Conduct a study of composite storage tanks and process vessels to thoroughly evaluate their use in topside process facilities with emphasis on defining and expanding the temperature and pressure allowable operating ranges, and development of design standards and specifications. The purpose of this effort will be to promote advancements in composite tank and vessel technology similar to that which has occurred in the fiberglass pipe industry over the past 10 years.

It is anticipated that these projects may evolve into joint industry projects (JIP) with one or more manufacturers as participants in addition to oil and service companies. It is recommended that CEAC charter a task group(s) to conduct a preliminary study to define and develop these projects.

In addition to the recommendations shown above, the Offshore Working Group believes that downhole applications of composites, which were deferred in Phase 1, have such great potential for reducing costs and offering enabling benefits that they should be investigated in a separate CEAC study.

Finally, it is in the best interest of the oil industry to continue to support the NIST ATP projects (drilling riser, drill pipe, production riser, and spoolable tubing). To be effective, this involvement must include providing the opportunity to field test full size prototype components once they have successfully passed all the laboratory and preliminary tests. Field testing of these components is a critical and very important step in their final acceptance for use offshore.

5. BASE CASE - TRADITIONAL MATERIALS

5.1 Topside Equipment

The topside facilities in the TLP and FPS scenarios are designed to produce and process 100,000 BPD of oil, 110 MMSCFPD of gas and 10,000 BPD of produced water. In addition, these facilities must safely house 100-130 people, provide for drilling operations especially during the first years of the project and allow well workover operations during the life of the field. The topside equipment was assumed to be essentially the same for the TLP and FPS scenarios.

All topside equipment for the TLP and FPS was assumed to be made from carbon steel and externally coated. The topside equipment for the SPS was assumed to have been made from corrosion resistant metal to reduce the need for maintenance to a minimum. Since the flowing wellhead temperature was assumed to be 150°F and the corrosivity of the produced fluids is low, carbon steel piping, tanks and vessels are adequate for the TLP and FPS, thereby precluding the need for duplex stainless steels or more costly alloy materials. The topside equipment was evaluated in a general way without using bills-of-materials or detailed equipment lists.

The topside facilities for the 4,000ft TLP and the 6,000ft FPS base cases are estimated to weigh 10,662 tons, with about 47% of that weight (5,000 tons) allocated to drilling equipment. This was largely based on the published figures for the Shell Auger TLP (19-20) with allowances made for the differences in production capacity and water depth. The topside weight for the Small Production Structure (SPS) is only 519 tons. The drilling module has been eliminated. All drilling will be done with a jack-up rig, and a workover rig will be brought to the platform for remedial work. Table 4 contains a breakdown by major equipment area for the topside facilities.

Table 4 - TOPSIDE FACILITIES WEIGHT

	Weight (tons*)	
Equipment	**TLP & FPS**	**SPS**
Drilling Equipment	5,000	0
Living Quarters	1,000	15
Helideck	45	20
Power Generation	1,280	10
Process Equipment	1,395	210
Piping	567	60
Secondary Structures	600	90
Misc. Equipment	250	37
Utilities Module	525	77
Total:	**10,662**	**519**

*: One ton = 2,000lbs.

5.2 Risers

The production risers are an essential component of any offshore development. They together with the production tubing contained inside the riser transport the oil and gas production from the seabed to the deck of the platform. Production risers used in connection with a FPS may not always contain production tubing. This would depend on the particular riser configuration used and whether or not some of the production is manifolded on the seabed into a single but larger riser.

A single casing production riser system design was used for the TLP scenario. In this system, the production tubing is located within the production casing which also serves as the production riser. In a dual casing system, the production tubing is contained within a production casing which in turn is contained within a second casing or the production riser. A standard 10-3/4 inch carbon steel casing (66 lbs/ft) was used for the production riser.

The 16 production risers and 2 injection risers used in the Basis of Assessment have a weight in air of approximately 2,376 tons for the 4,000ft TLP scenario. When the riser pretension of 20% is added, this results in a load on the hull of 2,851 tons. The total riser load is a significant cost factor in designing TLP's and FPS's in water depths beyond 2,000ft. Table 5 contains a summary of the properties of the steel production risers used in this study.

Table 5 - STEEL PRODUCTION RISERS

	Typical Steel GOM TLP (3,000ft)	Steel Base Case TLP (4,000ft)	Steel Base Case FPS (6,000ft)
Riser Length (ft)	3,000	4,000	4,000+4,000*
Riser Diameter (in.)	9-5/8	10-3/4	8-5/8
Weight/ft in air (lbs/ft)	43.5	66	48.4
Weight/riser-air (lbs)	130,500	264,000	168,800
No. of Risers	24	18	18
Total Riser Weight-air (tons)	1566	2376	1,519
Riser Pretension (tons)	313	475	-
Estimated Cost ($/ft)	100-110	140-150	100-110

*: 8,000ft of riser used in 6,000ft of water with a buoy at the 3,000ft water depth mark.

No production risers were used in the Small Production Structure scenario, a fixed platform.

The oil and gas export risers will be part of the pipelines used to transport the oil and gas from the platform to shore, possibly through another platform or pipeline. For this study, the oil export riser is 18 inches in diameter and the gas riser 14 inches. D/t ratios of 25(3,000ft), 20(4,000ft) and 15(6,000ft) were used. It was assumed that the export riser length would be 1.5 times the water depth for the FPS case. Typical X60 weldable pipeline steel would be used for the oil and gas export risers and the two flowline risers.

The two 8-inch diameter flowline risers tie-in production from 8 subsea wells. The size and weight of these risers are as follows:

OD	WT	D/t	Weight (air)	Filled Weight (water)	Riser Weight in 4,000ft
8.625in.	0.562in.	15.6	48.4 lbs/ft	~42.2 lbs/ft	~84.4 tons

The same steel pipe dimensions as shown above for the flowline risers were used to estimate the weight on the hull and the mid-depth buoy for the FPS scenario. It was assumed that the lazy "S" production riser design would require 8,000ft of pipe in 6,000ft of water with a buoy located at the mid-water depth (3,000ft). The 18 production risers would generate a load of 1,519 tons (18x84.4) on the hull and on the buoy. The cost of the massive buoy required to support 1,519 tons was estimated at $9,114,000 (3.038 million lbs x $3/lb).

5.3 Mooring Systems

5.3.1 TLP

The mooring system consists of three welded steel tendons per corner for a total of 12. The tendons extend from the base of each of the four platform columns to the seabed where they connect to a pile driven into the seabed. This design is similar to the tendon system used for the Mars TLP installed in the Gulf of Mexico in June 1996 (21). The Ursa TLP to be installed in 3,950ft of water in 1999 will have four tendons per corner (22). Each Ursa tendon will be 32 inches in diameter and weigh 1,000 tons in air. The total weight of 16,000 tons for the 16 Ursa steel tendons is essentially the same as the total weight of 15,809 tons for the 12 steel tendons used in the CEAC TLP Steel Base Case. However, the net weight of the 16 Ursa tendons is about 1648 tons, only 51% of the net weight of the 12 tendons used in the CEAC 4,000ft TLP Base Case.

The tendon design used in the 4,000ft TLP Steel Base Case was a steel pipe with an OD of 36 inches and a wall thickness of 1.80 inches. This produced a D/t of 20 and a weight of 658.7 pounds per foot in air. Table 6 contains a summary of the properties of the steel tendon system for the TLP Steel Base Case. The pretension of 1,450.5 tons per tendon produces a stress of ~15ksi in the tendon just above the bottom connector and ~ 18ksi just below the top connector.

Table 6 - TLP MOORING TENDONS - 4,000ft STEEL BASE CASE

Outside Diameter	36 inches
Wall Thickness	1.80 inches
D/t	20
Steel Cross-Sectional Area/Tendon	193.4 in.^{2}
Weight/foot	658.7 lbs (air) 574.9 lbs (water)
Weight/tendon	1317.4 tons (air) 1149.8 tons (water)
Total Weight - 12 Tendons	15,809 tons (air) 13,800 tons (water)
Upward Force on Tendon Bottom Due to Pressure at 4,000ft	882 tons
Net Total Weight of 12 Tendons	3,216 tons (water)
Pretension Load Per Tendon at the Bottom	1450.5 tons (~15ksi)

Note: 1. The weight of the top and bottom connectors was not included in the tendon weight.
2. A water density of 62.4 lbs/ft^3 was used.

The axial stiffness of the steel tendons for the 4,000ft TLP base case was designed to match that of the Mars TLP tendons, with allowances made for greater depth and deck/hull mass. The vertical heave period of the 4,000ft Steel Base Case should then be close to the 3.7-second period of the Mars TLP.

The cost of a TLP tendon mooring system can be 8-10% of the total development cost. The actual cost will depend on a number of factors such as platform mass, water depth and environmental loads. D'Souza estimates that TLP tendon (station-keeping) systems could be 20-25% of the total installed cost in the GOM (23). The percentage would be less for North Sea developments where the topside facilities are generally much larger than in the GOM.

The estimated cost for the tendon system for the 4,000ft Steel Base Case is compared to the tendon costs for a typical GOM TLP in 3,000ft and three existing TLP's of vastly different sizes and water depths in Table 7. The light weight (18,260 tons) Jolliet Tension Leg Wellhead Platform (TLWP) operated by Conoco in 1,760ft has the lowest estimated tendon cost of $30 million. At the other end of the scale is the massive (316,800 tons) Heidrun concrete TLP with a tendon system estimated to have cost $300 million.

Table 7 - COMPARISON OF TLP TENDON SYSTEM COSTS

	Hutton - North Sea	Jolliet - GOM	Heidrun - Mid-Norway	Typical 3,000ft GOM TLP	Steel Base Case TLP 4,000ft
Water Depth (ft)	496	1,760	1,150	3,000	4,000
System Type	Heavy Wall Forged Steel	Neutrally Buoyant-Steel Pipe	Neutrally Buoyant-Steel Pipe	Non-Buoyant Steel Pipe	Non-Buoyant Steel Pipe
Cost ($ million)	150	30	300	70-90	110-130

Note: Costs include design, materials, fabrication and installation.

5.3.2 FPS

The prevalent use of all chain mooring lines in water depths up to 1,500ft has given way to the chain/wire rope system for depths beyond 1,500ft. Although chain/wire rope system can be used in water depths up to 6,000ft (and beyond), excessive catenary sag due to the high "self weight" of the mooring line components reduces the station keeping performance. This enhances the possibilities for light weight synthetic mooring lines which offer the advantages of low self weight resulting in reduced FPS buoyancy requirements, and reduced handling and installation costs.

A 12-point chain/wire rope mooring system for a drilling rig in 3,000ft of water has a weight in water of ~1,637 tons. This assumes 2,000ft of chain and 5,800ft of wire rope per mooring line. As the water depth increases to 6,000ft, alternatives to the chain/wire rope catenary mooring system must be used to avoid excessive deck-hull loads.

5.4 Buoyancy Modules for Risers and Moorings

Buoyancy may need to be added in the form of jackets or modules in deep water to reduce the net load carried by the TLP or FPS hull resulting from drilling risers, production risers, flowline and export risers, and mooring systems. The buoyancy module may have a steel or fiberglass outer shell and be filled with a foam depending on the water depth at which the buoyancy module must operate. The cost for such buoyancy is the range of $1.50 to 2.00 per pound of buoyancy for shallow depths to ~3,000ft. The actual cost will depend on the water depth at which the module must operate and the total buoyancy load required. The greater the operational water depth of the buoy, the greater will be the cost per pound of buoyancy.

5.5 Subsea Equipment

Subsea equipment such wellheads, manifolds, flowlines and injection lines were not evaluated in Phase 1 of this study.

5.6 Downhole Equipment

Downhole equipment such as tubing and casing below the mudline were not evaluated in Phase 1 of this study. Specialized applications downhole, however, present a significant opportunity to utilize the unique properties of composites. Composite coiled tubing, drill pipe, and drillable casing are a few of the composite components available for use downhole.

5.7 Overall Weight and Cost Estimates

The weight estimates for the Shell Auger TLP, a typical 3,000ft GOM TLP, and the 4,000ft TLP Steel Base Case scenario are contained in Table 8.

Table 8 - TLP WEIGHT COMPARISON

	Auger (19-20) (2,860ft)	Typical GOM TLP 3,000ft (21,24)	Steel Base Case (4,000ft)
Capacity (BOPD)	46,000⇒100,000	100,000	100,000
Displacement (tons)	73,000	50,000	82,000
Total Weight (tons) [deck, topside & hull]	43,500	31,350	39,202
Total Deck and Topside Weight (tons)	23,000	14,700	19,202
Prod. & Inj. Risers (no.) [1] Riser Pre-Tension[3]	3,050 (32)[2] 915	1,566 (24) 313	2,376 (18) 475
Tendon Weight: (tons) Air / Water	5,800 / 148.6	6,150 / ~0	15,809 / 3,216
Tendon Pretension (tons)	10,440	7,891	17,406
Hull Weight (tons) [hull wt / deck wt[4]]	20,500 [0.89]	15,650 [1.06]	20,000 [1.04]
Total Load Carried by Hull (tons)	44,171	25,977	42,675
Total Load / Hull Weight	2.15	1.64	2.13
Foundation Templates (tons)	2,400	NA	NA
Piles (tons)	3,200	3,120	6,880
Lateral Mooring System (tons)	6,000	NA	NA

1. : Does not include weight and pretension for steel production tubing.
2. : Auger used dual casing design, 9-5/8" riser & 7" casing. All others are single casing design.
3. : Riser pre-tension calculated at 20% of weight in air. Auger pre-tension was 30%.
4. : Deck weight includes topside production facilities plus the deck structure.

Many of the estimates for the weight of a given topside module, the deck, hull, risers or mooring tendons were based on published information about the Shell Auger and Mars TLP's (19-21). These two TLP's were designed for the Gulf of Mexico, and represent the latest and most efficient designs for production scenarios very similar to those used in this study. In some cases the published weights were extrapolated to account for the production levels used for this study.

Table 9 presents a cost estimate for the overall development of the 4,000ft TLP Steel Base Case development scenario and compares it to a typical 3,000ft TLP development. The TLP cost projections in reference 23 were used to provide a first cut at generating realistic costs scenarios for the 4,000ft Steel Base Case and the typical 3,000ft TLP.

In estimating the overall cost of a typical TLP in 3,000ft of water in the GOM, two reference marks were used. First, the Shell Auger TLP was installed in 2,860ft in 1994. That project was estimated to have cost $1.2 billion (19). Second, the Mars TLP was installed in 2,940ft in 1996. Mars has been valued at $1.1 to 1.2 billion (21,24). Comments from Dan Godfrey, Mars Project Manager, in late October indicate that the final cost of the Phase I Mars development was $991 million, $75 million under budget.

Shell and partners BP, Conoco and Exxon will develop the 150,000 BOPD Ursa field located 130 miles southeast of New Orleans in 3,950ft of water. A TLP will be used to develop this field at a total cost of $1.45 billion (26). The cost of $1.45 billion for the Ursa development helps to validate

Table 9 - OVERALL COST ESTIMATE - TLP's IN GOM

Major System	Total Cost Allocation (23)	Typical GOM 3,000ft TLP ($million)	Steel Base Case 4,000ft TLP ($million)
Hull & Deck Steel (materials & fabrication)	30%	$190*	$220-260
Drilling & Process Facilities	25	180 (no drilling)	200 (no drilling)
Mooring System (includes installation)	25	70-90	110-130
Riser/Well System	13	450 (19) includes drilling	520 includes drilling
Engineering & Project Management	7	80	100
Total:	100	970-990	1,150-1,210
In Addition: Export Risers, PLs & Subsea Installation		120-200	150-200
Grand Total:		$1,090-1,190	$1,300-1,410

*: Equivalent to ~$8,315/ton for materials and fabrication.

the estimated cost of $1.30 to 1.41 billion for the 4,000ft Steel Base Case (Table 9). The Ursa TLP will use a steel tendon mooring system and only 14 production wells. Shell is an experienced operator in the deep water areas of the Gulf of Mexico and has applied the experience gained with its Auger, Mars and Ram-Powell TLP's to provide continuous improvement in the efficiency and economy of deep water development. The cost of export risers, pipelines and subsea installations will be very project specific and will depend on the distance to existing infrastructure and the need to develop satellite reservoirs with subsea wells.

6. COMPOSITE TOPSIDE EQUIPMENT

6.1 Piping

Composite piping in the form of fiberglass reinforced plastic (FRP) has been used extensively in onshore oilfield operations for over 25 years. Exxon's first major application of FRP linepipe for flowlines, gathering lines and produced water injection lines began in the early 1970's. A total of 260,000ft (~49miles) of 2-1/2, 3 and 4-inch FRP pipe was installed and continues to operate satisfactorily today (27).

Between 1970 and 1975, Exxon installed ~600,000ft (~115mi.) of FRP linepipe in West Texas oil fields undergoing CO_2 enhanced recovery. These operated successfully for 13 years (27). In 1984, Exxon installed almost 750,000ft (~141 mi.) of FRP pipe in another enhanced oil recovery project (WAG) for flowlines, water injection and oil gathering lines.

Royal Dutch Shell has more than 375 miles of FRP pipe in oil production service. The highest pressure used is 95 bar (1,378psi) and the maximum temperature is 212°F. About 37% of the pipe is used for hydrocarbon flowlines, most with water cuts of 80 to 90% (28). Shell has used FRP pipe offshore for over 20 years, mostly for handling water. Sea water risers (3 to 12 in. OD) have performed well at 13 bar (~190 psi) internal pressure. A number of 10 bar (145 psi) carbon steel firewater systems have been replaced with FRP.

Slowly the experience gained with FRP piping onshore and in other industries is moving to the offshore oil industry to meet the requirements of light weight, corrosion resistance, low maintenance and cost effective performance. Figures 5-8 show some typical offshore applications of FRP pipe.

Winkel has documented Phillips Petroleum's experience with FRP piping at the Ekofisk field in the Norwegian North Sea (15,29). Twenty (20) separate FRP piping systems have been installed at Ekofisk since 1982. These piping systems have been used primarily for low pressure (<16 bar, 232 psi) sea water applications. Phillips' experience at Ekofisk has shown that FRP pipe can produce substantial cost savings offshore with an installed cost 90% of that of carbon steel and life cycle costs only 60% of that of steel (29). Economics, not weight saving, was the reason FRP piping was chosen over steel piping in the Ekofisk field. Winkel determined that on a life cycle cost basis for five projects in the Ekofisk field, FRP pipe saved $6 per pound of steel replaced (15).

The first use of FRP pipe for a firewater system offshore was probably by TOTAL in 1975 (16). Aubert reported that the galvanized carbon steel piping used for the firewater and cooling systems were heavily corroded and had to be replaced. The FRP pipe was used in diameters of 1 to 16 inches at design pressures up to 14 bar (200 psi) and temperatures up to 100°C.

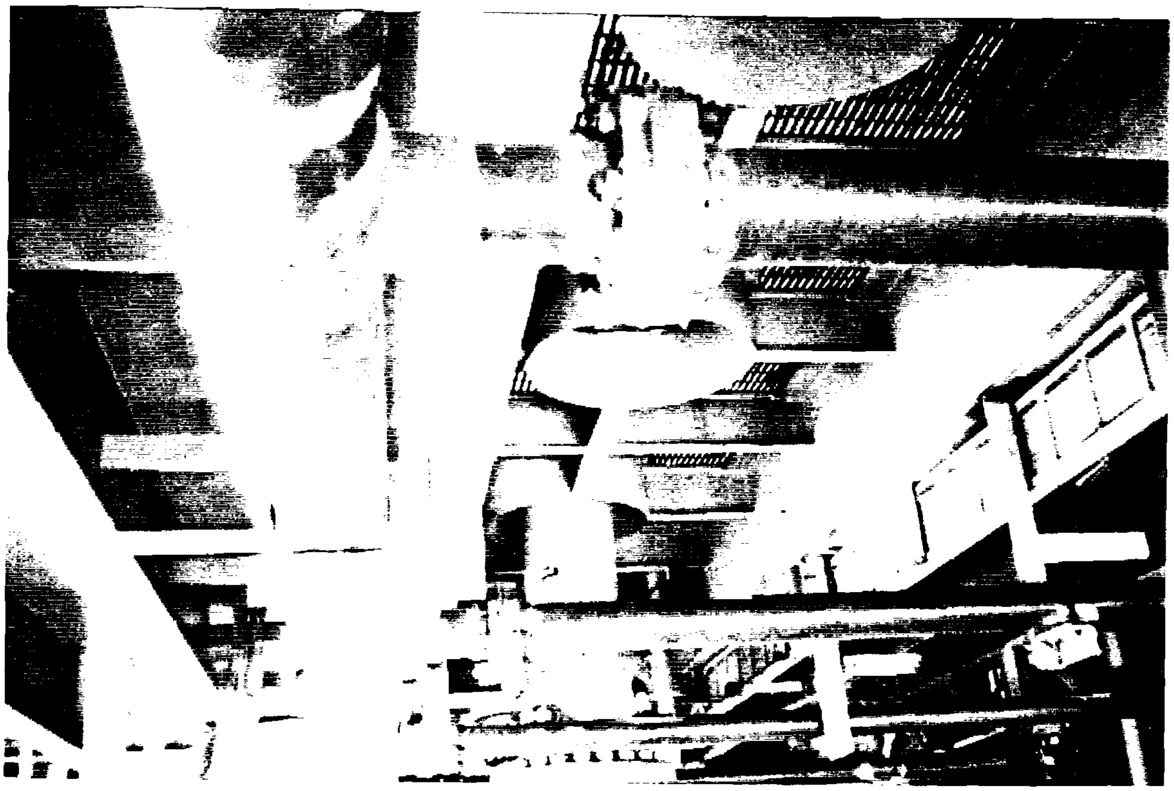

Figure 5. Offshore Application of FRP Pipe (Photo courtesy of Smith Fiberglass Products)

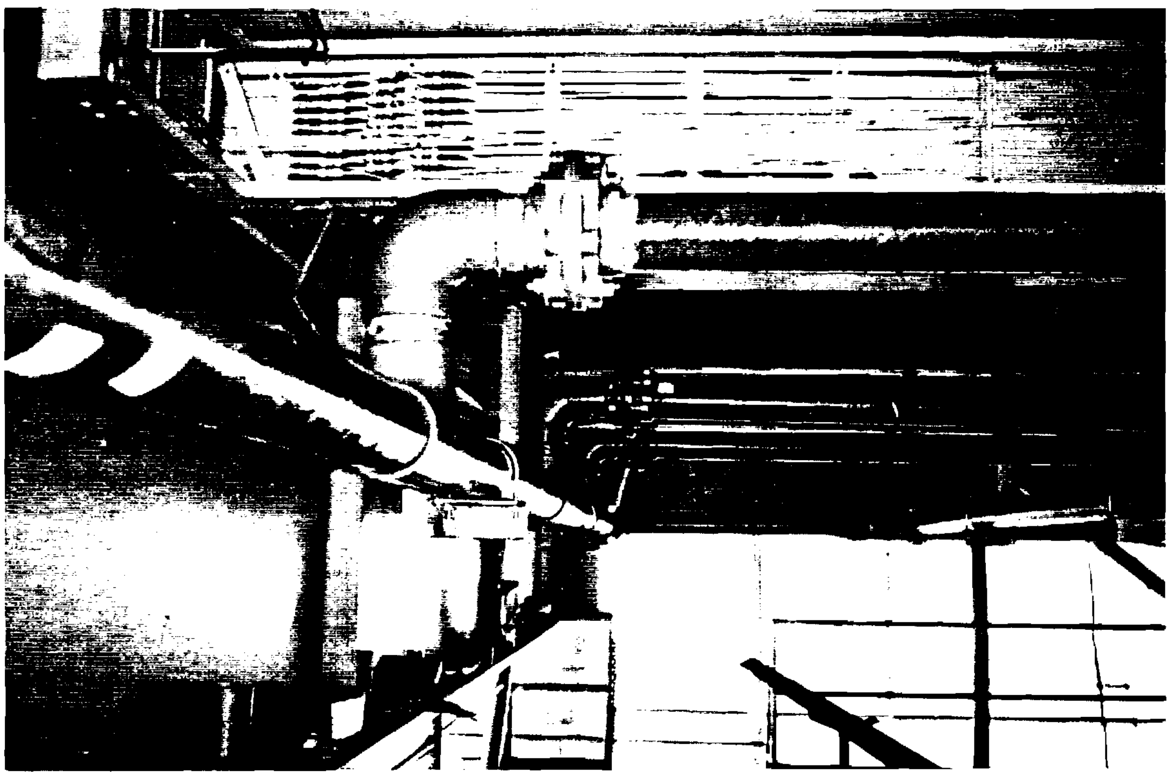

Figure 6. Offshore Application of FRP Pipe (Photo courtesy of Smith Fiberglass Products)

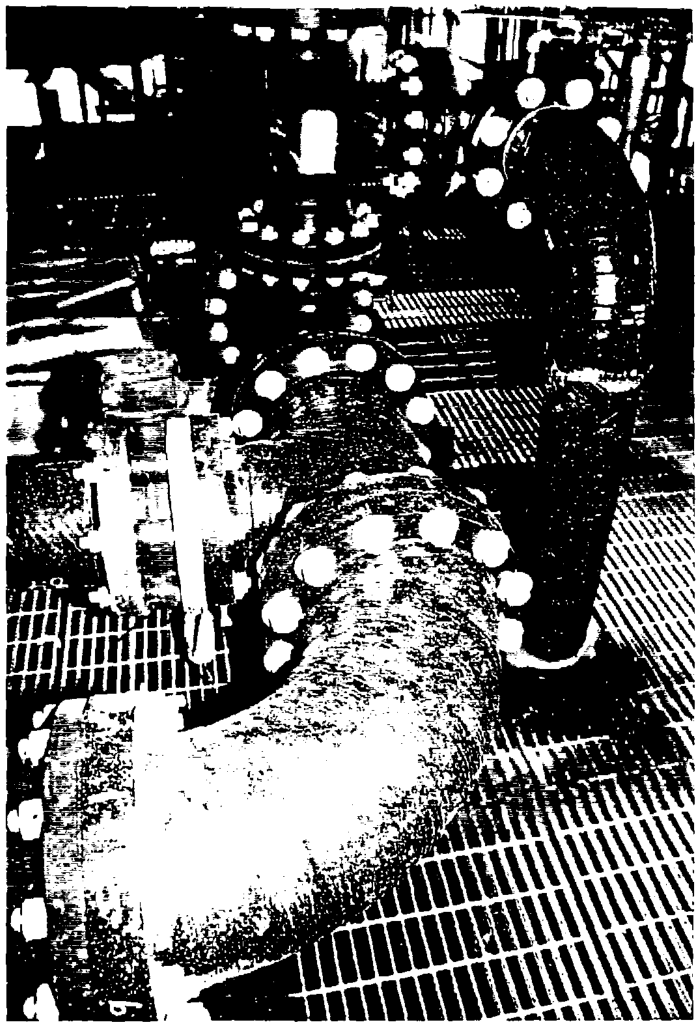

Figure 7. FRP Fire Water Pipe
(Photo courtesy of Ameron Fiberglass Pipe)

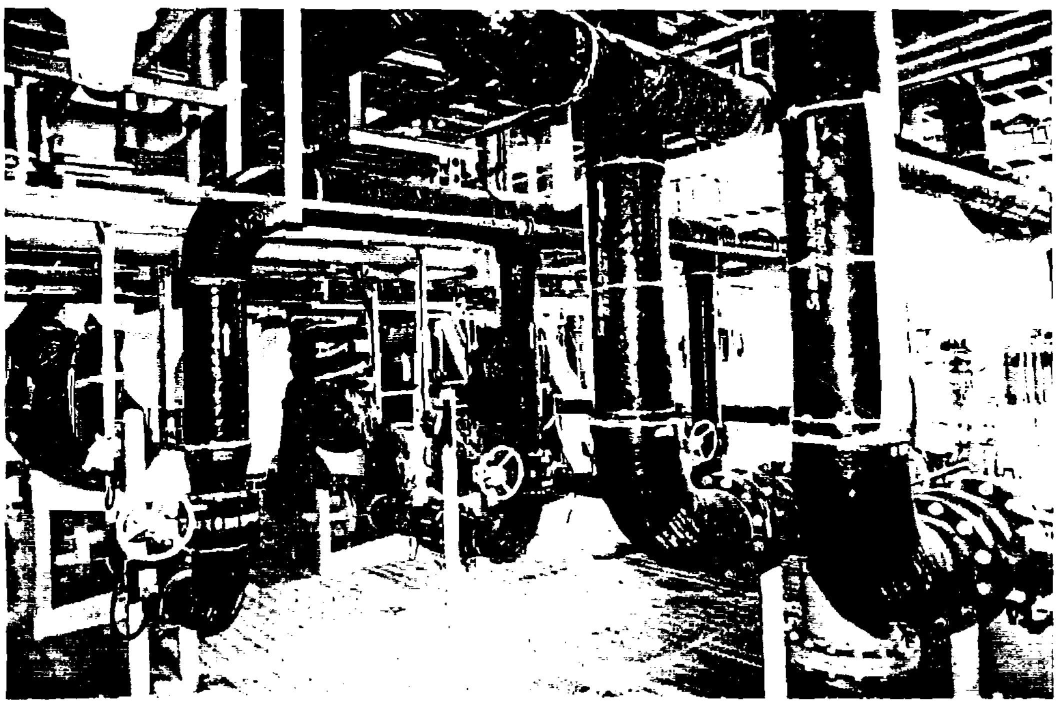

Figure 8. FRP Sea Water Coolant Pipe (Photo courtesy of Ameron Fiberglass Pipe)

In the last five years, FRP pipe has been used extensively offshore on new construction and as replacement pipe in firewater systems (30-34). FRP firewater systems have been installed on production platforms in the North Sea, Persian Gulf, Southeast Asia and the Gulf of Mexico. For some companies, FRP is now the standard for offshore deluge firewater systems. The primary factor in using FRP over coated carbon steel is not weight savings, but reduced maintenance and operating costs with increased reliability

Offshore operators and certifying agencies in the past have expressed concern about FRP deluge firewater systems performing "under fire". When Amoco Norway Oil Company started to discuss the use of FRP pipe to replace the maintenance plagued carbon steel firewater system on its Valhall platform in the Norwegian North Sea in 1990, it included the Norwegian Petroleum Directorate (NPD) in the discussions. These discussions led to the development of a risk assessment study, a fire survivability verification program, and detailed specifications and quality assurance systems (30). These three steps eventually led to the acceptance by the NPD of Amoco Norway's plan to replace the steel firewater piping on Valhall with FRP piping containing an insulating outer layer. One other equally important factor in gaining NPD approval was the change the NPD made in its acceptance criteria. The NPD changed its rules from material-based to performance-based. Since Amoco Norway demonstrated that the FRP firewater system would meet all performance criteria in a hydrocarbon fire, the NPD approved its use. British Gas conducted jet fire tests on Cu/Ni, carbon steel and FRP pipe to evaluate their suitability for topsides sea water piping applications. The most critical application from a safety standpoint, of course, is the firewater system (35). The results of the British Gas study indicated that for firewater applications, the following operational characteristics apply:

- Empty FRP piping without fire protection has a jet fire endurance comparable to that of Cu/Ni.
- Water filled FRP piping without fire protection can survive the start-up period of a firewater system.
- Empty FRP piping with a suitable fire protection coating has a fire performance comparable to that of steel.

The U.S. Navy has been evaluating composite piping systems for use on surface ships and submarines since the 1950's (36). The Navy's objective is to reduce weight and maintenance at an affordable price compared to conventional alloys used for marine service. A report in 1987 by the David Taylor Naval Ship R&D Center stated that **"Composite pipe ranks as the lightest and the least expensive corrosion resistant piping material that can be used in the marine industry"**(37).

The Navy conducted high velocity sea water erosion tests using a 2-inch diameter piping system mock-up similar to what would be found onboard ship. The Navy concluded that the composite pipe specimens showed no evidence of erosion after one year of exposure to sea water at 11 and 17 feet per second, and after 3 months exposure at 25 feet per second (36).

The Israeli Navy is using composite piping in its corvettes. Specialty Plastics designed, fabricated and installed nearly 12,000ft of small diameter FRP pipe for the Israeli Corvette Program (36). The pipe is used for sea water, bilge and sewage applications. Each 275ft long corvette has ~15,000ft of pipe.

Though composite piping is gaining industry acceptance for use offshore, it still suffers from a lack of standardization, a lack of acceptance by certain regulatory bodies, insufficient design codes, not enough properly trained installation personnel and the specter of fire, smoke and toxicity concerns.

The design of FRP piping systems must accommodate the lower elastic modulus of the composite pipe. Most composite pipe is filament wound with the fibers oriented +/-54° to the long axis of the pipe. This configuration results in a pipe with an elastic modulus in the longitudinal direction about 10% that of carbon steel (37). This lower modulus requires closer pipe support spacing to minimize the vertical deflection of FRP pipe.

Most analyses of the installed costs of piping systems indicate that composite (FRP) piping systems generally cost more than carbon steel for diameters below 4-6 inches (36,38). This is usually attributed to the higher cost winding small diameter pipe and making flanges, ells, tees and valves for composite piping relative to carbon steel. Table 10 contains a comparison of the relative installed cost for a 400ft, "complex" piping system made from 5 different materials. Note that for the 6-inch diameter case, a FRP system would be just over twice the cost of a carbon steel system, but would be 15% cheaper than a carbon steel system lined with polypropylene.

FRP pipe is used extensively in the columns and base of concrete platforms to handle sea water ballast. Ballast piping and bilge piping in a TLP or FPS hull is a good application for composites to reduce weight and operating costs.

Table 10 - TOTAL INSTALLED COST* OF COMPOSITE PIPE vs. SELECTED METALLIC MATERIALS

System	Carbon Steel Sch 40	316L SS Sch 40	FRP	C-Steel with PP Liner	Monel Sch 40
2-inch diam. 400ft, complex	1.00* ($12,480)	1.45	1.86	1.90	3.24
4-inch diam. 400ft, complex	1.00* ($18,923)	1.57	1.78	2.21	5.64
6-inch diam. 400ft, complex	1.00* ($25,519)	2.07	2.08	2.45	6.64

*: Costs shown are relative to carbon steel with a value of 1.00. The cost for a carbon steel system is shown in ( ).
Note: Material costs were based on typical U.S. Gulf Coast values in the fourth quarter of 1991. The complex system consists of 400ft of pipe with 21 90° elbows, 4 45° elbows and 15 tees (39).

6.2 Vessels and Tanks

Composite materials either in the form of FRP or a "dual laminate" (composite structure with a thermoplastic liner) offer significant weight savings and maintenance cost reductions when used for storage tanks and process vessels (40). Figure 9 shows four large (8ft x 56.5ft) dual laminate chlorine scrubbers made by C.P.F. DUALAM, Inc. Conoco Norway and Statoil used 11 FRP

Figure 9. Dual Laminate FRP Chlorine Scrubbers (Photo courtesy of C.P.F. DUALAM, Inc.)

storage tanks on the Heidrun concrete TLP installed off the coast of mid-Norway in July 1995. These storage tanks ranged in volume from 60,720gal (1,445bbls) to 113,520gal (2,700bbls).

One characteristic of FRP tanks and vessels little known and appreciated by many facilities designers is their good performance in a fire (41). Thon and Stokke summarized the results from 10 different investigations of the behavior of FRP, carbon steel and aluminum tanks in open pit hydrocarbon fires. The tanks contained a variety of liquids including naphtha, gasoline, heating oil and other hydrocarbons. Thon and Stokke concluded that:

- FRP tanks containing flammable liquids out performed steel and aluminum in fire tests mainly due to the lower heat conductivity of FRP versus steel (x40) and aluminum (x700).
- The support system for FRP tanks is an important factor in their performance in fire situations. With an inadequate support, the tank may collapse.
- Small amounts of fire protective coating will significantly increase the fire resistance of FRP tanks.

6.3 Living Quarters and Control Rooms

Composite materials, especially FRP, are getting a lot of attention in the UK and Norwegian offshore sectors for use in living quarters and control rooms. The light weight, low maintenance and thermal insulating properties of FRP particularly when formed into a sandwich structure wall panel make FRP an attractive alternative for these applications.

Without taking a close look at the design of living quarters and control rooms for the GOM in this study, it was assumed that very little weight could be saved except in the structural beams that support the living quarters module. The reduced need for thermal insulation in the GOM and the use of a stressed skin design for quarters modules have lessen the advantage of composites for such applications. A FRP office/temporary shelter for 4-5 people was used for the Marginal Field Structure scenario in place of a living quarters on this "not normally manned" platform.

6.4 Secondary Structures

Composite materials, FRP and glass/carbon hybrids, offer significant weight and cost savings for the many applications grouped together as "secondary structures".

Grating offers great opportunities to not only save weight, but also to save on installation and maintenance costs. The Mars TLP used ~87,000ft^2 of FRP phenolic grating with even more being planned for Shell's Ursa TLP. Figures 10 and 11 show a stack of composite grating in a fabrication yard and installed on an offshore platform. Note the small structural beams in Figure 11 that are excellent candidates for replacement by hybrid composite beams.

One application that has received little attention so far is structural beams. Hybrid composite beams containing mainly glass fibers but with higher elastic modulus carbon fibers placed in the top and bottom flanges are being designed, fabricated and tested as part of a NIST ATP project. Morrison Molded Fiberglass (MMFG) is the lead company in this project. Eight (8)-inch

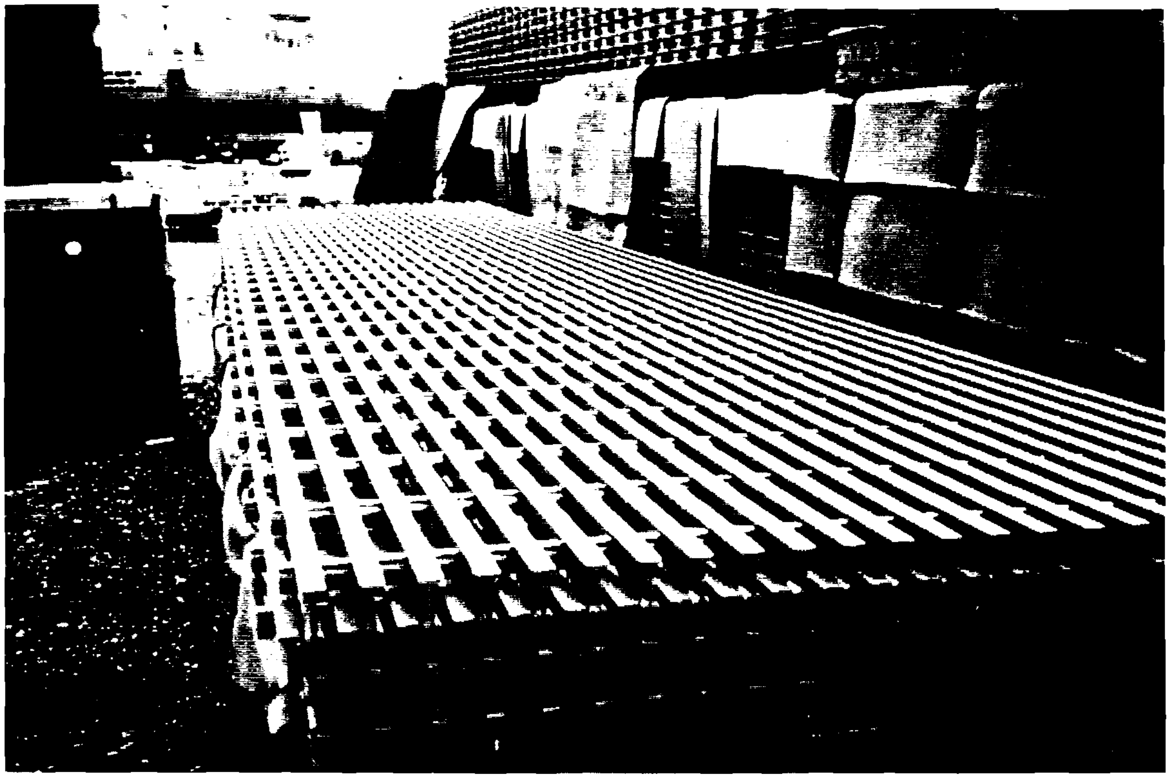

Figure 10. Stack of Phenolic FRP Grating in Fabrication Yard (Photo courtesy of MMFG)

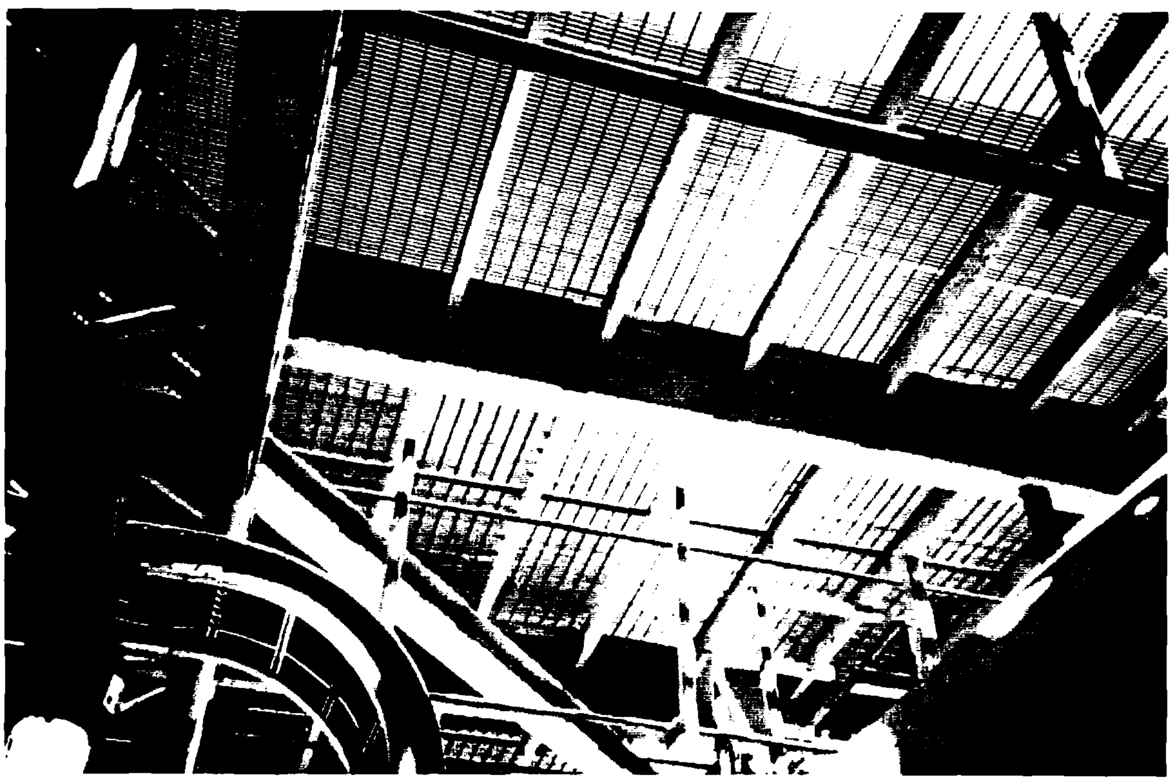

Figure 11. Offshore Application of Phenolic FRP Grating (Photo courtesy of MMFG)

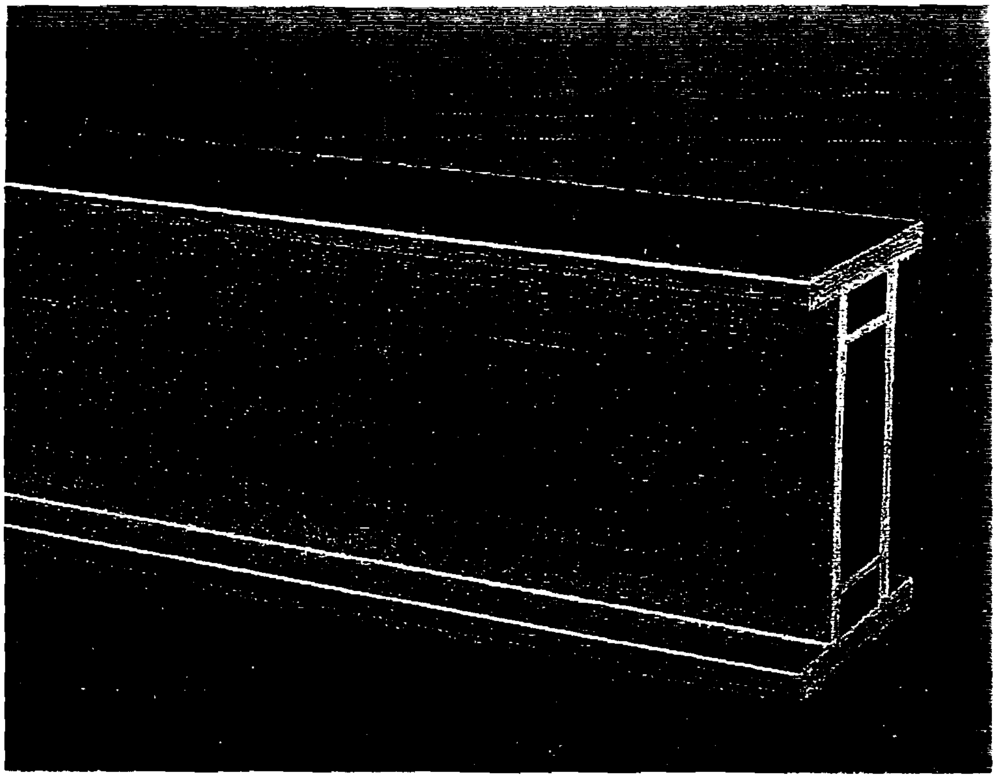

Figure 12. Eight-Inch Prototype Hybrid Composite Beam (Photo courtesy of MMFG)

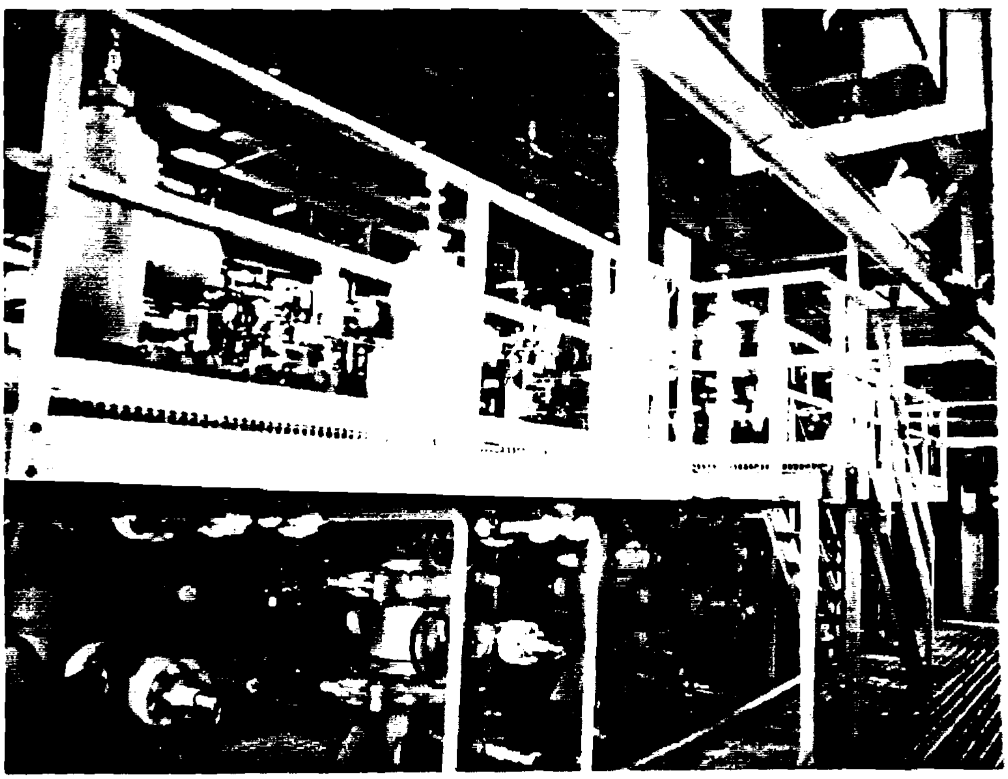

Figure 13. FRP Grating, Stairs, Handrails and Wellhead Access Structure on an Offshore Platform (Photo courtesy of MMFG)

prototype beams have already been tested and 36-inch beams are expected to be produced by late 1997. Figure 12 contains a photograph of the 8-inch prototype hybrid composite beam produced by MMFG as part of the NIST ATP project. The weight savings and cost assessments developed in this study were based on the following:

- 8-inch composite hybrid beam: 11.2 lbs/ft, $36/ft (cost of beam), $3.21/lb.
- The composite beam weighs 36% of the comparable steel beam
- The steel beam cost is $0.50/lb

Assuming that a composite beam costs $2.71/lb more than a steel beam before installation, and that a composite beam would reduce structural weight by 64%, each ton saved will cost $2,050. For a floating platform, such as a TLP or FPS, where the value of a ton of topside weight is from $6,000 to $10,000, the use of composite beams would certainly be cost effective. For a fixed platform, such as the SPS, where each ton of topside weight is valued at ~$2,000, the composite beams is probably a break-even proposition. If the cost of the composite beam were $4/lb (steel cost of $0.50/lb) before installation with a weight saving of 50%, the cost per ton of weight saved would increase to $6,000. If the composite beam cost were $5/lb and the weight saving was still 50%, the cost per ton saved would be $8,000. At $4-5/lb and a weight saving of 50%, the composite beam **may not** be cost effective. The weight saving from structural composites may have knock-on benefits regarding installation cost reductions. However, if passive fire protection is required for the composite beams, they **may** no longer be cost effective for fixed platforms.

Figure 13 shows FRP grating, stairs, and handrails associated with a wellhead access structure on an offshore platform. As larger beams become commercially available, properly tested and approved for use offshore, significantly greater weight savings are expected by 2005.

Carbon fiber composites are gaining acceptance as strengthening members for existing steel beams in many onshore infrastructure applications such as bridges. Within the past year, this concept has been used to strengthen an existing offshore platform in the UK sector of the North Sea (8,42). This concept involves adhesively bonding a carbon fiber composite strip to the underside flange of a deck beam. The use of composites to strengthen existing platform decks offer increased deck load capability with minimal additional structural weight and no need to stop production because of safety concerns associated with welding. This concept could also be used in new construction to reduce deck and hull structural weight.

6.5 Drilling Equipment

The drilling module is the largest single module (5,000 tons) in the TLP and FPS Steel Base Cases. The only weight savings that were assumed to be practical with the drilling module at this time included storage tanks and some secondary structural beams. Drilling equipment is a tempting target for weight reduction or elimination on floating production platforms. It may be possible in time to achieve a 30-40% weight reduction by using composite materials (for the drilling derrick, for example), but such an application is not expected in the near future. The drilling equipment could be reduced to a workover rig if all the wells were pre-drilled and any future need for additional wells was met either by semi-submersible drilling rigs tying back the wells to the TLP/FPS or by coiled tubing drilling from the TLP/FPS.

For the Small Production Structure, it was assumed that all wells would be either predrilled or drilled with a jack-up rig. The drilling module was eliminated completely.

Lincoln Composites offers a flexible drill pipe specifically designed for use in short radius (25-35ft) horizontal re-entry drilling applications (see Figure 14). The flexible drill pipe is available in 2-3/8in., 2-7/8in., and 3-1/2in. connection diameters at an internal operating pressure of 1,000psi and rated torque of up to 12,000ft-lbs. Lincoln Composites also supplies a drillable casing (see Figure 15) for use in straight hole sections where future side track operations are planned. The drillable casing is available in connection sizes up to 9-5/8in., tensile loads to 120,000lbs., and internal pressure rating of 3,000 to 5,000psi depending on application.

The objective of the NIST ATP Composite Drill Pipe project led by Phillips Petroleum Company is to develop a lightweight composite drill pipe that will enable offshore operators to reach out an additional 10,000ft horizontally from a platform to drain reservoirs of oil and gas not within reach with available materials today. This has enormous upside economic potential for the offshore oil industry. If this drill pipe project is successful, the economic life of many existing platforms could be extended as they could then be used to produce oil and gas from reservoirs that would have normally required separate and much more costly development scenarios. Other members of the Composite Drill Pipe project include Amoco Production Corporation, Cullen Engineering Research Foundation, SpyroTech and the University of Houston.

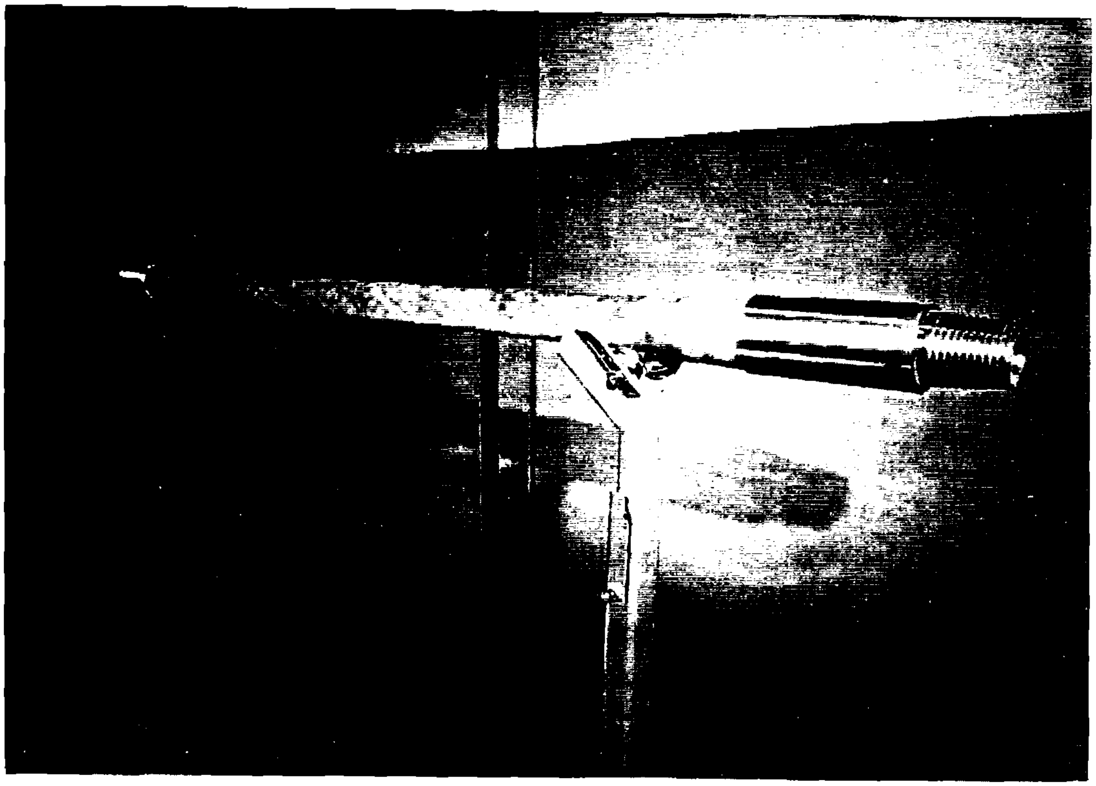

Figure 14. Flexible Composite Drill Pipe (Photo courtesy of Lincoln Composites)

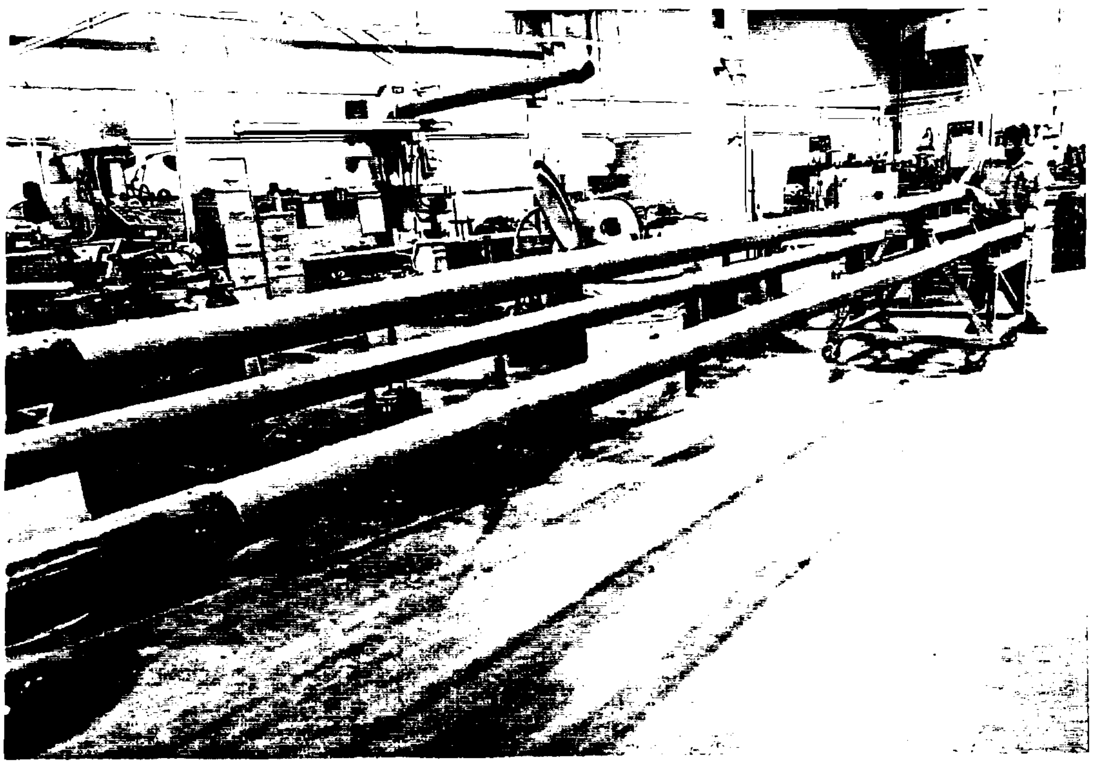

Figure 15. Drillable Composite Casing (Photo courtesy of Lincoln Composites)

7. COMPOSITE RISERS

7.1 Drilling Risers

Aker Omega and Westinghouse Marine concluded that a composite drilling riser was technically and economically feasible in 3,000ft of water in the GOM (43). A filament wound, glass/high temperature epoxy composite system was selected for their study. They found that a composite drilling riser would require 72% less buoyancy foam weight than the steel riser, and the dry deck storage weight/load would be reduced by about 370 tons in 3,000ft of water. Weight savings would be even greater in water depths of 4-10,000ft as shown in Table 11. The estimated deck loads shown for the steel and composite risers for water depths of 4,000 to 10,000ft are simple extrapolations of the 3,000ft data from reference 43. The top and bottom equipment were kept the same, and additional bare and jacketed (buoyancy) riser joints were added to obtain the required length. No consideration was given to strength or elastic modulus properties of the composite riser system. Each bare composite riser joint is 22 inches in diameter, 65 feet long and weighs 12,375 lbs (19,289lbs with foam modules). The 5-inch OD choke and kill lines are also made of composites and rated at 5,000psi. Aker Omega and Westinghouse concluded that the cost of a composite riser would be nearly the same as that of a steel riser. Recent evaluations of the cost of composite drilling risers, however, have concluded that composite risers would probably be more expensive than steel risers with buoyancy jackets included, but probably cheaper than titanium risers.

Table 11 - ESTIMATED DECK LOAD SAVED WITH COMPOSITE DRILLING RISER

	Water Depth							
	3,000ft		4,000ft		6,000ft		10,000ft	
	Steel	Composite	Steel	Composite	Steel	Composite	Steel	Composite
Total Dry Riser Deck Load (tons)	952	582	1,192	699	1,687	939	2,692	1,420
Deck Load Saved With Composites (tons) [%]	370 [39]		497 [42]		748 [44]		1,272 [47]	

Note: The numbers in the "3,000ft" column are from reference 43.

In 1995 Westinghouse Marine, now Northrop Grumman Marine Systems, was awarded a $4.824 million NIST Advanced Technology Program (ATP) contract to develop a composite drilling riser. Northrop Grumman along with the Texaco/DeepStar consortium (ABB Vetco Gray, the Offshore Technology Research Center, Reading and Bates, and Hercules) are working to produce a carbon-epoxy composite drilling riser prototype for field testing in 1997.

Conoco Norway used a titanium (Ti-6Al-4V ELI alloy, ASTM Grade 23) drilling riser in 1,150ft of water for the Heidrun concrete TLP off the coast of mid-Norway (44-45). The riser has a 23-3/4in. OD, a 0.875in. wall thickness, and each joint is 48ft long with flanged connections. A 3mm thick neoprene liner was applied to the internal diameter of all the riser joints to improve the wear performance against the steel drill pipe and drill collars. It has been reported that this neoprene liner had been destroyed by the drilling operations from at least one well and had to be replaced. This has raised concerns about the viability of such liners in a composite drilling riser where the liner not only protects against wear but also is the primary pressure containment system. Conoco Norway reported that the titanium drilling riser cost about $22 million, or 60% of the cost of a comparable pressure-rated steel drilling riser system (45). The total cost of the titanium metal was about $7,690,000 (~$5,920/ft for 1,300ft), about three times the $2,500,000 (~$1,920/ft for 1,300ft) cost of comparable steel forgings. Salama (4) estimated the cost of a titanium drilling riser at ~$10,000/ft and a composite drilling riser at ~$5,000/ft. Although the titanium cost was higher than the steel, the overall system cost savings resulted from reduced handling, tensioning, and support structure costs. The Heidrun TLP tensioners cost about 1/6 that of tensioners for a steel drilling riser, a $12,750,000 savings. Surface handling equipment for the pipe rack and V-door pipe shuttle system were rated for 5.5 tons versus 13-17 tons for the steel riser (45). Similar savings are expected with a composite drilling riser system.

Drilling in deep water is an expensive process that is being scrutinized from many angles. Reducing the weight of the drilling riser is just one of the options being considered. Pre-drilling all the wells in deep water and only putting a workover rig on the permanent production platform (TLP or FPS) is another consideration. Conoco and others are evaluating the advantages of riserless drilling in deep water (46). Because of the changing picture of deep water drilling and the lack of sufficient data regarding composite drilling risers, no in-depth analysis of the potential benefits from composite drilling risers was undertaken in Phase 1.

7.2 Production Risers

Production risers in deep water have long been a target for weight reduction through the use of composite materials. The total weight in air of 24 9-5/8inch steel production risers for a typical GOM TLP (Table 5) is about 1,566 tons, plus an additional 313 tons for pre-tension. The riser load that must be carried by the deck and hull increases to about 2,376 tons in 4,000ft. At $4.25/lb ($8,500/ton), it cost about $20 million to support these risers in 4,000ft of water. If the riser top tension could be reduced by 50%, the economic payoff of about $10 million would easily cover the cost premium for composite risers. The deeper the water, the greater the payoff from composite risers.

IFP and Aerospatiale pursued the development of a hybrid composite riser in the late 1980s under the sponsorship of several oil companies (47-48). A carbon and S-glass fiber composite riser prototype was evaluated in a number of static, fatigue, multi-axial loading and damage assessment tests. This composite riser development ended when the oil companies decided against a full size field test.

Lincoln Composites (formerly Brunswick Composites) is the lead company in a three year NIST ATP project expected to produce a hybrid composite production riser to replace the standard 9-5/8 inch steel riser. Other organizations participating in the project include: Amoco, Conoco, Cullen

Engineering Research Foundation, Shell, Brown & Root, Hercules, Hydril, Stress Engineering and the University of Houston. Lincoln hopes to build on the lessons learned in the IFP-Aerospatiale riser project and develop a composite riser with improved properties at lower cost. The projected cost of the carbon and glass composite riser has not been made public. A cost of $210/ft (including steel end connections) was used in this study as a realistic estimate for a composite riser. This estimate appears to be in line with current industry projections (4).

A composite hydraulic accumulator bottle is available from Lincoln for use on TLP production riser tensioner systems that is lighter and cheaper than the steel equivalent. Figure 16 shows four composite hydraulic accumulator bottles similar to the ones used offshore in the GOM.

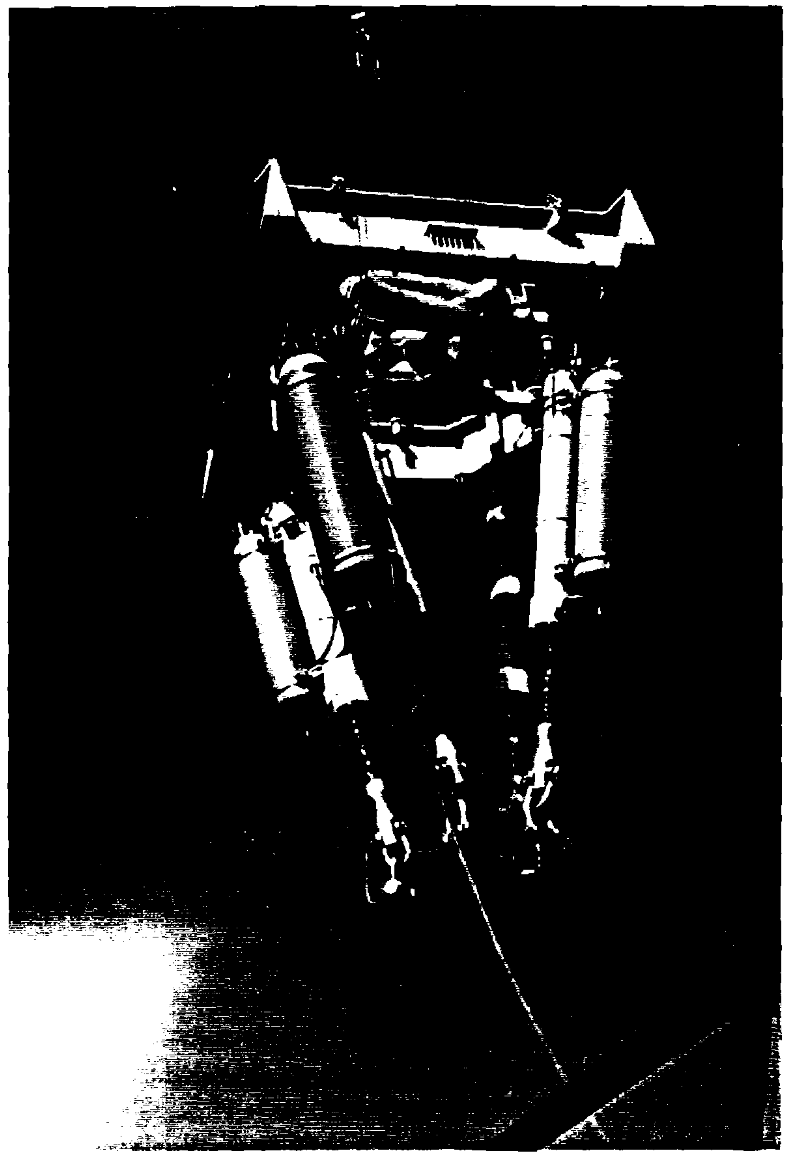

Figure 16. Composite Hydraulic Accumulator Bottles for a GOM TLP Production Riser Tensioner System (Photo courtesy of Lincoln Composites)

7.3 Flowline Risers

Composite flowlines to replace the 8.625-inch diameter steel flowlines carrying production from subsea wells to the deck of the TLP or FPS optimistically could be available by the year 2005. Spoolable composite flowlines with continuous lengths of 2-3 miles and internal working pressures as high as 5,000psi may be available in 1998 in diameters up to 4 inches from NAT/Compipe in Norway and FiberSpar in the U.S. Jointed FRP pipe is available in sizes up to 16 inches, but the internal pressure rating decreases with OD from 300psi at 2-inch to 100psi at 16-inch. Currently available jointed FRP pipe is not suitable for offshore riser and flowline applications.

The NIST ATP project led by Hydril is developing spoolable composite tubing technology. The Hydril led project plans to have short lengths of its first prototype composite tube by late 1996. Other companies in the $5.015 million Hydril spoolable composite tubing project are Amoco, Cullen Engineering Research Foundation, Elf Atochem, Phillips Petroleum, Shell Oil Products, and the University of Houston.

For very corrosive liquids, titanium flowlines are another lightweight alternative to carbon steel and duplex stainless steel (49).

7.4 Export Risers

Composite export risers with diameters greater than 6 inches could be another promising application for composite pipe development.

8. COMPOSITE MOORING SYSTEMS

8.1 Tension Leg Platform

A TLP tendon represents an ideal application for composite materials because the loads are predominately axial tension which best utilizes the high unidirectional strength and stiffness of composites. The potential cost savings associated with carbon fiber tendons can be achieved only if these low density components can be produced at an affordable cost. Two critical steps in attaining this goal are the production of large quantities of high quality carbon fibers at low cost and the development of a low cost manufacturing process. Neutrally buoyant steel tubular tendons become considerably more expensive in ultra deep water due to the need to resist collapse from external pressure. Collapse resistance can be provided by internal or external ring stiffeners, by internally pressurizing the steel tube to reduce the effective pressure differential, or by decreasing the diameter-to-wall thickness ratio (D/t) to well below 30 thus making the tendon heavier than water. The weight of the tendon in water must be carried by providing additional buoyancy to the hull or attaching buoyancy jackets to the tendons.

The potential advantages provided by a composite tendon compared to steel are discussed in references 50 & 51. Two configurations have been proposed, a composite tube similar to steel tendons, and a rod rope or ribbon tendon constructed as a unidirectional assembly of many small diameter pultruded unidirectional rods (51-55). The design of deep water TLP tendons is primarily driven by axial stiffness requirements and the resulting stresses in the tendons are relatively low. A carbon fiber polymeric resin composite tube is neutrally buoyant with a diameter-to-thickness ratio (D/t) of 5. A solid composite or steel tendon would have a D/t of 2. Resistance to hydrostatic collapse requires that a large percent of the fibers in the tube be oriented at an angle other than axial which significantly reduces the associated axial stiffness. A composite tube, therefore, is not a very structurally efficient configuration for a tendon.

A configuration composed of unidirectional fibers constructed as a composite rod and assembled as a rope or thick ribbon is the leading candidate for a composite tendon. A composite rod rope or a ribbon constructed of unidirectional fibers encapsulated in a polymeric matrix can be spooled to provide potential cost savings during tendon installation. Individual small diameter rods are permitted to slide relative to each other and thus impose very low bending stiffness. The strain imposed on a 5mm diameter composite rod bent to a 2-meter radius is only 0.125 percent, well within the allowable range. To provide the necessary axial stiffness and be competitive in cost with steel, the fiber of choice at this time is carbon. Although carbon fibers are available with modulus as high as four times that of steel, high modulus carbon fibers are much more expensive and exhibit low strain to failure. Based on current economics, a composite rod constructed of carbon fiber encapsulated in a vinyl ester or epoxy resin matrix will have an axial modulus of elasticity about two thirds that of steel. To match the axial stiffness of a steel tendon, additional cross-sectional area must be provided to the composite tendon. The areal profile to ocean currents and associated loads, however, will be less for the smaller diameter composite rope than for an equivalent neutrally buoyant steel tubular tendon.

8.2 Floating Production System

8.2.1 Catenary Mooring System

The mooring systems for use in deep water with various floating production systems are evolving from the traditional catenary spread chain/wire rope systems to taut leg spread systems with chain and synthetic mooring lines (56-57). For water depths beyond 3,000ft, the chain/synthetic mooring line combination appears to offer desirable performance characteristics with reduced weight at competitive costs compared to traditional chain/wire rope systems. A 12-point chain/wire rope mooring system in 3,000ft of water for a "typical" drilling rig weighs ~1,637 tons in water. A similar chain/aramid rope system would weigh ~1,000 tons, a savings of ~637 tons of deck and hull capacity. By comparison, a simplistic comparison of a chain/wire rope and a polyester mooring system for a FPS with a 150,000 BOPD production rate in 6,000ft points out the advantages of lightweight materials for deep water moorings:

	Weight in Air (tons)	Component Cost ($1,000)	Installation Cost ($1,000)	Total Cost ($1,000)
Chain/Wire	13,080	48,130	14,050	62,180
Chain/Polyester	2,730	24,730	12,030	37,160

The synthetic mooring line system offers an estimated front-end cost saving of $25 million.

The reduced weight and superior performance of the new chain/synthetic mooring line designs at competitive costs may offer little opportunity for "true" composite materials such as carbon-epoxy rod "ropes" to provide weight, performance or costs advantages. This could change if increased axial stiffness becomes important in future mooring system designs. A rod rope composite mooring line could be a candidate system for a taut leg mooring system.

8.2.2 Buoyancy Modules

Buoyancy modules can cost $3 to 5 per pound of buoyancy in the 4,000 to 6,000ft water depth range. A FPS will require buoyancy modules to support the various riser systems of whatever design and certain mooring system designs. This may offer an attractive application for composite materials. A water density of 62.4 lbs/ft^3 was used in this study.

9.COMPOSITE SUBSEA EQUIPMENT

9.1 Flowlines & Injection Lines

Composite subsea flowlines and injection lines in diameters up to 4 inches may be available in long (2-3 miles) continuous lengths in spoolable form in 1998 from the Compipe division of Norwegian Applied Technology (NAT). These spoolable composite lines will have an inner thermoplastic liner designed to handle the liquid (water, methanol, oil production, etc.) and an outer composite structure designed to handle the mechanical loads. The ability to spool these small diameter lines decreases the installation time and cost, and eliminates a big weakness in any jointed pipe - the connection. Continuous length pipe will have greater reliability than jointed pipe which is critical for subsea applications. Spoolable composite pipe is an emerging technology with great promise for subsea and downhole applications (58). As mentioned in Section 7.3, Fiberspar and Hydril are developing similar spoolable composite pipe technology.

The results from Phase 1 of a JIP composite flowline project conducted by NAT/Compipe indicate that a 4-inch (100mm) composite flowline with a PVDF liner will save 40% of the weight and 17-28% of the installed cost of a comparable duplex stainless steel line. With a PEX (cross-linked polyethylene) liner, the cost savings are 39-49% of the cost of duplex stainless steel. Amoco, Conoco, Saga and Statoil were participants in this project.

9.2 Subsea Production Equipment

FRP structures have been used in the North Sea to protect subsea wellheads from trawler boards. The lower weight of these FRP wellhead protection structures allows them to be installed by a wider range of vessels than normal, leading to lower costs. Shell used FRP subsea wellhead protective structures on its Draugen platform off the coast of Norway.

Composite materials are being considered, at least in concept, for other structures located on the sea bed. The lower weight of composite structures in sea water gives the offshore operator greater flexibility and a wider range of choices regarding installation and intervention, both potentially very costly operations in deep water.

Because of the nature of operations in the GOM, no subsea wellhead protection structures were used in this study. Any further consideration of the application of composites to subsea equipment will be done in future studies.

10. COMPOSITE DOWNHOLE EQUIPMENT

10.1 Production Tubing

FRP tubing is available for use in production wells from a number of companies including Ameron Fiberglass, Fiber Glass Systems, and Smith Fiberglass. Some grades of FRP tubing are rated to 3,500 psig for 4-inch diameter and up to 210°F. The pressure rating of 6-inch tubing is 2,500 psig. The greatest benefit from FRP tubing is received when it is used in high water cut, very corrosive oil wells. FRP tubulars have not been used for the generally deeper, higher pressure, high risk offshore wells.

The spoolable composite pipe originally designed for use as coiled tubing by Conoco, AMAT A/S and Fiberspar (59) is being considered as a siphon or velocity string in gas wells. The small diameter (~1-1/2in.) of this composite coiled tubing (CCT) increases the velocity of flow in aging gas wells and helps keep the well from shutting down due to water accumulation. The composite tubing will resist corrosion in corrosive gas wells with high water cuts.

A distinct advantage of CCT is the relatively light weight of a spool of 10 to 15,000ft of composite coiled tubing (CT) compared to steel CT. Many cranes on existing platforms in the UK sector of the North Sea do not have the required lifting capacity to offload a 9 to 12 ton spool of steel CT from a boat to the platform deck. This is also a problem in the GOM.

Once larger diameter spoolable composite pipe and jointed pipe with higher pressure ratings become available, composite tubing may be considered for use offshore.

10.2 Injection Tubing

Composite coiled tubing can be used for small diameter chemical injection lines. The thermoplastic liner can be chosen to resist whatever chemical is being injected. Lincoln Composites offers a "drillable casing" (jointed composite pipe) that has been considered as sea water injection tubing for North Sea applications. High flow rate water injection wells, especially where raw sea water may be used, would be a good application for such a composite pipe. In this case, the composite pipe would replace or compete with duplex stainless steel because of the corrosive nature of high velocity aerated sea water.

FRP tubing products available from Ameron, Fiberglass Systems and Smith can be used as injection tubing. Because of the generally corrosive nature of most injection water, this is a good application for composite tubing if it meets all the mechanical requirements.

10.3 Casing

FRP casing is available in diameters of 4-1/2 to 13-3/8in., and is used onshore, especially for wells passing through corrosive formations. Lincoln Composites' drillable glass/carbon hybrid composite casing is available in diameters of 4-1/2 to 9-5/8in. Jointed composite pipe generally does not have the properties required in the diameters used for casing, especially offshore.

11. CURRENT OFFSHORE APPLICATIONS OF COMPOSITE MATERIALS

Composite materials have been used offshore for over 20 years. Initial applications were generally related to replacement of carbon steel piping corroded in sea water service. Since then,

Table 12 - CURRENT OFFSHORE APPLICATIONS OF COMPOSITE MATERIALS

Component	Examples* of Offshore Fields Where Used (Operator)
Fire Water Piping	Marquette-GOM (Conoco), Mars-GOM (Shell) Valhall-North Sea (Amoco Norway)
Sea Water Piping	Ekofisk-North Sea (Phillips), Dubai-Persian Gulf (Conoco)
Storage Vessels	Heidrun-Norway (Conoco Norway) Davy/Bessemer-North Sea (Amoco)
J-tube Bellmouth	Troll-Norway (Norsk Hydro)
Grating	Mars-GOM (Shell), Ram-Powell-GOM (Shell)
Office Module	Davy/Bessemer-North Sea (Amoco)
Tensioner Accumulator Bottles	Mars-GOM (Shell), Ram-Powell-GOM (Shell)
Cable Trays and Ladders	Ekofisk-North Sea (Phillips)
Stairs and Handrails	Davy/Bessemer-North Sea (Amoco)
Strengthening of Steel Beams & Blast Walls	Beryl B-North Sea (Mobil)
Mud Mats	Garibaldi C-Adriatic Sea (Elf)
Subsea Wellhead Protection	Draugen-Norway (Shell) & Vigdis-Norway (Shell)

*: The example(s) shown of current applications of composite components are not meant to be all inclusive.

FRP components have been used for a wide variety of offshore applications because of FRP's resistance to corrosion and its light weight. The examples shown in Table 12 are used merely to provide an overview of the wide spectrum of applications, from mud mats to fire water piping. One advantage of using composite components in a maintenance or retrofit situation is the relatively easy handling of these components because of their light weight and the fact that no welding is required to install composite piping, vessels and structures. The lack of welding normally means a quicker, less costly installation because the production will not need to be shut down for safety reasons while the installation proceeds. Most, if not all, of the current applications of composite materials offshore have been on a material substitution basis (a drop-in replacement for steel) and not a system basis. Therefore, the offshore operators have not fully benefited from the use of composite components.

12. BARRIERS TO ACCEPTANCE OF COMPOSITE MATERIALS

Much has been written about the barriers that exist to the wider application of composite materials in the oil industry (4,5,6,11,18). Salama (4) characterized these barriers as consisting of technical, financial and emotional issues. Once these barriers are identified, a plan of action must be implemented to overcome or eliminate the barriers. Overcoming barriers to the wider application of composite materials is best done as a joint industry effort rather than by one or two companies acting on their own. The greater resources available from a multi-company, multi-organization effort will increase the probability of success by insuring that a critical mass of technology, personnel and industry support is brought to bear on the problems to be solved.

The most important barrier to the use of composites offshore is long term durability and reliability (18,42), especially for critical applications. Tied to this is the performance of composite materials in a fire. The durability and reliability of composite components will be enhanced by increased material data bases, proper risk assessment procedures, and improved methods for service life prediction. These and other technical issues are still being worked on for metallic components, but this has not slowed the advance of offshore development into deeper and more hostile waters.

Another major barrier is the lack of a cost-effective, high speed manufacturing process(es) to produce tubular and/or structural components with consistent properties. A continuous process capable of producing long lengths (2-3 miles) of tubular shapes with consistent properties would be a major step in increasing the reliability of tubular products by eliminating the joints or connections, and in reducing cost.

A third major barrier is the lack of user friendly composite design software (18). The design of composite systems must be moved into the hands of experienced engineers, not just a few composite experts. This will also require a significant educational effort to raise the level of composites knowledge and understanding amongst these new composite designers.

A fourth barrier is the general lack of knowledge and familiarity with composites amongst construction and operations personnel. This "ignorance factor" adds to the resistance to the use of composites, increases the cost of installation with new composite components, increases the likelihood of misuse and shortened service life, and prevents the offshore operator from realizing the full range of benefits possible with composite components.

The lack of a "champion" at a decision making level in a major offshore development project or technology support organization is a barrier to the introduction of new technology that is extremely difficult to overcome. These key people should be kept informed of major developments in the offshore application of composite components. Informed project and technology managers are more likely to support the use of new technology if they see it as a cost effective and natural progression of what has already been developed.

Another barrier is the need to provide a method to monitor the integrity of composite components. The areas of Nondestructive Testing (NDT) and Nondestructive Engineering (NDE) are of major importance to the full and widespread acceptance of composite materials for a range of applications. NDT and NDE are critical during the manufacturing process to insure that the composite component has the required minimum properties, and during service to determine if the composite component is still "fit" for the intended application.

Terminations, connections and attachment points for composite components, especially tubulars and structural elements, collectively are another issue related to composites that requires additional development. To fully utilize the strength properties of composites, to properly integrate metallic and composite components, and to increase the durability/reliability of composite components, terminations and connections must be properly designed and tested for the intended service application. The environmental degradation, and long term creep and fatigue loading of mechanical as well as adhesively bonded joints and connections are of concern to many offshore designers (42).

The lack of certification standards and design codes offers another barrier to overcome. When an engineer unfamiliar with composites can not readily find an appropriate design code, an API, ASME or British Standard specification or recommended practice for a particular component, the barrier to the use of composite materials becomes very difficult to overcome. Related to this are material-based design codes and regulations that were developed when steel was the only material considered. These material-based codes and regulations can be a major barrier to overcome when trying to use composite materials for the first time in certain applications. Performance-based codes and regulations can achieve the same level of safety and reliability desired by industry and the certifying authorities, but will not prevent the use of composite components. One of the best examples of this is the Norwegian NPD's acceptance of FRP firewater piping offshore based on performance criteria, not materials (30).

Above all else, composite materials must be cost effective compared to the available alternatives. If not, their use will be limited and they will always remain "just around the corner".

The oil industry can help remove the barriers to the wider application of composite materials by supporting technology development programs related to composites in certain key areas such as durability and reliability, design methods, NDT/NDE, terminations, and standards and design codes.

Removing these barriers to the wider application of composite materials offshore will result in lighter weight, more economically efficient offshore developments. The potential for future composite systems includes continuous subsea flowlines, hydrocarbon piping for topside applications, large diameter pipe and risers, wider use of composite tanks, process vessels, and structural components, and deep water tendon mooring systems for TLP's. Once the design engineers and operating personnel gain an understanding of the full range of benefits available with composite materials and develop confidence in this class of materials, many of the enabling capabilities of composites will open up new opportunities for the offshore operators. Many impossible to reach reservoirs may be drilled with composite drill pipe, economically marginal fields in deep water may become feasible with lightweight platforms and a scaled down marine installation spread, and the economics of developing and operating corrosive offshore fields may improve significantly through the use of composite materials.

13. SUMMARY OF BENEFITS DERIVED FROM COMPOSITE MATERIALS

13.1 Weight Reduction

The weight saved for each of the three cases (TLP, FPS and SPS) is shown in Table 13 for the major components of each platform type. The weight saved for the topside facilities of the TLP and FPS was identical (1,240 tons) because the production capacity and topsides facilities were assumed to be identical for the purposes of this study. See the individual case studies in the Appendix Section for details and background information on how the results shown in Table 13 were obtained.

An unpublished study for a North Sea operator in 1994 estimated that approximately 10% of the topside weight of a large fixed platform could be saved through the use of composite materials that would available by 1996. This is similar to the estimated savings of 12% in topside weight found in this study.

The TLP tendon mooring system appears to offer the largest weight savings in total tons and percentage of any major component in the TLP and FPS case studies. Unfortunately, composite tendons do not appear to be cost effective in 4,000ft water depths at this time.

No weight saving is expected with lightweight or composite mooring systems for FPS's since lightweight synthetic materials are rapidly becoming the norm for deep water mooring systems because of the significant weight savings possible (56). A true composite (ex. carbon-epoxy) appears to offer very little weight saving over a synthetic fiber mooring system that may contain aramid or other lightweight fibers.

Table 13 - SUMMARY OF WEIGHT SAVINGS FOR ALL THREE CASES

	Weight Savings (tons / %)		
Component	**TLP**	**FPS**	**SPS**
Topside Facilities	1,240 / 12	1,240 / 12	145.2 / 28
Deck Structure	108 /1.3	108 / 1.3	10 / 2.3
Production Risers	1,736 / 61	590 / 61	NA
Drilling Riser	497 / 42	748 / 44	NA
Mooring System	3,216 / 95	~0	NA
Piles	510 / 7	NA	will vary
Deck	1,873 / 22	1,873 / 22	NA
Hull	6,000 / 33	6,000 / 33	NA

13.2 Capital Investment Savings

The net investment cost savings are significantly greater for the TLP than for the FPS and the SPS. This is primarily because the value of a ton of topside weight saved on a TLP is worth approximately $8,500 versus $7,000 for the FPS and $2,000 for the SPS. In addition, a steel TLP production riser system is relatively costly, and offers significant cost savings by reducing the size of the riser tensioner system when a lightweight composite riser is used.

Table 14 - SUMMARY OF NET COST SAVINGS FOR ALL THREE CASES

Component	Cost Savings ($ million)		
	TLP	**FPS**	**SPS**
Topside Facilities	8.324	6.494	0.635
Deck Structure	0.918	0.756	‹0.003›
Production Risers	14.864	‹6.730› (composite) 0 (steel)	NA
Drilling Riser[1]	??	??	NA
Mooring System	[3]	~0	NA
Piles[2]	NA	NA	beyond scope of study
Deck[2] and Hull[2]	NA	NA	NA
Installation Costs	1.000	1.000	0.100
Total Net Investment Cost Savings:	**25.106**	**8.25** (with steel risers)	**0.732**
Maintenance Costs Over Life of Project	5.644	5.644	0.048
Decreased Down Time	38.4[4]	38.4[4]	1.44[5]
Total Savings Over Life of Project	**69.15**	**52.294**	**2.22**

1. : There was insufficient data available to assess the economics of composite drilling risers.
2. : No cost savings were attributed to these smaller components which were the result of downsizing due to reduced topside weight and riser tension for the TLP and FPS cases.
3. : Composite TLP tendons are not believed to be economic in 4,000ft of water.
4. : Value based on: 80,000BOPD (average production rate over life of project) x 24yrs x 1day/yr x $20/bbl
5. : Value based on: 8,000BOPD (average production rate over life of project) x 9yrs x 1day/yr x $20/bbl

13.3 Operational Cost Savings

Operational cost savings with composite materials for offshore platforms of all types will generally result from significantly lower maintenance costs because of the corrosion resistance of composites. The savings in maintenance costs estimated for just three categories in this study (fire water system, recoating of piping and tanks, and grating replacement) totaled $5.644 million over the first 25 years of service life or $234,000/year. This total includes the added costs of transporting personnel, equipment and materials to perform the maintenance.

Besides the direct cost savings of not having to recoat or replace composite components, there is the significant savings of indirect costs associated with **not** having to shut down production to allow welding and/or torch cutting to proceed safely as would be required to replace many steel components. The value of the savings resulting from decreased "down time" will depend on the production rate of the individual platform. Decreasing "down time" by just one day per year on average over a 5-10 year period, would result in an increase of $200,000 in average annual revenue for a 10,000 BOPD platform at $20/bbl. A platform producing 100,000 BOPD would generate an extra $2,000,000 per year. It was assumed that no maintenance would be performed in a project's last year.

13.4 Enabling Capabilities

Evaluating the enabling capabilities of composite materials is highly project specific and was not addressed in this phase of the study.

14. GUIDELINES FOR SUCCESSFUL APPLICATION OF COMPOSITE MATERIALS

Successful applications of composite materials don't just happen. They are carefully planned for from the very beginning of a project. Attention to detail and follow-up are essential at all stages. Nearly all designers, engineers, contractors, construction personnel and operations staff are accustomed to working with carbon steel. Even stainless steel can be a problem if careful attention is not paid to machining techniques, welding procedures, threaded joints, galvanic coupling, and the design of thermal insulation systems.

Even though engineers and construction personnel were trained to design and build with steel, it is still common practice and good business to check designs, and inspect materials, components and system operation. When good inspection and follow through are not practiced, the chances of costly shutdowns and safety hazards increase.

A brief discussion follows of some basic guidelines that an offshore operator should follow to insure a successful application for composite materials.

14.1 Human Factors

Engineers and designers trained in steel structures are uncomfortable when working with a new material that they do not understand. Complicating this is the lack of standards and design codes for composite components. Many designers fall back on the old adage "When in doubt, make it stout, out of things you know about". This approach is too expensive in deep water. If they don't know about composites, and they have no interest or incentive to learn, they will design with steel.

The steel mentality is pervasive throughout the oil industry. This is especially true for offshore operations where the investment cost, risk and environmental exposure are all high. The education of designers, engineers, contractors, offshore operators and industry managers in the properties, benefits and limitations of composite materials is necessary to achieve the level of acceptance and application of composites that will produce the greatest payoff to the oil industry.

Many designers and engineers have the impression that (resin matrix) composites will burn, are expensive and not worth the risk. These impressions normally result from ignorance or a bad experience with FRP years earlier. Almost any material will fail in service if used improperly.

14.2 Design

Designing with composite materials is not as well established or as regulated as it is with carbon steel, the material of choice for decades in the oil industry. Many specifications, recommended practices and standards have been introduced recently by API, ASTM, British Standards, The Composites Institute, NORSOK (Norway) and UKOOA to guide the designer in the proper application of composite piping and vessels (60-69). The designer should become familiar with the available standards, RPs and applicable codes before starting to work with composite components. A few guidelines for the designer to follow include:

- A system approach is best in order to take full advantage of all the benefits available with composites. The size of the structural support system required should be reduced once the weight savings exceed a certain threshold value.
- The use of composite components should be discussed during the conceptual or pre-engineering phase of a project.
- Decide on the use of composite components as soon as possible in a project to solicit quotes from multiple suppliers to keep costs competitive.
- Allow sufficient time for design and testing of non-standard or specialty components.
- Be aware of how all applicable codes will impact design, installation and operation. Allow time in the schedule to generate all test data required by certifying authorities.
- Static charge build-up can be avoided in piping and tanks/vessels with conductive fibers and resins.
- Composite structural components should be designed with extra attachment points for lifting and for connecting to adjacent structures and the main deck. This will allow greater flexibility during the installation phase and avoid delays when the inevitable platform layout change occurs during design.
- Use third party design, testing and installation verification and inspection.

14.3 Construction and Installation

- Work with contractor(s) and installation crews to make them familiar with the composite materials to be used and confident that they can do the job required at a cost competitive with steel.
- The supplier of composite components (pipe, vessels, secondary structures) should work with the platform fabricator to insure the proper installation of all composite equipment. A "turn key" approach by the composite supplier in cooperation with the platform fabricator and the offshore operator would go a long way toward overcoming some of the resistance to the use of composite materials.
- Proper training of the crews used to install the various composite components is essential and will require periodic inspection and follow-up by the operator or third party personnel. The old adage "You get what you inspect, not what you expect" certainly applies to composites.
- Do as much pre-fabrication of pipe spools and other equipment under controlled shop conditions as possible.
- Composite components should be shielded from hot weld splatter and the heat from a cutting torch, especially where the work is taking place immediately above or adjacent to the composite components.
- Construction procedures and schedules must be planned such that sufficient time is allotted for adhesive joints in composite pipe or other components to properly cure on site undisturbed.

15. ESTIMATE OF MARKET POTENTIAL

Most of the composite components discussed in this report are already available and in use in other industries and on a number of offshore platforms. Table 15 attempts to summarize the

Table 15 - ESTIMATED COMMERCIAL AVAILABILITY OF COMPOSITE COMPONENTS

Component	1997	2000	2005	Comments & Example Suppliers
Piping:				Ameron, Smith, Specialty Plastics, Fiberglass Systems
Low Pressure (<700psi)	X			
High Pressure (700-3,000psi)	X			
Hydrocarbon Service		X		An inner liner may be required.
Process Vessels:				C.P.F. DUALAM, Ershigs, Reinhold Industries
Low to Med. Pressure (<250psi)	X			
High Temperature (90-150C)			X	
Hydrocarbon Service		X		Depends on service temperature & pressure
Storage Tanks (low temp.):				Owens-Corning, Xenon Co., Tankinetics
Water Service	X			
Hydrocarbon Fuels	X			
Dry Bulk for Drilling	X			
Chemical Storage:				Xerxes/Heil
Acid	X			
Caustic	X			The particular chemical to be stored
Corrosion Inhibitors	X			may dictate the resin and inner liner used to
Biocides	X			contain the liquid.
Scale Inhibitors	X			
Solvents	X			
Valves		X		Dresser
Living Quarters & Control Rooms	X			Total Building Systems, Porta-Kamp
Fire & Blast Panels	X			Vosper Thorney Croft (UK)
Helideck	X			
Life Boats	X			Survival Systems International
Secondary Structures:				
Grating	X			MMFG, Creative Pultrusions
Stairs & Handrails	X			MMFG, Creative Pultrusions
Equipment Skids		X		MMFG, Creative Pultrusions
Structural Beams		X		NIST ATP project (MMFG), Creative Pultrusions
Cable Trays & Ladders	X			Enduro Composite Systems
Electrical Conduit	X			Creative Pultrusions, Enduro Composite Systems
HVAC Ducts	X			Fiber-Tech Engineering
Drilling Risers		X		NIST ATP project (Northrop Grumman)
Production Risers		X		NIST ATP project (Lincoln Composites)
Drill Pipe		X		NIST ATP project (SpyroTech), Lincoln Comp.
Downhole Tubulars:				
Tubing	X			Ameron, Smith, Fiber Glass Systems
Casing	X			Lincoln Composites
Coiled Tubing	X	X		Fiberspar (1997), NIST ATP project (Hydril-2000)
TLP Tendons				Probably not available until after 2005
Subsea Flowlines & Injection Lines		X		NAT/Compipe (Norway)

estimated commercial availability of many of the composite components discussed in this report. Only a few of the possible manufacturers of the various composite components are shown. This list is not meant to be all inclusive nor imply endorsement of the companies listed.

The NIST ATP projects are all nominal 5-year projects but full scale prototypes are planned for the third year in most of the projects. The ATP projects all started during 1995.

An average of 123 platforms were installed on the U.S Outer Continental Shelf (OCS) from 1992 through 1995, with 130-140 projected for 1996. It was assumed for the purposes of this study that only 15 platforms would be installed in the GOM each year of the 4-pile jacket variety that would be candidates for various composite components. This number of 15 4-pile jackets per year is in addition to the 5-10 deep water TLP's and FPS's predicted for the GOM over the entire 9 year period (1997-2005).

The estimated quantities of production risers, structural beams, storage tanks and accumulator bottles were based on the numbers used in this study for a deep water TLP or FPS with a 100,000 BOPD capacity. The quantities presented in Table 16 are only preliminary estimates that require more careful analysis and evaluation than were possible in Phase 1 of this study.

Table 16 - PRELIMINARY ESTIMATED MARKET FOR COMPOSITE COMPONENTS IN THE GULF OF MEXICO (1997 -2005)

Component	Quantity Per Platform (SPS/TLP&FPS)	Number of Platforms (TLP's & FPS's)	Total Quantity 1997-2005
Fire Water Piping	1,000ft/4-pile* 7,500ft/TLP	135 (5-10)	172,500-210,000 ft
Grating	20,000ft^2/4-pile 90,000ft^2/TLP	135 (5-10)	3.15-3.60 million ft^2
Production Risers	15x4,000ft/TLP	5-10	300,000-600,000 ft
Structural Beams (8-36inch)	500 tons	5-10	2,500-5,000 tons
Storage Tanks (250-750bbls)	5/10	135 (5-10)	725-775
Process Vessels	1/3	135 (5-10)	150-180
Riser System Accumulator Bottles	144/TLP	5-10	720-1,420
Piping (water service)	5/20 tons	135 (5-10)	775-875 tons
Tendon (>2005)	3884 tons**/TLP	1	3884 tons

*: This quantity was based on the 3 miles of FW pipe contained on Amoco Norway's three platform, 100,000 BOPD Valhall complex (32). A typical 4-pile structure in the GOM was assumed to produce 10,000 BOPD. All quantities of FW pipe were extrapolated from the Valhall basis with allowances for production rate and having a single integrated platform.

**: This assumes one spare tendon per TLP and 20% scrap. The amount of carbon fiber is ~50% of the total weight.

The worldwide offshore market for various composite components far exceeds the numbers shown in Table 16 for the GOM. One offshore operator forecasts that the market for carbon fiber composites could be as high as 84,000 tons over the next ten years (8). The worldwide production capacity of PAN-based carbon fiber was 21,000,000 lbs/yr (~10,500 tons) in 1993, which means a substantial growth in the carbon fiber production capacity must develop if these growth projections and those coming from other industries are to be realized.

16. AREAS WITH LIMITED INPUT IN PHASE 1

Some portions of the Phase 1 study were not as thorough nor as complete as originally intended because the overall project was more complex than initially thought and because of limited information in certain areas. Existing published information was extrapolated to bridge the gaps that existed with available input. Some items of interest where there were insufficient resources of time or information to properly assess have been deferred.

Areas where limited input was available include:

1. A thorough and detailed listing of all topside and interior hull applications for composite materials including sizes of all tanks and vessels, and the quantity and sizes of all piping, to cite just two examples.
2. Cost savings in construction and installation resulting from the use of light weight composite components.
3. The weight and cost savings available with a composite drilling riser.
4. The preferred production riser concept(s) for FPS's in the GOM
5. Comparative installed costs of carbon steel versus composite components.
6. Weight and cost estimates for deep draft floating caisson (DDFC) platforms in the GOM.
7. Maintenance and operation costs over the life of typical GOM platforms.
8. Enabling capabilities of composite components for deep water developments.

In addition, many aspects of the study would have benefited significantly from the scrutiny and input of an engineering/construction contractor.

17. ACKNOWLEDGMENTS

CEAC wishes to thank its members for their support in conducting this study, especially BP Exploration, Conoco Inc. and Shell Oil Products which contributed personnel to the Offshore Working Group and actively participated in the study. CEAC also acknowledges the contributions of the following companies which supplied photographs of composite components used in this study: Ameron Fiberglass Pipe, C.P.F. DUALAM, Lincoln Composites, MMFG and Smith Fiberglass.

18. REFERENCES

(1) *Offshore Stats*, Minerals Management Service, First Quarter 1996

(2) *Offshore*, June 1996

(3) Williams, J.G., "Opportunities for Composites in the Offshore Oil Industry", National Conference on the *Use of Composite Materials in Load-Bearing Marine Structures*, Arlington, VA, September 25-26, 1990; Volume II: Conference Proceedings, National Academy Press, Washington, D.C., 1991.

(4) Salama, M.M., "Advanced Composites for the Offshore Industry: Applications and Challenges", *Revue De L' Institut Français Du Pétrole*, International Conference on Composite Materials in the Petroleum Industry, Ruell-Maimaison, November 3-4, 1994. Vol. 50. No. 1, January/February 1995.

(5) Salama, M.M., "Advanced Composites for the Offshore Industry: Applications and Challenges", NIST Special Publication 887, *Composite Materials for Offshore Operations: Proceedings of the First International Workshop*, Houston, TX, October 26-28, 1993.

(6) Cole, Bill W., "Petroleum E&P Industry Perspective on the Use of Composites in Offshore Operations", NIST Special Publication 887, *Composite Materials for Offshore Operations: Proceedings of the First International Workshop*, Houston, TX, October 26-28, 1993.

(7) Williams, Jerry G., "Petroleum Industry Applications of Composites In E&P Operations", NIST Special Publication 887, *Composite Materials for Offshore Operations: Proceedings of the First International Workshop*, Houston, TX, October 26-28, 1993.

(8) Barnes, Frazer J., "Composite Materials in the UK Offshore Oil & Gas Industry", *SAMPE Journal*, Vol. 32, No. 2, March/April, 1996.

(9) Medlicott, P A C, "Using Composite Materials to Minimise Weight and Maintenance and Maximise Safety", *Offshore Platforms '96.*

(10) Croquette, J., "Potential Applications of Composites Offshore", *Revue De L' Institut Français Du Pétrole*, International Conference on Composite Materials in the Petroleum Industry, Ruell-Maimaison, November 3-4, 1994. Vol. 50. No. 1, January/February 1995.

(11) Dismukes, John P, and Luton, Michael J., "Polymer Composite Materials Performance Criteria for Offshore Petroleum Production: An Overview", NIST Special Publication 887, *Composite Materials for Offshore Operations: Proceedings of the First International Workshop*, Houston, TX, October 26-28, 1993.

(12) Robertson, Gordon G., "Composite Materials for Offshore Operations, Industry Perspective", NIST Special Publication 887, *Composite Materials for Offshore Operations: Proceedings of the First International Workshop*, Houston, TX, October 26-28, 1993.

(13) McConnell, Vicki P., "Fiberglass Goes Offshore", *Composites Technology*, January/ February, 1996.

(14) Lindsay, Karen F., "FRP Pipe Finds its Niche in Specialty Applications", *Composites Design and Application*, Spring, 1996.

(15) Winkel, John, "Economic Performance of Glass Fiber Reinforced Plastic (GRP) Piping at Ekofisk", *Engineering Solutions to Industrial Corrosion Problems*, NACE International, June 7-9, 1993, Sandefjord, Norway, Paper No. 43.

(16) Aubert, C.F.P., "The Use of GRP Materials in Piping Systems: The Experience of Total", OMAE Conference, Vol. III-A, *Materials Engineering* , ASME, 1993.

(17) Fischer,F.J., "A Course of Action for Introducing Composites into Offshore Operations", NIST Special Publication 887, *Composite Materials for Offshore Operations: Proceedings of the First International Workshop*, Houston, TX, October 26-28, 1993.

(18) Cole, B.W., Lo, K.H., Williams, J.G., and Wang, S.S., "Advanced Composites Offshore: Current Status And A Proposed Research And Development Program", NIST Special Publication 887, *Composite Materials for Offshore Operations: Proceedings of the First International Workshop,* Houston, TX, October 26-28, 1993.

(19) Enze, C.R., Brasted, L.K., Arnold, Pete, Smith, J.S., Breaux, J.N. and Luyties, W.H., "Auger TLP Design, Fabrication, and Installation Overview", Offshore Technology Conference, OTC 7615, 1994.

(20) Bacon, M.L., Bailliet, R.M., Brooks, A.M., Forster, L.D., Harris, K.H., Lindsay, M.S. and Schafer, D.R., "Auger TLP Topsides Facilities: Design and Construction Overview", Offshore Technology Conference, OTC 7616, 1994.

(21) Anon, "Installation Date Draws Near for Mars TLP", *Oil and Gas Journal*, April 6, 1966.

(22) Anon, "Shell Group Outlines Ursa Development Plan", *Oil and Gas Journal,* July 15, 1996.

(23) D'Souza, Richard B., "FPSO and TLP Deepwater Station-keeping Systems, Problems and Solutions", *Offshore Northern Seas*, Stavanger, Norway, August 23-26, 1994.

(24) Solomon, C. and Fritsch, P., *The Wall Street Journal*, April 4, 1996.

(25) Schott III, W.E., Rodenbusch, G., Mercier, R.S., and Webb III, C.M., "Global Design and Analysis of the Auger Tension Leg Platform", Offshore Technology Conference, OTC 7621, 1994.

(26) Ivanovich, D., *The Houston Chronicle*, July 3, 1996

(27) Chiu, Allen and Franco, R. J., "FRP Linepipe for Oil and Gas Production", *Materials Performance*, Vol. 29, No. 6, June 1990.

(28) Robbe, C., "A New Look at the Use of Glass-Fiber Reinforced Plastic Piping", *Materials Performance*, Vol. 29, No. 6, June 1990.

(29) Winkel, John D., "Maintenance and Cost Performance of Glass Fiber Reinforced Plastic (GRP) Piping at Ekofisk", OMAE - Volume III-A, *Materials Engineering*, ASME, 1993.

(30) Ciaraldi, S.W., Alkire, J.D. and Huntoon II, G.G., "Fiberglass Firewater Systems for Offshore Platforms", Offshore Technology Conference, OTC 6926, 1992.

(31) Sundt, John L., "Fire Water Systems in Composite Materials", OMAE Conference, Vol.III-A, *Materials Engineering*, ASME, 1993.

(32) Ciaraldi, Stephen W., "Experiences From the Offshore Installation of a Composite Materials Firewater System", OMAE Conference, Vol.III-A, *Materials Engineering*, ASME, 1993.

(33) Ciaraldi, Stephen W., "Safety Philosophy for the Use of Composite Materials Offshore", NIST Special Publication 887, *Composite Materials for Offshore Operations: Proceedings of the First International Workshop*, Houston, TX, October 26-28, 1993.

(34) Folkers, Joie, "Development of Fire Resistant Fiberglass Pipe", Composites Institutes 51st Annual Conference, Cincinnati, OH, February 5-7, 1996.

(35) Boothby, Peter J., "Jet Fire Testing of Topside Pipework", OMAE Conference, Vol.III-A, *Materials Engineering*, ASME, 1993.

(36) Lea, Richard H. and Conroy, P. Dennis, "Sea Water Corrosion Resistance of Composite Pipe Systems in the Marine Industry", 51st Annual Conference of Society of Plastics Industry, Cincinnati, OH, February 6, 1966.

(37) Lea, R.H., Griffin, S.A., Pang, S.S. and Cundy, V.A., "Use of Advanced Composite Pipe Technology to Design Seawater Systems on Open Type Offshore Production Platforms", OMAE Conference, Vol.III-A, *Materials Engineering*, ASME, 1993.

(38) Anon, "Breaking Tradition - Reducing Plant Construction and Maintenance Cost", *ESD Technology*, April 1995.

(39) Lindley, Nancy L. and Floyd, Joe C., "Piping Systems: How Installation Costs Stack Up" *Chemical Engineering*, January 1993.

(40) Glein, Gary A., "Dual Laminate Construction for Difficult Corrosion Problems--Selection Criteria and Techniques", *Materials Performance*, March, 1992.

(41) Thon, Harald and Stokke, Reidar, "Behaviour of GRP Tanks in Fire Situations", *Glass Fibre Reinforced Plastics (GRP) Offshore*, Senter for Industriforskning, Oslo, Norway, Report No. 85 02 02-5, May 25, 1988.

(42) Frieze, P.A., and Barnes, F.J., "Composite Materials for Offshore Application - New Data and Practice", Offshore Technology Conference, OTC 8143, 1996.

(43) Valenzuela, E.D., Anderson, W.F., Burgdorf, O., and Mickelson, C.S., "Comparative Performance of a Composite Drilling Riser in Deep Water", Offshore Technology Conference, OTC 7263, 1993.

(44) Sauer, Carl W., Sexton, Jay B., Sokoll, Robert E., and Thornton, James M., "Heidrun TLP Titanium Drilling Riser System", Offshore Technology Conference, OTC 8088, 1996.

(45) Sauer, Carl W., Actis, Stephen C., Thornton, James M., and Watkins, Harry B., "Lighter Titanium Translates Into Lower Riser Costs", *Hart's Petroleum Engineer International*, September 1996.

(46) Gault, Allen, "Riserless Drilling: Circumventing The Size/Cost Cycle In Deepwater", *Offshore*, May 1996.

(47) Sparks, C., Odru, P., Bono, H. and Metivaud, G., "Mechanical Testing of High Performance Composite Tubes for TLP Production Risers", Offshore Technology Conference, OTC 5797, 1988.

(48) Sparks, C., Odru, P., Metivaud, G., and Le Floc'h, C., "Composite Riser Tubes: Defect Tolerance Assessment and Nondestructive Testing", Offshore Technology Conference, OTC 6894, 1992.

(49) Berge, S., Saevik, S., Engseth, A.G. and Aarnes, R., "Titanium Risers and Flowlines Feasibility Studies and Research Activities", 1995 OMAE Conference, Vol.III-A, *Materials Engineering*, ASME, 1995.

(50) Hanna, S.Y., Thomason, W.H. and Williams, J.G., "Influence of Tension, Weight, and Hydrostatic Pressure on Deepwater TLP Tendons", Offshore Technology Conference, OTC 5610, 1987.

(51) Salama, Mamdouh M., "Lightweight Materials for Mooring Lines of Deepwater Tension Leg Platforms", *Marine Technology*, Vol. 21, No. 3, July 1984, pp. 234-241.

(52) Rogers, C.W., and Raczelowski, S., "Spoolable Composite Tethers", 1994 OMAE Conference, Houston, TX.

(53) Walton, J.M. and Yeung, Y.C.T., "Flexible Tension Members From Composite Materials", OMAE Conference, Vol.III-A, *Materials Engineering*, ASME , 1987.

(54) Hill, Paul S., "Long-Term Performance of Carbon Fibre Reinforced Tension Members", Structural Materials in Marine Environments, The Institute of Materials, London, 11-12 May 1994.

(55) Kim, K.S., Hahn, H.T., and Williams, J.G., "Application of Composites in TLP Tethers", OMAE Conference, Vol. III-A, *Materials Engineering*, ASME, 1987.

(56) Chaplin, C.R. and Del Vecchio, C.J.M., "Appraisal of Lightweight Moorings for Deep Water", Offshore Technology Conference, OTC 6965, 1992.

(57) Wilde, Bob, Kelly, Patrick, Librino, Filippo, and Whitehill, A. Simeon, "Conceptual Design and Comparison of Aramid and Polyester Taut Leg Spread Moorings for Deepwater Applications", Offshore Technology Conference, OTC 8145, 1996.

(58) Vennett, Richard M., "Composite Materials for Offshore Operations: Future Trends", *Composite Materials for Offshore Operations,* COMETT II UETP-EEE Short Modular Course, September 5-7, 1994, Sandefjord, Norway

(59) Sas-Jaworsky, A. and Williams, J.G., "Advanced Composites Enhanced Coiled Tubing Capabilities", *World Oil*, April 1994.

(60) "Recommended Practice for Care and Use of Fiberglass Tubulars", *API Recommended Practice* 15TL4 (RP 14TL4), First Edition, October 1, 1993.

(61) "Specification for Fiberglass Reinforced Plastic Tanks", *API Specification* 12P, Second Edition, January 1, 1995.

(62) "Specifications for Low Pressure Fiberglass Line Pipe", *API Specification* 12LR (SPEC 15LR), Sixth Edition, September 1, 1990.

(63) "Specifications for High Pressure Fiberglass Line Pipe", *API Specification* 15HR, Second Edition, April 1, 1995.

(64) "Recommended Practice for Fire Prevention and Control on Open Type Offshore Production Platforms", *API Recommended Practice* 14G (RP 14G), Third Edition, December 1, 1993.

(65) "Standard Specification for Thermosetting Resin Fiberglass Pipe and Fittings to be Used for Marine Applications", *ASTM*, April 1995.

(66) "Specification and Recommended Practice for the Use of GRP Piping Offshore", *UK Offshore Operators Association* (UKOOA), March, 1994.

(67) "Fire Tests on Building Materials and Structures", *British Standard* BS 476: Part 7: 1987.

(68) "Design and Construction of Vessels and Tanks in Reinforced Plastics", *British Standard* BS4994:1987.

(69) "National Specifications For Fiberglass Pipe", Fiberglass Pipe Institute of the Composites Institute, 355 Lexington Ave., NY, NY 10017.

(70) Glein, Gary A., "Metal, Fiberglass and Thermoplastic Tanks and Piping, A Review of Costs and Other Decision Factors", NACE International Corrosion 96, Paper 405.

(71) Fischer, F.J., "Composite Production Risers for Deepwater Offshore Structures", *Revue De L' Institut Français Du Pétrole*, International Conference on Composite Materials in the Petroleum Industry, Ruell-Maimaison, November 3-4, 1994. Vol. 50. No. 1, January/ February 1995.

(72) Read, D.T., Kriz, R.D., and Williams, J.G., "Multimode Optical Fibers as Damage Sensors in Composite Rods", OMAE Conference, Vol.III-A, *Materials Engineering,* ASME, 1990.

(73) Winkel, J.D., "Use of Life Cycle Costing in New and Mature Applications", SPE 35565, 1996.

(74) Salter, H. and Stadler, R.L., "The Galahad Platform - A State of the Art Minimum Facilities Installation for the Southern North Sea", Offshore Technology Conference, OTC 8201, 1996.

(75) Britt, Frank, "Stainless Steel vs. Fiberglass Pipe", *Chemical Engineering*, February 1990.

19. APPENDICES

19.1 Appendix 1: Fiber, Resin and Composite Laminate Properties

Table 17 - METAL AND FIBER PROPERTIES

Material	Fiber Diameter (10^{-3} in.)	Ultimate Tensile Strength (ksi)	Tensile Modulus (10^{6} psi)	Specific Strength (10^{6} in.)	Specific Modulus (10^{6} in.)	Strain to Failure (%)	Density (lb/in^{3})	Thermal Expansion Coefficient (10^{-6} in/in-°F)	Representative Cost ($/lb)
Metals									
Aluminum	-	60-83	10	0.83	1.0	10	0.100	13	1.00
Steel	-	70-120	30	0.43	1.0	16	0.289	6	0.50
Titanium	-	160	16.5	1.0	1.0	8	0.160	4.8	10
Fibers									
Boron on Tungsten	4	400	60	4.2	6.3		0.095	2.8	250
E-Glass	0.4	450	10.5	4.9	1.1	2.4	0.092	2.8	0.80
S-Glass	0.4	650	12.3	7.2	1.4	2.9	0.090	3.1	5
970 S-Glass	0.4	800	14.5	8.8	1.6		0.091		13
Graphite (High Strength)	0.28	510	32	8.1	5.1	1.4	0.063	-0.03	15
Graphite (Improved Strength & Modulus)	0.27	600	35	9.4	5.5	1.7	0.064	-0.03	17
Graphite (High Modulus & Pitch)	0.43	400	55	9.2	7.6	0.7	0.072	-0.72	52
Kevlar 29	0.48	330	12	6.3	2.3	2.8	0.052	-1.1	11
Kevlar 49	0.47	500	19	9.6	3.7	1.8	0.052	-1.1	15
Polyethylene (Spectra 1000)	1.5	375	28	10.7	4.9		0.035		1.50
Polyester	0.8	100	0.6	1.9	0.0		0.052	45	

Table 18 - METALS AND COMPOSITE LAMINATE PROPERTIES

Material	Ultimate Tensile Strength (ksi)	Tensile Modulus (10^6 psi)	Specific Strength (10^6 in.)	Specific Modulus (10^6 in.)	Density (lb/in^3)
Metals					
Aluminum (7075-T6)	83	10	0.8	1.0	0.100
Steel (4130)	120	29	0.4	1.0	0.289
Titanium (6Al-4V)	160	16.5	1.0	1.0	0.160
Composites*					
Boron	180	30	2.5	4.1	0.073
E-Glass	160	6.5	2.1	0.9	0.075
S-Glass	250	7.5	3.5	1.0	0.072
Graphite (High Strength)	180	21	3.2	3.7	0.057
Graphite (High Strength & Modulus)	400	25	6.8	4.2	0.059
Graphite (Ultra High & Modulus)	100	42	1.6	6.9	0.061
Kevlar 29	200	7.25	4.0	1.5	0.050
Kevlar 49	210	11	4.2	2.2	0.050

* Unidirectional laminates with 60 percent fiber volume

Table 19 - REPRESENTATIVE RESIN PROPERTIES AND COSTS

Resins	Type	Density (lb/in^3)	Tensile Strength (10^3 psi)	Tension Modulus (10^6 psi)	Representative Cost ($/lb)
Epoxy	Thermoset	0.042	6-12	0.3-0.8	1.50-10
Phenolic	Thermoset	0.051	5-9	0.4-1.0	2-20
Polyester	Thermoset	0.047	6-12	0.2-0.6	0.90-2
Vinyl Ester	Thermoset	0.040	6-13	0.3-0.6	1.10
Acetal	Thermoplastic	0.043	7-10	0.3-0.5	2
Nylon	Thermoplastic	0.040	8-13	0.2-0.5	1-2
Polycarbonate	Thermoplastic	0.043	8-10	0.3-0.5	1.50-2.25
Polyester	Thermoplastic	0.047	8-9	0.3-0.4	0.80-1.80
Polyethylene	Thermoplastic	0.034	3-5	0.1-1.0	0.35-0.45
Polypropylene	Thermoplastic	0.033	4-5	0.2-0.3	0.55

19.2 Appendix 2: Case Study 1 - Tension Leg Platform (TLP)

19.2.1 Background

The TLP scenario described in the Basis of Design (Table 3) is located in 4,000ft of water and has a production capacity of 100,000 BOPD. This scenario was chosen because it was believed to be near what is currently thought to be the water depth limit for TLP technology and had a production capacity that justified a deep water development.

The Steel Base Case (Tables 4 and 8) was developed by extrapolating available information about the Auger and Mars TLP's to 4,000ft (19-21,24). The 4,000ft Steel Base Case estimated weight and cost figures were very close to the figures since published for the Ursa TLP going in 3,950ft in the GOM (26).

The main factor driving the consideration of composite materials for TLP's and other deep water floating production platforms is weight reduction. Reducing the load carried by the TLP hull by one ton, can save $8-10,000 in project investment costs. This cost saving is achieved by reducing the size of the deck, hull, tendon mooring system and anchor piles to account for the reduced topside facilities weight and top tensions resulting from the use of light weight composite risers. Because a system approach is required to achieve the full benefits from the application of composite materials where weight saving is important, composite materials must be incorporated in the platform design strategy in the conceptual or pre-engineering stages of a project. Designing for steel but using composites may reduce weight and corrosion problems, but will not result in the major investment cost savings possible with light weight materials.

Composite materials were considered for all applications on a TLP from topside equipment to mooring tendons where it was believed a commercially available product would be ready by the year 2005. Some typical applications for composite piping and other composite components on a TLP are shown in Figure 17. Since detailed designs of the topside facilities, the deck structure and the equipment contained in the hull were not used in this study, a global approach to material substitution was used except for some specific components such as the production risers.

19.2.2 Topside Equipment

The topside weight of the Steel Base Case was estimated at 10,662 tons (see Table 4 for details), with 5,000 tons allocated to the drilling equipment. The results of the Phase 1 study indicate that approximately 1,039 tons could be saved in 1997 in topside equipment weight through the use of composite components. This saving is expected to grow to 1,240 tons in 2005 as higher pressure and temperature piping and vessels become available, and greater use is made of hybrid composite structural beams.

Table 20 lists many topside applications of composite components including secondary structures in addition to pipe, storage tanks and spill pans.

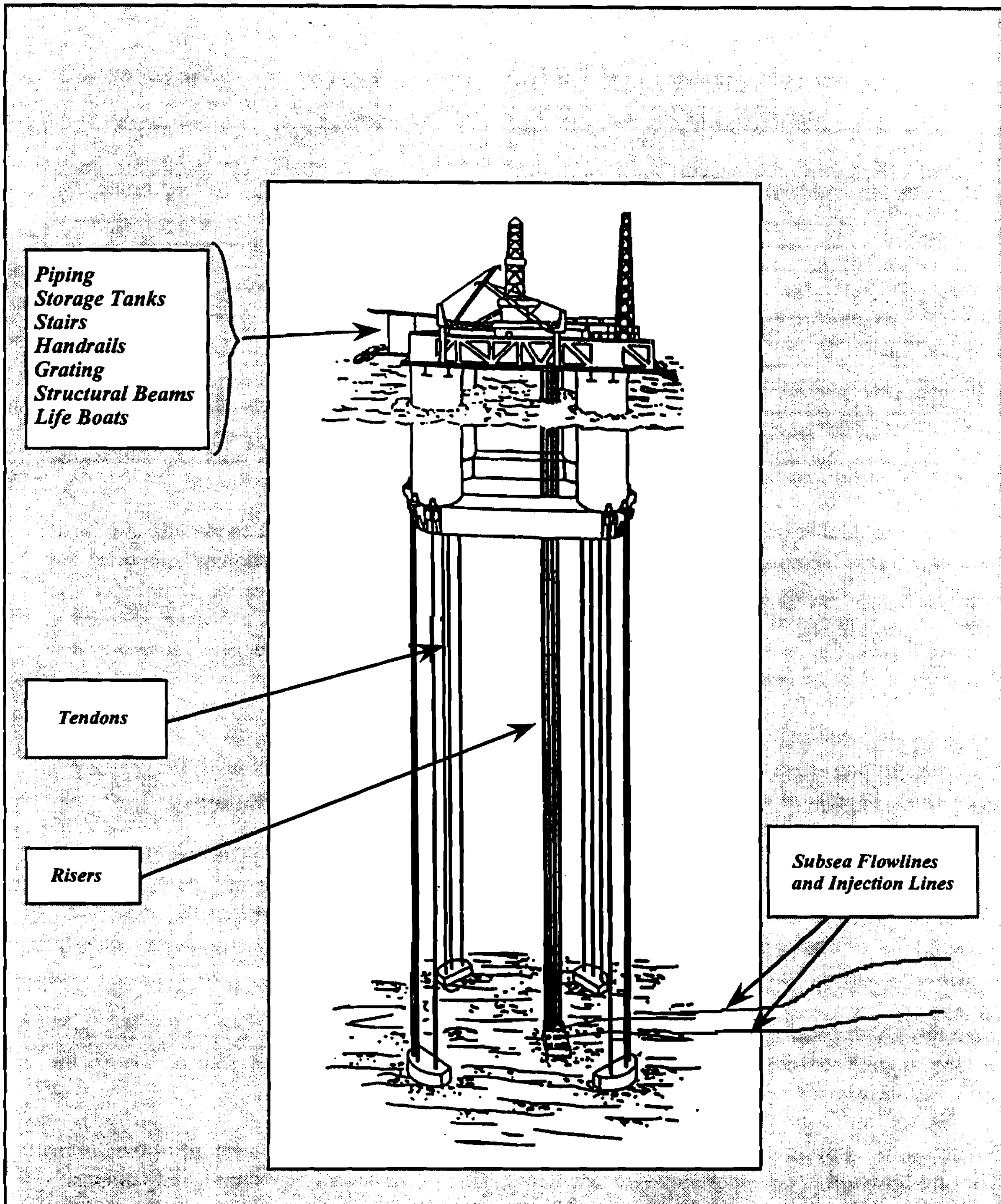

Figure 17. Some Applications for Composite Materials for TLP Components.

Table 20 - TOPSIDE WEIGHT SAVINGS FROM USE OF COMPOSITE COMPONENTS ON TYPICAL GOM TLP or FPS - CEAC 1997

Equipment	Steel Weight (tons)	Amount Replaced by FRP (%)	Weight of Steel and FRP (tons)	Weight Saved (tons)
Floor beams (6 & 8in. I-beams)	1400	50	952	448
Pipe (some HC service)	500	25	416	84
Grating	375	100	125	250
Equipment Supports	150	25	125	25
Storage Tanks	164	100	82	82
Spill Pans	75	100	25	50
Stairs	52	100	17	35
Hand Rails	38	100	13	25
Fire Walls	15	100	5	10
Ladders	10	100	4	6
Cable Trays & Access Structures	48	75	24	24
Total:	**2827**		**1788**	**1039**

Note: Total topside facilities weight: ~10,660 tons

It was estimated that by 1997, 448 tons could be saved in the topsides facilities through the use of relatively small composite beams for grating supports, and for equipment supports and foundations. This is one area that has been identified for further study because it appears to be relatively undeveloped as a source for savings weight on TLP's and FPS's. MMFG's current estimated price for the 8-inch composite hybrid beam is \$55/ft, which is expected to decrease once full scale production is underway.

Steel grating was assigned a weight of 11.4 lbs/ft^2 and FRP grating 3.4 lbs/ft^2. The cost of phenolic grating is ~\$13-14/ft^2 not including installation. The installed cost of FRP grating is roughly the same as for galvanized steel when crews experienced with FRP are used.

For the purposes of this study, 10 storage tanks were used (Table 21). The largest of these (30,000gal/750bbls) is only half the volume of the smallest FRP tanks used on the Heidrun TLP. Based on simply material substitution, the FRP tank should be ~60% lighter than the steel tank it replaces. It was assumed in this study that extra bracing and/or foundation supports would be required for the FRP tanks reducing the weight saving to only 50%.

Composite tanks and vessels designed to go on moving platforms such as TLP's an FPS's must contain internal baffles to reduce liquid sloshing, and must be structurally robust to resist the added stresses imposed by platform accelerations.

Process vessels generally offer a greater challenge to polymer composites because of the higher temperatures and pressures normally encountered. Table 22 shows two examples of composite process vessels, a low pressure (200psi) separator and a mud gas separator (150psi). The mud gas separator was designed, built and tested by AMAT A/S in Norway as part of a joint industry project. The vessel met all test requirements and is currently being used on the Smedvig drilling rig *West Vanguard*.

Composite storage tanks and process vessels appear to be another largely undeveloped source of weight savings for deep water floating production platforms that should be evaluated in more depth.

Table 21 - STORAGE TANKS: STEEL vs COMPOSITE

Size / Number[1]	Steel Weight/Tank	Steel Cost[2]/Tank	FRP Weight/Tank	FRP Cost[2]/Tank
10,000gal / 4 (250bbls)	10 tons	$30,000	5 tons	$34,000
20,000gal / 4 (500bbls)	18	46,000	9	54,000
30,000gal / 2 (750bbls)	26	51,000	13	81,000
Total: 10	164 tons	$406,000	82 tons	$514,000

1. Number of tanks assumed for the topsides scenario in this study.
2. Costs shown were double those found in Table 1 of reference 70 to account for use offshore.

Note: These tanks would be used to store potable water, fresh water, diesel fuel, deck runoff, off-spec oil, produced water and completion fluids.

Table 22 - PROCESS VESSELS: STEEL vs COMPOSITE

Size / Pressure	Steel Weight	Steel Cost	Composite Weight	Composite Cost
Low P. Separator 12x28'/ 200psi	30 tons	$115,000[1]	15 tons	$170,000
Mud Gas Separator 5.5x15'/ 150psi	6	23,000[2] (16,200[3])	2.75	34,000[2] (29,200[3])

1. From in-house oil company study.
2. Based on 20% of the LP Separator cost.
3. Based on information from references 40 and 70.

19.2.3 Drilling Riser

The weight of the composite drilling riser used in this study was taken from Valenzuella et al (42) and extrapolated to 4,000ft (see Table 11 for details). They used a glass/epoxy composite for their study, while Northrop Grumman is developing a graphite/epoxy riser in the NIST ATP project.

Because very little solid information could be obtained about the cost of a fully developed composite drilling riser, no credit was taken for the estimated weight saving of 497 tons shown in Table 23. The weight savings of 497 tons is equivalent to an investment cost savings of $4,224,500 minus the cost premium for the composite drilling riser.

19.2.4 Production Risers

The 18 10-3/4in. production risers used in the 4,000ft TLP Steel Base Case scenario weigh 2,376 tons in air (Table 5), a tempting target for weight reduction. All the production risers were considered to be candidates for the type of component being developed in the NIST ATP project led by Lincoln Composites. The hybrid composite production riser under development by the Lincoln-led consortium was assumed to be commercially available by the year 2000. Assuming a cost of $210/ft including steel end connections, a composite production riser would cost an estimated $240,000 per riser more than the 10-3/4 inch carbon steel riser in 4,000ft of water. With a composite riser, most industry experts believe that 40-50% of the cost of the riser tensioner required could be saved (70). It was assumed in this study that $200,000 could be saved on the estimated cost of $500,000 for each riser tensioner. Therefore, each composite riser and tensioner system would only cost an extra $40,000 more than the steel riser and tensioner system it would replace. The significant weight saving that comes with the composite riser would easily erase the cost premium for the riser and produce an overall cost savings for the TLP project. This analysis is based on a steel riser cost of $150/ft, a composite riser cost of $210/ft and a saving of $200,000 for each riser tensioner system. All the joints over the entire length of each production riser were assumed to be made from composites. Steel was not used for the top and bottom 2-3 joints in each riser as has been done in other analyses of steel versus composite risers (70).

19.2.5 Mooring Tendons

Mooring tendons for a TLP in deep water are another tempting target for the application of composite materials. The total dry weight of twelve 4,000ft long steel tendons for a TLP in the GOM including pipe and connections is estimated to be around 16,000 tons with a cross-sectional area of ~2,300in^2 (Table 6). If 29.6×10^6 psi is used for the elastic modulus of steel and 20×10^6 psi for a composite tendon, the composite tendon cross-sectional area needed to provide identical axial stiffness to moor the same hull and deck mass would be ~3,400 in^2. With a density of 0.057 lb/in.^{3} for the composite tendon, the weight of 12 composite tendons would be 4,650 tons. This would require 2,325 tons of carbon fiber with no allowance for spares or scrap. In this study, however, it was assumed that the use of composite components for topside equipment, risers and structural beams would reduce the total mass to be moored (CEAC-2005, Table 23) by ~37%, thus reducing the size of the composite tendons by a similar amount.

The cost for 12 steel tendons including couplings used to join discrete length, longitudinal seam welded sections is estimated at ~$40 million. This cost does not include installation, engineering, or top and bottom terminations. Assuming that $40 million was the cost of the tendons, the cost of steel and composite tendons with identical axial stiffness (excluding the cost of top and bottom connections and installation) would be ~$2.50/lb for the steel tendon and ~$4.3/lb for the composite tendon to moor the same hull and deck mass. A purchase price of ~$4.3-5/lb for the composite tendon will not provide sufficient incentive for composite manufacturers or fiber suppliers to develop a composite tendon. If a lighter hull and deck were to be moored, then the $40 million would be spent on a lighter composite tendon system at a cost of ~$7/lb. These cost comparisons, however, do not include differences in the cost of installation which for a steel tendon in 4,000ft of water represents over one third the total cost of the tendons. If a reliable, low cost, composite tendon spooling and deployment procedure could be developed and demonstrated, the associated cost saving ($10 million or more per installation) could provide additional economic incentive to justify the necessary manufacturing and technology development for some projects. If the assumed installation cost saving of $10 million were then applied to the cost of the composite tendons, the cost per pound would be ~$5.5, or ~$8.5 when the lighter hull and deck are used. The $8.5/lb cost may begin to provide the required economic incentive for manufacturers. However, because of the resulting weight saving on the hull of a deep water TLP, the offshore operator may be willing to absorb some extra tendon costs if the composite tendon makes the overall economics of the offshore development more favorable. Higher stiffness carbon fiber could also improve the economics if the cost of the fiber did not increase. The composite tendon economics would also improve if the axial stiffness required could be reduced below that of a steel tendon system.

Although the above comparison between steel and composite tendons shows a 42% weight savings advantage in air for the composite, this advantage is not realized for the 4,000ft water depth TLP since the steel tendons are designed to be near neutrally buoyant at a D/t of 20-22. This yields a weight in water only slightly greater than the weight of the composite tendon in water. The cost comparisons with steel become more favorable for the composite tendon in ultra deep (>6,000ft) water where the near neutrally buoyant steel tendon solution becomes increasingly more complex and expensive to reliably achieve. The added load on the hull imposed by the weight of the tendon can be counter-balanced by providing buoyancy either by increasing the size of the hull or attaching syntactic foam modules to the tendon. An alternative approach is to internally pressurize the lower portion of the tendon to resist hydrostatic collapse caused by the water pressure at water depths of 3-5,000ft and beyond. It may be attractive in deep water to use a steel tendon for the top portion where collapse is not a major factor and a composite tendon for the lower portion leading to the sea bed.

Other steel configurations are also possible such as welding steel tendons into a single long length as was done for the Jolliet and Heidrun TLP's. The entire tendon can be floated to the field site, up-ended and attached to the hull and foundation. The single piece welded concept lowers the overall tendon costs, but imposes additional installation complexity and cost.

The termination of a composite rod rope tendon at the hull and foundation is also an important consideration. One promising concept for terminating a carbon rod rope tendon is to use a simple potted termination similar to that used for steel mooring lines and suspension bridge cables. In service monitoring of the composite tendon performance could involve inclusion of fiber optics in some of the rods as described in reference 72.

Additional study is needed to assess if a composite tendon can be developed and manufactured which produces a significant cost savings to the operator in deep water. The greatest potential for a performance and cost advantage with composite tendons will be in ultra deep water. The economic advantage or disadvantage of composite tendons depends to a large extent on the cost effectiveness of the technology developed for steel tendons in deep water.

Note: Estimating the cost of a composite TLP mooring tendon to be produced 5 to 10 years in the future when no similar component has ever been produced is very difficult and highly inaccurate. For the composite mooring system to be cost competitive with the steel system, the cost of the composite tendon should be in the range of $10-12/lb.

19.2.6 Summary of Weight Reduction

The reductions in weight made possible through the use of composite materials for various topside components, structural beams, risers and TLP tendons are detailed in Table 23. Table 24 summarizes the weight savings for major TLP components such as topside equipment, deck, risers, mooring tendons, and piles.

Table 23 - WEIGHT COMPARISONS FOR TLP's IN GOM (tons)

	Typical Steel TLP (3,000ft)	Steel Base Case (4,000ft)	CEAC-2005 Steel/Composites (4,000ft)	Weight Savings		
				1997	2000	2005
Topside Facilities	9,594	10,662	9,422	1,039	1,176	1,240
Drilling Equipment	4,000	5,000	4,810	150	170	190
Living Quarters	1,000	1,000	915	75	75	85
Helideck	45	45	30	15	15	15
Power Generation	1,280	1,280	1,219	51	61	61
Process Equipment	1,395	1,395	1,159	181	216	236
HC & Water Piping	500	567	419	134	134	148
Secondary Structures	600	600	240	360	360	360
Misc. Equip. (tanks,pans,firewalls)	250	250	180	70	70	70
Utilities Module	525	525	450	25	75	75
Main Deck Structure (includes well bay)	7,200	8,540	6,667[1]	0 **78[3]**	1,514[2] **88[3]**	1,873[2] **108[3]**
Sub-Total:	**16,794**	**19,202**	**16,107**	**1,117**	**1,264**	**1,348[4]**
Hull	15,650	20,000	14,000[1]	-	1,877[2]	6,000[2]
Drilling Riser	952	1,196	699	-	-	497[2]
Prod.& Inj.Risers (no.) (wt in air) **Riser Pretension (20%)**	1,566 (24) 313	2,376 (18) 475	929 (18) 186	-	**1,736**	**1,736**
Accumulator Bottles (no.)	18 (100)	101 (144)	29 (144)	72	72	72
Flowline Risers (2) (includes 20% pretension)	152	203	203	-	-	-
Export Risers (PLs)-2	139	336	336	-	-	-
Sub-Total:				**1,189**	**3,072**	**3,156**
Mooring System 12 tendons	6,150 (air) ~0 (water)	15,809 (air) 3,216 (water)	2,988 (air) ~0 (water)	- -	- -	3,216[2]
Mooring Pretension (15ksi @ tendon bottom)	7,891	17,406	16,110			1,296[2]
Totals:				**1,189**	**3,072**	**3,156**

1. The vast majority of the weight savings is due to downsizing and not composite components.
2. Weight savings not shown in totals below.
3. Weight savings shown are for floor beams in the well bay and in areas not shown under **Topside Facilities**
4. Weight savings shown do not include savings in main deck structure except as noted for floor beams.

The equipment weights shown in the Typical Steel TLP (3,000ft) column of Table 23 were drawn from published data on the Auger and Mars TLP's (19-21,24). Since the Auger topside facilities were originally designed for only 46,000 BOPD, some of the equipment module weights were increased to account for the 100,000 BOPD throughput in the Basis of Assessment (Table 3). Once the topside equipment, deck and hull weights were determined, then they were extrapolated where appropriate to generate the Steel Base Case TLP in 4,000ft of water.

The weight savings shown under 1997 in Topside Facilities are closely related to recent experiences with composite (FRP) components in the GOM. The additional weight savings projected for years 2000 and 2005 were based on the expected increase use of composite piping, vessels and structural elements. These applications were not identified in detail, but a 10-13% growth in weight savings every 3-5 years is reasonable. Equipment and module floor beams were included in the weights of each topside equipment module in Table 23.

The hull weights shown for the Steel Base Case and CEAC-2005 (Table 23) are based on the total load-to-hull weight ratios calculated for the Auger and Mars TLP's (Table 8). This seemed to be a good first order approximation for the purposes of this study. The total load-to-hull weight ratio for CEAC-2005 is 2.38, about 11% greater than the Steel Base Case.

The weight reductions shown in the bottom half of Table 24 for the deck and hull were the results of "downsizing" made possible by the weight saved in the topside equipment, deck structure and production risers shown in the top half of the table. The hull weight reductions also included the projected savings from a composite tendon system. Only the weight reductions shown in the top half of Table 24 (except for the drilling riser) were used to estimate the value of the weight saved at a rate of $8,500/ton. It was assumed that the cost savings would be manifested as a smaller deck, hull and seabed pile system.

Table 24 - SUMMARY OF WEIGHT SAVINGS FOR MAJOR TLP COMPONENTS - CEAC-2005

Component	Weight Saved (tons)	Percentage of Weight Saved
Topside Facilities	1,240	12 (18% excluding drilling equipment)
Deck Structure	108	1.3
Production Risers	1,736	61
Drilling Riser*	497	42
Mooring Tendons*	3,216 (water)	~95
Piles*	510	~7
Deck*	1,873	22
Hull*	6,000	33

*: The weight savings indicated were not included in the totals shown for CEAC-2005 (Table 23) which were valued at $8,500/ton.

Currently industry thinking says that for every ton of topside weight saved in a TLP, approximately two tons will be saved in the deck, hull and mooring pretension. In addition, there would probably be additional savings in the anchor piles and foundations. The 3,156 tons of topside weight (including riser top tension) saved in the CEAC-2005 scenario, resulted in a structural weight savings of 6,000 tons in the hull and 1,873 tons in the deck. In addition, the mooring pretension was reduced by almost 1,300 tons. The 2:1 ratio mentioned above would have predicted a savings of ~6,300 tons for deck, hull and mooring pretension; about 2/3 of the savings predicted in this study.

Composite production risers offer the greatest potential for weight savings with the exception of the composite tendons. The estimated weight savings shown for the risers will increase in deeper water and when the number of wells is increased. There is a good possibility that the topside savings of 1,240 tons or 12% can be increased by carefully scrutinizing the details of the topside equipment lists. There was not enough time or the proper resources in this study to pursue the application of composite materials to topside facilities in great detail. The other area with good growth potential is that of structural beams made with hybrid composites. Close examination of the structural components of equipment modules and support structures, and the main deck structure will most likely uncover additional opportunities for saving weight with composite beams and structural panels.

19.2.7 Capital Investment Savings

The main cost savings with composite materials will be a reduction in the investment cost of a deep water development when the use of composite components is incorporated into the design of the development concept at the very beginning of the project. In this way a system approach to the use of composites can be taken and the full cost benefits can be realized by the offshore operator.

Table 25 summarizes the estimated installed cost differential for composite components versus coated carbon steel. Definitive cost data was used whenever it was available or could be derived from published sources. Costs for composite components that cost less than carbon steel are shown in **bold type.** Only $1.818 million in composite cost premiums could be identified. It was assumed that the piping and other undetermined components would cost an additional $0.9 million to bring the total to $2.72 million. This value does not include the weight savings cost benefit which is assessed below.

Table 26 shows the three main components that lead to the finding that the net investment cost saving from using composite materials is ~$25 million. The gross weight savings of 3,156 tons came from Table 23, the installed cost premium for composites came from Table 25 and the construction/installation cost benefit of $1 million was assumed. The savings in construction and installation costs was based on the assumption that use of lighter materials and equipment would provide greater flexibility to the fabricator in scheduling and the use of lifting equipment permitting operations to proceed faster, and reduce the need for welding. It was also assumed that the fabricator would be competent and familiar with composite materials, and not charge a premium to install composite components because of inexperience. It is anticipated that construction companies may even gain a competitive edge by using their experience with composite materials.

Table 25 - ESTIMATED INSTALLED COST DIFFERENTIAL COMPOSITE vs STEEL COMPONENTS: TLP

COMPONENT		COMPOSITE COST DIFFERENTIAL
Piping (complex):	<2-3 inch	+80-100% vs bare c-steel(39), +30% vs 316L(39)
	>4 inch	+60-100% vs c-steel (39,70),~0% vs 316L (39,70)
	8-30 inch	**❮10%❯ vs c-steel (29)**
Fire Water Piping:		~0% vs c-steel (32) **❮3-10%❯ vs duplex or titanium (32)**
Tanks :		+$ 108,000 (for 10 tanks)
Grating/Stairs/Ladders/Hand Rails:		~0%
Vessels:		+$ 66,000 (LP and mud gas separators)
Floor and Secondary Beams:		+$1,140,000
Production Risers: (10-3/4 in.)	steel@$150/ft composite@$210/ft	+$4,320,000 (18 x 4,000ft x $60/ft)
Riser Tensioner:		**❮$3,600,000❯** (18 x $200,000)
Accumulator Bottles:		**❮$ 216,000❯** ($1,500 x 144 bottles)
Net Cost Differential:		+$2,720,000 (w/o composite tendons) [only $1,818,000,000 identified above]

Table 26 - NET INVESTMENT COST SAVINGS ESTIMATE CEAC-2005 TLP

Gross Cost Savings-Weight : 3,156 tons x $8,500/ton =	~$ 26,826,000
Composite Installed Cost Premium :	❮2,720,000❯
Construction/Installation Cost Benefit (assumed) :	1,000,000
Net Cost Savings* (without composite tendons) :	**$ 25,106,000***

* This number does not include any savings in life cycle costs (operations and maintenance) plus the economic benefits from enabling capabilities that may be offered by composite materials in special project applications.

Table 27 shows the same total net cost savings presented in Table 26 but broken down by major platform component. This clearly shows the significant cost savings possible from the use of composite production risers and topside equipment. The production riser cost saving assumes

(Table 25), that the cost premium for the composite riser is $60/ft over steel and that there is a savings of about $3,600,000 in the riser tensioner system resulting from using a composite riser.

Table 27 - NET COST SAVINGS FOR 4,000FT TLP BY MAJOR COMPONENT

Major Component	Net Cost Savings
Production Risers	$14,864,000
Topside Equipment	8,545,000
Deck Structure	697,000
Installation	1,000,000 (est.)
Total	**$25,106,000**

Additional cost savings are possible in the topside equipment as more piping, secondary structural beams and process vessels are made of composites. This will also lower the center-of-gravity, a desirable feature in any floating production platform. This is also true as more structural composite beams are used in the deck structure.

19.2.8 Operational Cost Savings

Composite materials offer the offshore operator economic benefits unrelated to the significant weight savings that are so important for floating production platforms in deep water. Because composite materials are resistant to corrosion in most oilfield environments, especially sea water, they can significantly reduce the normal operating and maintenance costs that so often get over looked when the large investment cost of new developments is getting all the attention.

Winkel of Phillips Petroleum Norway did a comprehensive materials selection study during the conceptual phase of the Ekofisk Redevelopment Project (73). He reported that when FRP pipe was used to replace corroded carbon steel sea water pipe, the installed cost of the FRP pipe was 90% that of carbon steel while the life cycle cost was only 60%.

Elf (10) estimates that FRP piping is about equal to or slightly more costly than carbon steel for new construction. However, as replacement pipe on existing platforms, FRP is cheaper because no "hot" work or permit is required and installation is simpler. Furthermore, Elf estimates that the total life cycle cost of FRP piping is only 25% of that for carbon steel.

Maintaining a carbon steel fire water system in a safe operating condition was costing one North Sea operator $1 million a year. This provided the incentive needed to replace the heavily corroded carbon steel system with FRP.

The preliminary Net Present Value (NPV) calculation shown in Table 29 was based on an investment savings of $25,106,000, the maintenance cost savings as shown in Table 28, and the increased revenue generated by reduced production down time. This is a very rudimentary estimate of the NPV resulting from the use of composites. The savings in maintenance costs shown in Tables 28 and 29 are probably underestimated because of the limited input data available. It was assumed that no maintenance would be performed in year 25.

The fire water system saving assumed that no maintenance was required during the first three years and that beginning in year 4, some maintenance would be required. How much maintenance and at what cost is difficult to say. Maintaining a carbon steel fire water system cost one North Sea operator $1 million a year. That is probably an upper bound for yearly maintenance costs. It was assumed that a major refurbishment of the system would be required in year 11. That would be followed by three years of no maintenance costs, probably a false assumption.

Table 28 - MAINTENANCE COSTS ($) SAVED OVER LIFE OF PROJECT

Project Year ⇒ Maintenance Category	1-3	4	5	6-10	11	12-14	15	16-25	Indirect Costs	Totals
Fire Water System	0	50K	75K	500K	750K	0	50K	900K	2,325K	4,650K
Coating	0	0	0	124K	0	124K	0	124K	372K	744K
Grating Replacement	0	0	0	0	50K	0	0	75K	125K	250K
Total:	0	50K	75K	624K	800K	124K	50K	1,099K	2,822K	5,644K

The coating costs were based on $10/ft^2$ to recoat in the GOM and $5/ft^2$ to touch-up. If the initial coating was properly applied, touch-up would only be required every 7 years. The coated area to be touched-up was the area of the 10 FRP storage tanks, some FRP piping and composite beams; a relatively small area. It was assumed that no recoating would be required offshore, only touch-up.

The galvanized grating was assumed to have been partially replaced in the 11th and 19th years.

One North Sea operator has estimated that the indirect costs (the transportation and support of personnel, materials and equipment offshore) are 2.3x the costs of materials and labor for painting, and 1.4x for replacement of grating, handrails and ladders. A factor of 1.0x was used in this study to estimate the indirect costs for all maintenance work in the GOM. These costs will depend on location, distance from shore and proximity to existing platforms.

A very significant economic benefit resulting from the use of composite components is the projected decrease in production "down time" because of the reduction or elimination of the need for welding and torch cutting. Repair and replacement of traditional metallic components such as piping and grating will require shutting down platform production while "hot work" is underway. This is not necessary with composites. Saving one day of production down time per year on a platform with a production rate of 100,000BOPD will increase annual revenue by $2 million at an oil price of $20/bbl. If this added revenue is estimated over the entire project life of 25 years, the total increase in revenue over the life of the project could reach $40 million assuming an average production rate of 80,000BOPD and an average price of $20/bbl.

Table 29 - NPV CALCULATION FOR CEAC-2005 TLP SCENARIO

Financial Factors

Inflation	4.50%
Cost of Capital	12.00%
Tax Rate	34.00%

NPV, K$ (After Tax)

Year	0	1	2	3	4	5	6	7	8	9
Savings	25,106	1,600	1,600	1,600	1,700	1,750	1,800	2,048	1,800	1,800
Inflation Factor	1.000	1.045	1.092	1.141	1.193	1.246	1.302	1.361	1.422	1.486
Inflated $	25,106	1,672	1,747	1,826	2,027	2,181	2,344	2,787	2,560	2,675
After Tax	16,570	1,104	1,153	1,205	1,338	1,439	1,547	1,839	1,689	1,765
Discount Factor	1.000	1.120	1.254	1.405	1.574	1.762	1.974	2.211	2.476	2.773
PV	16,570	985	919	858	850	817	784	832	682	637
NPV	16,570	17,555	18,475	19,332	20,183	20,999	21,783	22,615	23,298	23,934

Year	10	11	12	13	14	15	16	17	18	19
Savings	1,800	3,200	1,600	1,600	1,848	1,700	1,800	1,800	1,800	1,950
Inflation Factor	1.553	1.623	1.696	1.772	1.852	1.935	2.022	2.113	2.208	2.308
Inflated $	2,795	5,193	2,713	2,836	3,422	3,290	3,640	3,804	3,975	4,500
After Tax	1,845	3,427	1,791	1,871	2,259	2,171	2,403	2,511	2,624	2,970
Discount Factor	3.106	3.479	3.896	4.363	4.887	5.474	6.130	6.866	7.690	8.613
PV	594	985	460	429	462	397	392	366	341	345
NPV	24,528	25,514	25,973	26,402	26,864	27,261	27,653	28,019	28,360	28,705

Year	20	21	22	23	24	25
Savings	1,800	2,048	1,800	1,800	1,800	0
Inflation Factor	2.412	2.520	2.634	2.752	2.876	3.005
Inflated $	4,341	5,161	4,741	4,954	5,177	0
After Tax	2,865	3,407	3,129	3,270	3,417	0
Discount Factor	9.646	10.804	12.100	13.552	15.179	17.000
PV	297	315	259	241	225	0
NPV	29,002	29,317	29,576	29,817	30,042	30,042

NPV (5 yrs)	K$ 20,999
NPV (10 yrs)	K$ 24,528
NPV (15 yrs)	K$ 27,261
NPV (20 yrs)	K$ 29,002
NPV (25 yrs)	K$ 30,042

19.3 Appendix 3: Case Study 2 - Floating Production System (FPS)

19.3.1 Background

The FPS scenario described in the Basis of Assessment (Table 3) is located in 6,000ft of water and has a production capacity of 100,000 BOPD. This scenario was chosen because it was about the average water depth for the GOM discoveries beyond what is currently thought to be the water depth limit (4,000ft) for TLP technology and had a production capacity that justified a deep water development.

The Steel Base Case (Tables 4 and 30) was developed by extrapolating available information about the Auger and Mars TLP's (19-21,24).

The main factor driving the consideration of composite materials for FPS's and other deep water floating production platforms is weight reduction. Reducing the load carried by the FPS hull by one ton, can save $6-8,000 in project investment costs. This cost saving is achieved by reducing the size of the deck and hull to account for the reduced topside facilities weight and top tensions resulting from the use of light weight composite risers. Because a system approach is required to achieve the full benefits from the application of composite materials where weight saving is important, composite materials must be incorporated in the platform design strategy in the conceptual or pre-engineering stages of a project. Designing for steel but using composites may reduce weight and corrosion problems, but will not result in the major investment cost savings possible with light weight materials.

Composite materials were considered for all applications on the FPS from topside equipment to production risers where it was believed a commercial product would be available by the year 2005. Since detailed designs of the topside facilities, the deck structure and the equipment contained in the hull were not used in this study, a global approach to material substitution was used except for some specific components such as the production risers.

19.3.2 Topside Equipment

The topside weight of the Steel Base Case was estimated at 10,662 tons (see Table 4 for details), with 5,000 tons allocated to the drilling equipment. The results of the Phase 1 study indicate that approximately 1,039 tons could be saved in 1997 (Table 20) in topside equipment weight through the use of composite components. This saving is expected to grow to 1,240 tons in 2005 as higher pressure and temperature piping and vessels become available, and greater use is made of hybrid composite structural beams.

Table 20 lists many topside applications of composite components including secondary structures in addition to pipe, storage tanks and spill pans.

It was estimated that by 1997, 448 tons could be saved in the topsides facilities through the use of relatively small composite beams for grating supports, and for equipment supports and foundations. This is one area that has been identified for further study because it appears to be relatively undeveloped as a source for savings weight on TLP's and FPS's.

Steel grating was assigned a weight of 11.4 lbs/ft^2 and FRP grating 3.4 lbs/ft^2. The cost of phenolic grating is ~$13-14/$ft^2$, which does not include installation. The installed cost of FRP grating is roughly the same as for galvanized steel when crews experienced with FRP are used.

For the purposes of this study, 10 storage tanks were used (Table 21). The largest of these (30,000gal/750bbls) is only half the volume of the smallest FRP tanks used on the Heidrun TLP. Based on simple material substitution, the FRP tank should be ~60% lighter than the steel tank. It was assumed in this study that extra bracing and/or foundation supports would be required for the FRP tanks. As a result, the weight saving was conservatively assumed to be only 50%.

Composite tanks and vessels designed to go on moving platforms such as TLP's an FPS's must contain internal baffles to reduce liquid sloshing, and must be structurally robust to resist the added stresses imposed by platform accelerations.

Process vessels generally offer a greater challenge to polymer composites because of the higher temperatures and pressures normally encountered. Table 22 shows two examples of composite process vessels, a low pressure (200psi) separator and a mud gas separator (150psi). The mud gas separator was designed, built and tested by AMAT A/S in Norway as part of a joint industry project. The vessel met all test requirements and is currently being used on the Smedvig drilling rig *West Vanguard.*

Composite storage tanks and process vessels appear to be another largely undeveloped source of weight savings for deep water floating production platforms that should be evaluated in more depth.

19.3.3 Drilling Riser

The weight of the composite drilling riser used in this study was taken from Valenzuella et al (41) and extrapolated to 6,000ft (see Table 11 for details). They used a glass/epoxy composite for their study, while Northrop Grumman is developing a graphite/epoxy riser in the NIST ATP project.

Because very little solid information could be obtained about the cost of a fully developed composite drilling riser, no credit was taken for the estimated weight saving of 748 tons shown in Table 30. The weight savings of 748 tons is equivalent to an investment cost savings of $5,236,000 minus the cost premium for the composite drilling riser.

19.3.4 Production Risers

The 18 8-5/8in. production risers used in the 6,000ft FPS Steel Base Case scenario weigh 3,485 tons in air, a tempting target for weight reduction. However, since a subsurface buoy would be used at the 3,000ft depth location, the effective length of each riser would be ~4,000ft, not 6,000ft. Therefore, the effective weight of 18 risers would be 1,742.4 tons in air and 1,519 tons in water.

The production risers were considered to be candidates for the type of component being developed in the NIST ATP project led by Lincoln Composites. This would mean that the composite riser would be jointed, not continuous, in an application that normally employs welded steel pipe because of the dynamic (fatigue) loads that it would experience. The hybrid composite production riser under development by the Lincoln-led consortium was assumed to be commercially available by the year 2000. At a cost of $210/ft including steel end connections, a composite production riser would cost an estimated $800,000 per riser more than the 8-5/8in. carbon steel riser in 6,000ft of water. The weight saving (590 tons) that results from the use of composite risers would save ~$4.13 million in deck and hull costs, and ~$3.54 million in buoyancy costs. This savings of ~$7.7 million is still not enough to offset the added costs of ~$14.4 million for composite risers. This analysis is based on a steel riser cost of $110/ft, a composite riser cost of $210/ft, a cost of $3/lb for buoyancy at a water depth of 3,000ft, and total riser length of 8,000ft. It was assumed that there would be no riser tensioner system for either the steel or composite riser systems on a FPS. The entire length of each production riser was assumed to be made from composites. Steel was not used for the top and bottom 2-3 joints in each riser as has been done in other analyses of steel versus composite risers (70). In the final analysis, steel risers were deemed to be the most cost-effective option for the FPS scenario.

19.3.5 Mooring System

The use of a traditional chain/wire rope catenary mooring system in 6,000ft for a permanent installation would require significant additional buoyancy making it uneconomic (see Section 8.2.1). A chain/synthetic mooring line system would provide the required performance characteristics with a much reduced weight (56,57). Since a chain/synthetic mooring line system would be used even for the FPS Steel Base Case in 6,000ft, there is no weight saving shown for the CEAC-2005 FPS scenario mooring system (Table 30).

19.3.6 Summary of Weight Reduction

The weight savings for the 6,000ft FPS scenario are not as great as for the 4,000ft TLP scenario because the estimated weight savings (590 tons) for the production risers are considerably lower than for the TLP scenario. This results from the fact that in nearly all FPS riser scenarios, a sub-surface buoy is used to reduce the net weight (in water) of the riser system and, therefore, the riser weight the FPS hull has to carry. A "lazy S" riser system was used for this study. The weight-in-water of the steel riser system was estimated to be 1,519 tons, only 53% of the weight for the 4,000ft TLP riser system, including pretension. A composite riser system for the 6,000ft FPS scenario reduced the net riser load on the hull by ~40% or 590 tons.

Table 30 - WEIGHT COMPARISONS FOR FPS's IN GOM (tons)

	Typical Steel FPS (3,000ft)	Steel Base Case (6,000ft)	CEAC-2005 Steel/Composites (6,000ft)	Weight Savings 1997	2000	2005
Topsides Facilities	**9,594**	**10,662**	**9,422**	**1,039**	**1,176**	**1,240**
Drilling Equipment	4,000	5,000	4,810	150	170	190
Living Quarters	1,000	1,000	915	75	75	85
Helideck	45	45	30	15	15	15
Power Generation	1,280	1,280	1,219	51	61	61
Process Equipment	1,395	1,395	1,159	181	216	236
HC & Water Piping	500	567	419	134	134	148
Secondary Structures	600	600	240	360	360	360
Misc. Equip. (tanks,pans,firewalls)	250	250	180	70	70	70
Utilities Module	525	525	450	25	75	75
Main Deck Structure (includes well bay)	7,200	8,540	6,667	0 **78**[1]	1,514[3] **88**[1]	1,873[3] **108**[1]
Sub-Total:	**16,794**	**19,202**	**16,107**	**1,117**	**1,264**	**1,348**[2]
Hull	15,650	20,000	14,000	-	1,877[3]	6,000[3]
Drilling Riser	952	1,687	939	-	-	748[3]
Prod. & Inj. Risers	760	1,519	929	-	590[3]	590[3]
Flowline Risers (2)	190	380	380	-	-	-
Export Risers (PLs)-2	208	1,132	1,132	-	-	-
Mooring System[4]				-	-	-
Totals:				**1,117**	**1,264**	**1,348**

1. Weight savings shown are for floor beams in the well bay and in areas not shown under **Topsides Facilities**
2. Weight savings shown do not include savings in main deck structure except as noted for floor beams.
3. Weight savings not shown in totals below.
4. Choice of materials for FPS mooring system is driven by cost, not by weight.

19.3.7 Capital Investment Savings

The main cost savings with composite materials will be a reduction in the investment cost of a deep water development when the use of composite components is incorporated into the design of the development concept at the very beginning of the project. In this way a system approach to the use of composites can be taken and the full cost benefits can be realized by the offshore operator.

Table 31 summarizes the estimated installed cost differential for composite components versus coated carbon steel. Definitive cost data was used whenever it was available or could be derived from published sources. Costs for composite components that cost less than carbon steel are shown in **bold type** and brackets **❮ ❯**. A total of $1,314,000 in composite cost premiums were identified. It was assumed that the piping and other undetermined components would cost an additional $872,000 to bring the total to $2,186,000.

Table 31 - ESTIMATED INSTALLED COST DIFFERENTIAL
COMPOSITE vs STEEL COMPONENTS: FPS

COMPONENT		**COMPOSITE COST DIFFERENTIAL**
Piping (complex):	<2-3 inch	+80-100% vs bare c-steel(50), +30% vs 316L(50)
	>4 inch	+60-100% vs c-steel (50,70),~0% vs 316L (50,70)
	8-30 inch	**‹10%› vs c-steel (15)**
Fire Water Piping:		~0% vs c-steel (40) **‹3-10%› vs duplex or titanium (40)**
Tanks :		+$ 108,000 (for 10 tanks)
Grating/Stairs/Ladders/Hand Rails:		~0%
Vessels:		+$ 66,000 (LP and mud gas separators)
Floor and Secondary Beams:		+$1,140,000
Net Cost Differential:		+$2,186,000 [$1,314,000 identified above]

Table 32 shows the three main components that lead to the finding that the net investment cost saving from using composite materials is only ~$8,250,000. The gross weight savings of 1,348 tons came from Table 30, the installed cost premium for composites came from Table 31 and the

Table 32 - NET INVESTMENT COST SAVINGS ESTIMATE CEAC-2005 FPS

Gross Cost Savings-Weight : 1,348 tons x $7,000/ton =	~$ 9,436,000
Construction/Installation Cost Benefit (assumed) :	1,000,000
Composite Installed Cost Premium :	‹2,186,000›
Net Cost Savings*:	**$ 8,250,000***

* This number does not include any savings in life cycle costs (operations and maintenance) plus the economic benefits from enabling capabilities that may be offered by composite materials in special project applications.

construction/installation cost benefit of $1 million was assumed. The savings in construction and installation costs were based on the assumption that use of lighter materials and equipment would provide greater flexibility to the fabricator in scheduling and the use of lifting equipment permitting operations to proceed faster, and reduce the need for welding. It was also assumed that the fabricator would be competent and familiar with composite materials, and not charge a premium to install composite components because of inexperience. It is anticipated that construction companies may even gain a competitive edge by using their experience with composite materials. Table 33 shows the same total net cost savings presented in Table 32 but broken down by major platform component.

Table 33 - NET COST SAVINGS FOR 6,000FT FPS BY MAJOR COMPONENT

Major Component	Net Cost Savings
Production Risers (steel)	0
Topside Equipment	6,715,000
Deck Structure	535,000
Installation	1,000,000 (est.)
Total	**$8,250,000**

Additional cost savings are possible in the topside equipment, deck and the equipment located within the hull as more piping, secondary structural beams and process vessels are made of composites. This will also lower the center-of-gravity, a desirable feature in any floating production platform.

19.3.8 Operational Cost Savings

Composite materials offer the offshore operator economic benefits unrelated to the significant weight savings that are so important for floating production platforms in deep water. Because composite materials are resistant to corrosion in most oilfield environments, especially sea water, they can significantly reduce the normal operating and maintenance costs that so often get over looked when the large investment cost of new developments receives all the attention.

Winkel of Phillips Petroleum Norway did a comprehensive materials selection study during the conceptual phase of the Ekofisk Redevelopment Project (73). He reported that when FRP pipe was used to replace corroded carbon steel sea water pipe, the installed cost of the FRP pipe was 90% that of carbon steel while the life cycle cost was only 60%.

Elf (10) estimates that FRP piping is about equal to or slightly more costly than carbon steel for new construction. However, as replacement pipe on existing platforms, FRP is cheaper because no "hot" work or permit is required and installation is simpler. Furthermore, Elf estimates that the total life cycle cost of FRP piping is only 25% of that for carbon steel.

Maintaining a carbon steel fire water system in a safe operating condition was costing one North Sea operator $1 million a year. This provided the incentive needed to replace the heavily corroded carbon steel system with FRP.

The maintenance cost savings shown in Table 34 are the same as used in the TLP Case Study. They were used together with the investment cost savings of $8,250,000 to develop the preliminary Net Present Value (NPV) calculation shown in Table 35. No maintenance cost savings or increased revenue from reduced production down time were credited for year 25. This is a very rudimentary estimate of the NPV resulting from the use of composites. The savings in maintenance costs shown in Tables 34 and 35 are probably underestimated because of the limited input data available.

Table 34 - MAINTENANCE COSTS ($) SAVED OVER LIFE OF PROJECT

Project Year ⇒ Maintenance Category	1-3	4	5	6-10	11	12-14	15	16-25	Indirect Costs	Totals
Fire Water System	0	50K	75K	500K	750K	0	50K	900K	2,325K	4,650K
Coating	0	0	0	124K	0	124K	0	124K	372K	744K
Grating Replacement	0	0	0	0	50K	0	0	75K	125K	250K
Total:	0	50K	75K	624K	800K	124K	50K	1,099K	**2,822K**	**5,644K**

The fire water system saving assumed that no maintenance was required during the first three years and that beginning in year 4, some maintenance would be required. How much maintenance and at what cost is difficult to say. Maintaining a carbon steel fire water system cost one North Sea operator $1 million a year. That is probably an upper bound for yearly maintenance costs. It was assumed that a major refurbishment of the system would be required in year 11. That would be followed by three years of no maintenance costs; probably a false assumption.

The coating costs were based on $10/ft^2 to recoat in the GOM and $5/ft^2 to touch-up. If the initial coating application was done properly, touch-up would only be required every 7 years. The coated area to be touched-up was the area of the 10 FRP storage tanks, some FRP piping and composite beams; a relatively small area. It was assumed that no recoating would be necessary.

The galvanized grating was assumed to have been partially replaced in the 11th and 19th years.

One North Sea operator has estimated that the indirect costs (the transportation and support of personnel, materials and equipment offshore) are 2.3x the costs of materials and labor for painting, and 1.4x for replacement of grating, handrails and ladders. A factor of 1.0x was used in this study to estimate the indirect costs for all maintenance work in the GOM. These costs will depend on location, distance from shore and proximity to existing platforms.

A very significant economic benefit resulting from the use of composite components is the projected decrease in production "down time" because of the reduction or elimination of the need for welding and torch cutting. Repair and replacement of traditional metallic components such as piping and grating will require shutting down platform production while "hot work" is underway. This is not necessary with composites. Saving one day of production down time per year on a platform with a production rate of 100,000BOPD will increase annual revenue by $2 million at an oil price of $20/bbl. If this added revenue is estimated over the entire project life of 25 years, the total increase in revenue over the life of the project could reach $40 million assuming an average production rate of 80,000BOPD and an average price of $20/bbl.

Table 35 - NPV CALCULATION FOR CEAC-2005 FPS SCENARIO

Financial Factors

Inflation	4.50%
Cost of Capital	12.00%
Tax Rate	34.00%

NPV, K$ (After Tax)

Year	0	1	2	3	4	5	6	7	8	9
Savings	8,250	1,600	1,600	1,600	1,750	1,825	1,900	2,272	1,900	1,900
Inflation Factor	1.000	1.045	1.092	1.141	1.193	1.246	1.302	1.361	1.422	1.486
Inflated $	8,250	1,672	1,747	1,826	2,087	2,274	2,474	3,092	2,702	2,824
After Tax	5,445	1,104	1,153	1,205	1,377	1,501	1,633	2,041	1,783	1,864
Discount Factor	1.000	1.120	1.254	1.405	1.574	1.762	1.974	2.211	2.476	2.773
PV	5,445	985	919	858	875	852	827	923	720	672
NPV	5,445	6,430	7,350	8,207	9,083	9,934	10,762	11,685	12,405	13,077

Year	10	11	12	13	14	15	16	17	18	19
Savings	1,900	4,000	1,600	1,600	1,972	1,750	1,900	1,900	1,900	2,125
Inflation Factor	1.553	1.623	1.696	1.772	1.852	1.935	2.022	2.113	2.208	2.308
Inflated $	2,951	6,491	2,713	2,836	3,652	3,387	3,843	4,015	4,196	4,904
After Tax	1,947	4,284	1,791	1,871	2,410	2,235	2,536	2,650	2,769	3,237
Discount Factor	3.106	3.479	3.896	4.363	4.887	5.474	6.130	6.866	7.690	8.613
PV	627	1,232	460	429	493	408	414	386	360	376
NPV	13,704	14,936	15,395	15,824	16,318	16,726	17,140	17,526	17,886	18,262

Year	20	21	22	23	24	25
Savings	1,900	2,274	1,900	1,900	1,900	0
Inflation Factor	2.412	2.520	2.634	2.752	2.876	3.005
Inflated $	4,582	5,731	5,004	5,229	5,464	0
After Tax	3,024	3,782	3,303	3,451	3,607	0
Discount Factor	9.646	10.804	12.100	13.552	15.179	17.000
PV	314	350	273	255	238	0
NPV	18,575	18,925	19,198	19,453	19,690	19,690

NPV (5 yrs)	K$ 9,934
NPV (10 yrs)	K$ 13,704
NPV (15 yrs)	K$ 16,726
NPV (20 yrs)	K$ 18,575
NPV (25 yrs)	K$ 19,690

19.4 Appendix 4: Case Study 3 - Small Production Structure (SPS)

19.4.1 Background

The big deep water developments may get the headlines, but it will be the more modest developments that will make up the majority of investment in the GOM over the next 10 years as they have ever since oil was discovered in the Gulf. For this reason, a third scenario or case study was added to the Phase 1 Study. Case Study 3 is a Small Production Platform (SPS) with a production capacity of 10,000 BOE. The SPS could also have been called a marginal field structure or an unmanned production platform. Since the SPS is a minimal facilities installation to be used in water depths up to about 300ft, Case Study 3 concentrated on the topside equipment and deck. The design of the jacket and piles will depend on the water depth and environmental forces at the field location. This Case Study may also be useful in evaluating the concept of a minimum facilities or unmanned installation in deep water.

Although a ton saved on a fixed platform is not nearly as valuable as a ton saved on a TLP, weight is still an important consideration even in small fixed platforms because it can influence the size of the derrick barge and other equipment used for construction and installation. Being able to use smaller offshore cranes, barges and associated equipment can be worth as much as $25-50,000 per day during installation.

Since it was assumed that a Small Production Platform in the future would be designed to require minimum maintenance, the base case materials used were corrosion resistant metals such as duplex stainless steel, copper-nickel and titanium. Designing for minimum maintenance will save maintenance costs, transportation and offshore personnel support costs, and production "down time". Using corrosion resistant materials will not only reduce maintenance costs during the life of the project, but the topside facilities will also likely be in condition to be re-used rather than scrapped.

19.4.2 Topside Equipment

The weight of the topside equipment in the SPS Steel Base Case was estimated to be 519 tons (see Table 4 for details). By comparison, Amoco's Davy/Bessemer monopod platforms in the UK sector of the North Sea have a topside weight of 440 tons (9) and Mobil's Galahad monopod platform also in the UK sector of the North Sea has a topside weight of 386 tons (74). Mobil's evaluation of various platform concepts indicated that the topside for a four pile structure would weigh 545 tons, slightly more than the SPS scenario used in this study. Both of these gas production platforms were designed to be minimum facilities installations. The monopod concept was chosen for these shallow water (65ft) platforms because it resulted in reduced topside weight, and reduced construction and installation costs when compared to the more conventional four pile concept (74). There is no drilling equipment, water injection, gas compression or living quarters on the SPS. Drilling will be done with a jack-up rig, and a workover rig will be brought to the SPS for remedial work on the wells. Since the SPS is an unmanned platform, it does not have a living quarters module. It does have a module located beneath the helideck that serves as a control/instrumentation room, storage locker and temporary shelter for 4-5 operating personnel.

The location of the SPS relative to existing platforms will determine what services, such as electric power or gas offtake, are available and do not have to be provided for on the SPS.

Table 36 - TOPSIDE WEIGHT SAVINGS FROM USE OF COMPOSITE COMPONENTS ON SPS - CEAC 2005

Equipment	Steel Weight (tons)	Amount Replaced by FRP (%)	Weight of Steel and FRP (tons)	Weight Saved (tons)
Floor beams (6 & 8in. I-beams)	156	50	106	50
Pipe (some HC service)	75	25	62	13
Grating	55	100	17	38
Equipment Supports	22	25	18	4
Storage Tanks & LP Separator	35	100	17.5	17.5
Spill Pans	11	100	3.7	7.3
Stairs	8	100	2.6	5.4
Hand Rails	6	100	2	4
Fire Walls	2	100	0.7	1.3
Ladders	2	100	0.8	1.2
Cable Trays & Access Structures	7	75	3.5	3.5
Total:	**379**		**233.8**	**145.2**

Note: Total topside facilities weight: 519 tons

The estimated weight saving of 145.2 tons is 28% of the total topside weight of 519 tons, a very significant amount. The topside weight saving for the TLP and FPS is about 18% when the drilling equipment is excluded. If the structural beams are excluded from the estimated SPS weight savings, the percentage of topside weight saved drops from 28 to 18. Medlicott estimated that Amoco saved 8% of the total topside weight by using FRP for grating, handrails, ladders, office and equipment modules, storage tanks, caissons and open drains (9). Composite beams were not used in the Davy/Bessemer project. If Medlicott used the same values (11.4 and 3.4lbs/ft^2) for the weight of steel and FRP grating as were used in this study, the Davy/Bessemer topside weight saving percentage would increase from 8% to 10%.

Table 37 - STORAGE TANKS: STAINLESS STEEL vs COMPOSITE

Size / Number[1]	SS Weight/Tank	SS Cost[2]/Tank	FRP Weight/Tank	FRP Cost[2]/Tank
6,000gal / 4 (143bbls)	4.8 tons	$ 42,000	2.4 tons	$ 24,000
10,000gal / 1 (250bbls)	10	60,000	5	34,000
Total: 5	29.2 tons	$228,000	14.7 tons	$130,000

1. Number of tanks assumed for the topsides scenario in this case study.
2. Costs shown were double those found in Table 1 of reference 70 to account for use offshore.
Note: These tanks would be used to store potable water, fresh water, diesel fuel, deck runoff, off-spec oil, produced water and workover fluids.

The storage tanks and process vessel were assumed to be stainless steel to reduce to a minimum the required maintenance for internal and external corrosion (Tables 37 and 38). The weights and costs were mainly extrapolated from data given in reference 70 and in a product catalogue. The number (5) of storage tanks required and their size are simply an estimate. Amoco used four FRP storage tanks ranging in size from 6.5 to 150bbls on their Davy/Bessemer platforms (9).

Table 38 - PROCESS VESSELS: STAINLESS STEEL vs COMPOSITE

Size / Pressure	SS Weight	SS Cost	Composite Weight	Composite Cost
Low Pressure Separator 6'x15'/ 200psi	6 tons	$205,000	3 tons	$140,000

Note: Based on information from reference 70.

19.4.3 Maintenance Cost Savings

Since the concept of the SPS was assumed to be a minimum maintenance platform, more corrosion resistant, but more costly, metallic components were used in the base case scenario. Therefore, there is not a significant savings in maintenance costs. It was assumed that the five stainless steel storage tanks, one process vessel, and various stainless steel and Monel piping systems would not require painting. If these metallic components require insulation, then they may also require a corrosion coating beneath the insulation to protect against pitting corrosion and stress corrosion cracking. Because of the inherent lower thermal conductivity of composite materials compared to metals, there may be situations in which the cost of insulation for piping, storage tanks and vessels could be saved by using composite materials. This would also save the maintenance costs associated with insulation systems over the life of the field.

The coating costs were based on touch-up costs of $5/ft^2$ in the GOM. The total coating cost of $20,000 in years 7 and 14 is one third the maintenance coating cost saving predicted for Amoco's Davy/Bessemer project in the North Sea due to the use of composite secondary structures.

One significant but often overlooked benefit of composite components, especially for offshore maintenance and retrofit, is the lack of a need to shut-in production for safety reasons. Even if only one extra day of production per year could be achieved by not having to shut-in production due to replacement of metallic components (piping and grating, for example), the revenue from a SPS-type platform would increase by $200,000 per year at $20/bbl.

Table 39 - MAINTENANCE COSTS ($) SAVED OVER LIFE OF PROJECT

Project Year ⇒ Maintenance Category	1-3	4	5	6-10	11	12-14	15	Indirect Costs	Totals
Coating	0	0	0	20K	0	20K	0	40K	80K
Grating Replacement	0	0	0	0	8K	0	0	8K	16K
Total:	0	0	0	20K	8K	20K	0	48K	96K

The estimated maintenance costs of $48,000 over 15 years for the two categories shown is low, but may indeed be higher if a more detailed analysis was performed. The $48,000 does not include the indirect costs of transportation and support of maintenance personnel and equipment offshore. One North Sea operator has estimated that the indirect costs (the transportation and support of personnel, materials and equipment offshore) are 2.3x the costs of materials and labor for painting, and 1.4x for replacement of grating, handrails and ladders. A factor of 1.0x was used in this study to estimate the indirect costs for all maintenance work in the GOM. These costs will depend on location, distance from shore and proximity to existing platforms.

19.4.4 Summary of Cost Savings

Table 40 contains a summary of the estimated cost differential of composite versus stainless steel or Monel components. FRP was compared to 316L stainless steel for most components because good comparative data was available for 316L SS. In many cases, duplex stainless steel would probably be the material of choice at a slightly different cost differential. The basis for the firewater comparison was a total length of 1,000ft of 6-inch diameter pipe in a "complex" system. The relevant costs were obtained from reference 39. It was assumed that most of the stainless steel piping replaced by FRP would be in the 4-6 inch diameter range with no net installed cost differential.

Since it was determined in Section 6.4 that each ton of weight saved through the use of composite beams cost $2,050, the 60 tons of structural weight saved with composite beams results in a cost increase of $123,000 as shown in Table 40.

Table 40 - ESTIMATED INSTALLED COST DIFFERENTIAL COMPOSITE vs STAINLESS STEEL COMPONENTS: SPS

COMPONENT		COMPOSITE COST DIFFERENTIAL
Piping (complex):	2 inch	+50% vs 316L (39)
	4-6 inch	~0% vs 316L (39,70)
	12 inch	**‹35%›** vs 316L (75)
Fire Water Piping:		**‹$250,000›** vs Monel Sch 10 (39)
Tanks:		**‹$130,000›** (for 5 tanks)
Grating/Stairs/Ladders/Hand Rails:		~0%
Vessels:		**‹$ 65,000›** (low pressure separator)
Floor and Secondary Beams:		+$123,000
Net Cost Differential:		‹$322,000›

Since the installed cost comparison (Table 40) is based on FRP versus a corrosion resistant metal such as stainless steel or Monel except for the secondary structures (grating, etc.) and beams, the composite components are generally less expensive than the metallic part they are replacing. This increases the front end investment savings and reduces the longer term maintenance cost savings because it was assumed that the corrosion resistant metallic components were chosen for their low maintenance requirements over the life of the platform.

It was assumed that the 145.2 tons in topside weight saved would result in a scaled down deck structure and jacket. The deck weight was reduced by 10 tons by using composite beams. This is roughly 10% of the estimated deck savings for the TLP and FPS cases. The topside and deck weight savings total 155.2 tons. With reduced topside equipment weight, it was assumed that smaller derrick barges/boats could be used for installation at a savings of ~$100,000.

For the SPS case, the net investment cost savings (Table 41) total is approximately $732,000, a rather modest amount compared to the TLP case ($25 million). The SPS case has only 10% of the production capacity of the TLP and FPS cases, and is a fixed structure located in shallow water. The savings of $732,000 should be compared to the cost of the topside and deck for the SPS and not the far bigger TLP and FPS.

It should be noted that the installed cost differential for the composite components used on the SPS is actually a positive number in favor of the composites. This results from replacing higher cost (than carbon steel) corrosion resistant metallic components with composite materials. This resulted from the assumption that the SPS would be a minimum maintenance platform to save on operating and maintenance costs over the life of the field. Therefore, the front end savings with composites are far more substantive than the maintenance costs.

Table 41 - NET INVESTMENT COST SAVINGS ESTIMATE CEAC-2005 SPS

Gross Cost Savings-Weight : 155.2 tons x $2,000/ton =	$ 310,000
Construction/Installation Cost Benefit (assumed) :	100,000
Composite Installed Cost Differential :	**- <$322,000>**
Net Cost Savings*:	**$ 732,000***

* This number does not include any savings in life cycle costs (operations and maintenance) plus the economic benefits from enabling capabilities that may be offered by composite materials in special project applications.

Table 42 summarizes the net cost savings by major component. Note that the composite structural beams produce a negative cost savings of $3,000. This results from the fact that each ton of weight saved with composite beams cost $2,050. The 60 (50+10) tons saved multiplied by the $50 differential between the cost ($2,050) of a ton of structural weight saved and the value ($2,000) of saving that ton on a fixed platform produced the negative value of $3,000.

Table 42 - NET COST SAVINGS FOR SPS BY MAJOR COMPONENT

Major Component	Net Cost Savings
Topside Equipment	$635,000
Structural Beams	‹3,000›
Installation (assumed)	100,000
Total	**$732,000**