I

Coiled-Tubing Technology
(1995-1998)

DEA-67
Phase II

PROJECT TO DEVELOP AND EVALUATE COILED-TUBING AND SLIM-HOLE TECHNOLOGY

By

MAURER ENGINEERING INC.
2916 West T.C. Jester Boulevard
Houston, TX 77018-7098

Telephone: (713) 683-8227 Facsimile: (713) 683-6418
Internet: http://www.maureng.com
E-Mail: mei@maureng.com

TR98-10

April 1998

Coiled-Tubing Technology

(1995-1998)

TABLE OF CONTENTS

1. Artificial Lift

TABLE OF CONTENTS

1. Artificial Lift

1.1 CENTRALIFT AND SHELL EXPRO (CT-DEPLOYED ESP)

Centralift and Shell Expro UK (Watkins and Stewart, 1996) described planning and implementing a successful CT-deployed electric submersible pump (ESP) offshore in the Auk field (North Sea). Several new tools and procedures were developed for this installation. Various methods were analyzed in the search for alternate techniques for deploying ESPs in the field. The first CT-deployed pump was working well one year after installation, and a utilization rate of 96% was reported.

The conventional method of artificial lift in the Auk field was wireline-retrievable hydraulic jet pumps installed with a rig. Limited capacity in the hydraulic supply system permitted only three wells to be lifted simultaneously. Shell therefore sought alternate systems for artificial lift.

After Shell settled on ESPs, potential deployment methods were investigated. Changing the conventional deployment method would allow a savings of 20% on future workovers, a 50% reduction in installation times, and a savings of 100 man-days in bedding. Deployment methods considered were: 1) hydraulic workover rig, 2) cable suspension, and 3) coiled tubing.

Cable deployment was not suitable due to the well's 74° inclination at depth. CT was determined to be more economic and better suited to operational experience in the field than a hydraulic workover system.

New equipment was developed, including high-strength CT connectors to join reels of 2⅞-in. tubing and to connect completion subassemblies (SSSV etc.). A new packer was designed that could be set and released hydraulically. The tubing spool was modified to permit the power cable to exit the wellhead at a right angle (Figure 1-1). This provided a major cost savings by maintaining the original flow-line height.

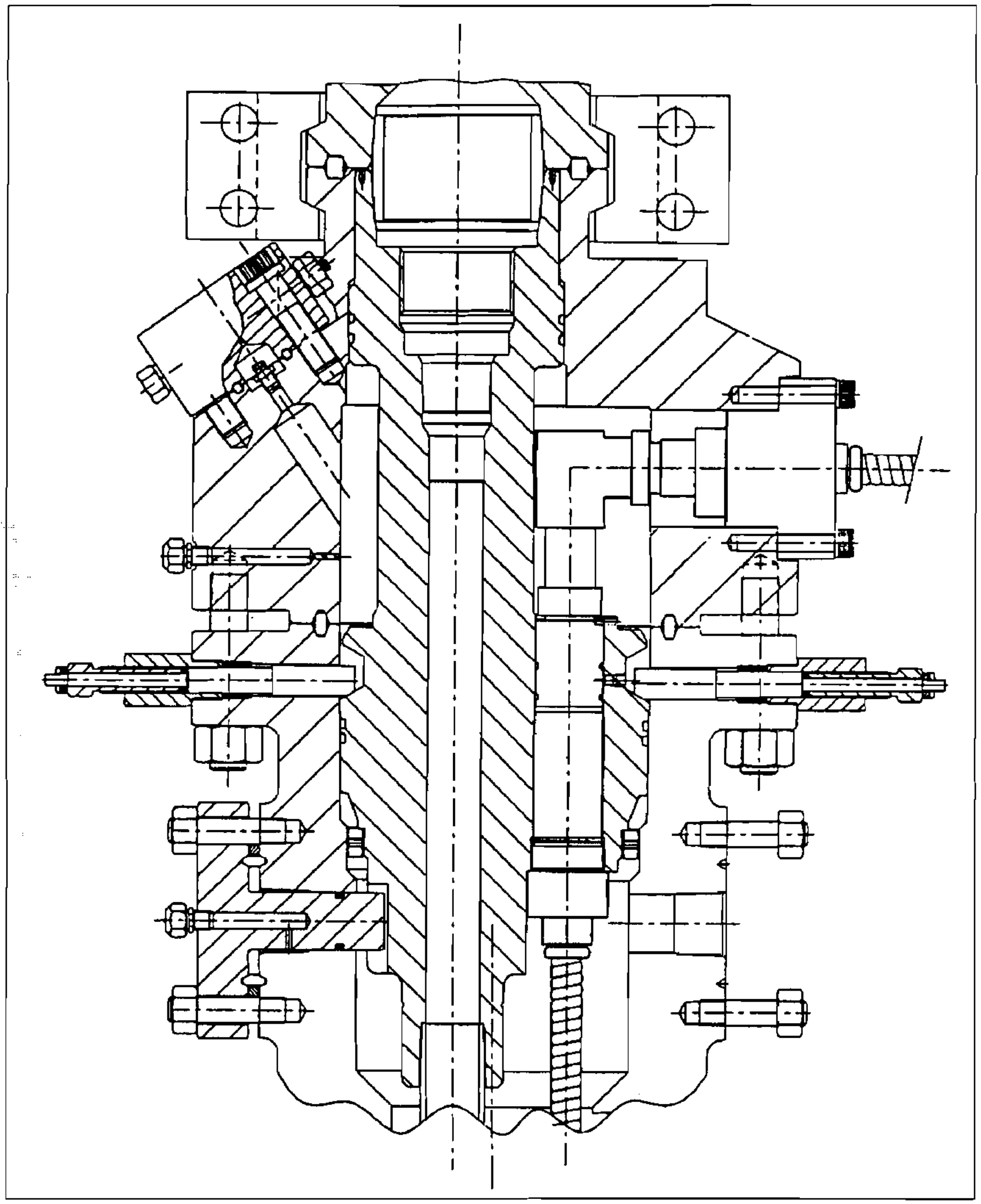


Figure 1-1. Modified Tubing Spool
(Stewart et al., 1996)

The ESP downhole assembly (Figure 1-2) included a 280-HP motor.

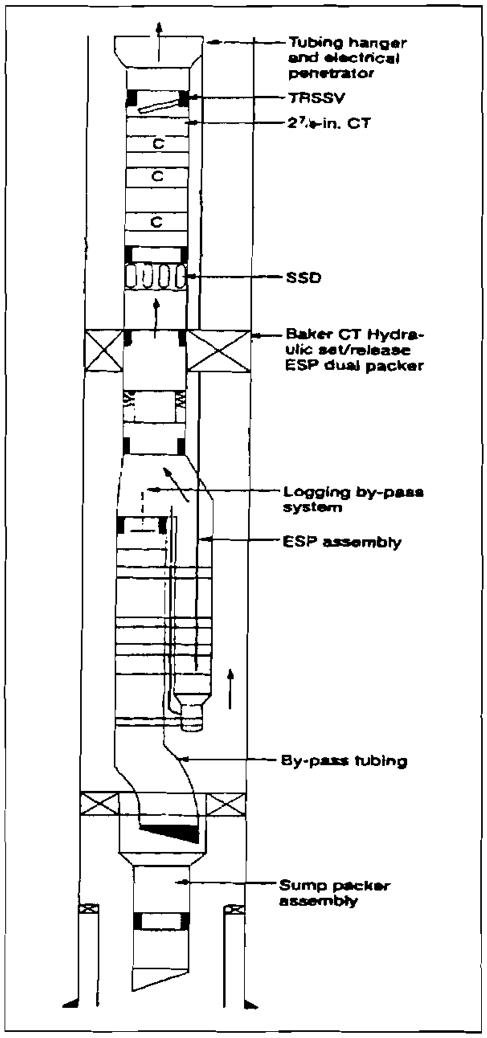


Figure 1-2. ESP Assembly for Auk Field (Watkins and Stewart, 1996)

Platform height restrictions required the fabrication of a special tower frame for supporting the gooseneck and extension. Three stack-up tests were performed with the new equipment, including a full trial installation in Aberdeen.

1.2 HALLIBURTON ENERGY SERVICES (CT ARTIFICIAL LIFT)

Halliburton Energy Services (Courville and Clark, 1995) summarized the increased potential of CT for artificial lift applications, particularly with the advent of larger tubing sizes. CT is clearly well suited for use in relatively low-pressure wells in non-hostile environments. ESPs can be deployed on CT, and several gas-lift methods are being developed and refined.

The well-known advantages of CT for production applications include reduced formation damage (underbalanced installation, no pipe dope), improved wellbore integrity (no joints, no leaks), easier operations (pressure tested at factory, rapid run-in speeds), and lower costs (competitive tubing cost, rigless operations). Disadvantages for production applications include the general undesirability of on-site welding, the need to perform hot work outside the well, and the lack of industry experience with large CT with respect to life and corrosive environments.

CT is particularly well suited for deploying ESPs because of the absence of connections. Threaded connections slow installation and provide a large number of potential crush points for the power cable and leak paths for production.

ESPs can be deployed on CT with either side-by-side or concentric methods. For the side-by-side method, the power cable is banded to the CT as it is run in the hole (Figure 1-3). This method is more practical and less complex than the concentric method (power cable inside the tubing), except during installation. An advantage of the concentric method is removal of the need to kill the well during the operation.

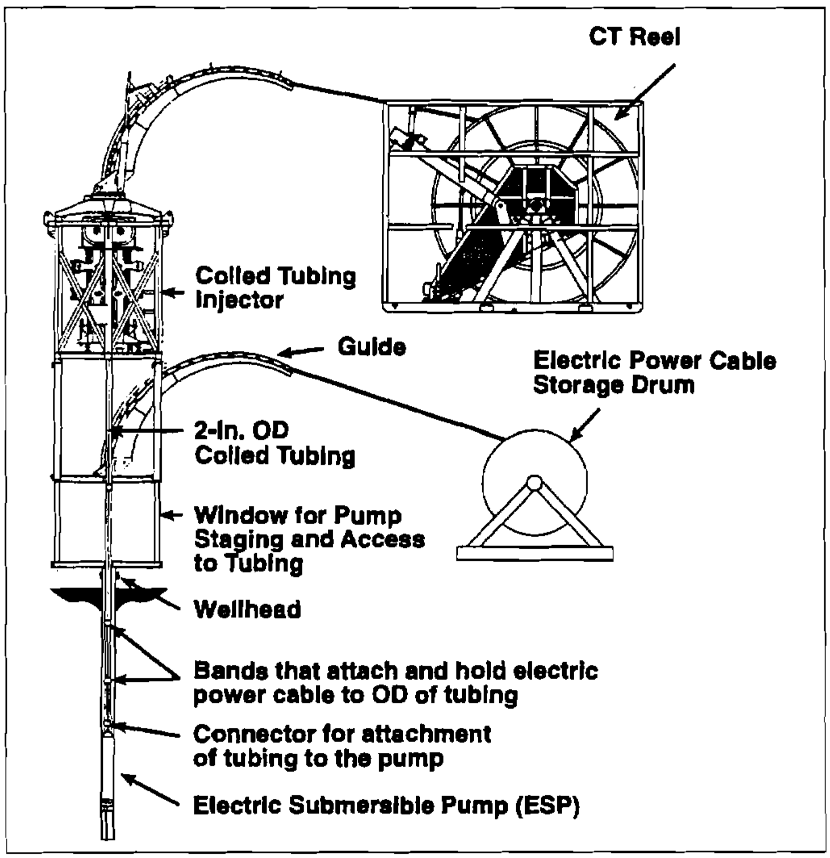


Figure 1-3. CT-Deployed ESP (Courville and Clark, 1995)

Earlier operations deploying ESPs on small CT required only mechanical support from the tubing, that is, the tubing was not used as a flow line. High friction losses inside the CT (Table 1-1) required that production be routed through the annulus. With larger CT, acceptable flow rates are now attainable through the CT.

TABLE 1-1. Maximum Flow Rates for CT (Courville and Clark, 1995)

Measured Depth (ft)	Maximum Calculated Flow Rates (B/D) Tubing Size (in.)						
	1¼	1½	1¾	2	2⅜	2⅞	3½
1,000	3,066	5,708	9,432	12,336	21,556	39,086	70,931
2,000	1,984	3,693	6,103	8,002	13,948	25,292	45,879
3,000	1,490	2,774	4,584	6,010	10,478	18,998	33,449
4,000	1,182	2,201	3,637	4,768	8,312	15,071	27,325
5,000	960	1,787	2,952	3,871	6,747	12,235	22,176
6,000	783	1,458	2,410	3,159	5,507	9,985	18,095
7,000	633	1,179	1,948	2,554	4,451	8,072	14,623
8,000	497	925	1,529	2,005	3,494	6,336	11,475
9,000	364	677	1,119	1,468	2,558	4,639	8,396
10,000	215	400	661	867	1,511	2,740	4,951
11,000	0	0	0	0	0	0	0
12,000	0	0	0	0	0	0	0
13,000	0	0	0	0	0	0	0

1.3 SCHLUMBERGER DOWELL (UNLOADING WELLS WITH CT)

Schlumberger Dowell (Gu, 1995) presented an analysis of transient flow for operations involving nitrogen injection through CT for unloading wells. Transient behavior is very important for determining optimum nitrogen volume, injection time, injection depth etc. for unloading a well. They used a CT simulator to investigate these interactions. Tubing OD, workover fluid, nitrogen rate and nitrogen volume were analyzed with respect to sensitivity on job design. Job costs can be minimized by optimizing injection rate and time (i.e., minimize total nitrogen volume).

For wells where reservoir pressure is sufficient to lift produced fluids after heavier fluids are removed from the wellbore, a short-term lifting process can be used to unload the well and restore production. The composition of the wellbore fluid changes during the unloading operation; steady-state conditions are not reached until the well is unloaded and production restored.

Schlumberger Dowell ran several test cases to investigate the interactions of various parameters on the success of the unloading operation. One parameter is the composition (i.e., weight) of the fluid in the wellbore. The assumed test conditions included a TD of 12,200 ft, 4-in. casing, no tubing, 4700-psi reservoir, and 15,000 ft of 1¼-in. CT. Nitrogen is injected at a rate of 300 scfm during run-in. At 12,000 ft, injection is increased to 600 scfm for 90 min. Flow rates for this operation are charted in Figure 1-4.

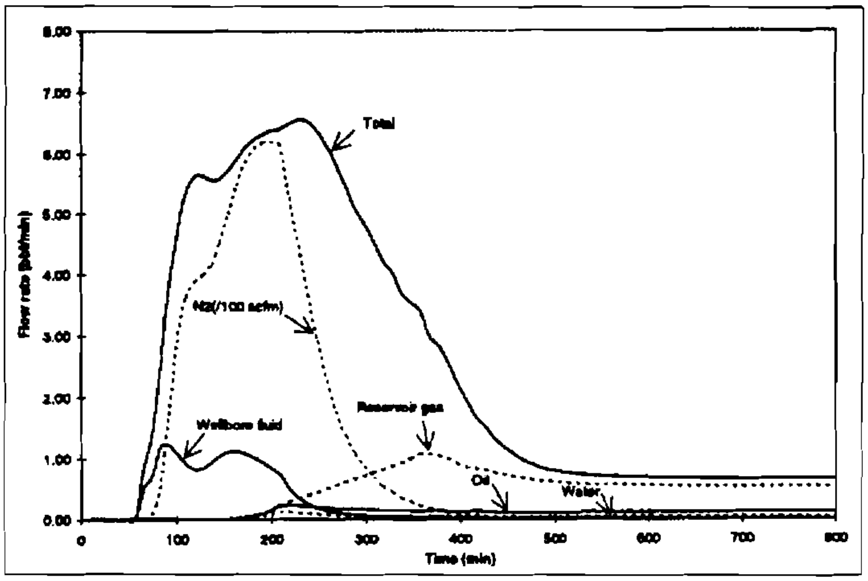


Figure 1-4. Nitrogen Injection to Unload Well (Gu, 1995)

The operation depicted in Figure 1-4 assumes that the wellbore fluid has an SG of 1.0. For these parameters, the wellbore will be successfully unloaded and begin producing after injection is stopped. However, if the fluid density is assumed to be SG=1.15, not enough fluid will be unloaded to sustain production after injection is halted. More injection time would be needed if a heavier fluid is in the wellbore.

Another important variable is the impact of reproduced workover fluids. For this analysis, a TD of 9030 ft, 2⅞-in. production tubing to 8500 ft, 4½-in. casing to TD, 3500-psi reservoir, and 15,000 ft of 1¼-in. CT were assumed. Nitrogen is injected at 300 scfm and the CT is parked at 8800 ft. Unloading can be completed in 150 min if workover fluid was not lost to the formation. If 50 bbl of workover fluid needs to be produced from the formation, injection time must be increased to about 240 min (Figure 1-5).

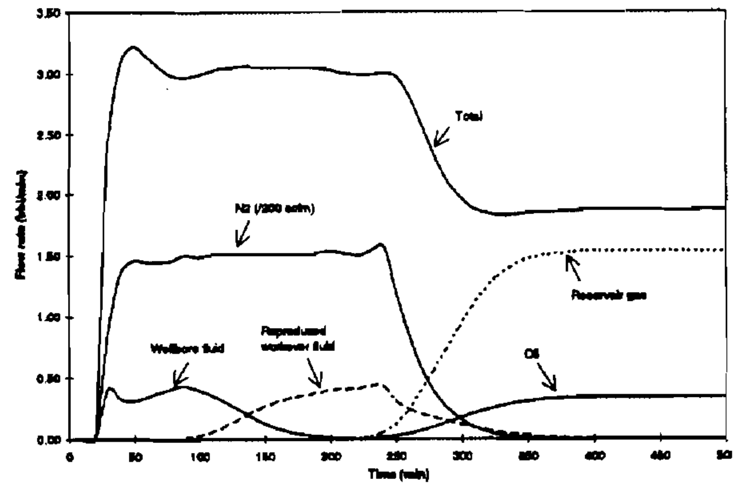


Figure 1-5. Unloading with Production of Workover Fluid (Gu, 1995)

An assessment of the volume of workover fluid to be produced back from the formation has to be estimated based on previous experience in the field. Upper and lower bounds should be used to design the unloading operation.

Optimizing injection rate is another important aspect of job design. As injection rate is increased, frictional losses in the annulus increase. The drawdown imposed on the formation is a combination of hydrostatic and friction pressure at the formation. It is desired to minimize nitrogen volume and injection time to minimize job costs.

For this analysis, job conditions included a TD of 11,050 ft, 2⅞-in. production tubing to 10,500 ft, 4½-in. casing to TD, 2800-psi reservoir, and 13,000 ft of 1½-in. CT. A constant total volume of 91,500 scf was injected. Several nitrogen injection rates were used. At higher rates, friction pressure lowers drawdown pressure at the formation, and unloading is not successful (Table 1-2).

TABLE 1-2. Effect of Injection Rate (Gu, 1995)

Unloading Results for Different Nitrogen Rates (CT OD = 1.5 in., N_2 Volume = 91,500 scf)		
N_2 Rate (scfm)	Stop Time (min)	Unloading Outcome
300	350	Successful
600	230	Successful
900	190	Unsuccessful
1200	170	Unsuccessful

CT size also impacts job success. For the case in Table 1-2, an injection rate of 900 scfm would be successful if CT diameter were decreased to 1¼ inches.

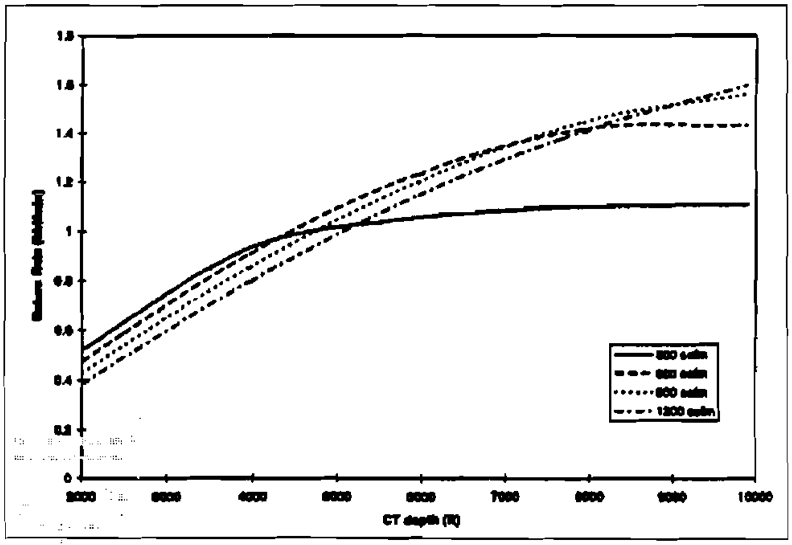


Figure 1-6. Return Rate with 1½-in. CT (Gu, 1995)

Depth of injection is another important parameter. The model well for this analysis had a TD of 10,000 ft, 2⅞-in. tubing to TD, a productivity index of 0.5 BPD/psi, and 15,000 ft of 1½-in. CT. Liquid return rate for a range of injection rates is shown in Figure 1-6. For 300 scfm, the liquid rate increases only slightly for injection depths greater than 4000 ft. A maximum practical depth can be estimated for any injection rate. Running the CT deeper than this may not provide any added benefits.

This depth analysis is of course impacted by CT OD (and annulus size). For smaller CT (1¼ in.) in larger tubing (5-in. casing), friction losses are less important. Higher injection rates can increase unloading rates without creating significant friction losses (Figure 1-7).

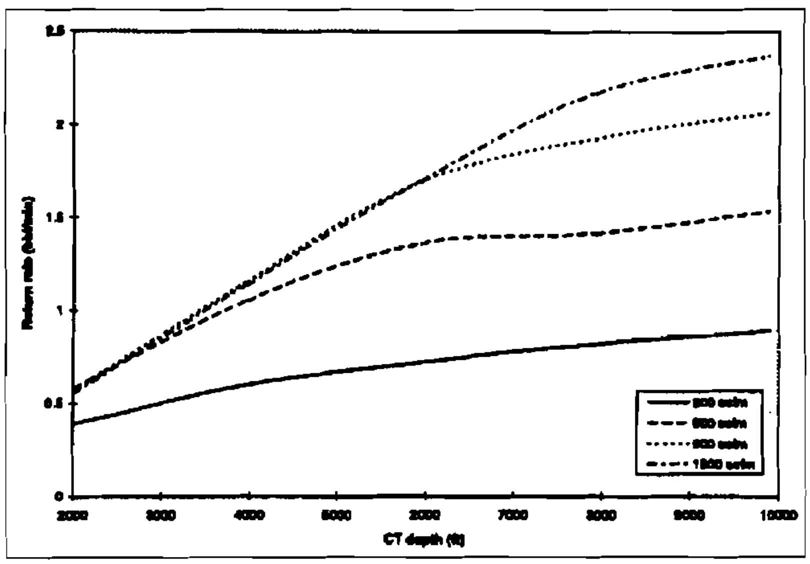


Figure 1-7. Return Rate with 1¼-in. CT (Gu, 1995)

1.4 SHELL WESTERN E&P (CT CO_2 GAS LIFT)

Shell Western E&P (Sorrell and Miller, 1997) described the design and evaluation of two CO_2 gas lift installations in the Denver Unit, a mature field in West Texas. The field is now under tertiary recovery with CO_2 water-alternating-gas (WAG) injection. Costs of the CT applications ranged between $65,000 and $75,000 (Figure 1-8).

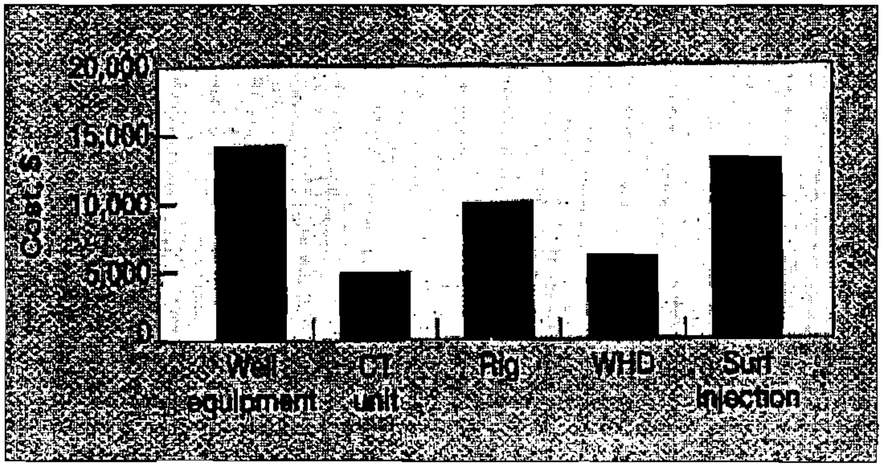


Figure 1-8. Costs for CO_2 CT Gas Lift (Sorrell and Miller, 1997)

More information is presented in *Production Strings*.

1.5 TEXACO, McMURRY-MACCO LIFT SYSTEMS, AND DOWELL (CT GAS LIFT)

Texaco E&P, McMurry-Macco Lift Systems, and Dowell (Tran et al., 1997) described several successful installations of CT gas lift. On-location make up of the gas-lift assembly reduced costs. The completion method has been mechanically and economically successful, and will be applied in other fields.

The gas-lift mandrels were installed on-site by cutting the CT as the completion is run in (Figure 1-9). The crew can perform a tensile test for checking connector and string integrity and a pressure test for the valves and connections.

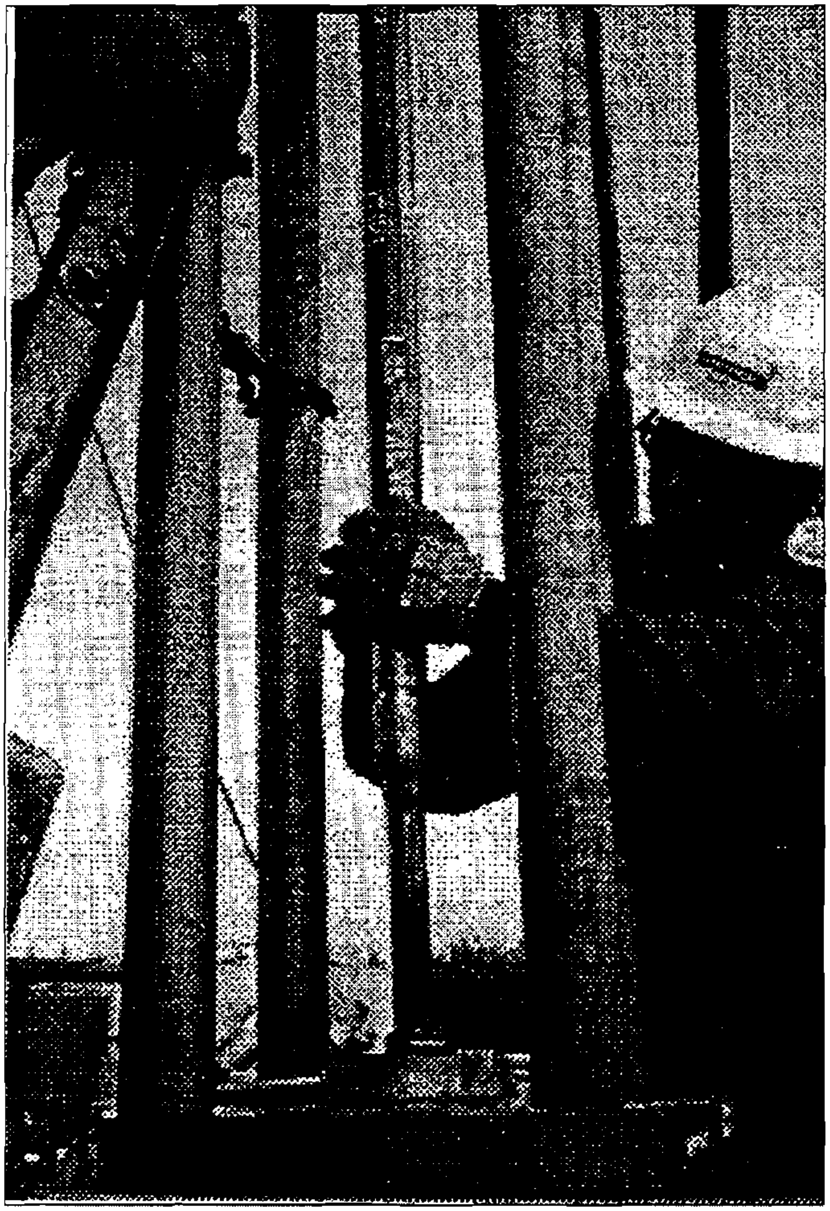


Figure 1-9. Work Window for Installing Gas Lift (Tran et al., 1997)

In one field installation, a 10,000-ft string of 1½-in. CT was run in the Brookeland Field. Bottom-hole pressure was too low for conventional gas lift. CT gas lift improved daily production (Figure 1-10) and reduced the initial annual decline from 97% to 20%. Installation cost was $60,000.

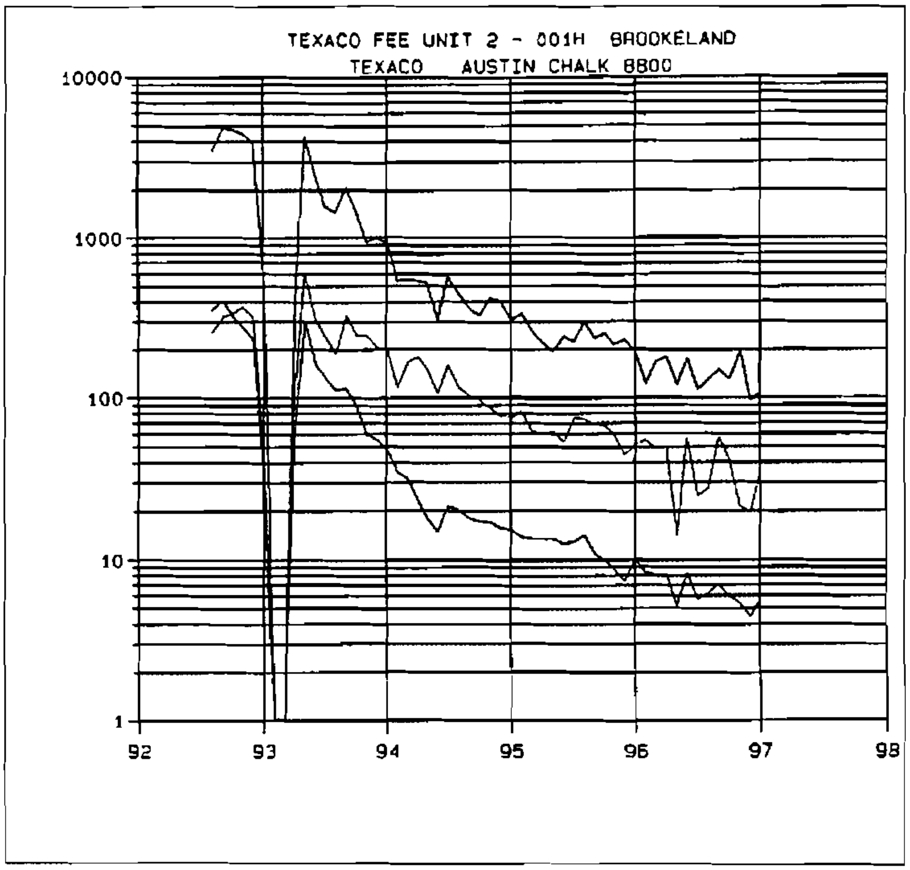


Figure 1-10. Production of CT Gas-Lifted Well (Tran et al., 1997)

Project members found that injection gas requirements were about half that used in conventional gas lift for the same production. The cost of the field-fabricated string was less than a manufactured spoolable string.

1.6 TRICO INDUSTRIES (JET PUMPS)

Trico Industries (Tait, 1995) enumerated the advantages of jet pumps run on CT for artificial-lift applications in horizontal and vertical wells. A primary advantage is the lack of moving parts in the assembly. Energy is provided to the jet pump by pumping power fluid from the surface (Figure 1-11). The power fluid may be produced oil or water, treated sea water, diesel , or other fluids. The primary advantages of jet pumps are a wide range of flow rates, deep lifting capacity, and the ability to handle fluids that have high sand concentrations, are corrosive, are at high temperatures or have significant free gas.

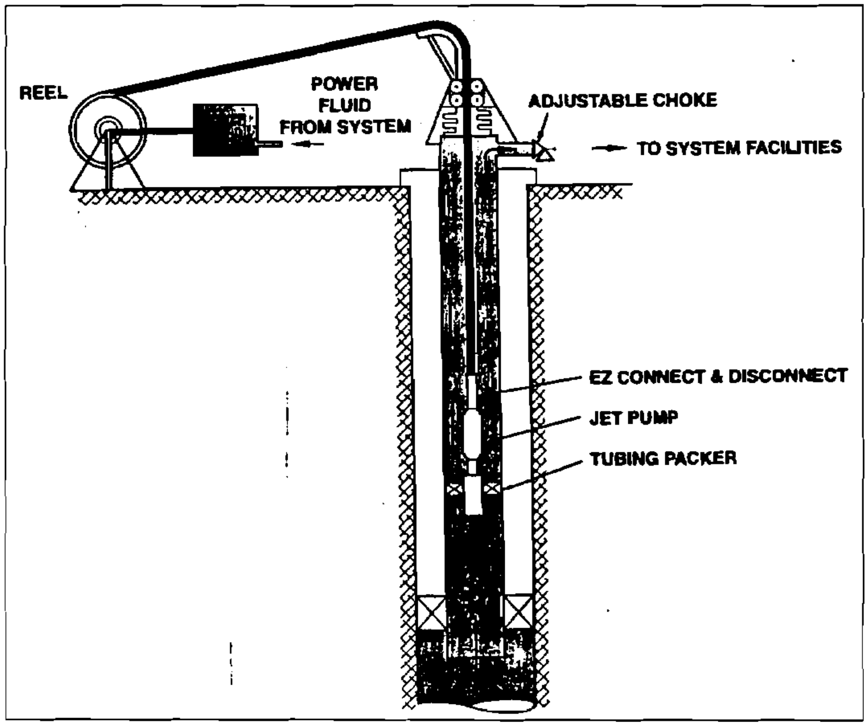


Figure 1-11. Jet Pump for Unloading Wells (Tait, 1995)

Lifting action is provided by energy transfer between the power fluid and the wellbore fluid. High potential energy in the pressurized power fluid is converted to kinetic energy as the fluid passes through a nozzle (Figure 1-12). A low-pressure zone is created in the throat, and the wellbore fluid is drawn into the power stream.

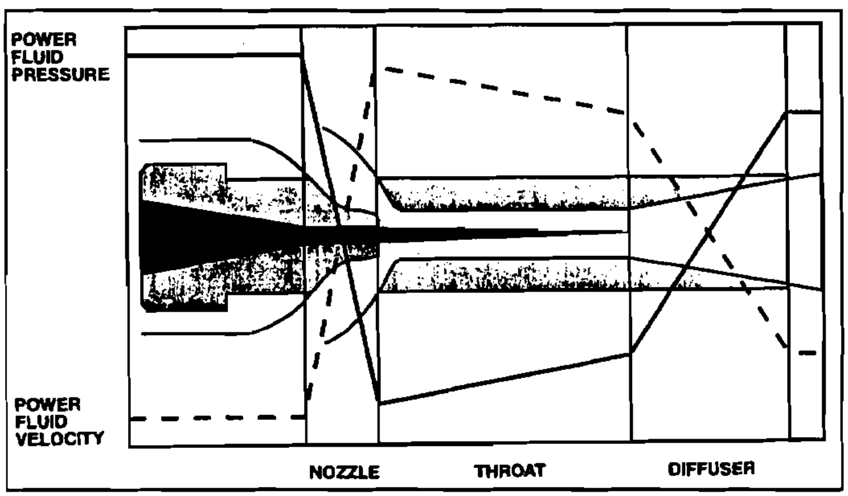


Figure 1-12. Jet Pump Operational Principle (Tait, 1995)

Jet pumps have been used since the 1970s for long-term artificial-lift applications around the globe. These can be sized for production rates ranging from 50 to 15,000 BPD at depths exceeding 15,000 ft.

Trico Industries described the use of a jet pump run on CT for production testing of horizontal wells. The pump can be run as a free pump (Figure 1-13), circulated into and retrieved from the well via the power fluid. This system can be used along with downhole pressure recorders to obtain inflow performance data in a production rate step-test procedure.

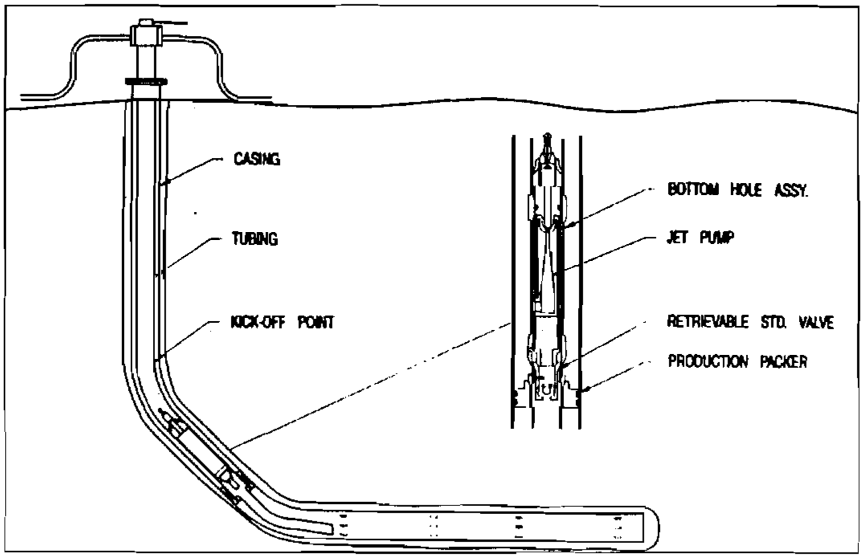


Figure 1-13. Free Jet Pump for Horizontal Production Testing (Tait, 1995)

1.7 UNOCAL AND SCHLUMBERGER DOWELL (CT JET PUMP RECOMPLETION)

UNOCAL and Schlumberger Dowell (Hrachovy et al., 1996) described the design process, installation, and results of a CT recompletion of two wells in Alaska's Cook Inlet fields. Several remedial options were compared for these wells. The most economic approach was to run a 1¾-in. jet pump at the bottom of a string of 1¾-in. CT. Produced fluids and exhausted power fluids were produced through the annulus between the CT and 3½-in. production tubing. Total costs for the first two wells were $220,000 and $120,000, significantly lower than other options considered.

The most common existing completion in this area of Cook Inlet includes a piston pump in a 3-in. cavity hung from dual 3½-in. production strings inside 9⅝-in. casing (Figure 1-14). Piston pumps are generally preferred due to higher efficiencies. Two wells, one on the Anna platform and one on the Baker, had been shut in due to problems with downhole hydraulic power fluid equipment. High costs for conventional workovers made shut-in necessary.

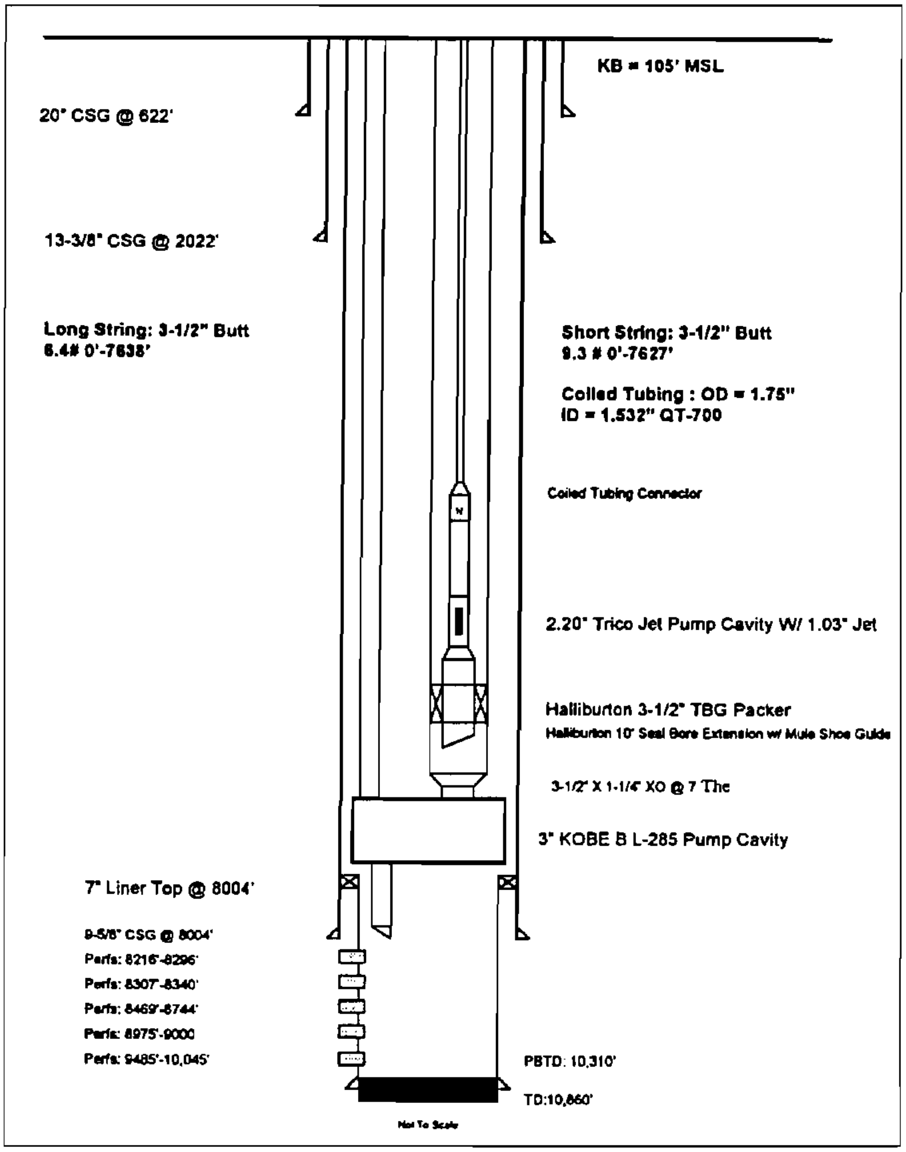


Figure 1-14. Anna 26 Completion/Recompletion (Hrachovy et al., 1996)

Inflow performance ratio (IPR) curves were prepared (Figure 1-15) to evaluate the performance of various recompletion options to bring the wells back on line.

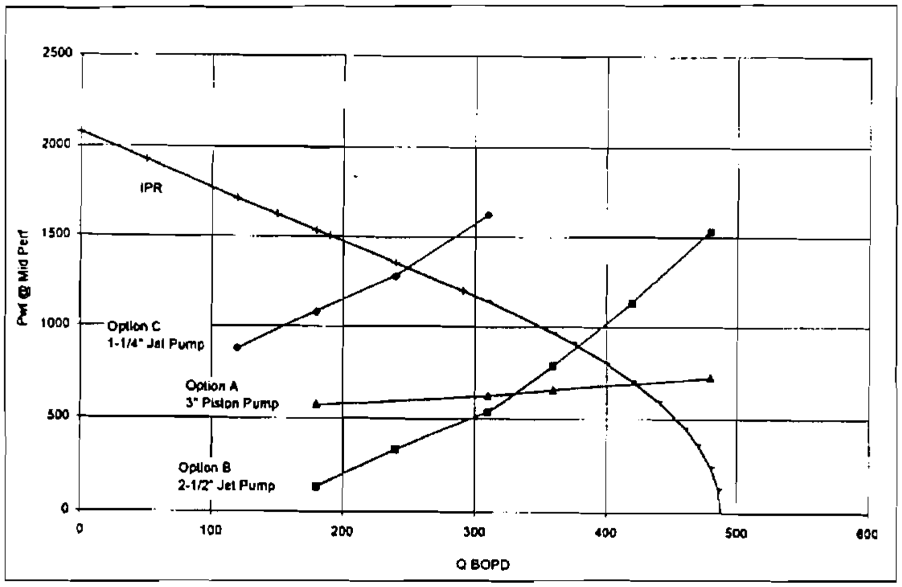


Figure 1-15. Anna 26 IPR Curves (Hrachovy et al., 1996)

Three completion options were considered: 1) a conventional workover including pulling the completion with a rig or jacking unit and running a new dual completion, 2) pull the completion and run a single 4½-in. production string with a concentric 2⅞-in. CT string, or 3) run 1¾-in. string of CT inside one of the existing 3½-in. production strings.

The first option (a new dual completion) was not pursued due to high estimated costs ($850,000) and lack of availability of a suitable rig. The second option (a new concentric production string) was technically the best because the pump could be placed deeper and improve the drawdown. Cost estimates were even higher for option 2 ($925,000) and the same scheduling problems were pertinent.

The third option was deemed the best compromise. A jet pump could be run on CT and production taken up the CT by production tubing annulus. The incremental production from options 1 or 2 was not sufficient to override higher costs and greater installation risks. Future workovers with option 3 could also be accomplished with a CT rig, thereby improving overall economics.

Costs to recomplete the two wells are summarized in Table 1-3. The pre-job cost estimate was $184,500 for the Baker 20 and $175,000 for the Anna 26. Several problems during field installation increased the cost of the Baker 20. Lessons learned on the first lead to cost savings on the Anna 26 ($54,500 below budget).

TABLE 1-3. Recompletion Costs (Hrachovy et al., 1996)

Item	Baker 20	Anna 26
Coiled-Tubing Unit Rental	$75,000	$40,000
1¾-in. Tubing Purchase	10,000	10,000
Wellhead	45,000	31,000
Packers	26,000	13,000
Perforating / Wireline	23,000	6,100
Logistics / Misc.	22,000	16,200
Supervision	14,000	4,200
Total	$215,000	$120,500

Production performance of the Anna 26 is shown in Table 1-4. UNOCAL believes that the difference in production from predicted rates is due to incorrect assumptions in deriving the IPR curve.

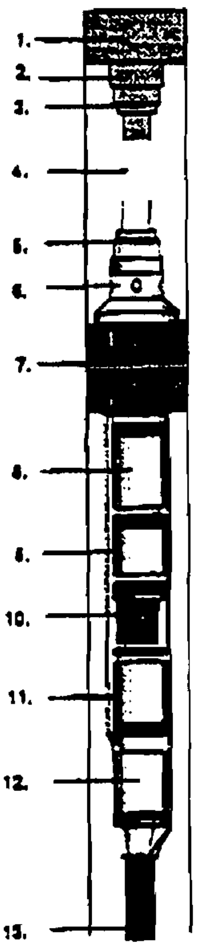
TABLE 1-4. Recompletion Performance (Hrachovy et al., 1996)

Item	Anna 26 Predicted	Anna 26 Actual
Power Oil Consumed, BOPD	1250	1600
Power Oil Pressure, PSIG	2450	3500
Produced Oil, BOPD	240	120
Produced Water Cut, %	40	7
Gross Fluid Production, BFPD	400	400
Pump Intake Pressure, PSIG	795	490

1.8 XL TECHNOLOGY (CT DEPLOYED ESPs)

XL Technology Ltd. (Tovar and Head, 1995) described the development and benefits of a new CT-deployed ESP system. This effort represents a joint-industry project ("Thermie") funded by the European Commission and several operators, service companies and manufacturers. The primary innovation is that the power cable is placed inside the CT, allowing rapid installation and deployment in live wells. Two field tests were conducted to demonstrate the efficiency of this method. Total estimated cost savings with this approach are over 40%, including a 20% reduction in equipment costs and 3 to 4 fewer days on site.

Basic equipment configuration of the ESP with internal power cable is shown in Figure 1-16. Downhole components include the CT/cable assembly, subs for pressure insolation and circulation, and SSSVs. The number of electrical connections is reduced from four with an external cable to two with an internal power cable. Additionally, the power cable is isolated from pressurization/depressurization cycles.



Item No	Description	Max Dia(in)
1.	Spool	
2.	Tubing hanger	6.12
3.	CT Connector	3.50
4.	CT / Power cable	2.375
5.	CT Connector	3.50
6.	Discharge Head	6.00
7.	Seals	6.20
8.	Pump	4.55
9.	Pump	4.56
10.	Pump Inlet	4.56
11.	Motor	4.56
12.	Protector	4.56
13.	Aux. Equiment	4.56

Figure 1-16. ESP Design (Tovar and Head, 1995)

Procedures for deploying the system in a live well are illustrated in Figure 1-17. Complete live-well deployment was simulated in the field tests.

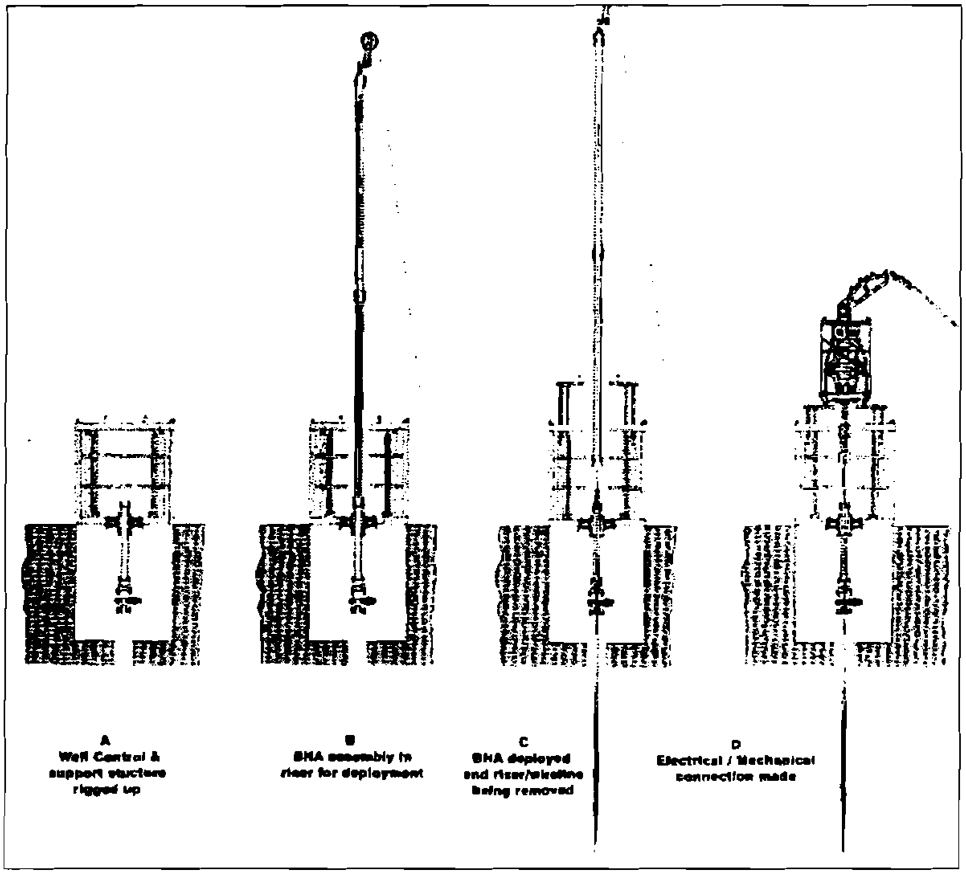


Figure 1-17. Live ESP Deployment (Tovar and Head, 1995)

The first field trial (Table 1-5) was onshore in Southern England in the Stockbridge Field to a depth of 3200 ft and deviation of 40°. The second well test was to 2900 ft and 50° deviation. Based on these successful operations, it is estimated that deployment speeds of greater than 50 ft/min are achievable.

TABLE 1-5. ESP Test Summary (Tovar and Head, 1995)

Information	Well No. 10	Well No. 5
Date of the test	September 1994	February 1995
Pressure deployment	Yes	No
BHA length	79 feet	79 feet
Riser length	90 feet	N/A
BHA deployed with	Wireline	Crane
Operational time	33 hours	14 hours
Run in speed	24 ft per min	29 ft per min

Electrical hook up time	N/A	2 hours
Completion landed	No	Yes
ESP assembly weight	2200 lbs	2200 lbs
Loads @ setting depth	15,000 lbs	7,500 lbs
Pull test performed	Yes	Yes
Cable integrity	Good	Good
Failure	Discharge head	none

Four primary options were identified for deploying ESPs (Table 1-6): conventional tubing deployment, running on CT with external power cable, cable-deployed pumping systems, and running on CT with internal power cable.

Costs are compared based on a deployment depth of 5000 ft.

TABLE 1-6. Options for ESPs in North Sea (Tovar and Head, 1995)

Feature/System	Conventional Tubing	CT External Cable	Cable Deployed Pumping System	CT Internal Cable
Depth Limits	None	None	None	None
Deviation Limits	None	None	59 degrees	None
Max Tubing Size	7.0"	3½	N/A	N/A
Min. Casing Size	N/A	N/A	7.0"	4½"
Flow Path	Internal Tbg.	Internal CT	Internal Csg/Tbg	Internal Csg/Tbg
Rate Limitation	No	Yes	No	No
Well Control Capacity	None	None	None	Yes
Cable Protection	None	None	None	Yes
Special Pump Reqd.	No	No	Yes	No
Reservoir Monitoring	Yes	Yes	No	Yes
Corrosive Fluids	Yes	Limited	No	Limited
Compression/Decomp.	Yes	Yes	Yes	No
Cable Splicing	Yes	Yes	Yes	Yes
No. Cable Connections	4	4	2	2
Well Intervention	Yes	Yes	No	Yes
Equipment Required	Rig	CT Unit	Special Unit	CT Unit

Avg. Equipment Cost	66.8 \$/ft	70.0 \$/ft	91.0 \$/ft	50.0 \$/ft
Avg. Service Cost	45.5 \$/ft	20.5 \$/ft	31.3 \$/ft	14.2 \$/ft
Average Workover Time	8 days	6 days	4 days	4 days
Subsea Application	No	No	No	Yes
HSE Approved	Yes	Yes	No	Yes

Time requirements for a CT deployment with internal power cable are 3 to 4 days less than conventional and 2 days less than CT with external cable. Total estimated job costs are compared in Figure 1-18.

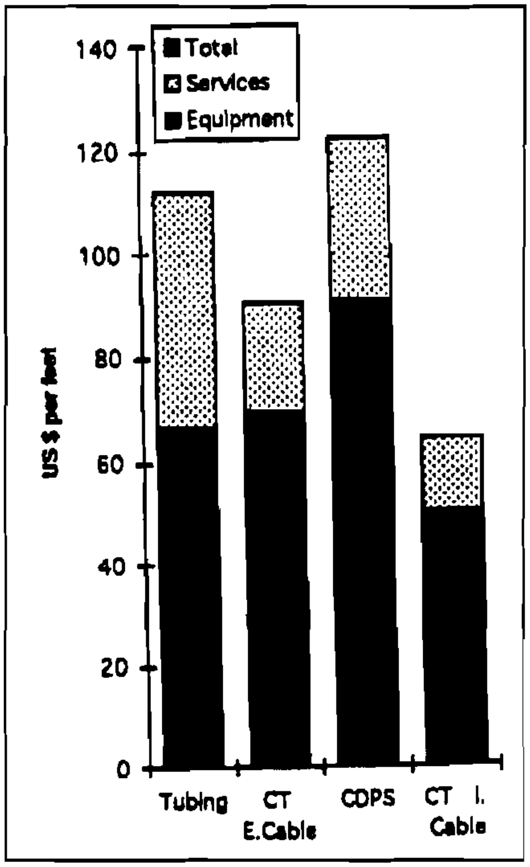


Figure 1-18. ESP Costs in North Sea (Tovar and Head, 1995)

XL Technology Ltd. believes that the new ESP deployment system shows great promise. Another area where this technology might be applied is running electric drills. This drilling technique is well established in the FSU, but relatively unknown in the West. Additional study is underway to investigate the feasibility of this application.

1.9 XL TECHNOLOGY (FIELD EXPERIENCE WITH CT ESPs)

XL Technology (Cooper and Head, 1997) presented an update of their work with CT-deployed electric submersible pumps (ESPs). These installations are proving to be well suited for installation in remote areas including offshore and areas with minimum facilities. The system was originally conceived to allow rigless completions that include ESPs. Several months of production experience have shown that the system is a viable completion option. Additional improvements might be added to the system, and it is foreseen that the installation time could be reduced to 14 hr/well.

Three components comprise the complete system: the ESP assembly (Figure 1-19), the CT string with power cable inside, and the tubing hanger. Production is through the CT by production tubing annulus. The power cable is preinstalled in the CT and supported by a series of anchors at regular intervals.

During installation, it was discovered that aligning the CT to motor connection was more difficult than anticipated. A more versatile connector was designed (Figure 1-20) to allow quick connection on the rig floor.

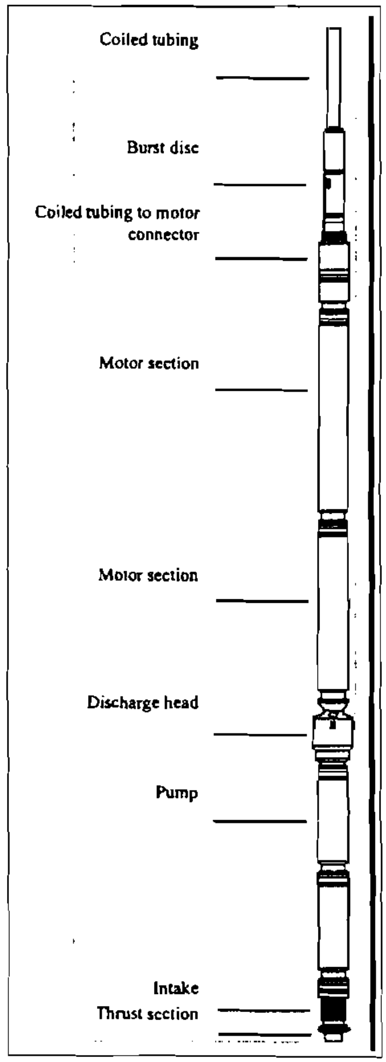


Figure 1-19. ESP Assembly (Cooper and Head, 1997)

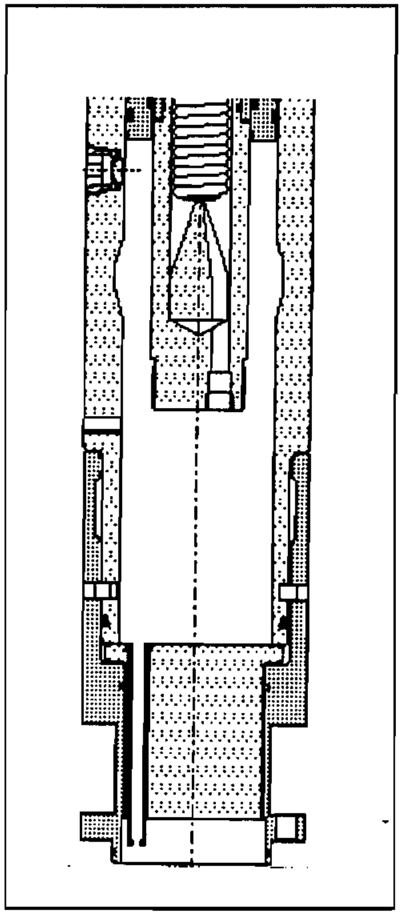


Figure 1-20. Quick Connect for CT to Motor (Cooper and Head, 1997)

1.10 REFERENCES

Cooper, R. and Head, P., 1997: "Coiled Tubing Deployed ESPs Utilizing Internally Installed Power Cable - A Project Update," SPE 38406, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Courville, Perry W., and Clark, Thomas R., 1995: "Coiled Tubing Completions: An Economic Discussion of Procedures," SPE 29781, presented at the Middle East Oil Technical Conference and Exhibition, Bahrain, March 11-14.

Gu, H., 1995: "Transient Aspects of Unloading Oil and Gas Wells With Coiled Tubing," SPE 29541, presented at the Production Operations Symposium held in Oklahoma City, Oklahoma, April 2-4.

Hrachovy, M. J., et al., 1996: "Case History of Successful Coiled Tubing Conveyed Jet Pump Recompletions Through Existing Completions," SPE 35586, presented at the SPE Western Region Meeting held in Anchorage, Alaska, May 22-24.

Sorrell, Dean, and Miller, Ron, 1997: "Coiled Tubing CO_2 Gas Lift Evaluated in West Texas," *World Oil*, January.

Tait, Howard, 1995: "Coiled Tubing Jet Pump for Extended Reach Horizontal Well Cleanups," presented at the Third Annual Conference on Emerging Technology — CT-Horizontal, Aberdeen, Scotland, May 31 - June 2.

Tovar, Juan J., and Head Philip F., 1995: "Technical and Economic Considerations for CT Deployed ESP Completions," presented at the Third Annual Conference on Emerging Technology — CT-Horizontal, Aberdeen, Scotland, May 31 - June 2.

Tran, T.B. et al., 1997: "Field Installed Coiled Tubing Gas Lift Completions," SPE 38404, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Watkins, Paul, and Stewart, David, 1996: "Coiled Tubing Deployed ESP Works Well for Shell in North Sea Field," *World Oil*, June.

2. Buckling

TABLE OF CONTENTS

2. Buckling

2.1 BJ SERVICES (FEASIBILITY OF TITANIUM CT)

BJ Services (Christie and Gavin, 1997) analyzed the feasibility of using titanium CT for routine applications offshore in the North Sea. The driving force behind the study is potential weight savings that might offset increasingly downrated deck and crane capacities on North Sea platforms. BJ Services performed a series of modeling simulations to analyze the capability of titanium strings to maintain sufficient WOB to push heavy BHAs downhole. Data from actual jobs performed with steel CT were used as the basis for the simulations. Results showed that titanium may have difficulty in these applications due to a lower Young's modulus.

In one horizontal well, the surface weight indication would be significantly less for titanium than was measured for steel (Figure 2-1). Less surface weight means a lower hanging weight and less weight available to push the BHA into the horizontal section. Compounding the problem is the higher friction coefficient observed for titanium on steel as compared to steel on steel.

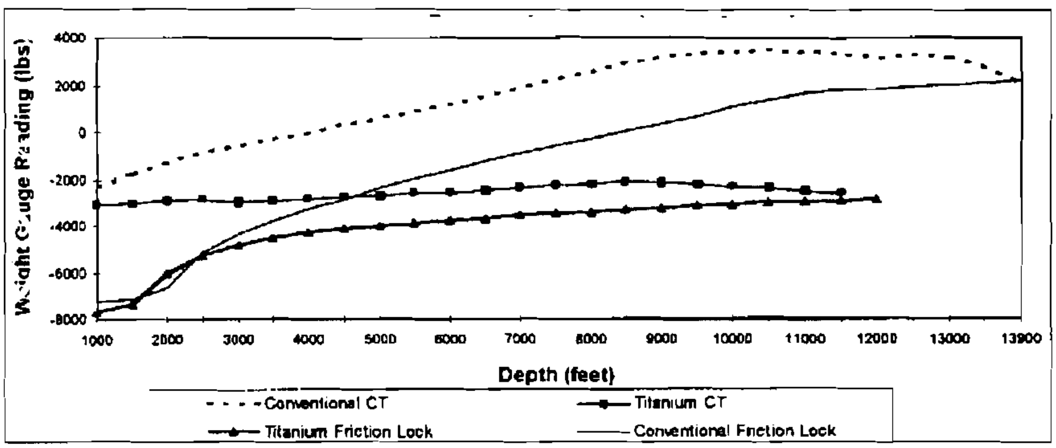


Figure 2-1. Modeled Surface Weights for Steel and Titanium CT (Christie and Gavin, 1997)

More discussion on this comparison is presented in *Coiled Tubing*.

2.2 CONOCO AND ARCO (DRAG REDUCER FOR HYDROCARBON FLUIDS)

Conoco Specialty Products and ARCO Alaska (Robberechts and Blount, 1997) reported the development and testing of a new drag-reducing additive for hydrocarbon-based CT applications. High pressures in CT pump operations to achieve high flow rates have the dual disadvantages of exceeding the capacity of surface pumping equipment and of reducing CT fatigue life. Drag reducers for water-base operations have proven very successful at the North Slope. Prior to this work, a drag reducer for addition to hydrocarbons was not available. A new dispersed-polymer drag reducer was formulated and tested with success.

Tests were conducted of a variety of drag reducers (Figure 2-2).

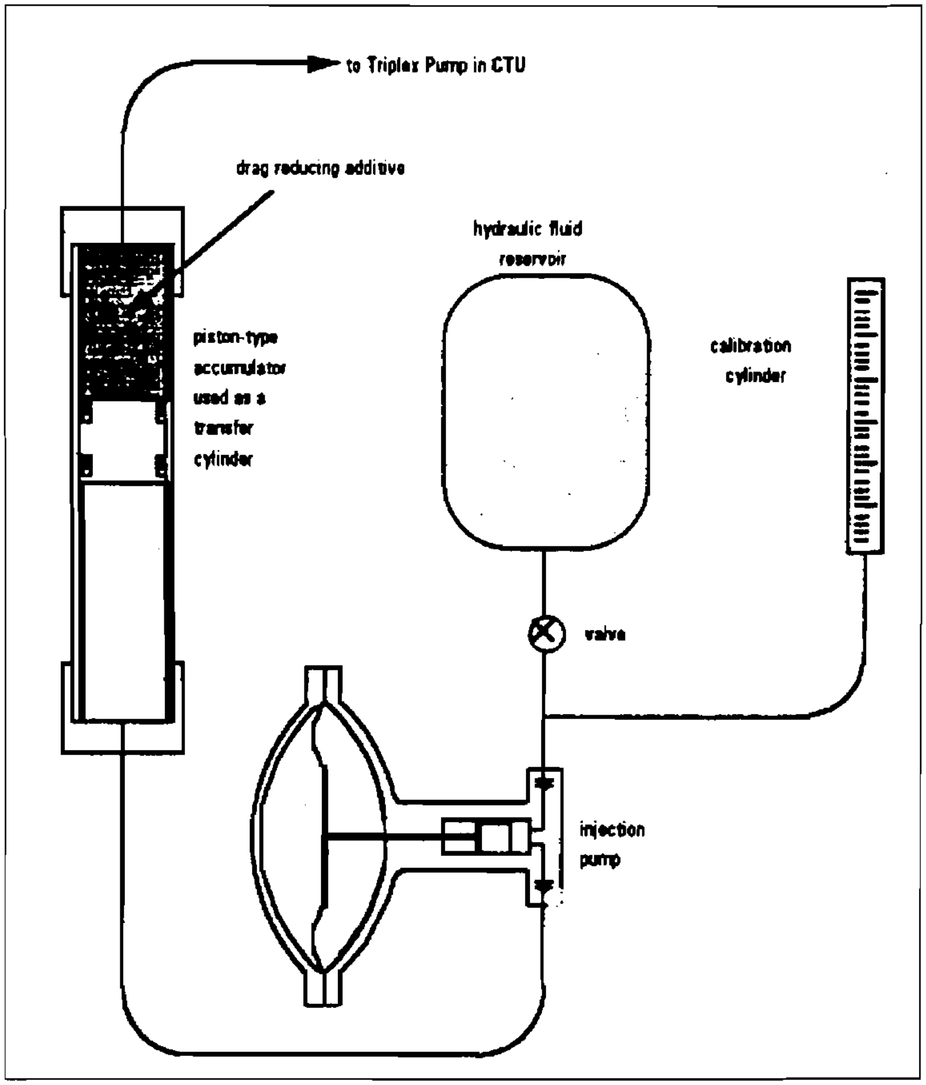


Figure 2-2. Drag Reducer Test Equipment (Robberechts and Blount, 1997)

The new Aqueous Suspension Drag Reducing Additive (AS DRA) has been found to be effective in batch-mixed operations (Figure 2-3). The additive is also available in low freeze-point suspensions for harsh areas such as the North Slope.

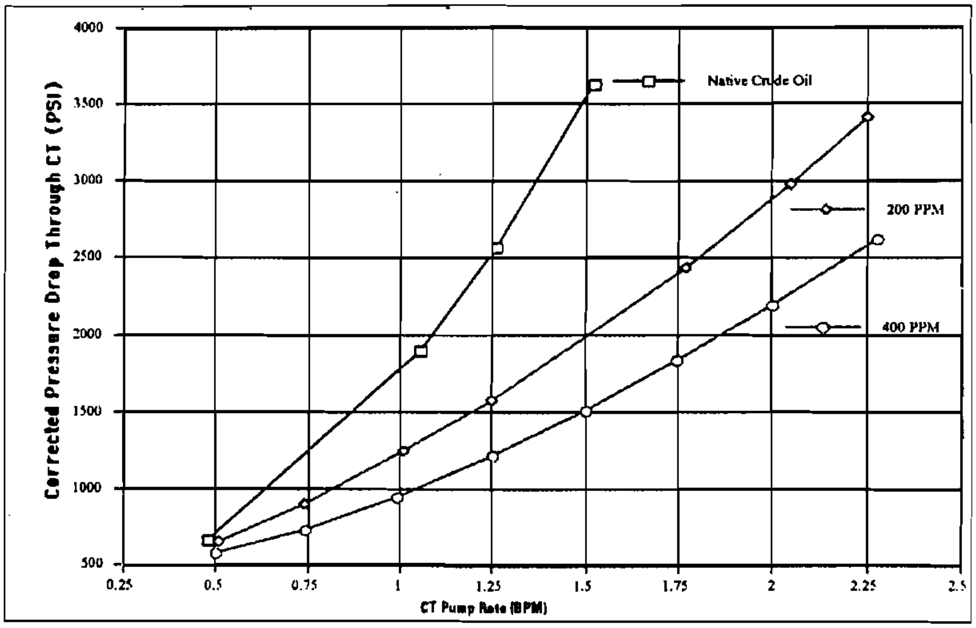


Figure 2-3. Pressure Drop with Drag Reducer (Robberechts and Blount, 1997)

Measured pressure drop versus AS DRA concentration was analyzed (Figure 2-4). Field experience showed that batch-mixed fluids can provide significantly more drag reduction than if treated downstream of the centrifugal pump.

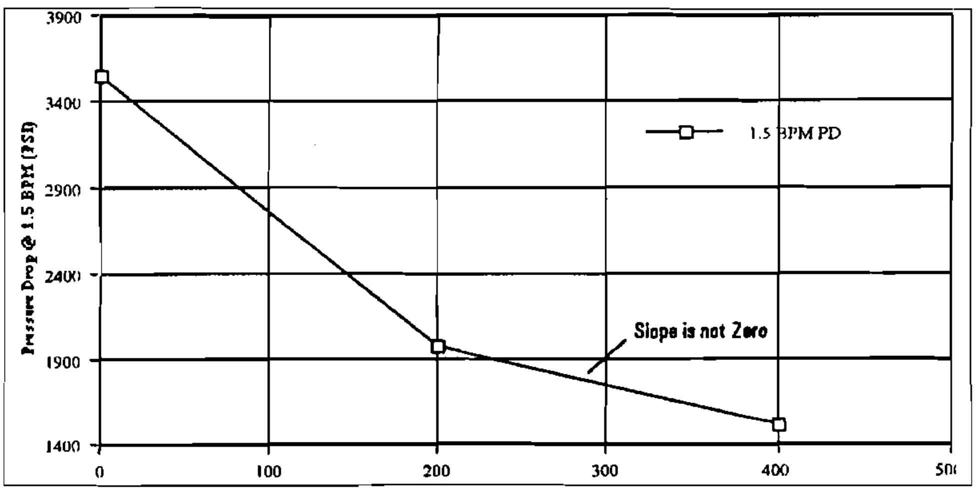


Figure 2-4. Drag Reducer Concentration (Robberechts and Blount, 1997)

These AS DRA additives have proven to be highly cost-effective for CT operations with hydrocarbon fluids.

2.3 NOWSCO UK AND STATOIL (DEPLOYMENT OF LONG BHA)

Nowsco UK Ltd and Statoil (Engel and Sehnal, 1996) developed and implemented a tool-string deployment system for running 140 m (459 ft) of perforating guns along a horizontal section. The well (B-15) was located in the Norwegian sector of the North Sea. A recompletion was planned to isolate a lower producing interval (due to high GOR) and perforate a higher interval. Rathole for dropping the guns was not available. Drag was a significant concern in the well, and friction was reduced by adding rollers to the BHA and using friction reducers. Field operations, including deploying, running and recovering the perforating guns, were completed successfully in 5½ days.

The deployment system included male and female connectors (Figure 2-5) for quick connection within the surface lubricator. OD is 2.5 inches. Make-up length of the assembly is 972 mm. Gate valves provide double-barrier isolation.

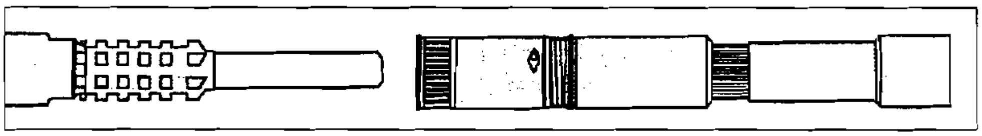


Figure 2-5. Deployment System Connectors (Engel and Sehnal, 1996)

The surface equipment for deploying long BHAs includes the deployment BOP and isolation gate valves. A secondary annular BOP was required below the deployment rams (Figure 2-6).

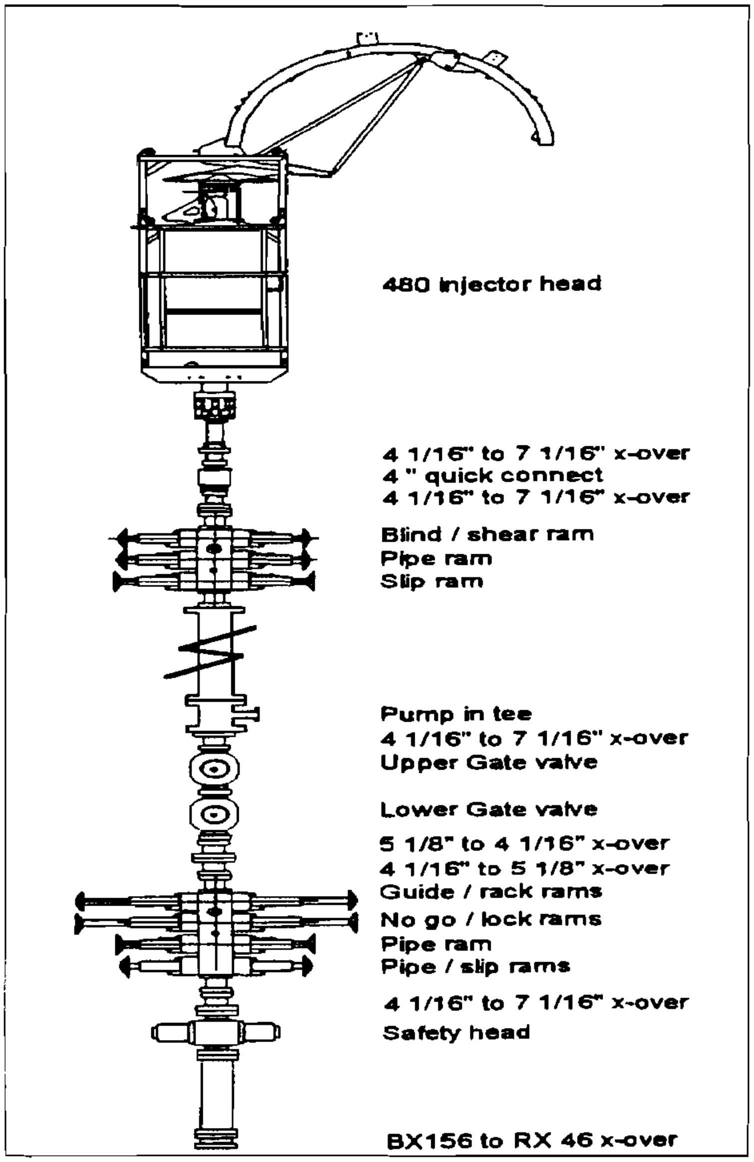


Figure 2-6. Surface Equipment for Deploying Long BHAs (Engel and Sehnal, 1996)

Extensive modeling of drag was conducted prior to the job. The hanging weight of the BHA was over 2500 kg; 2-in. CT was specified. Rollers were to be added at each joint of the guns. These had been found to reduce required pushing forces by 50%. A drag reducer was also planned to ensure that target depth was reached.

Drag predictions and results are compared in Figure 2-7. Nowsco stated that the difference between predicted/measured POOH weights is explained by gun debris or by low gun weights used in the model.

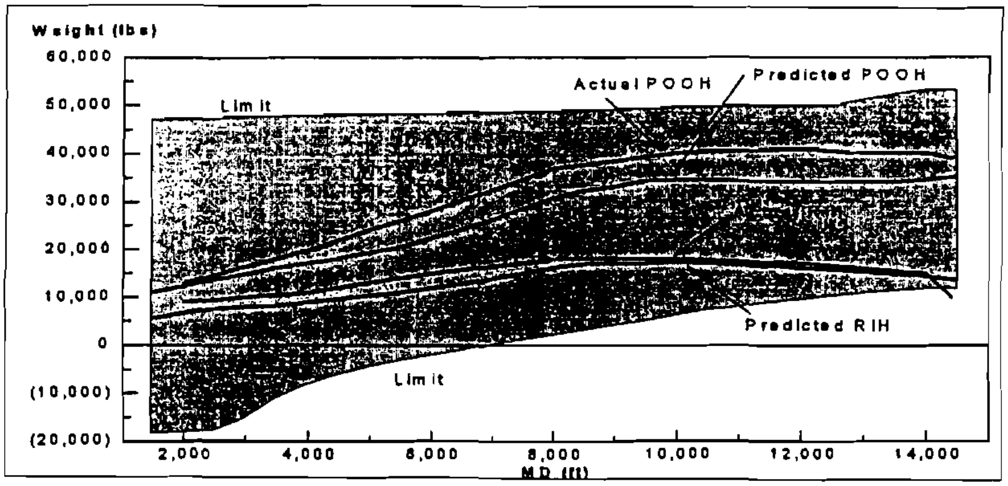


Figure 2-7. Weight Indication During Operation (Engel and Sehnal, 1996)

Nowsco advised that deployment systems similar to the one described are viable options when more than three separate trips are required to achieve the same objective with conventional deployment methods.

Additional information is presented in *Tools*.

2.4 PEI (CT STRAIGHTENER)

Petroleum Engineer International (*PEI* Staff, 1996) presented a description and some early results achieved by Schlumberger Dowell using a new straightener for CT. The design is based on a three-point bending fixture that is mounted between the gooseneck and injector.

In one field well, the string locked up at 13,400 ft MD. The same string was then run with a straightener installed. A sleeve at 13,750 was reached and shifted without problem.

2.5 SCHLUMBERGER DOWELL (EXTENDING CT REACH (PART 1))

Schlumberger Dowell (Bhalla, 1996) presented an analysis of the benefits of various methods to increase the reach of CT in horizontal and deviated wells. Methods to reduce CT buckling include increasing buoyancy of the CT, pumping friction reducers, optimum taper designs, larger OD of CT, removing residual bending, using downhole tractors, pumping fluid, and pump-down systems. These methods, either singly or in combination, can be used to substantially increase reach when applied appropriately.

Extended-reach technology has seen rapid development in the UK and Norwegian sectors of the North Sea. Some wells (Gullfaks and Statfjord) cannot be serviced with standard CT operations. New techniques and procedures have been refined for these applications.

Schlumberger Dowell simulated the impact of a variety of techniques to reduce buckling and increase penetration in these wells. The example well used in the simulations is shown in Figure 2-8.

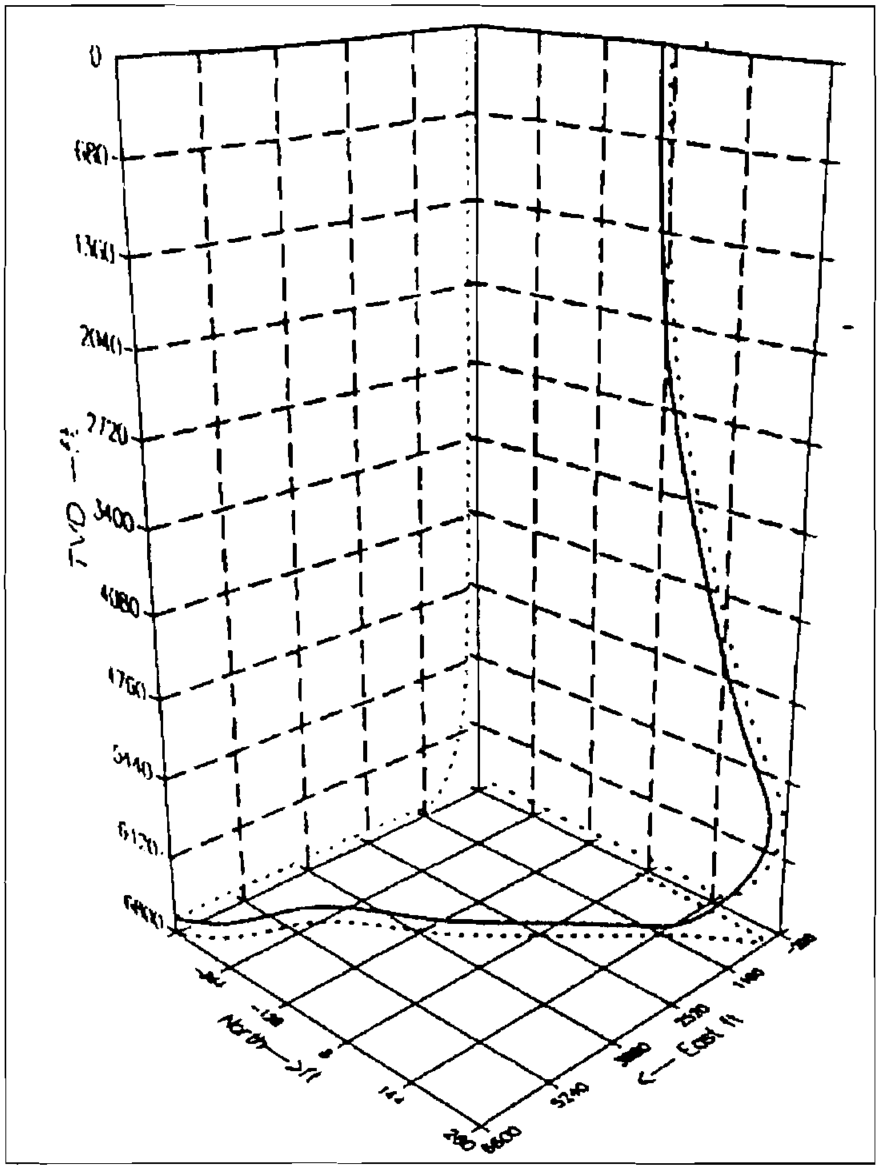


Figure 2-8. Example Well used for Buckling Simulation (Bhalla, 1996)

One technique used at Wytch Farm is pumping friction reducer. Reductions in friction coefficient of up to 15% have been achieved. The impact of friction reducers on surface loads for RIH is shown in Figure 2-9. Lock-up of the CT is expected at a depth of 10,849 ft. An additional reach of 200 ft is predicted for a 5% reduction in friction factor. Over 2000 additional feet of penetration can be achieved by reducing friction factor by 35%.

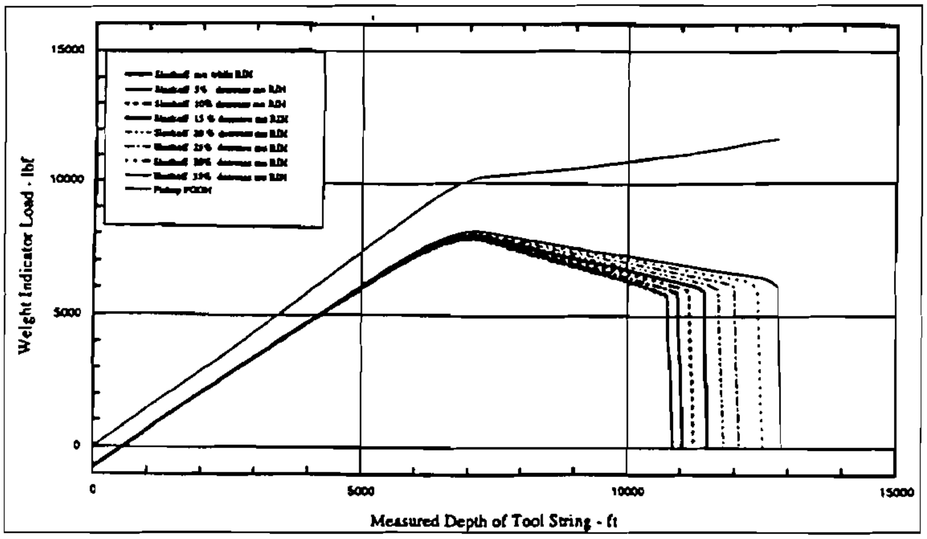


Figure 2-9. Impact of Friction Reduction (Bhalla, 1996)

Tapered CT strings can be used for extending penetration. Thicker pipe is placed in areas of maximum compression forces. Taper design 3 (based on 1¾-in. tubing) in the example well allows a penetration to 11,600 ft (Figure 2-10). Taper 4 (based on 2⅜-in. tubing) reaches to 13,800 ft.

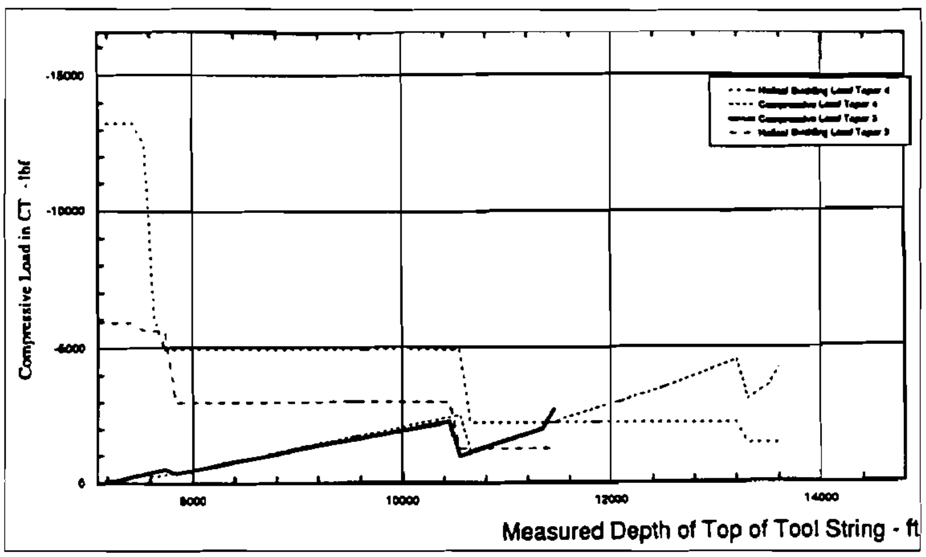


Figure 2-10. Penetration with Tapered Strings (Bhalla, 1996)

Residual bends in CT have an adverse impact on penetration limits. The injector constrains CT to be straight while in the chains, but does not completely unbend the tubing. Schlumberger Dowell measured residual bending radii on new 1½-in. 70-ksi tubing (Table 2-1). The reel radius was 58 in.; gooseneck radius was 72 inches.

TABLE 2-1. Residual Bends in 1½-in. CT (Bhalla, 1996)

	Residual Bend Radius
Reel to Gooseneck	227.9" (18.9 ft)
Gooseneck to Injector	102.8" (8.6 ft)
After Injector	252.5" (21.0 ft)

These tests demonstrated that CT enters the well with a bend radius of 21 ft. Since this bend will hasten the onset of helical buckling, removing this bend will increase penetration limits. Calculations for the example well (Figure 2-11) show that reach will be increased from 10,849 ft out an additional 2153 ft with straightened CT.

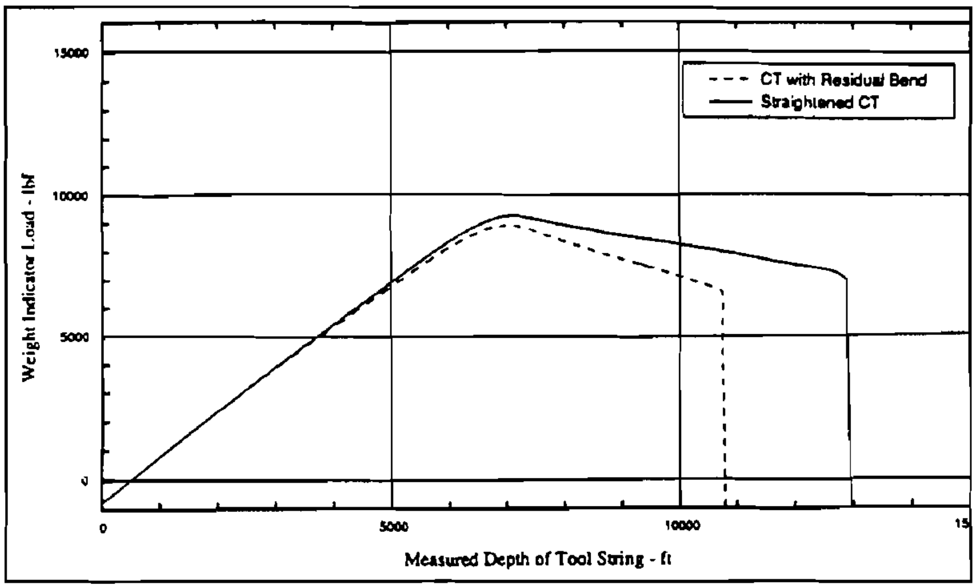


Figure 2-11. Surface Weight with Straight CT (Bhalla, 1996)

The disadvantage of using a straightener to increase CT reach is an increase in fatigue. The additional bending reduces cycle life (Table 2-2). To enjoy the predicted additional reach of 2153 ft, a reduction in cycle life of 15 to 23% for the coil will be forfeited. Thus, an economic decision is required with respect to the use of a straightener.

TABLE 2-2. CT Life with Straightener (Bhalla, 1996)

Pressure (psi)	Cycles Without Straightener	Cycles With Straightener
0	101	78
500	98	78
1,000	94	77
5,000	74	64
10,000	46	39

Well tractors are another approach for increasing penetration (see Welltec Section 2.9). The benefit of a tractor was modeled by applying a range of loads to the BHA. Predicted surface weights are compared in Figure 2-12. A tractor force of 100 lb on the BHA will increase reach by 201 ft. A pull of 2000 lb will increase reach by 4551 ft.

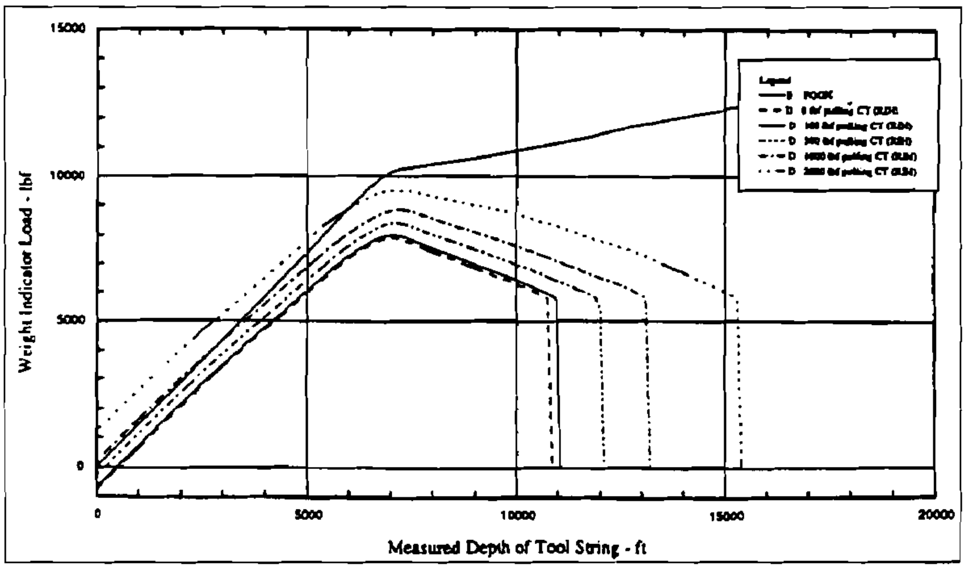


Figure 2-12. Increased Reach with Tractor (Bhalla, 1996)

Flow in the annulus can push or pull the CT due to hydraulic friction forces. Calculations showed that an additional 200 ft of reach can be attained by pumping water down the annulus in the example well. Reach is decreased by 100 ft if water is pumped up the annulus. Generally, the benefits from pumping are small (Figure 2-13), but may be important in certain critical situations.

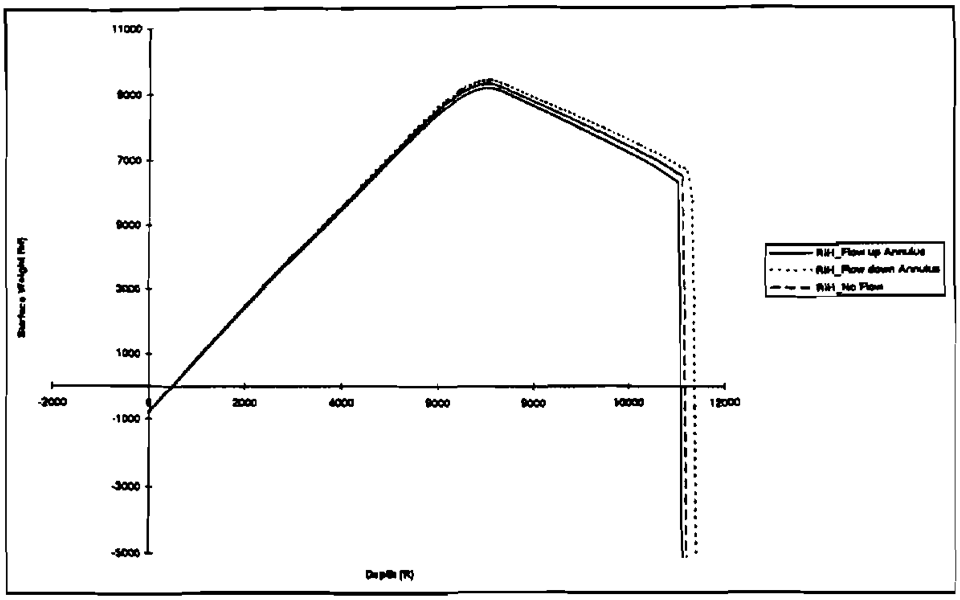


Figure 2-13. Impact of Flow on Reach (Bhalla, 1996)

A combination of these types of techniques can be used to maximize penetration limits for CT reach. An additional 15,000 ft of reach can be attained by increasing buoyancy, reducing friction, optimizing taper design and straightening the tubing (Figure 2-14).

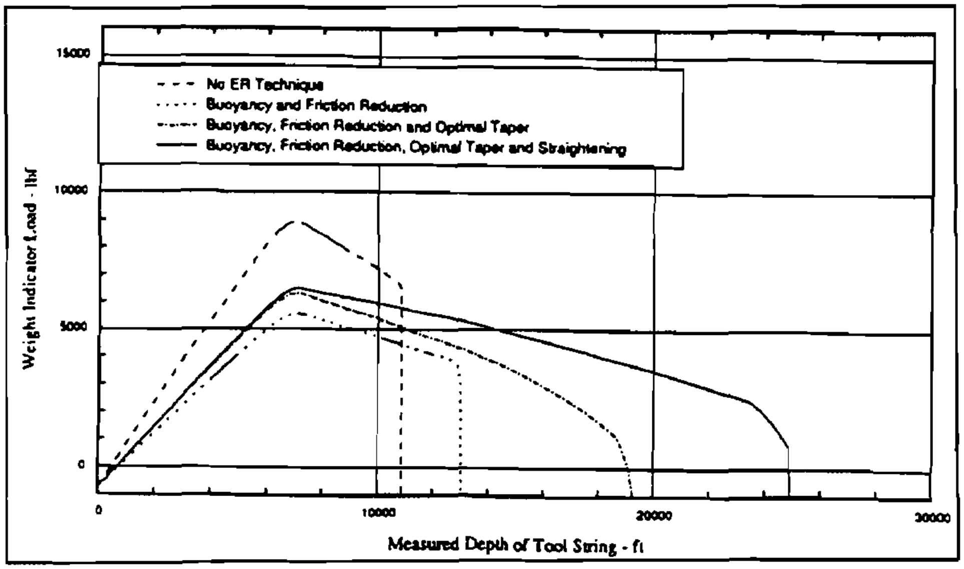


Figure 2-14. Combined Techniques for Extending Reach (Bhalla, 1996)

The additional reach with these combinations is summarized in Table 2-3. It should be noted that the effects of each individual technique are not linearly additive.

TABLE 2-3. Reach with Combined Techniques (Bhalla, 1996)

	Well 1 Lockup (ft)	Well 1 Additional Reach (ft)
No Technique	10,849	
Buoyancy Reduction & Friction Reducer	13,102	2,253
Buoyancy Reduction, Friction Reducer & Optimal Taper	20,101	6,999
Buoyancy Reduction, Friction Reducer, Optimal Taper & Straightening	25,000	4,899

2.6 SCHLUMBERGER DOWELL (EXTENDING CT REACH (PART 2))

Schlumberger Dowell, Amoco EPTG, and Techaid (Leising et al., 1997) continued their analysis of the potential of various techniques for extending the reach of CT in extended-reach wells. A variety of techniques were considered (Table 2-1) with respect to problems, costs, risks, and potential benefits.

Table 2-1. Techniques to Extend CT Reach (Leising et al., 1997)

Technique	Field Proven	Cost	Potential
Larger CT or smaller liner	yes	med.	high
Mud lubricant	yes	med.	low
Tubing straightener	yes	low	low
Hole optimization	yes	low	med.
Underbalanced drilling	yes	high	med.
Bumper sub	yes	low	med.
Equalizer	yes	low	med.
Tractor/locomotive	no	high	high
Slant well	yes	low	low
Abrasive/water jet drilling	no	med.	Med.
Rotator	no	high	high
Composite CT	no	high	low
Counter rotating bit	no	high	high

A bumper sub (Figure 2-15) provides a WOB that is proportional to differential pressure across the tool. The disadvantages of this type of tool are that 1) WOB is increased as the motor starts to stall, thereby aggravating the stall (that is, a positive feedback loop) and 2) open area in the tool and differential pressure must be matched to achieve the desired WOB.

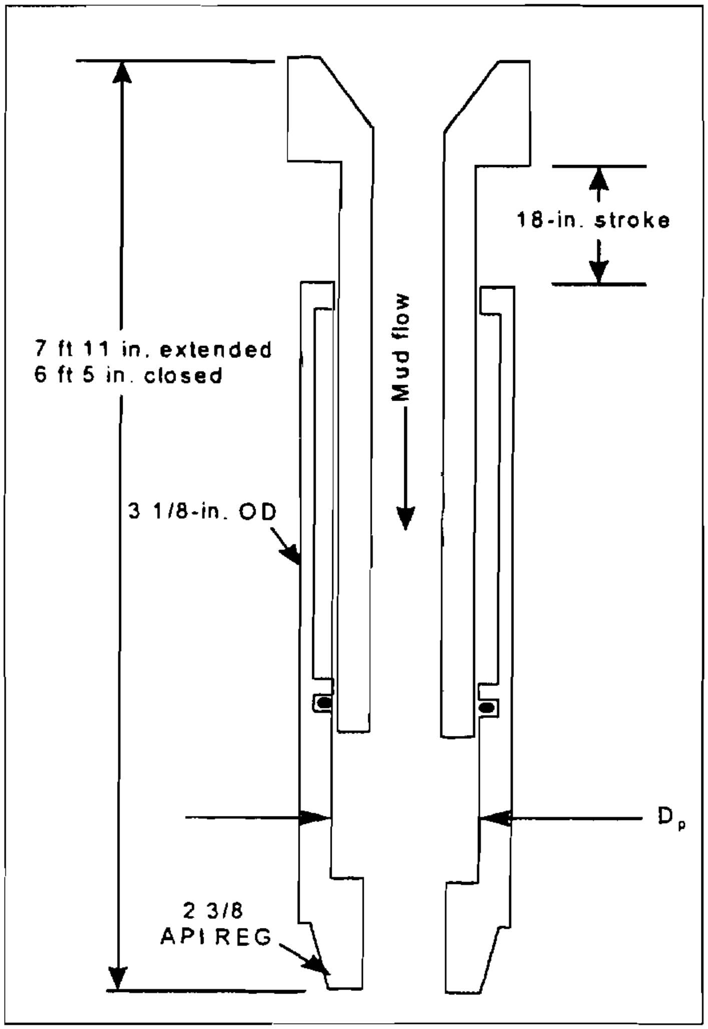


Figure 2-15. Bumper Sub Thruster (Leising et al., 1997)

Schlumberger Dowell developed and tested a weight-on-bit (WOB) equalizer. It is designed to provide a constant WOB regardless of friction (Figure 2-16).

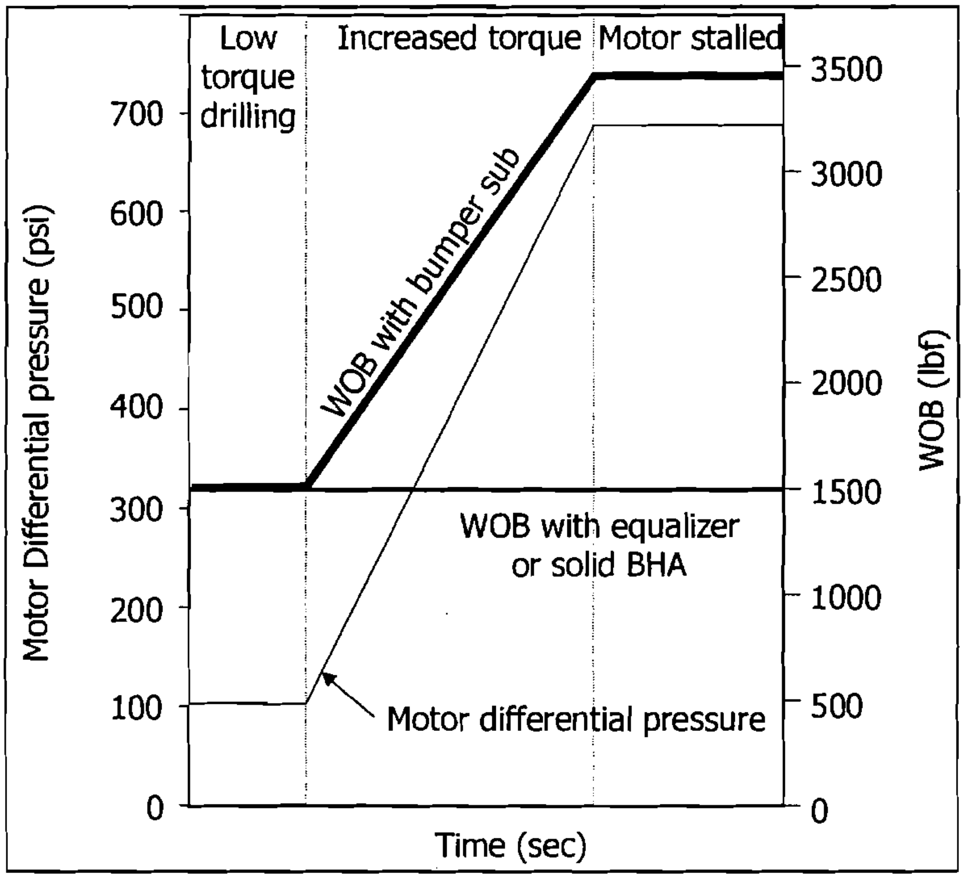


Figure 2-16. WOB Equalizer Response (Leising et al., 1997)

The tool (Figure 2-17) is not designed to reduce shock, but rather to provide a constant WOB regardless of stick/slip and variations in motor pressure. The primary disadvantage noted by Dowell is simply the additional length added to the BHA.

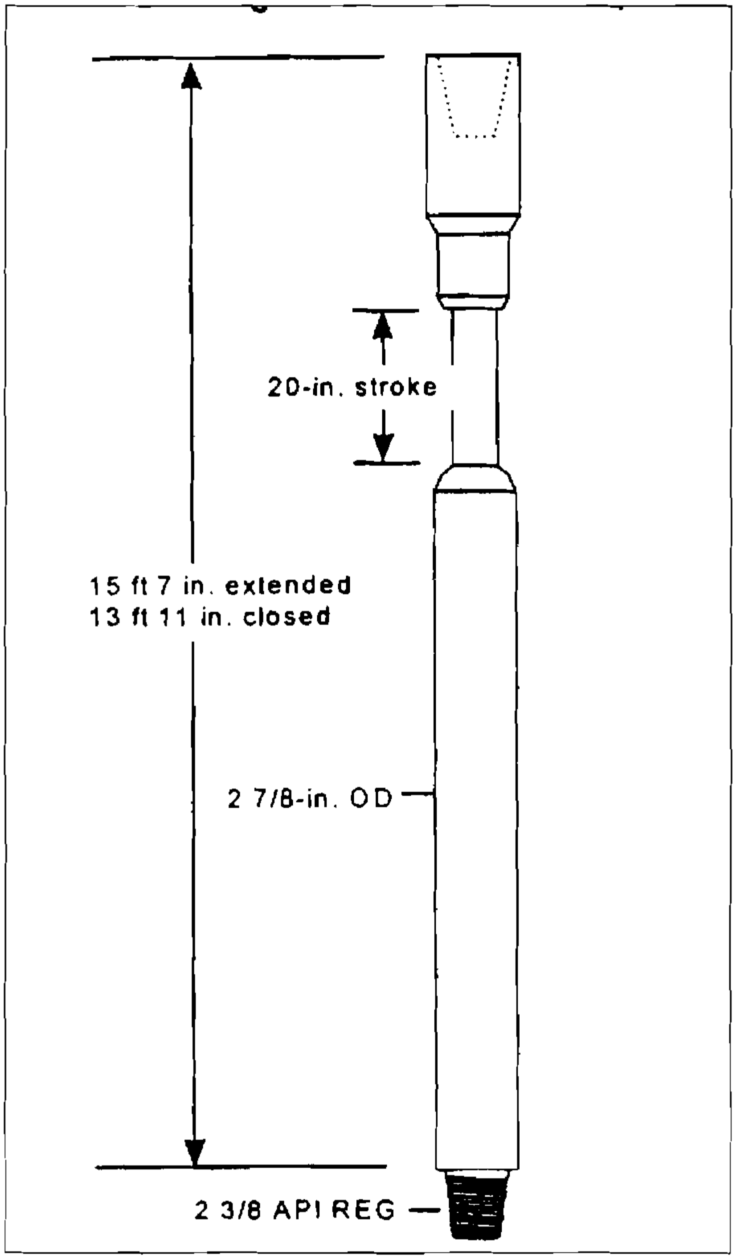


Figure 2-19. WOB Equalizer (Leising et al., 1997)

The WOB equalizer assembly is essentially a shock sub with a low spring constant. A chamber within the sub is precharged with nitrogen to provide the desired weight.

Of the best techniques to increase CT reach (larger CT, smaller liner, thin CT in the horizontal section, mud lubricants, underbalanced drilling, WOB equalizer, and a rotator), the highest ROP performance was obtained with the WOB equalizer. It was also the easiest system to drill with, and required very little intervention from the surface. While the sub does not in itself extend drilling reach, it increased ROP and resulted in more efficient penetration.

2.7 SCHLUMBERGER DOWELL (FLUID FLOW AND CT REACH)

Schlumberger Dowell (Bhalla and Walton, 1996) analyzed fluid flow inside CT and the annulus to predict its effect on penetration limits. Their analytical model showed that 1) fluid flow down (or up) the CT itself had no impact on achievable reach, 2) upward flow in the annulus decreases reach, and 3) downward flow in the annulus (i.e., reverse circulation) increases reach.

Theory for accounting for fluid hydraulics and shear stresses (Figure 2-18) was developed and incorporated into their tubing forces model. Any fluid rheology can be evaluated in the assumed concentric annulus.

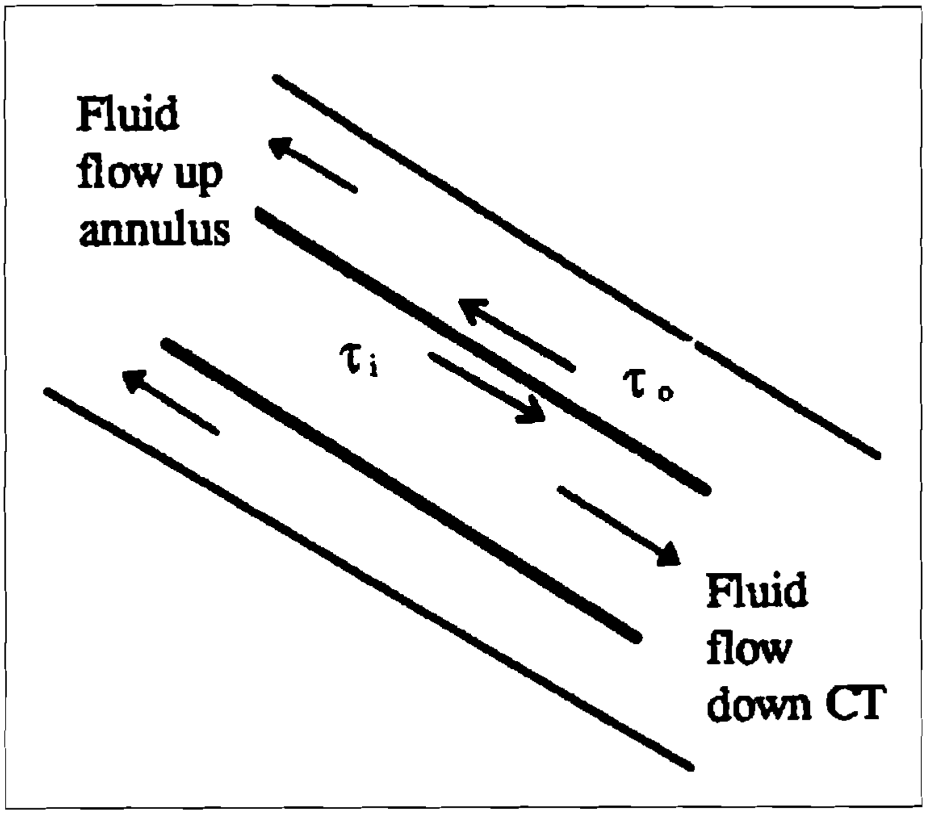


Figure 2-18. Shear Stress from Fluid Flow (Bhalla and Walton, 1996)

In one example case, a commercial well profile was evaluated (Figure 2-19). The ratio of MD to TVD is 2.28. The completion included 4½-in. production tubing. The modeled CT string was 1½- by 0.109-in. wall.

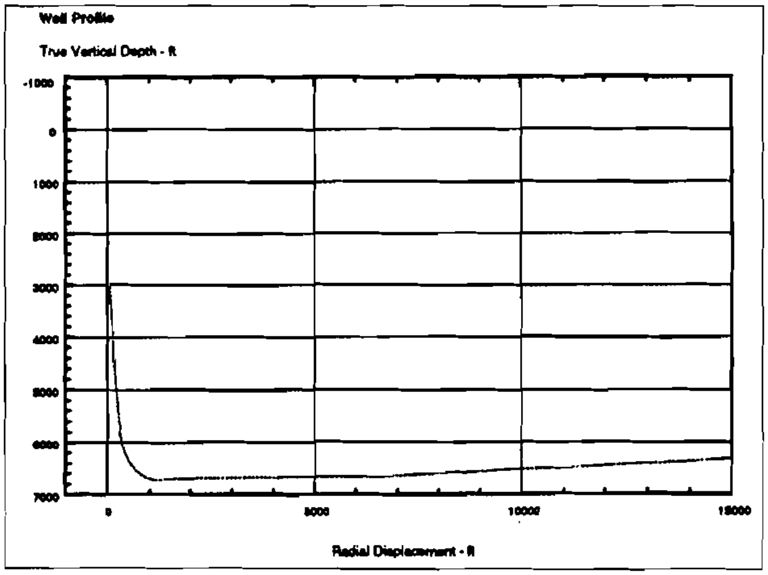


Figure 2-19. Example Well Profile (Bhalla and Walton, 1996)

Results for the example well showed that lock-up is expected at a depth of 10,850 ft (Figure 2-20). If water is pumped down the annulus at 2 bpm, an additional 500 ft (4.6%) of reach is expected. If water is pumped up the annulus, reach is decreased by about 400 ft (3.8%). Bhalla and Walton noted that these results are based on the assumption of an concentric annulus (centered CT). Tubing will most likely be eccentric, leading to a decrease in friction pressure. These results should thus be considered a worst-case prediction.

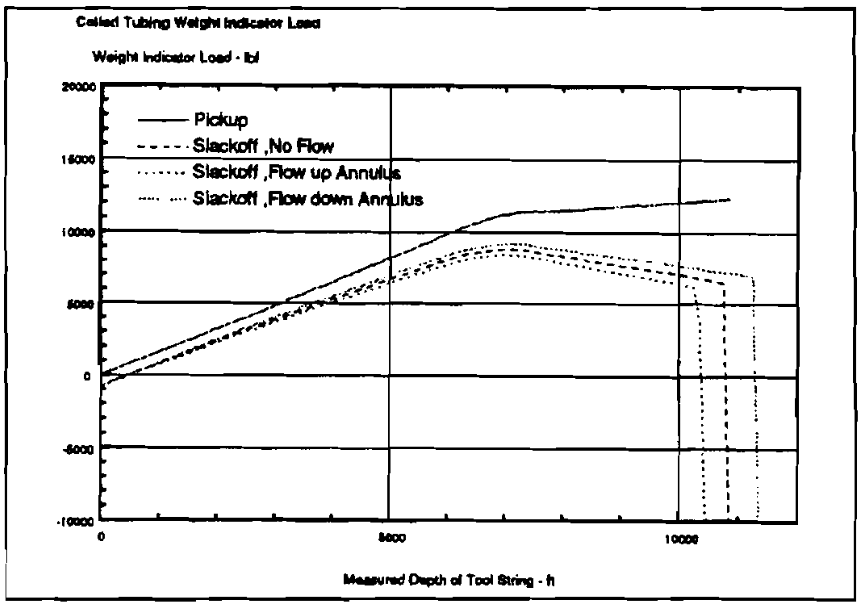


Figure 2-20. Penetration in Example Well (Bhalla and Walton, 1996)

Fluid rheology can be designed for specific field applications to increase CT reach, or to minimize the impact on reach.

2.8 UNIVERSITY OF TULSA, NIPER-BDM AND PETROBRAS (BUCKLING MODEL)

The University of Tulsa, NIPER-BDM, and Petrobras (Miska et al., 1996) described an improved buckling model for transmitting axial force through CT in straight inclined wellbores. They considered the stable sinusoidal region above the critical buckling load. Case studies and experimental verification demonstrated the usefulness and limitations of the model.

Their analytical model is summarized in Table 2-4. They defined a region of unstable sinusoidal buckling immediately prior to the initialization of helical buckling.

TABLE 2-4. Critical Forces for CT Buckling (Miska et al., 1996)

Axial Compressive Force	Coiled Tubing Configuration
$F < 2\sqrt{\frac{EIw\sin\alpha}{r}}$ (Ref. 3)	Straight
$2\sqrt{\frac{EIw\sin\alpha}{r}} \le F < 3.75\sqrt{\frac{EIw\sin\alpha}{r}}$	Sinusoidal
$3.75\sqrt{\frac{EIw\sin\alpha}{r}} \le F < 4\sqrt{\frac{EIw\sin\alpha}{r}}$	Unstable sinu-soidal
$4\sqrt{\frac{2EIw\sin\alpha}{r}} \le F$ (Ref. 9)	Helical

A variety of numerical case studies were performed to gauge the impact of pipe size, wellbore condition, drilling fluid, CT size, wellbore size, etc. One interesting result was found when considering the impact of increased axial force in an inclined well. As seen in Figure 2-21, force transmitted down sections greater than 6000 ft is not impacted by the pushing force. No more than 6200 lb will be transmitted to the bit.

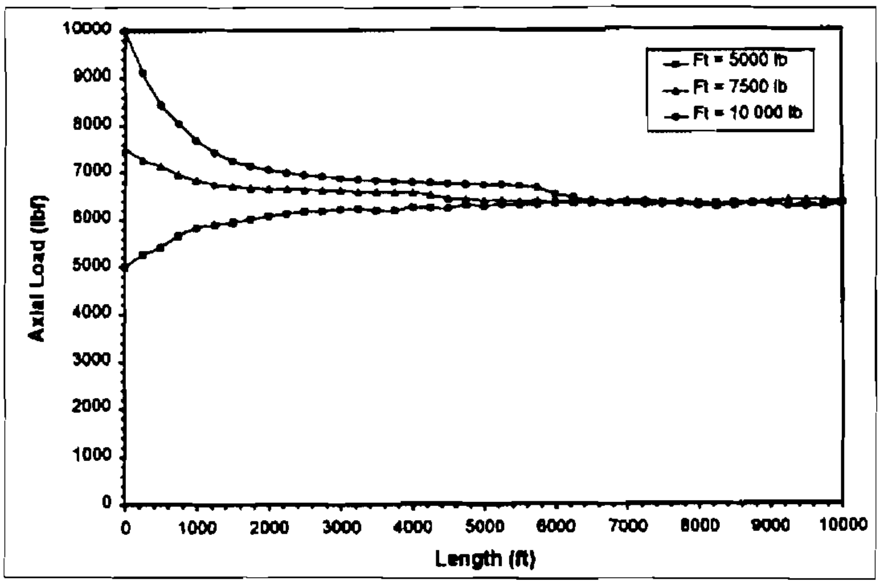


Figure 2-21. Transmitted Force in a 30° Wellbore (Miska et al., 1996)

Scale tests were also conducted for comparing with the model. The test fixture is shown in Figure 2-22.

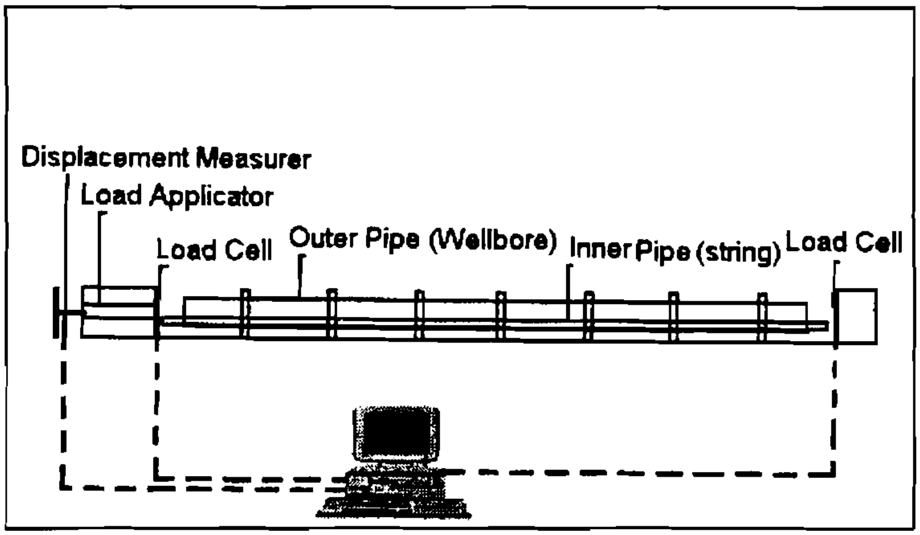


Figure 2-22. Buckling Test Facility (Miska et al., 1996)

In one series of tests, the importance of considering the impact of residual bending was clearly demonstrated. The difference between Test 1, 2, and 3 in Figure 2-23 is that Test 1 began with new straight pipe. This pipe was more difficult to buckle and gave a higher load transfer. Effective friction factors were calculated for these tests. The straight pipe produced a friction factor of 0.275. The other two residually bent pipes produced friction factors of 0.365.

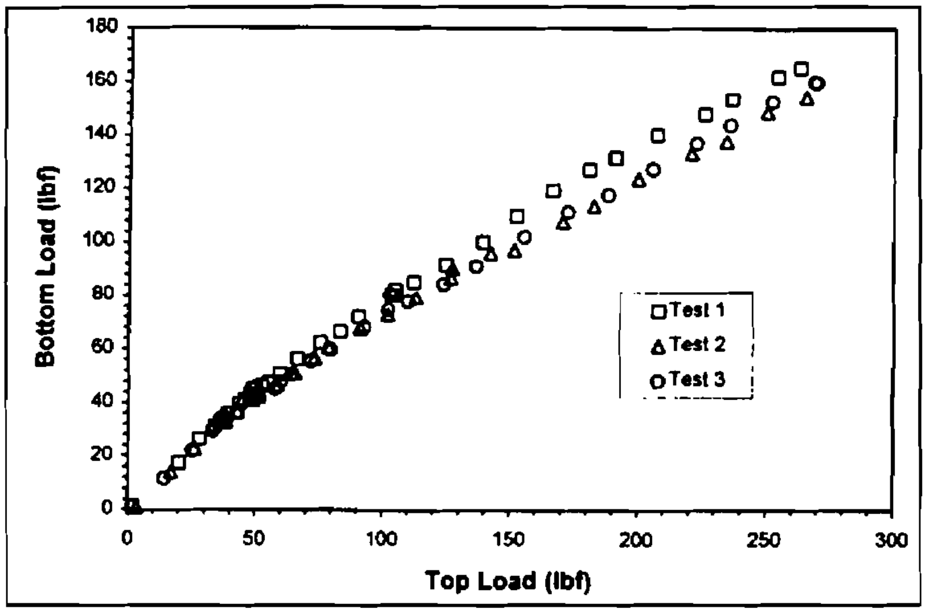


Figure 2-23. Impact of Residual Bending (Miska et al., 1996)

Experimental results and model predictions are compared in Figure 2-24. Error bars of 16% capture the majority of the experimental results.

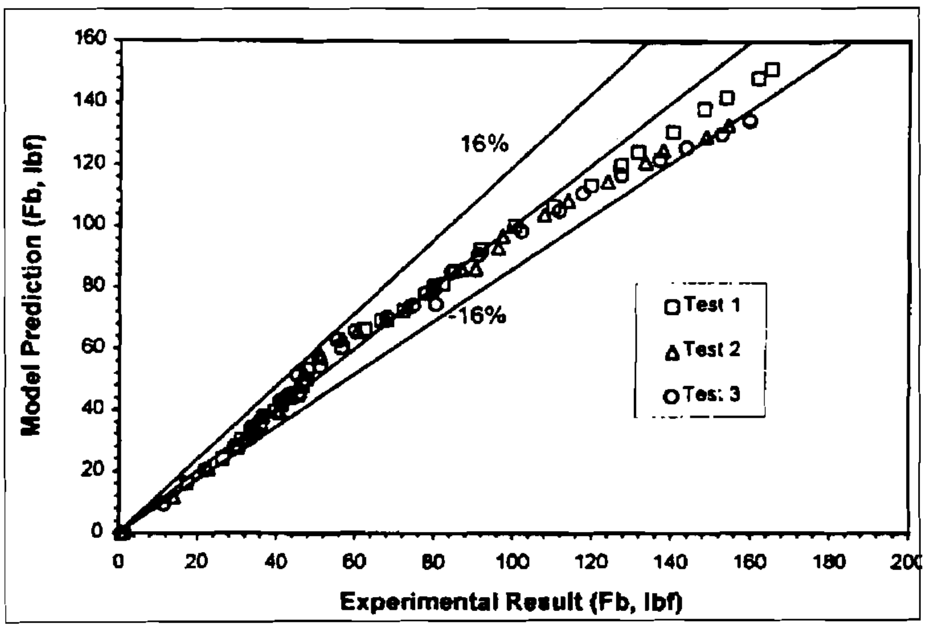


Figure 2-24. Comparison of Model and Experiment (Miska et al., 1996)

2.9 WELLTEC (WELL TRACTORS)

Welltec (Hallundbæk, 1995) developed a well tractor for use on CT in horizontal and deviated wells. The need for the tool was highlighted within Statoil's operations at Statfjord. The system can pull or push CT horizontally beyond 10,000 ft. When the tractor is run on CT, the impact of drag is reduced and lateral reach is increased considerably.

Both hydraulic- and electric-drive versions of the tool have been developed. The fluid-driven tool is 4-6 times more powerful than the electric version due to power transfer limits with wireline. Fortunately, less power and less pulling capacity are often not a problem for wireline operations (e.g., logging).

In offshore applications, drilling technology exists to drill wells to large displacements from the surface location and with long horizontal sections. In some cases, CT cannot be used to service these wells to TD due to drag, buckling and lock-up limits. Alternatives exist, chiefly drill-pipe conveyance, but these options are usually more expensive. A tractor placed behind a CT BHA will extend that system's capabilities and save costs in extreme reach wells.

Another important application for which a tractor will have significant benefit is CT drilling in horizontal holes. Maintaining sufficient weight on bit is often difficult in these operations. An effective tractor would solve this problem.

Welltec has designed three sizes of tractors:

- 4¾-in. tool for 4.9- to 12-in. tubing or open hole
- 3⅛-in. tool for 4.9- to 7-in. tubing or open hole
- 2⅛-in. tool for 2.2- to 4.5-in. tubing

The wellbore tractor is modular (Figure 2-25). The number of sections required depends on available power and the operation to be performed. The hydraulic version typically uses five sections; the electric version uses three. Adding sections increases maximum pulling force, but decreases potential running speed.

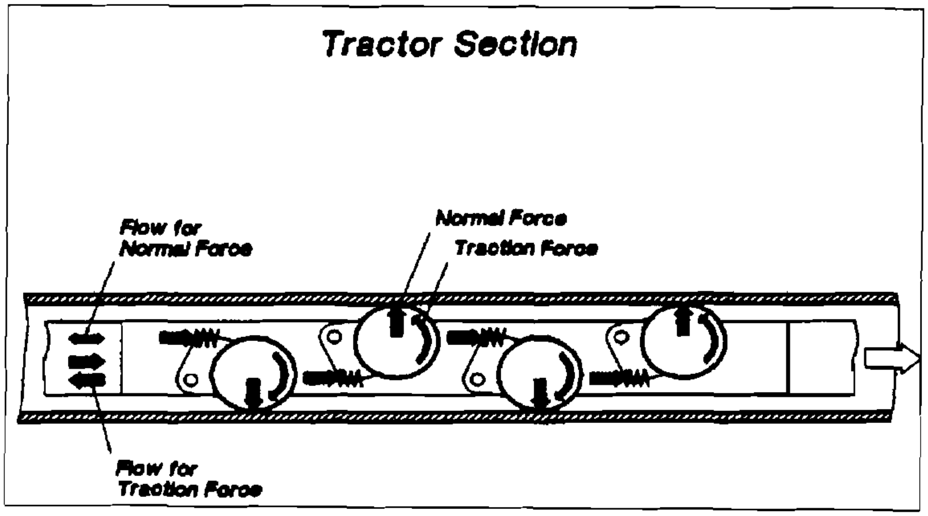


Figure 2-25. Tractor Section Schematic (Hallundbæk, 1995)

The hydraulically driven tractor (Figure 2-26) can be run on 1- to 2⅞-in. CT. Conventional fluids including acids can be used to provide power to the tool. An internal positive-displacement motor drives the tractor.

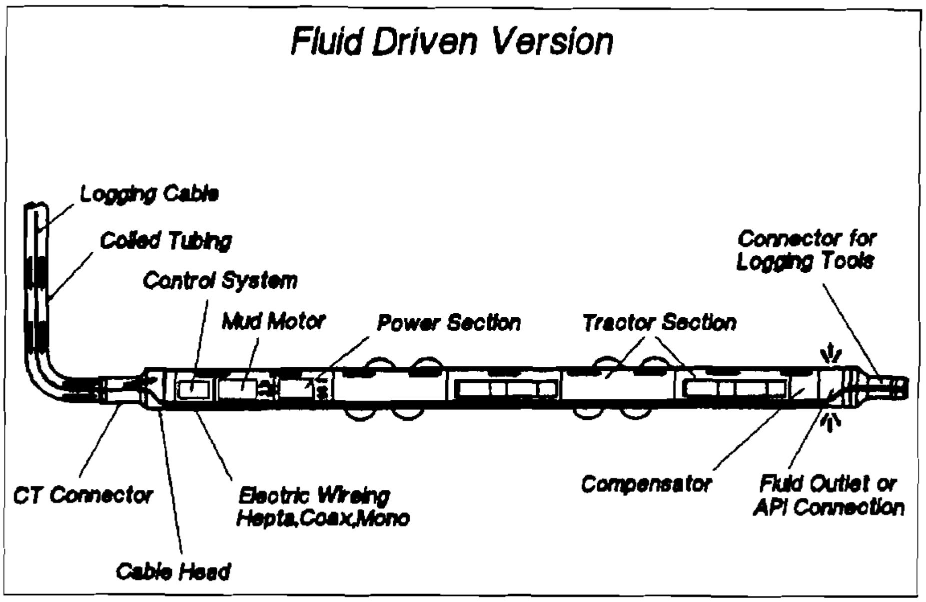


Figure 2-26. Hydraulic-Drive Tractor Assembly (Hallundbæk, 1995)

Tractor pulling capacity as related to flow rate and pumping pressure is plotted in Figure 2-27. The contribution of 6000 m (19,700 ft) of both 1¾- and 2⅜-in. CT is included. Running speed is also shown as the numbers above the curves.

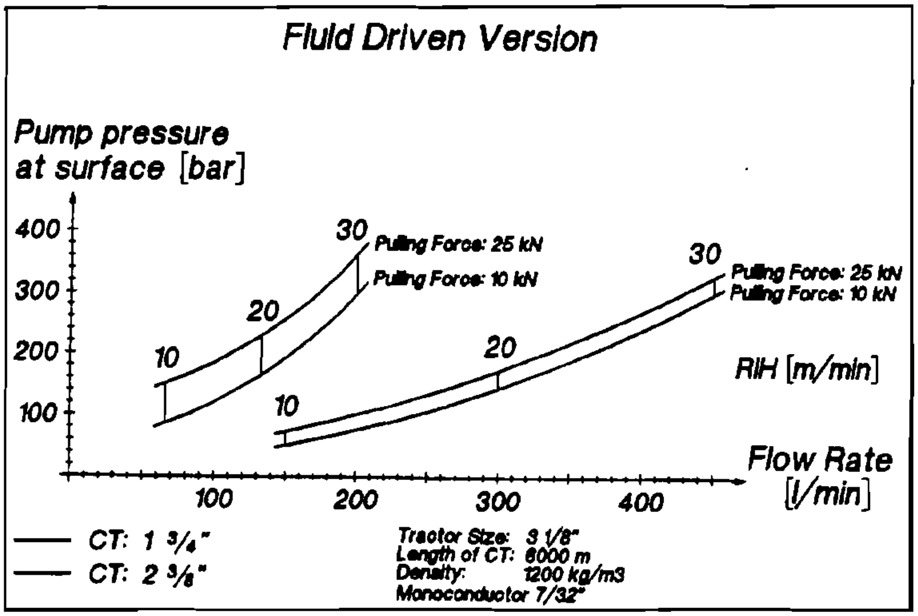


Figure 2-27. Hydraulic-Drive Tractor Performance (Hallundbæk, 1995)

Tool control is accomplished via an internal wireline. The number of conductors is determined by requirements of tools run in front of the tractor (Table 2-5). The system can be run without wireline for simple operations. This might allow the use of smaller tubing and/or higher flow rates.

TABLE 2-5. Hydraulic-Drive Tractor Specifications (Hallundbæk, 1995)

Outer diameter	4¾"	3⅛"
Max. Design flow rate	6 bbl/min	3 bbl/min
Max. Speed	5400 ft/hr	5400 ft/hr
Pulling force	6000 lbs	6000 lbs
Min. ID of tubing	4.9"	3.2"
Max. ID of tubing	12"	7.1"
Wiring through tool	10 wires	10 wires
Fluid channel ID	1"	¾"
Coiled tubing sizes	1" - 2⅞"	1" - 2⅞"
Wireline inside coiled tubing	mono, coax, hepta or none	

The capabilities of the electric-drive tractor (Table 2-6) are less than those of the hydraulic system. The specifications listed in the table are based on the use of heptaconductor wireline.

TABLE 2-6. Electric-Drive Tractor Specifications (Hallundbæk, 1995)

Outer diameter	4¾"	3⅛"	2⅛"
Max. Speed (¤)	3300 ft/hr	3300 ft/hr	3300 ft/hr
Pulling force at 3300 ft/hr	1000 lbs	1000 lbs	1000 lbs
Pulling force at 500 ft/hr	3300 lbs	3300 lbs	3300 lbs
Min. ID of tubing	4.9"	3.2"	2.2"
Max. ID of tubing	12"	7.1"	4.5"
Wiring through tool	10 wires	10 wires	10 wires

(¤) The performance of the tools are based on a hepta cable.
Power and control signals from a power supply box designed especially for this purpose.

The electric-drive system (Figure 2-28) is designed for cased-hole work only. Uses of the system include running production logs, setting and pulling plugs, running perforation guns, cement bond logging, running video cameras etc.

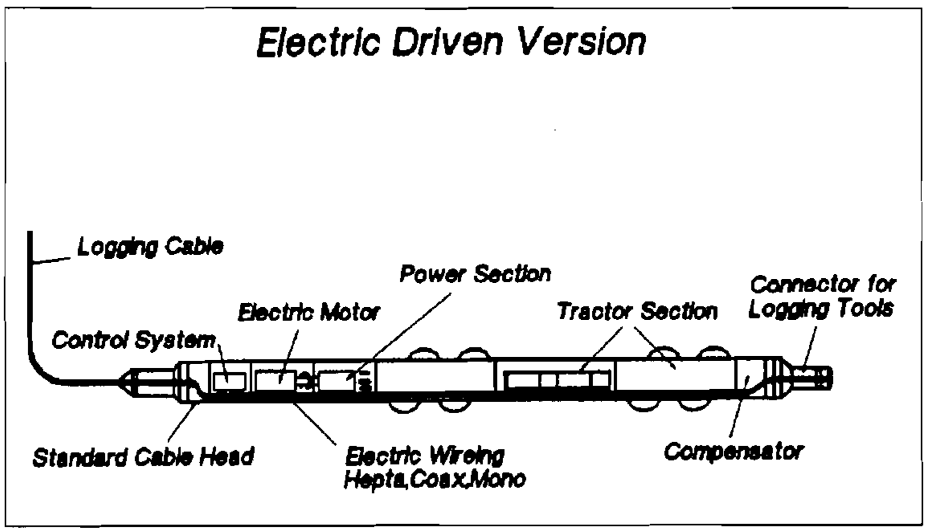


Figure 2-28. Electric-Drive Tractor Assembly (Hallundbæk, 1995)

Welltec noted that these tractors may be used with smaller CT than normal because the influence of tubing stiffness on penetration is no longer a factor.

Cost savings with the well tractor on CT may be considerable. In a study for Statoil, it was determined that the use of the system for operations that currently require a snubbing unit could save 50-60% of present costs.

2.10 REFERENCES

Bhalla, Kenneth, 1995: "Coiled Tubing Extended Reach Technology," SPE 30404, presented at the SPE Offshore Europe Conference held in Aberdeen, September 5-8.

Bhalla, K., and Walton, I.C., 1996: "The Effect of Fluid Flow on Coiled Tubing Reach," SPE 36464, presented at the 1996 SPE Annual Technical Conference and Exhibition held in Denver, Colorado, October 6-9.

Christie, Mike and Gavin, Bill, 1997: "Titanium as an Alternative to Conventional Coiled Tubing: A North Sea Case Study," SPE 38416, presented at the 2nd North American CT Roundtable, Montgomery, Texas, April 1-3.

Engel, Steve, and Sehnal, Zdenek, 1996: "Deploying and Recovering Long and Heavy BHAs in Live High Angle Wells," SPE 36330, presented at the 1st SPE Gulf Coast Section/ICoTA North American Coiled Tubing Roundtable held in Conroe, Texas, February 26-28.

Hallundbæk, Jørgen, 1995: "Reducing Costs With Well Tractors for Horizontal Wells," OTC 7875, presented at the 27th Annual OTC in Houston, Texas, May 1-4.

Leising, L.J. et al., 1997: "Extending the Reach of Coiled Tubing Drilling (Thrusters, Equalizers, and Tractors)," SPE 37656, presented at the SPE/IADC Drilling Conference, Amsterdam, March 4-6.

Miska, Stefan, et al., 1996: "An Improved Analysis of Axial Force Along Coiled Tubing in Inclined/Horizontal Wellbores," SPE 37056, presented at the 1996 SPE International Conference on Horizontal Well Technology held in Calgary, Canada, November 18-20.

PEI Staff, 1996: "Straightener Extends CT Reach," *Petroleum Engineer International,* May.

Plauche, Ricky and Koshak, W.E., 1997: "Advances in Sliding Sleeve Technology and Coiled Tubing Performance Enhance Multizone Completion of Abnormally Pressured Gulf of Mexico Horizontal Well," SPE 38403, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Robberechts, Hilde and Blount, Curtis, 1997: "A New Generation of Drag Reducer Additives Hydrocarbon Based CT Applications," presented at 5th International Conference on Coiled Tubing and Well Intervention, Houston, February 4-6.

3. Cementing

TABLE OF CONTENTS

3. Cementing

3.1 ADAMS CT AND NORCEN EXPLORER (FOAM CEMENT PLUGS)

Adams Coiled Tubing and Norcen Explorer Inc. (Noles et al., 1996) developed an improved method to reduce CT cement job failures in slim holes. Failures had previously occurred in jobs with small annuli and small cement volumes. Cement had been found to cure in tubing or the annulus at the wrong position (Figure 3-1). Methods to overcome these shortcomings were sought and developed.

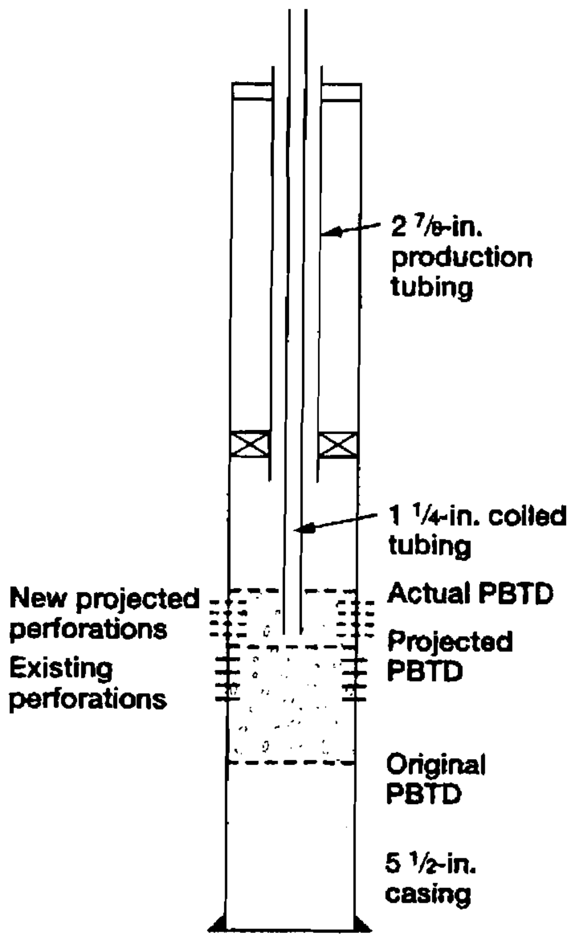


Figure 3-1. Cement Spotting Problems
(Noles et al., 1996)

Initially, it was assumed that these cement placement problems were caused by improper depth measurement and tubing placement. This could be addressed by a separate run with a tubing-end locator. Although an extra trip is required, this was considered to be a worthwhile means to avoid placement errors.

Pumping and volumetric control were evaluated through a series of tests. Special small-volume surface tanks (two 10-bbl compartments per tank) were designed. Pumping tests showed that cement volume had increased during the pumping operation, with a typical increase of 21 to 30 gallons. This observation suggested that original problems may not have been attributable to cement placement, but rather to cement contamination during pumping. It was found that friction properties distorted flow (Figure 3-2).

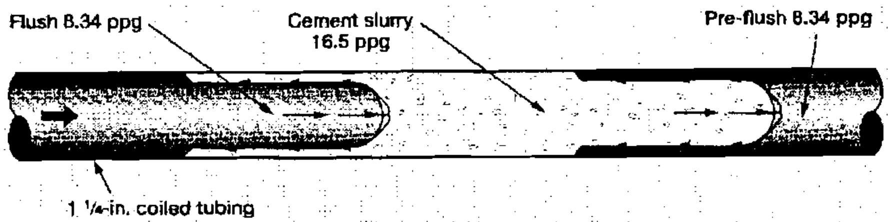


Figure 3-2. Cement Mixing/Contamination (Noles et al., 1996)

This problem of contamination was first addressed by attempting to design the original slurry and stages at higher densities/concentrations to compensate for the expected contamination. Tests showed that this approach was probably not viable due to variations in final fluid composition (that is, final results were not repeatable).

A mechanical foam plug (pig) was then used to prevent mixing and contamination of the cement during pumping (Figure 3-3). The plugs are 90% compressible, and have an OD twice that of the CT and a length of 6 inches.

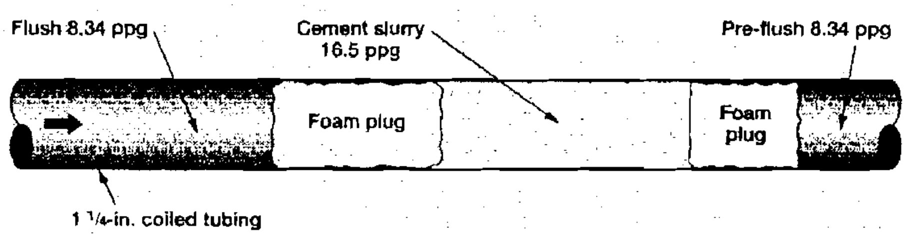


Figure 3-3. Foam Plugs to Avoid Contamination (Noles et al., 1996)

Stable test results were achieved with the foam plugs and several field applications were successfully completed placing small cement volumes in slim annuli.

3.2 BECHTEL AND HALLIBURTON (DEEP, HOT SQUEEZES)

Bechtel Petroleum and Halliburton Energy Services (Garner et al., 1995) reported a successful squeeze/reperforation procedure performed in the Elk Hills field in California. Close tolerances in the tubulars and the depth of the well caused concern regarding the feasibility of a through-tubing workover with CT. Simulations showed that a circulation rate of 1 bpm would be possible if friction-reducing additives were employed. The final result was an economical cement squeeze (about 20% less than the conventional approach) that greatly increased the profitability of this deep, hot well.

The cement squeeze was pumped to a depth of 9000 ft in 1½-in. CT. Production increased to 550 BOPD from 260 BOPD, while gas cut was decreased 75%.

Design of the slurry (Table 3-1) was critical for these conditions. A squeeze pressure of 2500 psi was planned. The slurry was contaminated by biopolymer to prevent it from setting up in the casing or CT.

TABLE 3-1. Cement Slurry (Garner et al., 1995)

Slurry Composition	
1.	33 sacks premium cement
2.	40% silica flour
3.	0.5% fluid loss additive
4.	0.4% suspending aid
5.	1.2 gal/sack latex
6.	0.05% de-foamer
7.	0.22 gal/sack latex stabilizer
8.	0.2 gal/sack retarder
9.	4.68 gal/sack water
Yield:	1.56 cu ft/sack
Density:	15.8 lb/gal
Thickening time:	12 hours at 250°F; no viscosity build-up after hesitation
Fluid Loss:	40 cc/30 min
Compressive strength:	1,550 psi after 24 hours at 250°F

The squeeze procedure (Table 3-2) included a hesitation squeeze pumping schedule. The operation was completed successfully as planned on the first attempt. No underreaming was required prior to reperforating the well.

TABLE 3-2. Cement Squeeze Procedure (Garner et al., 1995)

Job Procedure
1. Tag sand plug for depth correlation and pull up to 9,240 ft.
2. Kill well by pumping 50 bbl water down coiled-tubing/tubing annulus.
3. Mix cement slurry (see Table 3-1).
4. Pump at 1 bbl/min: A. 5 bbl water. B. 9 bbl cement slurry. C. 5 bbl water. D. 8 bbl polymer water (at 1.5 bbl/min).
5. Lay cement plug by continuing to pump polymer water (7 bbl total) while moving CT upward at 30 ft/min.
6. Pull CT up and circulate with polymer until returns are clean (about 40 bbl total circulated).
7. Follow hesitation squeeze schedule to bring pressure up to 2,500 psi.
8. While holding 1,500 to 2,000 psi back pressure, make contamination run to bottom of cement (1 bbl/min polymer water, while moving CT downward at 15 ft/min).
9. Drop ball and make cleanout run to bottom (top of sand plug)
10. Pull out of hole at 30 ft/min while pumping polymer water at 1 bbl/min.
11. Shut well in while maintaining 2,000 psi pressure.
12. Re-perforate in new zone
13. Jet well and return to production.

3.3 BP EXPLORATION AND ARCO (FIBER CEMENT WORKOVERS)

BP Exploration (Alaska) Inc. and Arco Alaska Inc. (Loveland and Bond, 1996) summarized recent innovative applications of CT and CT cementing at Prudhoe Bay. As the field declines, the drive to decrease workover costs has become more critical. Fiber cementing has proved a valuable addition to these operations.

Adding fiber to cement has at least three benefits: 1) it provides impact resistance when the plug is milled through, lessening the potential for cracking, 2) it helps hold the cement plug intact even if cracks develop, and 3) the fiber acts as a bridging agent, which is desirable in some cases. The primary applications of fiber cement at Prudhoe Bay are packer repair squeezes, cement sheaths for gas/water shut offs, and kick-off plugs.

Production packer failures have become more common as the field ages. As an alternative to a rig workover, packers have been squeezed with fiber cement. The operation is summarized in Figure 3-4. The CT approach has been highly successful and an important option.

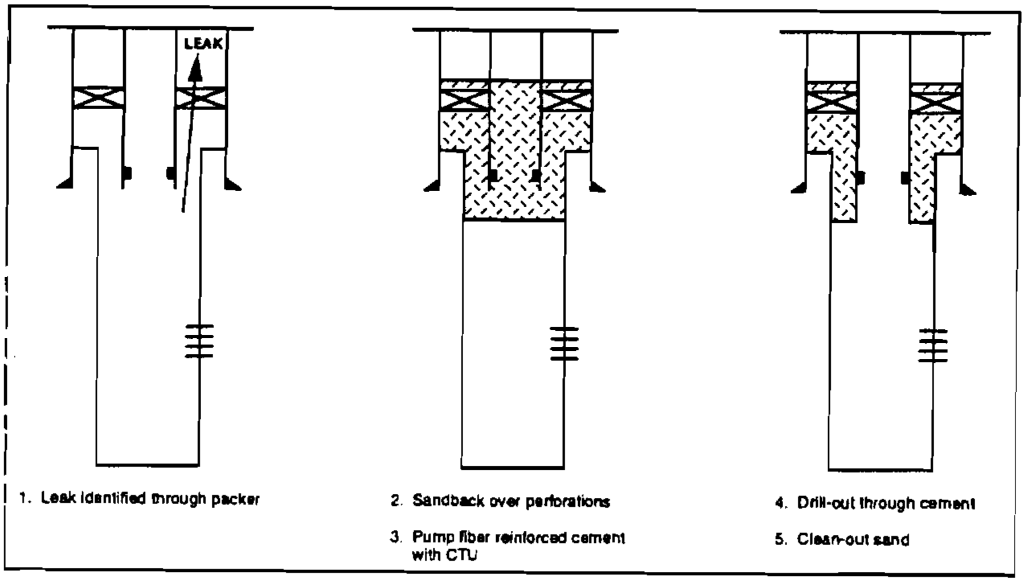


Figure 3-4. Fiber Cement for Repairing Packer (Loveland and Bond, 1996)

Fiber is added to a volume of cement that will fill the annulus from above the packer to the sand plug. The remaining cement is left neat.

All nine of these jobs have been successful. Cost is about 20% that of a rig workover.

A second CT application using fiber cement is for covering previously squeezed cement nodes for shutting off water or gas. The additional support of an annular sheath has allowed success in several wells where repeated failures of the cement-squeeze nodes were observed.

The principal risk in this squeeze operation (Figure 3-5) is that the mill tends toward the bottom of the hole and may drill an off-center hole. However, six of eight jobs of this type have been economically successful.

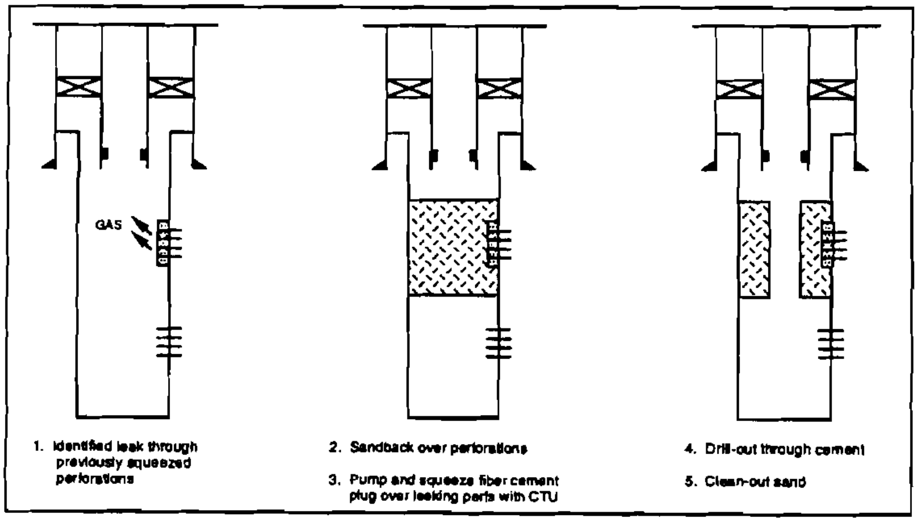


Figure 3-5. Fiber Cement Sheath for Covering Perforations (Loveland and Bond, 1996)

A more complicated approach to this shut-off problem is to run a scab liner prior to cementing. This procedure (Figure 3-6) adds a steel barrier to the cement barrier across the nodes. Advantages over the previous procedure (without the scab liner) are less cement must be drilled out, there is no risk of drilling off center, and it is more robust. The disadvantages are greater operational difficulty and the permanence of the liner in the wellbore.

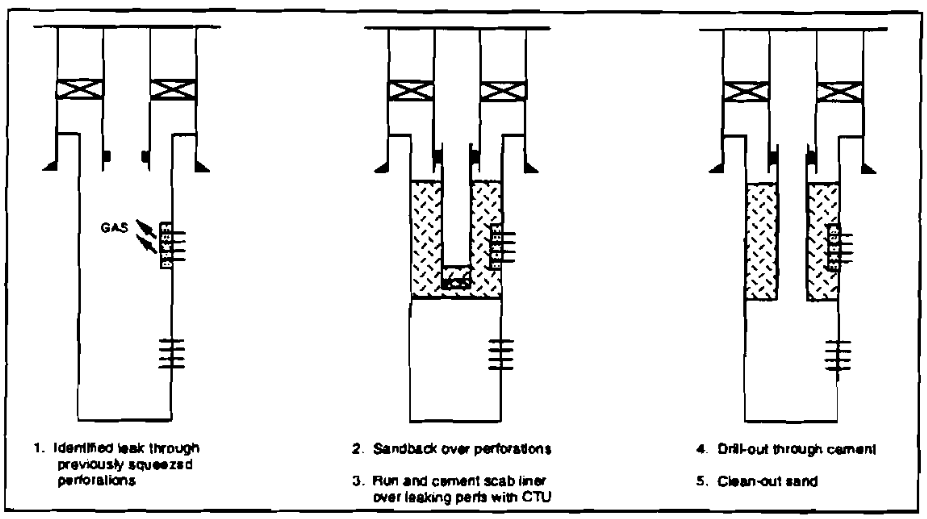


Figure 3-6. Scab Liner for Covering Perforations (Loveland and Bond, 1996)

All of fourteen scab liners have been successful at Prudhoe Bay. Costs for this operation are about 60% above a standard CT squeeze.

3.4 BP EXPLORATION AND SCHLUMBERGER DOWELL (MIXING ENERGY)

BP Exploration and Schlumberger Dowell (Hibbert et al., 1995) reported results of laboratory and yard tests of the impact of cement mixing energy on cement properties for batch-mixed slurries (typical of CT operations). Significant differences were observed between laboratory measurements and field-scale properties. They found that mixing energy is a critical parameter in slurry design, and that energy levels above API laboratory mixing energy may degrade slurry performance. Increasing the mixing energy up to the API laboratory value has been found to be beneficial.

Four different slurry types were tested in the yard in 20- or 50-bbl tanks. A lignosulphate-derivative compound was used as a retarder. Three fluid loss additives were used: latex (FL), polymer (FP), and cellulose (FC). Compositions are summarized in Table 3-3.

TABLE 3-3. Slurry Composition (Hibbert et al., 1995)

	Slurry Compositions			
	Slurry 1	Slurry 2	Slurry 3	Slurry 4
Density, ppg	16.0	16.4	16.0	16.0
Retarder R	0.02	0.02		
Fluid Loss FL		0.25	0.25	
Fluid Loss FC, %				2.0
Dispersant	0.02	0.02	0.02	0.02

Mixing energy for the laboratory test and yard test are compared in Table 3-4 for slurry 1.

TABLE 3-4. Thickening Times for Slurry 1 (Hibbert et al., 1995)

Volume	10 bbl		
Mixing time	20 minutes		
Slurry	16.0 ppg, 0.02 gal/sk Retarder R		
Sample	Temperature (deg. F)	Thickening Time (hrs:min)	Mixing Energy (kJ/kg)
Lab	150	3:42	5.9
Yard	150	2:00	30

A variety of slurries were tested by Hibbert et al. Readers are referred to their paper for further details. Tests showed that when mixing energy from the laboratory and yard batches are both close to the

API value, both show similar properties. They point out that mixing energy must be considered in slurry design in the same light as temperature and pressure.

3.5 CHEVRON USA AND DOWELL (PLACING CEMENT PACKERS)

Chevron USA Production and Dowell (Nowak and Patout, 1997) described the design and execution of cement-packer placement for recompleting multiple zones. This successful operation is believed to represent the largest cement packer placed through CT.

A variety of problems are associated with placing cement packers conventionally (Figure 3-7). Slurry density may vary 0.5 ppg if a continuous mix process is used. Inadequate slurry displacement may cause poor sweeping in the tubing.

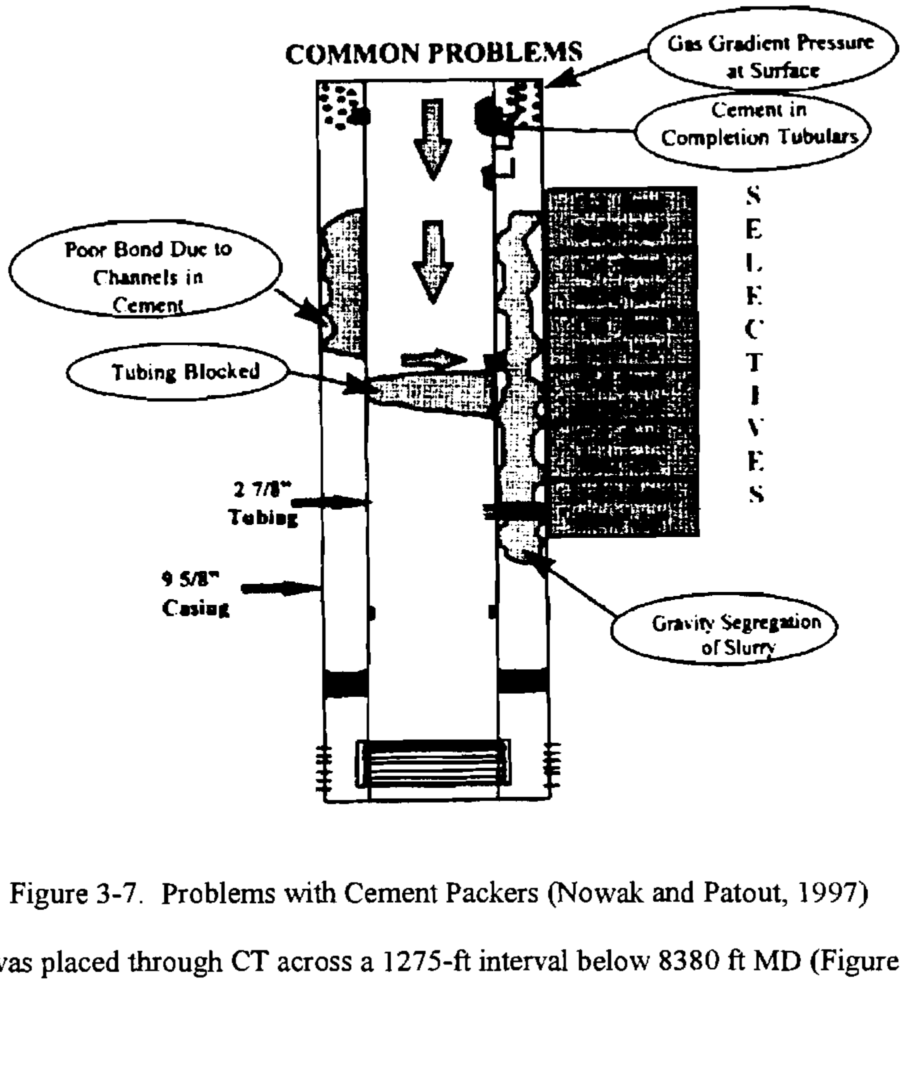


Figure 3-7. Problems with Cement Packers (Nowak and Patout, 1997)

Cement was placed through CT across a 1275-ft interval below 8380 ft MD (Figure 3-8).

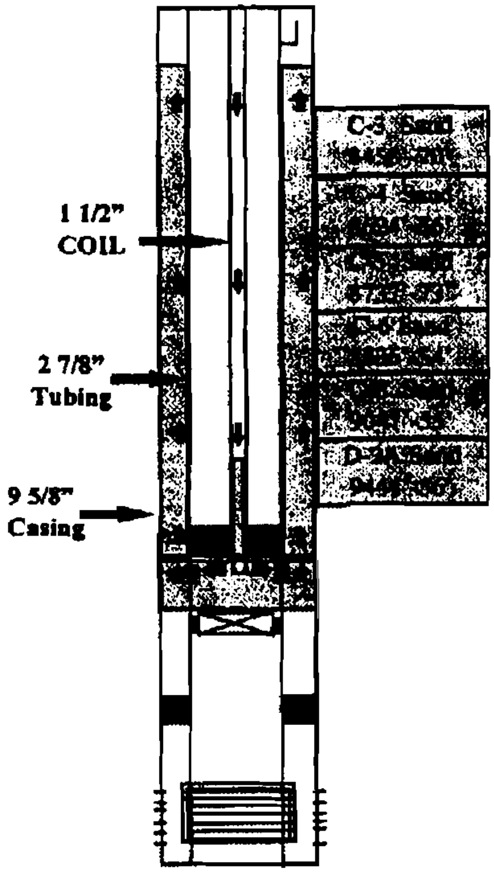


Figure 3-8. CT Placement of Cement Packer (Nowak and Patout, 1997)

Cement-packer recompletions with CT proved to be a cost-effective method to recover additional reserves from stacked sands previous not economical to recover. Larger cement slurries can be placed through CT than was previously considered feasible.

3.6 CHEVRON USA AND SCHLUMBERGER DOWELL (DUAL CEMENT SYSTEM)

Chevron USA Production Company, Chevron Petroleum Technology Company and Schlumberger Dowell (Nowak et al., 1995) presented results from a successful field operation using CT to shut off a geopressured water channel behind casing (Figure 3-9). A CT operation was the only viable option to work over the well and restore production. A unique dual cement system using a hesitation squeeze with limited thickening time was required to repair the well. Slurry with a high fluid loss and reduced thickening time was successfully pumped through CT.

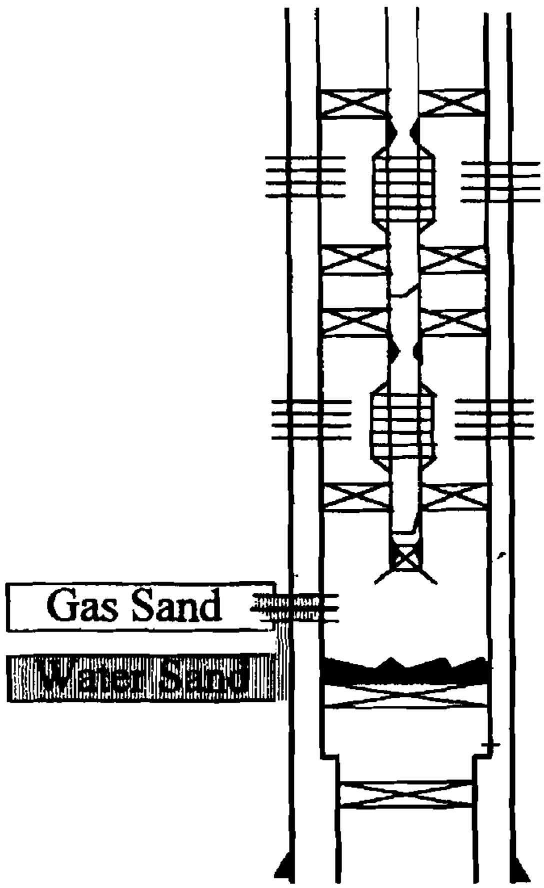


Figure 3-9. Geopressured Water Channeling (Nowak et al., 1995)

The well completion (offshore Louisiana) is illustrated in Figure 3-10. A previous rig workover consisted of two stacked gravel packs in the 10,800 and 10,600 ft sands and a primary completion in the 10,900 ft sand. Perforations inadvertently opened a geopressured channel. No hydrocarbons were produced during several weeks of observation.

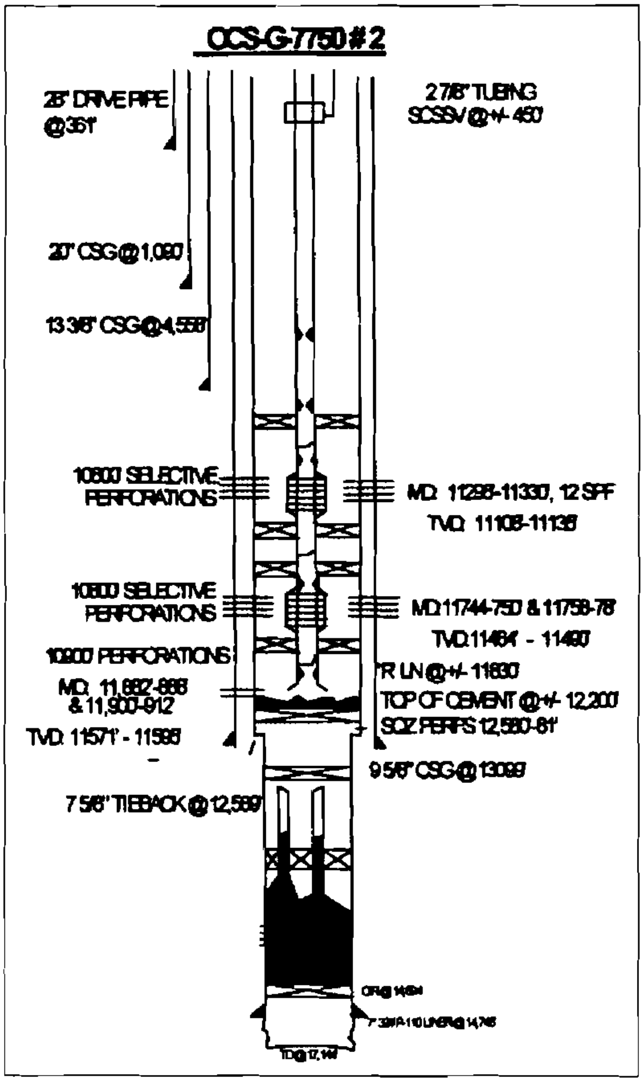


Figure 3-10. Offshore Well Completion (Nowak et al., 1995)

Chevron's analysis of options for squeezing the cement channel included three techniques: 1) a concentric (through-tubing) workover to isolate the water source and recomplete the 10,800 ft sand; 2) plug the well back to the 10,800 ft sand and hope the cement bond would not break down while producing that sand; and 3) perform a major rig workover to squeeze the zones. Economic and risk considerations led to the choice of a concentric workover to block the pressure communication with the geopressured water source.

Slurry placement was a major concern, with effective diversion paramount. The lead slurry would need to bridge the productive formation so that the tail slurry could be diverted toward the water source. The lead slurry would be designed with low thickening time and high fluid loss.

Concerns for job design included high friction pressures typically associated with high fluid-loss slurries; the need to model thickening time and test at conditions close to the field conditions; and that pressures needed to carefully maintained below fracture pressures for the 10,900 ft sand.

Typical CT strings used in workovers in the Gulf of Mexico are 1¼-in. OD. A 1½-in. string was specified for this job, primarily to allow higher pumping rates and lower friction pressures, resulting in less potential for fracturing damage.

The lead slurry was designed with a density of 16.2 ppg, a thickening time of 3 hr 55 min, a fluid loss of 707 ml/30 min, and a viscosity of 38 cp. The tail slurry was designed to be squeezed against the dehydrated lead slurry. Tail slurry specifications included a thickening time of 4 hr 14 min and a fluid loss of 27 ml/30 min.

The volume of the CT spool was measured by pigging on location. A 17-ppg mud was spotted up to the perforations to keep cement out of the rathole. Injection pressures (Figure 3-11) were estimated based on surface pressures in the annulus and corrected for temperature.

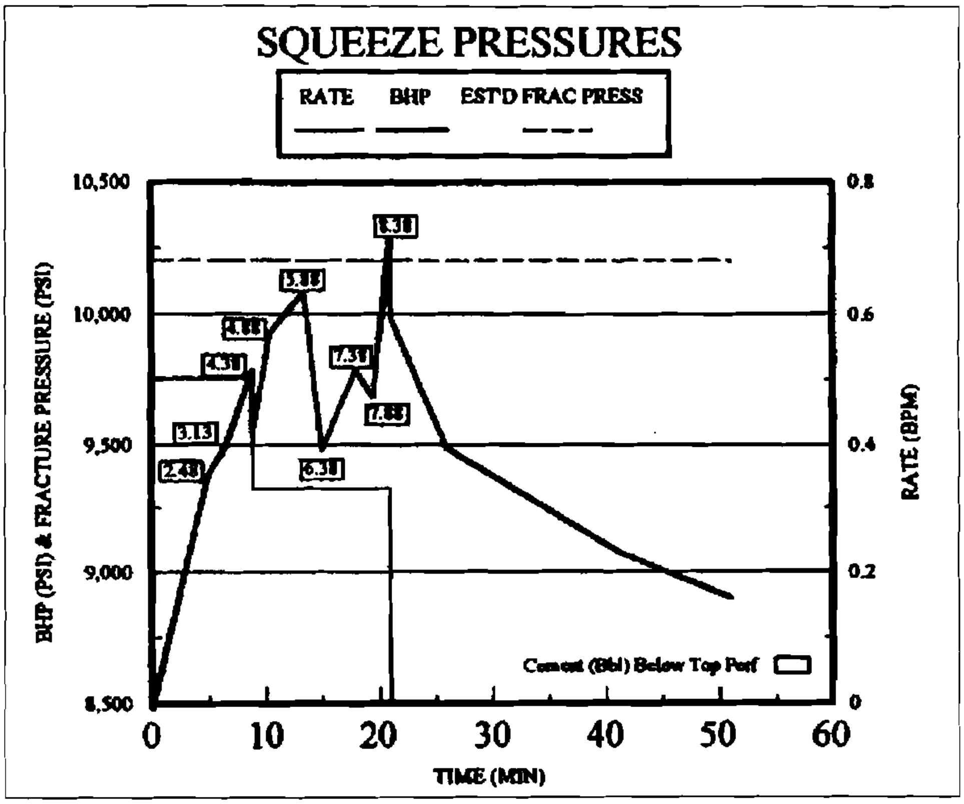


Figure 3-11. Squeeze Pressures (Nowak et al., 1995)

The slurries were placed successfully and allowed to cure for 48 hours prior to perforating the 10,800 ft sand. Initial production rates were 177 BOPD with no water cut, compared to only water prior to the squeeze. An acid stimulation increased production to 1103 BOPD and 16 BWPD.

3.7 PREEMINENT ENERGY, SAS INDUSTRIES AND BJ (MAGNESIAN CEMENT)

Preeminent Energy Services, SAS Industries and BJ Services (Coats et al., 1996) described the benefits and applications of magnesian cement placed with CT. This unique cementing material can be placed downhole, form a mechanical seal, and later be completely dissolved by acid and removed. These properties make the cement ideal for a variety of operations such as setting temporary plugs across productive zones to work over lower zones, squeezing and blocking zones that are expected to the produced later in the well's productive life, and as an effective lost-circulation material.

General benefits for using CT for placing cement downhole include faster trip times, improved accuracy in fluid placement, and effective well control during the entire operation. Conventional cements are not appropriate for jobs where complete removal of the cement is required after the job is completed. Magnesian cement is a recent development for these applications. This cement is a mixture of magnesium and calcium oxides, carbonates and sulfates. While a high compressive-strength material in the presence of water, magnesian cement is completely soluble in hydrochloric acid.

Typical densities range from 12.5 to 14 ppg, although weighting up to 21 ppg is possible with common weighting agents. Temperatures for use are from 60 to 230°F. Magnesian cement is highly resistant to contamination from other fluids. As a benefit, expensive flushes or spacers are not necessary. Another benefit is its tendency to expand while curing, thereby reducing the potential for small channels.

Magnesian cement is removed by a focused acid-wash program using CT and special wash nozzles. Adequate wash time is required for removing the cement from perforation tunnels.

Prior to running a cementing job in CT, several planning steps using computer models are prudent. The well's directional survey is used to model drag to ascertain that the tubing can be run to depth with the equipment available. Fatigue cycle life models are used to confirm safety of the proposed operations. Hydraulics models are run to verify injection pressures, pressure drops, etc. Buckling models are also necessary for many applications.

3.8 SERVICIOS HALLIBURTON DE VENEZUELA AND LAGOVEN (LINER SQUEEZE)

Servicios Halliburton de Venezuela and Lagoven SA (Lizak et al., 1996) described the planning and implementation of procedures to successfully complete a problem horizontal well in the Bolivar Coastal field in Lake Maracaibo. The slotted liner became stuck during completion operations, leaving a water-bearing zone in the curve exposed. CT was used to log the well, isolate the productive zone, squeeze the liner, and stimulate the well to bring on production. Careful planning saved this well. CT operations were paid out in 33 days.

The subject well was originally completed in 1956 as a vertical producer. By 1989, the well was nonproductive and awaiting repair. A horizontal re-entry was performed in 1995. During completion operations, the slotted liner became stuck 267 ft from TD. The inflatable packer to be used to isolate the water zone was stranded above the zone.

Four primary options were considered for completing the well with CT equipment. These included: 1) circulation squeeze with inflatable packer (place a high-viscosity pill in the productive interval, set an inflatable packer in 4½-in. casing, squeeze fine-particle cement, and drill cement from inside the liner), 2) perforate and circulate squeeze with inflatable packer (log the well, perforate below the top of the slotted liner, and use option 1 with conventional cement), 3) squeeze without a packer (run CT in with nozzle, place a plug of fine-particle cement across the top of the liner and squeeze, then drill out cement), and 4) perforate and squeeze without a packer (log the well, perforate below the top of the slotted liner, and use option 3 with conventional cement).

The project team decided that it was critical to know the precise location of the packers and liner top. This narrowed the options to two (number 2 or 4). The two types of cement available are described in Table 3-5. Fine-particle cement is able to be squeezed through the liner slots, with less chance for bridging than conventional cement.

TABLE 3-5. Comparison of Cement Properties (Lizak et al., 1996)

PROPERTY	CLASS H	FINE PARTICLE
Density, lb/gal	15.80	11.20
Plastic Viscosity, cp	94.50	51.00
Free Water, %	0.00	0.00
Fluid Loss, cc/30 min	14.00	18.00
Yield, cf/sk	1.15	1.41
Pump Time, hr	5.16	4.12
Water Requirement, gal/sk	5.10	8.50
24-hr Compressive Strength, psi	2,000	900

Halliburton and Lagoven chose a fine-particle cement and placed it using a hesitation squeeze. Cement was displaced from the string with welan biopolymer and the well shut in for 24 hours.

Nitrogen was used to bring the well back on production. Initial production was 900 BOPD without sand or water. It was considered too high a risk to acidize and increase production further, since the acid may have broken down the cement.

More details are presented in *Workovers*.

3.9 REFERENCES

Coats, Alan, et al., 1996: "Magnesian Cement, CT Offer Benefits," *The American Oil & Gas Reporter*, March.

Garner, Ted, and Fleckenstein, Will, and Shelley, Bob, 1995: "Recomplete Deep, Hot Wells Successfully with Coiled Tubing," *Petroleum Engineer Int'l*, June.

Hibbert, A. P., et al., 1995: "Effect of Mixing Energy Levels During Batch Mixing of Cement Slurries", SPE 25147, presented at the 1992 Offshore Technology Conference, May 4-7.

Lizak, et al., 1996: "Coiled Tubing Workover Saves Horizontal Well in Lake Maracaibo," OTC 8224, presented at the Offshore Technology Conference held in Houston, Texas, May 6-9.

Loveland, K.R., and Bond, A.J., 1995: "Recent Applications of Coiled Tubing in Remedial Wellwork at Prudhoe Bay," SPE 35586, presented at the SPE Western Regional Meeting held in Anchorage, Alaska, May 22-24.

Noles, Jerry, et al., 1996: "Small-capacity Cement Procedure Reduces Failure Potential," *World Oil* May.

Nowak, T.W., et al., 1995: "Shut-off of a Geopressured Water Channel Behind Casing via Coiled Tubing Utilizing a Dual Slurry Cement System," SPE 29474, presented at the Production Operations Symposium held in Oklahoma City, OK, 1995.

Nowak, T.W., and Patout, T.S., 1996: "Rigless Mutlizone Recompletion Using a Cement Packer Placed With Coiled Tubing: A Case History," SPE 35613, presented at the 1996 SPE Gas Technology Conference held in Calgary, 28 April - 1 May.

4. Coiled Tubing

TABLE OF CONTENTS

4. Coiled Tubing

4.1 BJ SERVICES (CT CONNECTORS)

BJ Services (Reaper, 1997) developed in-line CT connectors for use in weight-restricted offshore operations in the North Sea. Tubing is the heaviest single component that platform cranes must have the capacity to lift. As platforms have aged, cranes have been derated. At the same time, tubing OD (and consequently weight) has been increased for greater pump rates and load capacities. Previously, welding strings together and radiographic inspection was the only option for joining spools offshore. In-line connectors have since been developed for 1½- and 1¾-in. CT. These allow strings to be screwed together on site and are suitable for use with conventional fluids, gases, and stiff wireline operations.

Full-scale testing was conducted on the connectors, and safe operational ranges were developed (Table 14-1).

TABLE 14-1. Operational Limits for CT Connectors (Reaper, 1997)

Parameter	Connector	
	1.5"	1.75"
Maximum internal operating pressure at surface	3000 psi	2000 psi
Maximum pressure differential downhole	1500 psi collapse 4000 psi burst	1500 psi collapse 4000 psi burst
Minimum bore without wireline	0.556"	1.116"
Maximum running speed on/off reel and over gooseneck	50 ft/min.	50 ft/min
Maximum allowable tensile pull (The effect of pressure on the Axial Tension rating has NOT been applied to this figure)	33000 lbs	40000 lbs
Maximum allowable torque	200 ft/lbs	200 ft/lbs

Extensive fatigue tests were conducted with the 1½-in. connector (Figure 14-1). The connector fatigue life, though limited, was above the average life of field welds.

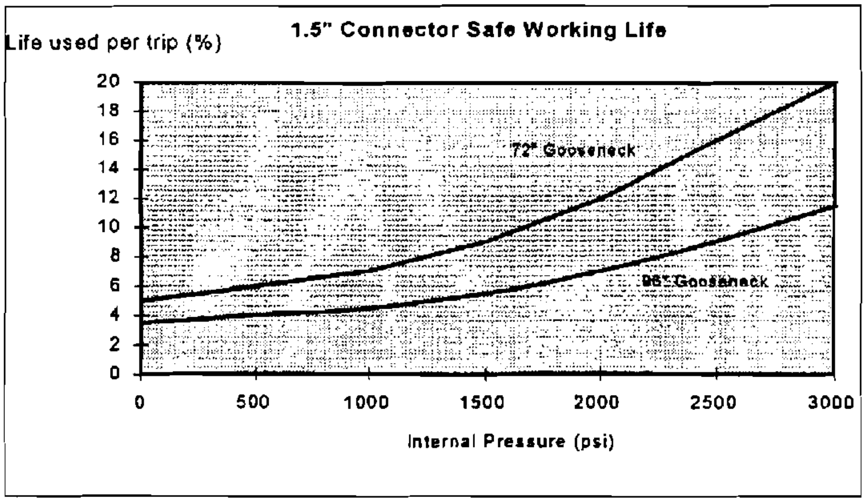


Figure 14-1. Fatigue Life of CT Connectors (Reaper, 1997)

These in-line connectors have been successfully applied in the field. Limited fatigue life is a problem with these connectors, and future improvements are needed.

4.2 BJ SERVICES (DETERMINING CT MECHANICAL PROPERTIES)

BJ Services (Crabtree et al., 1997) summarized testing results designed to investigate the impact of plastic strain on CT yield strength and Young's modulus. Field experience has demonstrated that performance is degraded when, for example, the measured yield stress in a failed sample of CT is much less than the rule-of-thumb 80% of nominal yield. A series of tests measuring principal stresses (Figure 4-2) and strains was designed and conducted. Their tests showed, however, that the 80% safety factor provides an adequate margin of safety to account for dimensional uncertainty, varying material properties, and inaccuracies of field instrumentation. Work softening may occur due to bending fatigue, but the reduction in load carrying capacity at yield is estimated as only about 5%.

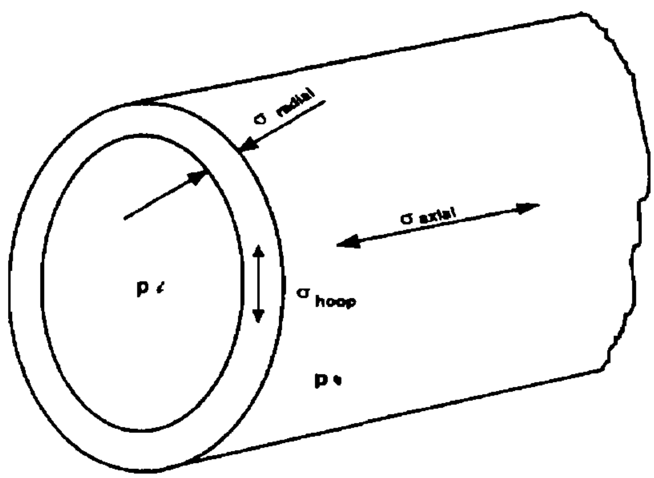


Figure 4-2. Principal Stresses in CT (Crabtree et al., 1997)

Hoop strain properties were investigated for straight CT (never bent) (Figure 4-3) and CT that had been bent. Yield point for the straight tube was 78,000 psi and Young's modulus was 35,000,000 psi.

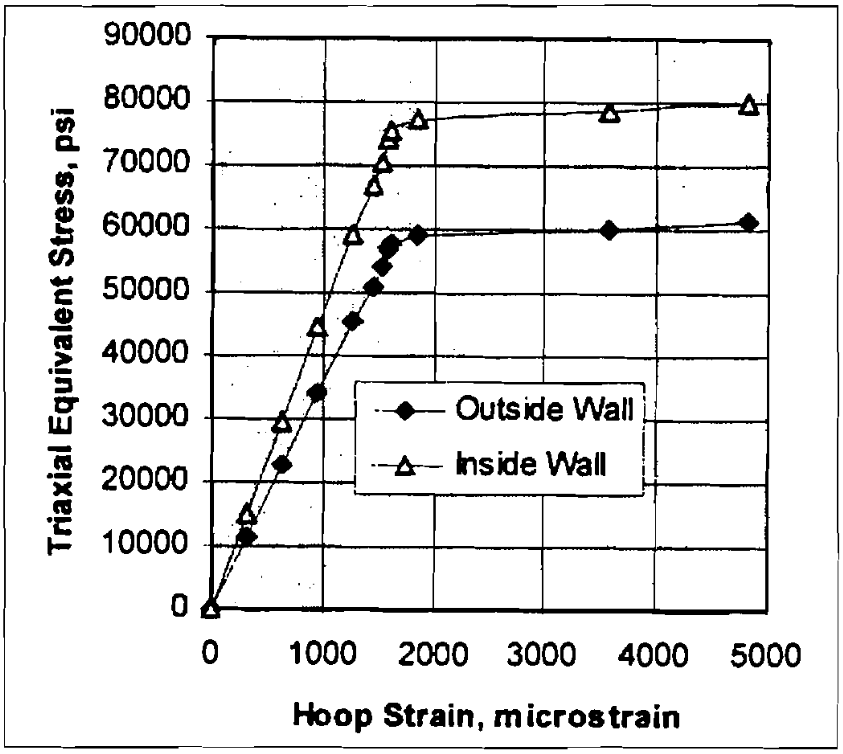


Figure 4-3. Stresses in Straight CT (Crabtree et al., 1997)

Hoop strain in the straight tube and bent tube at the neutral axis are compared in Figure 4-4. There is little observable effect on elastic properties by CT condition.

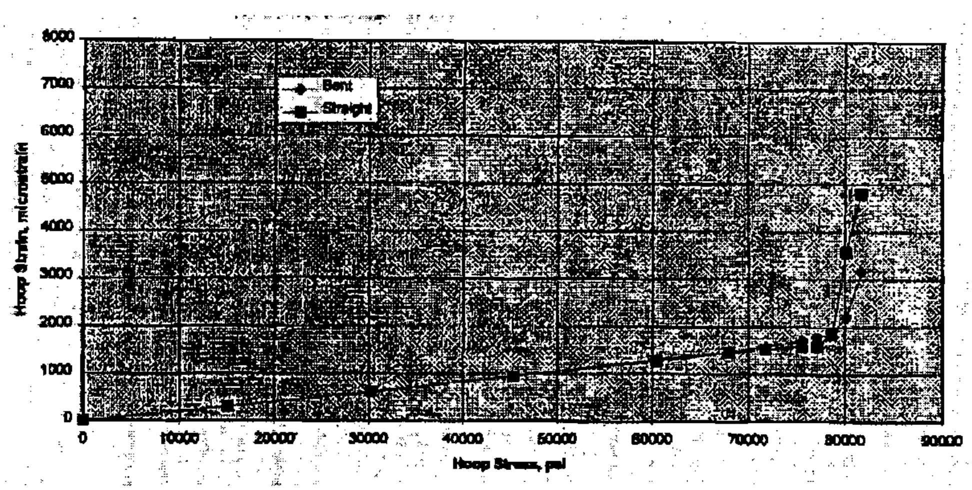


Figure 4-4. Hoop Stresses in Straight/Bent CT (Crabtree et al., 1997)

See Crabtree et al. (1997) for detailed test results.

4.3 BJ SERVICES (FEASIBILITY OF TITANIUM CT)

BJ Services (Christie and Gavin, 1997) analyzed the feasibility of using titanium CT for routine applications offshore in the North Sea. The driving force behind the study is potential weight savings that might offset down-rated deck and crane capacities on North Sea platforms. BJ Services performed a series of modeling simulations to analyze the capability of titanium strings to maintain sufficient WOB to push CT BHAs downhole. Data from actual jobs performed with steel CT were used for as the basis for the simulations. Results showed that titanium may have difficulty in these applications due to a lower Young's modulus.

In one horizontal well, the surface weight indication would be significantly less for titanium than was measured for steel (Figure 4-5). Less surface weight means a lower hanging weight and less weight available to push the BHA into the horizontal section. Compounding the problem is the higher friction coefficient observed for titanium on steel as compared to steel on steel.

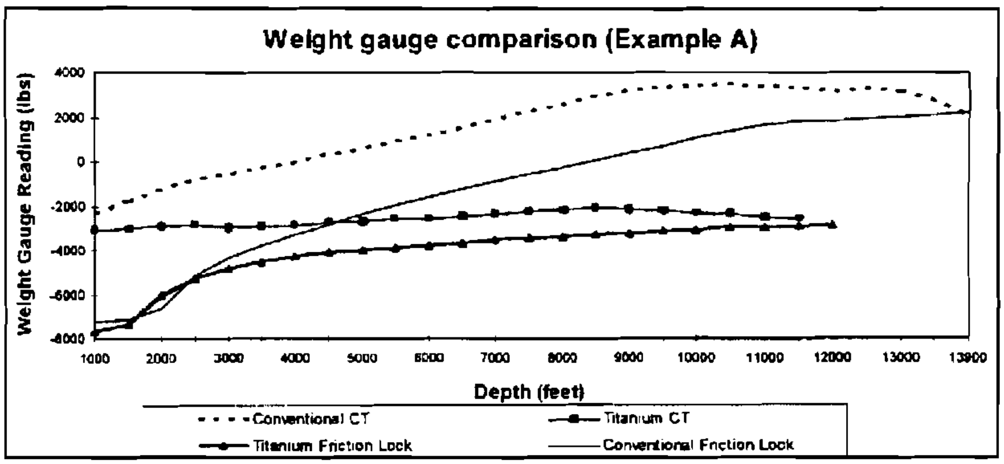


Figure 4-5. Modeled Surface Weights for Steel and Titanium CT (Christie and Gavin, 1997)

The maximum pull available for a titanium string with the same dimensions as steel is shown for the same well in Figure 4-6. This is a parameter where titanium excels due to its lower density for a similar yield strength.

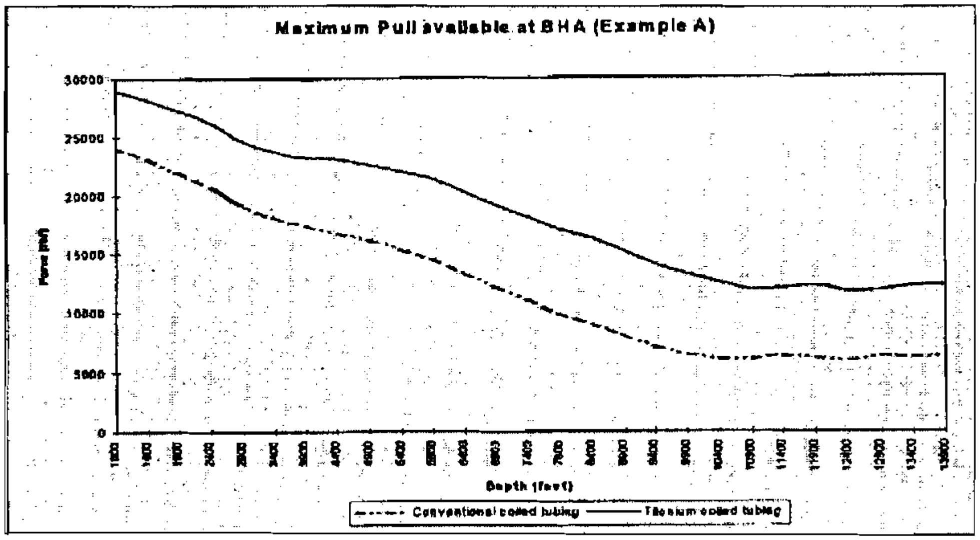


Figure 4-6. Maximum Pick-Up Weights (Christie and Gavin, 1997)

A string of titanium was designed that would be capable of transmitting an identical axial load in compression as the steel string (Table 4-2). It was necessary to increase the OD and wall thickness. Unfortunately, this equivalent titanium string weighs 75% as much as the steel string, so a good percentage of the weight advantage is lost due to the change in Young's modulus.

TABLE 4-2. Equivalent Steel and Titanium CT Strings (Christie and Gavin, 1997)

	Conventional		Titanium	
Length (feet)	Outer Diameter (inches)	Wall Thickness (inches)	Outer Diameter (inches)	Wall Thickness (inches)
10,216	1.5	0.095	1.75	0.150
1,633	1.5	0.102	1.75	0.160
1,516	1.5	0.109	1.75	0.195
2,110	1.5	0.125	1.75	0.220
1,573	1.5	0.134	1.75	0.225

Titanium is a superior solution in applications where light weight and high tensile strength are of primary importance. Operations where compressive strength is important are more likely suited for steel. Tractors at the BHA would make titanium more attractive.

4.4 CTES AND DREXEL (CT CABLE INSTALLATION)

CTES and Drexel (Newman et al., 1995) described the design of a CT wireline cable-installation system that will install wireline inside CT while still on the reel. The new fixture greatly reduces the cost of cable installation as compared to previous methods, which include: 1) hanging off CT in a vertical well and lowering the wireline inside, 2) laying the CT out horizontally and pumping the cable through, and 3) installing a steel pull line inside the CT during manufacture, laying the CT out horizontally and pulling the cable and wireline through. Each of these methods is expensive ($15,000 to $25,000).

It has long been known that cable can be pumped out of CT by pumping water at high rates. Turbulence causes the cable to vibrate and so removes the friction element, allowing the cable to advance with the flow. However, pumping cable into CT (Figure 4-7) is much more difficult due to the high pump pressure at the point the cable enters the system. Injection force (analogous to snubbing a string into a high-pressure well) is required to introduce the cable.

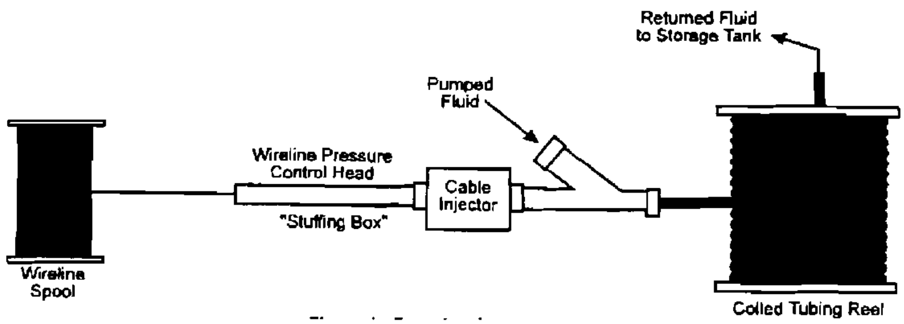


Figure 4-7. Pumping Cable into CT (Newman et al., 1995)

A cable injector was required for this design. Several concepts were devised and considered (Figure 4-8). The approach adopted for the final design was a capstan wheel inside a pressure housing.

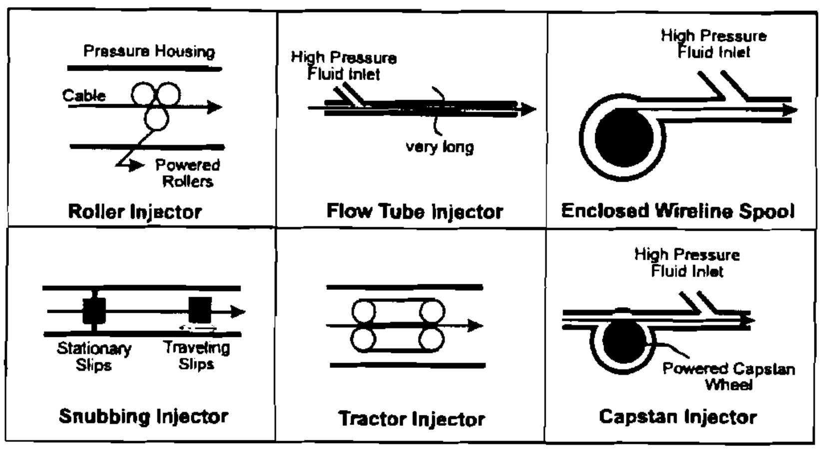


Figure 4-8. Potential Concepts for Injecting Cable (Newman et al., 1995)

The cable injection system design is shown in Figure 4-9. The wireline spool can be rotated about a vertical axis due to the need to remove torque from used cable. A storage tank is used so that the water can cool between pump trips through the CT.

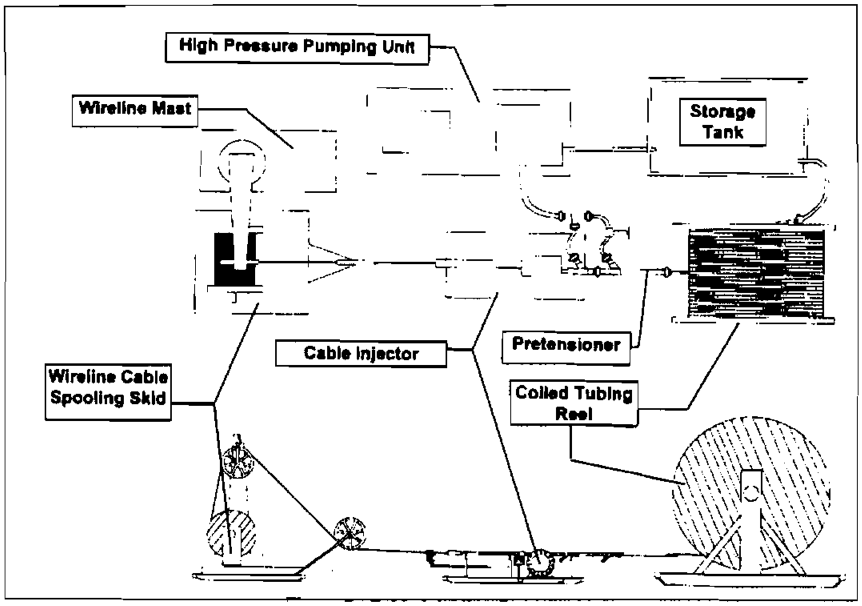


Figure 4-9. Cable Injection System for CT (Newman et al., 1995)

4.5 FIBERSPAR (COMPOSITE CT)

Fiberspar, Conoco, and SAS Industries (Quigley et al., 1997 and Fowler, 1997) provided a status report on the development of commercial composite CT. The concept has been pursued for several years due to the promises of extremely high fatigue life (tens of thousands of cycles in and out of the well, as compared to hundreds of cycles (or less) for steel), very light weight (about 1/3 the weight of steel), and high pressure capability (up to 20,000+ psi internal pressure). Samples of 1½- (Figure 4-10) and 2⅜-in. composite CT have been fabricated and tested extensively. The first commercial strings are expected to be manufactured during 1998.

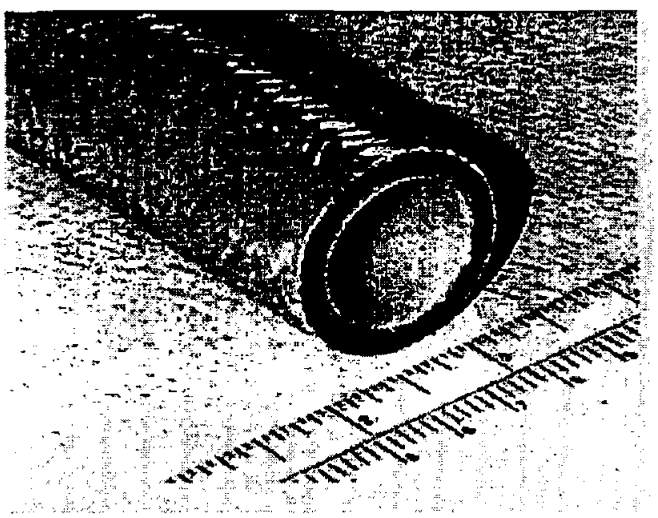


Figure 4-10. 1½-in. Composite CT (Fowler, 1997)

Performance specifications for the product are summarized in Table 4-3.

TABLE 4-3. Composite CT Specifications (Quigley et al., 1997)

PARAMETER	DESIGN CRITERION	SAFETY FACTOR
Operating Pressure	7500 psi	2.16
Differential Pressure	2500 psi	1.5
Tensile Load	11,000 lb	1.5
Compressive Load	7500 lb	1.5
Fatigue in Tension/Comp.	>500 cycles	–
Well-Head Pressure	3000 psi	–
Fatigue in Bending w/Press.	>5000 cycles	–
Operating Temperature	-40 to 212°F	–
Operating Pressure @ 212°F	6000 psi	1.5
Tensile Strength @ 212°F	6000 lb	1.5

A special bending test fixture (Figure 4-11) was fabricated for the composite CT. A full 2% bending strain was achievable while holding the CT internal pressure at 7500 psi. Cycling was normally halted after 5500 bending cycles with pressure. Fatigue performance of the material is more than an order of magnitude better than steel CT.

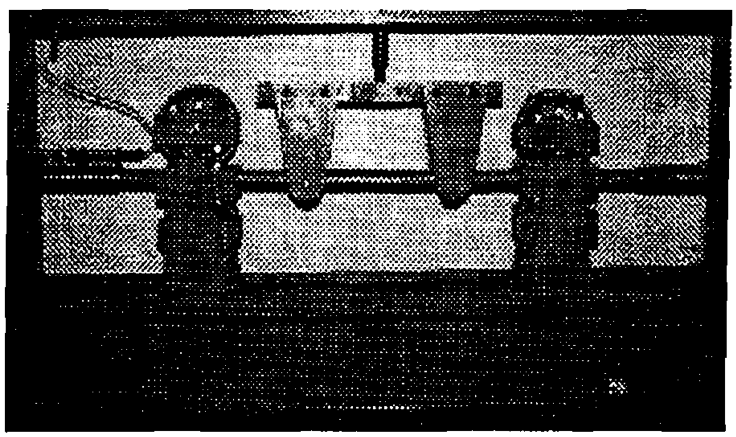


Figure 4-11. Fatigue Test Fixture (Quigley et al., 1997)

A 36-ft length of composite CT was cycled through an injector to study effects of snubbing and cycling. The average stripper loads were nearly independent of CT internal pressure. During trip no. 525 (Figure 4-12) injector loads are compressive both running in and pulling out due to a 2000-psi annulus pressure.

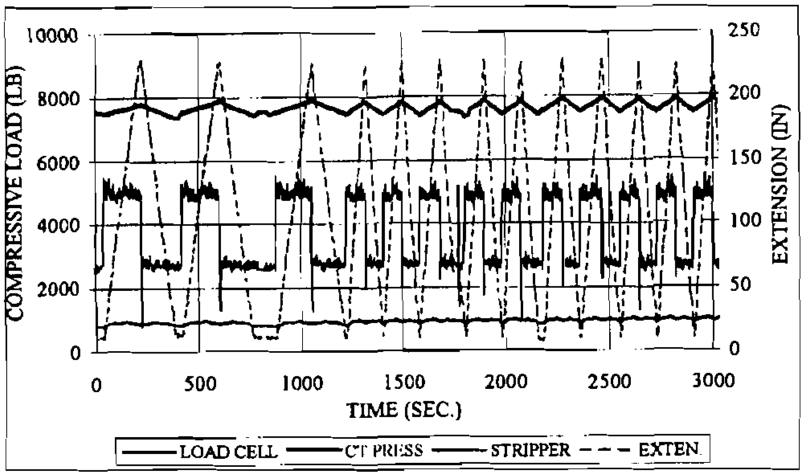


Figure 4-12. Snubbing/Cycling Tests (Quigley et al., 1997)

Final full-scale testing was conducted with an 880-ft length of CT. Snubbing/cycling testing were performed at a test well (Figure 4-13) using a 30k injector. The absence of residual bending can be seen even even though reel tension was less than 300 lb.

Figure 4-13. Full-Scale Composite CT Tests (Quigley et al., 1997)

Another exciting development being pursued with composite CT is embedding fiber-optic or electric cables within the tube body during manufacture. This would allow communication with the BHA without any interference in the flow path.

Even though potential performance of composite CT is enticing to operators and service companies alike, high material costs may hinder it from having a significant impact on the CT market. It will more likely be used in niche applications that are impossible or impractical with steel CT.

4.6 HALLIBURTON ENERGY SERVICES (CT COLLAPSE PRESSURE)

Halliburton Energy Services (Avakov and Fowler, 1996) presented an analysis of collapse pressure of CT when ovality, internal pressure and axial loads are present. They found that test data are in good agreement with the analytical solutions they developed.

Collapse pressure for 70-ksi and 80-ksi CT are shown in Figures 4-14 and 4-15. Internal pressure is zero for these data.

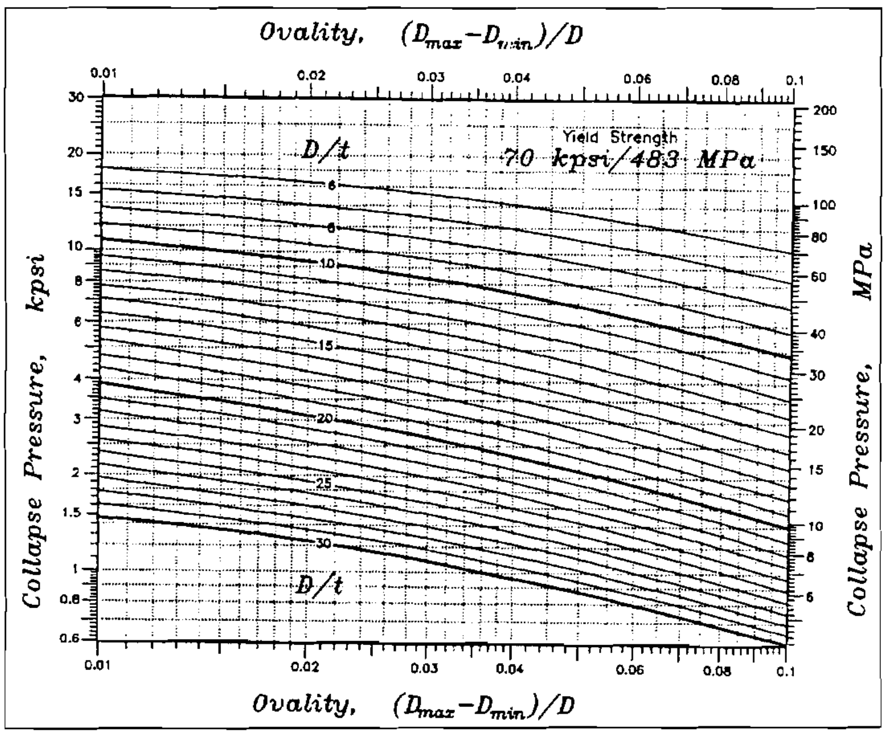


Figure 4-14. Collapse Pressure and Ovality for 70-ksi CT (Avakov and Fowler, 1996)

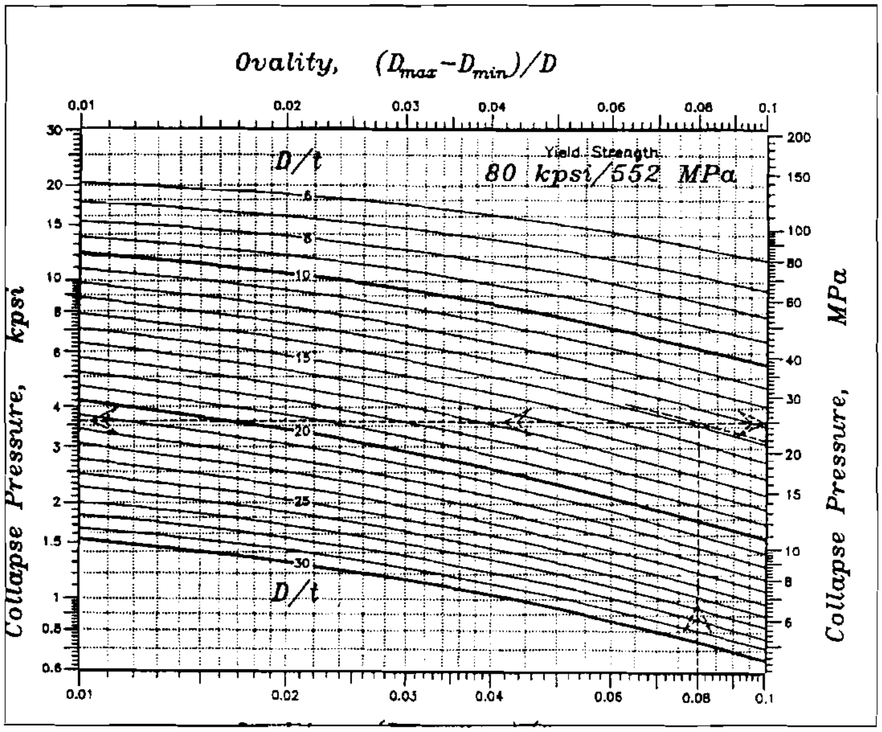


Figure 4-15. Collapse Pressure and Ovality for 80-ksi CT (Avakov and Fowler, 1996)

An example of the use of these charts was presented. Assuming 80-ksi, 1½- by 0.109-in. CT with major and minor diameters of 1.56 and 1.44 inches, ovality is (1.56-1.44)/1.50 = 0.08 and D/t = 13.8. Collapse pressure in the absence of internal pressure can be read from Figure 4-15 as 3.6 ksi or 25 MPa.

If internal pressure and axial load are present, collapse pressure can be calculated with equations presented in Avakov and Fowler's paper. Readers are directed to the paper for a detailed presentation of the analytical model for predicting collapse pressure with ovality, internal pressure and axial load.

4.7 HALLIBURTON ENERGY SERVICES (TAPERED-OD CT)

Halliburton Energy Services (Love et al., 1997) presented results from a case history where tapered-OD CT was used to clean out 31 restricted wells in a West Texas water-and-gas injector field. These wells have a 1.12-in. restriction near the bottom. One-inch CT was not feasible due to flow requirements for circulating fill through the annulus. The final CT design for the operation included 8000 ft of 1¼-in., 250 ft of 1-in. and 500 ft of ¾-in. tubing.

Hydraulics considerations were critical to the success of the project. The pressure loss through the tapered-OD string (Figure 4-16) was significantly less than through a ¾-in. string. Potential flow rates were 350% greater with the tapered string.

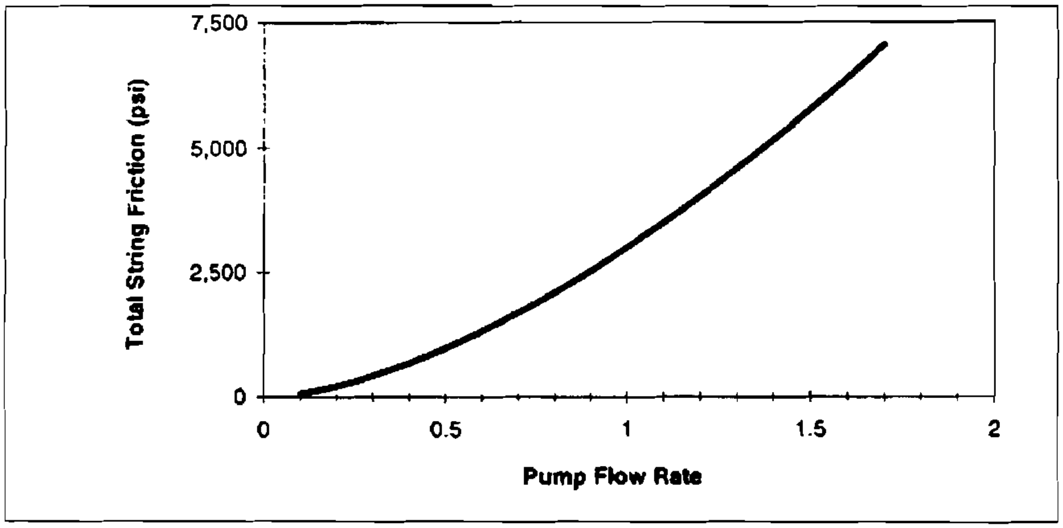


Figure 4-16. Pressure Loss Through Tapered-OD String (Love et al., 1997)

By comparison, pressure losses through a full string of 1¼-in. CT of the same length were only slightly improved (about 5000 psi pressure drop at a pump rate of 2 bpm).

Transition areas at OD changes were significantly worn and fatigued after a field operation. These regions could withstand 3-4 workovers before repair.

More information is presented in *Workovers*.

4.8 MOBIL E&P TECHNICAL CENTER (PRESSURE LOSS IN CT)

Mobil Exploration and Production Technical Center (McCann and Islas, 1996) conducted a series of full-scale flow experiments to measure pressure drops in CT on the reel. Increases in pressure loss due to the tubing being in a coiled geometry may be of serious concern for spools with multiple thousands of feet. Tests were conducted with several fluids pumped through 1¾-, 2-, and 2⅜-in. tubes on a 98-in. spool. Turbulent flow was considered primarily. Published formulas for water agreed well with measured data. A formula was found and modified that closely described results with non-Newtonian fluids.

The experimental set-up is depicted in Figure 4-17. Three sizes of tubing were installed on the spool. Flow was established at 20, 30, 40, 50 and 60 gpm for these tests.

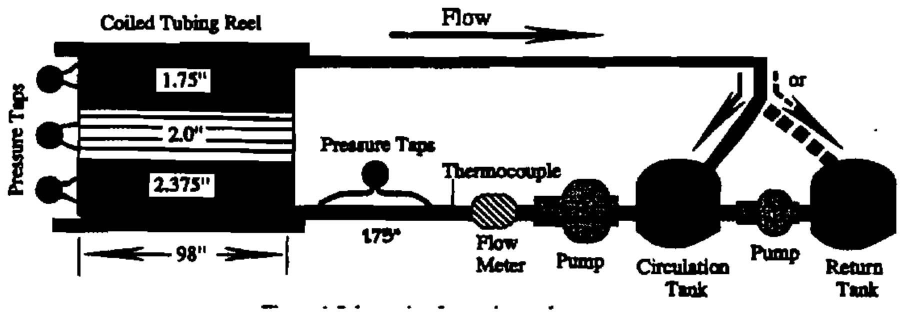


Figure 4-17. Flow Loop for Pressure-Drop Measurements (McCann and Islas, 1996)

A range of power-law fluids were tested (Table 4-4). "n" and "K" were calculated with all flow-rate data and again with the highest flow rate deleted due to difficulties with these data.

TABLE 4-4. Properties of Experimental Fluids (McCann and Islas, 1996)

Fluid	Density (lb/gal)	n	K ($lbf\text{-}sec^n/100\ ft^n$)	Higher Flow Rates Used (gpm)
water	8.4	1.000	0.00153	Tabulated
		0.971	0.00158	None
fluid 1	8.5	0.916	0.00262	50
		0.948	0.00196	None
fluid 2	8.6	0.979	0.00234	60
		0.759	0.01839	None
fluid 3	8.6	0.888	0.00640	50
		0.668	0.05008	None
fluid 4	8.7	0.775	0.02035	60
		0.673	0.05401	None
fluid 5	8.7	0.949	0.00520	60
		0.727	0.04068	None
fluid 6	8.7	1.000	0.00259	None

The Srinivasan et al. correlation fit the data very well for water. This equation was generalized and used for the six power-law fluids. Good agreement was observed (Figure 4-18), except at the highest flow rates (50+ gpm) in the 1¾-in. tubing. The research team had believed these high-rate data to be suspect (due to problems with the apparatus) prior to the correlations.

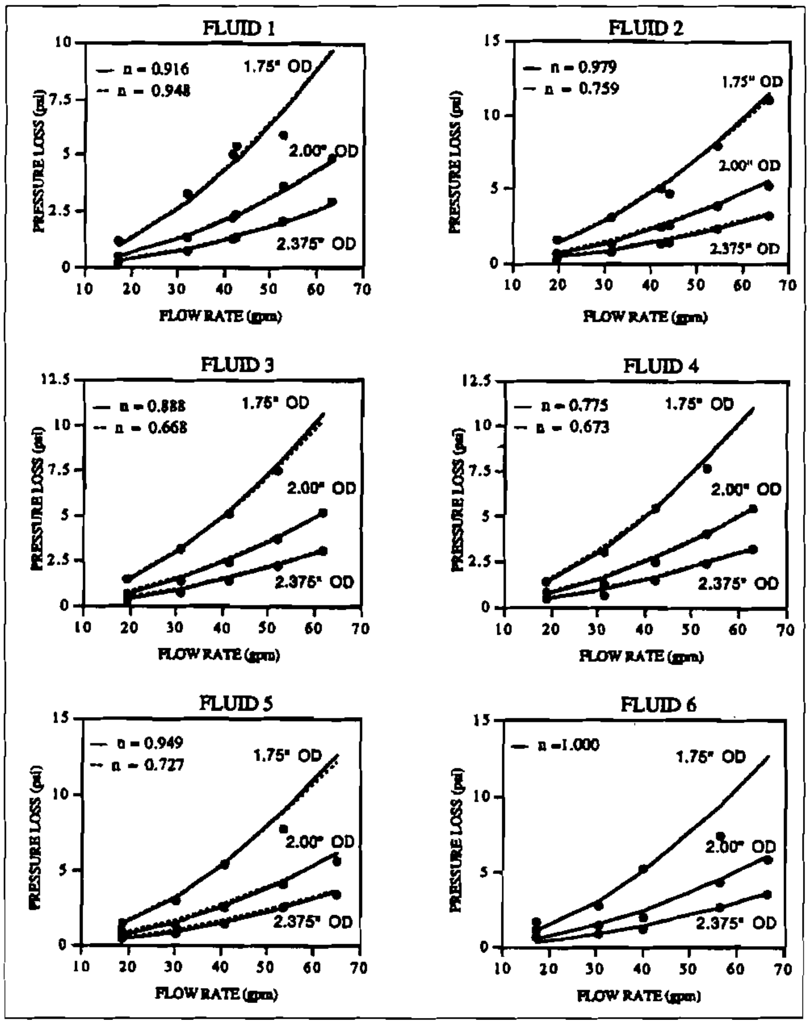


Figure 4-18. Pressure Drops in Coiled Tubes (McCann and Islas, 1996)

4.9 PRECISION TUBE TECHNOLOGY (COLLAPSE/BURST PRESSURE)

Precision Tube Technology (Yang, 1996) presented an analysis of models for collapse pressure, burst pressure and strain energy for spooling CT. He reviewed several theories for collapse and burst of round CT. He developed an analytical model for collapse pressure of oval tubing based on elastic instability theory and the von Mises criterion. Ovality can significantly decrease collapse pressure rating. A set of formulas was derived for torque and strain energy for spooling CT. These show that only a small part of total strain energy is recovered. Only 5-15% of total strain energy for spooling is stored and recovered as elastic strain energy.

The burst and collapse pressure envelope for a 2-in. by 0.109-in. tube with material yield rating of 70 ksi is shown in Figure 4-19. A safety factor of 80% is typically added to this curve for field operating limits.

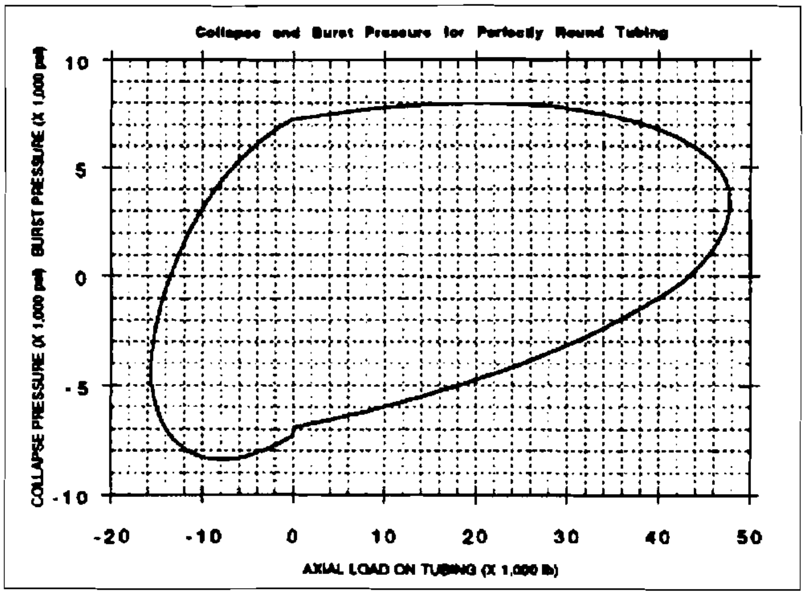


Figure 4-19. Collapse/Burst for Round Tubing (Yang, 1996)

Collapse pressure is severely impacted when the tubing becomes oval. Figure 4-20 shows the collapse rating of a 3½-in. by 0.190-in. tubing with increasing ovality.

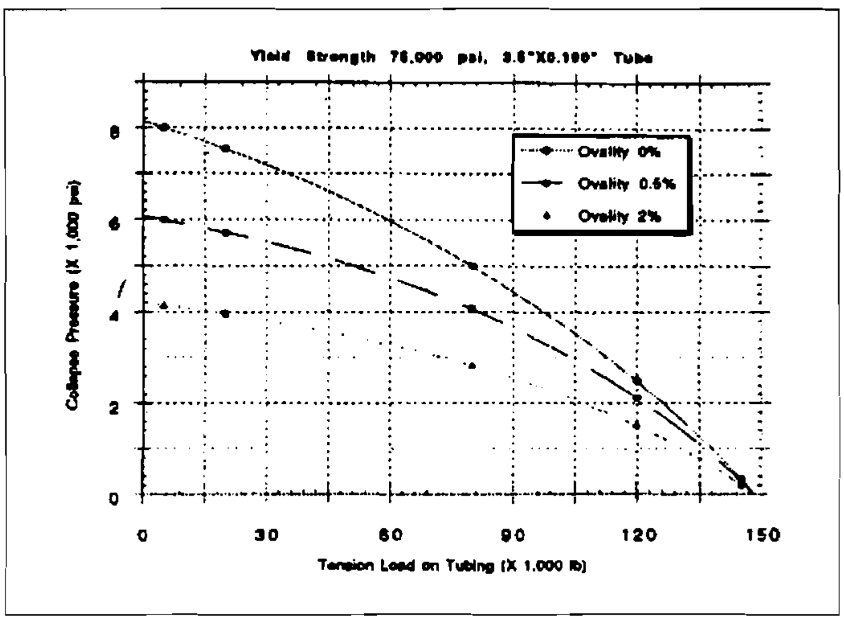


Figure 4-20. Collapse Rating for Oval Tubing (Yang, 1996)

Actual test data are compared to theory in Table 4-5.

TABLE 4-5. Collapse Tests for Oval Tubing (Yang, 1996)

Yield Strength (psi)	Tension Load (lb)	Ovality η (%)	Testing Results (psi)	Theoretical Predictions (psi)	Relative Error
74,600	40,000	0.11	7,050	6,277	0.110
74,600	0	0.14	7,150	7,166	0.002
74,000	0	0.16	6,800	7,032	0.034
74,600	40,000	0.16	6,600	6,102	0.075
76,400	0	0.23	7,200	6,923	0.038
76,400	12,000	0.24	7,600	6,668	0.123
76,400	0	0.26	7,200	6,816	0.053
74,600	0	0.26	6,650	6,697	0.007
74,600	0	0.27	6,900	6,665	0.034
74,600	0	0.29	6,900	6,601	0.043
78,000	0	0.36	6,800	6,604	0.029
75,000	0	0.71	6,100	5,654	0.073

Elastic and plastic energies for spooled CT are compared for several sizes in Table 4-6. Recoverable bending strain amounts to 8-15% of total energy for these geometries.

TABLE 4-6. Elastic and Plastic Spooling Energy (Yang, 1996)

Tubing Dimension	Tubing Length	Spool Core Diameter*	Stored Energy (U_e)	Dissipated Energy (U_d)	Total Energy (U_T)	(Ud/U_T)
1.5" x 0.109"	8,000 ft	72"	2.77 x 10^5J	1.86x10^6J	2.13 x 10^6J	13%
2.375" x 0.19"	15,000 ft	120"	2.53 x 10^6J	1.48x10^7J	1.73 x10^7J	14.5%
2.875" x 0.19"	8,600 ft	120"	1.41 x 10^6J	1.27x10^7J	1.41 x 10^7J	10%
3.5" x 0.19"	6,000 ft	120"	1.23 x 10^6J	1.30x10^7J	1.42 x 10^7J	8.6%

*Spool flange = 180", spool core width = 87"

4.10 PRECISION TUBE AND BJ SERVICES (CT INSPECTION)

Precision Tube Technology and BJ Services (Smith and Misselbrook, 1997) overviewed CT inspection technologies that are available and might be applied in the field or during manufacturing. Five general technologies were considered: visual/manual methods, electronic caliper, magnetic flux, eddy current, and ultrasonic measurement techniques (Figure 4-21).

Figure 4-21. CT Inspection Methods (Smith and Misselbrook, 1997)

Inspection Method	Accuracy	Intrinsic Safety	Non-Expert User	Dirty & Wet Pipe	Economic	Practicality		
						Wellsite	Base	Manufacturer
Visual/Manual Caliper	√√√	√√√	√√√	√	$	√√√	√√√	√√√
Electronic Caliper	√√	√√	√√	√√	$$	√√√	√√	√√
Magnetic Flux	√√	√	√	√√√	$$$$	√	√√	√√
Eddy Current	√√√	o	o	√√√	$$$$	o	o	√√√
Ultra-Sonic	√√√	o	o	√√√	$$$$$	o	o	√√√

Six categories of incidents can occur in the field: mechanical, CT fatigue, CT corrosion, operator error, material defects, and manufacturing defects. They found that there is no single inspection technology that can identify all potential problems with CT. Consequently, preventing problems should remain a priority.

They concluded that several areas could yield an effective reduction in operational incidents. These include 1) expanded training of personnel, 2) better monitoring of acid pumping, 3) more effective flushing and inhibition, 4) accurate recording of fatigue history, 5) better inspection methods at the wellsite, and 6) better inspection methods at the manufacturing mills.

4.11 QUALITY TUBING (FAILURES IN CT)

Quality Tubing (Stanley, 1998) presented an analysis of the causes of failure in steel CT along with methods and guidelines for derating CT after field use. Potential imperfections (including defects) include a wide range of conditions resulting from service life or occurring during manufacture (Table 4-7).

TABLE 4-7. Imperfections in CT (Stanley, 1997)

Imperfection	Cause	Detection Method
Ovality	Cycling, initial Ovality	Eddy Currents
Ballooning	Pressure & cycling	Eddy Currents
ID Corrosion pits	HCl, KCl, Chromates	Magnetic Flux leakage
OD Corrosion pits	HCl, KCl, Chromates	Magnetic Flux leakage
Splits	Lack of flash, "hipp-tripping"	Pressure loss
Open Seams	Incomplete weldline fusion	Eddy Currents
Loss of YS	Crystal transformation in steel	Eddy Currents/conductivity
Rig Injector Rings	Rotating pipe in injector	Flux Leakage
Gripper marks	Too much pressure	Flux leakage
Erosion (OD)	Rubbing Tubing agst tbg, csg, formation. Acid	Magnetic Wall measurement
Erosion (ID)	Cement, acid	
Necking	Force too large	Eddy currents, mag wall mmt

Results from standardized fatigue testing show that fatigue life increases with CT strength and decreases with internal pressure. Cycle lives are shown in Figure 4-22 for three grades of CT cycled at 3000, 4000, and 5000 psi (back to front, respectively). These results are for 1¾- by 0.109-in. CT.

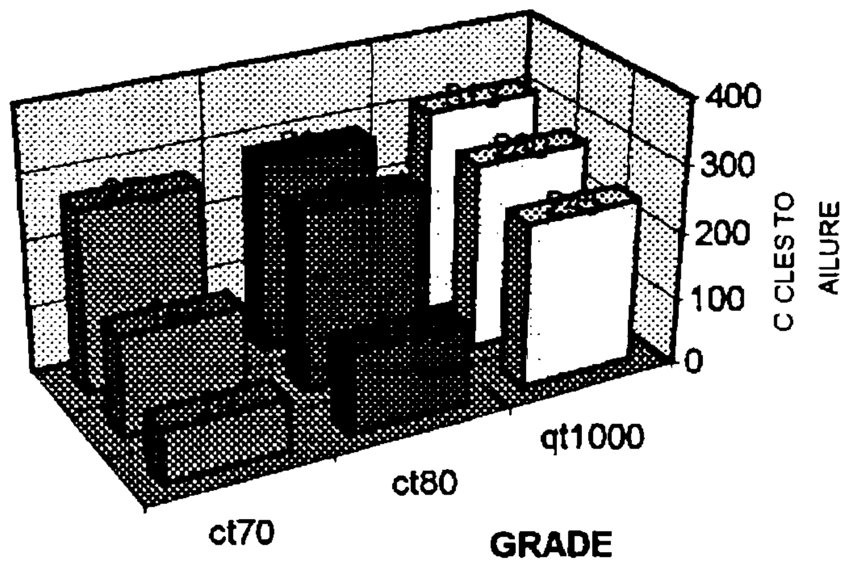


Figure 4-22. CT Strength and Fatigue Life (Stanley, 1998)

Although fatigue is a critical concern, field experience has shown that other failure modes (such as corrosion) are often the dominate cause of failure. Data reported from the field from 1994 to 1997 are summarized in Figure 4-23. It is likely that some of the failures attributed to corrosion could have been assigned to fatigue.

Quality Tubing presented a summary of several case histories of CT failures in the field. See Stanley

(1998) for details.

A list of three suggestions for derating CT was presented. These include: 1) assign 2% ovality to all CT strings after the first use in the field, 2) use CT in less stringent service after 10% of wall thickness has been removed by erosion or pitting, and 3) inspect the OD for mechanical damage and grind (file) away faults to a depth no deeper than 90% of specified wall thickness.

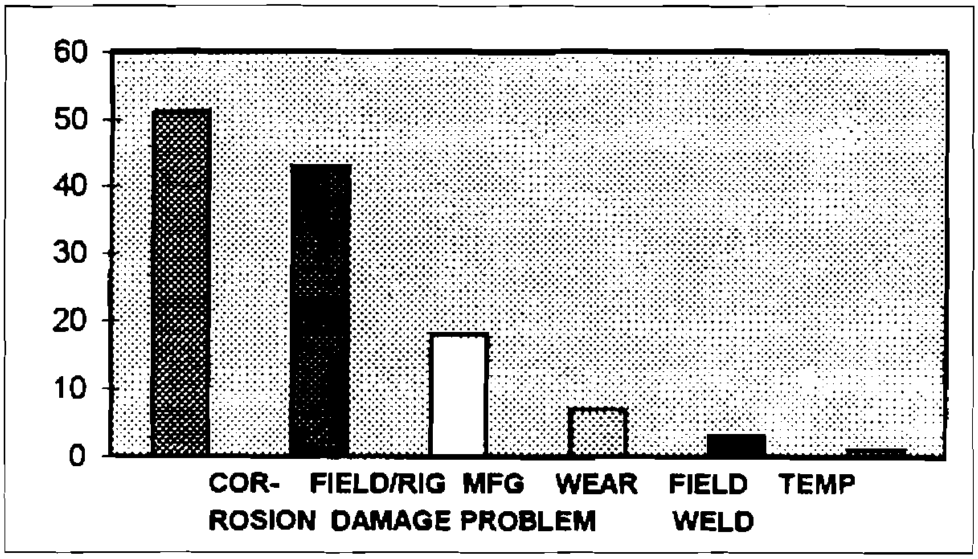


Figure 4-23. Causes of CT Failures (Stanley, 1998)

4.12 RMI TITANIUM COMPANY (RUTHENIUM ALLOY TITANIUM CT)

RMI Titanium Company (Klink, 1995) reported on the ongoing improvements in manufacture and performance of titanium CT. New alloys and grades have increased the range of applications of these products. A new Grade 9 alloy including ruthenium has improved resistance to corrosion at high temperatures.

Grade 12 titanium was the first alloy developed for use as CT. Grade 9 came later to raise the material yield to 90 ksi. Other benefits to Grade 9 include higher tolerance to hydrogen absorption and better fatigue life. Specifications for Grade 9 tubing are summarized in Table 4-8.

TABLE 4-8. Properties of Grade 9 Titanium CT (Klink, 1995)

OD (in)	Wall (in)	ID (in)	Weight (lbs/ft)	Load Capacity (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Internal Capacity (gal/m ft)	External Displ (gal/m ft)
1.500	0.072	1.356	0.6279	29071	7776	4702	75.01	91.79
1.500	0.083	1.334	0.7183	33254	8964	6752	72.60	91.79
1.500	0.087	1.326	0.7508	34758	9396	7497	71.73	91.79
1.500	0.095	1.310	0.8152	37739	10260	8988	70.01	91.79
1.500	0.109	1.282	0.9260	42869	11772	11597	67.05	91.79
1.500	0.125	1.250	1.0497	48597	13500	13750	63.74	91.79
1.500	0.134	1.232	1.1179	51755	14472	14644	61.92	91.79
1.750	0.087	1.576	0.8836	40908	8054	5181	101.33	124.94
1.750	0.095	1.560	0.9602	44454	8794	6459	99.28	124.94
1.750	0.109	1.532	1.0924	50574	10090	8695	95.75	124.94
1.750	0.125	1.500	1.2405	57432	11571	11251	91.79	124.94
1.750	0.134	1.482	1.3225	61227	12405	12689	89.60	124.94
1.750	0.156	1.438	1.5187	70308	14441	14615	84.36	124.94
2.000	0.095	1.810	1.1053	51170	7695	4562	133.65	163.19
2.000	0.109	1.782	1.2588	58279	8829	6519	129.55	163.19
2.000	0.125	1.750	1.4314	66268	10125	8755	124.94	163.19
2.000	0.134	1.732	1.5271	70698	10854	10013	122.38	163.19
2.000	0.156	1.688	1.7568	81335	12636	12945	116.24	163.19
2.000	0.188	1.624	2.0805	96318	15228	15330	107.60	163.19
2.250	0.109	2.032	1.4252	65984	7848	4826	168.45	206.53
2.250	0.125	2.000	1.6222	75104	9000	6814	163.19	206.53
2.250	0.134	1.982	1.7317	80170	9648	7932	160.26	206.53
2.250	0.156	1.938	1.9950	92362	11232	10665	153.23	206.53
2.250	0.188	1.874	2.3675	109607	13536	13783	143.27	206.53
2.375	0.125	2.125	1.7177	79522	8526	5997	184.22	230.12
2.375	0.134	2.107	1.8340	84906	9140	7056	181.11	230.12
2.375	0.156	2.063	2.1141	97876	10641	9645	173.63	230.12
2.375	0.188	1.999	2.5110	116252	12824	13121	163.02	230.12
2.375	0.203	1.969	2.6928	124666	13847	14070	158.17	230.12
2.500	0.125	2.250	1.8131	83940	8100	5261	206.53	254.98
2.500	0.134	2.232	1.9363	89642	8683	6267	203.24	254.98
2.500	0.156	2.188	2.2332	103389	10109	8727	195.31	254.98
2.500	0.188	2.124	2.6546	122896	12182	12305	184.05	254.98
2.500	0.203	2.094	2.8478	131841	13154	13429	178.89	254.98

Adding ruthenium to Grade 9 alloy has increased the corrosion resistance in hot sour brines up to 500 °F. Strength may also be improved; other properties are unaffected.

4.13 SAS INDUSTRIES (CT STRENGTH AND FATIGUE LIFE)

SAS Industries (Sas-Jaworsky, 1996) summarized concerns for CT fatigue life and presented example data for tube with a range of yield strengths. A comparison of fatigue life for 70-, 80-, and 100-ksi material for 1¾-in. CT is presented in Figure 4-24. Test results show that cycle life is relatively unaffected by material strength when internal pressure is low (less than about 3000 psi). At higher pressures, the life of 100-ksi material can be considerably greater than lower strength materials.

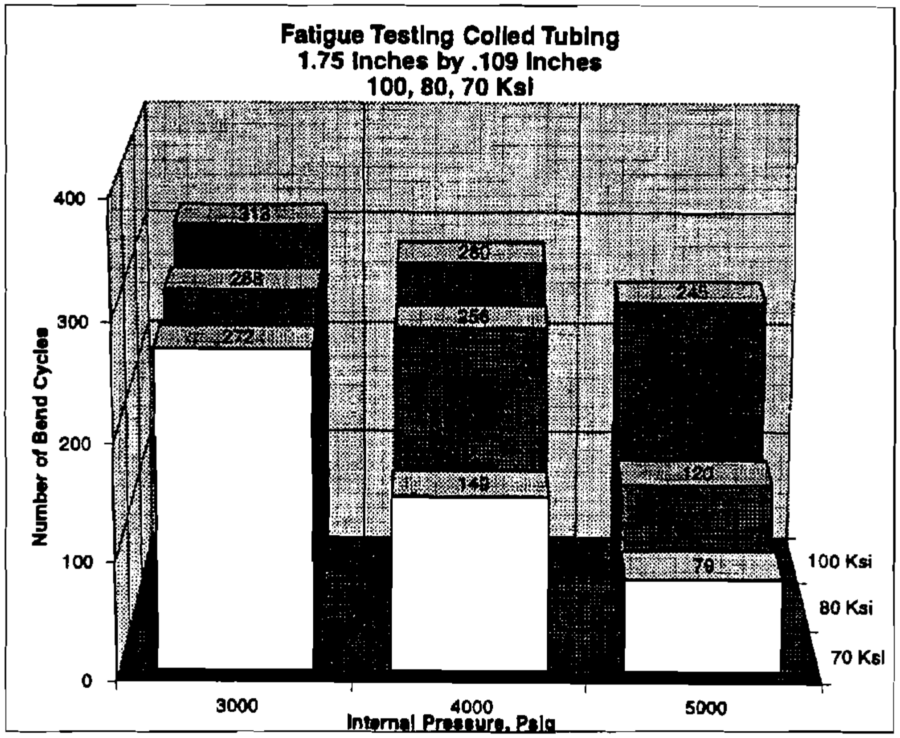


Figure 4-24. Fatigue Life for 1¾-in. CT (Sas-Jaworsky, 1996)

The effects of tubing welds on fatigue life are another issue of investigation. Quality Tubing performed a series of tests comparing virgin tube, a section with a bias weld, and a section with a step-tapered bias weld. The results (Figure 4-25) show that a normal bias weld causes almost no penalty (9% less than virgin tube). A tapered bias weld (0.109 welded to 0.125 in this case) averaged 57% reduction in cycle life. Other studies showed that butt welds have lower lives, that is, from 25-30% that of the tube body.

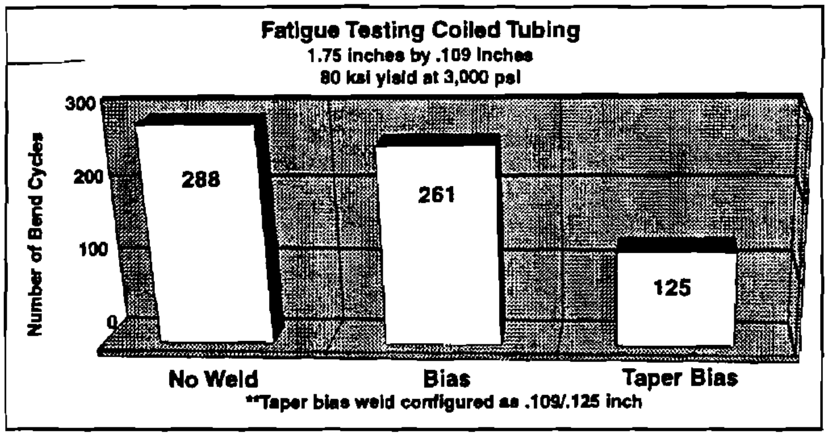


Figure 4-25. Fatigue Life for Welds (Sas-Jaworsky, 1996)

4.14 SAS INDUSTRIES (CT FLUID HYDRAULICS)

SAS Industries (Sas-Jaworsky and Reed, 1997) presented an analysis of several aspects of fluid hydraulics in CT both in the well and on the reel. Methods they presented account for the effects of internal CT wall roughness and tubing eccentricity (for CT in an annulus and for concentric strings of CT). A new method was developed for calculating pressure losses for turbulent flow through CT with wall roughness. Methods were presented to account for the impact of downhole eccentricity on pressure drops with laminar or turbulent flow.

The circulation system (Figure 4-26) boundary conditions can be specified for each node. Hydraulic parameters common to all are fluid velocity, Reynolds number, absolute roughness and friction factor.

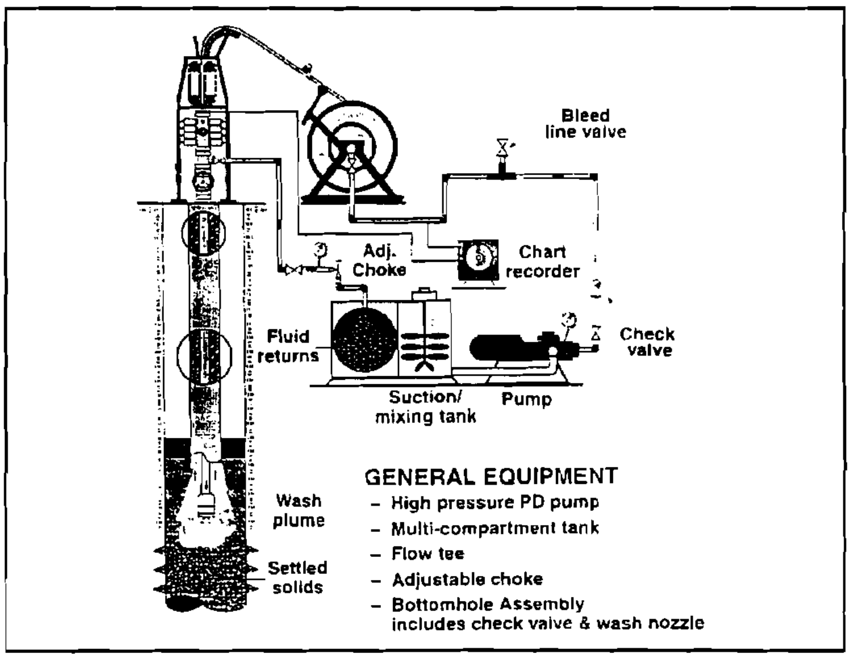


Figure 4-26. CT Circulation System (Sas-Jaworsky and Reed, 1997)

Friction factors (Figure 4-27) for laminar flow are only dependent on Reynolds number. In turbulent flow, relative roughness is an important aspect for determining friction factor.

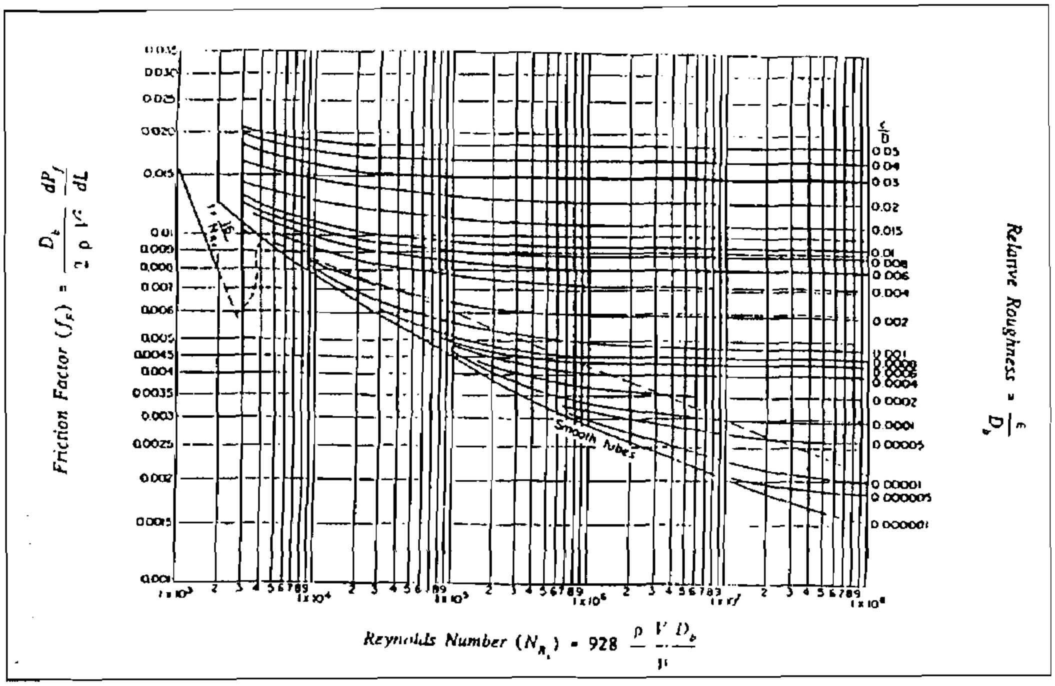


Figure 4-27. Friction Factor with Roughness (Sas-Jaworsky and Reed, 1997)

Sas-Jaworsky and Reed considered the impact of CT eccentricity (Figure 4-28) on frictional pressure losses. CT is always decentralized to some degree. Guidelines for initial calculations are eccentricities of 0.5 to 0.75 in vertical sections and 0.75 to 0.95 in horizontal sections.

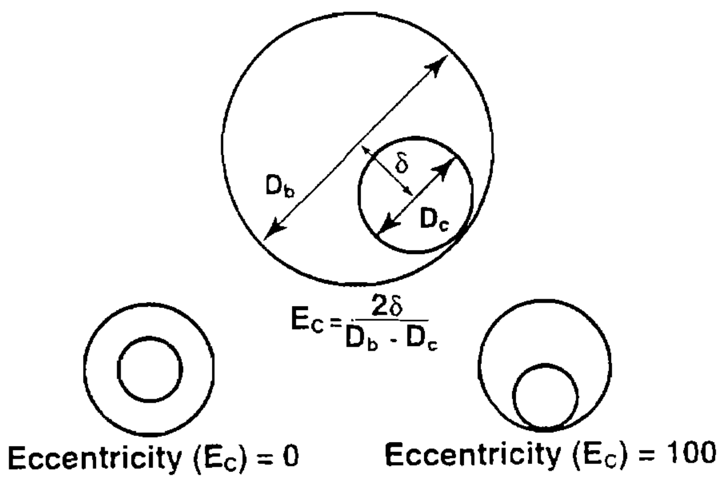


Figure 4-28. Tubing Eccentricity (Sas-Jaworsky and Reed, 1997)

An eccentricity friction factor (Figure 4-29) is introduced in the pressure-drop calculation to account for these effects. These results show how pressure losses decrease with increasing eccentricity, and that eccentricity impacts laminar flow more than turbulent flow.

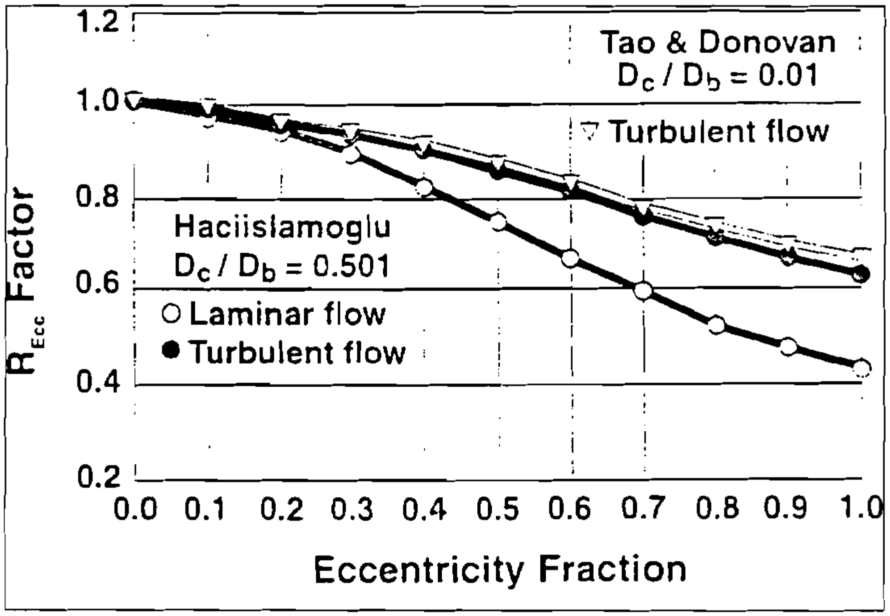


Figure 4-29. Eccentricity Factors for Laminar and Turbulent Flow (Sas-Jaworsky and Reed, 1997)

4.15 UNIVERSITY OF OKLAHOMA AND HALLIBURTON (PRESSURE LOSSES IN CT)

The University of Oklahoma and Halliburton Energy Services (Azouz et al., 1996) reported on a series of laboratory measurements investigating frictional pressure loss in coiled and straight sections of CT. Tests were conducted on CT with and without the internal weld bead. Fluids were tested that are commonly used in fracture stimulation operations: water, linear guar gum and hydroxypropyl guar, and borate-crosslinked guar gum and hydroxypropyl guar. Coiling the tubing and the weld bead were both found to have an important effect on pressure loss, although the magnitude of the impact of curvature was greater. For borate-crosslinked HPG, pressure loss per foot depends on fluid pH and the total length of CT.

Azouz et al. sought to investigate flow behavior of non-Newtonian fluids in curved tubing, especially fluids typical of hydraulic fracturing operations. The impact of tubing curvature on Newtonian fluids has been investigated by others.

The experimental set-up (Figure 4-30) included three tubing spools that can be connected to provide paths of 1000, 2000, 3000, 4000, and 5000 ft.

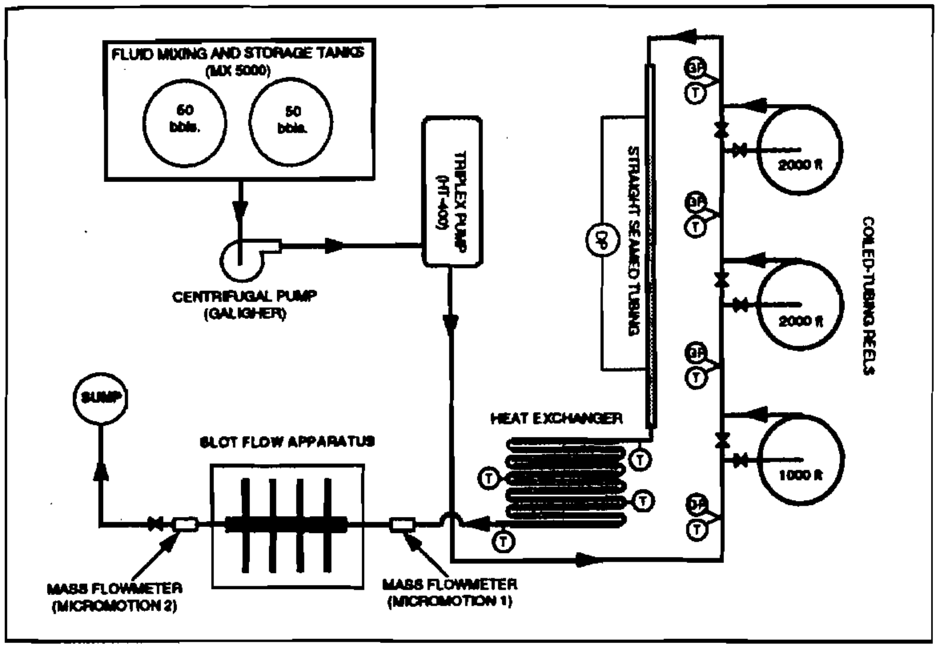


Figure 4-30. Experimental Equipment (Azouz et al., 1996)

The impact of the internal weld bead was first investigated. Friction factor is compared to Reynolds number for standard tubing (seamed) and that without the weld bead (seamless) for water in turbulent flow in Figure 4-31. Pressure losses were less in standard tubing with the weld bead. Azouz et al. surmised that the weld bead changes the turbulence spectrum and damps high frequencies, leading to a decrease in pressure drop.

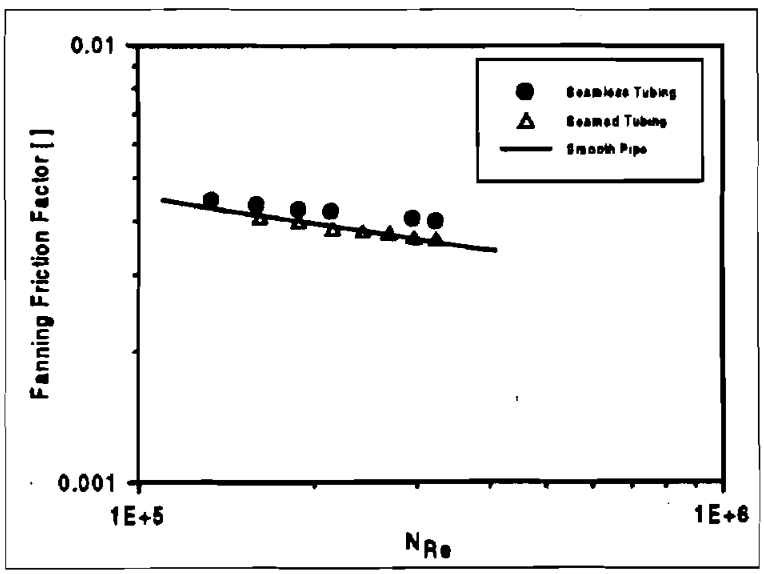


Figure 4-31. Friction for Water in Straight Tube without Weld Bead (Azouz et al., 1996)

For CT on a spool, pressure drop is significantly greater than in straight tubing (Figure 4-32). The relative increase due to curvature ranges from 31 to 44%.

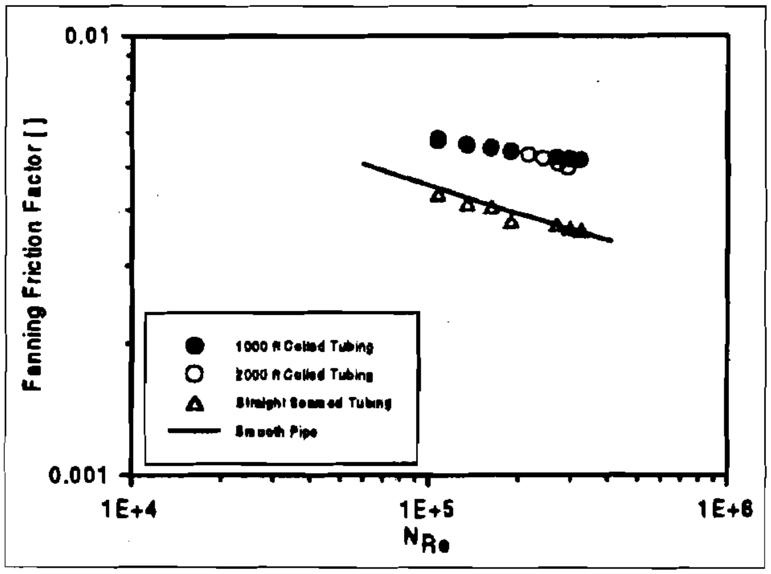


Figure 4-32. Friction for Water in CT (Azouz et al., 1996)

Typical non-Newtonian fracturing fluids were tested, including borate-crosslinked guar gel. The results (Figure 4-33) show that pH (an indication of the level of cross linking) strongly impacts pressure drop per unit length. This quantity is relatively unaffected by the length of the spool of CT over which pressure drop is measured.

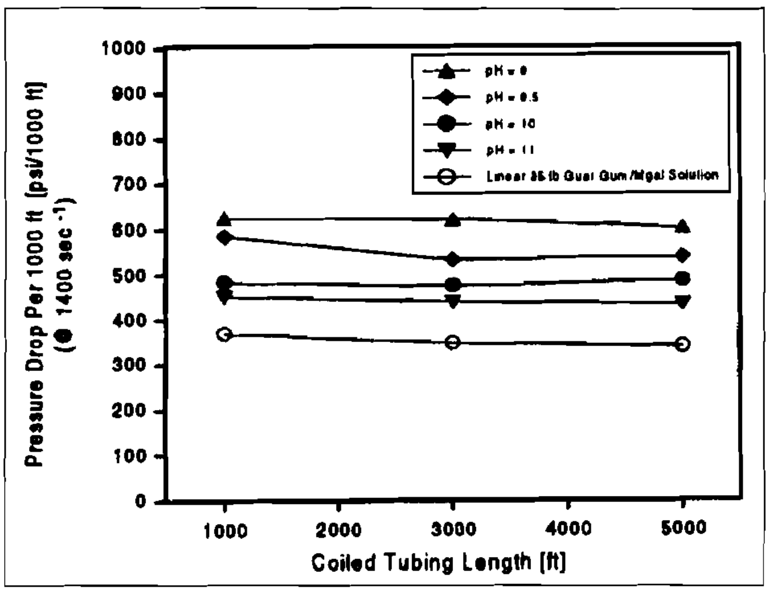


Figure 4-33. Pressure Drop for Borate-Crosslinked Guar Gel (Azouz et al., 1996)

This length consistency was not observed with borate-crosslinked HPG gel (Figure 4-34). These data may reach an asymptotic value at longer tubing lengths, although it is possible that only a local minimum would be observed.

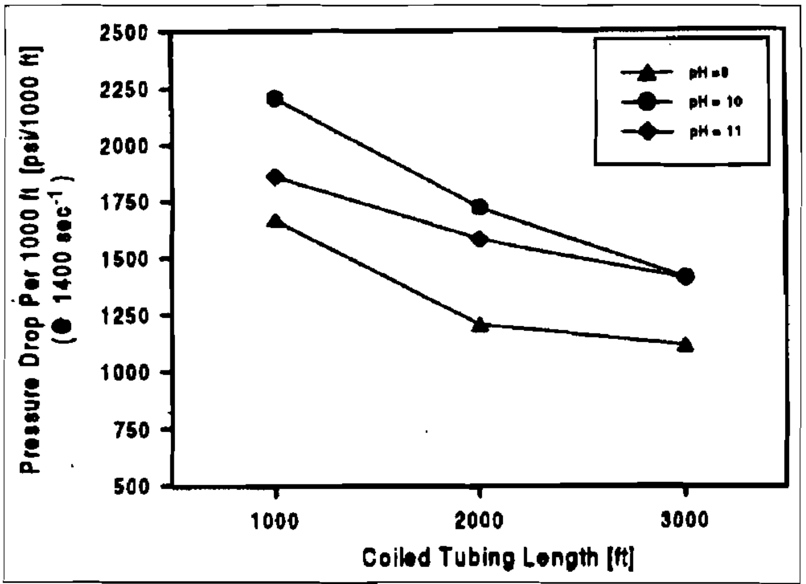


Figure 4-34. Pressure Drop for Borate-Crosslinked HPG Gel (Azouz et al., 1996)

4.16 REFERENCES

Avakov, V. and Fowler, H., 1996: "Computing Collapse Pressure for Coiled Tubing," SPE 36340, presented at 1st SPE/ICoTA North American Coiled Tubing Roundtable, Montgomery, Texas, February 26-28.

Azovz, I., et al., 1996" "Experimental Investigation of Frictional Pressure Losses in Coiled Tubing," SPE 37328, presented at Eastern Regional Meeting, Columbus, Ohio, October 23-25.

Christie, Mike and Gavin, Bill, 1997: "Titanium as an Alternative to Conventional Coiled Tubing: A North Sea Case Study," SPE 38416, presented at the 2nd North American CT Roundtable, Montgomery, Texas, April 1-3.

Crabtree, A. et al., 1997: "Determining the Mechanical Properties of Coiled Tubing," SPE 38412, presented at the 2nd North American CT Roundtable, Montgomery, Texas, April 1-3.

Fowler, Hampton, 1997: "Update on Advanced Composite Spoolable Pipe Developments," SPE 38414, presented at 2nd North American CT Roundtable, Montgomery, Texas, April 1-3.

Klink, Dale R., 1995: "Development of Titanium Coiled Tubing Extends of the Scope of CT Applications," presented at the 3rd Annual International Management Conference on CT, Dallas, February 6-8.

Love, Douglas, et al., 1997: "Coiled Tubing Injection-Well Cleanouts with Tapered-OD Strings," SPE 38420, presented at 2nd Annual SPE/ICoTA North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

McCann, R.C. and Islas, C.G., 1996: "Frictional Pressure Loss During Turbulant Flow in Coiled Tubing," SPE 36345, presented at the 1st SPE/ICoTA North American Coiled Tubing Roundtable, Montgomery, Texas, February 26-28.

Newman, K.R., and Fowler, H., 1996: "Computing Collapse Pressure for Coiled Tubing," SPE 36340, presented at the Annual Technical Conference, Dallas, Texas, October 22-25.

Quigley, P.A. et al., 1997: "Development and Application of a Novel Coiled Tubing String for Concentric Workover Services," OTC 8456, presented at Offshore Technology Conference, Houston, May 5-8.

Reaper, Alan, 1997: "Development and Application of Inline Connectors for Weight Restricted Offshore Operations," SPE 38424, presented at 2nd North American CT Roundtable, Montgomery, Texas, April 1-3.

Sas-Jaworsky, Alex and Reed, Troy, 1997: "Fluid Hydraulics Behavior in Coiled Tubing Operations — A Nodal Analysis Approach," presented at the World Oil Coiled Tubing & Well Intervention Conference, Houston, February 4-6.

Sas-Jaworsky, Alex, 1996: "High-Pressure Applications Enabled by CT Advances," *The American Oil & Gas Reporter,* January.

Smith, Larry, and Misselbrook, John, 1997: "An Overview of Injection Technology and Criteria for Inspecting Coiled Tubing," SPE 38423, presented at the 2nd North American CT Roundtable, Montgomery, Texas, April 1-3.

Stanley, Roderic, 1998: "An Analysis of Failures in Coiled Tubing," IADC/SPE 39352, presented at IADC/SPE Drilling Conference, Dallas, March 3-6.

Stanley, Roderic, 1997: "Failures in Coiled Tubing," presented at 5th International Conference on Coiled Tubing and Well Intervention, Houston, February 4-6.

Yang, Yong, 1996: "Collapsed and Burst Pressure of Coiled Tubing Under Axial Load, and Bending Torque and Strain Energy in Spooling CT," SPE 36338, presented at the 1st SPE/ICoTA North American Coiled Tubing Roundtable, Montgomery, Texas, February 26-28.

5. Drilling

TABLE OF CONTENTS

TABLE OF CONTENTS (CONT'D.)

TABLE OF CONTENTS (CONT'D.)

5. Drilling

CT DRILLING TECHNIQUES AND SYSTEMS

5.1 AMOCO TECHNOLOGY (TESTS OF CT WHIPSTOCKS)

Amoco Tulsa Technology Center (Townsend et al., 1997) conducted a series of tests of whipstock and milling systems for cutting windows with CT. They evaluated window-cutting systems for a candidate re-entry that would include milling through both 7- and 9⅝-in. casing at an inclination of 60° (Figure 5-1). As far as could be determined, this would be an industry first using CT through-tubing technology.

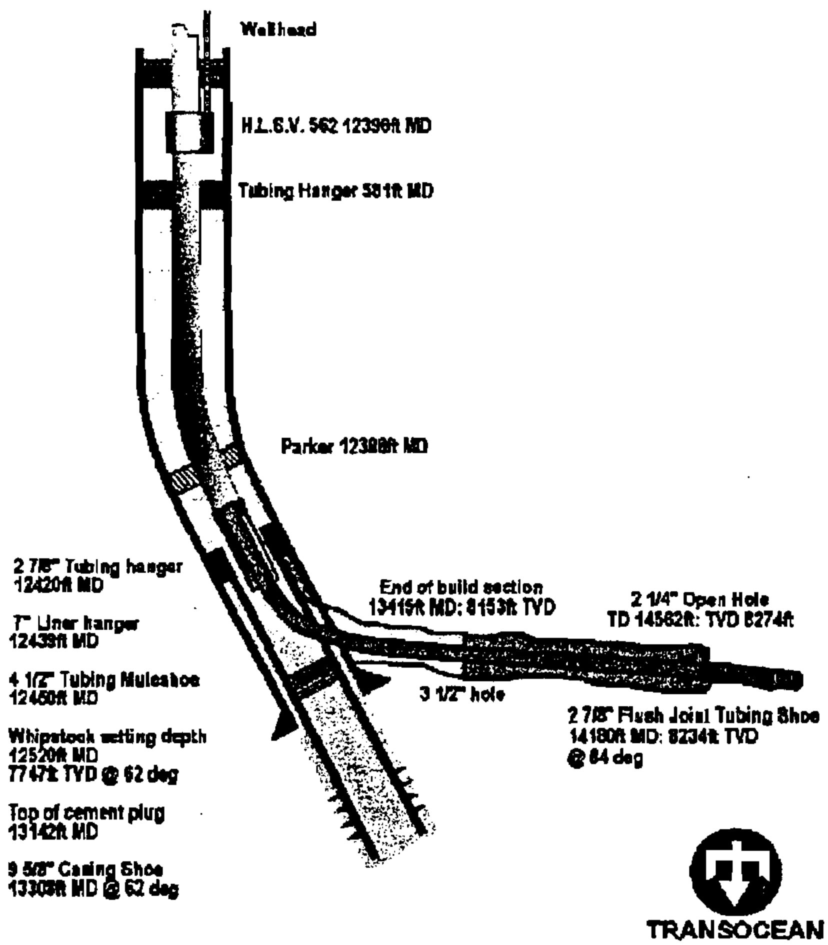


Figure 5-1. CT Re-entry (Townsend et al., 1997)

Full-scale milling tests were conducted at Amoco's facility at Catoosa, Oklahoma. Three commercial systems were tested. Each test was conducted in a test piece consisting of 7-in. casing cemented eccentrically in 9⅝-in. casing, in turn cemented eccentrically inside 16-in. casing.

An example of one of the window-cutting tests is summarized in Figure 5-2. One commercial systems would not enter the 9⅝-in. casing within an acceptable window length. With the second system, an exit through both casings was achieved across a length of 12 ft and required 26 hours of milling. With the third system, an exit through both casings was achieved across 12 ft and required 31 hours of milling.

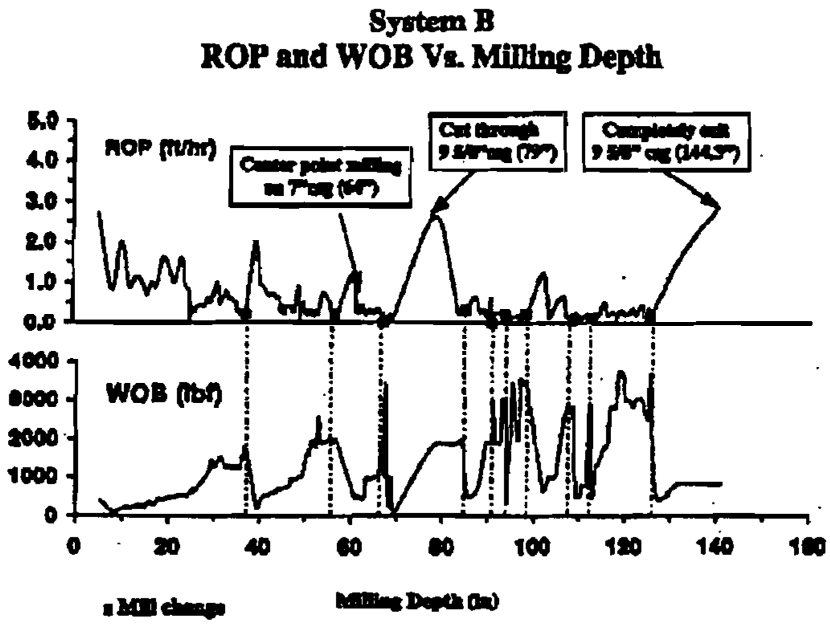


Figure 5-2. Milling Test Performance (Townsend et al., 1997)

Detailed results of these CT milling tests are presented in their paper.

5.2 ARCO ALASKA AND HUGHES CHRISTENSEN (WINDOW MILLING)

ARCO Alaska and Hughes Christensen (Hearn et al., 1996) described the development of CT cement window-milling technology for sidetracking at Prudhoe Bay. A comparison of sidetracking techniques and results from yard tests are described in Section 5.11 SCHLUMBERGER DOWELL (CT SIDETRACKING TECHNOLOGY) below. At the time of their paper, 14 wells had been sidetracked with CT, with the last eight successful. The technique involves cutting a window off of a specially formulated cement plug. No whipstock is used. Sidetracking costs have been reduced about 40% compared to conventional rig methods.

A variety of tests were performed while developing cement sidetracking techniques and tools. A rough transition was observed in the milled window (Figure 5-3). When the central axis of the mill is inside the casing, the reaction force pushes the mill to the left. When the mill axis is outside the casing, the force from contact with the casing wall moves to the right.

Mills used in cement sidetracking with CT (Figure 5-4) have been significantly improved throughout this development. Yard tests, field tests, and field operations have led to ongoing improvements.

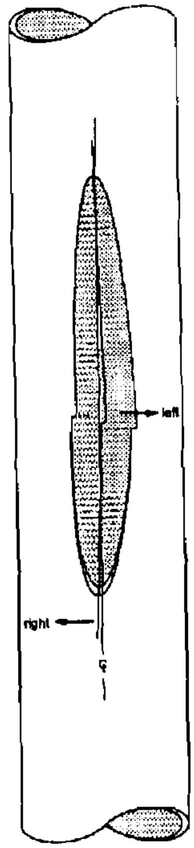


Figure 5-3. CT Milled Window
(Hearn et al., 1996)

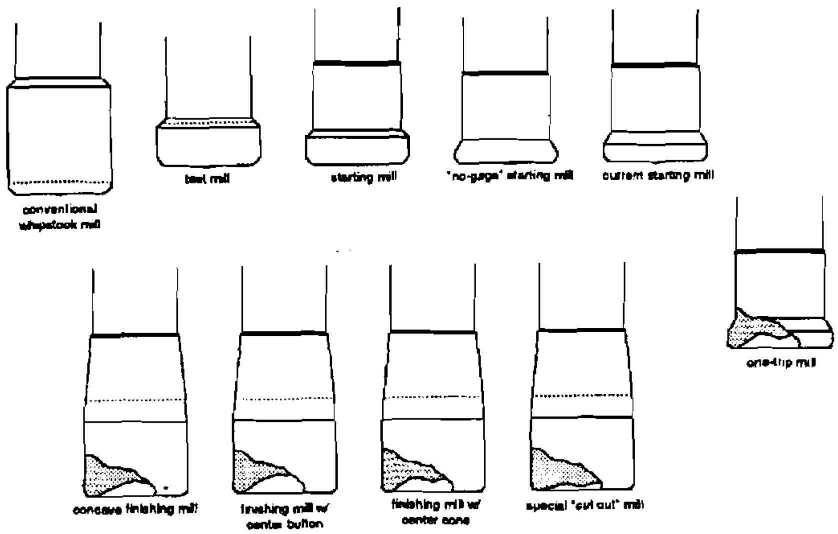


Figure 5-4. Window Mill Design Evolution (Hearn et al., 1996)

ARCO has had good success with cement sidetracking (no whipstock). Other operators are using whipstocks for window cutting with CT. Whipstocks may be a better choice if production needs to be maintained during the operation.

The overall performance of CT cement sidetracking has had fewer problems than anticipated. The cement ramp has been more durable than was originally assumed, with the reinforcing fibers in the cement credited with improving durability. Short windows have not caused significant problems either. Drilling BHAs and completions have been run through windows less than 5 ft long.

5.3 BAKER INTEQ, NORSK HYDRO AND NOWSCO (EXPLORATION CONCEPT)

Baker Hughes INTEQ, Norsk Hydro and Nowsco UK (Ehret et al., 1995) described results of field trials of elements and procedures which would be required as part of a fit-for-purpose slim-hole floating vessel. The first step in this investigation was to determine whether high-quality cores and electric logs could be obtained using slim-hole technology on a floating vessel, and to drill/core with CT from a floating vessel. Cores were taken with CT and with drill pipe. Although several problems were encountered, the technological feasibility of this approach for exploration was demonstrated.

An integrated slim-hole exploration system (including subsea BOPs, risers and small floating vessels) showed significant promise as an economically attractive system for exploration in deep water and/or remote locations. Rising costs in the North Sea have led to serious consideration of alternate exploration paradigms.

A test site was selected off Norway in over 400 ft of water. A semisubmersible rig would be used to drill to 5570 ft with drill pipe and to set 7-in. casing. CT and drill pipe would be used to drill and core with 4⅛-in. BHAs.

Additional equipment required for the offshore operation included an extra 5⅛-in. pipe ram between the standard triple BOP and 4-in. stuffing box. A drillstring lifting frame (Figure 5-5) was also devised. This connects the rig heave-compensation system to the injector. The frame had to be extended for planned operations.

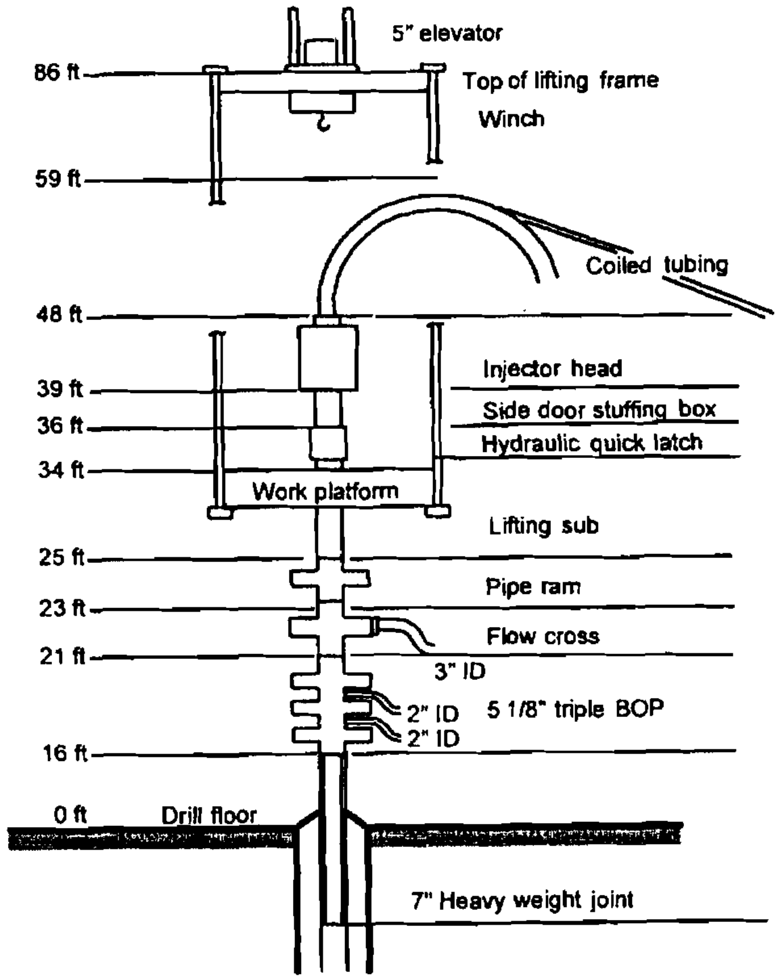


Figure 5-5. Drillstring Lifting Frame for CT Operations
(Ehret et al., 1995)

Subsea well control was maintained with a standard 18¾-in., 15,000-psi BOP. A 7-in. riser was run inside the existing 21-in. riser for CT operations. The smaller riser increased annular velocities and decreased the tendency for buckling.

CT fatigue was a concern with respect to rig heave. Continuous small-scale pay-out and reel-in of the tubing might dramatically shorten fatigue life. This potential was addressed by reducing the operational pressure of the hydraulic motor on the tubing reel. This decreased tension on the reel and introduced slack (about 9 ft) into the tubing wraps.

Two-inch CT was selected for the operation based on fatigue and pressure-loss estimates. Pressure-loss modeling was inconclusive based on the ether-based drilling fluid. A full-scale test was performed for pumping fluid through the spool. Results suggested that the fluid should be maintained at a temperature of about 50°C (122°F). A jetting assembly was added to the circulating system for pumping and shearing the fluid to increase its temperature.

Pressure losses within the CT dictated that maximum flow rates be maintained at about 80 gpm. This was much less than the 185-gpm allowable flow rate for the 3¾-in. mud motor. The motor was tested at a range of flow rates (Figure 5-6). Results showed that the motor could deliver 1000 ft-lb at 80 gpm and 1050 psi. This was determined to be sufficient for this operation.

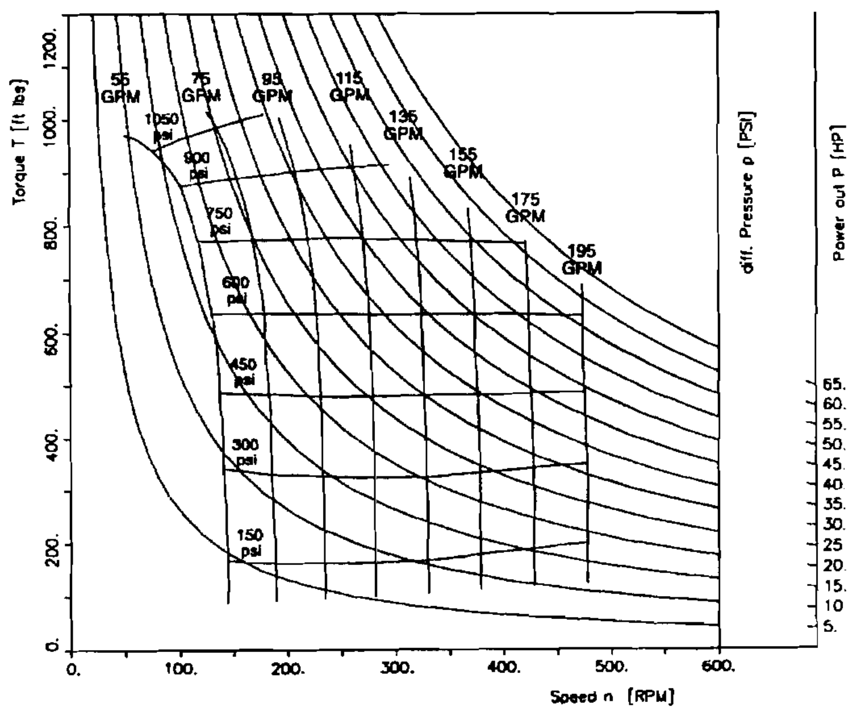


Figure 5-6. Motor Performance Tests (Ehret et al., 1995)

A 3½-in. core barrel was selected (delivers a 1¾-in. core). Aluminum was chosen for the inner tubes for its reduced friction and ease of handling on the rig floor. Three different core bits were used, including ballaset and PDC bits.

The CT coring BHA is shown in Figure 5-7. Drill pipe and drill collars were placed above the BHA to add weight, reduce stress on the CT, and keep the disconnect sub inside casing.

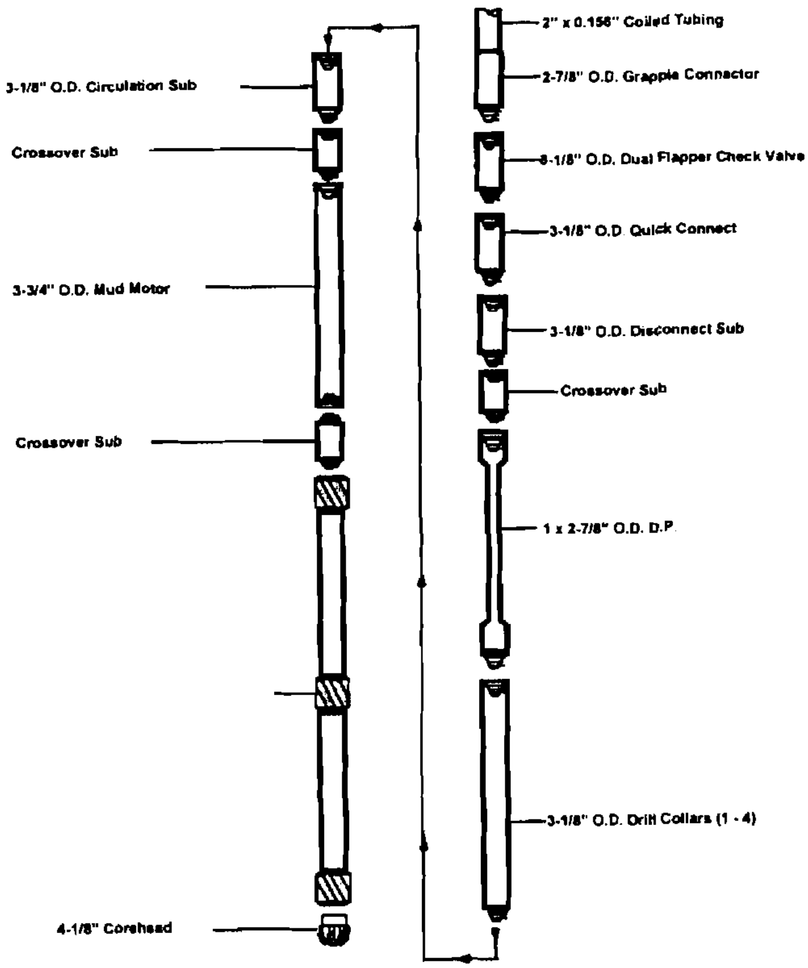


Figure 5-7. BHA for Coring on CT (Ehret et al., 1995)

After the 7-in. casing shoe was drilled out at 5525 ft, two coring runs were made on drill pipe to establish an operational reference for CT runs. Several coring runs were completed (Table 5-1). Recovery was generally low due to junk, fissile shales, unconsolidated sands, core jamming, washing of the core, and plugged nozzles. Recovery efficiency did not increase until the final runs, where the improvement was largely attributed to increasing hardness of the formations.

TABLE 5-1. Coring Performance (Ehret et al., 1995)

Core No	DP/ CT	From - To (ft)	Recovery	Avg ROP (ft/hr)	Flow (gpm)	WOB (lbf)	Pressure (psi)	Comments
1	DP	5545-5574	8.9%	5.2	80	1100-2200	1450-1550	Junk found in barrel
2	DP	5574-5584	33%	8.9	80	1100-2200	1390-1670	Jammed off core, motor stalling
3	CT	5584-5614	0.4%	16.4	58	7000-8000	2090-2450	Found steel junk on top of core
4	CT	5643-5670	23%	20.2	60	3000-8000	2750-2840	Barrel jammed
5	CT	5670-5683	8%	15.6	60	4000	2600	Steel junk. Corehead damaged
6	DP	5732-5747	75.5%	30.8	66	2000	1300-1550	Good run
7	DP	5747-5775	54%	45.4	66	1100	1390-1600	Washed down from csg shoe
8	DP	5775-5804	0%	14.8	87	900-2000	1410-1570	3 plugged nozzles
9	DP	5804-5834	35%	19.7	66	0-2000	1420-1580	Wash down assembly
10	DP	5834-5863	44.4%	21.1	66	0-2000	1450-1550	Wash down assembly
[illegible]	DP	5863-5893	81.7%	29.5	66	0-2000	1277-1520	Good run
[illegible]	DP	5893-5922	93.3%	15.5	66	0-2000	1277-1490	Good run

Project members found that core quality was generally high even though recovery efficiency was low. Lower flow rates (about 66 gpm) provided the best recoveries. The average coring rate was 15 ft/hr compared to an average drilling rate of 40 ft/hr. Performance of the mud motor was better than expected.

Baker Hughes INTEQ, Norsk Hydro and Nowsco UK found that the effectiveness of the CT operations would be greatly improved by a built-for-purpose heave-compensation system.

5.4 BAKER OIL TOOLS (EXITING CASING WITH CT)

Baker Oil Tools (Pitman et al., 1997) presented several case histories of CT sidetracks using whipstocks. Two basic approaches are being used: 1) monobore (unrestricted) completions are exited by setting a packer and oriented whipstock, then running a conventional starting mill and window mill; and 2) through tubing (restricted) completions are exited using a through-tubing whipstock without packer that hinges into position in the casing. The through-tubing system is typically run through 4½-in. casing and set in 7-in. casing.

Readers are directed to their paper for details of case histories with these systems.

5.5 CAMCO AND BPX (REAL-TIME MWD)

Camco Products & Services and BPX (Alaska) (Leismer et al., 1996) described a real-time MWD CT Drilling System. MWD and control of the BHA is enabled through a combination hydraulic/electric umbilical (Figure 5-8) run inside the CT string. This allows orientation of the BHA in 10° increments, applies WOB, operates a reusable circulating valve, and monitors WOB, internal and external circulating pressures, bottom pressure, downhole temperature, and survey data.

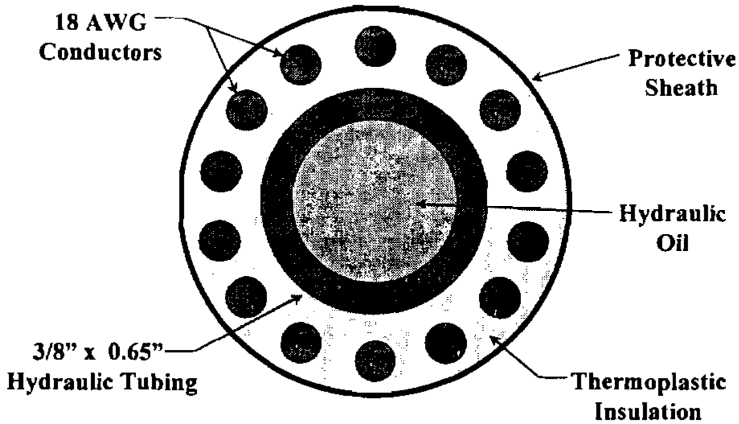


Figure 5-8. Camco's Electric/Hydraulic Umbilical (Leismer et al., 1996)

A thruster was also developed as part of the system to provide consistent WOB and anchor the BHA against reactive torque while drilling. Hydraulic force is applied to anchor the jaws or thrust the assembly forward via the umbilical. Modeling and testing of core samples were used to design the thruster jaw (Figure 5-9) to avoid fracturing the formation. The thruster had not yet been required at the time their paper was written.

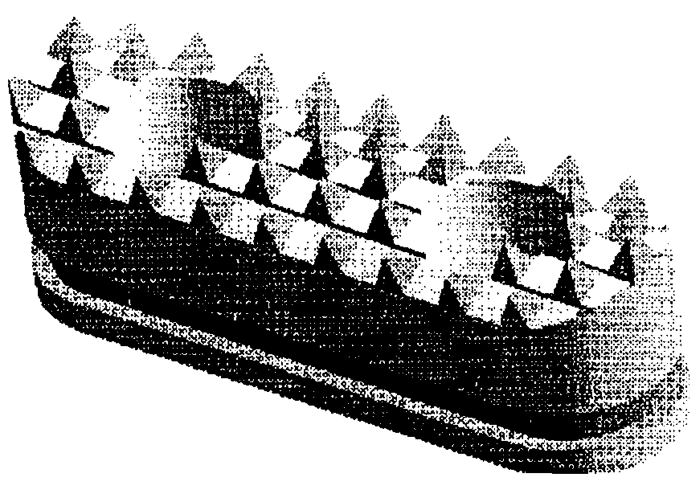


Figure 5-9. CT Thruster Jaw (Leismer et al., 1996)

A special deployment tower (Figure 5-10) was designed to allow lubricating the entire BHA (50 ft+) above the master valve. Five tower sections are stacked to a total height of 93 ft.

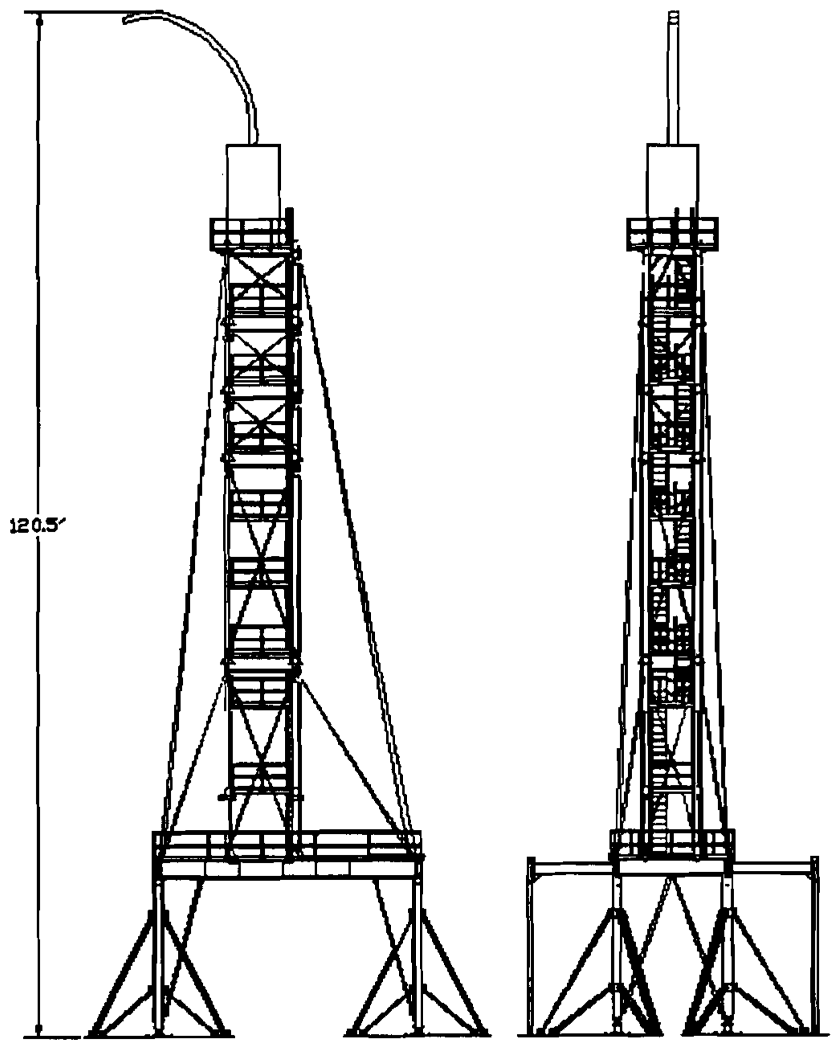


Figure 5-10. CT BHA Deployment Tower (Leismer et al., 1996)

5.6 CANADIAN FRACMASTER (WINDOW MILLS FOR CT)

Canadian Fracmaster Limited (Turley and Bogic, 1997) presented the design and test results with a new window milling tool system for use on CT. An evaluation of conventional window-milling tools showed that several obstacles existed for applying these tools to CT drilling. They decided that a fresh approach was warranted for tools designed specifically for CT operations. Systems for 4½- and 5½-in. casing were developed. Field trials have been successfully conducted with the 5½-in. system.

The mill design was based on a two-trip system that consists of a combination whipstock landing/starter mill followed by a window milling/reaming run.

The starter milling string (Figure 5-11) consists of :

- a starter mill that can carry and seat the whipstock
- a short drill collar
- a stabilizer
- a heavy-weight pup joint
- a mud motor

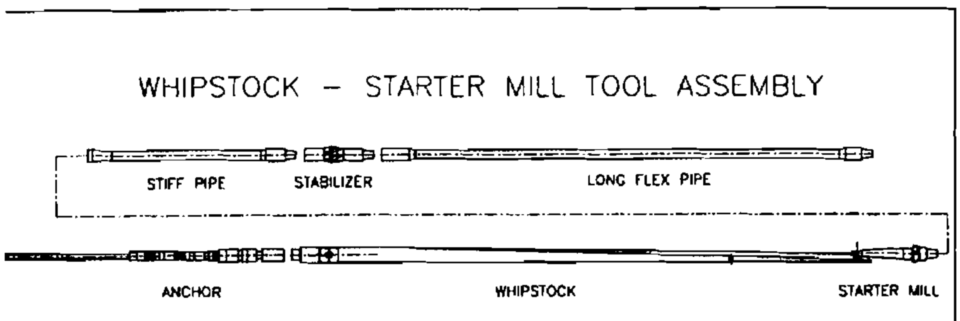


Figure 5-11. CT Window Mill Assembly for 5½-in. Casing
(Turley and Bogic, 1997)

The window milling tool string (Figure 5-12) includes:

- a full-gauge window mill
- a reamer
- a short drill collar
- a stabilizer
- a heavy-weight pup joint
- a mud motor

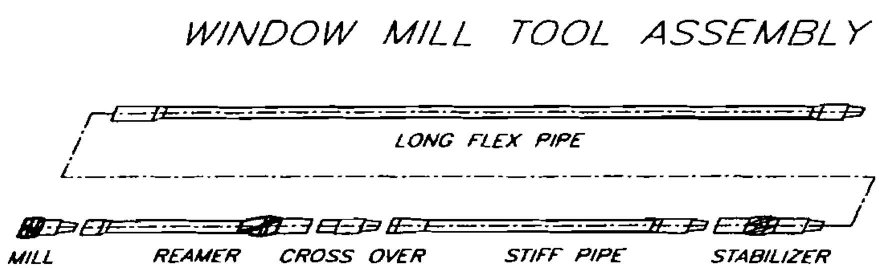


Figure 5-12. CT Starter Mill Assembly for 5½-in. Casing
(Turley and Bogic, 1997)

The 5½-in. milling system has been proven with laboratory and field trails. Milling operations have been completed in a time comparable to conventional rotary operations. The system for 4½-in. casing has been bench tested and found ready for field trials.

Future improvements will be sought with higher speed motors, which are hoped to increase ROP and decrease milling costs.

5.7 CANADIAN FRACMASTER (CT THRUSTER)

Canadian Fracmaster Limited (Smith, 1995) was granted a patent from the European Patent Office (publication no. 0 681 089 A1) for a CT thruster for providing weight on bit for drilling operations in deviated wells. The device (Figure 5-13) can be used to compensate for string weight lost to drag. Thrust is based on the pressure differential between the inside of the string at the tool to that in the annulus outside the assembly.

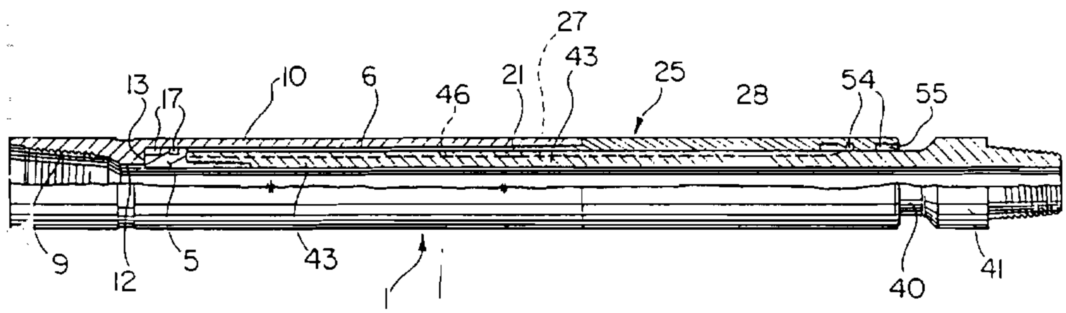


Figure 5-13. CT Thruster (Smith, 1995)

Splines (no. 46 and 27) are included within the assembly (Figure 5-14) for carrying reactive torque during drilling and similar operations. Typical placement for the tool is between the Monel collar and motor. System capability can exceed 12,000 psi at the bit/rock interface.

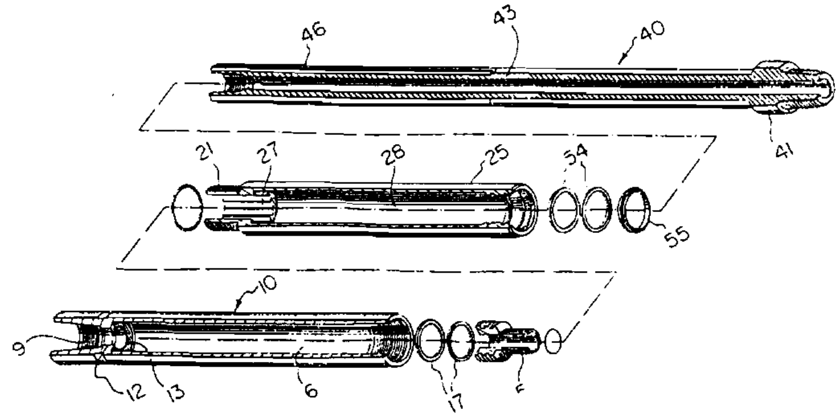


Figure 5-14. Internal Design of Thruster (Smith, 1995)

5.8 CTES AND GRI (ELECTRIC MOTOR FOR CT DRILLING)

CTES (Newman et al., 1996) performed a GRI-sponsored study of the feasibility of using electric motors for drilling on CT. They reviewed the historical usage of electric motors for drilling, developed a conceptual design for a CT electric motor, and analyzed the potential market for this type of drilling system.

Several advantages may be possible with an electric drilling motor as compared to a conventional Moineau mud motor, including:

- Longer time between failures
- Mud type does not impact motor operation or wear
- Mud flow not as restricted through motor (greater flow rates, better hole cleaning)
- Higher operating temperatures (up to 400°F)
- Fits well with telemetry systems
- Motor performance easily monitored from speed controller
- Auto-drilling systems easy to implement
- High voltages now available at the BHA could be used for other beneficial functions (tractors, rotation anchors, orienting, etc.)

Disadvantages of electric motors on CT are more surface equipment, more specialized subs and connectors, a reduction of flow inside the CT due to larger cable, higher capital costs, and added safety concerns.

It is foreseen that original applications of electric motors on CT would likely be in niche applications. These might include areas with high operating costs where an increase in time between motor failures would offset added cost of the electric system; high-temperature environments; formations where lost-circulation material is required; and operations with special drilling fluids that might damage mud motors.

More information is presented in *Tools*.

5.9 HALLIBURTON ENERGY SERVICES AND IRI (HYBRID CT RIG)

Halliburton Energy Services and IRI International (Selby et al., 1998) described the design of a hybrid CT drilling rig that includes a mast for pulling tubulars. In offshore operations, a jack-up pulling unit or independent mast has normally been required before CT services could be performed. The new rig (Figure 5-15) integrates the injector, the power unit, and reel into a transportable rig with a mast. This new system was designed for use servicing shallow to moderate depth wells in the Gulf of Mexico. Increased efficiency and safety are provided in rig up/down and tripping.

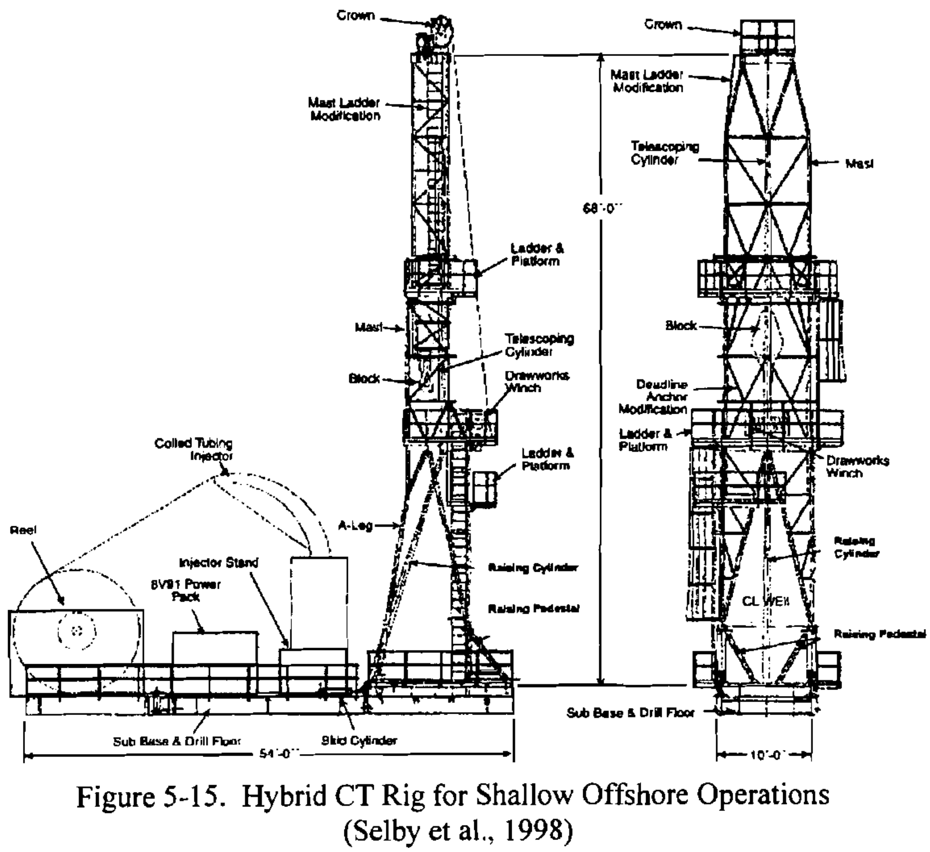


Figure 5-15. Hybrid CT Rig for Shallow Offshore Operations
(Selby et al., 1998)

The rig was first used in a shallow inland field in the Gulf of Mexico. The operation was to drill a new horizontal well for Rozel Energy. Large 2⅞-in. CT (80 ksi) was used for drilling and for the completion.

More information is presented in *Rigs*.

5.10 RF-ROGALAND AND SHELL RESEARCH (UB DRILLING MODEL)

RF-Rogaland Research and Shell Research B.V. (Rommetveit et al., 1995) described a model developed for underbalanced drilling with CT. The program is designed for transient one-dimensional multiphase flow, and includes a complete system of component models including a lift-gas system model, multiphase hydraulics model, reservoir/wellbore interaction model, drilling model, and a range of models for multiphase fluids. Rommetveit et al. (1995) presented several example calculations of drilling parameters and wellbore production of underbalanced drilling simulations using CT.

Field experience has proved the need for increased understanding of multiphase hydraulics in underbalanced drilling. CT is well suited for these operations. The advantages have been enumerated in several publications. (See Underbalanced CT Drilling Case Histories later in this chapter.) A schematic of underbalanced drilling with CT is shown in Figure 5-16.

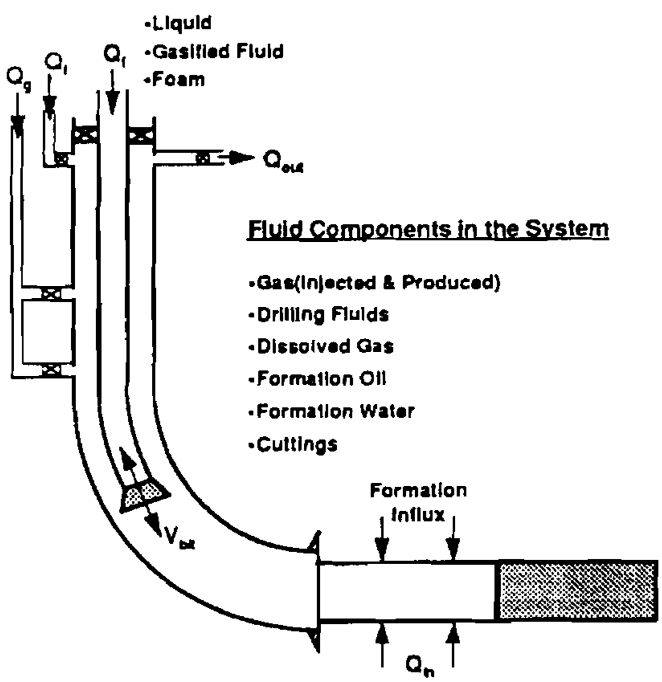


Figure 5-16. CT Drilling Model
(Rommetveit et al., 1995)

Rommetveit et al. derived eight governing equations based on conservation of mass and momentum. Twelve additional relationships were developed and incorporated into various submodels, some based on published results and some developed theoretically and empirically. Based on these sets of equations, the twenty unknowns can be calculated.

A horizontal well with a TD of 950 m (3117 ft) was assumed for a series of representative and comparative calculations (Figure 5-17).

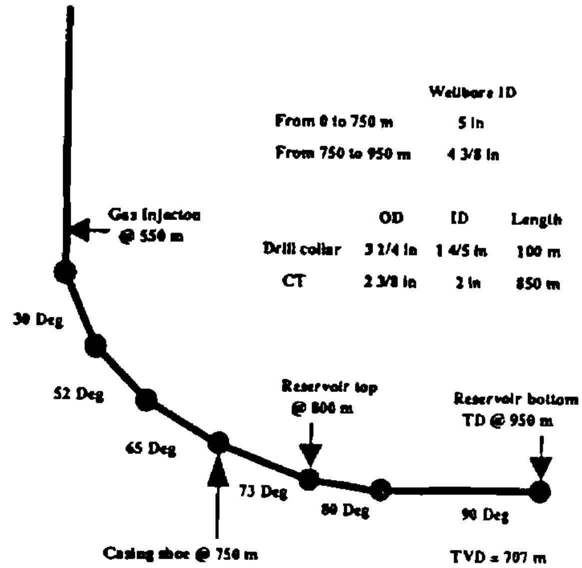


Figure 5-17. Example Wellbore Geometry (Rommetveit et al., 1995)

Reservoir properties assumed for the example calculations are summarized in Table 5-2.

TABLE 5-2. Example Reservoir Properties (Rommetveit et al., 1995)

Depth (MD)	800 - 950m
Permeability	1500 md
Porosity	20%
Pressure	65 bar
Temperature	50°C
Type of fluid	Oil
Gas/oil ratio	2,200 sm^3/sm^3
Water saturation	15%
Oil density	897 kg/m^3
Water density	1050 kg/m^3
Gas density	0.68 kg/m^3

Four reservoir/drilling scenarios were developed. These included using annular gas lift (e.g., a parasite string) or aerated fluid (gas injected at the standpipe) in both high-GOR and low-GOR reservoirs. BHP (bottom-hole pressure) due to the hydrostatic load was 77 bar (1117 psi).

Representative results for one of these cases (parasite-string gas lift in a reservoir with a low GOR) are presented below. Significantly greater detail and other cases are provided in Rommetveit et al. (1995).

Predicted pressure responses for several drilling operations during the parasite-string drilling operations are shown in Figure 5-18. BHP begins to decrease soon after gas injection is begun (300 scfm). Since no production from the reservoir is observed at the original rate, the injection rate is increased to 350 scfm.

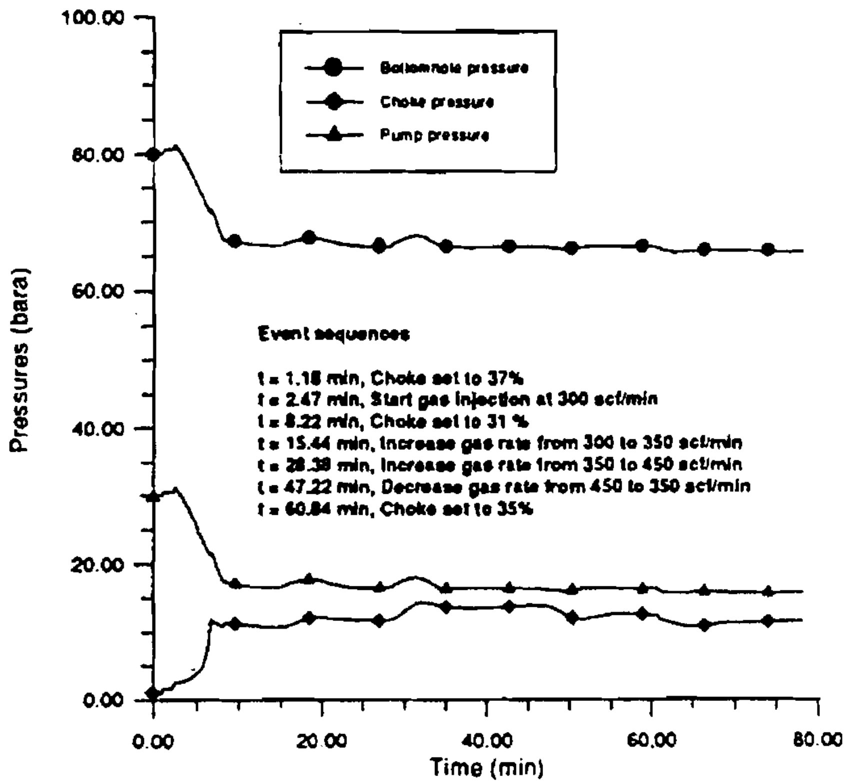


Figure 5-18. Pressure Response for CT Drilling Model
(Rommetveit et al., 1995)

The higher injection rate should cause production to begin. The oil fraction at 28 min verifies the onset of production (Figure 5-19).

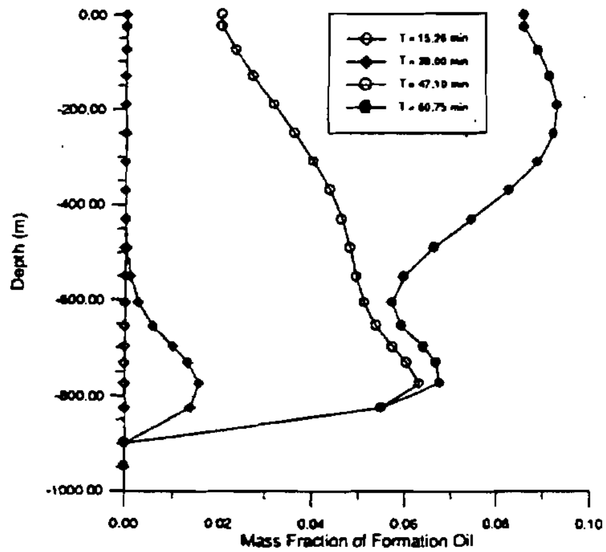


Figure 5-19. Oil Fraction for CT Drilling Model
(Rommetveit et al., 1995)

Pressure profiles along the wellbore at discreet times are compared in Figure 5-20. Early production is observed to originate near the heel of the horizontal well.

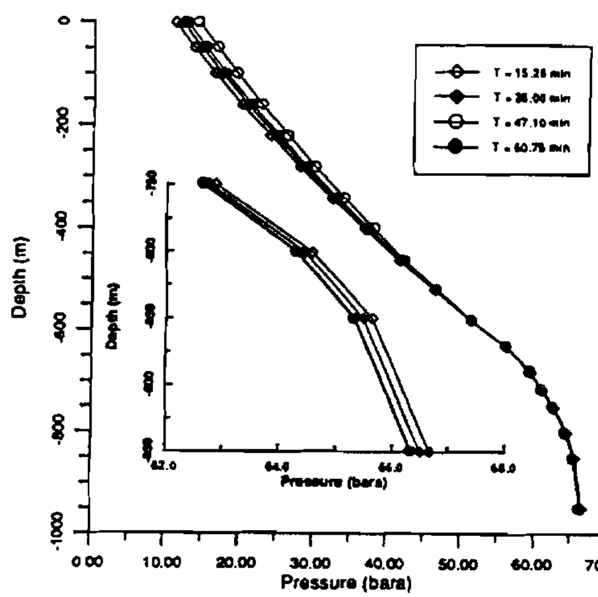


Figure 5-20. Pressure Profile for CT Drilling Model
(Rommetveit et al., 1995)

Gas fractions (Figure 5-21) show the impact of increasing gas injection rates, e.g., increasing to 450 scfm at 28 min. The effect of increased injection on BHP is minor. Consequently, injection rate was reduced to 350 scfm at 47 min.

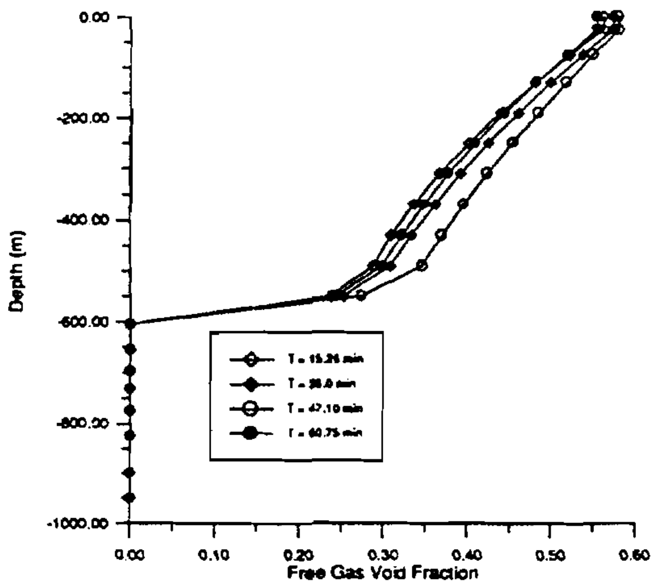


Figure 5-21. Gas Fraction for CT Drilling Model (Rommetveit et al., 1995)

These simulations and observations from the field have shown that a lower injection rate is required with aerated drilling fluid than with annular gas lift. A greater vertical head of gas is achieved with aerated fluid. Frictional pressure losses are also less at lower flow rates required with aerated fluid.

Flow out of the wellbore is also different with the two injection options. For the simulations based on a high-GOR reservoir, the liquid rate out of a well using annular gas injection increases rapidly as the first gas approaches the surface (Figure 5-22). This peak production may overload surface processing equipment. Peak production is much less with aerated fluid drilling.

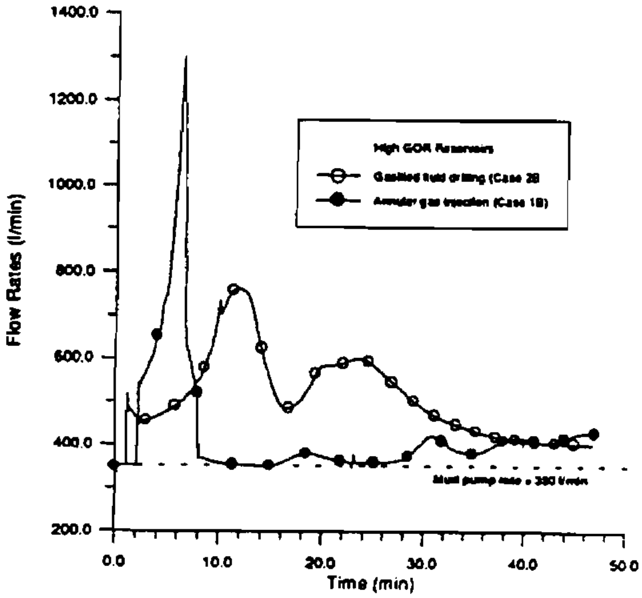


Figure 5-22. Liquid Production After Starting Gas Injection (Rommetveit et al., 1995)

RF-Rogaland Research and Shell Research B.V. believe that models of this type are an important tool for planning underbalanced drilling projects using CT.

5.11 SCHLUMBERGER DOWELL (CT SIDETRACKING TECHNOLOGY)

Schlumberger Dowell, ARCO Alaska and Techaid Corporation (Leising et al., 1995) investigated techniques for performing sidetracks through existing casing. Window-cutting and sidetracking are key technologies that will enable rigless drilling. Three sidetracking technologies were investigated: 1) cement sidetracking (CS), 2) whipstock in cement (WIC), 3) through-tubing whipstock (TTW). These are compared in Table 5-3 with respect to success and other mechanical factors.

TABLE 5-3. CT Sidetracking Techniques (Leising et al., 1995)

	CS	WIC	TTW
Estimated probabability % of success)	65 to 85	85	65 to 85
High side exit	Yes	Yes	Yes
Low side exit	Yes	Yes	--
Easy removal	Yes	--	Possible
Multilaterals with flow from all	Possible	Possible	Yes
Window length	Short	Long	Long
Whipstock intregrity	Poor	Good	Moderate
Iron in well	No	Yes	Yes
Oriented with < 3° hole	No	No	Possible
4 1/2-in. tbg.w/7-in. csg.	Yes	Yes	Yes
4 1/2-in. tbg.w/9 5/8-in. csg.	Yes	Yes	Possible

The advantages of cement sidetracking are that no iron (whipstock) is left in the well, the cement can be drilled out easily later, and few mechanical malfunctions are possible. Disadvantages are relatively short windows, higher sensitivity to drilling technique, and a fragile cement ramp into the sidetrack.

The project team developed a model of sidetracking forces, ROPs, and torques for window milling while cement sidetracking. Bit intrusion into the casing was modeled (Figure 5-23). These results correspond to a 2⅞-in. bit in a 3⅞-in. hole.

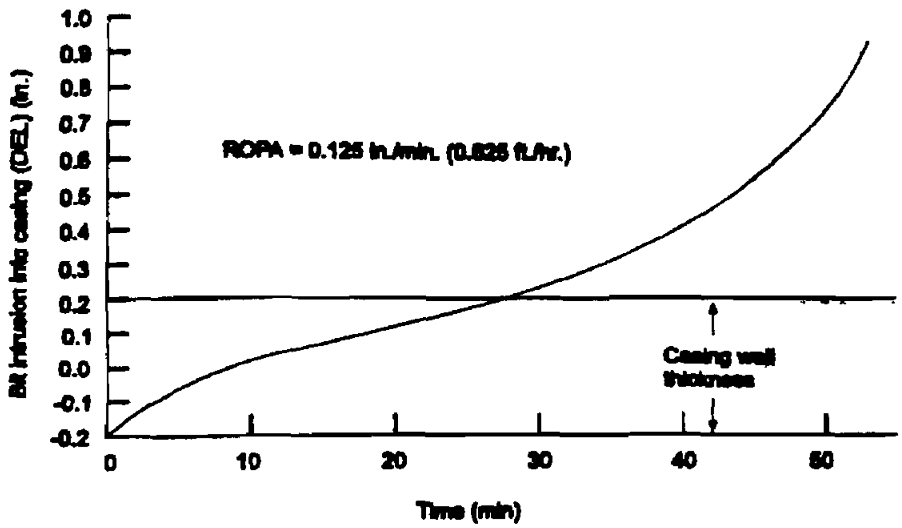


Figure 5-23. Bit Intrusion with Time (Leising et al., 1995)

Several yard tests were conducted to test tools, cements, procedures, etc. Results of five yard tests are summarized in Table 5-4.

TABLE 5-4. CT Sidetracking Yard Tests (Leising et al., 1995)

	Yard-Test Number				
	1	2	3	4	5
Test type	CSS	CSS	CSS	WIC	CSS
Window length, in.	—	42	—	92	49
Comments	Stuck, jumped lip	Stuck, ledges	Unable to put weight on lip	Good long window	Sidetrack when attempted to dress
Results	Bend not enough	Good	Poor	Good	Good/bad
Bent housing, degrees	1.5	3	2.6/3*	—	3/2.12*
Bent sub, degrees	0.75	—	1/0	—	—
Deviation, degrees	53	53	0	0	0
Exit side	Low	Low			

CSS tests run with 7-in., 29-lbm/ft casing.
*Indicates two runs; Run 1/Run 2.

Bits used to yard-test CT sidetracking techniques are shown in Figure 5-24. The tests were conducted in 40-ft joints of 7-in. casing. Cements were 6000-psi Class A or 3500-psi Class G with latex.

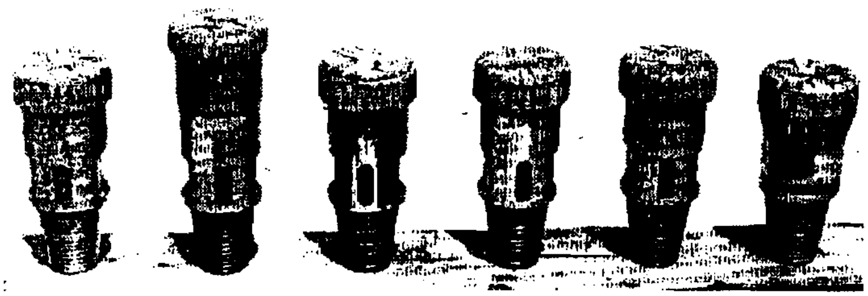


Figure 5-24. Bits for Sidetracking Yard Tests (Leising et al., 1995)

Cement sidetracking is the most popular approach. Windows cut with this approach are relatively short but cannot be lengthened by reducing the angle of the bent assembly. If the bend angle is too low, the side force will not be sufficient to hold onto the casing lip. Field experience has shown that a 3° bend works well for 3¾-in. windows and 2° for 4½-in. windows.

5.12 SCHLUMBERGER DOWELL (VIPER DRILLING BHA)

Schlumberger Anadrill has developed an innovative CT drilling BHA and has begun marketing the system under the name "Viper." The multifunctional system integrates MWD, downhole motor, orienter and safety devices for use with CT as well as underbalanced drilling operations with rotary equipment. Viper is powered and controlled via wireline cable. Therefore, mud type does not influence system operation. The entire system consists of four assemblies (Figure 5-25):

- CT head module
- Logging assembly
- Orienting tool
- Mud motor

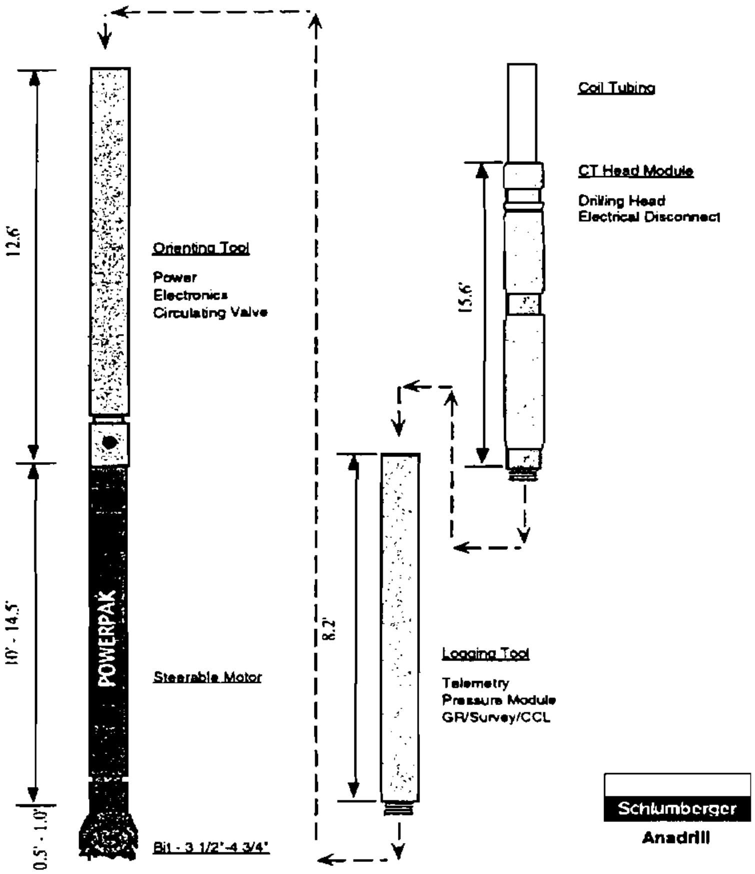


Figure 5-25. Viper CT Drilling BHA
(Schlumberger, 1996)

The physical specifications and measurement capabilities of the sensors are summarized in Table 5-5. The real-time display, log presentation and data base of all measurements are supported by Schlumberger Anadrill's standard surface directional equipment (e.g., the IDEAL system). All downhole measurements are transmitted on the 7-conductor wireline integral to the CT.

TABLE 5-5. Specifications and Capabilities of Viper (Schlumberger, 1996)

SPECIFICATIONS	
Pressure Rating	18,000 psi absolute, 5,000 psi differential
Temperature Rating	150°C
Flow	130 gpm
Drilling Fluid	Air, Foam, Mud
Max Sand Content	2.5%
Max Lost Circulation Material	40 lb/bbl medium nut plug or equivalent
Max Weight on Bit	11,500 lbs
Max Overpull	39,500 lbs
Inclination	0-125°, accuracy: ±0.1° (1 Sigma)
Azimuth	0-360°, accuracy: ±0.1° (1 Sigma) for inclination >5°
Tool Face	Magnetic or High Side, accuracy: ±0.1°
Casing Collar Locator (CCL)	Detects magnetic anomalies generated by the casing joints. -X axis magnetometer.
Annular Pressure	0-18,000 psi, accuracy: ±45 psi, res.: ±1 psi
Internal Pressure	0-18,000 psi, accuracy: ±45 psi, res.: ±1 psi
Differential Pressure	0-2,000 psi, accuracy: ±20 psi, res.: ±2 psi
Temperature	1-150°C, accuracy: ±1°
Gamma Ray	0-250 API, statistical precision: ±5% (100 API,100 ft/hour, 1 Sigma)

The Viper system is rated for operations in temperatures up to 150°C (300°F). Gamma (gross, i.e., non-spectral) is measured continuously while drilling. The gamma measurement point is about 24.5 ft behind the bit (Figure 5-26).

The orienting tool is the most innovative element of Viper. It consists of an electric motor geared down to turn at 1 rpm and powered via wireline. Orientation can be in either a clockwise or counter-clockwise direction. The torque rating is 900 ft-lb, allowing orientation with weight on bit. Unlike other orienters, the Viper orienter can rotate continuously in either direction. Continuous rotation is of benefit when drilling a straight section of the borehole, thereby decreasing hole rugosity and CT drag.

Current status of the Viper project is that prototype development and laboratory and field testing are complete. Six complete systems have been fabricated. Pairs of Viper systems (a back-up system is sent to each job) are scheduled to be used at three locations in the near future. In August 1996, one well will be drilled in the North Sea and one in Brazil. The third pair will be used in Oman in September. Several other customers (including some within the U.S.) are also requesting the system.

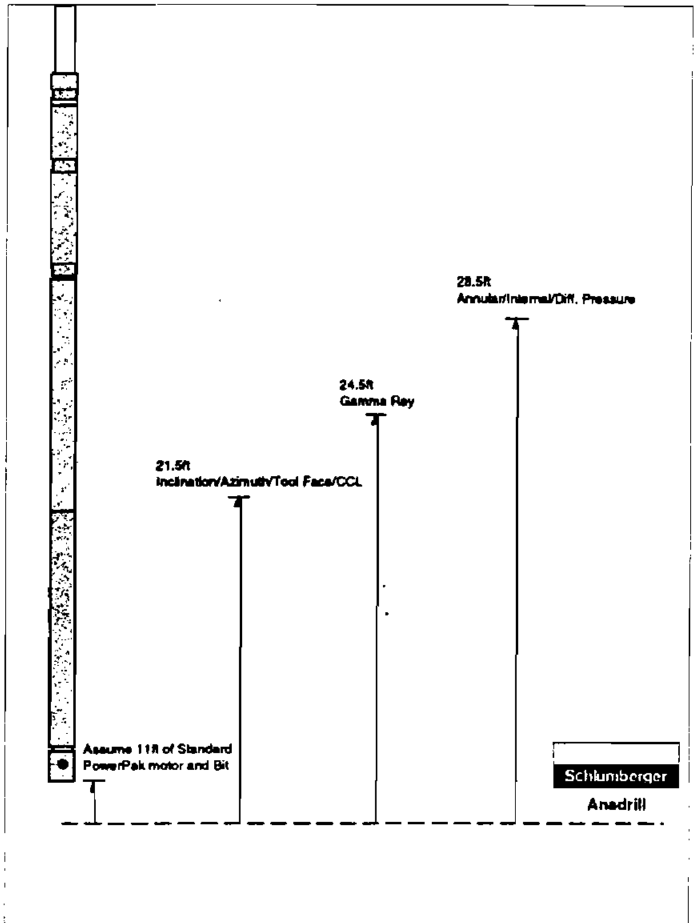


Figure 5-26. Viper Sensor Measurement Points (Schlumberger, 1996)

5.13 SCHLUMBERGER DOWELL (DESIGNING UNDERBALANCED DRILLING)

Schlumberger Dowell (Gu and Walton, 1996) presented a summary analysis of various aspects of design for underbalanced drilling operations with CT using foam or gas injection. Computer model results show that specific underbalances can only be achieved by certain combinations of liquid and gas rates. They investigated the impacts of cuttings loading, depth of injection point and reservoir pressure.

For an example case, underbalanced fluid systems were designed for drilling a 3½-in. hole through 3.96-in. production tubing using 2-in. CT. Liquid and gas injection rates for foam drilling (Figure 5-27) show that the desired bottom-hole pressure of 2600 psi can be achieved by more than one combination of rates. The intersections on the left side of the plot are probably desirable due to lower gas rates and gas consumption. For this case, reservoir underbalance can be increased on site if necessary by increasing gas rate.

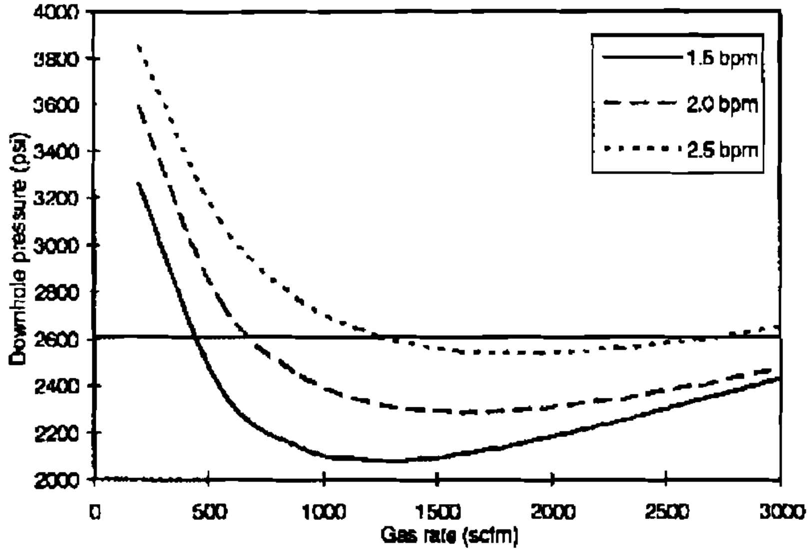


Figure 5-27. Gas Rate for Foam Drilling (Gu and Walton, 1996)

The additional loads due to cuttings create additional pressure downhole. The effect in a 3½-in. hole is not significant (Figure 5-28) for the modeled ROPs. However, in a 6-in. hole downhole pressures can increase 100-200 psi due to cuttings.

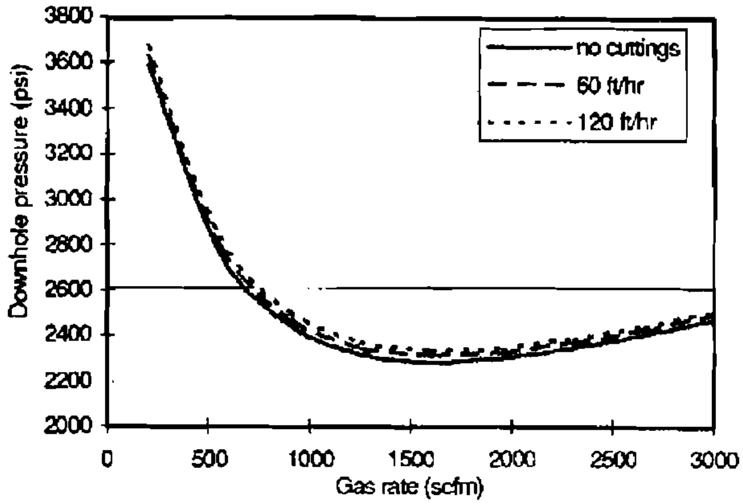


Figure 5-28. Impact of Cuttings Load in 3½-in. Hole
(Gu and Walton, 1996)

Instead of foam drilling, gas can be injected through a parasite string or gas mandrels to induce an underbalance. The depth of the injection point strongly impacts downhole pressures (Figure 5-29). Additionally, there is a limiting injection rate above which downhole pressure is unaffected by increasing gas flow.

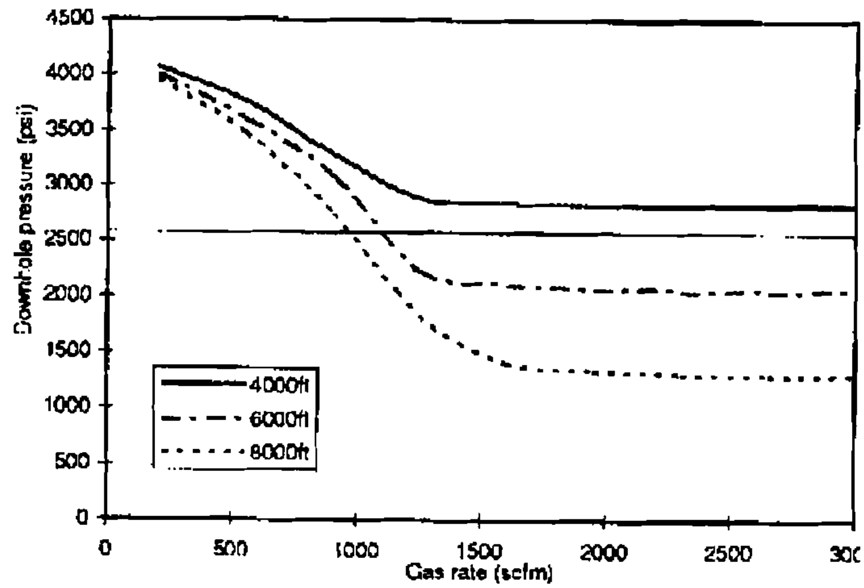


Figure 5-29. Gas Injection Depth (Gu and Walton, 1996)

5.14 SHELL RESEARCH, PDO AND BEB (COMPREHENSIVE DRILLING SYSTEM)

Shell Research B.V., Petroleum Development Oman and BEB Erdöl Erdgas GmBH (Faure et al., 1995) described a visionary drilling system based on reeled components, including umbilicals, casing, tubing and pipelines (Figure 5-30). They see this approach as the next quantum step forward to improve the economics of hydrocarbon development. At present, CT drilling comes closest to the envisioned technologies. While many of the enabling reeled technologies are only at the concept stage, development of the required components could reduce costs and broaden technical abilities.

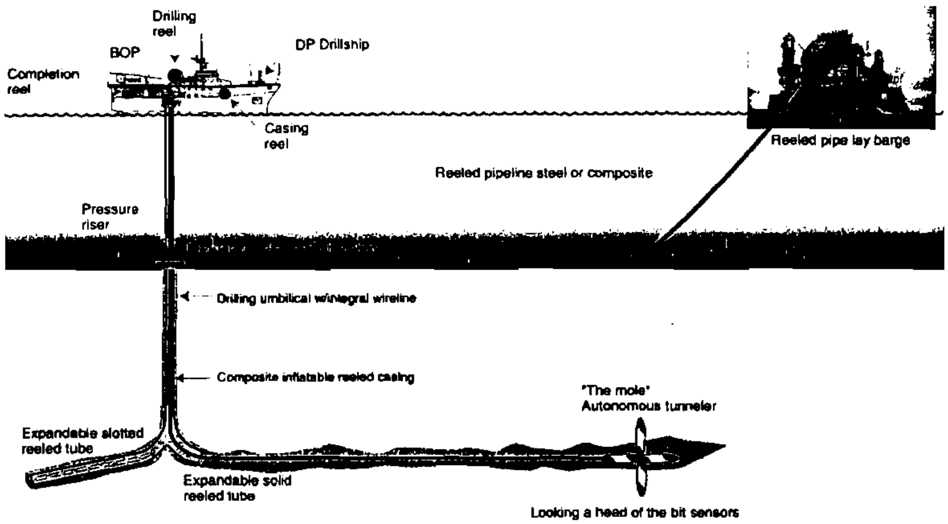


Figure 5-30. Reeled Tubing Drilling System (Faure et al., 1995)

Numerous field trials using CT systems to drill horizontal laterals have been successfully completed. Several of these are described by Faure et al. (1995). There exist, however, a number of technical challenges to be addressed before CT drilling could fulfil its potential within a comprehensive reeled drilling system. Most of these challenges are listed in the flow chart in Figure 5-31.

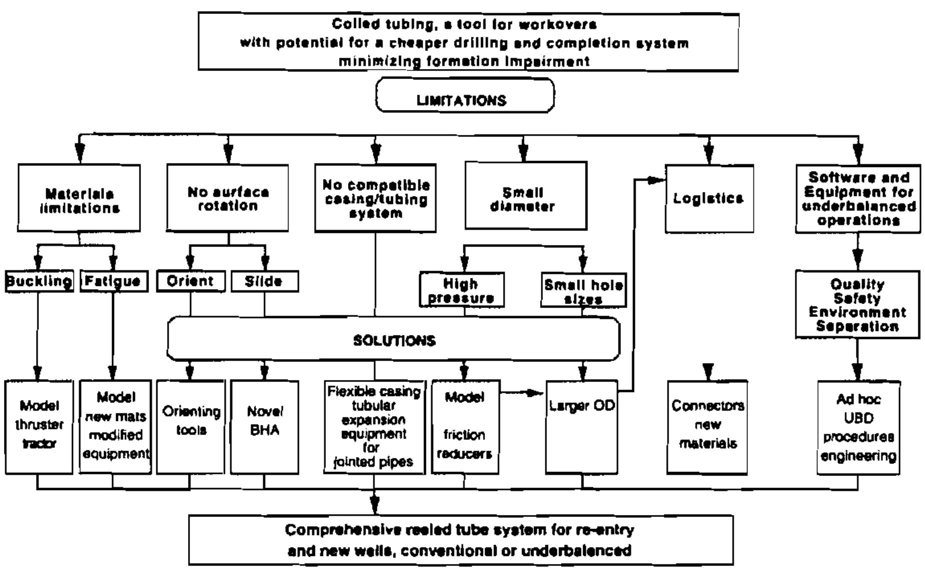


Figure 5-31. Limitations and Solutions for CT Systems
(Faure et al., 1995)

5.15 SPERRY-SUN, ARCO AND THUMS (CT DRILLING BHA ELEMENTS)

Sperry-Sun Drilling Services, ARCO E&P Technology, ARCO Alaska, THUMS Long Beach, and ARCO Long Beach (Gleitman et al., 1996) described the design of new components for CT drilling, specifically a hydraulic orienter and MWD system. Case histories in Alaska and California were also described.

The orienter is a simple hydraulically-actuated system that forms a critical element of the complete CT drilling BHA (Figure 5-32). The orienter indexes the BHA 20° clockwise with every pump cycle. No weight on or off bottom is required for indexing, and the system does not telescope.

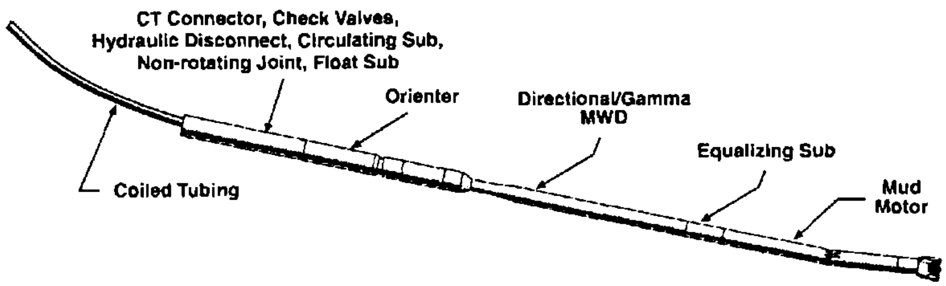


Figure 5-32. CT Drilling BHA (Gleitman et al., 1996)

The MWD assembly (Figure 5-33) was based on a standard directional/gamma system. New 3-in. collars were built for the assembly to provide adequate clearance in the 3¾-in. hole.

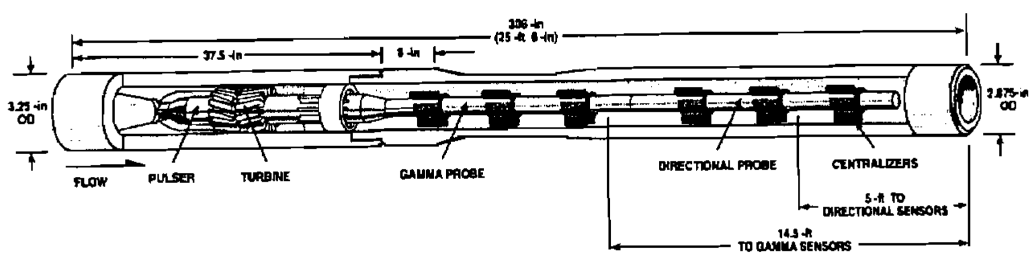


Figure 5-33. CT MWD Sub (Gleitman et al., 1996)

5.16 TEXAS A&M UNIVERSITY (WELL-CONTROL MODEL)

Texas A&M University (Choe and Juvkam-Wold, 1996) presented an analysis of well-control procedures based on their simplified two-phase model that analyzes kick and pressure responses in directional/horizontal slim holes and wells drilled with CT. They compared theoretical kill sheets to conventionally devised procedures. Conventional kill sheets overestimated kill pumping pressures. For directional/horizontal wells with high build rates, choke pressure is predicted to change quickly without much kick expansion due to TVD change as the kick migrates through the curve. Their study results suggested that a theoretically based kill sheet should be used for kill procedures in slim directional/horizontal wells, along with a small safety overpressure.

Choe and Juvkam-Wold's model is based on unsteady two-phase flow, one-dimensional flow along the wellbore, water-base mud, negligible gas solubility, incompressible mud, known mud temperature with depth, and the kick enters the well at current TD. Eight parameters are used to describe the system: pressure, temperature, and gas and liquid fractions, densities and velocities.

In conventional operations, frictional pressure losses at low kill rates are normally minor. However, frictional pressure losses are often critical for slim holes, for CT drilling, and in choke/kill lines for offshore wells.

Specifications for the slim-hole well analyzed in the well-control study are shown in Table 5-6.

TABLE 5-6. Well Specifications for Well-Control Study (Choe and Juvkam-Wold, 1996)

Initial kick volume, bbls	2.0
Mud density, ppg	12.0
Plastic viscosity, cp	10.0
Yield point, lbf/100 ft^2	15.0
Bit nozzle diameter, 1/32 in.	3 x 10
Well true vertical depth, ft	10,000
Depth of casing seat, ft	6,000
Inner diameter of last casing, in.	5.0
Open hole diameter, in.	4.25
OD & ID of drill pipe, in.	2.875 x 2.441*
Pump capacity, bbls/stroke	0.17
Pump rate while drilling, gpm	143.
Kill mud pump rate, gpm	50.
Kick intensity, ppg	1.0
Gas specific gravity (air = 1.0)	0.65
Surface temperature, °F	70.0
Mud temperature gradient,°F/100 ft	1.6
Formation permeability, md	5.0
Final hold length, ft	2,000**
Depth of kick-off point, ft	6,000**
Build-up rate, deg./100 ft	1.433**

* also used for coiled tubing OD and ID
** for horizontal wells

Choke pressures for a well with a 2000-ft horizontal section are shown in Figure 5-34 based on both the engineer's and driller's methods. No hydrostatic pressure reduction occurs in the annulus while the 2-bbl kick remains in the horizontal section. Therefore, the SICP and SIDPP are equal (520 psi) until the influx begins to rise. The reduction in choke pressure due to the kill mud (engineer's method) is not large because the effect of gas expansion near the surface dominates.

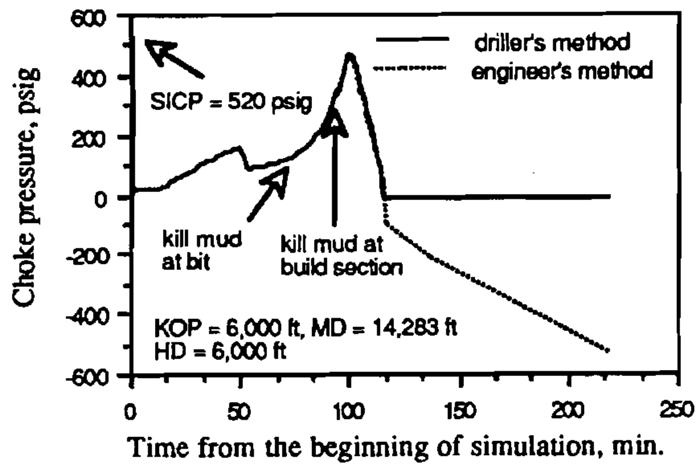


Figure 5-34. Choke Pressures in Horizontal Well
(Choe and Juvkam-Wold, 1996)

Kill sheets based on model predictions and conventional field procedures were compared. Kill sheets map the choke pressure required to maintain constant bottom-hole pressure. In the field, detailed hydrostatic and frictional pressure data are not readily available. Kill sheets are often constructed by calculating initial and final circulating pressures and assuming a linear path between them.

A comparison of modeled and field kill sheets for a vertical slim-hole well is shown in Figure 5-35. The conventional kill sheet maintains bottom-hole pressure above formation pressure by an amount equal to annular pressure losses. This overpressure may be too large in slim annuli, leading to fracturing, lost circulation etc.

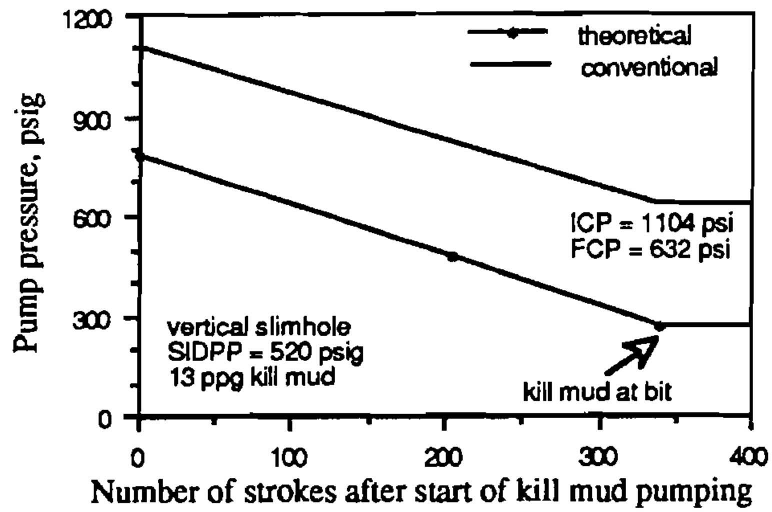


Figure 5-35. Kill Sheets for Vertical Slim Hole
(Choe and Juvkam-Wold, 1996)

Kill sheets for a slim horizontal well with a 4000-ft lateral are compared in Figure 5-36. Pump pressure is minimum when the kill mud first arrives at the lateral TVD. With the conventional sheet, bottom-hole pressure may be too high, resulting in failure of the casing shoe.

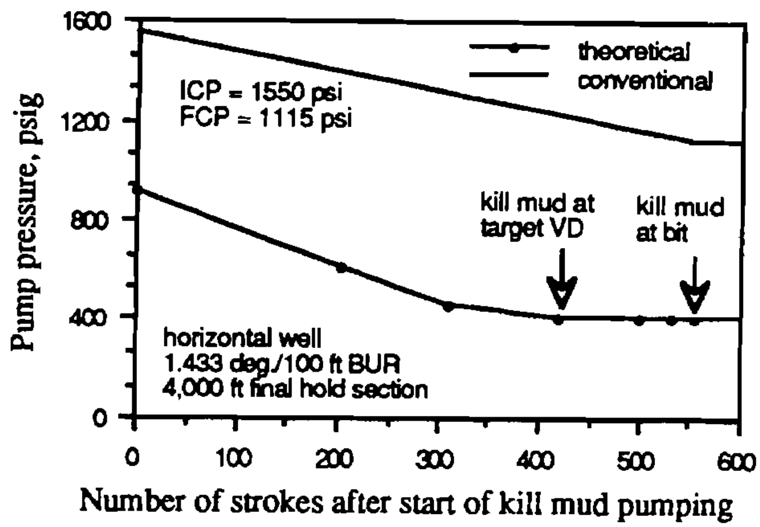


Figure 5-36. Kill Sheets for Horizontal Slim Holes
(Choe and Juvkam-Wold, 1996)

The same 4000-ft horizontal well was assumed for another case, this time drilled with CT (Figure 5-37). Pressure is constant until kill mud fills the entire spool on the rig (4000 ft assumed). For higher kill rates, pump pressure will increase due to frictional pressure drop in the spool.

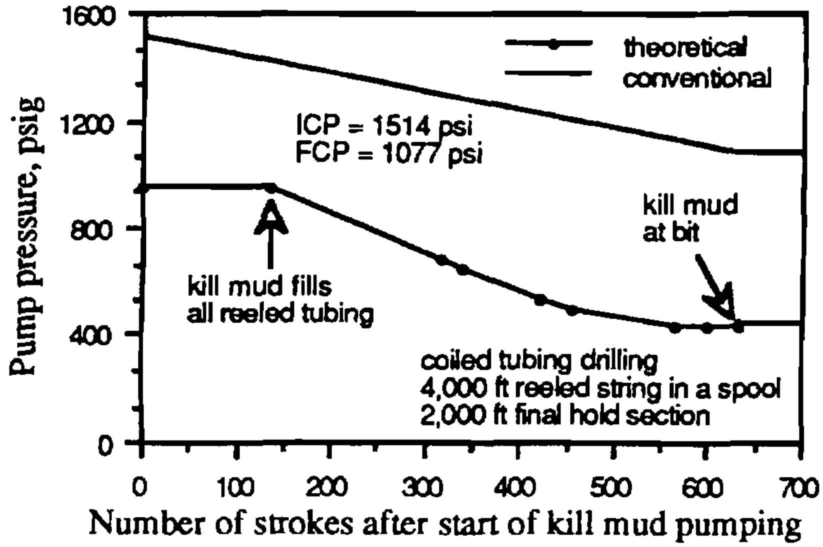


Figure 5-37. Kill Sheets for Horizontal Slim Hole Drilled with CT
(Choe and Juvkam-Wold, 1996)

5.17 TRANSOCEAN PETROLEUM TECHNOLOGY (DUAL CAPILLARY DRILLING BHA)

Transocean Petroleum Technology (Thomson, 1995 and Transocean, 1996) developed a unique BHA for drilling with CT. The most significant innovation with their system is the use of two internal control lines installed inside the CT string along with the wireline. These provide effective real-time control of directional characteristics of the assembly.

The CT directional drilling assembly developed by Transocean provides steering, standard MWD sensors (inclination and azimuth) and gamma ray. The system uses two hydraulic control lines installed internally in the coiled tubing for orienting the bent housing on the motor. Data from the MWD and gamma-ray sensors are transmitted to surface via a monocable wireline. The directional tools are available either as traditional magnetic tools or a gyro.

This system has been used to drill five underbalanced wells with more planned in the UK. During these drilling operations, build rates of up to 43°/100 ft and penetrations rates of up to 95 ft/hr have been achieved in sandstone and limestone. The Transocean system has also be used for re-entry drilling in Argentina.

The Transocean CT directional assembly consists of the following components starting from the top:

- "Dual Capillary" CT
- CT Connector
- Orienting Tool
- Double Check Valves
- Emergency Release Tool
- Steering Tool
- Monel Flow Sub
- Motor with Bent Housing
- Bit

The drillstring for the Transocean CT drilling system is named the "Dual Capillary System" (Figure 5-38) and consists of 80,000 psi or 100,000 psi minimum yield strength CT with two ¼-in. stainless-steel hydraulic control lines and a standard $^{7}/_{32}$-in. mono conductor wireline cable installed internally in the CT. For drilling, the two hydraulic control lines are used to operate the orienting tool, and the monocable is used to transmit the signals from the MWD/LWD sensors.

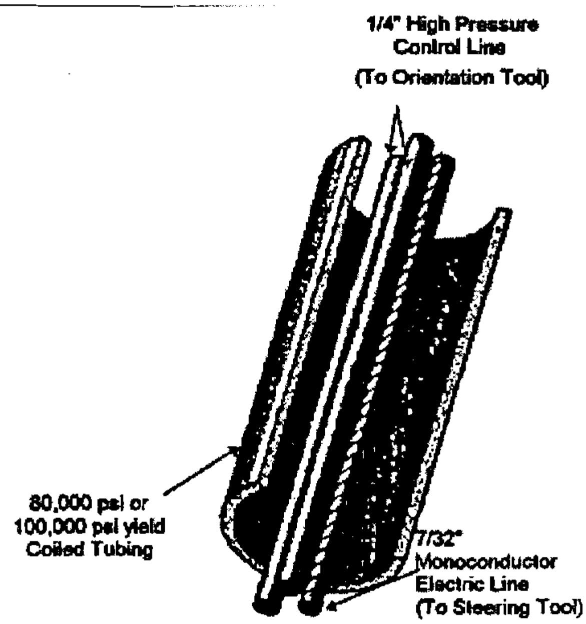


Figure 5-38. Dual-Capillary System (Transocean, 1996)

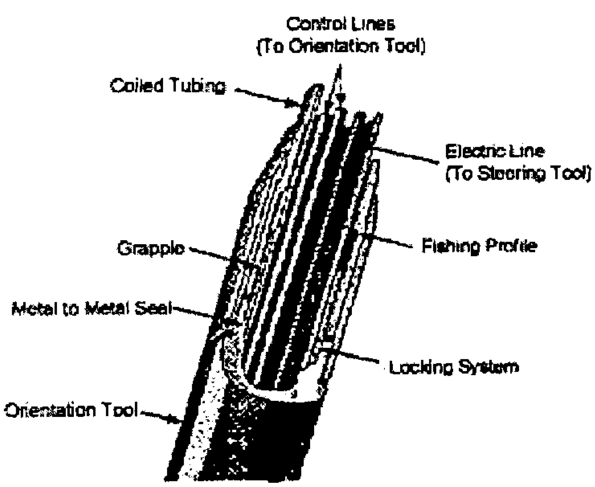


Figure 5-39. Coiled-Tubing Connector (Transocean, 1996)

The BHA is attached to the CT with a special connector. The connector (Figure 5-39) provides a mechanical connection which will resist tension, compression, and torsion. With the connector installed, a thread is available on the lower end of the CT for connection of other tools. Both of the control lines and the mono-conductor wireline pass through the CT connector.

The orienting tool is used to rotate the steering tool, motor and bit. This rotation ability is essential to controlled directional drilling. The orienting tool is hydraulically operated. This tool achieves rotation through linear motion of a helical floating piston engaged with a helical key (Figure 5-40). The tool will orient 360° clockwise by hydraulic fluid flow down one control line, and 360° counter-clockwise by hydraulic fluid flow down the other control line. The movement is infinite, i.e., not limited to indexing slots as is the case for previously developed orienters. The torque generated is sufficient to orient while drilling. The tool is hydraulically locked into position by isolating both control lines. The Transocean orienter is placed directly below the connector to allow termination of the hydraulic lines high in the assembly.

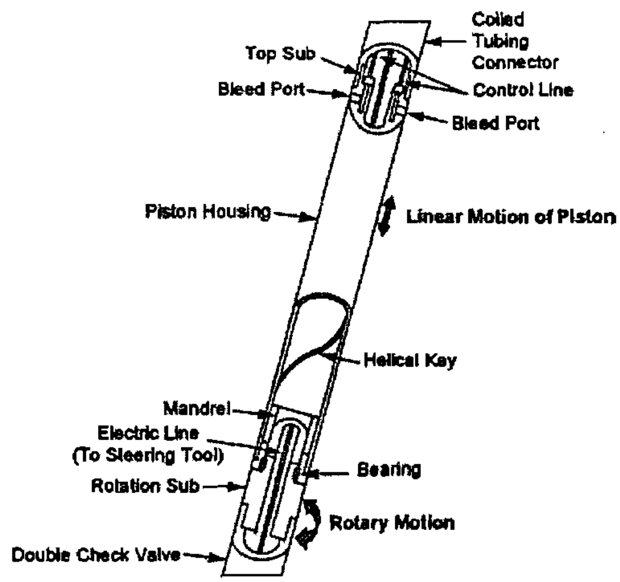


Figure 5-40. Transocean Orienting Tool (Transocean, 1996)

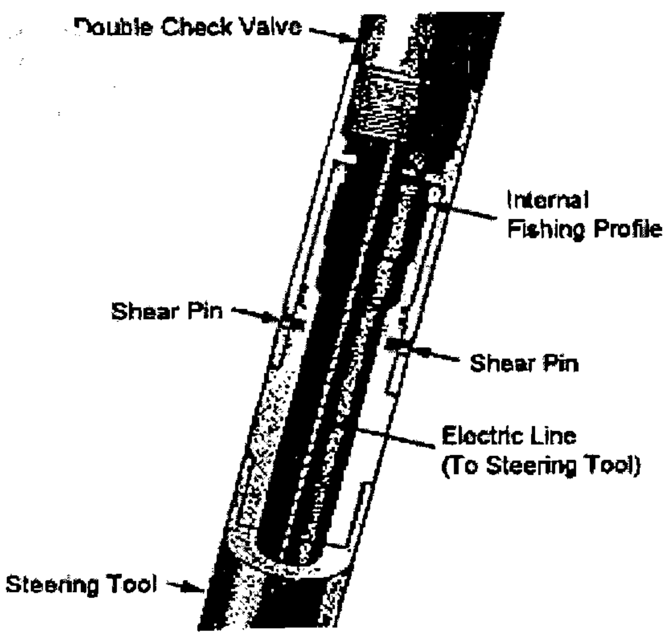


Figure 5-41. Emergency Release Tool (Transocean, 1996)

An emergency release tool (Figure 5-41) is installed in the string to allow controlled release of the downhole tool string in the event of hole collapse or other problems causing the BHA to stick. The release is operated by overpull. Should the bit, motor, or steering tool become stuck in the hole, overpull will shear the pins in the release tool, allowing retrieval of the orienting tool and CT drillstring. The release is placed below the check valves to maintain safety at the surface if release is required. When the tool is released, the wireline pulls loose at the wireline head in the steering tool.

The steering tool is used to measure the direction of the borehole and to guide the directional driller in properly orienting the bent housing on the motor to achieve the desired wellpath. Because magnetic surveying tools rely on sensing the Earth's magnetic field and are sensitive to magnetic interference, the survey tools are housed in a non-magnetic collar (Figure 5-42).

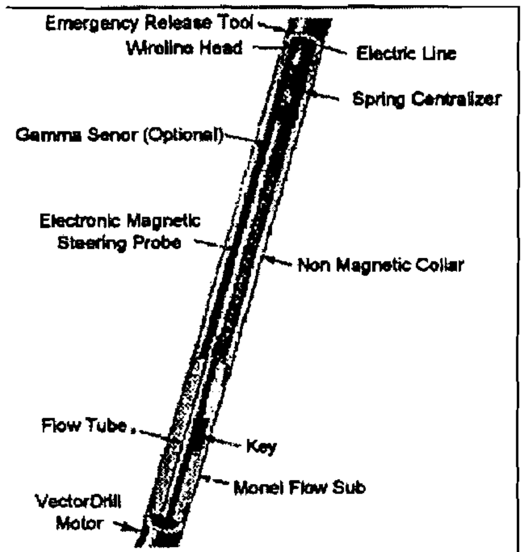


Figure 5-42. Steering Tool
(Transocean, 1996)

The signals from the survey tool are transmitted to the surface through the mono-conductor wireline cable. The wireline cable terminates at the top of the tool using a standard wireline head. The weak point on this head is where the wireline cable parts in the event of an emergency release of the BHA.

The Scientific Drilling survey and gamma-ray tools used in the Transocean steering system are standard wireline tools modified for use in a drilling environment. The modifications include addition of a shock-absorbing sub to reduce the shock loading to the electronics of the tools, and a heat shield to allow extended temperature operating range of the tools (up to 600°F). Directional information is usually acquired using inclination and magnetic azimuth sensors. For operations in areas where magnetic interference renders the azimuth readings unusable, a gyro survey tool can be used.

Pressure and temperature sensing devices are also available with this system. Pressure measurement can be take from the inside of the string above the motor or in the annulus. Both pressure measurements can be combined.

5.18 UNIVERSITY OF TULSA (SLIM MOTORS FOR CT DRILLING)

The University of Tulsa and the University of Alabama (Sanchez et al., 1996) presented a study on the torque and flow-rate requirements for slim-hole CT motor drilling, including PDMs, turbines and electric motors. They addressed the potential minimum diameter for slim motors while still satisfying drilling power requirements. Modeling results demonstrated that currently available motors are capable of producing more torque than is required for drilling horizontal sections.

Sanchez et al. considered torque, horsepower and required flow rate for selecting motors for short-radius re-entries. The basic wellbore schematic is shown in Figure 5-43.

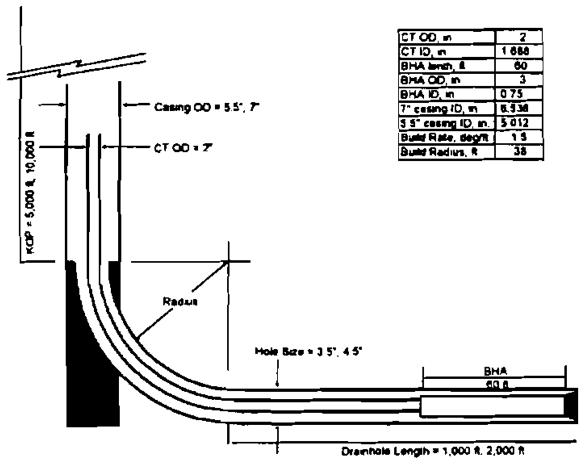


Figure 5-43. Re-entry for Modeling Studies (Sanchez et al., 1996)

Other geometric and parametric data are summarized in Table 5-7.

TABLE 5-7. BHA and Hole Description (Sanchez et al., 1996)

BHA and Hole Geometry	
Friction coefficient = 0.1	C1 = 1.9
Bit diameter (in) = 4.5	C2 = 8.1
Hole diameter (in) = 4.5	ROP (ft/hr) = 30
BHA OD (in) = 3	N (rpm) = 500
BHA ID (in) = 0.75	Formation const. = 1E-05
BHA Volume/1ft (ft^3) = 0.046	BHA Weight (lbs/ft) = 22.14
BHA Density (lbs/ft^3) = 481	Clearance (ft) = 0.0625
Moment of inertia (ft^4) = 0.0001	
E (Young's) (lbs/ft^2) = 4.3E+09	Parabolic distribution of Fs

Results suggested that fluid flow rates of 500-1000 scfm are required for drilling these re-entries. For muds, the critical velocity ranges between 90 and 120 ft/min in vertical wells, with a safety factor of 2 to 4 required in horizontal wells. Flow rates to meet these criteria are shown in Table 5-8. About 160 gpm is needed to clean the horizontal annulus, which is not sufficient to clean the larger vertical section. Almost 220 gpm is required.

TABLE 5-8. Mud Flow Rates for Hole Cleaning (Sanchez et al., 1996)

Vertical Section						
Hole OD (in) =	7	7	7	5	5	5
String OD (in) =	2	2	2	2	2	2
Annular area (in^2) =	35	35	35	16	16	16
Assumed Vmin (fpm) =	90	105	120	90	105	120
Flow rate (GPM) =	165	193	220	77	90	103
Horizontal Section						
Hole OD (in) =	5	5	5	4	4	4
String OD (in) =	2	2	2	2	2	2
Annular area (in^2) =	13	13	13	6	6	6
Assumed Vmin (fpm) =	180	120	240	180	210	240
Flow rate (GPM) =	119	139	159	61	71	81
BHA						
Hole OD (in) =	5	5	5	4	4	4
String OD (in) =	3	3	3	3	3	3
Annular area (in^2) =	9	9	9	3	3	3
Assumed Vmin (fpm) =	180	210	240	180	210	240
Flow rate (GPM) =	83	96	110	24	28	32

Several parametric studies were conducted for turbine design in slim-hole applications. The relationship between turbine speed and required rotor radius (Figure 5-44) shows that a 150-stage motor running at 150 rpm requires a rotor radius of less than 1 inch. Even smaller motors could be designed with higher flow rates or more stages.

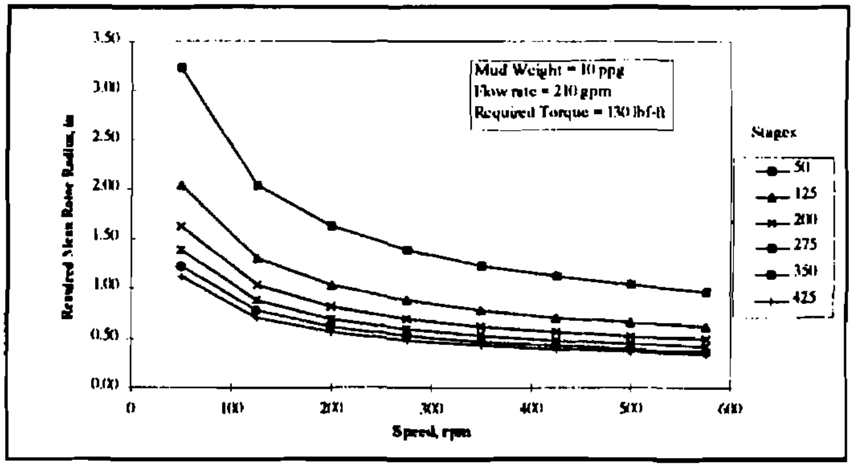


Figure 5-44. Turbine Speed and Rotor Radius
(Sanchez et al., 1996)

The constraints of short-radius drilling dictate that the lowest possible number of stages be used so that the assembly can pass through the curve. Sanchez et al.'s analyses suggested that a slim turbine motor could have between 50 and 300 stages and could be run at speeds ranging from 200 to 500 rpm.

PDM design would probably focus on a 1:2 lobe configuration to maximize rotary speed for the assumed low WOB for slim-hole drilling, particularly with CT. The relationship between shaft diameter and speed is shown in Figure 5-45.

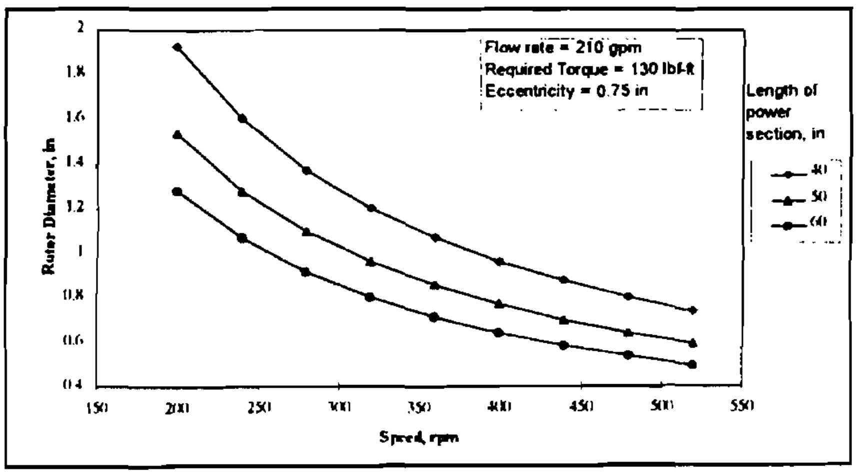


Figure 5-45. PDM Speed and Rotor Diameter
(Sanchez et al., 1996)

The results of a recent study on the feasibility of electric motors for CT drilling (conducted by CTES and sponsored by GRI) suggested that electric motors as small as 4¾ in. are feasible, running at 1200 to 3600 rpm. A gear box would probably be needed to lower bit rpm. Power output can be as great as 80 HP and torque as high as 160 ft-lb.

CT DRILLING CONSIDERATIONS AND BENEFITS

5.19 SCHLUMBERGER DOWELL (TECHNICAL AND ECONOMIC FEASIBILITY)

Schlumberger Dowell (Gary and Doremus, 1995) summarized the technical and economic factors involved in evaluating prospects for drilling with CT. Parameters that limit the feasibility include CT tension, buckling, collapse pressure, fatigue and standard hydraulic parameters. A procedure for assessing technical feasibility was mapped out (Figure 5-46). Other limitations may exist only because the required tools have not yet been developed.

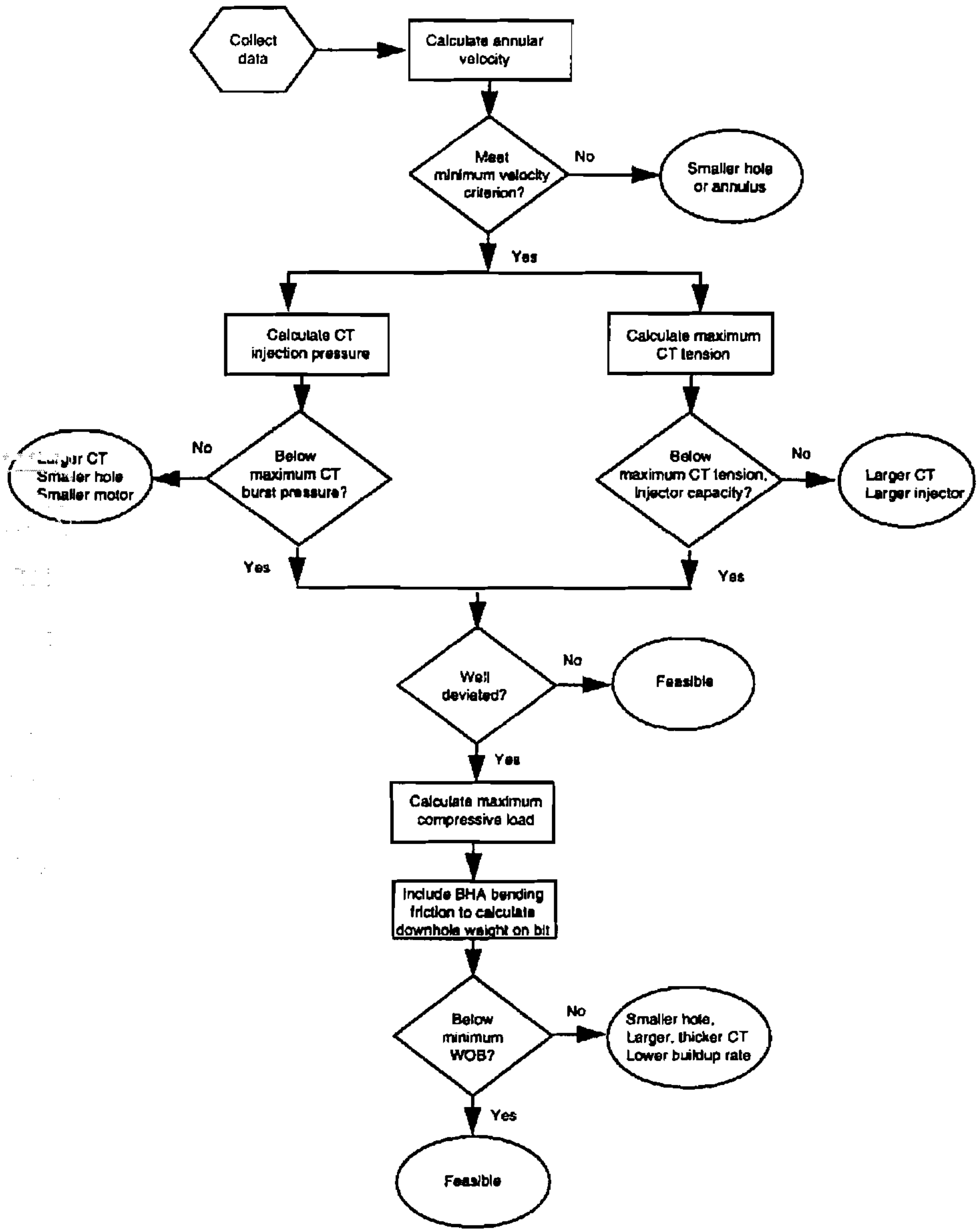


Figure 5-46. Flow Chart for Technical Feasibility
(Gary and Doremus, 1995)

CT drilling has been found to be suitable for several specific applications. Capabilities within each of these application types are summarized in Table 5-9.

TABLE 5-9. Technical Capabilities of CT Drilling (Gary and Doremus, 1995)

	Vertical	Deviated Horizontal Wells	
	New Shallow Wells/Deepenings	Conventional Reentry	Through-Tubing Reentry
Hole Diameter	. 12-1/4-in. hole and smaller. For holes larger than 6-3/4 in., formations need to be soft to be drilled with a 4-3/4 in. or a low torque 6-3/4-in. motor.	. Side tracks - 6 in. with BUR up to 15°/100 ft. - 4-3/4 in. and smaller with BUR up to 45°/100 ft. . Deepenings: 6 in. and smaller.	. 3-1/2 in. or 3-3/4 in. if through 4-1/2-in. tubing or larger hole size for larger tubing.
Total Depth	. Depends on the casing program and formation drillability.	. More than 10,000 ft.	. 15,000 ft
	. CT is limited to small and shallow wells: 5 to 6000 ft with only 3 or 4 casings.	. Horizontal drainhole can exceed 2000 ft but depends on BUR, KOD, casing ID, and CT size. A tubing force model is required to determine the feasibility.	. CTD is currently limited to 4-1/2 in. and larger tubing, because of the minimum OD of directional downhole tools. The maximum horizontal reach is determined using a tubing force model for conventional side tracks.
Limiting Parameters	. CT torque limits the motor size. . Pumping pressure limits the depth of the hole section larger than 4-3/4 in.	. Downhole WOB provided by the CT at the end of horizontal section, limits the horizontal drain length. . The BUR is limited by the BHA bending friction force which limits the downhole WOB available in the curve.	. Downhole WOB provided by the CT at the end of horizontal section, limits the horizontal drain length.
CT Size	. 2-3/8 in. for holes larger than 6-3/4 in. or for hole section larger than 4-3/4 in. and deeper than 5000 ft. . 1-1/2 in. can be used for holes smaller than 4 in. depending on the expected pumping pressure.	. 2 to 2-3/8 in. depending on the hole profile.	. 1-3/4 to 2-3/8 in. depending on the hole profile.

Economic feasibility is strongly impacted by the volume of CT drilling in a specific geographic area (Figure 5-47). Experience can significantly reduce personnel costs and equipment costs (perhaps through equipment purchase instead of rental).

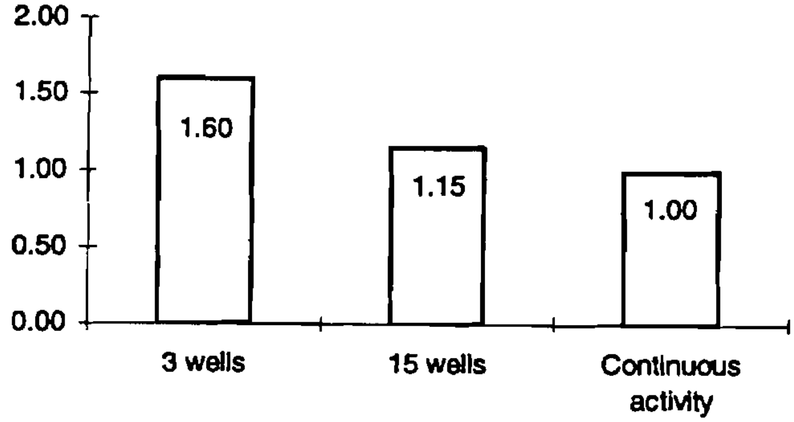


Figure 5-47. Costs and Experience (Gary and Doremus, 1995)

5.20 SCHLUMBERGER DOWELL (CUTTINGS TRANSPORT PROBLEMS)

Schlumberger Dowell (Leising and Walton, 1998) evaluated cuttings-transport problems and solutions for CT drilling. Cuttings transport is among the most significant problems remaining for CT drilling. Current solutions include fluid selection, flow rates, and special operational techniques (wiper trips and pumping viscous slugs).

They presented two novel approaches to understanding hole-cleaning problems. The first is applicable to laminar flow and involves considers the distance a cutting will travel up the annulus (the transport length) before it falls to the low side. The second approach is for turbulent flow, for which simple annular velocity is shown to be insufficient for characterizing hole cleaning. A parameter that includes the hydraulic diameter is developed and shown to be a more accurate predictor in turbulent flow.

CT drilling has undergone consistent growth (Figure 5-48). About one-fourth of these wells are drilled directionally (mostly horizontal). Cuttings transport remains a special problem in these applications.

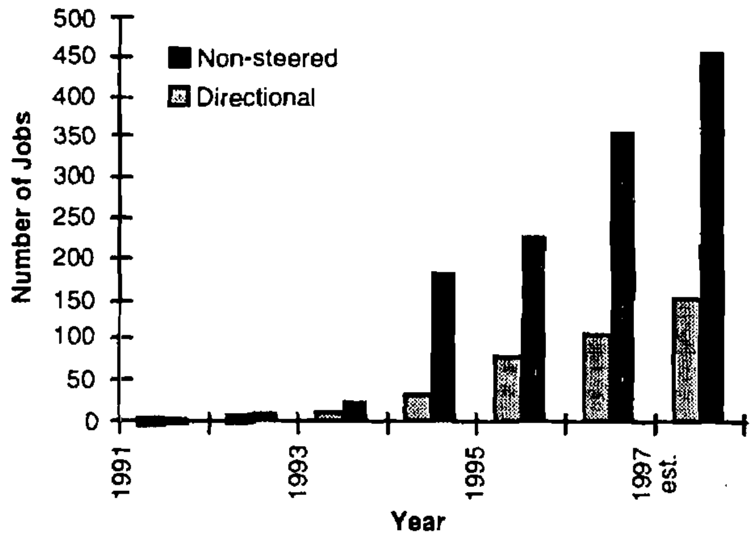


Figure 5-48. Growth in CT Drilling (Leising and Walton, 1998)

A thorough analysis of cuttings transport in laminar and turbulent flow was performed. Several important conclusions from their analysis are summarized in Figure 5-49, which illustrates that turbulent flow with sufficient turbulence and viscosity is the best combination for hole cleaning.

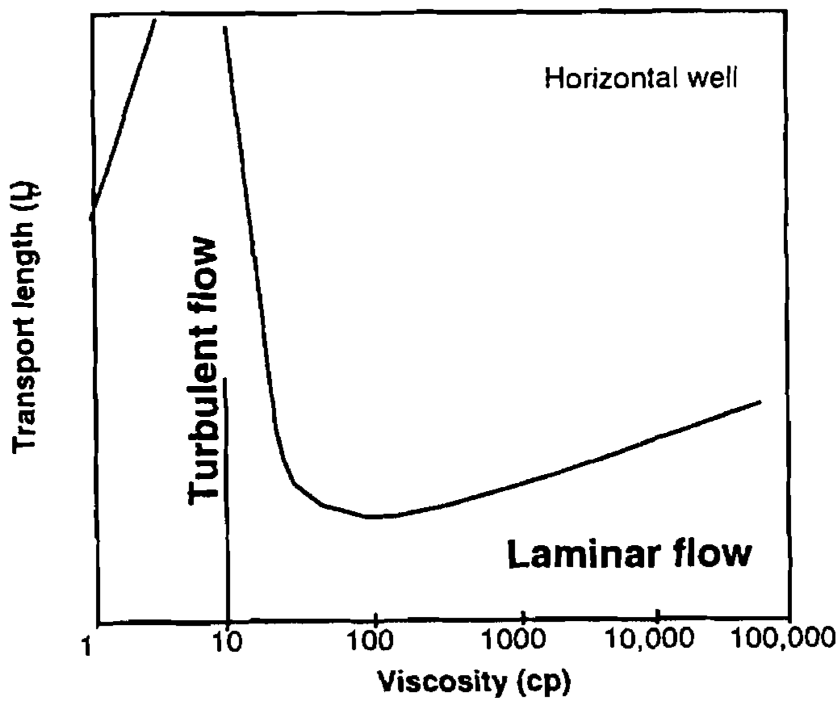


Figure 5-49. Cuttings Transport Length and Viscosity
(Leising and Walton, 1998)

Wiper trips can be an effective means to aid hole cleaning, if optimized. Typical trips for CT drilling are performed after 50-100 ft of drilling. The CT is normally POOH to just below the window. After the cuttings are stirred, they will fall back to the low side within some number of transport lengths (Figure 5-50). Once in a bed, only mechanical action of the BHA or turbulent flow can move the cuttings again.

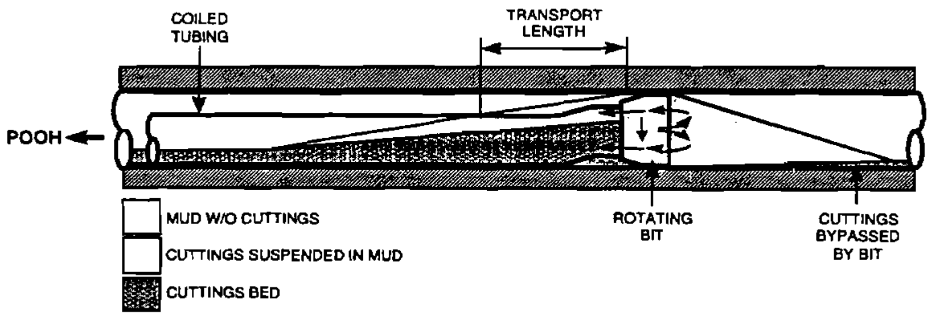


Figure 5-50. Cuttings Mixing When POOH
(Leising and Walton, 1998)

Schlumberger Dowell recommends turbulent flow as the best solution for hole-cleaning problems. As a second line of defense, wiper trips can be designed and optimized. This often means using fewer short trips and muds with lower viscosity.

In addition to detailed theoretical analyses, Schlumberger Dowell also presented three case histories illustrating different techniques to solving hole-cleaning problems. Readers are directed to their paper for more details.

CT DRILL BITS

5.21 HYCALOG (SLIM BIT SELECTION)

Hycalog (Feiner, 1995) summarized major concerns for bit selection with respect to slim-hole operations on drill pipe and CT. PDC, TSP, natural diamond, and roller-cone bits are all used in slim-hole drilling. Technical constraints at smaller diameters have lead to design modifications and adjustments to operating practices.

Lithological description is key in the initial steps of bit selection. After this type of data is analyzed, other constraints guide bit selection. Due to larger proportions of hydraulic horsepower being consumed by frictional pressure losses, less power is generally available to drive the bit, with correspondingly smaller ratios of HHP/inch^2. Torque may also need to be carefully limited due to relative weaknesses in drillstring elements.

Identifying the best bit type is the next step. Natural- and synthetic-diamond bits, roller cone, and combination bits have each proven the best choice in particular situations. Basic advantages of these bit types are compared in Table 5-10.

TABLE 5-10. Features of Slim Bits (Feiner, 1995)

Small Diameter Bits	Advantages	Disadvantages
Roller cone bits	Lowest torque requirements. Can drill most formation types. Can drill out shoes. Adjustable hydraulics.	Moving parts can fail. High weight on bit. Limited sizes available. Long lead times for new sizes.
Natural diamond	Low torque. Can be manufactured to any size quickly. Drill harder, more abrasive formations. Long life.	Fixed total flow area. Can easily ball in soft formations. Slow ROP. High weight on bit.
TSP	Normally faster ROPs than natural diamonds. Require less WOB than natural diamonds. Can be manufactured to any size quickly. Lower torque response than PDC bits.	Shorter drilling life than natural diamonds. May have shorter life due to inadequate cooling. Fixed total flow area. Has balling potential.
Combination ND and TSP	More impact resistant than natural diamonds. Can drill a greater variety of formations than natural diamonds or TSP bits alone. Can be manufactured to any size.	Slower ROPs than PDC bits. Fixed total flow area. Has balling potential.
PDC	Can produce high ROPs. Needs least weight for drilling. Adjustable hydraulics. Design flexibility. Shorter manufacturing time.	Highest torque. Limited drill out capabilities of float equipment.

Slim PDC bits require the least WOB and can typically drill faster and longer than other bit types. Their design parameters are also quite flexible. Reliability of slim PDC bits is also good. Disadvantages of PDCs for slim applications include the highest torque generated of any bit type.

Natural-diamond bits generate low torque. These bits have been used in build sections drilled on CT as a conservative approach to maintain directional control. However, if hydraulics change following a trip, diamond bits cannot be reconfigured at the rig.

TSP (thermally stable) bits allow a compromise between PDC and natural diamonds. ROP with TSP bits is faster than with natural diamonds, and less torque is generated than with PDC bits. As another approach to decrease limitations, combination TSP/natural-diamond bits have been successfully used in slim holes (Figure 5-51).

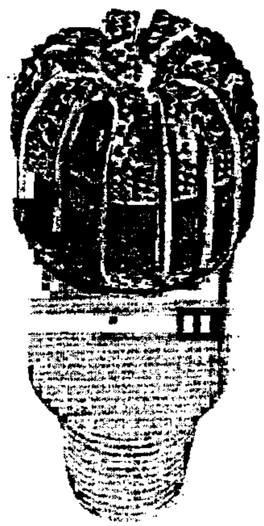


Figure 5-51. Combination TSP/Natural-Diamond Slim Bit (Feiner, 1995)

In one application in the Austin Chalk, the formation was first identified as able to be drilled with a PDC bit. A 4¾-in. lateral section was drilled with a PDC bit with 8-mm cutters. The bit drilled 4584 ft at over 25 ft/hr, amounting to a world-record run.

5.22 SMITH INTERNATIONAL (PDC BITS)

Smith International Inc. (Mensa-Wilmot, 1995) summarized considerations for using PDC bits for CT drilling. The usage of CT equipment for drilling operations is still relatively small (Figure 5-52), but the percentage continues to increase slowly. PDC bits have an inherent advantage for CT drilling in that they operate effectively with lower bit weights. Their primary disadvantage is that high torque is generally generated. However, improved designs have gone a great distance toward resolving this problem for CT operations.

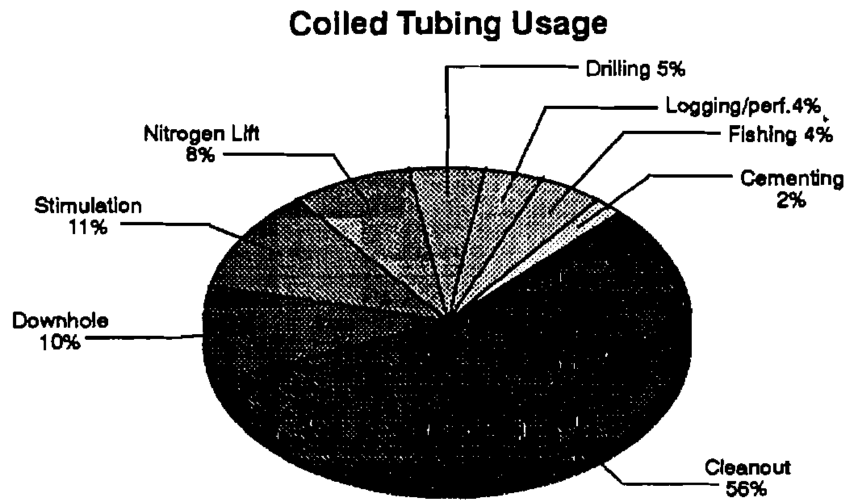


Figure 5-52. Distribution of CT Jobs (Mensa-Wilmot, 1995)

Proper bit selection is based on understanding the energy requirements and formation removal mechanisms for specific drilling applications. The general limitations of CT drilling are also key in establishing component compatibility. These limitations include the requirement for efficient ROP response to limited WOB, low torque response to increasing WOB, consistent torque response over time, and suitable TFA match to hydraulic limitations of CT.

Energy supplied to rotate a PDC bit falls into two general categories: drilling and vibratory. CT drilling efficiency can be greatly improved by reducing vibration tendency. Several features can be incorporated into a bit to reduce vibration (whirl). A stable PDC bit can exhibit a linear relationship between ROP and WOB, and be very effective for CT drilling.

In general, motor manufacturers specify operating torque be about half stall torque (safety factor of 2). Stable bits can be operated with a lower safety factor closer to the stall torque than might otherwise be feasible.

TFA (total flow area of bit nozzles) is considered differently with CT drilling. Total system pressure drop does not increase as significantly as the hole is deepened because the fluid always travels through the entire length of tubing. The pressure drops of various components are linked to the maximum standpipe pressure from the start of the operation.

5.23 APACHE CANADA AND FRACMASTER (DEEP UNDERPRESSURED GAS WELL)

Apache Canada and Canadian Fracmaster (McGregor et al., 1997) described results drilling a gas well with CT in a deep underpressured reservoir. This well was the deepest CT well in Canada at 2572 m TVD (8440 ft). A rotary rig drilled the curve to 90°. CT underbalanced drilling was used to drill 368 m of 4¾-in. hole including two sidetracks. Production from the formation averaged 5-6 MMscfd during drilling operations.

Underbalanced conditions were maintained once productive reservoir was encountered (Figure 5-53). Downhole remained relatively constant without pressure cycling that is more characteristic of underbalanced drilling with conventional jointed pipe.

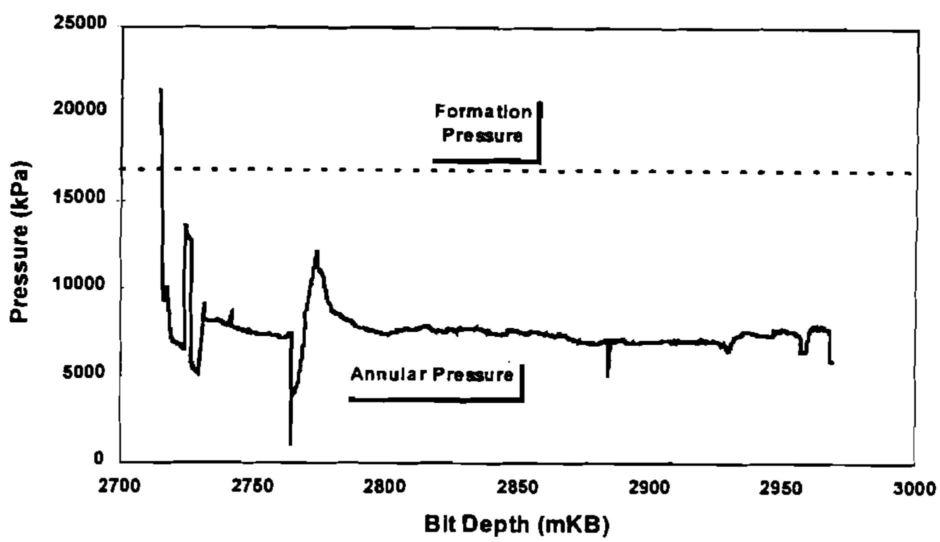


Figure 5-53. Annular Pressure While Drilling (McGregor et al., 1997)

In three of the wells, pressure deployment was required. Times to deploy improved throughout the campaign (Figure 5-54). Faster times were due to drilling and wireline crews becoming more familiar with procedures and equipment. Deployment times of 6-8 hours are expected for future operations.

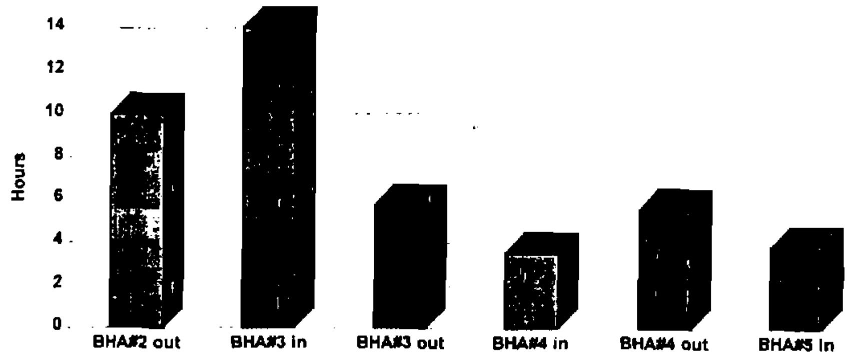


Figure 5-54. CT BHA Deployment Times (McGregor et al., 1997)

Two spools of CT were available for drilling: one 2⅜ and one 2⅞ inches. The larger string was preferred due to more WOB, stiffness, higher annular velocity, and lower pump pressure. WOB is compared in Figure 5-55 for the two strings. Significantly more WOB is predicted for the 2⅞-in. string, which should result in improved ROP.

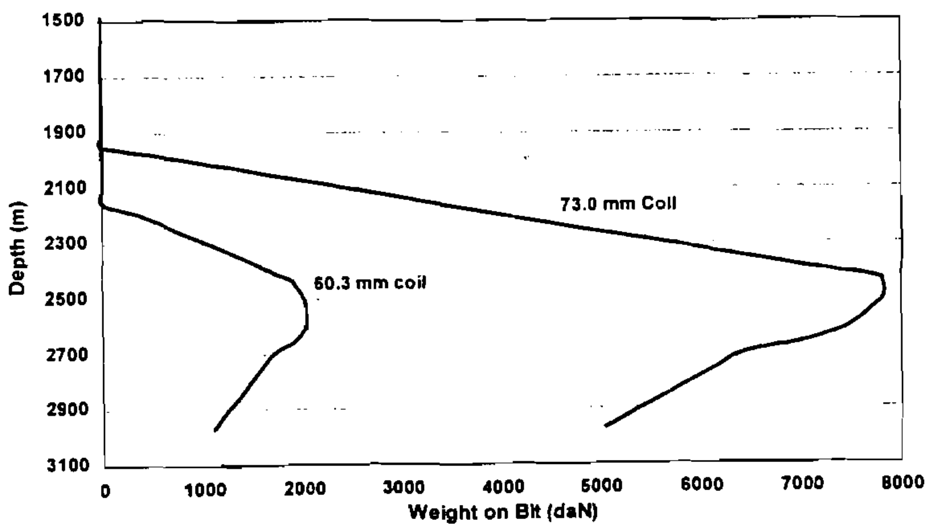


Figure 5-55. Available WOB with 2⅜- and 2⅞-in. CT
(McGregor et al., 1997)

Apache Canada found that results for this well established CT drilling as an excellent option for drilling deep underpressured gas reservoirs.

5.24 BP NORGE AND SCHLUMBERGER DOWELL (ULA FIELD)

BP Norge and Schlumberger Dowell (Weighill et al., 1996) used CT to deepen a well underbalanced in the Ula Field in the central North Sea. The deepening operation was performed simultaneously with other platform activity, and the drilling returns were routed to platform facilities.

A 7-in. liner was across the Jurassic reservoir. The drilling plan was to clean debris from the well, drill through the cement, and deepen the well by 100 m. The well flow would provide the underbalance and lift the cuttings (Figure 5-56). Commingled returns would be sent to the platform test separator.

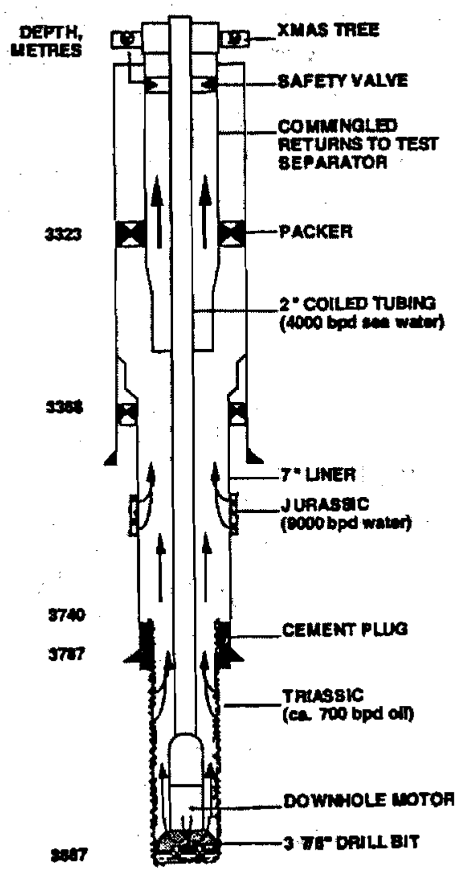


Figure 5-56. CT Drilling Configuration (Weighill et al., 1996)

The drilling BHA was 50 m in length, and included a 3⅞-in. bit, motor, double check valves, 2⅞-in. drill collars, bleed-off sub and connector to the 2-in. CT string. A pressure-deployment system was needed due to height limitations. The injector and riser (Figure 5-57) were removed and a wireline lubricator used to deploy the BHA.

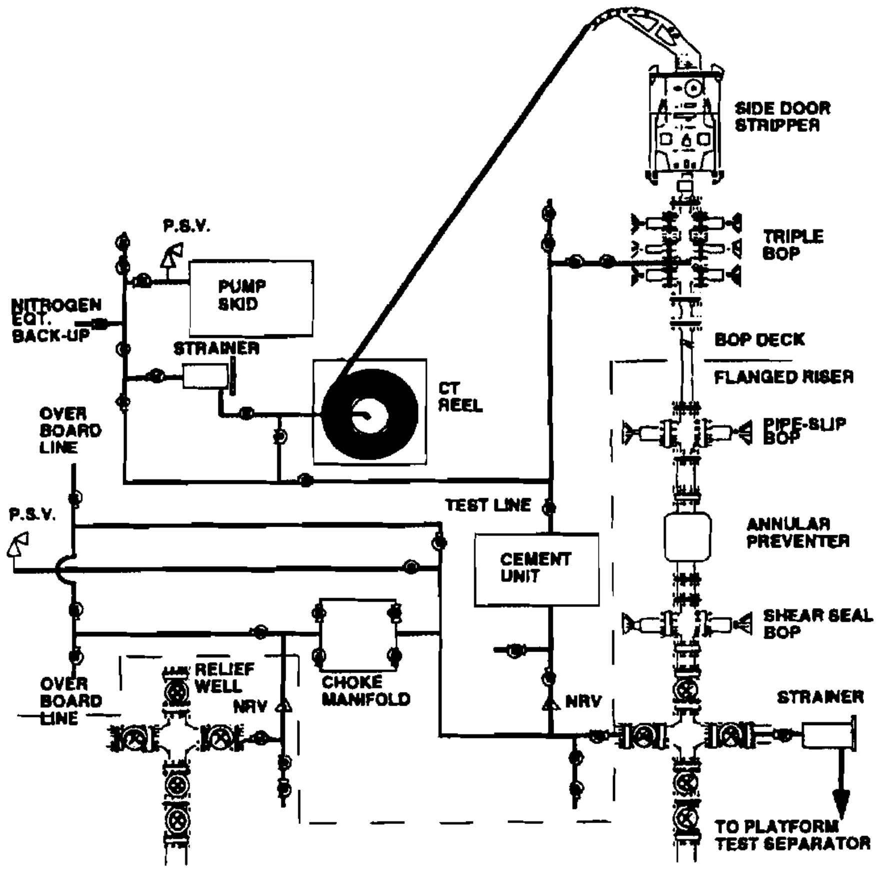


Figure 5-57. CT Drilling Equipment (Weighill et al., 1996)

The successful attempt at CT drilling was completed in 30 days (24 days planned). Extra days were due to clean-up runs and waiting while other work on the platform was completed. Drilling was 7% of the total time (Figure 5-58). Tripping and deployment consumed about 50% of the time.

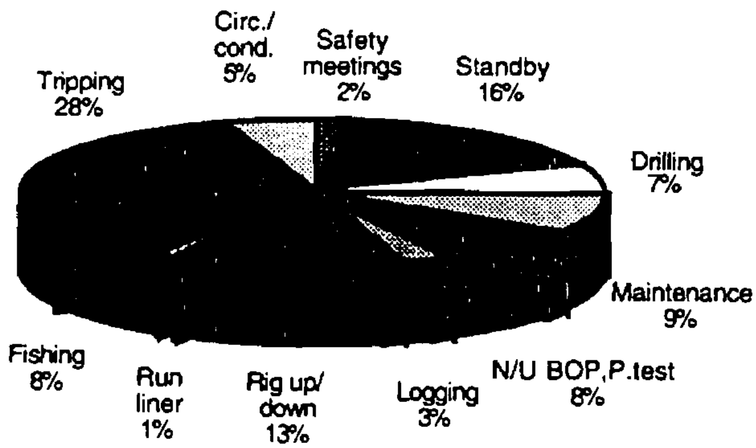


Figure 5-58. CT Drilling Time Distribution (Weighill et al., 1996)

Despite the problems, cost savings for the operation were about 25%, as compared to pulling the tubing and drilling conventionally. Additional cost savings are expected on future operations.

5.25 CANADIAN FRACMASTER (CT DRILLING FOR UNDERBALANCED GAS WELLS)

Canadian Fracmaster (Graham, 1995) described the successes of underbalanced drilling with CT. Costs and times were analyzed and operational procedures summarized for many wells. Most applications have been limited to 5½- and 4½-in. casing using 2-in. CT.

The effective cost for drilling with CT and hanging production tubing in these wells is compared to conventional in Figure 5-59.

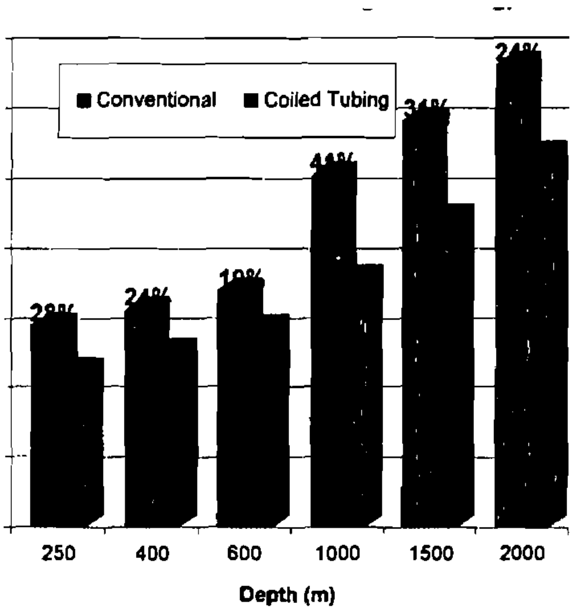


Figure 5-59. Costs for Drilling and Hanging Tubing
(Graham, 1995)

The effective time for drilling with CT and hanging production tubing in these wells is compared to conventional in Figure 5-60.

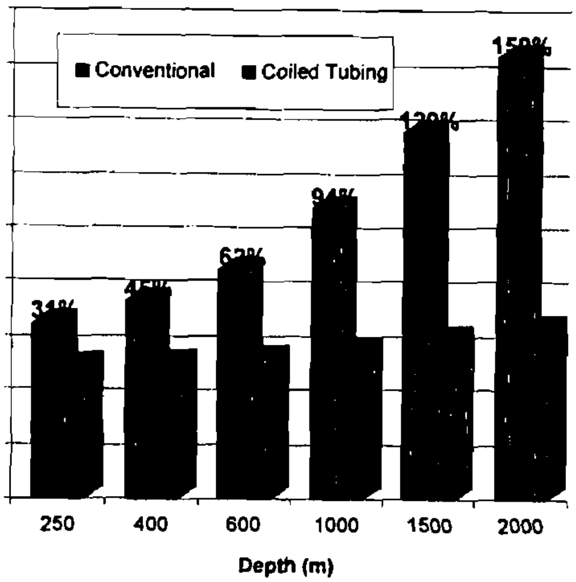


Figure 5-60. Times for Drilling and Hanging Tubing
(Graham, 1995)

Most layouts have taken the form of nitrogen with a blooie line, nitrogen with a test separator (Figure 5-61), or air with a blooie line.

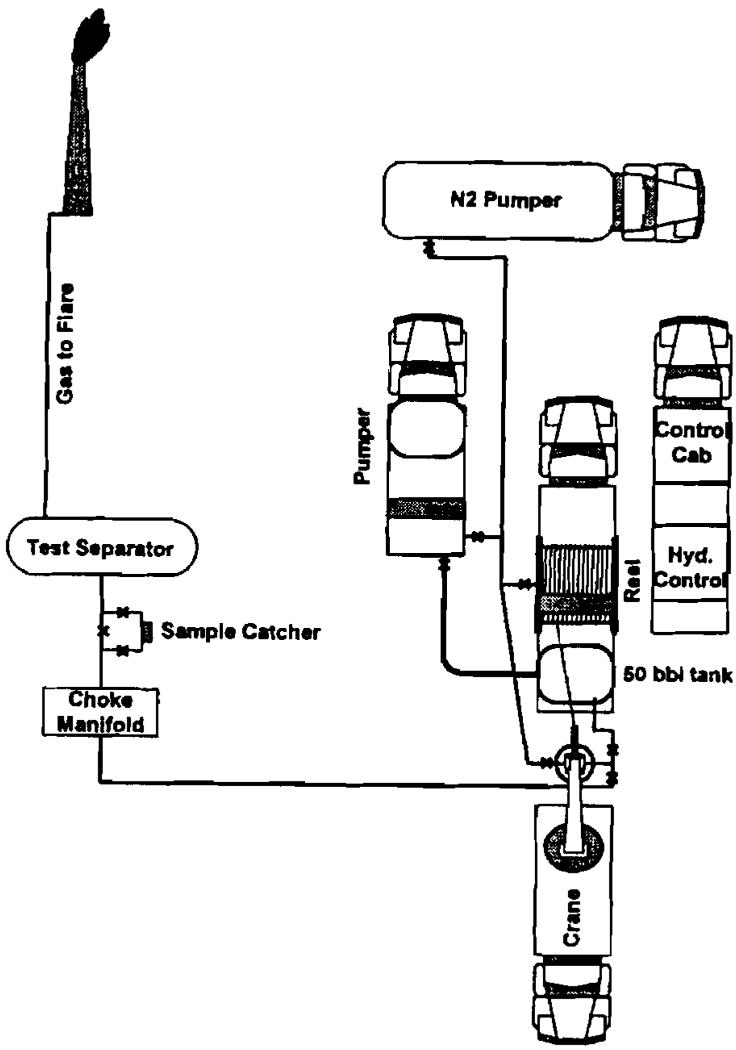


Figure 5-61. CT Drilling Site for N_2/Test Separator (Graham, 1995)

Over 90% of the CT underbalanced drilling operations have been completed without downhole or drillstring failures.

5.26 CANADIAN FRACMASTER (CT DRILLING SOUR GAS CARBONATE)

Canadian Fracmaster (Cox, 1996) reviewed the underbalanced CT drilling operation of a 2300-m TVD sour gas carbonate formation in Central Alberta. This well was a horizontal extension of a new well in the Crossfield formation. They analyzed problems and concerns with hole cleaning, wellbore stability, motor performance at low liquid rates, and recirculation of sour liquids as part of the drilling fluid.

The CT BHA (Figure 5-62) included a downhole pressure sub. Wireline was used for the steering tool and dual capillary tubes controlled the bidirectional orienting tool.

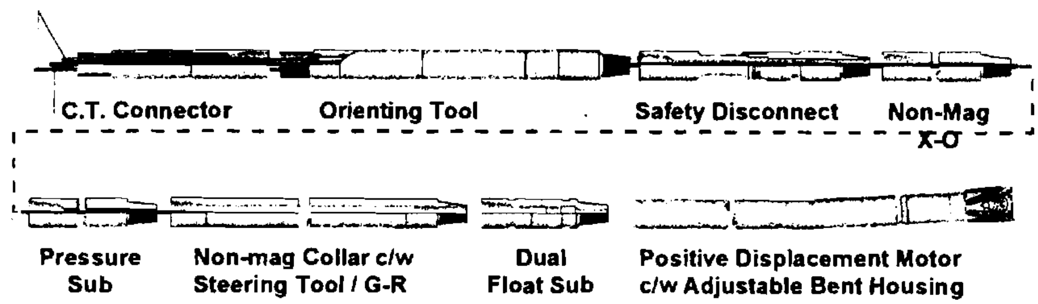


Figure 5-62. CT Drilling BHA (Cox, 1997)

Stalling occurred frequently early in the drilling operation. Peaks in tubing pressure may be used as indicators of stalling, but are not effective with high N_2 ratios. An effective indicator was found to be vibration amplitude (peak g readings). Peak g's with various fluid rates are shown in Figure 5-63. Increased liquid rates controlled vibration to a large extent. Vibration was most stable for an overbalanced drilling phase (at 2515 m MD) and least stable during mist drilling (distillate at 1 l/min).

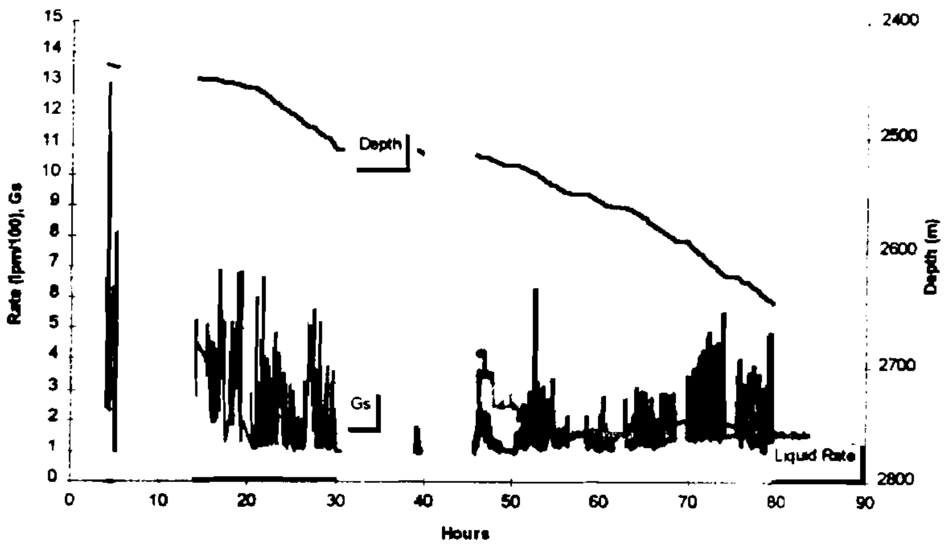


Figure 5-63. Liquid Injection Rate and BHA Vibrations (Cox, 1997)

Canadian Fracmaster found that drilling with high gas ratio fluids or mist can result in excessive vibration and potential damage to the steering tool. Vibrations can be minimized by increasing liquid ratios in the drilling fluid.

Monitoring peak-g vibration readings can help optimize drilling performance by indicating when the BHA is between the stall point and the damage threshold for downhole tools. Hole cleaning was found to be difficult with mist drilling in a horizontal well, requiring more frequent wiper trips.

5.27 CRESTAR ENERGY AND FRACMASTER (CT UNDERBALANCED COSTS)

Crestar Energy and Canadian Fracmaster (Borbely et al., 1997) summarized results of an analysis of costs and effectiveness of drilling underbalanced with CT for five horizontal wells in Southeast Alberta. Operational factors and costs were compared across the project. All drilling objectives were met. Two of the wells (in the Jenner pool) were drilled on budget; the other three (Majorville pool) were drilled 15% under budget.

Rotary rigs were used to drill the curves and set casing to 90°. CT rigs were then used to drill the horizontal sections underbalanced. ROPs for CT drilling are compared in Figure 5-64.

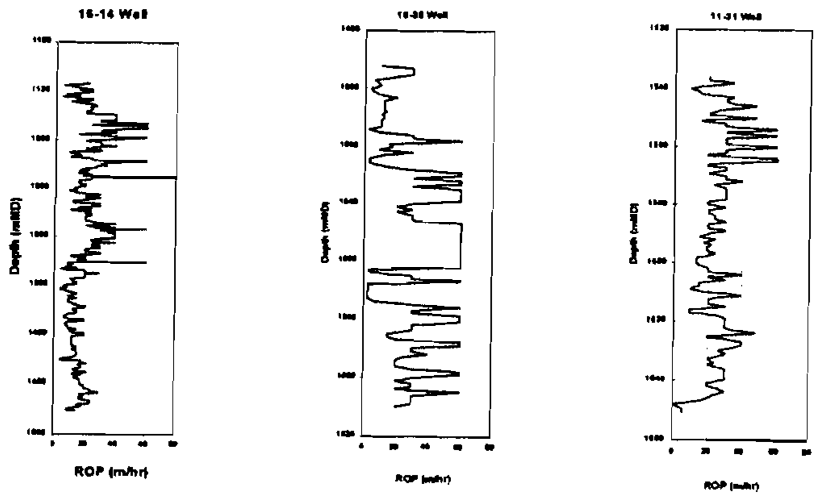


Figure 5-64. Example ROPs (Borbely et al., 1997)

The time distribution for the entire five-well project (Figure 5-65) illustrates that equipment reliability needs to be improved (15% total time for repairs), although this was not unexpected with new and still-developing technology.

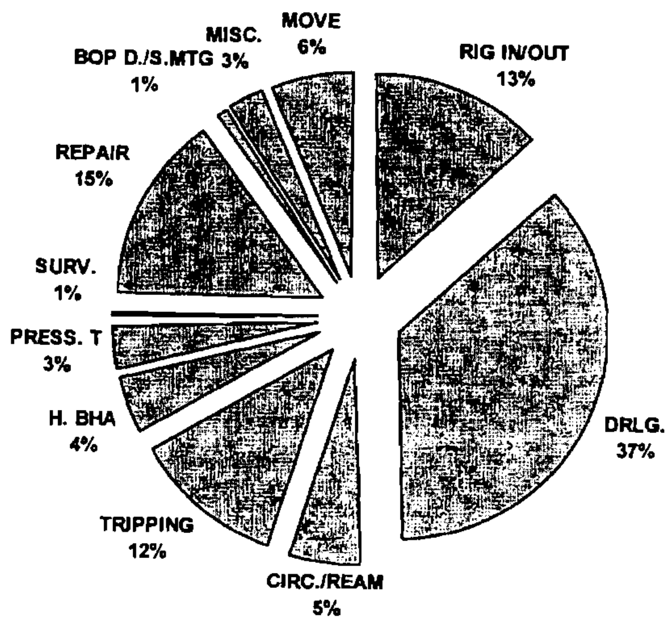


Figure 5-65. Operational Times of Five Wells
(Borbely et al., 1997)

The time/depth curves (Figure 5-66) shows nonproductive repair time for several of the wells. At the other end of the spectrum, well 11-31 was rigged up, drilled 119 m horizontally, and rigged down in less than 48 hrs.

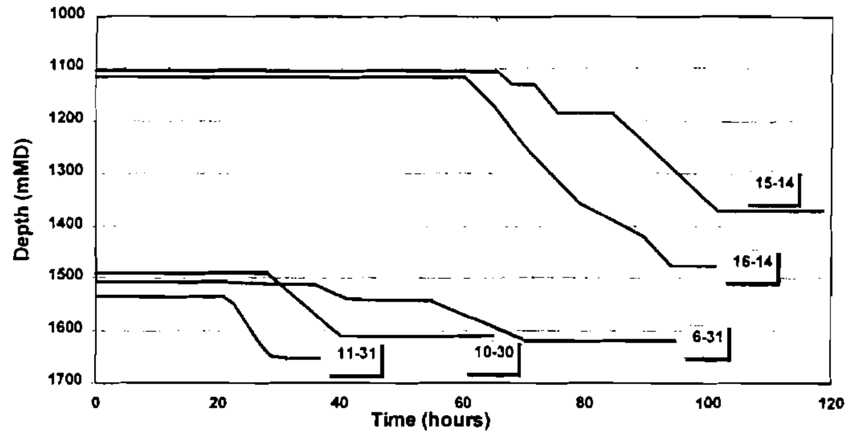


Figure 5-66. Time/Depth Curves (Borbely et al., 1997)

5.28 FLEXTUBE (CT DRILLING WITH AIR)

Flextube (Groves, 1995) discussed the evolution of CT drilling with air. Over 50 wells were deepened with CT and air in 1994 by Matrix/Flextube and Canadian Fracmaster. Depths ranged from 220 to 640 m. Generally, 2⅞-in. motors were run with 3⅞-in. tricone bits. A typical well-control BOP rig-up is shown in Figure 5-67 for air drilling.

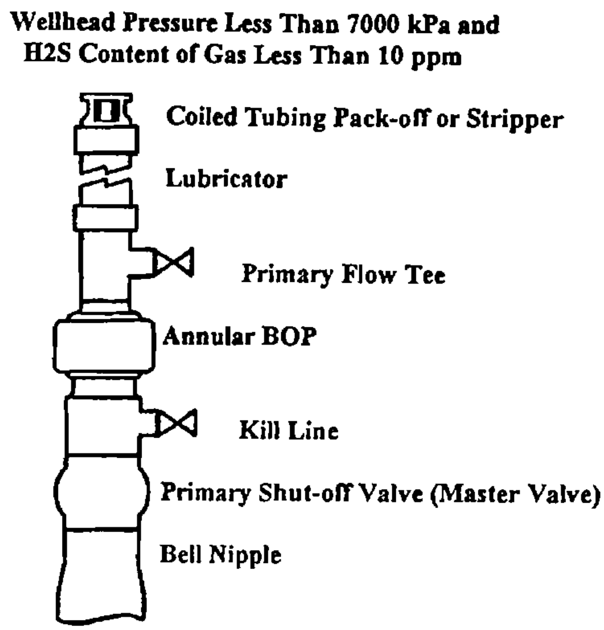


Figure 5-67. BOP for CT Air Drilling (Groves, 1995)

Air rates used in these jobs ranged from 320 to 775 scfm. Water/soap rates ranged from 5 to 40 l/min. The best performance with respect to hole cleaning and ROP seemed to be achieved with 17-19 m^3/min air and 5-10 l/min liquid. ROP ranged from 1 to 120 m/hr.

5.29 MOBIL OIL CANADA AND FRACMASTER (DRILLING WITH LARGE CT)

Mobil Oil Canada and Canadian Fracmaster (Elsborg et al., 1996) presented an analysis of the use of larger CT (2⅜ and 2⅞ inches) for drilling larger holes (up to 6¼ inches). CT and underbalanced drilling have proven of great benefit in the Glauconite "A" Field in southern Alberta. A significant reduction in formation damage is enjoyed by maintaining underbalanced conditions 100% of the time while drilling. Differential sticking is also reduced.

Two case studies were analyzed. Large CT (2⅞ in.) was used to drill 6⅛-in. hole out of 7-in. casing. The BHA (Figure 5-68) included non-magnetic collars and a bidirectional orienting tool.

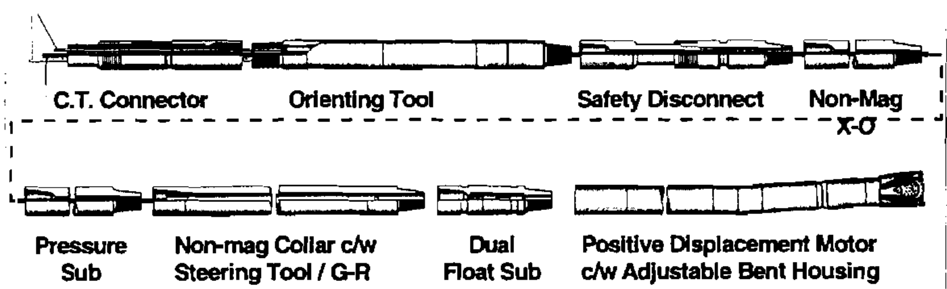


Figure 5-68. CT Drilling BHA (Elsborg et al., 1996)

Pressure data recorded by a downhole sub (Figure 5-69) showed that the entire horizontal section was drilled underbalanced with a BHP of near 5600 kPa (812 psi) as compared to an estimated wellbore pressure of 6000 kPa (870 psi). Over 100 m^3 of oil was produced while drilling the 235-m (770 ft) horizontal section.

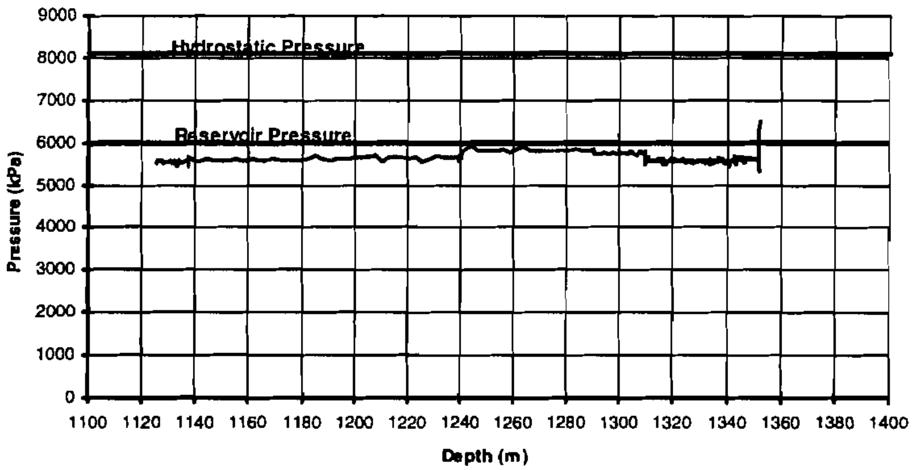


Figure 5-69. Downhole Pressure Data (Elsborg et al., 1996)

Two 6⅛-in. wells (one underbalanced and one overbalanced) and two 4¾-in. wells from an adjacent field were compared with respect to costs (Figure 5-70). It was noted that Taber N 16-2, the most costly case, was drilled during winter conditions; the other three were under more favorable summer conditions.

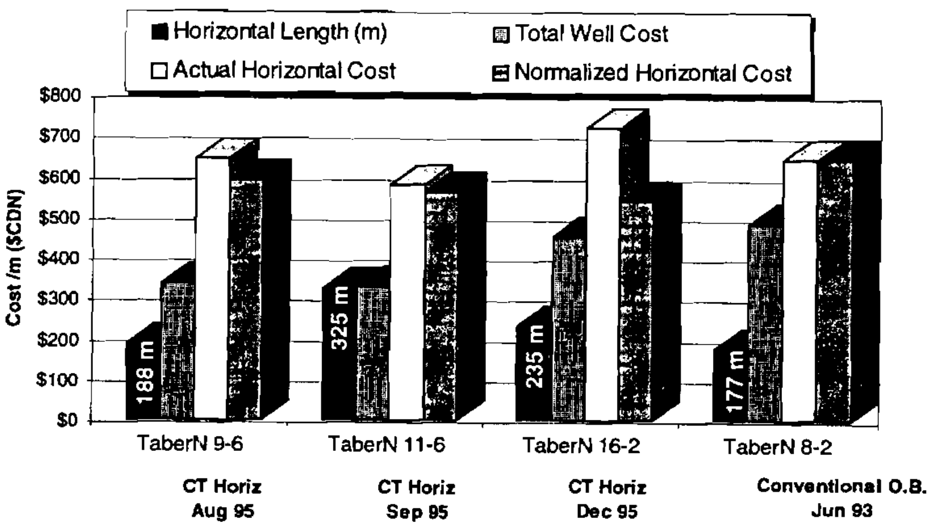


Figure 5-70. Cost Analysis of CT Drilling (Elsborg et al., 1996)

Mobil Canada found that, while there is room for much optimization in equipment and procedures, applying underbalanced drilling to the Glauconite pool yielded excellent results.

5.30 MOBIL OIL CANADA AND FRACMASTER (HIGH ROP DRILLING)

Mobil Oil Canada and Canadian Fracmaster (Elsborg et al., 1996) performed an analysis in the field with an objective of determining the highest ROP that can be attained with underbalanced CT drilling. Four wells were drilled with CT in the Glauconite formation in Alberta. ROPs up to 60 m/hr (197 ft/hr) were attained for sustained periods of drilling. Although high-rate drilling has obvious economic advantages, other complexities must be dealt with, such as directional steering capability and hole-cleaning effectiveness.

CT drilling costs are highly impacted by ROP (Figure 5-71). These data are for a typical Glauconite oil well in Southeast Alberta. The most important variable costs are rig day rate and nitrogen volumes, both of which are highly dependent on ROP.

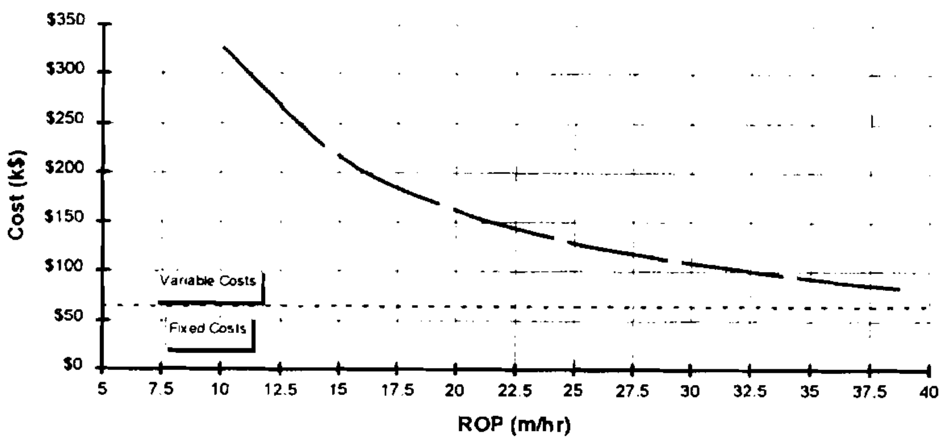


Figure 5-71. CT Underbalanced Drilling Costs and ROP
(Elsborg et al., 1996)

Hole-cleaning concerns can greatly decrease ROP. Wiper trips are a common strategy to assist hole cleaning. Typical wiper trips take 30 to 90 minutes, thereby slowing ROP and increasing day costs.

True and effective ROPs for these four CT underbalanced wells are compared in Figure 5-72. Only well 15-2 was drilled without wiper trips, so that true and effective ROP are equal for this case.

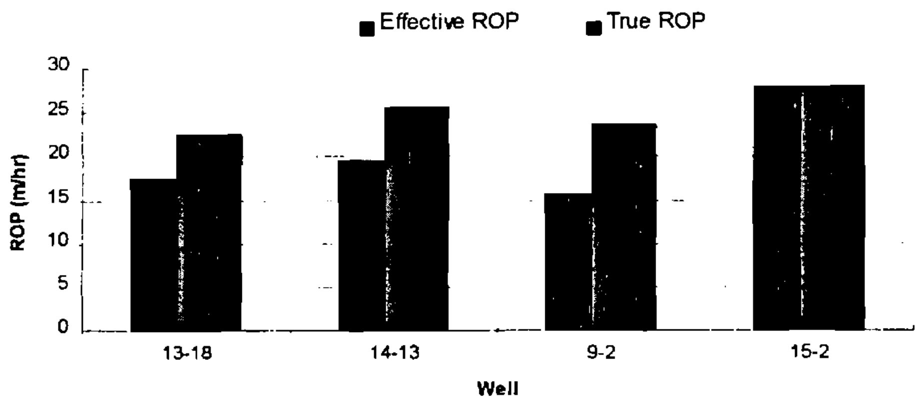


Figure 5-72. True and Effective ROP (Elsborg et al., 1996)

The long-term trend in ROP and costs for CT underbalanced wells in this area shows an overall decrease in costs and an increase in ROP (Figure 5-73). The impact of technological developments and optimization in drilling practices is evident in this graph.

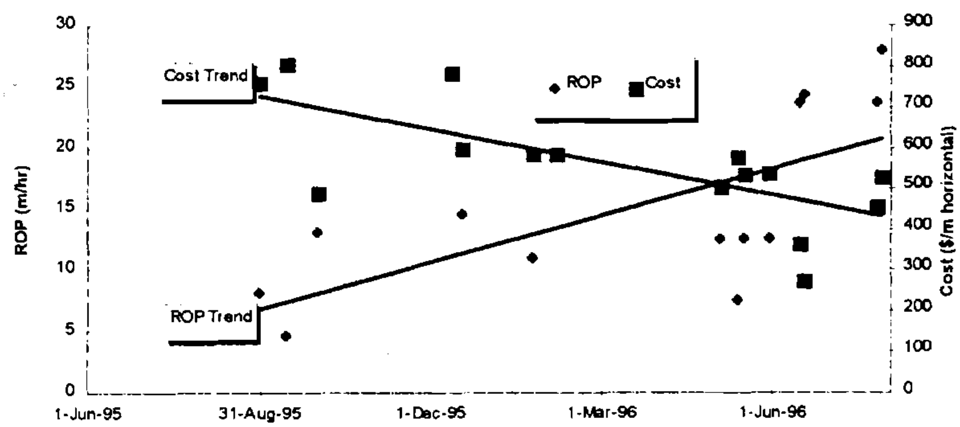


Figure 5-73. Trends in ROP and Drilling Costs (Elsborg et al., 1996)

High-ROP drilling with CT was found to be feasible. They also concluded that build rates should be as tight as possible (15-20°/30 m).

5.31 NAM (SIDETRACK OF DALEN 2)

Nederlandse Aardolie Maatschappij (Adam and Berry, 1995) provided a detailed account of planning, contracting, and field operations for drilling an underbalanced CT sidetrack in the Dalen sour gas field in the Netherlands. Underbalanced drilling with CT was shown to be an attractive approach for avoiding probelms with previously standard overbalanced drilling. There were a variety of problems with this first effort with CT, but great potential was demonstrated for this application.

The drilling plan (Figure 5-74) called for abandoning the lower section of the original vertical well, sidetracking to the top of the reservoir, cementing a liner (both with a workover rig), and finally drilling a 3¾-in. hole through the reservoir (underbalanced with CT).

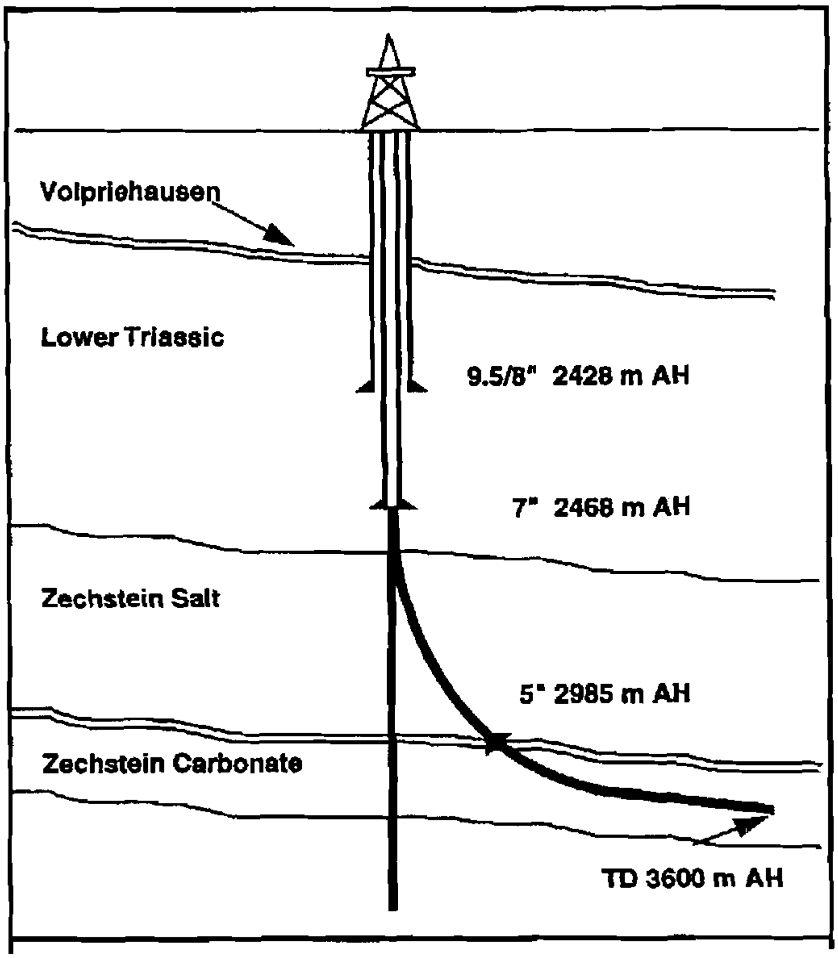
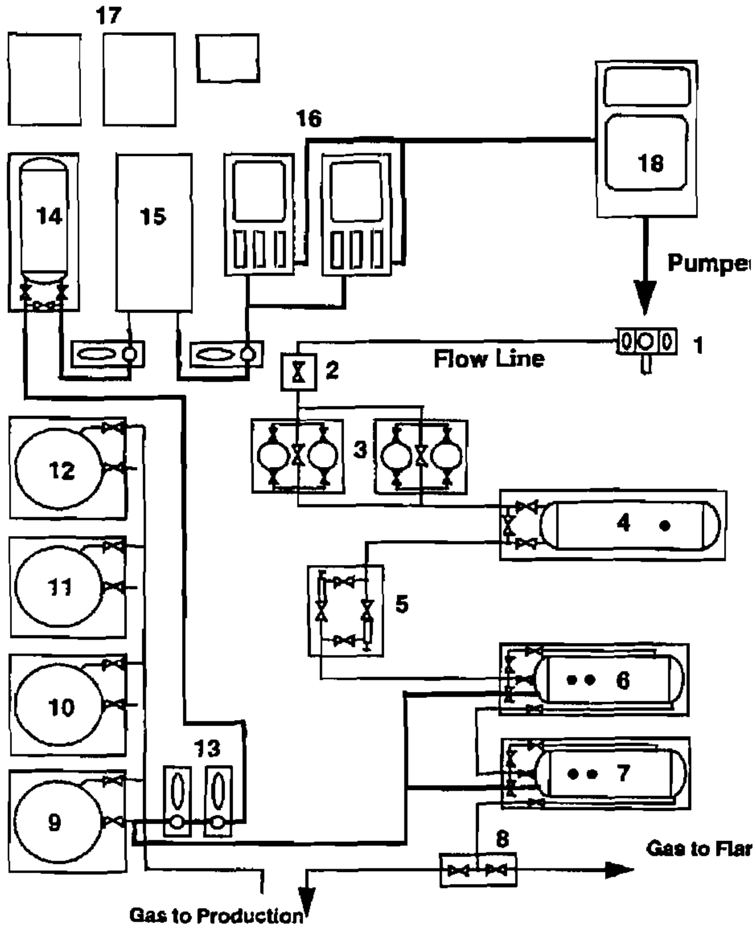


Figure 5-74. Planned Sidetrack of Dalen 2 (Adam and Berry, 1995)

Surface equipment layout at the site is shown in Figure 5-75.



1	**Wellhead**	10	**Condensate Surge Tank**
2	**ESD Hydraulic Safety Valve**	11	**Viscous Pill Surge Tank**
3	**Sand Filters and Catchers**	12	**Cuttings Tank**
4	**Heat Exchanger**	13	**Transfer Pumps**
5	**Choke Manifold**	14	**Settlement / Degassing Tank**
6	**Separator**	15	**Drilling Fluid Suction Tank**
7	**Knock-out Vessel**	16	**Mud Pumps**
8	**Gas Manifold**	17	**Drilling Fluid Storage & Mixing**
9	**Drilling Fluid Surge Tank**	18	**Coiled Tubing Unit**

Figure 5-75. Site Layout (Adam and Berry, 1995)

NAM provided a long discussion on the problems of the project and the valuable lessons for future efforts. Problems with the orienting tool were significant and the well was terminated far short of the planned length. The level of underbalance was easily controlled. High ROPs were demonstrated under underbalanced conditions (18 m/hr as compared to 2-3 m/hr for conventional overbalanced conditions).

5.32 PETROLEUM DEVELOPMENT OMAN (15-WELL CAMPAIGN)

Petroleum Development Oman (Surewaard et al., 1997) summarized results from a 15-well CT drilling campaign conducted in several Oman fields. About 800 of Oman's 2000 wells had been identified as candidates for re-entry with CT. PDO originally conducted a three-well campaign in 1994 to demonstrate basic technical feasibility of CT drilling. The second larger campaign was conducted in 1996 and 1997 (Figure 5-76) to demonstrate economic competitiveness with a conventional rig for sidetracking, and to demonstrate technical feasibility of short-radius, through-tubing, multilateral, and underbalanced drilling. They concluded that conventional sidetracks do not yet present an attractive application for CT drilling in PDO. Underbalanced through-tubing applications, however, were very successful and will be the focus in the future.

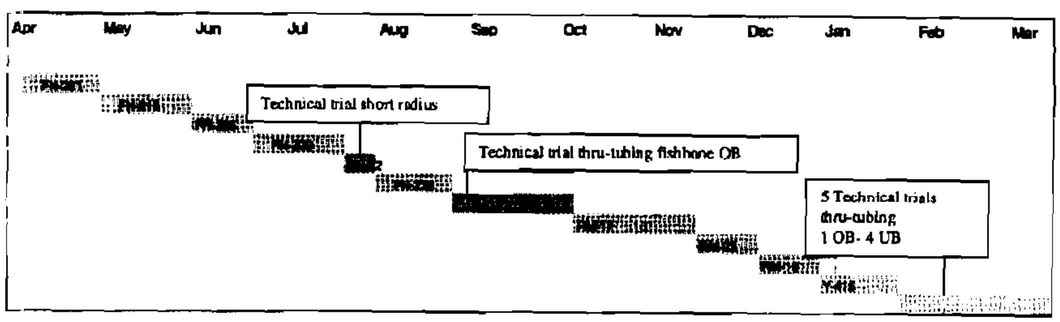


Figure 5-76. PDO CT Drilling Trials 1996-97 (Surewaard et al., 1997)

Overbalanced drilling was performed in five wells in the Fahud Field. The costs of these medium-radius horizontal re-entries was about 45% above conventional. The primary reasons for the higher costs were cited: 1) lack of commitment and skills of contractor, 2) specialized equipment not fit for purpose, and 3) poor selection of well candidates.

Another six CT wells were drilled in the Yibal Field. Four of the six were drilled underbalanced to demonstrate the improvements with this approach. Sidetracks were drilled out of existing horizontal liners. All CT holes were 3¾ in. out of 4½-in. completions.

A full package of test equipment was added to the CT underbalanced surface equipment (Figure 5-77). In addition to the normal closed-loop three-phase separator, a main solids filtration unit was included and found essential for solids removal to protect the BHA components.

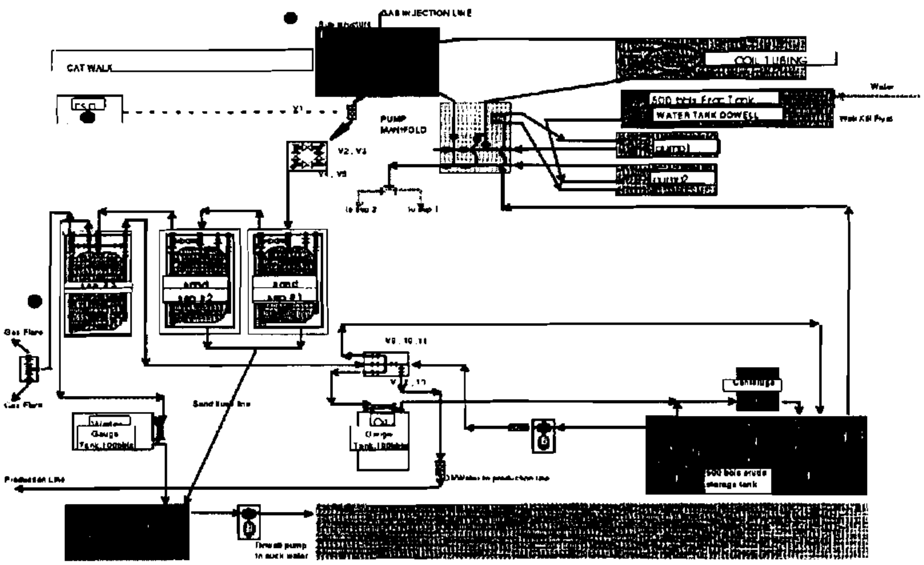


Figure 5-77. Surface Equipment for Underbalanced Drilling
(Surewaard et al., 1997)

A telling comparison is shown in Figure 5-78 between Yibal well Y-437 (which was drilled overbalanced) and well Y-199 (which was drilled underbalanced). Both are multilateral wells which were drilled through tubing. Significantly higher ROP for the underbalanced well (between 25 to 75 m/hr) reduced times dramatically for that case, as compared to a CT overbalanced drilling operation.

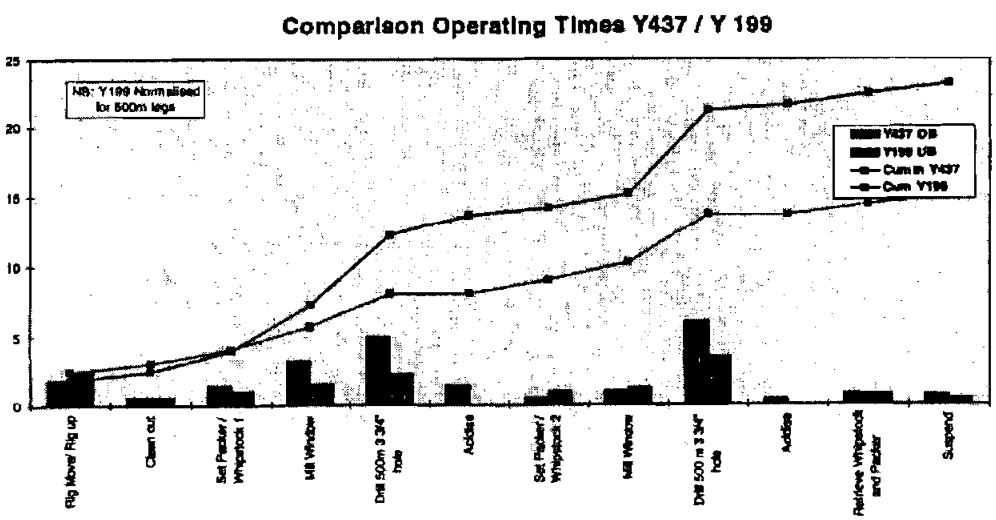


Figure 5-78. Time Distribution for CT Over/Underbalanced Wells
(Surewaard et al., 1997)

Early production results suggests that production rate is improved in the underbalanced wells, but has not yet been fully quantified based on offset data.

5.33 SHELL CANADA, DOWELL, NORTHLAND (HOUSE MT. SIDETRACK)

Shell Canada, Schlumberger Dowell, and Northland (Milligan et al., 1996) drilled the first horizontal section with CT in the House Mountain Field in Alberta. Large 2⅜-in. CT was used to drill underbalanced with nitrified water. ROPs were up to three times faster with underbalanced drilling.

The project used a combination rig approach, with a conventional rig used for window milling out of the existing 4½-in. casing and drilling the curve. CT was then rigged up to drill the horizontal section underbalanced.

A closed production control system was used to handle cuttings for underbalanced drilling (Figure 5-79). A special separator was used that could handle a gas flow rate of 45 MMscfd and a liquid rate of 25,000 BPD.

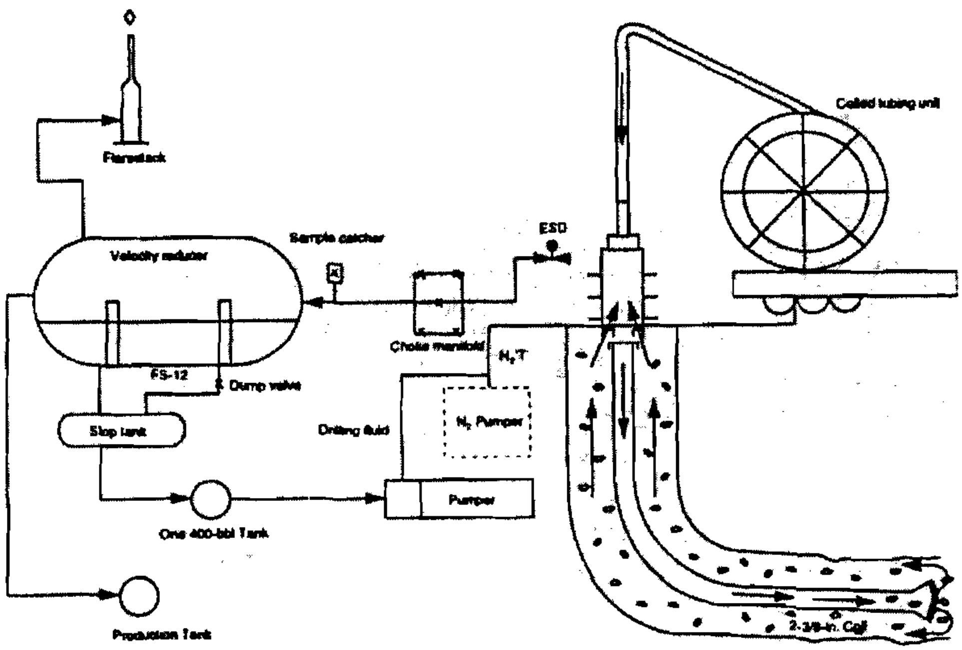


Figure 5-79. Closed Circulation System (Milligan et al., 1996)

The drilling BHA for the horizontal section is shown in Figure 5-80.

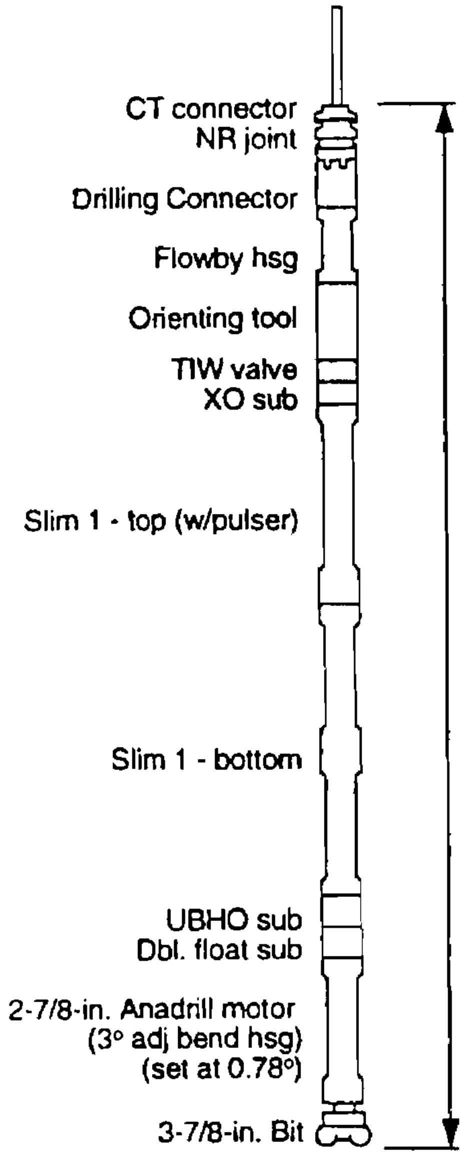


Figure 5-80. Drilling BHA
(Milligan et al., 1996)

The team found that no unusual problems were associated with underbalanced drilling. However, careful planning was a necessity. Bit orientation using mud-pulse telemetry was also effective. Circulating pressures were kept low, saving fatigue life of the CT string.

Fast trip times with CT contributed to the overall cost reduction. The time distribution for the 290-m (950-ft) horizontal section is shown in Figure 5-81.

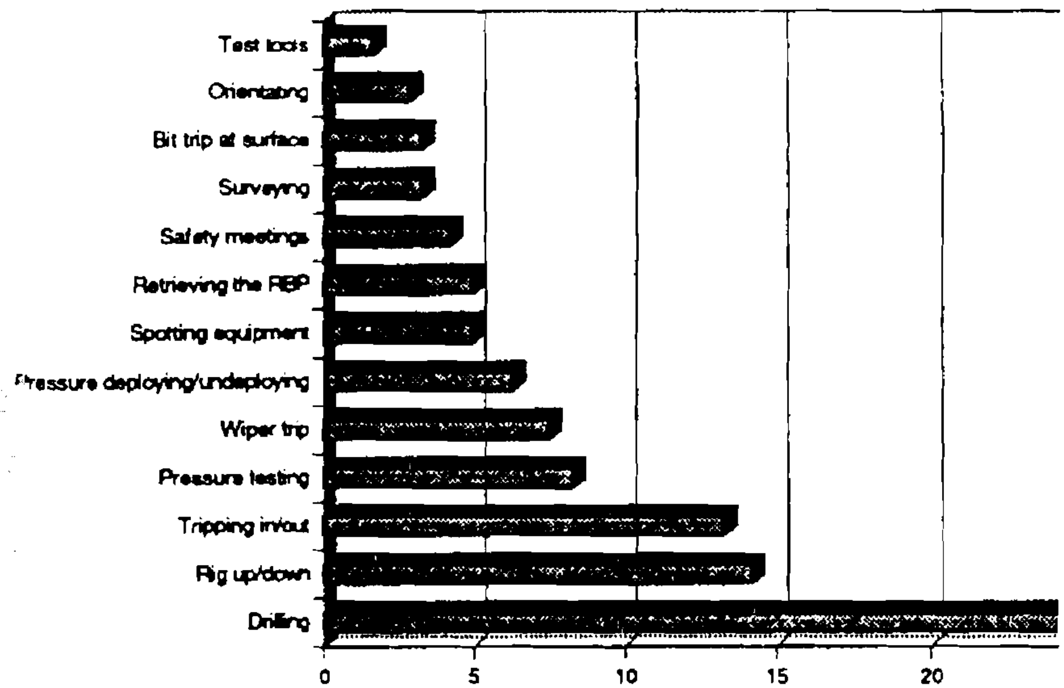


Figure 5-81. Time Distribution for CT Drilling (Milligan et al., 1996)

5.34 ARCO ALASKA AND DOWELL (CT DRILLING PRACTICES AT PRUDHOE BAY)

ARCO Alaska and Schlumberger Dowell (Goodrich et al., 1996) summarized general practices for CT drilling operations at Prudhoe Bay. Drilling with CT has included simple extensions through liners to horizontal sidetracks through tubing (Figure 5-82). MDs greater than 13,000 ft have been achieved with 3¾-in. bits on 2-in. CT. Less aggressive PDC bits are used to reduce stalling. ROPs average 10-20 ft/hr in shale and 30-70 ft/hr in sand. Weight transfer and hole cleaning have been improved through the use of low-solids polymer drilling mud to drill overbalanced.

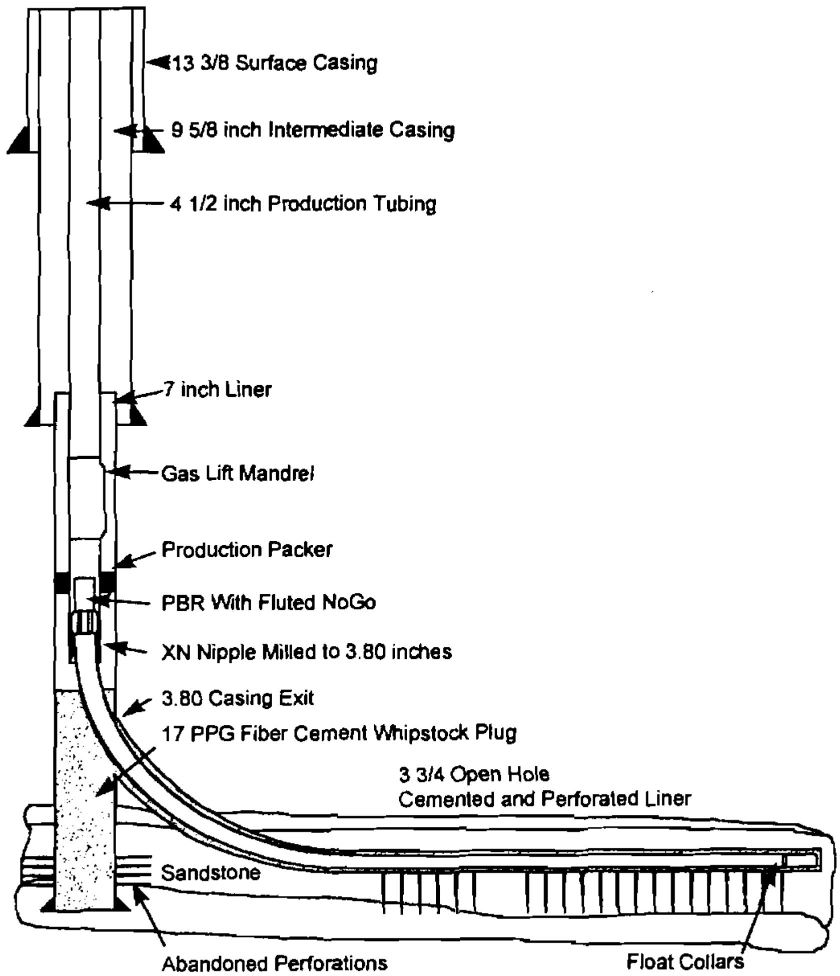


Figure 5-82. Typical CT Drilling Completion (Goodrich et al., 1996)

CT drilling operations at Prudhoe Bay combine a well service rig and a CT rig (Figure 5-83). This approach provides an effective all-weather platform for re-entries and completion operations.

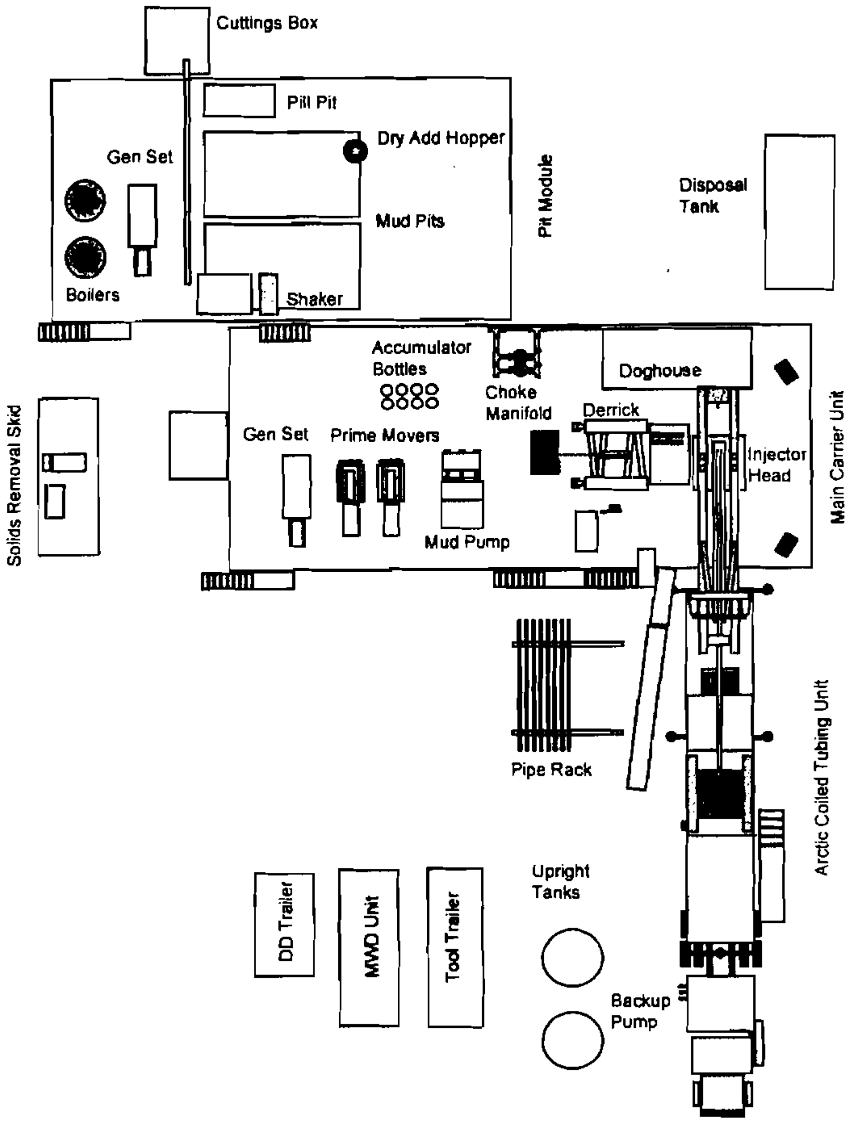


Figure 5-83. Typical CT Drilling Site (Goodrich et al., 1996)

A typical CT drilling BHA (Figure 5-84) is about 50 ft in length. These components may be combined in various ways for different operations.

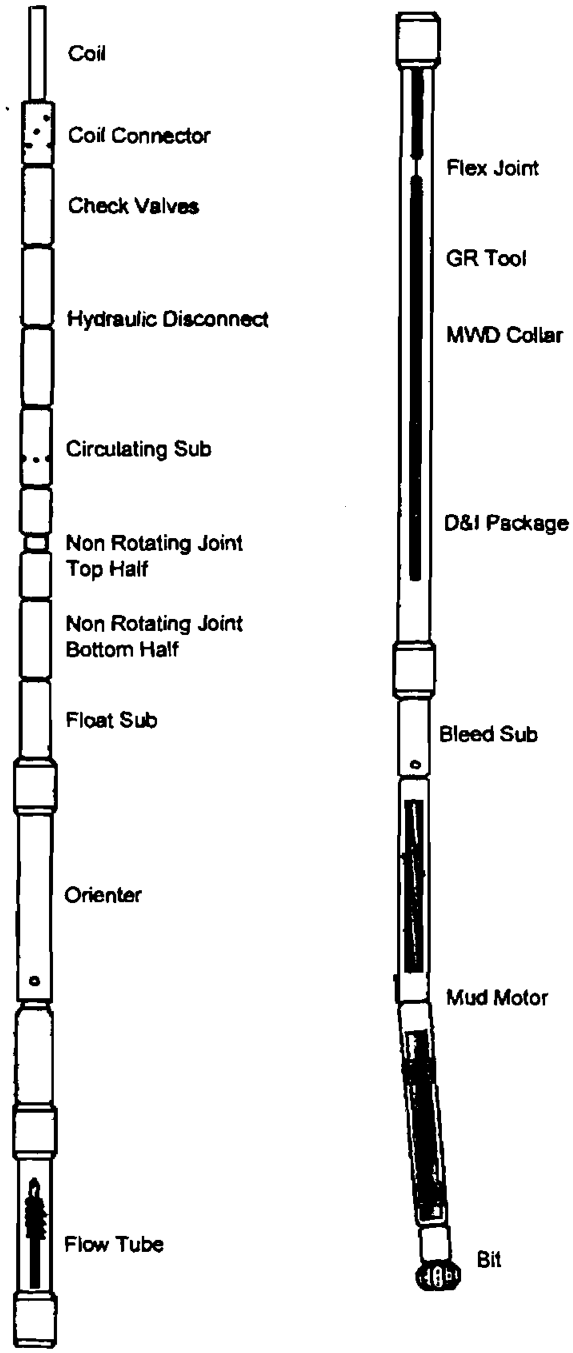


Figure 5-84. Typical CT Drilling BHA

CT drilling of new hole is performed overbalanced with a solids-free premium grade xanthan biopolymer system.

Sidetracking with CT costs about 40% less than rotary sidetracks. The economic advantage is in eliminating the cost of pulling/running or purchasing production tubing and completion equipment.

5.35 ARCO E&P (SUMMARY OF CT DRILLING EXPERIENCE)

ARCO Exploration & Production Technology (Hightower, 1997) summarized their experience drilling wells with CT in Texas, California, New Mexico and Alaska. ARCO has drilled about 70 wells, and has enjoyed overall success rates of 90% (mechanical) and 85% (economic).

Significant CT drilling activity has been ongoing and will continue into the foreseeable future at Prudhoe Bay (Figure 5-85).

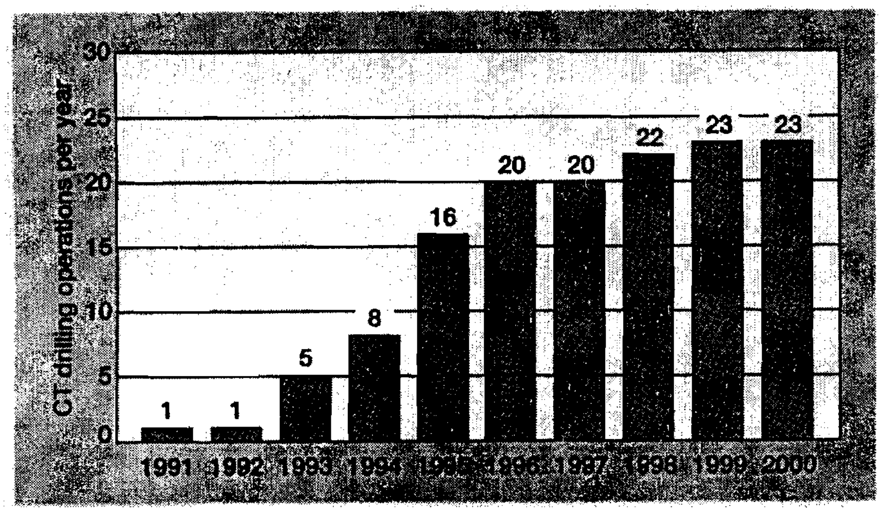


Figure 5-85. CT Drilling at Prudhoe Bay (Hightower, 1997)

Both major operators at Prudhoe Bay (ARCO and BPX) are using hybrid rigs that combine small arctic workover units with CT rigs (Figure 5-86). These hybrid systems can readily run jointed pipe as required. A third hybrid unit should be fabricated in 1998.

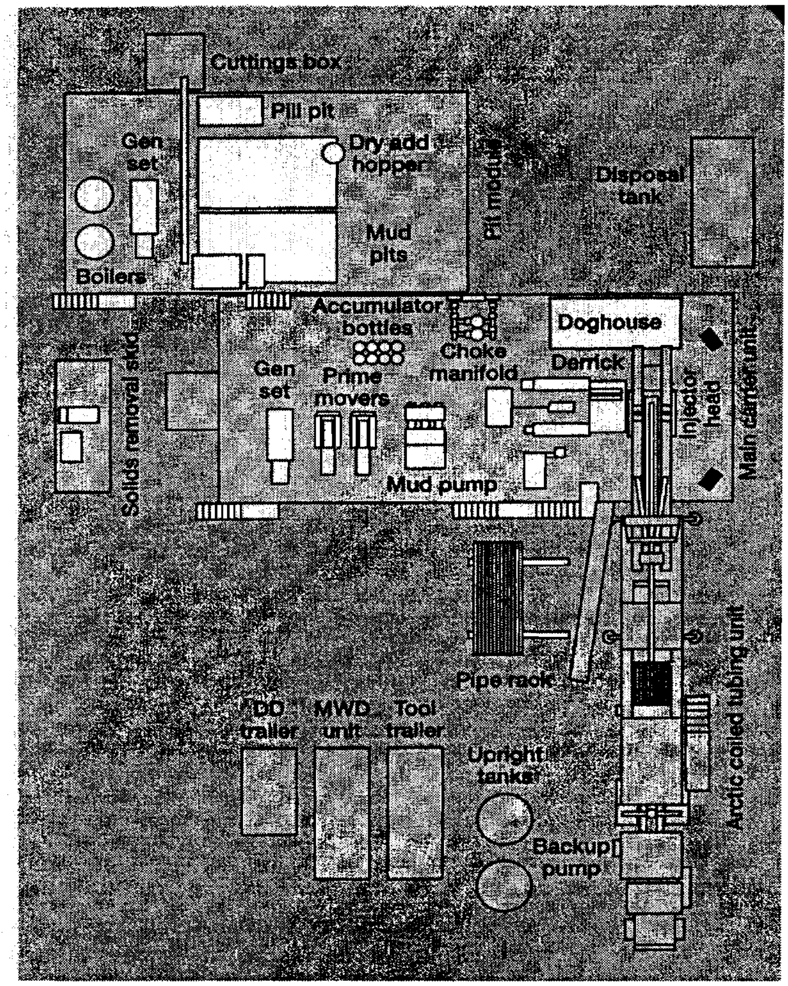


Figure 5-86. Hybrid Rig for Arctic Operations
(Hightower, 1997)

Most CT drilling jobs have run $2\frac{7}{8}$-in. BHAs on 2- or $2\frac{3}{8}$-in. CT. A low-solids, low shear-rate polymer drilling fluid is normally used at an overbalance of 200-300 psi.

Windows have been cut through 7 and $9\frac{5}{8}$-in. casing. Sidetracks with horizontal sections of up to 2300 ft have been drilled (Figure 5-87).

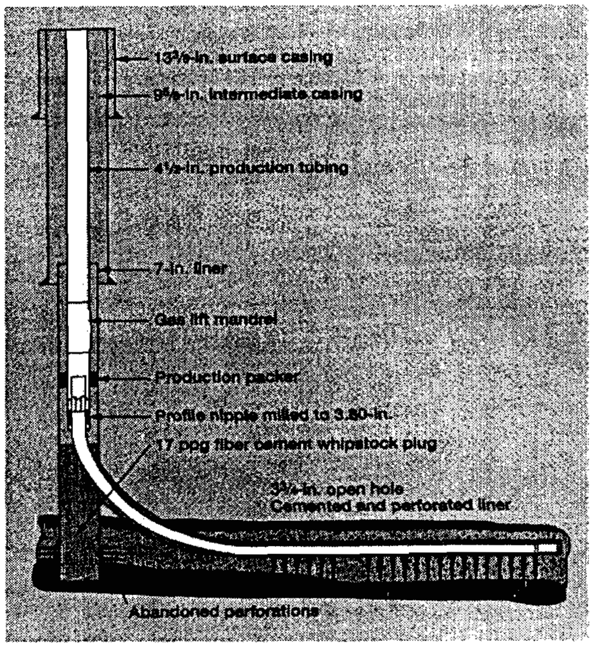


Figure 5-87. Typical CT Sidetrack at Prudhoe Bay (Hightower, 1997)

Tools and techniques have improved significantly since the CT drilling program was begun. A current cost distribution is shown in Figure 5-88 for Prudhoe Bay. ARCO noted that well costs have decreased despite the fact that re-entry candidates have become progressively more difficult.

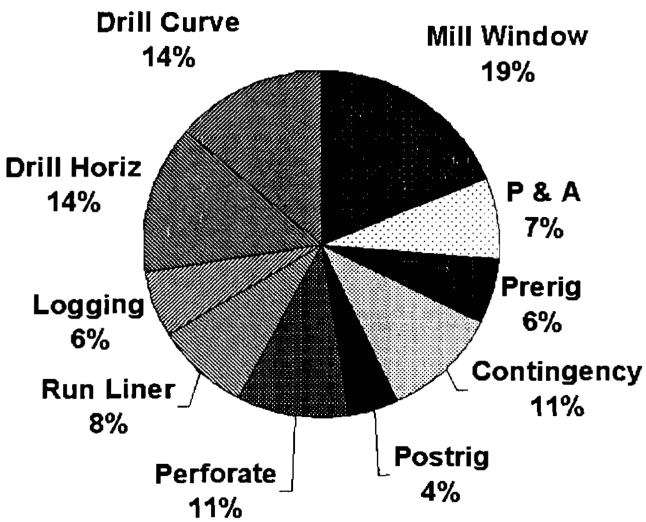


Figure 5-88. Cost Distribution for CT Drilling at Prudhoe Bay (Hightower, 1997)

About 60% of the CT wells are sidetracks; 40% are extensions (deepenings).

5.36 BEB, INTEQ AND NOWSCO (BARENBURG RE-ENTRY)

BEB Erdgas & Erdöl GmbH, Baker Hughes INTEQ and Nowsco UK Ltd. (Eide et al., 1995) performed a successful horizontal re-entry in a shallow, depleted, water-flooded reservoir in Northern Germany. The entire project was completed using a CT rig and without intervention from a conventional drilling rig or workover rig. CT systems were used to mill the window, drill the curve, run the curve liner, fish for a lost BHA, drill the horizontal section at balanced conditions, log the hole, and run production tubulars. The capabilities of CT drilling were extended significantly through developments made during this project. These developments included a special support structure positioned over the well to support the injector and serve as a work platform.

The support structure (Figure 5-89) constructed for use with the CT drilling system has a design load capacity of 55 tonnes (61 tons). The platform is large enough to allow the CT injector to be slid off to one side of the wellhead. A successful horizontal re-entry was drilled in the low-pressure Barenburg field. A 5⅞-in. window was cut through both 6⅝- and 9⅝-in. casing (Figure 5-90). Hole-cleaning problems slowed ROP in the curve. The BHA was lost during one wiper trip. Fortunately, the fish was successfully recovered.

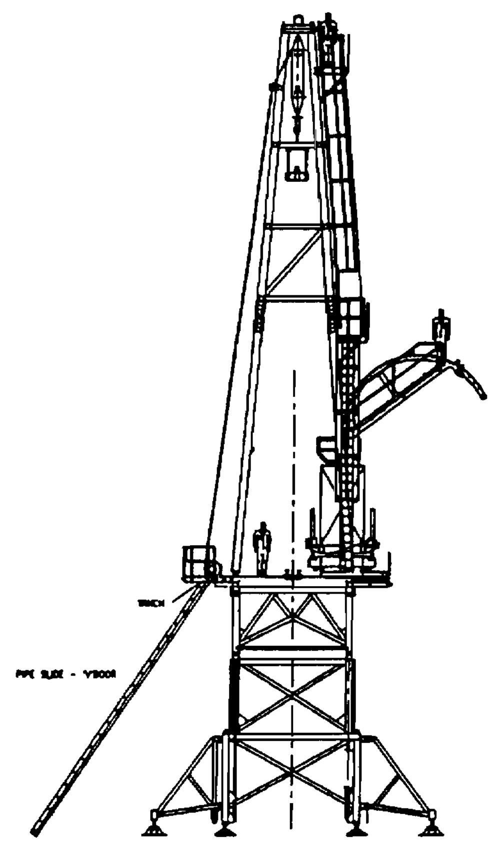


Figure 5-89. Support Structure for CT Drilling (Eide et al., 1995)

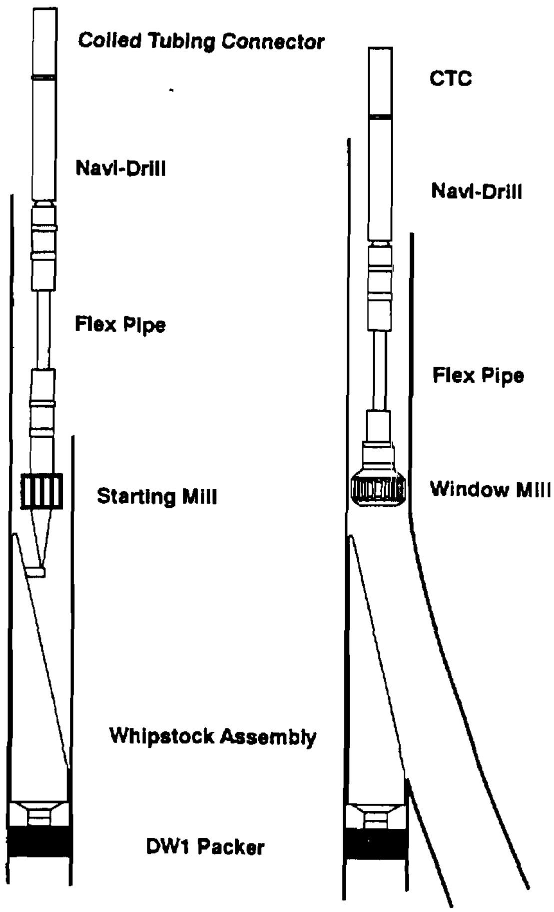


Figure 5-90. Window Cutting Assemblies
(Eide et al., 1995)

The lateral was drilled with a 4¾-in. assembly. Increasing fluid losses were combated by injecting nitrogen with the drilling fluid. ROP also slowed due to motor stalling. Finally, nitrogen was injected through a parasitic string, allowing maintenance of a slight underbalance with only small losses. The lateral reached TD at 1050 m (Figure 5-91). ROP averaged 10.5 m/hr (34 ft/hr) in the lateral. Small influxes and losses were safely handled.

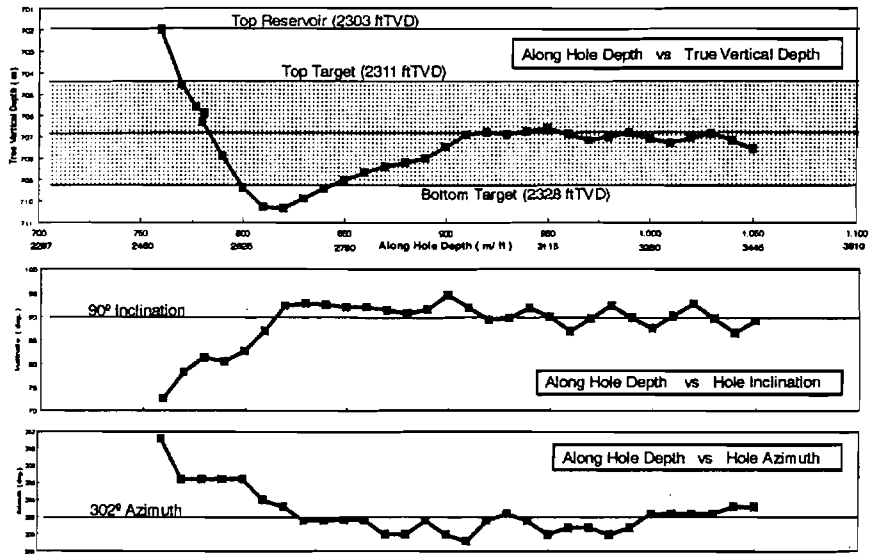


Figure 5-91. Barenburg Re-entry Well Path (Eide et al., 1995)

The Barenburg well was completed with 3½-in. slotted liner run on CT out to 946 m. The toe of the well was left open-hole. 4½-in. production tubing, which had been prepared for later installation of a beam pump, was run to complete the well (Figure 5-92).

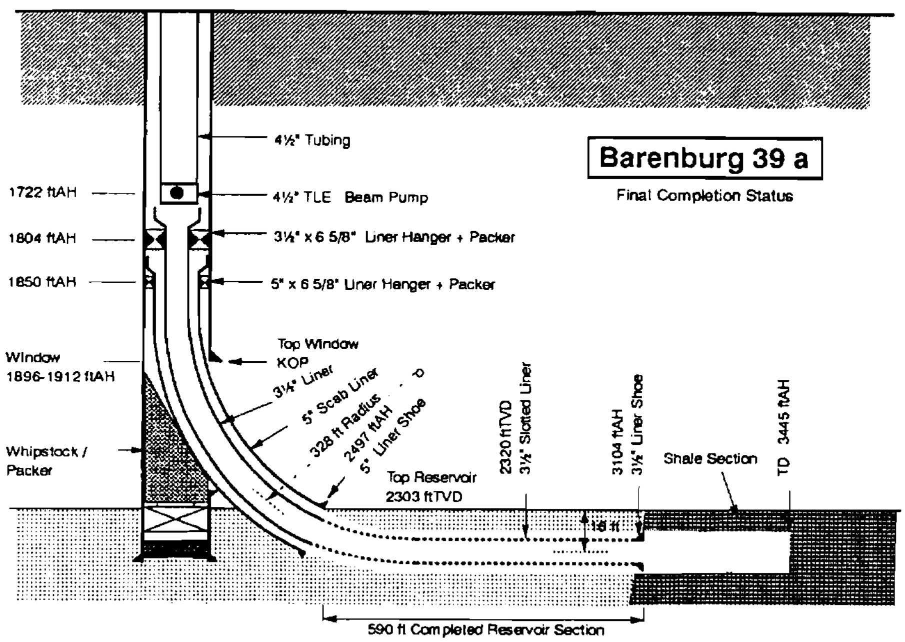


Figure 5-92. Barenburg Re-entry Completion (Eide et al., 1994)

5.37 HALLIBURTON AND AMOCO (SHALLOW GAS WELLS IN SAN JUAN BASIN)

Halliburton Energy Services and Amoco Production Company (Moon et al., 1996) drilled several wells to shallow gas targets in the San Juan Basin in Northwestern New Mexico. An initial three-well pilot project was completed first. Results were analyzed for several months, and then an additional six wells were drilled with the system. CT drilling was found to be an economical option for drilling shallow gas wells.

A standard workover rig was used to drill surface hole and run surface casing. After CT drilling of the production hole, the workover rig was used to install production casing.

A polymer water-base mud system was used for CT drilling. Mud weights of 9.2 ppg were sufficient to prevent water and gas flow. A 3000-ft string of 2- by 0.188-in. CT was used.

Following the three-well pilot project, job procedures were revised and a six-well development project was performed. ROP for these wells (Figure 5-93) shows that the first and last three wells had different ranges of ROP (40-60 ft/hr versus 60-80 ft/hr). These groups of wells were in different areas, so geologic differences are the probable cause.

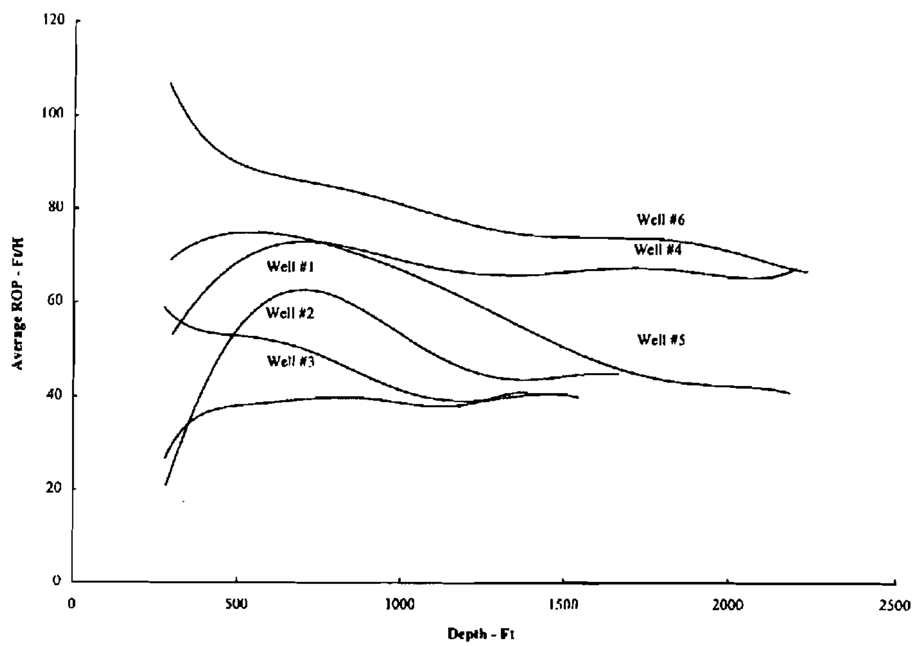


Figure 5-93. ROP for the Six-Well Project (Moon et al., 1996)

A cost comparison for the three-well pilot project (Figure 5-94) shows that costs were less than those of an offset well drilled with a conventional rig.

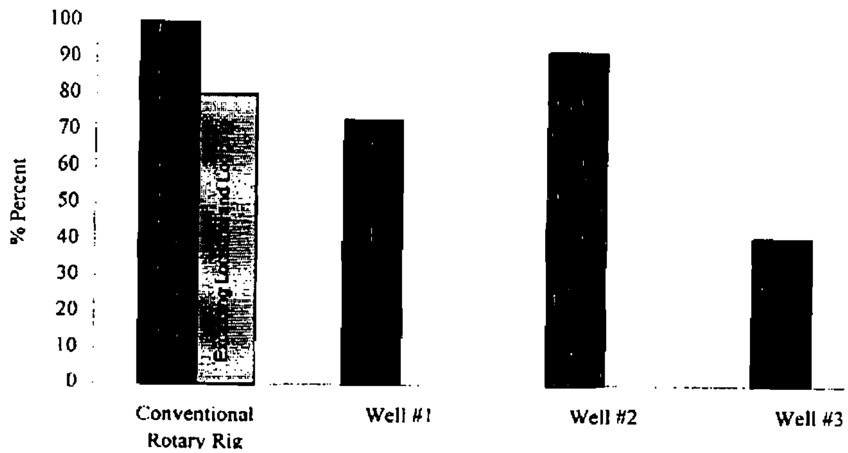


Figure 5-94. Costs for Pilot Project (Moon et al., 1996)

5.38 IMPERIAL OIL RESOURCES (CT DRILLING EXPERIENCE)

Imperial Oil Resources (Rice, 1995) described their early experiences with CT drilling of two vertical wells. The first well was drilled from a depth of 145 m to 1450 m using 2⅜-in. CT and overbalanced conditions. The second case was an underbalanced deepening. They found that costs were not competitive with conventional drilling systems for overbalanced grass-roots wells. They concluded that underbalanced operations, however, could be more safely and economically drilled with CT.

The first well operation was designed to assess the performance of CT drilling in a conventional overbalanced drilling application. The well was completed successfully, but costs for this operation (Figure 5-95) were high—about 16% over budget and 78% more than an offset conventional well. Mechanical failures with the early-generation drilling tools were a primary cause of cost overage.

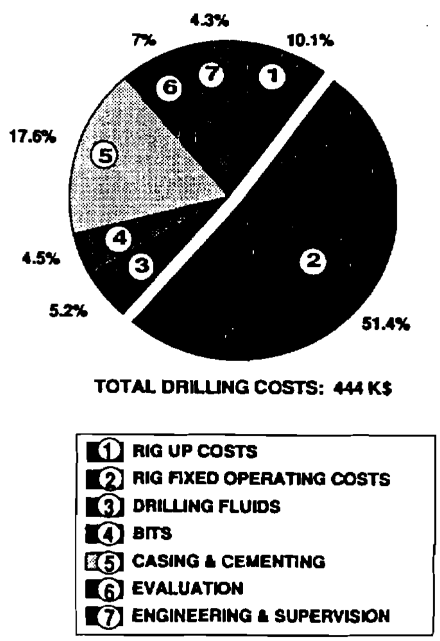


Figure 5-95. CT Drilling Cost Distribution (Rice, 1995)

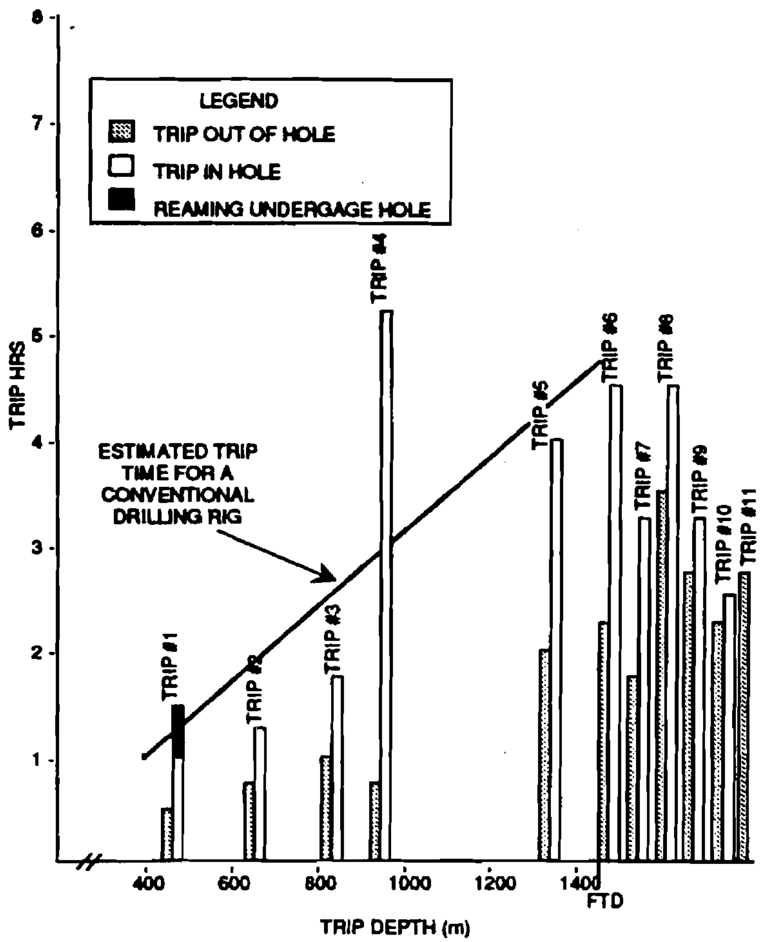


Figure 5-96. Trip Time Comparison (Rice, 1995)

Trip times with CT were faster than conventional operations (Figure 5-96). However, the higher day rates for CT equipment consumed the cost savings from faster trips.

ROPs for this new well drilled overbalanced with CT are summarized in Figure 5-97.

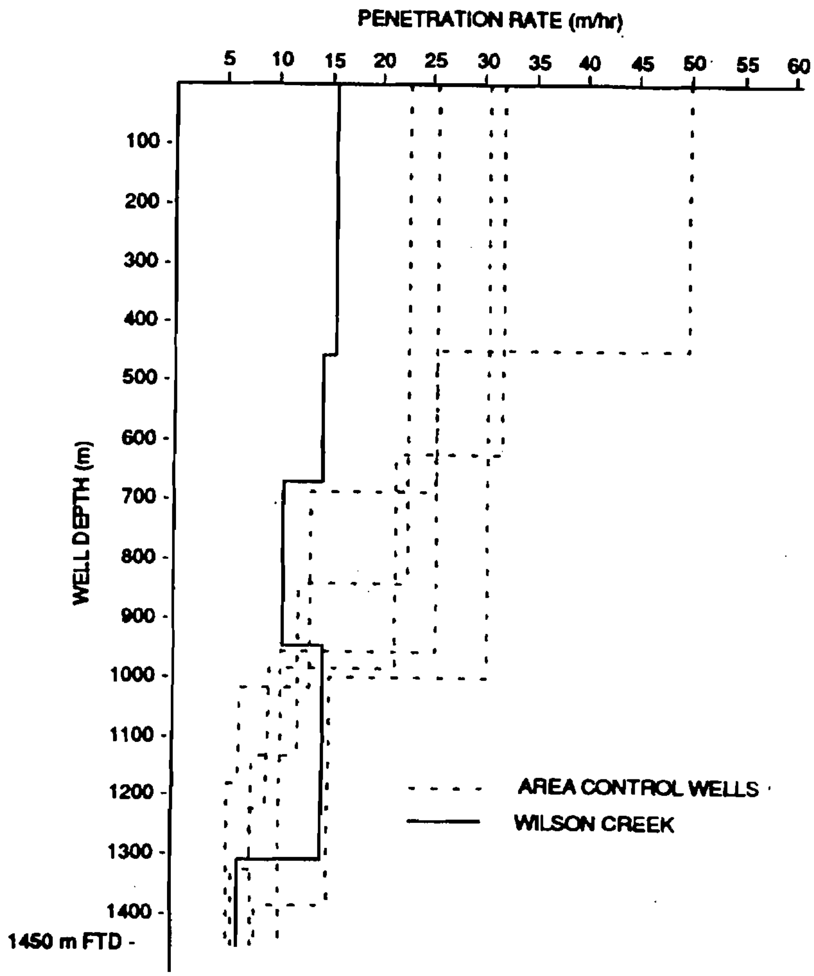


Figure 5-97. ROP Summary
(Rice, 1995)

5.39 NAM, HALLIBURTON, AND SPERRY-SUN (AME-203 RE-ENTRY)

Nederlandse Aardolie Maatschappij, Halliburton Energy Services, and Sperry-Sun Drilling Services (Gunningham et al., 1997) presented a case history from a well drilled in the Dutch Sector of the North Sea from a jack-up drilling unit. The rig was used to start the sidetrack and recomplete the well. CT was then mobilized to drill the new hole (230 ft of 3¾-in. hole). The operation was completed to 12,486 ft MD in 33.5 hours with one BHA and bit.

In the first completion of the well, incompatibility of the drilling fluid (much of which was stored in fractures) and the fracturing fluid resulted in the formation of gunk that plugged the well. A new sidetrack was planned with CT so that lost-circulation material would not need to be pumped.

A series of tests was conducted onshore prior to drilling. Fatigue life of the 2-in. string was tested, deployment of the 3-in. drilling BHA was demonstrated, and hydraulics models were validated.

The site lay-out on the jack-up rig is shown in Figure 5-98. Injector capacity was 100 kips pull; 2-in. CT was used.

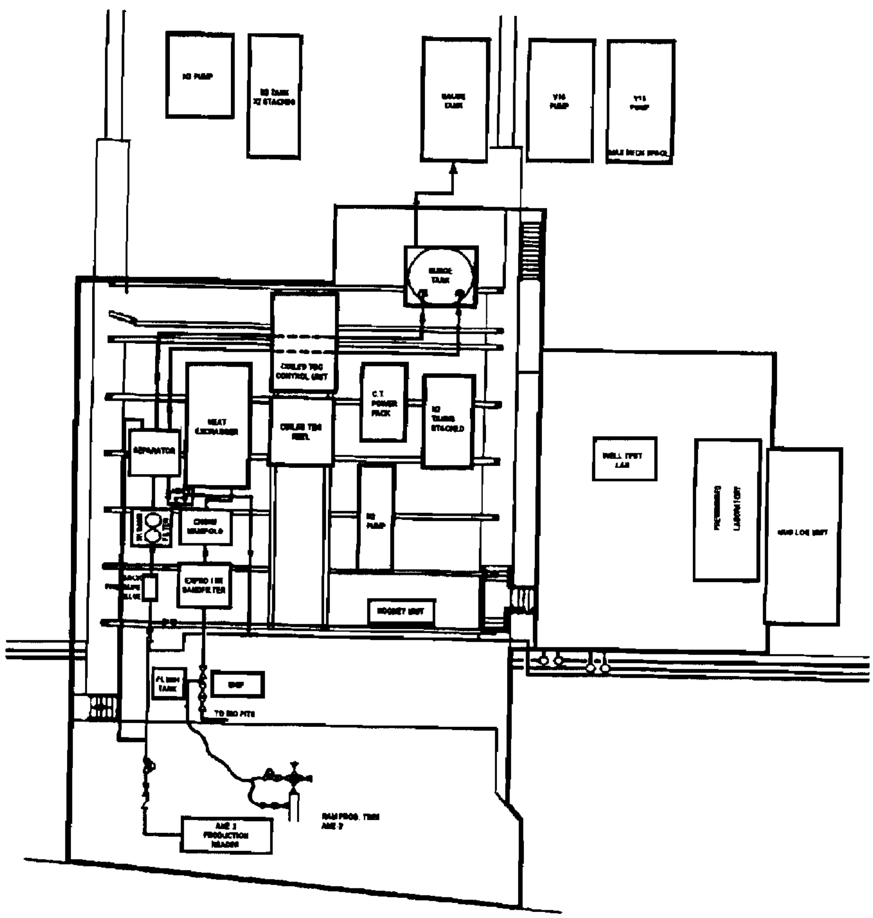


Figure 5-98. Rig Lay-Out (Gunningham et al., 1997)

Spacing from the swab valve above the Christmas tree to the hydraulic connector was over 60 ft (Figure 5-99). The BHA could be deployed into the riser and pressure tested with the swab valve closed.

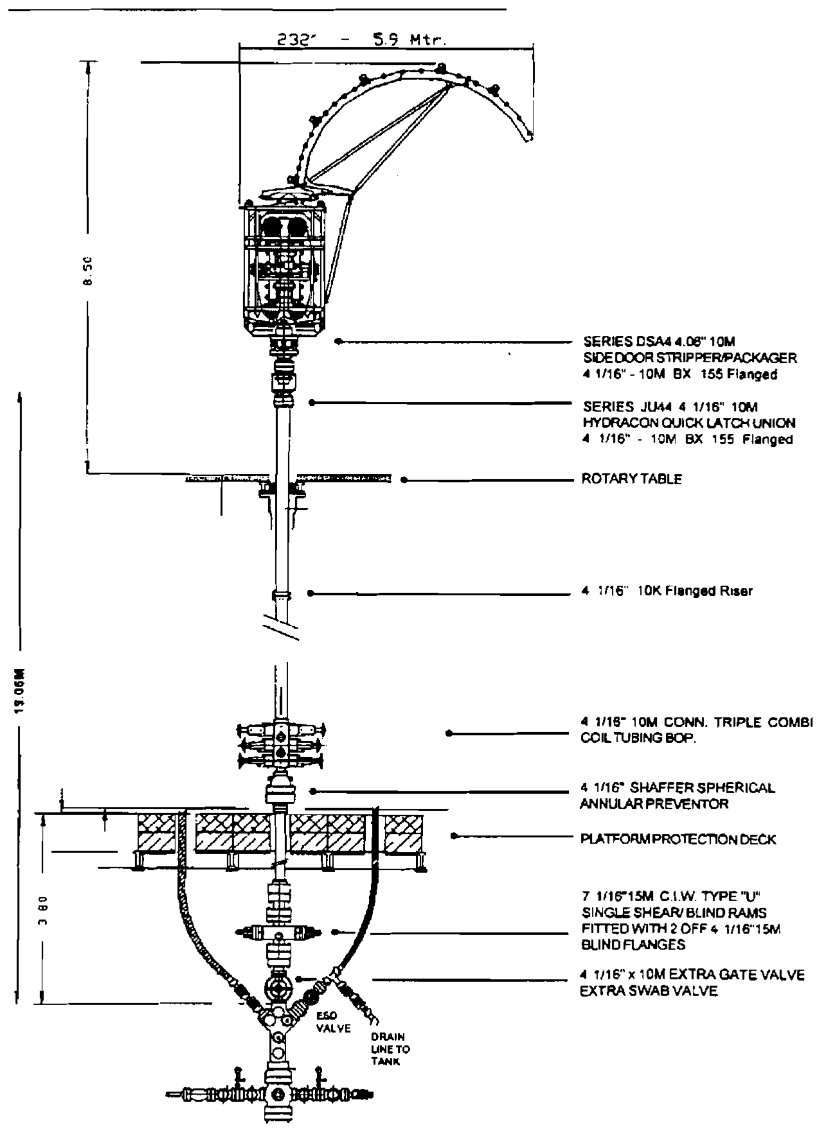


Figure 5-99. BOP Equipment (Gunningham et al., 1997)

Average ROP was 6.3 ft/hr through the Rotliegendes Upper Slochteren Sandstone. Short hole-cleaning trips were made to the casing shoe every 50 ft.

5.40 SAGA PETROLEUM (MULTIBRANCH CT DRILLING AT SNORRE FIELD)

Saga Petroleum ASA, Schlumberger Anadrill, The Red Baron, and Texas Iron Works (Pedersen et al., 1997) provided a highly detailed account of planning and qualification operations for a multilateral CT re-entry in the Snorre Field in the Norwegian North Sea. They outlined the reservoir development strategy, the plan for the re-entry, results from equipment qualification testing, and lessons learned from full-scale testing.

The overall project was broken into three phases. Phase I was a CT drilling feasibility study. Saga was in close contact with ARCO for consultation during this effort. Results showed that CT drilling was viable and that cost savings of up to 70% might be possible for drilling lateral branches through tubing rather than conventionally.

Phase II involved planning and qualification testing. The well candidate was selected. Surface equipment were identified for both underbalanced and overbalanced drilling. New purpose-built equipment was manufactured based on qualification tests. A full-scale drilling test was conducted onshore as a final part of Phase II.

Phase III efforts were to drill the well offshore, and was scheduled for summer 1997.

A two-branch multilateral completion was planned (Figure 5-100). TVD for the two horizontal branches is the same as their respective KOPs. Azimuthal separation between the horizontal sections is almost 180°.

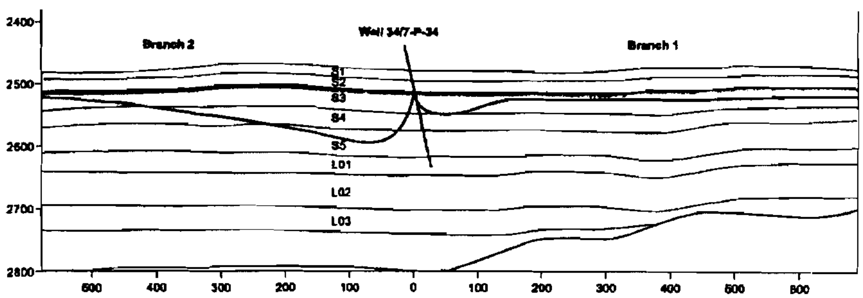


Figure 5-100. Planned Paths for CT Laterals (Pedersen et al., 1997)

Branch 1 is relatively simple with minimal azimuth changes. Branch 2 requires a change in azimuth of over 150°. The windows for the two branches are almost in the same azimuthal orientation (Figure 5-101). As a result, only limited WOB will be available at TD.

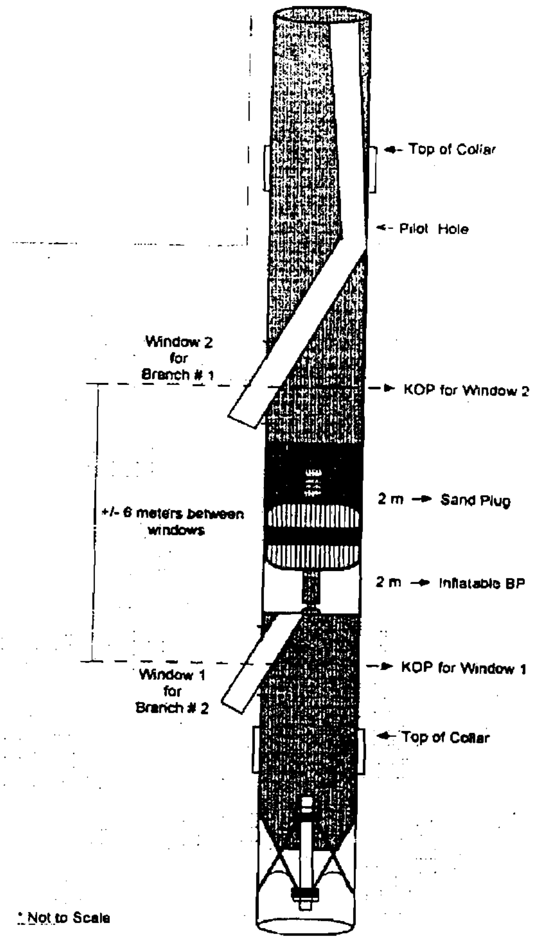


Figure 5-101. KOPs for two Windows
(Pedersen et al., 1997)

Readers are directed to Pedersen et al.'s paper for a wide variety of design details and testing results.

5.41 SHELL EXPRO (CORMORANT NORTH WELL)

Shell Expro UK (Lord et al., 1997) summarized the planning, yard tests, and CT drilling of a well (CN31) in the UK North Sea. An important feature of this operation was that the platform rig was drilling a conventional sidetrack nearby at the same time. CT operations included milling a window, drilling a 3¾-in. wellbore, and completing the section with 2⅞-in. predrilled liner.

The platform rig is scheduled for full utilization until the platform is to be abandoned. New drilling techniques were needed to access an additional 40 MMBO. CT drilling was tested as a potential concurrent drilling operation (Figure 5-102).

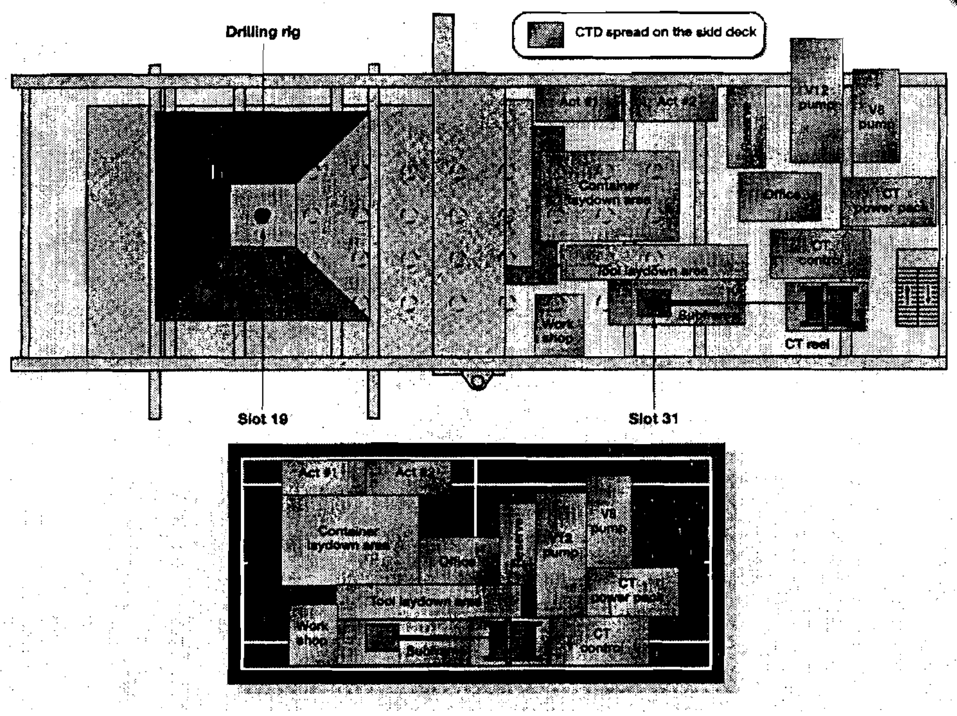


Figure 5-102. CT and Platform Rig Drilling Concurrently
(Lord et al., 1997)

Remedial work was required on CN31. After completion in December 1994, two of the target reservoirs were found to be missing. The KOP for the new section was chosen to avoid contacting shale layers while CT drilling, due to previous problems.

Four field trials were conducted prior to going offshore. The first was a pumping trial to ensure that 2 bbl/min could be pumped (to run the MWD system) while staying below the CT pressure limit of 4000 psi. A window milling trial was performed. Components of the drilling BHA were handled without a crane. Critical components were drifted in the existing completion with a drill bit.

The window milling procedure is shown in Figure 5-103. During the final milling run, the BHA became stuck, had to be disconnected, and was recovered after three attempts.

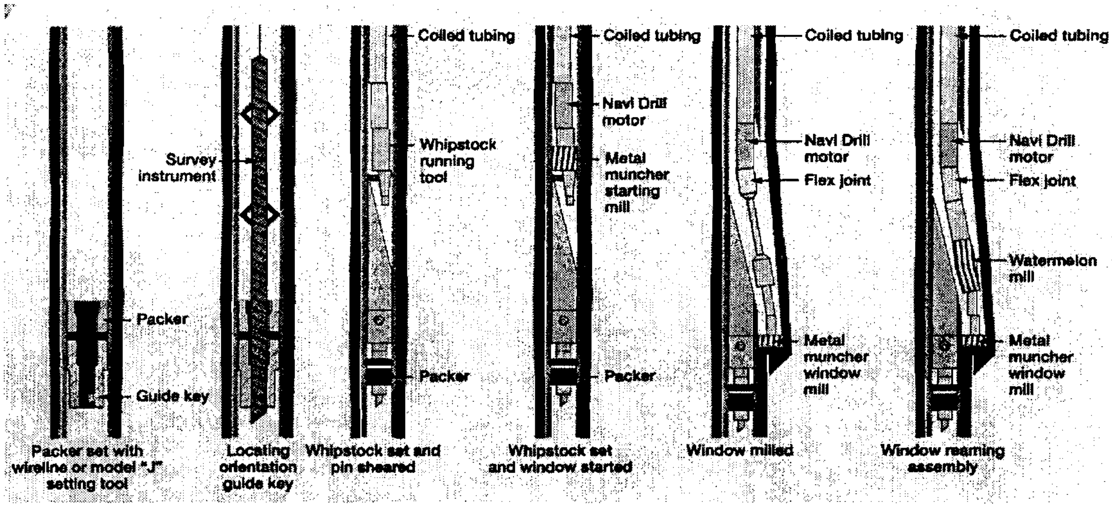


Figure 5-103. CT Window Milling (Lord et al., 1997)

5.42 SHELL UK E&P (CT WELL AT BRENT)

Shell UK E&P (Donald et al., 1997) described planning and successful field operations for the first CT-drilled well in the Brent Field in the UK Sector of the North Sea. Another publication describing the operation was presented by the CT contractor, Transocean ASA, whose perspective is summarized in Sjonberg (1997).

An alternative to conventional rigs is needed for through-tubing re-entries at Brent. About 40 wells are candidates for these sidetracks. CT was tested in well BD38 with a 3¾-in. bit through 5½-in. tubing. An open-hole section of almost 1500 ft was planned, with reservoir pressures of 5000+ psi, and the potential to cross as many as ten fluid contacts. Zonal isolation was vital.

The well was drilled, logged, lined, cemented, and perforated successfully. Major lessons learned were summarized by Shell. CT drilling was able to be performed concurrently while the main rig drilled. Differential sticking could be overcome by flowing the well and underbalancing the annulus. ROPs greater than 35 ft/hr were observed along with good hole cleaning. CT maintenance was an important concern due to the abnormal duration of drilling operations as compared to normal CT operations.

5.43 STATOIL (SIDETRACK IN GULLFAKS FIELD)

Statoil Norway (Gaasø et al., 1998) presented results from the first CT sidetrack on the Norwegian Continental Shelf. The A10A well was drilled from the Gullfaks A platform out 254 m to drain a small reservoir pocket. The operation was designed to qualify CT drilling for the field. After the tail-pipe assembly was removed from the well, a window was milled through 7-in. liner, a 3¾-in. hole drilled to TD, a 2⅞-in. liner run and cemented, and the well perforated under balanced.

The platform rig was out of service during the operation. The CT injector and strippers were placed over the drill floor and the BOPs below the floor (Figure 5-104).

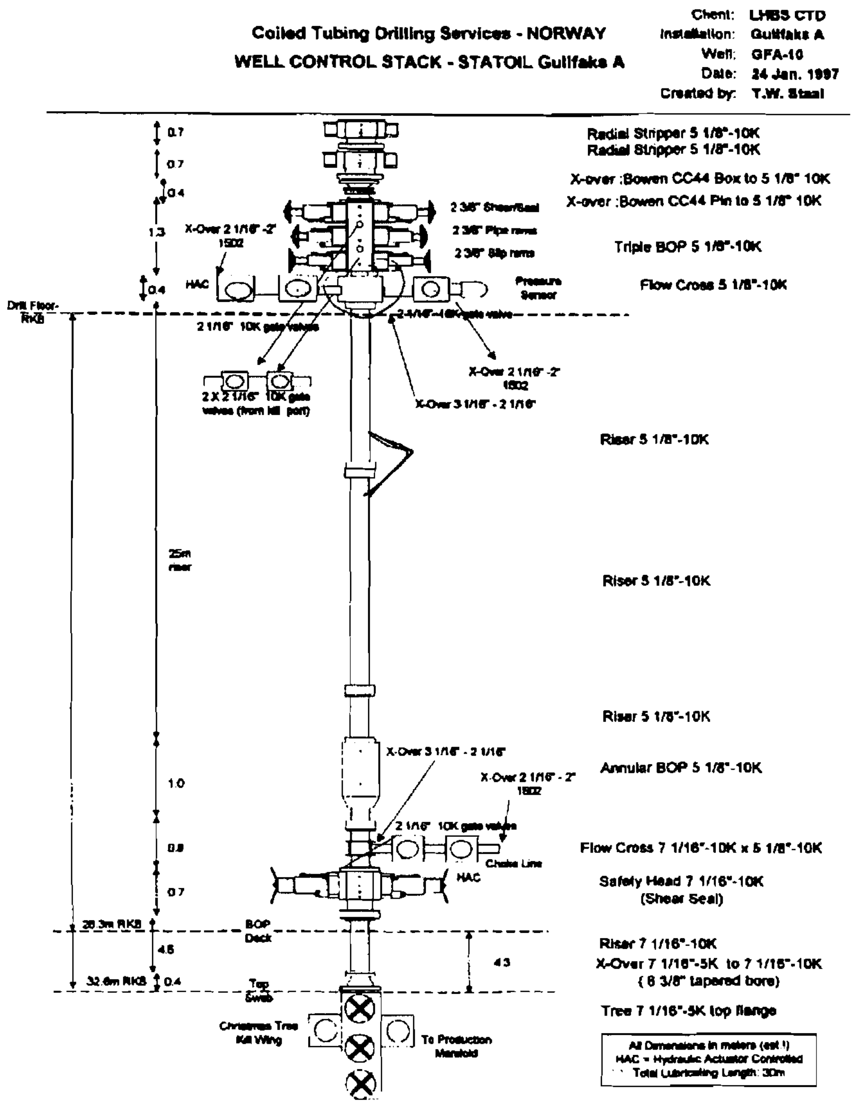


Figure 5-104. Surface Stack for A10A Sidetrack (Gaasø et al., 1998)

The build section was relatively problem free. Schlumberger Dowell's Viper BHA was used to drill a straight tangent by continuously rotating the BHA at 1 rpm. Differential sticking was a problem. TD was declared 15 m short of planned TD after sliding became impossible.

Statoil learned that the drilling fluid needs to be optimized with respect to differential sticking. They suggested that underbalanced drilling is the natural direction for CT drilling.

Statoil plans to sidetrack another two wells in the field in late 1998.

5.44 SULTAN QABOOS UNIVERSITY (CT DRILLING IN OMAN)

Sultan Qaboos University (Al-Harthy and Kalam, 1997) summarized experiences and lessons learned drilling with CT in Oman. Six horizontal sidetracks have been drilled in North Oman to analyze the feasibility of the technique. Three drilling problem areas they encountered on these wells were described in their paper:

1. **Difficulties setting the whipstock.** Premature shearing of the pins occurred with the hydraulic whipstocks used.

2. **Hole-cleaning problems.** They calculated lifting capacity for 1-, 2⅜- and 4½-in. tubing, cuttings diameters up to 1 inch, and drilling fluids of 2 and 14 cP. Under these conditions, 4½-in. CT was preferred for hole cleaning, but considered inappropriate due to tubing handling difficulties. Installing liners to reduce the annulus diameter while drilling was another option considered; however, tubing handling with the CT rig is still an issue.

3. **Difficulties handling jointed tubing.** In the future, a hybrid CT rig may be deployed that can easily handle jointed and coiled tubing. Another viable option is to have a part-time workover rig available.

Based on analysis of these problems and potential solutions, Sultan Qaboos University concluded that CT drilling is not feasible for sidetracks out of relatively large vertical completions unless tie-back liners can be run efficiently. A hybrid rig was seen as a solution for many of the field problems observed.

5.45 REFERENCES

Adam, J. and Berry, M., 1995: "Through Completion Underbalanced Coiled Tubing Side Track of Well Dalen-2," presented at the IADC Well Control Conference for Europe, Milan, June 9.

Al-Harthy, S.S. and Kalam, M.Z., 1997: "Coiled Tubing Applications in the Sultanate of Oman," SPE 38396, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Borbely, L. et al., 1997: "Coiled Tubing Horizontal Underbalanced Drilling Project; Costs and Operational Analyses," SPE 38399, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Cox, R. 1996: "Horizontal Underbalanced Drilling in a Sour Gas Carbonate Using Coiled Tubing: A Case Study," SPE 37075, presented at the SPE International Conference on Horizontal Well Technology, Calgary, November 18-20.

Donald, D. et al., 1997: "Brent's First Coiled Tubing Drilled Well," *JPT*, June.

Elsborg, C. et al., 1996: "High Penetration Rate Drilling with Coiled Tubing," SPE 37074, presented at International Conference on Horizontal Well Technology, Calgary, November 18-20

Elsborg, C.C. et al., 1996: "Large Diameter Coiled Tubing Drilling," SPE 37053, presented at the SPE International Conference on Horizontal Well Technology, Calgary, November 18-20.

Gaasø, R. et al., 1998: "The First Coiled Tubing Sidetrack in Norway, Gullfaks Field," IADC/SPE 39305, presented at IADC/SPE Drilling Conference, Dallas, March 3-6.

Gary, S.C. and Doremus, D.M., 1995: "Technical and Economical Feasibility of Coiled Tubing Drilling," SPE 30490, presented at Annual Technical Conference, Dallas, October 22-25.

Gleitman, D.D. et al., 1996: "Newly Applied BHA Elements Contribute Towards Mainstreaming of Coiled Tubing Drilling Applications," IADC/SPE 35130, presented at IADC/SPE Drilling Conference, New Orleans, March 12-15.

Goodrich, G.T. et al., 1996: "Coiled Tubing Drilling Practices at Prudhoe Bay," IADC/SPE 35128, presented at IADC/SPE Drilling Conference, New Orleans, March 12-15.

Graham, R., 1995: "Underbalanced Drilling with Coiled Tubing: A Safe, Economical Method for Drilling and Completing Gas Wells," paper 95-16, presented at the 46th Annual Technical Meeting of the Petroleum Society of CIM, Banff, Alberta, May 14-17.

Groves, W.G., 1995: "Drilling Using Coiled Tubing and Air," presented at the 3rd Annual North American Conference on Emerging Technologies and Application, Calgary, May 15-16.

Gu, H. and Walton, I.C., 1996: "Designing Under and Near Balanced Coiled Tubing Drilling Using Computer Simulations," SPE 35665, presented at Western Regional Meeting, Anchorage, May 22-24.

Gunningham, M.C. et al., 1997: "Coiled Tubing Drilling case History, Offshore The Netherlands," SPE 38395, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Hearn, D.D. et al., 1996: "Coiled Tubing Window Milling," IADC/SPE 35126, presented at IADC/SPE Drilling Conference, New Orleans, March 12-15.

Hightower, C.M. 1997: "Operator's Coiled Tubing Drilling Program Gets Good Results," *World Oil*, October.

Leising, L.J. et al., 1995: "Sidetracking Technology for Coiled Tubing Drilling," SPE 30486, presented at Annual Technical Conference, Dallas, October 22-25.

Leising, L.J. et al., 1998: "Cuttings Transport Problems and Solutions in Coiled Tubing Drilling," IADC/SPE 39300, IADC/SPE Drilling Conference, Dallas, March 3-6.

Leismer, Dwayne et al., 1996: "Coiled Tubing Drilling: Real Time MWD with Dedicated Powers to the BHA," OTC 8227, presented at Offshore Technology Conference, Houston, May 6-9.

Lord, David et al., 1997: "Shell Expro's First Application of Coiled Tubing Drilling," presented at 5th International Conference on Coiled Tubing and Well Intervention, Houston, February 4-6.

McGregor, B. et al., 1997: "Application of Coiled Tubing Drilling Technology on a Deep Underpressured Gas Reservoir," SPE 38397, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Milligan, M. et al., 1996: "Coiled Tubing Drilling of Horizontal Sidetrack in House Mountain Field, Alberta," IADC/SPE 35127, presented at IADC/SPE Drilling Conference, New Orleans, March 12-15.

Moon, R.G. et al., 1996: "Shallow Gas Well Drilling with Coiled Tubing in the San Juan Basin," SPE 36463, presented at the SPE Annual Technical Conference and Exhibition, Denver, October 6-9.

Newman, K.R. et al., 1996: "The Feasibility of Using and Electric Downhole Motor to Drill with Coiled Tubing," SPE 36343, presented at 1st North American Coiled Tubing Roundtable, Conroe, Texas, February 26-28.

Pedersen, Knut et al., 1997: "Multilateral Branch Drilling Through Tubing, with Coiled Tubing Drilling, Planned for Snorre Field, Snorred TLP (Tension Leg Platform) In North Sea, Norway," presented at 5th International Conference on Coiled Tubing and Well Intervention, Houston, February 4-6.

Pitman, Malcolm et al., 1997: "Casing Exit Techniques Using Coiled Tubing: Worldwide Case Histories," SPE 38428, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Rice, Bill, 1995: "Imperial Oil Resources Limited Coiled Tubing Drilling Experience," paper 95-903, presented at CADE/CAODC Spring Drilling Conference, April 19-21.

Rommetveit, Rolv et al., 1995: "A Dynamic Model for Underbalanced Drilling with Coiled Tubing," SPE/IADC 29363, presented at SPE/IADC Drilling Conference, Amsterdam, February 28-March 2.

Selby, Bruce et al., 1998: "Hybrid Coiled Tubing System for Offshore Re-entry Drilling and Workover," IADC/SPE 39374, presented at IADC/SPE Drilling Conference, Dallas, March 3-6.

Sjonberg, Geir, 1997: "Coiled Tubing Drilling: Successful Drilling Offshore in the North Sea," presented at 5th International Conference on Coiled Tubing and Well Intervention, Houston, February 4-6.

Surewaard, J. et al., 1997: "One Year Experience with Coiled Tubing Drilling," SPE/IADC 39260, presented at Middle East Drilling Technology Conference, Bahrain, November 23-25.

Thorby, Helge, 1995: "Underbalanced Drilling with Coiled Tubing—A Reference of Work to Date," presented at 3rd Annual Conference on Emerging Technology, Aberdeen, May 31-June 2.

Townsend, Steve et al., 1997: "Evaluation of Through Tubing Whipstock System to Exit Both 7-in. and 9⅝-in. Casing Strings Using Coiled Tubing," presented at 5th International Conference on Coiled Tubing and Well Intervention, Houston, February 4-6.

Weighill, Geoff and Thoreby, Helge, 1996: "Underbalanced CT Drilling Success on Ula," *BP Downhole Talk,* Issue 55, February.

Weighill, G. et al., 1996: "Underbalanced Coiled Tubing Drilling Experience on the Ula Field," SPE 35544, presented at European Production Operations Conference, Stavanger, Norway, April 16-17.

6. Fatigue

TABLE OF CONTENTS

TABLE OF CONTENTS (CONT'D)

6. Fatigue

6.1 AGIP AND NOWSCO (FATIGUE IN HTHP OPERATIONS)

Agip S.p.A. and Nowsco Well Service (Maroli et al., 1996) presented results from a study of the feasibility of modifying a conventional CT unit for use in workovers in deep HTHP oil wells. Prior to the study, maximum allowable wellhead pressure was set as 5000 psi, maximum depth 17,000 ft, and maximum pick-up 25,000 lb. Conditions in the Villafortuna/Trecate field in Italy required wellhead pressures of 8500 psi and downhole operations at temperatures of 330°F. Laboratory tests were performed to evaluate tubing and stripper life. The impact of tubing ovality and ballooning was also investigated for high-pressure operations.

A series of fatigue tests was conducted for surface equipment using a special full-scale fixture (Figure 6-1). Failure was defined as either a loss of internal pressure or of ballooning of the tubing beyond the limit for passing through the stuffing box.

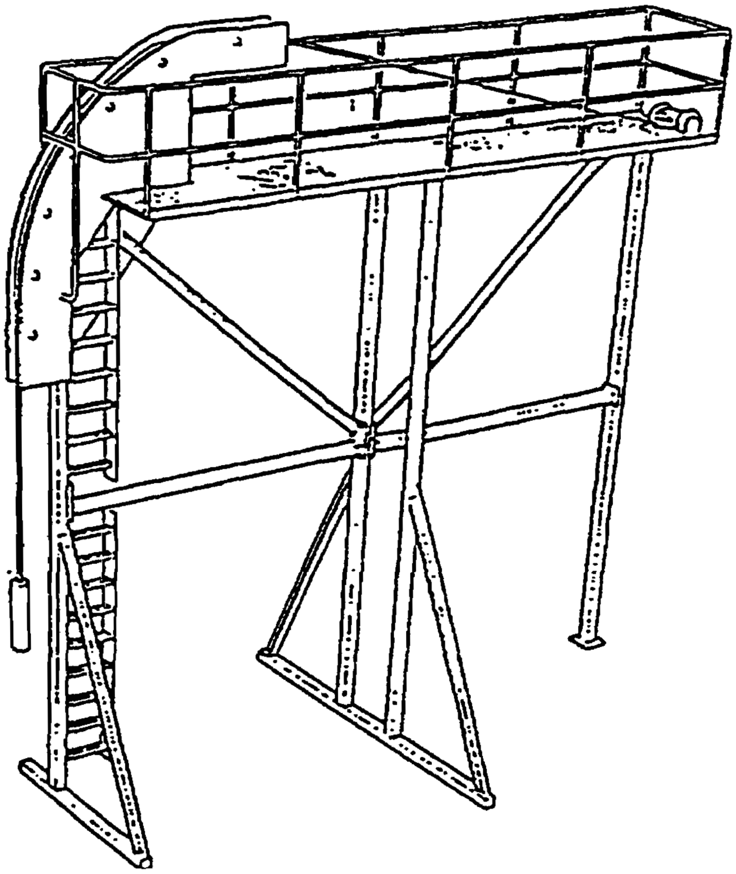


Figure 6-1. Test Fixture for High-Pressure Tests (Maroli et al., 1996)

New material for stripper rubbers was tested at 8000 psi. No benefits with respect to element wear were observed for the use of lubricant on the exterior of the tubing.

A gooseneck radius of 98 in. and reel core diameter of 100 in. were selected. The work spool was sized to hold 24,000 ft of 1½-in. CT.

Well-control equipment (Figure 6-2) was rated to operations at 10,000 psi. The most likely tubing failure mode was collapse. An annular BOP was included below the quad BOP to preserve well control in the event of collapse of the CT.

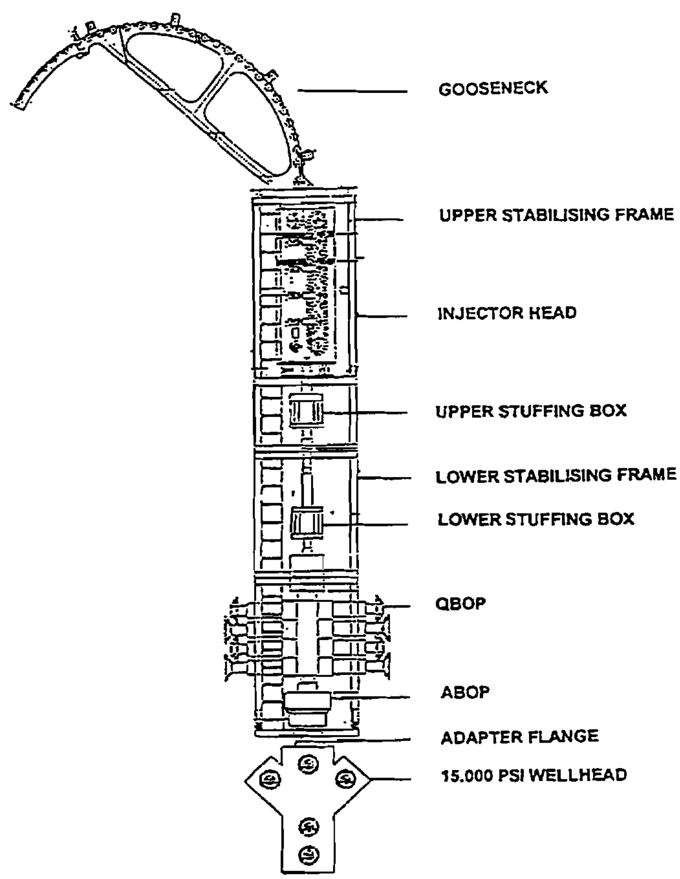


Figure 6-2. Surface Equipment for HPHT Operations (Maroli et al., 1996)

In high-pressure operations, tubing ovality and ballooning are major concerns. An ovality monitor was installed on the level wind.

The modified system was successfully mobilized in the HTHP field. In the first application, an asphaltene plug was removed. Maximum internal pressure was 7000 psi. About 9% of the string cycle life was consumed for the operation. The remaining cycles after the job are shown in Figure 6-3. Locations where wall thickness of this tapered string changes are clearly indicated.

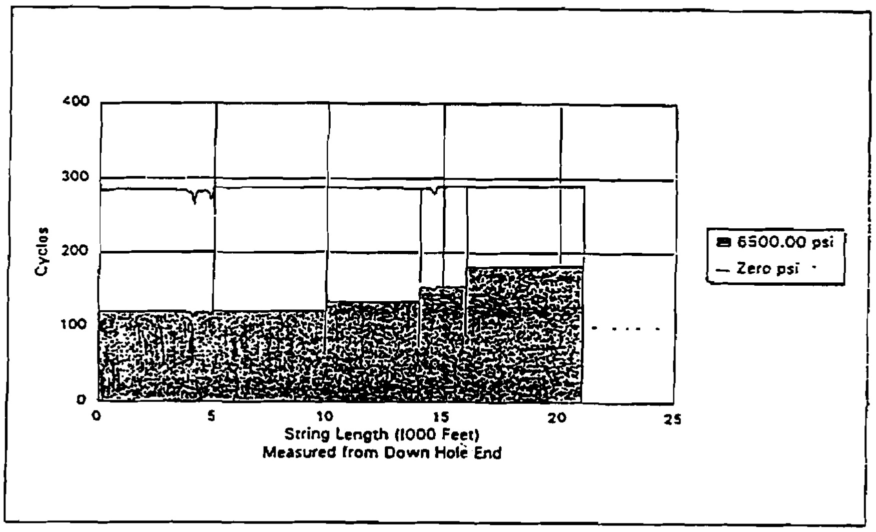


Figure 6-3. Available Fatigue Cycles for HTHP Work String (Maroli et al., 1996)

The remaining capacity of the same string with respect to ballooning is shown in Figure 6-4. An internal pressure of 6500 psi is assumed. About 30 cycles are available until the diametral growth limit of 0.050 inches is surpassed.

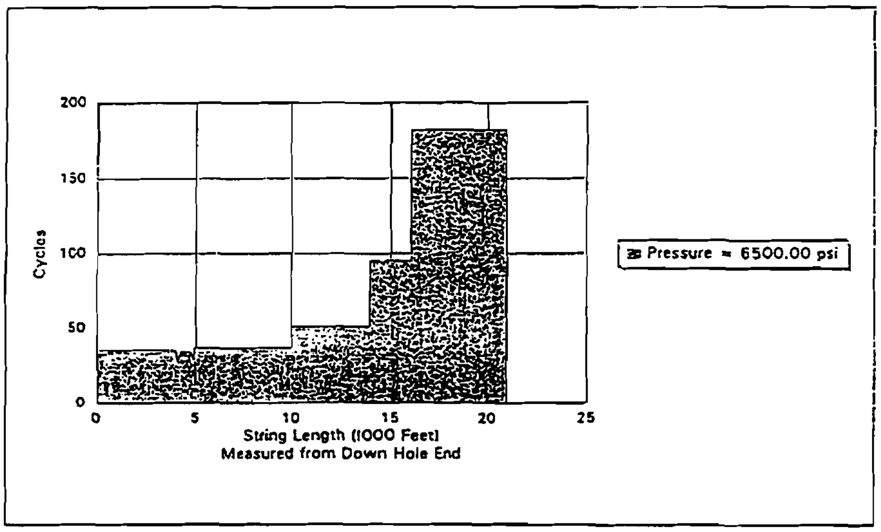


Figure 6-4. Available Cycles for Ballooning Limit (Maroli et al., 1996)

An economic evaluation of the first field application was performed. Results showed that the CT unit saved $500,000 compared to a snubbing unit for this HTHP application.

6.2 BJ SERVICES AND BP EXPLORATION (EFFECT OF RIG HEAVE)

BJ Services Company UK and BP Exploration (Engel and Monro, 1997) analyzed the impact of rig heave on CT reel motion and fatigue life. Reel placement on a floating vessel has a critical effect on the amount of reel movement resulting from rig heave. If the reel were at the same elevation as the gooseneck and positioned very far away, rig heave would have no impact on fatigue. The gooseneck is normally, however, at least 20 m above the level wind and offset no more than 40 m. This corresponds to a 26° inclination of the CT, and about 10% of rig heave is translated into reel rotation. BJ and BP analyzed techniques to minimize these effects.

An animation simulator was developed (Figure 6-5) for analyzing vertical working-window requirements under various rig-up configurations and heave conditions. The most common problem is that the superstructure of the derrick immediately above the V door is almost always lower than the top of the gooseneck. A critical limit is that the reel must be close enough to the well so that, during low tide at the trough of a heave, the CT cannot hit the top of the V door.

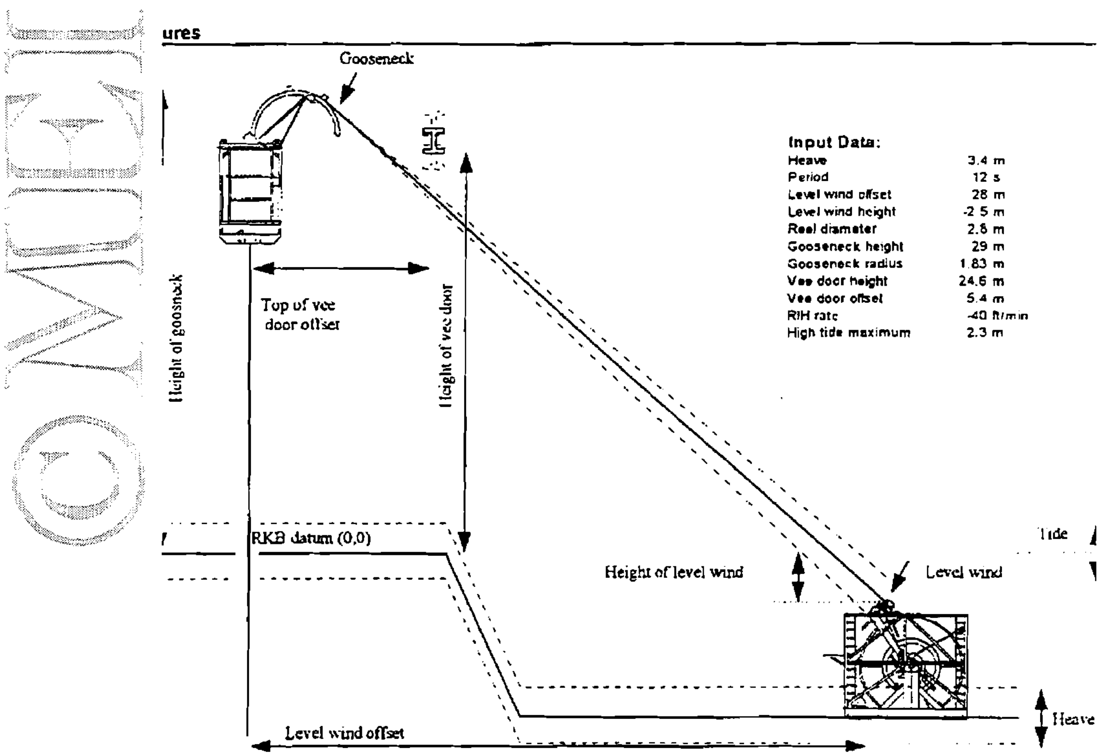


Figure 6-5. Rig Heave Simulator (Engel and Monro, 1997)

An example offshore CT working life graph (Figure 6-6) shows that the predicted working cycles of a spool are reduced on the order of 25-30% when rig heave is accounted for.

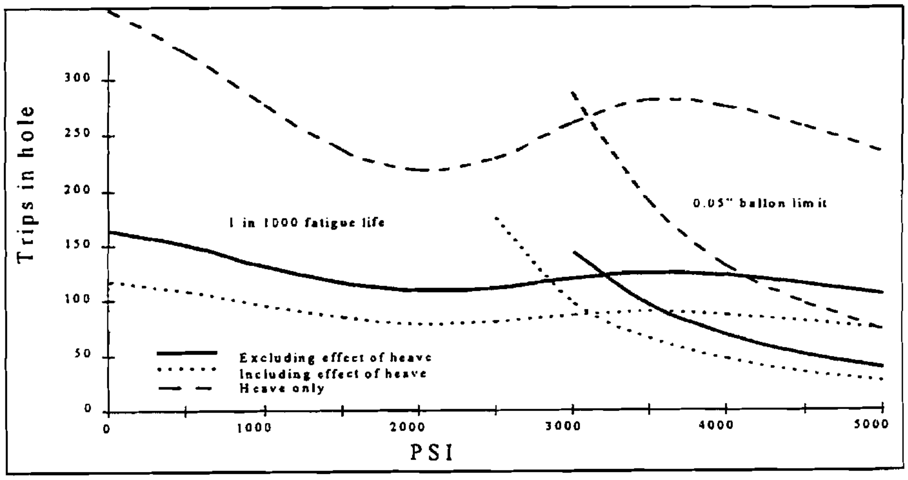


Figure 6-6. Example CT Working Life Chart (Engel and Monro, 1997)

Minimum CT running rates can be calculated (Figure 6-7) so that counter rotation of the reel during heave is avoided. CT is often run in at 15 m/min (50 ft/min). If the inclination of the string is 45° and the heave period is 12 sec, a running rate of 11 m/min (36 ft/min) or greater will avoid the need to counter rotate the spool.

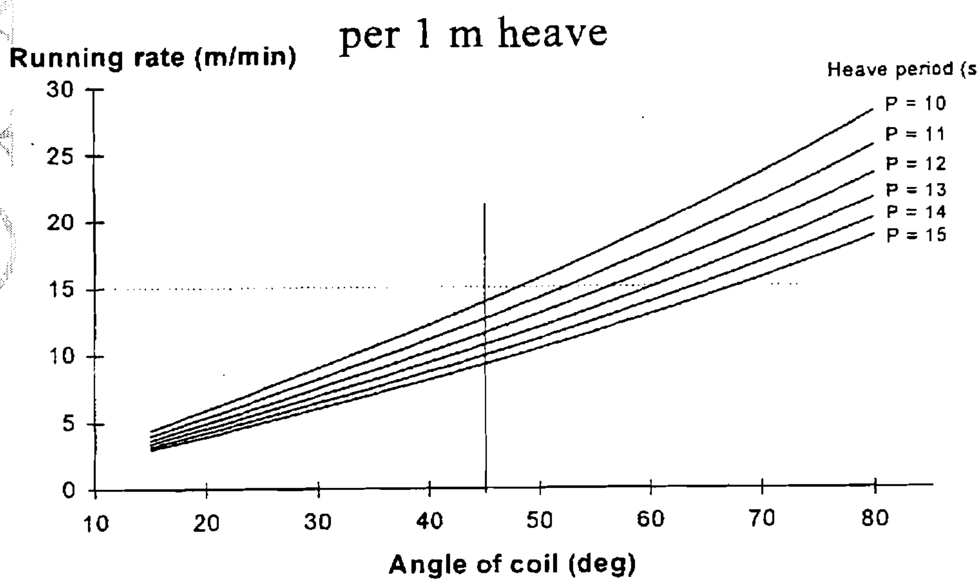


Figure 6-7. Running Rates to Offset Rig Heave (Engel and Monro, 1997)

Among methods to avoid problems with rig heave and CT life are optimized reel placement, maintaining minimum running rates, and introducing slack into the CT between the gooseneck and spool.

6.3 BRITISH PETROLEUM (GUIDELINES FOR BUTT WELDS)

British Petroleum (Leslie, 1996) enumerated several guidelines to be followed with respect to butt welding CT strings. Since this operation adversely impacts fatigue life and strength, butt welds are to be avoided as much as possible. However, banning the use of butt welds in the field is foreseen as presenting logistical and financial impacts that are too severe.

Among the recommendations BP instated are the following:

1. The maximum diameter of CT to be welded is 1¾ inches.
2. Welds should only be performed on pipes of similar thickness.
3. Butt welds should be positioned so that they are deep in the well, that is, in areas of lowest stress.
4. The maximum allowable fatigue life for a section of tubing with a butt weld is 40%.

6.4 CONOCO AND ARCO (DRAG REDUCER FOR HYDROCARBON FLUIDS)

Conoco Specialty Products and ARCO Alaska (Robberechts and Blount, 1997) reported the development and testing of a new drag reducing additive for hydrocarbon-based CT applications. High pressures in CT pumping operations to achieve high flow rates have the dual disadvantages of exceeding the capacity of surface pumping equipment and of reducing CT fatigue life. Drag reducers for water-base operations have proven to be very successful at the North Slope. Prior to this work, a drag reducer for hydrocarbons was not available. A new dispersed-polymer drag reducer was formulated and tested with success.

The new Aqueous Suspension Drag Reducing Additive (AS DRA) has been found to be effective in batch-mixed operations (Figure 6-8). The additive is also available in low freeze-point suspensions for harsh areas such as the North Slope.

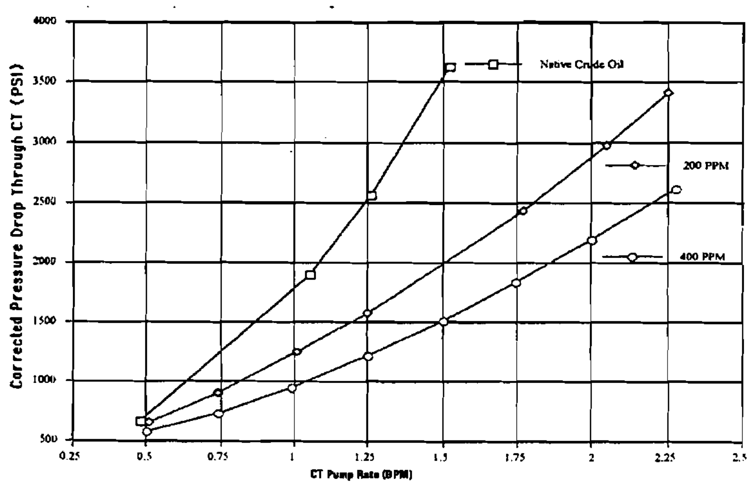


Figure 6-8. Pressure Drop with Drag Reducer (Robberechts and Blount, 1997)

Additional information is presented in *Buckling*.

6.5 CTES AND CAMCO (COMPARING FATIGUE MONITORING METHODS)

CTES and Camco Coiled Tubing Services (Brown et al., 1996) discussed and compared various methods to track fatigue life in individual CT strings. They showed that analytical methods, while the most costly to implement and utilize, typically allow more complete usage of available safe string life, as well as the ability to foresee and avoid costly failures due to localized high wear and/or damaged zones. Trends within the CT industry include less usage of job-count or running-feet methods, using shorter increments along the string for tracking fatigue life, accounting for factors other than plastic fatigue (ballooning, ovality, welds, corrosion), and the increased use of data acquisition systems for real-time fatigue modeling.

The four methods employed for tracking fatigue life are:

1. **Job count**–setting a maximum number of jobs for an individual string based on historical data for similar operations

2. **Running feet**–tracking the cumulative linear feet run over the gooseneck with an upper limit (say, 400,000 ft) based on historical data for similar operations

3. **Trip method**–keeping a manual log of the number of passes over the gooseneck for each section of the tubing (500-ft sections are a typical increment) with fatigue passes weighted for pressure, geometry, etc.

4. **Analytical methods**–a data-acquisition system is used to track pipe movement, pressure, etc. for short sections (5-10 ft) and predict fatigue life based on sophisticated theoretical/statistical models

The first two methods are clearly the simplest and least expensive techniques to implement. Brown et al. analyzed an example field operation to compare outcomes of these approaches with respect to string economics and overall safety. The example string was 12,000 ft of 1¼ by 0.095-in. 70-ksi tubing. This type of string is used to perform 50 cleanout jobs at depths from 6000 to 8000 ft. In the example life tracking, a field weld is assumed after 20 jobs.

If this string's life were tracked using the job-count method, the entire string is retired after the 50 job series (Figure 6-9). High-wear zones and welds are not considered.

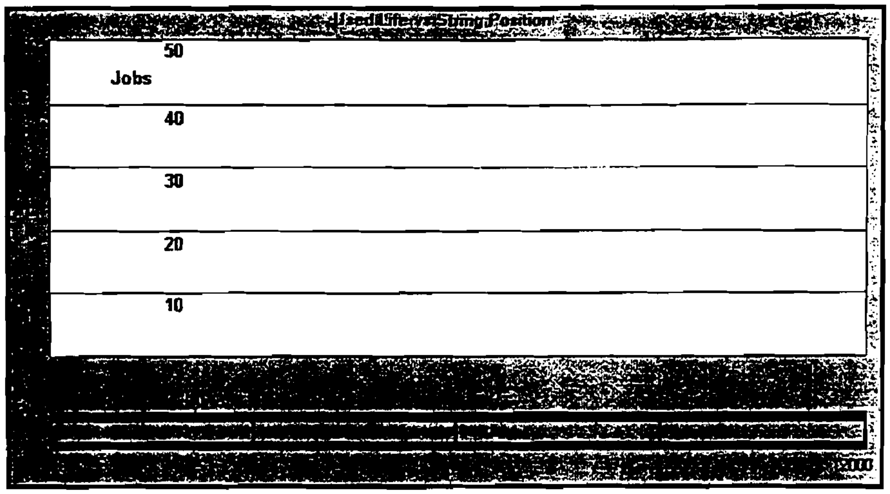


Figure 6-9. Example Fatigue Life Using Job Count (Brown et al., 1996)

The running feet may be based on a total of 400,000 ft, with lower values used for higher risk environments such as offshore. After the example 50 jobs are complete, about 395,000 running feet were tracked (Figure 6-10). This method also indicates that the string is ready to be retired.

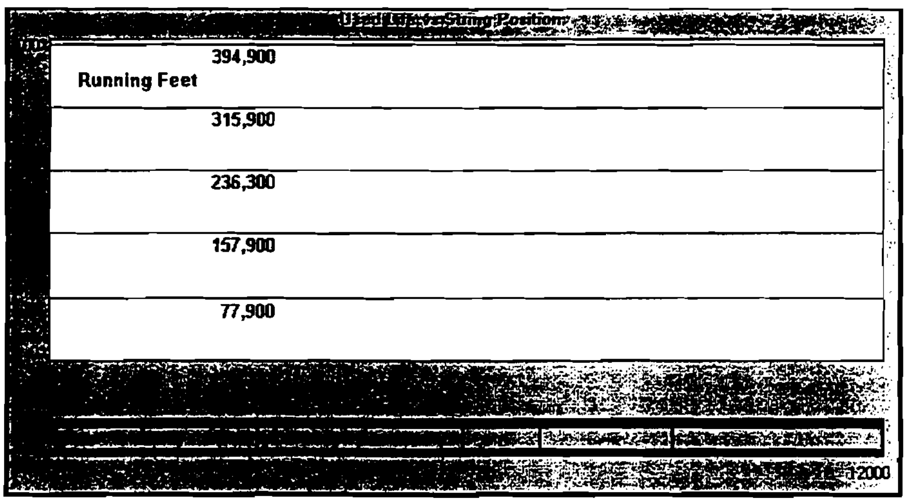


Figure 6-10. Example Fatigue Life Using Running Feet (Brown et al., 1996)

String-fatigue tracking results with the trip method based on 500-ft sections (Figure 6-11) show variation in consumed life along the string. The highest worn interval (two adjacent 500-ft sections) had wear of about 74%.

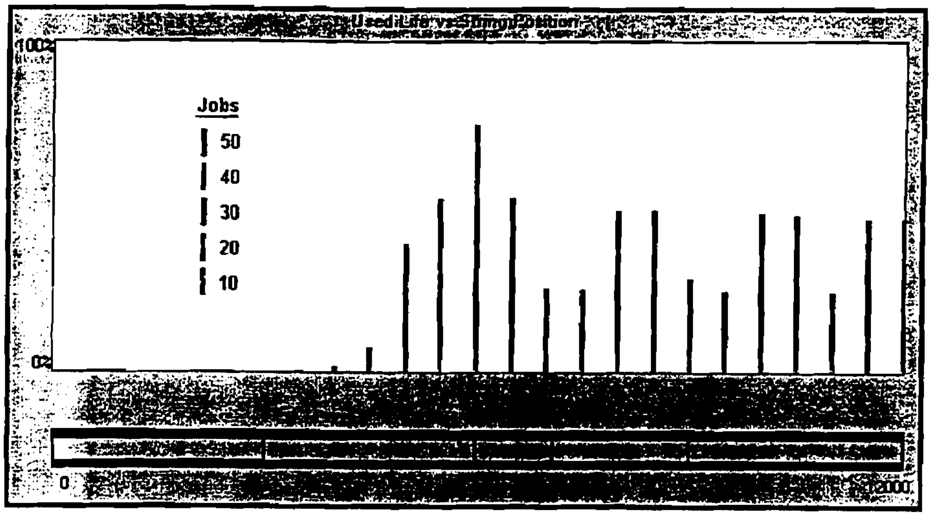


Figure 6-11. Example Fatigue Life Using Trip Method (Brown et al., 1996)

The analytical model based on 5-ft sections (Figure 6-12) shows important variations along the string. The butt weld at 7100 ft was derated to 25% of pipe life and is clearly visible in the string history.

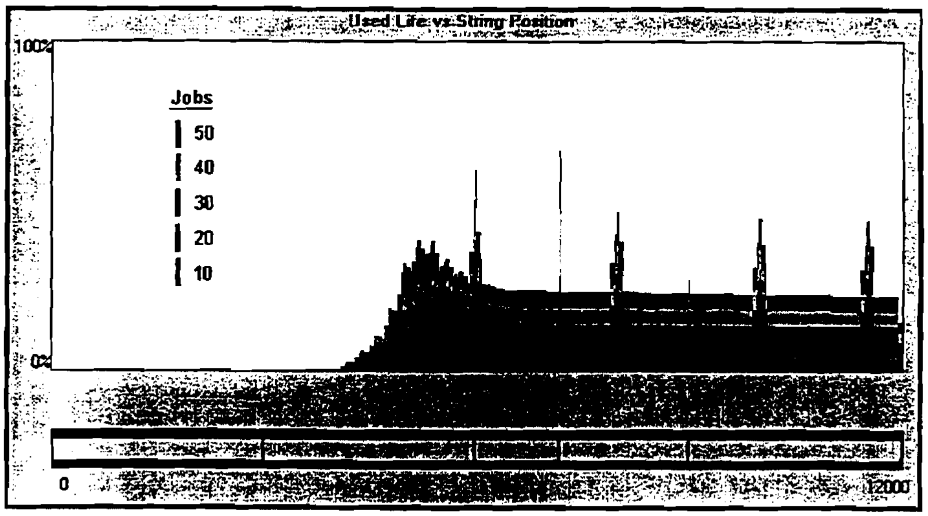


Figure 6-12. Example Fatigue Life Using Analytical Model (Brown et al., 1996)

The manual methods are shown to be typically very conservative and to therefore waste fatigue life. Analytical methods can foresee problems such as repetitive usage of the same section from job to job, and allow additional savings by changing procedures to more evenly distribute wear.

An example comparison of fatigue methods for field data from 18 workovers in shallow wells in California is shown in Figure 6-13. This comparison again demonstrates that manual methods can be overly conservative with regard to string life.

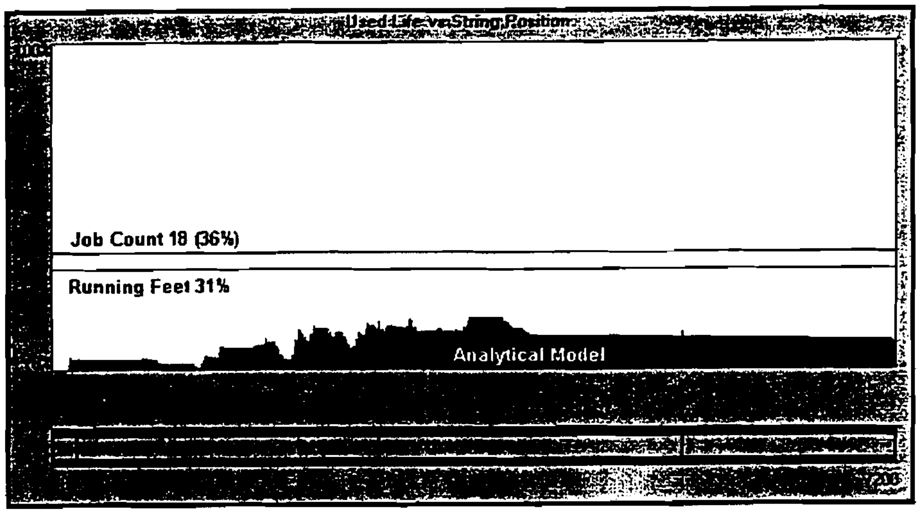


Figure 6-13. Comparison of Fatigue Methods for Field Data (Brown et al., 1996)

6.6 CTES (CT WELDING TECHNIQUES)

CTES (Newman et al., 1996) reported on a GRI-sponsored project to investigate the fatigue performance of field welds in CT. The project involved three aspects: 1) weld analysis of 400 samples of field welds, 2) a review of welding procedures, and 3) a consideration of alternative welding techniques. Based on the results of the project, an ICOTA standards committee was to develop an industry standard for CT field welding.

Three welding procedures for manual field welding were developed based on interviews with a variety of experts. These include 1) square butt welding (Figure 6-14), 2) V-groove weld with land (Figure 6-15), and 3) V-groove weld without land.

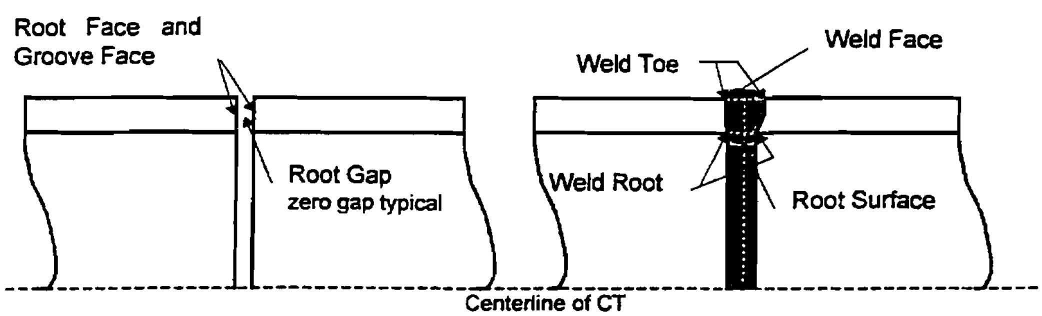


Figure 6-14. Square Butt Weld (Newman et al., 1996)

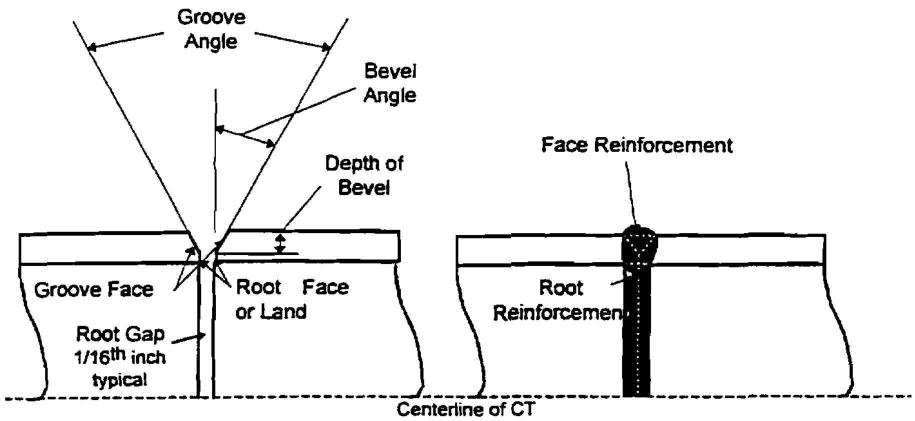


Figure 6-15. V-Groove Butt Weld with Land (Newman et al., 1996)

Orbital welding techniques were recommended if the equipment is available.

6.7 CTES (MODEL FOR DIAMETRAL GROWTH)

CTES (Brown and Dickerson, 1997) presented results from a study of CT diametral growth (ballooning). They compared modeled and observed results with respect to the impact of fatigue and ballooning on working life of the string. Common limits call for retiring a string of CT when the fatigue reaches 80% of predicted failure or when the OD is 6% greater than the nominal value.

CT ballooning with pressure is a well known phenomenon. An example of the growth of ballooning is shown in Figure 6-16 for 1¾- by 0.109-in. CT (80-ksi yield strength). CT ballooning per bending cycle depends on pipe geometry, pipe material, bending radius, and internal pressure. The most important difference between fatigue and ballooning is that internal pressure during bending is required for ballooning; pressure is not required for fatigue to occur.

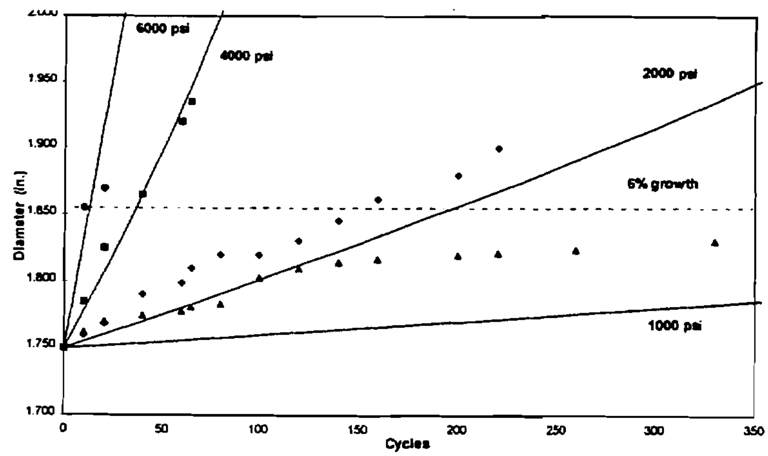


Figure 6-16. CT Ballooning with Pressure (Brown and Dickerson, 1997)

The interaction of fatigue accumulation and CT ballooning as they affect working life is shown in Figure 6-17. At pressures up to 2000 psi, ballooning does not impact CT working life. At higher pressures, 6% ballooning is often surpassed long before the fatigue cycle limit has been approached.

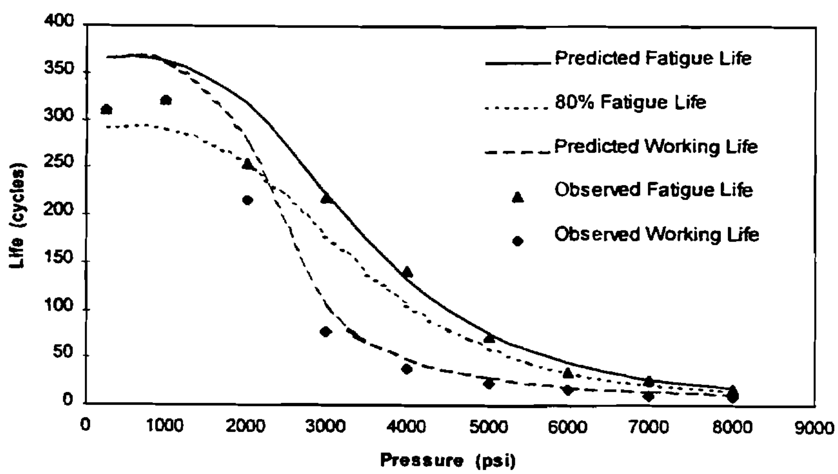


Figure 6-17. Fatigue Life and Overall Working Life (Brown and Dickerson, 1997)

A comparison of the build up of fatigue and ballooning in a CT string in the field is shown in Figure 6-18, which is based on a 1¼-in. string after 21 jobs. Fatigue and ballooning are well correlated, but important differences can be seen. For example, an average increase in fatigue occurs above 3500 ft, whereas ballooning is relatively constant. This is caused by several trips performed without pressure to 3500 ft (during a fishing job).

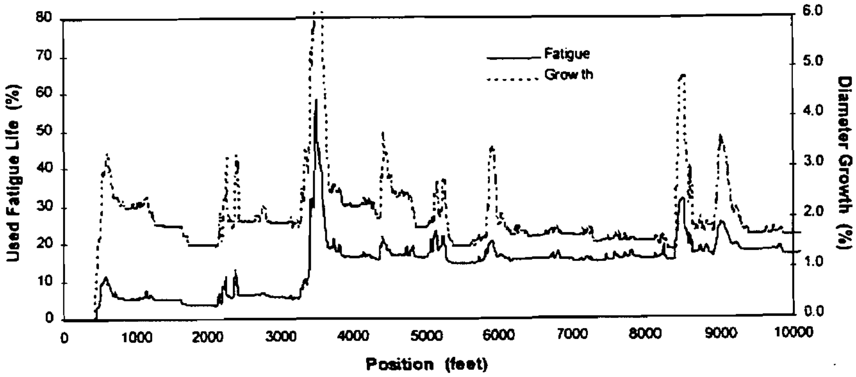


Figure 6-18. Example CT Damage after 21 Jobs (Brown and Dickerson, 1997)

6.8 CTES, ARCO, AND GRI (CT ELONGATION)

CTES, ARCO and GRI (Newman et al., 1997) investigated CT elongation while undergoing bending with axial loading. They found that elongation is permanent when the axial load is above a transition load. Elongation can be removed by bending when the axial load is less than the transition. The investigation sought to quantify CT elongation via finite-element analysis, numerical modeling, analytical modeling, and testing. Some of the more complicated scenarios could not be investigated experimentally. New test equipment was to be designed for these cases.

Modeling results (Figure 6-19) show that a bending cycle will remove most elongation due to axial load, provided the axial load is below the transition load.

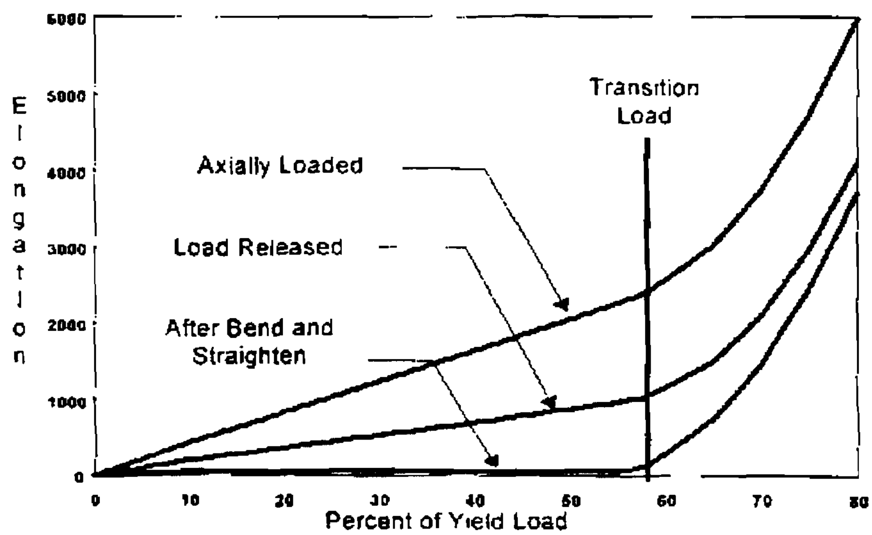


Figure 6-19. CT Elongation due to Axial Loading (Newman et al., 1997)

Several series of tests were conducted on a standard fatigue test machine. One set of tests is shown in Figure 6-20. The existence of a transition load was confirmed by test results.

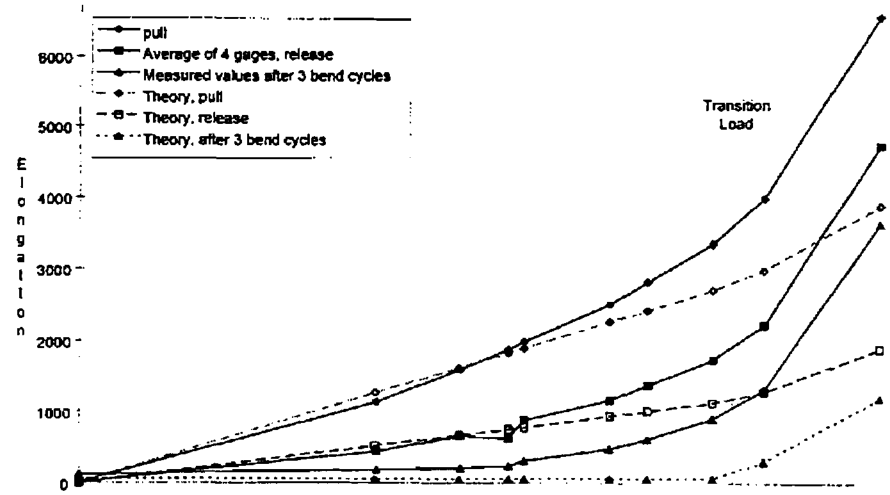


Figure 6-20. Example Test Results (Newman et al., 1997)

To study other more complicated scenarios, a new test machine was designed (Figure 6-21). This machine will allow applying a constant axial load while bending, and rotating the CT while in the straight position. Both of these conditions have been indicated as leading to significant elongation based on modeling results. Testing is needed to confirm this behavior.

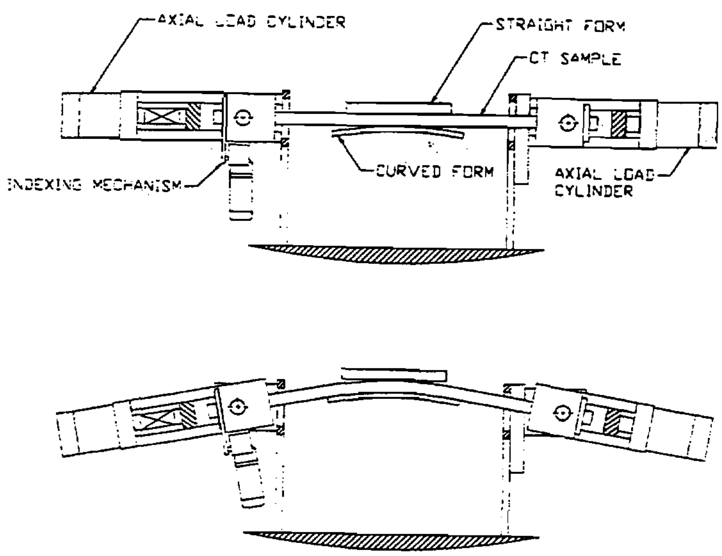


Figure 6-21. New CT Elongation Test Fixture (Newman et al., 1997)

6.9 DREXEL/TEXAS OIL TOOLS, CTES AND NOWSCO (BOP RAM DESIGN)

Drexel/Texas Oil Tools, CTES and Nowsco Well Services Limited (Palmer et al., 1995) investigated the performance of conventional and improved BOP rams for CT operations. The introduction of larger CT and improvements in fatigue-life modeling have made necessary the evaluation and improvement of standard shear and slip rams. They found that new designs for both shear and slip ram blades demonstrated superior performance.

Slip rams have been suspected as a source of damage that reduces fatigue life. Common practice has been to test the slip rams prior to every job, resulting in damage to the string.

Nowsco commissioned a series of tests to gauge slip-ram damage. Several samples of CT were gripped by various slip rams and placed in a fatigue fixture and bent to failure. Predictions for undamaged pipe were first developed for the test samples (Table 6-1).

TABLE 6-1. Fatigue Life Predictions for Slip Damage Tests (Palmer et al., 1995)

Internal Pressure (psi)	CT Wall Thickness (in)	Hoop Stress (psi)	Upper Confidence Limit (99%) (cycles)	Lower Confidence Limit (99%) (cycles)	Life Prediction (cycles
0	0.156	0	1,091	676	912
500	0.156	1,683	1,335	274	906
1,500	0.156	5,049	892	627	892
1,050	0.109	5,691	1,068	389	889
3,000	0.156	10,097	1,017	870	871

The greatest loss of fatigue life was observed for a knife-edge slip mark, with about a 70% reduction in cycle life (Table 6-2).

TABLE 6-2. Fatigue Life Lost by Slip Damage (Palmer et al., 1995)

Slip Mark Type	CT Wall Thickness (in)	Hoop Stress (psi)	Predicted Life for Unmarked (cycles)	Actual Life (cycles)	Life Reduction Due to Slip Mark (%)
Uninterrupted Teeth, Solid Slip	0.109	11,360	866	248	71.3%
Uninterrupted Teeth, Solid Slip	0.156	10,097	871	270	69.0%

Interrupted Teeth, Solid Slip	0.109	5,691	889	468	47.3%
Interrupted Teeth, Solid Slip	0.156	10,097	871	602	30.8%
Interrupted Teeth, Segmented Slip	0.109	0	912	488	46.5%
Interrupted Teeth, Segmented Slip	0.156	10,097	871	480	44.9%

An improved slip ram with interrupted teeth was found to have the least impact on fatigue life. These slips (Figure 6-22) reduce stress concentration and marking of the CT.

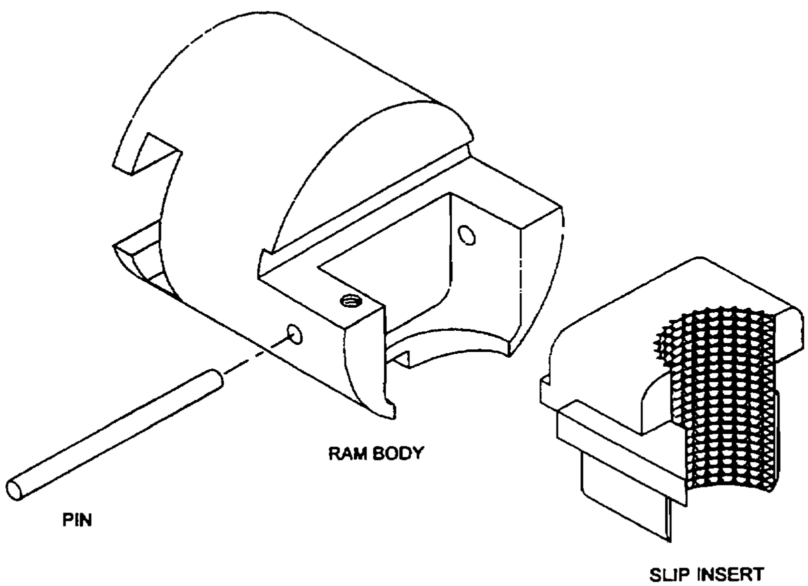


Figure 6-22. Improved Slip Rams (Palmer et al., 1995)

6.10 HALLIBURTON AND QUALITY TUBING (FATIGUE OF LARGE CT)

Halliburton Energy Services and Quality Tubing (Avakov and Martin, 1997) presented results of a new phase of fatigue tests and modeling for larger CT. Tests were conducted on CT from 1¼ to 3½ inches OD. Full-scale and standardized test-stand tests were performed on 70-, 80-, and 100-ksi material.

Measured results for field-test data (shown in Figure 6-23) were correlated with the model with a correlation coefficient of 0.94.

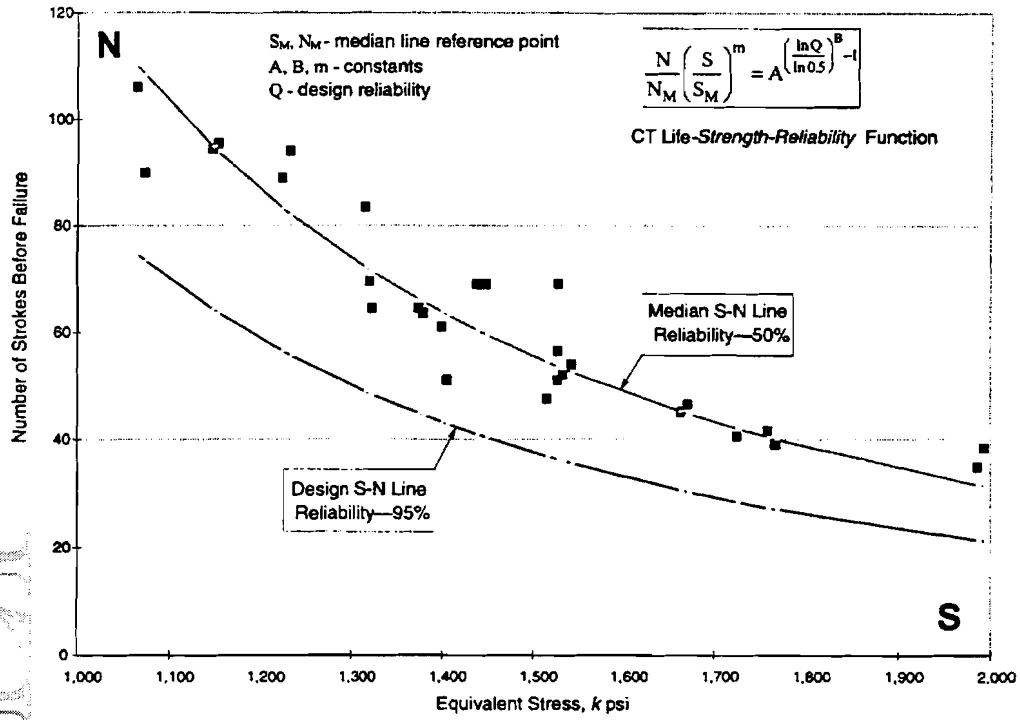


Figure 6-23. Fatigue Test Data (Avakov and Martin, 1997)

Predicted and recorded life for 28 individual samples (Figure 6-24) demonstrates good agreement.

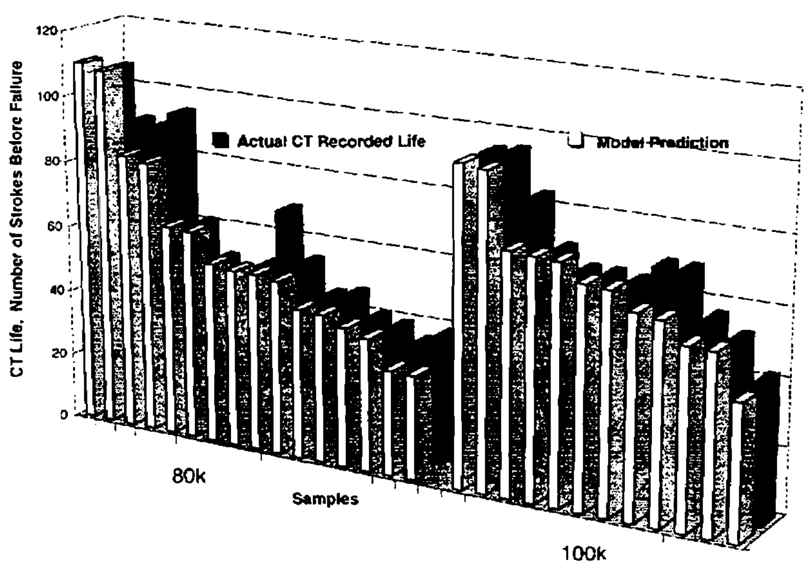


Figure 6-24. Predicted and Measured Fatigue (Avakov and Martin, 1997)

Results showed that 100-ksi CT does not have a significant fatigue-life improvement over 80-ksi unless the internal pressure is relatively high (Figure 6-25).

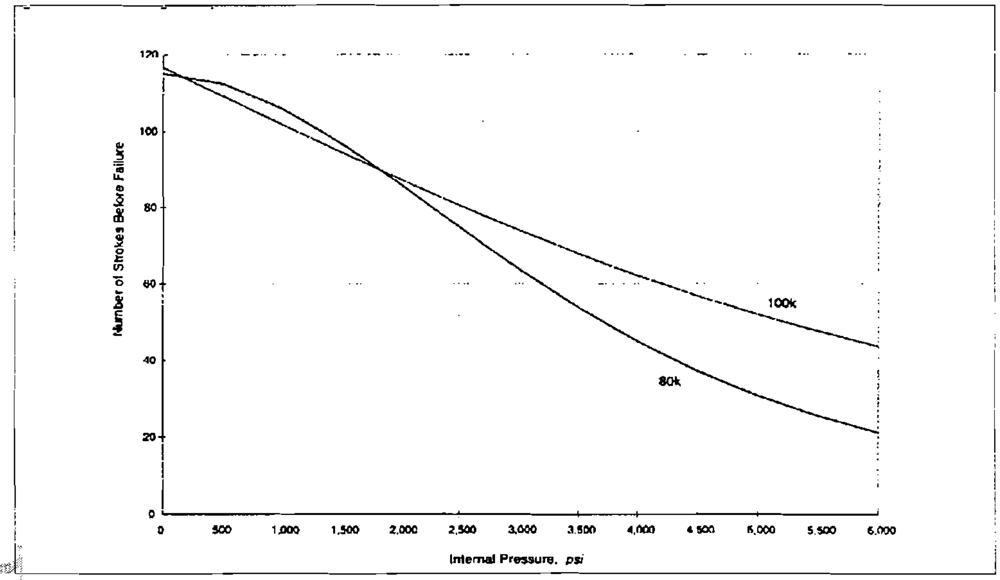


Figure 6-25. Fatigue and CT Strength (Avakov and Martin, 1997)

Based on the modeling efforts, a life safety factor was introduced into Halliburton's model to reflect the specific requirements of each type of field operation.

6.11 JNOC AND SUMITOMO METAL TECH (AMORPHOUS DIFFUSION BONDING)

Japan National Oil Corporation and Sumitomo Metal Technology (Cameron et al., 1997) performed comparative tests of fatigue life of welded CT. Diffusion welding was found to have several advantages over the commonly used CT butt-welding process of TIG (tungsten/inert gas). These advantages include the microstructure of welded joints is very similar to the base metal, and dissimilar alloys can be joined that are difficult to weld by fusion processes.

Several samples of CT were prepared that included welds of various types, as well as samples without welds. Fatigue test results (Table 6-3) show that the control sample lasted 502 cycles before fatigue failure. TIG-welded samples survived 92 to 157 cycles (18-31% of control). Amorphous diffusion bonded (ADF) samples survived 372 to 417 cycles (74-83% of control) before failure.

TABLE 6-3. Fatigue of CT Samples with Welds (Cameron et al., 1997)

	Material			Result of Life Cycle Bend Test	
Category	Mark	Joint Process	PWHT	Life Cycle (number of cycles)	Crack Site
New Joint Configuration	AP1	ADB	Applied	380	Parent Material
	AP2	ADB	Applied	417	Parent Material
	AP3	ADB	Applied	372	Parent Material
Conventional Joint Configuration	G1	TIG	Not Applied	152	Vicinity of Weld
	G2	TIG	Not Applied	92	Vicinity of Weld
	G3	TIG	Not Applied	137	Vicinity of Weld
	G4	TIG	Applied	157	Vicinity of Weld
Base Pipe	M	Not Applied	Not Applied	502	Parent Material

JNOC found that ADB welding may be an improved technique for CT field welding. It was found to have superior resistance to fatigue. It is also a semi-automatic process, is controllable and repeatable.

6.12 NAM, HALLIBURTON, AND ROSEN (CT INSPECTION SYSTEM)

Nederlandse Aardolie Maatschappij, Halliburton Energy Services, and Rosen Inspection Technologies (Koper et al., 1997) performed a series of full-scale fatigue tests and tested a CT inspection system. The automatic inspection/monitoring device measured OD and wall thickness over several axes continuously. Output from the device proved to be highly reliable for real-time determination of wall thickness, OD, and ovality.

Full-scale fatigue testing was conducted with their inspection/monitoring system (Figure 6-26). For one test of 100-ksi CT, predicted life was 70 cycles; failure occurred at 69 cycles at a location between the inspection device and the CT reel.

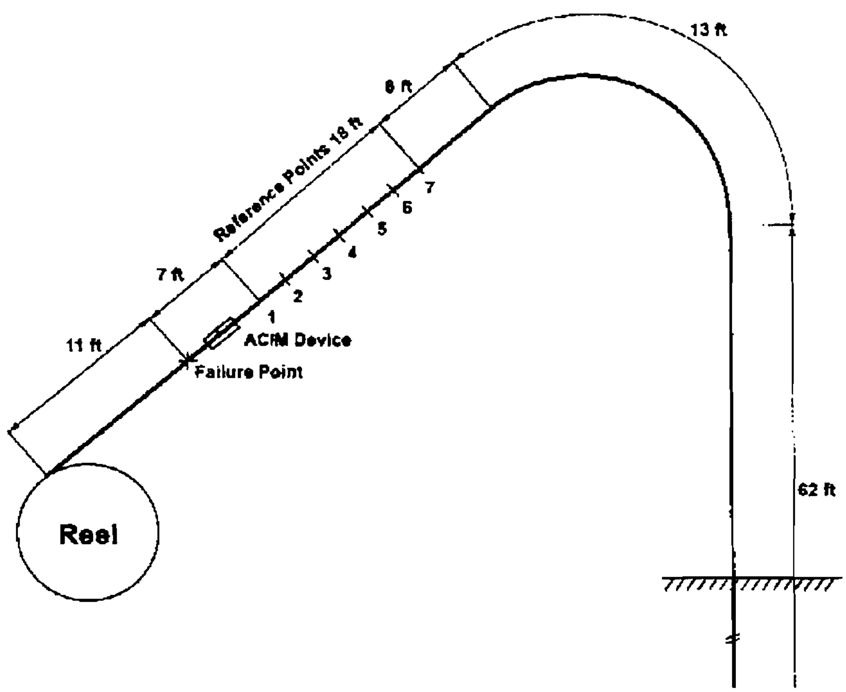


Figure 6-26. Fatigue Test Setup (Koper et al., 1997)

OD growth on the major axis (Figure 6-27) exceeded the 6% limit when the accumulated fatigue was about 50% of predicted total life. OD growth on the minor axis exceeded 6% at 65% of total fatigue life.

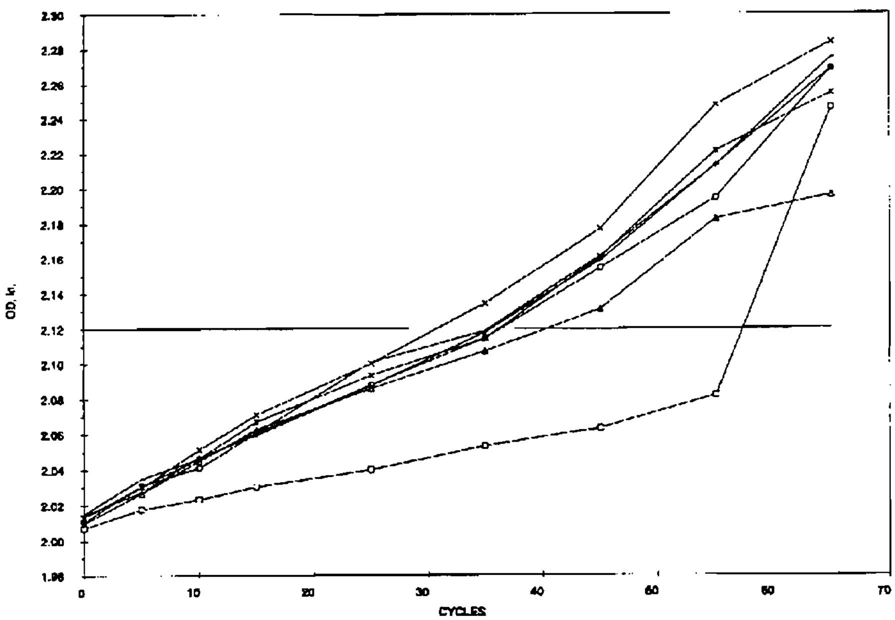


Figure 6-27. CT Ballooning on Major Axis (Koper et al., 1997)

The inspection and monitoring device (Figure 6-28) includes three major units which can be used independently. The system can be used for inspection during manufacturing, inspection after delivery, inspection before/after a CT operation, or inspection/monitoring during field operations.

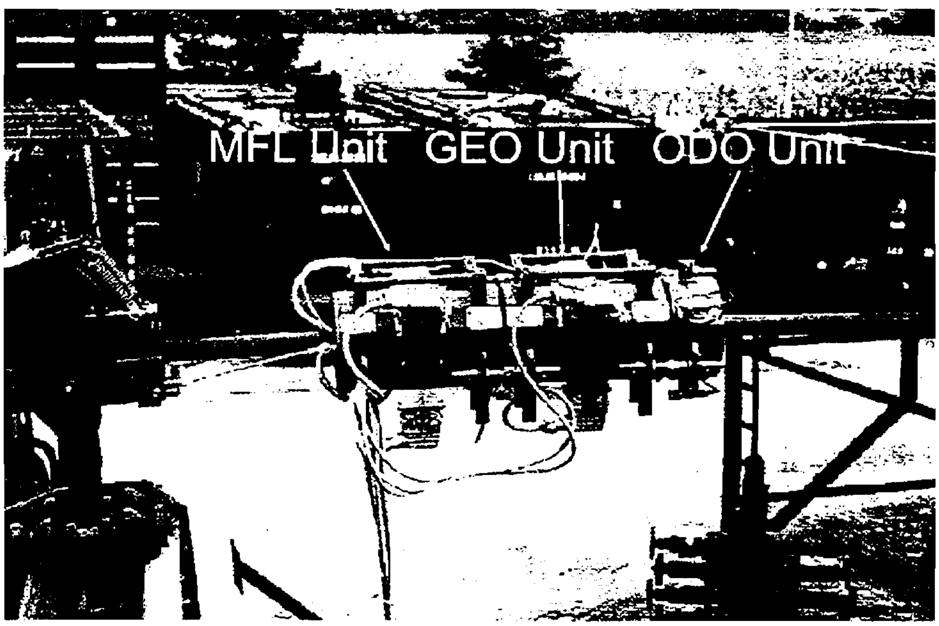


Figure 6-28. CT Inspection and Monitoring Device (ACIM) (Koper et al., 1997)

6.13 NOWSCO UK (FATIGUE MODEL)

Nowsco UK Ltd. (Campbell, 1996) described their fatigue-life management model CYCLE and compared predictions with field experience over the past several years. They found that using an analytical algorithm has increased string life in the field by two-fold as compared to running-feet methods for cycle life tracking. They have also found that the system is still generally conservative and that additional increases in cycle life by another factor of two may be possible. They believe that fatigue testing on special fixtures induces more rapid fatigue than do typical field operations, due to changes in the tubing axis relative to the bending plane that are characteristic of field usage. The small number of failures of CT that occurred when CYCLE was used (and were ascribed to fatigue failure) (Figure 6-29) were most likely due to the result of corrosion and/or other changes in the tube properties.

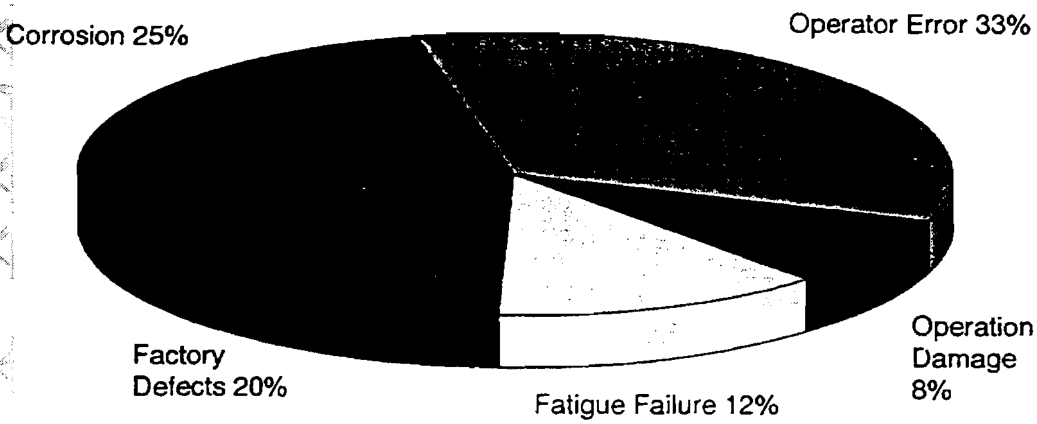


Figure 6-29. Causes of CT Field Failures (Campbell, 1996)

Before the CYCLE model was introduced into Nowsco's field operations, the decision to retire a string of CT was largely subjective and based on the opinion of the local manager. The CYCLE model (Figure 6-30) greatly extended the service life of strings as compared to previous procedures.

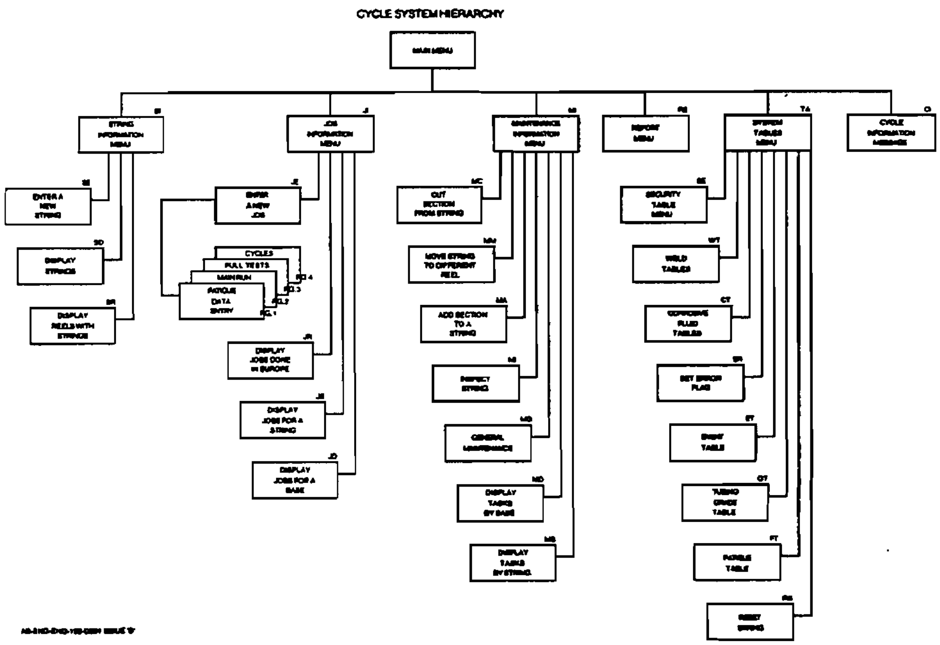


Figure 6-30. Design of CYCLE Fatigue Model (Campbell, 1996)

Nowsco's fatigue model is based on in-house testing using a special fixture (Figure 6-31).

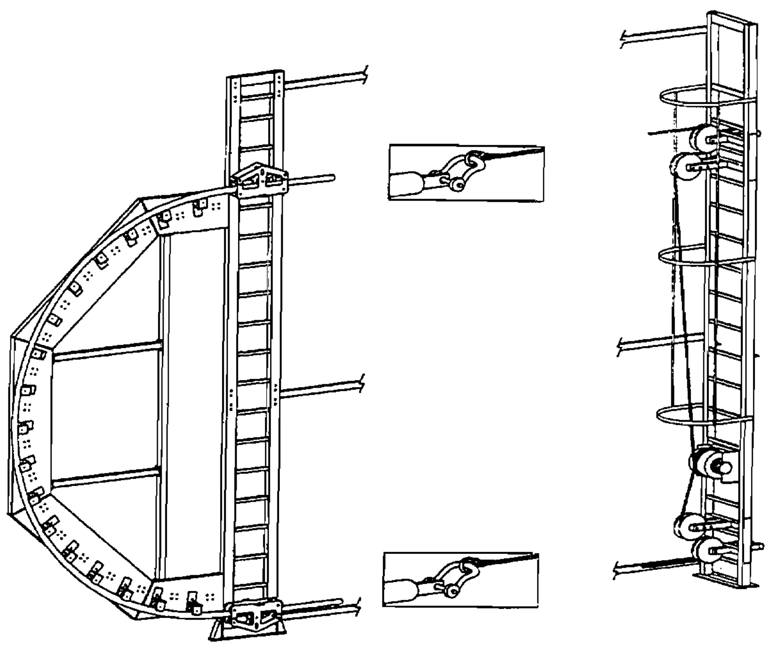


Figure 6-31. Nowsco's Fatigue Test Fixture (Campbell, 1996)

Fatigue data typically exhibit a broad scatter. Nowsco adopted a definition of safe working life based on the probability of failure of 1 in 1000. This corresponds to about 3 standard deviations below the mean, or a field service life of about 64% of the mean failure life (Figure 6-32).

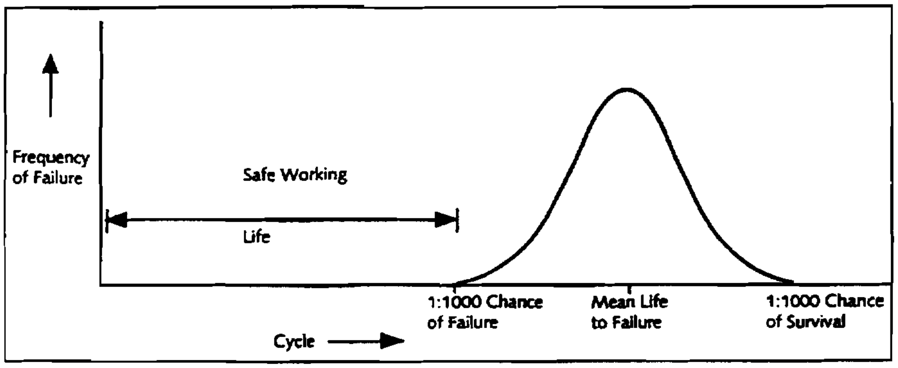


Figure 6-32. Definition of Safe Working Life (Campbell, 1996)

Abnormalities in the string are derated below the working life of normal tube. Butt welds with similar wall thickness are rated at 40% of standard life; at differing wall thickness, the rating is 20% of the thinner tube life.

Nowsco compared field experience from several areas around the world with model predictions. Generally, field life is greater than modeled life. An even greater disagreement was observed between the ballooning behavior of field and test samples. Field ballooning was much less than that for the test data. Nowsco believes that the high contact forces on the rollers on the test fixture significantly increase ballooning. Additional refinements to tests and the model should further improve predictions based on CYCLE.

6.14 QUALITY TUBING (FAILURES IN CT)

Quality Tubing (Stanley, 1998) presented an analysis of the causes of failure in steel CT along with methods and guidelines for derating CT after field use. Potential imperfections (including defects) include a wide range of conditions resulting from service life or introduced during the manufacturing process (Table 6-4).

TABLE 6-4. Imperfections in CT (Stanley, 1997)

Imperfection	Cause	Detection Method
Ovality	Cycling, initial Ovality	Eddy Currents
Ballooning	Pressure & cycling	Eddy Currents
ID Corrosion pits	HCl, KCl, Chromates	Magnetic Flux leakage
OD Corrosion pits	HCl, KCl, Chromates	Magnetic Flux leakage
Splits	Lack of flash, "hipp-tripping"	Pressure loss
Open Seams	Incomplete weldline fusion	Eddy Currents
Loss of YS	Crystal transformation in steel	Eddy Currents/conductivity
Rig Injector Rings	Rotating pipe in injector	Flux Leakage
Gripper marks	Too much pressure	Flux leakage
Erosion (OD)	Rubbing Tubing agst tbg, csg, formation. Acid	Magnetic Wall measurement
Erosion (ID)	Cement, acid	
Necking	Force too large	Eddy currents, mag wall mmt

Results from standardized fatigue testing show that fatigue life increases with CT strength and decreases with internal pressure. Cycle lives are shown in Figure 6-33 for three grades of CT cycled at 3000, 4000, and 5000 psi (back to front, respectively). These results are for $1\frac{3}{4}$- by 0.109-in. CT.

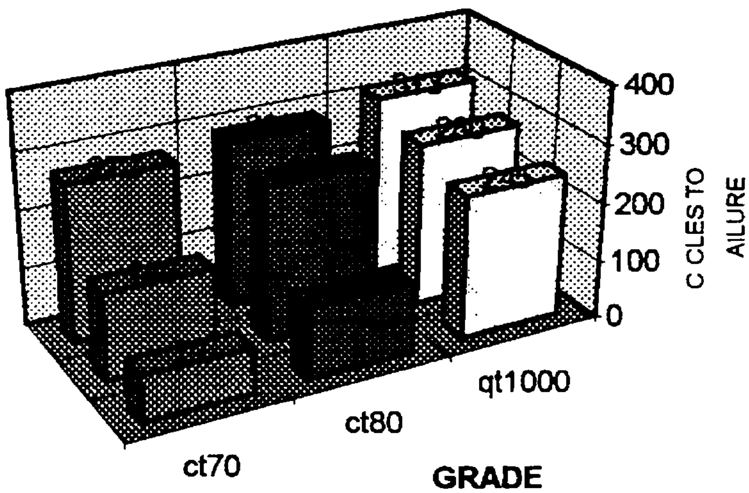


Figure 6-33. CT Strength and Fatigue Life (Stanley, 1998)

Additional information is presented in *Coiled Tubing.*

6.15 RIT (CT INTEGRITY MONITOR)

RIT has developed and marketed an Automatic CT Integrity Monitor (ACIM) for detecting and characterizing metal loss, general and pitting corrosion as small as 0.04 in., pinholes, inclusions, circumferential cracks and mechanical damage (Rosen, 1997). The ACIM is mounted near the spool (Figure 6-34) and consists of three major components: 1) magnetic flux leakage unit for metal loss, corrosion, and wall thickness, 2) an OD unit that measures six ODs and checks ovality, and 3) three odometer wheels for high-resolution measurement of CT depth and speed. ACIM systems are currently available for CT up to $2\frac{3}{8}$ inches.

More information is presented in *Rigs*.

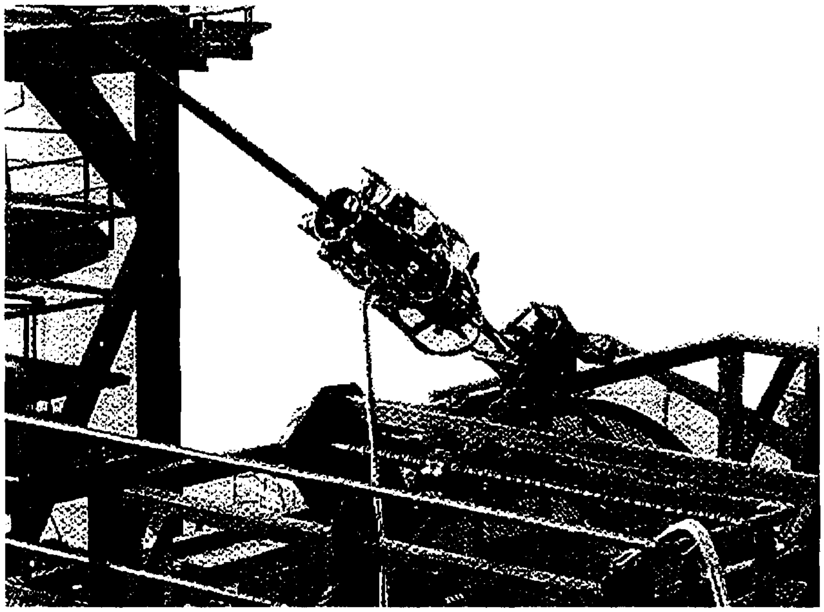


Figure 6-34. ACIM Integrity Monitor
(Rosen, 1997)

6.16 SAS INDUSTRIES (FATIGUE LIFE AND CT STRENGTH)

SAS Industries (Sas-Jaworsky, 1996) summarized concerns for CT fatigue life and presented example data for tube of a range of yield strengths. A comparison of fatigue life for 70-, 80-, and 100-ksi steel material for 1¾-in. CT is presented in Figure 6-35. Test results show that cycle life is relatively unaffected by material strength when internal pressure is low (less than 3000 psi). At higher pressures, the cycle life of 100-ksi material can be considerably greater than standard-strength materials.

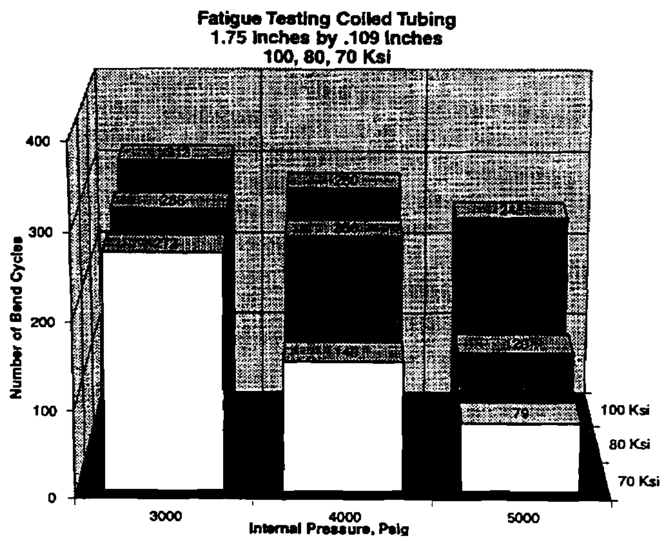


Figure 6-35. Fatigue Life for 1¾-in. CT (Sas-Jaworsky, 1996)

The effects of tubing welds on fatigue life are another area of investigation. Quality Tubing performed a series of tests comparing virgin tube, a section with a bias weld, and a section with a step-tapered bias weld. The results (Figure 6-36) show that a normal bias weld causes almost no penalty (9% less than virgin tube). A tapered bias weld (0.109 welded to 0.125 for this test) averaged 57% reduction in cycle life. Other studies showed that butt welds had lower lives, that is, from only 25-30% that of the tube body.

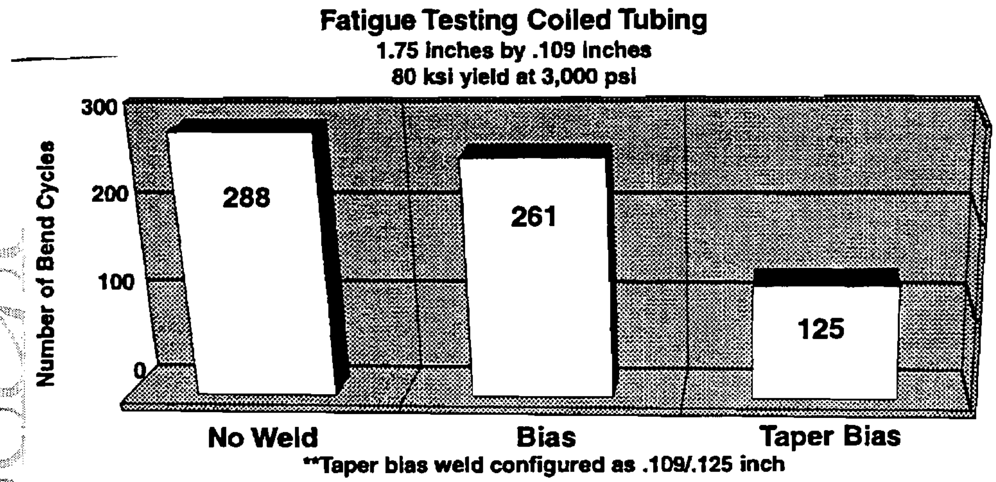


Figure 6-36. Fatigue Life for Welds (Sas-Jaworsky, 1996)

6.17 SCHLUMBERGER DOWELL (CT STRAIGHTENING AND FATIGUE)

Schlumberger Dowell (Bhalla, 1995) presented an analysis of the benefits of various methods to increase the reach of CT in horizontal and deviated wells. Methods to reduce buckling include increasing buoyancy of the CT, friction reducers, optimum taper designs, OD of CT, removing residual bending, using downhole tractors, pumping fluid, and pump-down systems. These methods, either singly or in combination, can be used to substantially increase reach when applied appropriately.

Extended-reach technologies have seen rapid development in the UK and Norwegian sectors of the North Sea. Some wells (Gullfaks and Statfjord fields) cannot be serviced with standard CT operations. New techniques and procedures have been refined for these applications.

Schlumberger Dowell simulated the impact of a variety of techniques to reduce buckling and increase penetration in these wells. The example well used in the simulations is shown in Figure 6-37.

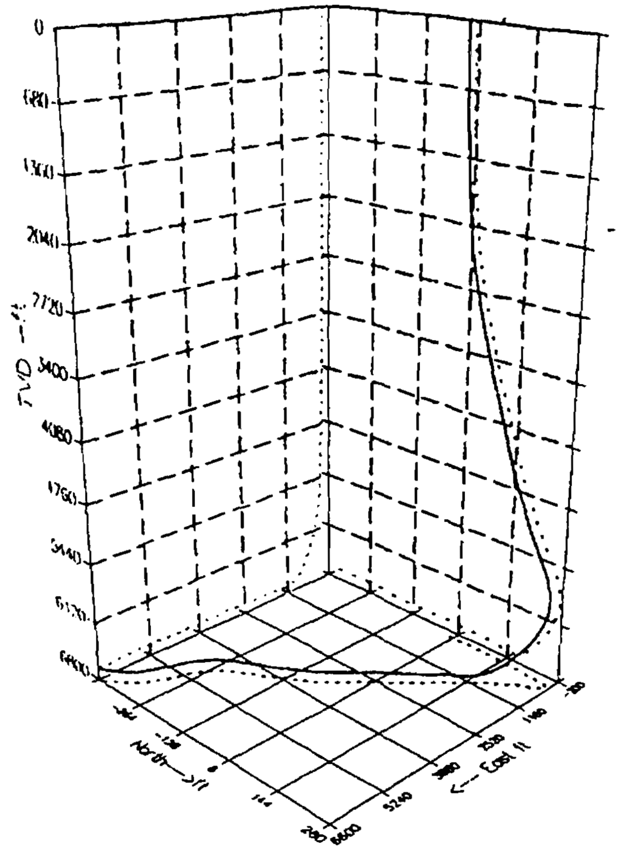


Figure 6-37. Example Well used for Buckling Simulation (Bhalla, 1995)

Residual bends have an adverse impact on penetration limits. The injector constrains the CT to be straight while in the gripper blocks, but does not completely unbend the tubing. Schlumberger Dowell measured residual bending radii on new 1½-in. 70-ksi tubing (Table 6-5). The reel radius was 58 in.; gooseneck radius was 72 inches.

TABLE 6-5. Residual Bends in 1½-in. CT (Bhalla, 1995)

	Residual Bend Radius
Reel to Gooseneck	227.9" (18.9 ft)
Gooseneck to Injector	102.8" (8.6 ft)
After Injector	252.5" (21.0 ft)

These tests demonstrated that CT enters the well with a bend radius of 21 feet. Since this bend will hasten the onset of helical buckling, removing this bend will increase penetration limits. Calculations for the example well (Figure 6-38) indicate that reach will be increased from 10,849 ft out an additional 2153 ft with straight CT.

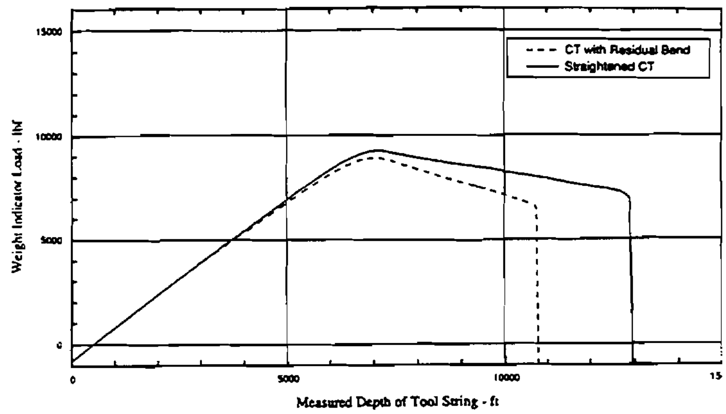


Figure 6-38. Surface Weight with Straight CT (Bhalla, 1995)

The disadvantage of using a straightener to increase CT reach is an accompanying increase in fatigue life. The additional bending reduces cycle life (Table 6-6). To enjoy the predicted additional reach of 2153 ft, cycle life of 15 to 23% for the coil will be consumed. Thus, an economic decision is required with respect to the use of a straightener.

TABLE 6-6. CT Life with Straightener (Bhalla, 1995)

Pressure (psi)	Cycles without Straightener	Cycles with Straightener
0	101	78
500	98	78
1,000	94	77
5,000	74	64
10,000	46	39

Additional information is presented in *Buckling*.

6.18 SCHLUMBERGER DOWELL (HIGH-PRESSURE OPERATIONS)

Schlumberger Dowell (van Adrichem et al., 1995) described the engineering process for designing CT rig equipment for use in high-pressure gas wells in South Texas. Previously, time-consuming snubbing units had been used. CT units were applied in the area to reduce costs. After equipment development and modification, average costs were reduced by 50% for the first fifty jobs. Field time was reduced from 7-12 days with snubbing units to 1-3 days with CT.

Operating limits were developed for the harsh conditions. Early limits (Table 6-7, middle column) were based on practical rules of thumb rather than calculations. CT is now stronger and thicker than in the past, so operating limits can be increased under appropriate conditions.

TABLE 6-7. CT Operating Limits (van Adrichem et al., 1995)

PARAMETER	CONVENTIONAL LIMITS	HIGH-PRESSURE LIMITS
Maximum Pressure at Wellhead, psi	3500	9000
Collapse Pressure, psi	1500	10,000
Static Burst Pressure, psi	5000	10,000
Dynamic Burst Pressure, psi	4000	10,000
Maximum Tension, % of yield	80	80

Tubing size selected for these operations was narrowed to the range of 1 to 1½ inches. One-inch would not allow sufficient pump rates. Good burst and collapse ratings highlighted 1¼ x 0.156-in. as a good solution. Safety factors with 1½-in. tubing were not as favorable.

A yard test of the equipment was conducted at high pressure to investigate the impact of ballooning and fatigue. It was found that ballooning (Figure 6-39) was the limiting factor. A limit for diametral growth of 5% was established for field operations.

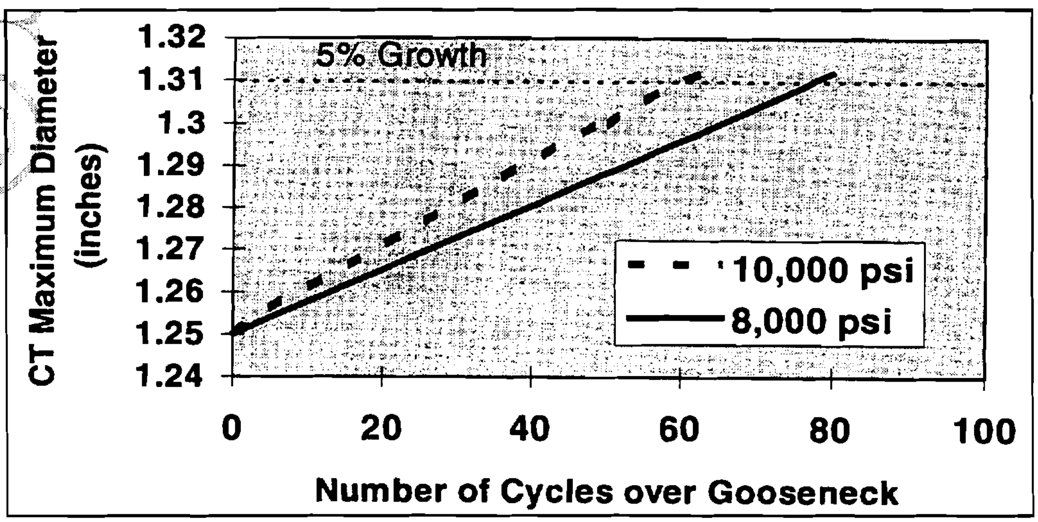


Figure 6-39. High-Pressure Ballooning (van Adrichem et al., 1995)

Economic analysis showed that several cleanouts could be performed with a single string of CT before the ballooning limit was exceeded.

6.19 UNIVERSITY OF TULSA (CT SURFACE CHARACTERISTICS AND FATIGUE)

Steven Tipton (1997) of the University of Tulsa reported preliminary results of a study of CT surface morphology and localized defects. It was demonstrated that there is an inherent tendency for fatigue cracks to initiate on the inner surface of CT. He tested about 90 coupon samples of three grades of CT, and cracks initiated on the inner surface for all samples.

There are distinct differences in the inner and outer surface profiles of CT after it is rolled during manufacture (Figure 6-40). Metal roughness is well known to have an important impact on fatigue. However, almost all previous investigations had been centered on high-cycle fatigue.

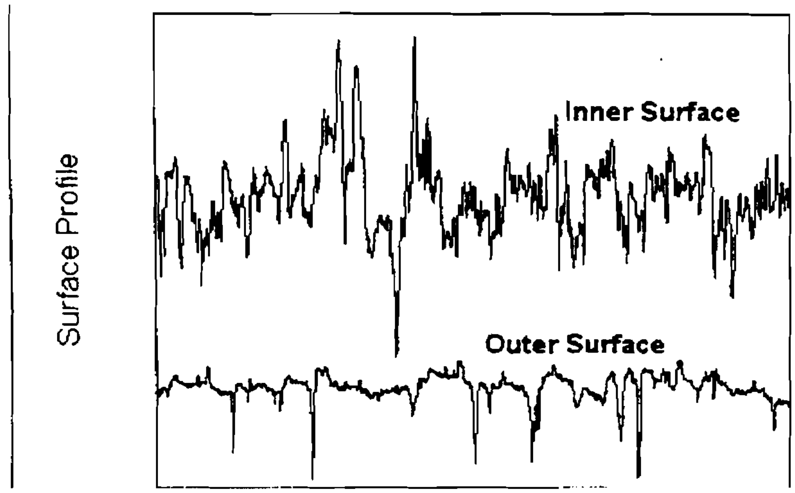


Figure 6-40. CT Surface Profiles (Tipton, 1997)

Samples of CT were polished to more than an order of magnitude smoother than as-rolled CT. The lessening of surface roughness was found to increase fatigue life. For 1.6% strain, fatigue life was nearly doubled (Table 6-8). (This level of strain is typical for CT field operations.) Primary cracks that led to fracture still initiated at the inner surface.

TABLE 6-8. Fatigue of Polished CT (Tipton, 1997)

Strain Range	As-Manufactured	Polished ID
1.6%	501 417	897 (95% increase)
2.6%	195 192	321 (66% increase)

Surface defects were simulated by cutting sharp notches into several samples. Notches cut to 5% of wall thickness reduced fatigue life by 57% (Table 6-9). Repairing a 10% notch by grinding restored fatigue life to 91% of the base value.

TABLE 6-9. Fatigue with Sharp Notches (Tipton, 1997)

Notch Depth / Type	Life (cycles)	% of Base Life
5% / EDM	243	43%
10% / EDM	172	31%
12% / Flaw Repaired	515	91%

Other tests were conducted with U- and V-notched samples (Figure 6-41). Higher strength 100-ksi material was observed to be less sensitive to notches than was lower strength material. Deep notches (12% wall) reduced fatigue life in all grades (although more impact was observed in lower strength material).

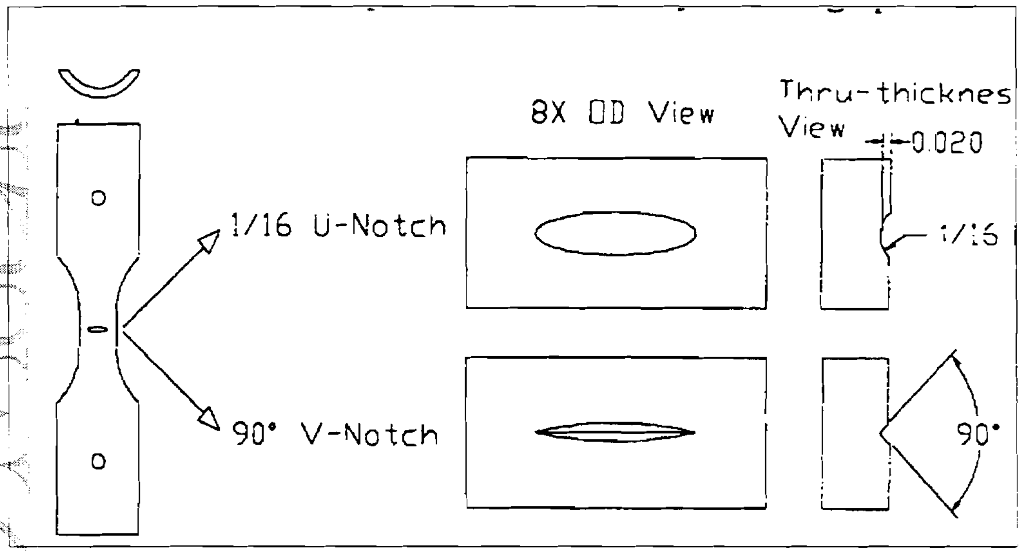


Figure 6-41. U and V Notches (Tipton, 1997)

Tipton found that tube rolling causes differences in surface roughness between the inner and outer walls. His testing results suggested that a threshold exists for surface-defect severity. It may be that this threshold must be exceeded before an external defect (notch) will have an important impact on fatigue life.

6.20 REFERENCES

Avakov, Vladimir A. and Martin, John, 1997: "Large Coiled Tubing Fatigue Life," SPE 38407, presented at 2nd Annual SPE/ICOTA North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Bhalla, K., 1995: "Coiled Tubing Extended Reach Technology," SPE 30404, presented at Offshore Europe Conference, Aberdeen, September 5-8.

Brown, Paul A. and Dickerson, J.L., 1997: "Development and Use of an Analytical Model to Predict Coiled Tubing Diameter Growth," SPE 38409, presented at 2nd Annual SPE/ICOTA North American

Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Brown, P., et al., 1995: "Economic Benefits of Advanced CT Life Monitoring," SPE 36337, presented at 1st SPE/ICoTA North American CT Roundtable, Montgomery, Texas, February 26-28.

Cameron, G. et al., 1997: "Amorphous Diffusion Bonding: New Technology Toward a Seamless-Reeled-Tubing System," *JPT*, May.

Cayard, M.S. and Kane, R.D., 1997: "Serviceability of Coiled Tubing for Sour Oil and Gas Wells," SPE 38410, presented at 2nd Annual SPE/ICOTA North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Cizek, Art, 1997: "Corrosion Effects of Hydrogen Sulfide on Coiled Tubing and Carbon Steel in Hydrochloric Acid," *JPT*, September.

Engel, S.P. and Monro, C., 1997: "Coiled Tubing Operations From a Floating Vessel," SPE 38400, presented at 2nd Annual SPE/ICOTA North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Koper, Mark G.M. et al., 1997: "Full-Scale, Low-Cycle Fatigue Tests with 2-in. Coiled Tubing and Automatic Coiled Tubing Inspection and Monitoring System," SPE 38415, presented at 2nd Annual SPE/ICOTA North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Leslie, Charlie, 1996: "Coiled Tubing Butt Weld Recommendations," *The Brief*, February.

Maroli, R. et al., 1996: "Development of HPHT Coiled Tubing Unit," SPE 35561, presented at European Production Operations Conference, Stavanger, April 16-17.

Newman, K.R. et al., 1996: "Analysis of Coiled Tubing Welding Techniques," ICOTA 96007, presented at 1st Annual SPE/ICOTA North American Coiled Tubing Roundtable, Conroe, Texas, February 26-28.

Newman, K.R. et al., 1997: "Elongation of Coiled Tubing During Its Life," SPE 38408, presented at 2nd Annual SPE/ICOTA North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Palmer, R. et al., 1995: "Developments in Coiled Tubing BOP Ram Design," OTC 7876, presented at 27th Annual OTC, Houston, Texas, May 1-4.

Rosen, P.M.A., 1997: "Coiled Tubing Integrity Monitoring During Operations," *World Oil*, December.

Robberechts, Hilde and Blount, Curtis, 1997: "A New Generation of Drag Reducer Additives Hydrocarbon Based CT Applications," presented at 5th International Conference on Coiled Tubing and Well Intervention, Houston, February 4-6.

Sas-Jaworsky, A., 1996: "High-Pressure Applications Enabled by CT Advances," *The American Oil & Gas Reporter,* January.

Stanley, R.K. 1997: "Failures in Coiled Tubing," presented at 5th International Conference on Coiled Tubing and Well Intervention, Houston, Texas, February 4-6.

Tipton, Steven M., 1997: "Surface Characteristics of Coiled Tubing and Effects on Fatigue Behavior," SPE 38411, presented at 2nd Annual SPE/ICOTA North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Tipton, Steven M. 1997: "Low-Cycle Fatigue Testing of Coiled Tubing," presented at 5th International Conference on Coiled Tubing and Well Intervention, Houston, February 4-6.

van Adrichem, W.P. et al., 1995: "Development and Utilization of a Coiled Tubing Equipment Package for Work in High Pressure Wells," OTC 7874, presented at 27th Annual OTC, Houston, May 1-4.

7. Fishing

TABLE OF CONTENTS

7. Fishing

7.1 AMOCO TRINIDAD OIL COMPANY (RECOVERING SLICKLINE)

Amoco Trinidad Oil Company (Forgenie et al., 1995) used CT to perform a strip-over operation of a slickline fish. The modified approach eliminated the risk of recovering the wire piecemeal using conventional wireline methods. Cost savings were considerable, if it is assumed that wireline operations would not have been successful.

The subject well is located in the Samaan field offshore Trinidad. Slickline operations were being used to recomplete the well. A problem arose when a shifting tool became stuck in a nipple profile.

After unsuccessful jarring, efforts were made to unlatch from the shifting tool. Two cutting devices (go-devils) were attached to the stuck wire and dropped in the hole. Neither reached the tool. Later, the slickline parted near the surface and fell in the hole (Figure 7-1).

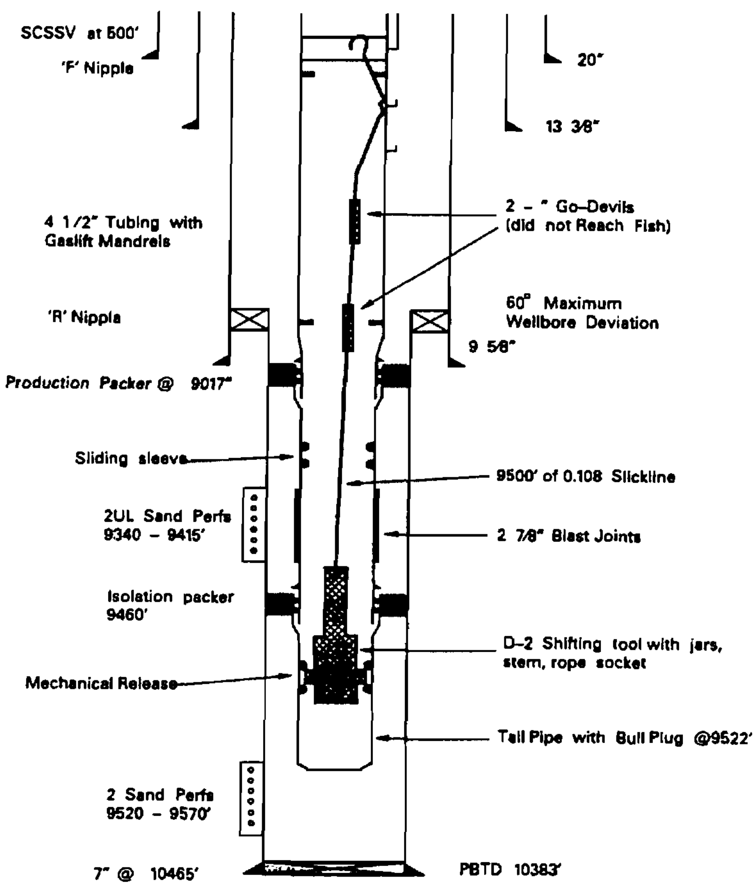


Figure 7-1. Wellbore with Fish (Forgenie et al., 1995)

The operator decided to avoid multiple wireline runs to retrieve the wire fish. A CT strip-over operation was designed that would allow constant well control throughout the recovery operations.

The first step was to fish the end of the slickline with wireline. Then, a guide shoe was fabricated for stripping over the wire with CT (Figure 7-2).

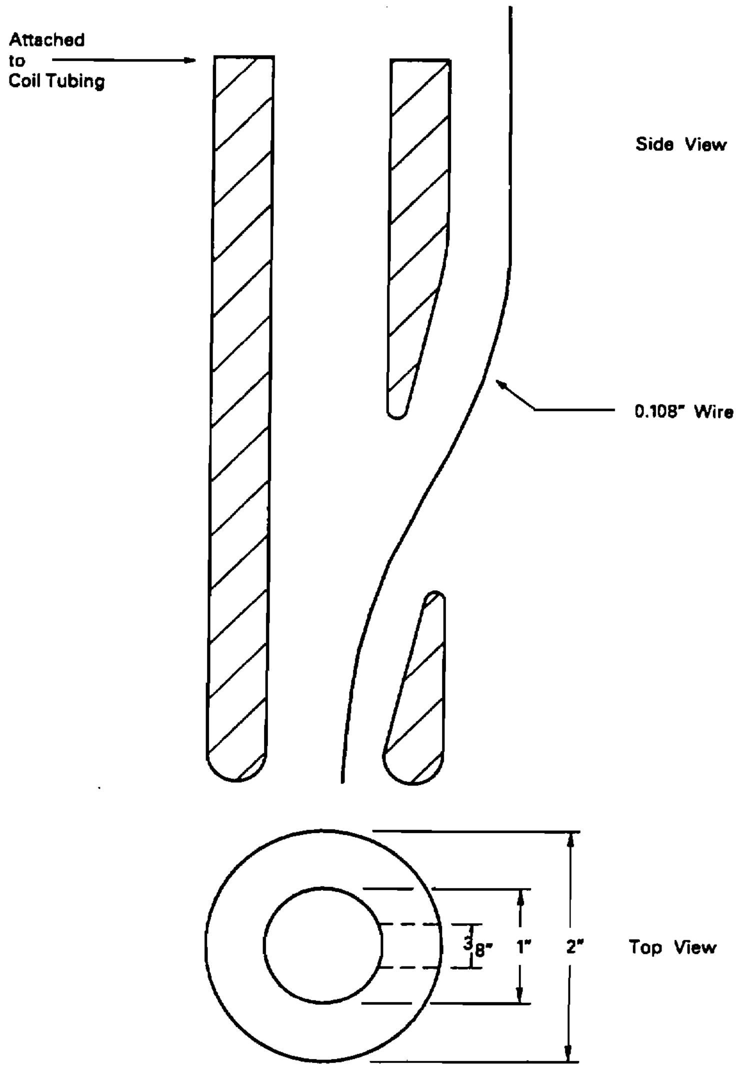


Figure 7-2. Wire Guide Shoe (Forgenie et al., 1995)

The wire was threaded through the shoe, out into the wellbore annulus and out through a special "Y" on the surface (Figure 7-3).

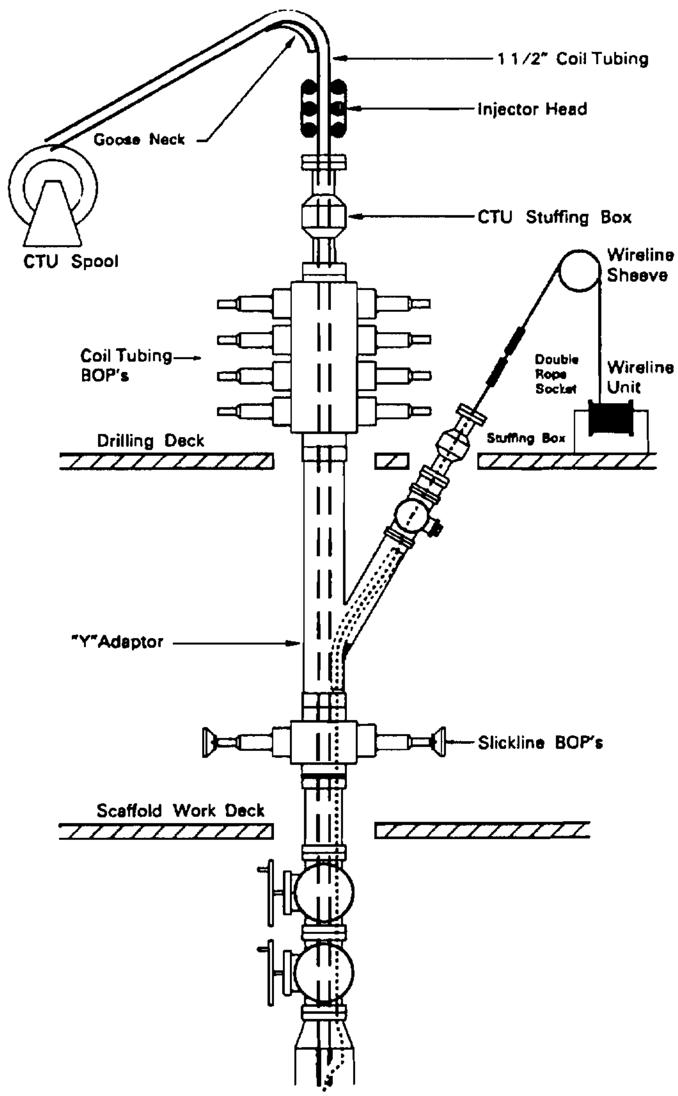


Figure 7-3. CT Rig-Up for Fishing Wire
(Forgenie et al., 1995)

The CT was tripped in at 30 ft/min while pushing the go-devils to the rope socket (Figure 7-4). The wire was cut when the CT weight was set on the fish.

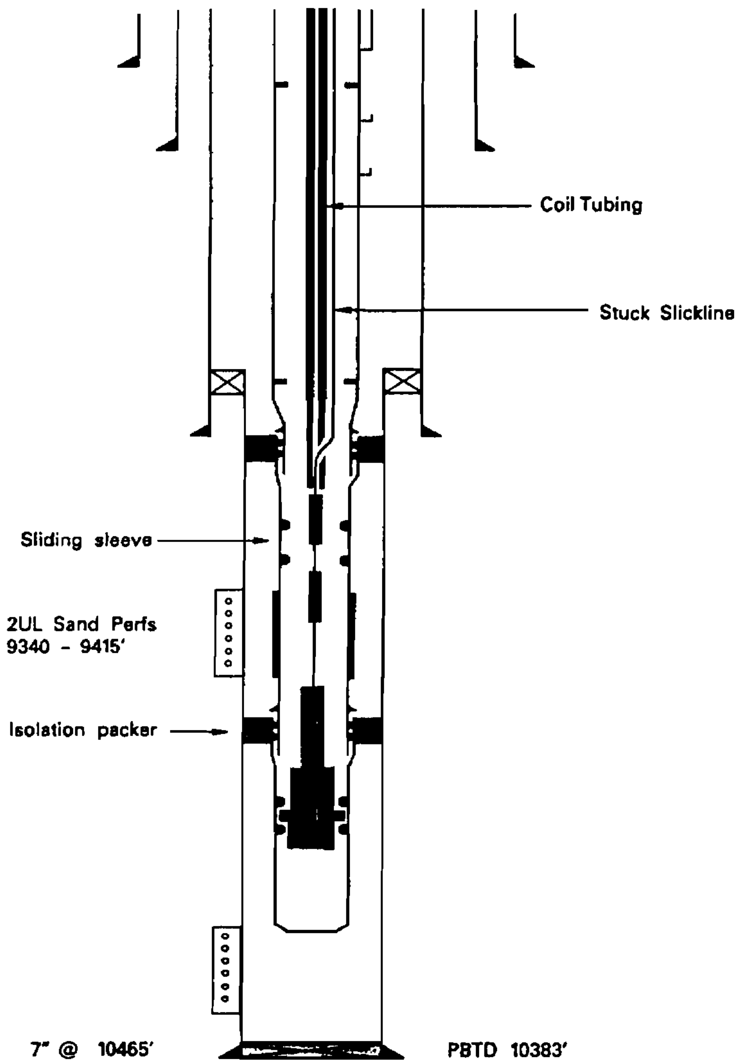


Figure 7-4. Pushing Go-Devils to Stuck Shifting Tool
(Forgenie et al., 1995)

The operator then attempted to fish the go-devils and shifting tool with wireline. The top go-devil was retrieved; the other fish were not. CT was then deployed to attempt the fishing job. However, rather than retrieving the fish, the CT pushed the tools into the tailpipe. Operations were halted since the tools were now out of the way.

Fishing operations were completed in 1½ days; costs totaled about $25,000. Had a rig workover been necessary to retrieve the tool and save the well, costs would have exceeded $500,000.

7.2 BRITISH PETROLEUM (CT FISHING TOOL)

British Petroleum successfully unstuck a string of CT with a new fishing tool (*PEI* Staff, 1996). The operator was evaluating a logging bypass plug when the plug became stuck on the adjustable spacer sub union below the packer (Figure 7-5, number 1). Several conventional approaches were tried without success.

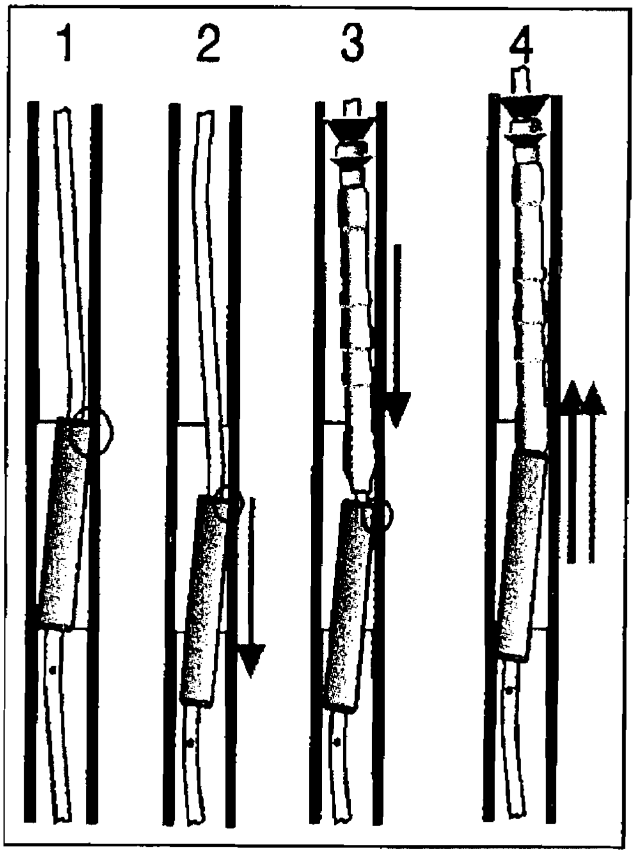


Figure 7-5. Fishing Tool to Unstick Bypass Plug (*PEI* staff, 1996)

The new solution was to run a sleeve down the outside of the CT to centralize the top of the plug and direct it around the obstruction. A wrap-around sleeve was devised and pumped down using a wiper dart on top of the assembly (Figure 7-5, number 3).

The CT string was run 50 ft past the hang-up point and placed in tension. The assembly was then pumped downhole. The string and bypass plug were retrieved successfully on the first attempt.

7.3 VIBRATION TECHNOLOGY (METHOD TO UNSTICK CT)

Vibration Technology LLC (Bernat, 1998) described a resonant vibration system for unsticking CT and other tubulars. Three components form the resonating system (Figure 7-6): 1) a mechanical oscillator, 2) a tubing string for transmitting vibration, and 3) a stuck fish to be freed.

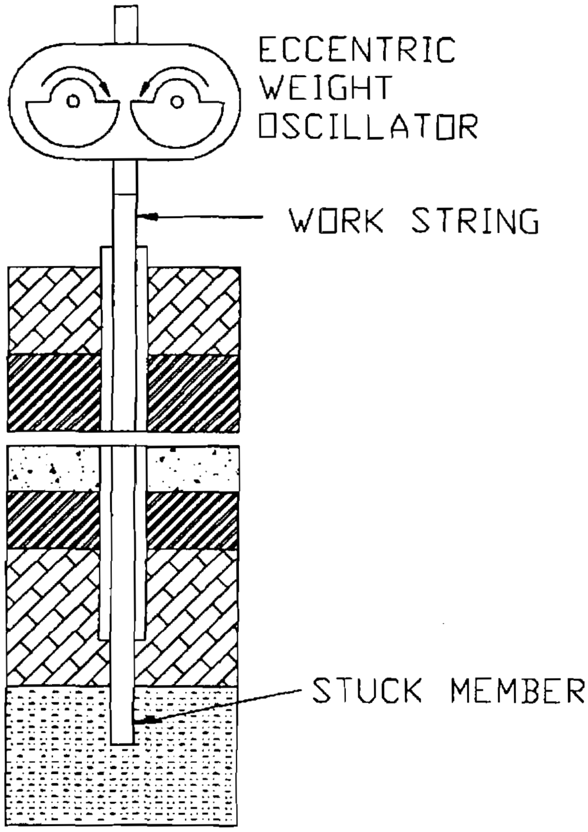


Figure 7-6. Vibration System for Unsticking CT
(Bernat, 1998)

Vibration is generated by an eccentric-weight mechanical oscillator that produces axial sinusoidal forces that can be tuned to specific frequencies. At resonance, energy developed by the oscillator is efficiently transmitted to the stuck CT.

The pipe oscillator (Figure 7-7) is attached to the CT above the injector by friction clamps. The injector remains in place to immediately recover the CT when it is freed.

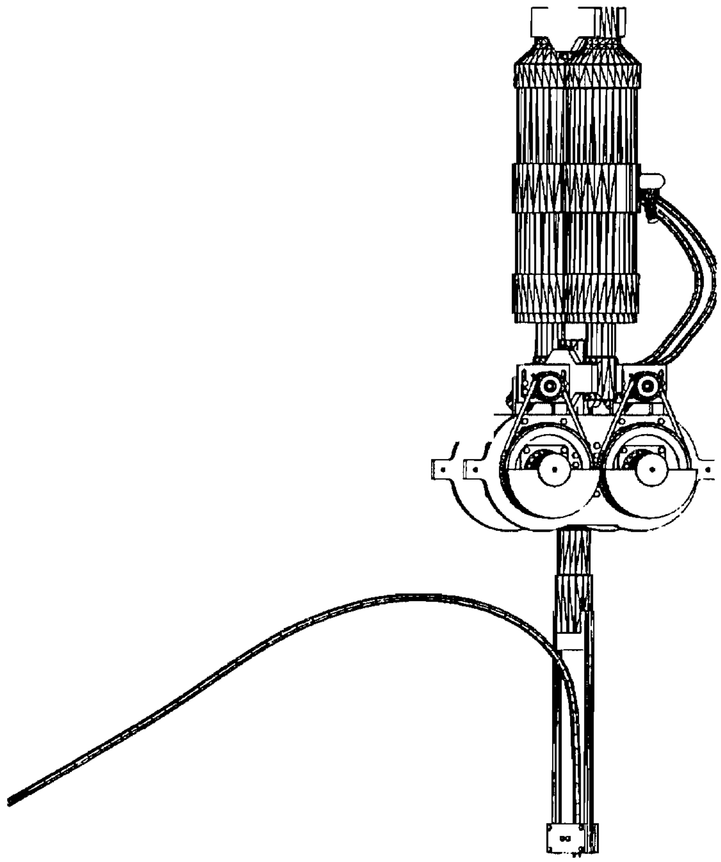


Figure 7-7. CT Oscillator (Bernat, 1998)

Typical job duration for freeing CT is 1 day. Several case histories of freeing CT are summarized in Table 7-1.

TABLE 7-1. Fishing Successes with Vibrator (Bernat, 1998)

Well Location	Reported Sticking Mode	Well Geometry	Well Depth / Freepoint	Coil and BHA Detail	Well bore fluid [ppg]	Prior Action	Vibration Results	Subsequent Action
Harris Co., TX	Sand stuck coil tubing	Deviated 20 deg.	10,500' / 8,500'	1 1/2" coil with wash tool - 10,500'	[9]	3 days working with coil injector	Successful - 30 minutes operation	Continued washing operation
Jim Hogg Co., TX	Mechanical stuck coil tubing	Deviated 25 deg.	13,000' + / 12,363'	1 1/2" coil with wash tool - 12,363'	Dry - gas flow	3 days working with coil injector	Ineffective - fish moved ~3 feet; 4 hours operation	Cut coil, RU snubbing unit, worked 2 weeks, no recovery
Gregg Co., TX	Velocity string corkscrewed and/or sand stuck	Vertical	10,500' / 10,050'	1-1/4" coil tubing - 230' * overshot * 1-1/4" coil tubing velocity string - 10,270'	[9]	3 days working with coil injector	Innefective after 4 hours operation	Cut coil, fish conventional
Polk Co., TX	Shale, sand due to clean-out	Vertical	14,000' / 1,000'	1 1/4" coil with wash tool - 14,000'	[9]	3 days working with coil injector	Successful. Moved Free Point to 9,750 ft.	Cut at freepoint for washover.
Starr Co., TX	Shale, sand due to clean-out	Vertical	14,000' / 12,000'	1 1/4" coil with wash tool - 12,000'	dry gas	3 days working with coil injector	Successful < 2 hrs. operation	Put on production
Brazoria Co., TX	Shale, sand due to clean-out	Vertical	12,500' / 10,500'	1 1/4" coil with wash tool - 12,500'	[9]	7 days working with coil injector	Successful. Freed 900 ft. to 11,400	Cut coil, produce well
Harrison Co., TX	Composite plug and frac sand due to clean-out	Vertical	9,600' / 9,200'	1 3/4" coil with motor and mill - 9,200'	[9]	1 day working with coil injector	Successful < 1 Hr. operation	Continued washing operation

7.4 REFERENCES

Bernat, Henry, 1998: "Coil Tubing Recovery Using Pipe Vibration Technology," published by Vibration Technology LLC, Shreveport, Louisiana.

Forgenie, V.H. et al., 1995: "Coiled Tubing Fishing Operations Utilize a First Time Technique to Strip Over and Recover 9500 Feet of Stuck Slickline Wire," SPE 30678, presented at the Annual Technical Conference and Exhibition, Dallas, Texas, October 22-25.

PEI Staff, 1996: "Stuck Coiled Tubing Spawns New Fishing Tool," *Petroleum Engineer International*, March.

8. Logging

TABLE OF CONTENTS

8. Logging

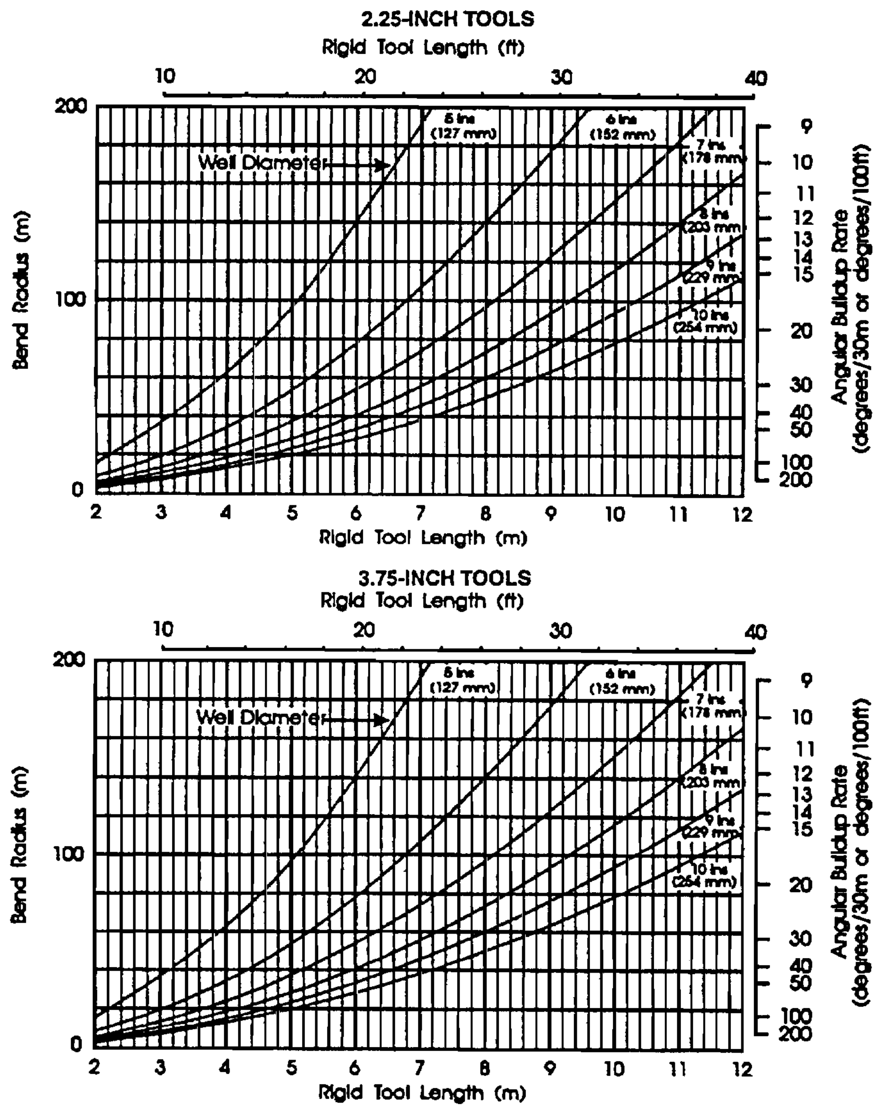
8.1 BPB WIRELINE SERVICES (CT-CONVEYED SLIM LOGGING TOOLS)

BPB Wireline Services (Houpe, 1996) summarized the benefits and availability of slim logging tools suited for use in horizontal wellbores. CT conveyance has been proven as generally superior to jointed-pipe methods. Lateral penetration limits resulting from buckling have been extended with larger CT and through various methods, including temporarily hanging small tubing or casing to the lowest vertical section of the well. A reduced diameter in the vertical section effectively reduces friction and extends horizontal penetration.

BPB Wireline Services' slim-hole logging tool line is based on the following general specifications: 2¼-in. OD, 255°F rating, and 12,500 psi rating. Oil-field slim tools include:

RESISTIVITY:	Array Induction Sonde Dual Laterolog Sonde
NUCLEAR:	Dual Density/GR/Caliper Dual-Neutron Sonde
ACOUSTIC:	Multichannel Sonic
AUXILIARY:	CT Adaptor Tension/Compression Sub Slim Repeat Formation Tester Four-Arm Dipmeter

Negotiating the curve with the logging string can be a significant obstacle/limitation for logging horizontal wells. The rigid tool length for 2¼-in. tools is plotted in the upper graph in Figure 8-1. The lower graph is for conventional 3¾-tools. A slim short logging tool string is preferred in most cases. Swivels, knuckles and cranks are also used to minimize effective string length.



Note: For a given tool diameter, maximum build tool length (L) that will traverse a well of diameter (d) and bed radius (R) is given by: L=2[(R+d)2-(R+t)2]1/2. Angular build rate (degrees/30 meters)=1718/R.

Figure 8-1. Maximum Tool Length Through a Curve (Houpe, 1996)

BPB Wireline provided example logs from a job in Germany to illustrate the benefits of logging in horizontal holes, even when significant offset vertical well data are available. In one case, a re-entry was drilled on CT and logged with the same rig. Coil size was 2⅜ inches. The logging tools were slightly smaller than the tubing, resulting in an ideal situation with respect to buckling and lateral penetration.

The dual-density/gamma-ray/caliper traces from a slim horizontal sidetrack are shown in Figure 8-2. Several tight lens were found between 1792 and 1865 m. These barriers were blamed for previously observed pressure variations across the field.

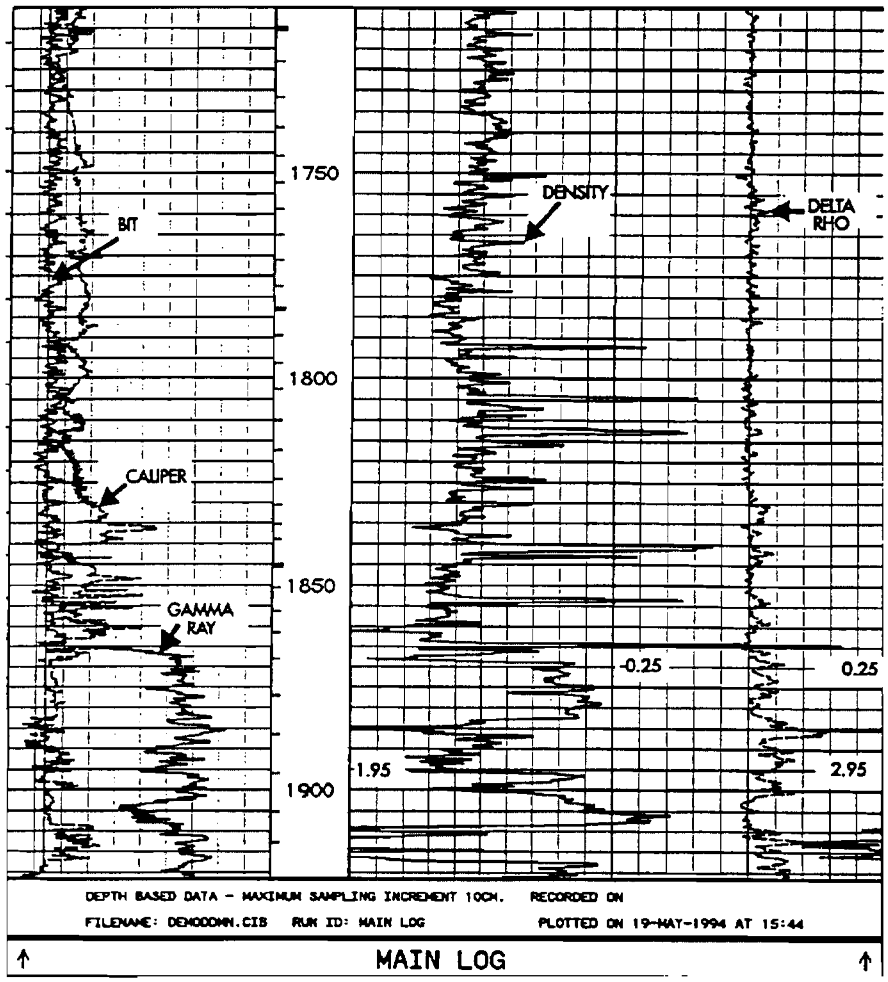


Figure 8-2. Log from Horizontal Sidetrack (Houpe, 1996)

Significant hydrocarbon deposits were revealed in the shaly sand analysis (Figure 8-3). The well-defined permeability barriers and faults were revealed in greater detail than expected.

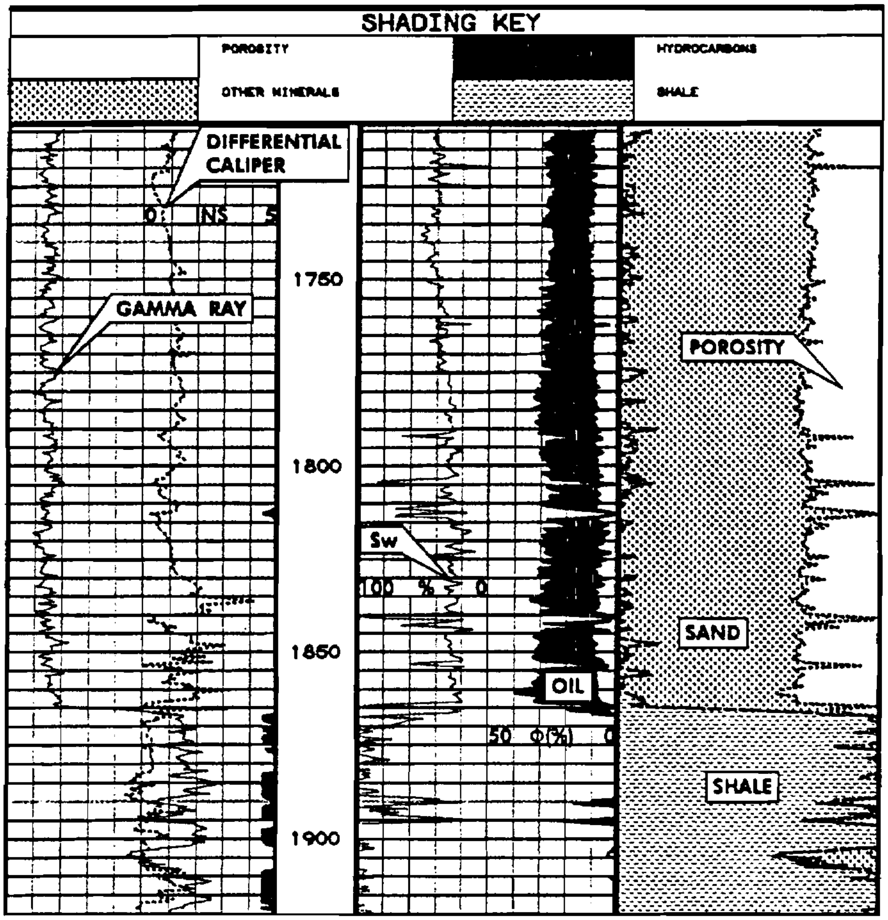


Figure 8-3. Lithology Log from Sidetrack (Houpe, 1996)

8.2 BP EXPLORATION (MEMORY LOGGING ON CT)

Significant cost savings have been reported from Prudhoe Bay by using memory logging tools on CT (Sas-Jaworsky and Bell, 1996) (Figure 8-4). Average costs were reportedly reduced almost 50% for running logs in horizontal wells (from $38,500 to $19,800). Since no wireline is required, CT spool and surface equipment requirements are greatly reduced. A standard string with five sensors can record data up to 22 hours at a sampling rate of 1/sec.

The principal disadvantage is lack of feedback on tool function and/or damage. BP has tried to minimize the potential for damage by performing dummy runs with tool strings of similar dimensions prior to running the logging string.

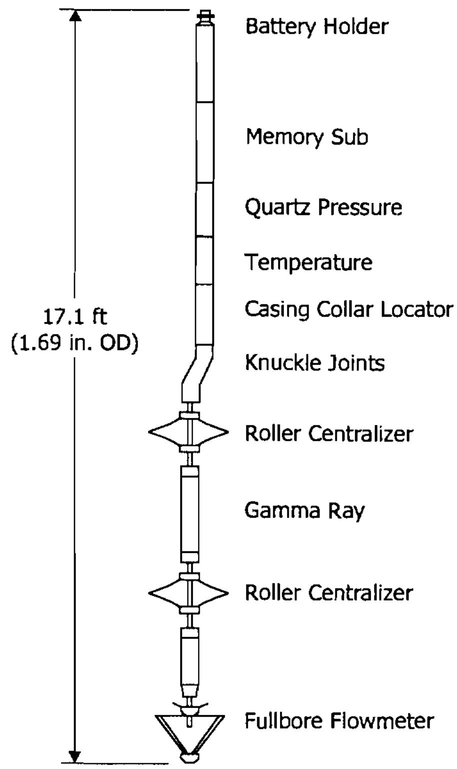


Figure 8-4. CT Memory Logging BHA (Sas-Jaworsky and Bell, 1996)

8.3 CTES AND DREXEL (CT CABLE INSTALLATION)

CTES and Drexel (Newman et al., 1995) described the design of a CT wireline cable installation system that will install wireline inside CT while still on the reel. The new fixture greatly reduces the cost of cable installation as compared to previous methods, which include: 1) hanging off CT in a vertical well and lowering the wireline inside, 2) laying the CT out horizontally and pumping the cable through, and 3) installing a steel pull line inside the CT during manufacture, laying the CT out horizontally and pulling the cable through. Each of these methods is expensive ($15,000 to $25,000).

It has long been known that cable can be pumped out of CT by pumping water at high rates. Turbulence causes the cable to vibrate and so removes the friction element, allowing the cable to advance with the flow. However, pumping cable into CT (Figure 8-5) is much more difficult due to the high pump pressure at the point the cable enters the system. Injection force (analogous to snubbing a string into a high-pressure well) is required to introduce the cable.

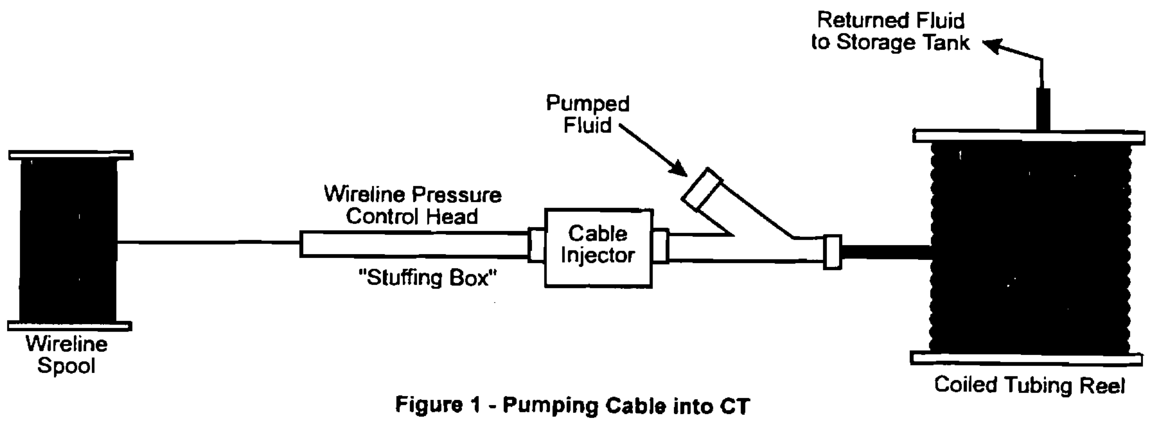


Figure 8-5. Pumping Cable into CT (Newman et al., 1995)

A cable injector was required for this design. Several concepts were devised and considered (Figure 8-6). The approach adopted for the final design was a capstan wheel inside a pressure housing.

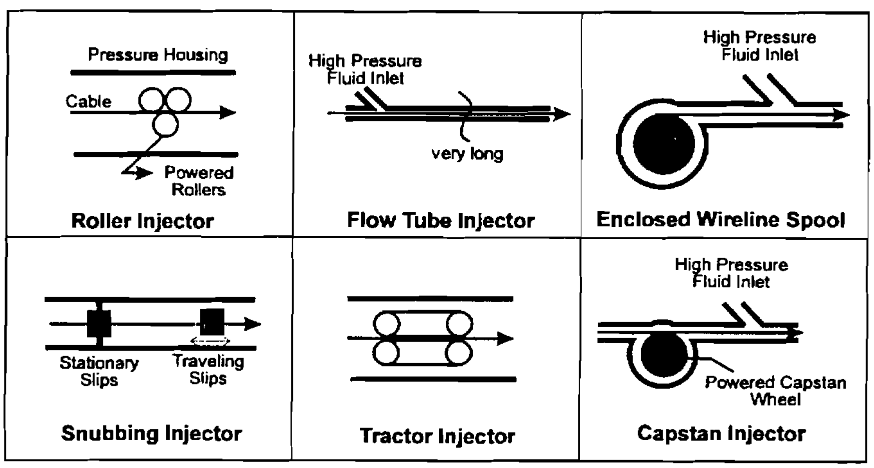


Figure 8-6. Potential Concepts for Injecting Cable
(Newman et al., 1995)

The cable injection system design is shown in Figure 8-7. The wireline spool can be rotated about a vertical axis due to the need to remove torque from used cable. A storage tank is used so that the water can be cooled between pump trips through the CT.

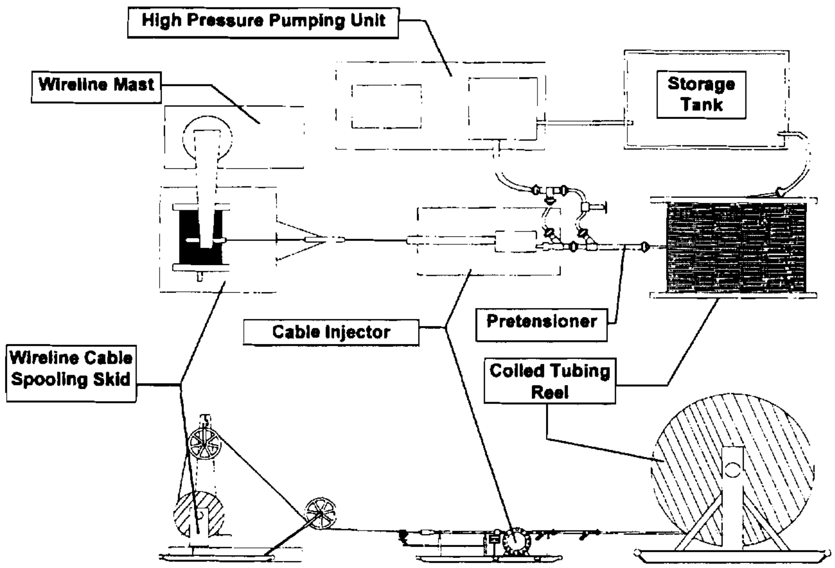


Figure 8-7. Cable Injection System for CT (Newman et al., 1995)

8.4 HALLIBURTON ENERGY SERVICES (VIDEO SERVICES)

Halliburton Energy Services (Maddox and Gibling, 1995) described several applications for downhole video services that allow planning conformance technology treatments, monitoring the treatment in progress, and confirming success after the treatment is complete. A video survey is especially useful for observing casing integrity and finding holes, cracks or corroded areas. Fluid entry or exit can also be observed at these areas (Figure 8-8).

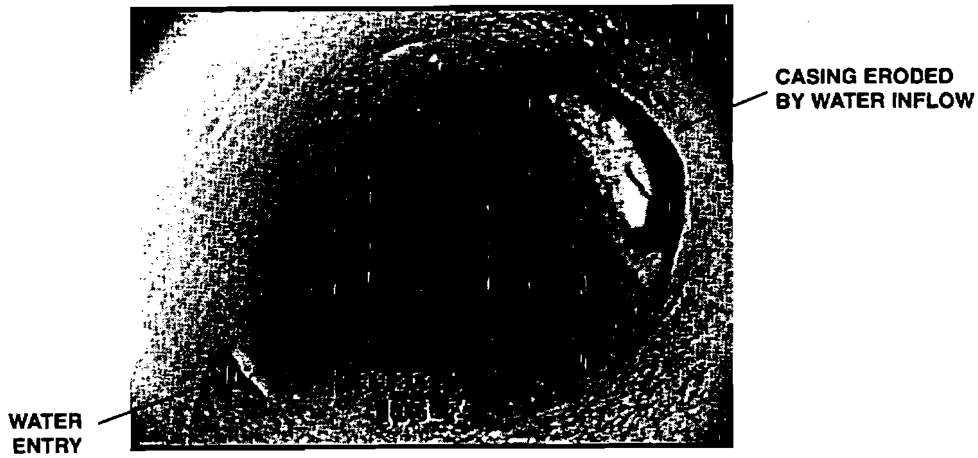


Figure 8-8. Video Log Showing Casing Condition
(Maddox and Gibling, 1995)

Video logs can also be used for types of production profiles. Video can be analyzed along with spinner data to estimate relative contributions of each section of the wellbore. Plotting observed influxes versus depth produces a video production profile (Figure 8-9).

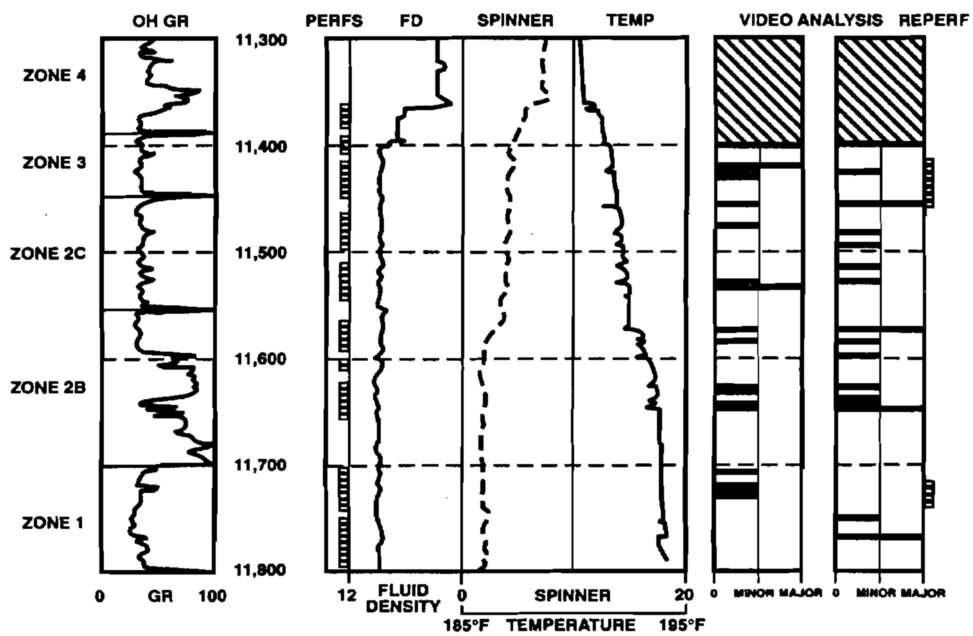


Figure 8-9. Post-Video Production Analysis
(Maddox and Gibling, 1995)

Confirmation of suspected problems and the appropriateness of planned remedial treatments prior to treatment application is another useful area for video. In one case, fractures in a gas-storage well were observed and confirmed prior to treatment (Figure 8-10).

Figure 8-10. Video Log of Fractures (Maddox and Gibling, 1995)

8.5 NOWSCO, ANDERSON, AND DOWNHOLE SYSTEMS (CONCENTRIC CT SYSTEM)

Nowsco Well Service Ltd., Anderson Exploration Ltd. and Downhole Systems Technology Inc. (Fried et al., 1997) described a new concentric CT logging tool to achieve optimum stimulation and production in long horizontal wellbores along with lower costs. An inflatable straddle packer is used for drill-stem testing and selective stimulation, all without resetting the packer. The inner string of CT is used for all well flow and stimulation operations. The annulus between the inner and outer strings is used for circulation and inflating the packers.

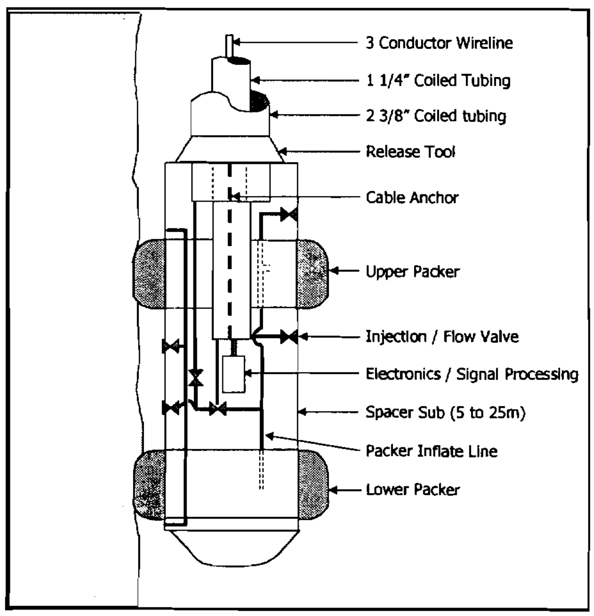


Figure 8-11. Concentric CT DST Tool (Fried et al., 1997)

The straddle packers (Figure 8-11) can be set at a separation of 12 to 150 ft of open-hole zone. If skin is indicated, the formation can be selectively stimulated without unsetting the packer. The flow test can be repeated afterwards. In this way, production of long horizontal wells can be optimized in a more effective way.

Formation damage is often a key issue in horizontal wells due to the extended exposure time of the formation to drill fluids and cuttings. It is usually more challenging to recover the well deliverability.

Underbalanced drilling has been applied in many environments to improve this situation by avoiding or minimizing formation damage during drilling. Fried et al. believe that some operators might prefer to drill horizontal wells overbalanced if more effective stimulation technology were available.

The new DST tool based on concentric CT includes a wireline for data telemetry and tool control. The surface equipment is similar to conventional CT logging operations. The spool must be equipped with two rotating joints, one for each string of CT (2⅜ and 1¼ inches). Corrosive fluids flow only in the inner string. The outer string is used for inflating the packers and gas lifting the well as required.

Pressures can be monitored continuously. Sensors are available for measuring surface pressures in both strings, formation pressure between the packers, wellbore hydrostatic pressure, inflation pressure in the packers, recovery pressure, and pressure outside the inner string. Downhole temperatures are also recorded.

Nowsco Well Service Ltd., Anderson Exploration Ltd. and Downhole Systems Technology Inc. believe that this new CT system for measuring and removing formation damage has several benefits. These include safety, sour-service rating, circulation control, multiple-setting inflatable equipment, test/treat/test capability, gas-lift capability, and real-time data and interpretation.

8.6 TRICO INDUSTRIES (JET PUMP FOR PRODUCTION LOGGING)

Trico Industries (Tait, 1995) enumerated the advantages of jet pumps run on CT for artificial-lift applications in horizontal and vertical wells. A primary advantage is the lack of moving parts in the assembly. Energy is provided to the jet pump by pumping from surface. The power fluid may be produced oil or water, treated sea water, diesel , or other fluids.

Lifting action is provided by energy transfer between the power fluid and the wellbore fluid. High potential energy in the pressurized power fluid is converted to kinetic energy as the fluid passes through the nozzle (Figure 8-12). A low-pressure zone is created in the throat, and the wellbore fluid is drawn into the power stream.

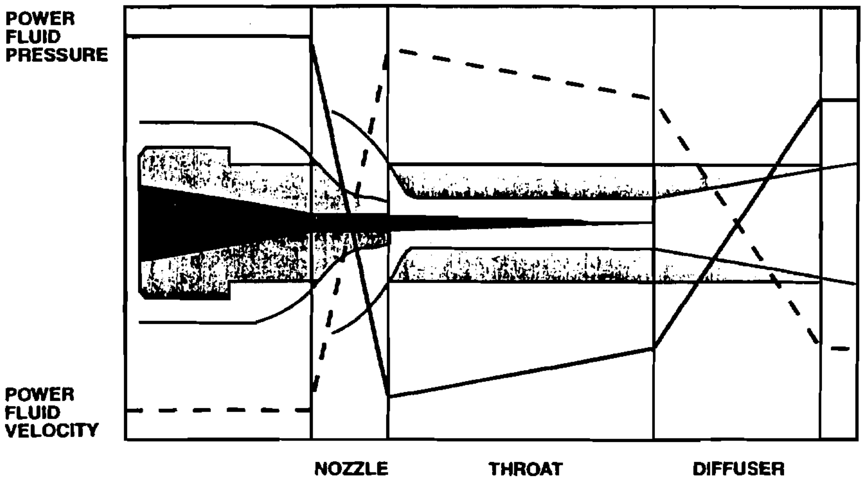


Figure 8-12. Jet-Pump Operational Principle (Tait, 1995)

Jet pumps have been used since the 1970s for long-term artificial-lift applications around the globe. These can be sized for production rates ranging from 50 to 15,000 BPD at depths exceeding 15,000 ft.

Trico Industries described the use of a jet pump run on CT for production testing of horizontal wells. The pump can be run as a free pump (Figure 8-13), circulated into and retrieved from the well by the power fluid. This system can be used along with downhole pressure recorders to obtain inflow performance data in a production rate step-test procedure.

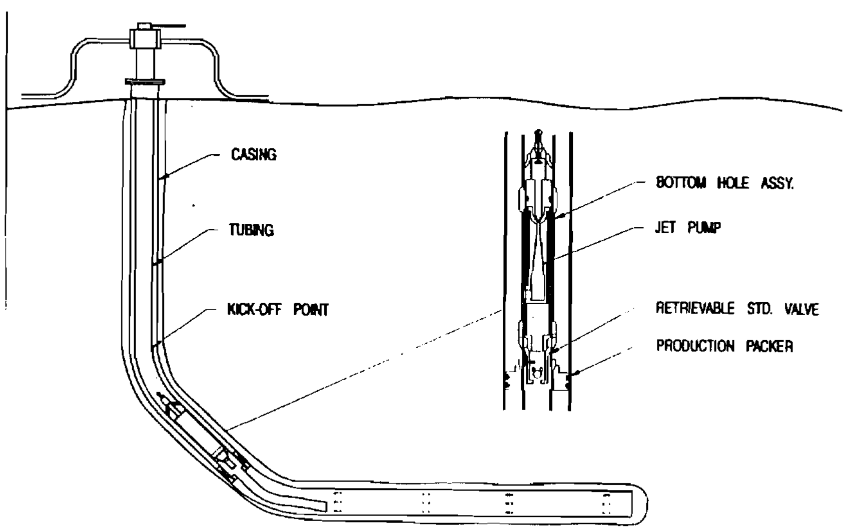


Figure 8-13. Free Jet Pump for Horizontal Production Testing
(Tait, 1995)

8.7 REFERENCES

Houpe, Mark W., 1996: "CT-Conveyed Slim Tools Deliver Critical Data In Horizontal Well Bores," *The American Oil & Gas Reporter*, September.

Maddox, Steve and Gibling, Glen R., 1995: "Downhole Video Services Enhance Conformance Technology," OTC 7872, presented at 27th Annual OTC, Houston, Texas, May 1-4.

Newman, K.R. et al., 1995: "Development of a Coiled Tubing Cable Installation System," SPE 30679, presented at SPE Annual Technical Conference & Exhibition, Dallas, Texas, October 22-25.

Sas-Jaworsky, Alex and Bell, Steve, 1996: "Innovative Applications Stimulate CT Development," *World Oil*, June.

Tait, Howard, 1995: "Coiled Tubing Jet Pump for Extended Reach Horizontal Well Cleanups," presented at 3rd Annual Conference on Emerging Technology – CT-Horizontal, Aberdeen, Scotland, May 31-June 2.

9. Overview

TABLE OF CONTENTS

9. Overview

9.1 SAS INDUSTRIES (API CT WELL-CONTROL GUIDELINES)

Sas-Jaworsky (1997) summarized the safety guidelines for CT well-control components and procedures. A complete standard has been published in the *API RP 5C7, Recommended Practice for Coiled Tubing Operations in Oil and Gas Well Services* (December 1, 1996). These recommended practices serve to further define the mechanical capability and limitations of CT equipment components, thereby enhancing the safety of wellsite operations. These practices were devised as the minimum safety requirements of onshore and offshore CT operations.

The minimum requirements for a CT well-control stack (Figure 9-1) call for:

- A stripper or annular-type component
- One blind ram
- One shear ram
- A flanged kill line outlet with isolation valves
- One slip ram
- One pipe ram

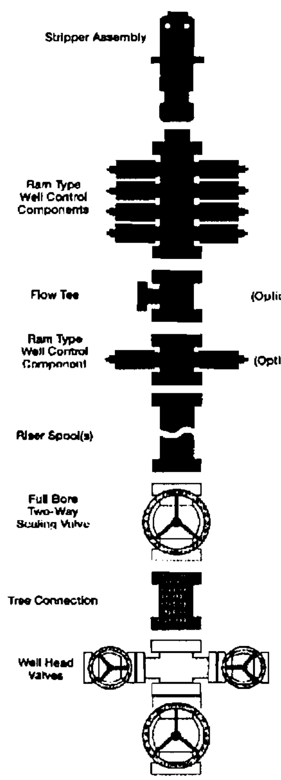


Figure 9-1. Well-Control Stack for CT Operations (Sas-Jaworsky, 1997)

Additional rams may be required for different OD strings that may be run or for tapered-OD CT strings.

A flow tee should be installed immediately below the well-control stack to provide an outlet for fluid returns. One full-bore valve must be installed (Figure 9-2), with a pressure rating as great as the well-control stack.

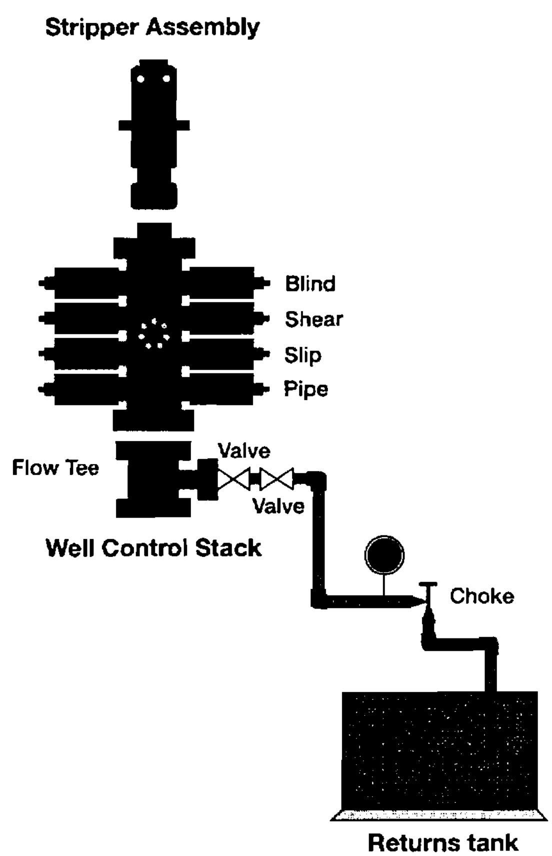


Figure 9-2. Piping for Choke/Returns Line
(Sas-Jaworsky, 1997)

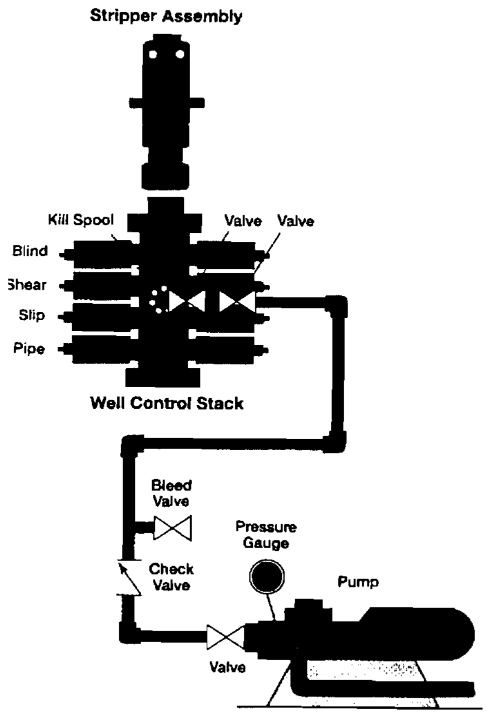


Figure 9-3. Dedicated Kill Line for CT Operations (Sas-Jaworsky, 1997)

For conditions when a kill line is required, API recommends that the kill line be equipped with two in-line valves (Figure 9-3) with the same pressure rating as the stack. Another set of pipe rams should be installed below the flow tee as a secondary annular pressure isolation barrier. It is emphasized that the kill-line outlet should not be used for taking returns from the well.

API describes recommended practices and procedures for other well-control elements including the stripper, construction of the various rams, downhole check valves, well-control tests and drills, and performance of the accumulator. See Sas-Jaworsky (1997) or API RP 5C7 for additional details.

9.2 SAS INDUSTRIES (CT FLUID HYDRAULICS)

SAS Industries (Sas-Jaworsky and Reed, 1997) presented an analysis of several aspects of fluid hydraulics in CT both in the well and on the reel. Methods they presented account for the effects of internal CT wall roughness and tubing eccentricity (for CT in an annulus and for concentric strings of CT). A new method was developed for calculating pressure losses for turbulent flow through CT with wall roughness. Methods were presented to account for downhole eccentricity on pressure drops with laminar or turbulent flow.

The circulation system (Figure 9-4) boundary conditions can be specified for each node. Hydraulic parameters common to all are fluid velocity, Reynolds number, absolute roughness and friction factor.

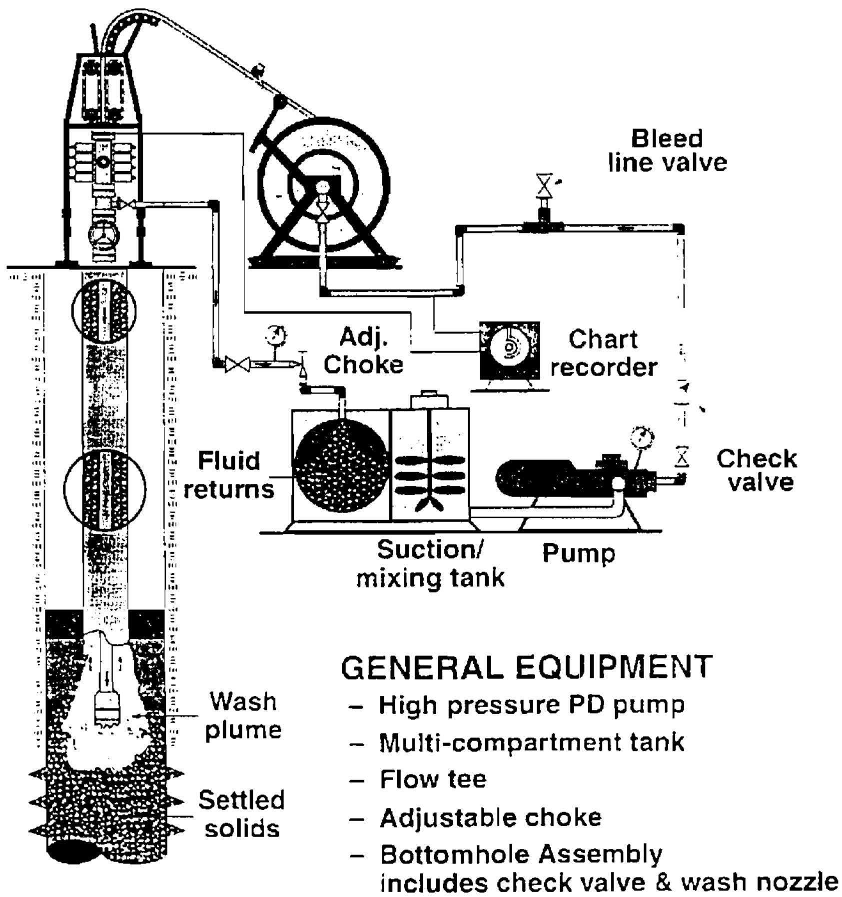


Figure 9-4. CT Circulation System (Sas-Jaworsky and Reed, 1997)

More information is presented in *Coiled Tubing.*

9.3 WILD WELL CONTROL (NOVEL CT WELL CONTROL)

Wild Well Control Inc. (Gebhardt et al., 1996) described a novel use of CT for controlling a wild well on a LPG storage well in a salt dome. Conventional techniques were determined to be inappropriate for this case. CT was used to run a cutter into the hole, cut the production tubing string, and set a packer inside casing to shut off the flow of LPG. Operations were completed successfully, saving the operator millions of dollars in product and well-control costs.

The storage-well design (Figure 9-5) included 5½-in. tubing inside 8⅝-in. casing. Tubing was hung within 100 ft of the bottom of the cavern. Production was directed by pumping water down the production tubing to force propane up the tubing/casing annulus.

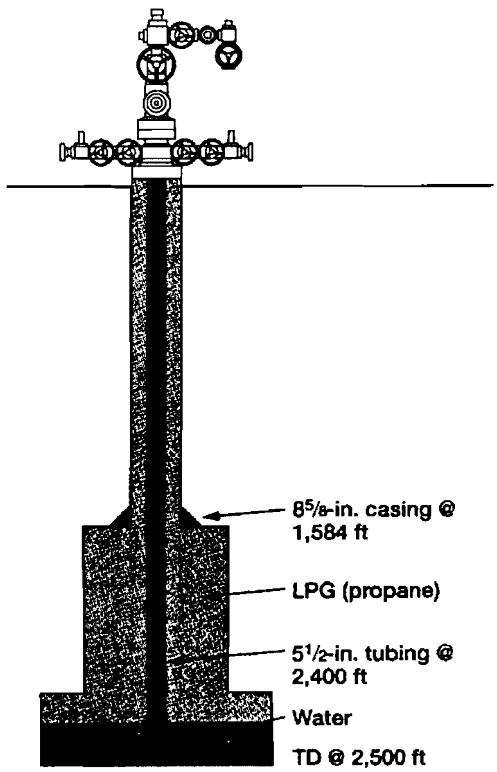


Figure 9-5. LPG Storage Well Design
(Gebhardt et al., 1996)

A leak developed in the casing, allowing propane to escape through the surface soils. Thirteen million gallons of propane were in the well when the leaking fuel ignited.

Two factors led to the conclusion that conventional wellhead removal and capping were not the optimum procedure for this case. One concern was that pipelines and the water pit restricted access for building ramps down to the new cellar that would be required for access to competent casing. Another was that unrestricted blowing after removing the wellhead would create fires as tall as 300 ft, endangering other components of the storage facilities.

A novel approach using CT was devised. The damaged tree was removed first. A string of CT was stung into the 5½-in. production tubing with a cutter and packer. An 80-ft lubricator was used to keep the injector well above the flames. A 500-ton crane with a 238-ft jib was used to support the 100-ft injector/lubricator assembly. Control lines were routed out the jib.

Cooling water was pumped to keep equipment cool, but extinguishing the fire completely was avoided. The production tubing was cut. Calculations indicated that the dropped tubing would buckle and be out of the way (Figure 9-6). An inflatable packer was installed with the CT string at 1450 ft. The flow was thereby shut off, and eventually died as propane bled off.

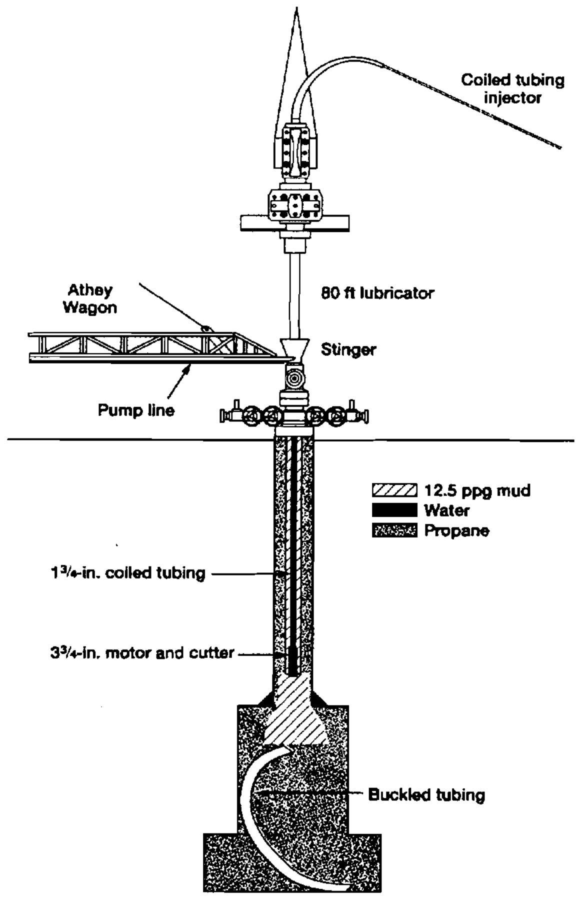


Figure 9-6. Well After Production Tubing Cut
(Gebhardt et al., 1996)

9.4 REFERENCES

Gebhardt, Freddy et al., 1996: "Novel Coiled Tubing Application Controls Large LPG Storage Well Fire," *World Oil*, June.

Sas-Jaworsky, Alex, 1997: "New Guidelines Should Enhance Coiled Tubing Well Control Security," *World Oil*, December.

Sas-Jaworsky, Alex and Reed, Troy, 1997: "Fluid Hydraulics Behavior in Coiled Tubing Operations — A Nodal Analysis Approach," presented at the World Oil Coiled Tubing & Well Intervention Conference, Houston, February 4-6.

10. Pipelines

TABLE OF CONTENTS

10. Pipelines

10.1 GULF OF SUEZ PETROLEUM (3½ AND 4½ COILED PIPELINES)

Gulf of Suez Petroleum Company and Precision Tube Technology (Hoffman et al., 1996 and Laithy, 1997) reported on the successful application of coiled pipelines in the Gulf of Suez. GUPCO is a joint venture between Amoco Production and Egyptian General Petroleum. The first international lay of 3½-in. coiled pipeline was conducted here. Cost savings from the first two jobs were estimated at 70% as compared to conventional lay-vessel costs. In 1996, three pipelines of 4½-in. coiled pipe were installed, with cost savings of 55% over conventional lays.

Job size for GUPCO's coiled pipeline projects is summarized in Figure 10-1.

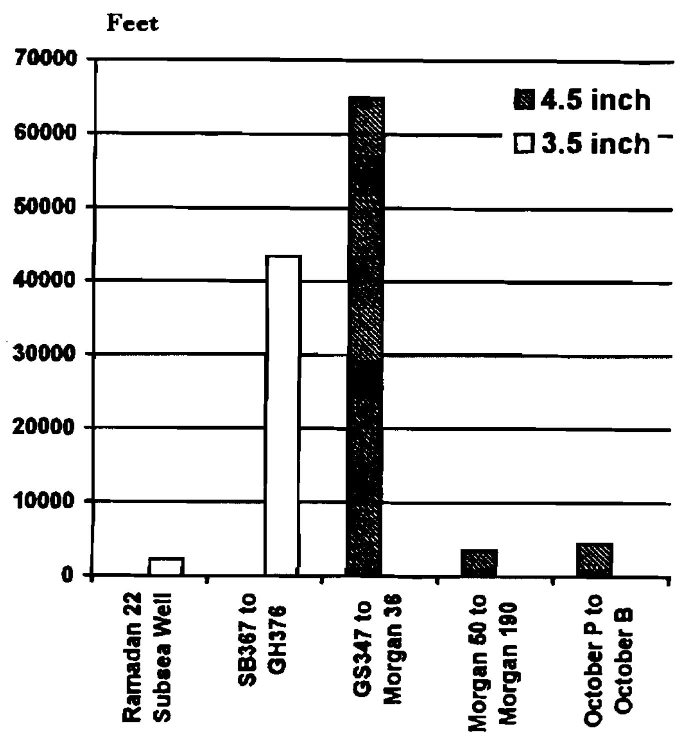


Figure 10-1. Coiled Pipeline Projects at Gulf of Suez (Hoffman et al., 1996)

After initial success with 3½-in. coiled pipeline projects, three candidates for 4½-in. pipeline were identified. These included: 1) Morgan 36 production platform to GS 347 platform for waterflood water supply of 12,000 BPD at 2000 psi, 2) October H platform to October B for waterflood water of 4000 BPD at 100 psi, and 3) Morgan 50 platform to Morgan 190 platform for waterflood water at 2500 BPD at 1200 psi.

Coiled pipe was delivered on nineteen shipping spools (Figure 10-2) with an average of about 4000 ft of pipe. Flange diameter was 17 ft; width was 105 inches. Maximum strain of the piping was designed as 3%.

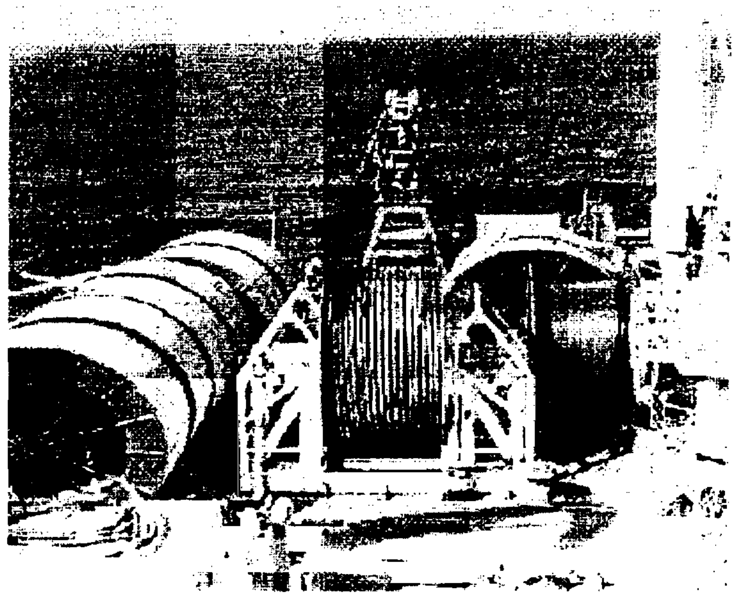
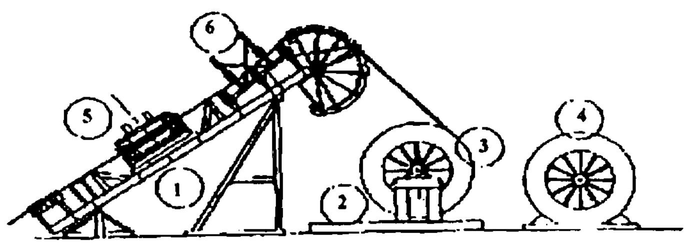


Figure 10-2. Coiled Pipeline at Gulf of Suez (Hoffman et al., 1996)

Basic surface equipment for deploying coiled pipeline is shown in Figure 10-3.



Lay Equipment

1 - Lay ramp support
2 - Powered reel support
3 - Coiled Tubing reel { Laying position)
4 - Coiled Tubing reels { storage }
5 - Tensionner
6 - Straightener

Figure 10-3. Coiled Pipeline Deployment (Laithy, 1997)

A comparison of pipe-laying methods (materials and installation costs) is shown in Figure 10-4. Coiled pipeline has been deployed from a workboat, small barge and a dynamically-positioned vessel. In each case, costs have been significantly less than conventional methods.

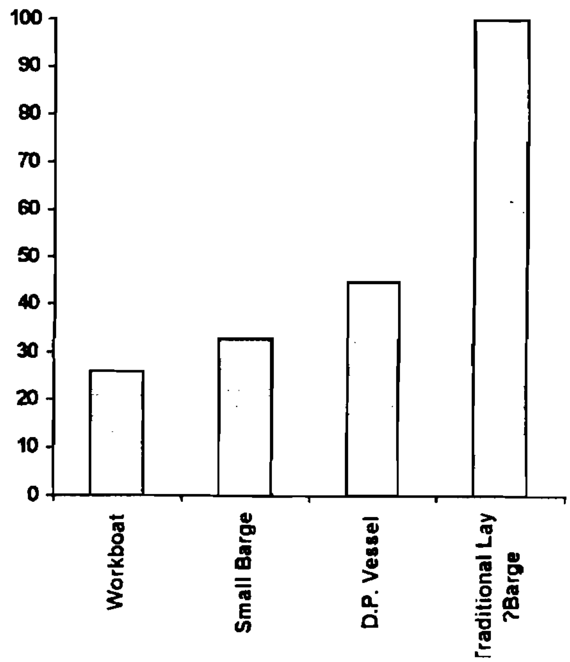


Figure 10-4. Cost Savings of Coiled Pipeline Projects
(Hoffman et al., 1996)

Gulf of Suez Petroleum stated that they are planning to install 6-in. coiled pipeline in the future.

10.2 RADOIL TOOL (CT CLEAN OUTS IN EXTENDED-REACH PIPELINES)

Radoil Tool Company (Baugh, 1997) presented a summary of analysis and test results for using CT for extended-reach pipeline blockage removal. They performed scale-model testing, full-scale testing, technical surveys, and computer analysis. The project is funded by the DeepStar consortium. The goal is to extend CT capability out to 5 miles for cleaning blockages from a typical pipeline (Figure 10-5). These pipelines include frequent and severe bending that restricts CT penetration.

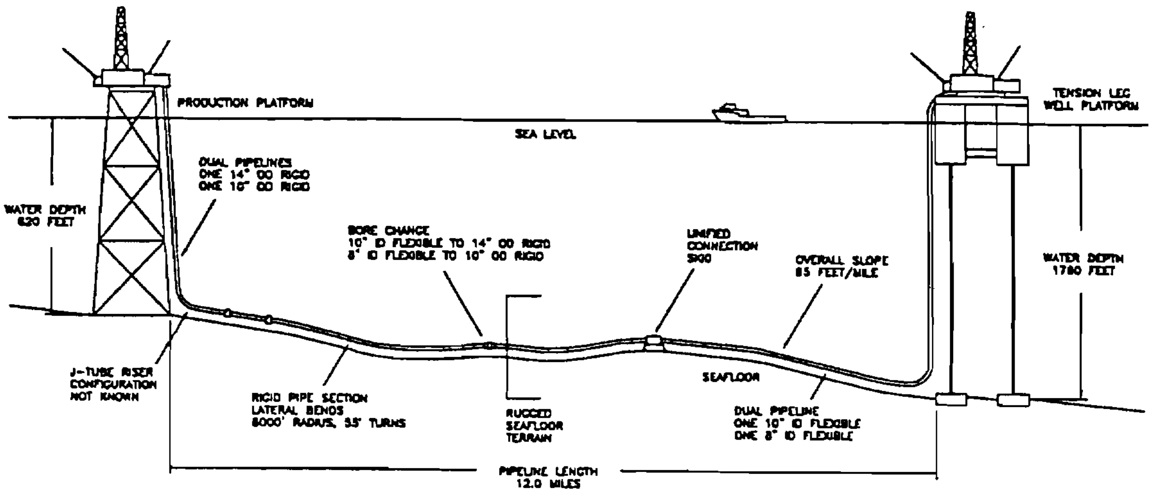


Figure 10-5. Pipeline at Conoco Jolliet TLP (Baugh, 1997)

Scale-model tests were conducted early in the project. Mechanical tubing of ⅜ inch was placed in 1-in. seamless line pipe and bent into the representative configuration. Results are shown in Figure 10-6 with the model flooded with oil.

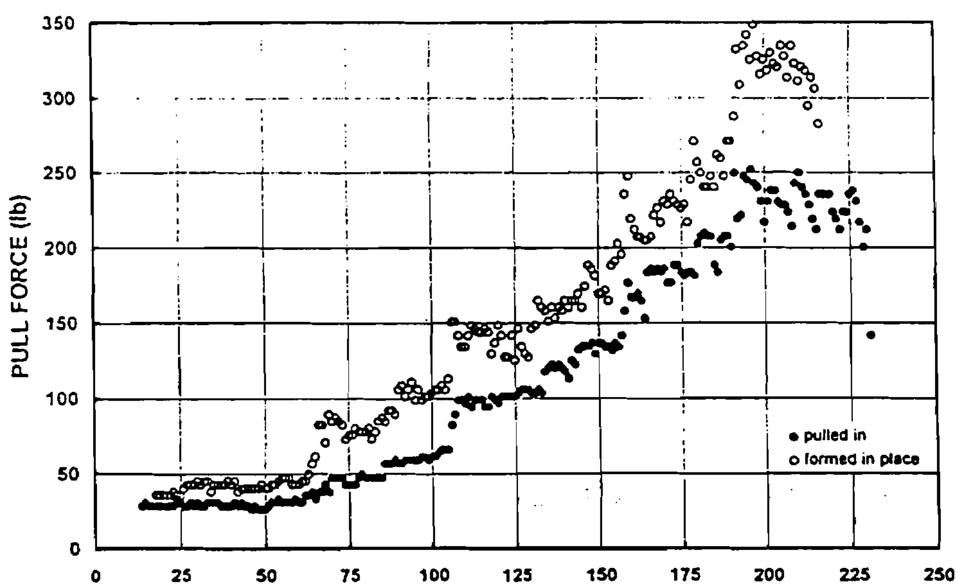


Figure 10-6. Scale-Model Results of Pull Force (Baugh, 1997)

One of the important goals of the project was to define the characteristics of a test pipeline that will simulate conditions in a 5-mile subsea pipeline. The configuration for the test loop (Figure 10-7) includes several bends.

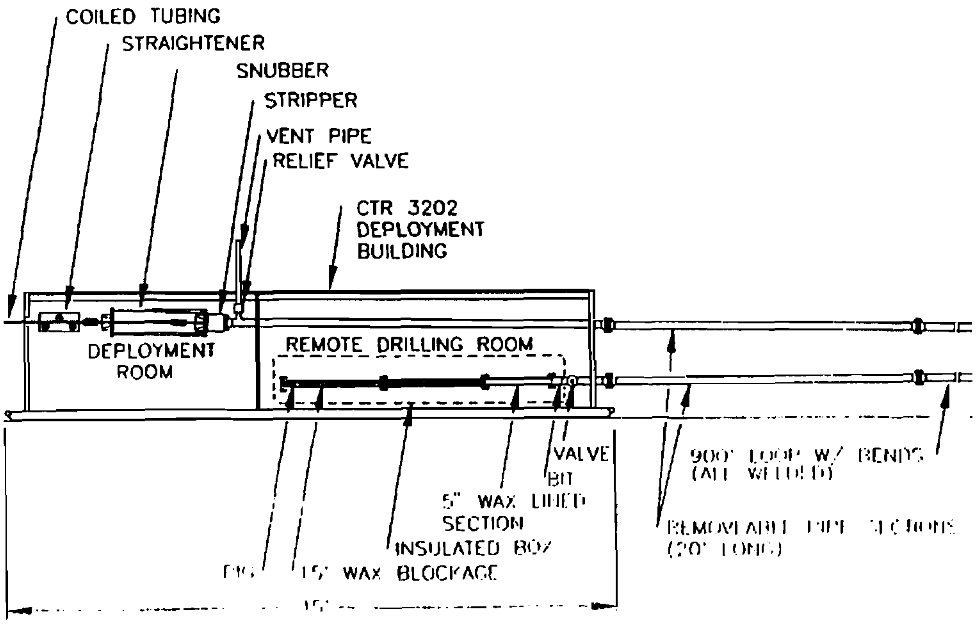


Figure 10-7. Test Loop for Extended-Reach Clean Outs (Baugh, 1997)

10.3 SAS INDUSTRIES (GROWTH IN COILED PIPELINES)

SAS Industries (Sas-Jaworsky, 1996) summarized the growth in the application of CT for pipelines and highlighted the cost-saving potential especially in the offshore environment. Greatly improved quality control of welding operations is a primary advantage.

Coiled pipelines can be shipped in spools ranging from about 3500 to 6000 ft, depending on tubing OD. These pipes can be externally coated with a variety of corrosion-resistant coatings.

Over 1.2 million feet of coiled pipelines and flow lines have been shipped in sizes as large as 4½ inches. A spool of 4½-in. pipeline is shown in Figure 10-8.

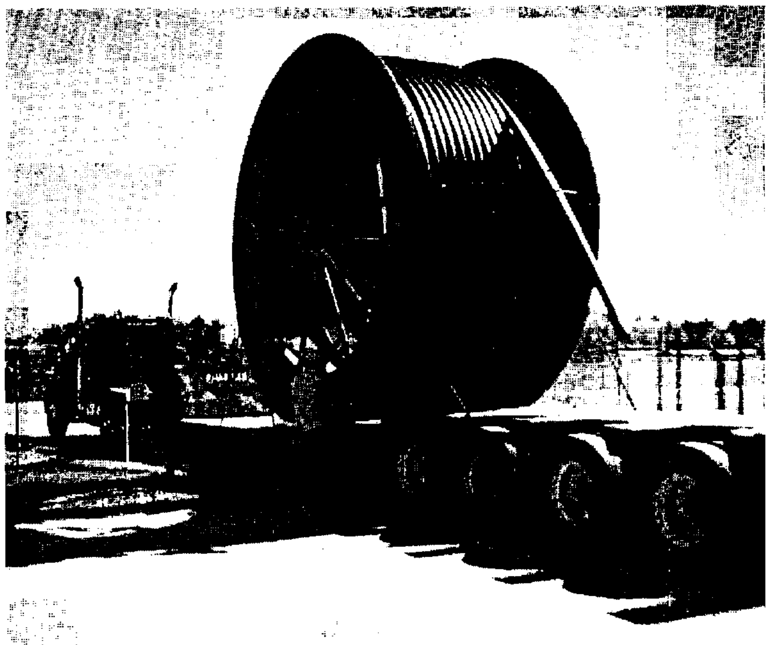


Figure 10-8. 4½-in. Coiled Pipe (Sas-Jaworsky, 1996)

One manufacturer has the capability of milling pipe as large as 5 inches. A significant quantity of flow lines has been shipped recently in 2⅜, 2⅞ and 3½ inch sizes.

10.4 REFERENCES

Baugh, Benton R., 1997: "Extended Reach Pipeline Blockage Remediation," presented at 5th International Conference On: Coiled Tubing and Well Intervention, Houston, Texas, February 4-6, 1997.

Hoffman, John G. et al., 1996: "Coiled Pipeline Technology: A Gulf of Suez Case History," SPE 36942, presented at European Petroleum Conference, Milan, October 22-24.

Laithy, W.F.El, 1997: "World's First 4.5" Coiled Tubing Pipeline," SPE 37769, presented at Middle East Oil Show, Bahrain, March 15-18.

Sas-Jaworsky, Alex, 1996: "New Offshore Applications Offer Value-Adding Utility," *The American Oil & Gas Reporter*, February.

11. Production Strings

TABLE OF CONTENTS

11. Production Strings

11.1 AMOCO UK EXPLORATION (CT INSERT STRADDLE)

Amoco UK Exploration Company (Kinnear and John, 1996) described the selection, design and installation of a CT insert straddle for repairing a failed gas-lift completion in the Arbroath Field in the North Sea. The well had ceased production due to holes in the tubing. Various through-tubing repair techniques were considered prior to selecting a CT straddle. These included a wireline-deployed straddle, CT straddle hung off the SSSV nipple, and a CT straddle suspended between two packers. The third option was selected after considering all advantages/disadvantages.

The final design of the repair (Figure 11-1) included 1500 ft of 3½-in. CT (70 ksi yield) with hydraulic-set packers at the top and bottom. The straddle was set about 500 ft below the holes in the tubing.

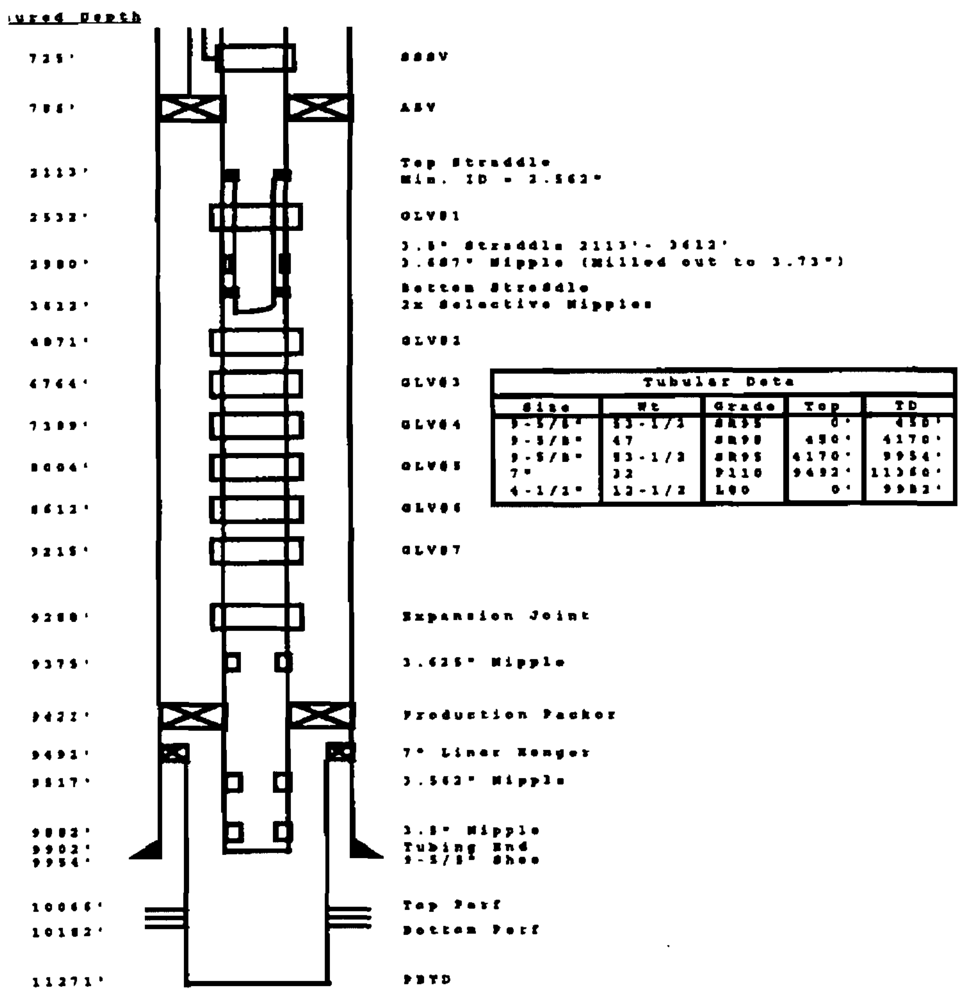


Figure 11-1. Repaired Production Tubing (Kinnear and John, 1996)

This CT insert staddle was successful at returning the well to production (3500 BOPD). Job cost was about 90% less than a full rig workover using a jack-up (£250,000 versus £3,000,000).

More information is presented in *Workovers*.

11.2 BP EXPLORATION AND ORBIS ENGINEERING (CT COMPLETIONS IN ALASKA)

BP Exploration (Alaska) and Orbis Engineering (Stephens et al., 1996) summarized experiences on Alaska's North Slope using large-diameter CT for production applications. Working with larger CT has proven to require thorough evaluation of equipment needs and a review of procedures, safety, and training. Experience has shown that large CT can be effective in a variety of remedial operations and initial completions.

The earliest use of CT in production applications was to straddle a bad section of production tubing. The next technological leap was to use 2⅜-in. CT equipped with spoolable gas-lift valves to straddle the entire production string (Figure 11-2).

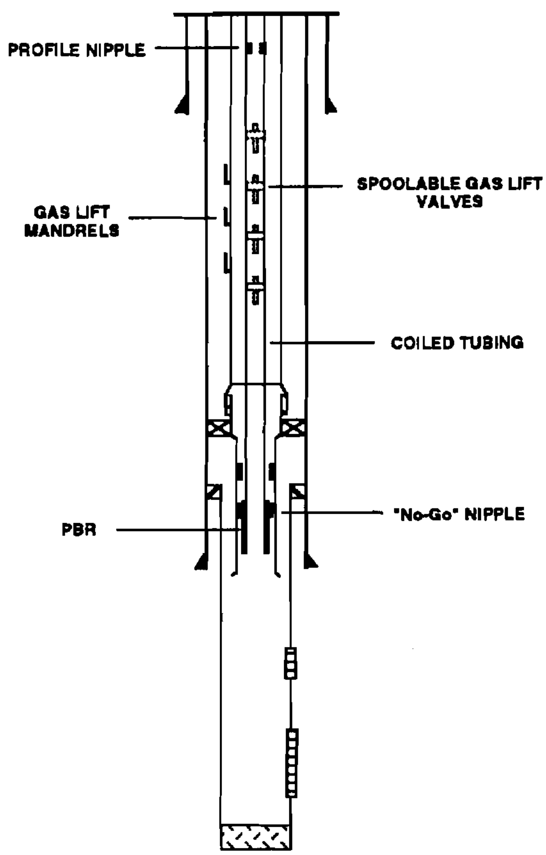


Figure 11-2. Large CT Recompletion with Gas Lift (Stephens et al., 1996)

Remedial applications of large-diameter CT at Prudhoe Bay have been of three general types: 1) straddles to core damage pipe, 2) perforation straddles for gas/water shut offs, and 3) scab liners of flush-joint pipe RIH on CT.

CT gas-lift completions were run in the Endicott field. Completion depths were near 12,000 ft. A special injector, reel stand, and two-level work window (Figure 11-3) had to be developed. Extra working height was found to be required for installing the gas-lift mandrels.

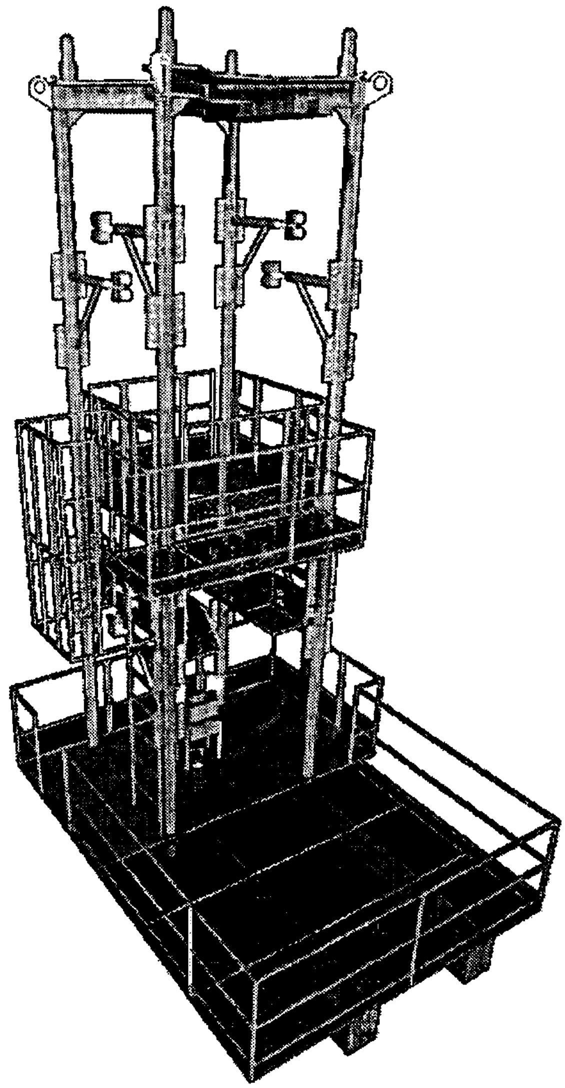


Figure 11-3. Special Two-Level Work Window (Stephens et al., 1996)

Six or seven 3½-in. mandrels were required for each completion (Figure 11-4). A slip-type connector was used to connect the mandrels into the CT string. The same connectors were also used on the SSSV and to splice the two spools of 3½-in. tubing required for each well.

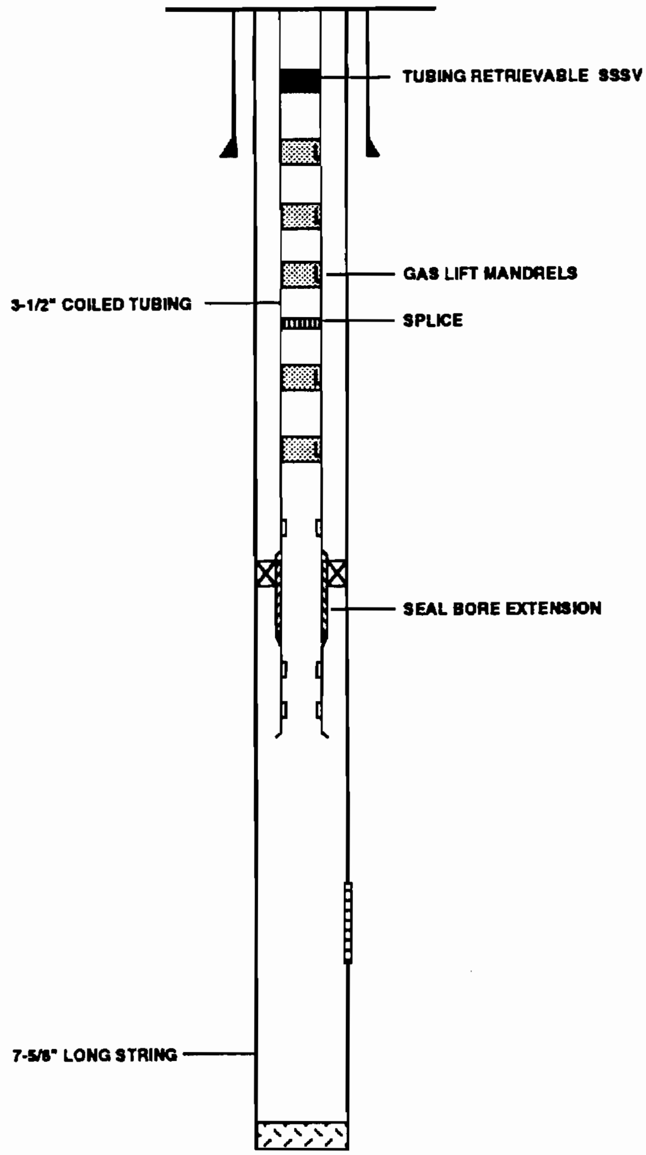


Figure 11-4. 3½-in. CT Gas-Lift Completion
(Stephens et al., 1996)

After the gas-lift completions were run, 2½-in. guns were run through tubing to perforate the 7⅝-in. casing.

Rugged and stronger equipment developed for these 3½-in. gas-lift completions was next applied in 2⅞-in. ESP completions in the Milne Point field. Installation of these strings (Figure 11-5) was far less complicated because the string did not need to be cut several times. In addition, 2⅞-in. tubing proved much easier to handle than 3½ inch.

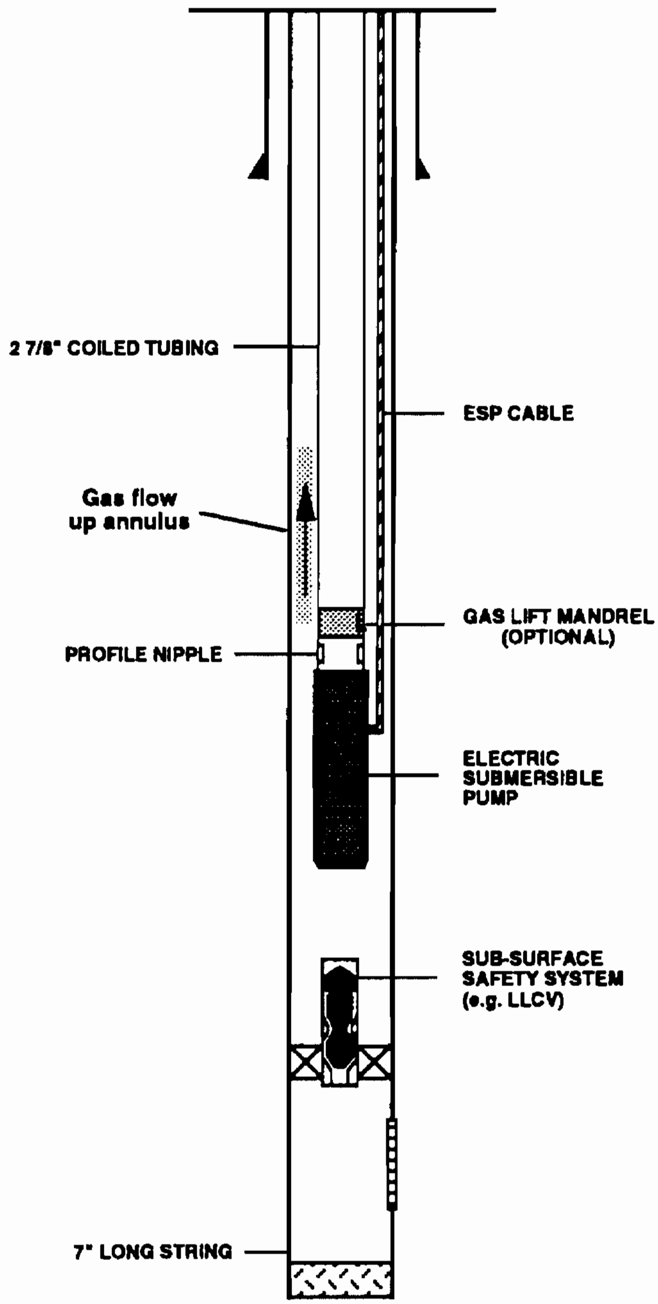


Figure 11-5. 2⅞-in. CT ESP Completion
(Stephens et al., 1996)

The forces required to handle large tubing increase exponentially with diameter. Several pieces of equipment had to be strengthened or redesigned for these applications. A large injector capable of 120 kips of pull was acquired. Large metal shipping spools were required as well as a large-radius guide arch. A 90-ton crane was on-site to rig up the equipment.

A ratchet-type internal CT connector (Figure 11-6) was used to run these completions. This tool is spoolable.

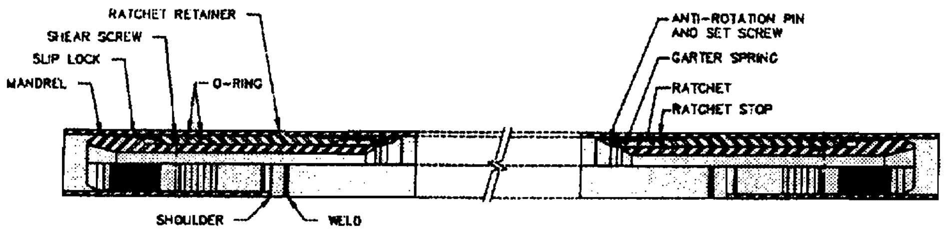


Figure 11-6. Spoolable CT Connector (Stephens et al., 1996)

BP Exploration and Orbis Engineering listed several lessons that have been learned throughout these campaigns centered on large CT completions. Among them are the following:

- Considerable energy is stored in large CT and the strings are very hard to handle. Both ends of the string must be well secured when the tube is cut.
- Ovality must be anticipated. Connectors must be designed to account for this situation.
- Gas-lift completions with standard mandrels can become too complex and expensive. In this instance, as many as 18 connectors were required per string, increasing the cost significantly.
- Running large CT completions also requires the commitment to maintain the equipment necessary to pull the completion in the future.

11.3 CAMCO CT SERVICES (SPOOLABLE COMPLETIONS)

Camco Coiled Tubing Services (Gauthier and Ducote, 1995) described the evolution and application of spoolable components for CT completion applications. Conventional approaches for installing completion components, such as gas-lift mandrels, do not permit continuous installation. The components must be installed below the injector in a work window (Figure 11-7), and well-control is lost during the installation.

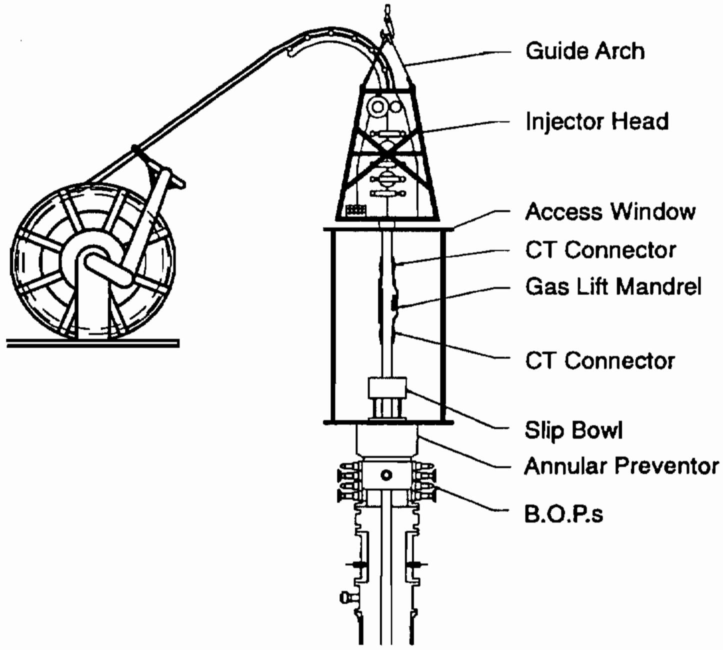


Figure 11-7. Work Window for Standard CT Gas Lift
(Gauthier and Ducote, 1995)

In the spoolable design, completion components are installed by the tubing manufacturer. The components are TIG welded into the string, and the string is pressure-tested and shipped. Benefits of spoolable installations are savings in installation time and the ability to work in live wells.

Good candidates for spoolable completions are wells with poor production due to oversized tubulars, production tubing leaks, and with sensitive formations where killing the well is undesirable. The most common candidate wells are those where the CT string is installed inside existing production tubing. Various designs can be used, including hanging the CT from the surface with a CT hanger, or hanging the CT in the production tubing with a packer (Figure 11-8).

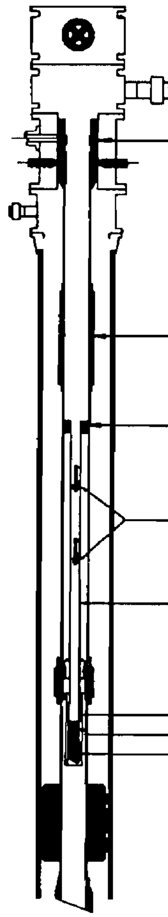


Figure 11-8. Packer-Hung CT
Spoolable Completion
(Gauthier and Ducote, 1995)

Production can be routed through the CT or the annulus when the string is hung from surface. When a hanger packer is used, a flow path is required for injecting the gas-lift gas into the CT/production-tubing annulus. Options include an existing gas-lift mandrel or a hole in the production tubing.

The next generation of spoolable equipment under development will include through-bore capability through the CT completion components (Figure 11-9) to allow workovers without pulling the CT string.

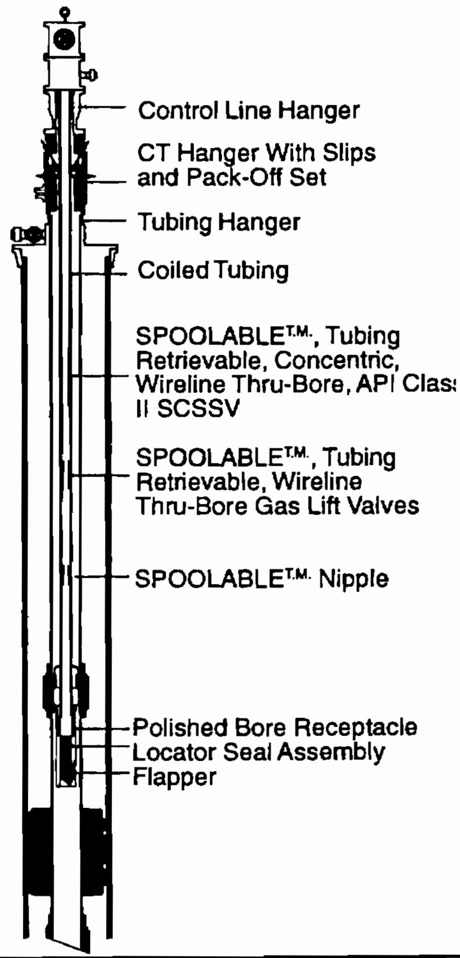


Figure 11-9. Through-Bore Design of Spoolable Completion (Gauthier and Ducote, 1995)

11.4 CAMCO CT SERVICES (ADVANCEMENTS IN SPOOLABLE COMPLETIONS)

Camco Coiled Tubing Services and Camco Products and Services (Gauthier et al., 1997) reported advancements in design of SPOOLABLE completion systems. Camco is continuing to develop "spoolable" completion components that can be installed inside the CT string before going to the field, and then run directly into the well. The completion string fitted with required completion accessories is simply spooled off the reel, over the gooseneck, and into the well using conventional CT and well-control equipment. The first spoolable component to be designed was a (non-retrievable) gas-lift valve. After the success of that system, additional components have been designed including a tubing-retrievable gas-lift valve, a wireline-retrievable gas-lift valve, and a surface-controlled subsurface safety valve (SCSSV) (Figure 11-10).

Options for controlling the SCSSV include an internal hydraulic control line, an external control line, an elliptical conduit formed in the wall of the CT, or concentric CT.

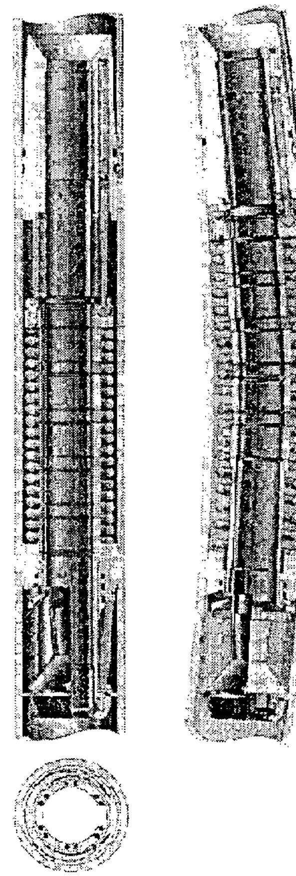


Figure 11-10. Spoolable SCSSV (Gauthier et al., 1997)

11.5 CHEVRON USA PRODUCTION (GROWING CT PRODUCTION USAGE)

Chevron USA Production Company (Adams, 1995) presented a summary evaluation of the use of large CT for production-tubing applications. Larger diameters have been introduced to the market rapidly in recent years (Figure 11-11). The first use of CT for primary production tubing was in 1991 in Oklahoma by Amoco. A 2-inch by 8900-ft string of CT was installed in 5½-in. casing.

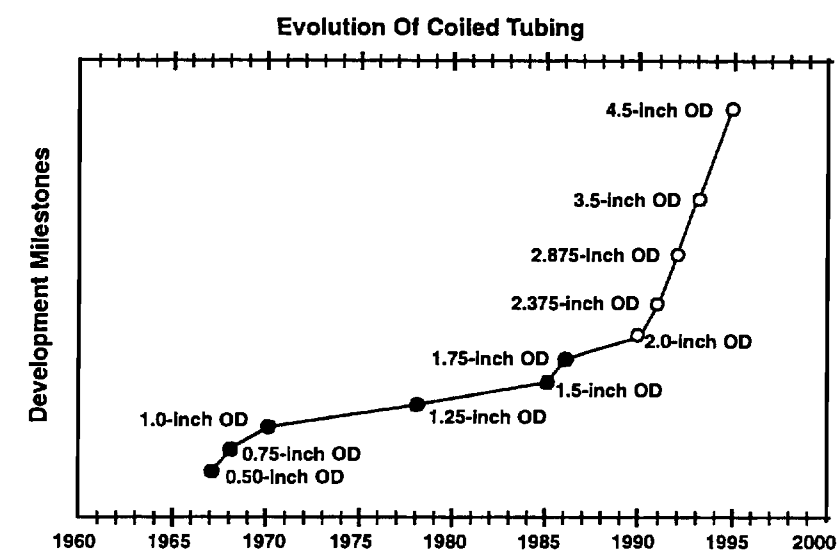
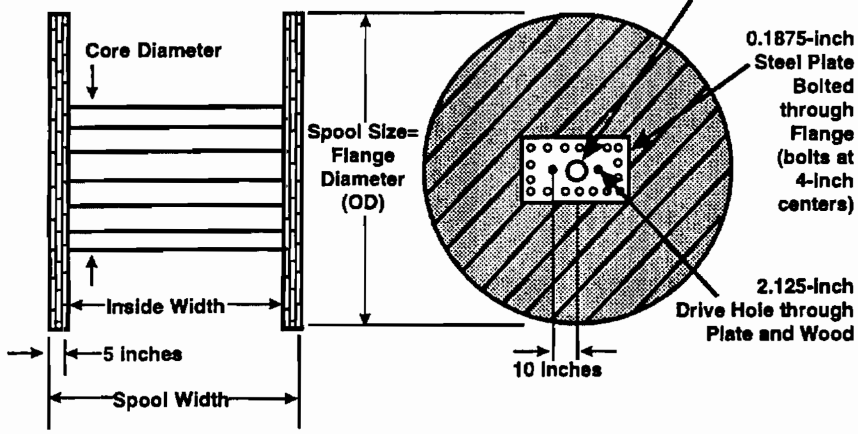


Figure 11-11. Introduction of CT ODs (Adams, 1995)

Spool capacity for larger CT is limited by spool size (Figure 11-12) which in turn is strongly impacted by logistical considerations for transportation. Reel capacity may vary, and may require special permits for exceeding width, height or weight limits.

Typical Shipping Spool Capacities



Coiled Tubing Size			Shipping Spool Size (in)				Capacity
OD (in)	Wall (in)	Weight (lbs./ft)	Spool OD	Core Diameter	Spool Width	Footage	Total Weight (lbs)
2	x.109	2.207	150	80	80	17,000	43,519
2	x.109	2.207	160	80	80	20,000	50, 140
2.375	x.125	3.011	150	95	80	9,600	36,006
2.375	x.125	3.011	160	95	80	11,000	40,221
2.875	x.156	4.541	150	120	80	4,200	25,072
2.875	x.156	4.541	160	120	80	5,800	33,438
2.875	x.156	4.541	180	120	96	11,500	59,322
3.5	x.175	6.23	150	120	80	2,300	20,329
3.5	x.175	6.23	160	120	80	3,100	26,413
3.5	x.175	6.23	180	120	96	6,300	48,249

Figure 11-12. Shipping Spools for Large CT (Adams, 1995)

Several advantages are available with coiled production tubing. Smaller size and weight of installation rig equipment reduce transportation costs and time to rig up/down. The need for kill fluids is eliminated. Formation damage is reduced by completing under pressure. The absence of downhole connections provides fewer corrosion/leak points in the production string.

Generally, the use of CT for production tubing in onshore wells in the U.S. is a marginal application. This is due to the cost of CT being higher than comparable jointed pipe. However, over the next few years, CT is expected to consume 10-20% of the market for new threaded production tubing.

11.6 HALLIBURTON, LL&E AND CHALMERS & COLLINS (GOM RECOMPLETION)

Halliburton Energy Services, LL&E and Chalmers & Collins (Waguespack et al., 1996) described the design and installation of a 2⅜-in. velocity string in a well in Eugene Island Block 384 in the Gulf of Mexico. It would have been uneconomical to mobilize a workover rig and recomplete the well. A CT string complete with gas-lift mandrels, landing nipples and SSSV was run inside the existing 4½-in. completion. The new completion was installed at a savings of 60% compared to the use of a workover rig.

The existing completion (Figure 11-13) had begun experiencing loading problems. The minimum drift in the well was about 3.8 inches. A new CT string was designed from 2⅜- x 0.188-in. 80-ksi tubing.

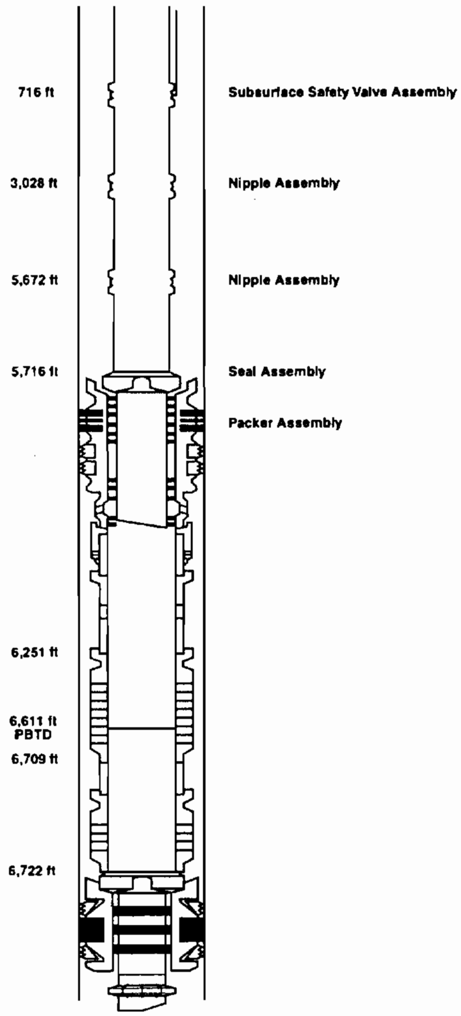


Figure 11-13. Existing GOM Completion (Waguespack et al., 1996)

Slip-type connectors were used for assembling the string (Figure 11-14). Full access to the tubing ID was provided.

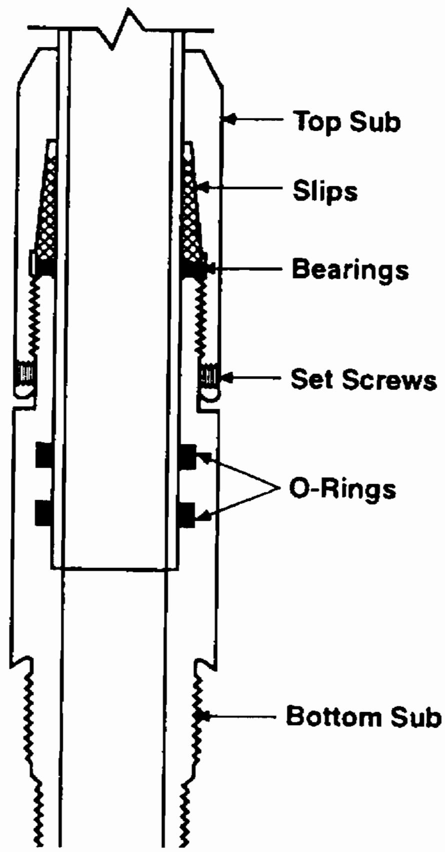


Figure 11-14. Slip Connector for CT
(Waguespack et al., 1996)

An 80-kip injector and 96-in. gooseneck were used to run the string. A 4- by 10-ft work window was devised to assemble the various components in the string (packer assembly, nipple, mandrels, SSSV) (Figure 11-15).

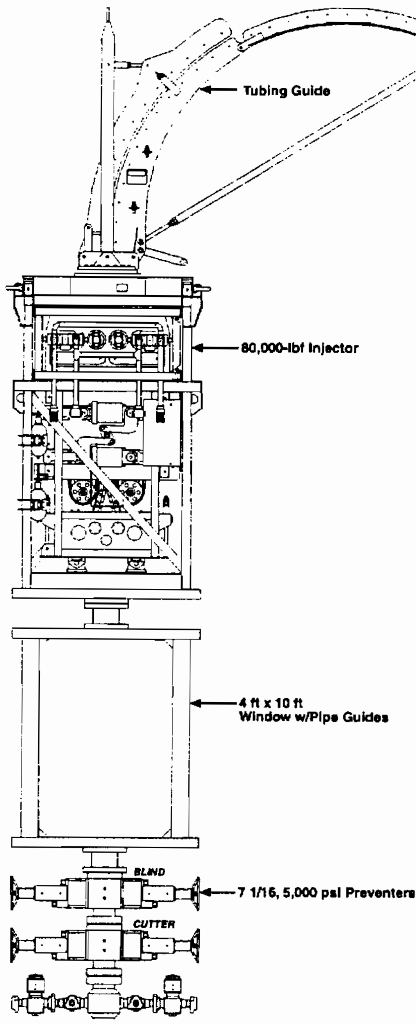


Figure 11-15. Surface Equipment and
Work Window
(Waguespack et al., 1996)

The recompletion was completed in 3 days. The final result is shown in Figure 11-16. The well returned to stable production. The operator is considering this procedure for other wells in the area.

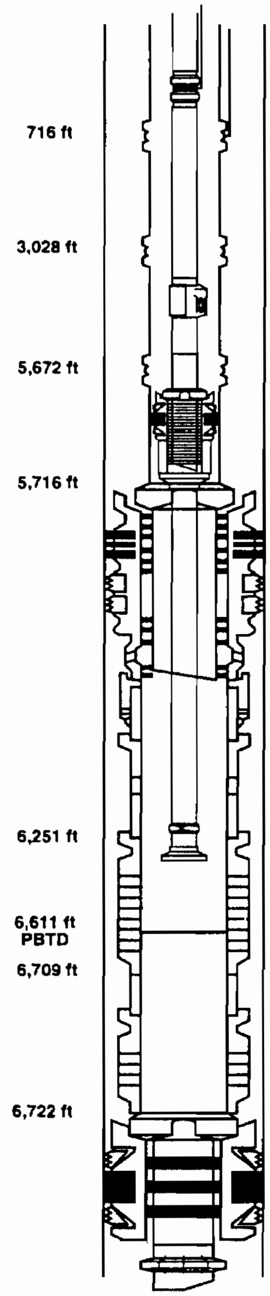


Figure 11-16. Recompletion Design
(Waguespack et al., 1996)

11.7 HALLIBURTON OMAN (LARGE CT COMPLETIONS)

Halliburton Oman (Taylor and Conrad, 1996) summarized design and installation issues and lessons learned with large CT in Oman. Large CT completions have been proven as technically feasible; however, the long-term issues with respect to production and well maintenance are not yet known. Typical completions designed and run in Oman are shown in Figure 11-17.

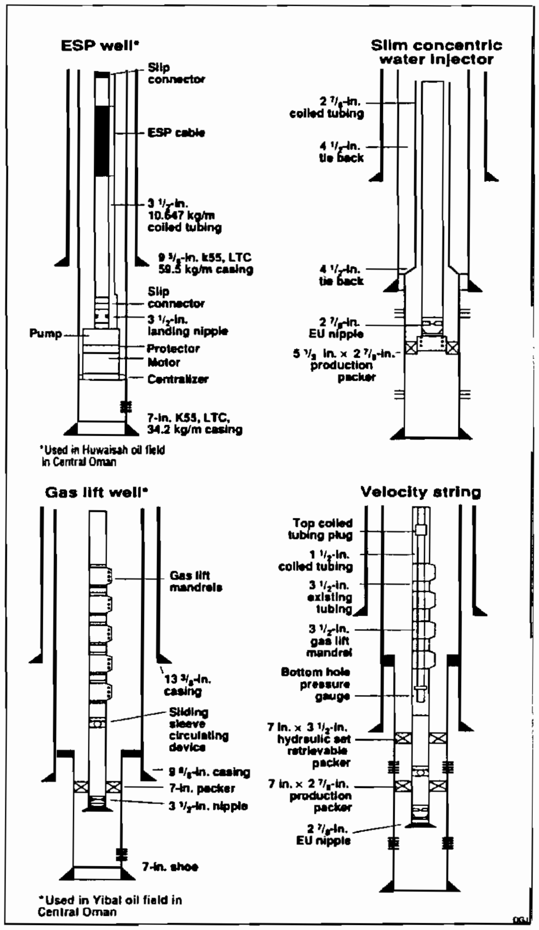


Figure 11-17. CT Completions in Oman
(Taylor and Conrad, 1996)

Running times were reduced substantially as experience was gained (Figure 11-18). Advantages are not completely quantified, but may include improvements to flow due to lower turbulence with nonjointed pipe.

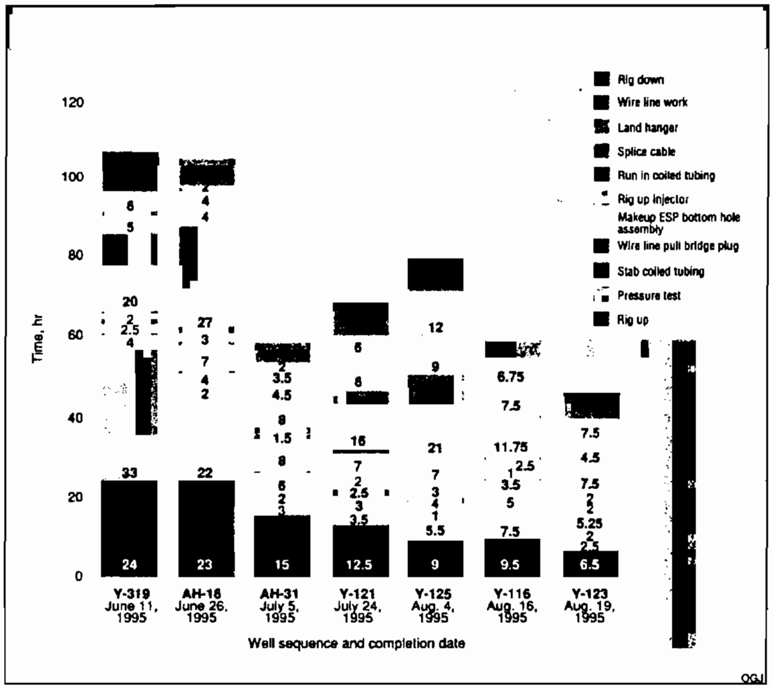


Figure 11-18. Time Analysis for Completions with Large CT (Taylor and Conrad, 1996)

Special equipment was designed and modified to handle large CT in this environment. A stabbing snake was devised from 1-in. cable and several 3½-in. steel upsets. This was attached to the end of the spool and allowed guiding the unwieldy tubing safely into the injector.

Ball bearings on the gooseneck rollers proved to be insufficient for withstanding side loads from the 3½-in. CT. Larger tapered roller bearings were installed to remedy problems with bearing failures.

A hydraulic straightener to decrease residual bend was fabricated to improve safety. Without a straightener, the string would have released significant energy when cut in the work window. With the straightener, the string deflected only 2-3 inches after the cut was complete.

11.8 NOWSCO WELL SERVICE AND ELAN ENERGY (CONCENTRIC CT SAGD)

Nowsco Well Service Ltd. and Elan Energy Inc. (Falk et al., 1996) described an innovative application of CT for heavy-oil production in Canada. Steam-assisted gravity drainage (SAGD) with a single horizontal wellbore was made possible by using a concentric insulated string of CT. The new single-well method allows lower drilling, completion and operating costs with more efficient placement of the steam.

Heavy-oil deposits are often positioned in thin zones 5 to 20 m thick. Due to rapid pressure depletion, primary recovery is usually only 10-15%. Enhanced recovery is required to access the remaining oil. SAGD is commonly applied in these reservoirs. Designs using horizontal wells for SAGD are shown in Figure 11-19.

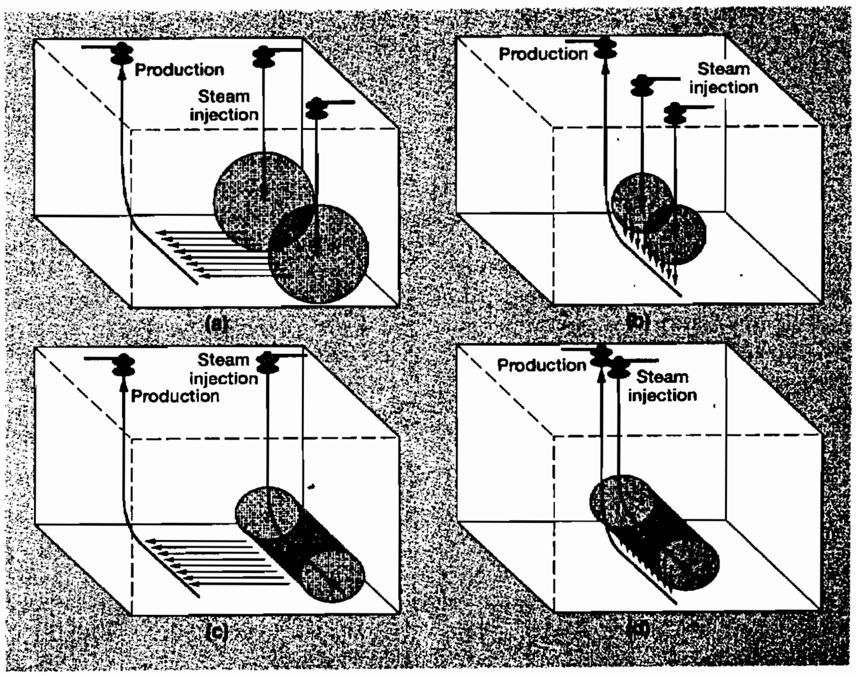


Figure 11-19. Multiwell SAGD Designs (Falk et al., 1996)

With the new single-well design (Figure 11-20), heated oil and condensate drain through the liner and flow toward the heel of the well, where they are pumped to surface. Flow of the heated oil is inherently gravity-stable. Low steam/oil ratios are possible, and the need to drill only one horizontal well increases economic viability.

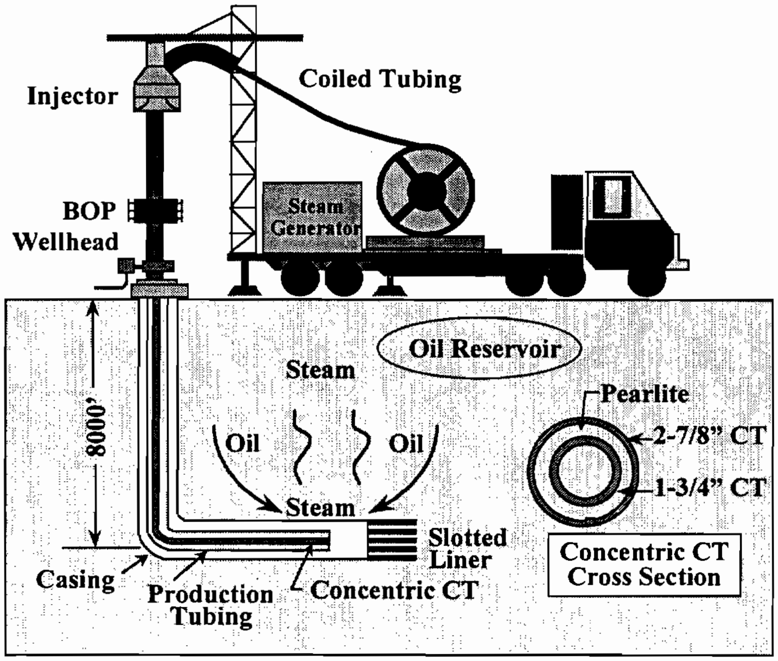


Figure 11-20. Single-Well Concentric CT SAGD
(Falk et al., 1996)

Concentric CT has previously been fabricated for other applications. The innovation required for this project was to devise a method to insulate the internal string. The final design developed for this project is shown in Figure 11-21. Prototype strings were fabricated by hanging off the outer string in a dead well, and then running in the inner string, feeding insulation in the annulus, and installing centralizers. Five short sections were spliced to the completed length of 5740 ft. Later improvements allowed splicing to be avoided.

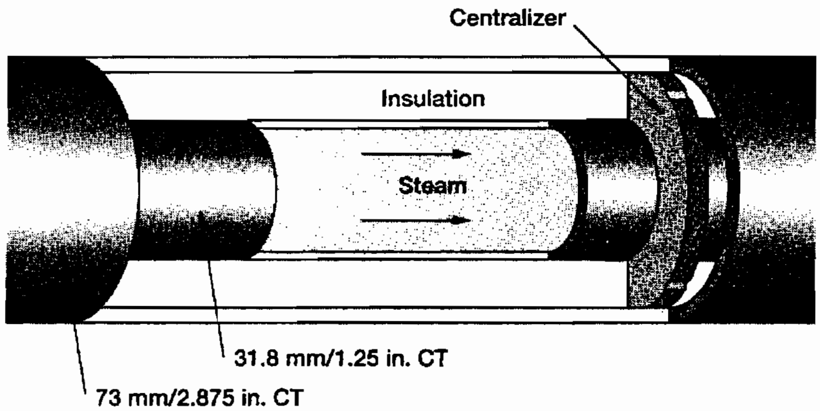


Figure 11-21. Insulated Concentric CT (Falk et al., 1996)

In the pilot project, the insulated concentric CT string was placed in a 7⅞-in. horizontal well. Oil rates gradually increased after production was started to more than 629 BOPD. Cumulative steam/oil ratio fell to less than 1.0 (Figure 11-22), a confirmation of high thermal efficiency.

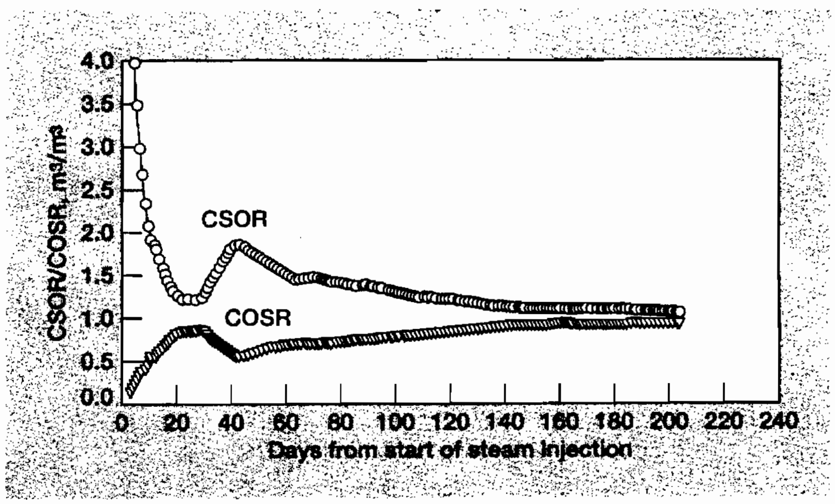


Figure 11-22. Cumulative Steam/Oil Ratio (CSOR) (Falk et al., 1996)

History matching of thermal parameters with performance indicated that the performance of the insulation compared very favorably with conventional vacuum-type insulated tubing strings.

Additional installations of single-well concentric CT SAGDs have been completed in Canadian fields. Results have been encouraging.

11.9 SHELL WESTERN E&P (CT CO_2 GAS LIFT)

11.9 SHELL WESTERN E&P (CT CO_2 GAS LIFT)

Shell Western E&P (Sorrell and Miller, 1997) described the design and evaluation of two CO_2 gas-lift installations in the Denver Unit, a mature field in West Texas. The field is now under tertiary recovery with CO_2 water-alternating-gas (WAG) injection. Costs of the CT applications ranged from $65,000 to $75,000 (Figure 11-23).

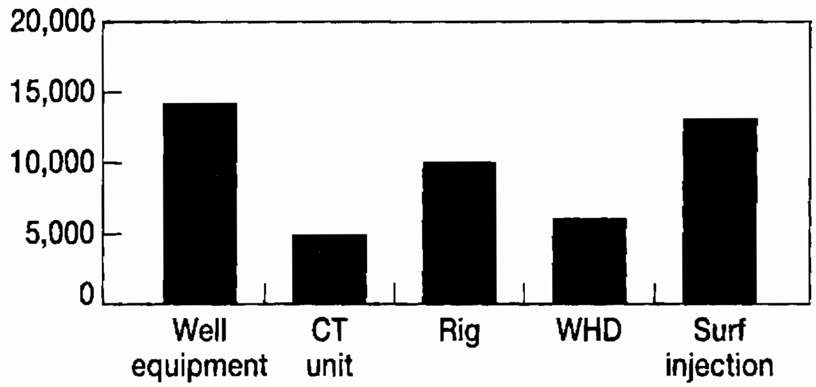


Figure 11-23. Costs for CO_2 CT Gas Lift (Sorrell and Miller, 1997)

One of the candidates for CO_2 gas lift was a recently fractured well. Liquid and gas rates were greatly increased by the stimulation. Several failures of the beam pump were caused by sand production and gas interference. This well was treated with CT gas lift to reduce well failures and downtime. The completion (Figure 11-24) included 2⅞-in. production tubing with a gas-lift mandrel installed 90 ft above the packer. Gas is injected through 1¼-in. CT strapped outside the production tubing.

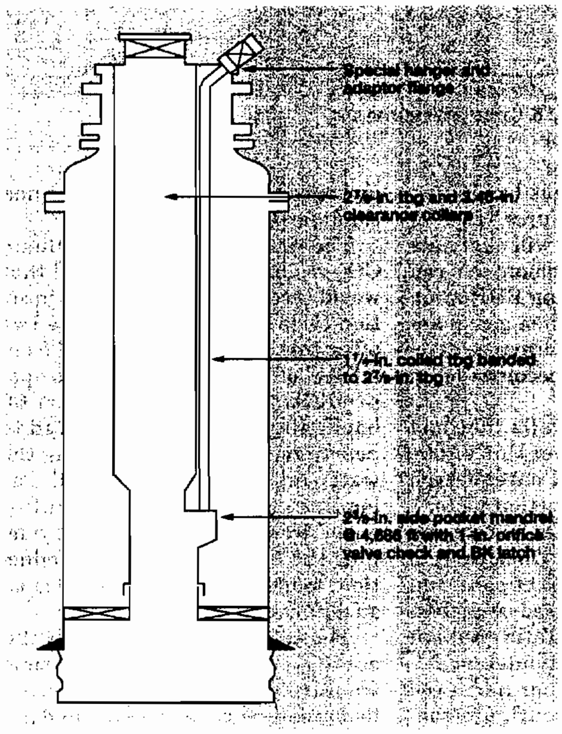


Figure 11-24. Completion Design of Denver Unit Well
(Sorrell and Miller, 1997)

The tubing hanger (Figure 11-25) is a special fixture manufactured to accommodate the CT/production tubing combination.

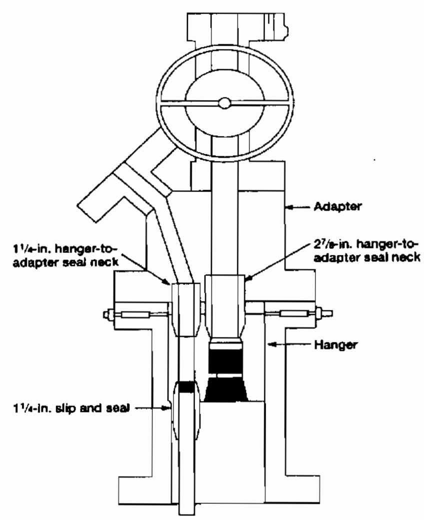


Figure 11-25. Special Tubing Hanger for CT Gas Lift
(Sorrell and Miller, 1997)

11.10 REFERENCES

Adams, Larry, 1995: "LDCT Gaining Momentum as Production Tubing," *The American Oil & Gas Reporter*, March.

Falk, Kelly et al., 1996: "Concentric CT for Single-Well, Steam-Assisted Gravity Drainage," *World Oil*, July.

Gauthier, Samuel J. and Ducote, Wayne J., 1995: " Spoolable Completions Are Alternative," *The American Oil and Gas Reporter*, September.

Gauthier, Sammy et al., 1997: "Advancements in SPOOLABLE Completions to Accommodate Wireline Operations," SPE 38401, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Kinnear, M.R. and John, H. 1996: "Repair of a Failed Gas Lift Completion Using a 1500 Ft. Long 3 ½ in. Coiled Tubing Insert Straddle," SPE 36908, presented at the 1996 SPE European Petroleum Conference, Milan, Italy, October.

Luft, H.B. et al., 1995: "Development and Operation of a New Insulated Concentric Coiled Tubing String for Continuous Steam Injection in Heavy Oil Production," SPE 30322, presented at SPE International Heavy Oil Symposium, Calgary, June 19-21.

O'Connell, Tim et al., 1997: "Flexible Plungers Resolve CT, Slim Hole Problems," *The American Oil & Gas Reporter*, January.

Sherwin, Thomas et al., 1996: "Well Completions in the Middle East Using 3½-inch OD Coiled Tubing: Case Study Evaluation," SPE 36138, presented at Asia Pacific Oil & Gas Conference, Adelaide, Australia, October 28-31.

Smith, M.I. and Brown, R., 1997: "Deployment of a Coiled-Tubing Gas-Lift Completion," *JPT*, October.

Sorrell, Dean and Miller, Ron, 1997: "Coiled Tubing CO_2 Gas Lift Evaluated in West Texas," *World Oil*, January.

Stephens, R.K. et al., 1996: "Lessons Learned on Coiled Tubing Completions," SPE 35590, presented at SPE Western Regional Meeting, Anchorage, Alaska, May 22-24.

Taylor, Robert W. and Conrad, Bruce, 1996: "Specialized Equipment Enabled Completions with Large Coiled Tubing," *Oil and Gas Journal*, February.

Waguespack, Sonny et al., 1996: "A 2 3/8-in. Coiled-Tubing Recompletion in the Gulf of Mexico," SPE 36334, presented at 1st SPE/ICoTA North American Coiled Tubing Roundtable, Houston, Texas, February 26-28.

12. Rigs

TABLE OF CONTENTS

12. Rigs

12.1 BAKER HUGHES INTEQ (COPERNICUS CT DRILLING RIG)

Baker Hughes INTEQ (Burge, 1996) designed a new drilling rig (Figure 12-1) that combines the capability to drill with CT as well as with jointed pipe. This project, called Copernicus, was undertaken in response to industry's need for fit-for-purpose slim-hole rigs and hybrid CT rigs that can handle jointed tubulars. The economics of the system are significantly improved through the use of a multitask crew and the integration of downhole and surface operations by means of a single control cabin.

Figure 12-1. Copernicus Rig (Burge, 1996)

Overall capabilities to be fulfilled with the new rig include pulling production tubing and preparing the well, drilling directional wells, running casing and liners, and drilling underbalanced.

Operational modules include conventional open fluid tanks and solids-control equipment, closed-loop fluid handling for underbalanced drilling, full CT operations, and tubing handling systems. A typical site layout (Figure 12-2) encompasses an area of about 625 m^2 (6727 ft^2).

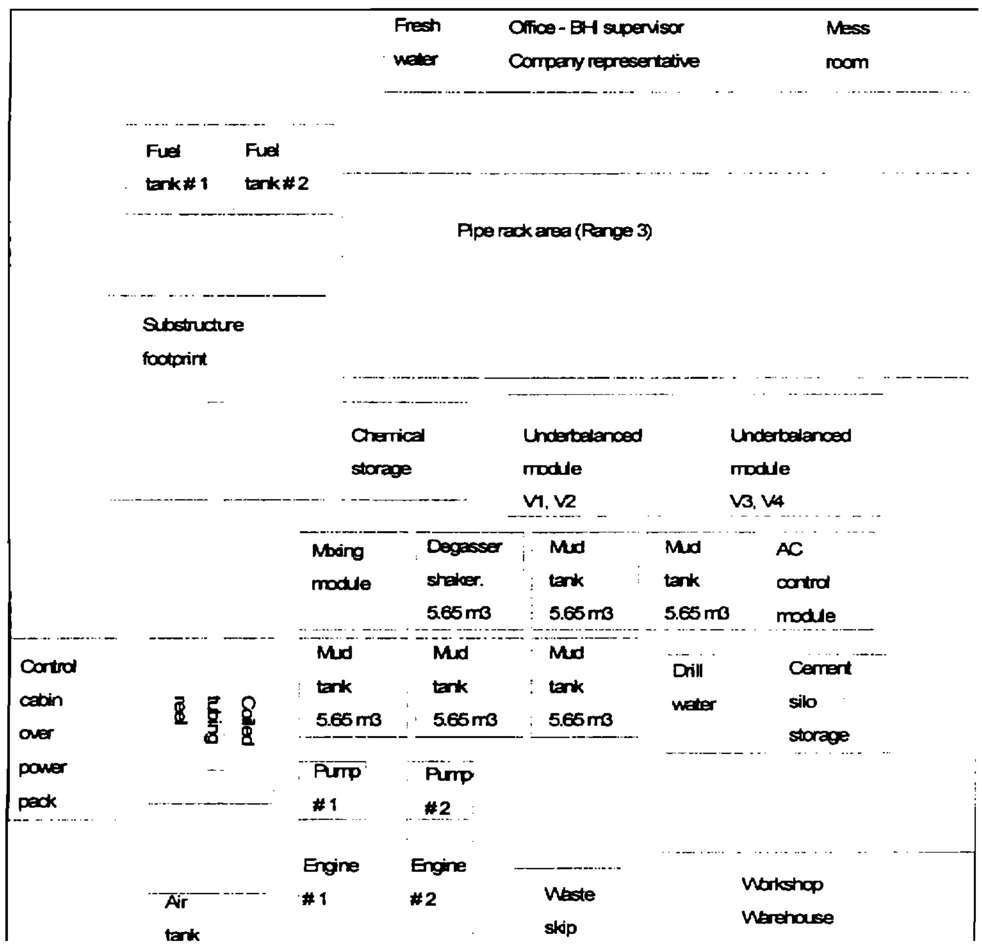


Figure 12-2. Site Layout (Onshore) (Burge, 1996)

Critical features of the rig include the use of a modified CT injector that can handle CT, drill pipe and casing. A lubricator is not required for deploying BHAs into live wells.

Hole sizes and rig capabilities are summarized in Table 12-1.

TABLE 12-1. Drilling Capabilities of Copernicus (Burge, 1996)

	CTD (Horizontal, through tubing)	Slim-hole exploration
Hole size	3½" to 5⅞"	3⅞" to 9⅞"
Depth	To 15,000' (4,500 m)	11,500' (3,500 m)
Temperature	max. 125 °C	max. 125 °C
Wellhead Pressure Differential Pressure	5,000- 10,000 psi (340 - 680 bar) 5,000 - 10,000 psi (340 - 680 bar)	10,000 psi (680 bar) 10,000 psi (680 bar)
Sour service	Yes	Yes
Build up rate	45°/100' (45°/30 m)	
Max. host casing size	9⅝" dependent on depth	Not applicable

A modified CT injector can also handle casing and drill pipe (Table 12-2).

TABLE 12-2. Capabilities of Injector (Burge, 1996)

Maximum load	100,000 lbs
Maximum operating load	80,000 lbs
Coiled tubing sizes	2" to 3 1/2"
Drill pipe sizes	2 3/8" to 3 1/2" (externally flush
Casing sizes	2 7/8" to 7 5/8"

Burge presents a detailed description of rig function, capacities and capabilities in his paper.

12.2 BAKER HUGHES INTEQ (GALILEO CT DRILLING RIG)

Baker Hughes INTEQ has introduced a third-generation CT drilling unit (named Galileo) with several improved features (Newman, 1998). The most obvious feature is the tubing pathway between the reel and injector. A traditional gooseneck is not used. Instead, matched computer-controlled injectors at the reel and wellhead keep the tubing suspended in an arc, thereby significantly reducing plastic deformation during cycling in and out of the well. The improvement in fatigue life is estimated at as much as 70%.

Galileo has several other improvements, such as more computerized control systems, as compared to Copernicus (INTEQ's previous CT drill rig design; see previous section). Future rigs should incorporate a folding 20-ft CT reel to increase fatigue life even more.

Galileo can drill with 18,472 ft of 2-in. CT or 12,854 ft of 2⅜-in. CT. The second rig is being barge mounted for use by Lagoven in Lake Maracaibo (Kunkel, 1997).

12.3 BAKER, NORSK HYDRO AND NOWSCO (OFFSHORE EXPLORATION CONCEPT)

Baker Hughes INTEQ, Norsk Hydro and Nowsco UK (Ehret et al., 1995) described results of field trials of elements and procedures which would be required as part of a fit-for-purpose slim-hole floating vessel. The first step in this investigation was to determine whether high-quality cores and electric logs could be obtained using slim-hole technology on a floating vessel, and to drill/core with CT from a floating vessel. Cores were taken with CT and with drill pipe. Although several problems were encountered, the technological feasibility of this approach for exploration applications was demonstrated.

An integrated slim-hole exploration system (including subsea BOPs, risers and small floating vessels) showed significant promise as an economically attractive system for exploration in deep water and/or remote locations. Rising costs in the North Sea have led to serious consideration of alternate exploration paradigms.

A test site was selected off Norway in over 400 ft of water. A semisubmersible rig would be used to drill to 5570 with drill pipe and set 7-in. casing. CT and drill pipe would be used to drill and core with 4⅛-in. BHAs.

Additional equipment required for the offshore operation included an extra 5⅛-in. pipe ram between the standard triple BOP and 4-in. stuffing box. A drill-string lifting frame (Figure 12-3) was also devised. This connects the rig heave-compensation system to the injector. The frame had to be extended for planned operations.

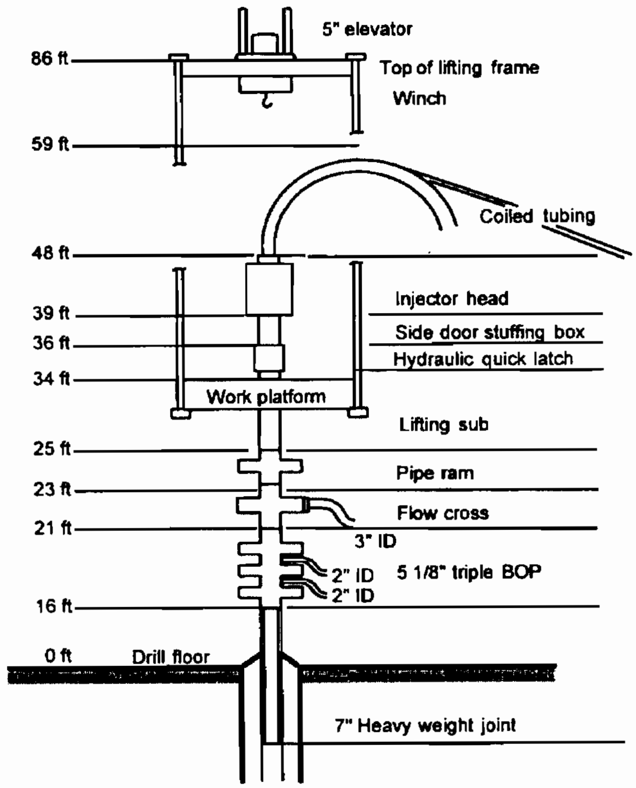


Figure 12-3. Drill-String Lifting Frame for CT Operations (Ehret et al., 1995)

Subsea well control was accomplished with a standard 18¾-in. 15,000-psi BOP. A 7-in. riser was run inside the existing (21-in.) riser for CT operations. The smaller riser would increase annular velocities and decrease the tendency of the CT to buckle.

The project team found that the effectiveness of the CT operations would be greatly improved by a built-for-purpose heave-compensation system.

More details on these tests are presented in *Drilling*.

12.4 BRITISH PETROLEUM (ARCTIC HYBRID RIG)

British Petroleum, Schlumberger Dowell, and Nordic Calista (Williams, 1997) described the design of a hybrid CT drilling rig capable of running jointed pipe. The rig is used for through-tubing sidetracks at Prudhoe Bay, where about 40 wells are drilled with CT per year. The hybrid unit was developed from an arctic workover rig and thoroughly modified for CT operations. The system is heavily winterized, enclosed, heated, and self-propelled.

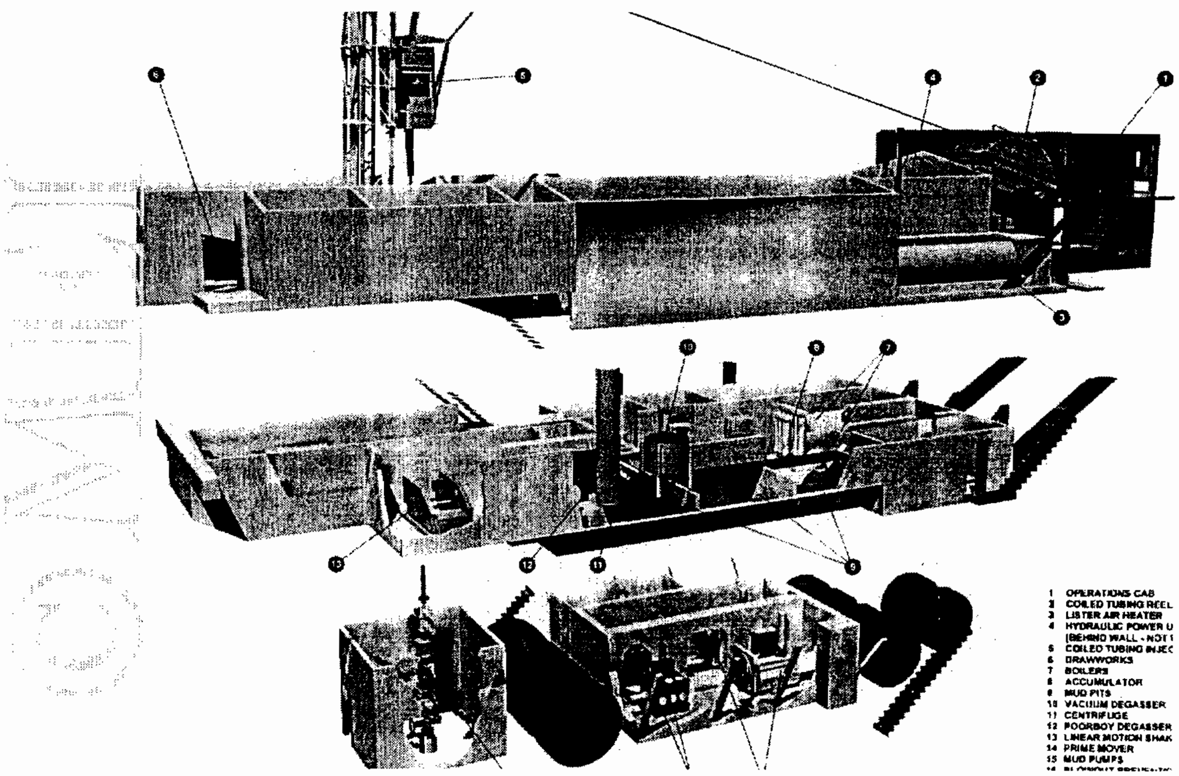


Figure 12-4. Arctic Hybrid CT Rig (Williams, 1997)

A complete package of software and electronics allows the operator to monitor all activities and operations from the CT cab. The original mast and traveling block are used to rapidly run jointed pipe for liners, as well as picking up the BHA and injector.

Flow rate in and out are continuously monitored by two mass-flow meters (Figure 12-5), which record flow rate, density, and temperature. An automatic monitoring system is incorporated, and voice alarms warn the operator if a kick has occurred.

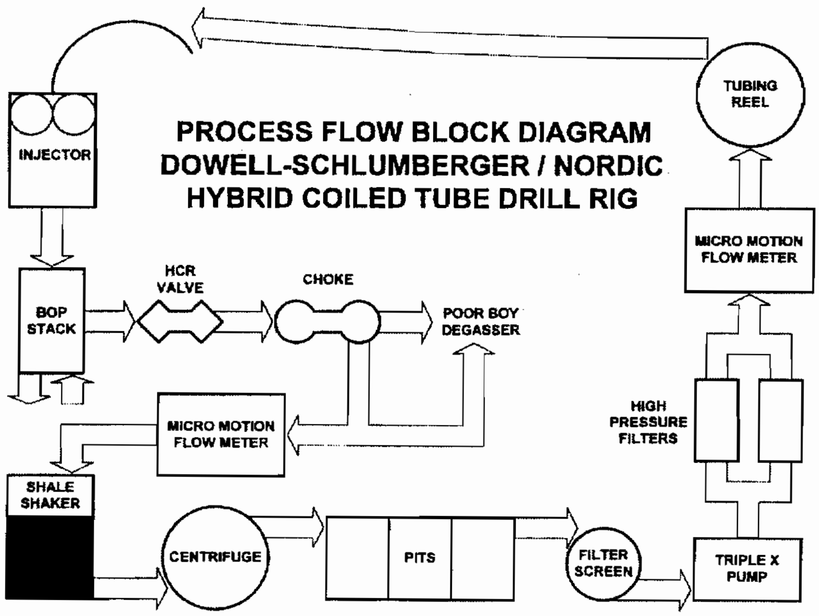


Figure 12-5. Process Flow of CT Rig (Williams, 1997)

12.5 DREXEL/TEXAS OIL TOOLS AND NOWSCO (BOP RAM DESIGN)

Drexel/Texas Oil Tools, CTES and Nowsco Well Services Limited (Palmer et al., 1995) investigated the performance of conventional and improved BOP rams for CT operations. The introduction of larger CT and improvements in fatigue-life modeling have made necessary the evaluation and improvement of standard shear and slip rams. They found that new designs for both shear and slip ram blades demonstrated superior performance.

Shear rams for CT must be able to cleanly shear the string with no axial load and with maximum internal pressure in the tubing. The profile on the fish should allow retrieving the string from the well. Early designs of shear blades (Figure 12-6, left) were not designed for multiple cuts or for shearing wireline inside the tubing.

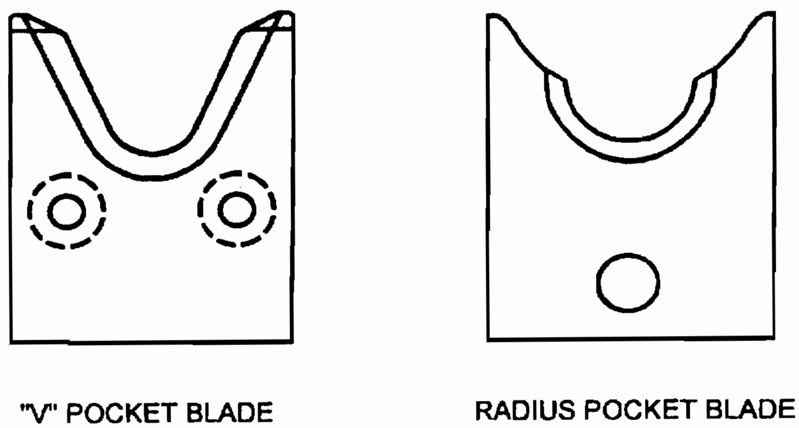


Figure 12-6. CT Shear Blades (Palmer et al., 1995)

The radius pocket blade (Figure 12-6, right) addressed the inadequacies of early blades. The profile on the lower string was elliptical and easily fished. Disadvantages of this blade included increased ram pressures (compared to conventional) and the requirement for specific blades for each size of CT.

Another blade profile, called the "RM" blade, addresses these problems. This blade will shear a wide range of tubing sizes and can operate at hydraulic pressures about 35% less than the radius pocket design.

Slip rams have been suspected as a source of damage that reduces fatigue life. Common practice has been to test the slip rams prior to every job.

Nowsco commissioned a series of tests to gauge slip-ram damage. Several samples of CT were gripped by various slip rams and placed in a fatigue fixture and bent to failure. Predictions for undamaged pipe were first developed for the test samples (Table 12-3).

TABLE 12-3. Fatigue Life Predictions for Slip Damage Tests (Palmer et al., 1995)

Internal Pressure (psi)	CT Wall Thickness (in)	Hoop Stress (psi)	Upper Confidence Limit (99%) (cycles)	Lower Confidence Limit (99%) (cycles)	Life Prediction (cycles)
0	0.156	0	1,091	676	912
500	0.156	1,683	1,335	274	906
1,500	0.156	5,049	892	627	892
1,050	0.109	5,691	1,068	389	889
3,000	0.156	10,097	1,017	870	871

The greatest loss of fatigue life was observed for a knife-edge slip mark, with about 70% reduction in cycle life (Table 12-4).

TABLE 12-4. Fatigue Life Lost by Slip Damage (Palmer et al., 1995)

Slip Mark Type	CT Wall Thickness (in)	Hoop Stress (psi)	Predicted Life for Unmarked (cycles)	Actual Life (cycles)	Life Reduction Due to Slip Mark
Uninterrupted Teeth, Solid Slip	0.109	11,360	866	248	71.3%
Uninterrupted Teeth, Solid Slip	0.156	10,097	871	270	69.0%
Interrupted Teeth, Solid Slip	0.109	5,691	889	468	47.3%
Interrupted Teeth, Solid Slip	0.156	10,097	871	602	30.8%
Interrupted Teeth, Segmented Slip	0.109	0	912	488	46.5%
Interrupted Teeth, Segmented Slip	0.156	10,097	871	480	44.9%

An improved slip ram with interrupted teeth was found to have the least effect on fatigue life. These slips (Figure 12-7) reduce stress concentration and marking of the CT.

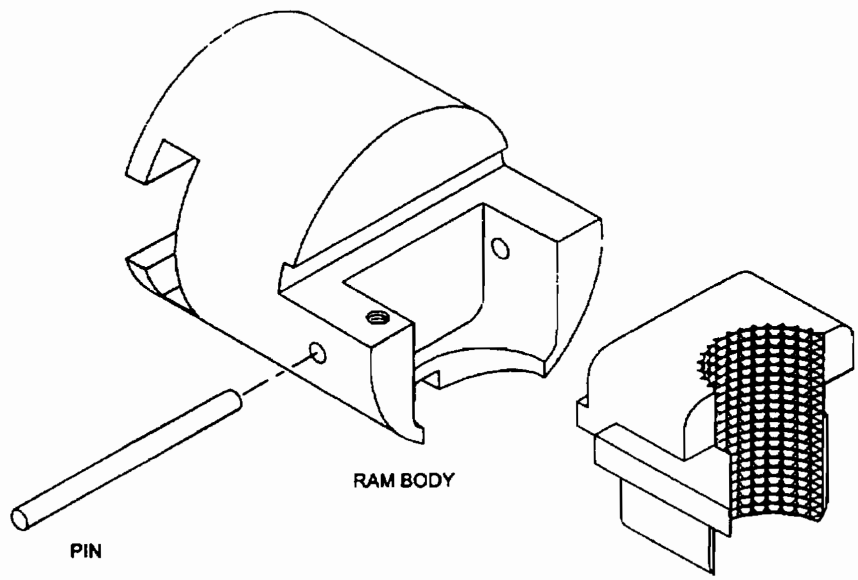


Figure 12-7. Improved Slip Rams (Palmer et al., 1995)

12.6 ENGINEERING CYBERNETICS, CAMCO AND BP (CT DRILL STRUCTURE)

Engineering Cybernetics, CAMCO Coiled Tubing Services and BP Exploration (Frishmuth et al., 1996) designed a special drilling structure for CT drilling operations at Prudhoe Bay. The tower is used to support the injector, drilling BHA and a pressurized lubricator. The drilling structure was designed as part of a concerted effort to apply CT drilling for re-entry applications on the North Slope. Long, heavy equipment would have to be supported over the well. The prime function of the proposed drilling structure was to prevent bending moments and large compressive loads from being transmitted to the wellhead.

A sketch of the drilling structure is shown in Figure 12-8. The design vertical load included 25 kips for the injector and 150 kips for the string weight. Wind loads and side pull from the CT reel are carried with the aid of stabilizing members.

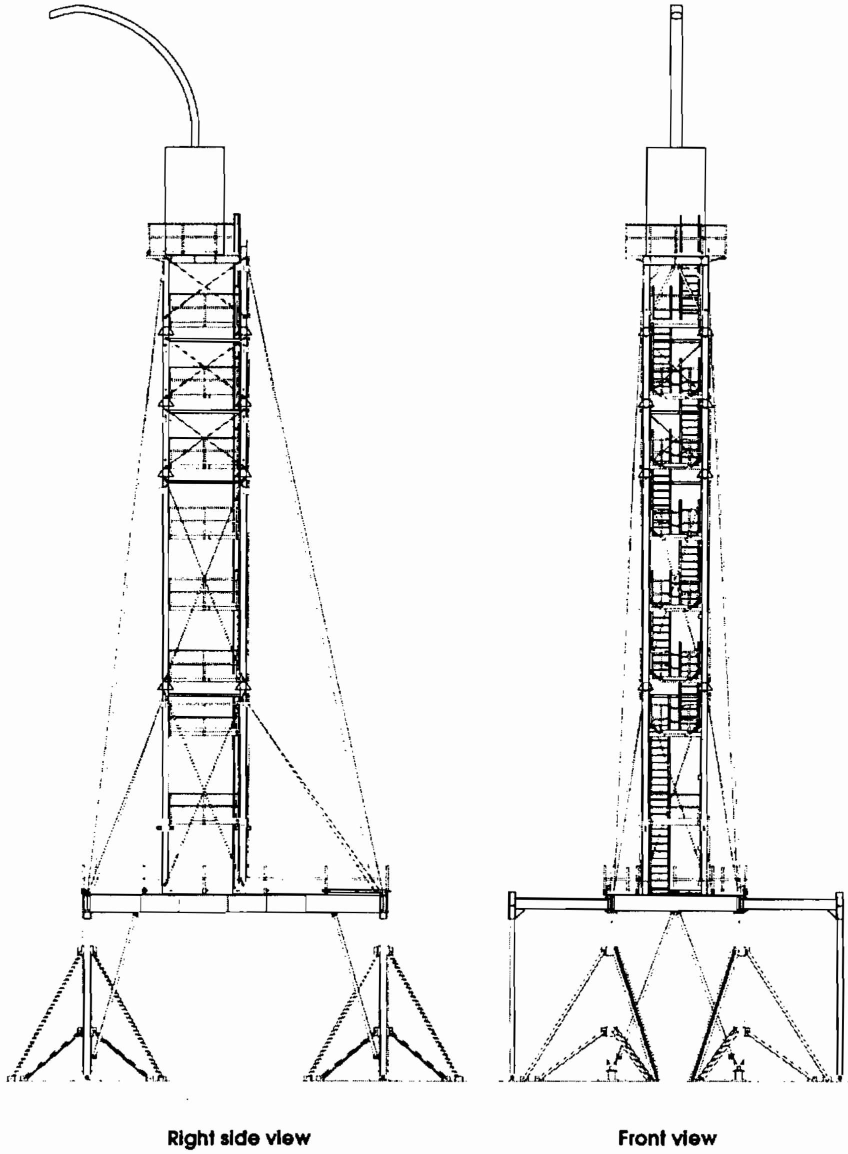


Figure 12-8. CT Drilling Structure
(Frishmuth et al., 1996)

After the bottom platform is set into position, a method to fine-tune position is required. Slots allow the tower base plate to be adjusted in four directions (Figure 12-9).

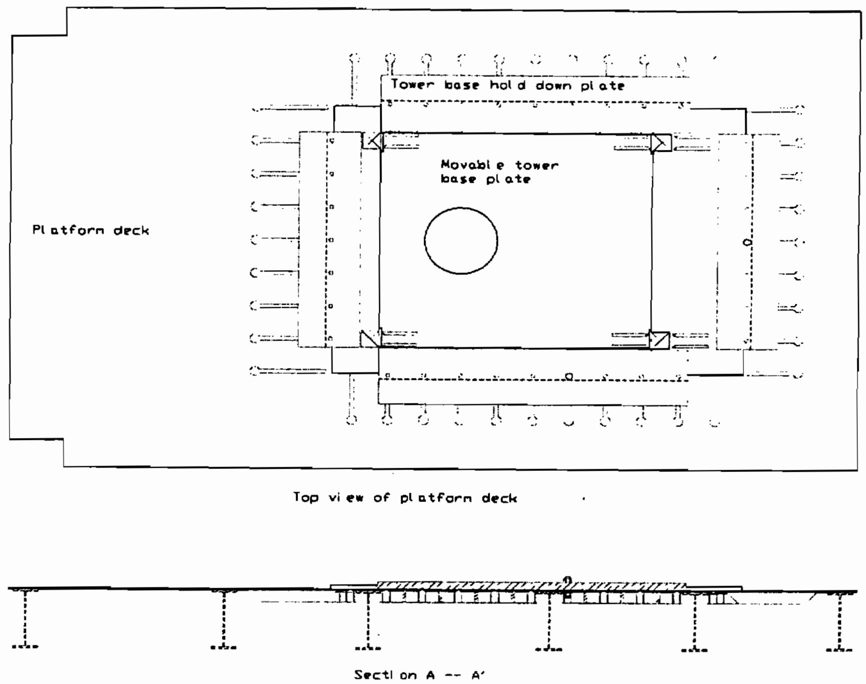


Figure 12-9. Platform Deck (Frishmuth et al., 1996)

The entire assembly is comprised of five sections. Rig up and down (Figure 12-10) can be completed in less than 12 hours. Crane lifting requirements have proven to be the greatest problem. A 150-ft boom is needed to place the injector at the top. This can only be completed in winds of less than 20 mph.

Figure 12-10. Field Erection of Drilling Structure
(Frishmuth et al., 1996)

The drilling structure has been used for running liners.

Only slight modifications would have to be made to transfer the technology to an offshore application. These include changes to the reel location (move closer to the tower), which would require additional idler wheels at the top. The lowest section, which is required to clear the well house, would not be required offshore. To reduce footprint, the outrigger legs could be replaced with guy cables attached to the platform.

12.7 HALLIBURTON ENERGY SERVICES AND IRI (HYBRID CT RIG)

Halliburton Energy Services and IRI International (Selby et al., 1998) described the design of a hybrid CT drilling rig that includes a mast for pulling tubulars. In offshore operations, a jack-up pulling unit or independent mast has normally been required before CT services could be performed. The new rig (Figure 12-11) integrates the injector, the power unit, and reel into a transportable rig with a mast. This new system was designed for use servicing shallow to moderate depth wells in the Gulf of Mexico. Increased efficiency and safety are in rig up/down and tripping speed.

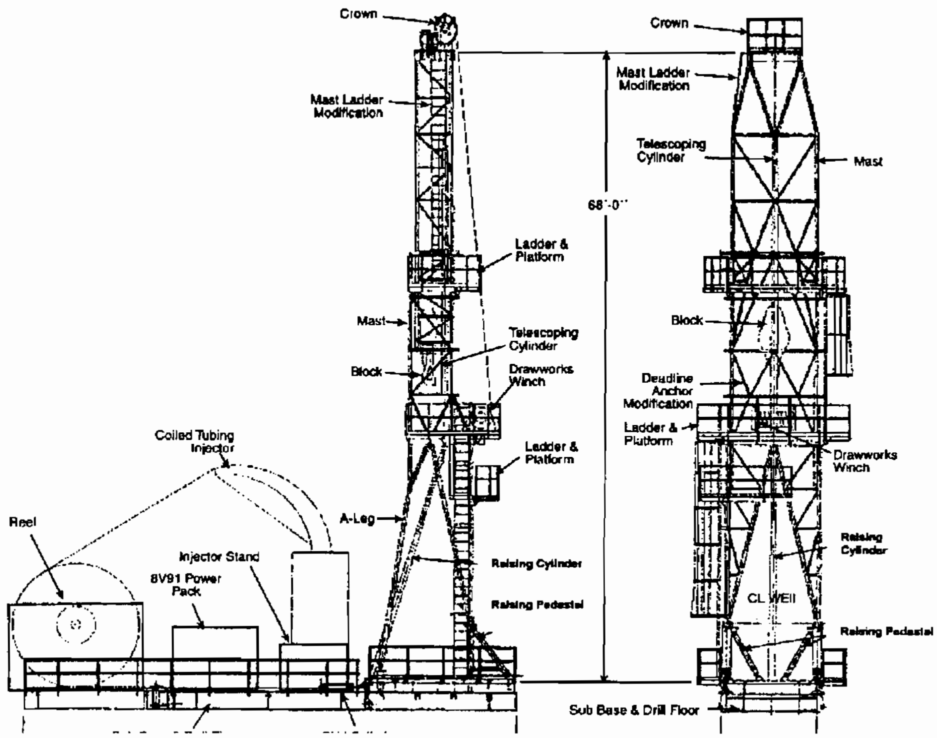


Figure 12-11. Hybrid CT Rig for Shallow Offshore Operations
(Selby et al., 1998)

The rig mast is 68 ft tall and is designed for 120,000 lb static hook load. Other handling tools and equipment for jointed-pipe operations are included. For transportation over roads, the mast can be laid down on the skid (Figure 12-12).

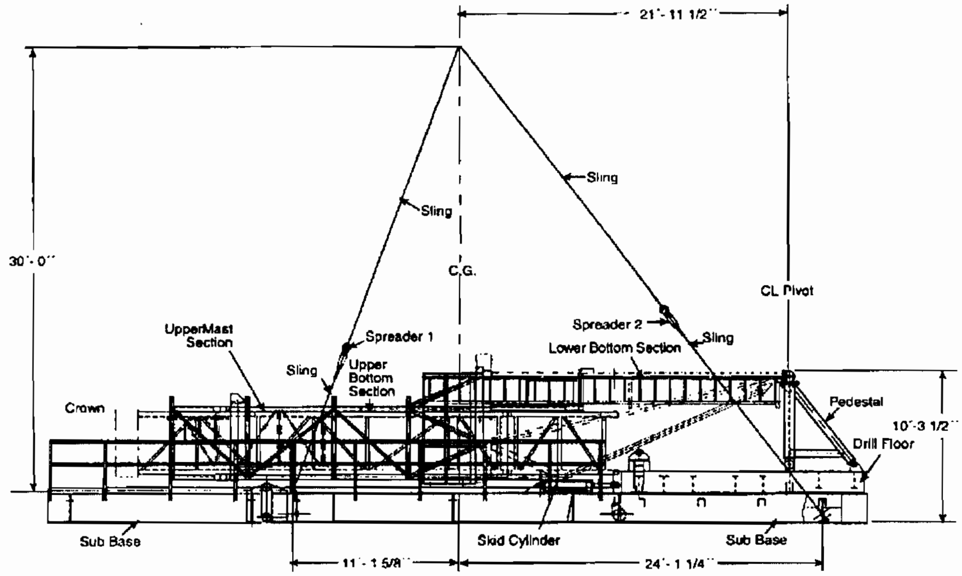


Figure 12-12. Hybrid CT Rig Folded for Transport (Selby et al., 1998)

The rig was first used in a shallow inland field in the Gulf of Mexico. The operation was to drill a new horizontal well for Rozel Energy. Large 2⅞-in. CT (80 ksi) was used for drilling and for the completion.

12.8 HITEC NORWAY (CT CONTROL SYSTEM)

HITEC Norway and HITEC ASA (van Walsum and Stakkeland, 1997) described the driller's work station for controlling the CDR-01, Tedtech's CT drill rig. This rig can perform standard jointed or CT drilling with only minimal changeover time. Benefits of the highly automated control system (Figure 12-13) include reduced costs, reduced rig weight, reduced rig-up/down time, as well as improved ergonomics for the drilling operator. A central programmable logic controller (PLC) interfaces the system.

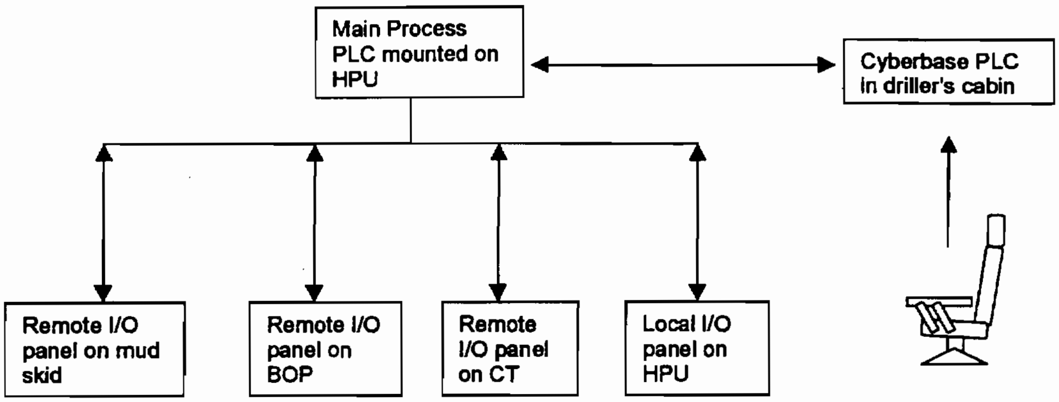


Figure 12-13. Control System of CDR-01 Rig
(van Walsum and Stakkeland, 1997)

All control instrumentation is displayed on two computer monitor screens. Data are also recorded from the operations for analysis after the job. Data from the downhole tool is sent through the PLC to the computer (Figure 12-14). All major rig functions are controlled by two joy sticks on the driller's chair.

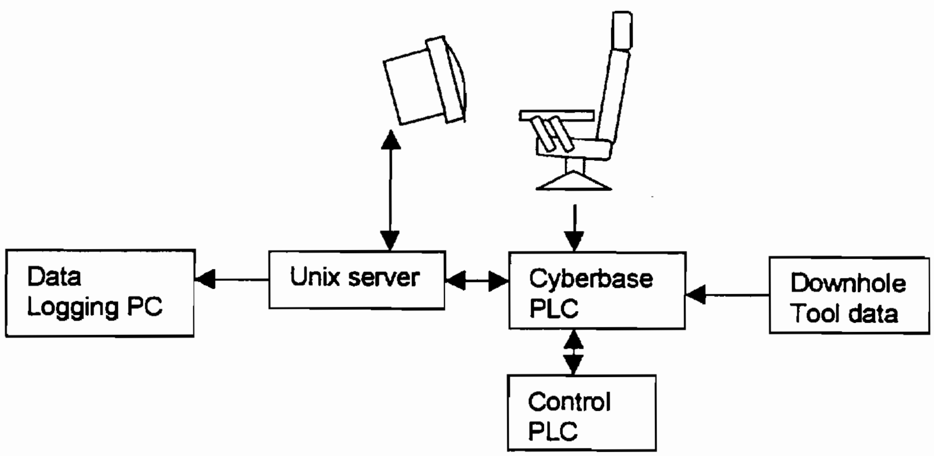


Figure 12-14. Data Communication Network
(van Walsum and Stakkeland, 1997)

12.9 KIDCO RESOURCES (METHOD TO ROTATE CT)

Kidco Resources Limited (Gray, 1994) described a method to rotate CT for orienting the downhole assembly in U.S. Patent no. 5,360,075. Their approach (Figure 12-15) involves spinning the injector and reel on separate fixed pivot points. Others have previously suggested rotating the injector to avoid the need for complicated orienting tools in the BHA; however, the typical approach is that the reel would be translated about the axis of the well along with the injector. Since the reel is heavy, this standard concept has never been pursued. Kidco's approach only requires that the injector be turned about its fixed position.

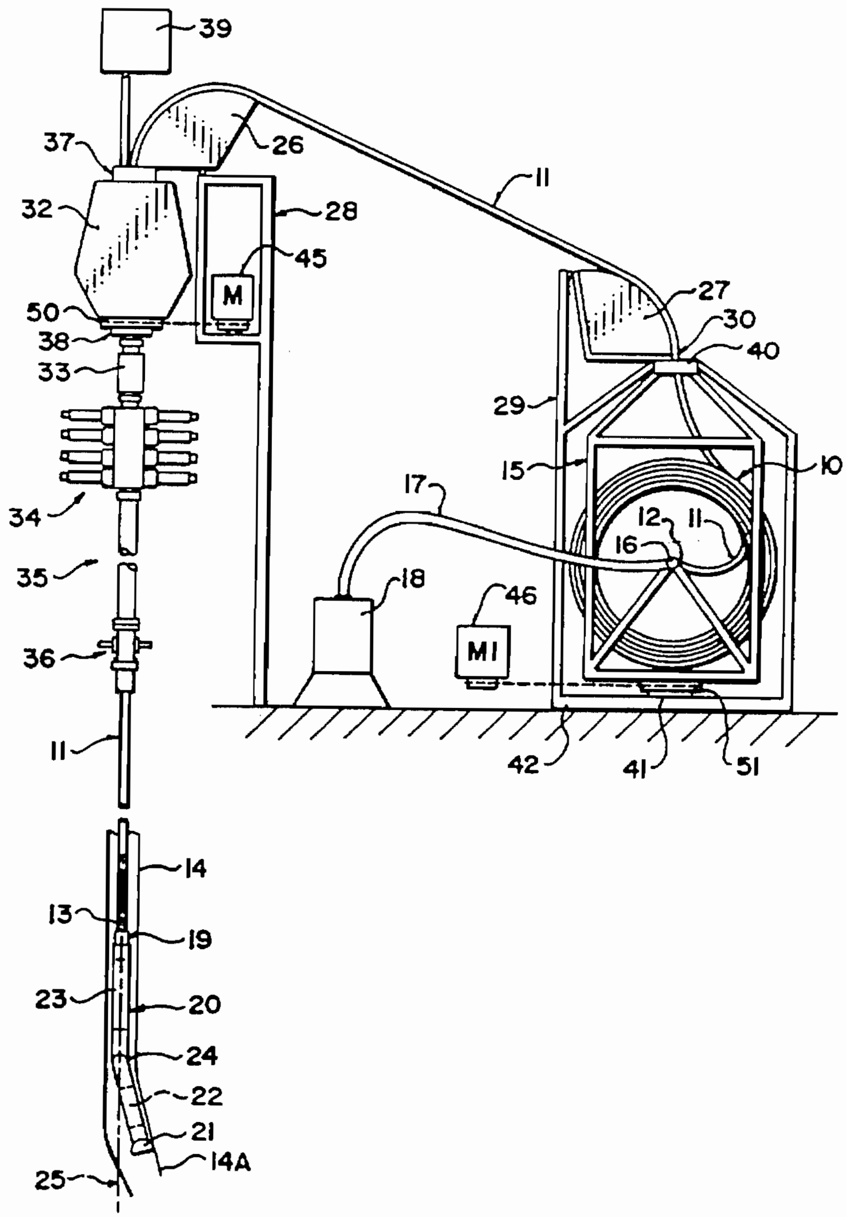


Figure 12-15. Injector and Reel for Rotating Tubing (Gray, 1994)

As the injector is rotated to orient the BHA, torque will be generated in the tubing between the injector and reel. This torque is removed by rotating the reel on its axis (Figure 12-16). Separate motors are used to rotate each assembly (M and M1) through an angle of less than 360°. (This is to avoid stressing or crimping the cables and hoses attached to the equipment.)

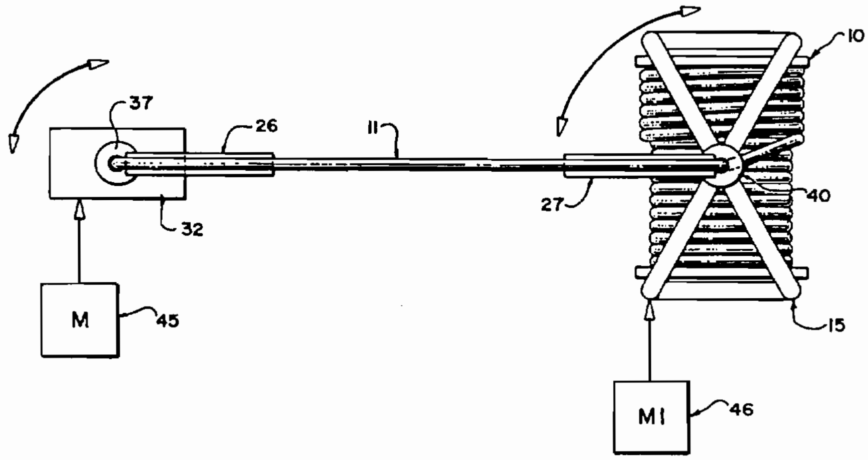


Figure 12-16. Reel and Injector Pivots (Gray, 1994)

It is not known whether this concept has been pursued in prototype or field applications.

12.10 PETROLEUM ENGINEER INTERNATIONAL (SIZE OF CT RIG FLEET)

CT rigs and systems have found widespread use in the oil field for drilling, completions (with several hybrid systems capable of running CT and jointed pipe), and workover operations. The market has been characterized by strong and steady growth throughout the 1990s continuing to the present, as reflected in the number of rigs in the field from 1991 to 1998 (Figure 12-17).

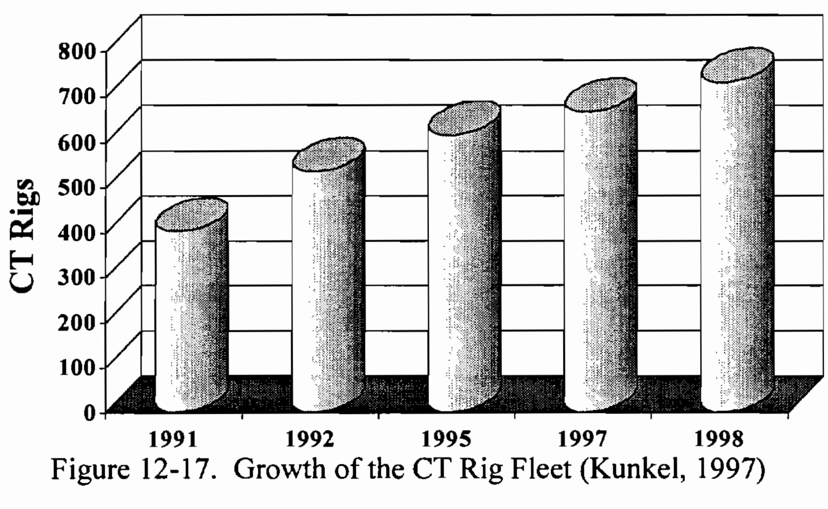


Figure 12-17. Growth of the CT Rig Fleet (Kunkel, 1997)

12.11 PRECISION TUBE AND BJ SERVICES (CT INSPECTION)

Precision Tube Technology and BJ Services (Smith and Misselbrook, 1997) overviewed CT inspection technologies that are available and might be applied in the field or during manufacturing. Five general technologies were considered: visual/manual methods, electronic caliper, magnetic flux, eddy current, and ultrasonic measurement techniques (Figure 12-18).

Inspection Method	Accuracy	Intrinsic Safety	Non-Expert User	Dirty & Wet Pipe	Economic	Practicality		
						Wellsite	Base	Manufacturer
Visual/Manual Caliper	√√√	√√√	√√√	√	$	√√√	√√√	√√√
Electronic Caliper	√√	√√	√√	√√	$$	√√√	√√	√√
Magnetic Flux	√√	√	√	√√√	$$$$	√	√√	√√
Eddy Current	√√√	o	o	√√√	$$$$	o	o	√√√
Ultra-Sonic	√√√	o	o	√√√	$$$$$	o	o	√√√

Figure 12-18. CT Inspection Methods (Smith and Misselbrook, 1997)

Six categories of incidents can occur in the field: mechanical, CT fatigue, CT corrosion, operator error, material defects, and manufacturing defects. They found that there is no single inspection technology that can identify all potential problems with CT. Consequently, preventing problems should remain a primary concern.

They concluded that several areas could yield an effective reduction in operational incidents. These include 1) expanded training of personnel, 2) better monitoring of acid pumping, 3) more effective flushing and inhibition, 4) accurate recording of fatigue history, 5) better inspection methods at the wellsite, and 6) better inspection methods at the manufacturing mills.

12.12 RIT (CT INTEGRITY MONITOR)

RIT has developed and marketed an Automatic CT Integrity Monitor (ACIM) for detecting and characterizing metal loss, general and pitting corrosion as small as 0.04 in., pinholes, inclusions, circumferential cracks and mechanical damage (Rosen, 1997). The ACIM is mounted near the spool (Figure 12-19) and consists of three major components:

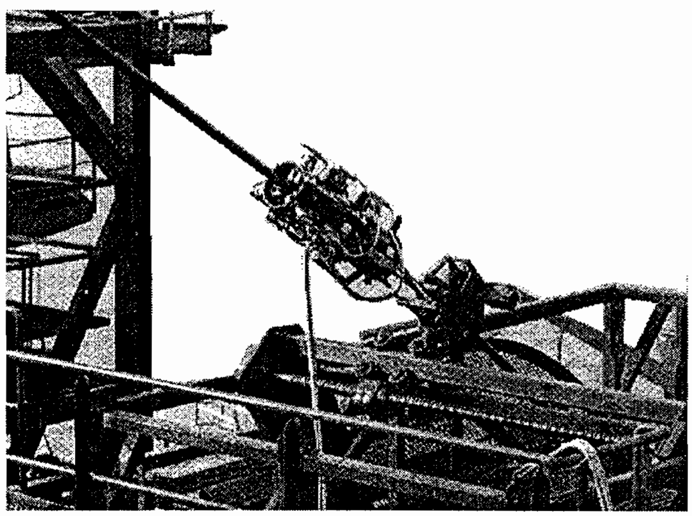


Figure 12-19. ACIM Integrity Monitor (Rosen, 1997)

1) magnetic flux leakage unit for metal loss, corrosion, and wall thickness, 2) an OD unit that measures six ODs and checks ovality, and 3) three odometer wheels for high-resolution measurement of CT depth and speed. ACIM systems are currently available for CT up to 2⅜ inches.

CT integrity parameters can be continuously monitored and displayed in a strip-chart view with time and depth (Figure 12-20).

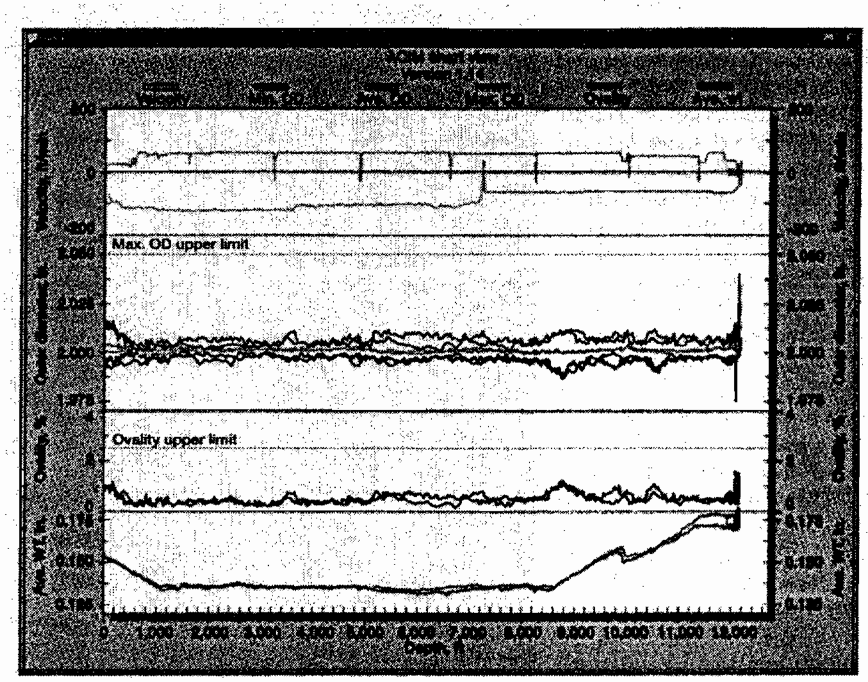


Figure 12-20. Monitoring CT Parameters (Rosen, 1997)

More information is presented in *Fatigue*.

12.13 SAS INDUSTRIES (OFFSHORE CT RIGS)

SAS Industries Inc. (Sas-Jaworsky, 1996) described several areas of technology implementation where CT is poised for significant growth. Offshore applications demonstrate particularly high potential because exploration and production expenses are often much higher than similar onshore operations. Cost savings must be sought in all areas to maximize profits in the offshore environment.

Sas-Jaworsky described a hybrid CT slim-hole drilling system. A stand-alone floating vessel (Figure 12-21) offers the advantages of both technologies.

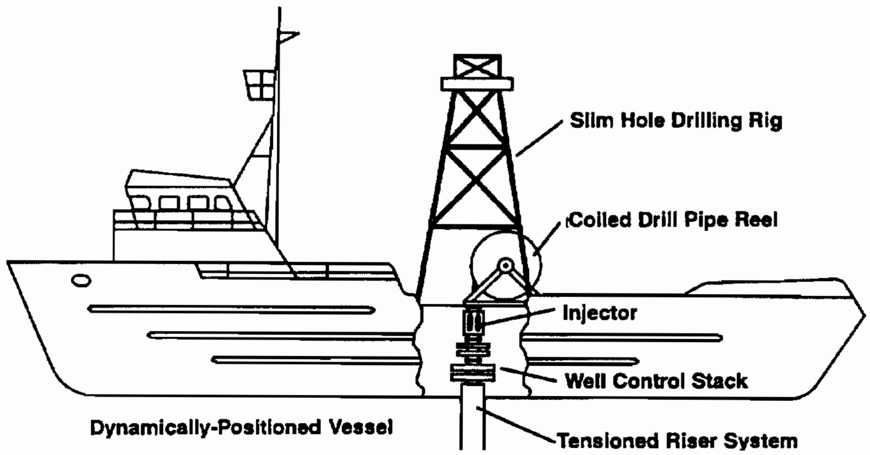


Figure 12-21. CT Drilling Ship (Sas-Jaworsky, 1996A)

Two areas that have generally limited CT drilling can be addressed with this type of drilling ship. The first is that larger spools can be accommodated, which allows longer strings and larger tubing diameters. The second improvement is that the reel can be positioned to feed directly to the injector without a gooseneck. This modification would significant increase fatigue life by eliminating two-thirds of the plastic bending cycles during operations.

It is envisioned that this type of drilling vessel could operate at a much lower cost than a full-scale drilling ship for exploratory drilling applications.

12.14 SCHLUMBERGER DOWELL (CT DEPTH MEASUREMENT)

Schlumberger Dowell (Pessin and Boyle, 1997) presented results of a comprehensive analysis of errors in depth measurement in CT operations. They analyzed the sources of error in depth measurement (Figure 12-22) and proposed a strategy to improve reliability and accuracy of depth control. Strategies for improving depth measurement were developed based on improved surface measurement device with minimized potential for wheel slippage, using pipe modeling to quantify the downhole deformation (stretching) of pipe, and improving operating procedures that eliminate random errors.

	"Everything Going Well" (feet / 10,000 feet)	Extreme Values (feet / 10,000 feet)
Errors in Length-of-Pipe Measurement		
Wheel Slippage	0	+/- 10,000
Wheel Wear	-25 to 0 *	-100 to 0 *
Depth Wheel Build Up	0 to 10	0 to 50
Depth Wheel Alignment	0 to 6	0 to 20
Thermal Growth of Measuring Wheel	-2 to 2 **	-3 to 3 **
Stretch/Shrinkage (Depth wheel below the injector head)	-3 to 3	-15 to 3
Total Length-of-Pipe Error (No Slippage)	-28 to 21	-118 to 76
Changes in the Length of Pipe Down hole		
Elastic Stretch due to Weight	2 to 7	2 to 10
Elastic Stretch due to Down hole Tensile Forces	-8 to 8	-15 to 15
Pressure Effect	<1	<1
Thermal Elongation of CT	2 to 8 ***	2 to 13 ***
Plastic Elongation of CT	0 to 2	0 to 10
Buckling of CT	-5 to 0	Neg. tens of feet...
Total Change in CT Length (No Buckling)	-3 to 25	-10 to 48
Errors in Reference Depths		
Errors in Reference Logs	0	-60 to 60
Errors Introduced during Depth Correlation	0	-20 to 20
Procedural Errors		
Zero at Incorrect Reference Point	0	-15 to 15
Sign Error in BHA Calculations	0	-15 to 15
TOTAL ERRORS	+/- 30	+/- 200
(Percent)	0.3%	2.0%

* Radial Wear of Depth Wheel --	Up to 0.005"	Up to 0.020"
**Temperature of Depth Wheel --	45 to 95 deg F	35 to 105 deg F
***Temperature Difference (Bottom Hole - Surface) --	50 to 200 deg F	50 to 300 deg F

Figure 12-22. Sources of Error in CT Depth Measurement
(Pessin and Boyle, 1997)

A new surface depth measurement device (Figure 12-23) was designed and tested under field conditions. Reliability is increased by two large wheels and local data processing for automatic redundancy. An anti-build-up feature keeps the wheel clean. Special wear-resistant material is used for the wheel. The error of the new system is reported as ±10 ft/10,000 ft.

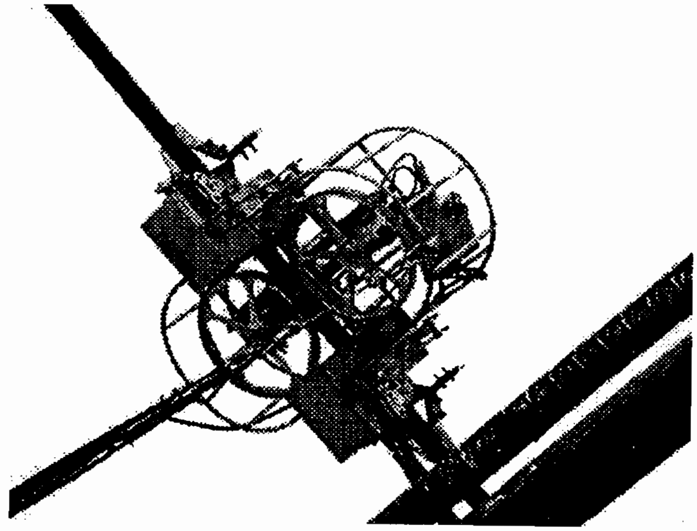


Figure 12-23. Improved CT Depth Measurement System (Pessin and Boyle, 1997)

12.15 SCHLUMBERGER DOWELL (HIGH-PRESSURE EQUIPMENT)

Schlumberger Dowell (van Adrichem et al., 1995) described the engineering process for designing CT rig equipment for use in high-pressure gas wells in South Texas. Previously, time-consuming snubbing units had been used. CT units were applied in the area to reduce costs. After equipment development and modification, average costs were reduced by 50% for the first fifty jobs. Field time was reduced from 7-12 days with snubbing units to 1-3 with CT.

Operating limits were developed for the harsh conditions. Early limits (Table 12-5, middle column) were based on practical rules of thumb rather than rigorous calculation. CT is now stronger and thicker than in the past, so operating limits can be increased under appropriate conditions.

TABLE 12-5. CT Operating Limits (van Adrichem et al., 1995)

PARAMETER	CONVENTIONAL LIMITS	HIGH-PRESSURE LIMITS
Maximum Pressure at Wellhead, psi	3500	9000
Collapse Pressure, psi	1500	10,000
Static Burst Pressure, psi	5000	10,000
Dynamic Burst Pressure, psi	4000	10,000
Maximum Tension, % of yield	80	80

Tubing size for these operations was narrowed to the range of 1 to 1½ inches. One-inch CT would not allow sufficient pump rates. Good burst and collapse ratings highlighted 1¼ x 0.156-in. CT as a good solution. Safety factors with 1½-in. tubing were not as favorable.

Operating stress limitations were modeled at the two harshest points: above and below the stripper. Above the stripper, compressive forces are highest and the burst pressure differential is the greatest. A tubing guide was positioned below the injector chains, thereby allowing a relatively large operational envelope (Figure 12-24).

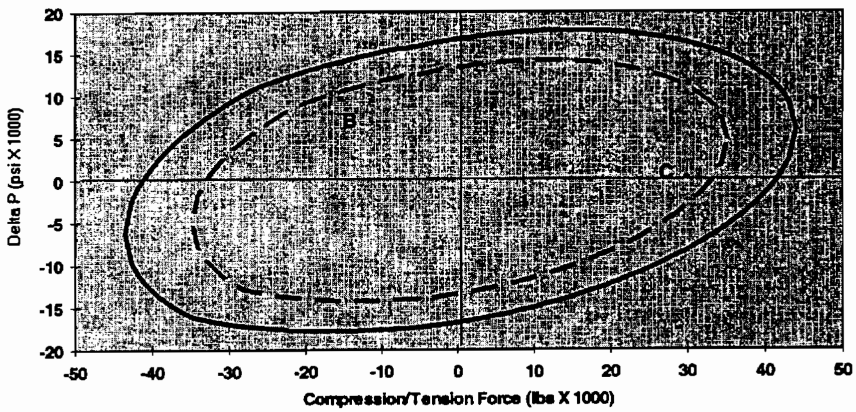


Figure 12-24. Stress Above Stripper for 1¼ x 0.156 in.
(van Adrichem et al., 1995)

The maximum expected compression force of 16,000 lb is just inside the envelope. Tension for pick up can safely be as high as 30,000 lb, which was judged to be adequate for these operations.

Tandem strippers were used, with the lower stripper rated to 15,000 psi and the upper to 10,000 psi. A lubrication point was added immediately above the upper stripper. Surface equipment for the high-pressure system is shown in Figure 12-25. A 15,000-psi quad BOP was developed for this application.

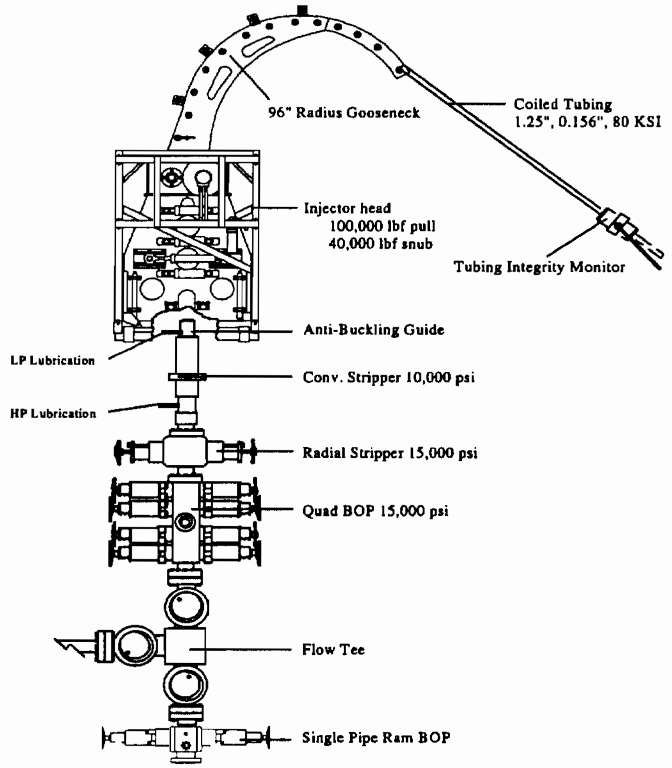


Figure 12-25. High-Pressure CT Equipment
(van Adrichem et al., 1995)

A yard test of the equipment was conducted at high pressure to investigate the impact of ballooning and fatigue. It was found that ballooning (Figure 12-26) was the limiting factor. A limit for diametral growth of 5% was established for field operations.

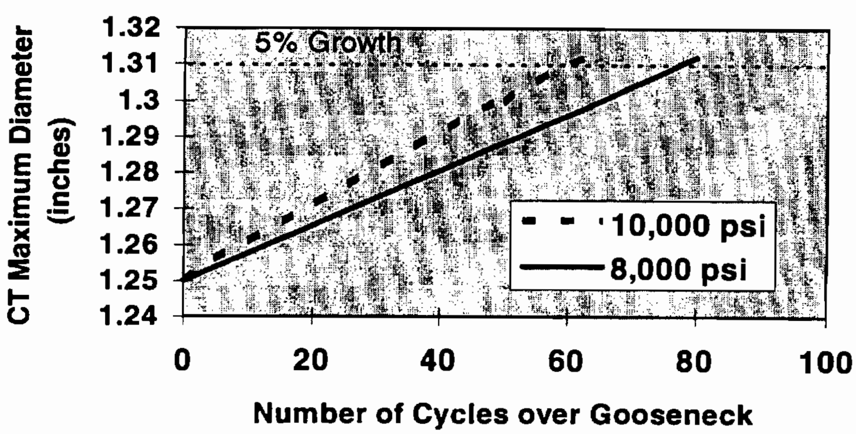


Figure 12-26. High-Pressure Ballooning (van Adrichem et al., 1995)

Economic analysis showed that several cleanouts could be performed with a single string of CT before the ballooning limit was exceeded.

12.16 STEWART & STEVENSON (HIGH-CAPACITY INJECTOR)

Stewart & Stevenson described a new high-capacity injector (Series 2000) with increased pulling/snubbing capacity (up to 200,000 lb pull and 100,000 lb snub), precise controllability at low speed, light weight, and the ability to run a wide range of tubing, both CT and jointed pipe (Toler, 1997). An articulated traction system allows continuous gripping over a majority of the tubing length as pipe joints (or other rises in tubing OD) pass through the chains. Jointed pipe as large as 6⅝ in. can pass through the injector without the need to stop the head, remove inserts or change inserts (Figure 12-27). Operators will have the capability to pull jointed strings for workovers or re-entry operations without having to rig up a workover unit in addition to a CT rig.

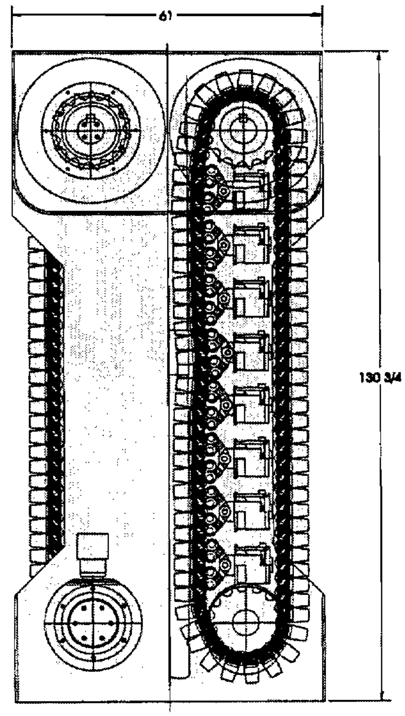


Figure 12-27. CT/Jointed-Pipe Injector (Toler, 1997)

12.17 TRANSOCEAN ENSIGN DRILLING (CT DRILLING RIG)

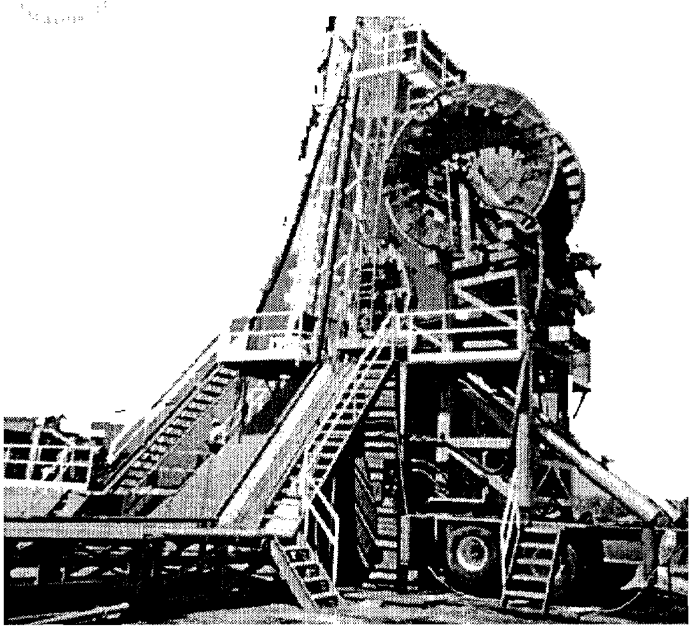


Figure 12-28. Tedtech CT Rig (*PEI*, 1997)

Transocean Ensign Drilling Technology (Tedtech) developed a new rig that reduces CT fatigue by a reported 300+% (Geddes and Sola, 1997). The CT spool on their rig is mounted up on the rig floor, and the CT is unspooled directly into the wellhead (Figure 12-28). This rig is of hybrid design, combining hoisting methods of a standard CT unit and a snubbing unit. Drilling ROPs with the system have been comparable to conventional rigs.

The system can use CT for re-entry or through-tubing applications, and jointed pipe for slim-hole applications. The unit combines the hoisting methods of a standard CT rig and a snubbing unit.

In another interesting development, Tedtech has filed patents for a large turntable that will rotate the spool around the well, thereby adding rotary capability to CT operations. Rotating the pipe between 5 to 15 rpm can significantly reduce friction, extend reach, and improve hole cleaning.

12.18 REFERENCES

Burge, Phil, 1996: "Project Copernicus - 2nd Generation CT/SHD Rig," SPE 36342, presented at the SPE/ICoTA North America Coiled Tubing Roundtable, Montgomery, Texas, February 26-28, 1996.

Ehret, J.R. et al., 1995: "Re-Defining the Exploration Drilling Technique in the North Sea; The First Step," SPE/IADC 29361, presented at the 1995 SPE/IADC Drilling Conference, Amsterdam, February 2-March 2, 1995.

Frishmuth, R.E. et al., 1996: "Design, Construction, and Use of a Coiled Tubing Drilling Structure for Onshore and Offshore Operations," OTC 8228, presented at the Offshore Technology Conference, Houston, Texas, May 6-9, 1996.

Geddes, Bob and Sola, Sonny, 1997: "The Continuous Drill String Rig 'A Drilling Solution to a Drilling Problem'," paper no. 97-143, presented at CADE/CAODC Spring Drilling Conference, Calgary, April 8-10.

Gray, Benjamin, 1994: "Steering Drill Bit While Drilling a Bore Hole," U.S. Patent No. 5,360,075, November 1, 1994.

Kunkel, Bill, 1997: "Benefits Fuel CT Growth," *Petroleum Engineer International*, July.

Larson, Eric et al., 1997: "Hybrid Rig Development Aids North Slope CT Operations," *World Oil*, August.

Newman, Ken, 1998: "Coiled Tubing Technology Continues its Rapid Growth," *World Oil*, January.

Palmer, R et al., 1995: "Developments in Coiled Tubing BOP Ram Design," presented at the 27th Annual OTC, Houston, Texas, May 1-4, 1995.

PEI Staff, 1997: "Coiled Tubing: Turning it to the Right," *Petroleum Engineer International*, September.

Pessin, J.L. and Boyle, B.W., 1997: "Accuracy and Reliability of Coiled Tubing Depth Measurement," SPE 38422, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Rosen, Patrick, 1997: "Progress in Onshore and Offshore Coiled Tubing Monitoring and Inspection," presented at the 5th International Conference on Coiled Tubing and Well Intervention, Houston, February 4-6.

Sas-Jaworsky, 1996: "New Offshore CT Applications Offer Value-Adding Utility," *The American Oil & Gas Reporter*, February.

Selby, Bruce et al., 1998: "Hybrid Coiled Tubing System for Offshore Re-entry Drilling and Workover," IADC/SPE 39374, presented at IADC/SPE Drilling Conference, Dallas, March 3-6.

Smith, Larry, and Misselbrook, John, 1997: "An Overview of Inspection Technology and Criteria for Inspecting Coiled Tubing," SPE 38413, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Strunk, Chris, 1997: "Coiled Tubing, Tool Advancements Invite New Look at Slim Hole Applications," *The American Oil & Gas Reporter*, February.

Toler, Scott, 1997: "High Capacity Injector Head for Large OD CT and Jointed Pipe," presented at the 5th International Conference on Coiled Tubing and Well Intervention, Houston, February 4-6.

van Adrichem, W.P. et al., 1995: "Development and Utilization of a Coiled Tubing Equipment Package for Work in High Pressure Wells," OTC 7874, presented at the 27th Annual OTC, Houston, Texas, May 1-4, 1995.

van Walsum, Eric and Stakkeland, Helge, 1997: "An Advanced Coiled Tubing Control System," SPE 38427, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Williams, Brock, 1997: "Update on Use of CT/Self Propelled Hybrid Workover Rig in Arctic Service," presented at the 5th International Conference on Coiled Tubing and Well Intervention, Houston, February 4-6.

13. Stimulation

TABLE OF CONTENTS

13. Stimulation

13.1 AMOCO PRODUCTION AND HALLIBURTON (BRAVO DOME COMPLETIONS)

Amoco Production Company and Halliburton Energy Services (Payton et al., 1996) used CT to reduce completion and stimulation costs in a 31-well campaign in the Bravo Dome CO_2 field in New Mexico. Costs were reduced 7.5% and production after six months was almost double expectations (5.1 versus 2.6 MMscfd/well). CT aided in achieving drilling and completion goals as well as in completing the project 30 days sooner than planned.

These 31 wells were drilled in 70 days by two rigs. Fiberglass and steel casings were cemented to TDs of 2100 to 2500 feet. CT was used to clean out cement displacement mud, perforate overbalanced, and clean out after fracturing. CO_2 foam frac treatments were performed on all wells. Sand remaining after fracing was cleaned out with CT (Table 13-1).

TABLE 13-1. Frac Clean-Up (Payton et al., 1996)

1. Rig up the coiled tubing unit to the wellhead and lay flow lines to the pit.
2. Open wellhead and start in the hole with the coiled tubing.
3. Start pumping foam at 70 quality.
4. Run coil at 100 ft/min to 200-500 ft above perforations. Then slow coil rate to start washing sand to TD.
5. Tag TD and pull back above perforations to rewash to TD.
6. Shut foamer off and switch to straight air while pulling the coiled tubing unit back to the surface.
7. Close in the wellhead and rig down the coiled tubing unit.

13.2 HALLIBURTON ENERGY SERVICES AND MOBIL (CT ACIDIZATION OF SCREEN)

Halliburton Energy Services and Mobil Exploration and Producing (Koshak and Attah, 1996) described a technique to more effectively remove residual drilling fluid and filter cake from behind prepacked screens using sliding sleeves and CT. With this method, screens can be run through the drilling fluid and later treated with a breaker. The sliding sleeve can be effectively shifted with CT instead of the impact method with wireline.

Prepacked screens, although an effective means of sand control, limit formation stimulation because the acid cannot be circulated (it must be bullheaded into the formation). A new method that allows circulation was developed by Halliburton Energy Services. Sliding sleeves are used to isolate the screen and permit circulation behind the screen.

In an early field application of the method, a well in the High Island field in the Gulf of Mexico was completed with 4½-in. prepacked screen (Table 13-2). Novel features of the approach include: drilling fluid is not displaced before the screens are run, CT is used to manipulate the screens, and acid is circulated behind the screen instead of being bullheaded.

TABLE 13-2. Description of Well F-10 (Koshak and Attah, 1996)

Well Type	Oil/Gas Producer
Completion Type	Openhole with Prepack Screen
Depth, TD	11,702 ft MD/9,864 ft TVD
Lateral Length	567 ft (completion length only)
Maximum Deviation	92°
Maximum Build Rate	15°/100 ft
Production Liner	5½ -in., 17-lb SHOE at 10,932 ft MD
TOL	10,067 ft MD
Open Hole	4¾-in., (10,932 ft to 11,702 ft MD)
Sand Name	MP-8 B
Equivalent Pore Press	11.1 lb/gal
Bottomhole Temperature	178°F
Drill-In Fluid	11.9-lb/gal polymer carbonate
Completion Fluids	12.0-lb/gal polymer carbonate
	12.0-lb/gal $CaCl_2$/$CaBr_2$
Completion Screen	2⅞-in. prepack

The stimulation procedure was performed in three trips of the CT string. In the first run (Figure 13-1), CT was run to 11,507 ft to confirm that depth could be reached and that the stinger could be stung into the seal bores. Tests were successful and the sleeve-shifting tool was added to the BHA.

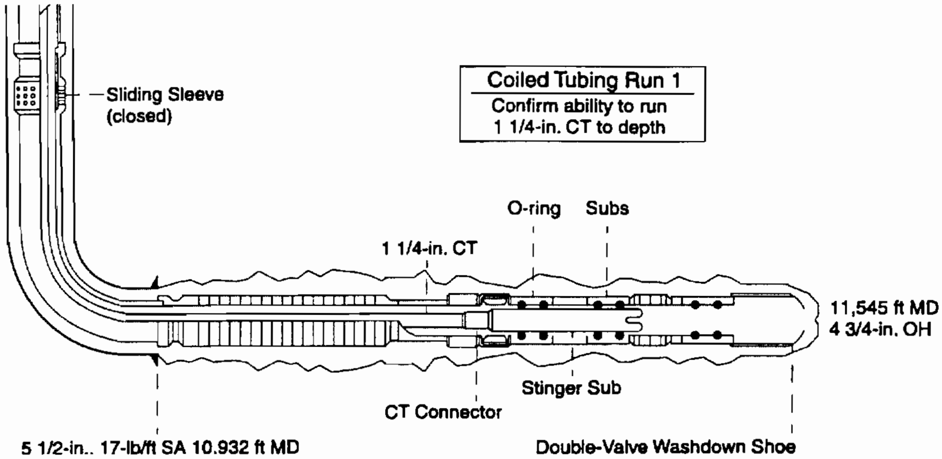


Figure 13-1. Run 1 with CT (Koshak and Attah, 1996)

The second trip was to sting into the seal bores at 10,531 and 10,535 ft, and pump the first phase of the acid job (Figure 13-2). Full returns were recovered, and the sliding sleeve was closed with a pick-up weight of 17,300 lb.

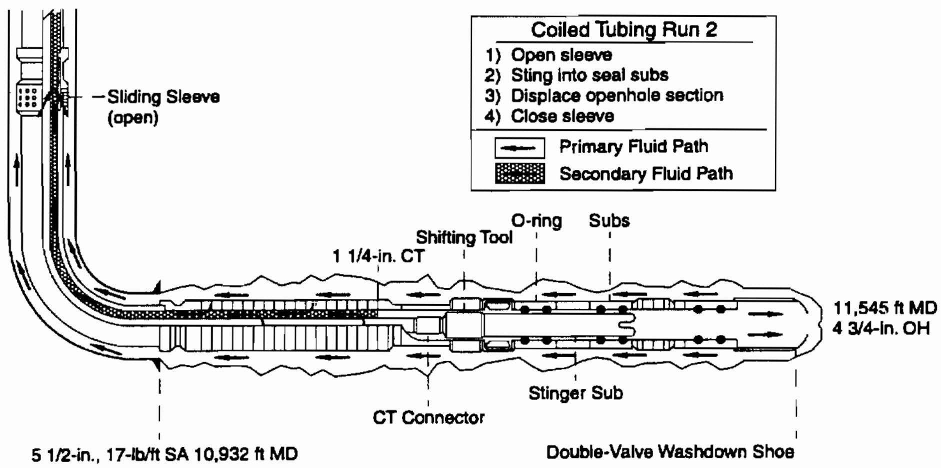


Figure 13-2. Run 2 with CT (Koshak and Attah, 1996)

The final CT run consisted of running to the end of the screen and spotting 67 bbl of 10% HCl across the gravel pack into the formation (Figure 13-3).

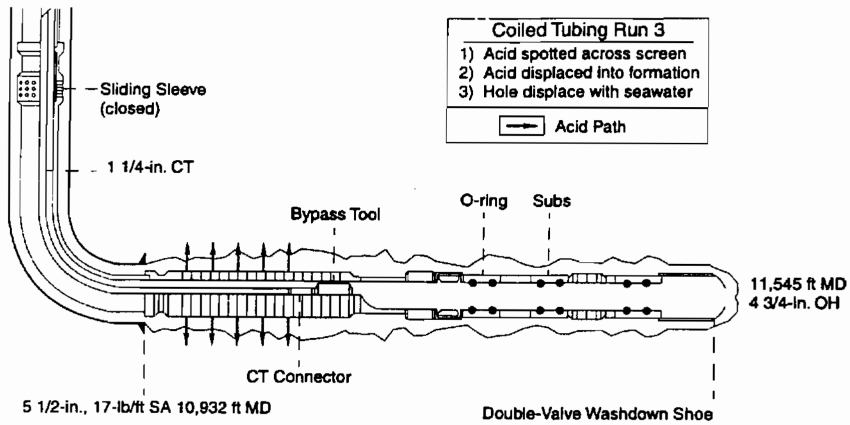


Figure 13-3. Run 3 with CT (Koshak and Attah, 1996)

The subject well was completed as planned and without any major problems.

13.3 HALLIBURTON ENERGY SERVICES (COMPOSITE BRIDGE PLUGS)

Halliburton Energy Services (Savage, 1995) described the advantages of using composite bridge plugs that can be drilled with CT instead of retrievable bridge plugs or sand plugs. Conventional techniques have shortcomings. Composite tools and CT save time, allow a definite schedule for fracing, provide positive zonal isolation, make reservoir testing possible, and often save money.

Retrievable bridge plugs do not well tolerate fluids with high sand concentrations. If they fail, fishing the plug out can be very costly. Sand plugs cannot be counted on to hold negative pressure, and are not dependable. Composite plugs solve these problems. In addition, drilling with CT allows one-day removal and well clean-up.

Representative parameters for drilling composite plugs with CT are summarized in Table 13-3.

TABLE 13-3. Drilling Composite Bridge Plugs with CT (Savage, 1995)

PLUG SIZE	WEIGHT	FLUID	PUMP RATE	COIL SIZE	MILLING TIME
4 1/2	5000 LBS	2% KCL	80 GPM	1.5	3:30 HOURS
4 1/2 (2)	10,000 LBS	2% KCL	1.75 BPM	1.75	2:30 & 1:30 HOURS
4 1/2 (3)	10,000 LBS	2% KCL	1.75 BPM	1.75	2:30, 4:00, & 1:30 HOURS
4 1/2	VARIED	2% KCL	1.75 BPM	1.75	3:00 HOURS
4 1/2 (3)	3,000 LBS	2% KCL	1.75 BPM	1.5	1:30, :50, & :45 HOURS
4 1/2 (2)	3,000 LBS	2% KCL	2 BPM	1.5	1:20, 2:18
4 1/2 (4)	3,000 LBS	2% KCL	2 BPM	1.5	2:10, :30, 1:20, :50
4 1/2 (2)	3,000 LBS	2% KCL	2 BPM	1.5	2:30, 1:05
4 1/2 (2)	3,000 LBS	2% KCL	2 BPM	1.5	1:45, 1:30
4 1/2 (3)	3,000 LBS	2% KCL	2 BPM	1.5	3:45, 1:45, 1:20 :50
4 1/2	3,000 LBS	2% KCL	2 BPM	1.5	:30
2 7/8	1,000 LBS	2% KCL	40 GPM	1.5	:25
2 7/8	1,000 LBS	2% KCL	40 GPM	1.5	:15
2 7/8 (4)	1,000 LBS	2% KCL	32 GPM	1.5	:30
2 7/8	1,000 LBS	2% KCL	32 GPM	1.5	:50
2 7/8 (3)	1,000 LBS	2% KCL	42 GPM	1.5	:40 TO 1:05

13.4 IMPERIAL OIL AND SCHLUMBERGER (NORMAN WELLS STIMULATION)

Imperial Oil Resources Limited and Schlumberger of Canada (Baker et al., 1995) described the application of CT and foaming technology to stimulate injectors and producers in the Norman Wells field in the Northwest Territories. Workover operations in 1994 included 38 foam-diversion acid treatments, a CT conveyed perforation, and ten wireline perforations. Costs per well decreased 44% due to replacing the service rig with a CT rig.

The Kee Scarp formation has an average pore size of 1-2 µm. Despite strong attention to filtering etc. in this field, well injectivity declines and must be restored via stimulation workovers. Costs to perforate and stimulate a well are about the same whether a service rig or CT rig is used. However, results are superior when CT is used.

Imperial Oil Resources has found that CT conveyed perforation is preferred, especially if more than one trip is required and the gun sections are short (less than 6 m).

The tools run for the operation include a perforating head with a weak point rated for 7500 to 8500 lbs. An accelerator is not normally required for absorbing the shock of firing the guns. Experience in Alaska suggested that accelerators are not required in deviated holes with this size of charge. Stress or deformation was not noted after initial runs at Norman Wells without an accelerator.

The time to pick up and arm the guns improved with experience. One run can be completed in about 2 hours, with tubing speeds at an average of 35 m/min (115 ft/min).

Schlumberger's Pivot Gun (Table 13-4) system has been employed, which allows the assembly to pass through 60-mm production tubing. A service rig is thus not required for removing production tubing. Pivot Guns are of expendable design (debris is left in the hole). The maximum gun length is 4.5 m in a vertical well. Shorter sections are required in a horizontal well due to friction. Three-meter guns have been successfully deployed in horizontal wells.

TABLE 13-4. Comparison of Casing Gun and Pivot Gun (Baker et al., 1995)

	101.6 mm PPG	Pivot Gun
Type	Casing Gun	Expendable TTG
OD (mm)	101.6	42.8
Phasing	90	180
Expl. Ld (g)	22.0	22.0
SPM	13	13
API RP-42 Section 1 (cm)	Pene = 57.18 EH = 1.02	Pene = 67.89 EH = .86
Norman Wells simulated (cm)	Pene = 24.5 EH = 1.0	Pene = 28.28 EH = .81

Acid diversion techniques have undergone significant development in the area. Diversion is currently achieved by using a stable foam in the channels behind pipe and thief zones, allowing acid to flow into damaged target zones.

13.5 NOWSCO WELL SERVICE (CONCENTRIC CT DST TOOL)

NOWSCO Well Service, Anderson Exploration, and Downhole Systems Technology (Fried et al., 1997) described a concentric CT logging tool to achieve optimum stimulation and production in long horizontal wellbores along with lower costs. An inflatable straddle packer is used for drill-stem testing and selective stimulation, all without resetting the packer. The inner string of CT is used for all well flow and stimulation operations (Figure 13-4). The annulus between the inner and outer strings is used for circulation and inflating the packers.

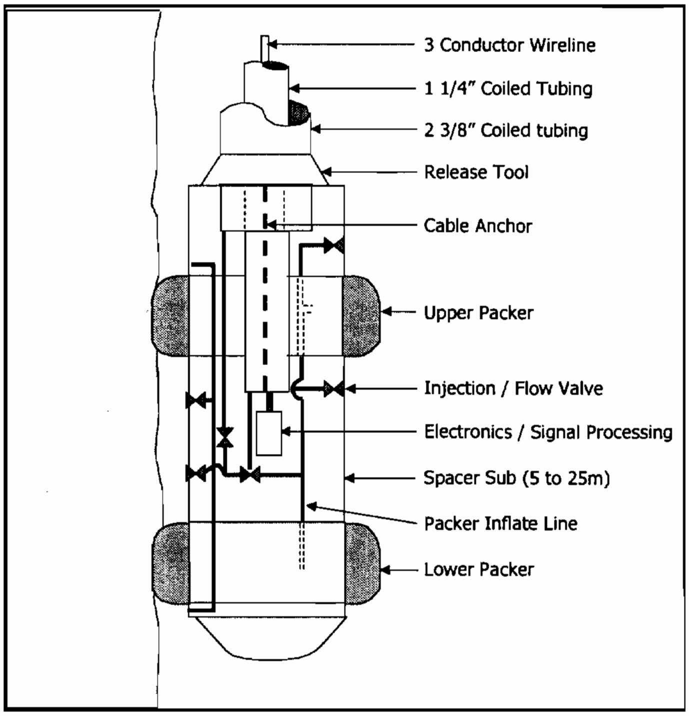


Figure 13-4. Concentric CT DST Tool (Fried et al., 1997)

Nowsco believes that this new CT system for measuring and removing formation damage has several benefits. These include safety, sour-service rating, circulation control, multiple-setting inflatable equipment, test/treat/test capability, gas-lift capability, and real-time data and interpretation.

13.6 NOWSCO UK AND STATOIL (DEPLOYMENT OF LONG PERFORATING BHAs)

Nowsco UK Ltd and Statoil (Engel and Sehnal, 1996) developed and implemented a tool string deployment system for deploying 140 meters of perforating guns along a horizontal section. The well (B-15) was located in the Norwegian sector of the North Sea. A recompletion was planned to isolate the lower producing interval due to high GOR and to perforate a higher interval. Rat-hole for dropping the guns was not available. Drag was a significant concern in the well, and friction was reduced by adding rollers to the BHA and using friction reducers. Field operations, including deploying, running and recovering the perforating guns, were completed successfully in 5½ days.

The deployment system includes male and female connectors (Figure 13-5) for quick connection within the surface lubricator. OD is 2.5 inches. Make-up length of the assembly is 972 mm. Gate valves provide double-barrier isolation.

Figure 13-5. Deployment System Connectors (Engel and Sehnal, 1996)

Each gun section (Figure 13-6) was 13.5 m in length. Thirteen sections and one firing head were required.

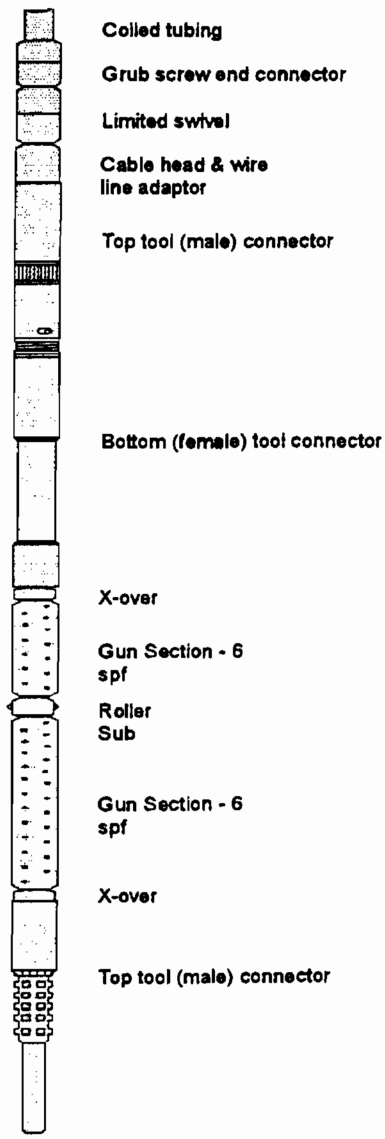


Figure 13-6. Single Gun Section
(Engel and Sehnal, 1996)

Extensive modeling of drag was conducted prior to the job. The hanging weight of the BHA was over 2500 kg; 2-in. CT was specified. Rollers were to be added at each joint of the guns. These had been found to reduce required pushing forces by 50%. A drag reducer was also planned to ensure that target depth was reached.

Drag predictions and results are compared in Figure 13-7. Nowsco stated that the difference between POOH weights is explained by gun debris or by low gun weights used in the model.

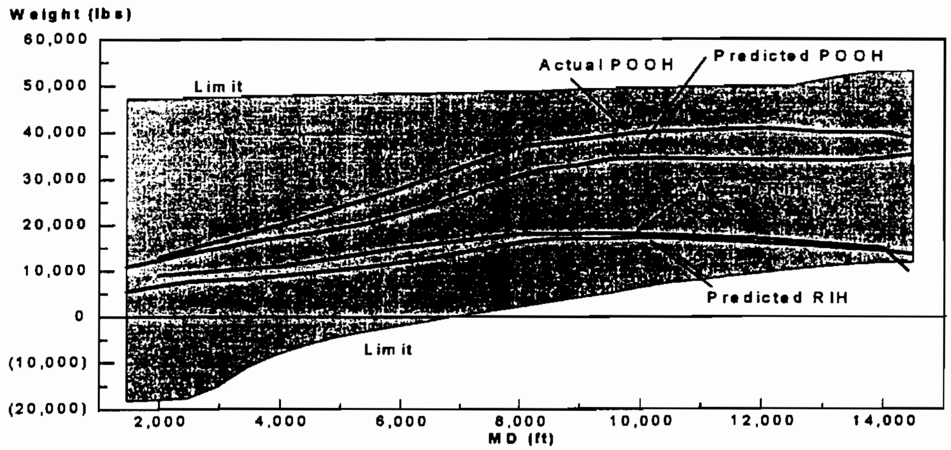


Figure 13-7. Weight Indication During Perforating (Engel and Sehnal, 1996)

Nowsco advised that deployment systems similar to the one described are viable options when more than three separate trips are required to achieve the same objective with conventional deployment methods.

Additional information is presented in *Tools*.

13.7 SCHLUMBERGER DOWELL AND SHELL OFFSHORE (ACID OPTIMIZATION)

Schlumberger Dowell and Shell Offshore (Acock et al., 1996) summarized the advantages of real-time data from downhole sensors during matrix acidization. Examples of production improvements were presented for several wells in the Gulf of Mexico. Sensor data were used to optimize treatment during field operations, resulting in lower costs and better performance.

CT is often a superior means to perform acid jobs. The string provides a clean conduit that reduces the risk of contamination from rust, dope and scale. Formation injectivity may be poor, greatly reducing the effectiveness of bullheading. Completion designs may lend themselves to CT for placing the treatment directly where it is of most benefit.

Injection pressures during acid treatments are conventionally estimated based on surface readings and estimates of friction pressures and hydraulics. The only means to know downhole conditions with certainty is to make use of downhole sensors. Schlumberger Dowell's downhole sensor package is described in Table 13-5.

TABLE 13-5. Specifications for Downhole Sensor (Acock et al., 1996)

Make-up length with flow-by housing (in.)	64
Diameter with flow-by housing (in.)	2.125
Maximum Operating Temperature (°F)	350
Maximum Operating Pressure (psi)	10,000
Pressure Acquisition Range (psi)	0 to 10,000
Temperature Acquisition Range (°F)	32 to 350
Pressure Acquisition Accuracy (% full scale)	0.075
Pressure Acquisition Resolution (psi)	1
Temperature Acquisition Accuracy (°F)	+/- 1
Temperature Acquisition Resolution (°F)	+/-0.1

The bottom-hole assembly incorporating these sensors is shown in Figure 13-8. Total BHA length is less than 12 ft with an OD of 1.70 inches.

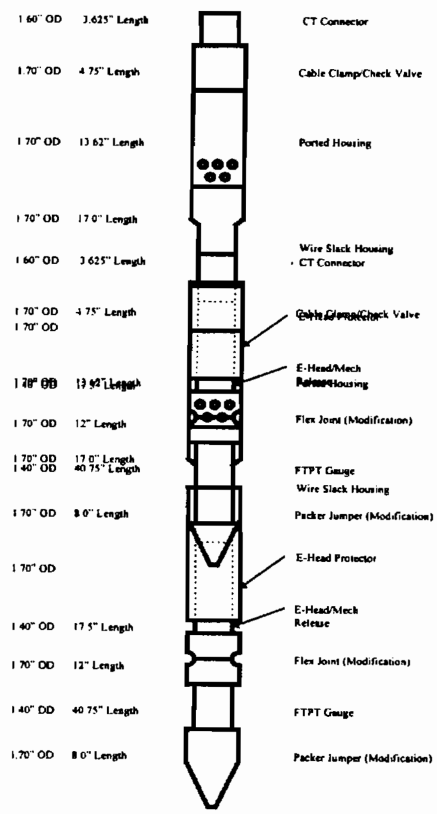


Figure 13-8. Downhole Sensor Assembly (Acock et al., 1996)

Schlumberger Dowell presented results from four example workovers from the Gulf of Mexico. Production improvements of optimized acid treatments are summarized in Table 13-6.

TABLE 13-6. Production Improvements from Acidization (Acock et al., 1996)

	CASE 1			CASE 2			CASE 3			CASE 4		
	bopd	bwpd	mcf	bopd	bwpd	mcf	bopd	bwpd	mcf	bopd	bwpd	mcf
Pre acid rate	136	1	1969	169	678	59	98	271	953	140	1008	3815
Post acid rate	147	1	2331	474	843	79	165	907	441	753	3432	7763
Rate Change	11	0	362	305	165	20	67	636	-512	613	2424	3948
% Change	9	0	18	180	24	35	68	235	-54	438	240	103

One of the treatments was in a horizontal well with a 2⅞-in. prepacked screen to a depth of almost 12,000 ft. A two-part treatment was planned to remove suspected fines which were plugging the prepacked screen.

The initial downhole pressure increased 130 psi above shut-in pressure, and then fell rapidly by 50 psi as ammonium chloride was injected (Figure 13-9). Injection pressure then remained steady just above reservoir pressure. The operator decided to stop treatment with less than half of the acid pumped.

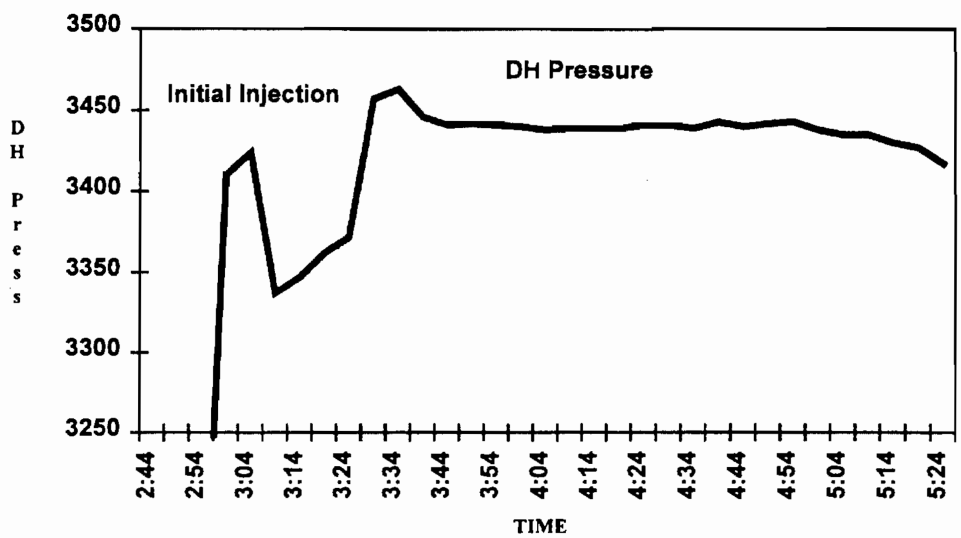


Figure 13-9. Downhole Pressure in Horizontal Well (Acock et al., 1996)

The entire treatment is shown in Figure 13-10 including downhole and wellhead pressures. The ability to monitor downhole pressures in real time allowed substantial savings in time and cost by indicating that the job could be stopped before the end of the planned program.

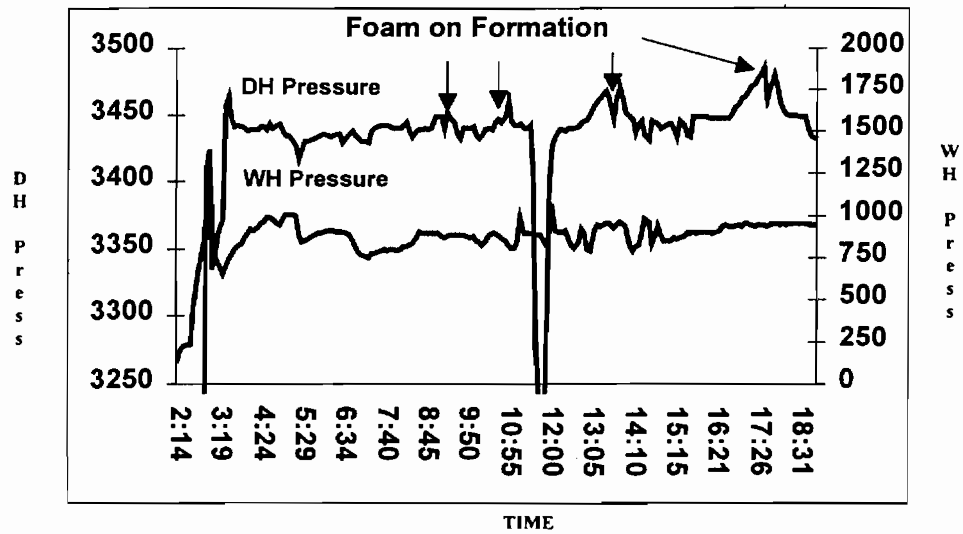


Figure 13-10. Pressure During Acid Job in Horizontal Well
(Acock et al., 1996)

Real-time monitoring of downhole conditions provides insurance of not exceeding formation limitations (fracture pressure), may reduce stimulation costs by increasing pump rates, and allows real-time changes to treatment design to optimize results.

13.8 UNIVERSITY OF OKLAHOMA (CT FRAC FLUID STUDY)

The University of Oklahoma (Shah and Subramanian, 1997) studied the effects of shear history on the rheological and hydraulic properties of several frac fluids pumped through CT. The work was performed in a special test fixture (Figure 13-11) at the Fracturing Fluid Characterization Facility. Results show that CT curvature increases pressure drops for water and fracing fluids. Pressure drops for borate-crosslinked HPG gels depend on CT shear history and pressure drops for borate-crosslinked guar gels are independent of CT shear history. Finally, their results showed that an optimum pH exists for some fluids such that shear history does not affect apparent viscosity.

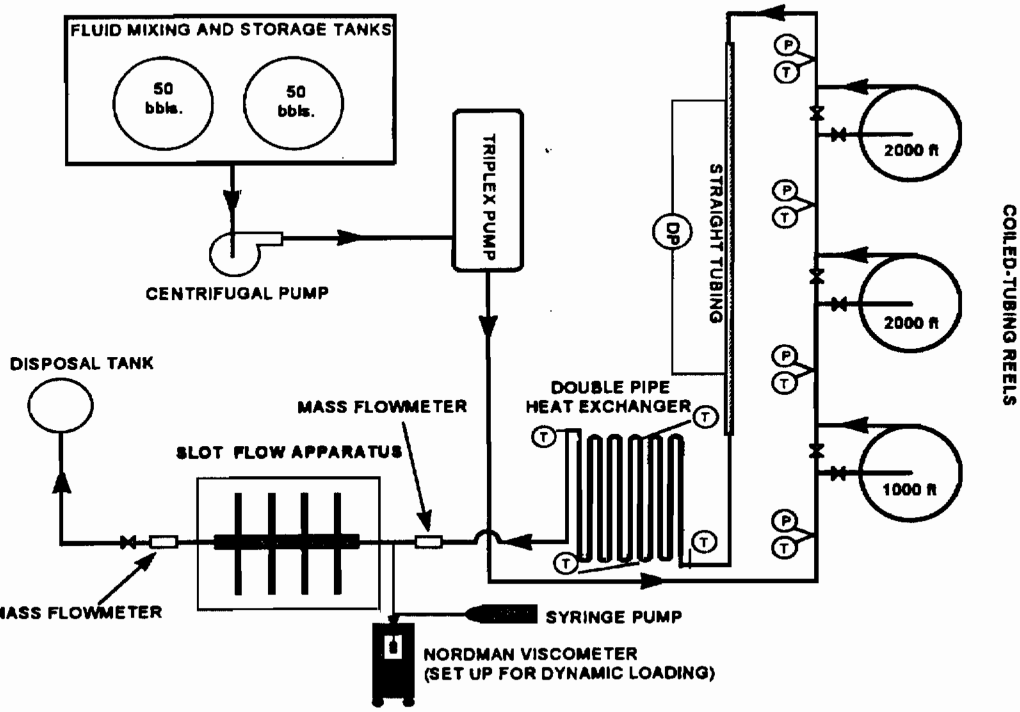


Figure 13-11. Experimental Apparatus for CT Fluid Study
(Shah and Subramanian, 1997)

Crosslinking frac fluids was found to increase the pressure drops through CT. The impact of pH on pressure drop was clearly observed (Figure 13-12).

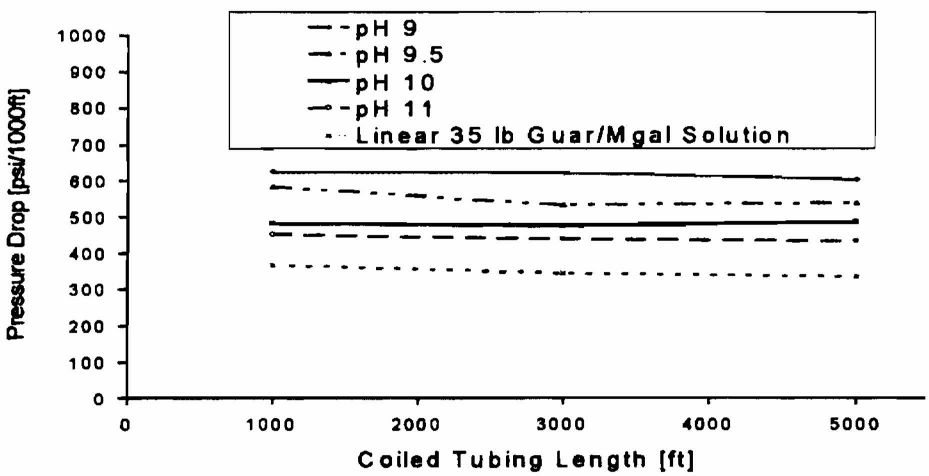


Figure 13-12. Pressure Drop for Borate Guar Gel
(Shah and Subramanian, 1997)

CT was also measured both on the reel and straightened. Pressure drops for borate-crosslinked 35 lb/Mgal HPG gel shows a significant impact of tubing curvature (Figure 13-13).

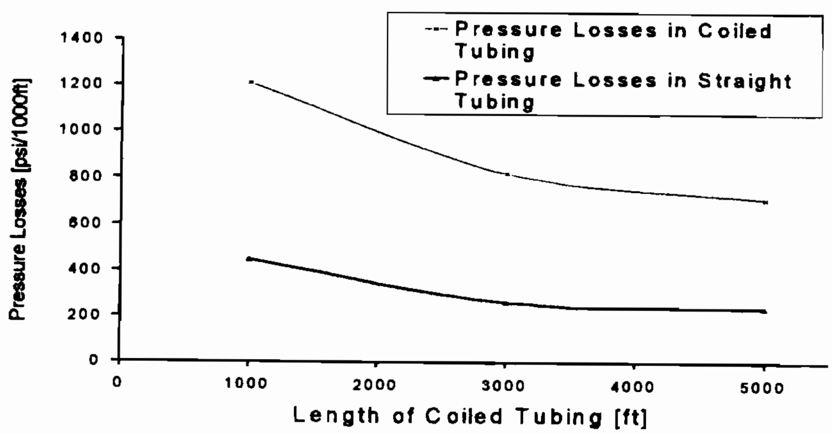


Figure 13-13. Pressure Drop in Straight/Coiled CT
(Shah and Subramanian, 1997)

13.9 REFERENCES

Acock, A.M. et al., 1996: "Real-Time Treatment Optimization," SPE 36331, presented at 1st SPE Gulf Coast Section/ICoTA North American Coiled Tubing Roundtable, Conroe, Texas, February 26-28.

Baker, C. et al., 1995: "Practical Application of Perforating with Coiled Tubing in Norman Wells," presented at 46th Annual Technical Meeting of the Petroleum Society of CIM, Banff, Alberta, Canada, May 14-17.

Engel, Steve and Sehnal, Zdenek, 1996: "Deploying and Recovering Long and Heavy BHAs in Live High Angle Wells," SPE 36330, presented at 1st Gulf Coast Section/ICoTA North American Coiled Tubing Roundtable, Conroe, Texas, February 26-28.

Fried, S.J. et al., 1997: "Concentric Coiled Tubing for Selective Evaluation and Stimulation," *JPT*, February.

Koshak, W.E. (Skip) and Attah, Mike, 1996: "Acid Stimulation of Openhole Horizontal Section Behind Prepack Screen Using Coiled Tubing and New Isolation Method," SPE 36332, presented at 1st SPE/ICoTA North American Coiled Tubing Roundtable,Conroe, Texas, February 26-28.

Payton, Ray et al., 1996: "Coiled Tubing Enables Rapid CO_2 Completions," *Hart's Petroleum Engineer International*, August.

Savage, R., 1995: "Using Coiled Tubing to Drill Up Composite Bridge Plugs," presented at 3rd Annual Petroleum Network Education Conference, Aberdeen, May 31-June 2.

Shah, S.N. and Subramanian, R., 1997: "Effects of Coiled Tubing Shear History on the Rheological and Hydraulic Properties of Fracturing Fluids," SPE 38421, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

14. Tools

TABLE OF CONTENTS

14. Tools

14.1 ANTECH (ELECTRIC RELEASE FOR CT)

AnTech (based in England) developed an electric safety release (*PEI*, 1997) that solves several problems found with conventional mechanical releases (premature release of shear-pin assemblies due to shock loads, failure to release with drop-ball assemblies when circulation cannot be sustained). The electric release functions independently of other electric tools and operates only under well pressure when higher current is sent for several seconds. The tool can be used with either monoconductor or multiconductor wireline.

14.2 BAKER OIL TOOLS AND DOWELL (EXTREME-SERVICE PACKER)

Baker Oil Tools and Schlumberger Dowell (*PEI*, 1997) developed an improved packer element for harsh conditions (above 300°F) for through-tubing applications (Figure 14-1). Conveyed on CT, the 2.12-in. OD element has a 2:1 expansion ratio at 5000 psi and a 3:1 expansion at 2000 psi. The element is constructed of a special hydrogenated nitrile rubber for standard service or fluoroelastomer for extreme conditions.

Testing has shown a success rate near 90% for a broad range of applications. Previous experience with earlier element designs showed average success rates of 50-75%.

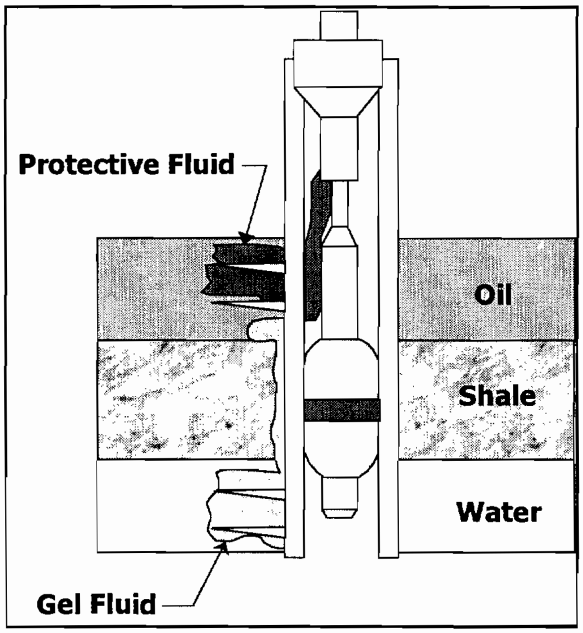


Figure 14-1. Extreme-Service CT Packer for Water Shutoff (*PEI*, 1997C)

14.3 BJ SERVICES (CT CONNECTORS)

BJ Services (Reaper, 1997) developed inline CT connectors for use in weight-restricted offshore operations in the North Sea. Tubing is the heaviest single component that platform cranes must have the capacity to lift. As platforms have aged, cranes have been derated. At the same time, tubing OD has been increased for greater pump rates and load capacities. Previously, welding strings together and radiographic inspection was the only option for joining spools offshore. Inline connectors have since been developed for 1½- and 1¾-in. CT. These allow string to be screwed together on site and are suitable for use with conventional fluids, gases, and stiff wireline operations.

Full-scale testing was conducted on the connectors, and safe operational ranges were developed (Table 14-1).

TABLE 14-1. Operational Limits for CT Connectors (Reaper, 1997)

Parameter	Connector	
	1.5"	1.75"
Maximum internal operating pressure at surface	3 000psi	2 000psi
Maximum pressure differential downhole	1 500psi collapse 4 000psi burst	1 500psi collapse 4 000psi burst
Minimum bore without wireline	0.556".	1.116"
Maximum running speed on/off reel and over gooseneck	50ft/min.	50ft/min.
Maximum allowable tensile pull (The effect of pressure on the Axial Tension rating has **NOT** been applied to this figure)	33 000lbs	40 000lbs
Maximum allowable torque	200 lbs/ft	200 lbs/ft

Extensive fatigue tests were conducted with the 1½-in. connector (Figure 14-2). Even though the results were lower than with new CT, the connector fatigue life was above the average life of field welds.

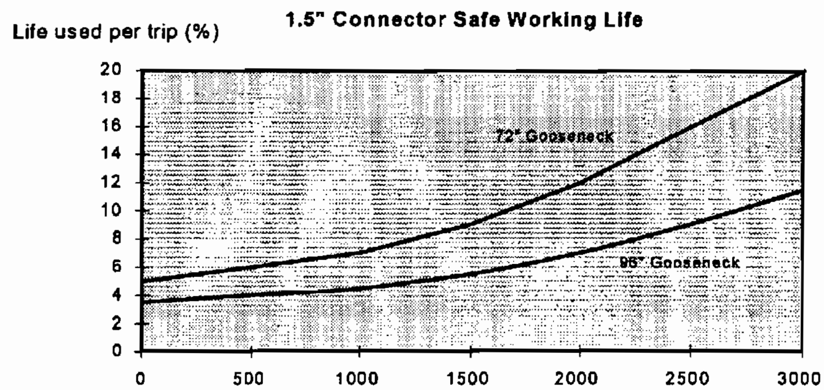


Figure 14-2. Fatigue Life of CT Connectors (Reaper, 1997)

These inline connectors have been successfully applied in the field. Limited fatigue life is a problem with these connectors, and future improvements are needed.

14.4 BRITISH PETROLEUM (CT FISHING TOOL)

British Petroleum successfully unstuck a string of CT with a new fishing tool (*PEI* staff, 1996). The operator was evaluating a logging bypass plug when the plug became stuck on the adjustable spacer sub union below the packer (Figure 14-3, number 1). Several conventional approaches were tried without success.

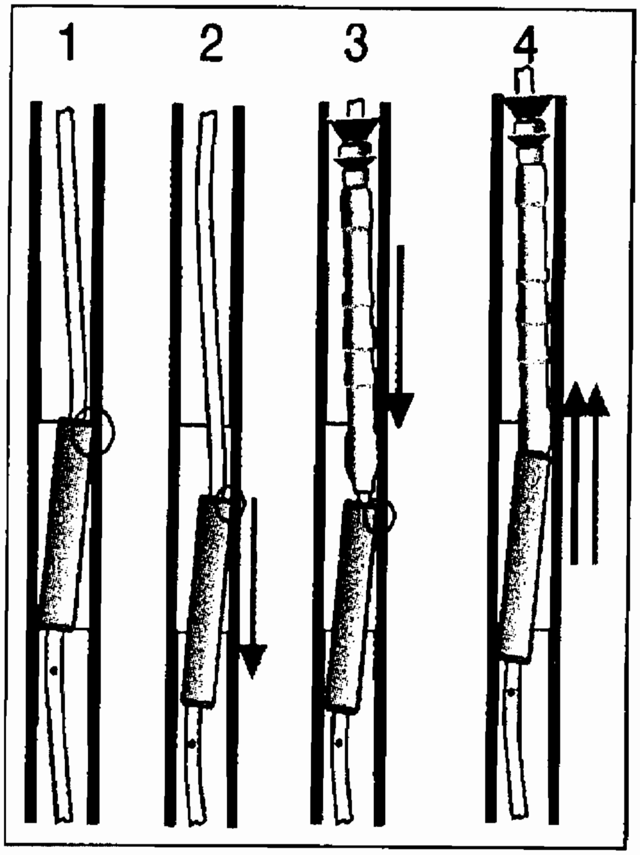


Figure 14-3. Fishing Tool to Unstick Bypass Plug (*PEI* staff, 1996)

The new solution was to run a sleeve down the outside of the CT to centralize the top of the plug and direct it around the obstruction. A wrap-around sleeve was devised and pumped down using a wiper dart on top of the assembly (Figure 14-3, number 3).

The CT string was run 50 ft past the hang-up point and placed in tension. The assembly was then pumped downhole. The string and bypass plug were retrieved successfully on the first attempt.

14.5 CANADIAN FRACMASTER (WINDOW MILL FOR CT)

Canadian Fracmaster Limited (Turley and Bogic, 1997) presented the design and test results with a new window milling tool system for use on CT. An evaluation of conventional window-milling tools showed that several obstacles existed for applying these tools to CT drilling. They decided that a fresh approach was warranted for tools designed specifically for CT operations. Systems for 4½- and 5½-in. casing were developed. Field trials have been successfully conducted with the 5½-in. system.

The mill design was based on a two-trip system that consists of a combination whipstock landing/starter mill followed by a window milling/reaming run.

The starter milling string (Figure 14-4) consists of :

- a starter mill that can carry and seat the whipstock
- a short drill collar
- a stabilizer
- a heavy-weight pup joint
- a mud motor

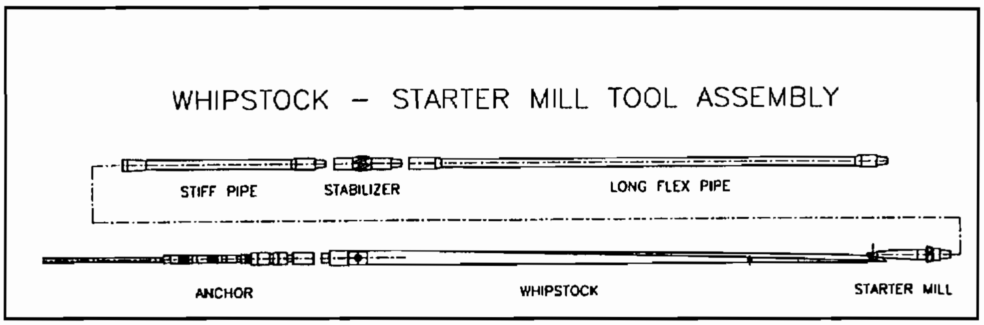


Figure 14-4. CT Starter Mill Assembly for 5½-in. Casing
(Turley and Bogic, 1997)

The window milling tool string (Figure 14-5) includes:

- a full-gauge window mill
- a reamer
- a short drill collar
- a stabilizer
- a heavy-weight pup joint
- a mud motor

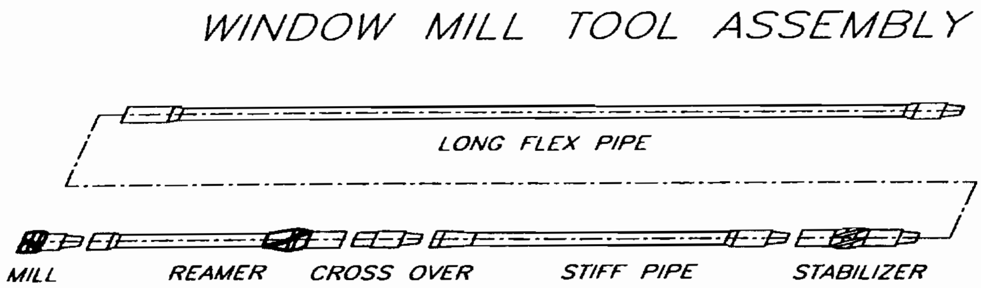


Figure 14-5. CT Window Mill Assembly for 5½-in. Casing (Turley and Bogic, 1997)

The 5½-in. milling system has been proven with laboratory and field trails. Milling operations have been completed in a time comparable to conventional rotary operations. The system for 4½-in. casing has been bench tested and found ready for field trials.

Future improvements will be sought with higher speed motors, which are hoped to increase ROP and decrease milling costs.

14.6 CANADIAN FRACMASTER (CT THRUSTER)

Canadian Fracmaster Limited (Smith, 1995) was granted a patent from the European Patent Office (publication no. 0 681 089 A1) for a CT thruster for providing weight on bit for operations in deviated wells. The device (Figure 14-6) can be used to compensate for string weight lost to drag. Thrust is based on the pressure differential between the inside of the string at the tool to that in the annulus outside the assembly.

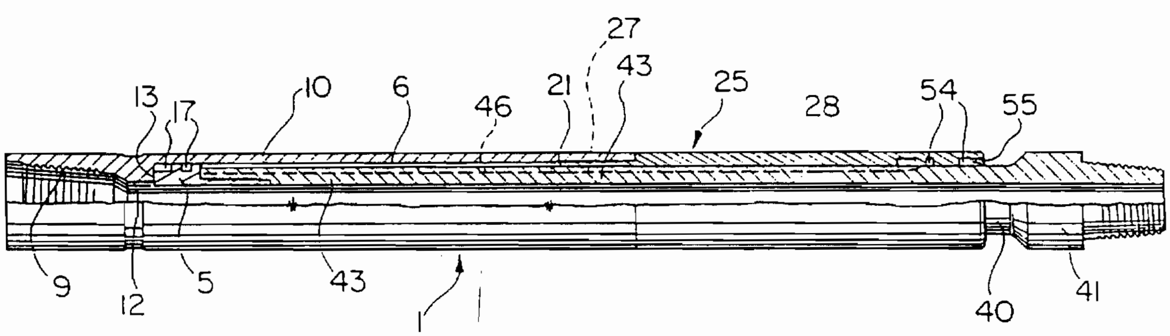


Figure 14-6. CT Thruster (Smith, 1995)

Splines (no. 46 and 27) are included within the assembly (Figure 14-7) for carrying reactive torque during drilling and similar operations. Typical placement for the tool is between the Monel collar and motor. System capability can exceed 12,000 psi at the bit/rock interface.

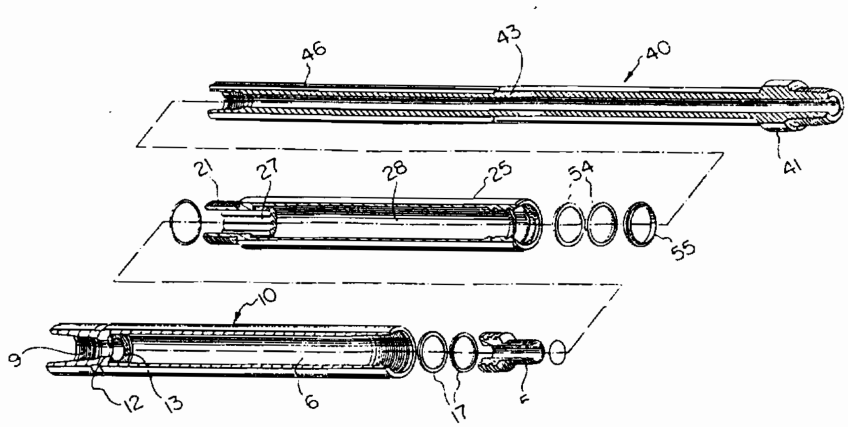


Figure 14-7. Internal Design of Thruster (Smith, 1995)

14.7 CTES AND GRI (ELECTRIC MOTORS FOR CT DRILLING)

CTES (Newman et al., 1996) performed a GRI-sponsored study of the feasibility of using electric motors for drilling on CT. They review the historical usage of electric motors for drilling, developed a conceptual design for a CT electric motor, and analyzed the potential market for this type of drilling system.

Several advantages may be possible with an electric drilling motor as compared to a conventional Moineau mud motor, including:

- Longer time between failures
- Mud type does not impact motor operation or wear
- Mud flow not as restricted through motor (greater flow rates, better hole cleaning)
- Higher operating temperatures (up to 400°F)
- Fits well with telemetry systems
- Motor performance easily monitored from speed controller
- Auto-drilling systems easy to implement
- High voltages now at the BHA could be used for other beneficial functions (tractors, rotation anchors, orienting, etc.)

Disadvantages of electric motors on CT are more surface equipment, more specialized subs and connectors, a reduction of flow inside the CT due to larger cable, higher capital costs, and added safety concerns.

The conceptual design was based on a similar 4¾-in. mud motor. Horsepower and torque need to be comparable, temperature limits above 250°F, ambient pressures of 15,000 psi, and mean time between failures of greater than 100 hrs. Electric motor horsepower and length are listed in Table 14-2. This conceptual design suggests that electric motors might be slightly longer than mud motors.

TABLE 14-2. Electric Motor Horsepower and Length (Newman et al., 1996)

Motor OD (In)	Horse Power	Surface Area (Sq. Ft.)	EDM Length (Ft.)
1.688	10	5.13	11.6
1.75	10	5.13	11.2
2.063	15	6.52	12.1
2.125	15	6.52	11.7
2.375	20	7.92	12.7
2.875	30	10.71	14.2
3.375	45	14.89	16.9
3.5	45	14.89	16.3
4.75	60	19.07	15.3

Motor designs were devised to maximize output torque at lower speeds. A family of theoretical torque/speed curves for different line frequencies is shown in Figure 14-8.

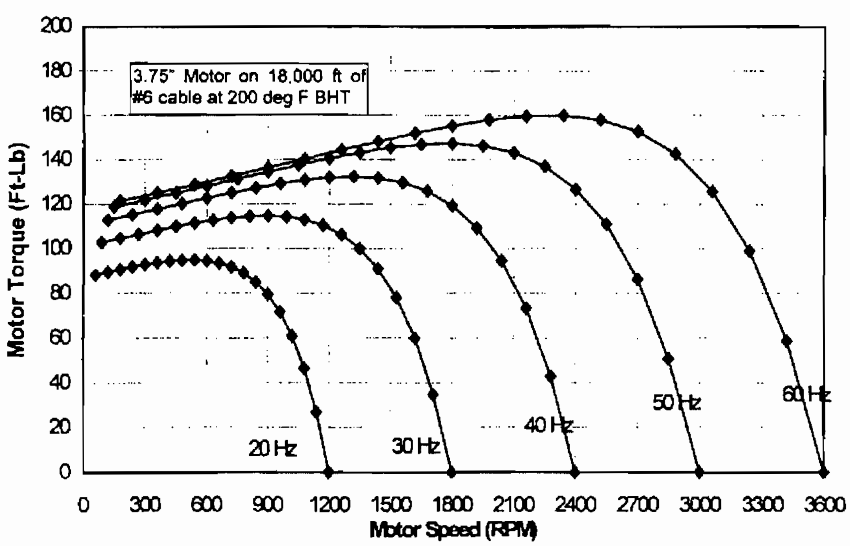


Figure 14-8. Electric Motor Torque/Speed (Newman et al., 1996)

It is foreseen that original applications of electric motors on CT would likely be in niche applications. These might include areas with high operating costs where an increase in time between failures would offset added cost of the electric system; high-temperature environments; formations where lost-circulation material is required; and operations with special drilling fluids that might damage mud motors.

14.8 HALLIBURTON ENERGY SERVICES (NEW SLIDING SLEEVE)

Halliburton Energy Services (Plauche and Koshak, 1997) presented a case history where new sliding-sleeve technology was used to complete an abnormally pressured, multizone horizontal well. The successful completion allowed production from both or either zone. A critical factor in the success of the project was a new sliding sleeve that could be shifted by CT with a force of only 500 lb, as compared to 2000+ lb for conventional sleeves.

The new sleeve made use of an advanced engineering composite which allowed a significant reduction in shifting force over a PEEK seal (Figure 14-9).

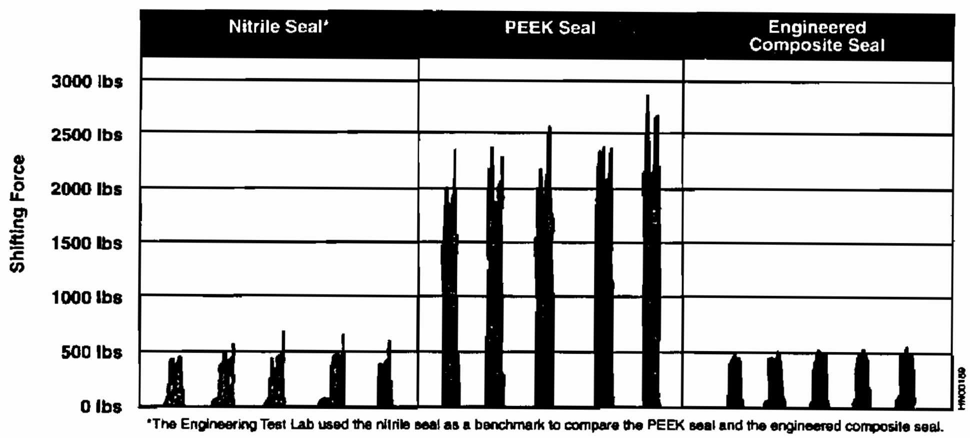
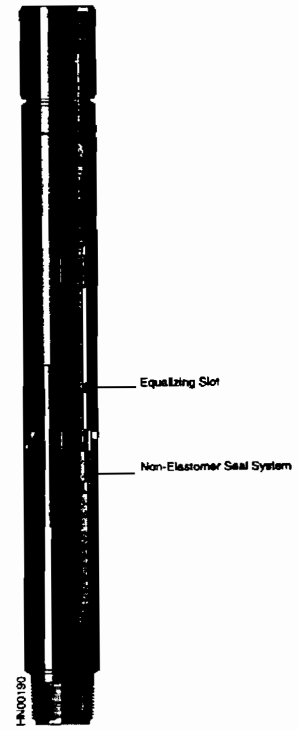


Figure 14-9. Shifting Forces for Sliding Sleeves (Plauche and Koshak, 1997)



The seal port design specifically accounted for high differential pressures to redirect the flow path more effectively to minimize the potential for damaging the sealing element. The complete sliding sleeve assembly is shown in Figure 14-10.

Figure 14-10. New Sliding Sleeve System (Plauche and Koshak, 1997)

The final completion (Figure 14-11) included nine sliding sleeves. Eight were integral to the concentric production string; the ninth was placed in the float shoe assembly below the lowermost gravel-pack screen.

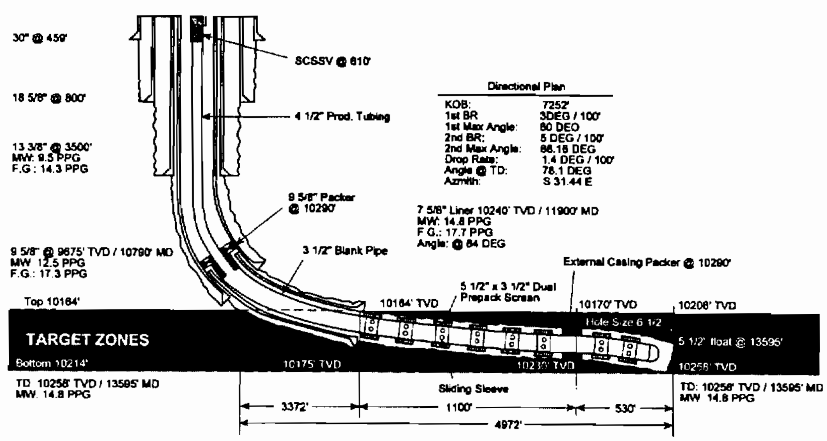


Figure 14-11. Sliding Sleeve Completion (Plauche and Koshak, 1997)

Fluid losses to the formation were minimized during completion operations. The sliding-sleeve completion provides zonal isolation in two zones, which should postpone or eliminate the need for future intervention.

14.9 NOWSCO WELL SERVICE (CONCENTRIC CT JET-PUMP TOOLS)

Nowsco Well Service Ltd. (Falk and Fraser, 1995) introduced a new tool for cleaning sand from horizontal sections. Their system, called the Sand Vac^{SM}, was developed for cleaning out low-pressure wells using a jet-pump assembly run on concentric CT. The system has been successfully deployed in several wells, cleaning out significant volumes of sand without difficulty.

In Fried et al. (1997), Nowsco Well Service, Technology & Research, and Murphy Oil Company described the Well Vac^{TM} (Figure 14-12), a modified jet-pump tool for increasing overall recoveries for drilling or stimulation fluids. The tool has proven highly useful in underpressured reservoirs common to horizontal completions.

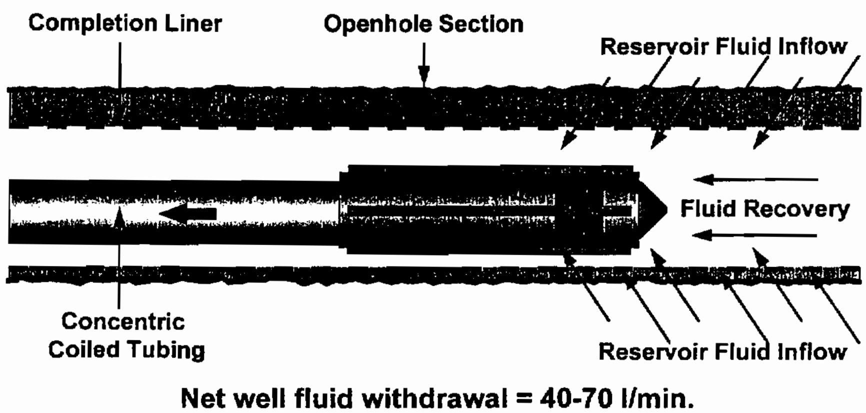


Figure 14-12. Well Vac for Fluid Cleanouts (Fried et al., 1997)

A description of these tools is presented in *Workovers.*

14.10 NOWSCO UK AND STATOIL (DEPLOYMENT TOOLS FOR LONG BHA)

Nowsco UK Ltd and Statoil (Engel and Sehnal, 1996) developed and implemented a tool string deployment system for deploying 140 meters of perforating guns along a horizontal section. The well (B-15) was located in the Norwegian sector of the North Sea. A recompletion was planned to isolate the lower producing interval due to high GOR and perforate a higher interval. Rathole for dropping the guns was not available. Drag was a significant concern in the well, and friction was reduced by adding rollers to the BHA and using friction reducers. Field operations, including deploying, running and recovering the perforating guns, were completed successfully in 5½ days.

The deployment system includes male and female connectors (Figure 14-13) for quick connection within the surface lubricator. OD is 2.5 inches. Make-up length of the assembly is 972 mm. Gate valves provide double-barrier isolation.

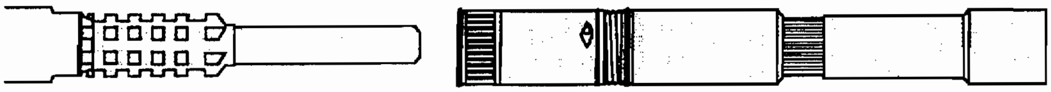


Figure 14-13. Deployment System Connectors
(Engel and Sehnal, 1996)

No-go rams (Figure 14-14) are closed on the shoulder of the connector to support the BHA weight during run-in.

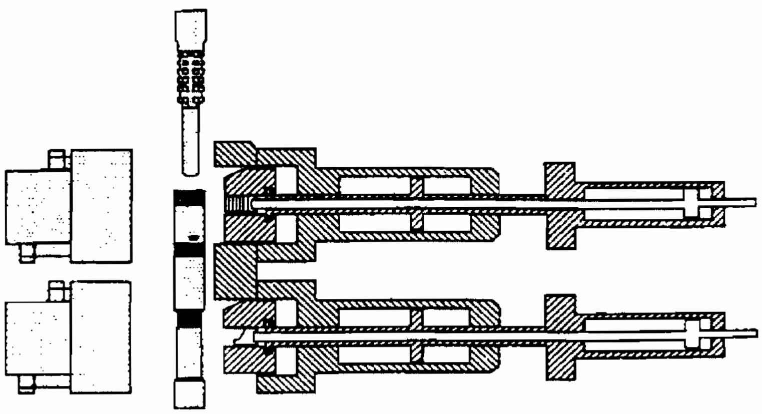


Figure 14-14. Special Rams for Deployment (Engel and Sehnal, 1996)

The surface equipment for deploying long BHAs includes the deployment BOP and isolation gate valves. A secondary annular BOP was required below the deployment rams (Figure 14-15).

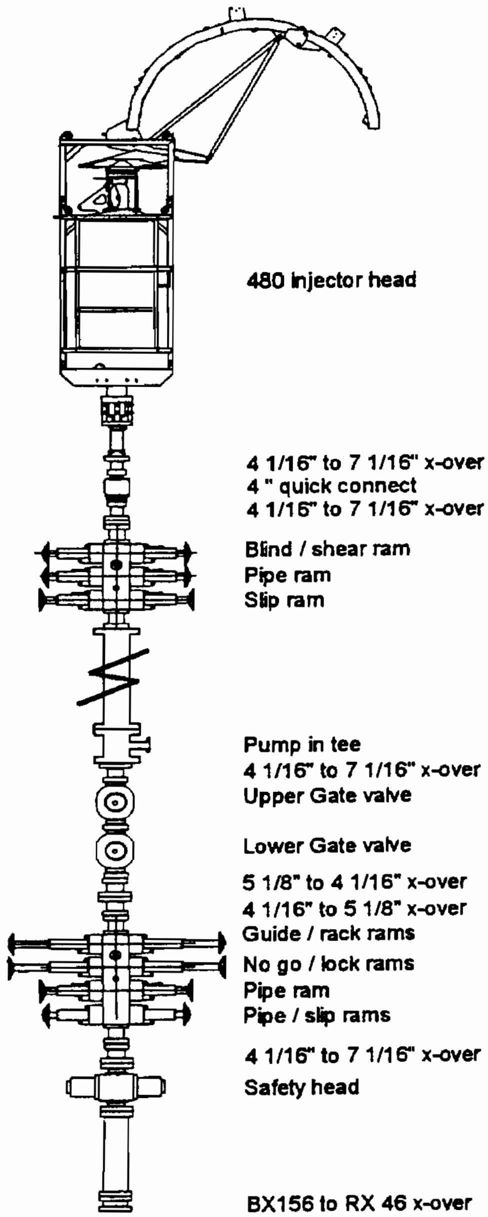


Figure 14-15. Surface Equipment for Deploying Long BHAs (Engel and Sehnal, 1996)

Each gun section (Figure 14-16) was 13.5 m in length. Thirteen sections and one firing head were required.

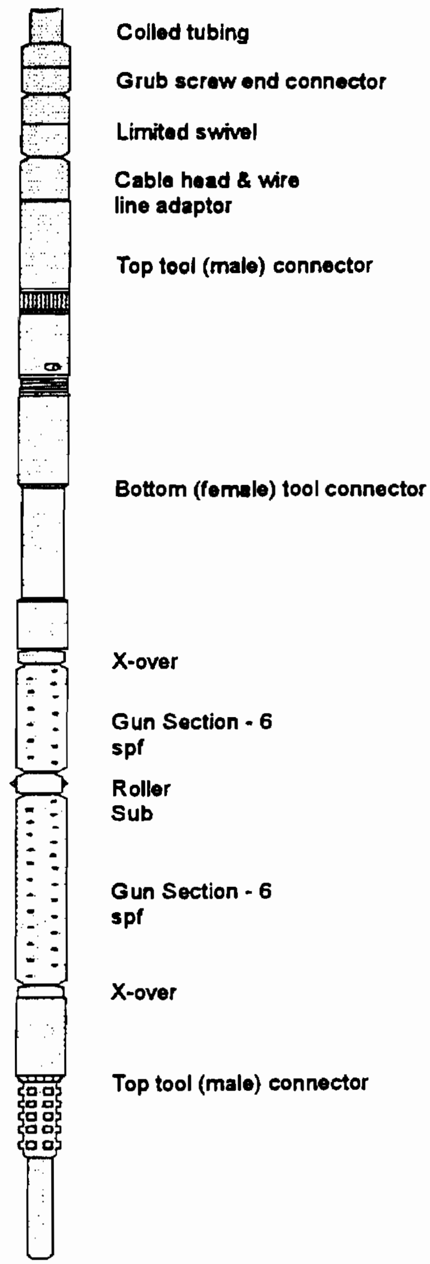


Figure 14-16. Single Gun Section
(Engel and Sehnal, 1996)

Extensive modeling of drag was conducted prior to the job. The hanging weight of the BHA was over 2500 kg; 2-in. CT was specified. Rollers were to be added at each joint of the guns. These had been found to reduce required pushing forces by 50%. A drag reducer was also planned to ensure that target depth was reached.

Drag predictions and results are compared in Figure 14-17. Nowsco stated that the difference between POOH weights is explained by gun debris or by low gun weights used in the model.

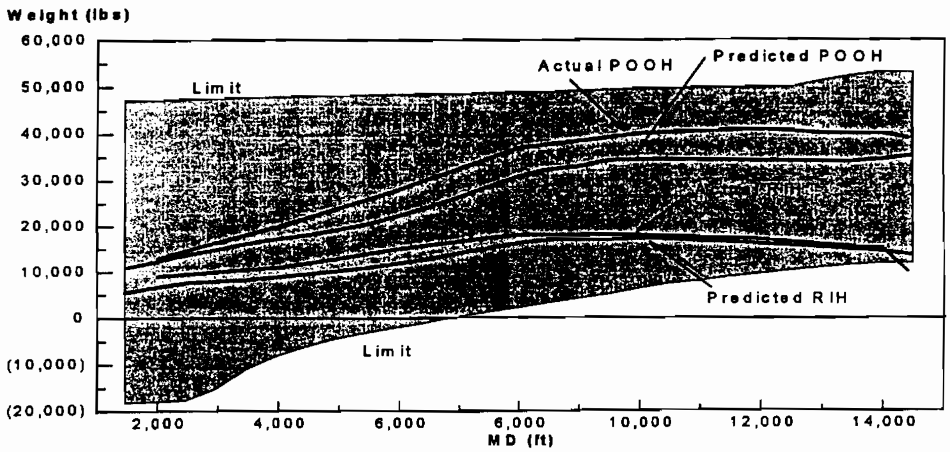


Figure 14-17. Weight Indication During Operation
(Engel and Sehnal, 1996)

Nowsco advised that deployment systems similar to the one described are viable options when more than three separate trips are required to achieve the same objective with conventional deployment methods.

14.11 SONOMA CORPORATION (IMPACT DRILL JARS)

Sonoma Corporation (Beynon and Thompson, 1997) described the performance advantages of their impact drilling jars (trade name "HIPP-TRIPPER") for scale clean-outs on CT. A significant percentage of CT field operations are clean outs, and many of these operations include motors of some sort. Mud motors are limited in some situations, such as high temperatures and hostile fluids (Table 14-3), and impact drills are often a very effective alternative.

TABLE 14-3. Comparison of Drill Jars with PDMs (Beynon and Thompson, 1997)

"HIPP-TRIPPER®" General Comparisons of "Hipp-Tripper" versus Conventional Equipment			
Considerations	**Conventional Equipment**	**Problems Associated With Conventional Equipment**	**Advantages of "Hipp-Tripper"**
High Temperatures	Drill Motor	• Effect of high temperatures on operating life. • High repair cost	• Operates efficiently in temperatures in excess of 600°F. • Low maintenance cost.
Fluid Medium	Drill Motor	• Use of certain fluid medium decreases the operating life of some conventional motors. • High repair cost.	• Hipp-Tripper operates efficiently using xylene, diesel, oil, drilling mud and water. • Hipp-Tripper operates efficiently using nitrogen, air and foam. • Hipp-Tripper operates efficiently in HCL acid and H2S using its "Hostile Environment Tool". • Low maintenance cost.
Circulation Rates	Drill Motor	• Fluid pump rates must be restricted to prevent damage to completion equipment/liner/tools as a result of the bit/mill/under-reamer spinning needlessly.	• Reciprocation and rotation of the "Hipp-Tripper" occurs only when weight to the bit is applied. • Full circulation without rotation is possible going into and out of the well without danger of damage to completion equipment/liner/tools.
Reverse Torque	Drill Motor	• Danger of tool backing off due to storing reverse torque.	• The "Hipp-Tripper" <u>will not</u> store reverse torque.
Length of Tool	Drill Motor	• Due to the length of most Drill Motors, long lengths of lubricator or special deployment equipment is necessary.	• The average length of the Single Directional "Hipp-Tripper" is 44 inches. • The addition of a conventional BHA assembly (Coil Connector, Double Flapper, Hydraulic Disconnect and Circulating Sub) will add approximately 47 inches. • Average overall lengths equal 8 Feet.

Key advantages of drilling jars include: 1) they don't operate until the bit meets resistance (the tool life is not consumed during trips), 2) they don't store reverse torque, 3) they can operate at temperature greater than 600°F, 4) make-up length is short (Table 14-4), 5) can operate in almost any fluid medium, and 6) have low costs for rebuild.

TABLE 14-4. Drill Jar Specifications (Beynon and Thompson, 1997)

MODEL O.D. (IN.)	OPERATING PRESSURE RANGE (PSI)	WEIGHT ON TOOL (LBS.)	TORQUE RANGE (Ft - Lbs)	Stroke (IN.)	RPM	MADE UP LENGTH (IN.)
1.375	400 - 1,000	400 - 1,000	40 - 150	.250 - 1.00	7 - 45	27.125
1.687	600 - 2,000	400 - 2,000	100 - 250	.250 - 1.00	7 - 45	36.375
2.125	600 - 2,000	400 - 2,400	120 - 360	.250 - 1.00	7 - 45	43.250
3.625	600 - 2,000	400 - 2,400	120 - 500	.250 - 1.00	7 - 45	63.500
4.750	250 - 2,500	400 - 31,000	50 - 750	.250 - 1.00	7 - 45	43.500

Sonoma Corporation cited results from several field case histories. In Lake Maracaibo, clean-outs in deep, hot holes using conventional motors required 2-3 days per well. Damage to the motors was common. With impact drilling jars, clean-out time dropped to 6 hr/well. In addition, acid was spotted through the tool string prior to coming out of the hole.

Several other case histories are described in Beynon and Thompson (1997).

14.12 SCHLUMBERGER DOWELL (TOOLS FOR EXTENDING CT REACH)

Schlumberger Dowell, Amoco EPTG, and Techaid (Leising et al., 1997) continued their analysis of the potential of various techniques for extending the reach of CT in extended-reach wells. A variety of techniques were considered with respect to problems, costs, risks, and potential benefits.

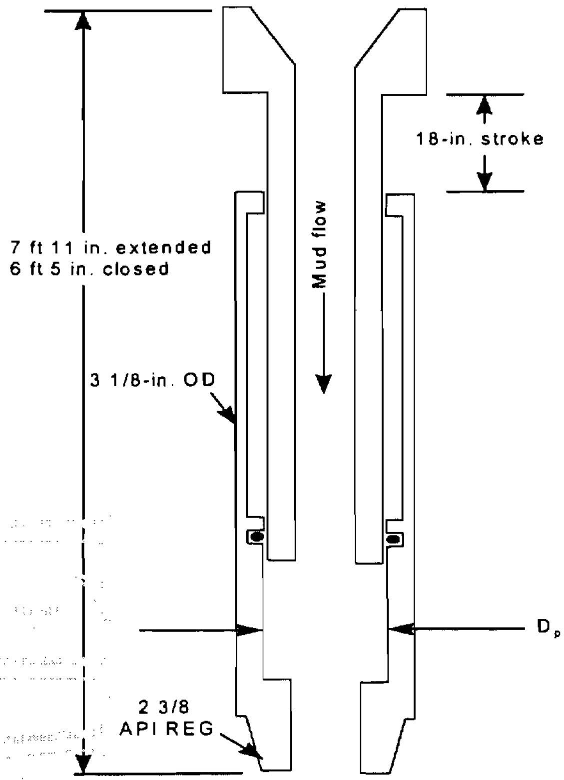


Figure 14-18. Bumper Sub Thruster
(Leising et al., 1997)

A bumper sub (Figure 14-18) provides a WOB that is proportional to differential pressure across the tool. The disadvantages of this type of tool are that 1) WOB is increased as the motor starts to stall, thereby aggravating the stall (positive feedback loop) and 2) open area in the tool and differential pressure must be matched to achieve the desired WOB.

Schlumberger Dowell developed and tested a weight-on-bit (WOB) equalizer. It is designed to provide a constant WOB regardless of friction. The tool (Figure 14-19) is not designed to reduce shock, but rather to provide a constant WOB regardless of stick/slip and variations in motor pressure. The primary disadvantage noted is simply the additional length added to the BHA.

The WOB equalizer assembly is essentially a shock sub with a low spring constant. A chamber within the sub is precharged with nitrogen to provide the desired weight.

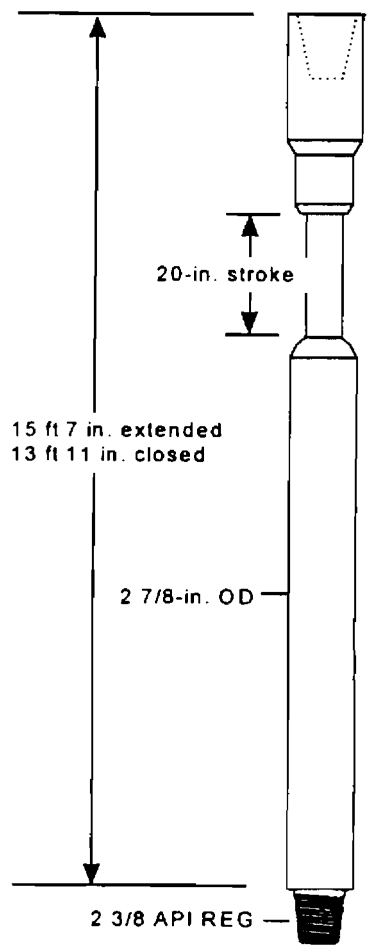


Figure 14-19. WOB Equalizer
(Leising et al., 1997)

Of the best techniques to increase CT reach (larger CT, smaller liner, thin CT in the horizontal section, mud lubricants, underbalanced drilling, WOB equalizer, and a rotator), the highest ROP performance was obtained with the WOB equalizer. It was also the easiest system to drill with, and required very little intervention from the surface. While the sub does not in itself extend drilling reach, it increased ROP and resulted in more efficient penetration.

14.13 STATOIL, MWS AND WELLTEC (WIRELINE TRACTORS)

Statoil, Maritime Well Service and Welltec developed a well tractor for use on CT and wireline in horizontal and deviated wells (Ostvang et al., 1997). The need for the tool was highlighted within Statoil's operations at Statfjord. The system can pull or push CT horizontally beyond 10,000 ft. The impact of drag is reduced and lateral reach is increased considerably. Both hydraulic- and electric-drive versions of the tool have been developed. The hydraulically driven tractor (Figure 14-20) can be run on 1- to 2⅞-in. CT. Conventional fluids including acids can be used to provide power to the tool. An internal positive-displacement motor drives the tractor.

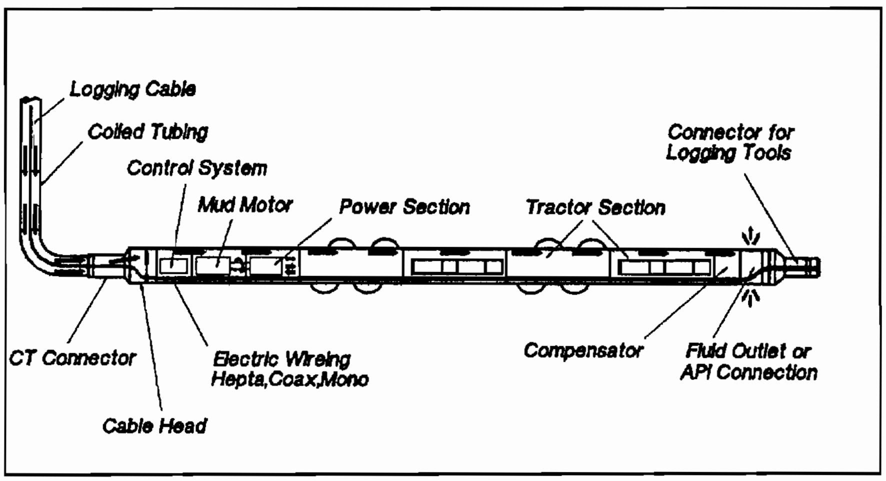


Figure 14-20. CT Tractor Assembly (Hallundbæk, 1997)

Welltec noted that these tractors may be used with smaller CT than normal because the influence of tubing stiffness on penetration is no longer a factor. Cost savings with the well tractor may be considerable. In a study for Statoil, it was determined that the use of the system for operations that currently require a snubbing unit could save 50-60% of present costs.

In Ostvang et al. (1997), several case histories with the wireline tractor are presented. Logging, setting plugs, and perforation operations have all been successfully performed in horizontal sections as long as 1600 m (5250 ft).

More information on CT tractors is presented in *Buckling*.

14.14 REFERENCES

Beynon, Douglas and Thompson, Daniel, 1997: "Performance Comparisons of 'Hipp-Tripper' Impact Drill-Jars with Conventional Downhole Motors," presented at 5th International Conference on CT and Well Intervention, Houston, February 4-6.

Engel, Steve and Sehnal, Zdenek, 1996: "Deploying and Recovering Long and Heavy BHAs in Live High Angle Wells," SPE 36330, presented at 1st Gulf Coast Section/ICoTA North American Coiled Tubing Roundtable, Conroe, Texas, February 26-28.

Falk, K. and Fraser, B., 1995: "Sand Cleanout Technology for Horizontal Wells," presented at 46th Annual Technical Meeting of the Petroleum Society of CIM, Banff, Alberta, Canada, May 14-17.

Fried, Spencer et al., 1997: "The Optimized Cleanup And Evaluation of Horizontal Wells Using Improved Jet Pump Technology," CADE/CAODC 97-126, presented at CADE/CAODC Spring Drilling Conference Technical Committee, Calgary, Alberta, Canada, April 8-10.

Hallundbæk, Jørgen, 1997: "Reducing Costs With Well Tractors for Horizontal Wells," OTC 7875, presented at 27th Annual OTC, Houston, Texas, May 1-4.

Leising, L.J. et al., 1997: "Extending the Reach of Coiled Tubing Drilling (Thrusters, Equalizers, and Tractors)," SPE 37656, presented at 1997 SPE/IADC Drilling Conference, Amsterdam, The Netherlands, March 4-6.

Newman, K.R. et al., 1996: "The Feasibility of Using an Electric Downhole Motor to Drill with Coiled Tubing," SPE 36343, presented at 1st SPE Gulf Coast Section/ICoTA North American Coiled Tubing Roundtable, Conroe, Texas, February 26-28.

Ostvang, Knut and Haukvik, John, 1997: "World's First Successful Horizontal Wireline Tractor Operations," presented at 5th International Conference on CT and Well Intervention, Houston, February 4-6.

PEI Staff, 1996: "Stuck Coiled Tubing Spawns New Fishing Tool," *Petroleum Engineer International*, March.

PEI Staff, 1997B: "Electric Release Improves Coiled Tubing Operations," *Petroleum Engineer International*, June.

PEI Staff, 1997C: "High Performance Inflatable Packer Performs Workover Tasks," *Petroleum Engineer International*, August.

Plauche, Ricky and Koshak, W.E. (Skip), 1997: "Advances in Sliding Sleeve Technology and Coiled Tubing Performance Enhance Multizone Completion of Abnormally Pressured Gulf of Mexico Horizontal Well," SPE 38403, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Ravensbergen, John and Campbell, Andrew, 1997: "A New Perforating Deployment System," presented at 5th International Conference on CT and Well Intervention, Houston, February 4-6.

Reaper, Alan, 1997: "Development and Application of Inline Connectors for Weight Restricted Offshore Operations," SPE 38424, presented at 2nd North American CT Roundtable, Montgomery, Texas, April 1-3.

Smith, Donald Alexander, 1995: "Coiled Tubing Thruster," European Patent Application, Publication No. 0 681 089 A1, August 8.

Turley, R. and Bogic, B., 1997: "Window Milling Tool Development for CT Drilling," presented at 48th Annual Technical Meeting of Petroleum Society, Calgary, June 8-11.

15. Workovers

TABLE OF CONTENTS

TABLE OF CONTENTS (CONT'D.)

15. Workovers

GENERAL

15.1 AMOCO UK EXPLORATION (CT INSERT STRADDLE)

Amoco UK Exploration Company (Kinnear and John, 1996) described the selection, design and installation of a CT insert straddle for repairing a failed gas-lift completion in the Arbroath Field in the North Sea. The well had ceased production due to holes in the tubing. Various through-tubing repair techniques (Figure 15-1) were considered prior to selecting the CT straddle. These included a wireline-deployed straddle, CT straddle hung off the SSSV nipple, and a CT straddle suspended between two packers. The third option was selected after considering all advantages/disadvantages.

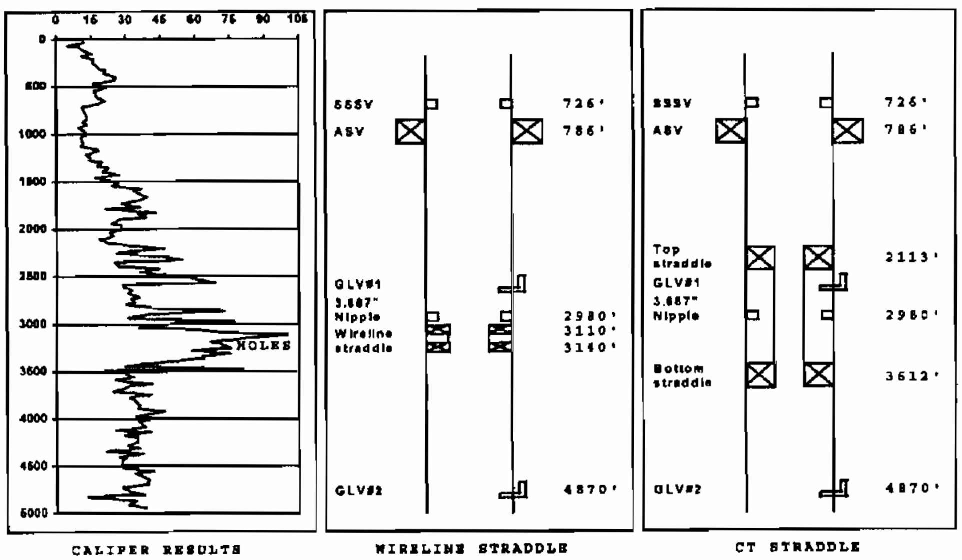


Figure 15-1. Tubing Repair Options
(Kinnear and John, 1996)

The final design of the repair (Figure 15-2) included 1500 ft of 3½-in. CT (70 ksi yield) with hydraulic-set packers at the top and bottom. The straddle was set about 500 ft below the holes in the tubing.

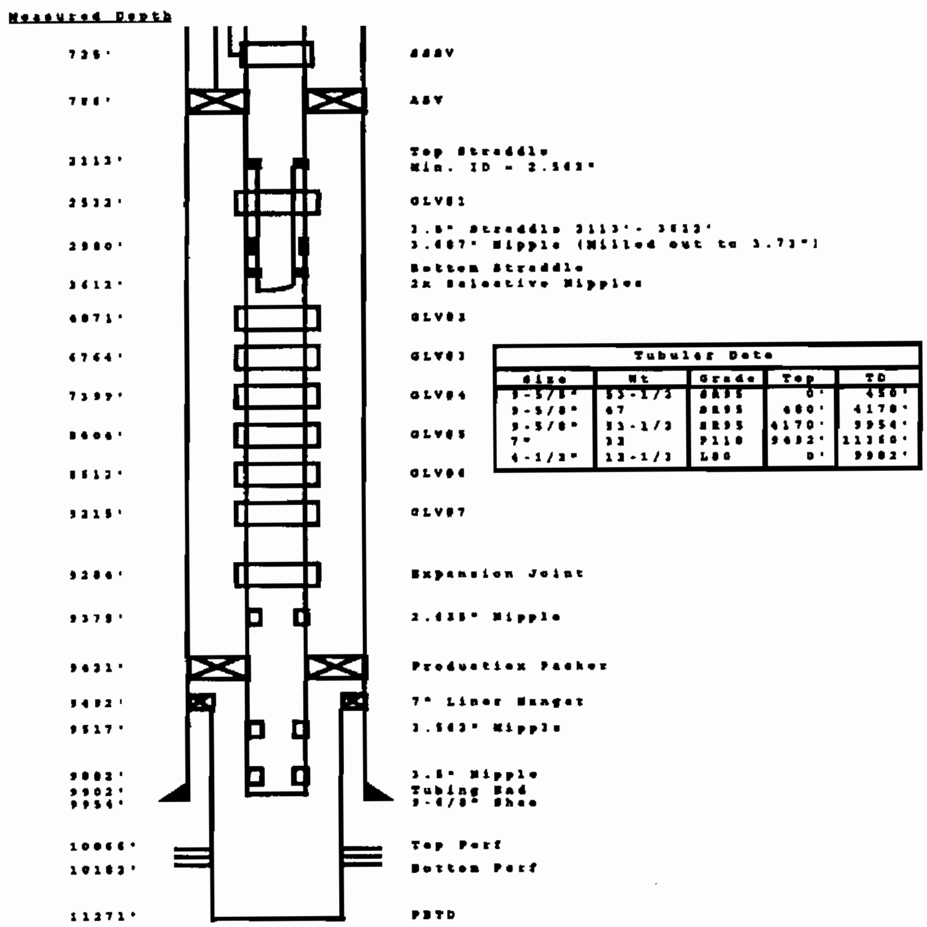


Figure 15-2. Repaired Tubing (Kinnear and John, 1996)

The 3½-in. CT straddle was run on 1¾-in. CT. A dual BOP stack (Figure 15-3) was required for the dual-OD string.

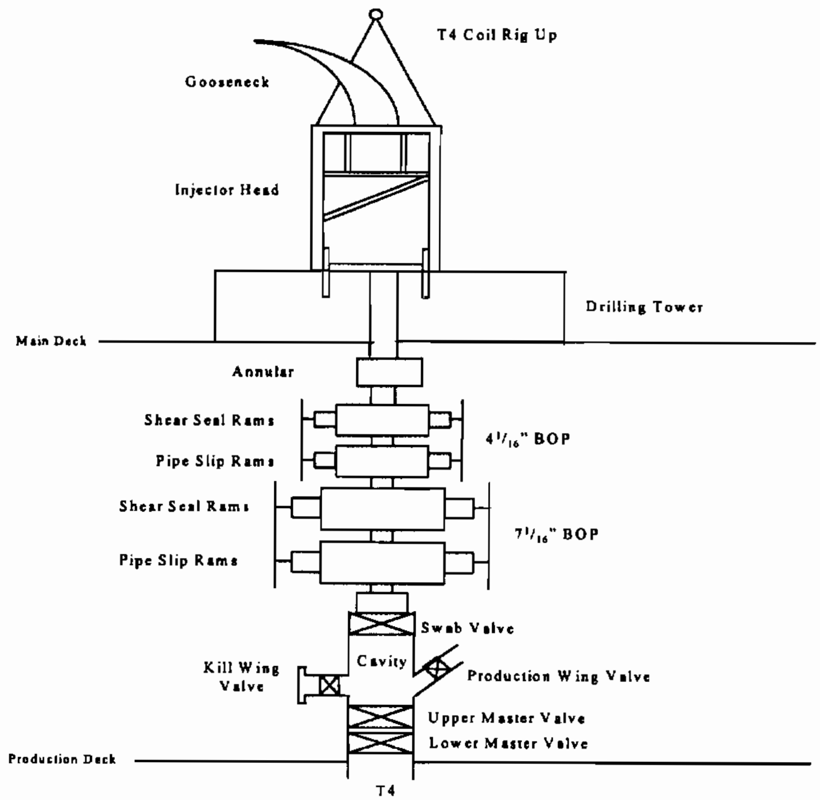


Figure 15-3. CT Pressure Control (Kinnear and John, 1996)

This CT insert straddle was successful at returning the well to production (3500 BOPD). Job cost was about 90% less than a full rig workover using a jack-up (£250,000 versus £3,000,000).

15.2 BJ SERVICES AND BP EXPLORATION (EFFECTS OF RIG HEAVE)

BJ Services Company UK and BP Exploration (Engel and Monro, 1997) analyzed the impact of rig heave on CT operations on a floating vessel. Reel placement has a critical effect on the amount of reel movement in response to rig heave. If the reel were at the same elevation as the gooseneck and positioned far away, rig heave would have no impact on fatigue. The gooseneck is normally, however, at least 20 m above the level wind and offset no more than 40 m. This corresponds to a 26° inclination, and about 10% of rig heave is translated into reel rotation. BJ and BP analyzed techniques to minimize these effects.

Minimum CT running rates can be calculated (Figure 15-4) so that counter rotation of the reel is avoided. CT is often run in at 15 m/min (50 ft/min). If the inclination of the string is 45° and the heave period is 12 sec, a running rate of 11 m/min (36 ft/min) or greater will avoid counter rotation.

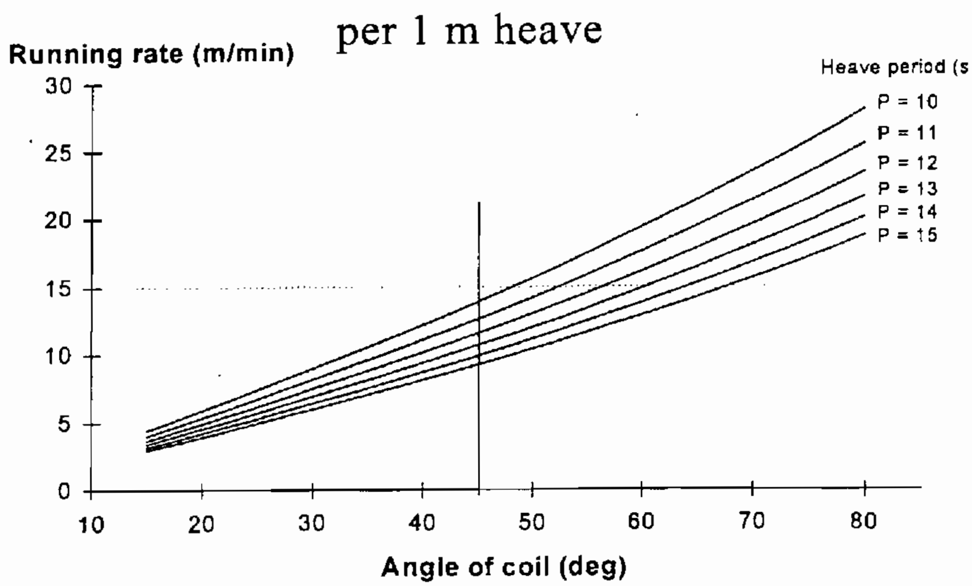


Figure 15-4. Running Rates to Offset Rig Heave (Engel and Monro, 1997)

Among methods to avoid problems with rig heave with respect to CT life are optimized reel placement, maintaining minimum running rates, and introducing slack into the CT between the gooseneck and spool.

More discussion is presented in *Fatigue*.

15.3 BP EXPLORATION, PETROLINE AND NOWSCO (WELL PLUGGINGOPERATIONS)

BP Exploration Operating Company, Petroline Wireline Services and Nowsco UK (Munro et al., 1996) described planning and operations with CT in the Foinaven Field, located in 500 m of water about 180 km west of Shetland. Deep set plugs were deployed, tested and retrieved via CT in extended-reach wells in the field. Problems which were addressed included large fluctuations in weight indicator due to heave, difficultly in controlling the impact hammer when jarring, and the effects of debris accumulation in the completion tubulars.

A typical completion includes 5½-in. 17 lb/ft tubing (Figure 15-5). Sand screens are required in the open hole due to low compressive strength. The ease of future interventions was maximized by including an unloaded no-go nipple system to decrease ID restriction. ECPs were placed across shale breaks to allow zonal insolation.

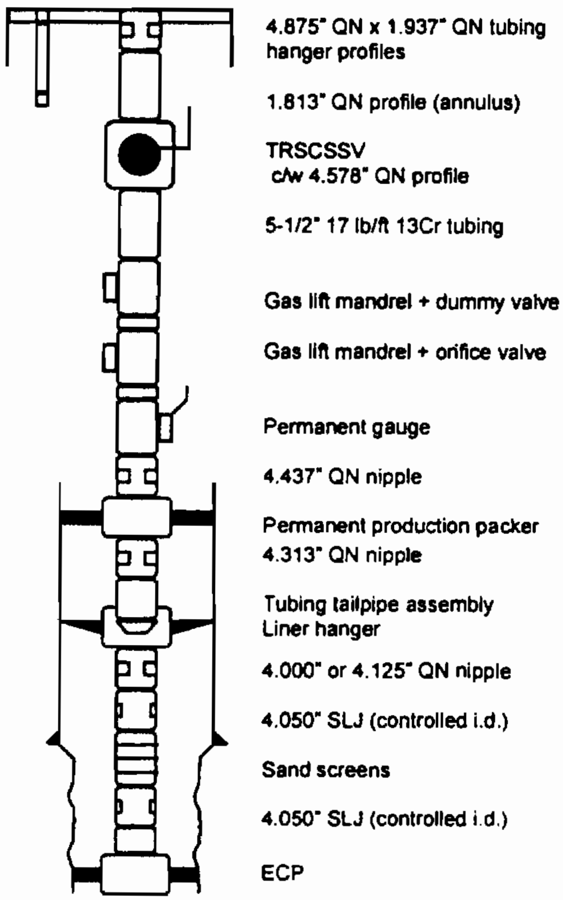


Figure 15-5. Typical Completion at Foinaven (Munro et al., 1996)

After production testing is completed, these wells are suspended. Live oil is left at the sand face to minimize formation damage. A deep-set wireline-type plug (Figure 15-6), a permanent production packer, kill-weight completion fluid above and wireline-type plugs in the tubing hanger are used to suspend the well.

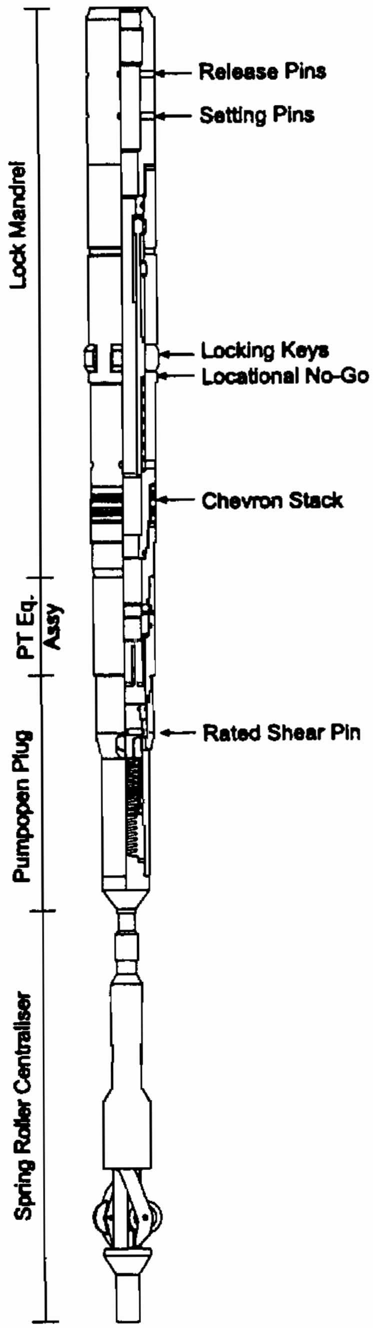


Figure 15-6. Suspension Plug Assembly
(Munro et al., 1996)

The largest CT that can be used in this environment is a 1¾-in. 80-ksi tapered string with a length of 4500 m (15,000 ft). The weight limit is 23 tonnes.

Tubing capacity for setting deep plugs was analyzed. The limiting concern was buckling and lockup in the extended-reach holes. The first solution to these limits was to use a bidirectional impact hammer to set the plugs.

Setting the suspension plug involves pushing the plug into the seal bore, jarring down to shear the setting pins, lifting to confirm that the locking keys are engaged, and jarring upward to shear the release pins to recover the running tool. The BHA for these setting operations with an impact hammer is shown in Figure 15-7.

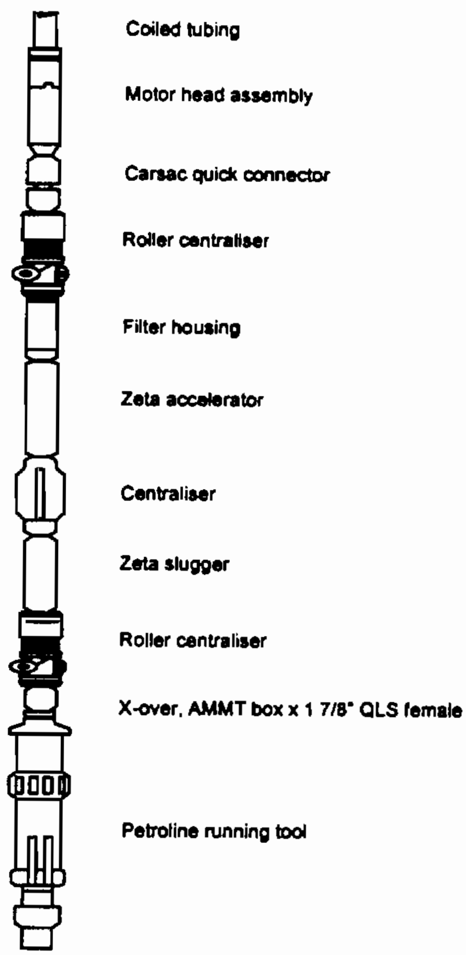


Figure 15-7. Mechanical Running Assembly
(Munro et al., 1996)

Heave caused large fluctuations in the weight indicator, especially in adverse weather. A pump-through force sub for true indication of downhole weight is under development for future interventions.

Limited deck space required careful planning for positioning equipment. The flow head was stabbed through a special lifting frame (Figure 15-8). A hydraulic winch supports the injector.

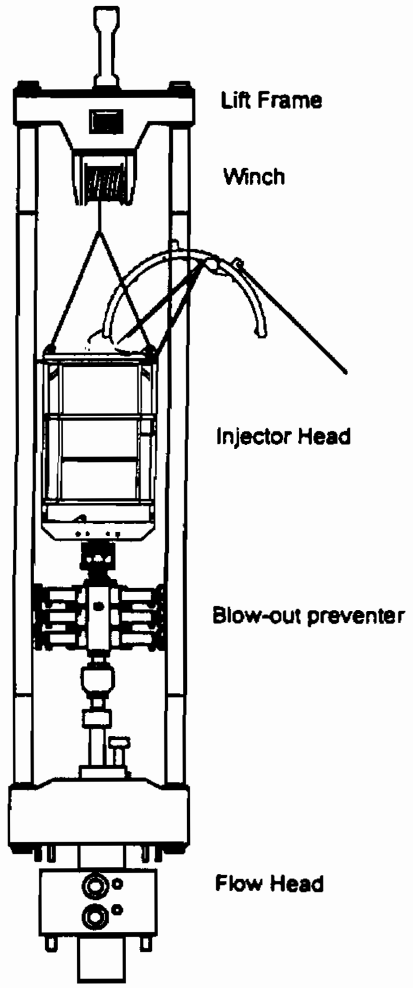


Figure 15-8. Injector Support
(Munro et al., 1996)

Operations with the impact hammer for setting plugs demonstrated that this could be a successful approach, but that it provided poor feedback at the surface. Long periods of jarring were often required before the lock set.

Another solution was sought. A new running BHA was designed that did not require jarring, gave positive indication of setting, and would not allow premature setting. A hydraulic system was developed (Figure 15-9) which used pressure inside the coil to set the plug. Straight overpull is used to lift the lock and shear off the running tool. A sequencing valve above the tool allows circulation through the string while running into the well.

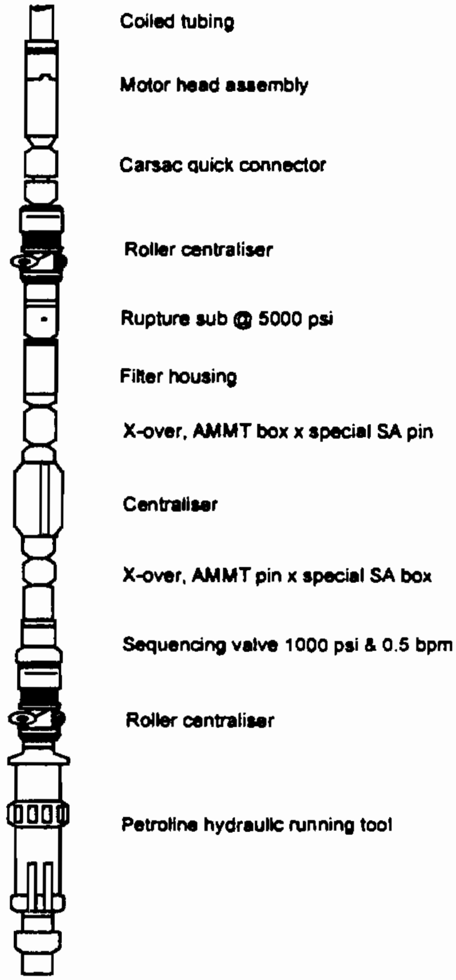


Figure 15-9. Hydraulic Running Assembly (Munro et al., 1996)

15.4 HALLIBURTON ENERGY SERVICES (CT PATCH)

Halliburton Energy Services (Coats, 1995) described the design and installation of an 8000-ft CT patch to extend the life of a marginal producing gas well in the Gulf of Mexico. The patch was installed inside of deteriorated production tubing. A complete conventional workover was not an economic choice. Rig charges and new tubing would have costed more than $800,000. The CT patch was installed for $50,000.

Caliper surveys had shown that the 2⅞-in. production tubing had developed holes below the SSSV and above a seal assembly at 9000 ft. A CT patch assembly (Figure 15-10) was designed to be hung off below the SSSV. The SSSV was not removed because there was no operational reason to do so and regulatory approval would have been required.

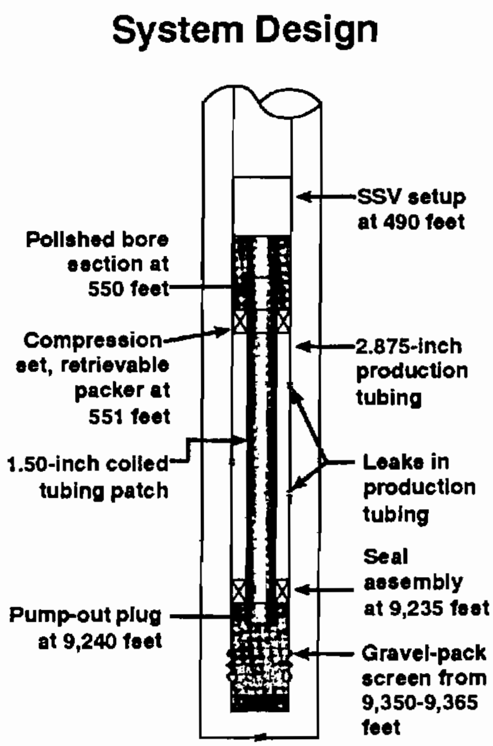


Figure 15-10. CT Patch for Repairing Leaking Tubing (Coats, 1995)

The patch assembly was suspended via a retrievable compression-set packer at 550 ft. CT diameter was 1½-in., which allowed an acceptable flow rate and good selection of downhole tools.

15.5 SERVICIOS HALLIBURTON DE VENEZUELA AND LAGOVEN (CT WORKOVER)

Servicios Halliburton de Venezuela and Lagoven SA (Lizak et al., 1996) described the planning and implementation of procedures to successfully complete a problem horizontal well in the Bolivar Coastal field in Lake Maracaibo. The slotted liner became stuck during completion operations, leaving a water-bearing zone in the curve exposed. CT was used to log the well, isolate the productive zone, and stimulate the well to bring on production. Careful planning saved this well. CT operations were paid out in 33 days.

The subject well was originally completed in 1956 as a vertical producer. By 1989, the well was non-producing and awaiting repair. A horizontal re-entry was performed in 1995. During completion operations, the slotted liner became stuck 267 ft from TD (Figure 15-11). The inflatable packer to be used to isolate the water zone was stranded above the zone.

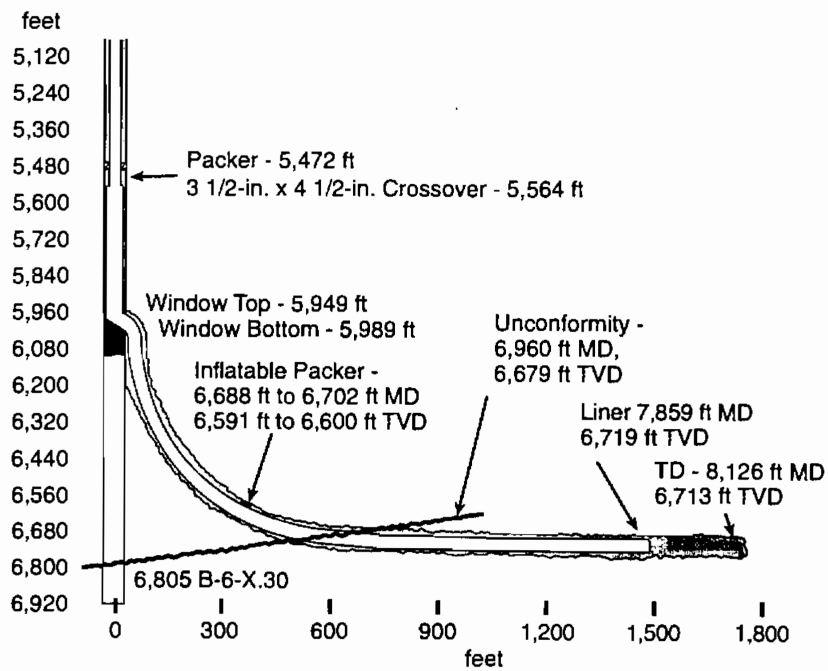


Figure 15-11. Wellbore Schematic (Lizak et al., 1996)

Four primary options were considered for completing the well with CT equipment. These included: 1) circulation squeeze with inflatable packer (place a high-viscosity pill in the productive interval, set an inflatable packer in 4½-in. casing, squeeze fine-particle cement, and drill cement from inside the liner), 2) perforate and circulate squeeze with inflatable packer (log the well, perforate below the top of the slotted liner, use option 1 with conventional cement), 3) squeeze without a packer (run CT in with nozzle, place a plug of fine-particle cement across the top of the liner and squeeze, then drill out cement), and 4) perforate and squeeze without a packer (log the well, perforate below the top of the slotted liner, use option 3 with conventional cement).

The project team decided that it was critical to know the precise location of the packers and liner top. This narrowed the options to two (number 2 or 4). The two types of cement available are described in Table 15-1. Fine-particle cement is able to be squeezed through the liner slots, with less chance for bridging than conventional cement.

TABLE 15-1. Comparison of Cement Properties (Lizak et al., 1996)

PROPERTY	CLASS H	FINE PARTICLE
Density, lb/gal	15.80	11.20
Plastic Viscosity, cp	94.50	51.00
Free Water, %	0.00	0.00
Fluid Loss, cc/30 min	14.00	18.00
Yield, cf/sk	1.15	1.41
Pump Time, hr	5.16	4.12
Water Requirement, gal/sk	5.10	8.50
24-hr Compressive Strength, psi	2,000	900

Laboratory testing was performed to determine the best gel for placing below the cement plug to protect the formation. A cross-linkable HEC gel was selected with some additions.

The flow chart for the decision process during the workover is shown in Figure 15-12.

Halliburton and Lagoven chose a fine-particle cement and placed it using a hesitation squeeze. Cement was displaced from the string with welan biopolymer and the well shut in for 24 hours.

Nitrogen was used to bring the well back on production. Initial production was 900 BOPD without sand or water. It was considered too high a risk to acidize and increase production further, since the acid may have broken down the cement.

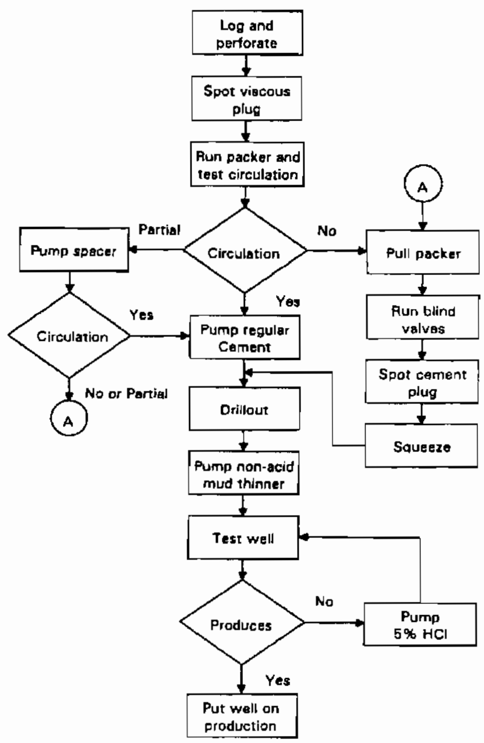


Figure 15-12. Summary of Workover Options (Lizak et al., 1996)

15.6 SMITH INTERNATIONAL (PDC BITS ON CT)

Smith International Inc. (Mensa-Wilmot, 1995) summarized the considerations for using PDC bits for CT drilling. The usage of CT equipment for drilling operations is still relatively small (Figure 15-13), but the percentage continues to increase slowly. PDC bits have an inherent advantage for CT drilling in that they operate effectively with lower bit weights. Their primary disadvantage is that high torque is generally generated. However, improved designs have gone a great distance toward resolving this problem for CT operations.

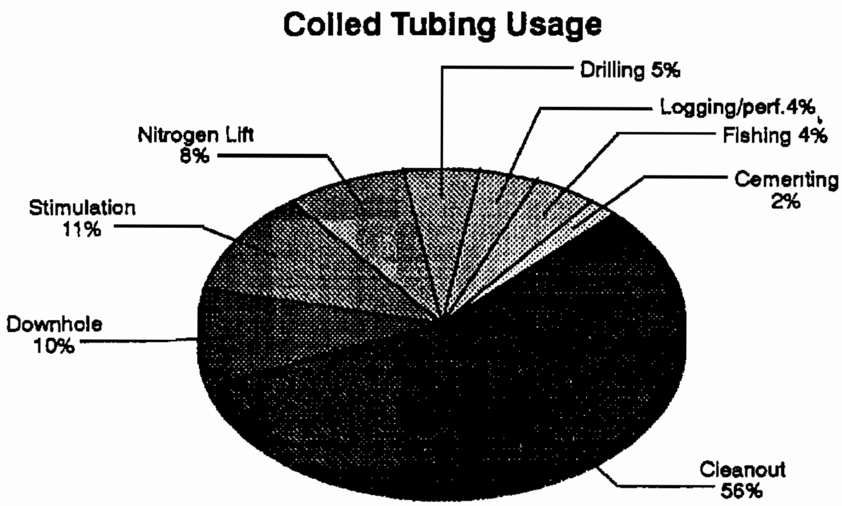


Figure 15-13. Distribution of CT Jobs (Mensa-Wilmot, 1995)

Proper bit selection is based on an understanding of the energy requirements and formation removal mechanisms for specific drilling applications. The general limitations of CT drilling are also key in establishing component compatibility. These limitations include the requirement for efficient ROP response to limited WOB, low torque response to increasing WOB, consistent torque response over time, and suitable TFA match to hydraulic limitations of CT.

Additional discussion of bit selection for CT workover/drilling operations is presented in *Drilling*.

SAND CONTROL

15.7 AMOCO TRINIDAD AND TUCKER ENERGY (CT GRAVEL PACKS)

Amoco Trinidad Oil Company and Tucker Energy Services (Holder et al., 1996) presented results and described operations for concentric gravel packs to repair screen damage of existing open-hole gravel packs in the Teak Field offshore Trinidad in 190 ft of water. Recent developments in circulating gravel packers and sand screens were effectively implemented. Cost savings were near $1.8 million (80% savings) and pay-out was reached in four months. One well (E-11) represented the longest circulating gravel pack run to date; another well (E-19) had the largest volume of sand placed through the packer. Clarified xanthan-gum gel carrier fluid enhanced gravel placement by reducing friction pressure losses.

These wells were part of a mature field where declining production and reservoir pressure have increased sand-control problems. Through-tubing gravel packs were indicated as a potential method to add significant value to the field.

One well (E-11) was originally completed with an open-hole gravel pack in 1993. Resin-coated prepack screens had been placed across 338 ft of interval. After a production decline, the well was acidized and immediately sanded up. Repair options were a rig workover (over $1 million) or a CT gravel pack placed through tubing.

A concentric gravel pack was placed with 1½-in. CT (Figure 15-14). Deposits of wax/asphaltene were removed from the upper 3000 ft of tubing and sand fill was cleaned from the bottom on a single trip.

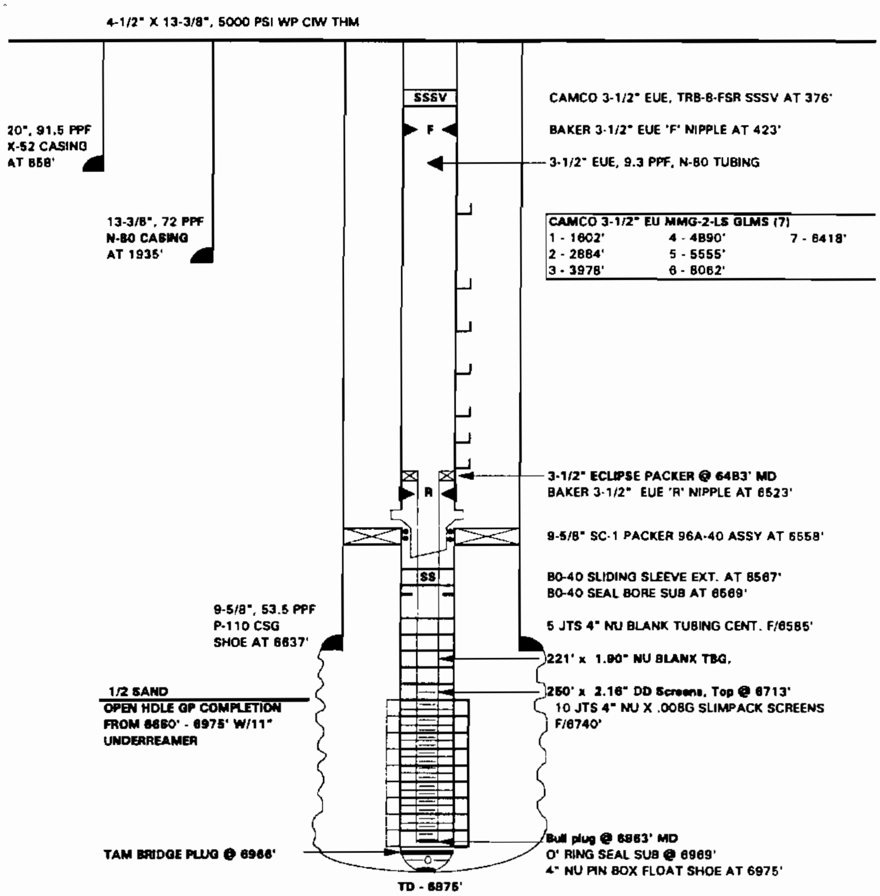


Figure 15-14. Schematic of Well E-11 (Holder et al., 1996)

Screenout occurred after 17 ft^3 of 40/60 sand was pumped (Figure 15-15). The theoretical annular volume for the job was 18 ft^3.

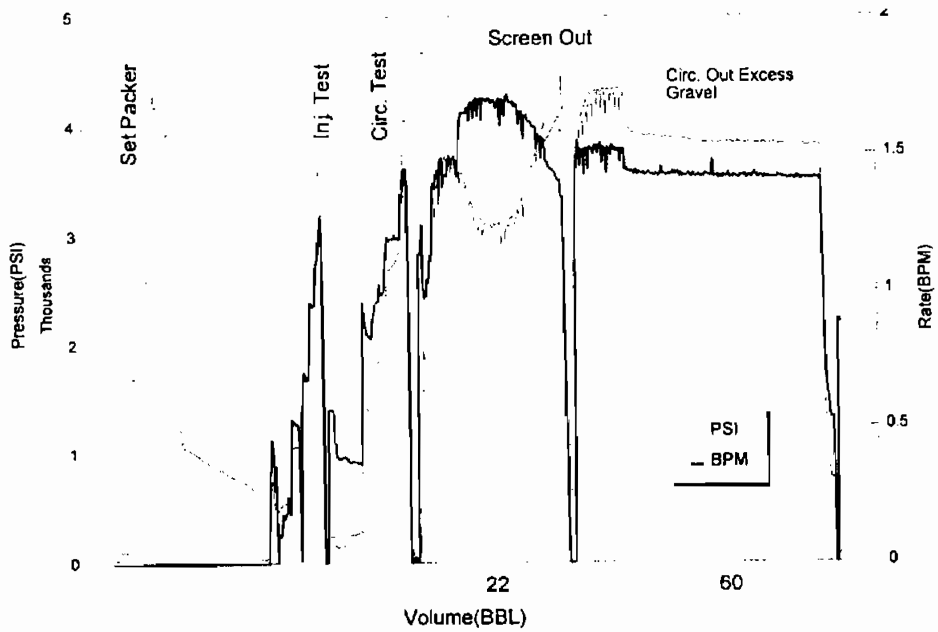


Figure 15-15. Gravel Pack Pressures and Rates (Holder et al., 1996)

A multilayered sintered-metal screen was used for both gravel packs in this field. This design has several advantages over prepacked wirewrap screens including higher tolerance to damage, higher ID/OD ratio (Table 15-2), and higher throughput.

TABLE 15-2. Sintered Metal Screens (Holder et al., 1996)

Nom. Size (in.)	Screen ID (in.)	Screen OD (in.)	Total Screen Weight (lb/ft)
1.315	0.95	1.60	~2.5
1.66	1.28	1.94	~3.1
1.90	1.50	2.16	~3.6
2.063	1.66	2.33	~4.0

Future improvements to these field procedures include jet washing existing screens with acid, perforating existing screens to improve gravel placement, and pumping acid ahead of gel slurry to improve wellbore clean up.

15.8 ECLIPSE PACKER AND CHEVRON (IMPROVED GRAVEL PACKS)

Eclipse Packer Company and Chevron (Picou and Hebert, 1996) summarized developments in through-tubing gravel packs deployed on CT that have become an effective and economical technique for sand control. Workovers based on one-trip circulating through-tubing gravel pack systems have become relatively common in the Gulf Coast area of Texas and Louisiana. Recent improvements have made implementing these systems more reliable and efficient.

The most frequent well problem remedied by installing a CT gravel pack is repairing failed packs. Also common is installing systems in wells that had no sand control but are currently experiencing sanding problems. Jobs performed by Eclipse Packer are summarized in Table 15-3.

TABLE 15-3. Gravel-Pack Job Summary (Picou and Hebert, 1996)

Job No	Run Date	Location	Tubing Size	Depth in feet	Well Dev @ Zone	Screen OD/Lenght In.	Screen OD/Lenght Ft.	Blank Pipe OD/Length In.	Blank Pipe OD/Length Ft.	Job Type*	Production Data
1.	2/94	Offshore - GOM	2 7/8	8500	25°	1.660	60	1.315	180	2	350 bopd
2.	8/94	Offshore - GOM	2 7/8	6500	15°	1.94	30	1.315	66	2	2 mmscfd
3.	6/94	Offshore - GOM	2 7/8	8700	45°	1.60	60	1.315	90	1	2.6 mmscfd
4.	6/95	Louisiana Land	3 1/2	4750	10°	1.94	135	1.660	66	1	3.2 mmscfd
5.	2/94	Offshore - GOM	2 7/8	9600	0°	2.16	46	1.660	260	1	750 mcfd
											200 bopd
6.	4/95	Offshore - GOM	2 3/8	10500	25°	1.60	35	1.315	60	1	250 bopd
											950 mcfd
7.	4/95	Offshore - GOM	2 3/8	11700	20°	1.60	23	1.315	84	1	1.5 mmscfd
8.	9/95	Offshore - GOM	2 3/8	10500	30°	1.60	60	1.315	90	1	550 bfpd
9.	10/95	Inland waters LA	2 7/8	11000	20°	1.60	33	1.315	90	2	350 bfpd
10.	3/95	Offshore - GOM	2 7/8	11200	62°	1.60	81	1.315	300	2	360 mcfd
											350 bcpd
11.	4/95	Offshore - GOM	2 7/8	11000	35°	1.94	34	1.315	400	2	Init-1100 bopd
											Curr-750 bopd
12.	11/94	Offshore - GOM	2 7/8	7200	29°	1.94	80	1.660	425	1	Init-5 mmscfd
											Curr-1.2 mmscfd
13.	9/94	Offshore - GOM	2 3/8	11300	0°	1.60	110	1.315	200	1	n/a
14.	11/94	Offshore - GOM	2 3/8	10050	28°	1.60	98	1.315	305	1	300 bfpd
15.	1/95	Offshore - GOM	2 7/8	11300	55°	1.60	46	1.315	120	2	n/a
16.	12/94	Offshore - GOM	2 7/8	8600	0°	1.94	60	1.600	150	2	n/a
17.	12/94	Offshore - GOM	2 3/8	7300	15°	1.60	57	1.315	80	2	n/a
18.	2/95	Offshore - GOM	2 7/8	11300	65°	1.94	85	1.660	160	2	750 bfpd
19.	6/94	Offshore - GOM	2 7/8	8920	70°	1.60	71	1.315	90	3	350 bopd
20.	8/94	Offshore - GOM	3 1/2	9800	25°	1.94	35	1.660	120	1	n/a
21.	6/95	Louisiana Land	2 3/8	7700	0°	1.94	33	1.660	90	1	n/a
22.	9/95	Inland waters LA	2 7/8	12100	0°	1.94	34	1.660	46	1	n/a
23.	9/95	Offshore - GOM	3 1/2	9300	12°	2.16	69	1.90	100	1	n/a
24.	3/95	Offshore - Trinidad	3 1/2	6000		2.16	250	1.90	250	2	300 bopd
25.	7/95	Offshore - Trinidad	3 1/2	7000	45°	2.16	102	1.90	131	2	370 bopd
26.	8/95	Offshore - GOM	2 7/8	10155	40°	1.60	33	1.315	47	1	n/a
27.	6/95	Offshore - GOM	2 7/8	11000	55°	1.94	104	1.660	33	1	4 mmscfd
28.	7/95	Offshore - GOM	2 7/8	9000	25°	2.16	90	1.90	326	1	n/a
29.	12/95	Offshore - GOM	2 3/8	12000	15°	1.60	56	1.315	850	1	n/a
30.	2/96	Offshore - GOM	2 3/8	7750	0°	1.60	35	1.315	90	1	n/a
31.	1/96	Offshore - GOM	2 3/8	9400	n/a	1.60	23	1.315	100	1	n/a
32.	1/96	Offshore - GOM	3 1/2	5800	n/a	2.16	23	1.90	56	1	4.6 mmscfd
33.	11/95	Offshore - GOM	2 7/8	10450	35°	1.94	55	1.66	15	1	n/a
34.	11/95	Offshore - GOM	2 7/8	3400	n/a	1.94	32	1.66	10	1	n/a
35.	9/95	Offshore - GOM	3 1/2	9800	30°	1.94	67	1.66	70	1	1.2 mmscfd
36.	12/95	Offshore - GOM	3 1/2	10800	n/a	2.54	100	2.375	162	2	6 mmscfd
37.	10/95	Offshore - GOM	2 3/8	9700	0°	1.60	33	1.315	117	1	n/a
38.	11/95	Offshore - GOM	2 3/8	7600	n/a	1.60	23	1.315	100	1	n/a

Through-tubing gravel packs have previously been limited to two basic procedures: over-the-top squeeze and wash-down methods. Both these methods have the disadvantage of not allowing the testing of the sealing or anchoring components prior to placing the well on production.

The principal components of the one-trip circulating gravel-pack system are a large-bore hydraulic-set retrievable seal bore packer and a multiposition crossover/running tool. These systems can be deployed in tubing sizes as small as 2⅜ inches (Table 15-4).

TABLE 15-4. Tubing and Packer Specifications (Picou and Hebert, 1996)

Tubing Sizes	Packer OD	Packer ID
2 3/8 in.	1.80 in.	1.06 in.
2 7/8 in.	2.24 in.	1.50 in.
3 1/2 in.	2.74 in.	1.81 in.
4 1/2 in.	3.65 in.	2.375 in.

Important advantages of the one-trip system include the capability of completing the entire operation in one trip, the ability to gravel-pack long intervals, and to test anchoring and sealing components prior to pumping gravel.

New screen products such as sintered metal have large ID/OD ratios and have contributed to the success of many of these jobs. Long-stroke safety joints have also been developed to allow movement of the production tubing while preventing buckling or tension loading of the gravel-pack assembly.

Job success was also increased due to better planning and supervision. Perforation density must normally be increased to increase net perforation area. Slurry designs are also impacted by limits in the CT workstring (friction pressure, load capacity).

In a variety of reservoirs, this one-trip through-tubing gravel pack has allowed the exploitation of reserves that would otherwise be uneconomical.

15.9 HALLIBURTON ENERGY SERVICES (CT SAND CONTROL)

Halliburton Energy Services (Coats and Allison, 1995) described and compared typical sand-control systems deployable on CT. Many operators in the Gulf of Mexico have extended the productive life of wells by using CT to remediate sand-control problems. Both mechanical and chemical methods have been successfully conducted through CT. Costs are reduced greatly by avoiding the need to deploy a rig and often by avoiding the need to shut in other producing wells on the platform.

Coats and Allison described the various methods to install gravel packs with CT. The most common application is the through-tubing squeeze pack (Figure 15-16). Where feasible, success rates are usually high. A disadvantage is that it may be difficult to place a complete gravel filter around the screen.

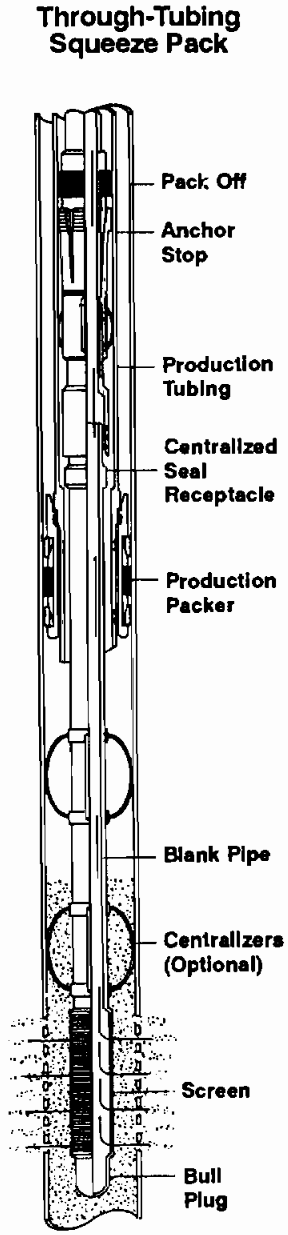


Figure 15-16. Through-Tubing Squeeze Pack (Coats and Allison, 1995)

The wash-down technique (Figure 15-17) is initiated by spotting sand or beads across the productive zone. The screen is then washed into the beads. Maximum interval length is about 90 feet.

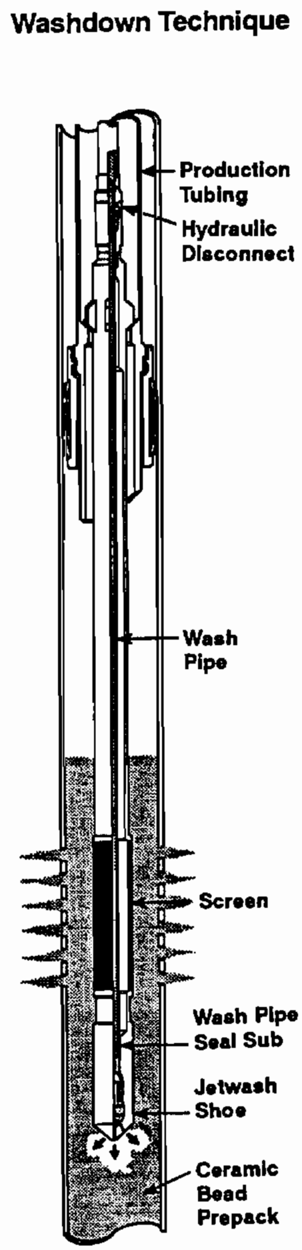


Figure 15-17. Wash-Down Gravel Pack
(Coats and Allison, 1995)

The dual-screen method (Figure 15-18) is used when the production tubing ends significantly above the productive interval. This approach minimizes flow restrictions of the assembly. Future logging and stimulation are hindered with this approach.

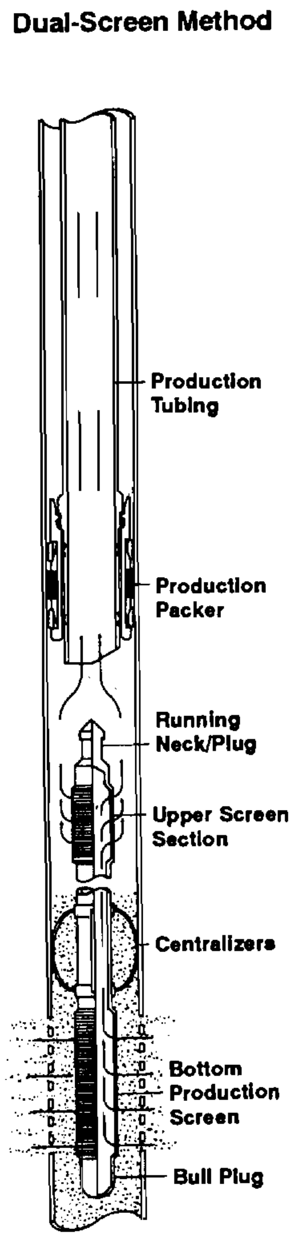


Figure 15-18. Dual-Screen Gravel Pack (Coats and Allison, 1995)

The circulating pack method (Figure 15-19) most closely resembles a full-scale conventional gravel pack. This approach provides improved chances of achieving a complete sand filter.

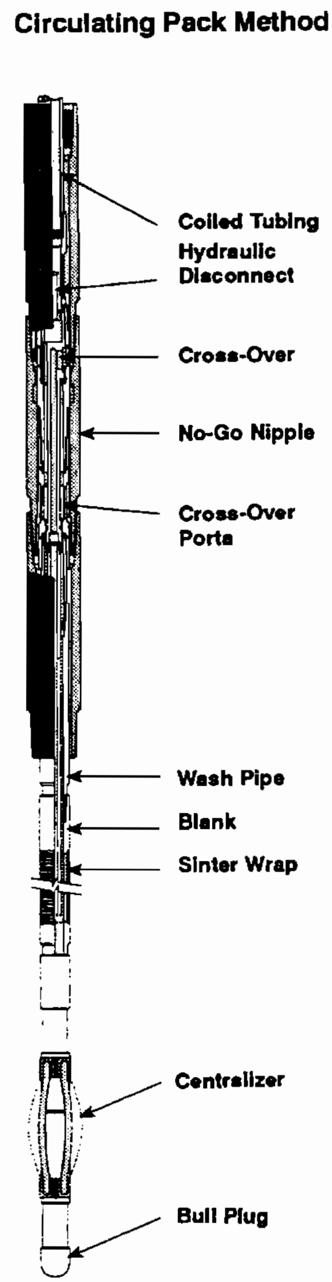


Figure 15-19. Circulating Pack Gravel Pack (Coats and Allison, 1995)

Another through-tubing gravel pack is the hang-off method (Figure 15-20). A sintered metal screen is hung without being surrounded by a sand pack. This approach represents the most economic option.

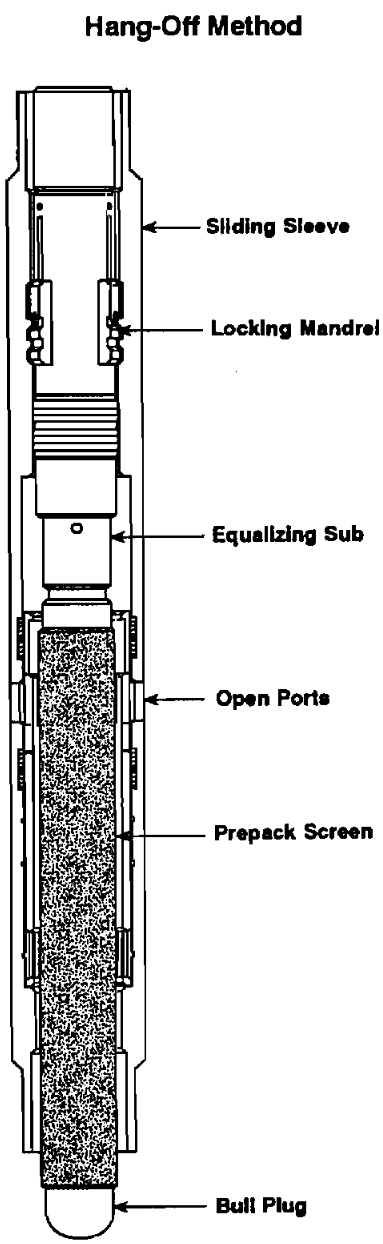


Figure 15-20. Hang-Off Method for Sand Control (Coats and Allison, 1995)

15.10 SAMEDAN AND PREEMINENT ENERGY (HIGH-PRESSURE CLEANOUTS)

Samedan Oil Corporation and Preeminent Energy Services (Zimmerman et al., 1997) described applying CT clean-out technology for removing cement residue and placing chemical sand-control treatments in high-pressure gas wells. Without CT options, offshore operators of high-pressure gas wells in the Gulf of Mexico have had few options for controlling sand production. Pump and well pressures typically exceed the normal limit for CT of 5000 psi. It is therefore important to carefully model and design the operation with respect to CT fatigue.

Using CT sand-control methods allowed working in an underbalanced condition, eliminating the previous need for expensive weighted completion fluids. Post-treatment performance is greatly improved because no heavy brines are lost to the formation. Non-damaging KCl fluids have been used successfully.

15.11 STATOIL, INTEQ AND HALLIBURTON (CT GRAVEL PACKS)

Statoil A/S, Baker Hughes INTEQ and Halliburton Energy Services (Zdenek et al., 1997) described the testing and implementation of CT through-tubing gravel packs in the Statfjord Field in the North Sea. Conventional gravel packs had been placed in dead wells; however, a significant loss of productivity has occurred after breakthrough of the injection water. Statoil determined that gravel packs in live wells with CT should eliminate formation damage caused by kill fluids and brines.

Planning prior to implementing CT gravel packs indicated the need for testing. A 30-ft long simulator was fabricated (Figure 15-21). Tests were performed to help determine the optimum placement of the gravel pack, the effects of water packing/slurry packing, the best rates, sand concentrations, and pumping other fluids down the annulus.

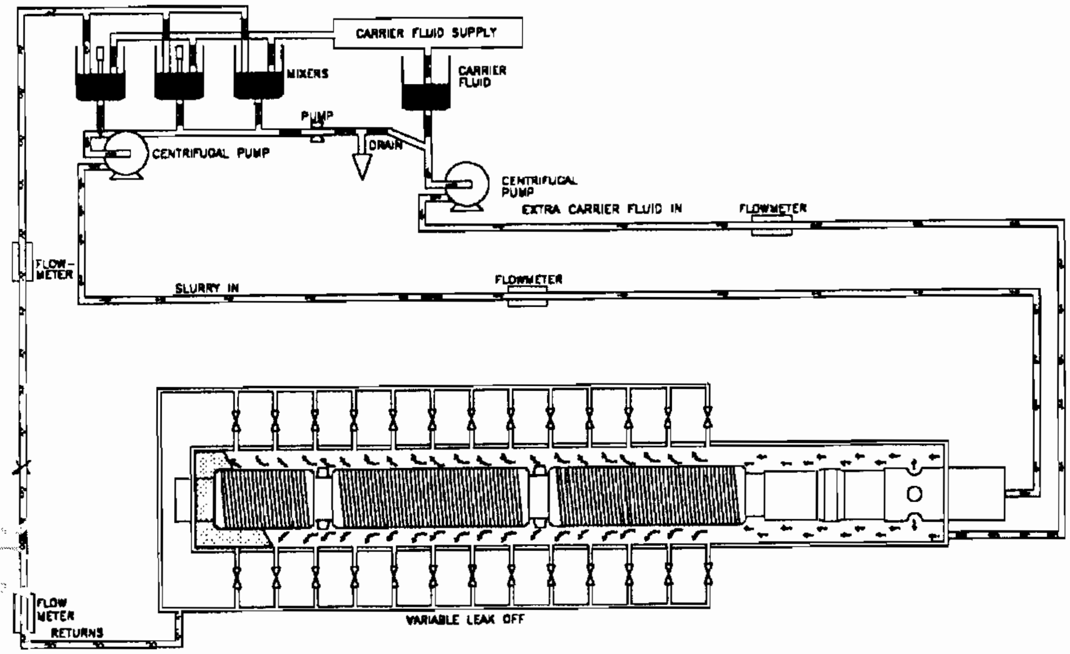


Figure 15-21. Gravel-Pack Simulator (Zdenek et al., 1997)

Testing results indicated that a low-viscosity/low-concentration water pack would give better perforation and annular-pack efficiency. Pumping only through the CT would prevent debris from the annulus from entering the pack.

WASHING/JETTING OPERATIONS

15.12 CHEVRON AND CUDD PRESSURE (DEEP UNDERBALANCED CLEANOUT)

CT with a yield strength of 100,000 psi is now readily available and routinely used in field operations. The increased capacity this material affords has allowed jobs to be economically performed that were not feasible with 70,000- or 80,000-psi CT. In a recent example, Chevron performed a successful scale cleanout in a deep (22,600 ft) gas well in the Gomez Field in West Texas (Adams and Overstreet, 1997). They used a 1½-in. x 23,000-ft string with seven ID wall tapers. Design overpull was to 72% of yield. The operator saved 85% of the costs of a conventional cleanout, which would have required pulling the production tubing. This job could not have been performed without high-strength CT.

A slim-hole impact drill (1.688 inches) was used for the job because of its tolerance for high temperatures and flexibility with respect to work fluid. A 2¼-in. button bit was used. All tools in the BHA (Figure 15-22) were constructed of Inconel 725 steel.

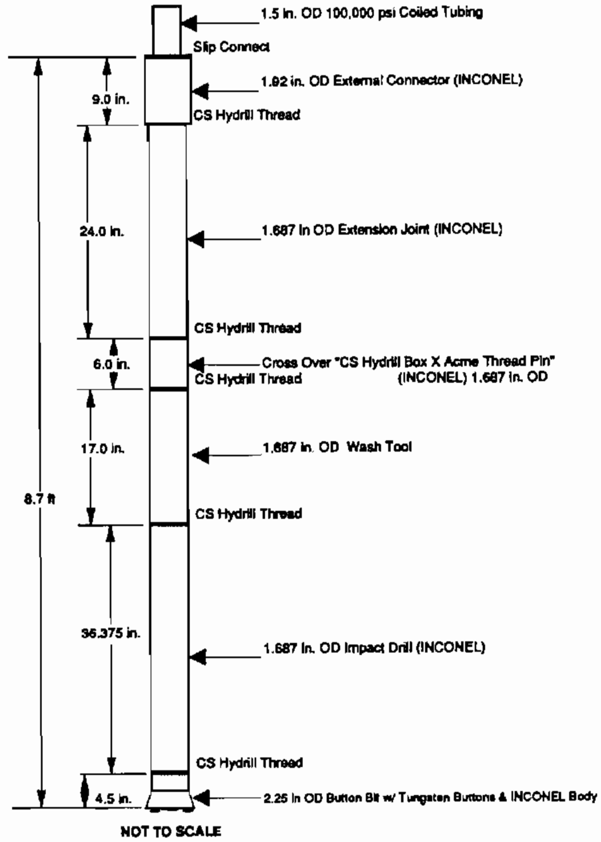


Figure 15-22. Cleanout BHA
(Adams and Overstreet, 1997)

Equipment layout for the operation is shown in Figure 15-23. Time on site was about 50 hours.

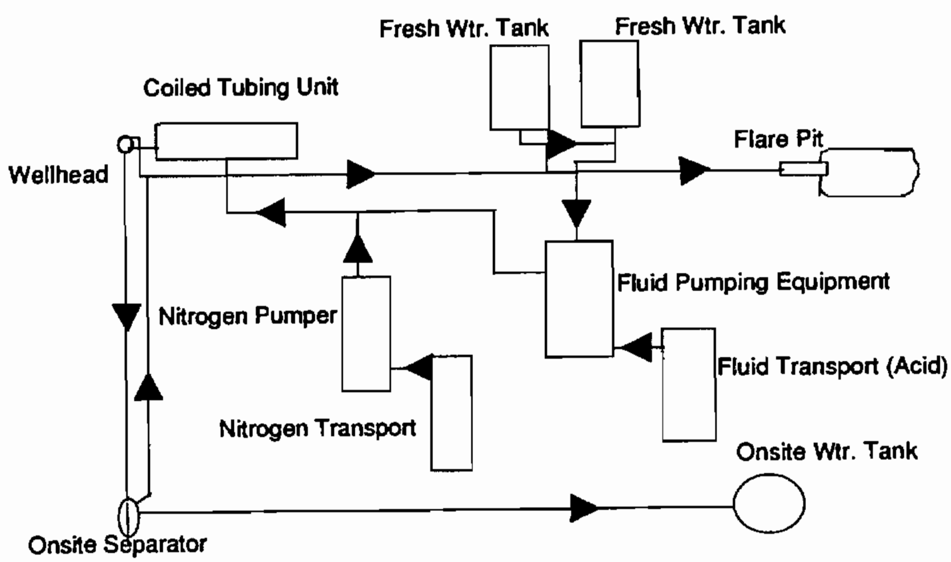


Figure 15-23. Pumping Equipment for Cleanout (Adams and Overstreet, 1997)

Tensile overpull was checked at several depths while RIH to ensure CT design limits were not exceeded. High drag was encountered at 11,800 ft (Figure 15-24). This was attributed to scale build up near the tailpipe.

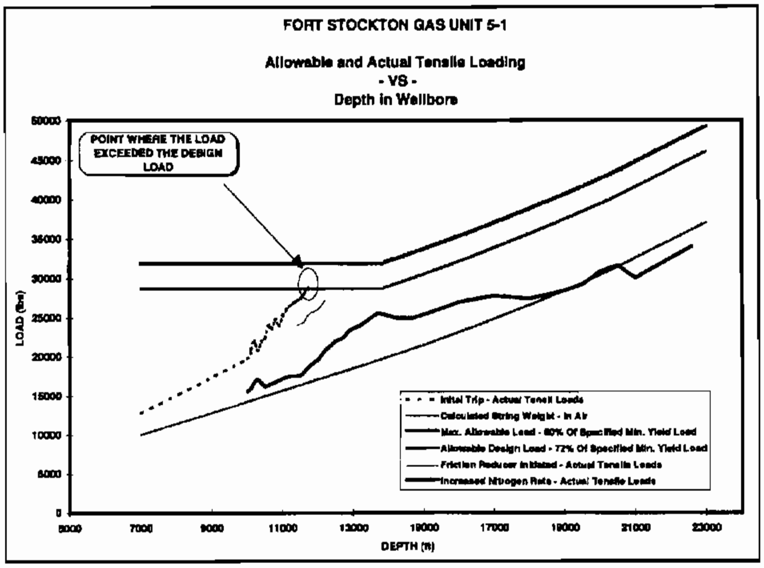


Figure 15-24. Tensile Load Limits
(Adams and Overstreet, 1997)

15.13 ELAN ENERGY AND GED CONSULTING (CLEANOUTS IN HORIZONTAL WELLS)

Elan Energy Inc. and GED Consulting Ltd. (Heinrichs and Dedora, 1995) described several methods for cleaning out sand bridges with CT in horizontal wells in Northeast Alberta and Northwest Saskatchewan. The wells for which these techniques were developed are generally heavy-oil wells completed at TVDs from 450 to 750 m (1476 to 2460 ft). Typical wells are completed with slotted liners with an average length of 900 m (2952 ft). A variety of improvements and several new systems have been developed in recent years for cleaning sand from these horizontal wells.

The earliest system used was conventional circulation. When sand bridges formed solid plugs, these could be removed by running in tubing and circulating water (Figure 15-25). This approach is limited to intermediate casing and is feasible only as long as returns can be maintained. The formation cannot normally support a full column of water. Returns are lost after bridges are breached.

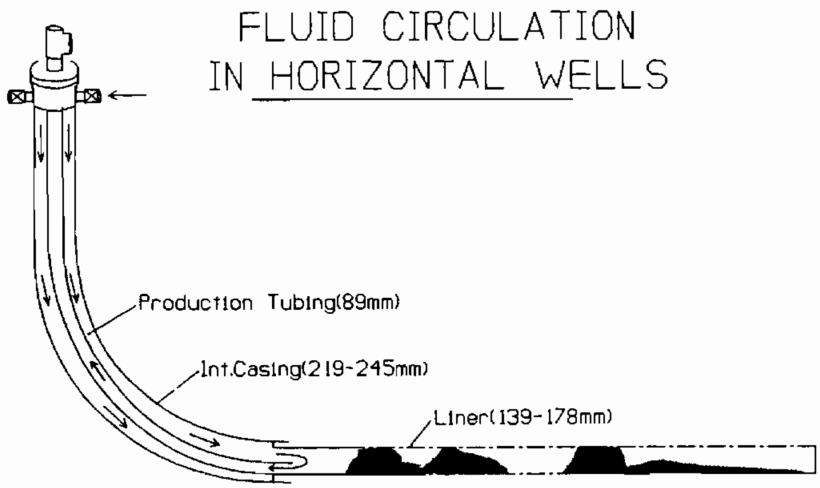


Figure 15-25. Conventional Circulation for Sand Cleanout
(Heinrichs and Dedora, 1995)

The advantages of conventional circulation include simplicity, low cost and the ability to rotate the work string. However, excessive hydrostatic pressures and high fluid losses limit the effectiveness of this approach.

Hydrostatic head can be reduced by injecting a gas into the build section (Figure 15-26). A temporary casing is run to the liner. Different nozzles and fluid-driven bits have been used to break up the sand. This system has the advantages of reduced hydrostatic pressure and continuous advance with CT. The high cost of nitrogen and difficulty in maintaining bottom-hole pressures limit the application of this technique.

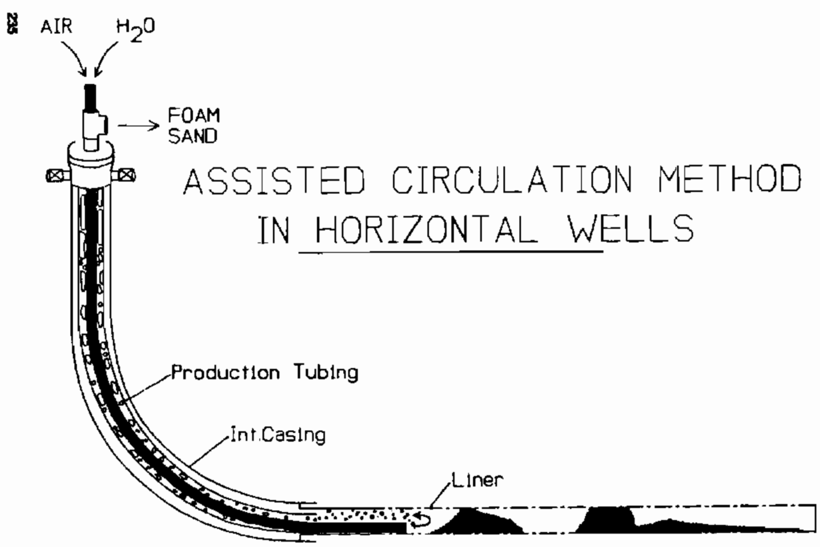


Figure 15-26. Assisted Circulation for Sand Cleanout
(Heinrichs and Dedora, 1995)

Pump-to-surface bailers (Figure 15-27) were used in vertical heavy-oil wells prior to horizontal. The tubing is connected to the plunger of a pump. The work string is stroked, displacing fluid through the tail pipe and pump to tanks on the surface. Tail pipe is added to the string as cleaning advances down the horizontal section.

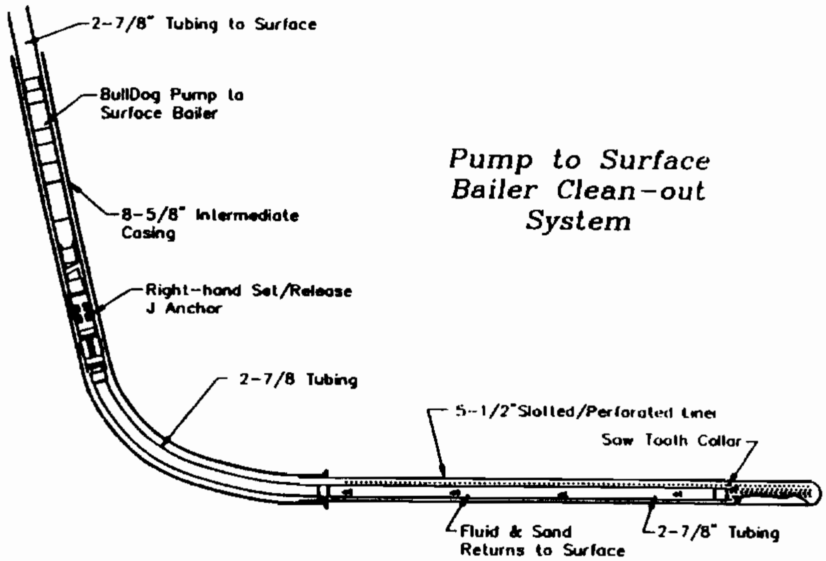


Figure 15-27. Pump-to-Surface Bailer for Sand Cleanout (Heinrichs and Dedora, 1995)

The advantages of pump-to-surface bailers include low costs for short laterals, no temperature limits, and the ability to remove debris other than sand. When using this approach, however, it is difficult to maintain the suction at the sand face, and efficiency becomes low with long tail pipes.

Another clean-out design is based on running two strings of tubing into the well. One string is 2⅜-in. tubing that is landed inside the liner (Figure 15-28). The second string is 3½-in. tubing outfitted with a progressing cavity pump and rods. CT is then run through the smaller tubing string into the liner. Returns are taken by the pump up the 3½-in. tubing.

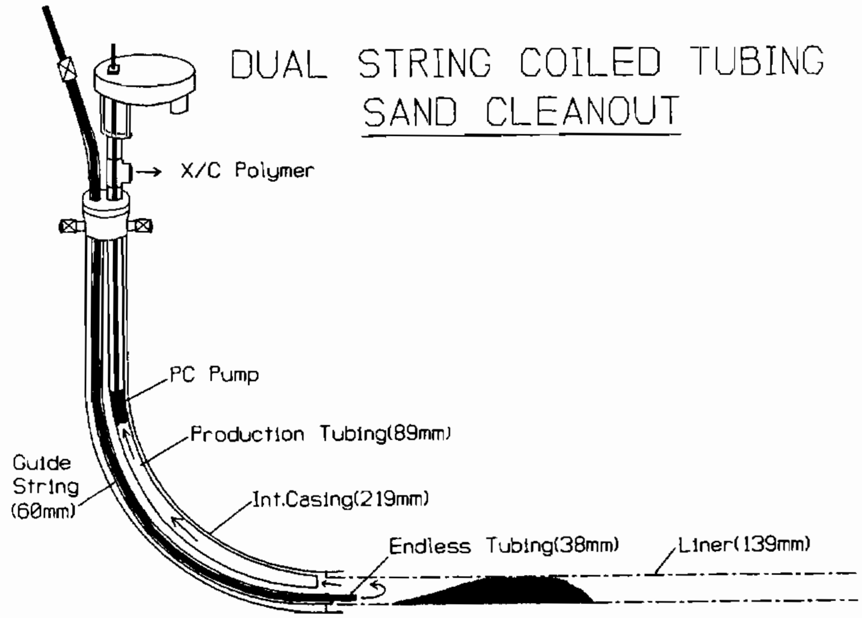


Figure 15-28. Dual-String CT Sand Cleanout
(Heinrichs and Dedora, 1995)

Advantages of the dual-string system include continuous circulation via CT, no pressure surges, and reduced costs for later workovers. Disadvantages are increased costs for well completion, a limit to horizontal reach of about 1000 m (3280 ft), and the requirement for polymer fluids.

Another option employed in some of these wells is the tubing-driven progressing cavity pump (Figure 15-29). A rotor of a progressing cavity pump is driven by rotating the work string rather than a rod string. The pump stator is anchored by grooved wheels against the liner. A bit is attached to the end of the BHA.

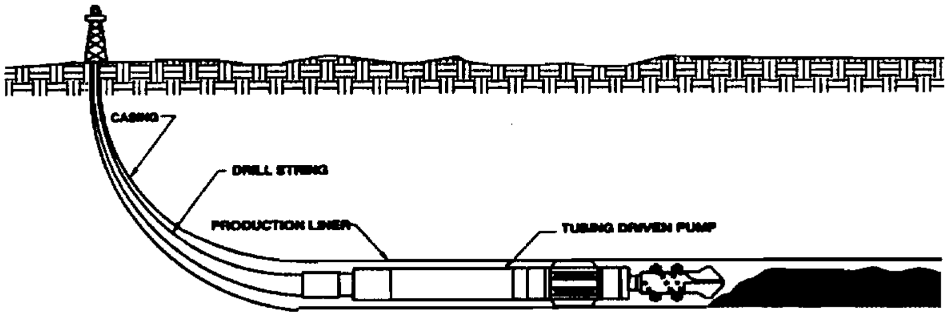


Figure 15-29. Tubing-Driven Pump for Sand Cleanout
(Heinrichs and Dedora, 1995)

The tubing-driven pump can be used with normal reservoir pressures, thereby reducing fluid losses. The system is limited to applications at inclinations of 60-70°.

A recently developed dual CT venturi pump has also been used with success. Wash fluid is pumped down the inner CT string and then pumped back up the CT by CT annulus. This system can be run in liners as small as 4½ inches and the use of water-base fluids results in clean operations. Disadvantages of this system are that a service rig has to moved onto the well both before and after the CT rig is deployed. In addition, this service is new and novel, so current costs are high.

Elan Energy has found that sand cleanouts have been the most expensive element in the production of horizontal heavy-oil wells in this area. Effective methods to remove sand have been developed and are being further improved. Measures to prevent sand production are very important. One successful technique is to gradually increase a well's production rate after shut-in, and thereafter maintain a lower production rate.

15.14 HALLIBURTON ENERGY SERVICES (CLEANOUTS IN GEOTHERMAL WELLS)

Halliburton Energy Services (Turton et al., 1997) described the application of CT cleanout techniques for removing silicate scale from geothermal wells. CT offers economic, environmental and safety advantages over conventional rig techniques. Six case histories were described by Halliburton in geothermal fields in Central Java, Indonesia, and Japan. Three different methods were employed in these operations.

In the first method, cleaning energy was applied by focused polymerized fluid jets. The down-jet nozzle (Figure 15-30) had the same OD as the indexing tool.

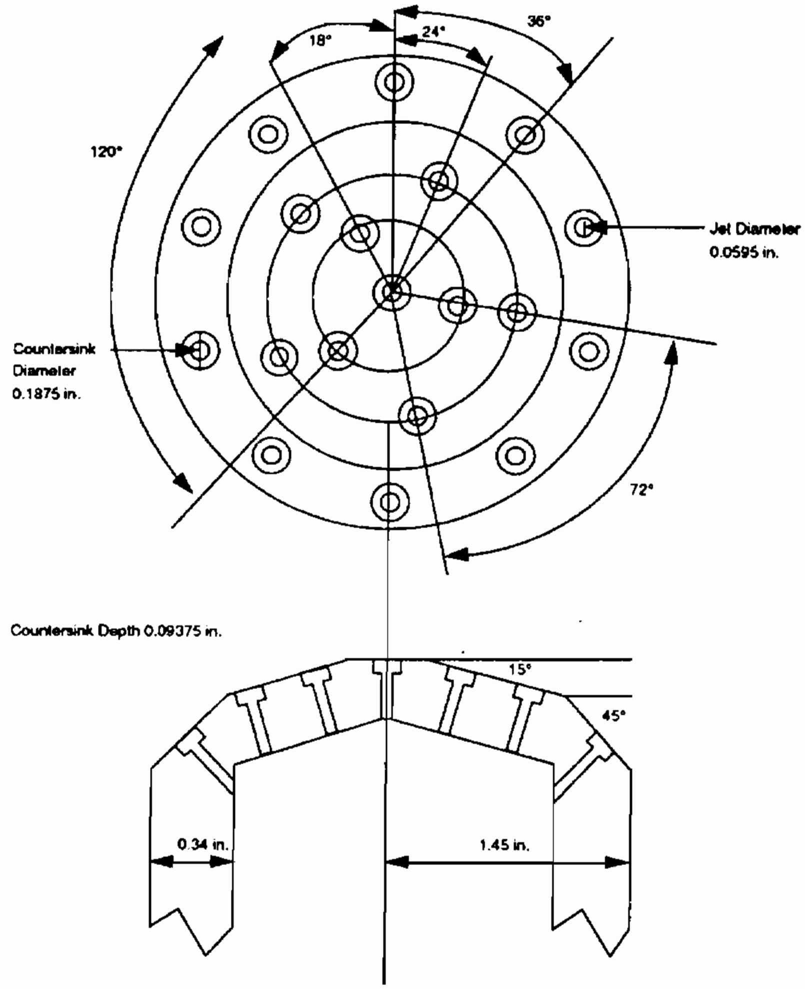


Figure 15-30. Down-Jet Nozzle (Turton et al., 1997)

To keep costs low, jetting treatments were performed on live wells, and produced fluids were depended on for removing cleanout debris. The polymer cleanout solution was blended in the batch mixer, filtered, and pumped to a storage tank (Figure 15-31).

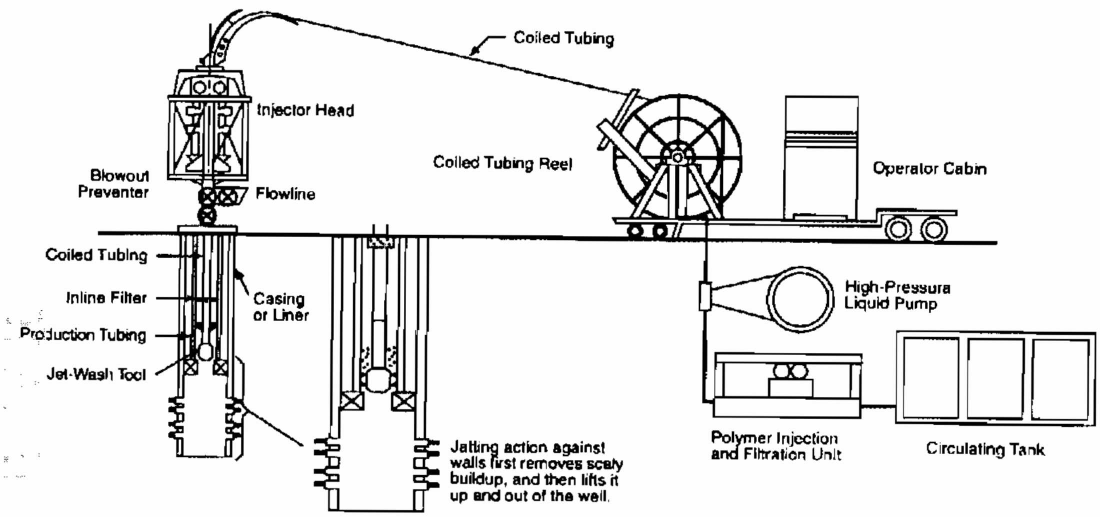


Figure 15-31. CT Equipment for Cleanout (Turton et al., 1997)

The second cleanout method incorporated a high-speed motor and flat-bottom junk mill. The third cleanout method was using silicate scale remover spotted between the slotted liner and formation face.

CT scale removal was more economical for these geothermal wells. Lessons were learned on these case histories that will improve job design and execution in future treatments.

15.15 HALLIBURTON ENERGY SERVICES (CLEANOUTS WITH TAPERED-OD CT)

Halliburton Energy Services (Love et al., 1997) presented results from a case history where OD-tapered CT was used to clean out 31 restricted wells in a West Texas water-and-gas injector field. These wells have a 1.12-in. restriction near the bottom. One-inch CT was not feasible due to flow requirements for circulating fill through the annulus. The final CT design for the operation included 8000 ft of 1¼-in., 250 ft of 1-in. and 500 ft of ¾-in. tubing.

Hydraulics considerations were critical to the success of the project. The pressure loss through the tapered-OD string (Figure 15-32) was significantly less than through a ¾-in. string. Potential flow rates were 350% greater with the tapered string.

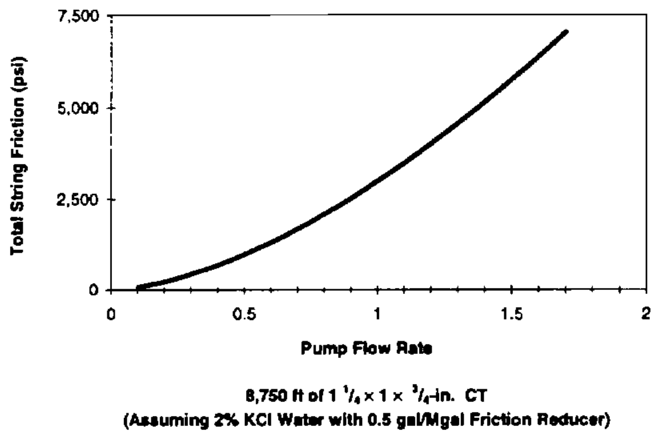


Figure 15-32. Pressure Loss through Tapered-OD String
(Love et al., 1997)

By comparison, pressure losses through a full string of 1¼-in. CT of the same length were only slightly improved (about 5000 psi pressure drop at a pump rate of 2 bpm).

V-block grippers (Figure 15-33) were used so that multiple ODs could be run through the injector without changing blocks. The injector also had floating linear beams to allow the CT to center itself at OD changes.

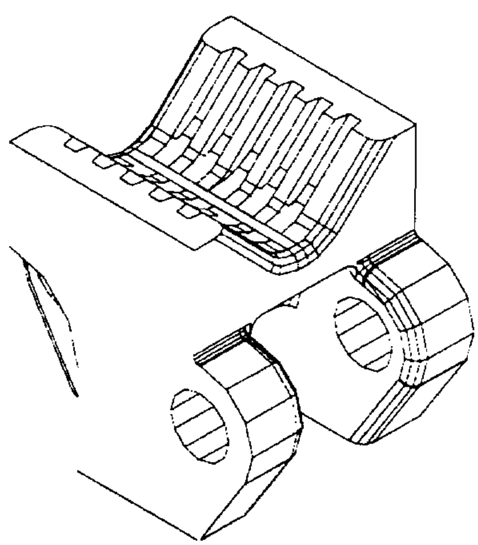


Figure 15-33. V-Block CT Gripper Block
(Love et al., 1997)

Conventional cleanouts required 10-14 days to complete. CT cleanouts with tapered-OD strings were completed in 8-10 hours.

Transition areas at OD changes were significantly worn and fatigued. These regions could withstand 3-4 workovers before repair.

15.16 NOWSCO WELL SERVICE (CONCENTRIC CT SYSTEMS)

Nowsco Well Service Ltd. (Falk and Fraser, 1995) introduced a new tool for cleaning sand from horizontal sections. Their system, called the Sand Vac^{SM}, was developed for cleaning out low-pressure wells using a jet pump assembly run on concentric CT. The system has been successfully deployed in several wells, cleaning out significant volumes of sand without difficulty.

In Fried et al. (1997), Nowsco Well Service, Technology & Research, and Murphy Oil Company described the Well Vac^{TM} (Figure 15-34), a modified jet-pump tool for increasing overall recoveries for drilling or stimulation fluids. The tool has proven highly useful in underpressured reservoirs common to horizontal completions.

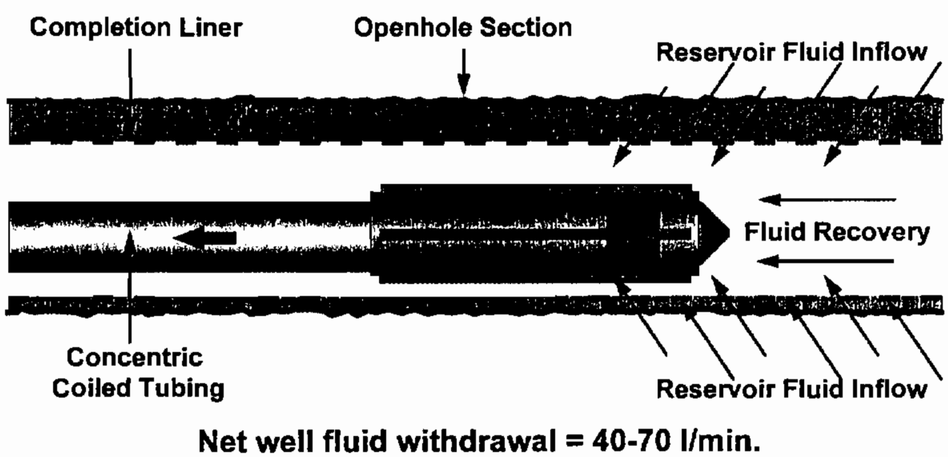


Figure 15-34. Well Vac for Fluid Cleanouts (Fried et al., 1997)

The Sand Vac^{SM} was developed as a cost-effective alternative for use in low-pressure formations and in high-viscosity oil applications. Cleanouts in these environments are hindered by minimum fluid velocities to prevent particle settling. The new system allows continuous cleaning with no moving parts since it is based on proven jet-pump technology.

The system is operating by pumping fluid through the inner string of a concentric pair of CT strings. Spent power fluid, in-situ fluid and sand are circulated up the annulus inside the concentric string. Equipment is shown in Figure 15-35.

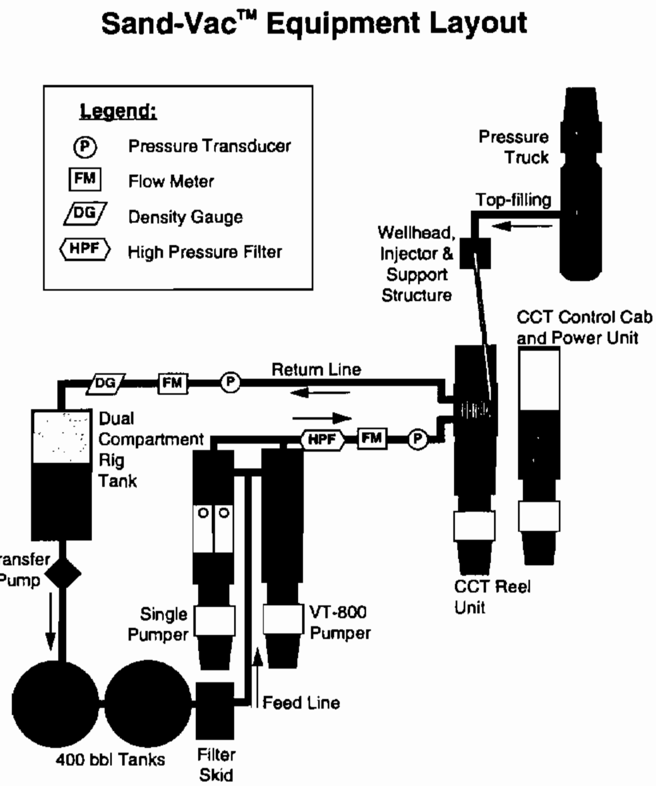


Figure 15-35. Sand Vac^{SM} Surface Equipment
(Falk and Fraser, 1995)

The cleaning assembly uses front and rear jets to fluidize the sand in the well (Figure 15-36). Fluid velocity in the annulus of the string is sufficient to prevent resettling of the solids.

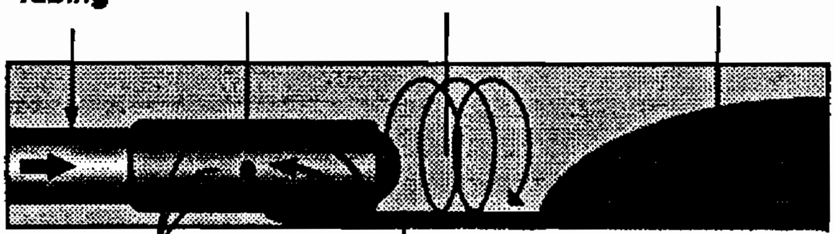


Figure 15-36. Sand Vac^{SM} BHA (Falk and Fraser, 1995)

The cleanout system is designed for use in liners as small as 4½ inches. Current specifications are well MDs up to 2150 m (7050 ft), TVDs to 1200 m (3940 ft) and bottom-hole pressures as low as 1 MPa (145 psi).

Computer design tools are used to calculate operating rates and pressures, sand pick-up rates, and CT stress conditions. Typical circulation rates are near 0.16 m3/min (42 gpm) with a sand pick up of 19 kg/min (42 lb/min). Typical jobs in horizontal wells are completed in 24-36 hours.

15.17 PREEMINENT ENERGY SERVICES (HIGH-PRESSURE CLEANOUTS)

Preeminent Energy Services (Coats et al., 1996) described successful workover operations cleaning out deep and high-pressure wells in the Gulf of Mexico. Prior to the development of high-strength CT and high-pressure CT equipment, snubbing units were the preferred system in this environment. CT cleanouts can now be performed safely and efficiently at a considerable cost savings.

Extra preparation is required prior to performing a CT operation in a high-pressure (greater than 5000 psi) well. Software is used to check drag for running into the well, equivalent stress on the CT, fatigue life, hydraulics and buckling.

In one type of cleanout operation, high-strength CT was used to remove zinc sulphide scale from three high-pressure gas wells with surface shut-in pressures exceeding 7000 psi. 100-ksi 1¼-in. tubing was used (Table 15-5) along with a 10,000-psi reel and BOP assembly.

TABLE 15-5. Workstrings for High-Pressure Cleanouts (Coats et al., 1996)

	ZnS And Hydrate Plug Workstrings								
	OD (in)	Wall (in)	ID (in)	Weight (lb/ft)	Area (sq. in)	Yield Load (lb)	Yield Pressure (psi)	Yield Strength	Length (ft)
ZnS	1.25	0.087	1.076	1.081	0.318	31,790	13,900	100,000	15,000
Hydrate Plug	1.25	0.134	0.982	1.600	0.470	37,580	16,510	80,000	6,000

A guide tube was added below the injector (Figure 15-37) to provide additional support to the tubing between the chains and the stuffing box.

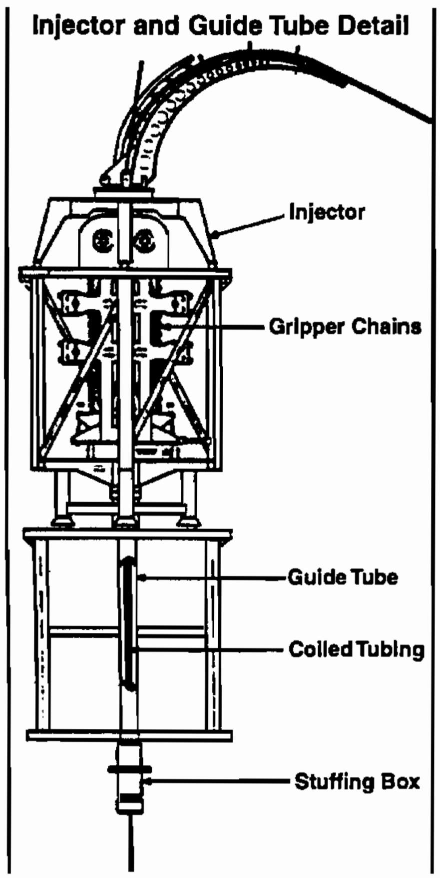


Figure 15-37. Guide Tube
(Coats et al., 1996)

Equipment to clean out the zinc sulphide included a string of high-strength CT, a jetting tool, acid sweeps, and an impact drill. Injection rates above 1 bpm and pressures above 7500 psi were used.

Cost savings were substantial. Conventional repairs were planned at a cost of nearly $6 million. All three wells were repaired for $357,000, a savings of 94%.

Another extreme application is deep wells in Mobile Bay. To clean out these wells, a tapered string of 1¼-in. 80-ksi tubing was used (Table 15-6).

TABLE 15-6. Tapered Workstring for Deep Cleanouts (Coats et al., 1996)

Deep Sand Washing Workstring												
Tube Dimensions					String		String					
OD (in)	Wall (in)	ID (in)	Tubing Weight (lb/ft)	Segment Length (ft)	Length Cumm (ft)	Segment Weight (lb)	Weight Cumm (lb)	Load Yield (lb)	% Of Yield %	Over-Pull (lb)	Safety Factor 100%
1.250	0.102	1.046	1.251	16,000	16,000	20,010	20,010	29,410	68	9,400	32%
1.250	0.109	1.032	1.328	1,000	17,000	1,330	21,340	31,240	68	9,900	32%
1.250	0.118	1.014	1.427	1,000	18,000	1,430	22,770	33,550	67	10,780	33%
1.250	0.125	1.000	1.502	1,000	19,000	1,500	24,270	35,330	68	11,050	32%
1.250	0.134	0.982	1.597	1,000	20,000	1,600	25,870	37,570	68	11,700	32%
1.250	0.156	0.938	1.823	2,500	22,500	4,560	30,430	42,870	70	12,440	30%

High pump pressures are required to achieve hole cleaning in the 21,000 wells. Pump pressures of 7000-8000 psi are required. Injector capacity of 40,000 lb is also recommended.

15.18 RADOIL TOOL (CLEANOUTS IN EXTENDED-REACH PIPELINES)

Radoil Tool Company (Baugh, 1997) presented a summary of analysis and test results for using CT for extended-reach pipeline blockage removal. They performed scale-model testing, full-scale testing, technical surveys, and computer analysis. The project is funded by the DeepStar consortium. The goal is to extend CT capability out to 5 miles for cleaning blockages from a typical pipeline (Figure 15-38). These pipelines include frequent and severe bending that restricts CT penetration.

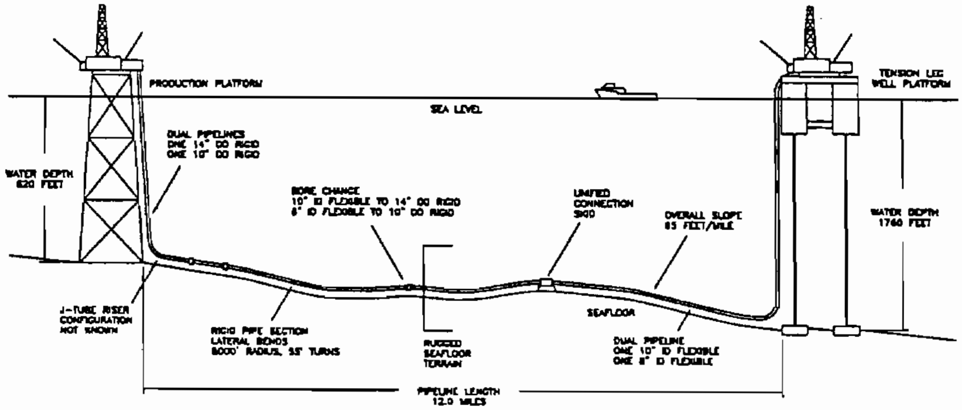


Figure 15-38. Pipeline at Conoco Jolliet TLP (Baugh, 1997)

Scale-model tests were conducted early in the project. Mechanical tubing of ⅜ inch was placed in 1-in. seamless line pipe and bent into the representative configuration. Results are shown in Figure 15-39 with the model flooded with oil.

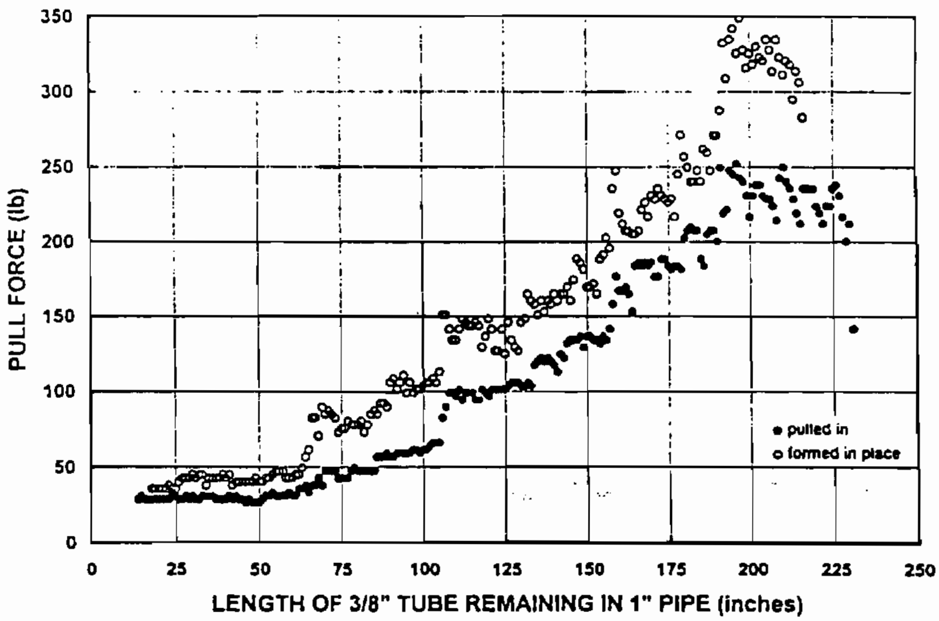


Figure 15-39. Scale-Model Results of Pull Force (Baugh, 1997)

One of the important goals of the project was to define the characteristics of a test pipeline that will simulate conditions in a 5-mile subsea pipeline. The configuration for the test loop (Figure 15-40) includes several bends.

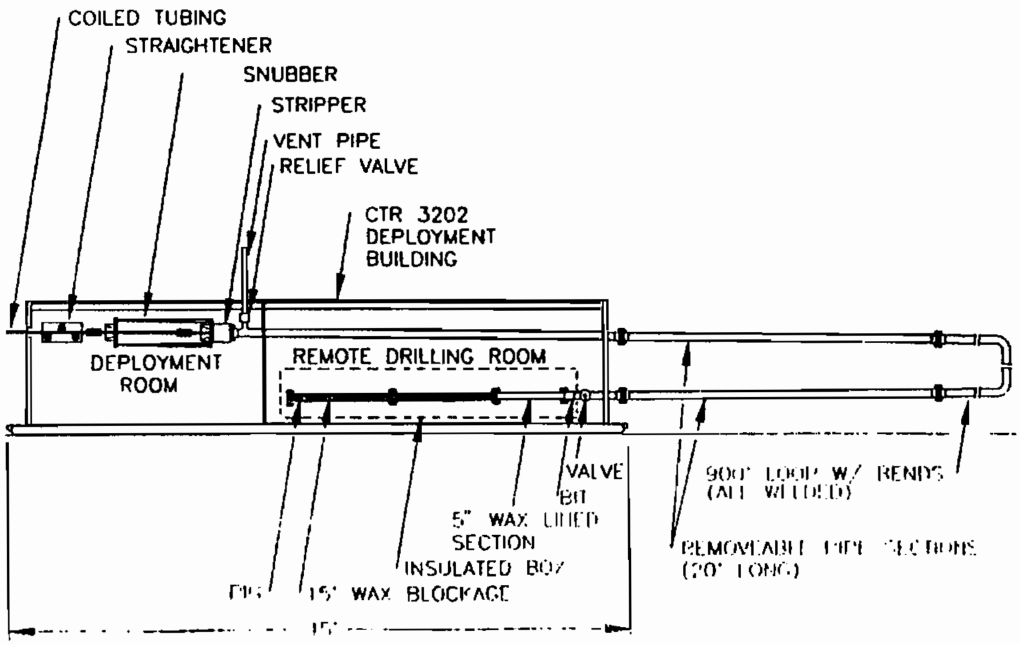


Figure 15-40. Test Loop for Extended-Reach Cleanouts
(Baugh, 1997)

15.19 SCHLUMBERGER DOWELL (CLEANOUTS IN DEEP WELLS)

Schlumberger Dowell and Chevron USA (Larsen et al., 1997) reported the success of CT operations in high-pressure wells in the Gulf of Mexico. High-strength 100-ksi CT has made feasible CT interventions in the Mobile Bay Norphlet wells (22,000 ft TVD, high pressures of 8000 psi shut in, H_2S production). A typical tapered CT string for operations in this field is described in Table 15-7.

TABLE 15-7. CT Design for Deep Wells (Larsen et al., 1997)

Diameter (in)	Gauge (in)	Length (ft)
1.5	0.109	15,500
1.5	0.109 - 0.134	2,200
1.5	0.134	1,000
1.5	0.134 - 0.156	2,000
1.5	0.156	2,800

Corresponding axial loads for the tapered string are shown in Figure 15-41.

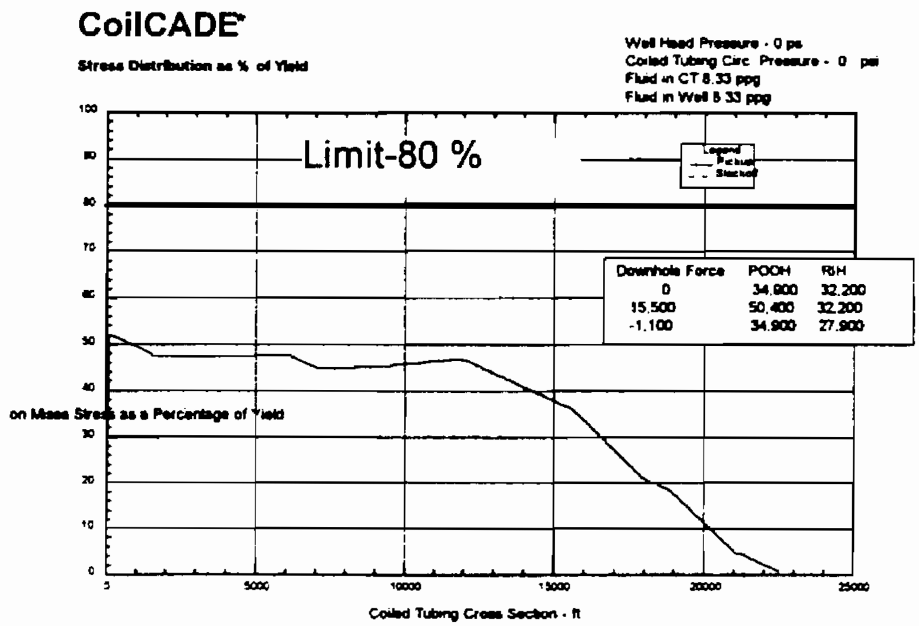


Figure 15-41. Axial Loads on Tapered CT (Larsen et al., 1997)

Operations reportedly completed in the Mobile Bay Norphlet wells include a scale cleanout to 22,000 ft. Cost savings of 60% were realized for the operation.

An HCl matrix acid job was performed in hot-hole conditions (415°F).

A third job was a scale cleanout of downhole safety valves. This operation was completed in less than a day at an estimated cost savings of 90+% compared to a rig workover.

See Larsen et al. (1997) for more details on these cleanout operations at Mobile Bay Norphlet.

15.20 SCHLUMBERGER DOWELL (PUMP RATE AND VISCOSITY MODEL)

Schlumberger Dowell (Walton, 1995) developed a quasi-1D mechanistic model of particle transport in a deviated annulus for use in designing cleanouts with CT. Efficient removal of sand with CT is dependent on selection of the proper fluid and pump rate. The new model predicts the conditions that lead to the deposition of a sand bed, calculates the equilibrium depth of the sand bed, and determines whether the bed slides upward, remains stationary or slides down the well. They presented the mathematical basis for their model and compared it to experimental results reported in the literature. Example results were also presented.

Sand cleanouts are one of the most numerous field operations with CT. Sand is jetted and transported to the surface up the casing by CT annulus. A significant difference between hole cleaning for CT operations, as compared to normal drilling operations, is a change in basic rheological requirements. Whereas typical drilling fluids are designed to keep cuttings in suspension when circulation is stopped, CT cleanout fluid is not required to have this property since circulation is continuous. Nonfoamed cleanout fluids for CT operations are usually pumped in turbulent flow, as compared to drilling fluids, which are often in the laminar regime.

In vertical wellbores, a rule of thumb is to use an annular velocity twice the settling velocity of the fill. Horizontal conditions are more complicated. Several different flowing conditions may be set up, depending on properties of the solids, fluid rheology, and size of the annulus. Symmetric suspension is possible wherein the particles are uniformly distributed across the annular cross section, although this condition is rare due to the high velocities required. Asymmetric suspension is another regime, with more of the particles in the lower section of the annulus. At lower velocities, a bed that gradually moves up the wellbore is developed. The other possible regime is a stationary bed.

Schlumberger Dowell developed a mathematical model to calculate simple guidelines for cleanouts with CT. Output from the model takes the form of a Flow Regime Map, which shows the relationship between flow regimes (bed patterns), flow rates and deviation angles. The other output is a map of minimum-suspension flow rate. Variables plotted are angle of deviation, fluid viscosity and sand pickup concentration.

The theory in the model was compared with experimental results from the literature. Data from the University of Tulsa were used. Predictions of cuttings concentration are compared in Figure 15-42. The theoretical predictions mimic the general trend of the data. Close quantitative agreement was not expected since the experiments were conducted with the inner pipe rotating at 50 rpm.

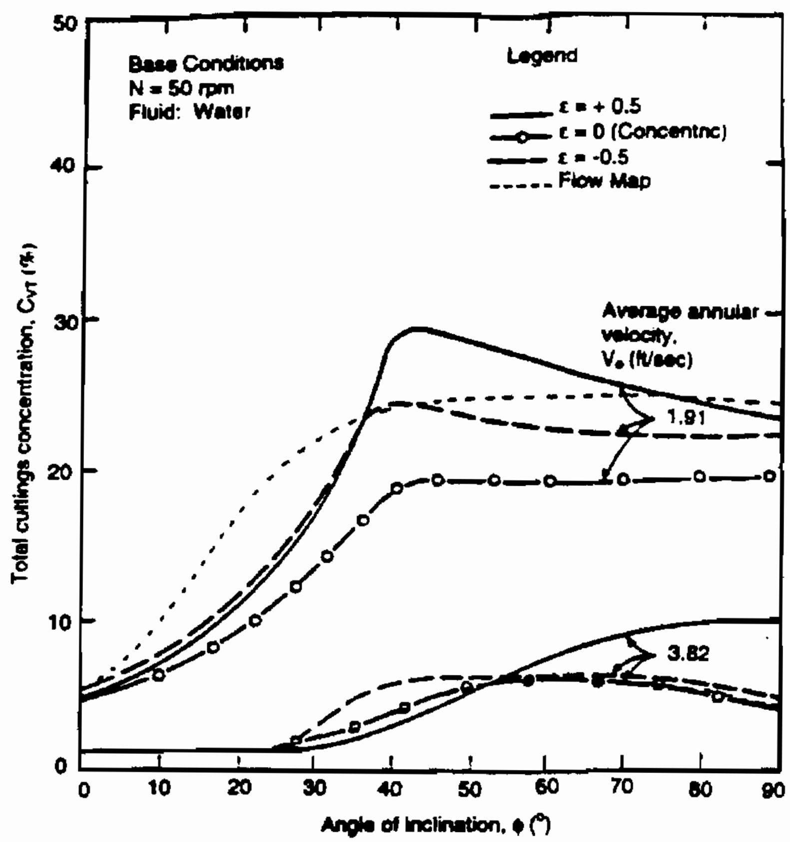


Figure 15-42. Particle Concentration with Deviation Angle
(Walton, 1995)

Predicted and measured bed height are compared in Figure 15-43. General trends are predicted as before. Agreement is closest at lower flow rates and higher angles of deviation.

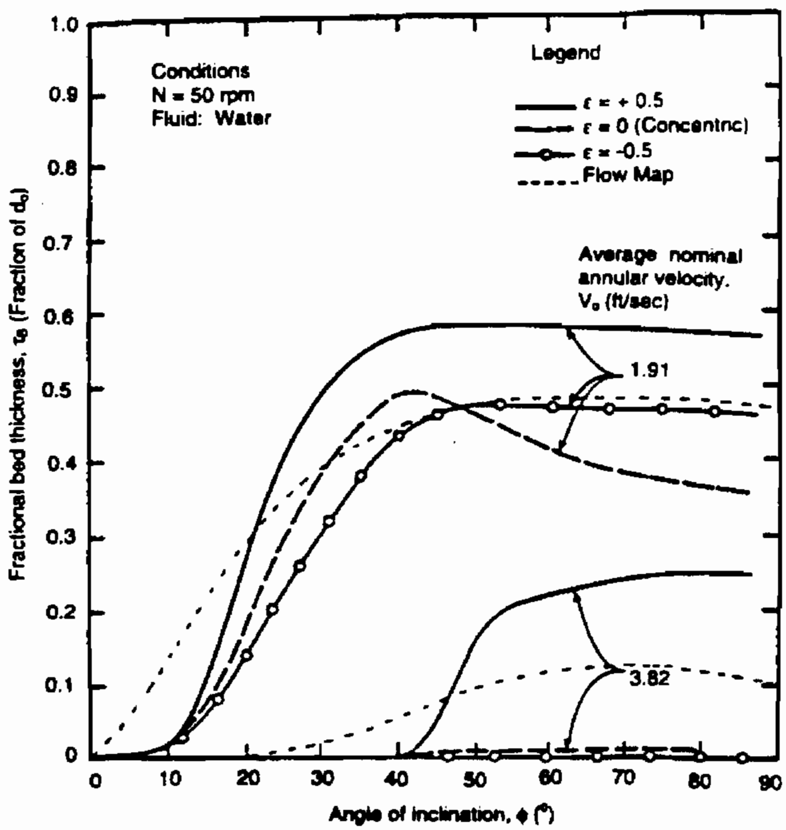


Figure 15-43. Particle Bed Height with Deviation Angle
(Walton, 1995)

Example results were presented for a cleanout job with CT in a 5½-in. cased horizontal well. The flow regime (bed pattern) map in Figure 15-44 shows that a flow rate of about 17 bpm would be required to avoid bed formation for a horizontal wellbore. This flow rate is unacceptably high. The job design could be modified to allow a lower flow rate by using larger CT, a different fluid, or a different sand pickup concentration (a function of run-in speed).

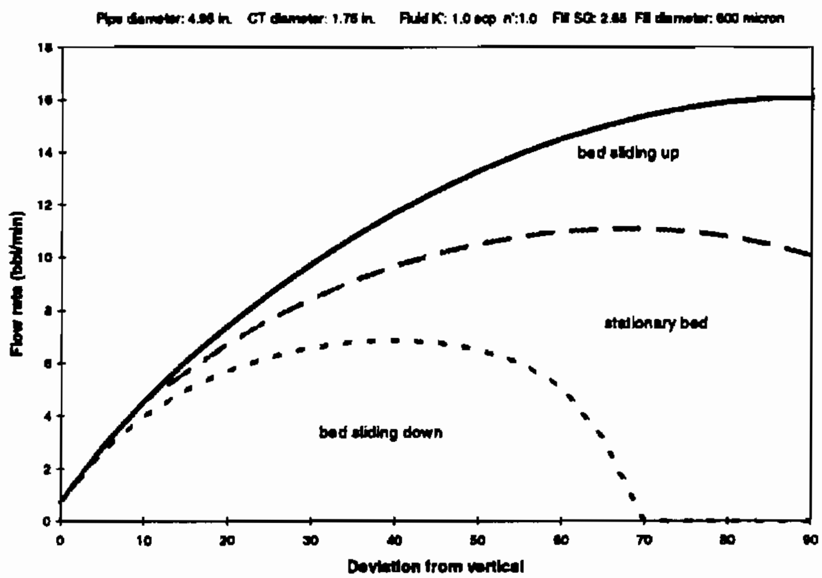


Figure 15-44. Bed Deposition Map for Example Horizontal Well (Walton, 1995)

The map of minimum flow rates to achieve suspension (Figure 15-45) shows that the results are not sensitive to particle pickup concentration, except at low concentrations. The minimum flow rate has a broad range, strongly depending on fluid viscosity. High flow rates are required with either high- or low-viscosity fluids. With a low-viscosity fluid, high flow rates are required to generate sufficient turbulence to keep the particles suspended. With a low-viscosity fluid, high pump rates are required to achieve even a low level of turbulence.

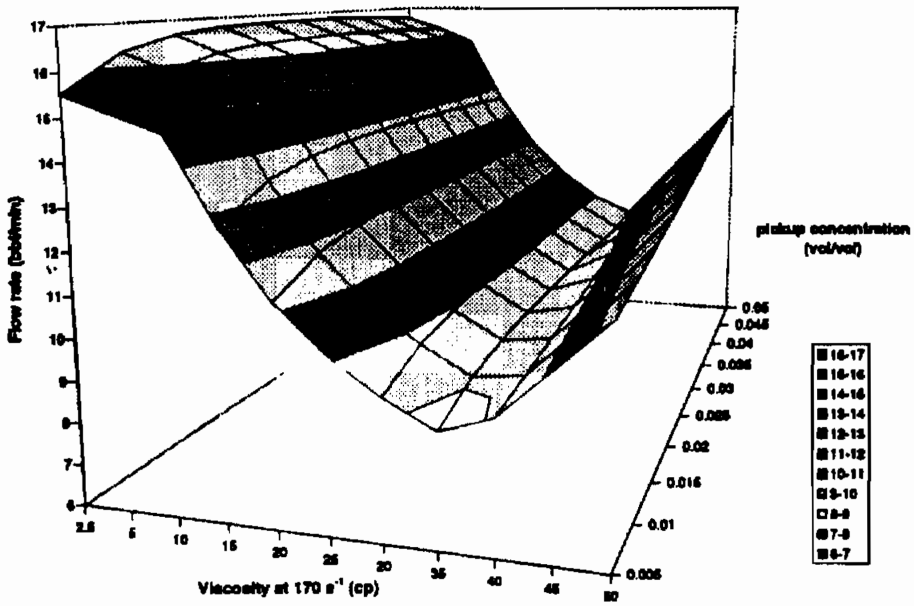


Figure 15-45. Minimum Flow Rate to Achieve Suspension
(Walton, 1995)

Normal design considerations would dictate that the lowest possible flow rate be chosen due to pumping constraints. Therefore, fluid viscosity and sand concentration should be set to minimize required flow rate. For the example shown in Figure 15-45, a minimum pump rate of 8 bpm would be suitable with a fluid viscosity of 32 cp and pickup concentration of 10% or less.

15.21 SCHLUMBERGER DOWELL (UNLOADING WELLS WITH CT)

Schlumberger Dowell (Gu, 1995) presented an analysis of transient flow for operations involving nitrogen injection through CT to unload wells. Transient behavior is very important for determining the optimum nitrogen volume, injection time, injection depth etc. for unloading a well. They used a CT simulator to investigate these interactions. Tubing OD, workover fluid, nitrogen rate and nitrogen volume were analyzed with respect to sensitivity on job design. Job cost can be minimized by optimizing injection rate and time to minimize nitrogen volume.

For wells where reservoir volume is sufficient to produce when heavier fluids are removed from the wellbore, a short-term lifting process can be used to unload the well and restore production. The composition of the wellbore fluid changes during the unloading operation; steady-state conditions are not reached until the well is unloaded and production restored.

Schlumberger Dowell ran several test cases to investigate the interactions of various parameters on the success of the unloading operation. One parameter is the composition (i.e., weight) of the fluid in the wellbore. The assumed test conditions included a TD of 12,200 ft, 4-in. casing, no tubing, 4700-psi reservoir, and 15,000 ft of 1¼-in. CT. Nitrogen is injected at a rate of 300 scfm during run-in. At 12,000 ft, injection is increased to 600 scfm for 90 min. Flow rates for this operation are summarized in Figure 15-46.

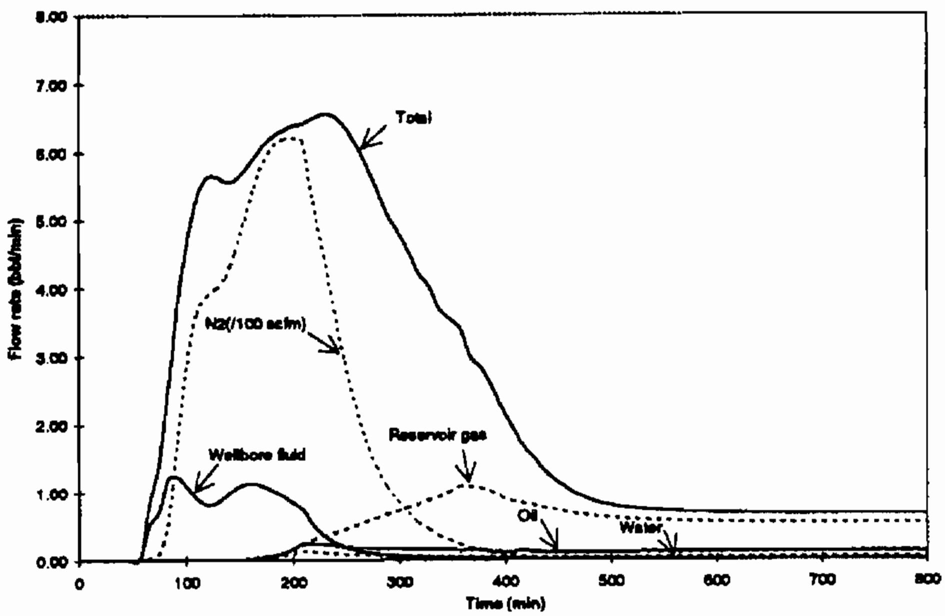


Figure 15-46. Nitrogen Injection to Unload Well (Gu, 1995)

The operation depicted in Figure 5-46 assumes that the wellbore fluid has an SG of 1.0. For these parameters, the wellbore will be successfully unloaded and begin producing after injection is stopped. However, if the fluid density is increased to SG=1.15, not enough fluid will be unloaded to sustain production after injection is halted. More injection time would be needed with a heavier fluid in the wellbore.

Optimizing injection rate is another important aspect of job design. As injection rate is increased, frictional losses in the annulus increase. The drawdown imposed on the formation is a combination of hydrostatic and friction pressure at the formation. It is desired to minimize nitrogen volume and injection time to minimize job costs.

For this analysis, job conditions included a TD of 11,050 ft, 2⅞-in. production tubing to 10,500 ft, 4½-in. casing to TD, 2800-psi reservoir, and 13,000 ft of 1½-in. CT. A constant total volume of 91,500 scf was injected. Several nitrogen injection rates were used. At higher rates, friction pressure lowers drawdown pressure at the formation, and unloading is not successful (Table 15-8).

TABLE 15-8. Effect of Injection Rate (Gu, 1995)

UNLOADING RESULTS FOR DIFFERENT NITROGEN RATES (CT OD - 1.5 IN., N_2 volume - 91,500 scf)		
N_2 Rate (scfm)	Stop Time (min)	Unloading Outcome
300	350	Successful
600	230	Successful
900	190	Unsuccessful
1200	170	Unsuccessful

CT size also impacts job success. For the case in Table 15-8, an injection rate of 900 scfm would be successful if CT diameter were decreased to 1¼ inches.

Depth of injection is another important parameter. The model well for this analysis had a TD of 10,000 ft, 2⅞-in. tubing to TD, a productivity index of 0.5 BPD/psi, and 15,000 ft of 1½-in. CT. Liquid return rate for a range of injection rates is shown in Figure 15-47. For 300 scfm, the liquid rate increases only slightly for injection depths greater than 4000 ft. A maximum practical depth can be estimated for any injection rate. Running the CT deeper than this may not provide any benefits.

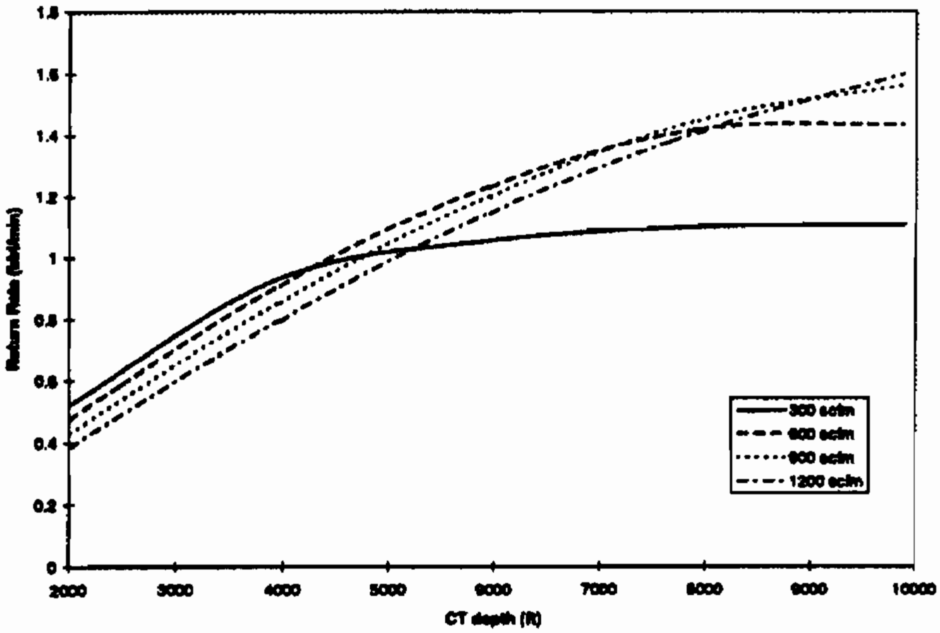


Figure 15-47. Return Rate with 1½-in. CT (Gu, 1995)

Additional analyses are described in *Artificial Lift*.

15.22 SONOMA CORPORATION (IMPACT DRILL JARS FOR CLEANOUTS)

Sonoma Corporation (Beynon and Thompson, 1997) described the performance advantages of their impact drilling jars (trade name "HIPP-TRIPPER") for scale clean-outs on CT. A significant percentage of CT field operations are clean outs, and many of these operations include motors of some sort. Mud motors are limited in some situations, such as high temperatures and hostile fluids (Table 15-9), and impact drills are often a very effective alternative.

TABLE 15-9. Comparison of Drill Jars with PDMs
(Beynon and Thompson, 1997)

"HIPP-TRIPPER®" General Comparisons of "Hipp-Tripper" versus Conventional Equipment			
Considerations	**Conventional Equipment**	**Problems Associated With Conventional Equipment**	**Advantages of "Hipp-Tripper"**
High Temperatures	Drill Motor	• Effect of high temperatures on operating life. • High repair cost	• Operates efficiently in temperatures in excess of 600°F. • Low maintenance cost.
Fluid Medium	Drill Motor	• Use of certain fluid medium decreases the operating life of some conventional motors. • High repair cost.	• Hipp-Tripper operates efficiently using xylene, diesel, oil, drilling mud and water. • Hipp-Tripper operates efficiently using nitrogen, air and foam. • Hipp-Tripper operates efficiently in HCL acid and H2S using its "Hostile Environment Tool". • Low maintenance cost.
Circulation Rates	Drill Motor	• Fluid pump rates must be restricted to prevent damage to completion equipment/liner/tools as a result of the bit/mill/under-reamer spinning needlessly.	• Reciprocation and rotation of the "Hipp-Tripper" occurs only when weight to the bit is applied. • Full circulation without rotation is possible going into and out of the well without danger of damage to completion equipment/liner/tools.
Reverse Torque	Drill Motor	• Danger of tool backing off due to storing reverse torque.	• The "Hipp-Tripper" will not store reverse torque.
Length of Tool	Drill Motor	• Due to the length of most Drill Motors, long lengths of lubricator or special deployment equipment is necessary.	• The average length of the Single Directional "Hipp-Tripper" is 44 inches. • The addition of a conventional BHA assembly (Coil Connector, Double Flapper, Hydraulic Disconnect and Circulating Sub) will add approximately 47 inches. • Average overall lengths equal 8 Feet.

Key advantages of drilling jars include: 1) they don't operate until the bit meets resistance (the tool life is not consumed during trips), 2) they don't store reverse torque, 3) they can operate at temperature greater than 600°F, 4) make-up length is short (Table 15-10), 5) can operate in almost any fluid medium, and 6) have low costs for rebuild.

TABLE 15-10. Drill Jar Specifications (Beynon and Thompson, 1997)

MODEL O.D. (IN.)	OPERATING PRESSURE RANGE (PSI)	WEIGHT ON TOOL (LBS.)	TORQUE RANGE (Ft - Lbs)	Stroke (IN.)	RPM	MADE UP LENGTH (IN.)
1.375	400 - 1,000	400 - 1,000	40 - 150	.250 - 1.00	7 - 45	27.125
1.687	600 - 2,000	400 - 2,000	100 - 250	.250 - 1.00	7 - 45	36.375
2.125	600 - 2,000	400 - 2,400	120 - 360	.250 - 1.00	7 - 45	43.250
3.625	600 - 2,000	400 - 2,400	120 - 500	.250 - 1.00	7 - 45	63.500
4.750	250 - 2,500	400 - 31,000	50 - 750	.250 - 1.00	7 - 45	43.500

Sonoma Corporation cited results from several field case histories. In Lake Maracaibo, clean-outs in deep, hot holes using conventional motors required 2-3 days per well. Damage to the motors was common. With impact drilling jars, clean-out time dropped to 6 hr/well. In addition, acid was spotted through the tool string prior to coming out of the hole.

Several other case histories are described in Beynon and Thompson (1997).

15.23 TRICO INDUSTRIES (JET PUMPS)

Trico Industries (Tait, 1995) enumerated the advantages of jet pumps run on CT for artificial-lift applications in horizontal and vertical wells. A primary advantage is the lack of moving parts in the assembly. Energy is provided to the jet pump by pumping from surface (Figure 15-48). The power fluid may be produced oil or water, treated sea water, diesel , or other fluids. The primary advantages of jet pumps are a wide range of flow rates, deep lifting capacity, and the ability to handle fluids with high sand concentrations, which are corrosive, are high temperature or have significant free gas.

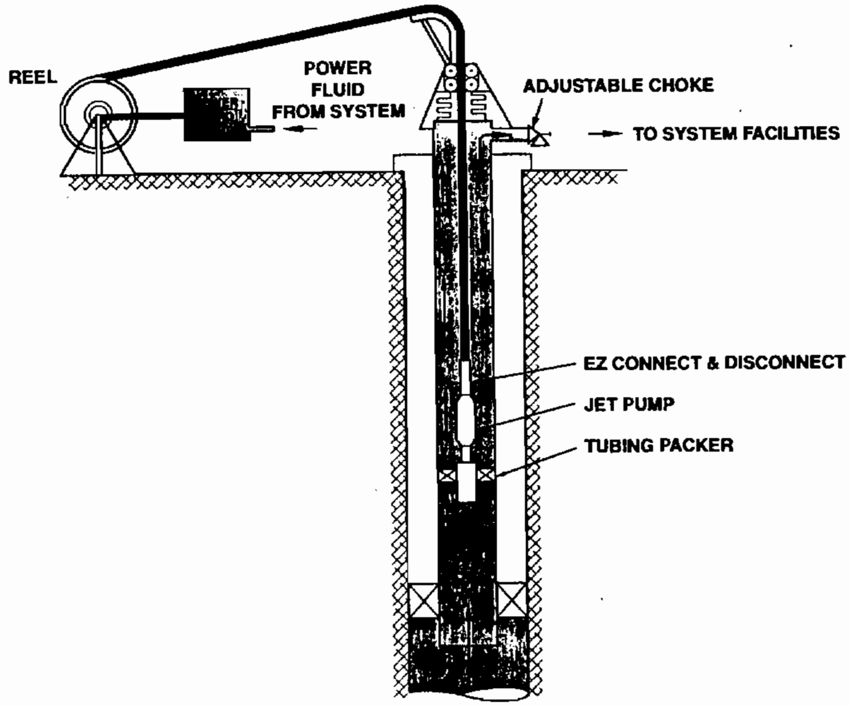


Figure 15-48. Jet Pump for Unloading Wells (Tait, 1995)

Lifting action is provided by energy transfer between the power fluid and the wellbore fluid. High potential energy in the pressurized power fluid is converted to kinetic energy as the fluid passes through the nozzle (Figure 15-49). A low-pressure zone is created in the throat, and the wellbore fluid is drawn into the power stream.

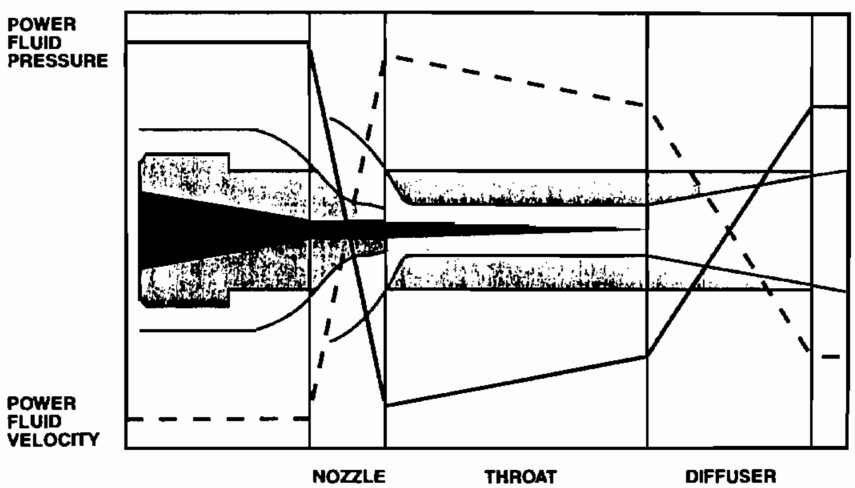


Figure 15-49. Jet Pump Operational Principle (Tait, 1995)

Jet pumps have been used since the 1970s for long-term artificial-lift applications around the globe. These can be sized for production rates ranging from 50 to 15,000 BPD at depths exceeding 15,000 ft.

ZONE ISOLATION

15.24 BPX, PETROLINE WIRELINE AND NOWSCO (WELL PLUGGING WITH CT)

BP Exploration Operating Company, Petroline Wireline Services, and Nowsco UK (Munro et al., 1996) described how deep-set plugs were successfully deployed, tested and retrieved using CT in the Foinaven Field in the North Sea. Wells are drilled and completed, and in some cases left suspended using CT until weather conditions are favorable. Problems with the operations were described, including significant fluctuations of the CT weight indicator, difficulty controlling the impact hammer during jarring operations, and problems with debris in the completion tubing and its effect on plug setting and retrieval.

A typical suspended well (Figure 15-50) includes a deep-set wireline plug, a permanent production packer, kill-weight completion fluid above the plug and packer, closed SSSV, and wireline plugs set in the tubing hanger.

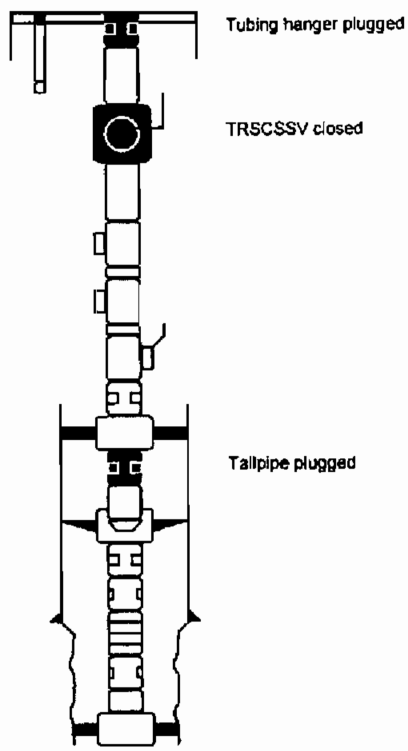


Figure 15-50. Typical Suspended Well (Munro et al., 1996)

Rig crane lifting limits defined the largest CT that could be used: a 1¾-in. tapered string. A force/stress analysis showed that buckling and lock-up of the CT would be the critical limit while setting plugs. Slack-off forces available at the BHA in a typical Foinaven well (Figure 15-51) indicated that downhole forces would not be sufficient to set plugs (12,500 lb required to shear pins). It was decided to use a bidirectional impact hammer to increase the force at the BHA.

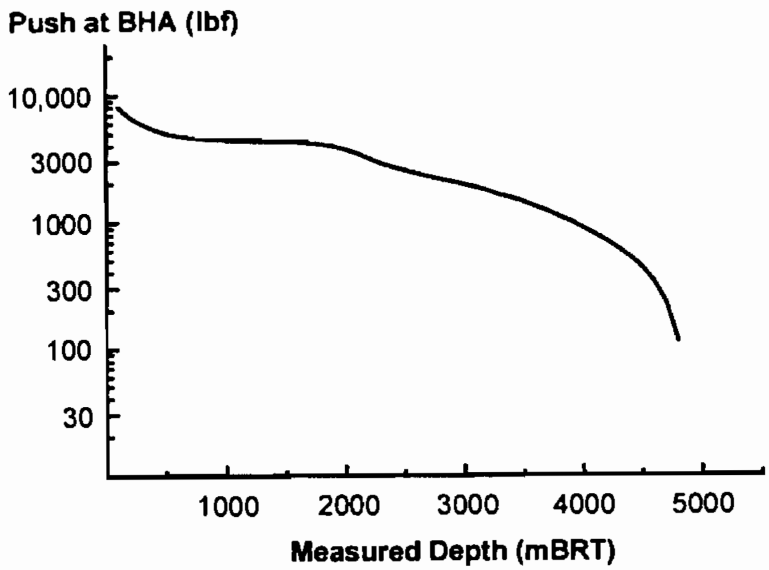


Figure 15-51. Modeled WOB Available (Munro et al., 1996)

The procedure for selecting equipment within site limitations is summarized in Figure 15-52. This procedure will be needed again for some wells for reaching TD; the currently designed string only needs to penetrate to the top of the liner.

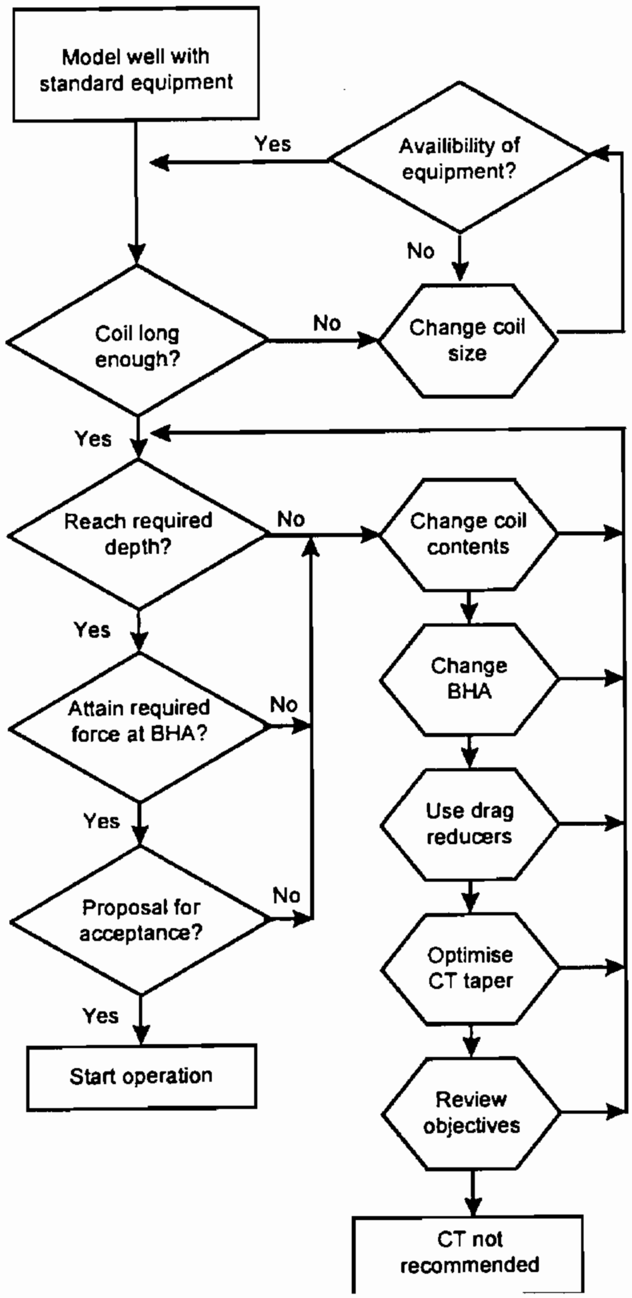


Figure 15-52. Force/Stress Analysis
(Munro et al., 1996)

The primary problem with these plugging operations was debris. Rig heave also caused difficulty with weight indication. For future operations, a pump-through force measurement sub is under development.

15.25 CHEVRON USA AND DOWELL (PLACING CEMENT PACKERS)

Chevron USA Production and Dowell (Nowak and Patout, 1997) described the design and execution of cement-packer placement for recompleting multiple zones. This successful operation is believed to represent the largest cement packer placed through CT.

A variety of problems are associated with placing cement packers conventionally (Figure 15-53). Slurry density may vary 0.5 ppg if a continuous mix process is used. Inadequate slurry displacement may cause poor sweeping in the tubing.

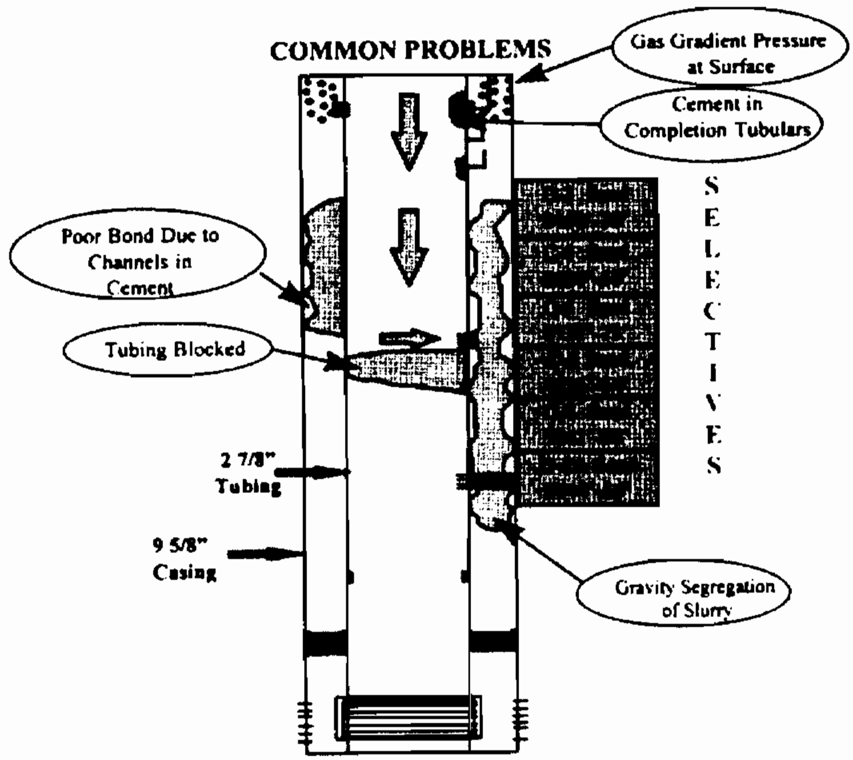


Figure 15-53. Problems with Cement Packers
(Nowak and Patout, 1997)

CT size was selected as 1½ in. instead of the more common 1¼ inch. Hydraulics predictions (Figure 15-54) suggested that pump rates could be 40% higher with 1½-in. CT. Force calculations showed that axial loads would rise to 57% of yield in the worst-case condition of picking up the CT full of 16.2 ppg slurry.

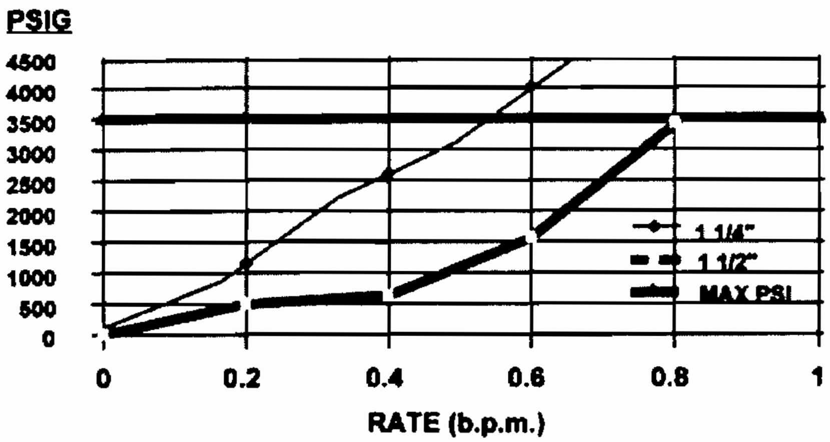


Figure 15-54. Pressure Drops with 16.2 ppg Slurry
(Nowak and Patout, 1997)

Cement was placed through CT across a 1275-ft interval below 8380 ft MD (Figure 15-55). A detailed description of the placement procedure is presented in their paper.

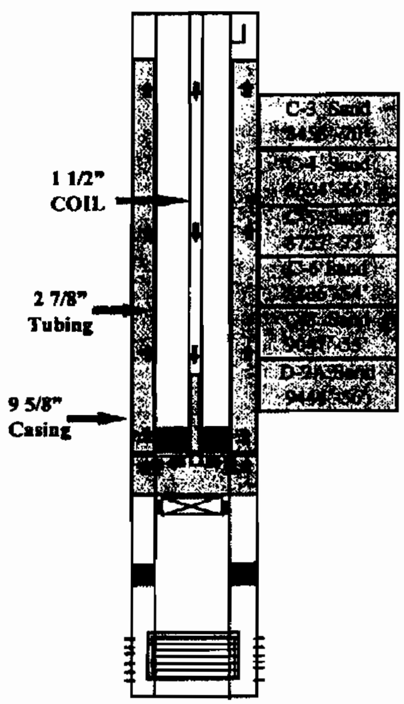


Figure 15-55. CT Placement of
Cement Packer
(Nowak and Patout, 1997)

Cement-packer recompletions with CT proved to be a cost-effective method to recover additional reserves from stacked sands previous not economical to recover. Larger cement slurries can be placed through CT than was previously considered feasible.

15.26 HALLIBURTON ENERGY SERVICES (NEW SLIDING SLEEVE FOR CT)

Halliburton Energy Services (Plauche and Koshak, 1997) presented a case history where new sliding-sleeve technology was used to complete an abnormally pressured, multizone horizontal well. The successful completion allowed production from both or either zone. A critical factor in the success of the project was a new sliding sleeve that could be shifted by CT with a force of only 500 lb, as compared to 2000+ lb for conventional sleeves.

The new sleeve made use of an advanced engineering composite which allowed a significant reduction in shifting force over a PEEK seal (Figure 15-56).

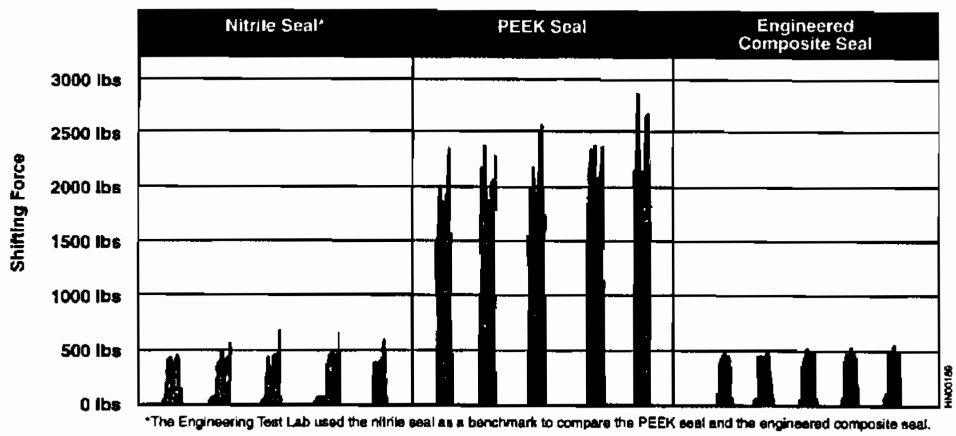


Figure 15-56. Shifting Forces for Sliding Sleeves
(Plauche and Koshak, 1997)

The seal port design specifically accounted for high differential pressures to redirect the flow path more effectively to minimize the potential for damaging the sealing element. The final completion (Figure 15-57) included nine sliding sleeves. Eight were integral to the concentric production string; the ninth was placed in the float shoe assembly below the lowermost gravel-pack screen.

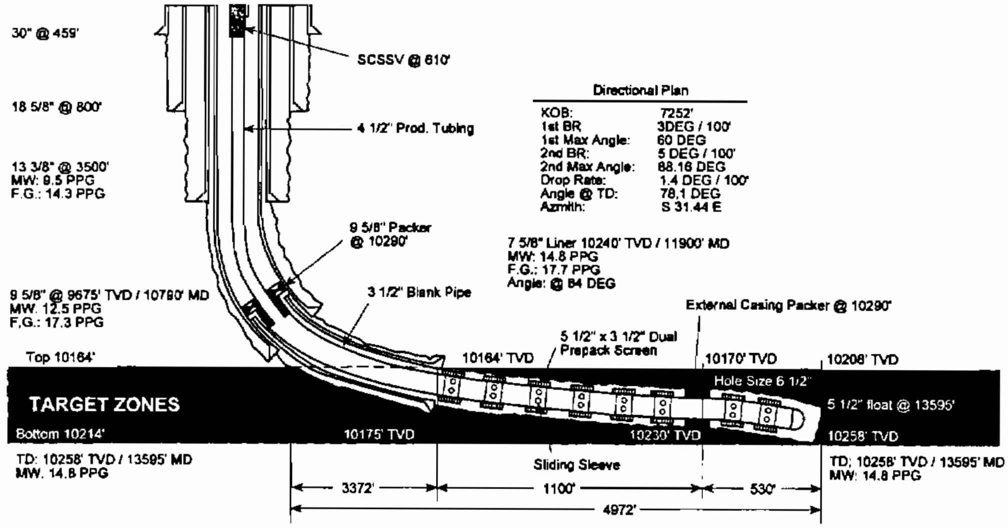


Figure 15-57. Sliding Sleeve Completion (Plauche and Koshak, 1997)

Fluid losses to the formation were minimized during completion operations. The sliding-sleeve completion provides zonal isolation in two zones, which should postpone or eliminate the need for future intervention.

15.27 MOBIL E&P AND MOBIL NIGERIA (CT RESIN SQUEEZE)

Mobil E&P Technical Center and Mobil Producing Nigeria (Ng and Adisa, 1997) reviewed research and field experience with resin squeezes to shut off water production in offshore wells. CT placement of resin is not used commonly because of concern that the resin may set up in the CT string. A computer model was modified for resin squeezes and can be used for other reacting polymer-gel systems for near-wellbore or deep gel placements.

In one candidate well offshore Nigeria (Figure 15-58), the target zone was the producing interval in a 15-ft milled window. CT workover is the preferred option due to significant costs of a conventional workover.

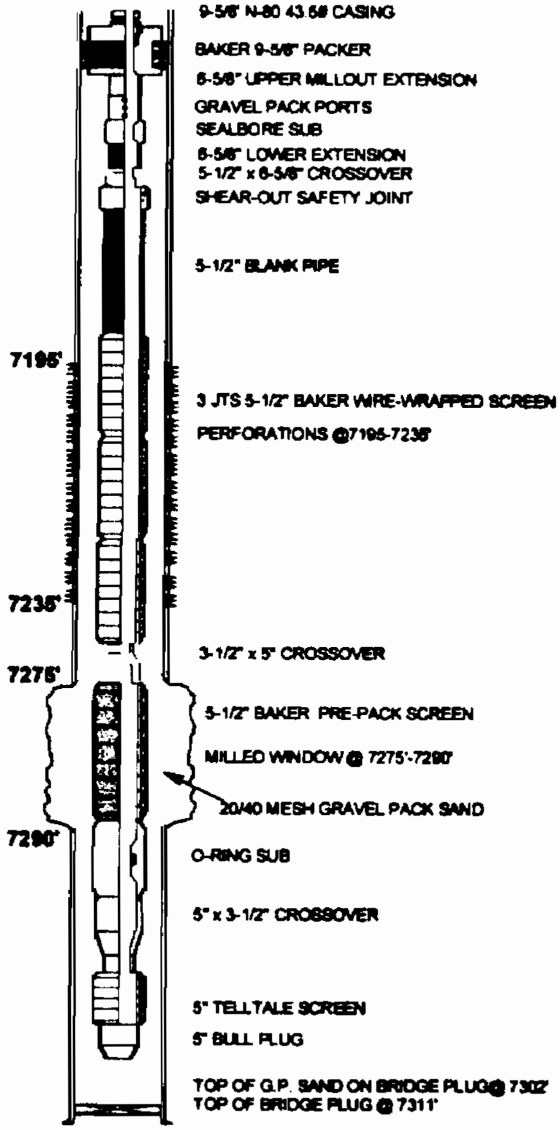


Figure 15-58. Iyak SE 2A Completion
(Ng and Adisa, 1997)

The CT string for the selective placement of resin into the gravel-pack zone is shown in Figure 15-59. Since the phenolic resin had not been placed with CT previously, a full-scale yard test was performed with 3600 ft of 1½-in. CT. The effectiveness of a wiper plug for displacing the resin was also demonstrated.

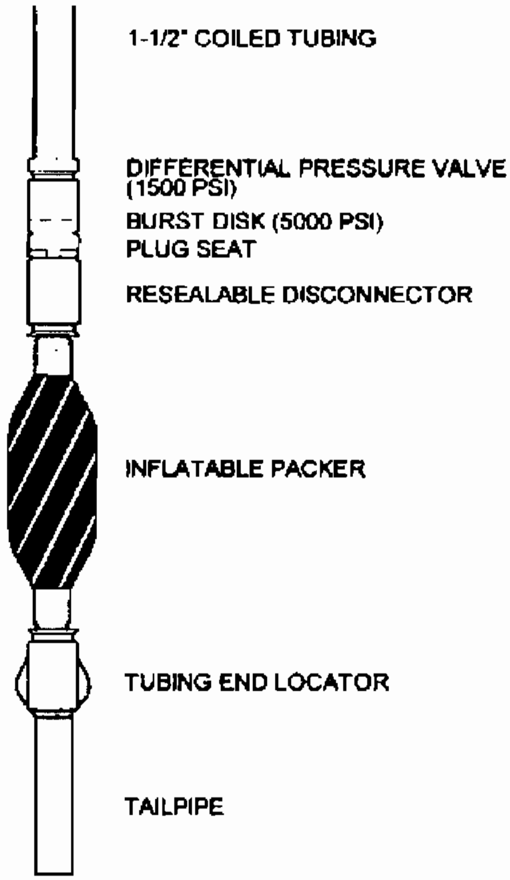


Figure 15-59. CT Resin Squeeze BHA
(Ng and Adisa, 1997)

Mobil designed a low-viscosity phenolic resin for CT placement that will allow a 4-6 hour pump time at a bottom-hole temperature of 190°F. Readers are directed to their paper for more details.

15.28 PREEMINENT ENERGY, SAS INDUSTRIES AND BJ (MAGNESIAN CEMENT)

Preeminent Energy Services, SAS Industries and BJ Services (Coats et al., 1996) described the benefits and applications of magnesian cement placed with CT. This unique cementing material can be placed downhole, form a mechanical sea for zone isolation, and later be completely dissolved by acid and removed. These properties make the cement ideal for a variety of operations such as setting temporary plugs across productive zones to work over lower zones, squeezing and blocking zones that are expected to the produced later in the well's productive life, and as an effective lost-circulation material.

General benefits for using CT for placing cement downhole include faster trip times, improved accuracy in fluid placement, and effective well control during the entire operation. Conventional cements are not appropriate for jobs where complete removal of the cement is required after the job is completed. Magnesian cement is a recent development for these applications. This cement is a mixture of magnesium and calcium oxides, carbonates and sulfates. While a high compressive-strength material in the presence of water, magnesian cement is completely soluble in hydrochloric acid.

Typical densities range from 12.5 to 14 ppg, although weighting up to 21 ppg is possible with common weighting agents. Temperatures for use are from 60 to 230°F. Magnesian cement is highly resistant to contamination from other fluids. As a benefit, expensive flushes or spacers are not necessary. Another benefit is its tendency to expand while curing, thereby reducing the potential for small channels.

Magnesian cement is removed by a focuses acid-wash program using CT and special wash nozzles. Adequate wash time is required for removing the cement from perforation tunnels.

Prior to running a cementing job in CT, several planning steps using computer models are prudent. The well's directional survey is used to model drag to ascertain the tubing can be run to depth with the equipment available. Fatigue cycle life models are used to confirm safety of the proposed operations. Hydraulics models are run to verify injection pressures, pressure drops, etc. Buckling models are also necessary for many applications.

15.29 REFERENCES

Adams, L.S. and Overstreet, C.C., 1997: "Design and Implementation of a 22,600 ft Underbalanced Coiled Tubing Scale Cleanout in the Gomez Field, Pecos County, Texas," SPE 38770, presented at Annual Technical Conference, San Antonio, Texas, October 5-8.

Baugh, Benton, 1997: "Extended Reach Pipeline Blockage Remediation," presented at the 5th International Conference on Coiled Tubing and Well Intervention, Houston, February 4-6.

Baugh, Benton, 1997: "Testing and Evaluation of Coiled Tubing methods to Remove Blockages from Long Offset Subsea Pipelines," OTC 8524, presented at 1997 Offshore Technology Conference, Houston, May 5-8.

Coats, Alan and Clawson, Greg, 1997: "Coiled Tubing Resin Sand Control in a Gulf of Mexico High Pressure Gas Well," presented at the 5th International Conference on Coiled Tubing and Well Intervention, Houston, February 4-6.

Coats, Alan et al., 1996: "Magnesian Cement, CT Offer Benefits," *The American Oil & Gas Reporter*, March.

Fried, Spencer et al., 1997: "The Optimized Cleanup and Evaluation of Horizontal Wells Using Improved Jet Pump Technology," paper no. 97-126, presented at CADE/CAODC Spring Drilling Conference, Calgary, April 8-10.

Kinnear, M.R. and John, H., 1996: "Repair of a Failed Gas Lift Completion Using a 1500 ft Long 3½-in. Coiled Tubing Insert Straddle," SPE 36908, presented at 1996 European Petroleum Conference, Milan, October 22-24.

Larsen, H.A., 1997: "An Operational Overview of the Use of High Pressure Coiled Tubing in the Gulf of Mexico," SPE 38418, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Larsen, H.A. et al., 1997: "Utilizing Coiled Tubing in Mobile Bay's 22,000 TVD Gas Wells Yield Economical and Technical Advancements," SPE 38423, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Larsen, H.A. et al., 1997: "Using Coiled Tubing in HPHT Corrosive Gas Wells," *JPT*, June.

Love, Douglas et al., 1997: "Coiled Tubing Injection-Well Cleanouts with Tapered-OD Strings," SPE 38420, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Morrison, Dan et al., 1997: "High Pressure Coiled Tubing Job Prepares Gulf Coast Well," SPE 38419, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Munro, C. et al., 1996: "Well Plugging Operations in West of Shetland Horizontal Wells Using Coiled Tubing Techniques," SPE 36909, presented at SPE European Petroleum Conference, Milan, October 22-24.

Ng, R.C. and Adisa, O.L., 1997: "Coiled Tubing Resin Squeeze to Mitigate Water Production in Offshore Gravelpack Wells," SPE 38836, presented at Annual Technical Conference, San Antonio, Texas, October 5-8.

Nowak, T.W. and Patout, T.S., 1997: "Rigless Multizone Recompletion Using a Cement Packer Placed with Coiled Tubing: A Case History," *SPE Drilling & Completion*, December.

Sas-Jaworsky, Alex and Reed, Troy, 1997: "Predicting Friction Pressure Losses in Coiled Tubing Operations," *World Oil*, September.

Sehnal, Z. et al., 1997: "Coiled Tubing Gravel Pack: Planning, Execution, and Verification," *JPT*, February.

Strickland, David, 1997: "Concentric Workovers in a Well Recovery Operation," presented at the 5th International Conference on Coiled Tubing and Well Intervention, Houston, February 4-6.

Turton, S.D. et al., 1997: "Using Coiled Tubing to Remove Silicate Scale from Geothermal Wells," SPE 38417, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Walton, I.C., 1997: "Real-Time Well-Site Monitoring and Evaluation of Coiled Tubing Cleanouts," SPE 37508, presented at SPE Production Operations Symposium, Oklahoma City, March 9-11.

Zimmerman, J.C. et al., 1997: "High-Pressure Coiled-Tubing Technology Solves Resin-Sand-Control Problems," *JPT*, June.

Appendix A
Coiled-Tubing References

Appendix A
Coiled-Tubing References

Acock, A.M. et al., 1996: "Real-Time Treatment Optimization," SPE 36331, presented at 1st SPE Gulf Coast Section/ICoTA North American Coiled Tubing Roundtable, Conroe, Texas, February 26-28.

Adam, J. and Berry, M., 1995: "Through Completion Underbalanced Coiled Tubing Side Track of Well Dalen-2," presented at the IADC Well Control Conference for Europe, Milan, June 9.

Adams, Larry, 1995: "LDCT Gaining Momentum as Production Tubing," *The American Oil & Gas Reporter*, March.

Adams, L.S. and Overstreet, C.C., 1997: "Design and Implementation of a 22,600 ft Underbalanced Coiled Tubing Scale Cleanout in the Gomez Field, Pecos County, Texas," SPE 38770, presented at Annual Technical Conference, San Antonio, Texas, October 5-8.

Al-Harthy, S.S. and Kalam, M.Z., 1997: "Coiled Tubing Applications in the Sultanate of Oman," SPE 38396, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Avakov, V. and Fowler, H., 1996: "Computing Collapse Pressure for Coiled Tubing," SPE 36340, presented at 1st SPE/ICoTA North American Coiled Tubing Roundtable, Montgomery, Texas, February 26-28.

Avakov, Vladimir A. and Martin, John, 1997: "Large Coiled Tubing Fatigue Life," SPE 38407, presented at 2nd Annual SPE/ICOTA North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Azovz, I., et al., 1996" "Experimental Investigation of Frictional Pressure Losses in Coiled Tubing," SPE 37328, presented at Eastern Regional Meeting, Columbus, Ohio, October 23-25.

Baker, C. et al., 1995: "Practical Application of Perforating with Coiled Tubing in Norman Wells," presented at 46th Annual Technical Meeting of the Petroleum Society of CIM, Banff, Alberta, Canada, May 14-17.

Baugh, Benton, 1997: "Testing and Evaluation of Coiled Tubing methods to Remove Blockages from Long Offset Subsea Pipelines," OTC 8524, presented at 1997 Offshore Technology Conference, Houston, May 5-8.

Baugh, Benton R., 1997: "Extended Reach Pipeline Blockage Remediation," presented at 5th International Conference On: Coiled Tubing and Well Intervention, Houston, Texas, February 4-6, 1997.

Bernat, Henry, 1998: "Coil Tubing Recovery Using Pipe Vibration Technology," published by Vibration Technology LLC, Shreveport, Louisiana.

Beynon, Douglas and Thompson, Daniel, 1997: "Performance Comparisons of 'Hipp-Tripper' Impact Drill-Jars with Conventional Downhole Motors," presented at 5th International Conference on CT and Well Intervention, Houston, February 4-6.

Bhalla, K. and Walton, I.C., 1996: "The Effect of Fluid Flow on Coiled Tubing Reach," SPE 36464, presented at the 1996 SPE Annual Technical Conference and Exhibition held in Denver, Colorado, October 6-9.

Bhalla, Kenneth, 1995: "Coiled Tubing Extended Reach Technology," SPE 30404, presented at the SPE Offshore Europe Conference held in Aberdeen, September 5-8.

Borbely, L. et al., 1997: "Coiled Tubing Horizontal Underbalanced Drilling Project; Costs and Operational Analyses," SPE 38399, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Brown, P., et al., 1995: "Economic Benefits of Advanced CT Life Monitoring," SPE 36337, presented at 1st SPE/ICoTA North American CT Roundtable, Montgomery, Texas, February 26-28.

Brown, Paul A. and Dickerson, J.L., 1997: "Development and Use of an Analytical Model to Predict Coiled Tubing Diameter Growth," SPE 38409, presented at 2nd Annual SPE/ICOTA North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Burge, Phil, 1996: "Project Copernicus - 2nd Generation CT/SHD Rig," SPE 36342, presented at the SPE/ICoTA North America Coiled Tubing Roundtable, Montgomery, Texas, February 26-28, 1996.

Cameron, G. et al., 1997: "Amorphous Diffusion Bonding: New Technology Toward a Seamless-Reeled-Tubing System," *JPT*, May.

Cayard, M.S. and Kane, R.D., 1997: "Serviceability of Coiled Tubing for Sour Oil and Gas Wells," SPE 38410, presented at 2nd Annual SPE/ICOTA North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Christie, Mike and Gavin, Bill, 1997: "Titanium as an Alternative to Conventional Coiled Tubing: A North Sea Case Study," SPE 38416, presented at the 2nd North American CT Roundtable, Montgomery, Texas, April 1-3.

Cizek, Art, 1997: "Corrosion Effects of Hydrogen Sulfide on Coiled Tubing and Carbon Steel in Hydrochloric Acid," *JPT*, September.

Coats, Alan and Clawson, Greg, 1997: "Coiled Tubing Resin Sand Control in a Gulf of Mexico High Pressure Gas Well," presented at the 5th International Conference on Coiled Tubing and Well Intervention, Houston, February 4-6.

Coats, Alan et al., 1996: "Magnesian Cement, CT Offer Benefits," *The American Oil & Gas Reporter*, March.

Cooper, R. and Head, P., 1997: "Coiled Tubing Deployed ESPs Utilizing Internally Installed Power Cable - A Project Update," SPE 38406, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Courville, Perry W., and Clark, Thomas R., 1995: "Coiled Tubing Completions: An Economic Discussion of Procedures," SPE 29781, presented at the Middle East Oil Technical Conference and Exhibition, Bahrain, March 11-14.

Cox, R. 1996: "Horizontal Underbalanced Drilling in a Sour Gas Carbonate Using Coiled Tubing: A Case Study," SPE 37075, presented at the SPE International Conference on Horizontal Well Technology, Calgary, November 18-20.

Crabtree, A. et al., 1997: "Determining the Mechanical Properties of Coiled Tubing," SPE 38412, presented at the 2nd North American CT Roundtable, Montgomery, Texas, April 1-3.

Donald, D. et al., 1997: "Brent's First Coiled Tubing Drilled Well," *JPT*, June.

Ehret, J.R. et al., 1995: "Re-Defining the Exploration Drilling Technique in the North Sea; The First Step," SPE/IADC 29361, presented at the 1995 SPE/IADC Drilling Conference, Amsterdam, February 2-March 2, 1995.

Elsborg, C. et al., 1996: "High Penetration Rate Drilling with Coiled Tubing," SPE 37074, presented at International Conference on Horizontal Well Technology, Calgary, November 18-20

Elsborg, C.C. et al., 1996: "Large Diameter Coiled Tubing Drilling," SPE 37053, presented at the SPE International Conference on Horizontal Well Technology, Calgary, November 18-20.

Engel, S.P. and Monro, C., 1997: "Coiled Tubing Operations From a Floating Vessel," SPE 38400, presented at 2nd Annual SPE/ICOTA North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Engel, Steve and Sehnal, Zdenek, 1996: "Deploying and Recovering Long and Heavy BHAs in Live High Angle Wells," SPE 36330, presented at 1st Gulf Coast Section/ICoTA North American Coiled Tubing Roundtable, Conroe, Texas, February 26-28.

Falk, K. and Fraser, B., 1995: "Sand Cleanout Technology for Horizontal Wells," presented at 46th Annual Technical Meeting of the Petroleum Society of CIM, Banff, Alberta, Canada, May 14-17.

Falk, Kelly et al., 1996: "Concentric CT for Single-Well, Steam-Assisted Gravity Drainage," *World Oil*, July.

Forgenie, V.H. et al., 1995: "Coiled Tubing Fishing Operations Utilize a First Time Technique to Strip Over and Recover 9500 Feet of Stuck Slickline Wire," SPE 30678, presented at the Annual Technical Conference and Exhibition, Dallas, Texas, October 22-25.

Fowler, Hampton, 1997: "Update on Advanced Composite Spoolable Pipe Developments," SPE 38414, presented at 2nd North American CT Roundtable, Montgomery, Texas, April 1-3.

Fried, S.J. et al., 1997: "Concentric Coiled Tubing for Selective Evaluation and Stimulation," *JPT*, February.

Fried, Spencer et al., 1997: "The Optimized Cleanup And Evaluation of Horizontal Wells Using Improved Jet Pump Technology," CADE/CAODC 97-126, presented at CADE/CAODC Spring Drilling Conference Technical Committee, Calgary, Alberta, Canada, April 8-10.

Frishmuth, R.E. et al., 1996: "Design, Construction, and Use of a Coiled Tubing Drilling Structure for Onshore and Offshore Operations," OTC 8228, presented at the Offshore Technology Conference, Houston, Texas, May 6-9, 1996.

Gaasø, R. et al., 1998: "The First Coiled Tubing Sidetrack in Norway, Gullfaks Field," IADC/SPE 39305, presented at IADC/SPE Drilling Conference, Dallas, March 3-6.

Garner, Ted, and Fleckenstein, Will, and Shelley, Bob, 1995: "Recomplete Deep, Hot Wells Successfully with Coiled Tubing," *Petroleum Engineer Int'l,* June.

Gary, S.C. and Doremus, D.M., 1995: "Technical and Economical Feasibility of Coiled Tubing Drilling," SPE 30490, presented at Annual Technical Conference, Dallas, October 22-25.

Gauthier, Samuel J. and Ducote, Wayne J., 1995: " Spoolable Completions Are Alternative," *The American Oil and Gas Reporter*, September.

Gauthier, Sammy et al., 1997: "Advancements in SPOOLABLE Completions to Accommodate Wireline Operations," SPE 38401, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Gebhardt, Freddy et al., 1996: "Novel Coiled Tubing Application Controls Large LPG Storage Well Fire," *World Oil*, June.

Geddes, Bob and Sola, Sonny, 1997: "The Continuous Drill String Rig 'A Drilling Solution to a Drilling Problem'," paper no. 97-143, presented at CADE/CAODC Spring Drilling Conference, Calgary, April 8-10.

Gleitman, D.D. et al., 1996: "Newly Applied BHA Elements Contribute Towards Mainstreaming of Coiled Tubing Drilling Applications," IADC/SPE 35130, presented at IADC/SPE Drilling Conference, New Orleans, March 12-15.

Goodrich, G.T. et al., 1996: "Coiled Tubing Drilling Practices at Prudhoe Bay," IADC/SPE 35128, presented at IADC/SPE Drilling Conference, New Orleans, March 12-15.

Graham, R., 1995: "Underbalanced Drilling with Coiled Tubing: A Safe, Economical Method for Drilling and Completing Gas Wells," paper 95-16, presented at the 46th Annual Technical Meeting of the Petroleum Society of CIM, Banff, Alberta, May 14-17.

Gray, Benjamin, 1994: "Steering Drill Bit While Drilling a Bore Hole," U.S. Patent No. 5,360,075, November 1, 1994.

Groves, W.G., 1995: "Drilling Using Coiled Tubing and Air," presented at the 3rd Annual North American Conference on Emerging Technologies and Application, Calgary, May 15-16.

Gu, H., 1995: "Transient Aspects of Unloading Oil and Gas Wells With Coiled Tubing," SPE 29541, presented at the Production Operations Symposium held in Oklahoma City, Oklahoma, April 2-4.

Gu, H. and Walton, I.C., 1996: "Designing Under and Near Balanced Coiled Tubing Drilling Using Computer Simulations," SPE 35665, presented at Western Regional Meeting, Anchorage, May 22-24.

Gunningham, M.C. et al., 1997: "Coiled Tubing Drilling case History, Offshore The Netherlands," SPE 38395, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Hallundbæk, Jørgen, 1997: "Reducing Costs With Well Tractors for Horizontal Wells," OTC 7875, presented at 27th Annual OTC, Houston, Texas, May 1-4.

Hearn, D.D. et al., 1996: "Coiled Tubing Window Milling," IADC/SPE 35126, presented at IADC/SPE Drilling Conference, New Orleans, March 12-15.

Hibbert, A. P., et al., 1995: "Effect of Mixing Energy Levels During Batch Mixing of Cement Slurries", SPE 25147, presented at the 1992 Offshore Technology Conference, May 4-7.

Hightower, C.M. 1997: "Operator's Coiled Tubing Drilling Program Gets Good Results," *World Oil*, October.

Hoffman, John G. et al., 1996: "Coiled Pipeline Technology: A Gulf of Suez Case History," SPE 36942, presented at European Petroleum Conference, Milan, October 22-24.

Houpe, Mark W., 1996: "CT-Conveyed Slim Tools Deliver Critical Data In Horizontal Well Bores," *The American Oil & Gas Reporter*, September.

Hrachovy, M. J., et al., 1996: "Case History of Successful Coiled Tubing Conveyed Jet Pump Recompletions Through Existing Completions," SPE 35586, presented at the SPE Western Region Meeting held in Anchorage, Alaska, May 22-24.

Kinnear, M.R. and John, H. 1996: "Repair of a Failed Gas Lift Completion Using a 1500 Ft. Long 3 ½ in. Coiled Tubing Insert Straddle," SPE 36908, presented at the 1996 SPE European Petroleum Conference, Milan, Italy, October.

Klink, Dale R., 1995: "Development of Titanium Coiled Tubing Extends of the Scope of CT Applications," presented at the 3rd Annual International Management Conference on CT, Dallas, February 6-8.

Koper, Mark G.M. et al., 1997: "Full-Scale, Low-Cycle Fatigue Tests with 2-in. Coiled Tubing and Automatic Coiled Tubing Inspection and Monitoring System," SPE 38415, presented at 2nd Annual SPE/ICOTA North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Koshak, W.E. (Skip) and Attah, Mike, 1996: "Acid Stimulation of Openhole Horizontal Section Behind Prepack Screen Using Coiled Tubing and New Isolation Method," SPE 36332, presented at 1st SPE/ICoTA North American Coiled Tubing Roundtable,Conroe, Texas, February 26-28.

Kunkel, Bill, 1997: "Benefits Fuel CT Growth," *Petroleum Engineer International*, July.

Laithy, W.F.El, 1997: "World's First 4.5" Coiled Tubing Pipeline," SPE 37769, presented at Middle East Oil Show, Bahrain, March 15-18.

Larsen, H.A., 1997: "An Operational Overview of the Use of High Pressure Coiled Tubing in the Gulf of Mexico," SPE 38418, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Larsen, H.A. et al., 1997: "Utilizing Coiled Tubing in Mobile Bay's 22,000 TVD Gas Wells Yield Economical and Technical Advancements," SPE 38423, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Larsen, H.A. et al., 1997: "Using Coiled Tubing in HPHT Corrosive Gas Wells," *JPT*, June.

Larson, Eric et al., 1997: "Hybrid Rig Development Aids North Slope CT Operations," *World Oil*, August.

Leising, L.J. et al., 1995: "Sidetracking Technology for Coiled Tubing Drilling," SPE 30486, presented at Annual Technical Conference, Dallas, October 22-25.

Leising, L.J. et al., 1997: "Extending the Reach of Coiled Tubing Drilling (Thrusters, Equalizers, and Tractors)," SPE 37656, presented at 1997 SPE/IADC Drilling Conference, Amsterdam, The Netherlands, March 4-6.

Leising, L.J. et al., 1998: "Cuttings Transport Problems and Solutions in Coiled Tubing Drilling," IADC/SPE 39300, IADC/SPE Drilling Conference, Dallas, March 3-6.

Leismer, Dwayne et al., 1996: "Coiled Tubing Drilling: Real Time MWD with Dedicated Powers to the BHA," OTC 8227, presented at Offshore Technology Conference, Houston, May 6-9.

Leslie, Charlie, 1996: "Coiled Tubing Butt Weld Recommendations," *The Brief*, February.

Lizak, et al., 1996: "Coiled Tubing Workover Saves Horizontal Well in Lake Maracaibo," OTC 8224, presented at the Offshore Technology Conference held in Houston, Texas, May 6-9.

Lord, David et al., 1997: "Shell Expro's First Application of Coiled Tubing Drilling," presented at 5th International Conference on Coiled Tubing and Well Intervention, Houston, February 4-6.

Love, Douglas et al., 1997: "Coiled Tubing Injection-Well Cleanouts with Tapered-OD Strings," SPE 38420, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Loveland, K.R., and Bond, A.J., 1995: "Recent Applications of Coiled Tubing in Remedial Wellwork at Prudhoe Bay," SPE 35586, presented at the SPE Western Regional Meeting held in Anchorage, Alaska, May 22-24.

Luft, H.B. et al., 1995: "Development and Operation of a New Insulated Concentric Coiled Tubing String for Continuous Steam Injection in Heavy Oil Production," SPE 30322, presented at SPE International Heavy Oil Symposium, Calgary, June 19-21.

Maddox, Steve and Gibling, Glen R., 1995: "Downhole Video Services Enhance Conformance Technology," OTC 7872, presented at 27th Annual OTC, Houston, Texas, May 1-4.

Maroli, R. et al., 1996: "Development of HPHT Coiled Tubing Unit," SPE 35561, presented at European Production Operations Conference, Stavanger, April 16-17.

McCann, R.C. and Islas, C.G., 1996: "Frictional Pressure Loss During Turbulant Flow in Coiled Tubing," SPE 36345, presented at the 1st SPE/ICoTA North American Coiled Tubing Roundtable, Montgomery, Texas, February 26-28.

McGregor, B. et al., 1997: "Application of Coiled Tubing Drilling Technology on a Deep Underpressured Gas Reservoir," SPE 38397, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Milligan, M. et al., 1996: "Coiled Tubing Drilling of Horizontal Sidetrack in House Mountain Field, Alberta," IADC/SPE 35127, presented at IADC/SPE Drilling Conference, New Orleans, March 12-15.

Miska, Stefan, et al., 1996: "An Improved Analysis of Axial Force Along Coiled Tubing in Inclined/Horizontal Wellbores," SPE 37056, presented at the 1996 SPE International Conference on Horizontal Well Technology held in Calgary, Canada, November 18-20.

Moon, R.G. et al., 1996: "Shallow Gas Well Drilling with Coiled Tubing in the San Juan Basin," SPE 36463, presented at the SPE Annual Technical Conference and Exhibition, Denver, October 6-9.

Morrison, Dan et al., 1997: "High Pressure Coiled Tubing Job Prepares Gulf Coast Well," SPE 38419, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Munro, C. et al., 1996: "Well Plugging Operations in West of Shetland Horizontal Wells Using Coiled Tubing Techniques," SPE 36909, presented at SPE European Petroleum Conference, Milan, October 22-24.

Newman, Ken, 1998: "Coiled Tubing Technology Continues its Rapid Growth," *World Oil*, January.

Newman, K.R., and Fowler, H., 1996: "Computing Collapse Pressure for Coiled Tubing," SPE 36340, presented at the Annual Technical Conference, Dallas, Texas, October 22-25.

Newman, K.R. et al., 1995: "Development of a Coiled Tubing Cable Installation System," SPE 30679, presented at SPE Annual Technical Conference & Exhibition, Dallas, Texas, October 22-25.

Newman, K.R. et al., 1996: "Analysis of Coiled Tubing Welding Techniques," ICOTA 96007, presented at 1st Annual SPE/ICOTA North American Coiled Tubing Roundtable, Conroe, Texas, February 26-28.

Newman, K.R. et al., 1996: "The Feasibility of Using and Electric Downhole Motor to Drill with Coiled Tubing," SPE 36343, presented at 1st North American Coiled Tubing Roundtable, Conroe, Texas, February 26-28.

Newman, K.R. et al., 1997: "Elongation of Coiled Tubing During Its Life," SPE 38408, presented at 2nd Annual SPE/ICOTA North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3

Ng, R.C. and Adisa, O.L., 1997: "Coiled Tubing Resin Squeeze to Mitigate Water Production in Offshore Gravelpack Wells," SPE 38836, presented at Annual Technical Conference, San Antonio, Texas, October 5-8.

Noles, Jerry, et al., 1996: "Small-capacity Cement Procedure Reduces Failure Potential," *World Oil* May.

Nowak, T.W. and Patout, T.S., 1997: "Rigless Multizone Recompletion Using a Cement Packer Placed with Coiled Tubing: A Case History," *SPE Drilling & Completion*, December.

Nowak, T.W., et al., 1995: "Shut-off of a Geopressured Water Channel Behind Casing via Coiled Tubing Utilizing a Dual Slurry Cement System," SPE 29474, presented at the Production Operations Symposium held in Oklahoma City, Oklahoma.

Nowak, T.W., and Patout, T.S., 1996: "Rigless Mutlizone Recompletion Using a Cement Packer Placed With Coiled Tubing: A Case History," SPE 35613, presented at the 1996 SPE Gas Technology Conference held in Calgary, 28 April - 1 May.

O'Connell, Tim et al., 1997: "Flexible Plungers Resolve CT, Slim Hole Problems," *The American Oil & Gas Reporter*, January.

Ostvang, Knut and Haukvik, John, 1997: "World's First Successful Horizontal Wireline Tractor Operations," presented at 5th International Conference on CT and Well Intervention, Houston, February 4-6.

Palmer, R et al., 1995: "Developments in Coiled Tubing BOP Ram Design," presented at the 27th Annual OTC, Houston, Texas, May 1-4, 1995.

Pedersen, Knut et al., 1997: "Multilateral Branch Drilling Through Tubing, with Coiled Tubing Drilling, Planned for Snorre Field, Snorred TLP (Tension Leg Platform) In North Sea, Norway," presented at 5th International Conference on Coiled Tubing and Well Intervention, Houston, February 4-6.

PEI Staff, 1996: "Stuck Coiled Tubing Spawns New Fishing Tool," *Petroleum Engineer International*, March.

PEI Staff, 1996: "Straightener Extends CT Reach," *Petroleum Engineer International,* May.

PEI Staff, 1997B: "Electric Release Improves Coiled Tubing Operations," *Petroleum Engineer International*, June.

PEI Staff, 1997: "Coiled Tubing: Turning it to the Right," *Petroleum Engineer International*, September.

Pitman, Malcolm et al., 1997: "Casing Exit Techniques Using Coiled Tubing: Worldwide Case Histories," SPE 38428, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Plauche, Ricky and Koshak, W.E., 1997: "Advances in Sliding Sleeve Technology and Coiled Tubing Performance Enhance Multizone Completion of Abnormally Pressured Gulf of Mexico Horizontal Well," SPE 38403, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Quigley, P.A. et al., 1997: "Development and Application of a Novel Coiled Tubing String for Concentric Workover Services," OTC 8456, presented at Offshore Technology Conference, Houston, May 5-8.

Reaper, Alan, 1997: "Development and Application of Inline Connectors for Weight Restricted Offshore Operations," SPE 38424, presented at 2nd North American CT Roundtable, Montgomery, Texas, April 1-3.

Rice, Bill, 1995: "Imperial Oil Resources Limited Coiled Tubing Drilling Experience," paper 95-903, presented at CADE/CAODC Spring Drilling Conference, April 19-21.

Robberechts, Hilde and Blount, Curtis, 1997: "A New Generation of Drag Reducer Additives Hydrocarbon Based CT Applications," presented at 5th International Conference on Coiled Tubing and Well Intervention, Houston, February 4-6.

Rommetveit, Rolv et al., 1995: "A Dynamic Model for Underbalanced Drilling with Coiled Tubing," SPE/IADC 29363, presented at SPE/IADC Drilling Conference, Amsterdam, February 28-March 2.

Rosen, P.M.A., 1997: "Coiled Tubing Integrity Monitoring During Operations," *World Oil*, December.

Sas-Jaworsky, Alex, 1996: "High-Pressure Applications Enabled by CT Advances," *The American Oil & Gas Reporter,* January.

Sas-Jaworsky, Alex, 1996: "New Offshore Applications Offer Value-Adding Utility," *The American Oil & Gas Reporter*, February.

Sas-Jaworsky, Alex, 1997: "New Guidelines Should Enhance Coiled Tubing Well Control Security," *World Oil*, December.

Sas-Jaworsky, Alex and Bell, Steve, 1996: "Innovative Applications Stimulate CT Development," *World Oil*, June.

Sas-Jaworsky, Alex and Reed, Troy, 1997: "Fluid Hydraulics Behavior in Coiled Tubing Operations — A Nodal Analysis Approach," presented at the World Oil Coiled Tubing & Well Intervention Conference, Houston, February 4-6.

Sas-Jaworsky, Alex and Reed, Troy, 1997: "Predicting Friction Pressure Losses in Coiled Tubing Operations," *World Oil*, September.

Sehnal, Z. et al., 1997: "Coiled Tubing Gravel Pack: Planning, Execution, and Verification," *JPT*, February.

Selby, Bruce et al., 1998: "Hybrid Coiled Tubing System for Offshore Re-entry Drilling and Workover," IADC/SPE 39374, presented at IADC/SPE Drilling Conference, Dallas, March 3-6.

Sherwin, Thomas et al., 1996: "Well Completions in the Middle East Using 3½-inch OD Coiled Tubing: Case Study Evaluation," SPE 36138, presented at Asia Pacific Oil & Gas Conference, Adelaide, Australia, October 28-31.

Sjonberg, Geir, 1997: "Coiled Tubing Drilling: Successful Drilling Offshore in the North Sea," presented at 5th International Conference on Coiled Tubing and Well Intervention, Houston, February 4-6.

Smith, Larry, and Misselbrook, John, 1997: "An Overview of Injection Technology and Criteria for Inspecting Coiled Tubing," SPE 38423, presented at the 2nd North American CT Roundtable, Montgomery, Texas, April 1-3.

Smith, M.I. and Brown, R., 1997: "Deployment of a Coiled-Tubing Gas-Lift Completion," *JPT*, October.

Sorrell, Dean and Miller, Ron, 1997: "Coiled Tubing CO_2 Gas Lift Evaluated in West Texas," *World Oil*, January.

Stanley, Roderic, 1997: "Failures in Coiled Tubing," presented at 5th International Conference on Coiled Tubing and Well Intervention, Houston, February 4-6.

Stanley, Roderic, 1998: "An Analysis of Failures in Coiled Tubing," IADC/SPE 39352, presented at IADC/SPE Drilling Conference, Dallas, March 3-6.

Stephens, R.K. et al., 1996: "Lessons Learned on Coiled Tubing Completions," SPE 35590, presented at SPE Western Regional Meeting, Anchorage, Alaska, May 22-24.

Strickland, David, 1997: "Concentric Workovers in a Well Recovery Operation," presented at the 5th International Conference on Coiled Tubing and Well Intervention, Houston, February 4-6.

Surewaard, J. et al., 1997: "One Year Experience with Coiled Tubing Drilling," SPE/IADC 39260, presented at Middle East Drilling Technology Conference, Bahrain, November 23-25.

Tait, Howard, 1995: "Coiled Tubing Jet Pump for Extended Reach Horizontal Well Cleanups," presented at 3rd Annual Conference on Emerging Technology – CT-Horizontal, Aberdeen, Scotland, May 31-June 2.

Taylor, Robert W. and Conrad, Bruce, 1996: "Specialized Equipment Enabled Completions with Large Coiled Tubing," *Oil and Gas Journal*, February.

Thorby, Helge, 1995: "Underbalanced Drilling with Coiled Tubing—A Reference of Work to Date," presented at 3rd Annual Conference on Emerging Technology, Aberdeen, May 31-June 2.

Tipton, Steven M. 1997: "Low-Cycle Fatigue Testing of Coiled Tubing," presented at 5th International Conference on Coiled Tubing and Well Intervention, Houston, February 4-6.

Tipton, Steven M., 1997: "Surface Characteristics of Coiled Tubing and Effects on Fatigue Behavior," SPE 38411, presented at 2nd Annual SPE/ICOTA North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Townsend, Steve et al., 1997: "Evaluation of Through Tubing Whipstock System to Exit Both 7-in. and 9⅝-in. Casing Strings Using Coiled Tubing," presented at 5th International Conference on Coiled Tubing and Well Intervention, Houston, February 4-6.

Tovar, Juan J., and Head Philip F., 1995: "Technical and Economic Considerations for CT Deployed ESP Completions," presented at the Third Annual Conference on Emerging Technology — CT-Horizontal, Aberdeen, Scotland, May 31 - June 2.

Tran, T.B. et al., 1997: "Field Installed Coiled Tubing Gas Lift Completions," SPE 38404, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

Turton, S.D. et al., 1997: "Using Coiled Tubing to Remove Silicate Scale from Geothermal Wells," SPE 38417, presented at 2nd North American Coiled Tubing Roundtable, Montgomery, Texas, April 1-3.

van Adrichem, W.P. et al., 1995: "Development and Utilization of a Coiled Tubing Equipment Package for Work in High Pressure Wells," OTC 7874, presented at 27th Annual OTC, Houston, May 1-4.

Walton, I.C., 1997: "Real-Time Well-Site Monitoring and Evaluation of Coiled Tubing Cleanouts," SPE 37508, presented at SPE Production Operations Symposium, Oklahoma City, March 9-11.

Waguespack, Sonny et al., 1996: "A 2 3/8-in. Coiled-Tubing Recompletion in the Gulf of Mexico," SPE 36334, presented at 1st SPE/ICoTA North American Coiled Tubing Roundtable, Houston, Texas, February 26-28.

Watkins, Paul, and Stewart, David, 1996: "Coiled Tubing Deployed ESP Works Well for Shell in North Sea Field," *World Oil,* June.

Weighill, Geoff and Thoreby, Helge, 1996: "Underbalanced CT Drilling Success on Ula," *BP Downhole Talk*, Issue 55, February.

Weighill, G. et al., 1996: "Underbalanced Coiled Tubing Drilling Experience on the Ula Field," SPE 35544, presented at European Production Operations Conference, Stavanger, Norway, April 16-17.

Yang, Yong, 1996: "Collapsed and Burst Pressure of Coiled Tubing Under Axial Load, and Bending Torque and Strain Energy in Spooling CT," SPE 36338, presented at the 1st SPE/ICoTA North American Coiled Tubing Roundtable, Montgomery, Texas, February 26-28.

Zimmerman, J.C. et al., 1997: "High-Pressure Coiled-Tubing Technology Solves Resin-Sand-Control Problems," *JPT*, June