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ECONOMIC AND ENABLING BENEFITS OF USING COMPOSITES IN ONSHORE OPERATIONS
Phase I

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Forward

This report summarizes the work of a study 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 the CEAC membership. The Onshore Task Group composed of Alex Y. Lou (Phillips Petroleum Company, Chairman), Joie L. Folkers (Ameron Fiberglass Pipe Systems), Bob Moyer (Saudi Arabian Oil Company) and Larry Cagle (Smith Fiberglass Products Company) provided overall guidance to the study. The CEAC employed the services of Seth A. Silverman to assist in conducting the study and Jerry G. Williams (CEAC) participated in the study and edited the final report. CEAC members include: U.S. Department of Energy, U.S. Minerals Management Service, Aker Maritime Inc., Ameron International, Amoco Corporation, BP Exploration Inc., Chevron, Conoco Inc., Phillips Petroleum Company, Saudi Arabian Oil Company, Shell E&P Technology Company, Smith Fiberglass Products Inc., and Strongwell.

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1.0 EXECUTIVE SUMMARY

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 economic and enabling benefits of using fiberglass reinforced plastic (FRP) pipe, tubing, casing, sucker rods and tanks in onshore oilfield production operations. The overall goals of the activity were to: (1) assess the current state of the market demand for FRP products in today's oilfield economic environment; (2) determine the various barriers to expanded use of FRP products; (3) assess the life cycle cost benefits of using FRP products; and, (4) document future requirements of end users and suggest new direction for additional product development.

The study included soliciting oil industry experience by circulating a survey questionnaire on composite product experience to onshore business units of oil companies and selected service and composite product manufacturing companies. The effort considered pipe, tank, and sucker rod applications and looked to identify new application opportunities for composite products. Personal interviews were also conducted with oil company, product manufacturer, and construction company personnel to document successful applications and to identify operational problem areas and opportunities to expand the cost-effective use of composite products onshore. A literature review of papers detailing composite experience was also conducted. A net present value economic assessment tool was developed to help compare the relative life cycle cost of using various material options including FRP pipe.

The study confirmed that there are thousands of miles of successful FRP pipe and other composite products installed throughout the world. Amoco and the Royal Dutch Shell Group appear to be the largest end users of FRP pipe. United States domestic use of FRP line pipe and tubing is estimated at about $60 million compared to a total market of $200 million worldwide. Canada, Mexico and South America have sales of FRP pipe of approximately $20 million, $5 million and $25 million respectively. The emphasis of many of the major oil companies has shifted away from domestic onshore developments toward deep offshore and international projects. However, recent advancements and affordability of 3D seismic and horizontal drilling technology are providing new opportunities for profitable onshore oil and gas development in the United States which may impact the need for more FRP products. Additionally, there is continued expansion of carbon dioxide injection in tertiary recovery projects, particularly in the West Texas area, which could increase the use of FRP products. These two activities along with the replacement of aging infrastructure in mature waterflood fields are seen as the major drivers for growth in the use of FRP pipe onshore in the United States.

The good experiences recorded in the study provide strong economic incentive for oil companies to increase their utilization of FRP products in onshore oil and gas production operations. The material cost of FRP pipe and other products are usually more expensive than carbon steel but are less expensive than corrosion resistant alloys and on the same range of cost as coated carbon steel. The cost differential narrows when installed costs are compared and usually shifts in favor of FRP when life cycle costs are considered. Life cycle cost savings of up to 70 percent, for example, have been recorded for FRP pipe. Clearly, there is economic incentive for oil companies to expand their utilization of FRP products. The net present value spreadsheet developed in this study provides a good tool to help the project engineer evaluate alternative material systems.

1.1 Primary Findings

The use of FRP pipe for flowlines and injection lines has proven to be cost-effective in onshore operations. The life cycle net present value tool developed in this study is available to help operators select the most cost-effective materials system for future field developments.

A synopsis of the main findings of the study is presented below.

(a) Current primary applications for FRP line pipe include small diameter (≤ 4 in.) lines used for hydrocarbon gathering and water injection distribution lines. High-pressure water injection lines are generally less than 6-in. diameter operating at less than 2000 psi and temperatures less than 200°F. Current demand for low pressure lines (> 500 psi) tend to be in larger sizes (6 inch to 10 inch) to permit greater through-put of produced fluids in maturing water floods.

(b) FRP line pipe products can provide reductions in life cycle costs of up to 70% compared to steel. Payout for projects vary, however, one engineering contractor estimated that they save 35-50% routinely using FRP products rather than steel for selected piping applications. The high cost-savings available should serve as an incentive to the growth of FRP pipe in onshore operations.

(c) One major end user cites future needs that include lines to transport corrosive oil and gas at temperatures that could approach 200°C (392°F) for gas pressures up to about 600 psi and crude lines for pressures up to 1160 psi. If composites are to be used, these high temperature applications will require advanced resin systems. Water injection lines are required for pressures up to 3050 psi and supercritical CO_2 service lines are required for WAG applications. Six, eight and ten-inch lines with pressure ratings as high as 5000 psi are needed. Ameron recently introduced a higher-pressure (5400 psi) pipe based on reinforcing fiberglass pipe with circumferentially wound steel strips.

(d) Liner technology is expanding to fill the higher temperature-pressure envelope. Polyamide (PA) liners are being used for service in the 80-90°C (176-194°F) range and PVDF liners are planned for use at 130°C (266°F) in high-pressure applications. These materials expand the use of HDPE which is limited to 40-65°C (104-149°F). Ameron has a product in development that will utilize a liner in conjunction with FRP pipe to reduce or eliminate the buildup of paraffin and to provide improved erosion and abrasion resistance.

(e) Operator comments indicate most field failures are a consequence of mechanical damage, inadequate design and support of the piping system, or improper installation procedures.

(f) FRP casing and other downhhole applications have been limited. The total market for casing is approximately $329,000,000 of which only $2,00,000 (less than 1%) is currently FRP. However, applications exist where use of slimhole FRP casing have resulted in millions of dollars of savings in recompletion of old water injection wells for carbon dioxide service. New running techniques and improved hanger/packers have been developed to facilitate this process. FRP casing and liners can be an economic choice when compared to CRA's for this application.

(g) The down hole tubular market in corrosive service is more than $436,000,000. Of this market, FRP down hole tubing currently represents approximately $5,000,000, which is approximately 2.5 % of total fiberglass tubular sales. Resolution and publication of an API specification for fiberglass tubing would help expand this specialty application of FRP pipe. The expected availability in the near future of low cost carbon fiber might also provide improved performance at affordable cost.

(h) FRP sucker rod use in some applications has exhibited a relatively short economic pay-back period. One major oil company estimates that 10-15% of its sucker rod purchases are FRP products. The composite rods are primarily used to reduce the loads on gearboxes on high fluid level wells and high water volume wells. Lowering the fluid level in the annulus allows for more effective corrosion inhibition treatments and generally results in an increase in production of oil. Lowering the economic limit allows additional reserves to be produced on marginal wells. FRP sucker rods have been run successfully on wells with a total depth as great as 12,500 ft.

(i) A barrier to the expanded use of FRP products in U.S. onshore oilfields appears to be the lack of adequately trained personnel to design FRP systems. This, in part, is due to the turnover and downsizing of technical staff in the industry over the last ten years. Younger staff members have not had much, if any, exposure to composite materials. For the companies surveyed in this study, many reported that engineering design firms may not have a composites expert in house to perform detailed engineering. The development of a training course for facilities and production engineers, and installation contractors is needed and could be offered by CEAC as an engineering service. This would increase exposure of many engineers to the use of composite materials both inside and outside the oil companies.

1.2 New and Improved FRP Products for Onshore Operations

Several new products are under development or have been recently introduced by manufacturers of FRP products. Some of these new products are initially targeted for the offshore petroleum or chemical industries, but could also provide cost effective benefits for onshore petroleum production operations. In addition, the study identified new application areas where composite products are needed to provide enabling capabilities or to extend the operating temperature and pressure ranges. These opportunities for new and improved products are outlined below and discussed in greater detail in the body of the report.

(a) SSL-FRP Piping

High pressure, larger diameter piping products called steel strip laminate (SSL-FRP) pipe is being developed by Ameron.[1] Products are available in sizes of 8 in. and higher with operating pressures in the range 140-350 bar (2030-5075 psi). The temperature envelope is expected to be -40°C to 110°C (-40°F to 230°F). This product could greatly expand the envelope of use for large diameter FRP systems.

(b) Fire Resistant FRP Pipe

Ameron has developed a fire resistant pipe called Bondstrand PSX, which is based on a polysiloxane phenolic resin[2]. The phenolic resole resin system has been modified with polysiloxane to enhance the fire and mechanical performance properties. Bondstrand PSX pipe, fittings and adhesives have been tested and certified by third party laboratories to verify performance against flame spread and heat, smoke and toxic fume generation. These products have received IMO Level 3 fire resistance acceptance by the United State Coast Guard. This system is for use with operating pressures less than 225 psi and is primarily aimed at use in fire water and utility systems where fire resistant piping with low smoke emissions and low toxicity are required.

(c) Dual Containment Piping System

Ameron has developed the concept of coaxial piping and fittings to address the use of FRP pipe for containment applications. Mechanical properties of this type of piping system are better than single wall FRP pipe due to the higher stiffness of the coaxial system. The cost of the coaxial system is expected to be less than a pipe-in-pipe system. The fittings are more compact than traditional pipe in a dual wall system. Impact resistance testing has shown a 400% increase in energy required to cause failure in the pipe.

(d) RTP (Reinforced Thermoplastic Pipe)

Reinforced HDPE pipe (RTP) has been developed by Tubes d'Aquitane[3] for service in corrosive hydrocarbon and gas service up to 2175 psi and 60°C. RTP consists of three layers: a primary HDPE tube, several crossed layers of Aramid yarns coated with HDPE, and a layer of HDPE for external protection. Hydraulic throughput is claimed to be enhanced due to the lower coefficient of friction of the smooth inner wall. Rapid installation is possible via screwed or flanged connections. For smaller sizes the pipe can be reeled. Several major oil companies are testing this material, including British Gas, Saudi Aramco, and PDO (Shell Oman).

(e) Chemically Resistant Resins

Smith Fiberglass has introduced a new FRP piping system (Z-CORE) developed with a proprietary resin system for aggressive solvent and acid applications including chemicals such as fluorobenzene, dichloroethane, chloroform and 98% sulfuric acid. The pipe is rated for 150 psig and 275°F in sizes 2 in. through 6-in. diameters. Applications for the onshore market might include drilling and workover rigs handling aggressive acids and solvents. There may be niche applications onshore for storage of certain acidic organic chemicals used in the field. Smith Fiberglass is also developing a new FRP pipe based on polydicyclopentadiene (DCPD) resin which is highly resistant to degradation from aggressive chemical and to damage from impact[4].

(f) Spoolable Pipe

The response to the survey indicated a strong interest in spoolable composite piping for flowlines and injection lines. Use of these systems would reduce the number of connections and decrease installation time significantly. There are currently at least five companies involved in the development of spoolable composite products, ProFlex[5], Tubes d' Aquitaine[3], Fiberspar[6], Hydril[7] and Compipe[8]. ProFlex piping is reportedly in use by 20 Canadian producers for applications in sour water injection risers. Compipe in Norway is developing spoolable pipelines for sub-sea chemical injection and flowlines. Arco recently conducted tests in Alaska using a section of Fiberspar spoolable pipe as a flowline. The product made by Tubes d'Aquitaine consists of an inner thermoplastic liner over which is wrapped several layers of thermoplastic prepreg tape.

(g) Cryogenic Fracturing

A new method of fracturing oil bearing formations has been developed based on shocking the formation with liquid nitrogen. At liquid nitrogen temperatures, steel pipe becomes brittle and may fracture. The glass transition temperature of epoxy resins used in making FRP pipe for the oil field is in excess of 200°F. Therefore, during use, the epoxy polymer is in the glassy state and changes little in brittleness at temperatures below the glass transition temperature whether at room temperature (70°F) or at the temperature of liquid nitrogen (-321°F). Glass fibers are not affected by the low temperature. FRP pipe has been used successfully in field tests as tubing to transport liquid nitrogen downhole. For the length of time required, the low thermal conductivity of FRP pipe serves to protect the casing against potentially damaging low temperatures. The use of FRP pipe should also be appropriate for increased use in arctic production operations.

(h) Reelable Casing and Pipe Liner Products0

Composite products are under development which are initially fabricated in long lengths with an unpolymerized resin and placed on a spool for transport. The products called Casing-Flex and Flextube are installed in a well or pipeline to repair defective casing or line pipe. The tube is pressurized and the resin is cured insitu.

(i) Higher Temperature and Pressure Capability

FRP pipe capable of operating at higher pressures and temperatures is needed. One company requested composite piping for gas flow lines up to 600 psi and crude oil lines up to 1200 psi operating at temperatures approaching 200°C. Resin systems capable of operating in this temperature range are currently available, but the cost would be significantly higher than currently used epoxies. The market for high temperature pipe should be assessed to see if the need would support the price required for products.

(j) Super-critical CO_2

A need exists for an FRP pipe capable of transporting CO_2 at super-critical temperature and pressure. FRP pipe with alternative resin materials are currently being evaluated in field tests.

(k) FRP Tanks Incorporating Carbon Fiber

The use of FRP tanks in production operations has been eliminated by several oil companies because of safety concerns related to presumed hazards associated with lightning strike and static charge initiated fires. In response, FRP tank manufacturers are introducing carbon fibers and other conductive materials into the body of the tank to help dissipate static charge build-up and mitigate the risk. The effectiveness of this approach, however, is not established and there is need for criteria and specifications to set the requirements.

1.3 Recommendations for Additional Activity

The results of the study indicate that there are several new products coming into the market which could provide significant benefit to the onshore petroleum industry. The onshore petroleum industry normally is willing to try new products, but provides very little direct support for technology advancement or new product development. CEAC could serve as a catalyst to encourage the introduction of new products into onshore applications and to address technology deficiencies to ensure safe reliable service. Listed below are several composites areas related to onshore applications where the CEAC could engage in a role of technology advancement. CEAC could also provide a strong role in training by providing short courses and software targeted for field facilities engineers and installation contractors.

(a) Carbon Fiber Sucker Rods

The proper use of FRP sucker rods has been shown to be a cost-effective way to increase oil production for certain types of wells such as those with high fluid levels requiring more efficient pumping. When this situation exists, the capital cost of installing composite sucker rods can be returned very quickly. One area where CEAC could provide a service is to develop a guide for users which could include software to help assess the economic merit of using composite sucker rods and to design their installation and tuning to achieve efficient pumping.

Spoolable carbon sucker rods should also be evaluated for improved performance. If the cost of large tow and pitch carbon fiber is reduced as promised, then spoolable carbon sucker rods will become competitive for a larger class of wells. In addition, there should be a significant cost benefit of using a reel method to pull the sucker rod string during well workovers.

(b) Tanks Designed for Static Charge

Most major oil companies are not taking advantage of the corrosion resistant advantages of FRP tanks because of concerns for static charge and lightning strike potential hazards. Tank manufacturers are trying to address the problem by incorporating conductive materials including carbon fiber into the tank body. There is a general lack of understanding of how to design tanks to address the static charge issues or specifications to define what is adequate. CEAC could conduct a study to scope the problem, develop specifications to insure sound principles were employed in providing protection and recommend test methods to evaluate compliance with the standards.

(c) Pressure Vessels

There appears to be an opportunity to use composites in low pressure vessels such as free water knockout vessels. Many thousands of these vessels are in service and corrosion imposes a high cost for maintenance. CEAC could initiate a project to investigate the opportunity to use composites for low pressure vessels and if the need was sufficient, work with suppliers to encourage the development of products.

(d) Spoolable Pipe

Spoolable pipe products will be available in the near future and it appears that there could be a number of applications in the onshore industry in addition to targeted coiled tubing and offshore applications. Such applications might include oil and gas line pipe, water and CO_2 injection lines, and capillary tubes. CEAC could accelerate the pace of introduction of these applications by working with oil companies and manufacturers to establish programs to evaluate the applications and develop the required supporting technology for product acceptance.

(e) FRP Cold Temperature Applications

FRP pipe has significant opportunity to see greater utilization in cold temperature applications ranging from arctic region operations to transporting cryogenic fluids downhole. Specific application opportunities should be explored and analyses and tests conducted to better define the limitations and safe operating parameters.

(f) Downhole Tubing Specification

The API has struggled for years to prepare a specification for FRP tubing. An accelerated test is needed which accurately predicts long term performance. In addition, analytical methods are required to reliably predict long term performance and thereby reduce the high expense of qualifying products. The ability to predict failure and understanding long term performance issues was demonstrated by the University of Houston in a recent study conducted for API. These methods and related technologies could be directed toward developing a methodology to predict long term performance of FRP tubing subjected to loads and temperatures typically applied in downhole tubing applications.

(g) Training

The study indicated a strong need for training courses to address the practical aspects of design and installation of FRP pipe, tanks, vessels, sucker rods and other products. An important part of training should be to provide the participants with user friendly tools such as handbooks and software to prepare them to size products and design engineering systems. Life cycle cost assessment tools such as developed in this study should also prove useful to help the designer make cost-effective choices from the available options. CEAC in conjunction with industry partners is ideally positioned to contribute to training activities.

2.0 INTRODUCTION

Fiberglass reinforced plastic (FRP) piping systems have been in use for over thirty years. The largest growth period for FRP products in the United States was during the late 1960's through the early 1980's when U.S. oil companies began large salt water injection projects. Corrosion resistant FRP pipe in 3 in. and 4 in. sizes were used for injection lines. FRP products were qualified for use in large carbon dioxide projects that further enhanced the application of the material.

Installations of FRP products in the United States reached a peak in 1981, remained at a high level until 1986, and then began to drop as production from U.S. oilfields declined predominantly because the price of oil fell to about $8.50/bbl. Worldwide, the oilfield use of FRP products continues to increase ($200 million market estimated) as the price of oil has stabilized and investment in foreign projects has increased. A better awareness of the technical capabilities and life cycle economic benefits of FRP products should lead to greater use by U. S. domestic oil companies ($60 million market estimated).

The purpose of this study was to evaluate the opportunity for FRP products to provide economic benefit to onshore petroleum production operations and to define new and to expand existing applications where the use of FRP products would provide advantages. Applications considered included line pipe, tubing, casing, tanks and vessels, and sucker rods. New products such as spoolable pipe and other emerging technologies were also reviewed for possible onshore applications.

3.0 CURRENT APPLICATIONS EXPERIENCE

One of the approaches to obtain information was to interview oil companies, FRP product manufacturers, and engineering & construction firms to determine their experiences and define their current needs. In addition a questionnaire was circulated to obtain more detailed information. The companies contacted were located in Houston and Midland, Texas. Additional information was gathered from the literature. The most comprehensive database on FRP identified was by Brouwer,[9] however, most of the information is proprietary. None of the companies interviewed have anyone responsible for tracking FRP product installations in a corporate database. Presented below is a summary of current applications and field experiences with FRP products.

3.1 Line Pipe

3.1.1 Competitive Materials Commonly in Use

R. Franco[10] summarized Exxon's experience with piping for produced water applications. The table below lists common engineering materials used for produced water applications and their estimated life.

MATERIAL	YEARS IN SERVICE	ESTIMATED LIFE*
FRP Pipe	15(successful)	20
HDPE Lining	15(successful)	25
Cement Lining	20(leaking joints)	20 with repairs
Shop Applied Coatings		
- Downhole Type	Many (with leaks)	5-7
- Flexible Type	3 (successful)	10-12
Bare Steel	Many (with leaks)	< 5

* Time onset of significant maintenance costs when replacement is needed.

3.1.2 Review of FRP Line Pipe Current Applications

The survey results indicated most current FRP applications are small diameter low pressure pipe in water flood service. High-pressure applications are mostly water transfer lines or injection lines less than 6 in. diameter. A review of some of the available literature is summarized in this section.

Brouwer[9] (Shell) conducted a thorough review of non-metallic piping materials in oilfield use throughout the Royal Dutch Shell organization. The Shell Group has over 2250 km (1395 miles or 7.4 million ft) of FRP piping materials in service in over 524 projects around the world. Figures 1 and 2 show the distribution of GRP in various operating units. Most applications are 2, 4 and 6 in. diameters with design pressures from 10-25 bar, however, there has been a shift in recent years to use larger sizes in the 8 and 16 in. diameter range. Recently, there was an installation in Oman of 45 km of 12 to 20 inch diameter pipe involving 3750 adhesive bonded joints with no leaks following the installation.

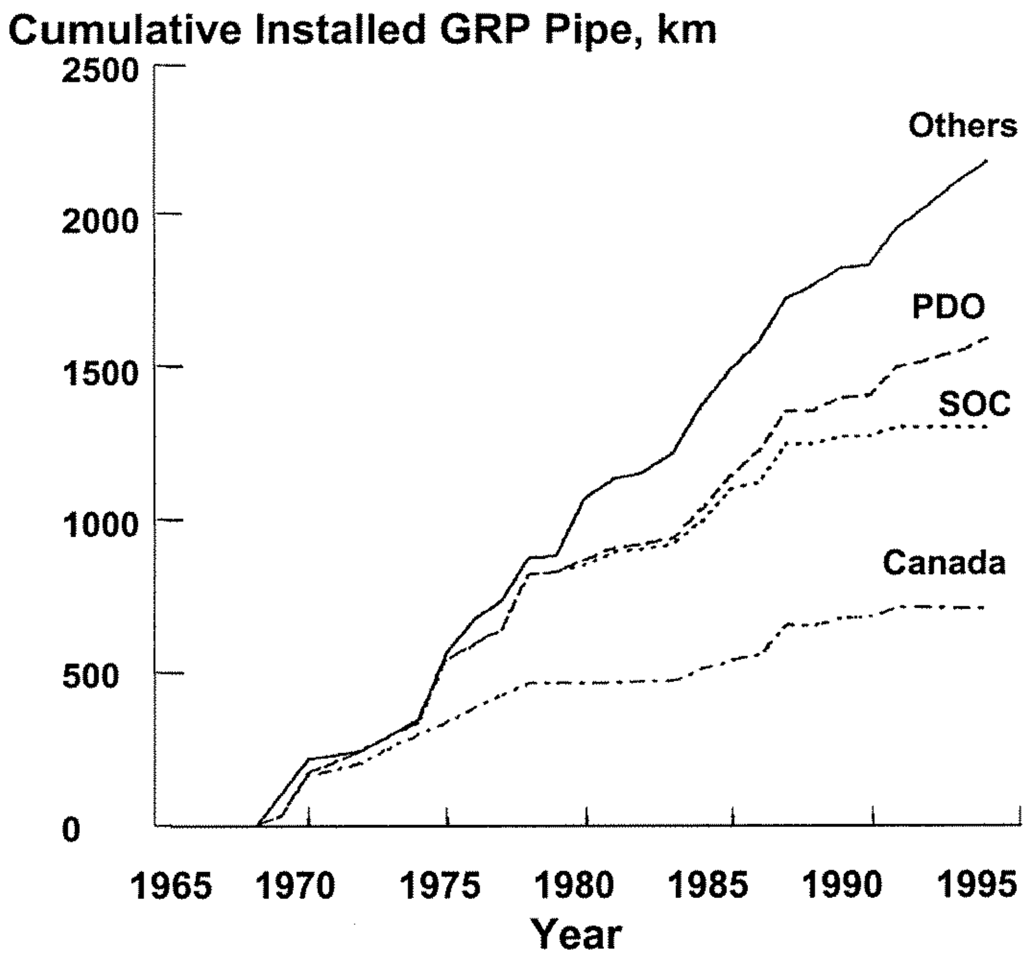


Figure 1. - Cumulative number of kilometers of GRE pipe installed by Shell Operating Companies.[9]

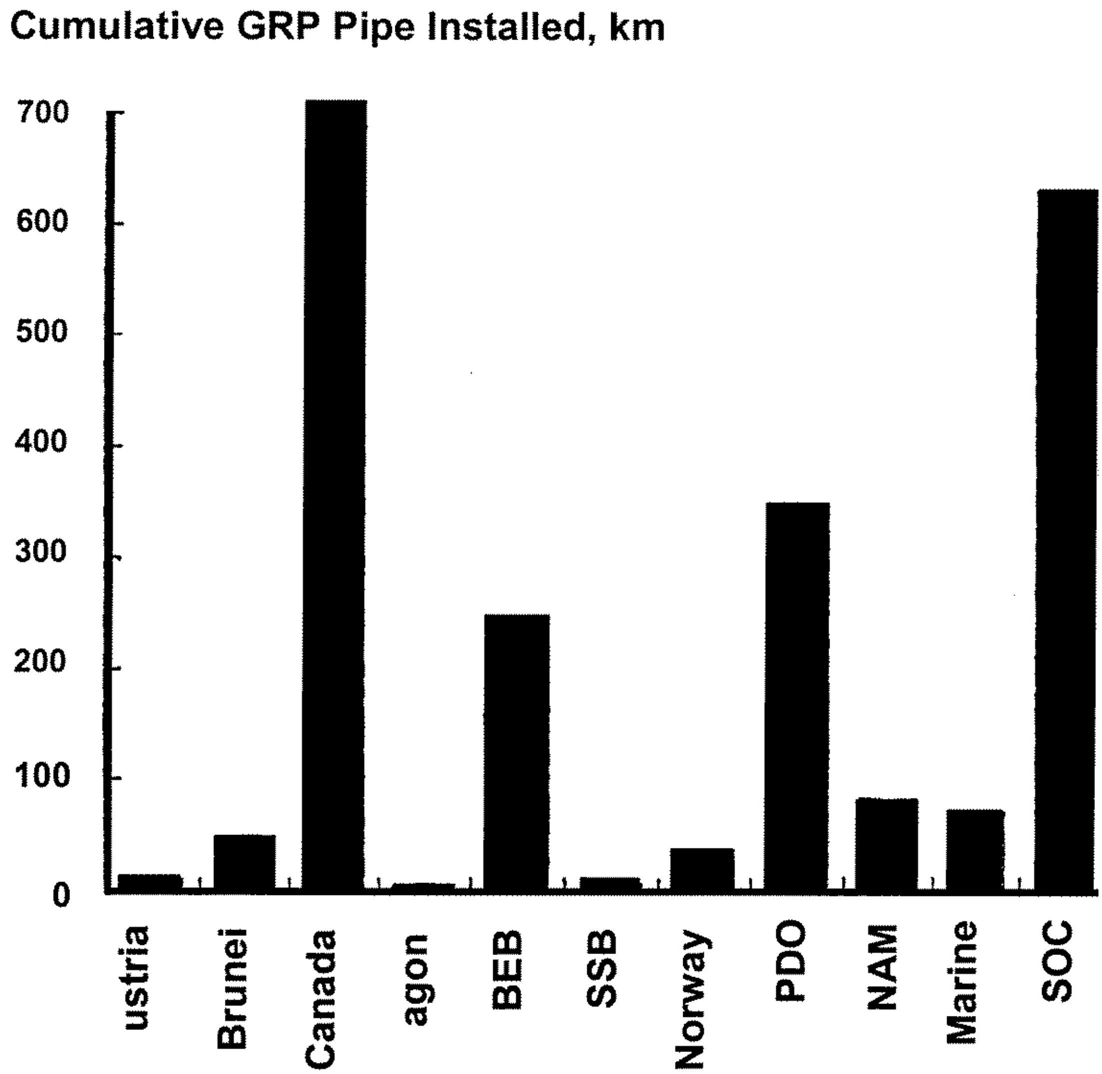


Figure 2. - Installed length of GRE pipe in Shell E&P Operating Companies.[9]

Operating Envelope of Pressure and Diameter

Figure 3 taken from reference 9 shows the operating range of carbon steel, carbon steel with thermoplastic liners, FRP, and potential of SSL-FRP (steel strip laminate FRP - in development by Ameron) in use by Royal Dutch. Note that GRE (glass reinforced epoxy) is a term frequently used by the European community and is synonymous with FRP pipe.

The operating envelope of carbon steel with liners is approximately equivalent to the envelope of carbon steel. In 1993, experience with liners was limited to 20 in. or less. and used HDPE for the liner material. This limits the operating temperature to 40°C or 65°C dependent on service (hydrocarbon vs. salt water). Application of PA or PVDF liners raises the allowable temperature to approximately 80/90° C or 130°C.

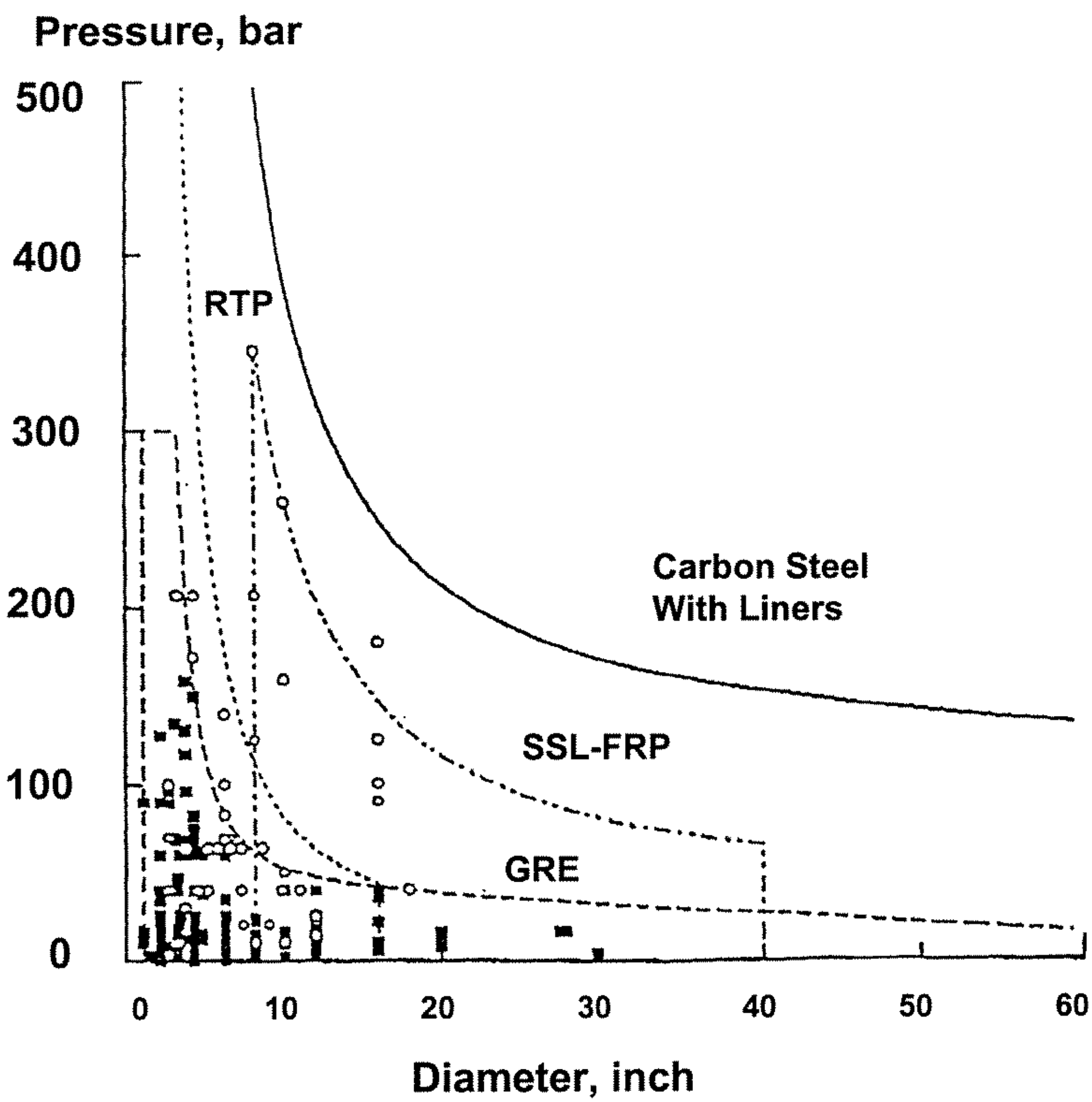


Figure 3. - Operating envelopes of carbon steel, GRE, lined carbon steel pipe, Steel Strip Laminate (SSL-FRP) and Reinforced Thermoplastic Pipe (RTP) pipe systems.

Robbe[11] (Shell) summarized applications in the Shell Groups worldwide as of 1990 and discusses future trends. For E&P applications, highest pressure used was up to 95 bar (1400 psi) and maximum temperature of 100°C. Most applications were water handling, and 37% of piping was used for high water cut hydrocarbon flowlines. A number of specific applications listed are included in the database for this project. Future developments need non-metallic piping for gas flow lines up to 40 bar and crude oil lines up to 80 bar at temperatures approaching 200°C. Current FRP products have resin systems that cannot resist the highest temperatures indicated as needed by Robbe. There is also a need for water injection lines at pressures up to 210 bar and for CO_2 injection lines.

Folkers[12] (Ameron) discussed the use of siloxane modified phenolic resin to produce fiberglass pipe and downhole products for steam floods, refineries, casing and well screens for use up to 300°F (150°C). Phenolic piping in steam floods has been identified as a high potential market. Short term tests were conducted on 2 in. modified and unmodified pipe to 50 psi steam (297°F) for periods up to 63 days. The siloxane modification to the resin stabilized the decay of short-term burst strength to essentially zero. To improve impact resistance, thermoplastic layers can be added on the outside of the pipe.

The Bondstrand PSX system addresses fire safety issues. DNV, Southwest Research Institute and SINTEF have certified the pipe and fittings for superior performance against flame spread, heat, smoke and toxic fume generation. IMO Level 3 fire resistance approval has been obtained from the USCG. Pipe is available in 1 thru 12 in. sizes and can be made in 14 and 16 inches, if required. Pressure rating is set at 225 psi for pipe and fittings.

Tolhoek (Ameron) presented data in reference 13 for high pressure FRP line pipe applications around the world. This information is included in the applications database (Appendix C). Range of sizes include 4 in. to 24 in. (10 to 60 cm), pressure from 28-75 bar (400-1090 psi), and temperatures to 120°C. Process fluids were crude oil, injection water and in one case geothermal reinjection.

3.1.3 Failure Causes

Most of the recent failures of FRP pipe have been due primarily to mechanical damage or improper installation practices. Franco[10] discussed the main causes of failures within the Exxon group of companies and categorized them as follows:

1. Rough handling.
2. Improper make-up procedure.
3. Inadequate support of above ground piping.
4. Inadequate installation.
5. Steel pin in FRP box- thread leaks associated with lower hoop modulus of elasticity of FRP box.
6. Soil erosion leading to poor pipe support.

Chemical degradation was deemed not to be a major factor in failures. Unlined aromatic epoxy has given 25 year life for flowlines in sour oil brine rod pumped wells. UV degradation has been observed on above-ground piping, but is normally limited to a thin layer near the surface and does not appear to cause any significant strength degradation.

A major oil company encountered problems on an installation in the Rocky Mountain area. Problems occurred on a 16-in. trunkline that was adhesive bonded FRP line pipe. The ends of the pipe were shaved prior to bonding and left exposed to sunlight for an extended time. The bonded joints did not develop adequate strength and the line failed the hydrotest. The manufacturer covered the cost of cutting the ends and rejoining each pipe with a butt end and wrap procedure. Despite the initial installation problems, the repaired line has been in gas gathering service with 90% CO_2 for about 10 years with no known operational problems.

One major oil company has recently experienced failures of 4-inch high pressure (2500 psi) FRP water injection lines installed in 1992. In February 1997, failures of API 8 round coupling occurred at numerous locations. The majority of the failures were on the field make up side of the couplings. The normal operating pressure was 2200 psig. The system is being replaced with HDPE lined steel pipe. The failure of this system may have resulted from a number of different factors. Due to the system design, pressure surges of up to 2900 psi were possible and occurred from time to time and may have contributed to the thread leakage problems. Limiting the pressure surges on start up by use of throttling valve would have decreased the cyclic stresses on this piping system. There were also other suspect installation problems related to the proper use and make up of Teflon® tape and qualified thread lube for the intended service requirement. Recent improvements in thread sealant are dramatically improving the leak problem. Smith markets a product called Hi Pro® based on a polymeric formulation and Teflon® which sets up to form an elastomeric seal along the entire length of the thread.

The API 8 round thread has been used successfully in small diameter pipes both steel and FRP for many years, however, the service record for larger diameter FRP pipes (4" to 8") has sometimes presented problems as evidenced by the experience described above. The small thread is difficult to align and easy to cross-thread in larger sizes. Under high pressure, the damaged thread is prone to leak and the coupling erodes due to the abrasive agitation of sand and soil. Larger more robust threads are available from manufacturers and should be seriously considered when making design decisions for larger diameter pipe sizes.

Many of the failures reported by the Royal Dutch Shell group[11] have been the result of system design errors or poor installations. The main areas of concern are leaking joints, insufficient support, overstressing pipe during installation and expansion problems. With proper installation and materials selection, a maintenance free life of 20 plus years can be expected.

3.1.4 Incentive Pay Improves Probability of Successful Installation

One oil company has devised an innovative incentive contract to improve the quality of FRP pipe installations. Workers are rewarded bonuses for achieving defined milestones. Member of the team are given monetary incentives for reaching safety and environmental goals, good housekeeping and finishing tasks within a specified period of time. This type of contract has proven to be very successful in improving the overall quality of the job resulting in an almost zero start-up failure rate.

3.1.5 Erosion Resistance of FRP Systems

FRP product manufacturer's currently limit liquid velocity to less than 25 ft/sec for low-pressure applications due to erosion concerns. Lindheim's[14] (SINTEF) study was an effort to quantify erosion and cavitation effects in FRP piping for a number of resin systems compared to 6Mo steel and titanium. FRP pipe generally showed higher erosion rates than 6Mo steel and titanium. The erosion resistance of HD polyethylene and polypropylene was comparable to or better than other metals or FRP pipe. The test results ranked the materials the same for erosion by slurry impingement and for cavitation.

The matrix material was the controlling factor governing erosion resistance. Epoxy performed better than vinyl ester or polyester. It was concluded that erosion resistance was improved by toughness at high strain rates, good fiber matrix adhesion, a resin rich liner which was well adhered to the structural layer and reinforced with a fine surface veil layer. The laminate should have low pore content and a high volume fraction of fibers well bonded to the matrix. Readers interested in this topic will find details of test data and techniques used in the manuscript[14].

The U.S. Navy has tested the erosion resistance of 2 in. nominal diameter FRP pipe in flowing seawater compared to 90/10 and 70/30 Cu Ni piping[15]. No erosion was evident after one year of exposure to seawater flows of 11 and 17 ft/sec and after three months of exposure to seawater at 25 ft/sec. Air saturated seawater jet-impingement produced no erosion damage after 60 days. In comparison, similar tests with both CuNi alloys did show erosion damage. Composite pipe is subject to fouling, but it is much more resistant to chlorination treatments typically used to remove fowling.

3.2 Downhole Tubing and Casing

FRP downhole tubing has been available for as long as FRP line pipe, but has not reached the same degree of utilization. There is considerable industry literature indicating that FRP tubing can be handled and made up using traditional equipment with minor modifications. Information readily available indicates that one can hang FRP in the well, log through it, drill through it, mill it and perform almost all of the operations common to oil and gas wells. FRP tubing is available in both threaded and coupled and integral joint configurations from suppliers who provide line pipe.

The corrosion resistance and light weight of FRP tubing make it a good candidate material for corrosive environment applications as brine disposal [CLASS II] wells, completion of wells with corrosive fluids and similar applications. However, FRP tubing has not been successful in claiming a significant portion of the downhole tubing market. This may, in part, be due to the very low price for J-55 steel tubing following the lower demand associated with the oil collapse in 1986. The price of J-55 steel tubing has increased about 32% since December 1995 and orders for FRP tubing have increased accordingly.

Industry acceptance of FRP tubing has not been universally achieved because of the following industry perceptions. One concern is that FRP threads are subject to rapid wear as the result of normal make and break. The perceived field service life of FRP downhole tubing is 5 to 10 years primarily because of pin thread wear. Early applications of FRP tubing experienced failure during retrieval operations as the pipe tended to seize and was unable to take the high torque required to break apart the connections. At least two manufacturers have developed products that are intended to resolve this issue and improved performance is reported from the field.

FRP tubing has been successfully used in the chemical industry in wells up to 10,400 feet deep, with bottom hole temperatures of 240^0F. In these CLASS I applications, the tubing is subjected to a well integrity test every 12 months.

FRP pipe has been successfully used in recent years to repair corroded casing. In this application, tubing with minimal collar upset is inserted inside the corroded and leaking steel pipe and smaller diameter tubing is placed inside the larger diameter FRP casing.

3.2.1 Survey Results

None of the major oil companies that responded to the survey use downhole FRP tubing or casing to any great extent. Arco uses some FRP tubing in water injection wells. The survey indicates that the barriers to use are largely due to the fact that special tools and handling procedures must be used, and special hangers or wellhead equipment must be specified. The initial cost of an FRP string is generally twice the cost of carbon steel. Plastic coated carbon steel and Rice Duoline or ICO Permian tubing are about 1.1 to 1.15 times the cost of carbon steel. The high initial cost is a deterrent to FRP use, even though over the life of the wells, a significant payout is possible as shown in case studies in this report.

A survey was conducted by Shell Oil in 1990 concerning the lack of use of down-hole products within the Shell divisions. The major technical limitations for down-hole products were considered to be (1) connection reliability, (2) resin performance at elevated temperatures (>180F) and, (3) high quality assurance standards and installation guidelines.

Practical problems cited with running, handling and operating with FRP tubulars and casing include: (1) lack of consistency in dimensions and pressure ratings between vendors, (2) finding qualified personnel to install product, (3) obtaining proper running tools (i.e., elevator slips, BOP rams crushing FRP joints and, (4) fishing parted tubing or casing, and (5) perforating improperly cemented casing which shatters the FRP pipe. At least one manufacturer provides hand tools free of charge, when running their FRP tubing.

The research needs cited in 1990 were: (1) FRP tubular for higher temperature applications, (2) improved reliability of connections, (3) increased tensile strength of pipe, (3) development of higher performance properties (e.g. hoop stress and axial stress) in different environmental conditions, (4) development of a new generation of FRP tubular with performance characteristics closer to that of J-55 tubing, and (5) quality control test methods.

3.2.2 Literature Case Histories - Successful Installations

Arian[16] (Fiber Glass Systems) tested aliphatic amine tubular with supercritical CO_2 at 2300 psi and 120°F under cyclic and static conditions. No visual damage was noted, however, there may be internal damage caused by the pressure generated by carbon dioxide trapped in microvoids in the laminate. Expansion of the trapped CO_2 would occur during the water injection phase of the WAG cycle. The injection water temperature and bottom hole temperature are critical process parameters. A damage model developed by Arian based on test data from the study predicts at higher temperatures (>175°F), damage effects gets progressively worse. No visual indication of delamination were observed when specimens were subjected to temperatures below 150°F. The data suggests CO_2 penetrates very slowly into aliphatic amine cured resin laminates. After six months of cyclic and static tests, the maximum penetration of tubulars was estimated at less than 0.016".

Samples of tubulars from a well site in Colorado were also examined. The 2 7/8 inch diameter

FRP tubing was in WAG service at a bottom hole depth of 6500 ft. Operating pressure was 2100 psi and the maximum temperature was 160°F. The retrieved samples showed no signs of microcracks or delamination after 6 years of service, including 3 years of WAG.

Bass and Maddux[17] (Oryx) highlight the successful use of FRP 2 3/8 in. tubing in a high water rate gas well in the Nome field, East Texas. The production parameters were 5.1 psi CO_2, 574 BWPD, 27 BPD condensate, 800 MCF gas with a FTP of 1400 psi. An aromatic amine cured resin was used for the 7750 ft string of tubing. The connections were 8 round EUE threads with 4 1/4 in. O.D. box. The tubing had a 2500 psi pressure rating. Down-hole temperature was 82°C (180°F) with a 3300 psi bottom hole pressure.

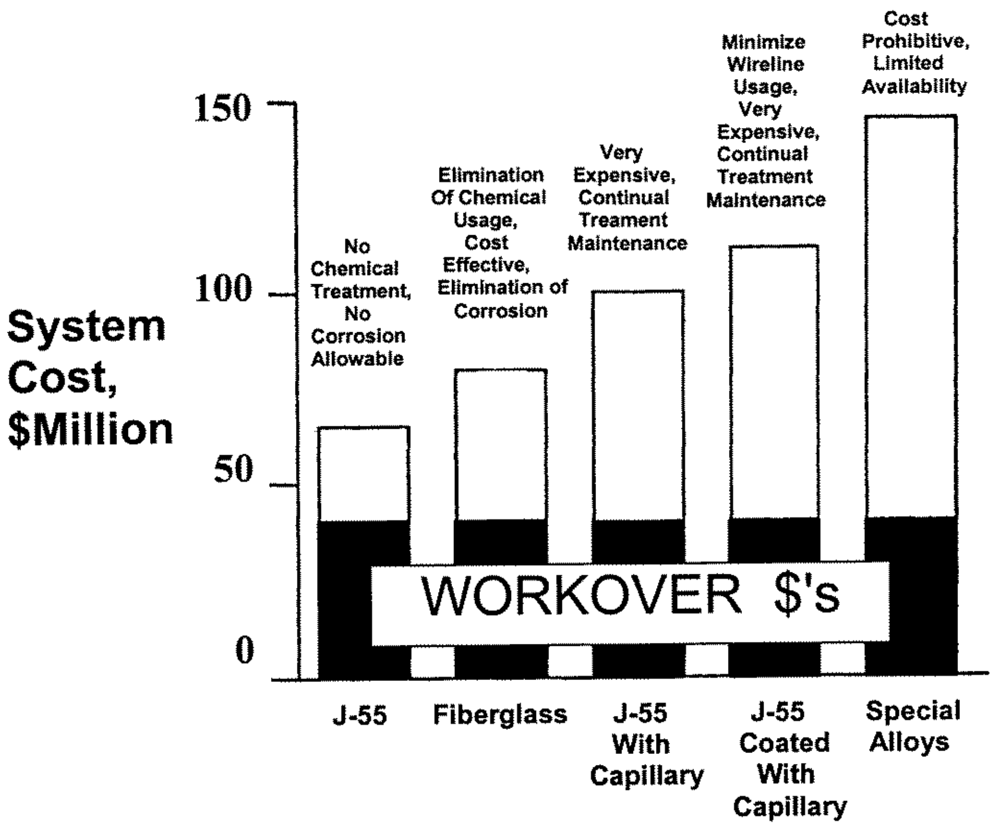
FRP tubing was selected over carbon steel and various coated alternatives due to the NPV analysis done by the authors.[17] FRP tubing was twice the initial cost for carbon steel J-55 and there was $8000 extra installation expense. The payout for the FRP installation was seven months versus a bare J-55 alternative. Over the two year well life, an estimated $25,000 was saved. The well depleted during this time. The economic evaluation for the project is shown in Figure 4. Post-evaluation of the FRP pipe was performed and little deterioration was evident.

Thorness[18] (Baker Oil Tools) discussed the application of a new hanger system for use in the Slaughter field in a West Texas CO_2 injection project. The special hanger tool was developed to support FRP liners in CO_2 injection wells. Aromatic amine was the resin chosen for the 2000 psi rated FRP liner. The wellbores were projected to produce for an additional 15-20 years. A short life (2-3 years) was predicted for steel liners and running a CRA liner was considered uneconomical. FRP liners 2 7/8 in. or 3 1/2 in. in diameter were installed in casing sizes ranging from 5 1/2 in. to 6 5/8 in. without problem. The project experienced a significant economic benefit with rapid pay back.

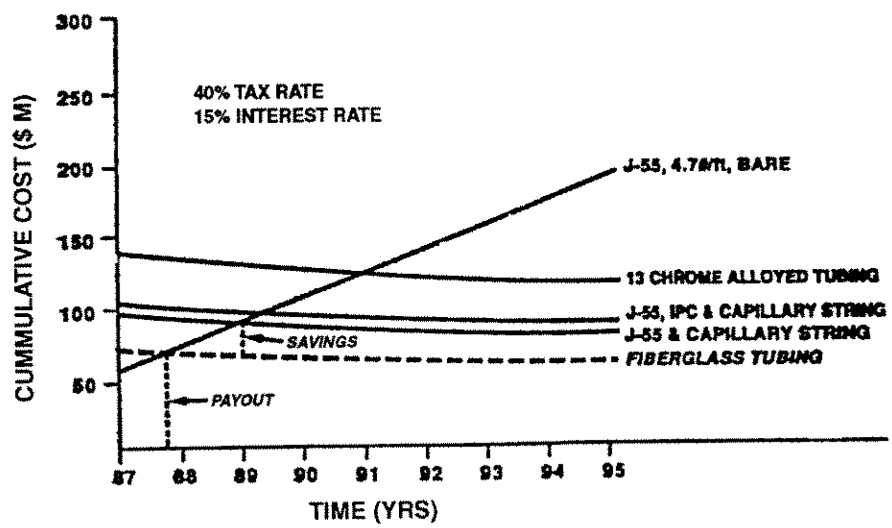
Lacy[19] (Conoco) describes a successful program to install slimline FRP casing in 30 year old water injection wells. A drillable permanent packer was used as the liner hanger and injection packer. The use of FRP casing provided the ability to re-enter the wellbore at a later time by drilling out the packer and removing the FRP liner. The injection wells had poor casing integrity due to corrosion and the small diameter steel casing limited the size FRP casing which could be deployed. A majority of wells had 4 1/2 in. O.D. and in some cases 5 1/2 in. O.D. casing. Redrilling the replacement wells was estimated at $14 million. Each of the recompletions represented savings of $275,000/well compared to drilling new wells. Slaton[20] provided additional details concerning this FRP slimline casing project.

Mobil installed Smith Red Thread Performance Plus product rated for 450 psi static, 300 psi cyclic in a sour gas gathering system (1000-3000 ppm H_2S) in sizes ranging from 10 in. for laterals to 12 in. and 16 in. for main lines. The operating pressure was 275-300 psig at 90-100°F. A matched tapered, adhesive bonded coupling was used to join the FRP pipe.

Unreinforced polyethylene liners (Driscopipe) were installed in 40 wells at Amoco's Bravo Dome carbon dioxide unit in New Mexico.[21] The installation process leaves the liner tightly wedged



(a) Cost Evaluation.



(b) Economics (Payout and Cost Savings).

Figure 4. - Economics of FRP tubing compared to J-55 steel and inhibition (Copyright NACE International 1990 Reprinted with Permission).

against the well's casing. FRP pipe was replaced by the smaller diameter HDPE liner to provide a greater cross-sectional area for flow. These installations were responsible for a 500 mmscfd increase in CO_2 production field wide. Production increases averaged 35% per well. Several of the wells produced at twice the pre-installation rate.

3.3 Piping Specifications

The purpose of this section is to list the common specifications available to FRP users and present some additional information gathered from company interviews that are usually more conservative than the API specifications. The most commonly referenced specifications are API 15 LR and API 15 HR. Most of the users that responded to this survey reference the API Specifications when ordering FRP piping materials.

A brief description of each specification follows.

API 15LR, *"Specification for Low Pressure Fiberglass Line Pipe"*, September 1990. This specification covers fiberglass pipe in diameters up to and including 16-inches rated for cyclic operating pressures up to and including 1000 psig. The design basis for low pressure line pipe is the Hydrostatic Design Basis regression line based on an elevated temperature (150°F) multi-specimen cyclic pressure test (ASTM D2992 Procedure A) as well as other tests.

API 15HR, *"Specification for High Pressure Fiberglass Line Pipe,"* April 1995. This specification is applicable to fiberglass line pipe and fittings operating at pressures from 500 psig to 5,000 psig. The design basis for high pressure line pipe is the Hydrostatic Design Basis regression line based on an elevated temperature (150F or higher) multi-specimen static pressure test.(ASTM D2992 Procedure B) as well as other tests.

Downhole Tubing: API C1/SC15, the same group responsible for API 15 LR and API 15HR, has been working for more than ten years to develop a suitable specification for downhole tubing. The specifications designated API Specification 15TR, *"Specification for Fiberglass Tubing"* was initially approved, but was subsequently withdrawn because of negative comments and significant unresolved issues. The difficulty centers on the developing an acceptable long term test and the expense and difficulty of performing multiple long term [6,000 hour] tests to establish an operating envelope.

CEAC conducted a study for API which developed a methodolgy to predict the long-term strength and leakage of multiaxial-loaded fiberglass pipe.[22,23,24] This work could be extended to predict the performance of tubes designed with high axial strength and stiffness typical of downhole tubing. The goal of such an effort would be to develop a qualification methodology which would use a few representative tests in combination with analytical methods to qualify new products for the downhole tubing application.

3.3.1 Company Specifications and Guidelines

One major oil company uses an in-house developed specification that references the API standards and the Canadian Pipeline Code Document CSA Z662 on FRP. The CSA document discusses installation guidelines.

Another major oil company has developed a set of Production Engineering Guidelines which are used as an adjunct document to the API specifications. Pipe purchases reference the API 15HR (static loading) and API 15LR (cyclic loading) documents. The latest revision of the Production Engineering Guidelines derates allowable pressure to 85% of API value. This serves as a safety margin to address installation and loading anomalies associated with anchors, supports, bending, etc. The old guideline used 66.67% of the API rating. The relaxation of the guidelines has made FRP more economical for end users within the company.

For conversion from a static rating factor to a cyclic rating factor for an API 15HR pipe, one oil company applies a factor of 0.51. This value is based on taking 0.6 of the HR value and multiplying by a factor of 0.85. For conversion from a cyclic pressure rating to a static pressure rating a factor of 1.5 x LR value x 0.85 is used.

For pipe not API rated, this company uses short term burst data determined at room temperature according to the formula provided below to determine long term pressure ratings:

Long Term Pressure Rating = 1/5 Short Term Burst Data (ASTM 1599) x 0.85

Cyclic Loading Service = (1/7.5) Short-term Burst Data x 0.85

Another major oil company with operations in the North Sea uses DOT 192 and the UKOOA FRP document to specify FRP pipe. Onshore pipe purchases reference API specifications 15HR and 15LR.

Another major oil company derates pipe 64-88% of the manufacturer's rating. Hydrostatic tests are performed before and after installation. Extensive in-house product evaluation is carried out on a case-by-case engineering design. The company limits service to a maximum operation pressure of 2000 psig and 200°F for lines less than 6" in diameter.

3.3.2 Hydrotest Procedure

The following procedures developed by another major oil company have proven to improve the probability of completing a pipe system installation without leaks.

Step 1. The system should be tested at 1.5 times the maximum working pressure of the system for the following times:

- 3 hours for diameters up to 200mm (8 in.)
- 6 hours for diameters from 250-400 mm (10-16 in.)
- 12 hours for diameters for greater than 450 mm (18 in.)

Step 2. The system should then be tested at the operating pressure of the pipeline for the following times:

- 3 hours for diameters up to 400 mm (16 in.)
- 12 hours for diameters from 450-700mm (18 in. to 28 in.)
- 21 hours for diameters greater than 750 mm (30 in.)

The allowable pressure drop during the main testing period should not be more than 0.3 bar (4 psi) per 1000 m (3280 ft.) of line.

3.3.3 Guidelines Available from the Society of the Plastics Industry

FRP users can obtain additional guideline information from SPI documents. These documents include: (1) Specification Guideline for Fiberglass Pipe Systems for Oil and Gas Service, (2) Purchasing Glass Fiber Reinforced Plastic Pressure Vessels, (3) National Specifications for Fiberglass Pipe, and (4) Users Guide to RP Industrial Equipment - Fiberglass Piping Systems. These documents are recommended as background, but not as a primary source for specifications.

3.4 FRP Pipe Applications Database

An applications database for FRP pipe was constructed using information gathered from various literature sources, and personal interviews conducted during the study. The purpose is to show the many successful applications of FRP pipe and tubing in onshore oilfields around the world. Unfortunately, limited response was obtained from the survey. In most of the companies surveyed, no individual or group is responsible for continuously tracking FRP product installations.

The database developed is printed in spreadsheet form in Section 10.3 as Appendix C. The Excel 5.0 file is called FRPSURV.xls and is included on the diskette containing the Excel pipe economic assess tool called LIFECYCLE.xls provided with this report. The list shows the use of FRP products in various types of oilfield projects and provides an estimate of the amount of FRP products in use by some of the major oil companies. The database includes some examples of crude oil transmission lines[25,26,27] from Europe, the Middle East and North Africa which represent an expanding market for FRP pipe.

3.5 Sucker Rods

Oxy was the only company interviewed that uses FRP sucker rods routinely and estimates 10-15% of rod purchases and FRP products. The FRP rods are used primarily to unload gear-box torque on high fluid level wells and high water volume wells. On new designs, FRP rods are used to reduce up front capital costs. Pump-off controllers are always placed on wells with FRP rods to ensure that the rods do not go into compression. The average well depth is 6000 ft. with a maximum depth of 10,000 ft. In addition to the benefit of increased production, corrosion inhibition efficiency is easier to achieve in wells with lower fluid levels. Many wells with high fluid levels often develop holes in the casing due to poor distribution of corrosion inhibitor and exposure to corrosive fluids.

3.5.1 Literature Review of Successful Sucker Rod Installations

Ghiselin[28] showed that FRP sucker rods offer distinct economic advantages under certain well conditions. Wells with high fluid levels could often produce more oil if the fluid levels were reduced. This condition is also an indication that the equipment is operating at capacity. High fluid level conditions can also result in ineffective corrosion inhibition and rod failures. For new installations, use of FRP rods that are 70% lighter than steel can result in the use of a smaller motor and gearbox and less power usage. FRP rods can be dynamically tuned to provide more stroke and pumping efficiency than steel rods. The lower coefficient of friction of FRP also generally results in less tubing wear.

This article[28] also presents data from three wells in the Clearfork unit in Andrews County, TX, producing from 6000 ft. with high fluid levels and equipment overloads. Mixed strings of FRP rods and steel rods (placed on the bottom to keep the string in tension and absorb compressive forces near the pump) were run in all three wells. The net effects were that the total fluid production increased 28%, oil production rose by 46.7 bpd (60.8%) with an average reduction in power consumption of 20% per bbl fluid lifted per day. The fluid levels were reduced an average of 949 ft. simplifying corrosion treatments. Annual increased profitability for the three wells was $255,683 with a recovery of cost pay back in 54 days. If all of the remaining wells in the field were converted, it was estimated a net profit gain of about $1 million could be achieved per year.

Patton[29,30] provided detailed data on the FRP sucker rod installations presented in the Clearfork installation. These wells were equipped with rod strings that were 57% 1.2 in. FRP rods and 47% 1 in. steel rods. A total of 12 wells were equipped with the mixed strings of FRP and steel. Only three were selected for detailed study. Several wells had experienced collapsed casing due to high fluid levels and poor corrosion inhibition treatments, which was a major motivation for using this approach to improve well performance. The combination of increasing the production and lowering the fluid levels in each well resulted in lowering the peak stress on the top rod by 28% and the stress range was reduced by 29%. Some additional horsepower was required with these combination designs, but this was more than offset by increased production.

Taylor[31] describes the use of FRP sucker rods in a deep, 12,500 ft., West Texas well. Lease expenses dropped 82% after the installation of an FRP /steel rod string. Previously, the well used a power oil jet pump system. The rod string design consisted of 6188 ft. of 1.25 in. FRP rods (50%), 2725 ft of 7/8 in. steel rods, and 3500 ft of 3/4 in. steel rods. The fiberglass rod loading was 53% of the allowable maximum stress and pump plunger travel increased from 156 to 196 in. at pumped off conditions. Lease expenses dropped from $7500/mo. to $1350/mo. The system cost of $100,000 was paid back in 1.4 years. The economic limit of the well was lowered from 450 bbl of oil per month to 64 bbl oil per month, thereby increasing recoverable reserves by 190,000 bbls.

The ribbon rod, developed for Amoco,[32] is a continuous carbon fiber sucker rod in the configuration of a reelable tape with dimensions of 1.45 in. by 0.212 in. It can be wound onto a 10-foot diameter reel, six inches wide and is designed to be used in combination with steel rods at the bottom of the well. Ribbon rod is currently under test in Shell's West Texas operations. It was conceived as a system that could be used to increase production rates to levels thought impractical, due to high stress loading in steel rods and limited fatigue life in fiberglass rods. Because of the light weight and flexibility, it is expected to conform to well-bore deviations with less rod/tubing friction than steel rods and should reduce loading and improve energy efficiency for the pumping units.

The fatigue life of the carbon ribbon rod material is superior to that of steel. At 10 million cycles, carbon fiber composites survive working at 60% of their ultimate strength, while steel operates at 40% and fiberglass operates at only 20% of ultimate tensile strength. The product is made from Thornel T-300 12K carbon fiber tow with a vinyl ester resin. Kevlar® fibers are added to the edges of the rod to improve toughness and damage resistance. The product can be made in continuous 3000-foot lengths by a pultrusion process.

The carbon fiber ribbon rod has been field tested in numerous wells by Amoco. The design of the string is accomplished by using a wave equation analysis. A number of different designs in combination with steel rods have been tested. High volume (nearly 1000 barrels fluid per day) are possible utilizing these mixed strings. It is not clear from the paper what the failure histories were on these wells. From a corrosion engineering standpoint, inhibition programs would need to be continued and rod/tubing wear at the bottom of the wells would need to be addressed perhaps with the use of guided rods.

3.6 Tanks and Vessels

3.6.1 Survey Results

This section will primarily serve to summarize the discussions on FRP tanks held with various oil company engineering staff in Midland and Houston. Use of FRP tanks is declining among major oil companies due to a concern regarding safety for use of FRP tanks with hydrocarbons. In particular, there is concern regarding the susceptibility of FRP tanks to lightning strikes.

Oxy uses FRP tanks of 500 bbls or less for salt water service. These tanks are one-piece filament wound and rated for atmospheric service only. No hydrocarbons are allowed due to concern for a lightning strike. Horizontal lightning rods are installed 20-30 feet above the tanks to help address the lightning strike issue. About 10% of the tanks purchased by Oxy are FRP tanks.

Chevron has been a user of FRP tanks, but usage has declined in recent years, due to the apparent concern about lightning strikes. They have devised a system to ground the fluid to prevent static charge buildup whereby a stainless steel (SS) tubing is run into the tank to the bottom through a packoff assembly at the top. The SS tubing is then attached to a buried ground rod.

Conoco does not use FRP tanks and is replacing FRP with steel on properties purchased with them.

Unocal (Spirit Energy) estimates that 50% of the tank purchases in 1997 are FRP. The engineer at Unocal envisioned that a composite FWKO (free water knockout) vessel for 30-50 psi service might compete on a life cycle cost basis with a coated steel vessel. These large vessels are difficult to rework and maintain. Large volumes of water are handled that result in corrosion, scale, sand, and sludge buildup that cause coating failure. Recoating the vessel is a large expense and often not reliable. The market may be sufficiently large to justify development expenses.

Altura Energy Ltd. uses FRP tanks purchased to API 12P specifications. FRP tanks as large as 750 bbls are used for water surge tanks. They also use FRP for pit enclosures, sumps, and chemical tanks and vents.

Ameron has developed electrical conductivity technology which was applied to the design of pipe and vessels to transport jet fuel and non-conductive fluids. This technology could be evaluated to develop design guidelines for the prevention of lightning strike on oilfield FRP tanks.

A review of the use of tanks and vessels offshore is presented in reference 33.

3.6.2 Fire Test Performance of FRP Hydrocarbon Storage Tanks

Amoco[34] conducted fire tests on FRP storage tanks containing hydrocarbons in 1973 and compared the performance of steel, aluminum, and FRP Hydrocarbon storage tanks. The pit fire reached 1000°C. The conclusions were that the increase in internal pressure in steel and aluminum tanks can result in jets of burning liquid in just a few minutes. Steel tanks can rupture and aluminum tanks can melt if fire continues for an extended period of time. Fires involving metal tanks are difficult to extinguish because leaking gas reignites on hot metal surfaces. The contents of the FRP tanks stayed cooler (due to lower thermal conductivity) and FRP tanks remained leak free considerably longer in a hydrocarbon pool fire.

Amoco used FRP tanks for diesel, lube oil, and water tanks on the Davy/Bessemer monotower in the North Sea. A typical diesel storage tank on this platform was 2.3m diameter by 6m long (24,000 liter) constructed to BS4994: 1987 Cat. 1. A capital cost saving of 36% was achieved compared to stainless steel. In addition, an 850-liter lube oil tank was constructed to BS4994: 1987 Cat. 3. An 82% cost savings was realized compared to stainless steel construction. Two 513 liter water tanks were also constructed to the same specification as the lube tank. Amoco estimates an 82% savings compared to stainless steel.

Specifications commonly used in the industry for composite tanks and pressure vessels include:

- ASTM 3299 Filament Wound, Corrosion Resistant FRP Tanks
- ASME Boiler Code, Section X, Class 1 (pressure < 150, 1500, 3000 psi), Class II ($p<75$ psi, $D<144$ in., $pD<7200$), RTP 1, ($p<15$psi).,

3.6.3 Literature Related to Composite Tanks

Oney[35] (Cities Services Oil & Gas) discusses the manufacturing processes used to produce common 500bbl FRP tanks for both the chop-spray and filament winding processes. Most oilfield tanks are constructed using a combination of both processes. Manufacturers should be advised of special conditions that might occur during service with respect to use parameters, loading by heavy equipment, possible temperature excursions, etc. Most leaks and damage occur during handling and installation of the tank. Adequate support is required for the bottom of the tank, preferably a concrete pad. Piping must line up accurately with the tank so external stresses are not imposed on fittings. This paper is a good source for practical information on tank design, manufacturing and installation.

Glein[36] (Norcore Plastics) reviews materials selection guidelines and provides cost information on: various metals (carbon steel, stainless steels, and alloys), lined steel, fiberglass and dual laminates (PVC, PP, PVDF, FEP, etc). Life cycle cost approaches are also discussed.

4.0 MARKET ASSESSMENT

4.1 General Market Information for Composites Industry

The market for corrosion resistant composites is about 400 million lb. per year.[37] Five growth areas for this market are in wastewater treatment/odor control, semiconductors, copper mining, pulp and paper and chemical processing. Semiconductors are the number one growth areas due to the high demand for computer chips. Another growth area is the construction market (potentially 627 million lb/year), due to the expanded use of composites in infrastructure rehabilitation.

4.2 Assessment of the Market for Oilfield Composite Products

The market for composites in the oil industry was assessed primarily from information provided by one major FRP product manufacturer. Some additional information was provided from an FRP industry consultant.

The worldwide market for FRP products is estimated at about $200 million. The onshore marketplace may further by broken down by regions as follows:

USA	$60 million
Canada	$20 million
Mexico/SA	$5 million
South America	$25 million

The total marketplace for the Western Hemisphere is over $100 million. The market is estimated to be segmented as follows:

80%	Onshore Line Pipe
10%	Offshore Utility Piping
10%	Tubing

The market for line pipe can be further segmented as follows: 25% gas gathering, 25% crude oil gathering (multiphase lines), and 50% salt water injection.

The market for all downhole tubulars in corrosive well systems is more than US $ 436,000,000 as indicated by TABLE 1. Of this market, FRP downhole tubing represents approximately US $5,000,000. This is approximately 2.5 % of total fiberglass tubular sales. Major users of FRP downhole tubing in the United States have been Amoco, Amerada-Hess, Conoco, Exxon, Mobil, Shell and Texaco. One manufacturer indicates increasing orders of FRP tubing due to increases in the price of J-55 steel tubing.

Alternative materials, are also shown in TABLE 1. As reservoirs become more corrosive, operators tend to use inhibitors pumped downhole to mitigate the effects of corrosion. They also consider alternative materials including FRP and corrosion resistant alloys.

TABLE I. - Estimated World Wide Tubing Market.

Tubing System	Estimated Sales US $ MM	Percentage
Inhibited Steel	19.8	4.5
Coated Steel	88.6	20.5
FRP Lined Steel	26.0	5.9
Other Lined Steel	57.2	13.1
CRA's	239.7	54.9
Fiberglass	5.0	1.1
Coiled Tubing	Not Included	Not Included
TOTALS	436.3	100

Cement and FRP lined steel are two choices with an expected life in excess of ten years. In both cases, used steel tubing in inventory can be rehabilitated by cutting new threads, blast cleaning and adding a lining of cement or FRP.

In addition to traditional alternatives, new technologies are becoming accepted. HDPE liners are installed in standard steel tubes to provide added corrosion resistance. The liner is not normally bonded to the steel and can be subject to explosive decompression if gases permeate the liner and rapid pressure drops are imposed.

Steel coiled tubing with a HDPE liner is also being used in some completions. Coiled tubing that is nearing the end of its useful fatigue life is lined with HDPE and installed in the well. This affords the economic advantage resultant from the use of CT and utilizes CT that might otherwise become scrap.

Composite coiled tubing may, in the future, find applications in production operations as flow lines, injection lines and tubing. Steel coiled tubing has already been introduced into these applications.

4.2.1 CRA Survey Data

Market data relevant to downhole FRP tubing potential can be found in NACE Publication 1F196, *Survey of CRA Usage*. This document represents a two-year study of Corrosion Resistant Alloy (CRA) tubular applications around the world. Twelve companies submitted data and it was estimated that the results of the survey account for 11.8 million feet of pipe.

The CRA with the greatest usage was 13Cr (UNS S42000). Nine companies reported using 13Cr in 51 different fields. The CRA with the second highest usage was 22Cr (UNS 31803). The lowest cost CRA's, 13Cr and 22Cr represent 82% of the CRA tubulars in the database (approx. 9.6 million feet of tubulars). Between 1990 and 1993, forty-three percent of tubulars installed were 13 Cr (approximately 3.5 million feet) which is double the quantity of the previous four year period. The common temperature application range for wells is between 200°F and 250°F (93°C and 121°C).

The highest percentage of pipe (47%) is installed in wells with modest bottomhole temperatures less than 250°F (121°C). Fifty-nine percent of the Cr alloys(9+13+22) were in service where there was no H_2S. An additional 22% were in service where there was 10 ppm H_2S or less. Thus, 4/5 of

Cr CRA's were in low or no H_2S environment. Fifteen percent of the Cr CRA's was in oil wells with over 100 ppm H_2S. The Cr CRA's were distributed over a wide range of CO_2 partial pressures.

Continuous spoolable composite pipe may in the future be applied to this type of application. This would reduce the concern for connection reliability and strength limitations.

4.2.2 Casing and Liners

FRP casing and liners have been used for several years. Casing is normally thought of as larger diameter [$\geq$ 4 1/2 in.] that runs to surface and is cemented in place to protect the well bore and adjacent aquifers. Liners serve a similar purpose but do not extend to the surface. They are "hung off" on a casing string below surface.

The casing application is a less severe environment for FRP pipes than tubing because casing is permanently installed in the well and there is no repetitive make and break to cause thread wear and a good cement job helps prevent leakage through the casing joints. Additionally, the product is significantly lighter than steel alternatives and can be installed using lighter, less expensive drilling rigs.

<u>End Users.</u> Oil and gas companies who have used FRP in casing or liner applications include Amoco, Chevron and Shell; however, applications are limited.

<u>Market Size.</u> The market for casing and liners is approximately US \$ 329,000,000 of which approximately \$ 2,000,000 (less than 1%) is currently FRP.

4.3 Internal Corrosion Cost Impact Study - US Natural Gas E&P Industry

In February 1996, the Gas Research Institute,[38] issued a report on the cost of internal corrosion to the lower 48 U.S. natural gas market. The cost was conservatively estimated at \$840,000,000 per year or \$0.054/mcf incurred in the production, handling, and gathering of natural gas based on 1990 gas production of 15.6 TCF. The cost does not include corrosion associated with coal-bed methane, storage gas or gas from federal offshore leases. The study found that 86% of the gas produced in the lower 48 is considered corrosive based on carbon dioxide content and standard industry rules of thumb (Dewaard/Milliams). Avoidable corrosion costs to the gas producing industry are estimated to be 10-15% of the \$840 million or \$100 million annually.

The study found that in 1991-1992 the US oil and gas industry utilized between \$300 and 400 million worth of CRAs. Most CRAs tubulars were for gas systems. Another \$224 million dollars annually is spent on chemical treatment programs and well servicing due to internal corrosion. An estimate was made that for the entire oil and gas industry, approximately \$2.5 billion was spent in 1991 on corrosion related problems in the oil and gas industry.

4.4 Survey Results - Market Data

Table 2 is a summary of the estimated amount of FRP tubing, casing, line pipe, and tanks purchased by survey participants in 1997. These numbers should be considered only as rough estimates. Responses were obtained from individual project engineers at Unocal, Conoco, Chevron, Arco, BP, Paragon, Marathon, Oxy and Smith.

TABLE 2. – Estimated Purchases of FRP Products.

Company	Tubing/Casing %	Line Pipe %	Tanks %
Altura	NA	NA	NA
Unocal	0	40	50
Conoco	NA	10	0
Chevron	0	10	0
Phillips	NA	NA	NA
Arco	2	4	0
BP	0	1	0
Paragon	0	1	1
Marathon	0	5-8	2
Oxy	0	50	10

Tubing/casing - Of the companies surveyed and interviewed only Arco reported usage of FRP tubing/casing products, and Arco's utilization was only two percent. None of the other major oil companies surveyed claimed to be users of FRP tubing/casing in any significant quantities and reported zero purchases.

Line Pipe - Oxy and Unocal report 50% and 40%, respectively, of their line pipe currently purchased in the Midland area is FRP. Usage among the other major oil companies surveyed, ranged from one or ten percent. One FRP manufacturer reports that about 5 years ago, major oil companies reported, at a NACE meeting, that FRP line pipe purchases were 25-35% of all line pipe procured.

Tanks - Unocal reported that 50% of their tank purchases were FRP and Oxy reports 10% usage. The remainder of the participants reported zero to one or two percent. The primary barrier to expanded use is associated with the lightning strike and static charge issue.

4.5 Currently Accepted Alternatives to FRP Products

The alternatives commonly used for corrosive service in onshore oil fields are carbon steel with continuous corrosion inhibition, HDPE lined steel, plastic coated steel, cement lined steel, and type 316SS or duplex SS. Some use of PA (polyamide liners) has recently been reported for higher temperature applications. For low pressure gas gathering service, bare HDPE pipe is used by some operators. Detailed economic calculations to determine life cycle costs must be run on a specific project basis. Figure 5, taken from a report by Brouwer,[9] shows the total installed CAPEX costs for PE liners, PA liners, FRP, and RTP (reinforced thermoplastic pipe. The installed cost of FRP or

RTP pipe ranges from cheaper to more expensive than carbon steel pipe. The steel pipe does not include the cost of corrosion inhibitors or life cycle costs. Often the complexity of the piping system will determine the choice of materials based on the number of fittings and the diameter of the pipe.

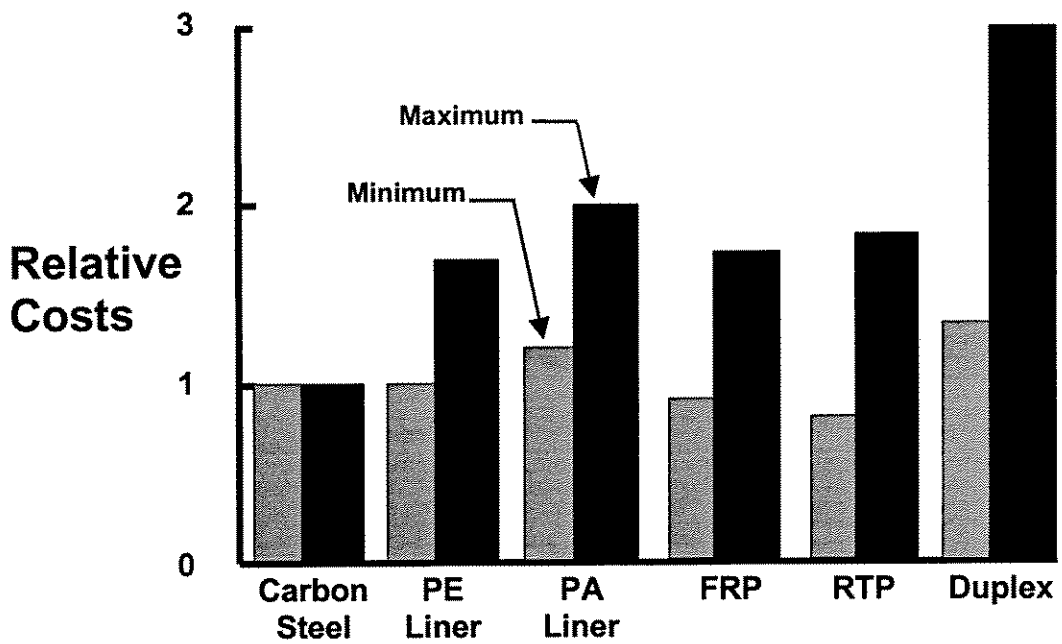


Figure 5. – Installed (CAPEX) costs of pipe relative to carbon steel.

4.6 Current Limitations or Barriers to Use of FRP Products

Survey participants identified various technical issues that limit the selection and use of FRP line pipe, tubing and tanks in onshore oilfields. These technical issues can be classified into the following broad categories: physical properties, inspection techniques, handling tools, availability of product to match applications, static charge buildup in tanks, regulations/corporate policy and contractor inexperience.

4.6.1 Physical properties

There is a need in the market for resins to withstand higher operating temperatures and for pipe to operate at higher pressures. According to Brouwer[9], there is a lack of products to fill the need for 6, 8, and 10 in. line pipe rated at pressures up to 350 bar (5145 psi), which is currently a niche filled by HDPE lined steel. Line pipe fabricated with resins resistant to wet, high-pressure, carbon dioxide for cyclic temperature service in WAG is also needed. Downhole FRP tubulars with resin systems qualified to 250°F could compete with 13Cr.

Mechanical integrity, robustness and toughness are issues that have been mentioned for many years as obstacles to use. This is a safety concern, particularly for high pressure CO_2 service, where a large release can cause suffocation.

4.6.2 Inspection

There is a need to further develop non-destructive techniques to inspect the fitting and connection make-up integrity in the field. Currently, the line must be hydrotested after completion of a section and/or after the entire line is constructed. Repairs must be made once a leak is identified. Smith provides a field-inspectable visual indicator to verify proper make-up of 2 in. through 4 in. API 8 round connections.

4.6.3 Handling Tools

Contractors involved in running various FRP line pipe products complain that new tooling is expensive. The lack of standardization in fittings and the pipe OD for line pipe has caused added expense for the FRP installers. This is not to be considered a major issue, but is a nuisance item for contract installers and generally adds to the price of installation.

4.6.4 Availability of Product

The lack of FRP line pipe in larger sizes and higher pressure ratings has resulted in use of alternate materials for these applications. This is primarily the case for higher pressure applications for sizes larger that 4 in. Currently, users feel more comfortable with HDPE lined steel or cement lined steel for larger diameter service.

4.6.5 Regulations/Corporate Policy Issues

Both Marathon and Paragon Engineering indicated more fire resistance information from manufacturers is needed. Ameron has developed a large amount of data in the process of qualifying the PSX product line for offshore use. There is a need for a greater diversity of products and fittings certified for use where fire is a hazard. Internal company standards sometimes are restrictive when using FRP products with hydrocarbons present. For example, internal Conoco standards prevent the use of FRP tanks due to the perceived fire hazard. Marathon states there is a poor management perception of the product and senior management tends to limit use.

4.6.6 Lack of Contractor and Engineering Expertise

Altura commented that there are a lack of engineers within both the oil companies, engineering contract firms, and contract installers to design and build FRP piping systems. Due to the lack of design experience, alternate materials systems are often utilized in place of FRP products.

4.6.7 Additional Comments from Literature Search on Limitations of Products

Exxon[10] reported in 1989 the following items required the attention of manufacturers. In the last ten years, manufacturers have addressed these issues and in most cases made improvements.

1. Field adhesive joints have inherent weakness.
2. Threaded connections are improved, but a proper makeup procedure and field makeup tool is required.
3. Thread dimensional tolerances are critical.
4. FRP to metal transition is problematic with temperature cycling.
5. For threaded and coupled connections, the factory-made connection is inconsistent and deficiencies are not always detected in short-term mill tests.

4.6.8 Static Charge Buildup in FRP Tanks

Several oil companies interviewed commented on the apparent propensity for FRP tanks to be hit by lightning. This is thought to be due to static charge buildup created by fluid flowing through the tank. Conoco has prohibited the use of FRP tanks for this reason. Other oil companies have devised lightning protection systems above the tank. Chevron has devised a method to ground the fluid using capillary tubing.

4.7 Potential Growth Areas

The following summarizes comments from the survey and interviews regarding potential areas for expansion of FRP products in the next few years. Expanded use of FRP line pipe products in larger diameter (6, 8, and 10 in.) products suitable for high pressure service are required for water transfer lines and high pressure gas gathering lines. Interest in lines for CO_2 WAG service was expressed. A demand for both low- and high-pressure products would be created if several large CO_2 projects at Chevron's Goldsmith and McElroy fields are approved. New opportunities in the West Texas area will depend on the success of tertiary recovery projects and new discoveries found using modern 3D seismic methods. Potentially, the use of FRP casing and tubing products could be expanded for new tertiary projects in injection wells. However, many of the tooling issues and questions about long term reliability must be resolved.

4.8 Market Interest in Spoolable Composites

There was great interest from all companies surveyed regarding new spoolable composite products (both steel and composite) for low pressure gathering lines and high pressure water injection lines. If composite products can be manufactured for a price comparable to current FRP discrete length products, a significant market share will be achieved within the next few years. This is discussed in more detail under the Emerging Applications section.

Steel coiled tubing (CT) is being introduced for use as line pipe and has contributed to a significant increase in the sales of conventional CT. An API specification for steel CT Line Pipe is being prepared for submittal to ballot in early 1998. The specification is being promoted as a means to more easily obtain DOT/MMS approvals for longer lines.

There are no CT manufacturers making products from corrosion resistant materials. However, steel CT is being coated and lined with HDPE for some applications. Coated and lined CT is priced competitively with FRP Line Pipe. However, a major WAG process installation effort in the Four Corners area of the United States with more than 600,000 feet of coated - lined steel CT budgeted for installation in 1997 has selected coated/lined CT over FRP pipe because of the concern for impact damage and leakage from threaded connections of FRP line pipe.

A review of spoolable composite products currently available and under development was presented at the Second International Conference on Composite Materials for Offshore Operations. Companies developing or marketing spoolable composite pipe products include: Hydril Company,[7] Compipe as,[8] Fiberspar Spoolable Products Inc.,[6] Proflex Pipe Comporation,[5] and Tubes d'Aquitaine.[3] Hydril is leading a NIST Advanced Technology Project joint venture to develop a broad range of spoolable high performance composite tubing products. The joint venture is a five-year program initiated in 1995. Compipe is developing products for subsea injection lines and flowlines. Compipe was initially supported in the development by Conoco and have also received support from THERMIE (European Community Funding). Fiberspar's efforts were initially in collaboration with Conoco[39] with primary focus on composite coiled tubing but has expanded to other applications. The Pro-Flex design consists of an inner thermoplastic liner surrounded by multiple independent (unbonded) cylindrical composite structural layers encapsulated in an outer cover. The product is available commercially in 2, 3, and 4-inch diameter sizes. Tubes d'Aquitaine is developing composite products constructed using thermoplastic resin. Royal Dutch Shell is conducting field trials in Oman on thermoplastic pipe made by Tubes d'Aquitaine from polyethylene resin and aramid fiber.

Spoolable pipe from each of these manufacturers has potential to be applied onshore for water injection lines, flowlines, and downhole tubing. It is expected that the price of the pipe will be more expensive than conventional FRP pipe, however, the cost of installation should be significantly lower. In addition, the elimination of most of the connections reduces a common source for leaks. The main limitation with spoolable pipe for onshore applications will be the maximum diameter pipe, which can be spooled and transported on roadways and cost.

5.0 ECONOMIC ASSESSMENT TOOL

5.1 Life Cycle Cost Comparisons

Life cycle costs of pipe systems depend on many parameters such as pipe diameter, pressure, temperature, number of fittings relative to number of pipe lengths, local installation costs, the corrosive nature of the fluids, etc. Material costs make up between 20 and 50% of the total costs of a pipeline or piping system. Figure 6 shows a comparison of various materials costs for a 6 inch diameter pipeline with a rated pressure of 70 bar (1022 psi) which is typical of pipe used for water injection or oil and gas flowlines. The number of fittings is small. Materials costs for all non-metallic options are greater than carbon steel but less than duplex SS.

A summary of Capital Expenditure (CAPEX) costs for various materials for a 6-in diameter, 70 bar pipeline (reference 9) is also presented in Figure 6. CAPEX costs include materials, transport, mobilization, engineering/design, right of way, trenching, welding (if required), coatings, cathodic protection (CP), corrosion inhibition, pig launchers etc. While materials costs vary greatly, the variation in CAPEX is much smaller. Installation costs of non-metallic pipe systems are less due to the relatively low weight and cost effective joining techniques. Also, CP and coatings are not required for non-metallic system applications. Reductions in total life cycle costs of 70% compared to carbon steel by applying non-metallic pipe systems have been achieved.

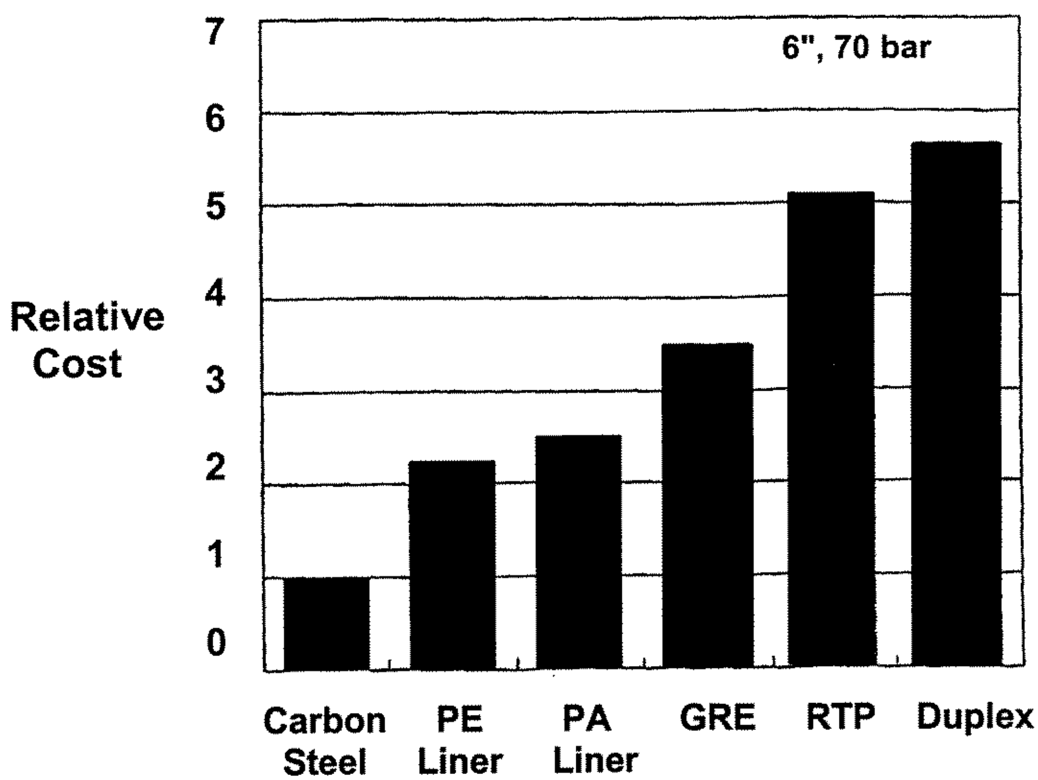


Figure 6. - Material costs relative to carbon steel for a 6 -inch diameter, 70 bar pipeline.

5.2 Background Information for Economic Analysis Spreadsheet

The net present value (NPV) approach described in NACE Publication 3C-*194, Economics of Corrosion*[40] was used as the foundation to develop an economic assessment tool to help project engineers select the most economical pipe system for a particular application. The economic analysis has been programmed in an EXCEL spreadsheet which is made available with this report. A detailed guideline for using the spreadsheet is provided in Appendix B.

Once all of the technically viable alternatives to a problem are identified, the decision of which alternative to choose becomes simply a question of engineering economics. This involves calculations related to time, money and interest rates. It is important that a proper engineering economic analysis be conducted to provide data to help decide how to best utilize capital in the current interest rate environment consistent with the corporation's goal for rate of return.

The engineer must identify the unique stream of cash flow expenditures related to each alternative solution. For example, when comparing the cost of a steel line versus FRP pipe, various operating and maintenance expenses for steel will include the cost of inhibitors, the chemical pump, cathodic protection equipment, anode replacement, cost of pipeline leaks, deferred production, etc. This series of cash flows can be readily translated to a net present value for comparison purposes. Often it is useful to convert the present worth of two alternatives with different lifetimes to an equivalent annual cost in order to provide a fair comparison.

The net present value (NPV) method, also known as the present worth (PW) method has the broadest application to engineering economy problems. Some refer to this approach as the "discounted cash flow" method. For this report, annual compounding of interest will be utilized. The effect of taxes, depreciation and salvage value must generally be considered and are included in the master equation to calculate net present value. Equation 1 is used in the spreadsheet to calculate present worth.

$$(PW) = -P + (t(P-S)/n)\,[P/A,i\%,n] - (1-t)(X)[P/A,i\%,n] + S[P/F,i\%,n] \qquad (1)$$

where PW is present worth or NPV, P is the initial investment at time zero. The second term involves the effect of straight-line depreciation. The operator in [ ] is the factor that converts the dollars back to present value. The third term considers chargeable expense items, X and tax rate, t and the operator in [ ] to convert costs back to present value. The fourth term translates the anticipated future salvage value, S, back to present value.

Present worth can then be converted to an equivalent annual cost by use of Equation 2.

$$A = (PW)\,[A/P, i\%,n] \qquad (2)$$

where A is the equivalent annual cost., PW is the present worth, and the term in [ ] is the capital recovery factor that translates present worth into a series of annual payments. If candidate materials have different lifetimes, one can convert the values of PW into A. The material with the lowest annual cost is the material of choice.

5.3 Net Present Value Analysis Example

An example of a comparative analysis for four material options is presented in this section for a 10,000 ft., 4 in. diameter, 1000 psig operating pressure water injection system intended to transport an aggressively corrosive fluid. The materials options considerd are (1) FRP 1500 psi rated pipe, (2) cement lined steel with external coating and a cathodic protection requirement, (3) HDPE liner in carbon steel with cathodic protection and (4) internally and, externally coated carbon steel with cathodic protection and chemical inhibition. Assumptions shown below were made for the costs for these systems. The cost assumptions used in the example are representative of recent product and installation costs, but are not intended to be used to select materials for a particular project.

System 1. FRP Line Pipe, 4 in. nom. dia., 1500 psi rating
Material cost $8.225/ft
Installation $ 20,000
No maintenance costs
Estimated life 25 years
Abandonment costs $5000

System 2. Cement Lined Steel (4 in. nom. dia.) with External Coating
Cathodic Protection
Material cost $5.06/ft
Installation $30,000
Cathodic Protection $2500 installed
CP Maintenance $500/yr
Rising maintenance costs after 15 years due to leaks ($1000/leak)
Estimated life 25 years
Abandonment costs $5000

System 3. HDPE Liner in Carbon Steel
Cathodic Protection
Material Cost $5.57/ft
Installation $40,000
Cathodic Protection $2500 installed
CP Maintenance $500/year
Abandonment cost $5000

System 4. Internally and Externally Coated Carbon Steel
Cathodic Protection and Chemical Inhibition.
Material cost $5.46/ft
Installation $30,000
Cathodic Protection $2500 installed
CP Maintenance $500/yr
Rising maintenance costs after 15 years due to leaks ($1000/leak)
Estimated life 12 years
Inhibition Cost $3500/yr
Abandonment costs $5000

The data entry sheet and summary pages are shown on the following two pages. In this example, the inflation rate was assumed to be 3.5% and the cost of capital was set at 10%.

FRP is shown to have the lowest Net Present Value (NPV) for a 25-year life as well as the lowest equivalent annual cost. Option 4 with only a 12-year predicted life is shown to be noncompetitive in NPV and equivalent annual cost for the time periods considered.

Table 3. – Pipe Economic Analysis Input Data.

	A	B	C	D	E	F	G	H	I	J
3	**Project**	Four Inch 1000 psi Water Injection System, 10,000 FT Section								
4										
5	**Financial Factors**									
6		Inflation	3.50%							
7		Cost of Capital	10.00%							
8		Tax Rate	34.00%							
9										
10										
11	**System 1**	FRP Pipe- 1500 psi Rating, T&C								
12	**Initial $**	102,250		**Estimated Life**	25	**Salvage $**	0		**Abandonment**	5,000
13					**Yearly Expense Costs**					
14	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**
15	0	0	0	0	0	0	0	0	0	0
16										
17	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**	**Year 16**	**Year 17**	**Year 18**	**Year 19**	**Year 20**
18	0	0	0	0	0	0	0	0	0	0
19										
20	**Year 21**	**Year 22**	**Year 23**	**Year 24**	**Year 25**					
21	0	0	0	0	0					
22										
23										
24	**System 2**	Cement Lined Steel- External Coating and Cathodic Protection								
25	**Initial $**	83,100		**Estimated Life**	25	**Salvage $**	0		**Abandonment**	5000
26					**Yearly Expense Costs**					
27	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**
28	500	500	500	500	500	500	500	500	500	500
29										
30	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**	**Year 16**	**Year 17**	**Year 18**	**Year 19**	**Year 20**
31	500	500	500	500	1,500	2,500	4,500	6,500	8,500	10,500
32										
33	**Year 21**	**Year 22**	**Year 23**	**Year 24**	**Year 25**					
34	12,500	13,500	14,500	15,500	16,500					
35										
36										
37	**System 3**	HDPE Liner in Carbon Steel plus Cathodic Protection								
38	**Initial $**	98,200		**Estimated Life**	25	**Salvage $**	0		**Abandonment**	5000
39					**Yearly Expense Costs**					
40	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**
41	500	500	500	500	500	500	500	500	500	500
42										
43	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**	**Year 16**	**Year 17**	**Year 18**	**Year 19**	**Year 20**
44	500	500	500	500	500	500	500	500	500	500
45										
46	**Year 21**	**Year 22**	**Year 23**	**Year 24**	**Year 25**					
47	500	500	500	500	500					
48										
49										
50	**System 4**	Internal Coated Carbon Steel with External Coating, CP and Chemical Inhibition								
51	**Initial $**	87,100		**Estimated Life**	12	**Salvage $**	0		**Abandonment**	5000
52					**Yearly Expense Costs**					
53	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**
54	4,000	4,000	4,000	4,000	4,000	4,000	6,000	8,000	10,000	14,000
55										
56	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**	**Year 16**	**Year 17**	**Year 18**	**Year 19**	**Year 20**
57	16,000	18,000	0	0	0	0	0	0	0	0
58										
59	**Year 21**	**Year 22**	**Year 23**	**Year 24**	**Year 25**					
60	0	0	0	0	0					

Table 4. – Economic Analysis Comparison Sumary.

NPV Calculations for Four Inch 1000 psi Water Injection System, 10,000 FT Section

FRP Pipe- 1500 psi Rating, T&C

Est Life	Initial Cost	Annual Cost	NPV (5 yrs.)	NPV (10 yrs.)	NPV (15 yrs.)	NPV (20 yrs.)	NPV (25 yrs.)
25	$102,250	$6,123	$62,214	$58,940	$56,908	$55,646	$55,582

Cement Lined Steel- External Coating and Cathodic Protection

Est Life	Initial Cost	Annual Cost	NPV (5 yrs.)	NPV (10 yrs.)	NPV (15 yrs.)	NPV (20 yrs.)	NPV (25 yrs.)
25	$83,100	$7,423	$51,941	$50,299	$49,662	$55,560	$67,376

HDPE Liner in Carbon Steel plus Cathodic Protection

Est Life	Initial Cost	Annual Cost	NPV (5 yrs.)	NPV (10 yrs.)	NPV (15 yrs.)	NPV (20 yrs.)	NPV (25 yrs.)
25	$98,200	$6,337	$61,129	$59,003	$57,801	$57,142	$57,518

Internal Coated Carbon Steel with External Coating, CP and Chemical Inhibition

Est Life	Initial Cost	Annual Cost	NPV (5 yrs.)	NPV (10 yrs.)	NPV (15 yrs.)	NPV (20 yrs.)	NPV (25 yrs.)
12	$87,100	$11,876	$59,167	$69,859	$0	$0	$0

6.0 EMERGING APPLICATIONS AND OPPORTUNITIES

6.1 Cryogenic Fracturing

A new techniques for fracturing downhole formations has been developed based on thermally shocking the formation using liquid nitrogen[41]. The technique uses FRP pipe to transport the liquid nitrogen to moderate depth formations at typical fracturing rates and at cryogenic temperatures (-320°F to -232°F) while protecting the casing from damage. Construction of all stainless steel surface piping, manifolding and wellhead components prevented thermal contraction problems and the use of free hanging FRP tubing protects the casing from thermal shock damage.

FRP tubing possessed several physical properties that allowed this technique to be developed in a manner that prevented casing damage. Samples of FRP pipe were tested at cryogenic temperatures. These tests showed the pipe increased in strength at the cold temperatures. There was no ductile to brittle transition point and thermal cycling of the pipe did not cause any apparent fatigue damage. Laboratory tests on a section of FRP tubing measured a thermal conductivity of 0.21 BTU/hr.ft.F at a temperature of -200°F. A thermal model predicted adequate time for injection of liquid nitrogen in the well before the casing would reach the -20°F ductile to brittle transition temperature. Thus, the insulation properties of FRP tubing were the enabling property for this process.

This work demonstrated the viability, safety and ease of pumping cryogenic liquid nitrogen. Patents are pending for the use of cryogenic liquid nitrogen in the initial stimulation process for completion of producing reservoirs. The use of cryogenic fluids in diverting applications is planned. The presence of water within the fracture face before it is exposed to cryogenic fluids is a potential force for additional stress effects on the rock. Preceding a cryogenic nitrogen treatment with a stage of water or low-quality foam is one obvious modification that can be made. The delivery of acids, surfactants, scale inhibitors, etc. may be able to be delivered in temporary solid form to formations through injection into flowing streams of liquid nitrogen. Thus there are many possibilities to be investigated that would have a significant economic payoff.

6.2 High Pressure, Large Diameter Line Pipe

Steel strip laminate (SSL)-FRP pipes are under development by Ameron. The additional reinforcement by steel enabled the pipe to be designed for higher pressure and larger diameters. A special conical threaded connection, using shear-locking strips was developed. Sealing was provided by two O-rings in combination with an adhesive sealant. Ameron has tested a number of 10 in. SSL-FRP pipes. Burst pressure was 375 bar which provided a pressure rating of 140 bar. The expected operating envelope of this class of pipe is shown in Figure 4. Smaller diameters (8 in.) will be produced with a maximum operating pressure of 350 bar and diameters of 40 in. may be produced with a pressure rating of 70 bar. Larger diameters may not be economical compared to alternate materials. Pipe is being developed and tested to operate at 110°C.

6.3 In-situ Processed Casing and Line Pipe

Saltel[42] describes a novel approach by two French entities, Drillflex and IFP, to develop two types of reelable casing and liner products. Drillflex has developed a flexible tube prepared from unpolymerized composite and protected by two elastomeric liners called Casing-Flex. This product can be manufactured in lengths to over 3280 ft. and reeled on a drum. The casing is run in the hole in a smaller diameter than the finished product. For monodiameter drilling very long tubes can be used to replace casing strings resulting in a substantial decrease in volume drilled. For remedial relining projects, short tubes that can pass through production tubing can be used to seal off perforations, repair corroded casing or seal off side tracked holes. Casing-Flex can be run with an electric wireline apparatus and can be manufactured in 4 in. to 14 in. diameters and placed on spools for highway transport.

Drillflex has developed controlled locking seals that seal the casing in place without the use of cement. The economic benefits for mono-diameter wells are estimated to be: (1) reducing the volume drilled by 70%, (2) reducing the weight of total pipe transported 75-80%, (3) reduction in the well-site pad by 90%, (4) 20-35% time-reduction in drilling/completion of well, and (5) 35% reduction in total cost of drilling the well.

This type of technology could make possible drilling and completing wells with reeled technology thus eliminating the derrick or draw works. A reduction in hole size with Casing-flex would make possible coiled tubing drilling from the surface.

Two limited field tests of this technology were reported in wells to prove the concept. Both field tests were reportedly successful. Current research is aimed at fine-tuning the materials selection of resins, curing agents and elastomers for these products. The technology has high payoff potential if commercialization is successful.

Fernandez[43] describes an invention known as Flextube, which is a flexible very high strength composite liner for old or new pipe installations. Tube lengths may vary from 656 ft. to 3280 ft. for diameter of 6 in. to 52 in. The Flextube, as manufactured, can withstand 5000 psi, however, the proposed operating pressure of the lines are 3250 psig in alignment with the ANSI 1500 class of fittings. Preliminary cost estimates indicate a total cost for the installed tube to be between 15 and 35% of a new steel line. The main benefit reported for flextube are: to be high tensile strength (270 ksi for E-glass and 530 ksi for S-2 Glass), material less expensive than steel, inexpensive to install, corrosion resistant, and enhanced properties to minimize erosion, abrasion impact and maintenance.

The main application is seen to be pipeline upgrading where the operator is faced with a major repair, downgrading or replacement of system. The Flextube when inflated carries the full operating pressure of the pipeline and does not depend on the steel casing for strength. Large diameter Flextube can be accordian packed in 1,080 ft. lengths. They are pre-assembled into 3280 ft. sections using steel nipples. Installation rates of 65,000 to 98,000 ft./day are claimed.

Other applications for insitu processed composite pipe include conventional, above ground pipelines and subsea pipelines.

6.4 Flexible Piping Technology

Wolfe[44] discusses a flexible composite product with an HDPE liner surrounded by multiple independent cylindrical structural layers and an outer cover called ProFlex. Each of the structural layers consists of thin, parallel, helically oriented, continuous fiber-reinforced composite strips separated by thermoplastic elastomer strips. Low bending stiffness is achieved with high structural strength by composite and elastomer materials in discrete helical strips.

ProFlex comes in sizes up to 4 in. and pressure rating to 3000 psi. It can be coiled for storage or used to a bend radius of 15 diameters. The application described in this paper was for a flexible riser connection for hot (55°C) sour brine injection wellheads. Several rigid FRP pipe systems installed in the same field had failed within six months due to cyclic temperature fluctuations. There are currently seven flexible pipe risers in service since August 1995 in Shell Canada with no problems reported. Corrosion resistance on the flange face is accomplished by extending the HDPE liner through the flange face. The pipe is joined using conventional flanges. The pipe's flexibility allows it to accommodate ground settlement or movement. The pipe is now used by 20 Canadian oil and gas producers

Von Flatern[45] briefly reviews the status of the development of composite coiled tubing by Fiberspar and Hydril. Fiberspar has two field tests of extended lengths of tubing in the North Sea scheduled for October 1997 deployment. One project is a 1.5 in. ID service string to be used by NAM to do plug and abandonment work for Shell. The second project is a 2.125 in. ID velocity string to be installed in corrosive wells. The first application will demonstrate the fatigue life of the material, while the second application demonstrates the corrosion resistant properties.

6.5 Reinforced Thermoplastic Pipe (RTP)

Reinforced Thermoplastic Pipes (RTP) are both in development and in service. Figure 4 shows the expected operating pressures and diameters. These pipes can be produced in continuous lengths between 656 ft. and 4920 ft. and are spoolable to facilitate quick and cost effective installation. Most thermoplastics have good impact resistance and are resistant to erosion. A wide variety of thermoplastic materials are available with some such as PVDF exhibiting higher temperature limits.

Reinforced HDPE pipes (RTP) manufactured by Tubes d'Aquitaine, Carsac, France, have been tested by Shell in the Hague[46] confirming its service pressures up to 150 bar (2175 psi) in a temperature range from -22°F to 86°F. At temperatures greater than 30°C the service pressure must be reduced by 10 bar for each 50°F temperature change. Several field trials are scheduled for Saudi Aramco (9 in.) and PDO (Shell Oman) (6 in.).

The RTP consists of three parts: (1) a primary HDPE tube, (2) several crossed layers of aramid yarns coated with HDPE welded to each other and the primary tube, and (3) a layer of HDPE for external protection. The pipe is designed for temperatures up to 140°F. The manufacturer claims hydraulic energy savings due to increased throughput permitted by a lower coefficient of friction. For example, a 16 in. RTP pipe is claimed to be equivalent to a 20 in. carbon steel pipe with respect to flow capacity.

The pipe can be connected with flanges or threaded connections. The company has patented two threaded connection sealing systems. These systems also allow the pipe to be reeled prior to installation cutting down on installation time in the field. The pipe normally is made in 12 m lengths for its 4, 6 and 10 in. diameter sizes. Installation is quite rapid, for example a 6 in. pipe for 100 bar operating pressure can be installed at the rate of 656 ft./hr by three technicians and 12 workers. Repairs to damaged pipe can be made in 2 hours.

As shown by Brouwer,[9] RTP is more expensive than FRP pipe but will be cost effective for very corrosive fluids where carbon steel is an unacceptable alternative due to rapid times to first leak and when the expense of leak repair is very expensive as in the case of PDO. Efforts are underway to make RTP in long, continuous lengths, which could be spooled for easy transport and rapid installation, while eliminating most of the joints.

6.6 Liners

Mason[47] describes the case histories of approximately 19,700ft. of polyamide-11 lined steel in Canada operating at 176°F. There were five pipelines with liners installed with a diameter reduction technique. These 4-in. and 6-in. lines owned by Amoco are used for sour gas service. The produced fluid contained 17% H_2S and condensate at 113°F. The problems that were overcome were finding the correct balance between compressive and tensile forces to prevent the collapse of the liner as it passed through the roller box. There are four other installations at two different Amoco sites. Two of the four lines are operating at 158°F to 176°F. The liner was installed at -4°F to 59°F ambient temperature.

6.7 Cold Temperature Applications

FRP tanks are used in other industries for storage of cryogenic temperature materials. FRP pipe has the potential to be used in expanded applications for cryogenic service such as the cryogenic fracturing approach described in Section 6.1 and for low temperature applications in the Arctic. The lower thermal conductivity of composites is an advantage when the fluid temperature must be maintained such as to avoid paraffin or hydrate deposits on the pipe walls or to avoid lowering of viscosity of the produced fluids.

6.8. Dual Wall Piping for Containment - Coaxial Pipe and Fittings

Ameron has developed the concept of coaxial piping and fittings to address the use of fiberglass pipe for containment applications.[48] The containment layer is formed over the primary pressure containment pipe or fitting after a porous layer (usually dry sand or an open weave mesh) is placed on the outside of the primary pipe. The result is a part with two distinct but linked pipe systems. Fluid fills the space rapidly because of the small volume between layers and reaches a detection sensor quickly, alerting operations prior to a major release.

Mechanical properties of this type of piping system are better than single wall FRP due to the higher stiffness of the coaxial system. The cost of the coaxial system is expected to be less than a pipe in pipe system. The fittings are more compact than in a traditional pipe in pipe dual wall system. Impact resistance testing has shown a 400% increase in energy required to cause a failure in the primary pipe. This improvement addresses one of the big concerns over the use of FRP line pipe.

Applications for onshore producing operations might include above ground tank battery piping, flowline headers and manifolds, and wellhead risers where traditionally stainless steel or internally coated steel has been used.

6.9 New Resin for Aggressive Chemical Applications

Smith Fiberglass has introduced a new FRP piping system developed with a proprietary resin system for aggressive solvent and acid applications. The pipe can be used for transport of chemicals such as fluorobenzene, dichloroethane, chloroform and 98% sulfuric acid. The pipe is rated for 150 psig and 275°F and is available in sizes 2 in. through 6 in. diameters. Fittings are available in socket and flanged ends. Applications for the onshore market might include drilling and workover rigs handling aggressive acids and solvents, but these applications would require higher operating pressures.

7.0 SUMMARY AND RECOMMENDATIONS

This study has shown that the currently available FRP pipe products are being utilized in increasing quantities worldwide due to their corrosion resistant properties and high benefit/cost ratios. There also exists great potential with products now in development to expand the pressure and temperature operating envelopes for application of these piping materials. The following paragraphs summarize the significant findings of the study and propose specific topics which could be addressed in subsequent efforts.

1. Based on discussions with oil company personnel and survey input, there appears to be strong interest in the development of a training course that would address the practical aspects of design and installation of FRP piping systems targeted to field facilities engineers of the oil companies and design facilities engineers at engineering and construction firms. A second course or workshop might be targeted for production engineers and focus on the use of FRP products in downhole applications and should include topics such as casing/liner installation for carbon dioxide wells, injection tubing installation, design and use of FRP sucker rods and utilization of new spoolable pipe products. Downhole applications cited in the literature indicate a very high potential economic impact for these applications. Mini-courses could be offered several times a year and expose hundreds of engineers as well as installation contractors to the use of composites over a multi-year period.

2. The technical barriers for larger diameter, high pressure pipe for waterflood and carbon dioxide projects should be identified. There is a need for development and testing of fittings for 6 in. and larger pipe at pressures of 3000 psi and above. The cost of fittings must be kept to a reasonable range such that a large diameter FRP system would be competitive with duplex stainless steel or carbon steel and a liner. There is a need to analyze the applicability or operating limits of the 8rd thread connection for 4 in. pipe and above in 2500 psi rated systems. A more robust thread or premium sealing system may be more appropriate.

3. There is a need to understand the properties and degradation mechanisms for FRP pipe used in cryogenic service, a new, emerging application. FRP tubing has been used recently for delivering liquid nitrogen downhole due to its insulation properties, excellent strength and toughness at extreme cold temperatures. There is a need to determine low temperature fatigue properties to assess the life of a string used for type of this service.

4. FRP line pipe and tubing for supercritical CO_2 service in WAG (water alternating gas) systems was identified as a high payoff item. Several of the manufacturers have new products that may meet those needs. It would be of interest to CEAC members to collect all relevant information on testing to date and perhaps be of assistance in solving any remaining technical issues for this intended application.

5. Interviews with corrosion engineers in oil companies identified that the potential for lightning strike and fire on fiberglass tanks is a major concern. In fact, the concern is so great that many companies currently refuse to consider fiberglass tanks in production

operations. Those companies who do use fiberglass tanks where there is the possibility of hydrocarbons take special precautionary measures to prevent static charge build-up and provide lightning rod protection. Another technique is to place a steel inlet pipes below the fluid surface level. The steel ground static charge and placing the inlet below the tank fluid level reduces the generation of static charge by mixing. In addition, fiberglass hatches are grounded.

It is not clear how static charge build-up affects the probability of lightning strike. Perhaps it is related to the increased electrostatic potential relative to the cloud. One tank manufacturer pointed out that in the last ten years, they had made and stored thousands of fiberglass tanks in their manufacturing yard and none had ever been struck by lightning. Something changes when the tank is placed in oil field service with flow and static charge is generated because many tanks, both steel and fiberglass, have been struck by lightning in oil field service.

Tank manufacturers are trying to address the concern by making the tank wall conductive to drain off static charge. Some solutions such as adding carbon veil to the tank during construction, or various forms of lightning protection and grounding schemes have been devised. Ameron has in-house technology in the use of carbon fiber to improve conductivity in jet fuel transport lines that may be transferable to this technical problem. A study funded by tank manufacturers and interested member companies could better define the reason for this phenomenon and propose acceptable solutions for grounding tank structures. Additional information should be compiled on fire safety experience in recent years with FRP tanks in hydrocarbon service.

6. Composite FWKO (free water knockout) vessels for 30-50 psi service might offer significant life cycle cost benefits for onshore applications. Maintenance on these vessels is high due to corrosion and buildup of scale, sludge and sand. Cathodic protection systems are difficult to maintain. Recoating the vessels in the field is difficult. The market potential is large considering there are thousands of FWKO's in the Permian basin alone.

7. For large CO_2 projects, spoolable pipe manufactured at the project site could result in significant savings. Hydrocarbon gathering lines (500 psi) and 2 in. to 6 in. water and CO_2 injection lines would be candidate applications. A project to investigate options for this type of endeavor may be of interest to CEAC member companies.

8. A future project could be funded to develop a hollow composite sucker rod based on spoolable pipe. The spoolable pipe would function both as a sucker rod and the tubing transporting produced fluids up the wellbore. New wellheads would have to be designed to accommodate this process. Another application for spoolable composites would be to hang a submersible pump from the bottom of a string that contains an imbedded electrical cable, thereby eliminating corrosion of the electrical system. Replacement costs for submersible pump cable is high ($40-50K) depending on well depth.

9. Developments in emerging reelable composite technology (Drillflex and IFP, both in

France) and spoolable composite tubing (Hydril, Compipe, and Fiberspar) provide the enabling technology for an all composite oil or gas well. The total cost and time required to drill and complete wells can be reduced significantly by eliminating the full sized drilling rig, the size of the drilling site, the volume drilled and by eliminating the transport of heavy pipe. Drilling of slim hole monodiameter wells with a coiled tubing rig could reduce drilling costs substantially. Completion of the wells could be performed with coiled tubing equipment using spoolable composite tubing. Small diameter flowlines up to 4-inch could also be installed using spoolable composite pipe.

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10.0 APPENDICES

10.1 Appendix A - Summary of the Industry Survey

CEAC FRP Survey Questionnaire

1. **Where do you currently use FRP line pipe, downhole tubing/casing and tanks?**

Altura - Water injections systems, water tanks.

Ameron - Supplier of fiberglass line pipe, tubing, casing and well screens.

Unocal - Emulsion gathering lines less than 500 psig, HP water injection lines less than 6" diameter primarily use 2" and 3" lines), battery piping(low pressure), limited use of tubing downhole (cemented some in place in a few wells with poor casing integrity).

Conoco - Water transfer applications for pressures greater than 300 psi, waterflood applications.

Chevron - Various waterflood applications

Phillips - Saltwater injection line service(2", 4"), downhole tubing in SWD wells and injection wells, low pressure flowlines, water tanks(110, 210, 300 bbls).

Arco - Water injection wells, low pressure water handling lines, firewater systems offshore, seawater systems.

BP Exploration - Minimal use to date

Paragon Engineering Services - Potable water storage tanks, firewater piping for offshore and onshore plants.

Marathon - Limited use in line pipe and tanks.

Smith Fiberglass - Supplier of line pipe, tubing, casing, no tanks.

2. **What internal or external specifications are used to purchase and install FRP products?**

Altura - API 15LR/HR

Ameron - API 15 LR, API 15HR, ANSI B31.3, UL, Factory Mutual, ISO 9001

Unocal - Reference API specs and vendor installation manuals.

Conoco - Midland division "Recommended Good Practices"

Chevron - API and company specifications.

Phillips - Vendor specifications primarily. Internal company service restrictions dictates material selected to satisfy design conditions for a specific application.

Arco - API 15LR/HR

BP Exploration - Performance Specifications.

Paragon Engineering Services - Specifications come from three areas: FRP manufacturers, client generated specs, and in-house specifications.

Marathon - internal guidelines plus manufacturers recommendations

Smith Fiberglass - API 15LR, API 15HR, ANSI B31.3, ISO 9001.

3a. Are these specifications adequate for your needs?

Altura - API 15HR is not useable in present form.

Ameron - Work is being done on API 15 LR and API 15 HR

Unocal - Yes

Conoco - Yes

Chevron - Yes

Phillips - No comment

Arco - Not really

BP - to date, acceptable

Paragon - database of design and procurement information from vendors adequate.

Marathon - Generally, yes.

Smith Fiberglass - API 15HR needs improvement.

3b. Does your engineering staff (i.e., production/facilities engineers) have adequate training to design systems with composite materials(FRP)? If not, would a training course targeted to design of composite line pipe systems be of value to

your company?

Altura - Yes. Yes.

Ameron - Yes. Would be willing to participate in the training.

Unocal - For their applications and staff, vendors support is adequate.

Conoco - For small diameter lines, yes. For composites other than fiberglass no.

Chevron - Yes

Phillips - Does not feel staff has enough training, but with limited use and heavy workload in the field, could not assemble enough people to hold a class.

Arco - No.

BP - No. Yes, would be interested in training.

Paragon - A training course would be of tremendous value for increasing awareness.

Marathon - Generally, do not design systems. This is done by engineering and construction firms. Would be useful if a course were developed for field engineers.

Smith - Yes. N/A.

3c. Are the manufacturers' installation guidelines adequate?

Altura - no, need improvement.

Unocal - yes, for low pressure and small diameter lines; better guidelines are need for high pressure line installation.

Conoco - yes.

Chevron - yes

Phillips - Some improvements are needed, but for most applications they are adequate.

Arco - Yes, generally.

BP - No comment.

Paragon - Most manufacturers have adequate information, however some have very limited information on fire rating.

Marathon - Have found them to be OK, problem is the contractors need permanent field inspections.

Smith - Has very complete guidelines on installation.

4. What factors currently limit your use of FRP products mentioned above?

Altura - Expertise of contractors installing the product, lack of design expertise inside engineering houses.

Unocal - Large diameter connections and fittings are expensive and troublesome (both low and high pressure). High pressure 4" and 6" connections are a weak point. Connections are not leakproof and/or require an inordinate amount of care.

Conoco - lack of application, corporate policy on restricted use, and cost.

Chevron - Hydrocarbons in FRP tanks, high pressure CO_2 in FRP pipelines.

Phillips - Initial cost has been a deterrent, tools for handling are usually designed for steel pipe.

Arco - No inspection techniques available, no QA/QC tests to perform in field.

BP - knowledge of applications and capability.

Paragon - Fire rating information.

Marathon - regulations, both offshore and onshore- fire resistance etc. Poor management perception of the product.

Smith - Robustness, temperature limitations, availability of steel vs FRP, lack of larger diameter, higher pressure products.

5. What are the alternative materials to FRP for your various applications?

Altura - Polyethylene lined steel pipe.

Unocal - HDPE pipe, plastic coated steel, cement lined steel, HDPE liner in steel, alloys.

Conoco - HDPE pipe, internal coated steel.

Chevron - Casing- steel, pipe- cement lined steel and HDPE liners in steel, HDPE for low pressure gas service.

Phillips - Duplex SS, internally coated steel w/ext. coating, steel w/corrosion inhibition.

Arco - Lined steel, alloys.

BP - Steel.

Paragon - steel, galvanized, or plastic (HDPE).

Marathon - Cu/Ni piping, internally coated pipe, SS pipe, carbon steel with inhibitors

Smith - Steel, CRA's , HDPE, SS, CuNi alloys.

6. **What type of economic calculations are performed in order to justify FRP compared to alternative materials?**

Altura - direct cost comparison with no life span differentiation.

Ameron - Initial cost and life cycle calculation programs available.

Unocal - Just review the total installed cost, no life cycle costs.

Conoco - Comparison on initial cost and installation, not life cycle costs.

Chevron - total cost of ownership.

Phillips - reduction in life cycle costs.

Arco - Installed cost.

BP - No comment.

Paragon - Life cycle costs compared to steel.

Marathon - lowest lifetime cost.

6a. **Does your company receive an economic payoff from FRP installations? Please estimate savings or percent return on investment.**

Altura - Yes, 30% less expensive than poly lined steel, much longer life than IPC steel.

Unocal - Yes, but have not quantified savings, assumption is FRP systems less maintenance intensive.

Conoco - no comment.

Chevron - no comment.

Phillips - hard to judge.

Arco - No comment.

BP -In very limited applications, economic payoff was generated by limiting impact to production operations and shut-in during installation.

Paragon -We perform services to end users, but estimate that in most cases studied, the economic payoffs are between 35 and 50%.

Marathon - No idea on ROI.

7. **What specific problems areas, that if addressed, would allow greater use of FRP equipment within your organization? (Examples: temperature rating, chemical resistance, tensile and pressure rating, connection performance)?**

Altura - No comment.

Ameron - Product emerging with improved temperature rating, pressure capability, fire resistance and impact resistance. Additional technology being evaluated for their applicability with FRP.

Unocal - Pressure rating/connection performance for 4" and larger pipe needs improvement. Quality control. CO_2 Service. Robustness/mechanical integrity. Quality control on flanges.

Conoco - Pressure rating on larger pipe.

Chevron - High pressure CO_2 service. High pressure pipe > 8 in. diameter.

Phillips - Downhole applications would offer the greatest benefit. Inhibition is a large expense. However, improvements are desired in many areas, i.e., all design ratings and the packaging so that conventional tools can be used to run and pull the tube.

Arco - Temperature rating, pressure rating, connection reliability.

BP - expanded application limits with respect to temperature, pressure.

Paragon - Fire rating, chemical resistance, durability under heavy duty industrial application around drilling rigs and production equipment.

Marathon - Wider accreditation to the API monogram program. Better management perception. Non-destructive method of ensuring the integrity of adhesive joints. Less restrictive/high expertise installation methods.

Smith - temperature rating, pressure rating boundaries increased.

8. **For downhole related FRP products, are there problems with related tools and**

services? Comment on problems with running, cementing, perforating, fishing etc. Problem with packers?

Altura - no comment.

Ameron - Wellhead slips may need to be modified to grip properly. Rod guides need to be nonabrasive.

Unocal - Little experience with FRP tubing. Requirement for a permanent packer is a disadvantage especially since well clean outs are routine.

Conoco - N/A.

Chevron - N/A.

Phillips - Tool damage and the fact that special running and handling tools are required.

Arco - Can't run heavy pumps, deep strings.

BP - N/A.

Paragon - N/A.

Marathon - Do not use FRP downhole.

Smith - N/A

9. **Would a continuous spoolable composite line pipe/tubing product be of interest and have applications in your operations? List the potential applications?**

Altura - Yes, well flowlines and water injection lines.

Unocal - Yes, low pressure 500 psi pipe for flowlines and gathering systems.

Conoco - Very much so.

Chevron - Production flowlines(LP), Water injection lines(HP)

Phillips - Yes. Advantages would be minimized connection, faster installation, reduction in potential leak paths.

Arco - Yes, jumper lines, quick connects, short flowlines.

BP - No comment.

Paragon - No. Applications are short runs, many turns.

Marathon - Yes, less joints and would be less prone to installation problems.

Smith - Flowlines, injection lines.

10. **Have you ever identified microbiological degradation of the pipe as a failure mode?**

Entire group answered no.

10.2 Appendix B - Lifecycle Cost Analysis Spreadsheet User Guide

I. Introduction

Materials and corrosion engineers spend much of their time providing technical solutions to corrosion problems. However, once all of the technically viable alternatives to a problem are identified, the decision of which alternative to choose becomes a question of engineering economics. This involves calculations related to time, money and interest rates. It is important that a proper engineering economic analysis be conducted so that the choice is based on the best way to utilize capital in the current interest rate environment consistent with the corporation's internal rate of return goals.

The engineer must identify the unique stream of cash flows related to each alternative, for example, when comparing the cost of a steel line versus FRP pipe, various operating and maintenance expenses for steel will include the cost of inhibitors, the chemical pump, cathodic protection equipment, anode replacement, cost of pipeline leaks, deferred production etc. This series of cash flows can be readily translated to a net present value for comparison purposes. Often it is useful to convert the present worth of two alternatives with different lifetimes to an equivalent annual cost in order to provide a valid comparison. The lifecycle spreadsheet developed in this study does this automatically for the user.

The net present value (NPV) method, also known as the present worth (PW) method has the broadest application to engineering economy problems. Some refer to this approach as the "discounted cash flow" method. For this report, annual compounding of interest is used. The effect of taxes, depreciation and salvage value must generally be considered and are used to calculate net present value in the spreadsheet program. Additionally, if abandonment of equipment is expected, these costs can be entered as an expense in the final year. Straight-line depreciation is used over the estimated lifetime of the equipment.

II. Data Entry

The user can compare up to four materials systems at one time. The worksheet labeled "Data Entry" is the main data entry template for the program. The user must enter the assumed inflation rate, company cost of capital and the corporate tax rate which is currently 34%. These three numbers should be entered as decimals. All figures should be entered in current year dollars as positive values, including estimates of salvage costs, abandonment costs, and yearly expense costs. The program automatically will inflate the input data, adjust the numbers for the proper sign convention(ie. positve or negative cash flows) and calculate the present value accordingly. The output may be found on the sheet called "Summary".

The user should enter the project name to the right of the box labeled "PROJECT". Enter a description of the materials system type to the right of the box labeled System 1, 2, 3 and 4. The titles are automatically linked to the "Summary" data sheet and the other detailed calculation worksheets.

III. Results

1. Interpretation

The results of the calculations are presented on the worksheet called Summary. The estimated life, initial cost, the equivalent annual cost and the NPV at 5 year intervals is generated. If the estimated lives of the alternatives are the same, then the NPV for the given time period are compared directly and the system with the lowest NPV is the most economical. However, if the lifetimes of the materials systems are different, the equivalent annual costs should be compared and the system with the lowest annual cost is most economical.

It is also useful to compare how the NPV varies with both inflation and interest rates to test the sensitivity of the investment in different economic environments. It is wise to check with the corporate finance group to determine their interest rate outlook for the future and obtain their guidelines for testing investment decisions against various interest rate scenarios.

2. Comparative Analysis Tools

Some common methods of comparing investment decisions include the internal rate of return method, the average rate of return, the NPV, and the payback period. Some oil companies use a method called, "net on net", which is the net present value profit divided by the net (after tax) investment. This is a useful method for comparing different materials systems to a base case or a do nothing case. The net on net can be calculated directly using the output data from the summary sheet. The user simply subtracts the two NPV values at year X, (i.e., 25 years) and divides the result by the net after tax initial investment obtained from the appropriate system type worksheet in the year zero column. This is represented by the following equation:

$$\text{Net on Net \%} = (\text{NPV2} - \text{NPV1})/\text{NPV2(year zero)} \times 100$$

This method is useful for comparing the rates of return of several materials options for a given cost of capital and inflation rate. Engineers are strongly urged to seek the advice of management to determine the specific criteria for their respective company.

10.3 Appendix C - FRP Product Applications Database.

FRP Applications Database- CEAC Study 1997

Field Location	Pipe Size	Pipe Pressure Ratin	Pipe Temp. Ratin	Joining Method	Application Type	Service Temperature	Service Pressure Int.	Service Pressure Ext	No. Feet	Fluid Characteristics	Depth(for downhole apps.	Design Specification Use	Time in Servic	Comments on Success/Failures
Phillips Co. Wide Est.	1in to 4in	Vacuum to 3000psi							>172,000				>= 20 years	
Phillips- Sidney MT		500			LP Gathering Line								1985	
Phillips- Smackover,AR	3in, 4in	200		Smith Silver Thread	Flowlines		200		7500				1975	
Phillips- Maureen	1in,2in	200			Flowlines									
Phillips- GANDU	4"	2200		Ameron	SW Injection				18,400	Salt water			1993	Failure on testing 4"x6" flange.
Phillips- GANDU	2"	2200		Ameron	SW Injection				27,800	Salt water			1993	
Phillips- New Mexico	2"	3000?			SW Injection		800		3000	Salt water			1991	No problems noted
Phillips- NPU	4.5"	2000		Ameron	SW Injection				22,500	Salt water			1991	No negative exp. very successful
	3.5"	2000		Ameron	SW Injection				14,500	Salt water			1991	No negative exp. very successful
	2.875"	2000		Ameron	SW Injection				24,000	Salt water			1991	No negative exp. very successful
Phillips- Dumas, TX	2", 2.5"	150			SWD gathering		150		53,000	Salt water/oil			1974	Lines plug w/oil,hard to clean
														Lines hard to detect, breakage
														numerous repairs.
Phillips- Gymon,OK	2"	vacuum			SWD gathering		vacuum		13,200	Salt water			late 1970's	Long life, minimal repairs
Amoco-Companywide	various								26,400,000	All types of service				
Amoco- Baroil, WY	12", 16"	500		Adhesive bonded.	Sour gas		300-400			90% CO2			late 80's	Initial system failed UV exposure
														of joints prior to bonding. Repaired
														system successful over 10 yrs.
Amoco-Bravo Dome,NM	5", 5.5"				wet 100% CO2					100% CO2				FRP casing liners-successful
Amoco-Bravo Dome					Tubing					wet 100% CO2				CO2 source wells.
Amoco-Rocky Mountains			180F		Oil/water flowlines	150F				oil/water			7 to 8 years	Pipe failed.
Exxon-Companywide-US	2" to 16"	150 to 2500 psig	<200F			<200F limitation	<2000 psi limitation		1,630,000			API 15LR/HR, in house		
Exxon- Conroe field	2.5" to 3"	1250 psig			flowlines		100		260,000				25 years	Successful installations,service
	4"	2000 psig		8rd threads	injection lines				?	salt water			25 years	Successful installations, service
Exxon- West TX EOR proj									600,000				20+ years	various applications
Exxon- Means Field									750,000				13 years	various apps in WAG project
Exxon- West TX	4" to 8"				gas gathering		60		38,000	1.5% CO2,1.5%H2S			26 years	Succesful
Royal Dutch Shell	2" to 16"	up to 1400psig	212 F		various				7,400,000				variable service	
Royal Dutch Shell	3.5"				waterflood inj. line	150F	1300 psig			salt water			17 years	Successful
Royal Dutch Shell	4"			integral threads	water injection	140F	150 psig		23000	salt water			11 years	Successful use in remote area
Royal Dutch Shell	16"				water transfer	122F	319 psig		32,700	formation water			11 years	Successful
Royal Dutch Shell	2.5"				oil flow line	130F	80 psig		16,400	oil/water			19 years	Successful
Royal Dutch Shell	2.5"				oil flow line	130F	150 psig		26,100	oil/water			14 years	Successful
Royal Dutch Shell					emulsion service		150 psig		420,000	oil/water			21 years	Successful
Royal Dutch Shell					high water cut lines		150 psig		49,000	oil/water			17 years	Successful
Royal Dutch Shell					dry gas lines	ambient	60 psi			gas, dehydrated				Successful
Royal Dutch Shell					salt water disposal		780 psi			sour water			variable servic	Successful
Oryx Energy Nome Field	2.375"	2500 psig	200F	8 rd threaded coupl.	gas well prod.tubing	180F max	1400 FTP		7750	wet gas	7750		2 years	Successful, no degradation
Mobil- Salt Creek Field	10-16"	450 psi		tapered adhesive joi	sour gas gathering	100F	275-300 psig			1000-3000 ppm H2S			1.5 years	Successful
Mobil- Anton Irish Field	various								300,000	various				Successful
Shell Canada- General	various	300 psi			water injection		300-400 psig		1,500,000	salt water-sour			30+ years	Sampled lines after 21 years
														No sign of delamination or structural
														failure. Few failures-human error
Shell Canada- Saskatchwn		500-800 psi			flowlines-oil				300 lines	unknown			30 years	very successful
Shell Canada- General		2500 psi			salt water disposal		1800		50 lines	salt water			unknown	successful- only one failure of
														fitting on an 1800 psi line.
Shell Canada- General	20"			bonded joints	low press. suction ln					salt water		B323	unknown	successful-one failure-mech.damage
Pan Canadian-General	various	low pressure		O-ring seal joint	low press.gathering				800,000	oil/water			unknown	some failures due to thread dope and
														one leak due to over pressure 1.25x sta
Amerada Minerals-Gener	various				WAG	-5F			1,000,000	CO2/water			<5 years	MASSIVE failure of system, pipe becam
														brittle CO2, fatigue, make-up problems,
														low temperatures.
Amerada Minerals-General		low pressure			water/gas service	100F				15%H2S gas service			<9 years	Hydrogen embrittlement, uniform dama
														over whole interior surface.
Aramco- Saudi Arabia	10-12"				Injection water	180F	435-652 psig							Ameron pipe
Unocal(California)	10"				Geothermal reinject.	248F	500 psig							Ameron pipe
PDO-Shell Oman	8"				Disposal water	95F	725 psig							Ameron pipe
Sonatrach-Algeria	10-12"				Injection water	176F	1100 psig							Ameron pipe
Sonatrach-Algeria	24"				Crude oil	140F max	400 psig							Ameron pipe
PDO- Shell Oman	4-16"				Injection water	77F	580 psig							Ameron pipe
Sonatrach- Algeria	12"				Injection water	158F	435 psig							Ameron pipe
ICI-United Kingdom	24"				Saturated Brine	77F	464 psig							Ameron pipe
ELF- France	4"-8"				Crude oil	113F	580 psig							Ameron pipe
Gupco/Amoco-Egypt	24"				Crude oil	113F	290 psig							Ameron pipe

FRP Product Applications Database, Continued.

Field Location	Pipe Size	Pipe Pressure Ratin	Pipe Temp. Ratin	Joining Method	Application Type	Service Temperature	Service Pressure Int	Service Pressure Ext	No. Feet	Fluid Characteristics	Depth(for downhole apps	Design Specification Use	Time in Servic	Comments on Success/Failures
Centron Applications from 1977 to present- Partial List of locations, end use and quantity.														
Chevron-Sacroc Unit					Flowlines, inj. lines				500,000					
Chevron-Sandmills,Penwell, TX					Flowlines, waterflood				400,000					
Conoco-Maljamar,NM					Injection lines				300,000					
Terra Energy-Traverse City,MI					Injection tubing				250,000					
Tenneco-Englewood,CO					Line pipe				200,000					
Exxon Pipeline-Longview, TX					Injection lines				500,000					
Exxon-Means Field-Andrews TX					Injection lines				1,760,000					
Exxon Pipeline,Fairfield ND					Injection lines				200,000					
Amoco, Durango, CO					Gas Gathering				4,100,000					
Marathon, Cody WY					Injection lines				300,000					
Mobil, Pegasis Field, Midland TX					Injection lines				150,000					
Mobil, Salt Creek,TX					Injection lines,tubing				400,000					
Sceptre Resources, Calgary, CAN					Injection lines, tubing				120,000					
Shell Oil, Denver City, TX					Injection lines				25,000					
Brunel Shell, Ranau Field					Line pipe				5,000					
Shell/Thailand					Line pipe				24,000					
Japex/PDO Oman	3"				Injection lines				65,000					
BP Leeds Field, Newark	2.375"				Tubing				8,000					
Gulf Canada, Stettler,AB	2.375"				Tubing				60,000					
Mobil, Countyline OK					Line pipe				175,000					
Henry Eng.,Seminole, TX	2.375"				tubing				230,000					
Mobil, Cement OK					Injection lines				120,000					
YPF, Argentina	2"-6"				Injection lines/tubing				2,400,000					
PetroPeru	4", 6", 8"				Line pipe				100,000					
Maraven, Venezuela	4"				Subsea injection line				7000					
Perez Companc,Argentina					Injection pipe/tubing				352,000					
Kondpetroleum Russia					Line pipe				4,000					
Urdmutneft, Russia	2.875"				Tubing				15,000					
Petrolera, San Jorge, Arg					Injection pipe/tubing				18,000					
Shell-Turkey	4"				Injection lines				55,000					
N.A.M.	6",8"				Line pipe				125,000					
Mobil-Indonesia					Refinery				10,000					
Wapet, Australia	2"				Line pipe				6,500					
Petrobras, Brazil	2", 4"				Line pipe				600,000					
Lagoven, Venezuela	4"				Casing				27,000					
Bunduq, Abu Dhabi					Subsea inj. Line				2,000					
Mim Holdings, Australia	2"				Gas line				28,000					
Western Power, Australia	4"				Slurry pipe				12,000					
Wester Mining,Australia	3"				Casing				8,000					
Conoco, Australia	2"				Gas Gathering				26,000					

11.0 ECONOMIC ANALYSIS DISKETTE

The attached PC diskette contains the life cycle cost analysis program called "Life Cycle Economic Analysis.xls" prepared in the EXCEL spreadsheet format. The FRP product applications database described in Section 10.2 is also available on the diskette.